

[Commenter 9]

**Comments on Draft
ISC Contract and
Preliminary
Proposal
Requirements**

From: [Commenter 9]

Sent: Mon 6/15/2026 4:58 PM

To: Illinois-RFP <Illinois-RFP@nera.com>

Subject: Summer 2026 Energy Storage RFP – Invitation to Comment (Round 2 of 2)

TO: Procurement Administrator, Illinois Power Agency Summer 2026 Energy Storage RFP

RE: Summer 2026 Energy Storage RFP – Invitation to Comment (Round 2 of 2)

[Commenter 9] is pleased to submit the following comments for consideration on the Final Draft Indexed Storage Credit (“ISC”) Contract and Final Draft Preliminary Proposal Requirements released by the Illinois Power Agency (“IPA” or the “Agency”) on June 1, 2026 for the Summer 2026 Energy Storage RFP.

As an active developer of energy storage and solar systems, [Commenter 9] commends the IPA for advancing a procurement structure that provides revenue certainty for new storage resources in Illinois. We offer the comments below in the constructive spirit of supporting broad developer participation and efficient price discovery in the Procurement. Our comments are organized by reference to the specified topics in Appendix A to the Invitation to Comment and, where applicable, by reference to the relevant section of the Preliminary Proposal Requirements.

1. Topic 2: Performance Assurance

Question: *Is the proposed schedule for the reduction of the amount of Performance Assurance Collateral held over the 20-year term reasonable? Why or why not? If not, what further refinements or changes should be considered for this requirement?*

We respectfully submit that the proposed collateral framework, even with the declining schedule in Table A, remains materially more stringent than comparable energy storage procurement programs. For Example, the New York Index Storage Credit program permits a Project to reach Commercial Operation by December 31, 2030 — a full year beyond the Agency's baseline deadline — and prices that one-year extension at a fixed \$10,000/MWac, rather than conditioning the additional year on a doubling of posted collateral (NYSERDA Index Storage Credit form agreement, Art. F.15 (Contract Security), at p. 50). By contrast, the Preliminary Proposal Requirements escalate the Performance Assurance Collateral from \$50,000/MWac to \$100,000/MWac to secure the equivalent one-year extension to December 31, 2030. Other competitive storage solicitations, such as Austin Energy’s 2025 Energy Storage RFP, treat the Commercial Operations Deadline (COD) as an evaluated commercial term rather than a fixed forfeiture trigger. Our principal concern is structural: the framework conditions collateral exposure on a COD that developers cannot reliably control, rather than allowing the market to compete on the delivery schedules it can commit to in good faith.

Under the Preliminary Proposal Requirements, a Project must reach Commercial Operations on or before December 31, 2029, and that deadline may be extended only to December 31, 2030 by the Seller posting additional collateral to satisfy an Increased Collateral Requirement; if the Project does not reach COD by the applicable deadline, that collateral is subject to forfeiture. Interconnection and permitting timelines are regularly extended for reasons outside a developer’s control, and a firm backstop of December 31, 2030 is not realistic for many otherwise viable projects.

The timeline the requirements assume is especially difficult in the current PJM environment. The Agency is sending a market signal in mid-2026 for utility-scale, transmission-connected storage

expected to reach COD by year-end 2029 — roughly three years of lead time for projects that must clear PJM interconnection, secure and construct network upgrades, coordinate with transmission owners, and procure long-lead equipment amid constrained global supply chains. PJM only reopened its interconnection queue to new generation in April 2026 — its first intake of new projects since 2022 — under a reformed, cluster-based process that uses a single annual application window and, by PJM's own estimate, takes one to two years to complete interconnection studies before network-upgrade construction even begins. A developer not already positioned in that first cycle faces the next annual window plus the multi-year study and construction sequence, making a firm year-end-2029 deadline genuinely difficult to guarantee. Queue processing, network-upgrade construction, and supply-chain timelines are largely outside any developer's control. A single fixed deadline backed by escalating forfeiture forces developers either to bid against schedules they cannot guarantee or to decline to participate altogether.

This concern tracks the CRGA's statute's own commands. The governing provision directs that these procurements be conducted in a manner that "maximizes projects available in the MISO and PJM queues" and that "aligns to the extent practicable with regional transmission organization study phases." A rigid year-end-2029 deadline backed by forfeiture does the opposite: it screens out otherwise-qualified projects that are in the PJM and MISO queues but cannot reach Commercial Operation by that date given the just-reopened PJM cycle and its one-to-two-year study timelines. Honoring the legislature's direction to maximize available queued projects and to align with RTO study phases calls for deadline and collateral terms calibrated to those study phases.

