ELEVATE ENERGY
Smarter energy use for all

To: Anthony Star, Illinois Power Agency
Brian P. Granahan, Illinois Power Agency
From: Vito Greco on behalf of **Elevate Energy**
Date: 07/14/2017 (REVISED)
Re: Response to Request for Comments on the Long-Term Renewable Resources Procurement Plan

A. GEOGRAPHIC ELIGIBILITY OF RENEWABLE ENERGY RESOURCES

Section 1-75(c)(1)(I) of the Illinois Power Agency Act ("IPA Act") contains provisions related the geographic eligibility of generating units that provide RECs for RPS compliance. Projects located in Illinois are deemed eligible. Projects located in states adjacent to Illinois "may" qualify if the generator demonstrates, and the IPA determines, that the operation of such facility or facilities will help promote the state's interest in the health, safety, and welfare of its residents based on public interest criteria enumerated in the statute.

1. What level of documentation and analysis should be required from an adjacent state project as part of a request that the Agency consider determining that the project is eligible to provide RECs for the Illinois RPS?
No Comment

2. What would be an appropriate methodology for the Agency to use to determine that a project located in a state adjacent to Illinois meets the public interest criteria enumerated in Section 1-75(c)(1)(I)? For example, should it be a weighted scoring system based upon each of the criteria outlined in the law contributing towards meeting a minimum aggregate score, or does a threshold level of compliance with each criterion have to be fully demonstrated?
No Comment

B. MEETING PERCENTAGE-BASED RPS TARGETS

Section 16-111.5(b)(5)(ii)(B)(aa) of the Public Utilities Act specifies that the LTRRPP "[i]dentify the procurement programs and competitive procurement events consistent with the applicable requirements of the Illinois Power Agency Act and shall be designed to achieve the goals set forth in subsection (c) of Section 1- 75 of that Act." The IPA Act further defines the specific targets for the Initial Forward Procurements (Section1- 75(c)(1)(G)) and the Adjustable Block Programs (Section 1-75(c)(1)(K)). Those targets alone are not expected to meet the overall annual RPS percentage goals for the utilities, which will climb to 25% of retail customer load by 2025.

1. To incent the development of new resources outside the Initial Forward Procurement requirements and the Adjustable Block Program, how should the Agency consider

balancing short-term REC procurements for meeting annual RPS percentage goals with procurements of multi-year commitments for RECs? In responding to this question, please consider that the eligibility requirements under the revised RPS may reduce the availability of eligible RECs from existing projects, potentially necessitating the development of new generation.
No Comment

2. Should the IPA develop distinct procurements that target specific renewable generating technologies beyond wind and solar? And if so, what technologies?
No Comment

C. ADJUSTABLE BLOCK PROGRAM

The LTRRPP requires the IPA to develop an Adjustable Block Program ("ABP") for the procurement of RECs from new photovoltaic projects that are distributed renewable energy generation devices or new photovoltaic community renewable generation projects (e.g., "Community Solar"). The ABP will provide a transparent schedule of prices and quantities to enable the photovoltaic market to scale up and for REC prices to adjust at a predictable rate over time. The prices set by the ABP can be reflected as a set value or as the product of a formula. The ABP will include for each category of eligible projects: a schedule of standard block purchase prices to be offered; a series of steps, with associated nameplate capacity and purchase prices that adjust from step to step; and automatic opening of the next step as soon as the nameplate capacity and available purchase prices for an open step are fully committed or reserved.
ILSfA projects must have access to all available incentives, including the Adjustable Block Program (ABP), because low-income households pay into these incentive pools as ratepayers, and these resources are essential to ensuring that the impact for ILSfA Program is maximized.

The ILSfA incentive could be an adder to address the REC source concerns expressed by IPA at the May 2017 workshops. However, incentives for ILSfA installations should not decline or be tied to declines in corresponding general market incentives and may actually need to increase if paired with declining general market incentives.

When pairing the ABP and ILSfA incentives, the end value must be an incentive level that allows developers, installers, or the nonprofit third-party program administrator(s) to offer solar at no upfront cost to the income-qualified participant with near term significant economic savings realized by the household.

Blocks

1. What approaches should the IPA consider for determining the size of blocks? What are the advantages/disadvantages of having a larger block size as opposed to a smaller block size?

   If IPA designs ILSfA incentives to be an adder to the ABP, the IPA should make the blocks larger to account for ILSfA.

   Block design should account for accurate project development timelines, especially specific to low-income community solar projects. Projects that serve low-income customers may take longer and cost more to develop. Additionally, non-profit developers are not as well resourced as larger for-profit companies so milestones like siting may take longer; larger blocks would help facilitate a longer development timeframe for ILSfA projects. IPA may consider a time-based approach, in which low-income projects should be allotted additional time for project development - i.e. 18 months for broader market, 24 months for low-income. This gives developers of low-income community solar projects additional time to overcome the unique challenges of these projects, including customer acquisition and financing. To account for the longer development timeframes for low-income community solar projects, the IPA should allow for reservation extensions for ILSfA projects in its block design.

   IPA may consider offering a block or interconnection pathway specific to low-income projects. These projects often have longer development timelines, including for siting and pre-development, and therefore may be disadvantaged or discouraged with highly competitive blocks.

2. Should the category for systems between 10 kW and 2 MW be subdivided into distinct blocks? And if so, what are the appropriate break-points (e.g., 100 kW, 200 kW, 500 kW) between categories, and why?
   No Comment

3. Should the initial block or blocks have a different structure than subsequent blocks to account for expected pent up demand?
   Developers will likely incur higher costs at the opening of the program, as they navigate community solar project development, and challenges unique to low-income projects. Including a larger block from the outset would help ensure project development targets are met.

4. What criteria should be used to prioritize projects within a block when applications exceed the remaining available capacity in a block? Should the projects be prioritized on a first-come first–served basis or by other criteria?

IPA may consider prioritization for low-income projects. Low-income projects typically face longer development timelines, and may not be able to compete with a first-come, first-served approach for allocating block capacity.

5. How should the Agency handle the transition between blocks? Should a block close automatically upon being filled? Or should a block remain open until a predetermined date? Upon a block being closed, should the next block open immediately, or should there be some delay?
Developers will likely incur higher costs at the opening of the program, as they navigate community solar project development, and challenges unique to low-income projects. Including a larger block from the outset would help ensure project development targets are met. The IPA and program administrators should also allow for flexibility to change block structures over time to more effectively meet market uptake and program goals.

Prices

At the May 17 afternoon workshop, the IPA outlined two potential approaches for setting ABP REC prices: a cost-based model, and a market observation approach.

