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Resource Adequacy Study
Appendices

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ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

IPA
ILLINOIS POWER AGENCY

ILLINOIS COMMERCE COMMISSION
ICC

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Appendix A. Stakeholder Engagement and Considerations

A core component of the Resource Adequacy Study (RA Study) development process included collaboration with stakeholders as both a means to explain the key goals of the RA Study and methodologies being employed, as well as providing a means for stakeholders to engage with the Agencies, asking questions and providing recommendations. The Agencies conducted two Stakeholder Workshops, the first taking place on June 16, 2025, and the second on October 8, 2025.

The focus of the first workshop was to provide stakeholders with an understanding of the processes the Agencies would implement to conduct the study, an overview of the key policy drivers, an explanation of the methodologies being utilized, an overview of the roles of each Agency in the development of the RA Study, and a schedule of expected activities leading to this Report's release on December 15, 2025. The second workshop provided stakeholders with insights into scenario design, an overview of key inputs and assumptions, provided preliminary analysis and results, and share technical findings. Throughout the course of the second workshop, multiple stakeholders asked in-depth and/or technical questions of the Agencies related to the materials being presented. As such, the Agencies both documented the questions and issued a formal response to the questions—22 questions and responses in total.[1]

Following each workshop, the Agencies issued a series of questions to stakeholders, seeking written feedback that could be considered to inform the RA Study. After the first workshop the Agencies issued 11 questions and received responses from 21 parties.[2] Following the second workshop the Agencies issued 5 questions and received response from 8 stakeholders.[3] The feedback provided by stakeholders across both question sets released was immensely helpful, providing recommendations that helped to shape scenario design, data inputs used, identification of key market and policy drivers, and general feedback on risk, challenges and opportunities related to electric reliability that the

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[1] Agency responses to Workshop 2 (Oct. 8, 2025) questions asked by stakeholders: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/rastudy-stakeholderworkshop2-qa-10oct2025.pdf.

[2] Stakeholder responses to the Agencies Question Set #1: https://ipa.illinois.gov/electricity-procurement/resource-adequacy/responses-to-post-workshop-stakeholder-feedback-request-for-reso.html.

[3] Stakeholder responses to the Agencies Question Set #2: https://ipa.illinois.gov/electricity-procurement/resource-adequacy/responses-to-second-post-workshop-stakeholder-feedback-request-f.html.

Agencies should consider in the context of this RA Study, any prospective Mitigation Plan development, and future RA Studies. While not every opinion or recommendation provided by stakeholders can be accommodated in the RA Study Report given its targeted scope and limited schedule, the Agencies appreciate the time and effort stakeholders made to provide input into this complex process.

Below is an overview of the questions issued by the Agencies to stakeholders and a summary of how those responses.

Post-Workshop #1 Question Set to Stakeholders (issued June 18, 2025)

In response to the Agencies' Post-Workshop #1 questions, stakeholders provided the following comments:

Question 1 sought input into additional goals, objectives, or evaluation metrics should be considered as part of the RA Study or future efforts. Comments varied but included recommendations such as the impact on customer affordability, emerging technologies, impacts of RTO market redesigns including accreditation changes, and load growth. The OAG's comments highlighted the importance of focusing on the cost of "essential electric service", while other parties, such as the CGA, 23 recommended specific initiatives, plans, technologies (including generation and grid-enhancing technologies), and scenarios be considered. Middle River Power and ReliabilityFirst both recommended the Agencies consider other market-based considerations, such as ancillary services including Black Start, Synchronous Reserves, and Frequency Regulation; while ReliabilityFirst also highlighted the importance of considering resource adequacy for Illinois neighbors (which could impact Illinois' own reliability in the future).

Question 2 sought input on which variables are of the greatest importance to consider. A number of stakeholders highlighted system/grid reliability, while others recommended focusing on customer affordability. Many stakeholders also made reference to recent market results, specifically citing the results of the MISO capacity auctions resulting in high costs and reinforcing the challenge imparted to customers. Responses also recommended different technologies be considered, such as the value of energy storage or the availability and capability of natural gas to meet customer needs in the short term to relieve resource adequacy challenges. Still other parties, such as ComEd, provided specific references to data sources that should be considered as a component of the process.

Question 3 provided a list of drivers and requested input into which were the most critical to explore through the RA modeling. These included extreme weather, demand growth, thermal requirements, transmission build, generation resource diversity, reliance of out-of-state resources, or to provide some other diver. Most stakeholders reaffirmed the primary objective of an RA study—to evaluate reliability and associated considerations impacting reliability—mainly the impact of demand growth and changing generation resources. Other responses, such as from Invenergy, highlighted the importance of transmission—its availability, need for new build, available capacity of the existing system, or the use different technologies such as HVDC—and other RTO managed processes such as the interconnection queue process and impacts. Some additional drivers not provided by the Agencies included: availability and deployment potential of new or emerging technologies, the impacts of RTO queue reforms to deploy resources, and demand response and peak shaving opportunities. Ultimately, nearly every identified topic was highlighted by stakeholders in different ways, signaling that there are a multitude of drivers that need to be considered, many aligned with stakeholder focus along with the broader association to resource adequacy.

Question 4 requested feedback on known or prospective federal and state policies that should be considered. The preeminent consideration highlighted in Federal Bill H.R. 1 signed into law on July 4, 2025. The Chemical Industry Council of Illinois noted the importance of evaluating Illinois policy targets and objectives on customer affordability, including how it relates to resource adequacy opportunities and challenges. Earthrise, among other stakeholders, identified numerous state and federal topics, such as supply chain impacts, import tariff risk, potential changes in siting reforms, and the impact of CEJA's mandatory generation facility retirements.

Question 5 focused on the best way to present cost implications or other such findings. Stakeholders recommended different approaches from refocusing findings as they relate to the cost to customers, the way such costs are offset to benefits, and the change in costs over time as it relates to customer affordability. ICJC emphasized that "[e]lectricity prices and bill impacts on ratepayers should be a key consideration", noting that analysis on state-wide energy burdens was possible while also considering other topics as health impacts.

Question 6 requested input into potential gaps or blind spots that may occur in the RA Study. Again, stakeholders identified various topics including how the results relate to the goals and objectives of CEJA, the impact on customer affordability, the importance of considering all technologies as part of a solution set to relieve resource adequacy issues, and the evolution of RTO market design (such as the PJM capacity market design or broader RTO accreditation processes) to name a few.

Question 7 requested information on any third-party or peer studies or scenarios on resource adequacy. Different stakeholder provided varying recommendations—for example, Ameren Illinois cited the Minnesota PUC/Xcel Energy docket, ICJC recommended review of the eastern interconnection resource adequacy study, while the IIEC and the

Illinois Chamber recommend a different approach by proposing utilities be required to submit different load forecasts incorporating iterations of generator and load interconnection requests, success rates, and signed interconnection study requests and deposits.

Question 8 requested information on specific data sources to be used in the RA Study process. Many stakeholders highlighted the overlap between the RA Study and ICC Renewable Energy Access Plan (REAP)—recommending similar data sets be used for both and that the REAP can potentially inform the RA Study. Various PJM and MISO resource adequacy studies and planning assessments were also cited, with stakeholders noting the importance of considering those assessments in the broader context of resource adequacy for the region. Third-party sources were also cited, including those by the National Renewable Energy Laboratory, various cost and benefits assessments and studies by Lazard, and research completed by the Electric Power Research Institute (EPRI) as some examples.

Question 9 sought information into any known or expected transmission-related constraints, expansions or support projects. Both PJM and MISO transmission planning processes were cited as source information that should be utilized in any resource adequacy modeling. LS Power also highlighted specific constraint considerations, including ComEd transmission constraints, transmission expansion needs, and specific projects.

Question 10 sought stakeholder feedback on what assumptions should be considered regarding generation resources, specifically seeking insights into facility buildout and retirements. Various sources and considerations were proposed, including utilizing the RTO published queues and facility retirement announcements and the impacts of RTO market changes that could impact resource adequacy projections and conclusions. Some stakeholders recommended specific scenario designs. For example, NRG recommended high/low load growth scenarios, high/low intermittent resource penetration scenarios, high/low energy storage penetration scenarios, and so on as a means to contextualize the impacts and opportunities of various prospective options and solutions.

Question 11 requested feedback on specific assumptions that should be embedded in the base case modeling assumption beyond use of the utility and RTO load forecasts. Many responses focused on load, including the impact of load growth from large load customers (such as Data Centers), the impact of energy efficiency and demand response programs, and the impact of distributed generation on customer profiles that aggregate to the transmission grid.

In summary, Stakeholder responses to the Agencies' Post-Workshop #1 questions addressed a host of concepts and considerations which aided the Agencies in defining foundational elements of the study, including the core goals of the RA Study process, important drivers, how state and federal policies could influence the analysis and should be considered, and potential risks to the process amidst a changing energy landscape. Responses highlighted that resource adequacy is inclusive of both technical considerations and qualitative factors; that there are a wealth of resources and studies available to aid in the RA Study, many of which were linked in stakeholder responses; and, that ultimately this RA Study process is one that will be iterative as new information and results emerge over time, requiring continuous re-evaluation through this RA Study process and in future efforts.

Post-Workshop #2 Question Set to Stakeholders (issued October 16, 2025)

In response to the Agencies' Post-Workshop #2 questions, stakeholders provided the following comments:

Question 1 asked what additional inputs, assumptions, and information stakeholders are interested in obtaining concerning the modeling approach and methodology for the RA Study. Participants emphasized the need for transparency in modeling methodologies and assumptions, particularly regarding RECAP, LOLE, and PLEXOS. Stakeholders recommended using the most current and verified data and modeling a range of scenarios, including baseline, pessimistic, and optimistic cases. Several stakeholders highlighted the importance of reflecting ongoing PJM and MISO capacity-accreditation reforms and requested that the study explore data center load flexibility in shaping future load forecasts.

Question 2 requested a list of follow-up questions or considerations to be addressed by the Agencies, either through the current RA Study process or that could be considered in future RA Study efforts or activities. Stakeholders identified areas for future consideration, including assessment of availability of regional gas supply during extreme winter events, greater understanding of how the intra-RTO and interregional capacity transfers are modeled, and inclusion of behind-the-meter distributed energy resources. Many emphasized the need for more comprehensive scenario analyses that account for energy portfolios with and without gas generation. Others suggested more direct communication with each individual stakeholder group and improved data-sharing in advance of workshops to enhance collaboration and transparency in the RA Study process.

Question 3 requested stakeholders to identify the most important issues and challenges to be considered in the analysis of resource adequacy through 2030 and if those challenges change for the 2030-2035 study period. Participants outlined the key challenges facing resource adequacy that will impact the 2030-2035 study. Stakeholders consistently cited customer affordability, fossil fuel resource retirements, and reliability as enduring priorities, while also identifying policy changes, interconnection queues, transmission constraints, data center demand, and electrification as growing influences on future conditions. Several emphasized the workforce and economic development impacts of decarbonization goals under CEJA, noting the loss of oil and gas industry jobs and the need to balance these objectives with reliability and cost considerations.

Question 4 requested stakeholder feedback on how power plant retirements outside of IL (in MISO and PJM) be considered in the analysis. Stakeholders agreed that retirements outside Illinois in both MISO and PJM should be considered and recommended drawing from verified RTO and federal data sources such as MISO's Generator Interconnection Queue, PJM's Generation Deactivation Notices, and EIA datasets. Participants also pointed to regional assessments and state planning processes, including those from the Michigan Public Service Commission, as potential reference points. Some recommended that the RA Study explore actions being taken by other states to retain nuclear generation as part of their long-term reliability strategies.

Question 5 asked stakeholders to provide a list of questions not answered during the workshop. Stakeholders raised several outstanding questions related to modeling transparency and data access. Participants requested clarification on slides and assumptions related to retirements, nuclear generation growth, and load projections. Many asked for a list of assumed retiring generation units and how this retirement data is being used, noting that sharing this information with stakeholders could improve accuracy and alignment within the RA Study. Stakeholders also reiterated the importance of assessing affordability and economic development implications across multiple modeling scenarios.

In summary, feedback from Workshop #2 reinforced the need for transparency, data accuracy, and scenario diversity in the RA Study. Stakeholders urged the use of current and verified data, clear documentation of modeling methodologies, and expanded scenario development that accounts for system flexibility, regional retirements, and evolving RTO market structures. Participants identified affordability, reliability, and the pace of decarbonization as ongoing priorities, while also emphasizing the growing influence of electrification, data center demand, and transmission constraints. The feedback underscored the importance of continuous stakeholder engagement, data sharing, and iterative refinement to ensure the RA Study process remains comprehensive, credible, and aligned with changing market and policy condition.

Appendix B. Generator Interconnection Queue Overview

B.1. Generator Interconnection Queues Overview

Chapter 3.4.5 identified a series of risks and constraints impacting the addition of new generation to the grid to relieve market constraints, reduce the risk of reliability challenges, and ultimately provide necessary resource adequacy throughout Illinois and broader RTO regions. Of these constraints, a foundational risk is the processes effected by RTOs concerning generator interconnection queues. These interconnection queues play a critical role in enabling open access to transmission under Federal Energy Regulatory Commission (FERC) rules, particularly in the context of wholesale electric markets. FERC's landmark Order No. 888 established the principle of open access to transmission, meaning all generators should have fair and non-discriminatory access to the grid. Interconnection queues operationalize this by attempting to prevent undue discrimination against new entrants, ensuring transparency in how and when generators can connect, and supporting competitive wholesale markets by allowing diverse resources to participate. The queue system ensures that requests are tracked and processed systematically, grid reliability is maintained during integration, and cost and upgrade responsibilities are fairly allocated.

Recently, the "first-come, first-served" model led to large backlogs, with many speculative projects joining the queue. FERC's Order No. 2023, issued in July 2023, introduced major reforms to respond to these challenges. The traditional "first-come, first-served" model has been replaced with a "first-ready, first-served" approach that prioritizes projects most likely to advance to construction. Cluster studies now evaluate groups of similar projects together, streamlining system impact analyses and reducing study backlogs. New withdrawal penalties are designed to discourage speculative queue entries, while stricter site control and readiness requirements help ensure that only viable projects move forward. Proportional cost allocation methods have also been adopted to more fairly distribute network upgrade costs among participants. [4,5] Collectively, these reforms aim to reduce delays, improve transparency, and better allocate limited transmission capacity.

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[4] "Improvements to Generator Interconnection Procedures and Agreements", Vinson&Elkins, *V&E Energy Update* (July 21, 2023): https://www.velaw.com/insights/improvements-to-generator-interconnection-procedures-and-agreements/.

[5] "FERC's Generator Interconnection Queue Reform Makes Welcome Improvements, but the Devil Will Be in the Details of the Compliance Filings", Husch Blackwell, *Thought Leadership* (August 8, 2023):

B.2. The MISO Generator Interconnection Queue Process

The Midcontinent Independent System Operator (MISO) has undertaken significant reforms to its Generator Interconnection Queue (GIQ) process to address delays and improve efficiency. MISO's interconnection process is structured around three Definitive Planning Phases (DPP):

- **DPP Phase 1**—Preliminary analysis of project impacts on transmission reliability.
- **DPP Phase 2**—Revised, more detailed analysis incorporating updated assumptions and project withdrawals.
- **DPP Phase 3**—Final detailed study before signing the Generator Interconnection Agreement (GIA).

Projects must meet milestones and site control requirements to advance through each phase. The process includes technical studies to determine necessary network upgrades and cost allocations.[6]

MISO has implemented a series of key reforms to reduce interconnection delays and improve the efficiency of its study process. Higher milestone payments now discourage speculative projects by requiring greater financial commitment at each stage: the Definitive Planning Phase entry milestone (M2) has doubled from $4,000/MW to $8,000/MW, the Definitive Planning Phase 2 entry milestone (M3) is now the greater of 20% of upgrade costs or $1,000/MW, and the Definitive Planning Phase 3 entry milestone (M4) has increased to 30% of upgrade costs.[7] Stricter site control requirements further ensure project readiness, with developers required to demonstrate 50% site control at application and 100% before executing a Generator Interconnection Agreement (GIA), or within 180 days under limited exceptions.[8] Automatic withdrawal penalties now escalate from 10% to 100% of the M2 payment depending on when a project exits the queue, helping reduce churn and queue

https://www.huschblackwell.com/newsandinsights/ferc-issues-landmark-order-no-2023-on-generator-interconnection-reform.

[6] "MISO interconnection queue reform and progress update", Aurora Energy Research, Aurora May 2023 MISO Power & Renewables Market Forecast (July 2024): https://www.energy.gov/sites/default/files/2024-08/0724_MISO_IQ_reform_and_2023_cycle_policy_note_draft_FINAL.pdf

[7] "FERC Approves MISO Interconnection Queue Reforms, Rejects Overall Queue Cap", *Power Magazine*, Maxwell Multer (February 22, 2024): https://www.powermag.com/ferc-approves-miso-interconnection-queue-reforms-rejects-overall-queue-cap/.

[8] "Generator Interconnection Queue Reform", MISO Knowledge Base, Article KA 01468: https://help.misoenergy.org/knowledgebase/article/KA-01468/en-us.

instability. [9] A new Queue Cap Tracker will also monitor total submitted capacity and apply regional caps beginning in the 2025 DPP cycle to better manage queue volumes.[10]

In addition, MISO has created the Expedited Resource Addition Study (ERAS), a fast-track, one-time process designed for projects addressing urgent reliability needs. ERAS will conduct serial quarterly studies and provide an expedited GIA within 90 days, enabling faster deployment of capacity to mitigate near-term system shortfalls. [11]

In addition to implementing reforms, MISO has piloted using technology to accelerate interconnection studies. SUGAR is a tool that conducts power flow analysis—with MISO comparing the results from SUGAR to prior MISO study cycle results using MISO's current tool (TARA) to determine the effectiveness of the new tool and its potential application in future studies. MISO's review of the results found that "SUGAR can be used confidently in MISO's DPP Phase 1 studies."[12] These are encouraging steps forward in the RTOs expanding their use of technology to meet the needs of the interconnection queue.

Together, these reforms are intended to expedite system technical analysis thereby reducing backlogs, deter speculative participation, and create a more transparent and predictable process for developers. By aligning financial, procedural, and readiness requirements, MISO aims to accelerate interconnection timelines, enhance grid reliability, and support the rapid integration of renewable and flexible resources needed to meet growing regional demand.

B.3. The PJM Generator Interconnection Process

PJM Interconnection, the largest regional transmission organization (RTO) in the U.S., has been actively reforming its generator interconnection queue process to address significant delays and improve grid reliability amid rising demand and renewable energy growth.

Historically, PJM relied on a serial, first-come, first-served interconnection process that became increasingly unworkable as renewable and storage project proposals surged. The result was a backlog exceeding 200 GW, with average wait times stretching beyond five

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[9] Ibid.
[10] "Generator Interconnection Queue Improvements PAC-2023-1", MISO Dashboard (June 26, 2025): https://www.misoenergy.org/engage/MISO-Dashboard/generator-interconnection-queue-improvements/.
[11] "MISO proposes framework to speed generation interconnection", *Utility Dive* (March 20, 2025): https://www.utilitydive.com/news/miso-eras-speed-generation-interconnection/743057/.
[12] MISO Benchmarking of Pearl Street SUGAR: https://cdn.misoenergy.org/MISO%20Benchmarking%20of%20Pearl%20Street%20SUGAR697461.pdf.

years and frequent restudies triggered by speculative project withdrawals. [13] This approach created significant uncertainty for developers and hindered the timely addition of new generation needed to support reliability and policy goals.

In July 2023, PJM transitioned to a cluster-based, “first-ready, first-served” model. Under this new framework, projects are grouped into study cycles based on readiness and progress through three defined phases that require increasing financial deposits and levels of site control. The new process is designed to reduce processing time to roughly one to two years from application to interconnection agreement, a major improvement from past timelines.[14] Early efforts to reduce delays have already shown results: PJM’s transition queue has dropped from over 200 GW to about 63 GW, and more than 46 GW of projects now have signed interconnection agreements—though many still face permitting and siting hurdles outside PJM’s control. [15] At the time of this report, the PJM queue is frozen as the RTO works through a backlog of projects, and it will reopen in April 2026.

To accelerate progress further, PJM has introduced several fast-track initiatives. The Reliability Resource Initiative (RRI), approved by FERC in February 2025, enabled a one-time expedited review of 50 projects—mostly natural gas plants—to address near-term reliability shortfalls.[16] PJM is also investing in technology and workforce improvements, including partnerships with Google and Tapestry to deploy AI-enhanced planning tools and increased staffing and automation to streamline internal processes.[17]

PJM has also begun the Critical Issue Fast Path (CIFP) process to help address the impact of large load additions to the grid and the risk to resource adequacy. Commencing in August 8, 2025, the PJM Board of Managers issued a letter[18] instructing PJM to “address the development of reliability-focused solutions to ensure large load additions can continue to be integrated rapidly and reliably, without causing resource inadequacy, and while recognizing jurisdictional boundaries and data center relationships with existing Load

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[13] “Unpacking PJM’s Interconnection Reform and the Transition Period Buildout”, Modolo Energy, Aaron Orelowitz: https://modoenergy.com/research/pjm-interconnection-reform-and-transition-period-buildout-battery-energy-storage-queue-cycle-forecast.

[14] “Interconnection Process Reform Progress Fact Sheet”, PJM Interconnection (June 2025): https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/interconnection-reform-progress-fact-sheet.pdf,%20Updated%20June%202025.

[15] Ibid.

[16] “The U.S. Interconnection Challenge: Why Renewables Are Stuck in Line”, Council on Foreign Relations (October 2, 2025): https://www.cfr.org/article/us-interconnection-challenge-why-renewables-are-stuck-line.

[17] Interconnection Process Reform Progress Fact Sheet”, PJM Interconnection (June 2025).

[18] PJM Board Letter: https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250808-pjm-board-letter-re-implementation-of-critical-issue-fast-path-process-for-large-load-additions.pdf.

Serving Entities and/or Electric Distribution Companies."[19] The PJM CIFP process is being conducted on an accelerated schedule, with stakeholder collaborative sessions occurring in August through November 2025, stakeholder packages (proposed solutions) issued and voted upon in November and December, and a prospective filing with FERC targeted for December 2025. At the time of this Report's issuance, discussions between stakeholders and PJM are ongoing, with no solution having been selected or FERC filing made.

Beyond technical and process improvements, PJM is pursuing policy and governance reforms to modernize its framework. These include revising Capacity Interconnection Rights Transfers to allow quicker replacement of retiring generation and engaging with state policymakers seeking greater transparency and oversight of planning decisions. [20] Despite meaningful progress, major challenges remain—particularly related to permitting, transmission upgrade bottlenecks, and growing political pressure from states frustrated with the pace of reform. [21,22] These ongoing issues underscore the complexity of aligning market, policy, and reliability objectives across PJM's diverse footprint.

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[19] PJM CIFP stakeholder process: https://www.pjm.com/committees-and-groups/cifp-lla.

[20] "States Threaten to Leave PJM if Demands Aren't Met", *Cape May County Herald*, Vince Conti (September 2025): https://capemaycountyherald.com/article/coalition-of-states-threaten-to-leave-grid-operator-pjm-unless-reform-happens-now/.

[21] "Lawmakers urge PJM to take steps so clean energy projects can meet tax credit deadlines", *Utility Dive*, Ethan Howland (September 29, 2025): https://www.yahoo.com/news/articles/lawmakers-urge-pjm-steps-clean-090423762.html.

[22] "Governors launch PJM collaborative to push for grid reform", *Daily Energy Insider*, Kim Riley (September 30, 2025): https://dailyenergyinsider.com/news/49782-governors-launch-pjm-collaborative-to-push-for-grid-reform/.

Appendix C. FEJA

C.1. Future Energy Jobs Act

In December 2016, Illinois enacted Public Act 99-0906, also known as the Future Energy Jobs Act (FEJA), which became effective June 1, 2017.[23] FEJA further advanced Illinois' efforts to meet environmental goals. Among other measures, FEJA:

(1) Encouraged the adoption of renewable energy resources including cost-effective distributed energy resources and technologies;
(2) Updated Illinois' energy efficiency standard to incorporate and optimize measures enabled by the smart grid and to provide incentives to achieve energy savings goals; and,
(3) Preserved zero-emission energy generation and promoted new zero-emission energy generation.

The General Assembly found that "[t]o ensure that the State and its citizens, including low-income citizens, are equipped to enjoy the opportunities and benefits of the smart grid and evolving clean energy marketplace," P.A. 99-0906 was intended to serve to "maximize the impact" of the state's RPS. This included direction that the State should "encourage the adoption and deployment of cost-effective distributed energy resource technologies and devices, such as photovoltaics, which can encourage private investment in renewable energy resources, stimulate economic growth, enhance the continued diversification of Illinois' energy resource mix, and protect the Illinois environment; investment in renewable energy resources, including, but not limited to, photovoltaic distributed generation, which should benefit all citizens of the State, including low-income households."

FEJA declared that "developing new renewable energy resources in Illinois, including brownfield solar projects and community solar projects, will help to diversify Illinois electricity supply, avoid and reduce pollution, reduce peak demand, and enhance public health and well-being of Illinois residents." Other findings also reinforce the value of community solar in expanding access to renewable energy, and the value of developing brownfield site solar projects to "help return blighted or contaminated land to productive use while enhancing public health and the well-being of Illinois residents."

Through the provisions of Public Act 99-0906, the General Assembly sought to promote more equitable and diverse access to the benefits of renewable energy, while emphasizing

[23] Illinois Public Act 099-0906: https://www.ilga.gov/Legislation/publicacts/view/099-0906.

the development of new generation resources and maximizing their environmental benefits and aligning with the law's technical requirements. It requires that the IPA "design its long-term renewable energy procurement plan to maximize the State's interest in the health, safety, and welfare of its residents, including but not limited to minimizing sulfur dioxide, nitrogen oxide, particulate matter and other pollution that adversely affects public health in this State, increasing fuel and resource diversity in this State, enhancing the reliability and resiliency of the electricity distribution system in this State, meeting goals to limit carbon dioxide emissions under federal or State law, and contributing to a cleaner and healthier environment for the citizens of this State."

Further, FEJA introduced the concept of a "community renewable generation project" in Illinois and defined it as an electric generating facility that:

(1) was powered by wind, solar thermal energy, photovoltaic cells or panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that did not involve new construction or significant expansion of hydropower dams;
(2) was interconnected at the distribution system level of an electric utility, a municipal utility that owns or operates electric distribution facilities, a public utility, or an electric cooperative;
(3) credited the value of electricity generated by the facility to the subscribers of the facility; and,
(4) was limited in nameplate capacity to less than or equal to 2,000 kilowatts.

A subscriber's subscription to such a facility was an "interest" in that facility, expressed in kilowatts and sized primarily to offset part or all the subscriber's electricity usage, and could not constitute more than 40% of the facility's nameplate capacity.

C.2. Adjustable Block Program and Illinois Solar For All Program

FEJA also required the development of an adjustable block program. Used to facilitate the development of new community solar and distributed photovoltaic generation, the Adjustable Block Program (ABP) featured a "transparent schedule of prices and quantities" for RECs "to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time." Stated differently, the adjustable block was not a competitive procurement event using "pay as bid" pricing with selection of bids on the basis of price. Thus, a party seeking a REC contract—such as a photovoltaic distributed generation or community solar project developer—knew the REC price in advance and had visibility into when and how that price might change.

The law sets forth other requirements of the adjustable block program: it was required to include a schedule of standard block purchase prices to be offered; a series of steps, with associated nameplate capacity and purchase prices that adjusted from step to step; and automatic opening of the next step as soon as the nameplate capacity and available purchase prices for an open step were fully committed or reserved. The initial goal for the adjustable block program was to have 1 million RECs delivered annually by the end of the 2020-2021 delivery year. Using a capacity factor of 17%, this would have resulted in approximately 666 MW of new community solar and distributed photovoltaic generation.

Similar in structure to the Adjustable Block Program, the Illinois Solar for All Program was created by FEJA and included incentives for low-income distributed generation and community solar projects and other associated approved expenditures to help grow the low-income solar market. Through more generous REC contracts, the Illinois Solar for All Program provided incentives for low-income participation in solar photovoltaic projects, whether as a system owner, community solar project subscriber, or system host. Those RECs are retired to satisfy electric utility compliance obligations just as with the other REC procurements, while the additional premium helps produce benefits specific to growing the low-income solar marketplace and ensuring more equitable access to the benefits of clean energy. Structurally, the Solar for All Program's incentives were offered through contracts for the delivery of RECs at a premium price above what would otherwise have been available, reflecting the additional incentive necessary to ensure low-income participation, with the ability to offer full contract prepayment or otherwise relax (or enhance) requirements in recognition of the unique challenges facing low-income project development.

For both the Illinois Solar for All Program and the Adjustable Block Program, FEJA authorized "prepayment" for a stream of RECs to be delivered over the course of a 15-year contract.

C.3. The Long-Term Renewable Resources Procurement Plan

Importantly, FEJA transitioned the state's RPS to a streamlined, centralized planning and procurement process, with both RPS targets and IPA's available budgets determined on the basis of an electric utility's load for all retail customers with funding collected through a delivery services charge. In other words, following a two-year transition period, separate RPS obligations for ARES ended and an electric utility's total load, whether served by the utility or an ARES, were subject to the RPS charge that funds the renewable resources procurements, thereby eliminating the prior budget uncertainty caused by customers switching supply service to and from ARES. Also, procurements for renewable energy resources were now consolidated in a separate Long-Term Renewable Resources Procurement Plan (Long-Term Plan), to be updated every two years.[24]

The Long-Term Plan included a schedule for procurements for renewable energy credits from utility-scale wind projects, utility-scale solar projects, and brownfield site photovoltaic projects. The Long-Term Plan was required to "include the goals for procurement of renewable energy credits to meet at least the following overall percentages: 13% by the 2017 delivery year; increasing by at least 1.5% each delivery year thereafter to at least 25% by the 2025 delivery year; and continuing at no less than 25% for each delivery year thereafter."

The renewable energy targets were 2 million RECs from new wind projects by the 2020 delivery year, 3 million by 2025, and 4 million by 2030. New photovoltaic projects feature the same overall procurement targets, while also containing requirements that at least 50% of new PV RECs be procured through the adjustable block program (and thus from distributed generation or community solar projects), at least 40% from utility-scale (above 2 MW) photovoltaic projects, and at least 2% from brownfield site photovoltaic projects that are not community renewable generation projects.

An additional new requirement in the law stated that RECs could not be counted toward RPS targets if they are sourced from a generating unit "whose costs were being recovered through rates regulated by this State or any other state or states on or after January 1, 2017."

C.4. Net Metering Changes in FEJA

Prior to FEJA, electric providers could, at their discretion, provide aggregated net metering. Aggregated net metering occurs when several customers subscribe to a single renewable energy facility—for example, a community solar electric generating system.

FEJA changed net metering provisions in two key respects: (1) once net metering load equals 5% of total utility peak load, electric utilities are no longer required to provide the delivery component of net metering credits to new customers and (2) electric providers must allow net metering aggregation.

It required Ameren Illinois and ComEd to file tariffs providing for a renewable distributed generation rebate for an electric generating facility that was:

- 2 MW or less;

[24] Biennial Long-Term Plans are differentiated by the year in which the plan goes into effect. This naming convention was maintained through later statutory updates (i.e. Clean Energy Jobs Act or CEJA). For example, the current Long-Term Plan filed by the IPA and being litigated before the ICC is the 2026 Long-Term Plan – expected to take effect in June 2026 and cover activities through May 2028.

- Located on the customer's premises;
- Intended primarily to offset the customer's own electric requirements;
- Interconnected to the electric utilities distribution network; and
- If installed on or after June 1, 2017, equipped with a smart inverter that converts output from DC to AC and can autonomously, in departures from normal operating voltage and frequency, provide dynamic reactive and real power support, voltage and frequency ride-through, ramp rate controls, communication with ability to accept external commands, and other functions.

The DG rebates were also available for aggregation customers and initially rebate values for non-residential customers and aggregation customers were set to $250 per kW. Once net metering load equals 5% of total utility peak load, the Commission was tasked with determining rebate values for residential, non-residential, and aggregation customers.

Residential customers on net metering prior to June 1, 2017, were given the option of a distributed generation rebate or to continue receiving net metering delivery credits. Customers that received a distributed generation rebate were no longer eligible for the delivery credit portion of net metering credits. They would, however, continue to receive energy supply credit.

C.5. Zero Emission Credits for Nuclear Power Plants

Nuclear power plants generate electricity without the air pollutants and greenhouse gas emissions that result from the combustion of fossil fuels. In most states, including Illinois, these nuclear power generating facilities are not considered to be "renewable" resources and therefore are not eligible to produce RECs. Consequently, they cannot be used to meet state renewable energy resource procurement targets, such as the Illinois RPS, thereby leaving them without a mechanism to receive value for the zero emission attributes associated with their generation.

While providing nuclear generating units with some compensation for the value of their emission free environmental attributes had long been a part of energy policy discussions (including any discussions around the institution of a carbon tax or the implementation of a "cap and trade" system for emissions credits), concrete discussions around how such a mechanism could be best implemented through Illinois law began in earnest in 2014. In that year, Exelon publicly announced that it was considering closing select non-profitable nuclear plants in Illinois. In response, the Illinois House of Representatives adopted House Resolution 1146 of the 98th General Assembly (HR 1146). That resolution contained a series of statements regarding the value of nuclear power generation and urged several state agencies, including the IPA, ICC, IEPA, and DCEO, to prepare reports concerning the impacts of premature closure of these plants. In addition, PJM was also asked to study the impacts of premature retirements of Illinois nuclear power plants and PJM estimated that allowing the Quad Cities nuclear plant to close would, in 2019, increase Illinois CO_2 emissions by 2.6 million tons. PJM's analysis also revealed that closing the Quad Cities plant would raise PJM-wide CO_2 emissions by an estimated 6.1 million tons.

Among FEJA's legislative findings was a declaration that "[r]educing emissions of carbon dioxide and other air pollutants, such as sulfur oxides, nitrogen oxides, and particulate matter, is critical to improving air quality in Illinois for Illinois residents," and that, as a result, "… Illinois must expand its commitment to zero emission generation and value the environmental attributes of zero emission generation that currently falls outside the scope of the existing renewable portfolio standard, including, but not limited to, nuclear power." With regard to existing zero emission facilities, the legislature found that "[p]reserving existing zero emission energy generation and promoting new zero emission energy generation is vital to placing the State on a glide path to achieving its environmental goals and ensuring that air quality in Illinois continues to improve." To best achieve these goals, the General Assembly found that "it is necessary to establish and implement a zero emission standard, which will increase the State's reliance on zero emission energy through the procurement of zero emission credits from zero emission facilities, in order to achieve the State's environmental objectives and reduce the adverse impact of emitted air pollutants on the health and welfare of the State's citizens." FEJA required the IPA to develop a Zero Emission Standard Plan setting forth its plan for ensuring compliance with that standard.

