2026 Illinois Resource Adequacy Study Mitigation Plan Post-Workshop Stakeholder Questions

Illinois Power Agency & Illinois Environmental Protection Agency

Comments Submitted By:

Name: Kiki Velez

Company or Organization: Illinois Clean Jobs Coalition (ICJC) Member Organizations (including Union of Concerned Scientists, Vote Solar, Natural Resources Defense Council, and Sierra Club)

Email: kvelez@nrdc.org

Company or Organization Website Address: www.ucs.org, www.votesolar.org, www.nrdc.org, www.sierraclub.org

Technical Questions (Mitigation Plan Inputs & Analysis)

Question 1: Are there any specific analysis, modeling, scenarios, or sensitivities that were not completed or incorporated as part of the RA Study process (recently completed), and that stakeholders did not include in the response to the ICC Request for Comments (due February 9) that should be considered by the Agencies as part of the Mitigation Plan modeling and analysis?

- If yes, please details on such recommendations, including their intended focus or methodology, and usefulness.
- Please provide any citations or references to support your recommendations, including data sets or inputs (or references to where those data sets or inputs can be found) that are necessary to complete the analysis.
- If modeling, scenarios or sensitivities were not recommended as part of the ICC Request for Comments process, please explain why they should be included in the Mitigation Plan analysis and not the IRP process?

Response:

Please refer to the Illinois Clean Jobs Coalition's February 9th comments to the ICC regarding the Integrated Resource Plan (IRP).[1] In those comments, we provided initial recommendations around how the Resource Adequacy (RA) Study modeling should be updated to include CRGA requirements and account for the significant uncertainty

[1] Accessible at https://icc.illinois.gov/api/web-management/documents/downloads/public/IRP/IL%20Clean%20Jobs%20Coalition%20Member%20Organizations%20RFC1.pdf.

surrounding large load additions. We also proposed updating RA Study modeling assumptions related to resources' effective load carrying capabilities (ELCCs) and "clean" fuels deployment in gas generators.

In these comments, we revise and expand on our initial recommendations around the specific scenarios that the ICC and IPA should model for both the IRP and the Mitigation Plan. In response to Question 6, we provide feedback on how the ICC and IPA should streamline these processes.

DER Deployment Scenario Driver

In addition to the scenario drivers that we proposed in our IRP comments, we recommend that the ICC and IPA incorporate an additional scenario driver focused on distributed energy resource (DER) deployment into the modeling that will drive both the Mitigation Plan and the IRP development. DER deployment is a serious consideration in other Midwestern states for their utility resource planning dockets because, in many cases, including DERs can make the overall resource mix more cost-effective. Even the ICC, in their request for comments on the IRP process, is looking at how the RPS budget and energy storage RPS budget can be used in modeling. DER deployment, which we call "DER as a Resource", could be very beneficial for Illinois. Below are examples from other states regarding modeling DER as a Resource in IRPs.

Minnesota: In the 2020 Xcel Energy IRP (Minnesota PUC Docket No. E002/RP-19-368), intervenors argued for the utility to model Distributed Generation (DG) as a resource to include as a resource input. Vote Solar's Will Kenworthy argued that "Distributed resources owned by the individual households, organizations, and the community provide multiple pathways towards capturing ratepayer savings and increasing energy equity…In an era where racial and economic justice are as pressing as ever, equity should be central to ensure that any approved plan minimizes cost, maximizes benefits, and ensures equitable distribution of those costs and benefits."[2] Mr. Kenworthy used a model created by Drs. Eric Williams and Eric Hittinger. They wrote a paper called "Empirical development of parsimonious model for international diffusion of residential solar."[3] The Minnesota PUC ordered Xcel Energy to model and include DG as a resource into the utility's next IRP.[4]

[2] MN PUC Docket No. E002/RP-19-368, Joint Comments of Vote Solar, Institute for Local Self Reliance, the Environmental Law & Policy Center at 29-32.
[3] Available at: https://www.sciencedirect.com/science/article/abs/pii/S0960148119319731
[4] MN PUC Docket No. E002/RP-19-368, Final Order at 21-22 (Apr. 15, 2022).

