RENEWABLE RESOURCES

ILLINOIS POWER AGENCY

Long-Term Renewable Resources Procurement Plan

Modifications to Revised Plan Upon Reopening

Prepared to conform with the Illinois Commerce Commission's Order on Reopening in Docket No. 19-0995, dated May 27, 2020.

June 7, 2021

Prepared in accordance with the
Illinois Power Agency Act (20 ILCS 3855), and the Illinois Public Utilities Act (220 ILCS 5).

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Appendices*

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Appendix B: Summaries of Goals and Targets, RPS Portfolios, and Budgets
Appendix C: [Reserved. In the Initial Plan: "Review of Other Programs"]
Appendix D: [Reserved. In the Initial Plan: "Renewable Energy Credit Pricing Model Description"]
Appendix E: [Reserved: In the Initial Plan: "Renewable Energy Credit Pricing Models" (spreadsheets)]
Appendix F: Income Eligibility Guidelines for Illinois Solar For All
Appendix G: Illinois Solar for All Phase I Evaluation Report

* Appendix C is no longer applicable to this Plan. The Agency's approach to REC pricing is unchanged from the Initial Plan (as discussed in Chapter 6 herein), therefore Appendices D and E were not updated for this Revised Plan. Appendices C, D, and E from the Initial Plan may be found at: https://www2.illinois.gov/sites/ipa/Pages/2018-Long-Term-Renewable-Appendices.aspx. Additionally, an updated Appendix B prepared for this Final Revised Plan can be found on the Illinois Power Agency's website at: https://www2.illinois.gov/sites/ipa/Pages/2020-LTRRPP-Appendices.aspx.

1. Introduction

This is the Final version of the first Revised Long-Term Renewable Resources Procurement Plan ("Revised Plan" or "Plan") of the Illinois Power Agency ("IPA" or "Agency"), consistent with the Final Order of the Illinois Commerce Commission ("ICC" or "Commission") entered on February 18, 2020.

The Initial Long-Term Renewable Resources Procurement Plan ("Initial Plan") was developed by the IPA pursuant to the provisions of Sections 1-56(b) and 1-75(c) of the Illinois Power Agency Act ("Act" or "IPA Act"), and Section 16-111.5 of the Public Utilities Act ("PUA"). That Initial Plan[1] was developed under authority established through Public Act 99-0906 ("P.A. 99-0906"), enacted December 7, 2016 (effective June 1, 2017), which substantially revised the Illinois Renewable Portfolio Standard ("Illinois RPS" or "RPS"). The Initial Plan covered the Agency's renewable energy resources procurement and programmatic activities for 2018 and 2019 and was approved by the Commission on April 3, 2018 in Docket No. 17-0838. The Agency published the final Initial Plan on August 6, 2018.

Section 16-111.5(b)(5)(ii)(B) of the Public Utilities Act provides that "[the Agency] shall review, and may revise, the plan at least every 2 years thereafter." This process of developing the Revised Plan constitutes the Agency's first such update. That subparagraph further provides that "[t]o the extent practicable, the Agency shall review and propose any revisions to the long-term renewable energy resources procurement plan in conjunction with the Agency's other planning and approval processes conducted under this Section." On August 15, 2019 a draft Revised Plan was released for public comment concurrently with the IPA's release of its draft 2020 Electricity Procurement Plan.[2] The Revised Plan was filed for Commission approval on October 21, 2019 and reflected the Agency's consideration of comments received on the draft Revised Plan. Under Section 16-111.5(b)(5)(ii)(C) of the PUA, the Commission then had 120 days to review the Revised Plan and enter is Order confirming or modifying the Plan.

The Initial Plan addressed the Agency's proposed set of programs and competitive procurements to acquire renewable energy credits ("RECs") for RPS compliance obligations applicable to three Illinois electric utilities: Ameren Illinois Company ("Ameren Illinois"), Commonwealth Edison Company ("ComEd"), and MidAmerican Energy Company ("MidAmerican"). The Initial Plan also described how the Agency would develop and implement the Illinois Solar for All ("ILSFA") Program, which utilizes a combination of funds held by the Agency in the Renewable Energy Resources Fund ("RERF") and funds supplied by the utilities from ratepayer collections, to support the development of photovoltaic ("PV") resources, along with job training opportunities (supported separately) to benefit low-income households and environmental justice communities. The Revised Plan updated those programs and procurements where applicable.

This Revised Plan reflects changes arising from the Commission's orders confirming and modifying the filed Plan. The Revised Plan as filed on April 20, 2020, was amended consistent with the IPA's

[1] The Initial Plan is available at https://www2.illinois.gov/sites/ipa/Documents/2019ProcurementPlan/Long%20Term%20Renewable%20Resources%20Procurement%20Plan%20%288-6-18%29.pdf.

[22] While the draft Revised Plan was initially released for public comment with a schedule of 30 days for the receipt of public comments and a subsequent 14 day period for the Agency to update the Plan based on those comments, on September 3, 2019 the Agency announced an update to that timeline to 45 and 21 days, respectively, after reconsideration of certain language in Section 16-111.5(b)(5)(ii) of the Public Utilities Act.
See: https://www2.illinois.gov/sites/ipa/Documents/Draft%20Revised%20Plan%20-%20Summer%202019/Revised%20Plan%20Schedule%20Update%20(3%20September%202019).pdf.

understanding of the Final Order issued by the Commission in Docket No. 19-0995 on February 18, 2020. The Revised Plan was further modified upon reopening, and subsequently amended consistent with the Order on Reopening issued by the Commission on May 27, 2021. While the Agency has strived to fully and accurately reflect the Commission's Order in this update, in the case of any unintended inconsistencies between this Modified Revised Plan Upon Reopening and the Commission's Order, the Final Order or Order on Reopening (as applicable) issued by the Commission shall govern. The Revised Plan covers the Agency's proposals for procurements and programs that could be conducted during calendar years 2020 and 2021. As discussed throughout the Plan, absent legislative changes, RPS budget limitations will constrain the ability of the Agency to conduct additional procurements or expand program capacity for its Adjustable Block Program. Therefore, this Revised Plan provides a general framework for changes to procurements and programs should additional funding become available.[3] The Agency expects that as part of its annual procurement planning process conducted in calendar year 2021 (for implementation in 2022), it will again update and revise this Plan.

1.1. Initial Plan Accomplishments

Subsequent to the approval of the Initial Plan by the Commission on April 3, 2018, the Agency has completed the following implementation activities:

- First Subsequent Forward Procurement (1.980 million RECs annually from new utility-scale wind projects.[4] October 2018)
- Photovoltaic Forward Procurement (2 million RECs annually from new utility-scale solar projects.[5] November 2018)
- Brownfield Site Photovoltaic Procurement (Met statutory target of 40,000 RECs annually from new brownfield site photovoltaic projects. July 2019)
- Adjustable Block Program opened for Approved Vendor registration on November 1, 2018 and for project applications on January 30, 2019.
- Illinois Solar for All Program opened for Approved Vendor registration on February 19, 2019, for project applications for the 2018-2019 program year on May 15, 2019, and for the 2019-20 program year on September 4, 2019.
- Second Subsequent Forward Procurement (1 million RECs annually from new utility-scale wind projects. Conducted December 2019). No projects were selected in this procurement.
- Community Renewable Generation Procurement (50,000 RECs annually over 15 years from community renewable generation projects that are not photovoltaic. Conducted December 2019). No projects were selected in this procurement.
- Low-Income Community Solar Pilot Procurement ($20 million budget for 15-year REC delivery contracts. Conducted December 2019).

These activities are in addition to the Initial Forward procurements authorized through Section 1-75(c)(1)(G)(i)-(ii) of the Act and conducted in the second half of 2017 and first half of 2018; those

[3] The Illinois Solar for All Program is not impacted by the same budget constraints as it features somewhat distinct funding sources, and this Revised Plan proposes updates to the administration of that program.

[4] The law defines "utility-scale wind project" as an electric generating facility that (1) generates electricity using wind; and (2) has a nameplate capacity that is greater than 2,000 kilowatts. 20 ILCS 3855/1-10.

[5] The law defines "utility-scale solar project" as an electric generating facility that (1) generates electricity using photovoltaic cells; and (2) has a nameplate capacity that is greater than 2,000 kilowatts. 20 ILCS 3855/1-10.

were conducted under P.A. 99-0906, but not through the development and approval of the Initial Plan.

Remaining activities approved in the Initial Plan include continuing to fill previously authorized blocks in the Small Distributed Generation category of the Adjustable Block Program.[6]

1.2. Plan Organization

This Final Revised Plan contains eight chapters.

Chapter 1 is this Introduction. It contains a brief overview of the Plan and a set of Action Items that the Agency requested that the Commission expressly adopt as part of its approval of this Revised Plan.

Chapter 2 provides an overview of the legislative/regulatory requirements contained in the Illinois Power Agency Act and the Public Utilities Act (particularly those that result from the enactment of Public Act 99-0906) that led to the development of the Initial Plan, and this Revised Plan, and the implementation of the resulting programs and procurements by the Illinois Power Agency.

Chapter 3 contains calculations of RPS targets, summaries of RPS portfolios, and summaries of RPS budgets. For this Revised Plan, it provides proposals related to calculating MidAmerican's RPS obligations and budgets, treatment of utility-held Alternative Compliance Payments, and a discussion of the forecast budget limitations that will constrain activities for the next several years.

Chapter 4 discusses the eligibility of RECs for use in the Illinois RPS. In particular, it addresses two requirements of the RPS: eligibility of RECs from facilities in adjacent states, and the requirement that RECs cannot be procured from facilities that recover their costs through regulated rates.

Chapter 5 describes the competitive procurement process and the potential procurements the Agency could consider conducting if funding becomes available. These include procurements for RECs from new brownfield site photovoltaic projects, utility-scale photovoltaic projects, and utility-scale wind projects.

Chapter 6 describes the Adjustable Block Program. This includes details on the structure of the blocks, REC (and adder) prices, the application process, payment terms, the process for adjusting prices, the process for approving vendors, project specifications, consumer protections, delivery requirements, and more. For this Revised Plan, the Agency proposed certain adjustments to the program structure contained in the Initial Plan and proposed a framework for managing waitlists of projects.

Chapter 7 describes the Community Renewable Generation Program including standards for co-location, eligibility of projects located in municipal utilities and rural electric cooperatives, subscriber requirements, consumer protections, legal issues around marketing claims related to RECs, and the responsibilities of utilities. In this Revised Plan, the Agency proposed certain clarifications of co-location requirements and additional codification of consumer protection requirements.

Chapter 8 describes the Illinois Solar for All Program including the program funding and design, customer terms, conditions, and eligibility, and an approach to designating environmental justice

[6] As approved through Docket No. 19-0995, the Agency is also authorized to conduct an additional utility-scale wind procurement under this Revised Plan in light of no projects having been selected in the Second Subsequent Procurement under the Initial Plan.

communities. For this Revised Plan, the Agency proposed certain adjustments to the program structure contained in the Initial Plan.

1.3. Action Plan

In this Revised Plan, the IPA recommended the following items for ICC action as part of the Plan's approval:

1. Approve the RPS targets, and budget estimates for Ameren Illinois, ComEd, and MidAmerican for the delivery years 2020-2021 through 2021-2022 contained in Chapter 3, and additionally that Ameren Illinois, ComEd, and MidAmerican will provide updated load forecasts and budget data to the Agency on a biannual basis (each spring and fall) to allow the Agency to update those numbers.
2. Approve the Agency's approach to prioritizing the use of any future available budget funds contained in Chapter 3.
3. Approve the continuation of the Agency's approach for considering and weighting the public interest criteria related to facilities located in adjacent states that is contained in Chapter 4.
4. Approve the proposed procurements contained in Chapter 5.[7]
5. Approve the continuation of the basic design of the Adjustable Block Program contained in Chapter 6, including the block design, schedule of REC prices (and adders), and program terms and conditions as well as the updates proposed in this Revised Plan.
6. Approve the continuation of the basic design and terms and conditions of the Community Renewable Generation Program contained in Chapter 7 as well as the updates proposed in this Revised Plan.
7. Approve the continuation of the basic design and terms and conditions of the Illinois Solar for All Program contained in Chapter 8 as well as the updates proposed in this Revised Plan.

The Illinois Power Agency respectfully submits this Final Revised Long-Term Renewable Resources Procurement Plan, which reflects the Commission's Final Order in Docket No. 19-0995 confirming and modifying this Plan consistent with Section 16-111.5 of the PUA.

[7] This includes a utility-scale wind procurement for 1,000,000 RECs delivered annual to occur no later than May 31, 2021. This utility-scale wind procurement was authorized to bring RECs under contract previously expected from the Fall 2019 utility-scale wind procurement. See Docket No. 19-0995, Final Order dated February 18, 2020 at 18.

2. Legislative/Regulatory Requirements of the Plan

As with the original Long-Term Plan, this Chapter of the IPA's Revised Long-Term Renewable Resources Procurement Plan describes the legislative and regulatory requirements applicable to the Long-Term Renewables Plan, retaining much of the background discussion from the Initial Plan.

A Legislative Compliance Index, Appendix A, provides a complete cross-index of regulatory/legislative requirements and the specific sections of this Revised Plan that address each requirement identified.

2.1. Renewable Energy Resource Procurement Prior to Public Act 99-0906

Public Act 99-0906 did not introduce a Renewable Portfolio Standard into Illinois law, and the IPA's Long-Term Renewable Resources Procurement Plan is not the first Plan that the Agency produced addressing renewable energy resources procurement. Instead, the Agency has been producing procurement plans addressing renewable energy resource procurements since 2008 and conducting renewable energy resource procurements since 2009, and it is helpful to understand the background of the Illinois RPS's original structure and subsequent challenges in understanding the changes made through P.A. 99-0906 and the choices made through its implementation.

Prior to P.A. 99-0906, the Illinois RPS effectively had three compliance mechanisms depending on a customer's supply source: eligible retail customer procurements, Alternative Retail Electric Supplier ("ARES") compliance, and hourly pricing customer compliance payments.

2.1.1. Original RPS—Eligible Retail Customer Load

Of the three former RPS compliance mechanisms, the compliance pathway that looked most like the revised RPS enacted through P.A. 99-0906 was that which applied to "eligible retail customers," or those customers still taking default supply service from their electric utility (ComEd and Ameren Illinois, and starting in 2015, MidAmerican). The Agency's annual procurement plans (developed primarily to propose procurements intended to meet the energy, capacity, and other standard wholesale product requirements of eligible retail customers) also were required to include procurement proposals intended to meet annually-climbing, percentage-based renewable energy resource targets. As with block energy procured by the Agency, the applicable utility would be the counterparty to any resulting contracts.

Sub-targets were also introduced to the overall procurement volumes: of the renewable energy resources procured, 75% were required to come from wind, 6% from photovoltaics, and 1% from distributed generation. Prior to June 1, 2011, resources from Illinois were expressly prioritized (looking next to adjoining states if none was available, and then to elsewhere); after June 1, 2011, the RPS required looking to Illinois and adjoining states together as a first priority, and then to elsewhere. Funds available for use under RPS contracts were subject to a rate impact cap—a fixed bill impact cap percentage (2.015% of 2007 rates), which was then applied to eligible retail customer load to produce a renewable resources procurement budget.

This system may have worked more effectively had Illinois not experienced significant volatility in the size of its eligible retail customer load. But it did, primarily for the following reason: upon the establishment of the IPA in 2007, the General Assembly required that the electric utilities enter into relatively long-term energy supply contracts (known as the "swap contracts") to serve eligible retail customer load. In the years that followed, energy prices plummeted in the wholesale market, and

these agreements served to inflate the default supply rate well above that which could be offered by a competitive supplier. From 2011 to 2013, massive waves of default supply customers switched to ARES, often through opt-out municipal aggregation (municipalities, whether individually or in a coalition with others, leveraging economies of scale to negotiate favorable electric supply rates for their residents, under authority of Section 1-92 of the Act), and eligible retail customer load dwindled—with the annual available renewable resources budget declining correspondingly.

As part of its 2009 Annual Procurement Plan, the Agency proposed, and the Commission approved, a procurement for "bundled" (energy and REC) long-term contracts from renewable energy suppliers (known as the Long-Term Power Purchase Agreements, or "LTPPAs"). The LTPPA contracts were executed through a 2010 procurement event, with winning suppliers receiving 20 year bundled contracts to help meet future years' RPS targets. While this procurement helped facilitate significant new renewable energy development in Illinois (especially in the form of wind projects), it also provided a floor of annual payment obligations under the renewable resources budget for future years.

As the annual renewable resources budget declined due to customer switching, not only was funding unavailable to conduct additional renewable energy resource procurements, funding was no longer available to meet the full commitments of the LTPPAs described above—resulting in two years in which ComEd's LTPPAs were curtailed, or payment not made through the renewable resources budget for the full expected output. And while some load has switched back to default supply service in recent years, future budget uncertainty made entering into any additional long-term agreements unworkable (especially if such contracts were to be junior in priority to the existing 2010 LTPPAs). Because the Agency could not have visibility into budgets available in future years, outside of targeted distributed generation ("DG") procurements (which were statutorily required to be at least 5 year contracts), the Agency's annual procurement plans after the 2010 LTPPAs proposed only the procurement of one-year contracts to meet each upcoming delivery year's renewable energy resource obligations. As obtaining financing for developing new facilities generally required revenue certainty over a long period, this short-term focus left the prior RPS as an ineffective (or "broken") tool for facilitating the development of new renewable energy generation.

2.1.2. Original RPS—Hourly Pricing Customers

For hourly pricing customers, Section 1-75(c)(5) of the Act required that the applicable electric utility apply "the lesser of the maximum alternative compliance payment rate or the most recent estimated alternative compliance payment rate for its service territory for the corresponding compliance period" to hourly pricing customers. Those funds were held by the electric utility—and thus not subject to the transfer, sweep, and appropriation risks facing special state funds—and subject to the Agency's annual procurement planning process.

In recent years, because contracts with distributed generation systems required contracts of at least 5 years, the IPA used these hourly Alternative Compliance Payments ("ACPs") to serve as the funding source for DG procurements, including its most recent DG procurements approved in the IPA's 2017 Annual Procurement Plan.

As discussed more fully in Chapter 3, even accounting for payments still to be made under those DG procurements, some balance of prior-collected hourly ACPs remains for renewable energy resource

procurement under programs and procurements developed under P.A. 99-0906's revisions to Section 1-75(c)(1) of the IPA Act.[8]

2.1.3. Original RPS—ARES Compliance

Lastly, adopted in 2009, the ARES RPS compliance mechanism was more complex. Under Section 16-115D of the Public Utilities Act, each ARES carried a percentage-based renewable portfolio standard requirement similar to the Section 1-75(c) requirement as a percentage of its sales, but could satisfy its obligation by making alternative compliance payments at a rate reflecting that rate paid by eligible retail customers for no less than 50% of its obligation. For the remaining 50% of its obligation, the ARES could either pay additional alternative compliance payments and/or self-procure RECs (with a requirement that any RECs procured for compliance be produced by facilities within the regional transmission territories of PJM Interconnection, L.L.C. ("PJM") and Midcontinent Independent System Operator, Inc. ("MISO"), a relatively broad geographic footprint).

With ARES competing with one another for customers (and, for residential and small commercial customers, also competing against default supply service), this paradigm created an incentive for an ARES to comply at the lowest cost possible.[9] Thus, alternative compliance payments were generally made for the minimum 50% amount (as the rate applicable to those ACPs reflected more expensive procurements made by the Agency to serve other ends, such as through the 2010 LTPPAs), and the self-procurement obligation was not structured to lead to the development of new renewable energy generation.

Alternative compliance payments were deposited into the IPA-administered Renewable Energy Resources Fund. Leveraging this fund for procurements carried significant challenges. As the IPA explained in its Supplemental Photovoltaic Procurement Plan (released in 2014 and approved in 2015):[10]

> *The procurement of renewable energy resources using the RERF is subject to a set of unique constraints. First, unlike with the utility renewable resources budgets, the RERF may only be used to procure renewable energy credits. While the term "renewable energy resources" is defined in the Illinois Power Agency Act as RECs or both renewable energy and associated RECs,[11] the Public Utilities Act makes clear that "alternative compliance payments . . . shall be deposited in the Illinois Power Agency Renewable Energy Resources Fund and used to procure renewable energy credits."[12]*
>
> *Second, Section 1-56(c) of the IPA Act calls on the IPA to use the RERF to "procure renewable energy resources at least once each year in conjunction with a procurement event for electric utilities required to comply with Section 1-75 of the Act."[13] Given the IPA's strategy of advance purchases to hedge load requirements and the unexpectedly*

[8] While any remaining ACP funds (including hourly ACPs and ACPs paid to utilities by ARES) are considered part of the available RPS budget for planning purposes, as funds are already collected, these ACP funds do not count against Section 1-75(c)(1)(E)'s rate impact cap.

[9] To the extent that a customer sought a more environmentally friendly product, the ARES could always offer a "green" product including 100% of megawatt-hours matched with renewable energy credits, disconnected from any RPS compliance obligation.

[10] The characterizations of state law in this excerpt refer to the requirements of the Illinois Power Agency Act prior to Public Act 99-0906.

[11] 20 ILCS 3855/1-10.

[12] 220 ILCS 5/16-115D(d)(4).

[13] 20 ILCS 3855/1-56(c).

> *high levels of migration to alternative retail electric suppliers, corresponding energy procurement events for electric utilities had not occurred since 2012.*[14] *This has left the Agency without a procurement event "in conjunction with" which it could procure RECs using the RERF.*
>
> *Third, Section 1-56(d) of the IPA Act requires that "the price paid to procure renewable energy credits" using the RERF "shall not exceed the winning bid prices paid for like resources procured for electric utilities required to comply with Section 1-75 of this Act."*[15] *The lack of a conjoining procurement event has also left the Agency without a statutorily envisioned price ceiling for "like resources," further constraining procurement using the RERF.*
>
> *Fourth, the IPA Act clearly articulates a preference for longer-term contracts using the RERF, presumably to provide a stable stream of revenue necessary to incent the development of new resources. Section 1-56(c) of the IPA Act calls for the Agency to, "whenever possible, enter into long-term contracts on an annual basis for a portion of the incremental requirement for the given procurement year."*[16] *Similarly, Section 1-56(b) of the Act requires that any contracts for resources from distributed generation ("DG") must run a minimum of 5 years.*[17] *But due to unsettled and dynamic load migration between utility and alternative supplier service, the Agency must approach long-term contracting with prudence and care, as the RERF's future balance is subject to the whims of future customer switching.*[18]

In addition to the above risks, as a special state fund, the RERF could always be—and indeed was—subject to the risks of borrowing and transfers. In 2010, $6.7 million was transferred out of the RERF, although ultimately repaid back into it. In 2015, $98 million was permanently transferred from the RERF to the state's General Revenue Fund ("GRF") to make up for insufficient Fiscal Year 2015 general revenues. And in August 2017, $150 million was temporarily transferred from the RERF to the GRF (after $12 million was permanently transferred from the RERF to the state's Public Utilities Fund in June 2017), leaving the RERF's balance temporarily below the level needed to cover existing contractual obligations ($37.5 million was transferred back into the RERF from the GRF in April 2018).[19] Given these risks, and given recent periods in which the state failed to enact a budget (and thus the IPA lacked appropriation authority to make payments under contracts regardless of actual funds available), the State of Illinois was an unattractive counterparty for REC delivery contracts.

With the majority of Illinois electric load being served by ARES, this stood as no small problem—while the RPS covered the vast majority of electricity delivered in the state, very little new renewable generation was able to be developed through it. Significant amounts were being paid into the RERF

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[14] After not having procured energy in 2013, the Agency did conduct energy procurements in April 2014 and September 2014.

[15] 20 ILCS 3855/1-56(d).

[16] 20 ILCS 3855/1-56(c).

[17] 20 ILCS 3855/1-56(b).

[18] For further discussion of the challenges associated with entering into long-term contracts using funding streams subject to load migration changes, see filings made in Commission dockets approving the IPA's 2013 and 2014 annual procurement plans (Docket Nos. 12-0544 and 13-0546).

[19] The transfer of $150 million was pursuant to Section 5h.5 of the State Finance Act (30 ILCS 105/5h.5) which authorizes transfers from special funds to the General Revenue Fund for liquidity purposes. As recently modified by Public Act 101-0010, that Section also contains a provision that funds will be repaid within "48 months after the date on which they were borrowed," and a provision to transfer funds back to special funds as needed to "satisfy outstanding expenditure obligations on a timely basis."

each year to support renewable energy development, yet the money was unable to be effectively leveraged for that purpose. While ARES were procuring millions of RECs in aggregate each year, the incentive structure facing those suppliers made it highly unlikely that those RECs would be sourced from anything other than the lowest-priced seller: generally, facilities already built and financed, and potentially from projects in vertically integrated states with costs already being fully recovered through rates. Hence, parties seeking changes to this system often characterized it as a "broken RPS,"[20] and one that would require a comprehensive legislative overhaul to be properly fixed.

2.2. Public Act 99-0906

The Agency's obligation to develop a Long-Term Renewable Resources Procurement Plan stems from requirements included in Public Act 99-0906, known colloquially as the "Future Energy Jobs Act" and referred to herein as P.A. 99-0906. P.A. 99-0906, was passed by both the Illinois House and Senate during the last days of the 99th General Assembly on December 1, 2016, and was signed into law on December 7, 2016 with an effective date of June 1, 2017.

In addition to the requirement that the Agency develop its Long-Term Renewable Resources Procurement Plan and implement the programs and procurement discussed herein, P.A. 99-0906 also contained other significant reforms to Illinois energy law. Among those reforms included the establishment of a zero emission standard requiring the Agency to develop a Zero Emission Standard Procurement Plan for the procurement of zero emission credits from zero emission (i.e., nuclear) generating facilities;[21] revisions to the state's energy efficiency portfolio standard found in Article VIII of the Public Utilities Act (220 ILCS 5) including the adoption of cumulative savings targets for energy efficiency programs and measures, and the elimination of the statutory pathway by which incremental energy efficiency programs were included in the IPA's annual procurement plans;[22] additional financial assistance for low-income ratepayers;[23] bill crediting for the energy production associated with subscriptions to community renewable generation;[24] and a smart inverter rebate for behind-the-meter generating facilities.[25]

More pertinently for purposes of this Plan, P.A. 99-0906 constituted a comprehensive overhaul of the state's renewable energy portfolio standard, elements of which can be found in Sections 1-56 and 1-75(c) of the IPA Act and Section 16-115D of the PUA. Under the prior Illinois RPS, compliance and planning depended on how a customer's supply requirements were met, with three separate compliance mechanisms for by default utility supply service, hourly-pricing customers, and load served by Alternative Retail Electric Suppliers. As discussed further below, changes to the Illinois RPS through P.A. 99-0906 have transitioned the state's RPS to a streamlined, centralized planning

[20] One notable success story from the RERF was the Supplemental Photovoltaic Procurement process, which resulted in the development of roughly 30 MW of new distributed generation photovoltaics in Illinois through five-year REC contracts using the RERF. But even this process required legislative changes to be effectuated, with the Agency's authority to develop its Supplemental Photovoltaic Procurement Plan coming from Public Act 98-0672 (signed into law in 2014), which created new Section 1-56(i) of the IPA Act.

[21] The Agency's Zero Emission Standard Procurement Plan, developed pursuant to new Section 1-75(d-5) of the Act, was filed with the Commission on July 31, 2017 and was approved by the Commission on September 11, 2017. See ICC Docket No. 17-0333.

[22] See 220 ILCS 5/16-111.5B.

[23] See 220 ILCS 5/8-103B(c) (requiring ComEd and Ameren Illinois to allocate $25 million and $8.5 million, respectively, annually for low-income energy efficiency programs); 305 ILCS 20/18(c)(5), (5.5), (7) (authorizing Percentage of Income Payment Plan ("PIPP") qualified customers to receive credits under a utility's Arrearage Reduction Program, and creating a new Supplemental Arrearage Reduction Program for utility customers who cannot join the PIPP due to timing or funding constraints); 220 ILCS 5/16-108.10 (creating new $10 million annual funding stream over five years for low-income assistance programs for ComEd customers).

[24] See 220 ILCS 5/16-107.5(*l*).

[25] See 220 ILCS 5/16-107.6.

and procurement process, with both RPS targets and available budgets determined on the basis of an electric utility's load for all retail customers[26] with funding collected through a delivery services charge. The state's approach to meeting its RPS targets is now addressed through the initial development and continued refinement of this Long-Term Renewable Resources Procurement Plan, with the Plan proposing programs and procurements necessary to meet the new requirements of Illinois law and satisfying the law's new emphasis on both using the RPS as a tool to facilitate the development of new generating facilities and expanding access to the benefits of renewable energy across a broader cross-section of the state's economy.

2.2.1. Legislative Findings

This new emphasis was reflected in the legislative findings associated with Public Act 99-0906. Specifically, in enacting P.A. 99-0906, the General Assembly found that "[t]o ensure that the State and its citizens, including low-income citizens, are equipped to enjoy the opportunities and benefits of the smart grid and evolving clean energy marketplace," P.A. 99-0906 should serve to "maximize the impact" of the state's RPS.[27] This includes direction that the State should "encourage . . . the adoption and deployment of cost-effective distributed energy resource technologies and devices, such as photovoltaics, which can encourage private investment in renewable energy resources, stimulate economic growth, enhance the continued diversification of Illinois' energy resource mix, and protect the Illinois environment; investment in renewable energy resources, including, but not limited to, photovoltaic distributed generation, which should benefit all citizens of the State, including low-income households."[28]

These themes are also found in the legislative findings and declarations of the IPA Act enacted through P.A. 99-0906. The IPA Act now finds and declares that" [d]eveloping new renewable energy resources in Illinois, including brownfield solar projects and community solar projects, will help to diversify Illinois electricity supply, avoid and reduce pollution, reduce peak demand, and enhance public health and well-being of Illinois residents."[29] Other findings also reinforce the value of community solar in expanding access to renewable energy,[30] and the value of developing brownfield site solar projects to "help return blighted or contaminated land to productive use while enhancing public health and the well-being of Illinois residents."[31]

This approach to the state's RPS was a meaningful shift in the logic governing the state's renewable energy requirements: prior to 2017, the state's approach to its RPS could have been understood as governed by the logic that statutory compliance should be achieved at "the lowest total cost over time, taking into account any benefits of price stability,"[32] as this criteria governed the Agency's

[26] For MidAmerican, the IPA understands that Section 1-75(c)'s renewable energy procurement targets generally relates to the supply procured for MidAmerican's jurisdictional eligible retail customers and not all retail sales in its service territory. Given recent changes to MidAmerican's eligible retail customer load forecasting methodology and the need to protect against curtailments and annual fluctuations, the IPA is proposing a fixed percentage approach to determining both these targets and to resultant budget availability as discussed further in Chapter 3.

[27] P.A. 99-0906, § 1(a).

[28] P.A. 99-0906, § 1(a)(1). In the legislative findings of P.A. 99-0906, the General Assembly also specifically found that "low-income customers should be included within the State's efforts to expand the use of distributed generation technologies and devices." P.A. 99-0906, § 1(b).

[29] 20 ILCS 3855/1-5(6).

[30] 20 ILCS 3855/1-5(7).

[31] 20 ILCS 3855/1-5(8).

[32] See 220 ILCS 5/16-111.5(d)(4).

annual procurement plan, in which renewable energy procurements were proposed. Through changes effected by P.A. 99-0906, state law now seeks outcomes of specific types—more equitable and diverse access to the benefits of renewable energy, and an emphasis on facilitating the development of new generation and maximizing its environmental benefits—in achieving compliance with the technical requirements of the law.

Guidance found in the RPS law itself also reflects that approach. Specifically, Section 1-75(c)(1)(I) of the IPA Act requires that the IPA "shall design its long-term renewable energy procurement plan to maximize the State's interest in the health, safety, and welfare of its residents, including but not limited to minimizing sulfur dioxide, nitrogen oxide, particulate matter and other pollution that adversely affects public health in this State, increasing fuel and resource diversity in this State, enhancing the reliability and resiliency of the electricity distribution system in this State, meeting goals to limit carbon dioxide emissions under federal or State law, and contributing to a cleaner and healthier environment for the citizens of this State." The Agency believes both its original and this revised Long-Term Renewable Resources Procurement Plan reflect these aspirations.

2.2.2. Changes to the RPS

Public Act 99-0906 also ushered in several changes to the RPS, including the introduction of new concepts, terms, and prescriptive requirements. As was done in the Initial Plan, several of these concepts are discussed below, in the subsections later in this chapter, and in the Chapters that follow.

2.2.3. New Concepts and Terms

First, as discussed further below, P.A. 99-0906 demonstrated a shift in compliance focus from compliance through the procurement of "renewable energy resources"—which may be either 1) a renewable energy credit associated with a megawatt-hour ("MWh") of generation, <u>or</u> 2) that REC <u>plus</u> the associated generation—to compliance through the purchase and retirement of "renewable energy credits."[33] This makes intuitive sense; the purchase of energy is not addressed through this planning process, and the Agency's planning for any energy purchases can only be for utility default supply customers ("eligible retail customers") through the development of a separate procurement plan (which focuses on a shorter timeframe than many of the REC contracts envisioned in the revised RPS).

Second, P.A. 99-0906 introduced the concept of a "community renewable generation project" to Illinois law. As defined by the IPA Act,[34] this is an electric generating facility that

> (1) is powered by wind, solar thermal energy, photovoltaic cells or panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams;
>
> (2) is interconnected at the distribution system level of an electric utility as defined in this Section, a municipal utility as defined in this Section that owns or operates electric distribution facilities, a public utility as defined in Section 3-105 of the Public Utilities Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act;

[33] See, e.g., 20 ILCS 3855/1-75(c)(1)(B), (C). The law continues to recognize that "renewable energy resources" may be used to satisfy the RPS, but focuses this Plan only on the procurement of "renewable energy credits" (which, standing alone, also may constitute "renewable energy resources").

[34] See 20 ILCS 3855/1-10.

(3) credits the value of electricity generated by the facility to the subscribers of the facility; and

(4) is limited in nameplate capacity[35] to less than or equal to 2,000 kilowatts.

A subscriber's subscription to such a facility is an "interest" in that facility, "expressed in kilowatts" and sized primarily to offset part or all of the subscriber's electricity usage, and may not constitute more than 40% of the facility's nameplate capacity.[36] Photovoltaic powered community renewable generating projects are frequently described herein (as well as in Sections 1-10 and 1-56(b) of the IPA Act) as "community solar" projects, and feature distinct procurement targets in the Illinois RPS.

Third, P.A. 99-0906 requires the development of an "adjustable block program" ("ABP"). Used to facilitate the development of new community solar and distributed photovoltaic generation, the Adjustable Block Program is required to feature a "transparent schedule of prices and quantities" for RECs "to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time."[37] This represented a significant shift in the state's approach to procuring renewable energy; prior to the ABP (and to the Illinois Solar for All Program), past efforts to procure renewable energy resources focused on competitive sealed bidding, pay-as-bid procurement events. Most bidder and supplier information, including resulting contract prices and quantities for winning bidders, was kept confidential. While these competitive procurement elements continue to be utilized for other activities under the Illinois RPS (including "forward procurements"), other compliance pathways now feature open application to a program featuring price and quantity transparency.

Fourth, both the Illinois Solar for All Program and the Adjustable Block Program require "prepayment" (or partial prepayment) for a stream of RECs to be delivered over the course of a 15-year contract. This likewise constituted a departure from prior activities under the Illinois RPS, all of which featured payment for RECs only upon delivery and invoice.

This, of course, is not a comprehensive list; many other new terms and concepts were also introduced through P.A. 99-0906. This non-exhaustive list is intended only to provide context for the discussions that follow.

2.2.4. Long-Term Renewable Resources Procurement Plan

As referenced above, P.A. 99-0906 required the IPA to develop a Long-Term Renewable Resources Procurement Plan. That original Long-Term Renewable Resources Procurement Plan or "Initial Plan" was filed with the Illinois Commerce Commission on December 4, 2017, and approved by the Commission on April 3, 2018 through Docket No. 17-0838.

This was a departure from past practice under the Illinois RPS; previously, Illinois law required that renewable energy resource procurements used to meet the requirements of Section 1-75(c) of the IPA Act be proposed through the Agency's annual procurement plan developed pursuant to Section 16-111.5 of the PUA. As required under Section 16-111.5, those plans were developed, published,

[35] "Nameplate capacity" is defined in the law as the aggregate inverter nameplate capacity in kilowatts AC. 20 ILCS 3855/1-10.

[36] Id.

[37] 20 ILCS 3855/1-75(c)(1)(K).

filed with the ICC, and approved by the ICC on an annual basis (and still are, with a more limited focus) with a planning horizon of the five upcoming delivery years.

By contrast, the Long-Term Renewable Resources Procurement Plan—prepared pursuant to Section 16-111.5(b)(5) of the PUA, introduced through P.A. 99-0906—was initially prepared in 2017, was approved by the ICC in 2018, is to be revised at least every two years (with this Revised Plan constituting the first such revision), and "shall include procurement programs and competitive procurement events necessary to meet the goals"[38] set forth in Section 1-75(c) of the IPA Act—which contains annual targets out until 2030.

2.2.5. Plan Requirements

While Illinois law lacks any single list of required elements for the Plan, both Section 16-111.5(b) of the PUA and Sections 1-56(b) and 1-75(c) of the IPA Act contain discrete requirements.

2.2.5.1. Section 16-111.5(b) Requirements

Section 16-111.5(b)(5) of the PUA provides that "[t]he Agency shall prepare a long-term renewable resources procurement plan for the procurement of renewable energy credits under Sections 1-56 and 1-75 of the Illinois Power Agency Act for delivery beginning in the 2017 delivery year,"[39] with "delivery year" defined as "the consecutive 12-month period beginning June 1 of a given year and ending May 31 of the following year"[40]—i.e., the first delivery year for which the Plan was developed was 2017-2018. As a consequence, the IPA's Initial Plan as filed proposed procurements necessary to meet "2017 delivery year" goals, as well as targets for future delivery years. However, as discussed further in Chapter 5,[41] the Commission's Order in Docket No. 17-0838 directed that no procurements be held to meet Section 1-75(c)(1)(B) of the Act's 2017 delivery year renewable energy credit procurement goals,[42] and the IPA does not propose additional procurements specifically designed to meet upcoming years' Section 1-75(c)(1)(B)'s annual percentage-based goals through this Revised Plan.

The PUA also contains three discrete requirements for what the Plan must contain:

First, the Plan must "[i]dentify the procurement programs and competitive procurement events consistent with the applicable requirements of the Illinois Power Agency Act and shall be designed to achieve the goals set forth in subsection (c) of Section 1-75 of that Act."[43] While the term "competitive procurement event" is not specifically defined in the IPA Act or the PUA, the IPA understands the term "competitive procurement event" to be an element of, if not commensurate with, a "competitive procurement process" or "competitive bid process," which the PUA describes subject to the requirements of Section 16-111.5(e)-(i) where applicable (i.e., conducted in a manner consistent with the Agency's prior competitive procurements).[44] The term "program" presumably

[38] 20 ILCS 3855/1-75(c)(1)(A).

[39] 220 ILCS 5/16-111.5(b)(5).

[40] 20 ILCS 3855/1-10.

[41] See generally the discussion of "Spot Procurements."

[42] See Docket No. 17-0838, Final Order dated April 3, 2018 at 42.

[43] 220 ILCS 5/16-111.5(b)(5)(ii)(B)(aa).

[44] 220 ILCS 5/16-111.5(b)(5)(iii).

refers to the programs specifically referenced in Section 1-56(b) and Sections 1-75(c)(1)(K) and (N) of the IPA Act.

As with the Initial Plan, this Revised Plan's specific procurement programs and procurement events designed to meet the goals of Section 1-75(c) can be found in Chapters 5 through 8.

Second, the Plan must "[i]nclude a schedule for procurements for renewable energy credits from utility-scale wind projects, utility-scale solar projects, and brownfield site photovoltaic projects consistent with subparagraph (G) of paragraph (1) of subsection (c) of Section 1-75 of the Illinois Power Agency Act."[45] This subparagraph concerns the quantitative procurement targets for RECs from new solar and wind facilities found in Section 1-75(c), and the schedule for those procurements can be found in Chapter 5.

Third, the Plan must "[i]dentify the process whereby the Agency will submit to the Commission for review and approval the proposed contracts to implement the programs required by such plan."[46] Under the prior RPS, pursuant to Section 16-111.5(e) of the PUA, the IPA's procurement administrator developed standard contract forms in consultation with other parties. A Commission decision was required only if parties could not agree on the contract form, and the standard form contract was required to be executed by winning bidders after a competitive procurement result (the results of which were subject to Commission approval). Under this revised model for use in implementing programs, both REC delivery contracts and the IPA's program administrator contracts[47] must first be approved by the Commission prior to execution.[48] The IPA's process for submitting contracts to the Commission for review and approval can be found in Chapters 6 and 8 of the Plan; it does not meaningfully differ from that which was proposed in the Initial Plan. As this requirement concerns only "the programs required by such plan," this requirement does not impact the contract development process for the competitive procurements described in Chapter 5, although Commission approval is also required prior to the execution of contracts for competitive procurements under the process described in Section 16-111.5(e)-(i).

2.2.5.2. Section 1-75(c) Requirements

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

First, the Plan must "include the goals for procurement of renewable energy credits to meet at least the following overall percentages: 13% by the 2017 delivery year; increasing by at least 1.5% each delivery year thereafter to at least 25% by the 2025 delivery year; and continuing at no less than 25% for each delivery year thereafter."[49] These percentages are described as a portion of eligible

[45] 220 ILCS 5/16-111.5(b)(5)(ii)(B)(bb).

[46] 220 ILCS 5/16-111.5(b)(5)(ii)(B)(cc).

[47] For the Agency's third-party program administrators, Section 16-111.5(b)(5)(iii) provides that "[t]hird parties shall not begin implementing any programs or receive any payment under this Section until the Commission has approved the contract or contracts under the process authorized by the Commission in item (D) of subparagraph (ii) of paragraph (5) of this subsection (b) and the third party and the Agency or utility, as applicable, have executed the contract."

[48] In its Order approving the Plan, the Commission held that under Section 16-111.5(b)(5)(iii)'s requirements, "it must review the individual [REC delivery] contracts between the utilities and Approved Vendors and "not just a master contract, although "a master contract that is updated by a confirmation agreement providing the batch details regarding seller, buyer, price, term, project location, etc. is a reasonable approach." Docket No. 17-0838, Final Order dated April 3, 2018 at 116.

[49] 20 ILCS 3855/1-75(c)(1)(B).

retail sales, which now includes sales by alternative retail electric suppliers. The law also contains a requirement that "in the event of a conflict between these goals and the new wind and new photovoltaic procurement requirements," the long-term plan shall prioritize the new wind and photovoltaic requirements.[50]

In Docket No. 17-0838, the Commission's Order approving the Initial Plan determined that any procurements originally proposed to meet annual percentage-based renewable energy credit procurement goals should be cancelled to avoid any potential conflicts with meeting "statutory long-term new build requirements."[51] As budget constraints have become a more acute concern given the massive progress in new renewable energy development spurred on by programs and procurements conducted under the Initial Plan (and corresponding budget impacts from REC delivery contracts), this Revised Plan has been designed in a manner that likewise reduces the likelihood of any such conflict occurring. Further discussion can be found in Chapter 3.

Second, the Plan "shall include the procurement of renewable energy credits in amounts equal to at least" the new wind and new photovoltaics targets found in Section 1-75(c)(1)(C) of the IPA Act. These targets are 2 million RECs from "new wind projects" by the 2020 delivery year, 3 million by 2025, and 4 million by 2030. "New photovoltaic projects" feature the same overall procurement targets, while also containing requirements that at least 50% of new PV RECs be procured through the Adjustable Block Program (and thus from distributed generation or community solar projects), at least 40% from utility-scale (above 2 MW) photovoltaic projects, and at least 2% from brownfield site photovoltaic projects that are not community renewable generation projects. Further discussion of these quantitative new build targets, including a discussion of progress made toward meeting these targets to date, can be found in Chapters 3 and 5.

Third, the law requires that, to the extent that annual RPS spending budgets[52] for each utility become a binding constraint, the Plan "shall prioritize compliance with the requirements of this subsection (c) regarding renewable energy credits" in the manner discussed in Section 1-75(c)(1)(F), which features the following priority ranking:

> (i) renewable energy credits under existing contractual obligations;
>
> (i-5) funding for the Illinois Solar for All Program as described in Section 1-75(c)(1)(O);[53]
>
> (ii) renewable energy credits necessary to comply with the new wind and new photovoltaic procurement requirements in Section 1-75(c)(1)(C); and
>
> (iii) renewable energy credits necessary to meet the remaining requirements of Section 1-75(c) (including the percentage-based delivery year goals in Section 1-75(c)(1)(B)).[54]

The IPA is committed to ensuring that this priority ranking is reflected in this Revised Plan and has assembled its Plan cognizant of and sensitive to this prioritization.

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[50] Id.

[51] Docket No. 17-0838, Final Order dated April 3, 2018 at 42.

[52] The statutory cost cap and resulting budgets for RPS spending, directed in Section 1-75(c)(1)(E) of the Act, are discussed in more detail in Section 2.4.4 and Chapter 3 of this Revised Plan.

[53] This requirement is discussed further in the subsection below.

[54] 20 ILCS 3855/1-75(c)(1)(F).

Fourth, the law requires that renewable energy credits procured under the Initial Forward Procurements shall be included in the Agency's long-term plan and shall apply to Section 1-75(c)'s goals.[55] The results of the Initial Forward Procurements, conducted in three events from August 2017 through April 2018, are reflected in the Agency's target procurement quantities found later in Chapter 3 of this Revised Plan.

Fifth, the Plan must set forth the process by which adjustments may be made when the cumulative amount of renewable energy credits projected to be delivered from all new wind projects in a given delivery year exceeds the cumulative amount of renewable energy credits projected to be delivered from all new photovoltaic projects in that delivery year by 200,000 or more renewable energy credits.[56] This provision is presumably intended to provide some balancing between wind and solar quantities under contract.

In its Order approving the Initial Plan, the Commission clarified that this balancing requirement becomes effective as of June 1, 2021, the original statutory deadline for deliveries from projects having initial forward procurement contracts (and not earlier, as argued by some parties in Docket No. 17-0838).[57] Since that time, Public Act 101-0113—signed into law on July 19, 2019—modified Sections 1-75(c)(1)(G)(i)-(ii) of the IPA Act such that these subparagraphs now provide that should an initial forward procurement project have "delays in the establishment of an operating interconnection with the applicable transmission or distribution system as a result of the actions or inactions of the transmission or distribution provider, or other causes for force majeure as outlined in the procurement contract," this statutory deadline may be extended to June 1, 2022. From the Act, it is unclear whether this would also then extend the effective date of the wind/solar balancing requirement outlined in Section 1-75(c)(1)(G)(iv) of the Act; the IPA proposes that it would, as the logic informing this determination would support aligning the effective date of the balancing requirement with the new required date for first deliveries under initial forward procurement contracts.[58]

Sixth, the Plan must describe in detail how each "public interest factor" enumerated in Section 1-75(c)(1)(I) "shall be considered and weighted for facilities located in states adjacent to Illinois" in determining whether those facilities' RECs may be considered "eligible" to satisfy the Illinois RPS. This limitation of eligible RECs to Illinois and adjacent states constitutes a departure from pre-P.A. 99-0906 practice under the RPS, under which competitive procurements first looked to RECs from Illinois and adjoining states and then to "elsewhere" in attempting to satisfy targets, and may serve to significantly limit the pool of renewable energy credits eligible to meet the RPS. The Agency's approach for applying these criteria can be found in Chapter 4; it does not differ materially from that which was proposed in its Initial Plan and approved by the Commission in Docket No. 17-0838.

Seventh, the Plan shall provide that renewable energy credits previously allocated from generating systems previously understood not to be rate-based for a state-regulated entity, but which end up being so rate-based, shall be made up through a procurement conducted in the Agency's next procurement event. This connects back to a statutory requirement that "renewable energy credits

[55] 20 ILCS 3855/1-75(c)(1)(G)(i).

[56] 20 ILCS 3855/1-75(c)(1)(G)(iv).

[57] See Docket No. 17-0838, Final Order dated April 3, 2018 at 47-48.

[58] As no party contested this issue in Docket No. 19-0995, the IPA understands that the wind/solar balancing requirement found in Section 1-75(c)(1)(G)(iv) of the IPA Act becomes effective as of June 1, 2022.

shall not be eligible to be counted toward" RPS targets "if they are sourced from a generating unit whose costs were being recovered through rates regulated by this State or any other state or states on or after January 1, 2017."[59] It appears that this could be accomplished through an adjustment in procurement volumes for subsequent procurement events, and the IPA commits through this Revised Plan to make any such adjustments. To date, the IPA is unaware of any instances for which this provision (which is reflected in all program and procurement contracts) has needed to be enforced.

Eighth, the Plan "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."[60] A description of the Agency's Adjustable Block Program, which has been open for project applications since January 30, 2019, and any proposed adjustments thereto, can be found in Chapter 6.

Ninth, and last among the requirements found in Section 1-75(c), the Plan "shall include a community renewable generation program," with a requirement that the Agency "establish the terms, conditions, and program requirements for community renewable generation projects with a goal to expand renewable energy generating facility access to a broader group of energy consumers, to ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties" and that any subscriptions to such projects "be portable and transferable."[61]

Because community solar is a subset of "community renewable generation projects"—which can include generating technologies such as wind, solar thermal, biodiesel, biomass, tree waste, and hydropower—*only* establishing an Adjustable Block Program featuring a community solar component would not satisfy this statutory requirement.[62] For a distinct, *non-PV* community renewable generation program, the IPA's Initial Plan set out a competitive procurement event with bids selected on the basis of price. This procurement event was held in late 2019 and no bids were selected.[63]

2.2.5.3. Illinois Solar for All Requirements

As discussed further below, in recognition of a finding that "the State should encourage . . . investment in renewable energy resources, including, but not limited to, photovoltaic distributed generation, which should benefit all citizens of the State, including low-income households," revisions to Section 1-56 of the IPA Act requires the creation of "the Illinois Solar for All Program, which shall include incentives for low-income distributed generation and community solar projects [. . .] to bring photovoltaics to low-income communities in this State."[64] In so doing, the Agency must "include a

[59] 20 ILCS 3855/1-75(c)(1)(J).

[60] 20 ILCS 3855/1-75(c)(1)(K).

[61] 20 ILCS 3855/1-75(c)(1)(N).

[62] More specifically, Section 1-75(c)(1)(N) provides that "[t]he Agency shall purchase renewable energy credits from subscribed shares of photovoltaic community renewable generation projects **through the Adjustable Block program** described in subparagraph (K) of this paragraph (1) or through the Illinois Solar for All Program described in Section 1-56 of this Act" (emphasis added). (As the IPA cannot be the counterparty to REC delivery contracts under Section 1-75(c), the Agency understands "purchase" effectively to mean "procure" in this context.)

[63] More information about the community renewable generation procurement can be found here: https://www.ipa-energyrfp.com/2019-community-renewable-generation-program-forward-procurement-aic-and-comed.

[64] 20 ILCS 3855/1-56(b)(2).

description of its proposed approach to the design, administration, implementation and evaluation of the Illinois Solar for All Program" in the Plan and "propose the Illinois Solar for All Program terms, conditions, and requirements,"[65] including REC prices (which may be through a formula).

The Illinois Solar for All Program began accepting project applications on May 15, 2019. A more comprehensive description of the Agency's Illinois Solar for All Program, including any revisions made thereto, can be found in Chapter 8.

In addition to describing what the Illinois Solar for All Program is and how it will be administered, the law also requires that should the IPA hire a third-party program administrator (or administrators) to assist with the administration of the Illinois Solar for All Program, the Plan shall identify at what interval it must report to the Agency and the Commission (provided that interval is at least quarterly). After an RFQ/RFP process, the IPA retained Elevate Energy to administer the Illinois Solar for All Program in September 2018. The Plan shall also provide for an independent evaluation of the program, and must contain a definition of the term "environmental justice" community. After a similar RFQ/RFP process, the IPA retained APPRISE, Inc. to serve as the Illinois Solar for All Program's independent evaluator in August 2019. These issues are further addressed in Chapter 8.

The Plan must also ensure that the Illinois Solar for All program is funded. Specifically, Section 1-75(c)(1)(O) of the Act provides that the Plan "shall allocate 5% of the funds available under the plan for the applicable delivery year, or $10,000,000 per delivery year, whichever is greater, to fund the programs." The IPA understands that the intention of this language in Section 1-75(c)(1)(O) is that 5% of utility-collected funds, or $10 million, whichever is greater, would be made available annually for Illinois Solar for All—in addition to whatever may be spent in a given year through the RERF.

Notwithstanding the language discussed in the paragraph above, the law also requires that for each of three particular delivery years—"the delivery years beginning June 1, 2017, June 1, 2021, and June 1, 2025"—the Plan "shall allocate 10% of the funds available under the plan for the applicable delivery year, or $20,000,000 per delivery year, whichever is greater," and $10,000,000 of such funds shall be used by ComEd to implement its Commission-approved workforce development plan filed under Section 16-108.12 of the PUA.[66]

If additional funding for Illinois Solar for All programs is available under Section 16-108(k)[67] of the PUA, then the Plan "shall provide for the Agency to procure contracts in an amount that does not exceed the funding," with the applicable utility or utilities as the counterparty to such contracts.[68] The IPA filed its Illinois Solar for All Supplemental Funding Plan for approval with the Illinois Commerce Commission on August 30, 2018. That Plan concluded as follows regarding whether to use any funding shortfall to provide additional funding for the Illinois Solar for All Program:

> Taking into account the status of the Illinois Solar for All Program, the statutory priority attached to ILSFA's annual RRB allocation, the legally-required availability of RERF funds

[65] 20 ILCS 3855/1-56(b)(4).

[66] 20 ILCS 3855/1-75(c)(1)(O). See also Docket No. 17-0332, in which ComEd's Workforce Development Implementation Plan was approved.

[67] As discussed in Sections 2.6.1 and 8.4.3, up to one-half of excess collections by utilities for RPS purposes in each of the 2017-2018, 2018-2019, and 2019-2020 delivery years may be used for the Solar for All Program in the event of a "funding shortfall." 220 ILCS 5/16-108(k).

[68] 220 ILCS 5/16-108(k).

> previously transferred to general funds under Section 5h.5 of the State Finance Act, Section 1-56(h)'s requirement that the RERF "shall not be subject to sweeps, administrative charges, or chargebacks," and thus the expected availability of funding sufficient to satisfy the Solar for All annual budgets included in the Long-Term Plan, the IPA does not propose supplemental funding for Illinois Solar for All using the Section 16-108(k) supplemental funding mechanism.[69]

The Illinois Commerce Commission affirmed this determination in Docket No. 18-1457. The Supplemental Funding Plan did note, however, that the Agency would seek to work with stakeholders and potentially reopen that proceeding should a change in circumstances (namely, permanent depletion of the RERF's balance) necessitate funding the Illinois Solar for All Program using the 16-108(k) funding shortfall mechanism.[70]

2.2.6. Items Not Included in Long-Term Renewable Resource Procurement Plan

While the Plan sets forth the IPA's proposed approach to meeting the state's renewable energy resource procurement targets, it is not the sole mechanism for facilitating the development of renewable energy in Illinois or providing value for the environmental attributes of electricity generation. Thus, many items that may be of interest to readers of this Revised Plan are not directly addressed in this Plan, and below is a non-exhaustive list of those items <u>not</u> addressed in the Plan:

- Contracts or tariffs for the sale of energy from renewable energy generating facilities, whether through bilateral contracts, wholesale market sales, community renewable generation bill crediting, or net metering;
- Previously effective renewable energy resource procurement obligations applicable to alternative retail electric suppliers under Section 16-115D of the PUA;
- The procurement of zero emission credits from zero emission facilities (i.e., nuclear generating facilities) under Section 1-75(d-5) of the IPA Act;
- Workforce development plans produced by a utility pursuant to Section 16-108.12 of the PUA;
- Renewable energy generating device installer certification requirements developed pursuant to Section 16-128A of the PUA;
- Renewable energy provider supplier diversity goals under Section 5-117(b) of the PUA;
- Tariff filings or modifications for the collection of funds used by utilities to pay for renewable energy credit and zero emission credit delivery contracts;
- Specific renewable energy generating projects, proposals, or sites, including any municipal, county, or non-IPA state permitting required;
- "Green" or "clean energy" retail supply products marketed and sold by alternative retail electric suppliers;
- Requirements and processes for the interconnection of new renewable energy generating facilities, including projects facilitated by IPA-administered programs and procurements.

These issues may indeed be of significant interest to the Agency, and in some cases, their presence or resolution informed decisions made in this Revised Plan. However, as they do not fall within the

[69] Final Illinois Solar for All Supplemental Funding Plan, dated November 26, 2018, at 30.

[70] See id. at 31.

scope and jurisdiction of what the IPA may propose and the Commission may approve as part of this Revised Plan, specific proposals related to the above-listed topics are not made within this document.

2.2.7. Revised Plan Development and Approval

The Initial Plan was released by the Agency as a draft on September 29, 2017, filed with the Commission for approval after public comments and revisions on December 4, 2017, and approved by the Commission on April 3, 2018 via Docket No. 17-0838.

Section 16-111.5(b)(5) of the PUA provides that the Agency "shall review, and may revise, the plan at least every 2 years" after the initial Plan. Further, "[t]o the extent practicable, the Agency shall review and propose any revisions to the long-term renewable energy resources procurement plan in conjunction with the Agency's other planning and approval processes"[71] conducted under Section 16-111.5 of the PUA. The Agency understands this to refer to the annual procurement plan development and approval process referenced in Section 16-111.5(d).[72]

The Agency develops its annual plan in July and August of each year, publishes that plan for comment by August 15, receives comments on that plan over 30 days, and then files that plan with the Commission 14 days later. The IPA took a similar approach for this revised Long-Term Plan, but with certain modifications. The draft Revised Plan was published on August 15 of this year, but per the requirements of Section 16-111.5(b)(5)(ii) of the PUA, the Agency announced[73] on September 3, 2019 a comment period of 45 days, resulting in a comment deadline of September 30, 2019.[74]

During the comment period, the Agency was also required to hold public hearings for receiving public comment on the Plan in the service territory of each affected utility. The Agency held public hearings on September 3, 2019 in Chicago (ComEd), and September 4, 2019 in Springfield (Ameren Illinois) and Moline (MidAmerican). No comments were received at these public hearings.

Written comments were received from 21 stakeholders: AES Distributed Energy, Ameren Illinois, Ameresco, Borrego Solar, Carbon Solutions Group – Updated, Citizens Utility Board, Clean Grid Alliance, ComEd, Community Energy Solar, Cypress Creek Renewables, Environmental Defense Fund, Environmental Law & Policy Center and Vote Solar, ICC Staff, Illinois Solar for All Working Group, Joint Solar Parties, Natural Resources Defense Council, Shariff Shakir, SRECTrade, Summit Ridge Energy, Sunrise Energy Ventures, and Trajectory Energy Partners.[75]

After the September 30, 2019 comment deadline, the IPA then took 21 days (again, as allowed under Section 16-111.5(b)(5)(ii)) to revise its draft Revised Plan. The Revised Plan was filed with the Commission for approval on October 21, 2019.

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[71] 220 ILCS 5/16-111.5(b)(5)(ii)(B).

[72] Section 1-75(c)(1)(A) of the Act contains a similar provision, stating that "[t]he Agency shall review, and may revise on an expedited basis, the long-term renewable resources procurement plan at least every 2 years, which shall be conducted in conjunction with the procurement plan under Section 16-111.5 of the Public Utilities Act to the extent practicable to minimize administrative expense."

[73] See https://www2.illinois.gov/sites/ipa/Documents/Draft%20Revised%20Plan%20-%20Summer%202019/Revised%20Plan%20Schedule%20Update%20(3%20September%202019).pdf.

[74] 30 days from August 15, 2019 is actually September 14, 2019, which is a Saturday; under the statute on statutes (5 ILCS 70/1.11), this 30-day deadline instead falls on September 16. 2019.

[75] Comments received by the Agency on the Draft Revised Plan may be found at: https://www2.illinois.gov/sites/ipa/Pages/2020-Draft-LTRRPP-Comments.aspx.

The Commission's approval of this Final Revised Plan took the form of a docketed proceeding pursuant to the Commission's Rules of Practice.[76] Within 14 days of the filing of the Revised Plan, parties taking issue with the plan were required to file an objection with the Commission by November 4, 2019.[77] The Commission granted Petitions to Intervene filed by Ameren Illinois Company, the Joint Solar Parties, Carbon Solutions Group, Cypress Creek Renewables, the Environmental Law & Policy Center, Vote Solar, the Natural Resources Defense Council, Commonwealth Edison Company, Summit Ridge Energy, the Illinois Chamber of Commerce, and the Citizens Utility Board; Commission Staff and the Illinois Attorney General's Office also participated in the proceeding.

Pursuant to the schedule set by the Administrative Law Judge, Responses to Objections were due on or by December 3, 2019, and Replies to Responses on or by December 17, 2019. The Administrative Law Judge issued a Proposed Order on January 15, 2020. Briefs on Exceptions were due by January 24, 2020, and Reply Briefs on Exceptions were due on January 31, 2020.

The Commission issued its Final Order approving the plan with certain modifications on February 18, 2020, within the 120-day timeline prescribed by statute.[78] The Commission found that "the Revised Long-term Renewable Resources Procurement Plan, as modified herein, will reasonably and prudently accomplish the requirements of Section 1-56 and subsection (c) of Section 1-75 of the Illinois Power Agency Act[.]"[79]

2.2.8. Plan Updates

While the Agency's long-term renewable resources procurement plan features a "long-term" focus, many elements informing future program and procurement decisions—technological progress, marketplace changes, the success or failure of work undertaken under a prior-approved approach—were unknowable at the time of the Initial Plan's publishing and are still unknowable as of the time of this first revision.

As described above, the PUA provides that the Agency "shall review, and may revise, the plan at least every 2 years" after the Initial Plan, and "shall review and propose any revisions to the long-term renewable energy resources procurement plan in conjunction with the Agency's other planning and approval processes"[80] conducted under Section 16-111.5 of the PUA—specifically, the annual procurement plan development and approval process referenced in Section 16-111.5(d). At present, and absent a statutory shift through new legislation, the Agency tentatively plans for its next revisions to its Long-Term Renewable Resources Procurement Plan to be proposed in 2021, as part of the development and approval process of the IPA's 2022 annual procurement plan, which will take effect for calendar year 2022.

The PUA also requires that "the Commission shall hold an informal hearing for the purpose of receiving comments on the prior year's procurement process and any recommendations for change"

[76] 83 Ill. Adm. Code 200, *et. seg.*

[77] 220 ILCS 5/16-111.5(b)(5)(ii)(C).

[78] Id.

[79] Docket 19-0995, Final Order dated February 18, 2020 at 109.

[80] 220 ILCS 5/16-111.5(b)(5)(ii)(B).

on or before July 1 of each year.[81] This has taken the form of written recommendations, technical or substantive, being submitted to the Commission and posted publicly on the Commission's website.[82]

2.3. The RPS and Percentage-Based Goals of the RPS

The Illinois RPS shares similarity with other state RPSs which require that a certain percentage of electricity sales be met with a climbing percentage of renewable energy or renewable energy credit procurement. For Illinois, this total is 25% by 2025: "13% by the 2017 delivery year; increasing by at least 1.5% each delivery year thereafter to at least 25% by the 2025 delivery year; and continuing at no less than 25% for each delivery year thereafter."[83]

2.3.1. Load Applicable to RPS Goals

At first blush, the Agency's 25% by 2025 goal appears to mirror the Section 1-75(c)(1) targets found in Illinois law prior to P.A. 99-0906. However, prior to P.A. 99-0906, only "eligible retail customer" load—meaning load associated with utility default supply customers, and not customers taking supply through alternative retail electric suppliers or through hourly pricing—was subject to this requirement. In recent years, only 30-50% of potentially eligible retail customer load actually received default supply service, while competitive class customers (including all medium to large commercial and industrial customers—who represent approximately half of total load) had no default supply option. Stated differently, while the RPS featured a "25% by 2025" requirement prior to P.A. 99-0906, the vast majority of retail customer load in Illinois was not covered by Section 1-75(c)(1)'s "25% by 2025" RPS goal.

Over two delivery years (beginning with the 2017 delivery year), P.A. 99-0906 transitioned those goals applicable only to "eligible retail customer" load to goals applicable to all "all load for retail customers." For the 2017 delivery year, those goals were "equal to at least 13% of each utility's load for eligible retail customers and 13% of the *applicable portion* of each utility's load for retail customers who are not eligible retail customers," with the applicable portion at 50%. For the 2018 delivery year, the percentage goal increased to 14.5% while the applicable portion increased to 75%. For the 2019 delivery year, the percentage goal increased to 16% and now applies to all retail customer load, including load associated with ARES customers.[84]

One exception exists to this load calculation transition: under Section 1-75(c)(1)(H), if an ARES owned one or more renewable generating facilities that were not wind or photovoltaic as of December 31, 2015, then that ARES may elect "to supply its retail customers with renewable energy credits from the facility or facilities" so long as those facilities continued to be owned by that ARES. This self-procurement from ARES-owned facilities by the ARES thus serves to reduce the statutory renewable energy resource obligation by the amount of RECs self-procured.[85]

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[81] 220 ILCS 5/16-111.5(b)(5)(vi). Information about the Commission's informal hearing can be found here: https://www.icc.illinois.gov/downloads/public/procurement/Public%20Notice%20of%20Informal%20Hearing%20Issued%20July%2012%202018.pdf.

[82] For example, see: https://www.icc.illinois.gov/workshops/Electricity-Procurement-Process-for-Plan-Years-Beginning-June-2019.

[83] 20 ILCS 3855/1-75(c)(1)(B).

[84] Id.

[85] For the 2019-2020 delivery year, see the following report on the RECs supplied under this provision: https://www2.illinois.gov/sites/ipa/Documents/2019ProcurementPlan/ARES-REC-Report-2019-2020-delivery-year-04-01-2019.pdf. The RPS goals described in Chapter 3 account for these RECs.

Further discussion of how these percentage-based multipliers apply to retail customer load to create actual REC procurement targets can be found in Chapter 3. As further discussed within that Chapter, of the renewable energy credits procured under Section 1-75(c), "at least 75% shall come from wind and photovoltaic projects."[86]

Notably, these requirements only apply to load served by Illinois' major electric distribution utilities: ComEd, Ameren Illinois, and that portion of MidAmerican load for which the IPA conducts procurements. The Illinois RPS goals do not apply to load served by municipal electric utilities, rural electric cooperatives, or Mt. Carmel Public Utility, and those entities do not have renewable energy procurement obligations under Illinois law.

2.3.2. Eligible Projects for the Illinois RPS

Not all renewable energy generating facilities are eligible to sell RECs into the Illinois RPS. Changes made through P.A. 99-0906 significantly narrowed the universe of facilities capable of generating RECs which qualify for the RPS, and specific criteria applicable to RECs or facilities producing those RECs are discussed further below.

2.3.2.1. Eligible Generating Technologies

The Illinois Power Agency Act's definition of "renewable energy resource" sets forth the generating technologies capable of producing RECs eligible for the Illinois RPS. As set forth in Section 1-10 of the IPA Act, the underlying energy must be generated "from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, anaerobic digestion, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams," as well as "landfill gas produced in the State." While this language largely mirrors the definition of "renewable energy resource" prior to P.A. 99-0906, that Act deleted the inclusion of "other alternative sources of environmentally preferable energy" from the former definition, thus clarifying that only those generating technologies delineated in the definition may qualify.[87]

The Act also sets forth certain generating technologies categorically incapable of producing RECs eligible for the Illinois RPS, which include "the incineration or burning of tires, garbage, general household, institutional, and commercial waste, industrial lunchroom or office waste, landscape waste other than tree waste, railroad crossties, utility poles, or construction or demolition debris, other than untreated and unadulterated waste wood."[88]

Please note that these requirements are merely threshold requirements for the Illinois RPS; specific programs, such as the Adjustable Block Program, or procurement targets may carry additional limitations.

[86] 20 ILCS 3855/1-75(c)(1)(C).

[87] The Agency understands that hydropower facilities featuring new turbines added to existing non-hydropower dams would not be eligible to participate as these facilities would constitute a newly constructed "hydropower" dam, and would thus be prohibited under Section 1-10 of the IPA Act's limitation of eligible hydropower only to "hydropower that does not involve new construction or significant expansion of hydropower dams."

[88] 20 ILCS 3855/1-10.

2.3.2.2. Eligible Projects—Locational

P.A. 99-0906 introduced new locational and public interest benefit requirements for generating facilities seeking to sell RECs into the Illinois RPS. From the introduction of the Illinois RPS in 2007 to June 1, 2011, Section 1-75(c) required the Agency to first look to renewable energy resources from Illinois, then to resources from states adjoining Illinois, and then to elsewhere. After June 1, 2011, the IPA first looked to resources from Illinois and adjoining states, and next to "elsewhere."

Through Section 1-75(c)(1)(I), a generating facility's RECs are no longer prioritized based on location; instead, the facility either qualifies for the Illinois RPS, or it does not.

Section 1-75(c)(1)(I) provides that the Plan must be designed "to maximize the State's interest in the health, safety, and welfare of its residents, including but not limited to minimizing sulfur dioxide, nitrogen oxide, particulate matter and other pollution that adversely affects public health in this State, increasing fuel and resource diversity in this State, enhancing the reliability and resiliency of the electricity distribution system in this State, meeting goals to limit carbon dioxide emissions under federal or State law, and contributing to a cleaner and healthier environment for the citizens of this State." While the statute presumes that a facility located in-state provides those benefits at a sufficient level, the Agency may also "may qualify renewable energy credits from facilities located in states adjacent to Illinois if the generator demonstrates and the Agency determines that the operation of such facility or facilities will help promote the State's interest in the health, safety, and welfare of its residents" based on this public interest criteria. As the law provides no discussion of potentially qualifying facilities located in states <u>not</u> "adjacent to Illinois," facilities located in those states cannot produce RECs for satisfying the Illinois RPS.

As with the Initial Plan, the Agency's discussion of how to apply these criteria to adjacent state facilities, as well as a listing of which states are considered "adjacent" to Illinois, can be found in Chapter 4.

2.3.2.3. Eligible Projects—Cost Recovery

Through Section 1-75(c)(1)(J), P.A. 99-0906 introduces an additional requirement on generating facilities seeking to generate RECs eligible for the Illinois RPS: "a generating unit whose costs were being recovered through rates regulated by this State or any other state or states on or after January 1, 2017" is ineligible. The statute's rationale behind this change is to "promote the competitive development of renewable energy resources in furtherance of the State's interest in the health, safety, and welfare of its residents." In application, the Agency has come to understand that this limitation does not apply to municipal utilities or rural cooperatives that effectively serve as vertically-integrated utilities (as even insofar as they can achieve full cost recovery for the development of renewable energy generating facilities through rates, their rates are in most cases still not regulated by "this state or any other state or states"[89]), but would still apply to *non-electric* utilities (e.g., water, gas, telecommunications) regulated by the Illinois Commerce Commission or by another state for which rate recovery could be sought for a photovoltaic system participating in the Illinois RPS.

The law also offers more punitive consequences if a non-regulated rate facility becomes a regulated rate facility after the execution of an Illinois RPS contract; in such a situation, the contract must be

[89] The Agency is aware that in Michigan, Kentucky, and Indiana, certain rural electric cooperatives may fall under state rate regulation, and the same true of certain municipal electric utilities in Wisconsin.

terminated and "the supplier of the credits must return 110% of all payments received under the contract"[90] (with those payments then being used for the procurement of additional RECs from new wind or photovoltaic generation in the Agency's next procurement event). Since the passage of P.A. 99-0906, contracts developed for the Agency's programs and procurements have contained provisions reflecting this penalty.

The Agency's approach to these issues is discussed in Chapter 4.

2.3.2.4. Installer Requirements

Certain facilities seeking to participate in the RPS are also subject to an installer qualification requirement. Specifically, after June 1, 2017, RECs from "new photovoltaic projects or new distributed renewable energy generation devices [. . .] must be procured from devices installed by a qualified person in compliance with the requirements of Section 16-128A of the Public Utilities Act and any rules or regulations adopted thereunder."[91]

In Docket No. 17-0268, the Illinois Commerce Commission adopted its Title 83, Part 461 administrative rules for the installation of new utility-scale photovoltaic generating projects under Section 16-128A of the PUA. In that proceeding, the Commission adopted the following definition for the term "qualified person" for new utility-scale solar installations:

> *"Qualified person" means a person who performs installations on behalf of the certificate holder and who has completed at least one of the following programs requiring lab or field work and received a certification of satisfactory completion: an apprenticeship as a journeyman electrician from a USDOL-registered or an applicable state-agency-registered electrical apprenticeship and training program; a North American Board of Certified Energy Practitioners (NABCEP) distributed generation technology certification program; an electrical training program for in-house employees established and administered by an electric utility regulated by the Commission; or an Associate in Applied Science degree from an Illinois Community College Board-approved community college program in solar generation technology.*[92]

The Part 461 rules also provide a definition of the term "install":

> *"Install" means to perform the electrical wiring and connections necessary to interconnect the new solar project with the electric utility's transmission or distribution system at the point of interconnection between the project and the utility. "Install" in this Part specifically does not mean:*
>
> - *Electrical wiring and connections to interconnect the new solar project performed by utility workers;*
> - *Electrical wiring and connections internal to the new solar project performed by the manufacturer;*

[90] 20 ILCS 3855/1-75(c)(1)(J).

[91] 20 ILCS 3855/1-75(c)(7). The "qualified person" requirement is expressly not applicable to the Illinois Solar for All Program (see 20 ILCS 3855/1-56(b)(2), final paragraph), although installers of ILSFA projects must, under state law, still have ICC certification under Part 468 as Distributed Generation Installers.

[92] 83 Ill. Adm. Code § 461.10.

- *The on-site construction and installation of a solar panel or a collector substation; or*
- *Tasks relating to construction, planning and project management performed by individuals such as an inspector, management planner, consultant, project designer, or contractor for the project or their employees.*

Definitions of these terms were initially approved by the Commission in a Second Notice Order entered on August 25, 2017, and approved with modification by the state's Joint Committee on Administrative Rules ("JCAR") on October 24, 2017 with an effective date of October 26, 2017.

Any parties seeking to develop new photovoltaic projects or DG projects in Illinois should also be aware of the Commission's Part 461 and Part 468 rules (governing distributed generation installers) and certification process more generally as well. The definition of "Qualified person"[93] may preclude the inclusion of self-installed new photovoltaic projects in the Adjustable Block Program (unless the self-installer meets the "qualified person" definition).

2.3.3. Compliance Mechanism: RECs vs. "Renewable Energy Resources"

One other change to the Illinois RPS through P.A. 99-0906 concerned an added focus on the use of RECs as the compliance mechanism for meeting Illinois renewable energy procurement targets. Prior to P.A. 99-0906, Section 1-75(c) required renewable energy procurement targets to be met through the procurement of "renewable energy resources"—either a REC, or the REC and its underlying energy. While the vast majority of the IPA's procurement activities focused only on the procurement of RECs, the 2010 long-term power purchase agreements are 20-year contracts for the delivery of a "bundled" REC and energy product.

Rather than using the term "renewable energy resources," Section 1-75(c)(1)(B) requires that the Plan "shall include the goals for procurement of <u>renewable energy credits</u>"[94] to meet the statute's targets. While the description of the ARES load transition later in that same subparagraph (B) uses the term "renewable energy resources," subparagraph (C) and later subparagraphs also refer only to the procurement of "renewable energy credits" (although subparagraph (E) references "renewable energy resources").

A shift in focus from "resources" to "RECs" makes intuitive sense; the IPA's prior Section 1-75(c) renewable energy planning and procurement processes were conducted in conjunction with the development of its annual procurement plan for meeting the energy supply requirements of eligible retail customers, and used to meet procurement requirements specific to that customer base. While the IPA now conducts renewable energy planning and procurement processes to (eventually) meet goals and targets applicable to all retail customer load,[95] its energy procurements still focus only on eligible retail customer load—thus creating a disconnect between the universes of supply requirements served by these two exercises.

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[93] For the definition of "qualified person" under Part 468, please see 83 Ill. Adm. Code § 468.20, http://www.ilga.gov/commission/jcar/admincode/083/083004680000200R.html.

[94] Emphasis added.

[95] Specifically, the IPA's long-term renewable resources procurement plan shall include renewable resource procurement for 100% of retail customer load beginning with the delivery year beginning June 1, 2019, after procuring for an increasing portion of retail customer load for the prior two delivery years. See 20 ILCS 3855/1-75(c)(1)(B).

Since the passage of P.A. 99-0906 and the competitive procurement events that followed, the IPA has become aware of concerns held by developers of utility-scale renewable energy projects that there may be a shallow market for long-term bilateral energy off-take agreements for geographically-qualifying new projects, which developers believe are necessary for providing the revenue certainty required for financing new facility construction. That concern will likely only grow in future years if additional utility-scale REC procurements are authorized, as buyers that may have been able to commit to purchase the generation of the first wave of these projects may no longer have room in their energy portfolios.[96] While the IPA continues to believe it is an open question as to whether it *could* eventually procure a bundled REC and energy product through the Plan or future revisions to it, or some combination of its concurrent planning and procurement processes, any such proposal carries numerous statutory and policy concerns, including but not limited to the following:

- Syncing developer need for long-term revenue certainty with shorter-term focus of IPA energy procurement planning horizons;
- Inability under law to bind competitive retail suppliers (which serve the majority of the Illinois market), municipal electric utilities, or rural electric co-operatives to purchase energy off-take from specific projects;
- Ensuring cost parity across customer classes (as default supply is procured for residential and small commercial customers);
- Managing fluctuating "eligible retail customer" supply levels due to ongoing customer switching;
- Ensuring that energy procured meets the "lowest total cost over time, taking into account any benefits of price stability" goal reiterated throughout the IPA Act and PUA.

To date, the IPA has not received proposals for the procurement of a bundled product (or for the separate procurement of energy from projects facilitated through IPA REC procurements) that sufficiently address these statutory and policy concerns. Absent statutory changes, the Agency continues not to propose any bundled product procurements as part of this Revised Plan and has no plans to do so in the near-term, but remains open to further proposals and feedback.

2.3.4. RPS Funding and Rate Impact Cap

The procurement of renewable energy credits is limited by an annual procurement budget established through a rate impact cap. Specifically, "the total of renewable energy resources procured under the procurement plan for any single year . . . shall be reduced for all retail customers based on the amount necessary to limit the annual estimated average net increase due to the costs of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of 2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatthour paid for these resources in 2011."[97] The greater of these amounts—the 2007 amount per kilowatt-hour ("kWh"), as both amounts are known and, for each utility, it is greater[98]—then "shall be applied to the actual amount of kilowatthours of electricity delivered, or applicable portion of such amount [. . .] by the electric utility in the delivery year immediately prior to the procurement to all retail

[96] These concerns were reinforced through comments received in the IPA's April 2020 utility-scale wind procurement comment process; for those comments, see: https://www2.illinois.gov/sites/ipa/Pages/wind-comments-2020.aspx.

[97] 20 ILCS 3855/1-75(c)(1)(E).

[98] The specific cost cap rate for each of the three utilities is shown in Table 3-4 in Chapter 3 of this Revised Plan.

customers in its service territory." This produces an annual REC procurement budget for the "costs of those resources" in a given year.[99]

Through the budgets established under the rate impact cap and the associated tariffs for the collection of funds, the applicable electric utility "shall be entitled to recover all of its costs associated with the procurement of renewable energy credits" under the Plan, including "associated reasonable expenses for implementing the procurement programs, including, but not limited to, the costs of administering and evaluating the Adjustable Block program."[100] As a result, annual procurement budgets based only on REC costs would be inaccurate, and some estimate of associated administrative expenses must be included and taken into account. For a limited period, Section 16-108(k) of the PUA allows for a given delivery year's unspent budget amounts to be "rolled over" to be available for later delivery years' expenditures. Specifically, rather than conducting annual reconciliations of collections and costs, the Commission "shall instead conduct a single review, reconciliation, and true-up associated with renewable energy resources' collections and costs for the 4-year period beginning June 1, 2017 and ending May 31, 2021, provided that the review, reconciliation, and true-up shall not be initiated until after August 31, 2021."[101] Over that four-year period prior to the eventual reconciliation, "the utility shall be permitted to collect and retain funds under this subsection (k) and to purchase renewable energy resources under an approved long-term renewable resources procurement plan using those funds regardless of the delivery year in which the funds were collected during the 4-year period."

Through the first two years of implementation of P.A. 99-0906, the eventual sunsetting of this rollover period is beginning to pose a challenge: nearly two years were required for the development and approval of the Initial Plan, the development of program requirements and project application processes for each of the ABP and Illinois Solar for All, and the selection of projects in each program's first phase. As a consequence, two years of RPS budgets were collected with few payments made. Many systems that successfully applied to the Adjustable Block Program (especially community solar projects) may not be energized until sometime in 2020 (or later), leaving a smaller portion of their payments eligible to be funded through collections made in the first four years. Additionally, projects facilitated through utility-scale procurements may not become energized and begin delivering RECs until sometime in 2021 or 2022.

