Storage for All Program RFI Response

Response to the Illinois Power Agency Request for Information 1 dated September 30, 2026

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Purpose and evidence basis

I recommend a phased Storage for All program that finances complete, safe solar-plus-storage systems, preserves Illinois Solar for All customer savings, and verifies customer benefits before expansion. The program should evaluate bill savings, normal-operation grid services, and outage continuity as distinct outcomes. It should maintain separate utility assumptions for Ameren Illinois in MISO/LRZ4 and ComEd in PJM.

These recommendations adapt the **Controlled Distributed Resilience Demonstration** framework in my September 14, 2026 ICC integrated resource planning comments [2] to this RFI [1]. They are program-design proposals, not claims of an operating portfolio, utility approval, customer enrollment, verified installations, or measured customer results. I am responding as a system architect. I do not represent an Approved Vendor, utility, or project developer in this submission, and no verified project-cost or customer-performance dataset is supplied.

The RFI states that public availability will be no earlier than 2028. Its Appendix A is a planning scenario. Eligibility, budget, tariffs, equipment costs, and funding available at launch should be verified again before any project award or financing commitment.

Program funding

Question 1 Initial funding and Appendix A assumptions

I propose an initial funding envelope of 10% of the eligible ILSFA subprogram allocation, with an evidence-based opportunity to increase it within the statutory ceiling. Using Appendix A solely for illustration, 10% of $30.5 million is $3.05 million, compared with approximately $7.625 million at 25%. The 10% proposal is a conservative starting design choice, not an empirically established optimum. It preserves more funding for solar while testing storage delivery, customer outcomes, and lifecycle costs.

At the Appendix A assumption of $10,000 per storage incentive, $3.05 million would support approximately 305 incentives before administration, evaluation, contingencies, and any other funded costs. If the entire amount came from solar incentives, it would also equal approximately 57 solar-project incentives at the stated $53,585 average. These figures describe a budget tradeoff, not projected awards, installations, or comparable customer benefit. Different project sizes and subprograms should be analyzed separately.

Questions 1.1 and 1.2: I do not have verified market quotations that establish replacement cost assumptions. Instead, I request clarification and sensitivity testing of Appendix A. At $300/kWh, the stated 13.5 kWh battery produces a modeled $4,050 rebate; actual eligibility and payment must be established under the applicable utility rules. The $270 VPP calculation appears to assume 5.4 kW × $10/kW × five annual payments. Please

identify the payment period, qualifying capacity, dispatch obligations, and treatment of backup reserve. A VPP filing alone should not establish a payable funding offset.

The $15,187 installation example, less a $4,050 rebate and $270 of modeled VPP receipts, leaves $10,867 before considering receipt timing, discounting, maintenance, replacement, or other costs. This should be reconciled with the rounded $10,000 incentive assumption. Five years of contingent operating receipts are not equivalent to cash available for construction.

Appendix A also lists approximately 700 storage projects, whereas $7.6 million divided by $10,000 is approximately 760 before other costs. Please disclose whether the difference reflects rounding, reserves, administration, or another allowance. A 13.5 kWh residential reference system should not be applied without adjustment to multifamily, nonprofit, and public-facility projects. Cost bands should distinguish usable energy, power, retrofit versus new installation, electrical upgrades, islanding equipment, and local permitting requirements.

Question 2: Staged funding release and expansion

Reserve the initial envelope and release funds in cohorts tied to project readiness, financing closure, commissioning, and evaluation. Include current and future ILSFA participants across eligible subprograms, with separate tracking for Ameren and ComEd projects. The purpose is to test a repeatable path from qualified customer through financing, agreement execution, installation, and measurable benefit.

Increase funding only after the initial cohort demonstrates safe operation, customer savings compliance, affordable lifecycle obligations, credible contractor delivery, and verified performance. Pause new commitments if customer charges, unresolved safety failures, or systematic underperformance emerge. Stop or redesign the affected delivery model where corrective actions fail. Publish the release and evaluation standards before selection; do not leave participants or contractors dependent on an undefined expansion decision.

