DRAFT Resource Adequacy Mitigation Plan



ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

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Table of Contents

TABLE OF CONTENTS III

TABLE OF FIGURES VII

TABLE OF TABLES XI

ACRONYM DEFINITIONS XIII

EXECUTIVE SUMMARY 17

Summary of Findings 17

Recommended Mitigation Strategy 22

Coordination with Integrated Resource Plan 24

1 INTRODUCTION 25

1.1 Purpose and Statutory Requirements 25

1.2 Resource Adequacy and Reliability 26

1.3 Summary of 2025 Resource Adequacy Study 26

1.4 Scope and Focus of Mitigation Plan 31

1.5 Linkage between Mitigation Plan and Integrated Resource Plan 32

1.6 Roles and Responsibilities in Developing Mitigation Plan 34

1.7 Stakeholder Engagement 39

1.8 Contents of this Mitigation Plan Report 52

2 ANALYTICAL FRAMEWORK 54

2.1 Cases Studied 54

2.2 Analytical Objectives 55

2.3 Analytical Workflow 56
2.4 Integrated Evaluation and Decision Framework 57
3 BASELINE ASSUMPTIONS 62
3.1 Illinois Resource Mix 62
3.2 State Policy Objectives and Programs 68
3.3 Expected Retirements 76
3.4 Load Forecast 78
3.5 Candidate Resources 91
3.6 Resources Not Included as Candidate Resources in This IRP 99
3.7 Transmission Systems and Import Capability 99
3.8 Fuel Prices 107
3.9 Comparison to the 2025 Resource Adequacy Study 109
4 UPDATED RESOURCE ADEQUACY BALANCE PROJECTIONS 111
4.1 Purpose, Scope, and Approach 111
4.2 Updates Since the 2025 Resource Adequacy Study 113
4.3 RTO-Wide Resource Adequacy Balance Results 117
4.4 Illinois Zonal Resource Adequacy Balance Results 121
4.5 Impact of CEJA-limited Unit Retirements 128
4.6 Sources of Uncertainty in Load and Resource Balance 128
4.7 Key Findings from the Updated Resource Adequacy Balance Analysis 129
5 CAPACITY MARKET ASSESSMENT 131
5.1 Current Capacity Market Conditions 132
5.2 Capacity Market Assessment Framework 135
5.3 Capacity Price Results 140

5.4 Key Findings of Capacity Market Impacts Assessment 145

6. RELIABILITY RISK ASSESSMENT 147

6.1 Analytical Scope and Scenario Design 147

6.2 RECAP Model Approach 150

6.3 Reliability Risk Results 156

6.4 Key Findings of the Reliability Risk Assessment 169

7 PLEXOS LONG-TERM PORTFOLIO ANALYSIS 171

7.1 Analytical Approach and Scenario Design 172

7.2 Reference Case PLEXOS Results 174

7.3 CEJA Extension Case PLEXOS Results 187

7.4 Comparison of Reference Case and CEJA Extension Case 194

7.5 Sensitivity Analysis Results 200

7.6 Comparison with the 2025 Resource Adequacy Study Base Case 202

7.7 Implications and Key Findings 203

8 INTEGRATED ASSESSMENT OF MITIGATION STRATEGY 206

8.1 Mitigation Plan Decision Framework 207

8.2 Persistence, Timing, and Materiality of Reliability Need 208

8.3 Feasibility of Resolving the Need Through Alternative Resources 209

8.4 Effectiveness of CEJA Extensions 212

8.5 Consequences for Illinois Customers, Residents, and State Policy 213

9 RECOMMENDATIONS FOR MITIGATION PLAN ACTIONS 216

9.1 Key Findings 213

9.2 Proposed Mitigation Strategy 215

9.3 Mitigation Plan Implementation 217

9.4 Relationship to the IRP and Other Planning Initiatives 218

9.5 Administrative Next Steps 219

1 APPENDIX A. 216

1.1 PLEXOS Modeling Approach 226

Table of Figures

Figure 1-1: 2025 Resource Adequacy Study: PJM RA Balance (2026-2035) | Resource Additions and Retirements 28

Figure 1-2: 2025 Resource Adequacy Study: MISO RA Balance (2026-2035) | Resource Additions and Retirements 28

Figure 1-3: 2025 Resource Adequacy Study: PJM ComEd Zone RA Balance (2026-2035) | Resource Additions and Retirements "As-Reported" 30

Figure 1-4: 2025 Resource Adequacy Study: MISO LRZ 4 RA Balance (2026-2035) | Resource Additions and Retirements "As-Reported" 30

Figure 3-1: Existing Generation Resources Nameplate Capacity in PJM (non-IL) 63

Figure 3-2: Existing Generation Resources Nameplate Capacity in MISO (non-IL) 63

Figure 3-3: Existing Generation Resources Nameplate Capacity in ComEd Zone 64

Figure 3-4: Existing Generation Resources Nameplate Capacity in MISO LRZ 4 64

Figure 3-5: Planned Generation Resources Nameplate Capacity in PJM (non-IL) 66

Figure 3-6: Planned Generation Resources Nameplate Capacity in MISO (non-IL) 66

Figure 3-7: Planned Generation Resources Nameplate Capacity in ComEd Zone 66

Figure 3-8: Planned Generation Resources Nameplate Capacity in MISO LRZ 4 67

Figure 3-9: Total Emission Cap for CEJA-regulated Electricity Generators 69

Figure 3-10: Emission Caps for CEJA-Regulated Electricity Generators by Region and Fuel Type 70

Figure 3-11: System-Wide RPS and CES Annual Volumetric Targets (GWh) 74

Figure 3-12: Distributed Solar Capacity Projections 76

Figure 3-13: Illinois Cumulative Retirements (GW) 77

Figure 3-14 PJM (Non-IL) Annual Energy by Component, TWh – Reference Case 79

Figure 3-15 MISO (Non-IL) Annual Energy by Component, TWh – Reference Case 80

Figure 3-16 LRZ 4 Annual Energy by Component, TWh – Reference Case 82

Figure 3-17 ComEd Annual Energy by Component, TWh – Reference Case 83

Figure 3-18 LRZ 4 Data Center Peak Load by Attrition Scenario, MW 86

Figure 3-19 LRZ 4 Data Center Annual Energy, TWh 86
Figure 3-20 ComEd Data Center Peak Load by Attrition Scenario, MW 87
Figure 3-21 ComEd Data Center Annual Energy, TWh..... 87
Figure 3-22: Candidate Resource Availability to PLEXOS Model 92
Figure 3-23: Illinois Candidate Resource CapEx (Nominal $/kWac)..... 94
Figure 3-24: Illinois Candidate Resource Levelized Cost of Energy (Nominal $/MWh) 95
Figure 3-25: Illinois Candidate Resource Levelized Fixed Cost (Nominal $/kW-yr)..... 95
Figure 3-26: Illustration of Transmission Components 100
Figure 3-27: PJM and MISO Transmission Topology Modeled in PLEXOS (2030)..... 102
Figure 3-28: Renewable Energy Access Plan (REAP) Zone Map 102
Figure 3-29: Local Network Upgrade Cost Illustration, $/kW..... 106
Figure 3-30: Monthly Fuel Prices Used in Modeling, 2022 $/MMBtu 108
Figure 7-7: Load and Resource Balance Framework 112
Figure 7-8: LRZ 4 Peak Demand (GW) 115
Figure 7-9: PJM-ComEd Zone Peak Demand (GW) 116
Figure 7-10: PJM Resource Adequacy Balance 119
Figure 7-11: MISO LRZs 1-10 Resource Adequacy Balance..... 120
Figure 7-12: ComEd Resource Adequacy Balance in (a) 2025 Resource Adequacy Study and (b) IRP 122
Figure 7-13: PJM-ComEd Zone 2030 Installed Capacity (ICAP), Accredited Capacity (UCAP) & Reliability Requirement Difference (2026 IRP- 2025 RA Study) (GW)..... 124
Figure 7-14: LRZ 4 Resource Adequacy Balance in (a) 2025 Resource Adequacy Study and (b) 2026 IRP 125
Figure 7-15: LRZ 4 2030 Installed Capacity, Accredited Capacity, & Reliability Requirement Difference (2026 IRP- 2025 RA Study) (GW) 127
Figure 5-1. CEJA Retirement Nameplate Capacity 136
Figure 5-2: PJM VRR Curves in the 2028/29 Auction and 2030/31 Analysis Year..... 138
Figure 5-3: MISO RBDC for Summer 2026/2027 Auction Used for 2030/31 Analysis Year 139
Figure 5-4: PJM 2030/31 Illustrative Capacity Price with CEJA-limited Unit Retirements . 140

Figure 5-5: MISO 2030 Illustrative Capacity Price with CEJA-limited Unit Retirements 143
Figure 6-1RECAP Topology..... 152
Figure 6-2: LRZ4 Component Load Shapes..... 153
Figure 6-3 ComEd Component Load Shapes 153
Figure 6-4 LRZ4 Renewable Generation Profiles 154
Figure 6-5 ComEd Renewable Generation Profiles..... 154
Figure 6-6: LRZs 1-7 Temperature vs Outage Assumptions 155
Figure 6-7: PJM Temperate vs Outage Assumptions 155
Figure 6-8: Heatmap of CEJA Unit Utilization 157
Figure 6-9: CEJA-limited Unit Utilization by Weather Year..... 158
Figure 6-10: Histogram of CEJA-limited Unit annual utilization by simulation year..... 158
Figure 6-11: ComEd CEJA-limited Unit Capacity Factor, Import Reliance 159
Figure 6-12 Weekly Dispatch, ComEd, High CEJA-limited Utilization..... 160
Figure 6-13: Renewable output versus Load during periods with and without CEJA-limited utilization 161
Figure 6-14: Distribution of the duration of CEJA-limited unit reliance events 162
Figure 6-15: Heatmap of CEJA-limited unit utilization in Ameren assuming access to imports and out-of-state gas 163
Figure 7-1: PLEXOS Modeling Framework..... 173
Figure 7-2: Reference Case PJM Wide Installed Capacity 176
Figure 7-3: Reference Case MISO Wide Installed Capacity..... 176
Figure 7-4: Reference Case Illinois Installed Capacity (MW) 178
Figure 7-5: Reference Case MISO LRZ 4 (Top) and ComEd (Bottom) Installed Capacity (MW) 179
Figure 7-6: Reference Case MISO LRZ 4 (Top) and ComEd (Bottom) Firm Capacity (MW) 181
Figure 7-7: Reference Case Illinois Generation..... 182
Figure 7-8: Reference Case LRZ 4 (Top) and ComEd (Bottom) Generation and Load (GWh) 183
Figure 7-9 Reference Case Total System Costs for LRZ 4 (Top) and ComEd (Bottom)..... 184

Figure 7-10: Reference Case, Illinois CO_2 Emissions from the Electric Sector (million short tons) 186

Figure 7-11: CEJA Extension Case Illinois Installed Capacity (MW) 188

Figure 7-12: CEJA Extension Case MISO LRZ 4 (Top) and ComEd (Bottom) Installed Capacity (MW) 189

Figure 7-13: CEJA Extension Case MISO LRZ 4 (Top) and ComEd (Bottom) Firm Capacity (MW) 190

Figure 7-14: CEJA Extension Case Illinois Generation (GWh) 191

Figure 7-15: CEJA Extension Case LRZ4 (Top) and ComEd (Bottom) Generation (GWh) ... 192

Figure 7-16 CEJA Extension Case Total System Costs for LRZ 4 (Top) and ComEd (Bottom) 193

Figure 7-17: CEJA Extension Case Illinois CO_2 Emissions 194

Figure 7-18: Comparison of Illinois Selected Capacity between Reference Case and CEJA Extension Case 195

Figure 7-19: Comparison of Illinois Generation between Reference Case and CEJA Extension Case 196

Figure 7-20 Total System Cost Difference between Reference and CEJA Extension Cases 196

Figure 7-21 Average Modeled Capacity Price 197

Figure 7-22: Difference of Illinois CO_2 Emissions Between Reference Case and CEJA Extension Case (CEJA Extension Case minus Reference) 198

Figure 7-23. Illinois Selected Capacity between CEJA Extension and Gas Only 200

Figure 7-24. Illinois Emissions between CEJA Extension and Gas Only 201

Figure 7-25: 2025 RA Study Base Case and 2026 Reference Case Selected Capacity Comparison 203

Figure 7-26: 2025 RA Study Base Case and 2026 Reference Case Generation and Load Comparison 203

Table of Tables

Table 1-1: Stakeholder Workshops 42

Table 2-1: Mitigation Plan Analytical Objectives 56

Table 2-2: Key Questions and Analytical Tools to Support Decision Making 58

Table 3-1: Renewable Portfolio Standard and Clean Energy Standard Constraints Modeled 72

Table 3-2: States in Each Non-IL RPS and CES Constraint 73

Table 3-3: Illinois Cumulative Retirements (GW) 77

Table 3-4 LRZ4 Data Center Facility Completion Rates by Scenario 81

Table 3-5 ComEd Data Center Facility Completion Rates by Scenario 83

Table 3-6: Historical Nuclear Uprate Capacity Increases 98

Table 3-8: Fossil Retirement-Driven Transmission Headroom Created by REAP Zone, MW 104

Table 3-9: Transmission Headroom Cost Schedule 105

Table 3-13 Regional Natural Gas Price Hubs to PLEXOS Regions 108

Table 3-14: Summary of Assumption Updates between 2025 RA Study and Mitigation Plan 109

Table 7-3: Summary of Changes in Assumptions for Resource Balance Analysis 114

Table 5-1. PJM 2028/2029 Auction Results 133

Table 5-2. MISO 2026/2027 Auction Results 134

Table 5-3: Illustrative ComEd Capacity Price Impacts of CEJA-limited Unit Retirements in 2031 141

Table 5-4: Illustrative MISO LRZ4 Summer Season Capacity Price Impacts of CEJA-limited Unit Retirements in 2030 144

Table 6-1: Summary of RECAP Cases 150

Table 6-2: ComEd Reliability Results 162

Table 7-1. Incremental Emissions (short ton/MW) of Firm Capacity Extended, Relative to Reference Case 199

Table 7-2. NPV of Total System Cost Savings vs. Reference Case ($ million) 201

Table 8-1 Decision Tests and Supporting Analytical Evidence 208

Table 8-2. Near-term RTO Capacity Shortfall according to the load and resource balance (GW) 209

Acronym Definitions

Acronym	Definition
EPAct	Environmental Protection Act
CEJA	Climate and Equitable Jobs Act
RA Study	Resource Adequacy Study
ICC	Illinois Commerce Commission
IPA	Illinois Power Agency
E3	Energy and Environmental Economics, Inc.
IEPA	Illinois Environmental Protection Agency
IRP	Integrated Resource Plan
RPS	Renewable Portfolio Standard
GHG	Greenhouse gas emissions
IPA Act	Illinois Power Agency Act
ZRCs	Zonal Resource Credits
EGUs	Electric Generating Units
ELCC	Effective Load Carrying Capability
RFI	Request For Information
LCOE	Levelized cost of energy

LFC	Levelized Fixed Cost
VPP	Virtual Power Plant
DERs	Distributed Energy Resources
CCS	Carbon Capture and Sequestration
CES	Clean Energy Standard
T&D	Transmission & Distribution
REC	Renewable Energy Credit
BTM	Behind-The-Meter
WARN	Worker Adjustment and Retraining Notification
EIA	Energy Information Administration
EVs	Electric Vehicles
LTLF	Long-Term Load Forecast
HPs	Heat Pumps
NREL	National Renewable Energy Laboratory
CRGA	Clean and Reliable Grid Affordability Act
ZIA	Zonal Import Ability
LTRRPP	Long-Term Renewable Resources Procurement Plan
CT	Combustion Turbine

USWTDB	U.S. Wind Turbine Database
WIND	Wind Integration National Dataset
NOAA	National Oceanic and Atmospheric Administration
HRRR	High resolution rapid refresh
NSRDB	National Solar Radiation Database
BOEM	Bureau of Ocean Energy Management
LWR	Light Water Reactors
SMRs	Small Modular Reactors
MTEP	MISO Transmission Expansion Plan
RTEP	Regional Transmission Expansion Plan
GW	Gigawatt
LRZ 4	Local Resource Zone 4
RRA	Resource Reliability Analytics
DLOL	Direct Loss of Load
FPR	Forecast Pool Requirement
PRMR	Planning Reserve Margin Requirement
LDA	Locational Deliverability Area
PRA	Planning Resource Auction

UCAP	Unforced Capacity
VRR	Variable Resource Requirement
E&AS	Energy and Ancillary Services
RBDCs	Reliability-Based Demand Curves
EUE	Expected Unserved Energy
MRI	Marginal Reliability Impact
RECAP	Renewable Energy Capacity Planning Model
LOLH	Loss of Load Hours
NLR	National Laboratory of the Rockies
SAM	System Advisor Model
LT	Long-Term
Net CONE	Net Cost of New Entry

Executive Summary

The Climate and Equitable Jobs Act (CEJA) was passed by the Illinois General Assembly and signed into law as Public Act 102-0662 on September 15, 2021. Among other important changes to Illinois energy policy, CEJA amended Section 9.15 of the Environmental Protection Act (EPAct) by adding subsection (o), which requires the completion of a Resource Adequacy Study (RA Study) to assess the current and projected status of electric resource adequacy and reliability throughout Illinois.

This new provision effectively implemented a two-step process: (i) a group of state agencies completes an RA Study and an accompanying report to determine if a resource adequacy shortfall is reasonably likely to occur given the current and projected state of the electric grid, and (ii) if the study finds a shortfall is reasonably likely, the agencies develop a Mitigation Plan to assess options to address the potential shortfall.

The Illinois Commerce Commission (ICC), the Illinois Power Agency (IPA), and the Illinois Environmental Protection Agency (IEPA) jointly published the RA Study in December 2025, as directed by the statute. The study found that Illinois faces a resource adequacy risk over the coming decade, largely because both PJM and MISO are projected to face sustained system-wide capacity shortfalls in the presence of rapid data center-driven load growth, changing market structures and associated accreditation methodologies. Given the conclusion of this study, IPA and IEPA ("the Agencies") are required by Section 9.15(o) to develop a Mitigation Plan that considers strategies to resolve the identified resource adequacy shortfall.

The remainder of this Executive Summary will document the key technical findings of the Mitigation Plan, identify the proposed temporary extension of the applicable emissions-reduction deadlines for specified CEJA-limited units (those units subject to Section 9.15(i) of the Illinois EPAct's zero carbon emission requirements enacted through CEJA), and describe the next steps and coordination with the Integrated Resource Plan (IRP) process required under Sections 16-201 and 16-202 of the Public Utilities Act.

Summary of Findings

Illinois continues to face a risk of resource adequacy shortfall, and that risk grows over the forecast horizon.

The shortfall risk reflects several related but distinct drivers. Growing electricity demand, primarily from data centers, increases capacity requirements. Separately, aging and

economically marginal generators may retire across PJM and MISO. The updated load and resource balance indicates tight regional capacity conditions which creates a risk of shortfalls if sufficient resources do not enter service on time. The ComEd zone meets its allocated zonal requirement through 2030, with imports needed by 2030, but remains exposed to PJM-wide capacity conditions. MISO LRZ 4 has less in-zone accredited capacity than its requirement in 2027 and must increasingly rely on imports; sufficient unused capacity may not be available elsewhere in MISO to support those imports during stressed conditions.

Retaining a subset of CEJA-limited units supports affordability by preserving flexibility in the timing and scale of investments in new firm capacity.

Illinois needs substantial wind, solar, and storage additions under both the Reference Case and the CEJA Extension Case. The primary difference between the cases is the amount and timing of new firm resources – nuclear generation, long-duration energy storage, and out-of-state capacity purchases – necessary to replace the reliability value of existing CEJA-limited capacity. Retaining eligible units can reduce the need to develop costly replacement capacity before it is needed and reduce exposure to construction, interconnection, and other delivery risks. In the long-term portfolio analysis, total ComEd system costs in 2045 are approximately 18% lower in the CEJA Extension Case than in the Reference Case. Retaining existing, already-interconnected units, especially gas and oil, also directly reduces loss-of-load risk and eases a resource buildout that would otherwise have to occur at more than three times Illinois' historical annual pace of resource additions. Separately, an illustrative PJM capacity market analysis estimates that, if PJM returns to balance by 2031, retiring the affected units would raise the projected capacity costs for ComEd customers by approximately $1.1 billion annually.

Extending existing units can support reliability during periods of system stress while allowing Illinois to continue progressing toward its decarbonization goals.

In the reliability simulations, the ComEd units are called upon in nearly every modeled weather year, but their capacity factors do not exceed 0.8%. Existing statutory emissions requirements would continue to apply to extended units, including the 12-month CO_2 and copollutant limits for applicable non-public gas-fired units under 415 ILCS 5/9.15(k-5). Even in the bookend case that extends every CEJA-limited unit statewide through 2047, 92% of in-state generation is zero-emitting in 2045, and the portfolios add substantial wind, solar, and storage either way. Overall, the extension is one piece of the solution and the first of several actions needed to support Illinois' decarbonization and reliability targets.

Reducing emissions and protecting environmental justice communities are central to selecting which units to extend.

Reducing greenhouse gas and criteria pollutant emissions remains an important State policy objective under CEJA and CRGA. Section 9.15(o)(3) of the Environmental Protection Act also directs the ICC to consider emissions impacts on environmental justice communities when reviewing a mitigation plan. Coal-fired units generally produce substantially more CO_2e and criteria pollutant emissions per MW of accredited capacity than existing gas-fired units. Oil-fired units provide capacity while operating infrequently, historically on the order of 30 hours annually, because of their comparatively high marginal operating costs. These characteristics support preserving the reliability contribution of gas and oil while maintaining the decarbonization timeline applicable to coal units. Avoiding an extension of coal units would also avoid prolonging a major source of local pollution burdens, including burdens experienced by environmental justice communities. These environmental and public-health considerations are core concerns alongside modeled electricity system costs.

Extending eligible gas and oil units, but not coal units, balances affordability, reliability, emissions reductions, and environmental justice considerations, and meets the statutory "minimum extent" standard.

Under Section 9.15(o) of the Environmental Protection Act, emissions-reduction requirements may be delayed only to the extent and for the duration necessary to address the State's resource adequacy and reliability needs. The ICC must also consider the least amount of CO_2 and copollutant emissions, effects on environmental justice communities, and the lowest total cost over time under subsection (o)(3). The Agencies therefore considered the benefits of retaining gas-fired units separately from those of extending all CEJA-limited units. Relative to the Reference Case, the Gas Only sensitivity provides approximately $612 million of cost savings between 2030 and 2035, compared with $868 million if all CEJA-limited units are retained. For 2036–2047, the corresponding savings are approximately $13.6 billion and $14.6 billion. Thus, retaining gas captures most of the modeled benefit of the full extension. The gas-only sensitivity replaces much of coal's accredited capacity with four-hour storage and reduces remaining in-state emissions by roughly 60% relative to the full extension. Oil-fired units are included in the proposed extension for their contribution during infrequent periods of high reliability need. The Agencies consider these cost and reliability benefits alongside the substantially different emissions impacts of coal generation.

The figures below illustrate the cost and emissions implications of these alternatives. The first compares total system costs and average annual emissions, on an inventory basis, over

2030–2047, while the second compares 2047 average modeled system supply costs and total portfolio emissions in 2047. Both demonstrate that retaining gas-fired units achieves most of the modeled cost savings of a full CEJA extension, with substantially lower emissions.

Figure 0-1: Comparison of NPV of Total System Costs vs Average Inventory Emissions

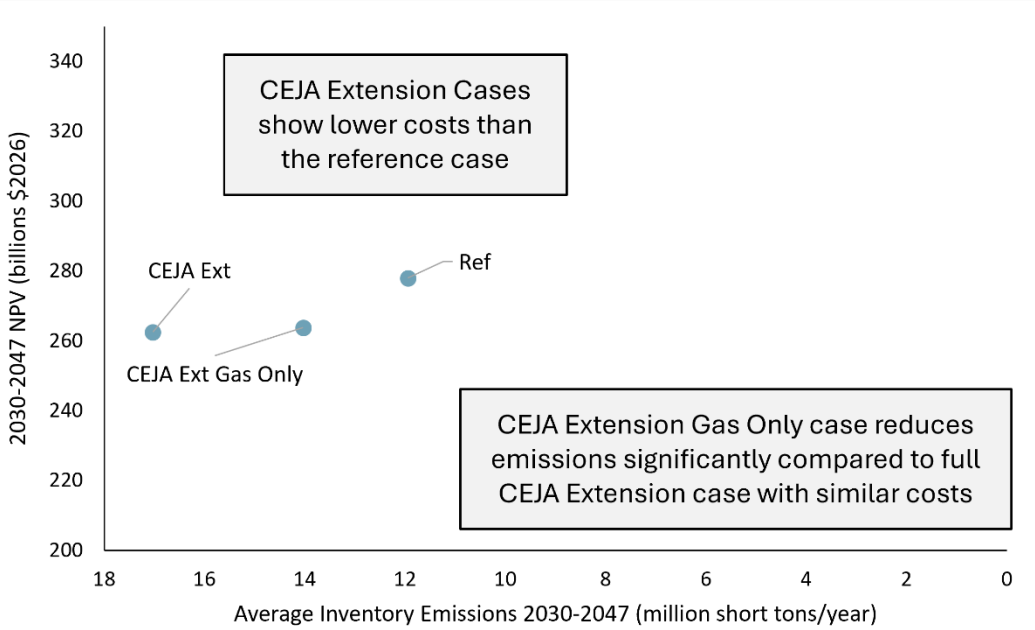
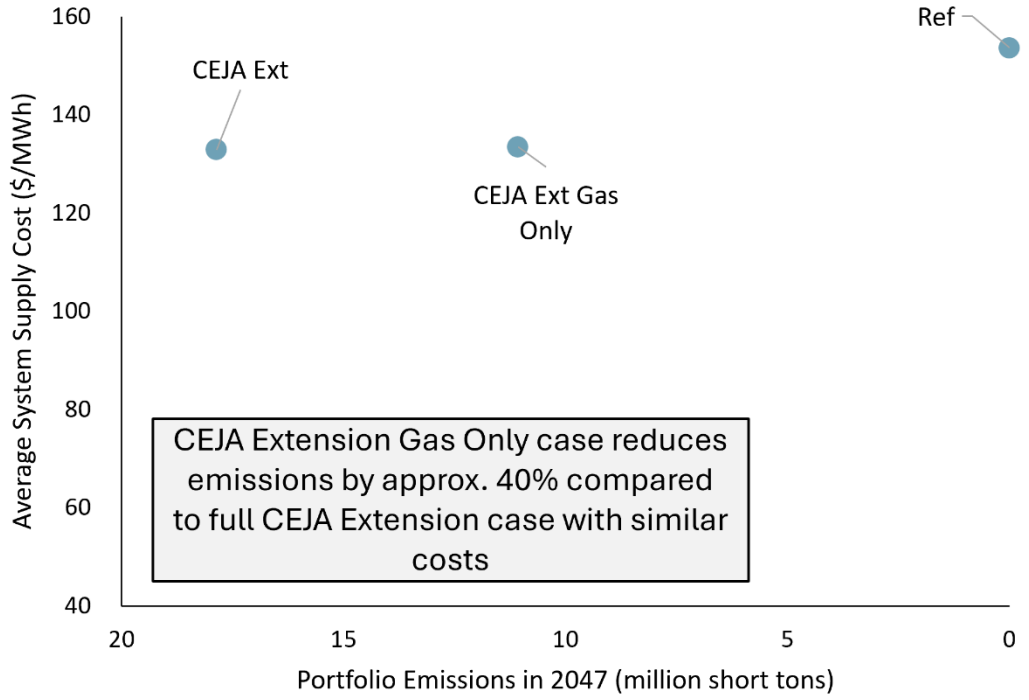


Figure 0-2: Comparison of 2047 Average System Supply Cost and 2047 Total Portfolio Emissions



Note: Average System Supply Cost = 2047 Total System Cost (nominal $b) / Retail Sales

To preserve near-term capacity while the next IRP evaluates replacement options, the Agencies propose extending the applicable 2030 deadlines for eligible gas- and oil-fired units in both PJM and MISO through May 31, 2033. The next IRP will reassess whether continued operation beyond that date is necessary.

The proposed endpoint reflects both resource-owner decisions and the need to reassess extensions in the next IRP.

Preserving an existing unit may require maintenance investment, staffing, and continued market participation, while retirement decisions can require advance notice. In PJM, capacity commitments are made 3 years before delivery. A unit facing a 2030 CEJA deadline may need to decide whether it can offer into the 2032/2033 capacity delivery year before the next IRP receives a Commission decision. In MISO, procurement takes place closer to the delivery period, but the 2030 emissions deadline could still remove needed capacity before the next IRP can reassess reliability needs and replacement options. The proposed common endpoint provides a limited bridge for both markets.

Proposed Mitigation Strategy

Based on the findings described above, the IPA and IEPA preliminarily conclude that a resource adequacy or reliability deficiency remains reasonably likely to occur and that a targeted delay of applicable CEJA emissions-reduction deadlines is warranted for specified gas- and oil-fired units in both PJM and MISO. Section 9.15(o) of the Environmental Protection Act permits a delay only to the extent and for the duration necessary to meet the State's resource adequacy and reliability needs. The Agencies apply that standard along three dimensions: which units are eligible, where they are located, and for how long their applicable deadlines would be delayed.

On scope, the Agencies propose a measured delay to applicable 2030 zero-emissions deadlines only for CEJA-limited gas- and oil-fired units whose continued availability is needed to address the identified reliability concerns. The proposal does not extend deadlines for coal-fired units. In particular, the January 1, 2030 zero-emissions deadline for privately owned coal-fired units under 415 ILCS 5/9.15(g) would remain unchanged. This targeted approach preserves gas and oil capacity to provide reliability value without prolonging the emissions and environmental justice burdens associated with coal-fired generation. The proposed extension would not reverse retirements expected to occur for reasons independent of CEJA, such as plant age or commercial decisions, or change deadlines for units not identified for extension.

On location, the proposed extension includes eligible gas- and oil-fired units in both the PJM ComEd zone and MISO LRZ 4, as seen in the table below. The reliability analysis identifies risks in both regional markets, although the sources and timing of those risks differ. ComEd is exposed to PJM-wide capacity tightness even when its in-zone balance meets the allocated requirement. The Load and Resource Balance analysis shows LRZ 4 increasingly depends on imports from the broader MISO market, where the availability of surplus capacity is uncertain. Preserving the contribution of eligible in-state units in both zones helps limit dependence on replacement capacity that may not be available when needed.

Proposed Mitigation Plan CEJA Plant Extensions

CEJA Facility Name	Zone	Resource Type	Current Retirement Year	Proposed Extension
Aurora	ComEd	Gas - CT	2031	2033
Calumet Energy Team, LLC	ComEd	Gas - CT	2031	2033
Crete Energy Park	ComEd	Gas - CT	2031	2033
Rockford Energy Center	ComEd	Gas - CT	2031	2033

Tilton Power Station	Ameren	Gas - CT	2030	2033
LSP University Park, LLC	ComEd	Gas - CT	2031	2033
University Park Energy	ComEd	Gas - CT	2031	2033
Venice	Ameren	Gas - CT	2030	2033
Zion Energy Center	ComEd	Gas - CT	2031	2033
Fisk	ComEd	Oil	2031	2033
Waukegan	ComEd	Oil	2031	2033

On duration, the IPA and IEPA propose extending the applicable deadlines for eligible units in both RTOs through May 31, 2033, the end of the 2032/2033 capacity delivery or planning year. It is intended to be a defined bridge to the next planning decision, not an indefinite extension. The next IRP is due to be filed with the ICC by September 30, 2029, and a Commission decision is expected in 2030. For PJM units, the proposed end date also avoids disrupting forward capacity commitments for the 2032/2033 delivery year. For MISO units, the end date preserves availability through the next IRP reassessment and a limited period for evaluating and implementing replacement options. The Agencies view this common endpoint as the shortest practicable extension that maintains needed capacity while leaving any subsequent extension to be evaluated against updated evidence under the next IRP. The proposal does not predetermine whether the units should operate beyond May 31, 2033.

The case for an extension in MISO does not depend on PJM's three-year forward auction structure. Although MISO procures capacity closer to each delivery year, the 2030 statutory deadline could still remove existing capacity before the next IRP establishes whether replacement resources, imports, or other solutions can reliably meet LRZ 4's needs. The Agencies therefore propose the same limited extension through May 31, 2033, for eligible units in MISO. That period allows the 2029 IRP and its subsequent Commission review to reassess whether any further extension is necessary while allowing time to implement alternatives.

The IPA and IEPA therefore recommend a temporary delay, through May 31, 2033, of the specifically identified 2030 CEJA zero-emissions deadlines for eligible gas- and oil-fired units in PJM and MISO. No extension is proposed for coal-fired units, and no additional operating-hour, dispatch, or emissions restrictions are proposed for extended gas- or oil-fired units. The extension would preserve existing accredited capacity while the Agencies continue to assess and advance replacement resources. It would remain subject to all other applicable statutory, permitting, monitoring, and reporting requirements and to any terms of the final ICC order.

Operating and Emissions Conditions of CEJA-limited Units

Continued availability under the Mitigation Plan does not imply continuous or high-utilization operation. The Agencies do not propose new operating-hour limits, dispatch restrictions, or emissions limits for units receiving an extension. Rather, the proposed action would delay only the specifically identified zero-emissions deadlines while leaving other applicable environmental requirements in place. Non-public gas-fired units would continue to be subject to the 12-month CO_2 and copollutant emissions limits under 415 ILCS 5/9.15(k-5), and applicable interim requirements under subsection (i) would also remain in effect except to the extent expressly delayed by an approved Mitigation Plan. Oil-fired units would remain subject to other applicable environmental and permit conditions. Section 9.15(o) authorizes limited relief necessary to address identified resource adequacy and reliability needs; it does not otherwise suspend statutory or permit obligations.

Coordination with Integrated Resource Plan

Section 9.15(o) of the EPAct requires the Mitigation Plan to consider renewable energy, energy storage, demand response, transmission development, and other strategies that could resolve the identified resource adequacy shortfall or reliability violation. Those alternatives are considered through the coordinated Mitigation Plan and IRP analytical framework. The Mitigation Plan's long-term planning analysis conducted within PLEXOS directly allows wind, solar, battery storage, firm imports, and other modeled resources to compete to meet load, reliability, and policy requirements. The resulting portfolios include substantial renewable and storage additions in both the Reference Case and CEJA Extension Case, demonstrating that the proposed CEJA extension is evaluated in combination with, rather than as a substitute for, continued clean-resource development.

Demand response, energy efficiency, and transmission are also reflected in the planning framework. Existing demand response and transmission import capability are represented in the common baseline assumptions used by the Mitigation Plan. Expanded programs and major new transmission projects follow different implementation pathways than retaining an existing generating unit; the broader IRP evaluates additional demand-side flexibility and transmission expansion more comprehensively because those strategies require separate program design, customer participation, permitting, planning, transmission development, or other implementation steps before they can contribute to resource adequacy needs at scale.

The IRP and Mitigation Plan were developed in parallel using aligned load forecasts, resource assumptions, reliability inputs, and modeling tools. The proceeding to approve the IRP therefore provides a complementary record for assessing how the broader set of

alternatives could reduce or ultimately eliminate the need for continued CEJA-limited-unit availability over time. Other than the proposed extension of specified CEJA-limited units, this Mitigation Plan does not itself establish new procurement programs, transmission projects, or demand-side programs. Those broader implementation decisions remain within the IRP and other applicable State and RTO planning processes.

The proposed extension is therefore a defined, near-term action intended to preserve the reliability contribution of existing gas- and oil-fired units while replacement resources are evaluated and developed. It does not predetermine decisions in the next IRP. The IPA and IEPA may also seek an amendment under 415 ILCS 5/9.15(o)(4) if the identified reliability deficiency is resolved or reduced before the approved extension expires.

1 Introduction

1.1 Purpose and Statutory Requirements

The Climate and Equitable Jobs Act (CEJA) was passed by the Illinois General Assembly and signed into law as Public Act 102-0662 on September 15, 2021. CEJA established a series of important changes to Illinois energy policy, including changes to the Illinois Renewable Portfolio Standard (RPS), creation of a statewide policy goal of 100% clean energy by 2050, targeted reduction of greenhouse gas (GHG) emissions from fossil generation facilities, incentives to promote electric vehicle adoption and reduce transportation sector fuel emissions, support for zero emission nuclear plants, financial support for communities faced with generation facility closures, financial support for clean energy workforce programs, and new equity requirements and labor standards applicable to the clean energy economy.

CEJA also amended Section 9.15 of the EPAct by adding subsection (o) which requires the completion of a Resource Adequacy Study (RA Study) to assess the current and projected status of electric resource adequacy and reliability throughout Illinois. In effect, this new provision implemented a two-step process whereby (i) a Resource Adequacy Study is completed to determine if a resource adequacy shortfall is reasonably likely to occur given the current and projected state of the electric grid—communicated through the issuance of a report, and (ii) if such a shortfall is projected as reasonably likely to occur, directing the development of a Mitigation Plan to assess options to address the potential shortfall.

Specifically, Section 9.15(o) requires that the IPA, in conjunction with the IEPA:

> "shall develop a plan to reduce or delay CO_2e and copollutant emissions reductions requirements only to the extent and for the duration necessary to meet the resource adequacy and reliability needs of the State, including allowing any plants whose emission reduction deadline has been identified in the plan as creating a reliability concern to continue operating, including operating with reduced emissions or as emergency backup where appropriate. The plan shall also consider the use of renewable energy, energy storage, demand response, transmission development, or other strategies to resolve the identified resource adequacy shortfall or reliability violation."

1.2 Resource Adequacy and Reliability

Resource adequacy refers to whether the electric system has enough available supply to meet customer demand in all hours with a defined level of certainty. The assessment considers both the amount of installed capacity and how much each resource can reliably contribute during periods of stress on the electric system. It also accounts for expected peak demand, reserve requirements, resource outages, weather conditions, and the ability to transfer power between regions.

Because no electric system can eliminate all risk of an electricity shortfall, system planners use a reliability standard to define an acceptable level of risk. The reliability standard establishes how often the system may be expected to experience insufficient supply across a wide range of possible weather, demand, and resource availability conditions. The 2025 Resource Adequacy Study evaluated portfolios against the standard used by PJM and MISO, commonly expressed as an expected loss-of-load event occurring at most once in ten years, referred to as a 0.1 LOLE standard.

In this context, the reliability standard is a planning target, not a guarantee that customers will never experience an outage. It is used to determine the amount of capacity the system requires and whether a future resource portfolio provides enough supply to manage the risk of an area-wide shortage. It does not directly assess local distribution outages, individual transmission constraints, or other real-time operational issues.

1.3 Summary of 2025 Resource Adequacy Study

The Illinois Commerce Commission (ICC or Commission), the Illinois Power Agency (IPA), and the Illinois Environmental Protection Agency (IEPA) jointly published the RA Study in December 2025. The Resource Adequacy Study assessed the reliability needs in MISO, PJM, and Illinois in the near-to-medium term (2026 through 2035) and also analyzed the expected

evolution of Illinois' resource adequacy needs within the context of the broader regional markets over a longer time horizon (2030 through 2045).

The study evaluated resource adequacy within the ComEd and Ameren zones, as well as across PJM and MISO, because Illinois is an integrated part of both regional electricity systems. Conditions elsewhere in each RTO can affect the capacity and energy available to Illinois, particularly during periods of high demand or system stress. An RTO-wide assessment was therefore necessary to understand the full range of reliability risks facing the state.

Based on the load forecasts and resource adequacy targets at the time of the study, the Resource Adequacy Study found that both PJM and MISO were projected to face capacity shortfalls compared to their reliability targets over the coming decade unless additional new capacity resources are added to the system beyond those already in advanced stages of development, as seen in Figure 1-1 and Figure 1-2.

The RA Study projected a capacity shortfall in PJM beginning in 2029, with the deficit projected to widen in subsequent years if left unabated. Under the RA Study analysis, MISO was projected to remain resource adequate through 2030, but a shortfall was projected to emerge in 2031 and grow thereafter. The RA Study found that resource adequacy targets in both markets were expected to increase by 10%-20% between 2025 and 2030, driven primarily by rapid, concentrated load growth from data center development in addition to load growth from residential and commercial customers.

At the time of the Study, both RTOs had significant new capacity in various stages of development; however, most of these new resources are renewable projects, which experience declining resource adequacy contributions as a function of their penetration and commensurate overlapping operational profiles. In aggregate, renewable resources' accredited capacity toward resource adequacy is 40% of their nameplate capacity. Capacity retirements, which primarily consist of aging thermal plants, further widen the supply shortfall.

Figure 1-1: 2025 Resource Adequacy Study: PJM RA Balance (2026-2035) | Resource Additions and Retirements

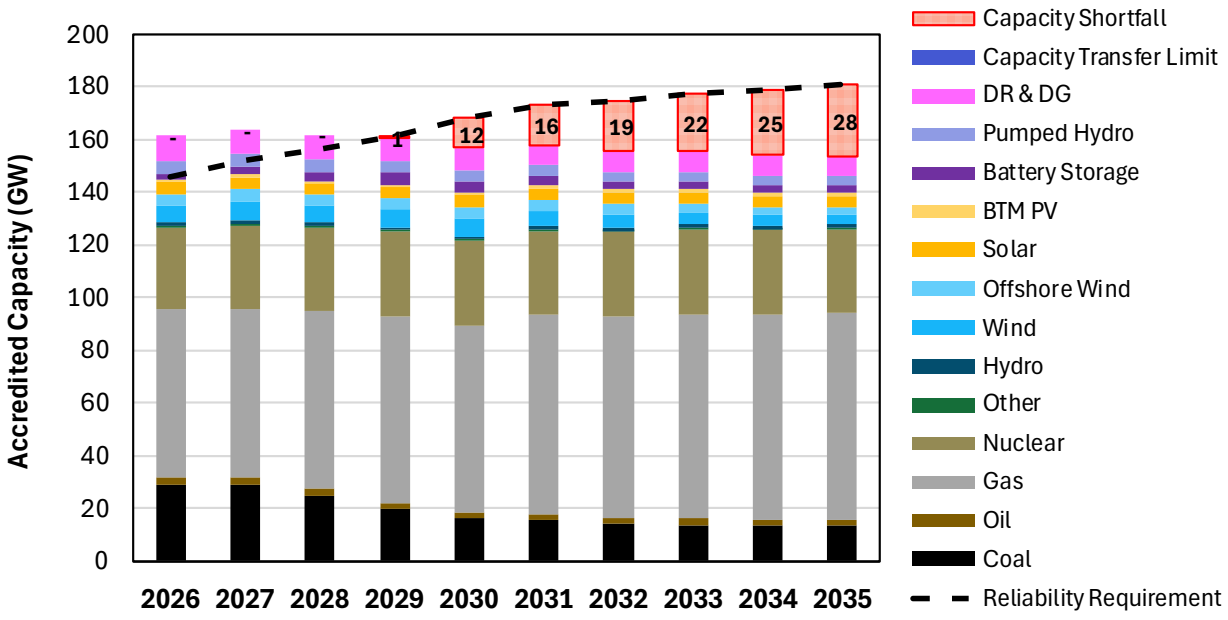
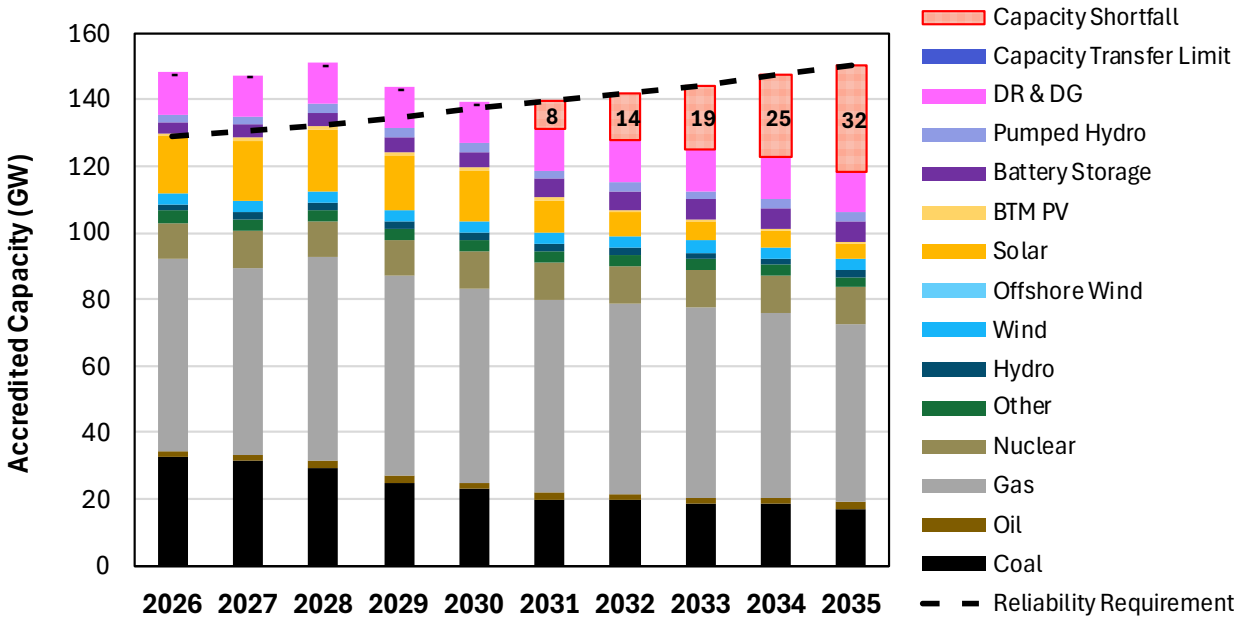


Figure 1-2: 2025 Resource Adequacy Study: MISO RA Balance (2026-2035) | Resource Additions and Retirements



Resource adequacy in Illinois was also evaluated, focusing on the PJM ComEd zone and MISO LRZ 4 (the primary Illinois zone in MISO). The RA Study projected that the ComEd zone met its zonal requirements through 2032 assuming the zone can rely on capacity imports

from the broader PJM system via existing transmission zonal transfer limits starting in 2030, as seen in Figure 1-3. Starting in 2033, the RA Study projected a capacity shortfall in the ComEd zone, as both in zone accredited capacity and the capacity transfer limit were modeled as no longer sufficient to meet the reliability requirement. The RA Study projected that MISO LRZ 4 meets its zonal requirements through 2035, assuming the region would be able to rely on capacity imports through existing transmission zonal transfer limits, seen in Figure 1-4. Even when the MISO LRZ 4 zonal capacity balance appeared sufficient, emerging reliance on interzonal transfers and the MISO-wide results indicated a risk of shortfall at the system level, which posed a corresponding resource adequacy risk for Illinois.

Figure 1-3: 2025 Resource Adequacy Study: PJM ComEd Zone RA Balance (2026-2035) | Resource Additions and Retirements "As-Reported"

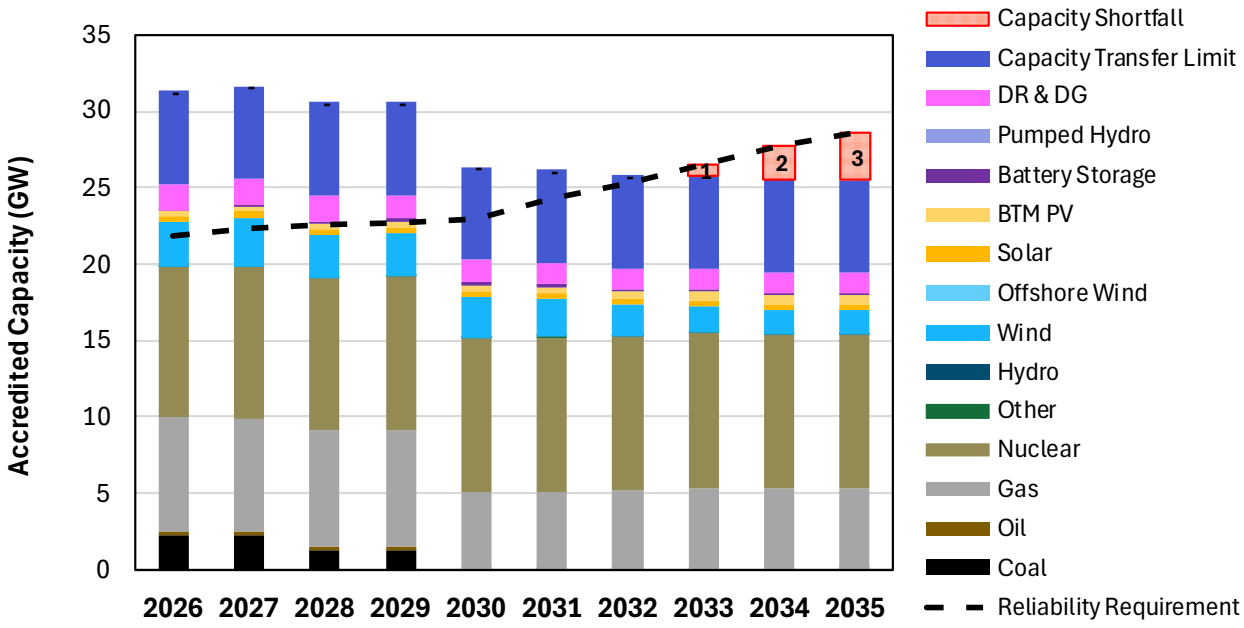
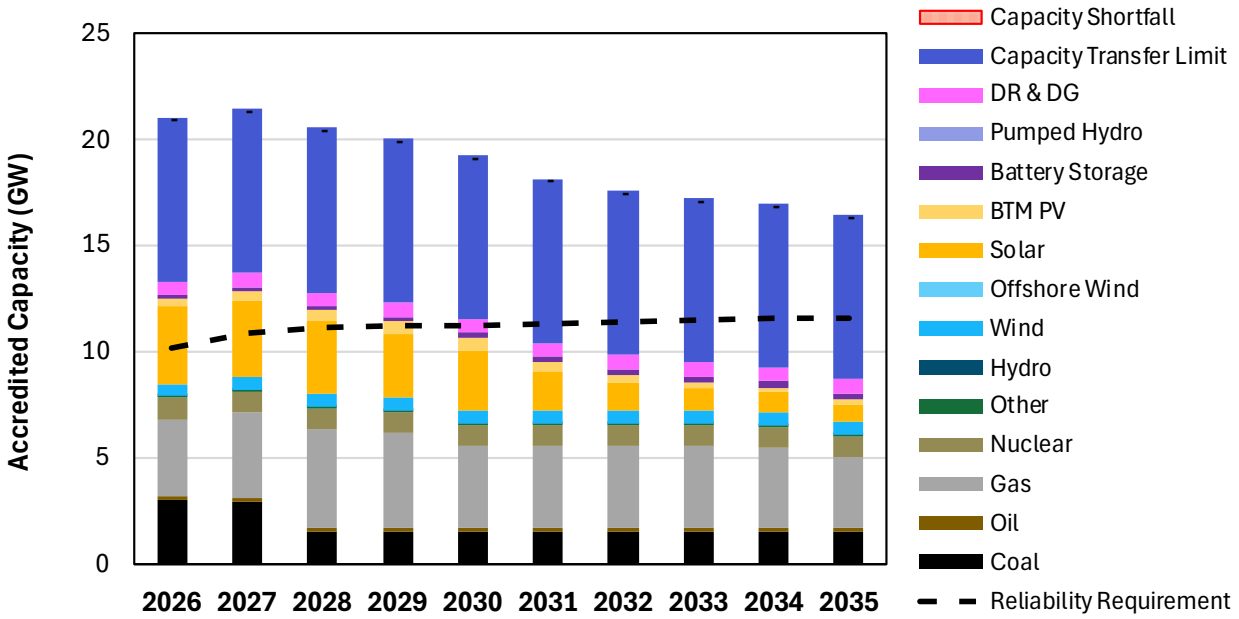


Figure 1-4: 2025 Resource Adequacy Study: MISO LRZ 4 RA Balance (2026-2035) | Resource Additions and Retirements "As-Reported"



The RA Study emphasized that Illinois is only resource-adequate if the broader regions in which Illinois is part of, MISO and PJM, are also resource-adequate. The study found that

Illinois faces a resource adequacy risk over the coming decade, largely because both PJM and MISO are projected to face sustained system-wide capacity shortfalls in the presence of rapid, data center-driven load growth, changing market structures and associated accreditation methodologies. Given the conclusion of the RA Study, IPA and IEPA are required to develop this Mitigation Plan to consider strategies that resolve the identified resource adequacy shortfall.

1.4 Scope and Focus of Mitigation Plan

The scope of the Mitigation Plan is to identify solutions that are appropriately sized to address the resource adequacy and reliability needs identified in the Resource Adequacy Study. As part of that evaluation, the Plan will determine whether any CEJA emissions-reduction or retirement deadlines for fossil-fueled plants need to be adjusted and, if so, for how long. Any adjustment would be "only to the extent and for the duration necessary to meet the resource adequacy and reliability needs of the State"[1] and considered alongside other available mitigation options. The Plan will also evaluate whether other actions could reduce or avoid the need to extend those deadlines. These actions may include additional deployment of renewable energy, energy storage, demand response, transmission development, and other measures that could address the identified reliability risk.

The IPA and IEPA are responsible for developing this Plan through a public process that includes stakeholder input. After considering public comments, the Agencies must file a revised Plan with the Commission for review and approval. The Mitigation Plan is also being developed in parallel with the State's Integrated Resource Plan, allowing for the use of consistent assumptions and supporting a coordinated approach to Illinois reliability planning. Both efforts examine how changes in electricity demand, resource availability, technology costs, and policy requirements could affect the reliability and cost of the Illinois power system. The Mitigation Plan is narrower in scope and focuses on two policy futures: a Reference Case and a CEJA Extension Case.

The Reference Case is intended to represent a central estimate of future electric loads, new resource availability and costs, and the achievement of Illinois state electric sector policy objectives as defined by CEJA. The CEJA Extension Case evaluates how extending the CEJA retirement deadlines for fossil-fueled plants in Illinois could affect the energy system, including the need for new resources, resource adequacy, total costs, and emissions. This report evaluates both cases through a near-term assessment of load and available resources and a longer-term capacity expansion analysis. Together, these perspectives

[1] 415 ILCS 5/9.15(o)

show how retirements under CEJA timelines may affect immediate reliability needs and the future development of the Illinois power system.

This additional analysis, updated to the newest forecasts available, provides the analytical foundation for the recommendations put forward in this report.

1.5 Linkage between Mitigation Plan and Integrated Resource Plan

This Mitigation Plan and the 2026 Integrated Resource Plan (due to be filed with the Illinois Commerce Commission in mid-November) were developed in parallel and are closely linked, but serve different purposes. To promote consistency across the two efforts, the Agencies used a common analytical framework and aligned key assumptions where the analyses overlap. This includes common load forecasts, assumptions regarding existing resources and retirements, candidate resource characteristics, transmission constraints, and resource adequacy inputs.

At the same time, the two processes are designed to answer different planning questions. This Mitigation Plan originates from the resource adequacy process established under Section 9.15(o) of the Illinois EPAct (415 ILCS 5). Following a finding of a projected resource adequacy shortfall, the statute directs the Illinois Power Agency and Illinois Environmental Protection Agency to develop a plan that evaluates whether delaying or reducing applicable CO_2e and copollutant emissions-reduction requirements may be necessary, while limiting any such delay to the extent and duration necessary to address the identified resource adequacy or reliability need. The statute also requires that in the development of the Mitigation Plan, the Agencies consider renewable energy, energy storage, demand response, transmission development, and other strategies that could address the identified shortfall. The statute does not provide any mechanism for implementing those strategies through ICC approval of the Mitigation Plan.

The IRP provides a broader planning framework for evaluating many of these alternative strategies and direct authority for implementing them. The IRP examines multiple load-growth futures and a range of existing and new resource options and evaluates portfolios across reliability, cost, emissions, and other policy objectives. Its statutory framework specifically contemplates consideration of load reductions, distributed energy resources, demand-side programs, energy efficiency, new supply resources, transmission, and alternative policy and technology assumptions. It also allows for the comparison of optimized portfolios based on system costs, customer rates and bill impacts, emissions trajectories, and reliability indicators. As the two studies have been developed concurrently, the IRP therefore became the primary analytical venue for examining the broader set of

resource, transmission, and demand-side pathways that could contribute to addressing Illinois' longer-term resource adequacy needs.

Through the approval of the IRP, the Illinois Commerce Commission may "order changes to existing programs" and "direct specific actions within existing programs including the authorization to support the expansion of an existing program."[2] Such changes include authorizing more substantial investment through renewable energy credit procurements, energy storage procurements, and demand-side resource programs. Changes may also include new programs, procurements, or other initiatives "designed to procure appropriate sources of new clean energy and capacity resources" in an effort to resolve a resource adequacy need. Under changes authorized through recently-enacted Public Act 104-0477, through its Order approving the IRP the Commission may authorize the modification of "any plan to reduce or delay CO_2e and copollutant emissions reductions requirements that is submitted by the Illinois Power Agency and Environmental Protection Agency and approved by the Commission under subsection (o) of Section 9.15 of the EPAct."[3] Consequently, should the Commission conclude in approving the IRP that any resource adequacy deficiency could be timely resolved through new resource investments authorized through approving the IRP, that conclusion could serve as the basis for modifying the conclusions found herein.

In light of the interplay between the two plans, the Mitigation Plan therefore draws upon the broader analytical work of the IRP while maintaining a more focused scope. The Reference Case and CEJA Extension Case evaluated in the Mitigation Plan are also evaluated within the IRP. The Reference Case represents a central planning trajectory based on mid-level load growth, current technology cost expectations, existing policy requirements, and assumed resource development timelines. The CEJA Extension Case evaluates how the electricity system and resource adequacy outlook would change if applicable emissions-reduction deadlines for Illinois fossil-fueled generators were extended, while maintaining interim emissions reductions targets up until 2044. The Mitigation Plan evaluates these futures through both a near-term load-resource balance and a longer-term capacity expansion and resource adequacy analysis, using assumptions aligned with the IRP where the analytical scopes overlap.

This division of analytical emphasis should not be interpreted to mean that the Mitigation Plan considers continued operation of CEJA-limited generating units as the only potential response to the identified resource adequacy need. The statute expressly requires consideration of other strategies, and these strategies were considered through the

[2] 220 ILCS 5/16-202(c).
[3] 220 ILCS 5/16-202(c)(1)(v).

coordinated development of the Mitigation Plan and IRP. The parallel development of the IRP with this Plan provided an opportunity to evaluate broader solutions within a more comprehensive portfolio framework that was specifically designed to assess new resource development, transmission expansion, demand-side resources, energy efficiency, storage, and other policy and technology pathways. The Mitigation Plan can therefore rely on and incorporate the relevant findings of the IRP when considering the potential contribution of these alternatives.

The distinction is particularly important for interpreting the recommendations of this Plan. Recommendations concerning whether, and under what circumstances, modification of CEJA emissions-reduction deadlines may be appropriate are addressed directly through the Mitigation Plan because that question is specific to the statutory process established under Section 9.15(o) of the Illinois EPAct. By contrast, recommendations concerning the broader mix of new resources, transmission investments, demand-side programs, and other actions needed to maintain resource adequacy are more appropriately developed through the IRP's comprehensive planning framework. Any potential extension of emissions limits should therefore be understood as one element of a broader resource adequacy strategy, rather than as a substitute for the development of new resources or other actions needed to maintain reliability over time.

This coordinated approach allows the two studies to provide complementary information to the Commission. The Mitigation Plan addresses the immediate statutory question arising from the resource adequacy findings, including the potential role of limited modifications to emissions-reduction timelines, while the IRP evaluates the broader portfolio of actions available to meet Illinois' reliability, affordability, and clean energy objectives. Considered together, the two analyses provide a more complete basis for evaluating both near-term mitigation needs and the longer-term actions needed to address the underlying drivers of Illinois' resource adequacy challenges.

1.6 Roles and Responsibilities in Developing Mitigation Plan

The Mitigation Plan was developed through a coordinated effort, with the Agencies bringing technical expertise and policy perspectives to ensure the design and execution of the study was responsive to the directive under Section 9.15(o) of the Illinois EPAct. The Agencies also utilized the services of IPA’s Procurement Planning Consultant, Energy and Environmental Economics, Inc. (E3), to conduct the analysis and support the overall process and development of the Mitigation Plan.

1.6.1 Illinois Power Agency

The Illinois Power Agency (IPA) is an independent state agency established under Illinois law in 2007 through the enactment of the Illinois Power Agency Act. Under the oversight of the Executive Ethics Commission, the IPA is committed to:

- Ensuring the process of power procurement is conducted in an ethical and transparent fashion, immune from improper influence.
- Conducting competitive procurement processes to procure the supply resources identified in procurement plans.
- Operating in a structurally insulated, independent, and transparent fashion so that nothing impedes its mission to secure power at the best prices the market will bear, provided it meets all applicable legal requirements.
- Continuing to review its policies and practices to determine how best to meet its mission of providing the lowest cost power to the greatest number of people, at any given point in time, in accordance with applicable law.

The IPA is charged with preparing annual electricity procurement plans[4] that define the methods and terms of procurement events the IPA will conduct to obtain supply on behalf of default service residential and small commercial customers of Illinois. The IPA conducts procurement events to obtain electric supply for Ameren, ComEd, and MidAmerican default service customers, and conducts capacity procurement events to obtain zonal resource credits (ZRCs) and/or financial ZRCs for Ameren default service customers. Additionally, CRGA established a new subsection of the Public Utilities Act authorizing the IPA to conduct a clean energy procurement. This new mechanism is intended to facilitate the development of additive new clean energy resources that address broader electric system needs identified through state-led planning processes. The 2027 Electricity Procurement Plan proposes preliminary principles and considerations for this mechanism's future use, to be informed by Integrated Resource Plans in the future. This new provision provides an expanded procurement mechanism to the IPA, subject to ICC approval.

The IPA is also responsible for facilitating achievement of the Illinois Renewable Portfolio Standard (RPS), a public policy designed to drive the development of renewables in Illinois, and other vital energy policy initiatives. To support achievement of the RPS goals, the Agency develops and implements a biennial Long-Term Renewable Resources Procurement Plan

[4] Illinois Power Agency Electricity Procurement Plan: https://ipa.illinois.gov/electricity-procurement/electricity-procurement-plan.html

(Long-Term Plan),[5] which defines a host of programs and procurement processes[6] to support the development of renewable energy systems throughout the state and support achievement of the RPS and clean energy targets and goals. Both the electricity procurement plan and the Long-Term Plan are filed with and approved by the ICC before implementation. The IPA has also previously conducted procurements of Zero Emissions Credits and Carbon Mitigation Credits to help support at-risk nuclear plants.

Additionally, as directed by P.A. 104-0458, the IPA is facilitating the procurement of up to 3 GW of energy storage resources. An initial procurement event was held on August 26, 2026 which brought 600 MW under contract. Future procurement events to secure the remaining resources are expected in 2027 and potentially 2028 as necessary. The IPA is also responsible for development and implementation of an energy storage procurement plan as approved by the ICC, which will establish the terms and content of future energy storage procurement events as necessary. At the time of this Mitigation Plan, the energy storage procurement plan is in development with a draft publication expected to be issued in June 2027. P.A. 104-0458 further directs the IPA to evaluate and potentially implement a new Illinois Storage for All program, as well as to develop and propose a new Geothermal Homes and Businesses Program.

Section 9.15(o) of the Illinois Environmental Protection Act also tasks the IPA, in conjunction with the IEPA, with a planning exercise bearing nexus with the forthcoming IRP. Upon a finding of a reasonable likelihood of a resource adequacy shortfall in coming years in a prior-published resource adequacy study co-authored by the IPA, IEPA, and ICC, the IPA and IEPA must develop and publish a plan "to reduce or delay CO_2e and copollutant emissions reductions requirements only to the extent and for the duration necessary to meet the resource adequacy and reliability needs of the State."[7] This Draft Mitigation Plan relies on the same core modeling and analysis as that which informs the IRP.

These responsibilities give the IPA an important role in connecting the IRP's long-term planning analysis with existing and future State procurement programs and potential implementation pathways. The IPA contributes expertise on wholesale electricity procurement, renewable and storage development, market conditions, resource costs, and

[5] Illinois Power Agency Long-Term Renewable Resources Procurement Plan: https://ipa.illinois.gov/renewable-resources/long-term-plan.html

[6] IPA programs are inclusive of the Illinois Shines Program (also referred to as the Adjustable Block Program) and Illinois Solar for All Program. IPA procurements include utility-scale renewable energy procurement events for wind and hydropower, solar, and brownfield photovoltaics. The Long-Term Plan also includes other programs and provisions such as the Self-direct Program, details surrounding RPS Budgeting, adjacent state project provisions, consumer protections, and diversity equity and inclusion.

[7] 415 ILCS 5/9.15(o)

the practical considerations associated with translating identified resource needs into procurement programs.

This connection between studies and plans is particularly important because Illinois law provides authority for the Commission, through approval of the IRP, to direct certain changes or expansions to existing plans or programs, including the IPA's Long-Term Renewable Resources Procurement Plan, Energy Storage Resources Procurement Plan, and the Mitigation Plan required under Section 9.15(o) of the Illinois Environmental Protection Act.

1.6.2 Illinois Environmental Protection Agency

The Illinois Environmental Protection Agency (IEPA) is an agency established under the Illinois EPAct in 1970.[8] The mission of IEPA is to safeguard environmental quality, consistent with the social and economic needs of the State of Illinois, so as to protect health, welfare, property, and the quality of life.

Under the EPAct, IEPA is designated as the air pollution control agency for the State of Illinois for all purposes of federal acts, including the Clean Air Act. IEPA's Bureau of Air has primary responsibility for carrying out the State's obligations to ensure clean and safe air for Illinois' residents and the environment. Among other responsibilities, IEPA has the duty and authority to collect and disseminate information and technical data required to carry out the purposes of the EPAct. This includes:

- Ascertaining the quantity and nature of discharges from any contaminant source;
- Operating and coordinating the operation of devices to monitor and assess air quality through the Illinois Ambient Air Monitoring Network;
- Collecting emissions data from regulated sources and developing emissions inventories and air quality attainment demonstrations;
- Administering permit programs for stationary sources of air pollution;
- Making recommendations to the Illinois Pollution Control Board for the adoption of regulations under Title VII of the EPAct; and
- Investigating possible violations of the EPAct and regulations adopted thereunder and taking appropriate enforcement action in response to violations.[9]

IEPA implements, maintains, and enforces State Implementation Plans for the National Ambient Air Quality Standards for criteria pollutants, which include carbon monoxide, lead,

[8] 415 ILCS 5/4
[9] Ibid.

oxides of nitrogen, ozone, particulate matter, and sulfur dioxide. The IEPA also administers a federally required vehicle inspection and maintenance program.