Absent a statutory extension of this rollover period, a possible consequence is a refund back to ratepayers of collections previously made to fund renewable energy resource procurement after the rollover period sunsets on June 1, 2021 (as renewable energy resources expenditures under Initial Plan programs and other prior contractual commitments would not have been made by that date in an amount equaling the four-year sum of RPS rider collections). Following that date, beginning with the 2021-2022 delivery year, annual renewable energy resources expenditures cannot exceed annual RPS rider collections, as there will be an annual reconciliation under Section 16-108(k). Moreover, as available funds become constrained, there could also be a spike in budget impacts as projects

[99] The exception referenced above in Section 1-75(c)(1)(H) serves to reduce available budgets as well, as "the charges that would otherwise be applicable to the retail customers of the alternative retail electric supplier . . . shall be reduced by the ratio of the quantity of renewable energy credits supplied by the alternative retail electric supplier compared to that supplier's target renewable energy credit quantity."

[100] 20 ILCS 3855/1-75(c)(6).

[101] Changes under P.A. 99-0906 also provide that the utility shall not be required to "advance any payment or pay any amounts that exceed the actual amount of revenues collected by the utility" under its Section 16-108(k) RPS rider, and "contracts executed under this Section shall expressly incorporate this limitation." 20 ILCS 3855/1-75(c)(1)(L)(vii); also see 220 ILCS 5/16-111.5(b)(5)(iv).

become energized en masse—leading to the need to draw upon additional funding sources (such as previously-collected alternative compliance payments) to ensure contract obligations can be met.

Further discussion of the rate impact cap, the projected budgets produced under the rate impact cap, and the potential impacts of the above-referenced rollover period sunsetting on June 1, 2021 can be found in Chapter 3.

2.3.5. Employment Opportunities

The law also provides that "the renewable energy credit procurements, Adjustable Block solar program, and community renewable generation program shall provide employment opportunities for all segments of the population and workforce, including minority-owned and female-owned business enterprises, and shall not, consistent with State and federal law, discriminate based on race or socioeconomic status."[102] The IPA believes strongly in the principles outlined in this statement in the law, and hopes that both its Initial Plan and this Revised Plan—including provisions to lower the barrier to entry in the Adjustable Block Program for minority-owned and female owned businesses, its Illinois Solar for All proposals, its approach to generation in adjacent states, and its approach to the geographic diversity of projects within Illinois—properly takes those considerations into account and will result in those opportunities being provided. As outlined in Section 6.17, in this Revised Plan the Agency is proposing additional reporting by Adjustable Block Program Approved Vendors on the utilization of graduates of job training programs

2.4. Quantitative New Build Targets of the RPS

Section 1-75(c)(1)(B) of the IPA Act establishes percentage-based umbrella goals for RECs required to be procured based on a percentage of applicable retail customer load, but within those umbrella requirements, other, more specific requirements must also be met—and indeed prioritized above meeting those percentage-based goals.

One such requirement is the procurement of RECs from "new wind projects" and "new photovoltaic projects" found in Section 1-75(c)(1)(C). Rather than expressed as a percentage of load, these requirements are expressed on a quantitative basis (i.e., a fixed, statutorily-defined minimum number of RECs) while still counting toward the overall renewables percentage-based procurement goals.

2.4.1. Quantitative Procurement Requirements

The quantitative targets found in Section 1-75(c)(1)(C) are straightforward and symmetrical, and operate as follows:

By the end of the 2020 delivery year (May 31, 2021):

- At least 2,000,000 renewable energy credits for each delivery year shall come from new wind projects; and
- At least 2,000,000 renewable energy credits for each delivery year shall come from new photovoltaic projects.

By the end of the 2025 delivery year (May 31, 2026):

[102] 20 ILCS 3855/1-75(c)(7).

- At least 3,000,000 renewable energy credits for each delivery year shall come from new wind projects; and
- At least 3,000,000 renewable energy credits for each delivery year shall come from new photovoltaic projects.

By the end of the 2030 delivery year (May 31, 2031):

- At least 4,000,000 renewable energy credits for each delivery year shall come from new wind projects; and
- At least 4,000,000 renewable energy credits for each delivery year shall come from new photovoltaic projects.

For the "new photovoltaic project" requirement, at least 50% must be procured from solar photovoltaic projects using the Adjustable Block Program (used to support distributed generation and community solar, as discussed further below), at least 40% from utility-scale solar projects, and at least 2% from non-community solar brownfield site photovoltaic projects.[103] The Agency has interpreted this "at least 50%" concept to be first, in terms of RECs (as opposed to budget or installed capacity), and also, of the quantitative target amounts listed in the law (as, in each of Sections 1-75(c)(1)(C)(i), (ii), and (iii) "of that amount" references the REC amount expressly preceding it in the law), and not necessarily 50% of the overall number of RECs procured.[104]

Significant progress has been made since the development of the IPA's Initial Plan on meeting these targets, with millions of RECs under contract to be delivered annually from new wind and new photovoltaic projects. Further discussion of this progress can be found in Chapter 3 of this Revised Plan, while the Agency's discussion of competitive procurements for meeting these targets can be found in Chapter 5.

2.4.2. "New wind project" and "new photovoltaic project" Definition

The definitions of a "new wind project" and a "new photovoltaic project" are also addressed through the statute. What constitutes a "new photovoltaic project" is straightforward; it is a "photovoltaic

[103] The IPA Act, as modified by P.A. 99-0906, defines a "brownfield site photovoltaic project" as:

> *[P]hotovoltaics that are:*
>
> *(1) interconnected to an electric utility as defined in this Section, a municipal utility as defined in this Section, a public utility as defined in Section 3-105 of the Public Utilities Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act; and*
>
> *(2) located at a site that is regulated by any of the following entities under the following programs:*
>
> *(A) the United States Environmental Protection Agency under the federal Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended;*
>
> *(B)the United States Environmental Protection Agency under the Corrective Action Program of the federal Resource Conservation and Recovery Act, as amended;*
>
> *(C) the Illinois Environmental Protection Agency under the Illinois Site Remediation Program; or*
>
> *(D) the Illinois Environmental Protection Agency under the Illinois Solid Waste Program.*

20 ILCS 3855/1-10.

[104] Thus, if the Adjustable Block Program were to exceed the targets of 1,000,000 RECs delivered annually by the end of 2020-2021 and 1,500,000 RECs by the end of 2025-2026, the "at least 40%" requirement for utility-scale photovoltaic projects remains at 40% of the new photovoltaic targets stated in the law, or 800,000 RECs by the end of the 2020 delivery year and 1,200,000 RECs by the end of the 2025 delivery year. 20 ILCS 3855/1-75(c)(1)(C)(i), (ii). The reverse must likewise be true (supra-target outcomes for utility-scale photovoltaic procurements do not increase ABP targets), as the Commission in Docket No. 17-0838 authorized utility-scale photovoltaic procurements resulting in significantly more utility-scale PV RECs under contract than the Adjustable Block Program could possibly sustain given budget limitations.

renewable energy facilit[y] that [is] energized after June 1, 2017."[105] Projects developed under Section 1-56 of the IPA Act (i.e., supplemental photovoltaic and Illinois Solar for All projects) are not eligible to meet quantitative "new photovoltaic project" targets.[106]

The definition of a "new wind project" is more awkward. The law defines "new wind projects" as "wind renewable energy facilities that are energized after June 1, 2017 for the delivery year commencing June 1, 2017 or within 3 years after the date the Commission approves contracts for subsequent delivery years."[107] The IPA understands that "for subsequent delivery years"—projects for which contracts are entered into on or after June 1, 2018—the "3 years after the date" of contract approval is effectively a deadline by when the facility must be "energized" for it to retain its "new" status under the law going forward. Stated differently, if the facility is able to be energized within 3 years after the date on which the Commission approves its REC contract, then those RECs may be counted toward the "new wind project" procurement targets in the law over the life of the contract. However, if the wind project cannot energize within 3 years after Commission approval, its RECs may not be used to count toward quantitative "new wind project" targets, and resultant REC delivery contracts should reflect a consequence for that change in legal status (as the project's RECs would then have less value in meeting the requirements of the RPS; they would meet the percentage goals of Section 1-75(c)(1)(B) of the Act, but not the quantitative REC targets of Section 1-75(c)(1)(C)).

Both of these definitions raise the question of what constitutes a facility being "energized." Unlike interconnection, where official approval is required and associated forms are produced and executed on a specific date, "energized" is more nebulous and, unfortunately, not defined through the law. Faced with a similar quandary in developing its Supplemental Photovoltaic Procurement Plan, the Agency settled on a definition of "energized" as being "the date by which the System has been turned on for a period of 24 consecutive hours and is operational for purposes of generating electricity regardless of whether the system has registered with a REC tracking system." Parties could then substantiate a system's energization through a certification accompanied by the submission of various forms establishing a system's energization timeline. The Agency notes that unlike the Supplemental Photovoltaic Procurement process, in which payment for RECs was made after REC generation and only upon delivery and invoice to the Agency, the Adjustable Block Program and the Illinois Solar for All Program feature prepayment for some, or all, of the RECs from a system upon energization. Therefore, as discussed in Chapters 6 and 8, consideration is also given to a system being registered in a tracking system to generate RECs in addition to the date on which interconnection to the utility was approved.

2.4.3. Initial Forward Procurements

Independent of (and, in some cases, prior to) the development of the Initial Plan, P.A. 99-0906 required the IPA to conduct "initial forward procurements" of RECs from "from new utility-scale wind projects" and "from new utility-scale solar projects and brownfield site photovoltaic projects."[108] Conducted through competitive procurement processes subject to applicable requirements of Section 16-111.5 of the PUA, the Initial Forward Procurement sought 15-year REC delivery contracts set to begin delivery on June 1, 2019 at the earliest and—initially—June 1, 2021 at the latest (that

[105] 20 ILCS 3855/1-10.

[106] Id.

[107] 20 ILCS 3855/1-75(c)(1)(C).

[108] 20 ILCS 3855/1-75(c)(1)(G)(i), (ii).

deadline has since been extended to June 1, 2022 through Public Act 101-0113 in the case of certain development risks). For both wind and solar, the targeted overall REC procurement quantities were 1,000,000 RECs delivered annually from each generating technology, with a single wind procurement event required to take place within 160 days of June 1, 2017 and the solar procurement potentially conducted across multiple procurement events up to one year from June 1, 2017.[109]

Section 1-75(c)(1)(G) of the Act provides that RECs procured through the Initial Forward Procurement "shall be included in the Agency's Long-Term Renewable Resources Procurement Plan and shall apply to all renewable energy goals"[110] found in Section 1-75(c) of the IPA Act, including the quantitative "new wind" and "new photovoltaic" targets discussed above. The Agency's Initial Forward Procurement events for new utility-scale wind and new photovoltaics, conducted in 2017 and 2018, have concluded;[111] the results of the Initial Forward Procurement, as well as how those results inform remaining quantitative procurement targets, are discussed further in Chapters 3 and 5.

2.4.4. Subsequent Forward Procurements

Section 1-75(c)(1)(G)(iii) also floats the concept of "subsequent forward procurements." That section sets forth conditions applicable to subsequent forward procurements: they must be "for utility-scale wind projects," they "shall solicit at least 1,000,000 renewable energy credits delivered annually per procurement event," and they shall be "planned, scheduled, and designed such that the cumulative amount of [RECs] delivered from all new wind projects in each delivery year shall not exceed the Agency's projection of the cumulative amount of [RECs] that will be delivered from all new photovoltaic projects," in that same delivery year.

The law does not contain statements either requiring that the Agency actually conduct a Subsequent Forward Procurement, or requiring that RECs from utility-scale wind projects may only be procured using a Subsequent Forward Procurement approach. However, in Docket No. 17-0838, the Commission approved two Subsequent Forward Procurements for RECs from new utility-scale wind projects as part of the Initial Plan, allowing the Agency to potentially meet its Section 1-75(c)(1)(C)(i) 2020 and 2025 Delivery Year quantitative new wind targets (and nearly achieving its 2030 targets as well).

RECs under contract from Subsequent Forward Procurements are included in tables found in Chapter 3, while further discussion of competitive procurement events including any proposed Subsequent Forward Procurements can be found in Chapter 5.

2.4.5. Balancing Expected Wind RECs vs. Solar RECs

In addition to the condition placed on subsequent forward procurements mentioned above, the law also contains a more general requirement that RECs under contract from new wind projects not significantly exceed RECs under contract from new photovoltaic projects. Specifically, if the projected amount of RECs from new wind projects to be delivered in a given delivery year exceeds the projected amount of RECs from new photovoltaic projects by 200,000 or more RECs, then "the

[109] Id.

[110] Id.

[111] More information about the Initial Forward Procurements can be found at on the IPA Procurement Administrator's website at the following address: https://www.ipa-energyrfp.com/2017-2018-initial-forward-procurements.

Agency shall within 60 days adjust the procurement programs in the long-term renewable resources procurement plan to ensure that the projected cumulative amount of renewable energy credits to be delivered from all new wind projects does not exceed the projected cumulative amount of renewable energy credits to be delivered from all new photovoltaic projects by 200,000 or more renewable energy credits."[112]

This requirement is not intended to be applicable to results from the Initial Forward Procurements, at least initially. Given that the Initial Forward Procurement calls for 1,000,000 RECs from "new wind projects" to be procured "within 160 days after the effective date" of P.A. 99-0906, but the Initial Forward Procurement from "new photovoltaic projects" is to be procured "within one year after the effective date," the law openly accommodates a longer time horizon for bringing solar RECs under contract from the initial forward procurements. As the law expressly establishes this matching requirement as only applicable "at any time after the time set for delivery of renewable energy credits pursuant to the initial procurements,"[113] the Agency understands that this requirement becomes applicable to its planning process after June 1, 2022, the latest date for first delivery of RECs from the initial forward procurements as discussed in Section 2.2.5.2 above.[114]

The law also provides that the Agency shall provide "its projection of the renewable energy credits to be delivered from all projects in each delivery year" on a "quarterly basis."[115] While the IPA will continue to regularly track RECs from new wind projects versus new photovoltaic projects internally, it understands that these quarterly updates would only need to begin being formally provided upon the matching requirement becoming applicable to its planning process.

Further discussion of this requirement, including the current balance of RECs under contract from new wind projects versus new photovoltaic projects, can be found in Chapter 3.

2.5. Adjustable Block & Community Renewable Generation Programs

As referenced above, at least 50% of the quantitative new photovoltaic targets found in Section 1-75(c)(1)(C) of the IPA Act shall be procured "from solar photovoltaic projects using the program outlined in subparagraph (K) of this paragraph (1) from distributed renewable energy generation devices or community renewable generation projects"—i.e., using the Adjustable Block Program.

2.5.1. Adjustable Block Program

At its core, the Adjustable Block Program is perhaps most notable for what it is not: it is not a "competitive procurement event" using "pay as bid" pricing with selection of bids on the basis of price. Nor is it a project selection process through which public interest criteria, such as those set forth in Section 1-75(c)(1)(I) or those employed for the selection of winning bids under the Zero Emission Standard found in Section 1-75(d-5) of the Act, determine the winning bidder.

Instead, the Adjustable Block Program provides "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."[116] Stated differently, a party seeking a REC contract—such as a

[112] 20 ILCS 3855/1-75(c)(1)(G)(iv).

[113] Id.

[114] See Docket No. 17-0838, Final Order dated April 3, 2018 at 47-48.

[115] 20 ILCS 3855/1-75(c)(1)(G)(iv).

[116] 20 ILCS 3855/1-75(c)(1)(K).

photovoltaic distributed generation or community solar project developer—knows the REC price in advance, and should generally have visibility into when and how that price may change. The law sets forth other requirements of the Adjustable Block Program: it must include "a schedule of standard block purchase prices to be offered; a series of steps, with associated nameplate capacity and purchase prices that adjust from step to step; and automatic opening of the next step as soon as the nameplate capacity and available purchase prices for an open step are fully committed or reserved."[117] Thus, each block constitutes a quantity of nameplate capacity with a REC price[118] attached to that block, and when a block is fully subscribed by qualifying projects, projects may then qualify for the next block (which features a different price). The Agency understands that "automatic opening" as used in the law need not be "immediate" or "instantaneous," and instead that "automatic" refers to the ability for the block to open in a predictable manner not requiring additional administrative action.[119]

2.5.1.1. Adjustable Block Program—Projects

The Adjustable Block Program is applicable to only two project types: photovoltaic distributed renewable energy generation devices (i.e., solar DG), and photovoltaic community renewable generation projects (i.e., community solar[120]).

Under Illinois law, a photovoltaic distributed renewable energy generation device must be:

(1) Powered by photovoltaics;
(2) interconnected at the distribution system level of either an electric utility as defined in this Section, a municipal utility as defined in this Section that owns or operates electric distribution facilities, or a rural electric cooperative as defined in Section 3-119 of the Public Utilities Act (and thus, must be located in Illinois to be interconnected to such an entity);
(3) located on the customer side of the customer's electric meter and is primarily used to offset that customer's electricity load; and
(4) limited in nameplate capacity to less than or equal to 2,000 kilowatts.[121]

Under Illinois law, a photovoltaic community renewable generation project is a generation facility that:

(1) is powered by photovoltaics;
(2) is interconnected at the distribution system level of an electric utility as defined in this Section, a municipal utility as defined in this Section that owns or operates electric distribution facilities, a public utility as defined in Section 3-105 of the Public Utilities Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act (and thus, must be located in Illinois to be interconnected to such an entity);

[117] Id.

[118] Prices can be a set value, or established as the product of a formula.

[119] Through its Final Order in Docket No. 19-0995, the Commission further reinforced this paragraph's description of what is statutorily required from an "Adjustable Block Program" by finding that a proposal under which block prices would be set through a reverse auction "would require legislative action." Docket No. 19-0995, Final Order dated February 18. 2020 at 46.

[120] There are other forms of community solar recognized by Illinois law, including (A) properties owned or leased by multiple customers that contribute to the operation of an eligible renewable electrical generating facility, and (B) individual units, apartments, or properties located in a single building that are owned or leased by multiple customers and collectively served by a common eligible renewable electrical generating facility. 220 ILCS 5/16-107.5(*l*)(1). These forms of community solar are not eligible for the Adjustable Block Program.

[121] 20 ILCS 3855/1-10.

(3) credits the value of electricity generated by the facility to the subscribers of the facility; and
(4) is limited in nameplate capacity to less than or equal to 2,000 kilowatts.[122]

Only new projects—those "energized on or after June 1, 2017"—are eligible for the Adjustable Block Program.

In terms of what project types participate at what level within the Adjustable Block Program, the law provides the following delineation:

(1) At least 25% from distributed renewable energy generation devices with a nameplate capacity of no more than 10 kilowatts;
(2) At least 25% from distributed renewable energy generation devices with a nameplate capacity of more than 10 kilowatts and no more than 2,000 kilowatts.[123]
(3) At least 25% from photovoltaic community renewable generation projects.
(4) The remaining 25% shall be allocated as specified by the Agency in the long-term renewable resources procurement plan.[124]

Through the Commission's determination in Docket No. 17-0838 requiring the remaining 25% allocation for the first phase of the Adjustable Block Program (25% of 1,000,000 RECs delivered annually, or of 666 MW of new installed capacity after applying a standard capacity factor) be withheld to be later allocated at the Agency's discretion,[125] it is clear that this language does not necessarily require express allocation to one (or a specific combination) of these three categories through this Plan, and that some or all of the "remaining 25%" could instead be allocated to adjust for ongoing program performance. This issue is discussed further in Chapter 6.

The law also provides that the Adjustable Block Program shall ensure that RECs are procured from "projects in diverse locations and are not concentrated in a few geographic areas." The Agency has spent time reviewing the geographic distribution of projects supported thus far through the Adjustable Block Program, and has found that the Program generally features very strong geographic diversity. Some exceptions certainly exist – for instance, while community solar projects facilitated through the program look well-dispersed on a map of the state, development has almost exclusively occurred in less populated rural areas featuring lower land cost – but the IPA has generally been pleased with the degree to which the thousands of projects supported to date through the Adjustable Block Program demonstrate geographic diversity.

Moving forward, the Agency commits to monitor the locations of proposed and completed projects. Further discussion of this issue can be found in Chapter 6.

2.5.1.2. Adjustable Block Program—Contracts

Section 1-75(c)(1)(L) sets forth certain requirements applicable to REC delivery contracts entered into through the Adjustable Block Program. The first is that contracts must be "at least 15 years in length," i.e., for at least 15 years of REC deliveries under the contract. Payment for RECs is made by

[122] Id.

[123] The Agency may create sub-categories within this category to account for the differences between projects for small commercial customers, large commercial customers, and public or non-profit customers.

[124] 20 ILCS 3855/1-75(c)(1)(K).

[125] See Docket No. 17-0838, Final Order dated April 3, 2018 at 60; for the IPA's April 3, 2019 decision allocating discretionary capacity, see: http://illinoisabp.com/wp-content/uploads/2019/04/Discretionary-Capacity-Rationale-4.3.19.pdf.

(and RECs are delivered to) the applicable electric utility (which is then required to retire the RECs), and payment is required by law to occur according to the following schedule:

For DG systems of no more than 10 kW, "the renewable energy credit purchase price shall be paid in full by the contracting utilities at the time that the facility producing the renewable energy credits is interconnected at the distribution system level of the utility and energized."[126] The Agency understands "purchase price" to refer to the sum of payments for RECs required to be made under the contract—i.e. full prepayment.[127]

For larger DG systems and community solar projects, "20 percent of the renewable energy credit purchase price shall be paid by the contracting utilities at the time that the facility producing the renewable energy credits is interconnected at the distribution system level of the utility and energized" with the remaining portion "paid ratably over the subsequent 4-year period."[128]

Prepayment poses unique challenges—while RECs are required to be delivered when generated to meet annual utility compliance obligations, prepayment reduces the incentive to actually deliver RECs. On this point, the law requires that each contract "shall include provisions to ensure the delivery of the renewable energy credits for the full term of the contract."

The Revised Plan's proposed approach to Adjustable Block Program contracts generally (including certain recommended changes to the contract form published on January 30, 2019 for which the Agency expressly sought Commission approval), as well as to the clawback provisions, collateral requirements, and other contract elements intended to ensure REC delivery, can be found in Chapter 6.

2.5.1.3. Adjustable Block Program—Changes

Unlike a competitive procurement process, through which changes in market conditions may be reflected in bidders' bids, the Adjustable Block Program requires that the Agency project future market conditions through establishing future block sizes and prices.

The law envisions these changes occurring in two ways: first, the Agency "may periodically review its prior decisions establishing the number of blocks, the amount of generation capacity in each block, and the purchase price for each block, and may propose, on an expedited basis, changes to these previously set values" subject to the Section 16-111.5 plan revision process.[129]

Second, "[p]rogram modifications to any price, capacity block, or other program element that do not deviate from the Commission's approved value by more than 25% shall take effect immediately and are not subject to Commission review and approval."[130] To prevent the requirement that the Agency seek formal administrative approval for large modifications from being effectively ignored, the Agency believes this threshold should be understood as a 25% change based on the last formally

[126] 20 ILCS 3855/1-75(c)(1)(L)(ii). The Agency understands this provision to mean that a system 10 kW in size would be included in this category.

[127] All prepayment remains subject to the amounts actually collected by the utilities under its Section 16-108(k) tariffs, however. (See Section 1-75(c)(1)(L)(vii)).

[128] 20 ILCS 3855/1-75(c)(1)(L)(iii).

[129] 20 ILCS 3855/1-75(c)(1)(K).

[130] 20 ILCS 3855/1-75(c)(1)(M).

approved (i.e., through establishment or revision of the Plan via Commission's Section 16-111.5 approval process) level.

For the Initial Plan, the Commission determined that "the final REC prices the IPA will publish should be filed within 60 days as a compliance filing" in Docket No. 17-0838.[131] Accordingly, the Agency published its REC prices for the Adjustable Block Program as a compliance filing in Docket No. 17-0838 on June 4, 2018 and these served as the baseline for any subsequent modifications of up to 25%.[132] For establishing a baseline for future price adjustments, this Final version of the Revised Plan filed with the ICC on April 20, 2020 provides those baseline prices. REC prices are shown in Table 6-2 of the Revised Plan. They are unchanged from the REC prices published in the version of the Revised Plan that was filed for ICC approval on October 21, 2019 in Docket No. 19-0995, and, aside from providing prices for Block 5, generally follow the prices found in the Initial Plan.[133]

Section 1-75(c)(1)(M) of the Act requires that the Agency "consider stakeholder feedback when making adjustments to the Adjustable Block design" and "notify stakeholders in advance of any planned change." Likewise, the law requires that "[t]he Agency and its consultant or consultants shall monitor block activity, share program activity with stakeholders and conduct regularly scheduled meetings to discuss program activity and market conditions." In implementing the program, the Agency has to date attempted to seek stakeholder feedback for the development of key program requirements or new forms and documents; such documents are published on the program website (www.illinoisabp.com) and new requirements generally become reflected in the Adjustable Block Program Guidebook.[134] The program website also features a program dashboard updated daily to provide stakeholders with daily updates on block activity,[135] and recently added project information spreadsheets to provide increased transparency about photovoltaic projects supported through the Adjustable Block Program.[136] And in preparing this Revised Plan, in addition to the comment process and public hearings required by law, the Agency held both in-person workshops and a written comment process in the summer of 2019 through which comments on program activity and market conditions were offered by stakeholders.[137]

As described further in Chapter 6, the Agency will continue to monitor program performance closely and shall seek to be proactive in communicating with stakeholders about program performance and making any necessary changes to the structure of the Adjustable Block Program.

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[131] Docket No. 17-0838, Final Order dated April 3, 2018 at 73-74.

[132] See id.

[133] In Docket No. 19-0995, the Commission additionally determined that "REC prices must be lower to both efficiently invest ratepayer money and limit oversubscription resulting in a lottery process" given the oversubscription of certain categories of the Adjustable Block Program upon the program's opening. To effectuate any price changes, the Commission held that "workshops should be held and stakeholder input considered." However, no specific changes to REC prices were directed through that Order. See Docket No. 19-0995, Final Order dated February 18, 2020 at 46.

[134] Both the presently effective Guidebook and prior editions of the Guidebook can be found here: http://illinoisabp.com/program-guidebook.

[135] The Adjustable Block Program dashboard can be found here: http://illinoisabp.com/dashboard-home.

[136] Project application disclosure information can be found here: http://illinoisabp.com/project-information-disclosure-process.

[137] Information about the IPA's June 20, 2019 and June 26, 2019 workshops, as well its request for comments and comments received, can be found here: https://www2.illinois.gov/sites/ipa/Pages/RenewableResourcesWorkshops.aspx.

2.5.2. Community Renewable Generation Program

P.A. 99-0906 also requires the establishment of a "community renewable generation program."[138] Unlike with the Adjustable Block Program, the law does not set forth procurement targets or a proposed contract structure for this program; the Agency thus has latitude to design its Community Renewable Generation Program in any manner otherwise consistent with state law and done "with a goal to expand renewable energy generating facility access to a broader group of energy consumers, to ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties."[139]

The statutorily-envisioned interaction between the Agency's Community Renewable Generation Program, and the portion of the Agency's Adjustable Block Program set-aside for community solar, is ambiguous; the law simply references that "subscribed shares of photovoltaic community renewable generation projects" shall be purchased through the Adjustable Block Program.[140] Thus, the IPA understands the community solar portion of its Adjustable Block Program to be something of a subset of its Community Renewable Generation Program, with a standalone Community Renewable Generation Program required to be established to provide support for community renewable generation projects using technology other than photovoltaics.

2.5.2.1. Portability and Transferability of Subscriptions

Section 1-75(c)(1)(N) requires that "subscriptions" to community renewable generation projects under the Community Renewable Generation Program must be portable (i.e., retained by the subscriber even if the subscriber relocates or changes its address within the same utility service territory) and transferable (i.e., a subscriber may assign or sell subscriptions to another person within the same utility service territory). These requirements apply to subscriptions for community solar projects participating in the Adjustable Block Program as well.

During the implementation of the Adjustable Block Program, some entities have raised questions regarding the scope of the portability and transferability of community solar subscriptions. It seems clear that the law did not envision completely unconditional portability or transferability: if a resident holding a community solar subscription were to move from a large house to a small apartment, the resultant drop in consumption would necessitate, at minimum, downsizing of the community solar subscription. Likewise, there may be numerous reasons why a transferee may be an unworkable recipient of an existing subscriber's community solar subscription, from being legally ineligible (outside of that utility's service territory) to posing a more significant non-payment risk than the transferor. At the same time, allowing unbounded Approved Vendor-imposed restrictions on portability or transferability could easily defeat the spirit of the law's requirement that subscriptions be portable and transferable.

Through this Plan revision process and other contemporaneous activities, the Agency hopes to provide more clarity around what restrictions on the portability and transferability of community solar subscriptions should be acceptable under the Adjustable Block Program and Community Renewable Generation Program. Further discussion of this topic may be found in Section 7.6.2.

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[138] 20 ILCS 3855/1-75(c)(1)(N).

[139] Id.

[140] Id.

2.5.2.2. Opt-Out Municipal Aggregation

Certain stakeholders have raised the question of whether community renewable generation project subscriptions (specifically, community solar subscriptions) may be eligible for execution via opt-out municipal aggregation authorized under Section 1-92 of the IPA Act. Under opt-out municipal aggregation, municipalities (after passing authorizing referenda) may aggregate their residential and small commercial customer load and contract with an alternative retail electric supplier to supply those customers with "energy and related services" at a negotiated supply rate unless that customer expressly chooses to "opt-out" of the transaction.

For the IPA, in its role as the entity charged with administering the Adjustable Block Program, Community Renewable Generation Program, and Illinois Solar for Program, this raises, at minimum, two questions:

First, is the enrollment of a customer into a subscription for a community solar project without their direct authorization or consent (i.e., on an "opt-out" basis) legally authorized by Section 1-92 of the IPA Act's governmental aggregation provisions?

Second, even if legally authorized, would that relieve Approved Vendors from program-related responsibilities with respect to individual subscribers, including the requirement that each customer complete a disclosure form acknowledging participation in the program?

The IPA is highly skeptical that opt-out municipal aggregation could legally cover community solar subscriptions, which were not contemplated anywhere in Illinois law when Section 1-92 was enacted via Public Act 96-0176 in 2009 (and notes that countless implementation issues would be raised under such an approach).[141]Only the second of these questions falls within the scope of this Plan. On that question, the Agency's disclosure form requirements found in Chapter 6 are fundamental to subscribers receiving standardized information. Those requirements constitute the backbone of the Agency's efforts to deliver uniform content about the rights and obligations under a ratepayer-funded program to everyday citizens. That standardized information and express acknowledgment by a subscriber is an essential form of education that must be provided to each individual participant to produce a transparent, positive experience through its programs. Thus, even if some colorable argument could be made that community solar subscribers could be enrolled without each individual subscriber having offered its direct consent to a given subscription, the Agency would not allow for its program-specific consumer protection requirements—including its standardized brochure and the receipt and execution of a disclosure form—to be waived.

In approving this Revised Plan, the Commission agreed with the Agency that any community solar subscription aggregation program (if legally possible) for a project participating in the ABP or ILSFA would be required to ensure that every individual subscriber receives and executes an individualized standard disclosure form, pursuant to Section 6.13 of this Revised Plan.[142] The Commission likewise agreed with the Agency that the question of whether opt-out municipal aggregation for community solar subscriptions is legally authorized under Section 1-92 of the IPA Act is an issue outside the

[141] Any community renewable generation project that does not participate in an IPA-administered program or procurement may freely operate outside of this Revised Plan's requirements. However, given the Agency's express statutory role (separate from its role administering renewable resources programs under this Plan) assisting governmental aggregation programs under Section 1-92(g) of the Act, the Agency's perspective should at least carry valuable advisory authority.

[142] Docket No. 19-0995, Final Order dated Feb. 18, 2020 at 7.

scope of Plan approval, finding that "this proceeding is not the forum for the Commission to decide the legality of opt-out municipal aggregation for community solar subscriptions, as numerous interested stakeholders - such as the many municipalities that might be interested and the private brokers that might assist them in soliciting bids - would not be on notice that the issue is being decided."[143]

Further discussion of the IPA's Community Renewable Generation Program can be found in Chapter 7.

2.6. Illinois Solar for All Program

As described in Section 1-56(b) of the IPA Act, the Illinois Solar for All Program shall "include incentives for low-income distributed generation and community solar projects, and other associated approved expenditures" in order "to bring photovoltaics to low-income communities in this State in a manner that maximizes the development of new photovoltaic generating facilities, to create a long-term, low-income solar marketplace throughout this State, to integrate, through interaction with stakeholders, with existing energy efficiency initiatives, and to minimize administrative costs." Further, the program shall be "designed to grow the low-income solar market."[144]

A statutory overview of the Illinois Solar for All Program (which began accepting project applications on May 15, 2019), as well as the individual sub-programs under the Illinois Solar for All banner, is below.

2.6.1. Illinois Solar for All—Overview

At its core, the Illinois Solar for All Program is an incentive program—through more generous REC contracts, the Illinois Solar for All Program incents low-income (as well as non-profit and public facility) participation in solar photovoltaic projects, whether as a system owner, community solar project subscriber, or system host. Those RECs are retired (either by the Agency or a utility, depending on which entity was the REC contract counterparty) to satisfy Section 1-75(c) compliance obligations just as with the other procurements and programs described above, while the additional premium helps produce benefits specific to growing the low-income solar marketplace and ensuring more equitable access to the benefits of clean energy. Thus, structurally, the law envisions the Solar for All Program's incentive being offered through contracts for the delivery of RECs at a premium price above what would otherwise be available, reflecting the additional incentive necessary to ensure low-income participation, with the Agency also having the ability to offer full contract prepayment or otherwise relax (or enhance) requirements in recognition of the unique challenges facing low-income project development.

While the program features no hard targets or goals for the quantity of RECs required to be procured, it does feature defined funding sources. First, Illinois Solar for All is funded through the Renewable Energy Resources Fund. At the time of publishing this draft Plan, the existing balance of the RERF is presently just over $50 million, with an additional $112.5 million remaining transferred to the state's General Revenue Fund for liquidity purposes. The IPA considers any contractual obligations from the RERF pre-dating Illinois Solar for All (specifically, Supplemental Photovoltaic Procurement contracts) to be senior to any new obligations entered into through the Illinois Solar for All

[143] Id.

[144] 20 ILCS 3855/1-56(b)(2).

Program,[145] and approximately $13.9 million in such prior obligations remain outstanding.[146] State law[147] requires that the remaining $112.5 million be transferred back into the RERF within 48 months of its transfer in August 2017, but no additional alternative compliance payments are due to be made into the RERF.[148]

Second, Illinois Solar for All is funded through a portion of funds collected by the utilities under their Section 16-108(k) RPS tariffs for purchases made under Section 1-75(c) of the IPA Act. Under Section 1-75(c)(1)(O), "5% of the funds available under the plan for the applicable delivery year, or $10,000,000 per delivery year, whichever is greater" is available for Illinois Solar for All annually in most years; while "for the delivery years beginning June 1, 2017, June 1, 2021, and June 1, 2025, the long-term renewable resources procurement plan shall allocate 10% of the funds available under the plan for the applicable delivery year, or $20,000,000 per delivery year, whichever is greater" with $10 million in each of those three delivery years going toward funding ComEd's workforce development plan. This mechanism ensures a base level of Illinois Solar for All funding annually, which is crucial given the uncertainty surrounding the RERF.

Third, Section 16-108(k) of the PUA contains the following provision:

> *If the amount of funds collected during the delivery year commencing June 1, 2017, exceeds the costs incurred during that delivery year, then up to half of this excess amount, as calculated on June 1, 2018, may be used to fund the programs under subsection (b) of Section 1-56 of the Illinois Power Agency Act in the same proportion the programs are funded under that subsection (b). However, any amount identified under this subsection (k) to fund programs under subsection (b) of Section 1-56 of the Illinois Power Agency Act shall be reduced if it exceeds the funding shortfall. For purposes of this Section, "funding shortfall" means the difference between $200,000,000 and the amount appropriated by the General Assembly to the Illinois Power Agency Renewable Energy Resources Fund during the period that commences on the effective date of this amendatory act of the 99th General Assembly and ends on August 1, 2018.*

Similar provisions exist in Section 16-108(k) for each of the delivery years commencing June 1, 2018 and June 1, 2019, meaning that there is no single "amount appropriated by the General Assembly to the Illinois Power Agency Renewable Energy Resources Fund" for the 14 months referenced in the paragraph above; instead, there are three separate fiscal year appropriations[149] covered by this period. Section 16-108(k) provides that should funding for Illinois Solar for All be available[150] under

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[145] This appears to be the intent evident in Section 1-56(b) as well, as that section prefaces the percentage-based allocation of RERF funds with the qualifier "monies available in the Illinois Power Agency Renewable Energy Resources Fund and <u>not otherwise committed to contracts executed under subsection (i) of this Section</u>." (emphasis added)

[146] Supplemental Photovoltaic Procurement contracts were for the delivery of RECs for 5 years, with payment for RECs made upon delivery; the procurement's original budget was $30 million.

[147] 30 ILCS 105/5h.5(b).

[148] Section 16-115D of the PUA provides that while "[t]hrough May 31, 2017, all alternative compliance payments by alternative retail electric suppliers shall be deposited in the Illinois Power Agency Renewable Energy Resources Fund," "beginning with the delivery year commencing June 1, 2017, all alternative compliance payments by alternative retail electric suppliers shall be remitted to the applicable electric utility" and not deposited into the RERF. (220 ILCS 5/16-115D(d)(4), (4.5).) See also 83 Ill. Adm. Code Part 455.

[149] These are the appropriations for Fiscal Year 2017 (July 1, 2016 through June 30, 2017), Fiscal Year 2018 (July 1, 2017 through June 30, 2017), and Fiscal Year 2019 (July 1, 2018 through June 30, 2019).

[150] Following each of the 2017-2018, 2018-2019, and 2019-2020 delivery years, the Agency asked or will ask each of ComEd, Ameren Illinois, and MidAmerican to provide an accounting of the utility's RPS rider collections during the preceding delivery year and the costs it incurred for Section 1-75(c) contracts during that delivery year.

this mechanism, then "the Agency shall submit a procurement plan to the Commission no later than September 1, 2018, that proposes how the Agency will procure programs on behalf of the applicable utility."[151]

The IPA filed its Illinois Solar for All Supplemental Funding Plan for approval with the Illinois Commerce Commission on August 30, 2018. That Plan concluded as follows regarding whether to use any unspent RPS rider collections to provide additional funding for the Illinois Solar for All Program:

> Taking into account the status of the Illinois Solar for All Program, the statutory priority attached to ILSFA's annual RRB allocation, the legally-required availability of RERF funds previously transferred to general funds under Section 5h.5 of the State Finance Act, Section 1-56(h)'s requirement that the RERF "shall not be subject to sweeps, administrative charges, or chargebacks," and thus the expected availability of funding sufficient to satisfy the Solar for All annual budgets included in the Long-Term Plan, the IPA does not propose supplemental funding for Illinois Solar for All using the Section 16-108(k) supplemental funding mechanism.[152]

The Illinois Commerce Commission affirmed this determination in Docket No. 18-1457, entering its Final Order on October 25, 2018. The Supplemental Funding Plan did note, however, that the Agency would seek to work with stakeholders and potentially reopen that proceeding should a change in circumstances (namely, permanent depletion of the RERF's balance) necessitate funding the Illinois Solar for All Program using the 16-108(k) funding shortfall mechanism.[153]

Under the Illinois Solar for All Program, payments "shall be in exchange for an assignment of all renewable energy credits generated by the system during the first 15 years of operation and shall be structured to overcome barriers to participation in the solar market by the low-income community."[154] The contract "may pay for such renewable energy credits through an upfront payment per installed kilowatt of nameplate capacity paid once the device is interconnected at the distribution system level of the utility and is energized," giving the Agency flexibility in proposing contract structures.[155]

The counterparty to Illinois Solar for All contracts entered into using RERF funds is the Agency, while the counterparty to contracts entered into using utility funds is the applicable utility.

While the Act does not require any particular annual budgetary allocation to ILSFA, the Agency chose in the Initial Plan, and continues to propose in this Revised Plan, to allocate funds and consider project applications within ILSFA based on "program years," which track the same period of time as energy delivery years (June 1st of one year to May 31st of the following year). The Agency's proposed budget allocations by program year are described in detail in Chapter 8.

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[151] 20 ILCS 3855/1-56(b)(7). Perhaps notably, while the requirement that the IPA submit a Plan is prescriptive, Section 16-108(k)'s funding allocation language is merely "permissive" ("up to half this excess amount . . . **may** be used to fund the programs"). The IPA thus did not need to propose, nor did the Commission need to approve, a full (or any) statutorily authorized allocation.

[152] Docket No. 18-1457, Final Illinois Solar for All Funding Shortfall Plan, dated November 26, 2018, at 30.

[153] See id. at 31.

[154] 20 ILCS 3855/1-56(b)(3).

[155] Id.

In addition to payments for REC delivery contracts, the law provides that "[t]he Agency shall ensure collaboration with community agencies, and allocate up to 5% of the funds available under the Illinois Solar for All Program to community-based groups to assist in grassroots education efforts related to the Illinois Solar for All Program."[156] Notably, for grassroots education efforts, this amount is not based only on the balance of the RERF; it is instead "up to 5% of the funds available under the Illinois Solar for All Program," and thus also inclusive of any Section 1-75(c) or 16-108(k) funds. In implementation, the Agency decided to award grassroots education contracts through a competitive RFP process, with those entities serving as subcontractors to the Agency's Illinois Solar for All Program Administrator and performing grassroots education activities under that master contract.[157]

In addition to grassroots education, "costs associated with procuring experts, consultants, and the program administrator . . . and related incremental costs, and costs related to the evaluation of the Illinois Solar for All Program" may be paid out of the RERF.[158]

2.6.2. Illinois Solar for All—Sub-programs

Illinois Solar for All is designed to incent specific defined project types, and to this end, Illinois Solar for All features four sub-programs with percentage-based Fund balance allocations applicable to each. Notably, and as described further in Chapter 8, the Agency understands these percentage-based allocations to be applicable only to RERF funds, and not to funds collected by the utilities but available for Illinois Solar for All use (as the law uses the phrasing "monies available in the Illinois Power Agency Renewable Energy Resources Fund"[159] in making those percentage-based assignments).

For the first three sub-programs, these allocations may be changed if, after stakeholder input through a stakeholder process, the Agency or its administrator determines that incentives for any those three sub-programs "have not been adequately subscribed to fully utilize the Illinois Power Agency Renewable Energy Resources Fund."[160] As explained further in Chapter 8, there have been varying levels of initial participation across the three sub-programs; however, the Agency believes that given that Illinois Solar for All opened for project applications only months ago, any such reallocation of funding would be premature.

The first three sub-programs also contain "a goal . . . that a minimum of 25% of the incentives for this program be allocated to community photovoltaic projects in environmental justice communities."[161] The Agency's definition offered to the term "environmental justice community" is discussed further in Chapter 8 and, at present, is described more comprehensively on the Illinois Solar for All website, which allows for users to search qualification status by address.[162]

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[156] Id.

[157] More information on the Illinois Solar for All grassroots education process can be found here: https://www.illinoissfa.com/grassroots-education and in Section 8.15.5.

[158] 20 ILCS 3855/1-56(b)(3).

[159] 20 ILCS 3855/1-56(b)(2).

[160] Id.

[161] 20 ILCS 3855/1-56(b)(2)(A), (B), (C).

[162] See: https://www.illinoissfa.com/environmental-justice-communities.

Discussion of the four sub-programs is below. In addition to these four sub-programs, "a party may propose an additional low-income solar or solar incentive program, or modifications to the programs proposed" and that additional program or modification will be approved "if the additional or modified program more effectively maximizes the benefits to low-income customers after taking into account all relevant factors, including, but not limited to, the extent to which a competitive market for low-income solar has developed."[163]

2.6.2.1. Low-Income Distributed Generation Incentive

The Low-Income Distributed Generation Incentive sub-program "provide[s] incentives to low-income customers, either directly or through solar providers, to increase the participation of low-income households in photovoltaic on-site distributed generation."[164] Used for this sub-program and others, the term "solar provider" has no definition in the statute; to allow the market to determine appropriate models, the Agency has determined that "solar providers" can refer to any entity which has a contractual relationship with the low-income customer in connection with the underlying photovoltaic system (whether in the form of purchase, leasing, installation, aggregation, or financing).

This program contains a firm, unequivocal commitment to using job trainees; the law provides that "companies participating in this program that install solar panels shall commit to hiring job trainees for a portion of their low-income installations,"[165] although the term "portion" is undefined in the law. Nevertheless, the IPA believes that "portion" should not be understood as too small to be de minimis, nor too large to be a "majority" (a term which likely would have been used had it been intended), and its determination for the required level of job trainee participation is discussed further in Chapter 8.

For this sub-program, the law also requires that "an administrator shall facilitate partnering the companies that install solar panels with entities that provide solar panel installation job training."[166] The IPA understands this to mean its third-party Program Administrator engaging in such facilitation and this is presently part of the Program Administrator's scope of work.

The law also includes a provision that "[c]ontracts entered into under this paragraph may be entered into with an entity that will develop and administer the program."[167] It is unclear how the administrator could leverage state funds for this use, and at present, all such contracts will be entered into between Approved Vendors (Sellers) and the State of Illinois or a participating utility (Buyers).

This sub-program is allocated 22.5% of available RERF funds.

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[163] 20 ILCS 3855/1-56(b)(4). While an additional program (focused on multi-family properties) was proposed by Elevate Energy and GRID Alternatives in Docket No. 17-0838, that proposal was not adopted by the Commission; instead, the Commission suggested that the IPA "monitor the treatment of multi-family buildings under the Low-Income Distributed Generation Incentive sub-program" and "include the results of that monitoring for the Commission and explain its decision regarding whether to propose a program for this market segment" as part of its 2019 Plan revision filing. Docket No. 17-0838, Final Order dated April 3, 2018 at 153. No additional programs were proposed in Docket No. 19-0995.

[164] 20 ILCS 3855/1-56(b)(2)(A).

[165] Id.

[166] Id.

[167] Id.

2.6.2.2. Low-Income Community Solar Project Initiative

Through the low-income community solar project initiative, "[i]ncentives shall be offered to low-income customers, either directly or through developers, to increase the participation of low-income subscribers of community solar projects."[168] Again, the term "developer" is undefined; as community solar project subscriptions may be actively marketed by entities other than the literal definition of photovoltaic project "developers," no guidance is provided as to whether this phrasing is intended to include all entities marketing such subscriptions or only the project's actual developer. The Agency has interpreted "developer" to be an Approved Vendor or their project partner.

A requirement of this program is that each participating project's developer "shall identify its partnership with community stakeholders regarding the location, development, and participation in the project."[169] Undefined in this phrasing is what constitutes a "community stakeholder," or whether the project itself must include "community stakeholders" from the community in which the project is located (presumably so), the community of any subscribers (unclear), or both (also unclear).

The law further provides that "[i]ncentives should also be offered to community solar projects that are 100% low-income subscriber owned, which includes low-income households, not-for-profit organizations, and affordable housing owners."[170] This phrasing leaves program eligibility unclear—must all subscribers be "low-income" for eligibility, or—as the law uses the term "also" in designating 100% low-income projects for eligibility—only a portion (and if so, what portion)? Not all subscriptions are "ownership"; does ownership matter, and should it result in a heightened incentive? These questions have no obvious answer from the law, but the Agency's approaches are discussed further in Chapter 8.

The law also provides that "[c]ontracts entered into under this paragraph may be entered into with developers,"[171] which the IPA has interpreted to mean that a project developer, upon a sufficient showing of low-income participation, may qualify for a contract award.

This sub-program is allocated 37.5% of available RERF funds.

2.6.2.3. Incentives for Non-profits and Public Facilities

The third sub-program provides that funding "shall be used to support on-site photovoltaic distributed renewable energy generation devices to serve the load associated with not-for-profit customers and to support photovoltaic distributed renewable energy generation that uses photovoltaic technology to serve the load associated with public sector customers taking service at public buildings."[172] Stated differently, the program operates similarly to the first sub-program—an incentive for on-site DG through a higher-priced REC contract—only with different eligibility requirements (not-for-profit customers and public sector customers taking service at public buildings).

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[168] 20 ILCS 3855/1-56(b)(2)(B).

[169] Id.

[170] Id.

[171] Id.

[172] 20 ILCS 3855/1-56(b)(2)(C).

This raises the question of whether all non-profits and all public sector entities may qualify for the sub-program, or whether some nexus with the broader "low-income" intent of Illinois Solar for All is required. As discussed further in Chapter 8, the IPA believes that some level of community involvement may be required to maintain consistency with the spirit of the law.[173]

This sub-program also combines referenced elements of each of the prior programs, stating that "[c]ontracts may be entered into with an entity that will develop and administer the program or with developers,"[174] which carries similar challenges to those referenced above.

This sub-program is allocated 15% of available RERF funds.

2.6.2.4. Low-Income Community Solar Pilot Projects

The fourth sub-program allows that "persons, including, but not limited to, electric utilities, shall propose pilot community solar projects."[175] Such projects are allowed by law to be larger than 2 megawatts ("MW"), but "the amount paid per project under this program may not exceed $20,000,000."[176] Such projects "must result in economic benefits for the members of the community in which the project will be located" and "must include a partnership with at least one community-based organization" (with that term again undefined).[177]

Beyond the allowance that the project may be proposed by an electric utility and may be larger than the law otherwise allows, it is not clear what other requirements make such facilities sufficiently distinct so as to be considered a "pilot project." While it may be tempting to require demonstration of innovation through this program, at present, the IPA does not believe that any additional limitations or conditions on such projects should be inferred.

While the manner through which contracts are entered into in the other sub-programs is not established in the statute, the low-income community solar pilot project sub-program must be "competitively bid by the Agency," which the Agency understands to be consistent with the procurement requirements of Section 16-111.5 of the PUA where applicable.

The law further provides that funding under this sub-program "may not be distributed solely to a utility," and that some funds "must include a project partnership that includes community ownership by the project subscribers." The IPA thus understands that, for bid selection purposes, disbursement to an entity other than a utility is a prerequisite for a utility bid to win, while satisfying the referenced partnership through a winning bid is a prerequisite for any other bid to win.

As with the other sub-programs, the law again provides that contracts under the Low-Income Community Solar Pilot Project program "may be entered into with an entity that will develop and administer the program or with developers."[178]

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[173] More information on what is presently required from qualifying non-profits and public facilities can be found here: https://www.illinoissfa.com/programs/nonprofit-organizations-and-public-agencies.

[174] Id.

[175] 20 ILCS 3855/1-56(b)(2)(D).

[176] Id.

[177] Id.

[178] 20 ILCS 3855/1-56(b)(2)(D).

This sub-program is allocated 25% of available RERF funds.

2.6.3. Illinois Solar for All—Additional Requirements

Section 1-56(b) also provides that, under Illinois Solar for All, "[e]ach contract that provides for the installation of solar facilities shall provide that the solar facilities will produce energy and economic benefits, at a level determined by the Agency to be reasonable, for the participating low income customer."[179] The Agency believes that this requirement is in part met through the premium attached to the REC price under Illinois Solar for All (and "energy benefits" for community solar and distributed generation projects are already handled though bill crediting and net metering provisions over which the Agency lacks jurisdiction), and provides support for consumer protections to ensure that low income customers indeed receive benefits in entering into contractual arrangements with installers, project developers, aggregators, or other intermediaries. Those specific requirements are discussed in more detail in Section 6.13 and Chapter 8.

Illinois Solar for All contracts must also "ensure the wholesale market value of the energy is credited to participating low-income customers or organizations,"[180] which, again, is an issue handled through net metering, but can be emphasized in resulting contracts. Contracts must also ensure that "tangible economic benefits flow directly to program participants, except in the case of low-income multi-family housing where the low-income customer does not directly pay for energy;"[181] while it is unclear from the law what constitutes a "tangible economic benefit" (or, for that matter, a "program participant," especially if the underlying contract is with a project developer or other such entity), the Agency will continue to require, consistent with the Commission Order approving the Initial Plan,[182] that ongoing annualized payments by the customer (if any) must be less than 50% of the annual first year estimated production and/or utility default service net metering value to be received by the customer. Additionally, this language appears to provide further support for ensuring that marketing practices are standardized such that low-income customers receive clear, standardized information about the benefits to be expected from an Illinois Solar for All project.

The law also seeks for priority to be given to projects that "demonstrate meaningful involvement of low-income community members in designing the initial proposal."[183] Here again, the law provides no definition of "meaningful involvement" nor does it define a "low-income community member," and it is unclear whether this would be distinct from an "environmental justice community" or what constitutes a community "member." The law further provides that "[a]cceptable proposals to implement projects must demonstrate the applicant's ability to conduct initial community outreach, education, and recruitment of low-income participants in the community;" again, the term "participants in the community" is undefined and entirely unclear, but the Agency does understand this language as providing that entities seeking to market installations or community solar subscriptions using Illinois Solar for All contracts must, at a minimum, be certified by the Agency and possess some baseline level of demonstrated competency. The Agency's approach to vendor certification through its Approved Vendor process is discussed further in Chapters 6 and 8.

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[179] 20 ILCS 3855/1-56(b)(2).

[180] Id.

[181] Id.

[182] Docket No. 17-0838, Final Order dated April 3, 2018 at 150-151.

[183] 20 ILCS 3855/1-56(b)(2).

As growing the low-income solar market involves more than just REC delivery contracts making photovoltaics more economic, the law also requires that projects "must include job training opportunities if available," and seeks that such job training opportunities should be effected through coordination with the job training programs proposed in ComEd's Workforce Development Plan. The Agency's approach to encouraging that projects use job trainees to help build the low-income solar marketplace is discussed further in Chapter 8.

2.6.4. Illinois Solar for All—Third-party Program Administrator

To assist the Agency in its administration of the Illinois Solar for All Program, Section 1-56(b)(5) provides that the Agency may retain a third-party program administrator (or administrators) through a Request For Qualifications and competitive bid process. The selection criteria and requirements must include, but are not limited to, "experience in administering low-income energy programs and overseeing statewide clean energy or energy efficiency services."

As both its Illinois Solar for All third-party program administrator and the "expert consulting firms" to assist with implementing and operating the Adjustable Block Program merely "may" be retained, the Agency understands that it could, in theory, use the same entity to assist it with the implementation of both programs (and is not prohibited from using either third-party administrator to assist it with the implementation of the Community Renewable Generation Program).[184] In September 2018, after the conclusion of its RFQ and RFP process, the Agency entered into a contract with Elevate Energy ("Elevate") under which Elevate serves as the third-party program administrator for the Illinois Solar for All Program.

2.7 2019 Legislative Proposals

During the Spring 2019 session of the Illinois General Assembly, multiple bills were introduced that would impact the IPA's planning and procurement processes for not only procuring renewable energy credits, but also for supporting the development of additional renewable energy generation more generally. These bills included the following:

- HB 3624/SB 2132 (the "Clean Energy Jobs Act")
- HB 2861/SB 660 (known colloquially as the "Clean Energy Progress Act")
- HB 2966/SB 1781 (known colloquially as the "Path to 100 Act")
- HB 2713/SB 2080 (the "Coal to Solar and Energy Storage Act")
- HB 125/SB 135 (the "Competitive Clean Energy Act")

The Spring 2019 session concluded on May 31, 2019 without any of the above bills making significant advancement.[185] The General Assembly concluded its veto session on November 14, 2019, again without enacting any energy legislation. None of the bills listed above, nor any new energy bills, advanced prior to the General Assembly going on hiatus starting in March 2020 due to the presently-ongoing COVID-19 pandemic.

As of the publishing of this Final Revised Plan (April 20, 2020), the Agency understands that negotiations among at least certain principal bill interests are ongoing, and that working groups

[184] In its Order approving the Plan, the Commission rejected a proposal requiring that the IPA use separate administrators for the Adjustable Block Program and Illinois Solar for All Program and rejected a proposed requirement that the program administrator and its subcontractors be limited to non-profit entities. See Docket No. 17-0838, Final Order dated April 3, 2018 at 161-164.

[185] For more background, see: https://www.dailyherald.com/news/20190521/energy-legislation-on-the-back-burner-in-springfield.

continue to convene – even if virtually or by phone rather than in person – to continue discussing potential legislation. However, as no legislation significantly reforming the Agency's responsibilities under this Plan has passed as of the time of the Plan's approval or the filing of this Final Revised Plan, the Agency will faithfully implement the Plan as described herein.

The Agency is presently monitoring legislative discussions and has been an active participant in hearings, working group meetings, and other discussions in which its interests and responsibilities are implicated. Should any legislation pass which significantly modifies the Agency's responsibilities under this Revised Plan, the Agency hopes that any such legislation will expressly address which portions of the Agency's Revised Plan, if any, shall continue to remain in effect.

3. RPS Goals, Targets, and Budgets

The original Illinois Renewable Portfolio Standard was established in 2007 through Public Act 95-0481 and became effective on June 1, 2008. That RPS set annual percentage goals relative to eligible retail loads in the state for the procurement of renewable energy resources, starting with at least 2% by the beginning of the 2008-2009 delivery year and rising to 25% by the 2025-2026 delivery year.[186] These goals initially applied only to the load associated with "eligible retail customers"—the residential and small commercial customers who receive fixed-price bundled service from the utilities, rather than switching to hourly priced service or to service from an Alternative Retail Electric Supplier. In 2009, Public Act 96-0033 added Section 16-115D to the Public Utilities Act, which created separate RPS obligations for ARES. The ARES RPS goals were based on the quantity of metered electricity delivered by the ARES to retail customers in Illinois, but with very different compliance mechanisms as explained in Section 2.1.3 above.

P.A. 99-0906 revised the RPS to apply the goals to all retail customers and to phase out the ARES compliance obligations over a two-year period which terminated on May 31, 2019 (see Section 3.2 for more information). These revisions also consolidated the RPS into a single, centralized planning mechanism for procurements and programs as described in this Plan.

The revisions to the RPS include a number of REC procurement goals and targets. As used in this Revised Plan, the Agency considers a "goal" to be an overall percentage of load to be procured in the form of RECs for a given year based upon that year's mandated RPS requirement.[187] A "target," on the other hand, is the number of RECs for a specific procurement event or program based upon the specific goal or numerical mandate.

Under the changes to the RPS made via P.A. 99-0906, the annual RPS percentage goal remains the same as was previously found in Section 1-75(c)(1) of the IPA Act—17.5% in the 2020-2021 delivery year, rising incrementally by 1.5 percentage points annually to 25% by 2025-2026—but this goal is now applied to all retail electricity sales rather than sales limited to eligible retail customers. Meeting the RPS goals of the Act for this Revised Plan would require procuring an additional 16.2 million RECs for the 2020-2021 delivery year, increasing to the forecasted procurement of an additional 19.8 million RECs for the 2030-2031 delivery year.

In addition, specific REC targets call for various quantities of RECs to be procured in increasing steps starting with the 2017-2018 delivery year through the end of the 2030-2031 delivery year, including:

- 1,000,000 RECs from new utility-scale wind projects and 1,000,000 RECs from new utility-scale and brownfield site solar projects to be delivered annually (with delivery beginning no earlier than June 1, 2019, and no later than June 1, 2021[188]) procured through the Initial Forward Procurement which was conducted separately from the Initial Plan; and

- A total of at least 2,000,000 RECs delivered annually each from new wind and new photovoltaic projects by the end of the 2020-2021 delivery year, ramping up to 3,000,000

[186] 220 ILCS 5/16-111.5(a).

[187] For example, the RPS "goal" for the 2020-2021 delivery year is 17.5% of the retail load.

[188] Public Act 101-0113 allows for an extension of this date if "the project has delays in the establishment of an operating interconnection with the applicable transmission or distribution system as a result of the actions or inactions of the transmission or distribution provider, or other causes for force majeure as outlined in the procurement contract." In such a case, the first REC delivery deadline may be extended to "not later than June 1, 2022."

RECs delivered annually each from new wind and new photovoltaic projects by the end of the 2025-2026 delivery year, and reaching 4,000,000 RECs delivered annually each from new wind and new photovoltaic projects by the end of 2030-2031. (RECs from the Initial Forward Procurement count toward these targets.)

This Chapter contains calculations of RPS targets, summaries of RPS portfolios, and summaries of RPS budgets for delivery years 2020-2021 through 2025-2026. Additional details are available in Appendix B.

3.1. Statewide Goals and Allocation of Cost and RECs from RPS Procurements to Each Utility

The specific numerical targets included in the Act—for instance, the 2,000,000 RECs from new wind and new photovoltaics by 2020-21—are *statewide* targets which do not specify individualized REC targets for each utility. In 2017, 2018, and 2019, the Agency procured RECs through its competitive procurements based on statewide RPS targets rather than individual targets by utility. Contract quantities stemming from those procurements were then assigned to each of the three participating utilities based on an RPS Budget-weighted basis.

For this Revised Plan, the Agency proposes to continue conducting the procurement of RECs (to the extent possible given budget constraints discussed elsewhere in this Chapter) based on statewide RPS goals and targets which, due to changes in load forecasts and the presence of new RECs under contract, have been updated from those contained in the Initial Plan. The cost of the RECs associated with RPS procurements will be allocated to each utility through REC procurement contracts specific to the applicable utility (and independent of supplier performance under other utilities' contracts), based on each utility's Renewable Portfolio Standard Budget ("RPS Budget"). Table 3-1 shows the proposed allocation across each of the three utilities based on each utility's cost cap rate and eligible load.[189]

[189] This allocation method was initially developed to allocate the RECs from the August 31, 2017 Initial Forward Procurement and was based on the RPS Budget for 2020-2021, which uses the prior year delivered volumes as reference. The 2019-2020 reference delivery year was used because it will be the first year when all load, including that served by ARES, will be under the IPA's REC procurements, thus making the resulting RPS Budget a better representation of future RPS Budgets. As shown in Table 3-1, the allocation to each utility is based on the utility's share of the 2020-2021 delivery year RPS Budget. As noted in Chapter 6, the same allocation will be used for the Adjustable Block Program procurements to each utility.

Table 3-1: Utility REC Cost Allocations

Utility	Reference Year Forecasted Delivered Volume [MWh][190]	Cost Cap Rate[191] [$/MWh]	RPS Budget for 2020-2021 Delivery Year [$][192]	Allocation Based on RPS Budget for 2020-2021 Delivery Year [%]
Ameren Illinois	35,079,537	1.8054	63,332,597	27.793%
ComEd	86,640,000	1.8917	163,896,888	71.925%
MidAmerican*	517,599	1.2415	642,599	0.282%

*MidAmerican Applicable load, explained in Section 3.4

Under this allocation, for every $1,000,000 of cost incurred to procure RECs, $277,930 and associated REC contracts would be allocated to Ameren Illinois, $719,250 and associated RECs to ComEd, and $2,820 and associated RECs to MidAmerican.

3.2. Impact of the Phase out of Alternative Retail Electric Supplier RPS Obligations

P.A. 99-0906 resulted in changes to the requirements for ARES RPS compliance. As outlined in Section 2.1.3, prior to P.A. 99-0906's revisions to Section 16-115D of the Public Utilities Act, ARES could meet their compliance requirements through Alternative Compliance Payments ("ACP") or through a combination of ACPs, generation using eligible renewable resources, purchasing electricity generated using eligible renewable resources, and purchasing RECs.

Under the RPS requirements enacted through P.A. 99-0906, after a two-year transition period that ended May 31, 2019, the IPA is now responsible for procuring RECs for virtually all retail load in Illinois, including load served by ARES. During the transition period, the REC quantity associated with ARES load covered by the Agency's programs and procurements was based on 50% of ARES load for the 2017-2018 delivery year and 75% for the 2018-2019 delivery year. For the 2019-2020 and each delivery year thereafter, the Agency is responsible for procuring the REC quantity associated with 100% of ARES load through its programs and procurements.[193] Therefore, ARES no longer have an obligation to procure RECs or make ACPs for RPS compliance.[194]

The impact of the ARES RPS compliance obligation phase-out is that the volume of RECs required to be procured by the IPA to meet Section 1-75(c)(1)(B)'s percentage-based goals increased significantly over the prior volumes required to meet those same percentages.

3.3. Section 1-75(c)(1)(H)(i) ARES Option to Supply RECs for their Retail Customers

Section 1-75(c)(1)(H) of the Act provides an exception to the phase out of ARES RPS obligations described in Section 3.2. Under this exception, an ARES may use self-supplied RECs to meet a portion

[190] The 2019-2020 delivery year is the reference year for the 2020-2021 delivery year.

[191] The Cost Cap Rate for each utility is defined in Section 1-75(c)(1)(F) of the Act as "the greater of 2.015% of the amount paid per kilowatthour by [eligible retail] customers during the year ending May 31, 2007 or the incremental amount per kilowatthour paid for these resources in 2011." 2.015% of the bundled price paid per kWh by eligible retail customers in the 2006-2007 delivery year was 0.18054 cents for Ameren Illinois, 0.18917 cents for ComEd, and 0.12415 cents for MidAmerican. The incremental amount per kWh paid for renewable resources in 2011 was 0.00584 cents for Ameren Illinois, and 0.0057 cents for ComEd. MidAmerican did not participate in IPA-administered renewable energy procurements in 2011; therefore, it did not have an incremental amount for that year.

[192] Beginning with the 2019-2020 delivery year, the RPS Budget for each utility is calculated by multiplying the values of the preceding two columns of the table, as specified by Section 1-75(c)(1)(F) of the Act ("To arrive at a maximum dollar amount of renewable energy resources to be procured for the particular delivery year, the resulting per kilowatthour amount shall be applied to the actual amount of kilowatthours of electricity delivered […] by the electric utility in the delivery year immediately prior to the procurement to all retail customers in its service territory.").

[193] 20 ILCS 3855/1-75(c)(1)(B); 220 ILCS 5/16-115D(a)(3.5).

[194] 220 ILCS 5/16-115D(i).

(and possibly all) of the REC procurement requirements applicable to its load. To do so, the ARES had to first make an informational filing to the ICC within 45 days of the effective date of Public Act 99-0906 (i.e., within 45 days of June 1, 2017), indicating that it owned a generating facility or facilities as of December 31, 2015, that produced RECs eligible to meet the RPS, provided that those facilities were not powered by wind or solar photovoltaics. The ARES must also notify the Agency and the applicable utility by February 28 of each year of its election to supply RECs to its retail customers and include the amount of RECs to be supplied.

One ARES informational filing covering an owned generation facility outside of Illinois was submitted on a confidential basis to the ICC by the deadline of July 15, 2017.

Section 1-75(c)(1)(H) of the Act provides that the procurement of renewable energy resources for a given year shall be reduced if the ARES uses RECs from an ARES-owned generation facility to supply its retail customers. The amount of RECs that can be supplied by ARES-owned/ generation is subject to several limitations. Specifically, the Act provides that:

> *"For the delivery year beginning June 1, 2018, the maximum amount of renewable energy credits to be supplied by an alternative retail electric supplier under this subparagraph (H) shall be 68% multiplied by 25% multiplied by 14.5% multiplied by the amount of metered electricity (megawatt-hours) delivered by the alternative retail electric supplier to Illinois retail customers during the delivery year ending May 31, 2016."* [195]
>
> *"For delivery years beginning June 1, 2019 and each year thereafter, the maximum amount of renewable energy credits to be supplied by an alternative retail electric supplier under this subparagraph (H) shall be 68% multiplied by 50% multiplied by 16% multiplied by the amount of metered electricity (megawatt-hours) delivered by the alternative retail electric supplier to Illinois retail customers during the delivery year ending May 31, 2016, provided that the 16% value shall increase by 1.5% each delivery year thereafter to 25% by the delivery year beginning June 1, 2025, and thereafter the 25% value shall apply to each delivery year."* [196]

The Act limits the total amount of RECs that can be supplied by all ARES through owned generation:

> *"For each delivery year, the total amount of renewable energy credits supplied by all alternative retail electric suppliers shall not exceed 9% of the Illinois target renewable energy credit quantity. The Illinois target renewable energy credit quantity for the delivery year beginning June 1, 2018 is 14.5% multiplied by the total amount of metered electricity (megawatt-hours) delivered in the delivery year immediately preceding that delivery year, provided that the 14.5% shall increase by 1.5% each delivery year thereafter to 25% by the delivery year beginning June 1, 2025, and thereafter the 25% value shall apply to each delivery year."*[197]

[195] 20 ILCS 3855/1-75(c)(1)(H)(iii).

[196] Id.

[197] Id.

In order to take into account the self-supply by the ARES, the Act requires that the charges which are applicable to the retail customers of the ARES be reduced by the ratio of the RECs supplied by the ARES to the ARES's RPS target. Specifically, the Act states that:

> *"If the requirements set forth in items (i) through (iii) of this subparagraph (H) are met, the charges that would otherwise be applicable to the retail customers of the alternative retail electric supplier under paragraph (6) of this subsection (c) for the applicable delivery year shall be reduced by the ratio of the quantity of renewable energy credits supplied by the alternative retail electric supplier compared to that supplier's target renewable energy credit quantity. The supplier's target renewable energy credit quantity for the delivery year beginning June 1, 2018 is 14.5% multiplied by the total amount of metered electricity (megawatt-hours) delivered by the alternative retail supplier in that delivery year, provided that the 14.5% shall increase by 1.5% each delivery year thereafter to 25% by the delivery year beginning June 1, 2025, and thereafter the 25% value shall apply to each delivery year."*[198]

By April 1 of each year, the IPA posts a report to its website outlining on the aggregate number of RECs being supplied by the ARES for the upcoming delivery year under this provision, starting June 1.[199] This quantity will be accounted as RECs from "other technologies" (i.e., other than wind or solar) and will reduce the overall RPS Target for that delivery year. Those targets are shown (unadjusted) in Table 3-13.

3.4. MidAmerican Volumes

While procurement plans are required to be prepared annually for Ameren Illinois and ComEd, Section 16-111.5(a) of the PUA states that "[a] small multi-jurisdictional electric utility . . . may elect to procure power and energy for all or a portion of its eligible Illinois retail customers" in accordance with the planning and procurement provisions found in the IPA Act. On April 9, 2015, MidAmerican first formally notified the IPA of its intent to procure power and energy for a portion of its eligible retail customer load through the IPA through its participation. That portion is essentially the incremental load that is not forecasted to be supplied in Illinois by what MidAmerican, a vertically-integrated utility in Iowa that owns generation there (as well as a share of the Quad Cities nuclear plant in Cordova, IL), assigns to Illinois as its jurisdictional generation. Each year since, MidAmerican has remained a part of that process to meet the remaining "portion" of its load.

MidAmerican's status as a multi-jurisdictional utility that uses its own generating resources to meet a portion of its Illinois load creates a unique situation for RPS compliance. Unlike Ameren Illinois and ComEd, for which all retail load is subject to the RPS goals and targets (subject to limited exceptions outlined above), the MidAmerican load for which the RPS goals and targets are applicable has traditionally been only that load that is subject to the IPA's annual planning and procurement process for conventional power. As mentioned above, that amount has been the forecast load in excess of

[198] Id.

[199] For the 2020-2021 delivery year, see: https://www2.illinois.gov/sites/ipa/Documents/2020-2021%20Delivery%20Year%20ARES%20REC%20Report.pdf..

MidAmerican's Illinois-allocated generation in any given delivery year, which has generally been only 25-35% of its total jurisdictional load.[200]

As a significantly smaller Illinois utility to begin with, and with only a portion of its load applicable to the Illinois RPS, the MidAmerican share of Illinois RPS and Zero Emission standard contracts has often been only a fraction of that allocated to ComEd and Ameren Illinois.

3.4.1. Change to MidAmerican's Load Forecast Methodology

In 2018, MidAmerican proposed and the Commission approved a change in approach to forecast MidAmerican's generation used for electricity procurement.[201] This change caused a sudden and significant reduction of the load subject to the IPA electricity procurement process, as seen in Table 3-2 below.

Table 3-2: MidAmerican Applicable Load and RPS Budget before and after Change in Forecast Approach

Compliance Delivery Year	Reference Delivery Year	Applicable Load Before Change [MWh][202]	Applicable Load After Change [MWh][203]	RPS Budget Before Change [$]	RPS Budget After Change [$]
2020-2021	2019-2020	616,844	0	765,812	0
2021-2022	2020-2021	527,768	0	655,224	0
2022-2023	2021-2022	519,093	126	644,454	156
2023-2024	2022-2023	509,457	400	632,491	497
2024-2025	2023-2024	390,919	644	485,326	800
2025-2026	2024-2025	372,831	929	462,870	1,153

In the 2019 Electricity Procurement Plan, the IPA explained the change in approach to forecast MidAmerican's generation:

> *In reviewing the load forecast and resource portfolio information supplied by MidAmerican for the 2019 Plan, the IPA notes that MidAmerican revised the methodology used for its generation supply forecast. The prior forecast methodology utilized production cost models to dispatch the Illinois Historical Resources whenever the expected cost to generate electricity is less than the expected cost of acquiring it in the market. The revised methodology is based on the utilization of MISO Unforced Capacity ("UCAP") from the baseload Illinois Historical Resources to determine the generation available to meet MidAmerican's Illinois eligible load.*[204]

[200] The Commission specified this approach for the procurement of renewable resources to meet the RPS compliance targets applicable to MidAmerican in Docket No. 15-0541, determining that only the portion of MidAmerican's load subject to the IPA's planning and procurement process is subject to Section 1-75(c) of the Act's requirements.

[201] Docket No. 18-1564, Final Order dated November 26, 2018.

[202] Based on load volumes presented in the Initial Plan.

[203] Based on volumes provided by MidAmerican in its response submitted for the preparation of this Revised Plan.

[204] MidAmerican allocates 10.86% of the UCAP ratings of its baseload units for Illinois Historical Generation.

MidAmerican's revised methodology utilizes the full capability of each baseload generation asset, represented by the UCAP MW values as determined by MISO for each year's Planning Resource Auction. The UCAP values de-rate generating unit capabilities by considering historical forced outage rates and operating conditions under summer peak conditions. The IPA, for the 2019 Plan, recommends no changes to the determination of monthly on-peak and off-peak block energy requirements other than the replacement of generation production values with the UCAP values for each of the following baseload resources:

- *Coal resources including: Neal Unit #3, Neal Unit #4, Walter Scott Unit #3, Louisa Generating Station, and Ottumwa Generating Station.*
- *Nuclear Resources: Quad Cities Nuclear Power Station.*

The supply capability that is determined is netted against the forecast of MidAmerican Illinois load to calculate the monthly on-peak and off-peak shortfalls which will be met with energy block purchases in the IPA procurements. In determining the amount of block energy products to be procured for MidAmerican, the IPA treats the allocation of capacity and energy from MidAmerican's Illinois Historical Resources in a manner analogous to a series of standard energy blocks. This approach is consistent with the 2018 Procurement Plan approved by the Commission.

As shown in Table 3-2 above, one unintended consequence of this reduction is that it would cause the annual commitments of already procured RECs and associated spending to exceed MidAmerican's projected RPS annual budget using the prior-applied methodology for determining that budget amount. Stated differently, MidAmerican was previously assigned contracts assuming it would have ~$650,000 available to spend annually on renewable energy procurement. Upon those obligations becoming due and payments needing to be made, applying MidAmerican's new load forecasting methodology in combination with the prior approach to determining MidAmerican's RPS budget would result in MidAmerican only potentially having hundreds of dollars available for renewable energy resource procurement.

This could have left entities holding contracts with MidAmerican at risk of contact curtailment (i.e., the curtailment of delivered contract quantities in line with money available for payment), as absent an alternative interpretation to calculating MidAmerican's available RPS budget, MidAmerican would not be authorized to meet those contract obligations without exceeding its statutory RPS rate impact cap. Such a curtailment could have caused some new renewable energy facilities dependent on revenue from MidAmerican's contracts to suffer losses, leaving them potentially unable to generate enough revenue to cover costs.

3.4.2. Proposal to Correct Unintended Consequences of MidAmerican's Changed Forecast Approach

As described in more detail throughout Chapter 2, a primary objective informing Public Act 99-0906's reforms to the Illinois RPS was to reduce year-over-year funding volatility that effectively paralyzed leveraging RPS funds to support the development of new renewable energy generation. While such volatility was not completely eliminated – the load forecasts received from ComEd and Ameren Illinois feature lower funding availability than the Agency perhaps expected, due to projected decline in the demand for electricity – year-over-year changes for those utilities remain relatively minor, and enough stabilization was introduced to allow for the execution of the types of

long-term contracts providing sufficient revenue certainty to allow developers to secure financing to develop new renewable generation. Within the spirit of these efforts, the Agency believes steps must be taken to stabilize MidAmerican's year over year RPS budgets. By so doing, the Agency can ensure that those funds collected can be put toward their intended use (facilitating the development of new generation), while protecting existing contract holders against unforeseen curtailments.[205]

Perhaps notably, MidAmerican's Zero Emissions Credit ("ZEC") payment calculation uses a fixed percentage allocator based upon the ratio of the supply gap (electricity procured by the IPA on behalf of MidAmerican) to MidAmerican's retail load. In determining that percentage (13.266%), actual load data for the 2016-2017 delivery year was used.

The IPA believes a similar approach is warranted for MidAmerican's RPS budgets. Thus, the IPA proposes in this Revised Plan to use a proxy to calculate MidAmerican's Applicable Load. This proxy for applicable load would likewise be a percentage of MidAmerican's total Illinois retail load.

Going forward, the Agency proposes that MidAmerican's Applicable Load for the purposes of RPS compliance (i.e., calculations of REC targets, budgets, and allocation of REC contracts in this Revised Plan) should be fixed at 26.025% of MidAmerican's annual total Illinois retail load. This percentage was calculated as follows: the average of MidAmerican's applicable load from the Initial Plan for the DYs 2019-2020 through 2037-2038 is 526,880 MWh. The average of the total retail load provided by MidAmerican in their July 2019 data response for the same period is 2,024,484 MWh. The ratio of the average applicable load from the Initial Plan to the average total retail load provided by MidAmerican in its data response yields a 26.025% proxy.[206]

Adopting this proposal produces Applicable Load volumes that are equivalent to those used in the Initial Plan, as shown on Table 3-3, which formed the basis to calculate MidAmerican's targets and budgets that supported MidAmerican's allocation of REC contracts and corresponding spending. Additionally, as can be observed in the Table below, MidAmerican's resulting Applicable Load and corresponding budget is relatively stable, year over year, helping to ensure not only that existing contracts are not curtailed, but also that the year to year volatility that resulted in years of advocacy to "fix" a "broken" RPS does not persist for MidAmerican.

As this proposal was uncontested in Docket No. 19-0995, the IPA understands this proposal to have been adopted by the Commission through its Final Order in that proceeding approving the Plan.

[205] The risk of under collection may not be an issue through 2020-2021, as through that period, MidAmerican's balance collected in prior delivery years (which may then be "rolled over" for future years until 2020-2021) should be sufficient to cover its contracted annual RPS expenditures.

[206] The Agency notes that it did not receive any objections to this proposed approach in comments received on its draft Revised Plan. Rather, the Clean Grid Alliance, Environmental Law and Policy Center/Vote Solar, and the Natural Resources Defense Council expressed support for it.

Table 3-3: Comparison of MidAmerican's Applicable Load Using the Generation Forecast before Change and the Proposed Proxy for Determining Applicable Load and Budget

Compliance Delivery Year	Reference Delivery Year	Applicable Load Before Change August 1, 2017 [MWh][207]	RPS Budget Before Change August 1, 2017 [$][208]	Applicable Load Using Proxy [MWh][209]	RPS Budget Using Proxy [$]
2019-2020	2018-2019	704,364	874,468	528,791	656,494
2020-2021	2019-2020	616,844	765,812	517,599	642,599
2021-2022	2020-2021	527,768	655,224	518,437	643,640
2022-2023	2021-2022	519,093	644,454	519,350	644,774
2023-2024	2022-2023	509,457	632,491	520,308	645,963
2024-2025	2023-2024	390,919	485,326	521,252	647,135
2025-2026	2024-2025	372,831	462,870	522,222	648,338
2026-2027	2025-2026	475,331	590,123	523,149	649,490
2027-2028	2026-2027	395,422	490,916	524,135	650,713
2028-2029	2027-2028	472,535	586,652	525,148	651,972
2029-2030	2028-2029	432,084	536,432	526,220	653,302
2030-2031	2029-2030	396,202	491,885	527,567	654,974
2031-2032	2030-2031	405,524	503,458	529,097	656,875
2032-2033	2031-2032	386,254	479,534	530,592	658,730
2033-2034	2032-2033	556,310	690,659	532,165	660,683
2034-2035	2033-2034	795,579	987,711	533,702	662,592
2035-2036	2034-2035	706,470	877,083	535,287	664,559
2036-2037	2035-2036	693,364	860,811	536,991	666,675
2037-2038	2036-2037	654,366	812,395	538,704	668,801
	Total All Years	10,010,717	**12,428,305**	10,010,717	**12,428,305**

For the balance of this Revised Plan, MidAmerican's Applicable Load will be determined by using the proxy approach proposed in this Section.

