Illinois Resource Adequacy Mitigation Study and Integrated Resource Plan
Workshop #2: Candidate Resources
Clean Grid Alliance Response to Request for Feedback

Q1. Are there specific resource types that are not adequately captured by the proposed categories and should be reflected in the IRP framework?

- **Storage.** CGA recommends that additional battery energy storage resource types be included in the portfolio of available resources. First, there should be 8-36-hour storage and technologies outside of Li-ion that the U.S. Department of Energy (DOE) refers to such resources as "inter-day storage."[1] DOE identifies different technology categories within the inter-day storage sector as Mechanical (Traditional Pumped Hydro, Novel Pumped Hydro, Gravity-based, Compressed Air, Liquid Air, Liquid CO2), Thermal (Sensible Heat, Latent Heat, and Thermochemical heat), and Electrochemical (Aqueous electrolyte flow batteries, metal anode batteries, and Hybrid flow batteries).

  Additionally, rather than representing a "Generic LDES" class, the IRP should include a "multi-day storage" class and should model several representative technologies within that class. The same DOE study referenced above identifies many technologies within the multi-day LDES class: flow batteries; metal anode batteries; thermal energy storage; compressed air energy storage and others.

  When displaying model outcomes, the IRP should represent aggregate inter-day LDES and multi-day LDES needs as distinct resource classes, rather than displaying individual technology outcomes or "generic" technologies. This will enable Illinois to identify broad resource class needs (e.g. short-duration, long-duration, and multi-day storage), while recognizing that many technologies are competing within these resource classes. This will also allow the model to accurately represent individual technologies in a manner that captures their attributes and differences.

  Further, when considering various types of storage, CGA notes that PJM offers capacity accreditation for these resources that scales by duration. For the purposes of determining resource adequacy, it is important to consider this factor.

- **Transmission.** The model should allow economic selection of transmission options, in line with practices described in the IRP CoLAB report, "Integrated Resource Planning Best Practice Rubric Reference Guide."[2] That report suggests that transmission can be integrated into the IRP modeling in three ways: 1) allowing endogenous, economic expansion of zonal transfer capabilities in capacity expansion modeling, 2) applying transmission cost adders to capture network upgrade costs, and 3) evaluating pre-selected transmission planning scenarios as candidates for economic model selection. The report also cites to PacifiCorp's 2023 IRP to allow the model to select incremental transmission line capacity.

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[1] https://www.sandia.gov/app/uploads/sites/256/2023/09/Pathways-to-Commercial-Liftoff-LDES-May-5_UPDATED.pdf
[2] https://irpcolab.org/portfolios/rubric-and-reference-guide/

Q2. Are there any resource categories that should be added, removed, or redefined to better reflect meaningful differences in cost, performance, or system value?

- **Hybrid (storage plus wind or solar)**. Hybrid projects offer operational flexibility, cost savings through shared infrastructure, and make up a significant portion of the near-term development pipeline. Further, as existing generation interconnection agreements have already been studied by a regional transmission operator ("RTO"), the RTO is able to approve surplus interconnection service in as few as 12 months, expediting these resources on a timeframe that supports Illinois goals. They also offer increased capacity accreditation for renewable energy projects. CGA suggests modeling these advanced capabilities and attributes of hybrid resources.

- **Long Duration Energy Storage (LDES).** The IRP presentation[3] ("Presentation") is unclear on the status of LDES technologies. On slide 15 LDES are labeled as "Emerging Technologies" and on slide 17 as being in the "Demonstration" stage, and then on slide 18 LDES are assigned the same timeline availability as Gas technologies (2032). For avoidance of doubt, CGA strongly recommends that the IRP consider LDES as a commercially available technology that should be included as a resource that is eligible for deployment consideration in the grid modeling exercise for the near term, as soon as 2030 in the Base Case, but no later than 2032.

