July 21, 2023

Ms. Stephanie Cook, Chief Clerk
Illinois Commerce Commission
527 East Capitol Avenue
Springfield, IL  62701

**RE: Docket No. 22-0485**
**Ameren Illinois Company d/b/a Ameren Illinois**
**Ameren Illinois RTO Cost-Benefit Study**

Dear Ms. Cook:

In compliance with the findings in Docket No. 22-0485, attached is the original copy of the Ameren Illinois RTP Cost-Benefit Study, which is being filed on behalf of Ameren Illinois.

If you have any questions or concerns, please call me at 217.535.5229.

Sincerely,

Brice A. Sheriff,  Senior Director
Regulatory Affairs and Energy Supply

BAS/sar

cc:    Matt Harvey

**Prepared for:**

Ameren Illinois Company

300 Liberty

Peoria, IL 61602

# Ameren Illinois RTO Cost-Benefit Study

**Prepared by:**

| | | |
|---|---|---|
| Charles River Associates | Astrapé Consulting | Quanta Technology, LLC |
| 200 Clarendon Street | 3000 Galleria Cir Suit 575 | 4020 Westchase Blvd. |
| Boston, Massachusetts 02116 | Hoover, AL 35244 | Raleigh, NC 27607 |


Date: July 21, 2023

CRA Project No.52020

# Disclaimer

# Table of contents

# 1. Executive Summary

On behalf of Ameren Illinois Company (AIC) and as directed by the Illinois Commerce Commission (ICC)[1], Charles River Associates (CRA) in collaboration with Astrapé Consulting[2] and Quanta Technology, LLC has assessed the costs and benefits of AIC remaining a member of the Midcontinent Independent System Operator, Inc. (MISO)[3] versus joining the PJM Interconnection Regional Transmission Organization (PJM).[4] As the study was directed by the ICC, overall net costs and benefits were assessed across the entire State of Illinois including the service territories of AIC, [Springfield] City Water, Light & Power (CWLP), Southern Illinois Power Cooperative (SIPC)[5], and Commonwealth Edison Company (ComEd). Based on the analysis performed, we conclude that AIC remaining in MISO avoids significant economic costs for the ratepayers of both AIC and the State of Illinois relative to AIC joining PJM.

While the overall conclusion of remaining in MISO is relatively robust, a number of qualitative considerations, scenarios, and sensitivities, have also been considered in this recommendation.

## 1.1. Study Methodology

Two different cases were analyzed over a 10 year period from 2025-2034:

1. MISO Zone 4 remains in MISO ("*Status Quo Case"), and*
2. MISO Zone 4 joins PJM as of January 2025 ("*Join PJM Case")*

Due to the level of interconnection and interdependence of AIC, CWLP, and SIPC, it was assumed that the entirety of MISO Zone 4 (referred to in short as Zone 4) would join PJM or remain in MISO. This assumption was confirmed with MISO, AIC, and the ICC Staff before proceeding with analysis. January 2025 was identified as the earliest withdrawal date based on the notification requirements in the MISO Transmission Owners (TO) Agreement.

Three highly regarded industry standard models were used to complete the study. CRA analyzed impacts on Zone 4 and the ComEd service territory using the zonal capacity expansion and production cost modeling software Aurora. Astrapé conducted reliability assessments of the Aurora results using the Strategic Energy & Risk Valuation Model (SERVM). The zonal capacity expansion results were used as input into the PROMOD

---

1 On July 21, 2022, the ICC directed AIC to perform an analysis of the benefits and costs of participation in MISO verses participation in PJM under Docket 22-0485.

2 Principal study investigators were Jim McMahon, Anant Kumar, and James Russell for CRA, Nick Wintermantel and Chase Winkler for Astrapé, and Rahul Anilkumar for Quanta. The findings and conclusions contained in this study are solely those of the CRA, Astrapé, and Quanta Team.

3 MISO coordinates the movement of wholesale electricity across all or parts of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, Wisconsin, and the Canadian province of Manitoba.

4 PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

5 AIC, CWLP, and SIPC collectively represent the load balancing authorities of MISO Zone 4.

production cost model run by Quanta, which produced assessments of energy trade benefits analyzing the impacts at the nodal level.

## 1.2. Findings

### 1.2.1. State-wide Net Costs

The net costs of Zone 4 joining PJM are summarized in Table 1 (and more fully detailed in appendix A). As shown, net costs over the period from 2025 to 2034 are $733.6 million and $2,696.2 million for AIC and ComEd respectively. The analysis did demonstrate $22.4 million of combined net benefits to SIPC and CWLP, but overall still resulted in net cost for the State of Illinois of $3,407.3 million (2023 net present value).[6]

**Table 1: 2025-2034 Benefits (Costs) of Joining PJM**

*(2023 NPV in millions of dollars; positive numbers are benefits)*

| | AIC | SIPC/CWLP | ComEd | Illinois |
|---|---|---|---|---|
| **1. Energy Trade Benefits** | 563.5 | 36.8 | (450.3) | 149.9 |
| **2. Transmission Expansion Costs** | (213.5) | (13.9) | 25.3 | (202.1) |
| **3. Capacity Costs** | (1,074.6) | 0.2 | (2,271.1) | (3,345.6) |
| **4. RTO Administrative Costs** | 17.3 | 1.1 | - | 18.5 |
| **5. Exit & Integration Fees** | (26.3) | (1.7) | - | (28.0) |
| **Net Benefits (Costs)** | (733.6) | 22.4 | (2,696.2) | (3,407.3) |

As listed in Table 1, the key cost/benefit components assessed in this study are: 1. Energy Trade Benefits; 2. Transmission Expansion Costs; 3. Capacity Costs; 4. RTO Administrative Costs; and 5. Exit & Integration Fees. Each category is discussed in further detail below.