[207] Based on load volumes presented in the Initial Plan.

[208] Budget used in the Initial Plan.

[209] Applicable Load equals 26.025% of Forecast Retail Load.

3.5. Cost Cap and Cost Recovery

The IPA's procurement of RECs on behalf of Illinois electric utilities is subject to monetary limitations in the form of a cost cap that limits the annual average net increase to all eligible retail customers to "no more than the greater of 2.015% of the amount paid per kilowatt-hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt-hour paid for these resources in 2011."[210] On a percentage basis, the cost cap determined under these criteria is unchanged from the RPS cost cap predating Public Act 99-0906; however, it is now applied to the actual quantity of electricity delivered in the prior delivery year to all applicable retail customers in the utility's service territory.[211] The cost cap rate, in cents per kilowatt-hour, is provided in Table 3-4.

Table 3-4: REC Procurement Cost Cap Rate by Utility[212]

Utility	RPS Cost Cap Rate [¢/kWh]
Ameren Illinois	0.18054
ComEd	0.18917
MidAmerican	0.12415

Each utility is entitled to recover the costs of the RECs procured to meet the RPS compliance requirements, subject to the cost cap limitations, along with "…the reasonable costs that the utility incurs as part of the procurement process and to implement and comply with plans and processes approved by the Commission…"[213]

Since the start of the 2017-2018 delivery year, the utilities are able to recover all of their costs—whether associated with RECs previously procured through prior-executed contracts, procured through the Initial Forward Procurements, procured through other competitive procurements, or procured through the other programs resulting from the implementation of the IPA's long-term renewable resource procurement plans[214]—through tariffs applicable to all of the utilities' customers. These tariffs took effect as of the June 2017 billing period and allow collections by utilities to recover the costs of RECs procured by the IPA. The Commission will conduct a single review, reconciliation and true-up of the utility's collections covering REC costs for the 2017-2018, 2018-2019, 2019-2020, and 2020-2021 delivery years no earlier than August 31, 2021.[215, 216]

3.6. RPS Compliance Procurement Priorities

The Act provides guidelines for prioritizing the REC procurements in the event that the cost cap limitations conflict with the RPS goals and targets such that the IPA cannot procure sufficient

[210] 20 ILCS 3855/1-75(c)(1)(E).

[211] Id.

[212] These figures are the same rates used in the IPA's 2017 Electricity Procurement Plan approved by the Commission. See: https://www2.illinois.gov/sites/ipa/pages/Prior_Approved_Plans.aspx at 12.

[213] 220 ILCS 5/16-108(k).

[214] For which the utility is the counterparty; for the Illinois Solar for All Program, the State of Illinois is (or will be) the counterparty to many REC delivery contracts with those payments funded using the Renewable Energy Resources Fund.

[215] See id.

[216] Subject to limits (discussed in Chapters 2 and 8 of this Revised Plan) based on any shortfall of funding to the IPA's Renewable Energy Resources Fund, a portion of any over-collection, up to half, in each of the 2017-2018, 2018-2019, and 2019-2020 delivery years may be used to fund the Illinois Solar for All Program.

additional quantities of RECs to meet goals or targets.[217] These priorities regarding the procurement of RECs take the following order, arranged based on descending priority:

- RECs procured under existing contracts;
- RECs procured with funding for the Illinois Solar for All Program;
- RECs procured to comply with the new wind and solar photovoltaic procurement requirements (including the Adjustable Block Program);
- RECs procured to meet the remaining RPS targets (REC Gap).

Based on the list above, the procurement of RECs under existing contractual obligations will have the highest priority, with the procurement of RECs to meet remaining RPS requirements having the lowest priority. The RPS Budget for each year will therefore be allocated in the order of these priorities, until goals are met, or there are no remaining funds available for that year (as well as allocation of expected expenditures for future years).

3.7. Wind/Solar Matching Requirement and Solar Split

The Act defines the annual REC targets for wind and solar generation in terms of the timing of the annual quantities to be procured and the technology preferences for the facilities generating the RECs.[218] The overall quantity of RECs procured to meet the RPS goals must include at least a combined 75% from wind and photovoltaic projects. This is a change from the prior RPS construct, under which there was a goal that 75% of the renewable energy resources come from wind, 6% from photovoltaics, and 1% from distributed generation.[219]

In addition to the wind and photovoltaic requirements that apply to the overall RPS goals, there are also specific numerical targets that apply to RECs from new wind and new photovoltaic projects. New projects are those projects energized after June 1, 2017.[220] The REC target deliveries from new projects from each technology are 2,000,000 RECs by the end of the 2020-2021 delivery year, 3,000,000 RECs by the end of the 2025-2026 delivery year, and 4,000,000 RECs by the end of the 2030-2031 delivery year. The new photovoltaic project REC procurement targets are further broken down to reflect the procurement of at least 50% of these targets from distributed photovoltaic renewable generation projects or photovoltaic community renewable generation projects using the Adjustable Block Program, at least 40% from utility-scale photovoltaic projects, at least 2% from brownfield site photovoltaic projects that are not community solar projects, and the remaining 8% not specified but determined through this Plan.

Furthermore, the total amount of RECs targeted for delivery from all new wind sources is intended not to exceed the total amount of RECs to be delivered from all new photovoltaic projects. In the event that the projected cumulative quantity of new wind project RECs to be delivered exceeds the quantity of new solar project RECs projected to be delivered by 200,000 RECs or more, the procurement targets for the programs contained in the Initial Plan will be adjusted as needed to bring the wind

[217] 20 ILCS 3855/1-75(c)(1)(F).

[218] 20 ILCS 3855/1-75(c)(1)(C).

[219] 220 ILCS 5/16-111.5(a).

[220] The IPA, in accounting for RECs from new projects towards the Section 1-75(c)(1)(C) REC targets, excludes RECs procured through the DG Procurements in 2017 because of their relative small quantity and uncertainty around their energized date. They are, however, included in compliance calculations to ensure that at least a combined 75% of RECs be from wind and photovoltaic projects.

and solar REC quantities back into balance.[221] Per the definition of "new photovoltaic projects" in the Act, RECs procured as part of the Illinois Solar for All Program (see Chapter 8) cannot be counted as new photovoltaic RECs for purpose of meeting Section 1-75(c)(1)(C)'s quantitative targets and therefore are not accounted as such in this Revised Plan, although these RECs would count toward the overall 75% of RECs coming from wind or photovoltaic resources.

In its Order approving the Initial Plan, the Commission confirmed that this balancing or "matching" requirement becomes effective as of June 1, 2021 (the last point at which projects from the Initial Forward Procurements can begin delivery of RECs).[222] Since that time, Public Act 101-0113 was signed into law, which extends the last point at which projects from the Initial Forward Procurements can begin delivery of RECs to "not later than June 1, 2022" should the project feature "delays in the establishment of an operating interconnection with the applicable transmission or distribution system as a result of the actions or inactions of the transmission or distribution provider, or other causes for force majeure as outlined in the procurement contract." As discussed in Chapter 2, this change in state law then should extend the applicable date under which the "matching" requirement until this new date on which deliveries from Initial Forward Procurement projects could be initiated; the IPA's proposal that the deadline for the matching requirement extend to June 1, 2022 was uncontested in Docket No. 19-0995 approving the Plan.

3.8. REC Portfolio

For the planning and development of the various procurements and programs under this Revised Plan, it is necessary to aggregate the utility level portfolios of all existing RECs under contract, including/in addition to all expected (procured and to be procured upon the closing of all blocks authorized under the Initial Plan) RECs under the Adjustable Block Program, into a single, statewide portfolio of RECs. That resulting statewide portfolio can then be examined against REC goals and targets mandated in the Act to estimate gaps that need to be closed through future procurement of RECs.

The following sections examine existing REC portfolios and the resulting statewide REC Portfolio after accounting for expected deliveries of RECs resulting from the planned Forward Procurement of utility-scale wind RECs, and the balance of the Adjustable Block Program.

3.9. Existing REC Portfolios - RECs Already Under Contract

The tables that follow show the existing REC portfolio of each utility and the aggregated statewide portfolio as of April 20, 2020.[223] The following glossary applies to these tables:

- "LTPPA" includes RECs procured under the Long-Term Power Purchase Agreements entered into in 2010;
- "Legacy DG" includes RECs procured under the Distributed Generation procurement events conducted by the IPA in 2015, 2016, and 2017;
- "Forward Procurements" include RECs procured under the initial forward procurements and the procurement events conducted to date by the IPA pursuant to the Initial Plan;

[221] Docket No. 17-0838, Final Order dated April 3, 2018 at 47-48.

[222] 20 ILCS 3855/1-75(c)(1)(B), (C).

[223] ILSFA REC commitments have been included in the utilities' existing REC portfolios (where a utility is contractual counterparty) for the 2018-2019 and 2019-2020 program years.

- "IPA Programs Solar" includes existing RECs procured and under contract resulting from the Adjustable Block Program and the Illinois Solar for All Program as of April 10, 2020.

Additionally, summary estimates of RECs to be procured and under contract upon the closing of all blocks authorized under the Initial Plan for the Adjustable Block Program (i.e., the new installed photovoltaic capacity estimated as needed to meet 2020's 1,000,000 REC target) are presented in Section 3.10, and additional details are presented in Chapter 6.

Table 3-5: Ameren Illinois Existing REC Portfolio

Del. Year	LTPPA Wind RECs	LTPPA Solar RECs	Legacy DG Solar RECs	Forward Procurements Wind RECs	Forward Procurements Solar RECs[224]	IPA Programs Solar RECs	Total Wind RECs	Total Solar RECs	Total RECs
2020-21	596,571	3,429	7,475	409,153	280,828	215,734	1,005,724	507,466	1,513,190
2021-22	596,571	3,429	7,040	863,696	883,363	287,668	1,460,267	1,181,501	2,641,768
2022-23	596,571	3,429	4,529	863,696	883,363	287,644	1,460,267	1,178,966	2,639,233
2023-24	596,571	3,429	4,330	863,696	883,363	287,621	1,460,267	1,178,743	2,639,010
2024-25	596,571	3,429	-	863,696	883,363	287,597	1,460,267	1,174,389	2,634,656
2025-26	596,571	3,429	-	863,696	883,363	287,573	1,460,267	1,174,366	2,634,633

[224] Including Brownfield Site Photovoltaics.

Table 3-6: ComEd Existing REC Portfolio

Del. Year	LTPPA Wind RECs	LTPPA Solar RECs	Legacy DG Solar RECs	Forward Procurements Wind RECs	Forward Procurements Solar RECs[225]	IPA Programs Solar RECs	Total Wind RECs	Total Solar RECs	Total RECs
2020-21	1,233,838	27,887	21,181	981,244	673,490	533,562	2,215,082	1,256,120	3,471,202
2021-22	1,233,838	27,887	20,138	2,071,340	2,118,507	703,621	3,305,178	2,870,153	6,175,331
2022-23	1,233,838	27,887	-	2,071,340	2,118,507	703,593	3,305,178	2,849,987	6,155,165
2023-24	1,233,838	27,887	-	2,071,340	2,118,507	703,565	3,305,178	2,849,959	6,155,137
2024-25	1,233,838	27,887	-	2,071,340	2,118,507	703,538	3,305,178	2,849,932	6,155,110
2025-26	1,233,838	27,887	-	2,071,340	2,118,507	703,510	3,305,178	2,849,904	6,155,082

Table 3-7: MidAmerican Existing REC Portfolio

Del. Year	LTPPA Wind RECs	LTPPA Solar RECs	Legacy DG Solar RECs	Forward Procurements Wind RECs	Forward Procurements Solar RECs [226]	IPA Programs Solar RECs	Total Wind RECs	Total Solar RECs	Total RECs
2020-21	-	-	580	4,603	3,160	3,272	4,603	7,012	11,615
2021-22	-	-	449	9,717	9,939	6,544	9,717	16,932	26,649
2022-23	-	-	-	9,717	9,939	6,544	9,717	16,483	26,200
2023-24	-	-	-	9,717	9,939	6,544	9,717	16,483	26,200
2024-25	-	-	-	9,717	9,939	6,544	9,717	16,483	26,200
2025-26	-	-	-	9,717	9,939	6,544	9,717	16,483	26,200

3.10. Forward Procurements Scheduled for the Fall of 2019, Planned Utility-Scale Wind Forward Procurement, and Balance of RECs to be Procured under the Adjustable Block Program

In accordance with competitive procurements approved in the Initial Plan, the Agency conducted two competitive procurements events in the Fall of 2019: the Second Subsequent Forward Procurement

[225] Including Brownfield Site Photovoltaics.

[226] Including Brownfield Site Photovoltaics.

for utility-scale wind projects (described in Section 5.8.2 of the Initial Plan), and the Community Renewable Generation Program Forward Procurement (described in Section 5.8.4 of the Initial Plan). Neither of these procurement events resulted in the procurement of RECs. The Agency, as described in Section 5.9.2, plans to conduct a utility-scale wind forward procurement in the Fall of 2020 or the Spring of 2021; volumes and delivery assumptions for this procurement are shown in Table 3-8 below.

Also, as described in Section 6.17 of this Revised Plan, the Adjustable Block Program is presently in the process of being implemented, with some blocks still open and some quantities targeted in the Initial Plan yet to be procured. The balance and deliverable estimates of ABP RECs yet to be procured and under contract is shown in Table 3-9.

Table 3-8: Planned Utility-Scale Wind Forward Procurement

Delivery Year	Utility Scale Target Wind RECs (estimate)
2021-2022	
2022-2023	
2023-2024	1,000,000
2024-2025	1,000,000
2025-2026	1,000,000

Table 3-9: Balance of ABP RECs to be Procured[227]

Delivery Year	Balance of ABP Solar RECs (estimate)
2020-2021	141,029
2021-2022	160,129
2022-2023	160,129
2023-2024	160,129
2024-2025	160,129
2025-2026	160,129

[227] Chapter 6, particularly Table 6-5, provides further details of the Adjustable Block Program procurement of RECs.

3.11. Statewide REC Portfolio

The utilities' existing REC portfolios, plus the expected RECs resulting from the scheduled procurements in the Fall of 2019, plus the estimated Adjustable Block Program balance of RECs to be procured and under contract,[228] in the aggregate, produce the Statewide REC Portfolio presented in Table 3-10. This table indicates the volume of RECs expected to be available to meet the various RPS goals and targets mandated in the Act without new authorization for additional procurements or program capacity.

Table 3-10: Statewide REC Portfolio

Del. Year	Existing Wind RECs	Existing Solar RECs	Fall 2020/Spring 2021 Utility-Scale Forward Wind RECs (estimate)	Other Technology RECs Supplied by ARES[229]	Balance of ABP Solar RECs (estimate)	Total Wind RECs[230]	Total Solar RECs	Total All RECs
2020-2021	3,225,409	1,770,597	-	1,569,978	141,029	3,225,409	1,911,626	6,707,013
2021-2022	4,775,162	4,068,586	-		160,129	4,775,162	4,228,714	9,003,876
2022-2023	4,775,162	4,045,436	-		160,129	4,775,162	4,205,564	8,980,726
2023-2024	4,775,162	4,045,185	1,000,000		160,129	5,775,162	4,205,314	9,980,476
2024-2025	4,775,162	4,040,804	1,000,000		160,129	5,775,162	4,200,932	9,976,094
2025-2026	4,775,162	4,040,752	1,000,000		160,129	5,775,162	4,200,881	9,976,043

3.12. Loads, RPS Goals and Targets, and REC Gaps

To start the procurement planning process, it is first necessary to calculate the annual REC targets and gaps to be filled. In the prior Section, a statewide REC portfolio was presented. The REC quantities in that portfolio will be used in conjunction with the REC targets developed in this Section to estimate REC gaps.

3.13. Applicable Retail Customer Load

The table below shows the forecasted retail customer load subject to RPS compliance through the 2025-2026 delivery year.[231] Because the Act mandates that statewide RPS goals are applied to all retail customer load by the 2019-2020 delivery year and beyond, this table takes into account that transition.

[228] REC deliveries for ABP are based on the "Assumed Energization" rate shown in Table 3-23.

[229] ARES option to supply RECs is discussed in Section 3.3 above.

[230] These totals reflect quantities from the LTPPAs, which do not count against Section 1-75(c)(1)(G)(iv)'s balancing requirement (as these are not from "new" projects, as that term is defined in the Act); as a result, these totals do not demonstrate that the 200,000 REC wind/solar balancing requirement is expected to be exceeded.

[231] As customary, in support of the IPA procurement processes, in the summer of 2019 the utilities developed and provided the actual and forecast loads used in this Revised Plan.

Table 3-11: Retail Customer Load Applicable to the Compliance Year

Compliance Delivery Year	Reference Delivery Year	Ameren Illinois [MWh]	ComEd [MWh]	MidAmerican [MWh]	Statewide [MWh]
2020-2021	2019-2020	35,079,537	86,640,000	517,599	122,237,136
2021-2022	2020-2021	34,608,468	85,892,000	518,437	121,018,905
2022-2023	2021-2022	34,330,656	85,314,000	519,350	120,164,007
2023-2024	2022-2023	34,093,802	84,797,000	520,308	119,411,110
2024-2025	2023-2024	33,873,550	84,578,000	521,252	118,972,802
2025-2026	2024-2025	33,873,550	84,258,000	522,222	118,653,772

The Agency notes that, for the forecast quantity used for the 2020-2021 delivery year, the Ameren Illinois load declined 7.73% from the forecast numbers included in the Initial Plan, for ComEd it declined by 0.43%, and for MidAmerican 16.09%.[232] This decrease in forecasted load will have a corresponding impact on estimated annual RPS goals and budget collections. The impact of variations in load forecasts is discussed further in Section 3.20.1.

3.14. RPS Goals and Targets

RPS annual goals are expressed as percentages in Section 1-75(c)(1)(B) of the Act. To determine the number of RECs required to meet the goals (the "Overall RPS Target"), the delivery year RPS goal is applied to the reference year applicable retail customer load ("Applicable Load") as shown in equation (1).

(1) Delivery Year Overall RPS Target = Delivery Year RPS Goal * Reference Year Applicable Load

The statewide RPS Goals and Targets for 2020-2021 through 2025-2026 are shown in the table below.

[232] Note that the MidAmerican load is impacted by the proposed adjustment to the calculation methodology contained in Section 3.4 and thus reflects a methodological change.

Table 3-12: Statewide RPS Goals and Targets

Delivery Year	RPS Goal	Reference Year	Reference Year Load (Applicable Load) [MWh]	Overall RPS Target [RECs]
2020-2021	17.5%	2019-2020	122,237,136	21,391,499
2021-2022	19.0%	2020-2021	121,018,905	22,993,592
2022-2023	20.5%	2021-2022	120,164,007	24,633,621
2023-2024	22.0%	2022-2023	119,411,110	26,270,444
2024-2025	23.5%	2023-2024	118,972,802	27,958,609
2025-2026	25.0%	2024-2025	118,653,772	29,663,443

3.15. Overall REC Procurement Targets - REC Gap

The overall number of RECs needed to be procured for each year to meet annual goals, the "REC Gap", is simply the difference between the RPS Target RECs from Table 3-12 and the total number of RECs in the Statewide REC Portfolio from Table 3-10, as shown below.

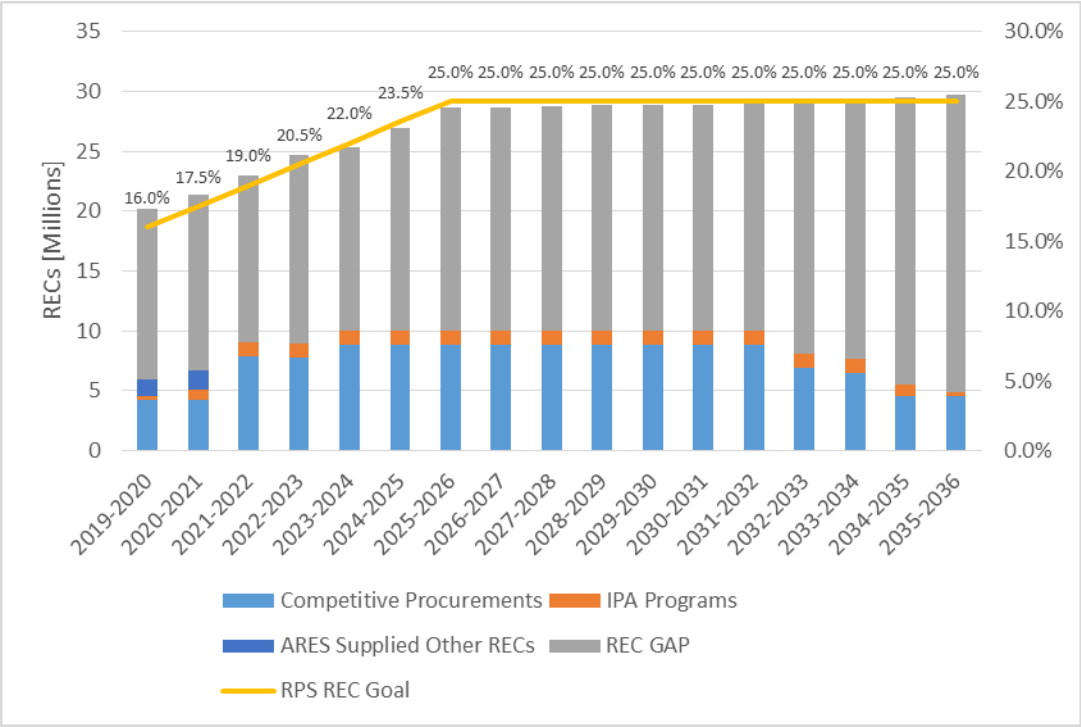
Table 3-13: Statewide Overall REC Gap[233]

Delivery Year	Overall RPS Target RECs	Statewide Portfolio Total All RECs	REC Gap
2020-2021	21,391,499	5,137,035	16,254,463
2021-2022	22,993,592	9,003,876	13,989,716
2022-2023	24,633,621	8,980,726	15,652,895
2023-2024	26,270,444	9,980,476	16,289,969
2024-2025	27,958,609	9,976,094	17,982,514
2025-2026	29,663,443	9,976,043	19,687,400

Figure 3-1 below provides a visual representation of the annual Statewide RPS Goals, REC Portfolio, and REC Gap discussed in this Section.

[233] Unadjusted for RECs supplied by ARES.

Figure 3-1: Statewide Annual RPS Goal, REC Portfolio and REC Gap



3.16. Procurement Targets to Meet Specific Wind-Solar Requirement and Overall RPS Targets

Section 1-75(c)(1)(C) of the Act, as explained in Section 2.3.1, requires that the overall quantity of RECs procured to meet the RPS goals must include at least a combined 75% from wind and photovoltaic projects. Table 3-14 below shows that currently nearly the entire portfolio of RECs is made up of RECs from wind and photovoltaic projects.

Table 3-14: Statewide Wind and Solar RECs in the Portfolio

Delivery Year	Total RECs	Wind RECs[234]	Solar RECs	Combined Wind and Solar RECs	Percentage of Wind and Solar RECs in Portfolio
2020-2021	5,137,035[235]	3,225,409	1,911,626	5,137,035	100%
2021-2022	9,003,876	4,775,162	4,228,714	9,003,876	100%
2022-2023	8,980,726	4,775,162	4,205,564	8,980,726	100%
2023-2024	9,980,476	5,775,162	4,205,314	9,980,476	100%
2024-2025	9,976,094	5,775,162	4,200,932	9,976,094	100%
2025-2026	9,976,043	5,775,162	4,200,881	9,976,043	100%

3.17. RPS Budget

As described in Section 3.5, the Act imposes monetary limitations on the RPS in the form of a cost cap that limits the annual average net increase in rates to retail customers. The cost cap rate, in cents per kilowatt-hour, is unique to each utility and is provided in Table 3-4. The cents per kilowatt-hour rate is applied to the actual electricity (expressed in kilowatt-hours) delivered in the delivery year immediately prior to determine a maximum dollar amount which constitutes the RPS Budget for the delivery year. Specifically, the Act states that:

> *"Notwithstanding the requirements of this subsection (c), the total of renewable energy resources procured under the procurement plan for any single year shall be subject to the limitations of this subparagraph (E). Such procurement shall be reduced for all retail customers based on the amount necessary to limit the annual estimated average net increase due to the costs of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of 2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatthour paid for these resources in 2011. To arrive at a maximum dollar amount of renewable energy resources to be procured for the particular delivery year, the resulting per kilowatthour amount shall be applied to the actual amount of kilowatthours of electricity delivered, or applicable portion of such amount as specified in paragraph (1) of this subsection (c), as applicable, by the electric utility in the delivery year immediately prior to the procurement to all retail customers in its service territory. The calculations required by this subparagraph (E) shall be made only once for each delivery year at the time that the renewable energy resources are procured. Once the determination as to the amount of renewable energy resources to procure is made based on the calculations set forth in this subparagraph (E) and the contracts procuring those amounts are executed, no subsequent rate impact*

[234] These totals reflect quantities from the LTPPAs, which do not count against Section 1-75(c)(1)(G)(iv)'s balancing requirement (as these are not from "new" projects, as that term is defined in the Act); as a result, these totals do not demonstrate that the 200,000 REC wind/solar balancing requirement is expected to be exceeded.

[235] Total RECs does not include RECs supplied by ARES under the provision of Section 1-75(c)(1)(H)(i) as those were not "procured" through the programs and procurements contained in Section 1-75(c)(1)

determinations shall be made and no adjustments to those contract amounts shall be allowed. All costs incurred under such contracts shall be fully recoverable by the electric utility as provided in this Section."[236]

A utility's annual RPS Budget is calculated as shown in equation (2).

(2) Annual RPS Budget ($/Year) = Prior Year Delivered Electricity (MWh) * Cost Cap Rate ($/MWh)

A utility's delivery year remaining available net RPS Budget ("Available Net RPS Budget") is determined by subtracting from the utility's total RPS Budget the direct financial obligations associated with existing REC contracts ("Contracted REC Spend"), the estimated direct financial obligations associated with the Forward Procurements scheduled for the Fall of 2019 and the balance of the Adjustable Block Program REC procurement authorized under the Initial Plan ("Scheduled REC Spend"), and indirect costs: (i) allocation to fund the Illinois Solar for All Program, (ii) allocation to fund job training programs, and (iii) set aside for administrative expenses ("Set Asides Allocation"), as shown in equation (3).[237]

(3) Delivery Year Available Net RPS Budget = Annual RPS Budget (equation 2) – Contracted REC Spend – Scheduled REC Spend – Set Asides Allocation

For the purpose of establishing funds available for REC purchases, as explained in the following Section, the Available Net RPS Budget amount will be adjusted prior to any procurement to account for rollover unspent funds from prior years, and utility-held Alternative Compliance Payments.

3.17.1. Utilities Budgets

Table 3-15 through Table 3-17 show, for each utility, the corresponding RPS Budget, Contracted REC Spend, Planned REC Spend associated with the competitive procurement planned for the Fall of 2020 or Spring of 2021 and the balance of the ABP REC procurement, the allocation of administrative Set Asides including the ILSFA Program allocation, the Available Net RPS Budget, and an estimate of the roll-over balance for delivery years 2019-2020 through 2025-2026. Table 3-19 summarizes those tables at a statewide level. The Available Net RPS Budget is an estimate that will be updated prior to conducting competitive REC procurements and prior to the expansion of Programs under this Revised Plan that depend on the RPS Budget.

The values contained in these tables reflect RPS funds collections and project completion rates (and thus REC expenditures) based upon load forecasts and assumed energization rates used for the development of this revised Plan from the Fall of 2019. A new section of the final version of this Revised Plan, Section 3.20.1, provides an analysis of slower project energization rates that may result from the disruptions created by the COVID-19 pandemic. RPS funds collection under Section 16-108(k) of the PUA will likely also be impacted by the

[236] 20 ILCS 3855/1-75(c)(1)(E).

[237] In the event that the cost cap limitations conflict with the RPS goals and targets such that the IPA cannot procure sufficient additional quantities of RECs to meet the RPS goals or targets, priority for procurement shall first be given to RECs under existing contractual obligations, followed by RECs for the Illinois Solar for All Program, followed by RECs necessary to comply with the new wind and solar procurement requirements, and finally RECs necessary to meet the remaining RPS requirements. 20 ILCS 3855/1-75(c)(1)(F). In its Order approving the Initial Plan, the Commission determined that "such a conflict is possible" if the Agency were to conduct procurements to meet the remaining RPS requirements (i.e., the annual goals found in Section 1-75(c)(1)(B) of the Act), and thus granted various parties' requests to cancel those procurements. Docket No. 17-0838, Final Order dated April 3, 2018 at 41-42.

decreased economic activity created by COVID-19 although the magnitude and longevity of that impact is not yet known.

In addition to direct expenditures on RECs, RPS budgets also feature allocations for several additional purposes, collectively referred to as "Set Asides". First, pursuant to Section 1-75(c)(1)(O) of the Act, the greater of 5% (of the combined RPS budgets of the utilities) or $10,000,000 each year will be allocated to the Illinois Solar for All Program. See Section 0 for details on that allocation. Second, also pursuant to Section 1-75(c)(1)(O), in each of the delivery years 2017-2018, 2021-2022, and 2025-2026, $10,000,000 of ComEd's RPS Budget will be allocated to fund solar job training programs pursuant to Section 16-108.12 of the PUA. Third, a reasonable amount of each budget will be set aside for administrative expenses (including, but not limited to, expenses related to development of this Revised Plan and future updates, the management of procurements and programs, Adjustable Block Program Administrator expenses not covered by fees charged to participants, and fees charged by tracking systems for the retirement of RECs). The IPA, for this Revised Plan, proposes to set aside 0.65% of the budget for these administrative expenses, and will refine this Set Aside as more information becomes available.[238] Table 3-18 shows the annual RPS funds to be allocated to each of these Set Asides.

Unspent funds for delivery years 2017-2018 through 2019-2020 will roll over and be available for the subsequent delivery year. Up to half of any roll over funds, moreover, may be allocated to cover any "funding shortfall" for the Illinois Solar for All Program (see Sections 2.6.1 and 8.4.3 for more details); however, at this time no allocation is planned or expected.[239] The Agency will request updated data from the utilities each spring and fall and will update RPS budgets and goals to reflect that updated information. The update will be posted to the Agency's website. The Agency will use those updates to make determinations related to utilization of any available funds as described further in Section 3.22.

The estimated expenditures presented in these tables are intentionally a high-end estimate that assumes all projects contracted to produce RECs are successfully completed and deliver RECs in accordance with the schedule shown in Table 3-10. Additionally, the estimates assume that, for community solar projects in the Adjustable Block Program, such projects satisfy the high end of adders for small subscribers (e.g., all projects have over 75% small subscribers by capacity). This allows these tables to portray the most constrained view of RPS budgets, which the Agency believes is the appropriate approach to take for planning purposes. Should projects fail to become energized, or should community solar subscription mixes change, it is possible that actual expenditures will be lower. At this time, the Agency lacks sufficient information to confidently predict those occurrences.

During the 2017-2018 through the 2020-2021 delivery years, RPS funds collected by the utilities and not spent each year are effectively "rolled over" to be available for the next delivery year. Because the first two years of collections primarily saw the development of the Initial Plan and building out programs for implementation, and because projects from competitive procurements have generally not yet began making deliveries, significant balances have accrued for the utilities to date. Funds from this four-year period not spent by the end of the 2020-2021 delivery year will be refunded to customers per Section 16-108(k) of the PUA. The potential amounts of those refunds are shown in

[238] The percentage set aside for administrative expenses assumes a retirement fee of 5 cents per REC and an estimated one million dollars for program administration cost annually.

[239] See 220 ILCS 5/16-108(k) and ICC Docket No. 18-1457.

the top cell (corresponding to 2020-2021) of the Remaining RPS Funds Balance column of Table 3-15 through Table 3-17. For the same reason, the Accumulated RPS Funds Balance column has no values for delivery years *after* 2020-2021.

The Available Net RPS Budgets do not include the ACPs held by the utilities[240] These ACP funds are potentially available to fill the shortfalls listed for delivery years 2021-2022 through 2023-2024. As of April 10, 2020, Ameren Illinois has $34,297,300 in uncommitted ACPs, and ComEd has $65,927,046. Based on present load forecasts and cost assumptions, these amounts would be barely sufficient to cover the total projected shortfalls ($27,890,552 for Ameren Illinois and $56,635,045 for ComEd).

For further discussion of the Agency's proposed update to the use of the utility-held ACPs, see Section 3.19.

Table 3-15: Ameren Illinois RPS Budget ($)

DY	Accumulated RPS Funds at Start of DY	Annual RPS Collection	Total Available	REC Spend Already Under Contract	Anticipated Approved REC Spend[241]	Set Asides[242]	Total Expenditures	Remaining RPS Funds Balance at end of DY	ACP Balance at Start of DY	ACP Drawdown for DG REC Payments and Balancing the RPS Budget
20-21	93,348,046	63,332,597	156,680,643	65,745,235	30,561,172	3,578,292	99,884,699	56,795,943	37,573,682	933,851
21-22	-	62,482,128	62,482,128	65,945,567	6,300,622	3,542,733	75,788,922	(13,306,794)	36,639,831	14,173,518
22-23	-	61,980,567	61,980,567	62,505,125	1,807,455	3,517,705	67,830,285	(5,849,718)	22,466,313	6,227,174
23-24	-	61,552,950	61,552,950	61,064,125	3,197,108	3,495,651	67,756,884	(6,203,934)	16,239,140	6,556,009
24-25	-	61,155,307	61,155,307	48,559,799	2,745,244	3,482,920	54,787,963	6,367,344	9,683,131	-
25-26	-	61,155,307	61,155,307	21,852,147	1,841,516	3,473,433	27,167,097	33,988,211	9,683,131	-

[240] ACPs were collected either from hourly pricing customers prior to June 1, 2017 or from ARES for their RPS obligations after June 1, 2017.

[241] Includes the balance of approved ABP Procurement, and the planned Fall 2020 or Spring 2021 Utility-Scale Wind Procurement.

[242] See Table 3-18.

Table 3-16: ComEd RPS Budget ($)

DY	Accumulated RPS Funds at Start of DY	Annual RPS Collection	Total Available	REC Spend Already Under Contract	Anticipated Approved REC Spend[243]	Set Asides[244]	Total Expenditures	Remaining RPS Funds Balance at end of DY	ACP Balance at Start of DY	ACP Drawdown for DG REC Payments and Balancing the RPS Budget
20-21	219,051,474	163,896,888	382,948,362	169,748,749	65,717,801	9,260,174	244,726,724	138,221,638	69,849,386	2,408,621
21-22	-	162,481,896	162,481,896	165,908,335	12,622,973	19,168,154	197,699,461	(35,217,565)	67,440,765	37,491,117
22-23	-	161,388,494	161,388,494	157,004,075	2,840,265	9,103,384	168,947,724	(7,559,230)	29,949,648	7,559,230
23-24	-	160,410,485	160,410,485	154,103,738	6,436,512	9,046,311	169,586,562	(9,176,077)	22,390,417	9,176,077
24-25	-	159,996,203	159,996,203	123,925,002	5,726,446	9,013,364	138,664,812	21,331,390	13,214,341	-
25-26	-	159,390,859	159,390,859	59,845,351	4,306,314	18,988,813	83,140,478	76,250,380	13,214,341	-

Table 3-17: MidAmerican RPS Budget ($)

DY	Accumulated RPS Funds at Start of DY	Annual RPS Collection	Total Available	REC Spend Already Under Contract	Anticipated Approved REC Spend[245]	Set Asides[246]	Total Expenditures	Remaining RPS Funds Balance at end of DY	ACP Balance at Start of DY	ACP Drawdown for DG REC Payments and Balancing the RPS Budget
20-21	871,608	642,599	1,514,207	209,070	215,021	36,307	460,398	1,053,809	13,556	-
21-22	-	643,640	643,640	266,077	98,361	35,946	400,385	243,255	13,556	-
22-23	-	644,774	644,774	192,976	73,796	35,692	302,464	342,310	13,556	-
23-24	-	645,963	645,963	192,976	87,896	35,468	316,340	329,623	13,556	-
24-25	-	647,135	647,135	167,836	69,447	35,339	272,622	374,513	13,556	-
25-26	-	648,338	648,338	117,555	32,549	35,243	185,347	462,991	13,556	-

[243] Includes the balance of approved ABP Procurement, and the planned Fall 2020 or Spring 2021 Utility-Scale Wind Procurement.

[244] See Table 3-18.

[245] Includes the balance of approved ABP Procurement, and the planned Fall 2019 or Spring 2021 Utility-Scale Wind Procurement.

[246] See Table 3-18.

Table 3-18: Statewide RPS Budget Set Asides ($)

Delivery Year	Illinois Solar for All	Job Training (ComEd Budget)	Administrative Expenses (0.65% of Annual RPS Budget)	Total Set Asides
2020-2021	11,393,604	-	1,481,169	12,874,773
2021-2022	11,280,383	10,000,000	1,466,450	22,746,833
2022-2023	11,200,692	-	1,456,090	12,656,782
2023-2024	11,130,470	-	1,446,961	12,577,431
2024-2025	11,089,932	-	1,441,691	12,531,623
2025-2026	11,059,725	10,000,000	1,437,764	22,497,489

Table 3-19. Statewide RPS Budget ($)

DY	Accumulated RPS Funds at Start of DY	Annual RPS Collection	Total Available	REC Spend Already Under Contract	Anticipated Approved REC Spend[247]	Set Asides[248]	Total Expenditures	Remaining RPS Funds Balance at end of DY*	ACP Balance at Start of DY	ACP Drawdown for DG REC Payments and Balancing the RPS Budget
20-21	313,271,128	227,872,083	541,143,212	235,703,054	96,493,994	12,874,773	345,071,821	196,071,391	107,436,624	3,342,472
21-22	-	225,607,664	225,607,664	232,119,979	19,021,956	22,746,833	273,888,768	(48,281,104)	104,094,152	51,664,635
22-23	-	224,013,835	224,013,835	219,702,175	4,721,516	12,656,782	237,080,473	(13,066,639)	52,429,517	13,786,404
23-24	-	222,609,397	222,609,397	215,360,838	9,721,516	12,577,431	237,659,785	(15,050,388)	38,643,113	15,732,086
24-25	-	221,798,645	221,798,645	172,652,636	8,541,137	12,531,623	193,725,397	28,073,248	22,911,027	-
25-26	-	221,194,504	221,194,504	81,815,053	6,180,379	22,497,489	110,492,922	110,701,582	22,911,027	-

3.18. Summary of REC Procurement Targets and RPS Budgets

The aggregation of REC Targets and RPS Budgets at a statewide level provides an important tool for planning and implementing the various procurements and programs under this Revised Plan. The table below presents a snapshot summary of the REC Gap to be procured and the Available Net RPS Budget under procurements approved through the Initial Plan, two essential factors to achieve the RPS Goals set forth by the Act.

[247] Includes the balance of approved ABP Procurement, and the planned Fall 2019 or Spring 2021 Utility-Scale Wind Procurement.

[248] See Table 3-18.

Table 3-20: Statewide REC Gap and Available RPS Budget

Delivery Year	REC Gap	RPS Funds Balance at end of DY estimated ($)[249]	Potential Refund to Customers ($)
2020-2021	16,254,463	196,071,391	196,071,391
2021-2022	13,989,716	(48,281,104)	243,255
2022-2023	15,652,895	(13,066,639)	342,310
2023-2024	16,289,969	(15,050,388)	329,623
2024-2025	17,982,514	28,073,248	28,073,248
2025-2026	19,687,400	110,701,582	110,701,582

3.19. Alternative Compliance Payment Funds Held by the Utilities

As of October 21, 2019, Ameren Illinois held $14,876,594 and ComEd held $29,622,496 of alternative compliance payments collected from retail customers that take service under electric utilities' hourly pricing tariff or tariffs ("HACP"). These funds are presently in part committed to fund the REC purchases from the 2015 through 2017 Distributed Generation procurements the Agency conducted for the utilities, which featured five-year REC delivery contracts with payment upon delivery (and not prepayment).[250] As of April 10, 2020, the remaining balance of uncommitted hourly alternative compliance payments—those not set aside to fund the Distributed Generation procurements—is $11,524,170 for Ameren Illinois, and $22,773,129 for ComEd.

Also, as of April 10, 2020, Ameren Illinois held $23,519,406, ComEd held $42,394,083, and MidAmerican held $13,556 of alternative compliance payment funds collected from ARES since June 1, 2017 ("ARES ACP")[251] as shown in Table 3-22.

The Tables below summarize the balances of these Alternative Compliance Payments.

Table 3-21: Expected Balance of HACP as of May 31, 2020 ($)

Ameren	ComEd	MidAmerican
14,054,276	27,455,302	-

[249] Does not include ARES ACP funds collected by the utilities, or uncommitted Hourly ACP funds.

[250] 2016 and 2017 Distributed Generation procurements for MidAmerican were funded out of MidAmerican's Renewable Energy Resources budget, as MidAmerican does not have any Hourly Alternative Compliance Payments.

[251] Section 16-115D of the PUA provides that while "[t]hrough May 31, 2017, all alternative compliance payments by alternative retail electric suppliers shall be deposited in the Illinois Power Agency Renewable Energy Resources Fund," "beginning with the delivery year commencing June 1, 2017, all alternative compliance payments by alternative retail electric suppliers shall be remitted to the applicable electric utility" and not deposited into the RERF. (220 ILCS 5/16-115D(d)(4), (4.5).) See also 83 Ill Adm. Code Part 455. ComEd's balance reflects interest earned on the ARES ACP funds held by ComEd, while Ameren Illinois' and MidAmerican's do not.

Table 3-22: Available ACPs ($)

ACP	Ameren	ComEd	MidAmerican	All Utilities
Uncommitted HACP	11,524,170	22,773,129	-	34,297,300
ARES ACP	23,519,406	42,394,083	13,556	65,927,046
Total Available ACPs	35,043,576	65,167,213	13,556	100,224,345

In its filed Initial Plan, the IPA proposed to set aside the uncommitted balance of the Hourly ACP funds, as well as the ARES ACP funds collected by the utilities (a total of approximately $100,000,000 as of April, 2020) for use at a later date in the event of a shortfall in the Available RPS Budgets, contemplating that the uncommitted funds could also be a source of the available funds used to help support the Illinois Solar for All Program. In its Order approving the Initial Plan, while the Commission agreed with the IPA that "spending ACP funds on RECs in the first four delivery years, while funds collected pursuant to Section 16-108(k) are unspent and refunded, would be contrary to the statutory intent of increasing the amount of renewable energy resources procured," the Commission ultimately found that "the best use of these funds is to provide funding for new wind and new solar" and thus ACP funds should be used to fund "an additional forward procurement," with funding for that procurement "prioritized such that any funds collected pursuant to Section 16-108(k) should be used prior to the ACP funds."[252] However, unlike the Adjustable Block Program, those procurements feature RECs paid upon delivery: meaning that such ACPs may not begin being spent until 2022 (when new utility scale projects begin REC deliveries) and could be tied up through 2037, frozen through being committed to funding those contract obligations when more urgent priorities exist which ACPs could help address.

In this Revised Plan, the Agency proposed to revise how the utility-held ACPs should be utilized. With the end of the rollover period rapidly approaching, the Agency is facing a potentially significant funding bottleneck starting in the 2021-2022 delivery year as unspent funds are returned to customers and RPS budgets begin being calculated only based on annual collections. Despite the Commission's conclusion in Docket No. 17-0838 seeking to utilize ACPs for additional Forward Procurements,[253] the Agency requires more flexibility in its use of ACPs given the significant expected expenditures in coming years needed to fulfill the prepayment requirements of Adjustable Block Program contracts.

Additionally, Sections 3.20 and 3.21 below provide a discussion of how uncertainty about project energization timelines and annual load variations, respectively, create budget uncertainty. This uncertainty has been further exacerbated by updated utility load forecasts received for the Revised Plan that indicate lower expected loads, and thus reduced RPS budget collections from customers than the Agency had previously expected. These factors create both additional uncertainty about annual RPS budget obligations and an increased likelihood that expenditures will outpace collections in certain future years.

[252] Docket No. 17-0838, Final Order dated April 3, 2018 at 8.

[253] The additional forward procurements authorized in the Initial Plan are estimated to require $35 million a year in funding assuming all projects are successfully energized.

Consequently, for this Revised Plan, the Agency proposed that the utility-held ACPs should be used in each delivery year after the use of funds collected pursuant to Section 16-108(k) for both Forward Procurements and the Adjustable Block Program, providing the Agency with a reserve balance of funds through which it can cover expenditures in excess of Section 16-108(k) collections. This approach may be necessary to avoid the potential curtailment of contracts in at least the 2021-2022 delivery year and possibly the two years directly thereafter, during which the Available Net RPS Budget is annually projected (as shown in Table 3-20) to be negative, meaning that absent this change to the use of utility-held ACPs, contractual expenditures would need to be pulled back (under curtailment clauses in the REC contracts) from what is now committed in order to bring the Available Net RPS Budget for the delivery year to zero. Having this additional flexibility with the use of utility-held ACPs will help mitigate these challenges.

As this issue was uncontested in Docket No. 19-0995 approving the Plan, the Agency understands the Commission to have adopted the Revised Plan's proposal for how to better utilize utility-held ACPs.

3.20. Budget Uncertainty Due to Unknowns in Project Energization Timelines[254]

One challenge the Agency has faced in understanding pending budget impacts is that project energization and REC deliveries—and thus resultant budget impacts[255]—are not scheduled to begin at a fixed point. Instead, supported projects may become energized at any point over a period of time, whether immediately upon program application, closer to the contractual deadline for first deliveries, or later still due to extensions. This creates challenges into budget visibility in part because Adjustable Block Program projects carry large budget impacts upon energization (20% of contract value for distributed generation above 10 kW up to 2,000 kW ("Large DG") and for community solar; 100% of contract value for distribution generation up to 10 kW ("Small DG")), and because the ability to roll over prior years' collections sunsets with the conclusion of the 2020-21 delivery year. Assuming a project becomes energized during the 2021-22 delivery year (or even just that its first payment would occur in that year) carries very different budget consequences than if that project becomes energized in 2019-20, as in the latter scenario, previously collected Renewable Resources Budget funds could help meet first year payment obligations—including the large payment due upon energization.

Because the Agency cannot have certainty about when funds for specific projects will begin to be spent, this dynamic has proven to be a significant challenge in modeling budgets for future delivery years. For example, Table 3-23 compares three different energization scenarios for projects from the Adjustable Block Program. Each column outlines the share of all projects across Blocks 1-4 that would be energized in the first year after the execution of ABP REC contracts began in spring 2019, the share energized in the second year, and the share energized in the third year.[256]

As shown below, the differences between the first and the third year in the "slow" and the "fast" energization scenarios are significant. It would be prudent to maintain RPS funds in reserve to absorb

[254] This section is unchanged from the Revised Plan filed for ICC approval on October 21, 2019. See Section 3.20.1 for a discussion on how the assumption contained here could change, and the impact of those changes, due to the COVID-19 pandemic.

[255] Under the Renewable Resources Budget reconciliation regime created by Section 16-108(k) of the PUA, the four-year reconciliation following the 2020-2021 delivery year, and the annual reconciliations after that, are based on *cash* accounting, i.e. actual cash inflows and outflows during a given delivery year.

[256] For Table 3-23, Year 1 is delivery year 2019-2020, Year 2 is delivery year 2020-2021, and Year 3 is delivery year 2021-2022.

the budget impact associated with this uncertainty. As indicated in Section 3.18, the IPA proposes additional flexibility with the use of utility-held ACPs to help mitigate budget uncertainty—although a statutory change allowing for extension of the 4-year rollover period would be more helpful still.

Table 3-23: Payments to Adjustable Block Projects under Various Energization Schedules

Delivery Year	Slow Energization 10% Year 1 40% Year 2 50% Year 3 [$ MM]	Fast Energization 50% Year 1 40% Year 2 10% Year 3 [$ MM]	Assumed Energization 25% Year 1 53% Year 2 22% Year 3 [$ MM]
2019-2020	41.8	208.9	104.4
2020-2021	184.6	254.7	289.1
2021-2022	296.5	199.5	199.5
2022-2023	175.2	175.2	175.2
2023-2024	175.2	175.2	175.2
2024-2025	157.7	87.6	131.4
2025-2026	87.6	17.5	43.8

These payment projections make the conservative (for planning purposes) assumption that community solar projects are fully subscribed and have at least 75% small subscribers (by capacity). Subscriber levels will not be finalized until one year after each project is energized. If subscription levels (particularly for small subscribers) are ultimately lower, payments would be lower.

3.20.1. Increased Budget Uncertainty Created by COVID-19 Related Delays in Project Completion

The three energization models described above were developed as illustrative examples in the Fall of 2019, and the tables contained in Section 3.17.1 reflect the Agency's best available estimate of energization rates at that time. With the onset of the COVID-19 pandemic, the Agency is reconsidering expected energization rates. As of the publication of the final Revised Plan on April 20, 2020, the length of time for which COVID-19 will disrupt the development and energization of Adjustable Block Program projects is unknown.

Table 3-24 contains illustrative example scenarios of how project energization delays would impact the amount of funds refunded to customers after the end of the four-year rollover period in 2021 (see Section 2.3.4 for further discussion) as well as the impact on the use of utility-held ACPs (see Section

3.19).[257] As the extent of delays is better understood, the Agency will provide updated estimates on the Renewable Resources page on the IPA website (www.illinois.gov/ipa). Furthermore, the COVID-19 pandemic is expected to reduce energy consumption; as RPS funds are collected from retail customers on a volumetric basis, this may impact the total amount of RPS funding potentially available to support the programs and procurements discussed in this Plan. As any impacts on collections are unknowable at this early stage, Table 3-24 does not reflect any revisions to expected RPS fund collection compared to the utility load forecasts used to develop the Revised Plan in the fall of 2019.

Scenario One is for reference—a base case, of sorts—as it is the energization rates assumed by the Agency in the fall of 2019.

Scenario Two is the Agency's fall 2019 slow energization rate example from Table 3-23, which pushed 50% of payments for Adjustable Block Program project energizations (either the initial 20% payment for the Large DG and Community Solar categories, or the full payment for the Small DG category) to the delivery year after the rollover ends (the 2021-2022 delivery year). While this scenario was developed prior to the onset of the COVID-19 pandemic, it may be a reasonable model for project development delays. In this scenario, the amount of rollover funds refunded to customers increases significantly, all of the utility-held ACPs are expended in the 2021-2022 delivery year, and there is a significant budget shortfall that could curtail payments.

While Scenario Two assumes all projects will be energized by the end of the 2021-2022 delivery year, Scenario Three illustrates the impact of even further delays with some projects not energized until the 2022-2023 delivery year (and also adjusts from Scenario Two to reflect actual energization rates to date that were not available in fall 2019). This scenario has an even larger amount of funds refunded to customers, but utility-held ACPs are not fully expended until the 2022-2023 delivery year. The subsequent budget shortfall is lower than in Scenario Two.

Scenarios Four and Five illustrate the impact of a legislative change to the rollover provision by extending the time before the rollover ends by two years. This legislative change would allow additional time for accumulated funds to be spent and open the possibility that both those rolled-over funds and the utility-held ACPs could be used to support additional procurements and ABP blocks as described in Section 3.22.

[257] These examples also assume that no additional blocks of capacity are opened for the Adjustable Block Program other than those identified in this Revised Plan and that the only utility-scale procurement conducted in 2020 or 2021 is the wind procurement described in Section 5.9.2

Table 3-24: Potential COVID-19 Impacts on Energization, Rollover Refund and Utility-held ACPs

Scenario 1: Adopted Energization (from Table 3-23 and used in Tables 3-15 to 17 and 3-18)			
	Small DG	**Large DG**	**CS**
2019-2020	**25%**	**25%**	**25%**
2020-2021	**65%**	**50%**	**50%**
2021-2022	**10%**	**25%**	**25%**
Refund after rollover period ends			$ 196,071,391
ACP drawdown			$ 81,183,125
Remaining ACPs			$ 22,911,027
Scenario 2: Slow Energization Assumption (from Table 3-23)			
	Small DG	**Large DG**	**CS**
2019-2020	**10%**	**10%**	**10%**
2020-2021	**40%**	**40%**	**40%**
2021-2022	**50%**	**50%**	**50%**
Refund after rollover period ends			$ 364,074,899
ACP drawdown (100% of ACPs)			$ 104,094,152
Budget Shortfall			$ 76,572,805
Scenario 3: Slow Energization extending to 2022-2023 due to COVID-19			
	Small DG	**Large DG**	**CS**
2019-2020	**20%**	**15%**	**0%**
2020-2021	**25%**	**30%**	**20%**
2021-2022	**30%**	**30%**	**50%**
2022-2023	**25%**	**25%**	**30%**
Refund after rollover period ends			$ 419,995,338
ACP drawdown (100% of ACPs)			$ 104,094,152
Budget Shortfall			$ 44,594,464
Scenario 4: **Slow Energization Assumption (from Table 3-23), 2-year extension of rollover**			
	Small DG	**Large DG**	**CS**
2019-2020	**10%**	**10%**	**10%**
2020-2021	**40%**	**40%**	**40%**
2021-2022	**50%**	**50%**	**50%**
Refund after rollover period ends			$ 204,466,233
ACP drawdown			$ 20,570,987
Remaining ACPs			$ 83,523,165
Scenario 5: Slow Energization extending to 2022-2023 due to COVID-19, 2-year extension of rollover			
	Small DG	**Large DG**	**CS**
2019-2020	**20%**	**15%**	**0%**
2020-2021	**25%**	**30%**	**20%**
2021-2022	**30%**	**30%**	**50%**
2022-2023	**25%**	**25%**	**30%**
Refund after rollover period ends			$ 297,147,900
ACP drawdown			$ 25,317,113
Remaining ACPs			$ 78,777,039

3.21. Budget Uncertainty Due to Annual Load Variations

The annual RPS Budget used in this Revised Plan is a function of the base-case load forecasts provided by the utilities and each utility's cost cap. These load forecasts are driven by a number of factors, which include but are not limited to weather, economics, demographics, assumed demand response and energy efficiency. Changes to any of the assumptions will result in actual load deviating from forecasted load. Examples include changes in weather patterns, changes in energy efficiency adoption rates, and changes to economic conditions. In practice, the annual RPS Budget for a delivery year will depend on the actual reference year load for each utility, which will likely deviate from the forecasted loads provided by the utilities—although in which direction that deviation will occur is impossible to know until that delivery year.

To see how deviations from the Base Case load forecasts may affect available RPS budgets, the IPA conducted a comparative analysis of the RPS Budget based on the Base Case, High Case, and Low Case. Load forecast data for Ameren Illinois and ComEd were used for this analysis. The RPS Budget for each utility, for each load case, is based on the product of the Applicable Load for a given year and the cost cap rate shown in Table 3-4.[258] For each utility, the impact of the High Case and Low Case is the difference between the RPS budget for each case and the RPS Budget for the Base Case. The total is the sum of the differences for these utilities. The results are presented in Table 3-25.

Table 3-25: Effect on RPS Budget of Annual Load Variations to the Utilities' Load Forecast

Delivery Year	Base Case Load Forecast [MWh]	Low Load Forecast [MWh]	Low Load Effect on RPS Budget [$]	High Load Forecast [MWh]	High Load Effect on RPS Budget [$]
2020-2021	121,719,53	117,961,970	(6,896,275)	125,477,105	6,896,275
2021-2022	120,500,468	115,506,875	(9,237,310)	125,532,061	9,309,194
2022-2023	119,644,656	113,438,510	(11,532,775)	125,966,802	11,752,212
2023-2024	118,890,802	111,502,236	(13,770,990)	126,511,368	14,209,864
2024-2025	118,451,550	109,894,401	(15,982,928)	127,392,698	16,709,341

As shown in Table 3-25 above, the impact of the low load forecast on the RPS Budget ranges from a reduction compared to the base case RPS Budgets of approximately $7 million in delivery year 2020-2021 to a reduction of approximately $16 million in delivery year 2024-2025. Alternatively, the impact of the high load forecast on the RPS Budget ranges from an increase compared to the base case RPS Budgets of approximately $7 million in delivery year 2020-2021 to an increase of approximately $17 million in delivery year 2024-2025.

As discussed in Sections 3.17.1 and 3.20.1, the forecasts (and thus annual RPS budgets) described in this section were developed prior to the onset of the COVID-19 pandemic. The Agency will receive updated load forecasts from the utilities in July 2020 as part of the Agency's annual electricity procurement planning process and those load forecasts will be used by the Agency to assess the ongoing impact on RPS collections on available budgets and

[258] The load data for the Base Case, High Case, and Low Case for Ameren and ComEd was provided by the utilities as part of their data submissions for this Revised Plan.

the ability of the Agency to consider additional procurements or opening of Adjustable Block Program Blocks in the future as discussed in Section 3.22 below.

Because of the budget risk associated with load variability, the IPA recommends a cautious approach to making financial commitments such as the forward procurement of RECs and the expansion of ABP. The Agency notes that the scale of load forecast uncertainty increases the further out the forecasts are made, which is logical because factors such as economic indicators and climate/weather are compounded and inherently difficult to predict. That increasing uncertainty underscores the need for caution as the Agency considers the impact of procurements and programs on future year budgets.

3.22. Impact of RPS Budget on Procurement and Program Activities

As described in Section 3.16, the Agency's current projection of forecast Section 16-108(k) collections, accounting for the sunsetting in mid-2021 of the ability to roll over past collections to pay for future contractual deliveries, and supplemented by utility-held ACPs, is barely sufficient to cover expected expenses in each delivery year (starting with 2021-2022) stemming from the programs and procurements authorized under the Initial Plan.

However, multiple factors could result in additional funding becoming available, including one or more of the following: First, future changes in utility load forecasts could demonstrate greater than expected retail sales of electricity, thus resulting in additional RPS budget funds. Second, community solar projects could seek reduced levels of small subscribers than presently expected, thus resulting in lower REC prices applicable to those systems. Third, some community solar projects could achieve less than complete subscribership of their physical capacity. Fourth, projects presently under contract could fail to be developed, freeing up additional budget capacity.[259] And fifth, legislative changes (short of an overhaul that would fundamentally rewrite the entire paradigm through which this Revised Plan is being developed) could extend the budget rollover's sunset period, thus freeing up funds collected under Section 16-108(k) tariffs but not spent by May 31, 2021 for future REC procurement rather than having those funds refunded to ratepayers.

The Agency is committed to biannually reviewing updated utility load forecast information and new/existing contract obligation/payment information to determine expected RPS budget availability, and will publish the resulting updated budget forecasts on its website. These budget analyses will provide the grounds for undertaking the procurement activity outlined below, and, starting with the 2021-2022 delivery year, the Agency will in all cases seek to have under contract projects with likely annual expenditures equaling no more than 95% of expected available funds for any given delivery year to guard against the potential curtailment of existing contracts.

Should funding become available, for this Revised Plan the Commission has ordered the Agency to utilize the following contingency approach addressing which programs and procurements it will prioritize supporting beyond those authorized by the Initial Plan.[260] That approach is as follows:

[259] Reductions in payment obligations to a community solar or a Large DG project within the ABP would have a ripple effect across the projected RPS expenditures in each of five sequential delivery years, due to the statutory payment schedule that compensates such a project for its RECs ratably over four years (further refined as seventeen quarterly payments by the initial ABP REC Contract). For example, a project that is expected to receive its first REC payment in September 2020, within the 2020-2021 delivery year, would receive its final payment in September 2024, within the 2024-2025 delivery year.

[260] See Docket 19-0995, Final Order dated February 18, 2020 at 19-20.

First, the Agency shall conduct a competitive procurement for up to 500,000 RECs delivered annually from utility-scale solar and/or wind projects.[261]

Second, should the additional/unexpected funding become available after a utility-scale procurement event noted above, the Agency would next look to conduct an additional brownfield site photovoltaic project competitive procurement ("brownfield procurement") with a target quantity of 50,000 RECs delivered annually. The Commission agreed that this is a prudent manner by which to provide ongoing support for a market segment that was offered robust narrative support in the declaratory passages of Public Act 99-0906, but with a relatively small minimum target (only 2% of new photovoltaic project RECs).[262]

Third, should funding be available after the above-mentioned procurement events, the Agency will open additional blocks of capacity for the Adjustable Block Program to accommodate whatever funds are available, up to the number of RECs needed to reach a total of 1,500,000 annually delivered RECs from the Adjustable Block Program (the 2025 Delivery Year target quantity found in Section 1-75(c)(1)(C) of the Act, as it is 50% of 3,000,000 annual REC deliveries).[263] The Commission agreed that smaller block sizes than those specified in Section 6.3.1 may be advisable and deferred to the IPA's determination at the time the opportunity presents.[264] Under the Commission's Order, the Agency shall not procure more than the 2025 Delivery Year Adjustable Block Program statutory target of 1.5 million RECs delivered annually under this contingency plan.[265]

Notwithstanding the revised contingency plan described above, pursuant to the Commission's Final Order in Docket No. 19-0995 approving this Revised Plan, the Agency must ensure that a minimum of 1,000,000 RECs delivered annually from the Adjustable Block Program be maintained at all times.

3.23. Spring 2021 RPS Budget Update and Proposed Payment Deferral Regime

3.23.1. Introduction

As described in Section 3.20, delays in project energization – and thus delays in REC delivery contract payouts, as renewable energy projects are not eligible for payment until energized – pull initial RPS budget impacts forward into chronologically later periods than previously forecast, and in many cases, into later delivery years. For Adjustable Block Program contracts in particular, because payments are front-loaded (100% due upon energization for Small Distributed Generation projects; 20% due upon energization for Large Distributed Generation projects and community solar projects, with the balance ratably paid out over the following four years), those initial payments made upon energization carry outsized RPS budget impacts. As expenses that had been expected to be incurred in the 2020-21 delivery year are pulled forward into the 2021-22 delivery year, this creates the following challenge: because Section 16-108(k) of the Public Utilities Act restricts the ability to utilize the first four years of RPS collections after the enactment of P.A. 99-0906 (the 2017-18 through 2020-21 delivery years) to meet RPS expenses beginning with the 2021-22 delivery year, expenses

[261] Id. at 20.

[262] Id.

[263] Id.

[264] Id.

[265] Id.

associated with that upcoming delivery year have a significantly lower budget of available funds than expenses associated with prior delivery years.

The Illinois Power Agency filed its Revised Long-Term Renewable Resources Procurement with the Illinois Commerce Commission in October 2019. Tables included in Chapter 3 of that filed Revised Plan demonstrated sufficient budget availability (through both collections pursuant to Section 16-108(k) and alternative compliance payments held by the utilities) to meet expected RPS expenditures based on the arc of projected expenditures as understood at that time. Because that analysis showed *sufficient* funding, no proposal was made for how Buyers under REC delivery contracts (ComEd, Ameren Illinois, and MidAmerican) should handle payment deferrals in the case of *insufficient* funding. That Revised Plan was approved by the ICC in Docket No. 19-0995 on February 18, 2020, with instruction that the IPA file a Final Revised Plan modified for consistency with the Commission's Order in that proceeding within 60 days.

During that 60-day period, the COVID-19 global health pandemic began to take grip in the United States. Assemblies and public activities began being restricted in mid-March 2020, and the IPA issued its initial COVID-19 guidance on March 20, 2020.[266] As the IPA considered the content of its Final Revised Plan, the Agency determined that some assessment of the COVID-19 pandemic's potential impacts on RPS activities warranted discussion in that filing.

Section 3.20.1, developed as part of the Final Revised Long-Term Renewable Resources Procurement Plan filed by the Agency in Docket No. 19-0995 on April 20, 2020, offered early insights into the potential effects of the COVID-19 pandemic on project energization timelines. Specifically, that section offered estimates for potential RPS budget impacts resultant from COVID-19 possibly delaying project energization timelines. Under the "slow energization" scenarios described in Table 3-24 as Part of Section 3.20.1, the RPS budget was projected to face shortfalls – i.e., insufficient collections plus alternative compliance payments to meet projected expenses – in the 2021-22 delivery year. Of course, any assessment made in April 2020 about the longer-term impacts of the COVID-19 pandemic carried massive uncertainty, and because Adjustable Block Program REC delivery contracts only began being approved by the Illinois Commerce Commission in April 2019, Approved Vendors had not yet begun offering energization deadline extension requests at volumes that provided meaningful insight into the effects of COVID-19 on new renewable energy project development timelines.[267] Thus, while concerns at that time were certainly genuine, those concerns were still mostly theoretical.

Since April 2020, over 1,200 energization deadline extension requests have been received and processed in connection with Adjustable Block Program projects. As discussed below, and as taken from narratives supporting the many extension requests provided by Approved Vendors to the

[266] https://www2.illinois.gov/sites/ipa/Documents/IPA%20COVID-19%20ANNOUNCEMENT%20(20%20March%202020%20330pm)_.pdf

[267] As described in Section 6.15.1, distributed generation projects are allowed 12 months from Commission approval (the REC delivery contract's "Trade Date") to achieve energization, while community solar projects are allowed 18 months. Thus, for example, a 1 MW distributed generation project with a contract approved by the Commission in July 2019 would have a July 2020 energization deadline, while a community solar project with a July 2019 Commission approval date would have an December 2020 energization deadline. Extensions to that deadline may be obtained as a matter of right through payment of additional collateral, or available at the discretion of the counterparty utility or the IPA for specified justifications (including permitting delays, good cause, etc.). As extension requests are often made by Approved Vendors in the weeks or days directly preceding a project's energization deadline, those requests have been received and granted on a rolling basis through 2020 and into 2021.

Agency, multiple factors directly resulting from the COVID-19 global pandemic have caused unforeseen delays in the development timeline for hundreds of ABP projects.

As is now well known, supply chains across the globe were halted or severely impacted by COVID-19 during the onset of the pandemic in early 2020, with some of those impacts continuing today. Many Approved Vendors seeking extensions for their projects had no way to plan for this type of massive supply chain disruption that kept various components necessary to the construction of a solar PV project in limbo across the globe. As any type of construction benefits from economies of scale, large component orders that impacted numerous projects slated for construction in Illinois in 2020 were delayed due to this global slow-down in shipping and receiving. Approved Vendors that expected to receive system parts such as panels, inverters, racking support, etc. in order to commence construction were often left to wait due to this unprecedented halt of large procurements of all sorts across the globe.

Additionally, lack of readily available labor was cited by Approved Vendors as a cause of project development delay brought on by the pandemic. Approved Vendors communicated that the number of available laborers declined, thus making construction planning difficult to impossible. Ongoing uncertainty in the amount of labor that would be available to support the development of projects caused many Approved Vendors to experience unanticipated delays in construction timelines that persist today as the pandemic conditions continue.

Another unexpected issue faced by Approved Vendors is that projects planned for construction on various schools across the state were delayed both by the inability for school district boards to meet due to safety measures in place to curb the spread of the virus, as well as construction being limited to only summer months. COVID-19 related delays ensured that construction for projects slated for schools during summer 2020 would not be possible, pushing construction timelines for these types of projects to the summer months of 2021.

While many of the issues described above could independently cause a major delay in a project's development timeline, many Approved Vendors that sought an extension experienced multiple issues related to COVID-19 that negatively impacted project development. Numerous projects faced not only a solitary set of issues related to supply-chain delays, inability to visit the project site, or a shortage of available of labor required to construct a project, but for many projects all of these issues coalesced to push the development timeline back even further than originally contemplated to create the need for at least one and in several instances two energization deadline extension requests.

Notably, of the 112 community solar projects featuring REC delivery contracts through the Adjustable Block Program, as of March 2021, energization deadline extension requests have been received for 109 projects. While not its only cause, examining the budget impacts of this community solar project energization delay phenomenon is particularly helpful for illustrating the current RPS budget crisis: because the first REC delivery contract payment for a community solar project can be large and lumpy – up to $1.2 million in standalone value, if the project received a Block 1 award and has achieved maximum small subscriber status – shifting 50 such payments from the 2020-21 delivery year to the 2021-22 delivery year results in at least $60 million in expenses moving across those delivery years (and possibly more, should any additional quarterly payments also be shifted out across delivery years). A similar phenomenon has occurred with distributed generation projects: as of March 2021, while approximately 20% of all Large DG projects have requested extensions, for projects over 100 kW in size, over 50% have requested extensions. For projects larger than 500 kW,

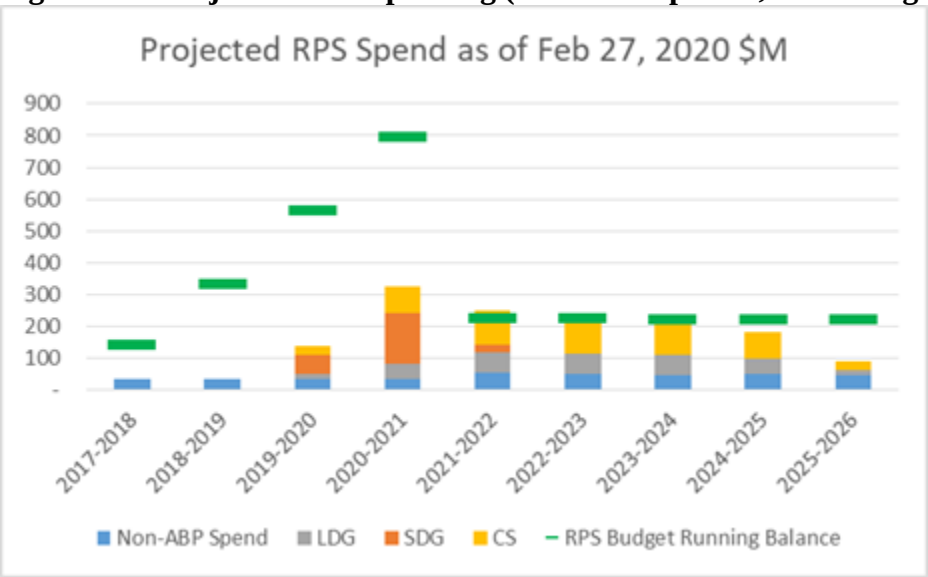
over 70% have requested extensions. Because larger systems have more expensive REC delivery contracts (as more RECs will be delivered from these projects), extensions for these larger projects have an outsized impact on RPS budget projections.

3.23.2. December 28, 2020 budget release

As outlined in Section 3.22, the Agency has committed to biannually reviewing updated utility load forecast information, as well as contract obligation and payment information, to determine expected RPS budget availability. The Agency's first effort at a biannual review came in late 2020. By that time, the impacts of the COVID-19 pandemic on project energization deadlines had become more apparent, and energization deadline extension requests received by the Agency provided important new data points to be folded into RPS budget modeling.

The IPA released this first biannual RPS Budget and Funding Update on December 28, 2020.[268] The update confirmed that what was viewed as a theoretical outcome of the COVID-19 pandemic in April 2020 was now very real: similar to the Final Plan's April 2020 slow energization scenario, the Agency's December 2020 modeling showed that, absent legislative action extending the rollover period, the statewide RPS budget (inclusive of available alternative compliance payments) would face an expected estimated shortfall of approximate $67 million in the 2021-22 delivery year. The release likewise estimated that over $180 million in expenses that the IPA had previously projected would occur within the first four delivery years were now projected to occur in the 2021-22 delivery year and beyond, creating significant budget constraints in those upcoming years given the current inability to utilize prior years' collections for meeting those expenses.[269] The following charts included in that update provide a useful illustration of that phenomenon:

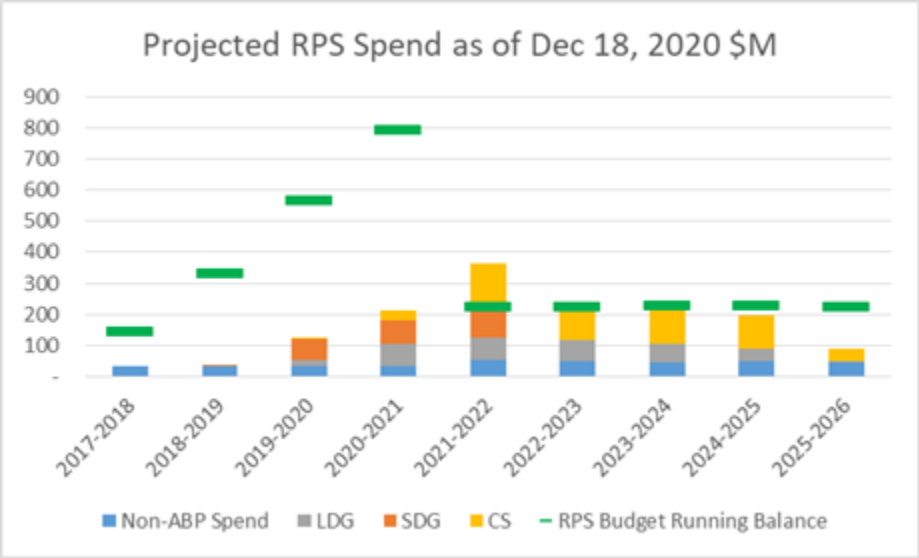
Figure 3-2: Projected RPS Spending (Based on April 20, 2020 Long-Term Plan)



[268] The IPA's December 28, 2020 RPS Funding and Budget Update can be found here: https://www2.illinois.gov/sites/ipa/Documents/RPS%20Funding%20and%20Budget%20Update%20(28%20Dec%202020).pdf.

[269] This difference is apparent through reviewing the amount potentially subject to reconciliation in the Agency's December 2020 RPS budget analysis ($381 million) versus the amount previously modeled as subject to reconciliation ($196 million).

Figure 3-3: Projected RPS Spending (Based on December 18, 2020 Update)



As demonstrated in Scenarios 4 and 5 found in Table 3-24, a statutory revision extending the rollover period forward would eliminate this risk of a shortfall. While a two-year rollover extension was modeled in Table 3-24, even a one-year extension of the rollover sunsetting date would eliminate shortfall risk: as 2021-22 delivery year expenses could be met wholly through prior years' RPS collections under a one-year rollover extension, alternative compliance payments no longer drawn down in the 2021-22 delivery year would then serve as a robust reserve fund sufficient to cover much smaller expected shortfalls in the 2022-23 and 2023-24 delivery years.

During the "lame duck" session of the 101st General Assembly (from January 8, 2021 through January 13, 2021), legislation was introduced which would have extended the rollover sunset date by two years while directing the Agency to conduct new program and procurement activities.[270] That bill failed to receive a floor vote. Legislation focused solely on solving this pending shortfall conundrum was introduced in the 102nd General Assembly,[271] as well as several larger energy bills, each of which failed to receive floor votes as of the date of the Commission's May 27, 2021 Order on Reopening. As of the date of this June 7, 2021 filing, the Agency continues to monitor the status of an omnibus energy bill that would, in part, address the RPS shortfall.[272]

3.23.3. March 3, 2021 Budget Update

In developing its March 2021 filing, the IPA prepared updated versions of the tables contained in its December 28, 2020 release. While less than three months passed between the December release, these updated tables contain useful new information for RPS budget modeling, as both Adjustable

[270] This legislation was offered through amendments to then-SB 3096; see:

https://www.ilga.gov/legislation/BillStatus.asp?DocNum=3096&GAID=15&DocTypeID=SB&LegId=124415&SessionID=108&GA=101.

[271] See HB 3822:
https://www.ilga.gov/legislation/BillStatus.asp?DocNum=3822&GAID=16&DocTypeID=HB&LegId=132890&SessionID=110&GA=102

and SB 2433:

https://www.ilga.gov/legislation/BillStatus.asp?GA=102&DocTypeID=SB&DocNum=2433&GAID=16&SessionID=110&LegID=135087.

[272] See, e.g.: https://www.wbez.org/stories/pritzker-says-energy-deal-can-happen-but-coal-plant-must-close-by-2035/a248960e-6934-402e-9568-f2f7931bd05a; https://www.chicagobusiness.com/utilities/heres-whats-big-state-energy-bill-still-awaiting-action.

Block Program contracts and utility-counterparty Illinois Solar for All contracts feature quarterly invoicing for all activities up through a certain date. Because February 28, 2021 constituted the close of the third quarterly invoicing period for the 2020-21 delivery year, the IPA was able to utilize information about projects verified as energized through that date (and thus subject to a March 2021 invoicing window) in estimating the arc of budget impacts extending from individual projects.

While useful and important, one quarterly period's worth of new information was unlikely to significantly change the overall RPS budget picture, and it generally did not. For example, the expected amount subject to reconciliation at the end of Delivery Year 2020-2021 declined from $381 million to $352 million, the expected 2021-2022 budget shortfall (after accounting for use of alternative compliance payments) for Ameren Illinois declined from $8.4 million to $2.2 million, the expected budget shortfall for ComEd declined from $58.6 million to $49.5 million, and the expected budget shortfall for MidAmerican remained unchanged. The key driver of these reductions was the accelerated energization of ABP projects relative to prior projections.

Tables incorporating the March 2021 information about expected RPS expenses are included below. As with the Agency's December 28, 2020 release, this analysis assumes that contracted activity—such as REC deliveries, system energizations, scheduled quarterly payments, or administrative costs—through May 31, 2021 (the sunset date of the rollover period) constitutes expenses associated with the 2020-21 delivery year (or prior delivery years, where appropriate), even if actual payments associated with those activities occur in June 2021.[273] Where applicable, budget modeling is based on the date at which the system is verified as energized by the Program Administrator and thus eligible for payment at the next quarterly invoicing window, and not the date of first commercial operation (which necessarily precedes the date of such verification, generally by 4-8 weeks for newly-developed projects). Lastly, consistent with the Agency's December 28, 2020 release (but slightly different than the April 2020 budget estimates contained in Section 3.20.1), these tables assume that prior delivery years' shortfalls constitute a liability to be paid in the next delivery year, thus providing a longer-running shortfall than if a delivery year's shortfall was considered to be altogether lost.

Table 3-26: Ameren RPS Budget ($M) (Updates Table 3-15)

	RPS Fund Balance at the start of DY			RPS Expenditures during DY				RPS Fund Balance at end of DY			Uncommitted ACPs		
DY	Start of DY Accumulated Funds (Deficit from Prior DY) (a)	DY Collections (b)	Available Funds at start of DY (c)=(a)+(b)	REC Spend Under Contract (d)	Approved REC Spend to be Contracted (e)	Set Asides (f)	Total Spend (g)= (d)+(e)+(f)	Balance before Using ACP Funds to Cover Shorts (c)-(g)	Balance after Using ACP Funds to Cover Shorts	Refund to Ratepayers	ACP Balance at Start of DY	ACP Drawdown to Cover Budget Shorts	ACP Balance at End of DY
2020-21	127.7	64.3	192.0	63.6	-	4.4	68.0	124.1	124.1	124.1	33.5	-	33.5
2021-22	-	63.2	63.2	88.5	6.1	4.3	98.9	(35.7)	(2.2)	-	-	33.5	-
2022-23	(2.2)	63.3	61.1	65.8	0.1	4.4	70.3	(9.2)	(9.2)	-	-	-	-
2023-24	(9.2)	64.2	55.1	61.2	0.1	4.4	65.7	(10.6)	(10.6)	-	-	-	-

[273] The Agency understands this approach to be consistent with the Illinois Commerce Commission's general approach to reconciliation proceedings as well as basic principles of accrual accounting. The Commission recently affirmed that this understanding is correct and adopted this approach specifically for the purposes of the RPS reconciliation process. See Docket No. 19-0995, Order on Reopening dated May 27, 2021 at 4.