6. Should the ABP REC prices be based on a cost-based model which takes into account the revenue requirements for new projects in Illinois, or should it be based on market observations of pricing data as well as developments in other jurisdictions?
Especially as it relates to the ILSfA Program, using a cost-based model allows IPA to set incentives at an appropriate level to cover a majority of system cost, but not over-incent projects. Certain aspects of low-income solar development cost more (customer acquisition, for example). IPA should account for that when setting incentive levels, and a cost-based approach is required to do so accurately.

    a. For the cost-based approach please provide recommendations for data inputs that should considered for the model. If there are publicly available models that could be used as a template, please provide information about those models.

For community solar, Elevate Energy has developed an Illinois specific financial modeling tool that provides flexible inputs and can allow for sensitivity analysis on REC prices. http://www.elevateenergy.org/community-solar/communitysolarbusinesscasetool/. Elevate modelled a community solar project with common project parameters and adjusted the system size to develop a sensitivity analysis for REC prices. See the file Community Solar REC Sensitivity Model.xlsx included with this submission.

The common project parameters used as model inputs are listed below. The financial indicators that are model outputs are listed in the table. The target financial indicator used is Internal Rate of Return (IRR). Stakeholder input from the Financial Modelling Working Group for the Cook County Community Solar Project determined that the IRR of a community solar project - or any solar develop from an investor perspective – should be, ideally, at least 10%. Based on this, the sensitivity analysis found the range of REC value for a community solar project based on this for various system sizes.

Community Solar REC Price Sensitivity

System Assumptions		**Subscriber Assumptions**	
Installation type	Ground	Subscriber model	Panel lease
Total installed cost ($$ per watt)	$2.00	Subscriber benefit	10% savings 1st year
Panel efficiency (watt per panel)	300	Average panels per subscriber	7.5
System financing	None	Years to full subscription	1
Land lease ($ per acre)	$1,000	Anchor share	40%
O&M ($/watt/year)	$15.00	Annual subscriber replacement	2.0%
ITC	30%	Annual energy cost increase	2.75%
MACRs	35%		
Capacity Rebate ($/kW)	$25		

2000 KW	**$40**	**$45**
Internal Rate of Return (IRR)	9.85%	11.22%
25-Year Costs:	($5,638,695)	($5,638,695)
25-Year Revenues:	$7,295,537	$7,466,374
25-Year Net Benefits:	$1,656,841	$1,827,679
25-Year Net Present Value (NPV):	$194,108	$330,634
Return on Investment (ROI):	29.38%	32.41%
Admin & Cust. Acquisition ($/watt)	$0.33	$0.33
Payback Period:	4.5	4.2

1000 KW	**$40**	**$45**
Internal Rate of Return (IRR)	9.16%	10.53%
25-Year Costs:	($2,884,053)	($2,884,053)
25-Year Revenues:	$3,647,768	$3,733,187
25-Year Net Benefits:	$763,716	$849,134
25-Year Net Present Value (NPV):	$60,999	$129,263
Return on Investment (ROI):	26.48%	29.44%
Admin & Cust. Acquisition ($/watt)	$0.34	$0.34
Payback Period:	4.6	4.3

500 KW	**$40**	**$45**	**$50**
Internal Rate of Return (IRR)	7.79%	9.12%	10.52%
25-Year Costs:	($1,506,731)	($1,506,731)	($1,506,731)
25-Year Revenues:	$1,823,884	$1,866,594	$1,909,303
25-Year Net Benefits:	$317,153	$359,862	$402,572
25-Year Net Present Value (NPV):	($5,555)	$28,577	$62,708
Return on Investment (ROI):	21.05%	23.88%	26.72%
Admin & Cust. Acquisition ($/watt)	N/A	$0.37	$0.37
Payback Period:	4.8	4.5	4.2

250 KW	**$40**	**$45**	**$50**	**$55**	**$60**
Internal Rate of Return (IRR)	4.93%	6.24%	7.61%	9.04%	10.50%
25-Year Costs:	($818,071)	($818,071)	($818,071)	($818,071)	($818,071)
25-Year Revenues:	$911,942	$933,297	$954,651	$976,006	$997,361
25-Year Net Benefits:	$93,871	$115,226	$136,581	$157,935	$179,290
25-Year Net Present Value (NPV):	($38,832)	($21,766)	($4,700)	$12,366	$29,431
Return on Investment (ROI):	11.47%	14.09%	16.70%	19.31%	21.92%
Admin & Cust. Acquisition ($/watt)	$0.42	$0.42	$0.42	$0.42	$0.42
Payback Period:	6.2	4.9	4.6	4.3	4.0

100 KW	$40	$45	$50	$55	$60	$85	$90
Internal Rate of Return (IRR)	N/A	N/A	N/A	N/A	-1.88%	8.69%	10.44%
25-Year Costs:	($404,874)	($404,874)	($404,874)	($404,874)	($404,874)	($404,874)	($404,874)
25-Year Revenues:	$364,777	$373,319	$381,861	$390,403	$398,944	$441,654	$450,196
25-Year Net Benefits:	($40,097)	($31,556)	($23,014)	($14,472)	($5,930)	$36,780	$45,321
25-Year Net Present Value (NPV):	($58,798)	($51,972)	($45,146)	($38,319)	($31,493)	$2,639	$9,465
Return on Investment (ROI):	-9.90%	-7.79%	-5.68%	-3.57%	-1.46%	9.08%	11.19%
Admin & Cust. Acquisition ($/watt)	$0.57	$0.57	$0.57	$0.57	$0.57	$0.57	$0.57
Payback Period:	20.0	20.0	20.0	20.0	5.5	3.8	3.7

The analysis shows that the smaller the system size, the increase in Administrative and Customer Acquisition costs and the need for higher RECs to maintain a positive financial model is disproportionately greater. The range of appropriate REC values starts at about $40 for a 2 MW system and as high as about $90 for a 100 kW system. The Administrative and Customer Acquisition costs stays static for each size system regardless of REC value, but increases from $0.33 for 2 MW system to $0.57 for a 100 kW system.

Power Purchase Agreement REC Price Sensitivity

The Cook County Community Solar Business Case Tool can model PPA values, as well – although probably not as well as proprietary developer models. These inputs and outputs are slightly different.