The governing statute itself anticipates precisely the delays this collateral framework penalizes. In directing the Agency to procure storage committed to reaching commercial operation by December 31, 2030, the legislature made that deadline "subject to extension for a delay due to interconnection of the energy storage system, a delay in obtaining permits necessary to build or operate the energy storage system, or other circumstances at the discretion of the Agency." The legislature thus understood that interconnection and permitting delays are foreseeable and outside a developer's control, and it prescribed a remedy: extension at the Agency's discretion. It did not authorize, direct, or contemplate confiscatory collateral forfeiture as the response to such delays. Where the legislature both anticipated an outcome and provided extension — rather than penalty — as the response to it, we respectfully submit that the Agency's discretion runs toward accommodating qualifying delays, and that a framework imposing forfeiture for the very delays the statute treats as extension-eligible is in tension with legislative intent.

Conditioning forfeiture of Performance Assurance / Collateral on a deadline that developers cannot reliably control unreasonably transfers material, uncontrollable timeline risk onto bidders. That risk discourages participation and is priced into Strike Prices, which flows through to Illinois ratepayers and reduces efficient price discovery in the Procurement — outcomes contrary to the Agency's objectives. Escalating collateral payments are not the appropriate instrument for managing schedule uncertainty. They raise the cost of timelines the developer cannot control and that cost is also passed through the ratepayers.

We instead propose a market-based approach that allows each Bidder to state, as part of its offer, the COD it can commit to in good faith, and let the Agency's competitive evaluation select from among the compliant offers received. This element would be in addition to Paragraph 5.1 of the Preliminary Proposal Requirements which currently provides that a Bid consists solely of the Strike Price (\$/MWh) and "cannot include any additional instructions, contingencies, or conditions." **We respectfully request that the Agency permit a Bid to be accompanied by a limited, standardized set of evaluable parameters specified in advance by the Agency — principally the Project's committed COD — with bids otherwise remaining directly comparable and ranked on Strike Price, preserving the evaluation and tie-breaking mechanics in paragraphs**

5.2 and 5.3. As noted, a strictly unconditional bid format paired with a fixed deadline requires developers either to commit to terms they cannot fully guarantee or to refrain from bidding; allowing offers to state achievable delivery dates would broaden participation, improve the accuracy of bids, and reduce the risk of post-award default. Structured this way, the Procurement performs genuine discovery on both price and delivery timing, rather than price alone.

Relatedly, we encourage the Agency to adopt a standing mechanism that automatically re-solicits unfilled or undersubscribed capacity rather than allowing it to lapse until the next planning cycle. We propose that any capacity left unawarded or unsubscribed at the close of a procurement event trigger a follow-on solicitation approximately three months later, on the same contract terms, seeking the residual capacity at a COD one year beyond the prior event's deadline, and repeating on that cadence until the target capacity is filled. Critically, the Increased Collateral Requirement should not apply to capacity procured through these follow-on events. A developer that commits at the outset to a 2030 or later COD is not seeking relief from a missed deadline; it is offering the Agency the most timely delivery the market can responsibly provide. Escalating collateral on such bids would penalize candor about achievable timelines and defeat the purpose of the mechanism. An automatic re-solicitation that competes residual capacity on later, committed CODs lets the Agency capture supply that a single one-shot event, fixed to an early deadline, would otherwise leave on the table.

The Agency's own procurement history illustrates the consequence of requirements that exceed what the market can offer in good faith. In the Summer 2023 Indexed REC RFP, there were no winning utility-scale wind projects. Unfilled utility-scale wind quantities have repeatedly rolled forward into subsequent events. The Fall 2023 Indexed REC RFP sought 5,600,000 RECs annually from new utility-scale wind projects, and the Fall 2024 event sought 5,041,483 RECs annually from wind and hydropower, with targets in each case defined as the sum of planned targets and unfilled quantities from the prior event. The Agency itself sought stakeholder feedback in March 2020 on "barriers that may have limited successful participation" in prior utility-scale wind procurements. We urge the Agency not to repeat this experience in its inaugural storage procurement: when participation requirements and risk allocation exceed what developers can responsibly accept, targets go unfilled and ratepayers bear the cost of delay. A pre-committed, automatic re-solicitation cadence is the simplest safeguard against exactly that outcome.