Table 3-27: ComEd RPS Budget ($M) (Updates Table 3-16)

	RPS Fund Balance at the start of DY			RPS Expenditures during DY				RPS Fund Balance at end of DY			Uncommitted ACPs		
DY	Start of DY Accumulated Funds (Deficit from Prior DY) (a)	DY Collections (b)	Available Funds at start of DY (c)=(a)+(b)	REC Spend Under Contract (d)	Approved REC Spend to be Contracted (e)	Set Asides (f)	Total Spend (g)= (d)+(e)+(f)	Balance before Using ACP Funds to Cover Shorts (c)-(g)	Balance after Using ACP Funds to Cover Shorts	Refund to Ratepayers	ACP Balance at Start of DY	ACP Drawdown to Cover Budget Shorts	ACP Balance at End of DY
2020-21	251.8	160.3	412.1	174.9	-	11.3	186.3	225.8	225.8	225.8	66.6	-	66.6
2021-22	-	156.7	156.7	236.4	15.3	21.1	272.8	(116.0)	(49.5)	-	-	66.6	-
2022-23	(49.5)	160.2	110.7	158.1	0.0	11.3	169.4	(58.7)	(58.7)	-	-	-	-
2023-24	(58.7)	160.3	101.6	152.5	0.0	11.3	163.9	(62.3)	(62.3)	-	-	-	-

Table 3-28: MidAmerican RPS Budget ($M) (Updates Table 3-17)

	RPS Fund Balance at the start of DY			RPS Expenditures during DY				RPS Fund Balance at end of DY			Uncommitted ACPs		
DY	Start of DY Accumulated Funds (Deficit from Prior DY) (a)	DY Collections (b)	Available Funds at start of DY (c)=(a)+(b)	REC Spend Under Contract (d)	Approved REC Spend to be Contracted (e)	Set Asides (f)	Total Spend (g)= (d)+(e)+(f)	Balance before Using ACP Funds to Cover Shorts (c)-(g)	Balance after Using ACP Funds to Cover Shorts	Refund to Ratepayers	ACP Balance at Start of DY	ACP Drawdown to Cover Budget Shorts	ACP Balance at End of DY
2020-21	1.6	0.6	2.2	0.3	-	0.0	0.3	1.9	1.9	1.9	0.0	-	0.0
2021-22	-	0.6	0.6	0.7	-	0.0	0.8	(0.2)	(0.1)	-	-	0.0	-
2022-23	(0.1)	0.6	0.5	0.6	-	0.0	0.6	(0.2)	(0.2)	-	-	-	-
2023-24	(0.2)	0.6	0.5	0.6	-	0.0	0.6	(0.1)	(0.1)	-	-	-	-

Table 3-29: Statewide RPS Budget ($M) (Updates Table 3-19)

	RPS Fund Balance at the start of DY			RPS Expenditures during DY				RPS Fund Balance at end of DY			Uncommitted ACPs		
DY	Start of DY Accumulated Funds (Deficit from Prior DY) (a)	DY Collections (b)	Available Funds at start of DY (c)=(a)+(b)	REC Spend Under Contract (d)	Approved REC Spend to be Contracted (e)	Set Asides (f)	Total Spend (g)= (d)+(e)+(f)	Balance before Using ACP Funds to Cover Shorts (c)-(g)	Balance after Using ACP Funds to Cover Shorts	Refund to Ratepayers	ACP Balance at Start of DY	ACP Drawdown to Cover Budget Shorts	ACP Balance at End of DY
2020-21	381.1	225.2	606.3	238.8	-	15.8	254.6	351.8	351.8	351.8	100.1	-	100.1
2021-22	-	220.5	220.5	325.7	21.3	25.4	372.4	(151.9)	(51.8)	-	-	100.1	-
2022-23	(51.8)	224.1	172.3	224.5	0.1	15.7	240.3	(68.0)	(68.0)	-	-	-	-
2023-24	(68.0)	225.2	157.2	214.4	0.1	15.8	230.2	(73.0)	(73.0)	-	-	-	-

Table 3-30: Statewide RPS Budget Set Asides ($M) (Updates Table 3-18)

DY	Illinois Solar for All [$]	Job Training [$] ComEd Budget	Admin. Expenses (2% of Annual RPS Budget) [$]	Total Set Asides	Total Set Asides less Job Training
2020-21	11.3	-	4.5	15.8	15.8
2021-22	11.0	10.0	4.4	25.4	15.4
2022-23	11.2	-	4.5	15.7	15.7
2023-24	11.3	-	4.5	15.8	15.8

While these tables constitute the Agency's best estimate of expected RPS expenditures as of March 3, 2021, it is important to note that these tables can inherently only be estimates. For instance, a new project may currently be projected to become energized in, say, the first quarter of 2021-22 (and thus would be modeled as having four quarterly payments associated with the 2021-22 delivery year), but in reality, it may not be energized until the final quarter of that year—meaning that project's actual budget impacts for the 2021-22 delivery year would be less than modeled. As discussed further below, because these expected budget impacts can only be estimated with certainty when actual energization dates are known, this creates significant planning challenges in determining how to maximize available RPS funding while implementing payment deferrals required to keep expenses below Section 1-75(c)(1)(E)'s statutory cap.

But those differences due to uncertainty cannot change the following bottom-line takeaway: expenses are virtually certain to exceed collections plus alternative compliance payments for the 2021-22 delivery year, and by a non-trivial amount.[274] As the Agency is unaware of any way in which the Commission, the IPA, or the utilities themselves could legally authorize additional funds to meet these expenses, maintaining the integrity of Section 1-75(c)(1)(E)'s rate impact cap requires that a regime be administratively authorized providing parties with clarity and certainty around how payment deferrals should be implemented. And as discussed further below, the RPS expenses are of various stripes, creating questions about which expected expenses, if any, should be considered senior to (or otherwise higher-priority than) others.

The Agency petitioned the Commission to reopen Docket No. 19-0995, the Illinois Commerce Commission's docketed proceeding for approval of the IPA's Revised Long-Term Renewable Resources Procurement Plan intended to govern RPS program, procurement, and payment activity for the upcoming 2021-22 delivery year, to incorporate these changed budget assumptions and to propose a path forward for resultant payment deferrals. On May 27, 2021, the Commission approved the Agency's proposed modifications to this Revised Plan intended to address this issue, thus providing much-needed clarity and certainty to all affected parties.

[274] While smaller shortfalls are also shown for the 2022-23 and 2023-24 delivery years, the approach for handling those shortfalls will be addressed through the Agency's filing of its next Revised Long-Term Renewable Resources Procurement Plan (scheduled to be filed in October 2021 with Commission approval in February 2022).

3.23.4. Precedent for Payment Deferrals: the 2010 LTPPAs

The Commission has previously authorized a regime governing reductions in payments to REC delivery contracts in the case that available RPS funding was projected as insufficient to meet expected expenditures.

Pursuant to the IPA's Commission-approved 2009 Procurement Plan, the Agency solicited bids in 2010 for long-term power purchase agreements (LTPPAs) to procure renewable resources. The Commission authorized the IPA to procure up to two million MWhs of renewable energy, along with the associated RECs, on an annual basis for a term of twenty years. This amount, based upon load forecasts made in 2009, represented less than 4% of the IPA's total expected energy requirement in the 2012 planning period. The total 40 million MWhs of renewable energy purchased through the LTPPAs over their twenty-year lives was to be divided as follows: 600,000 MWhs each year for 20 years for the Ameren service territory and 1,400,000 MWhs each year for 20 years for the ComEd service territory. The utilities were authorized to recover all reasonable and prudent costs associated with the purchase of the annual energy and RECs specified in the LTPPAs through ICC-approved tariffs. The LTPPA contracts specify that the utilities shall not be liable under the agreements for any costs that cannot be recovered from customers through those approved pass-through tariffs.

Subsequent to the 2010 LTPPA procurement, the retail supply market in Illinois grew more quickly than anticipated, in part due to the early success of municipal aggregation programs. The resulting shift in significant loads of eligible retail customers from the utilities to alternative suppliers in turn reduced revenues collected under the utilities' pass-through tariffs. A statutory rate impact cap under Section 1-75(c)(2) of the IPA Act limited the utilities' ability to recover the revenues at the amount forecasted when the 2009 Procurement Plan was developed.

By the time the IPA filed its 2013 Procurement Plan in September of 2012, it was clear that the statutory rate cap would reduce the budget significantly, such that curtailment of LTPPAs was required. The IPA indicated in the proposed 2013 Plan that purchases under the LTPPAs would need to be reduced, but the Agency was uncertain at the time of the 2013 Plan filing by how much the contracts must be reduced. Procedures in the contracts themselves dictated the method through which a utility must seek Commission approval in order to declare a curtailment event, and in approving the 2013 Plan, the ICC made a determination that curtailment of the LTPPAs was necessary and appropriate.[275] The Commission further found that the LTPPAs should be curtailed upon a pro-rata basis and required the Plan to be amended to state that any reductions in the agreements should be applied proportionately to the LTPPAs consistent with the terms of the contracts.[276] Additionally, the Commission found that alternative compliance payment funds (ACPs) collected by the ComEd from their hourly priced customers shall be used to help mitigate the need to reduce the LTPPAs.[277]

While useful precedent procedurally, that situation features key substantive dissimilarities with the current situation. First, the 2010 LTPPAs were a single contract structure. By contrast, current RPS expenses are made up of a variety of different contract types, including payment structures that, by law, vary by project type. Second, expected expenses for the 2010 LTPPAs were generally predictable: prices were known, and overall payments were reflective of a facility's REC deliveries.

[275] See Docket No. 12-0544, Final Order dated December 19, 2012 at 110.

[276] See id.

[277] See id. at 111.

Conversely, in the current situation, RPS expenses in the upcoming delivery year are expected to vary by, for instance, the level of subscribed shares for a community solar project and whether that project has met small subscriber adder thresholds. And with certain systems' payments frontloaded upon energization, not having perfect visibility into energization timelines means not having perfect visibility into when expenses associated with certain projects will begin to be felt. And lastly, unlike with the 2010 LTPPAs, there is no additional reserve fund available for mitigation—in the present case, the budget deficit at issue exists at the levels posited above *only after* the existing balance of alternative compliance payments is already exhausted.

3.23.5. Current RPS expenditure categories

Before proposing a regime for how expenses could be reduced to meet available budgets, a discussion of exactly what expenses are paid through the RPS budget may be helpful. Below is an outline of expenses projected to be paid through the RPS budget (i.e., collections under Section 16-108(k) of the Public Utilities Act and available alternative compliance payments), as well as estimated budget impacts associated with each for the 2021-22 delivery year in parentheses.[278]

2010 Long-Term Power Purchase Agreements (est. $24.1M)

Bundled REC + energy contracts entered into in 2010 to facilitate the development of new utility-scale renewable energy generation (primarily large wind farms); only the REC portion of the expense (the imputed REC price) is calculated as a drawdown from the RPS budget, with the energy price embedded into the rate paid by default supply customers.

2016-17 Utility Distributed Generation Procurements (est. $2.5M)

Procurements conducted under authority from the ICC's approval of the IPA's 2015, 2016, and 2017 annual energy procurement plans to support new distributed generation project development under the RPS pre-P.A. 99-0906. These procurements resulted in 5-year REC delivery contracts primarily utilizing alternative compliance payments collected from hourly customers, with final payments expected to be made in the 2022-23 delivery year.

Initial Forward Procurements (utility-scale wind, utility-scale solar) (est. $9.2M)

Authorized by Section 1-75(c)(1)(G)(i)-(ii) of the IPA Act, these procurements were intended to support the development of new utility-scale wind and solar projects prior to the Commission's authorization of the IPA's Long-Term Renewable Resources Procurement Plan through 15-year REC delivery contracts paid upon REC deliveries being actually made and invoiced monthly.

Unlike the other forward procurements discussed below, these carry a statutory deadline for first REC deliveries, although that deadline has already once been extended by the General Assembly.

Other Forward Procurements (utility-scale wind, utility-scale solar, brownfield site photovoltaics) (est. $18.8M)

Authorized primarily by the ICC's Order approving the IPA's Original Long-Term Renewable Resources Procurement Plan in Docket No. 17-0838, these procurements were intended to support the development of new utility-scale wind and solar projects, and new brownfield site photovoltaic

[278] As demonstrated in prior tables, both budgets and expenses vary by utility; as the IPA believes a uniform solution is warranted, statewide budget impacts are presented.

projects, to meet future years' Section 1-75(c)(1)(C) new project REC delivery targets. As with the initial forward procurements, these procurements feature 15-year REC delivery contracts with payments made upon delivery (and thus, once energized, the 2021-22 budget impact of these procurements will be approximately 1/15th of the overall contract amount).

ABP: Small Distributed Generation (est. $82.1M)

Small distributed generation photovoltaic projects (10 kW in size and below – generally residential) are supported through the Adjustable Block Program via 15-year REC delivery contracts with full up-front payment upon energization. Blocks for small distributed generation closed in December of 2020 (meaning no new project applications were promised REC delivery contracts after that date);[279] while those projects are allowed 12 months from ICC contract approval to become energized (and some are still under program administrator review), development timelines are generally shorter for smaller projects. The Agency currently projects that [66%] of all ABP Small Distributed Generation capacity will be energized prior to the 2021-22 delivery year.[280]

ABP: Large Distributed Generation (est. $69.3M)

Large distributed generation photovoltaic projects (over 10 kW to 2 MW in size) are likewise given 12 months to become energized, but generally take longer to become energized given the complexity inherent in larger scale project development and feature higher rates of energization deadline extension requests than Small DG systems. Large DG blocks closed in March 2020, but certain project types – especially schools or other projects involving public-sector commitments – may be more acutely impacted by COVID-related delays.

The payment structure in the 15-year REC delivery contracts for Large DG are likewise frontloaded, but less so than with Small DG; these projects are paid 20% of full contract value upon energization, with remaining payments made ratably on a quarterly basis over the subsequent 4-year period. The Agency currently projects that [85%] of all ABP Large Distributed Generation capacity will be energized prior to the 2021-22 delivery year.

ABP: Community Solar (est. $141.4M)

Given that community solar projects must also acquire subscribers, community solar projects are provided 18 months to become energized, with REC payments tied to the projects level of subscribed shares. The project's level of small subscriber participation may also impact REC delivery contract payments: as described in Section 6.15.4, reaching threshold of small subscriber participation increases the applicable REC price. RPS budget modeling assumes that community solar projects are a) fully subscribed and b) able to reach the highest available threshold of small subscriber participation (and thus will feature the largest possible RPS budget impacts); from the IPA's anecdotal observation and discussions with Approved Vendors, this assumption is likely a reasonable expectation.

As outlined above, 109 out of 112 community solar projects have requested extensions to energization deadlines; the Agency has surveyed community solar project developers for

[279] Projects applications received after block closure are waitlisted based on application date and may be selected off the waitlist should a selected project withdraw or fail to be successfully developed.

[280] For purposes of this analysis, becoming energized means not only reaching operational status, but also being verified as energized by the Program Administrator (and thus eligible for payment under REC delivery contracts).

information about expected actual energization dates for each of their contracted projects, and results from those surveys are incorporated into RPS budget modeling assumptions. As of March 1, 2021, 14 community solar projects have achieved energization status (and thus have already received initial payments, or are scheduled to invoice those projects in the March invoicing period) and the Agency expects that 24 additional projects will be energized prior to the end of the 2020-2021 delivery year.

Illinois Solar for All: Utility-counterparty REC delivery contracts (est. $11M)

While the Illinois Solar for All Program is funded primarily through funding in the state-administered Renewable Energy Resources Fund, Section 1-75(c)(1)(O) of the IPA Act also dedicates "5% of the funds available under the plan for the applicable delivery year, or $10,000,000 per delivery year, whichever is greater" to fund Illinois Solar for All. While this delivery year allocation is expected to be just over $11 million in 2021-22 (and thus this amount would support the 2021-22 program year budget), the amounts subject to payment in 2021-22 may be different, and depend on energization timelines for projects approved in prior program years.

For budget modeling purposes, the IPA has assumed that a single program year's budget of projects will be energized in the upcoming delivery year, resulting in a placeholder value of $11 million in RPS budget modeling. However, based on the portfolio of projects under utility contracts and revised energization dates applicable to those projects (specifically, accounting for delays experienced by earlier-approved projects), $15 million may be a "high-case" estimate for 2021-22 delivery year budget impacts, and the actual amount could vary considerably.[281]

An additional question for the Commission to consider is whether authorizing additional program year expenditures for the Illinois Solar All for the 2021-22 program year is advisable given the current state of the RPS budget. While doing so would layer new expenditures atop existing expenditures in an environmental where those existing expenditures cannot be met with funds available, payment for 2021-22 *program year* REC delivery contracts may not occur until future *delivery years*, and one could make colorable statutory arguments in favor of prioritizing this allocation. The IPA's RPS budget modeling generally assumes that ILSFA allocations under Section 1-75(c)(1)(O) will continue to be made.

Illinois Solar for All: Job Training Funds ($10M)

Also pursuant to Section 1-75(c)(1)(O) of the IPA Act, once every four years (with the 2021-22 delivery year being one such year) $10 million from ComEd's RPS budget is due to be allocated to job training programs authorized under Section 16-108.12 of the Public Utilities Act. As with ILSFA program year expenses, RPS budget modeling generally assumes that this allocation will continue to be made. And as with ILSFA program year expenses, this $10 million could be considered junior to existing REC delivery contracts given that it constitutes prospective expenses, but as outlined below, one could also make colorable statutory arguments for its prioritization.

Administrative Costs (est. $4.4M)

[281] Regardless of size or project type, Illinois Solar for All projects are paid out on energization in a manner similar to Adjustable Block Program Small DG projects. Therefore, the full budget impact of Illinois Solar for All project completions will be felt in the program year the project is energized.

Projected administrative costs for the 2021-2022 delivery year are estimated to be about $4.4M, which is equivalent to 2% of the Annual RPS Budget. Projected administrative costs are allocated as follows: $4M for Consultant Costs ($3.6M for the Adjustable Block Program Administrator, $0.25M for the Procurement Planning Consultant, and $0.2M for the Procurement Administrator), and $0.4M for REC retirement fees. This amount is also subject to variance.

3.23.6. Key considerations in implementing a deferral regime

In working through a proposed approach for a reduction in expenses to meet available funds, the IPA believes certain considerations should be highlighted (even if not necessarily resulting in an approach to accommodate that consideration).

Statutory considerations

At least two statutory clauses could be interpreted to prioritize to certain RPS expenses over others for purposes of payment deferrals. First, Section 1-75(c)(1)(F) of the IPA Act directs that if application of the rate impact cap prevents the IPA from meeting RPS goals, then the Long-Term Plan shall prioritize compliance with RPS requirements "regarding renewable energy credits" in the following order:

> (i) renewable energy credits under existing contractual obligations;
>
> (i-5) funding for the Illinois Solar for All Program, as described in subparagraph (O) of this paragraph (1);
>
> (ii) renewable energy credits necessary to comply with the new wind and new photovoltaic procurement requirements described in items (i) through (iii) of subparagraph (C) of this paragraph (1); and
>
> (iii) renewable energy credits necessary to meet the remaining requirements of this subsection (c).

It is not clear exactly what guidance this language offers for the present context. The present RPS budget crisis generally concerns *not* <u>prospective</u> additional program or procurement activity, but instead funding availability for a wide range of what are <u>already</u> existing contractual obligations. Prioritizing all contracts already executed would perhaps eliminate the approximately $21 million in prospective 2021-22 delivery year expenses for the Illinois Solar for All Program under Section 1-75(c)(1)(O), but doing so would a) still result in a significant shortfall, b) elevate Adjustable Block Program and utility-scale procurement obligations above the Illinois Solar for All obligations (which could be interpreted as inconsistent with the ordering between (i-5) and (ii), above), and c) do little to control expenses for Illinois Solar for All contracts already executed.

Another possible interpretation is that "existing contractual obligations" refers only to those obligations already in existence as of the effective date of Public Act 99-0906, which would exempt the LTPPAs and utility DG procurement contracts from payment deferrals. Were that the General Assembly's intent, however, one may expect (i) to specifically refer to "existing contractual obligations <u>as of the date of this Amendatory Act</u>" or otherwise feature scope-limiting text. Similarly, the prioritization of (i-5) expenses above could be read to prioritize existing Illinois Solar for All contract expenses above existing utility-scale and Adjustable Block Program expenses, as the latter

were contracts executed in an effort to meet a lower priority item under 1-75(c)(1)(F) (new wind and new photovoltaic procurement requirements).

Second, Section 1-75(c)(1)(O)'s allocation to Illinois Solar for All is written as follows:

> *For the delivery year beginning June 1, 2018, the long-term renewable resources procurement plan required by this subsection (c) shall provide for the Agency to procure contracts to continue offering the Illinois Solar for All Program described in subsection (b) of Section 1-56 of this Act, and the contracts approved by the Commission shall be executed by the utilities that are subject to this subsection (c). The long-term renewable resources procurement plan shall allocate 5% of the funds available under the plan for the applicable delivery year, or $10,000,000 per delivery year, whichever is greater, to fund the programs, and the plan shall determine the amount of funding to be apportioned to the programs identified in subsection (b) of Section 1-56 of this Act; provided that for the delivery years beginning June 1, 2017, June 1, 2021, and June 1, 2025, the long-term renewable resources procurement plan shall allocate 10% of the funds available under the plan for the applicable delivery year, or $20,000,000 per delivery year, whichever is greater, and $10,000,000 of such funds in such year shall be used by an electric utility that serves more than 3,000,000 retail customers in the State to implement a Commission-approved plan under Section 16-108.12 of the Public Utilities Act. In making the determinations required under this subparagraph (O), the Commission shall consider the experience and performance under the programs and any evaluation reports. The Commission shall also provide for an independent evaluation of those programs on a periodic basis that are funded under this subparagraph (O).*

One could interpret this prescriptive allocation as demanding program year allocations for Illinois Solar for All be backed out of the RPS budget before determining the budget available to meet other obligations, especially when read in conjunction with the (i-5) prioritization of Illinois Solar for All expenses in Section 1-75(c)(1)(F) of the Act. While the Agency has generally adopted this approach of "backing out" a *program year's* ILSFA expenses before determining the remaining available budget, it is unclear how that approach meshes with an upcoming *delivery year's* expenses; as outlined above, because of the unpredictable nature of project energization timelines, Illinois Solar for All expenditures in the 2021-22 delivery year could be greater than this annual program year allocation. Additionally, as these allocations are prospective expenses, they could likewise be understood as junior to any existing REC delivery contract expenses given the rank-ordering between (i) versus (i-5) in Section 1-75(c)(1)(F).

Pragmatic considerations

The primary pragmatic consideration worth highlighting is the administrative burden, confusion, and general messiness associated with "clawing back" any already-made payments under REC delivery contracts. Perhaps one could construct an argument that, for the sake of fairness, all Adjustable Block Program contracts should face similar payment obligation reductions regardless of payments already made to date. Because Small DG contract obligations are fully paid upon energization, placing all such ABP systems on equal footing would require recovering some portion of the one-time payments already made for systems energized by May 31, 2021. In theory, this approach could allow for an even pro rata deferral of payments by contract type, regardless of energization timing considerations. No party to the proceeding adopting these modifications to this

Revised Plan expressly raised or requested that clawbacks be implemented in the event that payment obligations are unable to be met.[282]

The Agency believes any focus on already-made payments is an unadvisable approach for a multitude of reasons. A clawback of prior delivery years' payments carries uncertainty of recovery, significant administrative burden and expense, and unknown potential consequences for customers (especially distributed generation project hosts—Illinois residents and businesses) who may be guaranteed a rebate on system purchase or financing equivalent only to that which is paid out under a REC delivery contract. One fear is that a clawback of already-made REC delivery contract payments could result in solar companies seeking partial recovery of corresponding payments already made to customers, creating massive confusion and negative customer experiences with a state-administered incentive program. To avoid this potential confusion, the Agency strongly believes a better approach is simply focusing on expenses associated only with the *upcoming* delivery year, the year for which funds on hand are insufficient to cover expenses, and implementing a payment deferral regime which brings those expenses in line with the available RPS budget.

Fairness considerations

The Agency believes that market participants developing new renewable energy projects in Illinois had no expectation that REC delivery contract payments could be subject to risk of reduction. Indeed, as described in Chapter 2, revisions to the RPS contained in Public Act 99-0906 were intended to give market participants budget certainty necessary for successfully developing new projects in Illinois; unfortunately, corresponding revisions to Section 16-108(k) of the Public Utilities Act – which fail to effectively "wall off" funding from potential reconciliation once that funding has been committed under a REC delivery contract – have not proven sufficient for handling unexpected project energization delays caused by a global health pandemic.

Consequently, the Agency's preferred approach to any payment deferrals is one which accomplishes the following:

a) ensuring that REC delivery contract holders are, in all cases, ultimately made whole for performance (i.e., any impact to payments should operate only as temporary deferral of payment obligations, rather than reductions in contract value amount); and

b) reducing the time period during which payment delays are felt by REC delivery contract holders to the maximum extent possible.

As discussed below, achieving those ends – as well as ensuring that REC delivery contracts define a Buyer's performance obligations as operating consistent with a Commission-approved payment deferral regime – will likely required adoption of a uniform amendment to existing REC delivery contracts.

3.23.7. IPA proposed payment deferral approach

With these and other considerations in mind, the Agency proposed, and the Commission approved, the following approach.

[282] See Docket No. 19-0995, Order on Reopening dated May 27, 2021 at 10.

First, REC delivery contracts will continue to be paid in full for at least the first six months of the 2021-22 delivery year. This approach will hopefully create as little disruption as possible to all parties; Sellers will be ensured full, expected payments through the end of calendar year 2021, and Buyers will have perfect clarity as to their payment obligations until incorporating future adjustments. Because actual 2021-22 delivery year expenses will not be clear until observing energization patterns within that delivery year, this approach will allow for a deferral of payment obligations to occur with the best possible information about those obligations. As available funds for the 2021-22 delivery year are expected to be approximately 98% of projected expenses for Ameren Illinois, 82% for ComEd and 80% for MidAmerican (according to March 2021 IPA projections), funding should be sufficient to cover all expected costs over this initial period.

Second, by December 30, 2021, the IPA will provide a compliance filing in Docket No. 19-0995 updating the status of the RPS budget and outlining the RPS budget available at the conclusion of the calendar year for use in the remainder of the 2021-22 delivery year, as well as updated projected expenses for that upcoming period. By this time, the first two quarterly invoicing periods of delivery year 2021-22 will have been completed for Adjustable Block Program contracts, and utility-scale project contracts will likewise have provided six months of monthly invoices. This compliance filing's updated estimates of projected expenses and available budget would then be utilized for implementing REC delivery contract payment deferrals and provide percentage-based payment obligation reductions for those projects subject to a deferral of payment obligations.

Third, the resulting payment deferrals will exempt both LTPPAs and the utility DG procurement expenses. Whatever reading one gives to Section 1-75(c)(1)(F) of the IPA Act, it seems likely that this set of contract holders had the expectation of that prioritizing "existing contractual obligations" in language signed into law in December 2016 would ultimately exempt these contracts (which were developed and executed before enactment of Public Act 99-0906, and prior to any additional contracts being executed) from any reductions in payments in the case that RPS budgets proved insufficient to cover expenses. Exempting these agreements also offers administrative ease, as the contract form and structure of these agreements was developed in an entirely different timeframe and under different applicable law than with the development of REC delivery contracts executed since Public Act 99-0906's enactment.

Fourth, the Agency believes that prioritization should be offered to Illinois Solar for All contract expenses, and payouts under those REC delivery contracts will not be reduced or deferred. Section 1-75(c)(1)(F) can indeed be interpreted as prioritizing Illinois Solar for All REC delivery contract expenses over Adjustable Block Program expenses or utility-scale REC delivery contract expenses; even if all such contracts could be considered "existing contractual obligations" as of March 2021, the drafters clearly believed that *some* priority should be assigned to Illinois Solar for All over other activities. Further, corresponding contracts with the IPA serving as the counterparty (paid out of the RERF) are not subject to these RPS budget constraints, and exempting utility-contracted Solar for All expenses form reduction thus keeps all Illinois Solar for All contracts on even footing (rather than disadvantaging particular Approved Vendors who happened to receive a utility counterparty agreement).

Fifth, the upcoming 2021-22 delivery allocations for Illinois Solar for All – including the $10 million job training program allocation – will be maintained. REC delivery contract expenses for projects participating in the upcoming program year are unlikely to impact the 2021-22 delivery year

budget, and the IPA understands Section 1-75(c)(1)(O)'s direction as essentially backing out job training program expenses before determining available budgets for other obligations.

Lastly, at the start of the 2022-23 delivery year, any payment deferrals implemented during the 2021-22 delivery year will immediately be prioritized as payments due to those Sellers in the first applicable invoicing cycle of the 2022-23 delivery year. Those expenses would thus be added to the 2022-23 delivery year expenses as the highest priority payments, and 2022-23 delivery year budget projections will be adjusted accordingly in line with these new costs. This approach will help ensure that any deferral of payouts serves only as a time-limited deferral of expenses, and as limited a deferral as possible at that.

To be clear, the above approach is not a solution to the current RPS budget situation. An actual solution can only be provided through legislation, and the Agency hopes that the process of working through these complexities heightens all parties' urgency in achieving a legislative fix. Instead, the above approach constitutes the Agency's best effort at emergency triage, and its attempt to limit the collateral damage resultant from an inherently problematic process brought on by an unprecedented global health crisis. In developing this approach, the Agency recognized that a payment reduction regime constitutes selecting between various flawed choices. The IPA believes the approach outlined above is sound, and the Commission agreed, confirming that the approach is prudent, reasonable, workable, well thought out, and most importantly, provides certainty and fairness to affected market participants.[283]

As outlined previously above, should a payment deferral approach also be required for the 2022-23 delivery year and beyond, that approach will be determined through the IPA's next Revised Long-Term Renewable Resources Procurement Plan developed in conjunction with its 2022 Annual Electricity Procurement Plan and due to be filed in October 2021 and approved by the Commission in February 2022.[284]

3.23.8. REC Delivery Contract Amendment

Ensuring that REC delivery contracts are ultimately paid in accordance with the approach outlined above and approved by the Commission will require modification to those contract forms which are potentially subject to payment deferral. Amending REC delivery contracts will help ensure that a Buyer is insulated from legal exposure for following a regulatory directive that may contradict a Seller's interpretation of its REC delivery contract, and will also ensure that the Seller has contractual rights around any deferred payments ultimately serving only as temporary deferral of those payment obligations.

For both programs and competitive procurements, exact contract language is not developed through a Commission proceeding; instead, the Agency's Procurement Administrator develops draft contract language consistent with Illinois law, the IPA's Plan, and the Commission's Order approving that Plan. Draft contracts are published for comment and feedback, and ultimately adopted only with the consensus of the IPA, ICC Staff, the Procurement Administrator, Procurement Monitor (where

[283] See Docket No. 19-0995, Order on Reopening dated May 27, 2021 at 27.

[284] Consistent with this statement and the Commission's Order on Reopening, the budget for delivery years after 2021-2022 will be determined by information from the prior delivery year. Docket No. 19-0995, Order on Reopening dated May 27, 2021 at 8.

applicable), and the counterparty utilities (with the Commission resolving any disputes should those parties fail to achieve consensus).

Having received sufficiently specific direction from the Commission upon reopening in approving a contract payment deferral approach, the IPA will follow this contract development process for the development and adoption of any necessary REC delivery contract amendments. In accordance with its commitments made in Docket 19-0995 and the Commission's order, the Agency will target August 31, 2021, for finalization of the amendments, which will reflect the Commission's determinations on the issues outlined above. As implicit in the Commission's ruling approving the IPA's proposal, the Commission does not need to take further action before both Buyer and Seller would execute, and ultimately have their relationship governed by, that amendment.

4. Renewable Energy Credit Eligibility

To be eligible for use in compliance with the Illinois RPS, RECs are required to meet a variety of eligibility requirements. First, the RECs are to be sourced from generating technologies permitted in the definition of "renewable energy resources" contained in Section 1-10 of the Act.[285] Second, Subsections (I) and (J) of Section 1-75(c)(1) create additional eligibility criteria. Subsection (I) contains locational eligibility criteria, while subsection (J) contains criteria related to how a facility that generates RECs recovers its costs. This Chapter discusses how the Agency interprets and implements the requirements of Subsections (I) and (J).

4.1. Adjacent State Requirement

Section 1-75(c)(1)(I) of the Act contains a locational eligibility requirement for the Illinois RPS. Enacted through P.A. 99-0906, this requirement replaced the prior locational standard under which renewable energy resources could come from Illinois and adjoining states, and if not available, then they could come from elsewhere.[286] By contrast, Section 1-75(c)(1)(I) now requires qualifying renewable energy credits can be generated by facilities located in Illinois, and *may* be sourced from facilities in adjacent[287] states—but *only* if these facilities can meet public interest criteria spelled out in the law. While not explicitly stated in the statute, the Agency understands that the consideration of the public interest criteria for adjacent states means that renewable energy credits from states that are not adjacent to Illinois (or from other countries) will not be eligible for the Illinois RPS.

The public interest criteria that the Agency considers include:

1. Minimizing sulfur dioxide, nitrogen oxide, particulate matter and other pollution that adversely affects public health in this State
2. Increasing fuel and resource diversity in this State
3. Enhancing the reliability and resiliency of the electricity distribution system in this State
4. Meeting goals to limit carbon dioxide emissions under federal or state law
5. Contributing to a cleaner and healthier environment for the citizens of this State

The Act specifies that the Agency "may qualify renewable energy credits from facilities located in states adjacent to Illinois <u>if the generator demonstrates</u> *and* <u>the Agency determines</u> that the operation of such facility or facilities will help promote the State's interest in the health, safety, and welfare of its residents based on the public interest criteria described above."[288]

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[285] That definition is:"'[r]enewable energy resources' includes energy and its associated renewable energy credit or renewable energy credits from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, anaerobic digestion, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams. For purposes of this Act, landfill gas produced in the State is considered a renewable energy resource. `Renewable energy resources' does not include the incineration or burning of tires, garbage, general household, institutional, and commercial waste, industrial lunchroom or office waste, landscape waste other than tree waste, railroad crossties, utility poles, or construction or demolition debris, other than untreated and unadulterated waste wood." (20 ILCS 3855/1-10). Note that Public Act 99-0906 removed "other alternative sources of environmentally preferable energy" from this definition.

[286] Former 20 ILCS 3855/1-75(c)(3), repealed June 1, 2017.

[287] For the purpose of assessing eligibility for compliance with the Illinois RPS, the Agency defines only states that have a common border as states adjacent to Illinois: Wisconsin, Iowa, Missouri, Kentucky, Indiana, and Michigan. Michigan is considered adjacent due to the border between Illinois and Michigan that exists in Lake Michigan. This is consistent with how other State Agencies interpret the federal Coastal Zone Management Act. See, for example, https://www.dnr.illinois.gov/cmp/documents/3_boundary.pdf.

[288] 20 ILCS 3855/1-75(c)(1)(I) (emphasis added).

To do so, and to "ensure that the public interest criteria are applied to the procurement and given full effect," the Plan "shall describe in detail how each public interest factor shall be considered and weighted for facilities located in states adjacent to Illinois." This Chapter provides that description.

In originally developing a methodology for considering and weighting these public interest criteria, the Agency faced certain challenges. The complex nature of an interconnected electric power grid and associated system operations (i.e., generation dispatch for economics and reliability), and how pollution flows across states, all prevented the Agency from simply quantifying and scoring facility eligibility requests using easily obtainable data. While predictions can be simulated, there is not one clear, unassailable way to determine how a renewable energy facility in an adjacent state will meet the public interest criteria.

In its Initial Plan, the Agency developed what it believes are reasonable proxies for each criterion.[289] In the Final Order approving the Initial Plan on April 3, 2018 in Docket No. 17-0838, the Commission found the Agency's methodology and assumptions for considering the eligibility of RECs sourced from adjacent states to be reasonable. That approach, described in more detail below, is generally unchanged in this Revised Plan.

While based conceptually on the same approach used for the Agency's Zero Emission Standard ("ZES") Plan, the basis for determining compliance with the pollution and emissions public interest criteria in this Revised Plan is focused on the displacement of potential new non-renewable gas-fired generation by renewable generation that could be eligible to supply RECs to meet the Illinois RPS requirements. Among the differences from the ZES Plan scoring approach are that renewable generating facilities are likely to be intermittent rather than baseload (a defining characteristic of zero emission facilities), typically impact generation on the margin of the dispatch order and are generally smaller in size relative to the ZES replacement generation.

To assess whether a renewable generating facility located in an adjacent state is eligible to participate in the IPA's REC procurements to meet the Illinois RPS, the Agency assigns a maximum of 20 points to each of the five public interest criteria, as described below, for a total of 100 possible points.

For a renewable energy generating facility in an adjacent state to have its RECs considered eligible for the Illinois RPS, the adjacent state facility needs to demonstrate that it can achieve a total score of at least 60 points for the Agency to approve that request. The IPA believes that this score threshold – previously affirmed by the ICC in Docket No. 17-0838,[290] and one which requires a better than average score demonstrating benefits to the health, safety, and welfare of Illinois residents, but yet not too onerous to prohibit any adjacent state participation – provides a balanced approach to ensuring that adjacent state facilities indeed provide sufficient benefits consistent with the law's directive.

For this Revised Plan, the Agency has reviewed and analyzed not only this scoring threshold, but also the methodology for the consideration of adjacent state facilities. After review and analysis, this

[289] The Agency also developed a similar set of criteria for use in its Zero Emission Standard Procurement Plan ("ZES Plan") developed pursuant to Section 1-75(d-5) of the Act, which was approved by the Commission on September 11, 2017 in Docket No. 17-0333. That ZES Plan includes consideration of how to minimize sulfur dioxide, nitrogen oxide, and particulate matter emissions that would result from the potential closure of zero emission facilities (i.e., nuclear plants located in PJM or MISO).

[290] In its Order approving the Plan, the Commission approved of this 60 point scoring threshold, finding that "the IPA's general methodology is a reasonable implementation of PA 99-0906 and a basic passing score of 60 points is an appropriate threshold." Docket No. 17-0838, Final Order dated April 3, 2018 at 20.

scoring threshold and methodology (described further below) remains the same as presented in the Initial Plan. As this scoring threshold and methodology was uncontested in the Commission's approval of the Plan in Docket No. 19-0995, the IPA understands it to be again adopted.

The Agency also notes that there are two wind facilities in adjacent states that were the recipients of contracts from the 2010 Long-Term Renewable Resources Procurement. One in Iowa has a contract with Ameren, while one in Indiana has a contract with ComEd. As these facilities were granted contracts at a time that Illinois law viewed them as providing sufficient benefits to Illinois residents for their renewable energy resources to be used to meet the Illinois RPS, the Agency considers these two facilities to be grandfathered into this requirement.

4.1.1. Public Interest Criteria

1. **Minimizing sulfur dioxide, nitrogen oxide, particulate matter and other pollution that adversely affects public health in this State**

In the Zero Emission Standard Procurement Plan, the Agency developed a scoring methodology for sulfur dioxide, nitrogen oxide, and particulate matter that considered the likely location of replacement generation compared to a bidding zero emission facility that could be at risk of ceasing operation. That methodology calculated, for any given zero emission facility, the percentage of the replacement generation that would occur in various states, an emissions factor related to each of those states based on its existing coal and gas generation, and an adjustment factor that recognized the frequency of prevailing winds and the distance from Illinois that could predict the amount of pollution that would impact the residents (and thus public health) of Illinois.

For the purposes of its Initial Plan (and maintained in this Revised Plan) and the consideration of this criterion, the Agency refined and simplified the methodological approach utilized in the ZES Plan. Under the ZES Plan, emissions are associated with replacement of generation that can be located anywhere in PJM or MISO; for the purposes of this Revised Plan, the Agency considers that a renewable energy facility would displace the emissions of a typical new natural gas-fired combined-cycle generation facility.

In the ZES Plan, the Agency weighted replacement generation across multiple states, in recognition that replacement generation for a large Zero Emission Facility would likely come from multiple sources (replacement generation would be a combination of changed dispatch of existing generation units as well as the potential development of new generating units). [291] The Agency simplified the weighting for this criterion to focus on comparing emissions from renewable generation to the emissions from a new natural gas-fired combined-cycle generating facility. This assumption reflects the fact that recent and anticipated additions to the resource mix in PJM and MISO will be predominantly natural gas, wind or solar[292] and natural gas is increasingly the fuel on the margin for both PJM and MISO, and thus more appropriate for comparison than, say, a baseload coal facility.[293]

[291] Specifically, 33% of the replacement generation was assumed to be in the bidding zero emission facility's own state, and the remaining 67% of replacement generation was assumed to occur across the relevant RTO, allocated by states based on each state's share of RTO-wide generation. ZES Plan, July 31, 2017, https://www.icc.illinois.gov/downloads/public/edocket/451223.pdf, at 37.

[292] U.S. FERC, Office of Energy Enforcement, Division of Market Oversight, "State of the Markets Report 2018." Item No.: A-3, April 18, 2019, p. 17. In the March 2017 report, "PJM's Evolving Resource Mix and System Reliability" (http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx), PJM states that from 2010 to 2016, natural gas and renewable made up 87 percent of new megawatts placed in service.

[293] See: MISO Market and Operations Analytics, MISO 2018-2019 Winter Assessment Report, April 2019; MISO 2018 Summer Assessment Report, September 2018. Potomac Economics, "2017 State of the Market Report for the MISO Electricity Markets, Analytic Appendix"

As discussed below, this comparison is a relevant factor in the evaluation criteria for renewable technologies that involve combustion (thus not including wind, solar, or hydro).

The emissions comparison includes sulfur dioxide (SO_2) and nitrogen oxide (NO_x) as proxies for all emissions because higher emissions of SO_2 and NO_x are generally correlated with higher emissions of PM, especially with regard to facilities that involve the combustion of solid fuels. SO_2 and NO_x are primary emission sources for the formation of $PM_{2.5}$ in ambient air away from the immediate emissions source. Larger PM (PM_{10}) is deposited nearer the source, while secondary $PM_{2.5}$ increases based on the formation of sulfates and nitrates from the SO_2 and NO_x in the atmosphere as the pollutants move away from the primary source.[294] The following table shows SO_2, NO_x, and CO_2 emissions rates of new natural gas-fired generation based upon 2016 data from the U.S. Energy Information Agency ("EIA"). [295]

Table 4-1: Natural Gas-Fired Combined-Cycle Generation Emissions Rates

Pollutant	Pounds/MWh
SO_2	0.007
NO_X	0.05
CO_2	772

The score is calculated by multiplying an emissions factor for the renewable resource facility (scaled from 0 to 1) by a wind duration/direction factor (scaled from 0 to 1) and then by 20 points to determine the number of points awarded for this criterion.

The emissions factor is calculated by taking one minus: the sum of the eligible renewable resource's SO_2 and NO_x emissions in pounds/MWh divided by the sum of the SO_2 and NO_x emissions from a new natural gas-fired combined-cycle generation facility in pounds/MWh.

The emissions factor for renewable energy generating facilities such as wind, solar, or hydro, which do not emit SO_2, NO_x, or Particulate Matter, would be 1.0 because those facilities would have zero in the numerator of the part of the equation that is subtracted from one.

For other renewable generating technologies, the Agency notes that those technologies eligible for the Illinois RPS include a combination of technologies that rely on combustion of a fuel source including biodiesel, anaerobic digestion (which presumably would create a biogas that is then burned), biomass, and tree waste; and other technologies that do not involve combustion (e.g., wind, solar thermal, photovoltaic, and hydro power).[296] Renewable generation technologies that involve combustion to generate electricity generate sulfur dioxide, nitrogen oxides, particulate matter, and CO_2, among other things. To assess the emissions impact of renewable resource technologies that involve combustion, the emissions from these facilities are compared to the emissions from a new

June 2018, https://www.potomaceconomics.com/wp-content/uploads/2018/06/2017-SOM_Report_Final_Rev.pdf; Monitoring Analytics, LLC, "Q1 2019 State of the Market Report for PJM," May 9, 2019, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017.shtml.

[294] U.S. EPA, "Particulate Matter Emissions," Report on the Environment, http://www.epa.gov/roe.

[295] Emissions rates for a natural gas turbine operating in combined cycle with a heat rate of 6,600 Btu/kWh are shown in Table 2-5 of the November 2016 U.S. EIA Report "Capital Cost Estimates for Utility Scale Electricity Generating Plants." The CO_2 emissions in pounds per MMBtu are 117 for CO2, 0.001 for SO_2, and for NOx 0.0075; which at the heat rate of 6,600 Btu/kWh, are 772 pounds per MWh of CO_2, 0.007 pounds per MWh of SO_2, and 0.05 pounds per MWh of NOx. See: https://www.eia.gov/analysis/studies/powerplants/capitalcost. Typical emissions rates have not changed since 2016.

[296] While landfill gas produced in Illinois is eligible, it is not relevant to this discussion of facilities located in adjacent states.

natural gas-fired combined-cycle facility. To the extent that the technologies that involve combustion generate SO_2 and NO_x emissions, and the emissions in pounds/MWh are lower than the emissions from a new gas-fired facility, then the calculation for the renewable energy facility would result in the facility receiving some points for this criterion based upon the formula listed below that also accounts for wind duration/direction (as would be the case for technologies with no emissions such as wind or solar for which the points would only be based on the wind duration/direction and not discounted by emissions rate). On the other hand, if the emissions are equal to or greater, on a pounds/MWh basis, than from a new natural gas-fired facility, then the calculation would result in the facility receiving zero points for this criterion. This reflects that an emissions rate that is greater than that for a natural gas-fired combined-cycle facility does not have a positive impact on the environment and public health.

The Zero Emission Standard Plan included consideration of wind direction and duration as well as the distance from Illinois to modify the emissions criteria scoring. In scoring the emissions related public interest criterion for this Revised Plan, the Agency simplified the wind duration/direction approach that was utilized in the Zero Emission Standard Plan. Since the renewable generating facilities supplying RECs from outside of Illinois must be located in the states adjacent to Illinois (as opposed to anywhere within PJM and MISO under the Zero Emission Standard), the distance of the emission source from Illinois is less important and is considered in the approach adopted for this Revised Plan.

The following table provides the wind duration/direction factors for each adjacent state.

Table 4-2: Wind Duration/Direction Factors

Adjacent State	Wind Direction Sectors	Wind Direction and Duration Factor[297]
Indiana	SSE, SE, ESE, E, NNE, NE, ENE	0.256
Kentucky	S, SSE, SE	0.201
Missouri	W, WSW, SW, SSW, S	0.439
Iowa	W, WNW, NW, NNW	0.269
Wisconsin	N, NNW	0.096
Michigan	NE, NNE	0.088

The wind duration factor is based on the percentage of the time the wind blows into Illinois from 16 directional sectors that form all of the directions in 360 degrees around Illinois. The wind direction and duration factors were developed based on 21 years of consistent climatological data. On average this data is relatively stable over time, although at some point in the future climate change could impact the data underlying the determination of these factors. For example, the wind blowing from Indiana would encompass seven directional sectors from which the wind blows on average 25.6 percent of the time. Thus, for example, a solar facility located in Indiana would receive 1 x 0.256 x 20 or 5.1 points. The following equation shows how this score is obtained (with the caveat that the minimum possible score is zero and cannot be a negative score):[298]

[297] Total factors exceed 1.0 because there may be more than one state represented in a given wind direction sector.

[298] See Docket No. 17-0838, Final Order dated April 3, 2018 at 21.

Figure 4-1: Pollution Score Calculation

$$Score = \left(1 - \frac{\sum_{renewable\ resource} SO_2\ and\ NO_x \left(\frac{lbs}{MWh} \right)}{\sum_{gas\ resource} SO_2\ and\ NO_x \left(\frac{lbs}{MWh} \right)} \right) \times Wind\ \ Duration / Direction\ \ Factor \times 20$$

The Agency's review of the scoring methodology for this criterion showed that the assumptions and analytical approach remain valid for this Revised Plan. In particular, the wind duration/direction factors were developed based on 21 years of consistent data reported by the Illinois State Water Survey, Water and Atmospheric Resource Monitoring Program from 17 reporting stations located around the state for the years 1996 through 2016.

2. Increasing fuel and resource diversity in this State

Fuel and resource diversity generally refers to the use of a balanced group of generating facilities and technologies which results in reducing the risk that a specific technology could adversely impact overall system reliability. For example, PJM defines fuel diversity as: utilizing multiple resource types to meet demand such that a sufficiently diversified system is expected to provide the flexibility and adaptability to: "1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility and fuel supply disruptions, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks."[299] In effect, fuel and resource diversity can act as a hedge to help ensure a stable and reliable supply of electricity.

Any generation source that promotes more reliance on generation sources other than coal and nuclear, which in 2018 had generation shares of 31.8% and 52.2% of Illinois' total generation respectively,[300] would contribute to increasing fuel and resource diversity in Illinois. By this measure, any of the eligible renewable energy resource generating technologies would contribute to diversity in Illinois. However, if these facilities were located outside of Illinois, in the adjacent states, the full impact on the State's fuel and resource diversity would depend on whether the electricity generated by these facilities could actually be available to Illinois end-users.

Given that renewable generation accounts for only a relatively small fraction of the resource mix in Illinois (7.1% of total generation in 2018), an increase of renewable generation in the region may, in theory, increase the fuel and resource diversity of Illinois. However, the Agency notes that Illinois is a net exporter of electricity, so the impact on fuel and resource diversity in Illinois may be limited for facilities located in adjacent states. While Illinois is a net exporter of electricity, that does not mean that there is no impact on Illinois from electricity generated in adjacent states, because on an hour-to-hour basis electricity may flow into, or out of, Illinois. To the extent that any electricity generated outside of Illinois but consumed in the state is generated by resources other than coal or nuclear, this generation is assumed to add to the fuel and resource diversity in Illinois.

[299] PJM, "PJM's Evolving Resource Mix and System Reliability," March 2017, available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[300] U.S. EIA, Electric Power Monthly with data for December 2018, February 2019. The Agency notes that the share of coal declined from 38% and share of nuclear increased from 50.2% as reported in the Initial Plan. This is a net decline in the percentage of generation that comes from coal and nuclear (88.2% to 84%), which indicates that the fuel and resource diversity of the state has increased slightly.

In addressing this issue for facilities located in the adjacent states, the Agency uses the location of the renewable resource facility relative to Illinois as the basis for modifying the fuel and resource diversity score. A distance factor is calculated for each facility.[301] The distance factor is based on the distance from the facility to Morris, Illinois (which is the city closest to the population weighted geographic center of Illinois,[302] and thus can serve as a reasonable proxy for the load-weighted center of the state). The factor is calculated as 1 minus the ratio of (i) the distance from the facility to Morris and (ii) 470 miles, which is roughly the furthest point in an adjacent state from Morris. Consistent with the Commission's Order in Docket No. 17-0838, the center point of the City of Morris is used for this calculation.[303] That factor is multiplied by the maximum possible 20 points to provide the score for this criterion for potentially eligible renewable resource facilities located in adjacent states. The fuel and resource diversity score formula is shown in Figure 4-2.

Additionally, consistent with the Commission's Order in Docket No. 17-0838 and the approach taken with respect to the third criterion below, a facility "that is not connected to either PJM or MISO" will receive a Fuel and Resource Diversity Score of zero.[304] Adjacent state generation facilities "within a transmission control area that have a transmission usage agreement with PJM or MISO" may still receive non-zero scores under Criteria 2 and 3, however.[305]

Figure 4-2: Fuel and Resource Diversity Score

$$Score = (1\ if\ in\ PJM/MISO, else\ 0\ )x\left(1 - \frac{Distance\ from\ facility\ to\ Morris,\ \ IL\ (miles)}{470\ miles}\right) x\ 20$$

3. Enhancing the reliability and resiliency of the electricity distribution system in this State.

While this criterion references the "electricity distribution system" and that term is generally understood to mean the local distribution system that serves homes and businesses and not the transmission grid that transports power over longer distances (and across state lines), the Agency was originally concerned that, read literally, there would be no direct way for a facility in an adjacent state to meet this criterion because a facility in an adjacent state would have (at best) only an incidental impact on the distribution system (or more accurately systems, each operated by a different utility) within Illinois. With that in mind, the Agency has come to interpret this criterion more liberally and instead considers the impact on the grid more generally, as distribution service is ultimately supported by the reliability of transmission service. The scoring for this public interest criterion involves a threshold and, based on the assumption that generating facilities located closer to Illinois would have a more beneficial impact on the State's distribution system reliability and

[301] Because wind farms cover a large geographic area, a wind farm's distance would be based on the geographic center of the area containing turbines that are part of that wind farm.

[302] Based on the 2010 Census. See: https://www2.census.gov/geo/docs/reference/cenpop2010/CenPop2010_Mean_ST.txt.

[303] See Docket No. 17-0838, Final Order dated April 3, 2018 at 21.

[304] Id. The Commission also offered that "if a facility is not connected to PJM or MISO, it should not be allowed to participate in Illinois' RPS procurement;" the Agency believes that because such a facility would score 0 out of 20 points on Criteria 2 and 3 and given the 60 point threshold, an adjacent state facility not connected to PJM or MISO would effectively be eliminated from consideration and no further scoring adjustments must be taken to give effect to the Commission's intent.

[305] Id.

resiliency, a distance factor. The criterion can be understood to refer to the transmission systems operated by PJM and MISO. To the extent that a facility in an adjacent state is not interconnected to the PJM or MISO grid (for example, in the portions of Iowa and Missouri that are part of the Southwest Power Pool("SPP")), those facilities would not score any points for this criterion. Otherwise, a facility in an adjacent state that is in either of the PJM or MISO control areas (or "within a transmission control area that has a transmission usage agreement with PJM or MISO") would be eligible to receive points. To obtain the distance factor, the Agency uses an approach that considers proximity to Illinois and thus an increased likelihood that electricity produced will provide increased system reliability and resilience.

The scoring for this public interest criterion involves the same distance factor as is applied to the fuel and resource diversity scoring; the formula for determining this factor is shown in Figure 4-3. The Agency's review of the scoring methodology and assumptions for criteria 2 and 3 confirms that distance is the factor which can be effectively incorporated into a simplified approach to determine the relative contributions of RECs from adjacent state renewable resources to meeting these public interest criteria.

Figure 4-3: Reliability and Resiliency Score

$$Score = (1 \text{ if in PJM/MISO; else } 0) \times \left(1 - \frac{\text{Distance from facility to Morris, IL (miles)}}{470 \text{ miles}}\right) \times 20$$

4. Meeting goals to limit carbon dioxide emissions under federal or State law

At the federal level, on June 19 2019, the U.S. EPA issued the Affordable Clean Energy Rule (ACE) as the replacement for the Clean Power Plan. The ACE focuses on heat rate improvement at individual coal-fired power plants as a means to reduce CO_2 emissions by improving plant operating efficiency. ACE does not contain specific CO_2 emissions limits; instead, ACE provides guidelines for states to follow in limiting CO_2 emissions.[306]

At the state level, Illinois does not have a specific law that limits carbon dioxide emissions. However, there are multiple provisions of Illinois law, such as the Zero Emission Standard and the Renewable Energy Portfolio Standard, that recognize the value of minimizing carbon dioxide emissions even if those provisions do not create explicit limits. To recognize the value in reducing carbon dioxide emissions, the Agency determines the score for each renewable resource facility by adjusting the 20 points available for this criterion by a factor which reflects the ratio of the CO_2 emissions from the renewable resource to the CO_2 emissions from a new natural gas-fired combined cycle generating facility, 772 pounds of CO_2 per MWh, as shown in Table 4-1 above. This is done by using the formula applied to the first emissions criterion except that the inputs are pounds of CO_2 emitted per MWh. The factor applied to the 20 points available for this public interest criterion is calculated as follows:

[306] https://www.epa.gov/stationary-sources-air-pollution/electric-utility-generating-units-repealing-clean-power-plan.

Figure 4-4: CO_2 Score Calculation

$$Score = \left(1 - \frac{CO_{2\,\substack{\text{renewable}\\\text{resource}}} \left(\frac{\text{lbs}}{\text{MWh}} \right)}{CO_{2\,\substack{\text{gas}\\\text{resource}}} \left(\frac{\text{lbs}}{\text{MWh}} \right)} \right) \times 20$$

Renewable generating facilities that do not emit any CO_2 receive the full 20 points, while renewable generating facilities that emit CO_2 receive points based on the factor multiplied by the 20 points. Because CO_2 emissions are generally considered to be a global problem (in that CO_2 emissions anywhere on the planet contribute to global warming, which then affects the health and welfare of the citizens of Illinois), wind direction, duration, and distance from Illinois's load-weighted center are not relevant for the scoring of this criterion and therefore are not included in the calculation.[307] Comparing the CO_2 emissions from each renewable resource to the emissions from the most likely alternative generation, usually a gas-fired combined-cycle plant, remains a practical means for determining the score for this criterion.

5. Contributing to a cleaner and healthier environment for the citizens of this State

This criterion is arguably the most subjective in nature, and presents unique challenges given that the Agency strives to use objective approaches to the greatest extent possible when considering the public interest criteria. The Agency believes that renewable resources inherently contribute to a cleaner and healthier environment generally (with the caveat related to emissions from renewable resources that involve combustion, discussed above) because they reduce the reliance on fossil fuels and have no safety issues associated with the containment and disposal of radioactive materials that result from nuclear generation. Under this Revised Plan, the points awarded for this public interest criterion are the average of the points awarded under the first and fourth public interest criteria described above. This approach takes into account the emissions from renewable resource facilities that involve combustion and, subsequently, emissions, which would not contribute to a cleaner and healthier environment for the citizens of Illinois.

4.1.2. Application Process

The eligibility of RECs from renewable energy generating facilities located in states adjacent to Illinois is not automatically granted, because the Act requires that approval comes only after "the generator demonstrates and the Agency determines" that the facility's operation meets the public interest criteria discussed above.[308] That determination requires an active request (demonstration) by an interested generator. Renewable generating facilities in adjacent states may apply to the Agency for consideration for eligibility for the RPS.[309]

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[307] The Agency notes that the Zero Emission Standard Plan contains a different scoring methodology for CO_2 emissions, but that methodology is based upon the impacts of replacement generation and the consideration related to "minimizing carbon dioxide emissions that result from electricity consumed in Illinois" (20 ILCS 3855/1-75(d-5)(1)(C)), which is not the same standard as under consideration in qualifying adjacent-state facilities for the RPS.

[308] 20 ILCS 3855/1-75(c)(1)(I).

[309] An exception is made for the out-of-state facilities that have LTPPA contracts with the utilities. As discussed in Section 4.1, those facilities will be grandfathered into this consideration and will remain eligible to provide RECs for compliance with the Illinois RPS.

Shortly after the approval of its Initial Plan, the Agency developed an application form (in the form of an Excel spreadsheet) for use by owners/agents of adjacent-state facilities that wish to have RECs from those projects considered to be eligible for the Illinois RPS.[310] The information to be entered into the application form includes the generating technology (including information on emissions rates if the technology involves combustion), state where the generator is located, distance from the geographical center of Morris, IL, the Regional Transmission Organization ("RTO") where the facility is or planned to be interconnected (e.g., PJM, MISO, SPP), and the tracking system ID (for existing facilities). The application form will automatically calculate the score for the facility. In addition, the generator will also have to include information related to the provision limiting the recovery of costs in rates described in the next Section. The Agency will review and, as necessary, update the data used in the eligibility calculations on a bi-annual basis in conjunction with the Plan update to use the most recent available inputs (and has done so for this Revised Plan, determining that no changes are needed), but a facility's determination of eligibility will be based on the data available at the time of the request for determination (in other words, a facility would not risk having its eligibility revoked at a later date if the inputs changed after the initial eligibility determination is made by the Agency).

The Agency will review applications to verify the information submitted (e.g., confirming the distance inputs), and if the facility has a score equal to or greater than 60 points (and meets the cost recovery requirement found in Section 1-75(c)(1)(J) of the Act, discussed further below), the Agency will approve the facility as eligible to produce renewable energy credits for compliance with the Illinois RPS. The Agency will inform the applicable tracking system (GATS or M-RETS) that the facility should be coded as Illinois RPS eligible.

In the case of a new adjacent-state facility that is not yet operational (and thus also not registered in GATS or M-RETS), an owner may submit a request for determination of eligibility based upon the planned design of the facility. If the Agency determines that the planned facility does meet the public interest criteria, then it will grant a pre-approval of the eligibility. It will be the responsibility of the facility owner to notify the IPA and the tracking system once the facility is operational to request being coded as eligible for the Illinois RPS in the applicable tracking system. The Agency will review final system information to verify consistency with the information submitted for the pre-approval.

4.2. Cost Recovery Requirement

Section 1-75(c)(1)(J) of the Act contains the following provision:

> *In order to promote the competitive development of renewable energy resources in furtherance of the State's interest in the health, safety, and welfare of its residents, renewable energy credits shall not be eligible to be counted toward the renewable energy requirements of this subsection (c) if they are sourced from a generating unit whose costs were being recovered through rates regulated by this State or any other state or states on or after January 1, 2017.*

[310] Available at: https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/IL-RPS-Adjacent-State-Facility-Determination-of-Eligibility-20180404.xls.

Generally speaking, the Agency understands that facilities owned by a rural electric cooperative or a municipal utility are not impacted by this criterion (as in Illinois, those entities' rates are not regulated by this *state* or any other), although the Agency notes that there are certain adjacent states which regulate some rural electric cooperative and municipal utility rates. Therefore, the Agency will not be issuing a blanket approval under this provision of facilities owned by rural electric cooperatives or municipal utilities service territories in adjacent states; rather, as those facilities request eligibility, their rate recovery status will be reviewed.

The Agency also understands that this provision was primarily intended to ensure that facilities owned by a vertically integrated utility, for which REC revenues may be incidental to building and financing the facility (as that facility's costs could be recovered from ratepayers in that other state, potentially resulting in a credit or discount to those ratepayers for any REC revenues—effectively causing Illinois ratepayers to cross-subsidize those in vertically integrated states) would not be eligible. Another situation that has been brought to the Agency's attention concerns a proposed project to be developed by an Illinois non-electric utility (a gas or water utility, for instance) featuring delivery service rates that are regulated by the Illinois Commerce Commission with cost recovery then sought over the cost of the renewable energy generating facility. Regardless of whatever may have been the primary purpose informing Section 1-75(c)(1)(J)'s enactment, this situation would seem to clearly fit Section 1-75(c)(1)(J)'s prohibition: the renewable generation facility's costs would be recovered through state-regulated rates. Consequently, the IPA understands such projects' RECs as being barred from participation in the Illinois RPS (including in, say, the Adjustable Block Program) insofar as rate recovery is sought for those projects.

On the other hand, the mere presence of a Power Purchase Agreement between a facility and a separate utility whose costs are recovered in regulated rates would not trigger these criteria (nor would participation in the IPA's energy procurement events, for which regulated utilities serve as contractual counterparties, or participation in a net metering or similar energy crediting program, which would serve to disqualify the very facilities that other portions of the Illinois RPS work to support). Likewise, the Agency believes that being a Qualifying Facility under the Public Utility Regulatory Policies Act ("PURPA")[311] (and also meeting the other aspects of the requirements of the Illinois RPS), would not be disqualifying because the Qualifying Facility does not directly recover its costs through rates; rather, it is compensated for its energy at the purchasing utility's avoided cost rate.

As described in Section 4.1.2, facilities located in adjacent states will proactively have to request eligibility for the utility RPS pursuant to the public interest criteria standard explained above. Those requests to meet the public interest criteria will also be required to include a notarized certification, and documentation, that the facility does not have its costs recovered through regulated rates. For a distributed generation facility, simple documentation of ownership will suffice. For larger facilities, the Agency has not utilized a firm standard of documentation, but believes there are multiple approaches that could be used by a requesting facility. These include, but are not limited to:

- For facilities tracked in M-RETS, documentation to support the status listed in the "Facility Ownership Type" field

[311] 16 U.S.C. §§ 796(17), 824a-3, 824i.

- A Market Based Rate authorization letter from the Federal Energy Regulatory Commission that demonstrates that the facility owner is not a utility with costs recovered through regulated rates
- Certification as a Qualifying Facility
- Use of information from other sources such as the S&P Global Intelligence Briefing Book, or the Platts UDI Directory of Electric Power Producers and Distributors

The Agency will review (in consultation with the ICC) information provided for a facility, and may, as needed, request additional information to verify a facility's status.

The Agency is not presently aware of any renewable facilities in Illinois that have their costs recovered through regulated rates.

In addition to the screening process described above, all contracts from IPA-administered REC procurements or programs utilized since the effective date of P.A. 99-0906 contain provisions to reflect this additional requirement of Section 1-75(c)(1)(J) (and will continue to do so going forward):

> *Each contract executed to purchase renewable energy credits under this subsection (c) shall provide for the contract's termination if the costs of the generating unit supplying the renewable energy credits subsequently begin to be recovered through rates regulated by this State or any other state or states; and each contract shall further provide that, in that event, the supplier of the credits must return 110% of all payments received under the contract. Amounts returned under the requirements of this subparagraph (J) shall be retained by the utility and all of these amounts shall be used for the procurement of additional renewable energy credits from new wind or new photovoltaic resources as defined in this subsection (c). The long-term plan shall provide that these renewable energy credits shall be procured in the next procurement event.*

The Agency notes that Section 1-75(c)(1)(J) also provides a limited exception to this provision for facilities that participate in the Illinois Solar for All Program outlined in Section 1-56 of the Act:

> *Notwithstanding the limitations of this subparagraph (J), renewable energy credits sourced from generating units that are constructed, purchased, owned, or leased by an electric utility as part of an approved project, program, or pilot under Section 1-56 of this Act shall be eligible to be counted toward the renewable energy requirements of this subsection (c), regardless of how the costs of these units are recovered.*

5. Competitive Procurement Schedule

As described throughout this Chapter, to help meet RPS goals outlined in Section 1-75(c) of the IPA Act, in this Revised Plan the IPA proposes to potentially conduct a variety of competitive procurements for RECs in calendar years 2020 and 2021. In combination with the programs described in Chapters 6, 7, and 8, as limited by the RPS budget caps, these competitive procurements would help make progress toward the RPS REC goals and targets outlined in Sections 1-75(c)(1)(B) and (C) as further discussed in Chapter 3. However, the ability to conduct the competitive procurements outlined in this Chapter depends on available funding—and as also outlined in Chapter 3, the Agency envisions significant funding constraints. As a consequence, this Chapter does not propose to automatically conduct any Competitive Procurements (outside of a utility-scale wind forward procurement intended to replace a prior procurement for which no bids were chosen), but rather to provide a framework for such procurements should they become feasible due to updated analysis of available funds (including the allocation of utility-held ACPs), or legislative changes to RPS funding sources (such as an extension of the four-year rollover period).

In the Initial Plan, this Chapter discussed two types of competitive procurements: Forward Procurements and Spot Procurements. The discussion further noted that pursuant to the Commission's Final Order in Docket No. 17-0838, the initial Plan no longer contained proposals for Spot Procurements in the 2017-2018 through 2019-2020 delivery years,[312] while Forward Procurement volumes were significantly increased through that Order (in both cases, compared to the Agency's proposed initial Plan filed for the Commission's approval in December 2017). As taken from the Initial Plan, the Agency uses the following definitions of these types of procurements:

- A **Forward Procurement** is a competitive procurement for RECs where the beginning delivery date is in a future delivery year and the delivery term is multiple years. Further, a Forward Procurement is for unit-specific RECs. Forward Procurements include those specifically outlined in the Act (e.g., a Subsequent Forward Procurement) and additional Forward Procurements proposed by the IPA as part of this Revised Plan. Unless specified otherwise in this Chapter, Forward Procurements will, to the extent practicable, follow the model used for the Initial Forward Procurement including:
    - 15-year REC-only contracts
    - Price per REC fixed over the term of the contract, no price escalation
    - Ability to bank RECs
    - Credit requirements and instruments

- A **Spot Procurement** is a competitive procurement for RECs for either the prior, current, or the prompt delivery year goals. The delivery term of a Spot Procurement is one delivery year. While the IPA does not believe the PUA or IPA Act requires that spot procurement proposals track exactly on the requirements of Section 16-111.5, the Agency proposes that should any spot procurements be authorized and subsequently conducted, to the extent practicable, they would follow the model the IPA has used for past similar REC procurements including:
    - Fixed price per REC
    - RECs must be from applicable delivery year

[312] See Docket No. 17-0838, Final Order dated April 3, 2018 at 40-44.

- Credit requirements and instruments

In this Revised Plan, the Agency is only proposing potential Forward Procurements.

5.1. Statutory Requirements

Section 16-111.5(b)(5)(ii)(B)(aa) of the PUA requires that this Plan:

> *"Identify the procurement programs and competitive procurement events consistent with the applicable requirements of the Illinois Power Agency Act and shall be designed to achieve the goals set forth in subsection (c) of Section 1-75 of that Act."*

The "competitive procurement events" contemplated by the IPA are discussed in this Chapter, while the "procurement programs" are discussed in Chapters 6, 7 and 8. Also specifically addressed in this chapter is the following additional provision (bb) of that subsection of the Act regarding REC procurements subsequent to the Initial Forward Procurement:

> *"Include a schedule for procurements for renewable energy credits from utility-scale wind projects, utility-scale solar projects, and brownfield site photovoltaic projects consistent with subparagraph (G) of paragraph (1) of subsection (c) of Section 1-75 of the Illinois Power Agency Act."*

Section 16-111.5(b)(5)(iii) further states that,

> *"For those renewable energy credits subject to procurement through a competitive bid process under the plan or under the initial forward procurements for wind and solar resources described in subparagraph (G) of paragraph (1) of subsection (c) of Section 1-75 of the Illinois Power Agency Act, the Agency shall follow the procurement process specified in the provisions relating to electricity procurement in subsections (e) through (i) of this Section."*

While it is unclear whether procurements such as those proposed in this Chapter are *required* to be conducted as "a competitive bid process," the Agency has achieved generally positive results in past experience with its competitive bid process (including the Initial Forward Procurements and competitive procurements conducted pursuant to the Initial Plan). Thus, outside of the programs it proposes in later Chapters—some of which statutorily require a different structure—it sees no need to deviate from this approach. Section 5.3 discusses the Agency's competitive procurement process specified in Section 16-111.5(e) through (i) in more detail, and specifically how this process will be applied to the competitive procurements proposed in this Revised Plan.[313]

[313] The provisions related to this Plan contained in Section 16-111.5 of the PUA and Section 1-75(c)(1) of the Act generally refer to "competitive procurement processes" or "competitive procurement events" while in this one instance there is reference to "a competitive bid process" that shall follow the procurement process contained in Section 16-111.5. However, that provision only applies to the Initial Forward Procurement. Nonetheless, while the Agency may have the discretion to conduct other competitive procurement processes through procedures other than those envisioned by Section 16-111.5 (e.g., rather than a sealed bidding with pay-as-bid settlement, offering a standard offer price, or perhaps a single clearing price), at this time the Agency believes that all the competitive procurements it administers should follow the framework set up by Section 16-111.5.

5.2. Background on past REC Procurements conducted by the IPA

In the years 2009 through 2016, with the exceptions of 2013 and 2014,[314] the IPA held procurements for renewable energy resources to meet the RPS requirements of the utilities' eligible retail customers. These procurements were conducted through a competitive procurement process.

While changes to Section 1-75(c) of the IPA Act through P.A. 99-0906 significantly increased the volume of RECs to be procured by the Agency, the Agency has a long track record of procuring renewable energy resources, predominantly RECs.[315]

Prior to Public Act 99-0906, the Agency's past competitive procurements for renewable energy resources are listed below (with the quantities of RECs procured listed in some cases):[316]

- Spot Procurements for one-year delivery of RECs
  - 2009 REC procurements for Ameren Illinois and ComEd (720,000 RECs for Ameren Illinois, 1,564,360 RECs for ComEd)
  - 2010 REC procurements for Ameren Illinois and ComEd (860,860 RECs and 1,887,014 RECs for Ameren Illinois and ComEd, respectively)
  - 2011 REC procurements for Ameren Illinois and ComEd (952,145 and 2,117,054 RECs)
  - 2012 REC procurements for Ameren Illinois and ComEd (523,376 RECs and 1,335,673 RECs)
  - 2015 SREC procurements for Ameren Illinois and ComEd (30,212 SRECs and 49,770 SRECs)
  - 2016 SREC procurements for Ameren Illinois and ComEd (33,271 SRECs and 67,952 SRECs)
  - 2016 REC procurement for MidAmerican

- Procurements for multiple delivery years of RECs
  - 2010 Long-term procurements for Ameren Illinois and ComEd (20 year contracts, bundled RECs and energy, 600,000 RECs per year and 1,261,725 RECs per year, respectively)
  - 2012 "Rate Stability" procurement for Ameren Illinois and ComEd (contracts for four years and seven months) (2,053,837 RECs over the delivery term, and 2,737,110 RECs over the delivery term, respectively)
  - 2015 Supplemental Photovoltaic procurements using the RERF (5 year contracts, with provision to allow time for identification of under 25 kW systems) (21,436 SRECs per year)

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[314] In the Agency's 2013 Procurement Plan, due to a decline of eligible retail customers' load served by the utilities, mainly attributable to municipal aggregation, the Agency determined, and the Commission agreed, that no new procurements of renewable energy resources (or for that matter energy) were required. See Order, Docket No. 12-0544, December 19, 2012, at 109-110.

[315] Section 1-75(c) of the Act prior to the changes enacted through Public Act 99-0906 focused on the procurement of "renewable energy resources." The revisions to the Section contained in Public Act 99-0906 focus the Long-Term Renewable Resources Procurement Plan on specifically acquiring "renewable energy credits" from programs and competitive procurements.

[316] Announcements of these procurements that contain additional information can be found at: https://www.illinois.gov/sites/ipa/Pages/Prior_Approved_Plans.aspx. Certain REC volume information has been redacted to maintain required confidentiality in accordance with 220 ILCS 5/16-111.5(h). Please note that because initial delivery timelines vary, the "per year" numbers may not be 100% accurate for a specific calendar period.

- 2015 Distributed Generation procurement for Ameren Illinois and ComEd (5 year contracts)
- 2016 Supplemental Photovoltaic procurement using the RERF (5 year contracts, with provision to allow time for identification of under 25 kW systems) (18,354 SRECs per year)
- 2016 Distributed Generation procurement for Ameren Illinois and ComEd and MidAmerican (5 year contracts)
- 2017 Distributed Generation procurements (5 year contracts, also include provision to allow time for identification of under 25 kW systems) (19,025 SRECs per year procured in Spring 2017, 8,153 SRECs per year procured in Fall 2017)

With the enactment of Public Act 99-0906, the Agency began conducting procurements to meet the RPS requirements of *all* retail customers. The first such procurements were the Initial Forward Procurements, conducted prior to the finalization of the Initial Plan. After the Initial Plan's approval, the Agency conducted a series of procurements conducted under the Commission's authority granted through its Order in Docket No. 17-0838. Those procurements are listed below:

- 2017 and 2018 Initial Forward Procurements (15 year contracts for new utility-scale wind and new utility-scale solar, 965,000 Wind RECs and 1,000,000 Solar RECs per year procured)
- October 2018 First Subsequent Forward Procurement (15 year contracts for new utility-scale wind, 1,979,753 RECs procured)
- November 2018 Photovoltaic Forward Procurement (15 year contracts for new utility-scale solar, 2,000,000 RECs)
- July 2019 Brownfield Site Forward Procurement (15 year contracts, quantity not released due to only two projects selected)
- Second Subsequent Forward Procurement (15-year contracts for new utility scale wind). No bids were accepted;
- Community Renewable Generation Procurement (15-year contracts for non-PV renewable technologies). No bids were accepted;
- Low-income Community Solar Pilot Project Procurement (15-year contracts; conducted pursuant to Section 1-56(b)(2)(D) of the Act)

5.3. The Agency's Competitive Procurement Approach

Based on previous REC procurement experience, the Agency has a solid foundation to build upon for conducting the potential additional competitive procurements proposed in this Revised Plan. The Agency believes that no significant modifications to the procurement approach itself are needed.

The procurement approach the Agency has used for prior REC procurements, including the Initial Forward Procurements and the forward procurements conducted under the Initial Plan, stems from the approach laid out in Section 16-111.5 of the Public Utilities Act for "standard wholesale product" (i.e., block energy, capacity, etc.) procurements. It includes the following key provisions:

- Standard contracts and credit provisions
- Sealed bids with pay-as-bid settlement

- Use of confidential benchmarks to eliminate bids not consistent with the market
- Bid selection based on price
- No post-bid negotiations
- Procurement Administrator evaluates bids and provides confidential recommendation to the Commission for approval
- Procurement Administrator provide bidder interface including training
- Uniform/standardized bid forms
- Uniform/standardized/harmonized credit requirements
- Procurement Monitor involvement

These provisions define a procurement process that has multiple stages.

- The Procurement Administrator develops draft contracts in consultation with the utilities, the Agency, the Procurement Monitor,[317] and ICC Staff.[318]
- Draft contracts are released for public comment.
- The Procurement Administrator, the Agency, the utilities, ICC Staff and the Procurement Monitor review all comments received on the draft contract and revise the contract as needed.[319]
- Typically, the Procurement Administrator holds an informational webcast upon release of the final contracts and RFP rules.
- Submission of Proposals is in two parts:
    - Part 1 for pre-qualification – allows bidders to provide basic information, and agree to the terms of the contract and the RFP rules.
    - Part 2 for registration of bidders – allows bidders to update information, make additional certifications including regarding confidentiality of bidding information, and post bid assurance collateral.
- Bids – on the bid date, bidders submit bids using a standardized bid form.
- Evaluation of Bids – the Procurement Administrator evaluates bids based on price, procurement objectives and priorities; identifies the winning bids; prepares a recommendation for the Commission. The Procurement Monitor observes the bidding and evaluation process and makes its own recommendation.[320]
- Commission decision – After review of the Procurement Administrator's and Procurement Monitor's reports and recommendations, the Commission renders a decision on the results of the procurement event.[321]
- Release of procurement results – The Procurement Administrator releases the results of the procurement event; confidential information is protected.[322]

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[317] The Procurement Monitor is an independent consultant that works on behalf of the Commission to oversee all aspects of the procurement process. 220 ILCS 5/16-111.5(c)(2).

[318] The Agency expects that the contract will generally be based on a modified ABA-EMA-ACORE REC Purchase & Sale Agreement, although as discussed further in this Chapter, it recommends a change in approach from prior REC contracts utilized by the Agency (with those prior contracts containing separate modifications to an attached standard agreement).

[319] If agreement between the Procurement Administrator and the utilities is not reached on the terms and provisions of the contracts, any disputes are resolved by the Commission. (See 220 ILCS 5/16-111.5(e)(2)).

[320] See 220 ILCS 5/16-111.5(f).

[321] See id.

[322] See 220 ILCS 5/16-111.5(h).

- Contract execution with the utilities – Within three business days of Commission approval of the procurement results, utilities and winning bidders sign binding contractual arrangements using the standard form contracts.[323]

Unless specifically noted in the following sections, the IPA proposes that the competitive procurements for RECs described in this Revised Plan follow these past practices that have been refined over the past ten years.

5.3.1. Contracts

For the competitive procurements conducted pursuant to the Initial Plan (as well as the Initial Forward Procurements), the Agency updated its REC contract used in previous competitive procurements for renewable energy credits (other than the Supplemental Photovoltaic Procurements, which featured the Agency as a counterparty rather than the utilities and followed a simplified structure). This update made changes to ensure that the contract was compliant with new requirements found in P.A. 99-0906, but otherwise followed the standard format of a Cover Sheet, Revisions to the Master REC Agreement, and the Master REC Agreement itself.

The Agency is concerned that this contract structure may be confusing and overly complex: with three separate documents, each of which may address the same universe of contract terms, a party reviewing the contract may not fully understand which terms are applicable or may require sophisticated counsel to work through inherent contradictions. The Agency thus believes the development of a new, cleaner, more straightforward REC delivery contract is warranted.

Because the potential procurements outlined in this Chapter are not time sensitive, the Agency believes it can conduct a more thorough contract development process providing more time for stakeholder input during calendar year 2020. As discussed in Section 6.7, the Agency proposes a similar update to contracts for the Adjustable Block Program which currently feature the same structure as the contracts used for competitive procurements. The Agency proposes that the new contract that is developed through that process should be considered as the starting point for a new contract for any competitive procurements that are held. The Agency would provide stakeholders the opportunity to provide written comments on a proposed competitive procurement contact prior to the start of any competitive procurement process. While the Agency believes the final decision on the contract should continue to reflect the past practice of the consensus of the Agency, the ICC Staff, the Procurement Administrator, the Procurement Monitor, and the utilities, this process will help to ensure that resulting contracts properly balance the needs and concerns of both the buyers (utilities) and sellers (developers of renewable energy resources that bid into procurements) under the resulting contracts.

Additionally, this Revised Plan received authority from Commission, similar to the discussion in Section 6.15.1, to allow the Seller to provide notification to the Buyer, the Agency, and the Commission that it is exercising its option to allow for a system's removal from the contract, with forfeiture of associated Performance Assurance, because the Approved Vendor no longer wishes to develop that system.[324] This approach would allow both parties to step away from unwanted contractual obligations and ease the Agency's RPS planning process.

[323] See 220 ILCS 5/16-111.5(g).

[324] See Docket No. 19-0995, Final Order dated February 18, 2020 at 80.

5.4. REC Eligibility

As discussed in Chapter 4, P.A. 99-0906 place two conditions on RECs that are eligible to be used for RPS compliance that narrowed the pool of RECs eligible for Illinois RPS compliance. First is a locational standard that allows for RECs from facilities located in Illinois to meet the Illinois RPS, and also from facilities located in adjacent states only if those facilities meet the public interest criteria set out in Section 1-75(c)(1)(I). By implication, RECs from states further afield than the states adjacent to Illinois do not qualify for the Illinois RPS. Second, P.A. 99-0906 introduced a new standard related to how generating units recover their costs. This standard not only prohibits the use of RECs from generating units that do not recover their costs through state-regulated rates, but also assesses penalties for RECs from systems later found to be non-compliant.[325]

These eligibility requirements require competitive procurements conducted by the IPA to feature additional steps to verify that RECs being procured (and, in most cases, the underlying generating facilities from which they are being procured) are indeed eligible for the Illinois RPS. For Forward Procurements, additional review is now required during the bidder registration process to allow the Procurement Administrator and the Agency to verify information about proposed facilities and if facilities located in the states adjacent to Illinois meet the public interest criteria (for example, see Chapter 4 for more information on how facilities would request this determination). As the Agency is not proposing Spot Procurements through this Revised Plan, the question of how to screen facility for Spot Procurements is not addressed herein, but the Agency notes that screening RECs from Spot Procurements would raise perhaps more complex issues than with Forward Procurements given the non-source-specific nature of those procurement events and the potential participation by aggregators or other third-parties who may have acquired those RECs through prior transactions.