**1. Energy Trade Benefits** are the change in energy costs resulting from Zone 4 joining PJM. In general, the elimination of seams charges between Zone 4 and PJM in the *Join PJM Case* results in more energy imports from ComEd. This change in imports as well as additional renewable builds in Zone 4 later in the forecast period result in a pattern of lower energy costs for Zone 4 and higher energy costs for ComEd. Overall, the Energy Trade Benefits for Illinois in the *Join PJM Case* resulted in a net benefit of $149.9 million over the 2025-2034 period.

**2. Transmission Expansion Costs** are the incremental transmission costs incurred as a result of Zone 4 joining PJM. As a new PJM member, Zone 4 will be subject to a load-ratio share of regional facilities (>345 kV double-circuit) and a portion of certain lower voltage

6 In line with the Climate and Equitable Jobs Act ("CEJA"), in discounting future societal costs and benefits for the purpose of calculating net present values, a societal discount rate based on actual, long-term Treasury bond yields (3.8%) was used. Historic values for underlying inflation were based on U.S. CPI data and future values were assumed to stabilize at 2.5%. Benefits and costs over the 2025-2034 period cited in the report are in 2023 present value dollars unless otherwise noted.

facilities (<345 kV single-circuit).[7] Transmission costs from MISO remain the same in both the *Status Quo Case* and *Join PJM Case* resulting in no net impact to Zone 4.[8] Overall, Transmission Expansion Costs are $202.1 million higher for Illinois in the *Join PJM Case* over the 2025-2034 period.

**3. Capacity Costs** are the net costs of participating in the PJM Reliability Pricing Market (RPM) versus the MISO Planning Resource Auction (PRA). In general, the addition of Zone 4 to PJM causes a significant increase in capacity prices in ComEd as Zone 4 is short on capacity.[9] Additionally, higher reserve margin requirements and the lack of seasonal capacity products in PJM drive higher capacity costs in Zone 4 relative to MISO. Capacity Costs for Illinois are $3,345.6 million higher in the *Join PJM Case* over the 2025-2034 period.

**4. RTO Administrative Costs** are the difference in administrative charges between PJM and MISO passed to member entities. Historically PJM has had lower administrative costs relative to MISO resulting in a net benefit of $18.5 million for Illinois in the *Join PJM Case* over the 2025-2034 period.

**5. Exit & Integration Fees** consist of charges associated with the withdrawal of Zone 4 from MISO and the costs incurred by PJM in connection with Zone 4's integration. Total costs for Illinois in the *Join PJM Case* are $28 million over the 2025-2034 period.

## 2. Introduction and Background

On July 21, 2022, the ICC issued an order in Docket No. 22-0485 directing AIC to conduct an analysis of the relative costs and benefits of participation in MISO versus PJM. The impetus for the study was based on three main points:

- The statutory restriction on state oversight of RTO membership for electric utilities expired on July 1, 2022;
- MISO is situated almost entirely in states having non-competitive electric markets and utilities serving those customers remain vertically integrated – AIC is one of a few non-vertically integrated utilities in MISO and the ICC thought it was worth considering if they are a better fit in PJM.
- The MISO 2022/2023 PRA resulted in an auction clearing price of $236.66/MW-day for MISO' North/Central region (up from $5/MW-day the year before). Additionally, with most utilities in MISO being vertically integrated, the ICC believed it raised the question of whether AIC could better meet its resource adequacy requirements in another RTO.

As AIC was ultimately responsible for the study, it was allowed a certain level of independence in how the study was conducted - within the ICC guidelines. AIC engaged CRA to lead the execution of the cost-benefit analysis who further partnered with Astrapé and Quanta to lead the reliability and nodal analysis, respectively.

---

7 Schedule 12 of the PJM Open Access Transmission Tariff describes the establishment of transmission enhancement charges in PJM.

8 Schedule 39 of the MISO Tariff states that Withdrawing Transmission Owners continue to be responsible for a portion of the cost of constructed and approved projects prior to exit. All MISO Multi-Value Projects (including Tranche 1 & 2) for the 10 year forecast period (2025-2034) are expected to be approved prior to Zone 4 exiting MISO for PJM.

9 Currently, Zone 4 relies significantly on imports from other MISO zones and PJM to meet its load serving obligations. In the 2022-2023 PRA auction, Zone 4 required 2,308.6 MW (UCAP) of imports to meet its capacity requirements.

### *Charles River Associates*

CRA has a long history of working on market design and RTO participation questions. CRA recently publicly worked on the Southeast Energy Exchange Market (SEEM) analysis exploring the benefits of a proposed market in the southeast. CRA's RTO analysis work dates back more than a decade, including work for East Kentucky Power Cooperative (decision to join PJM in 2012) and Entergy and Cleco (decision to join MISO in 2011). Moreover, the company, and the staff on this engagement, are regularly engaged on capacity expansion and cost-benefit questions, which are at the core of this engagement. For instance, CRA is currently conducting capacity expansion or system-wide modeling for clients that include AEP, NiSource, Alliant, Liberty, Entergy, Dominion, and Duke.