System Assumptions	
Installation type	Ground
Total installed cost ($$ per watt)	$2.00
Panel efficiency (watt per panel)	300
System financing	None
Land lease ($ per acre)	$1,000
O&M ($/watt/year)	$15.00
ITC	30%
MACRs	35%

PPA Assumptions	
PPA model	25 year off-taker agreement
Off-taker benefit	10% savings 1st year
Off-taker share	100%
Annual energy cost increase	2.75%

2000 KW	$40	$45	$50
Internal Rate of Return (IRR)	8.53%	9.63%	10.78%
25-Year Costs:	($4,974,000)	($4,974,000)	($4,974,000)
25-Year Revenues:	$6,795,537	$6,966,374	$7,137,212
25-Year Net Benefits:	$1,821,537	$1,992,374	$2,163,212
25-Year Net Present Value (NPV):	$68,305	$204,832	$341,358
Return on Investment (ROI):	36.62%	40.06%	43.49%
Admin & Cust. Acquisition ($/watt)	N/A	N/A	N/A
Payback Period:	5.0	4.7	4.4

1000 KW	$40	$45	$50
Internal Rate of Return (IRR)	8.17%	9.27%	10.42%
25-Year Costs:	($2,539,000)	($2,539,000)	($2,539,000)
25-Year Revenues:	$3,397,768	$3,483,187	$3,568,606
25-Year Net Benefits:	$858,768	$944,187	$1,029,606
25-Year Net Present Value (NPV):	$10,803	$79,066	$147,330
Return on Investment (ROI):	33.82%	37.19%	40.55%
Admin & Cust. Acquisition ($/watt)	N/A	N/A	N/A
Payback Period:	5.1	4.7	4.4

500 KW	$40	$45	$50	$55
Internal Rate of Return (IRR)	7.42%	8.53%	9.69%	10.90%
25-Year Costs:	($1,321,500)	($1,321,500)	($1,321,500)	($1,321,500)
25-Year Revenues:	$1,698,884	$1,741,594	$1,784,303	$1,827,012
25-Year Net Benefits:	$377,384	$420,094	$462,803	$505,512
25-Year Net Present Value (NPV):	($17,948)	$16,184	$50,315	$84,447
Return on Investment (ROI):	28.56%	31.79%	35.02%	38.25%
Admin & Cust. Acquisition ($/watt)	N/A	N/A	N/A	N/A
Payback Period:	5.5	4.8	4.5	4.2

250 KW	$40	$45	$50	$55	$60
Internal Rate of Return (IRR)	5.82%	6.94%	8.13%	9.36%	10.64%
25-Year Costs:	($712,750)	($712,750)	($712,750)	($712,750)	($712,750)
25-Year Revenues:	$849,442	$870,797	$892,151	$913,506	$934,861
25-Year Net Benefits:	$136,692	$158,047	$179,401	$200,756	$222,111
25-Year Net Present Value (NPV):	($32,324)	($15,258)	$1,808	$18,874	$35,940
Return on Investment (ROI):	19.18%	22.17%	25.17%	28.17%	31.16%
Admin & Cust. Acquisition ($/watt)	N/A	N/A	N/A	N/A	N/A
Payback Period:	6.6	5.0	4.7	4.4	4.1

100 KW	$40	$45	$50	$55	$60	$75	$80
Internal Rate of Return (IRR)					4.78%	9.62%	11.24%
25-Year Costs:					($347,500)	($347,500)	($347,500)
25-Year Revenues:					$373,944	$399,570	$408,112
25-Year Net Benefits:					$26,444	$52,070	$60,612
25-Year Net Present Value (NPV):					($13,644)	$6,835	$13,662
Return on Investment (ROI):					7.61%	14.98%	17.44%
Admin & Cust. Acquisition ($/watt)					N/A	N/A	N/A
Payback Period:					4.6	3.9	3.7

In general, PPA REC values show a narrower range, from about $45 to $80, instead of $40 to $90 for community solar systems of comparable sizes. This is primarily due to 1) the disproportionate increase in administration and customer acquisition costs based on system size, and 2) the impact on IRR from subscriber payments.

These models and outputs are not intended to be determinate of proposed REC values, but instead should provide a range of values that can serve as starting points, and guidance on the impact of system size and other variables on the financial viability of individual solar developments.

b. For the market observations approach, please identify the jurisdictions that could be considered, and any significant differentiators between those jurisdictions and Illinois that should be used to adjust results.
A Market Observation approach is not recommended. See Cost based approach recommendation details above.

c. Does the methodology for determining REC pricing have to be either cost-based or market observation based, or can it be a combination of both? Are there any other approaches that should be considered?
The IPA should reserve its ability to do both cost-based and market-based. The first set of RECs should be cost-based. Then IPA may move to market-based once a bigger set of data is available from Illinois' own market.

7. How should the approach for determining REC prices take into account geographic differences in price or cost factors, e.g. local labor/land costs etc.? How narrowly or broadly should geographic factors be considered?
IPA and third party program administrators should consider the differences in project economics by service territory,project type, andmarket segment; adjusting REC prices as needed to ensure geographic diversity. The tendency generally will be to develop solar on the least expensive land possible. This will typically be in rural or downstate greenfields. A mechanism to ensure greater diversity is to prioritize projects where offtakers (PPAs) or subscribers (Community Solar) are within a distinct, localized geography (5 to 10 miles), since they are more likely to be in denser urban/suburban areas. See community solar below for more details on this.

8. Besides geography and system size, are there other factors that should be considered to create differentiated pricing?
No comment

<u>Project Development Process</u>

9. How much time should be allowed between system application/contract approval and when a system must be energized? The time allowed could take into account issues like (i) the seasonality of applications, (ii) delays in permitting, interconnection, (iii) equipment availability and etc. Should this time vary by size of system, geographic location, or interconnecting utility?
Longer periods should be considered for ILSfA community solar projects to account for the added complexities in outreach and customer acquisition; i.e. 24 months. If IPA uses a shorter time period, it should include options for extension when appropriate.

10. What type of extensions to a guaranteed in-service date should be allowed, and what additional requirements should there be for extensions?
Delays with interconnection, zoning and permitting, or other legal barriers should be considered as criteria for approving extensions.