2. Topic 3: Commercial Readiness

Reference: Commercial Readiness, Preliminary Proposal Requirements, pp. 10–11.

We note that the specific question posed under Topic 3 concerns the 20 MW per-facility minimum. As the Invitation to Comment expressly invites feedback on any aspect of the requirement, we offer the following comment on the entities eligible to demonstrate the commercial readiness threshold.

The final draft requires evidence that the 100 MWac combined-nameplate threshold (with each facility at least 20 MWac) be satisfied by "a single entity, either the Seller or the Bidder," and that all notice-to-proceed documentation name that single entity. We respectfully request that the Agency **permit this threshold to be demonstrated by any member of the disclosed Project Team, not solely the Bidder or the Seller.**

Section 1-75(d-20)(6) of the IPA Act requires that “Bidders ... demonstrate experience in developing to commercial readiness,” defined as “having notice to proceed in owning or operating energy facilities with a combined nameplate capacity of at least 100 megawatts.” The statute speaks to the development experience a Bidder brings to the Project; it does not, by its terms, require that a single named legal entity hold the qualifying notices to proceed. Experienced developers commonly hold operating and development assets across affiliated entities, and the entity with the qualifying track record is frequently neither the Bidder nor the project-specific special purpose vehicle named as Seller. Moreover, the entity that originates and develops an energy asset is rarely its ultimate long-term owner. The prevailing market model is develop-and-transfer. Developers carry projects through siting, interconnection, permitting, and notice-to-proceed, and long-term owners and capital markets investors acquire the assets as they mature.

As drafted, the single-entity limitation may exclude developers whose demonstrated capability plainly satisfies the statutory intent, simply because that capability resides in a Project Team member rather than in the Bidder or Seller of record. We understand the Agency’s interest in maintaining a link between the demonstrated experience and the Project. That link is already preserved through the Project Team disclosure requirements in paragraph 3.3, under which each entity’s role in the Project must be specified. Permitting any disclosed Project Team member to provide the same notice-to-proceed documentation already required would preserve the rigor of the readiness test while aligning it with how development capability is actually organized.

Moreover, the entity that originates and develops an energy asset is rarely its ultimate long-term owner. The prevailing market model is develop-and-transfer: developers carry projects through siting, interconnection, permitting, and notice to proceed, and long-term owners and capital-markets investors acquire the assets as they mature. The State’s own experience under the Adjustable Block Program (Illinois Shines) demonstrates this pattern from the program’s inception. Among the earliest ABP-awarded community solar projects, Pivot Energy developed 29 MW across eleven projects that were acquired by Summit Ridge Energy through its dedicated funding vehicle (2019); Nexamp acquired one of the first operating projects under the program from developer Borrego (2020); Cypress Creek Renewables sold a 45 MW portfolio of fifteen Illinois community solar projects to Nexamp (2022); Trajectory Energy Partners has sold more than 24 MW of Illinois projects to Nexamp since 2020; and institutional capital has financed these long-term owners at scale, including HASI’s joint venture with Summit Ridge Energy supporting a 255 MW portfolio. Limiting commercial-readiness eligibility to entities that have themselves owned or operated facilities over the long term therefore screens out the very firms that perform the development work this procurement depends on — shrinking the pool of qualified bidders, reducing the number of competitive offers, and impairing efficient price discovery.

Separately, and regardless of the Agency’s disposition of foregoing request, we ask the Agency to expressly confirm how the “owning or operating” prong of the commercial readiness definition will be applied where operations functions are performed by a member of the Project Team. The Project Team, as defined in paragraph 3.3, is broad enough to encompass entities engaged for operations, asset management, and related functions — including third-party operations providers that own or operate substantial fleets of energy facilities. Please confirm that notice-to-proceed documentation evidencing the operating experience of such a Project Team member would satisfy the commercial readiness requirement, or, if not, clarify in the final RFP Requirements which entities’ operating experience will be recognized. Express confirmation on this point will allow Bidders to structure their Proposals with certainty in advance of the Part 1 Window.

[Commenter 9] sincerely appreciates the Agency's consideration of these comments and recommendations. Please contact the undersigned with any clarifications or requests for further information.

Respectfully submitted,

[Commenter 9]