COMMENTS ON THE DRAFT LONG-TERM RENEWABLE ENERGY RESOURCES PROCUREMENT PLAN FOR PUBLIC COMMENT ON BEHALF OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION

The Solar Energy Industries Association[1] ("SEIA") appreciates the opportunity to provide the following comments, recommendations, and specific language changes to the Illinois Power Agency's ("IPA") draft Long Term Renewable Resource Procurement Plan ("LTRRPP" or "Plan") for public comment.

Established in 1974, SEIA is the national trade association of the United States solar energy industry and is a broad-based voice of the solar industry in Illinois. Through advocacy and education, SEIA and its 1,000 member companies are building a strong solar industry to power America. There are 34 SEIA member companies in operation in Illinois working in all market segments – residential, commercial, community solar, and utility-scale – representing millions of dollars of in state investment and a significant portion of Illinois' 4000 solar jobs. SEIA member companies also provide solar panels and equipment, financing, and other services to a large portion of Illinois solar projects.

Our comments are focused on developing a program that efficiently allocates resources, grows a diverse and competitive solar business ecosystem in Illinois, ramps up the State's installation of solar, reduces costs over time, and drives customer and ratepayer benefit. We draw on the experience of our member companies to translate lessons learned from other markets and programs into our recommendations to the IPA.

We are encouraged by the Draft Plan and urge the IPA to use this LTRRPP to establish a program framework that works for the long term, focusing on creating a transparent pathway to 2020 legislative requirements for new solar DG build and allowing for some flexibility to tweak aspects along the way.

We have provided specific comments and suggestions on numerous Sections of the draft Plan. Where we have not provided specific comments, the IPA can assume we are in agreement with the Plan and support the IPA's interpretation. In several Sections we call out our support for what is in the Plan because the language or interpretation is of particular importance to us.

- **Sections 3.17**, **3.17.1**, **3.18**, **3.19**, and **3.20** explain SEIA's assessment of the overall RPS budget and its implications for IPA priorities and planning.
- **Section 6.3** reviews issues with and solutions to block structure.
- **Section 6.5.2** addresses REC adders in community solar, and incentivizing residential/small commercial participation in community solar.
- **Sections 6.6 and 6.16.1** highlight issues with collateral and payment terms.
- **Section 6.9** (as well as **6.10, 6.13,** and **7.6.2**) explores the IPA's proposed "consumer protections" and Approved Vendor requirements, recommending alternatives to fit within Illinois' legislative and business climate.

[1] The views expressed in this document represent the views of SEIA and not necessarily the views of any individual member company.

Although SEIA and the Illinois Solar Energy Association (ISEA) are submitting separate comments, the membership of these two organizations have collaborated very closely and the IPA will see the comments below referenced in ISEA's comments. Additionally, SEIA supports the comments of ISEA on issues related to program design for the onsite residential solar sector to the extent that ISEA's comments do not conflict with the positions taken by SEIA. We look forward to a continuing dialog with the IPA and other stakeholders and look forward to a successful implementation of the RPS.

1.1 Changing the RPS Framework

SEIA generally agrees with the statements made throughout the introduction to the plan, with one exception. We believe the prioritization of new projects should be noted, and we have suggested specific language to that end.

Language Changes:

Beginning on Page 2:

- While the RPS previously contained percentage-based carve-outs for specific technologies, the RPS now contains specific quantity-based targets for RECs from new wind and new solar and brownfield site solar projects. The RPS now specifically prioritizes purchasing RECs from new projects over purchasing RECs ~~These goals must be considered and balanced with the need~~ to meet annual percentage-based goals. The IPA Act explicitly requires the IPA to prioritize new build—including both utility-scale generation and Adjustable Block-eligible (community and distributed)—over meeting overall percentage targets. (20 ILCS 3855/1-75(c)(1)(B).)

2. Legislative/Regulatory Requirements of the Plan

SEIA supports the IPA's outline of the former structure of the RPS and the problems associated with that structure. Indeed, because of budget uncertainty, a disincentive for ARES to invest in new resources (outside of mandated payments to the Renewable Energy Resources Fund), and challenges in using the Renewable Energy Resources Fund on long-term commitments, little RPS-driven development—outside of the 2010 Long Term Contracts, the Supplemental Solar Procurement, and the DG Procurements–has occurred as a result of the RPS. Even the procurements identified above together have resulted in little over 2,000,000 annual RECs from "new" projects, representing less than 2% of utility-delivered electricity. This is rectified in the revised RPS, where new project development is explicitly required and prioritized. (*See* 20 ILCS 3855/1-75(c)(1)(B).)

2.2.5.1. Section 16-111.5(b) Requirements

SEIA recognizes that the Illinois Power Agency Act requires the Draft Plan to cover the Delivery Year 2017, but it also gives clear priority to meeting the new build requirements over meeting the annual obligations.

> In the event of a conflict between these [overall percentage] goals and the new wind and new photovoltaic procurement requirements described in items (i) through (iii) of subparagraph (C) of this paragraph (1) [which includes a reference to the Adjustable Block program], *the long-term plan shall*

> *prioritize compliance with the new wind and new photovoltaic procurement requirements described in items (i) through (iii) of subparagraph (C) of this paragraph (1) over the annual percentage targets described in this subparagraph (B)*.

(20 ILCS 3855/1-75(c)(1)(B) (emphasis and clarifying comments added).) As outlined in later Sections of these comments, SEIA believes that the funds needed to meet the new build requirements will take a significant portion of the RPS budget through Delivery Year 2020, and as a result, the IPA should be conservative in using spot procurements to meet the overall RPS goals.[2]

SEIA agrees with the IPA's definition of "competitive procurement event" and "program" and believes that the IPA should stick to using these two processes for implementation of the RPS. While the Illinois Power Agency Act does not explicitly restrict the IPA from using other methods to procure RECs, it would be confusing to the market to add yet another layer of complexity to RPS implementation. The competitive bid process is a well-known, comfortable process for large scale renewable developers, and has clear parameters around winners. In addition, bidding based on a standard contract solely on the basis of qualification and price has been an effective and appropriate strategy for the IPA, and SEIA sees no reason to depart from precedent. Developing a new process that is more subjective would open the IPA up to increased scrutiny if not legal action, which at minimum would disrupt new procurements. At this time, the IPA should stick to the programs specifically outlined in the law. However, we do believe that the IPA can and should expand the programs and procurements specifically outlined in the law should there be room in the budget for such expansions.

Language Changes:

Beginning on Page 13:

Section 16-111.5(b)(5) of the PUA provides that "[t]he Agency shall prepare a long-term renewable resources procurement plan for the procurement of renewable energy credits under Sections 1-56 and 1-75 of the Illinois Power Agency Act for delivery beginning in the 2017 delivery year," with "delivery year" defined as "the consecutive 12-month period beginning June 1 of a given year and ending May 31 of the following year"—i.e., the first delivery year for which the Plan is developed would be 2017-2018. As a consequence, the IPA believes that although its Plan may not be approved by the Commission until late March or early April of 2018, this Plan should propose procurements necessary to meet "2017 delivery year" targets, as long as funds are available after meeting other goals that have higher priority, as determined by 1-75 (c)(1)(B) of the Illinois Power Agency Act, as well as targets for future delivery years. Further discussion of the prioritization of various goals can be found in Chapter 3, and further discussion of those proposed procurements can be found in Chapter 5.

…

This raises the following question: does the Agency have the authority to propose (and does the Commission have the authority to approve) REC procurement structures different from a "competitive procurement event"

[2] SEIA also notes that the IPA should, based on projected and actual commitments to buy RECs via the Adjustable Block program and utility-scale procurements, periodically monitor impact on the overall RPS budget. This is not only for the purposes of procuring short-term RECs, but also to determine the extent to which the IPA will be able to meet the overall new build goals in Section 1-75(c)(1)(C).

or a statutorily-defined "program"? Stated differently, could the Agency propose the procurement of RECs to meet targets in Section 1-75(c) in a manner distinct from a competitive procurement process or "program"—such as, for instance, a standard offer price for a fixed quantity of RECs from a specific generating facility type, or a competitive procurement process in which bids are selected on a basis other than price—so long as it abides by the requirement to use those defined structures when specifically applicable? While no such alternative procurement processes are proposed as part of this Plan, the Agency believes the answer to this question is "yes," as the portions of the law which make clear when a competitive procurement process must be used effectively sanction the use of a different process (so long as not otherwise inconsistent with state law) in cases when they do not (such as meeting the percentage-based targets of Section 1-75(c)(1)(A), for instance). The Agency recognizes that additional processes or programs could create additional confusion in a nascent market, and would be subject to intense legal scrutiny, and therefore does not, at this time, propose any new programs or processes in this Plan. The Agency would be interested in feedback on this topic as part of comments on its draft Plan.

2.2.5.2. Section 1-75(c) Requirements

SEIA does not disagree with the IPA that the law specifically includes other types of generation in the definition of "community renewable energy program," however we disagree with the interpretation that the IPA must run a separate procurement for RECs from non-solar community renewable energy projects. Moreover, we are concerned that the addition of this procurement would put additional stress on the budget and make it harder for the IPA to meet the higher priority goals as defined in, for instance, Section 1-75(c)(1)(B) of the Illinois Power Agency Act. We recommend the IPA hold off on proposing this or any additional procurements not specifically called out in the statute until it is clear that there is room in the budget to do so.

Language Changes:

Beginning on Page 14:

Section 1-75(c) of the IPA Act contains the most robust set of requirements for the long-term plan; those include the following:

First, the Plan must "include the goals for procurement of renewable energy credits to meet at least the following overall percentages: 13% by the 2017 delivery year; increasing by at least 1.5% each delivery year thereafter to at least 25% by the 2025 delivery year; and continuing at no less than 25% for each delivery year thereafter." As explained further below, these percentages are described as a portion of eligible retail sales, which currently includes some sales by alternative retail electric suppliers while transitioning to all retail sales within two years. The law also contains a requirement that "in the event of a conflict between these goals and the new wind and new photovoltaic procurement requirements," the long-term plan shall prioritize the new wind and photovoltaic requirements. The IPA does not anticipate any such conflict prior to its next revision of this Plan, and has designed its Plan in a manner that reduces the likelihood of any such conflict occurring ~~(for instance, through using short-term contracts to meet percentage-based delivery year goals after new build is accounted for)~~. Further discussion of these goals can be found in Chapter 3.

...

Third, the law requires that, to the extent that annual RPS spending budgets for each utility become a binding constraint, the Plan "shall prioritize compliance with the requirements of this subsection (c) regarding renewable energy credits" in the manner discussed in Section 1-75(c)(1)(F), which features the following priority ranking:

(i) renewable energy credits under existing contractual obligations;

(i-5) funding for the Illinois Solar for All Program as described in Section 1-75(c)(1)(O);[45]

(ii) renewable energy credits necessary to comply with the new wind and new photovoltaic procurement requirements in Section 1-75(c)(1)(C);

and (iii) renewable energy credits necessary to meet the remaining requirements of Section 1- 75(c) (including the percentage-based delivery year goals in Section 1-75(c)(1)(B)).

While it is too early in the planning process for any one requirement to potentially cannibalize the other, the IPA recognizes that—unlike in previous years, where the budget was essentially a moving target based on customer switching and some REC purchases involved floating prices—a more predictable budget makes avoiding shortfalls mostly a matter of careful planning. To the extent advanced planning is inadequate to prevent one or more delivery years where the budget is anticipated to be exceeded, the IPA is committed to ensuring that this priority ranking is reflected in any future revisions to the Plan.

...

Ninth, and last among the requirements found in Section 1-75(c), the Plan "shall include a community renewable generation program," with a requirement that the Agency "establish the terms, conditions, and program requirements for community renewable generation projects with a goal to expand renewable energy generating facility 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" and that any subscriptions to such projects "be portable and transferable." ~~Presumably, although community solar photovoltaic is a subset of "community renewable generation projects"—which can include generating technologies such as wind, solar thermal, biodiesel, biomass, tree waste, and hydropower—this means that only~~ At this time, the IPA does not propose a procurement of RECs from community renewable energy generation outside of the ~~establishing an~~ Adjustable Block Program ~~featuring a community solar photovoltaic component would not satisfy this statutory requirement, and a distinct non-PV community renewable generation program must also be established. The Agency's proposed community renewable generation program, modeled on but distinct from its Adjustable Block Program, can be found in Chapter 7~~. The Agency will revisit this Section in future years once it is certain that it will meet the targets for higher-priority goals.

2.2.5.3. Illinois Solar for All Requirements

SEIA does not have a comment on the Solar for All program at this time.

2.2.8. Plan Updates

SEIA agrees with the proposal to conduct the first revision of the LTRR in 2019. This will give developers, customers, the program administrator, and advocates time to determine what is working and what needs revision. SEIA also notes, however, that the IPA is not required to remain static once the Adjustable Block program is open. Rather—as the IPA recognizes elsewhere in the LTRRPP—the IPA will be actively monitoring and adjusting the Adjustable Block program without further approval from the Commission (unless the IPA determines it must make an adjustment of over 25%, which SEIA believes will be less likely if the IPA adopts SEIA's recommendations on the Adjustable Block pricing model. However, the IPA correctly identifies exterior events that could have a significant impact on pricing, including: federal action on solar panel tariffs, and triggering of net metering or smart inverter caps. (*See, e.g.*, LTRRPP at 104-105.) As explained later, the IPA should build in an automatic contingency in the plan for Commission approval in this docket to allow changes (perhaps over 25%) without separate Commission approval.

2.3.2. Eligible Projects for IL RPS

SEIA has no comments on Section 2.3.2 at this time. To the extent that unresolved issues surface, SEIA recommends addressing these issues in the 2019 plan update proceeding.

2.3.4. RPS Funding and Rate Impact Cap

SEIA does not dispute the ability of the utilities to receive cost recovery for administrative purposes, but we do suggest the IPA seek to reduce administrative costs to the best of its ability, and to publish said costs periodically.

Language Changes:

Through the budgets established under the rate impact cap and the associated tariffs for the collection of funds, the applicable electric utility "shall be entitled to recover all of its costs associated with the procurement of renewable energy credits" under the Plan, including "associated reasonable expenses for implementing the procurement programs, including, but not limited to, the costs of administering and evaluating the Adjustable Block program." As a result, annual procurement budgets based only on REC costs would be inaccurate, and some estimate of associated administrative expenses must be included and taken into account. Although the IPA does not regulate the utilities, nor does it have the authority to modify utility administrative costs, in the interest of transparency, the IPA will seek this cost information from utilities and publish it on a periodic basis.

2.4.1. Quantitative Procurement Requirements

SEIA supports the IPA's interpretation that the "at least 50%" concept is in reference to the number of RECs, and not to the budget or to the overall annual goal. We do not suggest any language changes in this Section.

2.4.5. Balancing Expected Wind RECs vs. Solar RECs

SEIA agrees with the Agency's interpretation of when the first true up between wind and solar RECs would occur. It should occur after the latest date available for delivery of RECs from projects awarded contracts through the Initial Forward Procurements (June 1, 2021).

2.5.1. Adjustable Block Program

SEIA largely supports the program structure of the Adjustable Block Program. As outlined, the program would always be on, with blocks opening once capacity is filled, rather than a time-based approach. We provide more comments on the specifics of the proposed structure in future Sections, but suggest here that the IPA put some additional structure around the definition of "automatic."

<u>Language Changes</u>:

<u>Beginning on Page 31</u>:

… The Agency understands that "automatic opening" as used in the law need not be "immediate" or "instantaneous," and instead that "automatic" refers to the ability for the block to open in a predictable manner <u>that maintains market momentum and avoids start-stop dynamics while</u> not requiring additional administrative action. <u>As required by Section 1-75(c)(1)(K) of the Illinois Power Agency Act: "The Adjustable Block program shall be designed to provide a transparent schedule of prices and quantities to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time." The IPA believes that having an orderly transition with some advance notice better allows "adjust[ment] at a predictable rate over time," even if it means having some short gap between the close of one block and the open of the next block. The IPA is concerned that an instantaneous approach could lead to excessive resources being spent on monitoring blocks by each Approved Vendor, and potentially disputes if the instantaneous flip occurred while an Approved Vendor was submitting a project.</u>

2.5.1.1. Adjustable Block Program—Projects

SEIA agrees with the IPA's interpretation that the 25% of the Adjustable Block Program that can be allocated at the IPA's discretion can be allocated to any or all of the existing categories, and need not be only allocated to one category. SEIA does note, however, that without information about which Adjustable Block categories will be over- or under-subscribed, it is premature to permanently allocate this capacity in the initial Plan.

We also agree with the IPA's interpretation that the percentages outlined in the statute apply to the overall number of RECs, not to the budget or other metrics.

Finally, we strongly agree with the IPA's decision to not include geographic limitations on Illinois-based projects at this time. We believe that dividing the adjustable block program by utility territory as proposed will provide some diversity, and that interconnection limitations will provide additional geographic diversity. The IPA has the ability to make adjustments to the plan in future years if geographic diversity is not achieved in the early years.

We look forward to the opportunity to discuss what "geographic diversity" means in the first revision of the Final Plan in 2019.

Language Changes:

Beginning on Page 32:

The Agency believes that this remaining allocation requirement does not necessarily require a strict assignment of the remaining 25% to one of the prior three categories, and that the remainder can be allocated to adjust for ongoing program performance of the other categories. The Agency believes that allocating on the basis of program popularity while taking into account REC procurement goals in Section 1-75(c)(1)(C) would strike the appropriate balance.

The above categories also raise the question of "25% of what"—installed capacity? Budgets? RECs? While the statute is perhaps unclear, the IPA believes that, given that RECs are the standard compliance pathway in the revised Illinois RPS, 25% should be understood to refer to the number of RECs procured from projects of that type.

The law also provides that the Adjustable Block Program shall ensure that RECs are procured from "projects in diverse locations and are not concentrated in a few geographic areas." At present, the Agency believes that no special incentive or adder based only on geographic diversity is necessary to ensure that this objective is met, but commits to review this issue in the next revision to the Plan.

2.5.1.2. Adjustable Block Program—Contracts

SEIA agrees with the IPA's interpretation of "purchase price," that is that it is the full value of the REC contract.

2.5.1.3. Adjustable Block Program—Changes

As SEIA noted above, while the IPA generally speaking must seek approval from the Commission for changes to block pricing of over 25%, SEIA recommended that the IPA seek pre-approval from the Commission to make at minimum changes to the Adjustable Block for the reasons identified on pages 104 and 105 of the LTRRPP without additional Commission approval (even if the impact exceeds 25%).