11. What information about a system should be required for a system to be qualified to participate in the program (e.g. site control, local permitting, interconnection status, etc.)? Should the requirements be different for smaller systems (e.g., under 10 kW) than larger systems? Should the requirements be different depending on whether the system is being interconnected with an investor-owned utility, a municipal utility, or a rural electric co-op?
No comment

12. What development deposit/credit requirements should there be in addition to any program fees? And for how long should such requirements run?
No comment

13. Should there be intermediate project milestones to help ensure that projects that have reserved RECs out of a block are successfully developed, and that closure of blocks due to all RECs being allocated is effectively managed? If so, how should milestones and performance standards vary between smaller and larger projects?
No comment

14. For the Supplemental Photovoltaic Procurement, inverter readings were allowed for systems below 10 kW, and revenue grade meters were required for larger systems.5 How should these standards be updated for the ABP?
No comment

Clawback Provisions

The ABP allows for contracts to include provisions to ensure the delivery of the RECs for the full term of the contract. This is to account for the fact that upfront payments for RECs could create a variety of challenges including, but not limited to, (i) poorly installed or maintained systems that do not generate the intended amount of RECs (or energy), (ii) failure to provide generation data to the tracking system for the creation of RECs, and (iii) arbitrage risk related to sellers seeking revenue for committed RECs from other markets. *No comment*

15. What clawback provisions would be appropriate for ensuring that RECs are delivered while not creating potentially prohibitive additional costs or burdens?

16. What would be reasonable circumstances to allow for the waiving of clawback provisions? (e.g., fires, severe weather, etc.)
17. Should clawback provisions vary based on system size? If so how should these provisions vary?
18. How should clawback provisions carry over when a system and/or system location is sold? Consumer Protections
19. What consumer protection elements should the IPA consider adopting as part of the ABP program? How should those elements differ between distributed generation and Community Solar?
    See Consumer Protection responses at the end of this document; i.e. Il Solar For All.
20. Should the ABP require the use of a standard disclosure form? If so, what elements should that form include?
21. Are there examples from other states of model approaches to consumer protection, and/or lessons learned regarding insufficient consumer protections?
    No comment

D. COMMUNITY SOLAR

Geographic Considerations

1. Should the IPA consider taking steps to encourage projects to be located geographically closer to subscribers? If so, what steps should be considered?*There can be a higher price block or additional incentives for projects with all or a majority of local subscribers (i.e. within 5-10 miles). This incentive could be similar to that offered for projects that are 100% low-income. This approach could help fulfill geographic diversity requirements. However, prescriptively saying that all projects have to have subscribers within that range could dampen the market by eliminating those least expensive installations. This incentive-based approach could accelerate the market.*

2. How can geographic diversity be ensured? *IPA should maintain flexibility on mechanisms for ensuring geographic diversity; i.e. adjusting blocks or block values over time. It will be important to adjust based on market conditions and effectiveness of achieving this diversity from procurement to procurement.*

Project Application Requirements

3. Should Community Solar projects have different application requirements than a comparably sized distributed generation project? What level of demonstration of subscriber interest should be required prior to approving an application from a Community Solar project?
   The demonstration of subscriber interest should be minimal upon application. The proposed community solar project could be required to demonstrate a committed anchor tenant and/or a minimum number of subscribers. The minimum number of subscribers could be set at 3 given

that is the minimum number a project can have based on the cap on the percentage of the project that any one subscriber can account for.

4. How should co-location of Community Solar projects be addressed in light of the definition of community renewable generation projects that is capped at 2 MW.
Co-location of Community Solar projects should be prohibited with the possible exception of ISFA projects or projects developed on brownfields. Allowing co-location of community solar projects on brownfields makes sense to enable full site re-use in the case of large contaminated sites, provide cost advantages to more-expensive brownfields solar projects, and enable community solar development on brownfields as community solar projects are excluded from the brownfield carve-out of the RPS. It is also in line with the finding in the Future Energy Jobs Act that brownfield solar development is in the public interest.

However, if the IPA allows co-location, limitations should be placed on the number of projects and/or developers on a single site, to avoid market monopolization and deviance from statute definition of community solar.

<u>Community Solar Blocks</u>

5. Should the design approach for blocks for Community Solar vary from that used for Distributed generation (e.g., size of blocks, criteria for prioritizing applications)?
There may be blocks that align with distributed generation blocks, i.e. size (25kW, 100kW, 250kW, 1MW for example). However, the financial drivers and community engagement requirements are different and may require a different approach; i.e. geography from the example above where there are higher block values for projects within a close proximity to subscribers.

6. What would be reasonable assumptions to make for the cost of acquiring and maintaining subscribers? How will these costs be expected to vary over time (e.g., the difference between initial subscriber recruitment and managing churn rates)? How will these costs differ between managing residential and commercial subscribers?
Public data is minimal for administrative and transactional costs. However, the development of the Community Solar Business Case through for the Cook County Community Solar project involved a extensive process of vetting data through the National Renewable Energy Laboratory, the National Community Solar Partnership, as well as regional and national community solar developers and stakeholders.
    i. *All stakeholders agreed that, while ranges could vary significantly based on project design, legislative framework and geography, a range of between \$0.20 and \$0.60 per watt was reasonable. Projects could have aggregate administrative and transactional costs outside of this range, but they would be anomalies.*

ii. *SEPA has done some research on customer acquisition (Community Solar Program Design: Working Within the Utility, 2015 November). They found that of nine programs researched, eight reached 100% subscription with an average time of six months. 30% of these reached full subscription before the project was energized.*

iii. *Industry stakeholders in the Cook County process stated that any subscriber turnover of more than 2% per year is problematic and uncommon for healthy projects.*

iv. *Elevate modelled a 1 MW project for three scenarios: 100% C&I, 100% Residential and a mixed subscriber project with 40% Anchor/60% Residential. Basic subscriber assumptions include: 100% subscription in the first year, 1.5% average subscriber turnover annually for residential and after 10 years for commercial, breakeven energy credit year one, 2.78% average energy cost increases compounded each year, and a moderate level of difficulty in the recruit. This is an average community solar project. Even with commercial customer acquisition assuming 10x the effort, the models show how much easier an all commercial project is to subscribe:*

	First Year Admin and Customer Acquisition Costs	*Ongoing Admin and Customer Acquisition Costs*	*Total Admin and Customer Acquisition Costs for 25 years*	*Total Admin and Customer Acquisition Costs as % of lifetime costs*
Mixed (40% Anchor / 60% Residential)	*$62,113*	*$282,040*	*$344,154*	*9.1%*
100% Commercial	*$28,938*	*$105,553*	*$134,491*	*4.3%*
100% Residential	*$90,784*	*$470,156*	*$560,938*	*14.1%*

Models can be downloaded here:

- http://www.elevateenergy.org/wp/wp-content/uploads/Community-Solar-1-MW-Mixed-Subscribers-REVISED.xlsm
- http://www.elevateenergy.org/wp/wp-content/uploads/Community-Solar-1-MW-All-Commercial-Subscribers-REVISED.xlsm
- http://www.elevateenergy.org/wp/wp-content/uploads/Community-Solar-1-MW-All-Residential-Subscribers-REVISED.xlsm

7. Should the value proposition to the customer for a subscription to a Community Solar project be more, or less, attractive than for a comparable sized DG system at the customer's location?
Generally, a key principle of community solar is that it provides an option for customers who cannot install a solar system on their own property. We should be encouraging customers who can install their own system to do so, while not penalizing those who cannot. All of this is to say that the value proposition should be the same.

