INITIAL REC CONTRACT COMMENTS ON BEHALF OF [Commenter 6]

[Commenter 6] appreciate the opportunity to provide comments on the REC Contract. The [Commenter 6] hope these comments and the attached proposed REC Contract language changes addressing many of the items discussed below are the first step in productive dialogue to improve the REC Contract.

A Second Round of Comment

[Commenter 6] recommend that the IPA hold an in-person workshop during the first week of January and provide for a second round of comments to more fully address the issues in the contract. At nearly 40,000 words and not written out as a single unified contract, the REC Contract represents the final product of the 18 months of regulatory proceedings involving stakeholders, the Commission and the IPA. The REC Contracts will be in place for 15 years and this first round alone will collectively govern the purchase of hundreds of millions of dollars of RECs in satisfaction of the state's renewable portfolio standard. Therefore it is imperative that the contract reflect the sum total of these proceedings and create a reasonable covenant between utilities (buyers) and Approved Vendors (sellers) that will result in construction and operation of solar facilities in Illinois. Such a complex contract cannot be fully vetted by the parties to the contract in a single round of comments. As such, [Commenter 6] strongly urge IPA to hold a workshop and allow a second round of comments. [Commenter 6] believe both of these are possible without delaying the program's January 15 launch date.

Threats to Financeability

Based on the experiences of the members of [Commenter 6] in seeking and obtaining financing for a wide range of solar projects—including those relying in part on a state incentive program—there are certain "red flags" that throw financeability of a project into doubt. [Commenter 6] wish to make clear that these issues are not stylistic disagreements or even features that could make financing marginally more expensive. These are issues that the developers taking part in [Commenter 6] have flagged as severely impairing financeability even to the point projects using the REC contract being completely unfinanceable.

Master Contract. As an initial matter, [Commenter 6] assume that a utility may execute a master contract that applies to all systems in a single batch, but not multiple separate batches. However, given the language of the LTRRPP and the REC contract itself, it is unclear if the IPA intended to allow each utility a single master contract between a utility and a developer for multiple systems that cross batches (for example, multiple 2 MW (AC) systems). The latter—especially to the extent that the REC Contract appears to treat collateral across all projects under a single REC Contract as pooled—would be disastrous for financing.

The use of a Master REC Agreement is incredibly problematic and creates enormous financing difficulties, especially for smaller players or any party seeking to buy or sell a project to another party. Absent some amendment to the Master Agreement (described below) the IPA may see greatly diminished participation and potentially even risk missing REC procurement targets. When a financing party reviews a master agreement for a revenue stream such as RECs, the financing party—especially if the financing party is not the sole financier of all of an Approved Vendor's projects—will want safeguards so that issues with one project will not infect other projects. In other words, if the default of a single project leads to a default of all projects—or a loss by one project leads to a setoff of revenue from other projects—[Commenter 6] believe there will be a strong likelihood that this REC contract will render projects unfinanceable or only financeable by a small handful of entities.

Further, if a project-specific contract cannot be separated from a master contract, it will be difficult or impossible for the holder of that master contract to transfer all rights to another party. In this way, the Master Contract structure could severely limit project transactions.

The IPA should revise the cover sheet and master contract to make clear that, other than considering all systems on a portfolio-wide basis for REC delivery adequacy and pooling collateral (as required by the LTRRPP and Final Order), each project contract is considered independently and there are no other opportunities for setoffs or cross-defaults. Language should be added to Section 1(b) of the cover sheet to clearly state there are not to be setoffs or cross-defaults. Article 5 of the Master Agreement should also make clear that default is exclusive to a project or batch.

Determination of Subscriber Levels. The REC Contract creates tremendous financial pressure on the determination of subscriber levels—both overall subscribers and small subscribers—but provides no insight into how subscriber levels are actually calculated. Without clarification of how subscriber levels are calculated, it is not possible to foreclose commercially unreasonable interpretations (such as deciding that if there is even a day discontinuity in 100% subscription within a reporting period that a system is not 100% subscribed). [Commenter 6] describe *infra* a commercially reasonable way to assess subscriptions that will not undermine financeability.

Assignment to Financing Parties Without Consent. [Commenter 6] address a substantial number of issues with regard to the assignment provision *infra*. However, at least one issue related to assignability is also a financeability issue: the Approved Vendor must be able to assign the REC Contract to a financing party without counterparty consent.

