[Redacted] (collectively "[Submitter 6]") appreciate the opportunity to comment on the second draft of the REC Contract.

As an initial matter, [Submitter 6] greatly appreciate the improvements that the IPA has made to the REC Contract between the initial draft and the second draft released on January 11. [Submitter 6] support improvements made to several sections, including collateral drawdowns for underdelivery of RECs, changes to the assignment provision, and definition of how subscription levels are calculated. [Submitter 6] further appreciate the IPA's invitation to make further comment on these sections to further refine their effect.

Cover Sheet

Section 5(b)(iv)

[Submitter 6] appreciate the edits to this section to conform with the LTRRPP. However, [Submitter 6] recommend that the IPA expand the delay for interconnection in limited cases where the system is not electrically complete. Specifically, [Submitter 6] are concerned about scenarios such as the following: For a system further back in queue, ComEd—in following the modified Interconnection Agreement language approved in ICC Docket No. 18-1583—takes potentially over a year from the lottery to provide a final non-binding estimate to a system that is as early as fourth in queue.[1] For a community solar project that is fourth in queue or later, the developer is facing delays due to a process over which the developer has no control. That developer should not be forced to get their system electrically complete to receive an extension (without a substantial deposit) for energization. The potential delay in receiving non-binding cost estimates was not contemplated during the LTRRPP approval process, but should be considered here.

Section 5(e)(iv)(E)

[Submitter 6] appreciate the IPA explaining the standards for establishing subscription levels and subscription mix. [Submitter 6] credit the IPA for setting a standard for evaluating subscriptions that is straightforward to calculate and is reasonable, although additional clarification is necessary for how "daily" subscriptions are measured. For instance, it is not clear when subscriptions may be enrolled or disenrolled effective that day. In other words, if a customer adds or drops their community solar subscription effective on January 18, it is not clear—and may vary by utility or for the same utility over time—whether that customer is considered enrolled or disenrolled for that day. [Submitter 6] recommend the IPA put together a workbook as it has for other appendixes to further describe the calculation.

Another effect of the utilities not yet unveiling their procedures for adding and dropping subscriptions is a lack of clarity on the feasibility of fully subscribing on a particular day. For instance, it is not clear how much lead time each utility will require before enrolling or modifying a customer's subscription (however the effective date is treated). [Submitter 6] further understand

[1] This scenario was calculated using ComEd's estimates of 60 business days for each restudy and the required ten business days for a developer to decide whether to provide written project authorization. The first three in queue could take 210 business days, plus a 60 business day restudy of the fourth in queue position.

that the utilities may only allow a subscription to be added or dropped at the beginning of a billing cycle.

Unless the utility allows for same-day enrollments, there will be a date each quarter such that no subscription drops can be replaced. To illustrate, if utilities require five business day notice to add, any subscriptions dropped on June 23 or later will not be replaceable before July 1. In addition, it is not clear whether a utility will allow an Approved Vendor to begin the enrollment process if no subscriptions will be available until during the enrollment window. To illustrate, if the utility requires five business day advance notice, the utilities have yet to confirm that an Approved Vendor can provide notice on June 20 to switch on June 27 if capacity will not become available until another customer drops on June 24. This timing matters because, as noted above, under the five business day advance notice requirement June 24 will be too late to begin the enrollment process to be effective by June 30.

Because the utilities have not finalized these procedures and they are subject to change over time, a better approach would be to make the maximum payment based on the *highest* of the subscription mix at energization and the four quarterly reports. Of course, [Submitter 6] are not suggesting that the IPA change the approach of setting the first four quarterly payments and the energization payments based on the actual subscription percentage and mix for those quarters. However, the remaining 60% of contract value after the fourth quarterly payment should be based on the highest subscription level and subscription mix between energization and the first four quarterly reports.

Section 6(d)(v)

If, on the portfolio level, a performance shortfall is resulting in an aggregated drawdown in exceedance of $5,000, the payment should be made within 90 days.

Section 6(e)

[Submitter 6] are generally comfortable with the approach of this section, but recommend that the IPA make the following clarifications:

- With regard to subscription mix, an Approved Vendor only has to continue to maintain the *range* achieved in the final quarterly report, not the percentage. By way of example, if an Approved Vendor had 70% small subscribers (by capacity) in the final quarterly report, it should be able to maintain small subscriber levels as low as 50% in future annual periods and not have a reduction in payments. Similarly, if a system has 85% small subscribers in the final quarterly report, the obligation in future annual periods should only be 75% small subscribers.
- Similarly, if in the final quarterly report a system achieves a subscription mix and the system in a future annual report achieves a subscription mix sufficient to trigger a REC adder (for instance, 26% small subscribers) that is lower than the final quarterly report (for instance, 75%), the collateral drawdown should be the difference between the REC with the 75% small subscriber adder and 25% small subscriber adder, rather than the 75% small subscriber adder and no small subscriber adder.