   However, in the case of the ILSfA program, low-income households should receive the highest value proposition to entice customer participation and maximize program impact. Also, a potential gap remains for households with income of 80%-120% AMI (moderate-income households). These households have historically lacked options for access to clean energy and may be the segment that faces the biggest barrier in Illinois after the implementation of ILSfA - with less means and no incentive.

Development Milestones

8. Should the time allowed for Community Solar project development be different than for comparably sized Distributed Generation systems?

   Flexibility above what is available to DG system customers should be offered for community solar projects. It isn't unreasonable to expect that it requires more time and effort, as well as carries more risk and uncertainty to acquire multiple customers and appropriate space for a community solar project than a DG project located on one customer's premises. For example: 1) the higher risk level seen by investors, which can stretch the capital planning timeline, 2) the customer acquisition effort and time period and 3) the additional requirement to show subscriber interest.

9. What project development milestones should be required to demonstrate sufficient levels of subscriber interest before a contract may be terminated?
Generally, the requirements should be minimal. These can change over time depending on market activity. For example: A demonstrated anchor subscriber commitment, or support from community organizations in targeted subscriber markets. For low-income projects, demonstrated stakeholder engagement.

Residential versus Commercial Interest

10. What, if anything, should the IPA consider to ensure robust residential participation in Community Solar?
11. Should REC pricing vary based on the portion of the project that is residential? How can this be certified, and what would be required over time to ensure ongoing residential participation?
If there are no specific requirements to ensure significant residential access, community solar subscription is likely to be dominated by commercial and industrial subscribers, as happened in MN. It is clear that this is not the intention of the law. This happens because the administration

and customer acquisition costs are significantly lower for an all C&I subscriber model. Individual C&I customers may be more difficult to acquire. But, a developer may only need three C&I customers to fill a project, whereas hundreds of households would be needed to account for the same share of capacity. (see analysis above at COMMUNITY SOLAR Point 6.)

However, it is important that C&I entities still have access to community solar. According to NREL, about 50% of both residential households and C&I ratepayers cannot install solar on their roofs because of structural limitations. In urban areas, these percentages are higher because of density and housing stock. More are limited because of financial barriers. In general, all rate classes need access to community solar.

These less expensive and easier to manage 100% C&I models meet an important need in the market with a cost effective business model. If we require a per project minimum of residential subscribers, we will make these models more expensive and impede the market for that rate class. Developing a portfolio approach where a minimum amount of residential subscribers is required across many projects creates difficulty in establishing and monitoring compliance and presents difficulties in developing new clawback mechanisms. Instead, dedicated blocks with higher REC prices can be applied to incent partial or 100% residential projects, specifically, to levelize the additional costs associated with these projects (i.e. 100% C&I no incentive, at least 50% Residential adder or incentive, 100% Residential higher adder or incentive).

For low-income qualified projects, program design may consider that program administrators provide outreach or even subscriber management support for those projects.

Adjust as needed with subsequent procurements.

12. Should project application/viability requirements be different based on the mix of residential and commercial customers?
13. Are there additional considerations that should be made for projects that are entirely subscribed with commercial customers, or entirely subscribed with residential customers?
See above response for RESIDENTIAL VERSUS COMMERCIAL INTEREST points 9 and 10.

E. ILLINOIS SOLAR FOR ALL PROGRAM

1. How should the concept of "80% of area median income" be applied? What size area should be considered (e.g., municipality, county, utility service territory)
Elevate Energy recommends that area median income calculations should use U.S. Department of Housing and Urban Development (HUD) annual area median income (AMI) limits[1], and

1

American Community Survey (ACS) 5 year estimates for household income brackets, using the most recent survey data published. The geographic area of analysis should be the census tract level. Further, Elevate Energy recommends that a 50% density of qualifying households be the threshold to determine whether or not a census tract is qualified or non-qualified.

The U.S. Department of Housing and Urban Development publishes annual area median income (AMI) limits for every metropolitan area, referred to as metropolitan statistical area or MSA, and non-metropolitan county in the U.S. These income thresholds are then used to determine eligibility for several HUD programs, such as public housing and Section 8 Housing Choice Vouchers.

These income thresholds vary by family size, and are defined as "extremely low income" (30% of area median income), "very low income" (50% of area median income) and "low-income" (80% of area median income.)

The AMI is set for a large metropolitan area, like Chicago, which includes both urban areas in the city limits as well as suburban areas. For example, in the ComEd service territory, there are several metropolitan statistical areas (MSAs) as well as more rural counties, all with their own AMI:

	Total Households (2015)*	***Number of Households at or Below 80% Area Median Income(AMI) (2015)***	***% of Households at 80% AMI***	***2015 HUD AMI*****
Carroll County	*4,241*	*1,683*	*40%*	*$ 59,600*
Champaign-Urbana, IL Metro Area	*801*	*338*	*42%*	*$ 72,500*
Chicago-Joliet-Naperville, IL-IN-WI Metro Area	*3,119,359*	*1,431,990*	*46%*	*$ 76,000*
Davenport-Moline-Rock Island, IA-IL Metro Area	*5,412*	*2,012*	*37%*	*$ 69,000*
Jo Daviess County	*3,367*	*1,567*	*47%*	*$ 65,200*
Kankakee County / Kankakee-Bradley, IL Metro Area	*40,880*	*17,384*	*43%*	*$ 68,100*
Lee County / Dixon, IL Metro Area	*13,517*	*5,982*	*44%*	*$ 66,300*
Ogle County / Rochelle, IL Metro Area	*20,731*	*10,087*	*49%*	*$ 71,000*
Ottawa-Peru, IL Metro Area (previously called Ottawa-Streator, IL Micro Area)	*29,930*	*13,382*	*45%*	*$ 63,600*
Peoria, IL Metro Area	*4,221*	*1,752*	*42%*	*$ 72,800*
Pontiac, IL Metro Area	*13,542*	*5,421*	*40%*	*$ 67,900*
Rockford, IL Metro Area	*127,995*	*56,411*	*44%*	*$ 63,100*
Stephenson County / Freeport, IL Metro Area	*19,299*	*9,108*	*47%*	*$ 59,900*
Whiteside County / Sterling, IL Metro Area	*23,548*	*10,046*	*43%*	*$ 59,900*

HUD income limits and ACS income brackets data, at the census tract level, should be used to determine the number of households in each tract that fall below the 80% AMI threshold for that area, adjusted for household size. This number should be divided by the total number of households in the tract to give a percentage of households below 80% AMI. Census tracts should then be designated as qualifying or not qualifying at a given density threshold of 80% AMI. For a 50% density eligibility standard, any tract with more than 50% of households at or below 80% AMI would be considered qualifying. Effectively, any census tract with a median household income below 80% AMI for that rental market would qualify and all housing units would be considered affordable.

