STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Agency	**:**	
	:	
Petition for Approval of the IPA's 2024	**:**	**23-0714**
Long-Term Renewable Resources	**:**	
Procurement Plan Pursuant to Section	**:**	
16-111.5(b)(5)(ii) of the Public Utilities Act.	**:**	

ORDER

February 20, 2024

Table of Contents

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By the Commission:

I. PROCEDURAL HISTORY

On October 20, 2023, the Illinois Power Agency ("IPA" or "Agency") filed with the Illinois Commerce Commission ("Commission") a verified Petition for Approval of its 2024 Long-Term Renewable Resources Procurement Plan ("LTRRPP," "Plan," or "2024 Plan") pursuant to Section 16-111.5(b)(5)(ii) of the Public Utilities Act ("PUA" or "Act"). 220 ILCS 5/16-111.5(b)(ii). The 2024 Plan is the IPA's proposal for the procurement of renewable energy credits ("RECs") for Ameren Illinois Company d/b/a Ameren Illinois ("Ameren" or "AIC"), Commonwealth Edison Company ("ComEd"), and MidAmerican Energy Company ("MidAmerican") under Sections 1-56(b) and 1-75(c) of the Illinois Power Agency Act (20 ILCS 3855/1-56(b) and 1-75(c)) ("IPA Act") and Section 16-111.5(b)(5) of the PUA. Section 16-111.5(b)(5)(ii)(C) of the PUA requires the Commission to enter its Order "confirming or modifying" the Plan within 120 days after this filing, or February 20, 2024.

The Administrative Law Judges ("ALJs") granted the following Petitions to Intervene: Solar Energy Industries Association, the Coalition for Community Solar Access, and the Illinois Solar Energy Association (collectively, the "Joint Solar Parties" or "JSPs"); Clean Grid Alliance ("CGA"); LiveWire Electrical Systems, Inc., LiveWire Energy, Inc., and Blackrock Construction Services LLC (collectively, "LiveWire"); Ameren; ComEd; SunVest Solar LLC; Solar Landscape LLC ("Solar Landscape"); Equity Solar Illinois LLC ("ESI"); Direct Energy Business LLC, Direct Energy Services LLC, Direct Energy Business Marketing LLC, Energy Plus Holdings LLC, Green Mountain Energy Company, NRG Energy, Inc., Reliant Energy Northwest LLC d/b/a NRG Residential Solutions d/b/a NRG Retail Solutions d/b/a NRG Business d/b/a Reliant-NRG d/b/a NRG Business Solutions d/b/a Reliant d/b/a Reliant Energy, Stream Energy Illinois, LLC, and XOOM Energy, LLC (collectively, the "NRG Companies"); Natural Resources Defense Council; Environmental Law & Policy Center and Vote Solar, jointly (collectively, the "Joint NGOs" or "JNGOs"); Advanced Energy United ("AEU"); Summit Ridge Energy, LLC ("Summit Ridge"); Hawk-Atollo, LLC ("Hawk"); the Illinois Manufacturers' Association ("IMA"); and 22c Development, LLC ("22c"). Staff of the Commission ("Staff") participated in this proceeding as well.

Objections were filed on or about November 3, 2023, by the following parties: LiveWire, Joint Solar Parties, CGA, ComEd, Ameren, the NRG Companies, Solar Landscape, ESI, and the Joint NGOs. In their Objections, the NRG Companies requested that a hearing be held. The ALJs denied that request on November 13, 2024.

Responses to Objections were filed on or about December 1, 2023, by the following parties: the IPA, the NRG Companies, ESI, IMA, the Joint NGOs, CGA, ComEd, Staff, Summit Ridge, AIC, Hawk, AEU, and the Joint Solar Parties. Replies to Responses were filed on December 15, 2024, by the following parties: the NRG Companies, the Joint NGOs, IMA, the IPA, CGA, LiveWire, ESI, ComEd, Joint Solar Parties, AIC, and Staff.

The Proposed Order ("PO") was served on January 16, 2024. On or about January 26, 2024, Briefs on Exceptions ("BOEs") were filed by Ameren, Staff, AEU, ComEd, NRG Companies, 22c, the IMA, the IPA, LiveWire, the Joint NGOs, ESI, the Joint Solar Parties, and Summit Ridge. On February 5, 2024, Reply Briefs on Exceptions ("RBOEs") were filed by the IPA, Staff, AEU, Ameren, Hawk, ComEd, 22c, ESI, the Joint NGOs, LiveWire, the IMA, NRG Companies, and the Joint Solar Parties.

ESI and NRG Companies requested oral argument in their BOEs. No other party requested oral argument. The IPA and the Joint Solar Parties responded to ESI's and NRG Companies' requests for oral argument in their RBOEs. The Commission denied the request for oral argument on February 8, 2024.

II. CHAPTER 4. RENEWABLE ENERGY CREDIT ELIGIBILITY

A. Section 4.2. REC Eligibility

1. CGA's Position

CGA suggests minor edits to Condition 2 described in Section 4.2. Condition 2 describes penalties that can be imposed pursuant to subsection 1-75(c)(1)(J) of the IPA Act. CGA's proposed edits clarify to whom the penalties may be assessed, because CGA states that the language in Condition 2 is ambiguous and overly broad. CGA Obj. at 3.

Condition 2 states the following:

> P.A. 99-0906 introduced a new standard related to how generating units recover their costs. This standard not only prohibits the use of RECs from generating units that recover their costs through state-regulated rates, but also assesses penalties for RECs from systems later found to be non-compliant.

LTRRPP at 83. The last phrase – "but also assesses penalties for RECs from systems later found to be non-compliant" – could be understood as an assertion that the IPA has authority to assess penalties on a generating unit that is found to be non-compliant with any provision of the IPA Agency Act or its contracts. CGA Obj. at 3.

Condition 2 describes the scope of Section 1-75(c)(1)(J). CGA explains that Section 1-75(c)(1)(J) prohibits RECs from being eligible for the Illinois Renewable Portfolio Standard ("RPS") "if they are sourced from a generating unit *whose costs were being recovered through rates* regulated by this State or any other state or states on or after January 1, 2017." 20 ILCS 3855/1-75(c)(1)(J) (emphasis added). This is a specific exclusion that is narrowly limited to those generating units whose capital costs are recovered through utility rates. CGA states that this limitation is captured in the beginning of the second sentence of Condition 2, but not in the phrase after the comma in the second sentence. CGA Obj. at 4.

CGA recommends an edit to Condition 2 that clarifies that Section 1-75(c)(1)(J) only allows penalties to be applied to generating units whose costs are being recovered through rates regulated by Illinois or any other state.

CGA proposes the following edits to Section 4.2:

> P.A. 99-0906 introduced a new standard related to how generating units recover their costs. This standard not only prohibits the use of RECs from generating units that recover their costs through state-regulated rates, but also assesses penalties for RECs from ~~systems~~ said generating units that are later found to be non-compliant.

CGA Obj. at 4.

CGA does not object to Staff's proposal to change CGA's edit from "said generating units" to "such generating units." CGA Rep. at 12.

2. Staff's Position

While Staff believes the LTRRPP is clear that the IPA Act only authorizes penalties with respect to facilities providing RECs from systems whose costs are recovered through state-regulated rates, Staff supports CGA's proposed edit with one slight modification. Staff recommends replacing the word "said" with "such." "Said" means "mentioned earlier" whereas "such" means "of this kind." According to Staff, the use of the word "such" seems a better fit in the Plan here. Staff Resp. at 10-11.

3. IPA's Position

The IPA explains that Condition 2 of Section 4.2 provides a brief explanation of the prohibition from Section 1-75(c)(1)(J) of the IPA Act against utilizing RECs from rate-based projects to meet the RPS, stating that subparagraph (J) "assesses penalties for RECs from systems later found to be non-compliant." LTRRPP at 83. The IPA believes that this minor edit suggested by CGA would not change the application of the condition, and that the edit is reasonable and will better clarify which entities would be penalized for noncompliance. The Agency agrees to make this edit in the final version of the 2024 Plan. IPA Resp. at 4.

The Agency believes that Staff's edit to change "such" to "said" in this context refers to the generating units in the earlier part of the sentence, whereas "such" is a more general term that does not refer to the generating units in the earlier part of the sentence. As it is, the IPA states that CGA's proposed language - "said" - is more consistent with the intent of that condition, the Agency asks the Commission to approve CGA's minor edit to Section 4.2 to reference "said generating units are" in the last phrase of the second condition. IPA Rep. at 4-5.

4. Commission Analysis and Conclusion

Although the Commission does not see the LTRRPP's original language to be unclear, it could be improved. The Commission agrees that "generating units" is more specific than "systems." Moreover, the identified lack of clarity is that the LTRRPP language could be read to allow penalties in a broader scope of situations than intended. The Commission does not see that "said" or "such" necessarily clears up the perceived problem. Accordingly, Condition 2 should be modified as follows:

> This standard not only prohibits the use of RECs from generating units that recover their costs through state-regulated rates, but also assesses penalties for RECs from generating units ~~systems~~ later found to recover their costs through state-regulated rates~~be non-compliant~~.

III. CHAPTER 5. COMPETITIVE PROCUREMENTS

A. Section 5.4.8. Post-Award Contract Changes

1. CGA's Position

CGA supports the IPA's proposal to develop a process for post-award changes to Indexed REC contracts. CGA objects, however, to the proposed length of time for workshops – nearly one year -- to explore this issue. CGA Obj. at 4. CGA recommends the workshop process be reduced to 6 months. This should allow for a bid adjustment mechanism to be in place for the Summer 2024 competitive REC procurement and limit the premium for unexpected costs to the Fall 2023 procurement. CGA Obj. at 8.

The IPA has indicated at least seven topics that should be explored in the workshops to jumpstart the process. LTRRPP at 115-116. Most of those topics focus on process, such as what are the requirements to request a price adjustment, what project development timelines should be considered, and whether minimum fees or increased collateral should be required. CGA opines that these topics should not be contentious and may be easily resolved. The timeline can also be reduced by using a standard formula that is transparent and public for calculating the price adjustment. For instance, the IPA can build on a proposal recently considered by the New York Public Service Commission ("NY PSC"). In that case an advocate for renewable energy developers hired a consultant who prepared a formulaic bid adjustment mechanism that was based on market factors and public data. CGA notes that the NY PSC, in October of this year, rejected the filing as well as three other post-award bid adjustment mechanisms that were proposed by other parties. While the NY PSC rejected these formulaic approaches, the NY PSC's concerns would be mollified if not remedied by the IPA's proposal and the process the IPA uses for competitive bidding. Order Denying Petitions Seeking to Amend Contracts with Renewable Energy Projects at 40-43 (Oct. 12, 2023) ("NY PSC Order"); CGA Obj. at 5-7.

CGA further opines that the issues identified by the Agency can largely be addressed through written comments, so as to minimize the number of workshop meetings. Written comments are routine for the IPA. The IPA uses the same process for modifying the Indexed REC Contracts, which was a process that was held in Fall 2023 and took less than two months – draft document posted August and final contract posted on September. CGA Rep. at 4-5.

CGA agrees with the IPA that the integrity of the initial bids needs to be maintained, but the IPA overlooks the beneficial impact to the RPS Budget that a post award mechanism can provide to procurements in 2022, 2023, and 2024 if the workshops can be done in a shorter period of time. As explained in the LTRRPP, recent volatile market conditions have substantially increased the cost of development and construction, "making projects potentially uneconomic at the awarded Strike Price." LTRRPP at 115. The winners of the 2022 and 2023 procurements are at risk of having uneconomic Strike Prices and may need to default on the contract due to recent inflation and volatile supply chains. The sooner a post-award mechanism process is in place the greater the likelihood that Sellers will take advantage of the adjustment and avoid any potential default. Any default has negative impacts, in that the bidder may be suspended from participating in future procurements, which reduces competition, and Illinois will fall behind in achieving the clean energy goals of Public Act ("P.A.") 102-0662. CGA argues that a post-award mechanism has the potential to encourage more developers to participate in the procurements which could result in more competition and lower prices. CGA Rep. at 2-3.

In response to ComEd's assertion that parties will be negotiating contract terms in the workshops and therefore more time is needed for the workshops, CGA states that the workshops are not intended to be an actual re-negotiation of contracts but to establish a process an Indexed REC Seller can use to have key contract terms adjusted. CGA Rep. at 7.

In response to Staff's statement that it sees no need to rush this issue in-between LTRRPP filings, CGA notes that Staff did not respond to CGA's arguments that the post-award mechanism will reduce the burden on the RPS Budget by reducing the number of projects that add a premium to their bid price in an attempt to manage market volatility and uncertainty. Furthermore, the post-award adjustment is needed to help those existing Indexed REC contract holders who are experiencing dramatic increases due to changes in their project costs resulting from problems with supply chain and the increase in costs of goods and services between 2020 and October 2023. CGA Rep. at 8.

CGA further argues that a post-award bid adjustment mechanism will help competitive procurement bidders better accommodate unexpected market changes that are outside of the developer's control and can increase a project's capital costs between the bid submission and actual start of construction. Without a post-award bid adjustment mechanism, developers will need to add a premium to the bid price to account for potential unexpected market forces, which can be difficult to predict or estimate. Until a post-award bid price mechanism is known and approved, bidders will continue to include a premium to account for unexpected costs. CGA anticipates that the post-award bid adjustment will allow bidders to submit bids that are closer to a project's capital costs plus profit, with no adder for unexpected market conditions. CGA Obj. at 5.

CGA states that the IPA approaches this key change to the contract process in a balanced manner which is consistent with the PUA. The PUA sets forth the requirements of a competitive procurement plan – for both electric supply and RECs. 220 ILCS 5/16-

111.5(b)(1) - (5). The introductory paragraph to both types of procurements indicates that a competitive procurement is the default process "unless specified otherwise in this Section [of the statute], in the procurement plan or in the implementing tariff . . ." 20 ILCS 5/16-111.5(b). Therefore, the PUA allows the IPA to propose something different through the "procurement plan." CGA Resp. at 2-3.

CGA states that if the IPA is to deviate from a competitive procurement, the proposal must be approved by the Commission. The Commission must find that the proposal is designed to achieve the goals of the RPS, 220 ILCS 5/16-111.5(b)(5)(ii)(B)(aa), and that the proposal reasonably and prudently accomplishes the requirements of the RPS in Section 1-75 of the IPA Act, 220 ILCS 5/16-111.5(b)(5)(ii)(D). The IPA's proposal to consider post-award changes is intended to achieve the goals of the RPS. The purpose of the proposal is limited in nature – to address recent volatile market conditions that have dramatically increased project costs between the time of bid and the time of a project being placed in service. LTRRPP at 115. Both the industry and the country have experienced dramatic price increases due to increases in supply costs and inflationary pressures. The recent increase in costs related to these two factors makes most utility-scale wind and solar projects uneconomic under their submitted bids. Another reason to allow post-award contract adjustment is the impact it has on bidder's ability to participate in future Indexed REC procurements. If a project is uneconomic and has to default on its awarded contract for economic reasons, they potentially face a two-year suspension from Indexed REC procurements, which would be a penalty for reasons outside the developer's control. The IPA's post-award adjustment proposal is to ensure that existing contracts can be maintained, so the Illinois renewable energy market can be maintained, and that developers are not unjustly punished. CGA avers that those are reasonable and prudent positions. CGA Resp. at 3-4.

CGA notes that ComEd hypothesizes that a winning bidder would have undercut other bidders during the procurement phase and then press for a higher bid price in a post-award adjustment. The only way a bidder could press for a higher bid price is through negotiations. The PUA's procurement process only allows negotiations during a narrow window of time. The procurement process only allows the procurement administrator to negotiate a new bid price within 24 hours of the bid being submitted. 220 ILCS 5/16-111.5(c)(1)(vii) and (e). Furthermore, CGA does not support a post-award adjustment mechanism that is negotiated. While the actual post-award adjustment mechanism or process is not before the Commission at this time, CGA supports a post-award contract adjustment mechanism that is limited to changing the bid price using a transparent and reasonable formula. The formula would be comprised of specific factors impacting a bid price and are likely to change based on current market volatility. For example, the average cost of solar panels in the market would be a factor in the formula, because an increase in that component directly impacts the bid price. CGA does not support post-award contract adjustments through negotiation. CGA Resp. at 4-5.

It would be imprudent for a bidder to undercut other bidders with the hope of a higher price in the future. The purpose of this post-award mechanism is to enable the bidders to achieve the goals of the RPS, 220 ILCS 5/16-111.5(b)(5)(ii)(B)(aa), in a reasonable and prudent way, 220 ILCS 5/16-111.5(b)(5)(ii)(D). The post-award mechanism should account for an unexpected volatile market impacting REC bidders' material costs and financing. A bidder that pursues the strategy proffered by ComEd -- attempting to undercut other bidders during the procurement -- is being speculative and risky. CGA Resp. at 5.

ComEd "interprets CGA's proposal as allowing unlimited post-award changes to REC Contracts not only in scope but also as to when those changes are made." ComEd Rep. at 2. ComEd also argues that CGA does not respond to the IPA's statement that they need to identify the specific assumptions that warrant a change in the downstream contract price, how those assumptions can be fairly demonstrated. CGA states that it intends to provide a full proposal during the workshop process proposed by the Agency. CGA Rep. at 5.

ComEd also argues that the IPA's proposal does not grant the utility the ability to request a renegotiation of the contract based on changed circumstances. Under the structure of the RPS, the utility is not harmed. The utility is not financially at risk. The utility does not need to seek rate recovery for the money spent to purchase competitive RECs, because the RECs are paid from the RPS Budget that is funded through a legislatively approved and statutorily defined charge. 220 ILCS 5/16-111.5(i) and (l); *see also* 220 ILCS 5/16-108(k); CGA Resp. at 6-7.

ComEd also argues that a post-award bid price adjustment seeks a guaranteed return for the REC Seller outside of the competitive bidding process set forth in the PUA and could increase REC Budget uncertainty. CGA acknowledges that a change in bid price would impact the RPS budget; however, the purpose of the post-award changes proposed by the IPA is to promote and protect the IPAs competitive procurement methodology from forces outside of the bidders' control. To not take steps to protect the bids and bidders from market forces outside of a bidder's control sends a negative signal to renewable developers about Illinois' REC market. CGA Resp. at 7-8.

CGA points out that ComEd also argues that a REC Seller can voluntarily terminate a contract without a suspension. As support, ComEd points to a procurement Frequently Asked Questions ("FAQ") that states that "Suppliers may voluntarily terminate contract, forfeit collateral, and resubmit the same project in a subsequent Indexed REC RFP." ComEd Resp. at 3. Despite the ability to resubmit a project in a subsequent REC procurement, the termination of an Indexed REC contract still comes at the cost of forfeiting the collateral, which can be millions of dollars. Furthermore, the post-award adjustment is intended to minimize the likelihood of this very thing occurring and is intended to support the RPS procurement program. CGA Rep. at 6.

In response to Staff's statement that if the Commission allows workshops on this topic, that the final Order in this docket should clearly state that authorizing workshops should not be construed as implying that the Commission is in favor of allowing post-award contract changes if the Agency, or any other party, proposes them in the next LTRRPP. CGA agrees with that position. CGA Rep. at 7-8.

NRG asserts that any contract change should avoid negatively impacting the level of certainty of the rebate realized by Self-Direct Customers. The contract changes are not known at this time and this issue can and should be considered within the proposed workshops. Further, the issue can be raised before the Commission when the post-award contract change proposal is brought to the Commission for review and approval. CGA Rep. at 8-9.

2. ComEd's Position

ComEd notes that Section 5.48 of the LTRRPP discusses the possibility of allowing post-award changes to REC Contracts. The LTRRPP does not adopt that concept, but it proposes workshops with a strong implication that some form of the idea will be adopted. Post-award changes to REC Contracts, especially to material terms including quantities and pricing, as the LTRRPP correctly states, "could damage the integrity of the initial competitive bidding process." LTRRPP at 115; ComEd Obj. at 5.

ComEd argues that a bidding process in which the winning bidder can count on the possibility of changing its price (or quantity) not only after the bidding but even after the counter-party (here, the utility) has signed the contract is an extraordinary and dangerous way to run (or circumvent) a competitive bidding process. For example, a winning bidder who undercut losing bidders during the bidding process later on could press for a price higher than the losing bids. Making the signed contract between the winning bidder and the utility a nullity or not really a final agreement is a grave departure from the most basic principles of contracting. Moreover, the contemplated process appears to be entirely one-sided. It does not appear that a utility could seek to renegotiate quantities or pricing based on changed circumstances. The Indexed REC pricing structure already provides revenue certainty to the projects at the expense of increased REC budget uncertainty. The request to alter material terms such as price post bid is akin to seeking a guaranteed return outside of the competitive bidding process and further increase REC budget uncertainty. ComEd Obj. at 6.

ComEd states that the contemplated process also appears to be contrary to law. The Commission approves not only the LTRRPP as such (220 ILCS 5/16-111.5(b)) but also, among other things, standard contract terms and, perhaps most importantly here, the results of procurements conducted by the IPA so that the contracts that resulted from the procurement then can be signed by the winning bidders and the utilities (220 ILCS 5/16-111.5(e) - (i)). Post-award negotiations have no place in that statutory process, and they would alter or circumvent the Commission's authority. Having workshops on this concept, therefore, would not be a productive use of time or resources, even more so if the discussions were to be conducted with an expectation of leading to adoption of some form of the concept. ComEd Obj. at 6.

If the Commission nonetheless determines that workshops are appropriate in this instance, ComEd recommends the Commission should make clear that: (1) any proposed outcome must be consistent with the PUA and the IPA Act, including but not limited to the Commission's statutory role; (2) the IPA should manage and be the decision-maker in the change process, similar to its role in all other substantive pre-contract REC procurement activities (*see, e.g.*, LTRRPP, Section 5.1 on the IPA's role in past procurements); (3) post-contract changes should not include material terms, in particular quantities and pricing, the elements fundamental to the competitive bidding process; and (4) any ability to renegotiate terms should be bilateral. ComEd Obj. at 7.

ComEd, therefore, also opposes the proposal from CGA, which seeks to reduce the duration of the workshops to no more than six months. ComEd interprets CGA's proposal as allowing unlimited post-award changes to REC Contracts not only in scope but also as to when those changes are made. CGA appears to believe its broad proposal is necessary to address myriad issues that may impact a project during the time between when a contract is awarded and a project is energized. CGA believes that, unless a post-award bid price mechanism is known and approved, bidders will continue to include a premium to account for unexpected costs. ComEd Resp. at 2.

ComEd notes that CGA does not directly mention, much less respond to, the LTRRPP's recognition that: "Without strict parameters around which specific changed assumptions would warrant a downstream contract price adjustment, how those changed assumptions can be fairly demonstrated, and through what process, allowing post-award negotiation could damage the integrity of the initial competitive bidding process." LTRRPP at 115. ComEd agrees that parameters are needed to allow the IPA and buyers to evaluate whether requests for post-award changes are warranted based on project needs or are based on evaluations of market conditions such as more attractive REC prices or contract terms. The Commission previously addressed this topic in the 2022 LTRRPP, ordering changes to reflect an initial two-year suspension term as generally reasonable for voluntary contractual defaults for economic reasons. *See Ill. Power Agency*, Docket No. 22-0231, Order at 10 (July 14, 2022) ("*2022 LTRRPP Order")*. Indeed, a recently released IPA FAQ, which provides guidance to prospective bidders, states that suppliers may voluntarily terminate contracts, forfeit collateral, and resubmit the same project in a subsequent Indexed REC Request for Proposals ("RFP"). ComEd Resp. at 2-3.

ComEd believes that CGA's proposal to limit workshops to "no more than six months" is impractical. The LTRRPP workshop proposal provides for at least seven significant topics. *See* LTRRPP at 115-116. CGA appears to be unduly optimistic when it asserts that those topics should be easily resolved, pointing to the informal comments process as an example. However, a comment process is not the same thing as stakeholders with different objectives essentially negotiating all the specifics for a drastic departure from the existing competitive bidding process in which bids are accepted and then memorialized in binding contracts. ComEd Resp. at 3-4.

Curiously, CGA also cites an October 12, 2023 NY PSC decision rejecting a proposal to adopt a process for post-award changes to REC contracts. ComEd points out that the NY PSC litigation involved certain parties filing petitions making specific proposals to change specific contracts based on specific changes in circumstances, not a workshop on setting up a process for post-award changes in REC contracts. *See, e.g.*, NY PSC Order at 1-3; ComEd Resp. at 4.

It is true that, under the IPA's contemplated structure, the post-award contract change process would involve bidders who already won in the competitive bidding process and the changes then would be reviewed and approved by the Commission. However, a party could bid a price of "X" in the competitive bidding process, thereby coming in with a price under the losing bidders. That same party could achieve a higher price of "Y" in the post-award contract change process. "Y" might be higher than the prices bid by losing bidders. "Y" also might be higher than the price that losing bidders would have bid if they had the opportunity to compete against the party in the post-award contract change process. Moreover, the Commission, in reviewing the post-award contact changes, will not have the benefit of data on what losing bidders would have bid, and thus its review will be based on much less information than its review of the outcome of the competitive bidding process. As CGA acknowledges, the existing Illinois process is based on the prices offered by eligible bidders. Post-award contract changes effectively knock out that core principle of the competitive bidding process by rendering it inconclusive. ComEd Resp. at 4-5.

Staff agrees in general with ComEd regarding the subject post-award changes to material terms of REC contracts. Staff Resp. at 9. However, Staff does not oppose the LTRRPP's workshops proposal, and Staff does not support ComEd's alternative position on Commission guidance for the workshops. Staff Resp. at 9-10. Instead, Staff offers a different conditional recommendation: "Staff recommends that if the Commission allows workshops on this topic, that the Final Order in this docket clearly state that authorizing workshops should not be construed as implying that the Commission is in favor of allowing post-award contract changes if the IPA, or any other party, proposes them in the next LTRRPP." Staff Resp. at 9; ComEd Rep. at 6.

While ComEd disagrees with Staff that workshops may be useful, ComEd believes that Staff's conditional recommendation is a viable substitute for ComEd's alternative recommendation, provided that Staff's language should be amended to provide that the subject of bilateral renegotiation (changes in both directions) is within the scope of the workshops. The LTRRPP notes various post-award factors that might occur that could impact the costs of a bidder's project. *See* LTRRPP at 114-115. However, most, if not all, of those factors, such as interest rate changes, can move in both directions. Thus, there is no good reason to allow changes only in one direction. ComEd Rep. at 6.

In response to the IPA's argument that post-award changes in REC contracts would be lawful, ComEd states that Section 16-111.5(b) and (e)-(i) of the PUA provide for a specific and exclusive process and timeline for Commission approval of REC contracts. The proposed workshops, however, would address or assume a structure that provides for additional processes and timelines not authorized by the statute. Second, subsection (e)(2), regarding "Standard contract forms and credit terms and instruments", states in part: "The terms of the contracts shall not be subject to negotiation by winning bidders, and the bidders must agree to the terms of the contract in advance so that winning bids are selected solely on the basis of price." 220 ILCS 5/16-111.5(e)(2). The proposed workshops, however, would appear to allow unrestricted negotiation, which, if so, would mean that the standard terms apparently could be altered, contrary to subsection (e)(2). Finally, as noted by CGA, under subsections (c)(1)(vii) and (e), a procurement administrator can negotiate a new bid price only within 24 hours of the bid being submitted. The CGA sees that feature as a flaw, but it was the choice of the legislature. The CGA workshop proposal would conflict with that statutory limit. ComEd Rep. at 7.

The IPA goes on to state in part that it believes the IPA and ComEd are aligned around the potential risks around renegotiation, but then asserts that ComEd fails to recognize that there is a problem with volatile changes in conditions. ComEd understands that conditions may significantly change. The IPA's proposal, however, could have the effect of undercutting competition based on efficiency and superior management or financial strength. A bidder that better forecasts and/or is in a position to better manage its risks could see its bid rejected on price in the competitive process, only later to see a bidder that won based on a lower price obtain a renegotiated higher price that would have been rejected in the competitive process. Moreover, ComEd states that the IPA overlooks the one-sided nature of the LTRRPP proposal. The LTRRPP's workshops proposal contemplates allowing only one side to propose changes, unlike a normal contract renegotiation. ComEd Rep. at 7-8.

CGA to some extent criticizes the competitive bidding process, arguing that a bidder seeking to undercut other bidders in relation to managing the risks of changes is "speculative and risky" and "imprudent", but CGA does not support that view with any data. *See* CGA Resp. at 5; ComEd Rep. at 8.

CGA argues that, if a project becomes uneconomic, then a supplier that defaults as a result will be "unjustly punished" based on circumstances beyond its control and a resulting two-year suspension from competing in REC procurements. CGA Resp. at 3. In response to Objections filed in the 2022 LTRRPP docket based on similar concerns, the IPA clarified that it would "review all available facts and evidence and consider whether the supplier or applicant made a good faith effort at compliance and whether non-compliance resulted from circumstances outside of that party's control." LTRRPP at 124; ComEd Rep. at 8-9.

CGA argues that a post-award REC contract change process would reduce bidders' risks and thereby reduce their initial bids. CGA Resp. at 5-6. Such a concept nullifies the value of the winning bid price and as CGA later acknowledges, would adversely impact the IPA's REC budget. *See* CGA Resp. at 7-8. The IPA's REC budget is funded by customers and authorizing post-award changes to material terms is an extraordinary and dangerous way to shift risks associated with non-economic bids from developers to customers. ComEd Rep. at 9.

ComEd notes that CGA argues that post-award changes to REC contracts should not be negotiated at all, unlike the LTRRPP proposal, and instead should be driven by an index. CGA's index idea suffers from the same problems discussed with the LTRRPP's proposal. CGA also explicitly argues that changes should only be in favor of suppliers. CGA claims that utilities are not harmed because RECs are paid from the IPA's REC budget, but that claim utterly ignores the interests of utility customers. CGA also claims that ComEd has not shown any harm to barring utilities from seeking changes in the scenario that suppliers are allowed to do so. CGA Resp. at 8-9. Yet, CGA does not deny that circumstances that affect REC prices may change in either direction, as discussed above.

ComEd points out that JSPs argue that the current REC standard contract finalized on September 29, 2023, for the next REC procurement allows amendments. JSPs rely on Section 15.7(c) which states that: "No amendment or modification hereto or to any written Product Order is enforceable unless in writing and executed by both Parties." ComEd opines that this language cannot be read out of the context of the law and of the rest of the LTRRPP in the manner that JSPs suggest. Otherwise, a utility and supplier could agree to changes that could completely defeat every aspect of the competitive bidding process and the use of standard contracts. JSPs argue that having workshops makes sense because otherwise the utility and supplier could make changes to REC contracts “on an ad hoc basis”. JSPs Resp. at 3. JSPs’ argument only proves that Section 15.7(c) cannot be read in the manner that JSPs contemplate.

ComEd maintains that the Commission should adopt ComEd’s Objection. Alternatively, the Commission should adopt ComEd’s recommended proposed guidance for workshops, and/or Staff’s recommendation, if Staff’s recommendation is modified to provide for bilateral negotiation. The Commission should not adopt CGA’s Objection.

3. NRG Companies’ Position

The NRG Companies oppose post-award changes to REC contracts. The NRG Companies concur with ComEd’s recommendations regarding this issue and urge the Commission to also direct that any workshops held by the IPA concerning post-award changes to REC contracts recognize that any changes in contract terms should avoid negatively impacting the level of certainty of the rebate realized by Self-Direct customers, since that rebate level is based on the cost of utility-scale REC contracts. NRG Resp. at 7-8.

Post-award changes to REC contracts are problematic and contrary to the core concept of competitive bidding that is embedded in the Illinois regulatory construct. As such, the NRG Companies respectfully request that if the Commission elects to allow the IPA to undertake these workshops, that Section 5.4.8 of the LTRRPP be changed to incorporate the following: 1) the material issues of contract quantities and price should not be the subject of the workshops; and 2) any changes in contract terms should avoid negatively impacting the level of certainty of the rebate realized by Self-Direct customers, since that rebate level is based on the cost of utility-scale REC contracts. NRG Rep. at 18.

4. JSPs’ Position

The Joint Solar Parties support CGA’s viewpoint and urge the Commission to reject ComEd’s proposal. JSPs note that currently, each REC Contract explicitly allows for amendments in writing. For instance, the Indexed REC Contract finalized on September 29, 2023 for the now-pending Indexed REC procurement provides in Section 15.7(c) that “No amendment or modification hereto or to any written Product Order is enforceable unless in writing and executed by both Parties.” Amendment is plainly allowed and to the Joint Solar Parties’ knowledge has been part of the REC Contract since at least the first post-P.A. 99-0906 procurements. JSPs Resp. at 3.

The only question is whether that amendment process can take place within a known framework that is available to all parties or whether it will be on an ad hoc basis. The Joint Solar Parties believe the former is highly preferable, giving bidders a better ability to manage risk and—equally as important—bring projects online despite inherently long and risky development cycles for utility-scale systems. The best way forward is further discussion of different frameworks and presentation of options to the Commission for approval. JSPs Resp. at 3-4.

5. Staff’s Position

While ComEd argues that having workshops on this concept would not be a productive use of time or resources, ComEd requests that the Commission make some initial determinations if the Commission nevertheless allows workshops on this topic to occur. Staff's position regarding material contract changes after the contracts have been entered is similar to that of ComEd's. That said, Staff does not oppose workshops on this topic and Staff does not agree that the Commission needs to make those initial determinations ComEd is proposing. However, Staff recommends that if the Commission allows workshops on this topic, that the final Order in this docket clearly state that authorizing workshops should not be construed as implying that the Commission is in favor of allowing post-award contract changes if the IPA, or any other party, proposes them in the next LTRRPP. Staff Resp. at 9-10.

CGA recommends that any workshops for post-award contract changes be reduced to six months. Consistent with Staff's Response to ComEd's Objection to post-award contract changes discussed above, Staff recommends that the Commission reject CGA's proposal. Not only is six months a relatively short time frame for such a fundamental discussion, CGA's proposal assumes that the Commission approve any such proposed change before the next LTRRPP filing. While Staff is not rejecting the idea of workshops on this topic outright, Staff certainly sees no need to rush this issue in-between LTRRPP filings. Staff Resp. at 11.

For the above reasons, Staff recommends adopting the IPA's proposal on this issue and rejecting CGA's Objection. Staff Resp. at 12.

6. IPA's Position

The Plan proposes a new process under which the Agency would develop a process for considering post-award Indexed REC contract changes by conducting workshops to explore the best approach for potential post-award changes, with a goal that an Indexed REC contract renegotiation process may be finalized for inclusion in a compliance filing within one calendar year after the Plan's approval by the Commission. LTRRPP at 115. For background, the Agency conducts forward procurements for RECs from new utility-scale wind projects, new utility-scale solar projects, and new brownfield site photovoltaic projects to support the Illinois RPS. 20 ILCS 3855/1-75(c)(1)(G)(v). The current Indexed REC procurement structure requires utility-scale renewable energy project developers to bid a fixed Strike Price into the Agency's Indexed REC procurement, with most bidders bidding well before project development. The REC price component of the contract is determined through subtracting an Index Price (established through wholesale energy market indexes) from the Strike Price, thus ensuring that the developer is made whole at the Strike Price amount by selling the project's energy into wholesale markets. IPA Resp. at 5.

However, market and project-related variables—such as supply chain delays, component costs, interest rates, interconnection costs, interconnection delays, and other variables that impact that project's capital costs—may change significantly between contract execution and project energization. LTRRPP at 114-115. Even with the Indexed REC procurement structure in place, given that utility-scale renewable energy projects are capital-intensive and require up-front financing for items such as professional services, permitting, equipment, interconnection costs, and REC delivery contract deposits, the Agency has received feedback from utility-scale developers that volatile market conditions that are outside of the developers' control have significantly increased their project development costs and construction costs, causing some utility-scale projects that have been selected in the Agency's procurement events to become potentially uneconomic at the awarded Strike Price. By contrast, the Agency's competitive procurements for standard wholesale products, such as block energy and capacity to serve eligible retail customers, procure products that are widely traded in liquid markets. These liquid markets enable bidders to manage risk exposure by bidding competitive pricing based on current prices and price history of similar products, and delivery of the contracted product at the contracted price is not dependent on the development of a new generating facility (meaning that a Seller of standard wholesale products does not face the risks and uncertainties inherent in new project development in abiding by its bid price). Indeed, Table 3-8 of the Plan illustrates the 32% attrition rates that contracted renewable energy projects from the Agency's forward REC procurements faced prior to the Agency moving to an Indexed REC structure. If a project's competitively bid price submitted 3-5 years before actual energization is no longer viable, then the project developer will often default on the REC delivery contract, leaving Illinois further behind on meeting RPS goals. IPA Resp. at 5-6.

To prevent the State's RPS goals from becoming unattainable due to defaulting utility-scale renewable energy projects, the Agency believes that post-award Indexed REC contract changes may be warranted. While the Agency recognizes this is a departure from its traditional and current competitive procurement practices—and would require safeguards to protect the integrity of initial bids received, such that the competitive bidding process would not be reduced to artificially low bids submitted assuming a downstream price increase—utility-scale renewable energy project attrition is a problem requiring new and novel efforts at a solution. Contracted projects no longer being developed is not merely some mathematical RPS compliance challenge, as Illinois' decarbonization planning assumes the presence of new utility-scale wind and solar projects as more carbon-intensive generating facilities retire. In a vertically-integrated state, a planned project may be able to cover unplanned cost increases through increased rate recovery. A restructured state like Illinois utilizes a fixed bidding approach to determine the revenue available to that new renewable energy project. Consequently, other restructured states are facing this same challenge of determining how to ensure that proposed new renewable energy projects remain financially viable as those states strive to meet aggressive renewable energy goals. *See* LTRRPP at 115. Should conditions change such that a proposed project is no longer financially viable at its price, giving up and letting planned projects default cannot be the only option. Notably, other solutions to ensuring performance—such as increasing collateral, raising bid maturity requirements, or creating non-performance penalties—feature more substantial downsides, including reduced participation and competition in competitive procurement events, free-ridership, and increased bid premiums to manage risks. IPA Resp. at 6-7.

The IPA notes that allowing renegotiation of competitive bids would be a fundamental pivot and carries its own downsides and risks as well. Recognizing the complexity of implementing this system, Section 5.4.8 of the LTRRPP does not contain a specific proposal for authorizing post-award contract changes. Instead, it outlines a workshop process for exploring these issues, concluding with a renegotiation process proposal potentially made through a compliance filing in this proceeding. IPA Resp. at 7.

CGA supports the IPA's proposal to develop a process for post-award Indexed REC contract changes, but objects to the Agency's proposed one-year process development timeline. CGA proposes that the Agency carry out the workshop process in six months—half the proposed time—such that a solution is in place for the planned Summer 2024 Indexed REC procurement event. CGA Obj. at 8. For the IPA, six months is an unreasonable timeframe for a fulsome, thorough, and thoughtful consideration of all potential unintended consequences resulting from contract renegotiation. Contract renegotiation constitutes a stark departure from the competitive procurement approach allowed across the entirety of the Agency's history, and developing necessary safeguards to avoid compromising the integrity of initial bids received is far more important than concluding the process quickly. In proposing a one-year timeline, the Agency already elected to treat contract renegotiation with the maximum possible urgency by not deferring a proposal to development of the 2026 Long-Term Plan. Such a substantial structural change cannot be further short-circuited in service of a single upcoming procurement event. IPA Resp. at 7-8.

While CGA seeks to expedite workshops, ComEd objects to the IPA holding workshops altogether, claiming it would not be a productive use of time or resources and that it may lead to an expectation that post-award contract changes will be adopted. ComEd Obj. at 6. The Agency and ComEd are somewhat aligned on potential risks around renegotiation—with those very downsides proposed to be explored through workshops under the IPA's proposal—but ComEd fails to even acknowledge that a problem needs to be solved, and the Agency fundamentally disagrees that the proposed process would operate contrary to Illinois law or administrative authority. The IPA disagrees with ComEd's statement that allowing potential renegotiation of terms is a grave departure from the most basic principles of contracting. The IPA points out that terms of bilateral contracts are routinely renegotiated between parties when changed circumstances impact the timeline or cost of deliverables. Instead, contracts with a public utility as the Buyer are the exception, as a regulated public utility must receive administrative approval of those changes from a separate body (its public utilities commission) to ensure the prudency of any changed terms (especially increased expenditures). Renegotiation seeks only to allow developers of new utility-scale renewable energy projects under the Illinois RPS to have similar means for managing changed circumstances as they would have under the "basic principles of contracting" with a non-regulated entity.

The Agency's proposed workshops seek to evaluate what downstream Indexed REC contract changes may be allowable and a process for renegotiation would be included in a compliance filing. Should the Commission disagree with the proposal set forth in a compliance filing, the Commission may open an investigation into the matter. Further, this workshop process would be approved by the Commission in this proceeding, with the Commission's administrative order in this proceeding providing an avenue for the Commission to layer in any procedural safeguards it believes are necessary to include in a subsequent compliance filing. As outlined in Section 5.4.8 of the Plan, an Indexed REC contract addendum may need be developed, and any future contract awards containing that addendum would also be subject to Commission approval (as all Indexed REC contract awards are). Lastly, workshops are expressly proposed to explore the very issue of whether the Commission's approval of individual contract term changes is indeed legally required, allowing for collaborative exploration of ComEd's legal concerns. IPA Resp. at 8-9.

Flagging issues, as ComEd has, is not a valid basis for objecting to further exploring those issues through workshops. Ultimately, the Agency believes its proposed workshop process is a reasonable approach to exploring a process for downstream contract changes, with an aim toward ensuring that developers bidding into the IPA's competitive procurement events can successfully develop new renewable energy projects while also protecting the integrity of the competitive bidding process. The Agency urges the Commission to accept its proposal. IPA Resp. at 9.

7. Commission Analysis and Conclusion

The Commission shares both the concerns of ComEd that post-award contract changes could undermine the competitive process and the concerns of the IPA that Illinois' RPS goals could be hampered by projects becoming uneconomic. Ultimately, however, the Commission finds that the workshops proposed by the IPA address a valid and on-going concern and should be approved. And importantly, no post-award changes are being approved here, simply the workshop process as proposed by the IPA to discuss solutions. The Commission agrees with Staff that it is necessary to clarify that the Commission's authorization of workshops on this topic should not be construed as implying that the Commission is in favor of allowing post-award contract changes if the Agency, or any other party, proposes them in the next LTRRPP. Also, of course, any proposed outcome must be consistent with the PUA and the IPA Act.

The arguments raised by parties - both for and against post-award contract changes - are relevant and should be considered in the workshops. The Commission does not agree that a limitation should be placed on the discussions. In other words, it may be appropriate that there be no post-award changes or if there are post award changes, they may be negotiated or based on a formula and might result in higher or lower REC prices. The Commission makes no findings on these questions in this Order and looks forward to the IPA's discussion of this issue in the next LTRRPP.

The IPA seeks Commission approval of the workshop process in this proceeding, concluding with a compliance filing within one calendar year after the Commission approves the 2024 Plan. If the Commission disagrees with the proposal set forth in the Agency's compliance filing, the Commission can reject the filing and open an investigation into the matter.

With respect to CGA's proposal to shorten the workshop process, it is not adopted. The Commission finds the questions presented require sufficient time to be developed and properly considered by the IPA prior to submission to the Commission.

B. Section 5.5.3. Non-Photovoltaic Community Renewable Generation

1. CGA's Position

In Section 5.5.3. of the LTRRPP, the IPA briefly explains the state of the market for non-photovoltaic ("PV") community renewable resources. The IPA states that stakeholders did not indicate an interest in non-PV community renewable resources in comments submitted during Summer 2023. Furthermore, it is evident that the IPA does not intend to hold competitive procurements of non-PV community renewable resources because they are not listed in Table 5-6 of the LTRRPP, which identifies proposed competitive procurements for 2024-2025. CGA states that a segment of CGA's members is interested in the IPA holding a competitive procurement of non-PV community renewable resources because the tax credits provided for renewable resources in the federal Inflation Reduction Act would likely produce cost-effective community generation resources. CGA Obj. at 8.

Section 1-75(c)(1)(N) of the IPA Act directs the IPA to "consider [through the LTRRPP] whether community renewable generation projects utilizing technologies other than photovoltaics should be supported through State-administered incentive funding." The following non-PV resources that qualify for either federal Investment Tax Credits (26 USC §48) or Production Tax Credits (26 USC §45) are also included in the IPA Act's definition of "community renewable generation project" (20 ILCS 3855/1-10) - wind, solar thermal electric, certain biomass, and hydropower. Non-PV community renewable generation procurement could be a valuable tool at the Agency's disposal to remedy the REC target shortfall described in Chapter 3 of the LTRRPP. In particular, CGA explains that it could help chip away at the projected wind REC shortfall in future years as noted in Table 3-7. The definition of "community renewable generation project" includes resources less than 5,000 kilowatts, therefore, it also includes smaller distributed generation non-PV community projects that could be contracted through this procurement. CGA explains that these resources may be able to be energized sooner than the larger community and utility-scale projects and help address the REC shortfall in the near term. CGA Obj. at 8-9.

CGA states that it appreciates the Agency's workload but points out that the standard for the Commission is whether the proposal will reasonably and prudently accomplish the requirements of Section 1-75 of the IPA Act. 220 ILCS 5/16-111.5(b)(5)(ii)(D). While CGA supports the Agency having sufficient staffing or personnel and the Agency being granted or appropriated sufficient funds for it to conduct work that reasonably accomplishes the purpose of the RPS, staffing and workload has no bearing on the standard set forth in the PUA. Staffing is an Agency matter external to the consideration of whether the LTRRPP would reasonably and prudently accomplish the directives in the IPA Act. If the Commission finds that Agency staffing and workload is relevant to whether a plan is reasonable, then it is unreasonable and imprudent for the Agency to be understaffed for its workload because it discourages bidders from participating in the Agency managed procurements. CGA Rep. at 9-10.

In response to the JSPs, CGA states that its statements were made within the Agency's development of the long-term plan and therefore within the timeframe set forth in Section 1-75(c)(1)(N) of the IPA Act. The IPA Act does not limit the Agency's timeframe of consideration to the period of time prior to filing the draft LTRRPP for Commission approval, it applies to the entire process until the LTRRPP is finalized. Therefore, CGA's input is timely and addresses the statutory requirements. CGA Rep. at 10-11.

The Joint Solar Parties also comment that it is unclear whether such contracts would be economically viable and suggest that the IPA collect information from bidders/sellers about the economic viability of such REC Contracts. While CGA does not necessarily oppose the Joint Solar Parties' proposal, CGA believes these non-PV community projects will be cost-effective given the extension of the production tax credit pursuant to the federal Inflation Reduction Act of 2022. Furthermore, the competitive aspect of the competitive procurement is intended to keep the bid prices low. The REC Benchmark price is an additional mechanism to ensure that the bid is competitive – the bid price must be below a benchmark developed by the Agency, Procurement Administrator, procurement monitor, and Staff. Finally, the Procurement Administrator and Commission are to evaluate and make a determination as to whether the procurement was competitive. CGA Rep. at 11.

CGA recommends the IPA hold a competitive procurement for non-PV community renewable generation projects. The IPA should hold separate procurements for large and small community-scale projects. CGA Obj. at 9.

2. JSPs' Position

The Joint Solar Parties disagree with CGA's Objection. Given the lack of interest this past summer identified in the LTRRPP and that no bids were submitted when the last such procurement was held in 2019, the Joint Solar Parties note that the statutory prerequisite for further procurements has not yet been met. If and when the statutory prerequisite is met, then such a procurement may be considered in future LTRRPPs. JSPs Resp. at 4.

The Joint Solar Parties note two additional concerns with a non-PV community renewable generation procurement. The first is that all competitive procurements are required to use Indexed REC contracts, which require a bid of a "strike price" that is netted against an "index price" defined as the hourly locational marginal prices at the applicable regional transmission organization's Illinois zone. *See* 20 ILCS 3855/1-75(c)(1)(G)(v) (requiring Indexed REC structure); 20 ILCS 3855/1-10 (defining "strike price" and "index price"). Under Section 16-107.5(l)(3) of the PUA, a subscriber is compensated at the utility's applicable Price to Compare, which as a retail rate is stable during a month as opposed to the highly volatile locational marginal pricing. It is thus unclear whether such a contract would be economically viable—the Joint Solar Parties recommend that if the LTRRPP calls for future review of market appetite for a non-PV community renewable generation project procurement that market participants be asked about the economic viability of such REC Contracts. JSPs Resp. at 4-5.

Second, the Joint Solar Parties urge caution for any procurements that do not meet RPS goals, specifically those goals in Section 1-75(c)(1)(C) of the IPA Act, under current statutory language. The Joint Solar Parties appreciate that under 5 megawatt ("MW") of alternating current ("AC") (or "MWac") wind projects could be procured under a non-PV community renewable generation project procurement, but any other products should be rejected out of hand due to looming budget constraints according to the analysis done by the IPA in the LTRRPP. JSPs Resp. at 4.

3. IPA's Position

Section 5.5.3 discusses that the Agency may consider whether community renewable generation projects utilizing technologies other than PV should be supported through State-administered incentive funding and may issue requests for information to gauge market demand. As the Plan explains, feedback received by the Agency while developing the Plan during the Summer of 2023 did not indicate an interest in non-PV community renewable generation projects participating in IPA procurements, and recent statutory changes from P.A. 103-0380 require that the Agency procure RECs from modernized or retooled hydropower facilities. LTRRPP at 119; IPA Rep. at 11.

Section 1-75(c)(1)(N) of the IPA Act does not mandate a community renewable generation program and instead it says that the Agency "may consider whether community renewable generation projects utilizing technologies other than photovoltaics should be supported through State-administered incentive funding, and may issue requests for information to gauge market demand." 20 ILCS 3855/1-75(c)(1)(N). IPA Resp. at 10. Further, under P.A. 103-0380 (which takes effect on January 1, 2024), the Agency must already implement new requirements for REC procurements from non-photovoltaic and non-wind projects. P.A. 103-0380 will revise the Agency's REC procurement targets under Section 1-75(c)(1)(C) of the IPA Act, adding RECs from certain hydropower resources to the IPA's REC procurement goals. This revised language will require that 45% of the 45 million RECs delivered annually by the end of delivery year 2030 from new projects come from wind projects and hydropower projects, with eligible hydropower projects including newly modernized or retooled hydropower dams or dams that have been converted to support hydropower generation. Given that this new statutory hydropower REC procurement requirement will impose a substantial burden on the Agency, layering in an additional new administrative requirement that the IPA seek RECs from non-photovoltaic community generation projects would create overlapping changes that the IPA simply does not have the bandwidth to presently handle. Instead, the IPA will take stakeholder feedback for further exploring non-PV community renewable generation projects in preparing its 2026 Plan. IPA Resp. at 10-11.

4. Commission Analysis and Conclusion

Section 1-75(c)(1)(N) of the IPA Act states the following:

> Through the development of its long-term renewable resources procurement plan, the Agency may consider whether community renewable generation projects utilizing technologies other than photovoltaics should be supported through State-administered incentive funding, and may issue requests for information to gauge market demand.

20 ILCS 3855/1-75(c)(1)(N). Based on this statutory language, CGA may be technically correct that its proposal is not late, but it is nevertheless impractical at this point. The IPA met the statutory requirements and gauged the level of interest in a non-PV community renewable generation procurement, and reasonably designed the LTRRPP in response. Accordingly, CGA's proposal is not adopted. Indeed, even if CGA had shown interest at an earlier point, there is no requirement that the IPA propose a non-PV community renewable generation procurement in the LTRRPP.

The IPA should again request information regarding the level of interest in non-PV community renewable generation for the next iteration of the LTRRPP. Also, as suggested by the JSPs, this should include looking at whether projects such as this are economically viable.

C. Section 5.7.1. Credit Requirements

Ameren, CGA, JSPs, and the IPA address this section of the LTRRPP. The Commission notes that none of these parties suggest that this section of the LTRRPP be modified. Accordingly, no Commission discussion of Section 5.7.1 is necessary.

IV. CHAPTER 6. SELF-DIRECT RENEWABLE PORTFOLIO STANDARD COMPLIANCE PROGRAM

A. ComEd's Position

As outlined in the LTRRPP, the IPA manages RPS compliance primarily through delivery of RECs bought under contracts through IPA-administered programs and procurements, with Illinois electric utilities such as ComEd serving as buyers. Yet, there are risks and uncertainties in the RPS (particularly in the Indexed REC procurement model) that should be reduced, although ComEd notes that the IPA believes that legislative action will be needed for that purpose. *See e.g.*, LTRRPP at 67. The LTRRPP indicates and illustrates that Indexed REC prices (based on the difference between strike price named by a bidder and monthly energy settlement prices for one of the two hubs in Illinois) create significant REC budget uncertainty due to fluctuations in energy market prices. LTRRPP at 73-74; ComEd Obj. at 2.

ComEd believes that enhancement of the Self-Direct Program to achieve more robust participation can reduce RPS budget uncertainty and increase REC retirements. That objective likely will require changes to the Self-Direct Program crediting methodology (addressed in Section 6.5.1 of the LTRRPP). ComEd believes that it is essential to address this issue now to identify the extent that the Commission believes it can act, and/or to help explain any legislative modifications that will be necessary to improve program effectiveness. The Commission's *2022 LTRRPP Order* regarding the 2022 LTRRPP should not act as a barrier to lawful solutions to known problems based on information gained in the last 15 months. *See 2022 LTRRPP Order, generally*; ComEd Obj. at 3.

Through the Self-Direct Program, RECs can be procured and retired by private entities and reduce the RPS compliance obligations of the utilities. Participating private entities are required to obtain RECs "equivalent in volume to at least 40% of the eligible self-direct customer's usage, determined annually by the eligible self-direct customer's usage during the previous delivery year, measured to the nearest megawatt-hour." 20 ILCS 3855/1-75(c)(1)(R)(2)(iv); *see also* LTRRPP at 135. The participants receive a credit towards the RPS charge -- a charge that is fixed at a capped amount (the "rate impact cap"). 20 ILCS 3855/1-75(c)(1)(E), (F), (R)(4); *see also* LTRRPP at 61-63, 135; ComEd Obj. at 3.

