Joint Solar Parties Comments on LTRRPP Questions
June 11, 2025

LTRRPP Comments – Chapter 7:

Topic 2

Questions

1. Given the information above, and assuming the Group A and Group B block sizes will remain fairly consistent with the 2024 Long-Term Plan, what are the advantages and risks of establishing a developer cap process for CDCS consistent with the other categories?

JSP RESPONSE: The Joint Solar Parties continue to oppose a developer cap. The CDCS Block continues to be relatively small, there are a relatively low number of participants, and the IPA already includes an extensive scoring rubric to choose projects based on other criteria. In addition, CDCS has a single application window per year and all projects submitted within the 90-day timeframe (rather than first come/first served in TCS with an always-open waitlist) are scored together, reducing fears that a single developer could disadvantage competitors with quality projects by simply producing quantity.

However, to the extent that the IPA does impose a developer cap, the Joint Solar Parties recommend: (1) a higher cap than TCS, which is not only larger in size but also has far more participants in the last several program years and a scoring system that only applies to the waitlist; and (2) a cap that only applies in the event of oversubscription of the CDCS Block, because it makes little sense to leave capacity open just to respect a developer cap (as opposed to providing genuine opportunities for a broader range of participants). It would be counterproductive to have a number of CDCS projects that scored over the threshold to sit idly while capacity remained open simply to have a developer cap.

2. If a developer cap process for CDCS is appropriate, should the threshold be set at 20% or is there an alternative percentage that should be considered? Please provide any reasoning to support a different percentage level, if possible.

JSP RESPONSE: While a developer cap is not appropriate, if there is one it should be large enough at least for a 5 MWac system to fully participate and only apply to the extent that the developer cap does not prevent full allocation of open CDCS capacity for projects scoring over the minimum threshold during the initial selection process or from the waitlist. In other words, while the Joint Solar Parties oppose a developer cap, no developer cap should leave capacity unused simply for the purpose of holding a single developer or a small group of developers under an arbitrary threshold.

The Joint Solar Parties note that during both the 2023 and 2024 program years, it appears that each project that was applied received an award (including those that were initially waitlisted). The purpose of a developer cap is to ensure that a single participant or a very small number of participants do not monopolize capacity to the detriment of smaller participants; in this case where there is enough capacity to go around there is no group of (or even single) player that is being frozen out. On the other hand, because of the extensive community outreach that goes into project applications, it would be harmful to those communities asked to participate in pre-application processes to have their project rejected not on its merits but on a developer cap that would otherwise cause the capacity to go unused.

Finally, the Joint Solar Partes note that in the event a developer cap is invoked, even if all capacity is used after the developer cap is imposed such a structure would result in lower-scoring (i.e. less beneficial to the relevant community) projects being selected over higher-scoring projects from capped out Approved Vendors. This undermines the goals of the CDCS program to deliver community benefit and reward purposeful and meaningful community engagement.

Topic 3

Questions

1. Should the Agency establish an opt-in process for all community solar projects that are eligible for batching? Why or why not?

JSP RESPONSE: The Joint Solar Parties support flexibility and do not oppose opt-in processes for community solar projects for batching. While it is uncommon (though not unheard of) for multiple community solar projects to be in a single batch, the rebatching process delays submission to the Commission and Trade Date (Commission approval), and thus the deadline for posting collateral. In the event an early stage developer is seeking to sell the project after the IPA has selected the project but before the collateral obligation (or to assign the project before the REC Contract and assignment fees), allowing that delay can be helpful for projects and transactions.

2. Should there be a time limit for how long community solar projects can remain on the opt-out list? If so, for how long?

JSP RESPONSE: While the Joint Solar Parties (in the response above) support flexibility, it is important that opt-in rebatching for community solar not be used as a free extension for immature projects that need to further derisk prior to the collateral requirement attaching or setting an initial Energization deadline. Currently, the limit on remaining on the opt-out rebatching list is two Commission meetings. Given that the Commission has about three meetings per month, it makes sense to provide a nine meeting (approximately three month) limit, meaning the tenth time is an opt out rather than opt in. This allows flexibility while not allowing use of rebatching as an incentive to submitting more immature projects and using rebatching as a no-cost timeframe to derisk a project.

3. What other factors should the Agency take into consideration before adopting this solution?

JSP RESPONSE: The Joint Solar Parties respect the acknowledgement in the background that some projects encounter very real interconnection issues—many if not most of which are not the result of developer delay or error. However, the best solution to interconnection issues are changes to the Energization extension (Section 2.4 in the 2024 20-Year REC Contract) and termination for excessive interconnection (Section 7.2 in the 2024 20-Year REC Contract) provisions to incorporate flexibility. Examples of changes include extending or removing the time limit between the utility notice of changed price—which may not be the result of a study—or expanding the interconnection delay good cause shown extension to Scheduled Energization Date.

Topic 4

Questions

1. What would be the effect and/or benefits of once again requiring an executed interconnection agreement in the Part I application for community solar projects? Please provide details to support your response.

JSP RESPONSE: The Joint Solar Parties oppose creating this requirement. Currently, Ameren has a multi-*year* wait to even be studied for community solar, making it virtually impossible to submit projects that did not enter the queue a substantial amount of time ago. In addition, the study process can be frequently extended by disputes ahead in queue, utility delays or restudies based on changing conditions, or other disputes.

In addition, the interconnection points allow several pathways to the minimum five TCS points necessary to get on the waitlist (and frequently serves as a *de facto* minimum or near-minimum score to be selected even when there is no waitlist in Group B). Taking away the pathway of interconnection plus agrivoltaics/pollinator friendly would negatively impact the ability of greenfield development on agricultural land. Removing interconnection points would also and reduce the viability of rooftop community solar systems (which get certain points for rooftop development but not enough to meet the five-point threshold).

Thus the Joint Solar Parties oppose the requirement of an interconnection agreement. However, if it is implemented the two points for a signed interconnection agreement (one for first or second in queue and another one for the signed ISA) should be taken off of the five-point minimum.

The Joint Solar Parties note this position is relative to TCS; the Joint Solar Parties oppose adding an interconnection agreement requirement for CDCS as well and request that the signed interconnection agreement remain a points-scoring opportunity for CDCS.

2. What other requirements should the IPA consider in order to ensure that community solar projects are sufficiently mature when submitted to the Program such that the projects are ready to be submitted to the ICC upon Part I application verification?

JSP RESPONSE: Unfortunately, in the current environment of interconnection queue struggles in both Ameren and ComEd service territories, uncertainty at the federal level (on both tax/tariff and regulatory issues), and other factors (such as supply chain and labor shortage issues), it is not practicable to fully derisk a community solar system in Illinois at the time of application. The IPA should continue to incentivize obtaining an interconnection agreement but not requiring it, as attempts at interconnection reform hopefully bear fruit over the coming months and years.

Topic 5

<u>Questions</u>

1. Is there value to the Agency developing solutions to manage this issue given this challenge is primarily between an Approved Vendor and their customers? Please explain.

JSP RESPONSE: Yes, there is substantial value to finding a way to allow the solar system to keep generating and in compliance—even if there is no longer a customer attached to the account—with the REC Contract. This is because customer abandonment is (without formal guidance) currently a substantial risk for financing of PPAs, leases, or system sales. One of the few options available is an early termination fee (again, for all contract types including system sales) for if the project no longer qualifies for the ABP to charge <u>at least</u> the remaining REC Contract value and the collateral value for that system. This also creates issues of access to the ABP, because customers (both residential and non-residential) with relatively worse credit may face even worse terms to cover Approved Vendor and financing party risk. Of course, if the Approved Vendor was not at risk for a clawback if the customer abandoned the account, then the Approved Vendor and financing parties will not need to pass that risk onto the customer.

The easiest and cleanest way to do this is an explicit note—perhaps in 2.4(f) or 8.2(b)(iii) of the 2024 15-Year REC Contract—that after Energization that failure to remain a Distributed Renewable Energy Generation Device as defined in Section 1-10 of the IPA Act for failure to remain behind a customer's meter due to customer abandonment is not a default of the REC Contract.

The Joint Solar Parties note that this same issue applies not only to all behind-the-meter systems but also to Public School Block community solar projects as well, which require a minimum subscription from accounts owned by the district. Abandonment of buildings or district consolidation is a parallel risk, although it can be addressed through the Public School Block terms and conditions.

2. What type of relief should be offered to Approved Vendors that face a situation of an abandoned contract?

JSP RESPONSE: The Joint Solar Parties do not recommend compensation or relief other than allowing the REC Contract to continue as long as the solar generating device remains active and generating RECs. In other words, the only relief is that the Approved Vendor is not penalized under the REC Contract for customer abandonment.

3. What are preventative solutions to this issue that the IPA could implement?

JSP RESPONSE: Respectfully, there is nothing the IPA can do to prevent customer abandonment. Customers will move (and the property will sit abandoned or the new resident will refuse to accept assignment of the appropriate agreement), businesses may close or change—these are inevitable facts of life that cannot be fully contracted around. While Approved Vendors can of course impose early termination fees and restrict access to highly creditworthy customers, a better approach is to just protect the Approved Vendor so it does not suffer a loss for actions outside of their control <u>as long as the solar system is still delivering RECs</u>.

4. Are there other examples/events that should be considered an "abandoned contract"?

Topic 6

1. What barriers and decision-making challenges do public schools face when exploring the opportunity to install solar and participate in the Illinois Shines program?

JSP RESPONSE: Some of the barriers are statutory and can only be addressed by a change in law, while others can be addressed by (or are in fact a product of) the LTRRPP.

