Sustainable Energy Advantage, LLC

# Illinois ABP and ILSFA REC Pricing Policy Design Issues, Options, and Implications

Prepared on behalf of the Illinois Power Agency

# Context

In addition to the current proposed REC prices for the 2023-2024 program/delivery year, the IPA is exploring updating the methodology/model the Agency uses in calculating REC prices starting with the 2024-2025 program year.

This separate REC pricing review done by a neutral third party speaks to the Agency's interest in fostering growth in its renewable energy development. In the 2022 Long-Term Plan, the IPA committed to engaging an independent consultant to conduct a review of the REC pricing approach the Agency currently uses for the Illinois Shines and ILSFA programs as part of the preparation of the next iteration of the Agency's Long-Term Plan. That Long-Term Plan will contain the methodology used for setting REC prices starting with the 2024-2025 program year.

The Agency has engaged Sustainable Energy Advantage, LLC ("SEA") to conduct that review. SEA has been involved in the development, analysis and implementation of clean energy policies and markets, particularly throughout the Northeast U.S., and has advised a wide range of state government agencies and clean energy market participants across all technologies. The report developed by SEA will be used by the Agency to develop the REC pricing methodology for the next Long-Term Plan.

***The observations and preliminary recommendations contained herein reflect SEA's independent review and may or may not reflect the ultimate opinion and/or preferences of the IPA.***

# Policy Context

# Enabling Legislation

- **2017 Future Energy Jobs Act, 99-0906 (FEJA)**
  - Adjusted RPS goals, funding, and structure, and established the Long-Term Renewables Procurement Plan
  - Created the Adjustable Block Program (ABP) and Illinois Solar for All Program (ILSFA)
  - Set minimum procurement targets for "new" wind and solar (at least 2 million RECs annually each from new wind and solar by end of 2020 delivery year, 3 million annually by end of 2025 delivery year, and 4 million annually by end of 2030 delivery year)
    - 50% of new solar had to come from ABP (and established categories within ABP)
  - Defined "community renewable generation project"

- **2021 Climate and Equitable Jobs Act, 102-0662 (CEJA)**
  - Set target of 100% clean energy by 2050
  - Increased Solar and Wind REC procurement targets significantly:
    - Solar: 5.5 million RECs annually by end of 2020 delivery year and 24.75 million by end of 2030 delivery year
    - Wind: 4.5 million RECs annually by end of 2020 delivery year and 20.25 million by end of 2030 delivery year
  - Added the following categories to the ABP
    - Public Schools
    - Community-Driven Community Solar
    - Equitable Eligible Contractor
  - 50% of new solar must still come from ABP
  - Established diversity, equity and inclusion requirements and new labor requirements

# Program Design Guidance from Enabling Legislation - ABP

- "The Adjustable Block program shall be generally designed to provide for the steady, predictable, and sustainable growth of new solar photovoltaic development in Illinois." *(20 ILCS 3855/1-75(c)(1)(K))*

- "The Adjustable Block program shall be designed to ensure that renewable energy credits are procured from photovoltaic distributed renewable energy generation devices and new photovoltaic community renewable energy generation projects in diverse locations and are not concentrated in a few regional areas." *(20 ILCS 3855/1-75(c)(1)(K))*

# Program Design Guidance from Enabling Legislation - ILSFA

- “The objectives of the Illinois Solar for All Program are 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.” *(20 ILCS 3855/1-56(b)(2))*

- “The Agency shall strive to ensure that renewable energy credits procured through the Illinois Solar for All Program and each of its subprograms are purchased from projects across the breadth of low-income and environmental justice communities in Illinois, including both urban and rural communities, are not concentrated in a few communities, and do not exclude particular low-income or environmental justice communities.” *(20 ILCS 3855/1-56(b)(2))*

# REC Pricing and Program Design - ABP

- "The Adjustable Block program shall provide a transparent annual schedule of prices and quantities to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time. The prices set by the Adjustable Block program can be reflected as a set value or as the product of a formula." *(20 ILCS 3855/1-75(c)(1)(K))*
- "The Adjustable Block program shall include for each category of eligible projects for each delivery year:
  - A single block of nameplate capacity
  - A price for renewable energy credits within that block
  - Terms and conditions for securing a spot on the waitlist once the block is fully committed or reserved." *(20 ILCS 3855/1-75(c)(1)(K))*
- "For each category for each delivery year the Agency shall determine the amount of generation capacity in each block, and the purchase price for each block, provided that the purchase price provided and the total amount of generation in all blocks for all categories shall be sufficient to meet the goals in this subsection (c)." *(20 ILCS 3855/1-75(c)(1)(K))* (Subsection (c) is the Renewable Portfolio Standard)
- "The Agency shall strive to issue a single block sized to provide for stability and market growth." *(20 ILCS 3855/1-75(c)(1)(K))*
- "The Agency may periodically review its prior decisions establishing 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." *(20 ILCS 3855/1-75(c)(1)(K))*