2.5.2. Community Renewable Generation Program

As outlined in our comments in previous and future Sections of this document, SEIA does not believe the IPA should propose additional community renewable generation programs outside of the Adjustable Block Program. Though the IPA may have the authority to do so, the timeline for such programs is unclear. Thus, given the priority given achieving the new build requirements, and the Adjustable Bock Program requirements as a subset of those new build requirements, we do not feel it prudent to include additional community renewable generation programs at this time. This is something the IPA can revisit in revisions of the Plan.

Language Changes:

P.A. 99-0906 also calls for the establishment of a "community renewable generation program."Unlike with the Adjustable Block Program, the law does not set forth procurement targets or a proposed contract structure for this program; the Agency thus understands that, legally, it has latitude to design its Community Renewable Generation Program in any manner otherwise consistent with state law and done "with a goal to expand renewable energy generating facility 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."

From the law, the exact interaction and structure between the Agency's Community Renewable Generation Program, and the portion of the Agency's Adjustable Block Program set-aside for community solar, is unclear; the law simply references that "subscribed shares of photovoltaic community renewable generation projects" shall be purchased through the Adjustable Block Program. Thus, the IPA understands the community solar portion of its Adjustable Block Program to be something of a subset of its Community Renewable Generation Program~~, with a standalone Community Renewable Generation Program still required to be established to provide support for community renewable generation projects using technology other than photovoltaics~~. At this time, however, the Agency does not propose a community renewable generation program beyond the Adjustable Block Program. The Agency will revisit this issue in the first revision of the Plan.

~~Along these lines, Section 1-75(c)(1)(N) requires that "subscriptions" to community renewable generation projects under the Community Renewable Generation Program must be portable (i.e., retained by the subscriber even if the subscriber relocates or changes its address within the same utility service territory) and transferable (i.e., a subscriber may assign or sell subscriptions to another person within the same utility service territory). The Agency believes that these requirements apply to subscriptions for community solar projects participating in the Adjustable Block Program as well.~~ Further discussion of the IPA's Community Renewable Generation Program can be found in Chapter 7.

3. RPS Goals, Targets, and Budgets

SEIA does not disagree with the Forecasted Delivered Volumes provided, nor do we disagree with the overall REC targets laid out in Sections 3.1 - 3.16. Our comments are specific to the budget as outlined in 3.17 through 3.20 and the Tables therein, and we refer to future Sections to show how procurement decisions may affect the budgets. We do not offer specific language changes on the Tables, but encourage the IPA to provide a full accounting of the costs associated with the RPS in those tables, including known Solar for All costs and proposed administrative costs.

3.17. RPS Budget, 3.17.1. Utilities Budgets, 3.18. Summary of REC Procurement Targets and RPS Budgets, 3.19. Hourly Alternative Compliance Payment Funds Held by Ameren Illinois and ComEd, and 3.20. Impact of RPS Budget on Procurement Volumes

SEIA appreciates the IPA's difficult task of balancing the multiple requirements of the law and the limitations of the budget. The revisions to the Illinois Power Agency Act from Public Act 99-0906 allow for the IPA to consider the first four years of the budget in total before reconciliation, which will provide significant funds to meet program and procurement goals. However, SEIA has concerns that layering in additional spot procurements will take critical dollars away from the programs and procurements for new projects. SEIA is concerned from both a policy and compliance perspective. Further, SEIA has some concerns that the assumptions made throughout the Draft Plan are not necessarily an accurate reflection of likely outcomes, which would further affect the budget. Our specific concerns are laid out below, including several data tables.

Per the Draft Plan Table 3-15., the IPA has approximately $650 million dollars in the Available RPS Budget through the 2020 Delivery Year, prior to the first reconciliation. This number already subtracts monies needed to cover existing contracts from the overall RPS budget, as well as an estimated spend on the Initial Forward Procurement.

Table 3-15. Statewide RPS Budget[174]

Delivery Year	RPS Budget	Contracted REC Spend	Estimated REC Spend Initial Forward Procurement REC Spend	Available RPS Budget (est.)
2017-2018	$141,806,259	$33,242,248		$108,564,011
2018-2019	$189,960,753	$31,469,244		$158,491,509
2019-2020	$234,276,005	$31,594,913	$11,036,000	$191,645,092
2020-2021	$234,003,329	$30,960,189	$11,036,000	$192,007,140

As acknowledged in Section 3.17., this number does not take into consideration the required transfers of money to the Solar for All, job training programs, or administrative costs, nor does it adjust upwards for uncommitted Hourly ACP funds.

As outlined in Section 8.4.2., the Solar for All program will receive $33,413,978 from the RPS budget through Delivery Year 2020. This number does not appear to include the $20,000,000 allocated during the delivery year beginning June 1, 2017, ($10 million in regular funding and $10 million for training), so the total would actually be $53,413,978.

In Section 3.17.1., the IPA also proposes allocating 3% of the overall budget to administrative expenses, including but not limited to the costs of administering the Adjustable Block Program. The IPA acknowledges that this number is a placeholder, but for budgeting and planning purposes, the loss of these funds for REC purchases must be taken into consideration. It's unclear if the percentage should apply to the overall budget or the available budget, however, either way the expense is significant. Three percent of the overall budget over the delivery years 2017 - 2020 equals approximately $24 million dollars, whereas 3% of the available budget equals $19.5 million dollars. SEIA doesn't dispute the need for funds to cover administrative costs, nor do we dispute that 3% may be the correct amount. We do suggest the IPA subtract this amount, as well as the allocation for the Solar for All program, from the available budget to determine whether additional procurements are prudent. The available budget for is reduced to $573 million ($650 - $53 - $24 = $573).

Further, we question whether the IPA's assumptions on the total cost of the Forward REC Procurement Spend are correct. The first Initial Forward Procurement contracted 1,165,000 RECs at an average cost of $4.26 for a total cost of $4,962,900 per year for 15 years. In the budget above, the IPA assumes approximately $11 million in total costs per year for all the RECs procured through the Initial Forward Procurement. That means the IPA assumes the remaining 800,000 solar RECs[3] yet to be procured will cost a total of $6,073,100, or $7.59/REC.

While neither SEIA nor any other party can anticipate the results of future competitive procurements, $7.59/REC is considerably lower than the national average for new REC-only utility-scale solar projects (before taking into account location-specific costs, such as the cost impact of the Qualified Person requirement, or utility/RTO-specific interconnection costs). Furthermore, the IPA should not necessarily assume the prices obtained in the first forward procurement will necessarily be matched or beaten by subsequent procurements.

For all of those reasons, SEIA suggests the IPA assume the full cost of the Initial Forward Procurement will be higher than currently suggested in the Draft Plan. At minimum, the IPA should consider modeling multiple average prices, including at least one conservative estimate that assumes that the remaining solar RECs will cost at least as much as those contracted under the first Initial Forward Procurement RFP. For instance, if the first RFP for the Initial Forward Procurement resulted in $10 RECs, the IPA would need to budget an additional $2 million per year in REC costs in Delivery Years 2019 and 2020 for the remaining Initial Forward Procurement RECs.[4] If the RFP resulted in $15 RECs, then the IPA should budget an additional $6 million for the remaining Initial Forward RECs in these Delivery Years.

Similarly, the IPA should budget for REC prices for the Subsequent Forward Procurements to mirror prices in the Initial Forward Procurement. This would mean that the IPA should budget for $10-$15 million in Delivery Year 2020 for the subsequent Photovoltaic Forward Procurement.[5] Further, the IPA should assume the First Subsequent Procurement for wind resources will at minimum be equivalent to the results of the Initial Forward Procurement, likely resulting in between $2-$3 million[6] in REC costs for Delivery Year 2020. Finally, the Brownfield Site Forward, while small, will take up additional budget space. It is impossible to say exactly what a Illinois-based brownfield REC is worth, but the IPA can assume it is at least as much as the Initial Forward

[3] We assume this number does not include Brownfield Solar Forward Procurement.

[4] SEIA is sensitive to concerns that publishing this number in excessive detail may give away the REC bid for the sole winning solar bidder in the initial forward procurement. SEIA recommends that the IPA round or otherwise modify the number so that competitors cannot determine the winning bid price better than based on currently-available public information.

[5] The IPA assumes that RECS from the subsequent photovoltaic procurement will begin delivery in Delivery Year 2020. We do not dispute this assumption but note that it is unlikely that projects would produce an entire year's worth of RECs for the 2020 Delivery Year. Nonetheless the IPA should budget for an entire year's worth of RECs to cover its bases.

[6] We do not know the exact cost of the wind RECs contracted as a result of the Initial Forward Procurement, but we do know the blended price for 965,000 wind RECs and 200,000 solar RECs was $4.26. We assume wind prices were lower than solar prices and suggest wind on average was $2-3, then the resulting solar would have to be $10-$15. (965,000 + 200,000) x 4.26 = $4.962.900. $4,962,900 - (965,000 x 2) = $3,032,900. $3,032,900/200,000 = $15.16. Similar calculations can be done for $3 wind RECs.

Procurement results, which would add another $400,000 - $600,000 to the Delivery Year 2020 costs, at minimum.

In total, these procurements will cost at least $16.4 - $30.6 million[7] to the combined 2017-2020 Delivery Year budgets. Subtracting that from the $573 left after the Solar for All and administrative expenses, the remaining budget is $542.5 - $556.6 in total. It's unclear how much money will be available from the Hourly ACP funds after the costs associated with prior DG procurements are subtracted, but given the results post on the IPA bidder portal, the remaining funds will be minimal.[8]

Using the draft REC prices published in the October 6th Errata, the total cost of the Adjustable Block Program would vary from between $712 million in the cheapest case scenario (the lowest REC in any given category is taken) and $1.2 billion dollars in the most expensive scenario (the highest REC in any category is taken and the highest adders are applied where appropriate).[9] These Tables are meant for illustrative purposes only, and are provided to show the upper and lower bounds on the cost of the Adjustable Block Program. These tables use the published REC pricing, and we note that SEIA has submitted comments on the REC model and adders that, if adopted, will change the value of these prices. *Please note, we do not think the Low Total scenario is viable because it would not result in small customer participation in community solar, which would run afoul of the statute. Similarly, for reasons described elsewhere in these comments, we do not think the high cost scenario should be viewed as an upper limit on the costs that may be necessary to achieve the preferred policy outcomes. Nonetheless, these numbers represent what was proposed in the Draft Plan as the theoretic lowest and highest cost of the program, and we therefore use them for illustrative purposes only.* We also note that the IPA, in its Draft LTRRPP, stated that these REC values were preliminary and subject to change based on comments received.

[7] $2-$6 million in additional Initial Forward Procurement Costs x 2 delivery years + $10-$15 million for the second Photovoltaic Forward x 1 delivery year + $2-$3 million for the First Subsequent Forward Wind Procurement x 1 delivery year + $400,000-$600,000 for the Brownfield Site Forward Procurement x 1 delivery years = $16.4 - $30.6 from the total 2017-2020 delivery year budgets.

[8] The results posted on the IPA bidder portal website (www.ipa-energyrfp.com) show approximately $40 million of costs associated with the 2015-2017 DG procurements, leaving only $9 million available for carryover, at most. While not immaterial, this amount of money does not significantly impact the overall budget.

[9] In these calculations, for the Low Totals we assume the largest project possible (and therefore the lowest REC price) for each category is built using a 16.4177% capacity factor. For the High Totals, we assume the smallest project available (and therefore the highest REC price) is built and that Community Solar projects use a tracking capacity factor of 19.3149% and have the highest residential adder, while the Small and Large projects remain at 16.4177%.

Table 1 - Block 1 Cost Scenarios

	Block 1 MW	Block 1 Low $/REC	Block 1 Low Total (CS = non-tracking capacity factor, no resi adder)	Block 1 High $/REC	Block 1 High Total (CS = tracking capacity factor, resi adder)
ComEd Small DG	52	$72.85	$81,722,299.92	$72.85	$81,722,299.92
ComEd Large DG	52	$20.23	$22,693,783.49	$50.29	$56,414,748.98
ComEd CS	52	$43.09	$48,337,871.02	$107.55	$141,938,949.80
Ameren Small DG	22	$82.47	$39,140,498.82	$82.47	$39,140,498.82
Ameren Large DG	22	$31.56	$14,978,466.63	$60.76	$28,836,870.48
Ameren CS	22	$70.55	$33,483,232.59	$133.29	$74,423,155.17
	Total		$240,356,152.46		$422,476,523.16

Table 2 - Block 2 Cost Scenarios

	Block 2 MW	Block 2 Low $/REC	Block 2 Low Total (CS = non-tracking capacity factor, no resi adder)	Block 2 High $/REC	Block 2 High Total (CS = tracking capacity factor, resi adder)
ComEd Small DG	52	$69.94	$81,240,625.44	$69.94	$78,457,895.08
ComEd Large DG	52	$19.42	$22,557,805.92	$48.28	$54,159,953.88
ComEd CS	52	$41.37	$48,054,399.12	$103.72	$136,884,313.09
Ameren Small DG	22	$79.17	$38,906,988.12	$79.17	$37,574,309.34
Ameren Large DG	22	$30.30	$14,890,510.80	$58.33	$27,683,585.50
Ameren CS	22	$67.73	$37,817,392.90	$128.43	$71,709,549.24
			$243,467,722.30		$406,469,606.13

Table 3 - Block 3 Cost Scenarios

	Block 3 MW	Block 3 Low $/REC	Block 3 Low Total (CS = non-tracking capacity factor, no resi adder)	Block 3 High $/REC	Block 3 High Total (CS = tracking capacity factor, resi adder)
ComEd Small DG	52	$67.14	$75,316,886.98	$67.14	$75,316,886.98
ComEd Large DG	52	$18.64	$20,910,139.61	$46.35	$51,994,901.87
ComEd CS	52	$39.72	$46,137,798.72	$100.05	$136,724,328.00
Ameren Small DG	22	$76.00	$36,069,818.24	$76.00	$36,069,818.24
Ameren Large DG	22	$29.08	$13,801,451.51	$56.00	$26,577,760.81
Ameren CS	22	$65.02	$36,304,250.50	$111.94	$62,502,273.16
			$228,540,345.56		$389,185,969.06

It is difficult to say when projects will energize and therefore when their payments will begin, but if we use the same assumptions as the Draft Plan, that is that each block will roughly match one year, and that payments match the block projections, then is the IPA will have to budget roughly $500 million at minimum, and $700 million at maximum, to the adjustable block program, through Delivery Year 2020.

Table 4: Low Adjustable Block Program Annual Cost[10]

Low Yearly Cost				
Delivery Year	Block 1	Block 2	Block 3	Total
2018	$144,761,469.48			$144,761,469.48
2019	$23,898,670.75	$144,811,635.31		$168,710,306.05
2020	$23,898,670.75	$24,664,021.75	$134,817,433.29	$183,380,125.78
2021	$23,898,670.75	$24,664,021.75	$23,430,728.07	$71,993,420.56
2022	$23,898,670.75	$24,664,021.75	$23,430,728.07	$71,993,420.56
2023		$24,664,021.75	$23,430,728.07	$48,094,749.82
2024			$23,430,728.07	$23,430,728.07
2025				
			Total 2018-2025	$712,364,220.32
			Total 2018-2020	$496,851,901.32

[10] The following tables show projects in the Small category getting the entire REC value in Year 1, and the projects in the Large and Community Solar categories getting payment over 5 years. While the time span between the first and last payment for Large and Community Solar projects would only be 4 years, the costs are in 5 separate budget years.

Table 5: High Adjustable Block Program Annual Cost

High Yearly Cost				
Delivery Year	Block 1	Block 2	Block 3	Total
2018	$181,185,543.62			$181,185,543.62
2019	$60,322,744.88	$174,119,684.76		$234,442,429.65
2020	$60,322,744.88	$58,087,480.34	$166,946,557.99	$285,356,783.22
2021	$60,322,744.88	$58,087,480.34	$55,559,852.77	$173,970,078.00
2022	$60,322,744.88	$58,087,480.34	$55,559,852.77	$173,970,078.00
2023		$58,087,480.34	$55,559,852.77	$113,647,333.11
2024			$55,559,852.77	$55,559,852.77
2025				
			Total 2018-2025	$1,218,132,098.36
			Total 2018-2020	$700,984,756.49

With only $542-$556 million available before reconciliation, this leaves only $52-$69 million of wiggle room, at maximum, to purchase Spot Procurement RECs, to cover any underestimated costs of RECs from the Forward Procurements discussed above, and to cover costs of RECs purchased through additional Forward Procurements beyond the immediate procurements discussed above, as identified in Table 5-1 and subsequent sections (i.e. other Community Renewable Generation RECs outside of solar). Later in this document SEIA provides comments on the REC pricing model and the allocation of MW across the size categories that, if adopted, would change the overall cost of the program. Either way, however, the Adjustable Block Program is a significant undertaking and ensuring the funds to cover the costs is critical for the financing of projects.

SEIA recognizes that per Section 1-75 (c)(1)(L)(vi) of the Illinois Power Agency Act, the IPA has the ability to "borrow" from future budgets to cover Adjustable Block Program contract costs. However, we find it prudent that the IPA assume that the money to cover contracts will be available in the immediate budgetary period, not future budgetary periods. This assumes a timely payment for all potential REC contracts. If the IPA does not do so, SEIA recommends that additional risk be priced into the REC model to account for the potential for untimely REC payments.

Furthermore, SEIA recognizes that per Section 16-108(k) of the Public Utilities Act, the first "review, reconciliation, and true-up associated with renewable energy resources' collections and costs for the 4-year period beginning June 1, 2017 and ending May 31, 2021" will not occur until after August 31, 2021. We recommend the IPA clarify that the August 2021 reconciliation will consider funds obligated through contract before August 2021 under long-term commitments (such as the four-year payment cycle for most Adjustable Block-eligible generation or 15+ year utility-scale generation) as spent, even if the funds have not been dispersed. This will give REC producers and their finance/lending partners comfort that there is enough money to cover their contracts, as well as ensure that there is money available to meet the future new build requirements. It will also minimize the likelihood that the IPA is forced to invoke Section 1-75(c)(1)(F) of the Illinois Power Agency Act and pay less than all amounts owed on all contracts.[11]

SEIA recognizes that this is one of the more challenging pieces of the development of the LTRRPP, and it is impossible for the Draft Plan to capture exactly what will happen in the future or in all contingencies. For this reason, SEIA suggests the IPA take a more conservative approach to budgeting. If the IPA takes all of the above factors into consideration, SEIA believes there will be little room for spot procurements. While SEIA does not discount the importance of top-line RPS goals, it would be consistent with both the letter and spirit of FEJA—especially given the historic difficult procuring new renewable generation—to conservatively budget for the new build to ensure there is not a mid-planning cycle squeeze.

In Section 5.9, the IPA outlines three spot procurements for the 2017 - 2019 Delivery Years. In total these procurements total 38.5 million RECs. An aggressive budget for these spot procurements would assume $1 per REC, resulting in an $38.5 These projects are subject to the sourcing requirements laid out in Section XX, and may not be available at such a low price. Therefore, we believe the IPA should eliminate the spot procurements from the Draft Plan and revisit the issue once the costs of the Adjustable Block Program and other forward procurements are known.