  Additionally, CGA is concerned that the assumptions used for the "Generic LDES" technology are unreasonable, as they do not represent an actual individual technology, but rather an average of two very different technology costs (thermal energy storage and iron-air batteries). As outlined in response to Question 2, CGA recommends that the IRP remove the "Generic LDES" class, and instead include two additional technology classes: "inter-day LDES" and "multi-day LDES." Within these classes, the IRP should aim to accurately represent many individual technology costs. Within the MISO footprint, for example, two utilities have modeled 100-hour iron-air batteries using capex costs significantly different from those in the workbook[4]: Xcel Energy's 2024-2040 Upper Midwest IRP assumes $2,699/kW $nominal in 2030,[5] NIPSO's 2024 IRP assumes $2,500/kW (real $2024) in 2030.[6]

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[3] https://icc.illinois.gov/api/web-management/documents/downloads/public/IRP/IRP-Mitigation%20Plan%20Workshop_Resources_FINAL.pdf

[4] https://www.icc.illinois.gov/downloads/public/IRP/il-resource-cost-workbook.xlsx

[5] See MN PUC Docket E002/RP-24-67, 2024-2040 UPPER MIDWEST IRP, Appendix F, p. 53 (Xcel Energy): https://efiling.web.commerce.state.mn.us/documents/%7BA08F6B8D-0000-C618-9D8C-BA9E7352B3A7%7D/download?contentSequence=0&rowIndex=841

[6] https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf, p. 146-147.

Further, given the myriad challenges of accurately modeling long-duration storage resources, CGA recommends that the IRP model a scenario that forces in specific amounts of inter-day LDES and multi-day LDES, to evaluate portfolio impacts. This scenario should assume that at least 30% of total storage needs will be from non-lithium-ion long-duration and multi-day storage combined, with at least 15% from >10-hr inter-day LDES and 15% from multi-day LDES. As noted by DOE's nation-wide analysis of LDES, *multi-day storage* will comprise *at least* 28-35% of total U.S. storage needs between 2030-2050, and both multi-day storage and inter-day long-duration storage combined will comprise more than 90% of total nationwide storage needs by 2040 as part of a least-cost grid, depending on forecast li-ion costs.[7] DOE modeling also shows that multi-day storage (which DOE defines as >36 hrs) could comprise 30% of total US storage needs from 2030-2050, regardless of future li-ion cost sensitivities if included in grid studies.

- **Natural Gas (out-of-state supply option).** The IRP plan states that "Illinois may build new gas generation out-of-state for reliability, but imports are capped at transmission limits" and "Out of state gas is allowed to run for its entire useful life (it does not need to shut down by 2045)" (Presentation, slide 20). CGA is unclear as to the meaning and mechanics of this claim and requests the following clarifications:

  a. Under what authority would the state of Illinois build a new natural gas plant?

  b. How would such a power station be financed?

  c. Who would be the counterparties for such an arrangement?

  d. How does this approach align with the legislative intent of CEJA and CRGA which state clear positions concerning decarbonizing Illinois' power sector?

  CGA maintains that if any out-of-state resources are to be considered for modeling within the IRP, then merchant High Voltage Direct Current ("HVDC") transmission lines that connect Illinois to regional renewable energy resources would be more consistent with state policy.

- **Natural Gas (in-state resources).** The IRP plan states, "Illinois fossil generators retire by the earlier of i) CEJA emissions schedule or ii) owner-announced retirement date" (slide 20). As noted in CGA's response to the first request for comments, at least one peaking natural gas power plant representing over 1 gigawatt (GW) of capacity is scheduled to exit the northern Illinois market before the step down in emissions required by CRGA.[8] CGA strongly recommends that the IRP closely review its assumptions regarding this and potentially other

[7] https://www.sandia.gov/app/uploads/sites/256/2023/09/Pathways-to-Commercial-Liftoff-LDES-May-5_UPDATED.pdf, p. 17.
[8] https://www.chicagotribune.com/2026/04/17/editorial-elwood-will-county-jb-pritzker-ceja-clean-energy-law/

similar market exits by other natural gas plants in Illinois prior to the modeling exercise and to share those assumptions with the stakeholders.

Q3. 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.

CGA provides the following comments on the cost assumptions for solar, wind, lithium-ion storage, and gas resources considered for inclusion in the modeling for the IRP.

- **Natural Gas.** Per prior discussion, the cost of Natural Gas technologies should be factored to include separate costs for pipelines, storage, etc.

- **Weighted Average Cost of Capital (WACC).** It is unreasonable to use a WACC of 10.5% for LDES technologies in 2037. As noted in response to Question #2 above, the IRP should assume that LDES resources are commercially available by 2030. It may be appropriate to use a high 10.5% WACC in 2030, as these technologies are still relatively emergent; however, by 2037, when LDES resources should achieve widespread adoption nationally, the IRP should assume the same WACC for LDES as for li-ion energy storage.