Below is a list of RTO participation studies CRA has conducted.

- 2007 Aquila Missouri Cost Benefit Study (MISO and SPP)
- 2007 AmerenUE Cost Benefit Study (MISO, SPP, and ICT)
- 2010 Big Rivers Cost Benefit Analysis (MISO)
- 2011 Entergy Cost Benefit Analysis (SPP, MISO)
- 2011 ATSI Cost Benefit Analysis (MISO, PJM)
- 2012 EKPC RTO Membership Assessment (PJM)

More recently, the CRA team has used similar analytical approaches and modeling tools in the conduct of several Integrated Resource Plans (IRP) for electric utilities across the United States.

For the AIC Cost-Benefit Study, CRA used Aurora to perform the power market modeling. Aurora is a detailed capacity expansion and production costing model that simulated operation of the electric power system taking into account zonal transmission topology. The Aurora model determines commitment and hourly dispatch of each modeled generating unit, the loading of each element of the transmission system, and the zonal price for each generator and load area. CRA has extensive experience with the Aurora model and currently leverages it for all market modeling and utility portfolio modeling engagements.

### *Astrapé Consulting*

Astrapé provides expertise in resource adequacy and generation planning and is the owner and licensor of the SERVM model. SERVM has been used to support a wide range of planning studies within United States, Europe, and Asia. Within the United States, SERVM is used by ISOs, state commissions, and utilities to understand resource adequacy risks. The results of the model deliver a full distribution of expected reliability events and their costs, allowing system planners to mitigate reliability concerns and economically plan the expansion of their system.

### *Quanta Technology*

Quanta Technology has supported some of the major utilities and co-operatives in the United States with an evaluation of their RTO and Energy Imbalance Market (EIM) participation. The team has developed specialized tools, supported by complex grid modeling to guide the overall analysis. Quanta Technology maintains and develops models across several vendor platforms, including GridView, PROMOD, PLEXOS and GE MAPS – providing the flexibility to address the specific market efficiency and FERC Order 1000 protocols of all markets in the United States. The suite of software and models represent the system at the nodal level, allowing for detailed economic dispatch and production cost modeling that takes into account market security clearing (N-1). The models are used for major engagements across utilities, developers and RTO clients.

The following sections describe the study results, sensitivities, and assumptions. In Section 3, the individual cost and benefit measures are described. Section 4 summarizes the study's quantitative results and rate impacts. Section 5 describes different sensitivities and scenarios modeled, while Section 6 discusses qualitative considerations and risks. Appendix A provides additional detail on the study results, Appendix B provides a detailed discussion of the Aurora input assumptions, Appendix C describes the nodal modeling, Appendix D describes the reliability analysis and ELCC modeling, and Appendix E includes a copy of the ICC Initiating Order in Docket 22-0485.

# 3. Benefits and Costs

To assess the various cost/benefit components, CRA analyzed two cases over a 10-year period from January 2025 to December 2034:

1. *Status Quo Case:* Zone 4, including AIC, SIPC, and CWLP, continues to operate as a member of MISO.
2. *Join PJM Case:* Zone 4 joins PJMin January 2025.[10]

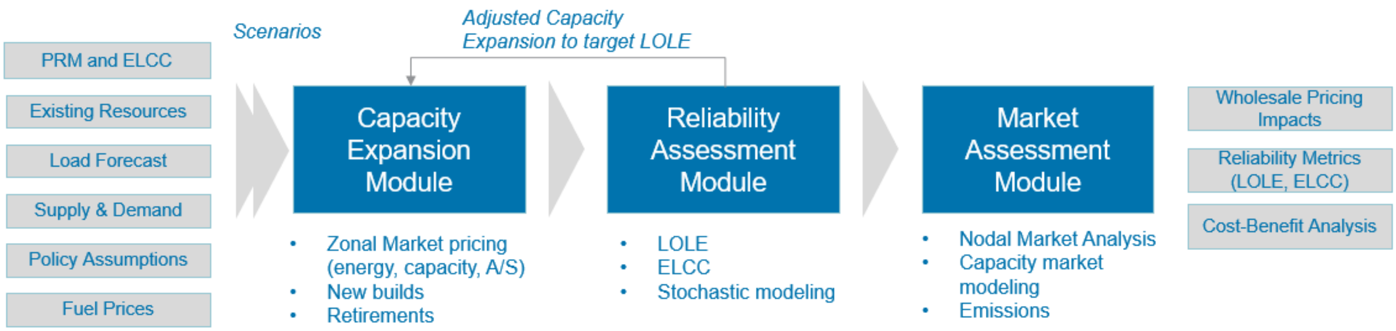
In the Status Quo *Case*, Zone 4 continues to meet MISO membership requirements and seams charges apply between Zone 4 and the interconnected PJM Zones. In the *Join PJM Case*, Zone 4 becomes a full member of PJM as its own Locational Deliverability Area (LDA) interconnected to ComEd area, and to the American Electric Power (AEP) service territories in Indiana and Michigan. Seams charges now apply between Zone 4 and the rest of MISO.[11]

## 3.1. Energy Trade Benefits

### 3.1.1. CRA Modeling Framework

The modeling framework used to evaluate the energy trade impacts under each case is comprised of three main modules: (i) a zonal capacity expansion module; (ii) a reliability assessment module; and (iii) a nodal market analysis module. Figure 1 illustrates steps followed in the framework.