<u>Global Issue: Inconsistency With Transaction And LTRRPP</u>

In several areas, the contract refers to or suggests affirmative action by Seller to transmit RECs to Buyer. [Commenter 6]'s understanding—which is reflected elsewhere in the REC contract—is that the Seller is required to execute a 15-year irrevocable standing order to transfer RECs. If that is the case, the references to trade dates or trades by affirmative action of Seller should be eliminated.

There are several areas where the contract appears to not be consistent with the LTRRPP. For example:

- **Cure Period:** The LTRRPP sets a cure period of 90 days. (*See* Final Approved LTRRPP at 139 ("Approved Vendors will be given 90 days to cure any deficiencies found by the Agency and/or utilities.")

- **Collateral Reduction**: The LTRRPP and Final Order make clear that collateral reduction for failure to deliver sufficient REC quantities must be on a three-year rolling average basis, which is not reflected in the REC Contract. That issue is covered in more depth *infra*.

<u>Global Issue: IPA Obligations</u>
Although the IPA is neither a party nor a third-party beneficiary to the contract, the IPA makes several determinations and has obligations to provide information (such as the Quarterly Netting Statement or assessment of Maximum Allowable Payment) with no explicit deadlines, standards of performance, or dispute resolution. Whether part of this contract or in a separate document, the IPA should set out its processes and deadlines for providing its deliverables and the process for dispute resolution in case an Approved Vendor disputes a decision or action of the IPA under this REC contract.

<u>Unnecessary Ambiguity In Recapture:</u>
In at least two places in the REC contract, there is ambiguous language about a potential recapture of payment in the event of early termination. The instances are in Section 2 (Term) and the second is in Section 4 (Facility Information). A better approach to contract structure would be for recapture to be handled either in the early termination section or in a separate recapture section. No matter where it is place, the IPA should more formally define the formula used to determine payment recapture. That formula will be of importance to financing decisions. In addition, the IPA should integrate the following exclusion language in Sections 2 and 4(d): “If termination is not due to default party, no Settlement Amount or Termination Payment shall be due from or to either party as a result of any such termination.”

<u>Determination of Subscription and Small Subscriber Levels</u>
The REC contract does not define how the IPA will evaluate subscription levels. For any Approved Vendor seeking to serve Small Subscribers—who typically have a higher turnover rate—or offer shorter-term contracts (which the IPA appears to otherwise favor), the REC contract must answer how customer churn impacts the IPA’s assessment of subscription levels.

This question is significant because depending on when a customer terminates a subscription and the practical limits to how fast a new customer can be signed up under the marketing rules—to say nothing of utility limits on enrollment and disenrollment—a system may have subscribers interested at all times but some time periods where a system is less than 100% subscribed due to time lags between customer drops and customer enrollments.

The same issue arises for percentage of Small Subscribers. This percentage may be variable during a reporting period due to customers leaving joining shorter-term contracts. The IPA should evaluate compliance with Small Subscriber percentages on an average basis (i.e. if the mean of all monthly Small Subscriber percentages is 75% or above, the IPA should deem those facilities to meet the 75% Small Subscriber threshold even if for certain days the percentage was lower).

While such an approach will work for Small Subscribers, it will not for the total subscription percentage because a system cannot be over 100% subscribed at any given time. Thus, the [Commenter 6] recommend that overall subscription levels be evaluated at the end of the relevant report (i.e. year or quarter). In the alternative, [Commenter 6] request a safe harbor so that a system that is (for instance) 100% subscribed at the end of the reporting period and was no less than 85% subscribed on any given day is deemed to be 100% subscribed.

Energization of Designated Systems (Section 5):
Section 5(b) outlines a number of circumstances in which the Scheduled Energized Date for a Designated System may be extended but does not appear to include general Force Majeure events, unless the IPA intended 5(b)(v) to cover general force majeure events. If that is the case, Section 5(b)(v) should be clarified to state that it is intended to be the section addressing force majeure events not explicitly addressed in other provisions.

In addition, Section 5(b)(iv) suggests that in the event a system is electrically complete but a utility does not energize, extensions only are allowed 365 days at a time. The Final Approved LTRRPP stated as follows:

> An indefinite extension will be granted if a system is electrically complete (ready to start generation) but the utility has not approved the interconnection. The Approved Vendor must document that the interconnection approval request was made to the utility within 30 days of the system being electrically complete, yet not processed and approved.