Language Changes:

Beginning on Page 55:

In addition to direct expenditures on RECs, RPS budgets will also feature allocations for several additional purposes. First, pursuant to Section 1-75(c)(1)(O) of the Act, the greater of 5% or $10,000,000 (of the combined RPS budgets of the utilities) each year will be allocated to the Illinois Solar for All Program. See Section 8.4 for details on that allocation. Second, also pursuant to Section 1-75(c)(1)(O), in each of the delivery years 2017-2018, 2021-2022, and 2025-2026, $10,000,000 of ComEd's RPS budget will be allocated to fund job training programs pursuant to Section 16-108.12 of the PUA. Third, a reasonable amount of each budget will be set aside for administrative expenses (including, but not limited to, expenses related to development of this Plan and future updates, the management of procurements and programs, Adjustable Block Program Administrator expenses not covered by fees charged to participants, and fees charged by tracking systems for the retirement of RECs). The IPA proposes initially to set aside 3% of the Available RPS budget for these administrative expenses, and will refine this set aside as more information becomes available.

Beginning on Page 57:

~~The Available RPS Budgets shown in the previous tables are gross amounts. For the purpose of establishing funds available for REC purchases, these amounts will be adjusted prior to any procurements to account for the allocation of funds to the Illinois Solar for All Program and administrative costs.~~

…

[11] SEIA believes that because spot REC procurements are the lowest on the payment priority in Section 1-75(c)(1)(F), a constrained budget may lead to a material increase in REC prices to cover the risk of curtailment.

In light of those observations, the Agency does not expect that the procurements and programs proposed in this Plan will be limited by available RPS budget funds through at least the 2020-2021 delivery year. The Agency will refine and update this estimate when it updates this Plan in 2019 for implementation in calendar year 2020, and if it appears there will be limitations created in the available RPS Budget, the Agency will propose procurement and program approaches to proactively address those limitations including potentially setting specific budgets for individual programs and procurements. Nonetheless, through 2019, the Agency will carefully monitor the results of its procurements and programs and will adjust procurement and program volumes accordingly if it finds it necessary to do so. In addition, the Agency will not undertake spot REC procurements initially, to avoid inadvertently exceeding the budget in case less conservative estimates end up not reflecting the actual experience.

5. Competitive Procurement Schedule

While SEIA does not object to most of this schedule, there are two issues SEIA urges the IPA to resolve. First and foremost, as noted above SEIA recommends against spot procurements. Second, SEIA recommends that the IPA adopt a universal three-year timeframe for REC delivery. SEIA also reiterates our position that the IPA should consider the Adjustable Block Program as meeting the statutory requirement for a community renewable energy generation program and should not include additional programs beyond the ABP.

SEIA addressed issues with spot procurements and the budget—especially in light of Section 1-75(c)(1)(B) procurement priorities and Section 1-75(c)(1)(F) payment priorities—in response to Sections 3.17-3.20 above. In addition, SEIA notes that spot procurements do not lead to new development and thus do not help the IPA meet the highest priority goal in Section 1-75 of the Illinois Power Agency Act: supporting new build.

SEIA recommends that, in the future, if the IPA is considering making spot procurements, the IPA should send out an RFI to all winning bidders currently developing projects and all other interested entities to determine whether any could deliver new-build RECs on a compressed timeline. As noted below, in an emerging solar market REC delivery can take up to three years. But if the IPA can identify a project that is already far along (and could add to its footprint) or a project that for whatever reason has a shorter development cycle, the RFI approach would allow for statutory favored new build over spot procurements.

With regard to REC delivery, SEIA proposes for new utility-scale development that the IPA adopt a 3-year across-the-board timeframe for REC deliveries. In SEIA's experience, emerging solar markets often encounter development challenges as utilities (with regard to interconnection) and units of local government work to balance rapid growth with existing planning processes. A 3-year development cycle can reasonably be anticipated in these types of markets. While SEIA understands that the IPA can do little to change the statutorily-imposed timing for the delivery of the first 2,000,000 solar RECs, the IPA should be noted that the deadline for delivery is aggressive and will likely be challenging for many developers to meet. As such, IPA should consider adopting a 3-year timeframe for any REC delivery timelines for future procurements and plan the timing of additional forward procurements accordingly.

To accommodate the recommendation above, SEIA recommends moving the next utility-scale solar RFP up to Summer 2018 (from Spring 2019) in order to get as close to three years as possible with the delivery timeline and still within the first reconciliation period. We believe that it will be extremely challenging (primarily due to the PJM and MISO interconnection timelines) for projects to hit the statutorily mandated deadline of June 1, 2021 if the procurement takes place is the Spring of 2019.

Language Changes:

Beginning on Page 71:

As discussed in Chapter 2, the Agency does not propose to use spot procurements at this time, but ~~the Agency~~ will review and update this Plan in 2019 in conjunction with the development of the Agency's 2020 Annual Procurement Plan, with those updates and revisions to take effect in calendar year 2020. The schedule of competitive procurements occurring after 2019 will also be addressed in that Plan update. A discussion of the general principles for future competitive procurements is discussed in Section 5.10.

Beginning on Page 79:

SEIA recommends deleting Table 5-2 on page 79 and Section 5.9 in its entirety, and update the "Procurement Date" cell the third non-title row in Table 5-1 on page 78 to say "Summer 2018" instead of "Spring 2019."

Beginning on Page 82:

… This 5.9 million RECs per year from procurements and programs specifically mandated in the IPA Act falls well short of the annual percentage-based RPS goals. Nonetheless, the IPA wants to ensure that there is sufficient budget space to achieve higher priority programs and procurements, and therefore does not propose any spot procurements at this time. The Agency will revisit this issue in the first revision of the Plan in 2019. ~~The IPA estimates that unless additional procurements are conducted in calendar years 2018 and 2019, for the delivery period of 2019-2020 and beyond, the annual REC shortage would be in excess of 16 million. (Forward Procurements would not to be able to meet REC Goals for the 2017-2018 or the 2018-2019 delivery years; Spot Procurements as discussed below will instead be used for RPS goals for those years.) To help close this gap and meet the percentage-based goals of the RPS found in Section 1-75(c)(1)(B) of the IPA Act, the Agency must also offer proposals to procure additional RECs. The following sections outline additional proposed procurements.~~

Beginning on Page 83:

The Photovoltaic Forward Procurement proposed herein for a minimum of 1 million RECs from new utility-scale photovoltaic projects would be conducted in summer 2018 ~~early 2019~~. The final target REC volume for this procurement will be set in early 2018 after the Plan has been approved by the ICC, and ~~2019 based upon a review of the results of the Adjustable Block Program and~~ a determination of the REC quantity that would be needed to allow for the Second Subsequent Forward Procurement (described in the next section) for new wind RECs to proceed. At minimum, the target procurement volume should be 1 million annual RECs, but the Agency reserves the right to adjust that amount. Unless the Adjustable Block Program is on track to produce substantially more than 1 million RECs by the 2020-2021 delivery year, procuring fewer than 1 million annual RECs through the Photovoltaic Forward Procurement could entail insufficient RECs to allow the Second Subsequent Forward Procurement for new wind RECs to proceed.

Beginning on Page 86:

SEIA suggests taking out Sections 5.8.4. and Section 5.9. out entirely.

6.2.1. Managing Initial Demand

SEIA appreciates that the IPA is taking steps to appropriately manage initial demand, and is looking to other jurisdictions to learn best practices. Further in the Plan, the IPA suggests requirements for projects to apply for the Adjustable Block Program, including requiring systems over 25 kW to have a signed Interconnection Service Agreement in hand, as well as all non-ministerial permits. These requirements will help manage that initial demand as both the permitting process and interconnection process can take considerable time. We note that New York did not have these requirements in place and more than 4 GW of projects applied for its community solar program at the outset. Almost 75% of those projects did not move forward. Similarly, Minnesota did not require a signed ISA, and more than 800 MW of projects immediately applied for the Community Solar Garden program.[12] On the other hand, Massachusetts uses similar project maturity milestones to those in the Draft Plan and has experienced relatively smooth market functioning. We agree with the IPA that they need not put any additional requirements on Approved Vendors to manage initial demand, and we strongly recommend that the IPA keep the requirements to apply for the Adjustable Block Program that are in the Draft Plan, not only for supporting an orderly functioning of the market but also as a way of managing initial demand. We address this in more detail in Section 6.12.1. below.

6.3. Block Structure

SEIA agrees with the IPA's approach to have a block program that is continuously on; where blocks are filled by capacity, not by time, and where the next block opens automatically. This should remain as a key program element in the Revised Plan.

We do not object to the IPA using a standardized capacity factor to determine the number of MW needed to meet the 1,000,000 REC goal; however later we suggest that the IPA use differentiated Community Solar and DG capacity factors for determining REC values, and project-specific capacity factors and production amounts for contracting and payment purposes. We also appreciate that the IPA recognizes that the 1,000,000 REC goal is not a cap, but rather a floor.

We also appreciate that the IPA could have carved up the needed MW of development into any number of categories, but instead chose to keep the program simple with two primary categories and three blocks per size per category. Further, we agree that adders are the most appropriate way to incent different sizes of systems. In a REC pricing model like the one the IPA uses for the Adjustable Block—i.e., where the REC price is based on an assessment of other costs and revenues—the adder is designed to estimate the additional costs required to specific types of project. Separating out an adder allows for the IPA to propose—and receive feedback on—their assessment of differing costs and revenues for adder-eligible projects. To the extent that, over time, demand is

[12] Minnesota also did not have co-location limitations at the time the program initially opened, so several projects of 30 to 50 co-located 1 MW community solar garden projects entered the queue. Those projects were ultimately minimized to 5 MW, which significantly reduced the queue backlog.

higher or lower than anticipated, the IPA can attempt to realign the adder's assessment of costs with developer perceptions of costs. We address the size and scope of the adders further on in our comments in Section 6.5. The IPA rightly assumes that block structure, size and pricing can be adjusted in the first revision of the Final Plan, which will happen in 2019 (for the 2020 Delivery Year). All of these items are critically important to the success of the program, and should be viewed as key elements in the Revised Plan.

SEIA has a few suggestions in this Section that we feel will make the program more cost-effective and accurate, and have suggested language changes at the end of our comments.

First, after analyzing rate structures in various municipal utilities, we feel that their rates more accurately align with Ameren's rates and therefore should be added to that category. Furthermore, similar to the rural electric coops, only 13 of the 49 municipal utilities are located in the northern part of the state.

Second, it is unclear whether the paragraph about assigning REC contracts to the appropriate utility means the contract may get a different REC price if it is assigned to a utility other than the one where it is located. To avoid confusion, the IPA should clarify that while the contract may be assigned to a utility other than where the project is located, the REC price paid to the project will be based on the utility in which the project is located.

Third, SEIA respectfully disagrees with the IPA's proposal to allocate the unallocated 25% of capacity evenly among the three size categories for several reasons. We believe that the IPA should use its discretionary capacity to help meet its objective of procuring 1m RECs by DY 2020. It is very hard for the IPA to know beforehand which market segments will develop at which speeds, and we do not believe that the IPA should presuppose which market segments will have the most uptake in the first two years of implementation. Furthermore, it would l create confusion in the market if later on the IPA makes course-correcting changes to the block sizes or allocations. Developers and other market participants are making marketing, land acquisition, and other development-related decisions based the final approved LTRRPP. Thus, it would impact developers to have the initial LTRRPP divide funds one way and a subsequent revision make sharp changes. Companies may staff up in the anticipation that more capacity is available in their market segment, only for the IPA to potentially later take away capacity, and therefore negatively affect those businesses. Further, it pits one market segment against the others if the capacity is allocated but certain segments do not fill up. For example, Community Solar developers in Ameren territory assume they have 66 MW of capacity available (per Section 6.4). If that segment moves slowly but the ComEd Community Solar category moves quickly, and the IPA proposes to shrink Ameren's Community Solar Block 3 by 10 MW and increase ComEd's Community Solar Block 3 by 10 MW, Community Solar developers in Ameren territory are left wondering what happened to their market.

Therefore, we recommend that the IPA reserve this capacity and allocate it in the first revision of the Final Plan in 2019, or before if the IPA deems it necessary. We suggest in the Tables on Section 6.3.1. that the IPA remove this capacity from the last block, not evenly across all blocks. We suggest that the IPA could then use the reserved capacity to increase Block 3 of fast-moving market segments, and add more blocks, if warranted. We have included a revision to the Illustrative Block Capacity Table in the next Section, though we recognize this table is for illustrative purposes only.

The 2019 revision will be 9 months to a year after the Adjustable Block Program opens, and the IPA will have a better sense of which market segments need additional capacity. If there is a need before the initial revision to maintain the "always on" aspect of the program, the Final Plan should explicitly give the IPA the authority to add this capacity without going back to the ICC.

Language Changes:

Beginning on Page 94:

To encourage simplicity, the Agency proposes to allocate incentives into two groups by service territory/geographic category, based upon load forecasts contained in Chapter 3.

• Group A: for projects located in the service territories of Ameren Illinois, Mt. Carmel Public Utility, municipal utilities, and rural electric cooperatives.

• Group B: for projects located in the service territories of ComEd~~,~~ and MidAmerican~~, and municipal utilities~~.

Incentive levels will vary by group. While the program administrator will strive to allocate REC delivery contracts with the electric utility in whose service territory the project is located (where applicable, as the IPA lacks authority to procure REC contracts on behalf of municipal utilities or rural electric cooperatives), in order to allocate RECs proportionately among Ameren Illinois, ComEd, and MidAmerican to meet their RPS obligations, that will not always be possible. REC delivery contracts will not affect the REC price the project is eligible for, rather just the specific utility that will receive the RECs and make payment for said RECs. The REC prices outlined in Section 6.4 below are applied by virtue of the location of the project.

The Agency also considered creating an additional group or groups for MidAmerican, Mt. Carmel Public Utility, rural electric cooperatives, and municipal utilities. However, given their small share of the load in Illinois, the resulting group or groups would be quite small. By consolidating them into the larger groups, block sizes are more administratively manageable, and prices are more transparent and easily understood. The assignment of projects in the service territories of Mt. Carmel Public Utility, the municipal utilities, and the rural electric cooperatives to Group A, and MidAmerican ~~and municipal utilities~~ to Group B, is intended to approximately match those smaller entities to a larger utility with comparable electric rates.

Within each group, the blocks will be divided by the allocations specified in Section 1-75(c)(1)(K) of the Act, which are 25% for systems up to 10 kW, 25% for systems greater than 10 kW and up to 2,000 kW, 25% for photovoltaic community renewable generation, and 25% to be allocated by the Agency. At this point in time, it is premature for the Agency to predict which sector will experience the strongest demand. Therefore, the 25% that is left to the Agency's discretion will be allocated as future blocks (i.e. Block 4, Block 5, etc.) to market segments that exhibit demand for additional capacity ~~evenly allocated across the three categories. In the Plan Update, the Agency will review and reallocate that 25% amount if needed~~. In the Plan Update, or before if deemed prudent, the IPA may allocate multiple new capacity and pricing blocks to multiple size categories in both Groups, or all of the capacity to a single new capacity and pricing block in one size category in one Group.

~~The allocations will be:~~

- ~~33.3% for DG PV systems up to 10 kW (Small systems)~~
- ~~33.3% for DG PV systems greater than 10 kW and up to 2,000 kW (Large systems)~~

- ~~33.3% for photovoltaic community renewable generation projects (Community Solar)~~

For systems in the Large DG PV and Community Solar categories, the use of adders (as discussed below in Section 6.5) will be used to differentiate the price for RECs from different sized systems. In the alternative, the Agency considered subdividing those categories into smaller blocks, but the Agency is not convinced that such an approach would be more efficient or a better way to match prices to demand from the market. The Agency invites interested parties to comment on which approach would be more likely to produce positive outcomes. Projects that participate in the Illinois Solar for All Program (as described in Chapter 8) will generally follow the program terms and conditions of the Adjustable Block Program, but will apply separately, and will not be considered part of these Groups and categories for the purpose of filling the capacity of each Block. Those projects will also be subject to additional terms and conditions, as well as a different contractual process.

6.3.1. Transition between blocks

SEIA strongly supports the gradual decline of price between the blocks. This decline represents a steady downward pressure on prices instead of a dislocation. A larger step between blocks would be harder for the market to weather.

SEIA also generally supports how the IPA proposes to close the blocks. The IPA correctly surmises that there will be pent up demand prior to the opening of the first block. The project maturity requirements outlined in Section 6.12.1. are critical to moderating pent up demand. With these project maturity requirements in place, only real projects will be ready to enter the queue when it opens. Nonetheless, we suggest the IPA consider a safety valve for in case there is an unexpected rush. Specifically, we recommend that the IPA maintain that Block 1 remain open for 60 days, or beyond if the block capacity is not reached, but close Block 1 if 200% of the block capacity is reached. If 200% of the block capacity is reached within the 60 days, the next block would open. Given that 200% of Block 1 represents the capacity of both Block 1 and Block 2, we recommend that Block 2 pricing be used for the remaining capacity. It is in this situation that the IPA might use its reserved capacity to add a Block 3 and Block 4, as suggested in our comments above.

SEIA also strongly supports that capacity for failed projects be assigned to the currently open block. This will prevent a waterfall effect of changing incentives.

Language Changes:

Beginning on page 95:

- For each Block 1, all projects submitted within 60 days of the program opening will be included in that Block 1 regardless of if the block volume is used up. However, the Block will close if 200% of the proposed capacity volume is filled. Projects will be admitted to Block 1 on a first come, first serve basis based on when the Adjustable Block Procurement Administrator approves projects (evaluation of projects will also be based on first come first serve submission).

- For subsequent blocks (and for each Block 1 if it is not filled in the first 60 days), the block will be held open for 14 days after the block volume is used up. The Agency will announce when a block has been filled and when the closing date will be.

Table 6-1 shows the amount of nameplate capacity that will be initially allocated to each block for each group and category. The remaining 25% of unallocated capacity (168 MW) will be added at the IPA's discretion, either in the first Plan Update or before, to Block Groups and Block Categories that exhibit a demand for increased capacity. The final amount for each block may change to accommodate the soft closing described above. In other words, if the initial demand for the Group A, Small category in the first 60 days is 30 MW, the final amount of capacity in that block would be 30 MW, and the next block would open with 22 MW of expected capacity available. Meanwhile if Group A, Large category only had 10 MW of demand in the first 60 days, it would remain open until its 22 MW of capacity were filled (subject to any adjustments in the final 14 days), and then the next 22 MW block for the Group A, large category would open.