Integration with Illinois Solar for All

Question 3: Selection timing and current versus future participants

Select and conditionally reserve storage funding during project development, before customers and financiers must rely on it in a final agreement. Confirm customer and solar-program eligibility, preliminary storage design, a complete cost estimate, applicable utility pathway, and a credible funding plan. Final payment should require installation and verified commissioning, including utility permission to operate where required. Funding reservation, approval, installation, permission to operate, VPP enrollment, and payment should remain separate recorded milestones.

Question 3.1: Use two coordinated pathways. For existing ILSFA participants, provide an add-on application linked to the original project record, with checks of equipment compatibility, warranty, lease or ownership rights, and whether utility interconnection approval must be amended. For new participants, use one coordinated solar-plus-storage intake with separately identifiable solar and storage decisions. Reuse valid eligibility documents rather than duplicating customer burden, subject to any recertification requirements.

Question 3.2: Storage funding should bridge the actual installation cash requirement without presuming that REC payment timing can be changed. Establish contractor or provider funding milestones, adequate working capital, and reconciled payment records. Prevent a delay in one component from silently extending commitments in the other. In addition to program selection, verify the customer agreement, financing, interconnection, permitting, equipment, and installation schedule before committing funds.

Program focus

Question 4: Customer outcomes and resilience priorities

Prioritize income-qualified customer benefit and continuity of designated critical loads, while retaining a path for bill-reduction projects that do not claim backup capability. Disaster preparedness and community resilience should be supported where the eligible host, loads, system configuration, and beneficiaries are documented. Project count alone would reward inexpensive installations without showing whether they deliver the intended benefit.

Use two distinct performance tracks: normal-operation bill and grid benefits; and outage continuity. A battery should receive resilience credit only where its transfer, islanding, protection, controls, critical-load circuits, reserve policy, and safe reconnection have been commissioned. Solar installation or battery nameplate capacity alone does not establish outage capability. Utility-reviewed locational evidence should support any claim of distribution upgrade deferral.

Question 5: Fair selection criteria

Publish eligibility gates and a transparent scoring rubric before applications open. Safety, customer savings, complete financing, and a viable interconnection pathway should be gates. Rank eligible projects using documented customer energy burden, critical-load needs, verified outage exposure, expected customer benefit, delivery readiness, and lifecycle cost. Provide technical assistance so readiness criteria do not exclude communities lacking application or engineering resources.

Use utility outage records, hosting-capacity and engineering information, customer-authorized load data, and site assessments when available. Medically necessary or sensitive customer information should be minimized and protected. Compare like projects within appropriate residential, multifamily, and facility categories; do not rank a public facility solely against residential cost per battery. Publish aggregate awards and outcomes without identifiable customer data. Contractor and job-training participation should be tied to safe installation, supervised work, and successful commissioning.

Incentive mechanism and incomplete projects

Question 6: Preferred incentive structure

Use a milestone-based capital grant as the primary storage mechanism rather than making capital recovery depend principally on an ongoing solar REC adder. A storage grant can identify storage costs and obligations directly, serve retrofits, and avoid implying that a solar production credit measures battery availability or performance. Provide a protected advance or equivalent provider financing at the appropriate readiness milestone, followed by installation and commissioning payments, with a limited holdback tied to documentation and corrective work.

Any advance should be paid through controlled provider arrangements with safeguards appropriate to the risk, such as escrow, recovery rights, or performance security. Do not expose an income-qualified household to contractor default. If an ongoing payment is added, tie it to a defined service or lifecycle obligation and prevent it from becoming an unsupported construction funding assumption. Specify who owns equipment, receives incentives, maintains it, replaces it, and may authorize dispatch.

Question 7: Solar projects that do not complete storage

A solar-plus-storage project could become solar-only because of customer withdrawal, technical incompatibility, permitting or interconnection limits, contractor failure, or an unresolved funding gap. These are foreseeable design contingencies, not outcomes established by my own project dataset.

Question 7.1: Track solar and storage obligations separately. Release the unused storage reservation, recover unearned storage funds from the responsible recipient, and require a corrected customer agreement and project record. Preserve an otherwise eligible, compliant solar incentive when storage is not completed, except where the applicable rules or misrepresentation justify a different remedy. A customer exercising an informed right to decline storage should not automatically lose a compliant solar project. Recalculate any combined benefit claim and prohibit reporting uninstalled storage as installed capacity.