- Statutory Challenges: The statutory requirement that the contract be 20 years with payment each year not exceeding the REC price multiplied by the "estimated annual renewable energy credit generation amount." (20 ILCS 3855/1-75(c)(1)(L)(iv).)
- Regulatory Challenges: The following requirements from the LTRRPP currently in effect make the Public School block challenging:
    - The requirement that the school or another account in the district subscribe at least 10% of a participating community solar system; every year in which the public school or another single account in the district is not 10% of nameplate capacity on the first business day of December, under Section 2.6(e) of the 2024 20-Year REC Contract the REC Contract payments for that year are $0.
    - The requirement that the school district own (and not lease) the land on which the system sits and that the school must own the land for the duration of the 20-year REC Contract.
    - The REC pricing was not sufficiently higher than the parallel blocks (Large DG or TCS/CDCS) to incentivize developers to take on the additional risks and costs of participating the same system in the Public School Block.

The Joint Solar Parties note that Section 1-75(c)(1)(K)(iv) of the IPA Act contains the following passage:

> Each of the Agency's periodic updates to its long-term renewable resources procurement plan to incorporate the procurement described in this subparagraph (iv) shall also include the proposed quantities or blocks, pricing, and contract terms applicable to the procurement as indicated herein. In each such update and procurement, the Agency shall set the renewable energy credit price and establish payment terms for the renewable energy credits procured pursuant to this subparagraph (iv) that make it feasible and affordable for public schools to install photovoltaic distributed renewable energy devices on their premises, including, but not limited to, those public schools subject to the prioritization provisions of this subparagraph.

(20 ILCS 3855/1-75(c)(1)(K)(iv) (emphasis added).) Thus, the IPA could conceivably create terms and conditions such as a capital advance that respects the 20-year REC Contract requirement while still providing the types of terms and conditions that could make the Public Schools program work.

2. What sort of education or outreach would make participation in the Illinois Shines program more accessible to schools?

JSP RESPOSNE: Illinois has several programs that provide energy audits for public schools including the Illinois State Board of Education (ISBE) Energy Efficiency Grants, Illinois Energy Now (via DCEO/Smart Energy Design Assistance Center), and Utility Programs. Public Schools that participate in these programs could be made aware of Public School Block and connected with Approved Vendors that wish to participate in the Public School Block.

3. What, if any, additional considerations should be made for Tier 1, Tier 2, and schools located in Environmental Justice Communities? Currently, they have prioritized capacity for part of the Program Year and do not require collateral.
4. What changes could be made to make the Public Schools category more attractive to developers and schools?

JSP RESPONSE: In parallel with identification of the parallel statutory and regulatory barriers:

As it relates to statutory barriers, the Joint Solar Parties note that Section 1-75(c)(1)(K)(iv) of the IPA Act contains the following passage:

> Each of the Agency's periodic updates to its long-term renewable resources procurement plan to incorporate the procurement described in this subparagraph (iv) shall also include the proposed quantities or blocks, pricing, and contract terms applicable to the procurement as indicated herein. In each such update and procurement, <u>the Agency shall set the renewable energy credit price and establish payment terms for the renewable energy credits procured pursuant to this subparagraph (iv) that make it feasible and affordable for public schools to install photovoltaic distributed renewable energy devices on their premises</u>, including, but not limited to, those public schools subject to the prioritization provisions of this subparagraph.

(20 ILCS 3855/1-75(c)(1)(K)(iv) (emphasis added).) Thus, the IPA could conceivably create terms and conditions such as a payment advance (similar to the EEC Block capital advance in concept) that respects the 20-year REC Contract requirement while still providing the types of terms and conditions that could make the Public Schools program work. At minimum, an advance of payment could put the projects economically on more even footing with the Large DG Block without increasing the per-REC prices.

Regarding regulatory barriers, the primary barrier is school or district ownership (as opposed to lease or sublease) of the relevant land. The project location should not be restricted to school district-owned land because there are other interests (leasehold, easement, etc.) that a public school or a school district could have in land other than fee simple ownership. In addition, allowing multiple public school or district (or neighboring district) accounts to comprise 10% of system nameplate capacity rather than just 10% from a single school or district account would help districts with smaller buildings gain the benefits of community solar by spreading them over more (but smaller) accounts. Finally, the 20-year subscription requirement could be relaxed to something closer to 10 years—similar to the EEC Block requirement that an EEC Approved Vendor hold the REC Contract from application to the sixth anniversary of Energization.

Topic 7

1. What are potential reasons for dividing parcels or projects in the pre-development stage that the IPA should consider, beyond maximizing category-specific REC prices and avoiding project labor agreement requirements? Please explain.

JSP RESPONSE: This question is really two separate issues. First, while the Joint Solar Parties are not aware of particular instances of attempting to divide parcels to maximize projects on separate parcels, a two-year lookback on subdivision of parcels has been part of the ABP since the initial LTRRPP. That rule works to ensure that a developer is not attempting to take advantage of economies of scale that the REC Contract pricing model does not anticipate.

Second, the Joint Solar Parties strongly disagree with the framing of multiple (separate) 5 MWac community solar facilities on the same parcel "avoiding project labor agreement requirements." Section 1-75(c)(1)(Q)(2) of the IPA Act provides in relevant part that:

> Renewable energy credits procured from new utility-scale wind projects, new utility-scale solar projects, new brownfield solar projects, repowered wind projects, and retooled hydropower facilities <u>pursuant to Agency procurement events</u> occurring after the effective date of this amendatory Act of the 102nd General Assembly must be from facilities built by general contractors that must enter into a project labor agreement, as defined by this Act, prior to construction.

The term "procurement events" specifically refers to competitive procurements rather than IPA programs such as the ABP. (*See, e.g.*, 20 ILCS 3855/1-75(c)(1)(A) ("The Agency shall develop a long-term renewable resources procurement plan that shall include procurement programs and competitive procurement events necessary to meet the goals set forth in this subsection (c).").) As a general matter, utility-scale solar projects not participating in a "procurement event" is not required to enter into a project labor agreement under Section 1-75(c)(1)(Q)(2).

Responding further, there are many reasons that a developer may choose multiple retail (under 5 MWac) systems outside of the ABP rather than a single utility-scale solar system that would qualify for a competitive procurement:

- Projects are often co-located based on landowner interest, and interconnection capacity.
- Agricultural landowners commonly have 50-100 acres that they're looking to develop for solar. This is too small for a cost-competitive utility scale project, but perfect for multiple community solar projects.
    - Under Section 1-75(c)(1)(K)(iii)(3), which incorporates the co-location standard from the first revised LTRRPP, if sufficient IX capacity exists this can be developed as one 5MW project in the ABP and an additional non-ABP project because the co-location standard is that no two or more <u>ABP projects</u> on a single parcel or adjacent parcels can exceed 5 MWac.
    - If a non-ABP project could not be constructed in this scenario, it would likely just result in fewer MW overall being interconnected at that location. The project

would not be economically viable as a 10 MWac utility-scale solar project that cannot receive the DG Rebate or community solar net metering.

- As interconnection queues lengthen in IL and hosting capacity is used up, the opportunities for successful interconnection of larger DG projects are starting to become more difficult to find. Co-locating projects allows for more efficient use of remaining available IX capacity.
- Plus, in many parts of the state, the best IX opportunities for larger DER projects are in confined areas - i.e., land in the immediate vicinity of substations or land within or just outside of incorporated municipalities.
- Occasionally, projects may even be immediately adjacent but interconnect via different utility circuits. In such circumstances, further limiting co-location may result in fewer MW getting interconnected overall, at least in the short term.
- Co-locating ABP and non-ABP projects creates efficiencies of scale for all involved:
    - EPC costs are lower due to economies of scale
    - Permitting burden is simpler for both developers and AHJs

2. How can the Agency ensure that co-location determinations properly ensure that 1) REC prices are being consistently adjusted to the aggregate size of co-located projects, 2) interconnection queues are not clogged, and 3) ensure compliance with labor requirements for projects over 5MW?

JSP RESPONSE: Senate Bill 40, House Amendment #6 (available at: https://ilga.gov/legislation/104/SB/PDF/10400SB0040ham006.pdf) starting on page 208 (Large DG) and 211 (community solar), includes compromise language arrived at with labor regarding co-location of ABP projects. Clogged queues, unfortunately, tend to highly incentivize maximal development around the few remaining substations with substantial capacity or to extensively develop around a filled substation to share mid-eight figure substation upgrade costs over multiple projects. Without the multiple projects, in many cases full substations are simply “black holes” where no additional development is possible. Under current interconnection rules, there is no formal (much less usable) mechanism to socialize such substation upgrade costs amongst multiple, unaffiliated developers meaning that the only upgrades that are ever undertaken are: (1) small enough for a single 5 MWac system to bear, or (2) when co-located projects (with only one in the ABP) can share in the upgrades.

The Joint Solar Parties note that if the language in Senate Bill 40 HAM #6, such co-location rule must only be applied prospectively because historically the co-location prohibition only applied to developers and applicants to the ABP—allowing a single owner/operator to purchase systems that had already been awarded to separate (and legitimately independent) developers and have the resulting systems not considered co-located.

3. The Program currently requires the following information through its Part I and Part II application process used for co-location determination: property information (name, company, address, parcel number), proof of site control, plot diagram or site map, Interconnection Agreement or Certificate of Completion/Permission to Operate, self-identification of previous applications on the same parcel, project ownership information (name, company, address, contact information), and additional information as proof of non-affiliation for projects in the same or adjacent parcels separately

requested. What additional documentation is available and/or should be requested by the Agency to ensure compliance with co-location requirements?