Block Group[13]	Block Category	Block 1	Block 2	Block 3
Group A (Ameren Illinois, Mt. Carmel, Municipal Utilities, Rural Electric Cooperatives)	Small	22	22	~~22~~ 6
	Large	22	22	~~22~~ 6
	Community Solar	22	22	~~22~~ 6
Group B (ComEd, Mid-American~~,~~ ~~Municipal Utilities~~)	Small	52	52	~~52~~ 12
	Large	52	52	~~52~~ 12
	Community Solar	52	52	~~52~~ 12
Total		222	222	~~222~~ 54

6.4. REC Pricing Model

SEIA provided separate comments on the REC pricing model, and therefore does not have additional comments on this Section.

[13] We've rounded for ease of reading.

6.5.1. Size Category Adjustments

SEIA strongly supports the use of adders to incent the development of different sized commercial and community solar projects. As written, the Draft Plan will allow developers to choose the right size system for the project instead of predetermining what the market should look like. We believe this approach will give both developers and customers the most flexibility. This should remain as a key element of the overall program.

That being said, we reiterate our position from our comments submitted in June that we believe the break points should be as follows:

- Less than or equal to 25kW
- Greater than 25kW to 250kW
- Greater than 250kW to 500kW
- Greater than 500 kW to 1MW
- Greater than 1MW to 2MW

We believe these break points more accurately represent real differences in installation cost and, therefore, the REC model based on accurately assessing costs and revenues should also reflect those break points. The IPA should rerun the REC model for DG and Community Solar, separately, using the updated factors outlined in SEIA's REC modeling comments, with these project sizes, to determine the appropriate adder.

The IPA should also clarify that only distributed generation systems or, separately, only community solar systems on the same property will be aggregated for REC pricing purposes, taking into consideration co-location allowances for community solar. There is a significant likelihood that a property may install a rooftop or other behind-the-meter system, and separately may host a community solar project interconnected in front of the meter where the property owner may or may not be a subscriber. The plan should make clear that this arrangement is allowed, and that the projects are considered separate for REC pricing and co-location purposes. The two types of project are distinguished by interconnection: one is behind the customer's meter, the other may be on the customer's premises but is interconnected in front of the meter. The two types of projects fulfill different purposes and will provide different benefits to different customers. ComEd's tariffs for community solar (Rider POGCS) and net metering (Rider POGNM), as well as Ameren's tariffs, are not mutually exclusive, so the Draft Plan should align with the approved tariffs.

Language Changes:

Beginning on Page 100:

Adders will only be available for systems over 10 kW in size in both the Large and Community Solar categories. The Agency does not believe there will be significant cost differences for systems in the up to 10 kW category that would require Adders within that category; therefore, the up to 10 kW category is a single calculated price. The Agency recommends setting a base price for systems larger than ~~500 kW~~ 1 MW, with the following schedule of adders for smaller systems.

These adders were calculated using the REC pricing model described in Section 6.4 with the system costs based on a typical sized system for each size category. While the adders were calculated using the REC Pricing Model as described above, the Agency notes that the resulting higher REC prices for smaller systems could lead to more systems being developed, which may help encourage the geographic diversity of the system locations.

The total capacity of distributed generation systems, or separately of community solar systems, ~~of a system~~ at a customer's location will be considered a single system. (For example, three 100 kW distributed generation systems at a single location will be considered a 300 kW system, but a 100 kw distributed generation system and a 500 kW community solar system at a single location will be considered separately.) If a system at a single location is subsequently expanded, the Agency reserves the right to revise the incentive amounts paid for the original system, and to set new incentives based on the total expanded system size rather than just the treat the expansion as a separate system. For the purpose of establishing an incentive level, a system's location would be a single building (regardless of the number of utility accounts at the location) for rooftop installations, and a single property parcel for ground-mounted systems (if a property had both rooftop and ground-mounted distributed generation systems, it will be considered a single system, but it would not if the ground-mount was a community solar system and the rooftop was behind the meter). Exceptions will be made if it can be demonstrated that two projects on one roof serve to offset the load of separate occupants (residential or commercial) of a building. Additional discussion of co-location of community solar projects is included in Section 7.3.

6.5.2. Community Solar Adder

In the Draft Plan, the IPA includes several cost provisions specific to community solar, including: a slightly higher debt service coverage ratio (DSCR) input in the CREST model; a REC payment of $4.98/MWh for administrative costs associated with community solar projects that are 500-2,000 kW; and "adder" REC values of $7.89/MWh and 11.83/MWh for projects that subscribe residential customers for 50% and 75% of their capacity, respectively. While SEIA addressed these values at some length in separate comments, SEIA wishes to revisit these three elements.

Assuming Higher Risk

SEIA supports the assumption that a higher DSCR should be used for community solar given that these projects experience a higher level of risk relative to those with only a single off-taker. While SEIA does not put forth a specific proposal, SEIA does support the concept. Further, it would also make sense to assume a higher internal rate of return (IRR) for community solar projects that are incorporating significant levels of residential and small commercial participation because a 20-25+ year commitment (even one that is transferrable or assignable) that adds additional layers of risk with residential and smaller commercial counterparties (especially residential).

Community Solar (base) Administrative Costs

The IPA correctly uses REC payments to address incremental administrative costs that are unique to community solar, such as the additional customer acquisition and ongoing billing and administrative needs associated with serving numerous customers. In separate comments, SEIA addressed the need to separate out asset management costs—essentially the costs that all developers of both distributed and community projects must take on to run basic business functions—and the costs specific to administering from three to theoretically as many as 10,000 (all 200W subscriptions from a 2MW project) contracts.

Community Solar Adders for Residential and Small Commercial Participation

SEIA strongly supports the Plan's proposal to include a mechanism that results in robust residential and small commercial participation as part of the community solar program design. While there is limited direct market experience, SEIA believes a properly designed adder could achieve this goal. There are real, significant costs that come with residential and small commercial customer participation that a REC adder must cover. These costs range from the increased costs of customer acquisition to billing (and collecting) to managing expected and unexpected customer turnover. However, SEIA believes that the proposed REC adder values in the Draft will not be sufficient for recovering costs associated with those projects, much less result in the "robust participation opportunity" that was intended by the Future Energy Jobs Act.[14] Further, the adders proposed by IPA did not include small commercial customers, without which SEIA expects smaller commercial customer participation to lag. SEIA recommends that the IPA revise the adder structure in three ways to address these issues:

- **Increase the adder values to align with costs and drive developers to pursue small customer participation.** The IPA is required by statute to create "robust opportunities" for residential and small commercial customers. There is experiential and analytical evidence from other states, described in the chart on the next page, as to what magnitude of project revenues are needed to create such opportunities, and the IPA's initial proposal is far short of those levels. The IPA should be looking to not only enable developers to cover their costs, but also provide enough incremental financial incentive to overcome business model inertia. When all costs are equal, developers are more likely to take the path of least resistance and partner with a handful of commercial customers rather than solicit hundreds of smaller-sized customers. An incentive is needed to simulate a higher rate of return to achieve a "robust" result.

  Though policies vary, Massachusetts, Minnesota, New York and Rhode Island provide examples of markets that have either actively attempted to identify the incremental cost of community solar projects with significant small customer participation or simply had higher credit values built into the program for those participants. Rhode Island provides the most explicit analysis in which they determine (via industry surveying) that projects with 50% of their capacity going toward subscriptions of 25 kW or less have an upfront (one-time) customer acquisition cost of $0.25/W, an ongoing (per year) customer replacement cost of $0.02/W/year, and a customer management billing cost of $0.01/W/year.[15] In comparison, when adjusting for a similar project and customer participation profile, Elevate's Community Solar Business Tool produced an upfront cost of $0.05/Watt, and total ongoing costs accumulated between years 2-25 (e.g., administrative billing, etc.) of $0.24/W. To the extent that the IPA relied on Elevate's tool, the IPA is relying on values inconsistent with the practical Rhode Island experience.

[14] Senate Bill 2814. Sec. 1-75(c)(1)(K). Pgs. 101-102.
[15] SEA. (2016) Rhode Island Renewable Energy Growth Program: 2017 2nd Draft Ceiling Price Recommendations. Found at: http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2016/49211.pdf.

For additional comparison, the relatively recently approved Solar Massachusetts Renewable Target (SMART) Program – of which the analysis in Rhode Island is based in part – provides a $0.05/kWh REC payment[16] for community shared solar (defined as projects with at least 50% capacity going to subscribers of 25kW or less) to be paid over 20 years.[17] In Minnesota, residential participants receive a credit rate that is about $.03 higher (paid over 25 years) than what's received by large commercial customers.[18] Despite this higher rate, only about 10% of the program's capacity (to date) has gone to residential subscribers, which the IPA should not view as a "robust" result in Illinois where residential customers alone (not including small commercial customers) account for 30% of load and 90% of all retail customers.[19] The table below outlines approaches other states have taken to achieve small customer participation in community solar, and the results available to date.

State	Residential/Small Commercial Bill Credit Differential	Actual Result
NY	$0.09/kWh for 25 years for residential customers and $0.06/kWh for 25 years for small commercial customers, for initial tranche of projects; as capacity is filled, these decline to $0.073/kWh for 25 years for residential customers and $0.046/kWh for small commercial customers (based on Market Transition Credit value filed by Orange & Rockland Utilities)	Unknown, but likely close to 100% residential/small commercial. All community DG projects must allocate at least 60% of capacity to subscriptions under 25 kW. The lack of large commercial participation (e.g. projects with 60% small customers, 40% large customers) is a result of the credit value for large commercial customers being too low to support project financing.
MA	SREC II: Approximately $0.08/kWh for 10 years (represents the difference between SREC Factor of 0.7 for a virtual net metering project serving only large customers (Managed Growth category) and 1.0 for community solar projects, at current SREC prices) SMART: $0.05/kWh for 20 years	No stats on customer breakdown for SREC II as a whole, but community solar projects by definition must allocate at least 50% of capacity to subscriptions under 25 kW (proxy for residential/small commercial) and there is well over 100 MW of community solar qualified and operational. Notably, policymakers chose to zero out Managed Growth capacity in recent years, in order to drive more development toward "preferred"

[16] This adder will decline at 4% per capacity block after the first 80MW of community solar projects.
[17] https://www.mass.gov/files/documents/2017/10/02/225cmr20.pdf
[18] Note – this additional value was associated only with projects that applied into the program prior to 2017 (which makes up the 95+% of the program capacity to date.)
[19] EIA-861 (2015)

		project types including those with small customers. SMART: no results yet
MN	$0.03/kWh for 25 years for residential customers, $0.025/kWh for 25 years for small commercial customers. Value based on differential of credit rate received by Residential or Small General Service versus General Service customers. (pre-2017 applications (95+% of program capacity)	As of November 1, 2017, 10% of subscribed capacity is allocated to residential customers, 5% to small commercial customers, and 85% to large commercial customers.[20]
Draft LTRRPP	50% residential: $0.008/kWh for 15 years 75% residential: $0.012/kWh for 15 years Although all bill credits are supply-only, residential customers will generally receive a bill credit rate 1-3 cents above large commercial.	Expected result: Likely very low, ~0-5%, due to lack of economic feasibility.

- **Incorporate small commercial customers in the adder.** It's unclear why the IPA chose to only include residential—but not small commercial—in the small customer adder given the specific language in Future Energy Jobs Act to create participation opportunities for both segments. (*See* 20 ILCS 3855/1-75(c)(1)(N).) The costs of serving small commercial customers are similar to those of residential customers and the small commercial customer market is similarly underserved by on-site solar due to siting and credit quality issues. Despite the challenges to serve, small commercial customers have shown interest in participating in community solar in other states.

  As with the costs comparison used above, there are examples from other markets which the IPA could reference in designing an adder that includes both residential and small commercial customers. For example, in Massachusetts, "community shared solar" is defined as projects with a least 50% of the project capacity going toward customers of 25 kW or less (remainder can go to two subscribers larger than 25 kW each). In New York, "community distributed generation" projects must have at least 60% of the project's capacity go to subscriptions of 25 kW or less.[21] SEIA recommends a similar approach as that

[20] Monthly report filed by Xcel Energy, November 8, 2017
[21] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B76520435-25ED-4B84-8477-6433CE88DA86%7D

used in these markets, whereby the adder is made eligible for projects with significant levels of subscriptions that are 25 kW (or other level) or less.

- **Set a target.** Because the IPA is tasked with creating "robust participation opportunities for residential and small commercial customers" it would be prudent of IPA to establish a vision of how that is defined. The IPA should not view these market segments as lacking interest in solar - the residential solar market has been the second strongest growth area (behind utility scale solar) in the industry for years[22], and studies show anywhere from 50% to nearly 80% of the residential sector is unable to have a rooftop solar system due to ownership, structural, and financial reasons.[23] Similar challenges have been identified for small commercial customers.[24] SEIA recommends the IPA use the portion of load and number of customers that residential and small commercial make up in the state in a methodology to develop the target. Ultimately, a target will provide an objective basis from which the IPA can evaluate the program in meeting the legislative requirements.

Recommended Methodology for the Residential and Small Commercial Adder

Taken together, SEIA recommends the following methodology for creating an effective REC adder that will have a greater likelihood of ensuring robust participation opportunities for residential and small commercial customers in the community solar program:

1. For ease of administration, establish a subscription size (such as 25 kW), rather than customer class, as a proxy for defining the "small commercial" eligibility requirement.[25]
2. Assume a higher IRR for these projects based on the level of participation by those 25 kW or less subscriptions.
3. Utilize the analysis developed in Rhode Island to inform the cost assumptions for projects with 50+% of their capacity dedicated to subscriptions of 25 kW or less (i.e., 25 cent/W upfront customer acquisition cost; 2 cents/W/year for ongoing customer replacement; and 1 cent/W/year for customer service and billing costs). We recommend the Rhode Island analysis because it is the most robust and detailed of its kind.
4. Monitor REC adder to determine whether the incentive levels drive developers to pursue enough small customer participation to meet the target. To the extent that small commercial participation is not reflecting goals, modifications to the adder may be achieved through a higher IRR or other means.
5. Rerun the REC modeling with these cost assumptions and needed incentives, and the additional suggestions in SEIA's REC modeling comments, to determine the REC adder needed to result in robust participation by residential and small commercial customers. The adder should strive to result in

[22] https://www.greentechmedia.com/research/subscription/u-s-solar-market-insight#gs.qVw=WEk
[23] The U.S. Department of Energy (DOE/NREL 2015) estimates that about 50% households and businesses are unable to host a PV system due to property constraints, and GTM Research (2015) estimates that 77% of U.S. households are locked out of the onsite rooftop market when accounting for policy and financial considerations
[24] Id.
[25] Note that the "small commercial" customer classification for some utilities may include customers with loads larger than 25 kW, however this subscription size limit would not preclude their participation.

subscriptions to community solar projects from small customers that align with the percent of load that those customer classes represent.[26][27]

Because community solar program capacity may be rapidly reserved, and it will take 18-24 months for projects to come online, it is important to ensure the REC adders are set properly at program launch, as opposed to waiting 2+ years for a review only to find that the program has failed to achieve robust participation by small customers. That said, a program review will be important for adjusting REC pricing as appropriate to reflect market evolution.

Language Changes:

Community solar projects may face additional costs and feature reduced eligibility for direct energy-related revenues than distributed generation systems. On the revenue side, subscribers to such projects are eligible only for energy-only net metering, while on the cost side, there is the cost of acquiring, maintaining, and managing subscribers. The initial block price for community solar reflects a baseline for those additional costs and potentially lower revenues. The REC prices for these projects also includes the Size Category Adjustment Adders discussed above.

To ensure that the benefits of solar energy are widely shared by Illinois residents and small commercial customers, the Adjustable Block Program will offer an additional incentive for community solar projects with a higher level of ~~residential~~ these smaller subscribers. The Agency will define 'small subscriber' to be based on a subscription size of 25kW or less. To account for additional costs related to ~~residential~~ these small subscribers, the following schedule of adders will be available to community solar projects that have minimum levels of ~~residential~~ small subscribers. For more discussion of issues related to ~~residential~~ small subscribers, see Section 7.6.2.

The ~~residential~~ small subscriber adders will be determined on the percentage of the energy output of the project subscribed to by ~~residential~~ small subscribers, and not the number of subscribers. As described in more detail in Sections 6.15.3 and 6.17, a community solar project will have to demonstrate a level of subscribers at the time of energization to initially receive an adder, and will have to maintain the ~~residential~~ small subscription levels or face having to pay penalties to remove the added value of the adders if the level is not maintained.

At this time, the Agency is not proposing an Adder that would distinguish between "developer-driven" projects and "community-led" projects. Such a distinction may be difficult to make in practice, may invite opportunities for abuse, and may create additional complexities to program administration. The Agency believes the combination of the Size Category Adjustment Adder, which would provide benefits to smaller projects, plus the option of participating in the Illinois Solar for All community solar program, adequately addresses the needs of those types of projects. For more details on this determination, see Section 7.5

[26] Statistics for these customers are available on the Illinois Commerce Commission "Electric Switching Statistics" website, found here: https://www.icc.illinois.gov/electricity/switchingstatistics.aspx
[27] Note that SEIA's proposed definition of small subscribers having 25kW or lower subscription levels does not directly align with customer classes.

~~Agency will derive a small commercial adder—based on a subscription size of 25kW, rather than the customer's utility delivery class—similar to how the residential adder is derived.~~

6.5.3. Adders to Adjust for Changing System Revenue

SEIA agrees that adders may have to be added over time to adjust for changing system revenue. We address the specific issues in Section 6.8., but note that the International Trade Commission has made its formal recommendation of remedies to the President in the Suniva/Solar World case. The President has until mid-January 2018 to decide whether or not to impose a quota or tariff, which will be during the contested case portion of the development of the Plan. We provide more comment on this in Section 6.8 below.

6.6. Payment Terms

SEIA supports the IPA's definition of "energized" and the "subsequent 4-year period." We believe these definitions are reasonable interpretations of the statute and provide clarity to the market. However, we do make specific suggestions on the payment terms.

First, we suggest that each project have the option to provide a project-specific capacity factor and 15-year estimated REC production quantity, with annual production amounts. This will allow projects to fully realize their full value, without concerns about draconian collateral forfeitures for falling short of 100% REC delivery based on a single IPA estimate for all projects. The IPA may want to suggest an upper bound on the capacity factor for guidance, but need not set a minimum as long as the capacity factor and nameplate capacity set a ceiling on the RECs that the IPA buys over the life of the project.

For small systems, the entire up-front payment should be based on this estimate. For Large DG and Community Solar projects, the first four payments should be based on this provided production estimate. For Community Solar projects this would be adjusted for subscription levels, as well as any adders for residential and small commercial customers. In a later Section, SEIA recommends more frequent check-ins for Community Solar projects than proposed in the Plan, on subscription levels and small customer participation.