# REC Pricing and Program Design - ILSFA

- “The Agency shall, consistent with the requirements of this subsection (b), propose the Illinois Solar for All Program terms, conditions, and requirements, including the prices to be paid for renewable energy credits, and which prices may be determined through a formula, through the development, review, and approval of the Agency's long-term renewable resources procurement plan described in subsection (c) of Section 1-75 of this Act and Section 16-111.5 of the Public Utilities Act.” *(20 ILCS 3855/1-56(b)(4))*
- “In the course of the Commission proceeding initiated to review and approve the plan, including the Illinois Solar for All Program proposed by the Agency, a party may propose an additional low-income solar or solar incentive program, or modifications to the programs proposed by the Agency, and the Commission may approve an additional program, or modifications to the Agency's proposed program, if the additional or modified program more effectively maximizes the benefits to low-income customers after taking into account all relevant factors, including, but not limited to, the extent to which a competitive market for low-income solar has developed.” *(20 ILCS 3855/1-56(b)(4))*
- “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.” *(20 ILCS 3855/1-56(b)(4))*
- “The Agency or contracting electric utility shall purchase renewable energy credits from generation……and 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 interconnecting utility and verified as energized. Payments for renewable energy credits shall be in exchange for 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.” *(20 ILCS 3855/1-56(b)(3))*

# Comparison of Historical and Current Illinois Program Designs

Illinois Adjustable Block Program (ABP)

Illinois Solar for All Program (ILSFA)

# Historical and Current Policy Design, ABP

| Policy Design Element | Pre-CEJA | Post-CEJA |
| --- | --- | --- |
| **Capacity Allocation Structure** | ABP Capacity Categories:<br>• 25% <10kW (Small DG)<br>• 25% 10kW-2MW (Large DG)<br>• 25% for Community Solar<br>• 25% discretionary for IPA to allocate | Created additional ABP capacity categories for:<br>• Community-driven Community Solar<br>• Public Schools, priority for EJ and Tier 1 and Tier 2 projects<br>• Equity Eligible Contractor<br>Changes to existing categories:<br>• Small DG: Maximum size increased to 25 kW<br>• Large DG: Now >25kW to ≤ 5MW<br>• Community solar: Now ≤ 5 MW<br>ABP Blocks sized annually, no more discretionary capacity, instead allocation of unused capacity via waitlists |
| **REC Price Formulation and Updates** | IPA administratively set prices for first block in each category using customized CREST Model (cash-flow model published by NREL)<br>• Data inputs from publicly available sources<br><br>Prices reduced by 4% for each successive block, but IPA could increase if not enough interest in block<br>• IPA did not make any upward price adjustments | To reflect new block structure mandated by CEJA, IPA will conduct **annual** refresh of REC pricing model updating inputs and seeking stakeholder feedback<br><br>IPA can modify block prices by up to 10% without ICC approval. Before any changes, IPA will conduct stakeholder feedback process |
| **REC Contract Duration and Payments** | 15-year REC Contracts<br>Contract payments vary by size category:<br>• Small DG: Contract pays for all RECs upfront (upon energization)<br>• Large DG and Community Solar: 20% upfront, 80% spread evenly over next 4 years | Revised ABP Contract parameters:<br>• Small DG: 15-year contract paid 100% up-front<br>• Large DG and Community-driven Community Solar: up-front payment of 15%, remaining 85% spread evenly over next 6 years; volume based on 15-year contract<br>• Traditional Community Solar: 20-year contract, paid-as-you-go based on delivered quantities<br>• Public Schools: 20-year contract, paid-as-you-go based on delivered quantities |

# Historical and Current Policy Design, ILSFA

| Policy Design Element | Pre-CEJA | Post-CEJA |
|---|---|---|
| **Capacity Allocation Structure** | ILSFA Sub-program funding percentages:<br>• 22.5% Low-Income DG<br>• 37.5% Low-Income Community Solar<br>• 15% Non-Profit/Public Facilities<br>• 25% Low-Income Community Solar Pilots (solicitation in 2018) | Changes to ILSFA sub-programs:<br>• Eliminated Community Solar Pilot procurement<br>• Divided Low-Income DG into two subprograms:<br>  • Large Multifamily subprogram<br>  • Single-Family and Small Multifamily<br>New funding percentages:<br>• 35% Low-income DG, includes:<br>  • Low-Income Single-Family<br>  • Small Multifamily<br>  • Large Multifamily<br>• 40% Low-income Community Solar<br>• 25% Non-profits and Public Facilities<br>  • Public Schools will be phased out of the ILSFA after 2022-2023 deliver year, as public schools now have a dedicated sub-category in ABP<br>A portion of each ILILSFA sub-program must be reserved for promoting energy sovereignty<br>• IPA will reserve 25% of each sub-program for energy sovereignty<br>• IPA will reserve 25% of each sub-program for EJ communities |
| **REC Price Formulation and Updates** | ILSFA REC prices are based on ABP prices, but adjusted for ILSFA goals<br>• Incentives are calculated to create direct economic benefits through lower net energy costs for customers<br>• REC prices at a premium to ABP to overcome challenges ILSFA target populations face- e.g., lack of access to credit markets, to provide no upfront costs, shorter target payback periods, and increased customer savings to deliver the direct economic benefits<br>• REC prices updated annually | Energy sovereignty projects may have higher REC incentives<br>• For on-site energy sovereignty projects with a planned ownership transfer, IPA will offer $10 adder<br>• Carve-out for EJ community projects of 25% of ILSFA budget<br>• REC prices will be reviewed and updated annually, still at premium to ABP for the same reasons as pre-CEJA |
| **REC Contract Duration and Payments** | 15-year REC contracts paid upfront (upon energization) | ILSFA contract length and payment structure unchanged. |