**Figure 1. CRA Modeling Framework**




10 Although the cost-benefit analysis focuses on the RTO membership of Ameren AIC, it is assumed that SIPC and CWLP will also join PJM given their reliance on Ameren Illinois transmission infrastructure to serve their costumers' load demand

11 Seams charges are fees imposed when electricity is transferred across the seams, or boundaries, between two RTOs. The respective MISO and PJM tariffs define rates for various seams charges. For the purposes of the study, AIC provided composite seams rates which averaged to ~$5/MWh from both MISO to PJM and PJM to MISO.

CRA relied on the Aurora[12] model to perform the capacity expansion analysis. Aurora's Long Term Capacity Expansion (LTCE) functionality provides an analytical framework to account for policy measures, market rules, and changes in market fundamentals. This model uses a recursive optimization process to identify the set of resources with the highest and lowest market values to produce an economical capacity expansion and retirement schedules.

This licensed model is set up to regional, long-term capacity expansion analysis for PJM and MISO, simultaneously; and to forecast hourly zonal price and economic dispatch using hourly demand. Aurora also includes individual resource operating characteristics in a transmission constrained system representing the Eastern Interconnect. Market inputs, for each RTO, for the Aurora model include fuel prices, emission prices, regional load forecasts, existing resource parameters and announced regional capacity additions and retirements, and costs and operational parameters for new technology resource options.

In this module, Aurora receives input assumptions on existing resources, planning reserve margin, existing and new capacity accreditation, load forecast, fuel prices, new technology options, among other assumptions[13]; CRA performed a long-term capacity expansion run for each case to determine capacity additions and retirements schedules for MISO and PJM zones. Resulting portfolios for each RTO are then sent to the reliability assessment module.

Reliability Assessment Module

This module receives the capacity expansion plan for each case and assesses the portfolio reliability and estimates the resulting planning reserve margin requirement and the effective load carrying capability (ELCC) for the capacity contribution of intermittent (wind and solar) or energy limited technologies (storage and demand response).

For this assessment Astrapé relies on SERVM, a tool used to perform resource adequacy analysis. SERVM is a probabilistic tool that optimizes the hourly commitment and dispatch of resources subject to maximizing reliability at minimum cost. The reliability target used for this analysis was Loss of Load Expectation (LOLE) and is defined as the number of loss of load events due to capacity shortages, calculated in days per year. Loss of load events are driven by a variety of factors but are particularly correlated to concurrent random forced outage events, severe weather, or a combination thereof.

To properly characterize the possible severe weather outcomes, SERVM utilizes a "weather year" framework. Under this framework, the system is simulated given 43 possible annual weather patterns (1980-2022) consisting of hourly temperature, wind profiles, solar irradiance, load, and hydro conditions. The weather years are coupled with five load forecast errors and five different iterations yielding a total of 43*5*5 = 1,075 yearly annual simulations per assessment. LOLE represents the weighted average expected number of shortage events across all these conditions.

This weather year framework was used to calculate the LOLE for future different study years of the MISO and PJM buildouts produced by the expansion planning models utilized by the CRA team. To ensure the expansion plans were reliable for each scenario, study years 2025,

12 The Aurora model is commercialized by Energy Exemplar and is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation; https://www.energyexemplar.com/aurora

13 The database includes approximately 25,000 electricity generating facilities in the contiguous United States (U.S.), Canada, and Baja Mexico. These generating facilities include wind, solar, biomass nuclear, coal, natural gas and oil. A licensed data provider, Hitachi Energy Velocity Suite, provides up-to-date information on markets, entities, and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the Aurora model.

2030, and 2035 were simulated in SERVM. This provided a feedback loop to the CRA team to add (if LOLE was higher than 0.1 days per year) or remove (if LOLE was lower than 0.1 days per year) effective capacity from the final portfolios. The resulting LOLE and the equivalent short or long effective capacity was provided to CRA to adjust the portfolio mix and ensure that reliable portfolios move to the market assessment module.

Once the MISO-PJM system was simultaneously calibrated to 0.1 LOLE (the planning target for both ISOs), the ELCC study could be performed. ELCC, or Effective Load Carrying Capability, represents the accreditation of a resource on a percentage basis relative to perfect capacity.

Market Assessment Module

After CRA adjusted the RTO portfolios following the guidance provided by Astrapé, based on the results from the LOLE assessment, the final capacity expansion plan, together with Aurora's input assumptions, are used to perform the nodal market analysis using PROMOD.

PROMOD[14] is a production cost modeling tool used in electric market simulation that performs a security constrained unit commitment while optimizing bid production costs, recognizing both generation and transmission impacts at the nodal and zonal level. Incorporating customer demand, generating unit operating characteristics, fuel usage, environmental considerations, transmission grid topology and limits, and external market transactions, PROMOD forecasts energy prices, unit generation, revenues and fuel consumption, transactions, transmission losses and congestion at the nodal level.

The baseline production cost models used for this analysis are obtained from the MISO MTEP 2021 cycle with a nodal representation of the network down to the 60 kV system. The models include a representation of the entire Eastern Interconnection, including PJM.

For this module, CRA's zonal inputs assumptions for MISO and PJM were translated to PROMOD to achieve an equivalent model at the nodal level. The inputs were originally designed for zonal simulations using the Aurora model. Typically, the nodal models include a hierarchy scheme wherein each node is a component of a zone, and each zone is a component of an ISO/RTO definition. The dissemination process to the nodal level was initiated after verification of consistency in zonal attributes against the input data.