JSP RESPONSE: The Joint Solar Parties recommend the approach outlined in SB 40 HAM 6, starting on page 211, which includes documentation by an Approved Vendor regarding affiliation and subdivision.

4. What challenges exist for developers to coordinate single Points of Interconnection with adjacent projects during their pre-development stages to alleviate interconnection struggles?

JSP RESPONSE: Please see the response to question 2 above, which explains the challenges with an interconnection "black hole." Note that developers rarely use a single Point of Interconnection even for co-located systems, although there may be shared interconnection facilities (as that term is defined in 83 Ill. Admin. Code § 466.10) and as described above distribution upgrades including substation upgrades.

The Joint Solar Parties note that the issue of co-location between non-ABP and ABP systems was an issue of substantial public comment on the last LTRRPP and the IPA ended up correctly restricting co-location to between ABP systems. This is the correct approach under Section 1-75(c)(1)(K)(iii)(3), because the first revised LTRRPP only addressed co-location between ABP-participating systems. In other words, from the ABP perspective, non-ABP systems (on the same or adjacent parcels) are irrelevant. On a going forward basis, the Joint Solar Parties strongly support the co-location guidelines reflected in SB 40 HAM 6 as described above.

In addition, the IPA should maintain the same Large DG rules from the current Program Guidebook. "Community solar projects sited on separate rooftops or structures on adjacent parcels will not be considered co-located unless located on the same building or structure"

<u>Topic 9</u>

<u>Questions</u>

1. What have been the impacts of the tariffs recently announced by the federal government on business operations of Illinois Shines participants?

JSP RESPONSE: As an initial matter, tariffs are highly significant but unfortunately only a small part of the potentially catastrophic risks at the federal level. Removal of tax credits (and potential modification of safe harbor rules) is the most prominent risk. FEOC (foreign entities of concern) rules could also drastically limit equipment availability and pricing. If tax credits are removed, the industry's economics will fundamentally shift—making it unclear what types of projects will work economically given the rest of the current environment. Tariffs increase EPC costs dollar-for-dollar, providing substantial back-end risk to projects that have already locked in their REC pricing (and for behind-the-meter systems, a customer-facing pricing) at the time of REC Contract approval and thus threaten projects that were more competitively priced (i.e. had less margin to absorb the new costs). FEOC language in the U.S. House-passed tax bill would drastically limit the available module and inverter options, driving costs up and likely causing supply chain concerns.

The Joint Solar Parties note that without contingency charges or reopening a contract, it is extremely difficult to quote a stable price today for a project that is not going to be placed in service this year.

2. To what degree have tariffs directly or indirectly impacted business costs for projects participating in Illinois Shines? Please provide detail and/or data to support your response. If the detail or data provided in the response constitutes commercial and/or financial information which is proprietary, privileged, or confidential, and disclosure of the commercial or financial information would cause competitive harm to your business, please note these conditions in your response and the materials provided will be kept confidential by the Agency.

JSP RESPONSE: Virtually every project that has not yet begun construction—and, depending on the safe harbor standard, even many that have—by the time the draft LTRRPP for Commission Approval is released will be substantially impacted by any tax changes. Tariffs are already impacting EPC pricing.

The "Liberation Day" tariffs announced earlier this Spring comprehensively impact the entire supply chain ecosystem. While many companies source finished products primarily from US-based suppliers, these partners depend on global supply chains for raw materials and subcomponents from China, Southeast Asia, Mexico, and Europe.

Affected Components:

- Solar modules and inverters
- Battery storage systems
- Mounting hardware and electrical balance of systems
- Tier-2 manufacturing inputs

Due to the dynamic nature of tariff levels and implementation timing, companies have developed multiple impact scenarios. There remains a great deal of uncertainty and volatility in the announcements and levels of impact that make specific impacts hard to precisely forecast. Based on our member understandings of the "Liberation Day" announcement, some member companies (particularly in the residential space) estimate that the tariff impacts in 2026 could result in a range from 30% - 70% increase to material cost

3. When a tariff change occurs, how long does it take for those changes to be reflected in procurement processes, impacting project development and construction? Please explain and provide examples.

JSP RESPONSE: It depends on the terms of the tariff (such as its implementation date). If the tariff takes effect in the short term, it can produce nearly immediate impacts on the market. Most early stage developers do not procure modules; instead, the modules are frequently procured by the long-term owner (which may be—but in many cases is not—the early stage developer) and even so usually procurement is usually after a project is derisked and thus in a more mature (i.e. closer to construction) rather than earlier stage.

4. Should the Program consider making changes to account for potential or existing tariff change effects on business operations and costs? If yes, please explain what changes

to make, through which elements of the Program, and how such changes would support project development and pricing.

JSP RESPONSE: Because tariffs and tax credit impairment (and FEOC) will impact the entire market with virtually no exceptions, the IPA should create a contingency in the LTRRPP for a REC Contract adder—priced by category—to mitigate the particular losses due to material tariff changes, tax credit impairment, and FEOC. Either these contingencies will occur—causing project economics to potentially fail in many if not most or virtually all cases—and *require* assistance in order to ensure the projects remain viable and not simply terminate the REC Contracts or they will not (and thus no contingency payment is needed). However, without such a contingency, the State of Illinois faces the prospect for a wave of withdrawn projects with REC Contracts because the tax credit, tariff, or FEOC changes that impact the entire industry were too harmful to the project.

The Joint Solar Parties note that FEOC and tariffs do not only impact modules—they also impact equipment such as batteries. Due to the tariff and FEOC uncertainty, the IPA should allow projects to remove batteries between Part I and Part II without withdrawing and reapplying the project. Currently, if a Part I application contains a battery but new storage tariffs are implemented that make batteries uneconomic, the project would have to reapply if the battery is removed. The Agency should also allow waiver of the restrictions on system size (AC) reduction at Part II because tariffs and FEOC may impact the viability of larger projects (including those with batteries).

Additional Topics in Chapter 7

The following topics are not related to specific question prompts but are relevant to Chapter 7 in the current LTRRPP and the Joint Solar Parties would urge the IPA to consider the following issues:

1. Agrivoltaics

JSP RESPONSE: Related to agrivoltaics (AgPV) and Part II applications as discussed in the Program Guidebook:

> Projects utilizing crop-based agrivoltaics should not submit the project's Part II application until the crops are planted and documentation of adherence to commitment to utilize agrivoltaics can be proved. Approved Vendors will be asked to prove the progress of planted crops and/or other agrivoltaics activities in the Part II application.

(2025-26 Program Guidebook at 157 n. 77.) This footnote highlighted above has the potential to create significant problems for AgPV projects through delayed REC incentive payments. At a high level, the Joint Solar Parties recommend that the IPA to allow a year for crops to be established, and in that year the array can be generating electricity and should receive RECs while demonstrating agriculturally relevant activity.

The Joint Solar Parties interpret this Footnote as restricting the ability of an Approved Vendor to receive REC incentive payments until Part II Applications are approved. This would require crops at facilities that secured points for AgPV to be planted and progress toward AgPV commitment to be "proved." After consultation with experienced AgPV experts, member companies within the Joint Solar Parties have determined this requirement may be problematic due to a variety of factors that affect crop planting schedules. These potential problems are outlined below below and these have the potential to apply to all AgPV projects with the exception of those solely growing hay:

- Developers make every effort to minimize land disruption and damage during project construction. However, if there may be unavoidable disturbance to soil during construction, planting crops within the first year (to comply with Part II Application requirements) could be setting the solar farm up for a challenging time managing soil health and weed pressure in the first year, which can then spread onward into the future. It could be more challenging if land not already in production is switching to vegetables depending on soil fertility and conditions. Therefore, delaying or modifying planting in the interest of long-term sustainability of the AgPV project may impact our ability to comply with Part II Application requirements and thus delay REC incentive payments. Typically, though in some states and projects it differs, cover cropping is necessary to reestablish soil stability before planting crops. Although, on its face, this is not revenue-creating agricultural activity, it is important to save revenue and costs down the road for the farmers. Therefore, the Program Guidebook should allow a year for crops to be established, and in that year, the array can be generating electricity and receive RECs while demonstrating agriculturally relevant activity.
- If the project site was an existing vegetable farm and if construction wrapped up in the summer, it may be possible to plant a late season vegetable crop, but likely the best move would be to plant a cover crop and implement the full growing season the following year. Therefore, if there are unavoidable construction delays, planting may have to be adjusted, which would impact developers' ability to comply with Part II Application requirements and thus delay REC incentive payments.
- If the land was originally in hay production and switching to vegetables, it would be best to leave the grass (i.e. do not grade) for construction to avoid compaction and erosion. Then, work can begin on incorporating the sod and planting vegetables when construction is finished. Transitioning hay land to vegetable production in spring is very challenging if the weather is too wet. The sod makes the soil take longer to dry out, and it can be very clumpy, which is not ideal for small-seed crops or sensitive transplants. This scenario could require an additional project timeline of 6 months to a year if transitioning from hay to vegetables, extending the time by which developers could submit a Part II Application and qualify for REC payments. This also impacts the timing of payments to the farmer. The alternative is to work on incorporating the sod before construction, but that would increase compaction, weed pressure, and risk of erosion during construction and the first growing season, reflecting the same potentially long-term negative consequences as the first bullet, above.

