IPA Integrated Resource Planning Workshop #2: Candidate Resources

April 10, 2026

Respondent Name: Chris Townsend

Respondent Organization: CJT Energy Law, LLC on behalf of The Coalition to Request Equitable Allocation of Costs Together ("REACT")

Respondent Email Address: chris@cjtenergylaw.com

Respondent Zip Code: 60601

Question 1

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

The IRP should more clearly identify and evaluate several resource types that are currently underrepresented or insufficiently defined within the framework.

First, the IRP should explicitly recognize behind-the-meter cogeneration (combined heat and power or “CHP”) as a distinct and viable resource type. Customer-sited CHP systems under 25 MW are not subject to certain emissions constraints applicable to larger generating units and can provide reliable, dispatchable capacity at or near load. This allows capacity expansions that can occur without the complications and system expense associated with transmission upgrades or extensions that are required of new grid scale resources. In addition, the IRP should evaluate scenarios reflecting expanding or eliminating the 25 MW threshold to assess the potential reliability and cost impacts of increased customer participation. To the extent these resources are currently aggregated within broader categories, the IRP should ensure that their unique performance characteristics, deployment potential, and contribution to near-term reliability are adequately represented in the modeling framework.

Second, the IRP should more clearly define how it will evaluate the continued operation of existing utility-scale natural gas generating resources that are subject to emissions reduction requirements. While the potential extension of these resources has been referenced in scenario discussions, it is unclear how the IRP will assess the full range of costs and benefits associated with maintaining their operation relative to alternative resource options. The IRP should include a transparent evaluation of these resources, including the capital, operational, and compliance costs associated with continued operation, as well as their contribution to system reliability, including their black-start capabilities. These IRP should present the cost and grid reliability offered by continued operations for existing utility-sale natural gas generating resources against all other resources so that policymakers can clearly understand the costs and benefits of the different options.

Third, the IRP should clarify how long-duration energy storage (LDES) technologies are treated within the proposed framework. While LDES may play an important role in future resource portfolios, its large-scale deployment, cost trajectory, and performance characteristics remain uncertain in the near term. The IRP should evaluate a range of scenarios reflecting different LDES deployment timelines and assumptions and should ensure that near-term reliability needs are not dependent on resources that may not be available within the required timeframe.

Fourth, the IRP should clearly identify how renewable energy and energy efficiency resources that are delivered through self-direct program options are included in the modeling. The self-direct programs deliver renewable energy and energy efficiency resources that may not be accounted for in targets and reporting by the IPA (for renewables) and the utilities (for energy efficiency). These programs are generally available to very large energy users and their use may become more prevalent as the number of very large energy users enter the Illinois market (e.g., data centers). The IRP should include reasonable assumptions concerning the current use of and possible expansions within these programs to ensure an accurate outlook for all available resources in the state.

These considerations are particularly important given the Resource Adequacy Study's identification of potential capacity shortfalls in Illinois and the surrounding regions beginning as early as 2029. The IRP should therefore ensure that all viable sources of near-term capacity—including existing resources and customer-driven solutions—are fully evaluated under realistic assumptions regarding performance, availability, and deployment timelines. These resources represent some of the most readily deployable and reliable capacity o

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?

REACT does not recommend major changes to the overall structure of the proposed resource categories. However, the IRP should ensure that resource categories are evaluated in a manner that reflects the full range of costs, performance characteristics, and system value associated with each resource type.

In particular, the IRP should incorporate the following considerations into its evaluation of resource categories:

- Cost Completeness. The modeling should consider the following system cost elements that are additional to the capital, fixed and variable costs of specific technologies and will ultimately flow to consumers:
  - Transmission interconnection costs;
  - Transmission upgrade costs; and
  - Other infrastructure investments necessary to integrate new resources.
- Performance Realism. The modeling should consider real-world performance elements that could cause modeled assets to underperform and thereby carry a higher cost:
  - Curtailments in the event of overproduction

    - Changes in long-term weather patterns (link to research)
- System Value and Reliability Contributions. The modeling should consider the following elements that could cause modeled assets to underperform and thereby carry a higher cost:
    - Increased ancillary costs to manage generation variability within PJM and MISO
    - Risk of rolling blackouts in the event of insufficient capacity on the regional grid

Ensuring that these factors are incorporated into the modeling framework will improve the IRP's ability to compare resources on a consistent basis and identify least-cost solutions that maintain reliable electric service.