The PROMOD representation of MISO and PJM systems was also verified and updated to include major approved transmission projects from the PJM Regional Transmission Expansion Planning (RTEP) cycle, MISO Transmission Expansion Planning (MTEP) cycle, which, in the case of MISO includes the Long- Range Transmission Planning (LRTP) Tranche 1 approved projects. For details about the nodal modeling process and other assumptions see Appendix C:

During the nodal modeling process, a benchmarking exercise was performed to verify consistency in trends and outputs between the zonal and nodal models. Following this, PROMOD simulations were performed for 2025, 2030, and 2035. Outputs were analyzed to evaluate load-weighted prices, generation-weighted prices, emissions, and transmission constraints. The resulting nodal load-weighted prices are used to assess the energy trade benefits under each scenario.

Energy Prices

Zonal energy prices are derived from the dispatch cost of the last unit in a zone needed to serve its net load. Dispatch costs are determined by fuel costs, variable O&M costs, and the

14 PROMOD is commercialized by Hitachi Energy and has been used for over 45 years in the energy industry to perform locational marginal price (LMP) forecasting, financial transmission right (FTR) and transmission congestion analyses.

costs of emissions allowances. By increasing energy trade, additional generation from other zones with lower costs of generation could lead to lower dispatch costs, resulting in cost savings.

Nodal energy prices, like the zonal, are derived from the dispatch cost. However, these prices capture congestion costs given that the nodal model contains more detailed representation of transmission limits and can identify congestion pockets throughout the network.

In this study, energy trade benefits are determined by calculating for the difference in nodal energy prices between the *Status Quo* and the *Join PJM* cases, for Zone 4 and ComEd, under each scenario, and multiplying this difference by the forecasted load in each of the zones.

### 3.1.2. Energy Trade Benefit Results

In the *Join PJM Case*, Zone 4 exhibits decreasing energy prices when compared with the *Status Quo Case*. In the mid-term, energy prices decrease due to the removal of seams charges between Zone 4 and ComEd. ComEd historically remains the lowest cost region amongst surrounding areas, due to the presence of a significant amount of baseload nuclear and wind capacity. By removing the transmission charges between ComEd and Zone 4, Zone 4 benefits from importing lower cost energy without having material differences on the supply side. In the long-term, Zone 4 decreasing energy prices stem from higher renewable capacity addition. Factors contributing to higher renewables builds in the *Join PJM Case* for Zone 4 are:

- Higher reserve margin requirements in PJM.
  PJM has a 9.18% Forecast Pool Requirement (FPR) vs. MISO having a 7.4% summer reserve margin requirement. The higher reserve margin requirements encourage more builds in areas with supply shortages, for example, the new Zone 4. Although it is unclear what the Reliability Requirement would be if Zone 4 joins PJM, the Reliability Requirement before netting off Capacity Emergency Transfer Limit (CETL) for ComEd is about 27%.
- Differences in capacity construct between PJM and MISO.
  From a modeling standpoint, PJM operates under a sloped demand curve, which tends to encourage capacity surplus in the system, whereas in MISO the vertical demand curve tends to restrict additional builds above the planning reserve margin requirement. In MISO, once the region is above the Planning Reserve Margin Requirement (PRMR) the incentives from a capacity payment perspective diminish quickly.
- Limitation in terms of new build options.
  In Illinois, no new gas capacity (aside from already scheduled projects) is allowed during the forecast horizon, leading Zone 4 to meet its PRMR with new solar, wind, and storage in CRA modeling framework. To meet the increase in reserve margin requirements with intermittent and energy limited resources, a greater amount of renewables and storage capacity is needed.

Even in the *Join PJM Case*, Zone 4 remains at a premium price relative to ComEd during the study period. However, higher amounts of renewables and storage builds in Zone 4, in the *Join PJM Case*, contribute to narrowing the price spreads between ComEd and Zone 4.

Removal of seams charges between Zone 4 and PJM leads to increased gas and coal generation in ComEd to increasing exports to Zone 4 due to higher electricity prices. This thermal generation increase leads to higher energy prices in ComEd in the *Join PJM Case* relative to the *Status Quo Case*.

Figure 2 captures the change in energy cost ($/MWh) across Illinois for forecast year 2030 in the *Join PJM Case*. As described above, ComEd sees higher energy prices universally across the zone, while Zone 4 generally has lower energy prices, although there are some pockets of congestion visualized in the heat map.

