

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?

Yes, there are a few resources that should be considered alongside the candidate resources listed on slide 15 of the Workshop presentation that are not captured in the current list. Demand-Side Management (DSM) resources (as discussed in slide 23 of the workshop presentation) – despite not being a supply-side resource – may be more accurately portrayed through consideration alongside and in a similar context as a supply-side resource. Specifically, DSM resources can be modeled the same way as supply-side resources and can therefore be selected as an eligible resource within a capacity expansion model. Virtual power plants (“VPP”) should be included among DSM resources. For example, in its 2025 Integrated Resource Plan (pg. 95), AES Indiana utilizes a Market Potential Study to understand the long-term forecast of different DSM technologies and organizes a variety of these resources into selectable bundles that can be selected by the capacity expansion model alongside supply-side resources. In the case of AES Indiana, it was determined that if no large load customers come online, the utilities’ increased load could be entirely accommodated through the expansion and use of DSM resources. This shows that when DSM resources are allowed to be selectable alongside supply-side resources, it is oftentimes cost-advantageous to utilize them. Overall, the state agencies should consider modeling DSM in a similar way as AES and consider utilizing DSM as a selectable resource within the IRP model.

Additionally, on Slide 26, there is a note that existing DR capacity was modeled. United notes that there is room for expanding demand response resources outside of a VPP context and this should be included in the modeling as well. Among DR resources that exist today, behavioral demand response (BDR), and Peak Time Rebates (PTR), should be considered as a DR resource that could be expanded. Nearly all residential and small business customers are eligible to participate in BDR or PTR programs. Behavioral demand response has been used by utilities in California, Arizona, Texas, and Maryland to meet peak system needs during extreme weather events. Baltimore Gas & Electric (BGE) has been running an opt-out PTR program for years. In 2025, during a peak event day, BGE reported 150 MW of reduced demand on the grid. Of the 1.1 million customers eligible to

participate in the energy savings day, 63% of those customers took action to reduce or shift their usage, earning \$3.2 million in bill credits. These results show the scale and impact of an opt-out behavioral demand response program.

When run as an opt-out program, BDR's potential is significant. In New York, Brattle released Volume #1 of its Grid Flexibility Potential Report, which included modeling for residential BDR and time-of-use rates as cost-effective resources among the 16 grid flexibility options. The report found residential BDR contributing close to 600 MW in 2040 summer and a little over 200 MW in 2040 winter. BDR/PTR resources can be forecast, scheduled, and measured like other demand response resources. The IRP resources that the state agencies have proposed are very focused on technologies and United encourages the planning team to consider behavioral resources as well.

It is also worth noting that Puget Sound Energy considers behavioral demand response as a key component of its Flex Program (akin to a VPP) so it is possible to choose to include behavioral resources within the representative VPP for IRP modeling purposes.

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?

Yes. On slide 15 of the workshop presentation, long-duration storage and advanced nuclear reactors are both listed within the supply-side resource category of "emerging technologies". Slide 15 states that the IRP model will be able to choose to build "emerging technologies" similar to mature technologies. United therefore asks if there is a specific reason for categorizing these resources if both "mature" and "emerging technologies" will be equivalently selectable. United makes this note to ensure that effective emerging technologies are not discriminated against when the IRP model selects specific resources. Specifically, long-duration storage is a quickly maturing technology that will soon be reaching commercialization within the next year. For example, the long-duration storage company, Form Energy, has an agreement in place with Xcel Energy to provide 300 MW / 30,000 MWh of multi-day energy storage to power a Google data center in Minnesota, and has two earlier 10 MW / 1,000 MWh projects with Xcel in Minnesota and Colorado, among other announcements totaling 750 MW / 75 GWh of supply (per press releases from Form Energy's website). Furthermore, Form Energy has developed modeling best-practices to properly model long duration storage in an IRP context, including in public studies with consultants like E3 and Charles River Associates. This showcases the importance of properly considering this resource alongside more mature technology sectors to help lower grid costs and improve reliability in the near-term. Additionally, the IRP should consider breaking storage resources out into the following more specific classes such as: 1) short-duration energy storage (under 10 hours), 2) inter-day long duration energy storage (10-24 hours), and 3) multi-day long duration storage (over 24 hours). This will provide added specificity to energy storage resources, as labeling energy storage resources as "Generic LDES" is an inappropriate, overly-simplistic way to model the distinct inter-day long-duration storage and multi-day storage resource classes.

