Environmental Defense Fund, Citizens Utility Board, and Respiratory Health Association's Responses to Illinois Power Agency's Long-Term Renewable Resources Procurement Plan Request for Comments

Environmental Defense Fund ("EDF"), Citizens Utility Board ("CUB"), and Respiratory Health Association ("RHA") (collectively, EDF/CUB/RHA) provide the following comments in response to the Illinois Power Agency's ("IPA") Request for Comments of June 6, 2017. EDF is a national nonprofit organization whose mission is to preserve the natural systems on which all life depends. Guided by science and economics, EDF finds practical and lasting solutions to the most serious environmental problems. EDF has a strong interest in minimizing the electric industry's significant contribution to climate change and other environmental problems. CUB is a statewide organization which advocates for the rights and interests of utility residential and small business customers. Focused on promoting affordable, safe and reliable utility services, CUB is interested in finding ways to integrate new distributed energy resources to lower customer bills. RHA is a nonprofit organization whose mission is to prevent lung disease, promote clean air, and help people live better through education, research, and policy change.

In these comments, EDF/CUB/RHA propose market-based solutions to advance the goals of the Illinois General Assembly and guide the IPA in drafting its Long-Term Renewable Resources Procurement Plan ("LTRRPP"). We commend the IPA for its diligent work educating stakeholders and considering stakeholder views in the May 17, 18, and 24 workshops on designing the procurements and programs required under the Future Energy Jobs Act (P.A. 99-0906) ("FEJA"). In particular, we appreciate the opportunity to offer additional feedback in response to the questions posed by the IPA. EDF/CUB/RHA understand the need for a successful Long-Term Renewable Resources Procurement Plan and associated programs and procurements under FEJA. The success of this initial LTRRPP will depend on its ability to kick-start a new solar industry, develop strong community solar and Solar for All programs that provide equitable access to solar for new participants, and create a long-term, sustainable procurement strategy to help achieve the state's renewable energy resource, health, environmental, economic development, and community goals.

These comments are guided by the mandated approach for the LTRRPP and the policy goals set forth in FEJA. The General Assembly stated that:

> The [Illinois Power] Agency shall develop a long-term renewable resources plan that shall include procurement programs and competitive procurement events necessary to meet the goals set forth... The [Illinois Power] Agency shall review, and may revise on an expedited basis, the long-term renewable resources procurement

> plan at least every 2 years… The long-term renewable resources procurement plans shall be subject to review and approval by the Commission under Section 16-111.5 of the Public Utilities Act.

20 ILCS 3855/1-75(C)(1)(A). The General Assembly directed that the LTRRPP should be designed to maximize Illinois's interest in the health, safety, and welfare of its residents, including: minimizing pollutants that affect public health; increasing fuel and resource diversity; enhancing the reliability and resiliency of the electric grid; limiting carbon dioxide emissions; and "contributing to a cleaner and healthier environment for the citizens of this State." 20 ILCS 3855/1-75(c)(1)(I).

With the goals set forth by the General Assembly in mind, EDF/CUB/RHA respond to the IPA's Request for Comments with proposals to assist in development in the LTRRPP. In general, we focus on the importance of incentivizing residential and small commercial and industrial participation in renewable programs (in the Adjustable Block Program and Community Solar program) in the earliest years of the LTRRPP, and provide suggestions as to how to achieve that goal and the goals of the General Assembly.

EDF/CUB/RHA have not provided comments on every question posted by the IPA in its request. Rather, we have provided technical expertise where applicable, and is available to provide additional explanation if needed. The assumptions, calculations, and models relied upon by EDF/CUB/RHA are the result of complicated technical analyses, and any errors are unintentional. We will update IPA as we improve and refine the models. EDF/CUB/RHA's lack of comment on any issue should not be construed as agreement with the position of any other stakeholder.

Included with these comments are the following attachments:

I. **RPS Load and Budget Calculations (XLS – Confidential)**
This includes tables related to the RPS load calculations and budget assumptions.

II. **Adjustable Block Incentive Formula – 10 kW (PDF – Public) (XLS – Confidential)**
This includes the complete model for the adjustable block incentive for systems < 10kW

III. **Adjustable Block Incentive Formula – C&I (PDF – Public) (XLS – Confidential)**
This includes the complete model for the adjustable block incentive for systems 10 kW – 2,000 kW

IV. **Adjustable Block Incentive Formula – Community (PDF – Public) (XLS – Confidential)**
This includes the complete model for the adjustable block incentive for community solar systems

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B. MEETING PERCENTAGE-BASED RPS TARGETS

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.*

In order to develop its LTRRPP process, the IPA will have to balance a variety of program design and policy components. The IPA's implementation decisions will be highly dependent on when projects are built and how long they are contracted for. EDF/CUB/RHA have carefully considered scenarios to meet all of FEJA's objectives, and offers the following insights below. A brief summary of our findings includes:

- Significant amounts of RECs need to be procured after the new-build requirement is met in order to meet the percentage-base goals.
- The IPA should focus on investments in the Adjustable Block Program in the first 4 years of the LTRRPP, a time when a rollover of funds provides sufficient budget for upfront or semi-upfront contracts. During those early years, there will be sufficient funding to enter into longer-term contracts that incentivize new qualifying renewable projects for the remaining life of the Plan.
- The IPA should prioritize achieving the long-term goals of the legislation to develop new eligible renewable projects through multi-year contracts that incent new development, rather than budgeting for single-year percentage obligations.

a. RPS Target Projections

As part of its LTRRPP process, the Illinois Power Agency is empowered to design procurement programs and competitive procurement events in order to meet individual program goals as well as meet the annual percentage goals of providing 25% of retail customer using renewable resources by 2025. 20 ILCS 3855/1-75(c)(1)(B). The first step the IPA should take in this process should be to project the load and corresponding target percentage goals as the statute gradually increases to 25% by 2025 and thereafter. The load projection is a complicated exercise, as the IPA should take into consideration the impact of energy efficiency, particularly expanded energy efficiency investments under FEJA, over time. This will not be a perfect projection, and should remain flexible for adjustments as the IPA updates its LTRRPP every two years.

For the purposes of these comments, we have provided the sample calculation below in Table 1.0, outlining the projected load, RPS % targets, existing contract, planned new build renewable energy resources, maximum allowable self-supply obligations, and the resulting RECs required to meet the annual percentage targets.

Table 1.0. RPS Load Projection

Load		RPS		Contracts & New Build			Self-Supply	Remaining
Del. Year	Total	RPS %	Overall RPS (MWh)	Existing LT Contracts (MWh)	New-Build Wind (MWh)	New-Build Solar (MWh)	Self-Supply MWh (Max)	Remaining RECs needed
2017	125,863,000	13.0%	16,362,190	1,750,000			6,135,824	8,476,366
2018	125,863,000	14.5%	18,250,135	1,750,000			3,421,902	13,078,233
2019	126,143,000	16.0%	20,182,880	1,750,000	1,000,000	1,000,000	1,362,349	15,070,531
2020	126,553,000	17.5%	22,146,775	1,750,000	2,000,000	2,000,000	1,494,910	14,901,865
2021	123,658,000	19.0%	23,495,020	1,750,000	2,000,000	2,000,000	1,585,914	16,159,106
2022	120,830,000	20.5%	24,770,150	1,750,000	2,000,000	2,000,000	1,671,990	17,348,160
2023	118,069,000	22.0%	25,975,180	1,750,000	3,000,000	3,000,000	1,753,320	16,471,860
2024	115,371,000	23.5%	27,112,185	1,750,000	3,000,000	3,000,000	1,830,078	17,532,107
2025	112,737,000	25.0%	28,184,250	1,750,000	4,000,000	4,000,000	1,902,435	16,531,815
2026	110,164,000	25.0%	27,541,000	1,750,000	4,000,000	4,000,000	1,859,013	15,931,987
2027	107,651,000	25.0%	26,912,750	1,750,000	4,000,000	4,000,000	1,816,603	15,346,147
2028	105,196,000	25.0%	26,299,000	1,750,000	4,000,000	4,000,000	1,775,180	14,773,820
2029	102,798,000	25.0%	25,699,500	1,750,000	4,000,000	4,000,000	1,734,721	14,214,779
2030	100,456,000	25.0%	25,114,000	1,750,000	4,000,000	4,000,000	1,695,202	13,668,798

For the above table, the following descriptions outline the source and reasoning for the data provided:

Retail Load. Load data for ComEd and Ameren customers was combined with actual current projections for 2017-2020, and thereafter the annual load is based on the savings goals for the new energy efficiency requirements of FEJA. *See* 220 ILCS 5/8-103B. Based on our analysis, ComEd would see an average 2.5% annual reduction in load by 2030, and Ameren would see an average 1.8% annual reduction in load by 2030, not accounting for any new significant market-changing events.

RPS %. The RPS percentage targets are from subsection (c)(1)(B) of Section 1-75 of the Illinois Power Agency Act, 20 ILCS 3855 ("IPA Act").

Overall RPS (MWh). The RPS megawatt-hour goal is calculated by multiplying the Retail Load by the RPS % target.

Existing LT Contract. The IPA has existing long-term contracts for Wind resources from 2010/11.

New Build Wind (MWh) and New Build Solar (MWh). The new build targets are listed in Section 1-75(c)(1)(C) of the IPA Act, requiring 4,000,000 annual RECs of new build wind and

4,000,000 annual RECs of new build solar by 2030, with interim targets in 2020 and 2025. New build is defined as projects energized on or after June 1, 2017. 20 ILCS3855/1-75(c)(1)(C)(iii).

Self-Supply (MWh). FEJA allows for retail electric suppliers to continue to self-supply a portion of their renewable obligation through two methods - first, through a two-year transition period during which suppliers can opt to self-supply 50%, and then 25% of their supplied load; and, second, if they meet the qualifications and elect to self-supply with owned resources that are not powered by solar or wind and grandfathered in to the new requirements, so long as the total grandfathered self-supply does not exceed 9% of total load. 220 ILCS 5/16-115D(i).

Remaining RECs needed. The resulting column outlines the remaining RECs needed in each year in order to achieve the percentage-based targets of 25% of retail load by 2025 and thereafter.

b. Budget Projections

Resources available for the procurement of Renewable Energy Credits under the LTRRPP are limited by statute to ensure that average net increases paid by retail customers do not exceed 2.015% of the amount paid per kWh by customers in the delivery year ending May 31, 2007, or the incremental amount per kWh paid for renewable energy resources in 2011. 20 ILCS 3855/1-75(c)(1)(E). These values are now fixed; the greater of the two is the 2007 calculation, which constitutes 0.18054 ¢/kWh for Ameren Illinois, 0.18917 ¢/kWh for ComEd, and 0.12415 ¢/kWh for MidAmerican. Below see EDF/CUB/RHA's projected available budget available:

	Total Retail Sales						**RPS Funds**
Del. Year	**ComEd**	**Ameren**	**Total**	**Self-Supply**	**ComEd Charge**	**Ameren Charge**	**Amount Collected**
2017	87,669,000	38,194,000	125,863,000	50%	$1.8917	$1.8054	$117,399,447
2018	87,669,000	38,194,000	125,863,000	25%	$1.8917	$1.8054	$176,099,171
2019	87,880,000	38,263,000	126,143,000	9.0%	$1.8917	$1.8054	$214,143,581
2020	88,177,000	38,376,000	126,553,000	9.0%	$1.8917	$1.8054	$214,840,500
2021	85,973,000	37,685,000	123,658,000	9.0%	$1.8917	$1.8054	$209,911,177
2022	83,823,000	37,007,000	120,830,000	9.0%	$1.8917	$1.8054	$205,096,170
2023	81,728,000	36,341,000	118,069,000	9.0%	$1.8917	$1.8054	$200,395,558
2024	79,684,000	35,687,000	115,371,000	9.0%	$1.8917	$1.8054	$195,802,455
2025	77,692,000	35,044,000	112,737,000	9.0%	$1.8917	$1.8054	$191,316,939
2026	75,750,000	34,414,000	110,164,000	9.0%	$1.8917	$1.8054	$186,938,853
2027	73,856,000	33,794,000	107,651,000	9.0%	$1.8917	$1.8054	$182,659,825
2028	72,010,000	33,186,000	105,196,000	9.0%	$1.8917	$1.8054	$178,483,142
2029	70,210,000	32,589,000	102,798,000	9.0%	$1.8917	$1.8054	$174,403,718
2030	68,454,000	32,002,000	100,456,000	9.0%	$1.8917	$1.8054	$170,416,467

For the above table, the following descriptions outline the source and reasoning for the data provided:

Total Retail Sales. Load data for ComEd and Ameren customers was combined with actual current projections for 2017-2020, and thereafter the annual load is based on the savings goals for the new energy efficiency requirements of FEJA. *See* 220 ILCS 5/8-103B(b), (b-5). Based on our analysis, ComEd would see an average 2.5% annual reduction in load by 2030, and Ameren would see an average 1.8% annual reduction in load by 2030, not accounting for any new significant market-changing events.

Self-Supply (%). FEJA allows for retail electric suppliers to continue to self-supply a portion of their renewable obligation through two methods - first, through a two-year transition period during which suppliers can opt to self-supply 50%, and then 25% of their supplied load, and, second, if they meet the qualifications and elect to self-supply with owned resources that are not powered by solar or wind and grandfathered in to the new requirements, so long as the total grandfathered self-supply does not exceed 9% of total load. 220 ILCS 5/16-115D.

ComEd Charge. The ComEd charge is based on the current Maximum Alternative Compliance payment for ComEd customers calculated by the Illinois Commerce Commission. 220 ILCS 5/16-111D(d)(1). The new FEJA non-bypassable charge for customers is calculated in a similar fashion.

Ameren Charge.[1] The Ameren charge is based on the current Maximum Alternative Compliance payment for Ameren customers calculated by the Illinois Commerce Commission. 220 ILCS 5/16-111D(d)(1). The new FEJA non-bypassable charge for customers is calculated in a similar fashion.

Amount Collected. The total amount that could be collected is the total amount of ComEd and Ameren load multiplied by their respective charges in each year.

[1] Due to the relatively *de minimus* nature of the budget impact for MidAmerican, EDF/CUB/RHA did not calculate separate blocks or budget for MidAmerican. EDF/CUB/RHA suggest that the IPA may incorporate blocks for MidAmerican with its procurements for Ameren.

i. Illinois Solar for All Allocations

Additionally, FEJA dedicates resources to the Illinois Solar for All program, plus separate funds for workforce training efforts. 20 ILCS 3855/1-75(c)(1)(O). Initially, and then again in the 2021 delivery year and the 2025 delivery year, $10,000,000 of the RPS budget is made available for workforce training initiatives directly through ComEd program administration. *Id*. Separately, up to 5%, but no less than $10 million, is available to be used for the Illinois Solar for All program in each delivery year, starting when Solar for All programs begin in the 2018 delivery year. 20 ILCS 3a855/1-75(c)(1)(O). An illustrative table is below.

Delivery Year	Funds to Solar for All	Funds to Training
2017		$10,000,000
2018	$10,000,000	
2019	$10,939,473	
2020	$10,975,013	
2021	$10,723,934	$10,000,000
2022	$10,478,713	
2023	$10,239,211	
2024	$10,005,291	
2025	$10,000,000	$10,000,000
2026	$10,000,000	
2027	$10,000,000	
2028	$10,000,000	
2029	$10,000,000	
2030	$10,000,000	

ii. Existing Long-Term Renewable Energy Contracts

As part of its long-term plan, the IPA must take into account the cost of long-term contracts already entered into by the state. The IPA has already procured new wind development producing 1,750,000 RECs per year through 2030, for which it is paying for RECs the difference between a market price for energy and a fixed contract price. The current projected schedule of costs of those contracts through 2030 is detailed in ICC docket 09-0373, Supplemental Filing of November 9, 2010 (Appendix K)[2], with an annual projected cost as follows:

[2] In its December 19, 2012 Order the ICC allowed for the release of the previously confidential "Appendix K" imputed REC prices. The conformed plan (ICC Docket No. 12-0544, 2013 Electricity Procurement Plan Conforming to the Commission's December 19, 2012 Order at 84) included imputed prices for the five subsequent Plan Years 2013-17.

Year	Projected LT Contract Cost
2017	$30,830,000
2018	$30,830,000
2019	$30,970,000
2020	$30,040,900
2021	$27,840,000
2022	$23,470,000
2023	$20,690,000
2024	$18,240,000
2025	$15,760,000
2026	$11,330,000
2027	$7,650,000
2028	$4,880,000
2029	$4,880,000
2030	$4,880,000

iii. Priority Budgeting

In FEJA, the General Assembly specifically required that the IPA procure renewable energy resources according to the following order:

1. Existing Long-Term Contracts
2. Solar for All
3. New Build
4. RECs to meet percentage-based targets

20 ILCS 3855/1-75(c)(1)(F)(1).

iv. Proposal for Meeting Percentage-Based RPS Targets

Based on our analysis, there seems to be sufficient funds for adjustable block incentives to meet the distributed generation new-build targets by 2021, as outlined in the statute. The legislation allows for the full collection of renewable funds from customers beginning June 1, 2017, and allows those funds to roll-over into each subsequent delivery year until June 1, 2021. 220 ILCS 5/16-108(k). Based on our estimate of resources collected, $722 million would be available during that period to be used toward all procurements. Of those funds, using the priority order outlined in FEJA, $122 million would be preserved for existing Long-Term Contracts, $62 million would be available for the Illinois Solar for All program and workforce training efforts, and the remaining

$538 million would be available to meet the new-build requirements and to meet percentage-based targets.

The IPA should endeavor to utilize all of those funds to meet its long-term goals under the legislation, as it will not be able to “catch-up” on funding if there are delays achieving early milestones. Rolled-over funds unused at the end of the 2020 delivery year will be lost.

The Adjustable Block Incentive for system sizes < 10 kW is paid upfront for the equivalent of 15 years of REC delivery. 20 ILCS 3855/1-75(c)(1)(L)(ii). For Adjustable Block Incentives between 10 kW and 2,000 kW, the 15-year contracts for REC delivery are paid out according to the following schedule: 20% upfront, and then 4 subsequent payments of 20%. *Id.* 1-75(c)(1)(L)(iii). Utility-scale contracts, however, are paid out over 15 years in the years of REC delivery. 20 ILCS 3855/1-75)(c)(1)(G). This means that a new utility-scale contract for a project built in 2019 would have, at most, two years of a 15-year contract - 13% of its value - paid in the roll-over years. A 250 kW distributed solar project taking the Adjustable Block Incentive built in 2019 would have likely 40 or 60% of its contract paid during the roll-over years. A < 10 kW project would be paid entirely upfront in the year it is energized.

