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IRP Stakeholder Workshop #2: Candidate Resources

1. Are there specific resource types that are not adequately captured by the proposed categories and should be reflected in the IRP framework?

We do not have comments to offer currently on this question.

2. Are there any resource categories that should be added, removed, or redefined to better reflect meaningful differences in cost, performance, or system value?

Gas Supply Change Constraints

Consistent with our prior comments in the Mitigation Plan Workshop, we support the model accounting for supply chain constraints associated with building new gas plants. While we acknowledge that the proposed model incorporates some supply chain limitations by not allowing new gas resources to be selected before 2032, we caution that supply chain challenges may persist beyond that date. Therefore, we recommend modeling a few scenarios that examine gas supply chain challenges past 2032.

If the model allows new gas resources to be selected too quickly, or without fully accounting for supply chain constraints, it risks overstating the availability and affordability of new gas generation. Such assumptions may cause the model to systematically favor new gas builds over other resource options, even where those gas projects may be infeasible due to turbine manufacturing backlogs, pipeline constraints, or interconnection delays. Failing to reflect these constraints can distort resource selection outcomes by understating project costs and accelerating assumed in-service dates. Moreover, overly optimistic assumptions about new gas availability may crowd out alternatives that could be deployed more quickly. For these reasons, we continue to support modeling these supply chain constraints.

Green Hydrogen and RNG

Slide 20 of the April 10 IRP Workshop Slides states that E3 will not model low-carbon fuels as a decarbonization mechanism for new gas generation in later years of the model, in either the Core Planning Scenarios or in the Alternative Decarbonization Scenarios. We strongly support this modeling approach, given the significant limitations and uncertainties around green hydrogen and RNG raised by the and other parties. As noted in our initial and reply comments to the March 2026 IRP Request for Comment, green hydrogen is highly limited in quantity and expensive to deploy, especially when produced in a truly zero-emissions manner with new, deliverable clean electricity. RNG is likewise high cost and limited in supply, and its emissions vary greatly by feedstock. We appreciate and support E3's proposal to not assume that these fuels will be available as cost-effective decarbonization solutions in this IRP.

3. What feedback do you have on the proposed base case cost assumptions for mature technologies (including solar, wind, lithium-ion storage, and gas)?

We do not have comments to offer currently on this question.

4. What feedback do you have on the proposed base case cost assumptions for emerging technologies (including nuclear and long duration storage)?

The costs provided for the "Generic LDES (100-hr)" resource are higher than the capital costs reported by Form and what utilities like Indiana Michigan Power Company and NIPSCO have modeled in their recent Integrated Resource Plans. Here are some example references for costs to use as a benchmark for the LDES capital costs:

- Navigating the Pacific Northwest's Energy Challenges: How Clean Dispatchable Resources Can Secure the Region's Energy Future, Table B-3 at 24. Retrieved from https://formenergy.com/wp-content/uploads/2024/06/Form-Energy-Navigating-the-Pacific-Northwest-Energy-Challenges-06.26.2024-1.pdf
- Indiana Michigan Power Company 2024 IRP Appendix 1, Exhibit E: Supply Side Resources. Retrieved from https://www.indianamichiganpower.com/lib/docs/community/projects/IM-irp/2025/IndMich_2024_IN_IRP_Appendix_1_Revised.pdf
- NIPSCO 2024 IRP at 146 – 147. Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf

5. What feedback do you have on the proposed commercial availability timelines shown on Slide 18? Please identify any technology timelines you believe should be revised, why you think it should be revised, and any supporting data or materials you have to support your recommendation.

We do not have comments to offer currently on this question.

6. Please refer to the approach to modeling VPPs in this IRP on slide 29. Are there any targeted refinements you would recommend to improve the robustness of this approach and the results

Modeling Virtual Power Plants in the Illinois Statewide IRP

This section addresses how distributed energy resources (DERs) and virtual power plants (VPPs) — aggregations of DERs such as residential and commercial behind-the-meter PV, storage, EV charging, smart thermostats, and flexible loads — should be represented in the Illinois statewide integrated resource plan. It is limited to the economic value of VPPs as selectable capacity resources in the capacity expansion framework. It does not address how that value is ultimately realized through PJM or MISO market mechanisms, which will be resolved in separate proceedings and program-design processes.