Section 6(h)

[Submitter 6] understand the purpose of Section 6(h) to be as follows:

- Start with an Approved Vendor's RECs generated in excess of delivery obligations from previous years, the "surplus" RECs;
- Assess the shortfall (if any) of RECs for the current delivery year
- Apply surplus RECs toward the shortfall
- If there are fewer surplus RECs than are needed to make up the shortfall, then:
    - REC shortfalls are evaluated on a system-by-system basis
    - For systems that had a shortfall, surplus RECs are applied starting with the system with the lowest value RECs.
    - The Approved Vendor will face a collateral drawdown equal to the value of the REC obligations not offset by surplus RECs.

[Submitter 6] recommend that the IPA apply surplus RECs to the highest value REC first, not lowest. At minimum, for Approved Vendors with community solar systems or systems of varying size, the IPA should apply surplus RECs from systems with small subscriber adders to other systems with the same category of small subscribers or RECs from smaller systems (with higher REC values) to systems in the same size range for Adjustable Block pricing purposes. Such an organizing principle avoid unnecessarily penalizing an Approved Vendor with a variety of system types and sizes where REC pricing wildly varies.

In addition, [Submitter 6] believe that this section would benefit from clarifying that in the event of a REC shortfall, only *systems* with a shortfall are considered for payment calculation purposes. In addition, [Submitter 6] believe that the section would benefit from a clearer transition between when the contract considers RECs to be undifferentiated to when RECs are first assigned a value.

Section 12(e)

[Submitter 6] understand that GATS allows for two methods of inputting meter data: inputting monthly generation or the lifetime meter read, allowing GATS to automatically calculate the monthly generation (based on the previous month's report). [Submitter 6] understand that a number of systems use the lifetime meter read approach. The REC Contract should explicitly allow that form of reporting.

Modification to Section 5.1 of the REC Agreement

The agency made it clear that there is to be no cross-default between projects within the same master contract with a single utility Buyer. [Submitter 6] appreciate that clarification, but it should be clearly and explicitly memorialized in the contract—perhaps as a statement in the preamble of Section 5.1. While [Submitter 6] recognize that the Cover Sheet does delete the cross-default section, a clear statement in Section 5.1 or other appropriate location would be more powerful. In addition, [Submitter 6] recommend that the IPA clarify that:

- Section 5.1(e) is a potential default on the Designated System level, not the master contract level (impacting all Designated Systems).

- For Section 5.1(b), the event of default is cured immediately when the payment is made, divesting Buyer the right to terminate pursuant to Section 5.2.

Modification to Section 9.2 of the REC Agreement

[Submitter 6] devoted a substantial amount of discussion to assignment—both for financing purposes and other purposes—in the first two rounds of comments. The updated assignment provision is an improvement over the initial draft. In particular, allowing for assignment at the Product Order level is a major step forward.

[Submitter 6] recommend the IPA make the following clarifications:

- The requirement that any assignment under the REC Contract be to an Approved Vendor should be modified to only apply to *direct* assignments. Notwithstanding the grace period noted immediately below, as currently drafted the REC Contract is susceptible to an interpretation—which [Submitter 6] believe the IPA did not intend, given other language about collateral assignment—that a collateral assignee has to register as an Approved Vendor for such collateral assignment. As [Submitter 6] have noted below and elsewhere, it is not realistic to expect the majority (or even many) financial institutions to be willing to register as an Approved Vendor given the necessary disclosures and attestations.
- In the event that a financing party forecloses on the system and obtains the REC Contract, or otherwise exercises legal remedies impacting rights to the REC Contract, the financing party should have 180 days to begin and diligently pursue the registration process as an Approved Vendor (rather than 120 days to complete the process) or transfer the system to an Approved Vendor. As [Submitter 6] noted in earlier comments, it is impractical to expect banks of any size to register as Approved Vendors, although some financing parties may elect to do so.[2] [Submitter 6] believe 180 days is a reasonable length of time for a financing party to sell the system to an Approved Vendor and assign the REC Contract with it. While 120 days may seem like a sufficient window to execute a transaction, in reality these types of transactions often take up to six months. Extending the allowable window would alleviate a time crunch that could result in sub-optimal process and costlier transactions for all involved. The IPA should also clarify the start date for the 180 days (such as the date of foreclosure)—making such a clarification is likely to prevent disputes about the 180 day window at a later date.
- Collateral assignment is distinguishable from a direct assignment, because the collateral assignee only has a contingent right to the contract. In other words, if a bank provides debt financing, it will not take immediate assignment of the REC Contract at the time of financing—it will only acquire the right to do so in the event of foreclosure. The IPA should remove Buyer's discretion to determine whether an assignment qualifies under the financing carveout, as exercise of such discretion undermines the purpose of the carveout for collateral assignment—namely, transactional efficiency.
- If Buyer assigns to an affiliate, the assignment must be to an affiliate with an investment grade credit rating at the time of assignment (not the Effective Date). [Submitter 6] note