# Analysis of REC Pricing Policy Design Issues, Options, and Implications

# Creating a Framework for Program Design
## What are we trying to accomplish?

- Effective and durable program design starts with a clear articulation of the intended outcome.
- Overall, the policy *objective* is to meet RPS targets with eligible resources.
- Within individual programs, however, one must describe – and prioritize – what the program *design* is trying to accomplish.
- Having multiple policy objectives is common, as is experiencing tension among them.
- The presence of tension does not represent a flaw in policy design - it simply underscores the reality that trade-offs are required when multiple objectives are desired.
- Common policy objectives include:
  - Cost effectiveness, sometimes “least cost”(of delivered MWh)
  - Rapid deployment (MW installed)
  - Technology Diversity
  - Installation Size Diversity (or interest in a particular category; e.g., DG)
  - Installation Type Diversity or Priority (e.g., brownfield, LMI, community solar)
- Which objectives apply, <u>and</u> how they are prioritized, must be reflected in program design.
- Therefore, it is appropriate to regularly benchmark program designs and outcomes to the question “what are we trying to accomplish?”

# Characteristics of Effective RE Incentive Programs (1)

- Through practical experience across geographies and over time, market participants and policymakers have generally concluded that:
  - Policies prioritizing cost effectiveness (especially ‘least cost’) generally favor competitive procurements open to all RPS-eligible technologies and project types, which allow larger projects (within the set of eligible projects) to gain advantage through economies of scale.
  - Policies prioritizing rapid deployment may impose an obligation to purchase on retail providers and then allow the market to set the price (although often subject to a cap, to mitigate ratepayer impact if the market is undersupplied).
  - Policies prioritizing one or more specific market segments, or with multi-faceted objectives related to technology, project type, and project size categories, tend to establish more prescriptive designs - such as standard offer incentives - intended to provide the predictability necessary to attract market participants and grow targeted market segments.
- Illinois’ ABP and ILSFA program objectives largely align with this third category.

# Characteristics of Effective RE Incentive Programs (2)

- Programs intended to incentivize a range of specified project types generally include some or all of the following characteristics:
  - Payments are guaranteed for qualifying facilities (often subject to capacity limits as a means of ratepayer cost control)
  - Pricing is fixed (specified $/kWh) or known (calculable)
  - Purchaser (typically the regulated utility) has ‘must-take’ obligation for all energy, capacity, and/or RECs
  - Contract is long enough to support project financing (typically 15 to 20 years)
  - Bundled Price (Energy + REC) or Strike Price (for indexed REC)
  - Incentive rates are updated periodically; new rates apply to new program entrants.
- Degree of subcategory differentiation (and allocation of MW thereto) drives overall balance between cost effectiveness and other policy objectives.
- **Objective:** Ensure coverage of costs and enable a risk-adjusted return sufficient to encourage market participation.

# Risk Mitigation Through Program Design

Policymakers can effectively mitigate many development risks, support least-cost financing, and promote sustained market participation through policy design choices.

| Risk Category | Risk Factor | Mitigating Measure | Policymaker ability to impact |
|---|---|---|---|
| Contracting | Difficulty securing offtake | Assured access to offtake contract | High |
| Development Timing | Delay/completion risk | Flexible COD (including ‘good cause’ extensions) | High |
| Price | Setting price before project costs can be reasonably estimated | Minimize time gap between finalizing project costs and financial closing | High |
| Revenue | Revenue volatility, *and* adequacy of revenues to provide target returns | Long-term contract at fixed or ‘known’ (i.e., by formula) price, based on project cost | High |
| Credit | Counterparty is unable or unwilling to pay | Program is implemented through IOU, which can rely on regulator approval for prudency | High |
| Transaction | Time and cost of contract negotiations | Incentive policy with a defined process and standardized contract | High |

- While program access cannot be guaranteed at all times and for all projects, these mitigation measures dramatically reduce many of the risks associated with renewable energy project development and financing.
- All else equal, this results in a lower delivered cost of energy.

# Cost-Based or Value-Based Incentive?

- New renewable energy capacity is built where the total revenue stream is both adequate and predictable enough to support financing and attract new market entry.
- The incentive payment represents an <u>estimate</u> of either the cost or value of renewable generation.
  - The objective is to minimize over- or under-payment to participating facilities.
- Incentives are commonly differentiated by technology, size, application, and other factors.
- The mechanics of cost- and value-based options are considered on the following slides.

# Approaches to *Cost*-Based Incentive Modeling

- Approaches to cost-based modeling are broadly grouped into discounted cash flow (DCF) and recovery factor analyses:
  - DCF analyses (including the CREST model) can incorporate cost, financing, and performance inputs to produce a year-by-year forecast of project cash flows
    - DCF analyses are an effective tool to calculate a project's expected after-tax net present value and to set incentive rates intended to ensure a project is able to cover all costs and meet the investors' assumed minimum required rate of return
  - Recovery factor analyses translate capital expenditures and financing costs into an annual "factor" that is multiplied by total project cost.  Annual O&M and overhead estimates are added to arrive at a total cost of energy.
    - An example of this approach is the "Economic carrying-charge rate" which amortizes all fixed costs to produce a stream of annual payments that increase at a constant rate
    - However, recovery factor analyses struggle to account for upfront tax benefits, and lack the complexity of a DCF analysis with respect to changes in year-on-year costs and the detailed breakout of various inputs

# Observations and Preliminary Recommendations

Sustainable Energy Advantage, LLC

# Observations on REC Price-Setting Process (1)

- The cost-based approach relies on the concept of a 'representative project' – the hypothetical project for which the all-in cost of energy represent a value within a specified percentile range for a specified category installed during a specified period of time.
  - The cost-based approach is not intended to reflect the actual economics of any specific project.
  - When done correctly, this approach enables projects in the modeled cost range to be economical – recognizing that project-specific costs will vary.
  - The cost-based approach must balance scrutiny of individual inputs with the overall objective of arriving at a revenue requirement (in $/kWh) representative of cost-effective projects available to enter the market during a specified period of time.
  - The cost-based approach is <u>not</u> intended to produce an incentive high enough to ensure that *all* projects are economical. Similarly, at the other extreme, adopting least-cost assumptions for *each* individual input is unlikely to result in an incentive that supports robust development.