Zero emission credits (ZECs) were created to recognize the environmental value of zero emission facilities, namely nuclear, that would not otherwise be recognized in the marketplace or under Illinois law. FEJA established that a zero-emission facility is a generating facility fueled by nuclear power interconnected to PJM or MISO. Likewise, a ZEC is defined as a tradable credit that represents the environmental attributes of one megawatt hour of energy produced from a zero-emission facility. The law specified that ZEC contracts "shall be for a term of 10 years ending May 31, 2027."

On January 10, 2018, the IPA's procurement administrator, NERA Economic Consulting, held a procurement event for the sale of ZECs to Ameren, ComEd, and MidAmerican. To evaluate the impact of zero emission facilities on the amount of CO_2 emissions resulting from electricity consumed in Illinois, facility reviews examined the fraction of the zero emission facility's replacement generation expected to be consumed in Illinois and the expected carbon content of that replacement generation consumed in Illinois. This resulting in the IPA's use of an assumed 33% replacement factor in-state generation and 67% replacement generation from another state. Further, the IPA assumed 7.79% of replacement generation produced outside of Illinois, but in MISO, would be consumed in Illinois and that 22.2% of replacement generation produced outside of Illinois, but in PJM, would be consumed in Illinois. The IPA further assessed the impact of replacement generation from each state by comparing the states' output of CO_2 per megawatt hour with the comparable regional figures. Further, to evaluate the impact of zero emission facilities on the amount of non-carbon dioxide emissions impacting Illinois citizens, facility reviews examined the degree to which emissions from a zero emission facility's replacement generation would increase the amount of sulfur dioxide (SO_2), nitrogen oxide (NOx) and particulate matters (PM) in Illinois and thus have adverse impacts on Illinois citizens. The same proxy assumptions were used I this evaluation as for CO_2 emissions.

Each bid facility could receive a maximum score of 25 points for each of the CO_2, SO_2, NOx, and PM criteria and a maximum overall score from these environmental criteria of 100 points. To get final scores, the emission scores for each facility were multiplied by an Economic Stress Multiplier (ESM). The ESM was calculated as the ratio of a zero-emission facility's operating cost per megawatt hour divided by an estimate of the market revenues such a facility might expect to receive. The successful Zero Emission Facilities in the ZEC RFP were those facilities that achieved the highest scores as determined through the evaluation process. The evaluation process selected zero emission facilities until the annual target quantity of 20,118,672 ZECs was reached.

Three winning suppliers were awarded:[25]

- Quad Cities Nuclear Power Station, Unit 1
- Quad Cities Nuclear Power Station, Unit 2
- Clinton Power Station, Unit 1

For the first delivery year June 1, 2017 through May 31, 2018, the ZEC price paid to each facility will equal $16.50, the Social Cost of Carbon, as specified in Public Act 99-0906. The value of avoided greenhouse gas emissions is calculated as the sum of the product of the Social Cost of Carbon specified in Public Act 99-0906 for each delivery year, multiplied by the projected annual output, summed across the contract term. This cumulative value over the expected life of the ZEC contracts, without any adjustments, is $3,583,277,212.

[25] ICC Public Notice: https://www.ipa-energyrfp.com/wp-content/uploads/filebase/Public-Notice-of-ZEC-RFP-Procurement-Results-2018-01-26.pdf.

Finally, the IPA communicated the estimated cost of replacement with other zero carbon dioxide resources was estimated as the simple average of the REC prices paid for new utility-scale wind projects (procured through the then most recent the Initial Forward Procurement) and the REC prices paid for solar projects (including new utility-scale solar projects also procured through the then most recent Initial Forward Procurement and photovoltaic distributed generation projects procured after January 1, 2015) multiplied by the projected annual output over the life of the contract. There were two defined means to estimated the cost of replacement:

1. Using the simple average of the winning bid prices for Wind RECs and the average of the winning bid prices for RECs from the photovoltaic projects, then being weighted by the annual quantity of RECs procured from the photovoltaic projects. This approach yields a value of $13.14 per REC and an estimated cost of replacement of $2,689,634,019.
2. Using the simple average of the winning bid prices for Wind RECs and the simple average of the average winning bid prices for RECs from the photovoltaic projects. This approach yields a value of $50.05 per REC and an estimated cost of replacement of $10,243,987,739,

Since the procurement held in 2018, the IPA has completed annual Delivery Year Payment Calculations—both preliminary payment notices and final payment notices. These notices can be found on the IPA's website **here** (see section "Other Plans" > "2017 Zero Emission Standard Procurement Plan").

Appendix D. CEJA

Enacted in 2021, the Climate and Equitable Jobs Act (CEJA), Public Act 102-0662, represented, at the time, Illinois' most comprehensive clean energy and decarbonization legislation to date, building on the foundation laid by the 2016 Future Energy Jobs Act. CEJA codified Illinois' long-term commitment to achieve a 100 percent clean electricity supply by 2050 and accelerated interim RPS targets, while introducing new mechanisms to ensure an equitable transition. The law restructured and expanded renewable procurement programs such as the adjustable block program and Illinois Solar for All, created new market instruments like Carbon Mitigation Credits to preserve non-emitting resources, and established programs for workforce development and community reinvestment. CEJA's reforms aligned clean energy deployment with affordability and reliability goals, with the aim of integrating climate, equity, and resource adequacy objectives into energy policy.

D.1. Renewable Portfolio Standard

CEJA substantially increased the REC procurement goals and targets in the Illinois RPS. The previous "25% by 2025" RPS standard was replaced by the more aggressive "40% by 2030" and "50% by 2040" requirements. The prior target of 8 million RECs delivered annually from new projects by 2030 was reset to a target of 45 million RECs. 45% of the RECs must come from wind and 55% from photovoltaic resources. Of the photovoltaic targets, 50% should be from ABP projects, 47% should be from utility-scale solar projects, and 3% from brownfield projects.

Renewable Portfolio Standard budget changes increased the rate cap from 2.015% to 4.25% and changes the baseline delivery year from the year ending May 2007 to the year ending May 2009. As a result, annual collections under the Illinois RPS total over $580 million, versus the approximately $230 million previously collected. CEJA established budget priorities such that resources with existing contracts as of June 2021 are prioritized first and that resources necessary to comply with the new wind and solar requirements are prioritized over resources necessary to meet other commitments of the RPS. CEJA also allowed the RPS collections to be rolled over for up to five years and directed that those should be spent on a first-in, first-out basis. If not spent within 5 years, the money must be refunded but refunds must not be made with respect to obligated funding even if not paid out.

CEJA included a few key changes to definitions that are important in the context of this study. Community Renewable Generation Projects increased to 5 MW (rather than 2 MW). Utility scale projects are now those above 5 MW (change from above 2 MW prior). While CEJA expanded the definition of “renewable energy resource” to include technologies such as waste heat to power systems (WHP) and qualified combined heat and power systems (CHP), there is no language authorizing program or procurement activity to procure RECs from WHP and CHP systems. Instead, CEJA establishes targets only for the procurement of RECs from “new wind and solar projects” with an express objective for the percentage-based RPS goals to be met entirely by procurements of RECs from new wind and photovoltaic projects.

D.2. Self-Direct Renewable Portfolio Standard Compliance Program

CEJA required the IPA to establish a self-direct renewable portfolio standard compliance program for eligible self-direct customers that purchase renewable energy credits from utility-scale wind and solar projects through long-term agreements. Qualifying customers must meet certain size thresholds, while qualifying projects must be “new” projects sited in locations otherwise eligible for RPS compliance.

The legislation defines eligibility as customers with 10,000 kW of demand. RECs must qualify as RECs pursuant to statute, be included in 10 year or longer contracts, be equivalent to 40% of the user’s usage, be retired on behalf of the customer, be sourced from utility scale projects, and satisfy diversity and prevailing wage requirements. Self-direct customers must file annual compliance reports.

CEJA directed IPA to determine how many self-direct RECs to include in the program, and if demand exceeds supply, the split between commercial and industrial participants must be 50/50. The ICC shall approve a reduction in RPS recovery for self-direct customers equal to the amount supporting utility-scale RECs (and not ABP or ILSFA portions). The ICC approves the self-direct filling each year.

D.3. Utility-Scale Procurements

CEJA included the following changes to Utility- Scale Procurements:

Contracts shifted for indexed renewable energy credits. The Index Price is the real time settlement price at the applicable trading hub (e.g., PJM-NIHUB or MISO-IL). The Strike Price is the contract price for energy and RECs. Payments shall be based on the index price less the strike price. If negative, the buyer shall pay the seller the absolute value of the difference. If the number is positive, the seller owes the buyer this amount. The contracts are for 20 years.

The IPA may qualify RECs from utility scale facilities delivered over an HVDC line meeting specified parameters if it: (1) is constructed under a project labor agreement; (2) is capable of transmitting at 525 kv; (3) has a converter station in Illinois interconnected into PJM; (4)

does not operate as a public utility; and (5) is energized after June 2023. It also cannot have generating units with costs recovered through regulated rates.

The definition of brownfield site photovoltaic projects was expanded to include projects at former coal mine sites and the minimum size for utility-scale projects was set at 5 MW (from 2 MW prior).

D.4. Adjustable Block Program

CEJA implemented the following major changes to the Adjustable Block Program:

The small distributed generation category size limits increased. Small DG changed to 25 kW rather than 10 kW. The large DG category size limits were also amended. Large DG increased from 25 kW to 5 MW. Three new categories (Public Schools, Community- Driven Community Solar, and Equity Eligible Contractors) were added to the Program's existing three categories (Small Distributed Generation, Large Distributed Generation, and Traditional Community Solar). Community Renewable Generation Projects could be up to 5 MW (rather than 2 MW).

The legislation required a category allocation of: 20% from small DG, 20% from large DG (25 kW–5 MW), 30% from CS; 15% from public schools, 5% from community-driven CS, and 10% from DG or CS built by equity eligible contractors (the IPA may propose this category to increase to 40% over time by decreasing capacity in categories 1 – 5 to achieve a balance of project types. The remaining capacity must be allocated to respond to market demand.

Small DG projects or small DG from equity contractors must have 15-year contracts and be paid upon energization; large DG projects and community driven CS and similar projects from equity contractors must have 15-year contracts and be paid 15% up front and the remainder over 6 years; CS projects, public school projects and similar projects built by equity contractors must be paid over a 20-year delivery term.

The IPA is to have a yearly schedule of prices and quantities and projects should be significantly mature to participate.

D.5. Illinois Solar for All

CEJA updated the sub-programs that comprise Illinois Solar for All, increased available funding, and prioritized expanding participation in Illinois Solar for All to areas of Illinois previously underserved by the program, increasing development by small and emerging businesses, and encouraging development of projects promoting energy sovereignty. Funding from utility RPS assessments is increased from $10 to $50 million per year and the

IPA must direct 5% of the funds to community-based groups for education purposes. In 2021, 2024, 2027, and 2030, $10 million from utility RPS assessments must go to DCEO for workforce development.

The updates to the sub-program structure of Illinois Solar for All eliminated the Low-Income Community Solar Pilot Projects and split the Low-Income Distributed Generation sub-program into separate sub-programs for distributed generation projects serving small residential (single- to four-unit residences) and large residential (five units or more) buildings. The Illinois Solar for All sub-programs now consist of: (a) Low-income Single-Family and Small Multifamily Solar; (b) Low-Income Community Solar; (c) Incentives for non-profits and public facilities (D) Low-income large multifamily solar.

The funding allocation percentages for these sub-programs were also adjusted, distributing the funding no longer allocated for the Low-Income Community Solar Pilot Projects to the new subprograms, with the Low-income Single-Family and Small Multifamily Solar and the Low-income multifamily solar sub-programs sharing a funding allocation. Either the IPA or utilities may contract for ILSFA RECs.

D.6. Carbon Mitigation Credits for Nuclear Power Plants

Through CEJA, the General Assembly again found that "nuclear power generation is necessary for the State's transition to 100% clean energy, and ensuring continued operation of nuclear plants advances environmental and public health interests through providing carbon-free electricity while reducing the air pollution profile of the Illinois energy generation fleet." Regarding preserving additional carbon-free energy resources, the General Assembly found that "[a]bsent immediate action by the State to preserve existing carbon-free energy resources, those resources may retire, and the electric generation needs of Illinois' retail customers may be met instead by facilities that emit significant amounts of carbon pollution and other harmful air pollutants at a high social and economic cost until Illinois is able to develop other forms of clean energy."

In early 2021, the IEPA commissioned a report assessing the financial condition of the nuclear plants in Illinois not receiving revenues from the sale of ZECs to help identify the specific nuclear units that are at risk of retirement and subsequently losing the environmental benefits associated with these plants. The results of the report, which involved a financial audit of the nuclear plants, indicated that under certain assumptions, subsidies may be needed to provide sufficient cash flow to continue the operation of several specific nuclear generating units. By contrast, that audit showed that the LaSalle facility would continue to operate without subsidy under the market and operating conditions assumed by the audit. In CEJA, the General Assembly thus expressly specified that the

LaSalle facility is "not eligible to participate in the carbon mitigation credit program." The Illinois EPA report also provided a forecast which projected that, between 2022 and 2027, a carbon-free energy resource could earn on average approximately $30.28/MWh from the sale of energy and capacity. This earnings forecast provided a comparative basis with regard to the baseline costs established in the legislation for determining the additional revenue that the nuclear facilities could receive from the sale of carbon mitigation credits.

CEJA established the definitions of a "carbon-free energy resource" and "carbon mitigation credits," with the latter being the tradeable environmental attributes of energy generated by the former. A carbon-free energy resource can thus sell carbon mitigation credits (CMCs), but these attributes can only be sold once after which these credits must be retired—and thus a facility cannot sell these attributes as both CMCs and ZECs.

While ZEC contracts are for a term of 10 years ending May 31, 2027, CMC contracts are for 5 years with deliveries starting with the 2022-2023 delivery year but similarly ending May 31, 2027.

While CMCs also constitute the environmental attributes of nuclear power generation with prices that will likewise vary based on market capacity and energy revenues, CMCs are priced differently than ZECs—and may operate as a credit to ratepayers should market revenues exceed a baseline annual cost cap. Also unlike the Zero Emission Standard, CMC prices may be adjusted based on the "value of any monetized federal tax credits, direct payments, or similar subsidy" provided by a unit of government that would not otherwise be reflected in market prices, and owners of applicant or participating facilities must "make commercially reasonable efforts" to apply for such subsidies, if available (as doing so would lessen any burden on ratepayers through a reduction in CMC prices).

The number of CMCs required to be procured also differs from the amount of ZECs required to be procured under the Zero Emission Standard. For the Zero Emission Standard, the amount of ZECs to be procured annually is set at "an amount approximately equal to 16% of the actual amount of electricity delivered by each electric utility to retail customers in the State during calendar year 2014 for ComEd and Ameren Illinois, and 16% of applicable load (that for which the IPA conducts procurements) for MidAmerican Energy Company's Illinois retail sales. That quantity was 20,118,672 ZECs annually. By contrast, CEJA specifies that no more than approximately 54,500,000 cost-effective carbon mitigation credits are to be procured annually, a significantly greater quantity than ZECs procured under the Zero Emission Standard.

In addition to providing an approximate annual limit on the number of CMCs that can be procured, CEJA establishes a customer protection cap to determine the maximum CMC bid price that the Agency can accept. The customer protection cap is determined by the statutorily prescribed baseline costs of carbon-free energy resources. The Baseline costs for the customer protection cap reflect the costs of carbon-free energy resources and a projection from the independent audit report that "a clean energy resource has the opportunity to earn on average approximately $30.28 per megawatt hour, for the sale of energy and capacity during the time period between 2022 and 2027."

As with the Zero Emission Standard and ZECs, carbon mitigation credits are to be received and retired by the electric utility counterparty and paid for using tariffed charges collected by the counterparty electric utility from its ratepayers. However, unlike the Zero Emission Standard (which supports at-risk nuclear facilities in both PJM and MISO), the counterparty for CMC delivery contracts is only ComEd, and thus only ComEd ratepayers are to be assessed surcharges for CMC procurement (which, correspondingly, supports at-risk nuclear facilities located only within ComEd's regional transmission organization, PJM).

The public interest criteria utilized for bid selection generally mirrors that used for the Zero Emission Standard (and the two laws often use identical language). As specified in the Act, the public interest criteria to be applied for bid evaluation include minimizing carbon dioxide (CO_2) emissions that result from electricity consumed in Illinois, as well as minimizing sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) emissions that adversely affect residents of the state.

If the price is positive, ComEd will multiply the price by the contract quantity and remit it to the seller. If the price is negative, the seller shall remit that amount to ComEd who shall credit customers. Bids above a baseline won't be accepted. The baseline costs for the applicable years are:

- For 22/23 - $30.30 per MWh
- For 23/24 -- $32.50 per MWh
- For 24/25 -- $33.43 per MWh
- For 25/26 -- $33.50 per MWh
- For 26/27 -- $34.50 per MWh

On November 23, 2021, the IPA's procurement administrator, NERA Economic Consulting, held a procurement event for the sale of carbon mitigation credits to ComEd. On December 1, 2021, voting in open session, the Commission approved the procurement administrator's selection of winning carbon-free energy resources.

The successful Carbon-free energy resources in the CMC RFP were those facilities that achieved the highest scores as determined through the evaluation process. If facilities had the same score, the relative ranking of the facilities would be based on the price bid with the lowest bid price receiving the higher relative ranking. The evaluation process selected carbon-free energy resources until an annual target quantity of approximately 54,500,000 CMCs was reached, from the following resources: Braidwood Nuclear Power Station, Unit 1; Braidwood Nuclear Power Station, Unit 2; Bryon Nuclear Power Station, Unit 1; Bryon Nuclear Power Station, Unit 2; Dresden Nuclear Power Station, Unit 2; and Dresden Nuclear Power Station, Unit 3.

CEJA mandates the disclosure of the following information:

(I) the value of avoided greenhouse gas emissions measured as the product of the carbon-free energy resources' output over the contract term, using generally accepted methodologies for the valuation of avoided emissions; and

(II) the costs of replacement with other carbon-free energy resources and renewable energy resources, including wind and photovoltaic generation, based upon an assessment of the prices paid for renewable energy credits through programs and procurements conducted pursuant to subsection (c) of Section 1-75 of the IPA Act, and the additional storage necessary to produce the same or similar capability of matching customer usage patterns.

The estimated value of avoided greenhouse gas emissions is calculated based upon the most recent estimates of the cost of carbon emissions contained in the Interagency Working Group on Social Cost of Greenhouse Gases, United States Government's Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 dated February 2021 and average emissions rates from PJM's report 2016–2020 CO_2, SO_2 and NO_X Emission Rates Dated April 9, 2021.

Using a 3% discount rate, the Interagency Working Group on Social Cost of Greenhouse Gases estimates an annual cost of carbon equal to $53 to $59 per metric ton for the years 2022 – 2027. The most recent PJM System Average CO_2 emissions rate is 791 lbs. per MWh for 2020, which equates to approximately 0.36 metric tons per MWh of generation. Assuming this emissions value for 2022-2027, the values of an avoided MWh of CO_2 emissions are approximately $19.02/MWh, $19.37/MWh, $19.73/MWh, $20.09/MWh, $20.45/MWh, $21.17/MWh for the years 2022 – 2027, respectively.

The cumulative value over the expected life of the CMC contracts, June 1, 2022, to May 31, 2027, without adjustments, is $5,426,329,606. This estimate does not account for additional greenhouse gas costs, such as those associated with methane or other emissions. Estimates would also increase if PJM System Marginal Emissions were used instead of PJM System Average Emissions.

The costs of replacement with other zero carbon dioxide resources, including wind and photovoltaic, can be estimated two different ways. The first approach uses the weighted average of the REC prices paid to the winning bidders in the IPA's utility-scale wind and solar procurements following Illinois Public Act 99-0906 (commonly referred to as the Future Energy Jobs Act) multiplied by the projected annual output over the life of the CMC contracts. This approach yields a value of $4.22 per REC or an estimated total cost of replacement of $1,150,040,833 over the life of the five-year CMC contracts.

The second approach uses the weighted average of the REC prices paid for the entire current portfolio of the Illinois RPS from procurements following the Future Energy Jobs Act. This includes the prices for RECs from the 2019 Brownfield Solar procurement, the Adjustable Block Program, and the Illinois Solar For All Program. This approach yields a value of $14.16 per REC or an estimated total cost of replacement of $3,859,856,992 over the life of the five-year CMC contracts.

The additional storage necessary to produce the same or similar electricity output of the winning carbon-free energy resource bidders in this RFP has been estimated through modeling conducted by Sandia National Laboratories (SNL), under funding by the DOE Office of Electricity Energy Storage Program. The storage estimates use the locations and estimated capacity factors of the winning bidders in the IPA's utility-scale wind and solar procurements following the Future Energy Jobs Act and they assume that energy storage is 85% efficient. Based on these assumptions and SNL's modeling, the estimated additional storage needed is 11,262 MW of power capacity with an estimated energy capacity of 2,762,770 MWh.

Following the successful completion of the CMC procurement event, the IPA began tracking monthly and average annual CMC prices, including the monthly charge or credit to ratepayers, and the net credit to ratepayers. This data is presented on the IPA's website via two graphs and includes links to both the CMC Procurement Plan and procurements results notice, all which can be found **here**.

D.7. Emissions Reductions

CEJA established a clear, enforceable schedule for reducing and ultimately eliminating carbon dioxide and co-pollutant emissions from Illinois' major fossil-fueled generating units. Under CEJA, all non-public coal-fired energy generating units (EGUs) and large greenhouse gas (GHG) Emitting Units (those over 25 MW) must reduce CO_2 and copollutant emissions to zero by January 1, 2030.

All public coal-fired EGUs and Large GHG Emitting Units must reduce CO_2 and copollutant emissions to zero by December 31, 2045. Such units must also reduce CO_2 emissions by 45% by January 1, 2035. If this reduction is not achieved, the plant must retire one or more units or otherwise reduce emissions by 45% from existing emissions by June 30, 2038.

The law also sets detailed decarbonization requirements for non-public gas-fired EGUs and Large GHG Emitting Units to reduce CO_2 and co-pollutants to zero (including through use of 100% green hydrogen) according to the following schedule: (1) by January 1st, 2030 for all units with specified NOx and SO_2 emissions rates within 3 miles of an EJC; (2) by January 1st, 2040 for all units with specified NOx and SO_2 emission rates that are not within 3 miles of an EJC (the units must also reduce CO_2 by 50% by January 1st, 2035); (3) by January 1st, 2035 for all units built prior to the effective date of the Act with values below the specified NOx and SO_2 emission rates and within 3 miles of an EJC (the units must also reduce CO_2 by 50% by January 1st, 2030); (4) by January 1st, 2040 for all remaining units with heat rates greater than 7000 BTU/kWhs (5) by January 1st, 2045 for all remaining units. No non-public gas-fired EGU or Large GHG Emitting unit may increase emissions over current emissions.

All public gas-fired EGUs and large GHG Emitting Units must reduce CO_2 and co-pollutant emissions to zero by January 1st, 2045, and all combined heat and power (CHP) must meet the same 100% reduction requirement by that date. CEJA allows limited exceptions where emissions are necessary to maintain power grid supply and reliability or if a large GHG Emitting plant (that is not an EGU) is necessary for emergency backup. Until the applicable reduction deadlines are reached, affected units must comply with several operational requirements: (1) if a unit that is part of an RTO plans to retire, it must submit timely retirement documents to the RTO; (2) if a unit receives a must-run it can run but must cooperate in remedying conditions necessitating the must-run requirement and must reduce its emissions to zero as soon as possible; and (3) units not part of an RTO can run as emergency units if approved by the ICC.

To support transparency and accountability, CEJA requires the Illinois Environmental Protection Agency (EPA) to publish annual emissions reports by June 30 of each year, beginning in 2025, documenting progress toward the mandated reductions. Sec. 1-128 of CEJA additionally requires that by January 1st, 2028, a Nonprofit Electric Generation Task Force shall be established to assess carbon reduction targets in CEJA. The “task force shall be established to assess the technological, economic and regulatory feasibility as well as legislative support mechanism necessary to achieve the carbon emissions reduction targets” set forth in CEJA. The task force may hire an auditor to audit Prairie State and identify ways to allocate support to joint indirect owners.

D.8. Coal to Solar REC Program

CEJA required the procurement of RECs from renewable resources or energy storage facilities at or adjacent to the sites that as of January 2016 were coal fired power plants. The program is funded from the Coal to Solar and Energy Storage Initiative Charge assessed by Ameren and ComEd, which is not limited by RPS budget restraints. The charge is assessed per kwh and is reconciled annually.

To be eligible for the program: (1) A facility must have burned coal on January 1st, 2016 and had capacity of 150 MW or more; (2) the applicant must not be a municipal or cooperative; (3a) if participating in the first procurement event, the applicant agrees to deploy at or adjacent to the coal plant a new renewable facility between 20 and 100 MW and an energy storage facility between 2 and 10 MW; (3b) if participating in the second procurement event, the applicant agrees to deploy at or adjacent to the coal plant a new renewable facility between 5 and 20 MW and an energy storage facility of at least 0.5 MW; (4) the applicant must agree to use a qualified installer; (5) employees must have the appropriate training to run the facility; (6) the applicant and its contractors will pay prevailing wages for construction of the facilities; (7) the applicant commits to having a project labor agreement containing diversity provisions; (8) the applicant will provide RECs at $30 per REC for 20 years unless the applicant is connected to PJM and has capacity of at least 1,200 MW as of January 1st, 2021 and then the contract shall be for 15 years; and (9) the application is certified by an officer of it and its parent.

The IPA held two procurement events for the Coal to Solar REC Program. The first coal-to-solar procurement event for RECs in spring 2022, and the results were approved by the Illinois Commerce Commission on April 29, 2022. A total of six solar projects, representing approximately 230 MW (MW) of solar along with 13.5 MW of storage, at the sites of coal facilities owned by Vistra Corp. were selected. Subsequently, the three smallest projects were cancelled. There were no participants in the second procurement event.

D.9. Coal to Solar Storage Program

DCEO must use up to $280,500,000 for grants for energy storage at five locations in the MISO region of Illinois. To be eligible, a facility: (1) must have had a capacity of at least 150 MW; (2) must have burned coal; (3) if retired, must have retired after 1/1/2016; (4) must not have been selected to provide coal to solar RECs at the site; (5) must be formerly owned by a public utility; (6) must not be owned by a municipal utility or cooperative utility; (7) must have storage capacity of at least 37 MW; (8) must be in operation by 6/1/2024 or 6/1/2025, subject to adjustment for delays; (9) must be constructed by qualified entities; (10) must be operated by qualified personnel; (11) must pay prevailing wage; and (12) must have a project labor agreement addressing diversity. Grants must be paid out equally over 10 years. Grants will be for $110,000 per MW with yearly totals not to exceed $28,050,000.

DCEO provided grants to energy storage systems at five closed or closing coal plant sites with a capacity of 255 MW. To date, none of the projects have signed contracts or proceeded to deploy storage under the program.

D.10. Net Metering Changes in CEJA

CEJA changed the definition pertaining to net metering customer eligibility (i.e. expanding eligibility to include those customers that host systems) and clarified that third-party owned systems are eligible for net metering. The updates enacted through CEJA also: (1) removed the 2 MW system size limitation, (2) limits net metering aggregated projects to 5 MW, (3) allows installed systems to offset expected future electrical requirements (i.e. providing opportunities to incorporate capacity for future electric vehicles and/or fuel switching for non-electric heating customers), (4) allows for the co-location of energy storage systems with DG, (5) removes reference to electricity supplied to the customer's premises and instead refers to electricity supplied to the customer, and (6) allows for time-of-use customers to participate in net metering.

Customers that registered for net metering before January 1, 2025, were eligible for full net metering indefinitely. Illinois electric utilities Ameren, ComEd, MidAmerican and Mt. Carmel are required to ensure credits are given for the life of the system. After January 1, 2025, net meting customers can choose kWh or monetary credits as a means of compensation for excess generation supplied to the grid. Net metering credits are specified in statute to include supply, capacity, transmission, and Purchased Electricity Adjustment (PEA) amounts and, where transmission or capacity is not charged on a per kWh basis, the utility will provide an estimate per kWh credit for such charges. Further, net metering credits can be carried over indefinitely and this allows budget billing customers to participate in net metering and receive monthly credits.

Concerning the provision of net metering credits to customers served by ARES, through CEJA, Ameren and ComEd are instructed to provide net metering credits to the customer, and if a customer is served by an ARES, the utility is required to derive the net metering credit using the price to compare. In the event that production from the facility does not offset the utility cost, the utility is permitted to recover the difference through its multi-year rate plan.

For smaller utilities, the ARES are instructed to provide the net metering credits to customers. Ameren and ComEd are also required to enter into agreements, if requested by the owner or operator of the net metering-applicable project, to assess subscription fees on the bill if the fee is a fixed percentage of bill credit value. The utility is permitted to assess a fee for this service, however, the fee may not exceed 2% of the bill credit value.

D.11. Distributed Generation Rebates

CEJA provided that eligible systems may be hosted by customers and may be third-party owned. Customers must have a smart inverter to get a DG rebate. A smart inverter is defined to be a device that meets IEEE 1547-2018 equipment standards. Until those standards are available, devices can meet UL 1741 SA standards. Systems can be up to 5 MW (rather than 2 MW) and systems need be on the customer's side of the meter (rather than on the customer's premises). CEJA also removes reference to systems being in the utility's service territory (but requires systems to be interconnected to the utility's distribution facilities).

The legislation specified that Ameren and ComEd's tariffs must include a base rebate to compensate for system-wide grid service and, after a Commission proceeding, additional payments for additive services. The tariff must state that the inverter shall provide autonomous response to grid conditions through its default settings (as approved by the ICC). The settings cannot change after execution of the interconnection agreement, except upon mutual agreement.

CEJA additionally defines the DG rebate such that all customers get $250 per kW of installed system capacity if they are not eligible for full net metering. Storage also gets a rebate at $250 per kW. Storage participating before the threshold date (January 1, 2025) must participate in peak reduction and flexibility programs. After the threshold date, the rebate will equal the base rate plus additional compensation (with the base rate no lower than $250 per kW).

Those eligible for full net metering will receive $300 per kW if they opt for the rebate instead of full net metering and can also get $300 per kW for storage (even if they do not apply for a DG rebate). After the threshold date, the rebate will equal the base rate plus additional compensation (with the base rate no lower than $300 per kW).

Rebates must be issued no later than 60 days after energization. CEJA allows the utility to defer a portion of its costs as regulatory assets based upon whether projects (1) deferred distribution costs, (2) provided environmental benefits, (3) provided reliability and resilience improvements, (4) are consistent with the utility's grid plan, (5) advance equity, and other factors the ICC deems appropriate. The regulatory asset must be amortized over 15 years, and the utility shall get its weighted average cost of capital return on the asset using actual debt costs and an equity cost of 5.8% plus the 30-year treasury yield. The utility must recover costs volumetrically through its automatic adjustment clause tariff that shall have an annual reconciliation.

CEJA directed the ICC to investigate and establish the value of, and compensation for, distributed energy resources. The Commission initiated an investigation on this subject in June 2023, conducting two different series of workshops in 2023 and 2024 with the assistance of an independent facilitator and a consulting firm. Following the conclusion of the workshops, the consultant retained by the Commission, Energy and Environmental Economics, Inc., ("E3"), produced a final report.

The statute directs the Commission to establish an annual process and formula for the compensation of distributed generation and energy storage systems, and an initial set of inputs for that formula; establish base rebates that compensate distributed generation, community renewable generation projects and energy storage systems for the system-wide grid services they provide; direct utilities to update the formula annually with inputs derived from their integrated grid plans developed under to Section 16-105.17 of the Act; determine whether distributed energy resources can provide any additive services and the terms and conditions for those services; ensure that compensation for distributed energy resources, including base rebates and payments for additive services, reflects all reasonably known and measurable values of the distributed generation over its expected useful life; consider the electric utility's integrated grid plan developed under Section 16-105.17 of the Act to help identify the value of distributed energy resources for calculating the compensation; and determine additional compensation for distributed energy resources that create savings and value on the distribution system by being co-located or in close proximity to certain components of electric vehicle charging infrastructure, as outlined in the utility integrated grid planning process under Section 16-105.17 of the Act.

Following a Staff Report, the Commission initiated a proceeding on May 15, 2025 to establish rates for compensation of distributed generation, community renewable generation, and energy storage systems. This proceeding is currently underway in Docket No. 25-0495.

D.12. Storage

Within 30 days of the effective date of the Act, ComEd was required to file a tariff that provides for compensation for energy storage paired with DG. It required that customers receive a rebate for previously incurred and future costs of installing interconnection facilities to enable participation in PJM's frequency regulation market, and all wholesale demand charges incurred after the effective date of the Act. The Commission suspended and investigated ComEd's proposed tariffs in Docket No. 21-0812, with a final Order issued in February 2022 and an Order on Rehearing entered in August 2022. ComEd filed compliant tariffs on August 22, 2022.

Appendix E. Literature Review and Parallel Work Evaluating Resource Adequacy

Resource Adequacy planning has undergone rapid and significant transformation in recent years, reflecting the electricity grid's changing needs. The rise of large, continuous loads, such as data centers, has introduced new challenges for capacity forecasting, reliability modeling, and system flexibility requirements. Additionally, meeting reliability requirements now faces significant challenges and opportunities from emerging resources and new operational dynamics. A comprehensive approach to resource adequacy must now consider the roles and characteristics of electricity storage (both utility-scale and distributed), as well as distributed generation resources that are not under utility control.

The increasing penetration of renewable generation, especially solar, has introduced new operational challenges. For example, solar tends to reduce net load during the day but can lead to steep evening ramp requirements as their output declines and electricity demand remains high or increases. This shift exacerbates the need for flexible generation resources capable of responding quickly to abrupt changes in net demand. The ability to meet these scheduling needs is now recognized as a vital ancillary service in electricity markets, ensuring reliability and supporting the integration of variable renewable resources.

Numerous public studies and reports have examined reliability at the national, regional, and state levels, many of which are directly relevant to Illinois. This subsection highlights a curated set of these documents, representing the work of organizations that routinely analyze and support energy reliability for Illinois and the surrounding region. While not exhaustive, this literature review provides a representative technical cross-section of resource adequacy approaches, offering insight into the methodologies, metrics, and findings that have informed this plan.

