IPA Integrated Resource Planning Workshop #2: Candidate Resources

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Question 1

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

No feedback.

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?

No feedback.

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 base case appears to assume that current federal tax credits and tariff related cost adders remain unchanged through 2030, followed by relief from tariff impacts and an extension of some tax credits thereafter. This assumption drives a material decline in installed costs for wind and solar in the post-2030 period. Nicor Gas recommends revising this assumption to avoid embedding reliance on the continuation of federal policy support, which is inherently uncertain and outside of Illinois policy maker control. Planning assumptions should reflect the full, unsubsidized cost of service absent any extensions of federal tax credits or favorable federal policies.

In addition, ongoing O&M cost assumptions for wind and solar should explicitly account for periodic repowering or major component replacement necessary to address performance degradation over time, particularly under a 30-year asset life assumption. Excluding these costs understates total lifecycle costs and may bias resource selection in favor of variable, non-firm renewable technologies.

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.

The base case assumes that installed costs for new nuclear capacity increases modestly in later years based on cited "Nath resource added" approach. It also assumes relatively short development and construction lead times for new nuclear additions (see slide 18). This assumption is overly optimistic. Illinois is not the only state considering additional nuclear capacity, and competition for skilled labor, supply chain, and engineering/construction expertise is likely to place upward pressure on costs. Rising costs and supply-chain will also likely lead to longer development cycles.

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 commercial availability timelines for new nuclear shown in slide 18 should be revised to reflect the full development and licensing schedule. See response to No. 4. Recent U.S. nuclear projects demonstrate end-to-end timelines exceeding 15 years from initial siting and licensing through commercial operation date. There is limited evidence that these timelines can be materially shortened, particularly in Illinois, which only recently lifted its moratorium on new nuclear construction. Given regulatory uncertainty, supply-chain constraints, and workforce availability, commercial availability should not be assumed before 2041 for realistic, conservative planning purposes.

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?

The overall modeling approach, treatment of VPP costs, and operating characteristics is confusing.

The modeling approach:

- It is unclear whether the scenarios are being set up where the model will select the VPP based on its cost and operating pattern, or if E3 will be forcing the VPP into the mix in order to have the model determine the cost/value of the VPP. (Or both.).
- The chart shows the process beginning with stakeholders and E3 specifying cost inputs, and also shows the process ending with the model calculating the value of the VPP. In the 4/10 meeting, E3 indicated it would then be used to set the actual VPP price. More description of this process would be helpful.
- If the VPP is being forced into the mix, it is unclear how E3 will select the optimal magnitude of VPP capacity for each scenario.
- If the model results show a net value for the IPP, and if it is used to set a VPP price that is higher/lower than the original input cost/price, it would increase/decrease the magnitude of the VPP available. It is unclear how E3 will address this dynamic feedback loop.

Costs:

- It appears that E3 will structure a "static" VPP with a set price, set capacity magnitude, and fixed operating characteristics (e.g., response time, duration). To address the dynamic value/price feedback issue mentioned above, E3 should consider creating a supply curve of VPP available at different prices.
- Creating a VPP from a mix of different sub-resources (e.g., storage, load control, backup generators) is likely to identify a suboptimal VPP or a VPP that cannot deliver the full resource specified in the IRP. The most expensive sub-resource increases the effective price of the overall VPP; without that sub-resource, the model would instead select additional VPP capacity. If the VPP price is set based on the average value of the modeled VPP, the most expensive sub-resource is unlikely to participate in that VPP market, so the model will have specified a VPP that is larger than the market can deliver.
- It is unclear how you will track market VPP prices (which will drive resource selection) and full societal costs, or how you will use those different metrics in resource and plan selection - i.e., customers may be willing to invest the full cost of storage systems to enhance reliability during outages, but they would be willing to participate in a VPP market for a much lower cost/price. Or customers may invest in the full cost of rooftop solar as an energy resource, but be willing to participate in a VPP market for a much lower cost/price.

Operating characteristics:

- The underlying sub-resources have different characteristics for response time, shifts vs. reductions, hourly duration, duration across multiple days, days per year, etc. Again, this approach is likely to select a suboptimal VPP - i.e., if the blended VPP produces 2 hours of load relief, while the system requires a resource providing at least 4 hours, the VPP will not be selected (or it will be selected at a lower magnitude). But, buried within the VPP are individual components that deliver 6-12 hours, and those cost-effective resources will be excluded with the entire blended VPP.

- It is unclear how VPP characteristics will be treated (and its individual sub-resources) in summer vs. winter - i.e., smart thermostats can control cooling loads in summer and heating loads in winter but have very different magnitudes and load relief characteristics. And the system will require additional costs to dispatch those resources in the winter. Similarly, water heater controls provide minimal load relief in summer, but substantial relief in winter. Winter VPP should not be ignored, otherwise the VPP will be undervalued, especially in scenarios with significant LOLP issues in the winter.

In general, these concerns could be addressed partially if E3 first ran the model to identify the general magnitude and shape of VPP needs, and then specified the VPP to meet those needs.

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).

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

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?*

See the answers to questions 6 & 7.

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.

- Federal Policy Drivers of Key Assumptions – As outlined in our response to Question #3, the approach seems to assume that tariff policy will revert back to 2025 levels, which has a substantial impact on some resources. The analysis should instead assume current federal policy/law continues as currently specified.
- Transparency on Key Assumptions and Constraints – For stakeholders to provide meaningful feedback, it is important that the consultant and facilitation team clearly outline the key assumptions and constraints embedded in the model. This includes, but is not limited to:
  - Reliability targets and how they are defined/measured

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.*

Nicor Gas believes that CCS is a promising technology that is making great strides. We have long been a supporter of CCS technology and have been at the forefront of its development. However, given the challenges around technology demonstration, permitting, infrastructure construction, transport, and storage, widespread utility-scale deployment of CCS technology is years away.

Due to prevailing operating and reliability risks and uncertainties for CCS on NGCC EGUs, along with the pipeline transportation and storage challenges, widespread utility-scale deployment of CCS technology for combustion turbines is years away. A realistic, widespread utility-scale deployment of CCS is December 31, 2039, or later.

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.

Using a 90% rate is consistent with the EPA's 2024 GHG New Source Performance Standards, which had assumed a 90% carbon capture efficiency for CCS technologies.