5.5. Credit Requirements

To ensure that RECs under contract to satisfy a compliance requirement are indeed delivered, the Agency proposes to continue requiring collateral with contracts, with the collateral amount established as a function of contract value. While specific collateral levels are not proposed as part of this Revised Plan (and are generally determined through the contract development process), the Agency believes that the level of collateral must be low enough to encourage participation and high enough to discourage suppliers from voluntarily defaulting on contracts for economic reasons. Further, the IPA proposes a strict requirement that suppliers and associated facilities who voluntarily default on contracts for economic reasons (such as choosing to sell the RECs elsewhere after making the commitment to sell them to an Illinois utility) or misrepresent their eligibility to participate in a procurement event will be barred from participation in future IPA procurements.

Similar to the discussion in Sections 6.15.1 and 8.12.1, any forfeiture of collateral by a project under a competitively procured REC contract with a utility will be considered to be returned to the Renewable Resources Budget, and any forfeiture of collateral by a project under a competitively procured REC contract with the Agency (namely, the Low-Income Community Solar Pilot Projects) will be deposited into the RERF.

[325] See 20 ILCS 3855/1-75(c)(1)(J). Note that Section 1-75(c)(1)(I) references "facility" and "facilities" for the geographic standard, while Section 1-75(c)(1)(J) references "generating unit" for the cost recovery standard. Section 1-10 of the IPA Act does not specifically define "generating unit" but does define a facility as, "an electric generating unit or a co-generating unit that produces electricity along with related equipment necessary to connect the facility to an electric transmission or distribution system." The Agency understands these terms to be generally interchangeable.

5.6. Benchmarks

Prior to the revisions to the RPS contained in Public Act 99-0906, benchmarks used for renewable energy resources procurements (i.e., confidential price levels above which no bids would be accepted) were developed pursuant to a statutory provision requiring that the price paid for renewable energy resources being procured "not exceed benchmarks based on market prices for renewable energy resources in the region," and required that such benchmarks "be developed by the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor" and "subject to Commission review and approval."[326]

For the procurements to be conducted under the revised Section 1-75(c) , the concept of being "cost-effective" for the competitive procurement of RECs was revised. Specifically, through changes by P.A. 99-0906, "cost-effective" now means that the prices for RECs

> *do not exceed benchmarks based on market prices for like products in the region. For purposes of this subsection (c), "like products" means contracts for renewable energy credits from the same or substantially similar technology, same or substantially similar vintage (new or existing), the same or substantially similar quantity, and the same or substantially similar contract length and structure. Benchmarks shall be developed by the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor and shall be subject to Commission review and approval. If price benchmarks for like products in the region are not available, the procurement administrator shall establish price benchmarks based on publicly available data on regional technology costs and expected current and future regional energy prices.*[327]

Due to the sensitive nature of the benchmark development process and how the release of information related to the level of the benchmark could impact bidder behavior in competitive procurements, additional information will not be provided regarding the process for developing the benchmark or any range of potential benchmark prices.

These benchmarks are not to be used to curtail or otherwise reduce contractual obligations entered into by or through the Agency prior to June 1, 2017.[328]

5.7. Procurements for RECs from New Projects vs. RECs to Meet Annual Goals

Section 1-75(c)(1)(F) creates a prioritization order for REC procurements, to the extent that the "budget" of utility-collected funds, pursuant to Sections 1-75(c)(1)(E) and 1-75(c)(6) of the Act and Section 16-108(k) of the Public Utilities Act, becomes a binding constraint:

1. RECs under existing contractual obligations;
2. RECs procured through funding for the Illinois Solar for All Program;

[326] 20 ILCS 3855/1-75(c)(1) repealed effective June 1, 2017.

[327] 20 ILCS 3855/1-75(c)(1)(D).

[328] Id.

3. RECs necessary to comply with the new wind and new photovoltaic procurement requirements described in items (i) through (iii) of subparagraph (C) of this paragraph (1) [of Section 1-75 of the IPA Act];[329]
4. RECs necessary to meet the remaining requirements of this subsection (c).

Chapter 3 describes a substantial gap between the quantity of RECs needed to meet annual percentage RPS goals and the RECs under contract from and pending prior procurements. The Agency has satisfied the utility-scale new wind and photovoltaic requirements through the 2025-2026 delivery year via RECs under contract from prior procurements, but believes that additional new generation is necessary to work toward ensuring that any percentage-based goals could eventually be achieved. Taking into consideration the REC procurement priorities discussed above, an in attempt to meet both quantitative targets and to help grow the pool of RECs eligible to meet the Illinois RPS's annually climbing percentage-based goals, the Agency will seek to meet the remaining requirements of Section 1-75(c) (which the IPA understands to refer primarily, if not exclusively, to the percentage-based goals found in Section 1-75(c)(1)(B)) through Forward Procurements to the extent budgets allow.[330]

5.8. Procurements Conducted Under the Initial Plan

In the Initial Plan, the Agency proposed a series of procurements as described in Table 5-1 below. As of the release of this Revised Plan, the First Subsequent Forward Procurement (wind), the Brownfield Site Forward Procurement, and the Photovoltaic Forward Procurements have all been conducted.

The original Brownfield Site Forward Procurement was conducted in the fall of 2018 and did not feature any winning projects. In February of 2019, the Agency sought feedback[331] from stakeholders and then petitioned the Commission to reopen Docket No. 17-0838 seeking clarification for the authority to reconduct the procurement with certain modifications. Following the Commission's approval of that request, the second Brownfield Site Forward Procurement was then conducted in spring/early summer 2019 with the Commission approving the results on August 1, 2019. While the specific quantity procurement in the brownfield site procurement was not disclosed given that only two bidders were successful,[332] the procurement did exceed the statutory target of 40,000 RECs annually by the 2020-2021 delivery year (although such RECs could begin being delivered after that date under the procurement's contracts).

The Second Subsequent Forward Procurement (new utility-scale wind), Community Renewable Generation Forward Procurement (non-photovoltaic), and the Low-income Community Solar Pilot Project Procurement (part of Illinois Solar for All) were all conducted in the Fall of 2019. Both the

[329] The provisions are for 2,000,000 RECs annually from each technology by the end of the 2020-2021 delivery year, 3,000,000 RECs annually from each technology by the end of the 2025-2026 delivery year, and 4,000,000 RECs annually from each technology by the end of the 2030-2031 delivery year.

[330] In the Initial Plan originally filed with the Commission, the Agency also proposed "spot procurements" to meet the annual RPS percentage goals found in Section 1-75(c)(1)(B) of the Act. However, in its Order approving the Plan, citing "the serious risk Spot Procurements can pose to the budget which may prevent the IPA from meeting its statutory long-term new build requirements," the Commission granted "various parties' requests to cancel the Spot Procurements." Thus, the final Initial Plan did not contain Spot Procurements, and given the budget constraints outlined in Chapter 4, the Agency is not proposing Spot Procurements in this Revised Plan.

[331] See https://www2.illinois.gov/sites/ipa/Documents/2019ProcurementPlan/Brownfield-Site-Procurement-Questions-5-Feb-2019-1.pdf.

[332] By releasing quantity information in a procurement with two winning bidders, each bidder would be able to determine the quantity of the other's selected bid, and thus determine that other bidder's bid price.

Second Subsequent Forward Procurement and the Community Renewable Generation Forward Procurement did not produce any winning projects. Following stakeholders' comments on the potential barriers to participation in utility-scale procurements, and consistent with the Commission's Order in Docket No. 19-0995,[333] the Agency is planning to conduct a procurement of RECs from new utility-scale wind projects in the Fall of 2020 or the Spring of 2021.[334]

With the completion of these and other prior procurements, the quantitative new wind and new utility-scale photovoltaic REC targets[335] for the 2020-2021 delivery year and the 2025-2026 delivery year will have been met.

Table 5-1: Forward Procurements Summary[336]

Procurement	Technology	Procurement Date	Delivery Start	Annual REC Target	Annual RECs Procured	Annual Spend $
First Subsequent Forward	Wind (utility-scale)	Fall 2018	2021-2022	2 million	1.98 million[337]	6.41 million
Brownfield Site Forward[338]	Photovoltaic (brownfield site)	Fall 2018 /Summer 2019[339]	2021-2022	0.08 million	Quantity not disclosed	Not disclosed
Photovoltaic Forward	Photovoltaic (utility-scale)	Fall 2018	2021-2022	2 million	2 million	9.28 million
Second Subsequent Forward	Wind (utility-scale)	Fall 2019	2021-2022	1 million	0	0
Community Renewable Generation Program Forward	Any non-photovoltaic (with subscribers)	Fall 2019	2021-2022	0.05 million	0	0
Low-Income Community Solar Pilot Project[340]	Photovoltaic (with community participation / subscribers)	Fall 2019	2021-2022	Set on a $20 million budget	Quantity not disclosed	Not disclosed
Utility-scale Wind Forward Procurement	Wind (utility-scale)	Fall 2020 or Spring 2021	2023-2024	1 million	TBD	TBD

[333] See Docket No. 19-0995, Final Order dated February 18, 2020 at 17-18.

[334] See Section 5.9.2 for additional information.

[335] See 20 ILCS 3855/1-75(c)(1)(C)(i) and (ii).

[336] 15-year REC delivery term from new generating facilities.

[337] As allowed under the procurement rules, the marginal bidder declined an award of 0.02 million RECs which would have represented a very small portion of their RECs bid and thus was not economically feasible.

[338] The procurement had only two winning bidders therefore certain information is not disclosed per previous Commission Orders in order to maintain bidder confidentiality. By releasing quantity information in a procurement with two winning bidders, each bidder would be able to determine the quantity of the other's selected bid, and thus determine that other bidder's bid price

[339] When originally conducted in 2018, the Brownfield Site Forward Procurement did not procure any RECs and a procurement was conducted a second time in the Summer of 2019.

[340] The procurement had only two winning bidders therefore certain information is not disclosed per previous Commission Orders in order to maintain bidder confidentiality. By releasing quantity information in a procurement with two winning bidders, each bidder would be able to determine the quantity of the other's selected bid, and thus determine that other bidder's bid price

5.9. Competitive Procurements

While the statutory new wind and new utility-scale solar REC targets for 2020-2021 and 2025-2026 have been met through procurements conducted to date (or, in the case of wind, are targeted to soon be met and exceeded through a scheduled procurement), there could be value found in additional competitive procurements for at least two reasons. First, while enough RECs to meet these targets have been procured and thus are under contract to date, procurement does not ensure that selected projects will be completed and begin to deliver RECs. Therefore, as discussed further below, the Agency proposes a process for considering holding Contingency Procurements if necessary. Second, to help make progress toward the annual percentage of load goals of the RPS, the Agency proposes a structure for potential additional Forward Procurements[341] should ongoing analysis and review of available RPS budgets (or future legislative changes that change the rate cap, extend the budgetary roll-over period under Section 16-108(k) of the PUA, etc., assuming such future new law still maintains the authority of this Revised Plan) suggest that there are sufficient funds that become available in future years to conduct those procurements. However, as discussed in Section 3.22, the Agency proposes in this Revised Plan to first prioritize opening additional blocks of capacity for the Adjustable Block Program over conducting additional competitive procurements.

5.9.1. Contingency Procurements

Contingency procurements may be necessary under two circumstances.

The first circumstance would be if the Agency receives notice that projects selected in previously conducted procurements will not be completed and thus the RECs expected from them will no longer be part of the RPS portfolio. If the reduced quantities are significant enough, this could result in the statutory 2020-2021 and/or the 2025-2026 REC targets for new wind, or new solar not being met.[342] In this circumstance, the Agency believes conducting an additional procurement (or if applicable and the timing allows for it, an adjustment to the REC quantities for any procurements conducted pursuant to Section 5.9.2) could be warranted, subject to a review of any budgetary limitations. However, as shown in Table 5-2, those previously conducted procurements put the RPS portfolio well ahead of those targets so this situation would only occur in very unlikely scenarios of many projects failing to be completed.

[341] The Agency is definitively planning to hold a second Low-Income Community Solar Pilot Projects competitive procurement (which is funded solely from the RERF) in the 2020-2021 or 2021-2022 program years of ILSFA, as discussed further in Section 8.6.4.

[342] Overall targets for RECs from new solar projects are the same as for new wind; however, 50% of those RECs must come from the Adjustable Block Program, 2% from brownfield site solar (which could also be considered utility-scale if over 2 MW in size), and 40% from utility-scale solar (with 8% not specifically described). Therefore, this Section only considers utility-scale solar, and not other types of solar.

Table 5-2: New Wind and New Utility-Scale Solar RECs Procured and Targets

	New Wind	New Utility-Scale Solar[343]
Cumulative Annual RECs Procured[344]	**3.945 million**	**3 million**
2020-2021 Target	2 million	0.8 million
2025-2026 Target	3 million	1.2 million
2030-2031 Target	4 million	1.6 million

The second circumstance would be if a new procurement conducted pursuant to Section 5.9.2 failed to meet its REC target. In this case, the failure to procure RECs would not necessarily impact statutory REC targets, but rather would just contribute to increasing the shortfall in meeting the annual percentage-based REC goals. Prior to considering conducting another procurement, the Agency will assess why the targets were not met and request stakeholder feedback on any changes to the procurement that would increase the likelihood that a procurement held again would be more likely to be successful. Part of that assessment will be an evaluation of the shortfall and if it were large enough to warrant another procurement (e.g., a shortfall of 10,000 RECs out of a 1 million annual REC target would be offered different consideration than a shortfall of 800,000 RECs).

Prior to conducting any Contingency Procurement, the Agency will consult with ICC Staff. The Agency will not seek formal Commission approval for conducting a Contingency Procurement, and will conduct such procurements based on the factors outlined above through the Commission's approval of this Revised Plan.

5.9.2. Forward Procurements

At the time this Revised Plan was filed, the Agency noted that one of the remaining activities approved in the Initial Plan included the Second Subsequent Forward Procurement of 1,000,000 RECs annually from new utility-scale wind projects. The results of that procurement were rejected by the Commission on October 30, 2019, and no projects were selected. Accordingly, during the process for Commission approval of this Plan, the Agency proposed that it conduct a utility-scale wind procurement in 2020 or 2021 to complete procurement of the 1,000,000 RECs that had been expected from the Fall 2019 utility-scale wind procurement. The Agency noted that the procurement is not depended upon the identification of additional funds, as the IPA previously factored into its Plan that 1,000,000 RECs annually would have been procured.[345] The Commission approved the Agency's proposal to allocate funds previously budgeted for the rejected Fall 2019 procurement towards a future utility-scale wind REC procurement.[346] Pursuant to the Commission's direction, the

[343] 40% of overall new solar target.

[344] Assumes that the 2019 Second Subsequent Forward Procurement for RECs from utility-scale wind projects meets its goal of 1 million RECs delivered annually and that projects selected from the Initial Forward Procurements and the Forward Procurements already conducted are successfully completed and begin REC deliveries.

[345] See Docket No. 19-0995, Final Order dated February 18, 2020 at 15.

[346] Id. at 17.

next utility-scale wind REC procurement will occur no later than May 31, 2021.[347] In March 2020, the Agency began planning this procurement through the solicitation of stakeholder feedback.[348]

Given the funding limitations described in Chapter 3, with the exception of the procurement of 1,000,000 utility-scale wind RECs discussed above, Forward Procurements for RECs from new utility-scale wind[349] or utility-scale solar projects will not be automatically conducted. Rather, on a biannual basis each spring and fall, the Agency will review available RPS budgets to determine if procurements can be conducted. Should available budgets (after the prioritization described in Section 3.22) allow for Forward Procurements to be conducted, the Agency will post to its website an announcement of the procurement(s) that includes an analysis of the available funding and the REC targets.

In general, the Agency recommends continuing the requirement from procurements conducted pursuant to the Initial Plan that REC deliveries begin within three years of the procurement event. However, the Agency does recognize that there are a variety of factors that can lead to project delays, including the RTO interconnection process, so the Agency will continue to include extension provisions in contracts.

5.9.3. Brownfield Site Photovoltaic

In the Initial Plan, the Agency proposed a procurement for RECs from brownfield site photovoltaic projects and included a target of 80,000 RECs delivered annually. As discussed above in Section 5.8, the procurement was initially held in the fall of 2018 in conjunction with the Photovoltaic Forward Procurement and did not successfully procure any RECs. The Agency subsequently issued a request for comments from stakeholders to gain a better understanding of factors that may have contributed to the lack of success of the procurement, and filed a motion with the Commission in March of 2019 for a clarification to provide the authorization to conduct another procurement. The Commission granted that motion on April 26, 2019.

The Agency made certain adjustments to the procurement guidelines (notably around acceptable age of documentation of eligibility) and conducted another procurement on July 26, 2019. On August 1, 2019, the Commission approved the results, which resulted in exceeding the upcoming statutory target of 40,000 RECs delivered annually by 2020-2021.

As discussed in Section 3.22, if funds are available and additional Adjustable Block Program procurement quantities are satisfied, the Agency would conduct a procurement for 50,000 RECs delivered annually from Brownfield Site Photovoltaic Projects.

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[347] Id. at 18. Additionally, if a new REC Contract is not in place as discussed in Section 5.3.1 of this Plan by May 31, 2021, the latest version of the utility-scale REC contract will form the basis for the 2021 contract, subject to minor modification where warranted.

[348] See: https://www2.illinois.gov/sites/ipa/Pages/wind-comments-2020.aspx for the Agency's request for feedback and responses received.

[349] For the purposes of Forward Procurements, the Agency understands that to be considered a "new wind project," a facility must be energized within three years of the Commission's approval of the procurement results. In addition, the Agency notes that it would generally not consider a repowered wind farm a "new wind project" for purposes of Section 1-75(c)(1)(C) of the IPA Act. Providing an incentive for existing generation to simply repower for increased efficiency would be inconsistent with statutory directives encouraging the development of "new" projects to "to diversify Illinois electricity supply, avoid and reduce pollution, reduce peak demand, and enhance public health and well-being of Illinois residents" (20 ILCS 3855/1-75(1-5)(6)), as the incremental benefits offered to Illinois residents by a repowered project would be significantly less than those offered by an entirely new facility.

5.9.4. Other Renewables Forward Procurement

As contemplated by the Initial Plan (see Section 5.8.3 of the Initial Plan), in June of 2019 the Agency issued a Request for Information to gauge developer and other stakeholder interest in a forward procurement for RECs from new renewable energy resources that are not wind or photovoltaic. The Agency received a very limited response to the Request for Information (only receiving responses from MidAmerican Energy and the Union of Concerned Scientists).[350] Those comments only provided limited information on a few potential projects under development in Iowa (but did not address if they have their costs recovered in rates regulated by a state, which would make them ineligible[351]), did not provide any insight into the economics or cost effectiveness of such a procurement, and raised a number of potential concerns related to the environmental impacts of biomass energy projects.

Based on the comments received, and with the concurrence of ICC Staff as described in the Initial Plan, the Agency does not recommend conducting a Forward Procurement for RECs from renewable energy resources that are not wind or photovoltaic. In Docket No. 19-0995 approving this Revised Plan, no party sought for such a procurement to be conducted.

5.9.5. Community Renewable Generation Program

In the Initial Plan, the Agency proposed a Community Renewable Generation Program Forward Procurement (see Section 5.8.4 of the Initial Plan). This procurement was designed to recognize that while Section 1-75(c)(1)(N) of the IPA Act required the creation of a community renewable generation program, the law provided firm guidance only on how to procure RECs from community solar projects (through the Adjustable Block Program), with other renewable generating technologies unaddressed. The Community Renewable Generation Program Forward Procurement would then create an opportunity for non-photovoltaic community generation projects to be developed. The procurement was conducted in December 2019 and did not yield any selected bids.

While the Agency appreciates the potential opportunities for additional community renewable generation procurements to expand the range and diversity of renewable energy resources in Illinois, due to the current budget constraints, the Agency does not propose another non-photovoltaic community renewable generation procurement in this Revised Plan. In Docket No. 19-0995 approving this Revised Plan, no party sought for an additional community renewable generation procurement to be conducted.

5.10. Wind/Solar Matching Requirement

As discussed in Section 2.4.5, Section 1-75(c)(1)(G)(iv) of the IPA Act requires that the projected amount of RECs procured (annually) from new wind projects not exceed the projected amount of RECs procured from new photovoltaic projects by more than 200,000 RECs, and that should this occur the Agency adjust the procurement plan accordingly.

The new photovoltaic project REC quantities presently under contract include RECs procured through the Adjustable Block Program and the Illinois Solar for All Program. As of the release of this Revised Plan (inclusive of expected volumes to be procured in the remaining 2019 procurements and the full allocation of the Adjustable Block Program RECs), it appears that new photovoltaic RECs procured exceed new wind RECs procured as shown in Table 5-1. Absent a significant fall off of RECs

[350] See: https://www2.illinois.gov/sites/ipa/Pages/Draft-Long-Term-Renewable-Resources-Procurement-Plan-Comments-2019.aspx.

[351] See 20 ILCS 3855/1-75(c)(1)(J).

procured due to projects not being completed and energized, it appears that this matching requirement may not be a significant concern in the near future.

Table 5-3: New Wind/Solar RECs Procured[352]

Delivery Year	All Solar RECs	All Wind RECs	Solar In Excess of Wind
2020-2021	1,851,074	1,395,000	456,074
2021-2022	4,169,771	2,944,753	1,225,018
2022-2023	4,169,719	2,944,753	1,224,966
2023-2024	4,169,668	3,944,753	224,915
2024-2025	4,169,616	3,944,753	224,863
2025-2026	4,169,565	3,944,753	224,812
2026-2027	4,169,514	3,944,753	224,761
2027-2028	4,169,463	3,944,753	224,710
2028-2029	4,169,413	3,944,753	224,660
2029-2030	4,169,363	3,944,753	224,610
2030-2031	4,169,313	3,944,753	224,560
2031-2032	4,169,263	3,944,753	224,510

Nevertheless, to keep this matching requirement from being exceeded, the Agency will assess the balance between RECs procured from new wind and new photovoltaics prior to proposing any Contingency or Forward Procurements. Should this assessment demonstrate the need to increase photovoltaic procurement quantities or reduce wind procurement quantities, the matching requirement would serve as the basis for adjusting REC procurement volumes, and such volumes would be adjusted to bring RECs under contract in line with the requirements of Section 1-75(c)(1)(G)(iv) of the Act.

5.11. Procurements after 2021

This Revised Plan covers the Agency's potential proposed procurements for calendar years 2020 and 2021. Absent legislative changes to available budgets (or other changes to the structure of the Renewable Portfolio Standard), it appears highly unlikely that even expanded REC targets for Forward Procurements will reach the annual percentage-based REC goals of the RPS for the time being. As described in Section 3.18, as initial payments for RECs from the Adjustable Block Program (that is, payments for projects in the blocks authorized by the Initial Plan) are completed in 2023 and 2024, the available annual RPS budget should begin to expand, which could allow for an increase in the scale of future Forward Procurements. However, that budget availability may be constrained by the requirement to meet future REC targets for the Adjustable Block Program.

Procurements to be conducted after 2021 will be considered in the next Plan update scheduled for release in the summer of 2021.

[352] This table assumes that the 1,000,000 REC target from the Second Subsequent Procurement for Wind RECs is fully met.

6. Adjustable Block Program

6.1. Background

Sections 1-75(c)(1)(K) and (L) of the IPA Act, as amended by Public Act 99-0906, required the Agency to establish an Adjustable Block Program for the procurement of RECs from new photovoltaic distributed generation systems and from new photovoltaic community renewable generation projects (colloquially known as "community solar"). The Adjustable Block Program stands in contrast to the competitive procurements described in Chapter 5 in that it features administratively determined prices for RECs and is open on an ongoing basis, rather than featuring discrete procurement events with competitively set, pay-as-bid prices.

Prior to the adoption of the Adjustable Block Program model, the development of new photovoltaic distributed generation in Illinois had been supported in other ways. From 1999 to 2015, the Department of Commerce and Economic Opportunity ("DCEO") offered rebates for photovoltaic projects; these rebates covered up to 25%-30% of the project cost and supported over 1,100 solar PV projects with a total capacity of 13 MW.[353] The DCEO rebates were available once per year and the available budget was quickly allocated, leading to uncertainty for installers about whether their projects would or would not receive a rebate in any given year. No funds have been appropriated for the rebate program in recent years.

Additionally, the IPA conducted Supplemental Photovoltaic Procurements in 2015 and 2016 under authority granted by Section 1-56(i) of the IPA Act, and the Agency proposed and conducted Distributed Generation procurements for the utilities from 2015 through 2017 (although these procurements for the utilities were not limited to photovoltaic systems or to new systems) to meet a statutory DG procurement target in the pre-P.A. 99-0906 RPS. The previous procurements administered by the IPA featured competitive bidding for projects, and each winning bidder received a contract through which RECs actually delivered were paid for at the bidder's bid price. While this approach created the market efficiency inherent in competitive bidding processes, installers of projects found it difficult to sell projects when the potential REC revenue would not be known until a bid was accepted (or alternatively there would be no REC revenue if a bid was not accepted). To mitigate that challenge, the Agency allowed bidders to bid on forecasted blocks of RECs for systems below 25 kW and give developers time to identify projects using a known REC price.

The Adjustable Block Program is intended to address these issues by featuring an approach that is continuously open, rather than relying on specific procurement events (or rebate application windows), features a clear set of prices, and can tap into a much larger budget. The program also expands this model to accommodate community solar so that homes and businesses that cannot place solar on their property can nonetheless participate in, and benefit from, direct access to renewable energy.

However, as discussed elsewhere in this chapter, while the continuously open model is currently effective for distributed generation projects, funding limitations (as discussed in Chapter 3) have created a long waitlist for community solar projects under the implementation of the Initial Plan. Additionally, once the blocks authorized by the Initial Plan and the Agency's allocation of

[353] See Renewable Energy, Energy Efficiency, and Coal Resources Development Law of 1997, 20 ILCS 687/6-1 *et seq.*; also see https://www.illinois.gov/dceo/AboutDCEO/ReportsRequiredByStatute/2013%20RERP%20Annual%20Report.pdf, https://energy.gov/savings/renewable-energy-resources-trust-fund.

discretionary capacity stemming from the Commission's Order approving that Plan are filled, waitlists may be needed for distributed generation projects if funding is not available for new blocks to open. Section 3.22 discusses how the Agency will review budget availability and under what circumstances new blocks could be opened.

6.2. Lessons From Other Jurisdictions

Illinois is far from being the first to adopt an approach of administratively-determined incentives or a block program to manage growth of the photovoltaic industry. Experience from other markets can inform best practices for setting prices and program design. Solar photovoltaic power has been a rapidly developing technology in recent years, with rapid price declines and industry growth. This dynamic environment has made it challenging for policymakers to design incentives that ensure healthy growth, without costing taxpayers and ratepayers too much or causing unsustainable "boom and bust" cycles that harm the industry and consumers.

To inform the program design of the Adjustable Block Program as described in the Initial Plan, the Agency's review and analysis of other programs included relevant experiences from Germany, Spain, California, and particularly Massachusetts and New York.[354]

While the New York and Massachusetts programs are both based on a declining block structure, and pay incentives on a first-come, first-served basis, key design aspects vary. The NY SUN program has 3 regions (Long Island, Con Edison, and Upstate) each with a distinct number of blocks, block sizes and block prices. Incentives are paid in dollars per Watt (capacity), declining differently for each region and sector, except for the residential sector where prices decrease by $0.10/W across all regions. Like the Illinois Adjustable Block Program, NY SUN pays small systems at the time of energization, whereas commercial projects receive a partial payment upfront with the remainder paid in installments over subsequent years.

The Massachusetts SMART program, which began accepting applications on November 26, 2018, is a 1,600 MW declining block incentive program that provides fixed Base Compensation Rates to qualified generation units.[355] To be eligible, generation units must be interconnected by one of three investor owned utility companies in Massachusetts. Capacity available in each utility's service territory was determined by multiplying 1,600 MW by each distribution company's percentage share of total statewide distribution load in 2016. Initial Base Compensation Rates were established using the results of a competitive procurement for larger projects (> 1 MW) and were announced on January 11, 2018. Incentive levels decline by prescribed amounts over up to eight blocks per EDC territory.

Following the first Capacity Block, SMART program Base Compensation Rates decline by 4% per Capacity Block. Under the SMART program, if a utility is eligible to have fewer Capacity Blocks and elects to do so, it may also establish a steeper rate of decline for Base Compensation Rates, and that rate shall yield an overall rate of decline as if the utility had elected to have eight Capacity Blocks.[356]

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[354] A summary of those other programs is available in Appendix C of the Initial Plan available at: https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/LTRRPP-Filed-Appendix-C-Review-Other-Programs.pdf.

[355] See: http://masmartsolar.com/.

[356] For example, Fitchburg Gas & Electric d/b/a Unitil elected to have four Capacity Blocks with an 8.8% decline in Base Compensation Rates per Capacity Block.

For three of the five utilities, available blocks for large (over 25 kW) projects are already filled and projects are being accepted for a waitlist.[357]

6.2.1. Managing Initial Demand

Some incentive programs have encountered problems dealing with a large quantity of applications coming in very quickly upon the application window opening. California's Self Generation Incentive Program ("SGIP") is a prime example. In 2016, $40 million of SGIP funding was made available. Applicants filed 658 reservation requests totaling $181 million in requested incentives in the first 10 minutes following program opening.[358] Some applicants were found to be deploying questionable strategies to get their application earlier in line, including filing applications from within the same server network as the application recipient. One vendor volunteered to give up half of its rewarded incentives to avoid litigation. As a result, the California PUC reformed the program to add a number of protections against awards being monopolized by early applicants:[359]

- Replacing the first-come, first-served system with a lottery in which projects having additional greenhouse gas/grid benefits are assigned priority;
- Making all of the incentive money available on a continuous basis in a declining incentive "step" structure, akin to the California Solar Initiative; and
- Restricting each project developer to a cap of 20 percent of the incentive budget, rather than the previous 40 percent cap that applied to equipment manufacturers

In developing the structure of the Adjustable Block Program, the Agency took into account its review of the experiences of other jurisdictions, what it learned from previous procurements it has administered, and the feedback it received from stakeholders. For issues that are not expressly addressed in the Act, the Agency made policy decisions to implement the program that it believed will result in a cost effective and successful program, with those decisions then vetted through the Commission's Plan approval process in Docket No. 17-0838. In some cases, opposing or variant positions taken by other litigants were ultimately agreed to by the Agency or otherwise adopted in the Commission's Order.

6.3. Block Structure

The core of the Adjustable Block Program is the concept of a "block." The program delineates incentives for various categories of eligible projects using blocks of generation capacity at certain prices per REC levels. The blocks are intended to create a progression from one price level to another based on the response of the market. A strong response from the market will result in a rapid progression to a lower price level, for example, while a weak response could elicit an increase in incentives if it is determined to be necessary. Figures 6-1 and 6-2 in Section 6.4 provide an illustration of how the blocks adjust by price.

Progression from one level to another is triggered by a certain volume of deployment, not by a time-based deadline. This deployment-based design is intended to act as a safety valve in case incentives

[357] See: https://masmartsolareversource.powerclerk.com/MvcAccount/Login.

[358] Eric Wesoff, Greentech Media, "Update: Stem's Response to the California SGIP Subsidy Award Process Imbroglio," May 16, 2016. https://www.greentechmedia.com/articles/read/Update-Stems-Response-to-the-California-SGIP-Subsidy-Award-Process-Imbrog.

[359] Eric Wesoff, Greentech Media, "California PUC Proposes Long-Overdue Reform on SGIP Subsidy," May 23, 2016. https://www.greentechmedia.com/articles/read/california-puc-proposes-long-overdue-reform-on-sgip-subsidy.

are set at too high a level, which has been a problem in previous attempts at administratively-determined prices. It can also provide long term certainty by giving an indication of future prices and quantities to all potential market participants.

The initial target for the Adjustable Block Program is to have 1,000,000 RECs delivered annually by the end of the 2020-2021 delivery year (i.e., May 31, 2021).[360] Using a capacity factor of 17%[361], this would result in approximately 666 MW of new photovoltaic generation. This amount is not a cap; if funding is available, there would be no barrier to going beyond that level to begin to work toward the statutory goal of an additional 500,000 RECs delivered annually by the end of the 2025-2026 delivery year. However, as discussed in Chapter 3, funding is a barrier for the next several years, and the Agency does not expect to be able to open additional blocks of capacity until those funding limitations (including the use of utility-held ACPs) are resolved. As discussed in Section 3.22, the Agency may have the opportunity to open new blocks of capacity for the Adjustable Block Program if funding is identified.

In order to achieve 1,000,000 RECs delivered annually by May 31, 2021, the Initial Plan featured a block structure that allocated three blocks per category to meet the statutory target for this program (i.e., 1 million RECs per year by the end of the 2020-2021 delivery year), and included a provision to allocate discretionary capacity (as discussed below) to categories through the opening of a Block 4 for each category determined to warrant additional capacity.

To encourage simplicity, the Agency allocates incentives into two groups by service territory/geographic category, based upon load forecasts contained in Chapter 3.[362]

- **Group A:** for projects located in the service territories of Ameren Illinois, MidAmerican, Mt. Carmel Public Utility, and rural electric cooperatives and municipal utilities located in MISO.
- **Group B:** for projects located in the service territories of ComEd, and rural electric cooperatives and municipal utilities located in PJM.

Incentive levels vary by group and are based upon the project's location. While the Program Administrator will strive to allocate REC delivery contracts with the electric utility in whose service territory the project is located (where applicable, as the IPA lacks authority to procure REC contracts on behalf of municipal utilities or rural electric cooperatives), in order to allocate RECs proportionately among Ameren Illinois, ComEd, and MidAmerican to meet their RPS obligations, that will not always be possible.

The Agency also considered creating an additional group or groups for MidAmerican, Mt. Carmel Public Utility, rural electric cooperatives, and municipal utilities. However, given their small share of the load in Illinois, the resulting group or groups would be quite small. By consolidating them into the larger groups, block sizes are more administratively manageable, and prices are more transparent and easily understood. The assignment to Groups of projects in the service territories of

[360] See Chapter 3 for more discussion of this requirement.

[361] This figure used in the Initial Plan was an assumed first-year capacity factor (relative to AC-rated nameplate capacity) for a fixed-mount photovoltaic system prior to any degradation over time.

[362] The combined allocation for Ameren Illinois and MidAmerican would be 29.66% and the allocation for ComEd would be 70.34%. For simplicity, these have been rounded to 30% and 70% for determining the size of blocks for Group A and Group B, respectively.

Mt. Carmel Public Utility, MidAmerican, rural electric cooperatives and municipal utilities is intended to approximately match those smaller entities to a larger utility with comparable electric rates.

Within each group, the blocks were divided by the allocations specified in Section 1-75(c)(1)(K) of the Act:

- 25% for systems up to 10 kW;
- 25% for systems greater than 10 kW and up to 2,000 kW;
- 25% for photovoltaic community renewable generation; and
- 25% to be allocated by the Agency.

Consistent with the Commission's Order in Docket No. 17-0838, the 25% left to the Agency's discretion was be held in reserve, with a reduction in the originally-proposed size of Block 3 used to account for that reduced capacity.[363] The Agency subsequently allocated that 25% of capacity to create new Block 4s for certain categories on April 3, 2019.[364]

For systems in the Large DG and Community Solar categories, the use of adjustments (as discussed below in Section 6.5) are used to differentiate the price for RECs from different sized systems.[365]

Projects that participate in the Illinois Solar for All Program (as described in Chapter 8) generally follow the program terms and conditions of the Adjustable Block Program, but apply separately to that program, and are not considered part of these Groups and categories for the purpose of filling the capacity of each Block. Illinois Solar for All projects are also be subject to additional terms and conditions, as well as a different contractual process.

6.3.1. Block Sizes

In the Initial Plan, the Agency originally proposed a block size structure of blocks of 22 MW for Group A categories, and 52 MW for Group B projects. Pursuant to the Commission's Order in Docket No. 17-0838, Block 3 for each Group/category combination was subsequently reduced to 5.5 and 13 MW respectively to allow the Agency to subsequently allocate discretionary capacity. As shown in Table 6-1, the Agency allocated that discretionary capacity through the opening of Block 4 for the Large DG and community solar categories (91.5 MW for Group A – Large DG, 33 MW for Group B – Large DG, 12 MW for Group A – Community Solar, and 30 MW for Group B – Community Solar).

[363] See Docket No. 17-0838, Final Order dated April 3, 2018 at 60. That the discretionary capacity is taken only from the third block is evident from the Order's statement that it "adopts the proposal of the Joint Solar Parties to hold 25% of the Adjustable Block Program capacity by megawatt in reserve," as this detail was present in the Joint Solar Parties' proposal, as well as the Order's statement that capacity would be reserved "as outlined in the IPA's BOE."

[364] See: http://illinoisabp.com/wp-content/uploads/2019/04/Discretionary-Capacity-Rationale-4.3.19.pdf.

[365] The Agency also considered subdividing those categories into smaller blocks; ultimately, the Agency was not originally convinced that such an approach would be more efficient or a better way to match prices to demand from the market, although it recognizes the resultant imbalance in system sizes across community solar applications (where the vast majority of applications are systems at or near the maximum size despite more lucrative REC prices for smaller community solar projects).

Table 6-1: Initial Plan Block Volumes (MW)

Block Group	Block Category	Block 1	Block 2	Block 3	Block 4
Group A	Small	22	22	5.5	0
Ameren Illinois, MidAmerican, Mt. Carmel, Rural Electric Cooperatives and Municipal Utilities located in MISO)	Large	22	22	5.5	91.5
	Community Solar	22	22	5.5	12
Group B	Small	52	52	13	0
(ComEd, and Rural Electric Cooperatives and Municipal Utilities located in PJM)	Large	52	52	13	33
	Community Solar	52	52	13	30
Total		222	222	55.5	166.5

As of April 20, 2020, Block 2 remains open for both Small DG categories. The Community Solar and Large DG blocks are filled and subject to a waitlist as discussed in Section 6.3.3 below. Under this Revised Plan, those blocks will continue to stay open (or become open) until filled at the size and structure outlined above.

Prior to opening any new blocks beyond those outlined above (which will likely require identification of additional funding through changes in utility load forecasts, clarification of the use of utility-held ACPs, or legislative changes to the RPS funding structure), the Agency will seek stakeholder comment on whether the block size should be adjusted from the original block sizes (22 MW for Group A, 52 MW for Group B). One goal of that block size adjustment would be to allow for the opening of smaller blocks if only limited funding is identified. The 25% discretionary capacity allocation among project types contemplated by Section 1-75(c)(1)(K)(iv) of the IPA Act will be determined by the Agency shortly prior to opening a new block, based on program performance, market developments, and stakeholder feedback.

6.3.2. Transition between Blocks

When a block's capacity is filled, subject to budget availability, the next block for that category (with a different price) would open at a price expected to be 4% lower than the previous block. For this Revised Plan, the Agency proposes that Small DG Blocks 1 and 2 will be held open for 7 calendar days (rather than the 14 days contained in the Initial Plan) after the block volume is filled (with block volume defined by a measurement of a project being submitted to the program through the payment of the application fee). For the closing of the Small DG Blocks 1 or 2 (should they remain open after the approval of the Revised Plan), the capacity of the next block will be adjusted down to account for any capacity submitted during that 7 day period.[366] The Agency will announce when a block has been

[366] Group B Small DG Block 1 reached its capacity on February 7, 2020 (prior to the approval of the Revised Plan) and closed on February 21, 2020 per the Initial Plan's 14-day soft close provision. Group A Small DG Block 1 reach its capacity on March 24, 2020 and closed on March 31, 2020 per the Revised Plan's 7-day soft close provision.

filled and when the closing date will be. For the Small DG categories, opening of new blocks other than Blocks 2 and 3 (that is, those blocks previously authorized through the Initial Plan) will not be automatic because it will be subject to the identification of available funding.

For Small DG Blocks 3 and Large DG Blocks 4, blocks will close when the block volume is filled, and any projects submitted after that time will be put on a first-come/first-served waitlist for the Group/category, pending the analysis of available funds and the verification of eligibility of projects that applied to the program prior to them.[367]

Subject to the conditions outlined above, a project will receive the price of the block that is open at the time the Part I project application is submitted. If a block closes while a project application is being reviewed and the project is not accepted, the capacity associated with that rejected project will be assigned to the next block.

As discussed further in Section 6.15.3 below, should a system in a given block fail to be developed and withdraw from the Program, that system's portion of the block will be forfeited. The volume associated with the forfeited system will be added to the block that is currently open (or, if no block is currently open, the most recently closed block) at the price for that block.

The public will be notified of the availability of capacity in each block via an online dashboard, as discussed in more detail in Section 6.10.

6.3.3. Managing Waitlists

6.3.3.1. Community Solar

When the Adjustable Block Program opened for project applications in early 2019, 919 community solar projects (representing 1,777 MW of capacity) applied during the initial 14 day application window. After the lotteries held on April 10, 2019, 34 projects in Group A and 78 projects in Group B were selected for contracts representing 215 MW of new community solar capacity in Illinois, 452 community solar projects in Group A (representing 859 MW of capacity) and 355 community solar projects in Group B (representing 703 MW of capacity) were placed on waitlists. Until any changes are made through the Commission's approval of this Revised Plan, projects will be accepted off the waitlist at Block 4 pricing when previously selected projects withdraw from the program (for example, due to high interconnection costs) based on the ordinal numbers allocated to each project in that lottery, and subject to available program capacity created by the withdrawn projects. As of the release of this Revised Plan, one project in Group A and three projects in Group B have been selected off the community solar waitlists.

During both the in-person and written stakeholder comment processes preceding the development of this Revised Plan, the Agency sought feedback on how best to manage this waitlist going forward. The simplest and most straightforward approach would be to simply maintain the existing waitlists and accept projects in that order off as additional capacity becomes available. However, this approach would not recognize the potential for the Agency to consider additional criteria for community solar projects that could help increase the diversity of projects being developed, nor would it address any potential qualitative differences between applicant projects.

[367] Group B Large DG Block 4 closed on March 4, 2020 and Group A Large DG Block 4 closed on March 5, 2020.

An alternative approach was proposed by several parties in their comments;[368] under this proposal, the waitlist would be eliminated, and projects would be ordered by the date of their original Interconnection Agreement (or, for projects in ComEd service territory, when those projects would have received their original Interconnection Agreement but for the waiver granted in Docket No. 18-1583 were they not originally able to obtain an agreement). As the Agency understands this proposal, projects would also be required to provide significant collateral if they had dropped out of the interconnection queue while on the waitlist and were to then seek to re-apply. The rationale provided for this approach is that, in other jurisdictions, this original interconnection agreement date is used as an indicator of project maturity, as it is the date after which the developer would have to post a deposit with the utility. In doing so, the developer presumably would have completed other due diligence and would have the confidence in making that deposit. The proposed approach did not address how to select between projects that have the same date on their Interconnection Agreement.

In theory, favoring more mature or serious projects is an appealing way to distinguish between hundreds and hundreds of applicant projects. But in practice, the obvious shortcomings of this approach are at least two-fold: first, in Illinois, there is no indication that the ability to have achieved an earlier interconnection agreement actually correlates to having a more mature (or possibly even more viable) project. The Agency's project application process required the proof of site control, the presence of a signed interconnection agreement, and the acquisition of all non-ministerial permits; there is no reason to believe (and indeed, none was alleged in comments) that projects which would have obtained an interconnection agreement earlier took additional project maturity steps beyond this threshold. Stated differently, this original interconnection agreement date is alleged in comments to be a useful proxy for project maturity, but on closer examination, it would not necessarily lead to favoring not more mature projects, but just favoring earlier-applying projects.

Second, there may be no inherently good reason to provide more favorable treatment to earlier-applying projects. P.A. 99-0906 was signed into law on December 7, 2016, became effective on June 1, 2017, and the IPA's Initial Plan—which provided visibility into many key requirements—was not approved by the Commission until April 3, 2018. Some developers may have begun started securing sites and seeking interconnection agreements upon the legislation's enactment (or before), while others may have waited until more details of the program were proposed or approved. As the earliest-applying projects may have in some ways been the most speculative of all (as they would have applied for interconnection with the least visibility into program requirements), does it make public policy sense to reward the earliest-applying projects?

For these reasons, it appears that this proposed approach may simply serve to disadvantage developers who did not rush to submit interconnection agreements—perhaps because there was no indication to those developers that they needed to do so—and does not appear to support the stated aim of promoting more mature and/or higher quality projects.

A third approach—or, at the very least, an additional set of considerations—was provided in comments by ELPC and Vote Solar.[369] While these entities recommended maintaining the existing waitlist for selected projects that drop out (i.e., backfilling already-allocated capacity), they raised

[368] Comments are available at: https://www2.illinois.gov/sites/ipa/Pages/Draft-Long-Term-Renewable-Resources-Procurement-Plan-Comments-2019.aspx. In particular, see the comments of the Joint Solar Parties, which are also referenced by several other commenters.

[369] See https://www2.illinois.gov/sites/ipa/Documents/Plan%20Comments%202019/ELPC_VS%20-%20IPA%20Comment%20Response%20July%202019.pdf.

concerns about the lack of urban vs. rural geographic diversity of community solar projects and the lack of projects driven by or located in specific communities.[370] As an alternative, these groups suggest creating a new pathway for projects that would increase the diversity of types and locations of projects—if new funding became available to open new blocks of community solar capacity, rather than utilizing the waitlist, a new application process would allow new projects to be considered (potentially along with waitlisted projects that contributed to increased project diversity). Among the potential considerations suggested by ELPC and Vote Solar were projects in higher density areas, projects making commitments regarding the proximity of subscribers, distance from other community solar projects, and projects resulting from development activities of public entities or community-based organizations. These groups also suggested prioritization be given to projects that feature environmentally friendly development, such as pollinator friendly habitats.

Comments received on the draft Revised Plan[371] largely mirrored (with refinements) the post-workshop comments described above. Some parties suggested options to increase diversity/variety of projects (Ameresco, EDF, ELPLC/Vote Solar, NRDC). Other parties proposed various approaches to resort or eliminate the waitlist, typically emphasizing project maturity milestones (Joint Solar Parties, Summit Ridge, Cypress Creek, Sunrise Energy Ventures). Some parties specifically emphasized that waitlisted projects should be selected before new projects (Summit Ridge, Joint Solar Parties, Borrego, AES DE), and several urged substantial upfront deposits (Borrego, Cypress Creek, Joint Solar Parties). Other approaches included requiring maintaining developmental milestones (Community Energy Solar, Trajectory Energy), or allowing developers to reorder their waitlisted projects (ICC Staff). The Agency appreciates the additional consideration that parties put into further fleshing out their thoughts on the waitlist and the approach described below reflects the Agency's consideration of those comments.

While the Agency believes that the community solar projects selected to date do feature, in some ways, strong geographic diversity (in that at a state-wide level, the projects are well distributed), the vast majority of both applicant and selected projects are located in rural areas. While this phenomenon is largely the result of developers seeking project locations with low costs of site acquisition (which could translate into better subscription offers for customers), the unintended consequences of this approach are that a) projects are less likely to be located near subscribers living in urban or suburban areas, and b) geographic diversity among community solar projects has not been achieved across various community types. As community solar remains a fairly new concept in the landscape of renewable energy options for consumers, the Agency is interested in encouraging additional projects located closer to potential subscribers on the hope that some selected projects will offer additional intangible benefits associated with being located in closer proximity to many of the state's "communities."

To that end, as described below, if new blocks of capacity for community solar are opened (starting with Block 5), project selection for new blocks will combine opportunities for a) selecting currently waitlisted projects and b) selecting from new project applications intended to increase the diversity of areas hosting community solar projects, the business models of projects, and the size of projects.

[370] The Agency notes that the addresses of projects were released, but that there is not information available for each project on who chose to initiate it, or where the subscribers would be recruited from, so it is assumed that projects are not community-based.

[371] Comments are available at: https://www2.illinois.gov/sites/ipa/Pages/2020-Draft-LTRRPP-Comments.aspx.

This approach was approved by the Commission through its approval of this Revised Plan in Docket No. 19-0995.[372]

6.3.3.1.1. Waitlist for Replacing Lottery-Selected Projects

In this Revised Plan, to replace projects originally selected in the lottery should they withdraw from the program, or fail to become energized in a timely manner, the Agency will maintain the existing waitlist and continue to select projects in that ordinal ranking for replacing those original projects. Until the opening of a new Block 5, projects will be selected at Block 4 pricing, but with any small subscriber adder updated through this Plan applied to their pricing while still maintaining the small subscriber commitment made for the lottery.

In order for a project to remain on that waitlist, Approved Vendors will have to verify with the Program Administrator within 90 days of the approval of this Revised Plan that the project has maintained any applicable land use permits and site control (e.g., leases or lease options).

6.3.3.1.2. Approach to Opening New Community Solar Blocks

The remaining 50% of new block community solar capacity will be reserved for projects whose selection would be in part intended to increase the variety of community solar locations, models, and options in Illinois.

To implement this new approach, the Agency proposed the following:

- When funding becomes available to open Block 5 (or any subsequent block) for each Group, the Agency will announce the specific block opening date with at least 60 days' notice prior to that opening date.[373]
- The Agency will then accept new community solar project applications for 60 days after the opening date.[374]
- If verified new project applications received during the 60-day application window are less than the available capacity (i.e., 50% of the Block capacity), then the remaining capacity would be released for selecting additional projects off of the existing ordinal waitlist.
- If new project applications received during the 60-day application window exceed the available capacity, then project selection will be conducted by scoring projects in the following manner and accepting projects based on the highest scores:

    - Projects will first be sorted into four categories based on the development density of the townships in which they are located.[375] The highest density class would get 3 points, the next class 2 points, the third class 1 point, and the lowest density class 0 points.

[372] Docket No. 19-0995, Final Order dated February 18, 2020 at 44-46.

[373] Community solar project applications will continue to be accepted after the approval of this Revised Plan and prior to the opening of Block 5; they will be placed at the end of the current waitlist. Once the new block has opened, those projects may withdraw from the waitlist and reapply to be considered under the new project application criteria.

[374] A project currently on the existing ordinal waitlist may be withdrawn from that waitlist and resubmitted as a new project application (subject to payment of the application fee) to be considered for these new project selection criteria.

[375] For determining the development density category, the Agency proposes to adopt the methodology proposed by ELPC/Vote Solar in their comments on the draft Revised Plan, which sorts all the townships of Illinois into four classes. See: https://www2.illinois.gov/sites/ipa/Documents/Draft%20Revised%20Plan%20-%20Summer%202019/Comments%20to%20Draft%20Revised%20Plan/ELPC_Vote%20Solar%20Plan%20Comments.pdf.

- Projects developed in response to a site-specific RFP issued by a municipality or community group (issued prior to the announcement of the opening of the block) would be awarded 1 point.
- Projects that commit to only serve subscribers in the same township as the project would be awarded 1 point. If the township population is below 50,000, then subscribers could also be in adjacent townships to meet this commitment and receive this point. (REC payments will be adjusted to only account for subscriber meeting this commitment.)
- Projects under 100 kW (AC) in size would be awarded 2 points. Projects between 100 and 500 kW (AC) in size would be awarded 1 point. A project's size will be determined through including any actual or proposed co-located community solar projects in that size determination.
- Random selection will only be utilized as a tie-breaker for equally scored projects to fill available capacity, if any; however, should the capacity available be so small so as to only accommodate one or more projects below a certain size, then the Agency may only consider those projects small enough to not exceed that remaining capacity.

Projects not selected for an open block will be given the option to be considered for the next block that opens, but will not be given prioritization over new applications. Project scores and new waitlists specific to this scoring-based application pathway will be maintained to replace any capacity (at the applicable block REC price) that becomes available if selected projects withdraw or are not completed. This new waitlist would be treated separately from the original April 10, 2019 lottery waitlist. New project applications or replacement projects taken from this second, new waitlist must be equal in size to or smaller than the project being replaced.

In approving this proposal, the Commission determined that stakeholder feedback is a valuable tool to refine the scoring approach and best achieve the goals of increasing the variety of community solar locations, models and options in Illinois.[376] In accordance with the Commission's directive, the IPA will issue a request for written comments on: (1) the timeline for project application to, and any potential reallocation of refunds from, community solar projects selected through scoring; (2) whether minimum scores should be required for any individual or subset of attribute(s) for all scoring pathway applicants; (3) automatic triggers to lower attribute scores; (4) qualification requirements for individual attributes (e.g., should site-specific RFPs be required to have been issued prior to the announcement of the opening of the block); (5) number of points awarded; and (6) other attributes that should be considered in order to increase the variety of community solar locations, models, and options in Illinois, such as proposals to award points to non-greenfield projects.[377]

6.3.3.2. Distributed Generation

For the Small Distributed Generation categories, unlike with community solar and Large DG categories, as of April 20, 2020, Block 2 remains open and Block 3 is yet to open.

When available capacity in a Distributed Generation block is filled (and assuming new blocks are not opened), the Agency proposes to continue accepting project applications and place those projects on a waitlist for each Group/Category on a first come/first served basis, with newly opened space

[376] Docket No. 19-0995, Final Order dated February 18, 2020, at 46.

[377] Id.

created by earlier projects not being approved or withdrawing being filled from the top of the waitlist at Block 4 pricing. A project will be considered submitted when the application fee for the project is paid.[378] When new blocks of capacity are opened, projects on the waitlist at that time would then be placed into the next block or blocks of capacity in the waitlist order at the REC price applicable to that next block.

6.3.3.3. Assignment of Waitlist Projects

Projects may be selected off a waitlist in any given Group/category combination either when a new block of capacity is opened (and receive that block's REC price), or if previously selected and approved projects drop out of the program, thus freeing up program capacity (with the project selected from the waitlist receiving the most recently available REC price). While projects are on a waitlist and thus not yet under contract,[379] an Approved Vendor may assign that project to another Approved Vendor, or the project itself may be sold, without penalty or impacting the project's position on the waitlist but must promptly notify the Program Administrator[380] of that transfer and provide appropriate documentation.

6.4. REC Pricing Model

For the Initial Plan, the IPA adopted and modified the National Renewable Energy Laboratory's Cost of Renewable Energy Spreadsheet Tool ("CREST") to develop a model for calculating REC prices. CREST is an economic cash flow model that estimates the cost of energy in terms of cents per kilowatt hour associated with specific input assumptions regarding technology type, location, system capital and operating costs, expected production, project useful life, and various project financing variables. The model established initial pricing for each block, with prices then declining 4% for each subsequent block. That system of prices changing between blocks is now a mechanism for price discovery (at least for the Small DG category where future blocks of capacity have not yet opened).

Many stakeholders who provided comments in response to the Agency's Request for Comments issued after the June 20 and 26, 2019 workshops felt that the prices for the Distributed Generation categories were roughly in line with market expectations.[381] The Agency believes that keeping a clear set of prices for Distributed Generation provides an appropriate market signal. Thus, in this Revised Plan, for Distributed Generation, the IPA proposed to maintain the prices for open blocks and continue the 4% per block price decrease for any new blocks—including those authorized by the Initial Plan (i.e., Blocks 2 and 3 for Small DG) and any additional blocks authorized by this Revised Plan. However, the Agency does note that, as described in Section 6.8, there are upcoming factors that may require a future adjustment to REC prices.

For community solar, the decisions related to REC prices are more complex. The Joint Solar Parties noted in their comments[382] that in many cases, interconnection costs are higher than the input

[378] This approach is intended to be consistent with the approach contained in the ABP Guidebook as of October 2019. See pages 15-16 of the latest version (5/31/19) at: http://illinoisabp.com/wp-content/uploads/2019/05/Program-Guidebook-2019_05_31.pdf.

[379] The allowances in this sentence also apply to a non-waitlisted Part I applicant project that has not yet been selected by the Program Administrator for a REC contract.

[380] For this Chapter, all references to the Program Administrator refer to the Program Administrator for the Adjustable Block Program. Discussion of the Program Administrator for the Illinois Solar for All Program can be found in Chapter 8.

[381] See: https://www2.illinois.gov/sites/ipa/Pages/Draft-Long-Term-Renewable-Resources-Procurement-Plan-Comments-2019.aspx.

[382] See https://www2.illinois.gov/sites/ipa/Documents/Plan%20Comments%202019/JSP%20Draft%20Post-Workshop%20Comments.pdf at 6-8.

assumption used in the initial REC pricing model, resulting in the need for higher REC prices. Likewise, in some areas land costs are higher. While the Agency appreciates those concerns, ultimately the Agency needs to balance a REC price that will allow for successful project development (including subscriber acquisition and maintenance) with the need to utilize scarce RPS budgets efficiently and in a manner that will maximize the number of RECs procured. For these reasons, the Agency believes it is premature to raise REC prices.

Holding the line on REC prices for community solar projects will allow for some natural selection in that projects with high interconnection costs would not proceed (and the Agency has already recognized in current contracts an option for projects with high interconnection costs to exit the program, and would expect to maintain a similar policy in the future). Higher REC prices simply to pay unusually high interconnection costs to the utilities is not an efficient use of resources and does not pass that value onto subscribers. The Agency further notes that the Block 4 REC price for a 2 MW community solar project inclusive of the small subscriber adder is slightly lower than the under 10 kW DG REC price. While the Agency understands that one potential value of community solar is to allow households who cannot install solar to participate in a solar project, paying a significantly higher REC price for RECs associated with small subscribers compared to what would be paid if they were to install solar could create a perverse incentive for households who could install solar—and would unlock the benefits of having more nodal, modular projects located closer to load—instead subscribing to a community solar project.

For the draft Revised Plan, the Agency solicited comments on whether community solar REC prices should be decreased to help further ensure that any selected projects are the most efficient projects and offer the lowest possible budget impact. Based on the limited comments received, the Agency proposed that for any project selected off the waitlist to replace an already-selected projects, those newly-selected projects will receive Block 4 REC pricing. Should funding become available to open new blocks, Block 5 will open at 4% below Block 4 prices.[383] However, as discussed below in Section 6.5.3, the Agency is proposed a change to the small subscriber adder to eliminate the over 75% small subscriber REC Price Adjustment that will apply to any projects accepted into Block 5 and beyond, or any projects from the waitlist selected to replace an initial project selected in the lottery after the Commission approval of this Revised Plan.

In its Order approving the Revised Plan, the Commission also stated that "REC prices must be lower," although it neglected to adopt any specific proposal for how to lower such prices (and no methodology for lowering prices was introduced into the record). Instead, the Commission required that "workshops should be held and stakeholder input considered" regarding how REC prices could be lowered, with a need to be mindful that, going forward, "the IPA must recognize market signals rather than solely relying on its cost modeling approach" in determining REC prices. Any changes to REC prices resulting from that process preceding the next Plan update would be authorized under the IPA's Section 1-75(c)(1)(M) authority to make price modifications "that do not deviate from the Commission's approved value by more than 25%" without Commission review and approval.[384]

Table 6-2 contains the REC prices for the Adjustable Block Program, factoring in the size category adjustments described in Section 6.5.1. This Table shows the prices from the blocks defined in the

[383] In approving the Final Revised Plan, the Commission directed the Agency to consider utilizing its discretionary power to reduce prices up to 25% without Commission approval for Block 5, should funding become available for additional blocks.

[384] Docket No. 19-0995, Final Order dated February 18, 2020 at 46-47.

Initial Plan, the allocation of discretionary capacity to create Block 4s for Large DG and Community Solar, and indicative prices should additional blocks be opened during 2020 or 2021. Blocks that have been filled are indicated in grey.

Table 6-2: Block Group REC Prices ($/REC)[385]

Block Group	Block Category		Block 1	Block 2	Block 3	Block 4	Block 5 (if applicable)
Group A (Ameren Illinois, MidAmerican, Mt. Carmel, Rural Electric Cooperatives, and Municipal Utilities located in MISO)	Small	≤10 kW	$85.10	$81.70	$78.43	$75.29	$72.28
	Large	>10 - 25 kW	$78.70	$75.55	$72.53	$69.63	$66.84
		>25 - 100 kW	$64.41	$61.83	$59.36	$56.99	$54.71
		>100 - 200 kW	$52.54	$50.44	$48.42	$46.48	$44.62
		>200 - 500 kW	$46.85	$44.98	$43.18	$41.45	$39.79
		>500 - 2,000 kW	$43.42	$41.68	$40.02	$38.42	$36.88
	Community Solar	≤10 kW	$96.12	$92.28	$88.58	$85.04	$81.64
		>10 - 25 kW	$87.07	$83.59	$80.24	$77.03	$73.95
		>25 - 100 kW	$70.95	$68.11	$65.39	$62.77	$60.26
		>100 - 200 kW	$60.47	$58.05	$55.73	$53.50	$51.36
		>200 - 500 kW	$55.46	$53.24	$51.11	$49.07	$47.10
		>500 - 2,000 kW	$52.28	$50.19	$48.18	$46.25	$44.40
		Co-located systems exceeding 2 MW in aggregate size	$47.03	$45.15	$43.34	$41.61	$39.94
Group B (ComEd, and Rural Electric Cooperatives and Municipal Utilities located in PJM)	Small	≤10 kW	$72.97	$70.05	$67.25	$64.56	$61.98
	Large	>10 - 25 kW	$73.23	$70.30	$67.49	$64.79	$62.20
		>25 - 100 kW	$65.61	$62.99	$60.47	$58.05	$55.73
		>100 - 200 kW	$53.75	$51.60	$49.54	$47.56	$45.66
		>200 - 500 kW	$48.07	$46.15	$44.30	$42.53	$40.83
		>500 - 2,000 kW	$44.64	$42.85	$41.14	$39.49	$37.91
	Community Solar	≤10 kW	$91.89	$88.21	$84.69	$81.30	$78.05
		>10 - 25 kW	$82.82	$79.51	$76.33	$73.28	$70.35
		>25 - 100 kW	$66.65	$63.98	$61.42	$58.96	$56.60
		>100 - 200 kW	$56.12	$53.88	$51.72	$49.65	$47.67
		>200 - 500 kW	$51.09	$49.05	$47.08	$45.20	$43.39
		>500 - 2,000 kW	$47.88	$45.96	$44.13	$42.36	$40.67
		Co-located systems exceeding 2 MW in aggregate size	$42.59	$40.89	$39.25	$37.68	$36.17

As demonstrated in the table above, after Block 1, prices decline by 4% with each transition between blocks. The Agency will monitor performance during the initial Blocks and may elect to modify the price change between blocks based upon the speed that each Block is filled. The process for making changes is described in Section 6.8.

[385] In the "Large" and "Community Solar" categories the prices listed include the Size Category Adjustments described in Section 6.5.1.

6.5. Adjustments and Adders

The following set of adjustments and adders are intended to adjust the base REC price to meet specific additional purposes. These include adjusting for system size, adjusting for the additional costs of small subscribers to community solar, and potentially accounting for the changes to net metering, smart inverter rebates and federal tax credits. Greater detail on issues in the REC pricing model can be found in Appendix D of the Initial Plan.

While the Act seeks to encourage projects "in diverse locations…not concentrated in a few geographic areas,"[386] at this time the Agency is not proposing any specific geographic REC price adders for distributed generation projects. The Agency believes that the split of the blocks between utility service territories adequately addresses geographic diversity, and initial DG project applications indicate that projects are well distributed across the state.

The Agency observes that while projects are spread across the state at a high level, community solar projects are predominantly located in rural areas that are not likely to be close to subscribers. As discussed in Section 0, the Agency sought stakeholder feedback on the draft Revised Plan on how to manage the community solar waitlists, and this Revised Plan filed for Commission approval presents a proposal for reserving a portion of new blocks of community solar capacity for projects intended to increase geographic diversity (and, specifically, address the imbalance between rural projects and urban/suburban projects). .

6.5.1. Size Category Adjustments

The Agency proposed a set of adjustments based on project size for projects greater than 10 kW and up to 2,000 kW. As there are significant economies of scale for larger systems compared to smaller systems, the Agency believes that setting a single REC price for all projects in this range will either over-incentivize large projects or under-incentivize small projects. Having a diversity of project sizes is important for creating a healthy and diverse distributed solar market, with robust opportunities for participation by all customers. These adjustments reflect REC pricing to reasonably match system sizes.

These adjustments will only be available for systems over 10 kW in size in both the Large DG and Community Solar categories and are reflected in the REC prices listed in Table 6-2. They do not constitute an additional adjustment to the prices listed in that Table. The Agency does not anticipate significant cost differences for systems within the "no more than 10 kW" category requiring similar price adjustments.

[386] 20 ILCS 3855/1-75(c)(1)(K).

Table 6-3: Size Category Adjustments

Size	$/REC	
	Group A	Group B
Over 10 kW to 25 kW	$35.28	$28.59
Over 25 kW to 100 kW	$20.99	$20.97
Over 100 kW to 200 kW	$9.12	$9.11
Over 200 kW to 500 kW	$3.43	$3.43
Over 500 kW to 2,000 kW	No adjustment	No adjustment

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

6.5.2. Co-location of Distributed Generation Systems

For purposes of Adjustable Block Program categories and applicable REC prices, the total capacity of distributed generation systems energized after June 1, 2017 on a single parcel that participate in the Adjustable Block Program will be considered a single system.[387] (For example, three 100 kW systems at a single parcel will be considered a 300 kW system.) If a system at a single parcel is subsequently expanded, the Agency reserves the right to revise the incentive amounts paid for the subsequent system(s), and to set the incentives based on the total expanded system size rather than just treat the expansion as a separate system. For the purpose of establishing a revised incentive level under these circumstances, the systems' location would be considered at the parcel level. Exceptions will be made if it can be demonstrated that two projects on one parcel have separate, non-affiliated owners and serve to offset the load of separate, non-affiliated entities on a parcel.

Additional discussion of co-location of community solar projects, including the approach to co-location of community solar projects adopted in the Commission's Final Order in Docket No. 17-0838, is included in Section 7.3. For the purposes of consideration of co-location, distributed generation systems and community solar projects would be considered separately and would not impact the size calculation applicable to each other. Furthermore, the Agency's co-location determinations only apply to projects participating in the Adjustable Block Program and not projects installed outside of the Program (e.g., through previously conducted Agency procurements, receiving DCEO rebates, or developed without incentives).

[387] Any system developed under this program would require a separate GATS or M-RETS ID from any system developed through a different program (e.g., the Supplemental Photovoltaic Procurement or the Utility DG procurements) or without programmatic support. This would allow for a clear demarcation between systems and their associated RECs.

6.5.3. Community Solar

Community solar projects may face additional costs and feature reduced eligibility for direct energy-related revenues than distributed generation systems. On the revenue side, subscribers to such projects are eligible only for energy-only net metering,[388] while on the cost side, there is the cost of acquiring, maintaining, and managing subscribers. The prices for community solar RECs shown in Table 6-2 reflect those differences. The REC prices for these projects also include the Size Category Adjustments discussed above in Table 6-3.

To ensure that the benefits of solar energy are widely shared by Illinois residents, the Adjustable Block Program offers an additional incentive for community solar projects with a higher level of small subscribers (residential and small commercial customers with subscriptions below 25 kW). To account for additional costs related to small subscribers, the following schedule of adders will be available to community solar projects that have minimum levels of small subscribers; these adders would be added to the REC prices shown in Table 6-2. For more discussion of issues related to small subscribers, see Section 7.6.2. For this Revised Plan, the Agency proposes to consolidate the categories of adders to eliminate the higher adder for over 75% small subscribers.[389] This change is to recognize that the desire to achieve at least 25% small subscriber participation in community solar (as discussed in Section 7.6.1) has been more than met by the community solar projects accepted to date and that the adders may be over-incentivizing small subscriber participation to the detriment of participation of larger subscribers while creating outsized impacts on available funding. This change would apply to any new projects selected after the approval of this Revised Plan including both waitlist projects selected to replace projects initially selected in the lottery that withdraw or are not completed, or projects selected in new blocks of capacity. The elimination of the 75% of greater small subscriber adder will not retroactively apply to any projects approved by the Commission prior to the approval of this Revised Plan.[390]

Table 6-4: Community Solar Adders

Adder	$/REC	
	Group A	Group B
Less than 25% small subscriber	No adder	No adder
25% or greater small subscriber and less than 50% small subscriber	$11.17	$10.88
50% or greater small subscriber	$22.34	$21.77

[388] 220 ILCS 5/16-107.5(*l*)(2). The IPA also notes that in ICC Docket No. 17-0350, the proceeding to approve ComEd's proposed community solar net metering tariff pursuant to Section 16-107.5(*l*-5) of the PUA, several parties argued that volumetric transmission charges should be part of the net metering supply credit granted to community solar projects, while ComEd argued that transmission charges should be excluded. The Commission's September 27, 2017 Order in this matter determined (page 15) that the transmission services charge should be excluded from the community solar net metering credit.

[389] The Initial Plan included a "Greater than 75% small subscriber" adder of $33.51 for Group A and $32.65 for Group B.

[390] This proposal was uncontested in Docket No. 19-0995, and thus adopted through approval of this Plan.

These Adders reflect an analysis of community solar subscription costs contained in the Initial Plan. The Agency notes that a recent GTM Research report[391] contained estimates of subscriber acquisition costs that ranged from $0.06 to $0.25 per Watt and ongoing subscriber management (including billing and replacing subscribers) of $0.12 to $0.35 per Watt. The low end of the combined costs from those estimates would be $0.18 per Watt and the high end $0.60 per Watt. Translating those costs to the REC output over 15 years of a typical 2 MW community solar project (with a 22% AC capacity factor), those ranges would imply additional subscriber-related costs of $6.85 to $22.83 per REC, which indicates that the current small subscriber adders may be too high, especially if the prior adder for systems with greater than 75% small subscriber participation were to be maintained.

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

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

6.5.4. Adders to Adjust for Changing System Revenue

As discussed in Section 6.8.1 below, the Agency anticipates that as net metering caps are met, smart inverter rebates are adjusted or created, and Federal tax incentives decrease, the revenue a system would receive from other sources will decline. Not accounting for that in REC prices could make a system that would have been economically viable no longer viable after those decreases.

The Agency did not propose specific adders to address these challenges in this Revised Plan, but notes that Section 1-75(c)(1)(M) of the Act provides that "[p]rogram modifications to any price, capacity block, or other program element that do not deviate from the Commission's approved value by more than 25% shall take effect immediately and are not subject to Commission review and approval," allowing the Agency to make small adjustments to REC prices to account for certain challenges.[392] If necessary, the Agency will use this authority to propose adders or adjustments to account for these changes following the process described in Section 6.8, or utilize the Commission approval process for revising its Plan for any larger changes.

[391] The Vision for U.S. Community Solar: A Roadmap to 2030. GTM Research, July 2018.

[392] The Agency's June 4, 2018 published prices (which mirror those included in this Revised Plan) in its Compliance Filing reflect the "Commission's approved value" for purposes of subsequent adjustments made by the IPA under this authority. See Docket No. 17-0838, Final Order dated April 3, 2018 at 73-74.

6.6. Payment Terms

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

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

The Agency proposes that the standard for being "energized" as used above must include the completion of the interconnection approval by the local utility and the registration of the system in GATS or M-RETS so that generation data can be tracked and RECs created.[393] In addition, as discussed in Section 6.15.4, to avoid a system being completed but RECs not created and delivered, before a system can be considered "energized" so as to initiate the processing of an invoice for REC delivery contract payments, automatic assignment of RECs to the applicable utility will need to be initiated. The Agency believes that by ensuring proper registration in the tracking system up front, future administrative challenges can be minimized.

For systems over 10 kW and community solar projects, it is not clear from the law how exactly the "subsequent 4-year period" would be calculated, and whether the frequency of payments should be annually, quarterly, or monthly. The Agency proposed in the Initial Plan that after the first payment of 20%, the balance of payments be made on a quarterly basis over the following 16 quarters. For example, if the first payment is made on September 30, 2019 (upon interconnection and energization), assuming continued compliance with contractual requirements, the next payments would occur approximately on December 31, 2019, March 31, 2020, etc., with the final payment on approximately September 30, 2023—resulting in 17 total payments that bookend a four-year period of time. Payment amounts occur on a set schedule and may be adjusted to reflect changes in REC quantities (per Section 6.16.2), or community solar subscription levels (per Section 6.15.4). Based on feedback received to date, the Agency does not believe that a change to the basic quarterly payment schedule is warranted. However, the Agency recommends that as part of the contract update process, new contracts allow for three separate quarterly delivery schedules to reduce the lag time between a project being approved for payment and the first (or only) payment being received.[394]

[393] This proposed standard is only intended to relate to the contractual payment terms for the Program. Section 1-75(c)(1)(K) specifies that, "[o]nly projects energized on or after June 1, 2017 shall be eligible for the Adjustable Block program." The Agency views this to mean that a project must be interconnected to the applicable utility after June 1, 2017 and that the registration date of the system in GATS or M-RETS does not impact that determination. The added contractual standard is meant to ensure that energized systems will produce the RECs that they are receiving upfront payments for.

[394] For example, a project approved for payment in January would be on a quarterly schedule of payments occurring in February, May, August, and November; a project approved for payment in February would be on a quarterly schedule of payments occurring in March, June, September, and December; and a project approved for payment in March would be on a quarterly schedule of payments occurring in April, July, October, and January.

Section 1-75(c)(1)(L) also requires that:

> *(vi) If, at any time, approved applications for the Adjustable Block program exceed funds collected by the electric utility or would cause the Agency to exceed the limitation described in subparagraph (E) of this paragraph (1) on the amount of renewable energy resources that may be procured, then the Agency shall consider future uncommitted funds to be reserved for these contracts on a first-come, first-served basis, with the delivery of renewable energy credits required beginning at the time that the reserved funds become available.*

The Agency will continue to carefully monitor project application approvals and available budgets. As described further in Chapter 3, the Agency does anticipate that obligations could exceed collections starting at the conclusion of the budget rollover period in mid-2021, but that this issue can be temporarily addressed through previously collected Alternative Compliance Payments presently held in reserve. Nevertheless, the Agency will not recommend Commission approval of contracts for specific projects if it determines that this provision may be invoked and contract obligations cannot be met through expected funds.

Additional provisions of Section 1-75(c)(1)(L) require that:

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

These provisions are discussed further in Section 6.16.

6.7. Contracts

The Agency notes that while payments will be made according to the terms described in Section 6.6, the Adjustable Block Program and its REC delivery contracts will feature ongoing performance requirements to ensure that RECs are delivered across the 15-year term of the contracts, especially after payments have been made. Section 6.16 describes in more detail how those performance requirements will be implemented.

The Agency, in consultation with its Program Administrator and/or its Procurement Administrator, developed a standard REC delivery contract between the utilities and Approved Vendors much as its Procurement Administrator had done for the competitive procurement processes. This included the opportunity for interested parties to comment on the contract. Ultimately the contract, reflecting the consensus of the Agency, the utilities, and Commission Staff, was published in January 2019, just prior to the opening of the Adjustable Block Program for project applications. The standard REC delivery contract, once finalized, was not subject to further negotiation for each project or batch accepted into the Program.

For this Revised Plan, the Agency proposes a substantial refresh of the standard delivery contract based upon lessons learned from the execution and early administration of the initial contracts. The January 2019 standard contract has proved to be complex and in cases inflexible in ways that may not benefit the Program.

The Agency plans to conduct stakeholder workshops in early 2020 to review the contract structure for the Adjustable Block Program, the Illinois Solar for All Program, and competitive procurements (see Section 5.3.1).[395] Key issues to be considered include, but are not limited to:

- Shortening and simplifying the REC Contract (and, if possible, synthesizing the contract into a single set of terms and conditions)
- Clarifying contract default versus system default versus penalties
- Clarifying Product Orders, Master Contracts, and Portfolio-level responsibilities
- Termination for convenience (subject to applicable penalties)
- Measurement of community solar subscription levels
- Mechanism of collateral holdbacks[396]
- Incorporation of Acknowledgement of Assignment forms
- Removal of a project from the contract[397]
- Adoption of a measure providing for mediation by the IPA between utilities and Approved Vendors in certain REC Contract disputes[398]

Based on the workshops, the Agency will work with the Program Administrator, Procurement Administrator, ICC Staff, and the utilities to develop a draft of updated standard contract and will provide stakeholders opportunities to comment on the updated contract prior to its finalization. Approved Vendors may withdraw projects submitted to the Program prior to the date the updated contract is finalized that are not yet ICC-approved with no penalty.

Assuming that the contract structure will be altered as a result of the above-mentioned stakeholder workshops and subsequent feedback process, the Agency recommends that projects approved by the Commission after the contract finalization date would use the new contract, regardless of application date. The Adjustable Block Program will also provide an "off-ramp" option offered for any already applied projects that were expecting to be subject to the original contract and could now be non-financeable (or otherwise unable to be developed) under the updated contract.

Contracts or individual batches (but not individual projects that form a subset of a batch) will be assignable. The assignee must agree to, and abide by, the applicable terms and conditions required of an Approved Vendor (or a Single Project Approved Vendor in the case of the assignment of a single project from a contract). Consistent with the Commission's Order in Docket No. 17-0838, the assignor and the assignee will be required to notify the contracting utility of any assignment, and provide the utility with all pertinent financial, settlement and contact information.[399] The assignor may be required to pay a fee to the contracting utility. The Agency and its Program Administrator will endeavor to cooperate with the assignor, assignee, and utility in generating required documents and updating Program records to accommodate the assignment.

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[395] This process began on April 9, 2020 with the release of a request for stakeholder feedback. See: https://www2.illinois.gov/sites/ipa/Documents/ABP%20REC%20Contract%20Update%202020/IL%20ABP%20REC%20Contract%20Request%20for%20Comments%209%20APR%202020.pdf.

[396] This topic is discussed further in Section 6.14.6.

[397] These topics are based on feedback provided by the Parties on July 22, 2019 to the Agency's Request for Comments issued after workshops held on June 20 and June 26, 2019.

[398] See Docket No. 19-0995, Final Order dated February 18, 2020 at 49.

[399] See Docket No. 17-0838, Final Order dated April 3, 2018 at 74.

6.8. Adjustments to Blocks and Prices

The Act contains two provisions that allow the Agency to review and adjust block quantities, sizes, and prices. The provisions are contained in Section 1-75(c)(1)(K):

> *"The Agency may periodically review its prior decisions establishing the number of blocks, the amount of generation capacity in each block, and the purchase price for each block, and may propose, on an expedited basis, changes to these previously set values, including but not limited to redistributing these amounts and the available funds as necessary and appropriate, subject to Commission approval as part of the periodic plan revision process described in Section 16-111.5 of the Public Utilities Act."*

And in Section 1-75(c)(1)(M):

> *"If necessary, the Agency may make prospective administrative adjustments to the Adjustable Block program design, such as redistributing available funds or making adjustments to purchase prices as necessary to achieve the goals of this subsection (c). Program modifications to any price, capacity block, or other program element that do not deviate from the Commission's approved value by more than 25% shall take effect immediately and are not subject to Commission review and approval. Program modifications to any price, capacity block, or other program element that deviate more than 25% from the Commission's approved value must be approved by the Commission as a long-term plan amendment under Section 16-111.5 of the Public Utilities Act. The Agency shall consider stakeholder feedback when making adjustments to the Adjustable Block design and shall notify stakeholders in advance of any planned changes."*

In essence, changes of less than 25% to the prices and other program components indicated in the Agency's Commission-approved REC prices can be made by the Agency without seeking review and approval from the Commission, while larger changes will require that review and approval as part of the Agency's regular annual procurement planning process.

The Agency is aware of at least four key events that could significantly impact solar project costs and potentially warrant a new look at REC pricing. First, upon a utility reaching its net metering cap (see Section 6.8.1 for more discussion), net metering for new enrollments by distributed generation systems will change from full retail net metering to energy-only net metering. Second, upon the net metering cap being met, the distributed generation rebate for smart inverters will change from $250/kW DC (for non-residential customers and community renewable participants) to a rebate based upon the locational value of the system to the grid, while a new distributed generation rebate will be created for residential customers. Third, the Federal Solar Investment Tax Credit is presently scheduled to step down from 30% to 26% for projects that start construction in 2020, and then to 22% in 2021; it is scheduled to be eliminated for residential projects after that time and be reduced to 10% for other projects. And fourth, U.S. President Donald Trump exercised his power under the federal Trade Act to impose import tariffs on crystalline solar photovoltaic panels and modules in January 2018, following an unfair trade practices proceeding at the United States International Trade Commission ("ITC"); these import tariffs are scheduled to step down in February 2020 and again in February 2021 before ending in February 2022.[400] While the IPA's REC Pricing Model has

[400] United States International Trade Commission, Investigation No. TA-201-75, Crystalline Silicon Photovoltaic Cells, https://www.usitc.gov/investigations/title_7/2017/crystalline_silicon_photovoltaic_cells_whether_or/safeguard.htm.

incorporated the projected market effect of those import restrictions,[401] there could be further changes to federal trade policy in this area.