In the utility's most recent IRP filing (Minnesota PUC Docket No. E002/RP-24-67), Xcel's Preferred Plan included standalone DG as a Resource. In other words, the utility's IRP model selected DG as a resource in their plan.[5] Even though we critiqued the size of Xcel's estimated DG adoption as too small due to the use of an outdated modeling approach, DG as a Resource was taken seriously and accepted by the utility's own model. Further,in this same IRP filing, Xcel Energy also proposed a "Distributed Capacity Procurement" pilot, where the utility recognized the distribution and bulk system value of distribution-sited battery energy storage systems. Because of the utility's exercise in modeling DG as a Resource, Xcel found additional value in energy storage on the distribution grid. We expect to come to the same conclusions in the RMP in Illinois through adding a scenario driver with DG/DERs as a Resource.

Michigan: In the 2022 Consumers Energy IRP (Michigan PSC Case No. U-21090), intervenors again used the Williams-Hittinger DG model to estimate the adoption rate of DG and offered it as an input in an alternative IRP model.[6] The utility settled with intervenors, wherein Consumers Energy agreed to model DG as a resource for their next IRP.[7] The Michigan PSC adopted this settlement agreement, and Consumers Energy has actively engaged with the intervenors to design an internal utility model that predicts DG adoption. The utility will file their next IRP in Q2 2026 with DG as a Resource in their model. One important thing to note about the Williams-Hittinger model is that the model is based on 2016 cost data. With its age (and the COVID pandemic) in mind, there are limits to how well this model predicts DG adoption rates today.

In the 2022-2023 DTE Energy IRP (Michigan PSC Case No. U-21193), intervenors used NREL's (now National Lab of the Rockies, or NLR) Distributed Generation market demand model, also called dGen. dGen uses the Energy Information Administration's Annual Technology Baseline data, and housing data, to estimate DER adoption in various states and regions.[8] Will Kenworthy also went into detail on DG as a resource in his direct testimony.[9] The utility also settled with intervenors and promised to run a DG as a resource based on testimony that used dGen.[10] Similar to the Consumers example, the Michigan PSC adopted this settlement agreement. Likewise, DTE has engaged with

---

[5] Minnesota PUC Docket No. E002/RP-24-67, Xcel IRP Report, Chapter 1 at 14.
[6] Michigan PSC Case No. U-21090, Direct Testimony of William Kenworthy at 21-26.
[7] Michigan PSC Case No. U-21090, Settlement Agreement at 12.
[8] Available at: https://www.nlr.gov/analysis/dgen/about-dgen
[9] Michigan PSC Case No. U-21193, Direct Testimony of William Kenworthy at 21-37, Direct Testimony of Boratha Tan.
[10] Michigan PSC Case No. U-21193, Settlement Agreement at 12.

intervenors to design a utility-specific model that predicts DG adoption, and expects to include this in their next IRP filing in Q3 2026. Even though dGen is six years old, it was most recently updated in 2025. Of course, those examples only focused on rooftop solar. dGen, however, is better than the Williams-Hittinger model because it can also estimate storage adoption.

These regulatory examples of DG as a Resource are from vertically-integrated states, meaning that applying this framework to Illinois would require a different perspective. Illinois provides RECs of various prices (from IL Shines to IL Solar for All) to apply to different types of solar categories. Indexed RECs are also paid out to eligible projects. If the IPA (and the ICC) contains a scenario driver with the current RPS budget, we must consider how to model DER adoption rates if the RPS budget is depleted. If the IPA also adds a scenario driver that assumes an expanded RPS budget, the IPA should make reasonable assumptions on future REC prices and how that can influence DER adoption.

The examples from Minnesota and Michigan also assume that customer DERs are not dispatched through any type of Virtual Powe Plant (VPP) program. Rather, the estimated DER adoption is offered to the model as simple "megawatts" and "megawatt-hours". At the times when those dockets were litigated, there were no VPP programs to take advantage of DERs. With CRGA enabling VPPs, the IPA should continue to work with interested stakeholders to understand how to model DER dispatch that maximizes benefits to customers and the grid, while being able to offer up these DER resources in the model.

Revised Modeling Recommendations for IRP and Mitigation Plan

Scenario Drivers

As discussed in our IRP comments and above, we propose that the Mitigation Plan and IRP consider eight scenario drivers, in line with CRGA requirements to consider resources that include energy efficiency, demand response, transmission development, and more.[11] In the table below, we summarize our proposed scenario drivers and offer specific recommendations of what could be modeled in “low” and “high” deployment cases for the CRGA-compliant resources.