Based on these statutory priorities, we recommend that the IPA focus any available budget on ensuring there are sufficient newly built projects to meet the goals of the RPS with qualifying RECs, rather than rely on traditional compliance RECs to meet percentage-based targets. There should be sufficient resources for new-build projects in the second half of the LTRRPP period (2024-2030) to accommodate short-term or longer-term contracts for new utility-scale wind and solar.

C. ADJUSTABLE BLOCK PROGRAM[3]

The Illinois Power Agency Act, as amended by FEJA, requires that:

> The long-term renewable resources procurement plan developed by the [Illinois Power] Agency… (1) shall include an Adjustable Block program for the procurement of renewable energy credits from new photovoltaic projects that are distributed renewable energy generation devices or new photovoltaic community renewable generation projects. The Adjustable Block program shall be designed to provide a transparent schedule of prices and quantities to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time. The prices set by the Adjustable Block program can be reflected as a set value or as the product of a formula.

20 ILCS 3855/1-75(c)(1)(I).

We reviewed similar block incentive programs from other states and carefully considered the goals of FEJA in preparing this analysis. In total, we present a common formula for the development of adjustable block programs that separately meet the goals of <10 kW systems, 10 kW – 2,000 kW systems, and similarly-sized community solar systems. Further, we propose the implementation of sliding scale block incentives to correctly account for the variable installation costs of different system sizes.

Administering an adjustable block incentive program to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predicable rate over time is difficult when looking forward to 2030, and the economics of solar photovoltaic systems are changing far more rapidly. However, we attempted to provide recommendations here that best enable the IPA to meet the needs of today, while also being able to easily adjust to changing market conditions over time.

<u>Block Structure</u>

Block sizes. Per FEJA goals, the procurement plan will include at least 2 million RECs from new solar photovoltaic projects by May 2021, of which at least 50% should be procured from the Adjustable Block Program (ABP)[4]. 20 ILCS 3855/1-75(c)(1)(C)(i). Using an IPA standard capacity factor[5], one million RECs will be met by 833 MW's of new solar build by May 2021.

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[3] Because of the inter-relatedness of the questions posed by the IPA in its Request, EDF/CUB/RHA present here answers to many of the questions under "C. Adjustable Block Program" in the below narrative, tables, and attachments. EDF/CUB/RHA are providing confidential workpapers to the IPA that support the analysis and models described.

[4] Section 1-75(c)(i)(C)(i).

[5] IPA Utility Distributed Generation Request for Proposals, Page 6. https://www.ipa-energyrfp.com/?wpfb_dl=901.

According to the ABP proportions set out in Section 1-75(c)(1)(K) of the IPA Act, that is approximately 200 MW's of residential, C&I, community solar, and low income solar by mid-2021.

We support offering larger overall blocks during the initial RPS years for residential, commercial and industrial, and community solar. Having larger blocks at the beginning of the program will alleviate the pent-up demand which is expected once the block program opens. Based on the RPS budget predictions referenced above, there will be sufficient RPS budget allocated until May 2021, during the years when the excess RPS budget can rollover year-to-year to allow for larger block sizes. EDF/CUB/RHA are recommending that among the initial blocks, there is sufficient benefit to creating a longer-lasting block for residential (< 10kW) systems crossing over several years. This strategy ensures that the RPS budget is utilized to incent maximum new <10 kW residential solar deployment prior to reaching the 5% net metering cap and 2020 new-build REC goals, and also to provide predictability and steady growth in the residential market where a boom-and-bust cycle can create lasting harm. After May 2021, the MW blocks should be based on annual RPS new build goals.

EDF/CUB/RHA also support splitting all the blocks between ComEd and Ameren to support geographic diversity. Through the formula provided in these comments, we use different avoided costs and potentially different installation costs as inputs, which are observed to create higher adjustable block incentive amounts for blocks in Ameren. To accommodate this block separation, we suggest splitting the overall RPS new build goals 70/30 between ComEd and Ameren territories. 70% should be allocated to ComEd and 30% should be allocated to Ameren. If the IPA feels that the block sizes are not appropriate for the demand, the IPA always has the jurisdiction to adjust the blocks.

Block Timing. We are concerned that if block prices change in the middle of a construction and sales season, there may be uncertainty for developers and for consumers. While the mid-construction block change should not be prohibited, the IPA should design the blocks of a capacity estimated to be completed at the end of a calendar year. A calendar-year block schedule will provide more certainty to developers and customers, and improve transparency of program pricing.

Further, in developing the formula presented in these comments, we found that it was important to factor in the impact of time and the year of installation on the decrease in installation costs and the avoided electricity costs that serve as foundational inputs. As such, to allow for consistent tracking of market changes, we recommend that, generally, blocks should be designed to close at the end of the calendar year, or once the MW size is filled, with sufficient capacity to meet a year's worth of projects. The one exception to this rule is the initial block for residential systems. As previously discussed, an initial long-term block can aid the steady and consistent growth of the residential solar PV market needed for quality projects. EDF/CUB/RHA are proposing the initial block for residential (< 10 kW systems) be sized for 200 MW, or approximately 3 years of capacity, or until January 1, 2021.

Subsequent Blocks. Once a block is retired the following block should immediately open.

Prices

EDF/CUB/RHA believe a core principle of the Adjustable Block Incentive is that it must lead to the achievement of the statutory goals for new construction of distributed solar PV. As such, the design of any such program must ensure that the block incentive price provides the economic incentive for development – it must cover the economic value between the cost of a system and the value the system provides to the customer over an expected period of time, including any additional incentives. We propose the following simple Adjustable Block Incentive Formula:

Adjustable Block Value =
Installation Cost - Solar Rebate Value - Value of System over Project Period

For this formula, the following definitions apply:

Adjustable block value will be that dollar-per-kW price of the Adjustable Block Incentive. Throughout our analysis, we will demonstrate this value as a direct $/kW reference, and as an inferred $/MWh or $/Renewable Energy Credit (REC) for most scenarios provided.

Installation cost is the average cost to install solar at a given sized system of kW installed capacity. Costs to install are highly variable depending on system size, and the proposed formula and implementation recommendations will allow for a sliding installation cost amount.

Solar Rebate Value is the value of the DER rebate authorized by PA 99-0906, or the expected future value of solar rebate once net metering reaches 5% and the new value of DER rebate is implemented.

Value of System over Project Period is the net present value over a defined number of years of the avoided projected energy, capacity, transmission, and demand costs as outlined by the utilities for an average customer in a class.

Installation Cost

We consulted with residential solar PV installers and support the industry's positions on what should be included in calculating the installed cost. Although, the IPA should consider whether the Investment Tax Credit ("ITC") should be included in the installed cost. Not all installers will be able to take advantage of the ITC, and we do not want to deter residential systems from being built. However, the bulk of systems in these next few years will likely be taking advantage of the ITC.

We recommend the IPA perform market research with solar developers and installers on the installed cost of systems 1-2,000 kW. For systems < 10 kW, the IPA can determine a single installation cost as an input into the formula. As described later in the C&I and Community Solar sections, the IPA can use the market research to determine installation costs at defined benchmark prices to feed into a sliding scale formula. The IPA can use the MA DOER Survey Questions[6] as a guide.

The block price that is established through research into installed cost should be held open for one calendar with an anticipated associated MW size. EDF/CUB/RHA believe calendar year aligns better with the installation cost patterns of solar, which typically are installed in the spring, summer, or fall. As previously discussed, blocks that close in December do not cut into standard solar construction season and allow developers to better plan their build year.

After the market research is complete, IPA will be able to apply the installed cost to the model for the upcoming year's block price. The IPA can use an average percentage price decrease (we provide an example in the model using data from NREL) to calculate the future block price or come up with their own average decrease in installed cost through the market research.

We recommend the IPA perform the market research analysis every two-to-three years, and caveat future block prices as potentially changing up to 10%. If the pricing that the IPA sets is not meeting the RPS based MW goals, the IPA can always adjust the prices to incentivize more installation.

After the first few years of performing market research, we believe the IPA will see predictable trends in installed cost. At this point, the IPA can cease performing market research and set block prices into the future using intelligence from those trends as they see appropriate.

Solar Rebate Value

Included in FEJA is a new Distributed Energy Resource Rebate that provides an upfront incentive to distributed energy resources, including distributed solar PV, for the value solar provides to the distribution system. The initial value of the rebate is set at $250 per kW of installed capacity for non-residential solar projects, including community solar. Eventually, that value will be established by the Illinois Commerce Commission to account for the geographic, time, and performance values of distributed solar.

[6] Task 1 Report: Evaluation of Current Solar Costs and Needed Incentive Levels Across Market Segments

Value of System over Project Period

The final piece of the formula is an estimate of the avoided costs the distributed solar PV system provides over a defined amount of time. We create in the model an estimate of the net present value of the avoided projected energy, capacity, transmission, and demand costs for an average customer in a class to use as an input into the formula. The defined period could be any number, but should represent the economic decisions made by customers when choosing to purchase or contract for solar PV. Currently, solar developers build projects when they are able to market to a customer that the solar array will have a net-present-value payback within 10 years. We recommend using that number for the analysis in order to ensure that the incentive price is at a level that will lead to projects being built, rather than a longer period such as life-of-the-system (25 years).

<10 kW Residential Model

Program Design Overview

We are presenting two models for the <10 kW Adjustable Block Incentive. These are cost based models producing $/REC or $/MWh values. The $/REC or $/MWh values should be benchmarked against the most recent DG RFP winning prices. These winning prices should not be used as a price ceiling but a reference point for the adjustable block.

Adjustable Block Value =
Installation Cost - Solar Rebate Value - Value of System over Project Period

Modeling the Adjustable Block

The RPS that was outlined in the Future Energy Jobs Act creates a large budget for new distributed solar which needs to be utilized by May 2021. This budget allows the IPA to have large blocks, especially for residential solar, to ensure that a sufficient amount of this market segments gets built prior to the 5% net metering cap being reached.

Below, EDF/CUB/RHA propose a model for consideration by the IPA to implement an adjustable block for <10 kW systems. Due to the minimal budget restrictions in the early years, we recommend through the first model that the Adjustable Block Program maintain the initial $/REC or $/MWh price for three years, or 200 MW of capacity (combined across the territory blocks). We believe this will help create price certainty for installers, while supporting the RPS goal of installing approximately 200 MWs of residential solar by May 2021. While in general, we believe that the drop in an adjustable block incentive should not exceed 15% on a block change-over, there are variations of this model, based on user inputs, that could show a larger step-down once that initial three-year period or block capacity has been reached. The IPA should decide, if a model were to result in a steep drop after a long hold period, whether the drop is appropriate.

The alternative to the large initial block modeled here would be a step down beginning after the first year, or achievement of a smaller capacity target (such as 66 kW combined), adjusting the price based on the installed cost % decrease method described above. This method would produce less sharp of a block price drop in exchange for a potentially low incentive price. We do not think this achieves the same level of residential solar deployment as maintaining the same price for three years, thus missing the RPS target for this customer group, and potentially creating untenable budget impacts in later years.

< 10 kW Residential Model Assumptions and Parameters

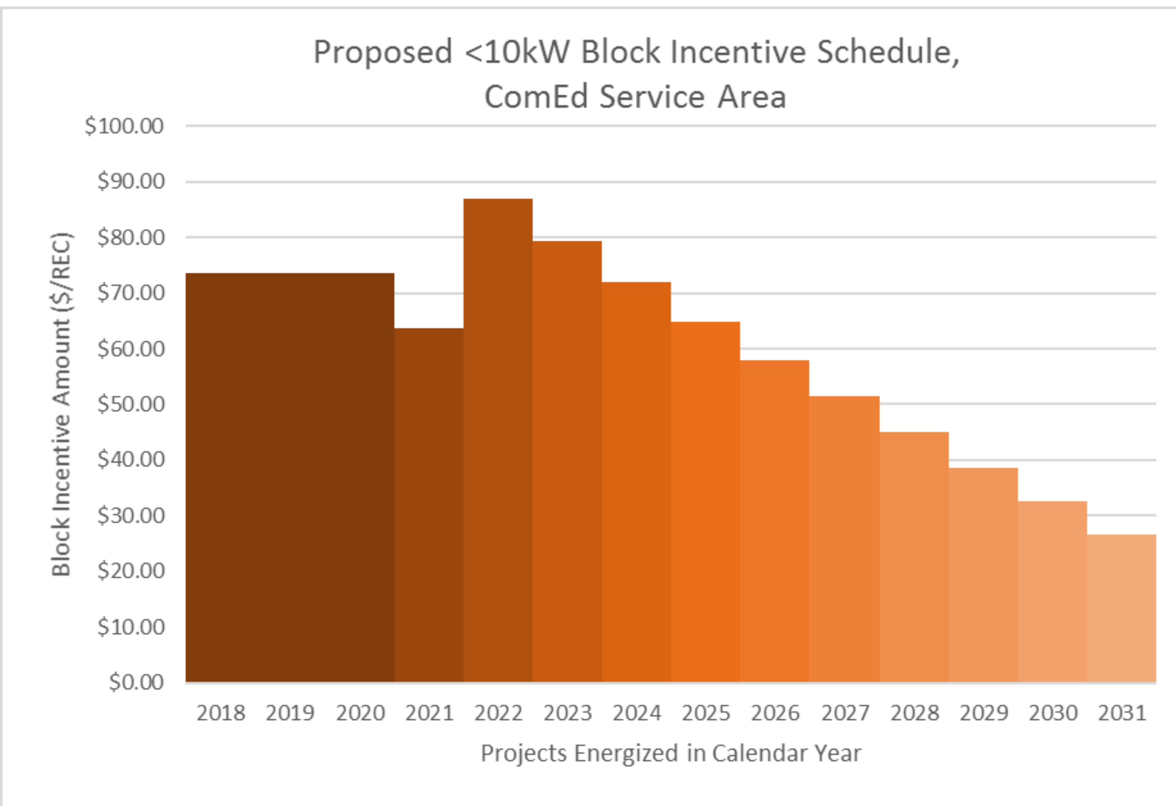
Discount Rate (%)	6.0%
Inflation Rate (%)	2.2%
Initial Installed Cost ($/kW)	$ 3,500
Installed Price Decrease (%)	4%
Annual Derate Factor (%)	0.5%
Capacity Factor (%)	14.38%
System Size (kW)	1
Value of Energy Duration (years)	10
Include ITC?	Yes

In this model, to reflect expected decreases in total installed cost over time, blocks will be indexed to projected installed costs and electricity rates. Blocks will be rolled-over annually at the end of the calendar year, or if the capacity target is reached. Incentives will step down, in the target year blocks, based on decreases in installed costs and increases in electricity rates. Block schedules and incentive levels will be adjusted periodically using IPA-conducted industry surveys and rates of adoption of the incentive. Incentive rates will be set for the 3 years after the most recent survey. Estimates of future incentives will be provided for long-term project planning purposes. Capacity caps for each block will ensure budgets are maintained. When a capacity cap is hit, the next block will begin without delay.

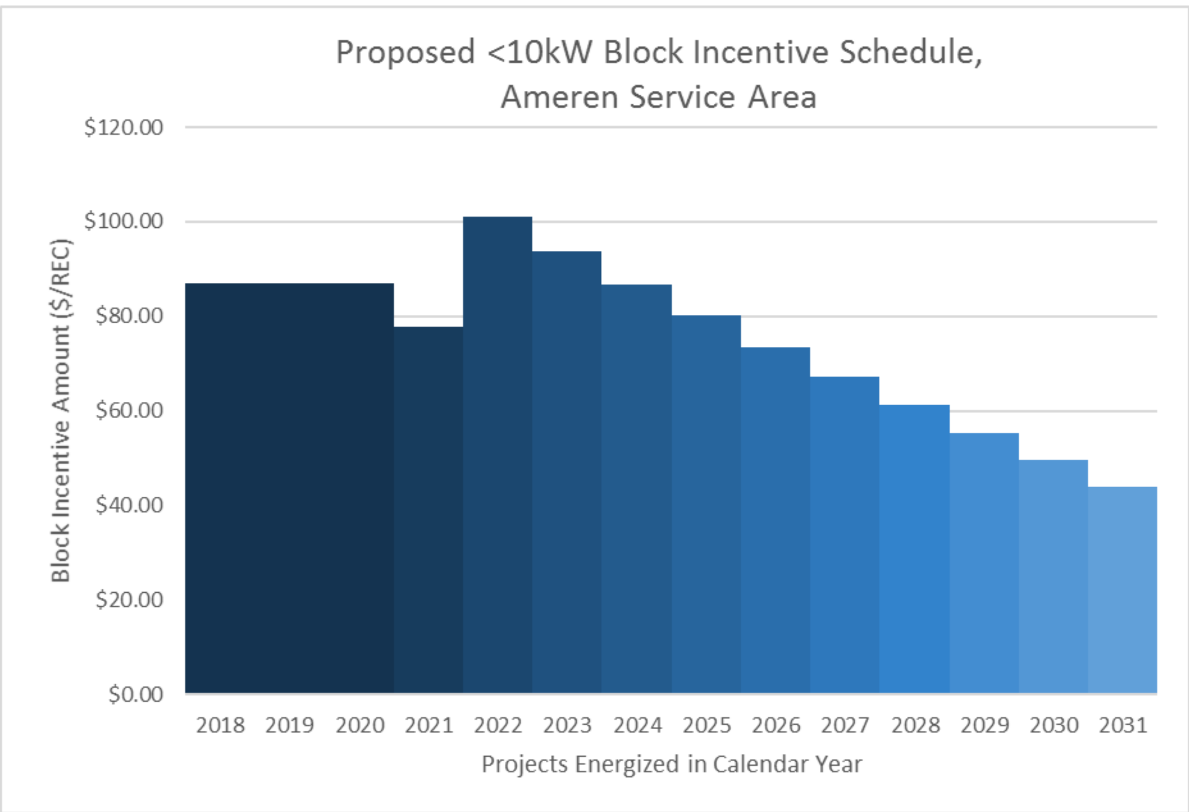
To reflect differences in avoided cost between service areas, ComEd and Ameren service areas will operate independently, with distinct blocks, schedules, and incentive rates. Capacity goals are divided between Ameren and ComEd service areas based on an estimate of current and future relative distribution load.