2. What should be the balance between verifying individual income eligibility and using other criteria such as median income of census tract?
In order to serve the greatest number of participants, and to reduce barriers to participation related to individual household documentation, Elevate Energy recommends a dual approach that is geographically based on census tract, and a secondary method using income verification for those households who are low-income but outside of the geographic designations. To qualify, a household or building must:
    (1) Reside in a census tract where the median household income is less than or equal to 80% AMI for that MSA or County (using a 50% density threshold.)
    (2) Demonstrate eligibility, ideally through an existing program that has income verified, such as LIHEAP; Weatherization; Housing Choice Voucher; ComEd CARES, etc

Lawrence Berkeley Laboratory notes that a double eligibility option (geographic and/or individual) could be a useful technique, as "The flexibility of such an approach would enable savings for low- and moderate-income households living in neighborhoods with diverse incomes and also from neighborhoods with significant concentrations of low- and moderate-income households".

There is also successful precedent for local programs implementing a geographically based eligibility criteria for federally funded programs. The National School Lunch (and Breakfast) Program (NSLP), administered by the Food and Nutrition Service (FNS) of the U.S. Department of Agriculture (USDA), is a federally funded program created to provide reduced price or free meals to low income school children throughout the country. To reduce the individual household income verification burden on families and schools, in 2010 the USDA created the Community Eligibility Provision for school districts (or individual schools) that eliminates the application process and other administrative procedures and provides free meals to all students in income eligible schools[2]. The statistical evaluations of the program conducted by Abt Associates[3] show

[2] https://www.fns.usda.gov/school-meals/community-eligibility-provision
[3] *Community Eligibility Provision Evaluation: Year 3 Addendum. USDA Nutrition Assistance Program Report, Submitted by Abt Associates. January 2015.* https://fns-prod.azureedge.net/sites/default/files/ops/CEPEvaluationAddendum.pdf

that it has: Increased participation (at the student and school level); decreased administrative time, and; almost eliminated income certification errors. As of the 2015-2016 program year, over 18,000 schools serving over 8.5 million children have adopted CEP. This represents roughly half of eligible schools, which a recent report describes as a "strikingly high take-up rate for such a new federal program".

3. What provisions in contract and REC payment structure should the IPA consider to ensure that any revenue received for RECs does not hinder participants' eligibility in other benefits programs?
The ILSfA Program should result in participants realizing meaningful and significant monthly savings on their monthly electricity bills, eliminating the need for enrollment in energy assistance programs and ultimately keeping their homes affordable. Revenue from RECs should not be delivered in such a way that it would qualify as income, which could impact participants' eligibility for other benefits. The most straightforward method would be either a credit directly on the customer's utility bill or a "refund" for utility costs paid.

4. What distinct requirements and considerations should apply to multi-family buildings?
In the legislation, the language that references multifamily housing is broad and sits outside of any specific program description.[4]

> *Section 20 ILCS 3855/1-56 (b) (2): "Contracts under the Illinois Solar for All Program shall include an approach, as set forth in the long-term renewable resources procurement plans, to ensure the wholesale market value of the energy is credited to participating low-income customers or organizations and to ensure tangible economic benefits flow directly to program participants, except in the case of low-income multi-family housing where the low-income customer does not directly pay for energy."*

Individual program language is then included in subsequent sections.[5]

Significant percentages of households at or below 80% AMI live in multifamily properties across Illinois. Any low-income household should qualify for benefits under ISFA. While ISFA language talks specifically about <80% AMI households in multifamily properties "where the low-income customer does not directly pay for energy" (referring to master-metered building), it also generally suggests that multifamily properties should be beneficiaries from ISFA programs.

Elevate Energy proposes that the IPA consider a distinct program that serves multifamily housing, separate from the four programs identified specifically in the legislation. Whether an installed distributed generation program or an incentive program, targeting multifamily property

[4] *Section 20 ILCS 3855/1-56 (b) (2)*
[5] *20 ILCS 3855/1-56 (b) (2) A, B, C and D*

owners serving low-income households will require distinct marketing and outreach, compliance, consumer protection and quality assurance.

> *Section 20 ILCS 3855/1-56 (b) (4): "In the course of the Commission proceeding initiated to review and approve the plan, including the Illinois Solar for All Program proposed by the Agency, a party may propose an additional low-income solar or solar incentive program, or modifications to the programs proposed by the Agency, and the Commission may approve an additional program, or modifications to the Agency's proposed program, if the additional or modified program more effectively maximizes the benefits to low-income customers after taking into account all relevant factors, including, but not limited to, the extent to which a competitive market for low-income solar has developed. Following the Commission's approval of the Illinois Solar for All Program, the Agency or a party may propose adjustments to the program terms, conditions, and requirements, including the price offered to new systems, to ensure the long-term viability and success of the program."*

In Illinois, 33% of the 5.3 million housing units are multifamily and 50% of all affordable housing units in the state are multifamily. In Chicago, the percentage of multifamily housing is above 75%. This underscores the importance of recognizing multifamily properties as a distinct segment of the affordable housing market especially given that it often serves as housing for households of 80% or less AMI. Multifamily is commonly defined as 5+ unit residential properties and affordable housing is defined as households with rent less than 30% of monthly income. While affordable housing is not the same as households with income of 80% or less of AMI, there is a high correlation between the two – especially relevant because data is not available for housing unit types by 80% AMI or less.

In the legislation, the language that references multifamily housing is broad and sits outside of any specific program description.[6] Individual program language is then included in subsequent sections.[7] Significant percentages of households at or below 80% AMI live in multifamily properties across Illinois, according to analysis by Elevate Energy shown below:

	Multifamily 5+ Units			Non-Multifamily Units					
ELECTRIC UTILITIES	Percent Affordable Units	Sum of Affordable Units	Sum of All Units	Percent Affordable Units	Sum of Affordable Units	Sum of All Units	Percent Affordable Units	Total Affordable Housing Units	Total Housing Units
Ameren Illinois	69%	120,476	175,120	40%	434,918	1,097,110	44%	555,394	1,272,230
Commonwealth Edison Co.	46%	455,760	998,902	30%	830,055	2,758,534	34%	1,285,815	3,757,436
Muni's, Coops, Other Utilities	65%	27,795	42,495	36%	115,962	324,715	39%	143,757	367,210
ALL ILLINOIS	50%	604,031	1,216,517	33%	1,380,935	4,180,359	37%	1,984,966	5,396,876

[6] *Section 20 ILCS 3855/1-56 (b) (2)*
[7] *20 ILCS 3855/1-56 (b) (2) A, B, C and D*

Note that Illinois has more than 400,000, 2-4 unit affordable housing properties. Elevate Energy recommends that these properties be included in the Distributed Generation program for single-family housing.