DERs and VPPs Should Be Modeled as Selectable Capacity Resources

The conventional utility practice for distributed energy resources (DERs) in capacity expansion modeling — to the extent they are addressed at all — is to treat them as exogenous inputs: a load modifier, a fixed scenario assumption, or a side calculation after the optimization has already selected large generation. This practice misses the point. DERs aggregated into dispatchable VPPs behave, from the system's perspective, much more like generation than like passive demand. They can be called on during system peaks, they can provide operating reserves, and they contribute firm capacity when properly designed and dispatched. Excluding them from the selectable resource set understates their value and biases portfolios toward larger, more expensive, and more polluting conventional additions.

Modeling DERs, and particularly VPPs, as selectable capacity resources also properly accounts for two features that are difficult to represent through load-modifier treatment:

- **Fuel cost risk elimination.** Every MW met through DERs rather than gas-fired generation is a MW permanently insulated from gas price volatility. Henry Hub spot prices have swung from under $2/MMBtu to over $9/MMBtu over the past quarter century, driven by hurricanes, geopolitical shocks, and shifting market fundamentals. Capacity expansion models routinely treat fuel-cost variance as a sensitivity driver on the cost side of gas-fired options; they should symmetrically credit resources that have zero fuel cost exposure. This is especially relevant for Illinois given the extensive gas-generation additions projected in the 2025 IPA/E3 Resource Adequacy Study baseline.
- **Customer capital contribution.** The cost of DER resources offered to the optimization should reflect only the utility's incremental cost to drive adoption above the status quo

baseline — incentive payments, enablement costs, measurement and verification, dispatch infrastructure — not the non-utility costs of the underlying customer-owned assets. Treating the customer's embedded investment as a utility cost in the model effectively double-counts and systematically disadvantages DER options. Functionally, this means the DER resource is capital-free from the ratepayer perspective.

Lawrence Berkeley National Laboratory's 2024 work on DER treatment in IRPs (Best Practices in Integrated Resources Planning, Dec. 6, 2024) reinforces this point: utilities that model DERs purely as exogenous load modifications consistently undervalue them relative to the same resources modeled as selectable capacity. The Illinois statewide IRP should adopt the selectable-capacity framing for both DG solar and aggregated VPP resources.

Value VPPs at Avoided Capacity Obligation

A VPP's economic value to the load-serving entity (LSE) arises principally from its ability to reduce the LSE's effective peak demand. When a utility-controlled VPP is dispatched during the hours that drive the LSE's capacity obligation, the LSE's metered peak is lower than it would otherwise have been. The LSE's resulting capacity requirement falls correspondingly, and the LSE avoids procuring some quantity of capacity it would otherwise have needed. That avoided procurement is the economic value of the VPP, and it is what the IRP should capture.

This framing is consistent with how mature energy efficiency is treated in resource planning. Fully implemented energy efficiency is embedded in the LSE's load forecast, and the lower forecast drives a lower capacity obligation; no capacity revenue is earned, but the LSE is permanently relieved of a capacity procurement it would otherwise have had to make. A dispatchable VPP that reliably shaves system peak operates on the same economic principle, with metered storage and telemetry providing measurement and verification far superior to deemed EE savings.

Modeling implementation

For the statewide IRP, the following representation is recommended:

- **Capacity value input:** avoided Cost of New Entry (CONE) for the LSE's capacity zone, per kW-year of firm VPP capacity. A single statewide CONE assumption or zone-specific values are both defensible for this purpose.
- **Firm capacity quantity:** nameplate VPP capacity multiplied by a dispatch-performance factor representing the fraction of nameplate reliably deliverable during the hours that determine the LSE's capacity obligation. This is a program-design parameter, not an RTO accreditation value. Reasonable base case: 80–90% for a well-designed utility-controlled distributed battery fleet; sensitivity range 70–95%.
- **Cost stack:** only the incremental utility costs — incentive payments, dispatch infrastructure, DERMS and telemetry, M&V, program administration. Customer-side capital for the underlying asset is explicitly excluded.

- **No RTO accreditation adjustment in the IRP.** Accreditation (ELCC in PJM, DRR/ESR/DEAR rules and DLOL transitions in MISO) governs how the capacity value is ultimately realized through market mechanics, not whether the economic value exists. For IRP purposes, accreditation is a pass-through: the VPP avoids a capacity obligation regardless of the vehicle used to capture the value. The specific RTO mechanism will be addressed in subsequent proceedings.