# Observations on REC Price-Setting Process (2)

- The cost-based approach is best aligned to Illinois' policy objectives
  - No approach can guarantee the perfect balance of market adoption and cost-effectiveness
  - However, IL's current administratively-managed, cost-based rate-setting process is likely to align renewable energy project costs and REC price incentives relatively effectively.
  - Continuing to rely on a discounted cash flow analysis (e.g., CREST model) is recommended, particularly for its ability to accurately and transparently account for federal tax incentives, detailed operating costs, financing assumptions, and project performance.

- Illinois RE facilities and ratepayers will benefit from enhancements to, or adaptations of, the ABP and ILSFA programs that enable well-timed, appropriately-scaled adjustments that complement the annual REC price-setting approach.

- The observations and preliminary recommendations herein are intended to provide options for IL to (1) optimize REC price-setting for the ABP and ILSFA programs, and (2) bolster cost-effective participation in underserved policy categories.

# REC Pricing Policy Design: Issues and Options, ABP

| By law, REC Prices Must Be… | Implication of Statute | Policy Design Options Likely Accessible Under Existing Statute | Policy Design Options Likely Requiring Legislative Change |
|---|---|---|---|
| Based on a "transparent annual schedule of prices" | • Prices must be set via a transparent process<br>• Prices throughout the year must be offered on a transparent basis and publicized appropriately | • Pricing based on project development, construction, operating and financing costs<br>• Blocks are opened at set price at set time | • Pricing based on spot/strip pricing (e.g., an SREC program)<br>• Pricing based on regular competitive procurements |
| Offered based on a "set value or product of a formula" | • Prices should not change substantially from the initial value set at the beginning of the program year<br>• If they do change from the initial value, any changes need to be based on a simple formula | • Set and unchanging value throughout the program year based on project cost analysis<br>• Set value to start, adjusted throughout the program year by a (simple) formula | • Price offerings based on a complex (or otherwise non-transparent) formula |
| (If pricing adjusts during the program year) "adjust(ed) at a predictable rate over time" | • Prices can be adjusted upwards and downwards in appropriate circumstances<br>• The upper and lower bounds of annual REC pricing must be limited to a fixed percentage | • No adjustments<br>• Predictable, discrete adjustments for all blocks based on objective block uptake milestones<br>• Predictable, discrete adjustments for certain blocks under certain circumstances based on objective block uptake milestones | • Pricing based on non-discrete (or strictly judgment-based) adjustments<br>• Pricing based on strictly iterative adjustments not publicized at the start of the year |

# REC Pricing Options, ABP
## Initial REC Price-Setting

### Near-Term Policy Options

| Options | Descriptions | Potential Advantages | Potential Drawbacks |
|---|---|---|---|
| **Option 1: Cost-Based w/ *F'casted* NM Credit** | • Retain annual, cost-based approach to PV Cost of Energy calculation and **modify PV NM Credit calculation** to ***forecast* individual rate components** based on applicable indices | • Estimates NM Credit based on market indicators rather than fixed %. Likely more closely-tied to market value of production, especially in the near-term. | • Modest incremental effort<br>• Need to identify and agree on indices used to adjust each component |
| **If pursue Option 1…** | … then select NM Credit *starting point* level as either:<br>• <u>Option 1A</u>: multi-year average of historical NM Credits<br>• <u>Option 1B</u>: current NM Credit | • <u>1A</u>: Smooths recent price fluctuations<br>• <u>1B</u>: Aligns cost to current market value | • <u>1A</u>: May noy accurately represent current market value of production<br>• <u>1B</u>: Could increase volatility of gap analysis and REC payment from program year to program year |
| **Option 2: No Change** | • No change to policy design. REC incentive requirement is estimated once, as the difference between category-specific PV Cost of Energy (i.e., revenue requirement) and PV NM Credit using current methodology (i.e., sum current rate components and escalate by 1%) | • Simplicity | • Potential for over (or under) payment for RECs<br>• Incentive for market participants to argue for conservative (lower) NM credit values to reduce uncertainty. |