Question 3

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

Please indicate which specific assumption you are commenting on, describe the reason for your feedback, and provide any alternative data source or supporting materials that you would like us to consider to support your recommendation. Please provide a link or share via email.

The projected capital, fixed and variable cost assumptions used in the IRP model should be benchmarked against the National Renewable Energy Laboratory's Annual Technology Baseline projections for natural gas, wind, solar, and batteries. All cost projections provided by NREL, along with the entire data set used by NREL is available for download using this link: https://atb.nrel.gov/electricity/2024b/data.

For instance, according to NREL, a 2-on-1 Combined Cycle (H-Frame) generation asset is projected to experience declining capital and operating costs over time. NREL estimates CapEx costs of $1,481/kW in 2026 and $1,236/kW in 2047; Fixed O & M costs of $32.80/kW-year in 2026 and $27.20/kW-year in 2047; and Variable O & M costs of $2.10/MWh in 2026 and $1.82/MWh in 2047.

These projected cost trajectories (and particularly the relatively low level of variable O & M costs) appear to differ from REACT's understanding of the assumptions currently proposed for the IRP. To the extent such differences exist, the IRP should clearly identify and explain the basis for those assumptions to ensure that resource comparisons are transparent and grounded in credible, publicly available data.

Additionally, the IRP should clearly address the costs associated with continued operation of existing utility-scale natural gas resources that are subject to emissions reduction requirements. This analysis should include capital investments, fixed and variable operating costs, compliance costs, and any other costs necessary to maintain those resources in service. Evaluating those costs transparently will allow the IRP to compare continued operation of existing resources against new resource alternatives on a consistent cost and reliability basis.

Finally, there should be additional transparency regarding E3's proprietary discounted cash-flow model, RECOST. At a minimum, stakeholders should have access to the model's key inputs, data sources, calculation methodologies, treatment of escalation and discounting, and the outputs that will be used in the IRP modeling process. This information is necessary for stakeholders to understand and evaluate the cost assumptions that will shape resource selection and policy recommendations.

Question 4

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

Please indicate which specific assumption you are commenting on, describe the reason for your feedback, and provide any alternative data source or supporting materials that you would like us to consider to support your recommendation. Please provide a link or share via email.

Cost assumptions concerning projected capital, fixed and variable costs for emerging technologies also should be benchmarked against authoritative public sources such as NREL and the U.S. Department of Energy (DOE). NREL's projections for nuclear resources are available online here: https://atb.nrel.gov/electricity/2024b/fossil_energy_technologies. DOE's report for long duration batteries is found here: https://atb.nrel.gov/electricity/2024b/fossil_energy_technologies.

The IRP should utilize dynamic cost projections rather than relying on static cost assumptions across the study horizon. NREL data, for example, reflects dynamic changes in capital and operating costs over time, which provide a more realistic basis for evaluating resource options in a long-term planning framework. Incorporating these dynamic cost trajectories will allow the IRP to more accurately assess the timing and cost-effectiveness of emerging technologies.

This approach is particularly important when comparing emerging technologies with other resource options across different time periods. Absent dynamic cost assumptions, the IRP may produce skewed cost comparisons that do not reflect expected market developments or technology maturation.

In addition, the IRP should recognize the inherent uncertainty associated with emerging technologies, including variability in deployment timelines, cost trajectories, and performance characteristics. Evaluating a range of cost scenarios and sensitivities will help ensure that the IRP identifies resource portfolios that remain reliable and cost-effective under different future conditions.