Align DER Deployment Trajectories with Distribution Value

DERs selected by the optimization provide systemwide grid services (per PUA Section 16.107.6). The modeling should reflect this alignment in two ways:

- **Hosting capacity and enabling investments.** Where the optimization selects high-DER scenarios, the distribution planning assumptions should reflect the hosting capacity headroom, interconnection queue throughput, and ADMS/DERMS capabilities required to deliver those resources. Conversely, where distribution constraints bind, the modeling should flag the capital requirement to unlock the DER pathway.
- **Avoided distribution investment.** Aggregated DERs can defer or avoid traditional distribution investments in addition to providing bulk-system capacity. To the extent the statewide modeling interfaces with the utilities' Multi-Year Integrated Grid Plans (ComEd Docket 26-0047; Ameren Docket 26-0051), avoided distribution investment should be captured as a benefit stream in the DER cost-benefit analysis, not left as a footnote.

Summary of VPP Modeling Recommendations

1. **Represent DERs and VPPs as selectable capacity resources** in capacity expansion. Costs reflect only the utility's incremental costs; the customer's underlying asset is treated as capital-free from the ratepayer perspective.
2. **Value VPP capacity at avoided capacity obligation cost.** Use zonal CONE (or a single statewide CONE assumption) times firm VPP capacity. Treat the RTO market participation pathway as outside the scope of this modeling exercise.
3. **Use a dispatch performance factor, not an RTO accreditation value,** to derive firm VPP capacity from nameplate. Base case 85%, sensitivity range 70–95%.

7. As shown on Slide 29, this IRP will model one representative VPP made up of multiple DER building blocks. Please rank which VPP building blocks you believe are most important to include in a representative VPP

We do not have comments to offer currently on this question.

8. Slide 30 identifies key VPP parameters that will inform the representative VPP to be modeled in the IRP. Please use the parameter categories shown when responding to the following questions. Please provide specific assumptions where possible with supporting data sources and/or program examples, where available.

We do not have comments to offer currently on this question.

9. Do you have any feedback to provide on the Assumptions workbook separately posted? Please note the specific assumption, your recommendation, and any data or supporting materials to support your recommendation

Although this assumption does not appear in the assumptions workbook, Slide 20 includes an important modeling assumption in its footnote: out-of-state imports of new gas combustion resources are constrained by transmission import limits, specifically the Capacity Emergency Transfer Limit (CETL) for the ComEd Zone and Zonal Import Ability (ZIA) for LRZ 4. That constraint is appropriate, but it should not be treated as static or applied only as a cap on imported gas resources. The IRP should also test whether targeted transmission solutions, including alternative transmission technologies, could increase effective import capability or relieve constraints affecting CETL/ZIA values. Dynamic line ratings, advanced conductors, power-flow controls, and topology optimization can increase transfer capability on existing facilities, reduce congestion, and improve deliverability without relying solely on conventional transmission expansion. At minimum, E3 should include a sensitivity evaluating how increased transfer capability, whether through traditional upgrades or ATTs, would affect resource needs, costs, emissions, and reliability outcomes. Transmission limits should be modeled not only as constraints on out-of-state imports, but also as planning signals that can identify cost-effective grid upgrades and reduce reliance on new combustion resources.

10. If CCS is considered as an added, co-paired technology with natural gas resources in a scenario:

We do not recommend adding CCS as a resource in this IRP cycle. Similar to RNG and hydrogen, CCS is high cost with an uncertain market development trajectory. Additionally, captured carbon is very frequently purchased and used in CO2-enhanced oil recovery, leading to more carbon emissions that are not necessarily captured in CCS emissions accounting. To the extent that E3 models CCS, they should share all assumptions regarding technology cost, type, and emissions accounting, including information about assumed CO2 storage method or potential CO2 utilization.

11. While current policy expects that CCS would fully sequester all carbon emissions to comply with CEJA (i.e. 100% carbon sequestration), a lower percentage of carbon sequestration may be more likely (e.g. 80% or 90% of sequestered carbon, i.e. 10-20% carbon emissions). Please provide a recommendation for a different percentage if 100% carbon sequestration is deemed to not be operationally likely during the term being modeled (2027-2047). If a different percentage is proposed, please support your recommendation.

We do not have comments to offer currently on this question.