This Appendix summarizes key reports relevant to Illinois' Resource Adequacy Plan by examining how different jurisdictions are adapting resource adequacy methods to account for growing electrification, renewable integration, generator retirements, and evolving market designs. This review also compares modeling approaches such as probabilistic simulations and scenario analysis that account for different climate and load scenarios.

This Appendix intends to situate Illinois' resource adequacy study within the context of what other regions are doing and what is generally agreed upon as best practice. This chapter concludes with a comparison of all the report's key findings, approach or recommendations with a focus on implications for the state of Illinois.

The reports reviewed as part of this literature review are summarized in Table E-1 below.

Table E-1: Reviewed Literature

Author	Scope	Title	Publish Date
NERC	National	2024 Long-Term Reliability Assessment	Dec, 2024
FERC	National	State of the Markets Report | 2024	March, 2025
DOE	National	DOE Resource Adequacy Report	July, 2025
ESIG	National	Wide-Area Resource Adequacy Assessments: Probabilistic Planning for Interconnected Grids	October, 2025
EPRI	National	Metrics and Criteria: Insights from Case Studies and Recommendations and Considerations for Future Practice	July, 2024
MISO	Regional	MISO's Response to The Reliability Imperative	February, 2024
PJM	Regional	PJM Manual 20A: Resource Adequacy Analysis	May, 2025

E.1. NERC 2024 Long-Term Reliability Assessment[26]

The North American Electric Reliability Corporation (NERC) is a not-for-profit organization tasked with the evaluation of North America's bulk power system as well as the development of national-scale recommendations for resource adequacy. NERC's 2024 Long-Term Reliability Assessment evaluates the adequacy and reliability of the bulk power system over a 10-year planning horizon across North America. The report examines regional and national trends, identifies emerging risks, and highlights areas that may face resource shortfalls under extreme conditions. It considers factors such as projected electricity demand growth, resource retirements and additions, integration of variable energy resources, and evolving market structures.

NERC utilizes a probabilistic modeling framework that incorporates load forecasts, generator performance data, and system topology (i.e., electricity system networks, interconnections, and pathways) to assess resource adequacy. The analysis involves scenario-based simulations to evaluate the likelihood of meeting peak demand under various conditions, including extreme weather events and fuel supply disruptions. The methodology also accounts for regional differences in resource mix, transmission constraints, and the increasing role of renewable energy and energy storage.

In Table E-2 below, several of the model assumptions used within NERC's resource adequacy modelling are listed.

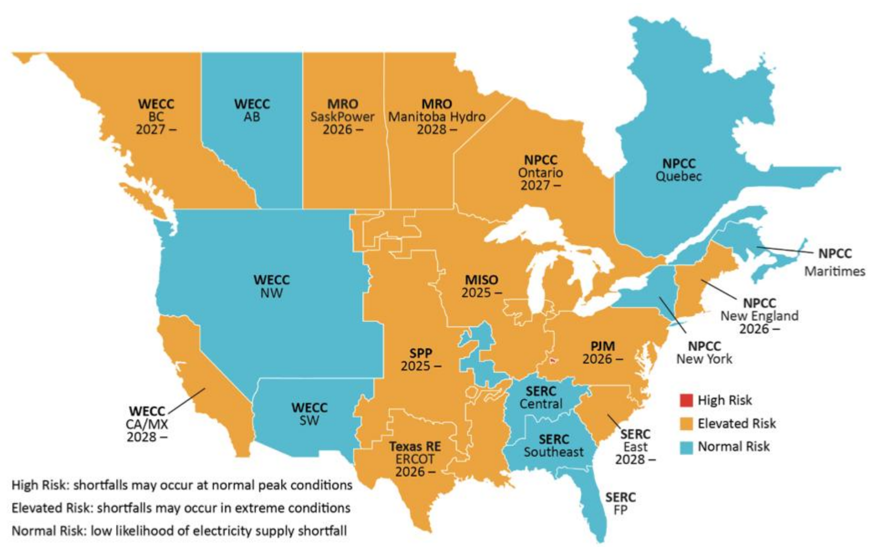
[26] NERC "2024 Long-Term Reliability Assessment" (December 2024): https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

Table E-2: NERC Model Assumptions

Model Area	Model Assumption
Supply/Demand Input	Supply and demand projections are based on industry forecasts submitted and validated in July 2024.
Peak Demand Defined	Peak demand for NERC resource adequacy is based on average peak weather conditions and assumed forecast economic activity at the time of submittal.
Summer Peak Change	The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 GW this LTRA up from over 80 GW in the 2023 LTRA.
Winter Peak Change	The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the 2023 LTRA.
Metrics for Probabilistic Evaluation Used	Probabilistic Assessment: This evaluation is part of the biennial resource adequacy assessment. Loss-of-Load Hours (LOLH): Expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours.
Expected Unserved Energy (EUE) Risk Categories	Normal Risk: Negligible amounts of LOLH and EUE. Periods of Risk: LOLH < 2 Hours and EUE < 0.002% of total annual net energy. Significant Risk: LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Illinois is served by PJM and MISO, two regions identified as having increased capacity risk during severe weather and peak demand periods, especially as traditional thermal generation retires, and renewable energy penetration rises. See Figure E-1 below for a national picture of shortfall risk through 2029:

Figure E-1: Risk Area Summary 2025-2029 (NERC, 2025)



- Delays in resource additions, accelerated retirements of coal and nuclear plants, and increased electrification are placing additional pressure on grid adequacy in Illinois.
- Recent winter events have exposed vulnerabilities in generator performance and fuel supply chains, making winter reliability a heightened concern for Illinois.
- Investment in new resources, including energy storage, flexible generation, and transmission upgrades, is essential for maintaining reliable service in response to Illinois' evolving electricity needs. Robust planning and operational models that accurately represent resource contributions and inverter-based resource performance under stress are critical.
- Demand-side management, resource flexibility, and scenario planning for extreme events are vital for Illinois due to its exposure to both regional and local reliability risks.

E.2. FERC State of the Markets Report | 2024[27]

The State of the Markets Report provides a comprehensive overview of market conditions, reliability concerns, and emerging trends across the nation's electricity markets. For Illinois, the report highlights evolving risks related to generation retirements and new resource integration and evaluates the impact of demand growth driven by increased electrification and data center expansion. The report aims to inform stakeholders, including policymakers and market participants, about potential reliability challenges and market dynamics that could affect service.

FERC outlines the market changes withing Regional Transmission Operators (RTOs) and Independent System Operators (ISOs) in addressing resource adequacy under changing grid constraints. Method changes enlisted by RTOs and ISOs as summarized in the report include:

- NYISO made changes to its methodology for procuring capacity to include capacity accreditation (i.e., determining how much a specific electricity resource contributes to grid reliability) for the first time in the 2024/2025 capacity auction.

[27] FERC "State of the Markets Report | 2024" (March 20, 2025): https://www.ferc.gov/media/state-markets-report-2024.

- Southern Power Pool (SPP) added a Winter Season Resource Adequacy Requirement for load responsible entities provides an incentive for load responsible entities to proactively procure and maintain sufficient capacity for the winter season.
- MISO moved to a sloped demand curve consistent with PJM, NYISO, and ISO-NE capacity markets to reduce volatility in auction clearing prices and send more accurate investment signals.
- MISO also shifted its planning reserve margin from 7.4% in the 2023/2024 planning year to 9.0% in the 2024/2025 planning year, which resulted in increased amounts of cleared capacity

The report identifies extreme weather events, a changing resource mix, and shifts in load profiles as key challenges to resource adequacy. FERC emphasizes the importance of investing in flexible generation, energy storage, and transmission upgrades to maintain reliable service. The findings highlight shifts towards greater reserve margins and adjustments to how peak demand is measured. These market level changes are consistent with changes Illinois has undergone to meet reliability standards.

E.3. U.S. DOE Resource Adequacy Report[28]

The Department of Energy (DOE) Report provides a comprehensive assessment of resource adequacy with particular attention to reliability risks posed by the evolving generation mix, increasing electrification, and climate-related stressors. The report evaluates national and regional trends, focusing on the adequacy of existing and planned resources to reliably meet projected electricity demand over the coming decade. It is intended to inform policymakers, regulators, and market participants by identifying areas of potential shortfall and recommending strategies to enhance system resilience. Despite the DOE being tasked via Executive Order (EO) 14262, Strengthening the U.S. Grid Reliability and Security, to establish a uniform methodology for identifying at risk regions and guide federal reliability interventions, including emergency action under Section 202(c) of the Federal Power Act, the DOE has no formal role in enforcing resource adequacy methodologies or oversight.

The DOE employs a multi-faceted analytical framework that combines probabilistic modeling, scenario analysis, and detailed system simulations. This approach integrates load forecasts, generator performance metrics, fuel supply considerations, and transmission system constraints. The analysis examines a range of scenarios, including

[28] U.S. Department of Energy "Resource Adequacy Report Evaluating the Reliability and Security of the United States Electric Grid" (July 7, 2025): https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

extreme weather events, rapid resource retirements, and accelerated deployment of renewable technologies. Sensitivity analyses are conducted to evaluate the impacts of policy changes, market dynamics, and technological advancements on resource adequacy outcomes.

In Table E-3 below, several of the model assumptions used within DOE's resource adequacy report modelling are listed:

Table E-3: DOE Model Assumptions

Model Area	Model Assumption
Demand for Electricity – Assumed Load Growth	The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI) and Lawrence Berkeley National Laboratory (LBNL).
Magnitude of Outages – Normalized Unserved Energy (NUSE)	Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh). This is employed to allow comparison of these metrics across different system sizes, demand levels, and periods of analysis.
Reliability Standard	Recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages. The methodology uses the following to define reliability standard: ▪ Duration of Outages: No more than 2.4 hours of lost load in an individual year. ▪ Magnitude of Outages: No more than an NUSE of 0.002%.

The DOE Report highlights the importance of timely resource procurement, investment in transmission infrastructure, and the development of flexible resources such as energy storage and demand response. The study underscores the need for coordinated planning and policy alignment within and across states to ensure long-term reliability, particularly in states like Illinois that are undergoing rapid changes in their resource portfolios.

The report cites that to restore reliability within PJM, it would "require 10,500 MW of additional perfect (i.e., 100% availability, instantaneous response, and constant full power) capacity by 2030."

Within these portfolio mixes and modeled against future load the DOE compiled the following central takeaways:

- The current trajectory of increased generation retirements without dependable replacements threatens both grid reliability and the nation's ability to support AI-driven load growth, putting affordable energy access at risk.
- Significant and rapid increases in electricity demand driven by AI cannot be accommodated using traditional approaches to grid expansion and management; transformative changes are necessary to keep pace with this evolving landscape.
- Simultaneous retirements of firm power sources and heightened load growth could raise the risk of power outages by as much as 100 times by 2030, with 104 GW of firm capacity scheduled for retirement nationally and not being replaced on a one-to-one basis leading to greater vulnerability during periods of low wind and solar output.
- Although 209 GW of new generation is planned nationally by 2030, only a small fraction (22 GW) will come from firm baseload sources, leaving reliability at risk and modeling shows outage risk increases even if no further retirements occur.
- Outdated resource adequacy assessment tools are insufficient for modern grid challenges; new methodologies must consider outage frequency, magnitude, and duration, analyze beyond peak demand periods, and use integrated modeling to accurately capture the complexities of a more interconnected and renewable-dependent power system.

E.4. ESIG Wide-Area Resource Adequacy Assessments: Probabilistic Planning for Interconnected Grids[29]

This report is the latest installment in The Energy Systems Integration Group (ESIG) Redefining Resource Adequacy Report Series, a four-part series that brings together subject matter experts nationwide to contribute to best practices for resource adequacy. ESIG is not a governing body but convenes experts to establish methodologies on capacity accreditation and resource adequacy. The ESIG Redefining Resource Adequacy Task Force preceding publications are summarized below:

[29] Energy Systems Integration Group, "Wide-Area Resource Adequacy Assessments: Probabilistic Planning for Interconnected Grids," A report by the Redefining Resource Adequacy Task Force (2025): https://www.esig.energy/wide-area-resource-adequacy-assessments/.

New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements.[30] This 2024 report examines how resource adequacy criteria should be updated to reflect the evolving demands of power systems during the energy transition, especially with increased renewable energy and changing load profiles. Through simulation studies and stakeholder engagement, it evaluates the effectiveness of new metrics, such as loss of load probability and expected unserved energy, in assessing system reliability. The study recommends modernizing reliability requirements with metrics that account for outage frequency, magnitude, and duration, urging policymakers to adapt standards for a decarbonizing grid.

Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation.[31] This 2023 report explores new design principles for capacity accreditation that recognize the reliability contributions of a diverse range of resources, especially renewables and storage. Using case studies and quantitative modeling, it finds that traditional methods often misrepresent resource value and recommends more flexible approaches that accurately reflect performance during critical periods. Incorporating stakeholder feedback, the report aims to promote efficient investments and operational decisions in modern power systems.

Redefining Resource Adequacy for Modern Power Systems.[32] The 2021 report highlights the need to update resource adequacy concepts for today's renewable-rich grids, drawing on literature, modeling, and expert insights. It identifies emerging challenges from new technologies and shifting demand, emphasizing the importance of advanced analytical tools. The authors recommend integrated frameworks that evaluate both supply- and demand-side resources and encourage coordinated planning across regions and sectors to maintain reliable electricity.

This 2025 report focuses on wide-area resource adequacy assessment to meet demand across an interconnection or continent which spans multiple regions and planning authorities and can assess both near-term risks and long-term needs under shared assumptions about load, weather, outages, and transmission. The type of assessment laid out in the report is meant to capture the benefits of interregional coordination as opposed to a siloed approach.

[30] Energy Systems Integration Group, "New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements" (2024): https://www.esig.energy/new-resource-adequacy-criteria.
[31] Energy Systems Integration Group, "Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation," A Report of the Redefining Resource Adequacy Task Force (2023): https://www.esig.energy/new-design-principles-for-capacity-accreditation.
[32] Energy Systems Integration Group, "Redefining Resource Adequacy for Modern Power Systems," A Report of the Redefining Resource Adequacy Task Force (2021): https://www.esig.energy/reports-briefs.

The Wide-Area Resource Adequacy Assessment report employs probabilistic modeling to capture the complexities of interconnected grid operations. While local and regional analyses offer valuable perspectives, they often do not fully capture the complex interdependencies and risks that span multiple jurisdictions. See Figure E-2 below for an illustrative example of the planning barriers encountered in various scales of resource adequacy assessments.

Figure E-2: Representation of Local, Regional, and Wide-Are Resource Adequacy Assessments

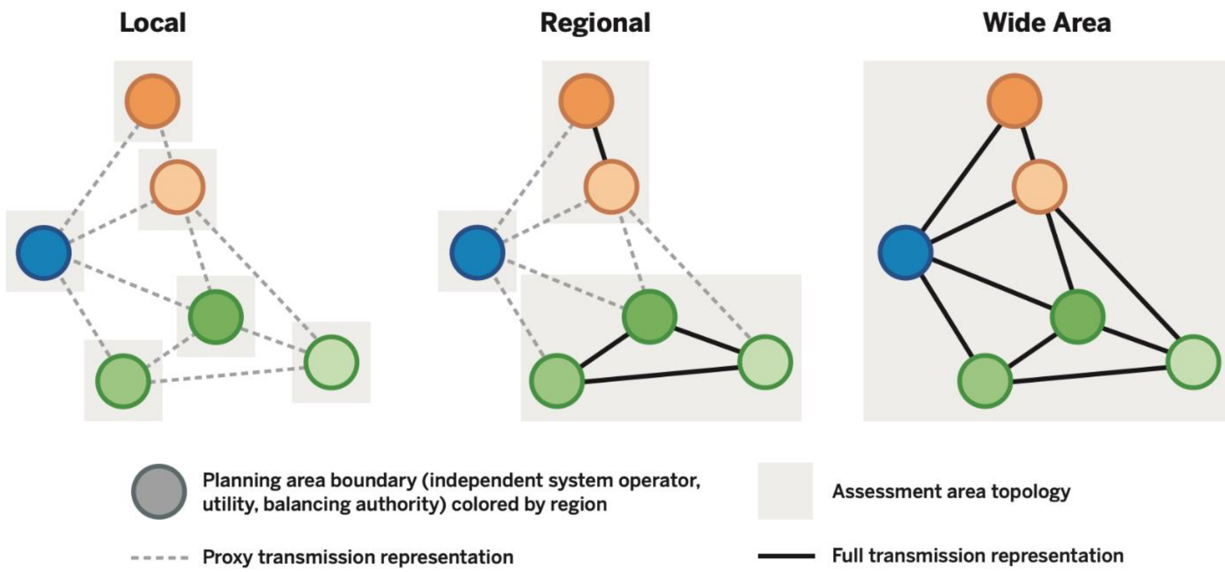


Illustration of local (left), regional (middle), and wide-area (right) resource adequacy assessments. Local assessments evaluate each system in isolation with only simplified or proxy representations of neighboring support. Regional assessments incorporate a group of local areas, allowing for coordinated analysis of shared resources and transmission. Wide-area assessments evaluate the entire interconnected system, enabling a holistic view of geographical diversity, extreme weather impacts, and interregional transfer capabilities.

Source: Energy Systems Integration Group.

Wide-area assessments equip planners with broader system visibility and facilitate coordination, resulting in more robust reliability strategies. Some of the benefits as outlined in the report are listed below:

Interregional transmission planning: Wide-area assessments identify limitations in power transfers between regions and highlight opportunities for new interregional transmission projects. These assessments are crucial for enhancing reliability and economic benefits through geographic diversity and may serve as alternatives to solely relying on local capacity resources.

Evaluating external assistance: By assessing regional capacity needs both with and without imports from neighboring systems, planners gain a clearer understanding of how much reliability depends on external support. This helps establish reasonable expectations for assistance without excessive reliance on neighboring regions.

Monitoring resource changes in adjacent systems: Shifts in resource mixes and load profiles in neighboring areas can significantly influence local adequacy. Wide-area assessments enable planners to anticipate these changes and coordinate with adjacent regions regarding generator retirements, resource additions, load growth, and transmission updates.

Scenario consistency: Wide-area analyses provide shared scenarios and assumptions that can be integrated into local and regional planning, promoting alignment among planning entities. This consistency increases stakeholder confidence, improves decision-making, and streamlines studies such as interregional transmission evaluations.

Assessing policy impacts: Local and regional policy decisions, including emissions targets and renewable standards, affect resource adequacy across boundaries. Wide-area assessments measure the effects of such policies and support coordinated planning to maintain adequacy.

Addressing extreme weather risks: These assessments help identify strategies for managing risks from large-scale weather events, such as polar vortexes or heat domes, and emphasize the importance of interregional cooperation during times of stress.

Methodological and metric alignment: Using common input data, modeling approaches, and reporting metrics enhances transparency and enables comparability across regions. While local criteria may persist, wide-area reporting can summarize important metrics uniformly throughout the system.

The goal of the report is not to recommend a replacement assessment for more focused resource adequacy studies but to rather complement those more regionally specific analyses with Wide-Area Assessments. Inclusion of multiple ISOs, utilities, and other relevant entities can strengthen coordination and encourage the use of consistent alignment of metrics and methods across regions.

E.5. EPRI Metrics and Criteria: Insights from Case Studies and Recommendations and Considerations for Future Practice [33]

This report, published by the Electric Power Research Institute (EPRI), is part of its broader Resource Adequacy for a Decarbonized Future initiative, which develops updated

[33] EPRI, "Metrics and Criteria: Insights from Case Studies and Recommendations and Considerations for Future Practice" (2024): https://www.epri.com/research/products/000000003002030638.

methodologies for evaluating resource adequacy in the context of growing demand, evolving resource portfolios, and increasing exposure to extreme weather. This specific report focuses on recommendations for selecting resource adequacy metrics and setting minimum adequacy criteria collected through the facilitation of six different regional case studies.

EPRI used a set of evaluation metrics in their methodology for six geographically diverse case studies. The case studies which cover Texas, SPP, MISO, the Western U.S., the Northeastern U.S. and Canada, and a region in the Southeastern U.S. looked at varying levels of renewables and storage penetration to better understand system risks. The metrics developed through these case studies are found in Table E-4 below.

Table E-4: EPRI Key Resource Adequacy Risk Metrics (EPRI, Page 12)

Metric	Abbreviation	Units	Definition
Loss-of-load expectation	LOLE	days/yr	Average event-days per year across all the random replications simulated
Loss-of-load hours	LOLH	Hours/yr	Average event-hours per year across all the random replications simulated
Expected unserved energy	EUE	MWh/yr	Average load not served per year due to shortfall events across all the random replications simulated
Normalized expected unserved energy	NEUE	% or ppm	Average load not served per year due to shortfall events across all random replications simulated, calculated as a percentage of system load
Annual loss of load probability	Annual LOLP	% of years	Probability of having a single loss of load event in any given year
Loss-of-load events	LOLEv	Contiguous events/yr	Average count of events per year across all the random replications simulated

This report aims to guide the resource adequacy process with transitive metrics to be applied towards unique power systems. The core conclusions were outlined as metric and criteria considerations. EPRI recommends the following metric considerations:

Reduce reliance on a single metric—examine several metrics such as LOLE, EUE, LOLH to get a better picture of anticipated risk exposure.

Consider top percentiles and outlier events – do not just look at the expected outcome of a given metric, but also its distribution across the wide range of simulations typically carried out in an adequacy assessment.

Better leverage existing metrics—examine issues such as seasonality, time of day and weather year and their impacts on results.

Describe characteristics of involuntary load shedding events examine outage duration, magnitude and timing to understand impact on customers from outages.

When setting minimum criteria for reliability, EPRI recommends the following criteria considerations:

Adequacy exists on a spectrum and should not be a binary choice – if using several metrics, identify where adequacy of the system lies on a gradient and determine whether a system is adequate across multiple metrics.

Criteria setting should not be conducted independent of economic assessment – examine the cost implications, whether directly through value of lost load, or at least considering the fact that meeting more stringent criteria will have a cost that may be non-linear with reliability.

Reliability criteria should evolve with customer expectations – as the energy system electrifies and nature of risk shifts, a means to update criteria regularly may be required.

There is no universal criterion for an adequate system - additional considerations of reliability should also be considered, not just supply adequacy.

E.6. MISO's Response to the Reliability Imperative[34]

MISO's response to the Reliability Imperative report is the fourth iteration of reports since 2020 addressing the reliability imperative which is a term used by MISO to summarize the critical and shared responsibility that MISO, its members and states have to address the urgent and complex challenges to electric reliability in the region. This fourth iteration of the report outlines how MISO suggests framing solutions to address the significant challenges associated with a rapidly evolving resource mix influenced by decarbonization, increased renewable integration, extreme weather events, and shifting demand patterns. The report prioritizes adaptation in regional system planning, market design, operational practices, and stakeholder engagement in support of sustained grid reliability as the power system undergoes transformation. Beginning in 2022, MISO shifted from annual to seasonal resource adequacy assessments to better anticipate and address reliability risks that vary throughout the year, particularly as weather dependence grows and system predictability declines.

[34] MISO, "MISO's Response To The Reliability Imperative" (2024): https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216&utm.

MISO utilizes a comprehensive suite of planning and modeling tools to evaluate prospective scenarios and to stress test system adequacy under a wide range of conditions. These tools include forward-looking probabilistic models that incorporate increased penetration of variable energy resources, greater electrification, fuel supply risks, and the possibility of correlated extreme weather events. The Resource Adequacy Construct leverages the Planning Resource Auction (PRA) with requirements that are both seasonal and locational, moving beyond the traditional single annual assessment. The locational granularity is addressed through more frequent updates of the reserve zones. The PRA employs a Loss of Load Expectation (LOLE) standard, ensuring sufficient reserves and integrating seasonal derates and outage data. MISO's models simulate thousands of scenarios to estimate resource sufficiency, evaluate transmission constraints, and generate market signals that encourage new investment. Additionally, MISO collaborates with stakeholders to refine modeling practices, apply lessons learned from significant reliability events such as Winter Storm Uri, and integrate emerging technologies, including hybrid resources and demand response, into resource adequacy frameworks.

MISO's Reliability Imperative demonstrates that maintaining grid reliability in the context of rapid transformation requires advanced risk assessment tools, frequent and granular resource adequacy evaluations, and enhanced coordination between planning and operations. Traditional annual resource adequacy approaches are inadequate for a power system where reliability risks can change substantially by season, location, and resource type. Seasonal resource adequacy analysis provides a more precise understanding of system vulnerabilities, allowing for targeted mitigation strategies. MISO identifies increased system flexibility, improved visibility of distributed energy resources, expanded transmission infrastructure, and robust market mechanisms as critical needs for reliable resource development. Success under the Reliability Imperative will depend on collaboration among regulators, market participants, and neighboring regions as the pace of the energy transition accelerates.

E.7. PJM Manual 20A: Resource Adequacy Analysis[35]

PJM Manual 20A provides PJM Interconnection's methodology for ensuring resource adequacy across its system, covering the calculation of required generating capacity, resource accreditation, and import requirements at both RTO-wide and Locational Deliverability Area (LDA) levels. See Figure E-3 below for a map of the PJM LDAs:

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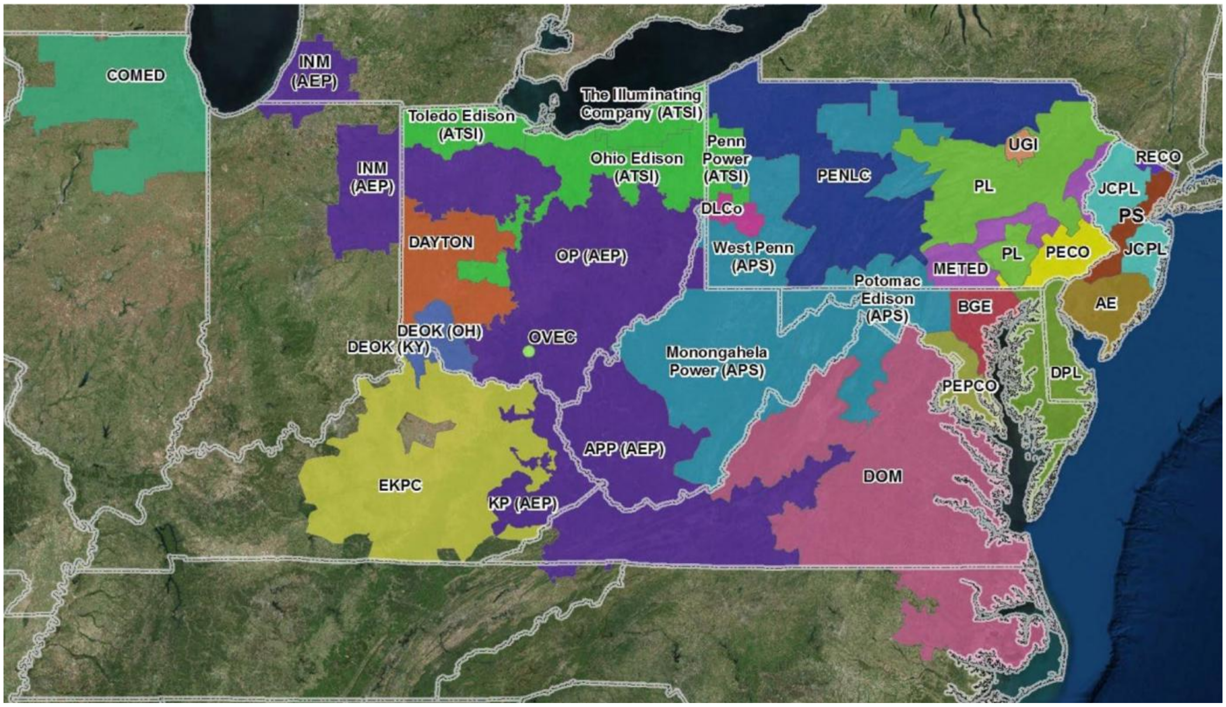
[35] PJM Resource Adequacy Planning, "PJM Manual 20A: Resource Adequacy Analysis" (May 21, 2025): https://www.pjm.com/-/media/DotCom/documents/manuals/m20a.ashx

Figure E-3: PJM Map



Source: PJM, "PJM Long-Term Load Forecast Report" (January 2025): https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf.

It informs capacity market offerings and planning for the 2025/2026 Delivery Year and beyond.

PJM conducts three primary studies: the Reserve Requirement Study (RRS) to determine RTO-wide reserve needs, the Effective Load Carrying Capability (ELCC) study to assess capacity accreditation for individual resources, and the Capacity Emergency Transfer Objective (CETO) study to calculate LDA import requirements. These studies use probabilistic modeling of load, generator availability, and system contingencies to calculate Loss-of-Load Expectation (LOLE), Expected Unserved Energy (EUE), and other reliability metrics. Outputs inform the Reliability Pricing Model (RPM) and are subject to stakeholder review and reporting processes.

PJM emphasizes probabilistic and locationally detailed resource adequacy assessment, accounting for seasonal variations, resource mix, and transmission constraints. Key findings include the critical role of flexible and accredited resources, the importance of inter- Locational Deliverability Area (LDA) transfers to maintain reliability, and the necessity of integrating resource performance into capacity market planning. The manual underscores that accurate accreditation, reserve calculation, and stakeholder engagement are central to maintaining reliable service under evolving grid conditions.

E.8. Resource Adequacy Literature Summary

Across the studies reviewed, there is broad convergence on several key themes related to resource adequacy. Most studies recognize the increasing complexity of maintaining grid reliability in the face of rapid decarbonization, greater renewable integration, and changing demand patterns. Illinois is characterized by the NERC report to be at an elevated risk for capacity shortfalls during extreme events through 2029. The FERC and DOE reports similarly outline Illinois' specific resource adequacy risk as elevated with general uncertainty related to generation retirements and an evolving resource mix. It is important to emphasize this is not unique to Illinois risk assessment. Both national and regional reports emphasize the need for advanced risk assessment tools, frequent and granular resource adequacy evaluations, and improved coordination among stakeholders. There is consensus that traditional annual resource adequacy approaches are insufficient, and that seasonal or more frequent assessments offer a clearer picture of system vulnerabilities. Enhanced system flexibility, expanded transmission infrastructure, and robust market mechanisms are also commonly identified as critical for supporting resource adequacy. The Illinois resource adequacy study involves many of the metrics, model assumptions, and methods that are outlined in the reports reviewed.

Appendix F. Power System Modeling Methodology

This appendix documents the key assumptions, data sources, and analytical methodologies used to support the Resource Adequacy Study. It is intended to provide details regarding how inputs were constructed and how modeling frameworks were applied across both the near-term and long-term resource adequacy analyses.

In addition to the information provided here, the Illinois Power Agency will publish underlying datasets and associated workpapers, where appropriate, to support independent review and replication of elements of the analysis. These materials will be made available on the Resource Adequacy Study webpage:

https://ipa.illinois.gov/electricity-procurement/resource-adequacy.html

The release of datasets and workpapers is scheduled for December 22, 2025.

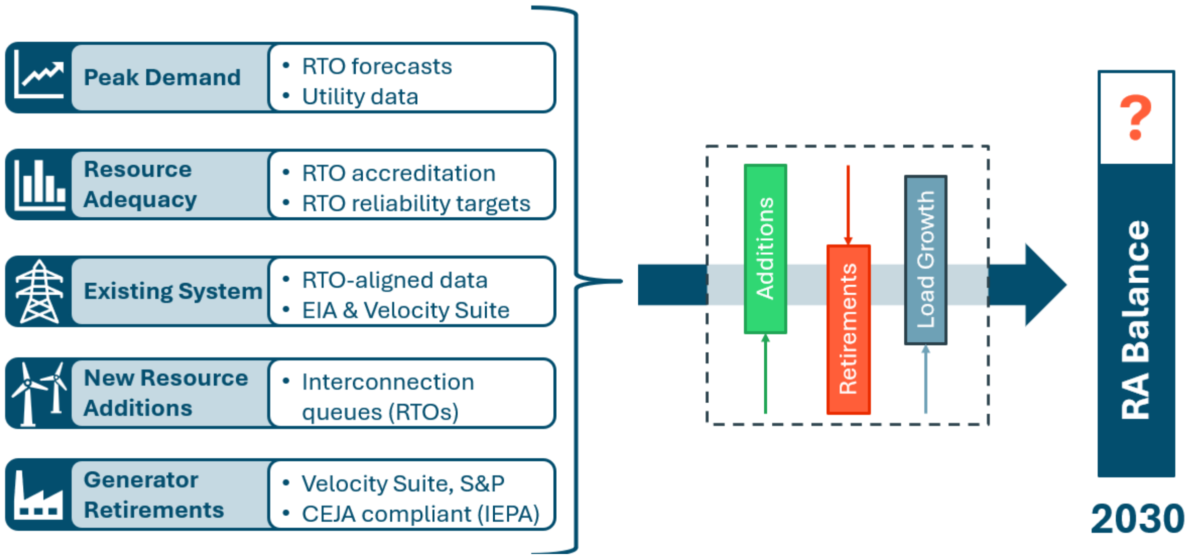
F.1. Analytical Framework and Methodology

F.1.1. Design Framework & Approach

The analysis consists of two major components: (1) an assessment of Illinois' resource adequacy situation over the next five years, and (2) a longer-term assessment of Illinois' ability to maintain resource adequacy while meeting both energy and emissions reduction goals over the next twenty years.

For the near-term analysis, the study uses a Resource Adequacy Balance model to assess supply and demand conditions through 2030. This model incorporates unit-level assumptions for generator retirements and new additions, recent load forecasts from utilities and RTOs, and accredited capacity contributions as defined by PJM and MISO. The model is used to quantify projected capacity balance in each Illinois utility zone, ComEd and MISO LRZ4, as well as RTO-wide in PJM and MISO. This analysis serves as the primary approach for evaluating the potential for a shortfall as defined by Section 9.15(o). The load and resource balance framework is depicted in Figure F-1 below.