[11] Section 16-202(b)(1)-(5) as added by CRGA.

Scenario Driver	Cases	Notes
Illinois Net Zero Emissions	Yes/No	This scenario driver is included in the RA Study.
New Illinois Gas Allowed	Yes/No	This scenario driver is included in the RA Study. Per CEJA, new gas plants must convert to net-zero emissions by 2045.[12] Assumptions around "clean fuels" deployed in new gas plants must be updated to account for the limitations and costs described in our IRP comments.
CEJA Retirement Extension	Yes/No	This scenario driver is included in the RA Study.
Interconnection Barriers	Yes/No	This driver was suggested by the ICC in their First Request for Comments on the IRP.[13] In our IRP comments, we explain why this scenario driver should be included. In response to Question 3 below, we provide greater detail about the opportunity for interconnection rights transfers from retiring coal plants to new storage facilities.
Energy Efficiency Deployment	Low or High	This driver is proposed in our IRP Comments. As discussed there, CRGA's EE targets should be included as a baseline in all scenarios; therefore, the "low" case should assume that, at minimum, CRGA's EE target is met. Additionally, a "high" case should be modeled that deploys even greater levels of EE, as CRGA will not necessarily result in deployment of all cost-effective electric EE, especially in ComEd territory. This is because a sizable portion of the CRGA EE goals can be met by gas EE, and the statute does not establish a peak demand goal for ComEd.[14]
DER Deployment	Low or High	Discussed in the previous section. A "low" case could model the deployment levels required by the RPS. A "high" scenario could look at deeper deployment levels.
Demand Response /	Low or High	Discussed in our IRP Comments. A "low" case could model the impacts of the time-of-use (TOU) rates codified by CRGA. A "high" case could model deployment of VPPs

[12] 415 ILCS 5/9.15.

[13] See Question 1.b.

[14] While the CRGA EE goals are high (2.0% of sales per year with an average savings life of at least 12 year), the statute allows up to half of the goal to be met by ComEd (up to 40% for Ameren) through gas EE converted to MWh equivalents and electrification savings translated to MWh equivalents. 220 ILCS 5/8-103B(b-25), (b-27). This means that ComEd, especially, will not deploy all cost-effective electric efficiency. Additionally, though CRGA establishes a peak demand goal for Ameren for the first time, it only establishes a MWh goal for ComEd. 220 ILCS 5/8-103B(b-16). Again, this likely means that there are significant cost-effective peak demand savings from EE that ComEd will not address or try to capture under CRGA requirements alone. Therefore, modeling a case that deploys more EE than is strictly required by CRGA is well-justified.

Load Flexibility Deployment		and/or the potential deployment of demand response at data centers.
Expanded Import Capabilities	Low or High	Discussed in our IRP Comments. A "low" scenario could reflect current transmission conditions. A "high" scenario could consider deployment of advanced transmission technologies (ATTs).

Scenarios

Currently, the RA Study assumes that all scenarios are designed to meet one load forecast. The ICC and IPA appear to suggest that changes to load forecasts should be modeled as "sensitivities." Accordingly, in our IRP comments, we proposed that potential differences in data center load be tested as "sensitivities." However, given the outsized influence of new data center additions on scenario results, we propose that IRP and Mitigation Plan **scenarios should instead be designed around differing load forecasts.** We propose the following scenarios:

- **Scenario 1 - Base Case:** This scenario updates the RA Study load forecast to only incorporate load in LSE queues with high probability of interconnection. Examples of how to determine whether load has a "high probability" of interconnection are discussed in greater detail in response to Question 2. This scenario also complies with the minimum requirements in CEJA and CRGA.
- **Scenario 2 - Maximize CRGA Resources:** Same load forecast as our updated Base Case but maximizes deployment of resources that CRGA requires the IRP to study. Our rationale for including these resources is described in our IRP comments and in the DER section above.
- **Scenario 3 - Signed Service Contracts Load**: Updates the RA Study load forecast to only incorporate data center loads for projects that have signed service contracts. All other scenario drivers are consistent with our Base Case.
- **Scenario 4 - No Data Center Load:** Update the RA Study load forecast to incorporate no data center load, to demonstrate the impact of data center additions. All other scenario drivers are consistent with our Base Case.
- **Scenario 5 – Climate-Aligned**: Similar to Scenario 2, this scenario assumes the same load forecast as our updated Base Case (only incorporate large loads in LSE queues with high probability of interconnection) and maximizes deployment of resources that CGRA requires the IRP to consider. However, this scenario additionally disallows the deployment of new IL gas plants.