Therefore, the Joint Solar Parties recommend the IPA amend the language to read "…until crops are planted OR documentation of adherence to commitment to utilize agrivoltaics can be proved." As part of this change, an Approved Vendor could submit documentation outlining the need to allow the land to rest or re-set post construction pre-planting to ensure long-term viability. This would prevent the arbitrary delay of REC incentive payments due to technicality.

As an additional item, a related challenge is between AgPV and incorporating pollinator habitat (and, thus, qualifying for scoring points in both categories). Currently, AV's who may seek to incorporate pollinator habitat into AgPV projects within the program are prevented from doing so, as the state Solar Siting Pollinator Scorecard (Scorecard) dramatically penalizes use of insecticides (often required at some level for significant food production, even if organic in composition), which results in projects unable to qualify as "pollinator-friendly." This is a missed opportunity to expand the combination of pollinator habitat and food production within solar projects, a mutually beneficial arrangement, as pollinators are often crucial for production yields.

Finally, the Joint Solar Parties recommend that the TCS scoring rubric be modified to add additional waitlist points for agrivoltaics projects by introducing two new categories.

- 1 point for commitment to utilize agrivoltaics or dual-use solar (includes haying)
- 2 points for agrivoltaics projects incorporating grazing without major design changes.
- 3 points for agrivoltaics projects requiring significant design modifications to support crop production (e.g., increased row spacing or array height).

The Joint Solar Parties believe that further encouraging the development of agrivoltaics (at no additional program cost) would help align the industry with delivering value to farmers and farmland, increasing support for the industry among a key constituency in the state.

While more discussion is necessary on the exact definitions of major design changes, this proposal differentiates between a project that incorporates agrivoltaics with minimal changes, and more complex agrivoltaics that support crop production and will require more design considerations but deliver additional agricultural value.

2. REC Contract Assignment In Event of Bankruptcy

JSP RESPONSE: There is a fundamental concern with the interaction of the collateral assignment provision (Section 13.1 of the 2024 15-Year and 20-Year REC Contracts), the default under the REC Contract if the Seller is Bankrupt (defined in Section 1.12 of the 2024 15-Year and 20-Year REC Contracts) and the treatment of the REC Contract as a "forward contract" under the U.S. Bankruptcy Code (Section 8.1(m) of the 2024 15-Year and 20-Year REC Contracts.

As an initial matter, the mutual representation in the REC contract that each party is a "forward contract merchant" and that the agreement is a "forward contract" for bankruptcy purposes (Section 8.1(m)) is not sufficient to make it so; the agreement must also independently comply with the bankruptcy test for forward contract merchants and forward contracts. (*See, e.g, In re First Energy Solutions Corp.*, 596 B.R. 631, 638-640 (Bankr. N.D. Ohio 2019) (parties' designation of each other as forward contract merchants in the contract not determinative of whether they were such, when independent legal test for that status was not satisfied).) Moreover, the Joint Solar parties believe that there is a very strong argument that the contract is not a forward contract for bankruptcy purposes, in part because its principal purpose is not to hedge against volatility and price fluctuations of financial markets, and is not clearly tied to those markets. The four part test for whether a contract is a "forward" contract protected by the safe harbor provisions of the Bankruptcy Code requires proof that: (i) substantially all expected costs of performance are attributable to the underlying commodity; (ii) the contract has a maturity date of more than two days after the contract was entered into; (iii) the price, quantity and time elements are fixed at the time of contracting; **and (iv) the contract has a relationship with the financial markets.** (*In re Arcapita Bank B.S.C.*, 628 B.R. 414, 468-472 (Bankr. S.D.N.Y. 2021) (emphasis added).) The last requirement "will be satisfied where the primary purpose of the agreement is 'financial and risk-shifting in nature', such as seeking to hedge against fluctuations in the price of a commodity." (*Id.*, at 468-469.) This requirement effectuates the Congressional policy behind those safe harbor provisions, which is to protect the stability of national financial markets that would otherwise be at risk from the bankruptcy of intermediate trading entities. Here, the purpose of the contract is not tied to the financial markets but rather the legislative policy of encouraging the development and use of renewable energy. Nothing in the agreement manifests a purpose to hedge against price fluctuations or volatility in financial markets. Thus, any effort by the utility to terminate the contract while the EEC is in bankruptcy would likely violate the automatic stay and be null and void.

As a result of that substantial risk of violating the automatic stay, the utility Buyer should be required (whether by LTRRPP, by amendment to the REC Contract, or Commission order) to seek court approval before seeking to terminate the REC contract. An additional layer of protection might include 60-day advance notice to the Seller and collateral assignee before any such motion is filed. The utility Buyer should also indemnify the Approved Vendor and collateral assignee for damages caused by any unlawful attempted termination of the agreement, including a violation of the automatic stay (in addition to any bankruptcy remedies for violation of the stay may exist).

However, without the clarity requested above, there remains risk that the REC Contract is treated as or determined to be a forward contract. The essential challenge is this: for situations from an end-use customer that purchased a solar array in a sale agreement and is using the developer as the Approved Vendor to smaller EEC Approved Vendors in the EEC Block, there is risk that the Seller will go Bankrupt. One way the customer (or other system owner) might protect themselves is perfecting a security interest in the REC Contract and providing notice to the Buyer that the customer (or other system owner) is taking collateral assignment. However, some financing parties are concerned that because the contract is treated as a forward contract, it will terminate on its own terms before the customer (or other system owner) can successfully foreclose on the REC Contract due to the automatic stay in bankruptcy proceedings. This means that the customer's REC Contract value may be destroyed while the customer vainly attempts to seize the REC Contract out of the bankruptcy proceeding.

The Joint Solar Parties see two potential solutions:

A. Estoppel Amendment

One solution that has been proposed is to add an estoppel amendment to the IPA's form REC contract that allows the AV to assign the REC contract to another AV after receipt of a potential termination notice for bankruptcy from the utility. Under federal bankruptcy law, a debtor's contract assignment rights cannot be restricted. (*See* 11 U.S.C. § 365.) Therefore, the proposed estoppel amendment purporting to restrict the EEC AV's rights to assign the REC contract only to another AV is likely prohibited as a matter of federal bankruptcy law. Such an amendment could add Section 13.2 to existing REC Contracts and incorporate into new REC Contracts going forward:

> **13.2 Buyer's Agreement to Delay Termination in Event of Bankruptcy.**
> Notwithstanding any right that Buyer may have to terminate this agreement pursuant to 11 U.S.C. 556 in the event Seller becomes Bankrupt, Buyer agrees that it will not exercise any contract termination right if, within 60 days of the commencement of Seller's bankruptcy case, Seller assigns this contract to another Approved Vendor pursuant to 11 U.S.C. 365. For purposes of this provision, an EEC AV is an entity that is registered with the IPA as an Approved Vendor and, if such Approved Vendor is required to be an Equity Eligible Contractor, then an Approved Vendor that is an Equity Eligible Contractor, as those terms are defined under the ABP and in this Agreement.

B. Notification of Termination

Another potential solution is to require the Buyer to provide the Seller and the collateral assignee with at least 60 days' notice of termination in the event of Seller bankruptcy. With the additional time provided by such notice, the Seller or collateral assignee owner could potentially obtain relief from the stay to exercise termination of the service agreement contemporaneously with the utility's termination of the REC contract. (*See* 11 U.S.C. § 362.)

3. Certified Transcripts of Payroll

JSP RESPONSE: The Joint Solar Parties understand that Energy Solutions is currently pulling Certified Transcripts of Payroll on an ongoing basis for projects that have entered construction that must pay prevailing wage. To the extent that Energy Solutions has already pulled CTPs, the Joint Solar Parties recommend that those CTPs are not required at Part II (leaving only CTPs that Energy Solutions was unable to pull or misplaced).

LTRRPP Comments – Chapter 8:

Topic 1

Questions

1. Should the Agency expand its use of self-attestation and allow Residential Solar (Small) sub- program participants residing in income-eligible communities, defined as census tracts where at least 50% of residents earn no more than 80% of the AMI, to confirm their household income by attestation without the need of further documentation? Are there any challenges or concerns with this approach?

JSP RESPONSE: Yes. Self-attestation, as the Joint Solar Parties have identified in the past, are consistent with best practices elsewhere and ensuring customer privacy.

The Joint Solar Parties note that there are a few challenges inherent in this approach. The core issue is the standard by which an Approved Vendor or Designee must diligence home income and how to answer questions regarding assessment. For instance: It can be challenging to define the household properly, especially in multi-generational houses or a house where there are adult children that are working part time (i.e. earning income) but still in school. These challenges are inherent both from the perspective of answering legitimate customer questions and meeting the level of diligence the IPA expects for collection of self-attestations.

2. Should the IPA only expand self-attestation to residents in income-eligible communities or should the option be extended to environmental justice communities as well? Or should self-attestation only be offered in HUD Qualified Census Tracts, which represent fewer communities but a higher portion of residents meet income eligibility?

JSP RESPONSE: For tracts that are identified as low-income, such as HUD Qualified Census Tracts, the assumption should be Solar for All eligibility without self-attestation. This would match the current interpretation of the federal IRA low income community adder. This would allow a Solar for All product to be the exclusive offer(s) within such communities. Outside of HUD Qualified Census Tracts, a self-attestation is appropriate, as long as Solar for All products need not be offered because some potential customers may not qualify.

The Joint Solar Parties note that while this question is about the residential behind-the-meter subprogram, this should apply equally to subscribers to the Low-Income Community Solar subprogram as well.

3. The Agency requests feedback on suggested parameters and structures for an income verification audit process. What policies, procedures, and guidelines should the Agency consider when developing the criteria of the audit? What methodology should be employed when defining the number of households being randomly selected to audit?