Figure F-1: Load and Resource Balance Framework

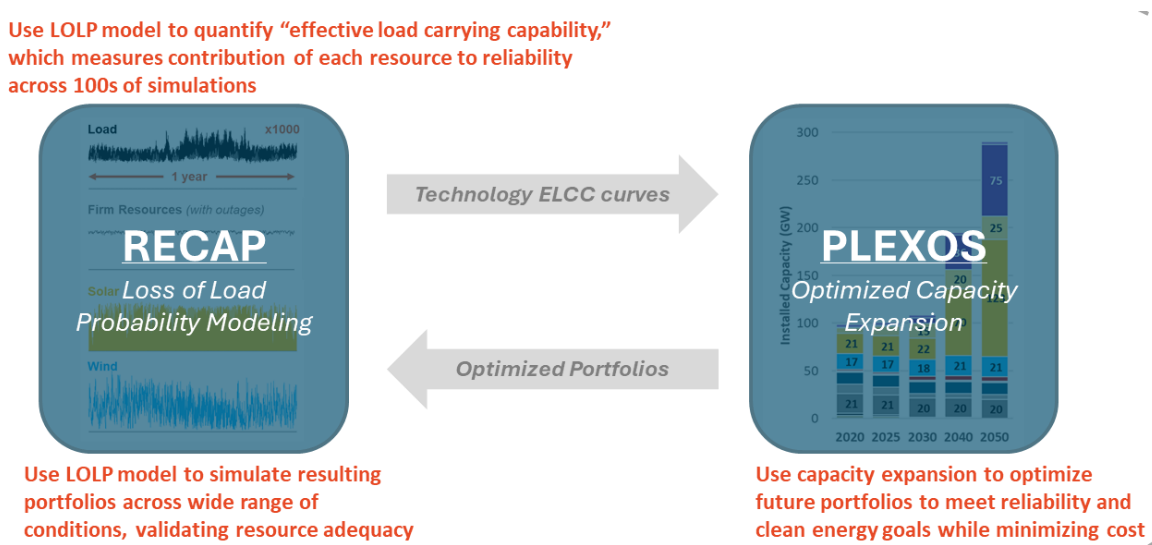


For the longer-term outlook, the study uses a probabilistic reliability model, E3's RECAP model, in conjunction with a capacity expansion model, Energy Exemplar's PLEXOS model. RECAP is used to simulate system reliability in 2030 and 2035 across a range of future scenarios. RECAP incorporates stochastic weather variability and resource outage profiles to assess system performance under various resource portfolios across a wide range of conditions. The results are expressed in terms of loss-of-load expectation (LOLE) and other standard reliability metrics. RECAP is also used to produce forecasted effective load carrying capabilities (ELCCs) of resources, aligned with the methodologies used by MISO and PJM, to assign accreditation values in the next step of the modeling framework.

PLEXOS is used to identify least-cost portfolios of resources that meet reliability and policy goals over time. The model optimizes new resource investments and dispatch decisions of a large portion of the Eastern Interconnection (inclusive of both RTOs) to ensure hourly demand is met across representative periods and the modeling horizon, subject to system constraints.

The modeling framework implemented for this study relies on the interplay between capacity expansion and resource adequacy models. Figure F-2 illustrates the interaction between these models. RECAP calculates Total Reliability Need (TRN) and Planning Reserve Margin (PRM) values that ensure sufficient effective capacity is built in each market, along with market- and technology-specific curves that relate the marginal Effective Load Carrying Capabilities of each resource type to its total penetration (expressed in MW) in the system. These curves are then used to constrain the PLEXOS model's resource selection to meet the TRN in each market and each projection year at the lowest total cost. Because these constraints can only approximate the complex system dynamics that feed into systemwide resource adequacy, we then use RECAP to stress-test the portfolios under thousands of simulated weather years based on historical conditions to confirm adequacy. Together, these models ensure portfolios are cost-optimal, reliable, and compliant with policy constraints. The same models and assumptions are also used in the Illinois 2025 Draft REAP, ensuring analytical consistency between the two studies which have complementary focus and objectives. This is also the same fundamental modeling framework used in most Integrated Resource Planning processes across North America, including those supported directly by E3.

Figure F-2: Electric System Modeling Approach with Resource Adequacy Considerations



This modeling framework enables a rigorous evaluation of how resource adequacy can be maintained over the long term, as system demand grows and the resource mix shifts. By simulating forward-looking portfolios under various scenarios and testing their ability to meet resource adequacy standards, the analysis provides insight into the types and quantities of resources that may be required to avoid resource adequacy shortfalls, particularly beyond what is already planned or in the interconnection queue. The modeling framework also highlights effective capacity and transmission needs that can inform future policy development, investment priorities, and engagement in regional planning processes. Its iterative structure allows for future updates as technology costs and availability evolve, new policies emerge, or system conditions change which ensures the state can remain well-equipped to meet both reliability and decarbonization goals.

F.1.2. Long-Term Outlook Scenario & Sensitivity Matrix

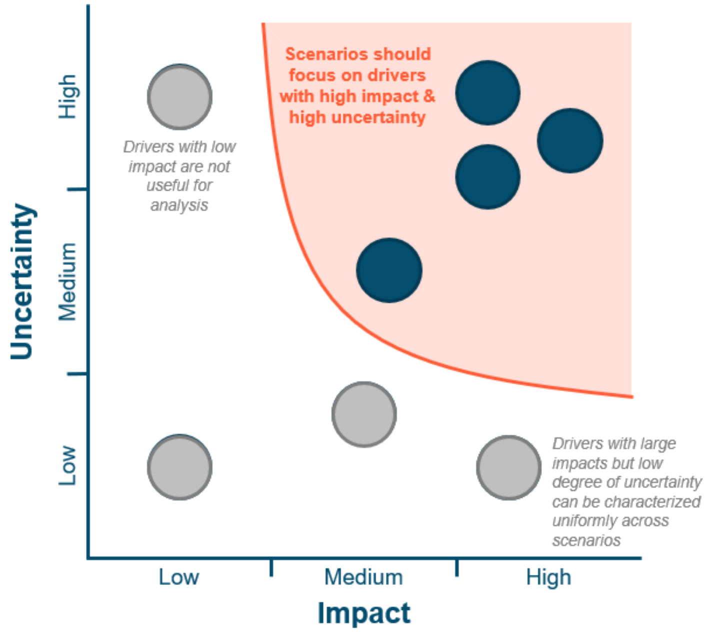
To ensure a comprehensive assessment of resource adequacy, the Agencies and E3 developed a set of scenarios and sensitivities based on the core risks identified. Key assumptions, such as generator retirements, interconnection queue timelines and feasibility, and transmission transfer capabilities, were informed through consultation with PJM, MISO, and Illinois utilities, and refined through two rounds of stakeholder input. The framework is designed to both comply with the statutory directive and to explore important uncertainties that may shape Illinois' reliability outcomes in the future.

The modeling tools and scenario framework provide a robust approach to identifying a range of plausible futures and clear findings regarding resource adequacy risks that the State should be prepared to respond to.

Evaluating resource adequacy requires understanding how system conditions may evolve under uncertainty. While the near-term load and resource balance focused on resource adequacy under known (yet variable) supply and demand trajectories, long-term outcomes are shaped by a wider band of uncertainty around policy implementation and achievement, fossil generation retirements, load growth, and technology advancement and costs. To capture a wide range of possible futures, this study uses a scenario framework to evaluate how these uncertainties impact system reliability and the types of resources needed to maintain resource adequacy over time.

Scenarios are designed to test high-impact, high-uncertainty drivers—those most likely to alter the capacity mix or challenge the system's ability to meet reliability standards, as illustrated in Figure F-3 below.

Figure F-3: Classification of Factors Informing Scenario Design by Impact and Certainty



In this study, four key scenario drivers were identified and applied in different combinations to create six modeling cases. Three policy drivers reflect different policy decisions that Illinois could make that would directly impact the forecasted RA needs and eligible new resource options, while the fourth driver reflects uncertainty in new battery storage costs.

Table F-1: Scenario Drivers Modeled

Scenario Driver	When included	When excluded
New Illinois Gas Allowed	New gas combustion resources are allowed to be developed in-state	No new gas resources can be constructed in Illinois
CEJA Extension	Thermal plant retirements under CEJA emissions standards do not occur by 2045[36]	Thermal plant retirements under CEJA occur as scheduled
Illinois Net Zero Emissions	Illinois must achieve net-zero carbon emissions by 2045[37]	Illinois does not have a 2045 net zero emissions target
Low Battery Costs	Lower costs for new battery storage projects are assumed	Base costs for new battery storage projects are assumed

These scenario drivers are used to define six modeling cases, inclusive of four scenarios and two sensitivities. The four scenarios are designed to allow detailed assessment and comparison of the two major policy drivers that Illinois faces: allowance of new in-state gas

[36] Age-driven projected retirements in Illinois still occur as planned.
[37] Net-zero emissions are achieved by requiring all in-state gas generation to convert to a zero-carbon fuel by 2045, as well as requiring Illinois to be a net exporter of energy in 2045.

and extensions to the CEJA-driven fossil generator retirement schedules. Two sensitivities to the Base Case are defined to explore how a net-zero carbon emission target or lower trajectory battery storage costs would impact the selected resource portfolios.

Table F-2: Scenario Matrix

Modeling Cases	New Illinois Gas Allowed	CEJA Extension	Illinois Net Zero Emissions	Battery Costs
Base Case	Yes	No	No	Base
CEJA Extension	Yes	Yes	No	Base
No New Illinois Gas	No	No	No	Base
CEJA Extension, No New Illinois Gas	No	Yes	No	Base
Illinois Net Zero	Yes[38]	Yes	Yes	Base
Low Battery Costs	Yes	Yes	No	Low

The Base Case serves as a central reference point, reflecting a continuation of current law and development trends. Other cases apply combinations of scenario drivers to examine how Illinois state policies (such as extending fossil generator retirement dates assumed for CEJA compliance or disallowing new in-state gas generation), meeting deeper decarbonization targets, and low battery cost trajectory affect system outcomes.

These scenario combinations are intentionally designed to isolate the effect of each assumption, as well as how overlapping policies and trends compound or mitigate resource adequacy challenges. The results are used to identify cost-optimal portfolios and to understand how those portfolios maintain system adequacy under a range of future conditions.

F.1.3. Loss of Load Probability Modeling

As the electric grid becomes more dependent on intermittent and energy limited resources, capturing a wide variety of resource performance conditions becomes critical to understanding a system's resource adequacy. There is a growing consensus behind the importance of probabilistic methods. This is underscored by the increasingly prevalent use within the industry from RTOs & ISOs[39] charged with managing resource adequacy in the

[38] New combustion equipment can still be selected, but all in-state gas generation is assumed to run on zero-carbon fuels by 2045.

[39] Used by NYISO, MISO, PJM.

context of organized markets to utilities that manage their own portfolios to ensure reliability for their customers.

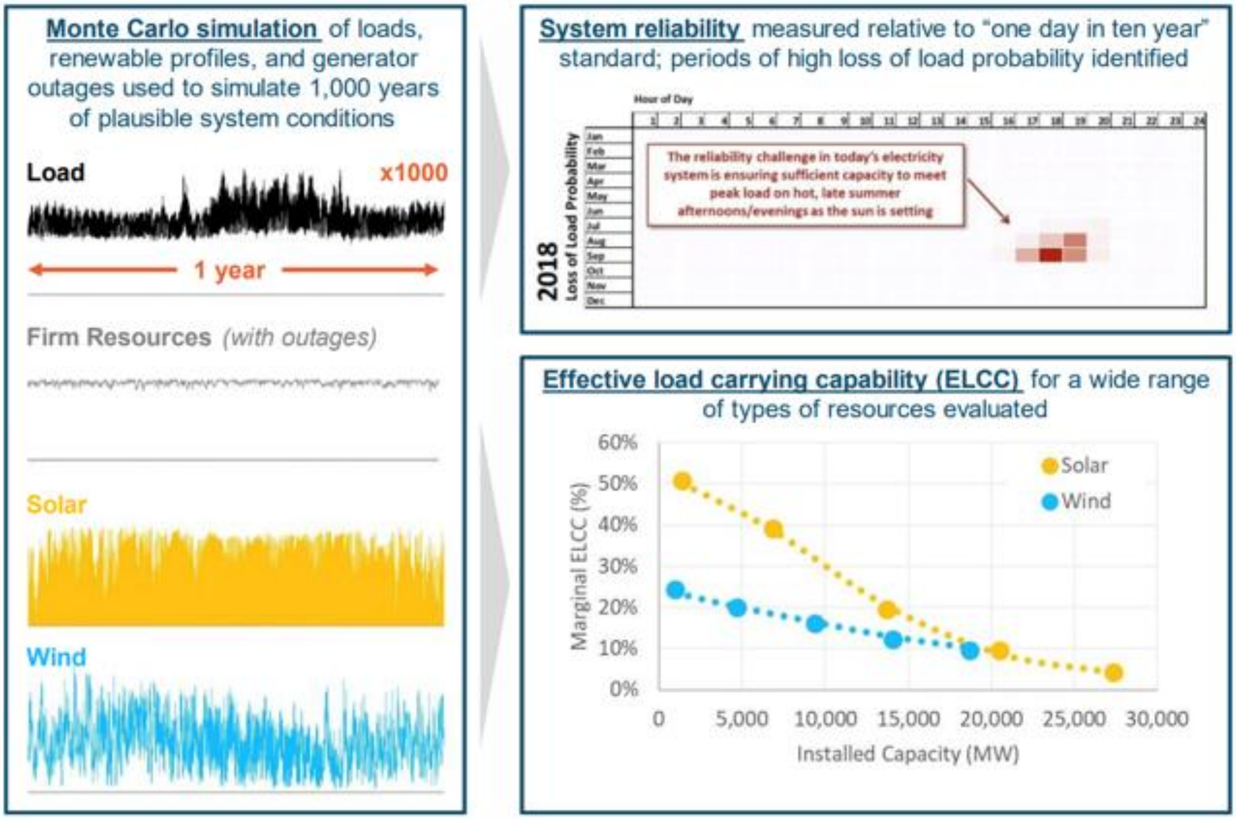
The probabilistic approach to resource adequacy requires a type of analysis known as "Loss-of-Load-Probability" (LOLP) modeling. LOLP models employ a variety of statistical and simulation techniques to compare electricity demand with available generation resources under a very broad range of conditions that accounts for variability of weather, loads, renewable generation, generator outages, and other constraints and stressors that could impact the ability of a portfolio of resources to meet loads. LOLP models simulate the performance of the electricity system on an hourly basis over the course of hundreds or thousands of simulated years—each iteration stochastically capturing a different combination of weather conditions and outages—to provide a robust assessment of the probability of tail events that drive resource adequacy challenges. The simulation of a broad range of conditions allows LOLP models to calculate a variety of statistical measures of resource adequacy. These metrics provide insights into the expected frequency, size, and duration of expected unserved energy events based on the results of the simulation of thousands of years.

E3 used its Renewable Energy Capacity Planning Model (RECAP) to calculate reliability, ELCCs, and PRM targets in MISO and PJM. RECAP evaluates resource adequacy through time-sequential simulations of thousands of years of plausible system conditions to calculate a statistically significant measure of system reliability metrics as well as individual resource contributions to system reliability. The modeling framework is built around capturing correlations among weather, load, and renewable generation, while simulating generator outages stochastically, capturing realistic renewable generation, simulating time sequential dispatch of energy limited resources, and capturing a diverse range of load conditions.

Both PJM and MISO determine their resource accreditation using LOLP[40] models that evaluate a diverse array of load conditions, resource performance, and a time sequential dispatch of energy limited resources. RECAP, PJM's RRA model, and MISO's SERVM model are all consistent with industry practice in calculating loss of load probability.

[40] PJM uses in house RRA model and MISO uses Astrape's SERVM model.

Figure F-4: E3 RECAP Framework



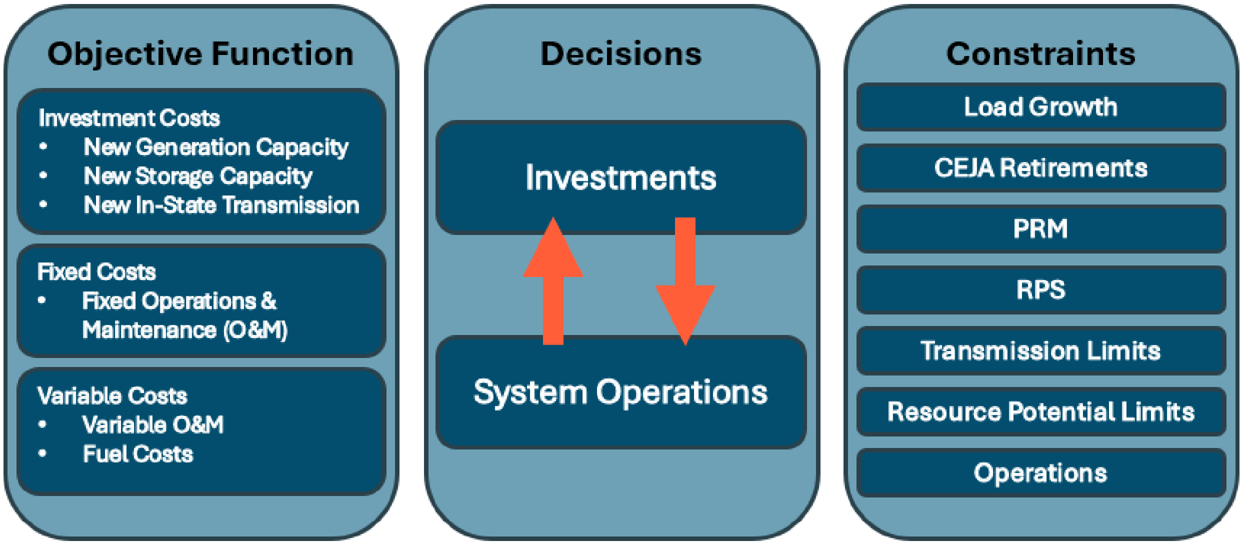
F.1.4. Capacity Expansion Modeling

To optimize the long-term resource portfolios required to meet future load growth and policy goals, capacity expansion modeling is performed using PLEXOS.[41] PLEXOS is an electricity system capacity expansion model that identifies the least-cost long-term combination of generation investments, subject to reliability, policy, and operational constraints. PLEXOS considers investment costs, fixed costs, and production costs to simultaneously optimize long-term capacity expansion and dispatch decisions. This allows the model to directly capture dynamic trade-offs between investments and dispatch, such as energy storage investments versus renewable curtailment and/or overbuild. PLEXOS also captures the reliability contributions of all resources towards satisfying its reliability constraint.

Figure F-5 provides an overview of the PLEXOS LT model, including the objective function, key model decisions, and key constraints.

[41] PLEXOS is a commercially available software package from Energy Exemplar for electricity system modeling. PLEXOS LT ("long-term") is the planning phase of PLEXOS used for capacity expansion modeling.

Figure F-5: Overview of the PLEXOS LT Model

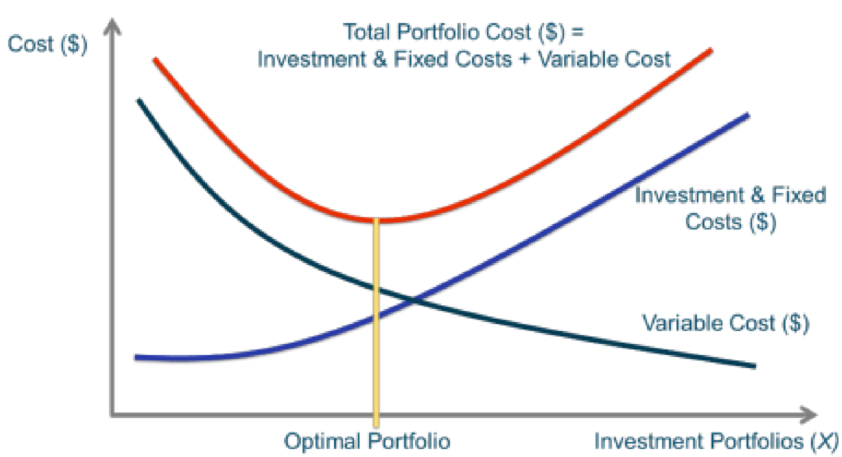


The objective function in PLEXOS LT minimizes the net present value (NPV) of electricity system costs over the planning horizon, subject to reliability, policy, and operational constraints. The planning horizon for this study is assumed to begin in 2030 and extend through 2045. Costs include investment costs, fixed costs, and production costs.

- **Investment costs:** capital costs of new generation and storage resources; new transmission costs required to ensure the deliverability of new resources
- **Fixed costs:** fixed operations and maintenance (FO&M) costs of resources
- **Production costs:** variable operation and maintenance (VO&M) costs of both existing and new resources, and fuel costs

An example of the optimal portfolio for a capacity expansion problem's objective function is provided in Figure F-6 below.

Figure F-6: Objective Function of a Capacity Expansion Problem in PLEXOS LT



PLEXOS LT identifies the cost-optimal mix of new generating capacity, storage capacity, and transmission capacity required to meet load growth forecasts, subject to planning targets, policy objectives, and other constraints applicable to the system. The major constraints enforced on the least-cost optimization are summarized in Table F-3 below.

Table F-3: Constraints Enforced in PLEXOS LT

Constraint Type	Description
Load Growth	A combination of in-state generation, energy storage, and net imports from neighboring regions must meet projected load growth in all hours of the planning horizon.[42]
Fossil Generator Retirements for CEJA Compliance	Pursuant to CEJA emissions standards, the existing thermal fleet capacity is scheduled for retirement throughout the planning horizon, and emission caps are enforced on generating units that remain online after 2030.
PRM	The total capacity of the resource portfolio, accredited using an ELCC framework, must be adequate to achieve a 0.1 LOLE in each year of the planning horizon.
RPS	The total electricity generated from RPS-eligible generation in Illinois must be consistent with the latest REC targets published in Long-Term Plan.
Transmission Limits	Power flow between regions is capped at the existing and planned transmission line limits, and resource capacity additions in-state must demonstrate deliverability during the system net peak window.
Generator Operating Characteristics	In simulating dispatch of generation resources, the model must respect modeled operating constraints of each generation resource. Thermal generator limits include minimum and maximum output levels, scheduled outages, and minimum run times. Renewable generator output is modeled using hourly generation profiles by resource by model region/zone.

The inputs and assumptions informing these modeling constraints are discussed in the subsequent sections.

The existing resource portfolio projected in 2030 determines the initial portfolio of the system at the start of the horizon. The carrying costs of these resources are not modeled in PLEXOS. Retirement assumptions for thermal generators subject to CEJA compliance are incorporated into the model following a fixed trajectory.

F.1.5. Long-term Modeling System Topology

The PLEXOS model utilizes the system transmission topology of the MISO and PJM RTOs with carve-outs in Illinois to separately represent the Ameren (MISO LRZ 4) and ComEd (PJM) zones. While all zones within PJM are included in the system topology, MISO North (LRZs 1-3 excluding Manitoba) and MISO Central (LRZs 4-7) are represented explicitly while MISO South (LRZs 8-10) is represented in aggregate by a net import assumption to help reduce the

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[42] PLEXOS LT assumes a reduced chronology to manage computation time. In each year of the planning horizon, PLEXOS simulates four representative days per month.

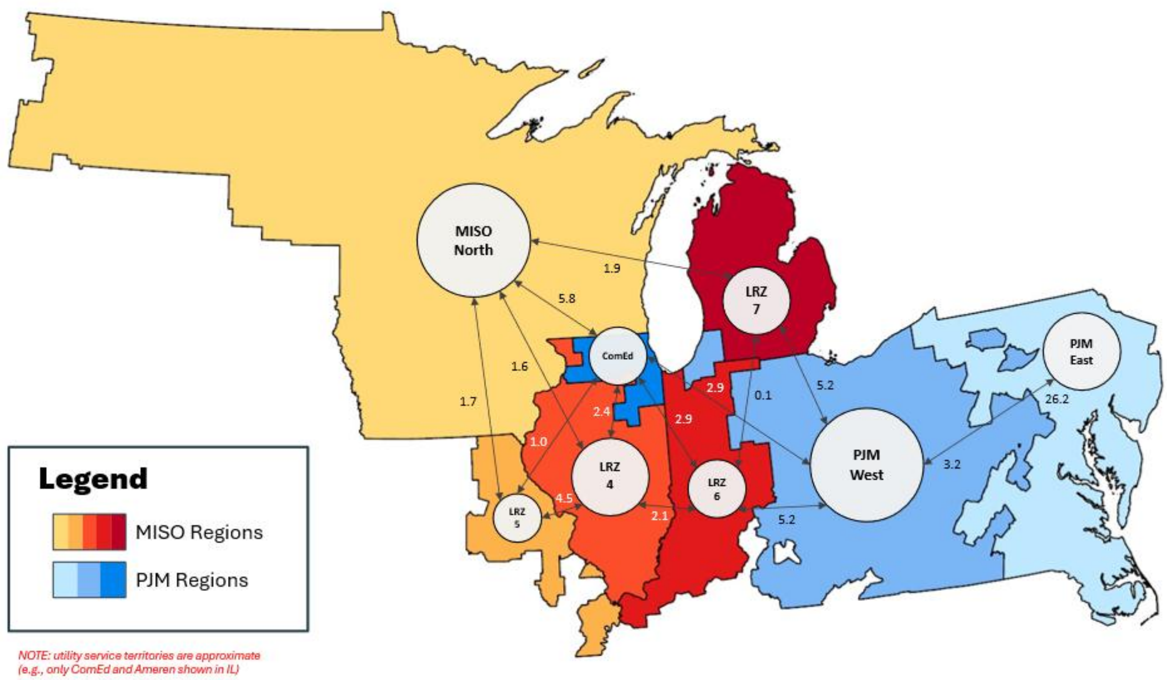
problem size of the optimization model. This representation is supported and aligned with past auction results and the limited transmission capacity between the MISO South zones and the rest of MISO. The interconnected power system is modeled with a zonal "pipe-and-bubble" representation, as shown in Figure F-7. Each zone contains the load and resources attributable to the load-serving entities within the zone, and aggregations of existing and planned interregional transmission lines are used to represent the maximum hourly bidirectional power flow limits between neighboring zones. Transmission line limits are informed by EIA hourly electric grid monitor[43], MISO 2024 LOLE Study Reports[44], MISO Transmission Expansion Plan (MTEP) 2024[45], PJM Regional Transmission Expansion Plan (RTEP) 2024[46] and MISO's Tranche 1 and 2.1 reports[47] under the Long-Range Transmission Planning process.

The PLEXOS model utilizes the system transmission topology of the MISO and PJM RTOs with carve-outs in Illinois to separately represent Ameren Illinois and the cooperatives or municipalities in MISO's LRZ 4, as well as ComEd and the cooperatives or municipalities in PJM's ComEd zone. Other Illinois load serving entities or municipalities are aggregated into the regions they reside, such as MidAmerican in MISO's LRZ 3 and Jo Carroll Energy Cooperative in MISO's LRZ 1. The system representation is shown in Figure F-7. Each zone contains the load and resources attributable to the LSEs within the zone and reflects existing and planned interregional transmission between neighboring zones. Transmission representation is informed by EIA hourly electric grid monitor,[48] MISO 2024 LOLE Study Reports,[49] MISO Transmission Expansion Plan (MTEP) 2024,[50] PJM Regional Transmission Expansion Plan (RTEP) 2024[51] and MISO's Tranche 1 and 2.1 reports[52] under the Long-Range

[43] EIA Grid Monitor: https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.
[44] MISO 2024 LOLE Study Report: https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf.
[45] MISO MTEP: https://cdn.misoenergy.org/20241001%20PAC%20Item%2002%20MTEP24%20Report%20Preview650567.pdf.
[46] PJM RTEP 2024: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250304/20250304-2024-rtep-window-1-reliability-analysis-report.pdf.
[47] MISO (Long Range Transmission Planning) LTRP projects: https://www.misoenergy.org/planning/long-range-transmission-planning/.
[48] EIA Grid Monitor: https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48
[49] MISO 2024 LOLE Study Report: https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf
[50] MISO MTEP: https://cdn.misoenergy.org/20241001%20PAC%20Item%2002%20MTEP24%20Report%20Preview650567.pdf
[51] PJM RTEP 2024: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250304/20250304-2024-rtep-window-1-reliability-analysis-report.pdf
[52] MISO (Long Range Transmission Planning) LTRP projects: https://www.misoenergy.org/planning/long-range-transmission-planning/

Transmission Planning process. This zonal representation enables the model to simulate transmission-limited power exchanges while maintaining computational tractability for long-term capacity expansion modeling. The PLEXOS model does not include representation of MISO's LRZs 8, 9, or 10 ("MISO South") because this region has more limited transmission interconnection with other zones and historically it has been a net exporter into MISO North/Central. To maintain a conservative modeling approach, MISO South and its projected future capacity needs were not represented in PLEXOS for this study.

Figure F-7: PJM and MISO Transmission Topology modeled in PLEXOS (2030)



To represent system reliability requirements, four capacity zones are modeled in PLEXOS: two external RTO zones and two zones within Illinois. The model footprint includes both MISO and PJM regions as external capacity zones to capture broader system reliability needs and interactions between the Illinois zones and the markets. Within Illinois, ComEd and MISO LRZ 4 (Ameren) are represented as distinct zones, each with their own local reliability needs. All resources are assumed to provide capacity attributes for the zone in which they are physically located, except for accredited capacity from thermal plants physically located in neighboring RTO regions but contracted to provide reliable capacity to Illinois utilities. These external-zone gas generators are available for selection as new candidate resources in PLEXOS LT.

Table F-4: ISO Zones Modeled in PLEXOS LT

ISO	PLEXOS Zone	Capacity Zone	RTO Zones and/or Utilities Included
PJM	ComEd	ComEd	ComEd (including Illinois munis and co-ops in PJM)
MISO	Ameren	MISO LRZ 4	Ameren (including Illinois munis and co-ops in MISO)
MISO	MISO North	MISO (excluding Illinois)	LRZs 1-3 (including MidAmerican Energy)
MISO	MIZO LRZ 5	MISO (excluding Illinois)	LRZ 5
MISO	MIZO LRZ 6	MISO (excluding Illinois)	LRZ 6
MISO	MIZO LRZ 7	MISO (excluding Illinois)	LRZ 7
PJM	PJM East	PJM (excluding Illinois)	East, Central, Northwest, Dominion
PJM	PJM West	PJM (excluding Illinois)	Allegheny Power Systems, American Electric Power, American Transmission Systems, Dayton Power & Light, Duke Energy Ohio & Kentucky, East Kentucky Power Cooperative

F.2. Modeling Input Assumptions

F.2.1. Load Forecasts

This study applies a consistent load forecasting framework across both the near-term resource adequacy balance assessment and the long-term capacity expansion modeling. The same underlying datasets, assumptions, and methodologies are used throughout.

E3's load forecasting methodology for this study occurs in three distinct steps. First, the baseline forecasts of annual energy and peak demand are collected directly from the RTOs and utilities—including the PJM Long-Term Load Forecast Report,[53] MISO's Long-Term Load Forecast Report,[54] and the IPA Long-Term Plan.[55] Second, E3 refines these forecasts where necessary to align with the most current utility-level data and industry expectations. Finally, underlying hourly load shapes linked to a model weather year are developed that account

[53] 2025 PJM Long-Term Load Forecast Report (January 24, 2025): https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf
[54] MISO Medium and Long-Term Load Forecast (December 18, 2024): https://www.misoenergy.org/events/2024/medium-and-long-term-load-forecast---december-18-2024/
[55] IPA Long-Term Renewable Resources Procurement Plan (October 20, 2025): https://ipa.illinois.gov/renewable-resources/long-term-plan.html.

for the annual contributions of individual major load components (e.g., base load, electric vehicles, data centers). The culmination of these components results in a comprehensive hourly load forecast.

F.2.1.1. Modifications to RTO Forecasts

To ensure consistency and realism in long-term planning, E3 applied a limited number of adjustments to the RTO forecasts:

1. **Updated Zonal Forecasts Based on Utility Data**: For Illinois zones (ComEd zone and MISO LRZ 4), the study uses updated utility-provided forecasts as provided in the IPA Long-Term Plan[56], which incorporate more up-to-date data than those originally embedded in the RTO forecasts.
2. **Adjustments to PJM Data Center Load Growth Trajectory**: PJM's long-term forecast assumes that current levels of high data center growth continue through 2045. E3 retains PJM's near-term assumptions through 2030 but moderates the trajectory thereafter, tapering the annual growth rate from ~14% to 1% by 2040. This reflects an assumption that current demand growth—driven largely by generative AI—will eventually stabilize due to market saturation, infrastructure constraints, and ongoing efficiency improvements. This assumption is informed by historical load trends, facility-level development data from sources including DataCenterMap,[57] CBRE,[58] Baxtel,[59] JLL,[60] and EPRI,[61] and broader analysis of U.S. electricity demand. Importantly, this adjustment should be seen as a optimistic input to the analysis from the perspective of resource adequacy. Any scenario with higher data center growth, such as that projected by PJM's current baseline, would result in greater resource adequacy shortfalls and increase the need for new reliable capacity. Additional justification and supporting evidence for the study team's assumptions are provided in section F.2.1.2.
3. **Exclusion of Specific Load Components in MISO load projections**: MISO's Current Trajectory scenario includes load growth projections from green hydrogen production and industrial development spurred by the Inflation Reduction Act. Given uncertainty around policy feasibility and actual demand realization, these loads were

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[56] Ibid.
[57] Data Center Map: https://www.datacentermap.com/.
[58] CBRE: North America Data Center Trends H1 2025: https://www.cbre.com/insights/reports/north-america-data-center-trends-h1-2025.
[59] Baxtel, https://baxtel.com/data-center/united-states
[60] JLL: North American Data Center Report Midyear 2025: https://www.jll.com/en-us/insights/market-dynamics/north-america-data-centers.
[61] EPRI: Analyzing Artificial Intelligence and Data Center Energy Consumption: https://www.epri.com/research/products/3002028905.

excluded from this study's base assumptions. All other MISO load drivers, including data centers, are retained consistent with MISO's forecast.

Although the study forecasts are derived from and align closely with RTO and utility forecasts for total annual energy and peak demand, differences in *net* peak demand can emerge due to differences in modeling methodology. In this study, hourly load profiles are generated for each zone using E3's weather-normalized neural network regression approach, tied to each year's expected annual peak and energy total. The load profiles, in conjunction with differences in underlying behind-the-meter normalized hourly profiles, will differ from RTO assumptions.

These modeling differences lead to slight variations in net peak timing and magnitude compared to RTO-reported values, particularly when assessing reliability hours and capacity needs. These variations are expected and appropriate for integration into hourly models such as PLEXOS and RECAP, which require internally consistent, weather-aligned load and generation profiles.

F.2.1.2. Data Center Load Forecast Discussion

E3's long-term data center forecast is based on RTO published data along with Illinois utility forecasts. From the baseline assumptions, adjustments are incorporated to the long-term data center forecast to account for an anticipated substantial moderation in data center load growth following the current short-term expansion. This projection is grounded in E3's analysis of the structural constraints, technological factors, and historical trends that shape data center development described below. This forms the basis for E3's utilization of PJM's near-term assumptions for data center load growth through 2030 but a moderation thereafter, tapering the annual growth rate from ~14% to 1% by 2040.