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

In addition to these factors, and in keeping with the adjustable nature of the Adjustable Block Program, the Agency recognizes that despite its best efforts to set REC (and adder) prices at "just right" levels, it is possible that factors that impact prices may need to be updated to reflect changing market dynamics. In response to very low or very high demand for the program, the Agency may adjust REC and adder prices, block sizes, and other variables as needed to maintain a vigorous and healthy market for distributed solar and to reach programmatic goals. The Agency will monitor program activity and consider such change if it determines they are warranted.[402]

In this Revised Plan, the Agency did not propose any REC price adjustments to the REC prices shown in Table 6-2, or to the 4% rate of change between blocks going forward. While the uptake of the Small DG category has been slow to date, there is anecdotal evidence[403] that it is increasing rapidly and that DG prices are generally in line with market expectations. When the Agency becomes aware of a situation that would require a change to block quantities, size, price, or other factors, including, but not limited to, the situations described herein, the Agency will post an announcement to its website regarding the proposed changes and will hold either a stakeholder meeting, or an online webinar to provide an opportunity for stakeholder input, and will proceed mindful of the need for incorporating market feedback into REC prices as outlined by the Commission in its Final Order in Docket No. 19-0995.[404] Stakeholders will also be invited to submit written comments on the proposed material changes which will be posted to the Agency's website. The Agency will consider feedback it receives prior to finalizing changes it makes that are less than 25% and do not require Commission review and approval, and will likewise consider that feedback in filings made before the Commission to update the Adjustable Block Program.

6.8.1. Net Metering Cap Adjustment

Under Section 16-107.5(j) of the PUA, net energy metering is generally credited at a value that accounts for the value of energy and delivery until net metering accounts for 5% of the total peak demand of each electricity provider's eligible customers. At that time, net metering for any new installations will be for energy only.[405]

When the net metering caps are met, the Agency will review the performance of the program and make price and policy adjustments needed to achieve compliance with RPS goals. As noted above, the Agency will be able to make adjustments to offset the impact of the changes in net metering revenue if those changes would result in less than a 25% change in the price of RECs. If the necessary

[401] See Docket No. 17-0838, IPA REC Pricing Model Update of February 27, 2018, at 1-2.

[402] The Agency is surveying project developers at the Part II application stage for the actual cost of various system development and installation components.

[403] See e.g., "More ComEd Customers Going Solar." Retrieved from https://finance.yahoo.com/news/more-comed-customers-going-solar-155500794.html, July 18, 2019.

[404] See Docket No. 19-0995, Final Order dated February 18, 2020 at 46-47.

[405] 220 ILCS 5/16-107.5(j), (n).

change in price is greater than 25%, then the Agency will seek Commission review and approval of a revised schedule of REC prices as outlined in Sections 1-75(c)(1)(K) and (M) of the Act.

In a data request response dated June 2019, ComEd advised the Agency that it expects to reach the 3% net metering enrollment level referenced in Section 16-107.6(e) of the PUA (discussed in Section 6.8.2 below) during the 2020-2021 delivery year, although it did not indicate an expected timeline for reaching the 5% level referenced in Section 16-107.5(j).[406] Ameren Illinois declined to estimate the timeline for either the 3% or 5% thresholds, citing a lack of data; however, on April 2, 2020, as this Final Revised Plan was being prepared for filing with the Commission, Ameren Illinois informed the Commission that its total generating capacity for net metering customers has reached 3%, and it anticipates the total will likely exceed 5% by the end of 2020. MidAmerican estimated that the 5% level would be met in 2027.

6.8.2. Smart Inverter Rebate

Under Section 16-107.6(e) of the PUA, when a utility's net metering customers reach total generating capacity equaling 3% of the utility's total peak demand supplied during the previous year, the Commission will initiate an investigation to adjust the smart inverter rebate from $250/kW DC (for non-residential customers and community renewable participants) to a new value or values (potentially varying based on location), and to establish a smart inverter rebate value or values (again, potentially locationally-based) for residential customers. Once the resulting rebate values are approved by the Commission, they will take effect when the load of net metering customers for that utility reaches 5% of the total peak demand supplied by the utility during the previous year.

As discussed above in Section 6.8.1, it is currently not clear when the 5% level will be reached or whether changes to the inverter rebate will have been approved by the Commission at that time. Therefore, the Agency is not presently proposing a specific REC price adder to adjust for the change to the inverter rebate (which could also be an increase in the rebate level for some projects, thus not requiring any new adders). The Agency will participate in each utility's investigation proceeding and will consider proposing price adjustments to DG REC prices, if needed, as those investigations proceed. The adoption of any new REC prices will either follow the process outlined in Section 6.8 or be proposed as part of a Plan update.

6.8.3. Federal Solar Investment Tax Credit Adjustment

The U.S. Congress has set a schedule for a decline and partial phase out of federal tax credits for solar photovoltaics.[407] Projects that start construction in 2017, 2018, and 2019 will receive a 30% Investment Tax Credit; projects that start construction in 2020 and 2021 will receive 26% and 22%, respectively; for construction starts after that, the credit will drop permanently to 10% for commercial projects and 0% for residential projects.[408] After 2015 legislation, project owners who start construction before 2022 may claim the applicable credit once construction begins, as long as the project is operational by the end of 2023.

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[406] In fact, ComEd indicated that the timeline for reaching the 5% level would depend on the Agency's allocation of Adjustable Block Program blocks beyond those authorized in the Initial Plan.

[407] Consolidated Appropriations Act of 2016, Public Law 114-113, December 18, 2015, at § 303 (modifying 26 U.S.C. § 48(a)); see also https://energy.gov/savings/business-energy-investment-tax-credit-itc, https://www.seia.org/research-resources/impacts-solar-investment-tax-credit-extension.

[408] 26 U.S.C. §§ 48(a)(2)(A), (a)(3)(A)(i), (a)(6)(A).

Additionally, federal tax legislation[409] passed by the United States Congress and signed by the President in December 2017 introduced a provision called the Base Erosion and Anti-Abuse Tax.[410] As discussed in more detail in Section 6.8.3 of the Initial Plan, this provision is widely thought to diminish the value of the Investment Tax Credit for solar generation for many "tax equity" investors, which are often parts of large multinationals.

The phase-out of the federal Investment Tax Credit, and any possible legislative change to that schedule, will affect project economics for distributed solar in Illinois. Like other anticipated changes, the Agency will review the performance of the Program and make price and policy adjustments needed to achieve compliance with RPS goals. For example, the Agency could adjust prices to reflect the change in the federal Investment Tax Credit from 30% to 26%. This adjustment will probably not be larger than 25% and thus would not require Commission review and approval. The Agency notes that advocates are presently making efforts to extend the federal Investment Tax Credit.[411]

6.8.4. Tariffs on Foreign Photovoltaic Modules and Cells

As discussed extensively in Section 6.8.4 of the Initial Plan, U.S. President Donald Trump issued a Proclamation on January 23, 2018 imposing certain import restrictions, pursuant to his authority under Section 203(a) of the Trade Act, 19 U.S.C. § 2253(a), following a petition brought at the U.S. ITC by certain American solar component manufacturers alleging that imports were entering the United States in such increased quantities as to be a substantial cause of serious injury, or the threat thereof, to the domestic industry.[412] The tariffs are set to last for 4 years, starting February 7, 2018. For solar cells, following the first 2,500 MW of imports in any year, the duty rate will be 30% in the first year, then 25% in the second year, then 20%, then 15%. For solar modules, the same annual duty rates apply, without any exemption.

Accordingly, the Agency included a modification to the REC Pricing Model related to the projected market effect of these new import restrictions in its February 27, 2018 REC Pricing Model Update.[413] The Commission approved that aspect, *inter alia*, of the February 27, 2018 REC Pricing Model Update.[414] The Agency filed its "final" REC prices (i.e., the "Commission's approved values" for purposes of any Section 1-75(c)(1)(M) adjustments) as a compliance filing with the Illinois Commerce Commission on June 4, 2018, reflecting these and other adjustments.

However, these tariffs have been challenged or may be limited in certain ways. Pursuant to the President's January 23, 2018 Proclamation, the United States Trade Representative accepted requests for exclusions of particular products during March and April of 2018;[415] one result of that

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[409] See Pub. Law 115-97 (Dec. 22, 2017), https://www.congress.gov/115/bills/hr1/BILLS-115hr1enr.pdf.

[410] Id. at § 14401 (adding new 26 U.S.C. § 59A).

[411] See e.g., "5-year ITC extension introduced in U.S. House, Senate." PV Magazine. Accessed from https://pv-magazine-usa.com/2019/07/25/breaking-5-year-itc-extension-introduced-in-u-s-house-senate/(July 25, 2019).

[412] See https://ustr.gov/about-us/policy-offices/press-office/press-releases/2018/january/president-trump-approves-relief-us (January 22, 2018); https://www.whitehouse.gov/presidential-actions/presidential-proclamation-facilitate-positive-adjustment-competition-imports-certain-crystalline-silicon-photovoltaic-cells (January 23, 2018); https://www.gpo.gov/fdsys/pkg/FR-2018-01-25/pdf/2018-01592.pdf (January 25, 2018).

[413] Docket No. 17-0838, IPA REC Pricing Model Update, February 27, 2018, at 2.

[414] Order, Docket No. 17-0838, April 3, 2018, at 74.

[415] https://www.regulations.gov/document?D=USTR-2018-0001-0001; https://www.regulations.gov/docketBrowser?rpp=25&so=DESC&sb=commentDueDate&po=0&dct=PS&D=USTR-2018-0001.

process was an exclusion for bifacial solar panels, announced by the Office of the U.S. Trade Representative in June 2019.[416] The bifacial panel exclusion was then *reversed* in a decision by the Office of the U.S. Trade Representative in October 2019,[417] with that decision then blocked by the U.S. Court of International Trade in December 2019,[418] and withdrawn by the U.S. Trade Representative in April 2020.[419] The Agency will continue to monitor these developments and, if any significant changes to solar component import restrictions occur, consider making commensurate changes to the final REC Pricing Model pursuant to its authority under Section 1-75(c)(1)(M) of the IPA Act.

6.9. Approved Vendors

Participation in the Adjustable Block Program takes place through, and is conditional upon, the Approved Vendor process developed by the Agency and implemented by the Program Administrator. The Approved Vendor model was originally based upon the experiences the Agency gained through the development and implementation of the Supplemental Photovoltaic Procurement, as well as observations of programs in other states. While arguably there could be more flexibility available to consumers through a program under which any entity may receive a contract, by having Approved Vendors—i.e., ensuring that any entity receiving a REC delivery contract is registered with and vetted by the Agency, and has met conditions predicate—the Agency is better able to monitor compliance with program terms and conditions, ensure the accuracy and quality of information submitted, and reduce the administrative burden on the contractual counterparties.

This model thus benefits consumers because they will be able to verify that an entity that proposes to develop a photovoltaic system for them (or sell them a subscription to a community solar project) is a legitimate entity participating in the Program. It is important for the Agency to have the ability to monitor the program and ensure high quality performance by the Approved Vendors; an Approved Vendor that fails to live up to the requirements of the Adjustable Block Program could have a significant negative impact on the entire renewable energy market in Illinois that would extend beyond just its own actions. Additionally, as discussed in more detail in Chapter 8, registration as an Adjustable Block Program Approved Vendor is a prerequisite to becoming an Illinois Solar for All Approved Vendor, and the loss or suspension of Approved Vendor status under the Adjustable Block Program would result in an Approved Vendor's status under the Illinois Solar for All Program to also being terminated or suspended.

The Agency does not restrict Approved Vendor participation by entity type; as such, Approved Vendors could include a company that specializes in the aggregation and management of RECs; a for-profit developer or installer of photovoltaic systems; a municipality; or a non-profit serving a specific sector of the community, among others.

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[416] See 84 FR 27684, June 13, 2019, https://www.federalregister.gov/documents/2019/06/13/2019-12476/exclusion-of-particular-products-from-the-solar-products-safeguard-measure; see also 83 FR 47393, September 19, 2018, https://www.federalregister.gov/documents/2018/09/19/2018-20342/exclusion-of-particular-products-from-the-solar-products-safeguard-measure.

[417] See https://ustr.gov/sites/default/files/enforcement/201Investigations/Withdrawal_of_Bifacial_Solar_Panels_Exclusion_to_the_Solar_Products_Safeguard_Measure.pdf.

[418] See https://www.cit.uscourts.gov/sites/cit/files/19-153.pdf

[419] See https://www.federalregister.gov/documents/2020/04/17/2020-08189/determination-on-the-exclusion-of-bifacial-solar-panels-from-the-safeguard-measure-on-solar-products.

Approved Vendors serve as the contractual counterparty with the utility, and thus are the entity that receives payments from the utility for REC deliveries as contract obligations are met.[420] Approved Vendors are therefore responsible for submitting necessary paperwork (project applications, status updates, quarterly and annual reports) to the Program Administrator (as the responsible party for the information contained in that paperwork), maintaining collateral requirements (and paying any contractual clawback not covered by posted collateral), and providing ongoing information and reporting. As such, the Approved Vendors must coordinate downstream information from installers/developers as well as individual system owners (who may well provide required information through the installer/developer).

The Agency does not require a specific delegation of duties between the Approved Vendor, sales generating firms, installer/developer, and system owner; rather, it believes that the market is better suited to allow a variety of business arrangements to develop. The key consideration is that the Approved Vendor is ultimately responsible for the fulfillment of contractual obligations, including any obligations delegated to subcontractors, in a manner consistent with the requirements of this Revised Plan and of the Approved Vendor's contract with the counterparty utility. As discussed in Section 6.9.1, the Agency proposes now requiring that designees be registered with the program. While this does not change the responsibilities of the Approved Vendor, or the potential for an Approved Vendor to be held accountable for the conduct of its designee, the Agency believes that this step will provide additional information and transparency to consumers and to the marketplace generally.

Approved Vendors must agree to the following terms:

- Participate in registration and complete any training developed by the Agency
- Abide by these ongoing Program terms and conditions
- Provide information to the Agency on the Approved Vendor's organizational history, capacity, financial information, regulatory status in Illinois and other states (including current complaints or other actions against the Vendor or prior complaints within the past five years), etc.
- Be registered to do business in Illinois
- Disclose to the Agency names and other information on installers and projects, while otherwise maintaining confidentiality of information
- Document that all installers and other subcontractors comply with applicable local, state, and federal laws and regulations, including for example, maintaining Distributed Generation Installer Certification
- Provide samples of any marketing materials or content used by the Approved Vendor, and/or their subcontractors/installers, designees, agents, and affiliates, to the Agency for review, as requested.[421]
- Agree to make changes to marketing materials as instructed by the Agency.[422]

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[420][420] The Agency imposes no requirement as to how the Approved Vendor shall share the REC payments with the installer, host, and other project parties.

[421] This requirement applies to, at minimum, printed materials, advertising through television and radio, websites (including affiliate websites), web ads, marketing via email or social media, telemarketing scripts, and leads purchased through lead-generation vendors.

[422] This requirement is not meant to impede the ability to market to customers, but rather to ensure that any types of marketing are not deceptive, confusing, or misleading. Likewise, the Agency is concerned about misrepresentations that could be made about the relationship between an Approved Vendor (or the subcontractors/installers) and the Agency or program.

- Register and maintain such registration in GATS or M-RETS and demonstrate the ability to manage project application and REC management functions in the applicable tracking system
- Pay applicable application fees
- Comply with all terms of contracts with utilities under the Program
- Submit Annual Reports on a timely basis

Approved Vendors must renew their approval once a year. Failure by an Approved Vendor to follow the requirements of the Adjustable Block Program, as determined by the Agency and/or its Program Administrator, could result in the entity having the suspension of or losing its status as an Approved Vendor and thus losing the ability to bring new projects into the Programs. Losing that status would not relieve an Approved Vendor of its obligations to ensure that RECs from its projects that have been energized continue to be delivered to the applicable utility; failure to meet those contractual obligations could result in having the vendor's credit collateral drawn upon. (See Section 6.16 for more discussion of contractual obligations.)

The Agency recognizes that there may be certain projects where the Approved Vendor model may not be completely appropriate, and therefore allows an Approved Vendor who has only one project to apply under a more limited set of requirements as a Single Project Approved Vendor. Specifically, this designation may apply to a project that is owned by that Single Project Approved Vendor (as opposed to a situation where the Approved Vendor is an intermediary between the system developer and/or owner and the contracting utility). In this situation, the following provisions related to Approved Vendors do not apply:

- Provide samples of any marketing materials or content used by the Approved Vendor, and/or their subcontractors/installers and affiliates, to the Agency for review, as requested.
- Agree to make changes to marketing materials as instructed by the Agency.

In addition, the consumer protection requirements found Section 6.13 would not apply to the Single Project Approved Vendor, but if the project is a community solar system, all applicable community solar consumer protection requirements related to subscribers would apply (including those concerning marketing materials referenced above).

Single Project Approved Vendors will need to request that status prior to submitting the system's Part I application, and the Program Administrator and Agency will review requests to ensure that this process is not used to avoid the more general requirements of this program through the establishment of nominally separate entities. The minimum size for a project submitted by a Single Project Approved Vendor is 100 kW.

The Agency also encourages the hiring of graduates of job training programs (as described in Section 8.10) to work on installations of projects supported by the Adjustable Block Program and the Program Administrator currently requests Approved Vendors to report on the planned usage of job training program graduates as part of the project application process, and will also include reporting on hiring as part of the annual reports submitted by each Approved Vendor. As more trainees become available, the Program Administrator will provide additional information to Approved Vendors to support this goal.

6.9.1. Approved Vendor Designees

Since launching the Adjustable Block Program, the Agency has become aware of instances of violation of program guidelines by Approved Vendor designees that may have been committed without the knowledge or control of the underlying Approved Vendor. For this Revised Plan, the Agency proposes to create a new requirement for Approved Vendor designees. This requirement is that designees must register with the program and be listed on the program websites (both www.illinoisabp.com and www.illinoisshines.com) along with the Approved Vendor(s) with whom they are working. Registration will also require the assent of the Approved Vendor(s), and can be withdrawn by an Approved Vendor working with the designee at its discretion, or by the IPA or Program Administrator if the designee is found to have violated program guidelines and is suspended or has its registration terminated.

As used herein, by "designee," the Agency is referring to third-party (i.e., non-Approved Vendor) entities that have direct interaction with end-use customers. This includes installers, marketing firms, lead generators, and sales organizations. The Agency reserves the right to add additional categories as needed.

Registration shall encompass the designee's provision of contact information, acknowledgment of the business relationship with the Approved Vendor, and identification of the categories of the consumer-facing services provided. Additionally, a designee is responsible for acknowledging that they will comply with all Program requirements applicable to installers or marketing agents, as applicable. Failure by a designee to comply with applicable requirements could subject the designee to suspension or termination from registration. If the designee ignores a suspension (or termination) decision made by the Program Administrator and continues its market activity nonetheless, any Approved Vendor that works with the designee during that period will be subject to discipline. Likewise, Approved Vendors found to be working with entities engaged in the proscribed activities that fail to register will be subject to discipline. Pursuant to the Commission's Order in 19-0995, Approved Vendors and their designees shall have 45 days of lead time for compliance once these requirements are implemented.[423]

The purpose of this new requirement is to increase transparency for the program. Potential customers will be able to verify that a company that reaches out to them is actually a program participant registered with the Program (and likewise be able to review if they are listed on the complaint or disciplinary databases). While the Agency had anticipated that smaller installers would work with Approved Vendors that are aggregators, over the first nine months of the program it has become clear that sales and marketing of solar includes a variety of different types of organizations and that this variance can create market confusion.

Approved Vendors will be responsible for ensuring that their designees register with the program, and Approved Vendors who fail to do so may be subject to disciplinary actions. This includes designees of designees. For example, for an Approved Vendor who has an installer as a designee, and that installer hires a lead generation firm to assist in marketing, the Approved Vendor will be responsible for ensuring that the lead generation firm (in addition to the installer) registers with the program. One possible benefit to Approved Vendors through this system will be that they will know what downstream firms are working with their direct designees, and they may be able to better

[423] See Docket No. 19-0995, Final Order dated February 18, 2020 at 56.

monitor those firms' behavior (as the Approved Vendor will ultimately be responsible with conformance with program guidelines).

6.10. Program Administrator

Section 1-75(c)(1)(M) of the Act authorizes the Agency to "retain one or more experts or expert consulting firms to develop, administer, implement, operate, and evaluate the Adjustable Block program." The Agency issued a Request for Qualifications to start the process of selecting a Program Administrator for the Adjustable Block Program on January 18, 2018.[424] The Request for Qualifications was a means to select qualified bidders who were then invited to respond to a Request for Proposals.[425] Responses to the Request for Proposals were received on April 13, 2018.[426] The Program Administrator selection process is expressly exempted from the Illinois Procurement Code.[427]

After the evaluation of proposals received and consultation with the Staff of the Illinois Commerce Commission, the Agency selected InClime, Inc. ("InClime") to serve as the Program Administrator for the Adjustable Block Program. The Illinois Commerce Commission formally approved the execution of a contract between the IPA and InClime at its July 12, 2018 Regular Open Meeting.

The Program Administrator runs the day to day operations of the Adjustable Block Program. This includes, but is not limited to:

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

The Program Administrator is authorized to charge fees to Approved Vendors as described in Section 6.14.4 for processing applications. The Program Administrator operates under a contract with the Agency and may also be reimbursed directly by the utilities for a portion of the cost of the services

[424] The Request for Qualifications was posted to the Agency's website, www.illinois.gov/IPA.

[425] This process generally follows the process contained in Section 1-75(a)(1) to (5) that the Agency has used to select its Procurement Administrator and Procurement Planning Consultant.

[426] The Agency also issued a separate Request for Qualifications/Request for Proposals for a dedicated Program Administrator or Administrators for the Illinois Solar for All Program.

[427] 20 ILCS 3855/1-75(C)(1)(M).

provided to them including, but not limited to, the preparation of contracts and review of Annual Reports.

Program Administrator costs, other than those covered by fees collected directly by the Program Administrator from Approved Vendors, are considered part of the administrative costs discussed in Section 3.17. The Program Administrator may not be an Approved Vendor.

6.11. Program Launch

Starting in September 2018, the Program Administrator began releasing draft program documents for stakeholder review and comments and held workshops in October and November of 2018. Input from stakeholders received through both those workshops and written comments was used to inform the development of final program materials. Key documents developed include:

- Approved Vendor Registration Requirements (released October 30, 2018)[428]
- Lottery Procedures (released November 28, 2018)[429]
- Distributed Generation Brochure and Disclosure Forms (released December 27, 2018)[430]
- Program Guidebook (released December 31, 2018, with subsequent revisions released)[431]
- Standard REC Contract (released January 28, 2019)[432]
- Community Solar Disclosure Forms (released January 31, 2019)[433]
- Distributed Generation and Community Solar Marketing Guidelines (released January, 31, 2019)[434]
- Community Solar Brochure (released February 20, 2019)[435]

Approved Vendor registration opened on November 1, 2018 and the Adjustable Block Program officially started taking project applications on January 30, 2019. Since then, and as of April 10, 2020, Approved Vendors (the direct participants serving as counterparties to Illinois utilities under REC contracts, as discussed in Section 6.9) have submitted applications for 16,487 projects. Those applications have resulted in 602.3 MW of capacity allocated with 75.3 MW of project capacity still available in the Small DG category (blocks 2 and 3). The Community Solar and Large DG categories have waitlists.

Table 6-5 presents a snap-shot of select program statistics as of April 10, 2020.[436]

[428] See: http://illinoisabp.com/wp-content/uploads/2018/10/Final-Approved-Vendor-Requirements-10.30.18.pdf.

[429] See: http://illinoisabp.com/block-1-lottery.

[430] See: http://illinoisabp.com/marketing-guidelines-marketing-materials-stakeholder-process.

[431] See: http://illinoisabp.com/program-guidebook.

[432] See: http://illinoisabp.com/rec-contract.

[433] See: http://illinoisabp.com/marketing-guidelines-marketing-materials-stakeholder-process.

[434] Id.

[435] Id.

[436] For additional information on REC quantities procured and budgetary commitments, see Chapter 3.

Table 6-5: Adjustable Block Projects as of April 10, 2020

Project Type	Project Applications	MW
ICC Approved[437]		
Small DG	9,548	69.9
Large DG	2,065	274.3
Community Solar	110	212.3
Total	11,723	556.4
Applications Currently Being Reviewed/Processed[438]		
Small DG	2,919	21.3
Large DG		
Community Solar		
Waitlists[439]		
Large DG	132	7.0
Community Solar	798	1,561.7
Remaining Available Capacity[440]		
Small DG		75.3
Large DG		None
Community Solar		None
Overall Program Capacity[441]		
Small DG		166.5
Large DG		296.9
Community Solar		214.3
Total		677.6

6.12. Project Requirements

Projects that are eligible for the Adjustable Block Program will have to meet, at minimum, two sets of requirements. The first relates to the technical aspects of the system itself, and the second to the customer (and additionally to subscribers, in the case of community solar). The purpose of the first set of requirements is to ensure that high-quality systems are installed that will be capable of generating the expected quantity of RECs over the 15-year duration of the contracts. The purpose of the second set of requirements is to ensure consumer protections.

[437] This reflects projects that successfully applied to the Program and have been included in batches of projects approved by the ICC (see Section 6.14.6). It will be updated for the Revised Plan to be filed for Commission approval to reflect projects that have been removed from the program due to failure to execute contracts/product orders or to provide collateral.

[438] This reflects projects that have applied to the program and are still in various stages of eligibility review and thus have not yet been included in batches of projects submitted to the ICC for approval. It does not include projects that applied and were found to be ineligible or withdrawn by the Approved Vendor.

[439] See Section 6.3.3.1 for a discussion of the community solar waitlists.

[440] This reflects capacity available for project applications. While this capacity will decline as new project applications are received, it may also be adjusted upwards if projects that have applied are not found to be eligible, or if ICC approved projects are subsequently removed from the program.

[441] Overall program capacity slightly exceeds the planned 666 MW of capacity due to the policy of accepting the final project in a block. For example, if a block had 22 MW of capacity and up to the final project used up 21 MW and the final project was 2 MW in size, the final block size would be 23 MW. The Overall program capacity can also change when a project in a block is withdrawn and subsequently replaced with another one, or more projects, from the waitlist with slightly larger capacity.

6.12.1. Technical System Requirements

In this Section, the Agency outlines what technical information will have to be submitted for each project. These standards apply for both distributed generation and community solar projects. The application process is described in more detail in Section 6.14.

The technical system requirements are as follows:

- Information about the system location, and size, including but not limited to
  - A description of the technical specifications of the main system components including the make and model, manufacturer, number (quantity) of panels, of panels and inverters and meters, array location (roof or ground mount), tilt, orientation
  - Site map or other project details
- Proof of site control and/or host acknowledgement
- Project-specific estimate of REC production during the 15-year delivery term using PV Watts or a similar tool
- For systems over 25 kW, an Interconnection Agreement signed by both the interconnecting utility and the interconnecting customer[442]
- For ground mounted systems over 250 kW a land use permit, when applicable from the Authority Having Jurisdiction ("AHJ") over the project. In the event a land use permit is not applicable, written confirmation from the AHJ that no permit is required must be provided.
- For systems that include a battery, a detailed schematic showing that either only solar generated power can be used to charge the battery or that the battery's output does not run through the meter used to measure solar output.

In the Initial Plan the Agency required that, "[f]or systems over 25 kW, evidence of having obtained all non-ministerial permits that, according to the commercially reasonable investigation of the Approved Vendor, are necessary to the project at the time of application to the Adjustable Block program." While the Agency is no longer requiring this provision in the Revised Plan (other than as specified above for land use permits), failure to obtain permits is a developer risk and one which the Agency believes likely would not allow for the invoking of force majeure provisions applicable to failing to meet contractual obligations.

For systems that have been energized prior to application, the following information will also be required:

- GATS or M-RETS unit ID[443]
- Certificate of Completion of Interconnection
- Photographic documentation of the installation

The Agency recognizes that there may be special situations where some portion of these documents may not be available (for example, some rural electric cooperatives and municipal utilities may not

[442] While the Adjustable Block Program provides for separate categories for systems up to 10 kW, and greater than 10 kW and up to 2,000 kW, for the purposes of the requirements related to each project, the Agency has determined that 25 kW is an appropriate breakpoint between different levels for certain requirements. While most residential systems are below 10 kW, the Agency observed from its Supplemental Photovoltaic Procurements that there can be larger residential systems, particularly in rural areas. 25 kW is a common breakpoint used in programs in other states and is thus adopted by the Agency for these requirements.

[443] GATS or M-RETS registration must be complete and unit ID verifiable through GATS or M-RETS public reports.

have standardized interconnection documents). The Agency will be willing to consider alternative documentation to demonstrate completion of interconnection in those situations.

6.12.2. Metering Requirements

In developing metering standards for the Supplemental Photovoltaic Procurements that took place in 2015 and 2016, the Agency developed a metering standard[444] that included:

- Systems registered in M-RETS must utilize an ANSI C.12 certified revenue quality meter.
- Systems over 25 kW registered in GATS must utilize a new meter that meets ANSI C.12 standards.
- Systems over 10 kW and less than 25 kW in size registered with GATS must utilize a meter that meets ANSI C.12 standards. Meters that are refurbished (and certified by the meter supplier) are allowed.
- Systems of 10 kW in size and below registered with GATS must utilize either a meter that is accurate to +/- 5% (including refurbished and certified meters), or an inverter that is specified by the manufacturer to be accurate to +/-5%. The inverter must be UL-certified and must include either a digital or web-based output display.

The Agency did not allow production estimates. A production estimate consists of GATS automatically generating RECs for a system based on the system size and engineering modeling of expected kilowatt hour generation. Production estimates do not require the system owner (or aggregator) to provide ongoing data to GATS.

In responses to the Agency's Request for Comments, several commenters suggested allowing production estimates for smaller systems. While several states do allow production estimates for smaller systems, because production estimates do not require any actual data being transmitted to the tracking system to verify production, production estimates could be problematic as there would be no way to verify the system's ongoing operation. By contrast, a meter read (from either a meter, or an inverter output) only needs to be submitted once per year to GATS.

Given the upfront payments for RECs paired with the 15-year requirement for RECs to be delivered, the Agency believes that receiving actual data on system performance is essential to ensuring the integrity of the RPS, and having meter reads as infrequent as annually (although they could be as frequently as monthly) appropriately balances the need for accurate data and the compliance burdens on the system operators. Therefore, in the Initial Plan required metered output for the generation of RECs, although the use of inverter readings for systems up to 10 kW were continued to be allowed.[445] In other words, the metering standard developed for the Supplemental Photovoltaic Procurement was the metering standard for the Adjustable Block Program, with the caveat that meter reads were only required on an annual basis. The Agency understands that as of January 1, 2020, M-RETS will no longer require an ANSI C.12 certified revenue quality meter, so the standards previously applicable for projects registered in GATS will now also be applicable to projects registered in M-RETS.

[444] See: https://www.illinois.gov/sites/ipa/Documents/IPA-metering-accuracy-standard-5-14-15.pdf.

[445] The Agency notes that while using an inverter rather than a meter may save on installation costs, if the inverter were to suffer a system failure and lose data, no RECs could be created. A meter may be a more reliable way to ensure REC creation.

Additionally, in Docket No. 17-0838, questions were raised regarding the applicability of these metering standards to DC-based technologies. In its Order approving the Plan, the Commission sought for the IPA to "ensure that its Plan does not inadvertently prohibit participation from systems that do not convert the DC electricity produced to AC electricity," with any resulting resolution to be presented to the Commission "before or in the 2019 Plan update." The IPA thus endeavored to work with stakeholders on solutions for facilitating permissible participation in the Adjustable Block Program from DC-based systems.[446]

During the more than twelve months since that Order, the Agency has communicated regularly and deliberately with industry stakeholders who are seeking to coordinate and obtain ANSI approval of a new DC metering standard. However, the Agency understands that this standard has not been finalized as of October 2019.[447] The Agency also received no comments on the topic of DC metering in response to its public request for comments dated July 3, 2019 regarding the revisions to this Plan. Thus, the Agency believes it would be premature at this time to incorporate a DC metering standard into the Adjustable Block Program (or, by implication, the Illinois Solar for All Program), but will continue its dialogue with industry professionals to understand the development of DC metering. The Agency intends to revisit this issue in the next Plan update in 2021.

6.13. Customer Information Requirements/Consumer Protections

In addition to the information about the technical system information described in Section 6.12.1, for distributed generation projects Approved Vendors are required to submit information to the Agency regarding the customer hosting the system and ensure that certain standardized information about the program was provided to that customer.

The purpose of requiring this information is to ensure consumer protections. Installing a photovoltaic system is a significant financial commitment on behalf of that system's host (and potential owner) and a system that has been sold (or leased) to a customer using incorrect, inaccurate, or deceptive information could put the financial security of Illinois residents or businesses at risk and poison the ongoing viability of the solar market in Illinois. In addition, a project that successfully applies to this program stands to receive a financial benefit from the program in the form of a REC delivery contract and by extension from the ratepayers who fund it. Requiring clear and consistent information on the relationship between the end customer, the installer/developer, and the Approved Vendor is critical to ensuring that the fiscal risks and controls of this Program are properly and prudently managed.

These requirements are Program terms and conditions for participation in a state-administered incentive program that provides the opportunity for additional project revenue through REC delivery contracts. In developing these requirements, the Agency recognizes that it is not a regulatory agency and does not have jurisdiction over all distributed generation installations or community solar projects across the state. It can, however, create common sense provisions to ensure that entities developing projects seeking to participate in this program are held to high standards for consumer protection, and enforce those provisions through suspending non-compliant entities from further participation in this state-administered incentive Program. Ultimately, the Adjustable Block Program is a ratepayer funded program intended to benefit the state's residents through enhanced ability to

[446] Order, Docket No. 17-0838, April 3, 2018, at 78-79.

[447] The Agency understands from industry representatives that a draft standard has been developed for consideration by the relevant ANSI committee.

participate in the clean energy economy, and in the Agency's view, it is essential to ensure that this Program produces not only project development, but also a transparent, positive experience for system hosts and subscribers.

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

- **Contracts:** A copy of the contract for the lease, sale, or financing arrangement of the distributed generation installation. A list of required contract terms (and, in limited cases, specific contract requirements) has been developed by the Agency in conjunction with its Program Administrator, and has been provided to Approved Vendors.[448] At a minimum, Approved Vendors may also use model leases and model financing instruments provided by the Solar Energy Industries Association ("SEIA"),[449] or other contracts that meet requirements provided by the Agency. While the Agency will not require that a specific contract form be utilized or require the submittal and approval of all contracts, it retains the right to request copies of contracts from Approved Vendors and develop new requirements for contracts, as well as to advise Approved Vendors that contract terms must be altered as a requirement of continued program participation should the Agency discover unreasonable contract terms.
- **Disclosure Form:** The Agency, in conjunction with its Program Administrator, has developed standard Disclosure Forms to be completed and provided to each program participant prior to contract execution.[450] For distributed generation projects, the form includes standard information on the system equipment and components, warranty, installer, and lease or financing structure. The form includes a standardized estimate of the price and performance of the system as installed, including anticipated first year production, expected annual system production decreases, expected overall percentage degradation over the life of the system, a standard forecast for retail electricity prices, a net cash flow analysis, and an internal rate of return of each project. The form also includes a disclosure that cash flows may change if the utility's net metering tariffs or distributed generation rebates change prior to the completion of the system (e.g., the changes that occur when net metering enrollment reaches 5%). The Agency provides standard electricity prices (and other inputs) to be used for these estimates as to allow equivalent comparisons between different offers. For community solar subscribers, the form includes similar applicable provisions as well as conform to the provisions listed in Section 7.6.2.[451] In its Order approving this Revised Plan, the Commission provided analysis reinforcing the requirement that every individual subscriber to a

[448] See http://illinoisabp.com/wp-content/uploads/2019/01/dg-contract-requirements-2019_01_23.pdf.

[449] Solar Energy Industries Association, "Model Leases and PPAs," https://www.seia.org/research-resources/model-leases-and-ppas.

[450] See http://illinoisabp.com/marketing-guidelines-marketing-materials-stakeholder-process.

[451] In the responses to the Request for Comments that the Agency issued in June, 2017, several commenters suggested that the Agency consider adopting the standard disclosure forms developed by the SEIA earlier in 2017 (see: https://www.seia.org/research-resources/solar-transaction-disclosures). While there may be aspects of those forms that are worth considering, the Agency is concerned that they do not fully capture the information the Agency believes that potential program participants need to have, in particular, standardized comparisons of energy costs. Therefore, the Agency instead developed its own disclosure forms that capture aspects of the SEIA disclosure forms, best practices from other states, as well as addressing the need to standardize energy cost comparisons.

For a general discussion of challenges related to the marketing of solar and consumer protection policies, see Barbara R. Alexander and Janee Briesemeister, "Solar Power on the Roof and in the Neighborhood: Recommendations for Consumer Protection Policies," March 2016 (http://utilityproject.org/wp-content/uploads/2016/03/Solar-Power-Consumer-Protection-Report-March-2016.pdf), in particular, Appendix B.

community solar project participating in the Adjustable Block Program or ILSFA must receive and execute an individualized standard disclosure form.[452]

- **Brochure:** The Agency requires Approved Vendors to distribute a brochure to program participants prior to the execution of the contract with the program participant. This consumer protection brochure is available in either print or electronic form, and has been prepared by the Program Administrator and approved by the Agency.[453] The brochure informs consumers of their rights, procedures for filing complaints, and point to more information on the Program website. The Agency has prepared the brochure in English and Spanish and will consider creating versions in other languages should sufficient demand exist.

Rather than including these materials with this draft Revised Plan for filing with the Commission (and thus seeking Commission approval of the specific forms), the Agency sought to seek authority from the Commission for the ability to later develop (or modify) its program-related forms and documents, while reserving the ability to draft actual program-related forms and guidelines independent of that approval proceeding.

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

Additionally, the IPA has developed both its Initial Plan and this Revised Plan mindful of the state's experience with the retail energy supply market and the marketing and sale of energy-related products. As such, it seeks to tap into the experience and institutional knowledge reflected in the state's conditions applicable to alternative retail electric suppliers. While the Agency recognizes that Approved Vendors will not necessarily be Alternative Retail Electric Suppliers, and thus as Approved Vendors are not governed as a matter of law by the Commission's Rules applicable to ARES, it believes that the Commission's Title 83, Part 412 rules provide a workable blueprint for expectations of Approved Vendors. Thus, as a condition of ongoing approval, for distributed generation systems or community solar subscription shares below 25 kW in size,[454] Approved Vendors are and have been expected to comply with marketing standards generally equivalent to the following sections of Commission-approved rules for marketing practices by alternative retail electric suppliers. (83 Ill. Adm. Code Part 412, Subpart B):

- 412.105(a)-(c)
- 412.110 (a)-(i)
- 412.120
- 412.130
- 412.140 (a)-(b), (d)
- 412.150

[452] See Docket No. 19-0995, Final Order dated February 18, 2020 at 7. In the event that the Commission or another authoritative adjudicatory body determines that an opt-out municipal aggregation may legally include community solar subscription aggregation for a project participating in the Adjustable Block Program or ILSFA, individually executed standard disclosure forms are still required for each individual subscriber.

[453] See http://illinoisabp.com/marketing-guidelines-marketing-materials-stakeholder-process.

[454] In its filed version of the Initial Plan, the Agency originally proposed that these requirements apply to systems below 100 kW in size. However, in its Order approving the Initial Plan, the Commission adopted a proposal of the Joint Solar Parties that compliance with standards equivalent to the Part 412 rules be limited only to systems or subscriptions below 25 kW in size. See Docket No. 17-0838, Final Order dated April 3, 2018 at 108.

- 412.160 (a)-(b), (d)
- 412.170
- 412. 180
- 412.210 (applicable only to community solar)
- 412.240 (applicable only to community solar)

The Agency is also aware that changes to requirements applicable to ARES have been made through Public Act 101-0590. The IPA will endeavor to update its marketing guidelines[455] and certain other program requirements in line with the new requirements applicable to alternative retail electric suppliers where applicable. As just one example, the revised marketing guidelines should likely require community solar subscription agreements to clearly disclose any terms of automatic contract renewal.[456] The Agency thus proposes that a new draft of its marketing guidelines (and other documents, where necessary) be published for stakeholder feedback within 45 days of the Commission's approval of this Revised Plan and finalized within 90 days of that approval date.[457]

The Part 412 section list above is not an exhaustive guide of all conditions that the Agency may place upon Approved Vendors, and key items referenced elsewhere in Part 412 (including disclosure forms, contract assignability, and green marketing) are addressed separately in this Revised Plan to the extent applicable to Approved Vendors.

Consistent with the Commission's Order in Docket No. 17-0838, the IPA "fully develop[ed] its procurement terms and conditions after the Commission's approval of the Plan and selection of the Program Administrator." To this end, the IPA and its Program Administrator held a series of stakeholder feedback sessions and solicited written stakeholder feedback before producing its Brochure, Disclosure Form, Contract Requirements, Guidelines for Marketing Material and Marketing Behavior, and Program Guidebook.

After deliberation, the Agency has decided not to seek Commission approval of these specific documents through approval of this Revised Plan. The Agency believes that the ability to adjust such documents, and the requirements embodied within them, based on market experience without further Commission approval outweighs the certainty associated with having an administrative order from a quasi-adjudicatory body affirming the specific contents contained therein. Instead, the Agency seeks that the Commission, through its Order approving the Revised Plan, instead affirm the following:

- The Agency maintains flexibility to adjust its program requirements, and the documents and forms through which they are expressed, without further Commission approval as warranted;
- Any significant adjustments to those requirements should be preceded by a process to receive stakeholder feedback;
- The principle that Approved Vendors may be held accountable for the conduct of their agents, subcontractors, or designees under the Agency's marketing guidelines and other program requirements is a reasonable requirement consistent with a) the Commission's

[455] See http://illinoisabp.com/marketing-guidelines-marketing-materials-stakeholder-process.

[456] For the analogue in Public Act 101-0590 (http://www.ilga.gov/legislation/publicacts/101/PDF/101-0590.pdf), see Section 10 of the Act at pages 86-89 (creating new Section 2EE(c)(7) of the Consumer Fraud and Deceptive Business Practices Act, 815 ILCS 505).

[457] This process of seeking stakeholder feedback has been initiated as of the publishing of this Final Revised Plan; see: http://illinoisabp.com/2020/04/03/request-for-comments-draft-marketing-guidelines-and-community-solar-disclosure-form/.

determination in Docket No. 17-0838 and b) the Agency's statutory authority to develop terms, conditions, and requirements applicable to the programs it implements.

6.13.1. Systems Energized Prior to Finalization of Consumer Protection Requirements

Additionally, as was also raised during the Docket No. 17-0838 proceeding, these consumer protection requirements are intended to apply to all Approved Vendors submitting projects into the Adjustable Block Program—but, as Section 1-75(c)(1)(K) of the Act envisions participation from "projects energized on or after June 1, 2017," some projects submitted into the Adjustable Block Program may have involved marketing, sales, disclosures, contracts, and other arrangements completed prior to the full development and finalization of the Initial Plan's consumer protection requirements.

By this time, the Agency assumes that all such systems have likely applied to the Adjustable Block Program. But it cannot be certain, and for such systems, the Commission's Order in Docket No. 17-0838 requires the following for consumer protection:

1. A signed contract amendment, that brings the contract or subscription agreement into full compliance with the minimum contract requirements from the Plan;
2. The disclosure form, signed by the customer post-contract execution; and
3. Proof that the brochure was provided to the customer.[458]

Failure to meet these requirements by the time the system is submitted to the IPA will result in rejection of the related system from the Adjustable Block program.

Approved Vendors can attest via a declaration form in the application process if their customers are not responsive to good faith attempts to contact or for customers that refuse to sign an amended contract or disclosure form. The Agency has also included guidance in consumer protection documents for the customer allowing that customer to contact the program administrator or the IPA for additional information, to ask questions, or to submit concerns or a complaint. The IPA and its Program Administrator retain the ability to exclude projects that in their determination represent deceptive marketing or bad faith business practices through complaints or other information brought to their attention (whether or not customers have signed contract amendments or disclosure forms), and will continue to "monitor, to the extent possible, potential Approved Vendors' conduct to ensure good-faith attempts of compliance with the spirit of pending consumer protection requirements."[459]

Consistent with the Commission's Order, this streamlined compliance path applies only to those projects energized between June 1, 2017 and before the IPA's consumer protections provisions were finalized on January 31, 2019.[460]

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[458] These requirements stem from the Joint Solar Parties' Response in Docket No. 17-0838, at p. 7, and were adopted by the Commission on p. 108 of its Order in Docket No. 17-0838 ("The Commission agrees with various parties that projects that have energized since June 1, 2017 should be eligible to participate in the Adjustable Block Program. The Commission finds that the proposal presented by the Joint Solar Parties in their Response (JSP Resp. at 7) as modified by the AG's Reply (AG Rep. at 2-3) provides an appropriately tailored pathway for the projects to participate.").

[459] See Docket No. 17-0838, AG Reply at 2-3; Docket No. 17-0838, Final Order dated April 3, 2018 at 107.

[460] Docket No. 17-0838, Final Order dated April 3, 2018 at 107.

6.13.2. Community Solar

For community solar projects, the Approved Vendor must submit the Technical System Requirements information and, if not a copy of the contract between the project developer and the Approved Vendor (if they are separate entities), basic information concerning the underlying project (owner, size, location and interconnection date at a minimum, to be provided as part of the Adjustable Block application forms).[461] The Agency reserves the right to request additional information about the project structure and financing in order to review project feasibility and contractual arrangements that could jeopardize consumer protections. There are additional program terms and conditions related to subscribers of community renewable generation projects (both community solar and those that use other technologies) that are discussed in Section 7.6.2.

Community solar projects are not required to demonstrate that they have acquired subscribers as part of their initial application. However, as described in Section 6.15.4, by the time that such systems are energized, minimum subscriber requirements must be met to be eligible for payment for RECs.

The Agency will use the subscriber mix to determine what adder, if any, will be given to the system, but the final adder (if any) used will depend on the subscription level demonstrated once the system is energized.

6.13.3. Monitoring of Consumer Complaints

The Program Administrator will provide consumer protection materials on a program website and through printed materials, and has developed its customer-facing IllinoisShines.com website and program branding in part to accomplish this end. It plans to continue to modify and improve that the IllinoisShines.com site, and the Agency received useful feedback during the stakeholder comment process preceding the Revised Plan's development as to what new content could prove most helpful.

The Program Administrator provides a toll-free consumer protection telephone hotline and web-based complaint forms, and the Program Administrator will receive, respond to, and document complaints about marketing practices, sales practices, installations, and other aspects of solar marketing.

If warranted, the Program Administrator will refer complaints to the Agency and to appropriate state and federal agencies, including the Consumer Protection Division of the Illinois Attorney General's Office, or the Illinois Commerce Commission (e.g., for failure of installers to maintain their status as Certified Distributed Generation Installers). To the extent feasible, the Agency will work with its Program Administrator to maintain a public database of complaints (with any confidential or particularly sensitive information redacted from public entries), as well as a database of any disciplinary determinations issued (including the written notices and explanations of discipline) due to a violation of Program requirements. The Agency has already begun a stakeholder comment process in September 2019 to refine what information on complaints should be published.[462] Approved Vendors found by the Agency to have violated consumer protection standards or related Program requirements may be subject to suspension or revocation of their Approved Vendor status by the Agency, and if in violation of local, state, or federal law, also potential civil or criminal penalties from other relevant authorities.

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[461] See id at 107-108.

[462] See http://illinoisabp.com/consumer-complaints.

The Agency will provide an annual written report to the Commission documenting the frequency and nature of complaints, and any enforcement actions taken. The first such report, covering calendar year 2019, was provided to the Commission through a filing in Docket No. 17-0838 on March 2, 2020.

6.13.4 Disciplinary Determinations

The Adjustable Block Program (and the Illinois Solar for All Program, for which the revised Plan's Consumer Protection requirements also apply) are ultimately state-administered incentive programs leveraging state- or utility-collected funds to provide additional incentives for photovoltaic project development. These programs do not constitute the solar project development market generally; an Approved Vendor, agent, or designee could simply choose to operate outside of the Agency's published marketing guidelines and consumer protection requirements should it choose not to avail itself of these additional incentive funding opportunities.

Consequently, the Agency views its disciplinary determinations as simply determining eligibility for state-administered incentives. No conduct is being restricted through the suspension or revocation of Approved Vendor status generally; all that is being restricted is the ability for an Approved Vendor to avail itself of additional incentive funding.

Nevertheless, the Agency appreciates that certain procedural safeguards should accompany its disciplinary determinations. Thus, through this revised Plan, the Agency proposes minimum procedural requirements applicable to such determinations. Specifically, mirroring and expanding on the process found in the Agency's Guidebook, the Agency proposes that Approved Vendors, designees, agents, or other third parties potentially subject to Program discipline for a violation of the Agency's Marketing Guidelines or Consumer Protection requirements generally be afforded the following:

- A 45-day lead time will be provided to Approved Vendors and designees in order to prepare for and implement general changes to consumer protection requirements. Unless otherwise specified, the lead time granted will not prohibit Approved Vendors and designees from taking earlier steps towards compliance. In situations where the IPA determines that emergency adoption of a new or modified consumer protection is necessary, no lead time will apply; however, the Agency commits to enforce any such requirements with an eye toward the practical challenges inherent in immediate implementation.[463]
- In the event that the Program Administrator identifies that it believes an Approved Vendor, designee, or other party is not acting, or has not acted, in compliance with Program requirements in connection with the Program, the Program Administrator will notify the Approved Vendor through an e-mail that:
    - Outlines the problematic behavior;
    - Explains how the behavior is non-compliant with program requirements; and
    - Requests more information about the issue.
- No disciplinary determination (such as the suspension or revocation of the ability to participate as or on behalf of an Approved Vendor) will be made by the Agency's Program Administrator without the allegedly offending party having the opportunity to offer a written or oral explanation of the problematic behavior for review and analysis by the Program Administrator;

[463] See Docket No. 19-0995, Final Order dated February 18, 2020 at 56, 62. For an example of emergency adoption of a consumer protection, see: http://illinoisabp.com/2020/03/20/ipa-covid-19-announcement/.

- All disciplinary determinations made by the Program Administrator will be communicated through a written explanation of the determination featuring at least the following:
  - A brief explanation of the infractions for which the Approved Vendor and/or Designee is being suspended;
  - A timeline of communications between the offending entity and the Program Administrator;
  - Specific reference to which specific Program requirement(s)/guideline(s) the offending entity violated;
  - An explanation of any suspension, including what specific conduct is no longer permitted in connection with the Program through the length of the suspension;
  - An explanation for how to appeal that disciplinary determination to the Agency and the deadline for submission applicable to any appeal.
- The IPA will endeavor to address any appeals of disciplinary determinations within two weeks of receiving an appeal (although the need to receive additional documents or information may lengthen that timeline).
- Any appeal determination made by the IPA will include, at minimum, a clear statement of the Agency's decision, the consequences of that decision, and a supporting explanation as to why that decision was made.

While the Agency understands that certain parties have offered comments seeking additional process and even more formalized requirements, the Agency believes additional process beyond the steps set forth above may not be warranted (and, if warranted, is best introduced through a broader update to the Agency's marketing guidelines).[464] Again, any party found in violation of the Program requirements is not barred from operating in the solar market in Illinois generally; it just may not participate in transactions benefitting from additional incentive payments provided through or by the Agency.

6.14. Application Process

The following section outlines the process and procedure that Approved Vendors will use to submit projects to the Program Administrator for review and approval, as well as how projects, once approved, will be placed into contracts with the utilities.

6.14.1. Batches

Under the Initial Plan Approved Vendors were required to submit projects bundled into batches. For this Revised Plan, the Agency proposes a simplification of the batch process. For a new Approved Vendor, there will still be the requirement for a submittal of a first batch of at least 100 kW of projects, and that 75% of the capacity of that batch must be verified to be approved. Approved Vendors will be allowed to select which batches approved systems are placed into, so that they can better manage their financing portfolios.[465] Once systems' Part I applications are verified, and before they are sent to the Commission for approval, an Approved Vendor will be consulted and given the opportunity to specify how its verified systems are batched, so long as those batches of verified systems are at least 100 kW in size.

[464] The Commission affirmed the adequacy of this process in approving the Plan. See Docket No. 19-0995, Final Order dated February 18, 2020 at 57, 62.

[465] See Docket No. 19-0995, Final Order dated February 18, 2020 at 75.

For established Approved Vendors that have had a contract approved by the Commission and do not desire to assemble batches into portfolios in this way, projects may be submitted on a rolling basis, and as projects are verified, the Program Administrator will place them into new batches that will result in a contract and/or new confirmations with one utility.

Utilities may use one master agreement with multiple confirmations (one confirmation per batch) from an Approved Vendor, rather than having multiple contracts with the same vendor.[466] The systems within the batch/confirmation will be listed on a schedule (or product order) attached to the contract and may not be substituted once approved.

A batch may contain projects in different groups/blocks (and thus with different prices) and with different adders. The price for the RECs for each system will be based on the price available within the applicable block on the date of the submittal. The failure of any system to be developed (and thus the forfeiture of any collateral associated with that specific system) will not impact any of the other systems on the same schedule, although the Agency will monitor system failure rates across Approved Vendors. Approved Vendors with high failure rates may be required to provide additional information to the Agency for subsequent applications.

The Program Administrator will determine which utility will serve as the counterparty for each contract. While a batch may contain projects in multiple utility service territories, the Program Administrator will strive to assign contracts to the utility where the bulk of the projects are located, but may not always be able to do so because the Program Administrator will also consider how assigning contracts to each utility will allow each utility to meet its pro-rata share of the RPS REC targets. The REC price for each system will be based on the applicable Group for that system's physical location, and not based on the identity of the counterparty utility to that contract.

After a batch of projects is determined by the Procurement Administrator, the number of RECs to be delivered annually and payment amount(s) for the batch will be provided to the utility by the Program Administrator for purposes of contract/confirmation preparation (i.e., the utilities will track the RECs by batch rather than by individual unit). Utilities will send a report of RECs delivered by batch semi-annually to the Program Administrator.[467]

6.14.2. Systems below 25 kW

In responses to the Request for Comments that the Agency issued in June 2017, several commenters recommended that systems under 25 kW only be submitted once they are completed and energized, to minimize administrative burdens and avoid project attrition. While the Agency is sympathetic to those ideas, this Revised Plan does not adopt that recommendation for several reasons. It may be difficult, or impossible, to have appropriate consumer protections if the Agency sees information about a system only after it is completed. Preventing problematic behavior (such as deceptive information about system costs and payback times) should be done prior to the homeowner or business paying for the system; that would not be the case if systems apply after being energized.

To be clear, there is nothing that would prevent an Approved Vendor from submitting a new system that has already been energized (for example, systems energized after June 1, 2017 but prior to the launch of the program), but the Approved Vendor will have to assume the risk that the system may

[466] See Docket No. 17-0838, Final Order dated April 3, 2018 at 109.

[467] See id.

not meet the required terms and conditions and could be rejected and thus not be included in a contract for the purchase of the system's RECs. A system that is rejected could be resubmitted at a later date if the deficiencies are cured, but the Agency cautions that some deficiencies may be difficult or impossible to cure (particularly when related to ensuring consumer protections from the beginning of the project's life).[468]

6.14.3. Application Fee

For each project, there will be a non-refundable application fee paid to the Program Administrator or the Agency of $10 per kW, not to exceed $5,000 per project. This fee will be used to offset the administrative costs of running the program and will decrease the administrative fees that would otherwise be taken from the utility RPS budgets.

6.14.4. Project Review

The Program Administrator will review the projects and, as needed, request additional information from the Approved Vendor in order to verify the submitted information and approve the project. An Approved Vendor will be given up to two weeks to cure deficiencies in an application. If deficiencies cannot be cured, the project application will be withdrawn. If the Approved Vendor can subsequently address the deficiencies, the Approved Vendor can resubmit the project (with a new application fee).

For an initial 100 kW batch, if, after any attempts to cure deficiencies have been made, projects representing at least 75% of the capacity of the batch are reviewed and approved by the Program Administrator, that batch will included in a contract presented to the Commission for approval. For established Approved Vendors, on a rolling basis in anticipation of the next scheduled Commission meeting, the Program Administrator will place verified projects for each Approved Vendor into batches for assignment to a counterparty utility, and prepare the confirmation information (and, in that case, master agreement information, if it is the Approved Vendor's first batch) or the contract information related to that batch.[469]

The Program Administrator will then submit the contract information for the batch to the Commission for approval. The Program Administrator will simultaneously forward the contract information to the applicable utility.[470]

An Approved Vendor that repeatedly submits deficient or noncompliant project applications may be subject to having its Approved Vendor status reviewed, and possibly suspended or terminated.

6.14.5. Converting System Size into REC Quantities

For each system that is approved, a 15-year REC payment amount and obligation level will be calculated for that system, and that payment amount will be included in the contract. Approved Vendors will have the option of using a PVWatts calculated capacity factor (stated relative to a system's nameplate capacity in AC rating) automatically computed by the application platform, or proposing an alternative capacity factor based upon an analysis conducted using an equivalent tool. Alternative capacity factors may be proposed as part of each system's application and will be subject to review and approval by the Program Administrator. Systems using bifacial panels must submit an

[468] See Section 6.13 above for further discussion of consumer protections applicable to systems energized after June 1, 2017 but before consumer protection requirements are finalized.

[469] See Docket No. 17-0838, Final Order dated April 3, 2018 at 115-116.

[470] See id.

alternative capacity factor subject to review and approval by the Program Administrator. All capacity factors submitted must be for a system's first year; as stated in Section 6.16.1 below, annual REC delivery commitments will incorporate a 0.5% per year degradation factor.

6.14.6. Batch Contract Approval

The Commission meets approximately every two weeks. The Program Administrator will strive to efficiently process approved projects and assign them to batches for submittal to the Commission. The Agency understands that Commission practice is that items for consideration by the Commission must be submitted to be placed on its open meeting agenda at least 8 business days prior to each meeting.

When the Program Administrator submits contract information to the Commission for approval, that submittal will include the Program Administrator's recommendation for approval of the batch, with a summary of factors relevant to Plan compliance. (Projects that are not approved by the Program Administrator are not submitted to the Commission.) This process is similar to that required for approval of contracts under annual electricity procurement plans pursuant to Section 16-111.5(f) of the PUA, or contracts under the Supplemental Photovoltaic Procurement Plan pursuant to Section 1-56(i)(5) of the Act.[471]

Pursuant to the Initial Plan, the Agency worked with Commission Staff to develop a Staff Report that includes the standards that the Commissions should use in considering the approval of contracts and product orders within the ABP and ILSFA.[472] The Commission approved the recommendations contained in the Staff Report on December 19, 2018. Once this Revised Plan is approved by the Commission, the Agency and Commission Staff will review and update that Staff Report if necessary.

Once a batch is approved by the Commission, the applicable utility will execute the REC contract and/or product order, as applicable. The Approved Vendor will then be required to sign the contract / product order within seven business days of receiving it from the utility.[473] Failure to sign the contract / product order may subject the Approved Vendor to discipline under the Program. Additionally, when a product order is not executed by the Approved Vendor within the seven business days after receipt, the constituent projects will be considered removed from the Program, with the option to re-apply later, subject to payment of a new application fee and available open block capacity (and subject to the applicant's Approved Vendor status not having been revoked due to the product order's non-execution). A collateral requirement to be held by the utility equal to 5% of the total contract value will be required in the form of either cash or a letter of credit with the utility within 30 business days of Commission approval of the contract.

For this Revised Plan, the Agency recommended and the Commission approved a clarification to the collateral withholding process to be reflected in the updated REC contract (as discussed in Section 6.7). In cases where collateral was posted through a letter of credit, the Approved Vendor may choose for the utility to withhold the collateral amount for each system from the last (or only, if a distributed

[471] See Docket No. 17-0838, Final Order dated April 3, 2018 at 115-116.

[472] See: https://www.icc.illinois.gov/downloads/public/edocket/490368.pdf.

[473] See id.

generation system of 10 kW or smaller in size) REC payment in exchange for a release/reduction of the letter of credit.[474]

In the Initial Plan, the Agency provided an option to allow an Approved Vendor to be able to forgo posting collateral for a system that was already energized and instead have that collateral withheld from the REC payment. The intent of that provision was to allow systems that had been developed prior to the program launch to have a simplified process, recognizing of those systems' absence of development risk. However, the Agency has observed that this process has had an unintended consequence of encouraging some Approved Vendors to submit projects only after their energization as a way of avoiding any collateral obligation. If the project does not apply until after it is built, enforcing and ensuring consumer protections (and other program requirements) becomes more challenging. Ultimately, consumers are better served if their project can be reviewed and approved by the program (and then submitted to the ICC for approval) prior to being built. For this reason, the Agency will require upfront collateral in all cases, including for energized systems.

Approved Vendors do not have the option to decline to post collateral within 30 business days once they have signed the contract. Failure to post collateral by the 30-business day deadline will violate the REC contract and may result in an Approved Vendor being suspended from further participation in the Program.

6.15. Project Development Timeline and Extensions

6.15.1. Development Time Allowed

Once a contract for a batch has been executed by the Approved Vendor and the utility, the next step is for projects not yet developed to be developed and energized. These timelines are based upon the contract execution date so that any delays in processing and approving an application will not reduce the time available for development.

- Distributed generation projects will be given one year to be developed and energized.
- Community solar projects will be given 18 months to be developed, energized, and demonstrate that they have sufficient subscribers.

A project that is not completed in the time allowed (plus any extensions granted) will be removed from the contract, and the REC volume associated with the project will be eliminated from the contract. The Approved Vendor will also forfeit the posted collateral associated with the project. Any forfeiture of collateral by the Approved Vendor under the REC contract will be considered to be returned to the utility's available Renewable Resources Budget. As described in Section 6.3.3, that newly open REC volume will become available to other projects, subject to budget availability.

A project that is not completed in time and is removed from the contract may be subsequently re-submitted by an Approved Vendor, but will be treated like any other new system being submitted.

[474] This provision would not apply to cash collateral for the following reason. If a project had a total REC value of $100, $5 of collateral would be due. To swap the 5% collateral for a withheld payment, $100 in total payments ($95 of REC payments plus a return of $5 collateral) would need to be made, leaving a balance held by the utility of $5, the same as before. On the other hand, if the collateral were a letter of credit, then a payment of $95 would eliminate the need for the Approved Vendor to maintain the letter of credit (or portion thereof) for the remaining life of the contract.

Since the development of the January 2019 REC delivery contract and the subsequent execution of that contract in connection with projects, one circumstance not adequately addressed through that contract may deserve Commission attention. In some instances, the developer of an Adjustable Block Program project may learn that development of the project is no longer feasible—whether due to financing falling through, the system host no longer wanting to move forward with the project, or myriad other circumstances. Presently, such a system could not be removed from the contract until contract requirements related to a Seller meeting the system's energization deadline were not timely met, a contract violation which may not occur until over one year from the point at time in which the Seller learns that development is no longer feasible. Thus, through this revised Plan, the Agency sought Commission permission to allow the Seller to provide notification to the Buyer, the Agency, and the Commission that it is exercising its option allowing for a system's removal from the contract because the Approved Vendor no longer wish to develop that system. Under these circumstances, the Seller would forfeit the posted Performance Assurance applicable to the system. Doing so would allow the contract parties (the utility Buyer and Approved Vendor Seller) to no longer maintain a contractual obligation when performance is no longer intended, while also providing clarity to the Agency and its Program Administrator about the availability of new Program capacity through removal of a project from a REC contract. This proposal was approved by the Commission; under the Commission's Order, the Agency will have responsibility for developing the specific forms and procedures to effectuate this option for Sellers.[475]

6.15.2. Extensions

Extensions will be granted for the following circumstances.

- An indefinite extension will be granted if a system is electrically complete (ready to start generation) but the utility has not approved the interconnection. The Approved Vendor must document that the interconnection approval request was made to the utility within 30 days of the system being electrically complete, yet not processed and approved.
- A 6-month extension will be granted for documented legal delays, including permitting delays.
- A 6-month extension will be granted upon payment of a refundable $25/kW extension fee, for distributed generation systems, and up to two 6 month extensions for community solar projects (the second extension is only for achieving the required subscriber rate, not for project completion and energization, and will require an additional refundable $25/kW fee). The extension fee(s) is payable to the contracting utility, and would be refunded as part of the first (or only for systems up to 10 kW) REC payment.
- The Agency may also, but is not required to, approve additional extensions for demonstration of good cause.

6.15.3. Project Completion and Energization

The Approved Vendor will provide the Program Administrator with a status update on each project under development but not yet energized at least every six months and will inform the Agency of any significant changes to the system.[476] For community solar projects, the update will include an update

[475] See Docket No. 19-0995, Final Order dated February 18, 2020 at 80.

[476] For systems under 25 kW, that status update is only be required for a system where there is a change in status (e.g., a project being completed, or canceled).

on the status of acquiring subscribers. The Agency and Program Administrator will provide a standardized form (including standard status categories to simplify reporting) for this purpose.

Once a project is energized, the following information will be required from the Approved Vendor in order for the Program Administrator to approve the final project and authorize the start of payment for RECs.

- Final system size
- Final system specific capacity factor and 15-year REC production estimate
- GATS or M-RETS unit ID[477]
- Certificate of Completion of Interconnection or comparable documentation[478, 479]
- Photographic documentation of the installation
- Disclosure of any changes to the system technical specifications that occurred between the initial application and the completion of the project
- Identity of the installer (must be a Qualified Person under Part 468 of the ICC's Rules)

Additional requirements may be published by the Program Administrator if the Agency determines that such requirements are warranted, and the Program Administrator may reference other sources (such as public databases) to determine the accuracy of any submissions.

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

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

The quantity of RECs used for payment calculations is based on the lesser of the RECs calculated based on the proposed (Part I) system size and capacity factor, and the RECs calculated based on the final (Part II) system size and capacity factor. The final capacity factor can be adjusted down from the initial capacity factor but cannot be increased from the original capacity factor, including changes in capacity factor due to switches between tracking technology, non-tracking and tracking systems, and bifacial vs standard module use. In this way, a system that is built smaller than planned will not benefit from excess REC payments that could result from purposefully submitting the project at a larger size than really intended. On the opposite side, if a project's final system size is significantly larger than the planned system size, an increase in the payment due could present unexpected budget management challenges. An Approved Vendor has the option of canceling and resubmitting a system if the final size is larger than the proposed system to align the REC quantities or if it desires to have the system change from a distributed generation project to a community solar project, or vice versa. However, that resubmittal would be at the price of the block open at the time, and not at the time of

[477] GATS or M-RETS registration must be complete and unit ID verifiable through GATS or M-RETS public reports.

[478] Comparable documentation would only apply for a rural electric cooperative or municipal utility that does not provide a Certificate of Completion of Interconnection.

[479] Per Section 1-75(c)(1)(K) of the IPA Act, the date of final interconnection approval must be no earlier than June 1, 2017.

the original submittal. Because the Program Administrator will need to review the system design (because of the change in system size), a new application fee will be required. If a project is resubmitted, the collateral associated with the original system may be applied to the resubmitted system, if approved.

The Agency emphasizes that, while the Approved Vendor is the entity that receives REC payments, the terms of sharing that REC payment value with customers (completely, partially, or not at all; immediately or over time; directly or indirectly) or obligations associated with a system's performance assurance payment are left to a customer and Approved Vendor (or customer and designee) to work out between themselves prior to executing an agreement.

The Agency reserves the right to request more information on an installation, and/or conduct on-site inspections/audits of projects to verify the quality of the installation and conformance with the project information submitted to the Agency. Projects found not to conform with applicable installation standards and requirements, or projects found not to be consistent with information provided to the Agency will be subject to removal from the program if the deficiencies cannot be remedied. Likewise, Approved Vendors who repeatedly submit projects featuring application errors or inconsistencies with Program requirements may be subject to suspension or termination of their Approved Vendor status.

6.15.4. Additional Requirements for Community Solar Projects

A community solar project will have to demonstrate that it has met a minimum subscription level to be considered energized and eligible to receive payment for RECs. At least 50% of the capacity of the project must be subscribed at the time of energization in order to receive payment for RECs, and that payment will be based upon calculating the number of RECs that correspond with the amount of the project's capacity that has been initially subscribed. The Approved Vendor will report subscription levels on a quarterly basis during the first year. The calculation of the number of RECs for payment will be updated after one year of operation (based on the final quarterly report of that first year) to allow for the acquisition of additional subscribers. A community solar project may request one additional extension (with a refundable extension payment as provided for in Section 6.15.2) to its energized date if it needs additional time to acquire subscribers.

To the extent that an Approved Vendor demonstrates additional subscriptions or updated subscription mixes that would entitle the Approved Vendor to a greater payment, the contract will require that the second payment reflect the increased value for quarters where the additional subscriptions or updated subscription mix entitled the Approved Vendor to additional revenue. If subscriber levels (or mixes) change in such a manner that contract value is reduced, the additional payments would also be adjusted downwards accordingly.[480]

The calculation of the maximum number of RECs due payment will be determined by the project's subscription level after one year of operation (and will be subject to the maintenance of subscription levels as described in Section 6.17). For example, if a project is expected to produce 1,000 REC/year and after one year of operation is 95% subscribed (on a project capacity basis), then the annual REC production value used for the contract payment level would be 950 RECs. Under the REC delivery contract, the Approved Vendor would then be obligated to deliver to the utility 95% of the RECs

[480] See Docket No. 17-0838, Final Order dated April 3, 2018 at 118.

produced by that system each year. The ownership (and any subsequent transfer or sale) of the remaining 5% of RECs would be outside of the contract.

The adders for small subscriber participation (i.e., for a minimum of 25%, 50%, or 75% of energy being subscribed) will only be added (on a prorated basis) to the REC price if the project demonstrates that level of participation for the subscribed amount at the time of energization. If the subscription level has not been met by the time of energization, the adder will be held back from the initial payment and the system will have to wait until it has been in operation for one quarter to demonstrate that it has begun to meet the small subscriber participation level to begin to receive this adder. If the small subscriber subscription rate is met, then the full value of the adder will be added pro-rata to the remaining payments.

Ongoing requirements for overall subscription levels and small subscriber participation are discussed further in Section 6.16.

6.15.5. REC Delivery

Once a system is energized, it will be required to begin REC delivery. For systems larger than 5 kW, the first REC must be delivered within 90 days of when the system is energized and registered in GATS or M-RETS. For systems smaller than 5 kW, 180 days will be allowed. The 15-year delivery term will begin in the month following the first REC delivery and will last 180 months.

Approved Vendors will be required to set up an irrevocable Standing Order for the transfer of RECs from the system to the utility.[481] As the Agency understands that automatic transfers can only be terminated with the consent of both parties, this will reduce the risk to the utility that the RECs could be sold to another party after the utility has paid for them.

As part of the Annual Report discussed in Section 6.17, the Approved Vendor will report on any systems that have not delivered a first REC, and report on any systems that have not delivered RECs for more than a year from their previous delivery. The report will also detail what corrective actions will be taken to ensure future deliveries. In the event of failure to remedy non-delivery of RECs, the utility may draw on the collateral it holds from the Approved Vendor.

6.16. Ongoing Performance Requirements

A significant challenge for the Adjustable Block Program is that the payment for RECs is front loaded; all RECs are paid for on energization for systems up to 10 kW, and all payments for systems over 10 kW will be made within the first four years of energization. Yet the contracts for REC delivery have a 15-year obligation for the RECs to be delivered. This creates a situation in which, absent any additional measures, the buyer (the utility) will be unable to use the typical contractual tool of withholding payments for the item not yet received to ensure REC delivery. Fortunately, the Act anticipated this issue and requires that "[e]ach contract shall include provisions to ensure the delivery of the renewable energy credits for the full term of the contract."[482]

[481] See Section 10.2 of the GATS Operating Rules available at https://www.pjm-eis.com/~/media/pjm-eis/documents/gats-operating-rules.ashx.

[482] 20 ILCS 3855/1-75(c)(1)(L)(iv).

The Agency will utilize the approach described below to ensure REC delivery over the full term of the contracts. This approach will also ensure proper matching of adders for photovoltaic community renewable generation projects at different levels of residential subscription levels.

REC delivery obligations will be managed at a portfolio level. As projects are completed and become energized, each Approved Vendor will therefore have a portfolio of systems with REC delivery obligations from the various contracts that it has with each utility. The obligation to ensure REC delivery will be at the contract level rather than the individual project level. In this way, the natural variation that some systems will produce more RECs than forecast and others fewer RECs will reduce the risk of contract default, compared to project-level contracts, and allow for some ease in contract administration.

6.16.1. Credit Requirements

An Approved Vendor is required to post collateral equivalent to 5% of the total contract value within 30 business days of when each Batch's contract (or product order) is approved. As described in Section 6.14.6, if the collateral was provided in the form of a Letter of Credit, then the Approved Vendor may choose for the utility to withhold the collateral amount for each system from the last REC payment for the system (or only REC payment for small systems) in exchange for not needing to maintain the collateral in the form of the Letter of Credit.. In this situation, the collateral would be reduced as described below, and fully returned at the end of the contract (net any amounts that were drawn to meet contractual obligations). As systems are energized, this collateral amount (or deferred payment) will be maintained through the life of the contract. This requirement will be maintained at the portfolio level, not the individual contract or system level.

By maintaining collateral requirements at the portfolio level, Approved Vendors can better manage the risk that some systems may underperform (or have other problems) while others may overperform. This allows the collateral level to be lower than it would be if maintained at the system level.

The Agency wishes to emphasize that this Plan does not prescribe the source of funds for collateral, whether it be an Approved Vendor's cash on hand, bank borrowings, the project owner's funds, customer-provided funds, a letter of credit, or some other source.

Nonetheless, an Approved Vendor will be responsible for delivering RECs each year under its contracts (subject to the reduction options described in the following Section). On an annual basis, failure to deliver RECs for the previous year will result in the utility drawing on the collateral to be compensated for the undelivered RECs from that year that already received payment. After any such drawing, the Approved Vendor will need to restore its collateral level to bring it back up to the 5% of remaining value of the portfolio within 90 days. If the amount of collateral held for an Approved Vendor is insufficient to compensate the utility, the Approved Vendor will be required to pay the utility for the balance of the value of the undelivered RECs from that previous year. Failure to make payment and/or maintain the collateral requirement may result in the Approved Vendor's suspension from participating in the Program.

Additionally, the Agency understands and appreciates that the natural degradation of photovoltaic system's productive capacity will likely result in reduced delivery quantities in the later years of a system's performance under a REC delivery contract. Annual contractual REC delivery volumes will

thus be decline by 0.5% each year, which the Agency believes should help ensure that collateral is not unfairly drawn upon due to reduced system performance.[483]

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

6.16.2. Options to Reduce REC Delivery Obligations

Section 1-75(c)(1)(L) of the IPA Act provides that "[t]he electric utility shall receive and retire all renewable energy credits generated by the project for the first 15 years of operation."[484] The capacity factor as described in Section 6.14.5 will be used to calculate the number of expected RECs each system generates, and thus the overall payment for that system. If a system produces more RECs than expected from that calculation, then no adjustment would be made to payments or to the statutorily mandated 15-year REC delivery term. However, if the system produces fewer than the expected number of RECs, then the following conditions would apply.

The Agency expects each Approved Vendor to take the steps necessary to ensure that projects contained within its portfolio meet all expected REC deliveries. This may include working with system owners to ensure that ongoing maintenance and repairs of systems occurs as well as to ensure that meter/inverter data is properly transferred to GATS or M-RETS for the creation of RECs. Furthermore, Approved Vendors will be responsible for ensuring the ongoing transfer of RECs to the applicable utility. However, because weather and other factors may impact annual production values, REC delivery performance will be evaluated on a three-year rolling-average basis, although any overproduction may be carried forward (or "banked") for performance evaluation and collateral purposes into future contract years without expiration.[485] However, a project or portfolio is not entitled to additional compensation if a carryforward remains as project-specific contracts expire.[486]

There are circumstances where a system may not be able to deliver the RECs it was expected to produce; the Agency believes that reasonable accommodations should be made for these situations that appropriately balance the requirements for the utilities to comply with RPS targets and their expectation to receive RECs for which payment has already been made while acknowledging that unexpected situations may arise at no fault of the Approved Vendor.

In force majeure type circumstances (including, but not limited to, physical damage to the system from fires, tornados, etc.) the Approved Vendor may request to have a delivery obligation suspended, reduced, or eliminated without penalty.[487] Approval of the recognition of a force majeure event requires consensus between the Agency and the applicable utility. Curtailments by either the utility (including those through a smart inverter) or the RTO that result in reduced REC production would allow for reduced REC delivery obligations.

In the case of reductions or eliminations of delivery obligations, the Approved Vendor must demonstrate what measures have been taken that do not adequately cure the situation (such as filing and receiving an insurance claim that is inadequate to restore the system to operation). For the

[483] See Docket No. 17-0838, Final Order dated April 3, 2018 at 129.

[484] 20 ILCS 3855/1-75(c)(1)(L)(ii).

[485] All RECs must be delivered to the counterparty in the delivery year when produced, regardless of any overproduction under the contract. See Docket No. 17-0838, Final Order dated April 3, 2018 at 129.

[486] See Docket No. 17-0838, Final Order dated April 3, 2018 at 129.

[487] Specific circumstances that constitute force majeure have been outlined and memorialized through the contract development process.

suspension of delivery obligations, the Approved Vendor must demonstrate that reasonable measures are being taken to have a timely restoration of production. Approved suspension of delivery obligations will serve to change the end date for the 15-year REC delivery timeline to reflect the time the delivery obligations were suspended.

An Approved Vendor may also determine that a system is not performing at the level expected in the absence of force majeure circumstances. In this circumstance, the Approved Vendor may request to have the delivery obligation related to that system within its portfolio reduced in exchange for the return to the utility of a payment adjustment to account for all undelivered RECs at the original delivery level as of the time of the request.

6.17. Annual Report

On an annual basis, each Approved Vendor is required submit an Annual Report of the contracts and systems in its portfolio.[488] The Annual Report serves as the basis for verifying that RECs from projects are being delivered to the applicable utility, and, absent corrective actions taken by the Approved Vendor, will be used to determine what actions should be taken by the utilities to enforce the contractual requirements that RECs are delivered, including, but not limited to, drawing on collateral. Additionally, the Annual Report will be used by the Agency to consider the ongoing eligibility of an Approved Vendor to continue participation in the program.

For distributed generation systems, the report will include information on:

- RECs delivered by each of the systems in the portfolio
- Status of all systems that have been approved, but not yet energized, including any extensions requested and granted
- Energized systems that have not delivered RECs in the year
- Balance of collateral held by each utility
- A summary of requests for REC obligations reductions due to force majeure events
- A summary of requests for REC obligations, suspensions, reductions, or eliminations due to force majeure events
- Information on consumer complaints received
- Other information related to ongoing program participation, including use of graduates of job training programs and other information related to increasing the diversity of the solar workforce[489]

For community solar projects, the report will also include:

- Percentage of each system subscribed on a capacity basis
- The number and type of subscribers (e.g., residential, small commercial, large commercial/industrial), including capacity allocated to each type
- Subscriber turn-over rates

[488] Approved Vendors may request confidential treatment of the Annual Report. However, aggregated information from Annual Reports may be publicly disclosed by the Agency to the extent that it does not disclose Approved Vendor-specific confidential information.

[489] As discussed in the Commission's Order approving the Revised Plan, this requirement was added in order to learn from and celebrate how the increase in solar development in Illinois is improving diversity in the state's renewable energy workforce. The IPA commits to seeking stakeholder feedback on how this information should be reported and commits to gathering this information for informational purposes only. See Docket No. 19-0995, Final Order dated February 18, 2020 at 87.

The Agency will review the annual reports to assess compliance with the requirements of the Adjustable Block Program and, if there are shortfalls of REC deliveries or subscription levels for photovoltaic community renewable generation projects, will coordinate with the applicable utility on what remedies should be taken, including drawing on collateral.[490] For this process and those described in the next two paragraphs, the performance evaluation and collateral draw methodologies have been specified in the standard REC delivery contract.

For community solar projects, subscription levels must be maintained to remain eligible for REC payments. If the annual report shows that subscriber levels on a rolling average basis have fallen below the subscribership level that the project contractually committed to, then if REC payments are still due, those payments will be reduced as described earlier in this chapter; if all payments have been made, then the Agency will work with the applicable utility on what remedies should be taken including drawing on collateral. If a project's subscribership falls below 50% for a given delivery year, no payment would be owed to the project for that delivery year, and a payment reduction or collateral draw would result (although the project could regain 50% subscribership the following year and qualify for payment in relation to that year).

A similar review will be conducted for projects that have received a small subscriber participation adder but do not maintain sufficient levels of small subscriber participation. If small subscriber participation levels are not maintained and there are remaining REC payments due, those payments will be reduced (to either the actual small subscriber adder category that has been maintained, or to remove the adder altogether if the level falls below 25%). If all payments have been made, then the Agency will work with the applicable utility on what remedies should be taken including drawing on collateral.

Approved Vendors will be given 90 days to cure any deficiencies found by the Agency and/or utilities.

[490] The Agency will request on a semi-annual basis a report from each utility on RECs delivered by contract.

7. Community Renewable Generation Projects

Community Renewable Generation is still a relatively new concept in Illinois. It is intended to allow consumers to participate in renewable energy generation even if they are unable to have an on-site system at their home or business, and to offer a more direct connection to the benefits of renewable energy than signing up for a renewable energy retail supply offer from an Alternative Retail Electric Supplier (where information about the specific sources, costs, and benefits of the renewable energy and the underlying generating system(s) may not be readily available).