JSP RESPONSE: The primary question should be implications of the audit for a Solar for All Approved Vendor or Designee. While prior knowledge of a potential audit allows salespeople to discourage potential customers from misrepresenting themselves as low income, with a self-attestation the customer may not be accurate or truthful about their income at the point of sale. It is important that individual employees/agents or Approved Vendors/Designees are not punished for improper self-attestations unless the Agency has proof that Approved Vendor/Designee employees or agents were encouraging such misrepresentations.

To the extent that the Agency does conduct audits, the parameters should be defined in advance, even if the specific Approved Vendors (or portion of all Approved Vendor applications) may not be identified in advance.

<u>Topic 2</u>

<u>Questions</u>

4. Should the Residential Solar (Small) program be reconfigured to require all offers to be “no cost?"
    a. If so, what considerations are relevant for different financing models (i.e., no-cost leasing, participant ownership)? Should any adjustments to requirements be included for different financing models?
    b. Are there any challenges or risks to this approach? Please explain.

JSP RESPONSE: The minimum required savings of 50% is high relative to federal programs and other states; Illinois already requires more savings than most other programs. While the 50% minimums can for some products be difficult to reconcile from an estimate to actuals, Approved Vendors and other involved parties should be given the space to design products and services other than a completely free approach (which, of course, some may offer).

Also, to the extent an Approved Vendor was going to recommend solar+storage, battery pricing and current economic structures for solar+storage mean that a free system is frequently infeasible. Solar+storage should not be *de facto* excluded by requiring only free products.

5. In disallowing ongoing payments (i.e., monthly, quarterly, annual), what one-time fees, if any, should be allowed or prohibited?

JSP RESPONSE: For behind-the-meter residential systems, an upfront fee should be allowed to address roof or other structural repairs. The customer in many cases will fix the roof or structure more cost-effectively going through the solar contractor than separately pricing the work—and will tie the roof or structural improvement to long-term cost savings even without a “free” requirement.

The Joint Solar Parties note that disallowing any periodic payments will also discourage deployment of solar+storage.

6. Should no-cost offers be required for household subscribers in the Low-Income Community Solar sub-program?
    a. Is a no cost ILSFA Community Solar offer an appropriate path to address concerns of participant trust and ease of participation, and negative experiences with current utility single billing?

JSP RESPONSE: No. Customers already save money on every month’s bill and have no direct payment to the system owner given the requirement that all systems enroll in net crediting and the

50% savings requirement. The issues with "net crediting" (which is really utility consolidated billing) are the utility's responsibility to address under the supervision of the Illinois Commerce Commission.

Given the federal climate, while the REC prices for Solar for All are certainly higher than the ABP, the delta is not enough to make up for not only the increased cost of customer acquisition and management but also loss of all subscription revenue—especially with potential loss of Inflation Reduction Act tax benefits appearing likely.

Topic 3

Questions

7. Given the current sub-program utilization, should the Non-Profit and Public Facilities sub- program be expanded to allow participation from critical service providers outside of income-eligible and environmental justice communities?
8. If the Program allows critical service providers outside of environmental justice and income-eligible communities to participate, should the Agency limit the projects sited outside of environmental justice and income-eligible communities? If so, on what criteria should this be limited? E.g., limiting by number of projects, portion of incentives (a carveout), not allowing submission until later in the program year, adjacency to an environmental justice community?

JSP RESPONSE: The IPA should consider which goal—system geographic in certain communities or the system reducing energy costs for a critical service provider serving specific communities—is the primary goal. The Joint Solar Parties submit that Solar for All's primary focus is (and should be) assisting low-income customers including the institutions supporting low-income customers rather than a geographic siting program.

9. How does the fact that the Non-Profit and Public Facilities sub-program budget is continually distributed close to or in its entirety impact this proposal?

JSP RESPOSNE: The existence of sufficient demand (currently, at least) should not prevent the IPA from allowing other meritorious systems whose functions are fully consistent with program goals also participate. The popularity of this subprogram is a grounds, however, for increasing its funding.

10. Should the Critical Service Provider list be amended to include fewer categories?

Topic 4

Questions

11. Is there a concern that projects that are Part I approved without collateral will have less of an incentive to complete projects?
    a. Could there be resulting risks to the participant or Program?
    b. If there is a risk that there is less of an incentive to complete projects, are there alternative solutions that should be considered?

c. If there is a risk that there is less of an incentive to complete projects, are there additional requirements or conditions that could be coupled with the change to drive projects to completion?

JSP RESPONSE: The Joint Solar Parties believe there are competing concerns that must be balanced on this issue. On one hand, the Joint Solar Parties recognize (and support) ensuring access by small or emerging businesses. On the other hand, solar developing is challenging and risky—with a high cost of entry for residential (and the requirements of mass market customer-facing contracts) and a very high cost of entry for the highly complex and risky Solar for All program. Given the challenges faced by experienced developers, Solar for All is unlikely to be an ideal starting point for small or emerging businesses.

That said, as long as Solar for All remains structured in its current form, there is a very real concern that a small or emerging business with less experience or access to capital may have trouble delivering on projects, creating strain both on Solar for All and poor customer experiences for low-income customers. While the REC Contract payment is incentive enough to encourage developers to bring a project to Energization, the challenges of development mean that many projects may be abandoned because they no longer pencil or run into other critical failures that small or emerging businesses cannot address.

To address these competing concerns, the Joint Solar Parties recommend that the 5% collateral be removed from the REC Contract payment rather than charged upfront. If a particular small or emerging business Approved Vendor does not deliver on too many projects before successfully Energizing 5-10 systems, the Program Administrator should remove that small or emerging business from the program. Alternatively, the IPA could require a permit or surety bond for all Approved Vendors or perhaps small and emerging businesses until those first several projects are Energized. This compromise provides a reduced burden and pathway for small or emerging businesses but without exposing customers to as much risk.

12. Should the option for Small and Emerging Businesses to utilize a portion of their REC incentive payment as collateral for a project also be allowed in other sub-programs aside from Residential (Small), or capped at certain amounts per project or Approved Vendor? If so, please provide reasoned suggestions of a cap level.

JSP RESPONSE: The Joint Solar Parties do not object to small or emerging businesses having access to taking collateral out of the REC Contract payment in other subprograms, although subject to parallel (though not necessarily identical) requirements for successful projects and a permit or surety bond.

Topic 6

<u>Questions</u>

17. Do stakeholders agree that continuing the Home Repairs and Upgrades Pilot and offering incentives enabling repairs and upgrades through REC adders is meeting the spirit of the program, as outlined in Section 1-56(b)(2) of the IPA Act?

JSP RESPONSE: The Joint Solar Parties agree with continuing these programs but note that the current roof replacement compensation is too low relative to the cost of the work.

18. What adjustments can be made to the Home Repairs and Upgrades Pilot to reinforce the equity and access goals which it is meant to address?

JSP RESPONSE: Because the current roof replacement compensation is too low relative to the cost of the work and the payment is not until after Energization as a REC adder (rather than after project selection but before Energization when such costs are incurred to affiliated or third-party roofing contractors), it is difficult for some Approved Vendors to maximize the programs. Either allowing an option for accelerated payment (to better pair with the value being provided, i.e. the roof repair) or to increase the adder is preferable.

19. Should the Home Repairs and Upgrades Pilot support additional repairs and upgrades beyond electric and roof repairs that help in installing solar photovoltaic systems? If so, what type of work should be included?

JSP RESPONSE: Tree removal and (in conjunction with the existing utility energy efficiency programs) HVAC and other repair work.

Topic 7

<u>Questions</u>

20. How often have Approved Vendors encountered vacant units in multi-unit buildings being considered for ILSFA? What portion of vacancy is common in buildings of various sizes?

JSP RESPONSE: In the experience of members with experience with Solar for All multi-family, about 5%.

21. How should the Program distinguish between "household" or "tenant" and "unit" for the purposes of building eligibility verification?

JSP RESPONSE: Typically the tenant and household are the same. When dealing with typical deed restricted affordable housing, there are income limitations that dictate who can live at the property. In a typical LIHTC situation 60% of the residents are at 80% of AMI or lower.

22. Have other relevant programs addressed the issue of vacant units? If so, what approach is used in the context of determining building eligibility for services?

23. Would making the change from "households" to "units" lead to potential gaming situations, in which otherwise ineligible buildings would participate in ILSFA? If so, how what process can the IPA adopt to prevent this?

JSP RESPONSE: No, as long as the core requirement of the unit being within affordable housing remains intact.

Topic 8

Questions

24. What are the benefits and challenges of allowing master-metered buildings to subscribe to a community solar project as anything other than an anchor tenant with the current anchor tenant REC price?
    a. Is there an alternative way that master-metered residential buildings and their residents could access benefits through ILSFA Community Solar?
    b. Should the Agency adopt an adjusted REC price for an eligible master-metered anchor tenant portion based on the ILSFA Community Solar REC price that takes into account the simplified acquisition costs?

JSP RESPONSE: As of June 2024, master-metered affordable housing buildings can no longer subscribe to a SFA community solar system and receive the residential REC value with allocation of any size, which limits the opportunity for income-eligible residents to participate in the program even further. Illinois is the only jurisdiction with a low-income community solar program that limits participation for non-anchor, master-metered buildings; the national standard is to create rules so that these entities can subscribe.

Currently in Illinois, master-metered buildings can only participate as anchor tenants as non-income-eligible residential. This prevents and bars individuals on the lowest end of the eligible income range, who do not have their own meter from receiving benefits from community solar.