Historical evidence further supports the characterization of data center development as a recurring "boom-slow" cycle. The boom of the early 2000s was followed by a prolonged period of modest growth: total load increased by 90 percent from 2000–2004, by 24 percent from 2005–2010, and by 4 percent from 2010–2014.[62] Analysts writing in 2016 projected continued deceleration through 2020, including the possibility of negative growth under certain efficiency assumptions. E3 assesses that continued efficiency gains from building

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[62] Berkeley Lab United States Data Center Energy Usage Report: https://eta-publications.lbl.gov/sites/default/files/lbnl-1005775_v2.pdf.

larger facilities,[63] implementing liquid cooling systems,[64] and ongoing chip improvements[65] will continue to apply downward pressure on data center load growth. Consistent with this pattern, E3 forecasts that the United States is currently in the midst of another boom phase that will eventually transition to a slow-growth period.

Hence, E3's near- to mid-term data center forecasts for PJM and MISO are initially based on RTO forecasts, confirmed by facility-level data of known and announced facilities provided by DataCenterMap,[66] and further shaped by data from CBRE,[67] Baxtel,[68] JLL,[69] and EPRI.[70] This informs E3 view on current load and expected additions over the next 6-8 years. Based on the expectation of market saturation, E3 then attenuates the growth towards a long term growth rate. The 10-year period of attenuation and 1% year over year long term growth rate are aligned with historical trends from the 2000-2014 period.

Along with PJM, MISO is also experiencing significant data center interconnection requests and forecasts large load growth in the near-term (500% growth of data center loads between 2025 and 2030 and an average of 10% year over year growth between 2030 and 2040).[71] However, compared to E3's adjustment of PJM's forecast, E3 did not apply an additional haircut to MISO's forecast because MISO already assumes a 41% attrition rate on announced capacity of data centers.

While the PJM baseline data center forecast is scaled back in the 2030s, E3 incorporated incremental data center load additions to reflect projected data center load growth in ComEd that has been forecasted by the utility but not yet reflected in the RTO forecast. ComEd expects rapid data center load growth in the 2030s with data center growth stabilizing by 2040. Similarly, E3 used MISO's forecast as the basis of its data center forecast only adding some incremental load to represent updates in Ameren's forecast. Similarly to ComEd, Ameren utility forecasts also reflected more amounts of data center growth that

[63] The Uptime Institute: Large data centers are mostly more efficient: https://journal.uptimeinstitute.com/large-data-centers-are-mostly-more-efficient-analysis-confirms/.
[64] The Uptime Institute: 2024 Cooling Systems Survey: https://datacenter.uptimeinstitute.com/rs/711-RIA-145/images/2024.Cooling.Survey.Report.pdf.
[65] IEA: Efficiency improvement of AI related computer chips, 2008-2023: https://www.iea.org/data-and-statistics/charts/efficiency-improvement-of-ai-related-computer-chips-2008-2023.
[66] Data Center Map: https://www.datacentermap.com/.
[67] CBRE: North America Data Center Trends H1 2025: https://www.cbre.com/insights/reports/north-america-data-center-trends-h1-2025.
[68] Baxtel: https://baxtel.com/data-center/united-states.
[69] JLL: North American Data Center Report Midyear 2025: https://www.jll.com/en-us/insights/market-dynamics/north-america-data-centers.
[70] EPRI: Analyzing Artificial Intelligence and Data Center Energy Consumption: https://www.epri.com/research/products/3002028905.
[71] "Long Term Load Forecast," MISO, December 2024, https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf.

was not yet incorporated into RTO's forecast. E3 added the incremental amount of data center load to both its Ameren and MISO forecasts to reflect latest utility data.

F.2.1.3. Resulting Load Forecasts

The next paragraphs describe the load forecasts utilized in the near-term resource adequacy balance. The PJM load forecast used in this study is based on the 2025 PJM Long-Term Load Forecast Report[72] with targeted adjustments to better reflect long-term uncertainty. In the near term (2026–2030), the peak load forecast aligns with PJM's projections, which account for residential, commercial, and industrial growth trends, as well as rapid growth in data center loads. However, beyond 2030, this assessment assumes a more moderate pace of data center growth compared to PJM's forecast, as previously described.

The MISO peak load forecast used in this study is based on the Current Trajectory scenario in MISO's 2024-2025 Long-Term Load Forecast Report.[73] MISO's baseline already incorporates adjustments for data center load realization, and this study uses MISO's data center load estimates without further adjustments. However, demand associated with green hydrogen production and Inflation Reduction Act–driven industrial growth explicitly split out in the forecast is excluded due to uncertainty around federal policy support and project viability.

The ComEd zone and MISO LRZ 4 peak load forecast used in this analysis is consistent with the values published in the IPA's 2026 Long-Term Plan.[74] The portions of Illinois load that fall within MISO LRZs 1 and 3, which includes MidAmerican Energy's service territory and Jo Carroll Energy Cooperative's service territory in western Illinois, are also consistent with the IPA Long-Term Plan. Because MISO LRZs 1 and 3 includes a multi-state footprint and represents a smaller share of Illinois load, detailed analysis of this sub-region is not presented in the zonal resource adequacy results, but its contribution is captured in the system-wide MISO analysis. The figures below, Figure F-8 through Figure F-11, show peak load forecasts expressed in the convention used for calculating resource adequacy requirements. Specifically, these peak loads represent the baseline values to which the applicable reserve margin is applied—using the Forecast Pool Requirement (FPR) in PJM and

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[72] 2025 PJM Long-Term Load Forecast Report (January 24, 2025): https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf.
[73] MISO Medium and Long-Term Load Forecast (December 18, 2024): https://www.misoenergy.org/events/2024/medium-and-long-term-load-forecast---december-18-2024/.
[74] IPA Long-Term Renewable Resources Procurement Plan (October 20, 2025): https://ipa.illinois.gov/renewable-resources/long-term-plan.html.

the Direct Loss-of-Load (DLOL) margin in MISO—to establish each region's planning reserve requirement.

Figure F-8: PJM Peak Load Forecast

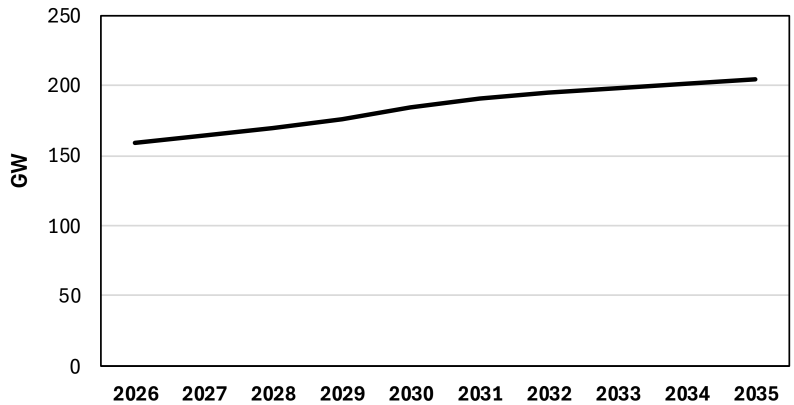


Figure F-9: MISO Peak Load Forecast

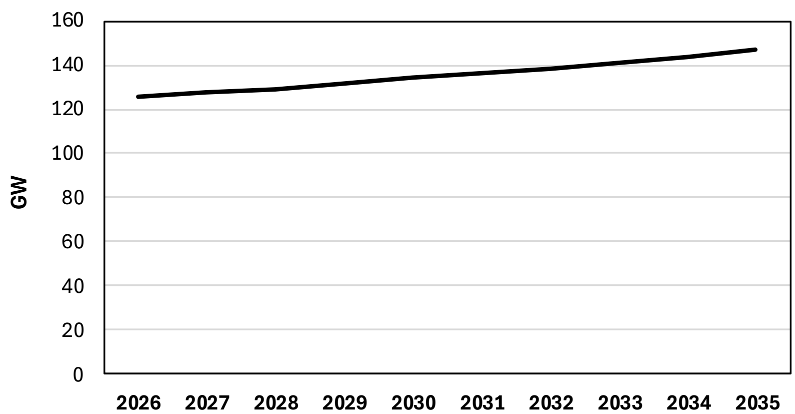


Figure F-10: ComEd Zone Peak Load Forecast

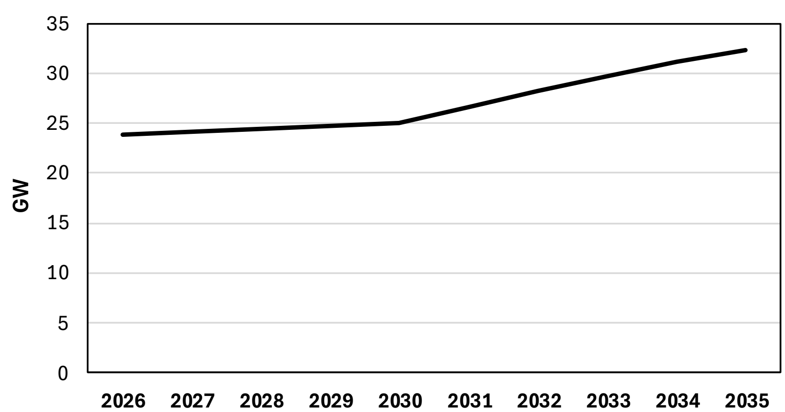
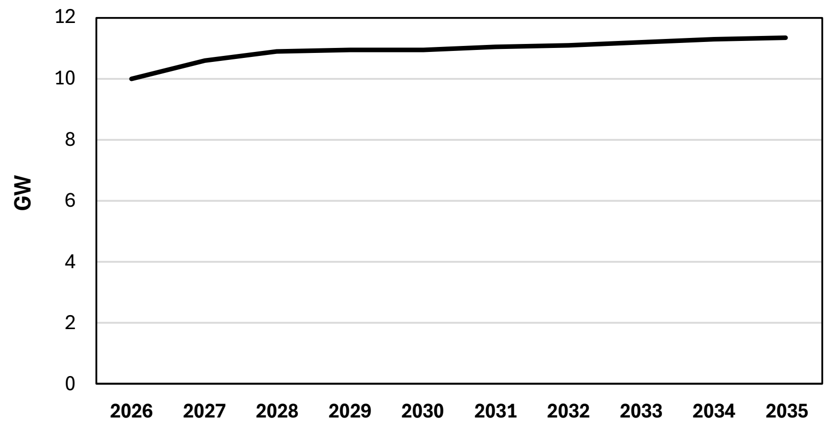


Figure F-11: MISO LRZ 4 Peak Load Forecast



The remainder of this section details the load forecasts used in the long-term capacity expansion analysis. For PJM, E3 forecasts that by 2035, total forecasted energy demand is 1,207 TWh, with data center load projected to reach 277 TWh, or 23% of PJM's total energy demand. Overall, total PJM load is expected to increase by approximately 20% between 2026 and 2035. The data center load forecast in 2045 is 329 TWh compared to PJM's forecast of 525 TWh. This still represents substantial growth relative to today's levels. There is also significant forecasted EV load growth with a 2x increase between 2026 and 2030, and a 3.5x increase between 2030 and 2040. In total, a 40% increase in load is forecasted between 2026 and 2045.

A portion of PJM's load can also be attributed to ComEd's load. E3 used PJM's ComEd load forecast but replaced the datacenter portion with the utility's own forecast to reflect updated data received from ComEd. The figures below show the "gross load" forecasts used in this study. Gross load refers to the total electric demand of each region or system that is inclusive (e.g. not reduced by) self-consumption of on-site distributed generation resources, namely behind-the-meter (BTM) solar photovoltaic resources. BTM solar resources were modeled as 'supply side' resources, meaning they are represented as generators with their own solar generation profile.

Figure F-12: PJM Gross Annual Load Forecast (GWh)

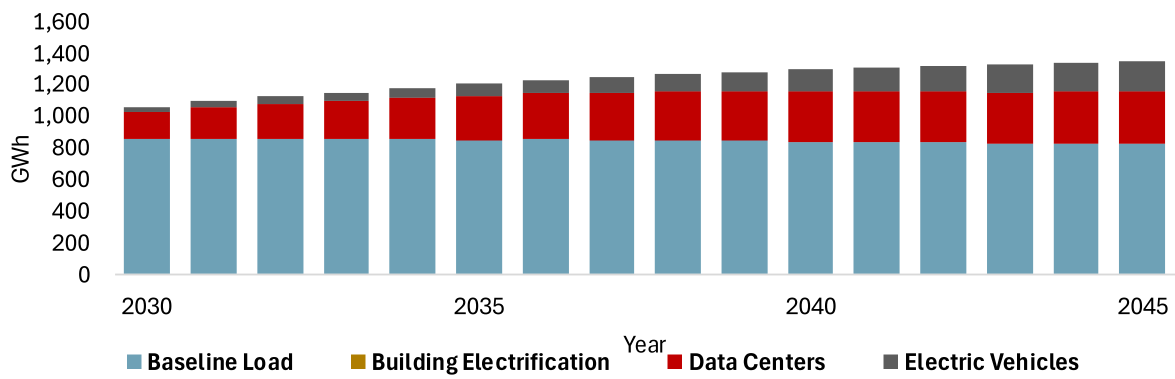


Figure F-13: ComEd Gross Annual Load Forecast (GWh)

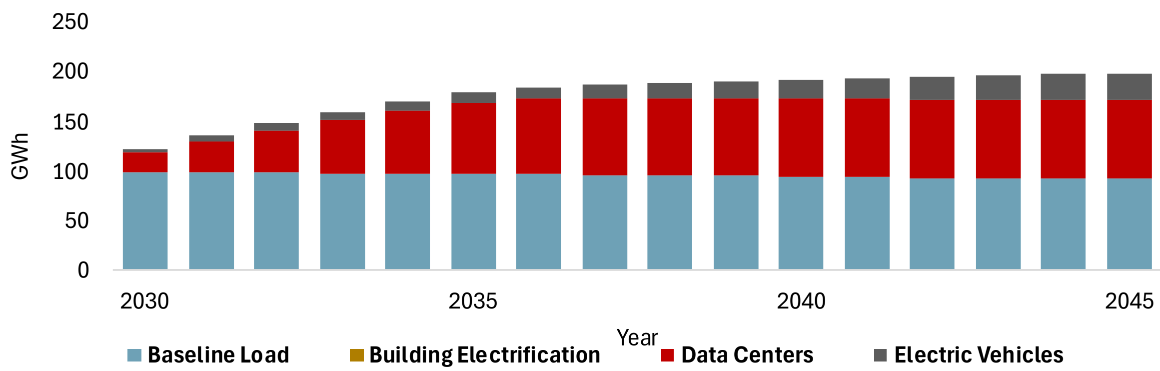


Figure F-14: PJM Gross Peak Load Forecast (GW)

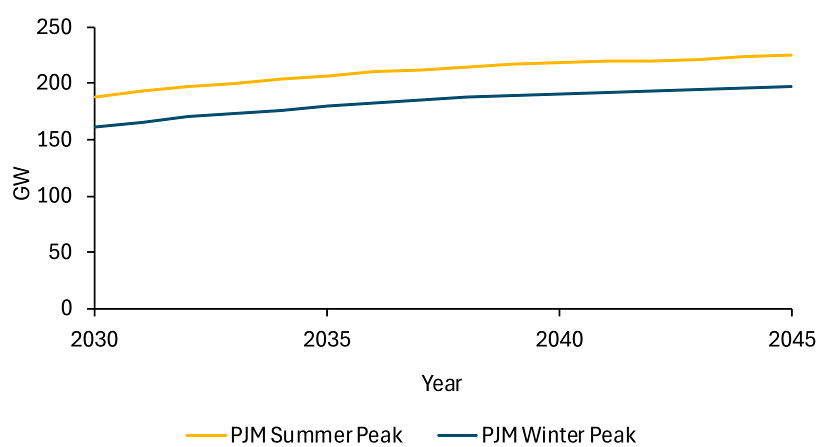
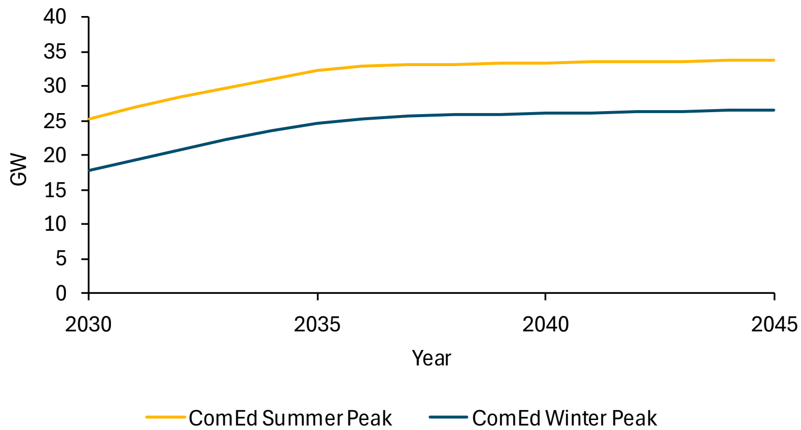


Figure F-15: ComEd Zone Gross Peak Load Forecast (GW)



MISO is forecasted to experience 50% total load growth between 2026 and 2045. Much of this growth is expected from data centers, which grow from 3% of the total load in 2026 to 19% of the total in 2045. Load in MISO LRZs 1-7 is projected to grow 52% between 2026 and 2045, driven largely by data centers.

Figure F-16: MISO Gross Annual Load Forecast (GWh)

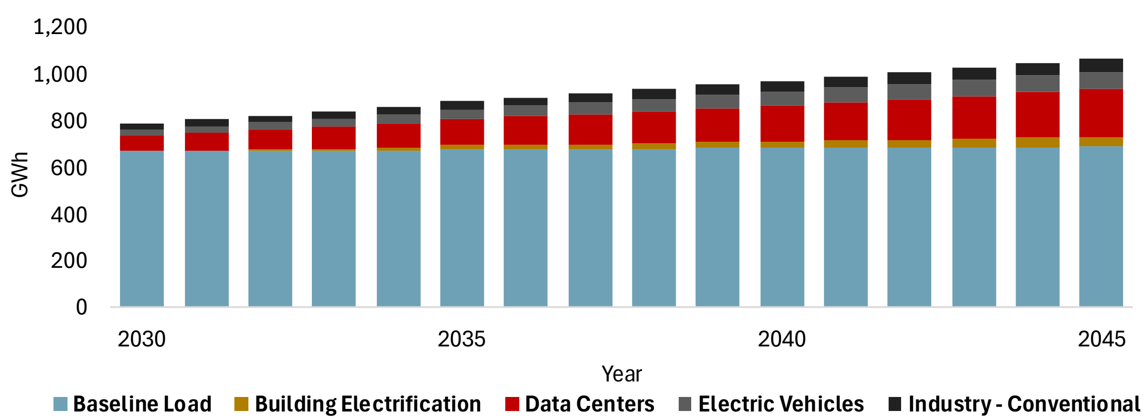


Figure F-17: MISO LRZs 1-7 Gross Annual Load Forecast (GWh)

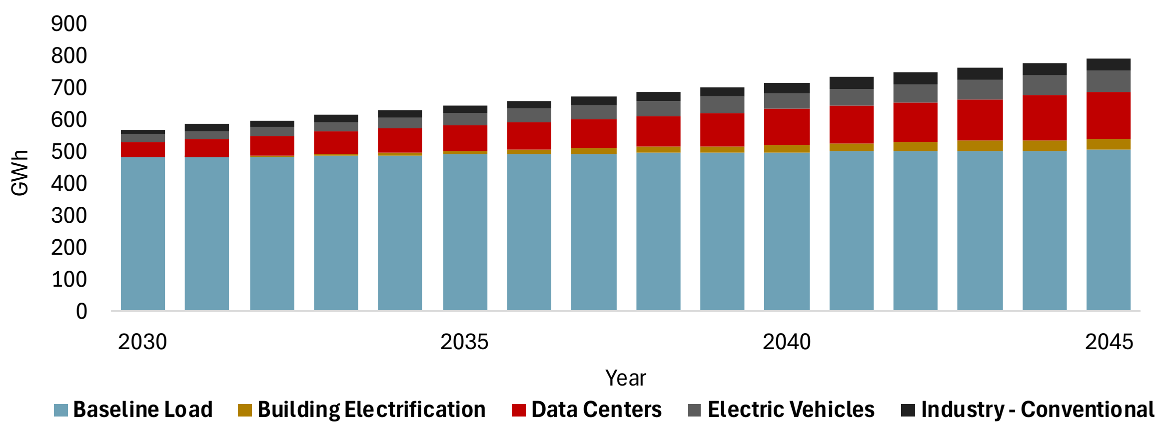


Figure F-18: LRZ 4 Gross Annual Load Forecast (GWh)

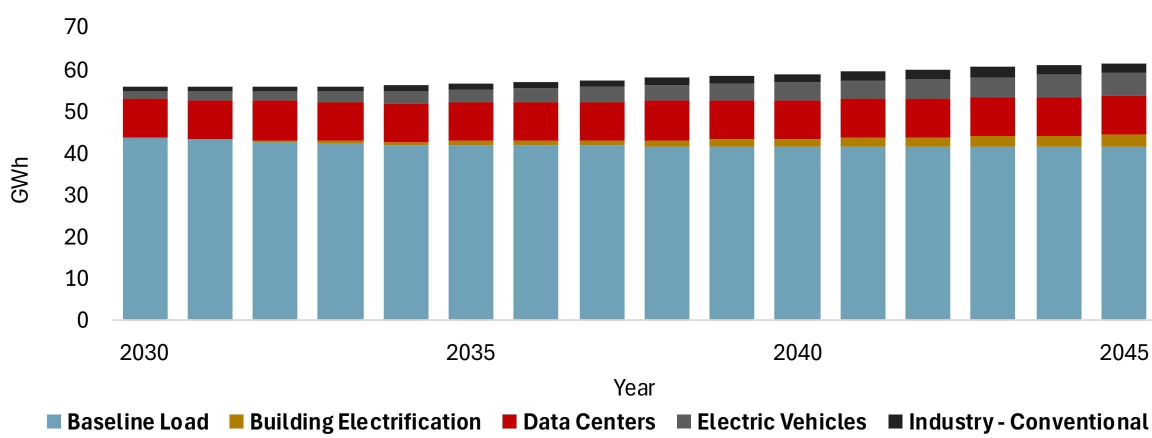


Figure F-19: MISO Gross Peak Load Forecast (GW)

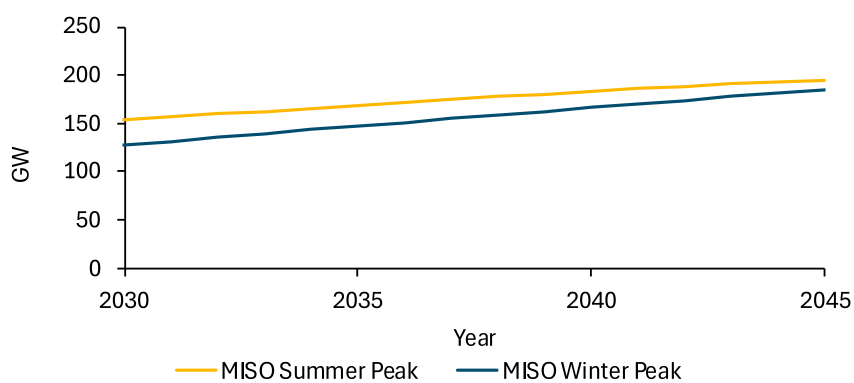


Figure F-20: MISO LRZs 1-7 Gross Peak Load Forecast (GW)

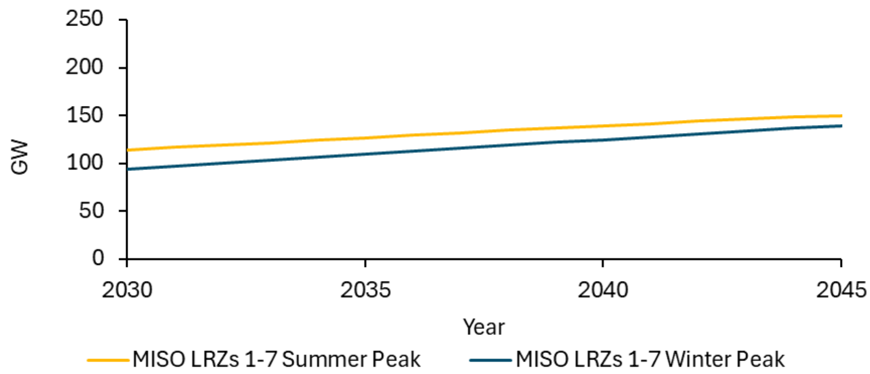
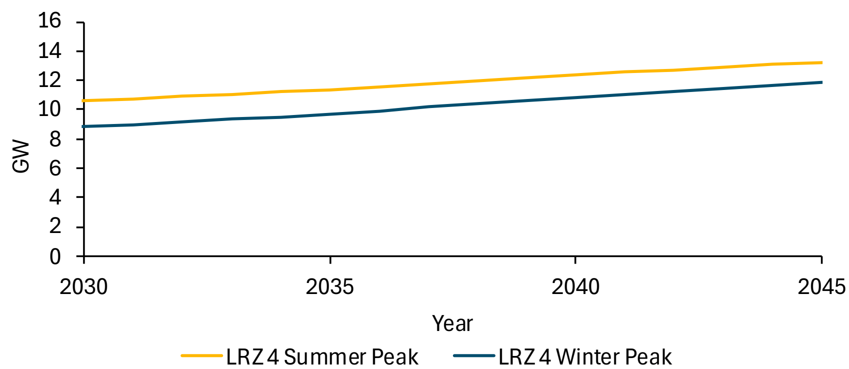


Figure F-21: MISO LRZ 4 Gross Peak Load Forecast (GW)



F.2.2. Hourly Profile Sources

E3 developed weather-correlated hourly profiles for both load and renewable generation across the regions studied. Load shapes were created using a neural network-based regression trained on recent historical data to capture the relationship between load and weather. While it is widely acknowledged that climate change will impact how weather patterns will deviate from historical norms in the future, the practice of incorporating the impacts of climate change into resource adequacy models and hourly profiles is still an emerging field and was not considered explicitly in this study. Profiles for load growth drivers—including data centers, building electrification, electric vehicles, and industrial electrification—were developed separately and layered onto the base load profile to preserve both weather correlation and the distinct load shape of each component. Renewable generation profiles for existing and candidate resources were similarly developed based on historical weather data, utilizing NREL's datasets. These time-synchronized load and generation profiles feed directly into the RECAP model for loss-of-load probability analysis and also inform the hourly inputs in the PLEXOS capacity expansion model.

E3 developed load shapes for each of the key components in the load forecast using a neural network-based regression. First, the relationship between load and weather in recent years is evaluated, then the relationship is applied to a longer period of weather data (1990-2024). Historical weather is detrended based on average daily max temperature to remove warming trends from historical weather data. However, no further adjustments are applied to future loads to account for future warming trends. Shapes for load growth drivers (building electrification, datacenters, EVs, and industry) are each developed separately, ensuring weather year alignment, and then layered on top of neural network results to create a unique blended load shape for each modeled year. The load shapes are scaled to each year's annual energy from which annual coincident peaks are calculated.

Existing and candidate resource profiles are simulated using NREL's suite of modeling tools for each PLEXOS region using several decades of historical weather data. These profiles are used to create an extended time series of weather-correlated resource output for use in E3's resource adequacy model, RECAP. A single weather year, 2022, is also used in PLEXOS for capacity expansion modeling. Weather year is selected by choosing a year where load is close to median conditions and where there are renewable resource profiles that have weather alignment with hourly load profile.

For land-based wind, the location of existing projects and their associated turbine configurations are derived from the U.S. Wind Turbine Database (USWTDB). Wind generation was then simulated at existing locations using NREL's Wind Integration National Dataset (WIND) Toolkit for 2007-2014, and NREL's Bias-Corrected NOAA High-Resolution Rapid Refresh (BC-HRRR) dataset for 2015-2023. For existing solar, profiles are simulated in SAM for 1998-2022 using weather data from NREL's National Solar Radiation Database (NSRDB) in each PLEXOS region.

Candidate resource profiles were generated for both offshore and land-based wind as well as utility-scale and distributed solar. For offshore wind, ten sites were randomly selected within each of the lease areas in PJM based on shapefiles published by the U.S. Department of the Interior's Bureau of Ocean Energy Management (BOEM). Profiles were generated at each of these sites for 2000-2020 using weather data from NREL's 2023 National Offshore Wind (NOW-23) database. For land-based wind and both types of solar, candidate project areas (CPAs) from NREL's renewable energy supply curves were mapped to PLEXOS regions and simulated in SAM using a similar methodology as described above.

F.2.3. Baseline Resources and Scheduled Retirements

This study utilizes a consistent starting point for characterizing existing generation capacity across both the near-term Resource Adequacy Balance assessment and the long-term portfolio modeling conducted in PLEXOS and RECAP. Installed generation capacity in 2026 serves as the baseline across all regions studied. To develop a complete and accurate representation of the existing resource fleet, E3 uses plant-level data from the Energy Exemplar 2024 PLEXOS Eastern Interconnect model as the starting point. The database also includes scheduled resource retirements. Baseline generation resources and projected retirements were benchmarked and refined based on data from Hitachi Velocity Suite, S&P Global Capital IQ, and additional E3 research.[75]

The load and resource balance model has a starting year of 2026 and projects different outlooks of resource adequacy through 2035 by incorporating varying assumptions around generator additions and retirements. This baseline also incorporates projected retirement dates for units affected by CEJA emissions standards, based on guidance provided by the IEPA. Where specific CEJA-related deadlines apply, those units are assumed to retire either in accordance with the policy, or before, if any announced retirement dates occur before the compliance date. Should a facility be identified as retiring in a given year to comply with CEJA (i.e., 2030), then that facility is assumed to be unavailable to contribute to summer resource adequacy needs in that year. The starting point for the baseline, existing generation resource nameplate capacity in PJM, MISO, the ComEd zone, and MISO LRZ 4 for the near-term resource adequacy balance are depicted below in figures Figure F-22 through Figure F-25.

[75] The model database is made up of granular, unit-level resource assignments to each zone defined according to the system topology. These are typically assigned based on physical location but may also consider known contracted shares, where applicable and finely tracked.