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 cost assumptions are provided on slide 21 and 22 of the workshop presentation. One issue with the cost assumptions that United wishes to note is the fact that Levelized Fixed Cost (LFC) is utilized to portray the costs associated with natural gas turbines (whether it is a CT or CCGT), as opposed to utilizing the Levelized Cost of Electricity. United notes that LCOE is typically utilized to portray the costs associated with most resources (including gas resources) due to the fact that LCOE considers fixed costs, variable O&M costs, fuel costs, as well as tax credits over the useful life of the energy resource. LFC, on the other hand, only takes into account fixed costs such as capital expenditures, interconnection costs, fixed O&M costs, and property taxes. Utilizing LFC to portray the costs of natural gas resources is inappropriate due to the fact that a significant portion of the costs associated with natural gas resources are variable costs (fuel costs). That being said, United recommends utilizing LCOE to portray costs of all resources, however, the use of LFC may be warranted for application on storage resources. Regarding the use of LFC for storage resources, however, United is perplexed on the projected rise in LFC for all storage resources, as cost projections for utility-scale BESS projects are widely expected to drop over the coming decades, as discussed in NREL's Cost Projections for Utility-Scale Battery Storage: 2025 Update. Beyond the expected increase in LFC due to the phaseout of federal tax credits, United seeks an additional explanation from the modeling team to explain the expected rise in LFC.

Additionally, United disagrees with the 42% tariff impact on utility-scale PV in 2030 and the resulting \$24 drop in LCOE from 2030 to 2031. Utility-scale PV projects coming online in 2030 will still be eligible to qualify for federal tax credits if they have been properly safe harbored, which leading developers are actively doing to ensure utilities can take advantage of low-cost power for their ratepayers. Lazard's 2025 LCOE Report shows a significant drop in LCOE for Solar PV and Wind projects that are subsidized with ITCs/PTCs. Even if tariff impacts are meaningful, United feels that it is incorrect to assume that the net effect of the ITC/PTC phaseout will lead to a drastic decrease in LCOE for solar, even with tariff impacts considered.

Specifically on Long-Duration Storage technologies, some of the assumptions that the state agencies make on the capital expenditures for these technologies is unrealistic. A CapEx of \$6,163/kW is unrealistic for LDES in 2030 is unreasonable. Specifically pertaining to 100-hour iron air battery storage technologies, the following are examples where CapEx is significantly below \$6,163/kW: 1) Xcel Energy's 2024 Just Transition Solicitation Plan: \$2,400/kW capex, 2030 COD, 2) PacifiCorp 2025 IRP: \$2,730/kW capex, 2027 COD, 3) Idaho Power 2025 IRP: \$3,000/kW capex, 2030 COD, 4) CPUC 2024-2026 IRP Inputs and Assumptions, \$2,904/kW, 2030 COD, 5) DOE LDES

Commercial Liftoff Report: \$1,900-\$2,500/kW, ~2030 COD. The state agencies should consider revising the cost assumptions associated with Long-Duration Storage resources.

Finally, United is curious as to the sources of the LCOE and LCF information, as there are some key differences between the LCOE and LCF information that EIA and NREL (specifically NREL ATB) provide on these metrics and what the ICC/IPA are utilizing.

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.

On slide 22 of the workshop presentation, Long Duration Energy Storage (LDES) is shown to have a significant increase in Levelized Fixed Cost during the 2038-2040 timeframe, and this is explained as the “higher cost uncertainty for generic LDES [because] costs reflect ‘nth of a kind’ deployments”. United has concerns regarding this cost assumption for long-duration storage resources. Specifically, United finds it unrealistic for a technology that is nearing market maturity in the near future to exhibit significantly increased Levelized Fixed Costs in the future (2040 and beyond). In fact, it is reasonable to assume that as LDES technology market grows and becomes more competitive, LFC should in fact reduce (or at least stabilize) overtime due to the nature of competition in an economic market and economies of scale. United suggests that the state agencies review the cost assumptions that are being used for LDES resources and provide greater detail on these assumptions. At minimum, the rate of LFC increase (due potentially to expiring investment tax credits) should be the same for all energy storage technologies. Additionally, for the ‘high flexible’ and ‘high load’ future load scenarios, United is curious as to what expanded EE trajectory is being considered by the state agencies? United encourages the state agencies to model all cost-effective EE.