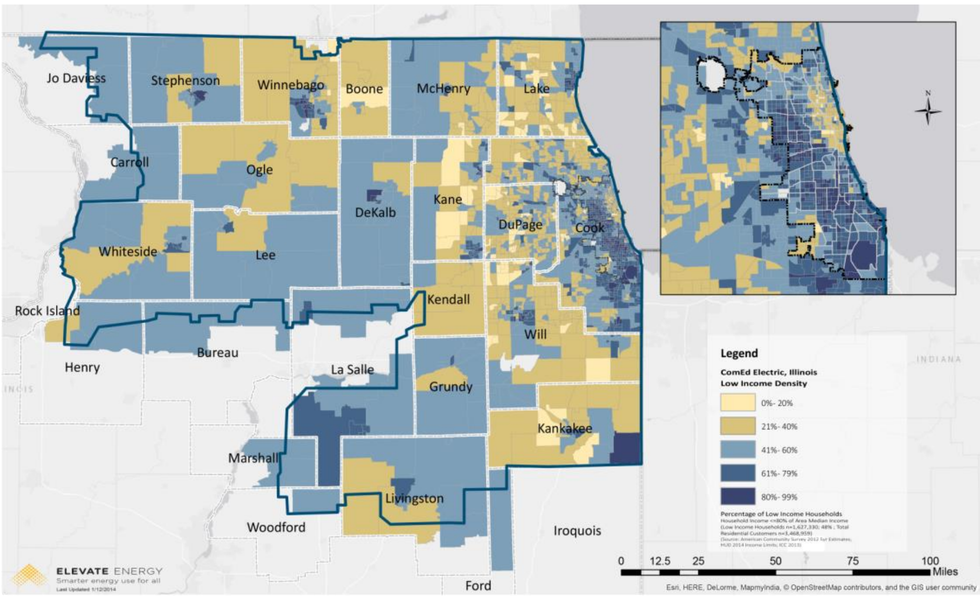
IPA can consider an incentive based on a per watt value. For example: $1.00 to $1.25 per watt, which could represent 30% of the installation cost depending on system size. Private multifamily property owners can couple this incentive with RECs and tax benefits to make solar more affordable. Developers can do the same in order to offer discounted third-party ownership models or even models where full ownership of the system is transferred to property owners after asset depreciation (6 years).

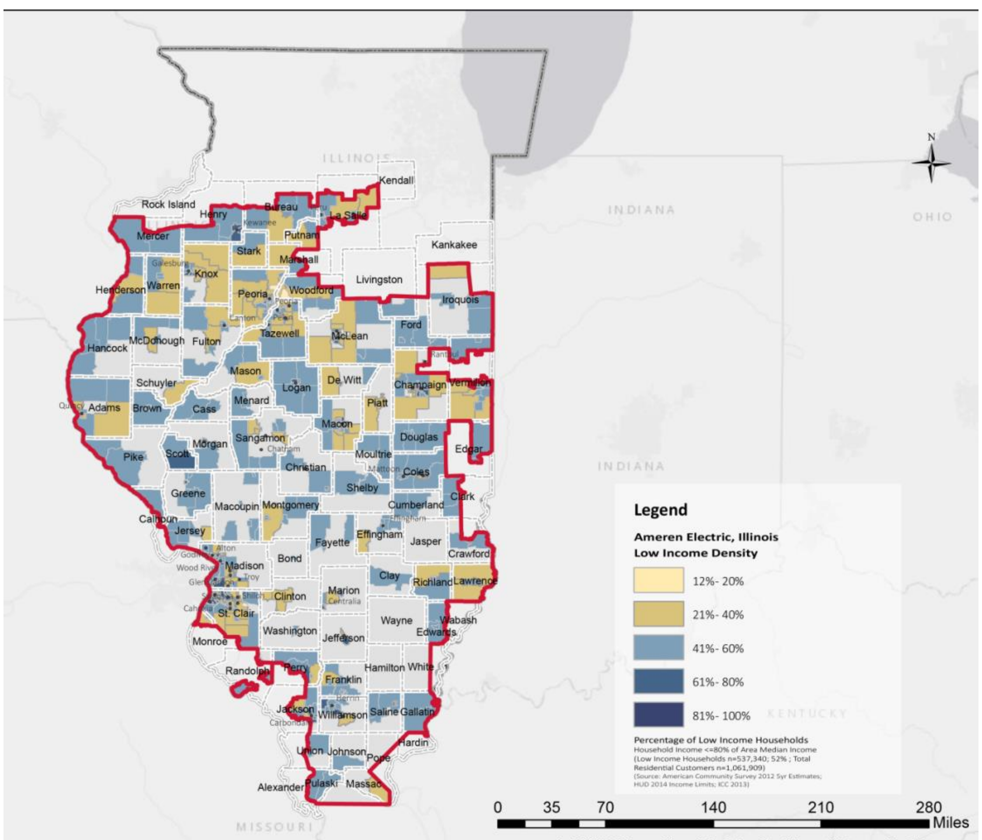
An example matrix of property type, incentive, eligibility and energy efficiency integration is below:

Program	Size	Incentive	Eligibility	Energy Efficiency Integration		
				Level 1	Level 2	Level 3
Single-family	2 kW to 5 kW	Fully installed	Owner-occupied, permanency, census tracts with < 80% AMI	No Verified Energy Efficiency work *Up to 2 kW*	Verified Measures taken (X # of EPA recommended measures) *Up to 3 kW*	Energy Star certified *Up to 5 kW*
2-4 units (same as or part of single-family)	2 kW to 5 kW	Fully installed	Owner-occupied, permanency, census tracts with < 80% AMI	No Verified Energy Efficiency work *Up to 2 kW*	Verified Measures taken (X # of EPA recommended measures) *Up to 3 kW*	Energy Star certified *Up to 5 kW*
5+ units	2 kW to 100 kW	$1.00 - $1.25 /Wt	Census tracts with < 80% AMI or verified through affordable housing provider	No Verified Energy Efficiency work *Up to 5 kW* *$.75 / Watt*	Verified Measures taken (X # of EPA recommended measures) *Up to 25 kW* *$1.00 / Watt*	Energy Star certified *Up to 100 kW* *$1.50 / Watt*
Nonprofit/Public Sector	Up to 500 kW	$1.00 - $1.25 /Wt	Nonprofit or Public Sector owned property	No Verified Energy Efficiency work *Up to 100 kW*	Verified Measures taken (X # of EPA recommended measures) *Up to 250 kW*	Energy Star certified *Up to 500 kW*
Community solar incentives	Up to 100% of load	25% to 50% of the monthly panel lease cost; 25% to 50% of upfront panel purchase price.	Census tracts with < 80% AMI or verified through affordable housing provider	NA	NA	NA