**Figure 2: Change in Illinois' Energy Prices (*Join PJM – Status Quo, 2030)***

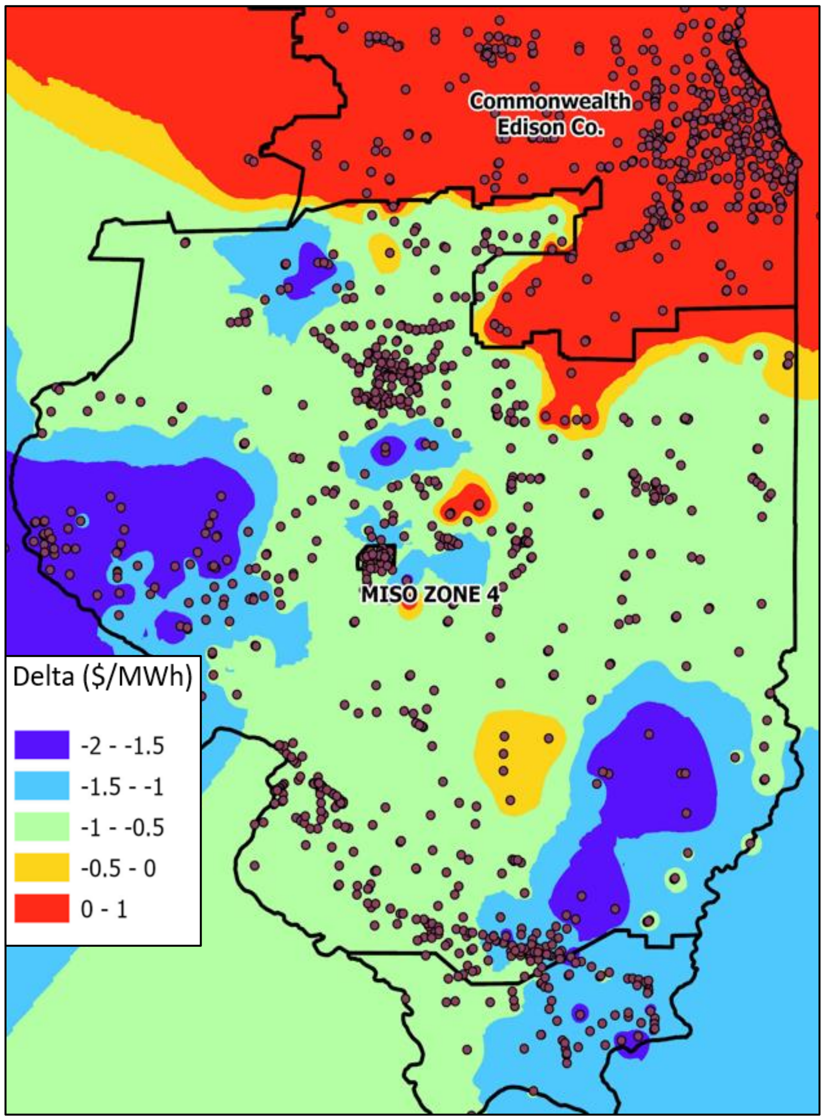



Table 2 summarizes the results of the energy trade benefit analysis. In the *Join PJM Case*, decreasing energy prices in Zone 4 results in a net present value of $600 million in energy trade benefits. However, increasing energy prices for ComEd leads to $450 million in energy trade cost. Therefore, when accounting for the benefit/cost of these two zones, the net benefit for the State of Illinois is $150 million.

**Table 2: Summary Trade Benefit Analysis for Scenario A (2025-2034)**

*(positive $ numbers are benefits)*

| Year | Zone 4 (2023$/MWh) | | | ComEd (2023$/MWh) | | | Benefit (Cost) (2023$ million) | | IL Net Benefit (2023$ million) |
|---|---|---|---|---|---|---|---|---|---|
| | Status Quo | Join PJM | Delta | Status Quo | Join PJM | Delta | Zone 4 | ComEd | |
| 2025 | 50.85 | 49.00 | 1.84 | 47.70 | 48.17 | (0.47) | 93 | (43) | 50 |
| 2026 | 49.16 | 47.93 | 1.24 | 45.49 | 46.37 | (0.88) | 63 | (80) | (17) |
| 2027 | 46.37 | 45.29 | 1.08 | 42.80 | 43.63 | (0.82) | 55 | (75) | (19) |
| 2028 | 45.47 | 43.89 | 1.58 | 41.92 | 42.56 | (0.64) | 81 | (58) | 23 |
| 2029 | 46.50 | 44.88 | 1.61 | 42.72 | 43.45 | (0.73) | 84 | (67) | 17 |
| 2030 | 47.15 | 45.65 | 1.50 | 43.93 | 44.52 | (0.60) | 78 | (54) | 24 |
| 2031 | 46.29 | 44.73 | 1.56 | 43.03 | 43.48 | (0.45) | 82 | (40) | 42 |
| 2032 | 44.80 | 43.38 | 1.42 | 41.45 | 41.90 | (0.45) | 75 | (41) | 34 |
| 2033 | 43.61 | 42.48 | 1.14 | 40.20 | 40.69 | (0.49) | 61 | (44) | 17 |
| 2034 | 42.65 | 41.61 | 1.04 | 38.90 | 39.32 | (0.42) | 56 | (38) | 18 |
| **Net Present Value (2023$ millions)** | | | | | | | **600** | **(450)** | **150** |

## 3.2. Transmission Expansion Costs

### 3.2.1. MISO Transmission Expansion Costs

***Background***

MISO's Long Range Transmission Planning (LRTP) initiative results in backbone transmission facilities required to solve specific grid issues and move bulk power reliably and efficiently across the MISO footprint. MISO's LRTP process aims to provide a cost-effective solution to allow future resources to serve load, more flexibility in resource mix for customers, and maintain robust and reliable performance in the future with greater supply uncertainty and variability. The scope of LRTP business case analysis includes quantifying the reliability and economic benefits such as congestion and fuel savings, avoided capital costs of local resource investments, avoided transmission investment, avoided risk of load shedding, and decarbonization over the 20- to 40-year period from project start.

MISO's LRTP Tranche 1, approved in July 2022, is the first of four tranches or phases of effort planned to address specific subregional transmission needs.[15] Tranches 1 and 2 are focused on the Midwest subregion; Tranche 3 will target the South and Tranche 4 will target the North/South interface limit. Tranche 2 planning is underway and expected to be finalized in 2024. Tranches 3 and 4 are not expected to be constructed within the forecast period and were not included in this analysis.