- **Discounted Cash Flow Model.** E3 proposes using a "proprietary" discounted cash flow model (RECOST, Slide 38) as part of the modeling process for the IRP. CGA requests a detailed explanation of the RECOST model, its inputs, calculations, and outputs so they can be assessed for applicability and accuracy.

- **Levelized Fixed Costs (LFC).** Regarding the use of levelized fixed costs (LFC) for storage resources, CGA disagrees with 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.[9] Beyond the expected increase in LFC due to the phaseout of federal tax credits, we would like additional explanation from the modeling team to explain the expected rise in LFC.

- **Tariff and tax credit impacts.** Additionally, we disagree 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

[9] https://docs.nrel.gov/docs/fy25osti/93281.pdf

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 (link) shows a significant drop in LCOE for Solar PV and Wind projects that are subsidized with ITCs/PTCs. Even if tariff impacts are meaningful, we feel 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.

Q4. 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.

CGA provides the following comments on the cost assumptions for nuclear and Long Duration Energy Storage resources considered for inclusion in the modeling for the IRP.

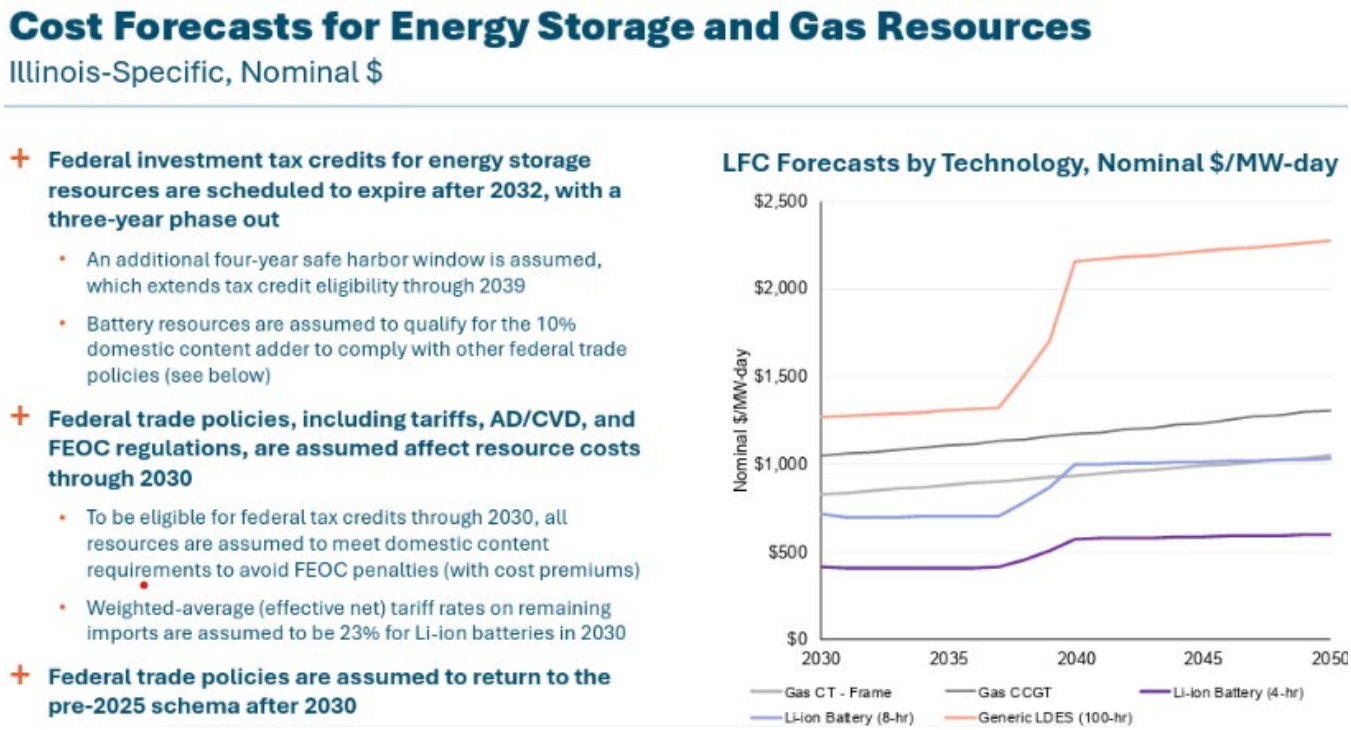
- **Long Duration Energy Storage (LDES).** The specific assumptions for "Generic LDES" are unreasonable, as explained above, because they do not realistically or accurately capture a range of actual technologies. The Cost Workbook "Output Tables" show a significantly inaccurate $6,163/kW capex cost for "Generic LDES" in 2030, which E3 explains is "the average between thermal energy storage (PNNL ESGC) and iron-air battery (Form) technologies." This does not accurately represent thermal energy storage or iron-air batteries.