Importantly, every scenario should be designed to deploy at least 3 GW of battery storage, as required by CRGA. The table below summarizes the load forecasts and "scenario driver" conditions that are applied in each of our proposed scenarios.

	Base Case	**Maximize CRGA Resources**	**Signed Service Contracts Load**	**No Data Center Load**	**Climate-Aligned**
Load Forecast	Only incorporate load with high probability of interconnection	Same as Base Case	Only incorporate load with signed service contracts	Assumes no data center load	Same as Base Case
Illinois Net Zero Emissions	Yes	Yes	Yes	Yes	Yes
New Illinois Gas Allowed	Yes	Yes	Yes	Yes	No
CEJA Retirement Extension	No	No	No	No	No
Interconnection Barriers	Yes	No	Yes	Yes	No
Energy Efficiency Deployment	Low	High	Low	Low	High
DER Deployment	Low	High	Low	Low	High
Demand Response / Load Flex Deployment	Low	High	Low	Low	High
Expanded Import Capabilities	Low	High	Low	Low	High

Question 2: Is there any new or updated data or information that has been issued or otherwise has been made available that was either not utilized in the RA Study, became available after RA Study modeling and analysis was already completed, and/or was not recommended for inclusion in the ICC Request for Comments that should be considered in the development of the Mitigation Plan?

- If yes, please provide references. (The Agencies prefer direct links and/or submission of the referenced material.)
- If not recommended as part of the ICC Request for Comments process, please explain why they should be included in the Mitigation Plan analysis and not the IRP process?

Response:

Yes.

Updated Load Forecast to Account for Data Center Uncertainty

As referenced in Question 4 below, since the publication of the RA Study, PJM has released its 2026 Long-Term Load Forecast Report, which provides an updated 20-year load forecast.[15] Compared to PJM's 2025 report, the updated report anticipates lower peak demand through 2032, in part due to adjustments in expected data center and other large load additions. Energy + Environmental Economics (E3) should incorporate this updated load forecast into its analysis.

As part of the updated load forecast report, PJM has also released information related to the large load requests that were submitted by Load Serving Entities (LSEs) and which requests were accepted by PJM for inclusion in its updated forecast. Figure 1 outlines the difference in the large load adjustments submitted by the LSEs and what level was accepted by PJM. Figure 2 shows the differences in requests made by LSEs and what PJM has deemed to either be firm or non-firm. For determining firm large load requests, PJM used metrics such as signed contracts, financial deposits, or construction status to determine which requests should be firm. Prospective customers with only a letter of authorization (LOA) were allocated as non-firm. PJM also excluded some customers, such as the EV battery plant in the ComEd territory, because of overlap with economic variables already captured in the load forecasting process.[16]

[15] 2026 Long-Term Load Forecast Report

[16] Slide 11. Retrieved from https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2025/20251124/20251124-item-03---large-load-adjustment-requests-summary.pdf

Figure 1. RTO Large Load Adjustment Forecast[17]