Specific to its role under CEJA, IEPA oversees compliance with the decarbonization provisions of Section 9.15 of the EPAct that phase out emissions of electric generating units (EGUs) and large GHG-emitting units while prioritizing environmental justice and equity investment eligible communities. Section 9.15 establishes deadlines by which subject units must reduce GHG emissions by specified amounts, as well as deadlines by which subject units must reduce GHG and copollutant emissions to zero.[10] Certain units are also restricted from emitting GHGs and copollutants in amounts that exceed the unit's existing emissions.[11]

Section 9.15 allows units to temporarily continue operating after an applicable deadline if necessary to maintain power grid supply and reliability or to serve as an emergency backup to operations.[12] Since the passage of CEJA, Illinois EPA has been incorporating applicable requirements of the law into the operating permits of subject facilities in Illinois.

Under CEJA, IEPA is also required to annually report actual GHG emissions from individual units and the aggregate statewide emissions from all units for the prior year. IEPA began reporting historical emissions in June 2025 with its Annual Greenhouse Gas Emissions Report for Sources Subject to the Illinois Climate and Equitable Jobs Act - 2024.[13]

Finally, under CEJA, IEPA is required to collaborate with other state agencies on this Mitigation Plan under Section 9.15(o) of the EPAct. The IEPA is contributing necessary emissions data to determine the status of GHG and copollutant reductions, consulting with other state agencies on permanently reducing sources' emissions to zero, and working in partnership with the IPA on stakeholder comments, revisions, and filing of the Mitigation Plan with the ICC.

1.6.3 Energy and Environmental Economics, Inc.

E3 serves as the IPA's Procurement and Planning Consultant. In this role, E3 supported the development of the Mitigation Plan by designing and implementing a modeling framework, collaborating with the Agencies, coordinating with the RTOs and Illinois utilities to align on data input assumptions and approach, helping facilitate the stakeholder engagement process, conducting the analysis, and drafting sections of the report and key findings.

[10] 415 ILCS 5/9.15(g) through (k)
[11] 415 ILCS 5/9.15(k-5)
[12] 415 ILCS 5/9.15(l)
[13] IEPA/BOA/IL-2025-001

1.6.4 Mitigation Plan Review and Approval Process

This Draft Mitigation Plan represents the first step in the formal plan development and review process established under Section 9.15(o) of the Illinois EPAct. Following publication of the Draft Mitigation Plan, stakeholders and members of the public will have 60 days to submit comments.[14] Such comments are encouraged to be specific, supported by data or other detailed analyses, and, if objecting to all or a portion of the plan, accompanied by specific alternative wording or proposals. The comments will be posted on the IEPA, IPA, and ICC websites. The Agencies will then have 30 days to consider those comments, revise the Mitigation Plan as necessary, and file the revised Plan with the Commission for approval. Together, these steps provide a 90-day period between publication of the Draft Mitigation Plan and filing of the revised Plan.

Within 60 days of the filing of the revised Mitigation Plan with the Commission, interested parties will have 60 days to file objections.[15] The Commission will determine whether an evidentiary hearing is necessary within 30 days after the expiration of the period for objections and will hold three public hearings within 90 days after the plan is filed. The Commission must enter its order approving the Mitigation Plan, with or without modifications, within 180 days, though the ICC may extend the period of review for no more than an additional 180 days.

In reviewing the Plan, the Commission shall only approve the plan if it determines that the proposed actions will resolve the identified resource adequacy or reliability deficiency with the least amount of CO_2e and copollutant emissions.[16] In order to approve the plan, the Commission must also find that the Plan will support adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account the impact of increases in emissions. If the resource adequacy or reliability deficiency identified in the Plan is subsequently reduced or resolved, the IPA and IEPA may file an amended plan adjusting any previously approved delay or reduction in emissions-reduction requirements.[17]

1.7 Stakeholder Engagement

Stakeholder engagement was an important component of developing the Mitigation Plan. Stakeholder engagement for the Mitigation Plan was held concurrently with Illinois' first Integrated Resource Plan (IRP), as the two use a common set of assumptions and modeling

[14] 415 ILCS 5/9.15(o)(1).
[15] 415 ILCS 5/9.15(o)(2).
[16] 415 ILCS 5/9.15(o)(3).
[17] 415 ILCS 5/9.15(o)(4).

framework.[18] The stakeholder engagement process was designed to provide transparency into both plans' analytical approach, gather input on key planning assumptions and uncertainties, and identify issues and priorities for consideration in the analysis and recommendations.

The Mitigation Plan and 2026 IRP built on a substantial foundation of stakeholder engagement conducted through the 2025 Resource Adequacy (RA) Study. Throughout that process, stakeholders provided input on Illinois' resource adequacy challenges, reliability risks, resource options, and potential policy responses. Additional feedback was solicited through stakeholder questions issued in late January 2026, with responses received in February. Together, these earlier engagement efforts provided the Mitigation Plan and IRP with a strong foundation of stakeholder perspectives and recommendations at the outset of the planning process.

Building on this foundation, the agencies conducted stakeholder engagement through four complementary mechanisms:

1. An initial in-person workshop in February 2026 to introduce the IRP process, establish shared planning priorities, and solicit early stakeholder input.
2. A series of five virtual workshops focused on specific elements of the IRP and Mitigation Plan, including analytical assumptions, methodologies, and scenario development.
3. Written requests for stakeholder feedback issued before or after workshops to provide opportunities for more detailed input on specific questions and analytical approaches.
4. Formal written Requests for Comment issued by the ICC on specific topics, providing additional opportunities for stakeholder input outside the workshop process, specific to the IRP.[19]

These mechanisms provided stakeholders with opportunities to contribute at different stages of IRP development. The initial workshop and early written feedback helped inform the overall scope and analytical framework, while subsequent topic-specific workshops and written comments provided more focused input as the analysis progressed.

The stakeholder engagement process began with a joint in-person workshop on February 18, 2026, hosted by the ICC, IPA, IFA, and IEPA. The workshop introduced the IRP process and

[18] Since stakeholder feedback was held concurrently for these plans, stakeholder feedback was summarized together between the two studies in this section.
[19] Requests for Comment were specific to the IRP, and were not included in Mitigation Plan analysis.

provided an opportunity for stakeholders to identify priorities and recommendations before the analytical framework and scenarios were finalized. The workshop included presentations from key stakeholder groups, such as the Clean Grid Alliance, Office of the Illinois Attorney General, Ameren Illinois, Union of Concerned Scientists, Southern Company, Invenergy, Constellation, and Climate Jobs Illinois.

In this workshop, the ICC, IPA, and IEPA requested additional stakeholder feedback to inform the IRP's modeling and analysis. The questions spanned topics such as scenario drivers, modeling scenarios, sensitivity analysis, data and data sources, modeling assumptions, model methodologies, and portfolio selection criteria. The Agencies received 22 responses to this first Request for Comments.

In terms of scenarios, stakeholders widely agreed that CEJA compliance versus extension of CEJA requirements was the most important scenario driver, followed closely behind by allowing new gas generation. Stakeholders were widely split, with some stakeholders advocating for extended retirement timelines and/or allowing new gas to preserve reliability, with others believing the fossil fuel plant retirements should continue on schedule while adding that there is growing skepticism that new gas could be built in time.

Second, stakeholders flagged data center demand as the most consequential, and arguably most uncertain, scenario driver. Stakeholders argued that it should be considered its own sensitivity with separate Low/Medium/High cases. Several respondents referenced the importance of analyzing the geographic clustering of large loads and data centers. Demand flexibility and the impact of distributed generation and energy efficiency were the next most commonly cited demand drivers.

The last common theme was affordability. A vast majority of stakeholders agreed affordability should be a central focal point of the proposed modeling framework. Some stakeholders were cautious about expanding storage, renewable, and energy efficiency budgets because those budgets affect ratepayer affordability. Others suggested utilizing net present value (NPV) and present value of revenue requirement (PVRR) metrics that are tied to energy-burden benchmarks for low-income customers.

Other scenarios presented by stakeholders were reduction of time to interconnect, aggressive decarbonization, high storage build out, and testing of different weather assumptions.

Workshops Held

Following the February in-person workshop, E3 facilitated five combined IRP and Mitigation Plan virtual stakeholder workshops, with sessions held from April-September 2026. The stakeholder sessions are shown in Table 1-1 below.

Table 1-1: Stakeholder Workshops

Workshop	Date	Attendees
Modeling Scenarios	April 7, 2026	149
Candidate Resources	April 10, 2026	143
Customer Cost Impacts Methodology	May 26, 2026	103
Load Forecast & Resource Capacity Accreditation (ELCCs)	July 31, 2026	137
Draft Results	September 24, 2026	168

Written stakeholder comments were invited and received after the virtual workshops. To ensure adequate and timely access to materials for stakeholders, the ICC established a dedicated webpage for all materials associated with the IRP stakeholder engagement process, including meeting materials, stakeholder responses to requests for feedback, and workshop recordings.[20] Further information related to the content presented in the IRP workshops, including meeting summaries of each session, can be found in Appendix B of the IRP.

Scenarios

The first virtual stakeholder workshop was held on April 7, 2026. This workshop covered the objectives of the IRP and Mitigation Plan, a summary of stakeholder responses on scenarios, the proposed approach to scenario design, proposed scenarios for modeling, and stakeholder Q&A. The workshop presentation contextualized the Mitigation Plan and IRP within Illinois's broader planning ecosystem and distinguished the two processes' objectives: the Mitigation Plan addresses reliability risks identified in the RA Study over 2026–2035, while the IRP focuses on near-term and longer-term resource planning through 2047 across six areas as required by CRGA.

[20] "Illinois Commerce Commission Integrated Resource Plan (IRP)," (2026): https://icc.illinois.gov/informal-processes/Integrated-Resource-Plan.

E3 reviewed the 22 stakeholder responses received from the first request for comment (RFC),[21] which identified CEJA compliance/extension, new gas generation, and demand growth as the highest-priority scenario drivers and large loads/data centers as the leading driver of demand sensitivity. E3 explained the three-step scenario design process, building on the RA Study's prior scenario framework. They presented three proposed load forecasts, the distinction between Core Policy Cases and Alternative Decarbonization Paths, and proposed technology factors including demand-side resources and accelerated advanced technology adoption. This culminated in a ten-scenario matrix spanning Core Policy Planning Futures, System Evolution Futures, and Alternative Decarbonization Paths.

The workshop concluded with questions for stakeholders on whether the proposed scenarios and load forecasts capture a reasonable range of drivers and requests for suggested sensitivities. A total of 15 responses were received.

Stakeholder Feedback Received on Scenarios

The first, and most prevalent, theme in the Scenarios workshop centered around load forecasting, data center growth and the need for more clarity around the stages of data center development. Many stakeholders sought clearer definitions around what counts as "in-development" data center load and advocated for large-load and electrification load being modeled separately.

Second, stakeholders were cautious about development timelines in relation to near-term resource adequacy risks and questioned whether the pace assumed in the model is realistic given supply chain-related lead times, interconnection delays, and capacity. Some stakeholders also questioned assumptions related to early fossil fuel retirements and suggested examining cases where units leave the market faster than assumed.

Third, multiple stakeholders proposed additional scenarios not currently covered in the modeling, such as a reinstated federal policy case, where federal tax credits and Clean Air Act regulations are reinstated, a "Cleaner Energy" pathway, supply constraint scenarios, a capacity-erosion case, and others.

Lastly, a vast majority of stakeholders included requests for additional sensitivities in the Base Case, such as fuel or gas price trajectories, federal tax credit and tariff timing, climate-adjusted weather and demand changes, import capacity limits, and development timeline delays.

[21] All stakeholder responses to RFCs and Workshops, as well as presentations for each Stakeholder Workshop, can be found at: https://icc.illinois.gov/informal-processes/Integrated-Resource-Plan

Candidate Resources

The second virtual stakeholder workshop was held on April 10, 2026, and covered the characteristics of resources for capacity expansion modeling, supply-side candidate resources, demand-side candidate resources, and Q&A. E3 presented a summary of the proposed scenario matrix from the prior workshop, then introduced PLEXOS LT, the linear optimization model used to identify a least-cost resource portfolio, then explained how PLEXOS will be paired with the RECAP loss-of-load-probability model to validate reliability across a range of weather conditions. The team then presented on how candidate resources are represented through cost, reliability contribution, RPS/CES eligibility, and operational characteristics.

Next, E3 detailed supply-side candidate resources spanning mature technologies, such as solar PV, lithium-ion batteries, onshore wind, natural gas, and Gen III+ nuclear, and emerging technologies, such as advanced nuclear/small modular reactors (SMRs) and long-duration storage (LDES). The workshop explained how resource availability phases in near-, medium-, and long-term horizons are based on development timelines and technology readiness. The workshop also introduced draft Illinois-specific capital expenditure, levelized cost of energy (LCOE), and levelized fixed cost (LFC) forecasts reflecting assumptions about expiring federal tax credits and trade policy. The presentation then discussed demand-side resources, defined key terminology, and explained baseline levels of distributed solar and energy efficiency. E3 noted that existing demand response will be included in all scenarios, while a "High Flexibility" scenario would additionally model a representative virtual power plant (VPP) resource to estimate the incremental reliability and cost value of aggregated distributed energy resources (DERs). E3 also discussed the stakeholder input requested to inform both this IRP cycle and future program design. The workshop closed with stakeholder Q&A and a request for written comments. A total of 19 responses were received.

Stakeholder Feedback Received on Candidate Resources

The first major theme of the feedback on Candidate Resources was in relation to commercial availability timelines, with some stakeholders commenting that the timelines were overly optimistic. In turn, some stakeholders argued that the model will attempt to solve reliability gaps with resources that could not feasibly be online in time. Stakeholders proposed updating the timelines to reflect delays in bringing new generation online.

Second, multiple stakeholders included requests to expand the candidate resource list to include resources such as industrial combined heat and power (“CHP”)/cogeneration,

behind-the-meter (BTM) industrial generation, natural gas with carbon capture and sequestration (CCS), long-duration and multi-day storage, demand-side management, behavioral demand response and peak-time rebates, among others. Stakeholders also noted that demand reductions could be conducted through demand response, energy efficiency, and storage.

Third, a vast majority of stakeholders presented arguments as to why DERs should not be collapsed into one representative VPP. In doing so, these stakeholders argued that this could obscure the actual differences in cost and reliability value.

Lastly, on CCS assumptions, some stakeholders argued the assumed 100% CCS rate is unrealistic, while providing additional recommendations to the percentage rate. Other stakeholders believed that CCS should not be included in this IRP cycle, noting a high cost with deployment uncertainties, particularly around timing of permitting, construction, transport, storage, and utility-scale deployment.

Customer Cost Impact Methodology

The third virtual stakeholder workshop was held on May 26, 2026 and covered the customer cost impacts methodology. The presentation focused on the Cost and Consumer Impacts area of CRGA's six required IRP components, outlining the key questions the analysis will address, such as total system costs by scenario, largest cost drivers, allocated costs by customer class, and impacts on electricity rates.

The presentation also described E3's proposed two-part approach to capture costs: (1) a system cost analysis across all scenarios, which calculates the net present value of each scenario's modeled resource portfolio plus incremental transmission; (2) and a customer cost analysis for a subset of scenarios, which uses an electric revenue requirement model to project utility costs forward and translate them into rate impacts.

The revenue requirement modeling process was presented as including four steps: establishing cost-of-service starting values; projecting costs forward using PLEXOS capacity expansion and production cost outputs; allocating the revenue requirement across different customer classes; and calculating average class rates, with projections running in five-year increments through 2047/2050. The presentation concluded with an overview of the stakeholder comments requested. A total of 16 responses were received.

Stakeholder Feedback Received on Customer Cost Impacts Methodology

The first major theme of stakeholder feedback on the Customer Cost Impact Methodology concerned the definitions of “commercial” and “industrial” with respect to customer classes. This was a widely contested question, with many differing proposals, such as

aligning to the U.S. EIA Form 861, including a "very large" category, utilizing voltage or load factors instead of industry labels, or adding a separate data center rate class.

The second major theme related to the proposed electric revenue requirement growth rate and the historical period used to establish the growth rate. The initial proposal was to estimate future revenue requirement growth based on the 10-year historical growth rate along with modeled additions for new transmission and distribution investments. When asked if this was the appropriate time period, nearly all respondents selected, "Yes, but should be adjusted" as their response. Clarifying further, stakeholders suggested that the models align growth rates with more recently ICC-approved multi-year rate plans rather than historical data from the past 10 years.

Third, some stakeholders argued that the assumption that program fees will remain flat across all scenarios was unrealistic for scenarios that are dependent upon high customer-side adoption. Stakeholders argued that, in these cases, higher program spending is needed to meet assumed adoption levels and thus requires higher collection of program fees. Stakeholders argued that modeling program fees as flat across all scenarios does not adequately depict the actual customer cost impacts.

Lastly, stakeholders were asked about definitions of energy burden, equity and barriers to clean energy programs. In terms of energy burden, most stakeholders recommend a business-as-usual baseline built upon current conditions, assuming that electric bills of 3% for non-electric heating customers established the threshold for energy burden. When asked about barriers to clean energy programs, many stakeholders agreed that the most common participation barriers within were financial barriers, renters or split-incentive problems in multifamily housing, as well as awareness and administrative barriers.

Load Forecasts and ELCC Methodology

The fourth virtual stakeholder workshop focused on Load Forecasts and Resource Capacity Accreditation (as represented through effective load carrying capability, or "ELCC", values). The agenda covered load forecasts, reliability methodology, reliability benchmarking, and ELCC results, followed by an extended Q&A period. The presentation began by reviewing the four load forecast scenarios being used in the IRP, which build on the three scenarios required under CRGA by adding a range of data center load and electrification assumptions. E3 explained that updated data center load forecasts shifted the geographic distribution of load toward the MISO footprint compared to the 2025 RA Study, with higher forecasts in the Ameren IL zone and lower forecasts in the ComEd zone, while data centers remain by far the largest driver of new load growth in both PJM and MISO.

The presentation then discussed reliability methodology, describing E3's RECAP model. E3 presented benchmarking results showing close alignment between its simulated system risk and both PJM's and MISO's published system dynamics, validating the reliability model ahead of its use in generating ELCC values. The session concluded with a review of 2030 ELCC results by technology for the PJM ComEd zone, the MISO LRZ 4 in which Ameren IL is located, and the broader PJM and MISO footprints, along with an explanation of next steps handing off these capacity value inputs to the PLEXOS portfolio model. The session concluded with a Q&A session, along with a request for written feedback. A total of nine responses were received.

Stakeholder Feedback on Load Forecasts and ELCC Methodology

First, a consistent theme in the feedback from this session was the uncertainty of data center load forecasts and a desire for more detailed documentation of the methodology. Many stakeholders requested more detail on how the Low/Mid/High data center cases were derived, what criteria and data sources were used, and how E3's forecast compares to the forecasts supplied by the utilities. Some stakeholders flagged real world examples of potential data center volatility, such as the cancellation of data center transmission service agreements. Stakeholders recommended: including alternative data center business models; including how the forecasts differ from previous Resource Adequacy studies; and implications of future policy and program additions. Also, stakeholders requested regular, periodic forecast updates due to the changing landscape and nature of data center load growth.

Second, and related to the first theme presented, stakeholders commented on how large-load and/or data center flexibility is modeled. Some stakeholders wanted more detail and granularity as to how large-load flexibility is incorporated into the load forecast and larger reliability framework and questioned what percentage of the forecasted large load is flexible.

Third, stakeholders requested more documentation on the ELCC and resource accreditation methodology and on how the IRP's methodology compares to PJM/MISO's accreditation methodologies. Stakeholders requested more data on how solar paired with storage could affect ELCC of storage.

Lastly, stakeholders requested more data on retirements and assumptions used for existing resources. Some stakeholders asked for more information on the coal and gas units that are set for retirement or those that are already assumed as retired, including retirement dates, with a request for a summary table indicating retirements and any other assumed resource additions in the near-term.

Draft Results

The fifth and final virtual stakeholder workshop was held on September 24, 2026, and focused on draft results from the IRP and Mitigation Plan modeling effort. This workshop included a review of the PLEXOS capacity expansion modeling framework, final scenario definitions, draft portfolio results, and key findings, followed by stakeholder Q&A. The workshop began with an overview of the modeling approach used to identify least-cost resource portfolios capable of meeting reliability requirements, RPS targets, and CEJA emissions constraints across a range of potential futures. E3 reviewed the final scenario matrix, including four load forecast scenarios incorporating varying assumptions for data center development and electrification, as well as sensitivities related to transmission expansion, technology costs, and policy assumptions.

The team presented draft modeling results across scenarios, including statewide outcomes and regional results for the ComEd and Ameren service territories. E3 explained that substantial new resource development will be needed to serve projected load growth while maintaining reliability and meeting clean energy goals, with portfolios generally selecting significant additions of solar, wind, energy storage, nuclear resources, and imported capacity. Results demonstrated that assumptions regarding data center growth and electrification were among the largest drivers of future resource needs, while alternative policy and transmission assumptions influenced the timing and mix of resource additions. The workshop concluded with a discussion of key themes, next steps for finalizing the IRP and Mitigation Plan reports, Q&A, and a request for stakeholder feedback. A total of 14 responses were received.

Stakeholder Feedback on Draft Results

The first theme of stakeholder feedback was the transparency of modeling assumptions and methodologies. Many stakeholders requested greater visibility into the key inputs utilized in the modeling, including load growth forecasts, data center demand assumptions, resource cost projections, import assumptions, transmission constraints, and the treatment of emerging resources, such as demand response, VPPs, and DERs. Stakeholders indicated transparency would improve confidence in the study outcomes and help stakeholders better understand the differences across scenarios.

The second major theme was related to reliability and resource adequacy under future load growth conditions. Many stakeholders expressed concern about increasing dependence on capacity imports from neighboring regions and questioned whether those resources would be available during periods of greatest system need. Stakeholders also highlighted challenges associated with transmission constraints, resource development timelines, interconnection delays, and uncertainty surrounding future load growth.

Third, stakeholders emphasized the importance of evaluating customer affordability and total system costs. Stakeholders recommended including system cost, revenue requirements, and rate impact analysis into the modeling, and noted that cost considerations are critical for comparing scenarios and informing long-term planning decisions.

Lastly, stakeholders requested a more decision-oriented presentation of results. Many stakeholders asked for clearer side-by-side comparisons of scenarios, better identification of key tradeoffs, and greater emphasis on near-term planning actions. Stakeholders expressed interest in understanding which investments or strategies appear to be the most beneficial, what risks could affect implementation, and how the modeling results can be translated into practical planning and policy decisions over the next several years.

How Feedback Was Considered in the Mitigation Plan and IRP

Stakeholder feedback informed the IRP at multiple stages of its development. Feedback received before the analytical work began was particularly important in establishing the overall scope of the analysis, identifying major areas of uncertainty, and shaping the initial scenario framework. Early comments emphasized uncertainty surrounding data center load growth, the potential implications of extending the operating timelines of generating units affected by CEJA, the role of demand-side resources, and the importance of customer affordability. These themes were incorporated into the initial design of the IRP and remained central throughout the analytical process.

As the IRP progressed, the Agencies, E3, and Viridis reviewed stakeholder comments following each workshop and considered how the feedback could inform the ongoing work. In general, comments fell into three categories: (1) feedback that could be incorporated directly into the assumptions, scenarios, or methodologies used in this IRP; (2) feedback that could not be incorporated directly into the analysis but informed how assumptions, results, limitations, or areas of uncertainty were presented; and (3) feedback that identified issues or analytical improvements for consideration in future IRP cycles.

This approach recognized both the value of stakeholder input and the practical constraints of the inaugural IRP process. The 2026 IRP was developed over approximately six months, requiring many foundational modeling decisions to be made early in the process. As a result, the initial stakeholder feedback had a significant influence on the overall analytical framework and scenario design, while there were fewer opportunities for iterative stakeholder review of detailed technical assumptions and methodologies once modeling was underway.

Future IRP cycles are expected to provide greater opportunity for this type of iterative engagement. With the foundational modeling framework established through this first IRP, subsequent cycles can provide stakeholders with earlier visibility into proposed assumptions and methods, create additional opportunities to comment before modeling decisions are finalized, and allow stakeholder feedback to inform successive refinements to the analytical framework.

Several themes raised throughout the stakeholder process influenced the IRP and the way the analysis was structured.

Data center load growth and uncertainty. Stakeholders repeatedly identified data center development as one of the most important and uncertain drivers of Illinois electricity demand. Early comments specifically recommended evaluating a range of low, medium, and high data center futures. The IRP therefore evaluates multiple data center load trajectories that span a wide range of possible outcomes. The low case reflects relatively limited additional development beyond facilities already operating or under construction, while higher cases examine substantially greater near-term development and sustained longer-term growth. This range allows the IRP to evaluate how resource needs, reliability, costs, and emissions could change if data center growth differs materially from current expectations rather than relying on a single deterministic forecast.

Addition of a data center flexibility case. Stakeholders requested greater consideration of whether some portion of future large-load and data center demand could respond to system conditions. The IRP therefore added a case specifically evaluating data center load flexibility. This case tests how allowing a portion of large loads to reduce or shift consumption during a defined set of system conditions could affect resource adequacy needs, resource development, and system costs.

The role of demand-side solutions. Stakeholders also emphasized the potential contribution of energy efficiency, demand response, distributed energy resources, virtual power plants, and flexible large loads. Feedback on candidate resources included requests to consider a wider range of demand-side options, while comments on the load forecasts specifically asked how much large-load demand could be flexible. In response, the IRP includes analysis designed to test the impact of increased load flexibility. This analysis helps illustrate how the ability to shift or reduce demand during periods of system stress could affect resource adequacy needs and the composition and cost of the future resource portfolio.

Maintaining flexibility and optionality as system conditions evolve. Stakeholders expressed differing views on the appropriate timing of CEJA-limited generating unit retirements and on the feasibility and timing of replacement resources. Some stakeholders supported extending retirement timelines to maintain reliability, while others supported retaining the statutory schedule and emphasized alternatives to new fossil generation.[22] The IRP does not resolve these policy differences through a single assumed future. Instead, it evaluates multiple CEJA extension sensitivities and alternative pathways for meeting Illinois clean energy objectives. This scenario-based approach allows the IRP to examine the value of preserving different resource options under uncertain future load, technology, market, and development conditions.

Addition of carbon capture and sequestration as a candidate resource in Clean Energy Standard scenarios. Stakeholder feedback included differing views on the feasibility and appropriate modeling treatment of carbon capture and sequestration, including questions about capture rates and commercial availability. To expand the range of potential technologies available in scenarios evaluating alternative clean energy pathways, the IRP includes natural gas generation with carbon capture and sequestration as a candidate resource in the Clean Energy Standard scenarios, set at a rate of capturing 90% of carbon emissions. Including the technology as a model option allows its economics and system value to be evaluated alongside other eligible resources without presupposing that it will be selected.

Keeping customer affordability central to the analysis. Affordability was one of the most consistent themes in the initial stakeholder comments. Stakeholders emphasized both total system costs and the potential effects of future investments on customers, including low-income customers. Accordingly, cost considerations were integrated throughout the scenario design rather than treated only as an output reported at the end of the analysis. The IRP evaluates multiple pathways for meeting reliability and policy objectives to compare their cost implications and identify the conditions under which different strategies may result in lower costs for Illinois customers. A dedicated customer cost analysis further evaluates how selected resource pathways may translate into utility revenue requirements and customer rates.

Together, these themes shaped the IRP as an analysis of alternative futures rather than a forecast of a single expected outcome. This approach is particularly important given the

[22] The Mitigation Plan is the primary vehicle for analyzing adjustments to CEJA-authored generating facility emissions limits and those issues are addressed more comprehensively through the Draft Mitigation Plan.

significant uncertainty surrounding load growth, resource development timelines, regional market conditions, and future technology costs.

Not every stakeholder recommendation was incorporated into the current IRP, but all were considered and discussed by the Agencies and their partners. Appendix B includes a detailed breakdown of all stakeholder feedback received as part of the IRP workshops and where the themes are addressed in the report, where applicable. Some proposed analyses would have required additional data, changes to the underlying modeling architecture, or additional scenarios beyond what could reasonably be completed within the first six-month IRP cycle. Where relevant, these comments informed discussion of analytical limitations and areas where the framework could be expanded in future cycles. The stakeholder record therefore serves not only as an input to the 2026 IRP but also as a source of priorities for continued improvement of future Illinois' IRPs.

1.8 Contents of this Mitigation Plan Report

The remainder of this Mitigation Plan is organized to move from the study assumptions and analytical framework through the individual analyses and, finally, to an integrated assessment and recommended actions.

- Chapter 2 describes the analytical framework, including the Reference Case and CEJA Extension Case, the principal questions evaluated, and how the different modeling tools are used together.
- Chapter 3 presents the baseline assumptions that are common across the analyses, including load forecasts, existing and planned resources, retirements, candidate resources, transmission and import capability, and fuel prices.
- Chapter 4 updates the near-term resource adequacy outlook for PJM, MISO, the ComEd Zone, and MISO LRZ 4 using the latest information on loads and resources.
- Chapter 5 evaluates how retirement or continued availability of CEJA-limited units could affect regional capacity market prices and costs to Illinois customers.
- Chapter 6 uses probabilistic reliability modeling to examine when reliability risks occur, how severe they are, and how CEJA-limited units contribute during those conditions.
- Chapter 7 extends the analysis over the longer term by comparing the resources, generation, costs, emissions, and imports associated with the Reference Case and CEJA Extension Case. It also evaluates the scale and timing of replacement resources needed under each pathway.

- Chapter 8 brings the preceding analyses together to assess the persistence of the reliability need, the feasibility of alternative resources and strategies, and the implications for Illinois customers, emissions, and implementation risk. Consistent with the statutory requirement to consider alternatives, this chapter also places renewable energy, storage, demand-side resources, energy efficiency, and transmission within the broader Mitigation Plan and Integrated Resource Plan framework.
- Chapter 9 presents the Agencies' findings, proposed mitigation strategy, implementation approach, relationship to the IRP and other planning initiatives, and the administrative steps that follow publication of the Draft Mitigation Plan.

2 Analytical Framework

This Mitigation Plan builds upon the analytical foundation developed for the 2025 Resource Adequacy Study while updating the data, assumptions, and modeling inputs used to evaluate Illinois' evolving electric system. The framework is designed to determine whether, and to what extent, the resource adequacy shortfall or reliability concerns identified in the RA Study persist under current projections; evaluate how the continued operation or retirement of generating units affected by CEJA's emissions-reduction requirements influences market and reliability outcomes; and assess whether other resources or strategies can resolve the identified need.

Section 9.15(o) of the EPAct directs the IPA, in conjunction with the IEPA, to develop a mitigation plan when the RA Study reasonably demonstrates that a resource adequacy shortfall will occur or a regional transmission organization determines that a reliability violation will occur. Any reduction or delay in applicable CO_2 and copollutant emissions-reduction requirements must be limited to the extent and duration necessary to meet the State's resource adequacy and reliability needs. The statute also requires consideration of renewable energy, energy storage, demand response, transmission development, and other strategies capable of resolving the identified shortfall or reliability violation.

No single analytical tool can fully evaluate the accounting, market, reliability, cost, and emissions questions relevant to that determination. The Mitigation Plan therefore uses four complementary analytical components: an Updated Resource Adequacy Balance Analysis, a Capacity Market Assessment, RECAP Reliability Modeling, and PLEXOS Capacity Expansion Modeling. This chapter identifies the questions assigned to each component, describes how the analyses are coordinated, and establishes the framework through which their results will be evaluated together.

2.1 Cases Studied

The Mitigation Plan evaluates a Reference Case and a CEJA Extension Case using a common set of baseline assumptions and the same load forecast. Holding these assumptions constant allows the analysis to isolate the implications of extending the operating availability of generating units subject to CEJA emissions-reduction deadlines. Chapter 3 provides additional detail on the baseline assumptions used in both cases, including existing and candidate resources, resource costs and development timelines, transmission limits, resource retirements, and other modeling inputs.

Both cases use the reference load forecast developed for the IRP. The forecast begins with existing-customer load forecasts provided by Illinois utilities and incorporates a mid-range trajectory for data center growth. Electric vehicle and heat pump adoption are forecasted to continue at currently anticipated rates rather than assuming the accelerated electrification trajectory evaluated elsewhere in the IRP. The Reference forecast is intended to provide a central planning trajectory for evaluating the two cases, recognizing that future load growth, particularly from data centers, remains uncertain.

In the Reference Case, Illinois generating units subject to CEJA emissions limits are assumed to retire consistent with applicable CEJA requirements. The retirement assumptions build on those developed for the 2025 Resource Adequacy Study, with targeted updates to reflect more recent information, including reliability-related extensions requested by PJM and changes in unit ownership or announced retirement timing. The model then identifies a least-cost portfolio of new resources and capacity purchases needed to serve the Reference load forecast while meeting reliability requirements, Illinois' Renewable Portfolio Standard, applicable emissions constraints, and existing transmission import limits.

The CEJA Extension Case uses the same Reference load forecast and baseline modeling assumptions but changes the treatment of CEJA-limited generating units. Rather than retiring according to the CEJA schedule assumed in the Reference Case, these units are allowed to remain available through the modeling horizon while continuing to comply with applicable interim CEJA emissions-reduction requirements through 2044. This case is designed to evaluate how continued availability of existing thermal capacity changes Illinois' resource adequacy needs, resource additions, system operations, costs, and emissions relative to the Reference Case. It should therefore be understood as a sensitivity that isolates the effects of extending CEJA-limited units, rather than as a separate forecast of future load or other system conditions.

2.2 Analytical Objectives

The analytical objectives of the Mitigation Plan translate the requirements of Section 9.15(o) into four distinct objectives concerning Illinois' updated resource adequacy outlook and the market, reliability, and resource implications of the policy strategies under consideration.

The first objective is a near-term update to the load-resource balance presented in the RA Study. It focuses on how projected conditions through 2030 have changed based on the latest available information regarding load growth, resource development, retirements, accreditation, and applicable resource adequacy requirements. The remaining objectives

evaluate CEJA-limited unit retirements on the Capacity Market, how reliability risk changes when CEJA-limited units are retired from the system, and the long term resources needed to meet Illinois energy needs in both the Reference Case and CEJA Extension Case. The primary analytical objectives are summarized below.

Table 2-1: Mitigation Plan Analytical Objectives

Analytical Component	Purpose	Primary Output
Updated Load and Resource Balance Analysis	Update the near-term outlook using the latest information on load, existing resources, retirements, and expected resource additions.	Annual capacity surplus or shortfall and timing of emerging resource adequacy needs.
RECAP Reliability Modeling[23]	Quantify probabilistic reliability risk of retiring CEJA-limited units and how retirement impacts system unserved energy risk	Frequency, timing, and magnitude of loss-of-load risk
PLEXOS Capacity Expansion Modeling	Identify the resources needed to maintain reliability and compare system outcomes across cases.	Resource additions, generation, system costs, and emissions.
Capacity Market Assessment	Estimate how changes in supply and demand may affect capacity market conditions and customer exposure to capacity costs.	Illustrative capacity prices and associated cost impacts.

These objectives are intended to produce distinct but complementary results and will ultimately be considered together in developing the Mitigation Plan's findings and recommendations.

2.3 Analytical Workflow

The four analytical components are coordinated through a common set of planning assumptions and Mitigation Plan cases. The framework combines a refreshed near-term assessment of expected loads and resources with several complementary analyses that

[23] RECAP is E3's probabilistic resource adequacy model that quantifies loss-of-load risk. See further description in Chapter 6.

evaluate the market, reliability, and resource-planning implications of alternative treatments of CEJA-limited units.

The Updated Load and RA Balance Analysis focuses on expected conditions from the beginning of the study period through 2030. It incorporates the latest available information on load growth, existing resources, planned additions, anticipated retirements, resource accreditation, and regional resource adequacy requirements. Its purpose is to determine how the near-term outlook has changed since publication of the RA Study and to provide an updated accounting of the timing and magnitude of potential capacity surpluses or shortfalls.

The remaining analytical components evaluate the implications of the mitigation strategies using longer-term modeling horizons from 2030 to 2047. The Capacity Market Assessment examines how changes in the availability of CEJA-limited units and other resources affect the regional capacity supply-demand balance and could impact capacity market prices under equilibrium conditions. In parallel, RECAP Reliability Modeling evaluates how those same system changes affect probabilistic reliability risk, including the risk of potential loss-of-load events.

PLEXOS Capacity Expansion Modeling addresses the related question of what resources would be required to maintain reliability under each mitigation strategy. The model evaluates resource additions, retirements, and system operations subject to the applicable reliability, policy, and planning constraints. Its outputs provide a basis for comparing the quantity and type of replacement resources required, the economics of those additions under projected market conditions, and the resulting effects on system costs and emissions.

The findings from these analyses are subsequently considered together. Capacity market results provide insight into the economic signals associated with changing resource availability; RECAP results quantify the corresponding reliability consequences; and PLEXOS results identify potential resource portfolios capable of addressing projected needs. This integrated interpretation allows the Agencies to evaluate both the consequences of scheduled retirements and the relative effectiveness of the mitigation strategies considered in this Plan.

2.4 Integrated Evaluation and Decision Framework

The analytical components described in Section 2.2 will be interpreted collectively to determine whether extension of CEJA emissions timelines is necessary and, if so, the form, scale, and duration of the mitigation strategy appropriate to address the identified resource adequacy or reliability concern. No single analysis is intended to determine the

recommended policy outcome. Instead, the Agencies consider the combined evidence regarding the persistence of reliability risk, the availability and feasibility of replacement resources, expected market responses, and the cost and reliability implications for Illinois customers.

The integrated evaluation is organized around three principal questions:

- Does a material resource adequacy or reliability risk continue to exist, and how would the treatment of CEJA-limited units affect that risk?
- Can other resources feasibly be developed in time to address the identified need?
- What are the potential cost and reliability consequences for Illinois customers under the mitigation strategies evaluated?

Table 2-2 summarizes how the analytical results will be combined to address these questions.

Table 2-2: Key Questions and Analytical Tools to Support Decision Making

Key Decision Making Question	How the Analytical Results Inform the Question
Does a material RA or reliability risk continue to exist?	Assess whether projected capacity shortfalls or reliability concerns persist using updated system conditions, and evaluate how continued availability of CEJA-limited units changes the timing or severity of those risks.
Can other resources feasibly address the identified need?	Identify the quantity, type, and timing of replacement resources needed, and consider whether those resources could reasonably be developed in time to address the identified reliability need.
What are the potential cost and reliability consequences for Illinois customers under the mitigation strategies evaluated?	Compare the reliability, resource, cost, and emissions implications of the Reference and CEJA Extension cases, including exposure to capacity market costs and reliability risk.

Persistence and Materiality of Reliability Risk

The first step in the integrated evaluation is to determine whether, and to what extent, the resource adequacy or reliability deficiency identified in the Resource Adequacy Study

persists under updated projections. This is not a determination made through a single metric.

The Updated RA Balance Analysis provides a forward-looking accounting of projected accredited capacity relative to applicable regional and zonal resource adequacy requirements through 2030. It indicates whether projected supply is expected to remain above or fall below those requirements and how the timing and magnitude of the balance have changed since the RA Study.

RECAP supplements that accounting assessment by simulating system performance across a broad range of weather, load, resource availability, and outage conditions. Its results characterize probabilistic reliability risk, including metrics such as LOLE, EUE, event frequency, duration, and depth. Together, the two analyses indicate whether the identified deficiency remains material and whether a change in the availability of CEJA-limited units materially reduces that deficiency.

Electric systems are not planned to eliminate all risk of supply shortfalls. Rather, resource adequacy planning is designed around an accepted level of reliability risk, recognizing that rare loss-of-load events can occur even in a well-planned system. The relevant question is therefore not simply whether some level of modeled risk exists. The analysis must also determine:

- When the risk emerges;
- How large and persistent it is;
- Whether it is regional, zonal, or Illinois-specific;
- Which system conditions drive it; and
- How much the continued availability of CEJA-limited units changes the outcome.

The accounting analysis identifies the timing and magnitude of projected capacity surpluses or shortfalls, while RECAP evaluates whether those conditions translate into elevated loss-of-load risk across a range of weather, load, and resource availability conditions. The Agencies consider the two analyses together, rather than treating either result as determinative on its own, to assess whether an identified shortfall represents a material reliability concern and to understand the circumstances under which that risk occurs.

Feasibility of Replacement Resources

A finding that a resource adequacy or reliability need persists does not, by itself, translate to a summary conclusion that a reduction or delay in CEJA's emissions-reduction requirements is necessary. Section 9.15(o) requires consideration of renewable energy,

energy storage, demand response, transmission development, and other strategies capable of resolving the identified shortfall or reliability violation.

The Updated RA Balance Analysis identifies resources already operating, under construction, or otherwise reasonably expected to enter service through 2030. PLEXOS identifies the additional resource portfolio required to satisfy modeled reliability and policy constraints. The PLEXOS results subsequently provide information regarding:

- The quantity and type of resources required;
- The years in which those resources must enter service;
- The location of additions across Illinois, PJM, and MISO;
- Associated transmission or interconnection needs;
- The role of storage, demand-side resources, and other alternatives; and
- The extent to which continued operation of CEJA-limited units changes the required portfolio.

The modeled portfolios are then evaluated for feasibility. The analysis considers the maturity and commercial readiness of resources in each portfolio and the necessary timeline to deploy the scale of resources, as compared to recent deployment trends in Illinois, to assess feasibility. A portfolio that appears sufficient but cannot reasonably be deployed by the date of need would not, by itself, establish a viable alternative resource adequacy mitigation pathway.

Customer Cost and Emissions Impacts

The Mitigation Plan compares the potential impact of the Reference and CEJA Extension cases on Illinois customers and communities. These consequences include direct electricity-market costs, the costs of developing and operating the future resource portfolio, and the emissions effects of continued operation, retirement, or replacement of CEJA-limited units.

The Capacity Market Assessment estimates changes in regional capacity prices under equilibrium conditions and the resulting capacity cost exposure of Illinois customers under each strategy. The analysis distinguishes between regional market price effects and the share of those costs expected to be borne by Illinois customers under applicable market, procurement, and cost-allocation arrangements.

PLEXOS provides a broader comparison of modeled system and portfolio costs, including capital investment, fixed and variable operating costs, fuel costs, transmission costs represented in the model, and other relevant cost categories. These results can be evaluated with the cost of satisfying reliability and policy requirements under each strategy.

PLEXOS and any supplemental emissions analysis will also compare CO_2 emissions and, where information is available, copollutant emissions under each case. The analysis will identify whether emissions effects are concentrated at particular facility types, regions, and contextualize the impacts of short-term emissions with longer-term portfolio effects.

Development of the Recommended Mitigation Strategy

The recommended mitigation strategy will be based on the evidence across these three questions. A change to the treatment of CEJA-limited units may be warranted should the analysis demonstrate that:

- A material resource adequacy shortfall or reliability concern remains reasonably likely;
- Continued operation of affected units materially reduces that concern;
- Alternative resources cannot reasonably be developed or supported by market conditions within the period of need; and
- The reliability benefits of the policy change justify its associated customer-cost, emissions, and implementation impacts.

Conversely, where replacement resources can feasibly and economically address the projected need within the required timeframe, a reduction or delay in applicable emissions-reduction requirements may not be necessary. Consistent with Section 9.15(o) of the EPAct, any recommended change would be limited to the extent and duration necessary to meet the resource adequacy and reliability needs of the State. In practice, this means any recommended change would be designed to limit both its emissions impact and its duration. Units whose retirement is delayed would remain subject to operational limits, such as annual emissions caps or generation limits, so that incremental CO_2 and copollutant emissions are kept to a minimum. At the same time, the State would continue developing replacement resources in parallel, so that the delay lasts only until those resources can reliably meet the need. The Mitigation Plan is not intended to resolve the State's resource adequacy need on its own; it addresses the near-term risk that arises before replacement resources can be developed. Longer-term needs and resource portfolios are being considered through the IRP.

3 Baseline Assumptions

3.1 Illinois Resource Mix

The starting points for characterizing existing generation capacity in this Mitigation Plan are consistent across both the near-term resource adequacy balance assessment and the long-term resource portfolio modeling, conducted in RECAP and PLEXOS, respectively. 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 PLEXOS Eastern Interconnect model as the starting point.[24] Baseline generation resources and projected generation unit retirements were benchmarked and refined based on data from Hitachi Velocity Suite, S&P Global Capital IQ, and additional E3 research. This baseline also incorporates projected retirement dates for units affected by CEJA emissions standards, based on guidance provided by the IEPA.

3.1.1 Installed Capacity by Resource Type and Market Zone

The starting point for the baseline existing generation resource nameplate capacity in PJM, MISO, the ComEd zone, and the Ameren (MISO LRZ 4) zone for the near-term resource adequacy balance are depicted below in Figure 3-1 through Figure 3-4. Note that the figures for PJM and MISO are exclusive of the Illinois zones (ComEd and Ameren MISO LRZ 4, respectively) and the existing capacity represents resources online in the Reference Case. The thermal capacity shown reflects projected coal generation unit retirements by 2030 based on announcements from plant owners in Illinois. Additional retirements of oil and gas generators affected by CEJA emissions standards are described in more detail in Section 3.3.

[24] 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 3-1: Existing Generation Resources Nameplate Capacity in PJM (non-IL)

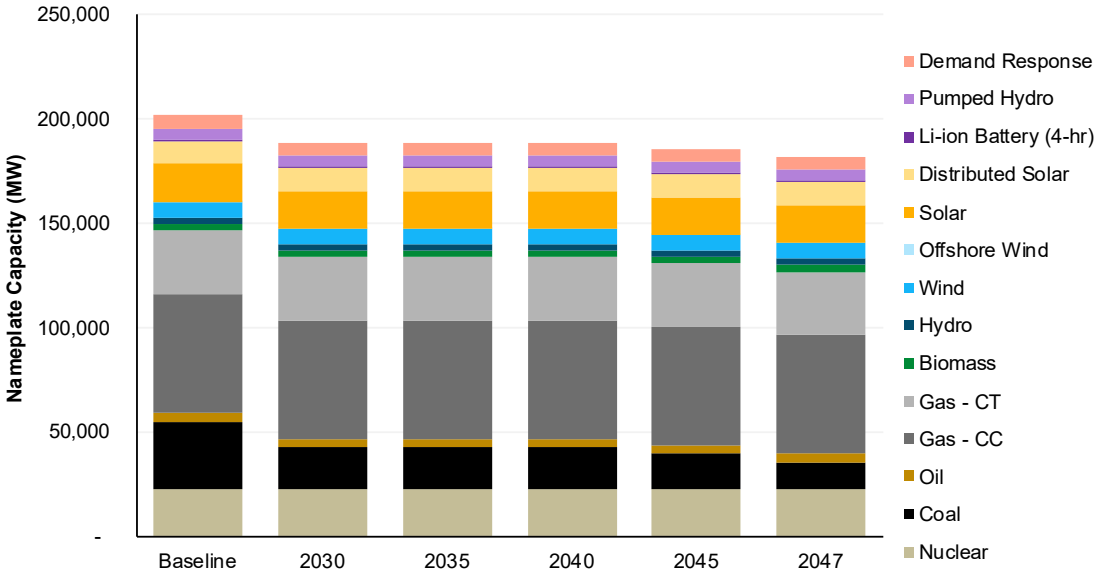


Figure 3-2: Existing Generation Resources Nameplate Capacity in MISO (non-IL)

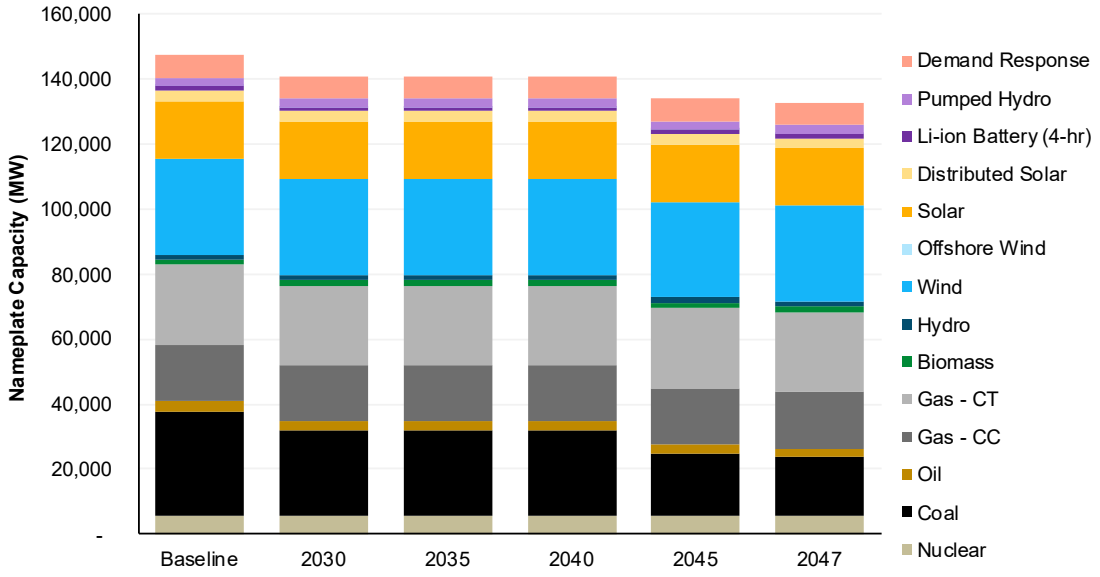


Figure 3-3: Existing Generation Resources Nameplate Capacity in ComEd Zone

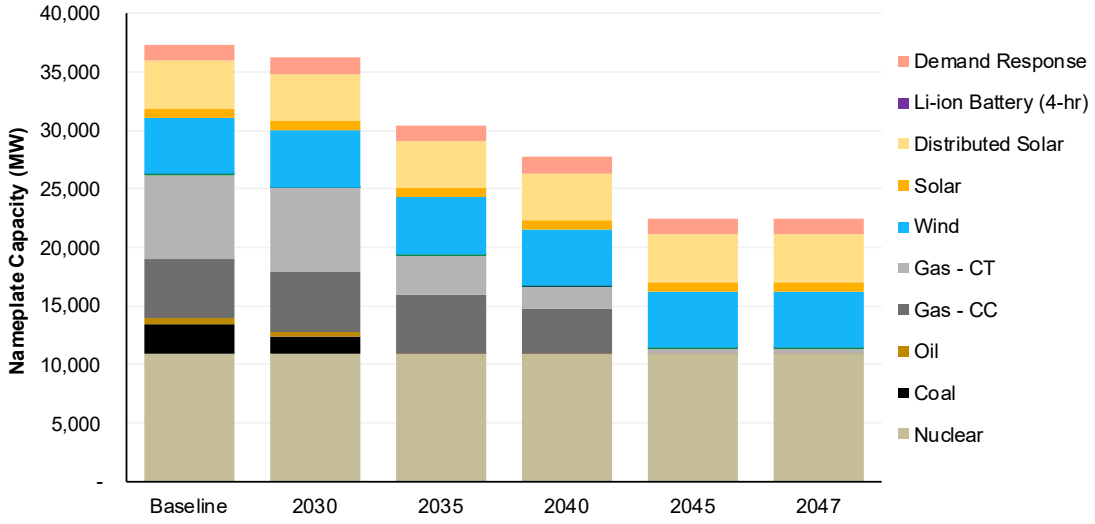
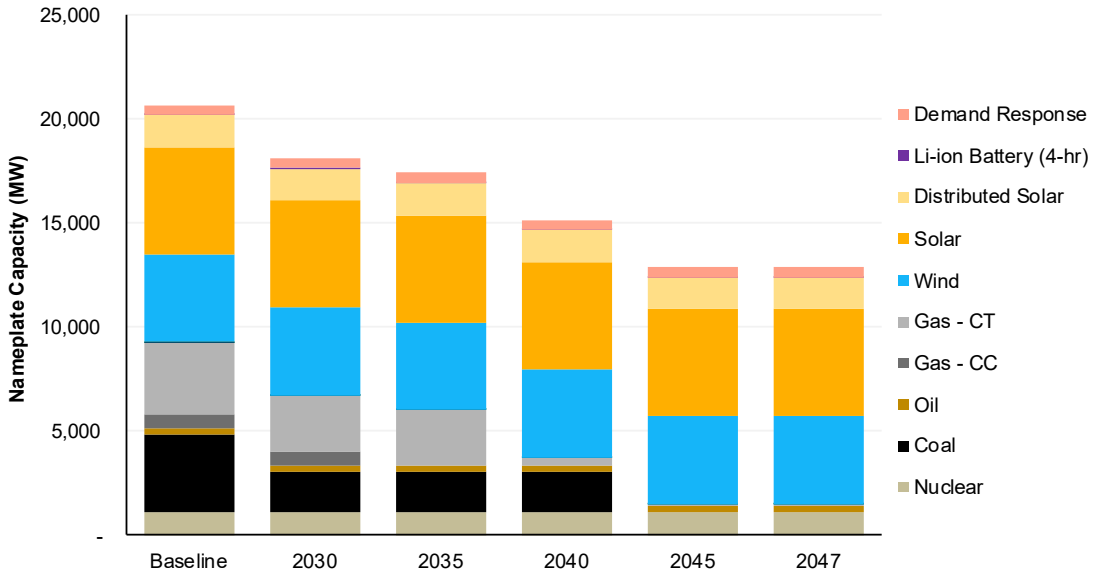


Figure 3-4: Existing Generation Resources Nameplate Capacity in MISO LRZ 4



The baseline existing resource portfolio in PLEXOS, which utilizes a starting year of 2030, is defined to include existing generation and storage resources, and scheduled resource retirements. The installed capacities of baseline resources are not optimized within PLEXOS—all retirements are directly input into the model to ensure the dates are correctly represented. In addition to the existing resources reported above, the modeling baseline used in PLEXOS considers planned capacity from generators that are undergoing active development. Planned capacity is comprised of units that are not yet online (commercial operation dates in 2027 or later), but whose capacity additions are included for the purposes

of this analysis as being presumed to operate and therefore not subject to optimization decisions in PLEXOS. Planned capacity totals for utility-scale technologies were derived from Hitachi Velocity Suite data. 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 in an "advanced development," stage while those in feasibility and proposed stages are considered in an "early development" stage. For distributed solar resources, a bottom-up forecast was developed. The figures below present the installed capacity for planned resources in PLEXOS for all resource types over the 2030-2047 modeling horizon. These capacities are distinct from the existing capacities reported above, as well as any PLEXOS-selected capacities, as discussed in the modeling results section (Chapter 7).

An additional necessary inclusion in PLEXOS requires reflecting both existing and projected REC resources in Illinois. The 2026 Long-Term Renewable Resources Procurement Plan (2026 Long-Term Plan)[25] outlines the state's existing REC contracts and projected REC procurements. In PLEXOS, distributed solar generation is aligned with near-term projected procurements in the 2026 Long-Term Plan. The IRP makes the assumption that Illinois will recontract RPS generation from existing resources after the expiration of these contracts or that such generation will otherwise be available on the system and accounted for in compliance, and therefore it is assumed that the MWh available from existing resources remains flat over the study period. Planned utility-scale wind and solar generation in PLEXOS reflect existing and contracted utility-scale resources as of June 2026, as detailed in the 2026 Long-Term Plan. Any incremental RPS-eligible utility-scale generation needed to meet Illinois' renewable energy targets, incremental to existing or contracted RECs, is assumed to require new generating capacity and is therefore optimally selected in PLEXOS.

[25] IPA 2026 Long-Term Renewable Resources Procurement Plan, (2026), https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20260602-2026-modified-ipa-long-term-plan.pdf

Figure 3-5: Planned Generation Resources Nameplate Capacity in PJM (non-IL)

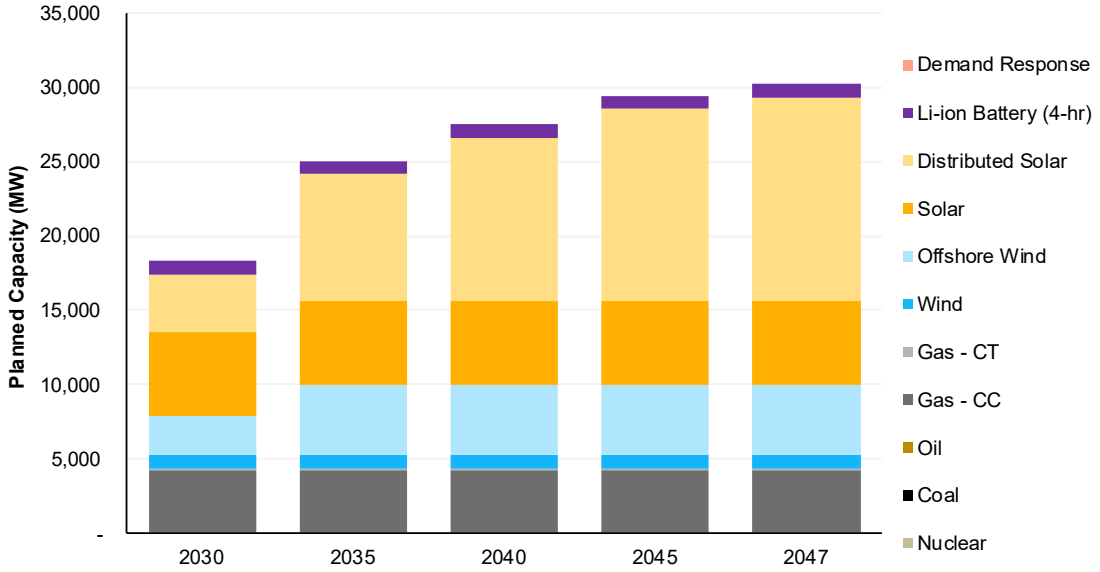


Figure 3-6: Planned Generation Resources Nameplate Capacity in MISO (non-IL)

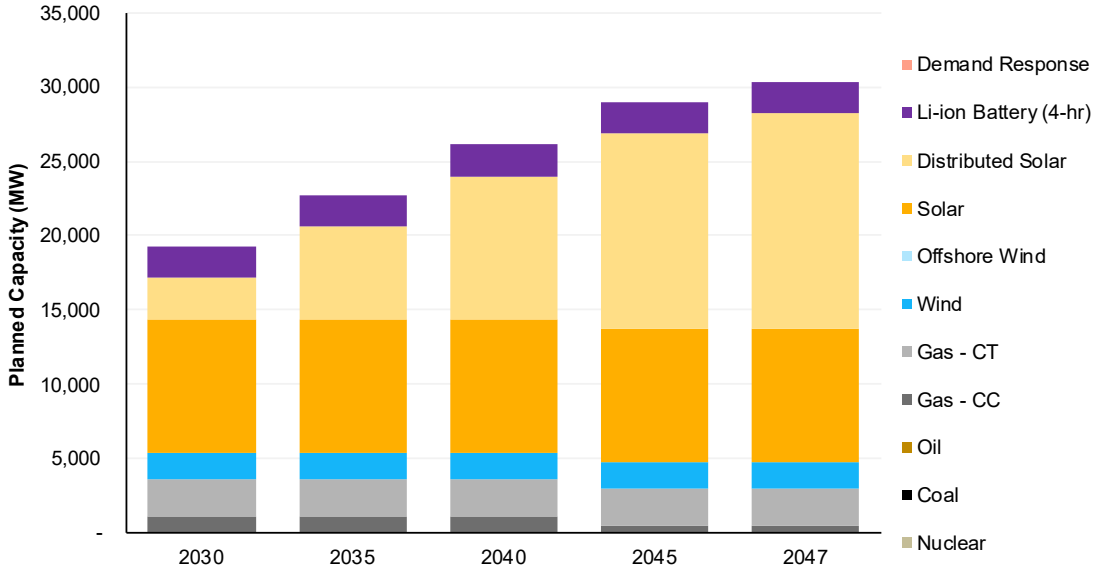


Figure 3-7: Planned Generation Resources Nameplate Capacity in ComEd Zone

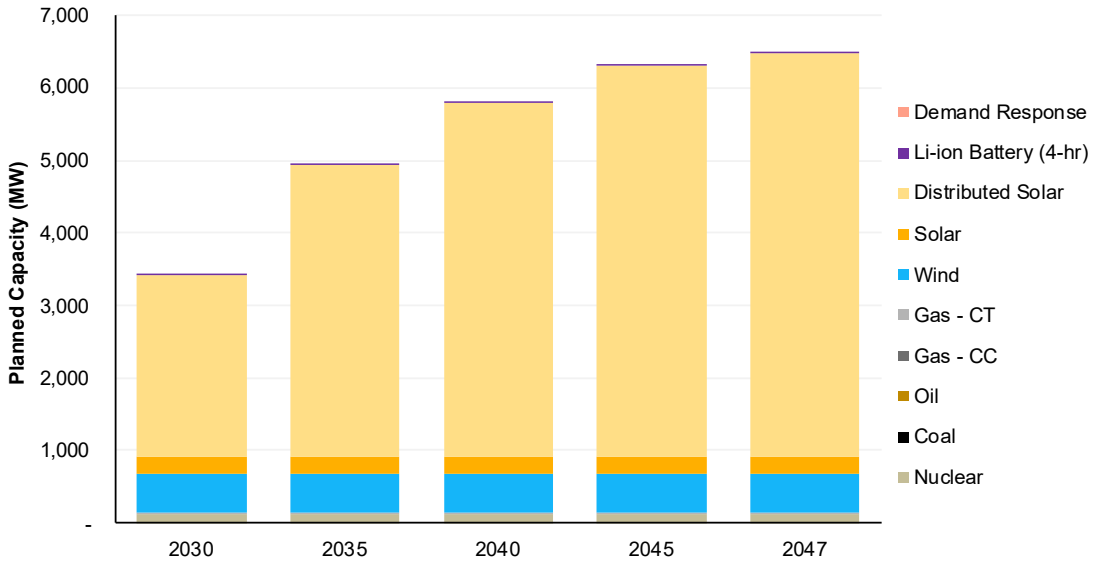
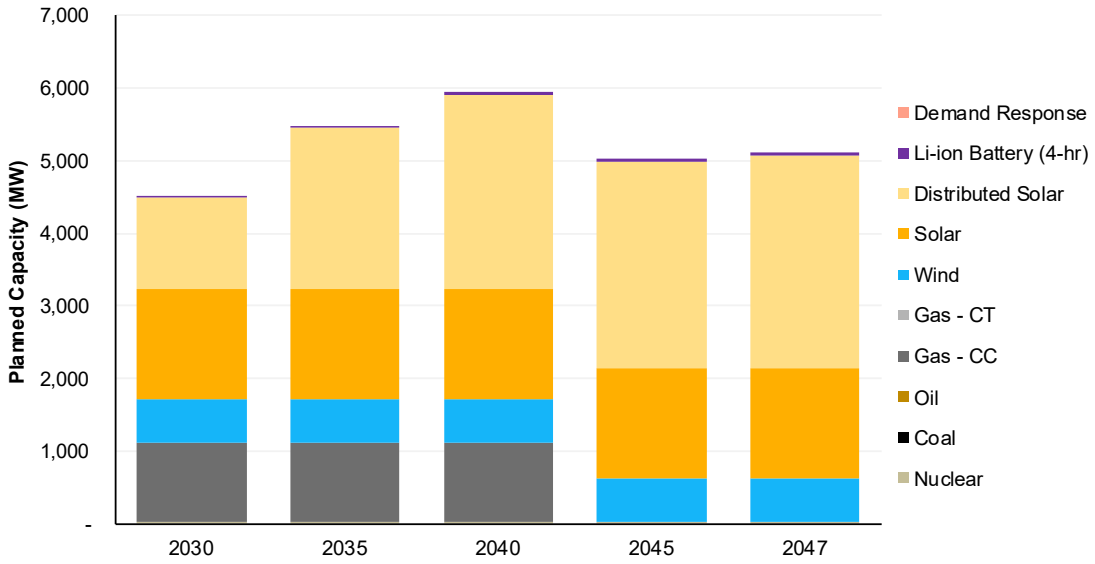


Figure 3-8: Planned Generation Resources Nameplate Capacity in MISO LRZ 4



The baseline planned resource portfolio in PLEXOS, which utilizes a starting year of 2030, is defined to include projected in-development and contracted generation and storage resource additions. The installed capacities of baseline resources are not optimized within PLEXOS— all additions are directly input into the model to ensure the dates are correctly represented. Declining planned capacity in MISO LRZ 4 is representative of the planned thermal units which will be subject to a 2045 CEJA-mandated retirement date.

3.2 State Policy Objectives and Programs

3.2.1 Electric-Sector and Economy-Wide Decarbonization Goals and Programs

Emissions Reductions Targets

While under CEJA all fossil fuel generation in Illinois is scheduled to either retire by or before 2045 or reduce emissions to zero, the law also establishes interim emissions limits on existing thermal generators. Emissions restrictions apply to all fossil fuel generating units over 25 MW, with exact requirements varying by ownership structure and fuel type. Additionally, exceedances to the emissions restrictions are permitted 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[26]. These operational emissions restrictions are applied across all scenarios, except where explicitly labeled No Emissions Cap.

- Privately Owned Generation: Under CEJA, privately owned coal- and oil-fired generation in Illinois must reduce emissions to zero by 2030[27]. 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[28]. 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[29]. Gas-fired generation must reduce emissions to zero by 2045 with no interim schedule[30].