The approved set of 18 regional Tranche 1 projects are designed to facilitate the integration of remote renewable resources and retirement of aging fossil generation, in line with state renewable portfolio standards and clean energy goals. Total portfolio cost for Tranche 1 is estimated to be $10.3 billion.

15 MISO, "Long-Range Transmission Planning Tranche 2 – Frequently Asked Questions," pdf p. 4,

Tranche 2 efforts began during Q4 2022 and is expected to be finalized and approved in 2024.

<u>Multi-Value Projects</u>

Multi-value projects are transmission solutions that meet one or more of the following criteria: deliver energy more reliably or economically than without the upgrade, provide total benefit-to-cost ratio of 1.0 or higher across multiple pricing zones, or address at least one transmission issue associated with a projected violation of NERC or regional entity reliability standard and provides economic value across multiple pricing zones. The project must have an expected cost of at least $20 million, consist of high-voltage transmission lines (100 kV or higher), help MISO participants meet state renewable energy goals, and fix reliability issues. The primary objective of MVPs is to enable cost-sharing of regional projects and enable compliance with public policy requirements and provide economic value. Production cost savings and capacity losses savings are some examples of the specific type of ‘economic value’ defined in the MISO Tariff.

The MVP projects are deemed by MISO to create a pool-wide benefit, and therefore the costs for these projects are 100% allocated to all MISO members using a “postage stamp” methodology., i.e., all members pay based on annual energy usage, irrespective of whether a particular line serves their applicable footprint or not. These costs are recovered under Schedule 26A of the MISO Tariff.

<u>Non-MVP Projects</u>

Non-MVP projects may include baseline reliability projects that are required to meet NERC reliability standards or other applicable regional reliability organizations metrics, generation interconnection projects that ensure the reliability of the system when new generators interconnect, and market efficiency projects which provide reductions in market congestion with benefit-to-cost ratio of 1.25 or higher.

MISO allocates regional transmission costs to member transmission owners at the time each project is approved. These costs, including 40-year depreciation schedules, are recovered over the economic lifetime of each project. Hence, Zone 4 will face (i) Legacy MTEP costs for MVP and traditional non-MVP projects that are already approved (or approved prior to Zone 4’s withdrawal date) and (ii) Future MTEP costs for MVP and non-MVP projects yet to be approved.

All of MVP project costs are allocated by MISO to the transmission zones based on an annual energy consumption ratio. Costs for baseline reliability and market efficiency projects are split among the transmission owners, with 80% allocated to local beneficiaries and 20% cost-shared across the MISO footprint for projects at or above 345 kV. The 20% component is divided among MISO transmission zones based on the “12CP” measure of average coincident transmission system peak loads for each of the 12 months in the preceding year. Generator Interconnection projects associated with transmission lines at or above the 345 kV threshold are cost shared as well, with 10% allocated across the MISO footprint (the other 90% being assigned to the connecting generator(s)).

The majority of Non-MVP projects are local or single-zone projects and will be allocated regardless of which RTO Zone 4 is in. As a result, these costs were not computed in this analysis.

#### *Analysis*

The MTEP database is the repository for all approved and recommended transmission projects, containing specific information including, but not limited to, project scope, cost estimates, facility type, project drivers, status, and completion dates for each facility.

MTEP's Schedule 26-A publishes a 20-year projection of the indicative annual charges for approved and pending MVP projects by local balancing authority. This currently is inclusive of LRTP Tranche 1, but does not include Tranche 2 which is expected to be approved during the first half of 2024.[16]

To project Tranche 2 annual revenue requirements, CRA assumed a $25 billion cost (mid-point of current $20 - $30 billion estimate) and in-service dates of 2030-2032 in line with the timeline established for Tranche 1 projects. CRA utilized a long-term carrying structure for these projects derived from MISO's published Indicative Annual Charges to estimate the annual revenue requirements.

The total sum revenue requirements of Zone 4's cost allocations for Schedule 26-A, Tranche 1, and Tranche 2 projects throughout the forecast period establishes the base case for MISO transmission expansion (Table 3).

**Table 3 Annual Revenue Requirements for MISO MVP Projects ($ millions)**

| Year | Schedule 26-A Projects (Legacy MVPs) | LRTP Tranche 1 (Approved and Pending MVPs) | LRTP Tranche 2[17] (Pending MVPs) | Total Cost to Zone 4 |
|---|---|---|---|---|
| | AIC, CWLP, SIPC | AIC, CWLP, SIPC | AIC, CWLP, SIPC | |
| 2025 | 74.91 | - | - | 74.91 |
| 2026 | 74.26 | - | - | 74.26 |
| 2027 | 73.60 | - | - | 73.60 |
| 2028 | 72.95 | 12.35 | - | 85.30 |
| 2029 | 72.30 | 52.68 | - | 124.98 |
| 2030 | 71.65 | 102.47 | 80.44 | 254.56 |
| 2031 | 71.00 | 122.11 | 185.54 | 378.65 |
| 2032 | 70.35 | 121.40 | 297.15 | 488.90 |
| 2033 | 69.70 | 120.69 | 295.20 | 485.59 |
| 2034 | 69.05 | 119.97 | 293.26 | 482.27 |

<u>Schedule 39</u>

As per Schedule 39 of the MISO Tariff, a withdrawing transmission owner is responsible for the portion of the cost of MVPs constructed or approved by the transmission provider's board of directors, prior to the transmission owner's exit. Likewise, the transmission owner will continue to receive the annual revenue requirement for the MVPs they constructed, even after withdrawing from MISO. As a result, Zone 4 will be responsible in perpetuity for all previously approved MVP projects since they are sunk costs.