Master-metered arrangements are common for HUD and LIHEAP-subsidized housing developments, and they should be able to enroll in community solar, without a cap on the size of the subscription, and receive the residential or adjusted REC value to deliver benefits to more income-eligible households. While generally speaking master metering is strongly discouraged in Illinois (*see* 83 Ill. Admin. Code § 410.130(a)), low income housing is a notable exception.

With changes at the federal level potentially eliminating or drastically reducing (both in terms of program dollars and program administration) the LIHEAP program at the federal level, there will be additional challenges simply using LIHEAP recipients as a guide for potential subscribers. Master-metered low-income housing is a way to lower the costs of housing for low-income customers.

The Agency should not adopt a bespoke master metered anchor tenant REC price. Master-metered residential low-income buildings should be considered residential low-income customers.

25. How would a carveout within the Community Solar sub-program that is solely dedicated to community solar projects that serve master-metered buildings compare to the above option?

a. Are there advantages, or disadvantages, to pursuing a carveout within the Community Solar sub-program? Please explain.
b. What would be a reasonable carveout be to ensure the community solar project is primarily benefiting individual households?

JSP RESPONSE: There should not be additional carve-outs within the SFA community solar subprogram.

Topic 9

<u>Questions</u>

26. If the current 36- or 24-month requirement is proving to be a challenge to satisfy the job training requirement, should the Agency increase the length of time a "trainee" would be considered as such? If so, for how long?

JSP RESPONSE: Yes, if not eliminate such timeframe. If someone comes from training programs and begins a successful career at a company, moving up the ladder, or other measure of success, that trainee should still be deemed as successful part of the requirements and not ineligible because they've had success.

27. Are there any recommendations for how the definition of "trainee" could be further improved?

JSP RESPONSE: While the Joint Solar Parties recognize that job trainees have a different definition than the Minimum Equity Standard "equity eligible person," efforts to create overlap in training would allow a job trainee to have an automatic advantage on ABP projects beyond just Solar for All trainee requirements.

28. How have Approved Vendors handled the aging out of trainees to date?

JSP RESPONSE: The aging out has been challenging both from an Approved Vendor from a paperwork management perspective and trainees in that their special regulatory status is arbitrarily removed and they are relegated to status of another employee (or potential employee) with some job experience.

29. How could the job training portfolio requirements be improved to both maximize the use of trainees and support long-term employment of trainees?

JSP RESPONSE: The hours-tracking is challenging and because job trainees' hours count only on Energized projects (even though the job trainee may have received valuable experience with their actual work done on unsuccessful projects), making compliance more challenging. Job trainees' highest and best use is working as other employees: on projects that work out and that do not, and on all types of projects (not just Solar for All).

30. What levels of trainee utilization across the ILSFA portfolio seems realistic and maintainable while simultaneously supporting job trainees in a significant portion of portfolios?

31. Are there currently challenges with elements of the job training programs and their ability to properly prepare trainees for work that requires reconsideration or enhancement for qualifying trainees? If yes, please explain.

JSP RESPONSE: Due to the challenges identified above, a better approach than the current job trainee requirements would be allowing Solar for All Approved Vendors to provide hours to job trainees outside of Solar for All and to simplify the hours tracking system to be less cumbersome. Also, some of the training programs (particularly FEJA-era training programs) have been very difficult to get ahold of to identify graduates or current students.

LTRRPP Comments – Chapter 9:

Topic 1

Questions

1. Should the vendor cap for the Solar Restitution Program be retained at $200,000, raised to a higher level (and if so, to what dollar amount), or be eliminated entirely?

JSP RESPONSE: It should be raised so that residential customers are taken care of to the maximum extent possible, but not eliminated.

2. Should the per-project cap be increased for Large Distributed Generation projects? If so, to what amount?

JSP RESPONSE: The cap should be raised but there still should be a cap. Legal recourse available to non-residential customers is typically more robust, including due to the increased value of the system.

3. Should forfeited collateral from utility-scale wind procurements be included as a source of funding for the Solar Restitution Program?

JSP RESPONSE: Yes.

4. What approach (or combination of approaches) should the Agency take if the forfeited collateral runs out?

JSP RESPONSE: The IPA should continue to actively monitor Approved Vendors and take action. This is especially true for the harm identified by the IPA of driving the initial strain on the restitution program, specifically two Approved Vendors failing to pass along REC Contract payments. If the escrow (or other IPA tools) fails to stem the tide of issues, then the per-Vendor limits may be less relevant as the limited funding will impair availability. The key is proactivity with escrow if an Approved Vendor should be but is not passing through REC Contract payments. In the meantime, the Joint Solar Parties support an exploration of other funding sources.

Topic 2

Questions:

1. In addition to the concerns described above, are there other consumer protection concerns related to solar financing of which the Agency should be aware?

JSP RESPONSE: The list is robust and appropriate. The Joint Solar Parties note that the list is equivalent to proposed changes to Section 1-75(c)(1)(M) in Senate Bill 40, House Amendment 6, which was agreed between the solar industry and the IPA.

2. Should the Agency require solar financiers who sell financial products for solar projects which are intended to be submitted to Illinois Shines register with the Program?

JSP RESPONSE: Yes. While the IPA might be able to require registration, it should be mindful that lenders already must be licensed and registered with either a federal agency (e.g., Office of the Comptroller of Currency) or the Illinois Division of Financial Institutions.

Another consideration is addressing situations where the loan product is not solar-specific. Consumers may choose products like Home Equity Lines of Credit or Fannie Mae Homestyle Energy loans to finance a residential solar and storage system. In these cases, solar is one of many approved uses and the lender may not know the exact purpose of the loan. Thus, the guidelines for *which* loans are required to make such disclosures should be defined within the ABP and take into account multi-use loans that can be accessed without reference to a specific purpose.

3. If the Agency requires financiers to register with the Program, should solar financiers be required to complete an application process similar to the application (see Appendix G of the Program Guidebook) that prospective Approved Vendors must complete? Is there any additional information that the Agency should collect in the application process to promote prospective solar financier compliance with Program requirements and safeguard consumer interests?

JSP RESPONSE: The Joint Solar Parties note that the solar industry did support changes to Section 1-75(c)(1)(M) in Senate Bill 40, House Amendment 6. Whether registration is more similar to Designees or Approved Vendors, industry did not in that context object to registration.

4. If the Agency requires financiers to register with the Program, are there other ideas for how the Agency can monitor and enforce Program requirements for solar financiers?
5. Do any of the proposed Program requirements for solar financiers or AVs/Designees listed above raise challenges or concerns?

JSP RESPONSE: The challenge are anticipated to be similar to lead generator or other Designee registration, in that there has been compliance by many Approved Vendors but also some difficulties in tracking 'through' Approved Vendors in some cases. The Joint Solar Parties recommend that the solar financing registration be done separately from Approved Vendors, but solar financers should identify like a Designee which Approved Vendors and Designees they are working with on ABP projects.

In addition, the Joint Solar Parties note that if the IPA decides to take such actions, substantial work will be required to ensure that the disclosures are not in conflict with federal or state requirements on lenders and that reflect the universe of possible transactions.

This is frequently a learning experience; to the recollection of some long-time members of the JSP and counsel, in early drafts of Standard Disclosure Forms for public comment (which no longer appear to be readily available online), the ABP would have prohibited a "fixed discount" community solar product that is nearly universally used today because it was not a fixed rate, fixed charge, or fixed rate plus fixed charge. Early drafts of the disclosure form also required a net savings calculation and would not accept a pricing structure that could not be fed into a savings calculator. Those issues were rectified by the IPA in response to public comment.

In the spirit of offering points of potential comment in advance so that this process could be accelerated in the event the IPA does implement these requirements, the Joint Solar Parties offer the following issues that may need resolution in any disclosure form creation process:

- Requiring solar financiers to provide customers with a Disclosure Form that the Agency would develop specifically for financiers must take into account Truth in Lending (TILA) requirements and should take into account Consumer Financial Protection Bureau (CFPB) models.
  - TILA requires lenders to provide various disclosures. TILA details what information must be given (e.g., total costs and creditors), how the information is described or calculated (e.g., APRs), and formatting (e.g., number of columns and segregating disclosures). A discussion of these requirements is available at: https://www.consumerfinance.gov/rules-policy/regulations/1026/17/
  - One example of model CFPB forms: https://www.consumerfinance.gov/rules-policy/regulations/1026/h/#H2
- Prohibiting solar financiers from charging solar vendors any kind of dealer fee (or "seller's points") for the ability to offer lower interest rates on a project may not be in the consumer's best interest;
  - Similar to mortgages and other consumer loans, there are times when dealer fees can make sense. For example, a contractor may pay a seller's points to a lender as part of the negotiations with the consumer.
  - A homeowner who feels that they will keep the loan for the entire term can expect to pay less over the term of the loan.
  - Requiring solar financiers to disclose to customers whether they received a dealer fee, seller's points, or other financial incentive from the customer's solar vendor is likely the cleanest disclosure approach.
- Requiring solar financiers to conduct additional due diligence related to a customer's agreement to the loan and ability to pay off the loan before approving a solar loan should be only added in context of existing federal and Illinois laws that have ability-to-repay requirements.
- Requiring solar financiers to get explicit customer approval before disbursing loan funds to a third-party, such as the solar vendor could cause issues with the underlying installation agreement.
- Requiring that repayment of the loan (regardless of the timing of the disbursement) not begin until the solar project is operational may cause substantial problems with interest accrual with a deadline largely (if not solely) within utility control.
- Requiring solar financiers to disclose that customers may "shop around" and look for financing from another financing entity is a general principle that the Joint Solar Parties support but it should be done in connection with existing loan disclosures and should be done in the context of the transaction (where some installers may have a preferred lender or preferred lenders).
- Requiring solar financiers to include a disclaimer that not all customers are eligible for the federal investment tax credit (FITC) and that certain promotional offers may depend on the customer's ability to receive the FITC may require nuance because while all systems may *qualify* for the FITC (with extremely narrow exceptions such as a historic requirement that solar not heat a swimming pool), the key issue is frequently whether the customer can

monetize or otherwise derive value from the FITC. These disclosures are better in the installation contract than a lending agreement, because the loan itself is not what leads to a FITC benefit.