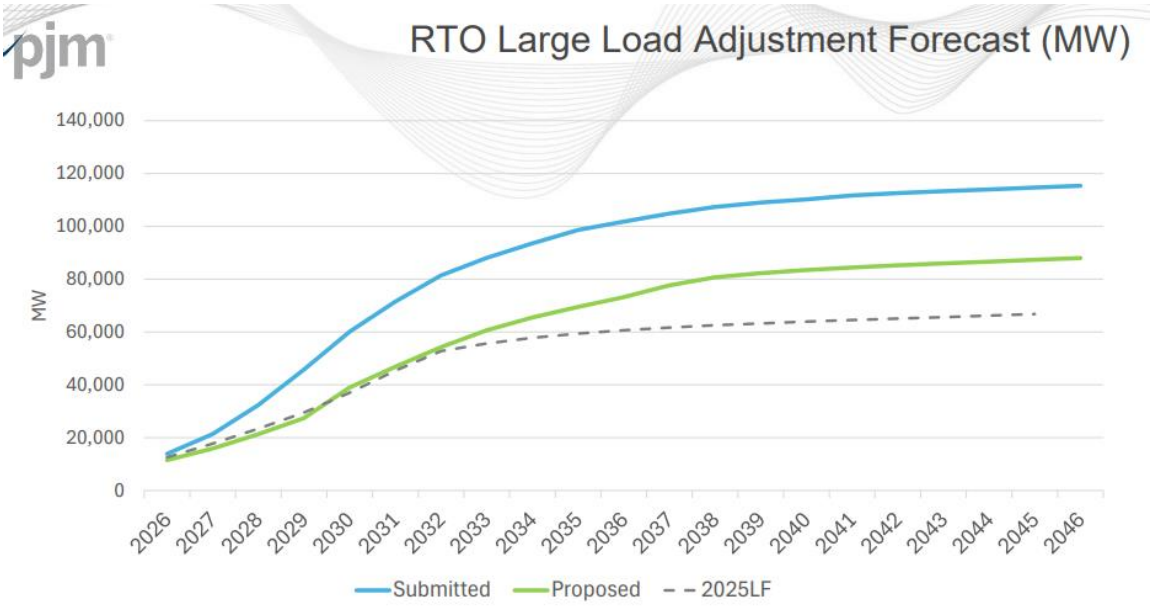
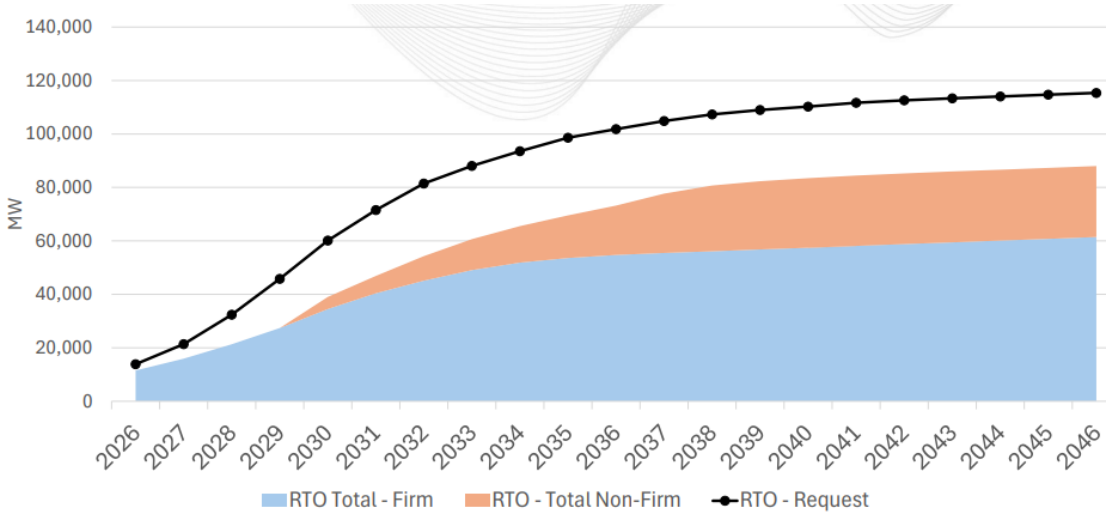


Figure 2. RTO Large Load Comparison[18]



MISO does not build up its own load forecast for purposes of its capacity auction and instead takes each forecast from its LSEs as a given. It also does not request this

[17] Slide 7. Retrieved from https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2025/20251124/20251124-item-03---large-load-adjustment-requests-summary.pdf

[18] Slide 8. Retrieved from https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2025/20251124/20251124-item-03---large-load-adjustment-requests-summary.pdf

information for more than one year in advance, so it has less visibility into long-term load growth. But MISO has come to recognize that it is not adequately studying operational security risks associated with these loads and will need to figure out how to do so.[19] MISO has not even begun this process, so it is impossible to say what specific implications this might have for Illinois—but the expectation should be that more will be required of large loads – more studies and more data, in particular. MISO does not independently develop a centralized load forecast for its capacity auction and instead relies on LSE-submitted projections, with procurement occurring only one year ahead. Unlike multi-year forward capacity markets, this framework provides limited advance visibility into large, rapidly developing loads.