**Applicability**: Consider applying to <u>all</u> ABP categories

# REC Pricing Options, ABP
## Initial REC Price-Setting

**Longer-Term Policy Options (due to likely need for expanded legislative authority)**

<table>
<tr><th>Options</th><th>Descriptions</th><th>Potential Advantages</th><th>Potential Drawbacks</th></tr>
<tr><td>Option 3: Indexed REC, $0 floor price</b></td><td><ul><li>Using CREST model, calculate <b>cost-based ‘strike price’</b> (all-in LCOE) for each category and guarantee this total revenue requirement ($/MWh) for contract duration.</li><li>REC price is calculated as the <u>difference</u> between LCOE and either: (a) current applicable NM credit, or (b) forecast of NM credit for the current program year (if current NM credit does not cover full program year).</li><li>Minimum REC price is $0 (i.e., when NM Credit > strike price</li><li>Note: This option requires a “pay as you go” approach (i.e., REC payments coincident with generation over time and not front-loaded, as in current program design)</li></ul></td><td><ul><li>Supports financing by guaranteeing total revenue requirement for full term</li><li>Introduces market-based element into REC price calculation to better align incentive and cost</li><li>Aligns policymaker and market participant interest around meeting revenue requirement as cost-effectively as possible</li><li>Allows for asset owner upside if NM Credit > strike price.</li></ul></td><td><ul><li>Requires recurring (but simple) calculation of indexed REC price</li><li>Modifying consumer education to focus on fixed total compensation rather than fixed REC price (once understood, expect this to be a net “advantage” that improves market adoption)</li></ul></td></tr>
<tr><td>Option 4: Indexed REC, no price floor</td><td><ul><li>Same as above, but without minimum REC price.</li><li>This approach represents a true contract for differences, in which market values above and below the strike price are netted against one another to determine the volume and direction of cash flow (i.e., to or from the asset owner)</li></ul></td><td><ul><li>Same, except does not provide upside when NM Credit > strike price. Instead, strike price = guaranteed revenue in all market conditions.</li></ul></td><td><ul><li>Same.</li></ul></td></tr>
</table>

**Exception**: Legislative authority and current program design likely allow the ‘strike price’ (i.e., total revenue requirement) approach to apply to Traditional Community Solar and Public Schools without the need for expanded legislative authority).

**Applicability**: Consider applying to ABP categories <u>>25kW</u>

# REC Pricing Options, ABP
## REC Contract Duration

### Near-Term Policy Options

| Options | Descriptions | Potential Advantages | Potential Drawbacks |
|---|---|---|---|
| **None** | No change. REC contract duration is set by legislation. | • Current design has been socialized | • Providing 25-year incentive over 15 years creates a greater budgetary and ratepayer burden than may be necessary to achieve programmatic MW and MWh targets. |

### Longer-Term Policy Options (due to likely need for expanded legislative authority)

| Options | Descriptions | Potential Advantages | Potential Drawbacks |
|---|---|---|---|
| **Option 1** | 20 years for all subcategories → paired with the 'strike price' approach and REC payments made monthly, based on delivered quantities. [may require legislative authority] | • ↑ cost effectiveness by more closely aligning contract duration (i.e., incentive payment) with project (equipment) life | • Less acceleration of investor returns than under current program |
| **Option 2** | 15 years for all subcategories | • Entices development by accelerating returns | • Fewer MW w/ same budget |

**Applicability**: Consider applying to all ABP categories

# REC Pricing Options, ABP

## REC Payment Frequency/ Timing

### Near-Term Policy Options

| Options | Descriptions | Potential Advantages | Potential Drawbacks |
|---|---|---|---|
| **None** | • No change. Payment timing is set by legislation. | • Stakeholder familiarity with current approach. | • In conjunction with price-setting approach, may not support objective of achieving robust participation in all project categories |

### Longer-Term Policy Options (due to likely need for expanded legislative authority)

| Options | Descriptions | Potential Advantages | Potential Drawbacks |
|---|---|---|---|
| **Option 1** | • Payments occur monthly, in line with production. | • Focuses stakeholder/IPA effort on cost modeling while reducing incentive to underestimate expected NM revenue.<br>• Minimizes over/under payment by removing revenue risk associated with forecasting NM rate | • May require legislative change to allow for some categories.<br>• Total REC expenditures will vary year to year based on market conditions. |
| **Option 2** | • If wish to retain some degree of upfront payments, calculate based on 50% of total contract volume and pay for remaining 50% monthly based on 'strike price' and delivered quantities. | • Maintains cash flow benefits of front-loaded payments while reducing (but not eliminating) risk that total payments do not align with total costs. | • Total payments likely to still be out of line with total costs over the full term of the incentive.<br>• May require legislative change to allow for some categories. |

**Exception**: Legislative authority and current program design likely allow the 'strike price' (i.e., total revenue requirement) approach to  apply to Traditional Community Solar and Public Schools without the need for expanded legislative authority).

**Applicability**: Consider applying to ABP categories >25kW

# REC Pricing Options, ABP
## Year-to-Year Pricing Adjustments (1)

| Options | Descriptions | Potential Advantages | Potential Drawbacks |
|---|---|---|---|
| **Option 1** | **This is a 'post-processing' adjustment to the annual cost-based calculation.** *Subsequent* program year price administratively adjusted based on block uptake in *prior* program year:<br>• If <25% of block capacity has been awarded at end of prior program year, then cost-based REC price for the following year is automatically increased by 10% <u>of the project's calculated revenue requirement</u> for the next year *[Example: If PV Cost of Energy is $100/MWh and calculated REC Price is $40/MWh, then adjusted REC price is $40+(10%*$100)=$50.]*<br>• If 25% to <50% of block capacity has been awarded at end of prior program year, then adjustment is 7.5%<br>• If 50% to 75% of block capacity has been awarded at end of prior program year, then adjustment is 5%<br>• If >75% to 100% of block capacity has been awarded at end of prior program year, then no exogenous REC price adjustment is made.<br>• If, at end of prior program year, the "Waitlisted Capacity" is 50% to 100% on top of the Program Year Block Size, then cost-based REC price for the following year is automatically decreased by 5% of the project's calculated revenue requirement for the next year<br>• If "Waitlisted Capacity" is >100% on top of Program Year Block Size, then automatically decrease by 10% of revenue requirement. *[Example: If PV Cost of Energy is $100/MWh and calculated REC Price is $40/MWh, then adjusted REC price is $40-(10%*$100)=$30.]* | • Market-responsive.<br>• Intended to spur market response through price signals.<br>• Provides additional incentive only where participation is significantly below MW targets.<br>• Measured annually (i.e., adjustment in one year does not necessarily mean adjustment will occur in the next)<br>• Allows program to account for non-price factors that may not be captured in annual cost modeling. | • May be somewhat susceptible to manipulation through unilateral project delay, but potentially mitigated by the implied cost of delaying a project's program participation<br>• Administrative price adjustment not directly connected to generator cost through research and analysis (the way initial REC prices are) |