To meet high installation rate required by 2020 REC goals, the 2018 block will be extended through the end of the 2020 delivery year.

PROPOSED Block Schedule (ComEd Service Area)				
For Calendar Year Ending:	Project Incentive ($/kW)	REC Price ($/REC)	Expiration Date	Block Capacity
2018 2019 2020	1341	$73.50	End of 2020	140
2021	1163	$63.75	End of 2021	19
2022	1585	$86.84	End of 2022	19
2023	1447	$79.29	End of 2023	19
2024	1314	$71.98	End of 2024	19
2025	1184	$64.90	End of 2025	19
2026	1059	$58.04	End of 2026	19
2027	938	$51.39	End of 2027	19
2028	820	$44.93	End of 2028	19
2029	705	$38.65	End of 2029	19
2030	594	$32.56	End of 2030	19
2031	486	$26.63	End of 2031	19



PROPOSED Block Schedule (Ameren Service Area)				
For Calendar Year Ending:	Project Incentive ($/kW)	REC Price ($/REC)	Expiration Date	Block Capacity (MW)
2018 2019 2020	1586	$86.91	End of 2020	60
2021	1418	$77.73	End of 2021	8
2022	1843	$101.02	End of 2022	8
2023	1712	$93.80	End of 2023	8
2024	1584	$86.82	End of 2024	8
2025	1461	$80.08	End of 2025	8
2026	1342	$73.56	End of 2026	8
2027	1227	$67.26	End of 2027	8
2028	1116	$61.16	End of 2028	8
2029	1008	$55.26	End of 2029	8
2030	904	$49.54	End of 2030	8
2031	803	$44.00	End of 2031	8



Block Sizes

As described previously, the blocks should be based on calendar year with an associated MW goal tied to the RPS goal. At the beginning of the block program, there should be one 200 MW “mega-block” which is open until December 2020 to incent as much residential installation at the beginning of the program. After December 2020, all blocks should be open until the end of the calendar year, or until the MW size is built, whichever occurs first.

Geographic Diversity

We are presenting both models for Ameren and ComEd territory. These utility territories have different residential rate structures. We believe that the division of block prices between Ameren and ComEd territory will help support more downstate solar growth since the Ameren introductory block price is estimated to be higher than ComEd’s introductory block price.

Adjustable Block Program Application Process

We support the initial feedback from the residential solar companies that projects should apply and be awarded the adjustable block once the system is energized and/or interconnected and has been registered with PJM-Gats or MRETS. We also support this group’s opinion on not having an application/ reservation fee for projects <10 kW.

Adjustable Block Program Award Requirements

Residential systems <10 kW should only apply and be awarded once the system is energized and/or interconnected and has been registered with PJM-Gats or MRETS.

We also agree with the input we have received from residential solar installers on reporting requirements. For residential projects <10 kW, the IPA should consider for systems 10 kW and smaller a requirement to report estimated production and only require that a reading be submitted once per year to ensure actual production is in line with the estimates. Other states allow for small projects to produce RECs based on estimates, and the Agency could ensure actual production by requiring an annual reading.

Application Requirements

The IPA should follow the lead of other states on documentation required to receive the incentive. Providing these documents can alleviate the concern that bad actors may build systems that will not produce REC’s for 15 years and that those actors are participating just to receive the upfront incentive payment.

- One or Three-Line Drawing (from NY-SUN residential handbook)
    - Quantity, conductor size, and insulation type of all energized (hot) conductors, neutral/grounded conductors, and ground conductors.
    - Type and characteristics of all raceways, conduit, and enclosures.
    - The configuration of solar electric array into electrical strings.
    - The voltage and amperage ratings of all combiner boxes, overcurrent protection devices, switches,inverters, batteries, electrical panels, and other relevant equipment as applicable. The rating of the main service panel and its main breaker must be given.
    - The quantity, manufacturer, and model of the inverter and solar electric modules.
    - Customer name and address.
- Site Map (from NY-SUN residential handbook)
    - Location of all solar electric system components, including solar electric modules, inverters,disconnects, point of interconnection, and utility meter.
    - Layout of solar electric array, showing the tilt, azimuth, and number of solar electric modules on each roof face or sub-array.
    - Length of all wire runs more than 100 feet.
    - Customer name and address.
- PVsyst or PVwatts
    - Showing the estimated annual output
- Proof of system warranty or O&M agreement
- Executed Interconnection Agreement or PTO
- W-9 or ACH information for party receiving the incentive

Clawback Provisions

Robust project application requirements will help ensure high quality systems are built. At this time, EDF/CUB/RHA do not offer suggested clawback provisions for the Residential Adjustable Block.

Commercial and Industrial 10-2000 kW Model

Program Design Overview

In the below section, EDF/CUB/RHA propose a formula for a Commercial and Industrial Adjustable Block Incentive that takes into account the variable installed cost of different system sizes for systems ranging from 10 kW to 2 MW, but otherwise is identical to the formula recommended for the < 10 kW systems. Accounting for a variable installed cost of a system is essential to allowing all customers to gain access to the incentive program, regardless of their possible distributed solar PV hosting capacity.

Some have argued for a fixed REC price for all distributed solar systems between 10 kW and 2,000 kW, or a fixed REC price for similar-sized Community Solar systems. However, such a model would unnecessarily incent only a portion of possible systems – making larger systems the only viable options, leaving most customers unable to participate. That model would assume an average price to install for a market that currently sees installation cost ranges of greater than 50% between a 10kW-sized system and 2 MW-sized system. If the IPA developed an average system price to calculate a REC value through a cost-based analysis, then the only projects that would be economic under a flat-REC model would be systems of that size or higher, ultimately over-paying for systems of the larger size.

To implement a block incentive that takes into account variable installation costs, we have evaluated three distinct approaches: a Sliding-Scale model, a Stepped Block model, and a Marginal Incentive Model. The Sliding Scale model creates a formula that attaches a value to a specific kW, the Stepped Block model creates an incentive amount for a range of system sizes, and the Marginal Incentive Model builds up an incentive much like how income tax brackets function.

We present these three distinct models with different formula inputs for Ameren and ComEd for the commercial and industrial adjustable block $/REC or $/MWh incentive value. These models are all based on the formula presented earlier and repeated below:

Adjustable Block Value =
Installation Cost - Solar Rebate Value - Value of System over Project Period

Attached to these comments are summaries demonstrating how each of these models could be implemented.[7] Each model has a series of inputs that allow the IPA to model the schedule of blocks through 2030, taking into account factors such as inflation, system costs decreases, and

[7] Workpapers are also being provided on a confidential basis to the IPA.

other incentives over time. The assumptions in the model are from a variety of sources (referenced) and IPA can choose to update these assumptions if necessary.

As with the residential model, the installed cost should be calculated using a market survey. Based on feedback received from C&I developers, we recommend that the installed cost inputs should include the following:

- Module, inverter, and balance of system costs
- Labor costs
- Interconnection costs
- The impact of the federal ITC step-down, including components of project cost that are ineligible
- The impact of rising interest rates on financing costs
- Lease rates, electricity prices, and real estate costs across the state (including expected inflation in such costs)
- Marketing and ongoing customer management costs
- The potential impact of revisions to the DG Rebate

EDF/CUB/RHA recommend the IPA consider whether they should include the ITC credit in installed cost as not all organizations can take that tax credit, but if it is excluded then the payback period and Value of System duration assumptions should be altered.

As with the < 10 kW systems, while we believe that a cost-based approach is the most appropriate method for setting the adjustable block incentives for the Illinois market, the IPA can use the most recent DG procurement results, or other similar states' incentives, as a benchmark for the adjustable block incentive's $/REC incentive rates as a cross-check and verification strategy.

Recommendation: After analysis of the three alternatives, we recommend that the IPA use the Sliding Scale Model, as it is a simple, straight-forward linear formula which appropriately compensates smaller systems, and only awards money when it is needed to build a project.

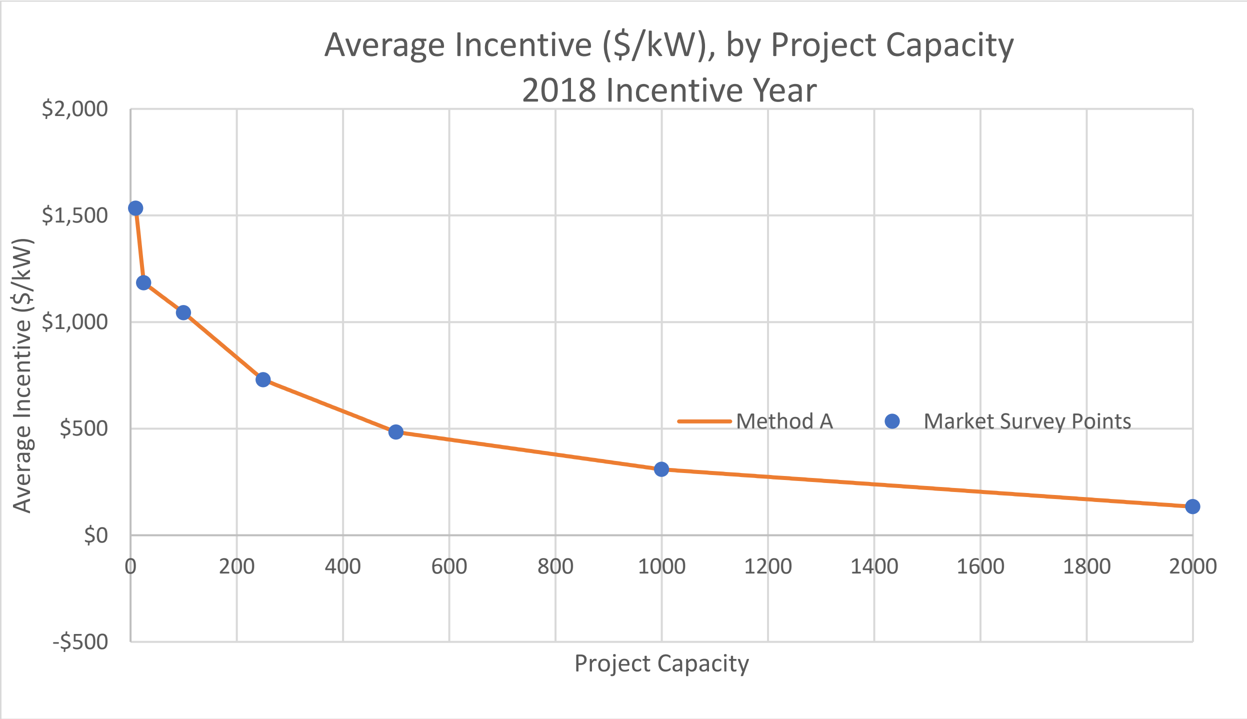
Method A: Sliding Scale Model

The first model we are proposing is a sliding scale model where each project size gets a unique incentive value based on installed costs collected by the IPA through market research. We recommend that the IPA conduct market research to calculate the total system installed costs at the following installed cost benchmark sizes:

- 10 kW
- 25 kW
- 100 kW
- 250 kW

- 500 kW
- 1000 kW
- 2000 kW

Once IPA has developed the benchmark installation cost levels, they would create a linear interpolation of the installed cost between the two nearest market survey points. In effect, this method draws a straight line on a graph of project capacity versus incentive market survey points. Proposed projects can determine their received incentive by finding their capacity on the line.



As demonstrated in the Chart and in the model, every project size has its own unique adjustable block incentive value based on the cost to install.

	System Size (kW)	$/kW
Incentive	10 kW	$1,534
	10 - 25 kW	$1534 - $1184
	25 - 100 kW	$1184 - $1044
	100 - 250 kW	$1044 - $729
	250 - 500 kW	$729 - $484
	500 - 1000 kW	$484 - $309
	1000 - 2000 kW	$309 - $134
	2000 kW	--

Also demonstrated in the model, in later years, projects of a certain size no longer receive an adjustable block incentive. This is because the $250/kW upfront DER rebate is covering enough of the installed cost and the avoided cost to make a project viable without it. This model ensures that the RPS funds are going to systems that actually need the adjustable block incentive.

Method B: Stepped Block for System Size Ranges

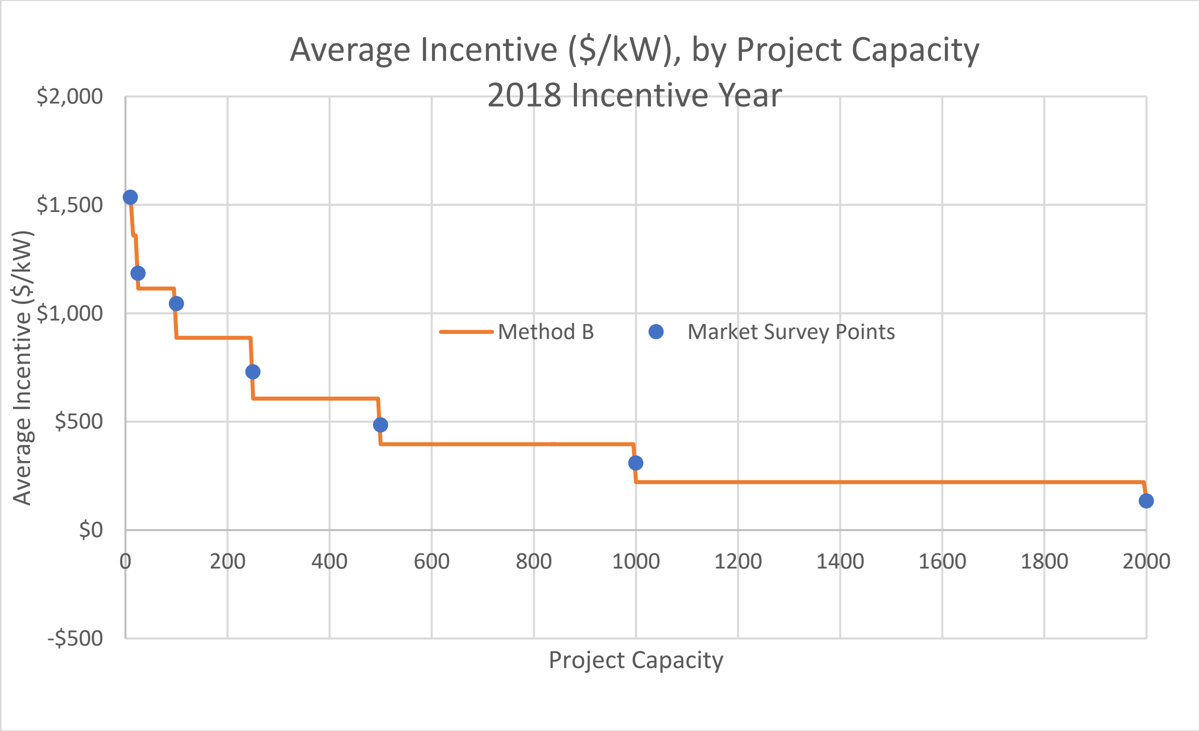
The second model we present to the IPA sets adjustable block incentive values for different project size segments. This method most closely approximates historical block incentive programs. For each capacity 'bucket' between market survey points, an average appropriate incentive is calculated, then applied to the entire bucket. The suggested project size segments are:

- 10-25 kW,
- 25-100 kW
- 100-250 kW
- 250-500 kW
- 500-1000 kW
- 1000-2000 kW

One block incentive value is set for each of these size segments. Unfortunately, this approach creates cliffs where projects are built slightly smaller so that the project can get a higher incentive. For instance, in the example below, projects will be incentivized to be built at 99 kW instead of 101 kW because that project will collect a larger total incentive. Not until the system reaches 128 kW will the total incentive become more valuable than building a smaller system. While simple in presentation, this could create odd economic impacts that lead to inconsistent project development.

Project Size (kW)	Incentive Rate ($/kW)	Total Incentive ($)
90	$1,114.00	$100,260.00
99	$1,114.00	$110,286.00
100	$866.00	$86,600.00
120	$866.00	$103,920.00
127	$866.00	$109,982.00
128	$866.00	$110,848.00

The output of the model, showing the different incentive levels at system capacity levels, is demonstrated in the chart below:



In table form, the model could be summarized as follows:

	System Size (kW)	$/kW
Incentive	10 kW	$1,534
	10 - 25 kW	$1,359
	25 - 100 kW	$1,114
	100 - 250 kW	$886
	250 - 500 kW	$606
	500 - 1000 kW	$396
	1000 - 2000 kW	$221
	2000 kW	$134

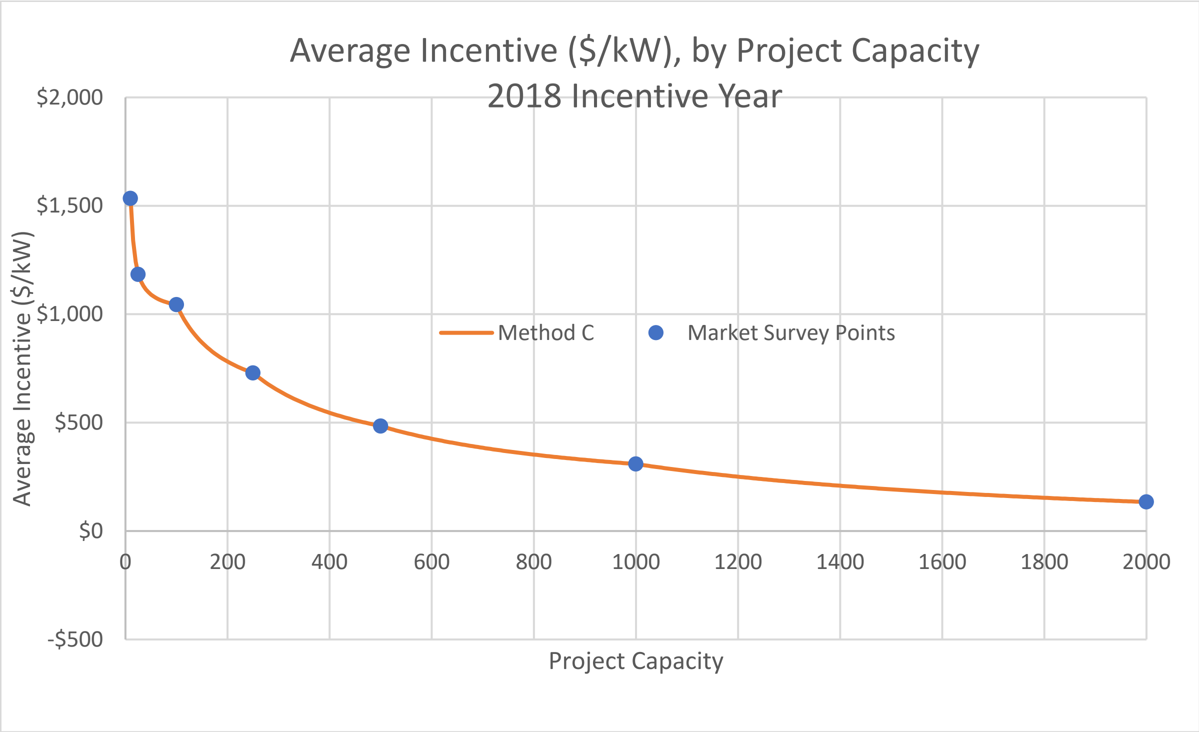
<u>Method C: Marginal Incentive Model</u>

The third model that we present to the IPA is the marginal incentive model. This model is designed to be similar to how taxes are calculated – where a tax rate is applied for the first block of income, and then a separate, higher, rate is applied against the next marginal income. In this model, an incentive value is applied for each system segment that the project applies for.