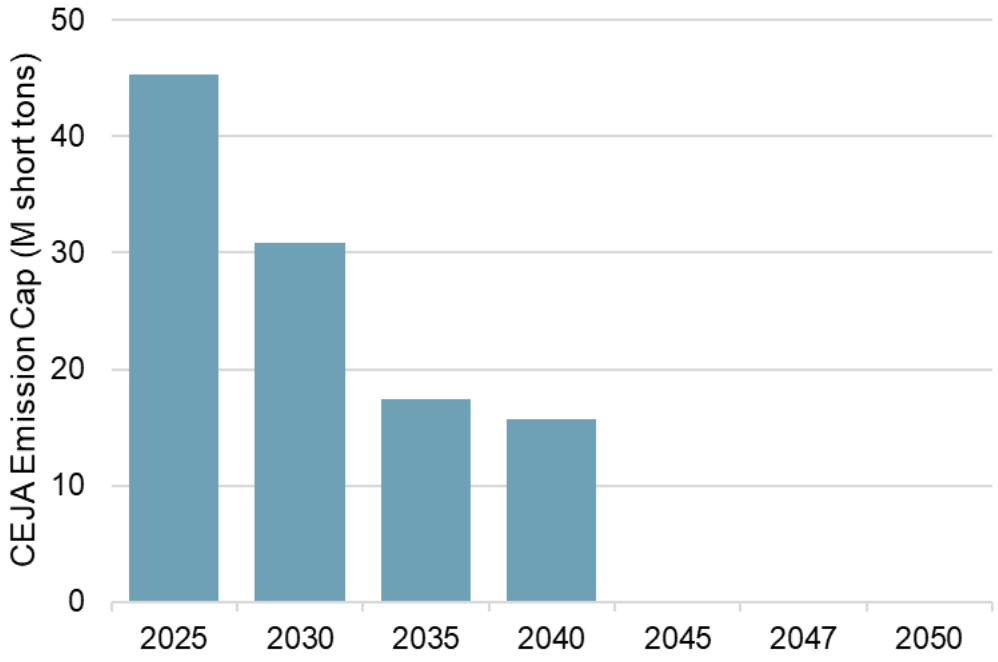
CEJA emissions requirements for electricity generators are represented in PLEXOS through 12 separate emissions constraints corresponding to the applicable generator categories defined under CEJA. For each category, the emissions cap is calculated by first determining each applicable generator's average annual emissions over the relevant three-year

[26] 415 ILCS 5/9.15(l).
[27] 415 ILCS 5/9.15(g).
[28] 415 ILCS 5/9.15(i).
[29] 415 ILCS 5/9.15(h).
[30] 415 ILCS 5/9.15(j).

historical period[31] and then aggregating those values across all generators in the category. Different interim emission requirements and retirement years are applied depending on the category. This structure allows the model to reflect differences in emissions requirements across generator categories rather than applying a single system-wide limit. The total emission cap varying by time for all CEJA categories is shown in Figure 3-9. Emissions caps by region and by fuel are shown in Figure 3-10.

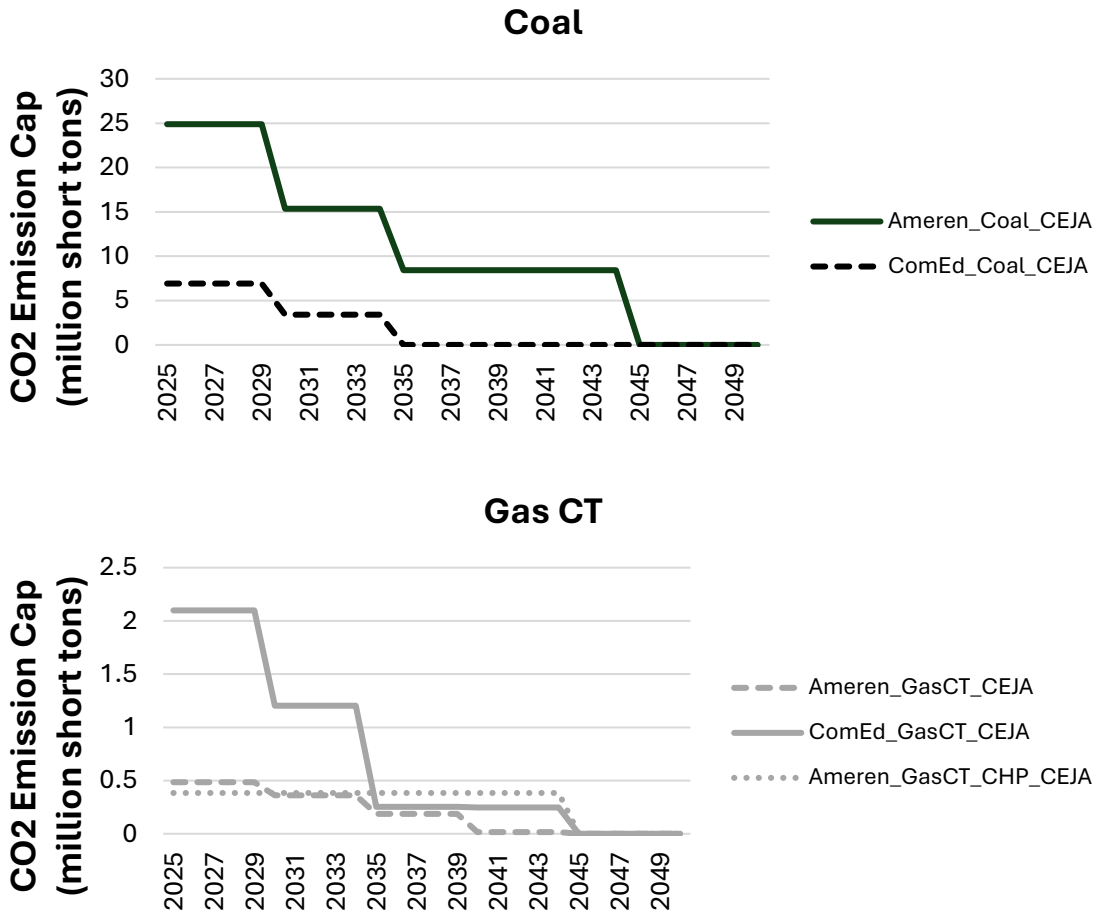
In the CEJA Extension scenario, emissions caps are enforced until 2044 and then the caps are held steady from 2044 to 2047. Essentially, this means that although the retirement dates of CEJA-limited units are extended until 2047, the units are still subject to emissions caps.

Figure 3-9: Total Emission Cap for CEJA-regulated Electricity Generators

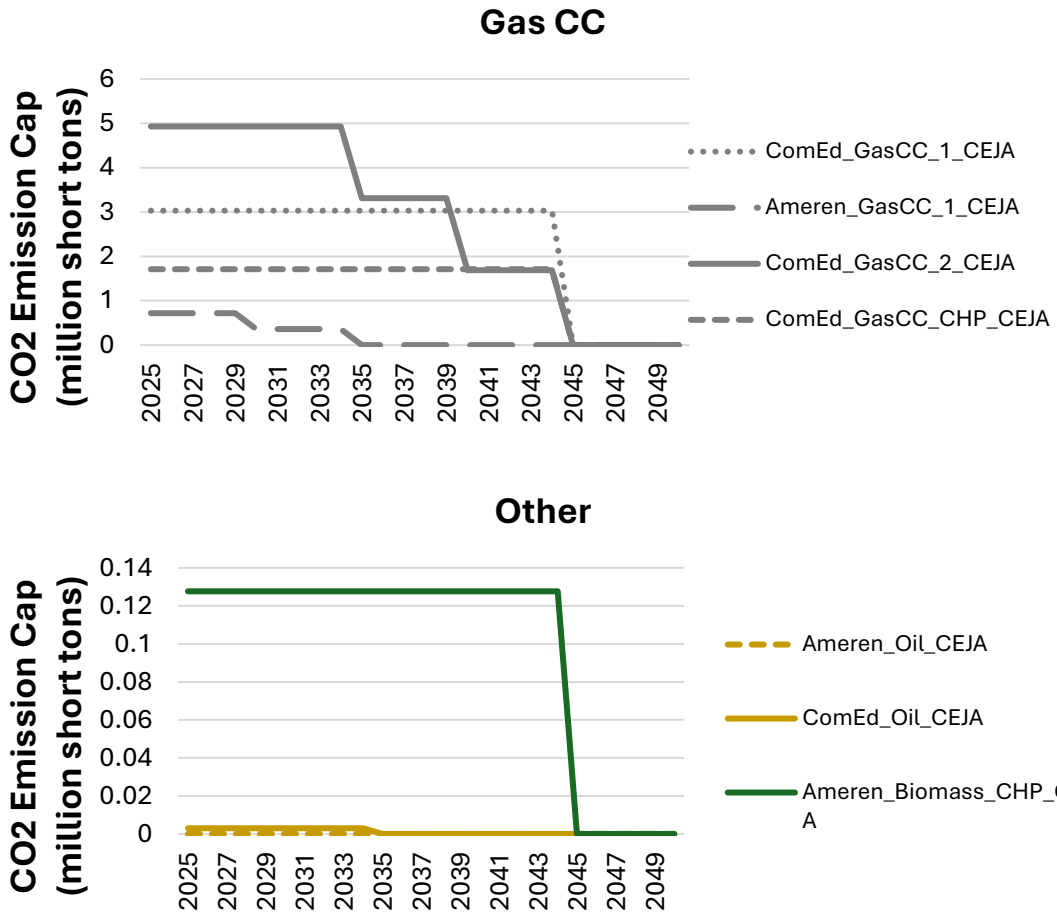


[31] Historical emissions data are collected from Form EIA 860.

Figure 3-10: Emission Caps for CEJA-Regulated Electricity Generators by Region and Fuel Type[32]



[32] Gas combined cycle (CC) units pair a gas turbine with a heat recovery steam generator and steam turbine to capture waste heat and improve efficiency, whereas combustion turbines (CTs) generate power from the gas turbine alone. Comparatively, CTs feature lower capital costs and faster start times but also higher heat rates. As a result, CTs are typically used as peaking resources and CCs as intermediate or baseload resources.



Renewable Portfolio Standard and Clean Energy Standard

Illinois has two statutory clean energy objectives relevant to this analysis. The first is the RPS under the Illinois Power Agency Act. It requires that RECs procured for retail customers of ComEd and Ameren Illinois equal 40% of retail sales by the 2030–2031 delivery year, and 50% by the 2040–2041 delivery year.[33] IPA implements this requirement through its Long-Term Renewable Resources Procurement Plan (Long-Term Plan), which sets REC targets by technology and procurement program. The Illinois RPS is modeled in PLEXOS as a minimum annual renewable energy constraint following the trajectory above, with targets for intervening years linearly interpolated. Eligible resources include new and existing wind and solar resources procured through IPA programs, consistent with the 2026 Long-Term Plan.

[33] Illinois General Assembly, Illinois Power Agency Act, 20 ILCS 3855/1-75(c)(1)(B), (2021), https://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=002038550K1-75.

The second is the goal established under CEJA whereby Illinois will pursue transitioning to 100% clean energy by 2050.[34] Unlike the RPS, this goal has no defined set of eligible resources or compliance mechanism. For this analysis, the Illinois CES is defined as a minimum share of retail sales. From 2030 - 2040, the CES target is defined as the sum of required REC production and estimated generation from existing nuclear generation, then it rises linearly from 94% in 2041 to 100% by 2045, met by generation from nuclear, hydropower, biomass, wind, utility-scale solar, and distributed solar resources.

The RPS and CES are modeled as seven concurrent aggregate targets for MISO, PJM, and Illinois, including RTO-wide and regional requirements. The RTO-wide targets for MISO and PJM (exclusive of Illinois) were calculated by applying each state's published RPS and CES percentage to its forecasted load, adjusted for a 6.5% transmission and distribution (T&D) loss to convert to retail sales. Additional carveouts are modeled for Dominion's RPS targets in PJM East, as well as the Illinois RPS target under the Long-Term Plan. Table 3-1 details the RPS and CES targets represented in the model and Table 3-2 includes states that have those RPS and CES constraints.

Table 3-1: Renewable Portfolio Standard and Clean Energy Standard Constraints Modeled

Footprint	Constraint	Eligible Resources[35]
PJM East and PJM West (excludes ComEd)	PJM RTO RPS	100% of generation from baseline and candidate utility solar, BTM solar, wind, biomass, and hydro
	PJM RTO CES	100% of generation from baseline and candidate utility solar, BTM solar, wind, biomass, hydro, and nuclear
PJM East only (used as a proxy for the Virginia	PJM East RPS	100% of generation from candidate utility solar, BTM solar, and wind

[34] Illinois General Assembly Illinois Power Agency Act, 20 ILCS 3855/1-5(1.5), as amended by Public Act 102-0662 (Climate and Equitable Jobs Act), (September 2021), https://ilga.gov/legislation/ilcs/documents/002038550K1-5.htm

[35] Describes what percentage of selected and/or existing resources are eligible to meet the policy target of the region in PLEXOS.

state RPS requirement)[36]		50% of generation from existing utility solar, BTM solar, wind, offshore wind, biomass, and hydro[37]
MISO North, LRZ 5, LRZ 6, and LRZ 7 (excludes Ameren)	MISO RTO RPS	100% of generation from baseline and candidate utility solar, BTM solar, wind, biomass, and hydro
	MISO RTO CES	100% of generation from baseline and candidate utility solar, BTM solar, wind, biomass, hydro, and nuclear
Ameren, ComEd	Illinois RPS	100% of generation from candidate wind, utility solar, and BTM solar and a share of generation from existing solar and existing wind[38], aligned with the sum of existing and projected RECs in the Long-Term Plan are eligible to meet RPS
	Illinois CES	100% of generation from existing and candidate nuclear, gas with CCS, biomass, candidate wind, utility solar, and BTM solar and a share of generation from existing solar and existing wind Note: This is a case studied in the IRP, not current policy in Illinois

Table 3-2: States in Each Non-IL RPS and CES Constraint

RPS/CES Requirement	States
MISO RTO RPS	Minnesota, Michigan

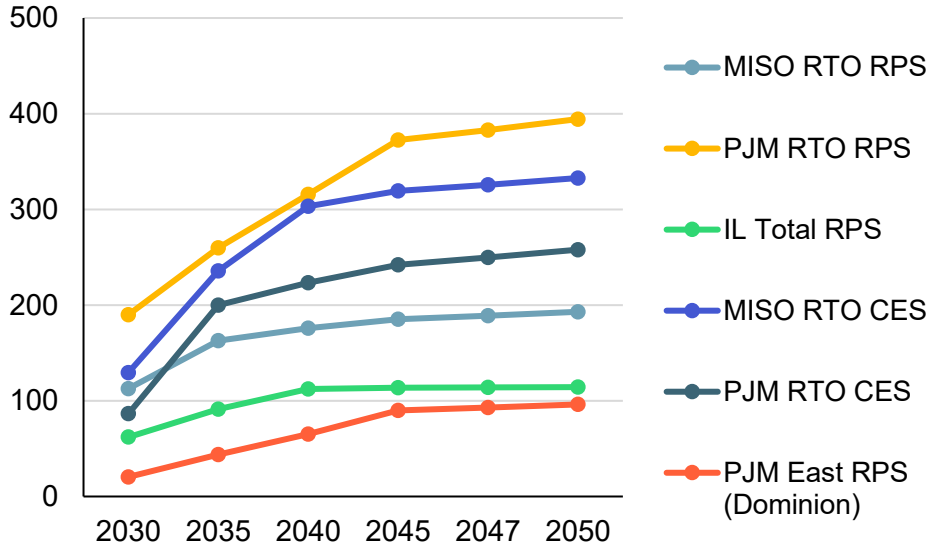
[36] A separate RPS constraint is defined for PJM East to reflect the need for load growth in PJM East, primarily driven by data center in Dominion, to be served by renewable energy, and to reflect Virginia's requirement that 75% of new renewable energy resources to meet state policies must come from in-state facilities.

[37] The 50% contribution represents the average 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 forecast years 2026 - 2050.

[38] Only a portion of generation from existing renewables contributes to the RPS because some associated RECs are assumed to be settled out-of-state or with commercial customers. Since there is not detailed data on breakdown of RECs settled out-of-state and those with commercial customers, the IRP conservatively assumes that none of those RECs are eligible towards Illinois' RPS goal. The eligible share is calculated using existing and projected RECs identified in the Long-Term Plan relative to total generation from existing renewables.

PJM RTO RPS	Virginia, Michigan, Ohio, Maryland, Pennsylvania, New Jersey, Delaware, Washington, D.C.
PJM East RPS	Virginia
MISO RTO CES	Minnesota, Michigan
PJM RTO CES	Michigan, Maryland, New Jersey

Figure 3-11: System-Wide RPS and CES Annual Volumetric Targets (GWh)



3.2.2 Distributed Solar Programs and Assumptions

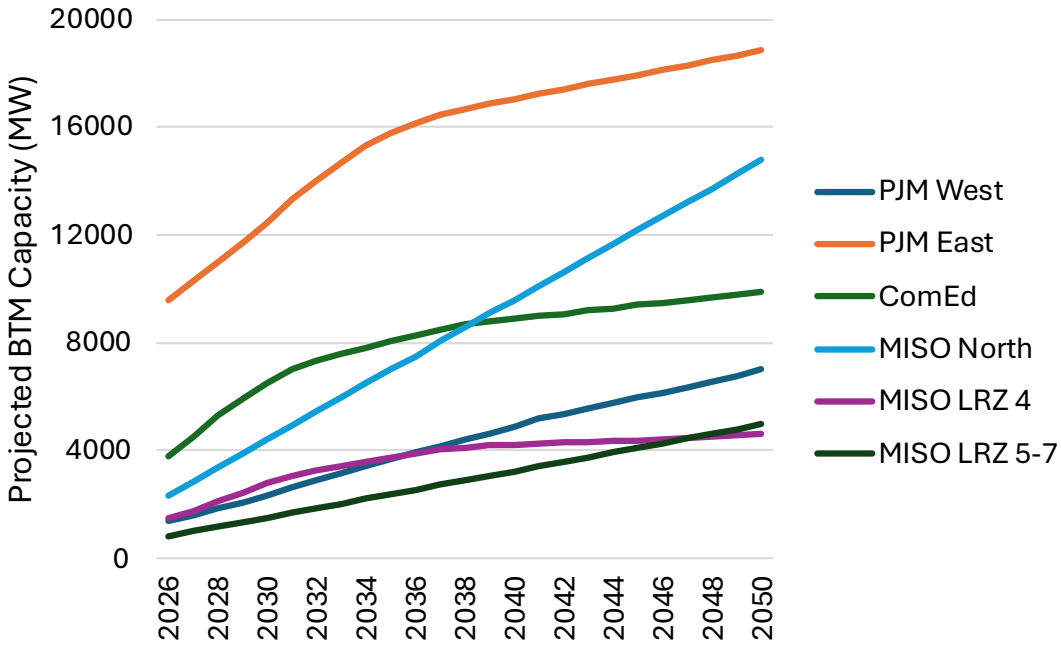
Distributed solar is treated differently from utility-scale renewable resources in the IRP modeling. Rather than allowing PLEXOS to select distributed solar capacity based on its relative economics, the model assumes a predetermined adoption trajectory that reflects continued growth in distributed solar supported by existing State policies and programs. The assumed trajectory is based on the Illinois Power Agency's 2026 Long-Term Renewable Resources Procurement Plan through 2030, followed by continued growth at a gradually declining annual rate, reaching one percent per year after 2040. The Reference Case therefore assumes that State programs and policy support for distributed solar continue over the planning horizon, rather than evaluating whether that level of deployment would occur based on wholesale system economics alone. Distributed solar generation contributes RECs toward Illinois compliance with the State's RPS requirements, reducing the additional utility-scale renewable generation that the model must select.

Representing distributed solar through an assumed adoption trajectory, rather than allowing the model to select it as a resource, recognizes that distributed solar adoption is currently driven by policy incentives and individual customer investment decisions that are not fully represented in a system-wide, least-cost optimization model. Because distributed solar generally has a higher cost per MWh than utility-scale solar from a wholesale system perspective, the model would likely select relatively little new distributed solar capacity. Instead, the model assumes continued growth of distributed solar based on existing State programs and policies and incorporates that generation into the resource portfolio.

The near-term (before 2030) capacity of distributed solar in Ameren and ComEd is estimated in accordance with statutory targets and projections in the IPA Long-Term Plan. In the long-term (2031 – 2050), the installed distributed solar capacity is added into the model as an assumed trajectory of continued policy support, which is the same across all scenarios and is not optimized in the model. This trajectory is estimated based on the assumption that the annual growth rate will gradually decrease to 1% after 2040 based on PJM's distributed solar projection[39]. As a result, the distributed solar capacity in Ameren and ComEd is projected to increase from 2.8 and 6.5 GW in 2030 to 4.6 and 9.9 GW in 2050, respectively. Distributed solar resources were modeled as 'supply side' resources, meaning they are represented as generators with their own solar generation profile.

[39] PJM Load Forecast Development Process: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process

Figure 3-12: Distributed Solar Capacity Projections



3.2.3 Storage Procurement Targets

A minimum capacity requirement at 3 GW for energy storage by 2030 is included in PLEXOS LT modeling to reflect the 3 GW of energy storage capacity target established by CRGA.

3.3 Expected 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. This baseline also incorporates projected retirement dates for units affected by CEJA emissions standards, based on guidance provided by the IEPA.

3.3.1 Announced and Delayed Retirements

Announced retirements are informed by publicly available information including RTO deactivation notices and Worker Adjustment and Retraining Notification (WARN) notices for specific plants as of August 26, 2026.

3.3.2 CEJA-Driven Retirements

In the Reference Case, fossil fuel generation units subject to CEJA-related deadlines are assumed to retire either in accordance with the policy or before, if there exists an announced

retirement date 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 resource adequacy needs in that year if its retirement date precedes the month in which peak load occurs.

Figure 3-13 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, 2,908 MW of projected coal retirements by 2030 are included in all cases, reflecting announcements that these plants are assumed to retire regardless of whether an extension to CEJA is granted.[40]

Figure 3-13: Illinois Cumulative Retirements (GW)

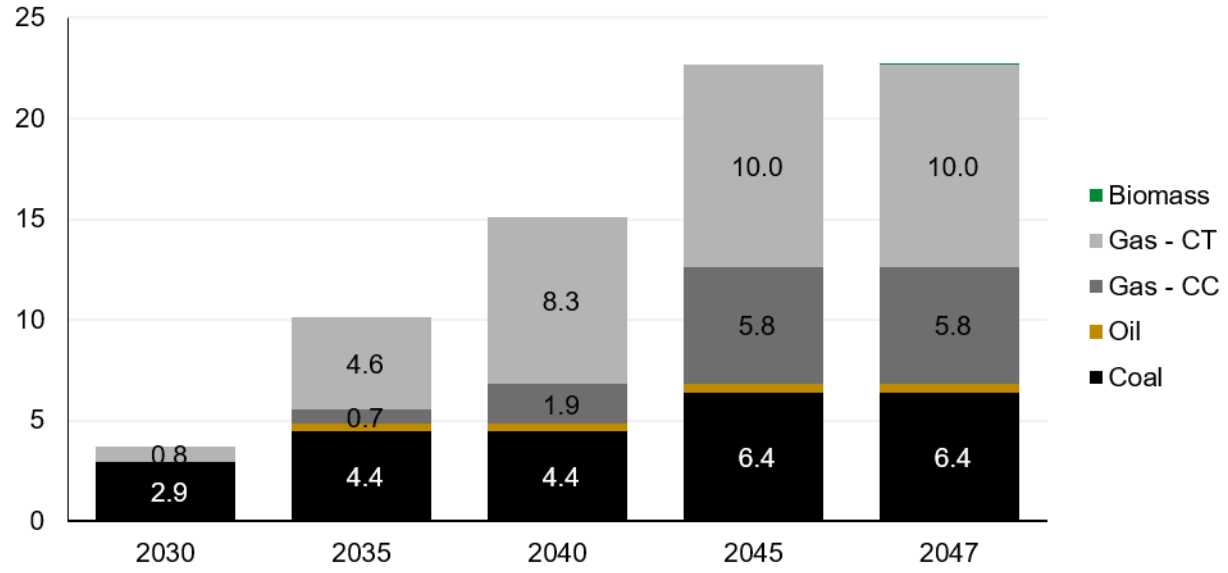


Table 3-3: Illinois Cumulative Retirements (GW)

Technology	2030	2035	2040	2045	2047
Coal	2.9	4.4	4.4	6.4	6.4
Oil	-	0.4	0.4	0.4	0.4

[40] Peoria Journal Star, "Company to Close Three Illinois Power Plants in Coming Years", (June 15, 2026), https://www.pjstar.com/story/news/state/2026/06/15/illinois-power-plants-to-be-shuttered-and-employees-to-lose-jobs/90554807007/

Gas Combined Cycle	-	0.7	1.9	5.8	5.8
Gas Combustion Turbine	0.8	4.6	8.3	10.0	10.0
Biomass	-	-	-	-	0.0

3.3.3 Outside-of-Illinois Plant Retirement Treatment

For generation resources outside Illinois, announced plant retirements through 2030 occur as scheduled, while those announced as occurring after 2030 are delayed by 10 years to reflect the growing trend of extending unit operations to meet reliability needs.

3.4 Load Forecast

3.4.1 Load Forecast by Component

General Approach

In developing the load forecast for this Mitigation Plan,[41] E3 evaluated all available sources of load data, including forecasts and supporting data provided by Ameren and ComEd, RTO long-term load forecasts, U.S. Energy Information Administration (EIA) data, and other public data sources. Utility data were reviewed alongside these other sources and benchmarked against E3's independent research for each load component. Where these sources conflict or are not directly aligned with one another, E3 applied reasoned adjustments informed by its load forecasting expertise to produce a consistent set of projections across regions. Baseload forecasts, representing existing and forecasted residential, commercial and industrial demand, for the Ameren and ComEd zones were provided by the utilities, while baseload for the portions of PJM and MISO outside of Illinois was based on 2025 actual loads from FERC 714 and RTO reports. These 2025 actuals were then escalated using the respective RTO long-term load forecasts. Where a primary data source reported load at a different point of measurement, values were adjusted for transmission and distribution losses so that all components are represented on a consistent basis. All loads presented in this report and included in this IRP are at the system level.

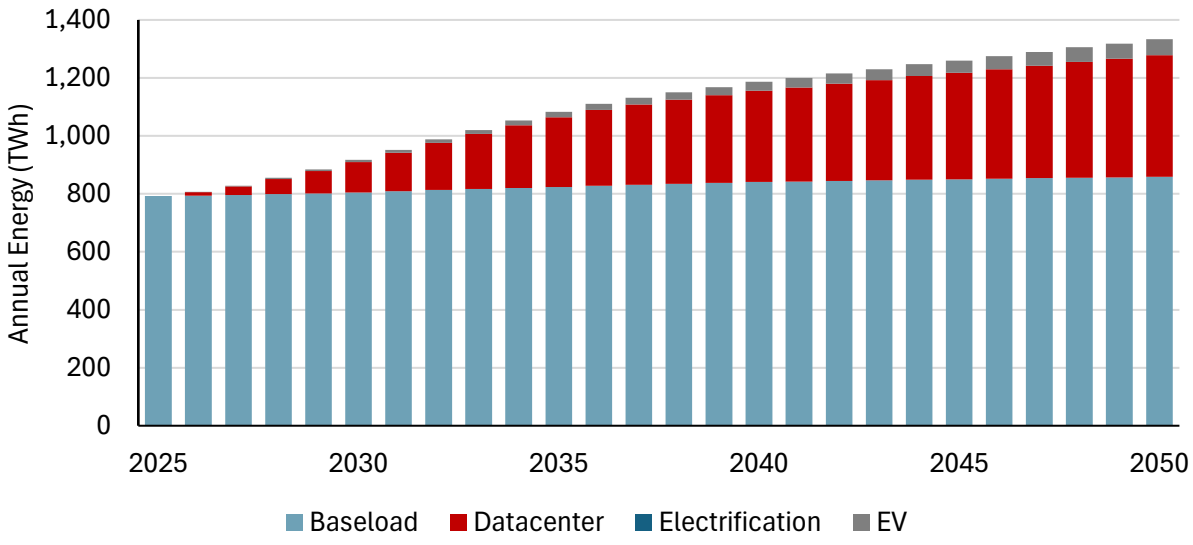
[41] This section reviews the Reference Case used in the Mitigation Plan, as well as alternative load scenarios used in the IRP (Low Data Center, High Data Center and Electrification). As the plans were developed concurrently, this report includes information on load forecasts not used in the Mitigation Plan to give further context. When referring to multiple load forecasts, the report refers to them as IRP load scenarios.

Baseload is defined as load excluding data centers, electric vehicles (EVs), and building electrification. For these three non-baseload components, E3 applied its own independent projection of load growth for each individual component to develop multiple projections for the IRP scenarios, as described in the Data Center Load and Electrification Load sections below. Hourly baseload profiles for each region were developed by training an artificial neural network on historical hourly load and weather data to produce an extended record of weather-driven load profiles; a 2022 weather-year profile was used in PLEXOS.

PJM Excluding Illinois

PJM excluding Illinois (PJM Non-IL) is defined as all of PJM except the ComEd zone. Annual energy for PJM Non-IL was aligned to 2025 actual gross load as reported in FERC 714 and RTO reports; this alignment has been adjusted and refined relative to the load forecast used in the 2025 RA Study. Load from 2026 onward is based on the gross load forecasts published in PJM's 2026 Long-Term Load Forecast (LTLF), supplemented by the residential, commercial, and industrial sector forecasts provided in the LTLF's Sector Models and End-Use Indices. Because the PJM LTLF begins in 2026, the growth rate between 2025 and 2026 was interpolated based on previous forecasts and the forecasted RTO growth rate from 2026 to 2027. The hourly demand profile is based on the 2022 weather year and was scaled using a flat multiplier to align with actual 2025 gross peak and energy. The PJM LTLF extends through 2046; loads beyond 2046 were extrapolated using the final-year growth rate. As shown in the figure below, data centers are the primary driver of load growth in PJM Non-IL, reaching approximately 420 TWh of the roughly 1,330 TWh of total Reference Case annual energy in 2050.

Figure 3-14: PJM (Non-IL) Annual Energy by Component, TWh – Reference Case



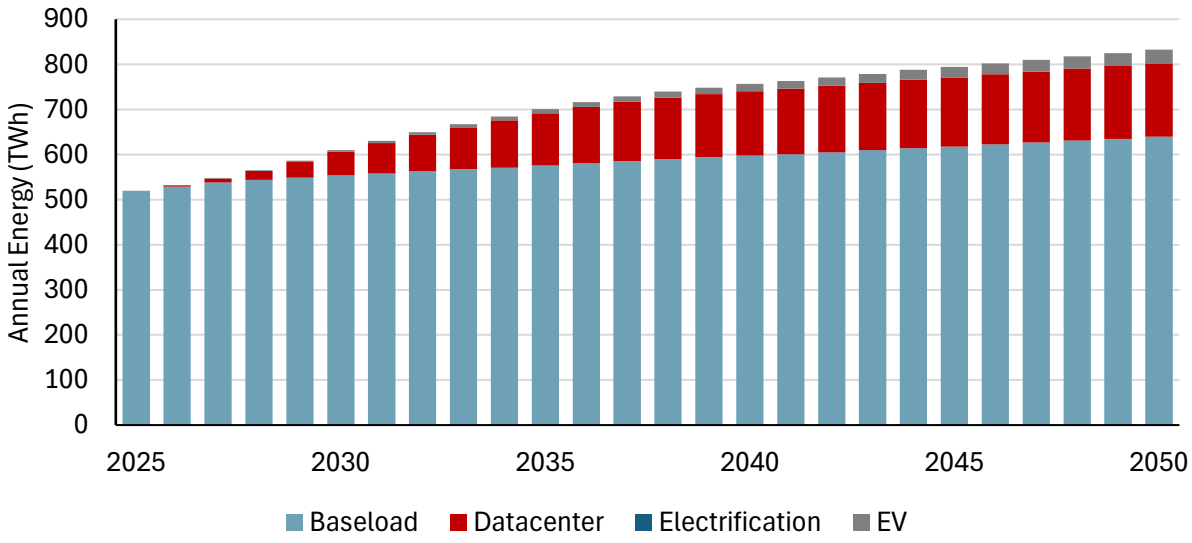
Source: E3 analysis based on the PJM 2026 Long-Term Load Forecast, FERC 714, and RTO reports.

Note: The PJM LTLF extends through 2046; values after 2046 are extrapolated using the final-year growth rate. Building electrification is included in baseload.

MISO Excluding Illinois

MISO excluding Illinois (MISO Non-IL) comprises MISO Local Resource Zones (LRZs) 1–3 and 5–7, representing all of MISO Central and North except LRZ 4. As with PJM Non-IL, annual energy was aligned to 2025 actual gross load from FERC 714 and RTO reports. This alignment was not performed for the 2025 RA Study, which results in a discrepancy between the 2025 starting points of the 2025 and 2026 IPA load forecasts. Load from 2026 onward is based on the net load forecasts presented in MISO's 2026 LTLF (Long-Term Load Forecast Workshop, April 13, 2026). Because the MISO LTLF begins in 2026, the growth rate between 2025 and 2026 was interpolated based on previous forecasts and the forecasted RTO growth rate from 2026 to 2027. The hourly demand profile is based on the 2022 weather year and was scaled using a flat multiplier to align with actual 2025 gross peak and energy. The MISO LTLF likewise extends through 2046, and loads beyond 2046 were extrapolated using the final-year growth rate. As shown in the figure below, data center load reaches approximately 163 TWh of the roughly 833 TWh of total Reference Case annual energy in MISO Non-IL in 2050.

Figure 3-15: MISO (Non-IL) Annual Energy by Component, TWh – Reference Case



Source: E3 analysis based on the MISO 2026 Long-Term Load Forecast, FERC 714, and RTO reports.

Note: The MISO LTLF extends through 2046; values after 2046 are extrapolated using the final-year growth rate. Building electrification is included in baseload.

MISO LRZ 4

Ameren's service territory accounts for most of MISO LRZ 4. The baseload forecast for the LRZ 4 was taken directly from Ameren's utility forecast, and a gross load forecast was developed by adding Ameren's BTM solar forecast back to its net load forecast. To represent the remainder of LRZ 4, Ameren is assumed to account for 80% of all non-data center load in the zone, based on the current breakdown observed in EIA data, FERC 714, and RTO reports. Non-data center load for LRZ 4 was therefore scaled by a factor of 1.25 to represent all of LRZ 4, which assumes that non-data center load in the rest of the zone grows at the same rate as in Ameren's service territory. This scaling was not applied to data center load. Because the data center forecast is driven by a small number of large, site-specific projects, applying Ameren's data center growth to the rest of LRZ 4 would overstate load; the LRZ 4 data center forecast instead reflects the identified projects directly.[42]

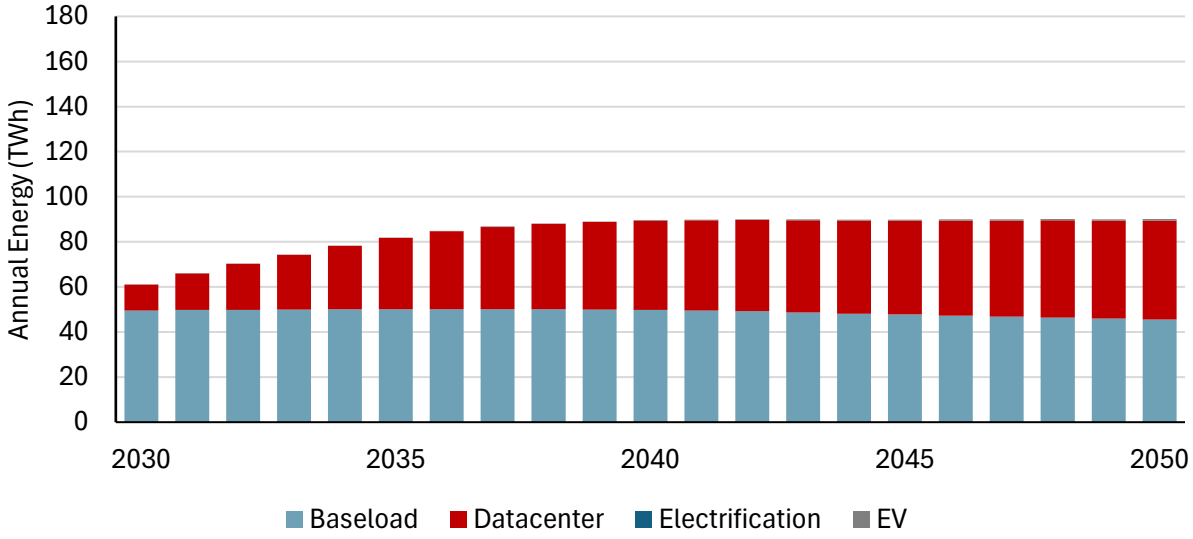
Data center load scenarios for LRZ 4 were developed by E3 and verified against utility forecasts (see Section 3.4.2 for details). These scenarios are based on public project announcements and estimated success and attrition rates for announced projects. Over the long term, data center load growth decays toward 1% per year, balancing population and economic growth against expected efficiency improvements. Data center forecasting assumptions are described in further detail in the Data Center Load section. In the Reference Case, data center load in LRZ 4 grows to approximately 44 TWh by 2050, nearly half of the zone's roughly 90 TWh of total annual energy, as shown in Figure 3-16. EV and building electrification load, shown as separate components, together remain a small share of the total in the Reference Case.

Table 3-4: LRZ 4 Data Center Facility Completion Rates by Scenario

Time Window	Low	Medium	High
Completion Rate (year 2)	65%	65%	71%
Completion Rate (year 3)	58%	58%	63%
Completion Rate (year 4)	0%	52%	61%
Completion Rate (year 5)	0%	45%	58%
Completion Rate (year 6)	0%	38%	55%
Completion Rate (year 7)	0%	30%	52%
Completion Rate (beyond year 7)	0%	20%	48%

[42] "Identified Projects" means specific announced projects listed in the datasets used to construct the LRZ 4 data center forecast.

Figure 3-16: LRZ 4 Annual Energy by Component, TWh – Reference Case



Source: E3 analysis based on Ameren's load forecast and the MISO 2026 Long-Term Load Forecast.

Note: Baseload includes industrial load.

ComEd Zone

The ComEd zone forecast was built from the gross load forecast provided by ComEd, which covers the entire ComEd load zone within PJM; no adjustment was made for non-ComEd load within the zone. Baseload was taken directly from ComEd's gross load forecast; ComEd's electrification forecast was reviewed but not used, and electrification load for the zone instead reflects E3's independent assessment described below. The hourly demand profile is based on the 2022 weather year and was scaled using a flat multiplier to align with actual 2025 gross peak and energy.

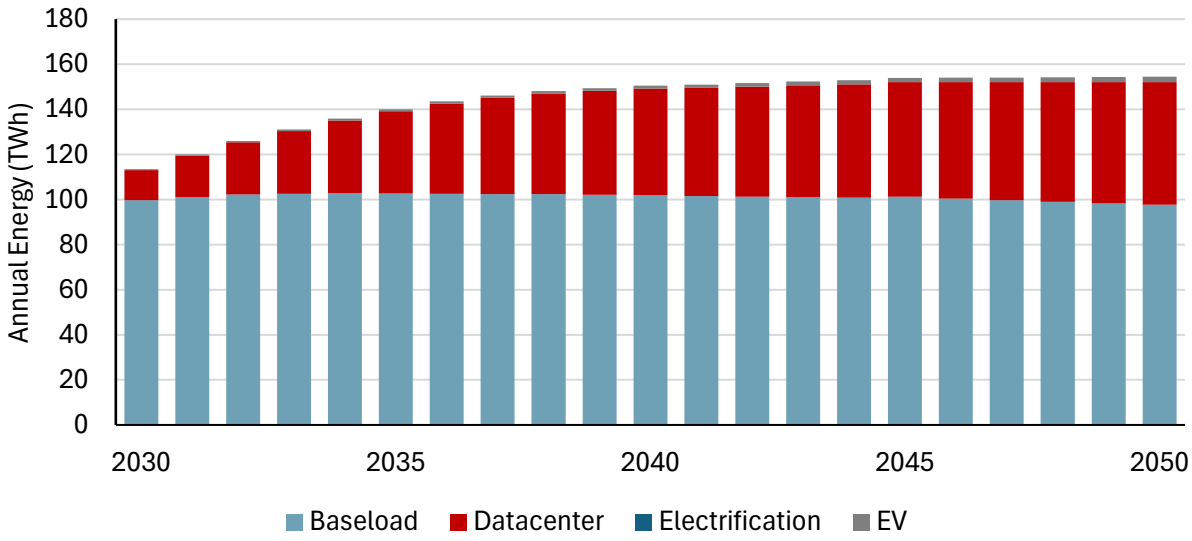
Data center load scenarios for the ComEd zone were developed by E3 and verified against utility forecasts (see Section 3.4.2 for details). As with Ameren, these scenarios are based on public project announcements and estimated success and attrition rates. ComEd provided a single data center forecast, which was significantly higher than E3's estimate of an aggressive development scenario. As a result of ComEd's higher forecast, E3 took this into account to set higher completion ratios in the medium and high data center projections. E3 developed Low, Mid, and High data center scenarios for the ComEd zone, which are described in further detail in the Data Center Load section. In the Reference Case, data center load in the ComEd zone grows to approximately 54 TWh by 2050, about one-third of the zone's roughly 154 TWh of total annual energy, as shown in Figure 3-17. EV and building

electrification load, shown as separate components, together remain a small share of the total in the Reference Case.

Table 3-5: ComEd Data Center Facility Completion Rates by Scenario

Time Window	Low	Medium	High
Completion Rate (year 2)	65%	83%	100%
Completion Rate (year 3)	58%	79%	100%
Completion Rate (year 4)	0%	76%	100%
Completion Rate (year 5)	0%	73%	100%
Completion Rate (year 6)	0%	69%	100%
Completion Rate (year 7)	0%	65%	100%
Completion Rate (beyond year 7)	0%	60%	100%

Figure 3-17: ComEd Annual Energy by Component, TWh – Reference Case



Source: E3 analysis based on ComEd's load forecast.

Note: Baseload includes industrial load.

3.4.2 Data Center Load

Projecting data center load is subject to considerable uncertainty. Publicly available information on the size, location, and timing of proposed data center projects is sparse,

which limits the ability to validate utility and RTO projections against observable development activity.

To address this uncertainty, E3 developed Low, Mid, and High data center load projections for the IRP for the Ameren and ComEd zones using its data center modeling, which is built from public project announcements and estimated success and attrition rates for those projects.[43] The resulting projections were benchmarked against the utilities' forecasts. Outside of Illinois, the Mid Case data center projection is used for PJM Non-IL and MISO Non-IL in every IRP scenario, keeping the analysis focused on uncertainty within Illinois. The IRP is being developed in parallel with the Illinois Gas Decarbonization Pathways Study (Pathways Study), which uses the IRP Reference Case data center projection.

Forecasting Methodology

E3's data center approach models capacity additions across all stages of the construction lifecycle. Existing facilities are assumed to continue operating. Facilities currently under construction are assumed to come online one to two years into the future, and planned facilities are assumed to come online three to six years into the future; in both cases, load ramps up to the facility's planned size over three years.[44] Nameplate capacity is translated to load assuming a facility reaches 85% of its nameplate capacity at peak and operates at a 95% average load factor. Beyond this six-year development window, the annual growth rate gradually decays toward a sustained long-term rate of 1% per year, reflecting population growth and economic activity balanced against efficiency gains. While facility-level data, including the locations of specific known and future facilities, was a core input into this modeling effort, load growth modeling was conducted at the zonal level of granularity; this analysis is not intended to forecast load growth at the sub-zonal level.

The IRP includes three data center load scenarios for Illinois: Low, Mid, and High. The same three scenarios are defined for both the Ameren and ComEd zones and are differentiated by how much of the announced, under-construction, and planned data center capacity is assumed to be built as projects progress through development:

[43] Data for this forecast was collected from the following organizations: Coldwell Banker Richard Ellis (CBRE), Jones Lang LaSalle Incorporated (JLL), the Electric Power Research Institute (EPRI), Baxtel.com, and DataCenterMap.com. "Public Project Announcements" means that the facilities listed are included in these datasets and are not just applications in the utility large load interconnection queues. Licensing agreements with these data sets do not permit publishing the named projects.

[44] "Under Construction" and "Planned" are categories given by the datasets used to create the data center forecast and are not independently assessed by E3.

- **Low**: Only existing facilities and those currently under construction are completed. No planned projects are built, representing a data center "bust" in which the current wave of development stalls.
- **Mid**: Existing and under-construction facilities are completed, and planned projects are built subject to delays and attrition consistent with observed development patterns. A portion of announced capacity is assumed never to materialize.
- **High**: Existing and under-construction facilities are completed, and planned projects are built with substantially lower attrition than in the Reference Case, representing a sustained, aggressive build-out of data center capacity.

Attrition assumptions are calibrated separately for each zone to reflect local development conditions and benchmarking against utility forecasts, as described below. Together, the Low-to-High range spans a broad range of uncertainty to inform low-regret actions in the near term. Periodic IRP updates will allow the State to revisit and refine long-term data center projections as development activity becomes clearer.

MISO LRZ 4

In LRZ 4, announced data center projects sum to approximately 44 TWh of annual energy by 2031. None of the IRP scenarios assume this pace of growth materializes in the near term. The Mid Case applies standard attrition to planned projects and reflects a future in which this level of growth materializes gradually over a roughly 25-year period, reaching approximately 43 TWh by 2047, broadly consistent with Ameren's independently developed high data center scenario. The High scenario applies reduced attrition. The updated High projection reaches approximately 68 TWh by 2047. While this remains above Ameren's high forecast of approximately 49 TWh, it is within the realm of possibility and maintains a material difference between the Mid and High scenarios. The Low scenario reaches approximately 3 TWh by 2047. Figure 3-19 compares the IRP scenario data center load forecasts with Ameren's Base Case, announced projects, and the 2025 RA Study.

Figure 3-18: LRZ 4 Data Center Peak Load by Attrition Scenario, MW

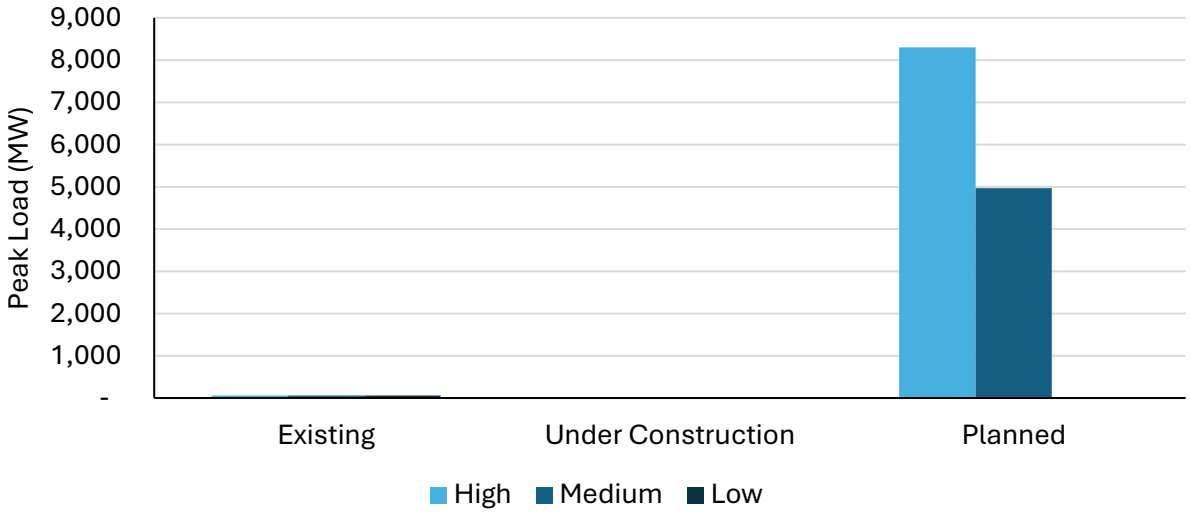
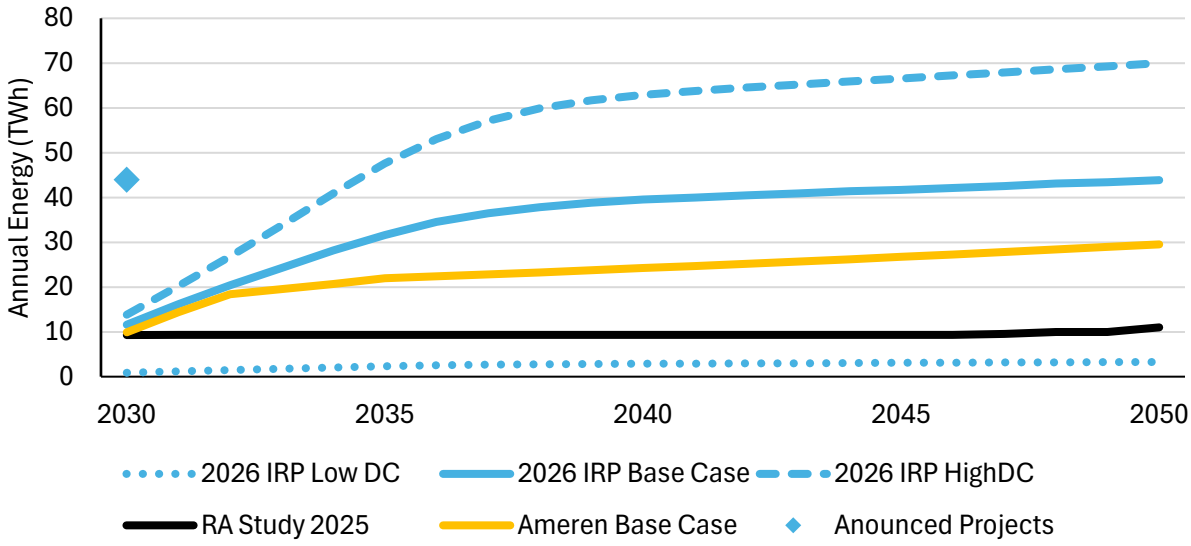


Figure 3-19: LRZ 4 Data Center Annual Energy, TWh



Source: E3 analysis; Ameren data center forecasts provided by Ameren; 2025 RA Study.

Note: Announced projects reflect the cumulative annual energy of publicly announced data center projects in LRZ 4.

ComEd Zone

ComEd provided a single data center forecast, reaching approximately 88 TWh by 2047, which is significantly higher than E3's estimate of an aggressive development scenario. The ComEd Mid Case applies a higher completion rate for planned projects than the Ameren Mid Case, in order to benchmark against utility forecasts, and reaches approximately 52 TWh by

2047. The High scenario assumes all under-construction and planned projects are built, reaching approximately 70 TWh by 2047, and the Low scenario reaches approximately 15 TWh. All three scenarios are below the approximately 83 TWh assumed for 2047 in the 2025 RA Study, reflecting updated information on planned data center projects. Figure 3-21 compares the IRP scenario data center load forecasts with ComEd's Base Case, announced projects, and the 2025 RA Study.

Figure 3-20: ComEd Data Center Peak Load by Attrition Scenario, MW

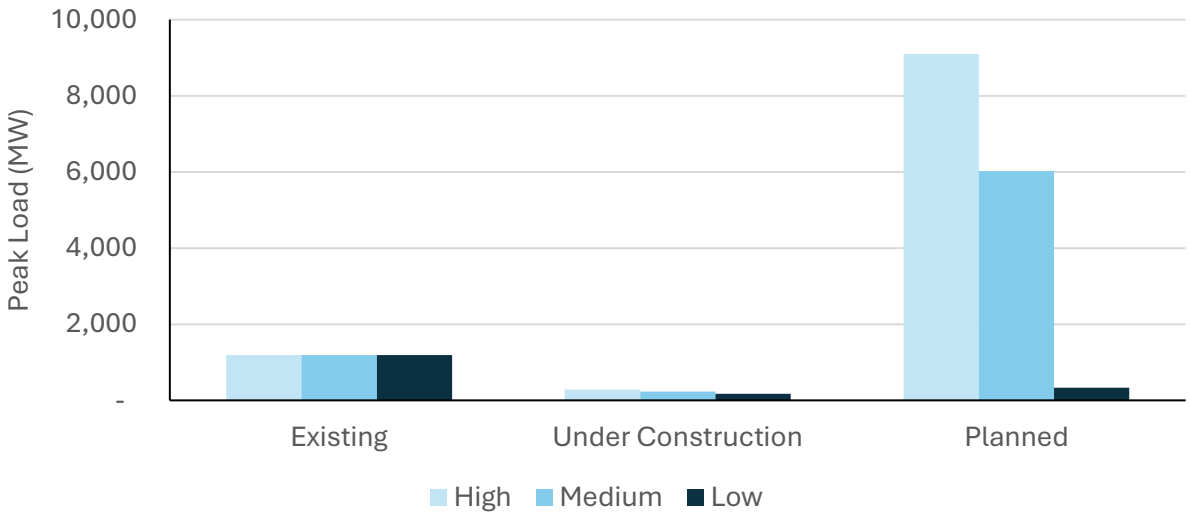
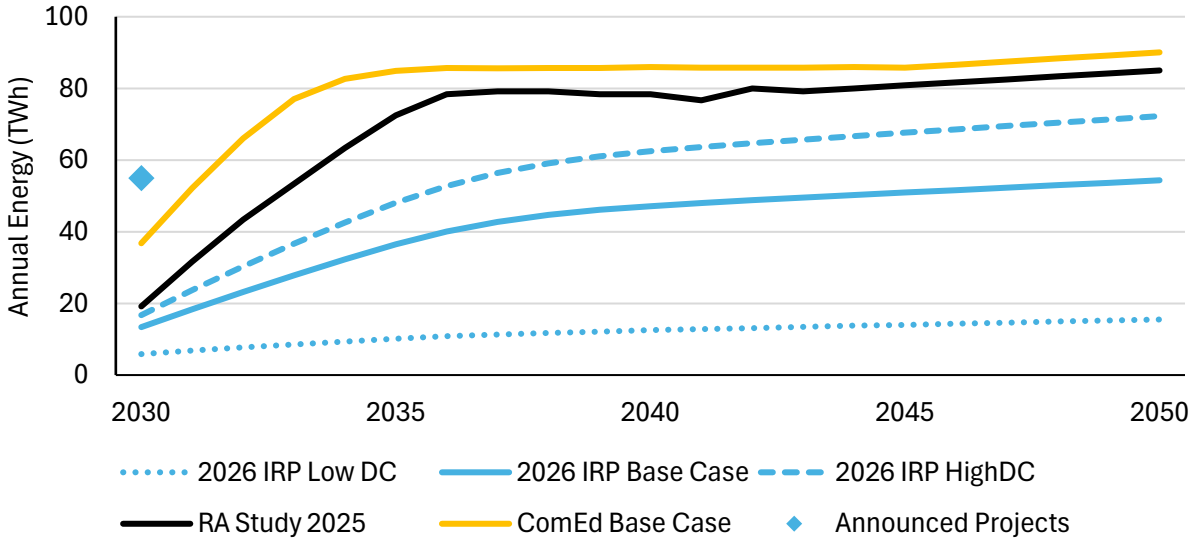


Figure 3-21: ComEd Data Center Annual Energy, TWh



Source: E3 analysis; ComEd data center forecast provided by ComEd; 2025 RA Study.

Note: Announced projects reflect the cumulative annual energy of publicly announced data center projects in the ComEd zone.

PJM and MISO Excluding Illinois

Data center load projections for PJM and MISO outside of Illinois were informed by each RTO's latest long-term load forecast, including the RTO's distribution of data center load across its zones. E3 then refined the RTO data center forecasts using the same data center modeling applied in Illinois. Both RTOs' latest long-term load forecasts for zones outside Illinois project materially higher data center load than last year, and E3's projections are correspondingly higher than those used in the 2025 RA Study, with slightly higher data center load in PJM (excluding Illinois) and higher data center load in MISO (excluding Illinois) across all years. In PJM, E3's refined projection is lower than PJM's own data center forecast, because the approach is based on public project announcements rather than interconnection requests, which limits the influence of speculative and duplicative projects. In PJM (excluding Illinois), data center load reaches approximately 390 TWh by 2047 and in MISO (excluding Illinois), approximately 160 TWh. Only a single Mid Case data center projection was developed for each region. No Low or High cases were developed, and the same projection is used in every IRP scenario so that the analysis remains focused on uncertainty within Illinois.

3.4.3 Electrification Load

The IRP cases include electrification load from buildings, industry, and transportation. E3 developed independent electrification forecasts for the Ameren and ComEd zones for two cases: the Reference Case that reflects a continuation of current adoption trends, and the Electrification case based on the Hybrid Electrification scenario from the Pathways Study, which includes building and industrial electrification aligned with reaching net zero emissions in the natural gas sector by 2050, and transportation electrification consistent with the net zero scenarios in the Illinois CCAP.[45] Outside of Illinois, EV load is based on the PJM and MISO long-term load forecasts, and building electrification is assumed to be embedded in the RTO baseload forecasts. Non-Illinois load is the same across IRP cases.

Overview

E3's Reference Case forecast of light-duty (passenger) EV adoption is based on a continuation of historical trends in Illinois. Historical EV adoption in the Ameren and ComEd zones was aggregated from county-level EV registration data published by the Illinois Secretary of State and fitted to a Bass diffusion curve to project adoption in future years. In

[45] Illinois Environmental Protection Agency, "Illinois Comprehensive Climate Action Plan", (June 1, 2026), https://epa.illinois.gov/content/dam/soi/en/web/epa/topics/climate/documents/IEPA-Final-CCAP.pdf

the Reference Case, total light duty vehicles on the road reaches approximately 1.5M vehicles in 2047. Because less historical data is available for medium- and heavy-duty vehicles, E3 used EV adoption projections from the EIA Annual Energy Outlook 2026, specifically the Alternative Transportation case, which removes the U.S. Environmental Protection Agency's Phase 3 tailpipe emissions standards. Under these assumptions, EV penetration for light medium-duty vehicles (e.g., delivery trucks) reaches approximately 10% by 2050, while penetration for larger medium- and heavy-duty vehicles remains very low (approximately 1%) through 2050. EV hourly load shapes assume a fixed charging mix in which 25% of EV charging is managed.

E3's Reference Case forecast of heat pump adoption uses the National Laboratory of the Rockies (NLR) Heat Pumps for All database to estimate the share of Illinois homes that could cost-effectively adopt a heat pump today. Cost-effectiveness is highest for homes currently heated with electric resistance or propane and for homes in the southern part of the state. Among homes for which a heat pump is currently cost-effective, market share is assumed to increase linearly to 100% by 2050, adding approximately 30,000 heat pumps each year, which is similar in magnitude to other estimates of the Illinois heat pump market. E3 also included an incremental 1,000 ground-source heat pumps per year starting in 2028 to represent the Geothermal Homes and Businesses Program established under the CRGA. When heat pumps replace gas or propane heating, they increase electric load; when they replace electric resistance heating, they reduce electricity load on an annual basis because heat pumps are more efficient. The net effect is a modest increase in electric load of approximately 1 TWh statewide by 2050.

The Electrification scenario was developed in coordination with the Pathways Study. It assumes that EVs reach 100% of new light-duty vehicle sales by 2035 and zero emission vehicles (ZEVs) (including some hydrogen fuel cell vehicles) reach 100% of new medium- and heavy-duty vehicle sales by 2040. The scenario also includes rapid adoption of heat pumps for space and water heating in buildings, electrification of other building end uses (e.g., cooking and clothes drying), and electrification of low temperature industrial heat. Statewide, the number of light-duty EVs reaches approximately 8.2 million by 2050 in the Electrification case, compared to approximately 1.6 million in the Reference Case, and residential heat pumps reach approximately 5.7 million, compared with approximately 1 million in the Reference Case.

Changes Since the 2025 Resource Adequacy Study

The electrification forecasts differ from those in the 2025 Resource Adequacy Study (2025 RA Study) in three ways. First, the Reference Case EV forecast is now anchored to historical EV adoption trends in Illinois rather than to utility or RTO forecasts, which results in

significantly lower EV load in the ComEd zone and similar EV load in LRZ 4. Second, building electrification is now modeled explicitly through heat pump adoption rather than being assumed to be embedded in the baseload forecast. Third, the IRP adds an Electrification case that reflects adoption consistent with deep decarbonization, allowing the IRP to test resource needs under a future with significant electrification.

MISO LRZ 4

Ameren's EV forecast projects approximately 1.2 million EVs by 2050, compared with approximately 270,000 in E3's Reference Case forecast. Since the Reference Case is meant to reflect current trends, E3 instead used its independent forecast, reserving policy-driven adoption for the Electrification case. In the Reference Case, EV load in LRZ 4 reaches approximately 0.5 TWh by 2047, and heat pump adoption adds approximately 0.7 TWh of net load by 2050, roughly two-thirds of the statewide heat pump load increase. In the Electrification case, total LRZ 4 load reaches approximately 116 TWh by 2047, compared with approximately 90 TWh in the Reference Case, and peak load reaches approximately 17 GW, comparable to the High Data Center Growth case scenario.

ComEd Zone

ComEd provided EV and electrification forecasts that were reviewed but not used. As in LRZ 4, E3 defined the Reference Case as indicative of current trends and used its independent forecasts instead. In the Reference Case, EV load in the ComEd zone reaches approximately 2.1 TWh by 2047, and heat pump adoption adds approximately 0.3 TWh of net load by 2050; heat pump net load growth is smaller in the ComEd zone, consistent with the higher cost-effectiveness of heat pumps in the southern part of the state. In the Electrification case, total ComEd zone load reaches approximately 203 TWh by 2047, compared with approximately 155 TWh in the Reference Case, and peak load reaches approximately 34 GW, compared with approximately 28 GW in the Reference Case. By 2047, the Electrification case scenario exceeds the High Data Center Growth case scenario, making electrification the largest potential driver of long-term load growth in the ComEd zone.

3.4.4 Changes Since the 2025 Resource Adequacy Study

Load forecasts for this IRP and Mitigation Plan are generally higher than those used in the 2025 RA Study, driven primarily by significant data center development activity in Illinois and across both the MISO and PJM regions. The RTO long-term load forecasts underlying the projections for MISO and PJM outside of Illinois are noticeably higher than those used in the 2025 RA Study, reflecting materially higher RTO expectations for data center load in both regions.

Within Illinois, the two utility zones show divergent trends. Ameren's load forecast is significantly higher than the forecast provided in the 2025 RA Study; data centers are the principal driver of this increase, which is supported by observable data center development in the area. As a result, data center load in LRZ 4 is significantly higher than in the 2025 RA Study. ComEd's latest load forecast, by contrast, remains similar to the forecast provided for the 2025 RA Study. E3's independent modeling finds that ComEd's load forecast is most closely aligned with E3's "high case" for data center load. As a result, the IRP mid case projection for the ComEd zone is lower than both the latest ComEd forecast and the forecast used in the 2025 RA Study.

Several methodological refinements also contribute to differences from the 2025 RA Study. For the portions of MISO and PJM outside of Illinois, baseload energy in the IRP was aligned to 2025 historical loads, an alignment that was not performed for the 2025 RA Study. Industrial loads are now modeled explicitly as a separate component in all regions. In the MISO regions, revised categorization results in significantly more load being classified as industrial. Together, these changes result in lower baseload values across all regions than in the 2025 RA Study, with higher combined baseload and industrial growth outside of Illinois and roughly the same growth within the Ameren and ComEd zones. Data center loads in all regions are reflected in E3's data center projections for the IRP. Finally, as a result of the updated methodology using current adoption rates, EV loads are significantly lower than in the 2025 RA Study in all regions except LRZ 4, where they are similar.

3.5 Candidate Resources

Candidate resources represent options that are made available to the model to be added on top of the existing and planned resource portfolio to meet Illinois' future needs. In-state candidate resources include utility-scale and distributed solar PV, onshore wind, 4-hr Li-ion battery storage, long-duration energy storage, nuclear uprates, and new nuclear (represented as light water reactors and small modular reactors). Additionally, capacity purchases from the rest of the RTOs were allowed. These purchases were priced at the cost of building a new gas combustion turbine (or combined-cycle gas plant) in neighboring states, and the total purchase volumes were limited by the Capacity Emergency Transfer Limit (CETL) for ComEd zone and the Zonal Import Ability (ZIA) for the LRZ 4 zone.

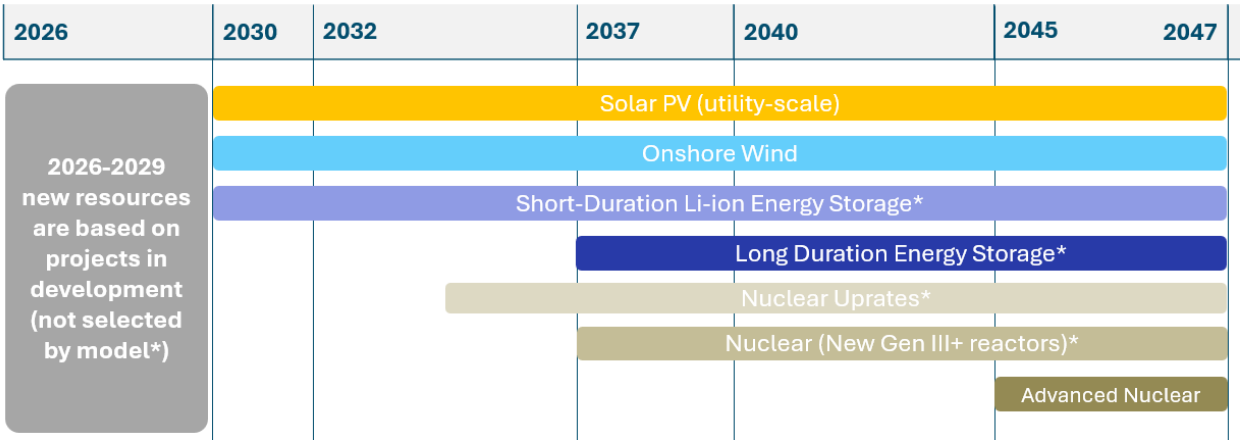
Non-powered dams converted to produce hydropower are also RPS-eligible. However, to date, the IPA's Indexed REC procurement events have only contracted for a small number

of RECs from this resource type.[46] In its Draft 2026 Long-Term Renewable Resources Procurement Plan (LTRRPP), the IPA requested stakeholder feedback on how to ensure these facilities participate in the IPA's competitive procurements and if RECs from these facilities should be procured through a different approach. No feedback was received.[47] As a result, this IRP does not study this resource type. If these resources participate in future procurement processes and data on site-specific potential and costs within Illinois emerge, then they may be studied in future IRP cycles.

3.5.1 How PLEXOS Selects Candidate Resources

Available candidate resource potential for utility-scale solar and wind resources are based on NLR datasets. New nuclear is assumed to be constrained by a build rate of not more than 1 GW per year, beginning in 2037, for all cases except for the Reference No Build Limit and Electrification No Build Limit sensitivities. No additional constraints are applied to Li-ion batteries. All resources are available to be built starting in 2030, aside from new nuclear capacity and long-duration energy storage, both of which are first available for selection in 2037. The Advanced Technology Acceleration case scenario also considers a future where certain new candidate resources are available sooner and at a lower cost as shown in Figure 3-22 below.