Community, or "shared," renewable energy is growing nationally, most often in conjunction with solar power. The Solar Energy Industries Association reports that nearly 1,400 MW of community solar had been developed through 2018.[491]

Many policy issues that have been debated in other states are resolved in Illinois through the Act itself, including elements of project size, ownership structures, and the number and type of subscribers. In addition to explaining those aspects of Illinois law, in this Chapter, the Agency outlines the terms and conditions for the Community Renewable Generation Program that are not prescribed by the Act.

7.1. Statutory Overview

The Act contains several key provisions designed to make community renewable generation economically viable and practical in Illinois. These provisions create a program, provide it with important structure, and increase the benefits to participants through changes to net metering and bill crediting and the ability to monetize the value of RECs from the systems.

Section 1-10 contains several key definitions:

> *"Community renewable generation project" means an electric generating facility that:*
>
> *(1) is powered by wind, solar thermal energy, photovoltaic cells or panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams;*
>
> *(2) is interconnected at the distribution system level of an electric utility as defined in this Section, a municipal utility as defined in this Section that owns or operates electric distribution facilities, a public utility as defined in Section 3-105 of the Public Utilities Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act;*
>
> *(3) credits the value of electricity generated by the facility to the subscribers of the facility; and*
>
> *(4) is limited in nameplate capacity to less than or equal to 2,000 kilowatts.*
>
> *[…]*
>
> *"Subscriber" means a person who (i) takes delivery service from an electric utility, and (ii) has a subscription of no less than 200 watts to a community renewable generation project that is located in the electric utility's service area. No subscriber's subscriptions*

[491] https://www.seia.org/initiatives/community-solar.

> *may total more than 40% of the nameplate capacity of an individual community renewable generation project. Entities that are affiliated by virtue of a common parent shall not represent multiple subscriptions that total more than 40% of the nameplate capacity of an individual community renewable generation project.*
>
> *[…]*
>
> *"Subscription" means an interest in a community renewable generation project expressed in kilowatts, which is sized primarily to offset part or all of the subscriber's electricity usage.*

These three definitions create the core of the idea of community renewable generation, where subscribers pay for shares or some other "interest" in a centralized (but small) renewable power project, receiving bill credits in exchange. It can be seen as a way of giving customers choices about their electricity generation in a manner that can serve as an alternative to the options created by the establishment of retail choice through the Electric Service Customer Choice and Rate Relief Law of 1997.[492]

Section 1-75(c)(1)(N) creates the community renewable generation program:

> *(N) The long-term renewable resources procurement plan required by this subsection (c) shall include a community renewable generation program. The Agency shall establish the terms, conditions, and program requirements for community renewable generation projects with a goal to expand renewable energy generating facility access to a broader group of energy consumers, to ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties. Any plan approved by the Commission shall allow subscriptions to community renewable generation projects to be portable and transferable. For purposes of this subparagraph (N), "portable" means that subscriptions may be retained by the subscriber even if the subscriber relocates or changes its address within the same utility service territory; and "transferable" means that a subscriber may assign or sell subscriptions to another person within the same utility service territory.*
>
> *Electric utilities shall provide a monetary credit to a subscriber's subsequent bill for service for the proportional output of a community renewable generation project attributable to that subscriber as specified in Section 16-107.5 of the Public Utilities Act.*
>
> *The Agency shall purchase renewable energy credits from subscribed shares of photovoltaic community renewable generation projects through the Adjustable Block program described in subparagraph (K) of this paragraph (1) or through the Illinois Solar for All Program described in Section 1-56 of this Act. The electric utility shall purchase any unsubscribed energy from community renewable generation projects that are Qualifying Facilities ("QF") under the electric utility's tariff for purchasing the*

[492] One aspect of the success of retail competition in Illinois has been municipal aggregation programs whereby a municipality negotiates an electric supply offer from an ARES on an opt-out basis for eligible retail customers. The Agency understands that those customers who participate in a municipal aggregation program remain individual customers and thus would be considered individually for the purposes of the 40% cap on individual subscriptions. The aggregator would not be considered a subscriber to a community renewable generation project.

> *output from QFs under Public Utilities Regulatory Policies Act of 1978. The owners of and any subscribers to a community renewable generation project shall not be considered public utilities or alternative retail electricity suppliers under the Public Utilities Act solely as a result of their interest in or subscription to a community renewable generation project and shall not be required to become an alternative retail electric supplier by participating in a community renewable generation project with a public utility.*

This Chapter describes the "terms, conditions, and program requirements" applicable to projects participating in an IPA program featuring community renewable generation project participation and how RECs produced by that facility are purchased. Certain other aspects of the Program requirements are administered by the applicable utility, and the Agency will coordinate with those entities to ensure compliance with the Act.

While the Act defines community renewable energy as including solar, wind, biomass, and other renewable sources, it creates an Adjustable Block Program only for photovoltaic generation, directing the Agency to "purchase renewable energy credits from subscribed shares" of community solar projects.[493] By procuring their RECs, the Agency is able to offer an additional financial incentive for customers choosing community solar.

Subscribers capture the value of their community energy subscription in the form of a "monetary credit" applied to the subscriber's subsequent utility bill for service, in proportion to the net output of their subscription to the project. The determination of that subscriber utility bill credit is not the subject of this Plan, and is instead established through tariffs filed by the utilities with the Illinois Commerce Commission as discussed further below. Instead, the Agency's role is simply in the procurement of RECs—which helps support the development of new projects and should reduce the subscriber's subscription price. While subscribers may not (if their subscription does not take the form of equity in the project) necessarily directly receive revenue for the RECs procured for the utilities by the Agency, that revenue should factor into the economics faced by the project developer and impact the subscription offer made to subscribers.

The monetary credits for net energy production flow from provisions of the Public Utilities Act that expand the concept of net metering, which had previously been available for distributed generation, to become available for community renewable generation subscribers. The previous version of Section 16-107.5(*l*) of the Public Utilities Act before the enactment of Public Act 99-0906 provided that electric utilities merely "shall consider" whether to allow community-owned facilities or meter aggregation projects in a single building. The revised version of that Section adds the requirement to Section 16-107.5 that utilities *shall allow*[494] net metering for subscribers to "community renewable generation projects," as well as the other two types of community renewable projects.

The new law requires an "electricity provider" (meaning an electric utility or alternative retail electric supplier) to provide net metering credits for a community solar subscriber's share of a project's net electricity production at the subscriber's energy supply rate.[495]

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[493] As discussed elsewhere, the Agency understands "purchase" effectively to mean "procure" as used in this provision, as the Agency would not directly enter into contracts with renewable providers using non-RERF (or otherwise non-state-held) funds.

[494] 220 ILCS 5/16-107.5(l)(1).

[495] Community solar projects are to receive energy-only net metering credits starting from the enactment of Public Act 99-0906 on June 1, 2017 (or whenever each electricity provider implements the tariff or terms to do so following June 1, 2017), in contrast to other types of

Public Act 99-0906 also required that each electric utility file a community solar net metering tariff within 90 days after the new law's effective date of June 1, 2017. Each of ComEd, Ameren Illinois, and MidAmerican filed a proposed tariff during August of 2017, and the Commission approved all three tariffs on September 27, 2017.[496] These tariffs are discussed further in Section 7.7 of this Plan.

ComEd's tariff consisted of modifications to its Rider POGCS (Parallel Operation of Retail Customer Generating Facilities Community Supply), Rider POG (Parallel Operation of Retail Customer Generating Facilities), Rider PORCB (Purchase of Receivables with Consolidated Billing), and Rate RESS (Retail Electric Supply Service). Ameren's tariff consisted of a complete revision to its Rider NM (Net Metering) to now incorporate provisions governing community renewable net metering. MidAmerican's tariff created a new Rate NMS to embody its new community renewable net metering program.

7.2. Eligible Generating Technologies and Procurement/Program Eligibility

Community renewable generation projects that are photovoltaic will be eligible to participate in the Adjustable Block Program outlined in Chapter 6. Other types of community renewable generation projects (the listing for which can be found in the definition of "renewable energy resources" found in Section 1-10 of the IPA Act) were eligible to participate in the competitive procurement outlined in Chapter 5 of the Initial Plan. These options define the process by which a system would come under contract with a utility to sell its RECs, and each option features different payment terms. The Adjustable Block Program has front-loaded REC payments, while competitive procurements will pay for RECs as they are delivered. Other than these contractual differences, the Agency believes all community renewable generation projects (including those participating in the Adjustable Block Program) should be treated the same as to other terms and conditions that follow in this Chapter, unless specifically noted.

For non-photovoltaic community renewable generation projects, the price per REC they will be paid will be based upon the price of each winning bidder's bid in the competitive procurement and is not tied to any adders or requirements for residential subscription rates.

7.3. Co-location of Projects

Co-location is when multiple projects are located adjacent to each other, perhaps using the same grid interconnection. Co-located projects can be structured to maximize income from incentives, such as by dividing up a larger project into smaller pieces that qualify for higher incentives. Community Renewable Generation Projects are defined in the Act as being smaller than or equal to 2,000 kW, and for photovoltaic projects, the Adjustable Block Program includes adders for smaller projects. Co-location strategies could therefore result in the gaming of prices.

Minnesota offers two points of experience with the issue of co-location, for both community wind and community solar. Under both policies, larger projects were structured as a series of smaller projects to qualify for higher incentives, undermining the legislative intent of promoting distributed, community-owned projects. A 30 MW wind project, owned by 15 corporate entities with the same owners, was developed under the Minnesota Community-Based Energy Development (C-BED) tariff

distributed generation, which will continue to receive full retail rate net metering from June 1, 2017 until total net metering for that electricity provider reaches 5% of the electricity provider's peak demand, as discussed in Chapter 6.

[496] See ICC Docket No. 17-0350 (ComEd), ICC Docket No. 17-0368 (MidAmerican), and ICC tariff no. ERM 17-144 (Ameren Illinois).

program, which was intended to encourage community-owned wind projects of 2 MW or less. That program was reformed in 2003 to be more prescriptive, limiting ownership to Minnesota residents, with a single owner limited to a 15% share of a project.[497]

The more recent Minnesota Community Solar Gardens policy led to a similar problem. While the legislature capped project size at 1 MW, it did not address co-location issues. As a result, 15 co-located, aggregated projects were proposed between 10 and 20 MW, three between 20 and 30 MW, and two in the 30 to 50 MW range. One developer, Sunrise Energy Ventures, filed applications for 100 projects within the first hour of the program. When the state Public Utilities Commission ("PUC") imposed co-location caps of 5 MW for projects with filed applications and 1 MW for newly proposed projects, Sunrise appealed to the Minnesota Court of Appeals. The Court, however, affirmed the PUC's decision to implement caps.[498]

While co-location can undermine the concept of smaller and more geographically diffuse projects, it can also capture economies of scale from larger projects: large, available parcels with good interconnection points can be low-cost and efficient ways to develop large amounts of renewables quickly. Low development costs could help compensate for the higher marketing and customer acquisition costs of community renewable generation and provide greater benefits to low-income customers. Also, different owners might apply to develop completely distinct projects at different times, that just happen to be on adjacent parcels; restrictive rules would limit the development of especially attractive parcels of land.

7.3.1. Co-location Standard

In enacting Public Act 99-0906, the General Assembly expressly included a size limit for community renewable generation projects of 2,000 kW,[499] and the Agency does not believe it should ignore the intent of that size limit being included in the definition of community renewable generation projects. Additionally, as discussed in Section 6.5.1, the Agency seeks to avoid the situation in which multiple smaller projects are co-located in order to obtain the higher REC prices available to smaller systems.

To appropriately balance these competing issues, in recognition of a need to avoid problems of the types seen in Minnesota,[500] and generally consistent with the Commission's Order in Docket No. 17-0838,[501] the following policy is applicable to the co-location of Community Solar projects participating in the Adjustable Block Program:

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[497] Jessica A. Shoemaker and Christy Anderson Brekken, Farmers' Legal Action Group, *Community Wind: A Review of Select State and Federal Policy Incentives,* August 2006, http://www.flaginc.org/wp-content/uploads/2013/03/CommWindAug061.pdf.

[498] Mitchell Williams, Selig Gates & Woodyard PLLC, "Community Solar Gardens: Minnesota Appellate Court Allows Public Utility Commission to Implement Caps on Usage," Lexology, August 23, 2016. http://www.lexology.com/library/detail.aspx?g=c4690835-61c4-40cf-8105-0cc8d3229c77.

[499] See 20 ILCS 3855/1-10 ("'Community renewable generation project' means an electric generating facility that . . . is limited in nameplate capacity to less than or equal to 2,000 kilowatts.").

[500] These principles are derived from the definition adopted in Minnesota regarding co-location. See, Minnesota PUC, In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program. Order Adopting Partial Settlement As Modified. August 6, 2015. Docket No. E-002/M-13-867. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={43AC9E59-AD57-44FE-A57A-5F8A572D3C74}&documentTitle=20158-113077-01.

[501] See Docket No. 17-0838, Final Order dated April 3, 2018 at 131. The Agency's standard makes minor modifications which the Agency considers to be within the spirit of what was approved in that proceeding, as the Commission's Order – if read literally – would allow for the co-location of two 2 MW projects, but would prohibit the co-location of two 1.9 MW projects.

- No Approved Vendor may apply to the Adjustable Block Program for more than 4 MW of Community Solar projects on the same or contiguous parcels (with each "parcel" of land defined by the County the parcel is located in).[502]
- Co-located projects summing to more than 2 MW of Community Solar may be permissibly located in one of two ways:
    - Two projects of up to 2-MW in size on one parcel or contiguous parcels; or
    - An up to 2-MW project on each of two contiguous parcels.[503]
- A parcel of land may not have been divided into multiple parcels in the two years prior to the project application (for the Adjustable Block Program) or bid (for competitive procurements) in order to circumvent this policy. If a parcel has been divided within that time period, this requirement will apply to the boundaries of the larger parcel prior to its division.
- If there are multiple projects owned or developed by a single entity (or its affiliates) located on one parcel of land, or on contiguous parcels of land, any size-based adders will be based on the total size of the projects owned or developed on the contiguous parcels by that single entity or its affiliates. Furthermore, the total combined size of projects owned or developed by a single entity (or its affiliates) on contiguous parcels of land may not be more than 2 MW, or more than 4 MW if co-located consistent with the provisions outlined above.[504]
    - "Affiliate" means, with respect to any entity, any other entity that, directly, or indirectly through one or more intermediaries, controls, is controlled by, or is under common control with each other or a third entity. "Control" means the possession, directly or indirectly, of the power to direct the management and policies of an entity, whether through the ownership of voting securities, by contract, or otherwise. Affiliates may not have shared sales or revenue-sharing arrangements, or common debt and equity financing arrangements.
    - "Contiguous" means touching along a boundary or a point. For example, parcels touching along a boundary are contiguous, as are parcels that meet only at a corner. Parcels, however near to each other, that are separated by a third parcel and do not touch along a boundary or a point are not contiguous. Additionally, parcels that are separated by a public road, a railroad, or other right of way accessible at all times to the general public are not contiguous.
- Projects owned or developed by separate entities (meaning that that they are not affiliates) may be located on contiguous parcels. If there is a naturally good location from an interconnection standpoint, one owner should not be allowed to prevent another owner from developing a project in that location.
- Projects must have separate interconnection points.

Additionally, on May 2, 2018, the Commission entered an Amendatory Order in Docket No. 17-0838 authorizing the IPA to "investigate outside of this docket the probability of cost savings (if any) for co-located projects that puts their average costs below those modeled in the IPA's REC pricing model, and if warranted based on the results of that investigation, establish a tier in its REC pricing model applicable to co-located systems exceeding 2 MW in aggregate size."[505] The IPA's June 4, 2018 REC

[502] See id.

[503] See id.

[504] See id.

[505] Docket No. 17-0838, Amendatory Order dated May 2, 2018 at 1-2.

Compliance Filing containing updated REC values reflects the establishment of a REC pricing model tier applicable to co-located Community Solar systems exceeding 2 MW in aggregate size.

If a single project is developed and then a second, co-located project is developed on the same or a contiguous parcel at a later date, the approach above contemplates that these two projects will be considered co-located and co-located project prices will apply. To make this price adjustment the least administratively burdensome on all parties involved, the price adjustment for both projects will only be applied to the second project, with that project's REC price reflecting not only the co-located project price, but also an additional discount reflecting the differential between the first project's contract price and the applicable Block's co-located project price. This co-located pricing provision will only be applicable if the Commission's approval of the second project is within one year or less of the Commission approval date of the first project. If the first project has not yet commenced construction at the time of the second project's approval, then the co-located pricing provision will apply.

In the case that there are two co-located projects on a single parcel (or two contiguous parcels) owned by a single entity or represented by a single Approved Vendor, any sale of one project to a different owner or transfer of one project to a different Approved Vendor would not avoid the price adjustment that applies to co-located projects. In such a case, the second project's REC price would be adjusted to a price accounting for both co-located projects (i.e., below the listed co-located project price) in line with the description above. This restriction also applies to projects that are accepted off the waitlist that would render an already developed project into a co-located project.[506]

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

The definition of community renewable generation projects specifically mentions rural electric cooperatives and municipal utilities,[507] but does not explicitly include or exclude them from any program or procurement to be run by the Agency. Moreover, the definition includes the concept of that project having "subscribers," a term which in turn has a definition that defines such "subscribers" as "tak[ing] delivery service from an *electric utility*," which as defined in the IPA Act does not include cooperative and municipal utilities.[508] This results in ambiguity around whether a community renewable generation project can be located within the service territory of a rural electric cooperative or a municipal utility.

Ultimately, the Agency recognizes the General Assembly's choice expressly to include those entities in defining "community renewable generation projects"—a term only used in the IPA Act in

[506] The Commission affirmed the propriety of this approach through approving the Plan. See Docket No. 19-0995, Final Order dated February 18, 2020 at 95.

[507] See 20 ILCS 3855/1-10 ("'Community renewable generation project' means an electric generating facility that is . . . interconnected at the distribution system level of an electric utility as defined in this Section, a municipal utility as defined in this Section that owns or operates electric distribution facilities, a public utility as defined in Section 3-105 of the Public Utilities Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act").

[508] Specifically, Section 1-10 of the IPA Act defines an electric utility as having "the same definition as found in Section 16-102 of the Public Utilities Act," which is "a public utility, as defined in Section 3-105 of this Act, that has a franchise, license, permit or right to furnish or sell electricity to retail customers within a service area." 220 ILCS 5/16-102. Section 3-105 of the PUA in turn defines "public utility" to expressly *exclude* "public utilities that are owned and operated by any political subdivision, public institution of higher education or municipal corporation of this State, or public utilities that are owned by such political subdivision, public institution of higher education, or municipal corporation and operated by any of its lessees or operating agents" as well as "electric cooperatives as defined in Section 3-119" of the PUA. 220 ILCS 5/3-105.

connection with the Agency's community renewable generation program—and believes that community renewable generation projects (including community solar) located in these service territories should, if possible, be included in this Plan.

The status of community renewable generation projects and distributed renewable energy generation devices located in the service territories of rural electric cooperatives, municipal electric utilities, and Mt. Carmel Public Utility Company was a contested issue in Docket No. 17-0838, and the Commission's Final Order in that proceeding determined that the Agency's filed Plan was correct in authorizing the participation of these projects in the Adjustable Block Program, the Community Renewable Generation Program, and the Illinois Solar for All Program.[509] In June 2018, Commonwealth Edison Company filed a petition seeking review of that determination (i.e., an appeal) with the state's Second District Appellate Court, case number 2-18-0504. On May 2, 2019, the Appellate Court affirmed the ICC's decision in this regard. On July 11, 2019, ComEd filed a Petition for Leave to Appeal, no. 124898, with the Supreme Court of Illinois. It was denied on September 25, 2019, resolving this issue and clarifying that projects in the service territories of rural electric cooperatives, municipal electric utilities, and Mt. Carmel Public Utility Company, are indeed eligible to receive REC delivery contracts under the Adjustable Block Program.

As mentioned above, there are already at least three community solar offerings by or within rural electric cooperatives. Illinois' first community solar project was a 126 kW installation in Elizabeth, built by Jo Carroll Energy in December 2014.[510] That project allows Jo Carroll customers to buy individual panels in the 460-panel ground-mounted system, with the energy produced credited against their bills. Prairie Power sells kWh blocks of solar power to customers of its 10 distribution cooperatives through the Bright Options Solar program. The program is supplied by two 500 kW solar installations near Shelbyville and Astoria, both built in 2015.[511] Neither of these projects would be eligible to participate in the Adjustable Block Program because they were energized prior to June 1, 2017, but they indicate that rural electric cooperatives have thus far been the leaders in community solar in Illinois. Several proposed community solar projects that would be located within the Jo Carroll Energy service territory applied to the Adjustable Block Program, and one – the Apple Canyon Lake Solar Farm – was allocated a REC contract via the April 10, 2019 lottery.

The Agency proposes the following standard for allowing community renewable generation projects in the service territories of rural electric cooperatives and municipal utilities to participate in the Agency's programs or procurements; it is unchanged from the standard proposed in the Initial Plan, approved by the ICC in Docket No. 17-0838. This standard may require actions be taken by the rural electric cooperative or municipal utility. As entities not regulated by the state, they are free to choose whether to take these actions, but should they choose not to, then the residents and businesses within their service territories would not benefit from receiving revenue through these programs for its RECs, and thus the economics of such projects may not be as attractive to developers or subscribers.

The requirements for participation that the Agency recommends for a rural electric cooperative or municipal utility follow from those required in the Act for electric utilities:

[509] See Docket No. 17-0838, Final Order dated April 3, 2018 at 177-179.

[510] Jo Carroll Energy, https://jocarroll.com/content/south-view-solar-farm.

[511] Prairie Power, https://www.ppi.coop/brightoptions.

- Be capable of "credit[ing] the value of electricity generated by the facility to the subscribers of the facility."[512] This can be accomplished though offering "virtual net metering" substantially similar to the provisions contained in Section 16-107.5(l) of the Public Utilities Act.[513] The value of electricity credited must be at no lower than the subscriber's supply rate.[514]
- Provide a monetary credit to a subscriber's subsequent bill for service for the proportional output of a community renewable generation project attributable to that subscriber.[515]
- Purchase any unsubscribed energy from community renewable generation projects that are Qualifying Facilities ("QF") under the electric utility's tariff for purchasing the output from QFs under Public Utilities Regulatory Policies Act of 1978.[516]

Prior to a photovoltaic community renewable generation project applying for the Adjustable Block Program, or a community renewable generation project powered by other renewable technologies participating in the competitive procurement, the Approved Vendor shall obtain a certification addressed to the Agency that the rural electric cooperative or municipal utility has met these conditions from the subject cooperative or municipal utility. Absent this information, a project located in the service territory of that rural electric cooperative or municipal utility will not be allowed to participate. All other programmatic requirements for community renewable generation projects (e.g., size limits, co-location, consumer protections) would apply to projects located in rural electric cooperatives or municipal utility service territories. For the purposes of rural electric cooperatives, these requirements apply at the distribution cooperative level, rather than for generation and transmission cooperatives (which do not directly interact with retail customers).

7.5. Types of Community Renewable Generation Projects

Community Renewable Generation remains a new concept for Illinois, and it is still developing nationally. Practitioners are still developing the most viable business models, and new models are likely to emerge, both for-profit and non-profit. In some models, customers take ownership of a share of a community project, identifying specific solar panels. In others, the developer owns the project and sells subscriptions for a contractually obligated term, or an indefinite term that can be ended at will. The value of the generation can be conveyed to the customer by virtual net metering (as an energy credit), by a value-of-solar tariff, or as a premium purchase.

One issue that the Agency has considered is the extent to which projects will be proposed by commercial developers who then seek to identify subscribers, and by community-led projects where interested parties in a community come together to seek to develop a project. A church parish, for example, could put photovoltaic panels on the roof of the church, with subscriptions sold to parishioners. In theory, developer-led projects are likely to be larger and located where interconnection costs are minimized, while community-led projects like the church parish could be smaller and face the possibility of higher interconnection costs because the location is determined by community-focused interests rather than pure engineering considerations. But in practice, the

[512] See definition of "Community Renewable Generation Facility" in 20 ILCS 3855/1-10.

[513] See 220 ILCS 5/16-107.5(*l*).

[514] If the municipal utility or rural electric cooperative does not have unbundled rates (e.g., separate line items for delivery services and electricity supply) then the applicable municipal utility or rural electric cooperative must indicate the portion of the bundled rate that reasonably correlates to the cost of electricity supply service.

[515] See 20 ILCS 3855/1-75(c)(1)(N).

[516] See id.

wide range of interconnection cost estimates offered to the many large community solar projects that have applied to the Adjustable Block Program demonstrate that the drivers of interconnection costs are not the size of the system itself but rather the broader infrastructure the project is interconnecting to.

Properly defining what is truly a community-led project could be problematic and subject to gaming. It is possible, for example, that community groups will team with professional solar developers to realize their projects, with varying ownership structures. Given the long waitlist of community solar projects that have already applied to the Adjustable Block Program, most of which appear to be developer-driven, the Agency is not proposing any changes (such as a price adder) for community-led projects. As discussed in Section 6.3.3.1, the Agency sought feedback on how to manage that waitlist of community solar projects, and has proposed an approach for new blocks of community solar capacity that may encourage applications from more community-driven projects.

Certain community-led projects may instead apply to participate in, and be eligible for, a higher level of incentives through the Illinois Solar for All Program as described in Chapter 8. Developers of Community Solar projects that participate in that program are required to "identify its partnership with community stakeholders regarding the location, development, and participation in the project, provided that nothing shall preclude a project from including an anchor tenant that does not qualify as low-income. Incentives should also be offered to community solar projects that are 100% low-income subscriber owned, which includes low-income households, not-for-profit organizations, and affordable housing owners."[517]

7.6. Subscriber Requirements

With community renewable generation still an emerging concept, the level of consumer interest and the most viable business models remain to be determined. The Agency seeks to allow creativity and flexibility in developing projects while at the same time ensuring basic consumer protections.

7.6.1. Small Subscriber Participation

The Act requires that the Agency propose terms and conditions that "ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties."[518] Collectively the Agency considers "residential and small commercial customers" to be "small subscribers" so long as their subscription size is below 25 kW. Perhaps notably, the above-quoted language of the Act refers to "robust participation **opportunities**"[519] for small customers—and does not mandate robust participation.

To date, as described in Section 6.5 and consistent with the Commission's Order in Docket No. 17-0838, the Agency has used adders in the Adjustable Block Program to recognize the value of small subscriber subscriptions. The Agency has found that this adder, along with the preference for a small subscriber commitment in the case of a lottery to select community solar projects upon the opening of the Adjustable Block Program (as described in Section 6.3.1),[520] have been effective mechanisms for ensuring robust participation opportunities for small subscribers. During the litigation of the

[517] 20 ILCS 3855/1-56(b)(2)(B).

[518] 20 ILCS 3855/1-75(c)(1)(N).

[519] Emphasis added.

[520] See also Docket No. 17-0838, Final Order dated April 3, 2018 at 144.

Initial Plan in Docket No. 17-0838, some stakeholders sought for 25% small customer participation to serve as a useful baseline for measuring small subscriber participation. 98.9% of community solar projects that applied to the program when it opened in early 2019 made a commitment to have *at least 50% small subscribers*, and the Agency is not aware of any evidence at this time that projects selected in the lottery will not fulfill those commitments.

Therefore, the Agency believes that the initial program design was successful in encouraging small subscriber participation, but cautions that almost all contracted community solar projects are still under development, and actual realized small subscriber subscription rates are unknown. For the purposes of this Revised Plan, the Agency is not proposing any changes to its small subscriber requirements (other than the changes to the small subscriber adder explained in Section 6.5.3), but will continue to monitor actual results of small subscriber acquisition by selected projects.

7.6.2. Marketing to Small Subscribers

Subscribing to a community renewable generation project is not the same as choosing to purchase or lease a system to be located on your own property. It does, however, bear similarities to signing up to take supply service from an Alternative Retail Electric Supplier. The Agency observes that the history of questionable marketing practices of some Alternative Retail Electric Suppliers gives reason to be concerned about the marketing of community renewable generation subscriptions.[521]

While competition in the natural gas and electricity markets has created many benefits for the residents and businesses of Illinois, those benefits have not been uniform, and in many instances, particularly in residential markets, the benefits have been non-existent; in fact, at times supply offers have been harmful to consumers. This Plan is not the place to have a full debate on acceptable marketing practices, but the Agency would like to highlight past practices that some alternative gas and electric suppliers have engaged in that cause concern for the Agency. These include improperly associating the supplier with the local utility or a government agency or program; implying that a customer must choose to enroll; inflating the price of green energy offers far beyond the actual incremental cost of procuring renewable resources; and targeting elderly, non-English speaking, and low-income customers who may have less access to quality information about energy prices.

The Agency recognizes that it may not be able to prohibit door to door, telemarketing, or online sales of community renewable generation subscriptions, but notes those marketing channels as ones of particular concern because of the information asymmetry between the salesperson and the consumer. The Agency believes an informed consumer is a wise consumer and strongly encourages marketing channels that respect the opportunity for consumers to have complete and accurate information about the decisions they may make regarding subscriptions, particularly those related to upfront payments, the net price of energy, and termination fees and conditions. The Agency and/or

[521] See, e.g., ICC Docket No. 14-0512, Consumer Services Division and Office of Retail Market Development Staff Report to the Commission dated August 20, 2014, https://www.icc.illinois.gov/downloads/public/edocket/384622.pdf (detailing misleading and noncompliant marketing tactics employed by one ARES); ICC Docket No. 15-0438, Consumer Services Division and Office of Retail Market Development Staff Report to the Commission dated July 20, 2015, https://www.icc.illinois.gov/docket/files.aspx?no=15-0438&docId=232481 (detailing several misleading telephone marketing tactics employed by a different ARES); ICC Docket No. 15-0512, First Notice Order, September 22, 2016, at 55 (expressly relying on information submitted with the ICC Staff Initial Comments dated November 5, 2015 (https://www.icc.illinois.gov/downloads/public/edocket/417068.pdf), which detailed trends in allegations of ARES wrongdoing including unauthorized switching, misrepresentation of the nature of the transaction, misrepresentation of identity of the ARES, misrepresentation of price or savings, failure to disclose cancellation fees or right to cancel, and more); ICC Docket No. 17-0273, Order, August 15, 2017, at 4-5 (denying a certificate of service authority to an ARES that, previously operating in Illinois under a prior corporate structure, had amassed numerous complaints related to sales and marketing).

its Program Administrators may conduct additional monitoring of Approved Vendors (and/or their partners/affiliates) that utilize door to door, telemarketing, and online sales, and reserves the right to request the Approved Vendor provide additional documentation of those marketing channels including, but not limited to, access to call center recordings for either sales or third-party verifications.

As discussed in Section 6.9.1, the Agency proposes to now require all in-person, phone, and online marketing / lead generation firms to register with the Adjustable Block Program, including disclosure by Approved Vendors of all such partners and their direct contact information prior to utilizing their services within the scope of the Adjustable Block Program.

As described in the Initial Plan, there are a number of state and federal consumer protection laws, regulations, and enforcement agencies that apply to all forms of marketing, including marketing of subscriptions to Community Renewable Generation Projects.[522]

Table 7-1: Federal Statutes that Apply to Community Solar

Statute	Topic
CAN-SPAM Act	Electronic marketing
Consumer Leasing Act	Leasing disclosures
Electronic Funds Transfer Act	Consumer rights in electronic fund transfers
Equal Credit Opportunity Act	Discrimination in credit transactions
Fair Credit Reporting Act	Collection and use of consumer information
Federal Trade Commission Act	Unfair and deceptive trade practices
Magnuson-Moss Warranty Act	Consumer product warranties
Right to Financial Privacy Act	Financial privacy from government intrusion
Truth in Lending Act	Lending disclosures and standardization
Telephone Consumer Protection Act	Telemarketing and automated telephone
Unfair Deceptive Practices Act (UDAAP)	Misleading financial products and services
Uniform Commercial Code	Sales and commercial transactions

Source: CESA, *Consumer Protection for Community Solar: A Guide for States*, 2017.

[522] Diana Chace and Nate Hausman, Clean Energy States Alliance, *Consumer Protection for Community Solar: A Guide for States*, June 8, 2017. http://cesa.org/resource-library/resource/consumer-protection-for-community-solar-a-guide-for-states.

Table 7-2: Illinois Statutes that Apply to Community Solar

Statute	Topic
Consumer Fraud and Deceptive Business Practices Act (815 ILCS 505)	Enrollment, marketing, billing, and collection by electric service providers
Electronic Mail Act (EMA) (815 ILCS 511)	Regulates e-mail solicitations
Telephone Solicitations Act (815 ILCS 413) and the Restricted Call Registry Act (815 ILCS 402)	Regulates telemarketing practices
Personal Information Protection Act (815 ILCS 530)	Requires companies that collect personal information to take reasonable measures to protect it and report unauthorized access to consumer's personal information.

These laws and regulations provide a starting point for protecting consumers, but their enforcement agencies typically only track and enforce violations if triggered by consumer complaints. In order to ensure that subscribers are well-informed and thus afforded adequate consumer protections, the Agency will require that all projects adhere to the following terms and conditions for subscriptions.

Drawing from the consumer protection guidelines for community solar adopted by the Maryland Public Service Commission, the Agency requires that Approved Vendors (or their subcontractors) seeking REC delivery contracts associated with Community Renewable Generation Facilities participating in the Adjustable Block Program or in Illinois Solar for All must include each of the following in any contracts entered into with subscribers:

(a) A plain language disclosure of the subscription, including:
  (i) The terms under which the pricing will be calculated over the life of the contract and a good faith estimate of the subscription price expressed as a monthly rate or on a per kilowatt-hour basis;
  (ii) 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;
(c) All nonrecurring (one-time) charges;
(d) All recurring (monthly, yearly) charges;
(e) A statement of contract duration, including the initial time period and any rollover provision;
(f) Terms and conditions for early termination, including:
  (i) Any penalties that the Project Developer may charge to the subscriber; and
  (ii) The process for unsubscribing and any associated costs.
(g) If a security deposit is required:
  (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 explaining any conditions under which the Project Developer may terminate the contract early, including:
(i) Circumstances under which early cancellation by the Project Developer may occur;
(ii) Manner in which the Project Developer shall notify the customer of the early cancellation of the contract;
(iii) Duration of the notice period before early cancellation; and
(iv) Remedies available to the customer if early cancellation occurs;
(j) A statement that the customer may terminate the contract early, including:
(i) Amount of any early cancellation fee;
(k) A statement describing contract renewal procedures, if any, including any automatic renewal provisions;
(l) A dispute procedure;
(m) The Agency's and Commission's phone number and Internet address;
(n) A billing procedure description;
(o) The data privacy policies of the Project Developer;
(p) A description of any compensation to be paid for underperformance;
(q) Evidence of insurance;
(r) A description of the project's long-term maintenance plan;
(s) Current production projections and a description of the methodology used to develop production projections;
(t) Contact information for the Project Developer for questions and complaints;
(u) A statement that the Project Developer does not make representations or warranties concerning the tax implications of any bill credits provided to the subscriber;
(v) The method of providing notice to the subscribers when the project is out of service for more than three business days, including notice of:
(i) The estimated duration of the outage; and
(ii) The estimated production that will be lost due to the outage.
(w) Any other terms and conditions of service.

The Agency may also develop additional conditions in the general course of developing program requirements, but will seek stakeholder feedback prior to doing so. As referenced above, the Agency and its Procurement Administrator have developed Standard Disclosure Forms for use in the marketing of community renewable generation project subscriptions, and the Agency has attempted to draw upon many of these same concepts in its Standard Disclosure Forms to ensure that key subscription terms are clearly disclosed to potential subscribers.

Additionally, the Agency notes that the Illinois General Assembly in its Spring 2019 legislative session passed Senate Bill 651 and the Illinois Governor then signed the bill into law on August 27, 2019.[523] The new act codifies certain ARES consumer protections around (among others) marketing conduct and automatic renewal already contained in Illinois Commerce Commission rules and introduces new consumer protections, including restrictions around enrolling low-income customers and a ban on termination fees for residential and small commercial customers.

[523] See 101st Illinois General Assembly, Public Act 101-0590, http://www.ilga.gov/legislation/publicacts/101/PDF/101-0590.pdf

The Agency is confident that the expressed will of the General Assembly supports the intent consistently expressed in the Initial Plan, in the early implementation of the Adjustable Block Program, and in this Revised Plan to hold community solar marketers to the highest standards of consumer protection. The Agency intends to update its Marketing Guidelines (and, potentially, other program documents and requirements) in light of Public Act 101-0590 and the specific issues which that legislation seeks to address. As described further in Section 6.13 above, the Agency proposes that a new draft of its marketing guidelines (and other documents, where necessary) be published for stakeholder feedback within 45 days of the Commission's approval of this Revised Plan and finalized within 90 days of that approval date.[524]

In addition, to ensure portability and transferability of subscription contracts, as required by Section 1-75(c)(1)(N) of the Act, any such contract should provide that the subscriber (i) may retain the subscription (or at least a downsized version of the subscription relative to the subscriber's new load) as long as the subscriber changes addresses for utility service within the same utility service territory, and (ii) may assign or sell the subscription to another person within the same utility service territory, without any fee owed to the subscription counterparty, subject to reasonable terms and conditions including matching the subscription size to the new subscriber's load. The Agency understands that the community renewable net metering tariffs for Ameren Illinois, ComEd, and MidAmerican approved by the Commission on September 27, 2017 are consistent with these principles. This is also consistent with guidance on this topic already published by the Program Administrator on the Program's consumer-facing website on October 3, 2019.[525]

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

The Agency's Adjustable Block Program for community solar, and the competitive procurement for other forms of community renewable generation, are both based on the core requirement that the value to the project developer (and in turn the ability to make a financially attractive offer to subscribers) is based upon the sale of the project's environmental attributes (in the form of RECs) from the project to a utility. Those RECs are then retired by the utility to meet the annual RPS goals of that utility, and the original REC holder's claims to those environmental attributes are effectively extinguished through that sale.

This raises the issue of what marketing claims may be made related to a subscription in a community renewable generation project receiving a REC contract (including community solar projects participating in the Adjustable Block Program), as such projects will have already contractually committed the sale of their environmental attributes to a third party. With the underlying "renewable" or "solar" element of that generation having been decoupled and sold to the utility, can it still be marketed as a "community solar" project? Moreover, can the subscriber make any claims for any commercial purpose about any "green" (or similar) aspect of his or her energy sourcing?

[524] The draft guidelines were released for stakeholder feedback on April 9, 2020. See: http://illinoisabp.com/2020/04/09/rec-contract-request-for-stakeholder-comments/.

[525] See http://illinoisshines.com/faq ("If I subscribe to a community solar project participating in the Adjustable Block Program, can I keep my subscription when I move? Can I transfer my subscription to someone else?").

Guidance from the Federal Trade Commission ("FTC") would appear to limit what claims can be made about energy sourced from projects whose RECs are transferred to another entity.[526] That guidance suggests that appropriate disclaimers about the fate of the RECs may satisfy rules against deceptive marketing. Yet, at some point, the issue begins to border on the absurd: a lengthy factual explanation of a community solar subscription and this Agency's various RPS programs would be permissible, but a shorthand description used to market that subscription may be legally problematic. These issues would also apply for the most part equally to installations of onsite photovoltaic generation at homes or commercial facilities; the customers whose load offsets the onsite installation would not be able to make any claims about using "green" or "clean" energy, and the marketers should similarly not market the installation opportunity as one to obtain "green" or "clean" power.

While the Agency recognizes that it is not the Federal Trade Commission (or the state's Office of Attorney General) and thus cannot provide reliable guidance on what marketing claims may be permissible, the Agency can play an important role in ensuring that any potential subscribers understand the value of a community solar subscription (or that any potential onsite hosts understand the value of an onsite installation)—even if more direct statements cannot be made about the environmental attributes of the underlying energy. To this end, the Agency has worked with its Adjustable Block Program Administrator on the development of a "brand" associated with Adjustable Block Program participation, "Illinois Shines." The Illinois Shines "brand," and associated content (including the public-facing web site http://illinoisshines.com) allows potential subscribers to a community solar project (or home and building owners seeking to install onsite solar) to understand that participation in such a project helps the state meet its renewable energy goals and may support the development of a new generating facility—but without risking the project developer itself making false or misleading claims about "renewable" or "clean" energy.

The Agency plans to continue to work closely with representatives of the solar industry, the state's Office of the Attorney General, the Staff of the Illinois Commerce Commission, and other parties in continuing to refine this approach and any associated content. This includes adding additional consumer-facing educational and informational content to the program website.

7.7. Utility Responsibilities

While the Agency, through the Adjustable Block Program and competitive procurements, will be responsible for the procurement of RECs from community renewable generation projects, it is not responsible for all aspects of a successful program. There are several additional key aspects of making community renewable generation projects successful that fall outside of the control of the Agency.

- The crediting of the value of energy through net metering
- Ensuring the portability and transferability of subscriptions within a utility service territory.

The Agency will work with system owners and developers as well as the utilities (and with rural electric cooperatives and municipal utilities should they choose to participate) to reflect these aspects in the terms, conditions, and operational aspects of the programs and procurements

[526] See 16 C.F.R. § 260.15(d), Example 5; see also U.S. EPA, "Making Environmental Claims," https://www.epa.gov/greenpower/making-environmental-claims; see also U.S. FTC letter dated February 5, 2015, https://www.ftc.gov/system/files/documents/public_statements/624571/150205gmpletter.pdf.

conducted by the Agency. The Agency will also coordinate with the utilities for the sharing of any pertinent data and information that each party collects and maintains regarding projects and subscriptions.

Public Act 99-0906 required each electric utility to file a tariff within 90 days after the Act's effective date, June 1, 2017, to implement net metering for community renewable projects.[527] A brief summary of those filings (and the resultant proceedings, where applicable) is outlined below.

ComEd's community renewable generation net metering tariff, Rider POGCS, was approved by the Commission in Docket No. 17-0350 on September 27, 2017. The Commission resolved a dispute between the Company and intervenors around indemnification by approving ComEd's proposal that both subscribers and the project itself will indemnify the Company against any liabilities relating to the reporting of a subscriber's share or a subscriber's interval usage data – and that ComEd will not have reciprocal indemnification obligations. The Commission indicated that existing regulations related to billing and meter usage data would be "more than sufficient to ensure that ComEd complies with its legal obligations."[528] The Commission rejected the proposal of certain intervenors that the net metering credit paid to community renewable generation projects include the volumetric transmission services charge, in addition to the supply charge (which includes an adjustment factor).

MidAmerican's community renewable generation net metering tariff, Rate NM, was approved by the Commission in Docket No. 17-0368 on September 27, 2017. The tariff stipulates that both subscribers and the project itself will indemnify the Company against any liabilities relating to the reporting of a subscriber's share or a subscriber's interval usage data. MidAmerican's tariff provides community renewable net metering credits at the "supply charge," plus certain adjustment factors.

Ameren Illinois proposed revisions to its existing net metering tariff, Rider NM, to include provisions for community renewable generation project net metering. The revisions were approved by the Commission on September 27, 2017. Ameren Illinois' revised tariff credits the energy service bills of subscribers to a community renewable generation project for net production at the "tariffed or contract rate for electricity supply as appropriate."

As discussed in Section 7.6.2, the Agency believes that the three approved tariffs will allow portability and transferability of subscriptions, as required by Section 1-75(c)(1)(N) of the Act.

[527] 220 ILCS 5/16-107.5(*l*), (*l*-5).

[528] Docket No. 17-0350, Final Order dated September 27, 2017 at 18.

8. Illinois Solar for All Program

8.1. Overview

The Illinois Solar for All Program was created through revisions to Section 1-56(b) of the IPA Act contained in Public Act 99-0906 to "include incentives for low-income distributed generation and community solar projects" with the following objectives:

> *"bring photovoltaics to low-income communities in this State in a manner that maximizes the development of new photovoltaic generating facilities, to create a long-term, low-income solar marketplace throughout this State, to integrate, through interaction with stakeholders, with existing energy efficiency initiatives, and to minimize administrative costs."*[529]

The Act creates four sub-programs within Illinois Solar for All, with incentives for each type of development:

(A) Low-income Distributed Generation, for on-site solar projects
(B) Low-Income Community Solar, for off-site solar projects
(C) Incentives for non-profits and public facilities to do on-site projects
(D) Low-Income Community Solar Pilot Projects, with distinct rules and incentives

The Agency is instructed to "include a description of its proposed approach to the design, administration, implementation and evaluation of the Illinois Solar for All Program" in this Plan. This Chapter fulfills that provision of the Act.

While the price of photovoltaics has declined dramatically over recent years, there can be significant upfront costs for the development of projects. The financial incentives offered through the Adjustable Block Program may not be sufficient for low-income households and communities to overcome the substantial barriers to participating in the growing solar energy market. The Illinois Solar for All Program is an alternative approach and program to help address this challenge.

8.2. Design Considerations

In developing the program, the Agency identified two key design elements for implementing the Illinois Solar for All Program that necessitated more focused discussion: the relationship to the Adjustable Block Program, and the creation of economic benefits for participants.

8.2.1. Relationship with the Adjustable Block Program

The goals of the Illinois Solar for All Program overlap with the goals of the Adjustable Block Program in that both promote distributed photovoltaic generation and community solar. The differences primarily involve the sectors that the programs serve, the structure of the incentives and program design, and the applicable funding sources.

As described in this Chapter, the Agency administers the Illinois Solar for All Program separately from the Adjustable Block Program, but it is built off of the program design of the Adjustable Block Program, with additional considerations specific to Illinois Solar for All. These include a different

[529] 20 ILCS 3855/1-56(b)(2).

level of incentives, additional requirements to be an Illinois Solar for All Approved Vendor, additional project application requirements, Illinois Solar for All specific contracts, and additional considerations to ensure community involvement, consumer protections, and eligibility. To the extent not specifically mentioned in this Chapter, the program design, terms, and conditions of the Adjustable Block Program also apply to the administration of, and REC delivery contracts executed under, the Illinois Solar for All Program.

The exception to this principle is the Low-Income Community Solar Pilot Project sub-program; this sub-program operates under an entirely different project selection structure (featuring a competitive procurement process), and as discussed in the Initial Plan, the Agency plans to fund this sub-program solely through the Renewable Energy Resources Fund.

8.2.2. Economic Benefits

The second consideration is the concept of "economic benefits" and how low-income participants can capture them. The Act stipulates that for the Illinois Solar for All Program, "[e]ach contract that provides for the installation of solar facilities shall provide that the solar facilities will produce energy and economic benefits, at a level determined by the Agency to be reasonable, for the participating low income customers."[530] In addition, contracts should "ensure [that] the wholesale market value of the energy is credited to participating low-income customers or organizations and to ensure tangible economic benefits flow directly to program participants, except in the case of low-income multi-family housing where the low-income customer does not directly pay for energy."[531]

A key barrier to low-income participation in renewable energy programs is lack of access to funds and financing to pay for the up-front costs of photovoltaic systems.

To create "tangible economic benefits" at a "reasonable" level, the Agency has determined that eligible residential participants in the Illinois Solar for All Program should not have to pay up-front costs for on-site distributed generation, or pay an up-front fee to subscribe to a community solar project.[532] Further, participation in the program should result in immediate, reliable reductions in energy costs for those residents or subscribers. Consistent with the Commission's Order in Docket No. 17-0838, this means that for projects that are financed or leased, any ongoing annual payments must be smaller than 50% of the annual first year estimated production and/or utility default service net metering value to be received by the customer.[533]

The Agency requires that Illinois Solar for All Approved Vendors verify that developers, installers, landlords, and other intermediaries ensure that the resulting value of the incentives offered by the program flow through to the people the program is meant to serve. However, the Agency notes that in order to avoid an overly complex administrative system, incentive levels will not be customized to each participant's specific economic circumstances.

As part of the evaluation of the Illinois Solar for All Program (see Section 8.17), the Agency will review the impact of the program on the energy costs of participants to assess how the benefits created by

[530] 20 ILCS 3855/1-56(b)(2).

[531] Id.

[532] As a clarification from the Initial Plan, in this Revised Plan the Agency does <u>not</u> propose that this requirement apply to multifamily buildings with more than five units, or to non-profit or public facilities.

[533] See Docket No. 17-0838, Final Order dated April 3, 2018 at 151. As required by the Commission's Order, this calculation must be "disclosed to the customer and reviewed and approved by the Agency."

the program reduces their energy burden. This evaluation will be used to inform any future modifications to the setting of incentive levels designed to create tangible economic benefits at a reasonable level for participants. At the time of the release of this Revised Plan, the program has only recently launched and there is insufficient information available to recommend a change in the incentive levels (i.e. the REC pricing structure and prices) from those contained in Chapter 8 of the Initial Plan.

For public and non-profit facilities that participate in the Illinois Solar for All Program, the Agency proposes to continue to utilize an approach in which the incentive level recognizes that these entities may not be able to capture the tax benefits that would be available to a comparable sized project participating in the Adjustable Block Program.[534] The higher REC price offered by the Illinois Solar for All Program can help overcome the financing barriers that certain non-profits and public facilities may face compared to private entities. The Agency observes that over 160 non-profit and public facility projects (totaling nearly 67 MW of capacity) have applied to the Adjustable Block Program, indicating that many such projects are viable at the REC prices offered by that program.

In light of this, for the Revised Plan, the Agency proposes, as discussed further in Section 8.6.3 below, that Approved Vendors submitting projects for non-profit or public facilities that *can* utilize the federal Investment Tax Credit under 26 U.S.C. § 48 will be required to demonstrate additional value to the project host.

Ensuring that "the wholesale market value of energy is credited to participating low-income customers" can be achieved through existing net metering provisions. Therefore, projects are required to participate in the applicable utility's or ARES's net metering program. This may prevent projects in the service territory of a municipal utility or rural electric cooperative that does not offer net metering from participating in the Illinois Solar for All Program. The Agency hopes that such municipal utilities and rural electric cooperatives strongly consider adopting net metering policies to bring the full value of solar to their residents and members.

Ensuring that tangible economic benefits flow directly to program participants can also be accomplished by providing documentation to the Agency that the project has no upfront cost to the residential participant, that the value of incentives are used by the project developer/installer to offset costs to the participant, and that there will not be ongoing costs or fees to the participant that exceed 50% of the value of energy produced. The resulting economic benefits to program participants will be accrued through the value they receive through net metering or avoided consumption from the energy the system produces. As described in Section 8.11, Illinois Solar for All Approved Vendors are required to document how they ensure that this goal is met. The case of low-income multi-family housing can be more complex and is discussed in more detail in Section 8.6.1.

It should be noted that these incentives are tied directly to creating economic benefits through lowered net energy costs and are calculated in that manner. As a result, there may be additional costs required to make a specific project viable (e.g., costs associated with roof repairs or wiring upgrades) that these incentives may not be able to address. Additional incentives to pay for those types of separate costs are not be available through the Illinois Solar for All Program, and the Agency encourages participants to explore alternative sources of funding as needed. The Agency and the Illinois Solar for All Program Administrator will work with Illinois Solar for All Approved Vendors to

[534] See Appendix E-5 to Initial Plan, available at https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/AppendixE-5ILSolarAllNon-ProfitPublicFacilitiesPricingModel.xls, at "CREST Inputs" tab, cell G73.

facilitate informing and educating program participants about opportunities that may be available to them through utility-administered energy efficiency programs, weatherization assistance programs, lead abatement programs, and other forms of support. This includes the provision of a Program Resource Guide on those programs.[535]

Additionally, in order to facilitate the direct flow of tangible economic benefits to low-income residential participants, the Agency and its Illinois Solar for All Program Administrator will explore, and if deemed feasible and prudent, pursue the possibility of receiving guidance from the United Stated Department of Housing and Urban Development that would clarify the treatment of Illinois Solar for All benefits with regard to cost allowance-based low-income housing programs.

8.3. Program Launch

In implementing the various new programs and procurements mandated by Public Act 99-0906, the Agency had a large and varied set of new tasks to undertake. The Agency appreciates the strong interest in the Illinois Solar for All Program and desire to make the benefits of the Program available to low-income households and communities so that they can benefit from lower energy costs. The Illinois Solar for All Program as proposed mostly builds on the Adjustable Block Program described in Chapter 6; therefore, it was necessary to first have the Adjustable Block Program's design finalized and put into operation before the Illinois Solar for All Program was able to launch. Like with the Adjustable Block Program, while the Initial Plan and this Revised Plan detail many programmatic considerations, final program design including contracts, program manuals, etc. needed to be developed and finalized by the Agency and the Illinois Solar for All Program Administrator(s) prior to program launch.

In November 2018, the Agency and Program Administrator initiated a series of stakeholder engagement sessions to share draft program details with the public and invite written feedback, which was considered in planning the implementation of the Illinois Solar for All Program. Stakeholder feedback sessions were held on a number of topics, including Environmental Justice Communities, Job Training, Approved Vendor Registration, Grassroots Education, Third Party Program Evaluation, Consumer Protection, and Project and Participant Eligibility. These opportunities to engage the public helped ensure that the process of finalizing program protocols and requirements was transparent and responsive to input from stakeholders from the solar industry, environmental advocates, and low-income advocates.

The program began accepting applications for registration to become ILSFA Approved Vendors on February 19, 2019 and opened for project applications on May 15, 2019. Due to anticipated high pent-up interest in the program's incentives for new low-income solar installations, the program launch included an initial project application window for the 2018-2019 program year of 30 days for Low-Income Community Solar projects and 45 days for Low-Income Distributed Generation and Non-Profit/Public Facilities projects. 45 Low-Income Community Solar applications (totaling nearly 60 MW of capacity), 28 Non-Profit/Public Facilities applications (totaling over 3 MW of capacity), and 1 Low-Income Distributed Generation application (2 MW of capacity) applied during that initial window. The applications for Low-Income Community Solar and Non-Profit/Public Facility projects exceeded allocated sub-program budgets for the program year, while the Low-Income Distributed Generation sub-program featured application levels below the allocated sub-program budget. Five

[535] See: https://www.illinoissfa.com/app/uploads/2019/03/ILSFA-Program-Resources-Guide-v1-20190318.pdf.

Low-Income Community Solar projects (totaling 4 MW of capacity), and 7 Non-Profit/Public Facility projects (1.3 MW of capacity) were selected. The community solar projects were selected using the project selection protocol (as discussed further in Section 8.12.2) while all the eligible Non-Profit/Public Facility projects were selected (the volume of project applications in that sub-program dropped below the annual sub-program budget after some were deemed ineligible during review). The one distributed generation applicant project withdrew. In the latter two sub-programs, unused 2018-2019 sub-program budget was rolled over to the respective 2019-2020 sub-program budget.

For the 2019-2020 Program Year, 30 Low-Income Community Solar projects (54.5 MW), 20 Non-Profit/Public Facilities projects (2.7 MW), and 11 Low-Income Distributed Generation projects (2 MW) applied during the initial project application window. The eligible applications for Low-Income Community Solar projects exceeded the allocated sub-program budget for that program year, so the project selection protocol was executed for the Low-Income Community Solar sub-program. Four community solar projects were selected (totaling 4 MW of capacity). The applications for the Low-Income Distributed Generation and Non-Profit/Public Facilities sub-programs did not fill available sub-program budgets. The Non-Profit/Public Facilities sub-program reopened on October 25, 2019 for rolling project applications and closed on February 26, 2020 after 24 projects (totaling 2.8 MW of capacity) were approved for the program year. The Low-Income Distributed Generation sub-program reopened for rolling project applications on October 1, 2019, to continue until the sub-program budget is filled or until May 31, 2020. As of the filing of the Final Revised Plan for Commission approval, 10 low-income residential projects (totaling over 2 MW of capacity) have been selected for the Low-Income Distributed Generation sub-program.

8.4. Funding and Budget

The Illinois Solar for All Program is funded through three sources. First, the Renewable Energy Resources Fund pursuant to Section 1-56(b)(2) of the IPA Act; second, funds from the renewable energy resources budgets of the utilities pursuant to Section 1-75(c)(1)(O) of the IPA Act; and third, potential additional funds from the renewable resources budgets of the utilities pursuant to Section 16-108(k) of the Public Utilities Act.

8.4.1. Renewable Energy Resources Fund Funding Available

While Section 1-56(b)(2) envisions the Illinois Solar for All Program being funded primarily through the Renewable Energy Resources Fund, as of August 14, 2019, the balance of the Renewable Energy Resources Fund was $50,422,472 (not including $112.5 million that has been lent to the state's General Revenue Fund as discussed below), while existing commitments from the Fund for contracts from the Supplemental Photovoltaic Procurements total $13.9 million.[536] This implies $149.0 million of RERF funds are available for Illinois Solar for All. Prior to the 2018-2019 program year (i.e. at the outset of the Program), before the Agency had paid any administrative costs to its Program Administrator, $150.0 million of RERF funds were available for Illinois Solar for All; this is the figure the Agency will use in this Section in explaining sub-program allocations from the RERF.

Since the filing of this Revised Plan, two transfers of $10 million each were made to the General Revenue Fund. As with the prior-transferred amount, these transfers are still required to be repaid back into the RERF, and that funding remains available for supporting expenditures from the RERF.

[536] The commitments consist of REC delivery contracts previously entered into and are being paid, or will be paid, over a five-year REC delivery schedule (invoiced quarterly) depending on when individual systems under contract were completed and began REC deliveries.

As of April 19, 2020, given the prior transfers, these two new transfers, and continued payments for RECs from the RERF, the balance of the Renewable Energy Resources Fund is now $27,509,942.62.

Prior to the enactment of Public Act 99-0906, the Renewable Energy Resources Fund received Alternative Compliance Payments each fall from Alternative Retail Electric Suppliers as part of their RPS compliance obligations. Under the revisions to Section 16-115D of the PUA contained in Public Act 99-0906, those payments are no longer made to the Fund as of June 1, 2017; rather, they are now made to the utilities, and will be paid to the utilities through Fall 2019.[537] With those payments no longer being made into the RERF, there is no new revenue that will be deposited into the Fund.

The RERF's current low balance is due to the fact that on August 10, 2017, $150 million was transferred from the Renewable Energy Resources Fund to the General Revenue Fund pursuant to the borrowing provisions contained in Section 5h.5 of the State Finance Act.[538] $37.5 million was paid back into the RERF in April of 2019,[539] and the remainder of borrowed funds are required by law to be paid back to the Renewable Energy Resources Fund within four years (i.e., by August 10, 2021).[540] As described above, two additional transfers of $10 million were also made over the past months under this same authority.

Section 5h.5(b) contains a provision that when the RERF (or for that matter other state funds that had similar transfers),

> *ha[s] insufficient cash from which the State Comptroller may make expenditures properly supported by appropriations from the fund, then the State Treasurer and State Comptroller shall transfer from general funds to the fund only such amount as is immediately necessary to satisfy outstanding expenditure obligations on a timely basis.*

Likewise, that Section also provides for,

> *continuing authority for and direction to the State Treasurer and State Comptroller to reimburse the funds of origin from general funds by transferring to the funds of origin, at such times and in such amounts as directed by the Comptroller when necessary to support appropriated expenditures from the funds, an amount equal to that transferred from them plus any interest that would have accrued thereon had the transfer not occurred…*

Were the RERF balance insufficient for payments under any new contractual obligations, these provisions would allow the Agency to make expenditures from the RERF prior to the repayment of the transferred amount—i.e., to operate as though the RERF's balance were at its original amount, even if transferred funds have not yet been moved back into the RERF. In addition, the Agency understands that the State Comptroller will coordinate with the Agency to make sure that any appropriated expenditures that the Agency makes through new contractual commitments are

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[537] See 220 ILCS 5/16-115D(i); after May 31, 2019, the ARES will no longer have any future Alternative Compliance Payment obligations, although "alternative retail electric suppliers and electric utilities operating outside their service territories shall be obligated to make all alternative compliance payments that they were obligated to pay for periods through and including May 31, 2019, but were not paid as of that date." Those payments are due to by September 1, 2019.

[538] 30 ILCS 105/5h.5(b);

[539] https://illinoiscomptroller.gov/financial-data/state-revenues/by-fund/?FundSel=0836&FundGrpSel=&FundCatSel=&FundTypeSel=&GroupBy=Agcy&FY=18&ShowMo=Yes&submitted.

[540] Section 5h.5 was initially created by Public Act 100-0023 and set the repayment time at two years. This was subsequently amended to four years by Public Act 101-0010.

honored by ensuring that the balance of the RERF is at all times sufficient to make timely payments on contracts. While the Agency understands that these transfers from the RERF have caused consternation, based on the assurances contained in the law, it does not believe that these transfers necessitate any adjustments to its proposed Solar for All program design, structure, and budget.

For the Low-Income Distributed Generation Initiative, the Low-Income Community Solar Project Initiative, and Incentives for Non-Profits and Public Facilities sub-programs the Agency plans to allocate up to $16.5 million per program year from the RERF for use for the Illinois Solar for All Program (the Low-Income Community Solar Pilot Projects sub-program is conducted through a different process that allocates funds to each procurement event rather than program year).[541] In this Revised Plan, the Agency clarifies that this allocation will be on an accrual basis, meaning that the amount allocated sets aside that much funding for selected applications during that program year, but are likely to actually be expended in future years in many cases due to the development timeline of photovoltaic projects (RECs are paid for upon energization). Unallocated RERF funds from any program year for a given sub-program would roll over and increase the balance available for the subsequent program year for that sub-program.

Table 8-1: RERF Funding for Solar for All[542]

Funding Source	Low-Income Distributed Generation Incentive	Low-Income Community Solar Project Initiative	Incentives for Non-Profits and Public Facilities	Low-Income Community Solar Pilot Projects
RERF Allocation Percent	22.5%	37.5%	15%	25%
Total RERF Allocation ($)	$33,750,000	$56,250,000	$22,500,000	$37,500,000
Previously allocated* for 2018-2019 Program Year	$4,500,000	$7,500,000	$3,000,000	($20 million allocated to 2019 procurement, balance for a 2020 or 2021 procurement)
Previously allocated* for 2019-2020 Program Year	$4,500,000	$7,500,000	$3,000,000	
Allocated* for 2020-2021 Program Year	$4,950,000	$8,250,000	$3,300,000	
Allocated* for 2021-2022 Program Year	$4,950,000	$8,250,000	$3,300,000	

* RERF funds not allocated within a sub-program for a program year will roll over to the next program year for that same sub-program.

Allocations are based on $150 million of the RERF available for Solar for All at the time of the Initial Plan development, and assume continuing level support from the RERF for the three non-pilot sub-programs in the 2022-2023, 2023-2024, and 2024-2025 program years (which, if fully allocated, would eventually deplete the RERF, leaving only utility-supplied funding available for program years after 2024-2025).

The funds allocated from the RERF are allocated according to the percentages specified in Section 1-56(b)(2) of the Act, namely 22.5% for the Low-Income Distributed Generation Incentive sub-

[541] As stated in Section 2.6.1, a program year for ILSFA corresponds to an energy delivery year and thus starts June 1 of each year. Therefore, a program year starts one month earlier than the state fiscal year, which begins July 1.

[542] The annual RERF sub-program budgets stated above are gross budgets *before* deducting administrative, evaluation, & grassroots education costs; the budgets actually available for REC incentives will be net of those costs.

program, 37.5% to the Low-Income Community Solar Project Initiative sub-program, 15% for the Incentives for non-profits and public facilities sub-program, and 25% for the Low-Income Community Solar Pilot Projects sub-program. While the Act includes an all-time cap of $50 million for the Low-Income Community Solar Pilot Projects, the 25% of available RERF funds is in fact closer to $37.5 million. As discussed further in Section 8.6.4, the Agency set a budget of $20 million for the first Low-Income Community Solar Pilot Project procurement held in December 2019; this budget is intended to cover the full 15-year value of contracts resulting from that procurement, although the contracts will be paid out continuously over time rather than upfront.

After accounting for all payments under the Supplemental Photovoltaic Procurement process pursuant to Section 1-56(i) of the IPA Act, as well as all payments under Illinois Solar for All contracts, whenever the balance of the RERF falls under $5,000, then the RERF shall be inoperative and any remaining funds shall be transferred to the Supplemental Low-Income Energy Assistance Fund for use in the Low-Income Home Energy Assistance Program, as authorized by the Energy Assistance Act.[543]

8.4.2. Utilities Annual Funding Available

Section 1-75(c)(1)(O) contains a provision that

> *The long-term renewable resources procurement plan shall allocate 5% of the funds available under the plan for the applicable delivery year, or $10,000,000 per delivery year, whichever is greater, to fund the programs, and the plan shall determine the amount of funding to be apportioned to the programs identified in subsection (b) of Section 1-56 of this Act; provided that for the delivery years beginning June 1, 2017, June 1, 2021, and June 1, 2025, the long-term renewable resources procurement plan shall allocate 10% of the funds available under the plan for the applicable delivery year, or $20,000,000 per delivery year, whichever is greater, and $10,000,000 of such funds in such year shall be used by an electric utility that serves more than 3,000,000 retail customers in the State to implement a Commission-approved plan under Section 16-108.12 of the Public Utilities Act.*

As discussed in Section 2.2.5.3, the Agency understands "funds available under the plan" in the above statutory provision to refer to funds collected by utilities through RPS riders under Section 1-75(c)(6) of the Act and Section 16-108(k) of the PUA. The following table lists projected amounts of utility funding that would be allocated to Illinois Solar for All based upon the load and budget forecasts contained in Chapter 3 for the Illinois Solar for All program years covered by this Revised Plan – namely, 2020-2021 and 2021-2022.

Table 8-2: Utility Funding

Delivery Year	Utility Renewable Energy Maximum Budgets	5% of Funds	Allocation to Illinois Solar for All
2020-2021	$227,872,083	$11,393,283	$11,393,283
2021-2022	$225,607,664	$11,280,062	$11,280,062

[543] 20 ILCS 3855/1-56(b-10).

These funds are supplied by each utility based on the allocation percentages contained in Section 3.1. These funds are not subject to the statutory percentage allocations for the funding from the RERF, specified in Section 1-56(b)(2). As discussed in Section 8.6.4, utility funding is not used for the Low-Income Community Solar Pilot Projects sub-program.

In this Revised Plan, the Agency proposes to continue the approach described in the Initial Plan that utility funding would be allocated to the three non-competitive sub-programs at a pro-rata level based on how the law allocates RERF funding to those three sub-programs (30% to the Low-Income Distributed Generation Initiative, 50% to the Low-Income Community Solar Project Initiative, and 20% to Incentives for Non-Profits and Public Facilities). As this allocation of utility funding to the sub-programs is not required by law, the Agency may adjust utility funding between those sub-programs on an as-needed basis during the program year if there are available funds in one sub-program and higher demand in another sub-program, with the exception that funds for the Distributed Generation sub-program will not be reallocated.[544]

For each of the three non-competitively procured sub-programs, approved project applications within a program year will be first funded by the utility funds, and then by the RERF funds. The reason for this approach is that utility funds shall be returned to ratepayers if not spent at the end of each program year starting with the reconciliation after 2020-2021,[545] while RERF funds are not subject to the same reconciliation and refund mechanism. Unallocated RERF funds within a sub-program from each program year would be rolled over to the following program year.

The funding for job training programs provided by ComEd (an electric utility that serves more than 3,000,000 retail customers) under Section 16-108.12 of the PUA is noted in the budget discussion in Chapter 3. As those funds are not directly part of the Illinois Solar for All Program as managed by the Agency, those funds are not included in this budget discussion. (The intersection between the Illinois Solar for All Program and the job training programs is discussed in Section 8.10.)

8.4.3. Section 16-108(k) Funding

Section 16-108(k) of the Public Utilities Act contemplates a possible situation in which the total amount of funds appropriated by the General Assembly from[546] the Renewable Energy Resources Fund during the period between June 1, 2017 and August 1, 2018 is less than $200,000,000, creating a "funding shortfall." This period encompasses part or all of three state Fiscal Years (running from July 1 of a given year to June 30 of the following year). If there is a funding shortfall, additional funding from the utilities could be available, as discussed below, and "may be used to fund the programs under subsection (b) of Section 1-56 of the Illinois Power Agency Act in the same proportion the

[544] See Section 8.6.1.1.

[545] See 220 ILCS 5/16-108(k).

[546] The sixth paragraph of the newly enacted Section 16-108(k) of the Public Utilities Act defines the "funding shortfall" based on amounts appropriated by the General Assembly ***to*** the Renewable Energy Resources Fund. However, the General Assembly has, in fact, never made an appropriation ***to*** the RERF. The General Assembly does, though, regularly make appropriations ***from*** the RERF. (See, e.g., Public Act 99-0524, enacted June 30, 2016, at Art. 24, § 10; Public Act 100-0021, enacted July 6, 2017, at Art. 45, § 10.) Thus, the IPA interprets the word "to" as a scrivener's error, intended to mean "from."

programs are funded under that subsection (b)" to provide additional support to Illinois Solar for All as part of a supplemental plan developed by the Agency.[547]

If this provision is interpreted to be based on the amounts appropriated for the whole of all three Fiscal Years covered (rather than a prorated amount of the appropriations for the first and last years, Fiscal Year 2017 and Fiscal Year 2019), then for each of the three fiscal years, the appropriation made totals $150 million for the relevant period.[548]

The Agency notes that an appropriation is merely authority to spend funds up to the appropriated amount for the purposes contained in an applicable Fiscal Year's appropriation bill. It may not correspond to the actual Fund balance or match actual expenditures made in that fiscal year.

In addition, this funding is only available if the funds collected from ratepayers by the utilities through their RPS riders exceed their expenditure to fund their purchases of RECs under the RPS during each of the 2017-2018, 2018-2019, and 2019-2020 delivery years, and half of each year's difference, if any, would be available to offset the shortfall. The Agency will ask each utility to provide an accounting of RPS collections and expenditures following the end of each of the three referenced delivery years. For the 2017-2018 delivery year, the total unspent RPS collections across the state's three large electric utilities were $102,229,434.[549] The Agency expects that there will be a similar excess for the 2018-2019 delivery year, given that no REC expenditures under the Initial Forward Procurements, the Adjustable Block Program, or Illinois Solar for All Program were made during 2018-2019, and also that the electric utilities' RPS rider collection levels grew relative to the 2017-2018 delivery year as the separate Section 16-115D's ARES compliance obligation continued to wind down, applying to 50% of ARES supplied retail load in 2017-2018 but then to only 25% in 2018-2019. In 2019-2020, the utilities' RPS collections will grow yet again due to the full phaseout of ARES compliance obligations, but REC expenditures under the Initial Plan's various procurement programs are beginning, so the expected balance of collections vs. expenditures is unclear.

If there is a funding shortfall and there are utility RPS rider overcollections during the 2017-2018, 2018-2019, and/or 2019-2020 delivery years that, in aggregate, do not exceed the funding shortfall, then Section 1-56(b)(7) provides that,

> *If additional funding for the programs described in this subsection (b) is available under subsection (k) of Section 16-108 of the Public Utilities Act, then the Agency shall submit a procurement plan to the Commission no later than September 1, 2018, that proposes how the Agency will procure programs on behalf of the applicable utility. After notice and hearing, the Commission shall approve, or approve with modification, the plan no later than November 1, 2018.*

The Agency developed and filed its Supplemental Funding Plan with the Commission on August 31, 2018.[550] That Plan concluded as follows regarding whether to use any funding shortfall to provide additional funding for the Illinois Solar for All Program:

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[547] 220 ILCS 5/16-108(k).

[548] See id.

[549] See Docket No. 18-1457, Final Illinois Solar for all Supplemental Funding Plan, November 26, 2018, at 16.

[550] See https://www.icc.illinois.gov/docket/files.aspx?no=18-1457&docId=276329.

> Taking into account the status of the Illinois Solar for All Program, the statutory priority attached to ILSFA's annual RRB allocation, the legally-required availability of RERF funds previously transferred to general funds under Section 5h.5 of the State Finance Act, Section 1-56(h)'s requirement that the RERF "shall not be subject to sweeps, administrative charges, or chargebacks," and thus the expected availability of funding sufficient to satisfy the Solar for All annual budgets included in the Long-Term Plan, the IPA does not propose supplemental funding for Illinois Solar for All using the Section 16-108(k) supplemental funding mechanism.[551]

The Illinois Commerce Commission affirmed this determination in Docket No. 18-1457. The Supplemental Funding Plan did note, however, that the Agency would seek to work with stakeholders and potentially reopen that proceeding should a change in circumstances (namely, permanent depletion of the RERF's balance) necessitate funding the Illinois Solar for All Program using the 16-108(k) funding shortfall mechanism.[552]

8.4.4. Updates to Funding and Budget in P.A. 102-0662

Modifications to Section 1-75(c)(1)(O) enacted through Public Act 102-0662 have increased the ILSFA funding available through utility collections. In contrast to the "5% of the funds available under the plan for the applicable delivery year, or $10,000,000 per delivery year, whichever is greater" (approximately $11,000,000) laid out in Section 8.4.2 above, the Act now permits allocation of "up to $50,000,000 per delivery year." Section 1-75(c)(1)(O) as modified by P.A. 102-0662 now reads in part as follows:

> *The long-term renewable resources procurement plan shall allocate up to $50,000,000 per delivery year to fund the programs, and the plan shall determine the amount of funding to be apportioned to the programs identified in subsection (b) of Section 1-56 of this Act; provided that for the delivery years beginning June 1, 2021, June 1, 2022, and June 1, 2023, the long-term renewable resources procurement plan may average the annual budgets over a 3-year period to account for program ramp-up.*

To ensure that these newly-authorized additional funds can be leveraged to support the *current* ILSFA program year (PY 2021-22), the IPA has petitioned the Commission to reopen Docket No. 19-0995, the Illinois Commerce Commission's docketed proceeding for approval of the IPA's Revised Long-Term Renewable Resources Procurement Plan which governs the ILSFA budget for the upcoming 2021-22 delivery year. The Agency proposes incorporating the changes made to Section 1-75(c)(1)(O) and Section 1-56(b)(2) into the current Long-Term Plan so as to make these funds available for the delivery year that began on June 1, 2021.

Section 1-56(b)(2), which was also amended by P.A. 102-0662, specifies the proportional allocation of the ILSFA budget across the four subprogram categories. What was previously the low-income distributed generation category within ILSFA has been split into two new categories for residential distributed generation: one for low-income single-family and small multifamily (1-4 units) solar (Section 1-56(b)(2)(A)), and one for low-income large multifamily (5+ units) solar (Section 1-

[551] Final Illinois Solar for All Funding Shortfall Plan, dated November 26, 2018, at 30.

[552] See id. at 31.

56(b)(2)(E)). Public Act 102-0662 also eliminates any allocation to the low-income community solar plot project category, formerly found under subparagraph (D).

Regarding the allocation of funds across these categories, Section 1-56(b)(2) now states that

> *Monies available in the Illinois Power Agency Renewable Energy Resources Fund ...,* ***as well as, in the case of the programs described under subparagraphs (A) through (E) of this paragraph (2), funding authorized pursuant to subparagraph (O) of paragraph (1) of subsection (c) of Section 1-75 of this Act****, shall initially be allocated among the programs described in this paragraph (2), as follows: 35% of these funds shall be allocated to programs described in subparagraphs (A) and (E) of this paragraph (2), 40% of these funds shall be allocated to programs described in subparagraph (B) of this paragraph (2), and 25% of these funds shall be allocated to programs described in subparagraph (C) of this paragraph (2).*

Accordingly, the statutorily prescribed percentage allocations now also apply to the funding from utilities, at least for the initial allocation. The Agency therefore must allocate 35% of funds to the two new low-income Distributed generation categories, 40% of funds to the Low-income Community Solar category, and 25% to the Nonprofit and Public Facility category

The 2021-22 Program Year of the ILSFA program has a waitlist for the Low-income Community Solar category and the Nonprofit and Public Facilities category. Furthermore, amendments to the IPA Act contained in P.A. 102-0662 include new efforts by the IPA, the Program Administrator, and partner agencies such as the Illinois Department of Commerce and Economic Opportunity to facilitate and drive greater participation in ILSFA. Given the uncertainty as to the how the programmatic changes made by P.A. 102-0662 might influence growth of project applications and the desire to accommodate existing waitlists, the IPA proposes to initially allocate the full $50,000,000 authorized by Section 1-75(c)(1)(O) for the 2021-22 Program Year, with the understanding that under Section 1-75(c)(1)(O)'s three-year averaging provisions, any unspent funds may rollover to the following two Program Years' budgets.

Regarding individual category allocations, Section 1-56(b)(2) establishes the initial proportionate allocation of both RERF and utility funds among the subprograms, as described above. However, that section does not specify how to allocate the 35% portion between the Small DG (single-family and 1-4 unit multifamily) and the Large Multifamily DG (5+ units). Because these are new categories and past program years have seen low participation in the previous distributed generation categories, the Agency has little data on which to base this allocation. For that reason, the Agency proposes to allocate the 35% evenly between the Small DG and Large Multifamily DG for the 2021-22 Program Year.

8.4.5. Setting Budgets

Based on the changes to the IPA Act enacted by P.A. 102-0662, the Agency proposes the following amendment to the 2021-22 ILSFA Program Year budgets:

Table 8-3: Total Illinois Solar for All Budgets for 2021-2022 Program Year

Funding Source	Low-Income DG 1-4 Units	Low-Income DG 5+ Units	Low-Income CS Project	Non-Profits and Public Facilities
RERF	$4,950,000		$8,250,000	$3,300,000
Utility	$8,750,000	$8,750,000	$20,000,000	$12,500,000
Total ($66,500,000)	$13,700,000	$8,750,000	$28,250,000	$15,800,000

8.4.6. Payment Structure

The Illinois Solar for All Program is structured so that the Agency "may pay for such renewable energy credits through an upfront payment per installed kilowatt of nameplate capacity paid once the device is interconnected at the distribution system level of the utility and is energized."[553] Section 6.14.5 describes the options for the capacity factor used in the Adjustable Block Program to convert kilowatt size of a project to the number of RECs the system would be expected to generate over 15 years. Those same options apply to Illinois Solar for All, the price paid will be expressed on a dollar per REC basis, and payments will be based upon the 15-year expected REC production of the system. For example, as described in that section, using the standard capacity factor would mean that for each kW of capacity for a fixed-mount system, approximately 21 RECs would be generated over 15 years.

Payments for Illinois Solar for All incentives take the form of upfront payments upon energization of systems, with the similar conditions as the Adjustable Block Program that a system must also be registered in GATS or M-RETS to verify that it will produce RECs. However, as discussed in Section 8.6.4, the Agency proposes a different payment structure for Low-Income Community Solar Pilot Projects, which do not participate in the Adjustable Block Program.

REC delivery contracts are either with the Agency or an electric utility, depending on the funding source,[554] and will include the assignment of RECs from each system for 15 years. RECs from these contracts will be applied to the annual RPS goals of the utility to which the project is interconnected, but do not count toward each utility's new photovoltaic project targets.[555] Projects that receive a contract through Illinois Solar for All will not be eligible also to receive a contract through the Adjustable Block Program.[556]

Contracts with the Agency (that utilize funds from the RERF) will be standard contracts that include required state contract provisions—such as terms, conditions, and attachments—including a clause stating that payment is subject to appropriation. Contracts with the utilities may have similarities, but will vary given the different requirements applicable to each.[557] Similar to what was discussed in

[553] 20 ILCS 3855/1-56(b)(3).

[554] See 20 ILCS 3855/1-56(b)(2) ("Contracts that will be paid with funds in the Illinois Power Agency Renewable Energy Resources Fund shall be executed by the Agency. Contracts that will be paid with funds collected by an electric utility shall be executed by the electric utility.")

[555] See id.

[556] Section 1-56(b)(3) of the IPA Act requires that for Illinois Solar for All contracts, "[t]he payment shall be in exchange for an assignment of all renewable energy credits generated by the system during the first 15 years of operation." Sections 1-75(c)(1)(L)(ii) and (iii) both contain provisions related to the various components of the Adjustable Block Program that, "[t]he electric utility shall receive and retire all renewable energy credits generated by the project for the first 15 years of operation." These two provisions from Section 1-56(b)(3) and Section 1-75(c)(1)(L) are mutually exclusive as only one REC can be produced, transferred, and retired for each MWh of generation.

[557] See Docket No. 17-0838, Final Order dated April 3, 2018 at 151-152.

Section 6.7 regarding contracts for the Adjustable Block Program, the Agency published standard REC delivery contracts (one for the Agency as counterparty and one for a utility as counterparty) for Illinois Solar for All in May 2019; following the approval of this Revised Plan, the Agency will endeavor to also update the Illinois Solar for All REC contract structure along similar lines to the Section 6.7 discussion, including updates to the payment withholding in lieu of collateral option as discussed in Section 6.14.6.

The Act is silent on how to allocate RECs from projects located in the service territories of municipal utilities, rural electric cooperatives, or Mt. Carmel Public Utility. The Agency suggests that RECs from those projects procured through contracts with the Agency using the RERF would not be applied to the utility RPS goals, while any RECs procured through contracts with a utility would be applied to the RPS goals of the contracting utility.

8.5. Programs

Section 1-56(b)(2) outlines four sub-programs of the Illinois Solar for All Program:

1. Low-Income Distributed Generation Incentive
2. Low-Income Community Solar Project Initiative
3. Incentives for Non-Profits and Public Facilities
4. Low-Income Community Solar Pilot Projects

The first three of these sub-programs provide an incentive based on the price per REC from the Adjustable Block Program, with adjustments to that price as described below to account for the specific needs of the Illinois Solar for All Program. The fourth sub-program will be competitively procured based on the competitive procurement approach discussed in Chapter 5, and further below in Section 8.6.4.