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.

United has concerns regarding the commercial availability of Long-Duration Energy Storage (LDES) resources that is portrayed on slide 18 of the workshop presentation. Specifically, United suggests shifting LDES availability to include 2032 through 2047 with LDES availability occurring in 2030 in “some scenarios”. As discussed in question 2, long-duration storage is a quickly maturing technology that will soon be reaching commercialization within the next few years. As noted above, the long-duration storage company, Form Energy, has agreements in place to provide long-duration storage to power data centers in Minnesota and Texas, with the Minnesota application reaching

expected commercial operation in 2026. This provides a real-world example that LDES resources may be available in 2030 in some scenarios, but will very likely be available by 2032. Ultimately, United recommends that the IRP assume LDES resources will be commercially available by 2030.

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?

United generally supports the process for modeling VPPs within an IRP as it is portrayed in slide 29 of the workshop presentation. One suggestion to consider on how to model a VPP within an IRP is to treat the VPP as a selectable resource comparable to supply-side resources within the IRP. This suggestion is different than the proposed methodology which would analyze the cost difference in supply-side resources chosen between scenarios with and without VPP adoption and the coinciding cost savings associated with this VPP adoption. As discussed in United's response to question 1, VPPs could be modeled in a similar way that vertically-integrated utilities model DSM technologies as a selectable resource. As noted above, AES Indiana utilizes a Market Potential Study to understand the long-term forecast of different DSM technologies and organizes a variety of these resources into selectable bundles that can be selected by the capacity expansion model alongside supply-side resources. This IRP model could utilize a similar process by bundling various different DSM technologies that could be representative of a multi-technology VPP. These bundles could then be made into a selectable resource alongside supply-side technologies.

Furthermore, Platte River Power Authority (PRPA) in Colorado has considered VPPs within its 2024 IRP, and utilizes a very similar framework as AES Indiana applies to DSM technologies (See Platte River Power Authority 2024 Integrate Resource Plan at Pg. 88). PRPA utilized a DER Study that was conducted which included an assessment of flexible DERs that could provide VPP capacity. The DER study that PRPA utilized used a multi-step approach that considered the technical feasibility (quantity of flexible DER capacity that theoretically exists), economic feasibility (costs and benefits of current and future flexible DER programs), and the achievable potential (economic potential realized as a dispatchable VPP capacity at the time of system need and considering enrollment rates in a VPP program). The DER study identified various programs that can be applied to a VPP such as: distributed storage management, EV charger management, large C&I demand response, HVAC demand response, and water heater demand response. Ultimately, PRPA concluded that the VPP could be capable of dispatching 32 MW of capacity by 2030 and 93 MW by 2040, however, with increased program focus and more projects could provide 52 MW by 2030 and 113 MW by 2040.

Another useful source for understanding how VPPs can be analyzed in an IRP context is Rocky Mountain Institute's (RMI) Power Shift Report from 2024. This report highlights the important role that VPPs can provide to reliability and resource adequacy when properly considered in a planning framework.

United also suggests that the state agencies provide more detail on how the Effective Load Carrying Capability will be estimated for VPPs. Specifically, United suggests that the state agencies provide the assumptions and calculation methodology that will be used to estimate the ELCC of a VPP.

Finally, United notes the importance of aligning the consideration of VPPs within this IRP context with the parameters/requirements of the multiple DER VPP provision within 220 ILCS 5/16-107.9 as codified through the Clean and Reliable Grid Affordability (CRGA) Act.

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

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?*

As discussed in United's response to question 6, the VPP capacity for individual DER resources will be best understood after conducting a Market Potential Study (or similar study) that analyzes the existing DER programs in Illinois and identifies a realistic potential for the amount of nameplate capacity that could be provided by a DER resource within a VPP program at both current and forecasted levels.

As noted above, another useful source for understanding how VPPs can be analyzed in an IRP context is Rocky Mountain Institute's (RMI) Power Shift Report from 2024. This report highlights the important role that VPPs can provide to reliability and resource adequacy when properly considered in a planning framework.

United also notes the importance of aligning the consideration of VPPs within this IRP context with the parameters/requirements of multiple DER VPP provision within 220 ILCS 5/16-107.9 as codified through the Clean and Reliable Grid Affordability (CRGA) Act.