Figure 3-22: Candidate Resource Availability to PLEXOS Model



** Indicates resource receives the investment tax credit (ITC) if built on or before 2037*

[46] The Summer 2026 IREC procurement resulted in a single contract for 60,000 RECs on an annual basis from a project with 10.26 MW of nameplate capacity. See the full procurement results at https://nera-content-media.s3.us-east-1.amazonaws.com/ipa/Summer_2026_Indexed_REC_RFP_Results_24_Jun_2026_69eb2e10f7.pdf

[47] For more information related to hydropower, see Section 5.5.4 in the final 2026 LTRRPP - https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20260602-2026-modified-ipa-long-term-plan.pdf

New gas generators, including combustion turbines (CTs) and combined-cycle gas turbines (CCGTs), are not available for selection in Illinois, except in the New Gas sensitivity case. However, candidate gas generation in the external zones is available for selection in all cases. In PLEXOS, Illinois is allowed to select firm capacity imports of out-of-state gas resources as an alternative to in-state resources. These out-of-state imports are modeled with the cost and performance characteristics of a new gas CT in neighboring states, and the total quantity of imported capacity for each zone is capped at the relevant Illinois zonal transmission import limit. Some cases consider expansion of these limits to explore the value that additional firm imports, accessed via incremental transmission investment, can provide as capacity resources for Illinois (i.e., Reference Transmission Expansion and Electrification with Transmission Expansion cases).

Demand-side generation resources, including BTM and other distributed solar PV, are represented in the PLEXOS LT model using a forced-in adoption forecast, and are consequently not shown in the above figure. 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. Additional demand response from enhanced load flexibility is considered in the Electrification High Load Flexibility Case.

In-state resource selections are also constrained by in-state resource deliverability constraints, as discussed in Section 3.7.

Figure 3-23 presents Illinois-specific upfront capital expenditure (CapEx) forecasts for key generation and storage resources modeled, while Figure 3-24 and Figure 3-25 illustrate the levelized cost of energy and levelized fixed cost for applicable technologies, respectively. These projections are primarily based on the NLR's Annual Technology Baseline (ATB),[48] 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 or other market factors 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 in current federal policy, and short-term gas turbine scarcity premiums that are assumed to normalize by 2035.

[48] NREL 2024 ATB: https://atb.nrel.gov/electricity/2024/data.

Firm capacity imports are priced at the cost of building new out-of-state gas CTs 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. 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 NLR ATB benchmarks.

Figure 3-23: Illinois Candidate Resource CapEx (Nominal $/kWac)

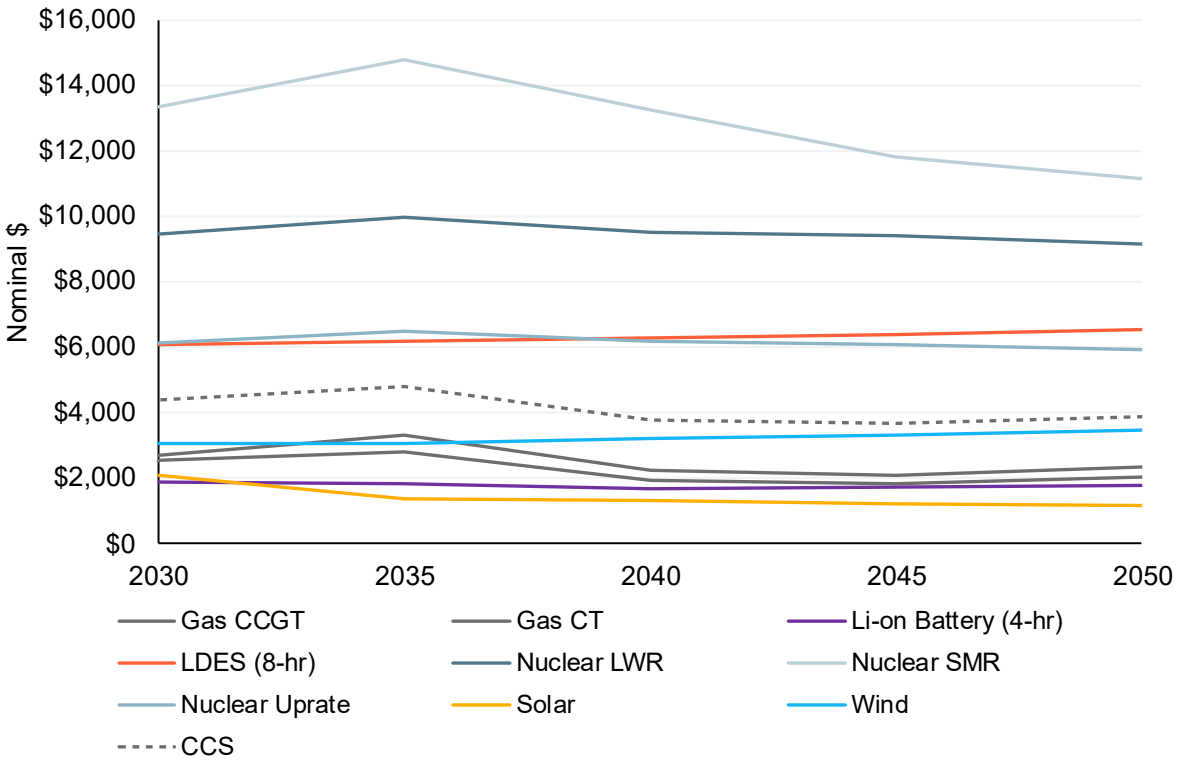


Figure 3-24: Illinois Candidate Resource Levelized Cost of Energy (Nominal $/MWh)

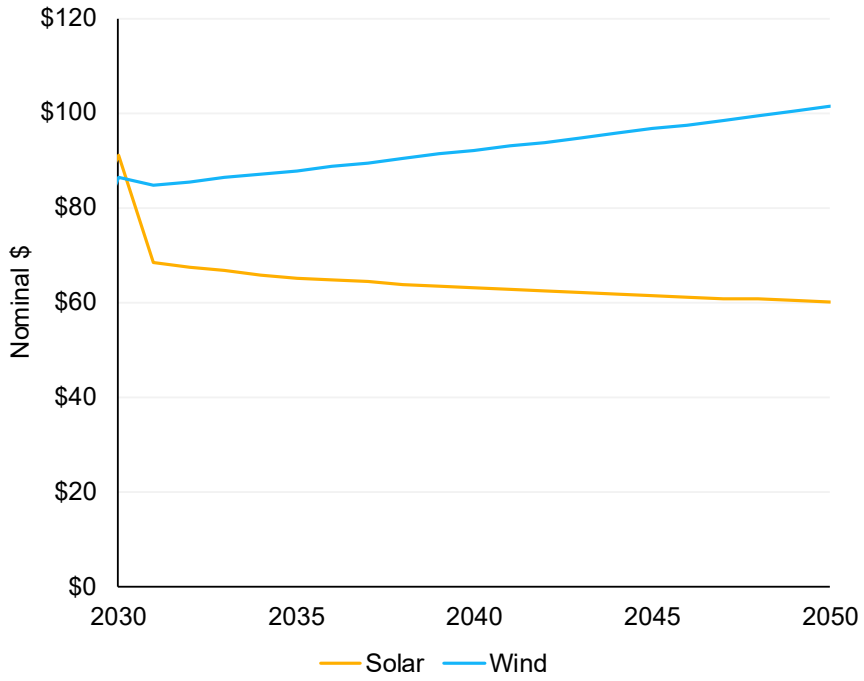
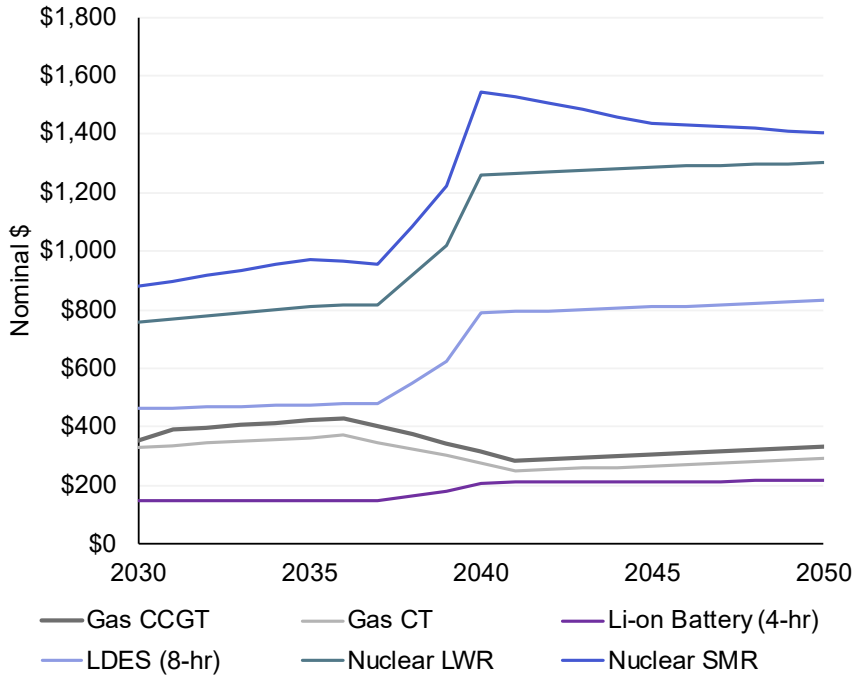


Figure 3-25: Illinois Candidate Resource Levelized Fixed Cost (Nominal $/kW-yr)



3.5.2 Renewables: Wind and Solar

Existing and candidate resource profiles are simulated using NLR'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 NLR'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 NLR'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 leased 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 NLR's 2023 National Offshore Wind (NOW-23) database. For land-based wind and both types of solar, candidate project areas (CPAs) from NLR's renewable energy supply curves were mapped to PLEXOS regions and simulated in SAM using a similar methodology as described above.

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 resource adequacy requirements.

Two categories of resources are added manually:

1. Distributed solar, which is added based on policy targets, and
2. Planned 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 contracted to other (non-IL) utilities or programs 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 resource portfolio optimization and maintains alignment between IPA planning years and PLEXOS calendar years.

3.5.3 Storage: Short-Duration Lithium-Ion and Long-Duration Storage

Candidate resources include 4-hr Lithium-ion batteries and 100-hr LDES. Lithium-ion projects of different durations often use the same battery cells; they differ mainly in inverter and interconnection rating. PLEXOS tracks storage additions by both capacity (MW) and energy (MWh), and energy scales linearly with the number of 4-hr battery units. Four-hour battery units can therefore deliver whatever total energy an 8-hr, 12-hr or longer duration battery would provide, and may provide higher flexibility than one single long-duration storage. Two 4-hr battery units can discharge for 8 hours in sequence, or at twice the output in a single hour, which an 8-hr battery of the same MWh cannot. A longer-duration unit may cost slightly less per MWh, but that difference is minor. Modeling a single duration also gives a more accurate representation of battery storage's declining ELCC than mapping between several durations with separate accreditation curves.

The 100-hr LDES candidate resource represents multi-day storage and can shift energy across extended low-renewable periods that a stack of 4-hr Li-ion batteries could serve only at much higher cost. Together, the two candidates let the model build any combination of power and energy capacity, from short-duration to multi-day. Storage between these two durations, including the 18-hr to 36-hr non-battery technologies proposed by developers, can be approximated as a combination of the two.

3.5.4 New Gas-Fired Generation

Consistent with the modeled interpretation of CEJA's emissions requirements, new in-state natural gas capacity is not permitted; however, it's assumed that IL may build out-of-state gas generation resources and import their capacity, up to existing transmission limits, to support reliability. In this report, capacity imported from these gas resources is referred to as "out-of-state capacity purchases."

3.5.5 New Nuclear Generation

Nuclear Notice of Intent

Nuclear uprates of up to 596 MW capacity are available for selection starting in 2032. Nuclear uprate potential is calculated based on the industry average of historical nuclear uprates in the U.S., based on Nuclear Regulatory Commission (NRC) data.[49] Historically, uprates have increased nuclear capacity by 5% on average. Illinois has 11,933 MW of existing nuclear capacity, and applying a 5% uprate potential results in 596 MW of additional capacity available for selection. The reasonableness of this estimate is borne out by the fact that Constellation Energy, owner and operator of Illinois's nuclear plants, has publicly announced a total of 663 MW of nuclear uprates estimated to be completed in 2028-2030.[50] Uprates can include Measurement Uncertainty Recapture (MU), which result in smaller capacity increases, Stretch (S) uprates, and Extended (E) uprates, which result in higher capacity increases. Table 3-6 shows the historical number of uprates and average capacity increase for each category of uprates, based on NRC's historical approved uprates.

Table 3-6: Historical Nuclear Uprate Capacity Increases

	Number of Uprates	Average Capacity Increase
Measurement Uncertainty Recapture (MU)	73	2%
Stretch (S)	65	4%
Extended (E)	30	14%
Total	168	5%

Nuclear light water reactors (LWRs) and nuclear SMRs are included as candidates with LWRs available for selection starting in 2037 and SMRs available in 2045. The combination

[49] Nuclear Regulatory Commission (NRC), "Approved Applications for Power Uprates" (n.d.), https://www.nrc.gov/licensing-applications/operating-reactor-licensing/power-uprates/status-power-uprate-applications/approved-applications-power-uprates

[50] For further detail on the specific uprates and PPA Customers, reference ICC's "Final Report for Notice of Inquiry 26-NOI-01" https://icc.illinois.gov/downloads/public/noi/NOI-26-01%20Staff%20Summary%20Report%20Final.docx

of LWRs and SMRs are limited to an aggregate build rate of one GW per year to reflect permitting and construction constraints on multiple simultaneous builds.

3.6 Resources Not Included as Candidate Resources in This Mitigation Plan

Bulk System Transmission

In general, transmission expansion between Illinois and neighboring zones is not modeled in PLEXOS. However, limited exploration of transmission expansion is explored in two sets of sensitivities (i.e., Reference Transmission Expansion and the Electrification with Transmission Expansion sensitivities) in the Mitigation Plan.

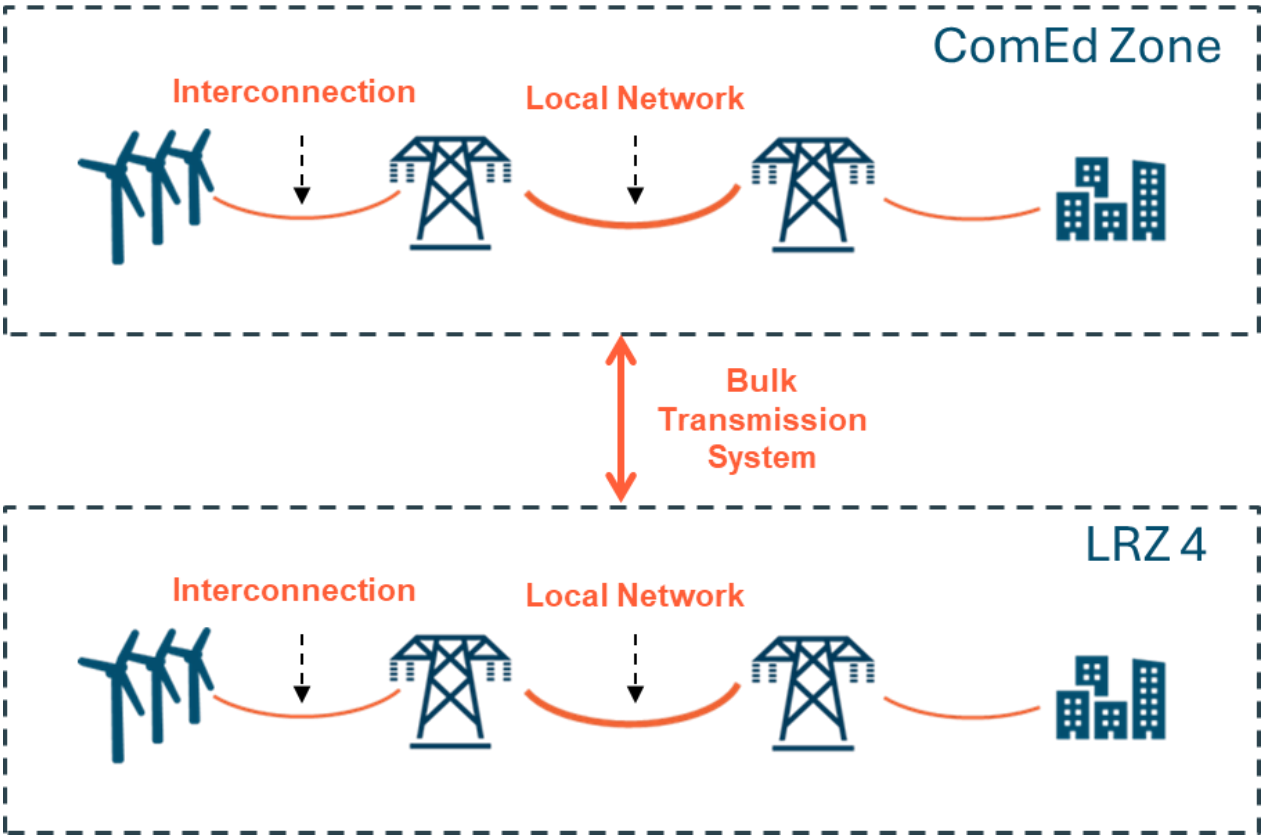
Demand response is not modeled as a candidate resource due to uncertainties regarding build costs. Instead, demand response capacity that cleared recent MISO and PJM auctions is forced into the PLEXOS modeling baseline model. The IRP explores demand response in further detail.

3.7 Transmission Systems and Import Capability

The PLEXOS model considers three distinct types of transmission components, as illustrated in Figure 3-26:

- **Bulk transmission system**: Inter-zonal transfer capacity
- **Local network**: Transmission headroom within a zone that ensures electricity can be delivered from where it is generated or discharged to load centers
- **Interconnection**: The “spur line” cost to connect generators to the closest substation

Figure 3-26: Illustration of Transmission Components



3.7.1 Bulk Transmission System

Power flow through the bulk transmission system is explicitly modeled, while simplifications are made to reasonably account for the cost of local network upgrades and interconnection in PLEXOS, as described below.

The PLEXOS model utilizes the bulk transmission system topology of the MISO and PJM RTOs, with carve-outs in Illinois to separately represent Ameren Illinois and the cooperatives or municipalities within MISO LRZ 4, as well as ComEd and the cooperatives or municipalities in PJM's ComEd zone. Other Illinois load-serving entities (LSEs) or municipalities are aggregated into the regions in which they reside, such as MidAmerican in MISO LRZ 3 and Jo Carroll Energy Cooperative in MISO LRZ 1. 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

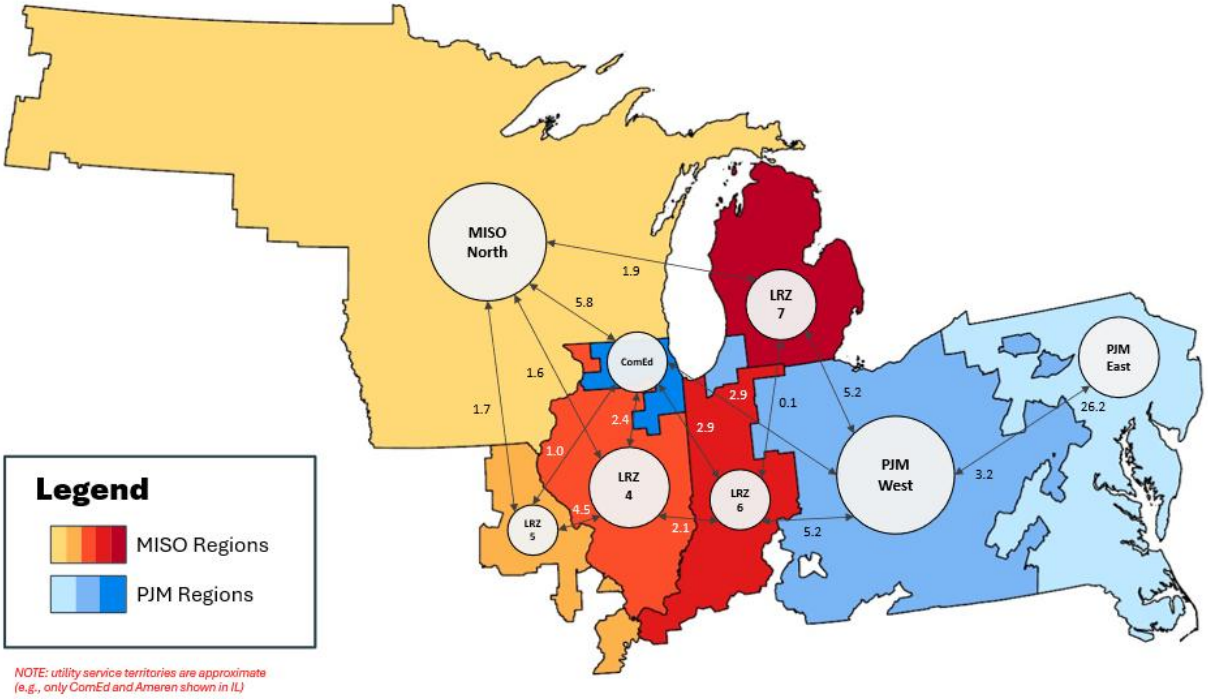
informed by the EIA Hourly Electric Grid Monitor,[51] MISO 2024 LOLE Study Reports,[52] MISO Transmission Expansion Plan (MTEP) 2024,[53] PJM Regional Transmission Expansion Plan (RTEP) 2024[54] and MISO's Tranche 1 and 2.1[55] reports under the Long-Range Transmission Planning process. This zonal representation 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 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.

The bulk power system is modeled with a zonal "pipe-and-bubble" representation, as shown in Figure 3-27. Each bubble contains load and resources within each zone, and the pipes represent the maximum hourly transmission flow in gigawatts (GW) allowed in each direction between each pair of zones. These flow constraints, represented on an hourly basis, affect how much energy can flow between Illinois and its neighboring RTO zones and

[51] EIA, "Hourly Electric Grid Monitor," (n.d.), https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.
[52] MISO, "Planning Year 2023-2024 Loss of Load Expectation Study Report," (May 1, 2023), https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf
[53] MISO, "MTEP24 Report Preview," (n.d.), https://cdn.misoenergy.org/20241001%20PAC%20Item%2002%20MTEP24%20Report%20Preview650567.pdf
[54] PJM, "Reliability Analysis Report 2024 RTEP Window 1," (February 10, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250304/20250304-2024-rtep-window-1-reliability-analysis-report.pdf
[55] MISO, "Long Range Transmission Planning," (n.d.), https://www.misoenergy.org/planning/long-range-transmission-planning/

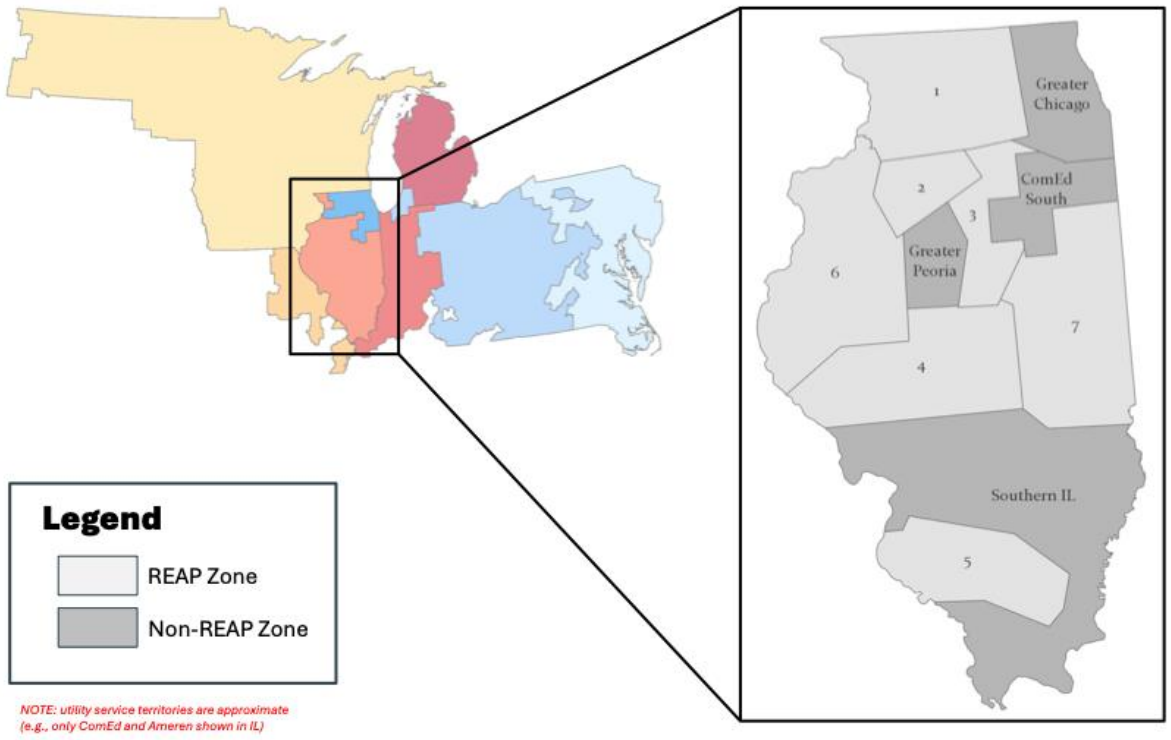
influence how much new generating capacity needs to be procured in-state to meet forecasted load growth.

Figure 3-27: PJM and MISO Transmission Topology Modeled in PLEXOS (2030)



3.7.2 Local Network Headroom and Upgrade Costs

Figure 3-28: Renewable Energy Access Plan (REAP) Zone Map



Hourly power flow over the local network within each zone in the bulk transmission system is not explicitly modeled in PLEXOS. However, within Illinois specifically, PLEXOS tracks the amount of available transmission headroom that exists within each REAP zone, i.e., how much additional power could feasibly be handled during the system's critical hours, with REAP zones as defined in the Draft 2025 REAP Report.[56] The critical hours where headroom needs to be reserved are assumed to occur between 4:00 – 8:00 PM from June through September. Given data limitations, it was assumed that no transmission headroom currently exists, and only one headroom constraint is modeled per REAP zone.

The model also tracks the evolution of transmission headroom over time as 1) fossil fuel unit retirements occur, and 2) economic upgrades are selected to accommodate new resource builds required to meet load growth. Upgrades can be thought of as any network improvement that is required to deliver power to load, whether that involves increasing the capacity of an existing line or upgrading a substation. These types of cost are incurred when the model determines it is economical to alleviate a transmission headroom constraint to build new resources within a given REAP zone. Additional transmission headroom is created at no cost when fossil fuel units retire, per the retirement schedule shown in Table 3-7.

[56] Illinois Commerce Commission, "Illinois' 2025 Draft Renewable Energy Access Plan," (December 2025), https://www.ethree.com/wp-content/uploads/2026/01/Illinois-2025-Draft-REAP.pdf

These constraints are designed to ensure adequate locational diversity in the selected resource portfolio and prevent an over-concentration of resources in areas of the state where the costs to deliver power may be unreasonably high.

Table 3-7: Fossil Retirement-Driven Transmission Headroom Created by REAP Zone, MW

REAP Zone	Region	2030	2035	2040	2045
Greater Chicago	**ComEd**	803	4,448	6,455	9,093
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**	1,108	1,108	1,289	1,615
REAP_Zone_5	**Ameren**	1,185	1,185	1,545	3,175
REAP_Zone_6	**Ameren**	0	0	0	0
REAP_Zone_7	**Ameren**	200	200	1,328	1,328
Greater Peoria	**Ameren**	0	1,538	1,538	1,538
Southern IL	**Ameren**	1,182	1,870	2,488	2,488

In cases where the retirement schedules for CEJA-limited units are extended, the model cannot leverage the above retirement-driven transmission headroom quantities and instead must invest in transmission upgrades to deliver new renewable energy.

After the initial transmission headroom from retiring fossil fuel units has been exhausted, if any existed at all, the cost of incurring additional transmission headroom is assumed to be

a step function. The first gigawatt of upgrades is estimated to cost $5,000/MW-mile,[57] or $250,000/MW for an assumed 50 miles of high-voltage transmission lines. Each subsequent gigawatt of upgrades is assumed to cost 15% more than the previous tranche.[58] For the fifth gigawatt of upgrades selected by the model and beyond, costs are assumed to remain the same.

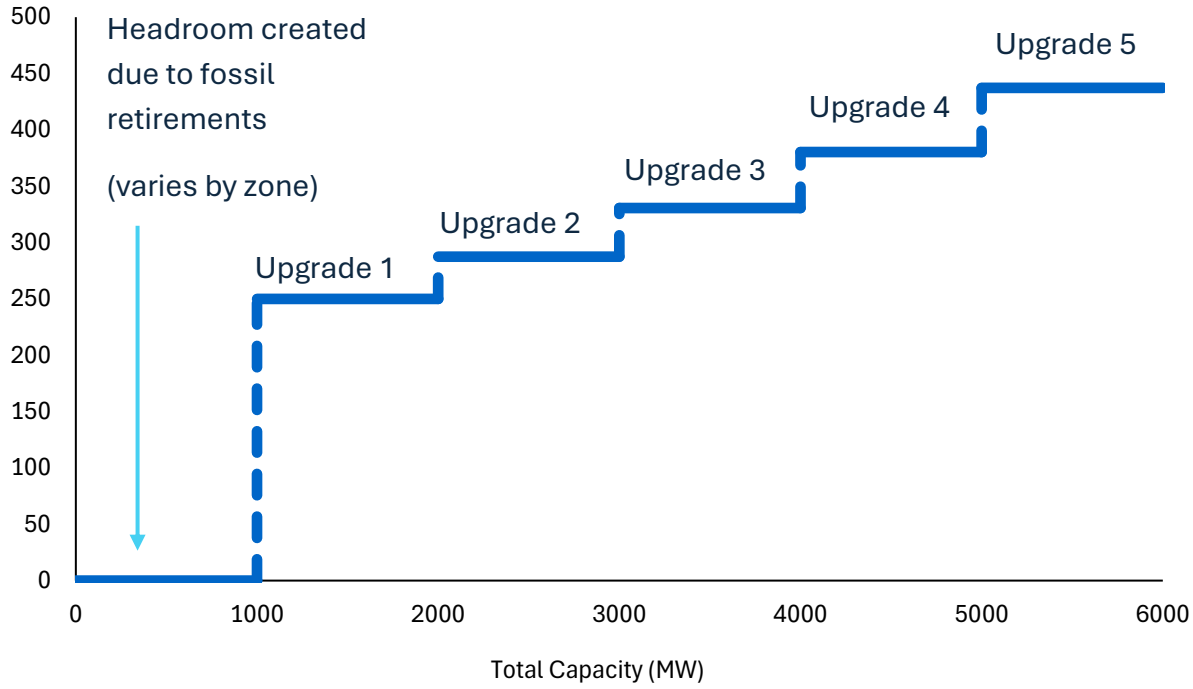
Table 3-8: Transmission Headroom Cost Schedule

Tranche	Unit Cost	Total Cost (50 Miles)
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

[57] 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

[58] 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.

Figure 3-29: Local Network Upgrade Cost Illustration, $/kW



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. 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. For example, if a resource consistently generates energy at 20% of its nameplate capacity in these hours, then five GW of this resource on a nameplate basis can be built before one GW of transmission headroom is exhausted and the next tranche of headroom upgrade cost is triggered.

3.7.3 Interconnection Costs

Interconnection costs incorporate all expenses associated with building a new spur line or making upgrades to the substation closest to the generator. They are primarily a function of the distance between the site under development and its nearest point of interconnection to the existing grid. The values used for this study represent a capacity-weighted average of all candidate project areas in each REAP zone from NLR supply curve data. [59]

[59] Anthony 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.

Interconnection costs are included in the total fixed cost of a resource and are incurred whenever that resource is built by PLEXOS.

3.7.4 Import Capability

In addition to hourly energy flows over the bulk transmission system, the PLEXOS model also imposes limits on the firm capacity that can be imported from out-of-state to meet the planning reserve margin. These firm transmission line capacities represent the amount of firm generating capacity that Ameren (in LRZ 4) and ComEd are assumed to be able to import during peak hours. The CETL and ZIA constraints, from PJM and MISO respectively, inform the limits on firm import capability towards meeting the PRM requirement. CETL for ComEd is assumed to be 3.9 GW, based on a rolling average of recent PJM Base Residual Auction Planning Period Parameters reports.[60] The ZIA for LRZ 4 is assumed to be 8.7 GW for Summer and 5.9 GW for Winter, based on a rolling average of recent MISO Seasonal CIL/CEL Final Results reports.[61] Winter ratings were only employed for electrification scenarios, in which LRZ 4 becomes a winter-peaking system. These CETL and ZIA values are assumed to remain fixed over time.

In select cases, additional firm import capability is made available to Ameren (LRZ 4) and ComEd at additional cost. In those cases, a cost adder is modeled on the out-of-state gas capacity built to serve IL peak loads, incremental to the existing firm import capability limits. The amount of additional firm capacity available for selection is equal to 50% of the above CETL and ZIA values (1.9 GW for ComEd, 4.4 GW for LRZ 4). For additional firm imports into ComEd, a $1,500/kW cost adder onto the out-of-state gas resource represents a dedicated 200-mile transmission line from Indiana to Illinois ($7,500/MW-mi). For Ameren (LRZ 4), a $600/kW cost adder reflects a 100-mile line ($6,000/MW-mi) from a neighboring LRZ into Illinois.

3.8 Fuel Prices

Monthly fuel prices used in PLEXOS modeling are based on S&P forward prices (near term) and EIA Annual Energy Outlook 2025 Reference Case (long term). Depending on the location of power plants, different gas prices are applied to capture variance in local transportation costs, pipeline capacity, and regional supply-demand dynamics.

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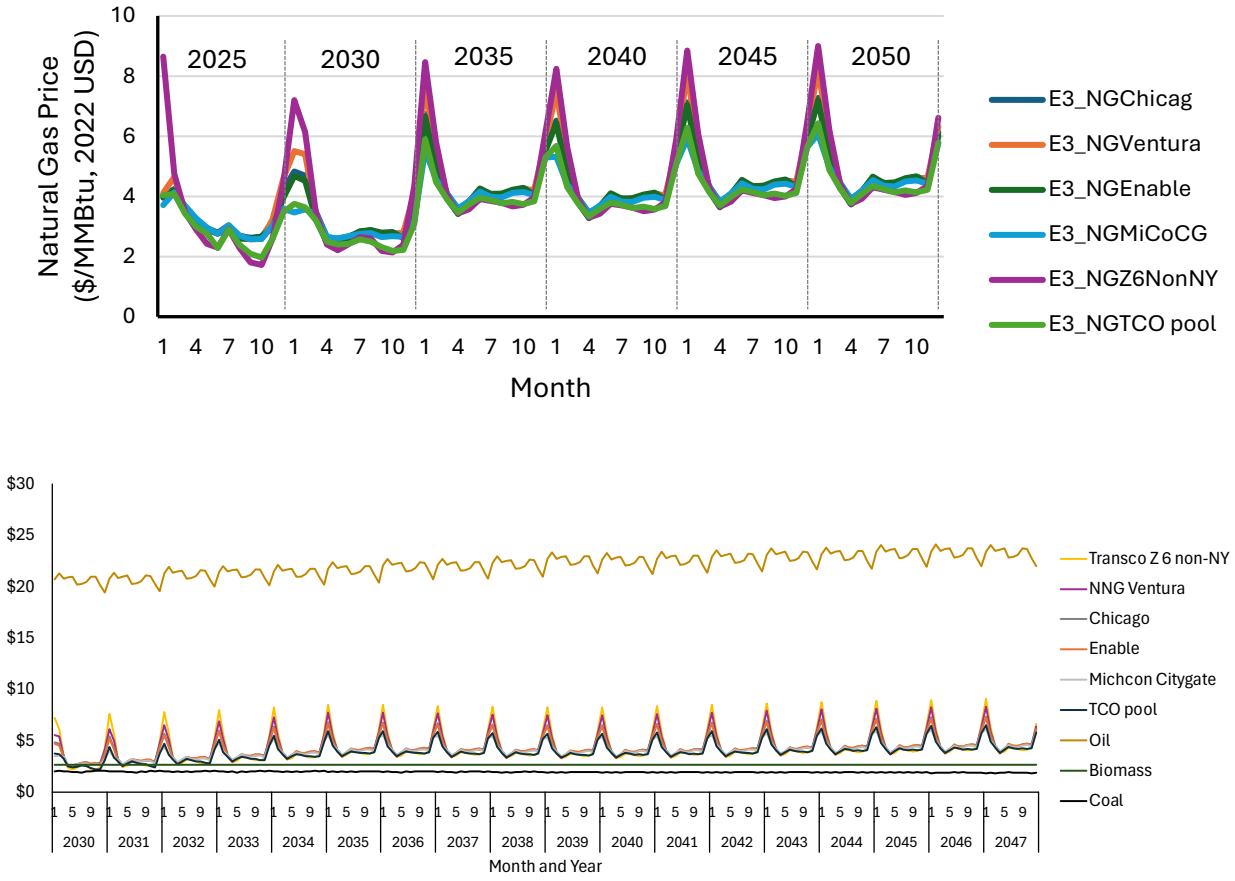
[60] PJM, "2026/2027 through 2028/2029 RPM Base Residual Auction Planning Parameters," (May 9, 2025), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-planning-period-parameters-for-base-residual-auction-pdf.pdf.

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

Figure 3-30: Monthly Fuel Prices Used in Modeling, 2022 $/MMBtu



The assignment of regional natural gas price forecasts to specific generators in PLEXOS is summarized in the table below. All other fuel prices, including oil, coal, and uranium for nuclear resources, are assumed to be uniform across regions in this analysis.

Table 3-9: Regional Natural Gas Price Hubs to PLEXOS Regions

Region	Natural Gas Hub
ComEd	Chicago
PJM East	Transco Z 6 non-NY
PJM West	TCO pool
MISO North (LRZs 1 -3)	NNG Ventura
MISO LRZ 4	Chicago
MISO LRZ 5	Enable
MISO LRZ 6	Michcon Citygate

MISO LRZ 7	Michcon Citygate

3.9 Comparison to the 2025 Resource Adequacy Study

The Mitigation Plan builds on the analytical foundation established in the 2025 RA Study but updates several key assumptions to reflect newer information, and a broader planning horizon. The table below highlights the significant differences between the two studies and is not intended to provide a comprehensive comparison of every modeling input or assumption. For additional detail, readers should refer to the published assumptions and methodology for the 2025 RA Study and to the IRP appendices, which document the assumptions used in the current analysis in greater depth.

Table 3-10: Summary of Assumption Updates between 2025 RA Study and Mitigation Plan

Study Input Area	Description of Change	Where in the report to find additional details
Load Forecasts	The 2025 RA Study relied primarily on published RTO and utility load forecasts to establish the planning outlook. The IRP developed its own Illinois load forecasts using utility and RTO data, with separate projections for data center growth and electrification so that uncertainty in future demand can be evaluated explicitly rather than represented through a single forecast.	Section 3.4 of this Chapter
Load and Resource Balance Inputs	Load forecasts as inputs to the load and resource balance reflect the changes in Load Forecasts between the two studies. The Load and Resource Balance chapter documents further changes in assumptions.	Chapter 4 – Load and Resource Balance

Changes in Representation of Candidate Resources	The 2025 RA Study aligned the planned addition of renewable resources to published IPA procurement plans, including technology specific breakdowns of procurements. The IRP aligns to the RPS targets of statute but does not impose the same technology specific breakdowns of procurements. Instead, it allows the model to economically optimize between solar and wind to see which combination of renewable procurements meets the RPS target at the lowest cost to Illinois.	Refer to Appendix F for IRP inputs and Refer to 2025 Resource Adequacy Study Data files, found at: https://ipa.illinois.gov/electricity-procurement/resource-adequacy/2025-resource-adequacy-study-data.html
Update to Candidate Resources	2025 RA Study included new in-state H_2-ready gas CTs/CCGTs, conventional renewables, 4-hour storage, nuclear, and firm imports. The IRP removes H_2-ready gas CTs/CCGTs from the Reference Case and expands the long-term resource menu to include long-duration storage, nuclear uprates, LWRs, and SMRs, with additional resources such as gas and gas with CCS tested in sensitivities.	Refer to Appendix F for IRP inputs and Refer to 2025 Resource Adequacy Study Data files, found at: https://ipa.illinois.gov/electricity-procurement/resource-adequacy/2025-resource-adequacy-study-data.html
Updates to interregional transmission	2025 RA Study did not consider interregional transmission projects. The IRP introduces two scenarios specifically designed to test the benefits of interregional transmission, including SOO Green Transmission and Grain Belt Express.	

4 Updated Resource Adequacy Balance Projections

The 2025 Resource Adequacy Study evaluated near-term resource adequacy conditions by projecting annual load-resource balances for PJM, MISO, and the principal Illinois zones within each regional transmission organization. That analysis compared projected resource adequacy requirements with the accredited capacity expected to be available after accounting for the existing resource fleet, anticipated resource retirements, and new resources expected to enter service. Because Illinois participates in the broader PJM and MISO systems, the analysis considered both RTO-wide conditions and the resource adequacy position of the ComEd Zone and MISO Local Resource Zone 4 ("LRZ 4").

This chapter updates the resource adequacy balance analysis presented in the RA Study using the latest available information regarding electricity demand, existing and planned resources, anticipated retirements, and interconnection-queue projects. The updated analysis focuses on the period from 2026 through 2030, consistent with the near-term scope of the Mitigation Plan, and is intended to determine how the projected load-resource balance has changed since publication of the RA Study. In particular, the analysis evaluates whether the previously identified risk of a resource adequacy shortfall remains reasonably likely under current projections and how the continued operation or retirement of generating units subject to CEJA's emissions reduction requirements affects that outlook.

Like the corresponding analysis in the RA Study, the updated resource adequacy balance provides a forward-looking accounting of expected capacity supply relative to projected resource adequacy requirements. It is not intended to optimize the future resource portfolio or independently quantify the probability of loss-of-load events. Rather, it identifies the timing and potential magnitude of projected capacity surpluses or shortfalls based on resources that are currently operating or expected to enter or exit the system. The reliability implications of alternative mitigation strategies are evaluated through RECAP modeling in Chapter 6, while the resources needed to maintain reliability are evaluated through PLEXOS capacity expansion modeling in Chapter 7.

4.1 Purpose, Scope, and Approach

Consistent with the approach used in the RA Study, the updated resource adequacy balance compares the quantity of accredited capacity projected to be available in each study year with the applicable resource adequacy requirement for the corresponding region. The analysis is performed for PJM and MISO at the RTO-wide level and for the Illinois zones within

each market, the ComEd Zone and LRZ 4. Evaluating both geographic levels recognizes that Illinois' resource adequacy outlook depends upon the resources located within the State as well as the availability and deliverability of capacity from the broader regional systems in which Illinois participates. Similarly, even when Illinois' resource adequacy outlook is sufficient, if the regions in which it is embedded require additional resources to meet the reliability requirement, then Illinois' resource adequacy position is similarly impacted.

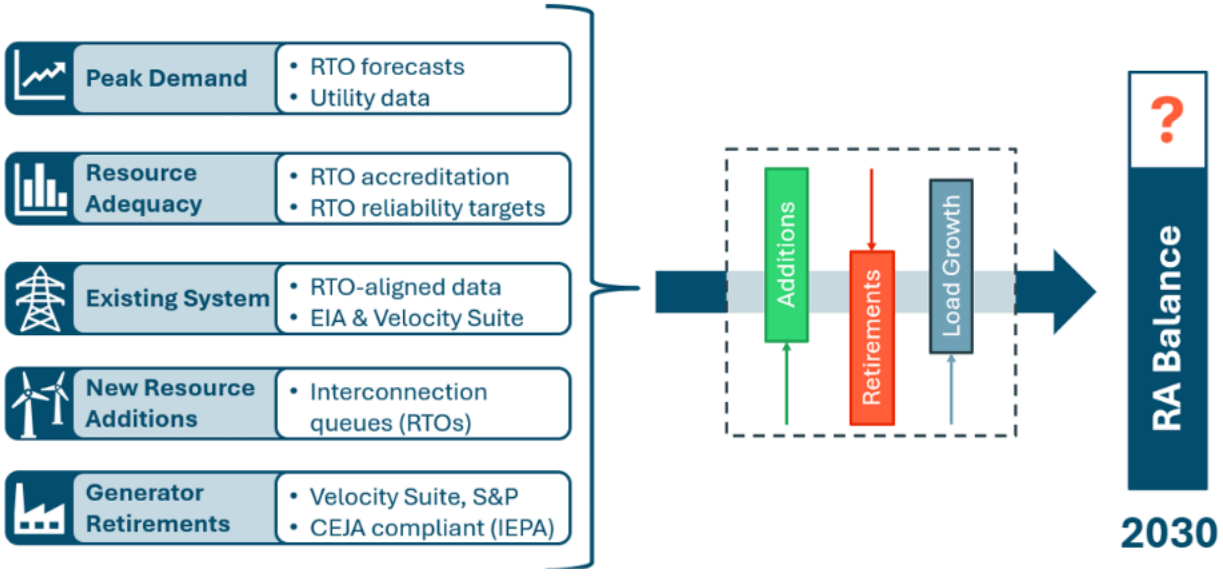
For each region and study year, the resource adequacy balance framework is illustrated in Figure 4-1 below and effectively can be simplified as the following calculation:

Equation 1: Resource Adequacy Balance Calculation

$$\textit{Resource Adequacy Balance} = \textit{Projected Accredited Capacity} - \textit{Resource Adequacy Requirement}$$

A positive balance indicates that projected accredited capacity exceeds the applicable resource adequacy requirement, while a negative balance indicates a projected incremental resource need. The magnitude of the balance provides a measure of the amount of additional accredited capacity available above the requirement or, conversely, the amount that would need to be added, retained, imported, or otherwise supplied to satisfy the applicable planning standard.

Figure 4-1: Load and Resource Balance Framework



Projected accredited capacity is developed from the existing resource fleet, adjusted to reflect resources expected to retire and new resources reasonably expected to achieve commercial operation during the study period. Each resource's contribution to resource adequacy is measured using ELCC for each resource type based on the results of E3's LOLP modeling as described in this chapter. The resulting accredited capacity is compared with

the forecasted resource adequacy requirement for each RTO aligned with the load projections and reserve margin requirements calculated by E3.

The treatment of planned resource additions is particularly important when interpreting the near-term resource adequacy balance.[62] The IRP separately evaluates the contribution of projects that have reached more advanced development milestones as described in Chapter 3 on Baseline Resources, recognizing that the timing and completion of projects in the interconnection queue remain uncertain. These approaches provide complementary perspectives: one illustrates how planned generation additions can satisfy future reliability requirements, while the other identifies the potential resource needs that could arise if some additions are delayed.

The updated projections are developed in the Reference Case, which reflects a reasonable outlook of additions, retirements, and maintains retirement assumptions for facilities covered by CEJA. The analysis is primarily an accounting assessment based on the resources presently known or reasonably expected to be available. Accordingly, the results are sensitive to uncertainty regarding load realization, project completion, retirement timing, accreditation methodologies, and changes to RTO planning standards. These results provide an updated near-term indicator of resource adequacy conditions but are interpreted in conjunction with the loss-of-load probability reliability and capacity expansion analyses presented later in the IRP.

4.2 Updates Since the 2025 Resource Adequacy Study

The updated analysis reflects information available as of August 2026, including updated load forecasts, recently completed capacity auctions, revised interconnection-queue information, announced resource additions or retirements, and updated accreditation assumptions. The analysis applies updated assumptions to the same general framework used in the RA Study. However, key updates are included in the table below and detailed further in the remainder of this chapter:

[62] MISO's resource adequacy outlook considers planned additions reported by market participants, including projects advancing through accelerated interconnection processes; as a result, the IRP's treatment of planned resource additions is more conservative by design as the starting point for the remainder of the planning exercise. The differences between the two outlooks reflects a difference in the purpose of the analysis; it also reaffirms the importance of, as MISO states, "maintain[ing] the increased pace of capacity additions; timely generation builds, Queue improvements and the Expedited Resource Adequacy Study (ERAS) [that] will help meet this need." See MISO, 2026 OMS-MISO Survey Results, June 4, 2026 - https://cdn.misoenergy.org/20260604%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation761711.pdf

Table 4-1: Summary of Changes in Assumptions for Resource Balance Analysis

Input Assumption	RA Study Treatment	IRP Update	Expected Impact on RA Balance
Study Horizon	2026 – 2035	2026 – 2030	Focus on near-term
Demand Forecasts	RTO projections	Load forecasts were developed from utility and RTO forecast and benchmarked against additional data sources to develop Reference Case Forecast. See Load Forecast for additional information.	Relative to the 2025 RA Study, 2026 IRP & Mitigation Plan peak loads are lower in both Ameren and ComEd pre-2030
Existing Fleet Retirements	S&P Global, Velocity Suite Market Data	S&P Global, Velocity Suite Market Data	Incorporates updated resource retirements based on recent public announcements
Planned Additions	RTO Queue and S&P market data + ERAS & RRI expectations	RTO Queue and S&P market data + ERAS & RRI expectations	Less planned additions from the queue are assumed to materialize by 2030 compared to the RA Study
Capacity Accreditation	RTO projections	E3 2026 IRP ELCCs developed in-house with RECAP	Results in shifts in resource accreditation that vary by resource type. Near-term ELCC values are not significantly different than RTO values.
RA Requirement	RTO projections	E3 2026 IRP reserve margins developed in-house with RECAP.	Changes in the reserve margin percentage and peak demand impact the overall requirement
CEJA-limited facilities	2025 vintage of projections	2026 vintage of projections	Additional capacity in the ComEd region is available due to changes in plant ownership and PJM

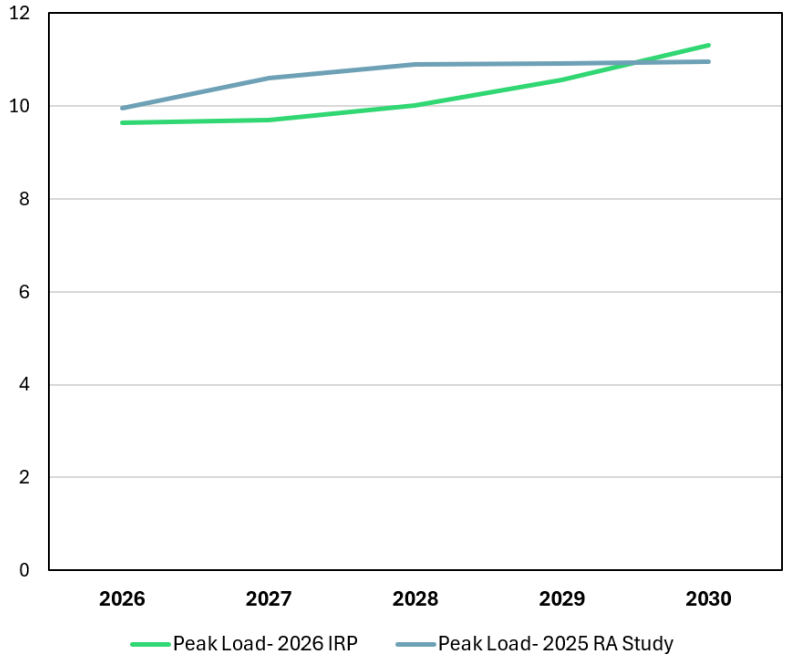
			requested extensions of CEJA-limited units to 2031

Load Forecasts

Projected peak demand is the core demand-side input to the resource adequacy balance. For each region, forecast peak demand is combined with the applicable resource adequacy standard described in this chapter to determine the quantity of accredited capacity required to maintain resource adequacy. Consistent with the approach used in the RA Study, the updated analysis develops separate peak demand forecasts for each region evaluated. This structure allows the analysis to evaluate both RTO-wide conditions and the portions of each regional system that serve the majority of Illinois load.

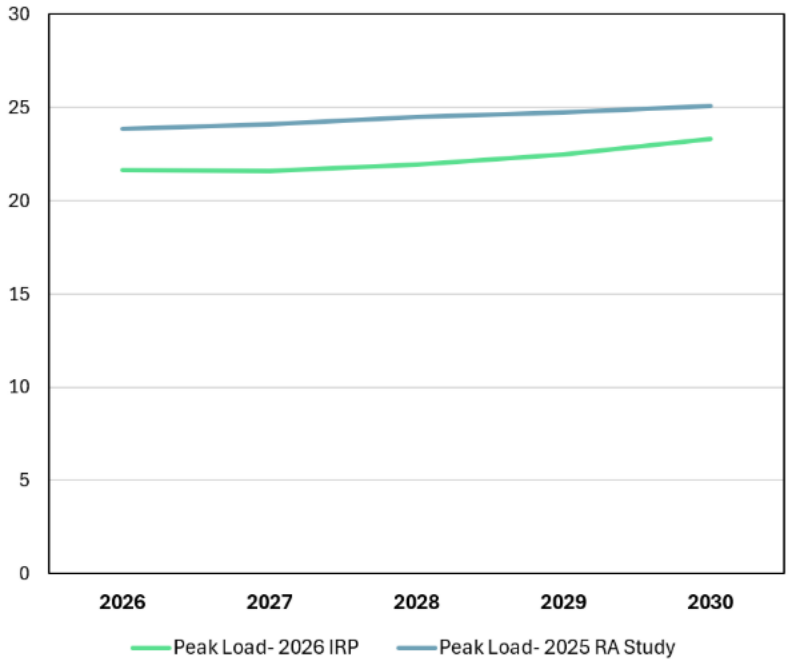
In LRZ 4, the peak demand projection in the 2026 IRP is lower than the 2025 RA Study projection from 2026 – 2029, but higher in 2030, as visualized in Figure 4-2.

Figure 4-2: LRZ 4 Peak Demand (GW)



In the PJM-ComEd zone, the peak demand projection in the 2026 IRP is lower throughout the study horizon than the 2025 RA Study projection, as seen in Figure 4-3.

Figure 4-3: PJM-ComEd Zone Peak Demand (GW)



Installed Capacity

The representation of existing and expected resource installed capacity makes up the supply-side input assumption to the updated resource adequacy balance. Consistent with the RA Study, the analysis begins with the current operating resource fleet, removes resources expected to retire, and adds new resources reasonably expected to achieve commercial operation during the study period. The resource fleet is developed separately for each study region and is aggregated by technology type and planning region. The supply-side input assumptions used unit-level fleet data supplemented by RTO queue information and project development screening rather than an assumption that the entire interconnection queue would enter service.

Capacity Accreditation and Reliability Requirement

Installed capacity alone does not fully reflect a resource's contribution to resource adequacy, since resources differ in their availability and performance during periods when the system is at greatest risk of loss of load. Capacity accreditation accounts for these differences by reflecting the portion of each resource's installed capacity that can be counted toward the resource adequacy requirement.

The resource adequacy requirement reflects the total accredited capacity needed to reliably serve forecast demand. These requirements account for projected peak demand and the additional reserve margin needed to meet the reliability standard.

Reliability requirements for the MISO RTO and LRZ 4 regions were calculated by interpolating between the 2026 requirements from MISO's PY 2026–2027 Loss of Load Expectation (LOLE) Study and the 2030 requirements calculated by applying E3's planning reserve margins to the 2030 load forecasts developed by E3, which was informed by the MISO 2026 Long-Term Load Forecast (LTLF) Current Trajectory. This interpolation provides a gradual transition from MISO's near-term reliability requirements to the longer-term requirements in E3's assumptions, thus bridging the underlying load forecasts.

Reliability requirements for PJM RTO and PJM ComEd incorporate the planning constructs, capacity accreditation values, and resource adequacy requirements consistent with E3's RECAP analysis as described in Chapter 6. No interpolation was applied.

For details on the previous capacity accreditation and reliability requirement approach, refer to the 2025 RA Study.

Zonal Resource Adequacy and Import Capability

The ComEd Zone and LRZ 4 participate in broader regional systems and may rely on capacity located outside the zone where that capacity is deliverable under the applicable transmission limits. The updated zonal balances therefore reflect PJM CETL and MISO ZIA, as applicable.

These limits measure the quantity of capacity that can be reliably transferred into a zone; they do not establish that sufficient surplus capacity will actually be available elsewhere in the RTO. A zone may therefore appear to satisfy its requirement after accounting for its transfer capability while remaining exposed to a broader RTO-wide resource adequacy position. For this reason, the RTO-wide balances are evaluated before the Illinois zonal results. This distinction was central to the RA Study's treatment of the ComEd Zone and LRZ 4.

4.3 RTO-Wide Resource Adequacy Balance Results

Before evaluating Illinois-specific resource adequacy conditions, this section presents the projected resource adequacy balances for PJM and MISO. Illinois participates in the regional systems operated by these RTOs and therefore depends on the adequacy of the broader regional resource fleet as well as the resources located within Illinois. A projected RTO-wide resource need may expose Illinois customers to tighter capacity market conditions and

increased reliability risk even where an Illinois zone appears to possess sufficient in-zone resources or transmission capability to import capacity.

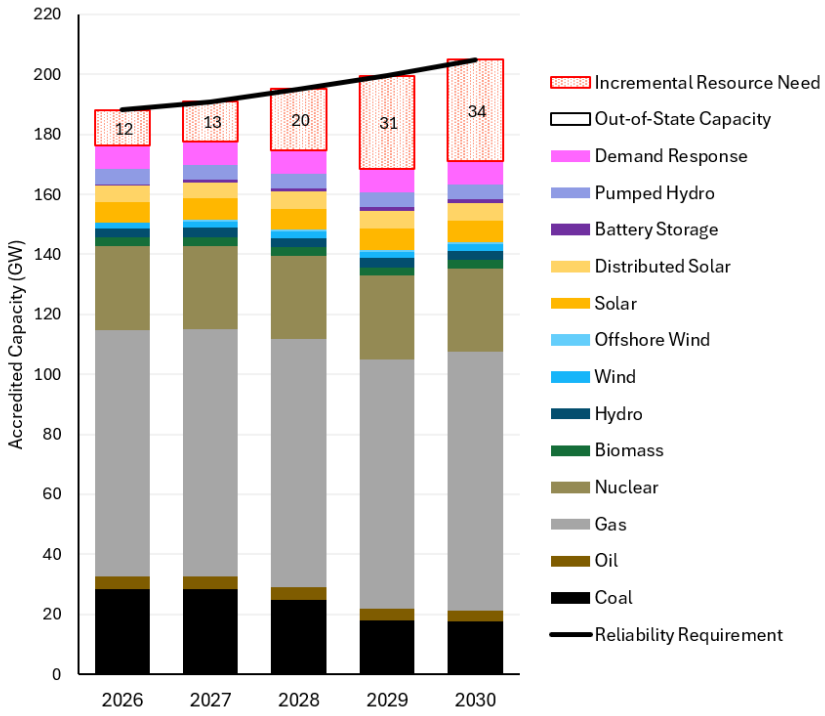
The updated results focus on the Reference Case outlook, which reflects the latest available core assumptions regarding load growth, the existing resource fleet, planned resource additions, resource development timelines, announced retirements, capacity accreditation, and resource adequacy requirements.

PJM RA Balance

Figure 4-4 presents the annual PJM resource adequacy requirement and projected accredited supply through 2030 under the Reference Case. The updated balance shows that PJM is projected to have an incremental resource need beginning in 2026. The projected balance changes from 12 GW of incremental need in 2026 to 34 GW in 2030. The principal drivers behind this change are significant load growth driven by data center load[63] coupled with insufficient resource additions to meet the requirement.

[63] PJM's Q1 Quarterly State of the Market report states that "Data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices". Available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q1-som-pjm-sec1.pdf

Figure 4-4: PJM Resource Adequacy Balance



PJM has made progress in reforming its generator interconnection process, including transitioning to a first-ready, first-served approach and advancing studies for a substantial number of projects in the interconnection queue.[64] These reforms have improved the pace of interconnection studies, although significant challenges remain in bringing new resources online quickly enough to keep pace with load growth and resource retirements. Projects that have completed interconnection studies may still face delays related to permitting, equipment procurement, financing, and construction. PJM, states, and FERC are continuing to evaluate additional reforms intended to accelerate resource development and address the region's growing resource adequacy needs. The success of these efforts, and the timely completion of planned resource additions, will be important to maintaining reliability in the region.

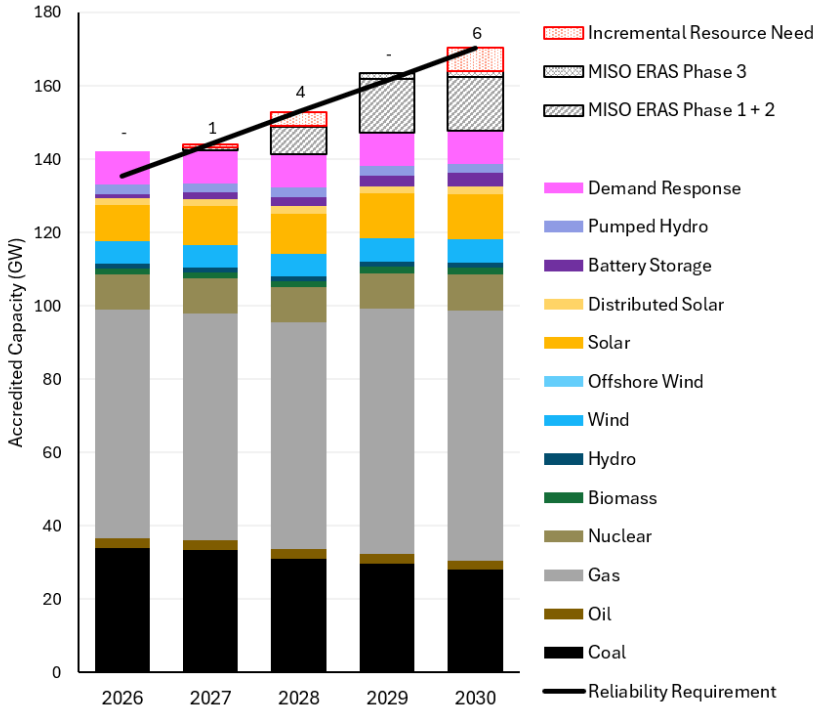
MISO RA Balance

Under the Reference Case, MISO is projected to have an incremental resource need beginning in 2027 as depicted in Figure 4-5 below. The projected reliability requirement increases from 135 GW in 2026 to 170 GW in 2030. The primary drivers are similar to those

[64] PJM, "New, Faster Generation Interconnection Process," (May 21, 2026), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/interconnection-reform-progress-fact-sheet.pdf.

identified in PJM, including load growth coupled with not enough resource additions at later stages of development to qualify as a planned addition in this analysis.

Figure 4-5: MISO LRZs 1-10 Resource Adequacy Balance[65]



This analysis demonstrates that the MISO system will be tight region-wide and will require substantial volumes of new generation capacity to meet load growth over the next five years. These additions include resources progressing through MISO's Expedited Resource Addition Study (ERAS) process, which represents an accelerated pathway for bringing new generation resources online through streamlined interconnection processes. Based on inputs and methods regarding future load growth and resource accreditation detailed in Appendix L, our analysis finds a minor incremental resource need (6 GW or 3.6% of system needs in 2030) above those already in the ERAS process. MISO's 2026 OMS-MISO Survey projects that the region can maintain sufficient capacity to meet its resource adequacy

[65] The MISO load and resource balance includes projects participating in MISO's ERAS process, aligned with the published Interconnection Requests 718481, retrieved November 6, 2026. ERAS projects were cross-checked against E3's existing planned-resource assumptions to avoid double counting, and their contribution to resource adequacy was calculated using E3's resource accreditation assumptions. For MISO LRZs 8–10, the analysis uses MISO's February 2026 LOLE report as a baseline and adds ERAS projects submitted after February 10, 2026. ERAS projects were grouped into three phases based on MISO-reported GIA status, request status, and study-cycle assignment: Phase 1 includes projects with executed/filed GIAs; Phase 2 includes active projects assigned to a study cycle without executed/filed GIAs; Phase 3 includes pending or waitlisted projects.

requirements over the next five years based on a substantial increase in planned generation additions.[66] Both this analysis and MISO's outlook are consistent in highlighting the general magnitude of resources needed over the next several years, and the important contribution that projects currently in development could make toward maintaining regional resource adequacy as electricity demand grows. The timing of these additions remains an important source of uncertainty; projects remain subject to potential delays associated with permitting, equipment procurement, construction, and other development challenges.

In summary, the ability to maintain sufficient capacity depends on the timely completion of planned and forthcoming resource additions and their alignment with load growth and resource retirements. This reinforces the importance of continued coordination among MISO, states, utilities, and project developers to ensure sufficient capacity enters service when needed.

4.4 Illinois Zonal Resource Adequacy Balance Results

This section evaluates the updated resource adequacy position of the ComEd Zone and LRZ 4 under the same principal outlooks used in the RTO-wide analysis.

The differences moving from RTO-wide results to the zonal results include:

- In-zone accredited capacity;
- The applicable zonal resource adequacy requirement;
- Import capability, represented by the applicable CETL or ZIA; and
- The resulting zonal balance after accounting for transfer capability.

While import capability represents the quantity of capacity that transmission planning criteria allow to be delivered into a zone, it does not establish that sufficient surplus capacity will be available elsewhere in the RTO. Thus, the zonal results are interpreted in conjunction with the RTO-wide balances in the previous sections. This distinction was also central to the RA Study's Illinois zonal analysis.

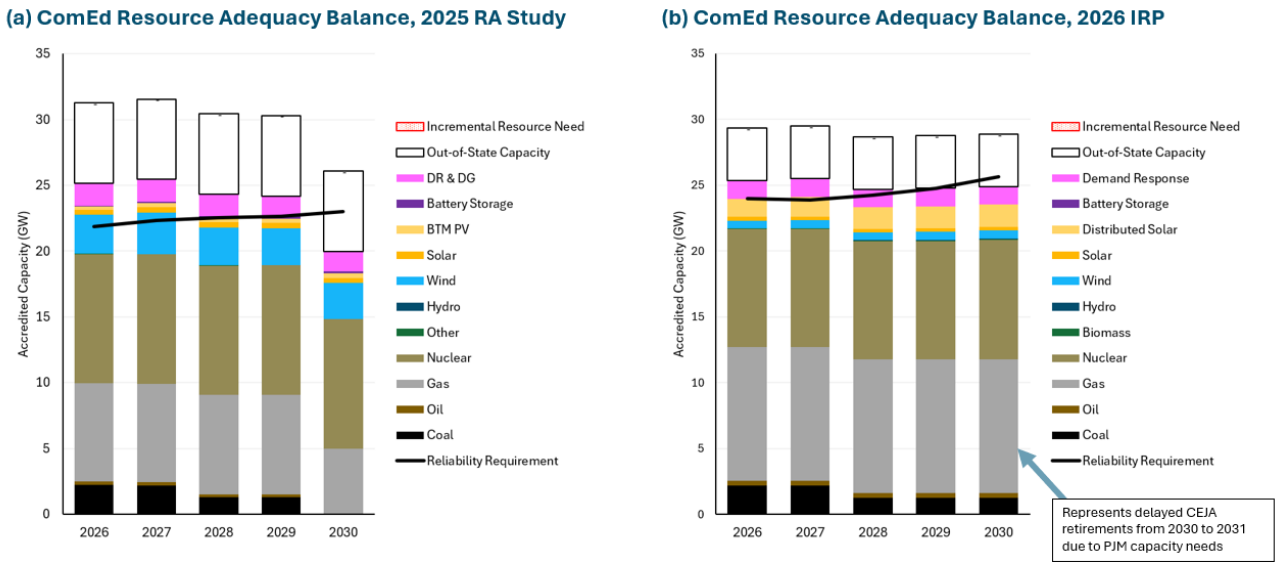
4.4.1 ComEd Zone

Under the Reference Case, in-zone accredited capacity is projected to remain at or above the ComEd Zone's allocated requirement throughout the study period after accounting for available import capability. However, the zone is projected to rely on imports within its CETL in the last year of the study period, 2030. The in-zone balance in 2030, as shown in Figure

[66] MISO, "2026 OMS-MISO Survey Results", (June 4, 2026), https://cdn.misoenergy.org/20260604%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation761711.pdf.