Question 8: Opportunities and challenges of the preferred approach

A capital grant can resolve installation liquidity, expose actual storage cost, and support existing solar participants. Its principal challenges are provider default, incomplete systems, excessive pricing, and insufficient maintenance or replacement funding. Address these through itemized competitive quotations, milestone evidence, commissioning, warranties, lifecycle responsibilities, and an independent evaluation.

An ongoing payment can support retention and maintenance but creates timing, performance, and financing uncertainty. Model those obligations separately from the capital grant. Preserve an auditable record from customer qualification and consent through installation, dispatch testing, payments, and retention. Track elapsed time, failed milestones, provider responsibility, and reasons for attrition so program changes address conversion failures rather than outreach volume alone.

No upfront costs and customer benefits

Question 9: Complete customer cost protection

Zero upfront cost should cover all necessary work, not merely the battery purchase. Assess design, permitting, interconnection, electrical upgrades, critical-load circuits, transfer equipment, controls, communications, commissioning, customer training, and initial service. Disclose and fund recurring communications, maintenance, insurance, and replacement obligations rather than moving them into later household charges. Avoid household bridge loans or deposits to cover expected rebates or grants.

Require plain-language agreements describing equipment ownership, lease or PPA charges if any, data permissions, dispatch rights, override rights, minimum outage reserve, warranties, maintenance, termination, transfer on sale or relocation, and replacement responsibility. Customer consent for data retrieval should be distinct from permission to dispatch. A grant or program registration does not itself create dispatch authority or broad data rights.

Question 10 Quantifying customer and grid benefits

Create a pre-installation baseline and a documented measurement plan for every claimed benefit. Bill analysis should use customer-authorized interval usage and bills, the applicable rate, weather or other material adjustments, solar production, and actual customer payments. Report storage charging cost, discharge benefit, losses, degradation obligations, and net incremental bill impact relative to solar without storage.

For normal grid operations, distinguish installed, enrolled, available, dispatched, and delivered capacity. Record event instructions, utility meter and device telemetry, baseline method, response time, sustained output,

reserve constraints, export limits, opt-outs, failures, rebound, and compensation. Utility interval-meter data and battery telemetry serve different purposes; neither should be assumed to substitute for the other.

For outage continuity, record designated critical-load kW, outage and islanding timestamps, usable kWh, minimum reserve, hours of load served, unserved critical-load energy, solar recharge, failures, and safe reconnection. Commissioning tests and engineering estimates should be labeled separately from actual outage results. Report continuity delivered at the customer site rather than claiming that a battery prevented the utility outage. Monetized outage value should be a separately identified scenario unless supported by observed avoided costs and an accepted valuation method.

Question 11 Preserving the 50 percent savings requirement

Apply the governing ILSFA savings methodology and eligibility rules to the complete customer offer, with a separate check of whether adding storage worsens customer outcomes relative to the eligible solar-only offer. Include every storage-related customer payment and material operating cost. Require disclosure and correction where performance or charges cause savings noncompliance, with responsibility assigned to the provider rather than the household.

Question 11.1: For an existing no-cost lease, do not introduce a battery charge merely because the program allows other incentive structures. Preserve the existing solar benefit and obtain informed consent to any amendment. A PPA should be evaluated only where permitted by the applicable program rules; PPA pricing, escalators, energy charges, utility bills, dispatch compensation, and termination provisions must be reviewed as a combined customer cash flow. Do not use hypothetical resilience value or unconfirmed VPP revenue to cure a cash-savings deficiency. Review low-income discounts and rate changes using a consistent current baseline.

Question 12 Installation and development cost data

I am not supplying verified developer cost data. The attached IRP comments provide a demonstration framework, not quotations, invoices, or installed-project cost records. Appendix A figures referenced in this response remain IPA scenario assumptions, and I am not presenting them as my own market evidence.

I recommend collecting itemized records from participating developers for equipment, usable capacity, inverter and controls, electrical upgrades, islanding equipment, permitting and interconnection, labor, communications, commissioning, warranty, maintenance, and replacement. Separate retrofit and combined-installation projects and maintain territory, system size, quote date, installation date, and source classifications. Confidential vendor pricing should be submitted only with proper authority and through the RFI confidential procedure, with a public redacted version. No confidential cost annex is included here.