Market Potential Studies identify a Realistic Achievable Potential (RAP) of certain DER resources which includes resources that exist under current existing programs, and resources that are forecasted to exist under expanded or new programs. Market Potential Studies are therefore useful to distinguish between resources that exist under existing programs and potential new resources under new programs. This will help to distinguish between the maturity and uptake of existing resources and newer less mature resources.

Alternatively, another option for making this determination could be to conduct technology adoption or least-cost adoption models to determine customer adoption of technologies. Specifically, NREL has produced technology adoption studies that include Illinois and county-level data such as RESSTOCK and dGEN. Furthermore, the state agencies could consider reaching out to EE/DR companies directly to gain more information on current levels and forecasts of data.

If the VPP does consider all of the technologies listed in the building blocks mentioned in question 7 and assumes growth in these respective DER programs over time (with new programs evolving), the VPP can provide considerable capacity to meet Illinois' energy needs. A proper analysis, however, would need to be conducted (such as a Market Potential Study) to understand the capacity that the DER resources can provide when combined into one VPP. The amount of capacity is also dependent on the type of coordinated dispatch strategy that the VPP will assume between the different types of DER.

The duration and frequency of VPP dispatch depends on the focus and goal of a VPP. VPPs can provide a variety of grid services such as capacity, energy, ancillary, or resiliency services. Depending on the specific focus of the VPP, the duration and frequency of dispatch may vary. However, VPPs can importantly provide value during peak load times on a daily basis.

The cost of this VPP will vary depending on what DER resources are used, the dispatch strategy that is utilized, the IT costs that will be needed to implement the program, and the performance payment levels that will be set to incentivize the dispatch of specific resources. For sake of example, within ICC Case No. 25-0678, ComEd is currently proposing a Bring-Your-Own-Device Load Reduction program (focused on smart thermostats and thermal load resources) that will operate in a similar fashion as a VPP. ComEd estimates the total cost of the proposed program is \$8,749,263 in 2030. It is important to note, however, that a portion of costs can be offset due to the revenue that is received through capacity bids that would utilize VPPs, and in this ComEd example, it is estimated that \$4,056,936 will be collected in capacity revenue in 2030. VPPs also have a

significant avoided cost consideration when applied, and can avoid the need for costly large-scale capacity resources.

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.

United is concerned regarding the assumption that Utility and Residential PV resources will claim the PTC rather than the ITC as this is not representative of typical modeling practice for solar in the Midwest and may bias results against solar resources. While the IRA allows projects to elect either credit, the PTC is generally more competitive in higher-irradiance regions where capacity factors are higher, such as in southwestern United States. In moderate-resource regions such as the Midwest, the value of the PTC is structurally lower because it is tied to energy production, whereas the ITC is based on upfront capital cost and is less sensitive to regional solar resource quality. This approach is consistent with other regional IRPs, such as AES and CenterPoint's most recent IRPs.

Beyond that, United does not have specific feedback on the cost assumptions workbook that has been provided, other than the comments that were provided in questions Nos. 3 and 4 on LCOE and LFC. The only note that United has is to ensure that the state agencies are utilizing the most recent NREL ATB values. Specifically, if 2025 NREL ATB values are released during the timeline of this IRP process, United recommends utilizing these values as opposed to 2024 NREL ATB values.

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.*

Given the multiple variables associated with Carbon Capture and Sequestration technology, Advanced Energy United does not have an opinion on the costs or commercial operation date of such technology. United, however, notes that advanced energy technologies such as renewable energy and storage resources are more mature technologies and have a better track record related to decarbonization than utilizing CCS paired with natural gas facilities. The lack of commercially operating CCS projects and overall immaturity of the technology signals that it will be difficult to accurately model the costs and availability over the coming decade, supporting the need for renewables and storage to be the primary resources that allow Illinois to reach its clean energy goals and maintain CEJA compliance.

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.

Advanced Energy United does not have an opinion on the percentage of carbon sequestration that is achievable by CCS technology.

United does not support a lower percentage of carbon sequestration being modeled in the IRP while there are alternative, zero-carbon resources available, like renewables and storage readily available that can be utilized to comply with CEJA. The lack of commercially operating CCS projects signals that modeling any percentage of sequestration with confidence will be difficult, so it is not reasonable to assume there would be a meaningful difference between 100% vs. 80% sequestration, for example.