ComEd opines that the requirement of 40% of the customer's prior delivery year's load provides an opportunity to accelerate renewable energy development and help the State catch up to the statutory targets because the minimum requirement far exceeds the current RPS requirement of 22% for 2023-2024. 20 ILCS 3855/1-75(c)(1)(B); *see also* LTRRPP at 52. Yet, ComEd asserts, the Self-Direct Program is under-achieving its potential under the current structure. ComEd Obj. at 3-4.

ComEd explains that the Self-Direct Program credit reduces RPS charges by about 7.249% ($0.364475 divided by $5.0280) while requiring participants to achieve accelerated compliance requirement that exceeds the current annual RPS goal of 22% by 18% (the 40% requirement versus the 22% goal). ComEd's analysis of utility-scale REC prices as well as the IPA's analysis presented on the "Indexed REC [Price] Calculator" tab of LTRRPP, Appendix B anticipates, for the foreseeable future, a utility-scale average REC price in excess of $5.03 per REC. ComEd Obj. at 4

Thus, ComEd states that a robust Self-Direct Program that encourages large customers to self-procure RECs to meet their own green-house gas reduction objectives could accelerate the achievement of the State targets, reduce the costs of achieving the State targets, and mitigate the budget uncertainty highlighted by the LTRRPP. Regulatory changes to enhance the Self-Direct Program in an appropriate and reasonable manner, such as increasing credit values to the lesser of the fixed RPS credit amount or the cost of IPA procurement of similarly situated RECs, would create more certainty for potential participants, leave more funds available not less, and allow the State to retire significantly more RECs. ComEd Obj. at 4-5.

The LTRRPP indicates that the IPA believes that it cannot act on the Self-Direct Program bill credit now because of statutory limits and the Commission's *2022 LTRRPP Order*. The Commission's authority stems from statute, and it must adhere to them. "The Commission only has those powers given it by the legislature through the Act." *Bus. and Prof'l People for the Pub. Interest v. Ill. Commerce Comm'n*, 136 Ill. 2d 192, 201 (1989) ("*BPI*"). However, Commission orders are not legal precedents or *res judicata*. Those decisions express the Commission's decision on the facts presented in those records. New evidence, such as the information gained since that Commission Order, or new arguments may warrant or require consideration of an issue based on that new record and may call for a different result than a past case. *E.g*., 220 ILCS 5/10-103; *Miss. River Fuel Corp. v. Ill. Commerce Comm'n*, 1 Ill.2d 509, 513 (1953); *Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 405 Ill. App. 3d 389, 407-408 (2d Dist. 2010). To the extent that the Commission can act within the parameters of existing law to improve the Self-Direct Program, the Commission should do so, notwithstanding its prior Order. ComEd Obj. at 5.

NRG Companies' Objections include what ComEd understands to be a highly similar suggestion, subject to certain confirmations and clarification. ComEd understands NRG Companies' suggestion, like that of ComEd, to refer to prices actually paid by utilities under REC contracts. That is, it would exclude REC contracts that for whatever reason ultimately are not performed, such as because the developer does not complete their project. By comparison, ComEd's initial proposal refers to the lesser of the fixed RPS credit amount or the prices actually paid by utilities under REC contracts. NRG Companies did not explicitly include that point in its suggestion, but ComEd anticipates that point likely is implicit in NRG Companies' views. ComEd contemplates the IPA using data from the most recent delivery year regarding prices actually paid by utilities under REC contracts. ComEd believes that it is important for a Self-Direct Program participant to have certainty for the life of the contract just as bidder has price certainty for the value of their bid in a utility-scale procurement and thus, the average price for new utility-scale RECs paid by the utilities in the prior delivery year should be the same value used in determining the credit value for the self-direct participant for the life of their contract. ComEd Resp. at 5-6.

The City of Chicago's contract to purchase 100% clean renewable energy starting in 2025 provides an example of the potential new renewable resource development and reductions in REC volumes needed to meet RPS targets a robust Self-Direct Program can enable. The City of Chicago's contract enables project financing for Double Black Diamond Solar, a utility-scale solar project in Virden, Illinois, that is expected to be the largest U.S. solar project east of the Mississippi River and the largest solar project in the Midwest Independent System Operator ("MISO") territory (approximately 800 megawatt direct current ("MWdc")). The City of Chicago is currently contracted to purchase approximately 604,440 utility-scale solar RECs from Double Black Diamond Solar. That purchase could reduce delivery loads subject to RPS requirements by at least 970,000 megawatt hours ("MWhs") (the amount of aggregated load of City of Chicago accounts included in its RFP) while providing statutory coverage for over 1,511,000 MWhs of deliveries (604,440/.40%). Under ComEd's Self-Direct Program credit proposal (the lesser of the fixed RPS credit amount or the cost of the IPA procurement of similarly situated RECs), the City of Chicago could be eligible for RPS credits of approximately $3 million and remain fixed throughout the contract period because of RECs produced by Double Black Diamond Solar. An effective and robust Self-Direct Program can both accelerate utility-scale development in the State and leave more funds available for the Adjustable Block Program ("ABP"), under this example the IPA's cost for procuring similarly situated RECs would be $3.36M using delivery year 2023/2024 anticipated utility-scale REC deliveries and costs. The City of Chicago and any other similarly situated large customer should be encouraged to control their own destiny when their actions help the State meet its goals and objectives instead of being disincentivized to do so. ComEd Resp. at 6-7.

ComEd notes that the IPA asserts that it is "premature at this point to assume that the [Self-Direct Program] crediting rate is the limiting factor for participation in the Program" (IPA Resp. at 15-16), but that view fails to recognize the degree to which the current design fails to incentivize customers. Under the Self-Direct Program's current credit methodology, participating customers are required to procure RECs from new wind and new solar projects for 40% of their load (the State's RPS REC target for delivery year 2030) and would pay nearly all (over 90%) of the monthly RPS charge. ComEd argues that a participating customer has very little economic incentive to enroll into a compliance mechanism to pay twice for RPS compliance. ComEd Rep. at 4.

The IPA's remaining argument is that ComEd's recommendation requires statutory change based on Section 1-75(c)(1)(R)(4) of the IPA Act, 20 ILCS 3855/1 75(c)(1)(R)(4), and the *2022 LTRRPP Order*. IPA Resp. at 16-18. ComEd does not agree that there is no room for improvement. Section 1 75(c)(1)(R)(4), while undoubtedly challenging, grants the IPA the authority to develop a "methodology" rather than merely perform a statutory calculation for the credit amount that is equal to the proportion of cost authorized by the RPS rate cap that supported the annual procurement of utility-scale RECs provided that the bill credit exclude amounts associated with procuring RECs under Illinois Shines and other authorized programs. ComEd's proposed credit methodology gives full effect to the General Assembly's intent by advancing the State towards its RPS goals, reduces the amount of utility-scale RECs the IPA needs to procure, and limiting credits to the amount paid for equivalent utility-scale RECs purchased through IPA procurement processes. ComEd Rep. at 4.

As a result, the Commission should reject the IPA's and JSPs' arguments, and instead, adopt and harmonize ComEd's and NRG Companies' suggestions regarding the Self-Direct Program credit level, subject to the confirmations and clarification requested in ComEd's Response. ComEd Rep. at 5.

B. JSPs' Position

In the *2022 LTRRPP Order*, following passage of P.A. 102-0662, JSPs note that ComEd and the NRG Companies proposed expansions of the Self-Direct Program beyond the statutory limitations, particularly as it related to the self-direct credit. The Commission rejected this approach after thorough analysis, adopting the IPA's reading of the statute. *See 2022 LTRRPP Order* at 38-40. JSPs point out that the law has not changed in the interim. NRG Companies and ComEd provide no new legal arguments or other reasons that the Commission should change its legal analysis. At best, ComEd and NRG provide policy arguments, none of which successfully counter the Commission's legal analysis. The Commission should thus reject the positions of ComEd and the NRG Companies and make no changes to the LTRRPP's proposed Self-Direct Program terms. JSPs Resp. at 7.

C. NRG Companies' Position

The NRG Companies state that the Self-Direct Program, if properly implemented, would align Illinois' RPS with the increasing and accelerating levels of REC purchases undertaken directly by consumers. With a properly structured Self-Direct Program, Illinois can attract more private sector investment in renewable energy to the State, support prevailing wage jobs for Illinois workers, and bridge the gap between Illinois' RPS goals and projected deliveries, which according to the IPA itself will be more than 19.2 million RECs for the 2026 delivery year. LTRRPP at 54. Stated differently, the Illinois RPS will only meet approximately 40% of the statutory statewide renewable energy policy goal in the 2026 delivery 2025-2026 Program Year. NRG Obj. at 13.

The NRG Companies encourage the Commission to consider the following guiding principles as it considers the Self-Direct Program:

- Competitiveness. Illinois consumers that are eligible for the Self-Direct Program can purchase RECs from renewable energy resources located anywhere in the US. The intent of the Self-Direct Program is to make Illinois a preferred location for such development, incentivizing green energy prevailing wage jobs in the state. The Commission can ensure that the LTRRPP meets P.A. 102-0662's intent by maximizing the RPS rebate that participating consumers can receive through the Self-Direct Program.

- Certainty. More eligible consumers will make the long-term commitments required to participate in the Self-Direct Program if the program provides a higher level of certainty regarding the value it provides to participants. P.A. 102-0662 recognized the importance of value certainty by setting forth a formula to calculate the Self-Direct Program rebate. The Commission can provide value certainty by requiring that the

LTRRPP provide a predictable, stable, and transparent value for RPS rebates for participants in the Self-Direct Program for a period of up to ten (10) years.

- Simplicity. P.A. 102-0662 imposes rational obligations on Self-Direct Program participants to ensure that project and off taker qualifications are met. The Commission can help enhance program simplicity by ensuring that the LTRRPP apply an application and reporting process required of Self-Direct Program participants is neither unduly burdensome nor invasive.

NRG Obj. at 13-14. With these guiding principles in mind, the Commission should revise the terms of the Self-Direct Program to align the level and term of the rebate with current market norms to encourage more consumer participation in renewable energy development in Illinois and to move the state closer to its RPS goals. NRG Obj. at 14.

The NRG Companies assert that the market has spoken regarding the current design of the Self-Direct Program: the fact that there are only two customers in the entire state with a total uptake of only one-third of the available REC volumes under the Self-Direct Program demonstrates that material changes are needed in the program. Given the magnitude of the projected RPS shortfalls and budget deficits, the Commission should consider all options that would increase participation in the Self-Direct Program. A key element in improving Self-Direct Program participation would be to align the level of credit earned by Self-Direct Program participants to the prices paid for RECs under the IPA's utility-scale procurements. NRG Obj. at 15.

The NRG Companies support the Objections filed by ComEd proposing changes to that program. Also, NRG Companies note that ComEd explains that, despite projected utility-scale REC prices of greater than $5.03 per REC, the IPA has calculated a self-direct rebate value (*e.g.*, the value granted by the IPA for utility-scale RECs provided through the Self-Direct Program) of only $0.364475/MWh for self-direct customers served by ComEd. *See* ComEd Obj. at 3-4; NRG Resp. at 3.

The NRG Companies argue that the IPA's exceedingly low valuation of the self-direct rebate is especially troublesome in light of the fact that self-direct customers must execute at least ten-year contracts to secure a minimum of 40% of their annual load from renewable resources while the IPA projects a statewide RPS compliance rate of only 7.9% in the 2024-2025 Program Year – far below the statutory goal of 23.5%. While the Self-Direct Program requires participants to provide a contractual guarantee of achieving 40% renewable energy supply, that program has only been allocated $0.364475/MWh by the IPA; on the other hand, the IPA will meet less than 8% renewable energy supply with a budget of $4.88/MWh in RPS funding. NRG Companies aver that funding for the Self-Direct Program is disproportionately low. NRG Resp. at 3-4.

It is NRG Companies' view that changes to other elements of the Self-Direct Program also would encourage greater participation and help the state move towards compliance with the statutory RPS goals. First among these would be for the Commission to require the LTRRPP to be revised to guarantee that self-direct customers receive a predictable and stable self-direct rebate over the entire 10-year term of their self-direct agreements. Currently, the self-direct rebate value is set annually based on a three-year rolling average of eligible utility-scale REC delivery contracts in the RPS portfolio (e.g., the average of the two program years prior to the year being determined and the third year being the anticipated costs as outlined in the relevant LTRRPP). This rolling average valuation was not specified in statute. Instead, the Commission crafted this approach as an alternative to the IPA's proposal which would have set the self-direct annual rebate values based on a single prior program year – an approach that the Commission identified in its ruling as "unreasonable" and "instills too much instability for Self-Direct Program participants." *2022 LTRRPP Order* at 39. The implicit suggestion by the Commission was that the current design would be stable enough to entice customers to participate; the experience thus far with the program demonstrates this assumption was not correct. NRG Resp. at 5.

A second change that the NRG Companies assert the Commission should implement is to require the LTRRPP to ratably increase self-direct rebate credit to customers that voluntarily offset more than 40% of their annual consumption with purchases from qualified renewable energy resources. Currently, all self-direct customers receive the same self-direct rebate regardless of whether they are purchasing 40% or 100% of annual consumption with purchases from qualified renewable energy resources. This approach provides a higher level of compensation on a per-REC basis to a Self-Direct Program participant that secures RECs equal to only 40% of its load than a participant that secures RECs equal to 100% of its load. NRG Resp. at 6.

NRG Companies note that the IPA attempts to dismiss valid criticisms of the lack of participation in the Self-Direct Program, but the IPA admits that only two (2) companies have enrolled in the Self-Direct Program for an annual volume of between 500,000 and 1 million RECs. *See* IPA Resp. at 12, fn 18. To put that participation in perspective, NRG Companies explain that upon information and belief, there are approximately 625 customers who could have participated in the Self-Direct Program. Thus, the participation rate in the Self-Direct Program seems to be approximately 0.32% (2 customers participating divided by 625 potential eligible customers). Such a low participation rate indicates that the program fails to present sufficient value for consideration by eligible customers. NRG Rep. at 7-8.

The IPA attempts to frame the 500,000 and 1 million RECs secured through the Self-Direct Program as a success by asserting that "[it] is more appropriate to describe the rate of participation in the Self-Direct Program as robust." IPA Resp. at 15. The NRG Companies assert that the program is not a success. The IPA's own report shows that in 2021 commercial and industrial customers usage was nearly 90 million MWh. *See* IPA "Large Customer Self-Direct RPS Compliance Program, Proposed 2023 Delivery Year Program Size" at 3 (Jan. 20, 2023). If the IPA data is accurate, and setting aside the load growth that likely has occurred since 2021, then the Self-Direct Program secured between 0.6% and 1.1% of the potential market represented by eligible self-direct customers (*e.g.*, 500,000 divided by 90 million equals 0.6%; 1,000,000 divided by 90 million equals 1.1%). NRG Rep. at 8.

The NRG Companies state that the IPA apparently does not believe poor program design could be the cause of limited participation in the Self-Direct Program. *See* IPA Resp. at 17; NRG Rep. at 8-9. The facts concerning the non-performance of the Self-Direct Program along with the IPA's demonstrated lack of serious attention to planning and managing the program should provide a sufficient basis for the Commission to intervene and correct the faulty program structure. The NRG Companies respectfully request that the Commission order the IPA to incorporate the following changes to Section 6 of the current LTRRPP:

- The value for the Self-Direct Program rebate should be increased to "the lesser of the fixed RPS credit amount or the cost of IPA procurement of similarly situated RECs".
- The value of the Self-Direct Program rebate should be calculated annually to reflect a rolling three-year average and that will remain fixed for the entire term of the qualifying contracts that are entered into that year.
- The value of the Self-Direct Program rebate should increase for Self-Direct Program participants that procure more than 40% of their supply needs under the terms of the Self-Direct Program.

NRG Rep. at 13.

D. IMA's Position

The IMA agrees with ComEd and the NRG Companies and recommends that the Commission revise the Self-Direct Program to: 1) modify the calculation of the rebate; 2) annually establish a credit amount that will apply for the full duration of all Self-Direct Program contracts entered that year; and 3) provide incentives for participants to exceed the 40% minimum load threshold for participating in the program. IMA Resp. at 2.

IMA explains that the Self-Direct Program was originally created as a part of the IPA's 2022 LTRRPP, which was addressed by the Commission in the *2022 LTRRPP Order*. In that proceeding, the IPA advanced a Self-Direct Program that severely limited the size of the credit provided to self-direct participants and provided for a variable credit that could not be calculated prior to customers having to sign the required ten-year contract. Although parties advocated for substantial revisions to the credit, the Commission rejected those proposals and allowed the IPA's reduced, variable credit to become part of the program, stating "[t]he Commission is not convinced by arguments that the IPA's proposed Self-Direct Program credit will be a disincentive to participation." *2022 LTRRPP Order* at 39. IMA states that the Commission now has evidence that the IPA's proposed credit is indeed a disincentive to participation. IMA Resp. at 3.

ComEd explains that the IPA's current methodology yields a credit of only about 7% of the customer's RPS charges or $0.364475/MWH. ComEd Obj. at 4. As a result, it is unsurprising to IMA that just two customers are participating in the program. IMA maintains that the Self-Direct Program clearly is not operating as the General Assembly intended or as the Commission anticipated. IMA Resp. at 3.

IMA notes that the IPA asserts that it expects that between 500,000 and 1 million RECs will be retired this year and claims that this demonstrates that the participation rate is "robust" because the IPA's evaluation "demonstrated that at most 1.5 million RECs could even be eligible to participate in the program." IPA Resp. at 14-15. It is unclear how this qualifies as robust participation given that the IPA admits that just two customers are participating in the Self-Direct Program. There are hundreds of businesses in Illinois that could have participated in the Self-Direct Program, and the IPA reported that it sent requests for information to sixty-six "potentially interested corporate end-users." IPA

Large Customer Self-Direct RPS Compliance Program, Proposed 2023 Delivery Year Program Size at 6 (Jan. 20, 2023). It is unclear how many customers the IPA expected to participate, but 97% of the companies that the IPA self-selected as being "potentially interested" chose not to participate. IMA Rep. at 5.

IMA further notes that the IPA has failed to identify any specific steps that it can or will take to make the Self-Direct Program more attractive going forward, and based on its own self-assessment of the program seems content with no further customer participation. Therefore, the obligation falls squarely on the Commission to decide whether the Self-Direct Program is going to be a meaningful incentive to encourage private investment in renewable projects in a way that will help the State meet its clean energy goals. IMA Rep. at 5.

As ComEd observes, the Commission is required to decide each case on the record presented and a change in circumstances can warrant a different conclusion in this proceeding. *See* ComEd Obj. at 5. The NRG Companies likewise explain that even when the Commission considers issues identical to those in a previous case, it is free to reach a different conclusion based upon the current record. *See* NRG Companies Obj. at 7. The IMA agrees. Indeed, the structure set forth in P.A. 102-0662 requires that the IPA revise its proposed procurement plan periodically and come before the Commission to enable the Commission to evaluate what revisions, if any should be made to the procurement plan, including the Self-Direct Program. *See* 20 ILCS 3855/1-75(c); 220 ILCS 5/16-111.5(b)(5); IMA Resp. at 3-4.

IMA avers that the Commission should take several unambiguous steps in this proceeding to improve the Self-Direct Program. If the Self-Direct Program is properly designed, it will provide an incentive for large energy users to satisfy their sustainability goals in a manner that will accelerate the Illinois' efforts to satisfy its RPS goals. IMA Resp. at 4.

First, IMA proposes that the Commission adopt ComEd's proposal to increase the Self-Direct Program credit value. ComEd proposes that the credit should be increased to "the lesser of the fixed RPS credit amount or the cost of IPA procurement of similarly situated RECs". ComEd Obj. at 4. This approach would recognize that it is cost-effective to engage and empower large energy users to help the State meet its RPS goals. IMA Resp. at 4.

Second, the Commission should require the IPA to annually determine the value of the self-direct credit that will be applicable for the entire term of the qualifying contracts that are entered into that year. Self-Direct Program participants are required to make a minimum of a ten-year commitment to purchase renewables under the terms of the Self-Direct Program. If the credit is to have any impact at all on customers' decisions about whether to enter into such a substantial long-term agreement, IMA asserts that the customers must be able to calculate the financial incentive upfront. IMA Resp. at 4-5.

Third, IMA proposes that the Commission provide incentives for Self-Direct Program participants to procure more than 40% of their supply needs under the terms of the Self-Direct Program. When parties challenged this component of the IPA's original program design, the Commission simply noted that "[t]he 40% threshold in the statute is an eligibility criteria, nothing in the statute suggests that the credit should be scaled based on the level of RECs purchased." *2022 LTRRPP Order* at 39. While P.A. 102-0662 may not clearly mandate that the credit be scaled, IMA argues that there is nothing that would prohibit such a structure. As currently designed, once a participating customer has committed to procuring 40% of its supply needs under the terms of the Self-Direct Program, there is no incentive for it to procure any further supply under the Self-Direct Program. Given the clear need to find ways to attract additional participants to the program and have them procure more RECs under the terms of the program, IMA avers that large energy users who procure more than 40% of their supply under the Self-Direct Program should receive additional credits to recognize the value of the additional contribution toward satisfying the State's RPS goals. IMA Resp. at 5.

With these three straightforward revisions to the Self-Direct Program, IMA states that the Commission could send a clear signal that large energy users are an important component in the State's transition to a clean energy economy. IMA Resp. at 5.

E. IPA's Position

The IPA explains that under the Self-Direct Program, large electricity customers who purchase qualifying RECs to offset at least 40% their electricity usage pay a reduced charge on their electric bill to support the state's RPS procurements, thus resulting in reduced charges to those customers and a commensurate reduction in RPS collections. The concerns of ComEd and the NRG Companies seem to be predicated upon the false pretense that the Self-Direct Program is underperforming in some way because the program was not completely filled in the first and only year it has operated thus far. The IPA states that the Self-Direct Program was not expected to fill in the initial year, as the Agency established a program size that was larger than necessary to prevent a situation in which enrollment in the program would be capped. It is premature to state today that excess program capacity is due to any one cause. IPA Resp. at 12-13.

As explained in the LTRRPP, Section 1-75(c)(1)(R) of the IPA Act requires the IPA to establish the Self-Direct Program and design it in such a way to "allow eligible self-direct customer to procure new renewable energy credits from new utility-scale wind projects or new utility-scale photovoltaic projects." 20 ILCS 3855/1-75(c)(1)(R)(3). The statute does not provide the Agency with a target quantity of RECs to be retired through the program. Instead, the Agency is directed to "annually determine the amount of utility-scale renewable energy credits that it will include from the self-direct renewable portfolio standard compliance program[.]" *Id*. To make this annual determination, the statute instructs the Agency to "evaluate publicly available analyses and studies of the potential market size for utility-scale renewable energy long-term purchase agreements by commercial and industrial energy customers and make that report publicly available." *Id*.; IPA Resp. at 13.

The Agency's preliminary analysis determined that the potential range of RECs that could be available for retirement as compliance with the Self-Direct Program was between 1,250,390 to 1,368,350 RECs. The Agency then issued a request for information, and responses indicated that end-users interested in participating in the program would potentially retire only 826,491 RECs in compliance with the Self-Direct Program. Nonetheless, the Agency initially proposed a program size of 3,000,000 RECs for the 2023 delivery year. In the stakeholder feedback process based upon the IPA's initial proposal, one entity urged the IPA to set the program size at 4 gigawatts ("GW") (approximately 14 million RECs). The Agency rejected this proposal, noting that a program of that size represents approximately 10% of the overall electric load statewide, and is a very substantial amount of renewable energy resources. Despite the fact that the Agency's analysis indicated a significantly lower number of RECs would be eligible for the Self-Direct Program in 2023, the IPA set the program size for 2023 at 3 million RECs in order to ensure that all initial applications to the Self-Direct Program could be accommodated. IPA Resp. at 13-14.

The Agency's evaluation of the potential market size, conducted in accordance with the provisions of Section 1-75(c)(1)(R) of the IPA Act and the *2022 LTRRPP Order*, demonstrates that the Self-Direct Program is achieving an expected level of participation. The IPA argues that it is appropriate to describe the rate of participation in the Self-Direct Program as robust, considering the resultant market size under the statutory limitations on eligibility (including the requirement that projects be "new," geographic limitations, customer size requirements, 10-year contract minimums, and REC retirement minimums). IPA Resp. at 14-15.

The Agency believes it is premature at this point to assume that the crediting rate is the limiting factor for participation in the Program. The IPA opines that there are many other possible reasons that eligible participants did not participate, apart from assumed dissatisfaction with the crediting level. For example, the Self-Direct Program is in its inaugural year, and it may be that there are low levels of awareness around the existence of the program. There may be confusion or limitations on participation due to the requirements that participating projects must be built with project labor agreements, pay prevailing wage, and meet requirements of the Minimum Equity Standard ("MES"). There may be other contractual requirements that prevent potential participants from applying. Finally, the Agency understands generally that renewable developers are continuing to experience energization delays due to lingering supply chain issues from the previous several years; given that projects cannot apply to the Self-Direct Program until after energization, this may have delayed participation by some entities. These are just some of the many speculative reasons that an eligible participant may not have sought to participate in the Self-Direct Program in 2023. IPA Resp. at 15-16.

Nonetheless, ComEd and NRG both gravitate towards a solitary solution to the non-existent issue of low participation rates in the Self-Direct Program: an increase in the crediting rate for the program. The IPA suggests that NRG and ComEd advocate for an increase to the crediting rate based solely upon policy considerations that contravene Illinois law. IPA Resp. at 16.

ComEd correctly recognizes the IPA's position that the Self-Direct Program bill credit cannot be modified due to statutory limitations and the Commission's *2022 LTRRPP Order*, which established the methodology for calculation of the bill credit rate. ComEd argues that there is no *res judicata* at the Commission, and that the Commission may consider new evidence gained since the matter was last evaluated and may entertain new arguments. ComEd Obj. at 5. The Agency agrees that the Commission is not strictly bound by its prior decisions; however, the Agency notes that the establishment of the bill credit rate is a matter of statutory interpretation and not a factual determination. IPA Resp. at 16.

The self-direct bill crediting methodology is set forth explicitly in Section 1-75(c)(1)(R)(4) of the IPA Act. The Commission rendered a well-reasoned decision that generously interpretated the provisions of 1-75(c)(1)(R)(4). The IPA likewise took a generous interpretation of the Commission's Order and adjusted the crediting methodology accordingly. The IPA maintains that the bill crediting methodology put forth in Section 6.5.1 of the 2024 LTRRPP follows the process set forth in the Final 2022 LTRRPP, in accordance with the law and the Commission's statutory interpretation rendered in the *2022 LTRRPP Order*. IPA Resp. at 17.

In the 16 months since the Commission issued its *2022 LTRRPP Order* interpreting the statutory requirements around the self-direct bill crediting methodology, there has been no change in law with respect to 1-75(c)(1)(R)(4) of the IPA Act. While the Commission has broad authority to reach a decision on the facts presented and the record before it and is not bound by *res judicata*, the courts do not look favorably upon decisions where an administrative agency departs from its prior practice in interpretation of rules and statutes. Illinois courts apply a heightened degree of appellate scrutiny where there is a departure from past Commission practice, and the courts afford less deference to the Commission's interpretation of the statute in such cases. *BPI* at 228. Here, where there is no change in law that would require a departure from its past practice, the Agency does not recommend that the Commission alter its recent interpretation of the IPA Act. IPA Resp. at 17-18.

Moreover, the Agency notes that the proposal of NRG Companies to align the crediting rate with competitively-bid REC prices would have been a straightforward statutory directive that the General Assembly could have chosen to include in Section 1-75(c)(1)(R) of the IPA Act. It did not; instead, the General Assembly seemingly recognized that such an approach would create a regressive system, whereby large commercial and industrial customers would essentially be exempted from contributing towards RPS collections. Worse still, large customers might be exempted from RPS charges for REC retirements that do not facilitate the development of new renewable energy facilities. At present, self-direct crediting thus results in the pool of funds available to support new renewable energy projects (the RPS budget) being reduced to support rate relief for large customers in a manner not structured to support new project development; this dynamic underscores why the bill crediting limitations of Section 1-75(c)(1)(R)(4) constitute sensible public policy choices that cannot simply be overlooked in service of increased participation. The IPA avers that the proposal of the NRG Companies to align the bill crediting rate with utility-scale REC prices is inconsistent with the provisions of 1-75(c)(1)(R)(4) of the IPA Act and must be rejected. IPA Resp. at 18.

The IPA states that ComEd's example regarding the City of Chicago only emphasizes that there is not a need to revamp the program and states that the City of Chicago announced in August 2022—after the *2022 LTRRPP Order* —that it planned to participate in the self-direct program based on its purchase of energy and RECs from the Double Black Diamond Solar project. To the best of the Agency's knowledge, the City of Chicago still plans to participate, although its purchase of energy from the project would not begin until 2025, and therefore the City cannot enroll in the program until that year. Providing an inflated credit to self-direct customers for actions already undertaken in full awareness of circumstances would do nothing to drive new renewables development and would be a significant misuse of RPS funds. The successful financing of the Double Black Diamond Solar project demonstrates that there is not a need for an inflated self-direct program credit. IPA Rep. at 15-16.

ComEd's and IMA's narrative that the current self-direct program creates a "disincentive" to participation is, in the IPA's view, false and was rejected by the Commission in Docket No. 22-0231. *2022 LTRRPP Order* at 39 ("The Commission is not convinced by arguments that the IPA's proposed Self-Direct Program credit will be a disincentive to participation. . . . The Self-Direct Program helps these companies pay for RECs that they intended to purchase anyway."). The Self-Direct Program provides a credit—that is, a decreased RPS charge—for participants. The IPA maintains that the Self-Direct Program is in no way a "disincentive," it is simply not as high an incentive as some stakeholders would like. IPA Rep. at 16.

ComEd, NRG, and IMA all emphasize that a robust self-direct program would help the State meet its RPS goals and use this posturing to support their claim that self-direct customers should be paid essentially the same as if they were directly providing RECs to meet the RPS targets. But when a customer participates in the self-direct program, the IPA explains, the RECs the customer purchases do not count directly toward meeting the RPS targets. The self-direct customer does not transfer the RECs to the IPA or to a utility for retirement towards the RPS, but instead keeps them, and may use these RECs to meet its own individual sustainability or social responsibility goals (which companies set for reasons wholly unrelated to the availability of the self-direct credit). When a self-direct customer procures RECs, this does reduce the RPS goals, but not at a one-to-one rate. It would therefore be both unlawful and unreasonable to credit self-direct customers at a one-to-one rate (i.e., the price at which the IPA procures utility-scale RECs) rather than at the rate based on the methodology the Commission approved last year, and ComEd, NRG, and IMA's proposal to do so must be rejected. IPA Rep. at 18.

ComEd, NRG, and IMA also argue that the self-direct credit rate should be set in the first year of a customer's contract for RECs and 'locked-in' for the duration of that contract. In response, the IPA notes that the IPA Act specifically requires the Agency to calculate the credit rate annually and must submit an annual compliance filing to the Commission with "the self-direct credit amount for new *and existing* eligible self-direct customers." 20 ILCS 3855/1-75(c)(1)(R)(4) (emphasis added). This IPA argues that this language would be read out of the statute if the credit rate was locked in for existing customers for the duration of their participation in the self-direct program. In the *2022 LTRRPP Order*, the Commission considered the same argument that the credit should be locked in for the length of a contract and did not adopt this approach. Instead, the Commission directed the Agency to increase predictability by using a three-year rolling average "to determine an annual credit amount." *2022 LTRRPP Order* at 39-40; IPA Rep. at 18-19.

Second, NRG and IMA argue that self-direct customers should receive a higher credit for matching a higher percentage of their usage with RECs. The IPA argues that this conflicts with the *2022 LTRRPP Order* and with the IPA Act. The 40% requirement is set out amongst a list of statutory requirements "[f]or renewable energy credits to count toward the self-direct renewable portfolio standard compliance program" and states that the RECs must be "be equivalent in volume to at least 40% of the eligible self-direct customer's usage." 20 ILCS 3855/1-75(c)(1)(R)(2)(iv). In the 2022 LTRRPP Order, the Commission explained that "[t]he 40% threshold in the statute is an *eligibility criteria*, nothing in the statute suggests that the credit should be scaled based on the level of RECs purchased." *2022 LTRRPP Order* at 39 (emphasis added). While IMA acknowledges that the law does not "mandate that the credit be scaled," it claims that "there is nothing that would prohibit such a structure." IMA Resp. at 5. The IPA contends that this is untrue. The Act gives a very detailed description of how the Agency should set the self-direct credit, and that single credit amount is set annually. Given the specific explicit directions from the legislature, there is no room to argue that another calculation may be made, as any "prorated" or "scaled" credit amount would necessarily be inconsistent with the statutory methodology. The Agency encourages the Commission to approve Chapter 6 of the 2024 Plan as filed. IPA Rep. at 19-20.

F. Commission Analysis and Conclusion

The Commission declines to direct the IPA to revise the Self-Direct Program. Rather than the principles that the NRG Companies want the Commission to adhere to, the Commission is guided by the fact that every dollar refunded back through the Self-Direct Program to large customers constitutes a dollar that is no longer available to support new renewable energy project development through IPA programs and procurements.

Under ComEd's proposal, as clarified by the IPA, the self-direct customers would provide little or no funding for the overall RPS budget, while only paying for the least expensive RECs (which they keep and retire for their own purposes). IPA Rep. at 16-17. It is necessarily more expensive to procure RECs from programs like Illinois Shines and Illinois Solar for All, which support smaller projects that incur substantially higher per-kW costs or pursue worthy social objectives such as equity and low-income customer support. The proposal from ComEd, NRG, and IMA, however, would allow self-direct customers to side-step their share as Illinois ratepayers of supporting the State's clean energy goals.

The Commission agrees with the IPA that the Self-Direct Program is performing as intended. The LTRRPP sets the credit amount as required by statute: the Agency looks at the percentage of the RPS budget that is used for utility-scale procurements (whether that is 5% or 40%) and reduces the customers' RPS charge by that percentage. No changes to the LTRRPP are adopted.

V. CHAPTER 7. ILLINOIS SHINES (ADJUSTABLE BLOCK PROGRAM)

A. Section 7.3.1.1. Group A Oversubscription Challenges and Solutions

1. JSPs' Position

JSPs state that the Commission should approve the changes that the LTRRPP proposes to the structure of the Small Distributed Generation ("DG") and Large DG Blocks for the 2024-25 and 2025-26 delivery years. The IPA correctly identifies the very real concern that Group A for both the Small DG and Large DG blocks has consistently sold out quickly while Group B has sold out far more slowly (if at all) in past years. *See* LTRRPP at 153. Although there are additional longer-term steps the IPA could also take—such as an evaluation of price and non-price barriers experienced by developers for Group B projects—JSPs point out that the LTRRPP proposes meaningful changes to how the Small DG and Large DG Blocks are set up to minimize the boom-bust cycle within Group A (quickly selling out then having no capacity for months) or the sometimes-stagnated capacity in Group B. JSPs Obj. at 3-4.

Except as otherwise provided in these Objections, the JSPs do not at this time object to the remaining aspects of the proposed changes in the LTRRPP. While there are multiple categories including Small DG and Large DG that consistently oversubscribe, the Joint Solar Parties appreciate the focus on behind-the-meter systems at minimum in the short term as the IPA addresses issues with block structure. JSPs Obj. at 5-6.

That said, the JSPs believe the benefits in the LTRRPP's proposed approach do not go far enough because they have limited impact on the 2023-24 Delivery Year. The JSPs propose to convert any Group B capacity still available on the date of the final Order in this docket to capacity that could be applied to either Group A or Group B to immediately relieve buildup of waitlisted projects in the Small DG and Large DG categories. This, in turn, not only helps customers that are ready, willing, and able to "go solar" to accelerate their systems, it also helps Illinois more timely meet its RPS goals by not delaying award of existing capacity. This also ensures momentum and clears the backlog heading into the 2024-2025 delivery year. Furthermore, the ABP budget will not be negatively impacted because all remaining capacity will by definition be in Group B (Group A has already closed for both Small DG and Large DG) and Group B the more expensive RECs for all but 2,000-5,000 kW systems. JSPs Obj. at 6.

The IPA did not appear to oppose the substance or legality of the JSPs' immediate relief objection. Instead, the IPA explains that while it believes there may be limited or no capacity for Group B Small DG to reallocate, the IPA has already worked out mechanics for how such a reallocation could work. The JSPs urge the Commission to approve the IPA's proposed implementation approach. JSPs Rep. at 4.

The only other party to respond was Hawk. According to the most recent project application reports from the ABP Program Administrator reviewed by the JSPs, Hawk does not have any Group A or Group B Small DG or Large DG systems that have been applied or approved. Instead, Hawk has applied about 31.75 MW of community solar to the Equity Eligible Contractor ("EEC") Block, of which 20 MW currently has a REC Contract. JSPs Rep. at 4.

Against that background, JSPs note that Hawk opposes the JSPs' proposal because apparently Hawk expected some of the Large DG and Small DG capacity in Group B would be reallocated toward the remaining 11.75 MW of community solar submitted by Hawk during post-block reallocation pursuant to Section 7.3.4 of the LTRRPP. Hawk does not argue that moving capacity from Group B Small DG and Large DG to Group A of those same categories will impact Hawk's Small DG or Large DG projects. Hawk does not even allege that the JSPs' proposal will prevent Hawk from having some or all of its 11.75 MW of its as-yet unselected projects from being selected (or, if a delay is anticipated, the hardship to Hawk of that delay). JSPs Rep. at 4-5.

The JSPs fully understand the need for predictability and stability in the ABP and the JSPs fully support the EEC Block as one of several P.A. 102-0662 mechanisms to benefit EECs. However, it is a bit far afield to argue that speculative reductions to reallocated capacity at the end of the delivery year are contrary to the statutory mandate to benefit EECs—especially when Hawk takes no objection to deprioritization of the EEC Block in future years within the unallocated capacity ranking. JSPs Rep. at 5.

JSPs opine that Hawk's authority arguments are equally unconvincing. Section 16-111.5(b)(5) of the PUA provides no restriction on the time period covered by an LTRRPP. In fact, rather than separate two-year plans as Hawk suggests, the General Assembly provided for an LTRRPP that could be revised at any time: "The Agency shall publish for comment the initial long-term renewable resources procurement plan no later than 120 days after the effective date of this amendatory Act of the 99th General Assembly and shall review, and may revise, the plan at least every 2 years thereafter." 220 ILCS 5/16-111.5(b)(5)(ii)(B); *see also* 20 ILCS 3855/1-75(c)(1)(A). The IPA and Commission would be exercising their authority to, respectively, propose and approve revisions to the LTRRPP within the two-year review window. That the IPA has typically proposed revisions for delivery years ending after approval is indicative of custom, but the plan revision was properly noticed and is an open proceeding before the Commission. JSPs Rep. at 5-6.

2. Hawk's Position

Hawk objects to JSPs' proposal for two primary reasons. First, JSPs' proposal is procedurally deficient. It is inconsistent with the 2022 LTRRPP and thus requires a modification to the 2022 LTRRPP in Docket No. 22-0231 rather than approval in this docket. Such a major modification to program administration at this stage (four months prior to the conclusion of the program year) and in this docket, rather than in Docket No. 22-0231 where the change to this program year can be litigated, is inconsistent with past practice and weakens reliance on LTRRPPs in the future. Hawk Resp. at 1-2.

Second, JSPs' proposal shifts capacity to Small and Large DGs at the expense of Approved Vendors ("AVs") with projects on the EEC waitlist. This result is inconsistent with the General Assembly's policy directives and is inequitable to the EEC AVs, who have justifiably relied on the 2022 LTRRPP and other program guidance to plan, develop and allocate their own resources for this program year. This late-stage change places those investments at risk without reasonable warning. Hawk Resp. at 2.

Lastly, from an equity perspective, Hawk also notes that EEC participants are not yet as well organized as the entrenched solar industry participants who are advocating for this change. The voices of EEC business are not as well represented in this proceeding because they are newer businesses with fewer advocacy channels. This late-stage rule change seems to further advance existing inequities as opposed to allowing for a more level playing field. The type of advocacy that has led to this change advantages large corporate residential and DG companies at the expense of less well-funded and less well-organized EEC businesses, the exact types of companies that P.A. 102-0662 was in part designed to support. Hawk Resp. at 2.

Section 16-111.5(b)(5) of the PUA requires that the IPA prepare and file an LTRRPP for review and approval by the Commission. 220 ILCS 5/16-111.5(b)(5)(i). The design of the PUA is for the LTRRPP to be reviewed and revised at least every two years for the forthcoming program years. 220 ILCS 5/16-111.5(b)(5)(ii)(B). Program participants rely on the LTRRPP because the Agency and the Administrator "shall implement all programs authorized by the Commission in an approved [LTRRPP] without further review and approval by the Commission." 220 ILCS 5/16-111.5(b)(5)(iii); Hawk Resp. at 2-3.

JSPs' proposal to restructure allocation of uncontracted capacity immediately, effective for the 2023–2024 Program Year, is an amendment to the 2022 LTRRPP and exceeds the scope of the 2024 LTRRPP. The 2024 LTRRPP acknowledges that the 2022 LTRRPP "detailed the Agency's proposals for procurements and program activity to be conducted during the 2022–23 and 2023–24 program years." LTRRPP at 3. Hawk maintains that constraining the scope of each LTRRPP to a two-year period is consistent with the review and approval processes set forth in Section 16-111.5 of the PUA. This schedule is further consistent with the IPA Act's objective in the Illinois Shines program to "provide a transparent annual schedule of prices and quantities to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time." 20 ILCS 3855/1-75(c)(1)(K); Hawk Resp. at 3-4.

Hawk notes that past practice is also consistent with litigating and amending the processes for the current Program Year in the 2022 LTRRPP Docket No. 22-0231, which is how the Agency amended provisions related to EEC protocols in early 2023. Commingling the 2024 LTRRPP with operational directives for the 2023–2024 Program Year, which are already established in the 2022 LTRRPP, will create confusion and uncertainty in the LTRRPP review process this year and in future years. If this practice is sustained, then stakeholders must assume going forward that operational directives in the second program year for each LTRRPP biannual period will be at risk of amendment in the docket litigating the forthcoming LTRRPP. That is, stakeholders participating in the 2025–2026 Program Year will face uncertainty during the 2026 LTRRPP comment, review, and litigation period. This injects uncertainty in the market and affects project and price planning, and thus undermines the General Assembly's policy directives in Section 1-75(c)(1)(K) of the IPA Act and 16-111.5(b)(5) of the PUA. This market uncertainty will exist not only in the Illinois Shine program, but in all procurement programs addressed in the LTRRPP. Hawk Resp. at 4.

Hawk argues that JSPs' proposal to reallocate uncontracted capacity away from the EEC block waitlist effective immediately is inconsistent with the General Assembly's policy directives and is inequitable to EEC AVs, which have relied on the allocation priorities set forth in the 2022 LTRRPP in their own resource planning. The EEC category in the Illinois Shines program was designed to advance "priority access to the clean energy economy for businesses and workers from communities that have been excluded from economic opportunities in the energy sector, have been subject to disproportionate levels of pollution, and have disproportionately experienced negative public health outcomes." 20 ILCS 3855/1-75(c-10). The AVs in the EEC block have justifiably relied on the 2022 LTRRPP, as set forth above. Hawk Resp. at 5.

The dismantling of the EEC AVs' expectations for rollover capacity is contrary to the General Assembly's policy directive. Hawk asserts that those AVs have historically faced barriers to entry and the Illinois Shines program incentives, including priority of access, have enabled AVs to invest in their projects on the EEC waitlist with a reasonable degree of expectation that uncontracted capacity will rollover to the EEC waitlist and those investments will matriculate to executed REC contracts once the program year concludes.

Currently, there are 19 projects on the EEC Group A waitlist totaling 81.433 MW and one project on the EEC Group B waitlist totaling 4.99 MW (including those developers on the waitlist due to the developer cap). The combined Small and Large DG capacity in Group B for the 2023-2024 Program Year is currently 80.19 MW. Thus, the uncontracted capacity in the Small and Large DG blocks, along with uncontracted capacity in the public schools block and the EEC DG block, is expected to rollover to the EEC block and allow some, if not all, of the waitlisted EEC projects to obtain REC contracts in the 2023-2024 Program Year. This is a significant advancement of the General Assembly's and the Agency's policy directives as they relate to EEC participation. Hawk Resp. at 6.

This reasonable expectation of return has allowed EEC AVs to continue to develop and supplement their investments accordingly, thus furthering the General Assembly's policy directive even while some Blocks of the program are currently at capacity. Reprioritizing allocation of uncontracted capacity in February 2024—fewer than four months before the end of the program year and approximately 9 months after approval of the 2022 LTRRPP, as modified on May 9, 2023—is unjust to those AVs, escalates risk to their investments and runs counter to the policy directive of the General Assembly. Hawk Resp. at 6.

3. IPA's Position

In Section 7.3.1.1 of the Plan, the Agency addresses a persistent issue impacting the DG categories of the Illinois Shines program, particularly with respect to Group A (generally, the Ameren and MidAmerican service territories as well as many rural electric cooperatives). Applications submitted to Group A in the Small and Large DG categories have historically filled available capacity at a significantly faster rate than Group B in the same categories. In recognition of the fact that the IPA Act requires the Agency to design the Program in a manner "to provide for the steady, predictable and sustainable growth of new solar photovoltaic development in Illinois," the Agency developed a five-part solution which it anticipates will have a positive benefit to participants in Illinois Shines, while still meeting the requirements of the law and having a minimal impact upon the RPS budget. 20 ILCS 3855/1-75(c)(1)(K). Under the proposed approach, the IPA will (1) eliminate the distinction between Group A and Group B for the purposes of allocating capacity across both distributed generation categories, (2) increase the overall size of the Illinois Shines program from 667 MW to 800 MW annually, (3) adjust the prioritization for the reallocation of uncontracted capacity at the close of each annual Program Year, (4) prioritize the ability of DG projects to participate in the Public Schools and Equity Eligible Contractor ("EEC") categories, and (5) implement a price adjustment cap to provide certainty around the REC price available to waitlisted projects. LTRRPP at 153-156; IPA Resp. at 19-20.

While supporting the approach for addressing the persistent lack of available capacity in Group A and B of the Small/Large DG categories, the Joint Solar Parties also ask the Commission to expand the elimination of the Group A and Group B distinction to the current 2023-24 Program Year in this proceeding. If the Commission believes that it is necessary to make capacity allocated to Group B distributed generation categories available to Group A projects upon the approval of the 2024-25 Long-Term Plan, the Agency will direct the Program Administrator to begin reviewing waitlisted Group A applications for Part I approval. If the Commission adopts this approach, the Agency will consider any project fully submitted to Group B before 11:59 p.m. on the date of the Commission's ruling to have secured capacity in Group B; the capacity that will be available to Group A projects will be considered the capacity that is available in the Group B distributed generation blocks at 12:00 a.m. on the first day following the approval of the Plan. The Group A projects would be allocated remaining capacity from Group B Small and Large DG blocks prior to the launch of the 2024-25 Program Year. The Agency notes that for projects to be considered to have received an allocation of capacity, they must be both batched and submitted, according to the process outlined in Section 7.10.1 of the Plan and in the Program Guidebook. IPA Resp. at 20-21.

The Agency does not agree with Hawk. The two-year revision cycle of the LTRRPP is determined by Section 16-111.5 of the PUA, but the posture of the LTRRPP governing the RPS for only the two program years subsequent to the Plan's approval is an interpretive decision made by the IPA and approved by the Commission. Hawk cites the 2024 Plan as governing only program years 2024-2025 and 2025-2026, but the language Hawk cites specifically notes that "*[u]nless otherwise indicated*, the activities in this plan operate on the same cycle[.]" LTRRPP at 1 (emphasis added). The Agency does not find this language to be controlling; in future years, the Agency may propose that the Plan provisions operate on a longer cycle than a two-year cadence. The Agency is not aware of any limitation on the Commission's authority to approve a provision in the pending LTRRPP that is applied to the current program year or to projects submitted in prior program years, but strongly cautions the Commission to weigh the policy implications of doing so. As noted by Hawk, applying potentially retroactive provisions may create confusion, uncertainty, and risk to participation in both the Illinois Shines program and, more broadly, across the RPS. The Commission may prefer the flexibility, however, to modify the administration of the RPS on urgent or priority issues on a going-forward basis only, while reducing some of the confusion, risk and uncertainty raised by Hawk in its response. IPA Rep. at 21-22.

4. Commission Analysis and Conclusion

The Commission agrees that there is flexibility in the statutory language regarding the cycle for LTRRPP but having approved the 2022 LTRRPP in Docket No. 22-0231, the Commission will not in this Order make changes to it. This docket considers the 2024 LTRRPP, not the 2022 LTRRPP. The Commission is concerned about notice, disruption, and confusion for participants in the RPS. Changes to the 2022 LTRRPP would more appropriately be considered in a re-opening of the 2022 LTRRPP. Accordingly, the JSPs' proposal concerning the current program year is not adopted. The Commission approves the Agency's five reforms to address uneven subscription for the 2024 LTRRPP.

B. Section 7.4.3.1. Traditional Community Solar Scoring Guidelines

1. EEC Subcontractors

a. JSPs' Position

Under the proposed updates to the scoring rubric for Traditional Community Solar ("TCS"), the Joint Solar Parties note that there are more scoring options for AVs that commit to using EECs for a portion of engineering, procurement, and construction ("EPC") tied to fixed percentages of the REC Contract. *See* LTRRPP at 164. The JSPs support the structure and policy behind the change in the LTRRPP, because it provides more points (and thus a greater incentive) to make greater use of EECs as contractors and subcontractors. The JSPs further support the top scoring opportunity going to a project where an EEC is not only the EPC, but an EEC also serves as the AV, providing a persistent preferential opportunity for EECs. JSPs Obj. at 12.

However, for the remaining three scoring categories that are open to non-EEC AVs that use EECs as their EPC, the JSPs urge the Commission to modify the LTRRPP to clarify what subcontractors an EEC general contractor may use. Specifically, the JSPs urge the Commission to direct the Agency to clarify that if an EEC general contractor retains some non-EEC subcontractors, the non-EEC subcontractors' contractual payments will not count toward the EEC spending goal, but the mere participation of a non-EEC subcontractor is not a complete disqualifier. The JSPs note that the language of the LTRRPP is ambiguous, and other documentation appears to be contradictory (or at least potentially inconsistent). JSPs Obj. at 13.

The JSPs believe the clarified approach to allow EEC prime contractors to hire non-EECs but to have the non-EEC's contract value subtracted out strikes the right balance between ensuring EEC general contractors can find subcontractors statewide as EECs still continue to register or form in response to P.A. 102-0662 while ensuring that AVs cannot claim any spend on non-EECs toward the EEC spending goal. This approach ensures an AV's commitment to spend at least 25% (3.d), 50% (3.c), or 75% (3.b) of REC Contract value on EECs actually applies toward contracts and subcontracts with EECs. JSPs Obj. at 14.

JSPs note that the IPA makes three arguments against the JSPs' proposal. First, the IPA argues that an EEC may simply pass along work to a non-EEC subcontractor under the JSPs' proposal. This argument is demonstrably incorrect. Under the JSPs' proposal, this approach would not succeed, because spend on an EEC Contractor would be reduced by spend on non-EEC subcontractors. In other words, if—to use extreme numbers—an EEC had a $1 million general contractor contract where the REC Contract is worth $1.8 million but subcontracted with a non-EEC for a $900,000 subcontract, the EEC amount would only be $100,000. That amount would not qualify for any threshold within the IPA's proposal and would lead to the system being removed from the ABP for failure to meet the EEC commitment. JSPs Rep. at 12.

Second, the IPA incorrectly asserts that it most helps EECs to prohibit subcontracting. To the contrary, JSPs argue that prohibiting EECs from subcontracting with non-EECs on complex community solar systems just means that an opportunity that would have been available to an EEC (as general contractor and to perhaps share some work with a non-EEC) is now unavailable. By requiring EEC general contractors to not subcontract, the IPA is paradoxically limiting work to companies to be owned by those with socio-economic disadvantage but that are expected to take on multi-million dollar full-scope EPC projects with no non-EECs. The IPA implies that this will create jobs at EECs, but the reality is it will just remove opportunity from all but the most established entities owned by Equity Eligible Persons ("EEPs")—which, of course, are unlikely to qualify for the as-yet-undefined socio-economic status. The JSPs further note this is especially challenging for the proposed 25-50% REC Contract value bucket, where an

EEC may perform subcontract or general contractor work of that value in parallel with non-EEC scopes. JSPs Rep. at 12-13.

Third, the IPA expresses concerns about "practical realities" of the JSPs' proposals, specifically about achieving commitment levels. The JSPs respond that the IPA can require submission of invoices by subcontractors (EEC and non-EEC) and payment (by the general contractor) to calculate the total spend on EECs backing out spend on non-EECs. This is hardly much of a step beyond demonstrating payments to the EEC general contractor. Because all community solar is subject to prevailing wage requirements and must submit certified transcripts of payroll, there will be an easy cross-check on the contractors involved. To the extent that an AV does not meet its REC Contract value goals, the AV will have their system removed from the ABP—a very strong incentive to ensure that EECs are receiving payment for work done by EECs at the level required by the claimed points. JSPs Rep. at 13.

The JSPs urge the Commission to examine the practical realities of construction (as well as engineering and procurement). The opportunity for EEC general contractors is far worse if they are forced to do everything and cannot subcontract to non-EECs. The JSPs' approach ensures that EECs are receiving every dollar that an AV pledges in its application while also empowering EECs to take on jobs they could not do without subcontracting. The JSPs' Objection to Section 7.3.1.1 should thus be adopted and the IPA's opposition rejected. JSPs Rep. at 13-14.

b. LiveWire's Position

For the first time in its BOE, LiveWire proposes that the Commission consider one additional mechanism to encourage AVs in the Traditional Community Solar block to include additional EEC subcontractors to undertake the work necessary to complete these projects. If the Commission wants a "strong incentive to ensure that EECs are receiving payment for work done by EECs at the level required by the claimed points," (PO at 41), it should also consider the ability for the non-EEC AV to include additional EEC subcontractors after the Part I submittal without the non-EEC AV needing to withdraw their Part I application. In other words, LiveWire explains, treat the EEC/non-EEC subcontractor value attribution on a "rolling" basis that may be later adjusted upwards to move the non-EEC AV's application ahead in the TCS waitlist for project selection. This would not only reduce the scoring appeal process and random selection for non-EEC AVs but would also increase participation of multiple EEC companies working alongside non-EEC AVs on TCS projects, enable EEC firms to support one another in meeting the 50% or 75% REC contract value, and prevent any "pass-through" scenarios to guarantee legitimate EEC firms are self-performing the designated labor per the attestation rule. LiveWire BOE at 2.