Figure F-22: Existing Generation Resources Nameplate Capacity in PJM

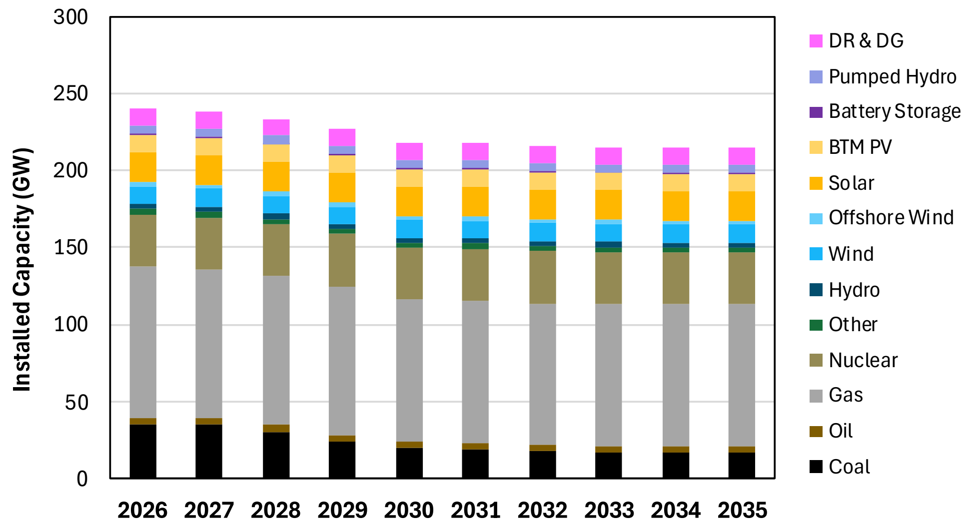


Figure F-23: Existing Generation Resources Nameplate Capacity in MISO

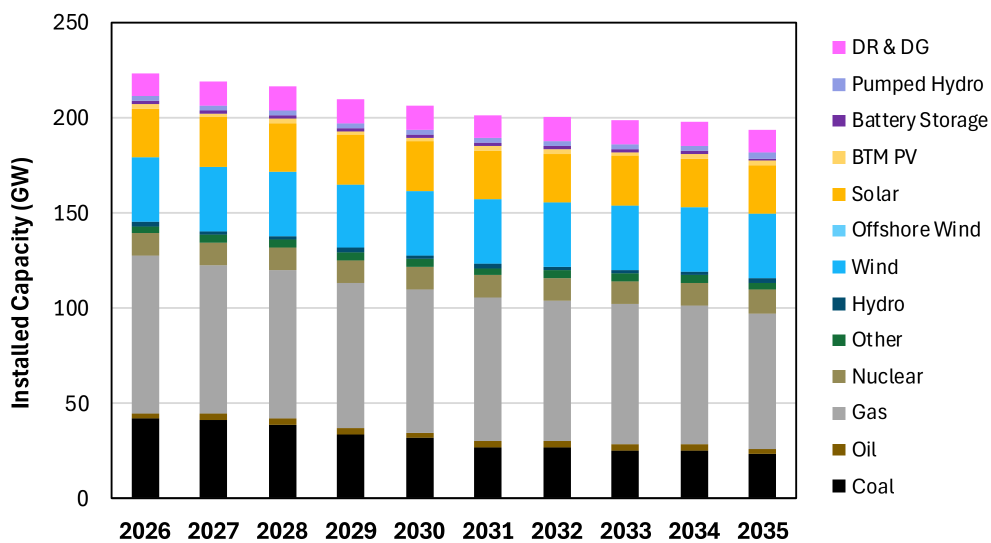


Figure F-24: Existing Generation Resources Nameplate Capacity in ComEd Zone

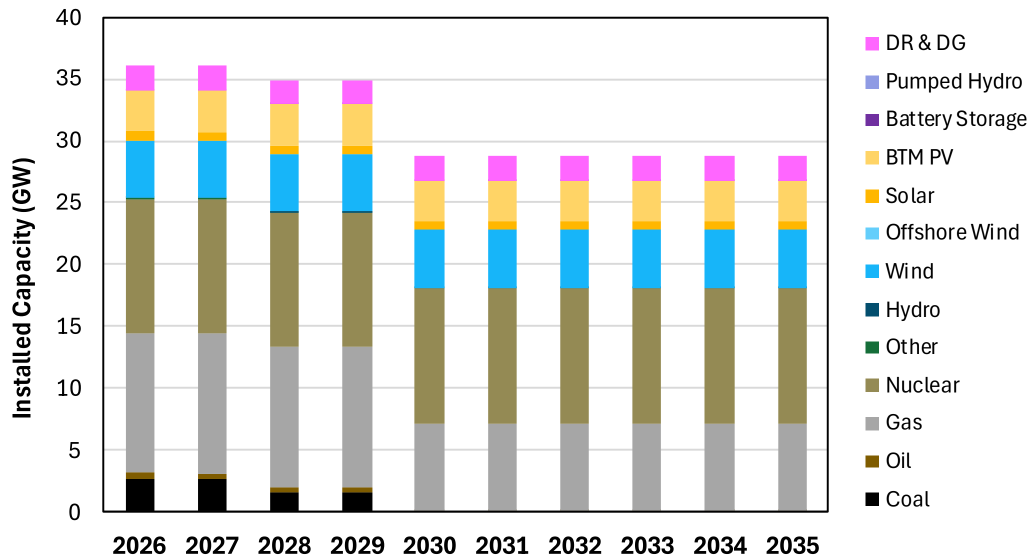
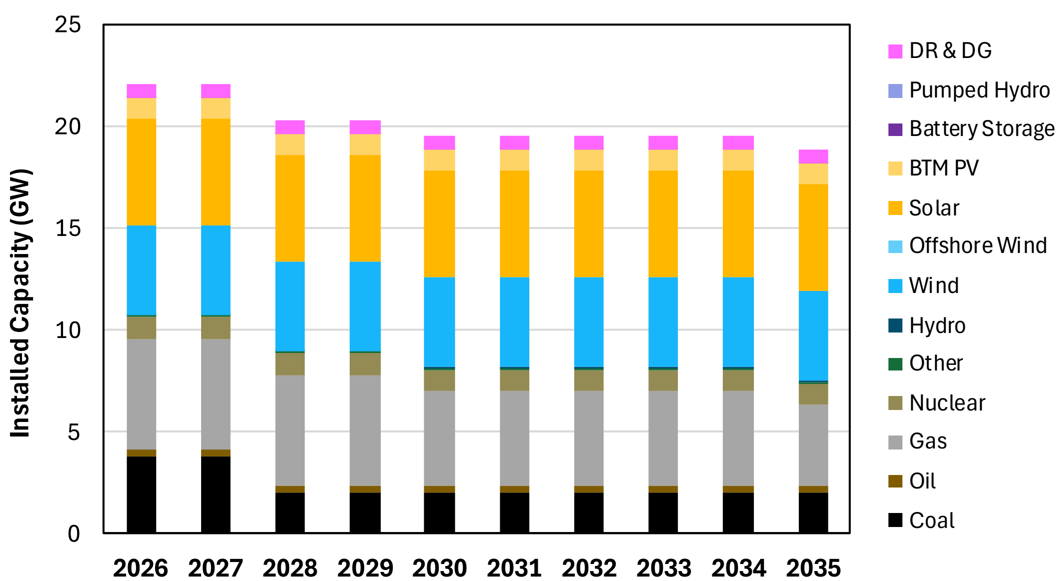


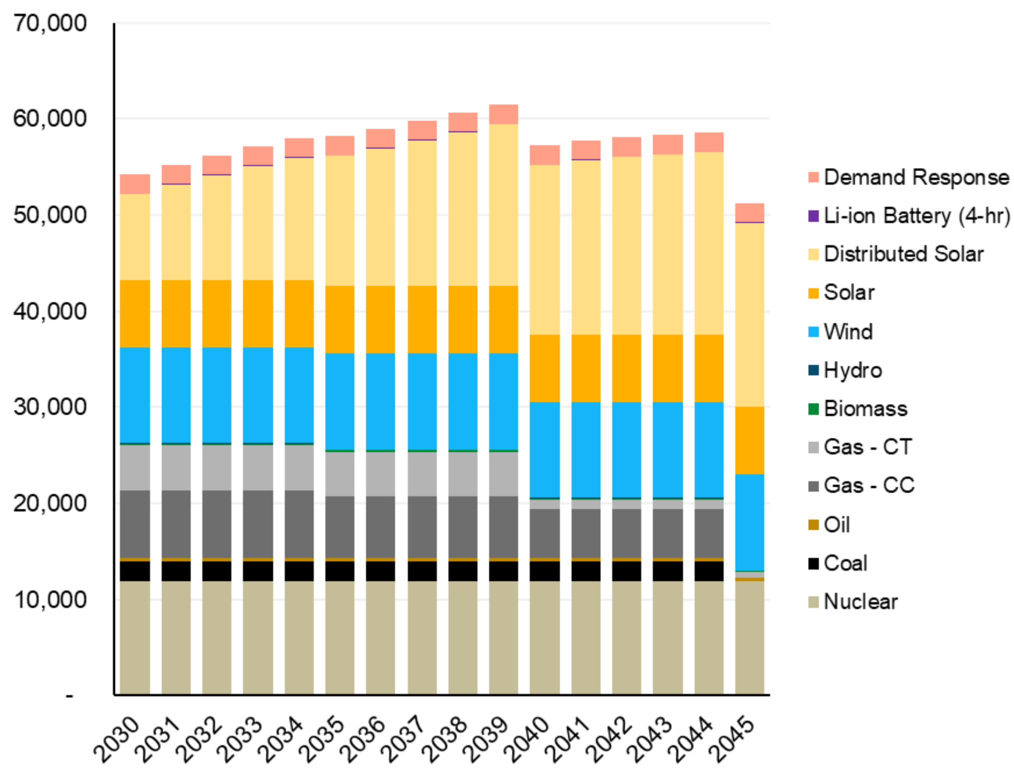
Figure F-25: Existing Generation Resources Nameplate Capacity in MISO LRZ 4



The baseline resource portfolio in PLEXOS, which utilizes a starting year of 2030, is defined to include existing generation and storage resources, scheduled resource retirements, as well as projected in-development and contracted resource additions. This differs slightly from the load and resource balance model due to the inclusion of assumed additions to occur between 2026 and 2030. Also, the installed capacities of baseline resources are not optimized within PLEXOS—all additions and retirements are directly coded into the model as targeted inputs to ensure the additions and retirements are correctly represented.

Figure F-26 presents the Illinois baseline installed capacity in PLEXOS for all resource types over the 2030-2045 modeling horizon. The resources represented in this figure are only inclusive of those resources not selected by PLEXOS modeling, thus representing the baseline and not a derivative model scenario. The thermal capacity shown reflects projected coal retirements by 2030 based on announcements from plant owners in Illinois and additional retirements of oil and gas generators assumed to retire to comply with CEJA emissions requirements through 2045.[76] The increasing distributed solar capacity throughout the horizon reflects projected capacity additions aligned with Illinois programs as projected in the Illinois Power Agency's 2026 Long-Term Renewable Resources Procurement Plan filed for ICC approval on October 20, 2025.[77] Future utility-scale wind and solar additions needed to meet Illinois' renewable energy targets are not included in the baseline resources in Figure F-26. These resources are instead modeled under the renewable portfolio standard (RPS) targets within the PLEXOS model and presented as part of the model's selected resource portfolios.

Figure F-26: Illinois Baseline Installed Capacity (MW)



[76] These are the default retirement assumptions for the Base case. In scenarios where the fossil generator retirements are extended, the baseline thermal capacity is flat through 2045.

[77] IPA 2026 Long-Term Renewable Resources Procurement Plan: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20251020-2026-long-term-renewable-resources-procurement-plan.pdf

All units are instead assumed to retire by 2045 in cases where fossil generator retirements are modeled to occur to comply with CEJA as a conservative assumption and based on the current, uncertain future of the green hydrogen economy. Figure F-27 presents Illinois thermal capacity retirements assumed over the planning horizon. Under CEJA, all coal, oil, and natural gas facilities larger than 25 MW must reduce emissions to zero by 2045 or retire. In addition to retirements assumed to occur to comply with CEJA, 4,488 MW of projected coal retirements by 2030 are included in all cases, reflective of announced retirements that are set to happen regardless of whether an extension to CEJA is granted. While gas generating facilities in Illinois could opt to convert to 100% green hydrogen to comply with the law, all units are instead assumed to retire by 2045 in cases where fossil generator retirements are modeled to occur to comply with CEJA as a conservative assumption and based on the current, uncertain future of the green hydrogen economy.

Figure F-27: Illinois Cumulative Retirements (GW)

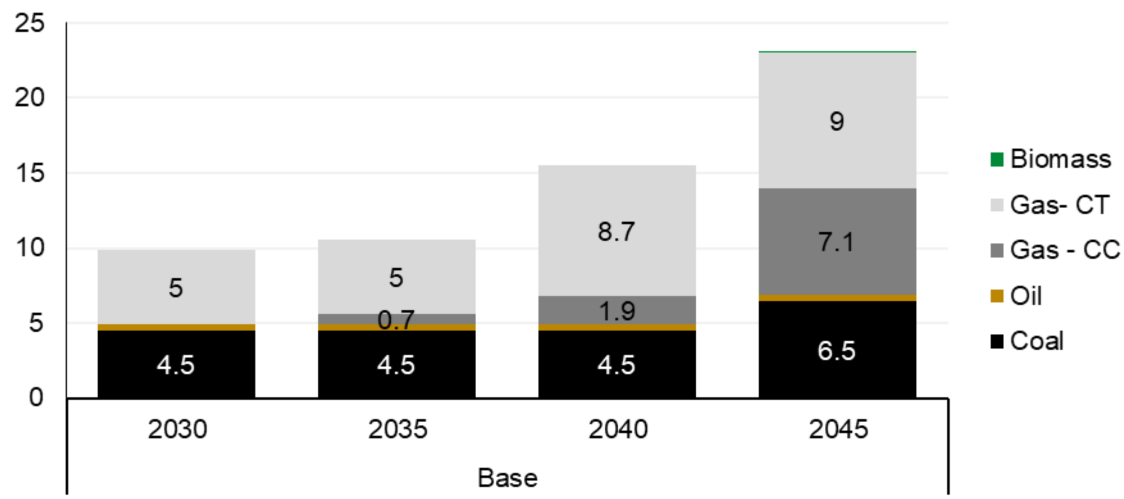


Table F-5: Illinois Cumulative Retirements (GW)

Technology	2030	2035	2040	2045
Coal	4.5	4.5	4.5	6.5
Oil	0.4	0.4	0.4	0.4
Gas Combined Cycle	0.0	0.7	1.9	7.1
Gas Combustion Turbine	5.0	5.0	8.7	9.0
Biomass	0.0	0.0	0.0	0.1

While all fossil fuel generation in Illinois is scheduled to retire by 2045 or reduce emissions to zero under CEJA, the law also establishes interim emissions limits on existing thermal generators. Emissions restrictions apply to all generating units over 25 MW, with exact requirements varying by ownership structure and fuel type. Additionally, exceedances to the emissions restrictions are allowed in certain instances if the relevant RTO determines that the facility is necessary to maintain reliability, support local power flow requirements, or provide emergency backup services to the grid. These operational emissions restrictions are applied across all scenarios.

- **Privately Owned Generation:** Under CEJA, coal- and oil-fired generation in Illinois must reduce emissions to zero by 2030. Gas fired generation must reduce emissions to zero by 2045, with accelerated emissions reductions based on emissions intensity, proximity to certain population zones or equity investment eligible communities, and heat rates. Annual emissions caps are based on 2018-2020 levels, with compliance demonstrated through rolling 12-month average emissions.
- **Publicly Owned Generation:** CEJA sets different emissions requirements for thermal generators in Illinois owned by public electric service providers such as municipal utilities and electric cooperatives. These publicly owned coal- and oil-fired generators must reduce emissions by 45% by 2035, with a possibility of extension to 2038, and to zero by 2045. Gas-fired generation must reduce emissions to zero by 2045 with no interim schedule.

F.2.4. New Resource Additions

Both the near-term resource adequacy balance and long-term PLEXOS capacity expansion model project outlooks for new resource capacity additions into the future. The key difference is the resource adequacy balance assessment projects new resources primarily based on the MISO and PJM interconnection queues while PLEXOS calculates optimal resource selections based on resource costs and availability. It should also be noted that the projections for new behind-the-meter solar generation capacity are aligned across both the resource adequacy balance and PLEXOS models.

In the resource adequacy balance, different outlooks are projected based on different assumptions around MISO and PJM interconnection queue project realized commercial operation dates. Figure F-28 through Figure F-31 depict all new resources in the queue that come online according to the as-reported Commercial Operation Date (COD). This data is drawn from the Velocity Suite database, which aggregates RTO queue data and applies in-house research to track project status and estimated online dates. Velocity Suite classifies queue projects into the following development categories: feasibility, proposed, application pending, permitted, under construction, and testing. Projects in the application pending, permitted, under construction, and testing stages are characterized as "advanced development" while those in feasibility and proposed stages are considered in an "early development" stage.

Figure F-28: Planned Resource Nameplate Capacity Additions in PJM

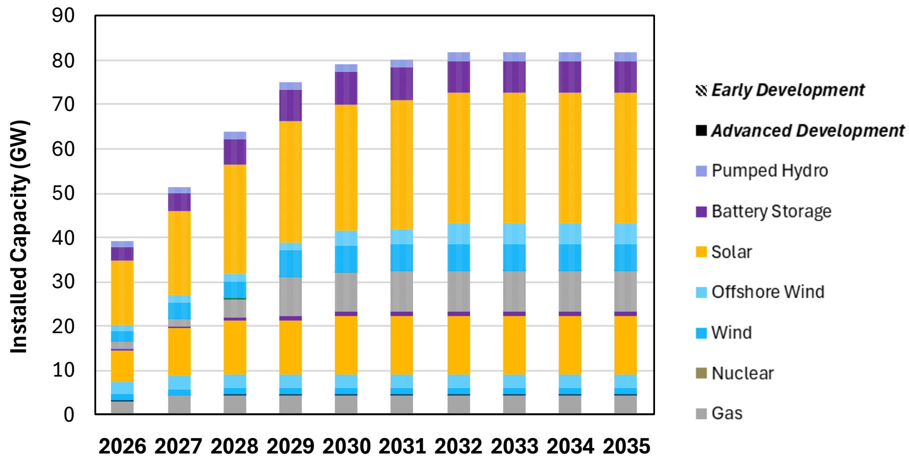


Figure F-29: Planned Resource Nameplate Capacity Additions in MISO

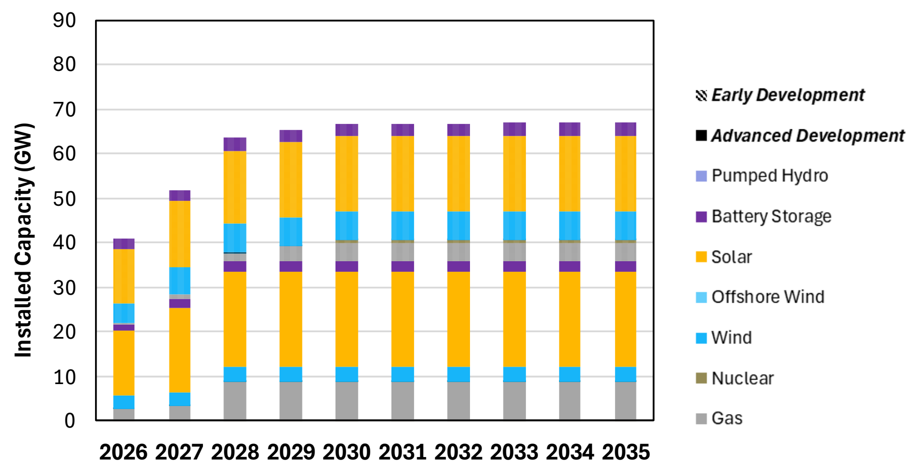


Figure F-30: Planned Resource Nameplate Capacity Additions in ComEd Zone

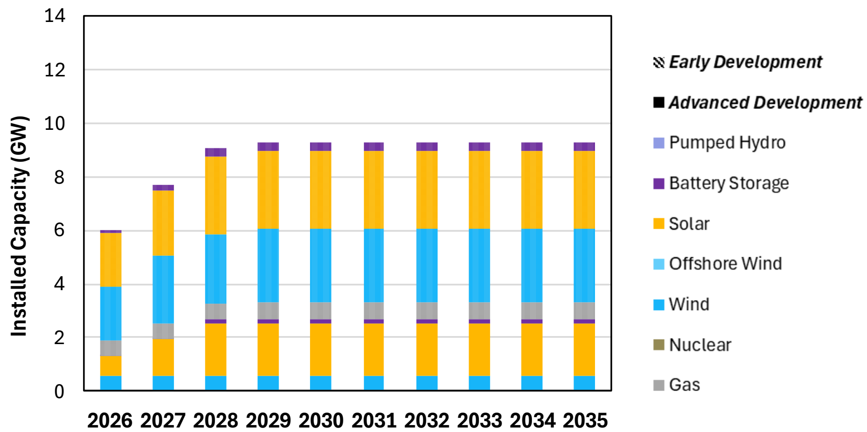
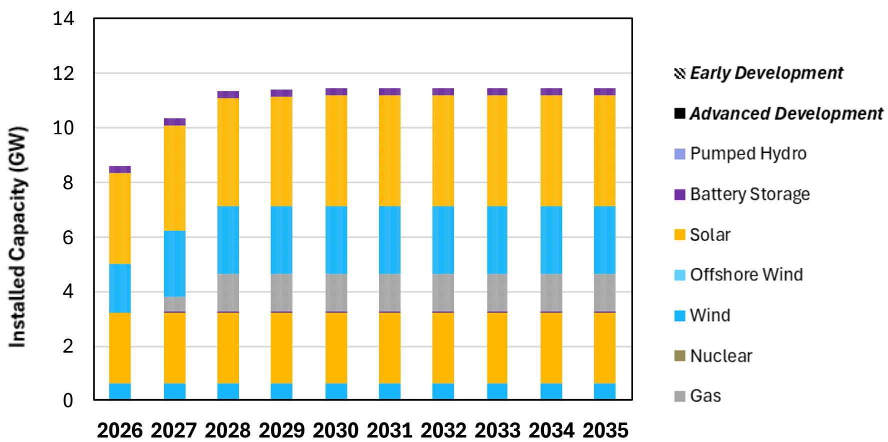


Figure F-31: Planned Resource Nameplate Capacity Additions in MISO LRZ 4



To reflect the practical challenges developers face—including interconnection process delays, supply chain constraints, and siting or permitting issues—an alternative outlook applies realistic delays to project CODs based on project maturity. Figure F-32 through Figure F-35 show the impact of these delays. The following delays are applied based on each project's development stage and are not cumulative across stages (i.e., each project receives a single delay based on its current status, not the sum of delays across all prior stages):

- Under construction and testing: 0-1 year
- Permitted: +2 years
- Application pending: +3 years
- Feasibility: +4 years

- Proposed: +5 years

Figure F-32: Planned Resource Nameplate Capacity Additions in PJM—Delay Scenario

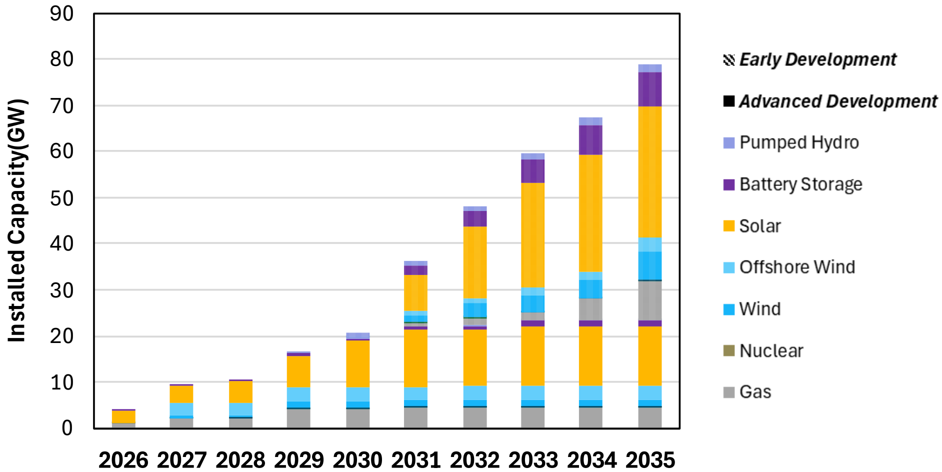


Figure F-33: Planned Resource Nameplate Capacity Additions in MISO—Delay Scenario

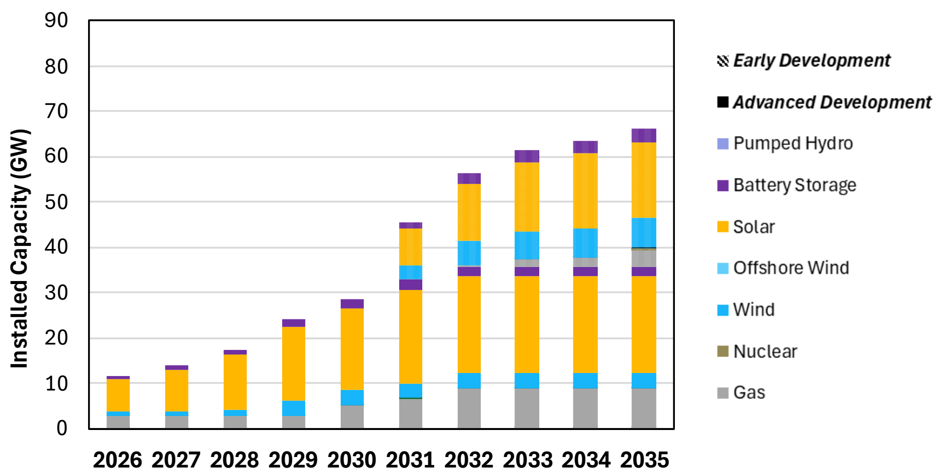


Figure F-34: Planned Resource Nameplate Capacity Additions in ComEd Zone—Delay Scenario

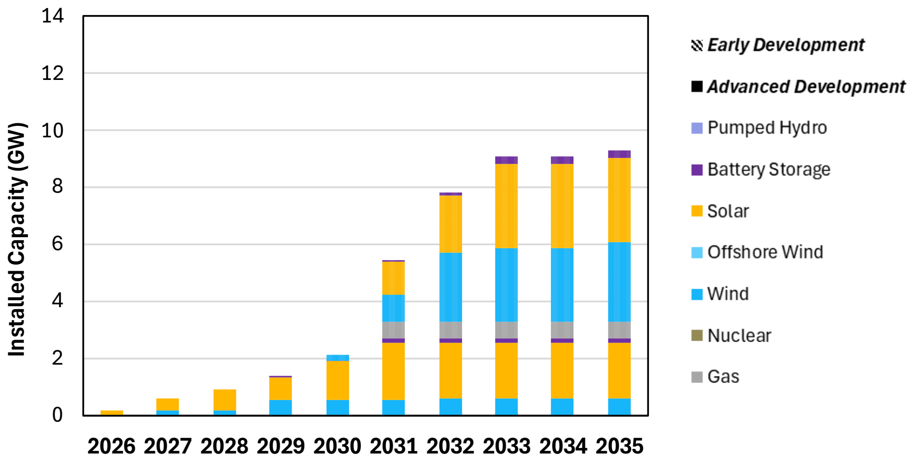
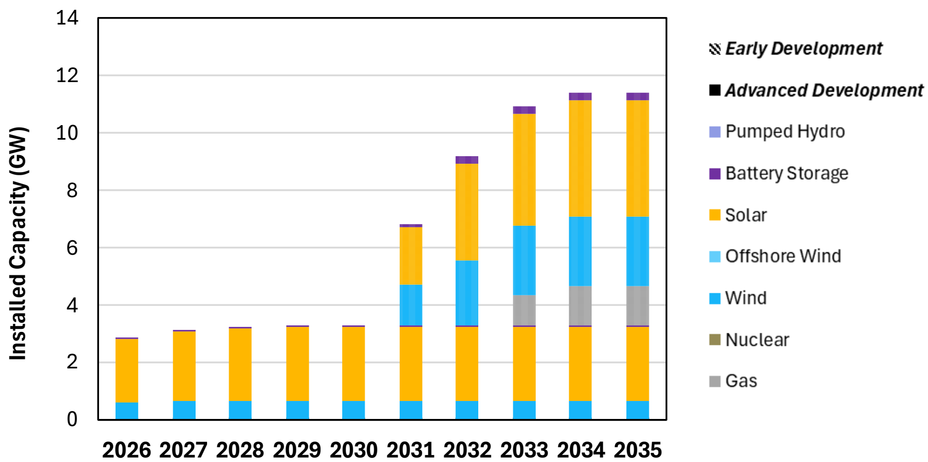


Figure F-35: Planned Resource Nameplate Capacity Additions in MISO LRZ 4—Delay Scenario



In parallel with standard queue developments, both RTOs have identified a subset of priority reliability resources expected to come online without delay. These are treated separately from queue-based projects in this analysis. These additions are also reflected in the resource adequacy balance model.

- In PJM, the Reliability Resource Initiative (RRI)[78] identifies specific capacity additions or existing generator uprates needed to address near-term system constraints and mitigate reliability risks flagged during the 2023–2024 capacity auctions. These

[78] Tariff Revisions for Reliability Resource Initiative, PJM Interconnection: [20241213-er25-712-000.pdf](20241213-er25-712-000.pdf).

projects are assumed to come online as scheduled and are exempt from the COD delay assumptions.

- In MISO, the Expedited Resource Addition Study (ERAS)[79] serves a similar role, designating key capacity resources that the RTO expects to interconnect and operate on an accelerated basis to maintain system resource adequacy. While the first set of resources are reflected in this analysis, MISO is evaluating additional projects for future ERAS considerations.

Figure F-36: Planned Resource Capacity Additions in PJM RRI Queue

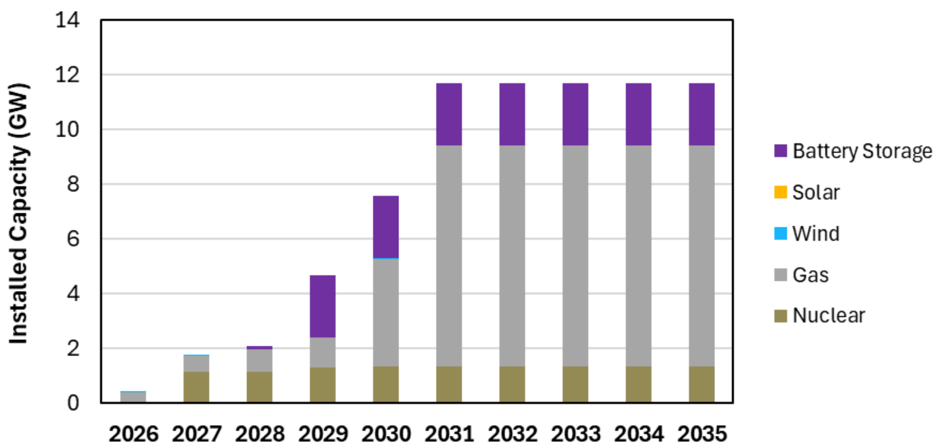
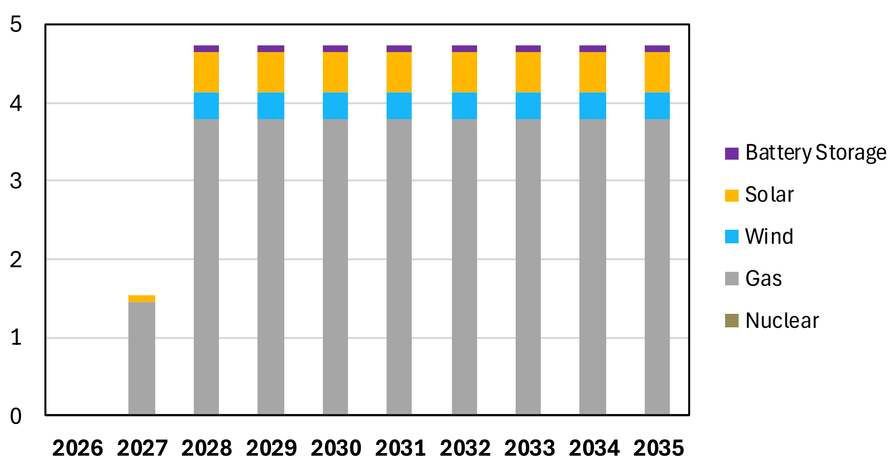


Figure F-37: Planned Resource NRIS Capacity Additions in MISO ERAS Queue



As mentioned, PLEXOS has a starting point in 2030 that assumes under construction and advanced stage projects between 2026 and 2030 come online; however, new resources in

[79] FERC Approves MISO's Expedited Resource Addition Study: https://www.misoenergy.org/meet-miso/media-center/2025---news-releases/ferc-approves-misos-expedited-resource-addition-study/.

2030 and beyond are optimized by the PLEXOS model via resource selections. The candidate resources described hereafter represent the menu of new resource options from which PLEXOS can select to create an optimal portfolio. The candidate resources identified for this study primarily represent established, commercially proven technologies available today. The guiding principles used to determine whether a resource technology should be modeled in PLEXOS include:

- **Established**: The resource is an established commercialized technology in use today.
- **Scalable**: New builds of the resource could be realistically selected at sufficient volume to meaningfully impact Illinois' electric portfolio.
- **Economic**: This resource is projected to be cost-competitive within the timeframe of the modeling horizon, with sufficient publicly available market data to validate the projections.
- **Actionable**: Mechanisms currently exist, or could be developed under reasonable expectations, to enable the State to guide procurement of this resource.
- **Timely**: This resource could be developed within the timeframe of the modeling horizon with a reasonable degree of certainty.

The candidate resource technologies represented in PLEXOS are listed below. These resources are made available across all of the PLEXOS zones for selection to meet reliability, hourly demand, and policy requirements. Candidate resources within Illinois are represented within each of the REAP zones, which help reflect deliverability constraints and consider economic transmission upgrades, described in more detail in section F.2.12. It should be noted that transmission expansion is aligned with known transmission plans (i.e. MISO's MTEP[80] and PJM's RTEP[81]) but not offered to the model for economic selection.

To ensure consistency with CEJA, all new in-state gas resources modeled in Illinois are assumed to be hydrogen-ready and thus capable of achieving compliance with the law's zero-emission requirements by 2045. These hydrogen-ready resources incur a cost premium over conventional gas generators, reflecting expected technology upgrades and

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[80] MISO MTEP: https://cdn.misoenergy.org/20241001%20PAC%20Item%2002%20MTEP24%20Report%20Preview650567.pdf.

[81] PJM RTEP 2024: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250304/20250304-2024-rtep-window-1-reliability-analysis-report.pdf.

fuel flexibility requirements. This premium is embedded in the cost trajectories shown further below.

Available candidate resource potential for new resources is based on NREL datasets; however, new nuclear is assumed to be constrained to 1 GW by 2035 and 3 GW by 2040 to reflect realistic project development timelines for this technology. All resources are available to be built starting in 2030, aside from new nuclear capacity which is first available in 2035. Certain scenarios also limit new gas availability.

- Hydrogen-ready combined-cycle gas turbines (CCGT)
- Hydrogen-ready combustion turbine (CT)
- Nuclear fission reactors
- Utility-scale solar photovoltaic
- Onshore wind
- 4-hour lithium-ion batteries
- Firm imports from out-of-state gas generators

PLEXOS is also allowed to select firm capacity imports for Illinois zones as an alternative to in-state resources. These import resources are modeled with the cost and performance characteristics of a new gas combustion turbine (CT) in neighboring states, however, the total quantity of imported capacity is capped at the relevant Illinois zonal transmission import limit defined by each RTO for its capacity auction. The PLEXOS modeling in this study considered expansions to transmission import capacity to Illinois zones resulting from transmission plans published by the RTOs, but the PLEXOS modeling did not consider additional transmission development beyond these plans as a capacity resource for Illinois. This is driven by the analysis of load resource balances which finds that both RTOs require new generation resources to meet future resource adequacy needs, meaning that transmission by itself would not represent a viable resource adequacy resource for Illinois because it would require available generation capacity from the RTOs as well.

Many emerging technologies, including long-duration storage and offshore wind, are not included pursuant to the guiding principles outlined above. Demand-side generation resources, including behind-the-meter (BTM) solar PV and distributed solar PV, are represented in the PLEXOS LT model using a forced-in adoption forecast, and are consequently not included in the table above. Demand response (DR) resources, which would be incremental to existing DR captured in the resource baseline, are not included as a candidate resource option in this study. The potential quantity, cost, and performance characteristics of new DR resources is highly uncertain and relevant data is limited—these resources are best explored through more detailed follow-on work under an Illinois IRP or similar action plan process.

Candidate resource options are presented to the PLEXOS LT model for each of the 7 REAP zones, and 4 additional zones relied on in the most recent draft REAP analysis, defined within Illinois (hereafter, these 11 zones will be referred to as the REAP zones); for more information on REAP zones, refer to section F.2.12. Within each REAP Zone, the total volume of candidate resources that can be selected by PLEXOS LT is constrained by resource quality, land area, or other procurement limitations. For candidate utility-scale solar and onshore wind resources, high-resolution supply curve data from the U.S. DOE's National Renewable Energy Laboratory (NREL) are used. These layers include detailed estimates of renewable energy potential (MW) at 4-km x 4-km resolution for solar and 2-km x 2-km resolution for wind, based on resource quality (i.e., solar irradiance or wind speed), technology design, siting constraints, and transmission costs. The resource potential for solar and wind, by REAP zone, is summarized in Table F-6.

Table F-6: Utility-Scale Solar and Wind Resource Potentials (GW)

REAP Zone	Utility	Solar Potential (GWac)	Wind Potential (GW)
Greater Chicago	ComEd	1.4	--
ComEd South	ComEd	2.3	1.5
REAP Zone 1	ComEd	6.1	4.7
REAP Zone 2	Ameren	2.1	2.7
REAP Zone 3	Ameren	2.0	1.9
REAP Zone 4	Ameren	7.5	4.4
REAP Zone 5	Ameren	8.1	0.2
REAP Zone 6	Ameren	13.2	0.8
REAP Zone 7	Ameren	5.9	6.2
Greater Peoria	Ameren	2.1	2.1
Southern IL	Ameren	19.7	1.4

NREL publishes the results of its analysis for three different sets of siting assumptions/scenarios. The "Limited Access" scenario is used for this study; it applies a combination of restrictive setbacks, stringent environmental constraints, and national defense considerations. An additional reduction to the NREL potentials was then applied to account for factors such as preservation of prime cropland and other land use considerations. As a result, the preliminary figures used in PLEXOS represent 20% of the solar potential and 50% of the wind potential estimated by NREL under the Limited Access scenario, a reduction that is designed to reflect the impact of socioeconomic, cultural, or competing land use considerations on land available for renewable development.[82] Variation in solar or wind potential between regions is primarily a function of 1) resource quality (e.g., solar irradiance or average wind speed) and 2) siting constraints (e.g., setbacks, protected lands, slope exclusions, etc.).[83]

The resource potential for new nuclear reactors is assumed to be constrained to 1 GW by 2035 and 3 GW by 2040 to reflect realistic project development timelines for this technology. Other thermal technologies, including CCGTs, CTs, and firm imports, are available starting in 2030. No other resource potential limits are assumed for in-state thermal or energy storage resources, but procurement of firm imports is capped at the maximum import capabilities specified by the ZIA (Ameren) and CETL (ComEd); additional discussion of those limits can be found in section F.2.7.