For each 'bucket' between market survey points, a marginal incentive per kilowatt is calculated, such that the appropriate incentive at each market survey points (as calculated by the formula presented above) is met. A project 'builds' incentive through the brackets. For example, a 28 kW system gets the 1-to-10-kW incentive rate for 10 kW, the 10-to-25-kW incentive rate for 15 kW, and the 25-to-100-kW incentive rate for 3 kW. A table of each of these marginal brackets is below:

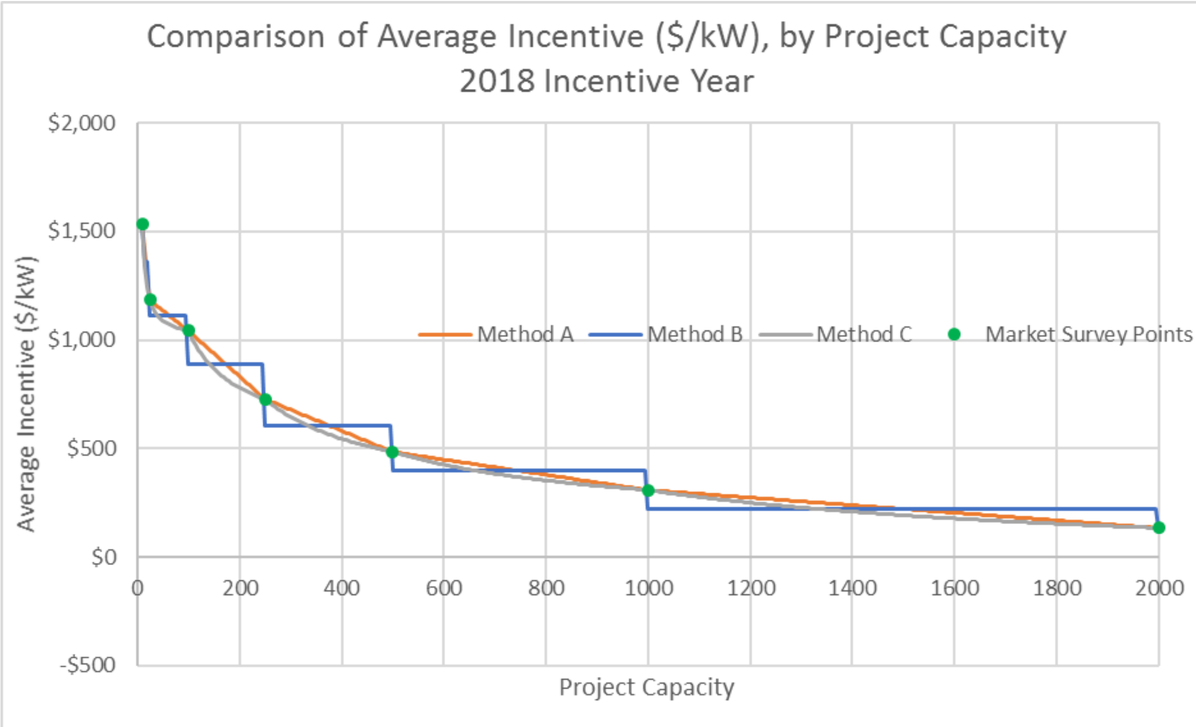
	System Size (kW)	Added $/kW
Marginal Incentive	10 kW	$1,534
	10 - 25 kW	$951
	25 - 100 kW	$997
	100 - 250 kW	$519
	250 - 500 kW	$239
	500 - 1000 kW	$134
	1000 - 2000 kW	-$41

Economies of scale of large systems result in lower installed costs per kilowatt-hour, and therefore lower required incentives per kilowatt-hour. In some cases, very large projects may receive a smaller total incentive than smaller projects, resulting in negative marginal incentive rates. Negative marginal rates prevent the situation where larger projects might take advantage of inefficient incentives by building total incentive through the marginal table.



Comparing methods of incentive calculation

When compared, the graphs follow the same general shape outlined by market survey points, but each method shows clear differences from the others:



Sliding scale calculation methods were evaluated for transparency and cost effectiveness:

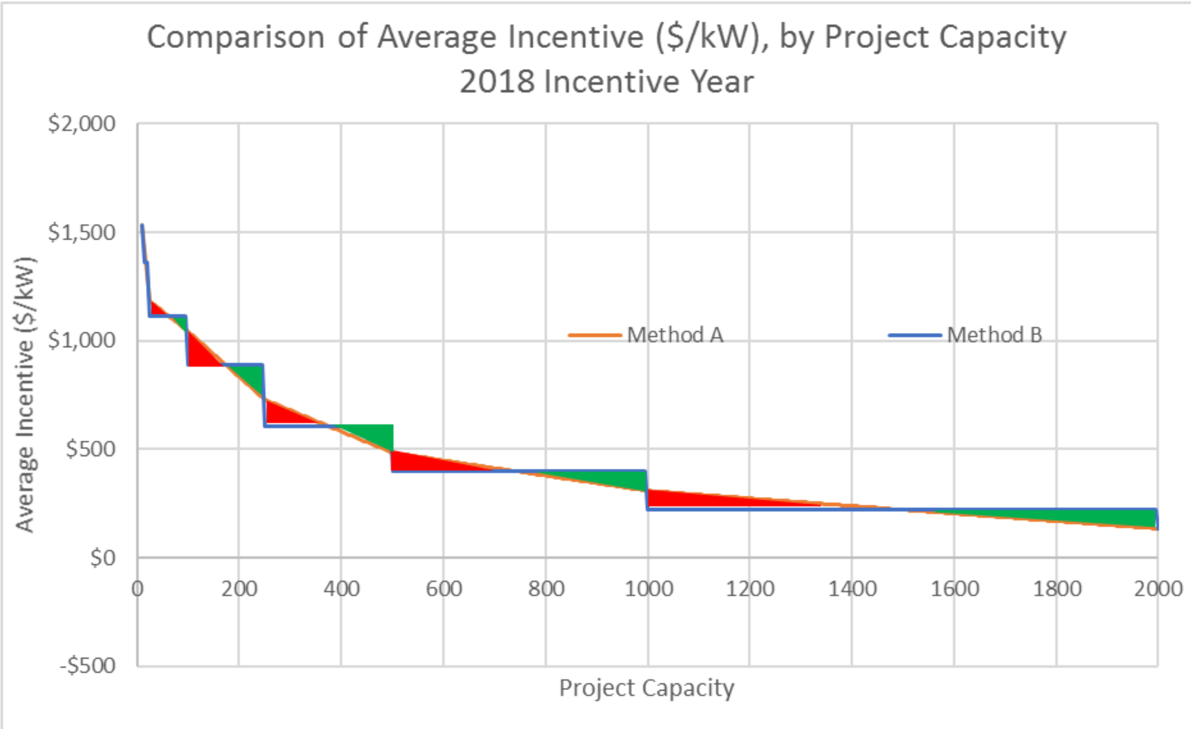
Transparency:

- Method A: Sliding-Scale does not provide single incentive numbers, but incentives for a given project capacity can be easily calculated from a given table.
- Method B: Stepped Block Incentive is the most transparent, providing a single incentive per 'bracket' and requiring no secondary calculation.
- Method C: Marginal Incentive is the least transparent, providing users little immediate idea of incentive level for their project and in many cases including negative marginal incentive rates, which, at best, may be confusing to customers.

Based on a review of the transparency of the proposed methods, we recommend that Method C: Marginal Incentive not be selected. Although the marginal rate provides an elegant average incentive curve, calculation of marginal rates is complex, and negative marginal rates may provide confusing signals to developers, policymakers, and customers.

Cost-effectiveness

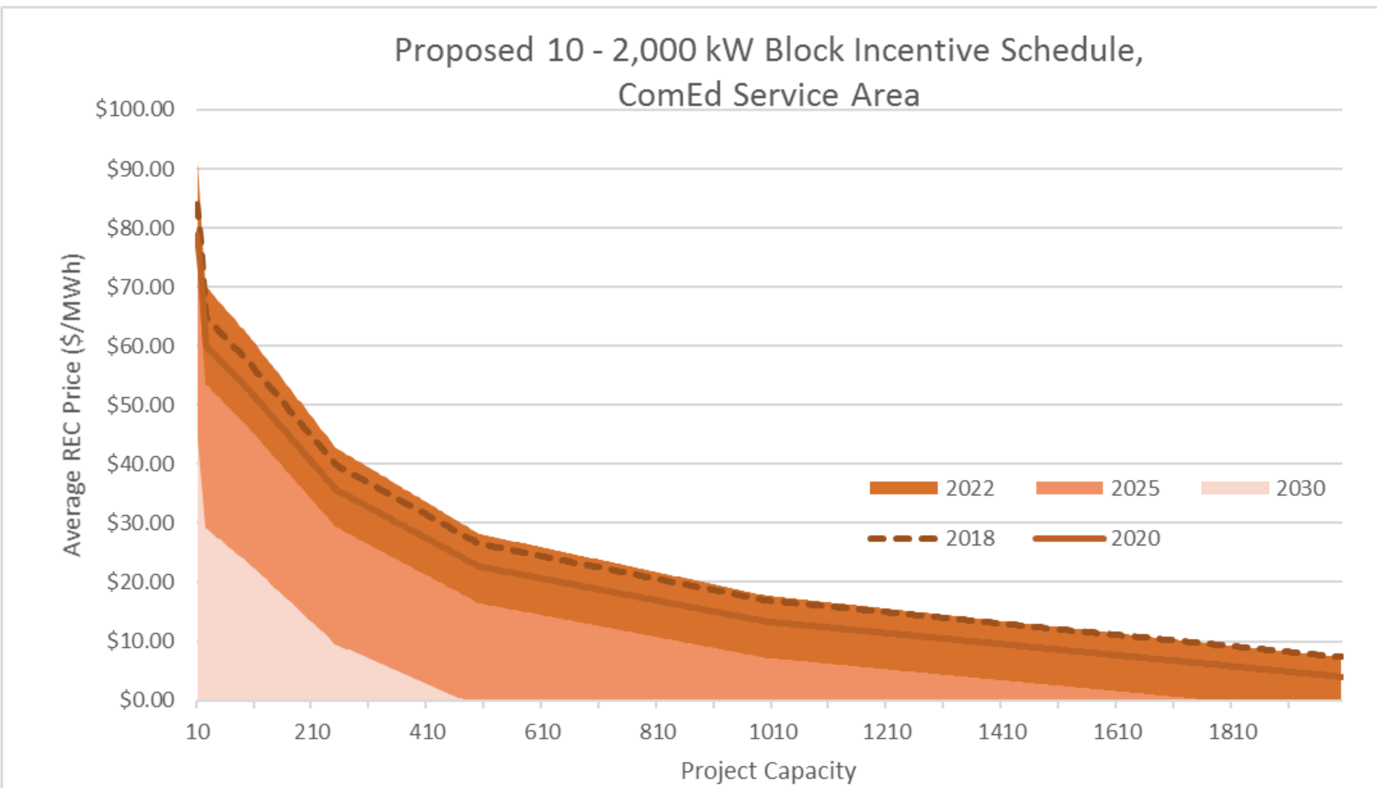
The below graph compares average incentives for Method A and Method B, with regions where Method B provides a greater incentive than Method A in green and where Method A provides a greater incentive than Method B in red. Under the assumption that appropriate incentive levels follow a similar curve to that outlined by Method A, these regions highlight where projects might be under- or over- incentivized by Method B. In threshold cases, differences between funding buckets might represent a change of total incentive of $100,000 or more.



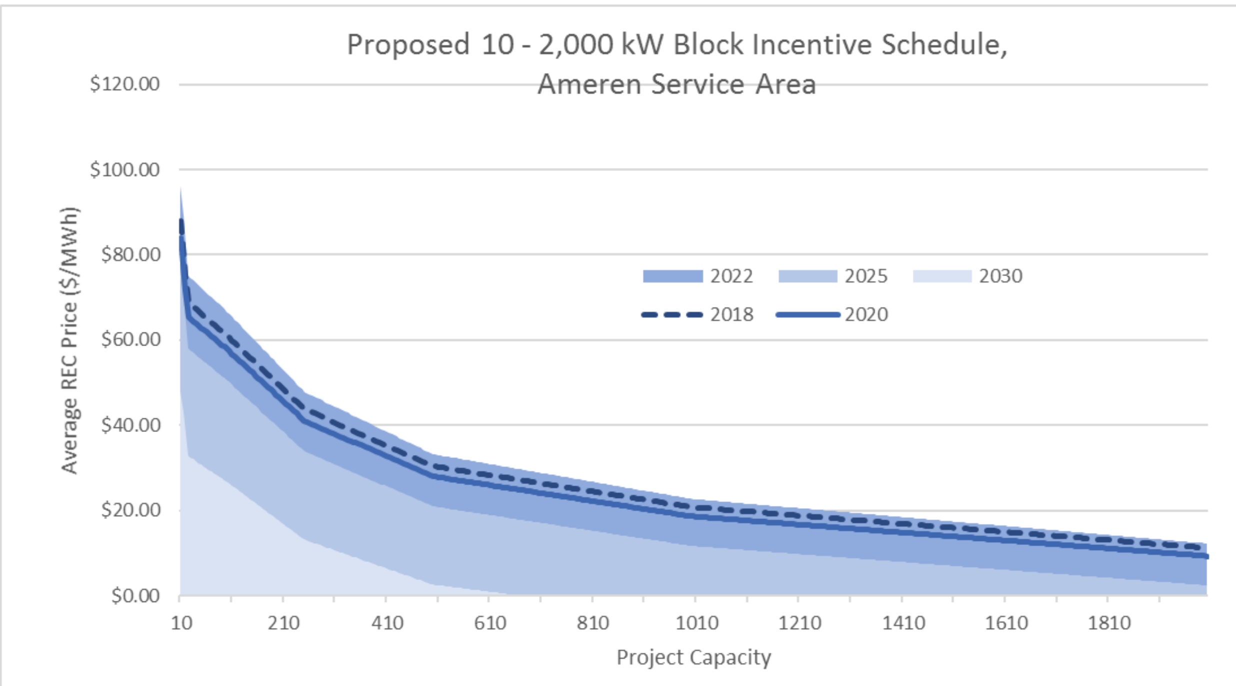
As designed, the single average incentive may provide inefficient or cost-ineffective incentives, and encourages developers to build at the high end of each capacity bucket (e.g. 99-kW projects instead of 101-kW projects). These incentives distort the market and encourage developers to build projects according to incentive structure, rather than the material parameters that might typically determine project size. Because Method B doesn't result in cost-effective incentives for diverse projects, it was ruled out.

As a result, we recommend Method A: Sliding-Scale Incentive as the most appropriate model:

PROPOSED Block Schedule (ComEd Service Area)									
For Calendar Year Ending:	Average REC Price ($/REC)							Expiration Date	Block Capacity
Project Capacity:	10 kW	25 kW	100 kW	250 kW	500 kW	1,000 kW	2,000 kW		
2018	$84.06	$64.88	$57.21	$39.95	$26.52	$16.93	$7.34	End of 2018	46
2019	$78.04	$59.63	$52.26	$35.69	$22.80	$13.60	$4.39	End of 2019	46
2020	$78.73	$60.04	$52.57	$35.75	$22.67	$13.33	$3.98	End of 2020	46
2021	$79.09	$60.18	$52.61	$35.60	$22.36	$12.91	$3.45	End of 2021	19
2022	$91.03	$70.09	$61.71	$42.86	$28.20	$17.72	$7.25	End of 2022	19
2023	$84.49	$64.38	$56.34	$38.24	$24.16	$14.11	$4.06	End of 2023	19
2024	$78.16	$58.86	$51.14	$33.76	$20.25	$10.60	$0.95	End of 2024	19
2025	$72.04	$53.51	$46.10	$29.42	$16.45	$7.19	$0.00	End of 2025	19
2026	$66.13	$48.34	$41.22	$25.21	$12.76	$3.87	$0.00	End of 2026	19
2027	$60.41	$43.33	$36.50	$21.13	$9.17	$0.63	$0.00	End of 2027	19
2028	$54.87	$38.47	$31.91	$17.16	$5.68	$0.00	$0.00	End of 2028	19
2029	$49.50	$33.76	$27.47	$13.30	$2.28	$0.00	$0.00	End of 2029	19
2030	$44.30	$29.19	$23.15	$9.55	$0.00	$0.00	$0.00	End of 2030	19
2031	$39.26	$24.76	$18.96	$5.90	$0.00	$0.00	$0.00	End of 2031	19



PROPOSED Block Schedule (Ameren Service Area)									
For Calendar Year Ending:	Average REC Price ($/REC)							Expiration Date	Block Capacity
Project Capacity:	10 kW	25 kW	100 kW	250 kW	500 kW	1,000 kW	2,000 kW		
2018	$87.91	$68.73	$61.06	$43.79	$30.37	$20.78	$11.19	End of 2018	20
2019	$82.57	$64.16	$56.79	$40.22	$27.33	$18.12	$8.92	End of 2019	20
2020	$84.02	$65.34	$57.86	$41.04	$27.96	$18.62	$9.28	End of 2020	20
2021	$84.22	$65.32	$57.75	$40.73	$27.50	$18.04	$8.59	End of 2021	8
2022	$96.01	$75.07	$66.69	$47.84	$33.18	$22.70	$12.23	End of 2022	8
2023	$89.30	$69.20	$61.15	$43.06	$28.98	$18.93	$8.87	End of 2023	8
2024	$82.81	$63.51	$55.79	$38.42	$24.90	$15.25	$5.60	End of 2024	8
2025	$76.53	$58.00	$50.59	$33.91	$20.94	$11.67	$2.41	End of 2025	8
2026	$70.44	$52.65	$45.54	$29.53	$17.07	$8.18	$0.00	End of 2026	8
2027	$64.54	$47.46	$40.63	$25.26	$13.31	$4.77	$0.00	End of 2027	8
2028	$58.82	$42.43	$35.87	$21.11	$9.64	$1.44	$0.00	End of 2028	8
2029	$53.27	$37.53	$31.24	$17.07	$6.05	$0.00	$0.00	End of 2029	8
2030	$47.88	$32.77	$26.73	$13.13	$2.55	$0.00	$0.00	End of 2030	8
2031	$42.65	$28.15	$22.34	$9.29	$0.00	$0.00	$0.00	End of 2031	8



Block Sizes

As stated earlier, the Commercial & Industrial Adjustable Block should have large block sizes, but overall the block is expected to be smaller than the residential initial block since it should not last the 3 years. This is because we believe that there will be less of an issue reaching the ~200 MWs of new build outlined as the FEJA goal by 2021. These blocks should open at 66 overall MWs, enough to last for a calendar year for each year until 2020. Within the overall MWs, a block 70% of that size should be created for ComEd and a block 30% of that size created for Ameren.