According to LiveWire, fulfilling 50%-75% of the total REC contract value for a single project is difficult for one EEC firm. Recognizing that one EEC may not be able to meet 100% of an AVs needs, if an AV applying for a project in the Traditional Community Solar block finds additional EECs with whom it might partner after Part I submittal, it should be given credit for "substituting" a non-EEC subcontractor with an EEC. Thus, while the current approach allows an AV to substitute one EEC for another EEC after Part

I submittal, the current rules discourage additional EECs joining the project after Part I submittal. LiveWire BOE at 2-3.

c. IPA's Position

The IPA explains that in Section 7.4.3.1 of the 2024 Plan, the Agency lays out a scoring process for TCS projects that prioritizes projects that commit to work with EEC contractors and subcontractors in development of a project. The Agency measures the level of commitment to work with EECs against the value of the REC Contract for the project. There are multiple scores available for varying levels of commitment to work with EECs; as the level of commitment to engage EECs to perform the substantive work on a project increases (25-50%, 50-75%, or over 75% of the REC Contract value), the points awarded during the TCS scoring process also increase. The purpose of the differentiation is to reward exemplary projects that seek out increasing opportunities to work with EECs and assist in the successful development of that market segment. It is the Agency's hope that through providing these opportunities, AVs developing TCS projects will assist in creating opportunities for EECs in the clean energy economy, and create meaningful, quality, and permanent jobs for the employees of EECs. IPA Resp. at 23-24.

In order to ensure that this portion of the scoring rubric assists in the development of opportunities for EECs, the Agency requires that the AV applying to the TCS category demonstrate a commitment to working with EEC partners at both the initial Part I stage of the application process (during which the project is initially scored and, if Part I verified and selected, awarded a REC Contract) and in the final Part II application stage (at which point a project is verified as built and energized in full compliance with Program requirements, and becomes eligible to invoice for REC incentives). In the event that the EEC identified on the Part I application is unable to participate in the project due to unforeseen circumstance, an AV may seek a substitution of the EEC between Part I and Part II, through a written request to the Program Administrator, which is subject to review and verification. IPA Resp. at 24.

To ensure that EECs actually perform the substantive work for which they are contracted, and the work is not simply passed through to non-EECs, EECs may not subcontract their work to non-EECs for projects participating in the TCS category where a project received additional points for EEC commitments. The Agency is concerned about the possibility that an EEP, perhaps one that is not from a historically disadvantaged group yet qualifies as equity-eligible based upon residency in a gentrifying neighborhood, may establish an EEC with no employees and merely pass through work to another non-EEC subcontractor. This type of business model would be incompatible with the spirit of the law and the establishment of the EEP/EEC designation under Section 1-10 of the IPA Act, which is intended to identify "persons who would most benefit from equitable investments by the State designed to combat discrimination." 20 ILCS 3855/1-10; IPA Resp. at 24-25.

The JSPs seek to allow EECs to subcontract a portion of their work to non-EEC subcontractors and subtract that portion from the commitment made to support EECs. The Agency is aware that the current slate of EECs is small; however, the Agency is also obligated under the IPA Act to assist in the development and growth of this market segment. *See* 20 ILCS 3855/1-75(c)(1)(K)(vi) (directing the IPA to increase the size of the EEC category from 10% to 40% of the entire Illinois Shines program over time). The IPA believes that the TCS scoring rubric as proposed both incentivizes AVs to work with the EECs currently operating in the marketplace and creates opportunities for newly-formed, emerging businesses developed by EEPs to fill gaps. If the Agency were to permit the subcontracting of work committed to go to EECs to non-EECs, it would not create opportunities within the program for the participation of new EECs in the future and reduce opportunities for additional job creation by EECs. Finally, the IPA has concerns about the practical realities of the Joint Solar Parties' proposal. AVs must make the commitment to work with EECs at the Part I application; any downstream decisions to subcontract out that work to non-EECs would change the commitment level after the points had already been awarded and the project selected. The Agency believes that the current TCS scoring rubric will help to facilitate the development of EECs in all categories of work while minimizing the complexity of overseeing fulfillment of the commitment level, and that the requirements surrounding the subcontracting out of EEC commitments should remain in place. IPA Resp. at 25-26.

In response to LiveWire, the IPA states that the approach suggested by LiveWire would be administratively burdensome and potentially create more challenges to the Program than benefits to EEPs and EECs. The IPA explains that it has always been a requirement in Illinois Shines that projects be fully designed and planned prior to Part I submissions; LiveWire's proposal would undermine this bright-line rule and create additional work for the Program to review and score projects multiple times. A better approach is for Approved Vendors to secure as many EEC subcontractors as they wish prior to submitting their TCS project. LiveWire's proposal would also potentially be unfair to other participants by introducing a new element of uncertainty. Projects on the TCS waitlist could not be assured of their spot because at any time a lower-ranked project could swap subcontractors and suddenly jump forward on the waitlist. For these reasons, the Agency cannot support the proposal at this time. The IPA notes that parties have not had the opportunity to fully evaluate this proposal and urges LiveWire and other stakeholders to provide feedback and suggestions on the Long-Term Plan as early as possible within the process to afford a thorough analysis and consideration of those proposals. IPA RBOE at 18.

d. Commission Analysis and Conclusion

In Section 7.4.3.1 of the 2024 Plan, the IPA provides a scoring process for TCS projects to prioritize projects committing to work with EEC contractors and subcontractors. Under the IPA's scoring process, higher levels of EEC commitments give projects the ability to earn more points on Part I applications. As the level of commitment to engage EECs to perform the substantive work on a project increases (25-50%, 50-75%, or over 75% of the REC Contract value), the points awarded during the TCS scoring process also increase. The IPA explains the purpose of the differentiation is to reward exemplary projects that seek increasing opportunities to work with EECs and assist in the successful development of that market segment. IPA Resp. at 24. The Commission approves the Agency's proposal to incentivize the use of EEC contractors and subcontractors in the development of TCS projects through this scoring model.

While the JSPs support the structure and policy behind the changes to the TCS scoring rubric, the JSPs request clarification on whether the mere participation of a non-

EEC subcontractor is a complete disqualifier where a project has received points in Part I scoring for EEC commitments. JSPs Obj. at 12. JSPs propose non-EEC subcontractors' payments would not count toward the EEC spending goal as calculated in Part II applications for purposes of determining whether a project's Part I commitments were met. The Commission agrees with IPA that EECs must perform the substantive work to qualify for additional points for EEC commitments in TCS Part I applications. The Commission clarifies that the business model contemplated by the JSPs is not prohibited. However, TCS projects that receive points for EEC commitments in Part I applications may not subcontract out work to non-EEC firms.

The Commission notes that LiveWire's proposal is untimely and therefore interested stakeholders have not had an opportunity to adequately respond to it. In addition, the Commission is concerned that it would be administratively difficult for the IPA to implement. Accordingly, it is not adopted.

2. Agrivoltaics and Pollinators

a. JSPs' Position

For TCS systems that receive agrivoltaics points by committing to agrivoltaics at the time of application, the LTRRPP requires that 50% of the project footprint must feature agrivoltaic production at the time of project energization. *See* LTRRPP at 163. For many agrivoltaic sites, the agricultural use includes grazing livestock. While this timing is not problematic in a vacuum, sites also adhering to pollinator-friendly standards must plant native plant species, which need two or three growing seasons to become established on a solar site prior to grazing begins or else the grazers will destroy them. The JSPs recommend that the Commission modify the LTRRPP to allow agrivoltaic production—specifically grazing—to start 2-3 years after planting pollinator-friendly plants rather than requiring grazing to begin at or before energization. This change will allow native plant species to become established on community solar sites to allow the plants to thrive and simultaneously achieve adequate growth to nourish grazers like sheep. JSPs Obj. at 28-29.

The JSPs note that the IPA drafted the LTRRPP in a way that encourages agrivoltaics and pollinator-friendly projects, and it is unclear why the IPA is opposed to projects that attempt to meet both favored policy outcomes at once. The JSPs interpreted the points system as the IPA's intention to incentivize certain types of projects because they provide desired policy outcomes. In other words, the JSPs believe the purpose of the points system (rather than another project selection approach) is to align the incentives of AVs and desired policy. If that is not the case, the Commission should reevaluate the basis for points and reassign points to outcomes that do provide favorable outcomes. JSPs point out that the Commission encourages coexistence of pollinator friendly and agrivoltaic projects by providing additional leeway for grazing agrivoltaics as proposed by the JSPs. JSPs at 24-25.

b. IPA's Position

The Agency understands that the issue is not one where the agrivoltaic feature—grazing of livestock—cannot be implemented at the time of energization, only that a project seeking to increase its total score available under the Built Environment category cannot easily do so when seeking to utilize both agrivoltaics and a separate pollinator-friendly habitat commitment. The Agency is not persuaded that JSPs' proposal is a necessary change. As explained above in the discussion of EECs, the IPA has developed scoring criteria that are designed to encourage the development of projects with certain attributes and achieve policy goals of more diverse projects around the state. The purpose of the criteria is not to establish a pathway towards maximizing points available for the use of greenfield space for photovoltaic development. If AVs find that it is difficult to incorporate pollinator-friendly habitats with grazing agrivoltaics, they may seek to utilize another type of agrivoltaics or forgo the points. Additionally, it would be administratively burdensome for the Agency to confirm whether a project has begun grazing two to three years after the project is energized and begins invoicing. Further, non-compliance risks increase substantially when program requirements are not enforced until several years after a project begins invoicing for REC incentives. As a result, the Agency urges the Commission to reject the proposed modification. IPA Resp. at 26-27.

c. Commission Analysis and Conclusion

The Commission does not adopt the JSPs' proposal. Unlike the previous issue regarding EEC subcontractors, future compliance with this proposal is not easily monitored. Also, the JSPs' proposal does not appear to further any goal of P.A. 102-0662, but rather it only increases the points available in order to increase a project's score.

3. Signed Interconnection Agreement

a. Ameren's Position

In the *2022 LTRRPP Order*, the Commission ordered the IPA to give greater weight in the current plan to TCS projects with a signed interconnection agreement ("ICA"). *See 2022 LTRRPP Order* at 58-60. Ameren notes that the primary indicator of whether a community solar facility is ultimately developed is whether it receives a REC award and not whether there are any issues related to the physical interconnection of the facility. Ameren also notes that due to the success in P.A. 102-0662 in spurring significant numbers of interconnection applications for renewable generation facilities, it is common for projects with approved RECs to be delayed while Ameren performs the required studies to interconnect the speculative community solar applications. These delays have an impact not only on the financing for the projects that have RECs in hand, but on customers as well, specifically, their receipt of the economic benefits from installing on-site generation, which affects the projects' economic viability. Based on these experiences, Ameren recommends the IPA and Commission reconsider this requirement, as it results in numerous speculative and complex interconnection applications being filed, which delays consideration of other applications that have a high likelihood of construction and operation. AIC Obj. at 3.

In its Reply, Ameren agrees that any DG project applying for RECs, including a community solar project, is more likely to proceed to fulfillment if it has a signed ICA than a project lacking a signed ICA. The issue is the impact of the IPA's inclusion of this factor in its weighting for awarding RECs within this very competitive segment of DG projects, especially since none of these projects actually proceed to construction unless they receive RECs. Community solar developers view the signed ICA as a de facto requirement since it is a large component of the overall scoring of the applications, and they properly strive for any advantage possible for their sites and projects to secure the RECs that make their projects viable. AIC Rep. at 2.

As a result, utilities like Ameren receive far more project applications than can be reasonably supported by available RECs. In the initial community solar REC award program, approximately 800 applications were submitted to Ameren for 34 potential project awards. That dynamic is being repeated in the current proposed REC award process. Ameren has, to date, received 247 applications for 5MW facilities that are intended to provide community solar services. The current community solar REC pool for Group A, including equity eligible contractors and community driven solar projects is 85MW, or enough to support only 17 (seventeen) 5MW projects. AIC Rep. at 2.

Of the 247 total 5MW projects currently in queue, 78 are at the top of their queue. Even assuming that each of the 78 projects has interconnection costs that are feasible and supportable from a project economics perspective, 61 of those projects will not be constructed because they will not receive RECs. That means those 61 projects are blocking consideration of all projects behind them in 61 different queues, and those blocked projects could include school projects, behind the meter projects, or EEC projects, projects that have received full REC funding, etc. AIC Rep. at 2-3.

The proposed LTRRPP is allocating 150MW of RECs in Group A for community solar projects. That equates to 30 generation facilities. Even if one assumes the more conservative current "applications received to available REC funding" ratio, it is reasonable to expect 430 applications for the 30 (thirty) available awards. Since there are 2,500 potential queues in Ameren's service territory, 1/6 of the queues could potentially have projects delayed due to speculative community solar applications. AIC Rep. at 3.

In addition to behind the meter customers and generation developers, these delays impact the IPA as it identifies and investigates the reasons why awarded RECs go unused. Delays in construction mean greater likelihood of changes in project financing or available markets that could halt some projects that were awarded RECs but languished behind speculative applications. AIC Rep. at 3.

Ameren states that the additional information and context surrounding the challenges that are being created by the current system should provide the Commission the necessary information to make an informed decision and adopt the Company's request to remove the inclusion of the ICA as a scoring metric for community solar REC awards. AIC Rep. at 3.

Ameren notes a technical correction to footnotes 316 and 318. The interconnection rules in Part 467 are for projects with nameplates >10 MW. Since community solar is limited to a maximum nameplate size of 5MW, the Part 466 processes are applicable to this section of the Plan. The footnotes should be revised accordingly to refer to Article 3 of Part 466 Appendix D. AIC Obj. at 9.

b. ComEd's Position

The LTRRPP's TCS solar scoring guidelines comprise 16 points. Four of those points essentially give weight to TCS projects with a signed ICA and based on their resulting interconnection queue position. LTRRPP at 163-167. ComEd supports

Ameren's request that the Commission reconsider its prior decision to give weight to TCS projects with a signed ICA and based on their queue position. As Ameren notes, whether a TCS project has an ICA has diminished significance in the environment of the large increase in the number of interconnection applications due to the enactment of P.A. 102-0662. AIC Obj. at 3; ComEd Resp. at 8.

ComEd's experience continues to overwhelmingly indicate that the status and queue position of a TCS project having an ICA is not an accurate indicator of the maturity of the project. The assignment of four points to this subject leads to a poor use of utility resources and creates costs that pass through to projects and utility customers. The resulting weighting leads to large numbers of speculative interconnection applications that artificially inflate the amount of pending distributed energy resources ("DER") in the interconnection queue which, in turn, causes more complex and time-consuming interconnection studies yielding unrealistically high distribution upgrades and associated interconnection cost estimates. These complications stemming from a glut of speculative projects further lead to increased time to approve interconnection applications. ComEd Resp. at 8-9.

The value of an executed ICA varies based on changes in the interconnection queue, because the applicant's spot in the queue can affect the costs assigned to the applicant and the costs required to accomplish the interconnection. Assigning any points to this subject is not warranted and can have detrimental effects on the utility, applicants, and utility customers. ComEd Resp. at 9.

The IPA disagrees with Ameren's recommendation, arguing in part that whether a project has an ICA "has proven to be a somewhat reliable indicator of project viability". IPA Resp. at 21-23. ComEd does not share the IPA's view. Since 2020, 428 community solar projects have executed ICAs, 365 remain active, 12 have been interconnected, and 51 have been withdrawn (as of December 7, 2023). It remains to be seen which of the 365 active projects proceed to interconnection. The active project volume is significantly higher than that which the IPA has availability of RECs to award, so ComEd states that additional withdrawals can reasonably be expected. Any project that remains in the queue causes adverse impacts on later-queued projects and creates interconnection cost uncertainty because cost estimates must assume that the earlier queued project proceeds to interconnection, and pursuant to 83 Illinois Administrative Code Part 466 and Part 467, the generating capacity of those earlier queued projects are required to be incorporated into the interconnection studies for later queued projects. ComEd Rep. at 12.

ComEd maintains that the Commission should direct the removal of the assignment of points to this subject in the Scoring Guidelines for TCS projects. ComEd Resp. at 9.

In response to 22c, ComEd explains that since the Commission's Order in Docket No. 20-0700, all interconnection requests are required to pay a fully refundable deposit equal to 100% of their project costs within 15 days of executing an IA. ComEd argues that awarding points for signed ICAs and additional weight to the earliest ICA creates ineffective incentives to sign ICAs, remain in the queue if a REC contract is not awarded, and block projects behind them from consideration. *Ill. Commerce Comm'n, Amendment* *of 83 Ill. Adm. Code 466 and 467*, Docket No. 20-0700, Order (May 25, 2022); ComEd RBOE at 4.

c. JSPs' Position

The Joint Solar Parties believe Ameren's viewpoint glosses over important issues. While it may be true that many community solar facilities do have REC Contracts prior to construction, it is also true that community solar systems with infeasible or prohibitively expensive interconnections do not get built—REC Contract or not. The REC Contract addresses this very contingency, allowing for an AV to recover 75% of its collateral if it receives an interconnection cost estimate of $0.30/Wac or higher. Having projects be selected and subsequently dropping out is not in the interests of the solar industry, the IPA, or achieving the goals of P.A. 102-0662 on behalf of the State of Illinois. The JSPs thus recommend that the Commission not change Section 7.4.3.1 of the LTRRPP. JSPs Resp. at 7-8.

d. 22c's Position

For the first time in its BOE, 22c suggests that to help separate projects that are speculative from those that have a high likelihood of construction and operation, points should continue to be awarded to TCS projects with signed ICAs only where the Approved Vendor can show proof it has fully paid the interconnection upgrade costs to the relevant utility company ranked in the order of the date of which costs have been received by the relevant utility company. 22c BOE at 2-3.

e. Joint NGOs' Position

For the first time in its BOE, the Joint NGOs state that they are troubled by the elimination of an ICA for scoring criteria under the TCS category. The Joint NGOs believe the IPA's scoring criteria helps ensure that all projects accepted into the program meet a minimum set of criteria to avoid speculative or immature projects. Its inclusion will help weed out projects that are likely to fail and support ones that are able to thrive. Additionally, the Joint NGOs state that eliminating a signed ICA will not do much to alleviate the congestion that the utilities are concerned with. There were many projects in the past year that had ICAs, and there were a number of projects without an ICA that scored highly and were selected for the 2023/2024 program year in the TCS category. Therefore, ICAs do seem to be a meaningful criterion without proving to be a barrier to otherwise viable projects. JNGO BOE at 2.

f. IPA's Position

The IPA explains that Section 1-75(c)(1)(K)(iii)(1) of the IPA Act states that "the Agency shall select projects on a first-come, first-serve basis, however the Agency may suggest additional methods to prioritize projects that are submitted at the same time." 20 ILCS 3855/1-75(c)(1)(K)(iii)(1). The Agency, in prioritizing projects for the TCS category, awards points to projects with a signed ICA. The ability to secure an ICA (and the cost of the interconnection) significantly affects the likelihood that a project is developed, thus the Agency does not support removing interconnection points from the TCS scoring guideline. IPA Rep. at 24.

The IPA further explains that prior to the approval of the 2022 LTRRPP, the Agency required all systems above 25 kW to have a signed ICA in hand to apply to the Illinois

Shines program. The IPA treated an executed agreement as an important indicator of project readiness; however, the requirement was repeatedly contested by some stakeholders who argued that it unnecessarily clogged utility interconnection queues with speculative projects. This ultimately spurred the Commission to order Staff to initiate workshops to explore revisions to the interconnection rules arising from the approval of the Agency's Revised LTRRPP approved in Docket No. 19-0995. *Ill. Power Agency*, Docket No. 19-0995, Order at 43 (Feb. 18, 2020). The Agency proposed for the first time in the 2022 Plan to remove the requirement that community solar projects must have a signed ICA to apply to the Program, and ultimately, the Commission determined that the ICA should not be categorically required but should be considered among the TCS scoring criteria. *2022 LTRRPP Order* at 58. The approach outlined in the 2024 Plan follows the Commission's directive from that proceeding. IPA Resp. at 21-22.

Ameren recommends the Commission and the Agency reconsider whether to award additional points to TCS projects that submit an application with a signed ICA, as ordered by the Commission in the approval of the 2022 Long-Term Plan. In support of its argument, Ameren states that "the primary indicator of whether a community solar facility is ultimately developed is whether it receives [a REC Contract] and not whether there are any issues related to the physical interconnection of the facility." AIC Obj. at 3. The IPA notes that Ameren appears to have inadvertently conflated "RECs" with "REC Contracts" in its discussion of ICAs. Projects do not have "RECs in hand" prior to interconnection, as the first REC from a project does not exist until 1 MWh of generation has been produced by a system. IPA Resp. at 22.

The Agency disagrees with Ameren's assertion. It has become clear to the Agency that interconnection cost has a significant impact upon whether any large photovoltaic facility is ultimately developed. The Agency sees community solar projects repeatedly held back in the Illinois Shines application process by AVs that are awaiting interconnection cost estimates. Additionally, the Agency has started to see project attrition for photovoltaic projects due to interconnection costs so high that the development of the system is not financially viable. Where the Agency previously felt that it may be possible to remove consideration of the community solar interconnection issue completely from project selection, it has proven to be a somewhat reliable indicator of project viability. Accordingly, the Agency does not believe it would be appropriate to remove consideration of the interconnection from scoring of TCS projects. IPA Resp. at 22-23.

The Agency agrees with the arguments of the JSPs. The JSPs are correct that having projects selected and then dropping out shortly afterwards is unfavorable, creating midstream changes in available program capacity and resulting in overall administrative efficiency challenges. The IPA agrees with the JSPs that an ICA is an important indicator of whether a project will be developed, and applicants with an executed ICA should receive additional consideration through the awarding of points at project selection. The Agency believes that the proposal to award additional points for projects during project selection that have a signed ICA appropriately balances the interests of solar developers, who are trying to navigate the interconnection queues, and the utilities, who are seeking to control the deluge of projects to the interconnection queue. IPA Rep. at 25-26.

Additionally, the Commission has considered this issue and similar arguments in the past and concluded that ICAs and their associated costs merit consideration in the application for a REC incentive contract. While the Commission is not bound by previous Orders or decisions, the Commission in its *2022 LTRRPP Order* determined that the ICA should be considered in TCS scoring, with the IPA (in consultation with stakeholders) given the discretion to determine the appropriate number of points to award to this category. *2022 LTRRPP Order* at 58. Given the continued frequency with which the IPA sees interconnection issues become a roadblock to project development, the 2024 Plan's approach aligns with the Commission's *2022 LTRRPP Order* and considers ICAs for TCS scoring but does not categorically require them. While the IPA appreciates the challenges presented by the increasing number of renewable projects being built in Illinois and thus entering the interconnection queue, the Agency does not believe ComEd raises any new arguments, and the ICA continues to be a reliable indicator of project maturity. As such, the Agency asks the Commission to approve Section 7.4.3.1 of the 2024 Plan as is. IPA Rep. at 26.

Ameren also raises two small technical corrections within Section 7.4.3, relating to footnotes identifying the model ICAs from the Commission's rules. The IPA appreciates Ameren's attention to these details and agrees the technical corrections are necessary. The Agency will update the footnotes 316 and 318 of the final 2024 Plan accordingly. IPA Resp. at 23.

In response to 22c, the IPA states in its RBOE that while the IPA believes that it may be too late for the parties to fully explore this proposal, the Agency notes that any scoring mechanism which retains consideration for an executed interconnection agreement is preferable to the complete elimination of interconnection status from scoring. The Agency notes that 22c's approach limits the ability to consider interconnection agreements by only awarding points if the developer can show proof that it has fully paid the transmission upgrade costs to the relevant utility ranked in the order of the date in which costs have been received by the utility. The IPA urges the Commission to allow for consideration of all signed interconnection agreements in the TCS scoring criteria in this proceeding. IPA RBOE at 16-17.

g. Commission Analysis and Conclusion

The Commission continues to be troubled by this issue and sees no good answer. The Commission appreciates the utilities' efforts to control the burden of performing multiple interconnections studies and alleviate issues with the queue. On the other hand, the Commission sees the merit in the IPA's argument that a signed ICA indicates that a project is ready to proceed to energization. The economics of making the determination of whether to go forward with a TCS project often requires knowledge of both the interconnection costs and the ability to secure incentives through the Illinois Shines program.

When addressing this issue in the *2022 LTRRPP Order*, the Commission hoped that having a signed ICA as merely a source of points but not actually a requirement for receiving a REC Contract would help lessen the issues raised by the utilities. It appears that these issues persist, as both Ameren and ComEd explain.

The Commission understands that this problem presents challenges to all interested parties: the AVs during project development, the utilities in the management of the interconnection queue, and the IPA in the administration of the Program. If a project is awarded a REC Contract and then submits an interconnection application and the cost of interconnection is too steep, it appears from the JSPs' comments that an AV is allowed to recover 75% of its collateral if it receives an interconnection cost estimate of $0.30/Wac or higher. An AV must submit an interconnection application prior to the development of a project and must most likely pay for one or more studies to determine the cost of interconnection with the utility. A project is entered into the interconnection queue with no certainty that it will be financially feasible to interconnect at that interconnection point, as any distribution system upgrades required for interconnection must also be paid by the interconnecting party. As explained by the IPA, the interconnection cost has a significant impact on whether any large photovoltaic facility—which, at sizes of up to 5MW, TCS projects are—is ultimately developed.

The Commission understands the difficult position of the utilities in determining the interconnection costs of projects in the queue, because the position of a project in a queue determines its costs and the costs of the project behind it. In other words, entering an interconnection queue impacts that TCS project, the IPA, and any other project wishing to interconnect at that point. Similarly, if a project is awarded a REC Contract and the project must drop out of the queue because it is later determined that the interconnection costs are too high, there is disruption to the AV who drops out, has paid for program application fees and interconnection studies, and lost a portion of its collateral under the REC Contract. Other projects in the queue behind that project at that interconnection point with a lower initial interconnection cost estimate are disrupted. As explained by the IPA in its Response, the Program is disrupted.

It is clear to the Commission that both the cost of interconnection and the ability to secure a REC Contract have an impact upon whether a community solar project in Illinois is ultimately developed. The Commission notes that whether or not a project in any category of Illinois Shines receives a REC contract under the Program, the project cannot be built and energized without a signed interconnection agreement. That is, large photovoltaic projects may move forward without securing a REC Contract, but they may not move forward without securing an interconnection agreement.

While switching from making a signed ICA a requirement to merely a source of points did not fully alleviate the issues raised by the utilities, the Commission finds that it is appropriate to continue to award points for projects that have a signed interconnection agreement. This approach balances the interests of the utilities in managing the interconnection queues, solar developers in understanding costs estimates and securing necessary agreements in the development of their projects, and the IPA in managing the TCS category. The Commission urges all stakeholders to continue exploring ways to expedite project development.

The Commission notes that 22c's proposal is untimely and fails to consider that all interconnection requests are required to pay a fully refundable deposit within 15 days of executing an ICA. It is not adopted.

C. Section 7.4.5. CDCS Project Selection

1. Joint NGOs' Position

The Joint NGOs object to the inclusion of physical location as a primary selection criterion for Community-Driven Community Solar ("CDCS") projects. The definition of "community" was clearly designed to accommodate community affiliations that do not obey geographic boundaries. P.A. 102-0662 states that Illinois' solar program must include:

> At least 5% from community-driven community solar projects intended to provide more direct and tangible connection and benefits to the communities which they serve or in which they operate and, additionally, to increase the variety of community solar locations, models, and options in Illinois.

20 ILCS 3855/1-75(c)(1)(K)(v). The use of the phrase "or in which they operate" clearly articulates the Legislature's intention that the physical array serving a CDCS project does not necessarily need to be in close physical proximity to the community which it serves. Nevertheless, the IPA has included physical proximity not only as a selection criterion, but it has used location as a screening criterion to exclude very strong candidate projects in the 2023-2024 Delivery Year, although it is not explicitly stated in the LTRRPP or the Program Guidebook. JNGOs Obj. at 2-3.

The Joint NGOs recognize the IPA's authority under the IPA Act to develop project selection criteria for the CDCS category but aver that the current utilization of these criteria does not align with the legislative intent of the statute. The IPA Act emphasizes the need for CDCS projects to provide a "direct and tangible connection" to the communities they serve. However, the interpretation and implementation of these criteria by the IPA, particularly the emphasis on location as a significant factor, appears to skew the intent towards a mere geographical consideration. This approach potentially overlooks the broader and more substantive aspects of what truly constitutes a "community-driven" initiative. JNGOs Rep. at 0-1.

The IPA's stance that its criteria aim to increase the variety of community solar location models and options raises practical concerns. By prioritizing location as a primary factor, there is a risk of inadvertently limiting the scope and diversity of CDCS projects. Particularly, this could restrict the development of innovative community solar models that, while not geographically situated within certain communities, could offer significant benefits and engagement to those communities. Furthermore, the IPA's response suggests that its approach is a remedy to the shortcomings of the initial authorizing statute. However, the Joint NGOs argue that this remedy, in its current form, does not fully realize the envisioned community-driven model. It is essential to strike a balance between geographical proximity and the broader objectives of community engagement, inclusivity, and diverse model development. JNGOs Rep. at 1.

2. IPA's Position

Physical location of the community solar project as a threshold criterion for selection in the CDCS category was included in the 2022 Long-Term Plan and uncontested in that proceeding; modifications to Section 7.4.5 have been proposed for the 2024 Plan that clarify this threshold requirement as a result of the fact that a single AV did not understand the threshold requirement. CDCS projects are intended to provide benefits to the communities in which they operate. Prior to the enactment of P.A. 102-0662, community solar projects were generally large and transactional, built to maximum size in agrarian areas to leverage low land costs and economies of scale. This was not the more localized, community-driven model that some advocates had envisioned. The creation of the CDCS category is one of several "qualitative" modifications to the Illinois Shines program that was established through changes to the IPA Act under P.A. 102-0662 that were intended to remedy shortcomings of the initial authorizing statute. IPA Resp. at 27-28.

While the Agency believes the requirement that CDCS projects be sited in the communities they serve is aligned with the intent of the General Assembly, the Joint NGOs argue that the requirement is contradictory to the provisions of the IPA Act. The IPA respectfully disagrees. While the Joint NGOs are correct that the IPA Act defines the CDCS category as projects "intended to provide more direct and tangible connection and benefits to the communities which they serve or in which they operate[,]" the Agency notes that the projects are also intended "to increase the variety of community solar locations, models, and options in Illinois." 20 ILCS 3855/1-75(c)(1)(K)(v). A CDCS category which continues to allow for the development of large, transactional projects built to maximum size in agrarian areas of the state simply does not increase the variety of community solar locations, models, and options as the Agency is directed to do by the statute. IPA Resp. at 28.

Furthermore, the Agency has the clear authority under the IPA Act to develop project selection criteria for the category, which has seemingly been ignored or overlooked by the Joint NGOs. The same subsection of the IPA Act quoted by the Joint NGOs provides explicitly that "the Agency shall develop selection criteria for projects participating in this category." *Id.* The Agency has already exercised its authority to develop selection criteria for the CDCS category in the 2022 Plan—with the approval of the Commission—and requires that projects be located in the community that they are intended to serve. This threshold criterion helps ensure that there is a "direct and tangible connection" to the community, while simultaneously "increasing the variety of community solar locations, models, and options in Illinois[,]" as required by the IPA Act. The Commission should not remove an important, established CDCS project selection criterion to facilitate the development of additional remote, agrarian solar farms physically disconnected from the communities they serve. In the alternative, should the Commission disagree with this approach, the IPA must have authority to adjust the CDCS selection criteria to require that projects located outside the communities they serve are not large projects built to maximum size in agrarian areas of the state, and instead include some other forms of "direct and tangible" connection to the community that they serve. IPA Resp. at 28-29.

3. Commission Analysis and Conclusion

Although the Joint NGOs may be correct regarding the language of the IPA Act, the IPA's interpretation is reasonable given the issues regarding the original community solar category. The Commission will not require any changes to the LTRRPP and allows the IPA to continue to require a project to be geographically located in the same community as it is intended to serve.

D. Section 7.4.5.3. CDCS Developer Cap

The IPA initially proposed that a developer cap be imposed on projects waitlisted from 2023-2024 for inclusion in the 2024-2025 program year, but in response to comments, has withdrawn that proposal. This issue appears to be settled for purposes of this LTRRPP proceeding, and the IPA's withdrawal of the developer cap is approved.

E. Section 7.4.6.2. EEC Eligibility

1. ESI's Position

ESI objects to the proposed wording change from "projects" to "contracts" in Section 7.4.6.2, which would prohibit EEC AVs from assigning a REC Contract to an AV that is not an EEC for six years after the Part II verification date of the project. ESI notes this change is confusing because the IPA did not explain the reason for or the intended consequence of the change. Also, the sentences immediately following continue to use the term "project". ESI asks that the IPA clarify the intended effect of this change via its response in this docket, provide revised language to make the intended effect clearer in the Plan, and make conforming changes to other pages in the Plan where the six-year moratorium is discussed. ESI Obj. at 8.

ESI has long followed the plain language of the EEC project-transfer moratorium in the approved Plan, requiring that any EEC project must be owned by the EEC for an initial period of six years beyond the Part II Application. *See* 2022 LTRRPP at 176. ESI understood this policy as intended to incentivize longer-term ownership and involvement by EECs and their EEPs in the development and operation of the EEC's solar facilities, while discouraging EEPs and EECs from flipping a planned EEC project to a non-EEC buyer as soon as a project receives a REC Contract award and before it is even constructed. Notably, the Program Guidebook defines "project" as "[a] solar photovoltaic array and all associated equipment necessary for its generation of electricity and connection to the distribution grid. (Same as "System")." *See* Program Guidebook at 103 (August 3, 2023). Meanwhile, the IPA Act defines "project" as "the planning, bidding, and construction of a facility," which is inconsistent with the Program Guidebook. 20 ILCS 3855/1-10. ESI Rep. at 3-4.

ESI argues the difference between the plain language in the rule as written, both in the current Plan and Program Guidebook, and its implementation appears to be a material change. ESI notes that it is imperative that rule changes contrary to the plain language of the approved Plan not be implemented until they are publicly published, go through the stakeholder process, and are approved by the Commission. A Plan approved by the Commission should not be changed without going back to the Commission for reapproval. *See* 220 ILCS 5/16-111.5(b)(5)(i); ESI Rep. at 4-5.

If it is the case that an EEC project can be sold to a non-EEC at any time after receiving a REC Contract, but the project-selling EEC must remain on the REC contract, ESI urges the IPA to look into what conforming changes may need to be made to the relevant form of REC contract, the EEC advance of capital process, transfer provisions of the Program Guidebook, and the Project Application Tracker. ESI Rep. at 5.

Finally, JSPs state that requiring EECs to continue to own their projects for 6 years after Part II application "would have made financing impossible." *See* JSPs Resp. at 9. ESI completely disagrees. Given the plain and long-standing language of the Plan and Program Guidebook, ESI is fully prepared to finance its own projects and to own them for the long term. JSPs do not provide any evidence to support their bold assertion. JSPs also ignore the utility of new tools for solar financing under the Inflation Reduction Act, along with the utility of the advance of capital mechanism that the IPA says is available to EECs that demonstrate a legitimate need for financing support under the program. ESI Rep. at 6-7.

2. JSPs' Position

JSPs state the clear intent of the change is to remove ambiguity over whether ownership of the system itself may be transferred, which would have made financing impossible and would make selling systems to end users (such as residential rooftop) impossible. JSPs assert IPA's change in language is appropriate and the Commission should not modify the Plan as requested by ESI. JSPs Resp. at 9.

3. IPA's Position

The Agency clarifies that the edit in the filed 2024 Plan that changed the word "project" to the word "contract" in the description of the required 6-year delay of any transfer was a clarification edit to align that provision with the existing position that the AV does not need to own the physical project or installation. The IPA concedes that the prior language was confusing, and that it should also update any related language in other parts of the Plan to reflect the more accurate characterization of the role of the AV as the holder of the REC contract. IPA Resp. at 41.

Despite ESI's characterization of this edit as a "significant change," it is in fact simply a continuation of the Agency's long-held approach of allowing AVs to hold REC contracts for projects regardless of ownership. AVs must have the rights to sell the RECs from the projects they develop to the utility-Buyers, but in many cases do not necessarily own the project itself. These edits are intended only to clarify that the REC Contract may not be transferred for six years, but there are no restrictions on project ownership. IPA Resp. at 41.

4. Commission Analysis and Conclusion

The Commission adopts the IPA's edit that changed the word "project" to the word "contract" in the description of the required six-year delay of any transfer. This edit was a clarification to align that provision with the existing position that the AV does not need to own the physical project or installation. The Commission encourages the IPA to make any other necessary conforming changes to the Plan as well.

F. Section 7.4.6.4. EEC Subcategories

1. ESI's Position

ESI disagrees with the IPA about the treatment of EEC subcategories. While ESI understands the IPA's desire to diversify the EEC category between community solar and other DG projects, the treatment of the sub-reservation was previously decided by the Commission. *See* Docket No. 22-0231, Order on Reopening at 14 (May 4, 2023) ("*2022*

Reopening Order"). The 25% subcategories are to remain open for the first nine months of the program year, at which time remaining capacity is to be reallocated to other EEC community solar projects that were submitted during the program year. *Id.* The IPA's proposal to keep the subcategory open for the entirety of the program year (eleven months) and then to direct any unused capacity to the new prioritization will only serve to remove capacity from EEC projects and redirect the capacity to other, non-EEC projects which would receive first priority of any uncontracted capacity at the end of the program year. ESI Obj. at 10.

Because the EEC category created by statute is required to expand until it encompasses 40% of program capacity, taking megawatts from EEC, reserving it for DG projects (of which to date there have been no EEC applications) and return it to the total pool at the end of the program year is inconsistent with statute and the supposed preference for EEC projects. The Commission should require the IPA to reallocate any uncontracted capacity in either EEC subcategory to any waitlisted projects within the other EEC subcategory within the same Group A or B. ESI Obj. at 10-11.

2. JSPs' Position

The JSPs oppose removal of a protected category for behind-the-meter systems. These systems are an important part of the solar ecosystem, which means opportunities for EECs should be provided. However, the JSPs also oppose reallocation of EEC Block capacity to other blocks, as the Plan apparently proposes to do. JSPs Resp. at 9.

The JSPs proposed in Docket No. 22-0231 (on reopening) that behind-the-meter systems have capacity protected for eleven months, which the JSPs believe would be appropriate here. This proposal addresses an issue the JSPs have long raised with behind-the-meter as an entry point for EECs: while the installation is relatively simpler, other aspects—marketing and solicitation, customer onboarding, administering REC Contracts, drafting and negotiating customer contracts, developing relationships with financing, warranty providers, etc.—are a substantial barrier to entry into the residential and small commercial marketplace. The JSPs urge the eleven-month protection of behind-the-meter capacity combined with encouraging EECs to work with established developers that already have such systems in place to ensure a positive EEC and customer experience. JSPs Resp. at 9-10.

3. Joint NGOs' Position

The Joint NGOs support ESI's objection with respect to ensuring that capacity reserved for EEC projects remains with EECs instead of reallocating unused capacity to other categories. JNGOs Resp. at 2.

4. Staff's Position

Staff agrees with ESI that the Plan should remain consistent with the Commission's *2022 Reopening Order*. Staff Resp. at 19. While Staff agrees that Commission Orders are not *res judicata*, when the Commission deviates from past practices it must articulate a reasoned basis to do so. *Citizens Util. Bd. v. Ill. Commerce Comm'n*, 166 Ill.2d 111, 132 (1995). Any departure by the Commission from prior orders or decisions must not be arbitrary and capricious. *United Cities Gas Co. v. Ill. Commerce Comm'n*, 235 Ill.App.3d 577, 591 (4th Dist. 1992). The IPA has failed to provide a reasoned basis for this change from the plan approved in Docket No. 22-0231. The Commission wanted to allow time for the development of DG in the EEC category. *2022 Reopening Order* at 14. The IPA's proposal is contrary to the goal stated in Docket No. 22-0231 and the IPA has failed to provide a reasoned basis for the Commission to suddenly depart from that goal at this point in time. Staff Rep. at 14-15.

Accordingly, the Commission should adopt ESI's proposed language set forth in its Objection. Staff Rep. at 15.

5. IPA's Position

While ESI is correct that this issue was also litigated in the reopening of the 2022 Long-Term Plan, prior Commission Orders are not *res judicata* and do not create binding precedent. *Miss. River Fuel Corp. v. Ill. Comm. Comm'n*, 1 Ill.2d 509, 513 (1953). The Commission has the authority to deal freely with each situation that comes before it, regardless of how it dealt with the same situation in a similar proceeding. *Commonwealth Edison Co. v. Ill. Commerce Comm'n* , 405 Ill. App. 3d 389, 407-408 (2d Dist. 2010). "[A]ny finding, decision or order made by the Commission shall be based exclusively on the record for decision in the case[.]" 220 ILCS 5/10-103. "A record containing new evidence that implicates past decisions compels reconsideration on the new record and may require a different result." *Commonwealth Edison Co.,* 405 Ill. App. 3d at 408. As explained in Section 7.3.1.1 of the 2024 Plan, a change in factual circumstances requires a change to the prioritization of the subcategory reallocation is necessary and reasonable. Furthermore, the context of the *2022 Reopening Order* was wholly different than the present circumstances. In that instance, the Agency faced an unexpected influx of community solar project applications into the EEC category with no established process for creating a waitlist or performing project selection. *See* Docket No. 22-0231, IPA Verified Petition for Reopening on the Commission's Own Motion at 5-8 (Dec. 2, 2023). But for the Plan filed to initiate this proceeding, the reservation at issue would not go into effect until the 2024-2025 Program Year; it is speculative to claim that the 25% of capacity reserved for EEC DG projects will not be used. IPA Resp. at 41-42.

In addition, Section 1-75(c)(1)(K) of the IPA Act, the provision that establishes the ABP, states that the "Agency may create subcategories within this [EEC] category to account for the differences between project size and type." 20 ILCS 3855/1-75(c)(1)(K). The Agency states that this language provides express authorization for creating a subcategory for DG within the EEC category. ESI also claims that this subcategory conflicts with creating preferences for EECs, but the IPA understands the entire purpose of the preference for EECs as creating space for new, small, and disadvantaged businesses to grow and access these State benefits. As explained above in the context of TCS scoring criteria and given the very large upfront capital required to develop large community solar projects, the Agency believes holding open program capacity for smaller projects provides the best way to encourage that growth. IPA Resp. at 43.

ESI also objects to the proposal to reallocate unused EEC category capacity according to the proposed prioritization outlined in Section 7.3.4 of the filed 2024 Plan. ESI argues that this is inconsistent with statute and "the supposed preference for EEC projects." *Id.* at 10-11. But ESI does not cite any statutory language that purportedly prohibits this approach. The IPA states that there is no provision of the statute requiring that unused capacity be allocated only to the waitlist of that same category. The Plan's proposal also does not disadvantage EEC projects. The Agency has already significantly increased the percentage of total program capacity allocated to the EEC Category in response to the unanticipated oversubscription of the last program year, and that capacity will increase again due to the proposed increase of the total program size contained in the filed 2024 Plan. Future program years will see continuous increases in the EEC category capacity as the IPA moves toward the statutory goal of the EEC category comprising 40% of total program capacity. Considering these already adopted and planned increases, the Agency does not believe it is necessary to deviate from the prioritization approach for unused capacity proposed in this Plan, which was designed to serve overall policy objectives regarding the types of projects developed in Illinois, not just the identity of the developer. IPA Resp. at 43-44.

The Joint NGOs take issue with this proposal as well and argue that capacity reserved for EEC projects should remain with EECs, instead of being reallocated to other categories. While the IPA is sensitive to the concerns raised regarding preserving opportunities for EECs, the Agency believes that the expansion of the Illinois Shines program size overall and the gradual expansion of the proportion of the program allocated to the EEC category ameliorate this risk. The Agency seeks to balance providing opportunities for EECs against the ability to move forward projects that in many cases are already under development and construction, leaving Illinois residents and businesses awaiting the expected REC incentives that they rely on to help finance the projects. The Agency believes that the 2024 Plan's approach where the proposed allocation process applies to the reallocation of uncontracted capacity remaining at the end of the 2023-2024 Program Year strikes the appropriate balance. IPA Rep. at 22-23.

The JSPs express their support for the Plan's continued use of a DG subcategory within the EEC block and the extension of the protection of that capacity for eleven months. The Agency agrees with the arguments raised by the JSPs and urges the Commission to approve Section 7.4.6.4 without modifications. IPA Rep. at 32.

The Agency notes that Staff also supports the continued use of subcategories within the EEC category, but states that the protection of capacity in the DG subcategory should be available for only nine months, consistent with the *2022 LTRRPP Order*. While Staff does not provide any rationale for this position, the Agency notes once more the myriad reasons raised by the JSPs for a longer timeline. The Agency also notes that any other oversubscribed category must wait until the next subsequent program year for the opportunity to access uncontracted capacity; the IPA argues that eleven months strikes a reasonable balance between the need to keep capacity available for distributed generation projects while providing additional opportunities to EECs that develop community solar projects. IPA Rep. at 32-33.

6. Commission Analysis and Conclusion

The Commission adopts the IPA's position to maintain the establishment of a DG subcategory for the EEC category and to extend the amount of time that the capacity would be held open for behind-the-meter projects from nine months to eleven months. The IPA has clear statutory authority pursuant to Section 1-75(c)(1)(K) of the IPA Act to make that determination. While the timeline was previously nine months, the Commission made that determination in the context of an unexpected influx of community solar project applications into the EEC category with no established process for creating a waitlist or performing project selection. The IPA and JSPs articulated various reasons justifying the longer timeline of eleven months. This reasoning paired with the change in circumstances provides more than enough support for the Commission to extend the timeline from nine to eleven months. The Commission further concludes that the IPA's prioritization approach for unused capacity proposed is reasonable and therefore adopted.

G. Section 7.4.6.5. EEC Developer Cap

1. Joint NGOs' Position

The Joint NGOs object to the exclusion of a lifetime cap on EEC capacity. Even though the EEC category is new, its goals are clear, as the IPA has recognized, and implementation of a lifetime EEC developer cap in the next Program Year is essential to ensure these goals are realized for the greatest number of people. The EEC category was created in P.A. 102-0662 to support EEPs launching new businesses and to enable the growth and stability of existing small EECs that have struggled. If an EEC is succeeding for multiple years in a row, the program has served its purpose for that contractor, and that contractor should make way for newly created EECs seeking the same opportunity. JNGOs Obj. at 4.

As stated in the Plan: "Beginning with the 2023-24 Program Year, the Agency layered a developer cap on top of the subcategories, such that no single EEC (or any of its affiliates—which includes any common ownership across privately-owned entities) may receive more than 20% of an EEC category's Group capacity in a given Program Year." LTRRPP at 183. The Plan goes on to recognize that the IPA received comments on its draft plan proposing a lifetime cap on capacity that a single developer (or family of affiliated developers) could claim from the EEC category. Such a cap could help to ensure that the intended effect of the EEC category to improve access to the clean energy economy for eligible businesses, communities, and workers is maximized, with as many EECs participating over time as possible. Despite acknowledging the potential value of a lifetime cap, the IPA declined to adopt it, stating: "While the Agency generally supports the spirit of this concept, it is premature to implement in the EEC category now, which has only seen two years of implementation thus far. The Agency notes its agreement with this concept and may consider it for possible inclusion in a future Long-Term Plan." LTRRPP at 183; JNGOs Obj. at 4-5.

Consequently, the Joint NGOs propose a cumulative EEC developer cap of 60% of total program capacity over a period of any 3 years of participation, which would operate in tandem with the annual cap of 20%. Once the EEC meets the cumulative cap after three years of participation, that contractor would no longer be eligible to apply for EEC capacity. The ultimate maximum EEC allocation based on the IPA Act is 40% of the total allocation for the ABP, which, for Program Year 6, would be 266.8 MW. Given that the EEC category is designed to scale up over time, the Joint NGOs suggest that a reasonable average capacity allocation for the category is 20%, or 133.4 MW. A company that claimed 20% of that 133.4 MW for three years would claim approximately 80 MW of capacity (20% x 133.4 x 3 = 80.04). This cap is the equivalent of 16 5-MW community solar projects or 11,428 7-kW residential rooftop projects. Building these many projects should be sufficient to allow an EEC to compete with non-EEC Avs. JNGOs Obj. at 5.

The Joint NGOs appreciate both the IPA and AEU noting that the EEC category is still being improved due to the age of this category. The Joint NGOs also believe that the IPA will continue to improve the administration of the EEC category through the next few years as more issues are identified and addressed. However, the Joint NGOs still maintain their position in favor of a lifetime cap on EECs for this category. JNGOs Rep. at 2.

The IPA also states that it will be tasked with growing the EEC category "to 40% of the total program size over time." IPA Resp. at 45. With this in mind, the IPA argues that the consequences of a lifetime cap is totally unknown if and when the EEC category is expanded. The Joint NGOs believe it best that the IPA, Staff, and interested stakeholders address this issue when it arises, including the issue of whether the cap should be recalculated and the mechanics of that process. JNGOs Rep. at 2-3.

While the Joint NGOs maintain that an EEC category cap will be needed to ensure as many newly created EECs get the opportunity to participate in the EEC category, the Joint NGOs look forward to working with the IPA and other stakeholders to analyze additional participation data and revisiting the developer cap at a future date. The Joint NGOs propose requiring future consideration of a cap or other mechanism designed to encourage broad participation instead or making its consideration discretionary. JNGOs BOE at 4-5.

2. AEU's Position

AEU shares the Joint NGOs' interest in seeing a thriving EEC sector in Illinois and agrees that a time may come when a particular contractor no longer needs the benefits of EEC status but concurs with the IPA's conclusion that it is premature to implement a lifetime cap on EECs. The Joint NGOs' alternative proposal of a cumulative EEC developer cap of 60% of total program capacity over a period of any three years of participation may seem more attractive on its face but assumes that an EEC's success rate has been stable or on an upward trajectory. AEU is hesitant to make that assumption since it could result in excluding a contractor that still merits the benefits of EEC status. Given the relatively recent implementation of the EEC category, AEU submits that experience should be gained under additional program years before definitive plans are made to remove contractors from the EEC rolls. The current program year cap of 20% is sufficient for this iteration of the Plan. AEU Resp. at 2-3.

3. JSPs' Position

The JSPs respectfully disagree with the Joint NGOs' approach. First, there is no apparent basis for 80 MW of awards as a threshold to stop EEC participation in the EEC Block. Second, the Joint NGOs' proposed approach simply encourages participants to accept awards of not more than 25 MW per year to stay under the cap without solving the issue of concentration of awards in the hands of a few EECs, which the Joint NGOs seek to resolve. Third, as the JSPs believe with regard to any lifetime cap, the far more effective approach is to impose a developer cap that ensures broad participation. JSPs Resp. at 8.

In its RBOE, the JSPs note the Joint NGOs urge the Commission to require consideration of its lifetime cap proposal in the future. The Joint Solar Parties note that any party can raise the issue in the next LTRRPP approval docket or seek reopening in the interim. The Commission need not predetermine whether a particular issue should or should not be litigated because it is within the control of stakeholders, including the Joint NGOs, to raise any concerns. JSPs RBOE at 5.

The JSPs also highlight that 22c for the first time in its BOE, proposes additional reporting and review. Other than for very specific situations such as co-location, the LTRRPP generally does not impose limitations or reporting regarding developers as distinct from the AV. In addition, EECs may choose to work with established developers for initial projects. That established developers may work with EEC-AVs on development, purchase, or financing of systems applied by an EEC-AV does not implicate a lifetime developer cap. At most, sustained success by a single or small group of EECs may lead to revisions to the annual developer cap. The 22c proposal should be rejected both on its timing and on its merits. JSPs RBOE at 6.

4. 22c's Position

While 22c agrees with the PO's conclusion, it is 22c's position that it could be modified to ensure that the EEC category maximizes access to the businesses, communities, and workers P.A. 102-0662 intended, including those new EEC businesses that have formed since the previous program year, in lieu of larger scale, established TCS or similar AVs or their affiliated non-AV entity (collectively the "TCS Entity"). To that end, 22c suggests that the PO be modified to request that the IPA consider as part of the Part I Application process for a particular project that the EEC submitting the proposal disclose to the IPA on a non-public or proprietary basis the TCS Entity AV ID of the EEC's project development partner as well as the previous project owner, if applicable. The disclosure of this data may assist the IPA in helping determine whether the EEC category is being properly utilized by the businesses, communities, and workers the General Assembly intended under P.A. 102-0662. The disclosure of this data may also assist the IPA with evaluating the merits of a lifetime developer cap in some form, including whether a cap could (or needs to) be applied to a participating TCS Entity at the time of the Part I Application after a certain amount of awards as opposed to EECs that submit project proposals to the IPA. 22c BOE at 4-5.

5. ESI's Position

ESI states in its RBOE that it supports 22c's proposed requirement for confidential disclosure of an EEC project applicant's affiliated developer. Additional disclosure of information regarding the structure and business practices of EECs may be relevant to the IPA's concern regarding who receives benefits from an EEC's participation in the program, both before and after a project is awarded a REC contract. It may also be appropriate to require such disclosures later in a project's lifecycle as well, for example, with the Part II application or upon the sale of a project after a REC contract is awarded. Additional reporting would allow the IPA to gain more information regarding how EEC projects are owned and operated in the longer-term, including whether ownership of the project is transferred to entities other than the EEC that holds the REC Contract. ESI RBOE at 10.

Based on this information, the IPA and the Commission could consider additional requirements in future iterations of the LTRRPP to ensure that non-EECs do not inappropriately participate in EEC project development or ownership. Additional reporting requirements would allow the IPA to address potential concerns on a more targeted basis to more directly address issues that are actually occurring in the market. ESI RBOE at 10.