In-state resource selections are also constrained by in-state resource deliverability constraints, as discussed in section F.2.12.

Figure F-38 presents Illinois-specific upfront capital expenditure (CapEx) forecasts for key generation and storage resources modeled, while Figure F-39 and Figure F-40 illustrate the levelized cost of energy and levelized fixed cost for applicable technologies, respectively. These projections are primarily based on the National Renewable Energy Laboratory's Annual Technology Baseline,[84] adjusted to reflect current market conditions. The trends illustrate both technological progress and inflationary effects over time. Declining nominal costs (e.g., for solar) indicate that real cost reductions are expected to outpace inflation, while rising or flat trajectories (e.g., for gas technologies) forecast that real cost declines are more modest and expected to be offset by inflation overall. Key modeling assumptions include the sunset of current federal tariff impacts by 2030, expiration of solar and wind tax credits before 2030 (in line with the July 2025 budget reconciliation bill), ineligibility of battery storage for investment tax credits due to foreign content-based eligibility restrictions

[82] "Draft 2025 Inputs and Assumptions for the 2024-2026 IRP Cycle," CPUC Energy Division (February 2025): 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_draft_inputs_and_assumptions_public_slides.pdf.
[83] Lopez et al., "Solar Photovoltaics and Land-Based Wind Technical Potential and Supply Curves for the Contiguous United States: 2023 Edition," *National Renewable Energy Laboratory* (January 2024): https://docs.nrel.gov/docs/fy24osti/87843.pdf.
[84] NREL 2024 ATB: https://atb.nrel.gov/electricity/2024/data.

in current federal policy, and short-term gas turbine scarcity premiums that are assumed to normalize by 2035.

Firm capacity imports are priced at the cost of building new out-of-state gas to reflect the RTO-wide capacity tightness expected and the potential need for new generation in the rest of the RTO for Illinois to confidently rely on imports and maintain reliability. In-state gas CTs are slightly more expensive than firm imports given higher labor costs and taxes relative to neighboring states, as well as a hydrogen readiness cost imposed on in-state gas to demonstrate compliance with CEJA by 2045.

New nuclear is also a candidate resource, with estimated CapEx ranging between $10,000 and $13,000 per kW over the modeling horizon, consistent with NREL Annual Technology Baseline benchmarks.

Figure F-38: Illinois Candidate Resource CapEx (Nominal $/kWac)

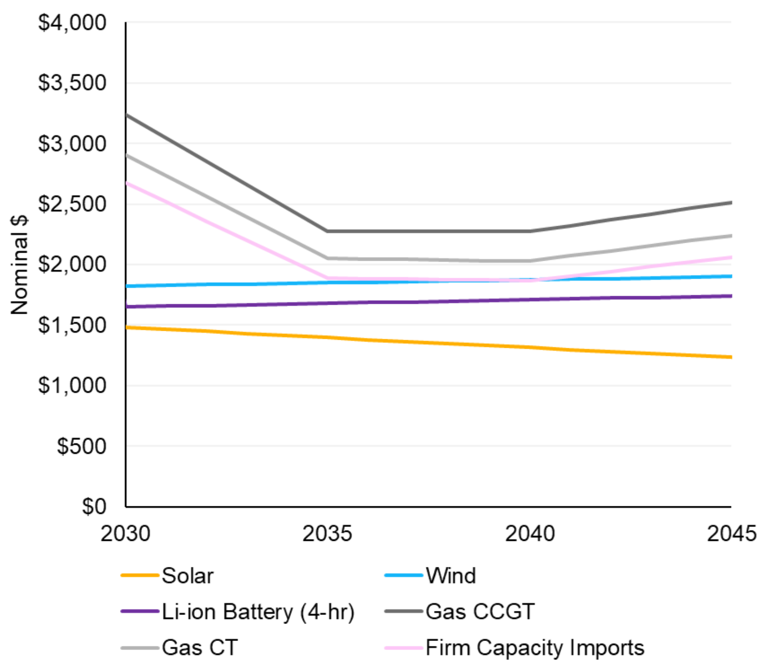


Figure F-39: Illinois Candidate Resource Levelized Cost of Energy (Nominal $/MW)

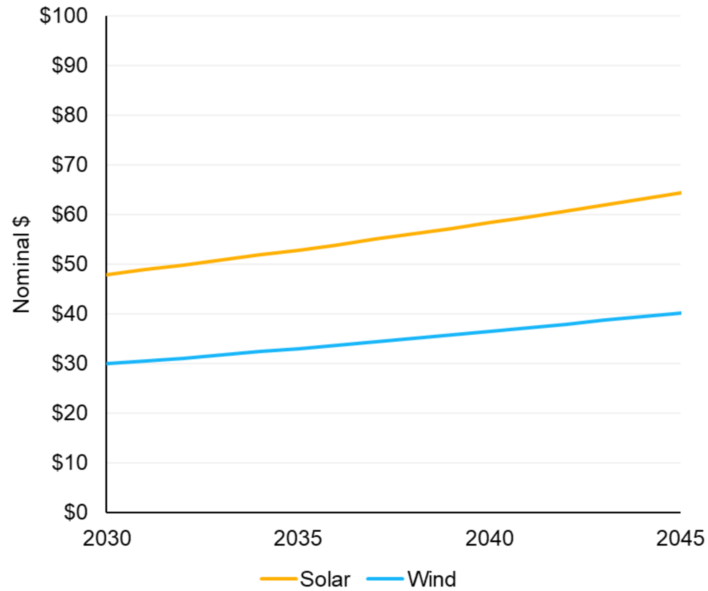
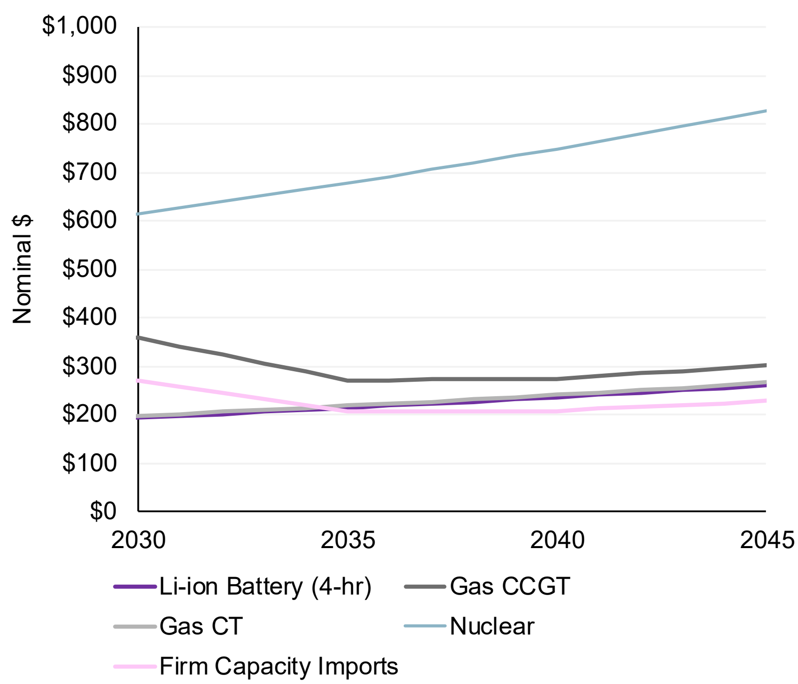


Figure F-40: Illinois Candidate Resource Levelized Fixed Cost (Nominal $/kW-yr)



F.2.5. Planning Reserve Margin

This study applies Planning Reserve Margin (PRM) assumptions differently across the near-term and long-term modeling frameworks, while maintaining alignment with the industry-standard reliability benchmark of 1-day-in-10-year Loss of Load Expectation (LOLE).

For the near-term RA balance presented, E3 directly applies RTO-calculated PRMs based on each region's established reliability planning methodology. PJM sets its resource adequacy requirements, shown in Figure F-41, through the Forecast Pool Requirement, a system-wide metric that translates the Installed Reserve Margin (IRM) into the amount of UCAP required to meet reliability standards. The FPR incorporates both the reserve margin and average forced outage rates across the system, allowing for a consistent planning benchmark across resource types. The FPR, shown in Figure F-42, is applied as a multiplier to forecasted peak demand and used in all capacity market constructs, including the PJM BRA and RPM. In this study, the near-term resource adequacy balance (2026–2035) adopts PJM's FPR trajectory as published, holding those values constant beyond 2026/2027 in cases where forward estimates are not available.

Figure F-41: PJM Resource Adequacy Requirement (GW) 2026-2035

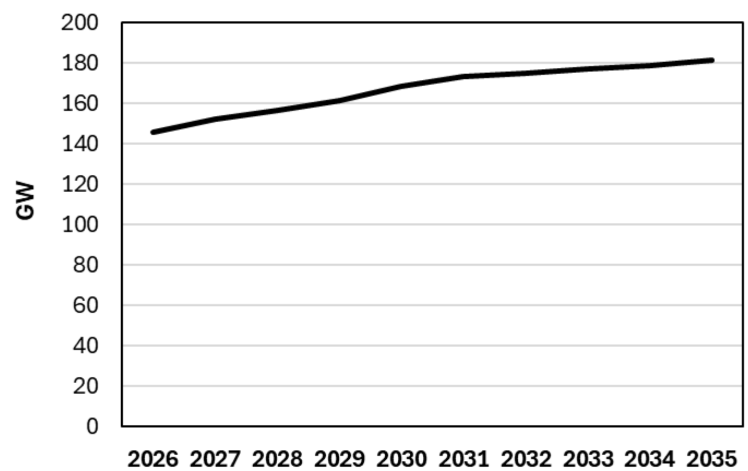
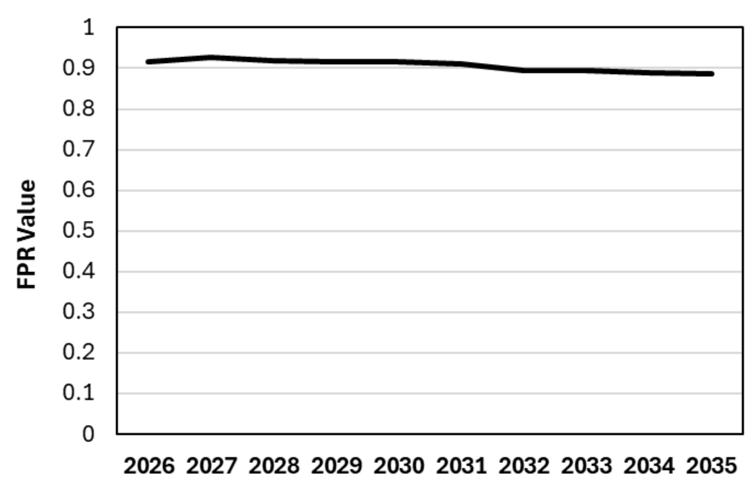


Figure F-42: PJM Forecast Pool Requirement 2026-2035



MISO determines its system-wide capacity needs through its annual Loss of Load Expectation Study, which assesses reliability based on probabilistic modeling of generator outages, load variability, weather conditions, and system stress events. The results of this study define the Planning Reserve Margin Requirement (PRMR), the minimum accredited capacity needed to maintain a one-day-in-ten-year LOLE standard. For this study's near-term RA balance, E3 uses the PRMR and accreditation assumptions from the 2025–2026 indicative DLOL studies to define MISO-wide and zonal adequacy targets. The PRMR values are held constant through 2035, shown in Figure F-44, and the MISO-wide requirement is shown in Figure F-43.

Figure F-43: MISO Resource Adequacy Requirements (GW) 2026-2035

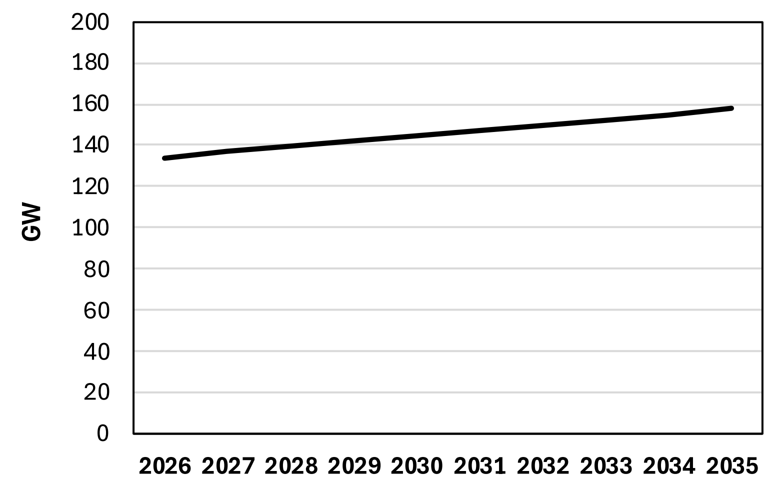
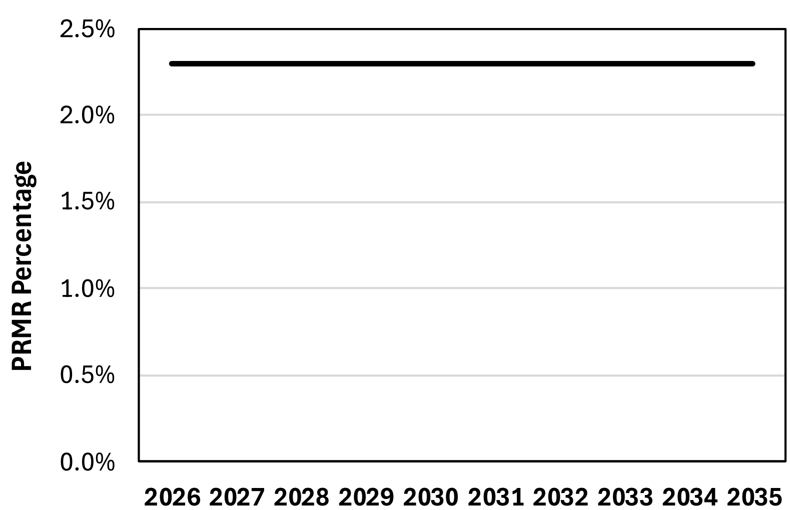


Figure F-44: MISO Planning Reserve Margin Requirement 2026-2035



E3 uses RECAP to calculate the PRMs applied in the PLEXOS capacity expansion model. These PRMs represent the minimum required capacity above projected gross peak load necessary to meet the industry-standard reliability threshold of 1-day-in-10-year (0.1 LOLE). While PJM and MISO each publish their own PRMs annually based on internal methodologies and inputs (i.e. MISO's DLOL[85] and PJM's FPR[86]), E3 calculates PRMs using RECAP to ensure alignment with the resource accreditation assumptions detailed in Table F-7. This approach harmonizes both the numerator (effective capacity contributions from each resource type) and the denominator (required reserve margins) using a consistent modeling framework, which is critical for maintaining fidelity in the capacity expansion optimization process. While PJM, MISO, and E3 utilize different resource adequacy frameworks to calculate the 1-day-in-10-year LOLE target, the result of achieving the industry standard reliability requirement will be aligned.

To represent system reliability requirements, four capacity zones are modeled in PLEXOS: two RTO zones and two Illinois zones. The model footprint includes both MISO and PJM regions as external capacity zones to capture broader system reliability needs and interactions between the Illinois zones and the markets. All resources are assumed to provide capacity attributes for the zone in which they are physically located, except for firm capacity from thermal plants physically located in neighboring RTO regions but contracted to provide reliable capacity to Illinois utilities. Each reliability requirement is represented as a planning reserve margin percentage, detailed in Table F-7.

Table F-7: Modeled Planning Reserve Margin by Region (% of Gross Median Peak Load)

Region	PRM
PJM	7.5%
MISO	5.5%
ComEd Zone	8.3%
LRZ 4	5.8%

The Planning Reserve Margin (PRM) is measured as the quantity of effective capacity needed above the median peak load expectation to ensure system reliability. This accounts for the possibility of load exceeding the median peak expectation and ensures that a 1-day-in-10-years reliability target[87] can be achieved. E3 uses a PCAP PRM framework in our capacity expansion work which represents the amount of perfect capacity needed above the median peak load to serve load and meet the LOLE standard. All resources are then accredited based on the amount of perfect capacity they provide to determine how they contribute to

[85] Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) results, MISO: https://cdn.misoenergy.org/PY%2025-26%20Indicative%20DLOL%20Results657893.pdf.
[86] 2025 PJM Effective Load Carrying Capability and Reserve Requirement Study, PJM: 2025-pjm-elcc-rrs.pdf.
[87] Equivalent to a 0.1 Loss of Load Expectation (LOLE) days in any given year.

meeting the PRM target. Consistent with the modeling practices of MISO and PJM, operating reserves are not accounted for in the PRM calculation.

Separate PRM requirements are calculated for each of the four regions, informed by their respective load shapes. Resource outages and performance limitations are reflected in the ELCCs estimated for each resource type. PLEXOS is constrained to build sufficient resources to ensure that the total sum of ELCCs from all resources is greater than or equal to the median peak load grossed up by the PRM.

F.2.6. Resource Accreditation and Effective Load Carrying Capabilities

This study applies different resource accreditation approaches in the near-term and long-term analyses, reflecting the distinct purposes of each assessment while maintaining consistency with established reliability frameworks that all achieve the 1-in-10-day LOLE standard. In the near-term resource adequacy balance, resource accreditation values are taken directly from the applicable RTO methodologies—specifically, the FPR framework in PJM and the DLOL framework in MISO. In contrast, the long-term analysis requires a dynamic treatment of ELCCs that reflects how the reliability contribution of resources evolves as the system changes. For this purpose, ELCCs are calculated endogenously using E3's RECAP loss-of-load probability model and passed into PLEXOS as ELCC curves that vary with resource penetration and portfolio composition.

PJM employs a probabilistic based accreditation methodology to assess the contribution of each resource class to system reliability. PJM calculates resource accreditation based using its Resource Reliability Analytics (RRA) model[88] which simulates system performance under various conditions to estimate each resource's contribution to reducing system unserved energy. The primary measurement is the Marginal Reliability Improvement Metric (MRIM),[89] which evaluates how incremental capacity of a given resource type improves system reliability, measured as a reduction in Expected Unserved Energy (EUE). This ensures that accreditation values reflect not just a resource's availability but also its incremental value to system reliability in the context of the broader resource mix.

PJM publishes annual preliminary MRI-based ELCCs ratings that forecast accreditation factors by resource type for a 10-year horizon. The load resource balance analysis in this chapter uses the full set of MRI-based ELCCs values from PJM's 2026/2027 through

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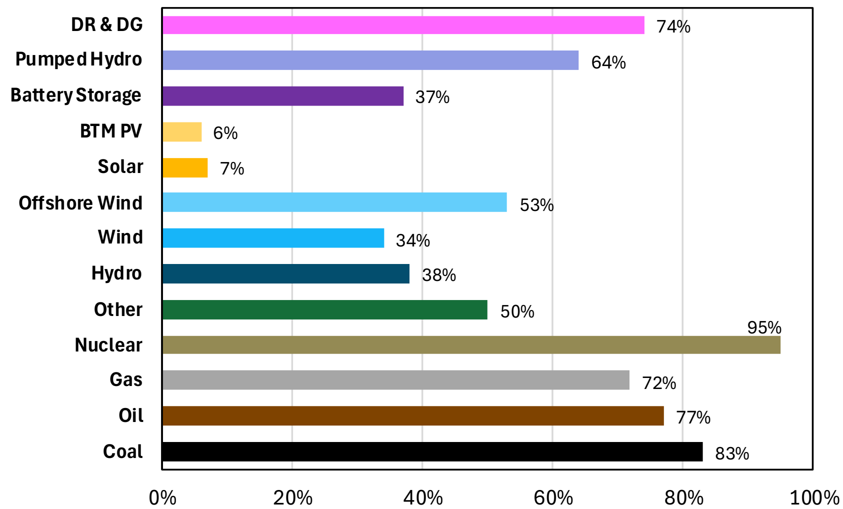
[88] 2025 PJM Effective Load Carrying Capability and Reserve Requirement Study, PJM: https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2025-pjm-elcc-rrs.pdf.

[89] This accreditation is called "ELCCs" or "marginal ELCCs" in PJM documents. However, there are slight differences in the way PJM calculates this accreditation and how ELCCs have been calculated for this study. To avoid confusion, we will refer to PJM's values as MRI accreditation. For more details see Appendix F.

2035/2036 delivery years, as presented in the latest ratings document.[90] These MRI-based ELCCs are applied consistently to both existing and new resources in the PJM system and the Illinois ComEd zone. These are depicted in Figure F-45.

Figure F-45: PJM Projected MRI-based ELCCs by Resource Type in 2030



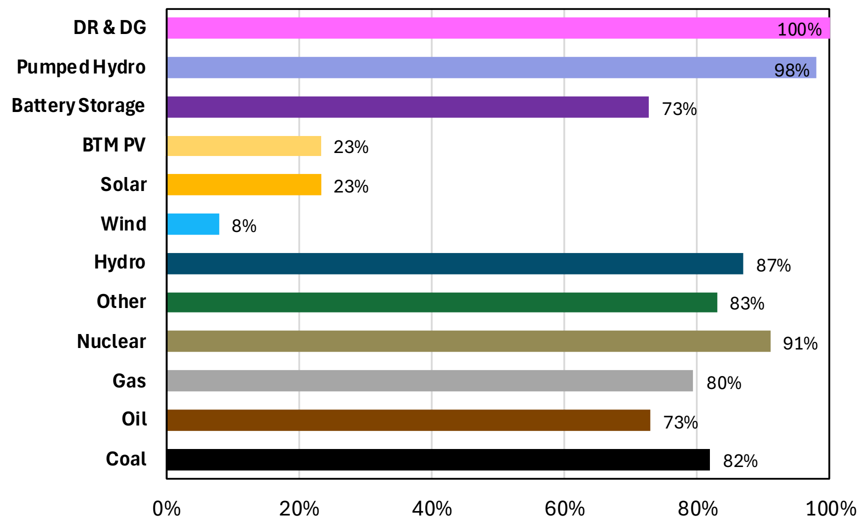
MISO is also transitioning to a probabilistic accreditation framework. Under the methodology, all resources will be accredited using a combination of the DLOL method and seasonal UCAP calculations as described in its accreditation reform process.[91]

For the 2025–2026 planning cycle, MISO has published indicative DLOL results,[92] which provide resource-class level capacity accreditation values for wind, solar, storage, and conventional resources. These values form the starting point for accreditation assumptions used in this study's near-term resource adequacy balance and are applied uniformly across MISO-wide and Illinois (LRZ 4) zones. To reflect how accreditation values may evolve, this study also draws on the forecasted DLOL results published in the technical appendix of MISO's 2024 Regional Resource Assessment (RRA). These materials indicate that DLOL values for solar and battery storage in particular can vary meaningfully as installed capacity increases, while DLOL values for wind and conventional resources remain relatively stable over time. Accordingly, this analysis does not apply a single fixed DLOL percentage for solar and storage across the full modeling horizon but instead applies calculated DLOL values for

[90] Preliminary ELCC Class Ratings for Period Delivery Year 2027/28 – Delivery Year 2035/36: https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings.pdf
[91] MISO Resource Accreditation White Paper Version 2.1: https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf
[92] MISO Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) Results: https://cdn.misoenergy.org/PY%2025-26%20Indicative%20DLOL%20Results657893.pdf

solar and storage based on resource penetration levels, utilizing the relationship between installed capacity and DLOL observed in the 2025–2026 indicative results and forward-looking DLOL tables provided in the RRA technical appendix. For wind and other resource types whose accreditation values change minimally across the RRA projections, the 2025–2026 indicative DLOL values are held constant through 2035. These are depicted in Figure F-46.

Figure F-46: MISO Projected DLOL values by Resource Type in 2030



E3 calculated ELCC values for this study using a methodology consistent with the core principles used by PJM and MISO—utilizing a LOLP model that measures resource performance during system-critical periods. While E3's ELCC methodology differs from PJM's MRIM and MISO's DLOL approach in its implementation, all three methods share a common foundation: measuring how resources contribute to system reliability during periods of peak risk. E3 calculates ELCCs based on changes in Loss of Load Expectation (LOLE), consistent with a 1-in-10-year reliability standard and applies these values within a unified framework for both accreditation and reliability need determination. This ensures that ELCCs and planning reserve margin (PRM) targets are harmonized.

Because long-term capacity expansion models must evaluate how ELCCs change as portfolios and load conditions evolve, ELCCs are not fixed inputs in PLEXOS. Instead, ELCC curves—which represent the marginal ELCC of a resource as a function of its penetration—are developed using the LOLP model and are passed into PLEXOS to ensure these dynamics are captured. This essentially allows PLEXOS to compare different resource types on a level playing field and select a cost-optimal portfolio that ensures the total reliability value of the portfolio is at least equal to the reliability requirement.

When discussing ELCCs, we will be referring to our calculation methodology which is determined based on the marginal change in LOLE. ELCC curves were produced for three resource types: wind, solar, and 4-hour storage, and for each of the 4 regions studied—MISO LRZs 1-7, PJM, MISO LRZ 4, and the ComEd zone—to capture the load-resource interactions unique to each region. ELCC curves produced for the four regions are shown Figure F-47 through Figure F-50. To confirm alignment with the RTOs, E3 conducted "apples-to-apples" comparisons to the RTO approaches and these show that E3's ELCC values closely track those published by PJM and MISO.

Since MISO and PJM are significantly larger systems than the ComEd zone and LRZ 4 respectively, the ELCC degradation is slower (e.g., the marginal ELCC at 20 GW of total penetration for 4-hr storage is 60% in PJM but only 21% in the ComEd zone). Using ELCC curves specific to each of the 4 regions in PLEXOS ensures that the resource portfolios selected maintain both "local" reliability within Illinois zones and RTO-wide reliability.

Figure F-47: PJM ELCC Curves

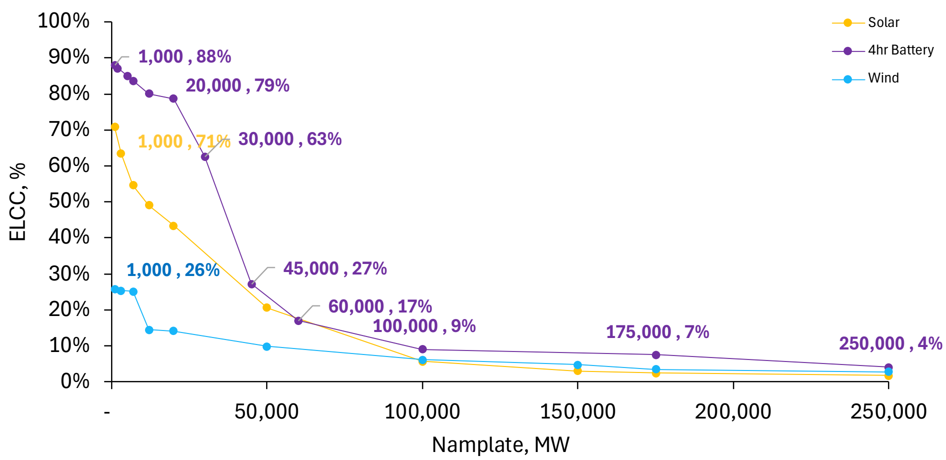


Figure F-48: MISO LRZs 1-7 ELCC Curves

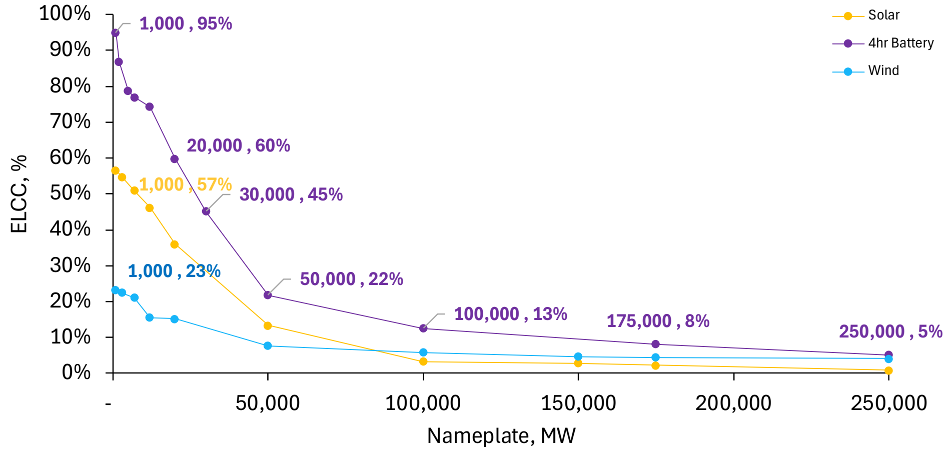


Figure F-49: ComEd Zone ELCC Curves

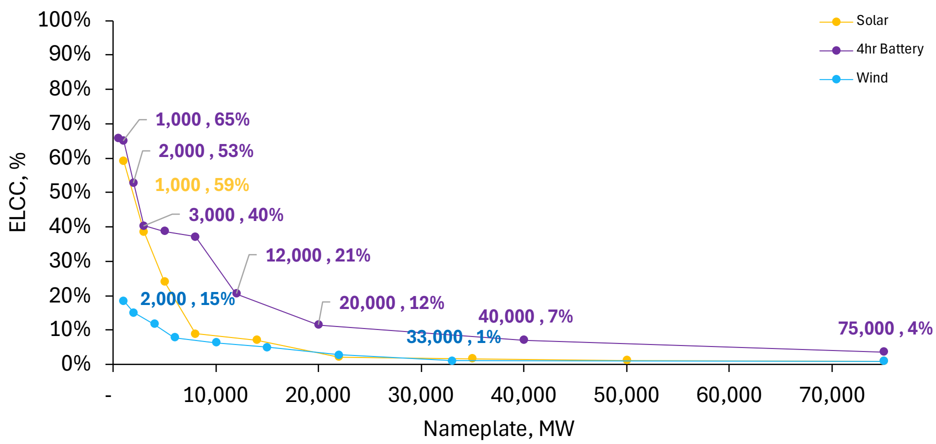
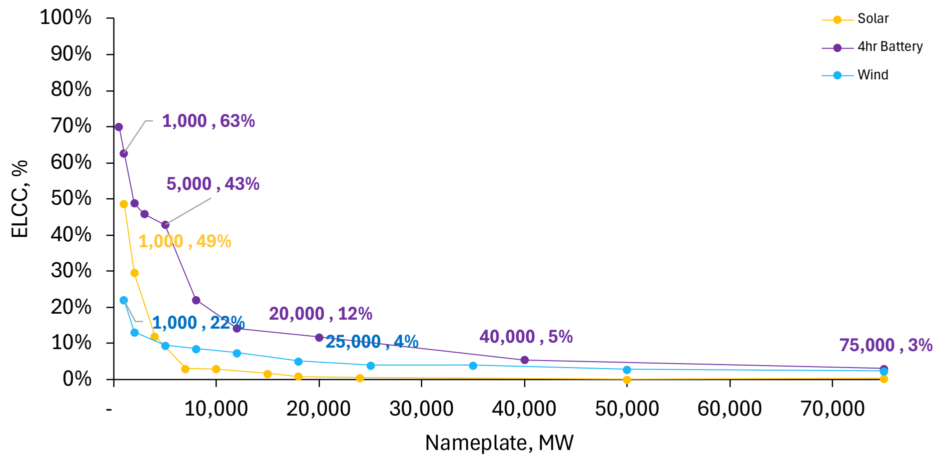


Figure F-50: MISO LRZ 4 ELCC Curves



Generally, variable renewable energy and battery storage ELCCs exhibit diminishing returns as penetration increases. To illustrate this principle, consider the timing and duration of the system gross peak, before any renewables are brought online. In PJM and MISO today (late 2025), gross peaks typically occur in the middle of summer and are driven by cooling loads in the mid-afternoon. The first MWs of solar on the system receive a high marginal ELCC, since solar production in these hours is relatively high. However, as more solar resources are added to the system, the net peak load gradually shifts later into the afternoon, outside peak solar hours, which causes marginal ELCCs to decline with increasing penetration.

For wind resources, ELCCs are generally lower than solar because wind production is typically highest overnight and in the winter months, outside of the peak window. Wind ELCCs also decline with increasing penetration because of the same saturation effects as solar—as more wind is added, the net peak gradually shifts to hours where wind production is not as strong.

Battery storage is subject to similar dynamics. Battery ELCCs start high since system reliability events are relatively short in duration at first. However, as additional 4-hour batteries are added to meet these shorter-duration events, the net peak window adjusts and becomes longer in duration, leading to diminishing returns with the next tranche of storage.

ELCC, or effective load-carrying capability, measures the percentage of a resource's nameplate capacity that can be relied upon to contribute to system reliability during critical periods. ELCCs are calculated using LOLP models and are a function of the underlying resource portfolio and load conditions. Both PJM and MISO publish RTO wide resource accreditations that reflect the marginal reliability contribution of adding incremental capacity from each resource class. While each RTO has a unique way of calculating ELCCs, each process reflects the same underlying principle—resources are accredited based on how they perform in critical hours.

PJM uses the "Marginal Reliability Improvement" Metric[93] to accredit resources. This methodology calculates how an incremental addition of a specific resource type reduces system unserved energy relative to an equivalent incremental addition of "perfect capacity." This calculation quantifies the amount of energy a resource can provide to the system when it is in need.

MISO uses the "Direct Loss-of-Load Method" (DLOL) to accredit resources. This method quantifies how a resource can serve load during scarcity periods identified in its LOLP model. MISO calculates DLOL values for each resource on a seasonal basis to capture differences in performance for critical periods within each season.

E3 developed the ELCC curves for each resource class following a three-step process: First, a base portfolio of resources and loads is developed and tuned by adding perfect capacity to meet the 0.1 LOLE reliability target. Next, the resource of interest is added to the portfolio, resulting in an increase in total system reliability. Finally, through an iterative process, perfect capacity is removed from the portfolio until the original reliability target is restored. This process is then repeated across a wide range of penetrations for each resource type.

In this process, the amount of perfect capacity removed represents the resource's ELCC. Conceptually, ELCC relates a resource's nameplate to its "equivalent perfect capacity." For example, a 100-MW resource with a 50% ELCC provides the same reliability value as a 50-MW, perfectly reliable resource that is effectively available in all hours and without outages.