**Applicability**: Consider applying to <u>all</u> ABP categories

# REC Pricing Options, ABP
## Year-to-Year Pricing Adjustments (2)

| Options | Descriptions | Potential Advantages | Potential Drawbacks |
|---|---|---|---|
| **Option 2** | **This is a 'post-processing' adjustment to the annual cost-based calculation.** Methodology is the same as Option 1 ***except*** that the adjustment would be calculated as a % of REC price and not a % of total revenue requirement:<br>• If <25% of block capacity has been awarded at end of prior program year, then cost-based REC price for the following year is automatically increased by 10%<br>*[Example: If calculated REC Price is $40/MWh, then adjusted REC price is $40*110%=$44.]*<br>• If 25% to <50% of block capacity awarded, then adjustment is 7.5%<br>• If 50% to 75% of block capacity awarded, then adjustment is 5%<br>• If >75% to 100% of block capacity awarded, then no exogenous REC price adjustment is made.<br>• If, at end of prior program year, the "Waitlisted Capacity" is 50% to 100% on top of Block Size, then cost-based REC price for the following year is automatically decreased by 5%<br>• If "Waitlisted Capacity" is >100% on top of Program Year Block Size, then REC price automatically decrease by 10%.<br>*[Example: If calculated REC Price is $40/MWh, then adjusted REC price is $40*90%=$36.]* | • Market-responsive.<br>• Intended to spur market response through price signals.<br>• Provides additional incentive only where participation is significantly below MW targets.<br>• Measured annually (i.e., adjustment in one year does not require adjustment in the next)<br>• Allows for non-price factors that may not be captured in annual cost modeling. | • May be somewhat susceptible to manipulation through unilateral project delay, but potentially mitigated by the implied cost of delaying a project's program participation<br>• Administrative price adjustment not directly connected to generator cost through research and analysis (the way initial REC prices are) |
| **Additional Options** | • Any number of variants on block capacity award percentages and associated percentage price adjustments | | |

**Applicability**: Consider applying to all ABP categories

# REC Pricing Options, ABP

## Intra-Year Pricing Adjustments

<table>
<tr><th>Options</th><th>Descriptions</th><th>Potential Advantages</th><th>Potential Drawbacks</th></tr>
<tr><td>Option 1</td><td><u>Current</u> program year price administratively adjusted based on block uptake in <u>current</u> program year:<br>• If <25% (block-specific) uptake at midpoint of applicable program year, then increase REC price by 10% of project’s calculated revenue requirement.<br>[Example: If PV Cost of Energy is $100/MWh and calculated REC Price is $40/MWh, then adjusted REC price is $40+(10%*$100)=$50.]<br>• If 25% to 50% uptake at midpoint of applicable program year, then increase by 5% of project’s calculated revenue requirement..<br>• If >50% to 100% at midpoint of applicable program year, no adjustment.</td><td rowspan="2">• Market-responsive.<br>• Intended to spur market response through price signals.<br>• Provides additional incentive only where participation is significantly below MW targets.<br>• Allows for non-price factors that may not be captured in annual cost modeling.</td><td rowspan="2">• May be susceptible to manipulation through unilateral project delay.<br>• Administrative price adjustment not directly connected to generator cost through research and analysis (the way initial REC prices are)</td></tr>
<tr><td>Option 2</td><td>Methodology is the same as Option 1 except that the adjustment would be calculated as a <u>% of REC price </u>and not a % of total revenue requirement</td></tr>
<tr><td>Additional Options</td><td>• Any number of variants on block capacity subscription and associated percentage price adjustments</td><td></td><td></td></tr>
</table>

**Applicability**: Consider applying to ABP categories <u>>25kW</u>

# Summary of Preliminary Recommendations, ABP

## Near-Term Policy Options

1. Maintain cost-based approach for setting *initial* REC prices, by category [See Slide 24]
    a) Continue to use CREST model to achieve maximum transparency and stakeholder participation
    b) Continue to reset cost-based benchmark annually
2. As part of annual cost-based approach, identify all components of NM Credit (for each utility and applicable rate class) and their current values
    a) For the 2024-2025 program year process, additional step of identifying historical NM Credit components for a specified multi-year period.
    b) Calculate NM Credit *starting point* as an average of prior NM Credit rates. [See Slide 24, Option 1A.]
3. Forecast NM Credit with component-specific indices [See Slide 24, Option 1]
4. Review prior year block uptake and determine if post-calculation adjustments are necessary [See Slide 28, Option 1]
    a) Pre-defined adjustments to be based on pre-defined criteria (intended to account for non-price/non-cost factors)
5. Consider intra-year, market-based adjustment for projects > 25kW (based on program participation during first 6 months of program year) [See Slide 30, Option 1]