6. IPA's Position

The Agency does not understand how the Joint NGOs' proposed lifetime developer cap and annual cap are different but does not support adopting either. As the Joint NGOs note, the IPA initially considered the merits of this concept during the stakeholder feedback process, yet ultimately did not include this in the 2024 Plan. The IPA believes that it is too early in the implementation of the Equity Accountability System ("EAS") to impose a difficult-to-track component related to EEC participation. The EEC category is still in its infancy, having launched in December 2021 for the acceptance of DG projects only. In its first full program year, the EEC category began to accept community solar applications, and that process was disrupted by the immediate oversubscription of the category and the reopening of the 2022 Plan in Docket No. 22-0231. The Agency continues to receive applications from new entities for EEC certification and is optimistic that with the other adjustments proposed in the 2024 Plan, there will be sufficient growth to continue fostering new EEC businesses. Finally, the IPA notes that it is directed to grow the EEC category to 40% of the total program size over time. 20 ILCS 3855/1-75(c)(1)(K)(vi). It is impossible in these early years of the category to understand what impact the imposition of a lifetime cap on developers would have on the ability of the Agency to expand the category to that size. Accordingly, the Agency asks the Commission to reject the proposal of the Joint NGOs. IPA Resp. at 44-45.

AEU, like the IPA, believes it is too early to implement a lifetime cap and opposes it. The IPA agrees with AEU and adds that the EEC category continues to receive applications from new entities, making the Agency optimistic that the proposed adjustments in the 2024 Plan will be sufficient to foster new EEC businesses. The IPA maintains that it is too early in the implementation of the EAS to impose a complex component related to EEC participation without sufficient evidence that such a requirement is necessary. As AEU points out, if a lifetime cap is implemented, there is a risk of excluding a contractor that still merits the benefits of EEC status, thus not fulfilling the category's purpose. The IPA appreciates and agrees with AEU, and continues to believe an annual, non-cumulative developer cap as proposed is the most appropriate method of achieving the EEC category's stated purpose. IPA Rep. at 29-30.

The Agency agrees with the JSPs that the purpose of the EEC category is better met by maintaining the proposed annual, non-cumulative developer cap and considering whether a lifetime cap may be appropriate for a future iteration of the Plan. The IPA understands that all stakeholders want the EEC category to succeed and reiterates that it may consider a lifetime cap for inclusion in a future Plan. Accordingly, the IPA urges the Commission to approve Section 7.4.6.5.1 as proposed. IPA Rep. at 30-31.

7. Commission Analysis and Conclusion

The Commission agrees with the IPA, JSPs, and AEU that it is premature to establish a lifetime cap on EEC capacity as the current focus should be on growing and fostering new EEC businesses as set forth in P.A. 102-0662. The Commission also agrees with the JSPs and declines to adopts 22c's proposed modification at this stage to allow for more robust discussion in the future. A cap or other mechanism designed to encourage broad participation as the EEC category grows could be considered at a later time once additional data regarding program participation is available. The Commission declines to adopt the Joint NGOs' proposal to make future consideration mandatory as any party has the discretion to raise it in the future.

H. Section 7.5. REC Pricing Model (and Appendices D and E)

1. JSPs' Position

The Joint Solar Parties' state that their position regarding the REC Pricing Model is that the REC Pricing Model should be as accurate as possible. Of course, a maximally accurate model does not preclude documented (and justified) changes to the cost-based results of the model—however, starting from an accurate model is imperative to justify and document departures from the cost-based approach. To that end, the Joint Solar Parties have identified errors or inaccurate values in the REC Pricing Model both that increase the REC price and decrease the REC price. This is because program optimization requires a REC value that is neither artificially high nor artificially low. JSPs Obj. at 14.

a. Tracking Systems on 5MW Community Solar

The JSPs note that Appendix E does not include costs for tracking systems for 5 MW community solar projects. In the 2022 REC model, the IPA included costs for both fixed tilt and tracking 5 MW community solar systems, the latter of which incurs higher cost. The Joint Solar Parties note the 2022 REC model calculated a cost premium of around 8.5% for tracking systems. However, the 2024 Exhibit E excludes the tracking system category without explanation. The Joint Solar parties believe the 2024 Exhibit E should include an additional tracking system category for 5 MW community solar to account for the premium costs incurred, as was included in the 2022 REC model. They explain that 5 MW community solar systems predominantly use tracking technology. JSPs Obj. at 15-16.

b. EPC Costs

The JSPs assert that the total EPC Cost line item is too low, and at best appears to assume EPC costs for rural areas of Ameren (particularly as it relates to wages) that are not applicable to the ComEd service territory or more population-dense areas. Data from the Illinois Department of Labor shows that average labor rates are 30-40% higher in ComEd territory compared to average Ameren rates based on prevailing wage rates required to be paid for work performed on or after August 15, 2023. Because these rates are statutorily mandated, they present a clear demonstration that labor costs in one service territory are markedly higher than the other. The JSPs opine that this disparity could provide some insight into why all blocks within ComEd territory have been slower than those in Ameren territory. At minimum, the Joint Solar Parties recommend a separate ComEd EPC cost to address higher prevailing wage. JSPs Obj. at 15-16.

The JSPs note that the IPA states that "labor costs are only one portion of the 'total engineering, procurement, and construction' cost" and that "Joint Solar Parties do not specifically recommend a data source that can be relied upon to update the Total EPC Cost line." IPA Resp. at 38. In response, the Joint Solar Parties aver that they provided exactly that data source in their Objections: an analysis of the labor rates that developers are required to pay by law. This cost may not be reflected in the National Renewable Energy Laboratory ("NREL") Benchmark Report, but these are the real-world, statutorily-mandated rates that Approved Vendors are legally bound to pay for installation labor. The JSPs maintain that this data is better than any national average. JSPs Rep. at 14.

Acknowledging IPA's argument that labor costs are but one portion of the total EPC cost, the Joint Solar Parties urge the Commission to direct the IPA to update the data point that feeds into the total EPC line. In Appendix E (REC Pricing Model) on tab "NREL Capital Costs," Installation Labor & Equipment is expressed in Cell H9, which is an input to the "Total EPC Cost" line, expressed on Cell H13. Adding a minimum 30% increase to Cell H9 (and any other relevant cells in the model) for Group B projects only would provide a more accurate reflection of the cost differential required under Illinois law. JSPs Rep. at 15.

c. Land Lease Rate

The Joint Solar Parties believe the land-lease rate is too low; current market rates are about $2,000-2,500 per acre while the model rate translates to a lease rate of about $1,000-1,250. To the extent that the IPA cannot review lease rates of current systems by reviewing site control documents, the JSPs recommend the IPA collect data from participants similar to what the IPA has done for interconnection. JSPs Obj. at 15-16.

d. NREL Benchmarks

In addition to these changes, the JSPs note that NREL provided community solar-specific cost benchmarks for the first time in its September benchmark report. The REC Pricing Model uses a 200 kW roof-mounted system as a proxy for community solar from a 2022 NREL benchmark report, but use of a proxy is not necessary when more accurate data has been produced by a reliable source such as NREL. JSPs Obj. at 16.

e. Rooftop Community Solar Adder

The Joint Solar Parties appreciate that the LTRRPP adopted a REC adder for rooftop community solar systems. *See* LTRRPP at 192-193. The Joint Solar Parties appreciate that the proposed additional $5 per REC was a good-faith attempt at providing a meaningful adder while taking into consideration program costs. However, the Joint Solar Parties reiterate their position that the REC Pricing Model should accurately reflect costs and revenues—at minimum, the LTRRPP should include an assessment of additional costs or impairments to revenue (such as reduced capacity factor due to orientation and use of fixed-tilt panels) for rooftop community solar. JSPs Obj. at 25-26.

As one example of the challenges faced by rooftop community solar, IPA project application report data demonstrates the real-world production differential with ground-mounted systems. The average 2 Mwac rooftop Large DG project on the project application report shows an 18-19% lower capacity factor than the average 2 Mwac community solar project primarily due to the fact that rooftop systems use fixed-tilt racking, while ground-mount systems use trackers. JSPs Obj. at 26.

There is also a material net increase in build costs for a rooftop system over ground-mount of the same size, but this differential is more difficult to introduce into the evidentiary record because collection by the trade associations comprising the Joint Solar Parties raises antitrust concerns. However, the Joint Solar Parties do note that the vast majority of rooftop community solar sites are in more densely populated areas, and that these areas have higher prevailing wages, as discussed above. JSPs Obj. at 26.

The Joint Solar Parties urge the Commission to direct the Agency to assess the differences between rooftop and ground mount community solar and reflect them in the pricing model results for the rooftop adder. Even if the LTRRPP ends up at a round number—though hopefully above $5—the Commission and stakeholders should all have access to a full accounting of diminished value to then debate on fuller information an appropriate adder given the other concerns (such as budget) raised by the LTRRPP. JSPs Obj. at 26-27.

The JSPs note that Summit Ridge provided evidence that the rooftop adder should be $18.47-27.26/REC based on lost revenues from reduced production and reduced useful life and increased costs. While the Joint Solar Parties have not independently vetted the values provided, Summit Ridge's explained logic aligns with evidence submitted by the Joint Solar Parties in Objections which demonstrate—using IPA's own data—that similarly-sized rooftop systems see significantly reduced yield compared with ground-mount Community Solar installations. JSPs Rep. at 22.

Summit Ridge's other assertions were also convincing to the Joint Solar Parties. Specifically, Summit Ridge states that the model should adjust "the EPC (installation) cost up by $0.10/watt" to accommodate for increased rooftop installation cost. While it is true that rooftop systems do not require grading or other site preparation, rooftop systems require other site staging, crane lifts, temporary stairs, and roof access. For warehouse sites, these staging areas diminish use of the parking lot or loading bays for the construction period, further impacting client revenue. Additionally, as noted supra, prevailing wage rates trend higher in areas where the vast majority of rooftop installations have occurred. Taken together, the Joint Solar Parties believe Summit Ridge's assumptions are at minimum directionally correct. JSPs Rep. at 22-23.

The IPA opposed a higher REC value, arguing that $5/REC took into account lost revenues and additional costs. While the Joint Solar Parties may have missed it, it appears that the IPA does not account for reduced project useful life. Developers of ground-mount Community Solar facility will assume a project life of 35-40 years and will model system economics based on that timeframe. But even the most well-built roofs have a typical lifetime of 25 years. In addition, while the IPA stated that it considered that rooftop systems are fixed tilt and "used that information to develop the $5/REC price adder," the IPA does not explain whether $5/REC is intended to fully compensate for lost production (including from useful life) or whether $5/REC is simply intended as a compromise. JSPs Rep. at 23.

To the extent that the Commission does not adopt Summit Ridge's proposed adders, at minimum the Commission should direct the IPA to use Summit Ridge's numbers as a starting point to a more precise adder that at minimum incorporates the lost revenue due to reduced yield, increased EPC cost and reduced system life. JSPs Rep. at 23.

f. Discount Rate

The Joint Solar Parties support ComEd's correction to the REC Pricing Model that looked at undiscounted revenue (i.e. not taking into account the timing of REC payments). JSPs Resp. at 10.

g. Revenue Stream

The Joint Solar Parties also do not object to the modification proposed by ComEd and Ameren to recognize that community solar subscribers receive the Price to Compare (a percentage of which a system owner typically bills the customer) and unsubscribed shares receive the qualifying facilities rate (typically the applicable locational marginal price. On review of the REC model, the percentage of the credit billed to the customer does appear to be accurately incorporated, flowing through the "ABP Scenario InputAssumptions" tab. However, the value of the community solar credit itself appears to be based on both supply and delivery plus taxes and fees on the Net Metering Credit tab-—which is not accurate. As noted, community solar subscribers receive the Price to Compare, equivalent to the sum of just the Energy, Capacity and Transmission charges, not distribution, taxes, or fees. A more accurate approximation for community solar revenues would therefore sum just the energy charge, capacity charge, and transmission charge lines in the Net Metering Credit tab, either as a mix of Residential and C&I (the Price to Compare received is based on the rate class of the offtake), or of just Residential as perhaps the simplest proxy. Once again, the Joint Solar Parties strive for accuracy, even when those changes may result in a lower modeled REC price. JSPs Resp. at 10-11.

h. Volumetric Taxes

With regard to Ameren's proposal for savings against state and local taxes, the Joint Solar Parties do not object in principle to the IPA calculating state taxes at minimum and modeling the impact of avoided taxes. However, before adding local taxes, the Joint Solar Parties wish to gather more information about how many units of local government assess such taxes, what the typical rate is, and the structure of such taxes. Because each local government may be different, it may be tricky to model the correct amount with the information in this docket. A stakeholder process would be a far better venue to gather that information. JSPs Resp. at 11.

2. ComEd's Position

a. Discount Rate

ComEd asserts that the REC Pricing Model Spreadsheet incorrectly calculates the REC price necessary to achieve the "missing money" target within the model by not discounting the annual production values thereby significantly understating the necessary REC price needed to achieve the missing money target. ComEd Obj. at 7.

Specifically, the current methodology discounts revenue to prevent value and then divides the value by a non-discounted generation factor (see "Data Processing Tab" cells U7 to U12 of Appendix E). To achieve the target equity IRR, the REC price should be determined by either (1) dividing the discounted "missing money" value by the discounted volumes or (2) finding the levelized REC price that can be applied against the expected production to calculate the annual revenue which when discounted will equal the "missing money" target. Attachment A to these objections provides illustrative examples that (1) use the methodology contained in the Renewable Energy Credit Pricing Model Spreadsheet (blue cells) that does not achieve the specified IRR; and (2) calculates revenue annually by multiplying the price by generation and then discounting, which achieves the specified IRR (green cells). ComEd Obj. at 7-8.

ComEd states that the IPA does not address the fact that, as it stands, the REC Pricing Model does not calculate required REC revenue to achieve the model's revenue requirement in a manner that accounts for the time value of money. ComEd asserts that, by not discounting annual (future) REC revenues to present value, the REC Pricing Model fails to recognize the core principle that a fixed price paid today has greater value than the same fixed price paid in the future. ComEd Rep. at 10-11.

ComEd explains that the REC pricing model calculates the present value of revenue necessary to achieve the targeted IRR. The model then divides by the generation expected over a 15-year period to arrive at a price per REC. If all the revenue were paid in a single year (e.g., residential or Illinois Solar for All ("ILSFA") systems), the model would arrive at the target IRR. However, large DG and community solar projects are paid out over time (up to 20 years) at a specified REC price. By the time the owners receive the payments, those payments are not equivalent to the value of the identical REC payment if it were to be received now. Put another way, a REC supplier will not and cannot be expected to treat one dollar to be paid to them in the future as just as valuable as one dollar to be paid today. The error ComEd identifies relates to how the REC Pricing Model turns missing cash flows into REC payments, payments at a fixed value that are made over time. ComEd Rep. at 11.

b. Revenue Stream

ComEd also notes that the REC pricing model does not use the appropriate supply rate values in estimating subscription revenues for community solar (see "Net Metering Credit Tab" cells U7 to U12 of Appendix E). Pursuant to Section 16-107.5(l)(3) of the PUA, all community solar subscribers receive supply credits equivalent to the residential Price to Compare. The current REC Pricing Model references commercial and industrial rates in its calculations and not the residential Price to Compare. The result of these errors is that the Spreadsheet, which is intended to "solve" to (achieve) specified Investor Rates of Return (i.e., "equity investors' minimum required after-tax return" (IRR), per LTRRPP, Appendix D ("REC Pricing Model Description"), pages 1, 4, will not do so and instead will result in lower values).

3. Summit Ridge's Position

a. Rooftop Community Solar Adder

Summit Ridge asserts that the REC pricing model and tools grossly undervalue rooftop community solar facilities and offers the following substantive model comments to address this. Summit Resp. at 2.

The number of community solar installations in Illinois has increased dramatically in recent years but there are very few community solar systems located in urban areas. This is primarily due to a lack of available land. There is, however, a large amount of available roof space in the state on which community solar projects can be sited. Unfortunately, under the current REC pricing structure, many of these projects are not financially feasible. Summit Resp. at 2.

While community solar rooftop projects are incentivized through the TCS scoring system within the ABP (3 points for being sited on a rooftop within the Built Environment category), they are not on equal footing with ground mount community solar systems when it comes to financial viability. Rooftop facilities have shorter system lives due to warranty terms and building owner preferences (20 years instead of the typical 35-40 years for ground mount systems), they produce significantly less energy (approximately 20% less than a typical ground mount system on single axis trackers), and the cost of labor for them can be more expensive due to typically being located in urban areas. Moreover, the potential cost of re-roofing that is sometimes necessary can significantly drag down economics even further. Summit Resp. at 2.

To address the disparities between the two system types, Summit Ridge proposes that a REC adder be implemented for rooftop community solar systems. To illustrate the impact of the primary two differences in terms of REC price, SRE used the REC Pricing Model for the proposed 2024 Long-Term Plan. While keeping all other inputs constant, we first adjusted the capacity factors (system yields) downward by 20% and then adjusted the EPC (installation) cost up by $0.10/watt. As a result, Summit Ridge submits that the size of an adder that will sufficiently level the playing field for rooftop community solar projects is approximately $20 - $25/MWh depending on system size. Summit Resp. at 2-3.

While the currently proposed value of $5/MWh by the IPA takes a laudable step in the right direction in acknowledging that there is a gap that needs to be bridged, Summit Ridge avers that a higher level of adder is necessary to enable many projects that will otherwise not be built to achieve financial viability and pave the way for the myriad of benefits that rooftop community solar provides. Summit Resp. at 3.

4. Ameren's Position

a. Revenue Stream

In Section 7.5.5 and Appendix D of the Plan, the IPA appears to have an errant assumption about the revenue streams available to community solar facilities, which is used as the basis for calculating REC values for community solar facilities. Additionally, the IPA uses a dated methodology for the applicability of credits resulting from a community solar subscription. In Section 7.5.5 on page 196, the Plan states, "Community solar projects face additional costs and reduced eligibility for direct energy-related revenues than distributed generation systems. On the revenue side, subscribers to such projects are eligible for energy-only net metering …" In Appendix D of the Plan, the errant assumption is repeated: "Community Solar projects face additional costs and less revenue than distributed generation systems. On the revenue side, they are eligible only for energy-only net metering, while on the cost side, there may be the cost of acquiring, maintaining, and managing subscribers. The price for community solar reflects a baseline for those additional costs and lower revenue." Appendix D cites Section 16-107.5(l)(2) as the basis for this assertion on page 2. AIC Obj. at 3-4.

Ameren believes the REC model inputs understates and undervalues the revenue stream available to developers of these facilities. Per Section 16-107.5(l)(1)(c) and as recognized in subsection (l)(4), these facilities offer subscriptions to the output of their facilities, and developers typically charge subscribers for that subscription service. As ordered by the Commission in Docket No. 22-0208, credits to community solar subscribers are based on Ameren's Price to Compare, which is a publicly available value representing the per kWh cost for electric supply service and transmission service under Ameren's fixed price supply service option (namely, Rider BGS – Basic Generation Service and Rider TS – Transmission Service). Ameren understands that developers typically price subscriptions as a percentage of the monetary value of the credits applied to their subscribers' accounts, and that the Agency in its Consumer Protection function has access to data on the percentages charged by community solar developers for their services. Additionally, these monetary credits are now applied to every charge on a Company issued bill for electric service instead of only the energy charge portion of the bill. AIC Obj. at 4.

Furthermore, Ameren explains that under Section 1-75(c)(1)(N) of the IPA Act, utilities are obligated to buy any unsubscribed capacity of a community solar facility through their qualified facilities tariffs. Combined with the ability to receive fees for the subscribed portion of the facility, this provision ensures that literally all of the output of community solar facility is monetized at rates equal to current electric market prices for energy or some value based on the market price. Again, Ameren understands that the IPA has access to subscription fee data that would enable it to adjust the REC pricing model for these facilities to accurately reflect the total revenue stream available to these facilities. AIC Obj. at 4-5.

b. Volumetric Taxes

In calculating the available revenue stream associated with net metering, on page 6 of Appendix D, Ameren states that the IPA correctly lists the volumetric-based tariff charges that will be reduced as the result of a customer installing a generator and receiving net metering service. Ameren recommends that the IPA add values reflecting the reduced state and local utility excise taxes (i.e., taxes that are applied on a volumetric basis) that result from the installation of on-site generation. For example, Ameren calculates, for a 10 kW solar system, that the customer will reduce their annual state tax liability by $42. For customers in municipalities that levy a utility tax, the annual tax liability avoided with a 10 kW system ranges from $18 to $80 (it should be noted that many municipalities in Ameren's service territory levy no utility tax, although all the larger communities do so). This dynamic is present for all sizes of on-site generation and will vary proportionally with the size of the generation unit. AIC Obj. at 8.

c. Ameren Technical Correction

Ameren notes that Appendix D states that "The net metering credit applied for small distributed generation up-to-10 kW AC pricing bin assumes subscribers will be in the residential rate class. The model did not include the Smart Inverter Rebate, as residential systems are not currently eligible for that rebate under Section 16-107.6(c)(1) of the PUA." LTRRPP App. D at 7. Ameren points out that residential customers have been eligible for the smart inverter rebate since the Commission's Order in Docket No. 21-0854, with a value of $300/kW-AC. In response to the directives in that Order, Ameren revised Rider CGR – Customer Generation Rebate in January 2023. This value also applies to small non-residential customers with demands <150 kW-AC. AIC Obj. at 9.

5. IPA's Position

Several parties to this proceeding took issue with various aspects of the administratively-set REC prices developed using the REC Pricing Model (Appendix E, as described in Appendix D) that are laid out in Section 7.5. The Agency's model is developed using the most recent NREL data available during the development of the Plan, which is 2022 cost data. The Plan contains an explanation of the development of the model, the use of an independent consultant to review the entire structure of the model pursuant to the *2022 LTRRPP Order*, updates that were made to the model for this 2024 Plan, and the process for updating REC prices annually. The Agency notes that while the establishment of REC prices has historically been a heavily litigious process, there are relatively few objections to the Illinois Shines REC pricing assumptions, and no specific objections to any ILSFA prices established through the model. IPA Resp. at 30-31.

a. Tracking Systems for 5MW Community Solar

The IPA notes that the Joint Solar Parties ask that the Agency include costs for tracking systems for 5 MW community solar projects. JSPs Obj. at 15. The Agency notes that its REC Pricing Model contained in Exhibit E models pricing for 5 MW community solar projects using a 500 kW rooftop system as a proxy for costs. Moreover, significant changes would be required to update the REC Pricing Model in order to utilize the NREL 2023 report which was released after the development of the REC Pricing Model and should not be approved in this proceeding. Furthermore, the NREL 2023 report models a 3 MW fixed-tilt ground mounted system and if the Agency were to update the community solar REC prices to reflect the community solar costs contained in the NREL 2023 report, it would result in a significantly lower REC price for the 5 MW community solar projects. IPA Resp. at 37.

b. EPC Costs

The Joint Solar Parties object that the total EPC (engineering, procurement, and construction) cost line item contained in the REC Pricing Model is too low. JSPs Obj. at 15. The Joint Solar Parties assume—incorrectly, as explained below—that the line utilizes EPC costs for rural areas of the Ameren service territory that are incongruous with the cost of labor in the ComEd service territory, or more population-dense areas. Furthermore, the Joint Solar Parties argue that because there is a clear demonstration (based upon information from the Illinois Department of Labor) that labor costs are higher in the ComEd service territory, a separate EPC cost should be developed in the Group B categories to address the difference. JSPs Obj. at 16. The Agency disagrees with this assessment, and notes that labor costs are only one portion of the "total engineering, procurement, and construction" cost. Additionally, the IPA states that the Joint Solar Parties do not specifically recommend a data source that can be relied upon to update the Total EPC Cost line. In the absence of a specific proposal, the Agency has reviewed the capital costs in the 2023 NREL benchmark report that accompanies the Objections of the Joint Solar Parties. The EPC Costs contained within the REC Pricing Model do not rely upon information from exclusively rural areas of the state, as assumed by the Joint Solar Parties; rather, the data is based upon the 2022 NREL cost report, which was the most recent report available at the time that the REC Pricing Model was developed. The Total EPC Costs in the NREL model reflect national average labor costs. The engineering, procurement, and construction capital costs contained within the 2023 NREL report for residential and community solar systems are in fact lower than the values reported in the 2022 NREL report, which was utilized in development of the REC Pricing Model. The Agency believes that it is reasonable to continue to rely upon the higher 2022 NREL data for total EPC Cost than the lower 2023 NREL data. IPA Resp. at 37-38.

In its Reply Brief, JSPs recommend that the Agency increase the value of the "Installation Labor & Equipment" cell, which is an input to the "Total EPC Cost" line, by 30% for Group B projects only. In its Brief on Exceptions, the Agency agrees that this modification would be a reasonable approach to adjusting the REC Pricing Model that would more accurately reflect the difference in labor costs between the service territories.

c. Land Lease Rate

The Joint Solar Parties complain that the land-lease rate included in the REC Pricing Model is too low by approximately half. The IPA states that the Joint Solar Parties do not provide an objective data point for the establishment of this rate; instead, they recommend that "the IPA collect data from participants similar to what the IPA has done for interconnection." JSPs Obj. at 15. The Agency does not fault the Joint Solar Parties for failing to provide an objective, third-party data source, however, the IPA and its procurement planning consultant are unaware of any reliable third-party data sources for community solar lease costs in Illinois. The IPA explains that in order to establish the land-lease rate in the current REC Pricing Model, the Agency used stakeholder feedback gathered during the development of the first REC Pricing Model and has not updated the land-lease cost since that time (2017). While the Agency is hesitant to survey program participants to establish an updated cost input, as those entities inherently have an incentive to report a higher cost, the Agency acknowledges that price volatility has been an issue in many markets in the last three years, including land and real estate markets. In recognition of the fact that it has been several years since this input has been updated, the Agency commits to undertaking a survey in 2024 to review contractual lease rates and update the input to the REC Pricing Model as appropriate for the 2025-2026 Program Year. The Agency will survey participants across community solar projects in all subcategories and subprograms of both the Illinois Shines and ILSFA and seek information on land-lease costs for agreements entered into in 2023. The Agency may request copies of lease agreements and other confidential, proprietary, and/or commercially sensitive materials to support the cost information provided through the survey; any such materials provided to the IPA and identified as such will be held confidential and considered exempt from Freedom of Information Act requests by the Agency. IPA Resp. at 38-39.

d. NREL Benchmarks

The Joint Solar Parties note that NREL released an updated benchmark cost report on October 24, 2023 (four days after the filing of the Agency's Long-Term Plan) and advocate for the reliance upon reliable, accurate data provided by NREL within the REC Pricing Model. JSPs Obj. at 15. In response to this suggestion, the Agency notes that this most-recently updated NREL cost report includes an update to NREL's approach in analysis, benchmarking, and data collection. JSPs Obj., Attach A. NREL made several changes to its benchmarked systems, including no longer modeling a commercial rooftop system or small commercial ground-mounted system and instead modeling a 3 MWdc ground-mounted community solar system. JSPs Obj. at 15; Attach. A. Incorporating the updated information from the most recent NREL study would be a significant undertaking that would require updating the underlying analysis of the REC Pricing Model and a full re-examination of the various assumptions that feed into the model in light of NREL's updated methodology. As a result, the Agency recommends that the Commission reject the proposed updated inputs to the REC Pricing Model advocated for by the Joint Solar Parties. Instead, the Agency will consider updating the REC Pricing Model in the next iteration of the Long-Term Plan consistent with the updated NREL benchmarking methodologies. IPA Resp. at 35-36.

e. Rooftop Community Solar Adder

The Joint Solar Parties applaud the addition of a REC price adder for rooftop community solar systems but believe that the adder recommended by the Agency is not evidence-based and urge the development of an adder that "includes an assessment of additional costs or impairments to revenue" for rooftop community solar projects. JSPs Obj. at 26. Specifically, the Joint Solar Parties advocate for an adder that includes lost revenue due to reduced capacity factors and higher build costs; however, the IPA points out that the Joint Solar Parties do not point to an objective source for data to be utilized to develop the adder. Instead, the Joint Solar Parties state unequivocally that construction and material costs for a rooftop community solar system are not equal to the cost of a ground-mounted system. The 2022 NREL study utilized by the Agency to establish the REC Pricing Model demonstrates that the Joint Solar Parties are correct that the costs are not equal; however, the 2022 NREL report indicates that the that the costs of a roof-mounted system are in fact lower than a ground-mounted system. While the installation costs are somewhat higher for a rooftop installation, the Agency understands that those costs are more than offset by the lower costs for site preparation, leasing, and often interconnection as well. Accordingly, the IPA suggests that there is no evidence-based support for the rooftop solar adder to accommodate higher build costs, as requested by the Joint Solar Parties. Conversely, the Agency does understand that there is a loss of revenue due to a reduction in capacity factors for rooftop community solar projects. For systems over 500 kW, the REC Pricing Model uses higher capacity factors based upon the assumption that ground-mounted systems are designed as tracking systems. The Agency understands that rooftop systems are most often fixed systems, rather than tracking, and this would result in a reduction of the capacity factor for the system. The Agency reviewed the difference between the capacity factors of a similarly-sized fixed and tracking system, and used that information to develop the $5/REC price adder for rooftop community solar. The IPA believes that its proposed $5/REC rooftop solar adder is reasonable, appropriate, and evidence-based, and should be adopted by the Commission. IPA Resp. at 39-40.

Like the Joint Solar Parties, Summit Ridge argues for a higher adder than the Plan proposes for rooftop community solar projects; specifically an adder set in the range of $20-25/REC. The Agency explains that it took a similar approach as Summit Ridge to developing the $5/REC adder that is included in the Plan, which adjusted capacity factors for rooftop community solar projects to mirror those of rooftop distributed generation systems. The Agency does not agree that labor costs adjustments are required, as the REC pricing model already incorporates appropriate labor costs that reflect prevailing wage costs. IPA Rep. at 34-35.

To date, the IPA continues, approximately 10% of community solar projects approved by the Agency have been located on rooftops without the additional REC incentives. This causes the Agency to believe that while the concerns raised by Summit Ridge and the Joint Solar Parties on this issue may be applicable in some cases, it is clearly possible to develop such projects under the existing pricing methodology. The Plan proposes a $5/REC rooftop community solar adder to explore the extent to which that could help increase interest from developers in pursing such projects. IPA Rep. at 35.

In contrast, a $20-25/REC increase in REC prices for community solar projects located on rooftops, as SRE proposes, would increase REC prices up to 50%, depending on project size and Group. If this were adopted, it could result in a large shift to rooftop community solar projects due to the higher REC price and have a significant impact on the RPS budget, reducing funds available to support all varieties of projects. The IPA asserts that such a fundamental change in policy for how and where the State supports community solar development should be carefully and thoroughly considered in the appropriate venues. For these reasons, the Agency does not support Summit Ridge's proposal, rather the Agency maintains that its proposed $5/REC adder is appropriate for this Plan. The Agency will continue its ongoing examination of cost inputs for the REC pricing model along with the level of participation of rooftop community solar projects and expects that refinements to this adder may be proposed in future revisions to the Plan. IPA Rep. at 36.

f. Discount Rate

ComEd argues that the REC Pricing Model incorrectly calculates the price necessary to achieve the "missing money" target within the model by not discounting the annual REC production values. ComEd Obj. at 7. The "missing money" target is in essence the amount of money needed to meet the revenue gap of project development and is the target that administratively-set REC prices are intended to fill. ComEd argues that the current methodology discounts revenue during the 15-year REC Period to present value and then divides that value by the non-discounted generation factor during the same 15-year period, resulting in an understated REC Price necessary to achieve the "missing money" during the term of the REC Contract. ComEd's argument is flawed, the

IPA argues, as it assumes that the REC calculation matches the conventional calculation of the levelized cost of energy. The REC Pricing Model, however, is a functional tool that uses various assumptions and estimates to produce usable results based upon limited data under varying market conditions. The REC price calculation differs from the conventional levelized cost of energy calculation, in that it uses different assumptions and estimates. The REC Pricing Model accounts for system degradation and therefore a reduction in the quantity of RECs produced by the system over time. There is no need to apply a discount rate to the REC quantities as those quantities are based on expected REC delivery quantities that already factor in system degradation over time. Additionally, the time period covered by the analysis for calculating REC values (15 years) is not equal to the assumed lifetime of the project (25 years), and the model considers other sources of revenue, such as the value of energy generated after year 15 and the sale of environmental attributes during the period beyond the 15-year REC Contract. These sources help fill the gap between the net present value of RECs and the revenue required to achieve the investor rate of return (IRR). Accordingly, no change to the calculation of the REC Pricing Model is required to achieve the missing money target. IPA Resp. at 34-35.

g. Revenue Streams

Ameren states that community solar developers typically price customer subscriptions at a percentage of the monetary credits applied to subscriber accounts and argues that because utilities are obligated to buy unsubscribed capacity of a community solar facility through qualified facilities tariffs, the combination of these two factors results in the REC Pricing Model undervaluing the revenue potential of community solar facilities. AIC Obj. at 3-5. Ameren argues that the Agency should utilize its access to subscription fee data to adjust the REC Pricing Model for community solar facilities to accurately reflect the total revenue stream available. Currently, the REC Pricing Model reflects an assumption that a system is 100% subscribed (i.e., that the project receives no revenues under qualified facility tariffs) and that subscribers receive 20% of the revenue from the project (in the form of net metering credits) while the developers receive 80% of project revenues (in the form of subscription fees). In the Agency's experience, most projects are fully subscribed, or close enough to fully subscribed that the first assumption is appropriate. The Agency does not have the subscription fee data readily available in a format that would allow it to easily undertake an analysis of whether or not the second assumption, on the 80/20 developer/customer revenue split, is correct. In order to study subscriber fee data, the Agency would have to pull the information from each customer's community disclosure form and compile it for review. For a large number of disclosure forms, this would be a manual process rather than automated, and therefore would be a laborious undertaking. The Agency could consider studying whether this assumption is reflected in the customer disclosure forms for subscription agreements and proposing an updated adjustment of this assumption in the next Long-Term Plan, if necessary. IPA Resp. at 31-32.

Ameren argues that the Agency's REC Pricing Model relies upon dated assumptions that understate the revenue stream available to community solar projects. AIC Obj. at 3-5. Ameren notes that in Section 7.5.5 of the Plan and in Appendix D, the Agency explains that subscribers are eligible for "energy-only net metering." This is only an inadvertent failure to update the description of customer eligibility, however, and not an issue with the REC Pricing Model itself. The Agency agrees that this language is outdated and will make corrections to the Plan and Appendix D to reflect that community solar subscribers receive bill credits at the utility Price to Compare (i.e., the cost of energy supply and transmission service). IPA Resp. at 33-34.

ComEd also states that the REC Pricing Model does not use the correct supply rate values in estimating subscription revenues for community solar on cells U7 to U12 of the "Net Metering Credit Tab" of Appendix E. ComEd Obj. at 7. In support of this statement, ComEd explains that all community solar subscribers receive supply credits equivalent to the residential Price to Compare, and the REC Pricing Model references commercial and industrial rates in its calculations, rather than the residential rates. The Agency recalls that the Joint Solar Parties raised alternative concerns surrounding the net metering credits for commercial and industrial customers in the litigation surrounding the 2022 Long-Term Plan. Docket No. 22-0231, JSPs Obj. at 11-12. The Agency is committed to reflecting the correct net metering values in the REC Pricing Model and will ensure that the values in these cells reflect the correct level of compensation to customers that is outlined in the utility tariffs. IPA Resp. at 34.

The Joint Solar Parties note that they believe that the REC Pricing Model should be based upon accurate information, and therefore do not disagree to any modifications to the REC Pricing Model that accurately reflect community solar net crediting. At the same time, the Joint Solar Parties agree with the Agency that the percentage of credit billed to the customer is accurately incorporated through the "ABP Scenario Input Assumptions" tab on the REC Pricing Model. Conversely, the Joint Solar Parties explain that the value of the community solar credit to customers within the model (specifically, on the Net Metering Credit tab) includes the full stack of the commercial and industrial customer tariff -that is, supply and delivery charges, plus taxes and fees, which is inaccurate. The Joint Solar Parties state that a more accurate approximation would instead be a sum of just the energy, capacity, and transmission charge lines, either as a mix of residential and commercial and industrial, or of just residential alone as the simplest proxy. The Agency agrees. The Agency understands that the Price to Compare varies by customer class, and accordingly will use a mix of residential and commercial and industrial supply and transmission charges to update the REC Pricing Model. IPA Rep. at 34.

h. Volumetric Taxes

In response to Ameren regarding volumetric taxes, the IPA agrees that the REC Pricing Model does not consider volumetric state and local taxes. The IPA notes that utilities are uniquely situated in their ability to calculate individual customer tax charges, or aggregated charges across their service territory. The IPA does not have this expertise, experience, or data, and therefore finds that it would be administratively burdensome to calculate an appropriate tax rate that can be utilized as a generic value statewide or across service territories due to the various layers of state and municipal tax authorities in Illinois. The Agency urges the Commission to reject Ameren's proposal to reflect volumetric tax charges in the REC Pricing Model. IPA Resp. at 32-33.

i. Ameren Technical Correction

Ameren suggests a technical correction to Appendix D, in order to clarify that residential systems are now eligible for the smart inverter rebate. AIC Obj. at 9. The Agency agrees that the text of Appendix D, which explains the assumptions in Appendix E, the REC Pricing Model, should be updated to reflect this recent change. The Agency will also update the text of Appendix D to reflect that while the rebate is now available to residential customers, the model itself does not include this rebate for residential customers, who are assumed to take the net metering credits over the rebate, as full retail rate net metering has a larger financial impact, and the Agency assumes that residential customers will choose this more valuable financial incentive. The Agency expects it will be necessary revisit this assumption in the next Long-Term Plan as the transition away from full retail net metering continues and the residential utilization of smart inverter rebates increases. IPA Resp. at 33.

6. Commission Analysis and Conclusion

a. Tracking Systems for 5MW Community Solar

The Commission appreciates the JSPs' focus on ensuring the most accurate REC pricing model but agrees with the IPA that implementation of this proposal would require significant work. Also, it appears that JSPs' proposal requires further modification prior to being adopted. Accordingly, the Commission does not adopt this proposal.

b. EPC Costs

The Commission agrees that the labor costs are different in the ComEd and Ameren service territories as demonstrated in the Illinois Department of Labor data provided by Joint Solar Parties. The IPA agrees that the JSPs' proposal to increase the "Installation Labor & Equipment" cell for Group B projects by 30% is a reasonable approach to adjusting the EPC Cost to reflect the difference between the labor costs in the two service territories. Accordingly, JSPs' proposal in their Reply is adopted.

c. Land Lease Rates

The JSPs disputed the land lease rates included in the REC Pricing Model in their Objections. The IPA proposes to conduct a survey of 2023 land lease costs and the JSPs did not reply to this proposal. The Commission agrees that this is appropriate since the IPA has not updated this information since 2017. However, the Commission finds that it is not appropriate to update the REC Pricing Model at this time because new data is not yet available.

d. NREL Benchmarks

The Commission accepts the IPA's explanation that incorporating the updated NREL benchmarks would be too great of an undertaking at this point in time. The IPA suggests that it will consider utilizing the updated benchmarks in the next Long-Term Plan, but the Commission emphasizes that generally updated benchmarks are preferred. Therefore, JSPs' proposal is not adopted for this Plan.

e. Rooftop Community Solar Adder

The Commission observes that the IPA has thoroughly considered the proposed $5/REC adder that is incorporated in the REC Pricing Model. Moreover, the IPA's analysis was similar to that performed by Summit Ridge. The Commission also notes that even without an adder, 10% of community solar projects are on rooftops. The Commission notes that Summit Ridge provides new information in its BOE. Provision of this information is untimely. Accordingly, the Commission sees no reason at this time to increase the IPA's proposed $5/REC adder for rooftop community solar.

f. Discount Rate

The Commission agrees with the IPA that the REC Pricing Model does not utilize conventional levelized cost of energy calculations and therefore it is not necessary to discount the generation factor. The REC Pricing Model is a functional tool that uses various assumptions and estimates to produce usable results based upon limited data under varying market conditions. The REC price calculation differs from the conventional levelized cost of energy calculation in that it uses different assumptions and estimates. The REC Pricing Model accounts for system degradation and therefore a reduction in the quantity of RECs produced by the system over time. There is no need to apply a discount rate to the REC quantities as those quantities are based on expected REC delivery quantities that already factor in system degradation over time. Accordingly, ComEd's proposal is denied.

g. Revenue Streams

Ameren, ComEd, and the JSPs make various arguments regarding the revenue streams available to community solar projects and whether they are accurately reflected in the REC Pricing model. For the most part, it appears that the IPA agrees with the parties' recommendations and will make the appropriate corrections. The only issue that is not resolved is whether the assumed 80/20% split between developers and subscribers should be changed. The IPA states that it does not have the necessary data to make this determination, and thus, neither does the Commission. The Commission agrees with the IPA that it should consider whether an update would be appropriate for the next Long-Term Plan.

h. Volumetric Taxes

The Commission notes that Ameren is likely correct that volumetric taxes will be reduced with the installation of DER. It appears that the actual amount of the reduction is not known and will vary based on the customers locations. Thus, the Commission agrees with the IPA that Ameren's proposal should not be adopted.

i. Ameren Technical Correction

Ameren proposed a technical correction, which the IPA agreed was appropriate. Accordingly, it is adopted.

I. Section 7.7.2. EEC Application Process

IPA's proposed EEC application requirements referenced by Section 7.7.2 are discussed in Section 10.1.2.1, below.

J. Section 7.9.4. Co-location of Systems

1. JSPs' Position

Generally speaking, the Joint Solar Parties applaud the revisions made to the LTRRPP from the public comment version, which is now much more consistent with the statutory language tying co-location for ABP projects to the standard in the First Revised LTRRPP litigated in Docket No. 19-0995, which in turn defined co-location in terms of projects applied to the ABP by a single or affiliated AVs. *See* LTRRPP at 211-212; *see also* 20 ILCS 3855/1-75(c)(1)(K)(iii)(3); Docket No. 19-0995, Final LTRRPP at 171 (Apr. 20, 2020) ("No Approved Vendor may apply to the ABP for more than 4 MW of Community Solar projects on the same or contiguous parcels" (emphasis added). However, the Joint Solar Parties recommend two changes. JSPs Obj. at 28-29.

First, because the maximum total nameplate capacity may be 5,000 kWac and need not be strictly less, the JSPs state the Commission should correct the following passage with the following language added: "For program compliance purposes, co-located distributed generation projects may sum to over 5MW in size if the co-located projects that are participating in the Program remain *at or* under the 5MW AC size requirement." LTRRPP at 211; JSPs Obj. at 29.

Second, the Joint Solar Parties recommend that the Commission modify the LTRRPP to incentivize rooftop community solar by not aggregating systems across different rooftops. *See* LTRRPP at 212. Elsewhere, the LTRRPP has expressed a clear interest in incentivizing community solar projects on rooftops, the built environment and close to population centers. *See, e.g.*, LTRRPP at 163 (additional points in TCS for rooftop systems) 163, 169 (two instances of proposed $5/REC adder for rooftop community solar). The co-location standard aggregating systems across rooftops was written for greenfield or farmland systems, which can benefit from economies of scale by locating on the same or adjacent parcels. The JSPs explain that two adjacent rooftop projects do not earn economies of scale by such proximity. Applying a co-location standard created for greenfield community solar projects to rooftop community solar projects creates unintended impediments to the rooftop projects the Agency is attempting to incent. To prevent this unintended consequence, the Commission should remove the co-location standard for rooftop community solar on rooftops on the same parcel. JSPs Obj. at 29.

The JSPs argue that the IPA assumes, without evidence, that there is shared equipment, that the systems are not separately designed, that each of the structures have the same owner and thus negotiation of roof leases are more efficient, and the like. The IPA provides no basis for these assumptions, which frequently are incorrect. The Commission should thus reject the IPA's opposition and adopt the Joint Solar Parties' Objection regarding co-located rooftop community solar. JSPs Rep. at 25.

2. IPA's Position

The 2024 Long-Term Plan includes revisions to the language surrounding the co-location of projects within the Illinois Shines program, which is intended to clarify and streamline the requirements. The Joint Solar Parties seek a small wording change in Section 7.9.4.1 to the requirements surrounding the maximum size for DG projects co-located with projects that are not participating in Illinois Shines. JSPs Obj. at 29. The Agency accepts this clarifying change and will add the phrase “at or” before “under the 5MW AC size” on page 211 of the Plan. IPA Resp. at 45.

The Joint Solar Parties also seek modification to the community solar co-location requirements outlined in Section 7.9.4.2 of the 2024 Plan. The 2024 Plan does not consider rooftop community solar projects sited on adjacent parcels to be co-located unless the projects are located on the same building or structure. However, multiple community solar projects sited on distinct structures located on the same parcel will be considered co-located and must demonstrate that the projects are unaffiliated in order to not be considered co-located. LTRRPP at 212. The Joint Solar Parties argue that rooftop systems located on separate buildings do not benefit from the same economies of scale as ground-mounted systems by proximity, and therefore rooftop systems on the same parcel but different buildings should not be considered co-located. JSPs Obj. at 29. While it may be true that not all costs benefit from the economies of scale from building two adjacent rooftop projects, the Agency notes that the siting of projects on the same parcel inherently results in economies of scale in terms of a vast majority of costs (such as the consolidation of costs for site acquisition, interconnection upgrades, shipping and deliveries, local permitting, design and engineering work, shared equipment, etc.), and urges the Commission to reject this proposed change to the Long-Term Plan. IPA Resp. at 46.

3. Commission Analysis and Conclusion

The Commission agrees that the addition of “at or” clarifies the language of the LTRRPP, and it is adopted. As for the JSPs’ remaining proposal, it is not adopted. The Commission finds that the IPA has considered the difference between co-locating on ground parcels as opposed to rooftops and defined co-location appropriately.

K. Section 7.9.6.2. Residential and Small Commercial Customer Participation

1. ESI’s Position

ESI states that understanding how the Agency is going to implement changes to the small subscriber requirements for community solar gardens is important for the development and long-term operation of these gardens. ESI appreciates the Agency acknowledging the challenges that come with changing interpretations of existing programs. However, the Agency’s concession that the change not be made retroactive and only apply beginning June 1, 2024, does leave questions on the implementation of this change. Subscription is a lengthy process, and subscriber acquisition activities are already currently underway for projects that will be energized both before and after this date. ESI Obj. at 11.

To create a clear, bright line rule that is easy to follow and administer for approved vendors and designees as well as the Agency and Administrator, ESI suggests that this June 1, 2024, date apply to projects that receive REC awards beginning on that date. Having multiple rules that apply to different subscribers of the same project is bound to be messy and cause more problems for the Administrator. Creating a clear delineation between projects that receive REC awards in the 2024 program year and beyond and those that have already applied for and will potentially be awarded in the 2023 program year is the cleanest way to implement this new policy. ESI Obj. at 11-12.

Of concern, ESI notes that the IPA indicates they do in fact intend to apply this requirement retroactively, by requiring all existing and operating gardens comply with the IPA's new interpretation by June 1, 2024. IPA Resp. at 48. As stakeholders have pointed out multiple times since the IPA first proposed this new interpretation in association with its March 14, 2023 update to the Program Guidebook, application of this new requirement to existing projects would require subscriber organizations to break existing long-term contracts with existing subscribers to bring gardens that have been operating, sometimes for years, into compliance with the new requirement. ESI Rep. at 10-11.

It is difficult for AVs and designees to apply new subscriber-mix requirements to projects that are already operating and fully subscribed. This is why ESI suggested the LTP include a clear rule that any new small-subscriber requirements avoid retroactive effect by only applying to new projects that are not yet subscribed. ESI Rep. at 11.

We also agree with the NRG Companies, ComEd, and Staff, that under the appropriate statutory interpretation (and earlier program practice), small subscribers should be allowed to have multiple subscriptions under 25 kW to multiple gardens and that as long as subscriptions did not exceed 25 kW to a single garden, the subscription should be counted to the required 50% small subscription requirement. ESI Rep. at 11.

ESI notes that JSPs raise a similar issue, giving additional examples of potential new requirements that should not be retroactively applied to AVs and Part I applications that have already been submitted to the program. JSPs Obj. at 23. ESI thus generally support JSPs' proposed clarifications and reiterate that modified additional LTRRPP requirements should not impact in-progress project applications that were developed and submitted under the prior LTP. A contrary approach would greatly reduce the ability of developers to do business and find project financing under a stable environment in the State of Illinois. ESI Resp. at 1-2.

2. NRG Companies' Position

In Section 7.9.6.2 of the LTRRPP (entitled "Residential and Small Commercial Customer Participation"), the IPA discusses the interaction of two statutory provisions related to community solar development. *See* LTRRPP at 215-217. First, the IPA identifies a section that provides that at least 50% of the subscriptions for a facility are to be of a maximum volume of 25 kW in order for a community solar project to qualify for a long-term REC contract under the ABP:

> projects shall have subscriptions of 25 kW or less for at least 50% of the facility's nameplate capacity and the Agency shall price the renewable energy credits with that as a factor.

20 ILCS 3855/1-75(c)(1)(K)(iii)(2). Second, the IPA cites a provision which instructs the Agency to expand access to ensure that there is robust participation by residential and small commercial customers:

> the terms, conditions, and program requirements for photovoltaic community renewable generation projects with a goal to expand access to a broader group of energy

> consumers, to ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties.

20 ILCS 3855/1-75(c)(1)(N); NRG Obj. at 8.

With that statutory backdrop, the IPA asserts that there are many subscribers who have multiple subscriptions that are below the 25 kW threshold but that when combined exceed a total of 25 kW:

> The Program Administrator recently discovered nearly 200 subscribers - erroneously counted as small subscribers - with multiple subscriptions that exceed 25 kW in sum.

LTRRPP at 215. As a result, the IPA proposes that:

> Program-wide, subscriptions for a single subscriber must not sum to over 25 kW to be counted toward this minimum 50% threshold. A subscriber that has a single or multiple subscriptions that sum to over 25 kW across all community solar projects in the Program will not have its subscriptions considered to be 25 kW or less for compliance with statutory requirements or REC contracting purposes.

Id.; NRG Obj. at 8-9.

NRG Companies aver that the IPA's proposed limits on subscriptions for residential and small commercial consumers is contrary to law, potentially damaging to residential and small commercial consumers, and unnecessary to promote preferences for community solar developers to serve residential and small commercial customers in Illinois. NRG Obj. at 9.

First, NRG Companies assert that the IPA's proposal to limit the program to only those subscriptions by individual residential and small consumers that have an aggregate demand of less than 25 kW is inconsistent with the language in the statute. The IPA Act states:

> A requirement that a minimum of 50% of subscribers to be the project's nameplate capacity be residential or small commercial customer [sic] with subscriptions of below 25 kilowatts in size;

20 ILCS 3855/1-75(c)(1)(G)(iv)(3)(E)(ii). As currently written, the statute does not prohibit a single residential or small commercial customer from acquiring multiple 25 kW subscriptions. Had the General Assembly intended there to be a limit on the number of 25 kW of community solar subscriptions, it certainly could have included such language. Instead, the statute uses the plural (e.g., "subscriptions") when describing the requirement. With no identified authority, the IPA's proposal would create a totally new class of customer that is not set forth in statute (residential or small commercial customers with multiple 25 kW subscriptions) and limit their ability to enter into community solar contracts. NRG Obj. at 9.

Second, the IPA's proposal could arbitrarily deny benefits to certain residential and small commercial consumers, though it is unclear precisely how the IPA's proposal would be applied to these consumers. For example, if a small commercial customer used more than 25 kW, it would require more than one 25 kW subscription to cover its total demand. This is currently allowed under the existing LTRRPP and should continue to be allowed, but the IPA's proposal would prohibit such a customer from matching its total annual consumption with community solar subscriptions. NRG Obj. at 9-10.

Similarly, the IPA's proposed language could prevent the owner of multiple neighborhood convenience stores - each being served as a small commercial account by the local utility - from securing separate 25 kW subscriptions for its multiple locations and allowing those subscriptions to count towards the community solar developer's mandated 50% small subscription requirement. Indeed, it appears that even a residential customer with multiple houses may be prevented from having both houses participate, under the IPA's proposed language. Accordingly, the IPA's proposed language does not engage customers to advance clean energy goals but instead restricts community solar development. NRG Obj. at 10.

In these and other cases, the IPA's proposal could prevent developers from serving certain residential or small commercial customers in order to satisfy the developer's small subscriber requirements. As a result, these residential and small commercial customers would effectively be forced to compete for subscriptions with much larger consumers against which it may have a competitive disadvantage in terms of scale, credit, or negotiating capacity. NRG Obj. at 10.

In summary, without any supporting statutory authority, the IPA proposed language in the LTRRPP that would undermine the state's policy objective to expand access to community solar and be harmful to multiple parties and programs. NRG Obj. at 11.

Lastly, the NRG Companies find that the IPA's proposal is a solution in search of a problem. Perhaps the IPA seeks to "free up" community solar subscriptions for small subscribers that have only a single site that can be served by a single subscription with a total volume of less than 25 kW. It is unclear to NRG Companies whether any such entities exist or that they are entitled to a priority under the terms of the P.A. 102-0662. Nevertheless, if that is the IPA's goal, then imposing the proposed 25 kW aggregate subscription limit on an estimated 200 accounts identified by the IPA would have little to no impact on participation by residential customers and small commercial customers who have a single site. Indeed, the ABP program does not prevent community solar projects from subscribing up to 100% of its capacity to eligible small subscribers and, upon information and belief, there are owner/operators of solar developers who are securing residential subscriptions for 100% of their project capacity. For such projects, the IPA's proposed language would have no impact. NRG Obj. at 11-12.

Further, it is possible that evolving federal policies will make this even less of an issue. The United States Internal Revenue Service recently released guidance on the Low to Moderate Income ("LMI") adders to the Investment Tax Credit ("ITC"). While community solar developers are only now synthesizing the process to meeting the LMI requirements, the LMI ITC adder may be a significant financial incentive that will ensure that community solar providers in Illinois maintain a focus on engaging with LMI residential customers in Illinois. NRG Obj. at 12.

While the NRG Companies respectfully request the Commission reject the IPA's proposed language as applied to all customers, the NRG Companies also recognize that there is a material difference between an industrial customer seeking multiple 25 kW subscriptions for a 10 MW load at a single site and a small commercial customer seeking multiple 25 kW subscriptions for multiple day-care locations. To the extent the IPA is simply seeking to prevent large single site consumers from qualifying as "small subscribers," then the IPA's proposed language is far too broad. The NRG Companies request that the Commission reject the IPA's proposed language as applied to all customers, or at least limit the scope of the IPA's proposed language so that it does not impact residential and small commercial customers. As proposed, the IPA's language would prevent multiple subscriptions for residential and small commercial subscribers from counting towards a community solar development's 50% small subscription obligation. NRG Obj. at 12.