(Final Approved LTRRPP at 132.) Section 5(b)(iv) should be consistent with the LTRRPP.

Section 5(e) outlines a process for reducing the REC payments to account for projects which do not achieve a sufficient level of small subscriber participation, the REC Contract is silent on whether the adder can be trued-up for projects which are able to exceed the proposed small subscriber threshold. For example, if a project commits to achieving 50% small subscribers upon Project Submission into the ABP, and is able to hit the 75% small subscriber threshold by Energization, then the project should be able to receive a higher small subscriber adder. Projects which are able to over deliver small subscribers should be rewarded for their ability to help the IPA achieve its long-term goal of ensuring "robust participation opportunities for residential and small commercial customers" (20 ILCS 3855/1-75(c)(1)(N). Because the IPA will be reviewing all project applications at Energization to validate the actual level of small subscribers, the [Commenter 6] propose that if it is determined that some projects miss their proposed small subscriber participation target, then the balance of available funds be available to reward those projects which are able to over deliver on their proposed small subscriber target into the next category.

Five Percent Threshold
Consistent with the comments of the [Commenter 6] on the Guidebook and final lottery guidelines, a greater than 5% capacity change (increase or decrease) that does not invalidate the facility's Interconnection Agreement should be allowed to proceed. The IPA provided more than sufficient (to the extent that it is independently burdensome) protections by requiring the contract be based on the lesser of the original estimate and the as-built capacity as measured in AC. Thus, Section 5(f) should be deleted in its entirety.

Deliveries and Quantity (Section 6):
Section 6(b) is ambiguous as to whether a reduction in a standing order to reflect reduced REC obligations (*see, e.g.*, Final Approved LTRRPP at 134 (contemplating reduced REC delivery requirements for undersubscribed community solar facility)) would be the extent of the Buyer's (utility's) right to RECs. Section 6(b) should be clear that in the event a Standing Order is reduced to below 100% of system output due to a reduction in REC delivery requirements, that (1) the utility assist in effectuating that change, and (2) the utility is not entitled to RECs beyond what is required by the then-in-effect Standing Order.

Section 6(c) appears to require use of a standard degradation factor of 0.5%. [Commenter 6] addressed this issue in comments on the Guidebook, noting that different panels degrade at different rates. Although [Commenter 6] believe that 0.5% is a reasonable default, it should not be required if an Approved Vendor has panels with different technical specifications.

In Section 6(d), the REC contract does not reflect the requirement from the LTRRPP that collateral drawdowns—at least for collateral drawdown purposes—must be evaluated on a three-year rolling basis. As the Final Approved LTRRPP stated: "However, because weather and other factors may impact annual production values, **REC delivery performance will be evaluated on a three-year rolling-average basis**, although any overproduction may be carried forward (or 'banked') for performance evaluation and collateral purposes into future contract years without expiration." (Final Approved LTRRPP at 137 (emphasis added).) This section should be modified to address this issue. Further, the Agency should not draw on collateral until after the first three-year period has completed and the rolling average has been assessed. And if a collateral is drawn upon, an Approved Vendor can recover the drawn collateral with REC surplus.

In Section 6(e), the IPA provides that the utility may draw an undefined "monetary amount, determined by the IPA" In the event of undersubscription. First, the IPA should adopt [Commenter 6] clarifications above to remove ambiguity about how to evaluate subscription levels. Second, the formula for these penalties should be clearly set out in the contract itself, and should be consistent with the Final Approved LTRRPP:

> For community solar projects, subscription levels must be maintained to remain eligible for REC payments. If the annual report shows that subscriber levels have fallen below 50% of the systems' capacity on a rolling average basis, then if REC payments are still due, those payments will be reduced as described earlier in this chapter; if all payments

> have been made, then the Agency will work with the applicable utility on what remedies should be taken including drawing on collateral.

(Final Approved LTRRPP at 139.) The Final Approved LTRRPP sets the subscription level at which the IPA will take action—at least after payments have been made—at 50% of the system's capacity on a rolling average basis. The contract should reflect this clear language.

Reporting (Section 10):
Generally, the contract imposes a heavy reporting requirement, including an annual, bi-annual and quarterly requirement, for a total of 7 reports per year. Some of this reporting can and should be automated by the utilities that hold this information (at least the three investor-owned utilities).