Given the time lag from when the Future Energy Jobs Act goes into effect and the opening of the first block, there will be a substantial amount of pent-up demand at the beginning of the program. Due to this, we suggest that the IPA reserve 25% of the each block for projects that are already energized with an executed interconnection agreement. 75% of the blocks should be left for open reservations. If the IPA finds that consistently there are more than 25% of the projects that have executed interconnection agreements and are energized that are applying for the C&I block, the IPA can either increase the size of the block or increase the percent of the standing block for projects that are already energized.

Geographic Diversity

EDF/CUB/RHA are providing different formulas for Ameren and ComEd for all three models. Ameren and ComEd have different avoided costs, and most likely have different installation costs. Providing segmentation between ComEd and Ameren will incentivize geographic diversity and more downstate development.

Adjustable Block Program Application Process

For the 75% of projects that are not interconnected and energized, the applicant must go through an application process to reserve their block position and budget. To reserve a block, an applicant must prove some form of site control or legal right to build on that property as well as prove that the interconnection process has begun. The program administrator could have the capability to see into the utility's interconnection queues to ensure that this criteria is met. As well, the applicant should provide an initial deposit of $10/kW which is refundable at on-time project completion.

During the initial application, the applicant must also provide a detailed outline of the expected project milestone dates. The IPA should reference the NY-Sun Commercial and Industrial PV Incentive Program Progress Report Form for examples of what to include in a milestone tracker. Once awarded, an applicant should have 9 months to build, with an optional 6-month extension period. Every 4 months, the applicant must provide an updated milestone tracker. If on the 8th month, the applicant does not think the project will be finished on-time, the applicant can submit for a 6-month extension. To apply for a 6-month extension, the project should be required to provide an additional deposit of $25/ kW which is refundable at on-time project completion.

Once the 75% of the block is reserved, the next block will immediately open for the 75% of reservations.

Adjustable Block Program Award Requirements

The first block payment should not be initiated until the project is energized and there is proof of interconnection.

EDF/CUB/RHA believe that the IPA should follow what documents other states require to receive the incentive. Providing these documents can alleviate the concern that bad actors may build systems that will not produce REC's for 15 years and that those actors are just participating to receive the upfront incentive payment:

- One or Three-Line Drawing
- Site Map or Project Details if not included in Interconnection Agreement
    - Location of all solar electric system components, including solar electric modules, inverters, disconnects, point of interconnection, and production meter data.
    - Layout of solar electric array, showing the tilt, azimuth, and number of solar electric modules on each roof face or sub-array.
    - Length of all wire runs more than 100 feet.
    - Customer name and address.
- PVsyst or PVwatts
    - Showing the estimated annual output
- Proof of system warranty or O&M agreement
- Documentation of Energy Assessment if one was performed
- Documentation of Environmental Assessment if one was performed
- Executed Interconnection Agreement or PTO
- W-9 or ACH information for party receiving the incentive

REC Delivery Requirements and Clawbacks

EDF/CUB/RHA believe the IPA should follow the Connecticut ZREC program's requirement for REC deliveries. The IPA should create a minimum and maximum annual REC delivery quantity. After each year, if the minimum quantity was not delivered, a clawback is initiated for the difference between the minimum obligation and the actual REC quantity delivered.

As an alternative, since the > 25 kW adjustable block incentive contracts are paid out over a roughly 5-year horizon, the IPA could evaluate a system's output over years 2 and 3 of production and determine whether the system has been set up in a way that will lead to the system being significantly below the assumed production over the 15-year REC delivery timeline. Any clawback could be done prospectively by reducing the remaining adjustable block incentive payments in years 4 and 5 (the last two, of four, adjustable block incentive payments).

The system owner is responsible for registering the project in PJM-Gats or MRETS and for installing a DAS system which can track the production of the system. The system owner is then responsible for ensuring that all REC’s produced from the array are minted into the appropriate tracking system.

D. COMMUNITY SOLAR[8]

In general, EDF/CUB/RHA believe there is a strong need to put "community" in Community Solar, focusing on the benefits of local shared systems and residential participation. FEJA defines Community Renewable Generation Project as an electric generating facility that: 1) is powered by a renewable resource, such as wind, photovoltaic cells or panels, etc., and 2) is interconnected at the distribution system level of an electric public utility. 20 ILCS 3855/1-10. FEJA requires the development of a Community Solar Program, noting "[d]eveloping Community solar projects in Illinois will help to expand access to renewable energy resources to more Illinois residents." 20 ILCS 3855/1-5(7). The General Assembly explicitly required that the community solar program should expand access to renewable energy to a "broader group of energy consumers," including residential and small commercial customers and those who cannot install renewable energy on their own properties. 20 ILCS 3855/1-75(c)(1)(N).

As the General Assembly acknowledged, there are a number of reasons why an Illinois electric customer would choose to subscribe to a community solar project rather than install their own solar system on-site.

- Poor project siting. Property owners sometimes lack the space necessary to install on-site solar photovoltaic ("PV") systems, residents' roofs may not be ideal for fully capturing the benefit of PV systems and/or may be partially or fully shaded.

- Renters have no land/rooftop ownership. Renters do not own the property and are therefore unable to install distributed generation themselves.

- Relocation disincentive. People who may relocate to a different residence are disincentivized from installing net metering systems on their property, which may take 10 to 20 years to realize the full monetary benefits of their investment.

- Upfront and ongoing capital expenses. Many distributed solar PV installations require upfront capital investment, or strong credit ratings, that may be prohibitive for residents who would otherwise support the project, particularly low-income residents.

- Supporting a Community Project. Residents in a community may wish to support a community solar project that has positive benefits for the community as a whole, such as

[8] Because of the inter-relatedness of the questions posed by the IPA in its Request, EDF/CUB/RHA present here answers to many of the questions under "D. Community solar" in the below narrative, tables, and attachments. We are providing confidential workpapers to the IPA that support the analyses and models described.

subscribing to a project on a school or community center, on an old brownfield site, or an abandoned lot, or one developed by local entrepreneurs or trades.

These effects are even more prominent in densely populated urban areas, where viable project siting is limited and a disproportionate amount of customers are renting tenants rather than homeowners. For example, over half (55%) of occupied housing units in the City of Chicago are occupied by renters.

While many community solar programs in other states have seen strong participation from larger Commercial and Industrial customers, the intent of the Community Solar program in FEJA was not to address a pressing policy need for those customers. *See* 20 ILCS 3855/1-75(c)(1)(N) ("...to ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties"). Illinois is already a retail choice state, and net-metering credits for larger commercial and industrial customers already only apply to the supply-side of those customers' bills. Large Commercial and Industrial customers today can enter into long-term contracts with retail electric suppliers and/or a renewable developer to provide their energy exclusively from a solar array of any size. The only difference is the new $250/kW upfront Distributed Energy Resource Rebate for distribution value created under FEJA to which community solar projects now have access.

For these reasons, EDF/CUB/RHA believe it is important that any Community Solar Program developed by the IPA should be focused on meeting the intent of the statute: to provide access to distributed solar PV for those that otherwise could not participate in this market. This leads to several foundational principals for any Community Solar Program:

1) It must ensure Robust Residential and Small Commercial Participation.
2) It should incentivize projects located in communities,
3) It should take into account the value of net metering and the Distributed Energy Resource rebate the ICC will implement.
4) It should recognize the higher costs to build smaller systems that are common in community projects, such as those on schools and churches.
5) It should allow for different participation and ownership models to allow for easier access for renters, low-income customers and community partnerships that do not have other options in the market.
6) It should implement strong consumer protection standards that ensure the Community Solar wave does not follow the same pitfalls of the early days of retail choice.

Program Design Overview

In the below section, EDF/CUB/RHA propose the following structure for a Community Solar program that meets the principles outlined above: an adjustable block incentive formula that takes into account variable installed cost of different system sizes, additional requirements and incentives for residential participation, and additional incentives for geographic considerations.

Modeling the Adjustable Block

EDF/CUB/RHA are presenting the same three model scenarios for community solar as for commercial and industrial to take into account the variable installation cost by system size. This will create a base adjustable block incentive upon which any adders could be layered.

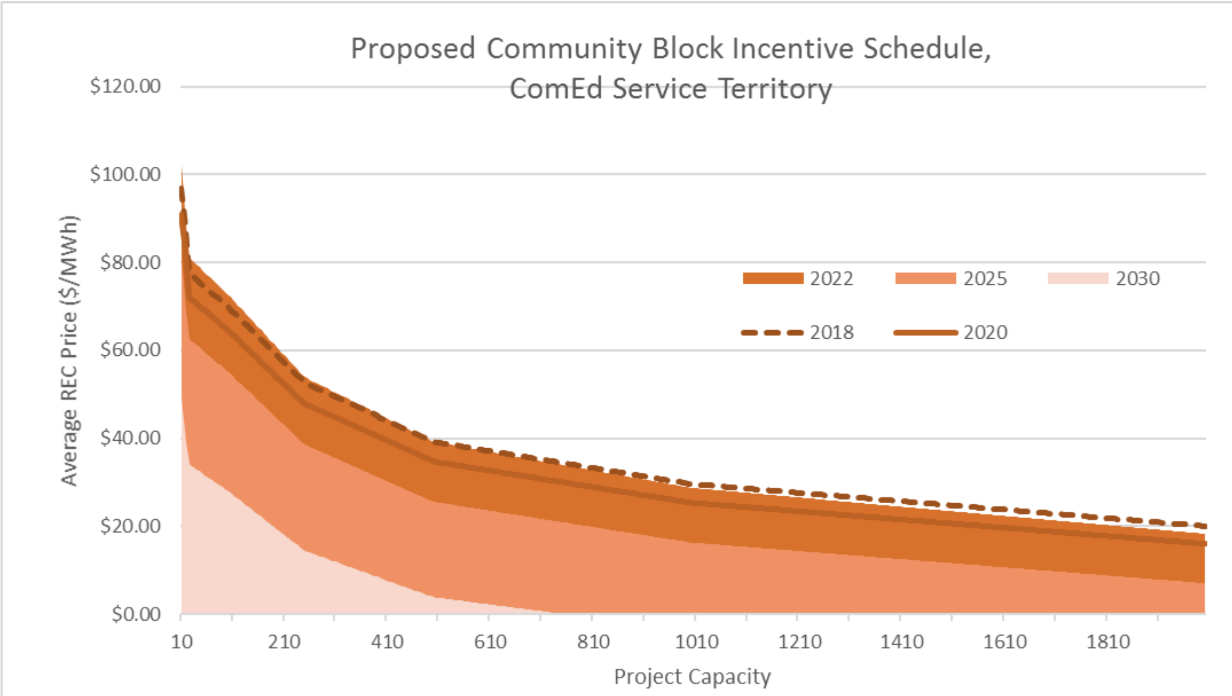
However, we suggest that the IPA conduct a separate market assessment to determine the average installation costs at landmark kW levels. For community solar, the IPA will need to collect the same installed cost details as C&I as well as perform market research around average commercial customer acquisition cost, average permitting cost for ComEd and Ameren territory, average site control costs for ComEd and Ameren, and average interconnection costs for ComEd and Ameren. We recommend the IPA consider whether they should include the ITC credit in the installed cost or in a formula at all, as not all individuals or organizations can take the tax credit. We believe that that the IPA should also use the most recent large scale DG procurement results as a benchmark for the $/REC incentive rates.

The basic assumptions of the model include:

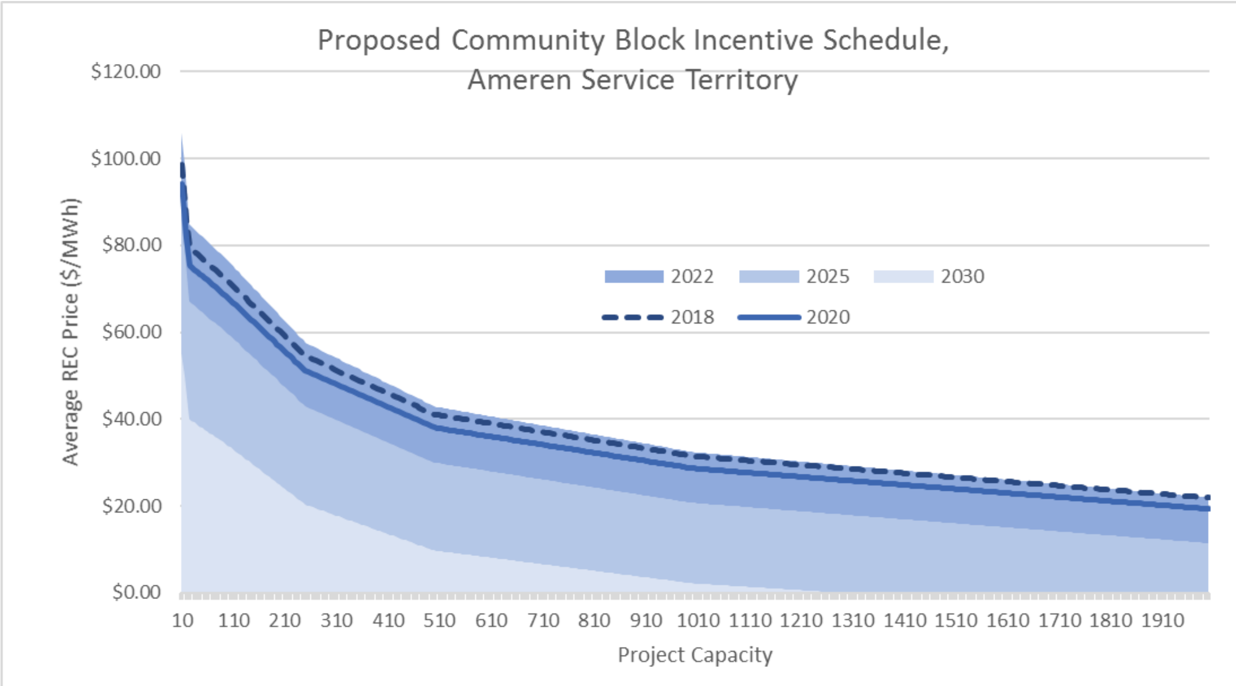
- To reflect the varied economic considerations between rooftop 10 kW projects and green-field 2,000 kW projects, incentives will be offered on a sliding scale based on project capacity.
- IPA will conduct an Illinois market survey to determine market clearing prices of projects at a number of project set points (currently 10 kW, 25 kW, 100 kW, 250 kW, 500 kW, 1,000 kW, and 2,000 kW)
- Estimated installed cost for new projects will be linearly extrapolated from the two nearest market survey set points and plugged in to the formula.
- Annual capacity caps will be used to ensure goals of long-term procurement are met.
- Installed costs are expected to decrease over time and deployment. Blocks will be indexed to projected installed costs and electricity rates. Blocks will be retired annually at the end of the calendar year.
- Incentives will step down, year-to-year, based on projected decreases in installed costs and increases in electricity rates.
- Block schedules and incentive levels will be adjusted periodically using IPA-conducted industry surveys and rates of adoption of the incentive.
- Incentive rates will be set for the 3 years after the most recent survey. Estimates of future incentives will be provided for long-term project planning purposes.

- Capacity caps for each block will ensure budgets are maintained. When a capacity cap is hit, the next block will begin without delay.
- To reflect differences in avoided cost between service areas, ComEd and Ameren service areas will operate independently, with distinct blocks, schedules, and incentive rates.
- Capacity goals are divided between Ameren and ComEd service areas based on an estimate of current and future relative distribution load.
- Block incentives listed here may be subject to additional incentives based on:
  - Geographic location
  - Residential subscribers
  - Low-income / Solar for All
  - Environmental Value
- A diversity of projects is incentivized through the sliding-scale incentive. As a result, multiple smaller blocks are not needed.
- 20% of the incentive will be paid up-front. The remaining 80% will be paid in four annual installments.
- Some portion of the block may be reserved with an appropriate application. Some other portion will be first-come, first-served.