The last payment for Large DG and Community Solar projects would be adjusted based on the performance of the system.

- If the project is under-producing within 10% of the production estimate (i.e. delivers 90%-100% of project-specific production), then the final payment is paid in full as initially contracted, but the system is responsible for producing and delivering the full original production amount, whether that takes the full 15 years, or 15 years plus or minus some amount of time.
- If the system is under-producing more than 10% of the production estimate, then the contract is recalibrated for the final payment based on actual delivery rates, and the project is required to deliver

the updated production amount.[28] The REC price doesn't change, just the volume to which that REC payment is applied.
- If the system is over-producing, regardless of the amount, then the system receives the final payment in full. However, these projects would be allowed to end their contract when the full production amount is delivered. In the alternative, the IPA could offer to purchase RECs from overperforming systems to fill in for spot procurements.

SEIA does not offer comment on whether 10% is the right collateral amount, however we do note that the IPA consider whether this amount will make it difficult for smaller developers and customers to participate in the market. One way around this is to allow the utility to withhold 10% of the full initial contract value from the final payment (or initial payment for Small systems) and pay it out at the end of the contract. This could be accomplished by the utilities—per order by the Commission—holding the final 10% in escrow, with detailed instructions from the Commission as to how and when to disburse. While we do not suggest the IPA model this scenario when setting REC prices, we do believe it could offer an attractive alternative for smaller developers or customers to a letter of credit or upfront cash payments.

Whether the project puts up the collateral in the form of cash or credit, or the utility withholds the collateral, we suggest that the amount be reduced over time as the project proves its production deliveries.

Finally, the Plan should make clear that for RECs produced by unsubscribed portions of Community Solar projects, for which the ABP contract does not cover, that the IPA will not count those towards compliance and that the project owner may sell those elsewhere.

Language Changes:

The Act sets up a clear schedule of payments for RECs for projects. Section 1-75(c)(1)(L) specifies the following schedule.

- For systems up to 10 kW, "the renewable energy credit purchase price shall be paid in full by the contracting utilities at the time that the facility producing the renewable energy credits is interconnected at the distribution system level of the utility and energized."
- For distributed generation systems greater than 10 kW and up to 2,000 kW and community renewable solar projects, "20 percent of the renewable energy credit purchase price shall be paid by the contracting utilities at the time that the facility producing the renewable energy credits is interconnected at the distribution system level of the utility and energized. The remaining portion shall be paid ratably over the subsequent 4-year period."

However, within that framework, the IPA has discretion to scale payments to actual performance as follows:

[28] For example, if after four years of actual production, a system shows that it is only producing 80% of its estimated RECs, then the final REC payment would be adjusted such that the sum of the REC payments equal 80% of the originally estimated value. The obligation to deliver RECs would be updated accordingly.

- If the project is under-producing within 10% of the production estimate (i.e. delivers 90%-100% of project-specific production), then the final payment is paid in full as initially contracted, but the system is responsible for producing and delivering the full original production amount, whether that takes the full 15 years, or 15 years plus or minus some amount of time.
- If the system is under-producing more than 10% of the production estimate, then the contract is recalibrated for the final payment based on actual delivery rates, and the project is required to deliver the updated production amount. The REC price doesn't change, just the volume to which that REC payment is applied.
- If the system is over-producing, regardless of the amount, then the system receives the final payment in full. However, these projects would be allowed to end their contract when the full production amount is delivered. In the alternative, the IPA could offer to purchase RECs from overperforming systems to fill in for spot procurements.

In addition, while the Agency will accept other forms of collateral, the Agency also will allow a project to elect to have the utility withhold 10% of the total contract amount from the final REC payment (or, if the system is under 25 kW, the only payment) as collateral. Because the utilities will be holding the collateral anyway (at least the cash collateral) and the utilities will be making the payments, this seems to the Agency to be a minor accounting issue for utilities and wholly consistent with the statutory framework. For systems over 25 kW, the adjustment provisions described above obviate the need for collateral draws before the final REC payment and thus the last payment date being four years after energization does not impact utilities' ability to draw upon collateral. The IPA believes this change may be a significant boost for smaller or less established players.

The Agency proposes that the standard for being "energized" as used above must include the completion of the interconnection approval by the local utility and the registration of the system in GATS or M-RETS so that generation data can be tracked and RECs created. [270] In addition, as discussed in Section 6.15.4, to avoid a system being completed but RECs not created and delivered, before a system can be considered "energized" so as to initiate REC delivery contract payments, automatic assignment of RECs to the applicable utility will need to be established The Agency believes that by ensuring proper registration in the tracking system up front, future administrative challenges can be minimized.

For systems over 10 kW and community solar projects, it is not clear from the law how exactly the "subsequent 4-year period" would be calculated, and whether the frequency of payments should be annually, quarterly, or monthly. The Agency recommends payments in equal 20% amounts on an annual basis. For example, if the first payment is made on September 1, 2018 (upon interconnection and energization), assuming continued compliance with contractual requirements, the next payments would occur on September 1, 2019, September 1 2020, September 1, 2021, and September 1, 2022 respectively. This would be five payments that bookend a four-year period of time. Section 1-75(c)(1)(L) also requires that for both categories:

- *"The electric utility shall receive and retire all renewable energy credits generated by the project for the first 15 years of operation."*
- *"Each contract shall include provisions to ensure the delivery of the renewable energy credits for the full term of the contract."*

These provisions are discussed further in Section 6.16

6.7. Contracts

SEIA has no issue with the content in this Section, however we suggest that the IPA begin contract negotiations as soon as practicable. Developers are making decisions now in order to be ready for the opening of the Adjustable Block Program. We posit that the majority of the projects built as a result of the Adjustable Block Program will be financed, and contract terms are a key aspect of whether projects will be able to receive favorable financing. SEIA notes that while protecting ratepayers and utility counterparties are important goals, these goals should be balanced with the impact on financeability, which will add costs mostly borne by solar customers.

6.8. Adjustments to Blocks and Prices

SEIA agrees with IPA's interpretation of its ability to make changes to the Adjustable Block Program without going back to the ICC for approval. The IPA should be able to adjust block sizes and prices without going through the formal procurement plan process. However, we add that the IPA should be allowed to make changes beyond the 25% if the final approved Plan allows the IPA the latitude to do so. For example, in Section 6.8.4. below we suggest that the IPA ask for explicit approval to update the REC prices if the Administration imposes tariffs on important solar modules. These tariffs could adjust prices significantly, perhaps even beyond the ability to change the price by 25%, and the IPA should seek explicit authority to change the price to account for the impact of the tariff. If the IPA requests advance permission to make this adjustment and the Commission grants the IPA's request by approving that part of the Plan, there is no need to delay the process by going back to the Commission.

Similarly, the industry and the electric utilities are only starting to learn the costs of interconnecting a large number of large distributed generation and community solar projects to the distribution grid. Illinois has excellent (recently updated) interconnection standards in place, but the cost of interconnection is dependent on the location of the project as well as the capabilities of the distribution grid. In separate comments, SEIA made specific recommendations to the REC model as to how the IPA should account for interconnection costs, but we acknowledge and caution that using examples from other states mean these costs are rough estimates and also that Illinois-specific data may be limited in its availability. In addition, even once Illinois-specific information is available, there is risk that a crowded interconnection and upgrade queue will mean bottlenecks and increased costs. Interconnection can be a significant cost for larger projects, and we suggest the IPA give itself the room to adjust prices if there is evidence that the assumption was too low. Whether that adjustment would change the REC prices more than 25% itself is unknown, but the IPA should cover that base in the plan as a precaution—especially if other adjustments are also anticipated, including the solar tariff adjustment noted above.

We agree with the IPA's proposal to not change anything for at least 6 months after the opening of the program. This will give program participants, the IPA and the program administrator the ability to test the system to some degree and distinguish developer runway and start-up time from customer demand. Also, the requirement to have a signed interconnection agreement for systems over 25 kW as a prerequisite for program application may mean there is lower demand in the first 6 months in some categories as the utilities manage interconnection demand and companies ramp up, so it may not be the best indicator of long-term program demand. Furthermore, SEIA cautions against the IPA interpreting slow uptake in a market segment – particularly during the period of the first Plan – as lack of customer demand, due to the reasons noted above.

We do have some concern that there is no definition in the plan for "very low or very high demand for the program." We do not offer a specific definition, but rather ask that the IPA or the program administrator check in with Approved Vendors, either in the form of a survey or Request for Information, before they officially make the determination that demand is too high or too low. The IPA should take into account factors including the time it took for block(s) to fill, expressions of Approved Vendor interest (either gathered by the IPA or Adjustable Block Administrator actively or passively), and for "very low demand" whether the IPA assesses that statutory goals are imperiled.

When the IPA does make changes, we suggest that the IPA give at least 3 months' notice, given the long development time for many of the larger projects, sudden changes will significantly impact the viability of many projects. For these projects SEIA prefers 9 months' notice for changes that have a materially downward impact on project economics and program availability. Three months is the absolute minimum amount of notice that industry participants require, particularly if the changes are downward.

Language Changes:

Beginning on Page 104:

In essence, changes of less than 25% can be made by the Agency without seeking review and approval from the Commission, while larger changes will require that review and approval as part of the Agency's regular annual procurement planning process.

The Agency is aware of at least four key events that could significantly impact REC pricing.

…

Each of these changes would impact the value proposition for developing a project and could require an adjustment in REC prices to keep project development viable. The Agency will notify stakeholders at least three months in advance of any changes, and provide opportunities for feedback for changes to reflect these circumstances, or others that may arise that would also require changes to be made.

In addition to these factors, and in keeping with the adjustable nature of the Adjustable Block Program, the Agency recognizes that despite its best efforts to set REC (and Adder) prices at "just right" levels, it is possible that factors that impact prices may need to be updated to reflect changing market dynamics. In response to very low or very high demand for the program, which will be determined with input from Approved Vendors, the Agency may adjust REC and Adder prices, block sizes, and other variables as needed to maintain a vigorous and healthy market for distributed solar and to reach programmatic goals. The Agency will monitor program activity and consider such change if it determines they are warranted.

The Agency intends to wait at least six months after program launch before considering making significant changes to help encourage program stability. However, if program participation is extremely low, the Agency may elect to act sooner than that.

When the Agency becomes aware of a situation that would require a change to block quantities, size, price, or other factors, including, but not limited to, the situations described herein, the Agency will post an announcement to its website regarding the proposed changes at least three months in advance of any changes and will hold either a stakeholder meeting, or an online webinar to provide an opportunity for stakeholder input. Stakeholders will also be invited to submit written comments on the proposed material changes which will be posted to the Agency's website. The Agency will consider feedback it receives prior to finalizing changes it makes that are less than 25% and do not require Commission review and approval, and will likewise consider that feedback in filings made before the Commission to update the Adjustable Block Program.

6.8.1. NEM cap

The NEM cap is particularly vexing for the high subscriber turnover of residential rooftop solar. This is because while customers on the current net metering rate are grandfathered in, new net metering customers are not. That means new customers (such as new owners of a house) start utility service, they are by definition not grandfathered in.

While the NEM cap directly impacts behind-the-meter projects, the calculation appears to be based on the load of *both* behind the meter and community solar customers. Even though community solar customers are essentially already subject to "energy only," they will be considered in the numerator of along with full retail-rate net metering customers. SEIA urges that community solar customers be left out; in addition to the reasons identified in the previous sentence, leaving in community solar customers will likely lead to accelerated impact of the NEM cap, and difficulties for developers targeting residential and small commercial customers. Similarly, utility customers on an hourly rate (either the RTP option for bundled-eligible classes or the default hourly rate for classes with a competitive declaration) receive a net metering benefit akin to a community solar subscriber. Thus, both utility hourly customers (even those with behind-the-meter projects) and community solar customers (even if on bundled service) should be excluded.

Moreover, SEIA is concerned with how the utilities will be calculating their NEM caps as suppliers. As a threshold matter, SEIA understands that the 5% NEM cap is based on the *supplier* of energy, not the delivery utility. Thus, bundled service customers—who are referred to as "eligible retail customers" in Section 16-111.5 of the Public Utilities Act—are their respective utility's supply customers. Bundled service customers should continue the full NEM credit until over 5% of that utility's bundled service customers are using net metering—who are referred to as "eligible customers" in Section 16-107.5 of the Public Utilities Act. In other words, a utility's bundled service customers should continue to receive full NEM benefits until 5% of the utility's eligible retail customers (i.e. bundled service customers) are also eligible customers (i.e. net metering customers). SEIA intentionally used the term "bundled" rather than "utility supply" customers, to exclude hourly customers (who, as noted above, should be excluded for the same reason community solar subscribers should be excluded). SEIA hopes that when the IPA "work[s] with the utilities to keep informed on when the net metering caps may be met" (LTRRPP at 105), the IPA will make sure the utilities are using the proper numerator and denominator for this calculation.

6.8.2. Smart Inverter Rebate

SEIA appreciates the IPA's recognition of the challenges that the net metering caps place on the implementation of the smart inverter rebate. The first issue is that the rebate could go up or down depending on the outcome of the ICC investigation. The IPA correctly outlines a plan to deal with this issue. The second, and perhaps greater, issue is that there is the potential for a gap between when the ICC starts the investigation and when the updated smart inverter rebate is available. It is entirely possible that a utility could hit the 3% net metering mark and very quickly thereafter hit the 5% cap. That timeframe may not be enough time for the ICC to finish the required investigation, and projects that are in development at that time may have to push the pause button, or readjust the project finances to account for a smart inverter rebate that is paid significantly later than previously expected.[29]

Furthermore, SEIA highlights that, depending on how the changes to the smart inverter rebate are implemented and degree to which projects with REC capacity reserved will be grandfathered into the $250/kW rebate level, the IPA may need to establish a transition period whereby they adjust REC values for projects with reserved capacity that ultimately receive an amount different than the $250/kW rebate.

6.8.3. Federal Solar Investment Tax Credit Adjustments

SEIA agrees with the IPA that the Investment Tax Credit (ITC) has significant impacts on project economics, but that Plan does not need to include remedies for changes in the ITC at this point.[30]

6.8.4. Tariffs on Foreign Photovoltaic Modules and Cells

SEIA agrees with the potential for tariffs could have a significant impact on project finances. Members of the International Trade Commission have given their proposed remedies to the President, and we now await his decision. Depending on the President's decision, module prices could increase up to 50%, which will affect project economics. The President has until January 13, 2018 to make a decision about what, if any, tariffs he will impose. By January 13th, the President could maintain his authority to impose tariffs for another 90 days if he announces he wishes to try to address the matter via international negotiations. Either way, the IPA will know the outcome of this case before it publishes its final REC prices 60 days after the ICC's Final Order. While there is nothing the IPA can do to affect the situation, the Plan should appropriately allow the IPA to make changes to the REC model to accommodate any tariffs.

[29] The smart inverter rebate is likely to be paid within 60 days of project beginning energy production. The utilities have said that projects that go online between hitting the 5% cap and when the new smart inverter rebate values are determined will still get the rebate, but it will be paid in arrears and in the amount that is determined by the ICC process. In other words, at this point, the $250 per kW does not continue until the ICC process has concluded.

[30] The U.S. Congress is currently debating tax reform legislation. SEIA urges IPA to monitor the outcome of this debate and potential impact on the IL solar market should a material change be made to the ITC.

6.9. Approved Vendors

I. Consumer Protections and Approved Vendor Qualifications

Consumer protections and consumer confidence in their solar providers are critical elements of a robust solar market. SEIA notes that both distributed and community solar involve 20+ year commitments, which may include (in the case of distributed generation) modifications to the customer's premises. In other words, SEIA agrees with the IPA that: "incorrect, inaccurate, or deceptive information could put the financial security of Illinois residents or businesses at risk and poison the ongoing viability of the solar market in Illinois." (LTRRPP at 112.) SEIA also believes that consumer education, consumer understanding of offers, and fair treatment by market participants promote the state's statutory goals.

That said, SEIA also understands that there are both statutory limits on what the IPA (and Illinois Commerce Commission) can mandate, and practical implications on what the IPA—especially given its size and structure—can achieve. In addition, while keeping bad actors out of the market is important, the IPA should not impose onerous, unnecessary, or unworkable burdens that lead to the unintended consequence of fewer reputable participants or reduced value to customers.

While achieving the appropriate balance is challenging, SEIA has addressed similar issues in other states and believes its proposal is a thoughtful, "down the middle" approach that balances consumer protections while avoiding unjustified (and ultimately consumer unfriendly) burdens on developers. These proposals address Sections 6.9, 6.10, 6.13, and 7.6.2 of the LTRRPP together, because SEIA believes that Approved Vendor requirements and consumer protections are two sides of the same coin (proposed language changes will be in the respective sections).

A. SEIA Proposal

SEIA recommends that the IPA adopt the following Approved Vendor requirements and consumer protections, which are designed to balance developing a new market with promoting customer-protective standards:

- **Approved Vendor Application**: SEIA believes this should include basic information about the company seeking Approved Vendor status, which would include:
  - Basics like name and contact information,
  - Evidence of registration to do business in Illinois,
  - Disclosure of final criminal or administrative actions against the entity in other US jurisdictions, and any pending formal criminal or docketed administrative proceedings involving fraud, deception or unfair marketing practices, or other similar allegations over the last 24 months.[31]
- **Approved Vendor Timeframe**: To ensure that developers can participate in the first round of the Adjustable Block program, SEIA recommends that the IPA set a 30-60 day deadline for taking action on an Approved Vendor application.

[31] SEIA drew this language from the application for certification as an Alternative Retail Electric Supplier.

- **Contract Requirements**: SEIA understands that the IPA wishes to see—but not specifically approve—the basic form contracts that Approved Vendors plan to use for each product (*e.g.*, leases or system sales).[32] SEIA believes it is helpful for the IPA to understand the products and services in the market. While SEIA believes that Approved Vendors will likely be receptive to informal IPA questions about contracts, the IPA should not approve or modify contracts as a condition of maintaining Approved Vendor status. The IPA can provide guidance on contract provisions that would trigger questions from the IPA.
- **Participation in IPA Training**: SEIA agrees with the IPA that offering IPA-designed training will improve the culture of compliance within the Approved Vendor community and address any confusion Approved Vendors, especially new or smaller companies, may have about any requirements.
- **Standard Disclosure Forms and Brochures**: On page 113 of the LTRRPP, the IPA referred to a disclosure form and brochure to be provided to all customers. SEIA recommends that either the IPA require use of the standard SEIA disclosure form and brochure, or the SEIA disclosure form and brochure supplemented with Illinois-specific information be an accepted alternative to any standard disclosure. SEIA forms have extensive and detailed disclosures that allow not only for price comparisons, but also unraveling what exactly is behind that pricing including other non-price benefits or risks. SEIA will separately address items that the IPA suggested that should be excluded from these forms.
    - SEIA does not necessarily object to standardized language explaining regulatory changes such as the smart inverter rebate or net metering credit formula once certain target values are hit.
    - SEIA recommends that the IPA look to the *SEIA Residential Consumer Guide to Solar Power* and the *Residential Consumer Guide to Community Solar* as models for the brochure. The guides summarize options for going solar, tips on evaluating whether one's home is right for solar, and key questions to ask a company.
    - The IPA should post the standard disclosures to its website. This will allow the customer to refer back to the IPA website at any time for this information.
    - The IPA requested evidence that each customer has been presented with a standard disclosure form and brochure; SEIA does not necessarily agree with this recommendation but suggests that the consumer contract contain separate initial or signature lines with statements to the effect of "I have received and read [name of form], which I understand is also available on the IPA's website at [address]."
- **Complaint hotline**: SEIA believes that a complaint hotline will help consumers get to the best agency for their needs. A guide of common issues and the agency who handles them would be invaluable for hotline staffers and consumers. Until the hotline is developed, as an interim measure, SEIA recommends including the Illinois Attorney General's Consumer Protection division number. SEIA hopes that any complaint trends are shared with stakeholders.