Question 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.

The assumption that natural gas resources would not be considered available prior to 2032 should be clarified. It is unclear whether this assumption applies to new resource development, existing resources, or both. To the extent this assumption limits consideration of existing generating resources, it may not fully reflect current system conditions, as natural gas-fired generation remains widely deployed and operational in Illinois. Public reporting also indicates that certain assets previously subject to earlier emissions-related deadlines may continue operating beyond those timelines due to changes in ownership structure, highlighting the importance of fully evaluating the availability of existing resources in the IRP.

The IRP should clearly distinguish between the treatment of existing resources and new resource development in its timeline assumptions. Existing resources should be evaluated based on their current and potential future availability, including the costs and requirements associated with continued operation.

More broadly, the IRP should ensure that resource availability timelines are aligned with the timing of projected capacity needs. The Resource Adequacy Study identified potential shortfalls as early as 2029, and the modeling framework should therefore prioritize evaluation of resources that can contribute to reliability within that timeframe.

In this context, the IRP should explicitly evaluate the costs and benefits associated with maintaining the operation of existing utility-scale generating resources, including those subject to emissions reduction requirements. This analysis should be conducted on a comparable basis with new resource options to ensure that the IRP identifies least-cost solutions that maintain reliable electric service.

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?

REACT strongly supports expanding customer participation as a core element of addressing the impending state and regional reliability challenges. Virtual power plants (VPPs) represent an important mechanism for enabling this participation and should be incorporated into the IRP framework. To fully capture the potential benefits that customers can provide to improve reliability, lower costs and advance the clean energy transition, however, the modeling approach should be refined to better reflect the diversity, performance, and real-world contributions of these resources.

First, the IRP should avoid modeling VPPs as a single "representative" resource and instead reflect the diversity of underlying technologies. VPPs are composed of a range of distributed resources -- including demand response, distributed generation, battery storage, and cogeneration (CHP) -- each with different performance characteristics, availability profiles, and contributions to reliability. Modeling a single aggregated resource risks overstating or understating the true system value of these components.

Second, the IRP should ensure that VPP performance assumptions reflect real-world operating conditions, including availability during peak demand periods and system stress events. This includes evaluating how different resource types within a VPP contribute to reliability under varying system conditions.

Third, the IRP should more explicitly incorporate customer-sited resources into the VPP framework, including behind-the-meter cogeneration and battery storage. To the extent that existing program structures or eligibility thresholds (e.g., size limits) constrain participation, the IRP should evaluate scenarios that reflect expanded participation to assess the potential reliability and cost impacts of increased customer engagement.

Finally, the IRP should evaluate how policy and program design can influence the scale and timing of VPP deployment, particularly examining self-direct program structures that allow large customers to procure or deploy their own generation and storage resources. Expanding or refining these mechanisms can unlock private capital, accelerate deployment of distributed resources, and provide scalable, near-term capacity solutions that enhance reliability while reducing system costs for Illinois consumers.

Question 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. (BTM solar, BTM storage, Managed EV charging, Residential smart thermostats, Water heater controls, Commercial building controls, Others).

BTM storage; BTM solar; Others; Commercial building controls; Water heater controls; Managed EV charging; Residential smart thermostats

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.

- *Based on the building block rankings you provided in your response to the previous question, please specify the percentage of total VPP nameplate capacity you recommend assigning to each building block.*
- *Of those building blocks, how would you distinguish between existing and new resources in your proposal?*
- *What available capacity should be assumed for this VPP? How should it be assumed to vary over the year?*
- *How long may this VPP sustain the response? How frequently?*

- *What may this VPP cost?*

REACT recommends against the IRP modelling a single "representative VPP." Evaluating a single "representative VPP" risks obscuring material differences in cost, availability, dispatchability, duration, and reliability contribution among the resources that may be aggregated into a virtual power plant. Instead, the IRP should model multiple VPP configurations or, at minimum, disaggregate the VPP into distinct building blocks with separate assumptions for performance, duration, availability, and cost.