Section 10 (b) imposes strict reporting deadlines that are undefined and unreasonable; missing those deadlines results in default. [Commenter 6] note that the Final Approved LTRRPP requires a 90-day cure period in the event of a default, yet the Contract does not clearly allow an Approved Vendor a full 90 days to cure after being notified of a deficiency. (*See* Final Approved LTRRPP at 139.)

Risk Allocation (Section 9):
Change in Law (Section 9) -- Generally, Seller takes change of law risk once it represents that RECs comply with regulatory requirements (e.g., meets the definition of "Regulatorily Continuing"). In the event of this or any other termination by the utility, the utility should immediately grant authority to terminate the standing order and return all RECs not yet retired.
Master REC Agreement:
When a financing party reviews a master agreement for a revenue stream such as RECs, the financing party—especially if the financing party is not the sole financier of all of an Approved Vendor's projects—will want safeguards so that issues with one project will not infect other projects. In other words, if the default of a single project leads to a default of all projects—or a loss by one project leads to a setoff of revenue from other projects—the [Commenter 6] believe there will be a strong likelihood that this REC contract will render projects unfinanceable or only financeable by a small handful of entities.

The IPA should revise the cover sheet and master contract to make clear that, other than considering all systems on a portfolio-wide basis for REC delivery adequacy and pooling collateral, each system is considered independently and there are no other opportunities for setoffs or cross-defaults.

Article 2.2 (Payment)
In the final paragraph referencing the utility's cost-recovery, the utilities should have a duty to mount a reasonable defense of their cost recovery and an absolute prohibition on exercising any out if the utility affirmatively advocates for (or does not actively oppose) disallowance in a regulatory proceeding that limits the utility's cost recovery. In other words, the utility should

not have the moral hazard of being able to benefit from its own actions or inactions that jeopardize cost recovery.

Article 5.3 (Net Out of Settlement Amounts)
The due date for a Termination Payment being within two (2) business days is commercially unreasonable. It should be changed to thirty (30) business days, which is standard industry practice.

Article 6 (Force Majeure)
Force Majeure excludes insufficiency or unavailability of insolation to operate the designated system. However, typical industry standards are such that if insolation falls below 80% than predicted in 3 consecutive years, it can be viewed as an act of God. The parties recommend that insufficiency or unavailability of insolation to operate the designated system should not be a termination exercise right, but instead a right that the claiming party can use to adjust performance expectations and collateral liability. However, per page 19 of the contract, the Seller should be relieved from the obligation if such an event occurs and no termination payment is due to either party.

Section (iv), "curtailment for economic purposes only…", is a right the Seller should have, and should not be excluded from Force Majeure. If a curtailment event occurs given utility action for economic reasons, the Seller should have the right to claim Force Majeure to adjust performance expectations. However, the utility (Buyer) should not have such a right. We recommend replacing (iv) with the following language: "Buyer may not claim Force Majeure for economic curtailments made by the interconnected utility or RTO responsible for the operation of the distribution or transmission system to which the Designated System(s) is interconnected."

Article 5(f) (Events of Default; Remedies)
The contract requires failures to be remedied within 20 business days. Industry practice is 90 business days, especially for commercial projects. In addition, if such failure is not remedied within 90 Business Days after written notice, and if such failure cannot be reasonably remedied within 90 Business Days and the Party is diligently pursuing a remedy, the parties should explore a reasonable extension that can be mutually agreed upon.

Article 9.2 (Assignment)
This section is commercially unreasonable, mostly (but not exclusively) stemming from the utility acceptance provisions. This section should be substantially rewritten consistent with these comments in addition to the recommendation *supra* to allow for assignment to financing parties without consent.[1]

[1] Financing parties should also be exempt from the Approved Vendor requirement as long as the financing parties post and maintain collateral.

As an initial matter, the utility acceptance provision is far too broad. [Commenter 6] do not agree that the assignee should have to be an Approved Vendor (especially if it is an end-use customer buying a behind-the-meter system interconnected behind their meter). Whether or not the assignee is ultimately required to be an Approved Vendor, the assignee will still be forced to post collateral (or assume assignor's 5% holdback, letter of credit, or cash). The assignee must accept the entire REC contract and thus will have the same performance obligations as an Approved Vendor.