PROPOSED Block Schedule (ComEd Service Area)									
For Calendar Year Ending:	Average REC Price ($/REC)							Expiration Date	Block Capacity
Project Capacity:	10 kW	25 kW	100 kW	250 kW	500 kW	1,000 kW	2,000 kW		
2018	$96.76	$77.58	$69.91	$52.65	$39.22	$29.63	$20.04	End of 2018	46
2019	$90.44	$72.02	$64.66	$48.09	$35.20	$25.99	$16.78	End of 2019	46
2020	$90.77	$72.08	$64.61	$47.79	$34.71	$25.37	$16.02	End of 2020	46
2021	$90.65	$71.75	$64.18	$47.16	$33.93	$24.47	$15.02	End of 2021	19
2022	$102.06	$81.12	$72.74	$53.89	$39.23	$28.75	$18.28	End of 2022	19
2023	$94.93	$74.83	$66.78	$48.69	$34.61	$24.56	$14.51	End of 2023	19
2024	$87.98	$68.68	$60.96	$43.59	$30.07	$20.42	$10.77	End of 2024	19
2025	$81.19	$62.66	$55.25	$38.57	$25.60	$16.33	$7.07	End of 2025	19
2026	$74.55	$56.76	$49.64	$33.63	$21.18	$12.29	$3.39	End of 2026	19
2027	$68.04	$50.96	$44.13	$28.76	$16.81	$8.27	$0.00	End of 2027	19
2028	$61.66	$45.26	$38.71	$23.95	$12.47	$4.28	$0.00	End of 2028	19
2029	$55.39	$39.65	$33.35	$19.19	$8.17	$0.30	$0.00	End of 2029	19
2030	$49.22	$34.11	$28.06	$14.47	$3.89	$0.00	$0.00	End of 2030	19
2031	$43.13	$28.63	$22.83	$9.77	$0.00	$0.00	$0.00	End of 2031	19



PROPOSED Block Schedule (Ameren Service Area)									
For Calendar Year Ending:	Average REC Price ($/REC)							Expiration Date	Block Capacity
Project Capacity:	10 kW	25 kW	100 kW	250 kW	500 kW	1,000 kW	2,000 kW		
2018	$98.61	$79.43	$71.75	$54.49	$41.07	$31.48	$21.89	End of 2018	20
2019	$92.96	$74.55	$67.19	$50.62	$37.73	$28.52	$19.31	End of 2019	20
2020	$94.08	$75.39	$67.92	$51.10	$38.02	$28.67	$19.33	End of 2020	20
2021	$94.13	$75.22	$67.66	$50.64	$37.41	$27.95	$18.50	End of 2021	8
2022	$105.75	$84.80	$76.42	$57.57	$42.91	$32.44	$21.97	End of 2022	8
2023	$98.84	$78.74	$70.69	$52.60	$38.52	$28.47	$18.41	End of 2023	8
2024	$92.13	$72.82	$65.10	$47.73	$34.22	$24.57	$14.91	End of 2024	8
2025	$85.58	$67.05	$59.64	$42.96	$29.99	$20.73	$11.46	End of 2025	8
2026	$79.20	$61.41	$54.30	$38.29	$25.84	$16.94	$8.05	End of 2026	8
2027	$72.98	$55.90	$49.07	$33.70	$21.74	$13.20	$4.66	End of 2027	8
2028	$66.89	$50.49	$43.94	$29.18	$17.71	$9.51	$1.31	End of 2028	8
2029	$60.93	$45.19	$38.90	$24.73	$13.72	$5.85	$0.00	End of 2029	8
2030	$55.09	$39.98	$33.94	$20.34	$9.77	$2.21	$0.00	End of 2030	8
2031	$49.36	$34.86	$29.06	$16.00	$5.85	$0.00	$0.00	End of 2031	8



Block Sizes

EDF/CUB/RHA believe that the community solar adjustable block segment will be the quickest of all customer segments to reach the roughly 200 MWs of its new-build requirement by 2021. Rather than a single "mega-block" size as we recommended in the adjustable block incentive analysis for residential systems, we instead recommend a smaller block-size for community solar systems. Given our previous comments in our RPS budget analysis section about the need to prioritize residential adjustable block incentives in the early years of the LTRRPP due to the roll-over capability, it is reasonable to implement a quicker step-down in blocks for Community Solar projects to ensure that there are sufficient resources. Additionally, it is important that a sufficient quantity of residential solar PV is installed prior to reaching the 5% net metering threshold. Therefore, the community solar program should be designed to appropriately pace development of these projects.

	Community		
	Utility Service Area		
Calendar Year	**ComEd**	**Ameren**	**Total**
2018	46	20	66
2019	46	20	66
2020	46	20	66
2021	19	8	26

2022	19	8	26
2023	19	8	26
2024	19	8	26
2025	19	8	26
2026	19	8	26
2027	19	8	26
2028	19	8	26
2029	19	8	26
2030	19	8	26
2031	19	8	26

Similar to residential and C&I, there will be a division between ComEd and Ameren MW block sizes. Also, we continue to propose that Blocks retire once the MW size is hit or at the end of the calendar year; whichever occurs first. Upon retirement of a block, the following block should immediately open.

Given the time lag from when the Future Energy Jobs Act goes into effect and the opening of the first block, there will be a substantial amount of pent-up demand at the beginning of the program. Due to this, we suggest that the IPA reserve 15% of the each block for projects that have already energized with an executed interconnection agreement. 85% of the blocks should be left for open reservations. If the IPA finds that consistently there are more than 15% of the projects that have executed interconnection agreements and are energized that are applying for the community solar block, the IPA can either increase the size of the block or increase the percent of the standing block for projects that are already energized.

Additional Policy Objectives

As discussed at IPA's May workshops, there are four general structures the IPA can follow in its Community Solar program design to ensure the program meets the customer and geographic goals of FEJA.

1. The IPA can offer a basic block incentive, without requirements or additional incentives (such as adders), for community solar.
2. The IPA can choose to have specific minimum requirements for all projects. For example, a requirement that all community solar projects must include at least 25% residential rate class subscription.
3. The IPA can offer an upfront adder on top of the general block incentive for policy goals such as residential participation or geographic diversity.

4. The IPA can offer an ongoing adder on top of the general block incentive for policy goals such as residential participation or geographic diversity.

Robust Residential and Small Commercial Participation

EDF/CUB/RHA agree with the position supported by CCSA, and other stakeholder groups that at least 25% of community solar subscriptions should be residential or small commercial class customers. The IPA should establish the 25% as a minimum requirement for all Community Solar projects to ensure each one serves residential and/or small commercial customers.

However, we believe that "robust," as called for in FEJA (20 ILCS 3855/1-75(c)(1)(N)) would not be able to best defined as only 25%, if the end result was all projects building community solar with the bare minimum residential participation. To ensure robust participation of residential and small commercial customers, that 25% minimum requirement should be paired with additional incentives should a project choose to engage more residential subscribers. Through an incentive, the projects that choose to do just the bare minimum would not be punished, but projects that choose to do more would be accommodated.

Thus, we propose two additional incentives: one, if a community solar project commits to subscribe at least 50% of its customers from a residential and/or small commercial rate class, that project should be awarded an incentive; two, if a community solar project commits to subscribe at least 75% of its customers from a residential and/or small commercial rate class, that project should be awarded a higher incentive.

Upfront incentive. EDF/CUB/RHA recommend an upfront incentive that would then lock-in the requirements over the life of the Adjustable Block Incentive's 15-year contract. ComEd has proposed that, through a portal designed for community solar that they will have to implement for the net metering functionality, they could restrict participation to residential rate class accounts at the moment of account entry. This upfront incentive should be calculated based on the following factors:

1. Average customer acquisition cost for a fully subscribed residential community solar garden ($/W)
2. Weighted average cost of capital for a fully subscribed residential community solar garden ($/W)

NREL has done research on this topic, but we suggest the IPA collect responses on these costs during their market research.

Ongoing incentive. While we believe an upfront incentive, with permanent restrictions based on the level of participation chosen, is more appropriate at this time, the IPA could also consider an ongoing incentive that annualizes the above costs, with the assumption that a project may need to expend operating dollars over the life of a system to reacquire a new residential subscriber.

Geographic Diversity

EDF/CUB/RHA see clear geographic values initiated through community solar. We encourage the IPA to incentivize, either through an upfront or ongoing adder, projects are developed to realize these benefits.

Statewide: FEJA clearly describes a need for the benefits of FEJA to be statewide: "The Adjustable Block program shall be designed to ensure that renewable energy credits are procured from...renewable energy generation projects in diverse locations and are not concentrated in a few geographic areas." 20 ILCS 3855/1-75(c)(1)(K)(iv). The separate blocks for ComEd and Ameren are one step that should be taken to ensure a geographic distribution of projects, but the IPA can also consider other policy objectives, such as capacity needs, to further incent projects in Ameren territory.

Community Value: EDF/CUB/RHA strongly believe there is value to bringing community solar to the community. That is, projects should, to the greatest extent possible and practical, be located in close proximity to subscribers. These projects create localized societal, community, and economic benefits.

FEJA sets forth a number of benefits to new renewable energy resources (such as community solar projects) in Illinois, including: diversifying Illinois electricity supply, avoiding and reducing pollution, reducing peak demand, and enhancing public health and well-being of Illinois residents. 20 ILCS 3855/1-75(c)(1)(I). Each of these benefits is enhanced to an even greater extent for community solar projects sited close to their subscribers. Additionally, FEJA mandates geographic diversity in projects. 20 ILCS 3855/1-75(c)(1)(K)(iv). Incentivizing projects to be located near subscribers encourages diversity of location, as, presumably, subscriber groups will be located in geographically disparate locations. Geographic diversity is an important consideration for all of the RPS programs, as it ensures equity in ability to participate, and benefit from, a clean energy economy for diverse populations and communities.

We anticipate this incentive will also increase residential and small commercial participation in community solar projects. Community solar projects in closer to proximity to subscribers are more visible, and greater visibility is likely to increase interest and participation, particularly from the more difficult-to-reach residential and small commercial and industrial sectors. Additionally, this incentive should be designed to encourage grassroots or community-driven (as opposed to developer-driven) projects. Those projects are more likely than developer-driven projects to desire proximity to subscribers. However, due to their nature (including the likely smaller size of the projects and the familiarity of the parties with solar development), these projects are likely to need additional incentives to be economically viable.

Encouraging proximity to subscribers through an incentive, such as an adder, also advances the policy goal described above of encouraging the greatest possible amount of residential participation as early in the project as possible. The amount of the adder should be enough to compensate for the higher costs of being located in a more populated area, but should not be so high as to dis-incentivize projects in less densely populated areas. Rather, projects in less urban areas may require less of an incentive, as the costs of developing in those areas are lower (less expensive and greater availability of land, etc.). At present, solar projects in Illinois have largely been developed in more rural areas of the state. As such, it is clear that additional incentive is needed to encourage projects closer to subscribers living in city centers.

It is possible that the amount or requirements of the adder may be different for ComEd and Ameren's territories, or even within those territories. For example, it may be appropriate to incentive projects where 60% of subscribers are within a 10-mile radius of the project in more urban areas, or within a 30-mile radius in less densely populated areas.

Environmental Value: EDF/CUB/RHA also suggest the IPA consider incentivizing projects to be located close to polluting generation sources where those projects can support reducing the average hours those polluting generators run, and the resulting emissions. 20 ILCS 3855/1-75(c)(1)(I).

Identifying the locations where this geographical environmental value would be eligible is on one hand easy, and on the other hand somewhat difficult. On a basic level, a project that is connected to the same transmission substation as a coal-fired or gas-fired power plant would be able to offset the generation hours of that plant if the plant operated flexibly in response to market signals. The reduction in generation, standby, and regulation hours, or other non-market hours, for polluting plants would lead to a direct reduction in harmful CO2, NO2, and SO2 pollutants, along with a reduction in particulate matter and other local impacts. While a single solar array may not have a demonstrable impact on the generation hours of a larger polluting power plant, 50 or 500 solar arrays certainly could. The incentive should then be structured based on the relative impact of a kW of solar PV capacity based on the impact of a larger aggregation.

In New York, MW Block projects were incentivized through a 20% adder in addition to the base incentive if they were developed in "strategic locations." This approach can solve two problems: diversifying community solar outside of just greenfield development and ensuring energy is generated where it is most needed.

Adjustable Block Program Application

Preserve a portion for first-come, first-serve. To accommodate the expected pent-up demand for projects when the program begins, and to allow projects an alternative path to a forward reservation process, EDF/CUB/RHA recommend that a certain percentage of a block - 15% for community solar - should be preserved for a first-come, first-serve application process. This would provide protection from a freeze in the market that has occurred in other states when an entire block gets reserved by prospective greenfield projects, leaving more community-driven projects waiting for less-beneficial subsequent blocks.

*Block Reservation***.** For the 85% of projects that are not interconnected and energized, the applicant must go through an application process to reserve their block position and budget. To reserve a block, an applicant must prove some form of site control or legal right to build. As well, the applicant must prove that the interconnection process has begun and provide the utility feasibility study. The program administrator could have the capability to see into the utility's interconnection queues to ensure that the interconnection process has been met. The program administrator must evaluate the project feasibility studies to make sure that the utility has deemed the project as viable.

To apply for the adjustable block the applicant must provide an initial deposit, refundable at on-time project completion. The IPA should consider the fee structure outlined by the NY MW Block program: an application security of $35K for project up to 750 kW and $80K for 750-1500 kW and $135K for greater than 1500 kW to be refunded when there is proof of project completion. The amount is forfeited if the system fails to be installed or interconnected within the designated time.

During the initial application, the applicant must provide a detailed outline of the expected project milestone dates. The IPA should reference the NY-Sun Commercial and Industrial PV Incentive Program Progress Report Form as a reference for a milestone tracker they can use. Applicants should also be required to upload subscribers into the program portal as subscription agreements are executed. The Program Administrator will track the project location and subscriber data to see if the project applies for a residential or geographic adder.

Once awarded, an applicant will have 12 months to build, with an optional 6 month extension period. Every 4 months, the applicant must provide an updated milestone tracker. If on the 11th month, the applicant does not think the project will be finished on time, the applicant can submit for a 6 month extension. To apply for a 6 month extension, the project should be required to provide an additional deposit of $25/ kW which is refundable at on time project completion.

Adjustable Block Program Award Requirements

Timing of first payment. The first block payment should not be initiated until the project is energized and there is proof of interconnection.

Upfront requirements to ensure quality systems. EDF/CUB/RHA believe that the IPA should follow what documents other states require to receive the incentive. Providing these documents can alleviate the concern that bad actors may build systems that will not produce REC's for 15 years and that those actors are just participating to receive the upfront incentive payment.

- One or Three-Line Drawing
- Site Map or Project Details if not included in Interconnection Agreement
  - Location of all solar electric system components, including solar electric modules, inverters, disconnects, point of interconnection, and production meter data.
  - Layout of solar electric array, showing the tilt, azimuth, and number of solar electric modules on each roof face or sub-array.
  - Length of all wire runs more than 100 feet.
- PVsyst or PVwatts
  - Showing the estimated annual output
- Proof of system warranty or O&M agreement
- Documentation of Energy Assessment if one was performed
- Documentation of Environmental Assessment if one was performed
- All Site Permits
- Executed Interconnection Agreement or PTO
- W-9 or ACH information for party receiving the incentive

At the time of energization, the project should have documented all executed subscriber agreement information in the program portal. EDF/CUB/RHA see a potential threat to the community solar program, where developers apply for a project to be a community solar project while their real intent is to sell at the avoided cost rate under PURPA, while taking the community solar adjustable block incentive to do so. EDF/CUB/RHA recommend that the IPA takes appropriate safeguards against projects that build and take advantage of an incentive that assumes additional costs (such as customer acquisition) related to community solar projects. The Program Administrator will monitor the project site information and subscriber information to see if the project may apply for an optional residential or geographic incentive. The project should only be allowed to apply for and be awarded any additional incentives at energization.

REC Delivery Requirements and Clawbacks

EDF/CUB/RHA suggest the same requirement as the commercial and industrial obligation. IPA could follow the Connecticut ZREC program's requirement for REC deliveries. The IPA could create a minimum and maximum annual REC delivery quantity. After each year, if the minimum quantity was not delivered, a clawback is initiated for the difference between the minimum obligation and the actual REC quantity delivered.

As an alternative, since the Community Solar contracts are paid out over a roughly 5-year horizon, the IPA could evaluate a system's output over years 2 and 3 of production and determine whether the system has been set up in a way that will lead to the system being significantly below the assumed production over the 15 year REC delivery timeline. Any clawback could be done prospectively by reducing the remaining adjustable block incentive payments in years 4 and 5 (the last two, of four, adjustable block incentive payments).

The system owner should be responsible for registering the project in PJM-Gats or MRETS and for installing a DAS system which can track the production of the system. The system owner should be responsible for ensuring that all REC's produced from the array are minted into the appropriate tracking system.

Co-Location

Per FEJA's description of community renewable project as being limited to 2 MW nameplate capacity, projects should not be allowed to co-locate. If the intention of a developer is to build a project greater than 2 MW's on one site, they should be required to participate in the utility scale procurement.

Other Adders

EDF/CUB/RHA believe there are other incentives which serve compelling policy purposes that could be considered. These include, but are not limited to:

1. An adder for installing solar after doing energy efficiency upgrades
2. An adder for EV charging stations at carports
3. An adder for alternate solar installations such as carports, and car canopies
4. An adder for brownfield community solar

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?

The ABP and Community Solar programs present great opportunities for consumers to take advantage of continually improving distributed generation resources. In particular, Community Solar provides an opportunity for the many residents who, for various reasons, are unable or unlikely to invest in solar. However, the importance of consumer protections for the community solar program cannot be overstated. While FEJA calls for "robust" residential participation, there has been minimal residential participation in solar projects to date. Therefore, most participants will be new to both renewable generation ownership and "community" ownership of such projects. In order to avoid the pitfalls seen in retail electric and gas choice programs, the IPA should implement stringent consumer protections and offer substantial guidance to potential participants. The IPA has a vested interest in ensuring positive customer experiences in the early days of the community solar program, as negative experiences could hamper further development and make it difficult for the IPA to meet its targets.

First, the IPA must recognize that existing consumer protection laws do not go far enough to ensure positive program experiences and growth. The Illinois Consumer Fraud and Deceptive Business Practices Act and other laws may not adequately address issues unique to these solar programs, are difficult to enforce, and have done little to discourage bad actors in the retail choice programs. Misleading marketing tactics have been of particular concern. The IPA should not wait until harm has been inflicted on this nascent market before implementing stringent consumer protections. As the Illinois appellate court ruled in *Dominion Retail Inc. and Interstate Gas Co., Inc. vs. Illinois Commerce Comm'n*., 2015 IL App (4th) 140173 ("Dominion") in upholding alternative gas supplier consumer protections, "the Commission should not have to wait until someone is run over by a train before it declares a railroad crossing to be dangerous."

While the IPA and ICC's jurisdiction may be limited, there are certain steps that each can take that are within their authority. First, the IPA can require standard terms and disclosures in community solar contracts. Among those should be a requirement that the customer be given a net cash flow analysis of their participation in the project. Presumably, such analysis will show, in many cases, a net positive cash flow over the life of the project for a subscriber. There may be instances where the cash flow is negative, and a customer may choose to subscribe for other reasons. In each case, the analysis should be both provided to the customer and attached to the contract, so that it is reviewable. While such analysis will not be binding on any party, it should include a disclosure that savings are not guaranteed, and it should be calculated using best practices.