Figure F-51: ELCC Calculation Methodology

While MISO, PJM, and E3 all use industry best practice methods to calculate ELCCs, differences remain in implementation. Even when applying the same ELCC calculation

[93] PJM Effective Load Carrying Capability and Reserve Requirement Study (ELCC/RRS) (October 22, 2025): https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2025-pjm-elcc-rrs.pdf.

technique, differences in results can also arise from the underlying assumptions of each LOLP model, such as weather data, load profiles, resource profiles, portfolio assumptions and outage rates. Thus, while E3's ELCCs may differ a bit from those of the RTOs, the overall dynamics of resource interactions are consistent with the methods used by the markets. Moreover, future ELCCs are inherently uncertain because they are a function of the resource portfolio in each market. The ELCC values used here are plausible projections of how ELCCs might evolve in each market in response to changes in the resource mix, but they are not intended to be precise forecasts of market accreditation in any given year.

E3 performed a benchmarking exercise between the LOLP modeling performed with RECAP for this study and the metrics calculated by the RTOs for their published resource accreditation values. This benchmarking exercise is summarized here for illustration purposes only to demonstrate general alignment between the LOLP approach used in this study and those used by PJM and MISO. This exercise is not intended to draw any conclusions about the efficacy or validity of the approaches used by each RTO.

For PJM, E3 replicated the marginal reliability improvement methodology on a representative 2035 system for Fixed Tilt Solar, Land Based Wind, and 4-hour storage. The resulting MRI ELCCs are within a similar order of magnitude. However, differences in underlying future portfolios used in the LOLP modeling are likely driving differences in results.

Table F-8: PJM vs E3 Marginal Reliability Improvement Methodology Comparison

Resource Group	2035 PJM ELCC[94] MRI methodology	2035 E3 marginal ELCC MRI methodology
Fixed Tilt Solar	6%	2%
Land Based Wind	19%	25%
4-hour storage	23%	41%

The same exercise was performed with MISO's published DLOL values on the same representative 2035 system. MISO's methodology of identifying seasonal critical hours was more difficult to replicate, so E3 used resource performance during summer loss of load hours in a model case tuned to a 0.1 LOLE standard to determine a comparable DLOL value. While MISO has not published 2035 DLOL values, comparing MISO's 2033 DLOL values to RECAP's 2035 results shows close alignment and reflects consistent trends. However,

[94] 2035 PJM ELCCs published here: https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings.pdf.

differences in underlying future portfolios used in the LOLP modeling are likely driving differences in results.

Table F-9: MISO vs E3 DLOL Comparison

Resource Group	2033 MISO DLOL[95] *Summer DLOL*	2035 E3 DLOL *Summer Generation during LOL*
Fixed Tilt Solar	5%	9%
Land Based Wind	10%	10%
4-hour storage	96%	80%

From this point forward in the report, when discussing ELCCs, we will be referring to E3's calculation methodology described above, which is determined based on the marginal change in LOLE. ELCC curves were produced for three resource types: wind, solar, and 4-hour storage. ELCC curves were developed sequentially, in that order, to ensure that interactions between different resource types are also captured. Curves were developed for each of the four regions studied—MISO, PJM, Ameren, and ComEd—to capture the load-resource interactions unique to each region.

The three-step methodology described above was used to calculate the ELCC of different thermal resource types. Since significant variation was not observed across resource types, a single fleet wide thermal ELCC of 90% was calculated and assumed for all existing and candidate thermal resource types. Solar and wind reach ELCC saturation with increasing penetration because their availability is constrained by weather – the critical hours eventually move to those without sunlight and low wind respectively. Storage ELCCs primarily saturate due to limitation on duration – critical events increase in duration as storage penetration increases. Thermal resources receive less than 100% ELCC due to risk of outages in critical periods that can impact the generator and/or the fuel supply. Thermal resources can similarly experience diminishing ELCCs with increasing penetration if outages are correlated. However, if thermal resources and fuel supply are weatherized, this risk is reduced and the resource class ELCC does not decrease drastically with increasing penetration and may even increase. In fact, ELCCs of existing thermal resources may also increase if they are weatherized. Thus, candidate thermal resources were also assumed to receive the same 90% ELCC without any further reduction.

ELCC curves produced for the four regions are shown in Figure F-47 through Figure F-50. The exact values vary based on the load-resource interactions within each region. Since MISO

[95] 2033 MISO DLOL results are published here: https://cdn.misoenergy.org/2024%20RRA_Technical%20Appendix676208.pdf.

and PJM are significantly larger systems than ComEd and LRZ 4 respectively, the ELCC degradation is slower (e.g., the marginal ELCC at 20 GW of total penetration for 4-hr storage is 60% in PJM but only 21% in ComEd). Using ELCC curves specific to each of the 4 regions in PLEXOS ensures that the resource portfolios selected maintain both "local" reliability within Illinois zones and RTO-wide reliability.

Generally, variable renewable energy and battery storage ELCCs exhibit diminishing returns as penetration increases. To illustrate this principle, consider the timing and duration of the system gross peak, before any renewables are brought online. In PJM and MISO today, gross peaks typically occur in the middle of summer and are driven by cooling loads in the mid-afternoon. The first MWs of solar on the system receive a high marginal ELCC, since solar production in these hours is relatively high. However, as more solar resources are added to the system, the net peak load gradually shifts later into the afternoon, outside peak solar hours, which causes marginal ELCCs to decline with increasing penetration.

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Battery storage is subject to similar dynamics. Battery ELCCs start high since system reliability events are relatively short in duration at first. However, as additional 4-hour batteries are added to meet these shorter-duration events, the net peak window adjusts and becomes longer in duration, leading to diminishing returns with the next tranche of storage.

F.2.7. Firm Capacity Imports to Illinois

The reliability requirements in each Illinois zone (Ameren, ComEd) can be met by a combination of baseline (existing) and candidate (new) in-state capacity, as well as new out-of-state capacity contracted to provide reliability attributes to Illinois. The volume of out-of-state thermal capacity that can be selected to meet the in-state reliability constraint is informed by system topology and line limits. While the transmission representation Table F-10 represents maximum line ratings, the import capability during the most challenging hours is generally much lower. The Capacity Emergency Transfer Limit (CETL) and Zonal Import Ability (ZIA) constraints from PJM and MISO respectively inform the firm import capability limits applied to new out-of-state thermal capacity towards meeting the in-state PRM requirement (Table F-10). The CETL for ComEd is assumed to be 5.7 GW in the first model year, expanding to 7.3 GW by 2035.[96] The ZIA for MISO LRZ 4 is assumed to be 7.7 GW in 2030, expanding to 11.5 GW and 11.7 GW by 2035 and 2040, respectively.[97] CETL and ZIA values increase over time in proportion to planned transmission expansions over time. The values in Table F-10 below reflect maximum build limits on out-of-state gas that could provide firm capacity towards the in-state reliability target.

Table F-10: Firm Import Limits for Illinois Capacity Zones (MW)

Zone	2030	2035	2040+
MISO LRZ 4 (ZIA)	7,757	11,505	11,723
ComEd (CETL)	5,700	7,283	7,283

F.2.8. Transmission Ties and Limits

Transmission limits are represented in both the near-term and long-term analyses to account for the ability of Illinois zones to import capacity from other areas within their respective RTOs. For the PJM system, transmission parameters were based on the Reliability Pricing Model (RPM) and the Base Residual Auction (BRA) assumptions for the ComEd zone. For MISO, transmission capabilities were aligned with the 2025–2026 Planning Resource Auction (PRA) and the Loss of Load Expectation (LOLE) study for Local Resource Zone 4 (LZ4).

F.2.9. Renewable Portfolio Standard

The renewable portfolio standard (RPS) is modeled as six concurrent aggregate volumetric targets for MISO, PJM, and Illinois, including RTO-wide, regional, and resource-specific requirements. The RTO-wide targets for MISO and PJM (exclusive of Illinois) were calculated by applying each state's published RPS percentage to its forecasted load, adjusted for a 6.5% transmission and distribution (T&D) loss to convert to retail sales. Additional carve-outs are modeled for Dominion's RPS targets in PJM East, as well as the Illinois RPS target under the Long-Term Plan, including technology-specific targets. Table F-11 details the RPS targets represented in the model.

[96] PJM, "2026/2027 RPM Base Residual Auction Planning Period Parameters" (May 9, 2025): https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-planning-period-parameters-for-base-residual-auction-pdf.pdf.

[97] MISO, "2025-2026 PY Seasonal CIL/CEL Final Results" (October 24, 2024): https://cdn.misoenergy.org/20241024%20LOLEWG%20Item%2004%20PY%202025-2026%20Final%20CIL_CEL%20Results654989.pdf.

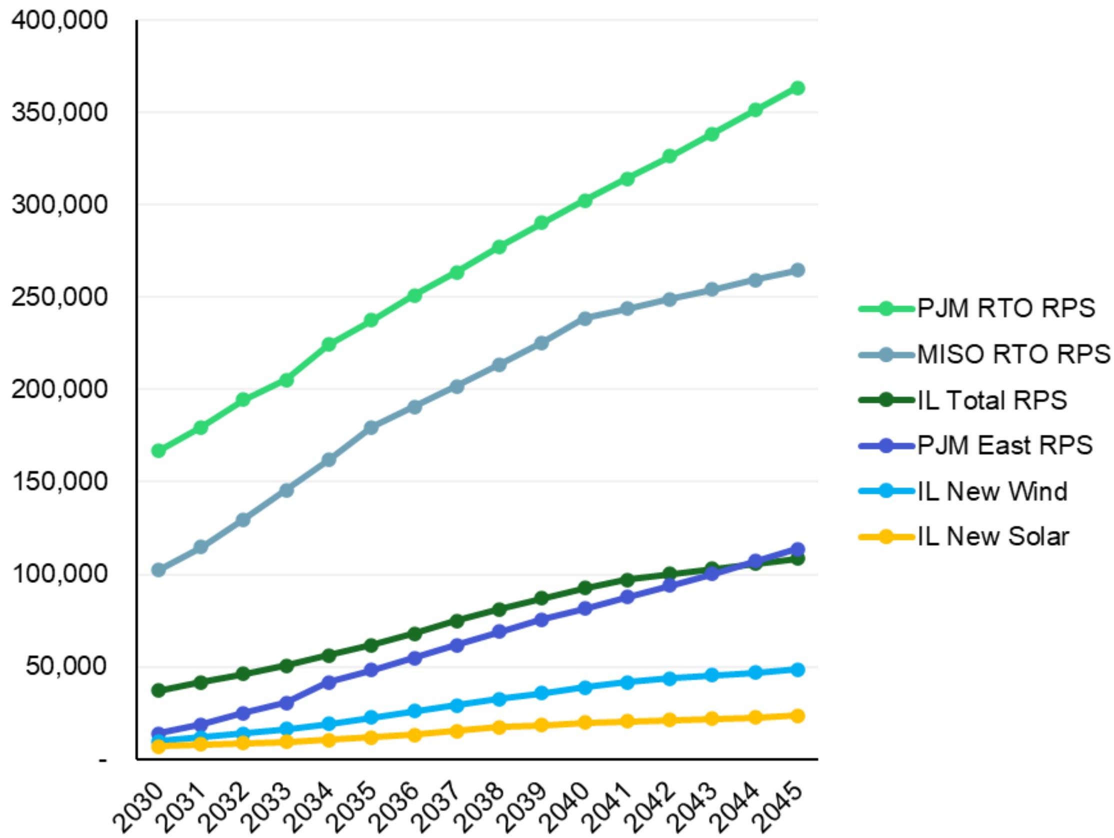
Table F-11: Renewable Portfolio Constraints Modeled

Constraint	Footprint	Eligible Resources
PJM RTO RPS	PJM East and PJM West (excludes ComEd)	100% of generation from baseline and candidate utility solar, BTM solar, wind, biomass, and hydro
PJM East RPS	PJM East only (used as a proxy for the Virginia state RPS requirement)[98]	100% of generation from candidate utility solar, BTM solar, and nuclear 43% of generation from existing utility solar, BTM solar, wind, offshore wind, biomass, and hydro [99]
MISO RTO RPS	MISO North, LRZ 5, LRZ 6, and LRZ 7 (excludes Ameren)	100% of generation from baseline and candidate utility solar, BTM solar, wind, biomass, and hydro
Illinois New Solar	Ameren, ComEd	100% of generation from candidate utility solar, aligned with the projected Utility Solar targets in the Long-Term Plan
Illinois New Wind	Ameren, ComEd	100% of generation from wind, aligned with the projected Utility Wind targets in the Long-Term Plan
Illinois Total RPS	Ameren, ComEd	100% of generation from candidate wind, utility solar, and BTM solar and a share of generation from existing solar and existing wind, aligned with the sum of existing and projected RECs in the Long-Term Plan

Figure F-52 presents the system-wide RPS targets present in the model for the modeling horizon of 2030 to 2045.

[98] A separate RPS constraint is defined for PJM East to reflect the need for load growth in PJM East, primarily driven by data center in Dominion, to be served by renewable energy, and to reflect Virginia's requirement that 75% of new renewable energy resources to meet state policies must come from in-state facilities.
[99] The 43% contribution represents the share of generation from resources in Dominion over all resources in the PJM East aggregate zone from E3's off-the-shelf market price forecast for the 2025 forecast year.

Figure F-52. System-Wide RPS Annual Volumetric Targets (GWh)



Additional details on the translation of the REC procurement targets from the Long-Term Plan into PLEXOS can be found in section F.2.11.

F.2.10. Representation of Renewable Resources and Illinois RPS Policies in PLEXOS

One key step in PLEXOS modeling is to reflect both existing and projected Renewable Energy Credit (REC) resources for Illinois. The 2026 Long-Term Renewable Resource Procurement Plan (2026 Long-Term Plan),[100] particularly Chapter 3 and Appendix B, outlines the state's existing REC contracts and projected REC procurements. To ensure that long-term resource portfolios modeled in PLEXOS align with the 2026 Long-Term Plan, it is essential to accurately translate the REC information from the plan into the physical resource framework used by PLEXOS.

[100] IPA 2026 Long-Term Renewable Resources Procurement Plan: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20251020-2026-long-term-renewable-resources-procurement-plan.pdf.

There are several important differences between the 2026 Long-Term Plan and PLEXOS that require translation and adjustment:

REC contracts vs. physical resource representation:

In the 2026 Long-Term Plan, Appendix B[101] summarizes existing and projected REC contracts. These contracts represent commitments to procure renewable energy credits, not necessarily physical generating assets that are currently operational. In contrast, PLEXOS represents only physical generation resources, which are actual megawatts (MW) and megawatt-hours (MWh) by resource type within each modeled transmission zone.

This difference has several implications. For example, the 2026 Long-Term Plan counts all existing REC contracts toward the total of "existing RECs," even if some of the contracted projects are still under development and have not yet been energized. In PLEXOS, however, these projects would not be considered as existing resources until they begin generating electricity. Another implication is that under the 2026 Long-Term Plan framework, most REC contracts expire after 15–20 years and stop counting toward total RECs after that point. PLEXOS, on the other hand, assumes renewable projects typically operate for 30 years or more. Therefore, it assumes that the projects continue generating energy to the grid over their operational lifetime.

REC programs vs. resource types:

The 2026 Long-Term Plan categorizes RECs by program, which includes the Indexed REC Program, Illinois Shines, Illinois Solar for All, and others. PLEXOS, however, organizes renewable energy by physical resource type, such as utility-scale solar, utility-scale wind, and distributed solar. Translating between these frameworks requires mapping the REC program categories in the 2026 Long-Term Plan to corresponding resource types in PLEXOS.

Procurement year vs. delivery calendar year:

In the 2026 Long-Term Plan, REC quantities are expressed by procurement year—the year in which REC contracts are signed. Each procurement year runs from June 1 through May 31 of the following year. PLEXOS, however, operates on a delivery calendar year basis, representing the time when physical resources are online and generating energy (January 1 to December 31).

There is typically a lag between REC procurement and energy delivery. Therefore, adjustments are needed to align the time conventions. For example, the 2026 Long-Term

[101] IPA Long Term Renewable Resources Procurement Plan Appendices: https://ipa.illinois.gov/renewable-resources/long-term-plan/2026-appendices.html.

Plan assumes that REC contracts generally begin delivering energy about three years after procurement. Translating RECs into PLEXOS requires shifting quantities from procurement years to delivery years to accurately reflect when generation occurs.

F.2.11. Translation Steps from the 2026 Long-Term Plan to PLEXOS

The translation of RECs from the 2026 Long-Term Plan into the format required for PLEXOS involves the following steps:

1. **Translate REC contracts to REC deliveries**: For certain programs, such as existing Illinois Shines and the Adjustable Block Program (ABP), REC contracts are equivalent to REC deliveries and can be directly transferred into the PLEXOS framework. For other programs, such as projected ABP RECs, additional calculations are required to account for the lag between contract execution and the start of REC delivery.

2. **Re-categorize RECs as existing or projected**: Existing RECs represent projects that have been energized and are currently producing energy. Projected RECs represent either contracted but not yet operational projects or anticipated future REC procurements.

3. **Assume contract renewal for long-term delivery**: To maintain consistency with the long-term operation of renewable resources, it is assumed that projects will continue delivering energy throughout their operating lifetimes regardless of the length of their REC delivery contract.

4. **Regroup RECs by resource type**: RECs are reorganized into the main PLEXOS resource categories: utility-scale solar, utility-scale wind, and distributed solar.

5. **Translate REC quantities from delivery years to calendar years**: REC quantities are adjusted to reflect calendar years, which align with PLEXOS modeling conventions. Existing REC quantities remain constant across delivery years, while projected REC quantities vary by delivery period. To perform this translation, hourly generation profiles for each resource type are converted into percentages of total annual generation by period. These percentages are then applied to allocate REC quantities from delivery years to corresponding calendar years. Table F-12 below presents the resulting allocation of RECs by calendar year.

Table F-12: RECs by Calendar Year

	DG Solar	Utility Wind	Utility Solar
Share Jan- May (%)	39.7%	51.0%	37.6%
Share June- Dec (%)	60.3%	49.0%	62.4%

Table F-13 shows the resulting energy deliveries in MWh from the 2026 Long-Term Plan to PLEXOS.

Table F-13: IPA Long Term Plan Renewable Energy Generation in PLEXOS (MWh)

Status	**Existing**	**Existing**	**Existing**	**Projected**	**Projected**	**Projected**
Calendar Year	**DG Solar**	**Utility Wind**	**Utility Solar**	**DG Solar**	**Utility Wind**	**Utility Solar**
2025	6,339,699	4,359,928	2,356,056	88,781	-	-
2026	6,368,853	4,359,928	2,356,056	847,185	289,581	441,371
2027	6,368,853	4,359,928	2,356,056	2,658,908	1,022,563	1,939,548
2028	6,368,853	4,359,928	2,356,056	4,575,811	3,052,820	3,733,003
2029	6,368,853	4,359,928	2,356,056	6,034,212	6,672,786	5,312,642
2030	6,368,853	4,359,928	2,356,056	7,466,212	9,699,638	6,940,206
2031	6,368,853	4,359,928	2,356,056	9,043,175	11,699,638	7,934,274
2032	6,368,853	4,359,928	2,356,056	10,614,656	13,699,638	8,606,602
2033	6,368,853	4,359,928	2,356,056	12,016,382	16,189,655	9,398,793
2034	6,368,853	4,359,928	2,356,056	13,324,686	19,149,655	10,481,963
2035	6,368,853	4,359,928	2,356,056	14,626,449	22,395,498	11,709,553
2036	6,368,853	4,359,928	2,356,056	15,921,702	25,833,828	13,231,551
2037	6,368,853	4,359,928	2,356,056	17,210,480	29,193,828	15,335,557
2038	6,368,853	4,359,928	2,356,056	18,492,813	32,472,159	17,188,170
2039	6,368,853	4,359,928	2,356,056	19,768,735	35,794,663	18,442,338
2040	6,368,853	4,359,928	2,356,056	20,966,153	38,989,655	19,579,744
2041	6,368,853	4,359,928	2,356,056	21,794,004	41,663,812	20,361,846
2042	6,368,853	4,359,928	2,356,056	22,232,297	43,655,465	21,140,036
2043	6,368,853	4,359,928	2,356,056	22,668,399	45,255,465	21,914,336
2044	6,368,853	4,359,928	2,356,056	23,102,320	46,855,465	22,684,764
2045	6,368,853	4,359,928	2,356,056	23,362,984	48,455,465	23,451,341
2046	6,368,853	4,359,928	2,356,056	23,362,984	49,238,770	23,928,431

This section describes how renewable energy resources and associated RECs are represented in the PLEXOS model.

1. **Resource baseline**

The PLEXOS model begins with a representation of all generators expected to be online in 2025, including their installed capacity and generation potential. Each generating unit is placed within the model's transmission zones based on its physical location in the real world. Renewable generators are represented by their nameplate capacity (MW) and a location-specific hourly generation profile, which indicates the megawatt-hours (MWh) produced in each of the 8,760 hours per megawatt of installed capacity. For the 2025 base model year, all online generation resources within and outside Illinois are represented. Distributed solar is modeled as a single aggregated generation profile for each transmission zone to maintain computational simplicity.

2. **Existing REC resources for Illinois**

Energy deliveries by year for existing distributed solar, utility-scale wind, and utility-scale solar are obtained directly from the table above and therefore consistent with the 2026 Long-Term Plan. These resources represent facilities that are online and under contract with the IPA for the delivery of RECs. There are also existing wind and solar resources located within Illinois that do not contribute toward the state's RPS target—for example, solar or wind resources in Illinois which are contracted to a load serving entity in another state would confer the rights to those RECs to the other entity and these RECs could not be used to meet Illinois state RPS targets. These are represented in the model using the full dataset of online generators in the MISO and PJM Interconnection regions. Similarly, existing wind and solar resources located outside Illinois but contracted to the IPA are included and represented using the same regional dataset. For all existing resources contracted by the IPA, it is assumed that these facilities will continue operation upon expiration of current agreements, given that their operational lifetimes typically extend beyond the terms of existing REC contracts.

3. **New resources**

New renewable resources are added to PLEXOS in two ways:

1. Manually, based on defined assumptions and external datasets, or
2. Through endogenous selection by the model based on cost optimization to meet RPS and RA requirements.

Two categories of resources are added manually:

1. Distributed solar, which is added based on policy targets, and
2. Projects that are under construction, as identified in subscription datasets from S&P Global and ABB Velocity Suite.

Distributed solar resources in Illinois are represented using single aggregated generation profiles with corresponding capacity factors. The model adds sufficient megawatts of this generic distributed solar resource such that annual generation (MWh) matches the annual “energized” REC quantities in the 2026 Long-Term Plan by calendar year.

For resources under construction that are manually added, those located within Illinois are assumed to contribute to the IPA’s RPS targets and to be under contract with the IPA. Resources located outside Illinois are assumed to be uncontracted and therefore do not contribute toward Illinois RPS compliance.

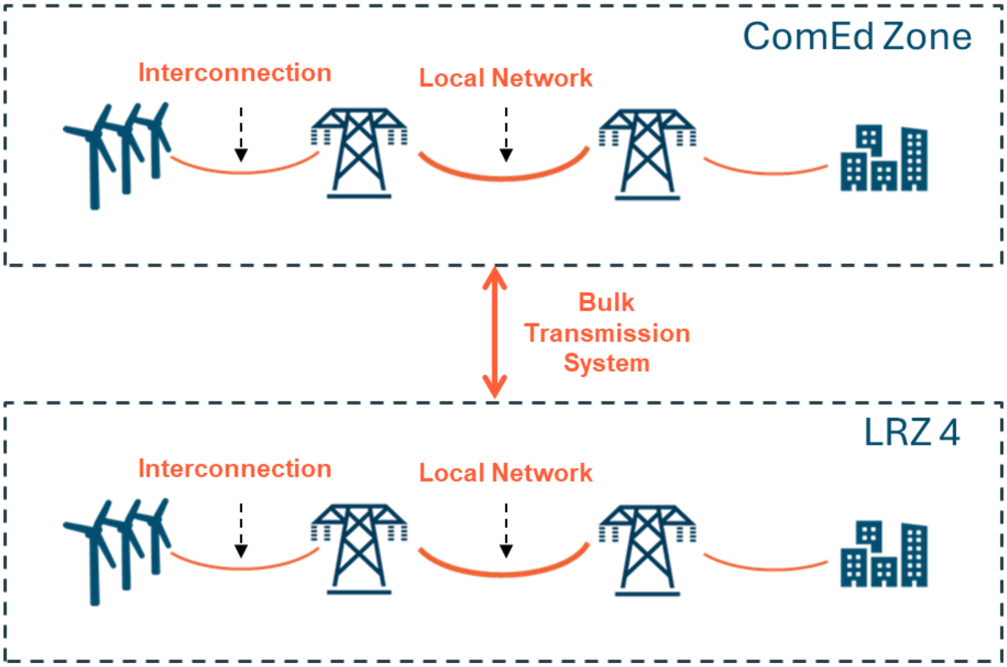
New wind and solar additions are also determined endogenously by PLEXOS to meet Illinois RPS constraints. Specific modeling requirements ensure that the model builds new resources to satisfy incremental RPS generation targets. All new resources, whether added manually or selected by the model, are assumed to enter service on January 1 of each projected year. This approach ensures consistency with long-term portfolio optimization and maintains alignment between IPA planning years and PLEXOS calendar years.

F.2.12. Implementation of REAP Zones in PLEXOS

In PLEXOS, three types of transmission system components are considered in the capacity expansion model, as summarized below and in Figure F-53:

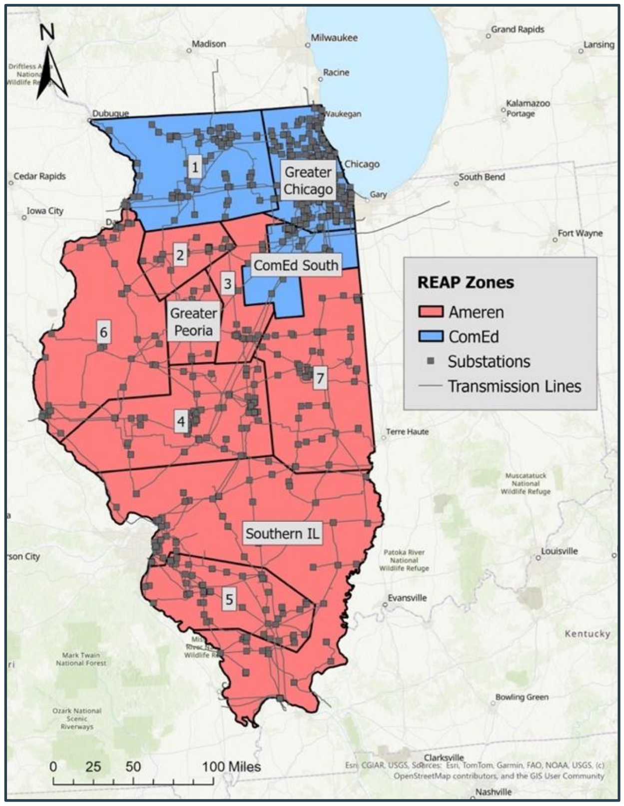
1. **Bulk transmission system**: Interzonal transfer capabilities, which are represented by the system topology and hourly flow limits between zones;
2. **Local network deliverability upgrades**: Transmission headroom within a zone that ensures that electricity can be delivered from where it is generated or discharged to load centers;
3. **Interconnection:** Spur lines and/or other local upgrades at the point of interconnection to connect generators to the transmission system.

Figure F-53: Illustration of Transmission Components



The REAP zones, as discussed in the Illinois 2025 Draft REAP, are used to define deliverability sub-areas within the MISO LRZ 4 and ComEd PLEXOS zones. These represent local network deliverability constraints and upgrade costs. The model tracks available headroom and may select transmission upgrades, at a cost, to unlock additional headroom to integrate additional resources. A map of the REAP zones is provided in Figure F-54 below.

Figure F-54: REAP Zones in Illinois



Hourly power flow over the local network within each REAP zone is not explicitly modeled in PLEXOS. Instead, the model defines additional constraints and decision variables to track the amount of transmission headroom available in each zone. Headroom is represented using a deliverability framework and represents the ability of generation and storage capacity to physically deliver electricity to load centers during the system's critical hours, which are assumed to occur between 4:00–8:00 PM from June through September. One deliverability constraint is modeled per REAP zone.

Per the assumptions in the REAP report, no transmission deliverability is assumed to exist within Illinois; headroom can only be created via fossil fuel unit retirements or investment in new transmission upgrades to accommodate resource capacity expansion. Headroom is added to the REAP zones at no cost when fossil fuel units retire under CEJA, per the schedule shown in Table F-14. These values were determined by assignment of the baseline thermal generation in Illinois to the REAP zones in Figure.

Table F-14: Fossil Retirement-Driven Transmission Headroom Creation by REAP Zone, Cumulative MW

REAP Zone	Region	2030	2035	2040	2045
Greater Chicago	ComEd	1,106	3,511	5,150	7,610
ComEd South	ComEd	0	0	0	1,445
REAP_Zone_1	ComEd	0	564	1,280	2,493
REAP_Zone_2	Ameren	0	0	0	0
REAP_Zone_3	Ameren	0	0	0	0
REAP_Zone_4	Ameren	1,701	1,701	1,882	1,993
REAP_Zone_5	Ameren	2,815	2,815	3,175	3,175
REAP_Zone_6	Ameren	0	0	84	84
REAP_Zone_7	Ameren	0	0	1,328	1,328
Greater Peoria	Ameren	1,538	1,538	1,538	1,538
Southern IL	Ameren	735	1,302	2,471	3,416

In addition to planned headroom additions, PLEXOS can select transmission upgrades, incurring a cost to accelerate resource procurements into REAP zones where thermal retirements have not yet occurred. While not linked to any explicit planned or conceptual project, these transmission upgrades are meant to represent network improvements that would be required to deliver power to load, including but not limited to line reconducting, substation upgrades, and/or new transmission lines.

The cost of incurring additional headroom is assumed as a piecewise step function. The first gigawatt of transmission upgrades in each REAP zone is set at the cost of a new 50-mile HVAC transmission line, estimated to cost $5,000/MW-mile,[102] or $250/kW of headroom (linearized). Each subsequent gigawatt of upgrades is assumed to cost 15% more than the previous tranche.[103] For the fifth gigawatt of upgrades selected by the model and beyond, costs are assumed to remain flat.

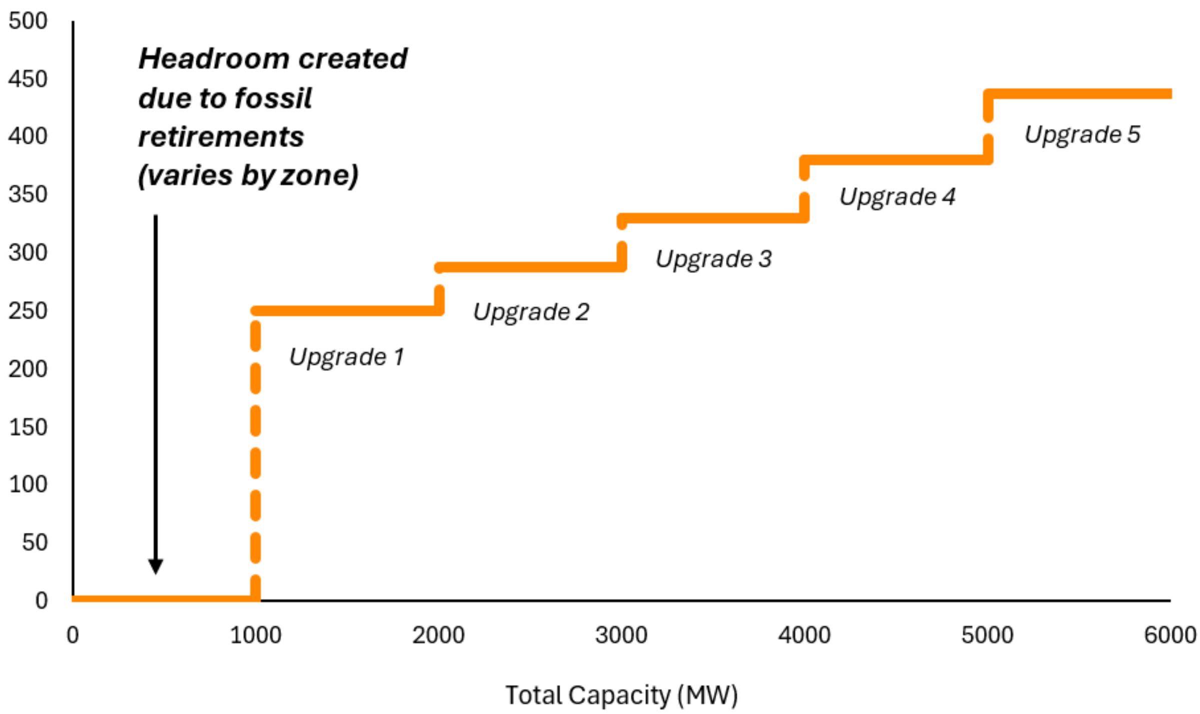
[102] Informed by latest approved transmission projects in PJM. Subject to refinement in future cycles. "Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board," PJM Staff (December 2023): https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20231205/20231205-pjm-teac-board-whitepaper-december-2023.ashx.

[103] The 15% compounding assumption is based on a similar assumption used in New York's Coordinated Grid Planning Process. This assumption is also subject to refinement in future cycles. "2023-2042 System & Resource Outlook, Appendix H: Capacity Expansion Model Results," NYISO (July 2024): https://www.nyiso.com/documents/20142/46037616/Appendix-H-Capacity-Expansion-Model-Results.pdf.

Table F-15: Transmission Upgrade Cost Schedule

Tranche	Unit Cost	Total Upgrade Cost
GW	$/MW-mile	$/kW
0-1	$5,000	$250
1-2	$5,750	$288
2-3	$6,613	$331
3-4	$7,604	$380
4+	$8,746	$437

Figure F-55: Local Network Upgrade Cost Illustration, $/kW Transmission Headroom



The power flow from different resource types varies across the day. Renewables are unlikely to be consistently producing at 100% of their nameplate capacity when the transmission system is most stressed. The critical deliverability window is assumed to be between the hours of 4:00–8:00 PM from June through September.[104] The contribution of solar and wind towards the transmission headroom constraint of each REAP zone is thus defined based on their average capacity factor in these hours. This means the model can build more than a GW of solar or wind capacity before a GW of transmission headroom is exhausted and the next tranche of headroom upgrade cost is triggered.

[104] Additional deliverability windows will be added in future REAP cycles.