6. Are there additional Program requirements for solar financiers or AVs/Designees that the Agency should consider?

JSP RESPONSE: The financier disclosure should consider current disclosure requirements such as the Truth in Lending Act and Regulation Z so that any required disclosures gap-fill or are consistent with—rather than in conflict with—those or other existing requirements.

Regulation Z details the information that must be included in the disclosures, such as amount borrowed, total payments, APRs, and payment schedules. The rule also dictates how disclosures, like APRs, must be calculated, the presentation of the disclosures, and timing of the disclosures.[1]

Topic 3

Questions

1. Should the Agency create a process to allow projects to be reassigned if the original Approved Vendor goes out of business and becomes entirely unresponsive and/or there is no person who can sign off on assignments on behalf of the Approved Vendor?

JSP RESPONSE: Yes. This is an issue the Joint Solar Parties addressed at some length in an addendum to comments on Chapter 7, specifically what happens if the Approved Vendor goes Bankrupt (as defined in the REC Contract) and how that interacts with a customer security interest in the REC Contract or Product Order thereto and the interaction with the "forward contract" status. However, while that is one special case and that can apply outside of a "customer" context for behind-the-meter systems, the general issue of a non-responsive or incapable/dissolved Approved Vendor is one of essential customer and system owner protection.

The best approach is to allow termination of the REC Contract but survival of the Product Orders. If multiple unaffiliated customers have systems within the same Product Order, the IPA can ensure it is assigned to an Approved Vendor willing to undertake stranded Product Orders. If there is a single customer or system owner, then the IPA should use an Approved Vendor willing to take on stranded Product Orders as a backstop but allow the customer/system owner to identify a preferred landing spot.

[1] For more information see 12 CFR Part 1026 - Truth in Lending (Regulation Z), available at https://www.consumerfinance.gov/rules-policy/regulations/1026/

2. Should the Agency revise the REC Contract to allow for unilateral reassignment of batches in place of (or in combination with) termination of the REC Contract? What complications might arise from this approach? Would there be any downsides?

JSP RESPONSE: Yes. However, this remedy should be used judiciously except in cases where an Approved Vendor is out of business or completely non-responsive. Unilateral reassignment should not be a remedy for garden-variety disputes between an Approved Vendor and a customer.

3. If a REC Contract is terminated by the utility, should the Agency allow projects that were subject to that REC Contract reapply to the Program? Should this depend on whether there is an option for batches to be unilaterally reassigned instead of terminated? If reapplication is allowed, what process should be followed? What limitations and/or requirements should apply? Should the new Approved Vendor be required to pay an application fee and collateral for the project?

JSP RESPONSE: For operating systems, the new Approved Vendor should only post collateral if the system is under a 15-Year REC Contract and the collateral from the original Approved Vendor is not cash (and thus capable of being transferred with the Product Order). The new Approved Vendor should not be required to pay an application fee but may be required to pay an assignment fee under some circumstances (such as if the customer or system owner dictates the Approved Vendor as described in responses above). The original Approved Vendor should not be allowed to represent the same systems again and any Approved Vendor that triggers the need for unilateral assignment should be in strong consideration for discipline.

LTRRPP Comments – Chapter 10:

<u>Questions</u>

1. What additional guidance or clarity can the Agency provide regarding the project workforce definition?

JSP RESPONSE: The project workforce definition is reasonably clear at a high level, however it frequently runs into challenges when addressing the minutia of particular categories of projects (or even projects themselves). For instance, there may be individual questions as to whether the environmental consultant, engineering firm creating designs, third-party equipment brokers, or others would (or would but for use of the 5% threshold) count toward the project workforce.

Ultimately, the Solar industry has a wide diversity of types of projects and even within those categories a wide range of business models to address needs. As a result, instead of high-level guidance it would be helpful for the Program Administrator to keep a public FAQ of project workforce questions.

2. Are there any populations currently excluded from the project workforce definition that should be included?
    a. Are there any populations that are currently included in the project workforce definition that should be excluded?

JSP RESPONSE: The most glaring issue to community solar developers within the Joint Solar Parties is the paradox that hiring an EEC that is a Designee or an Approved Vendor (such as for TCS points) to perform EPC or a portion thereof does not count toward the Approved Vendor's MES compliance because the EEC Approved Vendor/Designee workforce (like all Approved Vendors/Designees) is only counted toward the project workforce of that EEC Approved Vendor/Designee.

A better approach is to modify the general rule that an Approved Vendor's project workforce does not include the workforces of its Approved Vendor/Designee vendors to allow the project workforces of EEC Approved Vendor/Designee vendors to count toward that prime Approved Vendor's project workforce. This makes working with EECs (including those already registered as Designees or Approved Vendors) more desirable and attractive for non-EEC Approved Vendors. It also ensures that EECs Approved Vendors and Designees will have a built-in advantage in competing for EPC work because of the positive effect on project workforce.

3. Are the current thresholds (e.g., 5% of REC value) and definitions for counting subcontractor employees clear and equitable?

JSP RESPONSE: The Joint Solar Parties generally recommend keeping the 5% threshold the same.

However, as long as independent contractors count toward the project workforce, the IPA should consider whether an independent contractor or personnel referred by a staffing agency *should* be considered part of the employees/contractors of the Approved Vendor and not external contracts subject to the 5% rule. Subjecting independent contractors and personnel submitted by staffing agencies to the 5% rule places EEPs attempting to offer independent contracting services or referred through a staffing agency at a severe disadvantage because they do not count toward the project workforce if the 5% threshold is invoked.

Topic 3

Questions

1. Should the Agency maintain or adjust the proposed MES percentage increase schedule? If it should be adjusted, how?

JSP RESPONSE: The Joint Solar Parties support the goals of the minimum equity standard. However, as job training programs referred to in the definition of "equity eligible person" in Section 1-10 of the IPA Act and shifting maps for the locational requirements, the Joint Solar Parties are concerned that some Approved Vendors and Designees (particularly those involved in construction) will have an increasingly difficult time remaining in compliance until the programs are consistently and reliably producing graduates and participating entities have a better sense of map changes. Until these two steps are in place, the Joint Solar Parties recommend a stable or near-stable equity eligible person percentage in the first year of the LTRRPP.

The Joint Solar Parties further note that constraints on some participating companies make it more difficult to collect information on some of the pathways for equity eligible person qualification, such as participating in the foster care system or former incarceration. Many member companies suspect they have more equity eligible persons within the project workforce than reported, but that employees are unwilling to tell (or internal risk management discourages asking) about those statuses.

2. What resources, tools, or supports would help entities meet higher MES thresholds while also providing opportunities for EECs to build their skills and experience?

JSP RESPONSE: Currently, MES reporting is challenging from a paperwork perspective. Reporting is exclusively hosted on Microsoft Forms, there is no ability to save progress while entering data, and the year-end report is 105 questions. Investment in better reporting processes or allowing for submission of Excel or CSV responses or alternative reporting would greatly improve the Approved Vendor and Designee experience.

In addition, investment by the State of Illinois in job training programs and (relatedly) job fairs and other ways to connect participants and alumni of job training programs to Approved Vendors and Designees—particularly outside of the Chicagoland area—will be particularly helpful.

3. How effective are the current enforcement tools in encouraging compliance? Are there unintended consequences or equity impacts in how the Agency currently handles MES noncompliance?

JSP RESPONSE: As noted above, the Joint Solar Parties support the goals of the minimum equity standard and remain committed to supporting equity within the solar industry. Much of how the IPA handles reporting and non-compliance is driven by statute. However, there are some unintended consequences within the compliance framework:

- While all Approved Vendors are evaluated on a corporate (Approved Vendor) rather than project level, waivers for community solar are requested at the project level. If some of an Approved Vendor's EEPs worked on multiple community solar projects, it is conceivable (depending on factors including project workforce size and number of EEPs working on all projects) that the Approved Vendor could miss the MES on a corporate level but—viewed individually for waiver purposes—each project would itself be in compliance and thus would have to ask for a waiver from a position of compliance.
- As noted above, because the project workforces of Approved Vendors and Designees that an Approved Vendor has contracted with are not counted toward the project workforce of the contracting Approved Vendor, use of EECs that are also Designees or Approved Vendors is artificially discouraged. While the general approach of having individuals count toward the project workforce of only one Approved Vendor or Designee makes practical sense, EECs should be an exception.
- The scoring rubric for waivers is helpful but incomplete. Because each category allows for "up to" certain numbers of points for actions, it would be helpful for industry to understand the effort level typically expected—even if the IPA reserves the right to score on a case-by-case basis—to earn a certain level of points. While no Approved Vendor or Designee goes into a year seeking a waiver, the waiver rubric helps organize recruitment efforts.