Additionally, the IPA and/or the ICC can serve as a clearinghouse of sorts for developers and operators. As the IPA suggested in the workshops, EDF/CUB/RHA support the idea of an "approved vendor" list for entities seeking subscribers. These "approved vendors" should meet stringent criteria related to marketing practices and contract terms. In the retail choice space, many customer complaints have been related not to the contracts themselves, but to marketing practices. Such dangers are even more likely to impact community solar marketing without appropriate protections in place, as there are currently no rules in place similar to those like Part 412 83 Ill. Admin. Code §412. Though the IPA and ICC have no direct jurisdiction over community solar marketers, they can offer a list of "approved vendors" who have voluntarily agreed to meet certain requirements. Because this list would be strictly voluntary, there should be no issues of jurisdictional authority.

Key to the successful implementation of both programs will be ensuring customers are fully informed about the financial structures and technology options available to them. Fundamentally both the ABP and Community Solar will need to be programs that customers can invest in with confidence, knowing their rights and potential remedies. In this vein, EDF/CUB/RHA also support the IPA's suggestion of price transparency via a public website akin to pluginillinois.com. Although such transparency is not wholly effective in protecting consumers from deceptive marketing practices (highlighting the importance of the voluntary "approved vendor" list described above), it provides some accountability and may encourage competitiveness among entities offering community solar subscriptions.

However, the IPA can most directly provide for transparency and confidence in projects through the use of mandatory disclosures of contract terms and conditions, billing and pricing, explanation of key terms to name a few, to be provided to customers up front before project investments are made, the adoption of standard contract terms and conditions for projects participating in the ABP and Community Solar programs and finally by working with the ICC on rules governing the marketing of both programs.

Many consumers, particularly in the early days of these programs, may not understand how a REC differs from the energy they might expect to use to offset their usage. The IPA should require developers to be clear upfront on what a REC is, what the value of RECs associated with a particular project will be, and how that value will be realized.

Maryland and Minnesota have adopted disclosures that require consumers be provided upfront information about billing and pricing terms; a summary of charges (both nonrecurring and recurring); information about the circumstances under which the charges are subject to change; conditions of services; transfer and termination fees and any other penalties; and a production projection and method for calculating it. The IPA should include similar requirements for both programs. Mandatory contract terms should also clearly delineate the expected project costs, the amount each party or subscriber is expected to invest and when that investment must be made, how the project will be financed and how energy and REC values will be assigned. Contracts should clearly define how the risk of any claw back will be assigned and what process will be used to settle any disputes between the parties. It should also be made clear who will maintain the project's resources over the life of the project, and how any tax credits can be applied and by whom. Further questions have arisen as to whether or not an investment in Community Solar creates a security interest, and while the state of the law is unsettled on this point, the IPA should require disclosure of that possibility, including what happens if it is ultimately determined that a security interest arises.

Given the long-term investments involved, customers must understand how solar systems can be expected to perform over their lifetime and for Community Solar projects, what will happen if a customer wishes to terminate a subscription in a project before the end of the project's useful life. Customers also need to understand how the risk for clawbacks affects their investment and ultimately how to calculate the economic value they can expect to receive for their investment. For projects that are not yet energized, the expected process for interconnection should be spelled out along with what will happen if the project for some reason is not ultimately energized.

In short, the following questions need to be answered for any project that the IPA funds through the ABP and Community Solar programs:

- What is the duration or term of the contract?
- What happens to a consumer's contract if they move to a different home?
- Do they have a right to terminate the contract without penalty, either within a certain period of time or at any time?
- Is a sign-up fee or deposit required? Is this additional to any upfront or monthly payment? Will the sign-up fee or deposit be refunded if the project is never built?
- Does the contract include a production guarantee?
- Will the consumer be able to take advantage of state and federal solar incentives, or will those go to the project owner or developer?
- What is the compensation rate for electricity generated from the project? Is the consumer assuming "regulatory risk" that compensation rates may change, based on actions of the ICC?
- How long will it take for savings to cover the cost of the system (the "payback period")?
- If paying upfront, how much is the upfront payment and what does that include?
- If paying monthly, are there any escalator clauses that will make payments increase over time? What is the rate of increase? How much will the consumer be paying each month by the end of the contract? Are there late payment penalties?

For Community Solar in particular,

- What happens if the community solar array goes down or is taken offline? Must the consumer be notified if the array is offline?
- Does the consumer own part of the array, including panels?
- Is it possible that the system will expand or decrease in size over time?

- Is there a minimum number of subscribers required, and what happens if that number is not met, either at the project's outset or at some point over the life of the project?
- Can consumers sell their subscription? If yes, are there any restrictions on who they can sell it to?

A workshop to discuss these questions and what would then need to be included in a model contract used by the IPA could be used to help refine recommendations for the IPA to include in its draft LTRRP released later this year.

Standard Disclosures

EDF/CUB/RHA recommend the IPA require standard disclosures. These disclosures should include the rights and responsibilities of both parties, as defined by PA 99-0906 and the LTRRP. Disclosure should also include all identified risks pertaining to project payback period and ROI, as well as the calculation of the division of developer/participant returns described above. The Federal Trade Commission has issued guidance on the marketing of RECs that the IPA can look to for disclosures around RECs in particular. For other model disclosures, please see below.

Hawaii, Maryland and Minnesota all have standard disclosure requirements that the IPA can look to as it creates its own requirements. As with the model contract terms and conditions, another workshop would be useful to discuss how to integrate these examples based on Illinois' own experience with alternative retail electric suppliers and the expected types of ABP and Community Solar projects.

Hawaii

The following disclosures are copied from the Hawaii, Community-Based Renewable Energy (CBRE) Program, Hawaii Public Utilities Commission, "Application for Approval to Establish a Rule to Implement a Community Based Renewable Energy Program." October 1, 2015, Order 34388 (Feb. 10, 2017).

Future Costs and Benefits of the Subscription

a. Production projections and a description of the methodology used to develop production projections;

b. Bill savings or added cost projections and a description of the methodology used to develop bill projections;

c. All non-recurring (*i.e.*, one-time) charges;

d. All recurring charges;

e. Terms and conditions of service;

f. Whether any charges may increase during the course of service, and if so, how much advance notice is provided to the Subscriber;

g. Whether the Subscriber is required to sign a term contract; State Community Solar Disclosure Requirements a ppendix B 30 Clean Ener g y Stat e s Alliance Sustainable Solar Education Project

h. Terms and conditions for early termination, including a straight line depreciation table of Subscription value;

i. Any penalties that the CBRE Subscriber Organization and/or Operator may charge to the Subscriber and under what circumstances; and

j. The process for unsubscribing or transferring subscription and any associated costs.

Disclaimers

a. An explanation of how the CBRE Subscriber Organization and/or Owner and Administrator will share the Subscribers' data with each other;

b. Data privacy policies of Administrators, Commission, and CBRE Subscriber Organization and/or Owner;

c. Under what circumstance and by what method will notice to Subscribers be issued when the CBRE Project is out of service, including notice of estimated length and loss of production;

d. Assurance that all installations, upgrades, and repairs will be under direct supervision of a qualified professional and that maintenance will be performed according to industry standards, including the recommendations of the manufacturers of solar panels and other operational components;

e. Allocation of unsubscribed output;

f. A statement that the CBRE Subscriber Organization and/or Operator is solely responsible for resolving any disputes with Administrator utility or the Subscriber about the accuracy of the CBRE Facility production;

g. A statement that Administrator is solely responsible for resolving any disputes with the Subscriber about the applicable rate used to determine the amount of the bill credit;

h. Copy of the executed Subscriber Organization's Standard Form Contract with Administrator for the CBRE Program;

i. Copy of the solar panel or wind turbine, inverter, energy storage device, and/or any other core component's warranty;

j. Definition of underperformance and a description of the compensation to be paid by the CBRE Subscriber Organization and/or Owner for any underperformance (i.e., an output guarantee);

k. The type and level of insurance, and what insurance benefits protect Subscribers;

l. Proof and description of a long-term maintenance plan including which services the plan includes (module or inverter failures, etc.); and

m. CBRE Subscriber Organization and/or Owner contact information for questions and complaints and agreement to update and notify the Subscriber if ownership changes hands;

Maryland

The following disclosures are copied from a Maryland Public Service Commission (PSC) order adopting regulations for a community solar pilot program., the Community Solar Energy Generation System (CSEGS). Maryland Public Service Commission, "Notice of Proposed Actions." March 18, 2017. http://mgaleg.maryland.gov/pubs/ committee/aelr/16-039p-regulation.pdf. Maryland's program requires disclosure of the following terms and conditions:

a. A plain language disclosure of the subscription, including: (i) The terms under which the pricing will be calculated over the life of the contract and a good faith estimate of the subscription price expressed as a flat monthly rate or on a per kilowatt-hour basis; and (ii) Whether any charges may increase during the course of service, and, if so, how much advance notice is provided to the subscriber.

b. Contract provisions regulating the disposition or transfer of a subscription to the [community solar energy generating system], as well as the costs or potential costs associated with such a disposition or transfer.

c. All nonrecurring (one-time) charges.

d. All recurring (monthly, yearly) charges.

e. A statement of contract duration, including the initial time period and any rollover provision

f. Terms and conditions for early termination, including: (i) Any penalties that the Subscriber organization may charge to the subscriber; and (ii) The process for unsubscribing and any associated costs.

g. If a security deposit is required: (i) The amount of the security deposit; (ii) A description of when and under what circumstances the security deposit will be returned; (iii) A description of how the security deposit may be used; and (iv) A description of how the security deposit will be protected.

h. A description of any fee or charge and the circumstances under which a customer may incur a fee or charge.

i. A statement that the Subscriber organization may terminate the contract early, including: (i) Circumstances under which early cancellation by the Subscriber organization may occur; (ii) Manner in which the Subscriber organization shall notify the customer of the early cancellation of the contract; (iii) Duration of the notice period before early cancellation; and (iv) Remedies available to the customer if early cancellation occurs.

j. A statement that the customer may terminate the contract early, including: (i) Circumstances under which early cancellation by the customer may occur; (ii) Manner in which the customer shall notify the Subscriber organization of the early cancellation of the contract; (iii) Duration of the notice period before early cancellation; (iv) Remedies available to the Subscriber organization if early cancellation occurs; and (v) Amount of any early cancellation fee.

k. A statement describing contract renewal procedures, if any.

l. A dispute procedure.

m. The Commission's toll-free number and Internet address.

n. A notice that the contract does not include utility charges.

o. A billing procedure description.

p. The data privacy policies of the Subscriber organization.

q. A description of any compensation to be paid for underperformance.

r. Evidence of insurance.

s. A long-term maintenance plan.

t. Current production projections and a description of the methodology used to develop production projections.

u. Contact information for the Subscriber organization for questions and complaints.

v. A statement that the Subscriber organization and electric company do not make representations or warranties concerning the tax implications of any bill credits provided to the subscriber.

w. The method of providing notice to the subscribers when the CSEGS is out of service for more than three business days, including notice of: (i) The estimated duration of the outage; and (ii) The estimated production that will be lost due to the outage.

x. An explanation of how unsubscribed production of the CSEGS will be allocated.

y. Any other terms and conditions of service.

<u>Minnesota</u>

The following disclosures are taken from Minnesota's "Community Solar Garden Subscriber Disclosure Checklist," https://www.edockets.state.mn.us/EFiling/edockets/search

Documents.do?method=showPoup&documentId=%7B54A21CD2-F0E9-4582-BEB9-07213AD69DA5%7D&documentTitle=20164-120893-02. The checklist is available online for consumers to use in reviewing their subscription agreements. Although community solar providers must comply with the requirements outlined in the form, use of the checklist is voluntary. The form lists the following required disclosures: •

- All nonrecurring (i.e., one-time) charges
- All recurring charges
- Terms and conditions of service
- Whether any charges may increase during the course of service, and if so, how much advance notice is provided to the Subscriber
- Whether the Subscriber is required to sign a term contract
- Terms and conditions for early termination
- Any penalties that the Community Solar Garden may charge to the Subscriber
- The process for unsubscribing and any associated costs
- An explanation of how the Community Solar Garden Operator and the Utility will share the Subscribers data with each other
- Data privacy policies the Utility of the Community Solar Garden Operator
- Under what circumstance and by what method will notice to Subscribers be issued when the Community Solar Garden is out of service, including notice of estimated length and loss of production
- Assurance that all installations, upgrades and repairs will be under direct supervision of a NABCEP-certified solar professional and that maintenance will be performed according to industry standards, including the recommendations of the manufacturers of solar panels and other operational components
- Allocation of unsubscribed production
- A statement that the Community Solar Garden Operator is solely responsible for resolving any disputes with the utility or the Subscriber about the accuracy of the Community Solar Garden production
- A statement that the utility is solely responsible for resolving any disputes with the Subscriber about the applicable rate used to determine the amount of the Bill Credit
- Copy of the contract with the utility for the Solar Rewards Community Program
- Copy of the solar panel warranty

- Definition of underperformance and a description of the compensation to be paid by the Community Solar Garden Owner for any underperformance
- The type and level of insurance, and what insurance benefits protect Subscribers
- Proof and description of a long-term maintenance plan including which services the plan includes (module or inverter failures, snow, etc.)
- Production projections and a description of the methodology used to develop production projections
- Community Solar Garden Operator contact information for questions and complaints and agreement to update and notify the Subscriber if ownership changes hands
- Demonstration to the Subscriber by the Community Solar Garden Operator that it has sufficient funds to operate and maintain the Community Solar Garden

E. ILLINOIS SOLAR FOR ALL PROGRAM

EDF/CUB/RHA join and support the comments of the Illinois Solar for All Working Group that relate to this section. All comments and positions EDF/CUB/RHA specifically address in these comments and the modeling attachments, however, supersede any positions contained in those comments (notably, around the need to incentivize community-focused community solar).

In addition to contract and disclosure requirements pertaining to the ABP, Illinois Solar for All programs should have periodic reporting requirements to ensure such programs are proceeding as proposed and achieving appropriate benchmarks. This reporting should be required regardless of IPA's decision whether to hire an Illinois Solar for All program administrator.

Moreover, given the purpose of the Illinois Solar for All Program is to "bring photovoltaics to low-income communities" while "maximiz[ing] the development of new photovoltaic generating facilities" and "create a long-term, low-income solar marketplace" in Illinois, EDF/CUB/RHA believe this is best achieved by balancing the benefits of ratepayers and program participants themselves. To this end, the IPA could consider using an ROI formula applied to proposed contracts under this program should place a higher emphasis on returns, inclusive of upfront payments and persistent cash flows, to participants as opposed to developers. This will incent the broadest possible participation in the Program, which will ultimately determine the long-term sustainability of the program, while maximizing the ratepayer benefits of robust DER investment in low-income communities.

PROPOSED ADJUSTABLE BLOCK INCENTIVE FORMULA
Projects with Nameplate Capacity <=10 kW

June 27, 2017

1 To ensure that REC prices are cost-effective (1-75.(c)(1)(D)), RPS goals are met (1-75.(c)), and blocks are transparent (1-75.(c)(1)(K)), the following formula will be used to calculate block incentives for the <10kW Adjustable Block Program:

Incentive = Average Installed Cost - Solar Rebate Value -

Value of System over project period (10-Year NPV of Avoided Costs (Energy, Capacity, Transmission, Demand))

*Solar Rebate Value is the value-of-solar tariff to be developed by utilities after the 5% Net Metering cap is hit (estimated as the 20-year discounted avoided distribution costs in the initial year).
*Modeled Installed Costs assume developers take the Solar Investment Tax Credit.
*Average installed costs will be established through an IPA-conducted Illinois market survey of solar developers. A $3,500/kW placeholder is currently in use.
*For 2018-2031, formula results are given below and calculated on the 'Residential Analysis' tab.

2 To reflect expected decreases in total installed cost over time, blocks will be indexed to projected installed costs and electricity rates. Blocks will be retired annually at the end of the calendar year.
Incentives will step down, year-to-year, based on decreases in installed costs and increases in electricity rates.
Block schedules and incentive levels will be adjusted periodically using IPA-conducted industry surveys and rates of adoption of the incentive.
Capacity caps for each block will ensure budgets are maintained. When a capacity cap is hit, the next block will begin without delay.

3 To reflect differences in avoided cost between service areas, ComEd and Ameren service areas will operate independently, with distinct blocks, schedules, and incentive rates.
Capacity goals are divided between Ameren (30%) and ComEd (70%) service areas based on an estimate of current and future relative distribution load.

4 To meet high installation rate required by 2020 REC goals (see Appendix A1), the 2018 block will be extended through the end of the 2020 delivery year. '

5 Block incentives listed here may be subject to additional incentives (adders) based on location, technology, or other factors.

6 Some portion of the block may be reserved with an appropriate application. Some other portion will be first-come, first-served.

Tables and Graphs are included below.

PROPOSED BLOCK SCHEDULE (ComEd Service Area)

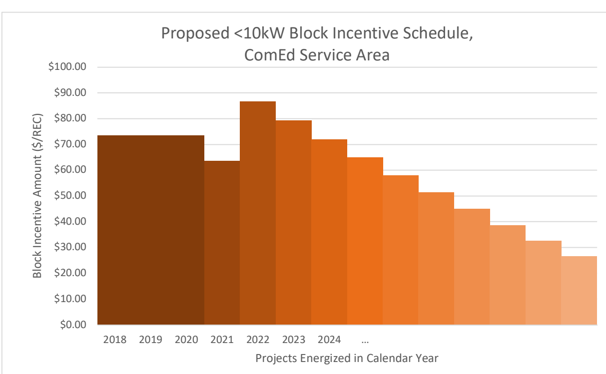
For Calendar Year Ending:	2018	2019	2020	2021	2022	2023	2024	
Project Incentive ($/kW)	$1,341	$1,341	$1,341	$ 1,163	$ 1,585	$ 1,447	$ 1,314	...
REC Price ($/REC)	$73.50	$73.50	$73.50	$ 63.75	$ 86.84	$ 79.29	$ 71.98	...
Expiration Date		End of 2020		End of 2021	End of 2022	End of 2023	End of 2024	...
Block Capacity		140		19	19	19	19	...