[Commenter 6] also note that Articles 4.1 (Financial Information) and 4.2 (Credit Assurances) have been deleted from the Master Contract. Thus, there is no reason that the utility should have the right to request the information or assurances in Articles 4.1 and 4.2 in the event of an assignment when it could not do so as part of the (unassigned) contract from the original counterparty.

It is not clear why, given those basic requirements, the utility or IPA should have *any* right to refuse an assignment. There is no reason for the utility or IPA to conduct financial diligence on the assignee—both assignee and assignor have had the IPA conduct their own diligence as part of the Approved Vendor registration process and ongoing reporting obligations. Further, the Buyer already has several actions to ensure seller's credit (e.g. collateral, suspension if collateral isn't maintained, termination and asking for non-delivered RECs). The Buyer's consent should not be required for assignment approval, and should not be unreasonably withheld. The assignee will be posting its collateral as part of accepting the contract.

It is also unclear why there is a blackout on assignment within a certain number of days of a "trade date." Trades are not affirmatively executed quarterly by the Approved Vendor under this REC contract—instead, the Approved Vendor must have a 15-year irrevocable standing order to transfer. There is no harm to the utility counterparty if the REC contract counterparty changes because the transfer will happen the same with both the assignee and assignor (who will also be required to issue an irrevocable standing order for the duration of the REC contract to the extent the standing order is not transferred as part of the transaction between assignee and assignor).

In addition, there should be no ability for Buyer, i.e. the utility, to transfer without an order from the Illinois Commerce Commission. The utility is buying RECs as part of a state program. The contract is in part conditioned on rate recovery, allowing potential gaming by utilities to seek to avoid contractual obligations by assigning the contract to a creditworthy affiliate and the creditworthy affiliate claiming they do not receive rate recovery (or, if the affiliate is a utility in another state, that Section 4(a) of the cover sheet is now violated). [Commenter 6] can see no reason why a utility would be allowed to—much less have a legitimate reason to—assign this contract unless explicitly directed to do so by order of the Illinois Commerce Commission.

<u>Exhibit A and B Issues with Batch PTO:</u>
These exhibits currently require a batch to have the same PTO. Section 6.14.1 of LTRRPP the mentions: "Once approved, or modified, each batch will result in a contract with one utility.

Utilities may use one master agreement with multiple confirmations for multiple batches from an Approved Vendor rather than having multiple contracts with the same vendor. The systems within the batch will be listed on a schedule attached to the contract and may not be substituted once approved." "A batch may contain projects in different groups/blocks (and thus with different prices) and with different adders." "The failure of any system to be developed (and thus the forfeiture of any collateral associated with that specific system) will not impact any of the other systems on the same schedule, although the Agency will monitor system failure rates."

There are unique benefits from a performance standpoint to have a batch of projects, but they should not all have the same PTO. The contract terms should allow for the PTO of the last project in the batch serve as the PTO for all and confirm that each project can receive REC payments separately but that the portfolio of as a whole will determine the relative portfolio performance.

<u>Exhibit C:</u>
The utility would be the best source of this information. Specifically, the utility will be making QF payments for "unsubscribed portions" to the extent that the utility's portal does not record 100% subscriptions at all times. To the extent the utility is making QF payments, the utility has determined (and the owner/operator has not disputed) that a portion is unsubscribed.

Similarly, because the utility separately keeps records of the customer class associated with each meter number, the utility will be able to easily determine whether a subscription is for a Small Subscriber (aggregate of less than 25 kW for a single system and attached to a meter associated with one of the rate classes identified by the IPA). While Approved Vendors should have the ability to dispute a utility's report if inaccurate, the utility collects all of the information that the IPA is seeking.

However, if the IPA insists on collecting the information directly from the Approved Vendor, the IPA should remove customer name from the required disclosure. Providing a meter number is sufficient identification, because it is easily confirmable in the utilities' own systems whether a particular meter number is associated with a subscription. [Commenter 6] are concerned that the IPA is unnecessarily associating a customer's name and meter number on a single document, making it vulnerable to data breaches or other misuses.

<u>Exhibit G:</u>
Shortfall / Surplus RECs – Parties to further describe the mechanics related to a prospective shortfall and surplus of RECs, particularly as it might be calculated across multiple systems.