To the extent the Commission authorizes any change to this portion of the community solar program, the NRG Companies respectfully request that the proposed aggregated limit of 25 kW for community solar subscriptions apply only to large commercial and industrial accounts (e.g., accounts that are not residential or small commercial). NRG Obj. at 12-13.

In response to the IPA's assertion that its proposed cumulative cap "has existed since its inception," IPA Resp. at 49, NRG Companies point out that in none of the prior LTRRPPs did the IPA reference or provide examples of how a cumulative 25 kW cap was to be applied. The IPA's proposed cap in this LTRRPP varies dramatically from the language used in all prior iterations of the LTRRPP and those differences are material to the interests of residential and small commercial customers that benefit from being able to secure multiple 25 kW subscriptions. NRG Rep. at 14-15.

Instead of addressing these concerns, the IPA pivots to arguing that "[n]othing in the proposal to enforce a statutory requirement for small subscriptions prohibits customers from having multiple subscriptions or having subscriptions above 25 kW." IPA Resp. at 50. However, neither the NRG Companies nor any other party has asserted that the IPA has prohibited any subscriptions above 25 kW. Instead, the NRG Companies, Staff, ComEd and the JSPs all explain that the IPA's proposed cap is contrary to statute and would erode the market value of residential and small commercial customers that can support multiple 25 kW "small subscriber" subscriptions; they all recommend the removal of this arbitrary limitation from the LTRRPP. Simply put, applying the IPA's cap, residential and small commercial customers improperly would be placed in a position where they must compete for subscriptions with large institutions and corporations. NRG Rep. at 15.

The IPA asserts that the basis for its proposal is the statutory direction of Section 1-75(c)(1)(N) of the IPA Act "to ensure robust participation opportunities for residential and small commercial customers" in community solar projects. *See* IPA Resp. at 47. The implication is that large commercial and industrial customers are somehow "squeezing out" residential and small commercial customers from being able to qualify as "small participants." However, the IPA's claim is misleading; unequivocally, this is not the case. NRG Rep. at 15-16.

The NRG Companies submitted a series of data requests to the IPA seeking specific data, information, and analysis that informed the IPA's position. The IPA provided a spreadsheet that tabulated the number, customer type (residential, commercial, etc.) and subscription volumes of 951 customers that currently hold multiple community solar subscriptions that in sum exceed 25 kW. *See* Attach. C, Response to Data Request 1.05, including attached spreadsheet. The data conveys the following information:

- 263 or 28% of the accounts are residential, 688 or 72% accounts are small commercial, and none of the accounts are medium or large commercial or industrial accounts. Therefore, the objective of "robust participation" for residential and small commercial customers is already being realized.
- 566 of the accounts (59.5% of all accounts identified) hold two subscriptions; only three accounts (0.3% of all accounts identified) hold more than 10 subscriptions.
- Of those three accounts holding more than 10 subscriptions, two are small commercial accounts and one is residential (which appears to be a multi-family account).

NRG Rep. at 16, Attach. C.

Based on the above and the fact that the utilities prevent customers from subscribing for more than 110% of the account's prior year consumption, it is apparent that the consumers that the IPA has labeled as being "problematic" are simply residential and small commercial customers who are seeking to match their subscriptions with their annual consumption. As such, the IPA's cumulative 25 kW cap would have no impact on the volume of community solar subscriptions that serve residential and small commercial customers. Further, the IPA's proposal actually would be harmful to residential and small commercial customers, denying them the opportunity to have multiple subscriptions. Moreover, the proposed cap would surely complicate the ability of community solar project developers to meet their small subscriber requirements. NRG Rep. at 16-17.

The NRG Companies respectfully request that the Commission order the IPA to remove the proposed 25 kW cap for residential and small commercial customers to acquire multiple "small participant" subscriptions from Section 7.9.6.2 of the Draft LTRRPP. NRG Rep. at 17.

3. JSPs' Position

The LTRRPP caps the total allowable subscription for a single customer—defined by their account number—at 25 kW if an AV wishes to count such subscriber toward their small subscriber obligation. The Joint Solar Parties did not object to this requirement. While the Joint Solar Parties disagreed with the statutory interpretation in the LTRRPP for reasons described below, defining a customer by account number—which to the Joint Solar Parties' understanding is different from premises to premises—prevents undesirable outcomes such as a single municipality being restricted to 25 kW for numerous accounts that are in small subscriber-eligible delivery classes. While the LTRRPP provides no information about how the Program Administrator will administer the 25 kW cap—for instance, whether AVs will be notified and when a customer's aggregate subscription size will be verified—many of the worst outcomes of this proposed change are mitigated by the confirmation that a single "customer" for these purposes is defined at the account number level. JSPs Resp. at 11-12.

However, because other parties raised the issue, the Joint Solar Parties note that Section 1-75(c)(1)(K)(iii)(2) requires that TCS "projects shall have subscriptions of 25 kW or less for at least 50% of the facility's nameplate capacity and the Agency shall price the renewable energy credits with that as a factor." 20 ILCS 3855/1-75(c)(1)(K)(iii)(2). Although there is no reference to "small subscribers," the Joint Solar Parties agree it is consistent with the previous program requirements and Section 1-75(c)(1)(N)'s direction that the IPA "ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties." 20 ILCS 3855/1-75(c)(1)(N). The statutory cap combined with a regulatorily-imposed "small subscriber" requirement ensures that large users such as steel mills or data centers do not take up all of the 25 kW subscriptions (which, for a single system and a single customer, would be aggregated anyway). The Joint Solar Parties believe this approach would provide the appropriate balance of providing opportunities to residential and small commercial customers without imposing undue barriers. The maximum subscription volume of 25 kW per account number across all systems takes the logical limitation of Section 1-75(c)(1)(K)(iii)(2) to small subscriptions and applies an unnecessary burden. JSPs Resp. at 12.

The Joint Solar Parties note that ESI requests that all projects "receiving a REC Contract by June 1, 2024" should be exempt from this requirement. ESI Obj. at 11-12. The Joint Solar Parties take no position on this individual issue but argue for additional clarity regarding which of the ever-changing program requirements lock in at Part I application, Trade Date (Commission approval of a Part I application), Energization, or other dates. JSPs Obj. at 22-23. Addressing issues of regulatory change categorically rather than on an ad hoc basis as suggested by ESI would provide greater transparency and predictability, especially as the program continues to shift every LTRRPP and multiple times during the time between LTRRPP revisions. JSPs Resp. at 12-13.

Unlike many other state RPS programs, the ABP and ILSFA have a legislative framework but are implemented by constantly changing LTRRPPs (revised at minimum every two years) and informal guidance implementing documents such as the Program Guidebook, the Consumer Protection Handbook, and various other guidance documents that can be changed without an administrative order. As a result, the JSPs have noted some confusion from long-term owner/operators and financing parties about what requirements apply when the LTRRPP, Program Guidebook, and the Consumer Protection Handbook (among other documents) may be different at the Part I application, Part I approval by the Commission, and Part II application. JSPs Obj. at 23.

The JSPs acknowledge that some requirements—such as some consumer protections—are inherently more dynamic. Other aspects, such as Part I application requirements at the time of the Part I application—are inherently static. Many others are gray areas and would benefit from explicit clarification in the LTRRPP. For example:

- The LTRRPP should explicitly state that if an AV qualifies as an EEC at the time of the Part I application, loss of EEC status (other than for fraud, misrepresentation, or generally applicable discipline) due to regulatory change should not invalidate the application;

- The LTRRPP should make explicit that there are currently no restrictions on ownership of the applying system other than for energy sovereignty ILSFA projects, that the ABP and ILSFA only impose restrictions on assignment of the REC Contract (not ownership of the underlying system itself), and any future restrictions on system ownership would not apply to systems that have already submitted a Part I application; and

- Subsequent revisions or reinterpretations of scoring systems (such as Traditional Community Solar, Community-Driven Community Solar, or some ILSFA systems) will not lead to revocation of REC Contracts for previously selected systems or rejection of Part II applications.

JSPs Obj. at 23-24.

Although the Joint Solar Parties did not take an Objection to the 25 kW cap on aggregate total subscriptions across community solar projects, after reviewing the Responses of Staff, ComEd, and NRG, the Joint Solar Parties have been fully convinced that the Commission should lift the cap of 25 kW aggregate subscription per customer—particularly for the reasons identified by Staff. Staff correctly interpreted the IPA Act's plain language explicitly defining a small subscriber, rather than interpreting generalized "robust participation" language in direct conflict. *See* Staff Resp. at 15-16. Only the IPA seeks to impose the cap, and its reasoning does not extend beyond repetition of its belief that it intended to impose such a cap (even though it is not required or supported by statute) and ill-defined concerns that subscriber acquisition may in some limited cases be easier than anticipated. For the latter point, the IPA does not explain why customer acquisition costs are reduced when a customer subscribes to two separate systems. JSPs Rep. at 25-26.

4. ComEd's Position

ComEd supports the NRG Companies' Objection. As NRG Companies explain, the LTRRPP appears to rely on a Section 1-75(c)(1)(K)(iii)(2) of the IPA Act. 20 ILCS 3855/1-75(c)(1)(K)(iii)(2); NRG Obj. at 8. ComEd believes that NRG is correct, however, that while that subsection includes a minimum required level for subscriptions of 25 kW or less, that subsection does not prohibit a subscriber from having multiple subscriptions that aggregate over 25 kW as long as the minimum required level is met. NRG Companies also present examples of how the LTRRPP's new limit potentially and unnecessarily might negatively impact small businesses and, in some scenarios, even residential customers with more than one residence. *See* NRG Obj. at 9-10; ComEd Resp. at 9-10.

As a result, NRG Companies recommend that the Commission either: (1) not adopt the proposed new LTRRPP provision; or alternatively (2) limit the proposed new LTRRPP provision to large commercial and industrial customers (i.e., the provision would not apply to customers that are residential or small commercial customers). NRG Obj. at

12-13. ComEd agrees, and the Commission should adopt NRG Companies' above recommendation in its primary or alternative form. ComEd Resp. at 10.

5. Staff's Position

Staff explains that for the past two Program Years (2022-2023 and 2023-2024) and the Program Years governed by this Plan (2024-2025 and 2025-2026), the Agency defined small subscribers as residential and small commercial customers so long as their subscription size was below 25 kW. Section 1-75(c)(1)(K)(iii)(2) of the IPA Act requires that (community solar) "projects shall have subscriptions of 25 kW or less for at least 50% of the facility's nameplate capacity and the Agency shall price the renewable energy credits with that as a factor." 20 ILCS 3855/1-75(c)(1)(K)(iii)(2); Staff Resp. at 12-13.

The Plan under consideration proposes, beginning with Program Year 2024-2025, "program-wide, subscriptions for a single subscriber must not sum to over 25 kW to be counted toward this minimum 50% threshold. A subscriber that has a single or multiple subscriptions that sum to over 25 kW across all community solar projects in the Program will not have its subscriptions considered to be 25 kW or less for compliance with statutory requirements or REC contracting purposes." LTRRPP at 215; Staff Resp. at 13. According to the IPA, the impetus for this change is that the Program Administrator recently discovered nearly 200 subscribers – erroneously counted as small subscribers – with multiple subscriptions that exceed 25 kW in sum. LTRRPP at 215; Staff Resp. at 13.

The IPA Act defines "Subscriber" to mean "a person who (i) takes delivery service from an electric utility, and (ii) has a subscription of no less than 200 watts to a community renewable generation project that is located in the electric utility's service area. No subscriber's subscriptions may total more than 40% of the nameplate capacity of an individual community renewable generation project. Entities that are affiliated by virtue of a common parent shall not represent multiple subscriptions that total more than 40% of the nameplate capacity of an individual community renewable generation project." 20 ILCS 3855/1-10. The IPA Act further defines "Subscription" to mean "an interest in a community renewable generation project expressed in kilowatts, which is sized primarily to offset part or all of the subscriber's electricity usage." 20 ILCS 3855/1-10; Staff Resp. at 13-14.

The IPA Act states that "… a minimum of 50% of subscribers to be the project's nameplate capacity be residential or small commercial customer [sic] with subscriptions of below 25 kilowatts in size." 20 ILCS 3855/1-75(c)(1)(G)(iv)(3)(E)(ii); Staff Resp. at 14.

Staff supports the NRG Companies' Objection on this issue. Staff agrees with NRG Companies that the IPA Act does not prohibit a single residential or small commercial customer from acquiring multiple 25 kW subscriptions. While Staff appreciates the IPA's attempt to "ensure robust participation for residential and small commercial customers in Illinois Shines," LTRRPP at 215, Staff believes that if the IPA is simply seeking to prevent large single site consumers from qualifying as "small subscribers," then the IPA's proposed language is too broad in this case. This attempt to limit residential and small commercial participation from acquiring multiple 25 kW is not supported by the IPA Act. The IPA Act already contains a limit on such subscriptions in that in total the subscriptions cannot exceed the subscriber's electricity usage. 20 ILCS 3855/1-10 Definition of Subscription; Staff Resp. at 15-16.

Staff opines that the Commission should reject the IPA's arguments. The IPA's support for its position is based upon a misreading of the IPA Act. The IPA Act states that "… a minimum of 50% of subscribers to be the project's nameplate capacity be residential or small commercial customer [sic] with subscriptions of below 25 kilowatts in size." 20 ILCS 3855/1-75(c)(1)(G)(iv)(3)(E)(ii). The 25-kW limit is a limit imposed on a project's subscriptions, not on subscribers in general. By the plain language, the IPA Act does not prohibit a single residential or small commercial customer subscriber from acquiring multiple 25 kW subscriptions. Staff Rep. at 21.

Based upon the above, Staff recommends that the Commission direct the IPA to remove from the Plan its proposed cumulative 25 kW subscription cap and adopt NRG's objection. Staff Rep. at 21.

6. IPA's Position

The IPA Act requires that community solar projects "have subscriptions of 25 kW or less for at least 50% of the facility's nameplate capacity and the Agency shall price the renewable energy credits with that as a factor." 20 ILCS 3855/1-75(c)(1)(K)(iii)(2). As a result, REC prices for community solar projects assume that developers face an increased cost in the acquisition and maintenance of small subscribers, and in turn, result in higher overall REC prices. In order for a subscriber to count towards this minimum 50% threshold, the sum of the subscriber's subscriptions must not exceed 25 kW across all community solar projects. IPA Resp. at 46-47.

The IPA states that this is not a new requirement; rather, a clarification of an existing requirement. As explained in the Long-Term Plan, the Agency believes that the small subscriber requirement must be interpreted in a manner that facilitates residential and small commercial customer participation opportunities. LTRRPP at 215-16. Under an alternative interpretation where individual subscriptions are viewed purely in isolation, community solar developers may circumvent providing opportunities for residential and small commercial customers through instead marketing multiple 25 kW or smaller subscriptions to larger commercial and industrial customers. As this interpretation would frustrate the statutory direction of Section 1-75(c)(1)(N) of the IPA Act "to ensure robust participation opportunities for residential and small commercial customers" in community solar projects, the Agency does not believe that it is a viable reading of Section 1-75(c)(1)(K) of the Act to allow multiple subscriptions at or under 25 kW associated the same utility account to be considered small subscriptions for the purposes of meeting the minimum 50% small subscriber threshold. 20 ILCS 3855/1-75(c)(1)(N); 20 ILCS 3855/1-75(c)(1)(K)(iii)(2). IPA Resp. at 47.

The Program Administrator discovered in Spring 2023 that nearly 200 subscribers had multiple subscriptions below 25 kW that exceed the maximum 25 kW threshold when combined, and yet each of these subscriptions were erroneously counted as small subscribers towards the 50% minimum for the projects to which they are subscribed. 2024 Long-Term Plan at 215-216. The Agency originally planned to implement a process to enforce this requirement through updates to the Program Guidebook in 2023-24; however, when proposed changes to the Guidebook were released, the IPA received feedback from stakeholders that new processes would need to be developed in order to maintain compliance, and that additional time was required to implement those processes. Accordingly, the Agency removed the clarification from the 2023-24 Program Guidebook updates in favor of clarifying the requirement in the 2024 Plan. In order to provide community solar developers the necessary time to develop processes and procedures to correctly adhere to the small subscriber requirements, the Agency has proposed to begin enforcement of this statutory requirement beginning on June 1, 2024. Two parties objected to this proposal; the Agency's response to each is set forth below. IPA Resp. at 47-48.

In Objections, ESI expresses its appreciation for the Agency's consideration of the challenges facing developers in meeting this requirement and explains that subscriber acquisition is a lengthy process. ESI objects to the enforcement of the requirement on June 1, 2024, and seeks to set aside the requirement for all projects currently under contract. ESI notes that a bright line rule is easiest to follow and asks that the requirement be enforced for only projects that receive a Commission-approved REC Contract on or after June 1, 2024. The Agency does not believe that it is appropriate to apply a different statutory interpretation to one set of projects that are currently under contract, and a separate statutory interpretation to another set of projects. This proposal adds enormous administrative complexity for the Program Administrator – and for AVs with projects on contracts issued both before and after June 1, 2024 – to determine whether a particular utility account may or may not have multiple subscriptions totaling over 25 kW to count as small subscriptions. This complexity is exacerbated further when considering the potential that a customer may have one 20 kW subscription to a project with a pre-June 1, 2024 REC Contract and a post-June 1, 2024 REC Contract. The approach put forward by ESI is inconsistent with the Agency's interpretation of the law, would be administratively burdensome to implement, and must be rejected. IPA Resp. at 48-49.

The IPA states that the NRG Companies seem to fully misunderstand the requirements outlined in Section 7.9.6.2 and the lengthy explanation provided therein. First, NRG mistakenly characterizes the enforcement of a requirement that was already a part of the program as a "new limitation" on community solar subscriptions. NRG Obj. at 7. As explained above, the limitation that multiple subscriptions would disqualify an account as a "small subscriber" under the Program has existed since its inception; it is only recently that the Agency's new Program Administrator found that accounts with multiple subscriptions across different projects were not being monitored by its former Program Administrator and that efforts to enforce this requirement must be improved. IPA Resp. at 49.

Second, the NRG Companies incorrectly argue that the IPA proposes to limit the community solar program only to those customers that have an aggregate demand of less than 25 kW. NRG Obj. at 8. This is flatly wrong—there is no prohibition on participation by customers of any size in the program. Any residential or small commercial customer account may enroll in community solar, regardless of their subscription size. These customers are not required to qualify as small subscribers to obtain a subscription to a community solar project. Residential and small commercial customers may qualify as a small subscriber, provided that their subscription or subscriptions total no more than 25 kW, regardless of the size of customer's aggregate demand. However, residential or small commercial customers that have one or multiple subscriptions that sum to more than 25 kW are ineligible to count towards the 50% small subscriber requirement under the law. IPA Resp. at 49-50.

Third, the NRG Companies argue that the proposal could "arbitrarily deny benefits" to residential and small commercial customers. The Agency notes that in the case of a single entity owning multiple store locations or homes with subscriptions at or below 25 kW, each of those subscriptions would count as a small subscription, assuming they are separately metered and have separate utility accounts. In each of these examples, NRG Companies attempt to argue that the IPA's proposal would prohibit the customer from obtaining these subscriptions. NRG Obj. at 9-10. This is incorrect. Nothing in the proposal to enforce a statutory requirement for small subscriptions prohibits customers from having multiple subscriptions or having subscriptions above 25 kW. The Agency does not propose any limitation on the customer in terms of the quantity or size of subscriptions. The Agency proposes only to enforce statutory requirements that a subscriber—recognized as an individual utility account—with one or more subscriptions that exceeds 25 kW will not count towards the 50% minimum small subscriber requirement. These subscriptions will still validly count towards the remaining 50% of the nameplate capacity, which is not required to be subscribed by small subscribers. IPA Resp. at 50.

It appears to the Agency that NRG's concerns regarding the provisions of Section 7.9.6.2 of the 2024 Plan are misguided. The flawed arguments, based upon a misunderstanding of the provisions of the Plan, must be rejected by the Commission. The Agency requests that the Commission approve the provisions of Section 7.9.6.2 as set forth in the 2024 Long-Term Plan. IPA Resp. at 50-51.

It appears to the IPA that the NRG Companies and Staff incorrectly interpret the requirement as prohibiting Illinois customers from having multiple community solar subscriptions. This premise is false. The Agency has no ability to prohibit or limit enrollment in community solar subscriptions in any way. Both ComEd and Ameren host portals through which community solar developers must enroll subscribers in a community solar project. It is within this portal that the customer is actually enrolled in the subscription for purposes of receiving credits from the community solar project and billing. Any limitations on subscription sizes are governed by the applicable utility's tariffs which allow for community solar enrollment. The Agency has no oversight or control of the utility enrollment portals. The Agency cannot invalidate a community solar subscription, unenroll a customer from a subscription, prevent or disallow a customer from obtaining multiple subscriptions, limit or require modification to a subscription size, or otherwise make or order any changes to a customer subscription or subscriptions. The Illinois Shines program collects subscription information from AVs to confirm the subscribed nameplate capacity of the project, which directly affects the REC price of a community solar project as explained further below. IPA Rep. at 37.

Under the Initial Long-Term Plan approved in Docket No. 17-0838 and the Revised Plan approved in Docket No. 19-0995, Approved Vendors could receive a monetary bonus in the form of an adder to the REC price for enrolling a higher percentage of small subscribers to a project. The small subscriber REC pricing adder was intended to provide additional compensation in recognition of the fact that acquiring smaller subscribers is more difficult and costly. To encourage community solar developers to seek out small subscribers, the first REC Contract for Illinois Shines developed in 2019 awards a REC price adder for enrolling smaller subscriptions. This adder provides additional compensation to projects which secure subscriptions from small subscribers. To prevent exploitation of the small subscriber adder, the Illinois Shines program has always prohibited subscribers with multiple subscriptions that sum to more than 25 kW from counting towards the small subscriber calculation. This prevents developers from circumventing the guidelines by enrolling large subscribers with multiple subscriptions below 25 kW and receiving an inflated REC price through the use of the adder. IPA Rep. at 38.

P.A. 102-0662 amended the IPA Act to modify the TCS category, including a requirement that "projects shall have subscriptions of 25 kW or less for at least 50% of the facility's nameplate capacity and the Agency shall price the renewable energy credits with that as a factor." 20 ILCS 3855/1-75(c)(1)(K)(iii)(2). In response to this statutory directive, the Agency's 2022 Plan removed the small subscriber REC price adder and instead built into the REC Pricing Model an assumption that reflects increased costs of acquiring subscriptions of 50% of the nameplate capacity of the project from small subscribers, i.e., those customers with subscriptions of 25 kW or less. Essentially, the small subscriber adder is now built directly into the REC Pricing Model. As a result, allowing customers with subscriptions in the aggregate of above 25 kW or less count toward the 50% threshold inappropriately inflates the compensation received by community solar developers that do not incur the cost of acquiring small subscribers, but rather enroll large subscribers for multiple subscriptions of 25 kW or less. The proposal in the Long-Term Plan to only count customers with subscriptions totaling 25 kW or less towards the 50% minimum threshold ensures that participating projects are not overcompensated for the cost of subscriber acquisition. IPA Rep. at 38-39.

Again, the Agency emphasizes that this policy will not cause customers to be unenrolled from their community solar subscriptions. The Program Administrator will review the community solar subscriptions by account number or a unique customer identifier, both of which are tied to the utility meter, and use that information to determine whether the customer may count as a valid small subscriber under the original REC Contracts, where a small subscriber adder is available, or under the REC Contracts developed pursuant to the 2022 Plan, where a 50% minimum small subscriber threshold is embedded into the REC pricing. Under the Plan's approach, a residential customer that wants to enroll in two community solar projects to cover over 25 kW of usage will be permitted to do so pursuant to the terms of the utility tariffs – but the AV (or Vendors, if not the same) will not be able to count that customer towards the 50% small subscriber minimum threshold if the Program Administrator confirms the aggregated subscriptions exceed 25 kW. Likewise, a business owner that runs multiple convenience store locations will be able to enroll each location in community solar, without limitation beyond those set forth in the utility tariffs. However, where a subscription or subscriptions for any individual convenience store (since the Agency assumes each store would have its own electric meter) exceed 25 kW, that customer will not count towards the calculation of the small subscriber requirements of the applicable REC Contract. A large energy customer that is enrolled in four separate 25 kW community solar subscriptions will not see any change to their subscriptions based upon the Plan's requirements, but the community solar developer will not see these four subscriptions counted towards the small subscriber requirements. IPA Rep. 39-40.

The Joint Solar Parties admit that this interpretation is consistent with the previous program requirements, is consistent with the provisions of Section 1-75(c)(1)(N), and preserves opportunities for residential, small commercial, and other customers who cannot install renewable energy to participate in the clean energy economy. As such, the Joint Solar Parties did not initially object to the proposal, though it is unclear to the Agency whether that remains the case. The Joint Solar Parties seem to recognize the potential for exploitation of the small subscriber adder and the fact that small subscriber acquisition costs are now embedded into the REC Pricing Model, as required under Section 1-75(c)(1)(K)(iii)(2) of the IPA Act. The Joint Solar Parties argue that the current statutory requirements do not mention "small subscribers" but rather "subscriptions of 25 kW or less" and thus there is room to make another statutory interpretation. JSPs Resp. at 12. The Agency disagrees, as the full text of the statute states that "the Agency shall price the renewable energy credits with that as a factor." 20 ILCS 3855/1-75(c)(1)(K)(iii)(2). If the General Assembly did not intend for the community solar REC prices to account for the increased costs associated with the enrollment of individual small subscribers, rather than a large subscriber with multiple 25 kW subscriptions, this language would be meaningless, and is therefore an inappropriate interpretation of the statute. Finally, the Joint Solar Parties state that imposition of a "maximum subscription volume of 25 kW per account number" imposes an unnecessary burden. JSPs Response at 12. The Agency notes once again that there is no "maximum subscription volume" on customers imposed by the Agency – customers may be enrolled up to the volume permitted under the utility tariffs. IPA Rep. at 40-41.

ComEd states that it agrees with the NRG Companies' objection, as the IPA Act does not prohibit a subscriber from having multiple subscriptions that aggregate over 25 kW as long as the minimum required level is met. ComEd Response at 9-10. As discussed above in response to the Joint Solar Parties, this considers only a portion of the statutory language. The IPA has adjusted the assumptions within the REC Pricing Model to reflect that this 25-kW subscription size requirement reflects "small subscriber" acquisition costs. If this is not the case, and large energy customers with multiple subscriptions at or below 25 kW may count towards achievement of the 50% minimum threshold, the Agency believes that: (1) this approach should still be continued for the determination of the small subscriber adder under the 2019 REC Contracts and (2) the IPA should evaluate whether this is a frequent occurrence requiring adjustments to the REC Pricing Model assumptions related to subscriber acquisition costs. IPA Rep. at 41.

In its Objections, the Joint Solar Parties recognized that certain elements of the Long-Term Plan are necessarily dynamic and require flexibility but urged the adoption of explicit clarification around when and to which projects certain requirements arising from the Plan apply. In its Response brief, ESI specifically asks the Commission to "lock in" all project and applicant requirements based upon the Part I application date of the project. ESI response at 1-2. The grey areas for which the Joint Solar Parties sought specific clarification included the timing of an EEC qualification, system ownership requirements, and updates to project selection processes for categories that utilize a scoring approach to prioritize certain project attributes. ESI agrees with the Joint Solar

Parties that the iterative nature of the Long-Term Plan and its evolution due to changes in Illinois law causes a burden on developers in securing project financing, and that clarifications around these qualifications would improve the ability to finance projects. IPA Rep. at 41-42.

The Agency sees merit in the Joint Solar Parties' proposal but believes that the position of ESI goes beyond the original request of the objection and is unworkable. The Agency has and will continue to clarify application of program requirements in future iterations of the Long-Term Plan, and indeed, in many cases does so at the request of developers seeking flexibility and certainty for external partners. Yet the Agency doubts even developers would prefer the rigid, blanket policy of having all program requirements "locked in" at Part I application. The Agency – and the Commission, in its authority to approve the Plan – cannot reasonably impose this requirement on all Plan provisions. There will be situations that arise where the Agency requires the flexibility to adjust requirements in the administration of the RPS, either within or outside of the Long-Term Plan process. To limit application of any adjustments based on the time of an application's submission may have unforeseen consequences, and therefore the Agency cannot support the adoption of this proposal. IPA Rep. at 42.

Furthermore, the Agency urges the Commission to explicitly reject ESI's proposal to allow for projects to move forward within the EEC category in the situation where the entity has lost its status as an EEC after the Part I application is submitted. This item is discussed further in Chapter 10, below. IPA Rep. at 43.

7. Commission Analysis and Conclusion

Under the IPA Act "a minimum of 50% of subscribers to the project's nameplate capacity [must] be residential or small commercial customers with subscriptions of below 25 kilowatts in size." 20 ILCS 3855/1-75(c)(1)(G)(iv)(3)(E)(ii); Staff Resp. at 14. NRG Companies rely on the phrase "subscriptions of below 25 kilowatts in size" to aver that a customer may have subscriptions, in the aggregate, totaling over 25kW across multiple projects and still count as a "residential or small commercial customer" for purposes of a single facility's 50% subscriber requirement. The Commission agrees with NRG Companies. The relied-upon provision does not say "in the aggregate" after "with subscriptions of below 25 kilowatts in size." 20 ILCS 3855/1-75(c)(1)(G)(iv)(3)(E)(ii). Further, the provision's reference to "the" project suggests that it applies only to subscribers on a project-by-project basis.

The IPA justifies its interpretation of the IPA Act, in part, by asserting it needs to guard against larger commercial and industrial customers having multiple subscriptions to community solar projects that sum to over 25kW in the aggregate. IPA Resp. at 47. NRG Companies provided evidence rebutting the IPA's concerns. *See* NRG Rep. at 16, Attach. C.

Allowing developers to use a residential or small commercial customer that has multiple project subscriptions to comply with the 50% small commercial or residential requirement is consistent with the IPA Act. Accordingly, the Commission adopts NRG Companies' objection because it is consistent with P.A. 102-0662. The IPA is directed to revise the Plan to make clear that, for a particular project, a developer can count a residential or small commercial customer with subscriptions not exceeding 25kW at that project, toward the project's 50% minimum requirement. A developer's inclusion of a customer's subscriptions (<25kW in total) for purposes of counting toward the 50% minimum requirement at one project is not affected by the customer's subscriptions to other projects, where eligibility for the 50% minimum requirement is determined separately. The Commission remains aware of the possibility that the REC Pricing Model might not reflect the actual amount of marketing taking place for TCS projects. The Commission directs the IPA and stakeholders to monitor this process as necessary to promote the goals of the IPA Act.

The Commission further notes that LTRRPPs are reviewed upon record evidence. Any new evidence offered in future iterations of the LTRRPP regarding this issue will be considered and may impact future decisions.

With respect to the process clarification addressed by ESI and the JSPs, the Commission agrees with the IPA that situations will arise where the Agency requires the flexibility to adjust requirements in the administration of the RPS, either within or outside of the Long-Term Plan process. To limit application of any adjustments based on the time of an application's submission may have unforeseen consequences, and therefore the Commission does not adopt this proposal. Additionally, the Commission declines to adopt ESI's proposal to set aside the enforcement of this requirement for all projects under contract prior to the June 1, 2024 enforcement date.

L. Section 7.11.4. Additional Requirements for Community Solar Projects and Section 7.15. Annual Report

1. ESI's Position

ESI states that it appreciates the Agency's proposal to allow greater flexibility when it comes to the requirement to submit Annual Reports by July 15. It is often difficult to pull together the necessary information, specifically over a short period of time that includes a holiday. For smaller approved vendors and designees, this can be especially challenging when only one or a handful of employees are involved in the creation of these reports and must coordinate vacation schedules. The current penalties are too harsh and can result in adverse consequences for customers or subscribers in the event of inadvertently missing a single deadline. ESI Obj. at 12.

In addition to the changes proposed to the annual reports, ESI objects that similar changes to the quarterly reporting deadlines were not made as well. Currently, these reports are open on the first of the month and the deadline is 10 days later. However, this does not consider weekends or holidays. ESI suggests that the 10-day reporting period be changed to read 10 business days to account for the fact that the calendar can shift from period to period depending on which day of the week the first of the month falls on. ESI Obj. at 12-13.

ESI also objects to the language of the disclosure form attestation in Section 7.15. LTRRPP at 233-234. The proposed requirement reads: "Attestation that any and all Community Solar Disclosure Forms were signed by the subscribers." *Id*. at 234. This absolute language does not consider several instances where disclosure forms are not required to be signed to remain in compliance with program requirements. To take into account the instances where a project may have disclosure forms that are not signed, but are still operating within program requirements, ESI suggests the following change to the attestation requirement: Attestation that any and all required Community Solar Disclosure Forms were signed by the subscriber. ESI Obj. at 13-14.

2. IPA's Position

Among the updates proposed by the Agency in the 2024 Long-Term Plan is a proposal to introduce more flexibility around the deadline set forth in the REC Contract for the submission of annual reports. The 2024 Plan explains that the failure to meet the July 15 annual filing deadline is an event of default under the terms of the contract, and the penalty is extremely strict. 2024 Plan at 235-36. The Plan explains that there is significant potential for problems or delays in completing the report over a two-week period in early July, when that period conflicts with a national holiday over which many employees of AVs take leave or travel. The Agency proposes to develop an amendment to the REC Contract through the normal contract development process to address specific remedies to this issue, and the 2024 Plan details the proposed terms of the amendment. *Id.* The IPA would consider the Commission's approval of this approach to permit the amendment to be executed without additional approval from the Commission, and the developed amendment would be applicable to all versions of the previously executed REC Contracts under the Illinois Shines program. ESI supports this proposal. ESI Obj. at 12; IPA Resp. at 51.

ESI objects to the fact that the Agency did not make a similar proposal with respect to the quarterly reporting deadlines for community solar projects. *Id.* ESI argues that the 10-day window for submission of quarterly reports on subscription data are similarly short and that one period (the September reporting period) falls over a national holiday, resulting in only five business days to complete the required reports. ESI suggests that a simple fix to the Program Guidebook would allow for submission of these reports on the tenth business day of the month, rather than the tenth calendar day. However, the update to the Program Guidebook suggested by ESI would be ineffectual, since the window for submission of these reports between the first and the tenth day of the month following the end of the quarterly period is specified into the applicable REC Contracts. The IPA believes that changes to this deadline, like the change in the timing for submission of annual reports, would likewise require an amendment to the REC Contract. In the case of the quarterly reports, however, the Agency does not believe that an amendment is warranted. The failure to timely submit an annual report under the REC Contract constitutes an event of default under the terms of the contract. Conversely, there is no penalty under the terms of the contract for the failure to timely submit the community solar quarterly report, though there may be financial ramifications. Given that there is no strict punitive measure that attaches to the quarterly reports as there is with the annual reports, the Agency believes that the process of developing an amendment to the REC Contract to address the timing of quarterly reports is unwarranted. IPA Resp. at 51-52.

3. Commission Analysis and Conclusion

The Commission accepts the IPA's explanation for the differentiation between annual and quarterly reports. Importantly, that there is no financial ramification for submitting an untimely quarterly report. Accordingly, the clarification for the annual report filing date is not extended to the quarterly reports.

The IPA does not appear to have responded to ESI's clarification regarding when attestation is required. The Commission finds ESI's clarification to be appropriate and it is adopted.

VI. CHAPTER 8. ILLINOIS SOLAR FOR ALL

A. Section 8.5.5. Community Solar Sub-Program

1. JSPs' Position

Section 8.5.5 of the LTRRPP makes explicit the requirement in footnote 6 of the Solar for All Approved Vendor Manual version 6.1 that a master-metered building serving low-income customers that demonstrates 50% of subscription value goes to the benefit of its residents is restricted to 25 kW in subscriptions unless it is the sole anchor tenant for that Solar for All system. *See* LTRRPP at 271. The Joint Solar Parties urge the Commission to modify the LTRRPP by removing this requirement and explicitly state in the LTRRPP that there is no size limit on such master metered building subscriptions. JSPs Obj. at 27.

The Joint Solar Parties believe removing the 25 kW subscription cap is fully consistent with the goals of ILSFA and the LTRRPP, given that the requirement the subscriber demonstrate 50% of subscription value would go to residents would remain in place—thus, the larger the subscription, the greater the residents benefits. Master-metered buildings must have at least five residents to qualify (*see id*. at 267-268) meaning multiple residents that do not have individual meters to subscribe themselves will be benefiting and a larger number of customers will benefit for each subscription. Because of these requirements, benefits will be dispersed and there is not an opportunity for gaming and somehow reducing benefits to low-income customers—instead, it ensures the low-income customers least able to benefit from solar (because they have no meter) are best able to do so (through resident benefit obligations). JSPs Obj. at 27-28.

The IPA responded in opposition, stating "The Agency believes it is the best use of ratepayer funds to ensure that the savings required and generated by ILSFA community solar projects benefit income-eligible households, rather than multi-unit property owners." IPA Resp. at 54. The Joint Solar Parties agree that low-income customers should benefit—which they do under the LTRRPP requirement that to enroll master-metered buildings the building must demonstrate that savings are going to benefit all tenants. *See* LTRRPP at 267-268. The low-income residents who (because they have no individual meter) cannot otherwise benefit from subscriptions receive a benefit from Solar for All. In addition, multifamily master metered buildings receiving subscriptions whose benefits must be shared with residents ensure that more individuals receive benefits from solar than one residential unit at a time. The Joint Solar Parties urge the Commission to reject the IPA's proposed elimination of master-metered buildings serving low-income residential customers as Solar for All non-anchor tenants and instead allow such master-metered buildings to receive subscriptions over 25 kW in size. JSPs Rep. at 23-24.

2. Joint NGOs' Position

In its Objections, the JSPs objected to the IPA's proposal to disallow master-metered buildings to count as Income-Eligible Residential Households if subscriptions exceed 25 kW. The Joint NGOs agree with this Objection and request the Commission to reject the IPA's proposal. JNGOs Resp. at 2.

3. IPA's Position

The IPA notes that the purpose of the ILSFA program is to encourage and incentivize "photovoltaics [in] low-income communities in this State." 20 ILCS 3855/1-56(b)(2). One of the sub-programs in ILSFA, the Low-Income Community Solar ("LICS") is intended "to increase participation of low-income subscribers of community solar projects." 20 ILCS 3855/1-56(b)(2)(B). To help achieve this objective, starting in the 2024-2025 Program Year, no master-metered multi-unit buildings of any size will qualify as an income-eligible non-anchor subscriber for a LICS project. ILSFA Community Solar projects may include an anchor tenant that is not income-eligible. Master-metered buildings may still subscribe to an ILSFA Community Solar project and count as an anchor tenant, in which case the RECs generated by the anchor share would receive the REC price established for the Community-Driven Community Solar category in Illinois Shines. Previously, master-metered buildings with an energy demand of up to 25 kW could be counted as income-eligible subscribers if at least 50% of the tenants were verified as income-eligible. IPA Resp. at 53.

As stated in the LTRRPP, there are significantly more income-eligible households (income-eligible households and low-income households will be used interchangeably) than available community solar subscriptions, and the limited number of community solar subscriptions should go to households that would most benefit from the program. The total number of ILSFA community solar subscriptions is approximately 1,700, while the number of income-eligible households is in the hundreds of thousands. *Id.* While some LMI households live in a multi-unit building that is master-metered, income-eligible households living in sub-metered buildings must pay their own utility bill, making them subject to fluctuating energy prices. The Agency believes it is the best use of ratepayer funds to ensure that the savings required and generated by ILSFA community solar projects benefit income-eligible households, rather than multi-unit property owners. While Section 8.5.5 contains a requirement that the "building owner/manager will need to commit to passing along the value of at least 50% of the energy savings realized," the goal of reducing the energy burden of income-eligible households is better met with a direct reduction of their energy costs. Monthly utility bill savings are more direct benefits for income-eligible households facing disparate energy burdens than in-kind benefits passed through by property owners. LTRRPP at 271 ("Options for methods of passing benefits to residents include: reduced (or not raised) rents; new staff that serves all tenants; facility upgrades (excluding repairs and renovations necessary to maintain building codes or organization certifications); new equipment that serves all tenants; or other payments, benefits, or services to all tenants that would not otherwise have been possible without the savings generated by the photovoltaic system."). IPA Resp. at 53-54.

The IPA asserts that the Joint Solar Parties seem to have misinterpreted the LTRRPP and believe that Section 8.5.5 simply maintains the current limit on the eligibility of subscriptions of non-anchor master-metered buildings to under 25 kW in size. JSPs Obj. at 27. In fact, the 2024 Plan provides that master-metered buildings will no longer qualify as income-eligible non-anchor subscribers in the ILSFA Community Solar Subprogram regardless of subscription size. IPA Resp. at 54.

The Joint Solar Parties urge the Commission to remove the size restriction on master-metered building subscriptions. JSPs Obj. at 27. They assert that removing the size limit would further the goals set under ILSFA because residents without individual meters would benefit from the requirement that 50% of the subscription value be passed down to them as energy savings in a variety of ways. *Id.* However, the goals of ILSFA are better met, according to the Agency, by ensuring that the subscription value goes directly to income-eligible households as opposed to the property owner. Income-eligible household subscribers will see an immediate and direct reduction in their monthly utility bill, whereas residents of a master-metered building would eventually access a tangible benefit (chosen by the property owner) to the building which may or may not lead to financial savings or a reduced energy burden. IPA Resp. at 54-55.

The Joint NGOs support Joint Solar Parties' objection but provide no rationale or reasoning for their support. The Joint NGOs, like the Joint Solar Parties, seem to misinterpret Section 8.5.5 of the Plan. The Joint NGOs believe Section 8.5.5 sets a size limit on the eligibility of subscriptions of non-anchor master-metered buildings to under 25 kW. The IPA acknowledges that the Plan's language may have been confusing and reiterates that, starting in the 2024-2025 Program Year, no master-metered multi-unit buildings of any size will qualify as an income eligible non-anchor subscriber for a ILSFA Community Solar project. IPA Rep. at 44.

Accordingly, the Agency encourages the Commission to approve Section 8.5.5 as filed with the following clarification to remove any ambiguities or confusion:

> In the 2023-2024 Program Year, the Agency allowed master-metered affordable housing buildings with a subscription size under 25 kW to qualify as income-eligible household non-anchor subscribers. ~~Beginning in the 2024-2025 Program Year, master-metered buildings will no longer be allowed to qualify as income-eligible non-anchor subscribers, regardless of subscription size. Beginning with the 2023-2024 Program Year, the Agency added language to the Approved Vendor Manual allowing master-metered affordable housing buildings under 25 kW to qualify as an income-eligible household subscribers. The expansion of the qualification to master-metered buildings over 25 kW would not align with the overarching aims of Illinois Solar for All, as it would significantly restrict income-eligible household access to the already-limited community solar subscription capacity under the Program.~~ There are over 341,000 households that received LIHEAP in the 2022- 23 Program Year who must manage their own energy burdens, and the current pipeline of available ILSFA Community Solar subscriptions that can be created annually is only in the thousands, several orders of magnitude smaller. The Agency believes that allowing master-metered accounts to subscribe in place of individual

> income-eligible households is contrary to the goals of the program and therefore ~~that~~ master-metered buildings should not be allowed to subscribe as an income-eligible household at any building or subscription size beginning in the 2024-2025 Program Year.

IPA Rep. at 45.

4. Commission Analysis and Conclusion

Although the JSPs raise a valid point that low-income residents of master-metered buildings should ideally also be eligible to receive the benefits of a community solar subscription, the limited availability of such subscriptions makes the IPA's proposal to bar master-metered buildings pragmatic and reasonable. Also, the limitation will ensure that the benefits accrue only to low-income tenants and not perhaps commercial anchor tenants that would otherwise not be eligible. Master-metered buildings remain capable of participating in the Illinois Shines program. The Commission adopts the IPA's proposed language as described above.

B. Section 8.10.3.2. Income Verification

1. JSPs' Position

If the goal of the LTRRPP is to increase participation in ILSFA, the JSPs respectfully recommend that the Commission eliminate from Section 8.10.3.2 of the LTRRPP the requirement for every member in a household to verify their income. Instead, the Commission should direct modification of the LTRRPP to simplify the enrollment process to increase the number of participants in this program by using self-attestations for residents of qualifying census tracts in which at least 50% of residents are at or below 80% of Area Median Income ("AMI"). JSPs Obj. at 19.

Allowing subscribers and residential behind-the-meter customers to certify via self-attestation that they meet the income threshold would ensure benefits of the program effectively reach the intended recipients. Intrusive and complicated verification rules impose an inequitable burden on income-eligible subscribers that recipients under the ABP are not faced with, thus doing a disservice to the very customers that Solar for All aims to serve. Using low-income assistance program participation as an alternative pathway encourages AVs to market to and concentrate benefits with customers already receiving assistance. The estimated 265,704 LIHEAP customers in Illinois according to the LIHEAP Data Warehouse would primarily benefit rather than the larger number of customers that are eligible but not participating—for instance, the estimated Illinois LIHEAP-eligible population of 1,221,576. Finally, the JSPs are unsure whether a customer participating in the Percentage of Income Payment Program ("PIPP") or LIHEAP will be the primary beneficiaries of bill credits or whether the low-income assistance program—which by virtue of bill credits will have to pay less to keep the bill at the appropriate size—primarily benefits from subscriptions. JSPs Obj. at 20.

The JSPs note that New Jersey, Maryland, and Delaware as well as the Inflation Reduction Act behind-the-meter program all use self-attestation for income eligibility, so Illinois would hardly be the first state or program to use self-attestation. The JSPs recommend the Commission review the research establishing that potential subscribers who are not on limited incomes are reluctant to identify as being low-income, and the risk that non-income-eligible households would fraudulently self-identify as low-income is relatively lower. Record-keeping requirements and the potential for an audit should ensure that AVs remain diligent in applying proper subscriber sales and marketing practices. JSPs Obj. at 20-21.

2. Joint NGOs' Position

The Joint NGOs object to the Agency excluding self-attestation from the options for income verification in the residential subprograms. Self-attestation could lead to accelerated program deployment, a dignified and respectful process for customers, and tighter controls of sensitive information. JNGOs Obj. at 5-6.

The ILSFA residential subprograms have deployed less than 20% of the funding that they have been allocated since the program launched over four years ago. This is due to multiple pain points in the project application and customer acquisition processes and certainly partially due to the challenges of determining and demonstrating that customers are income qualified. An easy remedy exists, one that increases the flow of program benefits and allows for a more dignified and manageable process for customers: self-attestation. JNGOs Obj. at 6.

Self-attestation is a process whereby customers can attest to their income qualification through a signed affidavit. To limit abuse of this new income verification option, the Joint NGOs have in the past recommended that the Agency restrict self-attestation to specific geographies, namely the Qualified Census Tracts established by the Department of Housing and Urban Development ("HUD"). This process is already used in the ILSFA program. Community solar customers can demonstrate that they are income qualified via residency and affidavit. Customers in all subprograms can also use affidavits to demonstrate that they have zero income. JNGOs Obj. at 6.

The Joint NGOs note that the Commission indicated its support of expanding self-attestation options in the *2022 LTRRPP Order*. The Commission asked the Agency to "examine whether it is successful at expanding participation in the program and if there is evidence of abuse of that process" and, if there is no abuse, to "explore wider use of self-attestation…throughout ILSFA subprograms." *2022 LTRRPP Order* at 122; JNGOs Obj. at 6.

Hence, the Joint NGOs propose the following changes to Section 8.10.3.2 on page 295:

> The Agency has previously received comments suggesting streamlining of the income verification process, particularly for potential participants that demonstrate household-level third-party qualification such as LIHEAP or IHWAP. Establishing income eligibility is a fundamental part of Illinois Solar for All, and the Agency will continue to work with the Program Administrator and stakeholders to identify ways to simplify the income verification process. <u>The Agency received comments regarding providing income verification pathways that allow for self designation via affidavit, often referred to as self-</u>

> attestation. The Agency recognizes that the slow uptake of the Illinois Solar for All residential sub-programs indicates the need for significant adjustments, but seeks to balance accelerated program deployment with prevention of fraud, waste, and abuse. The Agency proposes adding a self-attestation option to the Residential Solar Pilot, also known as Bright Neighborhoods program, to better explore this option for income verification. Customers participating in the Bright Neighborhoods program who live within HUD Qualified Census Tracts (QCTs) will have an option to sign an affidavit confirming that they make less than 80% Area Median Income. If there is no or negligible evidence of abuse in this limited pilot, the Agency will work with the Program Administrator to expand the use of self-attestation before the next Plan. ~~However, the present approach offers a variety of options for verifying a household's income to provide flexibility and accommodate customers' various income documentation availability while maintaining Program integrity and performing due diligence of participant eligibility. The Agency is aware that other state solar programs that only require affidavits to verify household income. The Agency recognizes that those programs are often offering community solar savings, as opposed to incentives for distributed generation systems, and do not offer as high a savings requirements as those that are required by ILSFA. The benefits to households are at a much higher level based on their eligibility in ILSFA and the size of those incentives warrants a robust income verification process.~~

JNGOs Obj. at 7.

In response to the Joint NGOs' Objection against the exclusion of self-attestation, the IPA relies on circular reasoning. The contention that allowing self-attestation will hinder the IPA from determining whether increased participation is due to self-attestation or the increased role of the Program Administrator is unnecessarily restrictive and counter-productive. The ILSFA residential subprograms have deployed less than 20% of the funding that they have been allocated since the program launched over four years ago, in part, because of challenges in determining and demonstrating that customers are income qualified. The easiest remedy is one that increases the flow of program benefits and allows for a more dignified and manageable process for customers—self-attestation. The IPA should not place the tracking of successful program outcomes to certain policies over the implementation of policies that will surely increase the program's success. The Joint NGOs encourage the IPA to focus on achieving efficient results before it attempts to understand what policies proved to be the most effectual. JNGOs Rep. at 3.

The Joint NGOs support Staff's modification to their proposal, which allows for a limited expansion of self-attestation to the Bright Neighborhoods program and requires the IPA to report its experience with this limited expansion and make a recommendation on whether it should be expanded in the next Plan. JNGOs Rep. at 3.

3. Staff's Position

The Joint NGOs propose changes to Section 8.10.3.2 at page 295. Staff is not opposed to the JNGOs' proposal, subject to some modifications to the proposed Plan language. Instead of automatically expanding the use of self-attestation if the IPA finds "no or negligible evidence of abuse" during the pilot, Staff recommends that the IPA petition the Commission for approval of expanding the use of self-attestation or the discontinuation of the self-attestation for the Residential Solar Pilot. Similar to the Commission approving self-attestation for the Residential Solar Pilot in this Docket, the Commission should be deciding whether to expand the use of self-attestation in a future Docket. As a result, Staff's Response recommends the following language instead of JNGOs':

> <u>The Agency received comments regarding providing income verification pathways that allow for self designation via affidavit, often referred to as self-attestation. The Agency recognizes that self-attestation simplifies the income verification process and potentially accelerates program deployment, but the Agency is also tasked with prevention of fraud, waste, and abuse. In this Plan, the Agency proposes adding a self-attestation option to the Residential Solar Pilot, also known as Bright Neighborhoods program, to better explore this option for income verification. Customers participating in the Bright Neighborhoods program who live within HUD Qualified Census Tracts (QCTs) will have an option to sign an affidavit confirming that they make less than 80% of the Area Median Income. The Agency will report its experience with this limited expansion when filing the next Plan. The Agency shall make a recommendation in the next Plan as to whether to continue the self-attestation option for the Residential Solar Pilot and whether to expand this option for other Solar For All subprograms.</u>

Staff Resp. at 24-25.

In its Reply, however, Staff states that consistent with Staff's Response which is in line with the IPA's Response on this issue, the Commission should reject JNGOs' Objection. While Staff proposed alternative language to the Plan, Staff defers to the IPA on whether that language is acceptable to the IPA. If the IPA rejects Staff's proposed language change, then Staff withdraws its proposed language. Staff Rep. at 24.

4. IPA's Position

The IPA Act defines income-eligible households as "persons and families whose income does not exceed 80% of [AMI]." 20 ILCS 3855/1-56(b). The Agency offers several options for determining income eligibility of customers in the ILSFA Program, including: (1) third-party qualifying party program verification, where households participating in programs that have equivalent or stricter income eligibility requirements than ILSFA would automatically qualify upon validation by the Program Administrator; (2) tax transcript verification, where a third-party tax transcript vendor will provide income verification of the household income; and (3) tax returns or pay stubs. LTRRPP at 294; Approved Vendor Manual at 63. The Agency also allows customers in the Residential Solar (Small) and Community Solar sub-programs to have their income verified by the Program Administrator, rather than the AV, offering an alternative to furnishing sensitive information to a private company and reducing the burden on AVs. LTRRPP at 295. Additionally, Community Solar Projects allow subscribers that reside in a census tract where at least 50% of residents earn no more than 80% AMI qualify to verify their income by signing an affidavit stating they meet the income qualification level. LTRRPP at 296; IPA Resp. at 55-56.

The Joint NGOs and Joint Solar Parties object to the IPA not allowing self-attestation for income verification across all ILSFA sub-programs. The Joint NGOs believe that "self-attestation could lead to accelerated program deployment" because they claim the biggest hurdle to increasing participation in the Residential sub-programs is demonstrating that a customer is income qualified. JNGOs Obj. at 6. The Joint NGOs speculate that easing the income verification requirement will "increase the flow of program benefits and allow for a more dignified and manageable process for customers." JNGOs Obj. at 6. The IPA acknowledges that deployment of the ILSFA Residential subprograms has been slower than other subprograms but disagrees that self-attestation is the best solution. The IPA has taken substantial steps to reduce the burden of income verification, such as providing a number of verification methods, allowing for self-attestation for those claiming no income and community solar subscribers that live in certain census tracts, and offering the services of the Program Administrator directly to households. The Agency continues to believe that significant size of ILSFA REC incentives, with the majority of projects receiving a lump sum payment of $15,000-$30,000 for a Small Residential distributed generation project, warrants rigorous eligibility review. The IPA also notes that other state benefit programs that offer much smaller scale incentives also do not permit self-attestation. The various income verification methods available to applicants to ILSFA provide flexibility for households while maintaining program integrity. IPA Resp. at 56-57.