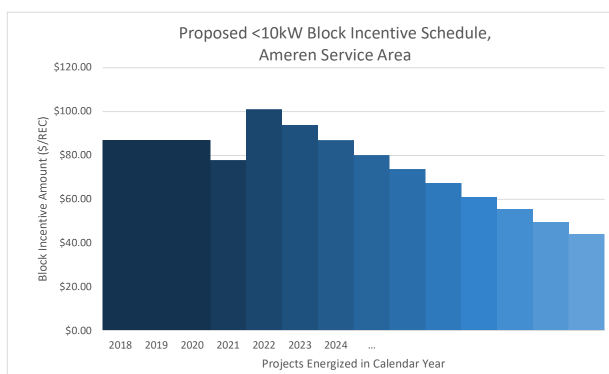
For Calendar Year Ending:	2025	2026	2027	2028	2029	2030	2031
Project Incentive ($/kW)	$ 1,184	$ 1,059	$ 938	$ 820	$ 705	$ 594	$ 486
REC Price ($/REC)	$ 64.90	$ 58.04	$ 51.39	$ 44.93	$ 38.65	$ 32.56	$ 26.63
Expiration Date	End of 2025	End of 2026	End of 2027	End of 2028	End of 2029	End of 2030	End of 2031
Block Capacity	19	19	19	19	19	19	19

PROPOSED BLOCK SCHEDULE (Ameren Service Area)

For Year Ending:	2018	2019	2020	2021	2022	2023	2024	
Project Incentive ($/kW)	$1,586	$1,586	$1,586	$ 1,418	$ 1,843	$ 1,712	$ 1,584	...
Price ($/REC)	$86.91	$86.91	$86.91	$ 77.73	$ 101.02	$ 93.80	$ 86.82	...
Expiration Date		End of 2020		End of 2021	End of 2022	End of 2023	End of 2024	...
Block Capacity		60		8	8	8	8	...

For Year Ending:	2025	2026	2027	2028	2029	2030	2031
Project Incentive ($/kW)	$ 1,461	$ 1,342	$ 1,227	$ 1,116	$ 1,008	$ 904	$ 803
Price ($/REC)	$ 80.08	$ 73.56	$ 67.26	$ 61.16	$ 55.26	$ 49.54	$ 44.00
Expiration Date	End of 2025	End of 2026	End of 2027	End of 2028	End of 2029	End of 2030	End of 2031
Block Capacity	8	8	8	8	8	8	8





PROPOSED ADJUSTABLE BLOCK INCENTIVE FORMULA

Projects with Nameplate Capacity 10 - 2,000 kW

June 27, 2017

1 To ensure that REC prices are cost-effective (1-75.(c)(1)(D)), RPS goals are met (1-75.(c)), and blocks are transparent (1-75.(c)(1)(K)), the following formula will be used to calculate block incentives for the 10 kW - 2,000 kW block of the Adjustable Block Program

Incentive = Modeled Installed Cost - Solar Rebate Value -

Value of System over project period (10-Year NPV of Avoided Costs (Energy, Capacity, Transmission, Demand))

*Solar Rebate Value is the $250 smart inverter rebate, or the value-of-solar tariff to be developed by utilities after the 5% Net Metering cap is hit.
*Modeled Installed Costs assume developers take the Solar Investment Tax Credit.
*Incentives are paid for 15 years of RECs from the project. Project value is based on the net present value of a 10-year lifetime.
*Average installed costs will be established through an IPA-conducted Illinois market survey of solar developers.
*For 2018-2031, formula results are given below and calculated on the 'Calculation' tabs.

2 To reflect the varied economic considerations between rooftop 10 kW projects and green-field 2,000 kW projects, incentives will be offered on a sliding scale based on project capacity.
IPA will conduct an Illinois market survey to determine market clearing prices of projects at a number of project set points (currently 10 kW, 25 kW, 100 kW, 250 kW, 500 kW, 1,000 kW, and 2,000 kW)
Estimated installed cost for new projects will be linearly extrapolated from the two nearest market survey set points and plugged in to the formula above.
Annual capacity caps will be used to ensure goals of long-term procurement are met.

3 Installed costs are expected to decrease over time and deployment. Blocks will be indexed to projected installed costs and electricity rates. Blocks will be retired annually at the end of the calendar year.
Incentives will step down, year-to-year, based on projected decreases in installed costs and increases in electricity rates.
Block schedules and incentive levels will be adjusted periodically using IPA-conducted industry surveys and rates of adoption of the incentive.
Capacity caps for each block will ensure budgets are maintained. When a capacity cap is hit, the next block will begin without delay.

4 To reflect differences in avoided cost between service areas, ComEd and Ameren service areas will operate independently, with distinct blocks, schedules, and incentive rates.
Capacity goals are divided between Ameren (30%) and ComEd (70%) service areas based on an estimate of current and future relative distribution load.

5 Diversity of projects is incentivized through the sliding-scale incentive. As a result, multiple smaller capacity-based blocks are not needed.

6 20% of the incentive will be paid up-front. The remaining 80% will be paid in 4 annual installments.

7 Some portion of the block may be reserved with an appropriate application. Some other portion will be first-come, first-served.

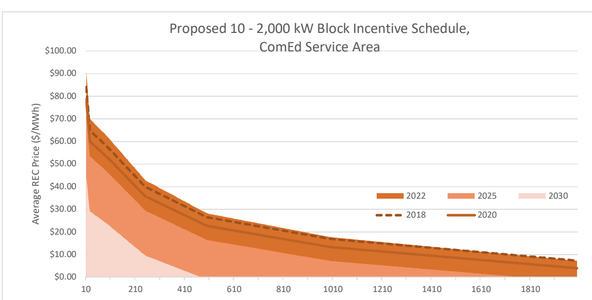
Tables and Graphs are included below.

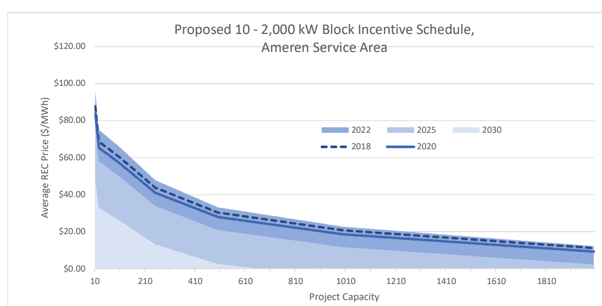
PROPOSED BLOCK INCENTIVE SCHEDULE (ComEd)

For Calendar Year Ending:		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Price ($/REC)															
Capacity (kW)	10	$ 84.06	$ 78.04	$ 78.73	$ 79.09	$ 91.03	$ 84.49	$ 78.16	$ 72.04	$ 66.13	$ 60.41	$ 54.87	$ 49.50	$ 44.30	$ 39.26
	25	$ 64.88	$ 59.63	$ 60.04	$ 60.18	$ 70.09	$ 64.38	$ 58.86	$ 53.51	$ 48.34	$ 43.33	$ 38.47	$ 33.76	$ 29.19	$ 24.76
	100	$ 57.21	$ 52.26	$ 52.57	$ 52.61	$ 61.71	$ 56.34	$ 51.14	$ 46.10	$ 41.22	$ 36.50	$ 31.91	$ 27.47	$ 23.15	$ 18.96
	250	$ 39.95	$ 35.69	$ 35.75	$ 35.60	$ 42.86	$ 38.24	$ 33.76	$ 29.42	$ 25.21	$ 21.13	$ 17.16	$ 13.30	$ 9.55	$ 5.90
	500	$ 26.52	$ 22.80	$ 22.67	$ 22.36	$ 28.20	$ 24.16	$ 20.25	$ 16.45	$ 12.76	$ 9.17	$ 5.68	$ 2.28	$ -	$ -
	1000	$ 16.93	$ 13.60	$ 13.33	$ 12.91	$ 17.72	$ 14.11	$ 10.60	$ 7.19	$ 3.87	$ 0.63	$ -	$ -	$ -	$ -
	2000	$ 7.34	$ 4.39	$ 3.98	$ 3.45	$ 7.25	$ 4.06	$ 0.95	$ -	$ -	$ -	$ -	$ -	$ -	$ -
No incentive at (kW capacity)		2,000	2000	2000	2000	2000	2000	2000	1780	1435	1075	850	650	480	400
Expiration Date		End of 2018	End of 2019	End of 2020	End of 2021	End of 2022	End of 2023	End of 2024	End of 2025	End of 2026	End of 2027	End of 2028	End of 2029	End of 2030	End of 2031
Block Capacity		46	46	46	19	19	19	19	19	19	19	19	19	19	19
*indicates estimated incentive.					*	*	*	*	*	*	*	*	*	*	*

PROPOSED BLOCK INCENTIVE SCHEDULE (Ameren)

For Calendar Year Ending:		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Price ($/REC)															
Capacity (kW)	10	$ 87.91	$ 82.57	$ 84.02	$ 84.22	$ 96.01	$ 89.30	$ 82.81	$ 76.53	$ 70.44	$ 64.54	$ 58.82	$ 53.27	$ 47.88	$ 42.65
	25	$ 68.73	$ 64.16	$ 65.34	$ 65.32	$ 75.07	$ 69.20	$ 63.51	$ 58.00	$ 52.65	$ 47.46	$ 42.43	$ 37.53	$ 32.77	$ 28.15
	100	$ 61.06	$ 56.79	$ 57.86	$ 57.75	$ 66.69	$ 61.15	$ 55.79	$ 50.59	$ 45.54	$ 40.63	$ 35.87	$ 31.24	$ 26.73	$ 22.34
	250	$ 43.79	$ 40.22	$ 41.04	$ 40.73	$ 47.84	$ 43.06	$ 38.42	$ 33.91	$ 29.53	$ 25.26	$ 21.11	$ 17.07	$ 13.13	$ 9.29
	500	$ 30.37	$ 27.33	$ 27.96	$ 27.50	$ 33.18	$ 28.98	$ 24.90	$ 20.94	$ 17.07	$ 13.31	$ 9.64	$ 6.05	$ 2.55	$ -
	1000	$ 20.78	$ 18.12	$ 18.62	$ 18.04	$ 22.70	$ 18.93	$ 15.25	$ 11.67	$ 8.18	$ 4.77	$ 1.44	$ -	$ -	$ -
	2000	$ 11.19	$ 8.92	$ 9.28	$ 8.59	$ 12.23	$ 8.87	$ 5.60	$ 2.41	$ -	$ -	$ -	$ -	$ -	$ -
No incentive at (kW capacity)		2,000	Over 2,000	Over 2,000	Over 2,000	Over 2,000	Over 2,000	Over 2,000	Over 2,000	1920	1560	1180	885	670	480
Expiration Date		End of 2018	End of 2019	End of 2020	End of 2021	End of 2022	End of 2023	End of 2024	End of 2025	End of 2026	End of 2027	End of 2028	End of 2029	End of 2030	End of 2031
Block Capacity		20	20	20	8	8	8	8	8	8	8	8	8	8	8
*indicates estimated incentive.					*	*	*	*	*	*	*	*	*	*	





PROPOSED ADJUSTABLE BLOCK INCENTIVE FORMULA

Community Solar Block Group

June 27, 2017

1 To ensure that REC prices are cost-effective (1-75.(c)(1)(D)), RPS goals are met (1-75.(c)), and blocks are transparent (1-75.(c)(1)(K)),
the following formula will be used to calculate block incentives for the Community Solar block of the Adjustable Block Program:

Incentive = Modeled Installed Cost - Solar Rebate Value -

Value of System over Project Period (10-Year NPV of Avoided Costs (Energy, Capacity, Transmission, Demand))

*Solar Rebate Value is the $250 smart inverter rebate, or the value-of-solar tariff to be developed by utilities after the 5% Net Metering cap is hit.
*Modeled Installed Costs assume developers take the Solar Investment Tax Credit.
*Incentives are paid for 15 years of RECs from the project. Project value is based on the net present value of a 10-year lifetime.
*Value of system over project period is evaluated for average community subscriber (25% residential, 75% commercial)
*Residential customers will not avoid distribution costs; commercial customers will not avoid demand charges
*Average installation costs for will be established through an IPA-conducted Illinois market survey of solar developers.
*For 2018-2031, formula results are given below and calculated on the 'Calculation' tabs.

2 To reflect the varied economic considerations between rooftop 10 kW projects and green-field 2,000 kW projects, incentives will be offered on a sliding scale based on project capacity.
IPA will conduct an Illinois market survey to determine market clearing installed costs of projects at a number of project set points (currently 10 kW, 25 kW, 100 kW, 250 kW, 500 kW, 1,000 kW, and 2,000 kW)
Estimated installed cost for new projects will be linearly extrapolated from the two nearest market survey set points (creating a 'sliding scale') and plugged in to the formula above.
Annual capacity caps will be used to ensure goals of long-term procurement are met.

3 Installed costs are expected to decrease over time and deployment. Blocks will be indexed to projected installed costs and electricity rates. Blocks will be retired annually at the end of the calendar year.
Incentives will step down, year-to-year, based on projected decreases in installed costs and increases in electricity rates.
Block schedules and incentive levels will be adjusted periodically using IPA-conducted industry surveys and rates of adoption of the incentive.
Capacity caps for each block will ensure budgets are maintained. When a capacity cap is hit, the next block will begin without delay.

4 To reflect differences in avoided cost between service areas, ComEd and Ameren service areas will operate independently, with distinct blocks, schedules, and incentive rates.
Capacity goals are divided between Ameren (30%) and ComEd (70%) service areas based on an estimate of current and future relative distribution load.

5 Block incentives listed here may be subject to additional incentives based on:
Geographic location
Residential subscribers
Solar for All
Diversity of projects is incentivized through the sliding-scale incentive. As a result, multiple smaller capacity-based blocks are not needed.

6 20% of the incentive will be paid up-front. The remaining 80% will be paid in 4 annual installments.

7 Some portion of the block may be reserved with an appropriate application. Some other portion will be first-come, first-served.

Tables and Graphs are included below.

PROPOSED BLOCK INCENTIVE SCHEDULE (ComEd)

For Calendar Year Ending:		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Price ($/REC)															
Capacity (kW)	10	$ 96.76	$ 90.44	$ 90.77	$ 90.65	$ 102.06	$ 94.93	$ 87.98	$ 81.19	$ 74.55	$ 68.04	$ 61.66	$ 55.39	$ 49.22	$ 43.13
	25	$ 77.58	$ 72.02	$ 72.08	$ 71.75	$ 81.12	$ 74.83	$ 68.68	$ 62.66	$ 56.76	$ 50.96	$ 45.26	$ 39.65	$ 34.11	$ 28.63
	100	$ 69.91	$ 64.66	$ 64.61	$ 64.18	$ 72.74	$ 66.78	$ 60.96	$ 55.25	$ 49.64	$ 44.13	$ 38.71	$ 33.35	$ 28.06	$ 22.83
	250	$ 52.65	$ 48.09	$ 47.79	$ 47.16	$ 53.89	$ 48.69	$ 43.59	$ 38.57	$ 33.63	$ 28.76	$ 23.95	$ 19.19	$ 14.47	$ 9.77
	500	$ 39.22	$ 35.20	$ 34.71	$ 33.93	$ 39.23	$ 34.61	$ 30.07	$ 25.60	$ 21.18	$ 16.81	$ 12.47	$ 8.17	$ 3.89	$ -
	1000	$ 29.63	$ 25.99	$ 25.37	$ 24.47	$ 28.75	$ 24.56	$ 20.42	$ 16.33	$ 12.29	$ 8.27	$ 4.28	$ 0.30	$ -	$ -
	2000	$ 20.04	$ 16.78	$ 16.02	$ 15.02	$ 18.28	$ 14.51	$ 10.77	$ 7.07	$ 3.39	$ -	$ -	$ -	$ -	$ -
No incentive at (kW capacity)		2,000	2000	2000	2000	2000	2000	2000	2000	2000	1970	1525	1040	760	495
Expiration Date		End of 2018	End of 2019	End of 2020	End of 2021	End of 2022	End of 2023	End of 2024	End of 2025	End of 2026	End of 2027	End of 2028	End of 2029	End of 2030	End of 2031
Block Capacity		46	46	46	19	19	19	19	19	19	19	19	19	19	19
*indicates estimated incentive.					*	*	*	*	*	*	*	*	*	*	*

PROPOSED BLOCK INCENTIVE SCHEDULE (Ameren)

For Calendar Year Ending:		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Price ($/REC)															
Capacity (kW)	10	$ 98.61	$ 92.96	$ 94.08	$ 94.13	$ 105.75	$ 98.84	$ 92.13	$ 85.58	$ 79.20	$ 72.98	$ 66.89	$ 60.93	$ 55.09	$ 49.36
	25	$ 79.43	$ 74.55	$ 75.39	$ 75.22	$ 84.80	$ 78.74	$ 72.82	$ 67.05	$ 61.41	$ 55.90	$ 50.49	$ 45.19	$ 39.98	$ 34.86
	100	$ 71.75	$ 67.19	$ 67.92	$ 67.66	$ 76.42	$ 70.69	$ 65.10	$ 59.64	$ 54.30	$ 49.07	$ 43.94	$ 38.90	$ 33.94	$ 29.06
	250	$ 54.49	$ 50.62	$ 51.10	$ 50.64	$ 57.57	$ 52.60	$ 47.73	$ 42.96	$ 38.29	$ 33.70	$ 29.18	$ 24.73	$ 20.34	$ 16.00
	500	$ 41.07	$ 37.73	$ 38.02	$ 37.41	$ 42.91	$ 38.52	$ 34.22	$ 29.99	$ 25.84	$ 21.74	$ 17.71	$ 13.72	$ 9.77	$ 5.85
	1000	$ 31.48	$ 28.52	$ 28.67	$ 27.95	$ 32.44	$ 28.47	$ 24.57	$ 20.73	$ 16.94	$ 13.20	$ 9.51	$ 5.85	$ 2.21	$ -
	2000	$ 21.89	$ 19.31	$ 19.33	$ 18.50	$ 21.97	$ 18.41	$ 14.91	$ 11.46	$ 8.05	$ 4.66	$ 1.31	$ -	$ -	$ -
No incentive at (kW capacity)		2,000	Over 2,000	Over 2,000	Over 2,000	Over 2,000	Over 2,000	Over 2,000	Over 2,000	Over 2,000	Over 2,000	Over 2,000	1745	1295	905
Expiration Date		End of 2018	End of 2019	End of 2020	End of 2021	End of 2022	End of 2023	End of 2024	End of 2025	End of 2026	End of 2027	End of 2028	End of 2029	End of 2030	End of 2031
Block Capacity		20	20	20	8	8	8	8	8	8	8	8	8	8	8
*indicates estimated incentive.					*	*	*	*	*	*	*	*	*	*