[2] [Submitter 6] note that issues with registration as an Approved Vendor are not limited to large, publicly traded banks. In addition, private banks may be sensitive to disclosing their shareholders—especially if those shareholders are not natural persons thus triggering additional reporting.

that a key tenet of financeability of the REC Contract is the creditworthiness of the counterparty. Utilities tend to have investment-grade credit ratings. The threat of assignment to a non-investment grade rated affiliate could cause at minimum degradation of available financing terms; Buyer's assignment during the term to a non-investment grade affiliate may lead to an event of default in the financing agreement between Seller and its financing party or parties.

- There is reference to providing the Buyer with "pertinent financial, settlement, and contact information" in the event of an assignment to another Approved Vendor or for financing. [Submitter 6] are unclear what pertinent financial or settlement information would be for these purposes, and are concerned about Buyer possessing the ability to delay or cloud a transaction by continually requesting more "pertinent" information (without regard to whether [Submitter 6] believe Buyers will ever actually use that ability). Information provided to Buyer should be limited to contact information.
- In previous comments, [Submitter 6] suggested the approach that surplus RECs should stay with the assignor's account. However, upon further consideration, this approach raises concerns with stranded carryforwards if an Approved Vendor sells some or all of its assets after the project is energized. A better approach would be for carryforwards to be assignable with a Product Order per instructions of the assignor Approved Vendor (except in the case of collateral forfeiture). To be clear, [Submitter 6] are not recommending that surplus RECs be independently assignable, only that surplus RECs in any amount specified by the assigning Approved Vendor to an assignee Approved Vendor.

In addition, [Submitter 6] have some concerns about assignment fees.

- As an initial matter, [Submitter 6] recommend that assignment payments to the utility go back to the Renewable Resources Budget. It is not clear that a utility needs $5,000—or even $1,500—to cover any costs.
- [Submitter 6] recommend that the IPA clarify that the $1,500 fee applies to the first time a specific Product Order is assigned and the $5,000 fee applies the second time that same Product Order is assigned. In other words, an Approved Vendor should pay $1,500 to assign each Product Order if it has multiple Product Orders, not $1,500 for the first Product Order then $5,000 to assign a separate Product Order for the first time.
- [Submitter 6] recommend a fee of $1,000 instead of $1,500 and $5,000. While [Submitter 6] do not anticipate that systems will be assigned a large number of times or for frivolous reasons, industry-standard financing processes often require assets to be transferred more than once before they are sold to a long-term passive investor. Feeds associated with these transactions should be priced to cover any real, incremental administrative expenses; they should not be punitive.
- No assignment fee should apply to an Approved Vendor assigning to an affiliate.

Default and Remedies

The REC Contract was modified to extend the time to demonstrate that a default has not occurred from five to 15 days. [Submitter 6] appreciate this increase in time, but recommend further extending to 30 business days. In addition, [Submitter 6] recommend 90 days—as opposed to 20 days—to cure a default with an allowance for a mutually agreed extension if the Approved Vendor is diligently seeking to remedy. These timelines are standard industry practice in other states and private transactions.

Force Majeure

Currently the REC contract does not exclude economic curtailment claimed by the Buyer, which may not be acceptable to financiers. While [Submitter 6] are not attempting to supersede Ameren or ComEd's Smart Inverter Rebate tariffs, the utility buyers should not other than the Smart Inverter Rebate tariffs have the ability to engage in economic curtailment.

Limitation of Liability

Currently the REC contract does not include any monetary cap to limit the Seller's liability. In typical industry contracts, especially private contracts, Seller's liability is capped at the total value of the contract.

Letter of Credit

To the extent REC collateral is placed in the form of a Letter of Credit, it must be in 1 of 2 forms attached as Exhibit E to the REC agreement. Though there is standardization in the market with respect to the forms of Letters of Credit, certain banks may have their own particular requirements or adjustments to the forms proposed, and may not have the flexibility to accept verbatim the two options in the REC Contract. In order not to unduly restrict the pool of potential banks able to issue this form of credit support (which is often more cost effective than a cash deposit), [Submitter 6] propose adding the qualifier that any Letter of Credit will be in "substantially in the form of" the attachment, consistent with the approach taken by other utilities.

Timing of Collateral

In addition, [Submitter 6] are aware of concerns that projects in ComEd that may be required to provide REC Contract collateral before ComEd has confirmed a non-binding cost estimate. [Submitter 6] anticipate that other commenters will thoroughly address these issues and potential solutions for the IPA to consider implementing in the REC Contract.