# Summary of Preliminary Recommendations, ABP

## Longer-Term Policy Options (due to likely need for expanded legislative authority)

1. Calculate a 'strike price' for each category, for each program year; this is the revenue requirement (i.e., levelized cost of energy) [See Slide 25, Option 3]
   a) Intent = Provide total $/MWh revenue guarantee. Expected to result in lower cost of capital, lower LCOE, and lower REC incentive requirement. Increases investor confidence while decreasing likelihood that IL ratepayers overpay for RECs.
2. For each year incentive is provided to an operating project, calculate actual REC price incentive payment as difference between 'strike price' and 'market value of production' (i.e., NM credit) [See Slide 25, Option 3]
   a) REC price fills the gap (if any) between cost and market value, ensuring that (a) project revenue requirement is met, and (b) ratepayer cost is minimized (e.g., possible that in some years, some projects may not require a REC premium)
   b) REC price cannot be less than zero (i.e., if strike price < NM credit, REC payment is zero)
3. To maximizing financing benefits and minimize ratepayer cost, provide 20-year REC contract with payments made monthly based on delivered quantities. [See Slide 26, Option 1 and Slide 27, Option 1]

# Preliminary Recommendations, ILSFA

1. Maintain cost-based approach for setting initial REC prices, in coordination with ABP.
2. Where adjustments to ILSFA REC Adders are required to meet statutory customer savings targets, these adjustments should be modest and incremental over time, allowing the market time to respond to price signals.
   a) More generally, customer savings targets (to encourage adoption) are an administrative policy element. The causal link between savings rate and program adoption can't easily be researched or modeled. Therefore, adders intended to drive participation based on customer savings are appropriately based on policymaker discretion, rather than cost-based modeling. IPA should, however, track adoption data to refine adders over time.
3. ILSFA single and multi-family LMI under-participation largely related to non-REC price factors (e.g., roofing, electrical infrastructure, trust amongst communities of interest, etc.)
   a) Pilot program is underway to address non-price factors.
   b) Recommend waiting for results of pilot before trying to address these issues through immediate additional incentive payments. Expect that additional adoption will occur to inform incentive setting prior to the 2024-2025 program year.

# Other Observations/Recommendations

1. Recommend that all projects participating in ABP and ILSFA be required to submit actual project cost and performance data.
    a) The purpose of this recommendation is to support revenue requirement benchmarking and enable future incentive-setting to take Illinois-specific market conditions into account
    b) Data submitted should include appropriate documentation/substantiation

2. In addition to the REC Pricing Policy recommendations included herein, IPA may wish to consider modifications to program management (which are outside the scope of this engagement, but which relate to policy fulfillment).
    a) For example, to discourage manipulation of the intra-year price adjustments recommended herein, it may be appropriate to institute a maximum duration between the execution of an Interconnection Service Agreement (ISA) and the execution of a project or batch-specific contract/Product Order. E.g., 12 months

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# Appendix A

Evolution of Relevant REC Incentive Policy Design in Other States

Sustainable Energy Advantage, LLC

Sustainable Energy Advantage, LLC

# Evolution of Relevant REC Incentive Policy Design in Other States

State Policy Updates since August 2021

# Consideration of REC Pricing Policies in Other States

- IPA's scope for '*Independent Review of Renewable Energy Credit Pricing*' requests a "Discussion of REC pricing used in other states" and consideration of how those approaches may or may not be applied within Illinois' policy context
- The REC pricing policy observations included in the main body of this presentation consider SEA's first-hand experience with DG contracting and REC policies in all six New England states, New York, PJM (primarily PA, NJ, MD, DC, VA, NC), California, among others.
- When developing its preliminary recommendations, SEA considered:
  - Overall policy design in other markets
  - The relative success (e.g., deployment and cost) of these policies in other markets
  - How Illinois' current enabling legislation may, or may not, accommodate design elements from other states
- Not all policy design options from other states are well aligned to Illinois' policy objectives and legislative authority.
- The following slides reference several policy design updates since Levitan's August 2021 Whitepaper, as well as an overview of the California Re-MAT program.

# New Jersey Solar Policy Evolution

- The New Jersey Solar Successor Program (SuSI) described in Levitan's August 2021 White Paper has moved from concept to reality.
  - Although the program rollout has not been without setbacks (mostly due to projects in the transitional incentive program not reaching their project milestones on time) the program has largely proceeded apace.
  - The Administratively Determined Incentive (ADI) Program, which is the most relevant program for our purposes because it covers similar projects, recently completed its first year, and stakeholders can view the 1-year review webinar here.
  - Most recently, the BPU issued an Order that opened the Competitive Solar Incentive (CSI) Program for projects >5 MW. While a program for resources >5MW is not directly applicable to Illinois' ABP and ILSFA programs, it is important to observe NJ's lessons learned as it relates to block re-allocation. Specifically, NJ reallocated significant capacity from its CSI program into its residential market segment:
    - **NJ reallocated 69.81 MW** of capacity from the closed Interim Transition Incentive (TI) program, **and 30.19 MW** of non-residential market segment capacity **to the residential market segment**. The BPU found that the residential sector was on track to exceed its allocated capacity, while the non-residential segment was lagging. The REC prices are unchanged to date.
  - While reallocating capacity between blocks was how NJ chose to address over- and under-performance of certain blocks, this may not be the best solution for IL based upon the statutory framework and sector-specific policy objectives.