[32] SEIA understands this to be similar to the requirement in 83 Ill. Admin. Code § 412.310(a), which requires that Retail Electric Suppliers submit to the Illinois Commerce Commission Staff sample contracts for residential customers. SEIA further understands that the Illinois Commerce Commission and its Staff do not approve these contracts, but rather keep them for reference.

B. Rationale for Departure from IPA Recommendations

The SEIA proposal above is a modification of the IPA's recommendations for consumer protections and Approved Vendor prerequisites. SEIA will explain below its reasoning for modifying the IPA's original proposal.

1. Modifications Based on Authority

SEIA recognizes that the IPA is in a unique situation—as the IPA noted itself, it "is not a regulatory body." (LTRRPP at 135.) The Illinois Commerce Commission is, but its direct jurisdiction over solar developers is mostly limited to "Qualified Person" requirements. (*See* LTRRPP at 113.) This is not to say that the IPA and Illinois Commerce Commission do not have tremendous influence over the development of a robust and consumer-positive solar market—SEIA readily acknowledges the role both agencies play. However, within the statutory framework, SEIA noted the following gaps:

- The Illinois Commerce Commission does not license Approved Vendors, and SEIA is unsure of the statutory basis (if any) for jurisdiction over complaints directed at Approved Vendors (unless of course the Approved Vendor holds another certificate or license issued by the Commission);
- While SEIA acknowledges that the Illinois Power Agency does have the authority to set program terms and conditions—which is explicitly acknowledged in Section 1-75(c)(1)(N) of the Illinois Power Agency Act and SEIA believes implicit in Section 1-75(c)(1)(K) of the Illinois Power Agency Act—SEIA is not sure whether that authority extends to taking and adjudicating complaints. SEIA is also unsure of whether the IPA is structured in a way to provide due process to solar developers faced with one or more complaints, especially to the extent the IPA reserves the right to revoke Approved Vendor status based on complaints. (*See* LTRRPP at 113 (suggesting the IPA could revoke Approved Vendor status based on complaints).)

SEIA strongly believes that addressing consumer complaints is important, and acknowledges that the Illinois Attorney General's Office is better able to address systemic concerns than individual complaints. (*See* LTRRPP at 113 (considering referring complaints to Illinois Attorney General's Office).) In the absence of new legislation, SEIA believes that trying to shoehorn complaint proceedings into existing structures is not the proper way to handle them.

Finally, it appears that the IPA would like to impose the requirements of Section 2EE of the Consumer Fraud Act and/or aspects of Part 412 on solar developers. SEIA explains below why Part 412 (and the requirements of 2EE) are inapplicable to solar developers as a policy matter. However, as an authority matter, SEIA is unsure of the statutory basis for the IPA requiring compliance with Section 2EE, a statutory provision that is not applicable to solar developers. (*See* LTRRPP at 132 (suggesting that the IPA could impose Third Party Verification requirements on solar developers using certain marketing channels).) Similarly, it is unclear the IPA's authority for imposing Commission rules applicable to Alternative Retail Electric Suppliers—and then only to residential customers—on all solar developers.

Surely the IPA does not believe it has unlimited authority to impose any term or condition it wanted on Approved Vendors without limitation. SEIA strongly recommends that if the IPA persists in the putting the items above in its LTRRPP it submits to the Commission for approval that the IPA not only identify the specific authority it relies on but also the limiting principle that prevents absurd results (such as the IPA requiring Approved Vendors to use one color for all solar panels).

2. Modifications Based on Potential Consumer Fraud and Deceptive Business Practices Act Liability

Section 2 of the Consumer Fraud and Deceptive Business Practices Act states in relevant part:

> Unfair methods of competition and unfair or deceptive acts or practices, including but not limited to the use or employment of any deception fraud, false pretense, false promise, misrepresentation or the concealment, suppression or omission of any material fact, with intent that others rely upon the concealment, suppression or omission of such material fact, or the use or employment of any practice described in Section 2 of the "Uniform Deceptive Trade Practices Act", approved August 5, 1965, in the conduct of any trade or commerce are hereby declared unlawful whether any person has in fact been misled, deceived or damaged thereby.

(815 ILCS 505/2.) Section 2 of the Consumer Fraud Act prohibition against deceptive acts encompasses both knowing misrepresentations and innocent misrepresentations and misrepresentations of both present and future conditions. (*See* 815 ILCS 505/2; *Duran v. Leslie Oldsmobile, Inc.,* 594 N.E.2d 1355, 1360-61 (Ill. App. Ct. 2d Dist. 1992).) The statutory test is not whether the statement made was actually deceptive, but whether the statement had a "capacity to deceive." (*Williams v. Bruno Appliance & Furniture Mart, Inc.*, 379 N.E.2d 52, 54-55 (Ill. App. Ct. 1st Dist. 1978).) The bar for establishing fraud under Section 2 of the Consumer Fraud Act is significantly lower than under common law because certain common law elements have been eliminated. (*Duran* 594 N.E.2d at 1360.)

In setting out the standard disclosures on, the IPA includes the following:

> price and performance of the system as installed, including first year production, annual system production decreases, overall percentage degradation over the life of the system, a standard forecast for retail electricity prices, a net cash flow analysis, and a target rate of return of each project.

(LTRRPP at 112.) Although the IPA does clarify that it plans to fill in the blanks for "electricity prices (and other inputs)," SEIA is concerned that estimates of future electricity prices (and derivative numbers such as target customer rate of return) have a "capacity to deceive" because they are speculative and will vary not only over time but by electricity supplier. Due to the potentially disastrous effects of a lawsuit from the Attorney General or class action lawsuit and the uncertainty regarding whether the protections in Section 10b(1) of the Consumer Fraud Act would apply, SEIA recommends that the IPA not require standardized estimates of production, degradation, future electricity prices, or any numbers derivative of these values. Of course, if a particular developer wishes to make voluntary statements on these issues, SEIA notes that developers should be allowed to make the business decision to provide estimates and face any risks of doing so.

3. Modifications Based on Potentially Unintended Negative Consequences or Disproportionate Developer Burdens

While SEIA appreciates the IPA's goal of protecting consumers, some of the protections impose disproportionate burdens on developers (to the customer benefit) or lead to negative consequences. SEIA recommends removing these requirements.

First, SEIA recommends removing provisions that require developers to guarantee their contractors' compliance with law (especially Qualified Persons who are already regulated by the Commission). Installers and contractors are already required to follow the law, and it is not clear why the IPA seeks to make the developer a supplemental guarantor of compliance. In addition, companies already need to take *commercially reasonable* oversight measures with their contractors. However, SEIA cautions that compelling developers to undertake too much oversight could tip the balance in multi-factor federal tests in a variety of legal arenas—including tax, occupational health and safety, and employee benefits—leading agencies to treat entities intended to be independent contractors as "employees."

Second, SEIA understands why the IPA would be interested in financial information and corporate structures of Approved Vendors. Regardless—especially as it remains unclear how the IPA would evaluate such information—SEIA is concerned it could be used to exclude newer and smaller players from the market, instead only allowing large national players to enter the market. SEIA recommends the IPA not seek this information from Approved Vendors. Collateral requirements should be at least a partial deterrent to fly-by-night entities.

Third, SEIA recommends against conditioning approval on IPA review of marketing materials (including telemarketing scripts). While SEIA appreciates that the IPA is likely doing so to monitor potential bad acts, the IPA has not set out a standard for reviewing these documents and it is unclear whether the IPA or the Program Administrator will have personnel trained to evaluate legality or prudence of marketing materials. SEIA is concerned that this program could lead to uneven enforcement (to the extent the IPA takes any action), unintentionally imposing the IPA's preferences instead of screening for misleading claims, and putting certain companies' marketing materials unjustifiably under the microscope. Furthermore, it is not clear what remedy a developer would have if they disagreed with the IPA's conclusions about marketing materials or IPA suggested revisions, potentially depriving Approved Vendors of due process. SEIA suggests that the IPA direct Approved Vendors to FTC advertising and marketing guidelines. SEIA also recommends that the IPA create its own consumer education materials to be disseminated on a voluntary basis by any entity.

Also, several of the Maryland community solar disclosure form protections are a challenge or inapplicable in Illinois:

- Section (a)(2) requires "The terms by which any net metering credits will be calculated and applied to the subscriber's account," but those are within the control of the customer's electric supplier (whose identity the solar developer may not know), and are likely to change over 20-25+ years unless the customer keeps the same supplier over that entire period.
- Section (n) requires "A notice that the contract does not include utility charges." This may not be true of some products and services.

- Section (p) and (r), which require privacy policies and proof of insurance, may make the disclosures very lengthy and it is unclear what benefit customers will receive from either (but particularly proof of insurance). This would defeat the efficacy of any disclosure form which is meant to provide a snapshot of key terms.
- Subsection (x) requires: "An explanation of how unsubscribed production of the project will be allocated." Respectfully, as long as the burden is not placed on that residential subscriber, this is irrelevant to the customer.

Additionally, when considering the issue of disclosure forms, SEIA urges IPA to keep in mind that disclosure forms are designed to provide a snapshot of key terms to an agreement, not regurgitate the contract. Through its own efforts to develop disclosure forms and incorporating input from stakeholders, SEIA experienced firsthand the challenge in balancing brevity with usefulness. As a result, SEIA cautions the IPA from mandating a lengthy set of disclosures which would result in an unwieldy disclosure form and thereby frustrate the form's purpose of being a useful reference tool for consumers.

SEIA reserves the right to recommend deletion or modifications to other sections drawn from the Maryland protections during future proceedings.

4. Inapplicability of Part 412

The IPA recommended that: "as a condition of ongoing approval, Approved Vendors will be expected to comply, at a minimum, with marketing standards equivalent to the Commission-approved rules for marketing practices by alternative retail electric suppliers where applicable. (83 Ill. Admin. Code Part 412, Subpart B)" (LTRRPP at 113.) These standards are inapplicable to solar developers to the point that the IPA would be better served in its draft LTRRPP for ICC approval if it sets out solar-specific requirements for Approved Vendors. However, as a general rule, the concepts in Subpart B to Part 412 should not apply.

As an initial matter, it is worth understanding the difference between retail electric suppliers (RES) and solar developers. In order to "sign up" a customer, RES must represent to the utility that the utility's customer wishes to switch its current supply service to that RES. The customer does not and cannot do this directly with the utility—the RES must do it. This, of course, creates a concern that RES may (intentionally or unintentionally) "slam" a customer, or cause the utility to switch a customer's supply service without customer consent. As a result, the legislature provided three pathways for a RES to prove that a customer intended to switch in Section 2EE of the Consumer Fraud Act (815 ILCS 505/2EE(a)-(c).) Most of Subpart B of Part 412 is explaining additional requirements beyond what is in Section 2EE of the Consumer Fraud Act to sign up a customer through various marketing channels (for instance, in person solicitation, telemarketing, direct mail, etc.)

Immediately, there is a distinction between solar developers and RES: A solar developer does not cause a customer to change their supply choice. Although it is true that a community solar developer does disclose a customer's share of a community solar project, that involves a utility (or RES) *credit* to the customer, not a charge. In other words, the developer-customer-utility relationship is very different from the RES-customer-utility relationship. There is no slamming concern from the solar developer's interactions with the customer's utility.

Perhaps what the IPA intended to signal was it wished to impose minimum disclosure requirements on various solar developer marketing channels. An example would be an affirmative statement that the developer is not "employed by, representing, endorsed by or acting on behalf of the electric utility, a governmental body . . . , or a consumer group." (*See, e.g.*, 412.120(a).) With respect, SEIA is unsure what authority the IPA has to regulate the content of marketing of solar developers to their customers. While SEIA does not challenge the IPA's authority to require standard disclosures at the time of contracting, minimum marketing requirements do not appear to have a basis in statute. If the IPA persists in this recommendation, SEIA recommends that the IPA further explain the basis of its authority to do so.

Even if the IPA does have the authority to impose these requirements, it is important that the IPA separately spell out what it wishes to import rather than simply referring to Subpart B of Part 412. Of note, here are some of the standard disclosures that a blanket reference to Subpart B would require:

- Any fees assessed by the RES to a customer for switching to the RES (412.110(h));
- A statement that the customer may rescind the contract, by contacting the RES, before the RES submits the enrollment request to the electric utility (412.110(j));
- A statement that the customer may rescind the contract and the pending enrollment, within 10 calendar days after the electric utility processes the enrollment request, by contacting the RES. Residential customers may rescind the contract and the pending enrollment by contacting either the RES or the electric utility. The statement shall provide both toll-free phone numbers (412.110(k));
- A statement that the RES is an independent seller of power and energy service certified by the Illinois Commerce Commission . . . . (412.110(*l*)); and
- A statement that the customer will receive written notification from the electric utility confirming a switch of the customer's power and energy supplier (412.110(n).)

(83 Ill. Admin. Code 412.110 (accessed 11/9/17).) Simply changing "RES" to "solar developer" would confuse customers, because these statements are completely inapplicable or misleading. SEIA notes that these standard disclosures are incorporated by reference in all of the marketing channel-specific requirements.

SEIA also notes that once the revisions to Part 412 that were approved in ICC Docket No. 15-0512 are printed in the Illinois Register and effective, there will be several requirements that are confusing at best and inapposite or harmful at worst for the solar context. Those include 83 Ill. Admin. Code §§ 412.165 (rate notice), 412.170 (training of agents), 412.180 (record retention), and 412.190 (product description). The Product Description section would be particularly vexing, especially given that the RECs are intended to be sold to the IPA and not distributed to customers or subscribers.

For these and other reasons, SEIA strongly urges the IPA to abandon reference to Part 412. Instead, if the IPA wishes to import requirements from Part 412—which SEIA also opposes—the IPA should separately set those out so there is not confusion about requirements that cannot and should not apply to solar developers.

<u>Language Changes (Section 6.9 only):</u>

The Agency does not anticipate restricting Approved Vendors by the entity type; as such, the types of Approved Vendors could include a company that specializes in the aggregation and management of RECs; a for-profit developer or installer of photovoltaic systems; or a municipality or non-profit serving a specific sector of the community, among others. Approved Vendors will have to agree to the following terms:

- Participate in registration and complete any training developed by the Agency
- Abide by these ongoing program terms and conditions
- Provide information to the Agency on the Approved Vendor's organizational history, capacity, ~~financial information,~~ regulatory status in Illinois and other states (including any prior or current criminal or regulatory adjudications or any docketed complaints ~~or other actions~~ involving fraud, deception or unfair marketing practices, or other similar allegations over the last 24 months against the Vendor), etc.
- Be registered to do business in Illinois
- Disclose to the Agency names and other information on installers ~~and projects~~, while otherwise maintaining confidentiality of information
- ~~Document that all installers and other subcontractors comply with applicable local, state, and federal laws and regulations, including for example, maintaining Distributed Generation Installer Certification~~
- ~~Provide samples of any marketing materials or content used by the Approved Vendor, and/or their subcontractors/installers and affiliates, to the Agency for review, as requested.~~
- ~~Agree to make changes to marketing materials as instructed by the Agency.~~
- Register in GATS or M-RETS and demonstrate the ability to manage project application and REC management functions in the applicable tracking system
- Pay applicable application fees
- Provide and maintain credit and collateral requirements
- Submit Annual Reports on a timely basis

6.10. Program Administrator

SEIA agrees with the IPA's approach to the Program Administrator role, but suggests that the Program Administrator should also be involved in linking Approved Vendors with workforce development programs. While workforce training is outside the scope of this Plan, the IPA, the Program Administrator, and Approved Vendors all have a vested interest in making sure that the workforce training programs authorized by Public Act 99-0906 lead to work on the development and construction of actual solar projects. We do not have specific recommendations on how the Program Administrator would accomplish this task, but rather that the Program Administrator initiate discussions with the solar industry and the organizations doing workforce training to see if the Program Administrator can play a role.

SEIA also suggests that the Plan limit the Program Administrators ability to charge excessive fees. Already in the Plan, the IPA has identified a $10/kW non-refundable application fee, as well as a set-aside of 3% of the RPS budget to cover administrative costs. SEIA recognizes some of that money will cover the utilities' administrative costs, but some will also cover costs for the Program Administrator. We do not believe additional fees will be warranted, and suggest the IPA put some language in the Plan to limit the ability of the Program Administrator to charge additional fees.

SEIA also refers back to the discussion in Section 6.9, although there are no proposed language changes related to the discussion.

Language Changes:

Beginning on page 109:

This includes, but is not limited to:

- Assisting the Agency with Approved Vendor registration and training
- Developing a Program Manual
- Establishing an online portal for Approved Vendors to submit projects (and providing technical support to Approved Vendors) and collecting application fees
- Maintaining an online dashboard to show block status
- Reviewing and approving submitted batches of projects
- Preparing contracts for Commission review and utility execution
- Ongoing monitoring of project development status
- Verifying completion of projects and the processing of approvals for payments, as well as conducting on-site inspections for quality assurance purposes.
- Reviewing Annual Reports submitted by Approved Vendors
- Providing information for the public including maintaining an online list of Approved Vendors and educational materials related to distributed generation and community solar
- Assisting in workforce development efforts to the extent feasible

The Program Administrator will be authorized to charge fees to Approved Vendors as described in Section 6.14.4 for processing applications, subject to review by the Agency. The Program Administrator will strive to minimize any additional fees beyond those already approved in the Plan. The Program Administrator will operate under a contract with the Agency and may also be reimbursed by the utilities for a portion of the cost of the services provided to them including, but not limited to, the preparation of contracts and review of Annual Reports

6.11. Program Launch

SEIA appreciates the amount of work that the IPA and the Program Administrator will need to accomplish before the Adjustable Block Program can launch. Developers and customers are assuming a Summer/Early Fall 2018 launch, and any delays to this timeframe will add costs to projects under development, and therefore the entire program. Therefore, we suggest expediency and transparency in determining the launch date.