4-6, has improved relative to the 2025 RA Study, primarily due to the deferral of CEJA-limited unit retirements from 2030 to 2031.

Figure 4-6: ComEd Resource Adequacy Balance in (a) 2025 Resource Adequacy Study and (b) IRP



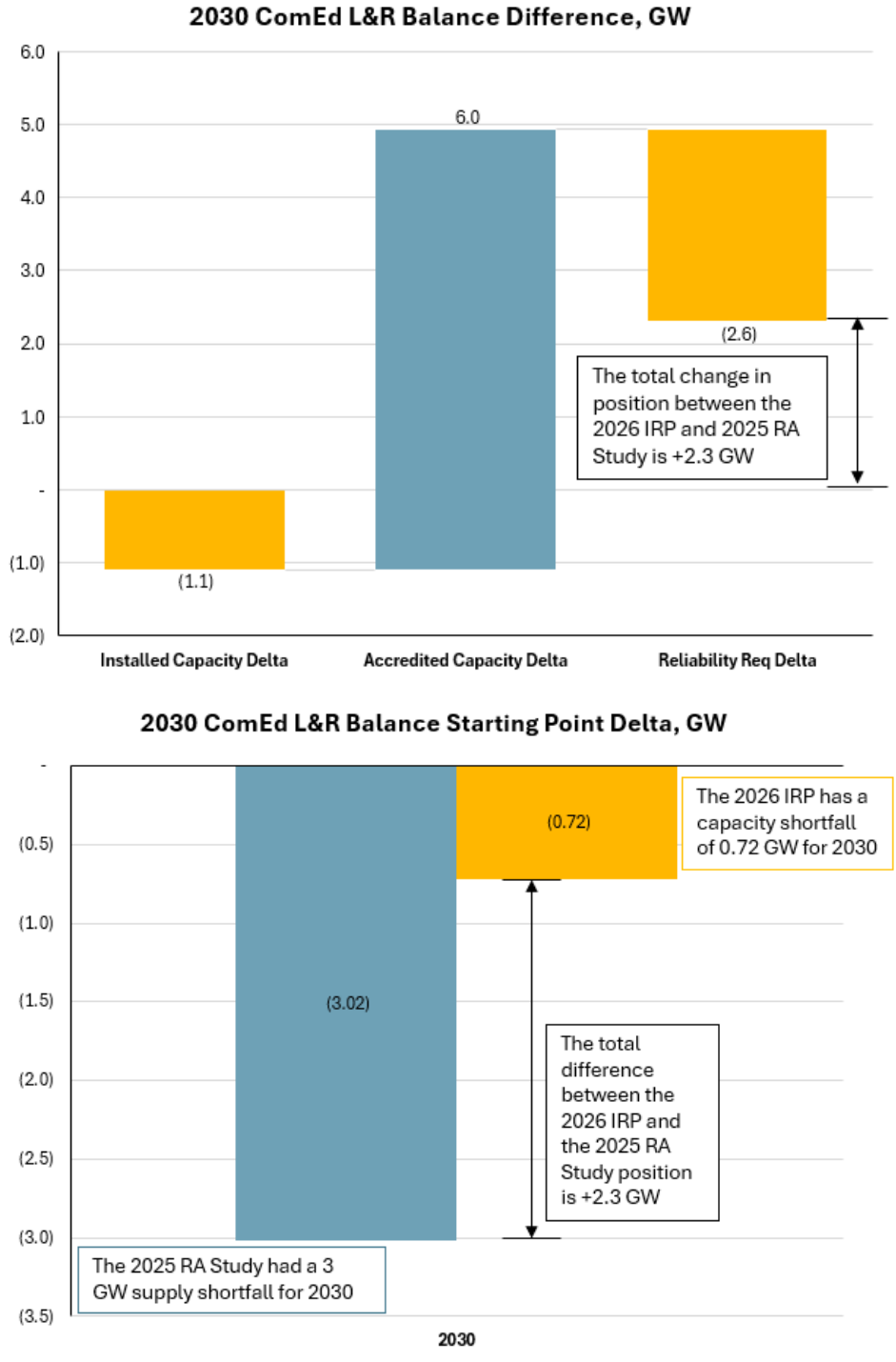
In the PJM-ComEd zone, the projected 2030 capacity need, calculated as the accredited capacity not including out-of-state resources less the reliability requirement, decreases from 3 GW in the 2025 RA Study to 0.7 GW in the 2026 IRP. Figure 4-7 illustrates the factors contributing to this 2.3 GW improvement. The net decrease in installed capacity is primarily driven by planned resources in the interconnection queue that are no longer expected to come online, partially offset by the continued operation of certain existing fossil fuel units. PJM has used CEJA's reliability provision to allow these units to operate through the 2030/2031 delivery year.[67]

In turn, the Reference Case defers the first tranche of CEJA-mandated retirements from 2030 to 2031, retaining more existing thermal capacity in 2030 than the 2025 RA Study. Higher overall capacity accreditation more than offsets the effects of lower total installed

[67] Under Section 9.15(l) of the Illinois Environmental Protection Act (415 ILCS 5/9.15(l)), a unit that would otherwise have to stop operating can keep running temporarily if the regional transmission organization finds it is needed for reliability. PJM's requests let the affected units take part in the 2029/2030 and 2030/2031 BRAs. Selected PJM letters: "Notice of Temporary Continued Operation of Midwest Generation resources," PJM Interconnection (July 2026): https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/generation-resources/ceja-reliability-extension-agreements/nrg-energy-inc-midwest-generation.pdf; "Notice of Temporary Continued Operation of Illinois Generating Assets," PJM Interconnection (July 2026): https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/generation-resources/ceja-reliability-extension-agreements/nrg-energy-inc-illinois.pdf.

capacity and a high reliability requirement, resulting in the overall improvement in the resource adequacy position.

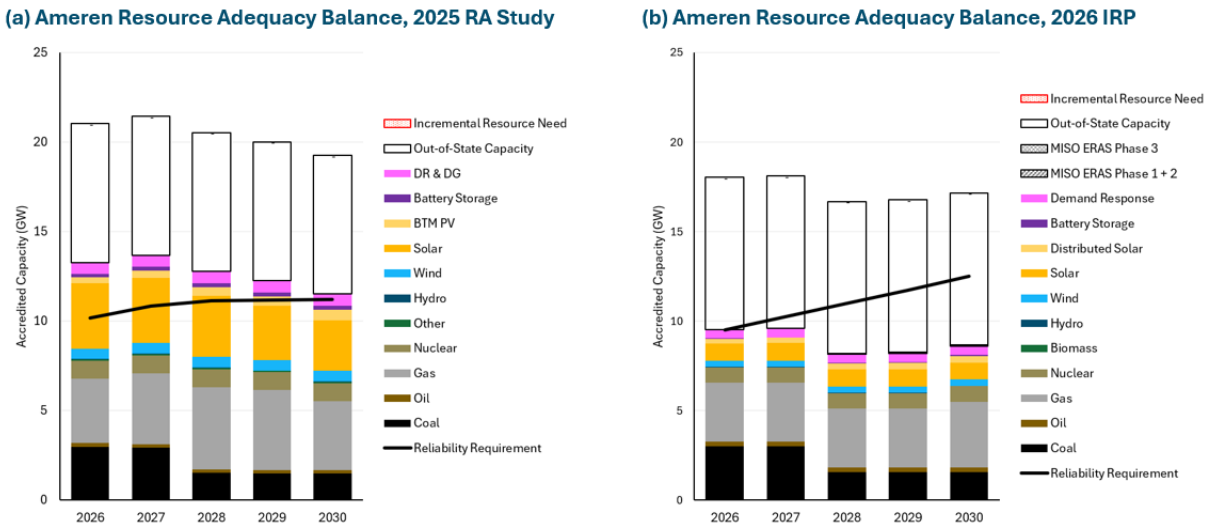
Figure 4-7: PJM-ComEd Zone 2030 Installed Capacity (ICAP), Accredited Capacity (UCAP) & Reliability Requirement Difference (2026 IRP- 2025 RA Study) (GW)



4.4.2 LRZ 4

Under the Reference Case, in-zone accredited capacity is projected to fall below the applicable LRZ 4 requirement beginning in 2027. From 2027 through 2030, LRZ 4 is projected to rely on out-of-state imports within its ZIA. Consistent with MISO's approach, the 2026 IRP includes accredited capacity from ERAS resources. In LRZ 4, these resources contribute less than 100 MW of accredited capacity and are therefore not readily visible at the scale of the figure. The updated in-zone balance is depicted in Figure 4-8 below.

Figure 4-8: LRZ 4 Resource Adequacy Balance in (a) 2025 Resource Adequacy Study and (b) 2026 IRP



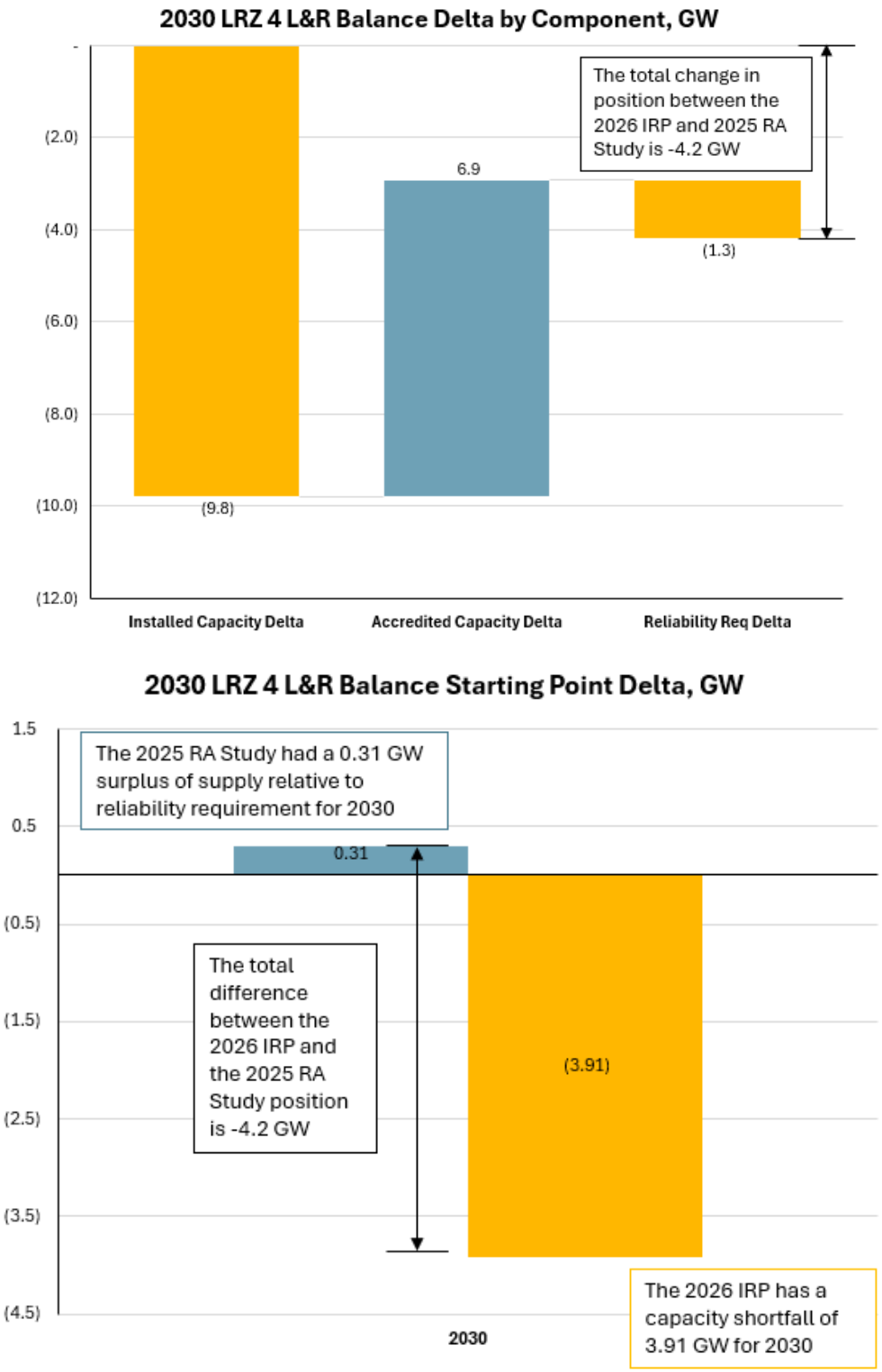
Compared with the RA Study, the updated LRZ 4 balance in 2030 shows a reliance on out-of-state resources to meet its resource adequacy requirement while the RA Study projections showed satisfying the requirement with in-state resources. The principal drivers are higher peak demand and less planned resource additions, as depicted in Figure 4-9.

While the results indicate LRZ 4 could be resource adequate through capacity import reliance, that reliance is predicated upon availability of resources to import which could be undermined by a broader MISO-wide need for incremental capacity resources. Starting in 2027, LRZ 4 would also be exposed to the MISO-wide incremental resource need to meet the reliability requirement.

Excluding out-of-state capacity, compared to the RA Study, the 2026 IRP has a net difference of -4.2 GW in the 2030 resource adequacy position, defined as the accredited capacity not including out-of-state resources less the reliability requirement. The projected 0.31 GW surplus in the 2025 RA Study becomes a 3.91 GW shortfall in the 2026 IRP for the 2030 study year.

Figure 4-9 illustrates the contributions of changes in installed (nameplate or ICAP) capacity, accredited (UCAP) capacity, and the reliability requirement to the overall delta in position. Changes in existing and planned resources, including resources exiting the queue before completion, result in a net reduction in installed capacity of 9.8 GW. The associated reduction in accredited capacity is partially offset by higher ELCC accreditation in the 2026 IRP. Higher projected peak loads in 2030 and reserve margins in the IRP increase the reliability requirement, further widening the incremental resource need.

Figure 4-9: LRZ 4 2030 Installed Capacity, Accredited Capacity, & Reliability Requirement Difference (2026 IRP- 2025 RA Study) (GW)



4.5 Impact of CEJA-limited Unit Retirements

The effect of the potential closure of CEJA-limited units has a limited effect on the resource adequacy in Illinois's two principal zones from 2026 through 2030.[68] Since PJM requested to extend the commercial operation dates of most facilities subject to a 2030 CEJA retirement date in the PJM-ComEd zone, there is no impact of CEJA extensions in this region in the 2026 through 2030 period. PJM has an incremental resource need market-wide throughout the study horizon and while the PJM-ComEd zone has enough inter-zonal resources to cover its resource adequacy requirement, there are still significant risks of insufficient resources to meet the reliability requirement which minimizes the value of being resource adequate within its zone.

In LRZ 4, the CEJA extensions would only improve the resource adequacy balance by 615 MW (accredited capacity). The zone still relies on out-of-state capacity via the ZIA and the broader market is projected to require incremental accredited capacity throughout the time horizon.

4.6 Sources of Uncertainty in Load and Resource Balance

The principal results in the previous sections are based on the Reference Case and the alternative treatment of CEJA-limited units. These cases provide the primary basis for the updated resource adequacy assessment. There are many sources of uncertainty that may impact the projected resource adequacy balance results. These include:

- Load forecast peak demand materialization
- Planned resource additions
- Existing resource retirements

These uncertainties could materially shift both the timing and magnitude of projected resource adequacy needs. Peak demand may materialize above or below the Reference Case forecast, particularly given uncertainty around the timing and scale of new large loads, which would directly increase or decrease the amount of capacity required to maintain reliability. Planned resource additions may also enter service earlier or later than assumed, or may not be completed at all, affecting the amount of new accredited capacity available in each study year. Similarly, existing generators may retire earlier or remain in service longer than assumed due to market conditions, plant economics, regulatory requirements, or

[68] References to CEJA-limited unit retirements in the near-term load and resource analysis primarily concern units scheduled to retire in 2030 under CEJA's requirements. Units expected to retire in 2026 and 2028 are assumed to retire ahead of their applicable CEJA deadlines for other reasons, including plant age and commercial decisions, and therefore these retirements are not considered to be driven by CEJA compliance.

reliability needs. Higher load, delayed resource additions, or accelerated retirements would tighten the projected load and resource balance, while lower load, faster resource development, or delayed retirements would improve it. These factors may also occur simultaneously, which could amplify their effect on the timing and severity of any projected incremental resource need.

4.7 Key Findings from the Updated Resource Adequacy Balance Analysis

Taken together, the updated resource adequacy balance projections provide a current assessment of expected capacity supply relative to applicable regional and zonal requirements through 2030. The results should be used to determine whether the near-term resource adequacy concerns identified in the RA Study have persisted, improved, or gotten worse and to quantify the contribution of CEJA-limited units to the projected balance.

The chapter's findings can be organized around four conclusions.

The updated resource adequacy outlook has grown more constrained since the RA Study, and the Reference Case continues to indicate a risk of a near-term resource adequacy shortfall.

Based on the latest available information on projected load, resource additions, retirements, capacity accreditations, and resource adequacy requirements, the analysis identifies an incremental resource need of approximately 34 GW in PJM and 6 GW in MISO, after accounting for projects advancing through MISO's ERAS process. The ComEd zone is expected to meet its zonal capacity requirement with in-state resources through 2029, while LRZ 4 relies on out of state resources beginning in 2027, even though the entire MISO footprint is projected to have a significant RA need by this time (similar to PJM). The principal changes in this near-term outlook versus the previous RA Study are attributable to changes in projected resource additions and higher demand levels. The lower projection of resource additions reflects the latest queue analysis, while the higher demand levels are driven by projected data center load growth.

CEJA-limited unit retirements will have the greatest impacts on Illinois after 2030.

Relative to the Reference Case, continued operation of the affected units contributes approximately 615 MW of accredited capacity in MISO and does not change the outlook in PJM, given PJM's intervention to keep CEJA-limited units online through 2030. Within Illinois, this additional capacity slightly reduces the projected shortfall and reliance on regional imports in MISO LRZ 4. The results identify the extent to which the treatment of CEJA-limited

units changes the accounting-based resource adequacy outlook, but do not by themselves establish the reliability performance or economic consequences of either strategy.

Illinois' resource adequacy outlook remains driven by broader PJM and MISO conditions through 2030.

The ComEd zone and LRZ 4 may possess sufficient in-zone resources and import transfer capability to satisfy zonal capacity market requirements in each RTO, but both zones are expected to depend on capacity in the larger RTO markets to meet these needs by 2030. PJM and MISO are both projected to have significant resource adequacy needs in the same time period, meaning such imported capacity may not be physically or commercially available to Illinois. Furthermore, even if Illinois were to build additional in-zone resources, a resource adequacy shortfall in either RTO footprint could still present a reliability risk to Illinois customers due to the integrated electricity systems of each region.

The conclusion is subject to uncertainty regarding load realization and timely resource development.

The projected balance depends on whether anticipated demand materializes, planned resources enter service when expected, existing resources remain available, and accreditation and planning requirements evolve as assumed.

The resource adequacy balance is a forward-looking accounting assessment and does not independently quantify the probability, frequency, duration, or depth of potential loss-of-load events. It also does not determine the optimal portfolio of resources that could address a projected gap. Accordingly, these findings should be interpreted together with the Capacity Market Assessment, RECAP Reliability Modeling, and PLEXOS Capacity Expansion Modeling before determining whether a change to CEJA's emissions-reduction requirements is necessary and, if so, the extent and duration of that change.

5 Capacity Market Assessment

The capacity markets administered by PJM and MISO provide an important indicator of prevailing resource adequacy conditions and the economic value placed on accredited capacity within each regional system. Capacity market outcomes reflect the relationship between projected resource adequacy requirements and available accredited supply, as well as resource offer behavior, transmission constraints, administrative demand curves, and other market rules. Capacity prices also provide revenue to existing and new resources in exchange for their commitment to remain available during future delivery periods.

The 2025 Resource Adequacy Study used the latest PJM and MISO capacity auction results to characterize near-term regional resource adequacy conditions and provided an illustrative assessment of future capacity prices and costs under conditions in which the regional systems maintain their target reliability levels. The RA Study concluded that projected tightening in regional load-resource balances could place both markets at or near the applicable price caps absent sufficient new resource development.

This Mitigation Plan updates that analysis and expands it through a fundamentals-based assessment of potential future capacity market outcomes. The capacity markets in PJM and MISO are designed to compensate resources according to their reliability contributions and provide price incentives to resources and loads to develop new capacity when the system needs it. Capacity markets provide recurring, dynamic price signals designed to support long-term system reliability year over year, but there is no guarantee that these markets will achieve equilibrium (resource adequacy supply equals demand) in any given year. Both markets use downward sloping demand curves, meaning any resource additions will push prices lower and any resource retirements will push prices higher. The net effect of any single generator retirement (such as a CEJA-limited unit) will tend to push up market prices, but the specific price impact will depend on (i) where the supply-demand balance would be before the retirement, (ii) the shape of the demand curve itself in that year, and (iii) whether or not the resource is replaced by equivalent accredited capacity.

The load and resource balance projections demonstrate a significant need for new accredited capacity resources in both RTOs by 2030. If the RTO markets are sufficiently below their targets, capacity prices will rise to the market ceiling price and any additional deficits from resource retirements or peak load growth would have no further price impact (but every MW of capacity would become more valuable at the market cap price). The increase in the capacity market price from any given retirement will also be higher if the markets are tighter (supply is near to or below reliability target) and lower if the markets are longer (supply is greater than the reliability target). Lastly, the price impact of any given

retirement will be larger if the benchmark cost of new capacity (net cost of new entry or "net CONE") increases, which will increase the slopes of the demand curves. This analysis evaluates a hypothetical set of market conditions in which 1) each market clears at its reliability requirement in 2030 or 2031, 2) the CEJA-limited units retire according to the schedule of emissions reductions defined in CEJA, and 3) no new resources are added to replace them by the year of their retirement.

The purpose of this chapter is to evaluate a range of potential market impacts of retiring the CEJA-limited units, to estimate the resulting costs to Illinois ratepayers, and to discuss those market signals in relation to the revenue required to support development of new capacity. These impacts are evaluated under defined, hypothetical market conditions that isolate the effect of the retirements. They are illustrative and are not forecasts of future capacity prices or expectations of future auction outcomes. This approach is distinct from the methods the IPA uses to develop procurement benchmarks.

5.1 Current Capacity Market Conditions

The latest forward supply and demand balance in the PJM and MISO capacity markets provides the empirical starting point for the forward assessment. The markets indicate the quantity of accredited capacity presently available to meet regional requirements, the value assigned to that capacity under current market rules, and the extent to which supply-demand conditions have tightened since publication of the RA Study. The latest auction results also provide a basis for calibrating the assumptions used to construct the forward capacity supply and demand curves beyond the latest auctions. Auction outcomes should be interpreted as point-in-time observations applicable to a specific delivery period rather than forecasts, as many factors may impact future prices.

5.1.1 PJM Base Residual Auction Results

PJM's most recent Base Residual Auction procured capacity for the 2028/2029 Delivery Year. The auction cleared approximately 138,318 MW of unforced capacity through the Reliability Pricing Model, while approximately 10,864 MW was committed through Fixed Resource Requirement arrangements.[69] Together, these resources totaled 149,182 MW of accredited capacity, 6,831 MW below PJM's 156,013 MW reliability requirement. This was the second

[69] The Fixed Resource Requirement alternative allows a load-serving entity, typically a vertically integrated utility, to satisfy its full capacity obligation through self-designated resources rather than through the Base Residual Auction. An FRR election covers a minimum of five consecutive delivery years under Schedule 8.1 of the PJM Reliability Assurance Agreement, and FRR capacity is not compensated at the auction clearing price.

consecutive PJM auction in which total committed resources fell materially below the target reliability requirement.

All PJM locations, including the ComEd Locational Deliverability Area, cleared at the FERC-approved price cap of $325/MW-day in the 2028/2029 auction. Although ComEd was modeled as a separate Locational Deliverability Area (LDA), it did not experience a locational price separation because the broader PJM system was itself short of the reliability requirement. ComEd cleared approximately 20,919 MW through the auction at the same price as the rest of PJM.

Table 5-1: PJM 2028/2029 Auction Results

Metric	Result
RPM capacity cleared	138,317.8 MW
FRR capacity committed	10,863.8 MW
Total RPM and FRR capacity	149,181.6 MW
PJM reliability requirement	156,012.9 MW
Shortfall relative to requirement	6,831.3 MW
PJM RTO clearing price	$325/MW-day
ComEd clearing price	$325/MW-day

The 2028/2029 auction was conducted with a temporary price collar applied to PJM's normal Variable Resource Requirement curves. For that auction, the collar established a $325/MW-day price cap and a $175/MW-day price floor. FERC approved extension of the collar for both the 2028/2029 and 2029/2030 auctions.

PJM also published an illustrative simulation of the 2028/2029 auction without the cap and floor. Using the offers submitted for the actual auction, the simulation produced an RTO clearing price of $554.72/MW-day and a ComEd price of $776.69/MW-day.[70]

[70] PJM 2028/2029 Base Residual Auction Report, Page 17. https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2028-2029/2028-2029-bra-results-report.pdf

5.1.2 MISO Planning Resource Auction Results

MISO's most recent Planning Resource Auction (PRA) covers the 2026/2027 Planning Year. MISO conducts seasonal resource adequacy auctions for summer, fall, winter, and spring. MISO also uses a downward-sloping Reliability-Based Demand Curve that assigns incremental value to capacity above and below the initial seasonal planning reserve targets.

The 2026/2027 PRA secured sufficient capacity to satisfy regional, subregional, and zonal resource adequacy requirements in all four seasons. In summer, MISO North (including LRZ 4) cleared at $424.30/MW-day. Fall, winter, and spring cleared at $33.92, $35.97, and $7.61/MW-day, respectively. These prices produce an annualized value for the region of $126.19/MW-day.

Summer remained the tightest season. MISO reported approximately 4.6 GW of summer capacity above the initial planning reserve target, producing a cleared reserve margin of 11.4% compared with the initial 7.9% target. Capacity additions and increased imports more than offset retirements, suspensions, and reduced accreditation, although MISO continues to identify the need for additional resource development as load growth driven by data centers accelerates.

Table 5-2: MISO 2026/2027 Auction Results

Season	MISO North and LRZ 4 Price
Summer 2026	$424.30/MW-day
Fall 2026	$33.92/MW-day
Winter 2026/2027	$35.97/MW-day
Spring 2027	$7.61/MW-day
Annualized North price	$126.19/MW-day

Most MISO capacity does not transact as a price-sensitive sale through the PRA. MISO reported that approximately 92% of customer capacity requirements for 2026/2027 were satisfied through advance arrangements or self-supply. The auction price nevertheless remains relevant as the marginal valuation of capacity, a benchmark for bilateral contracting and utility planning, and the residual cost for load not otherwise covered.

5.2 Capacity Market Assessment Framework

5.2.1 Analytical Scope, Study Horizon, and Cases

The capacity market assessment estimates how the retirement of CEJA-limited units would affect capacity prices in PJM and MISO. It applies each market's published demand curve to a common starting point, in which each market clears at its reliability requirement, and then removes the accredited capacity of the retiring units without adding replacement resources. The resulting change in clearing price, applied to the ComEd and Ameren Illinois capacity obligations, gives the potential cost impact on Illinois customers, all else being equal. This is a hypothetical exercise, not a forecast of future capacity prices. The equilibrium starting point was chosen because it provides a neutral reference for isolating the effect of the retirements, not because it is the expected market outcome, and the market conditions it represents are not expected to materialize. The results therefore show the potential direction and magnitude of cost impacts rather than an expectation of future auction outcomes.

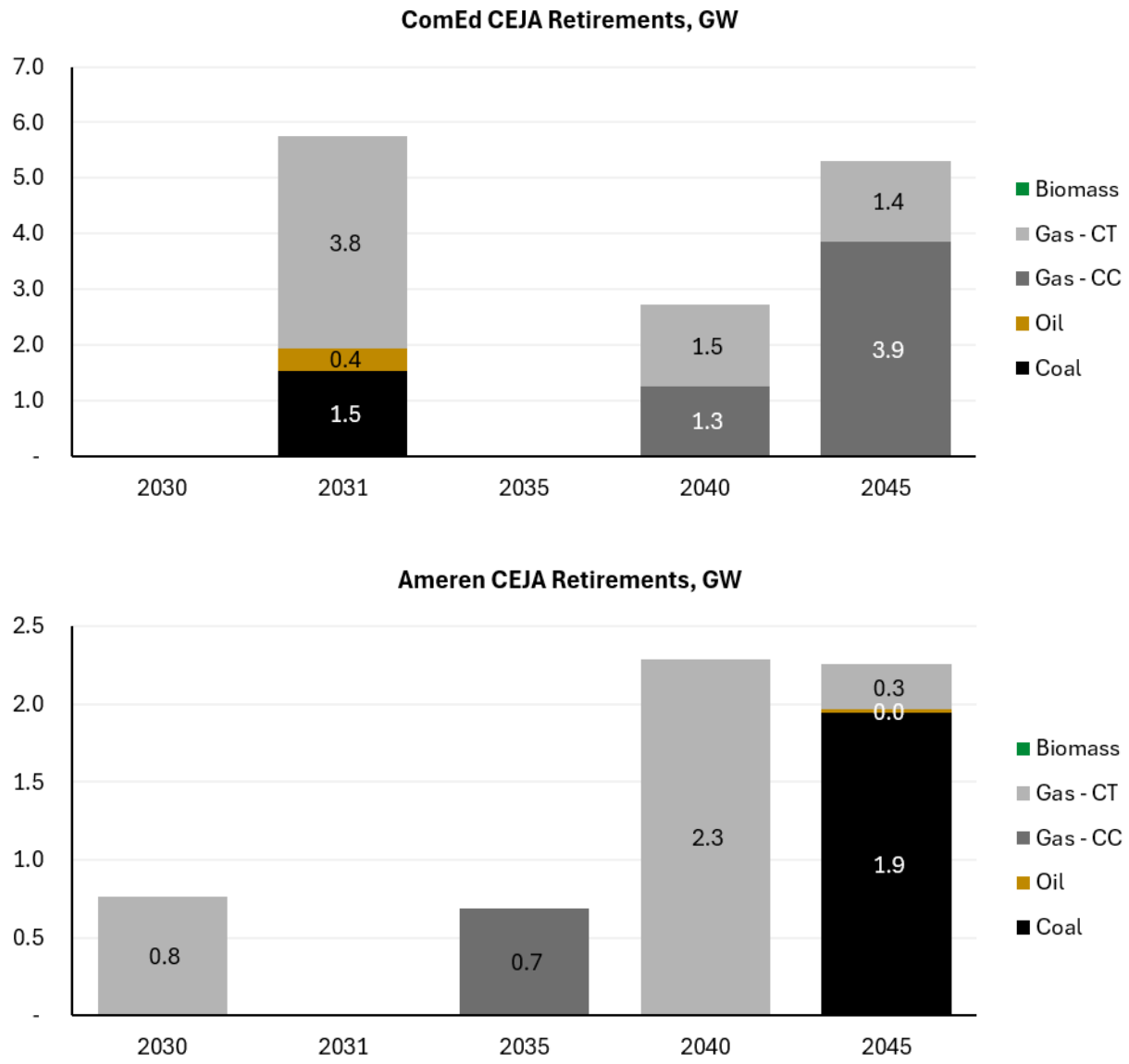
The capacity market assessment and the resulting capacity price impacts focus on the potential near-term market consequences of the retirements required under CEJA, and specifically on the 2030 and 2031 delivery periods. This horizon is consistent with the purpose of the Mitigation Plan, which is directed at near-term measures to address reliability needs that arise before replacement resources can reasonably be developed and placed in service. The compliance tranches that occur later in the CEJA schedule are addressed through the long-term portfolio analysis presented in Chapter 7.

Within the ComEd zone, the retirement tranches assumed in this analysis occur in 2031, 2040, and 2045. The first tranche is assumed to occur in 2031 rather than 2030 because PJM has invoked the reliability provision of CEJA. Section 9.15(l) of the Illinois EPAct permits an electric generating unit that is otherwise required to cease operation to continue operating on a temporary basis where the regional transmission organization determines that continued operation is necessary to maintain power grid supply and reliability.[71] The requested extension allows the affected resources to participate in the 2029/2030 and 2030/2031 BRAs, and PJM indicated that it will assess the need for their continued operation prior to each subsequent delivery year beginning with 2031/2032. Accordingly, the capacity market effect of the first ComEd tranche is first reflected in 2031.

[71] 415 ILCS 5/9.15(l)

Within the Ameren Illinois footprint, which is located in MISO Local Resource Zone (LRZ) 4, the corresponding retirement tranches are assumed to occur in 2030, 2035, 2040, and 2045. A summary of CEJA retirements is shown below.

Figure 5-1: CEJA Retirement Nameplate Capacity



The assessment proceeds through the following steps.

1. Construct the applicable auction demand curves. Capacity demand in each market is represented through the administratively determined auction demand curve, which defines the price that the market assigns to incremental accredited capacity at different supply levels relative to the applicable resource adequacy requirement.

The PJM demand curve is reconstructed for the study year, while the MISO curve is taken directly from the most recent auction. PJM's curve is defined by tariff formulas and can be rebuilt with updated parameters, whereas MISO's is derived from loss-of-load modeling that cannot be reproduced outside MISO's own model. The demand curve for each market represents the entire RTO, assuming the RTO is at equilibrium.

2. Determine the capacity price at the applicable reliability requirement. The analysis establishes a reference price at which the market clears at 100% of the reliability requirement. This condition differs from recent PJM and MISO auction outcomes, in which committed supply has not been at the target level. The purpose of the reference point is not to predict the price that will be observed in 2030 or 2031, but to establish a common equilibrium starting condition and evaluate the impact of the CEJA-limited unit retirements in isolation, all else being equal.[72]
3. Remove the capacity associated with the CEJA-limited units. An equivalent quantity of perfect capacity, corresponding to the accredited capacity of the units retiring in the applicable tranche, is removed from the supply position while all other supply is held constant. RTO accredited capacity is used to convert nameplate capacity to perfect capacity. No replacement resources are added, which isolates the price effect attributable to the retirements alone.
4. Calculate the resulting capacity price. The reduced supply position is evaluated against the demand curve constructed in Step 1 to determine the change in the market price of capacity (paid by consumers) resulting from the loss of CEJA-limited unit capacity if it is not replaced.

5.2.2 Capacity Demand Curve Representation

PJM Variable Resource Requirement Curve

PJM represents capacity demand through the Variable Resource Requirement (VRR) curve, a downward-sloping administrative demand curve that assigns a price to committed capacity relative to the applicable reliability requirement. The curve is defined by three points, with committed unforced capacity (UCAP) on the horizontal axis and price in $/MW-day (UCAP) on the vertical axis. The VRR curve is impacted by several factors, including the reliability requirement, the total annualized cost of new entry (gross CONE) for the marginal reliability resource (modeled as a new gas combustion turbine or CT), and the expected energy and ancillary services revenue (E&AS Offset) such a unit could earn from operations in the wholesale market.

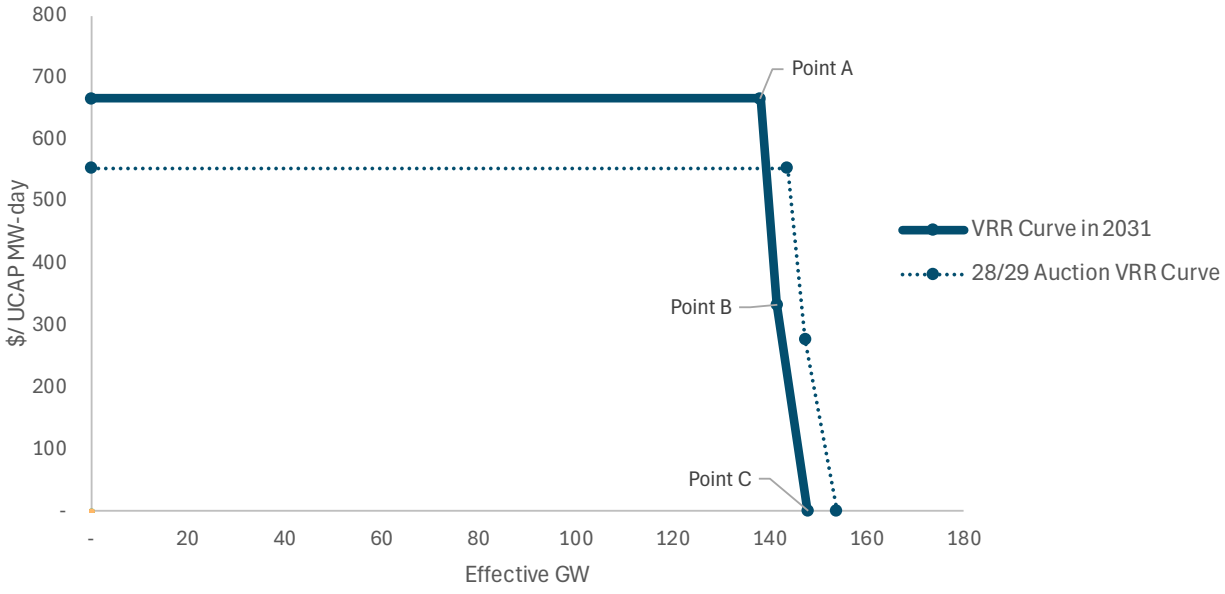
[72] See Chapter 7 for the PLEXOS capacity expansion results identifying the resources required to close the projected gap.

1. Point A: 99% of the reliability requirement, priced at the greater of (1.15 × Gross CONE − 0.75 × E&AS Offset) and (0.2 × Gross CONE)[73]
2. Point B: 101.5% of the reliability requirement, priced at 50% of the Point A price
3. Point C: 106% of the reliability requirement, priced at zero.

The VRR curve in this analysis is reconstructed for 2031 with two changes to the published parameters. First, Gross CONE is escalated from the most recently published value for the 2028-29 auction. PJM does not re-estimate Gross CONE each year. The value is reset through the Quadrennial Review in which PJM and an independent consultant re-examine both the shape of the curve and its cost inputs. Between reviews, PJM applies annual escalation of Gross CONE by considering the labor, material and turbine costs of combustion turbines. This analysis applies a 5% annual escalation rate, consistent with recent observed escalation factors. Second, the reliability requirement is recalculated using the forecasted peak load aligned with the Reference Case load forecast.

Compared to the VRR curve in the 2028/29 auction, the new curve has a higher price cap and, therefore, a steeper slope. Both curves are shown in Figure 5-2.

Figure 5-2: PJM VRR Curves in the 2028/29 Auction and 2030/31 Analysis Year



[73] PJM Interconnection, L.L.C., *Quadrennial Review Proposal*, Market Implementation Committee, September 10, 2025; filed with FERC in Docket No. ER26-455-000.

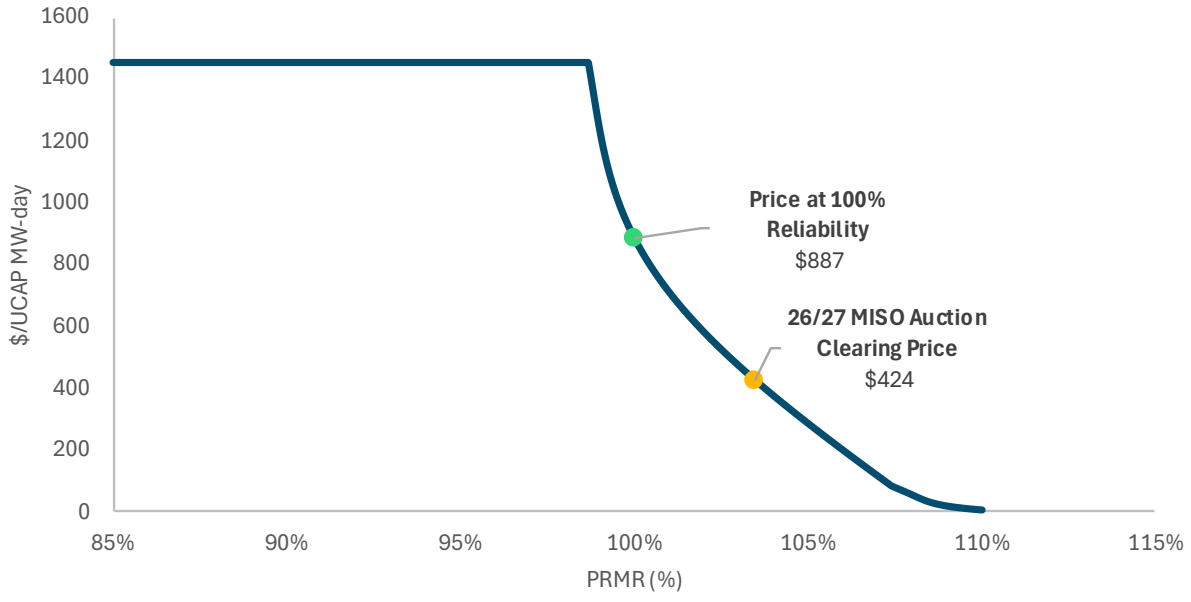
MISO Reliability-Based Demand Curves

MISO represents capacity demand through seasonal Reliability-Based Demand Curves (RBDCs). Each curve begins with loss-of-load modeling, which establishes the relationship between expected unserved energy (EUE) and the quantity of perfect capacity on the system. That relationship, the Marginal Reliability Impact (MRI) curve, is then converted into a demand curve: EUE in MWh per MW-season is translated into price in $/MW-day using a scaling factor derived from the cost of new entry, and the quantity of perfect capacity is expressed as a percentage of the Planning Reserve Margin Requirement (PRMR) representing the system reliability target. The resulting curve is capped at the seasonal CONE value.

A separate curve is developed for each season. This analysis uses the MISO North summer curve, because summer has consistently set the highest seasonal capacity price. Unlike PJM's VRR curve, which is defined by tariff formulas and can be rebuilt for a future year from published parameters, the shape of the RBDC is produced by MISO's loss-of-load modeling for a specific planning year and cannot be reconstructed outside that model. The curve published for the most recent auction, the 2026/2027 Planning Resource Auction, is applied directly to 2030.

As shown in Figure 5-3, the 2026/2027 summer auction cleared at $424.30/MW-day at 103.5% of PRMR. The price corresponding to 100% of PRMR is derived from that point along the published curve. Because the curve reflects the load and resource conditions modeled for the 2026/2027 Planning Year, applying it to 2030 holds the relationship between reliability and price fixed while the underlying system changes.

Figure 5-3: MISO RBDC for Summer 2026/2027 Auction Used for 2030/31 Analysis Year



5.3 Capacity Price Results

5.3.1 PJM Capacity Price Results

Figure 5-4 and Table 5-3 summarize the illustrative PJM capacity price for 2031 with and without the CEJA-limited unit retirement. With the market clearing at 100% of the reliability requirement, the scaled demand curve yields a price of $534/MW-day. If the CEJA-limited units retire in 2031 and no replacement resources are added, the projected price rises to $668/MW-day, an increase of $134/MW-day. Applied to the ComEd zone's capacity obligation in 2031, this increase represents approximately $1.1 billion in additional capacity costs to Illinois ratepayers every year until the accredited capacity of these units is replaced by other resources.

The post-retirement price reaches to Point A, the maximum price on the reconstructed VRR curve. The retirements are therefore sufficient to move the market to the quantity at which the curve reaches its highest value. The projected price increase is consequently bounded: further capacity loss beyond the CEJA-limited units would not raise the price above $668/MW-day, but would deepen the quantity shortfall relative to the reliability requirement.

Figure 5-4: PJM 2030/31 Illustrative Capacity Price with CEJA-limited Unit Retirements

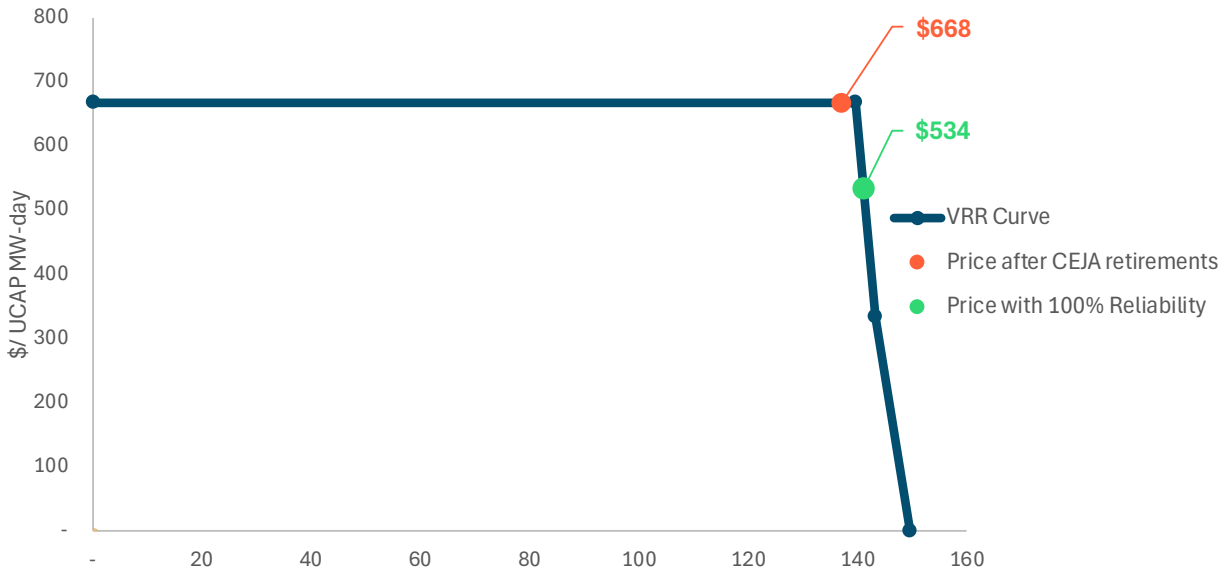


Table 5-3: Illustrative ComEd Capacity Price Impacts of CEJA-limited Unit Retirements in 2031

Variable	Value
Reliability Requirement	138 GW
CEJA-limited Retirements	5.7 GW Nameplate Capacity
CEJA-limited Retirements	3.8 GW Effective Capacity
Capacity Price at 100% reliability	$534/MW-day
Capacity Price with CEJA-limited Retirements	$668/MW-day
Capacity Price Difference	$134/MW-day
IL Zone Obligation	22 GW
Capacity Cost with CEJA-limited Retirements	$1.1 billion/year

These results are based on a few key simplifying assumptions used for estimation purposes. First, the RTO is assumed to clear at its reliability requirement before the retirements occur. While this may not be the case based on current and near-term market conditions, this provides a way to estimate the capacity market cost impacts assuming that the retirement of CEJA-limited units pushes the market up the demand curve. This analysis also assumes that no binding transmission constraints remain in place between the ComEd zone and the balance of the RTO, so the zone clears at the RTO price. Additionally, no administrative price cap is applied to the reconstructed curve.

As mentioned above, the 2028/2029 auction indicates that the RTO is presently short of its reliability requirement and cleared at the administratively established cap. If that condition persists into 2031, the CEJA retirements would not raise the observed clearing price, because the price would already be at the cap. However, removing firm capacity from a system that is already short increases the quantity of new resources required to return the market to its reliability requirement, thereby extending the period over which the market clears at the cap, the highest price possible. This means Illinois ratepayers would bear the

high capacity cost for longer until the system returns to equilibrium. Put another way, the retirement of CEJA-limited units in a tight capacity market will either increase prices in that year or increase the length of time in which prices remain at their maximum level.

The level at which the cap is set is an important consideration. The demand curve in this analysis is escalated from PJM's published Gross CONE, which is conservative relative to observed market conditions for new combustion turbine capacity. Turbine supply has tightened substantially. Large gas turbines now require more than five years from order to delivery, and a turbine ordered today would not enter service until 2031 on average.[74] E3's own cost forecast also estimates a higher value than PJM's current CONE for a new CT.

A higher cost of new entry would raise the demand curve and the resulting capacity price. If the applicable price cap is set below the revenue required to develop new capacity, the RTO would face higher reliability risks due to insufficient supply.

5.3.2 MISO North Capacity Price Impacts

Figure 5-5 and Table 5-4 summarize the illustrative MISO North summer capacity price for 2030 with and without the CEJA-limited unit retirement. MISO settles capacity seasonally, and the prices reported in this section apply to the summer season only. With the market clearing at 100% of the PRMR, the fundamentals-based summer price would be $7/MW-day. If the CEJA-limited units retire in 2030 and no replacement resources are added, the projected summer price rises to $1,035/MW-day, an increase of $148/MW-day. Applied to Ameren Illinois' capacity obligation across the 92-day summer season, this increase represents approximately $160 million in additional annual capacity cost to Illinois ratepayers, equivalent to $37/MW-day on an annualized basis.

[74] Bobby Noble (EPRI), "5-year waits and rising costs: How demand is redefining the gas turbine market," *Utility Dive* (March 23, 2026). EPRI research cited in the same piece shows average gas turbine prices rising from roughly $2,000/kW to $3,000/kW over six months.

Figure 5-5: MISO 2030 Illustrative Capacity Price with CEJA-limited Unit Retirements



Table 5-4: Illustrative MISO LRZ 4 Summer Season Capacity Price Impacts of CEJA-limited Unit Retirements in 2030

Variable	Value
Price basis	Summer Season
Reliability Requirement	109 GW
CEJA-limited Retirements	0.8 GW Nameplate Capacity
CEJA-limited Retirements	0.6 GW Effective Capacity
Capacity Price at 100% reliability	$886/MW-day
Capacity Price with CEJA-limited Retirements	$1,034/MW-day
Capacity Price Difference	$148/MW-day
Annualized Equivalent Price Increase	$37/MW-day
IL Zone Obligation	11.6 GW
Capacity Cost with CEJA-limited Retirements	$0.16 billion/year

If the price is evaluated starting from 103% of PRMR, which was the cleared PRMR in the latest auction, rather than from 100% of PRMR, removing the CEJA-limited units without replacement resources would increase the summer capacity price by approximately $59/MW-day. The difference reflects the shape of the RBDC, which is comparatively flat where supply exceeds the reliability target and steepens as supply approaches and falls below it.

The RBDC is scaled using a conversion factor derived from the cost of new entry, and the curve is capped at the seasonal CONE value. The CONE underlying MISO's published curve is lower than the combustion turbine cost assumed in the PLEXOS analysis presented in Chapter 7. Substituting that cost assumption would raise the scaling factor, more than doubling the seasonal cap and steepening the curve throughout. The price effect of the

CEJA-limited retirements reported above should therefore be read as conservative with respect to the potential capacity price impact of retiring the CEJA-limited units without replacement.

5.4 Key Findings of Capacity Market Impacts Assessment

The capacity market assessment quantifies the potential market price and ratepayer cost impacts of retiring the CEJA-limited units under a common set of demand curve, load, and accreditation assumptions. The results can be used to establish a range of capacity market effects that would be attributable to the retirement of those units.

Current capacity market conditions indicate tightening regional supply-demand balances.

PJM's 2028/2029 Base Residual Auction procured approximately 149,182 MW against a reliability requirement of 156,013 MW, the second consecutive auction in which committed resources fell materially below the target. PJM's illustrative simulation of the same auction without the cap and floor produced an RTO price of $554.72/MW-day and a ComEd price of $776.69/MW-day. MISO secured sufficient capacity in all four seasons of the 2026/2027 Planning Resource Auction, but value remains concentrated in summer, which cleared at $424.30/MW-day for MISO North and Central.

Retirement of the CEJA-limited units could materially increase capacity prices until replacement resources can be developed.

Under the illustrative scenario in which each market clears at its reliability requirement, retiring the CEJA-limited units without replacement resources increases the projected PJM capacity price by $134/MW-day on an annual basis in 2031. At this level, the price reaches the maximum on the PJM demand curve, so $134/MW-day represents the upper bound of the price effect. Any further loss of capacity would deepen the shortfall relative to the reliability requirement without raising the price. In MISO, the retirements increase the projected MISO North summer capacity price by $148/MW-day in 2030, equivalent to approximately $37/MW-day annualized. Applied to the ComEd and Ameren Illinois capacity obligations, these increases represent approximately $1.1 billion and $160 million annual capacity cost to Illinois ratepayers.

If both markets are short, the retirements would extend the period of price-cap conditions rather than raise prices further.

The analysis examines the capacity price impacts under theoretical conditions in which markets return to their reliability requirements in 2030 and 2031. However, the updated

resource adequacy balance presented in Chapter 4 projects shortfalls in both markets across that period. Where a market is already short and clearing at its administrative price cap, further retirements would not raise the observed clearing price, because the price is already at its maximum. The effect would appear instead in the quantity of new resources required to return the market to its reliability requirement. Therefore, the length of time over which the market price stays at the cap would be prolonged. Illinois ratepayers would bear the capped price for longer rather than a higher price, and the system would carry elevated reliability risk throughout that period, as examined in Chapter 6.

The prices in each region's demand curves may be lower than the cost of new entry for replacement capacity.

The demand curves used here are anchored to the CONE values published by PJM and MISO. Both are lower than the combustion turbine costs assumed in the PLEXOS analysis presented in Chapter 7, which reflects recent industry data on rising gas turbine costs and longer delivery lead times in recent years. A higher cost of new entry would raise and steepen both demand curves and increase the projected price effect of the retirements. Other factors not represented here, including administrative price caps, the composition of the supply stack, and participant offer behavior, will also determine realized prices.

These results do not illustrate the system reliability impact of CEJA retirements, which is addressed through the RECAP modeling presented in Chapter 6, and they do not determine whether replacement resources can be developed at the scale and within the period required, which is addressed through the PLEXOS portfolio analysis presented in Chapter 7. The comparison between projected capacity market revenue and the revenue required to support new entry is qualitative and does not establish whether market-driven development is financeable. These findings should therefore be interpreted together with other chapters of the report.

6 Reliability Risk Assessment

The Updated Resource Adequacy Balance Analysis presented in Chapter 4 compares projected accredited capacity with applicable regional and zonal resource adequacy requirements. That accounting analysis provides an important indicator of whether sufficient capacity is expected to be available, but it does not fully characterize the probability or severity of a capacity shortfall under the range of conditions that the electric system may experience. Actual resource adequacy depends not only on the total quantity of capacity, but also on the timing and correlation of extreme weather, electricity demand, renewable generation, thermal generator outages, and transmission availability.

This chapter evaluates the reliability implications of the principal Mitigation Plan strategies using E3's Renewable Energy Capacity Planning Model (RECAP). RECAP is a probabilistic resource adequacy model that simulates electric system operations across hundreds of plausible combinations of weather, load, renewable generation, and resource outages. Through statistically informed simulations of weather and load conditions, RECAP produces the expected frequency, duration, and magnitude of outages across sample years. The framework described here is the same as the one leveraged by the 2025 RA Study to calculate reliability requirements, effective load-carrying capability, and the reliability contribution of Illinois' generating resources.

This analysis addresses a central question: under what system conditions, and for how many hours, are CEJA-limited units needed to avoid or reduce unserved energy? To do so, the analysis evaluates how projected reliability risk changes when generating units subject to CEJA's emissions-reduction requirements are retired on their current schedules. It starts from the CEJA Extension Case portfolio developed in PLEXOS, in which the affected units remain online and sufficient new resources are added to meet the 0.1 LOLE standard. The CEJA-limited units are then removed from that same portfolio, with all other resources held constant. Because the two cases differ only in whether the CEJA-limited units are available, any increase in reliability risk is directly attributable to their retirement. This comparison isolates the contribution of CEJA-limited units to resource adequacy and identifies the system conditions under which those units provide reliability value.

6.1 Analytical Scope and Scenario Design

6.1.1 Reliability Analysis

The Mitigation Plan uses probabilistic resource adequacy modeling (via E3's RECAP model) to report sufficiency of capacity under challenging combinations of weather, load, and

resource availability. Analysis reports both the severity and frequency of outage events under system conditions drawn from trajectories of historical weather years 1990-2024. Introducing random variations in historical generation supply and electrical demand curves simulates possible real world conditions under deep uncertainty about future conditions.

The reliability estimates for portfolios under each Mitigation Plan strategy are based on a broad set of potential outcomes / weather conditions. The range of encompassed trajectories is bounded by historical weather record and does not reflect the potential impact of climate change. 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. The use of historical weather years is similar to the approach used by the RTOs in establishing their reliability requirements.

Reliability is measured using several complementary metrics: Loss of Load Expectation (LOLE) estimates the number of days in which available resources are insufficient to serve load. Loss of Load Hours (LOLH) estimates the number of hours over which such shortfalls occur. Expected Unserved Energy (EUE) estimates the magnitude of shortfall events by reporting the total electricity demand in MWh that goes unserved during shortages. Together, these metrics explore the frequency, duration, and severity of reliability risk. In cases where portfolios fall short of the reliability standard, RECAP additionally reports the additional perfect capacity that would be needed to calibrate the system to the standard target of 0.1 LOLE, equivalent to 1 day per decade with a loss of load event.

Analysis covers RTO zones PJM and MISO, concentrating specifically on sub-RTO zones ComEd and Ameren (also known as “LRZ 4”) for the selected study years beginning in 2030 and extending through 2047. When reporting the reliability of a given zone (i.e., ComEd or Ameren), the remainder of the RTO is taken as external, with its energy only accessible via imports. The implications of these assumptions are tested further via import sensitivities described below.

6.1.2 Reliability Need for CEJA-limited Units

The following steps were followed to evaluate the reliability contribution of CEJA-limited units:

1. Develop the resource portfolios in PLEXOS for the CEJA extension case, assuming CEJA-limited unit lifespan is extended. Ensure enough resources are added to satisfy the 0.1 LOLE standard.

2. From these portfolios of existing, planned, and candidate PLEXOS builds, retire CEJA-limited units under their current expectations for retirement timelines.
3. Determine how far from a 0.1 LOLE standard the portfolio has fallen with the CEJA-limited units removed.

RECAP confirms that the initial portfolios (with PLEXOS-proposed candidate resources in addition to the CEJA extensions) meet the baseline 0.1 LOLE standard. Because the only difference between the two cases is whether the CEJA-limited units remain online, any reliability shortfall in the retirement case is directly attributable to the retirement of those units on the schedule set out in the law. Differences in LOLE, LOLH, and EUE between these two cases indicate exactly when and to what extent CEJA-limited units are responsible for maintaining reliability standards. Differences in these metrics allow reliability analysis to elucidate the duration, timing, and magnitude of CEJA-limited unit utilization across simulated weather conditions.

6.1.3 CEJA-limited Unit Reliability Under Import Sensitivities

As mentioned in Section 6.1.1, analysis was performed on sub-RTO zones ComEd and LRZ 4 separately, taking the context of the rest of their associated RTOs as external. While this allows the analysis to narrow in on more fine-grained geographic areas of interest, it also removes some degree of freedom from the model in exploring how different weather conditions across wider areas may lead to antagonistic relationships between zones. For example: if reliability events occur in the rest of PJM contemporaneously with ComEd, how do the resultant impacts on imports change the overall reliability estimates seen in the subregion? We perform additional sensitivities to better bound these impacts.

In the cases described in Sections 6.1.1 and 6.1.2, we assume that regions have full access to historical levels of imports throughout the timeseries. To assess regions' reliance on imports, we run an additional set of sensitivities where imports are completely removed. These explore the other extreme, where reliability events in external zones completely overlap with reliability events in study regions.

Systems dependent on weather-dependent generation should generally experience correlated troughs in energy availability. Still, there is geographic diversity in resources across zones, as well as portfolio diversity in what discrete regions have installed. Realistic import availability is therefore likely lower than historical values but nonzero. Accordingly, we can consider the cases described in Sections 6.1.2 and 6.1.3 to be upper and lower bounds on portfolio reliability, respectively.

The primary cases analyzed are summarized in the table below.

Table 6-1: Summary of RECAP Cases

Case	Purpose	Treatment of CEJA-limited units
PLEXOS Replacement Portfolio (i.e., CEJA Extension Case)	Determines the capacity additions needed to achieve the 1-in-10 standard.	CEJA-limited units are extended
PLEXOS Replacement Portfolio with Retirements	Determines the portfolio's dependence on CEJA-limited unit capacity	CEJA-limited units are retired
Import Sensitivities	Determines the portfolio's reliance on imports from external zones.	Separate cases, both with and without retirements

6.2 RECAP Model Approach

6.2.1 Probabilistic Resource Adequacy Modeling

Probabilistic resource adequacy modeling evaluates the performance of the electric system across a broad range of possible conditions, rather than relying on a single peak load forecast or expected resource availability assumption. Exploring a wider range of conceivable outcomes provides more accurate modeling for weather-dependent systems which are subject to inherent uncertainty. The larger decision spaces provided by probabilistic models are also more resistant to errors in input forecasts.

For each simulated model year, RECAP combines weather-dependent data (load profiles and corresponding renewable generation profiles) with stochastic thermal generator outages. The model then dispatches available resources, imports, storage, and demand-side resources on a time-sequential basis to determine whether demand can be served in every hour despite the case's stochastic outages in baseload generation.

Repeating this process across 35 years and 20 Monte Carlo outage simulations creates a wide distribution of potential system outcomes. Many simulations result in no loss-of-load event, while more challenging simulations result in periods of unserved energy of varying severity. These outages are generally caused by some combination of high demand, low renewable output, generator outages, transmission constraints, and/or sustained stress

across multiple hours or days. By ensuring variables maintain their relationships and interactions with historical weather data, realistic correlations are preserved among renewable resource output, load, and thermal outage rates. RECAP uses a heuristic dispatch algorithm that mirrors the optimized chronological dispatch of all resources in its portfolio. The dispatch order and state of charge of energy-limited resources is realistic and preserved across the timeseries.

The RA Study used this same modeling framework both to evaluate system reliability and to develop ELCCs. The RECAP model used in the RA Study was also applied and updated to reflect the latest system conditions and align assumptions with the Mitigation Plan.

6.2.2 Geographic Representation and Transmission Assumptions

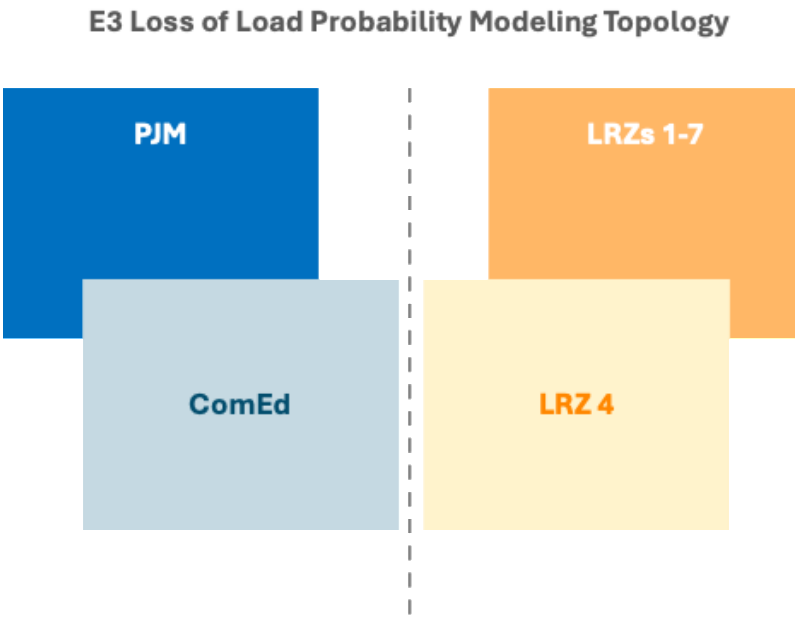
The RECAP model evaluates PJM, MISO, the ComEd Zone, and LRZ 4 as individual study regions. Resources are assigned to the region in which they are located, with simplified import assumptions where out of state resources are modeled in the same zones with no constraints on transmission availability.

The geographic representation is intended to capture two related dimensions of Illinois resource adequacy:

- The reliability of the broader PJM and MISO systems; and
- The ability to deliver regional resources into the ComEd Zone and LRZ 4 during periods of system need.

The model therefore distinguishes between the existence of capacity elsewhere in an RTO and the ability to transfer that capacity into an Illinois zone. The figure below illustrates the geographic representation in RECAP to study each zone for reliability risk.

Figure 6-1: RECAP Topology



6.2.3 Load and Renewable Generation Profiles

E3 used load shapes to model the behavior of each load component modeled: data centers, baseload, and electric vehicles. Each component was modeled using a distinct methodology based on the component's behavior:

Data centers: Load shapes were simulated based on data center location, efficiency, responsiveness to used demand, and temperature. Data center loads generally have high load factors, but demand is dependent on factors mentioned above.

Baseload: Load shapes were created using a neural network-based regression trained on recent historical data to capture the relationship between load and weather. Load shapes were refreshed relative to the 2025 RA Study to model MISO loads more granularly. In this study, a unique LRZ 4 and LRZs 1-7 load shape was modeled to more accurately capture differences between the regions. PJM East, West, and ComEd shapes were refined to more accurately capture load during extreme winter periods. Load shapes for each region were simulated for weather years 1990-2024.

Electric Vehicles: Load shapes were simulated using E3's EV load shaping tool based on driving patterns and weather correlated charging efficiency.

Each load component was then scaled to the forecasted annual energy in each modeled year to create a unique blended shape. Load remains summer peaking across all zones in the BAU scenario of the IRP and Mitigation Plan.