# SMART Program Evolution

- The Solar Massachusetts Renewable Target (SMART) program has undergone minor updates since August 2021. On December 30, 2021, the Massachusetts Department of Public Utilities (DPU) issued an Order regarding "Phase I" of its review of the electric distribution companies' (EDCs) Petition for Approval of the Revised SMART Tariff.
- The Order:
  - Expanded program capacity by an additional 1,600 MW.
  - Broadened the eligibility for the low-income incentive adder.
  - Created carve-outs for LMI customers (5% of each overall capacity block, and 20% of projects between 25-500 kW).
  - Discounted the distribution, transmission, and transition components of the value of energy 35% for virtual net metered and qualifying facilities.
  - Doubled the adder for public facilities from 2¢/kWh to 4¢/kWh.
  - Reduced the decline between program blocks for BTM resources from 4% to 2%.
- More controversial program alterations will be addressed in the "Phase 2" Order, which has been significantly delayed relative to the expected timeline and have not yet been released.
- Additionally, while not directly related to the SMART program, the Massachusetts DPU, EDCs, and solar developers have created an interim system for interconnection upgrade cost socialization. The Capital Investment Plan (CIP) proceedings aim to socialize a certain portion in interconnection cost upgrades for Affected System Operator study projects, as such costs have become a significant driver of project attrition in the SMART program.

# Additional Policy Design Considerations:
## California Re-MAT Program

- Program format 2013-2017
  - Feed-in-tariff program for projects under 3 MW
  - IOU's issued solicitation every two-months for 10, 15, or 20-year contracts (bidder selected contract length),
  - Contracts were bundled (Energy + RECs)
    - Three project types with their own capacity:
      - As available peaking (solar)
      - As available non-peaking (wind)
      - Baseload (biomass)
    - Contract rate increased or decreased based on previous auction volume, increments of $4, $8 or $12
      - Example:
        - One round of undersubscription = $4 increase, Three rounds of undersubscription = $12 increase (see pricing illustration on next slide).
        - "Undersubscribed" defined as under 20% subscription, oversubscribed as over 100%. 5 MW in each solicitation block. See next slide for SEA analysis of first 8 rounds.
- Program shut down temporarily in 2017 following lawsuit from a generator alleging that the program violated the avoided cost pricing requirement of PURPA (program was procuring both power and RECs). A 2020 Order restarted the program.
- New Program: REC prices administratively set (fixed) at estimate of avoided cost, updated annually
  - Avoided cost calculated by weighted average price of all non-state mandated long-term RPS contracts with facilities <20 MW executed by the three largest utilities over the last six years.
    - Applies time-of-delivery periods and factors for each utility to calculate avoided cost
  - Eliminates the bi-monthly program periods and 5 MW solicitation blocks

# CA Re-MAT Pricing Illustration, first 8 rounds

Figure 4- Re-MAT Adjustment Mechanism

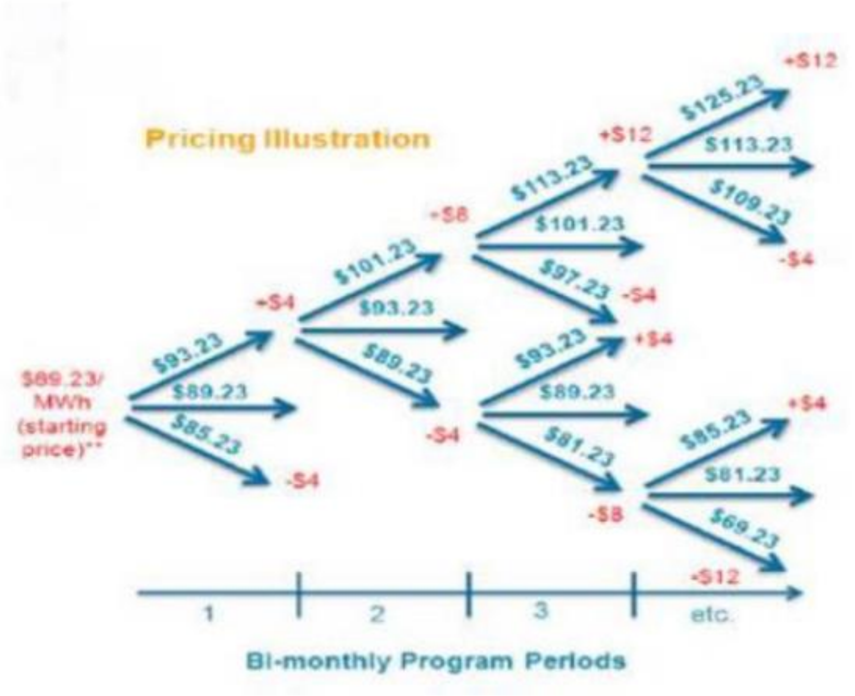


Table 3- Re-MAT Prices Rounds 1-8

| Utility | Round 1 | Round2 | Round 3 | Round 4 | Round 5 | Round 6 | Round 7 | Round 8 |
|---|---|---|---|---|---|---|---|---|
| PG&E | $89.23 | $85.23 | $77.23 | $65.23 | $53.23 | $57.23 | $57.23 | $57.23 |
| Southern California Edison | $89.23 | $85.23 | $77.23 | $77.23 | $77.23 | $81.23 | $81.23 | $77.23 |
| San Diego Gas & Electric | $89.23 | $89.23 | $89.23 | $89.23 | N/A – segment fully subscribed | N/A – segment fully subscribed | N/A – segment fully subscribed | N/A – segment fully subscribed |