 # Households of 80% AMI or less:

- *ComEd territory: 1,627,300 <80% households*
- *Ameren Territory: 537,340 <80% households*





5. How should the concept of low-income be considered for non-profit and public facilities? Should all non-profits and public facilities be eligible for that Solar for All program, or should there be some nexus with low-income criteria?
   The nonprofit incentive should be provided to address the gap in access to tax benefits to these entities. Nonprofits and public sector entities have lagged behind commercial and for-profit entities in adopting renewables because they have historically been unable to qualify for tax-based incentives. In that context, there should be no requirement that either entity should serve low income communities.

   The nonprofit/public sector incentive should be equivalent to the Investment Tax Credit (ITC) at 30% of the cost, with limits or blocks based on system size.

   Similar to multifamily entities as stated above, regardless of whether IPA pursues an installed distributed generation program or an incentive program, targeting nonprofit or public sector property owners will require distinct marketing and outreach, compliance, consumer protection and quality assurance. For these reasons, Elevate Energy recommends the non-profit and public sector program be administered separately, or in conjunction with the multifamily program because it is the most similar in terms of potential incentive structure, eligibility and overlap in ownership (more so than single-family properties for example).

6. For Illinois Solar for All grassroots education efforts in rural areas, what opportunities are there for partnering with community organizations and institutions?

<u>Utility Funded and Administered Job Training Programs</u>

7. In some instances, trainees may be unavailable to participate in project development (due, for instance, to the time to complete training programs or geographical constraints). What flexibility should be considered to account for the potential lack of availability of trainees to work on projects?
   Programs for trainees should include both in the classroom and out in the field components; ideally in the form of apprenticeships. Training programs should be made available throughout the state to achieve greater access for all. For content taught in the classroom, students who live 50+ miles from a training center should be given the opportunity to participate in their education through an online course. Additionally, for trainee instruction to be successful, a significant portion of the training, at least 50 percent of course instruction, need be in the field; observing work being done and practicing the skills they have learned in the classroom. Consequently, the field component of the trainee education would need to be less flexible, and could not be taught through most alternative strategies; i.e. online. Trainees should be provided a stipend for transportation to training facilities 10+ miles away from their home.

Trainees should be fairly compensated for the hours spent during the training program and during all apprenticeships. This will ensure that trainees will not have to choose between supporting their livelihood and their future career.

8. How can the IPA ensure that project developers offer meaningful employment opportunities and career advancement to job trainees and others in the workforce development pipeline?
IPA should require that every project executed by a developer or contractor to have a minimum their crew represented by trainees. If, for example, contractors achieve more than 25 percent of their crew made up of trainees they should receive a further incentive for said project. Further, the IPA should provide incentives to encourage developers/contractors to hire members of their crew from within five miles of their project.

Environmental Justice Communities

In defining an Environmental Justice Community, how should the IPA weigh factors such as (i) Income, (ii) Race/Ethnicity, (iii) Environmental Impacts, (iv) Regional Economic Conditions, or (v) Other demographic factors? What environmental impacts should the IPA prioritize, and what other factors should the IPA consider?

9. What level of community self-designation should be considered (or community ability to decline designation)?

Consumer Protections

10. What additional consumer protections should be specific to the Illinois Solar for All programs above and beyond the consumer protections offered more generally to participants in the Adjustable Block Program?[8]
    - *The ILSfA third-party program administrators should all be non-profits to ensure that the maximum economic benefit and interests of income-eligible participants are at the forefront of the ILSfA Program areas, including ensuring opportunities for auxiliary benefits.*
    - *Program design and compliance should ensure that participants in low-income programs have no upfront costs and receive clear and tangible benefits. These financial barriers are typically insurmountable for low-income households. Consumer protection issues can arise from these financial barriers if families are offered a subprime solar deal that may not result in long-term savings, or a solar loan/lease product that could result in a negative economic outcome.*
    - *Low-income Community Solar*
        - *Developers that take advantage of ILSfA incentives should be required to keep capacity allocated to low-income subscribers for 20 years (so developers don't switch capacity to non low-income households after 5 years).*

[8] *See slides 41 to 46 of the Illinois Solar for All workshop presentation, https://www.illinois.gov/sites/ipa/Documents/Solar-for-All-presentation-20170518.pdf for an overview of some possible consumer protections.*

- *The third-party program administrator should produce a disclosure form and guide(s) similar to the materials used in Minnesota's Xcel Energy Community Solar Garden program (http://www.cleanenergyresourceteams.org/sites/default/files/CommunitySolarGarden_DisclosureChecklist_12-11-14_0.pdf)*
- *The third-party program administrator should develop standard contracts that community solar operators will use to transact with low-income subscribers. In unique situations in which a standard contract may not apply, the third-party program administrator can provide technical assistance to arrive at a workable solution.*

The IPA could consider requiring additional layers of oversight for marketing materials and sales representatives that are offering projects to low-income households under the ISFA program. The risks to these customers from unexpected costs or conversely, overstated savings, are higher than those for customers in other income brackets. If low-income customers have a poor experience with this program in the beginning it will likely have a detrimental impact on its overall success, so we should do what we can to ensure that it is implemented transparently and honestly.

To that end, the IPA should require that all savings claims, prices and customer contracts are vetted by the IPA to confirm their validity and to protect residents from predatory practices.

11. What does providing that "tangible economic benefits flow directly to program participants" imply in terms of either upfront payments to participants and/or assurances that participation creates a positive cash flow?
Income-eligible households participating in ILSfA should have a cash-flow positive experience from day one and have, ideally, no financial liability to the system owner; however, should any particular financing model require financial liability from eligible households, then the savings from the solar should far exceed the payment.

    As stated above in reference to multifamily property owners, tangible benefits can flow directly to multifamily building owners and should include both master-metered and non master-metered properties.