The IPA asserts that the Joint NGOs correctly point out that self-attestation was considered in the litigation over the 2022 LTRRPP and the Commission favored a cautious approach that only allowed self-attestation for households in census tracts where at least 50% of households earned no more than 80% of AMI and only for projects in the Community Solar sub-program. JNGOs Obj. at 6. The Agency is committed to exploring whether this use of self-attestation has been successful, but it is still too early to draw any conclusions. Only one full Program Year has passed since the IPA instituted the option of self-attestation for community solar subscribers in certain geographic areas. In the *2022 LTRRPP Order*, the Commission recommended that the IPA "examine whether it is successful at expanding participation in the program and if there is evidence of abuse of that process." *2022 LTRRPP Order* at 125. The Agency has implemented the option of self-attestation for households in the qualifying geographic areas but requires more time to make the determination requested by the Commission and to monitor whether there is evidence of abuse. IPA Resp. at 57-58.

The Joint NGOs claim that allowing self-attestation for all Residential projects would be the solution to accelerating program participation. The Agency notes that current Program Year has featured an uptick in projects applying to the Residential (Small) sub-program and relying on the current income verification methods, with 1150 projects submitted, worth $29.35 million, of an available budget of $34.34 million. As an alternative to their preference of adopting self-attestation program-wide, Joint NGOs propose limiting the expansion of self-attestation to the Pilot Program known as Bright Neighborhoods to balance reducing barriers to participation and the prevention of fraud, waste, and abuse. JNGOs Obj. at 7. Yet the Bright Neighborhoods Pilot Program is already designed to address stakeholder-identified barriers to participation from the customer enrollment process, and to test specific ways to reduce those barriers, and has only been running for four months. The Bright Neighborhoods Pilot Program will focus on upstream customer acquisition and have the Program Administrator assume most of the customer-interaction and public outreach functions and provide support and guidance to customers. In the Bright Neighborhoods Pilot Program, the Program Administrator will perform customer acquisition, including income verification, for the AV as a way of increasing participation. The IPA explains that the Program Administrator is tracking customer engagement and the points at which households drop out of the process or express any resistance to complex processes. Thus, the Pilot will already evaluate the role of income verification in reducing participation in the Residential sub-programs, but it is too early to draw any conclusions, and reworking the carefully designed Pilot would just delay further any informative results. IPA Resp. at 58-59.

If the Joint NGOs' proposal to also allow for self-attestation in the Bright Neighborhoods Pilot is approved, then the Agency will not be able to determine whether any change in participation was due to the increased role of the Program Administrator in customer outreach and eligibility determinations or whether it would be the self-attestation. The Agency believes that the best approach would be to continue the Pilot as designed and see whether there is significant improvement in participation. The Program Administrator is taking on the duty of income verification and will be tracking where and if people withdraw during the income verification process. If the Pilot demonstrates that income verification is the biggest barrier for customers, then the Agency will return to the possibility of self-attestation, but adding another variable to the Pilot will only muddy the waters. IPA Resp. at 59.

The Joint Solar Parties also object to the exclusion of self-attestation as an income verification method for DG. JSPs Obj. at 19. They recommend that the Commission eliminate the requirement that every household member verify their income and instead allow self-attestation in all sub-programs for residents in census tracts where 50% of the residents earn no more than 80% of AMI. JSPs Obj. at 19. Although the JSPs do not specify, the Agency assumes that they are requesting that ILSFA allow self-attestation for such residents for the distributed generation Residential sub-programs, since the Agency already accepts self-attestation from households in census tracts that are majority income-eligible for community solar projects. The Joint Solar Parties argue that the current income verification options are still too burdensome for income-eligible households. Yet, like Joint NGOs, they fail to provide specific evidence that the income verification methods are the main barrier, and instead simply assume that participation rates are primarily due to the income verification requirements. IPA Resp. at 59-60.

The Joint Solar Parties claim that several other states and the Inflation Reduction Act behind-the-meter program all use self-attestation for income eligibility so Illinois should do so as well. JSPs Obj. at 20. The Joint Solar Parties fail to mention that savings in the other states' programs and required by the Inflation Reduction Act are far lower than the savings offered in ILSFA, at most 20% of the energy value, thus reducing the financial risk associated with incentive funding supporting households that in fact do not qualify. Furthermore, the IPA states that higher tax credit available for photovoltaic installations that directly benefit low-income communities, established by the Inflation Reduction Act does not generally allow for self-attestation to verify household income. The IPA further explains that, contrary to the JSPs' belief, the Internal Revenue Service ("IRS") will accept self-attestation as "income verification … via program verification where the relevant jurisdiction specifically accepts self-attestation [because]… subscribers and applicants should not have to double verify when a State program accepts self-attestation." *Id.* Therefore, unless the IPA permits self-attestation as a form of income verification, AVs will not be able to use self-attestation for demonstrating eligibility for the credit. IPA Resp. at 60-61.

The Joint Solar Parties also argue that research supports the claim that fraud and abuse when relying on self-attestations is rare. The Joint Solar Parties recommend that the Commission review research "establishing that potential subscribers who are not on limited incomes are reluctant to identify as being low-income, and the risk that non-income-eligible households would fraudulently self-identify as low-income is relatively lower [sic]." JSPs Obj. at 20. The Agency is already increasing outreach and streamlining customer enrollment with the Bright Neighborhoods Pilot and asks that the Commission approve the Agency's proposal to continue that Pilot as is and revisit the potential for self-attestation once there is sufficient data upon which to make a determination. IPA Resp. at 61.

Staff supports the Joint NGOs' Objection proposing self-attestation for income verification in the Bright Neighborhoods Pilot Program. However, Staff takes issue with the automatic expansion of self-attestation if the IPA finds no or negligible evidence of abuse during the Bright Neighborhoods Pilot Program. Instead, Staff recommends that, if the Pilot's use of self-attestation is a success, the Agency seek approval to expand the use of self-attestation in the next Plan filing. IPA Rep. at 46.

Staff does not provide any new information, rationale, or argument for their support of the Joint NGOs' proposal. The IPA does not support Staff's modified proposal. Adding another variable (self-attestation) to the Bright Neighborhoods Pilot Program may do more harm than good because changing the design of the Pilot may result in multiple possible causes of specific outcomes. IPA Rep. at 46.

The Agency does not support Staff's modified proposal of accepting self-attestation in the Bright Neighborhoods Pilot Program because it will jeopardize the utility of the Pilot, thus preventing the IPA from determining whether income verification is the biggest barrier to participation. As such, the Agency asks the Commission to approve the Agency's approach as outlined in the 2024 Plan. IPA Rep. at 48.

5. Commission Analysis and Conclusion

The Commission believes adding a self-attestation option to the Residential Solar Pilot (with appropriate study modifications), also known as Bright Neighborhoods Pilot Program, is a reasonable measure to better explore the implications of income verification. Customers participating in the Bright Neighborhoods Pilot Program who live within HUD Qualified Census Tracts (QCTs) will have an option to sign an affidavit confirming that they make less than 80% Area Median Income. After evaluating the practical effect of expanding self-attestation to the Pilot, including evidence of abuse, if any, the Agency will provide recommendations on whether to incorporate self-attestation in its next Plan.

C. Section 8.16. Illinois Solar for All Advisory Committee

1. Joint NGOs' Position

The Joint NGOs object to the Agency's limited scope for leveraging the ILSFA Advisory Committee to inform and improve successful program implementation. The Advisory Committee should have additional visibility into program functionality and should be consulted to help create performance metrics for the ILSFA Program Administrator. JNGOs Obj. at 7.

The Joint NGOs point out that ILSFA residential subprograms have not been successful, having deployed less than 20% of the budget since it began over four years ago. This under enrollment is due to multiple reasons, many of which the Joint NGOs and other commenters have discussed at length in past comments. Some of these barriers are being addressed through new pilot programs, such as the Residential Pilot and the Pilot Program on Home Repairs and Upgrades. Others are being addressed programmatically, like the additional integration with the Illinois Shines program and the new dedication to supporting small and emerging contractors. JNGOs Obj. at 7-8.

However, the Joint NGOs assert the concern remains that this subprogram has failed to launch primarily due to a lack of AVs that are developing projects in the residential subprograms. Only a small handful of AVs have successfully completed projects in the residential program. Some have since exited the program, having decided that it is too complex and burdensome to navigate, especially when compared with other opportunities. JNGOs Obj. at 8.

The Joint NGOs argue something must change in the project submission, review, and approval process. AVs are best equipped to identify specific changes that are needed. They should be consulted regularly about where the program administration falls short and where there are unnecessary barriers to the project approval process. The Joint NGOs recommend that this type of consultation happen as part of the existing ILSFA Advisory Council process. JNGOs Obj. at 8.

The Joint NGOs believe that the Agency should go further, however, and propose performance metrics for the Program Administrator. These metrics should not only be used to improve performance of the residential subprograms as currently designed, but also used to identify opportunities for further program design improvements. JNGOs Obj. at 8.

The Joint NGOs are troubled by the IPA's response concerning the limited scope of the Advisory Committee. Proposing to limit the Advisory Committee from criticizing the Program Administrator is not appropriate or useful. Limiting criticism of a government contractor from a committee specifically constituted, in part, to comment on a program's performance unnecessarily constrains the Advisory Committee and fails basic tenets of transparency and accountability. JNGOs Rep. at 4.

The Joint NGOs hope the Commission does not accept the constrained role the IPA casts for the Advisory Committee. The ILSFA residential subprograms have not been successful, having deployed less than 20% of the budget since it began over four years ago. The Advisory Committee should have additional visibility into program functionality and should be consulted to help create performance metrics for the ILSFA Program Administrator. JNGOs Rep. at 4.

2. IPA's Position

The IPA explains the ILSFA Advisory Committee was formed to encourage stakeholder collaboration, provide visibility into program performance, and create a consistent space for stakeholders to propose improvements to increase participation in the Program. LTRRPP at 311. The Advisory Committee discusses issues raised from those involved in ILSFA programming and provide expertise and advice to the IPA and the ILSFA Program Administrator" on several topics. The Committee has met regularly since its formation and the Agency deeply appreciates the members' time and attention in this effort and commits to continue engaging the Committee and inviting open feedback. IPA Resp. at 62.

The IPA notes the Joint NGOs object to what they characterize as the limited scope of the Advisory Committee. JNGOs Obj. at 7. The Advisory Committee already meets with the Agency and the Program Administrator regularly and receives updates on program progress. If Committee members find the current approach to sharing information on "program functionality" insufficient, the Agency is open to working with the Committee to better design the content and format of data and updates shared in Committee meetings. IPA Resp. at 62.

The Joint NGOs also argue that AVs are best equipped to identify specific changes that could address barriers to participation and that AVs should be consulted in the Advisory Committee. The IPA clarifies that AVs make up the biggest group within the Advisory Committee, with five members in a fifteen-to-twenty-person Committee. Thus, they are already consulted six to ten times a year through the Advisory Committee meetings, which is the action requested by the Joint NGOs. If there are pieces of the application process that AVs take issue with or think may be improved, those members are more than welcome to offer ideas as to how the IPA can increase participation within statutory requirements. But the IPA notes that no AVs filed objections to any ILSFA application requirement other than income verification, which was addressed above. Furthermore, the Program Evaluator has begun interviewing stakeholders, including AVs, and identified the barriers to AV participation as a key theme to focus on in the Program Evaluation. The Agency, like the Joint NGOs, wants the ILSFA Program to succeed, and looks forward to continuing its collaboration with the Advisory Committee as the Program progresses. IPA Resp. at 62-63.

The Joint NGOs also propose that the Advisory Committee, in collaboration with the Agency and Program Administrator, "design and implement performance metrics for the Program Administrator." Joint NGOs Obj. at 9. They also propose that monthly updates on achievement of such metrics be posted publicly to the ILSFA website. The IPA states the Program Administrator is a contractor of the Agency; the selection of the Program Administrator and its duties and reporting requirements are established in Section 1-56(b)(5). Specifically, that section directs the Agency to conduct "a competitive bid process based on selection criteria and requirements developed by the Agency." It also requires the Program Administrator to submit quarterly reports to the Agency and the Commission on program performance. While the Advisory Committee is always welcome to provide feedback on its experience with the Program Administrator, the IPA asserts it would not be appropriate for an external, multistakeholder body to provide direct input on the performance metrics of a third-party contractor of the Agency. The Agency relies on third-party contractors to implement many of its programs and procurements, and technical terms of those contracts are carefully constructed by the Agency, as is the case for any state entity seeking services from an external firm. The Agency does not support the Joint NGOs' proposed additions to the 2024 Plan on this topic. IPA Resp. at 63-64.

3. Commission Analysis and Conclusion

The Commission declines to adopt the Joint NGOs' recommendation that AVs should be consulted regularly about ILSFA program administration. The IPA's explanation of how it is working to improve ILSFA enrollment with the help of the Advisory Board, of which a significant number are AVs, along with its work product and on-going interviews with AVs demonstrably shows that AVs are already an important part of the process. The Commission further declines to establish performance metrics for the Program Administrator as the contractor's performance and evaluation is already subject the IPA's contractual terms. Furthermore, the Advisory Committee is not constrained in its ability to provide feedback on the effectiveness of the Program Administrator.

VII. CHAPTER 9. CONSUMER PROTECTION

A. Net Crediting

1. JSPs' Position

The JSPs argue the LTRRPP requires several consumer protections that are only required because ComEd and AIC offer "net crediting" that is really "pay-when-paid" utility consolidated billing, instead of true New York-style net crediting. Under New York-style net crediting, the utility first calculates the total bill credit, but instead of placing the entire credit on the customer's bill, the utility will first back out the subscription fee and direct those funds to the system owner. The net amount of the credit is then placed on the customer's bill. The JSPs state this approach virtually eliminates the risk of serving low-income customers, because receiving subscription fees is not contingent on the customer making payment to the utility. In addition, it allows for a customer to truly offset their bill by placing the net credits on the bill without a separate bill or payment obligation to the customer. JSPs Obj. at 21.

If the Commission directs ComEd and Ameren to implement proper net crediting as required in New York, several potentially burdensome consumer protections will either become moot or will no longer be burdensome:

- Section 9.4.2.3.1: Customer bill agency is largely unnecessary if the utility handles community solar revenue by directing the contractual percentage for subscription fee directly to the system owner and applying only the "net" credit to the customer's bill. *See* LTRRPP at 329-330.
- Section 8.5.5: The awkward requirement for ILSFA Low Income Community Solar use the utilities' "pay-when-paid" approach where subscription payments are deprioritized in the event of partial or late payment and making the most disadvantaged customers unnecessarily challenging and risky to serve would be completely erased if proper net crediting took payment risk off the table and eliminated the second bill to the subscriber. *See* LTRRPP at 270.
- Exhibit H (Consumer Protection Handbook), Section VI.B.2: Issues with late billing and payment plans would be eliminated, because the utility would only be providing the net credit and there would be no separate bill for an AV or their Designee to fall behind on issuing. *See* LTRRPP Exhibit H at 27-28.

While the Commission cannot necessarily order a direct change to Rider POGCS and Rider NMCS in this proceeding, the JSPs suggest the Commission direct Staff to prepare a Staff Report to open proceedings investigating whether ComEd and AIC properly offer net crediting as required under Section 16-107.5(l)(4) or otherwise open an investigation or other contested proceeding. The JSPs note that doing so would greatly streamline these requirements and more in the LTRRPP, enhancing consumer experience and obviating the need for consumer protections to be imposed on imperfect workarounds. JSPs Obj. at 21-22.

While neither AIC nor the IPA supported the JSPs' Objection, it appears that neither provided substantive opposition to the proposed relief. The IPA notes that utility bill crediting is outside the scope of the LTRRPP. The JSPs agree that the LTRRPP does not dictate utility community solar bill crediting practices, which are authorized and directed by Section 16-107.5(l) of the Act. However, because the lack of actual net crediting has led to consumer protection proposals in the LTRRPP, the JSPs argue it is within the Commission's authority to order additional contested proceedings. JSPs Rep. at 18-19.

The JSPs agree with some of AIC's assertions but strongly disagree with others. AIC is correct that the Commission did not order actual net crediting in the Rider POGCS and Rider NMCS dockets in implementing Section 16-107.5(l)(4). Contrary to AIC's assertions, there is a reason for the Commission to revisit the issue. Specifically, ILSFA now requires use of the utility's "net crediting" programs. The JSPs have raised concerns regarding utility implementation of Section 16-107.5(l)(4). AIC does not counter the fundamental issue that a customer in arrears would both greatly benefit from community solar subscriptions and will not pay a single penny to the system owner under ComEd or AIC's consolidated billing tariffs until the entire arrearage is cleared. While AIC may get rate recovery for uncollected charges, solar developers do not and cannot make up that lost revenue. In the end, the system owner faces increasing pressure to terminate the subscription in the face of non-payment and the customer loses out on beneficial community solar bill credits. JSPs Rep. at 19.

While the JSPs respect AIC's viewpoints, AIC gets several items wrong and, in several cases, completely inverts the actual money flow and economics. For instance, AIC argues that "By shifting all collection risk associated with subscription fees to the other customers of AIC, a moral hazard for developers is created to perform little or no due diligence in enrolling low-income subscribers other than verifying their qualifying income status." AIC Resp. at 5. This statement is not accurate. AIC appears to be conflating purchase of receivables and net crediting, where the utility takes a defined percentage of the bill credit and places it on the customer bill and remits the remaining amount directly to the system owner. Instead, AIC appears to baselessly assume that if a low-income customer cannot or does not pay their subscription fee, the system owner will essentially provide a free subscription. While that may be a business model of some in the ILSFA program, it is certainly not widely used even within ILSFA and much less across all community solar systems. JSPs Rep. at 20.

AIC also suggests that "the IPA has asserted and exercised its ability to adjust REC pricing to ensure that all facets of the renewable energy portfolio, including low-income community solar, are vibrant." AIC Resp. at 5. AIC's assertion is directly contradicted by the LTRRPP's discussion of under-utilization of the ILSFA program and considered ban on verified low-income customer participation in ABP systems. *See* LTRRPP at 330-331; JSPs Rep. at 20.

AIC is also incorrect that net crediting completely eliminates the risks associated with REC payments and subscription revenue. An ABP or ILSFA customer must still be acquired through rigorous consumer protections. The ABP and ILSFA REC contracts only pay on RECs to the extent the system is subscribed. The system owner cannot ignore subscription challenges with net crediting; however, net crediting allows system owners to ignore a customer's credit score, which is a consumer-beneficial outcome especially for low- and medium-income customers that may not pass a traditional credit check. JSPs Rep. at 21.

Discussion of AIC's current practices in a Commission proceeding is welcome. The JSPs respect that AIC has concerns about net crediting as defined by the JSPs, but those issues can be fully vetted in the appropriate Commission proceeding. As a result, the Commission should adopt the JSPs' Objection and open new proceedings to direct ComEd and AIC to modify Rider POGCS and Rider NMCS respectively to introduce true New York-style net crediting. JSPs Rep. at 21.

2. AIC's Position

The JSPs allege that several of the IPA's LTRRPP goals would be better met with true net crediting than additional consumer protections. In support of its position, the JSPs assert that the LTRRPP requires several consumer protections because AIC and ComEd, in contravention of Section 16-107.5(l)(4), do not offer a "true New York-style net crediting" and instead offer "net crediting" that is really "pay-when-paid" utility consolidated billing. JSP Obj. at 21. JSPs continue to describe how "New York-style" net crediting operates. However, when synthesized down, the JSPs are requesting that the IPA require that community solar developers be guaranteed to collect in full all the subscription fees billed on their behalf by the utilities before any credits are applied to the customer's bill for electric service and assert that doing so would eliminate the need for a second bill or payment by the subscriber. AIC Resp. at 1-2.

Specifically, the JSPs assert that if the Commission directs AIC and ComEd to implement "proper" net crediting as required in New York, several burdensome consumer protections will either be mooted or no longer burdensome. The assertions and arguments raised by JSPs in support of their request and recommendations are not completely accurate and are misleading. It should be noted that this issue is not new to the Commission. The Commission has already addressed this issue in Docket No. 21-0859, and appropriately rejected the same request and the same arguments in that proceeding. *See Ameren Ill. Co. d/b/a Ameren Ill.*, Docket No. 21-0859, Order at 13-19 (Jan. 13, 2023). The JSPs have not provided any new facts or change in fact to differentiate their current position from the previous proceeding. AIC Resp. at 2-3.

The JSPs do not accurately describe the billing and payment process that will occur when subscription fees are placed on customer bills. For customers receiving an AIC-issued bill for electric service, the bill statement includes credited electric service charges and the subscription fee. The customer is required to make only one payment to the utility for both electric service charges and subscription fees. The JSPs would have the Commission believe that there is need to amend current practices; however, there is no separate or second bill or payment obligation has ever been discussed, much less programmed, for billing subscription fees on behalf of developers. AIC Resp. at 3

The account agency approach predates the availability of the subscription option in Illinois and has primarily been used by a third party to market their ability to deliver large numbers of subscribers *en masse* to developers willing to enter into a business partnership with that third party. By assuming account agency status, the third party makes all enrollment decisions, such as community solar subscriptions and third-party electric supplier enrollments, for customers without needing to secure additional authorization. The JSPs would have the Commission believe that the third party will change its business practice of having electric service bills sent directly to that entity, with that entity issuing its own bill and controlling the information seen by subscribers simply because developers have the option of including the subscription charge on the utility's bill. However, the Company believes this to be erroneous and recommends the Commission reject the JSPs' recommendation as it relates to account agency. AIC Resp. at 3-4.

The JSPs' recommended "New York" approach pays developers first out of the community solar credits produced by the subscription, and then apply the remainder of the credits to the subscriber's bill for electric service. The JSPs make the novel argument that the Illinois practice of making all of the credits produced by a subscription available to pay a low-income customer's bill creates a greater risk of disconnection of service than making only part of the total credit available to pay the bill. AIC disagrees. Under the Illinois approach, the full benefits and credits of community solar are made available to support all subscribers, including the most vulnerable. Again, similar to JSPs' proposal in Docket No. 21-0859, the only beneficiaries of the proposed approach are the solar developers because it would speed their cash flow and virtually eliminate any risk associated with their community solar investment. In other words, the approach advocated by the JSPs would remove all risk of development associated with these projects. In addition to receiving guaranteed subscription fee revenues, the unsubscribed portion of the generator can be sold to the Company under its Rider QF-Qualified Facilities tariffs, and that is after the developer receives customer-funded RECs, a smart inverter rebate, and federal income tax credits. AIC Resp. at 4.

By shifting all collection risk associated with subscription fees to the other customers of AIC, a moral hazard for developers is created to perform little or no due diligence in enrolling low-income subscribers other than verifying their qualifying income status. Developers will have no incentive to research the right size of capacity to reserve for individual subscribers and will instead be motivated to sign up low-income customers for the largest subscriptions allowed to reduce up front marketing and administrative costs. A similar dynamic has been observed with some electric suppliers who use the utility consolidated billing/purchase of receivables program that guarantees payment for their services regardless of the relationship of the supplier's charges to the electric market price. Thus, the approach advocated by JSPs would seem to require the adoption of additional consumer protections and responsibilities by the IPA to ensure the rightsizing of subscriptions. AIC Resp. at 5.

Additionally, AIC notes that the risk of serving low-income customers, as asserted by the JSPs, does not seem to be impeding the willingness of developers to build these facilities should they receive RECs. Moreover, the IPA has asserted and exercised its ability to adjust REC pricing to ensure that all facets of the renewable energy portfolio, including low-income community solar, are vibrant. AIC Resp. at 5.

The JSPs conclude their objection by requesting that the Commission direct Staff to prepare a report to open proceedings investigating whether ComEd and AIC properly offer net crediting, as required under Section 16-107.5(l)(4). Again, the JSPs made the same request, using the same supporting material, in Docket No. 21-0859. In that proceeding, the Commission noted that, based on the same set of information provided by JSPs here, Staff had no reason to recommend that the Commission direct the Company to revise its tariff to provide the risk-free subscription fee payment process requested by the JSP. *See* Docket No. 21-0859, Order at 18. The Commission should continue to disregard the JSPs' arguments based on these assertions. AIC Resp. at 5-6.

3. IPA's Position

Chapter 9 of the filed 2024 Plan outlines existing and newly proposed consumer protection requirements. The Agency appreciates the JSPs' support for three significant new consumer protection initiatives including the increased incentives for AVs that rescue "stranded" customers; an escrow process when there is a risk that an AV will not provide a promised pass-through payment to customers; and a solar restitution program. IPA Rep. at 49.

AIC addresses the Joint Solar Parties' argument that the utilities should use "New-York style" bill crediting for community solar subscribers. Under the current approach, the utilities provide a credit on the customer's bill, calculated by multiplying the electricity generated by the customer's subscription by the utility's Price to Compare. The customer then pays the community solar provider the subscription fee, which is usually a set percentage of the total bill credit amount, such as 80% or 90%. The customer's payment to the community solar provider may be direct or indirect. The JSPs propose that the utilities condense the process by directly paying the community solar provider the customer's subscription fee, and then placing the netted credit on the customer's bill. IPA Rep. at 49.

This topic is outside the scope of this proceeding, as the Agency has no authority to direct the utilities on crediting methodologies. The Agency does recognize, however, that there could be consumer benefits from the "New York" approach. The customer would experience a much simpler transaction. This approach could also virtually eliminate the situation where a community solar customer may pay more than they would had they not enrolled in community solar, which happens when the customer "buys" more credits than they can use in a month. IPA Rep. at 49-50.

AIC does, however, raise valid concerns about the approach, including that it might lead to community solar providers not doing due diligence to ensure rightsizing of subscriptions. The "New York" approach might further untether the connection between the customer and the subscription to make it even more transactional in nature. The Agency also agrees with AIC that the implementation of "New York" crediting would not necessarily eliminate the need for all the consumer protection requirements. Some of the requirements are related to the business model where a community solar provider takes over control of the customer's utility account. As Ameren points out, there is no reason to assume that this model would be eliminated if the "New York" crediting was adopted. The Agency reiterates that this topic is outside the scope of the current docket but does not take a position on whether the Commission should open a separate docket to consider the potential adoption of "New York-style" net crediting. IPA Rep. at 50-51.

4. Commission Analysis and Conclusion

As the IPA and AIC properly note, the issue of net crediting is outside the scope of this LTRRPP proceeding. Furthermore, the Commission considered JSPs net crediting proposal, which shifts billing and collection risk to the utility, in Docket No. 21-0859 and noted that "nothing in Section 16-107.5(l)(4) provides that utilities must take on the potential of bad debt risk or address cost recovery for bad debt costs incurred through the net crediting program." Docket No. 21-0859, Order at 18. The Commission further noted that "[i]f that was the intent of the General Assembly, it would likely have been included." *Id*. In the absence of any change in circumstances or legislative changes, the Commission declines to initiate a proceeding solely for the consideration of the potential adoption of "New York-style" net crediting.

B. Section 9.4.2.1.1. Economic Incentive for Stranded Customer Projects

1. AIC's Position

In Section 9.4.2.1.1, the IPA notes that customers can become "stranded" when they have contracted with a solar company, but the AV can no longer move forward with the project. To mitigate this issue, the IPA proposes an economic incentive for AVs that assist stranded customers in the form of a 'REC adder' – that is, an increased price in the

REC Contract for RECs generated by projects that were stranded and then 'unstranded.' AIC supports the establishment of such an incentive, as well as the IPA's commencement of a process to solicit stakeholder feedback on the proposed incentive, as AIC would appreciate the opportunity to provide such feedback. AIC respectfully requests that the IPA consider the contract administration and monitoring components of the proposed incentive program as the IPA develops the finalized program as the administrative burden for AIC in administering and monitoring new programs has proved difficult in the past. To this end, AIC believes that the IPA and Program Administrator should be responsible for determining the eligibility of vendors qualifying to receive any such REC adder. AIC Obj. at 5.

2. IPA's Position

AIC generally supports the Agency's proposals in Chapter 9 along with the specific proposal to develop and implement an economic incentive for Illinois Shines AVs to take on stranded solar projects. The Agency recognizes and appreciates that the initiative will take significant administrative effort and does intend that the Program Administrator and Agency will make eligibility determinations. IPA Resp. at 65.

3. Commission Analysis and Conclusion

Through the 2024 LTRRPP, the IPA proposes implementing an economic incentive for Approved Vendors that assist stranded customers in the form of a "REC adder"—an increased price in the REC Contract for RECs generated by projects that were stranded and then "unstranded." 2024 Plan at 322. The Commission notes AIC's support for the incentive along with the IPA's intent to have the Program Administrator and Agency make eligibility determinations. The Commission approves IPA's proposal to use a stakeholder process to fully develop the initiative as set forth in the 2024 Plan. The Commission approves the IPA's request to allow the possible REC adder to be available even for REC Contracts that pre-date the Agency's 2024 Plan, as this will allow the benefits of IPA's proposal to reach currently stranded customers as well as future stranded customers. The Commission approves IPA's request to make the REC adder available even after the original or "base" REC incentive payments were made. The Commission encourages the IPA, AIC, and other relevant stakeholders to continue to discuss implementation.

C. Section 9.4.2.1.2. Escrow Process for Approved Vendors that Do Not Pass Through Promised Incentive Payments

1. AIC's Position

In Section 9.4.2.1.2 of the Plan, the IPA sets forth an escrow process "to be activated in situations where an [AV] is very likely not going to pass through the promised incentive payments to customers." AIC supports the establishment of an escrow process, as well as the notion of using an escrow agent to administer payments thereunder. Additionally, AIC recommends that the escrow agent or the IPA provide, once per quarter, a detailed invoice of the incentive payments, on which the utility would rely upon to send the appropriate amount of funds to the escrow agent. In turn, the escrow agent would administer payments to individual customers. Furthermore, AIC believes that the IPA and

Program Administrator should be responsible for determining the eligibility of customers qualifying to receive such payments. AIC Obj. at 6.

2. IPA's Position

Chapter 9 of the filed 2024 Plan proposed the development of an escrow process in Illinois Shines when necessary to ensure that customers receive promised pass-through REC incentive payments. The IPA states some AVs use a business model where they make a lump-sum payment to the customer passing through all or some of the Illinois Shines REC incentive payment. The escrow process would be used when there is a serious risk that the AV will not actually pass through the payment as promised. In these situations, the utility would make the incentive payment to an escrow agent, who would in turn make the appropriate payments to the customer and AV. AIC supports this proposal, suggests a quarterly invoicing process, and asserts that the Program Administrator and Agency should be responsible for determining customer payments. The Agency does intend that the Program Administrator and Agency would make determinations regarding eligibility and payment amount, and that invoicing for each project or batch would continue on the normal pre-existing schedule. IPA Resp. at 65-66.

3. Commission Analysis and Conclusion

The Commission notes AIC's support for the escrow process. The IPA intends for its Program Administrator and Agency to make determinations regarding eligibility or payment amounts as requested by AIC. However, the IPA indicates that invoicing for each project or batch would continue on the normal pre-existing schedule. AIC does not provide any support or explanation for diverging from the IPA's pre-existing schedule. Therefore, the Commission declines to adopt AIC's proposal requiring the IPA to use a quarterly invoicing process. The Commission approves IPA's proposed development of the escrow process in Illinois Shines.

D. Section 9.4.3.2.3. Illinois Shines Community Solar Offers Marketed to Low-Income Customers

1. JSPs' Position

The JSPs recommend the Commission reject both the policy behind and the implementation of the LTRRPP's proposal that if an AV or Designee identifies income-qualified subscribers to an ABP system that the AV or Designee must provide a notice encouraging ILSFA participation. *See* LTRRPP at 330-332. The JSPs argue the Commission reject the implementation because if the ABP system is participating in the Inflation Reduction Act low-income bonus program, the subscriber must already be guaranteed to retain at least 20% of the bill credit value and thus will have substantial benefits that should not be discouraged. The JSPs further state the Commission should reject the policy behind the IPA proposal because if there are persistent openings in ILSFA Low-Income Community Solar projects, the best approach is to identify and remove barriers to subscribing customers to those systems rather than discouraging income-qualified customers from obtaining savings from ABP systems. JSPs Obj. at 17-18.

The JSPs argue the Commission should forcefully reject the LTRRPP's longer-term proposal of potentially prohibiting ABP projects from receiving the IRA low-income bonus credit. *See* LTRRPP at 331. The LTRRPP conjectures that "This would hopefully drive more community solar projects to participate in [ILSFA], creating more opportunities for greater economic benefits for low-income customers." *Id*. Such an approach would unjustifiably reduce federal dollars supporting low-income savings captured by renewable energy investments in Illinois—all of which advance P.A. 102-0662's goals. JSPs Obj. at 18.

The JSPs further note that ILSFA already has a substantially higher per REC value and relatively more limited competition for capacity especially compared with the TCS block. The JSPs fully support an internal or third-party review by the IPA to determine why existing AVs across all segments do not currently participate in the ILSFA program despite these advantages. Without having undertaken a formal survey, the JSPs suspect burdensome additional requirements unrelated to the 50% savings requirements, including system inspection delays, burdensome income verification requirements, and requirements to use utility consolidated billing that virtually ensures non-payment from the customers that would benefit most from heavily discounted subscriptions. JSPs Obj. at 18-19.

Even if the Commission does not address these broader concerns, the JSPs believe the Commission should remove the disclosure requirement proposed in the LTRRPP regarding ILSFA. *See* LTRRPP at 332. First, JSPs argue advertisement for ILSFA or any other program should not be the obligation of ABP AVs, who will be essentially performing uncompensated business development work for ILSFA AVs. Furthermore, the LTRRPP conceded that "Illinois Solar for All still lacks brand recognition and trust among income-eligible communities and households across Illinois, which presents ongoing challenges to [AVs] seeking to engage potential ILSFA participants." LTRRPP at 250. ILSFA brand recognition is not the responsibility of ABP AVs. Rather, it is a shared responsibility of participants in the ILSFA program but particularly of the Program Administrator. JSPs Obj. at 19.

Second, JSPs further argue such a disclosure may cause confusion and distrust from potential low-income subscribers, who the LTRRPP concedes are better off with 20% retained bill credit value than no money-saving subscription at all. *See* LTRRPP at 331-332. By telling a potential customer that they could save more with a competitor, the customer may lose trust in the entity marketing them. JSPs Obj. at 19.

The JSPs strongly disagree with the conclusions and reasoning of the IPA's opposition and urge the Commission to adopt the JSPs' Objections. JSPs Rep. at 15. The JSPs urge the Commission to reject the IPA's framing of the issue. Repeatedly, the IPA discusses AVs representing ABP systems "targeting" low-income customers as if enrolling low-income customers on a money-saving product is nefarious. *See, e.g.,* IPA Resp. at 66, 68. The IPA also refers to additional consumer protections in ILSFA that are not available for ABP systems. The JSPs note that the overwhelming majority of the required contract terms are exactly the same or substantially similar for both programs with the exception of: (1) the required 50% savings for ILSFA; and (2) requirements under ILSFA related to loans to purchase panels, which are unlikely to be an issue for third-party financed ABP projects. Thus, the only real difference in the minimum terms required for contracts achieving the low-income Inflation Reduction Act adder between the ABP and ILSFA are the 20% retained bill credit value by the Inflation Reduction Act and 50% retained bill credit value under ILSFA. JSPs Rep. at 15-16.

The JSPs of course acknowledge that 50% retained bill credits are more valuable than 20% retained bill credits. The IPA suggests that the solar industry's greed is what would push AVs of ABP projects to offer 20% retained bill credits to low-income customers instead of participating in ILSFA. Assuming the IPA's REC Pricing Model for ILSFA accurately accounts for the additional low-income customer acquisition costs and decreased subscription value, the higher REC value in ILSFA should leave AVs indifferent between ILSFA and the ABP. Based on the volume of participants in ILSFA compared to the ABP, this is clearly not the case. The IPA concedes by its proposal that AVs outside of the ILSFA program seek to bring savings to low-income customers and achieve Inflation Reduction Act bonuses. JSPs Rep. at 16.

While the IPA unfortunately dismisses the problems and issues with the ILSFA program in its Response, the JSPs specifically identified other ILSFA non-monetary challenges as a reason that AVs might acquire low-income customers outside of ILSFA. Instead of dismissively rejecting concerns about ILSFA including verification, benefits to master-metered buildings, remaining silent on inspection and customer verification delays and causing whiplash from constant ILSFA program rule changes, the JSPs suggest IPA instead take feedback on ILSFA challenges and what it would take to encourage more participation. JSPs Rep. at 6-17.

The JSPs note the LTRRPP concedes that ILSFA is not filling up and even the ILSFA community solar subcategories does not have a waitlist, while equivalent ABP programs have substantial waitlists. *See* LTRRPP at 331. There is clearly interest from AVs to serve low-income customers but not a parallel interest for AVs to participate in ILSFA. Given that the ILSFA REC Pricing Model is supposed to account for additional costs, ILSFA should be oversubscribed like the ABP, but it is not. The Commission should not approve the proposal in the LTRRPP that requires AVs and their Designees not participating in the ILSFA program to market its offers. Instead, the Commission should modify the LTRRPP to direct the IPA to identify the cause of lack of AV participation in ILSFA and encourage the next LTRRPP to include solutions to improve the ILSFA program. JSPs Rep. at 17.

The JSPs also urge the Commission to specifically reject the IPA's argument that a hypothetical low-income customer that theoretically has access to ILSFA offers having second thoughts is reason to impede or ban ABP projects from acquiring low-income customers. Having second thoughts about savings is no different than finding out one's ABP subscription charge is higher than another offer in the market. As with ILSFA subscriptions, an ABP subscription may include an early termination fee under some circumstances. In both programs, the customer can make a decision and change their mind later by switching to a new product; such pricing differences and consumer choices are the sign of a healthy, functioning, and competitive market. JSPs Rep. at 17-18.

The JSPs argue that just because a product with more savings may be available or the low-income bonus could have gone to a ILSFA system is not a reason to limit ABP systems or their subscribers with additional marketing rules now or a ban down the road.

If the IPA is concerned about ILSFA participation, the Commission should direct a review of the ILSFA program and identify the barriers to AV participation. Otherwise, it is unclear why the IPA believes that ILSFA participation will increase without changes to whatever forces are driving away AVs today. JSPs Rep. at 18.

2. IPA's Position

The IPA sets forth that JSPs object to the LTRRPP's two-part proposal to address community solar projects that seek to take advantage of both Illinois' solar incentives, and also the federal Low-Income Economic Benefit Bonus Credit ("Bonus Credit") for projects that serve low-income customers. The IPA explains federal Bonus Credit is an additional credit on top of the regular federal investment tax credit. *Additional Guidance on Low-Income Communities Bonus Credit Program*, 88 Fed. Reg. 55,506, 55,507 (Aug. 15, 2023) (to be codified at 26 C.F.R. pt. 1). The filed 2024 Plan proposed that, for now, these solar projects be allowed to participate in Illinois Shines and take advantage of both the 50% federal investment tax credit and the Illinois Shines REC incentive. However, the Agency is concerned that these projects will be marketed to many of the same low- and moderate-income customers who would be eligible for ILSFA, which comes with heightened consumer protections and higher customer savings requirements. There is a clear policy concern with Illinois Shines solar developers targeting low- and moderate-income customers for community solar projects that do not provide the additional protections and benefits that are provided in ILSFA. The Agency therefore proposed that if a community solar provider in Illinois Shines chooses to conduct income verification of subscribers and determines that an individual subscriber is income-qualified, that the provider must give the customer a one-page notice that informs the customer about ILSFA. IPA Resp. at 66-67.

The JSPs argue that requiring community solar providers to give the one-page notice to customers amounts to requiring Illinois Shines participants to perform uncompensated marketing for ILSFA vendors and may "cause confusion and distrust." JSPs Obj. at 19. The Agency notes that the Illinois legislature specifically created two separate solar incentive programs with one specifically designed for low-and moderate-income individuals. Income-eligible customers who sign up for a community solar project that both participates in Illinois Shines and receives the federal Bonus Credit will almost certainly have a subscription fee of 80% of the value of the community solar credits. To be eligible for the Bonus Credit, the community solar offer must provide a 20% bill discount rate. *Additional Guidance on Low-Income Communities Bonus Credit Program*, at 516-17. In ILSFA, income-eligible customers pay no more than 50% of the value of the community solar bill credits. The Agency believes the policy concern related to community solar providers marketing offers specifically to income-eligible customers that have significantly less savings and other protections as compared to ILSFA justifies the minimal burden on Illinois Shines vendors of having to present a one-page notice. Again, these vendors would be taking full advantage of both state incentives and a 50% federal investment tax credit. In terms of consumer confusion and distrust, the Agency believes up-front transparency about a customer's options is preferable to the alternative of not providing customers with relevant information about their decision to go solar. The Agency believes much greater "distrust" would be created if income-eligible customers realized after signing up for an Illinois Shines offer that they could have received greater savings and protections with ILSFA. IPA Resp. at 67-68.

The IPA points out that Section 9.4.2.3.2 also proposes that, if additional funding becomes available to significantly expand the size of the ILSFA community solar program through the award of federal grants, the Agency may consider a requirement in the future that community solar projects that take advantage of the federal Bonus Credit may not participate in Illinois Shines but may participate in ILSFA. The JSPs argue that "[s]uch an approach would unjustifiably reduce federal dollars supporting low-income savings captured by renewable energy investments in Illinois." JSPs Obj. at 18. The Agency disagrees with this assertion. Ensuring that community solar projects targeting low-income customers participate in ILSFA would simply ensure alignment of federal and state policies by encouraging projects that seek the Bonus Credit to participate in the state incentive program that is specifically designed for projects serving income-eligible customers. In fact, requiring Bonus Credit projects to participate in ILSFA could result in greater savings for low-income residents, as a higher savings requirement would apply to the projects. IPA Resp. at 68.

3. Commission Analysis and Conclusion

The Commission agrees there is a clear policy concern with low- and moderate-income customers enrolling in community solar projects without awareness of the additional protections and benefits they may qualify for under ILSFA. The Commission recognizes the IPA's proposal is intended to increase awareness of ILSFA as an option in situations where a customer qualifies for both programs.

The Commission is not convinced that providing a one-page marketing handout with other solar materials will increase awareness of or enrollment in ILSFA. This proposal is concerning considering the proposal hinges on the Illinois Shines AVs, who may or may not be ILSFA AVs, to sufficiently explain the program. Inclusion of the one-page notice may lead to distrust and confusion. The Commission appreciates the IPA's attempt to increase enrollment in ILSFA and is interested in exploring the refinement of this and other proposals.

The Commission is concerned with ILSFA's consistently low enrollment rates. The ILSFA residential subprograms have deployed less than 20% of the funding allocated since the program launched over four years ago. *See* JNGO Reply to Responses at 3. The Commission directs the IPA, through a stakeholder process, to explore alternative solutions and marketing options that would appropriately educate the intended and eligible communities of ILSFA. The IPA is encouraged to use the stakeholder process to examine reforms to ILSFA that would increase awareness and participation. The IPA shall propose enrollment solutions in its next LTRRPP.

E. Section 9.5.2. ILFSA Disclosure Forms

1. IPA's Position

The Agency would also like to note a proposed minor update to Section 9.5.2 of the filed 2024 Plan. The Plan states that the Agency "intends to develop a Disclosure Form for 'no cost' Illinois Solar for All offers." Upon further exploration, there does not appear to be a significant desire amongst ILSFA AVs and Designees for a "no cost"

Disclosure Form. The Agency will revise the final Plan to state that the Agency "will develop a Disclosure Form for 'no cost' Illinois Solar for all offers if the Agency or the Program Administrator determines that the need exists" and commits to the creation of such a Disclosure Form if demand for a "no cost" ILSFA Disclosure Form materializes in the future. IPA Rep. at 51.

2. Commission Analysis and Conclusion

The Commission agrees with the IPA's change to the "no cost" ILSFA Disclosure Form and notes its commitment to create one if requested in the future.

F. Section 9.9. Solar Restitution Program

1. AIC's Position

AIC notes the IPA recognizes that, while most customers have had positive experiences in connection with Illinois Shines or ILSFA, some bad actors have caused certain customers to have negative encounters with these programs. The IPA provides by way of example that "one Illinois Shines Approved Vendor promised customers that it would pass through thousands of dollars in REC incentive payments, and then failed to do so." LTRRPP at 342. To provide compensation to those customers who have been harmed by Illinois Shines and ILSFA, the IPA proposes to establish a restitution fund. AIC supports this initiative and believes that the IPA and Program Administrator should be responsible for determining the eligibility of harmed customers to receive compensation from the fund. AIC Obj. at 6.

Additionally, AIC believes that the utility should not directly disburse payments to harmed customers for a number of reasons. The accounts payable systems of utilities are robust, and onboarding individual customers into such systems would be a complicated and cumbersome process. For instance, AIC's current accounts payable process for onboarding suppliers is designed to facilitate transactions with other business entities, as opposed to individual customers. It is possible that an entirely new accounts payable system would be required for AIC to onboard individual customers, which would be costly. Further, AIC observes that the customers applying for compensation will be predisposed to frustration with the Illinois Shines or ILSFA programs, as they have already experienced financial harm in connection therewith. Requiring such customers to navigate an overly complex process would further damage relationships with those customers. AIC Obj. at 7.

As an alternative to customers receiving payments directly from the utility, AIC suggests establishing an escrow process for distributing funds similar to the escrow process discussed in Section 9.4.2.1.2 of the Plan. The IPA or Program Administrator would provide, once per quarter, a detailed and aggregated invoice of the approved payments, on which the escrow agent would rely on, to disburse payments to individual customers. If the IPA wishes to fund the customer payments through separate sources, it could do so by submitting to the escrow agent multiple invoices, along with clear instructions regarding which invoice corresponds to which funding source. AIC Obj. at 7.

AIC also posits that utilities should not be responsible for contacting individual customers regarding compensation, as this arrangement would create an unnecessary administrative burden on utilities and engender additional frustration among customers.

AIC respectfully notes that the ABP model was designed with an AV model due to the impracticality of utilities transacting directly with individual customers. Put simply, utilities are not best equipped to manage individual customer questions and requests with respect to the retribution fund program. The entity responsible for overseeing the retribution fund program (either the IPA or the Program Administrator), not the utilities, should answer customer questions regarding the program. If the utilities were responsible for engaging directly with customers, they would likely contact either the IPA, the Program Administrator or both, in instances of uncertainty, which would lead to a delay in response time to customers and also creates the possibility for inconsistent messaging to customers. AIC Obj. at 7-8.

2. IPA's Position

The IPA states Section 9.9 of the filed 2024 Plan proposes the development of a solar restitution program, which would provide payments to customers harmed through their participation in Illinois Shines or ILSFA. AIC supports the proposed restitution program. AIC Obj. at 6. As with the other consumer protection initiatives, AIC proposes that the Program Administrator and Agency should be responsible for determining eligibility and communicating with the customers, which is consistent with the Agency's proposal. The IPA appreciates Ameren's feedback about the customer experience and is open to alternatives to the utilities making payments directly to the relevant customers. There may be options less expensive than using a third-party escrow service such as having the Program Administrator pass through the restitution payments. The Agency believes this is one of many implementation details that is appropriate to consider further after approval of the 2024 Plan. The Plan is intended to provide the general structure of proposals, with more specific details decided after Plan approval. IPA Resp. at 70.

3. Commission Analysis and Conclusion

The Commission approves the solar restitution program and encourages the IPA, AIC, and other interested stakeholders to continue discussions regarding implementation with the goal of streamlining the process for customers.

VIII. CHAPTER 10. DIVERSITY, EQUITY, AND INCLUSION

A. Section 10.1.1. Definitions and Eligibility: EEPs

1. Two-Year Residency Requirement

a. JNGOs' Position

The Joint NGOs argue that the Commission should direct the IPA to add a two-year residency requirement in an Equity Investment Eligible Community ("EIEC") to qualify as an EEP. EEPs would be required to demonstrate residency in an EIEC for the two years preceding application for certification in tandem with a two-year recertification requirement. The Joint NGOs suggest that this residency requirement will guard the program from being abused by persons who recently moved to EIEC areas but are not representative of the intended persons meant to qualify as EEPs and access the benefits of these programs. JNGOs Obj. at 9.

b. JSPs' Position

While the JSPs appreciate the concern about the possibility that an individual may move to an EIEC for the sole purpose of becoming an EEP, the documentation requirements would be onerous as more and more EEPs are identified. Also, it creates challenges when an individual lives in an EIEC and moves to another address within an EIEC. The JSPs note the current verification process is not conducive to providing proof of extended residence, and the human review of supporting documentation that would be required would make EEP management hugely burdensome to AVs and Designees looking to hire or verify EEPs, the Program Administrator, and EEPs themselves. The Plan provides a superior solution, requiring the EEP to recertify to maintain their status and thus ensuring that EEPs currently live in EIECs. The JSPs recommend rejecting the Joint NGOs' proposal. JSPs Resp. at 17.

c. ESI's Position

ESI would not object to a minimum length of residency in one or more EIEC as a condition to certifying an EEP that seeks to qualify based on residency. A minimum length of residency requirement would be consistent with the statutory goals of prioritizing access to the equity category for businesses and individuals from communities that have been excluded from economic opportunities in the energy sector, have been subject to disproportionate levels of pollution, and have disproportionately experienced negative public health outcomes. 20 ILCS 3855/1-75. It would also help to ensure that those communities receive the "most benefit[s] from equitable investments," as the IPA Act seeks to ensure. 20 ILCS 3855/1-10. The longer a person has lived in an EIEC, the greater the likelihood that the entire community will benefit from that person's participation in the IPA's programs. Without such a requirement, it is difficult to describe an individual as "from" an EIEC or to ensure that the benefits of the program will benefit that EIEC. ESI BOE at 12-13.

d. IPA's Position

One way for an individual to qualify as an EEP is to demonstrate residency in an EIEC. The Agency proposed that EEPs that qualify through their residency must re-certify every two years. The Joint NGOs argued that there should also be a requirement that the individual lived in an EIEC for the past two years to qualify. While the Agency agrees that the current EEP certification process for the primary residency qualification requires more guardrails, the Agency is not convinced that a two-year residency minimum as proposed by the Joint NGOs would be the best approach and is uncertain whether it would address the concerning patterns described above. First, many areas that have seen an influx of development and wealthier residents have been undergoing that change for much longer than two years; this minimum would therefore only address part of the issue. Second, individuals facing structural barriers are more likely to move residences frequently. The IPA believes that a minimum residency requirement would be too narrow in one direction, excluding individuals facing recent financial hardship and relocating to an EIEC, while casting too broad a net in the other direction by not excluding those that chose to live in a gentrifying EIEC as an investment opportunity, even though they could have afforded to live in wealthier communities. IPA Resp. at 73-74.

Furthermore, a residency minimum requirement would present several implementation challenges. The Agency currently accepts requests by individuals to certify as an EEP on a rolling basis through the Energy Workforce Equity Portal ("Equity Portal"), however, EEPs are not required to certify using the Equity Portal. AVs and Designees may also submit the certification documents at the end of the Program Year when submitting the Year-End Report showing compliance with the MES. The Agency does not know when the "two-year" requirement would vest. Documenting a current residence through last month's utility bill or a current lease is significantly easier than documenting one's residence from two years ago. The Joint NGOs did not provide any recommendations on these points, nor did they describe what documents would be sufficient evidence of such residency and would not unfairly burden a population that moves addresses frequently. IPA Resp. at 74.

The IPA is approaching the myriad challenges and policy options associated with the certification of EEPs and EECs as a whole—the conclusion that a minimum residency requirement would not be the most precise or effective means of preventing gaming does not mean that the Agency has taken no steps to do so. Instead of increasing the burden of proof required for EEPs generally, the Agency has opted to put additional guardrails around the certification of EECs, particularly those where the majority-owner qualifies based on residency. The IPA believes this compromise strikes the appropriate balance, creating a narrower program adjustment to directly address the behavior at issue. IPA Resp. at 74-75.

The JSPs also oppose the Joint NGO's proposal, noting that such a requirement would not only increase the administrative burden on the Program Administrator, but also be a burden for AV and Designees that need to track EEP certifications to meet the MES. Instead, the JSPs support the approach proposed by the IPA in the 2024 Plan where EEPs must recertify every two years to ensure they currently reside in an EIEC. The Agency appreciates this support and agrees that the 2024 Plan's approach is the most sensible. IPA Rep. at 55.

e. Commission Analysis and Conclusion

The Commission agrees with the IPA and JSPs that a minimum residency requirement would not be the most precise or effective way to ensure that EEPs are representative of the EIECs or further the goals of the EAS. In addition to implementation concerns, a minimum residency required does not seem to be a precise method of ensuring that the equitable workforce goals of P.A. 102-0662 are met because it could still inappropriately exclude qualifying EIEC residents while including others. Instead, the IPA has proposed requiring EEC applicants to demonstrate socio-economic status and for a majority-owner EEP to demonstrate control and active management of the EEC. Both proposals are discussed below.

2. Changes in EEP Eligibility

a. ESI's Position

ESI believes it is important to provide clear and fair rules for how changing EEC participant requirements will impact projects already submitted to the program under existing rules. The LTRRPP provides, "For EECs that may lose the status of EEC due to a majority-owner EEP no longer qualifying as an EEP, any projects already under contract through the EEC Category will not be affected by that loss of status." LTRRPP at 349. ESI argues that using that late-stage milestone for purposes of grandfathering would be unjustly detrimental to AVs that have worked in good faith to develop a project and have submitted their project application to IPA. As such, ESI suggests the milestone should instead be the AV's submission of a completed project application. At the time of project application, the EEC AV has already invested significant time and capital into projects, has submitted a good faith project application to the IPA, and, therefore, should not then later be disqualified based on changing program rules. Moreover, project applicants likely will be required to invest significant additional time and capital between the date of submission and signing the REC contract. ESI Obj. at 9.

ESI notes this change is especially concerning given the long application review timelines experienced in the Illinois Shines program, sometimes exceeding twelve months between Part I Application and REC award. If a project meets the eligibility requirements at the time the EEC AV submits its project application to the IPA, the IPA's review timeline should not later impact the qualification of a project for the category to which it applied based on midstream changes in program requirements. For this reason, ESI suggests the Plan be edited so that any projects with a Part I Application already submitted and under review will not be affected by that loss of status. ESI Obj. at 9-10.