Figure 6-2: LRZ 4 Component Load Shapes

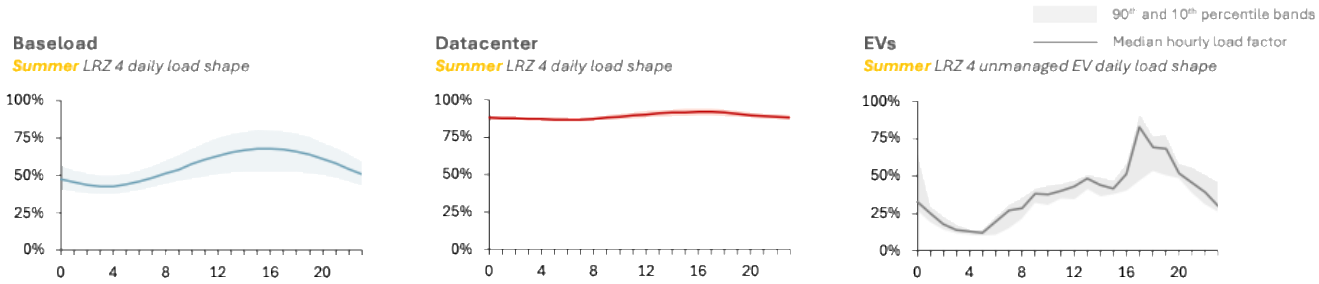
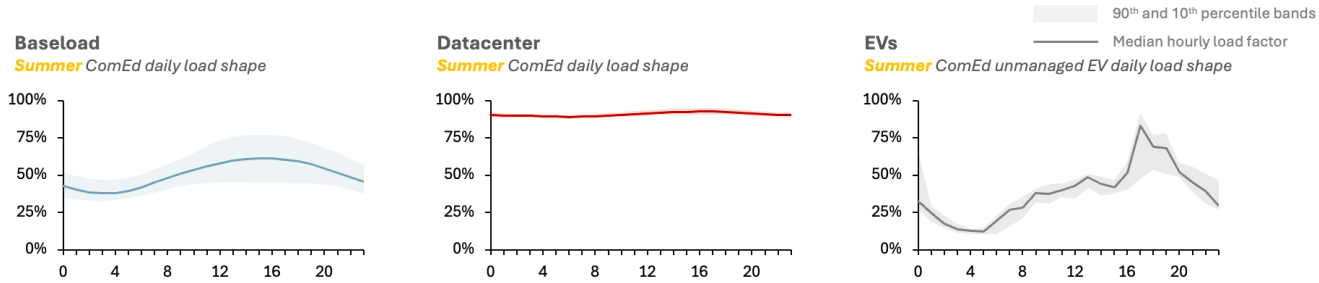


Figure 6-3: ComEd Component Load Shapes



Renewable profiles were then simulated using National Laboratory of the Rockies (NLR) suite of modeling tools for each PLEXOS region using several decades of historical weather data. Wind profiles were simulated using NLR's Wind Integration National Dataset (WIND) Toolkit for 2007-2014, while NLR's Bias-Corrected NOAA High-Resolution Rapid Refresh (BC-HRRR) dataset was used for 2015-2023. Wind profiles used in RECAP spanned from 2007-2023. Solar profiles were simulated using NLR's National Solar Radiation Database (NSRDB) and NLR's System Advisor Model (SAM). Solar profiles used weather conditions from 1998-2022. Both sets of profiles were taken from the 2025 RA Study.

Maintaining weather consistency between load and renewable generation is important because extreme demand and renewable performance are not completely independent. Additionally, simulating renewable performance under a range of weather conditions allows us to model a wide range of generation conditions.

Figure 6-4: LRZ 4 Renewable Generation Profiles

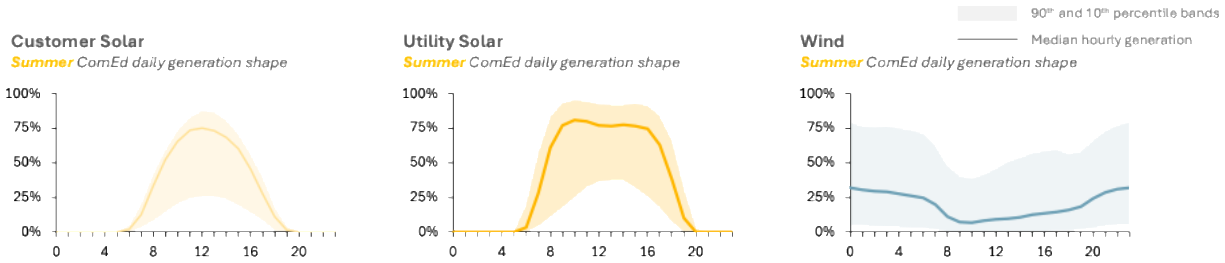
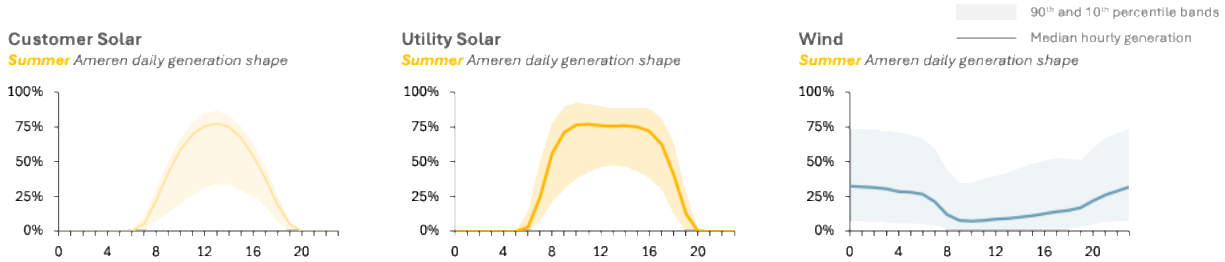


Figure 6-5: ComEd Renewable Generation Profiles



6.2.4 Thermal Resource Availability and Forced Outages

Thermal and other dispatchable resources are represented using technology-specific outage assumptions. RECAP stochastically samples forced outages in each simulated year to reflect uncertainty regarding whether a resource will be available during periods of system need.

The outage representation may include:

- Forced outage rates;
- Planned outage schedules;
- Temperature-dependent de-rates;
- Fuel supply limitations; and
- Unit start, ramp, or minimum operating constraints.

In previous modeling of PJM outages, E3 drew on Murphy et al. (2019),[75] a Carnegie Mellon University study of temperature-dependent generator failures, to develop an average outage rate at each temperature for each thermal resource type. This outage rate was then utilized in RECAP as an input to a Monte Carlo simulation of forced outages at the unit level. However, the outage rates taken from that study represent temperature averages, and the

[75] Sinnott Murphy, Fallaw Sowell, and Jay Apt, "A Time-Dependent Model of Generator Failures and Recoveries Captures Correlated Events and Quantifies Temperature Dependence," *Applied Energy* 253 (November 2019): 113513, https://doi.org/10.1016/j.apenergy.2019.113513.

resulting fleet-wide range of outages from RECAP did not sufficiently capture the large range of outages present in historical data provided by PJM. RECAP is a model designed to capture and analyze extreme events, and representing the full range of outage possibilities is key to answering RA questions. In this modeling for the IRP and Mitigation Plan, E3 adjusted the RECAP model to account for noise in outage rates at low temperatures. This increases the range of simulated outages at lower temperatures and better aligns the range of RECAP's simulated outages with PJM's historical outage data. The noise profiles for PJM were then applied to MISO with small adjustments made for the temperature difference between the regions (MISO-specific noise profiles were not generated due to a lack of historical data). Conceptually, these noise profiles capture a variety of events that influence fleet-wide outage behavior, such as wide-spread mechanical failures due to temperatures far below freezing or interruptions of fuel supply during winter storms.

Figure 6-6: LRZs 1-7 Temperature vs Outage Assumptions

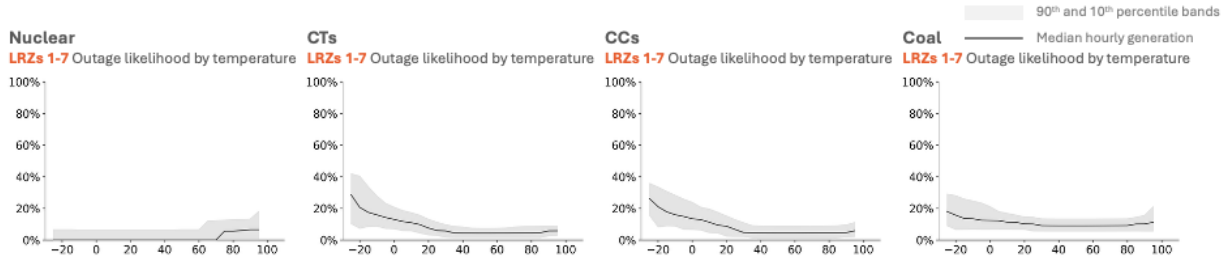
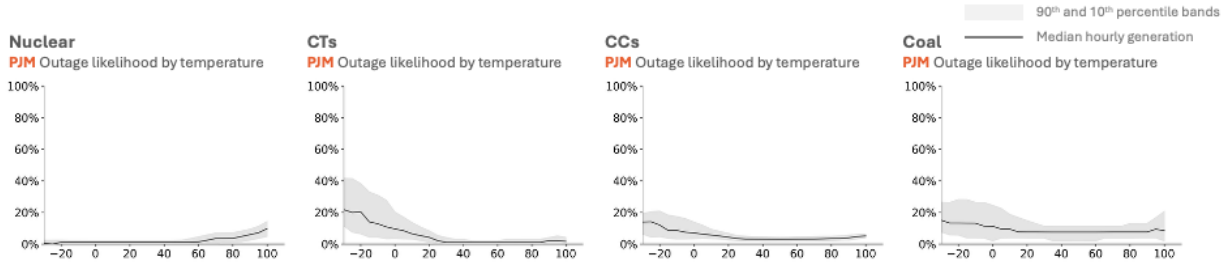


Figure 6-7: PJM Temperature vs Outage Assumptions



6.2.5 Energy-Limited and Demand-Side Resources

Energy storage, demand response, and other energy-limited resources are dispatched chronologically to reduce loss-of-load risk. Their reliability contribution depends not only on installed capacity but also on energy duration, charging availability, state of charge, activation limitations, and the duration and recurrence of system stress events. Demand response was modeled as a 4-hour storage resource in RECAP. Its performance represents the upper bound of resource performance, as it can be called an unlimited number of times.

The RECAP representation of these resources includes:

- Storage power and energy capacity;
- Charging and discharging efficiency; and
- Initial and minimum state-of-charge assumptions.

6.3 Reliability Risk Results

6.3.1 ComEd Zonal Results

Assuming CEJA extension, PLEXOS recommends building 142 MW of solar, 4.1 GW of wind, and 2.6 GW of storage in ComEd. While some new gas capacity is built in this case, none of it lies in ComEd. Both 2035 and 2045 show an achieved LOLE of approximately 0.1, demonstrating that PLEXOS calibrated its portfolio to the desired reliability standard. Any LOLE above this benchmark once CEJA-limited units are removed can be directly attributed to CEJA-limited unit retirement.

As summarized in Table 6-2, retiring CEJA-limited units in ComEd means a loss of 5,747 MW of capacity in the year 2035, 22% of ComEd's existing thermal capacity. The case run with CEJA-limited unit retirement leads to 6.8 LOLE, confirming that reliability of the proposed portfolio hinges on access to CEJA-limited units. The case with CEJA-limited unit retirement totals 57 GWh EUE (compared to 266 MWh without retirement: 215x increase), and LOLH of 27 hours (compared to 0.3 hours without retirement: 90x increase).

Figure 6-8 below shows a month hour distribution of loss of load events across the simulation. Reliability risk is concentrated in late afternoon summer hours and is driven principally by higher ComEd loads in both the summer and the early evening, as well as low wind and solar generation in the summer and evening time, respectively.

Figure 6-8: Heatmap of CEJA-limited Unit Utilization

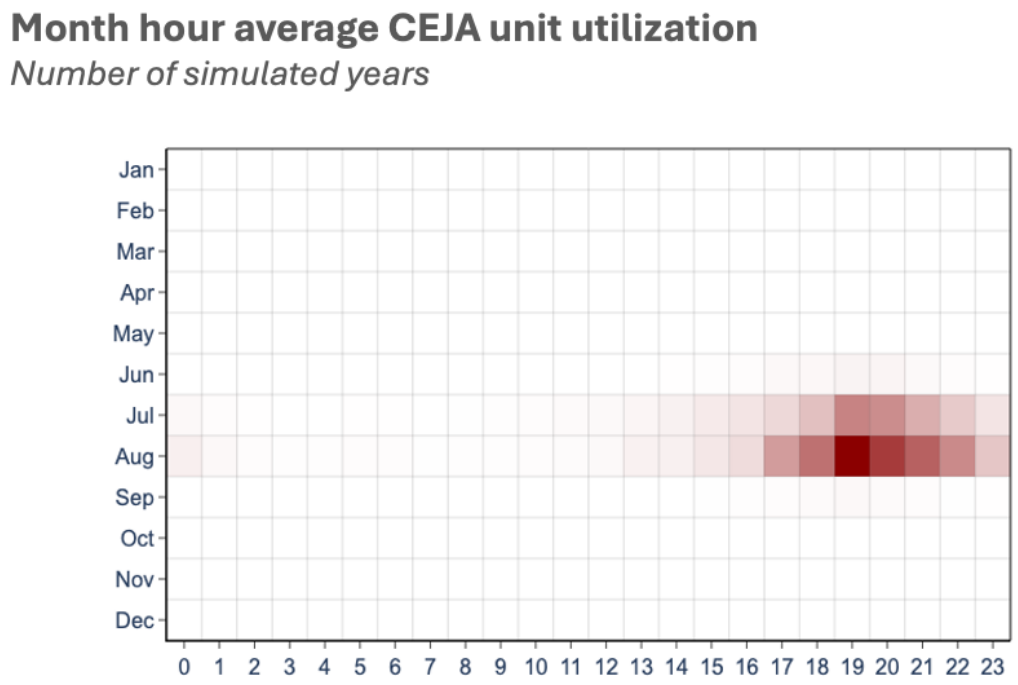


Figure 6-9 illustrates the number of hours in each year in which CEJA-limited units are utilized across a wide range of load and system operation conditions. Each point in Figure 6-9 represents one of the 700 model runs studied in RECAP; to derive these runs, each of 35 weather years (1990 – 2024) was simulated across 20 Monte Carlo draws. Incorporating historical weather data via Monte Carlo simulation allows for the exploration of reliability under both real conditions and deep uncertainty. As expected, the per-draw impact of CEJA-limited unit retirement is variable. As a first order correlation, the weather years with the highest load (2005, 1991, 1995, 2007, 2012) all have anomalously high reliance on CEJA-limited units. In general, hotter weather years (as a second order correlation with these high loads) rely more heavily on CEJA-limited unit generation. July of 2012 was a particularly hot year in Illinois, and its reliability impacts appear both in heavy usage of CEJA-limited units (Figure 6-9) and in a correlating spike in outage rates in July (Figure 6-8).

Figure 6-9: CEJA-limited Unit Utilization by Weather Year

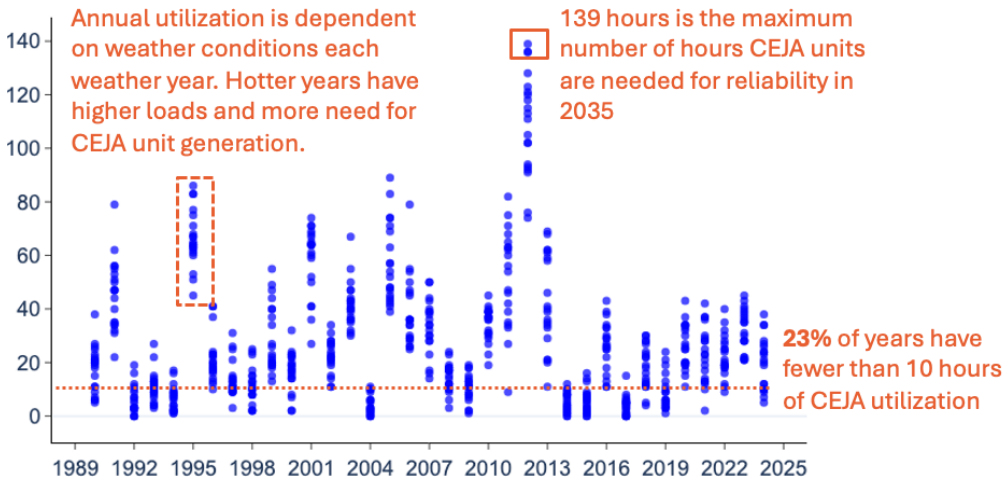
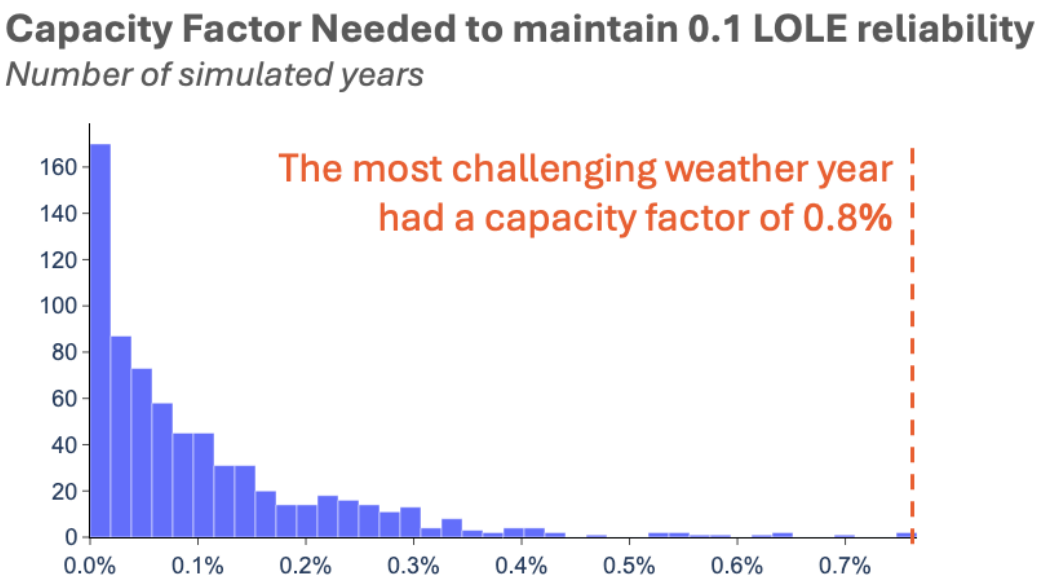


Figure 6-10 is a histogram of all Monte Carlo simulations tested, binned by the capacity factor of their CEJA-limited units. The sharp peak and heavy taper of the figure indicates that while some anomalous conditions may lead to higher usage of CEJA-limited units, most cases rely only sparingly on CEJA-limited units, mobilizing them in very few hours of the year.

Figure 6-10: Histogram of CEJA-limited Unit annual utilization by simulation year



While the degree of reliance on CEJA-limited units is variable, there are some base correlations that hold across most simulations. In ComEd, 97% of simulations rely on CEJA-limited unit generation for some portion of the year; 77% of these draws rely on CEJA-limited unit capacity at least 10 hours per year (Figure 6-9). Still, while most draws rely on CEJA-

limited unit capacity and we do see spikes in use of CEJA-limited units during extreme weather conditions, these spikes do not imply high capacity factors for CEJA-limited units. Even the most challenging weather year had a plant capacity factor of just 0.8% (Figure 6-10), demonstrating that units are valuable first and foremost for capacity, not energy value.

The results described above assume that ComEd can rely on imports from neighboring regions during times of potential scarcity. The amount of energy available for import is derived using historical values. This may not be a safe assumption, however, particularly if neighboring regions are experiencing troughs in renewable availability at the same time as resources in ComEd. This is a reasonable expectation given reliability events' concentration in evening hours (Figure 6-8). Additional analysis was therefore performed to determine the impact should imports be unavailable during shortages in ComEd: the same cases were run as above, but under the assumption that no extra zonal generation was available for import.

Figure 6-11: ComEd CEJA-limited Unit Capacity Factor, Import Reliance

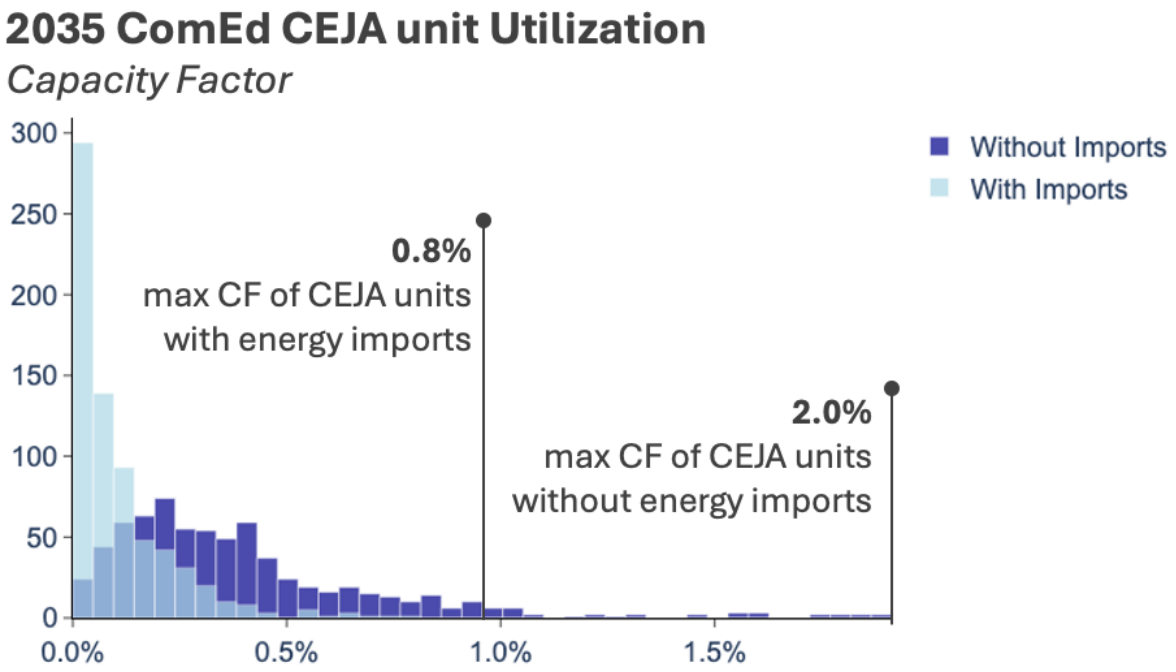
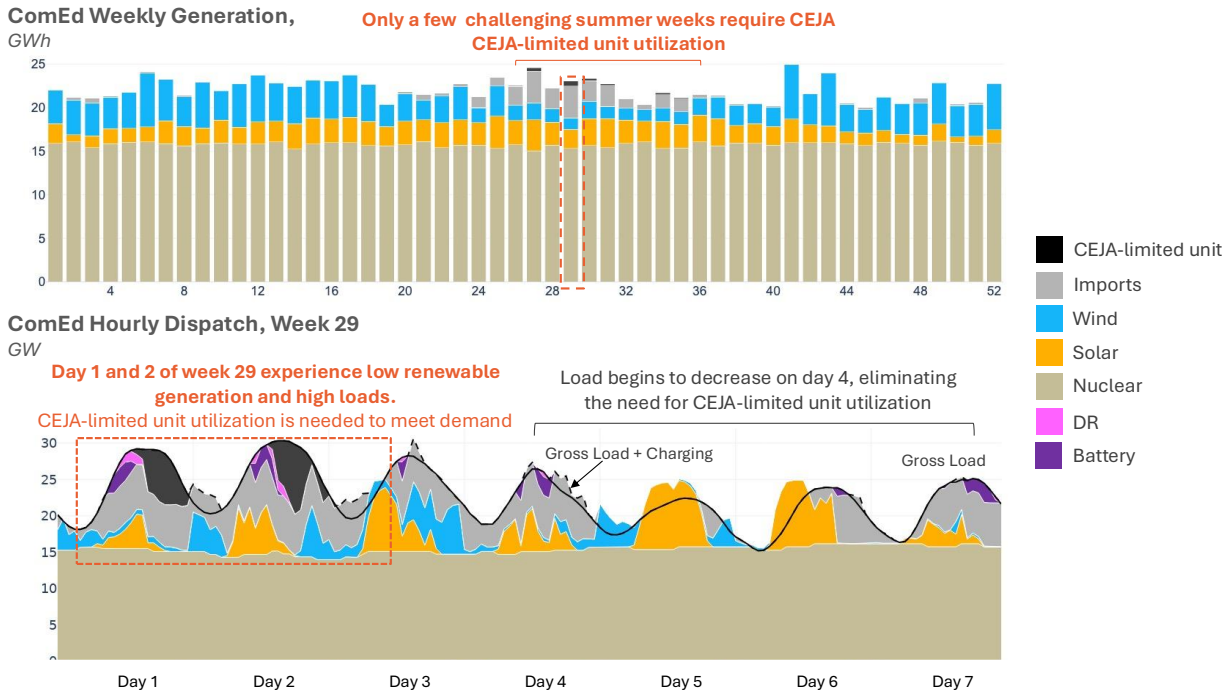


Figure 6-11 shows that preventing imports drives the maximum capacity factors for CEJA-limited units from 0.8% to 2.0%. As shown in Table 6-2, LOLE also increases from 6.7 to 17.4 in 2035. Annual EUE increases from 57 GWh to 216 GWh. Energy value from CEJA-limited units is thus increased.

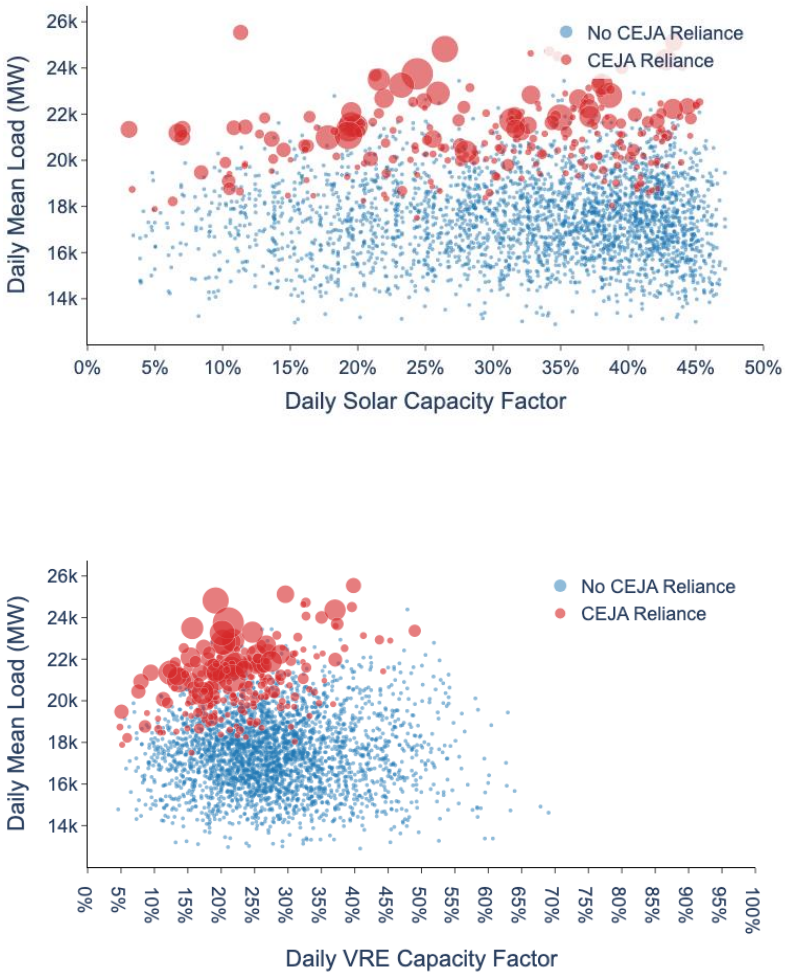
Figure 6-12: Weekly Dispatch, ComEd, High CEJA-limited Utilization



Reliance on CEJA-limited unit generation in the case with imports is largely caused by high loads. As previously confirmed, CEJA-limited unit reliance is concentrated in the summer due to a combination of high summer loads and decreased wind capacity factor. Figure 6-13 shows the daily correlation between load and renewable generation for a particularly challenging simulation year (year selected was in the 99th percentile for amount of annual CEJA-limited generation). Points representing days with CEJA-limited generation are colored in red. Renewable generation includes both wind and solar. The relatively low capacity factors seen in the figure are due both to the lower capacity factor of wind in summer months, and a lack of solar generation in evening hours. Figure 6-13 confirms the trends posited in the discussion of Figure 6-8, that CEJA-limited utilization tends to occur during periods of coincident high load and low renewable generation.

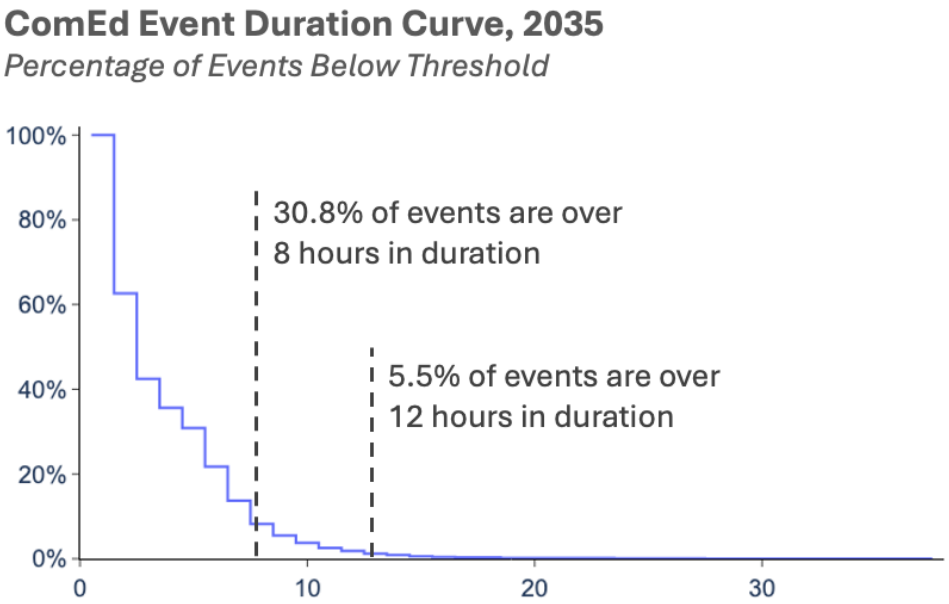
Figure 6-13 also shows CEJA-limited unit utilization compared to the summer capacity factor of solar, alone. A much weaker correlation is confirmed. This is likely because solar generation is not decreased during summer months, as is wind availability. When calibrating system reliability, coincident increases in energy demand and decreases in supply are likely to lead to the most challenging periods. Accordingly, it is wind, not solar, generation which emerges as a primary driver of risk due to the overlap of its lower generation during periods of high load.

Figure 6-13: Renewable output versus Load during periods with and without CEJA-limited utilization



We also examined the duration of CEJA-limited unit reliance events across simulation years, as shown in Figure 6-14. While some days require CEJA-limited unit *capacity* for a short period to meet peak loads, other days have an *energy* shortfall caused by higher loads throughout the day. During these times additional CEJA-limited unit generation may be required for an extended period. About 31% of periods of CEJA-limited unit reliance had a duration longer than 8 hours, and 5% had a duration longer than 12 hours; the most extreme events required CEJA-limited unit generation for entire days.

Figure 6-14: Distribution of the duration of CEJA-limited unit reliance events



While systems more dependent on renewable resources are generally expected to demonstrate correlated troughs in energy availability, there is geographic diversity in resources across zones. Realistic import availability is therefore likely lower than historical values but nonzero. Accordingly, we can consider the reliability metrics in Table 6-2 that include and exclude imports to be upper and lower bounds on reliability, respectively.

Table 6-2: ComEd Reliability Results

Year	CEJA Retirement?	Access to Imports?	LOLE (Events)	LOLH (Hours)	EUE (MWh)
2035	No	Yes	0.1	0.24	266
	Yes	Yes	6.7	27.3	57,367
	Yes	No	17.4	91.2	215,661

6.3.2 Ameren Zonal Results

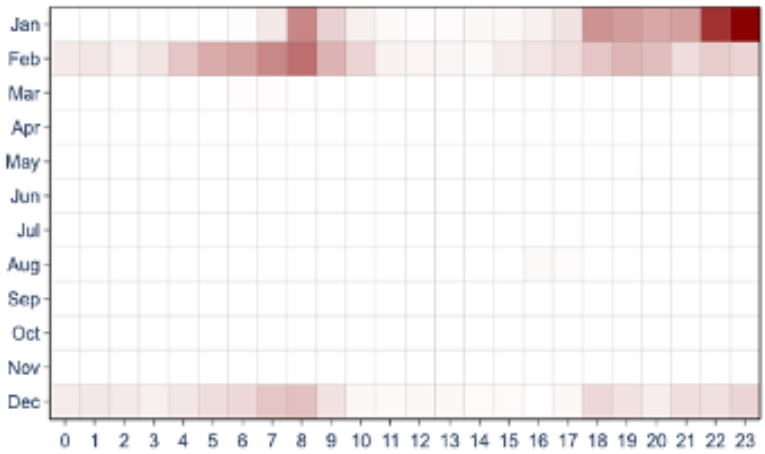
Planning for CEJA extensions, PLEXOS adds 2 GW of storage, 715 MW of solar, and 7.2 GW of wind in the Ameren region, incremental to existing capacity. As with PJM and ComEd

analysis, some gas capacity is added in MISO, but it is not in Illinois. The Ameren portfolio reaches 0.1 LOLE with CEJA-limited units included, confirming that PLEXOS correctly calibrated to the desired reliability standard. Table 6-3 shows 653 MWh of EUE and 0.4 LOLH in this case. Any reliability risk above this once CEJA-limited units are removed is directly attributable to the need for the CEJA-limited units themselves.

Retiring CEJA-limited units in Ameren results in a loss of 1,454 MW of capacity in the year 2035, around 35% of Ameren's existing gas capacity (a similar percentage to what is retired in ComEd by 2035). While reliability risk increases in Ameren when CEJA-limited units are retired, risk patterns in Ameren differ greatly from those seen in ComEd. Ameren primarily shows risk in a few, sporadic wintertime events in the late evening and early morning. During these rare events, a large fraction of the CEJA-limited fossil fuel unit fleet was mobilized. Overall, retiring CEJA-limited units in Ameren leads to a LOLE of 0.31, an *additional* 1,145 MWh per year of EUE, and an LOLH of 1.3 (assuming that Ameren has access to both imports and out-of-state gas (OOSG)).

In Ameren, LOL risk is concentrated in the winter months, with risk that can fall in the late evening, overnight, or early morning hours (Figure 6-15). Winter risk dominates in Ameren due to the presence of thermal outages. While summer load is slightly larger in magnitude than winter load, the decrease in thermal generation from summer to winter is larger, leading to energy shortfalls on winter days. This risk of LOL manifests on winter days that also have lower than usual renewable generation, preventing storage from charging in the daytime and leading to evening, overnight, and morning EUE. While loads reach somewhat higher peaks in the summer (the median summer peak was 20% higher than the median winter peak), the timing of these peaks typically overlaps well with the availability of solar resources as well as imports from neighboring systems. Given this LOL pattern, generation from CEJA-limited units would primarily be needed in the winter during non-daylight hours.

Figure 6-15: Heatmap of CEJA-limited unit utilization in Ameren assuming access to imports and out-of-state gas



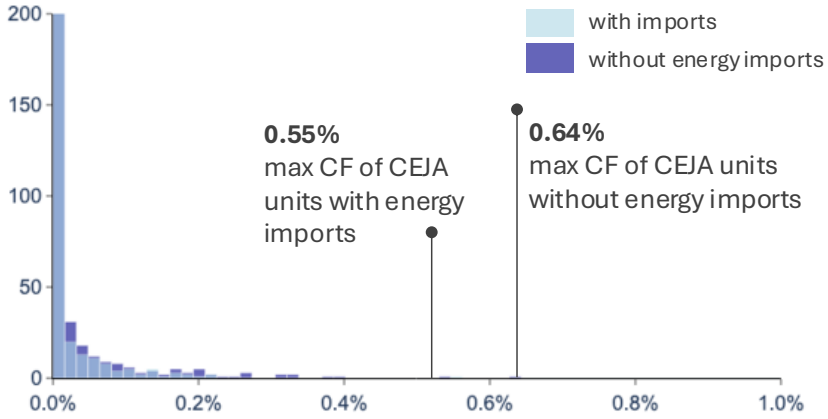
Due to the relative rarity of scarcity events in Ameren as compared to ComEd, we see a lower frequency of CEJA-limited unit utilization across the year. Ameren mobilizes CEJA-limited units more than 10 hours per year in just 4% of simulation years (compared to 77% of cases in ComEd, Figure 6-9). Only 137 (20%) of Monte Carlo draws representing Ameren relied on these units, at all (compared to 686 (98%) of draws in ComEd), and the worst-case year in Ameren uses CEJA-limited unit capacity in 38 hours (compared to 139 hours in ComEd).

Ameren relies on CEJA-limited units less frequently than ComEd. Beyond this, when examining the years with the most CEJA-limited unit utilization, Ameren demonstrates a lower energy value. Assuming availability of imports, the most challenging year in ComEd ran CEJA-limited units at a capacity factor of 0.8%, while Ameren's most challenging year ran CEJA-limited units at a capacity factor of 0.55% (Figure 6-16). Ameren and ComEd CEJA-limited unit maximum annual capacity factors increase to 0.64% and 2%, respectively, in absence of import availability.

Figure 6-16: Histogram of CEJA-limited Unit Capacity Factor by simulation year both with and without imports (access to OOSG assumed for both)

2035 Ameren CEJA unit Utilization

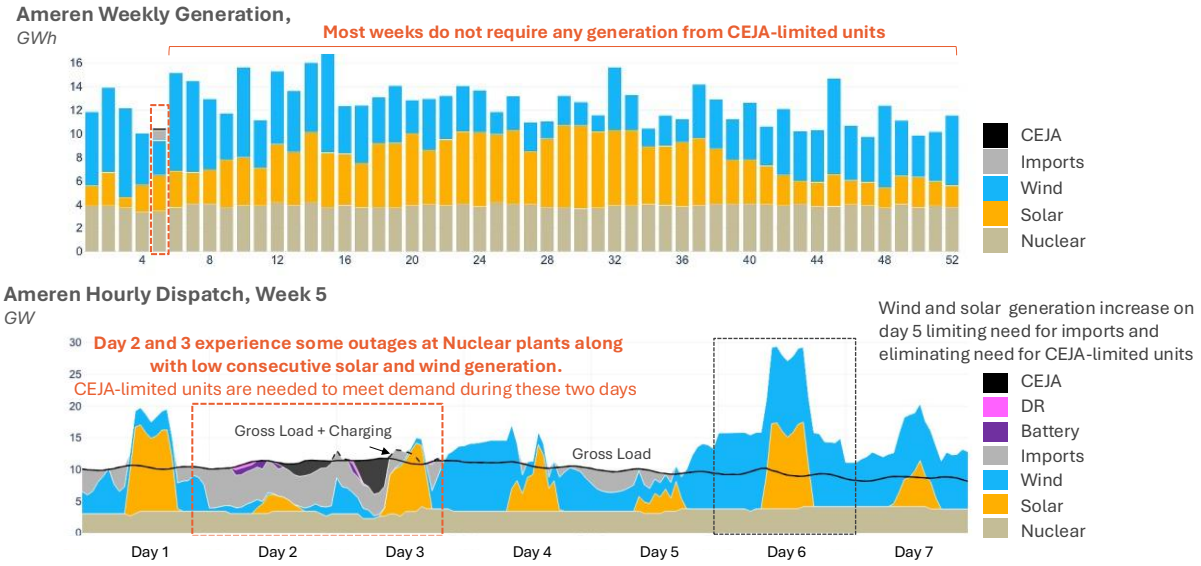
Capacity Factor



Without access to imports, the LOLE increases from around 0.31 events per year to 0.58 events per year, with the EUE increasing by around 1,208 MWh, as shown in Table 6-3. This translates to a higher need for generation from CEJA-limited units, though Figure 6-16 suggests that this comes in the form of having more simulation years with CEJA-limited unit generation, rather than substantially increasing the max CEJA-limited unit utilization in the most extreme simulation years.

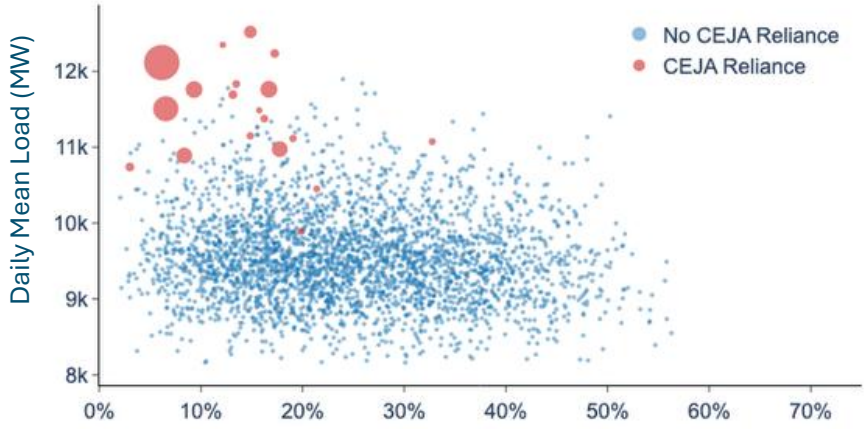
Reliance on CEJA-limited unit generation in the case with imports is caused by multiple factors. As discussed, CEJA-limited unit reliance is concentrated in the winter due to having more imports in the summer and having more thermal outages in the winter. In Figure 6-17, we show the weekly dispatch for the year that falls in the 99th percentile of total CEJA-limited generation. Even in this extreme year, CEJA-limited reliance is concentrated primarily in one week that falls in the winter. Figure 6-17 also shows the hourly dispatch during the week that the majority of CEJA-limited generation occurred in for this year. Reliance on CEJA-limited units occurs at the end of a multi-day period that has limited generation from wind and solar power, during which Ameren is highly reliant on imported out-of-state gas and generic imports.

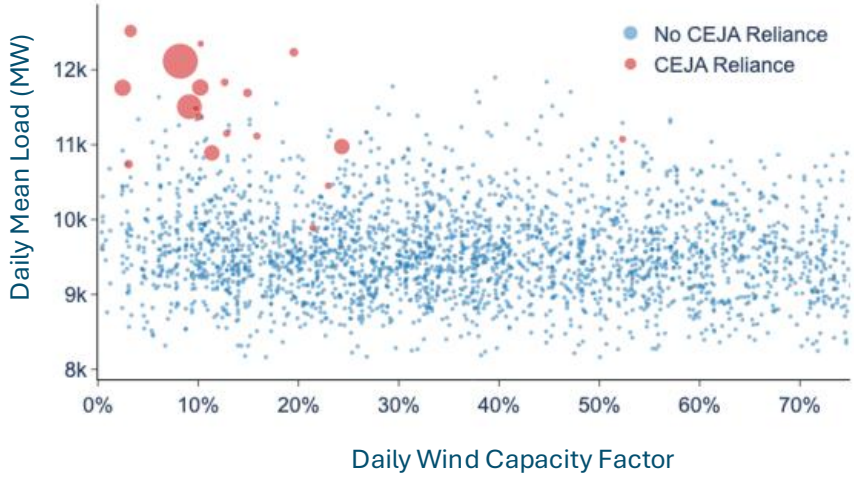
Figure 6-17: Weekly Dispatch



Across all simulated years, CEJA-limited unit reliance primarily occurred on days with both high load and low renewable generation. The daily correlation between load and renewable generation (for the same MC-draw that was used to generate Figure 6-17) in the top plot of Figure 6-18, with days that required CEJA-limited generation colored in red. In winter in Ameren, wind capacity factors are much higher than solar capacity factors, and there is significant variation in wind output from day to day. Thus, the bottom plot of Figure 6-18 shows correlation of load and just wind generation, again with days with CEJA-limited unit reliance colored in red. Overall, CEJA-limited unit reliance depends more strongly on lulls in wind generation, rather than renewable generation as a whole, and high load is a key factor that impacts CEJA-limited unit utilization.

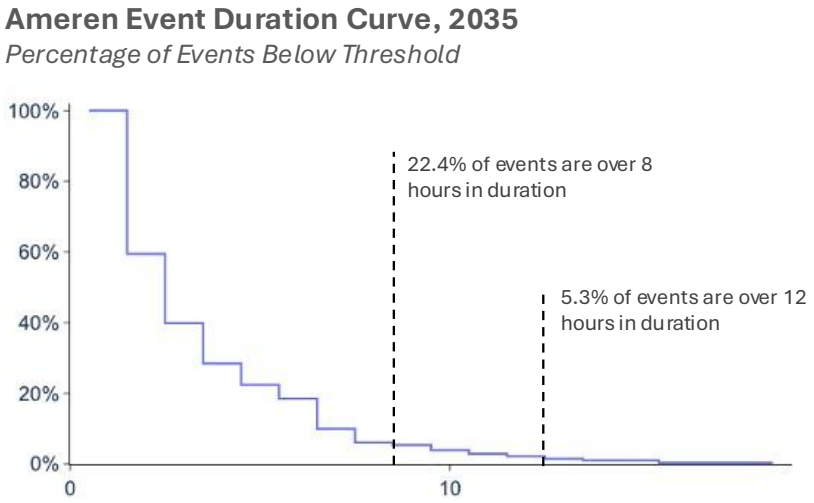
Figure 6-18: Relationship between CEJA-limited generation and the correlation of daily load and variable renewable energy generation





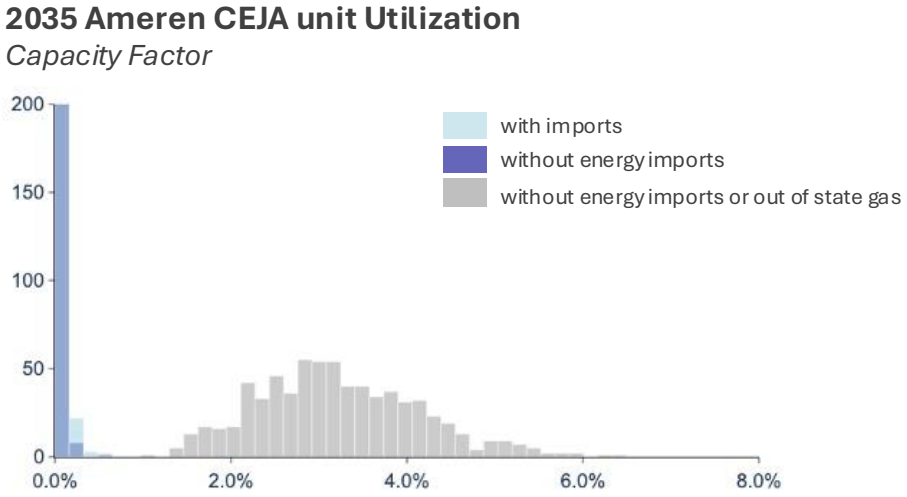
We also examined the duration of CEJA-limited unit reliance events across simulation years, as shown in Figure 6-19. While some days require CEJA-limited unit *capacity* for a short period to meet peak loads, other days have an *energy* shortfall caused by higher loads throughout the day combined with low wind generation (as discussed above). During these times additional CEJA-limited unit generation may be required for an extended period of time. About 22% of periods of CEJA-limited unit reliance had a duration longer than 8 hours, and 5% had a duration longer than 12 hours.

Figure 6-19: Distribution of the duration of CEJA-limited unit reliance events



In the sensitivity where we remove out-of-state gas (OOSG),[76] the EUE increases by a factor of over 100 (see Figure 6-20, Table 6-3), resulting in much higher capacity factors for CEJA-limited plants.

Figure 6-20: Histogram of CEJA-limited Unit Capacity Factor by simulation year for OOSG + imports, OOSG + no imports, and no OOSG + no imports



As shown above, the capacity factor in the most challenging years would exceed 6% in the sensitivity without OOSG, challenging the Agencies' goal of minimizing in-state emitting generation. Therefore, retiring CEJA-limited plants while maintaining reliability would be very

[76] OOSG is only selected in Ameren, not ComEd

challenging without OOSG, and if CEJA-limited plants are extended purely for reliability reasons, OOSG would still be needed on a frequent basis to keep CEJA-limited unit generation low.

Table 6-3: 2035 Ameren Reliability Results

Year	CEJA Retirement?	Access to Imports?	OOSG?	LOLE (Events)	LOLH (Hours)	EUE (MWh)
2035	No	Yes	Yes	0.1	0.43	653
2035	Yes	Yes	Yes	0.31	1.3	1,798
2035	Yes	No	Yes	0.58	2.3	3,006
2035	Yes	No	No	71	342	410,555

6.4 Key Findings of the Reliability Risk Assessment

Continued availability of CEJA-limited units materially reduces reliability risk, particularly in the ComEd zone.

The reliability value of the CEJA-limited units is not primarily associated with producing large quantities of energy throughout the year; rather, the units provide capacity and energy during the relatively small number of hours when the rest of the modeled portfolio is insufficient to meet demand. In Ameren, approximately 1,145 MWh per year of average CEJA-limited unit generation is needed to maintain the 0.1 LOLE criterion. In ComEd, the corresponding value is approximately 55 GWh per year.

The reliability value of CEJA-limited units differs materially between Ameren and ComEd.

In Ameren, the CEJA-limited units are needed only in a minority of simulated years and primarily during winter reliability events. Of the 700 simulated years, only 137 require any generation from the affected units, and 96 percent of years require fewer than 10 hours of operation. When the units are needed, however, the need is concentrated in December through February when load is high and renewable generation, especially wind generation, is low.

In ComEd, the pattern is different. CEJA-limited units are needed in nearly every simulated year, but only for a relatively small and targeted number of hours. Of the 700 simulated years, 686 require some generation from the affected units. The need is concentrated in summer, particularly during non-daylight hours from June through August when load remains high and solar output has declined. Even though the units are called on much more consistently than in Ameren, their annual utilization remains low because the reliability need is concentrated in a narrow set of peak-risk hours.

The analysis supports preserving the availability of CEJA-limited units as a reliability backstop.

The low average utilization of the affected units should not be interpreted to mean that their reliability contribution can be preserved through a predetermined annual limit on operating hours, capacity factor, or generation. Reliability needs are concentrated in unusual system conditions and vary materially across weather years, resource performance, and the availability of imports and other capacity. Sensitivity analysis on import availability illustrates this point. When non-firm energy imports are unavailable, maximum CEJA-limited unit utilization increases, including from approximately 0.8% to 2.0% capacity factor in ComEd. In Ameren, removing both non-firm energy imports and modeled out-of-state gas capacity increases maximum CEJA-limited unit utilization to approximately 6.4%.

These results suggest that the contribution of CEJA-limited units is availability during critical conditions, rather than a particular expected level of annual operation. It could also affect how the units participate in regional energy and capacity markets in ways that are not evaluated through this reliability analysis. Accordingly, the results are better suited to informing when and under what conditions continued unit availability may have reliability value than to prescribing a firm limit on actual utilization.

Continued availability of CEJA-limited units does not eliminate the need for substantial new resource development.

The CEJA Extension Case assumes continued availability of the affected units but still requires significant additions to meet growing load, reliability requirements, and Illinois policy requirements. By 2035, the modeled Ameren portfolio includes approximately 2 GW of four-hour battery storage, 4 GW of out-of-state gas capacity, 8 GW of solar, and 7 GW of wind. In ComEd, the 2035 portfolio includes approximately 3 GW of four-hour storage and 4 GW of wind in addition to the continued availability of existing resources. The extension therefore functions as a reliability backstop within a broader portfolio transition rather than as a substitute for the development of new resources.

7 PLEXOS Long-Term Portfolio Analysis

The preceding analyses evaluate Illinois' near-term resource adequacy outlook, capacity market conditions, and the value of in-state thermal generators for meeting the reliability needs of the state across a range of possible weather and load conditions. This chapter addresses the related question of what resources would be required to meet demand and maintain reliability under two scenarios: In the Reference Case, CEJA-limited units retire on the schedule required under current law, and the portfolio reflects central assumptions for load growth, technology costs, policy requirements, and resource development timelines. The CEJA Extension Case applies the same assumptions, except that the CEJA-limited units remain available through the end of the projection period in 2047. These units continue to comply with CEJA's interim emissions-reduction requirements through 2044, and their emissions are then held at the 2044 limits through 2047.

The analysis uses the PLEXOS Long-Term (LT) capacity expansion model to identify cost-optimal portfolios of generation resources over the planning horizon from 2030 to 2047. PLEXOS simultaneously evaluates resource investment and system-operation decisions while satisfying modeled reliability, policy, emissions, transmission, and operational constraints. The model therefore captures tradeoffs among retaining existing resources, developing new resources, relying on imports, investing in transmission, and changing the operation of the electric system. The RA Study used the same modeling framework to identify long-term portfolios capable of satisfying Illinois and RTO-wide reliability and policy requirements.

The Mitigation Plan analysis is narrower in purpose than the broader scenario analysis conducted for the RA Study. Given the more limited solutions which the ICC may authorize in approving the Mitigation Plan, the Mitigation Plan analysis focuses principally on comparing the Reference Case with the CEJA Extension Case to evaluate how the continued availability of CEJA-limited thermal generators could change the quantity, type, timing, location, and cost of resources needed to maintain reliability.

The candidate resource portfolio includes renewable generation, energy storage, firm generation, and capacity purchases from the wider RTO region, with demand response considered as an existing resource. This resource menu supports the statutory requirement that the Mitigation Plan consider renewable energy, storage, demand response, and other strategies before reducing or delaying applicable emissions-reduction requirements.

While the portfolios selected by PLEXOS should not be interpreted as precise forecasts of future development or procurement plans, they illustrate the lowest-cost modeled

response to the assumptions and constraints represented in each case and provide information regarding:

- The scale and timing of additional resource needs;
- The types and locations of resources selected;
- The degree to which continued availability of CEJA-limited units avoids or defers replacement investments;
- The costs and emissions associated with each portfolio;
- The transmission and deliverability requirements associated with new development; and
- Whether the modeled resource additions appear feasible within the period of need.

The results should be interpreted alongside other analyses in the Mitigation Plan to holistically assess costs and risks of addressing resource adequacy risk in Illinois.

7.1 Analytical Approach and Scenario Design

7.1.1 Planning Objective and Modeling Horizon

The purpose of the capacity expansion analysis is to identify the portfolio of resources needed to satisfy projected electricity demand, reliability requirements, and applicable policy constraints under each scenario. The analysis begins from the projected electric system in 2030, after accounting for existing resources, anticipated additions, expected retirements, and other developments included in the Reference Case. The Mitigation Plan narrowly considers two scenarios: the Reference Case and the CEJA Extension Case. The IRP considers a broader range of scenarios across different policy and technology futures, which should be considered as supplemental analysis to the Mitigation Plan.

The planning horizon for the Mitigation Plan extends through 2047, which is the end of the IRP modeling timeframe, with investment and operational decisions evaluated for 18 years. By beginning the capacity expansion analysis in 2030, the model connects to the endpoint of the Updated RA Balance Analysis, in Chapter 4, while allowing it to evaluate longer-term resource needs and the effects of the different CEJA compliance dates.

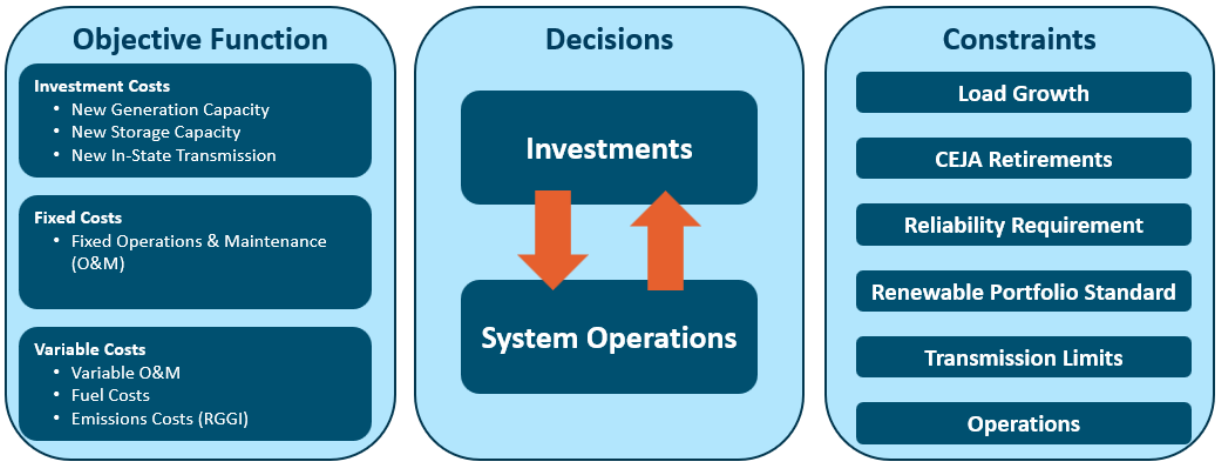
The analysis is designed to answer four principal questions:

- What additional resources are needed to maintain reliability under the Reference Case?
- How does continued availability of CEJA-limited units change the type, quantity, timing, and location of those additions?

- Are the modeled replacement portfolios feasible to develop within the period of need?
- What are the comparative cost, emissions, and system-operation consequences of the strategies evaluated?

The model optimizes over the full planning horizon rather than selecting resources independently in each study year. This allows PLEXOS to consider whether a near-term investment remains economic over time, whether a temporary resource need can be addressed through a shorter-lived option, and whether delaying an investment changes longer-term portfolio costs.

Figure 7-1: PLEXOS Modeling Framework



7.1.2 Scenario Design

The capacity expansion analysis is organized around two primary scenarios representing alternative treatments of generating units subject to CEJA's emissions-reduction requirements. The Reference Case represents the core planning scenario based on the latest available expectations regarding load growth, the existing resource fleet, planned resource additions, anticipated retirements, candidate resource costs and availability, fuel prices, transmission development, resource adequacy requirements, and applicable renewable portfolio standard and emissions policies. CEJA-limited units are treated as retiring according to their applicable emissions-reduction deadlines.

The CEJA Extension Scenario applies the same assumptions as the Reference Case except that CEJA-limited units remain available for the study period (until 2047), beyond the zero-emission deadlines that would otherwise apply. The interim emissions-reduction requirements of Section 9.15(h), (i) and (k-5) are assumed to remain in effect. These requirements are applied as annual emissions caps for each CEJA-limited generator

category rather than as unit-specific limits, so the aggregate emissions of the units in each category must stay at or below the level CEJA would otherwise require. The caps follow CEJA's interim reduction schedule through 2044 and are then held at the 2044 level through 2047. Maintaining consistent assumptions across the two scenarios allows differences in modeled portfolios and system outcomes to be attributed primarily to the continued availability of those units.

Instead of isolating specific CEJA-limited units for evaluation on a case-by-case basis, units are grouped by class. This means that, for example, Gas CT units in ComEd are aggregated and considered as one class of resources that the model can select to dispatch, rather than a unit-level analysis. As such, conclusions from the PLEXOS analysis are best interpreted at a resource class level and not on a unit level.

One key consideration in evaluating results is distinguishing between resources that are permanently avoided and resources that are deferred until the assumed extension ends. Because the model optimizes investments over the full planning horizon, the CEJA Extension Scenario may produce lower near-term additions while selecting similar resources in later years. This distinction will help determine whether continued operation of the affected units changes Illinois' long-term resource pathway or primarily provides additional time for replacement resources and transmission to be developed.

7.1.3 Sensitivity Analysis

The Mitigation Plan considers one additional sensitivity in addition to the Reference Case and CEJA Extension Case: a variation of the CEJA Extension Case where coal generating units maintain their CEJA Retirement Dates and only gas units' retirement dates are extended through the end of the modeling scenario. This allows for a comparison between the impact on the resource portfolio when all capacity resources are maintained, versus the impact of only maintaining a subset of those capacity resources.

7.2 Reference Case PLEXOS Results

The Reference Case represents the central planning outlook under which generating units subject to CEJA's emissions-reduction requirements are retired according to the compliance and retirement assumptions described in Chapter 3 Baseline Assumptions. PLEXOS identifies the cost-optimal combination of resource additions, system operations, regional transfers, and other modeled decisions needed to satisfy projected reliability, policy, emissions, and operational requirements under those assumptions.

This section presents a comprehensive view of the resulting portfolio. It first examines the resources selected across PJM and MISO and the accredited capacity those resources

contribute toward meeting regional resource adequacy requirements. It then focuses on the resources selected within Illinois, including the ComEd Zone and MISO LRZ 4. Subsequent subsections describe how the selected portfolio operates, the modeled cost of developing and operating the system, and the resulting emissions.

Not all PLEXOS-selected resources will necessarily be driven solely by the resource adequacy requirement. Some resources may be selected principally to satisfy energy demand, renewable portfolio standard requirements, emissions constraints, operational needs, or local transmission limitations.

Figure 7-2: Reference Case PJM Wide Installed Capacity

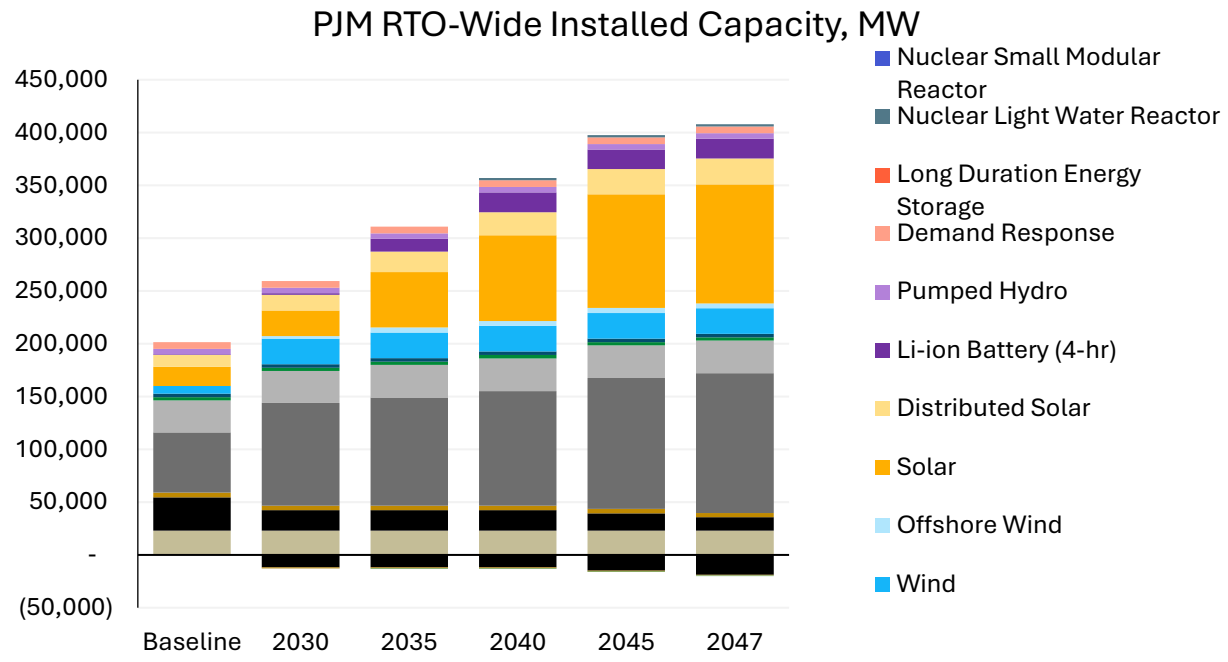


Figure 7-3: Reference Case MISO Wide Installed Capacity

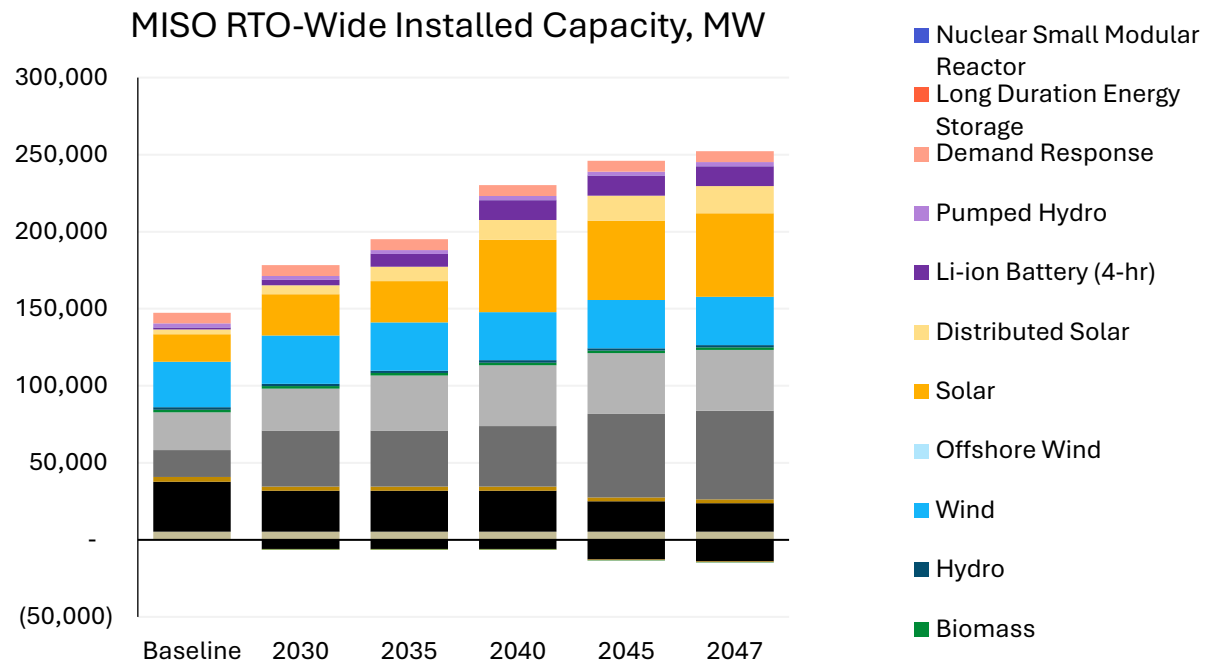


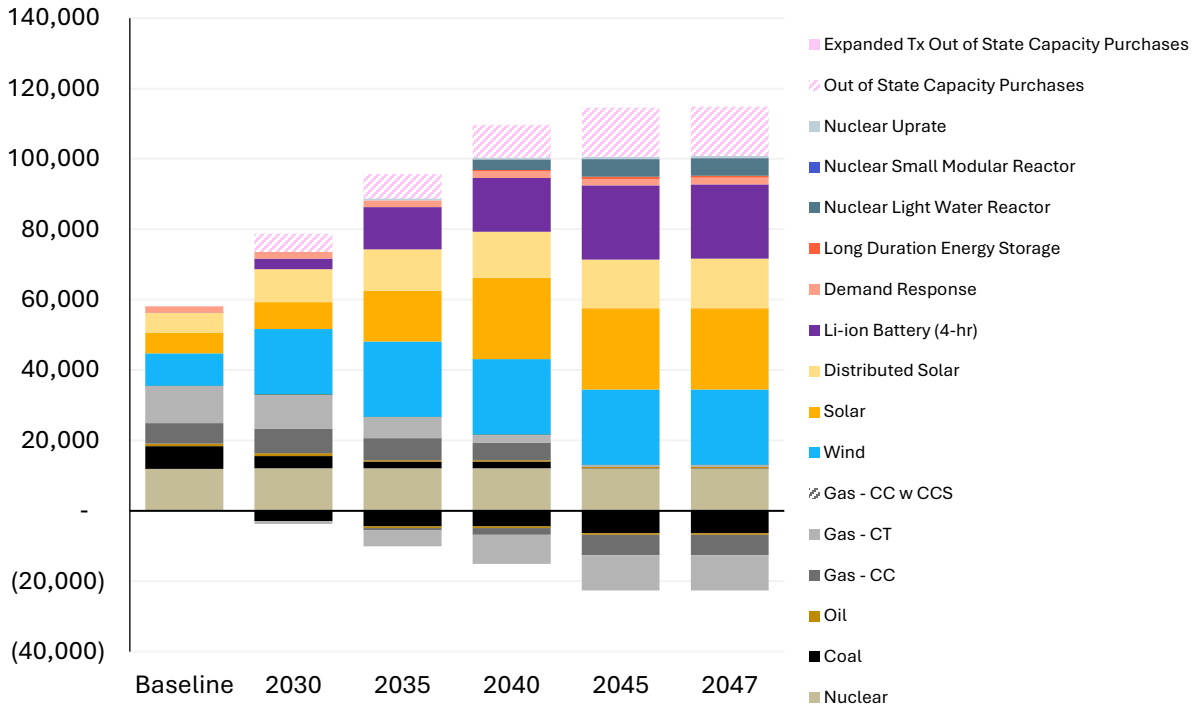
Figure 7-2 and Figure 7-3 show the installed capacity across both PJM and MISO across the modeling horizon with resource additions growing substantially to meet load growth in both

markets. In PJM, the installed capacity on the system must more than double to meet load growth, and in MISO the system grows by 71%. As discussed in Chapter 4, from an accounting perspective of simply looking at resource retirements, resource additions, and load growth over the near term, PJM and MISO both face reliability deficits unless significant new reliability resources are developed. The above results consider what would need to be built in order to meet load growth needs in both regions. PJM and MISO are not modeled as having the same policy constraints as Illinois, and therefore the model largely selects new gas generation, storage and renewables to meet load over time. In the context of the Mitigation Plan, this context of the broader region is important to understanding the scale of resource builds that would need to happen in Illinois, and across all of PJM and MISO, to meet forecasted loads in these scenarios.

