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?

N/A

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?

N/A

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 JSP appreciates E3's transparency in documenting the data sources underlying its cost assumptions. With respect to utility-scale solar PV and lithium-ion battery storage, the JSP submits that the proposed assumptions — derived from the NREL 2024 Annual Technology Baseline (ATB) Moderate Scenario — do not adequately reflect the pace of observed market cost reductions and are likely to overstate the cost of these resources over the IRP planning horizon. More accurate cost assumptions would improve the reliability of the portfolio optimization by ensuring that lower-cost clean energy resources are not systematically disadvantaged in PLEXOS relative to alternatives.

The NREL ATB Base Year Benchmark Exceeds Observed Market Prices:

The ATB's 2023 base-year benchmark for utility-scale solar is $1.56/W-AC. However, the Lawrence Berkeley National Laboratory (LBNL) Utility-Scale Solar, 2024 Edition — which compiles empirically observed, project-level capital cost data from EIA and FERC filings across more than 1,760 U.S. projects — found that the capacity-weighted average installed cost for projects completed in 2023 was $1.43/W-AC, approximately 8% below the ATB benchmark. LBNL's data is publicly available and represents actual contracted and constructed market costs rather than modeled estimates. See LBNL, Utility-Scale Solar, 2024 Edition (September 2024), available at https://emp.lbl.gov/publications/utility-scale-solar-2024-edition.

Because E3's cost trajectory is anchored to the ATB's 2023 base year, this overstatement of the starting point propagates forward throughout the entire modeling horizon — resulting in systematically higher projected costs for solar in every year the model selects resources.

Independent Benchmarks Confirm Lower Projected Costs:

Several additional publicly available, widely-cited sources project lower costs for utility-scale solar and storage than the NREL ATB Moderate Scenario and support use of a lower-cost trajectory as the base case:

NREL ATB Advanced Scenario: The NREL ATB itself offers an Advanced Scenario that projects a 58% reduction in utility-scale solar CAPEX between 2023 and 2035, compared to 44% under the Moderate Scenario. Given that actual 2023 market costs already came in below the ATB's Moderate base year, the Advanced Scenario trajectory better reflects observed market dynamics. The ATB Advanced Scenario data is publicly available at https://atb.nrel.gov/electricity/2024/utility-scale_pv.

BloombergNEF (February 2026): BNEF reported that the global benchmark levelized cost of storage for a 4-hour battery system fell 27% year-over-year to $78/MWh in 2025 — a record low since BNEF began tracking costs in 2009, and a trajectory significantly steeper than the NREL ATB Moderate Scenario projects. See BNEF, Battery Storage Costs Hit Record Lows (February 18, 2026), available at https://about.bnef.com/insights/clean-energy/battery-storage-costs-hit-record-lows-as-costs-of-other-clean-power-technologies-increased-bloombergnef/

SEIA/Wood Mackenzie U.S. Solar Market Insight, 2025 Year in Review (March 2026): Wood Mackenzie's own market pricing data reports that utility-scale single-axis tracking system prices were $1.35/W-DC in Q4 2025 — and that these prices reflect a tariff-driven increase of 14% year-over-year. This confirms that observed utility-scale solar costs, even under current elevated tariff conditions, remain well below the NREL 2024 ATB's 2023 base-year benchmark of $1.56/W-AC. Available at https://www.seia.org/research-resources/us-solar-market-insight.

Recommendation

The JSP requests that E3 revisit the base-year anchor point for utility-scale solar and battery storage costs by reference to LBNL's and Wood Mackenzie's empirically observed market data, and that E3 give consideration to the NREL ATB Advanced Scenario — or a blend of the Moderate and Advanced scenarios — as the cost trajectory for base case modeling.

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.

N/A

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.

N/A

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?

N/A

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; Managed EV charging; Water heater controls; 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?*

Percentage of total VPP nameplate capacity recommended for each building block:

- BTM Solar Paired with Battery Storage: 65%
- Standalone BTM Battery Storage (no solar): 25%
- Smart Thermostats and other Demand Response: 10%

Solar-paired-storage systems reinforce each other's ELCC: daytime solar generation charges batteries, enabling firm dispatch during the evening net-load peak window when solar output is declining and grid stress is highest. Residential battery enrollments grew 153% year-over-year in 2025 nationally, making this the fastest-growing and most scalable VPP building block (Ohm Analytics, 2025 VPP Market Report: https://pv-magazine-usa.com/2026/01/27/ohm-analytics-2025-vpp-market-report-reveals-21-growth-in-overall-capacity/). For reference, the CESA/SEPA database of active battery-based VPP programs in the U.S. is available at: https://www.cesa.org/projects/energy-storage-policy-for-states/virtual-power-plant-programs-summary-table/

Available capacity and how it should vary over the year:

Near-term (2026–2028): Approximately 150–250 MW net controllable capacity, drawing on existing BTM solar+storage and battery customers enrolled via CRGA's scheduled-dispatch VPP program, which must launch no later than June 30, 2026.

Growth phase (2029–2032): Scale to 500–800 MW as new solar+storage installations grow under Illinois Shines and CRGA incentives.

Peak availability should be modeled during the summer season (June–September), concentrated in the late afternoon and evening hours when solar output declines and grid net load peaks. BTM batteries with paired solar should be modeled to retain approximately 80% of nameplate capacity available for dispatch, with the remaining 20% held in reserve for customer backup power.

Unlike thermostat-based demand response, which is primarily a summer resource, solar+storage systems can be dispatched year-round, making this archetype well-suited to serve both summer and winter reliability needs in Illinois.

Duration and frequency:

Events per season: 15–60 events per summer season. Massachusetts and Rhode Island's ConnectedSolutions program dispatches up to 60 events per season (https://www.tesla.com/learn/pay-for-performance-vpp-connectedsolutions). Maine's Energy Storage Solutions program requires a minimum of 15 dispatch events per season to qualify for incentive payments (CESA VPP Programs Summary Table: https://www.cesa.org/projects/energy-storage-policy-for-states/virtual-power-plant-programs-summary-table/).

Duration per event: 2–4 hours. This is well-matched to standard 4-hour battery systems. It is important to note that a 4-hour battery does not need to cover a continuous multi-hour window on a single day to provide full resource adequacy value. ELCC is calculated across hundreds of simulated loss-of-load hours over the full planning horizon — what matters is whether the battery is available and fully charged at the start of each dispatch event. A 4-hour battery dispatched for 2–4 hours per event, with a minimum 24-hour rest between events and 15–60 dispatches per season, provides adequate and reliable coverage of the critical peak hours that drive reliability risk. This is consistent with California's July 2025 CAISO coordinated VPP test event, in which over 100,000 home batteries averaged 535 MW over two hours during the 7–9 PM window — a meaningful grid contribution well within a standard 4-hour battery's operational envelope (Brattle Group, "Assessing VPP Performance: Impacts of a Test Event in California," August 2025: https://www.brattle.com/wp-content/uploads/2025/08/Assessing-VPP-Performance-Impacts-of-a-Test-Event-in-California-1.pdf).

Minimum rest between events: 24 hours (one event per day maximum).

Cost:

The CRGA statutory floor is $10/kW of average dispatch (220 ILCS 5/16-107.6(e)(3)). The ICC may establish a higher compensation amount but for modeling purposes, JSP suggests that this is a reasonable assumption on which to base the cost of the modeled VPP.

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.

N/A

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.*

N/A

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.

N/A