We agree with the idea of training Approved Vendors before program launch, and suggest that the Program Administrator do as much pre-application work as possible before launch the program. We do not believe, however, that the IPA should accept manual submittal of documents. SEIA would prefer a delay in the launch of the program in order for online submittal to be available at the outset.

SEIA believes that blocks should launch concurrently to the extent possible. The requirements for projects to apply to the program will help manage initial demand, as well as demand throughout the program, making a concurrent launch more manageable. If a delay between block launches is warranted, we suggest the IPA limit that to a week or two at most.

Language Changes:

This Plan is expected to be approved by the Commission by early April 2018. At that time, assuming the Agency's program administrator RFP process proceeds on its expected timeline, the Agency will also seek approval from the Commission for the selection of the Program Administrator. With these two elements in place, implementation of this Plan will then commence. Due to the scope and complexity of the Adjustable Block Program, and the need to develop standard contracts, a Program Manual, an online portal, and other tasks, it is reasonable to assume that it will take several months for the Program to launch. The Agency will work with the Program Administrator to find ways to expedite program opening. Until the Agency has received bids from potential Program Administrators, it is premature for the Agency to commit to a set schedule for Program Launch. The IPA will update interested parties on a regular basis as to the expected schedule for Program Launch.

To the extent possible, the Agency will prepare the application process for potential vendors to be Approved Vendors on an expedited schedule so that Approved Vendors will be in place prior to program launch. The IPA and Program Administrator will strive to launch blocks concurrently, and when not possibly, will limit the space between block launches to two weeks. ~~In theory, it may be possible to phase in certain aspects more quickly, like the community solar portion of the Adjustable Block program, because it is expected to have fewer, larger projects proposed than would distributed generation. Another option could be for the Adjustable Block to launch prior to all predicate elements being ready: for instance, without having the online portal for project submittals fully in place, instead relying on manual submittal of documents by Approved Vendors. For this draft Plan, the Agency seeks comments from interested parties on if the various program categories should launch concurrently, or start at different times.~~

6.12. Project Requirements

6.12.1. Technical System Requirements

SEIA strongly supports the technical system requirements outlined in this section. We maintain that these requirements will ensure that only viable projects enter the program, and that valuable program capacity will not be wasted on "ghost" projects. However, we do suggest the IPA provide clarity on the definition of non-ministerial permits. The Massachusetts DOER defined non-ministerial permits as:

> "permits in which one or more officials consider(s) various factors and exercise(s) some discretion in deciding whether to issue (typically with conditions) or deny permits. Examples of ministerial permits include, but are not limited to building permits and electrical permits."

We would further add that approval by a government committee or board where a vote happens (i.e. the approval is subjective) is an example of a non-ministerial permit.

We do recommend that the IPA update the annual production bullet to account for project-specific production. As outlined in our comments in Section 6.6, we believe that each project should be awarded a REC contract based on the project-specific production instead of a standard capacity factor.

Furthermore, we recognize that the IPA has no control over the interconnection process, but recommend that the IPA check in with Approved Vendors as to the functioning of the interconnection queue. This plan is based on the assumption that the utilities will adhere to the timeline in their interconnection process. We have no reason to believe otherwise, but we also recognize that the utilities have not seen the volume of interconnection applications they are about to receive as result of this program. SEIA members will continue to work with the utilities and the ICC to fine-tune the interconnection process, and we will propose remedies for any perceived shortfalls or disputes. We suggest that the IPA check in on this issue during the revision of the Plan, and make corrections if necessary.

Language Changes:

- Project-specific e~~E~~stimate of ~~annual~~ production during the 15-year contract term using PV Watts or a similar tool

6.12.2. Metering Requirements

SEIA agrees with the metering requirements outlined in this Section. We suggest in Section 6.6 that REC contracts are based on project-specific capacity factors and thus project-specific REC production. More detail on this recommendation and language to support it is included in Section 6.6.

6.13. Customer Information Requirements/Consumer Protections

Please refer to Section 6.9 above for a discussion of relevant issues and support for the language changes below.

Language Changes:

The information that must be provided to all customers (and such provision documented to the Agency) includes:

- **Contracts:** A copy of the contract for the power purchase agreement, lease, or sale. Vendors may use model leases and model power purchase agreements ("PPAs") provided by the Solar Energy Industries Association ("SEIA"), or other standard contracts ~~that have been approved by the Agency~~.
- **Disclosure Form:** The Agency will develop and provide to Approved Vendors standard Disclosure Forms to be completed and provided to each program participant prior to contract execution. For distributed generation projects the form will at minimum, include standard information on the system equipment and components, warranty, installer, and lease or financing structure. The form will also include an estimate of the price ~~and performance of the system as installed, including first year production, annual system production decreases, overall percentage degradation over the life of the system, a standard forecast for retail electricity prices, a net cash flow analysis, and a target rate of return of each project~~. The form may be substantially similar to the SEIA standard disclosure. The form will also include a disclosure that cash flows may change if the utility's net metering tariffs or distributed generation rebates change prior to the completion of the system (e.g., the changes that occur when net metering enrollment reaches 5%). ~~The Agency will provide standard electricity prices (and other inputs) to be used for these estimates as to allow~~

~~equivalent comparisons between different offers~~. For community solar subscribers, the form will include similar applicable provisions as well as conform to the provisions listed in Section 7.6.2.

- **Brochure:** The Agency will require Approved Vendors to distribute to program participants prior to the execution of the contract with the program participant, a consumer protection brochure in both print and electronic form prepared by the Program Administrator and approved by the Agency. That brochure will inform consumers of their rights, procedures for filing complaints, and point to more information on the program website.

Full details will be provided to Vendors who apply for participation in the Adjustable Block Program or the Illinois Solar For All program.

Vendors must also agree to provide sales and marketing information, included contract prices and sales volumes, to the Agency on a confidential basis. The Agency will use this information for internal purposes to track market progress.

~~Lastly, as a condition of ongoing approval, Approved Vendors will be expected to comply, at a minimum, with marketing standards equivalent to the Commission-approved rules for marketing practices by alternative retail electric suppliers where applicable. (83 Ill. Admin. Code Part 412, Subpart B).~~

In this draft Plan the Agency proposes the same requirements related to information disclosure (listed above) for all project sizes. The Agency invites interested parties to comment on if these requirements should vary by project size/customer segment, and if so in what ways.

6.13.1. Community Solar

Please see Section 6.9.

6.13.2. Monitoring of Consumer Complaints

Please see Section 6.9.

6.14. Application Process

6.14.1. Batches

SEIA recognizes the difficulty of approving so many contracts, and the limitation that the statute requires around ICC approval of all contracts. In light of this, we agree with the concept of using batches to approve contracts, however we request that the IPA clarify that while a project may have a REC contract with a different utility than the one where the project is located, the REC price is determined by where the project is located. In other words, a project located in ComEd territory gets the ComEd block price, but may have a contract to sell the RECs at the ComEd block price to Ameren.

6.14.3. Batch Size

SEIA agrees with the proposed batch sizes, nor do we take issue with the non-refundable fee proposed in this project. However, we do ask that the IPA take this proposed fee into consideration in Section 6.10. when discussing the Program Administrator's ability to charge Approved Vendors fees.

6.14.5. Converting System Size into REC Quantities

SEIA disagrees with the IPA's decision to use a mandated standardized capacity factor for calculating the number of RECs for each project. While SEIA does not object to the IPA using a standardized capacity factor for budgeting or other internal purposes, the requirement becomes problematic when combined with the 100% REC delivery requirement where there is no upside (at least within the Adjustable Block program) to overproducing but significant penalties for underproducing. In light of these concerns, SEIA instead suggests that the IPA use a project-specific capacity factor and contract production amount. This will help project developers and system owners realize the full value out of their systems, and it will help the IPA meet its requirement to ensure geographic diversity.

We understand that a standard capacity factor was used for the Supplemental Solar Procurements and the Utility DG Procurement, however, these procurements had contracts for only 5 years' worth of RECs, and the contracts ended if the production requirements were met early. In these programs the IPA also has the ability to purchase additional RECs produced beyond the contracted amount, though we are not at a point of knowing whether that is likely to happen or not.[33]

We believe that contracts for RECs through the ABP should be treated differently because of the length of the contract and the scope of the program. SEIA recommends that upon application to the Adjustable Block Program each project submit a projected capacity factor, and an accompanying 15-year REC quantity that takes into account system production declines. This will allow each system to realize the value of every REC produced. A roof-mounted system in Peoria would be expected to have different production than a ground-mounted fixed-tilt system in Cairo, and the Cairo system may end up producing the standardized number of RECs by year 12, making it harder for the developer and potential system owner to make the project pencil. Using a standard capacity factor means that developers and system owners may have to undersize the system components so as to overproduce less, and therefore not fully realize the system potential. We do suggest the IPA have some guardrails around the potential capacity factors it will accept, however, and make suggested language changes to that effect below.

We also believe that using project specific capacity factors will help the IPA realize more geographic diversity. Standard capacity factors will encourage developers to target areas and customers where the standard capacity factor is most likely to produce the exact amount of RECs required. A project-specific capacity factor will encourage developers and system owners to build projects throughout Illinois.

We do support the IPA using standardized capacity factors to predict overall REC deliveries and accompanying budgetary needs, as well as for REC modeling purposes. We believe the capacity factor should be conservative

[33] The first DG contracts have only been effective since 2015, so we are not yet at the 5 year mark.

and to the specific Group and Category. We suggest specific capacity factors for those purposes in our suggested language changes below.[34]

Language Changes:

For each system that is approved, a project-specific 15-year REC obligation will be calculated for that system and that will be included in the contract. The calculation will be based on the projected 15-year production provided in the project application. The Agency will not accept capacity factors higher than 25% AC or lower than 10% AC. ~~following average capacity factors which, as discussed below, are based upon the capacity factor used in the Fall 2017 Utility DG procurement and adjusted for an expected degradation rate over 15 years.~~

- ~~Fixed-mount system 16.4177%~~
- ~~Tracking system 19.3149%~~

~~These numbers vary from the capacity factor used by the Agency for the Supplemental Photovoltaic Procurements and the Utility Distributed Generation Procurements for the following reasons.~~

~~First, prior to the Fall 2017 Utility Distributed Generation Procurement, the Agency used a capacity factor of 14.38%. This capacity factor was calculated using a DC rating. Public Act 99-0906 included the following new definition, "`Nameplate capacity' means the aggregate inverter nameplate capacity in kilowatts AC." With this change for the Fall 2017 Utility Distributed Generation Procurement, the Agency updated the capacity factors to reflect an AC rating and established them as 17% for a fixed mount system and 20% for a tracking system.~~

~~Second, the Supplemental Photovoltaic Procurement and the Distributed Generation Procurement were for five-year REC contracts. While photovoltaic panels experience annual degradation in their output, it was not factored into the capacity factors for those procurements. Given the 15-year REC delivery obligation for the Adjustable Block Program, degradation is a more significant concern, and thus a 0.5%/year average output degradation factor was used to calculate the capacity factors listed above.~~

~~Using these capacity factors which have been adjusted by the degradation rate, for every 1 kW of capacity, approximately 21 RECs would be expected to be generated over 15 years for a fixed-mount photovoltaic system. For a tracking system, for every 1 kW of capacity, approximately 25 RECs would be expected to be generated over 15 years.~~

For budgetary and planning purposes, however, the IPA will use the following capacity factors to estimate the number of MW in each block.

	Small and Large DG Category	Community Solar (50% fixed, 50% tracker)	
		Ground Mount (fixed tilt)	Ground Mount (tracker)

[34] See SEIA comments on the REC model for further detail.

Group A (Ameren - average of several downstate capacity factors)	14.2% DC 17.04% AC	15.75% DC 18.9% AC	18.9% DC 22.7% AC
Group B (ComEd Rockford)	13.6% DC 16.3% AC	15.1% DC 18.1% AC	18% DC 21.6% AC

6.14.6 Batch Control Approval

In Section 6.14.6, the IPA states that it believes the Illinois Commerce Commission must approve individual Approved Vendor contracts with utilities under the Adjustable Block program. Respectfully, SEIA believes that Commission approval of the *standard* Approved Vendor contract may be necessary, but not of individual contracts. Specifically, the Public Utilities Act requires that:

> The Agency or third parties contracted by the Agency shall implement all programs authorized by the Commission in an approved long-term renewable resources procurement plan without further review and approval by the Commission. Third parties shall not begin implementing any programs or receive any payment under this Section until the Commission has approved the contract or contracts under the process authorized by the Commission in item (D) of subparagraph (ii) of paragraph (5) of this subsection (b) and the third party and the Agency or utility, as applicable, have executed the contract.

(220 ILCS 5/16-111.5(b)(5)(iii).) Subsection (b)(5)(ii)(D) referenced above contains the following language:

> The Commission shall also approve the process for the submission, review, and approval of the proposed contracts to procure renewable energy credits or implement the programs authorized by the Commission pursuant to a long-term renewable resources procurement plan approved under this Section.

(220 (ICS 5/16-111.5(b)(5)(ii)(D).) Taken together, it is clear that the IPA must get Commission approval of the standard Approved Vendor-utility contract. However, SEIA notes that Commission approval of *specific* Approved Vendor-utility or Approved Vendor-IPA contracts is not a specified precondition to the utility or IPA executing. Instead, SEIA believes that (b)(5)(ii)(D) requires the IPA to recommend and the Commission to approve the process and standards for how the Adjustable Block Program Administrator will decide whether to authorize a contract with an Approved Vendor for a specific project. The IPA sets this out in Section 6.14.4 of the LTRRPP.

Conversely, there is no need for the Adjustable Block Program Administrator to be compelled to send pending contracts (using the pre-approved form) to the Commission for final approval. There is no statutory standard for the Commission to review and approve, and it is not even clear what facts the Commission would review to make an approval decision or what grounds there would be to not approve. The better approach would be for the Commission to approve the form contract, and the Adjustable Block Program Administrator to approve contracts for utility or IPA countersignature "without further review and approval by the Commission"

Language Changes:

~~The Commission meets approximately every two weeks. The Program Administrator will strive to efficiently process approved batches for submittal to the Commission. The Agency understands that Commission practice is that items for consideration by the Commission must be submitted to be placed on its open meeting agenda at least one week prior to each meeting.~~

~~Once a batch is approved by the Commission, the Program Administrator will forward the contract to the applicable utility for execution. The Approved Vendor will be required to also sign the contract within seven business days of receiving it from the utility. A collateral requirement equal to 10% of the total contract value will be required in the form of either cash or a letter of credit with the utility within 14 business days of Commission approval of the contract.~~

6.15.1 Development Time Allowed

SEIA supports the project timelines suggested in this Section.

6.15.2. Extensions

SEIA agrees with the extension options outlined in this Section.

6.15.3. Project Completion and Energization

SEIA does not object to any of the requirements for project completion and energization. However, we do request that the IPA or Program Administrator develop a standardized form for the required 6-month check-in, and make the form as simple as possible. We also suggest that the project submit a final capacity factor and 15-year production estimate before energization for contracting purposes.

The IPA should also consider a situation where a project may switch from being a distributed generation project to a community solar project. For example, the host may, for a variety of reasons, decide in the development of a project that it can only contract for a portion of the output of the system on its property. In this situation the Approved Vendor would have to notify the IPA of the intent to switch the project, and it would receive the block price of the block that is currently open for community solar. The capacity of distributed generation would be added to the currently open block of DG.

Language Changes:

The Approved Vendor will provide the Agency an update on each project that is under development but not yet energized at least every six months and will inform the Agency of any significant changes to the system. For community solar projects, the update will include an update on the status of acquiring subscribers. The Agency and Program Administrator will develop a standardized form for these purposes.

Once a project is energized, the following information will be required to approve the final project and authorize the start of payment for RECs.

- Final system size
- Final project-specific capacity factor and final 15-year production estimate
- GATS or M-RETS approval including unit ID
- Certificate of Completion of Interconnection or comparable document
- Net metering application approval letter (if applicable)
- Photographic documentation of the installation
- Disclosure of any changes related to the contract for installation that occurred between the initial application and the completion of the project

If the final system size is larger than the proposed system size such that it would cause the system to change from the up to -10 kW to the over-10 kW category, the payment terms will be adjusted from the full payment on energization to 20% on energization and the balance over the next four years. The price per REC will also be changed to the applicable REC price for the over 10 kW category in effect at the time when the system is energized.

For systems over 10 kW, any adders received will be based on the final system size if that final system size would cause the adders to decrease. A system that is developed at a size smaller than the original application will not be eligible for additional adders.

The quantity of RECs used for the calculation of the payment for RECs will be based on the final project-specific 15-year production estimate provided by the Approved Vendor. ~~lesser of the proposed system size and the final system size. In this way, a system that is built smaller than planned will not benefit from excess REC payments that could result from purposefully submitting the project at a larger size than really intended. On the opposite side, if a project's final system size is significantly larger than the planned system size, an increase in the payment due could present unexpected budget management challenges.~~ An Approved Vendor would have the option of canceling and resubmitting a system if the final size would put the system into a different size category than the proposed system, or if the project changes from a distributed generation project to a community solar project, or vice versa, ~~is larger than the proposed system in order to align the REC quantities~~. However, the resubmittal will be at the price of the Block open at the time, not the original submittal. A new application fee will be required because the Agency will need to review the system design which would be different from what was originally submitted (e.g., because of the change in system size). The Agency will reserve the right to request more information on an installation, and/or conduct onsite inspections/audits of projects to verify the quality of the installation and conformance with the project information submitted to the Agency. Projects found not to conform with applicable installation standards and requirements, or projects found not to be consistent with information provided to the Agency will be subject to removal from the program if the deficiencies cannot be remedied. Likewise, Approved Vendors who repeatedly submit projects that have these problems may be subject to losing their Approved Vendor status.

6.15.4 Additional Requirement for Community Solar Projects

SEIA appreciates the difficult challenge of making sure that REC payments are made for RECs from only the subscribed portion of community solar projects. We agree that the project should be at least 50% subscribed before payment for RECs begins, but we have some concerns that the check-in timeframe proposed in the Plan will subject community solar projects to significant loss of potential revenue.

If the only check-in for community solar projects is one year after energization, with no look-back period, then a project could lose 50% of 3 years' worth of REC value, as every 20% payment represents approximately 3 years' worth of RECs. This could ruin the financial viability of projects. We suggest instead that projects check-in more frequently, and that payments are calculated on a backward-looking, prorated basis. For example, if a project has only 50% of the project subscribed at energization, the first payment would be 50% of 20% of the value of the REC contract. However, if one month later the project is 100% subscribed, the second payment should include both 100% of the 2nd 20% payment, as well as 48.6% of the previous 20% payment.[35]

We support the IPA's proposal to have the community solar project maintain the subscription levels for the life of the contract, including the level of small subscriber participants, though we do suggest that the IPA allow for some level of cure period, 3 months or so, without being penalized.