7.2.1 Illinois Installed Capacity and Firm Capacity

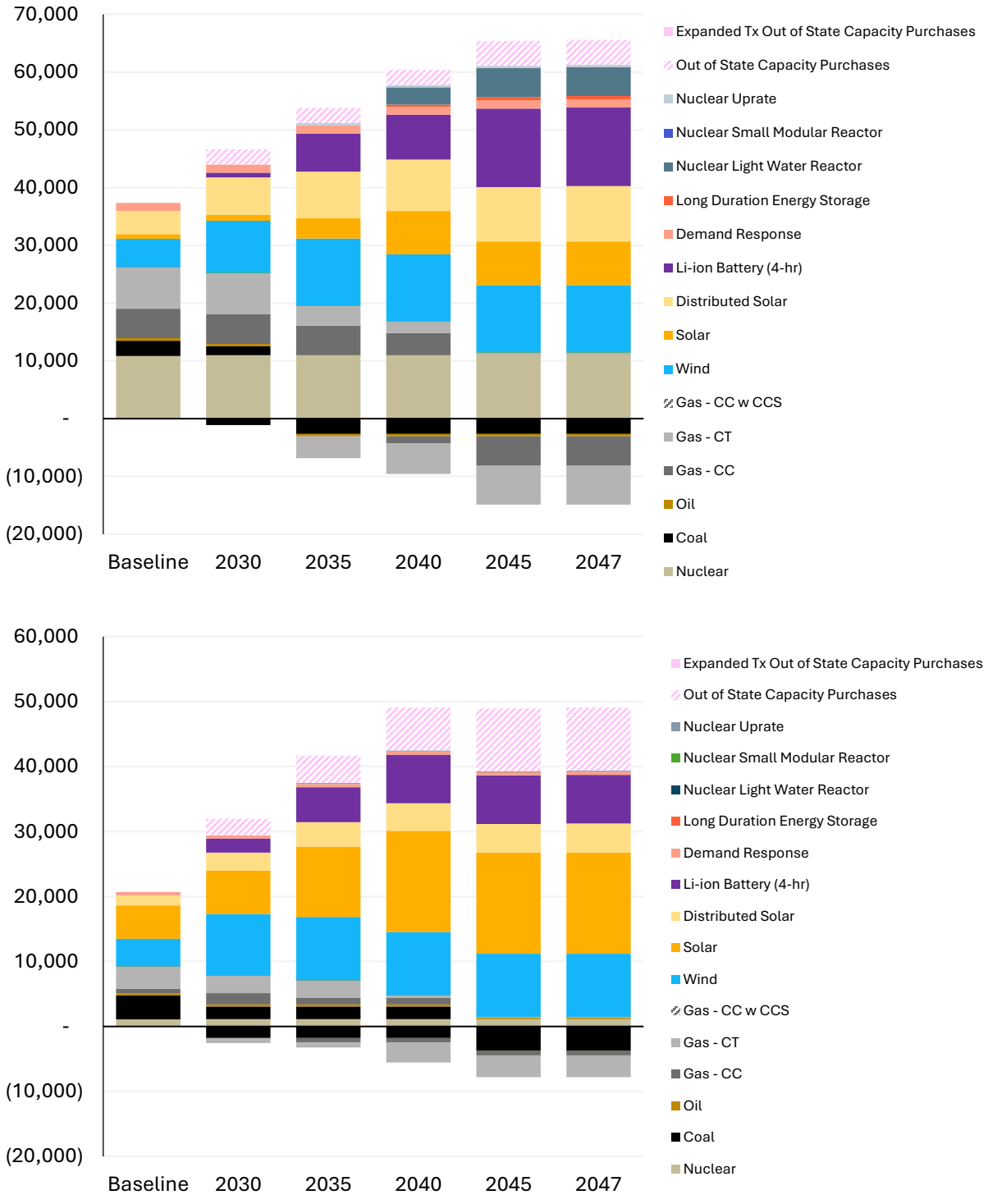
Within Illinois, the Reference Case requires a substantial expansion of the resource portfolio to serve projected load while meeting reliability and State policy requirements. Illinois installed nameplate capacity more than doubles by 2045 (see Figure 7-4). New wind, solar, four-hour battery storage, nuclear uprates, firm capacity imports, and, in the longer term, new light-water-reactor nuclear and long-duration energy storage are selected as CEJA-limited thermal units retire.

Figure 7-4: Reference Case Illinois Installed Capacity (MW)



The buildout differs by Illinois region. In MISO LRZ 4, in-zone nameplate capacity more than doubles over the modeling horizon. The model selects a mix of new resources in the early years and increasingly relies on imported firm capacity from MISO over time. These firm capacity imports represent firm capacity resources, namely gas CTs, that are built outside of Illinois but are dedicated to meet Illinois firm capacity needs. These are modeled as deliverable to Illinois up to existing ZIA import limits (See Chapter 3). In ComEd, in-zone nameplate capacity increases by approximately 66% by 2047. As CEJA-limited units retirements occur, storage, firm out-of-state capacity, and new nuclear resources provide an increasing share of capacity.

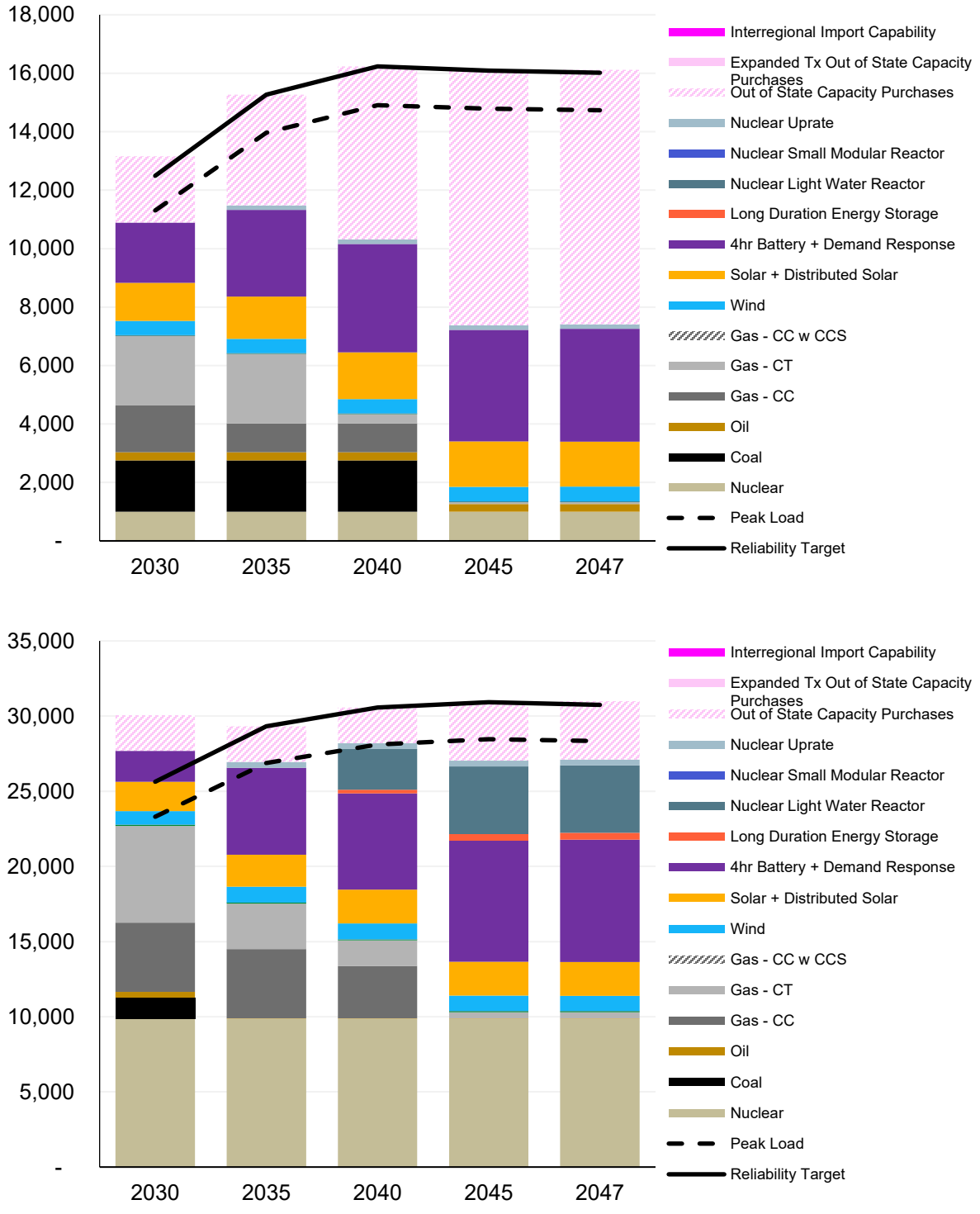
Figure 7-5: Reference Case MISO LRZ 4 (Top) and ComEd (Bottom) Installed Capacity (MW)



Note different y-axis between LRZ 4 and ComEd Cases

Importantly, the Firm Capacity contributions differ from the Installed Capacity, as seen in Figure 7-5. Firm capacity means the accredited capacity that group of resources represents in terms of meeting the reliability requirement of the region. This reflects the ELCC of the resources. Firm Capacity does not equate to how much a resource generates, as discussed in the following section, but simply represents its reliability value to the system—how much the resource is capable of generating across a wide range of possible reliability risk hours. In both LRZ 4 and ComEd, fossil units make up a significant portion of firm capacity prior to CEJA-limited units retirement dates in 2045. The model must then build resources that meet the reliability requirement to both account for load growth, and therefore higher reliability requirements, and the CEJA-limited units retirements. These are primarily met through increased 4-hour storage, nuclear uprates, new light water reactors and long duration energy storage. In LRZ 4, imports from out of state capacity resources increasingly make up the largest portion of firm capacity over the model time horizon.

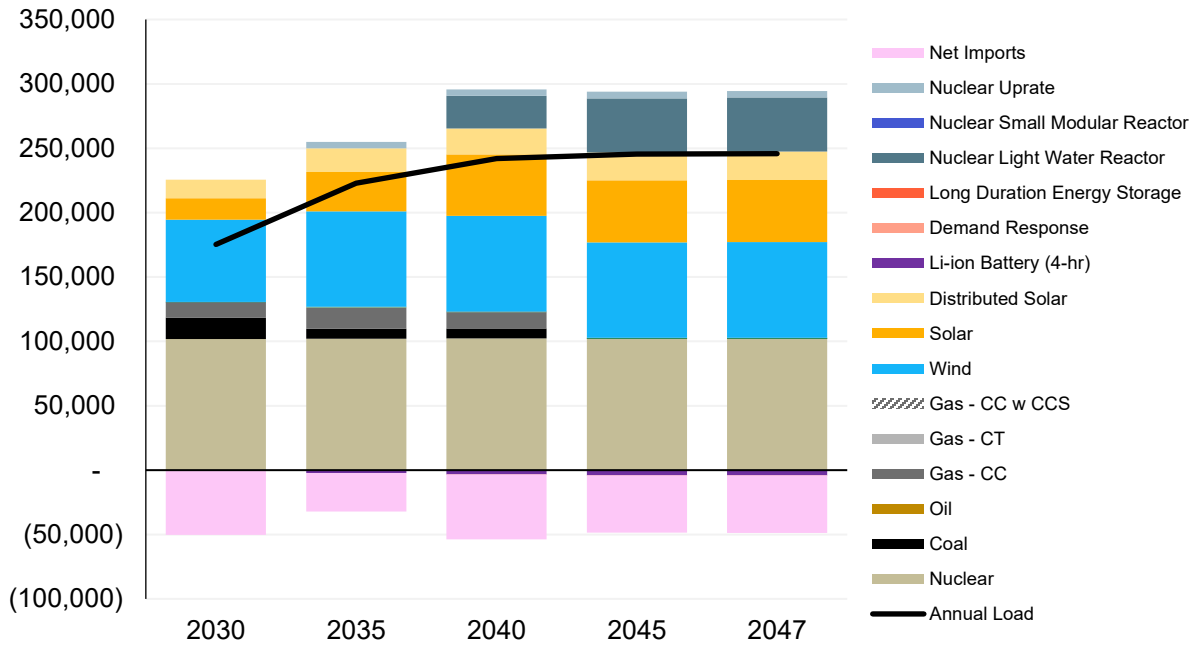
Figure 7-6: Reference Case MISO LRZ 4 (Top) and ComEd (Bottom) Firm Capacity (MW)



7.2.2 Generation Dispatch and Energy Balance

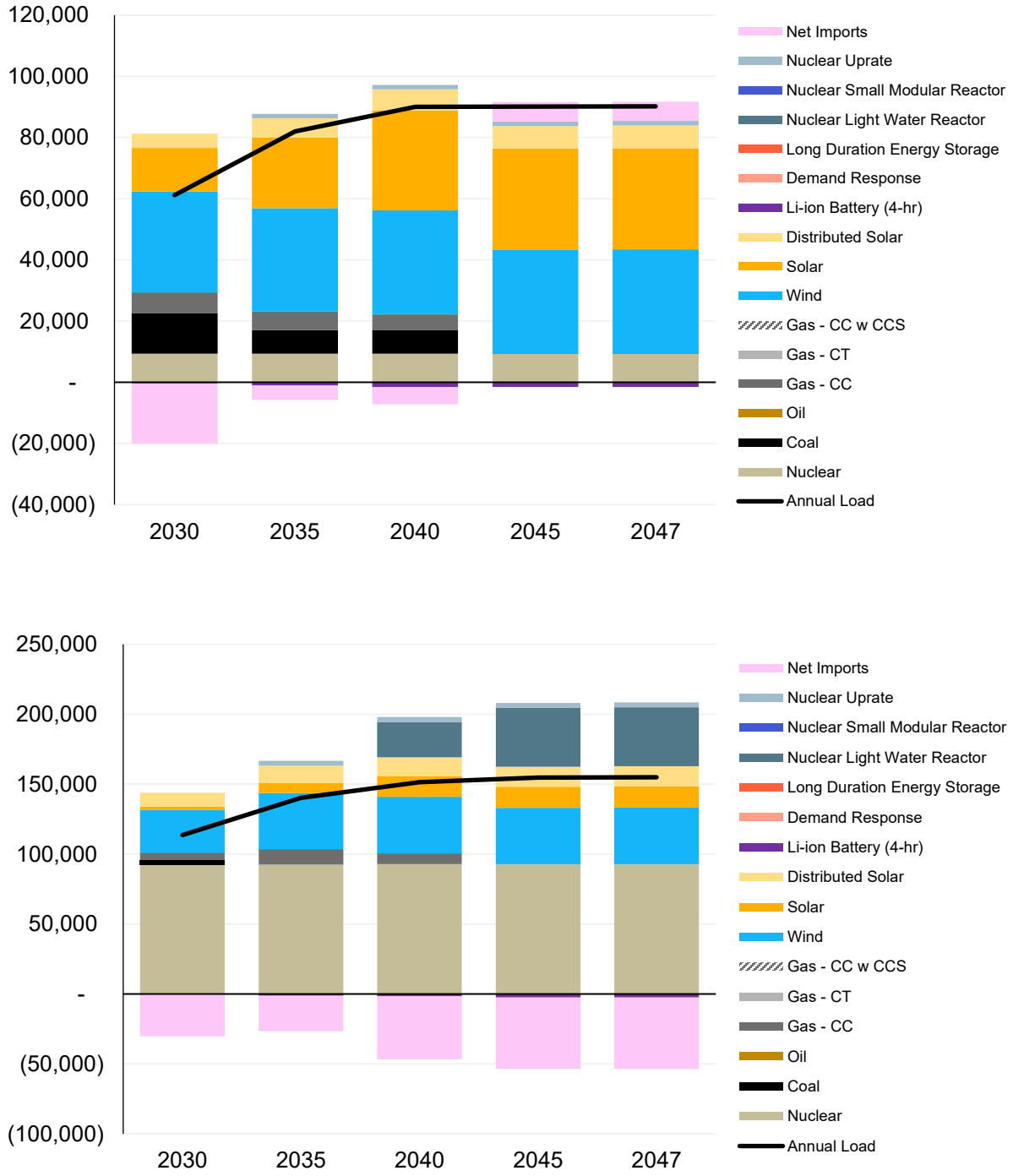
Across Illinois, most annual energy is supplied by clean resources throughout the modeling horizon. Approximately 89 percent of in-state generation is zero-emitting in 2030, increasing to approximately 99.9 percent by 2045. Illinois remains a net exporter of energy in the statewide results across the modeled years.

Figure 7-7: Reference Case Illinois Generation



The regional energy balance differs between the two Illinois zones. LRZ 4 is primarily served by clean generation across the forecast horizon but becomes a net importer after 2040. ComEd increases net exports over time as new nuclear capacity and renewable generation exceed in-zone energy needs and the surplus is exported to the broader PJM system. ComEd is exporting because the zone must build new nuclear to meet its reliability requirement, while simultaneously meeting 50% of load by renewable resources by 2040 (required by current state policy), leading to a dynamic where ComEd exports excess energy produced by nuclear, a high capacity factor resource, to the rest of PJM.

Figure 7-8: Reference Case LRZ 4 (Top) and ComEd (Bottom) Generation and Load (GWh)



7.2.3 Portfolio Costs

Figure 7-9: Reference Case Total System Costs for LRZ 4 (Top) and ComEd (Bottom)

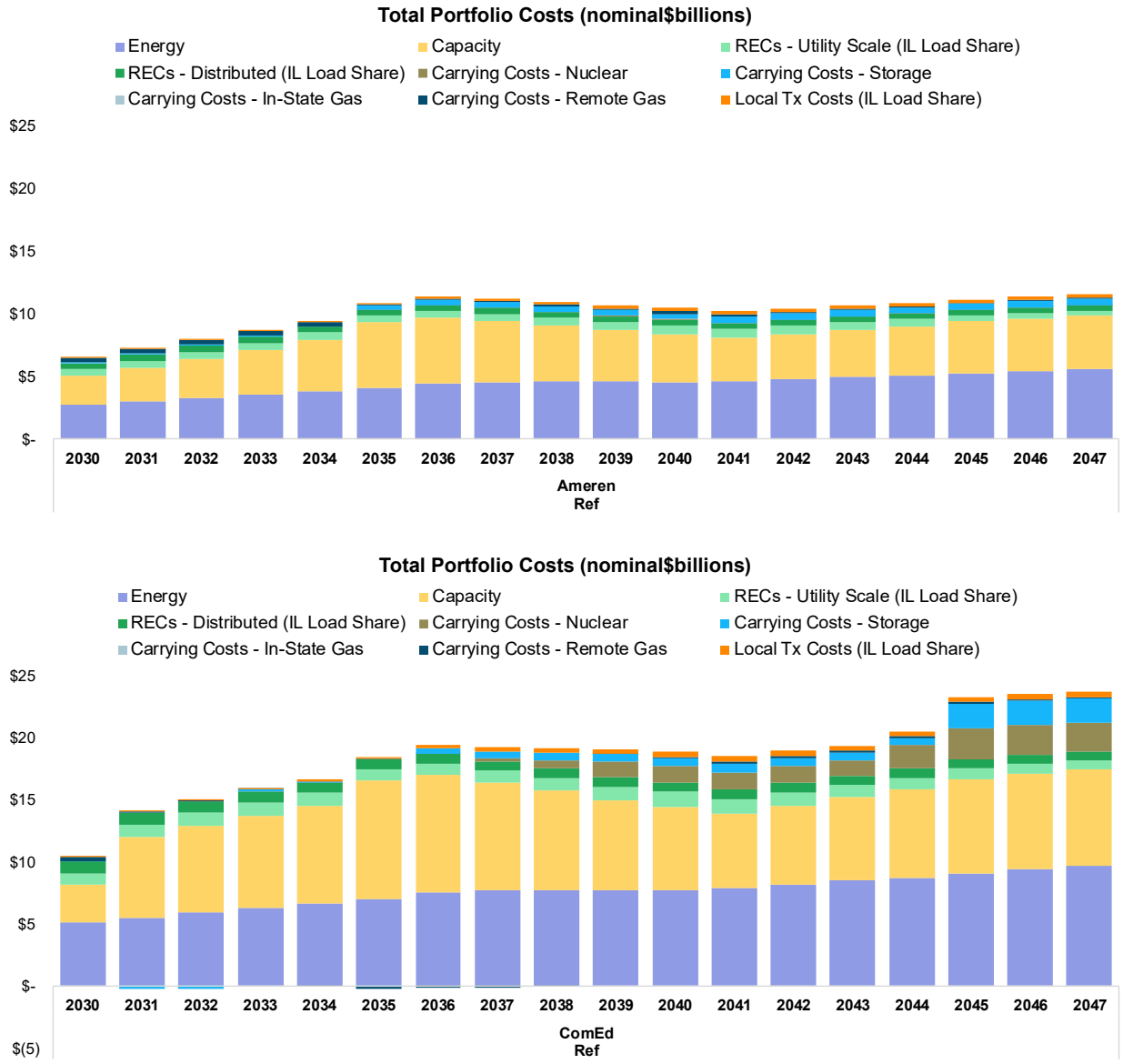


Figure 7-9 shows total system costs for Ameren and ComEd under the Reference Case. Energy costs are the production costs of all resources in the portfolio, taken directly from PLEXOS. Capacity costs are based on the Net Cost of New Entry (Net CONE) of the marginal capacity resource in the market. The one exception is ComEd before 2030, where capacity costs use actual PJM capacity prices, which cleared at the administrative cap. Energy and capacity make up most of the total system costs.

Capacity costs vary over the forecast horizon because the marginal capacity resource, and therefore the Net CONE, changes over time. From 2030 through 2034, four-hour battery storage is the marginal resource in both markets, and capacity prices reflect its Net CONE.

Beginning in 2035, the markets reach the cost of new gas capacity: combined-cycle units set the marginal price in PJM, while combined-cycle and combustion turbine units alternate as the marginal resource in MISO. Capacity costs peak in 2035 and 2036, when prices first transition to the Net CONE of new gas capacity, which is elevated at that point. Prices then decline as gross CONE falls until 2041. After that, capacity prices rise again as gross CONE increases with inflation while net energy revenues remain roughly flat, pushing Net CONE higher through the end of the forecast period.

All resources in the PJM and MISO markets earn revenues from participation in energy and ancillary services markets and annual capacity auctions. New resources need stable revenues to secure investment capital, and this revenue typically comes from multi-year contracts with load serving entities. Such contracts can be structured in many ways, but the common principle is buyers offer a certain amount of fixed revenue to a resource in exchange for some or all of the resource's variable market revenues. Sometimes this fixed revenue covers all of the resource's annual costs and sometimes the resource remains exposed to market revenue variability, thus sharing this risk with the buyer.

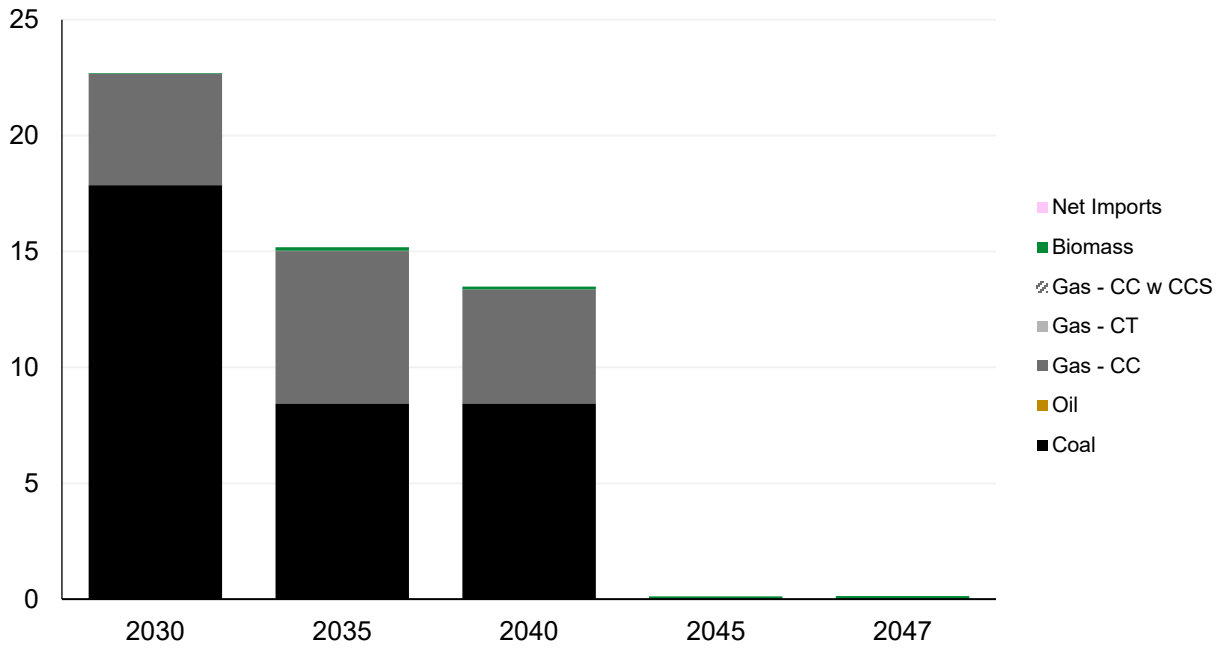
"Carrying costs" represent the difference between a resource's total annual costs (including recovery of investment costs with a return on capital, plus fixed and variable costs of operations) and market revenues from energy, ancillary services, and capacity markets in a given year. Carrying costs may be positive or negative for a given resource in a given year. If these costs are positive, it means that market revenues are lower than the resource's total costs (representing an additional cost to the buyer or resource owner). If carrying costs are negative, market revenues exceed the resource's total costs and represent additional value to the buyer or the resource owner depending on the contract structure. This analysis calculates carrying costs for new resources selected in each portfolio for each forecast year—namely new nuclear, out-of-state gas and battery storage resources. ComEd's total costs are higher than Ameren's due to higher resource builds. In these two scenarios, new gas generation is the marginal capacity resource in MISO and PJM in the long term, but is not allowed in Illinois according to state policy. As an alternative, ComEd and Ameren zones must rely on out of state gas capacity or in-state storage or new nuclear power for reliability, and these resources have higher costs than the market over the forecast horizon. By 2045, carrying costs for new resources make up 15% of total system costs in ComEd.

These results are the modeled cost of building and operating the electric system under Reference Case assumptions. These results show the likely direction and magnitude of system costs needed to meet long-term system needs with these technology and policy assumptions.

7.2.4 Emissions

This study evaluates electric sector CO2 emissions for Illinois based on the sum of emissions from in-state generators (coal, gas, and oil) and emissions from net imports from outside the state (on an annual basis). This conceptual framework is aligned with the principal framing of CEJA as well as practices used in other states. Generation projections for in-state fossil units, imports, and exports are derived from simulated dispatch results in the PLEXOS LT model. In each year, if imports to Illinois zones (ComEd and LRZ 4) exceed exports, the remaining net imports are assigned the average emissions rate of the exporting region. If exports exceed imports, no emissions from imported electricity are attributed to Illinois. Under the Reference Case, Illinois is a net exporter throughout the modeled period, and so the state's electric sector CO_2 emissions are based solely on the emissions of in-state fossil generators. The decline in reported Illinois electricity-sector emissions therefore reflects the phaseout of in-state fossil generation, reaching approximately zero by 2045.

Figure 7-10: Reference Case, Illinois CO_2 Emissions from the Electric Sector (million short tons)



The Reference Case substantially reduces emissions produced within Illinois, but part of the reliability need previously served by in-state fossil resources shifts to resources located outside the state. In LRZ 4, the model increasingly relies on firm capacity located outside Illinois, including new out-of-state gas resources developed to support Illinois reliability needs. Although emissions from imported electricity are offset by Illinois exports under the

study's net import accounting framework, the imported electricity itself is still produced by resources that emit CO_2 and which are developed to support Illinois state reliability needs.

7.3 CEJA Extension Case PLEXOS Results

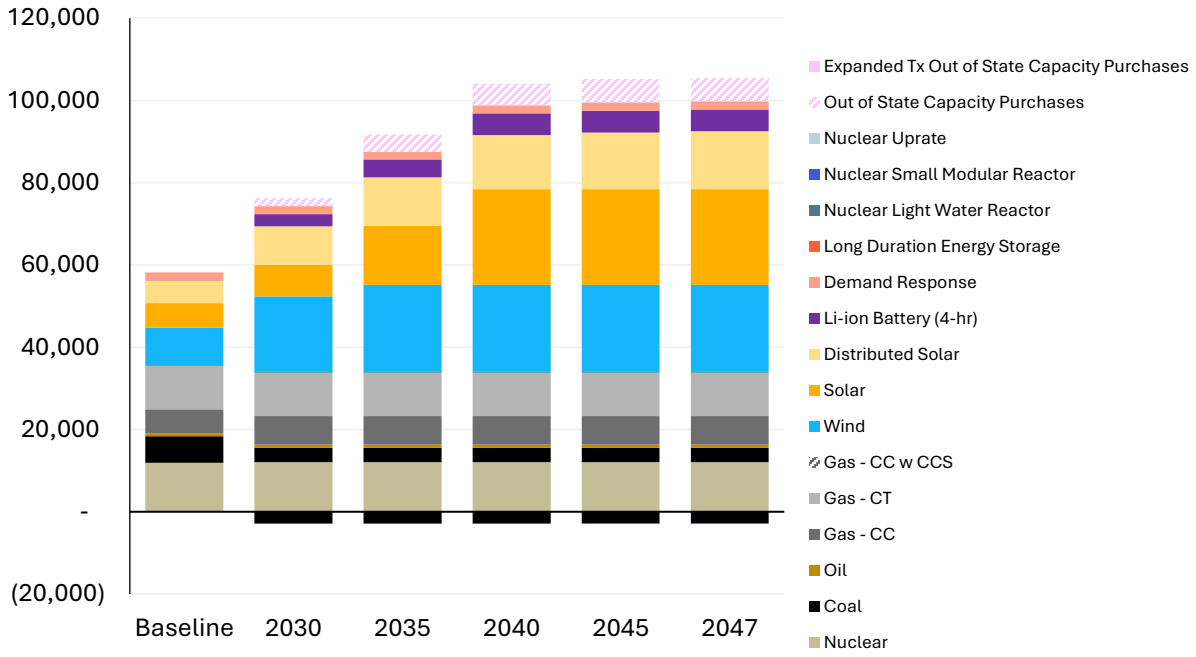
The CEJA Extension Case tests the impact of retaining all CEJA-limited units for the entire modeling horizon, while still applying the annual emissions reductions targets by fuel and unit type through 2044 and applying the 2044 emissions limits through 2047. All other assumptions are unchanged. The results are presented primarily as changes relative to the Reference Case, including resources avoided or deferred and changes in accredited capacity, regional generation and imports, system costs, and electric sector emissions.

The comparison is intended to determine whether the continued availability of CEJA-limited units materially changes the scale, timing, composition, or feasibility of the replacement-resource portfolio. It also distinguishes between investments that are permanently avoided and investments that are deferred until the assumed extension ends.

7.3.1 Selected and Installed Capacity

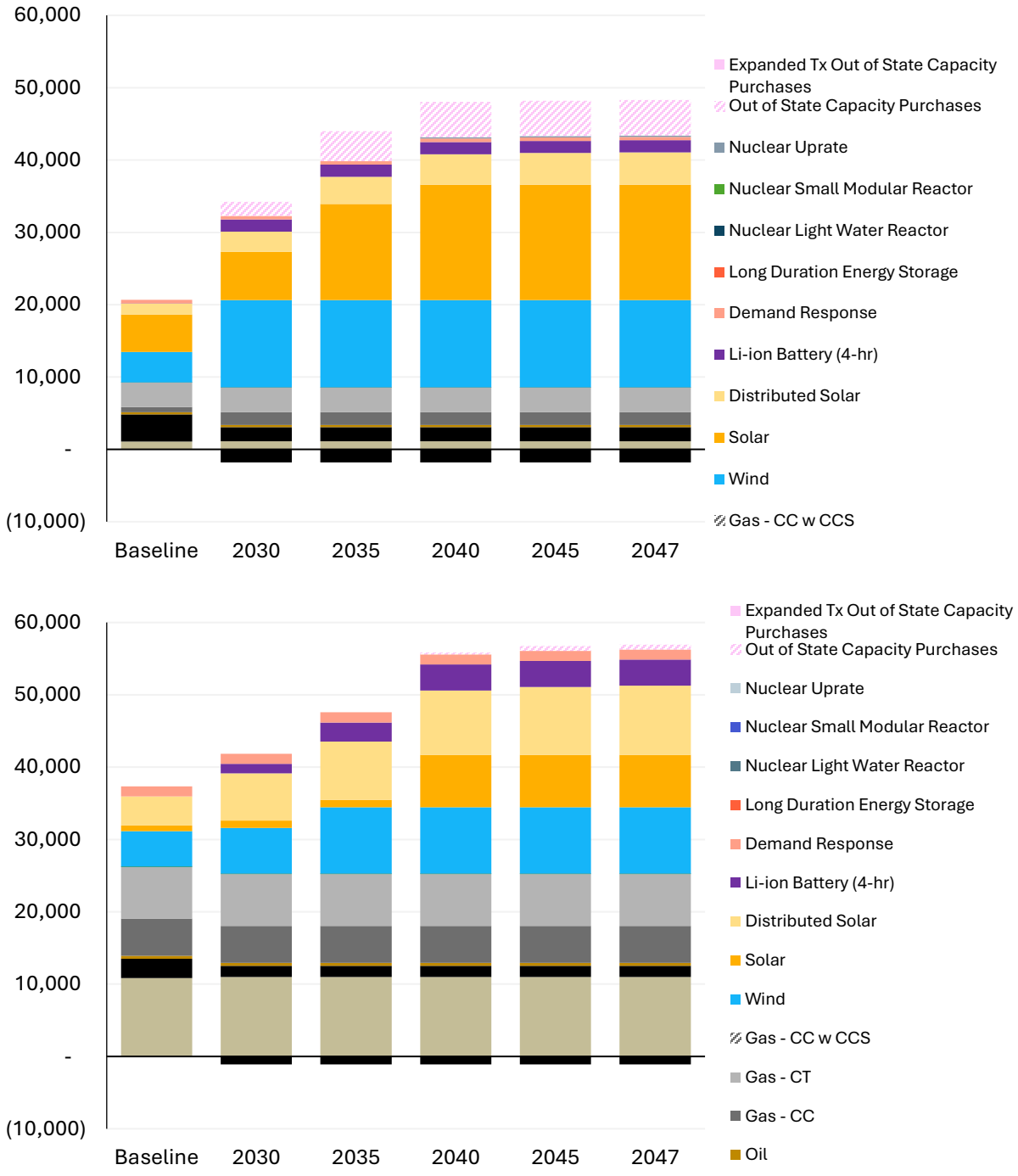
Like the Reference Case, the CEJA Extension Case also requires a substantial expansion of Illinois resources to serve projected load and meet the Renewable Portfolio Standard, but retaining CEJA-limited units reduces the amount of new firm capacity that must be developed to maintain system resource adequacy standards. Illinois nameplate capacity still grows by approximately 90 percent by 2045 relative to today.

Figure 7-11: CEJA Extension Case Illinois Installed Capacity (MW)



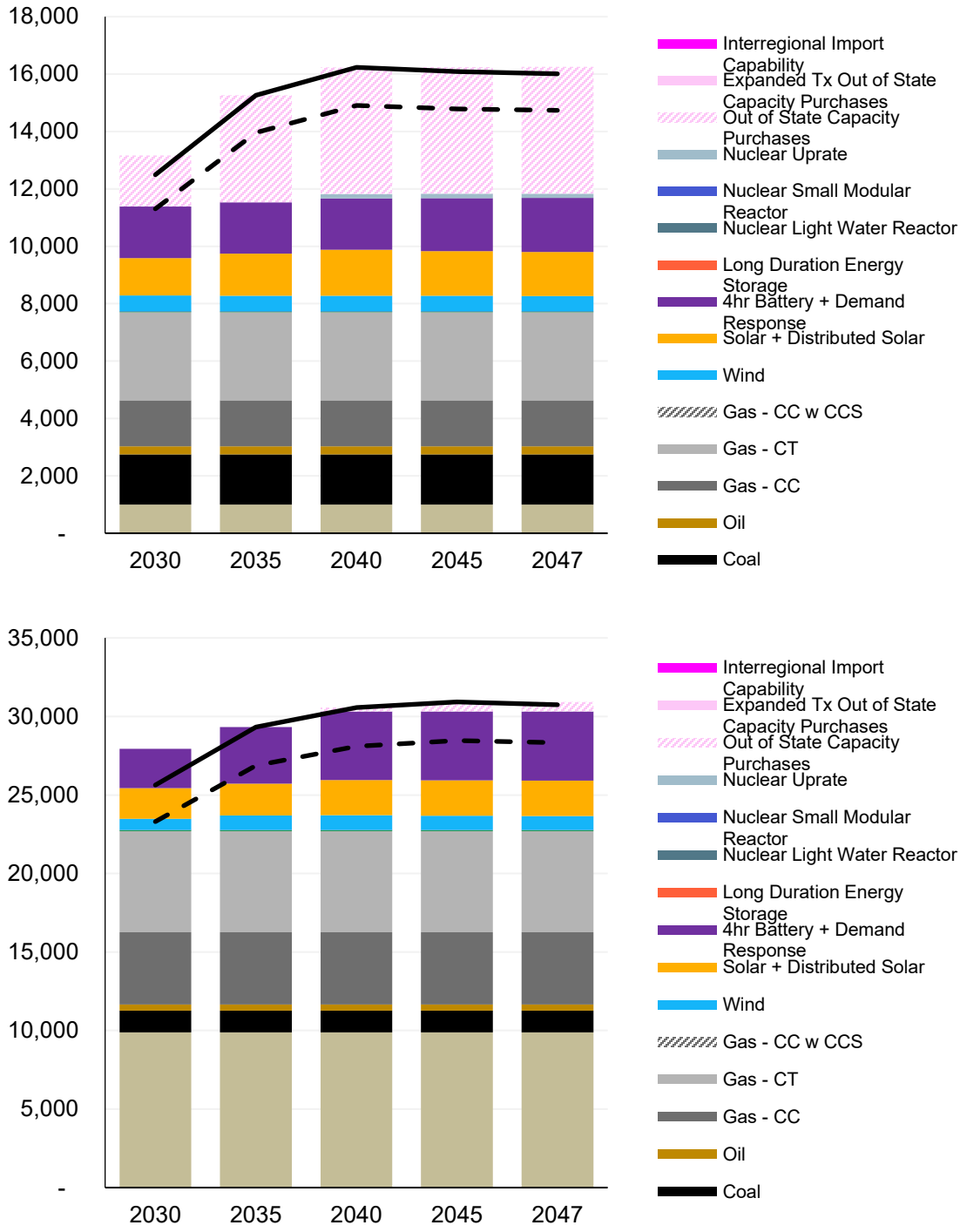
New resource additions in the CEJA Extension Case are concentrated in technologies that are commercially deployable today, principally wind, solar, and four-hour battery storage, together with firm capacity imports and nuclear uprates (Figure 7-11). Because existing thermal resources remain available for firm capacity, a larger portion of new builds is driven by the Renewable Portfolio Standard rather than by replacement of retiring firm capacity. More wind and solar is added in LRZ 4 relative to ComEd (Figure 7-12). LRZ 4 continues to rely much more on out-of-state capacity than ComEd, but both zones rely primarily on gas resources for reliability (whether in state or imported) (Figure 7-13).

Figure 7-12: CEJA Extension Case MISO LRZ 4 (Top) and ComEd (Bottom) Installed Capacity (MW)



In the CEJA Extension Case, both zones reduce reliance on out-of-state capacity relative to the Reference Case. In ComEd, between existing nuclear and maintaining CEJA-limited units, the remaining reliability requirement is met by storage and renewables with a small amount of out-of-state capacity imported into the zone.

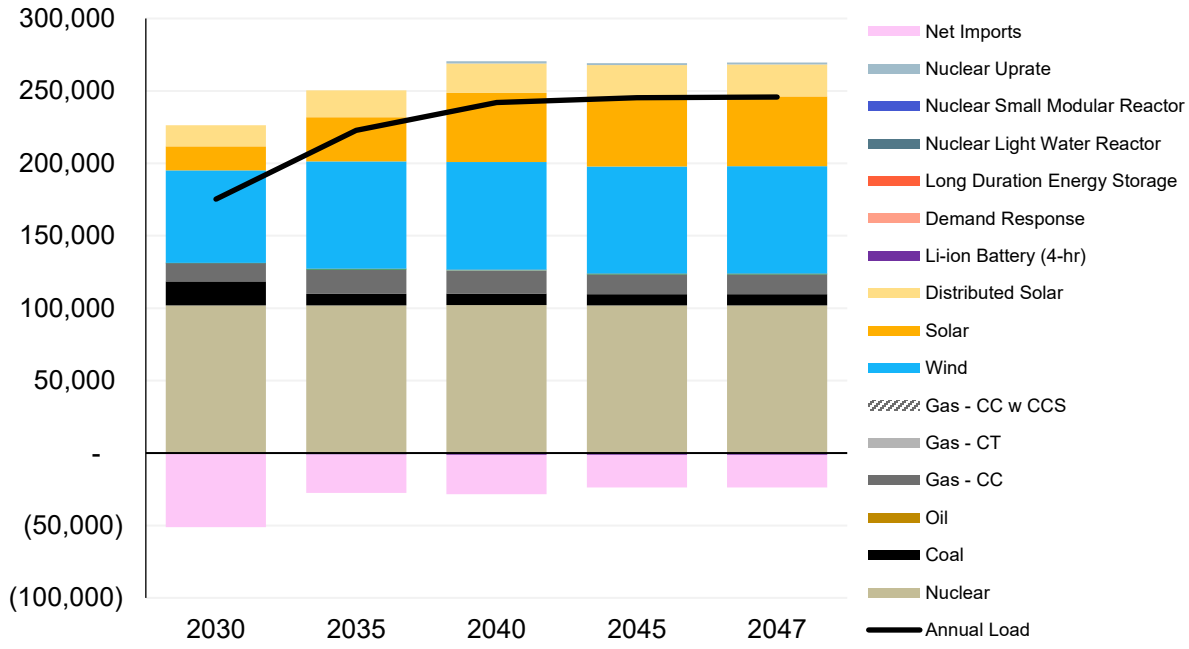
Figure 7-13: CEJA Extension Case MISO LRZ 4 (Top) and ComEd (Bottom) Firm Capacity (MW)



7.3.2 Generation Dispatch and Energy Balance

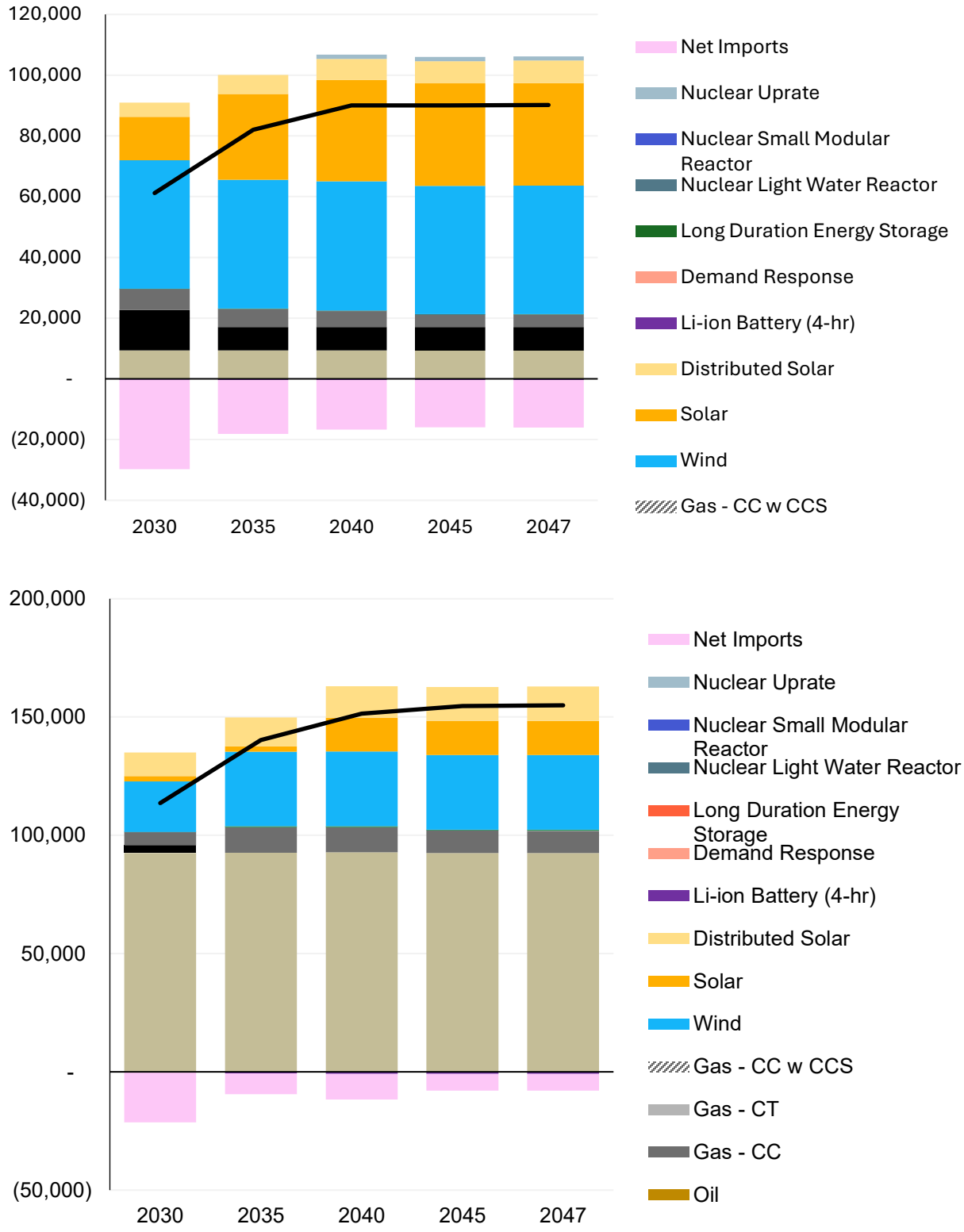
Continued availability of CEJA-limited units changes the composition of firm capacity more than it changes the overall direction of the energy transition. Gas generators represent a larger share of firm capacity but operate infrequently. Across Illinois, approximately 88 percent of in-state generation is zero-emitting in 2030 and approximately 92 percent is zero-emitting by 2045 even with CEJA-limited units remaining available.

Figure 7-14: CEJA Extension Case Illinois Generation (GWh)



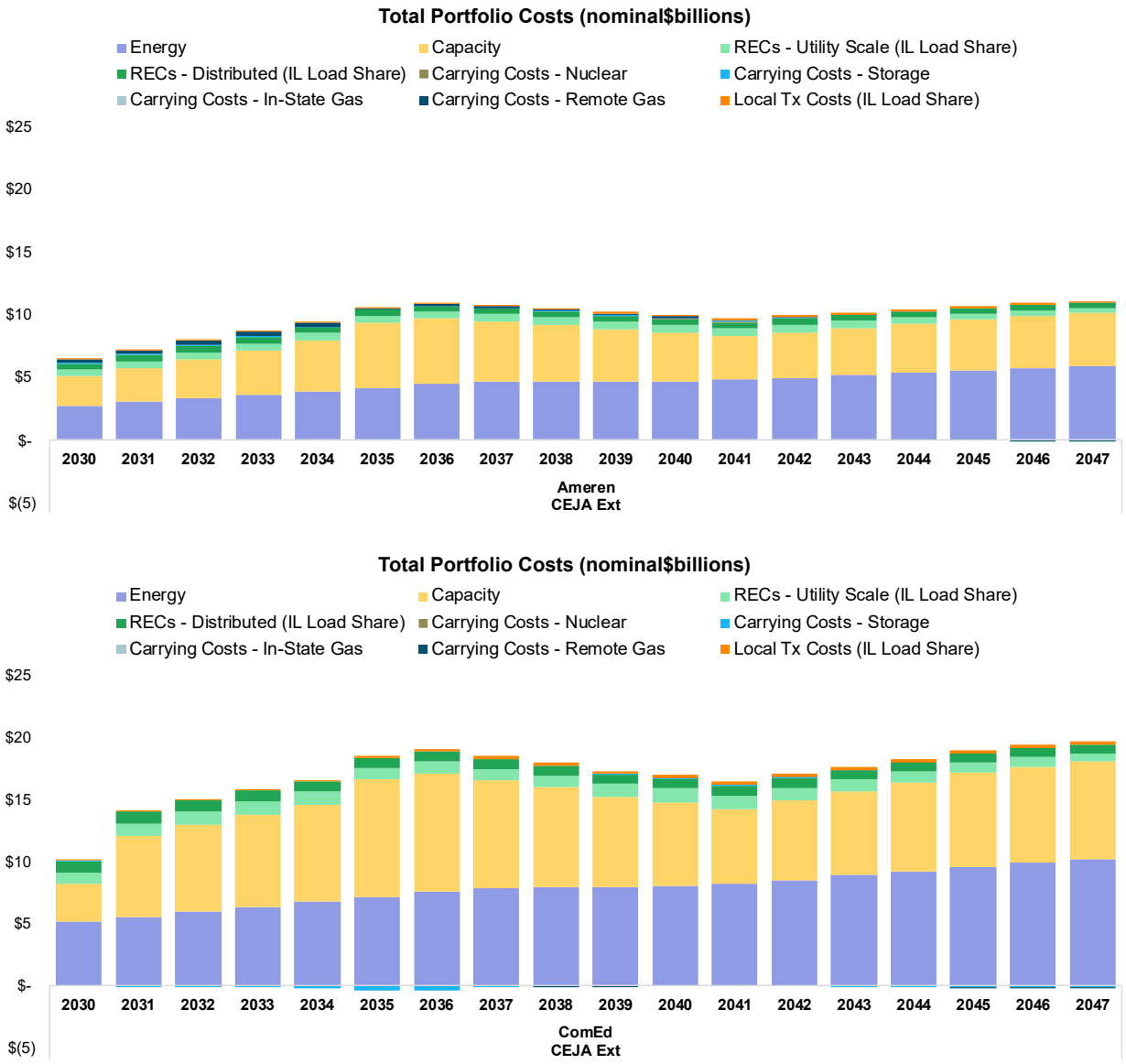
In both LRZ 4 and ComEd zones, even as CEJA-limited units remain online, the majority of energy demand is met with clean resources. In LRZ 4, from 2030 to 2045, in-state clean generation rises from 81% to 89%. In ComEd, in-state clean generation remains at 94% throughout the model time period. When juxtaposed with firm capacity, this affirms the finding that even if Illinois maintains fossil generation by delaying CEJA retirements, Illinois can still achieve substantial emissions reductions in the electric sector comparable to the Reference Case.

Figure 7-15: CEJA Extension Case LRZ 4 (Top) and ComEd (Bottom) Generation (GWh)



7.3.3 Portfolio Costs

Figure 7-16: CEJA Extension Case Total System Costs for LRZ 4 (Top) and ComEd (Bottom)

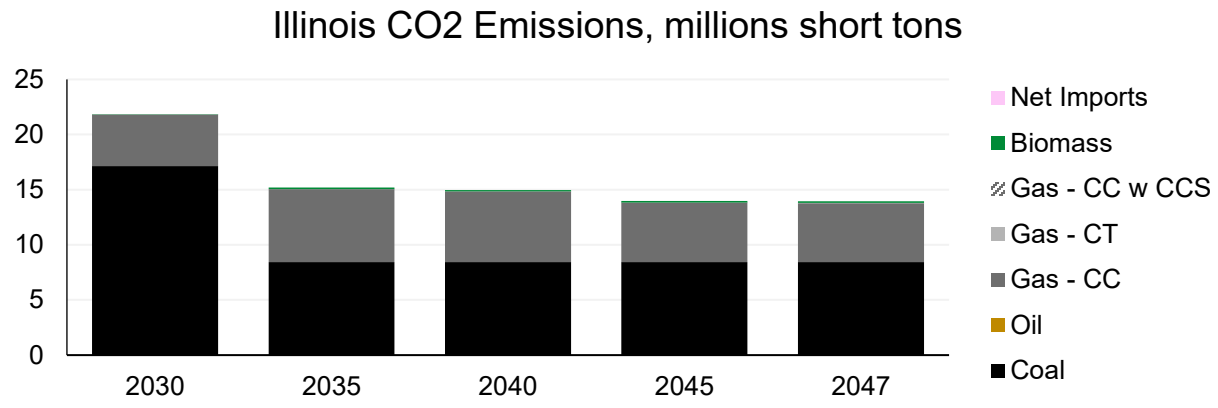


In the CEJA Extension Case, system costs are lower in both ComEd and LRZ 4 compared to the Reference Case, and total costs remain higher in ComEd than in LRZ 4. Because the CEJA-limited units stay online, PLEXOS builds little out-of-state gas and no new nuclear in ComEd. As a result, ComEd has no new-resource carrying costs in this case, nearly all of system costs come from energy, capacity, and RECs.

7.3.4 Emissions

The CEJA Extension Case produces a different emissions trajectory than the Reference Case because CEJA-limited units remain available beyond their otherwise applicable retirement dates. These units continue to comply with CEJA's interim emissions-reduction requirements through 2044, and their emissions are then capped at the 2044 level for the remainder of the modeling period. As a result, Illinois power-sector CO_2 emissions decline substantially from 2030 through the mid-2040s, but do not fall to nearly zero as they do in the Reference Case. Instead, modeled emissions level off at roughly 14 million short tons per year after 2040.

Figure 7-17: CEJA Extension Case Illinois CO_2 Emissions

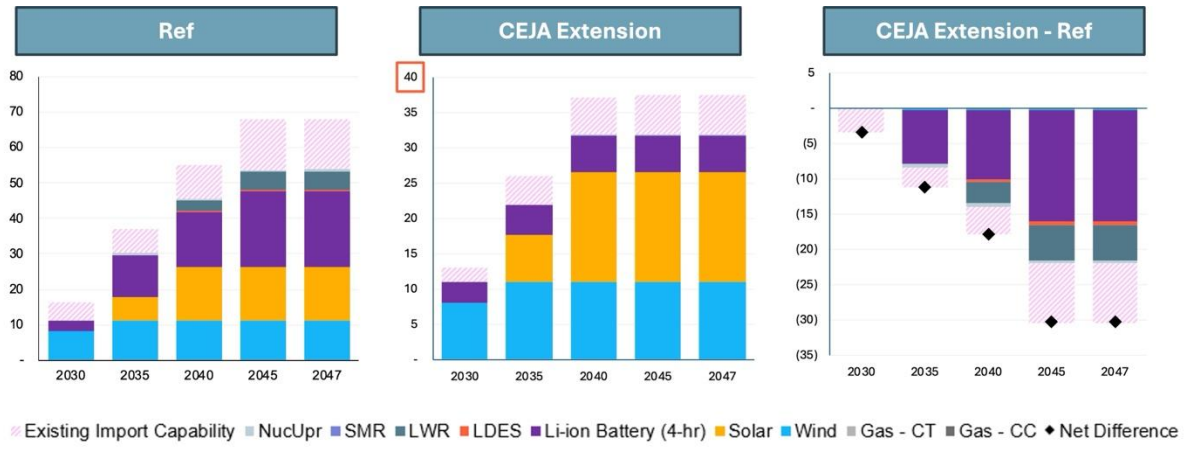


7.4 Comparison of Reference Case and CEJA Extension Case

The two cases share the same load forecast, resource cost assumptions, RPS requirements, transmission limits, and candidate resource options. The principal difference is the continued availability of CEJA-limited generating units. This allows the study to isolate how the retirement schedule changes the scale and composition of the replacement portfolio.

Both cases require Illinois to add a substantial amount of new capacity; renewable resources make up the largest share of new nameplate capacity in both cases to achieve the state's RPS goals. The key difference is the amount and type of firm capacity required. By 2045, the CEJA Extension Case saves a total of 31 GW in nameplate capacity across all resource types compared to the Reference Case. The avoided resources include 16.5 GW of four-hour battery storage, 5 GW of new nuclear light-water-reactors, 0.5 GW long-duration energy storage, and approximately 8.3 GW of capacity imports (see Figure 7-18). These reductions are possible because more than 20 GW of existing CEJA-limited capacity remains online in the Extension Case.

Figure 7-18: Comparison of Illinois Selected Capacity between Reference Case and CEJA Extension Case[77]



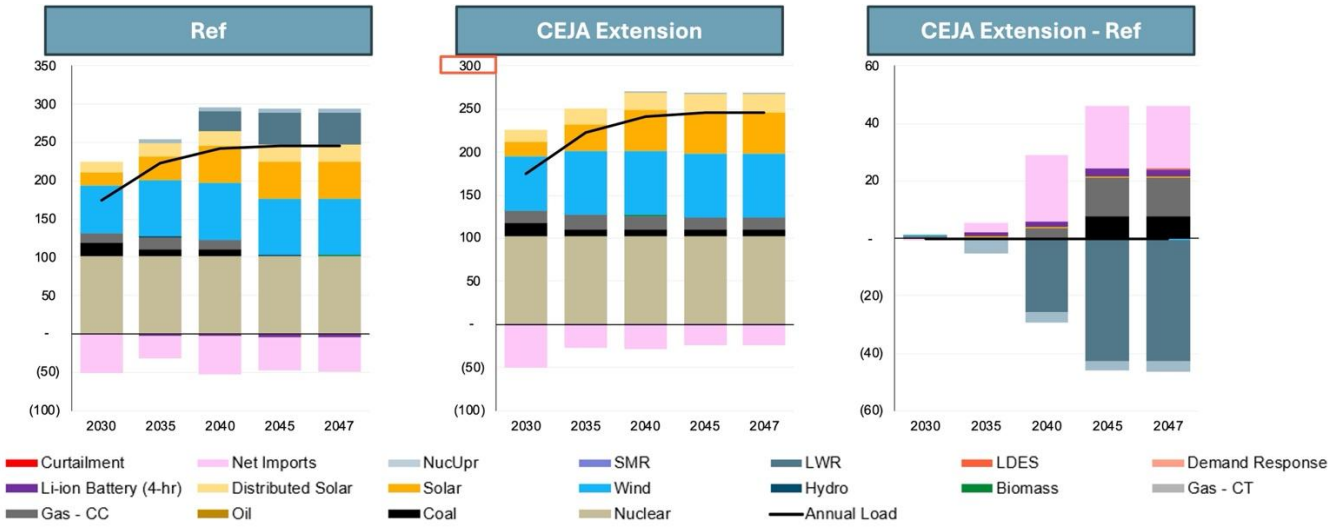
The technology mix between the two cases also differs in an important way. The CEJA Extension Case relies on resources that are already commercially deployable at scale, principally wind, solar, and four-hour battery storage. The Reference Case requires new light-water-reactor nuclear plants and long-duration energy storage to replace retiring firm capacity. Only three new nuclear light water reactors have reached commercial operation in the United States in the past 30 years (since 1996): Watts Bar Unit 2 (2016), Vogtle Unit 3 (2023), and Vogtle Unit 4 (2024). All three of these units encountered significant delays and cost overruns. No long duration battery storage technology has been deployed at a GW scale in the U.S., nor has any of these technologies demonstrated a significant commercial operating history.[78] As a result, the Reference Case carries greater long-term execution risk associated with the timing, cost, and commercial availability of replacement firm resources.

When comparing the generation across Illinois between the two cases, the difference mirrors the difference in selected capacity (Figure 7-19). The CEJA Extension Case has less generation from new nuclear (which is not selected in that case), more generation from in-state fossil units after 2045, lower reliance on out-of-state gas capacity, and fewer total exports than in the Reference Case.

[77] NucUpr = Nuclear Uprate, SMR = Small Modular Nuclear Reactor, LWR = Light Water Nuclear Reactor, LDES = Long Duration Energy Storage

[78] Pumped hydro storage is not included in this category as Illinois does not have any suitable sites for traditional pumped hydro development at a material scale.

Figure 7-19: Comparison of Illinois Generation between Reference Case and CEJA Extension Case



7.4.1 Cost comparison

Figure 7-20: Total System Cost Difference between Reference and CEJA Extension Cases

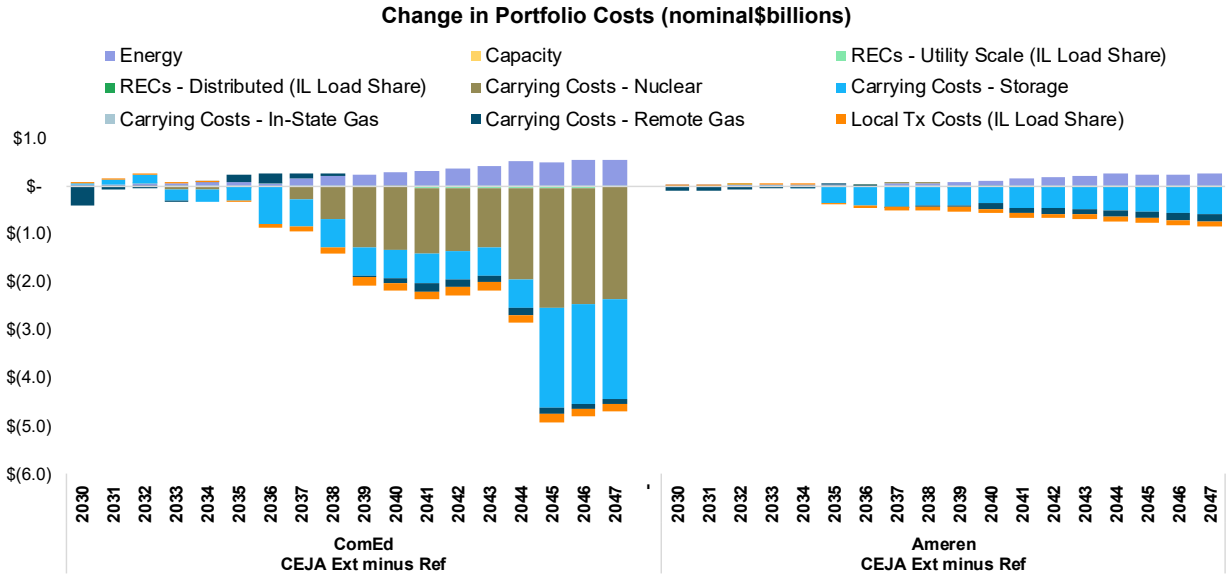


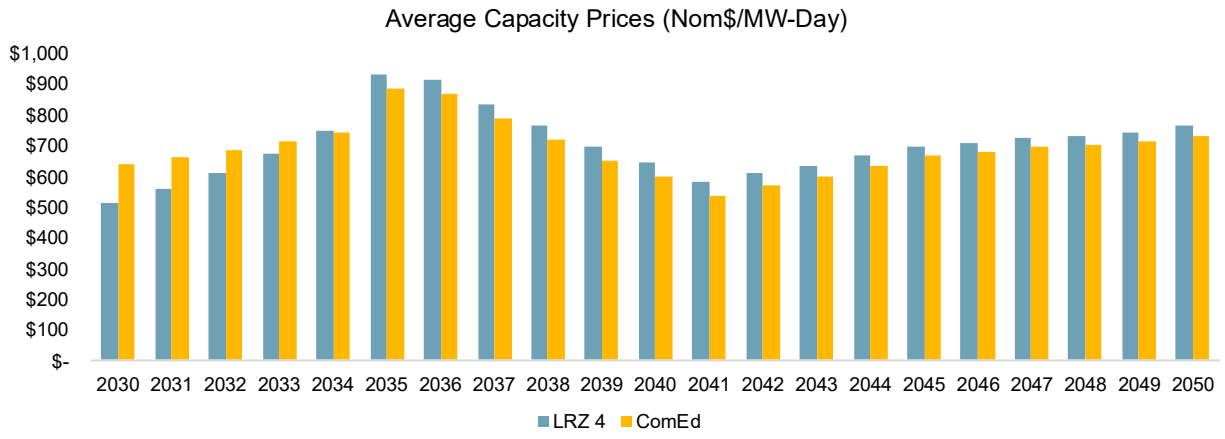
Figure 7-20 compares the cost difference between the Reference Case and the CEJA Extension Case. In 2035, total system costs in the CEJA Extension Case are $93 million lower than in the Reference Case for ComEd and $330 million lower for LRZ 4. By 2045, the savings grow to $4.4 billion for ComEd and $537 million for LRZ 4. The main difference

between the two cases in later years comes from carrying costs for new firm resources such as nuclear, remote gas, and batteries. The amount of these carrying costs depends on the energy and capacity revenues those resources earn.