In addition to those four components, a provision of the Act allows stakeholders to propose alternative programs,

> *"In the course of the Commission proceeding initiated to review and approve the plan, including the Illinois Solar for All Program proposed by the Agency, a party may propose an additional low-income solar or solar incentive program, or modifications to the programs proposed by the Agency, and the Commission may approve an additional program, or modifications to the Agency's proposed program, if the additional or modified program more effectively maximizes the benefits to low-income customers after taking into account all relevant factors, including, but not limited to, the extent to which a competitive market for low-income solar has developed."*[558]

Based on experience and best practices in other states and jurisdictions, the Agency is proposing program elements in Section 8.7 intended to increase the success of low-income solar deployment in Illinois. Those elements are intended to go beyond providing financial incentives to include providing guidance on project development for low-income customers, non-profits, and public sector

[558] 20 ILCS 3855/1-56(b)(4).

customers. Additionally, the Agency will continue to monitor the treatment of multi-family buildings under the Low-Income Distributed Generation Incentive sub-program.[559]

Any changes (compared to the Initial Plan) to sub-program terms and conditions, and other general aspects of Illinois Solar for All, described subsequently in this Chapter 8 (as well as the budgetary discussion in Section 0 above) will be effective for the 2020-2021 and 2021-2022 program years and will not apply to the 2019-2020 program year which will still be underway at the time the Agency expects this Revised Plan to be approved by the Commission.

As listed in Table 8-3, approximately $27.9 million is expected to be available in program year 2020-2021 and $27.8 million in program year 2021-2022 for the non-competitively procured sub-programs. The utility-supplied funding will not be available for the Low-Income Community Solar Pilot Projects,[560] and the percentage funding allocations only apply to the funds from the Renewable Energy Resources Fund. The Agency proposes that the utility-supplied funding will be evenly allocated to the other three programs at the same relative weightings, but will monitor activity and may shift the use of the utility funding between sub-programs as needed.

8.6. Setting Incentive Levels

The incentive levels described in the following Sections were derived by utilizing the REC prices for the Adjustable Block Program as described in Section 6.4 and adjusting those prices to meet the objectives of the Illinois Solar for All Program. These incentives will be offered through a 15-year REC delivery contract, either with the Agency for projects funded with the Renewable Energy Resources Fund, or a utility for projects funded through utility-supplied funds.

Incentive levels are expressed as REC prices, and will be set according to the same groups and categories as the Adjustable Block Program (Group A for projects located in Ameren Illinois, Mt. Carmel, MidAmerican, and rural electric cooperatives and municipal utilities located in MISO; Group B for projects located in ComEd, and rural electric cooperatives and municipal utilities located in PJM). Unlike the Adjustable Block Program, these incentives will initially not be adjusted upward or downward based upon blocks of capacity filling up. Rather, the Agency proposes to review and update the incentive levels on an annual program year basis. That update will include an adjustment to account for how the comparable Adjustable Block Program REC price for each Group and category has changed since the previous update (or original REC prices as determined in this Plan), allowing for the prices offered through Illinois Solar for All to track overall market conditions while continuing to be offered at a higher level than for the Adjustable Block Program.

For this Revised Plan, the Agency is not proposing any changes to REC prices because with Solar for All. Because the Program opened for project applications in May 2019, the Agency lacks sufficient market information to make confident market-based adjustments to REC prices.

For the Low-Income Distributed Generation Incentive sub-program, the Adjustable Block Program's REC prices were adjusted in the CREST model by setting the assumed debt financing of the project to 0%, and increasing the net metering benefit shared with participants from 20% to (i) 100% for residential participants in 1-4 unit buildings, and (ii) 50% for residential participants in larger

[559] See Docket No. 17-0838, Final Order dated April 3, 2018 at 153.

[560] See Section 8.6.4 for a discussion of funding sources for the Low-Income Community Solar Pilot Projects.

buildings.[561] For the Low-Income Community Solar sub-program, those REC prices were adjusted by shortening the financing term to five years and lowering the debt financing to 35%. For the Incentives for Non-Profits and Public Facilities sub-program, REC prices were adjusted from the ABP DG pricing model by considering the project as a non-taxable entity; the up-to-10 kW size segment was assumed to be non-residential instead of residential; and the net metering benefit to be shared with participants was increased from 20% to 50%. The Agency believes these approaches represent reasonable proxies for the higher incentive level needed for Illinois Solar for All projects to overcome the financing barriers and other hurdles these project face.

8.6.1. Low-Income Distributed Generation Incentive

The Low-Income Distributed Generation Incentive sub-program is intended to provide funding for photovoltaic projects located on individual homes and multi-unit residential buildings. In addition to the requirements of the Adjustable Block Program, qualifying projects will be subject to the additional low-income consumer protections outlined in Section 8.14. As described in Section 8.15.4, 25% of available funding in this sub-program will be targeted to environmental justice communities. In approving and modifying this Revised Plan, the Commission noted that multi-faceted challenges to participation in this sub-program must be addressed; the Agency will continue to work with the Environmental Law and Policy Center, the Natural Resources Defense Council, Vote Solar, and other interested parties to develop improvements to the sub-program.[562]

8.6.1.1. Eligibility

The Agency proposes to treat residential buildings with one to four units differently than residential buildings with five units or more. For single-family homes, households must verify that they are low-income; for two- to four-unit residential buildings, at least two of the households must be verified as low-income. For five-unit and larger residential buildings, either at least 50% of the tenants must be verified as low-income, or the building must be demonstrated to meet the definition of "affordable housing" contained in the Illinois Affordable Housing Act.[563] In addition to projects being eligible based on household income, projects developed on homes or buildings that qualify for US Department of Housing and Urban Development ("HUD") Project-Based Vouchers or Project-Based Rental Assistance (which are programs for housing units dedicated to low-income tenants) also qualify. The income qualification levels required for participation in these programs is lower than income requirements for the Illinois Solar for All program.

The project selection protocol[564] developed by the Program Administrator scores projects in a manner that will help to ensure a diversity of projects between 1-4 unit buildings and larger buildings. To further ensure that diversity of projects, 25% of the program year budget will be reserved for 1-4 unit building projects. At the end of each program year, unused funds in this reserved sub-category will rollover to unreserved funds for the following program year of

[561] See Docket No. 17-0838, Final Order dated April 3, 2018 at 155; see also Appendices E-3-a and E-3-b.

[562] See Docket No. 19-0995, Final Order dated February 18, 2020 at 101.

[563] See Section 8.13.1 for more information on income verification and Section 8.13.2 for more information on income eligibility (including a required commitment for owners of multifamily buildings).

[564] See: https://www.illinoissfa.com/app/uploads/2019/05/ILSFA-Project-Selection-Protocol.pdf for the 2018-2019 and 2019-2020 program year protocol. As stated in Section 8.6.2, an updated project selection protocol will be developed for program years 2020-2021 and 2021-2022.

Distributed Generation sub-program, in accordance with the Commission's order in approving and modifying this Revised Plan.[565]

8.6.1.2. Demonstrating Tangible Economic Benefits for Residents of Multifamily Buildings

Section 1-56(b)(2) requires that the Illinois Solar For All incentives deliver tangible economic benefits for eligible low-income customers, including those that live in multifamily buildings. Multifamily buildings can be either master metered or individually metered. For master-metered buildings, the economic benefits of installing a photovoltaic system will not directly impact the occupants of the building because they do not individually pay an electric bill to their electric utility; but instead the benefits accrue to the building owner/manager. Therefore, for master-metered building owners to be eligible for the Low-Income Distributed Generation Incentive sub-program, the building owner/manager will need to commit to passing along at least 50% of the energy savings from net metering to all the tenants, regardless of income level, through reduced (or not raised) rents, or by other means, and additionally communicate to residents those benefits and how they resulted from the installation of solar. The commitment should also include a description of how this will be accomplished.

For multifamily buildings that are not master metered, one challenge is that the photovoltaic system will most likely be connected to the main building account that serves common areas and building-wide load rather than to any individual unit's account. For these buildings, the owner/manager must either provide the same demonstration of passing along benefits to all tenants as for master-metered buildings, or in the alternative, must commit to offering all tenants the opportunity (at no additional upfront cost levied by the landlord) to participate in net metering pursuant to the provisions of Section 16-107.5(*l*)(1)(B) of the PUA, which allows for net metering of "individual units, apartments, or properties located in a single building that are owned or leased by multiple customers and collectively served by a common eligible renewable electrical generating facility."

8.6.1.3. Incentive Level

Table 8-4: Incentives for the Low-Income Distributed Generation Program, 1-4 unit buildings ($/REC)

System Size	Group A	Group B
≤10 kW	$143.09	$143.09
>10 - 25 kW	$127.55	$127.55
>25 - 100 kW	$103.28	$103.28
>100 - 200 kW	$90.40	$90.40
>200 - 500 kW	$84.41	$84.41
>500 – 2,000 kW	$80.69	$80.69

[565] See Docket No. 19-0995, Final Order dated February 18, 2020 at 100-101.

Table 8-5: Incentives for the Low-Income Distributed Generation Program, 5+ unit buildings ($/REC)

System Size	Group A	Group B
≤10 kW	$117.62	$118.20
>10 - 25 kW	$107.08	$107.65
>25 - 100 kW	$87.70	$88.28
>100 - 200 kW	$74.67	$75.26
>200 - 500 kW	$68.59	$69.19
>500 – 2,000 kW	$65.32	$65.92

These incentive payments are intended to be sufficient to provide tangible economic benefits to participants through enabling project developers to eliminate upfront costs to the participants for the installation of photovoltaic projects. The incentive will be a standard incentive expressed as a payment for the contractually obligated delivery of a renewable energy credit and not customized for each project.

Projects that participate in this incentive will also be subject to the provisions related to job training discussed in Section 8.9.

8.6.2. Low-Income Community Solar Project Initiative

This sub-program, or initiative, is intended to support participation in community solar by low-income subscribers. To qualify for this initiative, community solar projects must meet conditions beyond the requirements for community renewable generation projects outlined in the Act and beyond those applicable community solar projects that participate in the Adjustable Block Program. These include:

- *"Each project shall identify its partnership with community stakeholders regarding the location, development, and participation in the project, provided that nothing shall preclude a project from including an anchor tenant that does not qualify as low-income."*
- *"Incentives should also be offered to community solar projects that are 100% low-income subscriber owned, which includes low-income households, not-for-profit organizations, and affordable housing owners."*[566]

For the first provision, ILSFA Approved Vendors' project applications must include a description of a partnership with community stakeholders in the community where the project will be located applicable to that project. While the Act does not define the term "community stakeholders," the

[566] 20 ILCS 3855/1-56(b)(2)(B).

National Community–Based Organization Network (NCBON) defines a community-based organization as one in which:

- The majority of the governing body and staff consists of local residents,
- The main operating offices are in the community,
- Priority issue areas are identified and defined by residents,
- Solutions to address priority issues are developed with residents, and
- Program design, implementation, and evaluation components have residents intimately involved, in leadership positions.[567]

The Agency will consider entities that demonstrate that they meet this definition as being able to represent community stakeholders in a partnership. Furthermore, the Agency believes the intent of the Act was to create substantial partnerships, going beyond just holding a few community meetings. In addition to information regarding location, development and participation, these partnerships should include a description of how the partnership shows that it is responsive to the priorities and concerns of low-income members of the community.

The Agency proposes that a public entity may qualify as a community-based organization for this purpose, but only if the public entity meets the following requirements:

- The public entity must represent a municipality or county (or school district, park district, etc.) in a municipality or county in the bottom 25% of the state by population.
- The public entity must certify that no local community-based organizations exist that are capable of filling this role.
- The public entity must provide the same showing of robust community engagement as a non-public entity would be required to show.
- Public entities that have failed to act as community-based partners in a past project certification would be ineligible.

The public entity would be qualified as a "community-based organization" only in the context of one project application; the qualification would not be retained for a future project application (the public entity would need to demonstrate the same factors again). Finally, the public entity must provide ongoing reporting of its engagement approach, including public participation opportunities and disclosure of its approach to the project location selection (if applicable).

If the proposed project has an anchor tenant that does not qualify as a low-income residential household, the application should describe that anchor tenant in detail; the Illinois Solar for All incentive will be reduced to account for the share of the system subscribed by that tenant not receiving a low-income incentive. For this Revised Plan the Agency proposes that for any anchor tenant, that reduction would be achieved by pricing their share at the equivalent applicable Adjustable Block Program REC price (i.e., non-profit or public anchor tenants would no longer qualify for the higher ILSFA price). A project may only have one anchor tenant, and that anchor tenant must be identified at the time of application.

[567] National Community–Based Organization Network (NCBON), "What is a Community–Based Organization (CBO)?" https://sph.umich.edu/ncbon/whatis.html. Accessed September 2017.

In order to encourage projects that have deep community connections, the Agency proposes that the separately-developed project selection protocol for the 2020-2021 and 2021-2022 program years (see Section 8.12.2) be updated to reflect the following prioritization in project selection:

- Projects for which the anchor tenant is a non-profit or public facility critical service provider and also the project host;
- Projects for which the anchor tenant is a non-profit or public facility that is not a critical service provider and is also the project host;
- Projects for which the anchor tenant is a non-profit or public facility critical service provider but not the project host;
- Projects for which the anchor tenant is a non-profit or public facility that is not a critical service provider but not the project host;
- Projects for which the anchor tenant is not a non-profit or public facility.

To qualify for any preference in project selection for a project with an anchor tenant, the anchor tenant subscription must be at least 10% of the project size (and, by law, may not be more than 40%).

Regarding projects "that are 100% low-income subscriber owned," the Agency assumes the Act intended the plain meaning of the word "ownership," and not that projects be merely 100% "subscribed" by low-income customers. For projects that can demonstrate that they are 100% owned by low-income subscribers (including not-for-profit organizations, and affordable housing owners), the incentive level will be increased by $5/REC. To be eligible for this additional incentive, the Illinois Solar for All Approved Vendor will need to certify the intent for the project to be 100% low-income subscriber owned at the time of application, and if the project is not initially structured this way, the applicant will have up to six years after energization to complete the full transfer of ownership to the low-income subscribers. The price of the transfer must be provided at the time of application and will be subject to approval by the Agency. The application must also contain a commitment that the project remain 100% low-income subscriber owned after the transfer. The additional incentive will be paid only upon the Illinois Solar for All Approved Vendor providing documentation to the Agency that the project is 100% low-income subscriber owned. The Agency understands that 100% low-income subscriber owned projects may face challenges in arranging financing. However, as the Act clearly states "100% low-income subscriber owned," the Agency is not able to offer flexibility to allow other ownership models for this provision.

As described in Section 8.15.4, 25% of available funding in this sub-program will be targeted to environmental justice communities.

8.6.2.1. Incentive Level

Table 8-6: Incentives for Low-Income Community Solar Projects ($/REC)

System Size	Group A	Group B
≤10 kW	$121.99	$119.55
>10 - 25 kW	$111.98	$109.52
>25 - 100 kW	$93.32	$90.82

>100 - 200 kW	$80.72	$78.20
>200 - 500 kW	$74.78	$72.23
>500 – 2,000 kW	$71.29	$68.74
Co-located systems exceeding 2 MW in aggregate size	$64.88	$62.30

These incentives for Low-Income Community Solar Projects are for the portion of the project that is subscribed by low-income subscribers (which includes a non-profit or public facility anchor tenant). In order to receive the incentive at the time of energization, the Approved Vendor will have to verify the level of low-income subscribers to the Project as outlined in Section 8.13.1. The Agency notes that the Adjustable Block Program only requires 50% of subscribers (in kW volume) to be identified at the time of energization, and that small subscriber adders are granted only if the project meets the small subscriber level after one year of operation. This principle will apply to Low-Income Community Solar as well. Only 50% of the low-income subscribers will need to be identified by the time the project is energized to receive the incentive. However, the amount of incentive payment will be prorated to the anchor and low-income subscription levels at the time of energization. After one year, a payment adjustment shall potentially be made based upon the anchor and low-income subscription level achieved by that time.

To ensure ongoing subscription levels by low-income subscribers, the Approved Vendor will have to provide ongoing collateral for ten years equal to 5% of the remaining REC value and report annually on low-income subscription levels. If those levels are not maintained, then the collateral may be called upon to claw back the incentives to the level of low-income subscription.

Additionally, the "adders" for small subscriber participation, as defined and described in Section 6.5.3 above relating to community solar projects in the Adjustable Block Program, will also apply to the REC prices for participating projects in the Low-Income Community Solar Project Initiative sub-program.[568] Only residential low-income subscribers with subscription sizes below 25 kW will count as "small subscribers" for this purpose.

8.6.3. Incentives for Non-Profits and Public Facilities

Section 1-56(b)(2)(C) of the Act specifies that "non-profits and public facilities" are eligible to receive incentives for on-site photovoltaic generation. These incentives are designed to "support on-site photovoltaic distributed renewable energy generation devices to serve the load associated with not-for-profit customers and to support photovoltaic distributed renewable energy generation that uses photovoltaic technology to serve the load associated with public sector customers taking service at public buildings."[569] The Act does not specify what specific non-profit organizations or public sector customers may be eligible.

Given that the objective of the Illinois Solar for All Program is in part "to bring photovoltaics to low-income communities,"[570] it is reasonable to infer that only non-profits and public sector customers

[568] See Docket No. 17-0838, Final Order dated April 3, 2018 at 155.

[569] 20 ILCS 3855/1-56(b)(2)(C).

[570] 20 ILCS 3855/1-56(b)(2).

that in some manner serve low-income communities should be eligible. However, the Act could also be interpreted such that all non-profits and public facilities would be eligible to participate; this interpretation would be consistent with the General Assembly's findings that "the State should encourage the adoption and deployment of cost-effective distributed energy resource technologies and devices, such as photovoltaics, which can encourage private investment in renewable energy resources, stimulate economic growth, enhance the continued diversification of Illinois' energy resource mix, and protect the Illinois environment,"[571] which could involve a wider range of photovoltaic facilities that would be eligible for these incentives. Because current funding levels are such that only a few large projects might make up the whole of the Non-Profit/Public Facilities budget in a single program year, focusing available funds on low-income and environmental justice communities to align with the implied legislative objectives has been the Agency's approach.

To balance these objectives, initially Illinois Solar for All Approved Vendors will have to demonstrate that the project:

1. Documents that it meets the standards described in Section 8.11 related to projects having sufficient connection to, and input from, low-income community members;
2. Is sited within an environmental justice community[572] or low-income community;[573] **and**
3. Serves the electricity load of a building that is occupied by an organization that is a critical service provider for the community (e.g., youth centers, hospitals, schools, homeless shelters, senior centers, community centers, places of worship, affordable housing providers including public housing sites).[574] For a public facility, the building must host a department/agency that is a critical service provider meeting this standard.
4. The Approved Vendor must either certify that the project's owner will not apply for the federal Investment Tax Credit in relation to the project installation, or if it will apply for the Investment Tax Credit, then the savings level for the participating host of the project must be 65% of energy value rather than 50%.

As described in Section 8.15.4, 25% of available funding in this sub-program will be targeted to environmental justice communities.

8.6.3.1. Incentive Level

Table 8-7: Incentives for Non-Profits and Public Facilities ($/REC)

System Size	Group A	Group B
≤10 kW	$155.87	$156.57
>10 - 25 kW	$142.55	$143.26
>25 - 100 kW	$118.57	$119.28

[571] Public Act 99-0906, Section 1(a)(1) ("Findings").

[572] As defined by the methodology outlined in Section 8.15.2 of this Revised Plan.

[573] A "low-income community" for this purpose is defined as a census tract where at least half of households are not exceeding 80% of AMI.

[574] If the building is not owned by the organization or public agency, then either a lease with at least five years remaining on it, or a commitment by the building owner to lease the facility to a critical service provider for at least five years must be provided.

>100 - 200 kW	$102.83	$103.55
>200 - 500 kW	$95.61	$96.34
>500 - 2,000 kW	$91.31	$92.04

8.6.4. Low-Income Community Solar Pilot Projects

Low-Income Community Solar Pilot Projects will participate in the Illinois Solar for All Program in a manner that is different from projects that participate in the other portions of the Program.

Unlike those other programs, the Low-Income Community Solar Pilot Projects "shall be competitively bid by the Agency, subject to fair and equitable guidelines developed by the Agency."[575] This means that rather than applying to the Illinois Solar for All Program and receiving an administratively determined REC price, the incentive will be determined through a competitive bidding process as outlined in Chapter 5. The Agency has a well-established process for competitive procurements, and for this process, the Agency will leverage that experience.

In addition to the general provisions that the Agency uses for competitive procurements (e.g. sealed, pay-as-bid request for proposal process), the Agency also recommends that certain provisions related to other community solar projects also apply to the pilot projects: including the eighteen-month window of time for project development, and project and customer information requirements.

The procurement for Low-Income Community Solar Pilot Projects will be bid on a $/REC basis, for contracts for 15 years of delivery of all RECs from the project to the Agency once the project is energized. The price paid will be based solely on the bid price and will not include any payment based on the Adjustable Block Program REC prices (or adders/adjustments). For this Revised Plan, the Agency proposes that payments for projects contracted through this sub-program via the second Pilot Projects procurement, to be held in 2020-2021 or 2021-2022, will be made over the 15 years of REC deliveries (rather than the first 10 years as provided in the Initial Plan for the first Pilot Projects procurement). To ensure that the procurement follows "fair and equitable guidelines," the Agency proposes that bids be evaluated only on the basis of price, as this is the most objective way to consider bid evaluation. While the Low-Income Community Solar Pilot Project procurement process requires additional considerations (described below), the Agency believes that those considerations are better applied as minimum criteria for determining eligibility to participate in the procurement rather than applied to the evaluation of competing bids (with the limited example provided below for why bids could be considered out of price order).

There are several considerations under Section 1-56(b)(2)(D) of the Act for how the competitive procurement is conducted that must be specifically considered and adapted for the Low-Income Community Solar Pilot Projects competitive procurement.

First, the Agency notes that the total funding over time for Low-Income Community Solar Pilot Projects cannot exceed $50,000,000, and that it cannot exceed $20,000,000 per project. However, as discussed in Section 8.4.1, only a maximum of $37.5 million is available from the RERF for this sub-

[575] 20 ILCS 3855/1-56(b)(2)(D).

program. Furthermore, projects are allowed to be larger than the 2,000 kW limit that otherwise applies for community renewable generation projects under net metering laws and tariffs.

Second, projects "must result in economic benefits for the members of the community in which the project will be located." The Agency believes that this provision can be met by requiring projects that wish to bid in the procurement adhere to the same provisions as the Low-Income Community Solar Projects in terms of partnerships with community stakeholders. Projects must also provide information about how they will comply with this provision through options such as providing commitments to local hiring and use of M/WBE contractors, describing impact on payments to community residents or community-based organizations as part of the project development process, and offering of subscriptions to community residents and community-based organizations (which will have to meet the same 50% savings requirement as the other Low-Income Community Solar sub-program). Failure to meet commitments made during the bidder/project registration phase of the procurement will be considered actions that would result in a default and cancellation of the contract.

Third, projects "must include a partnership with at least one community-based organization." Information on the partnership will be required to register during the initial bidder registration phase and projects that cannot demonstrate such a partnership will not be eligible to bid. As described in Section 8.6.2, the community-based organization(s) should be an existing non-profit (or in limited circumstances a government agency) organization that provides programs and services within the same defined community as where the proposed project will be located.

Fourth, funds "may not be distributed solely to a utility;" and fifth, "at least some funds under this subparagraph (D) must include a project partnership that includes community ownership by the project subscribers." These two provisions create interesting challenges in the evaluation of bids. For example, if bids are received and only the highest priced bid includes "a project partnership that includes community ownership," (a distinct requirement around ownership that goes beyond the requirement that applies to all projects that they have a partnership with a community-based organization) but constitutes the only project able to be supported under the available budget, it would have to be selected. Similarly, to ensure that funds are not distributed solely to utilities, bids may need to be selected out of price order, otherwise, only a utility project would win.

Because utilities are potentially bidders in this procurement, contracts resulting from this procurement may only be entered into by the Agency and only use the Renewable Energy Resources Fund as a source of contract funding. While generally the Illinois Solar for All Program allows for contracts to be entered into either with the Agency (using the RERF) or with one of the utilities, it would be inappropriate for utilities potentially to enter into contracts with themselves, and furthermore, the procurement process could allow for them as the Buyer to receive confidential information from competing bidders (e.g., potential Sellers).

The Agency conducted a procurement for Low-Income Community Solar Pilot Projects in late 2019 with a budget of $20 million (which will cover the 15-year REC contract value of selected projects). The Agency will consider changes to the requirements for bidder participation based upon a review (including the opportunity for stakeholder input) of the results of that first procurement, and will hold another procurement for the remaining balance of funds in this sub-program (the total value across both procurements being approximately $37.5 million, as discussed in Section 8.4.1) during either the 2020-2021 or 2021-2022 program years.

8.7. Providing Guidance and Education

The Illinois Solar For All Program provides substantial financial incentives intended to enable low-income, non-profit, and public sector customers to share in the benefits of solar power. These customers are specifically identified in the legislation partly because they face additional hurdles in deploying solar, such as a lack of taxable income needed to monetize tax-based incentives, a lack of access to capital, or institutional barriers that limit deployment.

At the same time, such customers have access to a wide variety of non-energy programs and policies intended to promote economic development, provide affordable housing, and reduce the burdens of poverty. Programs from the U.S. Department of Housing and Urban Development, for example, provide financial assistance for housing and utility bills. Such programs are supporting solar deployment to reduce utility expenses for both residents and taxpayers.

Experience in other states has shown that there are many finance-related and other policies and programs at the federal, state, and local level that can be applied to low-income solar development. The Agency believes that the Illinois Solar For All Program would benefit from guidance and education provided to Illinois Solar for All Approved Vendors, community groups, public-sector customers, and others, in addition to the financial incentives described in other sections of the Plan. One vehicle for providing such guidance is the Program Administrator(s) that manages the Illinois Solar For All Program.

8.8. Illinois Solar for All Program Administrator

The Program Administrator for the Illinois Solar for All Program was selected via a two-part Request for Qualifications/Request for Proposals process conducted by the Agency in 2018, which culminated in Commission approval of the contract for Elevate Energy to serve as the ILSFA Program Administrator on September 14, 2018.

The Illinois Solar for All Program Administrator(s) will at minimum:

- Take applications and verify project eligibility in Illinois Solar for All and coordinate this information with the Adjustable Block Program Administrator (who will process the actual generation of contracts). This includes, but is not limited to, review of project technical specifications, income verification, review of community involvement in projects, review of job training coordination, and review of Illinois Solar for All consumer protections such as verification of ensuring tangible economic benefits flow to low income participants.

- Act as the centralized source for income verification and maintain database of program participants.

- Assist in the development of contracts, disclosure forms, and brochures for use by Illinois Solar for All Approved Vendors and their partner community-based organizations.

- Coordinate the distribution of funding for grassroots education efforts by community-based organizations. A priority for this funding will be to promote the availability of the Illinois Solar for All Program in Environmental Justice Communities to achieve the goal of 25% of the incentives being allocated to those communities.

- Facilitate Illinois Solar for All Approved Vendors meeting the additional requirements of the Illinois Solar for All Program. In particular, the Program Administrator acts as a liaison between Illinois Solar for All Approved Vendors participating in the programs and organizations providing job training. The Program Administrator shall also work to inform Illinois Solar for All Approved Vendors of energy efficiency, weatherization, lead abatement, and other program opportunities that could provide additional benefits to participants.

- Provide guidance and education to Illinois Solar for All Approved Vendors, community groups, local government agencies, and others on how to leverage other governmental policies to facilitate low-income solar projects and energy efficiency programs. Other relevant policies include affordable housing, economic development, public finance, and tax policies, at the federal, state, and local level. The Administrator will act as liaison with other governmental agencies that administer such programs to facilitate their use on solar development.

- Provide Program Manual and related materials for use by Illinois Solar for All Approved Vendors.

- Provide reports to the Agency and the Commission on a quarterly basis on the status of the Program including, but not limited to, number of applications received, number of applications approved, number of projects completed, REC payments, payments for and status of grassroots education efforts (if applicable), and a summary of technical assistance provided.

8.9. Quality Assurance

Due to the higher incentive level that Illinois Solar for All projects will receive compared to those that participate in the Adjustable Block Program, as well as the additional vulnerabilities that program participants may face, it is especially important for the Agency to ensure that projects are properly installed and produce their expected amounts of energy. In conjunction with the Program Evaluator (as described in Section 8.17), the Illinois Solar for All Program Administrator has developed and implemented a process for quality assurance, including assessing 1) the suitability of sites for solar installation and/or the proper planning for mitigating site deficiencies before installation, 2) a thorough photo documentation of all projects while under construction, and 3) on-site inspection of a random sample of installations. If installations are found to have deficiencies or nonconformance with specifications from the application, the Illinois Solar for All Approved Vendor, at its own expense, will be responsible for any repairs, alterations, or additions to remedy the deficiencies. A deficient project may be removed from the Program if already contracted. Illinois Solar for All Approved Vendors who have a disproportionately high number of deficient systems may lose their eligibility to continue to participate in the Illinois Solar for All Program.

8.10. Coordination with Job Training Programs

Section 1-56(b)(2) of the Act contains two provisions that are designed to ensure that the job trainees supported by the ComEd job training programs[576] established under Section 16-108.12 of the Public

[576] ComEd's job training implementation plan was approved by the Commission on September 27, 2017 in Docket No. 17-0332.

Utilities Act participate in the installation of photovoltaic projects supported by the program. The first of these requirements is aspirational in nature, while the second is more specific.

The first provision is that "[p]rojects must include job training opportunities if available, and shall endeavor to coordinate with the job training programs described in paragraph (1) of subsection (a) of Section 16-108.12 of the Public Utilities Act."[577] This program is known as the "solar training pipeline program." Under this provision, ComEd is to spend $3,000,000 in each of 2017, 2021, and 2025 to train installers for the solar projects authorized and contemplated under the Solar for All program and other RPS programs. The job training program is to be "designed to ensure that entities that offer training are located in, and trainees are recruited from, the same communities that the program aims to serve and that the program provides trainees with the opportunity to obtain real-world experience."[578]

The availability of job training opportunities for Solar for All projects depends, in part, on the availability of graduates of the solar training pipeline program. ComEd's Request for Proposals from potential training providers was issued August 1, 2017 and remained open until September 30, 2017.[579] The RFP emphasizes the need for training providers to include trainee recruitment, substantive solar industry training, and post-training opportunities.[580] Moreover, ComEd has committed "to coordinate with the Illinois Power Agency or its administrator of Illinois Solar for All."[581]

The second relevant provision is that, for the Low-income Distributed Generation sub-program, "[c]ompanies participating in this program that install solar panels shall commit to hiring job trainees for a portion of their low-income installations" and further that, "an administrator shall facilitate partnering the companies that install solar panels with entities that provide solar panel installation job training."[582]

The Act does not specify what is meant by "a portion" and also does not define who would qualify as a "job trainee" in contrast with the prior provision that specifically ties it to the solar training pipeline program. The Agency notes that Section 16-108.12 of the Public Utilities Act not only creates the solar training pipeline program described above but also creates a "craft apprenticeship program" and a set of six "multi-cultural jobs programs." The Agency infers that graduates of those programs could reasonably be considered "job trainees" for the purposes of the Low-income Distributed Generation Incentive sub-program within Illinois Solar for All.

ComEd stated in the ICC proceeding reviewing its Section 16-108.12 job training plan that it intends to implement the Solar Craft Apprenticeship Program in coordination with the International Brotherhood of Electrical Workers ("IBEW") Local 134, which will integrate solar training curricula into its existing electrical craft/trade/skill apprenticeship programs at 18 IBEW sites as well as

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[577] 20 ILCS 3855/1-56(b)(2).

[578] 220 ILCS 5/16-108.12(a)(1).

[579] See https://www.cct.org/what-we-offer/request-for-proposals-solar-job-training.

[580] Docket No. 17-0332, ComEd Ex. 1.0 (http://www.icc.illinois.gov/downloads/public/edocket/451215.pdf) at 8. As described further at the webpages linked below, recipients of Multi-Cultural Jobs Program grants were announced in August 2017: https://www.comed.com/News/Pages/NewsReleases/2017_08_01.aspx and recipients of Solar Training Pipeline Program grants were announced in December 2017: https://www.comed.com/News/Pages/NewsReleases/2017_12_07.aspx.

[581] Docket No. 17-0332, ComEd/EDF/ELPC/LVEJO Joint Initial Comments at 5.

[582] 20 ILCS 3855/1-56(b)(2)(A).

certain community colleges and high schools.[583] According to the Plan submitted by ComEd in that proceeding, the Solar Craft Apprenticeship Program appears to include training locations located across the entire State, and not just in ComEd's service territory.[584] This program may be essential for ensuring the availability of job trainees across the State. In July 2019, ComEd released an annual report detailing the status of its job training programs under Section 16-108.12.[585]

To ensure that "a portion" of projects use job trainees, Illinois Solar for All Approved Vendors who participate in the Illinois Solar for All program should demonstrate that at least 33% of Low-Income Distributed Generation projects (on a rolling average basis) include the use of one or more job trainees from the solar training pipeline program, the craft apprenticeship program, or the multi-cultural jobs program. Furthermore, each Illinois Solar for All Approved Vendor will have to demonstrate that for its first year of participation, 10% of the hours worked on all projects will be by job trainees, and that amount would increase to 20% in their second year of participation, and 33% in the third year. This timeline for these increasing annual percentage requirements will start with the beginning of construction of the Approved Vendor's first project contracted under the Program.

Illinois Solar for All Approved Vendors will be required to document the use of job trainees, and to provide a summary of their work to the Program Administrator. Illinois Solar for All Approved Vendors may also request to use job trainees from other job training programs so long as they can demonstrate that completion of the job training program would lead to the trainee becoming a "Qualified Person" under the Part 468 Rule related to the certification of installers of photovoltaic systems (see Section 2.3.2.4 for additional discussion of these requirements). The Agency will consider requests for waivers of this requirement on a case-by-case basis if an Illinois Solar for All Approved Vendor can demonstrate that, despite diligent efforts at recruitment, job trainees are not available in the area where projects are being installed and this would prevent the project from being completed.

The Illinois Solar for All Program Administrator is coordinating with the entities providing job training to maintain a clearinghouse of information that Illinois Solar for All Approved Vendors can use to identify potential job training program graduates to hire.

The Agency and its Program Administrator(s) will not run the job training programs, and therefore, the Agency has limited ability to ensure the success of those programs in effectively training new workers. Rather, the Agency will seek to ensure that the Illinois Solar for All Program creates employment opportunities for those new workers.

8.11. Additional Requirements for Approved Vendors

Because the Illinois Solar for All Program (other than the Low-income Community Solar Pilot Projects) works similarly to the Adjustable Block Program, direct participants must first be approved as ABP Approved Vendors through the process outlined in Section 6.9. Approved Vendors who seek to submit projects into Illinois Solar for All will additionally have to register with the Illinois Solar for All Program and agree to additional terms and conditions to become an Illinois Solar for All Approved

[583] ICC Docket No. 17-0332, ComEd Ex. 1.0 at 12.

[584] Id. at 13.

[585] https://www.icc.illinois.gov/docket/files.aspx?no=17-0332&docId=288221.

Vendor.[586] An Approved Vendor that does not achieve this status will not be eligible to submit projects. A list of Illinois Solar for All Approved Vendors is available on both the Adjustable Block Program website and Illinois Solar for All website.

The additional requirements for registering to be an Illinois Solar for All Approved Vendor include:

- Description of plans for community involvement in projects (where applicable)
- Plan for inclusion of job training opportunities
- For those indicating intention to submit projects that receive the Low-income Distributed Generation incentive sub-program, a commitment to hire job trainees for a portion of the projects as described in Section 8.10
- Coordination with the Program Administrator on income verification
- Agreement to allow the Program Administrator and Agency to review and approve marketing materials geared towards the Illinois Solar for All Program
- Agreement to ensure additional consumer protections as described in Section 8.14
- Demonstration that for low-income distributed generation and community solar projects that participants do not have any up-front payments.

The Act provides that "[p]riority shall be given to projects that demonstrate meaningful involvement of low-income community members in designing the initial proposals" and that "[a]cceptable proposals to implement projects must demonstrate the applicant's ability to conduct initial community outreach, education, and recruitment of low-income participants in the community."[587] For community solar projects, these requirements apply through the requirement to identify partnerships with community stakeholders. It is less clear how those provisions would apply directly to projects that participate in either the Low-Income Distributed Generation Incentive sub-program or the Incentives for Non-profits and Public Facilities sub-program.

To satisfy these provisions, the registration process for the Illinois Solar for All Program will require Illinois Solar for All Approved Vendors to demonstrate their capacities in this area. An Illinois Solar for All Approved Vendor will do so by satisfying all of the following requirements:

- Providing narrative summary of efforts taken prior to the application to conduct community outreach, education, and recruitment
- Listing community-based organizations the applicant has partnered with, including letters from those organizations to verify the partnerships
- Describing in detail ongoing plans for community outreach, education, and recruitment
- Describing staffing for dedicated outreach, education, and recruitment
- Describing plans for ensuring that tangible economic benefits flow to program participants
- Participating in training offered by the Program Administrator on guidelines for marketing, contracting, and standard disclosures for program participants

[586] This includes the option to be an Illinois Solar for All Single Project Approved Vendor similar to the Adjustable Block Program Single Project Approved Vendor option. The minimum project size would be 50 kW.

[587] 20 ILCS 3855/1-56(b)(2).

Failure to maintain a demonstrated commitment to these requirements may result in an Illinois Solar for All Approved Vendor being removed from participating in the Illinois Solar for All Program.

8.12. Application Process

8.12.1. Project Submissions and Batches

Except for Low-Income Community Solar Pilot Projects, the process for a project to be submitted to the Illinois Solar for All Program generally mirrors that for the Adjustable Block Program described in Section 6.14. Projects are submitted by Illinois Solar for All Approved Vendors through a similar process as the Adjustable Block Program but the initial minimum batch size is 50 kW. There is no application fee for Illinois Solar for All projects.

Applications will be submitted through the Illinois Solar for All project application portal and will provide the supplemental information required for those projects for Illinois Solar for All in addition to what would be required for an Adjustable Block Program project. If the supplemental information does not demonstrate that the project qualifies for participation in the Illinois Solar for All Program, the project may still be eligible to participate in the Adjustable Block Program through a separate application (including the payment of an application fee), although any such application would be subject to the availability of block capacity in the Adjustable Block Program. A project may not apply to the Illinois Solar for All Program if it is included in a batch of Adjustable Block Program projects that have been submitted to the Commission for approval (or subsequently approved). If a project applies to both programs, the Solar for All application will have to be withdrawn at the time the Adjustable Block Program sends its approval recommendation to the Commission (and vice versa). Additionally, a project may not apply to two sub-programs of Illinois Solar for All within the same program year.

Like for the Adjustable Block Program, Illinois Solar for All projects will be bundled into one contract or confirmation for each approved batch. The Agency will request Commission approval for contracts that include additional Illinois Solar For All provisions. In this Revised Plan the Agency proposes that those contracts will be executed first with the utilities using the allocation from their Renewable Resources Budgets, and then by the Agency using funds from the Renewable Energy Resources Fund. This change from the order contained in the Initial Plan (which was to execute contracts with the Agency first) is to recognize that with the end of the rollover period for utility collected funds there is more urgency to allocated and spend those funds. For contracts allocated to a utility, the Program Administrator will strive to allocate contracts to each utility for projects in their service territory, and in a manner that will obligate funds at a level consistent with each utility's share of funds committed to Illinois Solar for All.

Like the Adjustable Block Program contract process described in 6.14.6, an Approved Vendor's failure to timely execute a product order will potentially subject that Approved Vendor to discipline, and the constituent projects will be considered removed from the Illinois Solar for All Program. Additionally, as discussed in Section 6.15.1 for the ABP, when an Approved Vendor's collateral is forfeited under its ILSFA REC contract (if the contract is with a utility), that collateral amount will be restored to the utility's Renewable Resources Budget, and if the contract is with the Agency, that collateral amount would be deposited into the Renewable Energy Resources Fund.

The process for posting collateral will mirror that for the Adjustable Block Program described in Sections 6.14.6 and 6.16.1. For a Low-Income Community Solar project that is not yet energized at

the time of Commission approval, the contract value (for purposes of calculating the required collateral posting) will be based on an assumption that 100% of the project is subscribed by low-income residential households qualifying as "small subscribers."

For Low-Income Community Solar Pilot Projects, the application process will take place through registering for, then bidding in, the competitive procurement for those projects. Prior to accepting bids for the Low-Income Community Solar Pilot Project competitive procurement process, the Agency and its Illinois Solar for All Program Administrator will work with stakeholders to refine and finalize requirements for bidder participation.[588] The approval of contracts by the Commission will take the form of the Commission approving the results of the competitive procurement.

8.12.2. Project Selection for Sub-programs with High Demand

Projects for each sub-program (except for Low-Income Community Solar Pilot projects) must initially be submitted within pre-determined project submission windows for each program year. In the case that a sub-program has a large number of applications such that the funding required for all eligible applications received within the submission window exceeds that sub-program's total budget (including RERF funds and utility funds)[589] for that program year, the Agency will establish a protocol that provides a basis for scoring each individual project based on attributes that align with the goals of this Revised Plan and creates a ranking of projects based on these scores.[590] The highest scoring projects will be selected for funding first, where possible, ensuring funds prioritize projects that directly meet Plan objectives. One objective of this selection protocol will be to minimize the use of random tie-breaking as a means of selection.

Attributes that will receive higher scores include:

- Location with an Environmental Justice Community,
- Location within a low-income community (as defined above in Section 8.6.3),
- Projects developed by Approved Vendors that are women- or minority-owned businesses,[591] or
- Preferences for types of subscribers in Low-Income Community Solar projects, as outlined in Section 8.6.2;
- Other attributes that align with Plan priorities.

In addition, scoring will be weighted in such a way that helps to ensure a diversity of project development compared with all projects submitted for a given sub-program. For example, additional weighting might be given for:

- Geographic location,

[588] See Docket No. 17-0838, Final Order dated April 3, 2018 at 161.

[589] Note that sub-program budgets are adjusted to account for any funds not committed in the previous program year and rolled over (although utility budgets cannot be rolled over starting with the uncommitted 2020-2021 utility budget), administrative expenses, and grassroots education costs. Furthermore, the Agency may adjust allocations of utility-supplied funding if needed.

[590] This approach has been utilized for the 2018-2019 and 2019-2020 program years. See: https://www.illinoissfa.com/app/uploads/2019/05/ILSFA-Project-Selection-Protocol.pdf. The Agency expects that an update to the protocol will include additional granularity in scoring to minimize the likelihood of tied scores that would require random selection of projects.

[591] During the proceeding to approve this Revised Plan, the Agency recommended a workshop or public comment process to explore expanding this criterion beyond Approved Vendors to include contractors and subcontractors. The Commission agreed that such a process is appropriate. See Docket No. 19-0995, Final Order dated February 18, 2020 at 105.

- Project size, or
- Other such attributes that reflect a diversity of projects.

The project selection protocol should be executed in a way that ensure the goal of 25% of funds going to Environmental Justice communities is met whenever possible. As discussed in Section 8.15.4 below, the 25% allocation for projects located in Environmental Justice communities within each sub-program will be held open until the end of each program year.

After each program year's initial project submission window, if funds for a given sub-program remain available, project applications will be accepted and reviewed on a first-come/first-served basis for the remainder of the program year. If annually allocated RERF funds in a sub-program remain at the end of the program year, the unused funds will be rolled over to the next program year for that sub-program.

The 2019-2020 project selection process may result in a waitlist of unselected projects within one or more sub-programs for that program year. The Agency proposes through this Revised Plan that each 2019-2020 waitlist would not be used after May 31, 2020 and that the project selection protocol for the 2020-2021 and 2021-2022 program years will not give preference to projects that were on previous years' waiting lists.

8.13. Customer Eligibility

Customer eligibility for the Illinois Solar for All Program is partly defined in the Act. Further refinements are proposed in this section.

8.13.1. Income Guidelines

The Act states that for the Illinois Solar for All Program, "'low-income households' means persons and families whose income does not exceed 80% of area median income, adjusted for family size and revised every 5 years."[592]

The Agency proposes to use income eligibility guidelines from HUD. HUD bases its housing assistance programs, such as the Section 8 Housing Choice Voucher program on 80% of area median income, adjusted for family size.[593]

Because the Act does not define "area," the Agency is proposing to use HUD's definition of an area as a Metropolitan Statistical Area (MSA), a Fair Market Rate (FMR) Area, or a county not in an MSA or FMR. There are 20 MSAs and FMRs, and 62 other counties in Illinois.

Eligibility levels for Illinois Solar For All, based on 2017 HUD guidelines for every area and adjusted for family size, are presented in Appendix F. These guidelines will be updated in 2022.

For Fiscal Year 2017, the HUD eligibility income limits for Illinois as a whole are shown in the table below. For example, a family of four would be considered "low-income" if their household income were less than $59,300. (Actual eligibility depends on income for an area, rather than for the state as

[592] 20 ILCS 3855/1-56(b).

[593] HUD, FY 2017 Income Limits Documentation System at https://www.huduser.gov/portal/datasets/il.html.

a whole.) HUD has other programs that use "very low" and "extremely low" income measures, at 50% and 30% of AMI that are provided here for reference.[594]

Table 8-8: HUD Income Limits

HUD State Income Limits: Illinois FY 2017								
Median family income (MFI) = $74,100								
Persons in household	1	2	3	4	5	6	7	8
30% of median ("extremely low income")	$15,550	$17,800	$20,000	$22,250	$24,000	$25,800	$27,550	$29,350
50% of median ("very low income")	$25,950	$29,650	$33,350	$37,050	$40,000	$43,000	$45,950	$48,900
80% of median ("low income")	**$41,500**	**$47,400**	**$53,350**	**$59,300**	**$64,000**	**$68,750**	**$73,500**	**$78,250**

It should be noted that other low-income energy programs, such as the Illinois Home Weatherization Assistance Program ("IHWAP") and the Low Income Home Energy Assistance Program ("LIHEAP") have eligibility guidelines that are updated each program year, based on the federal poverty level (not area income), with statewide values. Eligibility guidelines are set for households with income below 200% and 150% of the federal poverty level, depending on the program. Illinois eligibility guidelines are set by the Department of Commerce and Economic Opportunity and are shown in Table 8-9.[595]

Table 8-9: Eligibility Guidelines for LIHEAP and WAP in Illinois

	2017 Illinois LIHEAP eligibility			**2018 IHWAP Income Eligibility Guidelines**	
Household Size	30 Day Income	Annual income (150% of FPL)		State Funds (150% of FPL)	Federal Funds (200% of FPL)
1	$1,508	$18,090		$18,090	$24,120
2	$2,030	$24,360		$24,360	$32,480
3	$2,553	$30,630		$30,630	$40,840
4	$3,075	$36,900		$36,900	$49,200
5	$3,598	$43,170		$43,170	$57,560
6	$4,120	$49,440		$49,440	$65,920
7	$4,643	$55,710		$55,710	$74,280
8	$5,165	$61,980		$61,980	$82,640

[594] https://www.huduser.gov/portal/datasets/il/il17/State-Incomelimits-Report-FY17.pdf. For metropolitan area and county level income limits, see: https://www.hudexchange.info/resource/reportmanagement/published/HOME_IncomeLmts_State_IL_2017.pdf.

[595] Illinois Department of Commerce and Economic Opportunity, "Community Assistance, Energy Efficiency and Infrastructure," https://www.illinois.gov/dceo/CommunityServices/Pages/default.aspx. Accessed September 2017.

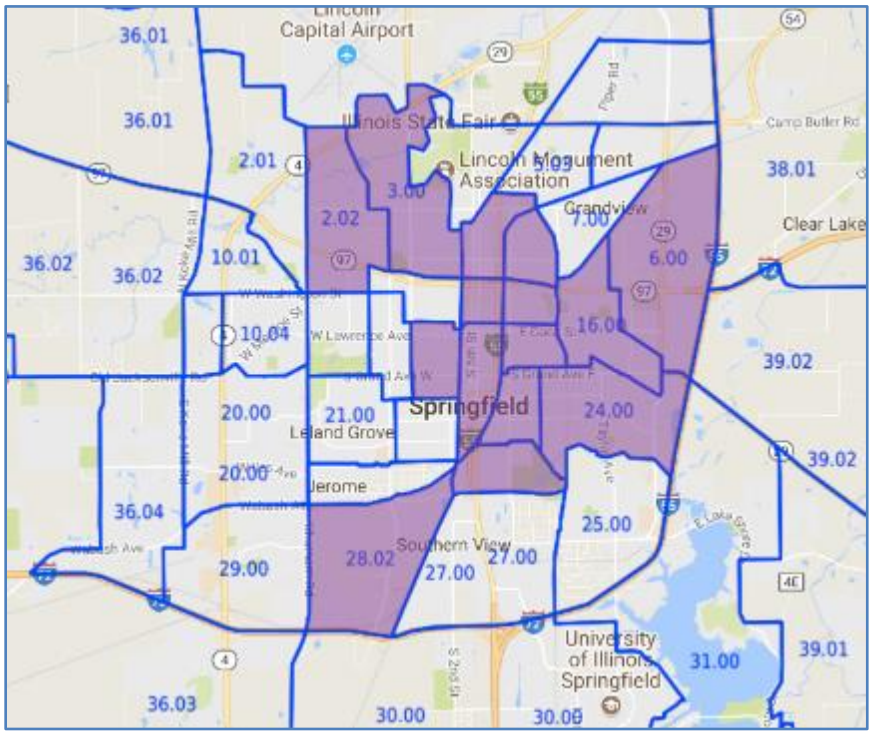
In all regions of Illinois, 150% of the federal poverty level is lower than 80% of Adjusted Median Income ("AMI") for all household sizes. Thus, all households eligible for LIHEAP are also eligible for Illinois Solar For All. Households participating in IHWAP using state funds are also eligible, while those using Federally funded IHWAP (200% of FPL) may be eligible in some areas of the state and some household sizes, but not others. The tables in Appendix F compare HUD eligibility levels to LIHEAP and IHWAP income eligibility levels.

Another approach to identifying low-income customers, by geographic area rather than by individual household income, is to use HUD's "Qualified Census Tracts," which are used to define eligibility for the Low-Income Housing Tax Credit (LIHTC).[596] Qualified Census Tracts must have 50 percent of households with incomes below 60 percent of the Area Median Gross Income (AMGI) or have a poverty rate of 25 percent or more.

HUD has identified and mapped Qualified Census Tracts ("QCT") nationwide. Overall, there are 657 QCTs in metropolitan areas in Illinois and 49 in non-metropolitan areas (out of 3,123 total census tracts in Illinois). Cook County has the largest portion with 441. Springfield, which has 15 QCTs, is shown in Figure 8-1 as an example.

The Agency will use QCTs (along with subscriber affidavits) as a streamlined method for determining eligibility for low-income community solar subscribers, as discussed in the next section.

Figure 8-1: Springfield Qualified Census Tracts



[596] HUD, "Qualified Census Tracts and Difficult Development Areas," web site accessed July 19, 2017. https://www.huduser.gov/portal/datasets/qct.html.

Source: HUD, https://www.huduser.gov/portal/sadda/sadda_qct.html

8.13.2. Determining Income Eligibility

The Agency proposes several approaches to determining income eligibility for the Illinois Solar for All Program.

For projects that participate in the Low-income Distributed Generation Incentive Program sub-program, verification of income should be done at the household resident level. This can be done in several ways.[597]

For buildings with between one and four units, household income can be verified by one of the following means:

- Review of the most recent federal income tax returns
- Income verification through a third-party income verification system
- Verification of participation in another low-income energy program (such as LIHEAP or state-funded IHWAP), in HUD's housing assistance programs where the income eligibility standard is lower than 80% of AMI for that participant, or in other benefits programs where the income eligibility is lower than 80% of AMI.

Additionally, while the Agency generally expects the Approved Vendor to verify a potential low-income community subscriber's income through one of the methods described above, the Agency recognizes that some potential subscribers would prefer to have their income verified independently of their community solar subscription. In such cases, the potential subscriber may request income verification directly through the Program Administrator and, if approved, that verification would remain valid for six months. The Program Administrator would provide the potential subscriber with a verification letter that could be provided to the Approved Vendor.[598]

For two- to four-unit buildings, at least two of the households in the building must qualify. For a multi-family building (five or more units), either at least 50% of the households must qualify, or the building owner may demonstrate that the building meets the definition of "affordable housing" contained in the Illinois Affordable Housing Act, namely:

> *"Affordable housing' means residential housing that, so long as the same is occupied by low-income households or very low-income households, requires payment of monthly housing costs, including utilities other than telephone, of no more than 30% of the maximum allowable income as stated for such households as defined in this Section.*[599]

[597] In response to concerns raised by various stakeholders in the process of approving this Revised Plan, the Commission determined that the Agency and the Program Administrator shall explore implementing a process to connect interested income-qualified customers with ILSFA Approved Vendors. The Agency will implement any such process in a competitively neutral fashion and strive to provide equal information and opportunities to all applicable ILSFA Approved Vendors. Additionally, the Agency will conduct a stakeholder feedback process to work through key implementation details prior to implementation of such a process. See Docket No. 19-0995, Final Order dated February 18, 2020 at 108.

[598] See Docket No. 19-0995, Final Order dated February 18, 2020 at 108.

[599] See 310 ILCS 65/3(e). Note that the definition of low-income household contained in that Act mirrors the definition used for Illinois Solar for All, and that very low-income households have an income standard that is even lower.

In addition, participation in energy efficiency programs that also have an income eligibility requirement that is equal to or less than 80% of AMI may also be considered a means of qualifying a multifamily building.

For residential buildings of two or more units, the building owner will be required to agree to maintain at least half the units as affordable housing for a period of ten years.

For low-income community solar projects, the Agency recognizes that transaction costs of proving income eligibility compared to the value of the incentive may be higher than for an installation of a project on-site, and therefore proposes a streamlined income verification approach:

- A subscriber can be verified as low-income via the same provisions used for the Low-Income Distributed Generation Incentive sub-program.
- A subscriber can be verified as low-income if they reside in a HUD Qualified Census Tract and also provide a signed affidavit that they meet the income qualification level.[600]

It is the responsibility of the Illinois Solar for All Approved Vendor to track subscribers and document income eligibility for community solar projects[601]. Approved Vendors will be required to report to the Agency on subscription rates once a year. Illinois Solar for All Approved Vendors will not be required to verify that existing subscribers continue to meet the low-income eligibility requirements, but new subscribers over time will be required to meet those requirements.

8.14. Consumer Protections

The Agency believes that the Plan features a strong set of consumer protections as part of the Adjustable Block Program for both distributed generation and for community solar (see Sections 6.13 and 7.6.2). These protections will also apply to the Illinois Solar for All Program. But several factors lead the Agency to require additional consumer protections for the Illinois Solar for All Program. Thus, to be an Illinois Solar for All Approved Vendor for the Solar For All program, Illinois Solar for All Approved Vendors must agree to the following additional provisions for low-income customers.

- In order to "ensure tangible economic benefits flow directly to program participants," Illinois Solar for All Approved Vendors must also verify that for residential program participants there are no up-front payments for distributed generation projects, or up-front subscription fees for community solar projects. Illinois Solar for All Approved Vendors must also provide documentation to both the program participant(s), and to the Program Administrator explaining how the project or community solar subscription will result in a cash-flow positive experience for the participant(s) (including an estimate of the monthly savings) – and specifically, ensuring that the savings accruing to each participant, net of any ongoing participation fees, are at least 50% of the value produced by the solar system through avoided usage or net metering credits.[602]

[600] The Agency will monitor the use of this provision and may consider modifying the consideration of eligible census tracts (for example to census tracts where at least 50% of households are below 80% of AMI) if the proposed use of the QCT approach appears to be a barrier to facilitating subscription verification.

[601] While generally the Agency would expect the Approved Vendor to verify a potential low-income community solar subscriber's income through one of the methods described in this Revised Plan, the Agency recognizes that some potential subscribers would prefer to have their income verified independently of their community solar subscription. In such cases, a potential subscriber may request income verification directly through the Program Administrator, and if approved, that verification would remain valid for six months. The Program Administrator would provide the potential subscriber with a verification letter that could be provided to the Approved Vendor.

[602] See Docket No. 17-0838, Final Order dated April 3, 2018 at 151.

- For distributed generation projects, a site suitability report is required to ensure that projects are being installed on properties that will not need substantial structural, roofing or electrical repairs. If repairs are needed, the Illinois Solar for All Approved Vendor must identify the plan for the repairs and how they will be paid for, ensuring that such costs do not place an unsustainable financial burden on the participant. While the site suitability report does not need to be completed prior to the program participant entering into a contract with the Illinois Solar for All Approved Vendor (or their sub-contracted installer), if the site suitability report indicates that the project is not viable, the contract must contain a no-cost cancellation provision.

- Contracts between Illinois Solar for All Approved Vendors (or their sub-contracted installers) and program participants for Low-Income Distributed Generation projects are required to offer clear disclosure of the costs seven calendar days before consummation of the transaction, and the right to cancel the transaction within seven calendar days after consummation. For contracts related to subscriptions to projects participating in the Low-Income Community Solar Project Initiative or the Low-Income Community Solar Pilot Procurement, that right to cancel the transaction would be within three calendar days after consummation.

- Financing amounts, terms, and conditions must be based on an assessment of the program participant's ability to repay the debt, as defined by Regulation Z, which is a federal rule that implements aspects of the Truth in Lending Act and the Dodd-Frank Act.[603]

- For low-income customers, loans should not be secured by the program participant's home or home equity. While such unsecured loans may entail a higher interest rate, especially for customers with low credit scores or little credit history, they avoid the risk of liens and foreclosures for customers who default on their loans.[604]

- Contracts for financial products must offer terms that include forbearance. If a program participant can show good cause in a request for forbearance, financers must offer a) suspension of total payments for up to three months, b) a suspension of interest payments for up to six months, or c) a reduction in interest rates for up to twelve months. Missed revenues may be recovered later in the stage of the contract, but no interest may be applied.

- Contracts may not include prepayment penalties.

- Marketing and contractual materials must be in the language requested by the customer.

- Contracts must allow a grace period of at least seven calendar days after the customer payment due date before late fees are charged.

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[603] See Consumer Financial Protection Bureau, April 10, 2013. *Ability-to-Repay and Qualified Mortgage Rule, Small Entity Compliance Guide*, http://files.consumerfinance.gov/f/201304_cfpb_compliance-guide_atr-qm-rule.pdf. Under the regulation (12 C.F.R. § 1026.43, issued under authority of 15 U.S.C. § 1639c), creditors generally must consider eight underwriting factors: (1) current or reasonably expected income or assets; (2) current employment status; (3) the monthly payment on the covered transaction; (4) the monthly payment on any simultaneous loan; (5) the monthly payment for mortgage-related obligations; (6) current debt obligations, alimony, and child support; (7) the monthly debt-to-income ratio or residual income; and (8) credit history.

[604] For example, the Illinois Energy Efficiency Loan Program offers unsecured loans at moderate interest rates through on-bill financing, but is only available for certain energy efficiency measures. See: http://programs.dsireusa.org/system/program/detail/5152.

- All Illinois Solar for All contracts must include full system warranty, as well as operations and maintenance guarantees for the duration of the REC Contract or 15 years, at no additional cost to participants.

8.15. Environmental Justice Communities

The Act directs the Agency to define and provide special consideration to Environmental Justice Communities in implementing the Illinois Solar For All program. The Act sets as a goal that at least 25% of funds for the Low-Income Distributed Generation Incentive, the incentives for non-profit and public facilities, and Low-Income Community Solar projects sub-programs "be allocated to projects located in environmental justice communities."[605] (The provision does not apply to the Low-Income Community Solar Pilot Projects, which are competitively bid.)

The following sections include definitions of terms, a methodology for determining which Illinois communities should be considered Environmental Justice Communities, and how the Agency determined to implement the relevant provisions of the Act. In developing the Illinois Solar for All program participation requirements, the Agency committed to consulting with stakeholders and relevant state agencies, including the Illinois Commission on Environmental Justice and the Illinois Environmental Protection Agency ("IEPA"), to establish specific values and designate specific communities as Environmental Justice Communities; the results of that process are outlined within this section.

8.15.1. Definitions

The Act states that "the Agency shall define 'environmental justice community' as part of long-term renewable resources procurement plan development, to ensure, to the extent practicable, compatibility with other agencies' definitions and may, for guidance, look to the definitions used by federal, state, or local governments." The term "environmental justice" is not defined in the Act or in other Illinois statutes, but it is helpful to define "environmental justice" in order to define "environmental justice communities."

The Environmental Justice Act, the 1997 legislation that created the Illinois Commission on Environmental Justice (415 ILCS 155), found that:

> *(i) the principle of environmental justice requires that no segment of the population, regardless of race, national origin, age, or income, should bear disproportionately high or adverse effects of environmental pollution;*
> *(ii) certain communities in the State may suffer disproportionately from environmental hazards related to facilities with permits approved by the State; and*
> *(iii) these environmental hazards can cause long-term health effects.*[606]

The Illinois EPA defines the term "environmental justice " as follows:

> *"Environmental Justice" is based on the principle that all people should be protected from environmental pollution and have the right to a clean and healthy environment.*

[605] 20 ILCS 3855/1-56(b)(2)(A), (B), (C).

[606] 415 ILCS 155/5.

> *Environmental justice is the protection of the health of the people of Illinois and its environment, equity in the administration of the State's environmental programs, and the provision of adequate opportunities for meaningful involvement of all people with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.*[607]

The Illinois EPA has also defined a "potential environmental justice community" based on demographic factors, but not environmental factors:

> *A "potential" EJ community is a community with a low-income and/or minority population greater than twice the statewide average. In addition, a community may be considered a potential EJ community if the low-income and/or minority population is less than twice the statewide average but greater than the statewide average and that has identified itself as an EJ community. If the low-income and/or minority population percentage is equal to or less than the statewide average, the community should not be considered a potential EJ community.* [608]

The United States Environmental Protection Agency defines an "overburdened community" under both social and environmental terms as:

> *Minority, low-income, tribal, or indigenous populations or geographic locations in the United States that potentially experience disproportionate environmental harms and risks. This disproportionality can be as a result of greater vulnerability to environmental hazards, lack of opportunity for public participation, or other factors. Increased vulnerability may be attributable to an accumulation of negative or lack of positive environmental, health, economic, or social conditions within these populations or places. The term describes situations where multiple factors, including both environmental and socio-economic stressors, may act cumulatively to affect health and the environment and contribute to persistent environmental health disparities.* [609]

Both the IEPA and US EPA have developed analytical tools based on their definitions of EJ communities. The IEPA's EJ START is a Geographic Information Systems demographic screening tool developed by IEPA staff that identifies regions with high minority population and/or low-income population. IEPA also adds a one-mile buffer around each regulated facility as a simplified way to identify potential local environmental impacts. It draws from the Census Bureau's American Community Survey 5-year estimates (2011-2015) and is updated annually.

The US EPA tool is called EJ SCREEN.[610] It uses standard and nationally-consistent data to identify communities with greater risk of exposure to pollution based on 11 environmental indicators that measure potential exposure, hazard/risk and proximity, including traffic proximity, particulate matter, and proximity to superfund sites. These indicators are combined with demographic data from the Census Bureau, enabling users to identify areas with minority or low- income populations who also face potential pollution issues.

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[607] Illinois EPA web site, "Environmental Justice Policy," http://www.epa.illinois.gov/topics/environmental-justice/ej-policy/index. Accessed July 19, 2017.

[608] Id.

[609] US EPA, "EJ 2020 Glossary," https://www.epa.gov/environmentaljustice/ej-2020-glossary. Accessed July 19, 2017.

[610] See: https://ejscreen.epa.gov/.

While these tools are useful, they do not holistically address all aspects of environmental justice. For example, EJ SCREEN evaluates individual environmental indicators but does not look at cumulative impacts.

The most rigorous tool for analyzing impacted communities is the California Communities Environmental Health Screening Tool (CalEnviroScreen) from the California Office of Environmental Health Hazard Assessment (OEHHA).[611] CalEnviroScreen compiles data on 12 indicators of pollution burden and 8 population characteristics collected at the Census tract level. It then weights certain factors to develop a score for each area. High scoring areas are then considered eligible for a number of state policies, including disposition of some of the revenues from the state cap-and-trade program created under Assembly Bill 32.

Table 8-10: Summary of CalEnviroScreen 3.0 Identification Methodology

Pollution Burden	Population Characteristics
Exposures	***Sensitive populations***
Ozone Concentrations PM2.5 Concentrations Diesel PM Emissions Drinking Water Contaminants Pesticide Use Toxic Releases from Facilities Traffic Density	Asthma Emergency Department Visits Low Birth Weight Infants Cardiovascular disease (emergency department visits for heart attacks)
Environmental effects	***Socio-economic indicators****
Cleanup Sites Groundwater Threats Hazardous Waste Impaired Water Bodies Solid Waste Sites and Facilities	Educational Attainment Housing burdened low income households Linguistic Isolation Poverty Unemployment

Source: OEHHA. * California law prohibits the use of race as a factor in CalEnviroScreen.

The CalEnviroScreen approach is an attractive way to consider defining environmental justice communities but the Agency notes that the development of it was a multi-year, multi-million dollar undertaking. Therefore, the Agency will utilize a streamlined approach that takes the concept of CalEnviroScreen and simplifies it for use in Illinois through using readily available data from the U.S

[611] California Office of Environmental Health Hazard Assessment ("OEHHA"), *California Communities Environmental Health Screening Tool (CalEnviroScreen)*, https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-version-20.

EPA's EJ SCREEN tool. CalEnviroScreen does not account for race in its calculations, but by using data from EJ SCREEN, the Agency will be able to do so.

8.15.2. Approach for Defining Environmental Justice Communities

The Agency determined which areas qualify as Environmental Justice Communities by analyzing data from Illinois census block groups[612] for the following environmental indicators, as described by the EJ SCREEN Tool:[613]

- National-Scale Air Toxics Assessment (NATA) air toxics cancer risk
- NATA respiratory hazard index
- NATA diesel PM
- Particulate matter
- Ozone
- Traffic proximity and volume
- Lead paint indicator
- Proximity to Risk Management Plan sites
- Proximity to Hazardous Waste Treatment, Storage and Disposal Facilities
- Proximity to National Priorities List sites
- Wastewater Dischargers Indicator

The following demographic indicators are also used by EJ SCREEN and were incorporated into the Agency's methodology:[614]

- Percent Low-Income
- Percent Minority
- Less than high school education
- Linguistic isolation
- Individuals under age 5
- Individuals over age 64

The Agency considered including the following seven indicators that use data not contained in EJ SCREEN. These are not available at the same level of detail as the indicators using data from EJ SCREEN (more typically they have data at the zip code or county level), and would need to be translated to the block group level. Therefore, the Agency determined in the final methodology that these indicators would be too difficult to incorporate to provide meaningful impact on the evaluation criteria. Namely, these include the following demographic indicators for Sensitive Population Characteristics from the Illinois Department of Public Health:

- Asthma Emergency Department Visits
- Low Birth Weight Infants

and the following environmental indicators from the Illinois Environmental Protection Agency:

- Drinking Water Watch

[612] There are approximately 10,000 census block groups in the state of Illinois.

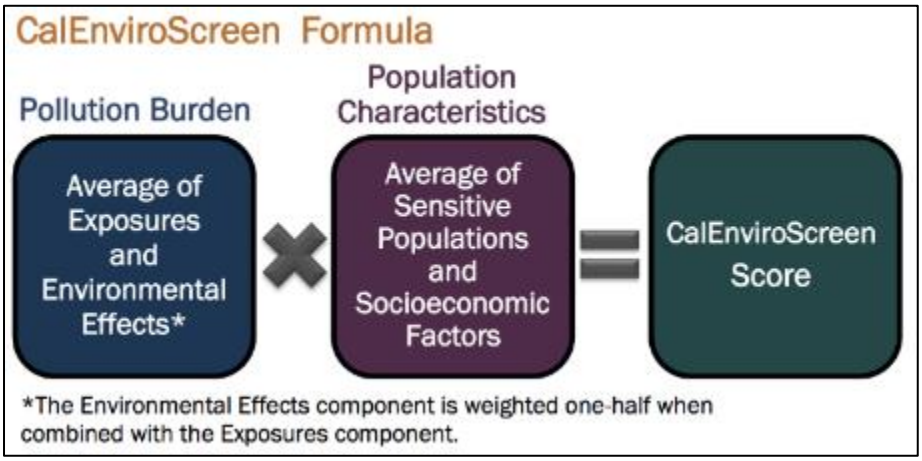
[613] See https://www.epa.gov/ejscreen/overview-environmental-indicators-ejscreen.

[614] See https://www.epa.gov/ejscreen/overview-demographic-indicators-ejscreen.

- Site remediation program
- Leaking Underground Storage Tank Incident Tracking
- State Response Action Program
- Solid Waste Facilities

Using the eleven environmental and six demographic factors listed at the top of this Section 8.15.2, the Agency then weighted each factor using an approach adapted from CalEnviroScreen: census block groups were ranked for each environmental and demographic indicator, a resulting percentile score determined for each census block group within each indicator, and the percentile scores averaged, resulting in an environmental score and a demographic score for each census block group. The two averages were then multiplied together to determine a single Environmental Justice score for each census block group.

Figure 8-2: CalEnviroScreen Formula



Source: OEHHA

Communities with scores in the top 25% of all census block groups statewide are defined as Environmental Justice Communities for the purpose of the Illinois Solar for All Program. This definition will be used to target grassroots education funding and incentives for the Low-income Distributed Generation, Non-profits/Public Facilities, and Low-income Community Solar sub-programs.

A community that is not in the top 25% of scores and thus is not initially defined as being an Environmental Justice Community may request consideration from the Agency to be included. The Agency will consider requests from community-based organizations, local units of government, or community residents for self-designation as an environmental justice community based on a consideration of demonstrated quantitative and qualitative environmental and/or socioeconomic factors that show a disproportionate burden and were not adequately captured in the screening defined above. A request for self-designation must be approved through an Environmental Justice Community Self-Designation Process[615] prior to any project application being submitted that seeks

[615] The initial Self-Designation Process developed by the Agency and Program Administrator can be found at https://www.illinoissfa.com/app/uploads/2019/05/042219EJ-Self-Designation-Process_Final.pdf. The Agency reserves the right to modify this process in the future based on program experience.

to utilize its location in an approved self-designated Environmental Justice Community as part of its project selection.

The Agency notes that this approach focuses on analysis of census block group-level data, and that communities are typically understood by their residents to be defined through geographic, cultural, and other factors that may, or may not, correspond to census block group boundaries. In addition, the US EPA cautions that data in the EJSCREEN tool is not always reliable at the block group level, and recommends that it may be necessary to aggregate up to larger geographic areas in a "buffer report."[616]

The Agency will therefore also consider reasonable adjustments to the borders of environmental justice communities from what is calculated through the census block group analysis, provided this does not create an unacceptable analytical burden.

8.15.3. Environmental Justice Community Designations

The Illinois Solar for All Program Administrator undertook the analysis described in Section 8.15.2 in early 2019 prior to the program launch, which included a workshop and an opportunity for written stakeholder comments. The resulting interactive map of Environmental Justice Communities, as well as information from that stakeholder process, is available at www.illinoissfa.com/environmental-justice-communities. The map of environmental justice communities will be updated on a semiannual basis to reflect any additional approved requests for self-designation.

8.15.4. Environmental Justice Communities 25% Goal

The Act states that "It is a goal of this program that a minimum of 25% of the incentives for this program be allocated to projects located within environmental justice communities."[617]

For the Low-Income Distributed Generation Incentive, the Low-Income Community Solar Project Initiative, and the Incentives for Non-profits and Public Facilities sub-programs, the Agency will reserve 25% of each sub-program's annual budget to support projects in environmental justice communities. If the 25% of funds in each sub-program are fully allocated to projects in environmental justice communities, then subsequent applicant projects in environmental justice communities would still be eligible using the general available budgets. The 25% reservation of funds for environmental justice communities will be held open within a sub-program until filled within a program year, then reset at the beginning of each new program year.

8.16. Program Changes

Several provisions in the Act anticipate the ability to revise and change program provisions. In addition to the provision described in Section 1-56(b)(4) of the Act that allows stakeholders to propose additional programs, an additional provision allows the Agency to reallocate funds between programs:

> *"The allocation of funds among subparagraphs (A), (B), or (C) of this paragraph (2) may be changed if the Agency or administrator, through delegated authority, determines incentives in subparagraphs (A), (B), or (C) of this paragraph (2) have not been*

[616] EJSCREEN Technical Documentation, at https://www.epa.gov/ejscreen/technical-documentation-ejscreen.

[617] 20 ILCS 3855/1-56(b)(2).

> *adequately subscribed to fully utilize the Illinois Power Agency Renewable Energy Resources Fund. The determination shall include input through a stakeholder process."*[618]

With this Revised Plan, the Agency is not proposing a change in allocation of funds.

Likewise, the Agency has not proposed any adjustments to the programs pursuant to the following provision:

> *"Following the Commission's approval of the Illinois Solar for All Program, the Agency or a party may propose adjustments to the program terms, conditions, and requirements, including the price offered to new systems, to ensure the long-term viability and success of the program. The Commission shall review and approve any modifications to the program through the plan revision process described in Section 16-111.5 of the Public Utilities Act."*[619]

8.17. Evaluation

Section 1-56(b)(6) requires that this Plan include an approach for independent evaluation of the Illinois Solar for All Program:

> *"At least every 2 years, the Agency shall select an independent evaluator to review and report on the Illinois Solar for All Program and the performance of the third-party program administrator of the Illinois Solar for All Program. The evaluation shall be based on objective criteria developed through a public stakeholder process. The process shall include feedback and participation from Illinois Solar for All Program stakeholders, including participants and organizations in environmental justice and historically underserved communities. The report shall include a summary of the evaluation of the Illinois Solar for All Program based on the stakeholder developed objective criteria. The report shall include the number of projects installed; the total installed capacity in kilowatts; the average cost per kilowatt of installed capacity to the extent reasonably obtainable by the Agency; the number of jobs or job opportunities created; economic, social, and environmental benefits created; and the total administrative costs expended by the Agency and program administrator to implement and evaluate the program."*

In January 2019, the Agency held a workshop and took stakeholder feedback to assist in the development of the scope and process for the evaluation.[620] The Agency then issued a Request for Qualifications/Request for Proposals to select an independent evaluator to conduct the evaluation.[621] This selection process is expressly exempted from the Illinois Procurement Code.[622] On August 7, 2019, the Commission approved the contract for the Agency's selected evaluator, APPRISE, Inc.

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[618] 20 ILCS 3855/1-56(b)(2).

[619] 20 ILCS 3855/1-56(b)(4).

[620] See: https://www.illinoissfa.com/announcements/2019/01/written-comments-on-illinois-solar-for-all-third-party-program-evaluation/ and https://www.illinoissfa.com/announcements/2019/02/public-comments-on-third-party-evaluation/.

[621] See: https://www2.illinois.gov/sites/ipa/Documents/IPA%20-%20IlSfA%20-%20Program-Administrator%20-%2018-RFQ-02%20%28Released%2001182018%29.pdf and https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/IPA-ABP-Program-Administrator-18-RFP-01-20180312.pdf.

[622] 20 ILCS 3855/1-56(f).

The Act calls for an evaluation "at least every 2 years," but the Agency notes that Illinois Solar For All did not launch for project applications until May 2019. Therefore, during its first months of work, the Evaluator conducted research and prepared a Phase I Evaluation Report that focused on the stakeholder outreach process, development of program materials and guidelines, initial Approved Vendor registration, initial project applications, and the development of Grassroots Education efforts. It is attached as Appendix G to this Revised Plan.

Recommendations from the Phase I Evaluation Report are summarized below. Generally, these recommendations do not require specific changes to this Revised Plan but rather can be considered and potentially implemented through the ongoing program administration.

Recommendations

- Illinois Solar For All Program Design: Consider the Illinois Solar For All Program design a work in progress. Develop a comprehensive understanding of what is permitted to be changed without modifications to FEJA or the Long-Term Plan, and what changes require legislative or Long-Term Plan modifications. Be open to changes that are seen to be needed as the program evolves and additional data and information become available.

- Illinois Solar For All Program Materials and Website: Many stakeholders and Grassroots Educators commented that the Illinois Solar For All materials are too complex and the website needs to be streamlined and organized.

- Stakeholder Outreach: Several recommendations are made to increase the amount and diversity of participation in the stakeholder outreach process based on feedback from stakeholders and Grassroots Educators.

- Approved Vendors: Consider additional outreach and/or support to encourage Approved Vendor participation in all areas of the state, by MWBE, and by new and smaller businesses.

- Grassroots Education: In general, the Grassroots Educators have found a low level of awareness, a high level of interest, and skepticism about the Illinois Solar For All Program. They stated that customers have a low level of understanding of energy and solar energy. Potential participants do not believe that the program has no upfront costs, or that they will actually benefit from participation. Additionally, the organizations found confusion between the Illinois Solar For All Program and other solar programs. This indicates the importance of the Grassroots Education initiative, which should be continued and expanded.

- Participant Screening: Many low-income customers who are interested in participating in the Illinois Solar For All Program may have a roof that is not in the required condition for rooftop solar to be installed or other home issues that prevent participation. Grassroots Educators noted deferred maintenance issues and lack of solar readiness as a barrier.

- Energy Efficiency and Home Repairs: The Illinois Solar For All Program should aim to provide additional resources and information for Approved Vendors to work with potential low-income participants on energy efficiency and remediating homes so that they are solar-ready.

- Job Training: Consider whether support is needed for potential job trainees to help them overcome barriers to participation in the job training programs.

- Data Collection: The Program Administrator should provide specific information about its current plans for databasing household-level data for DG and community solar. There should then be an assessment of whether such data will be sufficient to meet FEJA mandates and IPA reporting goals, or whether additional data may need to be databased. While there is a critical need to protect participant privacy, many programs collect these data, and it is important to have the ability to document program participation characteristics and impacts. One stakeholder suggested that it may be preferable to have the Program Administrator collect and process confidential household qualification data rather than the Approved Vendors.

The Evaluator will be embarking on the more detailed Phase II evaluation process starting in early 2020, which will include opportunities for additional stakeholder engagement and input on the full evaluation design.

8.18. Grassroots Education Funding

The Act also directs the Agency to "allocate up to 5% of the funds available under the Illinois Solar for All Program to community-based groups to assist in grassroots education." [623] For 2020-2021 and 2021-2022, the Agency interprets the "funds available under the [Program]" to be the annual contribution of approximately $11.7 million from the Renewable Resources Budget under Section 1-75(c)(1)(O) of the Act, plus $16.5 million allocated annually from the RERF for the three non-competitive sub-programs, plus $2.5 million allocated annually from the RERF for the Low-Income Community Solar Pilot Projects.[624] Therefore, the maximum available annual budget for grassroots education is $1.53 million for these two program years; the Agency reserves the right to allocate less than this amount.

For the purposes of grassroots education, community-based organizations must be registered non-profit entities, excluding trade or political non-profits. It is recognized that the definition of community-based organizations or non-profit is very broad and may include a variety of organization types. It is not required that non-profit organizations have federal 501(c)(3) status, and collaborative or fiscal sponsorship should be encouraged to ensure that very small, hyper-local organizations can participate. Qualified organizations should work within the communities in which they will be providing grassroots education. Grassroots educator entities will be chosen through competitive RFPs issued periodically and selected grassroots educators will be subcontractors of the ILSFA Program Administrator. Pursuant to the Initial Plan, the first selection of grassroots educators was made in June 2019.[625]

As noted in Section 8.8, grassroots education funding will be prioritized towards Environmental Justice Communities to help meet this goal. Up to 60% of the funding (or 3 percentage points of the

[623] 20 ILCS 3855/1-56(b)(3).

[624] While for three of the sub-programs there are defined program year funding levels available, that concept does not apply cleanly to the Low-Income Community Solar Pilot Project sub-program. For simplicity, the Agency is proposing to allocate the total available funding for that sub-program ($37.5 million) over 15 years, which is the length of time that projects from the sub-program would be delivering RECs to the Solar for All Program.

[625] See: https://www.illinoissfa.com/announcements/2019/06/announcing-grassroots-organizations.

5%) will be used for this purpose. Grassroots education topics could include solar basics, program requirements, consumer protection, program benefits and opportunities, job training opportunities, environmental justice community issues, or community engagement, among many others. One objective of the grassroots education strategy will be to ensure that campaigns collectively reach a diversity of households and communities, topics, and geographies over time.

Non-profit organizations providing grassroots education to communities must ensure that outreach and education provided does not serve the interest of any Approved Vendor or other solar developer above any other. When grassroots education events are open to Approved Vendors, all Approved Vendors should have an equal opportunity to participate in a transparent manner. No organization providing grassroots education services should have a financial relationship with an ILSFA Approved Vendor at the time of performing those services, and any past relationships should be clearly disclosed when submitting proposals.