In its Reliability Imperative reporting and regional assessments, MISO has acknowledged that large new load additions and other emerging trends pose distinct operational and reliability risks that are not fully captured under current planning constructs, and it is exploring additional analytical and procedural enhancements to address these gaps. One especially notable gap in the MISO operational and reliability analysis is a lack of a zonal perspective – in order for the long-term forecast to be useful it needs to be broken out by zone, distinguishing between forecasts of shortfall in Illinois and forecasts of a general shortfall across the Louisiana to Canada MISO footprint.

PJM nominally does its own forecasts; however, those forecasts are informed by the forecasts of utilities/LSEs as PJM has adopted load forecasting planning standards or practices that are intended to harmonize members' forecast practices. For a detailed review of the approaches used in Large Load forecasting by PJM and MISO, see the recent report from the Energy Systems Integration Group (ESIG) on this general topic.[20]

This information from both PJM and MISO underscores the importance of scenario testing around the level of large load that is assumed at the RTO level. As documented in the ESIG Report, the Exelon Large Load Forecast notes the existence of a substantial number of variables and steps that can shape and change the load forecast.[21] An example of how these forecasts could be tested include:

- Base case with no large load growth;
- Large load set to the firm level identified by PJM;

---

[19] https://cdn.misoenergy.org/20260130%20Large%20Load%20Workshop%20Presentation738349.pdf

[20] Forecasting for Large Loads Current Practices and Recommendations, ESIG Large Loads Task Force, John D. Wilson and Sophie Meyer (December 2025) available at https://gridstrategiesllc.com/forecasting-for-large-loads/

[21] ESIG Report at p. 36

- Large load set to the firm level identified by PJM but then adjusted by a certain percentage to reflect the risk that some level of firm adjustments may not materialize; and
- Large load set to the firm and non-firm level identified by PJM, noting that these scenarios are consistent with, but more sophisticated than, the approach adopted by MISO.[22]

Update Assumptions to Include Gas Supply Constraints

Th IRP should evaluate the implications of a constrained gas supply chain. To the extent the IRP considers new gas buildout, it must also assess the impacts that this surge has on demand. Reporting has shown that a nationwide surge in demand for gas turbines has already produced significant supply chain constraints.[23] These constraints are increasing project costs, lengthening equipment lead times, and delaying operation.[24]

In addition to these grid side constraints, the gas supply chain is facing a new and growing source of pressure. Recent reporting from Cleanview shows that data centers are increasingly bypassing traditional grid interconnection queues and instead constructing their own behind-the-meter gas power plants to meet rising electricity demand. [25] Cleanview's analysis indicates that roughly 30% of planned U.S. data center capacity will rely on behind-the-meter generation, with a significant portion powered by gas.[26] The report also noted equipment lead times for new gas turbines stretching from 5–7 years.[27]

---

[22] ESIG Report at p. 38.

[23] Accessible at https://rmi.org/gas-turbine-supply-constraints-threaten-grid-reliability-more-affordable-near-term-solutions-can-help/

[24] Accessible at https://rmi.org/gas-turbine-supply-constraints-threaten-grid-reliability-more-affordable-near-term-solutions-can-help/

[25] Accessible at https://newsletter.cleanview.co/p/bypassing-the-grid-how-data-centers?subscribe_prompt=free

[26] Accessible at https://newsletter.cleanview.co/p/bypassing-the-grid-how-data-centers?subscribe_prompt=free

[27] Accessible at https://newsletter.cleanview.co/p/bypassing-the-grid-how-data-centers?subscribe_prompt=free

This growing trend compounds existing supply chain issues. The IRP must incorporate these dynamics or risks underestimating costs, delays, and reliability impacts across the entire system.

