COMMENTS ON BEHALF OF SOLAR LANDSCAPE ON REC PORTFOLIO AND PRICING STAKEHOLDER FEEDBACK REQUEST FOR THE 2026 LONG-TERM PLAN DEVELOPMENT

July 10, 2025

Solar Landscape appreciates the opportunity to provide feedback on the IPA's June 25, 2025 stakeholder feedback request on Illinois' REC Portfolio, REC Pricing, and RPS Budget Forecast. Our comments reflect our deep experience in the Illinois Shines program, particularly in the Community-Driven Community Solar (CDCS) category, developing equity-focused rooftop solar projects across Illinois. We urge the IPA to recalibrate its REC pricing model and forecasting assumptions to ensure the continued viability of these high-impact, community-serving projects.

Topic 1: REC Portfolio and RPS Budget Forecast

We believe varying Indexed REC strike prices by resource type and forecast year is an essential reform. For resource type, solar and wind have different cost structures, development timelines, and siting constraints. Treating them uniformly obscures key budgetary risks and reduces model accuracy. Likewise, adjusting strike prices by year accounts for real-world inflation, federal incentive changes, and labor market fluctuations. The IPA should incorporate resource-specific price curves and generation-weighted valuations, especially on-peak output weighting for solar, as a standard modeling practice.

When modeling by resource, we also recommend including interconnection timelines, regional labor market dynamics, and escalating grid upgrade costs. Reasonable risk-adjusted return expectations for developers should also be incorporated, especially for projects with more complex siting and permitting requirements.

The IPA's long-standing assumption of a 4% annual REC price reduction no longer aligns with market realities. Hardware costs have plateaued, while soft costs, such as interconnection, permitting, and labor, have risen across nearly all categories. For rooftop, CDCS, and small DG projects, a flat or at most 1–2% annual reduction is more appropriate. This recommendation is supported by IREC's Soft Cost Benchmarks and IL Shines project data, which show a steady increase in non-equipment costs.[1]

We also believe the REC model should be differentiated by program category. CDCS and rooftop projects experience higher customer acquisition and development costs than utility-scale or large DG systems. These higher costs justify higher REC prices, and slower or no cost de-escalators. Rooftop projects avoid land-use issues, reduce transmission and distribution costs, and reduce the need for grid upgrades. As a result, rooftop projects can come online much more quickly and add new generation to the grid. In New Jersey and Pennsylvania, Solar Landscape worked with The Brattle Group to conduct a study that demonstrates that these positive effects ultimately lower costs for ratepayers. CDCS developers in Illinois are also required to pass a portion of the REC value to the community. Increasing REC compensation for rooftop CDCS therefore further increases the direct financial benefit delivered to historically underserved communities. Furthermore, the IPA should use a five-year performance baseline before adopting any permanent REC floor, to ensure assumptions reflect actual market trends. **In short, a higher REC price incentivizes more community-based projects, and with it, lower costs and greater equity for the communities that need it most.**

Updating capacity factors is also necessary to optimize for continued viability of projects. Rooftop systems, especially in urban areas, face production limitations due to fixed tilt, azimuth, and shading, while ground-mounted systems in rural zones do not face these issues. We encourage the IPA to use Illinois Shines and NREL PVWatts data to refine these assumptions. While the current 0.5% degradation rate accurately reflects industry averages, we recommend that the IPA use multi-year Illinois Shines performance data to determine whether this rate remains appropriate.[2] If Illinois systems show consistently lower or higher degradation, such as by system type or location, adjusting this 0.5% assumption could improve REC value accuracy.

For forward guidance, we also support an IPA expansion of its modeling functionality. Scenario analysis tools can help compare community solar and utility-scale growth under different REC prices, budget caps, and interconnection scenarios. Publishing model assumptions would also improve transparency and stakeholder feedback.

Topic 2: REC Pricing and the REC Pricing Model

Regarding the REC pricing model itself, there are several prior assumptions that require a revision to reflect updated market dynamics.

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[1] Soft Costs | Department of Energy

[2] Annual relative performance degradation in photovoltaic solar plants - ScienceDirect

Interconnection costs are a significant burden for small-scale and rooftop systems. These often exceed $300/kW and are compounded by delays and local grid constraints.[3] Inverter costs also vary, with microinverters used in rooftop projects costing more per watt than central inverters. Treating all projects with uniform cost assumptions distorts actual economics.

Return expectations (IRRs) also diverge between categories. CDCS and rooftop projects typically yield lower IRRs due to their complexity and soft costs. Project timelines are another critical factor: while rooftop and CDCS projects often move faster than utility-scale projects, development timelines can still vary due to utility interconnection timelines and local permitting constraints, especially in urban areas. We encourage the IPA to preserve or expand deadline flexibility for these projects to accommodate real-world conditions without penalizing timely, community-serving development.

The IPA should update inputs such as customer churn, regional permitting delays, and subscriber acquisition costs, particularly for community-driven models like CDCS. We recommend using utility interconnection data and CDCS working group findings to calibrate the model.

For balance-of-plant (BoP) cost estimates, the IPA should rely on specific Illinois Shines data rather than the broader Annual Technology Baseline from the National Renewable Energy Laboratory. Rooftop projects in Illinois face specific challenges not captured in broad, nationwide datasets. The same applies to modeling rooftop versus ground-mount community solar performance. Capacity factors for rooftop systems are typically lower due to aforementioned design constraints and should be modeled as such.

To enhance financial predictability for equity-serving projects, we believe the Agency should adopt a cost-based REC floor. While some market-based mechanisms may be appropriate for large or utility-scale segments, REC pricing for CDCS and rooftop projects must prioritize stability and transparency. Dynamic price adjustments or mid-year changes, if considered, should be carefully constrained to avoid introducing financing risk.

Additional Big Picture Questions

Oversubscription and waitlists, particularly in CDCS, reflect unmet demand due to constrained MW allocations. This is why, in the previous stakeholder feedback round this year, we supported an expansion of the overall Illinois Shines MW capacity, increased MW allocation toward oversubscribed categories such as CDCS, and prioritization of CDCS in the Uncontracted Capacity

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[3] Interconnection Costs Have Risen Steeply in MISO: Berkeley Lab Report | American Public Power Association

waitlist. To further reduce queue congestion, the IPA should balance realistic price signals with adequate budget and interconnection capacity.

We applaud the IPA's commitment to continuous improvement and urge swift adoption of the above recommendations. Doing so will ensure that Illinois Shines continues to serve as a national model for inclusive, equitable clean energy deployment.

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