The modeled cost savings reflect reductions in the need for replacement resources and associated system costs. However, the analysis does not include any additional costs that may be necessary to keep CEJA-limited units economically viable under the applicable emissions restrictions. Actual savings from extending these units would depend in part on the costs of maintaining their availability, including necessary capital investments, staffing, and other commercial arrangements.

Capacity prices are the same in both cases because each uses the same Net CONE assumptions for the marginal capacity resource. The average capacity price rises to $889/MW-day in ComEd and $938/MW-day in MISO LRZ 4 by 2035, as shown in Figure 7-21. Both are well above current capacity prices in PJM and MISO, which are below the costs of new entry for new gas generation. If capacity costs were calculated at current capacity price levels, new resources would earn less capacity revenue, and the carrying costs in the Reference Case would be higher.

Figure 7-21: Average Modeled Capacity Price

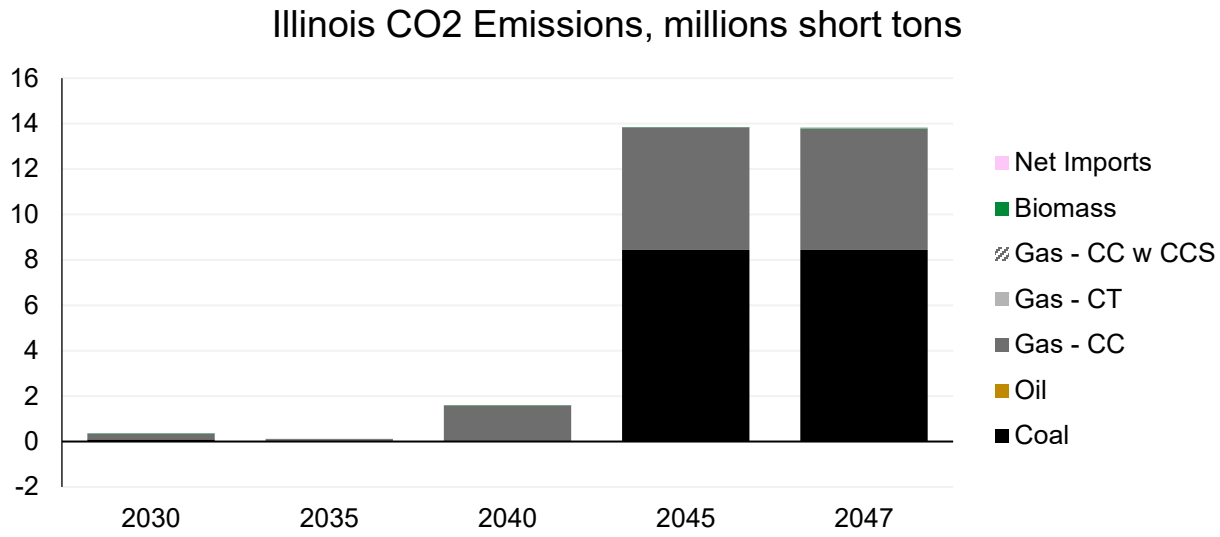


7.4.2 Emissions comparison

The comparison between the Reference Case and CEJA Extension Case highlights the central tradeoff examined in the Mitigation Plan between costs (Figure 7-20) and emissions (Figure 7-22). Retiring CEJA-limited units eliminates most in-state emissions from fossil-fired generation in the electricity sector by the mid-2040s and requires Illinois to replace the reliability contributions from these resources with additional storage, firm imports, and

other resources such as new nuclear generation. Extending the units reduces new in-state resource builds and reliance on out of state capacity but results in higher in-state emissions associated with their continued operations.

Figure 7-22: Difference of Illinois CO_2 Emissions Between Reference Case and CEJA Extension Case (CEJA Extension Case minus Reference)



When the comparison is expanded to include emissions associated with gross imports, the difference between the Reference Case and CEJA Extension Case narrows substantially. In the Reference Case, retiring Illinois fossil generation reduces in-state emissions, but part of the lost firm capacity is replaced by out-of-state fossil resources that generate electricity to support Illinois reliability needs. Those emissions occur outside Illinois and are not captured in the primary net-import accounting framework when Illinois remains a net exporter. By contrast, the CEJA Extension Case retains more of that firm capacity within Illinois, so a larger share of the associated emissions occurs in-state. The combined comparison therefore suggests that the two cases may produce similar total regional emissions associated with serving Illinois, while differing more significantly in where those emissions occur. While not a major differentiating factor for greenhouse gas emissions, whose impact is global, the location of resulting emissions could have important environmental justice implications.

Table 7-1 isolates the emissions consequence of extending each fuel class by reporting the incremental Illinois electric-sector emissions attributable to the extended units, divided by the MW of firm capacity of each fuel that remains available, for 2035 and 2047.

Table 7-1: Incremental Emissions (short ton/MW) of Firm Capacity Extended, Relative to Reference Case

	2035	2047
CO_2		
Coal	17,173	10,163
Gas	208	370
Oil	-	-
SO_2		
Coal	26.8	15.8
Gas	0.1	0.1
Oil	-	-
NOx		
Coal	5.7	3.4
Gas	0.1	0.2
Oil	-	-

The comparison shows that the emissions burden of an extension is concentrated in coal. Per MW of reliability value retained, coal units emit one to two orders of magnitude more CO_2, SO2, and NOx than gas units, reflecting both their higher emission rates and the fact that their lower marginal costs lead them to dispatch far more often than gas peaking units. Extended oil-fired units add no measurable emissions. Their contribution is limited to accredited capacity, consistent with their historical role as emergency resources. Extending coal units therefore means accepting a large increase in greenhouse gas and criteria pollutant emissions, with corresponding public health consequences for the surrounding communities, in exchange for firm capacity that the gas-only sensitivity shows can be

replaced at modest cost. Extending gas and oil units carries a small fraction of that burden for most of the reliability value.

7.5 Sensitivity Analysis Results

The gas-only sensitivity applies the same assumptions as the CEJA Extension Case, except that the coal-fired CEJA-limited units retire on their CEJA compliance schedule and only the gas-fired units remain available through 2047. The sensitivity isolates the contribution of approximately 3.5 GW of coal capacity within the broader extension and illustrates how the resource portfolio and emissions change if only the gas-fired units are extended. As with the CEJA Extension Case, this sensitivity is an illustrative bookend and not a recommended configuration.

Figure 7-23 compares the selected capacity in the two cases. Through 2030 the portfolios are identical. Beginning in 2035, the gas-only sensitivity replaces the retiring coal capacity primarily with additional four-hour battery storage, approximately 2.3 GW in 2035 rising to 3.2 GW by 2040. From 2045 onward, the sensitivity also relies on approximately 1.2 GW of additional existing import capability, bringing the net difference in selected capacity to about 4.4 GW. Renewable additions are essentially unchanged, so retiring the coal units changes the type of firm capacity in the portfolio without altering the overall direction of renewable development.

Figure 7-23: Illinois Selected Capacity between CEJA Extension and Gas Only

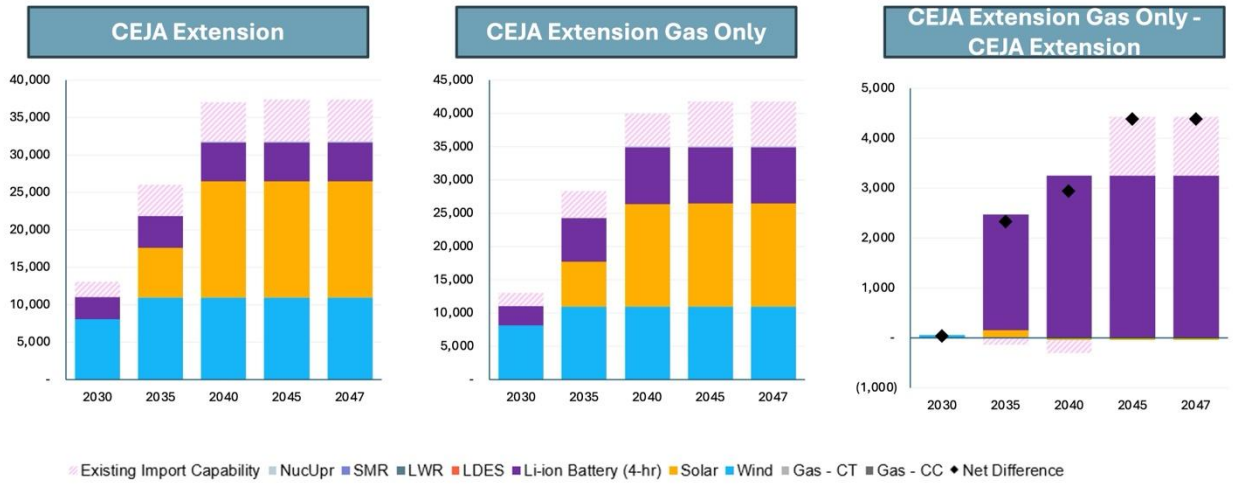
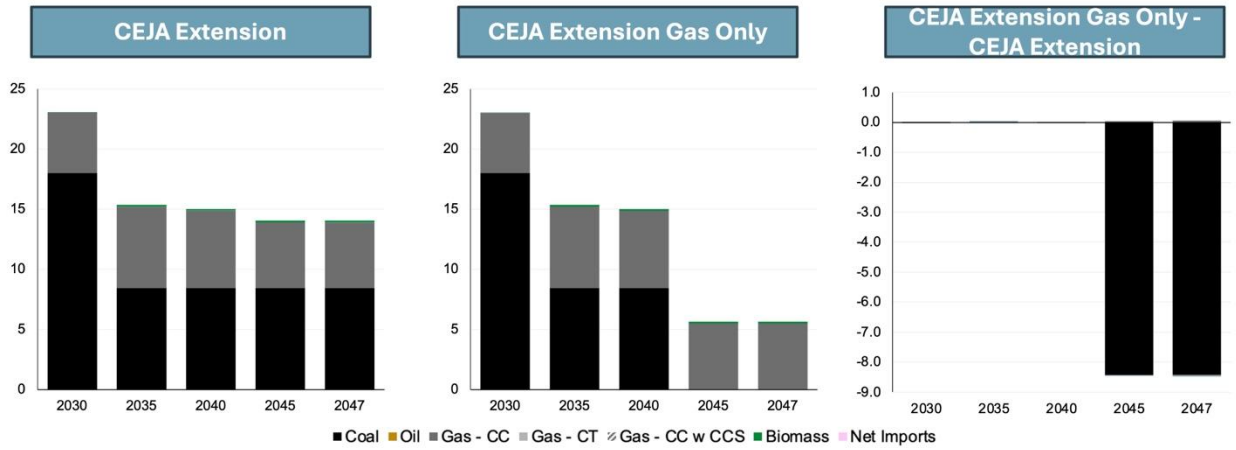


Figure 7-24 compares Illinois electric-sector CO_2 emissions under the two cases. Through 2040, emissions are nearly the same because the coal units remain online in both cases and operate under the same interim emissions limits. Once the coal units retire in 2045, emissions in the gas-only sensitivity fall to approximately 5.5 million short tons per year,

compared with approximately 14 million short tons in the CEJA Extension Case. Retiring the coal units therefore reduces emissions by roughly 8.4 million short tons per year, or about 60%, while the extended gas units continue to operate under their interim emissions limits.

Figure 7-24: Illinois Emissions between CEJA Extension and Gas Only



The comparison highlights a material difference between the coal and gas units in the ratio of capacity retained to emissions produced. The approximately 3.5 GW of coal capacity accounts for about 8.4 million short tons of annual emissions in 2045, while the 15.8 GW of extended gas capacity accounts for about 5.5 million short tons under its emissions limits. Extending gas units therefore preserves more firm capacity per ton of CO_2 than extending coal units.

Table 7-2 summarizes the total system cost savings of the CEJA Extension Case and the gas-only sensitivity relative to the Reference Case, expressed as the net present value over the near-term period (2030 through 2035) and the longer-term period (2036 through 2047).

Table 7-2: NPV of Total System Cost Savings vs. Reference Case ($ million)

	2030-2035	2036-2047
CEJA Extension	868	14,642
CEJA Extension Gas Only	612	13,614

The Gas Only sensitivity captures approximately 70% of the near-term and more than 90% of the longer-term system cost savings of the full CEJA Extension Case. The proposed inclusion of oil-fired units is also supported by their potential reliability contribution during infrequent periods of system stress, although the analysis does not separately quantify the

incremental system cost savings from retaining oil units. The remaining difference is the cost of replacing the coal capacity, primarily with four-hour storage, and it is small because coal contributes little to the system beyond its accredited capacity.

7.6 Comparison with the 2025 Resource Adequacy Study Base Case

The 2026 Reference Case updates the 2025 Resource Adequacy Study Base Case with newer load forecasts, planning reserve margins, resource accreditation values, and resource cost and availability assumptions. These updates change both the level and geographic distribution of resource needs. Statewide load is lower in the 2026 Reference Case than in the 2025 RA Study Base Case, while load shifts toward the Ameren zone and away from ComEd relative to the earlier study.

Several modeling changes also affect the selected portfolio. The 2025 RA Study allowed new in-state gas generation to be selected to meet energy and firm capacity needs with the assumption that these generators could switch to a carbon-free fuel (at a higher cost) by 2045, while the 2026 Reference Case does not allow new in-state gas builds at all. This restriction, together with updated RPS and capacity-purchase assumptions, results in greater reliance on four-hour battery storage, solar, wind, and firm imports in the 2026 Reference Case. The updated Reference Case also reflects revised assumptions for nuclear and long-duration energy storage availability and costs.

These updated assumptions affect optimal resource portfolios in each Illinois region differently. In Ameren, higher peak load projections in the 2026 analysis results in increased reliance on battery storage and import capability for firm capacity. In ComEd, lower peak load reduces reliance on imports, while PJM requested delays to certain CEJA retirements increase the amount of thermal firm capacity available in 2030. The restriction on new in-state gas generation increases the amount of battery storage selected for later years and also contributes to the selection of new nuclear capacity in the ComEd zone in the 2040s.

Generation differences also reflect changes in the representation of CEJA emissions limits. The 2025 RA Study represented the limits through annual average maximum capacity factors, while the 2026 analysis uses volumetric emissions targets with more granular resource groupings. Both analyses reach the State's 50 percent RPS target, although the annual target quantities differ because of updated load projections and methodology.

Figure 7-25: 2025 RA Study Base Case and 2026 Reference Case Selected Capacity Comparison

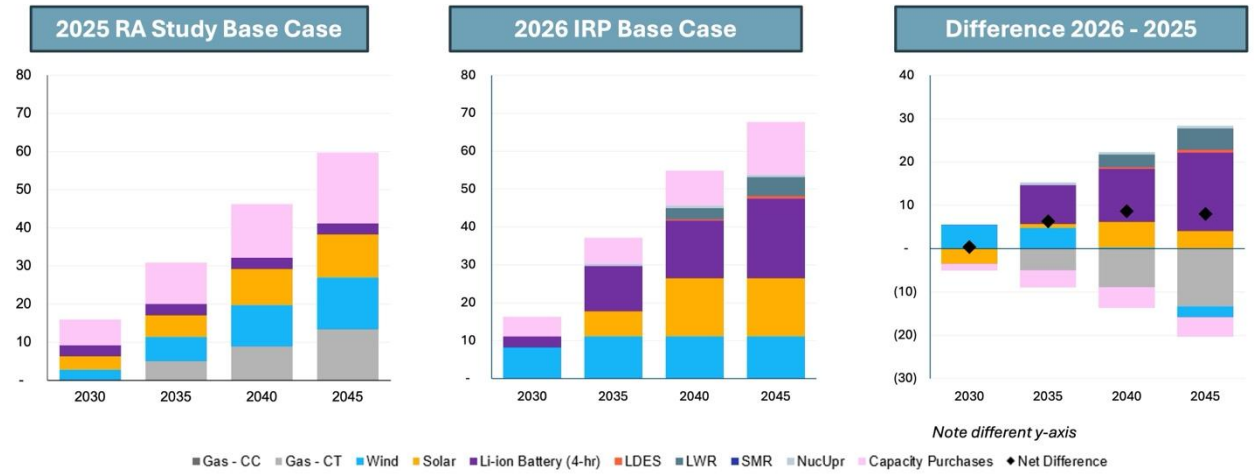
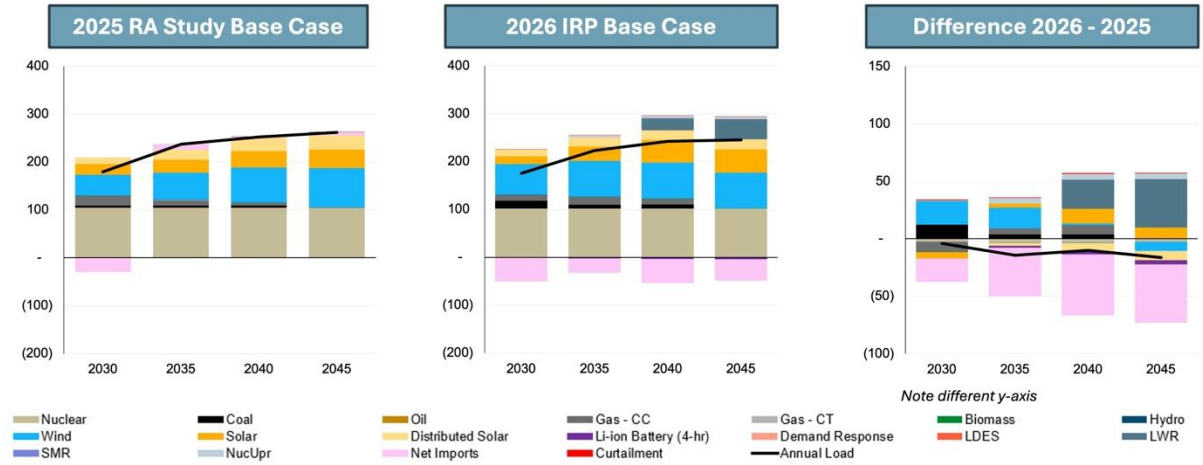


Figure 7-26: 2025 RA Study Base Case and 2026 Reference Case Generation and Load Comparison



7.7 Implications and Key Findings

All modeled cases require a substantial buildout of new resources in Illinois over the coming decades. Load growth and State policy requirements drive significant additions even when CEJA-limited units remain online for longer.

Load growth and State policy requirements drive significant additions even when CEJA-limited units remain available. In the Reference Case, Illinois nameplate capacity more than doubles by 2045. Even in the CEJA Extension Case, where more existing thermal capacity remains available, Illinois nameplate capacity grows by approximately 90 percent.

Extended operation of existing CEJA-limited units reduces, but does not eliminate, the amount of new firm capacity needed to meet projected load growth in Illinois.

Renewable resources make up the largest share of new nameplate capacity in both cases to meet growing RPS targets while total energy demand also rises. Utility-scale wind and solar are the cheapest sources of new carbon free energy in Illinois, but these resources have limited reliability value because of their variable and intermittent generation profiles. Storage and fueled resources (gas and nuclear) complement these additions by contributing capacity during periods when renewable generation alone cannot satisfy the reliability requirement. Storage is an energy-limited resource and requires energy from other resources to charge, which also limits its reliability contributions (which decline with higher storage penetrations). The extended operations of CEJA-limited units primarily affects the amount and type of new firm capacity that is needed without significantly affecting the overall direction of renewable resource development.

The two cases rely on different strategies for meeting LRZ 4's firm capacity needs, with different execution risks.

In the Reference Case, LRZ 4 increasingly relies on firm capacity imports as CEJA-limited units retire. These imports represent new out-of-state fossil capacity, primarily gas CTs, that would need to be developed outside Illinois and deliverable to LRZ 4 within existing import limits. In-state emissions from CEJA-limited units are reduced while out-of-state emissions increase to meet Illinois needs. Furthermore, the CEJA Extension Case presents a lower risk profile compared with the Reference Case, because the CEJA Extension Case requires much less development of new resources to maintain reliability, and it does not rely significantly on resources with higher commercial risks such as new nuclear and long duration storage. The Reference Case also depends more heavily on future development and deliverability of out-of-state capacity, including the timing of new resource construction and the continued availability of transmission import capability. The CEJA Extension Case relies more on existing in-state resources whose capacity is already physically present on the system. As a result, the CEJA Extension Case presents lower risks of timing, cost, and execution to maintain reliability in Illinois.

Firm capacity and annual energy generation serve different system needs, and the resource mix should be interpreted accordingly.

Firm capacity represents a resource's accredited contribution toward meeting the system's reliability requirement. It does not indicate how frequently that resource operates or how much electricity it produces over the course of a year. This distinction is particularly important in the CEJA Extension Case. Fossil resources continue to provide a significant

share of firm capacity, but they operate infrequently. At the same time, the large majority of in-state electricity generation continues to come from zero-emitting resources. Statewide, approximately 88 percent of in-state generation is zero-emitting in 2030 and approximately 92 percent is zero-emitting by 2045 in the CEJA Extension Case. The breakdown by zone in the CEJA Extension Case is, in ComEd, approximately 94 percent of in-state generation is zero-emitting throughout the modeled period, while LRZ 4 increases from approximately 81 percent in 2030 to 89 percent in 2045. The CEJA Extension Case illustrates that maintaining thermal resources for their reliability value does not necessarily mean relying heavily on those resources for energy production.

Continued availability of CEJA-limited units materially reduces the amount of replacement firm capacity that must be developed.

By 2045, the CEJA Extension Case selects approximately 31 GW less incremental capacity than the Reference Case. The largest differences include approximately 16.5 GW less four-hour battery storage, 5 GW less new light-water-reactor nuclear capacity, approximately 0.5 GW less long-duration energy storage, and approximately 8.3 GW less firm import capability. These differences reflect the more than 20 GW of existing CEJA-limited capacity that remains available in the Extension Case.

The benefits and burdens of an extension are unevenly distributed across fuels. Gas- and oil-fired units deliver most of the cost and reliability value, while coal accounts for most of the emissions.

Extending gas- and oil-fired units alone captures approximately 70% of the near-term and over 90% of the longer-term system cost savings of a full extension. Per MW of firm capacity retained, coal units emit one to two orders of magnitude more CO_2, SO2, and NOx than gas units, and oil units add no measurable emissions because they are not dispatched for energy. These results support differentiating any extension by fuel type.

8 Integrated Assessment of Mitigation Strategy

The preceding chapters provide four complementary perspectives on Illinois' future resource adequacy needs. The Updated Resource Adequacy Balance Analysis evaluates whether projected accredited capacity is sufficient to meet regional and Illinois-specific requirements under the latest available outlook. The Capacity Market Assessment evaluates how changes in resource availability affect projected capacity prices and the economic signals available to retain or develop capacity. RECAP quantifies the probability and severity of loss-of-load events under a broad range of system conditions. PLEXOS identifies the resource portfolios needed to satisfy modeled reliability and policy requirements and evaluates the associated costs, operations, and emissions.

Determining the appropriate mitigation strategy requires interpreting all the analytical results together – not looking only at a single component of the analysis. For example, a projected capacity shortfall from the Resource Adequacy Balance must be evaluated in the context of its probabilistic reliability consequences. A technically sufficient replacement portfolio must also be evaluated to determine whether it can reasonably be developed and economically supported within the period of need. Differences in customer costs must be considered alongside differences in reliability, emissions, and implementation risk.

This chapter synthesizes the results of the four analytical components to evaluate three principal questions:

- Does a material resource adequacy or reliability need persist given updated circumstances since the RA Study, and how does the availability of CEJA-limited units affect that need?
- Can alternative resources or strategies feasibly resolve the identified need within the required timeframe?
- What are the comparative cost, reliability, emissions, and implementation consequences of the strategies evaluated?

This chapter focuses on identifying where the results of the previous chapters support one another, where important differences arise, and how the combined evidence can be used regarding the need, feasibility, benefits, and consequences of potential mitigation to make an informed strategic decision about actions the State should take.

The analysis focuses on the Reference Case, under which CEJA-limited units become unavailable due to statutory emission limits, and the CEJA Extension Case, under which

specified units remain available for the study period, until 2047. The resulting integrated findings provide the analytical basis for the recommendations presented in the next chapter.

8.1 Mitigation Plan Decision Framework

8.1.1 Decision-Making Sequence

Section 9.15(o) of the EPAct does not require the Agencies merely to determine whether continued operation of CEJA-limited units would improve reliability. The Mitigation Plan must evaluate whether the identified resource adequacy or reliability deficiency persists, consider renewable energy, energy storage, demand response, transmission development, and other potential solutions, and limit any reduction or delay in emissions-reduction requirements to the extent and duration necessary to meet the State's needs. The ICC may approve the plan only if it resolves the identified deficiency with the least amount of CO_2 and copollutant emissions, considers impacts on environmental justice communities, and supports adequate, reliable, affordable, efficient, and environmentally sustainable service at the lowest total cost over time, taking into account the impact of increases in emissions.

Accordingly, the integrated evaluation is organized around five sequential decision tests:

- Need: Does the updated evidence demonstrate that a material resource adequacy or reliability deficiency persist?
- Alternatives: Can other resources or strategies resolve that deficiency within the required timeframe, and would the market support these alternatives?
- Effectiveness: To what extent would continued availability of CEJA-limited units reduce or delay the deficiency?
- Consequences: What are the comparative customer-cost, reliability, emissions, and implementation impacts of the available strategies?
- Implementation: What form, scale, operating conditions, and duration of action are supported by the analytical findings?

These questions do not constitute a mechanical scoring system. Instead, they establish a structured sequence for interpreting the analytical results and identifying a mitigation strategy that addresses the demonstrated need without extending emissions-reduction requirements more broadly or for longer than necessary.

8.1.2 Evaluation Criteria and Analytical Evidence

The following results from the analytical components used in each of the prior chapters are used in this chapter to support the decision tests. This is depicted in the table below.

Table 8-1: Decision Tests and Supporting Analytical Evidence

Decision	Key Question	Analytical Evidence	Implication
Need and Materiality	Does a meaningful capacity or reliability deficiency persist, and when and where does it occur?	Updated RA balance; RECAP loss-of-load risk; capacity market projections; scale of PLEXOS resource need	Determines whether mitigation should be considered
Feasible Alternatives	Can available new resources or transmission solutions resolve the need in time?	PLEXOS replacement portfolio; interconnection queue & development timelines	Determines whether the deficiency can be addressed without extending CEJA-limited units' operations
Market Support	Are existing capacity market signals likely to attract the required resources?	Capacity price forecasts; resource revenue requirements	Identifies whether market-driven development is sufficient
Extension Effectiveness	How much does continued availability of CEJA-limited units reduce reliability risk?	Changes in RA balances, RECAP metrics, capacity prices, and PLEXOS additions	Determines whether extension materially addresses the identified deficiency
Comparative Consequences	What costs, reliability outcomes, emissions, and customer and community impacts result under each strategy?	Capacity price exposure; portfolio costs; outage risk; emissions analysis	Establishes the principal tradeoffs between strategies

8.2 Persistence, Timing, and Materiality of Reliability Need

The combined analytical results indicate that a material resource adequacy and reliability need persists under the updated Reference Case outlook, and that the need is larger and

arrives earlier than the 2025 RA Study projected. The Updated RA Balance indicates that both MISO and PJM face resource adequacy risks by 2030. The drivers are the same in both markets: load growth outpaces the accredited capacity expected to enter service. Illinois is exposed to this regional condition even when its own zones appear to balance. The ComEd Zone satisfies its zonal requirement with in-zone resources until 2029 and MISO LRZ 4 relies on out-of-zone capacity beginning in 2027. However, the out-of-state import limits measure deliverability, not availability. Where the broader RTO is itself short, permitted import capability may not translate into capacity that is physically or commercially available to supply Illinois.

Table 8-2: Near-term RTO Capacity Shortfall according to the load and resource balance (GW)

	PJM	MISO LRZs 1-10
2026	12	-
2030	34	6

Observed capacity market outcomes also indicate resource adequacy risks. PJM's 2028/2029 Base Residual Auction was the second consecutive auction in which committed resources fell materially below target, with every location clearing at a negotiated $325/MW-day price collar cap. PJM's simulation of the same auction without the collar produced an RTO price of $555/MW-day and a ComEd price of $777/MW-day, indicating that the observed price understates the reliability scarcity in the market. MISO cleared all four seasons of its 2026/2027 auction, but summer remains tight in MISO North with only 4.6 GW above the initial reserve target.

8.3 Feasibility of Resolving the Need Through Alternative Resources

Section 9.15(o) of the EPAct directs the Agencies to consider renewable energy, energy storage, demand response, transmission development, and other strategies capable of resolving an identified shortfall before reducing or delaying applicable emissions-reduction requirements. This section evaluates each of those alternatives against the near-term need in Illinois. Renewable energy and storage are evaluated directly through the PLEXOS portfolio analysis. Existing demand response and transmission import capacity are reflected in baseline assumptions and additional development are analyzed in more detail through the IRP.

8.3.1 Scale and Timing of Potential Replacement Resources

Renewable energy and energy storage are represented as candidate resources in PLEXOS, which selects large amounts of those resources in both cases. The model builds large quantities of wind, solar, and four-hour battery storage whether or not the CEJA-limited units remain available, because those resources are needed to serve load growth and to satisfy the State's emissions and renewable energy targets. Renewables and storage therefore cannot be characterized as an unused alternative to a CEJA extension. They are already required under both cases. The key difference between the scenarios with and without CEJA extension lies in the firm capacity required. By 2045, the CEJA Extension Case selects 31 GW less installed capacity of all resources than the Reference Case, including 16.5 GW less four-hour storage, 5 GW less new nuclear generation, 0.5 GW less long-duration storage, and 8.3 GW less capacity from out of state.

New demand response and transmission development are considered in the IRP, which evaluates various technologies and programs across a broader set of futures and a longer horizon. New transmission alone does not solve the resource adequacy issues in MISO or PJM because these are driven by a lack of firm generation capability compared to system needs, and these regional issues are creating near term reliability risks to Illinois. Furthermore, transmission development is governed by the MISO and PJM regional planning processes rather than by State action, and large transmission projects take many years to complete. For these reasons, new transmission projects (without associated generation) are not an adequate reliability solution to the resource adequacy risks beyond 2030.

Demand response can be expanded more quickly, but not at a magnitude of GW of accredited capacity that would retire in 2030-2031 under CEJA limitations. The RECAP representation of demand response in this analysis already reflects an upper bound on its performance. These strategies remain relevant to Illinois' longer-term resource pathway and are evaluated on that basis in the IRP, but they do not resolve the near-term need identified in this Plan.

8.3.2 Reliability Value

Replacing the firm capacity of the CEJA-limited units with renewables and storage is theoretically possible, but the reliability value of these resources declines as more is added. Wind and solar generate only during certain hours, and storage must be charged from other resources, so the accredited capacity of each additional increment falls with penetration. By 2035, marginal ELCC in the Reference Case falls to roughly 15% of nameplate for solar, 5% for wind, and 60% for storage. By 2045, the marginal ELCC further drops to roughly 10% for solar, 5% for wind, and 50% for storage. As penetration of renewable and storage

increases, each new increment contributes less to reliability and costs more per unit of accredited capacity. As shown in the Reference Case, without the CEJA-limited units, PLEXOS selects large additions of storage, new nuclear, and firm imports as its least-cost replacement, and these resources are costly because storage loses reliability value at high penetration and new nuclear runs continuously in a market where renewables set low energy prices for much of the year.

8.3.3 Capacity Market Support for New Resources

Capacity market prices are the main signal for new resources to enter the market. The cost results of the Reference Case suggest the capacity markets alone will not cover the new firm resources selected. Even assuming capacity prices after 2030 reach the Net CONE of a gas combustion turbine, new nuclear, out-of-state gas, and battery storage still have carrying costs beyond their energy and capacity revenues—all of which would need to be paid for by Illinois customers. By 2045, these carrying costs make up 15% of total system costs in ComEd.

The assumed prices are also well above what the markets pay today. PJM's 2028/2029 auction cleared at the $325/MW-day cap, while simulated capacity price coming out of PLEXOS is more than $800/MW-day in 2035. At current price levels, the revenue shortfall for new resources would be significant. In the CEJA Extension Case, less new firm capacity is built, and ComEd has almost no carrying costs, so the portfolio relies less on out-of-market support, making the resources that are built in this case more economic and thus cheaper for Illinois customers.

8.3.4 Resource Development Feasibility

A portfolio that satisfies the modeled reliability requirement establishes a viable mitigation pathway only if it can be developed on the schedule the model assumes. The interconnection queues contain nominally large volumes of capacity, but queue projects vary widely in development maturity and have historically experienced attrition, delay, and changes in scope. Applying development-stage screening to the queue, as described in Chapter 4, yields materially less capacity reaching commercial operation by 2030 than the as-reported commercial operation dates suggest, and less than was assumed in the RA Study. The queue as presently constituted does not close the near-term shortfall, and the Reference Case portfolio depends on development beyond what current queue activity supports. Between 2030 and 2035, the Reference Case requires Illinois to add

approximately 5 GW of new nameplate capacity every year, compared with 1.4 GW per year added in Illinois over the past five years.[79]

Two features of the Reference Case portfolio compound that timing risk. First, it depends on resources whose development carries substantial cost and execution risk, namely new light-water-reactor nuclear and long-duration energy storage. Two nuclear reactors have been built in the U.S. in the past three decades, Vogtle Units 3 and 4 in Georgia, which entered service in 2023 and 2024 roughly seven years behind schedule and at more than double the original budget, with final costs exceeding $30 billion.[80] No long-duration storage project has yet been demonstrated at utility scale over multiple years of operation. The CEJA Extension Case, on the other hand, relies principally on wind, solar, and four-hour battery storage that are widely deployable now. Second, it relies increasingly on firm capacity imports, represented as gas combustion turbines developed outside Illinois and made deliverable to LRZ 4. That reliance is subject to the constraint identified in the capacity market assessment. Large gas turbines now require more than five years from order to delivery, and a turbine ordered today would on average not enter service until 2031.[81] Baseline assumptions apply development-stage delays to queue projects precisely because interconnection processing, supply chain lead times, siting, and permitting routinely extend commercial operation dates. Stakeholders also raised the same concern regarding the realism of modeled development timelines. Where replacement resources arrive later than modeled while load growth and retirements proceed as assumed, the period of high reliability risks and capacity costs would be prolonged.

8.4 Effectiveness of CEJA Extensions

As shown in Chapter 4, the CEJA retirements have a negligible effect on the projected resource adequacy balance through 2030. Their effect appears at the end of the near-term window and beyond, as the first ComEd tranche of statutory emission reductions takes effect in 2031 and the LRZ 4 tranches proceed from 2030.

The capacity market consequences depend on whether the markets have returned to their reliability requirements by that point. If each market clears at 100% of its requirement, retiring the CEJA-limited units without replacement resources raises the projected PJM capacity price by $134/MW-day, and the MISO North summer price increases by $148/MW-

[79] EIA State Electricity Profiles, Table 4B, https://www.eia.gov/electricity/state/illinois/
[80] U.S. Energy Information Administration, "Vogtle Unit 4 begins commercial operation," *Today in Energy*, May 2024, https://www.eia.gov/todayinenergy/detail.php?id=61963.
[81] GE Vernova. (2026, July 22). *Second Quarter 2026 Earnings Webcast Presentation*. https://www.gevernova.com/sites/default/files/gev_webcast_presentation_07222026.pdf

day ($37/MW-day annualized). These increases together represent a potential $1.3 billion annual capacity cost to Illinois ratepayers. If the markets remain short through this period, as indicated in the load and resource balance, the retirements would not raise the observed clearing price, because the price would already be at its administrative cap. The effect would appear in the quantity of new capacity required to restore equilibrium, and in the time needed to develop it. Illinois ratepayers would likely bear the cap price for longer, rather than a higher price. Removing firm capacity from a system that is already short would also deepen the reliability shortfall over that period, increasing exposure to loss-of-load events.

The reliability analysis indicates that the CEJA-limited units function as insurance to the electric system in Illinois rather than as major sources of generated energy. When extended through 2035, the CEJA-limited units in ComEd are utilized at least ten hours per year in 77% of simulations but the overall capacity factor is low, with maximum capacity factor at 0.8%. In ComEd, reliance on these units concentrates in late-afternoon and early-evening summer hours, when high load coincides with declining solar output and low summer wind, and it is strongly weather-dependent. In the Ameren Illinois footprint, scarcity events are rarer and appear in infrequent winter late-evening and early-morning hours, rather than the summer. In both zones, the value of the units rises sharply when import availability is constrained. Removing import access increases LRZ 4 LOLE from 0.31 to 0.58 events per year and adds approximately 1,208 MWh of unserved energy. The units therefore contribute little energy in expectation while providing disproportionate reliability value in the tail conditions in order for the system to meet its standard.

As described in Chapter 7, Illinois requires substantial renewable and storage development whether or not the CEJA emissions limits are extended. The capacity additions that the extension prevents are primarily new firm resources, which face the greatest development, interconnection, and permitting uncertainty. The CEJA-limited units, on the other hand, are existing resources that are already connected and deliverable. Retaining them reduces the Illinois portfolio's dependence on replacement resources arriving on the modeled schedule, a schedule that would require new capacity to be added far faster than Illinois has historically achieved.

8.5 Consequences for Illinois Customers, Residents, and State Policy

8.5.1 Customer Cost and Affordability Impacts

The cost impacts on customers play out over two time horizons. Two framing points apply to both. First, neither the portfolio costs nor the capacity cost estimates presented here are customer bill impacts; they measure changes in system cost and capacity market payments, not retail rates. Second, the longer-term results assume that after 2030, capacity prices are

set by the Net CONE of corresponding marginal resources. If capacity prices were lower, new resources would recover less of their costs from the capacity market, and Reference Case carrying costs would be higher.

In the near term, CEJA retirements affect customer costs mainly through capacity market prices. If PJM and MISO clear at their reliability requirements before the retirements, retiring the CEJA-limited units without replacement capacity raises capacity prices in both markets, which is equivalent to approximately $1.3 billion for Illinois customers. If the markets stay short, as the updated resource adequacy balance shows, prices would already be at the administrative cap. The retirements would then not push the clearing price higher. Instead, more new capacity would be needed before the market reaches equilibrium, so Illinois customers would pay the capped price for longer.

Over the longer term, the cost difference between the two cases comes mainly from new firm resources. In the Reference Case, retiring CEJA-limited capacity is replaced with new nuclear, four-hour storage, long-duration storage, and out-of-state gas. The market revenues of these resources do not fully cover their costs. By 2045, carrying costs for these resources make up 15% of total system costs in ComEd. In the CEJA Extension Case, the retained units cut new firm additions by approximately 31 GW by 2045, and ComEd has almost no carrying costs. By 2045, total system costs in this case are 18% lower in ComEd and 5% lower in Ameren than in the Reference Case. Given the density of environmental justice communities located in ComEd territory, this differential in potential impact on energy burden is notable.

These results assume that after 2030, capacity prices are set by the Net CONE of a gas combustion turbine. If capacity prices were lower, new resources would recover less of their costs from the capacity market, and Reference Case carrying costs would be higher.

8.5.2 Emissions and Community Impacts

Under the study's GHG accounting approach, emissions in the two cases start to diverge after 2030. In the Reference Case, CEJA-limited units retire and Illinois power-sector CO_2 emissions fall to nearly zero by 2045. By then, 99.9% of in-state generation is zero-emitting. In the CEJA Extension Case, the retained units follow CEJA's interim emissions-reduction requirements through 2044 and remain at the 2044 limits through the modeling horizon of 2047. Emissions then level off at approximately 14 million short tons per year, and 92% of in-state generation is zero-emitting in 2045. The portfolio analysis quantifies modeled SO_2 and NO_x emissions by generator fuel type, but does not evaluate how changes in emissions would affect local air quality, population exposure, or public health. Continued operation of fossil fuel generators could therefore affect nearby communities, including environmental

justice communities, although the magnitude and location of these impacts would depend on which units continue operating and their actual generation.

In the Reference Case, new gas capacity outside of Illinois replaces part of the firm capacity the CEJA-limited units provided, especially for MISO LRZ 4. Under net-import accounting, the output from those resources that serves Illinois is not counted toward Illinois, because Illinois remains a net exporter. Both cases, however, rely on new out-of-state gas capacity to maintain Illinois reliability. PJM and MISO are each projected to be short of their reliability requirements, so there is no surplus capacity for Illinois to import. Illinois must rely on the regional markets to build enough new capacity for a share of its needs under either case, and that reliance is larger in the Reference Case, in which retiring CEJA-limited units are replaced in part by firm capacity imports until new nuclear is built in ComEd. Some of the capacity serving Illinois load under both cases is therefore new emitting resource located outside the State.

9 Recommendations for Mitigation Plan Actions

Section 9.15(o) of the EPAct directs the Illinois Power Agency ("IPA"), in conjunction with the Illinois Environmental Protection Agency ("IEPA"), to develop a mitigation plan following identification of a reasonably likely resource adequacy shortfall or reliability violation. Following publication and public review of the draft plan, IPA and IEPA must revise the plan as appropriate and file it with the Illinois Commerce Commission ("ICC") for review and approval.

This chapter summarizes the key findings of the Mitigation Plan, culminating in the recommendation for a temporary extension, through May 31, 2033, of specified CEJA emissions-reduction deadlines for eligible gas- and oil-fired units in both PJM and MISO. It does not recommend extending the applicable deadlines for coal-fired units. This chapter also explains how the broader resource needs and potential portfolio solutions identified through the analysis will inform the ongoing IRP and subsequent implementation planning.

9.1 Key Findings

Illinois continues to face a risk of resource adequacy shortfall, and that risk grows over the forecast horizon.

The shortfall risk reflects several related but distinct drivers. Growing electricity demand, primarily from data centers, increases capacity requirements. Separately, aging and economically marginal generators may retire across PJM and MISO. The updated load and resource balance indicates tight regional capacity conditions which creates a risk of shortfalls if sufficient resources do not enter service on time. The ComEd zone meets its allocated zonal requirement through 2030, with imports needed by 2030, but remains exposed to PJM-wide capacity conditions. MISO LRZ 4 has less in-zone accredited capacity than its requirement in 2027 and must increasingly rely on imports; sufficient unused capacity may not be available elsewhere in MISO to support those imports during stressed conditions.

Retaining a subset of CEJA-limited units supports affordability by preserving flexibility in the timing and scale of investments in new firm capacity.

Illinois needs substantial wind, solar, and storage additions under both the Reference Case and the CEJA Extension Case. The primary difference between the cases is the amount and timing of new firm resources – nuclear generation, long-duration energy storage, and out-of-

state capacity purchases – necessary to replace the reliability value of existing CEJA-limited capacity. Retaining eligible units can reduce the need to develop costly replacement capacity before it is needed and reduce exposure to construction, interconnection, and other delivery risks. In the long-term portfolio analysis, total ComEd system costs in 2045 are approximately 18% lower in the CEJA Extension Case than in the Reference Case. Retaining existing, already-interconnected units, especially gas and oil, also directly reduces loss-of-load risk and eases a resource buildout that would otherwise have to occur at more than three times Illinois' historical annual pace of resource additions. Separately, an illustrative PJM capacity market analysis estimates that, if PJM returns to balance by 2031, retiring the affected units would raise the projected capacity costs for ComEd customers by approximately $1.1 billion annually.

Extending existing units can support reliability during periods of system stress while allowing Illinois to continue progressing toward its decarbonization goals.

In the reliability simulations, the ComEd units are called upon in nearly every modeled weather year, but their capacity factors do not exceed 0.8%. Existing statutory emissions requirements would continue to apply to extended units, including the 12-month CO_2 and copollutant limits for applicable non-public gas-fired units under 415 ILCS 5/9.15(k-5). Even in the bookend case that extends every CEJA-limited unit statewide through 2047, 92% of in-state generation is zero-emitting in 2045, and the portfolios add substantial wind, solar, and storage either way. Overall, the extension is one piece of the solution and the first of several actions needed to support Illinois' decarbonization and reliability targets.

Reducing emissions and protecting environmental justice communities are central to selecting which units to extend.

Reducing greenhouse gas and criteria pollutant emissions remains an important State policy objective under CEJA and CRGA. Section 9.15(o)(3) of the Environmental Protection Act also directs the ICC to consider emissions impacts on environmental justice communities when reviewing a mitigation plan. Coal-fired units generally produce substantially more CO_2e and criteria pollutant emissions per MW of accredited capacity than existing gas-fired units. Oil-fired units provide capacity while operating infrequently, historically on the order of 30 hours annually, because of their comparatively high marginal operating costs. These characteristics support preserving the reliability contribution of gas and oil while maintaining the decarbonization timeline applicable to coal units. Avoiding an extension of coal units would also avoid prolonging a major source of local pollution burdens, including burdens experienced by environmental justice communities. These environmental and public-health considerations are core concerns alongside modeled electricity system costs.

Extending eligible gas and oil units, but not coal units, balances affordability, reliability, emissions reductions, and environmental justice considerations, and meets the statutory "minimum extent" standard.

Under Section 9.15(o) of the Environmental Protection Act, emissions-reduction requirements may be delayed only to the extent and for the duration necessary to address the State's resource adequacy and reliability needs. The ICC must also consider the least amount of CO_2 and copollutant emissions, effects on environmental justice communities, and the lowest total cost over time under subsection (o)(3). The Agencies therefore considered the benefits of retaining gas-fired units separately from those of extending all CEJA-limited units. Relative to the Reference Case, the Gas Only sensitivity provides approximately $612 million of cost savings between 2030 and 2035, compared with $868 million if all CEJA-limited units are retained. For 2036–2047, the corresponding savings are approximately $13.6 billion and $14.6 billion. Thus, retaining gas captures most of the modeled benefit of the full extension. The gas-only sensitivity replaces much of coal's accredited capacity with four-hour storage and reduces remaining in-state emissions by roughly 60% relative to the full extension. Oil-fired units are included in the proposed extension for their contribution during infrequent periods of high reliability need. The Agencies consider these cost and reliability benefits alongside the substantially different emissions impacts of coal generation.

The figures below illustrate the cost and emissions implications of these alternatives. The first compares total system costs and average annual emissions, on an inventory basis, over 2030–2047, while the second compares 2047 average modeled system supply costs and total portfolio emissions in 2047. Both demonstrate that retaining gas-fired units achieves most of the modeled cost savings of a full CEJA extension, with substantially lower emissions.

Figure 9-1: Comparison of NPV of Total System Costs vs Average Inventory Emissions

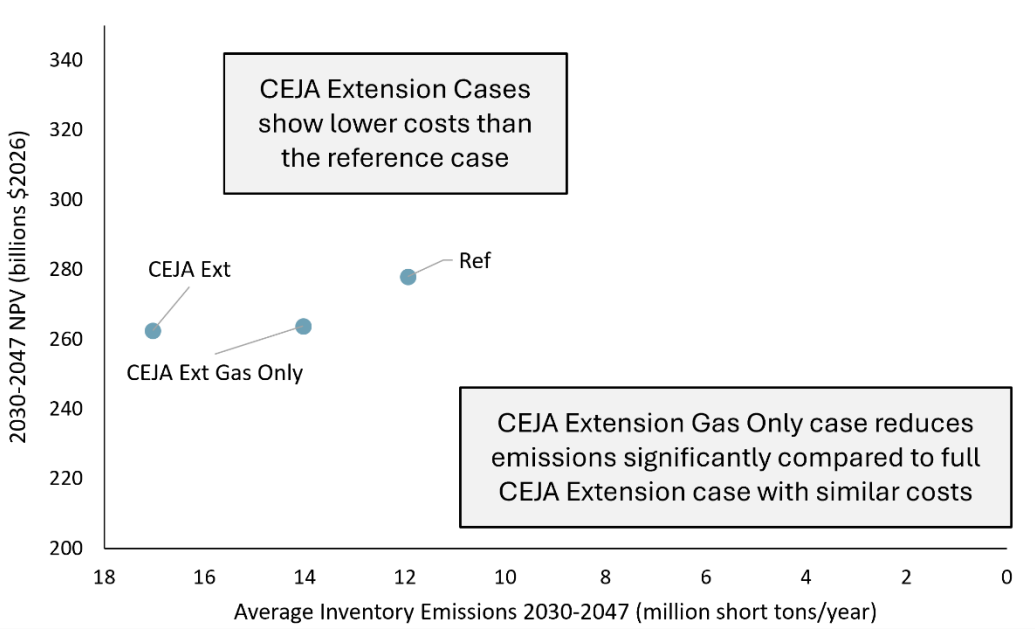
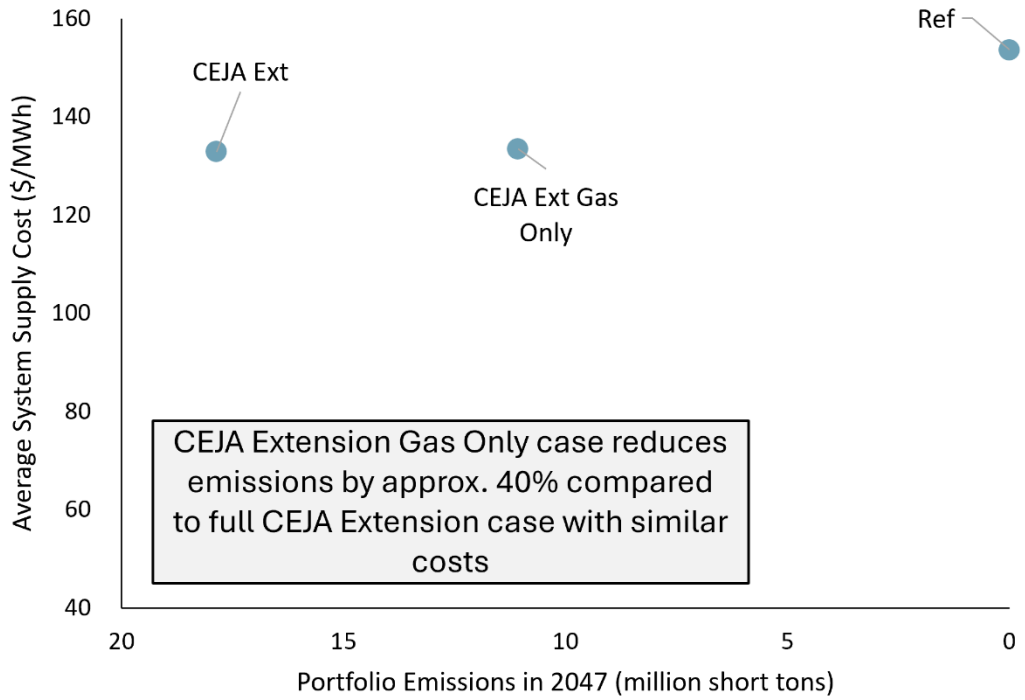


Figure 9-2: Comparison of 2047 Average System Supply Cost and 2047 Total Portfolio Emissions



Note: Average System Supply Cost = 2047 Total System Cost (nominal $b) / Retail Sales

To preserve near-term capacity while the next IRP evaluates replacement options, the Agencies propose extending the applicable 2030 deadlines for eligible gas- and oil-fired units in both PJM and MISO through May 31, 2033. The next IRP will reassess whether continued operation beyond that date is necessary.

The proposed endpoint reflects both resource-owner decisions and the need to reassess extensions in the next IRP.

Preserving an existing unit may require maintenance investment, staffing, and continued market participation, while retirement decisions can require advance notice. In PJM, capacity commitments are made 3 years before delivery. A unit facing a 2030 CEJA deadline may need to decide whether it can offer into the 2032/2033 capacity delivery year before the next IRP receives a Commission decision. In MISO, procurement takes place closer to the delivery period, but the 2030 emissions deadline could still remove needed capacity before the next IRP can reassess reliability needs and replacement options. The proposed common endpoint provides a limited bridge for both markets.

9.2 Proposed Mitigation Strategy

Based on the findings described above, the IPA and IEPA preliminarily conclude that a resource adequacy or reliability deficiency remains reasonably likely to occur and that a targeted delay of applicable CEJA emissions-reduction deadlines is warranted for specified gas- and oil-fired units in both PJM and MISO. Section 9.15(o) of the Environmental Protection Act permits a delay only to the extent and for the duration necessary to meet the State's resource adequacy and reliability needs. The Agencies apply that standard along three dimensions: which units are eligible, where they are located, and for how long their applicable deadlines would be delayed.

On scope, the Agencies propose a measured delay to applicable 2030 zero-emissions deadlines only for CEJA-limited gas- and oil-fired units whose continued availability is needed to address the identified reliability concerns. The proposal does not extend deadlines for coal-fired units. In particular, the January 1, 2030 zero-emissions deadline for privately owned coal-fired units under 415 ILCS 5/9.15(g) would remain unchanged. This targeted approach preserves gas and oil capacity to provide reliability value without prolonging the emissions and environmental justice burdens associated with coal-fired generation. The proposed extension would not reverse retirements expected to occur for reasons independent of CEJA, such as plant age or commercial decisions, or change deadlines for units not identified for extension.

On location, the proposed extension includes eligible gas- and oil-fired units in both the PJM ComEd zone and MISO LRZ 4, as seen in Table 9-1. The reliability analysis identifies risks in both regional markets, although the sources and timing of those risks differ. ComEd is exposed to PJM-wide capacity tightness even when its in-zone balance meets the allocated requirement. The Load and Resource Balance analysis shows LRZ 4 increasingly depends on imports from the broader MISO market, where the availability of surplus capacity is uncertain. Preserving the contribution of eligible in-state units in both zones helps limit dependence on replacement capacity that may not be available when needed.

On duration, the IPA and IEPA propose extending the applicable deadlines for eligible units in both RTOs through May 31, 2033, the end of the 2032/2033 capacity delivery or planning year. It is intended to be a defined bridge to the next planning decision, not an indefinite extension. The next IRP is due to be filed with the ICC by September 30, 2029, and a Commission decision is expected in 2030. For PJM units, the proposed end date also avoids disrupting forward capacity commitments for the 2032/2033 delivery year. For MISO units, the end date preserves availability through the next IRP reassessment and a limited period for evaluating and implementing replacement options. The Agencies view this common endpoint as the shortest practicable extension that maintains needed capacity while leaving any subsequent extension to be evaluated against updated evidence under the next IRP. The proposal does not predetermine whether the units should operate beyond May 31, 2033.

The case for an extension in MISO does not depend on PJM's three-year forward auction structure. Although MISO procures capacity closer to each delivery year, the 2030 statutory deadline could still remove existing capacity before the next IRP establishes whether replacement resources, imports, or other solutions can reliably meet LRZ 4's needs. The Agencies therefore propose the same limited extension through May 31, 2033, for eligible units in MISO. That period allows the 2029 IRP and its subsequent Commission review to reassess whether any further extension is necessary while allowing time to implement alternatives.

The IPA and IEPA therefore recommend a temporary delay, through May 31, 2033, of the specifically identified 2030 CEJA zero-emissions deadlines for eligible gas- and oil-fired units in PJM and MISO. No extension is proposed for coal-fired units, and no additional operating-hour, dispatch, or emissions restrictions are proposed for extended gas- or oil-fired units. The extension would preserve existing accredited capacity while the Agencies continue to assess and advance replacement resources. It would remain subject to all other applicable statutory, permitting, monitoring, and reporting requirements and to any terms of the final ICC order.

9.2.1 Operating and Emissions Conditions of CEJA-limited Units

Continued availability under the Mitigation Plan does not imply continuous or high-utilization operation. The Agencies do not propose new operating-hour limits, dispatch restrictions, or emissions limits for units receiving an extension. Rather, the proposed action would delay only the specifically identified zero-emissions deadlines while leaving other applicable environmental requirements in place. Non-public gas-fired units would continue to be subject to the 12-month CO_2 and copollutant emissions limits under 415 ILCS 5/9.15(k-5), and applicable interim requirements under subsection (i) would also remain in effect except to the extent expressly delayed by an approved Mitigation Plan. Oil-fired units would remain subject to other applicable environmental and permit conditions. Section 9.15(o) authorizes limited relief necessary to address identified resource adequacy and reliability needs; it does not otherwise suspend statutory or permit obligations.

9.3 Mitigation Plan Implementation

The immediate action proposed through this Mitigation Plan is a temporary delay of the specified CEJA deadlines for eligible gas- and oil-fired units in both PJM and MISO, through May 31, 2033.

Table 9-1: Proposed Mitigation Plan CEJA Plant Extensions

CEJA Facility Name	Zone	Resource Type	Current Retirement Year	Proposed Extension
Aurora	ComEd	Gas - CT	2031	2033
Calumet Energy Team, LLC	ComEd	Gas - CT	2031	2033
Crete Energy Park	ComEd	Gas - CT	2031	2033
Rockford Energy Center	ComEd	Gas - CT	2031	2033
Tilton Power Station	Ameren	Gas - CT	2030	2033
LSP University Park, LLC	ComEd	Gas - CT	2031	2033
University Park Energy	ComEd	Gas - CT	2031	2033
Venice	Ameren	Gas - CT	2030	2033
Zion Energy Center	ComEd	Gas - CT	2031	2033
Fisk	ComEd	Oil	2031	2033
Waukegan	ComEd	Oil	2031	2033

Following an ICC order approving or approving with modifications the Mitigation Plan, the IPA and IEPA would coordinate with the ICC, affected unit owners, PJM, and MISO, as applicable, to confirm the administrative and operational treatment of each approved extension. This coordination may include:

- Reflecting the revised deadline in applicable compliance documentation or regulatory records;
- Confirming the affected unit owner's intended operating and retirement schedule;
- Addressing any permitting, reporting, or emissions-compliance requirements administered by IEPA;
- Coordinating any required updates to RTO retirement, deactivation, capacity accreditation, or market-participation information; and
- Documenting the effective treatment of each affected unit under the approved plan.

The specific unit-level legal and administrative steps will depend on the terms of the final ICC order and the regulatory status of each affected facility. The filed Mitigation Plan will identify any additional permit, compliance, RTO notification, or documentation requirements that must be completed before an approved extension can take effect.

Approval of the Mitigation Plan would establish the authorized delay in the applicable emissions-reduction requirement but may not, by itself, resolve every commercial or operational issue necessary for an affected unit to remain available. Continued operation may also depend upon the unit owner's decisions, market participation, maintenance and staffing requirements, applicable permits, and any other contractual arrangements determined to be necessary by the owner.

9.4 Relationship to the IRP and Other Planning Initiatives

Section 9.15(o) of the EPAct requires the Mitigation Plan to consider renewable energy, energy storage, demand response, transmission development, and other strategies that could resolve the identified resource adequacy shortfall or reliability violation. Those alternatives are considered through the coordinated Mitigation Plan and IRP analytical framework. The Mitigation Plan's long-term planning analysis conducted within PLEXOS directly allows wind, solar, battery storage, firm imports, and other modeled resources to compete to meet load, reliability, and policy requirements. The resulting portfolios include substantial renewable and storage additions in both the Reference Case and CEJA Extension Case, demonstrating that the proposed CEJA extension is evaluated in combination with, rather than as a substitute for, continued clean-resource development.

Demand response, energy efficiency, and transmission are also reflected in the planning framework. Existing demand response and transmission import capability are represented in the common baseline assumptions used by the Mitigation Plan. Expanded programs and major new transmission projects follow different implementation pathways than retaining an existing generating unit; the broader IRP evaluates additional demand-side flexibility and transmission expansion more comprehensively because those strategies require separate program design, customer participation, permitting, planning, transmission development, or other implementation steps before they can contribute to resource adequacy needs at scale.

The IRP and Mitigation Plan were developed in parallel using aligned load forecasts, resource assumptions, reliability inputs, and modeling tools. The proceeding to approve the IRP therefore provides a complementary record for assessing how the broader set of alternatives can reduce or ultimately eliminate the need for continued CEJA-limited-unit availability over time. Other than the proposed extension of specified CEJA-limited units, this Mitigation Plan does not itself establish new procurement programs, transmission projects, or demand-side programs. Those broader implementation decisions remain within the IRP and other applicable State and RTO planning processes.

The proposed extension is therefore a defined, near-term action intended to preserve the reliability contribution of existing gas- and oil-fired units while replacement resources are evaluated and developed. It does not predetermine decisions in the next IRP. The IPA and IEPA may also seek an amendment under 415 ILCS 5/9.15(o)(4) if the identified reliability deficiency is resolved or reduced before the approved extension expires.

9.5 Administrative Next Steps

Following publication of this Draft Mitigation Plan, interested parties will have 60 days to submit comments to IPA and IEPA.[82] The statute encourages comments to be specific, supported by data or detailed analysis, and accompanied by alternative language or proposals where a commenter objects to all or part of the plan. IPA and IEPA must consider the comments received, revise the plan as necessary within 30 days after the close of the public review period, and file the revised plan with the ICC for approval. The agencies do not plan to conduct additional modeling in response to stakeholder comments within the 30-day revision window.

[82] 415 ILCS 5/9.15(o)(1)

Following filing of the revised plan, parties will have 60 days to file objections with the ICC.[83] The ICC will determine whether an evidentiary hearing is necessary, conduct three public hearings within 90 days after filing, and issue an order approving or approving with modifications the Mitigation Plan within 180 days.[84]

Comments on the Draft Mitigation Plan will be particularly useful where they address:

- The analytical support for the proposed extension;
- The units included or excluded from the proposed strategy;
- The proposed duration of the extension;
- Unit-specific operating or emissions conditions;
- The administrative and operational feasibility of implementation;
- The treatment of broader resource-development questions through the IRP; and
- Specific revisions or alternative proposals supported by data or analysis.

The IPA and IEPA will review all comments received and revise the findings, proposed CEJA-limited unit extensions, and implementation provisions as appropriate before filing the Mitigation Plan with the ICC. Additional opportunities for participation will be available through the ICC review process.

[83] 415 ILCS 5/9.15(o)(2)
[84] Id. The statute further permits the Commission to extend the period of review for no more than an additional 180 days.

1 Appendix A.

1.1 PLEXOS Modeling Approach

1.1.1 Objective Function and Model Decisions

PLEXOS identifies the combination of resource investments and system operations that minimizes the net present value of modeled electricity-system costs over the planning horizon, subject to the constraints enforced in the model, discussed in Chapter 7.

Modeled costs include:

- Capital costs for new generation and storage;
- Incremental costs for modeled transmission and deliverability upgrades;
- Fixed operations and maintenance costs;
- Variable operations and maintenance costs (not inclusive of specific labor or full-time job costs);
- Fuel costs;
- Start costs and other unit-commitment costs; and
- Costs associated with firm capacity purchases or imports.

Modeled constraints include:

- Resource potential limits for new generation investment;
- Operational constraints of existing and new generators;
- Resource adequacy constraints such as RTO planning reserve margins;
- Clean energy policies such as State RPS targets; and
- Decarbonization targets such as annual emissions restrictions.

1.1.2 Reliability Constraints and Integration with RECAP

PLEXOS represents resource adequacy through reliability requirements and resource-accreditation assumptions developed using RECAP. RECAP determines the amount of effective capacity required to meet the selected reliability criterion and develops marginal ELCC curves that describe how the capacity contribution of weather-dependent and energy-limited resources changes as their penetration increases.

The model applies region- and technology-specific ELCC curves to wind, solar, battery storage, and other applicable resources. These curves allow the capacity value of incremental additions to decline as greater quantities of a resource are added and the periods of highest system risk shift.

Reliability constraints are represented for:

- PJM
- MISO LRZs 1-7
- The ComEd zone
- MISO LRZ 4

This structure requires the portfolio to satisfy both broader RTO-wide needs and Illinois-specific zonal needs. A resource located outside Illinois may support the applicable RTO requirement but may not satisfy an Illinois zonal requirement unless it is modeled as firm and deliverable to that zone.

The final PLEXOS-selected portfolios are evaluated in RECAP to validate reliability and resource adequacy requirements are satisfied. If a portfolio does not meet the applicable loss-of-load criterion when tested in RECAP, the reliability requirements, ELCC representation, or portfolio is iteratively adjusted before the results are finalized.

1.1.3 Policy, Emissions, and Clean Energy Constraints

The capacity expansion analysis represents the Illinois and regional policies relevant to resource selection and system operation. These include, as applicable:

- CEJA emissions-reduction and retirement requirements;
- The Illinois Renewable Portfolio Standard;
- Applicable clean energy procurement requirements;
- Existing clean energy contracts and programs;
- Fleet-level emissions limits; and
- Limits on the construction or operation of specified resource types.

CEJA compliance is represented differently across the Reference Case and CEJA Extension Case. Other policy requirements are held constant. The Renewable Portfolio Standard is represented through an annual requirement for eligible renewable energy generation or renewable energy credits. The model input assumptions are aligned with the latest available outlooks from the IPA's Long-Term Renewable Resources Procurement Plan. Where operational emissions limits apply to CEJA-limited units that remain online, PLEXOS reflects those limits through annual emissions caps, generation limits, fuel constraints, or other appropriate model constructs.

1.1.4 Operational Representation

Capacity expansion decisions are informed by modeled system operations. PLEXOS dispatches the available resource fleet across representative days for each modeled year

while respecting unit operating constraints and the availability of weather-dependent resources.

The operational representation considers:

- Hourly electricity demand;
- Hourly wind, solar, and hydro generation profiles;
- Thermal resource operating limits;
- Minimum generation and minimum run times;
- Start costs and ramping constraints;
- Planned or forced outage assumptions;
- Energy storage charging, discharging, duration, and efficiency;
- Demand response activation limitations;
- Regional transmission limits;
- Renewable curtailment; and
- Annual fuel and emissions constraints.

These operational parameters allow the model to make informed investment and dispatch decisions between resources of different characteristics.