Question 3: The primary focus of the Mitigation Plan analysis will be on what solution sets of resources and/or policy options can be accessed over various terms (periods of time) to mitigate electric reliability risks and meet resource adequacy needs. A function of the analysis includes expectations and timing surrounding CEJA-driven fossil generation facility retirements throughout Illinois (specifically coal). The initial deadline for such retirements by coal facilities is 2030. The Agencies are seeking further insight from coal generation owners/operators or any other stakeholders with pertinent and detailed information – requesting clarity around when the final determination surrounding closure is required. This includes when a determination to remain operational for a period of time into and beyond 2030 is required. Specifically:

- What is the 'drop-dead' date (at least by year) that facilities must be notified that facility retirement is delayed ensuring the facility can remain operational? (e.g., facility owners must receive notification to continue operation by Q1 2029 to remain operational into or beyond 2030)
- What are the specific considerations that impact any such date? Please provide details and the timing-based impacts of those considerations. (this may include investments in expanded emissions technology, substantive investments in facility assets to ensure facility remains operational, fuel)
- Please explain if any such timing considerations include RTO or federal reliability must run (RMR) provisions which could mandate a facility remain operational for a specified period of time.

Response:

MISO requires generator deactivation notices at least four full quarterly study periods in advance[28], i.e., at least a year, so that it can study the reliability implications of generator retirement. In the case in which the interconnection rights are reused, generator replacement is required within 3 years of retirement.[29]

---

[29] https://www.misoenergy.org/planning/resource-utilization/generator-interconnection/#:~:text=For%20a%20replacement%20request%20with,date%20of%20the%20original%20unit.

One additional item that might be useful to address is how many of these facility sites and/or their Capacity Interconnection Rights (CIRs) and/or physical grid ties could be reused for the purposes of bringing online new energy/capacity resources. Such reuse could potentially include new natural gas fired generation (although planning for gas expansion is hard to reconcile with a statutory scheme that mandates zero-emissions from private and public generators by 2045[30]) but could also involve replacement with battery storage and/or a hybrid resource that combines battery storage with generation, whether it be gas, wind, and/or solar. Such reuse would mitigate any impact of the statutorily mandated retirement and reduce any pressure to delay said retirements. We note that under some scenarios that are being discussed and planned, like a future with lower battery storage costs, such reuse involving deployment of storage would be far more economic and likely—as storage drops in price we should recognize that facility owners (or those who might buy such sites for reuse) will see greater incentive to deploy that technology and reuse the land, CIRs, and the physical grid ties for that purpose. Not contemplating increased reuse of such sites, rights, and infrastructure in planning would neglect a powerful and expanding option for efficiently and cost effectively meeting reliability needs while meeting the environmental mandate of the guiding statutes.

Question 4: A substantive driver identified and modeled through the RA Study is load growth, heavily influenced by data center interconnection forecasts. Since issuance of the RA Study, the Agencies are aware of a recent update to PJMs load forecast, inclusive of data center interconnection projections. During the January 27th RA Study Workshop, questions and comments were received surrounding data center load forecasts, requesting further consideration of how data center interconnections are impacting load forecasts used in the RA Study and/or to be used in the Mitigation Plan.

- In addition to the forecasts considered in the RA Study (utility forecasts and RTO forecasts) and the recent PJM load forecast update, are there any additional load growth forecasts and/or sensitivities that should be considered?
- If yes, please provide reference(s) to the forecasts and a detailed breakdown of the sensitivities that should be considered (including over relevant time horizons).

Response:

[30] 415 ILCS 5/9.15(g)-(j). *See also* Illinois EPA Guidance Document, Private Gas Facility Requirements in SB 2408/P.A. 102-662, https://epa.illinois.gov/content/dam/soi/en/web/epa/topics/ceja/documents/illinois-epa-private-gas-guidance.pdf.

As discussed in response to Question 1, we propose that different levels of large load additions should be considered in scenarios, rather than as sensitivities, given the outsized impact that varying assumptions around large load additions will have on the state's resource adequacy future.

Within the scenarios we've outlined above, additional assumptions could evaluate the potential impact of data center load departing the system sooner than anticipated (e.g., after 10 years). For example, if 5,000 MW of data center load is assumed for 2030, the Mitigation Plan and IRP modeling might consider how results would change if those customers are no longer part of the system in 2039.

Question 5: Are there any additional factors that should be considered or explored in greater details in addition to those provided in response to questions 1-4, above, to support the development of the Mitigation Plan?

Response:

We do not propose any additional factors at this time.