A VPP composed primarily of residential smart thermostats will have a very different reliability value than a VPP composed of customer-sited battery storage, cogeneration, industrial demand response, or distributed generation. Treating these resources as one generic VPP could either overstate or understate the ability of customer-driven resources to support reliability during peak or stressed system conditions.

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.

REACT appreciates the opportunity to provide the following recommendations regarding modifications to the e Assumptions Workbook. The assumptions underlying the IRP modeling framework are critical to ensuring that resulting resource portfolios are both reliable and cost-effective.

Recommendation #1:

The IRP should explicitly incorporate total system costs, including:

- transmission interconnection costs;
- network upgrade costs;
- ancillary service costs; and
- other integration-related expenses.

The IRP modeling frameworks should recognize that resource costs extend beyond plant-level expenses and include system integration requirements such as interconnection and infrastructure investments. Failure to incorporate these costs can bias results toward resource types that appear low-cost at the plant level but impose higher system costs on consumers.

Recommendation #2:

The IRP should adopt time-varying cost trajectories for all major resource types, particularly for:

- renewable generation;
- storage technologies; and
- emerging technologies.

Cost trajectories for energy technologies are not static and evolve over time due to learning curves, supply chain changes, and market dynamics. Using static assumptions over a multi-decade planning horizon can distort resource selection and lead to suboptimal outcomes. All cost projections provided by NREL can be found at the following link: . The entire data set used by NREL is also available for download using this link: https://atb.nrel.gov/electricity/2024b/data.

Recommendation #3:

The IRP should explicitly model the cost and availability of existing resources, including:

- the all-in costs associated with continued operation of existing resources (including capital reinvestment, O&M, and compliance costs); and
- the potential availability of those resources across the modeling horizon.

Assumptions regarding existing resource availability significantly influence modeled capacity needs and portfolio outcomes. Assumptions regarding retirements and continued operation of these resources are among the most critical drivers of IRP results.

Recommendation #4:

The IRP should expand the Assumptions Workbook to include cost data for a broader range of distributed energy resources and technologies that are expected to comprise virtual power plants (VPPs), including variations by technology type and system size. The Assumptions data sets report costing for only one (1) type of distributed generation resources (e.g., residential solar PV).

While the IRP proposes a "representative" VPP product comprised of multiple technologies, there are no references to those multiple technologies in the Assumptions files. Because the IRP proposes to model VPPs as a combination of multiple distributed technologies, it is important that the underlying cost assumptions reflect that diversity. Developing cost assumptions across multiple technologies and system sizes will allow the IRP to more accurately assess the cost, scalability, and reliability contributions of customer-driven resources (e.g., residential solar PV, commercial/industrial solar PV, residential Li-ion batteries, commercial/industrial Li-ion batteries, etc.) The primary source for most of the cost data contained in the Assumptions Workbook is from NREL Annual Technology Baseline which includes a wide range of data for distributed technologies that could be easily included, including Distributed Wind, Commercial PV, Commercial Battery Storage, and Residential Battery Storage.

Expanding these assumptions will better position the IRP to evaluate the potential impact of self-direct programs and other customer-driven investment mechanisms (e.g. lifting the 5 MW caps for DER), which can unlock private capital, accelerate deployment of distributed generation and storage while providing scalable, near-term capacity solutions that enhance reliability while reducing system costs for Illinois consumers.

Question 10

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

- *What is a likely timeframe for when this technology could be reasonably expected to be commercially operational and accessed?*
- *What is reasonable costing for this technology to be included in modeling and analysis? Include data and reports to support your answer.*

REACT reserves its right to respond to this question once it has had the opportunity to review responses and data provided by other stakeholders.

Question 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.

REACT reserves its right to respond to this question once it has had the opportunity to review responses and data provided by other stakeholders.