In its Response, the IPA appears to conflate ESI's broad objection (regarding any new changes to AV or project application requirements) with a narrower objection to one specific proposed change (regarding geographic changes to EEP eligibility), then argue that the mitigation it offers for that specific change addresses ESI's broader concern. *See* IPA's Resp. at 92-93. In response, ESI reiterates the JSPs' point that there should be a single coherent policy for application of new program rules to existing projects and applications that applies to all changes to program application and approval requirements going forward. ESI Rep. at 7.

ESI agrees with the IPA that if a majority-owner of an EEC no longer qualifies as an EEP due to the EEP losing eligibility, the Plan essentially provides for an unpredictable grace period of one to twelve months during which the EEP owner can attempt to sell its interest in the EEC AV to another EEP. ESI argues the sheer variability of this grace period, and the fact that it would essentially force the good faith EEP into a fire sale makes this proposed mitigation insufficient to address ESI's stated concerns. Other IPA-proposed changes could cause a qualified EEC AV to be retroactively disqualified. As ESI has stated, in any such scenario the rules in place at the time of the relevant application to the Illinois Shines Program should control. ESI Rep. at 8.

ESI observes that currently, EECs and other AVs have continued to do business and submit projects relying on the rules in place at the time of application. Where even Part I application review timelines have exceeded six or twelve months in some cases, and when other program requirements subsequently change, existing Part I applications still under review should not be adversely impacted. ESI thus respectfully suggests that, as a general matter, administrative rules and policies in place at the time of Part I application should apply to any and all program applications that are submitted prior to the approval of a Plan containing new application requirements. This practice is consistent with how similar programs work in other states. ESI Rep. at 8.

ESI respectfully disagrees with Staff's proposed six-month limitation when it comes to projects relying on regulatory rules in place at the time of application. While AVs often have a six month notice of potential program changes proposed through the Plan process, the IPA has also in the past updated the Illinois Shines program requirements throughout the year with much shorter timelines. Part I application processing should not take more than one to two months for the IPA and its consultants to review EEC applications for approval, as the IPA indicates in its Going Solar publication. ESI recommends that the Plan include a reasonable expected processing period, during which the Administrator must approve or deny the project applications or do so as soon as reasonably possible thereafter. ESI Rep. at 8-9.

ESI claims this uncertainty makes it difficult to plan and develop projects. Financing takes time and a six-month waiting period puts too much uncertainty on the project and would have a chilling effect on private capital investment that goes into these projects well before the Part I application date. The statute delegates to the IPA the authority to "make prospective administrative adjustments to the ABP design . . . as necessary to achieve the goals of this subsection." 20 ILCS 3855/1-75(c)(1)(M). ESI argues any changes in program policy, either in the Plan or in subsequent modifications to the Program Guidebook, should only apply prospectively and should not impact existing projects and applications awaiting review. ESI encourages the Commission to consider its original proposal of a Part I application date cutoff. ESI Rep. at 9-10.

b. JSPs' Position

ESI recommends that if EEP majority owners of an EEC had EEP status on the date of the Part I application, loss of EEP status of those individuals should not impact EEC block eligibility of that system. To the JSPs, this recommendation is the mirror image extreme of the Joint NGOs' two-year residency requirement in that it creates a residency requirement that is too lax to meet EEC program goals. While the JSPs believe it is important that projects remain eligible even if EEP majority ownership loses EEP status, a better approach is if EIEC maps become effective on a known date with at least six months of lead time so EECs know well in advance whether their status is at risk without ownership changes. JSPs Resp. at 17-18.

c. Staff's Position

While Staff agrees with ESI in that project applications consume a considerable amount of time and resources from an applicant, Staff proposes a modification to ESI's objection. By taking into consideration an assumed six-month period to review an application, Staff believes only those projects under review for more than six months should be considered. Therefore, Staff recommends the Commission direct the IPA to modify the Plan at Section 10.1.1, if ESI's changes regarding EEC are included, to exempt any projects with a Part I Application that has not been under review for more than six months from being affected if a majority-owner EEP of the EEC loses its qualifying status. Staff Resp. at 20-21.

d. IPA's Position

The Agency does not agree with ESI's approach. The Agency recognizes the disruption that a EIEC map update and resulting change in EEC status may cause, but the Agency is obligated to submit projects verified as eligible for a REC contract to the Commission. 220 ILCS 5/16-111.5(b)(5)(ii)(D), (b)(5)(iii); *see also Ill. Power Agency, Docket* No. 17-0838, Order at 115-16 (Apr. 3, 2018). The IPA cannot submit a project to the Commission claiming to have verified that the project qualifies for the EEC Category of Illinois Shines if in fact the AV is no longer an EEC. The Agency included in the 2024 LTRRPP a proposal to allow an EEC AV that would otherwise lose its status as an EEC due to its majority-owner no longer qualifying as an EEP to maintain that EEC status until the next renewal of its AV registration. LTRRPP at 349. Thus, the Agency states it has already provided a buffer to allow an AV to finish project applications and receive a REC contract for projects already submitted to the EEC category, and then transition other projects to new categories if necessary. The Agency asks that the Commission reject ESI's proposal and approve the Agency's approach as written. IPA Resp. at 92-93.

Furthermore, the Agency points to the fact the LTRRPP proposes several program elements that would provide a grace period for when an EEP or EEC lose eligibility for such status. First, an EEP that is not a majority-owner of an EEC would remain certified as an EEP until their next recertification, which takes place every two years. EEPs who are the majority-owner of an EEC would retain their EEP status until the next renewal of the EEC's AV or Designee registration. In addition to these grace periods, the Agency will, as it has in the past, accept both the updated map and the previous map for the remainder of Program Year in which the map was updated. To provide even further certainty for EECs, the Agency also clarified that EEC category projects already Part I verified and under a REC contract would maintain that verified status even if the EEC loses their EEC certification before energization. The IPA considers these extensions to be a generous accommodation not necessitated by a strict reading of the law, and sufficient vehicle for managing disruption inherent from changing addresses or changing maps. ESI, however, objects that this approach does not go far enough. IPA Rep. at 52.

Staff in part supports ESI's objection, modifying its approach by only applying it where a project's Part I application has been under review for at least six months. Staff provides no support or rationale for proposing an "assumed six-month time to review an application," implying that it was arbitrarily chosen as a convenient period. There are many factors that may lengthen the review of an application. Furthermore, the Agency already has proposed a grace period for EEC firms where the EEP status of the majority owner changes, and a transition year when the EIEC map changes. The IPA believes that relying on the date of approval by the Commission of the REC contract offers a clear, workable boundary that maintains the integrity of the Commission's REC contract approval process. IPA Rep. at 53-54.

e. Commission Analysis and Conclusion

The Commission adopts the IPA's position that projects already under contract through the EEC Category will not be affected if the EEC loses its status due to a majority-owner EEP no longer qualifying as an EEP. The Commission notes that changes in EEP eligibility will inevitability occur as the qualifications are refined and EIEC maps change over time. Nonetheless, the IPA takes a reasonable approach in providing flexibility where possible while still maintaining its obligation to only submit projects verified as eligible for a REC contract to the Commission. JSPs concern regarding EIEC map changes are valid, but the IPA's acceptance of both the current map and the previous map seem to eliminate these concerns. Accordingly, the Commission declines to adopt JSPs' suggested six-month notice at this time. The record also lacks sufficient support to implement Staff's six-month review period in lieu of the reasonable accommodations the IPA provides. Therefore, the Commission declines to adopt Staff's proposal.

B. Section 10.1.2.1. Ownership by EEPs

1. New EEC Requirements, Generally

a. ESI's Position

ESI objects to the Agency's proposal to institute additional new requirements for participation in the EEC category of the Illinois Shines program. LTRRPP at 350-352. ESI notes that the Agency did not incorporate stakeholder feedback to address its equity concerns that EEC AVs should be made subject to the MES just like non-EEC AVs, because the IPA "hesitates to put additional burdens on EECs when the concept is new and when there are still few certified EECs". LTRRPP at 352-353. ESI objects to the IPA's non-inclusion of this common-sense approach to ensure that bona fide equity benefits are delivered by the EEC project category. ESI Obj. at 1-2.

Despite the IPA's purported reason for rejecting this proposal, ESI argues the IPA's proposals do in fact place additional, more onerous burdens on EECs without ensuring that the value of the EEC project category flow to the intended beneficiaries of the new EAS as all non-EEC projects do. Instead of adopting changes to the statutorily-mandated requirements for EEC eligibility, the IPA should instead clarify that EEC AVs must also meet the MES already required for all other AVs participating in the Illinois Shines program. ESI Obj. at 2.

ESI also notes that, unlike the IPA's proposed new EEC eligibility requirements, the statute does support applying the MES to EEC AV project applicants: "Equity accountability system. It is the purpose of this subsection . . . to create an equity accountability system, which includes the [MES] for all renewable energy procurements . . . ." 20 ILCS 3855/1-75(c-10); ESI Obj. at 2-3.

In addition, the proposed Plan includes two new requirements for majority-EEP-owned companies to be qualified as EECs. ESI argues these requirements go well beyond the statutory requirements to be an EEC and overstep the IPA's authority by putting additional requirements in the Plan that should only be incorporated through legislative action. Under P.A. 102-0662, the statute authorizing the EEC category, EECs or "eligible contractor" are clearly defined as:

> (1) a business that is majority-owned by equity investment eligible individuals or persons who are or have been participants in the Clean Jobs Workforce Network Program, Clean Energy Contractor Incubator Program, Returning Residents Clean Jobs Training Program, Illinois Climate Works Preapprenticeship Program, or Clean Energy Primes Contractor Accelerator Program;
>
> (2) a nonprofit or cooperative that is majority-governed by equity investment eligible individuals or persons who are or have been participants in the Clean Jobs Workforce Network

> Program, Clean Energy Contractor Incubator Program, Returning Residents Clean Jobs Training Program, Illinois Climate Works Preapprenticeship Program, or Clean Energy Primes Contractor Accelerator Program; or
>
> (3) an equity investment eligible person or an individual who is or has been a participant in the Clean Jobs Workforce Network Program, Clean Energy Contractor Incubator Program, Returning Residents Clean Jobs Training Program, Illinois Climate Works Preapprenticeship Program, or Clean Energy Primes Contractor Accelerator Program and who is offering personal services as an independent contractor.

Importantly, P.A. 102-0662 does not set forth different standards for different types of "equity investment eligible individuals" under category (1) and (2) above. It does set forth different requirements for "business" EECs versus "nonprofit or cooperative" EEC. ESI Obj. at 3-4.

b. IPA's Position

The IPA states ESI objects to the Agency's decision to continue considering EECs to automatically be in full compliance with the overall EAS, including the MES, and seems to position application of the MES to EECs as an alternative to the Agency's proposed updates to the EEC certification process. The MES is established in Section 1-75(c-10) of the IPA Act and requires that the project workforce of all projects participating in the ABP, competitive procurements, and the Self-Direct Program include at least 10% equity eligible persons, with that percentage increasing over time. As the IPA explained in the Draft 2024 Plan, requiring EECs to achieve the MES would remove one of the major advantages that EECs have as participants in IPA programs and procurements, apart from eligibility for the EEC category of Illinois Shines—a higher count toward meeting the MES. Non-EEC AVs currently must include any EEC Designees as part of the "project workforce" to which the MES applies. Those non-EEC AVs may count the EEPs employed by a subcontractor EEC 1.5 times for purposes of calculating whether the non-EEC AV has met the MES, providing an incentive for entities to work with EECs. If the EECs were required to meet the MES independently, non-EEC AVs would not include the EECs in their own project workforce and thus could not count them toward meeting the MES. The Agency continues to believe it is important to preserve this market advantage to encourage growth and addition of EECs. IPA Resp. at 88.

ESI also argues that the IPA's consideration of EECs as fully complying with the EAS and therefore not subject to the MES conflicts with its commitment to reducing barriers for EECs in participating in IPA programs and procurements because the Agency is also proposing to heighten the certification requirements for EECs. The IPA does not see these positions as conflicting; on the one hand, the Agency seeks to prevent the certification of entities that do not reflect the equity aims of the statute, and on the other it seeks to facilitate participation and ease burdens for true EECs that do represent the communities and businesses the IPA Act envisioned as EECs. The Agency would prefer to introduce slightly higher bars to entry to ensure that the EEC prioritization and advantages go only to truly "equity eligible" businesses than to maintain the current certification and have entities that do not meet the spirit of the law taking up program capacity while simultaneously creating additional reporting requirements for true EECs. IPA Resp. at 89.

In addition, ESI objects to the Agency establishing any new requirements for certification as an EEC. ESI claims that "IPA's proposals … place additional, more onerous burdens on EECs without ensuring that the value of the EEC project category flow to the intended beneficiaries of the new EAS." ESI Obj. at 2. The entire purpose of the proposed certification requirements is to ensure that the benefits of the EAS flow to "businesses and workers … excluded from economic opportunities in the energy sector," as explained extensively above. 20 ILCS 3855/1-75(c-10). Some entities, including those that are exhibiting the troubling behavior noted above, may dislike the resulting inability to access benefits meant for others, but that just underscores that the chosen approach would be effective. IPA Resp. at 79-80.

ESI further argues that the Agency's proposed certification requirements "overstep the IPA's authority" and must be enacted through legislation. ESI Obj. at 3. This assertion is incorrect. Rather, the IPA Act explicitly authorizes the IPA to update criteria related to equity requirements through the Plan where the Agency finds that the existing requirements are not achieving the equity goals "to its fullest potential." 20 ILCS 3855/1-75(c-10). The Agency has seen several entities that may not align with the spirit of the law benefit from the prioritization provided in these equity provisions, and thus reasonably has determined that the existing minimum requirements are not fulfilling the aims of P.A. 102-0662's equity provisions to the fullest potential. Therefore, the Agency has ample legislative authority to tighten the requirements for certification as an EEC. IPA Resp. at 80.

c. Commission Analysis and Conclusion

The Commission adopts the IPA's position that it may adopt new requirements to maintain the integrity of the EEC category and continue to provide the benefit of a higher count to meet the MES to EECs. The Commission further finds that the IPA has the statutory authority to tighten the requirements for EEC certification to ensure that EAS benefits flow to the intended parties.

2. Socio-economic Status

a. Joint NGOs' Position

The Joint NGOs object to the inclusion of demonstrating socio-economic status as a requirement for EEC certification because there are better and more efficient forms of documentation that will guard against potential abuse of the system and further the goals of P.A. 102-0662. These alternatives include documents illustrating ownership, control, and/or contract value residing in and flowing to an EEP. Furthermore, the Joint NGOs believe that the IPA's "Proposed Advance of Capital Evaluation Criteria" submitted for stakeholder feedback offers the requisite thresholds needed to ensure the appropriate beneficiaries are selected for this program. The Joint NGOs emphasize the importance of prioritizing data collection at the EEC level as opposed to the EEP level. JNGOs Obj. at 10.

Hence, the Joint NGO proposed edits to EEC certification requiring a demonstration that no less than 51% of REC contract value flows to the EEP or EEC and that the EEC must submit documentation that speaks to the business performance and confirms its disadvantaged status. The Joint NGOs also propose eliminating the socio-economic status requirement for the reasons described above. JNGOs Obj. at 10-11.

The Joint NGOs reject the assertion from ESI that requiring a demonstration of control and active management is beyond the authority of the IPA. The Joint NGOs feel strongly that potential abuse of the system be carefully guarded against by requiring substantial documentation of ownership, control, and/or contract value residing in and flowing to the EEP as proposed by the Joint NGOs. JNGOs Resp at 3-4.

The Joint NGOs agree with the JSPs that the "spirit" of the Plan must be preserved to ensure that true EECs and EEPs have access to these opportunities. However, rather than join the JSPs in seeking additional information and clarification on the "demonstration of socio-economic status," we reiterate our stance that this additional metric be removed entirely from the Plan. The Joint NGOs urge the Commission to reject the inclusion of this burdensome socio-economic requirement and use its proposed metrics instead. JNGOs Rep. at 4.

Finally, the Joint NGOs respectfully disagree with Staff that additional requirements are unnecessary. The Joint NGOs feel strongly that potential abuse of the system should be carefully guarded against by requiring substantial documentation of ownership, control, and/or contract value residing in and flowing to the EEP. JNGOs Rep. at 4.

b. JSPs' Position

As a threshold matter, the LTRRPP proposal regarding demonstration of socio-economic status is insufficiently developed to fully comment. The JSPs note that the LTRRPP does not commit to a single, objective formula or value threshold. Even if the IPA were to later develop an objective dollar amount or formula, setting the threshold at one level as opposed to another would have a material impact on the development of the EEC ecosystem. It is not possible to comment, though, without even the most basic indication of what the threshold would be or if it will be based on an objective standard. The JSPs would strongly oppose a subjective standard as the sharing tax documents or equivalent information may discourage applicants and cause confusion amongst the very groups the JSPs, IPA, and many others seek to encourage to form EECs. JSPs Obj. at 7-8.

Because this draft LTRRPP is the first with the demonstration of socio-economic status proposal, the JSPs explain the lack of detail makes it difficult to engage in a docket with a 120-day statutory deadline and no pre-filed testimony. As a result, the JSPs urge the Commission to direct the IPA to hold stakeholder workshops that specifically include EEPs to refine this proposal for consideration by the Commission at a later date. Such workshops could also address the JSPs' implementation concerns identified below. JSPs Obj. at 8.

In the event the Commission does approve a demonstration of socio-economic status requirement in this docket, the JSPs urge the Commission in the strongest terms to make three further modifications. These modifications will preserve the spirit of the LTRRPP proposal but will address unintended consequences and artificial barriers to the vibrant EEC ecosystem that P.A. 102-0662 envisions. JSPs Obj. at 8.

First, the Commission should modify the LTRRPP to create an irrebuttable presumption that an EEC that is a participant in good standing in the State of Illinois Department of Central Management Services Business Enterprise Program ("BEP") demonstrates socio-economic status for inclusion as an EEC AV. The BEP carefully vets minority-, women-, and disabled person-owned businesses for qualification and inclusion to better distribute the value of State of Illinois contracts to BEP participants. This preexisting and well-developed program can relieve the burden of vetting while ensuring that broader State of Illinois goals are met. *See, e.g.,* 30 ILCS 575/1. To be clear, the JSPs propose that BEP certification only meets the socio-economic criteria and is not an end-run around the statutory requirements for an EEP. However, EECs that have gone through vetting of the BEP program should not have a secondary level of vetting and uncertainty. JSPs Obj. at 8-9.

Second, the Commission should modify the LTRRPP to definitively clarify that demonstration of socio-economic status is only a threshold requirement for an EEC upon its initial application or upon change in ownership where less than 50% of current owners have previously demonstrated their socio-economic status. While the LTRRPP did not explicitly state that demonstrating socio-economic status would be an ongoing requirement for existing ownership, the JSPs vehemently oppose a structure where success of an EEC and flow of wealth to EEPs would disqualify those EEPs from EEC opportunities. The LTRRPP stated goal of preventing gaming is not served by restricting wealth of EEPs generated through their EECs. JSPs Obj. at 9.

Third, the Commission should explicitly confirm that demonstration of socio-economic status would only apply to EEPs that qualify by residence or job-training program. The JSPs believe that formerly incarcerated individuals and alumni and current participants in the foster-care system should be entitled to an irrebuttable presumption that they suffer socio-economic disadvantage given the stigma and/or disadvantage that can be associated with both. JSPs Obj. at 9.

The JSPs wish to reiterate that P.A. 102-0662 both broadly envisions a large number of EECs in the solar marketplace and specifically in Section 1-75(c)(1)(K)(vi), which will eventually allocate 40% of capacity in the ABP to EEC AVs. *See* 20 ILCS 3855/1-75(c)(1)(K)(vi). A vibrant EEC community and particularly an EEC AV community is a statutory and moral imperative of a just and equitable solar program. As a result, the JSPs have and will continue to vocally identify barriers to EEC participation and proposed solutions. To both meet the objectives of P.A. 102-0662 policy and the core values of the trade associations, the JSPs demand a well-functioning, enticing, and low-barrier EEC program. The JSPs thus urge the Commission to direct that the LTRRPP be modified consistent with the proposals in this Section. JSPs Obj. at 10.

The Joint NGOs oppose the "socio-economic criteria" evaluation from the LTRRPP and propose a completely unworkable replacement of requiring EECs to retain 51% of REC contract value. *See* JNGOs Obj. at 10. First, the socio-economic criteria approach of the IPA can be substantially improved with some changes. Second, the JSPs note that the AV must receive REC contract payment. Unlike for TCS and ILSFA community solar scoring of REC contract spending on EECs or MWBEs respectively, it is an aggressively intrusive burden to make an AV account for where REC contract revenue flows net of contractual, salary, debt, or other obligations. The Commission should reject any requirements that an EEC-AV participating in the EEC block "retain" a certain amount of REC contract value. JSPs Resp. at 18.

The JSPs note that the Plan suggested recertification for EECs and certain EEPs. *See* LTRRPP at 352. The JSPs recommend that if there is recertification of EEC status, the recertification should be early enough in the calendar year so it can be evaluated and resolved prior to the next delivery year block opening on June 1. JSPs Resp. at 18.

The JSPs further note that the LTRRPP proposal does not address two critical questions. First, the LTRRPP proposal does not provide even a hint of the threshold for participation or how it will be measured. Second, the LTRRPP does not explain how regularly reviewing socio-economic status greatly encumbers EECs from achieving wealth-building goals for EEPs. The JSPs believe that these issues should be addressed in the present docket and if not in a future docketed proceeding prior to being implemented, because there is a lack of information about what exactly the Commission is approving. JSPs Rep. at 8.

If the Commission is going to approve the LTRRPP's proposed socio-economic status evaluation, the JSPs appreciate the IPA's support for JSPs' three proposed clarifications with limited exceptions. First, the JSPs support the IPA's clarification to limit the scope of socio-economic review to EEP majority owners of an EEC who qualify based on residence. Second, the JSPs would not object to the IPA's clarification of the single recertification review of EEP majority owners of existing EECs with one critical clarification. Specifically, tax equity, lenders, back-leverage, long-term owners, and other parties involved in financing and long-term operation of projects will need explicit clarity that for any Designated System that has achieved Trade Date, the EEC can continue as an AV even if it loses its EEC status during the recertification review. This clarification will prevent chaos in the market for financing parties working with AV EECs that qualified under the IPA's previous qualifications for EECs in good faith and would be consistent with the IPA's general policy regarding loss of EEC status by virtue of residence. JSPs Rep. at 8-9.

Third, Staff responded to JSPs' proposal regarding BEP participation as a presumption of socio-economic status but interpreted it as though the JSPs were suggesting BEP participation as an alternative to EEP majority ownership. The IPA correctly understood that the JSPs suggested that participation in the BEP should only create a presumption of socio-economic status, not whether the majority owner(s) are EEPs. Staff's critique should thus be rejected because it is based on a misunderstanding of the JSPs' proposal. JSPs Rep. at 9-10.

Staff further responded to the JSPs' proposal about recertification review of socio-economic status of the EEPs comprising majority ownership. Staff appears to read in requirements that the IPA itself does not impose. Staff explains why the IPA could review socio-economic status annually, but not why it should especially in light of the IPA's own Response that clarified it did not seek to do so. JSPs Rep. at 10.

The JSPs further appreciate the IPA's rejection of the Joint NGOs' well-intentioned but ultimately ineffective and difficult to implement proposal regarding payment of the value of the REC Contract. Particularly, the JSPs fully agree with the IPA that monitoring of the flow of 51% of REC Contract value is impractical. Like the IPA, the JSPs believe that review of socio-economic status is superior to dictating the flow of REC Contract proceeds. JSPs Rep. at 10.

By rejecting the approaches of the Joint NGOs and Staff, the Commission can approve the compromise between the IPA and JSPs and strengthen the EEC program. JSPs Rep. at 10.

In its RBOE, JSPs note that 22c proposes that determinations of socio-economic criteria should be made for each EEC before participating in the next block. While the JSPs understand the basis for the proposal, it is unrealistic without IPA confirmation of timing to conclude all interested EEC-AVs will have sufficient time before June 1, 2024 to apply and receive approval. The JSPs fear that if many EECs submit information to the ABP Program Administrator, some will receive responses faster than others, creating an unfair advantage for some EEC-AVs over others. The JSPs do not wish to delay implementation of the socio-economic criteria but believe a fairer solution is to not require confirmation of socio-economic criteria prior to participating in the EEC Block opening on June 1, 2024. Thus, 22c's proposal should be rejected. JSPs RBOE at 9.

c. ESI's Position

ESI argues that requiring EEP owners of EECs to provide documentation of "socio-economic status" is overly burdensome, vague, and beyond the statutory requirements and authority delegated to the IPA. To be clear, setting any income or net-worth threshold specific to majority-owned EECs would go well beyond the statutory authority of the IPA to administer the EEC program and is not consistent with the purpose of P.A. 102-0662. If the legislature had intended only EECs to benefit natural persons with a certain socio-economic status, it would have explicitly done so under P.A. 102-0662, but it did not. Instead, the legislature chose to focus on "business and workers from communities that have been excluded from economic opportunities" (20 ILCS 3855/1-75(c-10)) and persons who live in geographical areas that "would most benefit from equitable investments by the State designed to combat discrimination and foster sustainable economic growth". 20 ILCS 730/5(5-5). This category includes all types of individuals, including those that qualify as EEPs based on location of residence, participation in workforce training programs, previous incarceration status, or participation in foster care. Defining EEPs based on socio-economic status alone simply is not supported by P.A. 102-0662 and inappropriately limits the individuals that can benefit from P.A. 102-0662. As the IPA stated, it "hesitates to put additional burdens on EECs." LTRRPP at 353; ESI Obj. at 4.

Even if P.A. 102-0662 allows the IPA to limit EEP participation pursuant to socio-economic status, which it does not, the IPA has not proposed what socio-economic status would be acceptable to the IPA. Moreover, it would be inappropriate for the IPA to request sensitive documents from EEPs seeking to become majority owners of EECs to determine their socio-economic status. Without subsequent legislative action, the Commission should reject the IPA's new proposal that EEP owners of EECs must submit additional new sensitive financial information, on top of the information already required under the current statute and Plan. ESI Obj. at 5.

In its response, Staff does not support ESI's position and believes that demonstration of socio-economic status is consistent with the statutory definition of EEC and the IPA's duty to ensure that the owners of an EEC company is an eligible person. *See* Staff Resp. at 22-23. While ESI is concerned with the lack of transparency as to what the objective standard will be, it trusts that the stakeholder workshops proposed by the IPA will result in more objective standards. In light of the statute stating that EEPs are persons "who would most benefit from equitable investments by the State designed to combat discrimination," ESI respectfully asks the IPA to mindfully interpret and apply the approved LTRRPP in such a manner to combat discrimination. ESI Rep. at 1-2.

ESI appreciates the IPA's response clarifying that socio-economic status must only be demonstrated one time to qualify as an EEC, as ESI believes that any ongoing requirement would penalize EEPs by disqualifying them from the EEC category simply as a result of being successful. Requiring an EEC to continually requalify on an annual basis would create uncertainty in the EEC market for project development and financing as receiving REC awards in the category could then immediately disqualify an EEC from further participation in the category while also creating additional administrative burden on the IPA and Administrator. Imposing additional socio-economic status requirements on EEP majority owners of existing EECs with active applications and projects in the EEC category without clarifying how these new regulatory requirements will impact existing projects will create more burdens for EECs as addressed below. The Plan should also clarify that any such requirements will not go into effect until the completion of IPA's proposed stakeholder feedback process and determination of the objective qualification criteria. ESI Rep. at 2-3.

ESI asserts in its BOE that by failing to set forth specific socio-economic criteria in this proceeding and delaying development and implementation of those criteria until a later, informal stakeholder process, the IPA has not satisfied the procedural requirements of the statutory provision that allows it to modify the definitions of EEPs "[a]s part of the update of the long-term renewable resources procurement plan," either in this docket, or earlier if the IPA deemed necessary. 20 ILCS 3855/1-75(c-10)(7). While ESI appreciates the Agency's informal engagement efforts to determine the socio-economic criteria, these processes do not afford the same opportunities that Commission proceedings do, which allow for discovery, legal briefing, comments on other parties' positions, opportunities for hearing and oral argument, and final decision-making by ALJs and Commissioners. ESI BOE at 12. In addition, ESI's RBOE asks the Commission to reject 22c's proposal to rush the development and implementation of the socio-economic requirement because it would only heighten due process concerns. ESI RBOE at 7.

d. Staff's Position

Staff does not support ESI's objection to the first new IPA requirement. Staff finds the first new requirement consistent with the definition of EEC in the IPA Act, namely, that owners of the business be an eligible person. Staff agrees with the IPA that requiring a showing of one's socio-economic status will enable the IPA to determine that the individual is an EEP. Staff finds that adding this new requirement to the Plan would be consistent with the IPA Act. It is a well-established rule that the express grant of authority to an administrative agency also includes the authority to do what is reasonably necessary to accomplish the legislature's objective. *Lake Co. Bd. of Rev. Prop. Tax App. Bd.*, 119 Ill. 2d 419, 427 (1988). Here, the IPA is merely ensuring that individuals and owners are eligible persons under the IPA Act. Staff recommends that the Commission direct the IPA to retain the requirement to show proof of socio-economic status. Staff Resp. at 22-23.

Staff initially opposed JSPs' recommendations. *See* Staff Resp. at 6-9. Given the IPA's general support for JSPs' proposal, Staff will defer to the IPA and no longer opposes JSPs' proposals, subject to the modifications sought by the IPA. Staff Rep. at 31.

Staff does not take issue with the requirement that a showing be made of one's socio-economic status. Such a requirement as an update to the Plan is consistent with Section 1-75(c-10)(7). The IPA Act requires individuals be equity eligible and this new requirement ensures that is the case. Staff Rep. at 35.

e. 22c's Position

While 22c agrees with the PO and the IPA's new socio-economic determination requirement, in its BOE 22c suggests that for those current EECs with majority-owner(s) or EEPs that are qualified based on primary residency in an EIEC these EECs should be required to meet the IPA's new requirement prior to the start of the next Program Year to ensure that the new requirement is applied expeditiously. Some current EECs would be able to participate in the next Program Year without having to comply with the IPA's new socio-economic determination requirement because their next AV registration renewal will occur after the start of the next Program Year. 22c believes that this timing quirk and quasi-grandfathering period for AV registration renewal undermines the efficacy of the IPA's new socio-economic determination requirement and should be eliminated since there is a finite number of awards and already an extensive EEC Category project waitlist that exists despite many new EECs having been formed after much of the waitlist submissions have occurred to date. 22c BOE at 6-7.

22c states in its RBOE that it finds ESI's position to be unpersuasive and unproductive as the IPA has ample statutory authority to impose both the socio-economic and control and active management requirements under the IPA Act. In addition, 22c agrees with the IPA's position that it should "ensure that the EEC prioritization and advantages go only to truly 'equity eligible' businesses than to maintain the current [EEC] certification and have entities that do not meet the spirit of the law taking up program capacity." 22c agrees with the IPA's view that established and sophisticated non-EEC developers should not be participating in the EEC Category under the guise that they are EECs when the underlying EEPs are potentially inactive and lack managerial control. 22c finds it is reasonable and necessary for the IPA to implement these two new requirements and to require EEC AV recertification prior to the new program year in June. 22c RBOE at 2.

Accordingly, 22c suggests that the IPA should remove from the waitlist any unawarded, pending applications of EECs that fail to meet the IPA's new requirements prior to the start of the new program year in June. The pending applications on the waitlist that should be subject to potential removal are those that remain unawarded as of the date of the Commission's final Order in this proceeding and may have been submitted as early as November 1, 2022. It is 22c's position that the IPA remove these unawarded, pending applications from the waitlist for EECs that fail to meet the new requirements even if the recertification review by the IPA causes a reasonable delay in the opening of this Program Year's EEC Category block award capacity. 22c RBOE at 2-3.

f. IPA's Position

The Agency appreciates the thoughtful objections filed in response to the proposed changes to the process for certifying an AV or Designee as an EEC. Before addressing the specific points made in individual objections, the IPA thinks it valuable to provide further elucidation of behaviors observed in the first two years of certifying EECs. These patterns broadly fall into two categories: an overly-broad residency basis for qualification as an EEP, and "sleeving" or using on-paper-only EEP majority-owners to access benefits meant for disadvantaged businesses. IPA Resp. at 75.

The Agency is not claiming that all or even most of the participants in the equity system are seeking to deceive or manipulate the program. The Agency has been encouraged by the steady increase in certification of EEPs and EECs and by the earnest and enthusiastic participation of many EECs in Illinois Shines, including their willingness to assist and advise new EECs. Despite those positive trends, there have also been troubling indications that some EECs may not be representative of the communities the legislature sought to uplift through State preferences, or for whom continued support through the EEC category would not further the goals of the EAS. The Agency's proposed adjustments to the certification of EECs in the 2024 LTRRPP were designed to address these patterns and prevent entities that may not embody the legislative intent from receiving the lion's share of benefits. They were not adopted lightly nor without multiple rounds of stakeholder input; while the Agency understands that such adjustments will impact EECs that have acted in good faith, preserving the integrity of the equity goals of P.A. 102-0662 demands closing such loopholes. IPA Resp. at 75-76.

The Agency believes that, while well-intended, the qualification basis for EEPs of residency in an EIEC has resulted in certification of EEPs that do not seem to reflect the statutory aims of prioritizing "businesses and workers from communities that have been excluded from economic opportunities in the energy sector, have been subject to disproportionate levels of pollution, and have disproportionately experienced negative public health outcomes." 20 ILCS 3855/1-75(c-10). The Agency notes that several areas that qualify as EIECs have experienced rapidly shifting demographics, such that many residents living in those communities now have not been excluded from economic opportunities in the energy sector, have not been subject to disproportionate levels of pollution, and have not disproportionately experienced negative public health outcomes" from energy production. The Agency proposed several adjustments to the EEC Certification to address this specific phenomenon, such as inclusion of a socio-economic status criterion for EEPs that qualify based on residency and seek to serve as the majority-owner for an entity requesting EEC status. IPA Resp. at 76.

The Joint NGOs objected to the inclusion of "demonstrating socio-economic status as a requirement for EEC certification." JNGOs Obj. at 10. The JSPs also object to this criterion and request a "modification" that limits this requirement to EEPs that qualify based on primary residency in an EIEC or based on participation in a qualifying workforce training program. JSPs Obj. at 9. It seems that the Joint NGOs and JSPs base their objections on potential misunderstandings of the proposal and other elements of the EEC Category, which the Agency believes are important to clarify before addressing the substance of the objections. The Agency clarifies that it did not intend to require that all EEP majority-owners of entities seeking EEC status demonstrate their socio-economic status. Rather, it meant to propose a requirement that EEPs who qualify based on residency in an EIEC and seek to certify an EEC as the majority owner must submit demonstration of socio-economic status. This proposal was specifically designed to address the above-described patterns the Agency has seen resulting from shifting demographics in many EIECs. The Agency recognizes that the language in the Plan only references EECs broadly and proposes clarifying that it only applies to EEPs that qualify based on residency in an EIEC. IPA Resp. at 77-78.

The Joint NGOs also argue against the socio-economic status demonstration requirement by claiming that the proposal to create “evaluation criteria” for approval of EEC requests for an AOC is adequate to “ensure the appropriate beneficiaries are selected for this program.” JNGOs Obj. at 10. For background, EECs who submit projects in the EEC category of the Illinois Shines Program may submit a request to receive up-front funding, referred to as an AOC. But requesting an AOC is by no means a requirement for EECs. EECs may choose to submit projects to the EEC Category of the Illinois Shines Program and not request an AOC, which many have done. An EEC may also decline to submit projects into the EEC Category at all, and benefit from the EEC designation in other ways, such as offering services to other AVs looking to qualify for points under project selection for the TSC category. Therefore, the review process for requests for AOC does not function as a “threshold” eligibility requirement for EECs and thus is inapposite to the objection at issue. IPA Resp. at 78-79.

Aside from these clarifications, the Joint NGOs, JSPs, and ESI all objected to the socio-economic criterion and proposed alternative strategies they claimed would sufficiently address the troubling conduct exhibited by some entities seeking EEC certification. The Agency will first address the substantive objections and then turn to the proposed alternatives. IPA Resp. at 79.

ESI’s substantive objections are contrary to the plain language of the statute and the broader equity goals established in the IPA Act. ESI also claims that there is no basis for considering socio-economic status in qualifying EEPs or EECs in the statue, yet in the very next sentence ESI says “[i]nstead the legislature chose to focus on ‘business and workers from communities that have been excluded from economic opportunities.’” ESI Obj. at 4 (*quoting* 20 ILCS 3855/1-75(c-10)). ESI seems to consider exclusion from economic opportunities as wholly unrelated to socio-economic status when one’s socio-economic status is often quite directly caused by whether one has been excluded from economic opportunities. Indeed, the existing requirements are too broad, enabling entities that have most definitely not been excluded from economic opportunities to still qualify as EECs. IPA Resp. at 80-81.

ESI also argues that the demonstration of socio-economic status is vague and “inappropriate.” ESI Obj. at 4. The JSPs similarly argued that the IPA did not provide sufficient detail as to how this would be applied. The IPA concedes that it did not propose a specific indicator for socio-economic status, nor the threshold that might apply, but clarifies here that it did not intend to imply that the criterion would be subjective. The Agency agrees with JSPs that there should be a clear, objective threshold. The JSPs recommend that the IPA host workshops with stakeholders, particularly EEPs, to develop a full proposal. The Agency agrees that a stakeholder workshop process would be appropriate and can commit to doing so before the opening of the next Program Year. As to concerns voiced by both ESI and JSPs regarding the potential sensitivity of documents that would demonstrate socio-economic status, the Agency already requires sensitive information for many participants in its programs—from past incarceration for EEPs to income documentation for participants in ILSFA. The Agency commits to maintaining the same high standard of data security and confidentiality for any documents collected during the EEC certification process as it does in these other program processes. IPA Resp. at 81-82.

The Agency generally supports the modifications proposed by the JSPs. First, as clarified above, the Agency's intention was always to limit application of the requirement to demonstrate socio-economic status to EEPs that qualify based on primary residency in an EIEC that serve as majority-owners of entities seeking EEC certification. EEPs that are not majority-owners of entities seeking EEC certification and EEPs that qualify based on one of the other criteria, regardless of any ownership of an EEC, would not be required to demonstrate socio-economic status under the Agency's proposal. Second, the Agency supports JSPs' recommendation that entities already certified through the BEP be presumed as meeting the demonstration of socio-economic status requirement. That certification process also requires demonstration of socio-economic status through submission of personal income tax returns of owners, and therefore that information will have been reviewed already. Illinois Commission on Equity and Inclusion, *Certification Application Checklist* at 1. The Agency also agrees with JSPs that such certification should not be a substitute for the other elements of the EEC certification process. Third, the JSPs recommend that the Commission limit the requirement to demonstrate socio-economic status to the initial application for EEC status. JSPs Obj. at 9. While the Agency supports this approach generally, it would request a narrow exception for the current EECs where the majority-owner(s) is or are EEP(s) that qualified based on primary residency in an EIEC must provide the socio-economic status documentation at the next renewal of their AV registration. IPA Resp. at 85-86.

The Joint NGOs' recommended alternative does not solve the challenge that the Agency was targeting in requiring that EEP majority-owners that qualify based on residency provide demonstration of socio-economic status. The IPA appreciates the Joint NGOs' support in pursuing this common goal of implementing not just the letter of the law, but its purpose and spirit, and reads their objections to take issue with the specific approaches proposed by the Agency. They argue that the IPA should "prioritize[e] collecting data at the EEC level as opposed to the individual (EEP) level." JNGOs Obj. at 10. The statute conditions status as an EEC on ownership by EEPs – the Agency does not know how to certify that an entity is an EEC without collecting information verifying the majority-owner's qualification as an EEP. Instead, the Joint NGOs suggest that the Agency require that an entity seeking to register as an EEC demonstrate "that a minimum percentage (no less than 51%) of REC contract value flows to the EEP or EEC." JNGOs Obj. at 10; IPA Resp. at 86-87.

The Agency sees several problems with such a requirement. First, the process at issue is certification as an EEC—there is no REC contract involved. Furthermore, by definition, 100% of the REC Contract value is paid to the EEC for projects submitted into the EEC Category, seeming to make the proposed requirement only relevant for EEC participation outside of that category. Second, such a requirement would not actually solve the problem that the Agency is trying to address, which is that there are many residents of certain EIECs that are in no way "excluded from economic opportunities in the energy sector" (20 ILCS 3855/1-75(c-10)) and therefore are not the intended beneficiaries of the prioritization created by the EAS. The Agency concludes it would not correct for the overbroad residency basis for qualification as an EEP and therefore do not support this change to the 2024 Plan. IPA Resp. at 87.

The JSPs also oppose the Joint NGOs' alternative proposal. The JSPs note that in the EEC category, 100% of the REC contract incentive is paid to the EEC, and in the TSC category there is already a mechanism for incentivizing projects where increasing portions of the REC contract value go to an EEC. The IPA agrees with agrees with the JSPs that the Joint NGOs' proposal is unworkable. IPA Rep. at 58.

The Joint NGOs also propose that the Agency require an entity seeking EEC status to "submit documentation that speaks to the businesses performance and confirms its disadvantaged status." JNGOs Obj. at 10. The Joint NGOs did not list any documents that would prove "disadvantaged status" of a business, and the Agency is not sure what Joint NGOs mean by "business performance." There are many other types of certifications, but the Joint NGOs did not point to which specific document they believe would demonstrate "disadvantaged status." Without a more specific recommendation, the Agency cannot respond to or support the Joint NGOs' proposal. IPA Resp. at 87-88.

Staff generally supports the IPA's proposal but initially opposed the JSPs' proposed modifications to this requirement. IPA Rep. at 58-59. In its Reply, Staff stated it will defer to the IPA and no longer opposes JSPs' proposals, subject to the modifications sought by the IPA. Staff Rep. at 31. Therefore, the Agency asks the Commission to adopt the requirement with the modifications proposed in IPA's Response to Objections. IPA Rep. at 60.

The IPA points out in its RBOE that while ESI is correct that Section 1-75(c-10)(7) requires that changes to the EAS be done through the Long-Term Plan, that is exactly what the IPA is doing – proposing changes through the filed 2024 Plan. The Commission has never required the IPA to include the exact details of how program requirements will be implemented in the Long-Term Plan; if it did, the Plan would be much longer than its already voluminous 370 pages. The Commission has permitted the details of other Program aspects to be developed through stakeholder feedback processes outside of the Long-Term Plan litigation. The Agency sees no reason why this process cannot be different. IPA RBOE at 36.

The IPA also counters that ESI incorrectly claims that "stakeholders will be unable to comment on the specific socioeconomic criteria that the IPA proposes to adopt." As stated in the 2024 Plan, the IPA will conduct a stakeholder feedback and comment process, through which stakeholders will be able to comment on the specific socio-economic criteria that the IPA proposes to adopt. ESI claims that this process is insufficient because it does not "allow for discovery, legal briefing, comments on other parties' positions, opportunities for hearing and oral argument, and final decision-making by ALJs and Commissioners." The IPA Act does not require these processes for every single detail of implementation. The administrative burden posed by following ESI's argument to its logical conclusion—that discovery, legal briefing, oral argument, and a finding by an ALJ and the Commission is necessary for every process the IPA administers—can hardly be overstated. IPA RBOE at 36-37.

g. Commission Analysis and Conclusion

The Commission declines to adopt the IPA's socio-economic status determination requirement. The Commission finds that additional stakeholder discussions would provide better direction on striking the right balance between adding EEP requirements and reducing manipulation of the EEC designation. The Commission recognizes the Agency engaged stakeholders prior to Plan submittal but finds this issue would benefit from further focused discussion. The Commission welcomes alternatives to imposing additional requirements on EEPs, including determining whether the R3 and EIEC maps should be updated to avoid program manipulation. Therefore, the Commission also adopts the JSPs' suggestion and directs the IPA to hold a stakeholder workshop process prior to the opening of the next Program Year and incorporate and submit alternative options for the Commission to consider in the next Plan. The Commission notes that the IPA offered to conduct this process and welcomed further dialogue on this issue.

The Commission notes the IPA's support for JSPs' recommendation that entities already certified through the BEP be presumed as meeting the demonstration of socio-economic status requirement and encourages the stakeholders to discuss qualification methods along with other alternatives. However, the Commission agrees with the IPA that a minimum REC Contract and business performance criteria proposed by ESI are not the best nor most practical indicators of EEC eligibility and declines to adopt this proposal.

The Commission declines to further expedite the application of the socio-economic requirement as proposed by 22c to ensure robust participation in the stakeholder workshop process.

3. Control or Active Management

a. ESI's Position

ESI argues that this requirement also goes well beyond the statutory requirements for EECs and thus the authority of the IPA to impose via the Plan. In setting the definition of an EEC, the legislature was explicit that EECs only had to be "majority-owned" by EEPs. 20 ILCS 3855/1-10. This requirement is in contrast to EEC nonprofits or cooperatives, which are statutorily required to be "majority-governed" by EEPs. Had the legislature intended that "control" or "active management" be an element of EECs, it would have explicitly said so in P.A. 102-0662 (as it did with nonprofits and cooperatives). Reading such a requirement into P.A. 102-0662 goes well beyond the authority of the IPA. ESI Obj. at 5.

Even if P.A. 102-0662 allowed this new requirement, ESI asserts it is unworkably vague. Under the current proposal, control would be left entirely to the discretion of the

IPA. The proposal also ignores the realities of how companies are governed. In fact, the IPA itself recognizes the need for experienced partners. For example, the IPA has proposed changes to the AOC feature of the EEC category and in its justification stated:

> [T]he Agency understands that some EEPs will want to partner with more experienced AVs to learn from them; the Agency does not wish to prohibit those arrangements. However, if that partner AV is able to assist that EEC to develop multi-million-dollar project applications, it is difficult for the Agency to understand why that partner AV would not similarly be able to assist the EEC in accessing capital.

LTRRPP at 180; ESI Obj. at 5-6.

ESI explains that the standard financing of solar projects always comes with significant limits on control of those projects. ESI does not agree that an EEC's AOC should be contingent on the EEC's showing that it cannot access capital by any other means. Indeed, an EEC will need to access significant amounts of capital beyond the AOC amounts to complete its projects. As such, providing an AOC to an EEC that has not demonstrated an ability to raise capital beyond the AOC amounts would be ill-advised. Simply put, those experienced investor partners will require that the projects are controlled by persons with the experience and knowledge to bring the projects to fruition. These investor partners will not invest without that basic level of control. The vague, subjective nature of the IPA's proposed requirement would significantly limit the ability for any EECs to obtain capital financing for the projects, and the proposed limitations to AOC will even further discourage the development of EEC projects through the Illinois Shines program, contrary to the legislative intent. ESI Obj. at 6.

ESI acknowledges the IPA is likely seeing many different and novel ownership structures in the EEC space, some of which were formed specifically to develop projects for the EEC category. That does not mean these approaches should be discouraged, but rather the opposite. In fact, P.A. 102-0662 encourages these structures by specifically establishing a 51% minimum ownership threshold. 20 ILCS 3855/1-75(c-10). Clearly the legislature contemplated that a new-entrant EEP could, and most likely would, want to partner with other entities or persons who provide skills or resources required for successful development and ownership of these projects, that the EEP owner itself does not possess such as a successful track record of raising construction capital, navigating complex tax equity structures, and achieving and maintaining commercial operation. With this context in mind, it would be strange if an EEP chose to partner with anyone other than an experienced developer partner for the purpose of developing MW-scale solar projects. ESI Obj. at 6-7.

The IPA should embrace the fact that EEC partnerships may be designed in a bespoke fashion, with diverse parties coming together to bring their own unique and valuable skills, resources, knowledge base, community, and professional networks, to the task of building new solar projects across Illinois. For this reason, we suggest the Plan focus on the delivery of actual benefits to individuals and communities that "have been excluded from economic opportunities in the energy sector, have been subject to disproportionate levels of pollution, and have disproportionately experienced negative public health outcomes" as required under the MES. ESI Obj. at 7.

ESI suggests that the first and highest goal of the ABP is to efficiently develop solar and other renewable energy resources across Illinois to achieve the State's climate and renewable energy goals. Of course, P.A. 102-0662 also includes equity goals that must be pursued, but as long as the EEP participants are bona fide EEPs, the IPA should take care to not unnecessarily create additional roadblocks that diminish the program's ability to bring sufficient levels of solar online in a timely and cost-efficient manner. To be clear, imposing high equity requirements are meaningless if the result is to prevent the actual installation of EEC solar projects in Illinois. ESI Obj. at 7-8.

Imposing additional active control and management requirements on EECs goes beyond what is called for in the statute according to ESI. Moreover, IPA's proposal is vague, and would put arbitrary limits on the ability of EEC AVs to engage in solar development above and beyond the burdens faced by other AVs in the Illinois Shines program when it comes to financing projects, especially considering the new restrictions on advance of capital in this category. Staff agreed with ESI stating that the plain reading of the statute did not provide such a requirement. *See* IPA Resp. at 22; ESI Rep. at 3.

In its RBOE, ESI argues if the Commission approves the PO's finding that "the IPA Act provides a catchall to allow the Agency" to re-write all definitions (or even all definitions related to the equity accountability system), it would render the explicit authority provided in the IPA Act for revising these two definitions superfluous. The Commission must reject such a reading. *See Wernikoff v. RCN Telecom Srvcs. Inc*., 341 Ill. App. 3d 89, 101-02 (1st Dist. 2003) ("We must construe the statute so that each word, clause, and sentence, if possible, is given a reasonable meaning and not rendered superfluous"). Therefore, ESI supports Staff's exception. ESI RBOE at 7-8.

b. JSPs' Position

The JSPs do not object to the requirement that EEPs be part of active management or control of EECs. JSPs Resp. at 13. ESI took a broader objection to both socio-economic status review and the requirement that EEPs actively manage or control EECs. *See* ESI Obj. at 4-7; JSPs Resp. at 15-16. Despite ESI's opposite conclusion, the JSPs believe ESI's arguments counsel in favor of EEP active management of the EEC, noting that the EEP owners will have to draw upon substantial internal and external resources to fully develop a solar project. Indeed, all the more reason for EEP owners to manage the EEC and then hire or contract with third parties for the required resources to develop a project and administer the REC Contract. The EEPs will remain in ultimate control of the EEC company, which like all companies will procure on the market anything that it cannot internally produce. The Commission should thus reject ESI's Objection to the Plan requirement that EEP owners actively manage or control the EEC. JSPs Resp. at 16.

While the JSPs disagree with ESI's ultimate conclusion, the JSPs do note that ESI is not incorrect about how control or active management will be defined or measured. Rather than using this as a reason to reject the requirement that EEP owners actively manage or control their EEC, the Commission instead should direct the IPA to provide minimum indicia of control or management so that an EEP knows if the EEP meets one of several defined pathways, the EEP knows they have met the threshold. Given the volume of likely EECs and different ownership structures, this list will inherently be dynamic and will promote a more transparent review of the current and expanding number of EECs in the marketplace. JSPs Resp. at 16-17.

c. Staff's Position

Staff supports ESI's objection to this new IPA requirement to show control and active management. Staff Resp. at 21. As set forth in the IPA Act, EEC means "a business that is majority-owned by eligible persons, or a nonprofit or cooperative that is majority-governed by eligible persons or is a natural person that is an eligible person offering personal services as an independent contractor." 20 ILCS 3855/1-10. Staff agrees with ESI there is no requirement in the IPA Act that the EEC show "control" and "active management". It is well settled that the "primary objective in construing the meaning of a statute is to ascertain and give effect to the intention of the legislature." *In re Det. of Lieberman*, 201 Ill. 2d 300, 307 (2002). To determine that intention, one must examine "the language of the statute, which is the most reliable indicator of the legislature's objectives in enacting a particular law." *In re Det. Of Lieberman*, 201 Ill. 2d at 308 (2002) *quoting Mich. Ave. Nat'l Bank*, 191 Ill.2d at 504 (internal quotations omitted). The only requirement is that the business be majority-owned by an EEP or EEPs. Given the absence of language in the IPA Act, that an EEC must also prove control or active management by an eligible person, Staff recommends the Commission reject the IPA's reading of such a requirement into the IPA Act. Staff Resp. at 22.

Staff argues the Commission should reject the IPA's argument that the IPA has the authority to rewrite P.A. 102-0662's definition of EEC. Section 1-75(c-10)(7) of the IPA Act gives the IPA the authority to revise two statutorily defined terms used in its Plan. Those two terms are: (1) equity investment eligible persons; and (2) equity investment eligible community. It did not grant the IPA the authority to rewrite a term where P.A. 102-0662 has clearly defined the term. Staff clarifies that the IPA can and does define undefined terms in the IPA Act. For example, the IPA sets forth in the Plan a definition of the term "persons who were formerly incarcerated." That term is used in the definition of "equity eligible persons" or "eligible persons" (2024 Plan at 348) but is not defined in the IPA Act. Staff Rep. at 34.

Except when authorized, such as provided for in Section 1-75(c-10)(7) of the IPA Act, Staff asserts the IPA does not have the authority to redefine statutorily defined terms where there is no ambiguity. There is no ambiguity in the term "majority owned" used in the definition of EEC. Ownership does not require a person to exercise "active management" or "control." The IPA's imposition of "active management" and "control" with respect to ownership would be a fundamental change to the term. By imposing "active management" and "control" with respect to "ownership," the IPA is rewriting P.A. 102-0662's definition of EEC. Staff Rep. at 34.

Finally, despite the IPA's argument to the contrary, the term "equity eligible contractor" is not referenced in Section 1-75(c-10)(7) of the IPA Act. It is only by boot-strapping the term "eligible persons" referenced in the definition of EEC to that term in EEP, that the IPA can say it has the authority under Section 1-75(c-10)(7) to revise the definition of EEC. To require "control" and "active management" involves a rewriting of P.A. 102-0662, which authority the IPA was not given by the legislature. Based upon the above, the Commission should reject the IPA's new requirement that there be a showing of control and active management. Staff Rep. at 34-35.

Staff further argues in its BOE that requiring a showing that one is an eligible person through their socio-economic status is not the same as requiring an EEC to show control and active management. There is no dispute that the IPA Act requires owners to be eligible persons. The LTRRPP is merely imposing a requirement on how the owner shows that it is an eligible person. However, there is no requirement in the IPA Act that owners, besides showing ownership, must demonstrate control and active management. Staff BOE at 10.