  As we note above, the IRP model should represent many actual technologies. Several resources include technology costs: the DOE LDES study referenced above; a recent EPRI and LDES Council Benchmarking study.[10] Additionally, several recent utility IRPs have included LDES technology cost assumptions that are significantly lower than those in the Workbook. Please see: Xcel Energy 2024 Just Transition Solicitation Plan: $2,400/kW capex, 2030 COD; p. 198;[11] PacifiCorp 2025 IRP: $2,730/kW capex, 2027 COD;[12] Idaho Power 2025 IRP: $3,000/kW

[10] https://ldescouncil.com/wp-content/uploads/2026/01/Benchmarking-Report-21-Jan-EXTERNAL.pdf
[11] https://xcelnew.my.salesforce.com/sfc/p/#1U0000011ttV/a/8b000003N3eQ/QodCDDNR0HUF75Rb_nOkwu_MzfeKzPduYws13FjugGs
[12] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/2025-irp-support-studies/Public_SSR_Database_Summary_Tab_2025.xlsx

capex, 2030 COD, p. 22;[13] CPUC 2024-2026 IRP Inputs and Assumptions, $2,904/kW, 2030 COD, p 108;[14] DOE LDES Commercial Liftoff Report: $1,900-$2,500/kW, ~2030 COD.[15]

Cost escalation for LDES and other storage options at 2035-2040 requires clarification. CGA assumes that this escalation pertains to the expiration of federal tax incentives for these technologies. However, we are unclear as to why the increase is significantly more dramatic as to LDES over other storage technologies.



Q5. 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.

[13] https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/2025IRP/2025%20IRP%20Appendix%20C.pdf
[14] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf
[15] https://www.sandia.gov/app/uploads/sites/256/2023/09/Pathways-to-Commercial-Liftoff-LDES-May-5_UPDATED.pdf, p. 12.

LDES Technology Availability. As noted above, CGA strongly urges that LDES technologies be reclassified from "Emerging Technologies" to Commercially Available. CGA's position is supported by the Presentation, slide 18 where LDES is assigned the same timeline availability as Gas technologies. Additionally, the DOE identifies LDES as viable, valuable and available in its report "Pathways to Commercial Liftoff: Long Duration Energy Storage". Further, the market is already responding in the manner described by DOE. Form Energy has entered multiple commercial agreements to deploy more than 75 GWh of long-duration (100-hour) iron-air batteries with Xcel Energy, Crusoe, and FuturEnergy Ireland), and Noon Energy, which is developing 100+ hour reversible solid oxide fuel cells technology, recently announced a partnership to supply 1 GW of 100+ hour duration storage to Meta for data centers.[16] Clearly, various long duration batteries are commercially viable and available and should be prioritized as a near-term solution for Illinois' capacity needs capable of deploying by 2030.

Q9. Do you have any feedback to provide on the Assumptions workbook[17] separately posted? Please note the specific assumption, your recommendation, and any data or supporting materials to support your recommendation.

CGA is concerned that assuming Utility and Residential PV resources claim the PTC rather than the ITC 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*.

Q10. If CCS is considered as an added, co-paired technology with natural gas resources in a scenario:

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

[16] https://www.noon.energy/post/noonenergyandmetapartnership
[17] https://www.icc.illinois.gov/downloads/public/IRP/il-resource-cost-workbook.xlsx

- The lack of commercially-operating CCS projects and overall immaturity of the technology signals that it will be difficult to accurately model the costs, which would include CO2 transport and storage costs in addition to the cost of the CCS technology itself, and CCS availability over the coming decade, supporting the need for renewables and storage to be the primary resources that allow IL to reach its clean energy goals and maintain CEJA compliance.

Q11. 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 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.

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