Question 13 Observed customer benefits and low income discounts

I am not supplying observed customer-storage results. I recommend an independently evaluated cohort using the methods in Question 10, with customer consent, data quality checks, and a clear distinction between measured results, engineering estimates, and targets. Report net bill outcomes, retention, dispatch delivery, critical-load continuity, failures, and costs over multiple operating conditions. Outreach, enrollment, installation, and permission to operate should not be represented as verified grid performance.

Question 13.1: A low-income discount rate can alter the dollar value of avoided purchases and the appropriate customer baseline. The direction and size depend on the applicable rate, discount design, charging behavior, and billing treatment; they should be calculated for each territory and customer. Evaluate incremental storage value against the discounted bill the customer would actually pay. Discounted bills do not establish outage

capability, so critical-load continuity remains a separate measurement. Avoid counting the discount itself as a storage benefit.

Incentive coordination and funding assumptions

Question 14: Preventing duplicate incentives and value claims.

Maintain one project and asset ledger linking the eligible solar project, battery serial or asset identifier, customer consent, utility territory, incentive source, eligible cost, funding recipient, reservation, award, payment, and operating obligation. Distinguish legitimate funding combinations from prohibited payment twice for the same eligible expense or obligation. Adopt explicit stacking rules and reconciliation rather than assuming every combination is prohibited or permitted.

Also prevent double counting of physical service. State-of-charge reserve committed to outage readiness must reduce the energy available for dispatch over the relevant duration. Register overlapping dispatch obligations and assign scheduling priority. Attribute customer payments, REC incentives, grants, and grid-service compensation to their actual recipients. Document lead and referral attribution, contract rights, data access, portfolio participation, and licensing where applicable. Program participation or submission of this framework should not be treated as granting proprietary implementation rights or overriding negotiated commercial agreements separately.

Question 15: Other sources of funding

For both territories, distinguish funding that is confirmed and payable, conditionally awarded, proposed, and modeled. A financing plan should include a source only after checking project eligibility, recipient rights, amount, timing, conditions, interaction with other funding, and the evidence supporting payment. Do not net five years of uncertain VPP receipts against today's construction cost without separately arranging financing and disclosing the risk.

For Ameren Illinois in MISO/LRZ4, verify the applicable Ameren rebate, interconnection and export limits, customer-authorized data pathway, rate, and dispatch program independently. For ComEd in PJM, perform the same checks under ComEd rules. No ComEd tariff or wholesale-market assumption should be transferred to Ameren, or vice versa. Utility VPP participation should also be distinguished from independently accessible wholesale-market revenue; both require their own eligibility and operational proof.

The Appendix A utility rebate and VPP assumptions can inform sensitivity cases but should not establish customer funding commitments. Federal tax benefits, third-party capital, grants, or other sources should be included only after qualified review of current eligibility, deadlines, ownership, and payment mechanics. Publish base, delayed-payment, and unavailable-funding cases, and require a financed completion plan that does not transfer the shortfall to an income-qualified household.

Closing position

I support Storage for All as a pathway to complete, operating solar-plus-storage systems with verifiable customer benefit. The first cohort should establish evidence for a repeatable delivery process, preserve solar access and savings, and distinguish normal-operation grid response from outage continuity. Expansion should depend on safe performance, auditable economics, customer protection, and a confirmed utility and regulatory pathway.

Source documents

[1] Illinois Power Agency. Storage for All Program Request for Information 1. September 30, 2026. Supplied file 20260929-RFI-Storage-For-All(1).pdf. Funding and questions: pages 5–7; submission and confidentiality: pages 3–4; Appendix A: page 8. https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20260929-rfi-storage-for-all.pdf

[2] Michael T. Thomas. Illinois Commerce Commission Second Request for Comments Integrated Resource Planning. September 14, 2026. Supplied file ICC- (RFC) for Integrated Resource Plan (IRP)(1).docx. Framework source for performance measurement, customer protection, resilience, and staged evaluation; not proof of implementation or counterpart endorsement.

Submission routing: IPA.Storage@illinois.gov. Required subject: Michael T. Thomas Response –StorageForAllRFI_Sept2026. Deadline: November 6, 2026, at 5:00 p.m. Central. This public draft contains no customer records, confidential vendor quotations, or proprietary implementation annex.