4. Should the Agency develop paths to demonstrate compliance in situations where an entity demonstrates it will not qualify for Safe Harbor, does not have the requisite number of EEPs in the project workforce, and cannot expand its workforce due to economic constraints faced by the clean energy marketplace?
    a. If the Agency were to explore alternative pathways for entities to demonstrate alignment with the MES, in what ways could an entity meaningfully demonstrate this?

JSP RESPONSE: If the IPA is not willing to allow EEC Approved Vendor/Designee personnel to count toward the project workforce of an Approved Vendor that contracts with that EEC Approved Vendor/Designee, perhaps a certain level of spend on EECs (including Approved Vendors/Designees acting in a contractual/vendor capacity) could provide an alternative safe harbor.

5. Should the Agency create different Minimum Equity Standards for projects in different areas of the state? If so, which areas?
    a. If the Agency were to adopt differing standards for distinct geographic areas, what criteria or factors should the IPA consider in setting those standards?

JSP RESPONSE: While the Joint Solar Parties do not support different MES for different locations, the Joint Solar Parties note that unavailability of identified EEPs in the Equity Portal—especially a lack of EEPs not already employed by Approved Vendors or Designees—should be a substantial point-scoring category within the waiver.

Topic 4

<u>Questions</u>

1. What enhancements to the Equity Portal would improve its effectiveness in helping EEPs find employment opportunities in the clean energy sector?
2. Conversely, what changes or features would make it easier for clean energy companies to connect with and hire EEPs?

JSP RESPONSE (Combined): The list of "Key Skills" within the Equity Portal is extremely limited. They indicate that the individual has skills of an electrician, foreman, installation, service, sales. Because these categories are too broad to match to particularly jobs or to understand EEP interest, there is currently not an effective way of sourcing EEP's from the Equity Portal directly. Approved Vendors and Designees do not know if these individuals work on projects associated with these skills, if they are qualified/licensed in the skills, or are simply interested—and the term "installation" is extremely broad relative to the multiple skillsets involved.

In addition, the classification of "region" is too broad and makes it difficult to locate a local potential employee or independent contractor. Approved Vendors and Designees need more clarity on what each region means and preferably more granular information—if not by zip code at least by county or group of zip codes. A better approach is for the EEP to provide information about the area where the EEP is willing to work, if the EEP is able to travel across the states and if so, how far are they willing to travel (in miles).

Approved Vendors and Designees cannot currently contact EEPs efficiently in the Equity Portal. Approved Vendors and Designees instead must call or email EEPs individually, which (in contrast with an in-platform messaging function) leads to concerns of spoofing. The list of EEPs cannot be exported into a word doc to send out mass emails with job opportunities or info about hiring events, making wide-ranging outreach much more difficult.

The following additional information would be extremely helpful to be added to EEP profiles:

1. Is the EEP a union affiliated. If so, which union.
2. List what companies the EEPs are associated with (if any).
3. Note if the EEP has experience in community, large DG, small DG, storage, or some combination thereof.

Finally, it would be tremendously helpful if the job training programs that qualify a worker for equity eligible person status to strongly encourage (if not require) registration in the Equity Portal. Many of the EEPs listed in the portal are listed because they registered as part of Approved Vendor or Designee compliance (in other words: they are already employed). Approved Vendors and Designees poaching each others' Designees through cold calls or recruiter outreach cannibalizes—not creates—opportunity and the better approach is to find ways to expand the number of EEPs participating in the portal *before* they find employment.

Topic 5

<u>Questions</u>

1. In addition to workforce demographic information (race, gender), geographic information, and employment classification information, are there other workforce characteristics or data that the IPA should collect and monitor?
    a. Given that the MES Compliance Plans, Mid-year Reports, and Year-end Reports are required by statute, are there other ways the Agency could streamline data collection on these topics?

JSP RESPONSE: The MES Compliance Plan is required by statute "[a]t the start of each delivery year." (20 ILCS 3855/1-75(c-10)(1)(A).) While the IPA has historically interpreted that as the first day of the new delivery year, the IPA—quite correctly—does not apply the same literality to the Year-end Report which is required by statute "[a]t the end of each delivery year" (20 ILCS 3855/1-75(c-10)(1)(C)) but not required until about 45 days later. The IPA could streamline compliance by providing a similar grace period after the "start of each delivery year" and allow for combined submission of the past delivery year Year-end Report and the new delivery year MES Compliance Plan.

2. The Agency is in the process of planning a DEI Data Dashboard to be published on the Equity Portal. Metrics such as number of EEPs, Clean Energy Companies, and Job Postings registered through the Equity Portal will be highlighted, as well as data points sourced from the Shines program's Compliance Plans, Mid-Year Reports, and Year-End Reports. What other data metrics would be useful for our stakeholders to be able to access through this public facing dashboard?
3. The IPA is interested in requiring that EEP registration only occur through the Equity Portal to allow for data integrity and consistency, meaning Approved Vendors and Designees would no longer be able to register EEPs through the Illinois Shines MES reporting process. The Agency is interested in hearing any barriers or unintended consequences that may arise for entities as a result of this change.

JSP RESPONSE: The Joint Solar Parties strongly oppose eliminating methods that many Approved Vendors and Designees use to collect EEP information for the MES Year-end Report. For instance, some member companies report that individual workers do not want to register or share their personal information with the IPA through the portal, or be listed in the portal. Whether any individual worker's concerns or preferences are founded is immaterial because the Joint Solar Parties are uncomfortable with a framework that requires workers that qualify for EEP status (i.e. proxies for being members of disadvantaged communities) to provide personal or sensitive information a particular way.

The Joint Solar Parties hasten to note that many Approved Vendors strongly encourage their workforce (including the workforce of non-Designee or Approved Vendor construction contractors or subcontractors) to register EEPs exclusively through the portal. However, if an EEP refuses to do so, they will not be counted as an EEP unless there is an alternative compliance method (such as currently exists). Some Approved Vendors or Designees are not set up to handle personal information for submission to the IPA, but others have the systems and procedures to handle such personal information in a compliant manner.

If there is additional information or data that the IPA needs to collect through the EEP registration, the allow AVs to collect and provide this information through the annual reporting as well as an alternative pathway.

Topic 6

Questions

1. Does the current treatment of EEP employees (1.5x credit for EEPs employed by an EEC) in MES compliance calculations appropriately incentivize partnerships with EECs?
    a. Would alternative compliance credit structures better encourage entities to partner with EECs?
    b. Are there any other methods by which the Illinois Shines program could incentivize partnerships with EECs? E.g., making entities in the Traditional Community Solar and Community-Driven Community Solar categories that work with EECs eligible for points.

JSP RESPONSE: The Joint Solar Parties are unsure of what an "alternative compliance credit structure" would look like and thus cannot at this time form an opinion. However, as described in responses above, currently use of EECs that are Approved Vendors or Designees is somewhat discouraged because their workforces do not count toward the contracting Approved Vendor's project workforce. Whether the IPA allows EEC Approved Vendor/Designee personnel to count toward the contracting Approved Vendor's project workforce, whether using EEC Approved Vendors/Designees is a form of excuse or waiver or alternative compliance, or whether spend on EEC Approved Vendors/Designees "buys down" compliance, ironically the very requirements intended to advantage EEC Approved Vendors and Designees actually puts them at a disadvantage.

2. Are there current program policies or practices that have inadvertently discouraged legitimate EEP participation? How?

JSP RESPONSE: In the experience of some member companies, some EEPs that qualify due to participation in the foster care system or having been formerly incarcerated are extremely reluctant to discuss at all—much less provide written proof—to employers or third parties. While the Joint Solar Parties appreciate that the IPA intends to prevent fraud, requiring workers to share information that may (or they perceive may) embarrass them or put their current employment in jeopardy or threaten their pathway to advancement is likely to lead to underreporting.

3. Are there ways in which EECs and/or EEPs can be taken advantage of, given the structure of EEP/EEC- based incentives (e.g., subcontracting an EEC and giving very few hours)?
    a. If so, how can the Agency prevent this type of gaming?

JSP RESPONSE: Historically, the IPA has not allowed a *de minimis* exception within the project workforce calculation—as it applies to either the numerator (EEPs) or denominator (all workers)—in terms of how much time was spent on a project. Workers of all types (EEP or otherwise) and vendors/contractors of all types (EEC or otherwise) may be pulled into the scope of the project workforce despite minimal work on a project. Also, the number of hours to be "minimal" depends on the type of project—the hours involved to develop and build a 5 MWac community solar system is anticipated to be much more than a residential rooftop system.

Because of the diverse business models, types of solar, and other factors, the Joint Solar Parties do not have a position on this issue generally speaking. However, the Joint Solar Parties urge that if the IPA plans to propose or float for consideration a *de minimis* amount of work for EEPs or EECs, the same *de minimis* threshold should attach to all workers and vendors/contractors working on the same project.

4. Some stakeholders have suggested that the EEC Category should accommodate different stages in a business' development (e.g., emerging, growing, established). What might be the benefits of doing so, and how could the Agency structure that (e.g., lanes or reserved capacity, preference or priority, etc.)? What types of support, criteria, or benefits should be included at each stage?
5. How has the requirement that EECs hold the REC Contract for 6 years affected EEC participation, business growth, or partnerships?

JSP RESPONSE: The Joint Solar Parties provided an extensive discussion of the interaction between Bankruptcy, forward contract status, and collateral assignment in comments on Chapter 7 following the IPA's questions. These issues apply equally to EEC Block projects and in fact more so to the extent that the EEC is a small or emerging business that is less creditworthy or has less of a track record than a company that is typically holding REC Contracts of similar size or value.