In contrast to ESI, in its RBOE Staff rejects the notion that in some instances there is a catch-all that could allow the IPA to impose a "control" or "active management" requirement on EECs. ESI appears to support a catch-all argument in certain circumstances, but not under the circumstances here. Accordingly, Staff supports its alternative language over ESI's. Staff RBOE at 6.

d. Joint NGO's Position

The Joint NGOs explain in their RBOE the legislative intent of the EAS is to advance equity by providing access to the clean energy economy for persons from communities that were historically excluded from energy sector opportunities and subjected to disproportionate levels of pollution and negative public health outcomes. The IPA's EEC requirements are intended to help meet that goal. The claim that this new requirement strays from the General Assembly's intent is incongruent with the language of the Act. JNGOs RBOE at 2-3.

Secondly, the Joint NGOs argue in their RBOE that due to the provisions of Section 1-75(c-10)(7) of the IPA Act, it is inconsequential that the Act does not specifically mention an EEC requirement for "control and active management." In Section 1-75(c-10)(7), the General Assembly grants the IPA the power to modify the EAS if the IPA finds that the system has failed to meet its goals. The provision explicitly allows for the IPA to make modifications that are necessary to achieve the goals of the Act. Both EEPs and EECs are mentioned in the provision as being a part of the EAS. Thus, ESI and Staff's argument that IPA does not have the authority to add requirements to the EECs and EEPs is misplaced. The statute's plain language and legislative intent of advancing equity leave no ambiguity that the IPA is empowered to make necessary changes to the equity accountability system to achieve the goals of the program. Thus, ESI's and Staff's arguments should be rejected. JNGOs RBOE at 3.

Finally, Staff makes the argument that ownership does not require a person to exercise "control and active management" and that allowing this requirement would "be a fundamental change to the term," and a rewriting of CEJA. The JNGOs disagree. "Control and active management" are one of numerous ways to demonstrate the goals of the Act are being fulfilled. The Joint NGOs support the inclusion of this component in the PO. JNGOs RBOE at 3.

e. LiveWire's Position

In its RBOE, LiveWire supports the IPA's goal of keeping EEC projects in the hands of EECs to increase energy equity. If the Commission elects to adopt a "control or active management" requirement, LiveWire encourages the IPA to engage in a robust stakeholder process so as to adopt policies that encourage relationships between EECs and non-EEC Developers, eliminate barriers for EEPs to access growth in capital, and promote increased cohesion and participation of EECs and non-EEC Developers in both the EEC Block and the Traditional Community Solar Block. LiveWire RBOE at 2.

f. IPA's Position

The Agency notes that one of the concerning behaviors observed has been the formation of EECs that appear to function as shell companies for existing firms active in Illinois Shines. For example, one EEC is 49% owned by a large, national solar company that has been successfully financing and developing projects that receive REC contracts in Illinois Shines for years and 51% owned by EEPs that qualify based on residency. The national company that is the minority owner appears to be performing all the work associated with the project development and the REC Contract application for the projects the EEC submitted to the EEC Category. While the Agency understands that EEPs may wish to temporarily partner and learn from experienced companies as they build an independent business, the EEC at issue seems to have the EEP majority owners as silent partners with no role in the business, simply passing through the priority access meant for disadvantaged entities to an already-successful, sophisticated firm. This structure is not in line with the legislative intent to prioritize "access to the clean energy economy for businesses and workers from communities that have been excluded from economic opportunities in the energy sector" 20 ILCS 3855/1-75(c-10). It was with these behaviors in mind that the IPA proposed the requirement that a majority-owner EEP demonstrate control and active management of the EEC as part of the EEC certification process. IPA Resp. at 76-77.

ESI objects to the requirement that entities seeking EEC certification demonstrate that EEP(s) who serve as majority owner(s) have control of and manage the business. ESI argues that the definition of EEC signals legislative intent that control by the EEP(s) is not required, because the definition says a business must be "majority-owned" by eligible persons whereas a non-profit qualifies as an EEC when it is "majority-governed" by eligible persons. This argument is a red herring; non-profits do not have owners, so the legislature chose the language most analogous to the position they thought the business owner would have. In fact, the equivalence in the presumed level of control exercised between an individual serving as an independent contractor, the governors of a non-profit or cooperative, and the owners of a business in the EEC definition strengthen the IPA's position. It would be nonsensical for the legislature to identify two types of EECs where the EEP exercises direct and active management of the entity's affairs, but then include a third where the EEP merely plays a passive, on-paper role, essentially creating a higher bar for the least powerful entities identified, independent contractors and non-profits, than for profit-based companies. IPA Resp. at 82-83.

ESI also objects to the requirement to demonstrate control and management as vague, arguing that EECs will not know whether or how to demonstrate control. The Agency has asked for public input from stakeholders, including ESI, as to what types of documents the Agency could request to document such control, but has received no specific suggestions. Other public entities require demonstration of control for similar business certifications, such as the City of Chicago's Minority and Women-Owned

Business Enterprise Certification for Construction Contracts. That certification process requires that the applicant "establish by a preponderance of the evidence that it is owned and controlled by qualifying individuals." City of Chicago, *Regulations Governing Certification of Minority- and Women-owned Business Enterprises, Veteran-Owned Business Enterprises, and Business Enterprises Owned or Operated by People with Disabilities for Construction Contracts* (hereinafter "MBE/WBE/VBE/BEPD Regulations for Construction"), (updated October 5, 2023), available at: https://www.chicago.gov/content/dam/city/depts/dps/Certification/Certification%20Documents/CertificationRulesConstruction_100523.pdf. Those regulations require that the qualifying individual "[e]xercise responsibility for the critical areas of the Applicant's daily operations and make independent and unilateral business decisions." *Id.* Furthermore, the regulations specify that:

> 2. Ownership and control by such qualifying individuals shall be real, continuing and shall go beyond the pro forma ownership of the Applicant as reflected in ownership documents. …
>
> 5. Qualifying owners must, either collectively or individually, possess the power to direct or cause the direction of management, policies, and objectives of the Applicant and to make all substantive day-to-day decisions on the Applicant's major and essential operations…

Id. Applicants may demonstrate control through documentation of the qualifying owner's contribution of capital, assets, or expertise, and organization records such as articles of incorporation, partnership agreement, or board of directors' rules that vest the qualifying individual with decision-making authority. The Illinois Department of Transportation uses the U.S. Department of Transportation's Disadvantaged Business Enterprise application, which includes questions about the frequency with which all officers, owners, directors, and key personnel make decisions on or are responsible for key business activities such as bidding for contracts, major purchases, hiring senior managers, and signing contracts. *See* U.S. Dep't of Transp., *Uniform DBE/ACDBE Certification Application* (accessed Nov. 29, 2023), https://idot.illinois.gov/content/dam/soi/en/web/idot/documents/idot-forms/dbe/us-dot-uniform-dbe-acdbe-certification-application.pdf; IPA Resp. at 83-84.

The IPA states these examples belie ESI's claim that any requirement to demonstrate control is unworkable, as indeed other State and local agencies have been implementing the same requirement for years. The Agency plans to research those certification processes and conduct a stakeholder feedback process to determine the best and most appropriate method for demonstrating control in this context. IPA Resp. at 84.

Finally, ESI objects that a requirement that the EEP majority-owners exercise control of and manage the affairs of the EEC would put EECs at a financial disadvantage, since many investors require that the project be controlled by individuals with significant experience. ESI also again repeats that it is reasonable for EEPs to "partner" with more experienced firms. First, the Illinois Shines program does not require that the AV, EEC or not, own the physical project. Therefore, to the extent investors are concerned with the ownership of the physical installation, the requirement that the EEP(s) actively manage the EEC AV should not be a barrier to financing. Being the majority-owner that demonstrates control over the business activities does not mean that the EEP may not partner with a more experienced firm or receive input or assistance—all it means is that the EEP must be actively involved. Again, the Agency is witnessing some firms establish essentially shell companies, but the EEPs appear to be completely absent or silent, and the minority-owner company seems to undertake all the duties of the AV. The result is a passing-through of State benefits to an entity that was not the intended beneficiary—not a partnership where all parties significantly contribute and collaborate. The equity provisions of the IPA Act, again, are meant to advance the access of entities and people that historically have been excluded from economic opportunities to the potential wealth-building careers being created in the clean energy sector. Business models that instead capture that access and divert it to primarily benefit firms already succeeding in this space do not align with that goal. IPA Resp. at 84-85.

Staff argues that "the absence of language in the IPA Act[] that an EEC must also prove control or active management by an eligible person" ends the inquiry, and is sufficient to conclude that the IPA does not have authority to require demonstration of control or management by the EEP-owners. Staff Resp. at 22. The IPA respectfully disagrees; while the words "control" and "management" do not appear in the IPA Act definition of EEC, Section 1-75(c-10)(7) of the IPA Act expressly authorizes the Agency to "revise … definitions for equity investment eligible persons and equity investment eligible community; and (C) such other modifications necessary to advance the goals" of P.A. 102-0662. Requiring that the EEP-majority-owner(s) "control and manage" the business speaks to whether they truly "own" that business, whether it is their venture. To meet the legislative goals of creating "priority access to the clean energy economy for businesses … that have been excluded from economic opportunities in the energy sector," the Agency believes that the business itself should be led and driven by individuals that would have previously or otherwise faced barriers to starting or growing that business. 20 ILCS 3855/1-75(c-10). A business at its core is a person or group of persons organizing and acting toward a commercial end. If the persons taking those actions face no barriers to achieving those commercial ends, even if another person simply receiving the occasional payment from the profits of the business might have faced such barriers were they to have taken those actions, then the business is not, in fact, "excluded from economic opportunities." *Id*. Rejecting the "control and management" criterion would in essence invite large, existing, successful companies to approach any person living in an EIEC, make them a silent, on-paper-only EEP majority-owner, and apply massive community solar projects to the EEC category to receive millions of dollars in REC incentives meant for disadvantaged businesses for projects it should have submitted to non-EEC categories. The IPA, and by proxy the State of Illinois, would then be in a position where it would have to characterize such ratepayer-funded REC incentive payments as directly supporting "communities that have been historically excluded from economic opportunities in the energy sector, have been subject to disproportionate levels of pollution, and have disproportionately experienced negative public health outcomes." *Id.* Such an outcome would make a mockery of the word "equity." IPA Rep. at 62-63.

Even apart from the authority to adjust the elements of the EAS that Section 1-75(c-10)(7) of the IPA Act expressly grants to the Agency, the IPA states Staff's argument on this issue is wholly inconsistent with its position on the proposed requirement that EEP-majority-owners demonstrate their socio-economic status. On that issue, Staff argued that "requiring a showing of one's socio-economic status will enable the IPA to determine that the individual is an eligible person or persons," yet the words "socio-economic status" do not appear anywhere in the definition of "equity eligible person." 20 ILCS 3855/1-10. Staff instead points to the "well-established rule" that a grant of authority includes the "authority to do what is reasonably necessary to accomplish the legislatures [sic] objective." Staff Resp. at 23 (citing *Lake Co. Bd. of Rev. v. Prop. Tax Appeal Bd.*, 119 Ill. 2d 419, 427 (1988)). The exact same "well-established rule" would equally apply to the requirement to show that the EEP-majority-owner exercises control of the business. Instead, the IPA argues Staff applies a rigid, textualist approach when evaluating the control and management requirement, simply stating that the IPA Act does not include that specific requirement. *Id*. at 22. Staff points to Illinois case law as establishing the "well settled" principle that the "primary objective in construing the meaning of a statute is to ascertain and give effect to the intention of the legislature," and that such intention should be drawn from the statutory language. *Id*. (quoting *In re Det. of Lieberman*, 201 Ill. 2d at 307). But the definition of "equity eligible contractor" is not the only language in the statute; the IPA Act establishes the purpose of the EAS, of which the EEC category is a part, as "advancing priority access to the clean energy economy for businesses and workers from communities that have been excluded from economic opportunities in the energy sector, have been subject to disproportionate levels of pollution, and have disproportionately experienced negative public health outcomes." 20 ILCS 3855/1-75(c-10). Ultimately, Section 1-75(c-1) provides "the intention of the legislature," and the Agency's proposal is "reasonably necessary" to accomplish the legislative objective. *In re Det. of Lieberman*, 201 Ill. 2d at 307; Staff Resp. at 23 (citing *Lake Co. Bd. of Rev. v. Prop. Tax Appeal Bd.*, 119 Ill. 2d at 427). The IPA explains it ensures the EEP majority-owners, as the intended beneficiaries of the EEC designation and the EAS, are the true participants and recipients of the advantages of the EEC category. The Commission's Order in this proceeding should not permit a non-EEC company with ample resources to set up a purported EEC and take advantage of the benefits available to disadvantaged EEPs within the Illinois Shines program. IPA Rep. at 63-65.

The JSPs and the Joint NGOs oppose ESI's objection to the requirement that the EEP-majority-owner(s) demonstrate control and active management of an EEC. The Agency agrees that while the statute allows EEPs to partner with a more experienced firm in creating an EEC, the entire purpose of the EEC designation is to advance businesses that "have been excluded from economic opportunities in the energy sector." 20 ILCS 3855/1-75(c-10). Clearly, an already successful firm has not been "excluded" from the energy sector, so to the extent that those firms are allowed to benefit from the EEC category, it should only be in support of the EEP-majority-owner developing their business and eventually no longer needing the partner's help. If there are specific products or services that the EEP cannot provide even with support from a minority-owner partner, they can rely on suppliers and contractors like all other AVs. The Agency urges the Commission to approve the requirement that EEPs demonstrate control of the EEC as proposed in the 2024 Plan. IPA Rep. at 65-66.

In its RBOE, the IPA asserts it has never proposed to "rewrite" Public Act 102-0662. Rather, it proposes to use authority explicitly granted to the Agency under the provisions of the IPA Act to modify its implementation of the EEC category of Illinois

Shines to meet the equity objectives of the law. Notably, the Agency states it is not trying to "bootstrap" this provision to modify unrelated aspects of its programs as suggested by Staff. The Agency explains this section of the law is specifically about ensuring that the EAS, which includes the EEC category, is successful in its goals. On the other hand, ESI acknowledges the language of Section 1-75(c-10)(7), but dismisses it as a "catch-all," implying that it somehow should be read out of the statute. But the legislature explicitly included this "catch-all," and it cannot be given no meaning. IPA RBOE at 37-38.

The IPA suggests the legislature's broad grant of authority to the Agency to effectuate the purpose of the EAS clearly shows that the legislature was concerned about unanticipated consequences or loopholes that could not be adequately identified in advance. It is specifically because of concern surrounding the emergence of one such loophole that the Agency finds it necessary to make this update. The purpose of the EAS is to develop a robust segment of the solar market where EEPs have an active and meaningful role in the clean energy economy. Finally, the Agency notes that it has not proposed to take any unilateral action and has appropriately raised this proposal in its Long-Term Plan. This docketed proceeding provides the opportunity for other stakeholders to weigh in, and the Agency's proposal must ultimately be approved by the Commission before implementation. IPA RBOE at 38-39.

g. Commission Analysis and Conclusion

The Commission declines to adopt the IPA's proposal to require that EEPs must demonstrate control or active management of an EEC. Similar to the Commission's finding in Section VIII.B.2, more discussion amongst stakeholders is necessary before making significant changes to EEP access, to ensure the Agency's Plan strikes a fair balance between EEP requirements and reducing manipulation of the system. The Agency has consistently stated that AVs should have flexibility to design corporate structures and relationships to facilitate project development. The Commission is not convinced that EEPs should be limited in their ability to enter into long-term partnerships with minority share owners who have more experience in the renewable energy industry. The Commission directs the Agency to include in the aforementioned stakeholder process (Section VIII.B.2) identification of the best and most appropriate, balanced methods to prevent manipulation without overly burdening EEPs and submit alternatives for the Commission to consider in the next Plan.

4. AV and SPAV Ownership

a. JSPs' Position

While the JSPs reserve their right to modify their position based on EEP and EEC voices in this docket, the JSPs do not object to the spirit of the requirement that a single EEP can only count toward majority-EEP ownership of a single EEC. However, the Commission should make two practical changes to greatly improve the ability to finance EEC block projects. JSPs Obj. at 10.

First, the LTRRPP proposes that an EEP can only count toward EEP-majority ownership of a single EEC-AV that can also register as a Designee. *See* LTRRPP at 352. However, the JSPs explain for a variety of financings it is highly desirable to have separate legal entities handle the EPC (or other Designee work) and AV responsibilities.

The reason is that project finance would be concerned about the EPC business draining resources for project development or operation, while EPC (or other Designee work) business expansion financing may be concerned about project-specific risk reducing their chances of repayment. As a result, the JSPs propose that an EEP be allowed to count toward EEP-majority ownership of no more than one EEC (subject to the additional proposal *infra*) and no more than one Designee but that the EEC and Designee may be separate legal entities. JSPs Obj. at 10-11.

Second, the LTRRPP suggests an exception to the "one EEC per EEP" rule that would allow for an EEP to count toward EEP-majority ownership of a series of single-project AVs ("SPAV") for financing purposes. *See* LTRRPP at 352. The JSPs agree that some financing parties require or at least favor SPAVs for larger systems and applaud the concept. However, elsewhere the LTRRPP in describing the SPAV designation as on that may apply to a project that is owned by that SPAV**.** LTRRPP at 201. Because tax equity financing generally requires the tax equity investor to own the system to the maximum extent, an EEC SPAV cannot both be majority owned by EEPs and 99% owned by the tax equity financing parties. Thus, under the LTRRPP as it exists today, EEC SPAVs are not a viable financing pathway. JSPs Obj. at 11.

Because so much of project value is tied to tax equity, particularly under the Inflation Reduction Act, and the LTRRPP should eliminate or mitigate as many barriers to EEC success as possible, the JSPs propose that EEC SPAVs be exempt from the requirement that the EEC SPAV own the system(s) subject to the REC contract. This exemption will allow EECs to more successfully and cleanly finance their projects using the SPAV model without foregoing a substantial portion of tax equity benefits. JSPs Obj. at 12.

While the JSPs have raised SPAV issues informally and through public comments previously, it appears that no accommodating changes have been made to date. Without financing or with impaired financing, EECs will be at a severe disadvantage competing in the marketplace and unlocking the wealth-building value of REC contract awards. The JSPs urge the Commission to direct explicit modifications to the LTRRPP consistent with these recommendations. JSPs Obj. at 12.

The JSPs note LiveWire, an EEC, objected to two components of the restrictions on EEP ownership of multiple EEC entities. One of the objections appears to make a similar recommendation to the JSPs that an EEP should be allowed to count toward EEP-majority ownership of both an EEC AV and a separate EEC Designee. *See* LiveWire Obj. at 4. While the JSPs relied on the perception of the financing community, LiveWire spoke to the additional revenue streams for EEP owners if the EEP-majority ownership could be majority owners of both an AV and a Designee. *See id.* The JSPs believe this is a valid independent basis to arrive at the same result. JSPs Resp. at 15.

LiveWire argues further that EEPs should be allowed to count toward EEP-majority ownership of multiple EECs because EEPs may choose as LiveWire's ownership has to create multiple companies for more vertically-integrated service delivery. *See* LiveWire Obj. at 2-3. The JSPs note that some non-EECs in the solar marketplace choose to take the same approach of a single or multiple, related companies taking on complementary roles within the solar development, construction, and operations cycles. From a policy perspective, allowing the same structure for EECs and access to EEC-protected opportunities will allow the EEC structures grow to compete with similarly situated non-EECs that exist in the solar marketplace today. Conversely, the JSPs urge that the Commission not allow the Plan to impose a single vision of what an EEC company structure must be to compete with the myriad different structures within the solar marketplace. JSPs Resp. at 15.

The JSPs appreciate that the IPA agrees with LiveWire and the JSPs to allow an EEP be the majority owner of both an EEC AV and an EEC Designee that are separate legal entities. The JSPs recommend that the Commission adopt the IPA's "option" discussed on page 90 of the IPA's Response to Objections. JSPs Rep. at 11.

The JSPs also addressed the need for EEC SPAVs to not be required to own projects. The JSPs do acknowledge that the IPA did not reject or oppose the JSPs' proposed clarification that an EEC SPAV need not own the solar system; instead the IPA "defers to the Commission" on the issue. *See* IPA Resp. at 91. The JSPs urge the Commission to allow EEC Block projects to realize full tax equity benefits by allowing the tax equity investor to own (typically 99-100%) the system but to allow a SPAV majority owned by an EEC to serve as that system's AV. This ownership structure allows the EEC AV to maximize the value of the project by having it generate the highest tax equity value. For these reasons, the JSPs urge the Commission to allow EEC SPAVs to not own the underlying solar system. JSPs Rep. at 11.

b. LiveWire's Position

EEP Shon Harris objects to the IPA's statute prohibiting an individual EEP from serving as the majority-owner for multiple EEC AVs or Designees. LiveWire notes there are several compelling reasons why there should be an exception to this rule. First, LiveWire explains the IPA allows for multiple AVs to be owned by the same parent company in the TSC block, and thus the IPA's enforcement of a limitation on the EEC block by not allowing EEPs to own multiple EEC AVs places an additional and unreasonable limitation on the EEC block, which is inconsistent with the statutory mandates to encourage the development of the EEC block. Second, LiveWire claims preventing EEPs from owning multiple EEC-qualified businesses interferes with normal business activity to grow and expand business operations within a market that has historically left EEPs without any substantial enterprise. Third, the EEC block was created to assist disadvantaged businesses who face barriers in building opportunities and meaningful capacity in the energy sector, and thus imposing additional and unreasonable limitations on permissible business activities is inconsistent with the statutory mandates to encourage the development of the EEC block. Fourth, limiting business growth and expansion for EEPs with identified capacity and capabilities to expand their business or partner with other EECs in the program will lead to slower growth of the firms in the EEC program and could possibly lead to further attempts to game the program along with the EEC program not reaching its intended goals it set out to achieve. LiveWire states this limitation is counterproductive as to why the EEC Block was created in the first place. Fifth, there is a legitimate market need for the additional services that BlackRock and LiveWire Energy (commonly owned companies by EEP Shon Harris) provide. Sixth, this rule damages the EEP's other businesses by not allowing developers to utilize BlackRock Construction and LiveWire Energy with any credit as an EEC. Seventh, the IPA's position to not allow EEPs to own multiple EEC firms is contrary to the other public agency certifying practices that allow separate commonly owned businesses to hold a designated certification. LiveWire Obj. at 1-2.

LiveWire illustrates the reality of the current EEC experience, through the background of LiveWire and its owner, Shon Harris. EEP Shon Harris is the 100% owner of EEC, LiveWire Electrical Systems, Inc.; 100% owner of non-EEC Designee, BlackRock Construction; and 100% owner of non-EEC AV, LiveWire Energy. These three companies previously existed under the same company but were reorganized into independent companies to self-perform different scopes of work for enhancing individual business potential, and each serves a commercially useful function. As defined by the BEP, "'Commercially Useful Function' means responsibility for the execution of a distinct element of the work of the contract, which is carried out by actually performing, managing, and supervising the work involved, evidencing the responsibilities and risks of a business owner such as negotiating the terms of (sub)contracts, taking on a financial risk commensurate with the contract or its subcontract, responsibility for acquiring the appropriate lines of credit and/or loans, or fulfilling responsibilities as a joint venture partner as described in the joint venture agreement." LiveWire Obj. at 2-3.

LiveWire Electrical Systems, Inc. self-performs electrical construction scope; BlackRock Construction self-performs civil and mechanical construction scope; and LiveWire Energy seeks to self-perform EPC services, REC management and administration, professional services with other EEC firms, and mentorship to other EECs. LiveWire Energy's mission is to break down economic barriers by mentoring, training, and partnering with fellow EEC companion companies in the EEC Alliance to build a network of EECs that can live up to the purpose that the IPA envisioned for the EEC Program. LiveWire Obj. at 3.

The experience of EEP Shon Harris and his participation in IPA administered solar programs in Illinois contradicts the IPA's belief that an EEP is not capable of directly managing multiple EEC firms, as Shon Harris is fully active in managing LiveWire Electrical Systems, Inc.; BlackRock Construction; and LiveWire Energy. Further, BlackRock Construction was established before the IPA's implementation of the EEC program, which underscores BlackRock Construction served a commercial useful purpose to Shon Harris and the affiliated companies that he owns and manages. Put simply, it is not an enterprise created to somehow participate "illegitimately" in the IPA's programs, but rather an ongoing business concern that complements and supports Shon Harris' other affiliated companies. LiveWire Obj. at 3.

LiveWire requests the IPA make an exception to the aforementioned rule for EEPs that can demonstrate the ability to 100% own and operate multiple EEC businesses or initiate a separate rulemaking or working group to develop appropriate qualifications to allow one EEP to participate in multiple EEC business where certain conditions are met. Until that time, EEP Shon Harris, requests LiveWire Energy be granted EEC AV status and BlackRock Construction be granted EEC Designee status. Live Wire Obj. at 3.

EEP Shon Harris, objects to the Agency's statement that "an EEP's involvement in the second or third EEC would be minimal, and only designed to gain preferential treatment in the TCS scoring system" (LTRRPP at 352) for the following three reasons.

First, an EEP who owns multiple legitimate firms should not be penalized with a limitation of utilization by the IPA to register these firms as EEC AVs and Designees because it interferes with normal business activities and prohibits growth and expansion, which is supposed to be a desired outcome of this Program. Second, the TSC Scoring System promotes multiple EECs to collaborate through the same scope or be selected to perform separate scopes of work to earn a higher percentage of scoring. Therefore, if an EEP has multiple businesses that serve separate commercially useful functions, an exception should be made for those EECs. Third, the IPA has introduced a tiered scoring approach to increase EEC participation up to 100% of the total REC contract value. While it is possible for a single EEC to perform 25% of the total REC contract value, 50%-100% would likely require more than one EEC to perform the work. To fairly obtain 50% or more of the REC Contract value based on the TSC Scoring Criteria, owning multiple EECs would not be gaining preferential treatment from the Program, but is instead a necessity to support market demands. LiveWire Obj. at 4.

The IPA made this TCS EEC scoring criteria change because of the IPA's recognition of decreased participation for EECs in the TSC block with the understanding that fulfilling 50% to 100% of the total REC contract value for a single project is difficult. To increase EEC participation and opportunity in the TCS block, the IPA should also understand that self-performing 50% to 100% of the total REC contract value with one EEC firm is also difficult. LiveWire Obj. at 4.

EEP Shon Harris believes that owning multiple EEC AVs would not be preferential treatment, but a status that is deserving of the higher percentage on the TSC Scoring criteria. EEPs that have built multiple companies from grassroots start-ups to sustainable businesses should be allowed to own multiple EEC firms with no penalty or limitation from the IPA. Live Wire Obj. at 4.

LiveWire requests the IPA create an exception for LiveWire Energy to register as an EEC AV and BlackRock Construction to register as an EEC Designee because they are 100% owned and operated by EEP Shon Harris. The IPA should also permit the value of work performed by commonly owned EEC-AVs and Designees to count toward the REC contract value requirement in the TCS Scoring Criteria. The intent of this request is not to achieve the ability to obtain an increased number of projects by owning multiple EEC firms, but rather to recognize legitimate commercial approaches of developers in this space to deploy more than one business entity. Live Wire Obj. at 4.

The IPA states in response to LiveWire's objection that it is "open to adjusting the limitation on EEC ownership by an individual Equity Eligible Person." IPA Resp. at 90. The IPA's proposal is "to allow an individual EEP to serve as the majority-owner of one EEC Designee and one EEC Approved Vendor, which may be separate legal entities." *Id*. LiveWire appreciates and commends the IPA for being "open to adjusting the limitation on EEC ownership by an individual Equity Eligible Person." *Id.* at 90; LiveWire Rep. at 1-2.

The JSPs articulate that, "for financing purposes, it is important to segregate EPC/contractor business from the development/REC Contract administration business, and thus an EEP should be allowed to be the majority owner or part of the majority ownership group of both an AV and a separate Designee." JSPs Resp.at 14. LiveWire appreciates and commends the JSPs for recognizing additional reasons as to why the limitation on allowing an individual EEP to qualify only one EEP. LiveWire Rep. at 2.

c. IPA's Position

LiveWire objected to the limitation that an individual EEP may serve as the majority-owner for only one EEC AV or Designee (or both, if the same legal entity), with the exception of SPAVs. The JSPs also raised concerns as to the implementation of this requirement but did not object to the overall objective. The JSPs specifically pointed to the advantage of having separate legal entities performing different scopes of work when seeking financing for a project. JSPs Obj. at 10-11. As background, the IPA felt it necessary to create this limitation due to the combination of the patterns described above and the efforts by some EEPs that qualified based on primary residency that did not align with the spirit of the equity provisions to register multiple EEC companies. Again, the Agency is concerned that the advantages of being an EEC may go to entities that do not further the aims of the law, that are owned by individuals that have not faced exclusion from economic opportunity and have ample access to resources via existing successful solar companies. If those individuals then create multiple EECs, the Agency feared they might dominate market demand and crowd out small or emerging EECs like LiveWire. The Agency does not want to create additional barriers for true EECs and appreciates LiveWire's detailed explanation of how this limitation is affecting its business and JSPs' outline of the expectations of project financiers. The intention was never to hobble the efforts of legitimate EECs in growing their business and diversifying the services they offer, but rather to avoid domination of the market by a handful of individuals that do not reflect the legislative goals. IPA Resp. at 89-90.

The Agency is open to adjusting the limitation on EEC ownership by an individual EEP. As an option, the IPA proposes to allow an individual EEP to serve as the majority-owner of one EEC Designee and one EEC AV, which may be separate legal entities. This option would allow for the diversification discussed by LiveWire and JSPs while still providing some guardrails against the concentration of the benefits of EEC AV status in a small number of individual EEPs. Given that the statute directs the Agency to "create programs with the purpose of increasing access to and development of equity eligible contractors, who are prime contractors and subcontractors, across all of the programs it manages," the IPA maintains that it must design an EAS that drives a dynamic, diverse portfolio of EECs and encourages new entrants. LiveWire refers to the advantage offered by TCS scoring criteria for AVs utilizing EECs for a certain percentage of the project as another reason an EEP should be permitted to serve as the majority-owner of multiple EECs. That point category in TCS project scoring was never meant to imply that a single EEC should be able to independently perform all scopes of work involved in a solar project. Instead, the Agency intended that scoring to encourage AVs to work with multiple EECs owned by different EEPs, to provide economic benefits to as many EEPs as possible. IPA Resp. at 90-91.

Finally, the JSPs note that while they appreciate the flexibility provided in the 2024 Plan for an individual EEP to serve as majority-owner of multiple EEC SPAVs, they note inconsistencies with guidance elsewhere in the Plan regarding SPAVs. Specifically, the Plan provides that an entity may seek SPAV status for projects owned by that entity. LTRRPP at 201. The JSPs argue that this would prevent an EEC from leveraging tax equity financing, in which the tax equity investor has to own the system to receive the tax benefits. While the Agency acknowledges the potential financial challenges posed by the requirement that an SPAV own the project, it does not have sufficient expertise in the financing models to determine whether the challenge is severe enough to warrant a blanket exemption. The original proposal to allow an EEP to serve as the majority owner of multiple EEC SPAVs was in fact to counter the very limitations on financing options that JSPs point to resulting from the Agency's limitation of an EEP to serving as majority owner of only a one legal entity that registers as an EEC AV and/or Designee. Given the Agency's proposal to allow for registration of two separate legal entities as an EEC AV and an EEC Designee, the Agency defers to the Commission as to whether to adopt the JSPs' proposal regarding EEC SPAVs. IPA Resp. at 91-92.

The Agency also addresses a procedural item contained in LiveWire's Objections. LiveWire requests an exception to the limitation on EEC ownership for its EEP majority-owner. The Agency does not believe the Plan is the appropriate vehicle for granting or denying any request for an exception for an individual company from program requirements. If LiveWire has an alternative approach to propose that could apply equally to all EECs and still achieve the aim of preventing a small number of individual EEPs from dominating the market, the Agency welcomes any ideas. IPA Resp. at 92.

ESI agrees with the JSPs' Objections drawing attention to the problems of achieving standard financing structures for EEC projects under the current requirements. ESI incorrectly argues that the current EEC requirements "may not allow [the tax equity investor to become a true owner of the project] to occur." ESI Response at 3. The modifications to Section 7.4.6.2 address ESI's objections on this point. IPA Rep. at 31.

In its Response, the JSPs correctly note that the Agency's modifications to Section 7 of the Plan alleviate ESI's concerns. The JSPs agree with the language of the Plan, which would allow the type of tax equity financing identified by ESI, pointing out that the Plan modification has "clear intent to remove ambiguity over whether ownership of the system itself may be transferred, which would have made financing impossible and would make selling systems to end users (such as residential rooftop) impossible." JSPs Resp. at 9. The Agency agrees with this characterization of the Plan and its intent and urges the Commission to reject ESI's Objection and its Response. IPA Rep. at 31-32.

The 2024 Plan includes the Agency's current program requirement that an individual EEP may serve as the majority-owner of only one AV and/or Designee (a single legal entity, which may register as both an AV and a Designee). This limitation was adopted in response to the Agency's concerns that, due to the gaming potential previously noted, created by the option to qualify as an EEP based on primary residence in an EIEC and the rate of gentrification in some of those communities, some EEPs that did not align with the legislative purpose of the EAS would start multiple EECs and crowd out EECs owned by EEPs that more closely aligned with the spirit of the EAS. LiveWire objects and argues that, as an EEC, there are several legitimate business reasons for why an EEP may choose to utilize multiple legal entities, each with a different business function or service, rather than one vertically integrated company or corporation. In its Response, the IPA explained that it found LiveWire's objections persuasive and agreed to allow an EEP to serve as majority-owner of one AV and one Designee that are separate legal entities. IPA Rep. at 55-56.

The JSPs generally support LiveWire's Objections. The JSPs argue that the Plan should allow for an individual EEP to serve as the majority-owner of more than one EEC and agree with LiveWire that this would allow more growth for EEP-owned businesses. The IPA appreciates this added perspective and agrees that the Plan should allow an EEP to serve as majority-owner of both an AV EEC and Designee EEC. However, to prevent gaming and ensure broad access to the EEC category, the IPA maintains its position that multiple AVs cannot be majority-owned by the same EEP. IPA Rep. at 56.

d. Commission Analysis and Conclusion

The Commission adopts the IPA's proposal to allow an individual EEP to serve as the majority-owner of one EEC Designee and one EEC AV, which may be separate legal entities. Both JSPs and LiveWire support this proposal, which addresses some of their concerns.

The IPA explicitly deferred to the Commission on whether to adopt the JSPs proposal, which would eliminate the requirement that the EEC SPAV must own the system or systems subject to the REC contract. The JSPs propose this change to allow EECs to leverage tax equity financing for these projects. The Commission agrees that opening up this financing option to EEC SPAVs would incent further development by these entities. Paired with the other new requirements including the establishment of socio-economic status, this proposal seems reasonable. If this change does not have its intended effect, it can be revisited in a future proceeding. The Commission adopts JSPs' proposal.

The Commission declines to provide an exemption for LiveWire, or any other individual company, from the program requirements in this LTRRPP proceeding.

C. Section 10.1.3. Definitions and Eligibility: Project Workforce

1. JSPs' Position

The JSPs sought limited clarification to the definition of "project workforce," which the JSPs supported pending confirmation of the JSPs' understanding. *See* JSPs Obj. at 24-25. The IPA provided the requested confirmation in its Response. *See* IPA Resp. at 93-94. The JSPs recommend that the Commission memorialize the IPA's confirmation in its Order, including the JSPs' support. JSPs Rep. at 21-22.

2. IPA's Position

The JSPs requested clarification as to the intended meaning of the change made to the definition of "project workforce" for the MES in Section 10.1.3 of the 2024 Plan. As proposed in the 2024 Plan, the definition of "project workforce" going forward would be:

> Employees, contractors and their employees, and subcontractors and their employees, whose job duties are directly required by or substantially related to the development, construction, and operation of a project that is participating in or intended to participate in the IPA-administered programs and procurements under Section 1-75(c) of the IPA Act. This shall include both project installation workforce and workforce in administrative, sales, marketing,

> and technical roles where those workers' duties are performed in Illinois. For purposes of this definition, 'directly required by or substantially related to' shall be construed to be any direct employee of the Approved Vendor, Designee, or Indexed REC contract holder, or any contractor and its employees whose contract exceeds 5% of the REC Contract value. Employees of contractors below that threshold may be counted on a voluntary basis, but then all contractors below the threshold must be included.

2024 Plan at 353-54; IPA Resp. at 93-94.

The JSPs described their understanding of this addition to the definition as meaning that "if the Approved Vendor/Designee/winning bidder of an Indexed REC procurement includes at least one such contractor [whose contract is less than 5% of the REC Contract value] all such contractors must be included." *Id.* This reading is correct; an entity obligated to meet the MES may only include employees of a subcontractor that receives less than or equal to 5% of the REC contract value if it includes all such subcontractors in the project workforce. In other words, an entity may not cherry-pick only those subcontractors that qualify as EEPs or EECs and have a small role in the project but not include all workers with a small role. IPA Resp. at 93-94.

3. Commission Analysis and Conclusion

Through the 2024 Plan the IPA proposes adding the following language to the definition of "project workforce" as it relates to the MES:

> For purposes of this definition, 'directly required by or substantially related to' shall be construed to be any direct employee of the Approved Vendor, Designee, or Indexed REC contract holder, or any contractor and its employees whose contract exceeds 5% of the REC Contract value. Employees of contractors below that threshold may be counted on a voluntary basis, but then all contractors below the threshold must be included.

2024 LTRRPP at 353-54.

The JSPs understood this addition to mean that "if the Approved Vendor/Designee/winning bidder of an Indexed REC procurement includes at least one such contractor [whose contract is less than 5% of the REC Contract value] all such contractors must be included." 2024 Plan at 353-54; IPA Resp. at 93-94. The IPA agrees with the JSPs understanding of this language. The JSPs support IPA's language with this clarification. The Commission approves the IPA's proposal to add language to the definition of "project workforce" as it relates to the MES.

D. Section 10.1.5.1, 10.1.5.2, and 10.1.8. MES Compliance Plans, Mid-year Progress, and Special Considerations for Utility-scale Projects

1. CGA's Position

CGA objects to the Section 10.1.5 compliance requirements and timelines because it leads the reader to believe that all utility-scale developers are required to file an annual MES Compliance Plan. CGA clarifies that is not the case, utility-scale developers are only required to file if they win a competitive procurement. CGA Obj. at 10. CGA recommends that Sections 10.1.5. and 10.1.8. of the filed 2024 Plan be amended to clarify this ambiguity and be internally consistent. CGA also recommends that Section 10.1.8. be amended to clearly state that only utility-scale developers that are successful bidders in a competitive procurement are obligated to file a Mid-year Progress Report as CGA proposed for Section 10.1.8. CGA Obj. at 13.

2. JSPs' Position

CGA takes issue with several areas in the Plan that suggests utility-scale developers generally-rather than winning bidders in competitive procurements specifically-must comply with the minimum equity standard. *See* CGA Obj. at 10-13. The JSPs agree. The JSPs are strong advocates for the policy behind the MES. However, the JSPs see CGA's objections as clarifications rather than a weakening of the statutory framework or its regulatory implementation. JSPs Resp. at 18-19.

3. Staff's Position

Staff agrees with CGA that these Sections should be clear and consistent regarding utility-scale projects' MES Compliance Plan requirements. Staff concurs with CGA's language in an effort to remove any ambiguity concerning these requirements. Accordingly, the Commission should direct the IPA to modify the Plan consistent with CGA's proposed language set forth in its Objections. Staff Resp. at 12.

4. IPA's Position

CGA objected to what it sees as ambiguity regarding the applicability of the MES reporting requirements to utility-scale project developers contained in Sections 10.1.5, 10.1.8, and 10.1.5.2 of the 2024 Plan. While the Agency does not believe that failure to repeat the phrase "that submitted a winning bid in a competitive procurement" after each use of the phrase "utility-scale developers" means the Plan requirements are ambiguous, the Agency agrees to add the language proposed by CGA in an abundance of caution. IPA Resp. at 94.

5. Commission Analysis and Conclusion

The Commission adopts the amendments to Sections 10.1.5, 10.1.8, and 10.1.5.2 as suggested by CGA and agreed to by the IPA to ensure clarity and consistency.

E. Section 10.4.1. Scope of Data Collection

1. Joint NGOs' Position

The Joint NGOs object to the exclusion of various forms of documentation that the IPA has decided to forgo. Robust data collection is essential to ensuring effective achievement of our shared equity goals and will determine our ability to identify whether communities and populations intended to benefit from these programs are being served or left out, and to craft effective reforms shaped by a nuanced understanding of what aspects of the programs are and are not working. The Joint NGOs state there is a clear need to collect specific types of data to assess the effectiveness of the EAS (and by implication, the P.A. 102-0662 workforce ecosystem), which will directly impact the ability of AVs and competitive bidders to meet the MES, and of competitive bidders to increase their employment of EEPs. Data resulting from these programs will also help the IPA assess the validity of contractor claims that a limited pool of qualified EEPs is undermining their ability to comply with their hiring obligations. JNGOs Obj. at 11.

The Joint NGOs propose that under Section 10.4.1 the Agency be required to collect:

- Data on the workforce hubs, including, disaggregated demographic data on program applicants, applicants admitted and denied, admitted applicants that matriculate, applicants that graduate, and post-graduation hiring status;
- Data on all the bases for EEP status, including whether a person resides in an EIEC, is a foster care alumnus and/or formerly incarcerated or is a graduate of specified workforce and contractor programs;
- Data with specific address information and other demographic characteristics to inform any future deliberations around the need to adjust the geographic boundaries of the EIEC definition to better serve intended beneficiaries;
- Data that allows for an evaluation of the quality of opportunities offered to intended beneficiaries. Including data on total hours worked, temporary vs. permanent positions, employees vs. independent contractors, the value of the contracts received by independent contractors, and what growth and mentoring opportunities are offered by it; and
- Data for all "protected classes" under state and federal anti-discrimination law, including specific racial/ethnic group, gender, gender identity, disability status, national origin, and language status.

JNGOs Obj. at 11-12.

The Joint NGOs also object to the exclusion of aggregated data collection and reporting on AV compliance with the MES. To ensure the success of this program it is important that AV level data be acquired to prove compliance with P.A. 102-0662's standards. JNGOs Obj. at 12. Therefore, the Joint NGOs propose amending Section 10.4.1 to require this publicly available aggregated data to be released for every AV and Designee to allow for visibility into MES compliance and progress towards a diverse and inclusive workforce. JNGOs Obj. at 12.

The Joint NGOs are not opposed to the Staff's proposal that the IPA consult with the "the JNGOs and other interested parties in advance of filing the next plan" and include recommendations for what additional data should be collected then. Staff Resp. at 29; JNGOs Rep. at 4-5.

2. AEU's Position

While AEU also wishes to see a diverse and inclusive workforce and does not question the Joint NGOs' intentions, AEU is concerned that the Joint NGOs may not fully appreciate the import of the proposal. P.A. 102-0662 and the IPA already impose significant reporting requirements, which include data on ethnicity, past incarceration, and foster program participation. Collection of this sensitive information already presents obstacles for AVs, particularly when some front-line workers are not direct employees of an AV. Some employers fear that inquiring about such sensitive information could, at least in the opinion of an employee, violate privacy interests and lead to legal action against the employer. Requiring the collection of additional information, such as gender identity, disability status, national origin, and language status, will only exacerbate this risk. AEU Resp. at 4.

In addition, it is not clear who the Joint NGOs expect to provide all the information they list. For example, data on the workforce hubs, including disaggregated demographic data on program applicants, applicants admitted and denied, admitted applicants that matriculate, applicants that graduate, and post-graduation hiring status, would not be information held by AVs. But the Joint NGOs do not identify the authority under which the IPA could require the workforce hubs to provide the data, or under what authority the Commission could require the production of such data. AEU Resp. at 4.

The submission and handling of the data is another concern for AEU. Despite the best and much appreciated efforts of the IPA, over the past year the transition from the prior to the current program administrator experienced several wrinkles and hiccups. Respectfully, it may be judicious to ensure that the program administrator can smoothly administer the Illinois Shines program in the coming program years before dramatically expanding the data collection aspects of the program. AEU Resp. at 4-5.

Overall, participation in the Illinois Shines program requires significant time and expense by AVs to collect and submit the extensive information already required by P.A. 102-0662 and the IPA. While this may be viewed as a cost of doing business, such cost is real and growing and affects a business' decision to operate, or continue to operate, in Illinois. AEU knows of no one who questions the equity aspects of P.A. 102-0662 but submits that the data collection associated with achieving those goals can and should be done in a practical manner. To that end, AEU is willing to engage with stakeholders to discuss data collection concerns, particularly how data collection requirements can be consolidated and streamlined. But in the meantime, AEU supports the IPA's decision to not collect data on any new workforce characteristics. AEU submits that the release of each AV's aggregated data as described in the Joint NGOs' second objection should be part of that discussion since it is not entirely clear to AEU what the Joint NGOs are proposing. AEU Resp. at 5.

3. JSPs' Position

The JSPs note that the data collection burden is already substantial and the first delivery year with the MES applicable is exactly half-way through. It is premature to expand data collection efforts at this point. The JSPs appreciate the proposal to solicit feedback from AVs about EIEC boundaries although it should be done outside program data collection. While the JSPs oppose the new data collection otherwise, the JSPs wish to particularly emphasize the reporting challenges with "quality opportunities" including information about hours worked is overly burdensome because it is challenging to track an individual's hours for the overwhelming majority of functions (such as sales, administrative, or other professional) that do not involve prevailing wage-eligible construction. JSPs Resp. at 19.

The IPA, Staff, and AEU also oppose additional data collection requirements. The IPA explained that while it already collects some data, that additional data would be additional burdens in an already burdensome data collection process that impacts both the IPA and program participants such as AVs. *See* IPA Resp. at 95. Staff opposed additional requirements in the present docket and recommended that the IPA consult with the Joint NGOs and other interested parties to consider additional reporting in the next LTRRPP proceeding. *See* Staff Resp. at 27-28. AEU opposes additional data collection because of the impacts on worker privacy and burdens on program participants. *See* AEU Resp. at 3-5. Because of the multiple issues with the Joint NGOs' proposals, the Commission should reject the Joint NGOs' proposal or, in the alternative, adopt Staff's proposal to direct the IPA to work with the Joint NGOs and other stakeholders on data collection issues. JSPs Rep. at 26-27.

4. Staff's Position

Staff is not necessarily opposed to additional data collection, but Staff's position is the Commission need not to make specific decisions in this docket as to what additional data to collect. This is especially true for disaggregated demographic information about the applicants. In addition, it is not entirely clear which parts of this proposed additional data should be published and/or is allowed to be published. For these reasons, Staff recommends in its Response that the IPA consult with the Joint NGOs and other interested parties in advance of filing the next plan and include recommendations for additional data collection and publishing in its next plan. Staff Resp. at 27-28. In its Reply, Staff clarifies it defers to the IPA on this issue and accordingly supports the Commission rejecting the Joint NGOs' proposal on this issue. Staff Rep. at 39.

5. IPA's Position

The Joint NGOs object to what they characterize as the IPA forgoing the collection of various types of data that the Joint NGOs claim would better enable assessment of the effectiveness of the EAS. The Agency agrees that robust performance metrics will be critical in performing the EAS Assessment but disagree that all the data identified by the Joint NGOs should be included as mandatory reporting under IPA programs. First, the IPA already collects several of the elements listed by the Joint NGOs. JNGOs Obj. at 11-12. The Agency is open to offering the option to report on other protected class characteristics, such as national origin, language, and disability status, but does not agree that these items should be mandatory. The Agency already has had a difficult time collecting the data required by the IPA Act and AVs often must trace workforce data through multiple subcontractors. The Agency disagrees that adding more reporting requirements would improve the quality of data received by the Agency. IPA Resp. at 94-95.

While the IPA appreciates the value of understanding the diversity of the workforce, it is not a workforce development agency. Thus, it also objects to the Joint

NGOs recommendation that the IPA collect detailed data on the participants of the workforce hubs administered by its sister agency, the Department of Commerce and Economic Opportunity ("DCEO"). Almost all those programs span industries across the clean energy sector, not just solar installation, so the Joint NGOs' proposal would require the IPA to collect data on training programs wholly irrelevant to IPA programs and procurements. Furthermore, the Agency is actively collaborating with DCEO on aligning approaches to data collection and sharing that data. There is no need to duplicate efforts. The Agency urges the Commission to reject any proposal that the IPA collect data on individuals outside of its programs and procurements. IPA Resp. at 95-96.

The Joint NGOs object to what they characterize as "the exclusion of aggregated data collection and reporting on Approved Vendor compliance with the minimum equity standards." JNGOs Obj. at 12. It is unclear to the Agency whether the Joint NGOs are referring to the collection of demographic and geographic data regarding the project workforce or whether they are referring to the number of EEPs in the project workforce, which is the data used to assess compliance with the MES. The former is collected from all project workforce participants, whereas the latter focuses on the number of EEPs. The Joint NGOs argue that "Approved Vendor level data" is important to "prove compliance with P.A. 102-0662's standards," (JNGOs Obj. at 12) which the IPA understands to mean the MES, implying that the Joint NGOs are asking the Agency to publish the data on the total percentage of project workforce made up of EEPs for each AV. Yet the Joint NGOs then provide suggested language for Section 10.4.1, which describes the statutory requirements regarding collection of demographic and geographic data on the entire workforce, not those individuals' qualification as an EEP. IPA Resp. at 96.

Without clarity on what the Joint NGOs are requesting, the IPA cannot fully assess the merits. The Agency believes that its commitment in the 2024 Plan to publish aggregated data on both the reported demographic and geographic makeup of the project workforce and the compliance with the MES will provide sufficient transparency as to the efficacy of the EAS. The EAS Assessment will contain analysis of that data and the Equity Portal will provide visualizations of the aggregated data as well. If these measures still do not provide the information sought by stakeholders, the Agency may reconsider them in the next Long-term Plan. IPA Resp. at 96-97.

AEU and the JSPs both opposed the Joint NGOs' objection that requested the Agency collect more and different types of workforce data. The IPA agrees with AEU and the JSPs and opposes the Joint NGOs' proposal. IPA Rep. at 66-67.

Staff takes no position on the substance of that proposal but recommends that the Agency work with the Joint NGOs and other stakeholders outside of this proceeding to determine the best approach to data collection and publication. The Agency takes no position on this item and asks the Commission to determine what is appropriate for the Plan in this proceeding. IPA Rep. at 67.

6. Commission Analysis and Conclusion

The Commission agrees with the IPA, AEU, and JSPs and does not adopt the Joint NGOs proposal to require additional data collection at this time. The opposing parties do not contest the value of understanding the diversity of the workforce, but question whether the collection of certain data is valuable or practical. The Commission appreciates the

IPA for taking steps to improve its data collection through collaboration with DCEO and notes that the EAS Assessment and the Equity Portal will provide further information and transparency about the data that is currently being collected. Both Staff and the IPA suggest that additional data collection could be reconsidered in the next Long-term Plan. The Commission agrees and encourages the stakeholders to have further discussions within the process described in Section VIII.B.2 and VIII.B.3 above, to explore whether additional data collection will be insightful and not overly burdensome to program participation.

IX. MISCELLANEOUS

A. Ameren's Technical Corrections

In Objections, Ameren raises three technical corrections to the LTRRPP. Two of the corrections are addressed by the IPA and discussed above in the relevant Sections. The remaining objection addresses Ameren's wind RECs. The IPA does not appear to have objected to this correction. Accordingly, it is adopted.

B. Appeal Process

1. Equity Solar Illinois' Position

The current process for appealing an adverse determination by the Program Administrator is unclear and hard to navigate. What little guidance there is on this topic (from the Program Guidebook, at 60) simply states:

> If an Approved Vendor or Designee elects to appeal a determination made by the Program Administrator related to application review or any other Program requirement, it must email the appeal to the Program Administrator at admin@illinoisabp.com. The appeal should be on the Approved Vendor or Designee's letterhead, be addressed to the Illinois Power Agency, contain the reasons for which the Approved Vendor or Designee believes the appeal should be granted, and be accompanied by any supporting documentation.
>
> Unless otherwise provided, the Approved Vendor or Designee will have no more than two weeks to appeal a determination made by the Program Administrator, after which the determination may no longer be appealed.

ESI Obj. at 14.

The IPA should provide improved clarity around the IPA appeals process under the Long-Term Plan, and not just in the Program Guidebook. There should be a structure followed for all appeals including expected timeline for agency decision, clarity about tolling of deadlines under dispute, and the ability to track the status of project-related appeals in the program portal. More specifically, as our minority partner suggested in their feedback to the IPA dated September 29,2023, the IPA should include language in the Long-Term Plan to update the Program Guidebook to provide the following (or similar) clarification regarding the process for IPA appeals:

> 1. IPA shall acknowledge its receipt of an application's formal appeal within five business days and toll any relevant program-related deadline during the pendency of the appeal.
>
> 2. IPA should endeavor to promptly collect and/or request any other information relevant to the appeal (including via conference call with the applicant), and to issue its considered determination on the appeal within 30 business days or as soon as possible thereafter.
>
> 3. Application may appeal an adverse IPA appeal decision to the ICC, as long as they do so within ten business days.

ESI Obj. at 15.

2. Commission Analysis and Conclusion

The Commission does not see that any party has responded to this proposal. Although it may be appropriate to include language in the LTRRPP regarding how to appeal an adverse decision by the Program Administrator, the Commission does not agree that these decisions can necessarily be appealed to the Commission. ESI provides no support for this proposal. The Commission notes that the IPA, in its BOE, provided detailed information regarding its appeal process and where the process is explained in the applicable IPA publications.

X. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record herein and being fully advised in the premises, 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 2024 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 2024 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 2024 Long-term Renewable Resources Procurement Plan is hereby approved.

IT IS FURTHER ORDERED that the Illinois Power Agency is directed to file with the Illinois Commerce Commission a compliance filing within 60 days of this Order consistent with the findings herein.

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 20th day of February, 2024.

(SIGNED) DOUGLAS P. SCOTT

Chairman