<u>Mitigation Plan & IRP Process Alignment</u>

Question 6: Both the Mitigation Plan required under Section 9.15(o) and the Integrated Resource Plan required under CRGA begin with an assessment of Illinois energy resource needs and require a proposal for meeting those needs leveraging a broad solution set (emission reduction requirement relaxation; new generation resources; energy storage; transmission development; demand-side options) optimized across a fairly consistent set of metrics (including cost, emission impacts, environmental justice community impacts, and ensuring "adequate, reliable, efficient, and environmentally sustainable electric service").

- What suggestions do you have for how the IPA, IEPA, and ICC can most effectively merge these processes to keep parties from duplicative work and to ensure clarity and certainty of administrative/regulatory outcomes?
- Are there any unique considerations which you believe the IPA, IEPA, and ICC must navigate in working to merge these workstreams?
- Would you be supportive of coordinating administrative filings and consolidating plan approval proceedings?

Response:

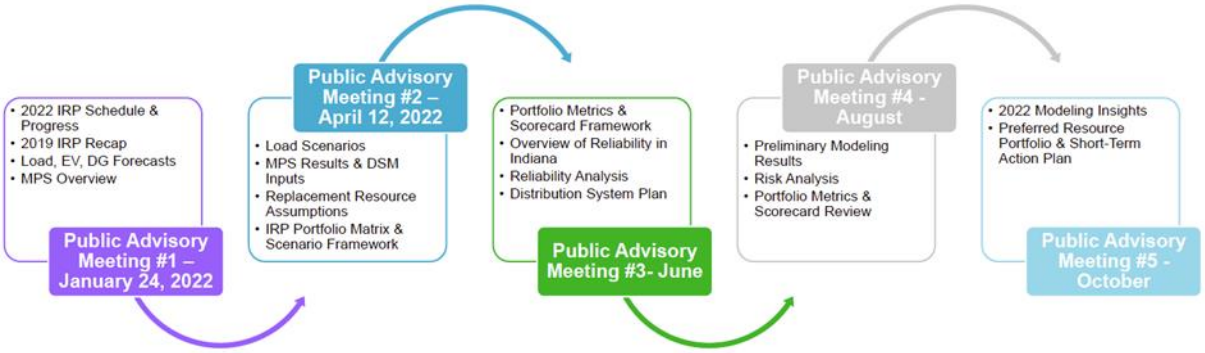
Yes, we generally think the consolidating filing and proceedings make sense especially if the RA modeling is a check for resource adequacy of the IRP modeling. In general, it seems that it would be useful to perform portfolio verification since the IL agencies would otherwise be enforcing disparate assumptions about unit accreditation and reserve margins.

Overall, we suggest the IPA work with the ICC to update the new modeling for the IRP for the new scenarios and sensitivities that we are suggesting. This should be a combined process that does not include the need for running two different models. Once preliminary results begin to become available, a better understanding of the resource adequacy need will emerge and what actions the IRP and mitigation plan should recommend undertaking. We also recommend coordinating workshops and comment requests and clarifying that the recommendations put forth in the mitigation plan will inform the IRP and that work will not be duplicated.

As discussed in our IRP comments to the ICC, we found the data and methodologies in the RA Study to be highly opaque and recommend a different approach as the agencies move forward with both the IRP and Reliability Mitigation Plan. We recommend a schedule of meetings with specific dates and a commitment to release data that the IL agencies intend to use prior to those meetings so that at each meeting stakeholders can provide comment on the specific data sources used. Ideally, the data directly being used in the modeling, not just summary data, would be released along with draft models as they are developed.

An example of this process is one used by AES Indiana for its 2022 IRP (see graphic below). We recommend that the IL agencies establish a schedule of meetings with topic areas identified in advance, along with a commitment to share agendas, presentations, and other relevant material at least 5-7 days in advance of the meetings. Stakeholders should also have a minimum amount of time to provide feedback following the meetings, and the IL agencies should respond to that feedback in the subsequent stakeholder meeting. Finally, stakeholder meetings should allow for remote/hybrid access to encourage participation by technical experts who are not able to travel to Illinois.

Figure 3: AES Indiana IRP Process



Given the large amount of interest in the IRP and Reliability Mitigation Plan processes, the stakeholder meetings are likely to be quite large in terms of number of participants. The IL agencies could consider forming a technical working group to more closely advise the processes, alongside the possibility of an environmental justice working group to ensure effective input from affected communities.