We suggest that the IPA use an annual check-in process that is coordinated with the utilities for this process. Every project will have to maintain subscription levels in a utility-owned community solar portal, and will have to verify those subscription levels on a monthly basis throughout the lifetime of the project. Community solar owners or the utilities, whichever is easiest, should be able to provide project-specific reports on subscription levels. It appears that project owners will be able to download project information from the utility-maintained Community Solar portals. Community solar owners can include this information in their annual reports, redacting any customer specific information. If the utility-maintained portals ultimately are not able to provide this information to project owners, then we suggest the IPA work with the Approved Vendors and the utilities to facilitate a random annual audit of 10% of the projects to check for discrepancies between annual reports and data the utility has for the audited projects.

Language Changes:

A community solar project will have to demonstrate that it has met a minimum subscription level to be considered energized and eligible to commence receipt of payment for RECs. The Agency proposes that at least 50% of the capacity of the project must be subscribed at the time of energization in order to receive payment for RECs, and that payment will be based upon calculating the number of RECs that correspond with the amount of the project's capacity that has been initially subscribed. The Approved Vendor will update the subscription levels on a monthly basis over the first year. The final subscription level in those monthly updates will determine the second payment, which will include an *additional* proportionate amount of the first year payment the corresponds to the filled subscription level over 50%. If the system is not fully subscribed after the first year, the Approved Vendor will continue to update the subscription levels on a monthly basis, and additional prorated

[35] 1 month of production is 1/36th of the 20% payment. As 50% has already been paid, the remaining is 35/36 x 50% = 48.6% of the first 20% payment. For a 2 MW project with a 18% capacity factor in Group B, with the largest residential adder, based on the current prices ($43.09 + $11.83 = $54.92), this represents $250,000 in lost revenue. 20% x 45,468 RECs (the 15-year production total) x $54.92 x 50% = $250,700.

REC payments will be made with the third REC payment. ~~The calculation of the number of RECs for payment will be updated after one year of operation to allow for the acquisition of additional subscribers.~~

A community solar project may request one additional extension (with a non-refundable extension payment as provided for in Section 6.15.2) to its energized date if it needs additional time to acquire subscribers. The adders for residential participation (i.e., for a minimum of 50% or 75% of energy sales) will only be added (on a prorated basis) to the REC price if the project demonstrates that level of participation for the subscribed amount at the time of energization. If the subscription level has not been met by the time of energization, the adder will be held back from the initial payment and the system will have to wait until it has been in operation for one year to demonstrate that it has met the residential participation level to receive this adder. The Approved Vendor will update the residential participation percentage on a monthly basis, and future payments will include the adder in the payment for past months, as described above. ~~If the residential subscription rate is met, then the full value of the adder will be added pro-rata to the remaining payments~~.

If a community solar project fails to attract sufficient subscribers by the time of energization, but also meets the definition of a distributed generation project (i.e., is located on-site, behind a customer's meter, and used primarily to offset a single customer's load), it may request to be recategorized as a distributed generation project and receive a REC payment at the lesser of the original price and the price of the distributed generation block open at the time this determination is made. A community solar project that does not meet the definition of a distributed generation project that fails to attract subscribers will not be eligible for this option and would not be eligible for REC payments. Likewise, an approved distributed generation project may switch to a community solar project before energization and receive the REC price of the currently open community solar block, and any appropriate adders. In both of these situations, the project may only switch one time.

Ongoing requirements for overall subscription levels and residential participation are discussed further in Section 6.16

6.15.5 REC Delivery

SEIA agrees with the concept set out in this Section, but reiterates the need to have project-specific capacity factors and 15-year production amounts in order for projects to receive the full value of their production. Also, based on SEIA's read of Section 10.2 of the PJM-GATS Operating Rules cited by the IPA, the project would be forced to transfer all RECs to the utility *without regard to whether the RECs were receiving payment under the Adjustable Block program*. This could happen for a variety of reasons; overproduction and undersubscribed community solar is another. It is also not clear how an irrevocable standing order would mesh with the remedies available to developers in Section 6.16.2 to reduce REC deliveries in the event of system underperformance.

While SEIA appreciates the value of the automatic REC transfer to efficiency and ease of administration, SEIA will be uncomfortable with this arrangement unless or until the IPA also explains how RECs that are not compensated under the Adjustable Block program can be held back from the utility.

Language Changes:

~~Approved Vendors will be required to set up an irrevocable 15 year Standing Order for the transfer of RECs from the system to the utility. 294 As the Agency understands that automatic transfers can only be terminated with the assent of both parties, this will reduce the risk to the utility that the RECs could be sold to another party after the utility has paid for them.~~

6.16. Ongoing Performance Requirements

SEIA appreciates the IPA's attempt to make ongoing performance requirements easier on Approved Vendors by suggesting a portfolio-level approach. We disagree with this approach and suggest that the IPA adopt our recommendations regarding project-specific capacity factors and 15-year production amounts, as well as our REC delivery and payment term recommendations outlined in Section 6.6. These recommendations include reasonable project-specific performance requirements that the industry can support. This Section becomes unnecessary and we suggest the IPA remove it in its entirety.

6.16.1. Credit Requirements

SEIA refers the IPA to our previous suggestions about collateral. We suggest that there should be an option for the collateral to be withheld from the final REC payment. Again, we believe that maintaining a portfolio-level approach is unnecessary if the IPA adopts our recommendation to use project-specific capacity factors and 15-year production amounts, as well as our REC delivery and payment term recommendations outlined in Section 6.6.

Language Changes:

An Approved Vendor is required to post collateral equivalent to 10% of the total contract value when each Batch's contract is approved. The Approved Vendor may choose for the utility to withhold the collateral from the last REC payment (or only REC payment for Small systems). In this situation the collateral would be reduced as described below, and fully returned at the end of the contract. As systems are energized, this collateral amount will be maintained through the life of the contract, and can be reduced in the later years of the contract when the collateral requirement exceeds the remaining value of the contract. ~~This requirement will be maintained at the portfolio level, not the individual system level.~~

~~By maintaining collateral requirements at the portfolio level, the Agency is allowing Approved Vendors to manage the risk that some systems may underperform (or have other problems), and others will not, or even overperform. This allows the collateral level to be lower than it would be if maintained at the system level.~~

~~Nonetheless, an~~ An Approved Vendor will be responsible for delivering the RECs under its contracts per the terms laid out in Section 6.6. (subject to the reduction options described in the following Section). Failure to deliver RECs will result in the utility drawing on the collateral to be compensated for undelivered RECs that were paid for. After any such drawing the Approved Vendor will need to increase its collateral to bring it back up to the 10% of remaining value within 90 days. If the amount of collateral is insufficient to compensate the utility, the Approved Vendor will be required to make an additional payment to the utility for the remaining balance.

Failure to make payment and/or maintain the collateral requirement will result in the Approved Vendor's suspension from participating in the Program.

Reconciliation of REC deliveries and collateral requirements will be conducted on an annual basis based on the Annual Reports filed by the Approved Vendors as described in Section 6.17.

6.16.2. Options to Reduce REC Delivery Quantities

SEIA agrees that there may be situations outside of the system owner's control that will affect REC delivery. In addition to the situations listed in the Plan, SEIA suggest the IPA include curtailment of the system by the utility or Regional Transmission Organization as a reason REC delivery amounts may be suspended without penalty (along with other force majeure events). If a system owner chooses to apply for the Smart Inverter Rebate–SEIA expects that virtually all Large systems and Community Solar systems will apply for the rebate—then those systems have to agree to give the utility control of the inverter during "reliability events." While the details of the rebate tariffs are not final, we believe these situations will be infrequent. Nonetheless, curtailment poses a risk to REC delivery that is out of the system owner's control.

Language Changes:

In force majeure type circumstances (including, but not limited to, physical damage to the system from fires, tornados, etc.) the Approved Vendor may request to have a delivery obligation suspended, reduced, or eliminated without penalty. Utility and RTO curtailment would also suspend, reduce, or eliminate delivery obligations without penalty in the amount of the curtailment(s). Approval of the request will require consensus between the Agency and the applicable utility. For this draft Plan, the Agency is interested in comments from interested parties on what type events should, or should not, constitute a force majeure circumstance.

6.17. Annual Report

SEIA generally supports the contents of the annual report. However, SEIA notes that subscription levels and adders can be verified through the utility-sponsored portals that track such information. It would be more straightforward to have utility data populate these fields in the first instance rather than the Approved Vendor manually inputting them and being subject to checks by the IPA and/or utilities.

7.2. Eligible Generating Technologies and Procurement/Program Eligibility

At this time, IPA should not suggest procurement beyond the ABP for Community Renewable Generation. The ABP should be considered the Community Renewable Generation Program until the first revision of the program, when the IPA will have more information regarding program performance and budget constraints. Furthermore, should IPA consider expanding the Community Renewable Generation Program beyond the ABP, it should use its authority to require that such projects to be new projects that are additional to development that will have occurred under the ABP.

7.3. Co-location of Projects and 7.3.1. Co-location Standard

SEIA believes that there are real benefits to limited co-location. First and foremost, co-location helps to de-risk project development. Currently, REC prices are based on certain assumptions, including the cost of interconnection. Most projects will not have completed the interconnection process by the time the Plan is finalized, or even by the time the REC prices are updated. Even then, interconnection costs (and other costs) are estimates. Developers will strive to develop projects where they expect costs to be equal to or lower than the assumptions in the REC model in order to make the project pencil, but it takes time to determine those locations, and community solar projects will trigger distribution upgrades, particularly in areas where there may not have been distribution investment for many years. For the foreseeable future, some level of co-location will help project economics and will allow more early projects to succeed. Furthermore, limited co-location will help communities that have limited number of sites available for development. Particularly in urban areas, there may be only one or two parcels that are suitable for development.

We recognize the desire of both the legislature and the IPA to encourage a geographically diverse program and limit gaming of the system. We recognize and share the IPA's desire to limit the possibility of one developer leasing multiple contiguous parcels and selling them to different entities in order to get around the co-location standard. And we want to help IPA avoid unintended consequences. For instance, there is a real risk to projects if the Plan imposes restrictions based simply on a gross number of projects or megawatts without considering project ownership. At this early stage of the program, developers (and ultimately the financiers who will likely be project owners) have little knowledge of the exact location of where other developers (and ultimately owners) are developing projects. We posit that the possibility of more than 4 MW of contiguous projects is unlikely, both because of landowner limitations, and of interconnection limitations. Nonetheless, there may be situations where one development is close to another development and the project developers won't be aware of the each other until well into development. Even then, it's not a foregone conclusion that both developers will be able to successfully develop their projects. Therefore, adjacent ownership shouldn't be unfairly targeted.

We respectfully suggest that the co-location is limited by the Approved Vendor that is submitting the application to the Adjustable Block Program. In most cases a developer that doesn't intend to be the long-term owner of the asset will have to apply to the ABP before selling the project. Limiting the developer to 2 projects in one location (on a single parcel or contiguous parcels) will limit the possibility of development on contiguous projects beyond the 2 the standard would allow. We submit the following co-location standard and suggest the IPA examines the issue in the first revision of the Plan.

Proposed language:

In enacting Public Act 99-0906, the General Assembly expressly included a size limit for community renewable generation projects of 2,000 kW, and the Agency does not believe it should ignore the intent of that size limit being included in the definition of community renewable generation projects. However, the Agency recognizes some benefit to co-location, particularly as the market begins to grow.
On the other hand, as discussed in Section 6.5.1, the Agency seeks to avoid the situation in which

multiple smaller projects are co-located in order to obtain the higher REC prices available to smaller Systems.

To appropriately balance these competing issues, and with a slight preference for a stricter colocation standard to avoid problems of the type discussed above, the Agency proposes the following co-location policy. ~~For the purposes of this policy, being a "separate entity" means that the entities do not share a common ownership structure, shared sales or revenue-sharing arrangements, or common debt and equity financing arrangements.~~

- ~~For each parcel of land (as defined by the County the parcel is located in), no more than 2 MW of community renewable generation may be installed.~~
- No Approved Vendor may apply for the Adjustable Block Program for more than 4 MW of Community Solar projects on the same or adjacent parcels. These projects may be co-located in one of two ways. Either a) two 2-MW projects on one parcel, or b) one 2-MW project on each of two contiguous parcels.
    - A parcel of land may not have been divided into multiple parcels in the two years prior to the project application (for the Adjustable Block Program), or bid (for competitive procurements) in order to circumvent this policy. If a parcel has been divided within that time period, the requirement will apply to the boundaries of the larger parcel prior to its division.
- If there are multiple projects owned by a single entity (or, ~~non-separate~~ affiliated entities) located on one parcel of land, or on contiguous parcels of land, any size-based adders will be based on the total size of the projects on each parcel that are owned by the entity(ies).
- ~~Projects owned by separate entities may be located on contiguous parcels.~~ If there is a naturally good location from an interconnection standpoint, one owner should not be allowed to prevent another owner from developing a project in that location.
- ~~For projects located on contiguous parcels, if the total combined size of the projects is greater than 2 MW, then the projects must be owned by separate entities.~~
- Projects must have separate interconnection points.

7.4. Eligibility of Projects Located in Rural Electric Cooperatives and Municipal Utilities

SEIA strongly supports the standards the IPA proposes for the inclusion of projects from municipal utilities and rural electric coops. Ratepayers from these utilities do not pay into the RPS budgets, yet projects in these utilities are eligible to participate in the Adjustable Block Program. We agree that these utilities should meet the requirements that the investor-owned utilities in order for projects in their jurisdictions to be eligible.

7.5. Types of Community Renewable Generation Projects

SEIA agrees with the IPA's proposal to not include adders for "community-led" projects. We suggest the Agency revisit this issue in the first revision of the Plan in 2019.

7.6. Subscriber Requirements

As described in previous and future Sections of these comments, SEIA strongly supports the use of adders to encourage small customer participation. Further, we believe that small commercial customers should be considered with residential customers. We encourage the IPA to look at other states' community solar programs, but we caution the IPA from drawing to close a parallel to any other state. No other state has a structure exactly like Illinois, so a direct comparison is not appropriate.

7.6.2. Residential Subscribers

Please see discussion in Section 6.9 above.

Language Changes:

The Agency recognizes that it may not be able to prohibit door to door or telemarketing sales of community renewable generation subscriptions, but notes those marketing channels as ones of particular concern because of the information asymmetry between the salesperson and the consumer. The Agency believes an informed consumer is a wise consumer and strongly encourages marketing channels that respect the opportunity for consumers to have complete and accurate information about the decisions they may make regarding subscriptions, particularly those related to upfront payments, the net price of energy, and termination fees and conditions. ~~The Agency may conduct additional monitoring of Approved Vendors (and/or their partners/affiliates) that utilize door to door or telemarketing sales, and reserves the right to request the Approved Vendor provide additional documentation of those marketing channels including, but not limited to, access to call center recordings for either sales or third-party verifications.~~

* * *

Drawing from the consumer protection guidelines for community solar adopted by the Maryland Public Service Commission, the Agency proposes to require that Community Renewable Generation marketers provide consumers with the following disclosures:

a) A plain language disclosure of the subscription, including:
   i) The terms under which the pricing will be calculated over the life of the contract and a good faith estimate of the subscription price expressed as a monthly rate or on a per kilowatt-hour basis;
   ii) ~~The terms by which any net metering credits will be calculated and applied to the subscriber's account; and~~
   iii) Whether any charges may increase during the course of service, and, if so, how much advance notice is provided to the subscriber.
b) Contract provisions regulating the disposition or transfer of a subscription, as well as the costs or potential costs associated with such a disposition or transfer;

c) All nonrecurring (one-time) charges;
d) All recurring (monthly, yearly) charges;
e) A statement of contract duration, including the initial time period and any rollover provision;
f) Terms and conditions for early termination, including:
   i) Any penalties that the Project Developer may charge to the subscriber; and
   ii) The process for unsubscribing and any associated costs.
g) If a security deposit is required:
h) The amount of the security deposit;
   i) A description of when and under what circumstances the security deposit will be returned;
   ii) A description of how the security deposit may be used; and
   iii) A description of how the security deposit will be protected.
i) A description of any fee or charge and the circumstances under which a customer may incur a fee or charge;
j) A statement that the Project Developer may terminate the contract early, including:
   i) Circumstances under which early cancellation by the Project Developer may occur;
   ii) Manner in which the Project Developer shall notify the customer of the early cancellation of the contract;
   iii) Duration of the notice period before early cancellation; and
   iv) Remedies available to the customer if early cancellation occurs;
k) A statement that the customer may terminate the contract early, including:
   i) Amount of any early cancellation fee;
l) A statement describing contract renewal procedures, if any;
m) A dispute procedure;
n) The Agency's and Commission's phone number and Internet address;
~~o) A notice that the contract does not include utility charges;~~
p) A billing procedure description;
~~q) The data privacy policies of the Project Developer;~~
r) A description of any compensation to be paid for underperformance;
~~s) Evidence of insurance;~~
t) A long-term maintenance plan;
u) Current production projections and a description of the methodology used to develop production projections;
v) Contact information for the Project Developer for questions and complaints;
w) A statement that the Project Developer and utility do not make representations or warranties concerning the tax implications of any bill credits provided to the subscriber;
x) The method of providing notice to the subscribers when the project is out of service for more than three business days, including notice of:
   i) The estimated duration of the outage; and
   ii) The estimated production that will be lost due to the outage.
y) ~~An explanation of how unsubscribed production of the project will be allocated~~; and

z) Any other terms and conditions of service

7.6.3. Marketing Claims Related to the Ownership of RECs and Community Renewable Generation Subscriptions

SEIA has addressed its preference for IPA guidance on marketing issues but direct regulation in Section 6.9 above. In addition, SEIA supports the analysis of CCSA, to the extent it is not inconsistent with SEIA's comments.

7.7.Utility Responsibilities

SEIA does not have any comments on this section except to recommend that the Adjustable Block Program Administrator work with utilities to audit community solar subscription rates (i.e. how subscribed a project is) and residential participation levels.

Language Changes:

To be added at the end of the Section:

In other sections, the Agency has explained the various ways that Approved Vendors will report on community solar subscription rates and residential participation levels—both of which will impact Adjustable Block program payments. The utilities keep parallel records about both, and can be a valuable partner with the Adjustable Block Program Administrator in auditing the filings and submissions made by Approved Vendors. Accuracy will reduce instances in which the Adjustable Block program made payments in circumstances where it should not have.

8. Illinois Solar for All Program

SEIA does not offer comments on the Illinois Solar for All Program at this time.

Respectfully submitted,

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