MISO Rate Schedule 1 Transmission Owner Agreement states that the earliest date a member's withdrawal from MISO can take effect is December 31 of the calendar year following the calendar year in which notice to withdraw is given. Hence, the earliest Zone 4 can withdraw from MISO would be Dec 31, 2024, and Tranche 2 projects are expected to be approved prior to that date. Zone 4 will incur all costs allocated for Tranche 1, Tranche 2, and other MVP projects approved prior to the withdrawal date, regardless of whether they stay in MISO or exit the RTO and join PJM resulting in no change between the *Status Quo Case* and

16 MISO LRTP Tranche 2 – Frequently Asked Questions

17 If Tranche 2 projects were approved after Zone 4's withdrawal from MISO, this would result in ~$650M (2023$) less transmission expansion costs in the *Join PJM Case*

*Join PJM Case*. As a result, CRA focused on estimating the transmission buildout and associated costs in PJM.

### 3.2.2. PJM Transmission Expansion Costs

***Background***

PJM performs the RTEP process annually, which looks ahead up to 15 years in the future to identify transmission system upgrades and improvements needed to maintain grid reliability and economic performance. Transmission owners are obligated to construct the transmission projects approved by PJM through the RTEP.

Under Schedule 12 of PJM's Open Access Transmission Tariff, the associated costs are recovered/socialized using different cost allocation methods based on the type of project:

1. **Regional Facilities and Necessary Lower Voltage Facilities:** Enhancements for A.C. facilities that operate at or above 500 kV, A.C. double-circuit facilities that operate at or above 345 kV and below 500 kV, D.C. facilities that operate at voltage of 433 kV D.C. or above, or D.C. double-circuit facilities that operate at voltage of 298 kV D.C. are termed "regional facilities" or backbone projects. 50% of the cost responsibilities for such facilities are allocated to each transmission zone based on annual load-ratio share calculated using the zone's annual peak load. The other 50% is assigned to zones that benefit using PJM's distribution factor (DFAX) analysis. DFAX is a power-flow calculation based on relative contribution from each customer zone to the flows on new baseline upgrades. Zones that contribute less than 1% per MW are not assigned cost responsibility.
2. **Lower Voltage Facilities:** For single-circuit facilities that operate at 345 kV or lower, 100% of the cost responsibilities are allocated using the DFAX analysis. Distribution Factors are calculated for every constrained transmission facility that requires the Lower Voltage facility to avoid violating a reliability criterion or to relieve congestion. The cost of such Lower Voltage facilities is socialized among the owners of impacted transmission facilities proportionate to the distribution factors for those facilities.

This study does not estimate the cost additions for other project categories such as supplemental upgrades, which are allocated to a sponsoring single transmission zone, as the net cost or benefit in the *Join PJM Case* and *Status Quo Case* should remain approximately the same for such projects.

***Analysis***

PJM's Transmission Cost Information Center (TCIC) workbook provides a list of the total cost estimate for each individual approved baseline, network and supplemental project that is in-service, under construction, in engineering and planning phase, cancelled or on hold. It provides an interface to run future scenario studies to analyze the impact of transmission zones leaving or integrating with PJM.

The TCIC uses the cost estimates for existing projects, along with applicable carrying charges with formula rate filings by transmission owner to estimate the annual revenue requirement and monthly zonal charges within a 10-year horizon. CRA utilized the same methodology to estimate the total costs incurred by Zone 4 in the *Join PJM Case*.

Regional Projects – Load-Ratio Share

As a new member to PJM, Zone 4 would likely be subject to the full cost allocations for expansion without any phase-in period. To estimate the load-ratio share cost portion of new regional projects, CRA assumed the PJM-wide annual additions to be equal to the 10-year average of historical plant additions ($368 million) and escalated it by 3.84% each year to account for increasing growth and inflation.[18] As PJM does not publish carrying charges, carrying charges from MISO were assumed and Zone 4's PJM load share of 5.4% (Table 4) was applied to 50% of PJM annual additions to derive Zone 4's annual revenue requirement.

**Table 4: Load Ratio Share Allocation by PJM Transmission Zone**

| Responsible Zone | Current Peak Load (MW) | Current LRS (%) | Future Peak Load (MW) | Future LRS (%) |
|---|---|---|---|---|
| AEC | 2631 | 1.7% | 2,631 | 1.6% |
| AEP | 21925 | 13.9% | 21,925 | 13.2% |
| APS | 8865 | 5.6% | 8,865 | 5.3% |
| ATSI | 12604 | 8.0% | 12,604 | 7.6% |
| BGE | 6486 | 4.1% | 6,486 | 3.9% |
| **ComEd** | **21167** | **13.5%** | **21,167** | **12.7%** |
| Dayton | 3329 | 2.1% | 3,330 | 2.0% |
| DEOK | 5305 | 3.4% | 5,306 | 3.2% |
| DL | 2759 | 1.8% | 2,759 | 1.7% |
| Dominion | 20404 | 13.0% | 20,405 | 12.3% |
| DPL | 4006 | 2.5% | 4,006 | 2.1% |
| ECP | 0 | 0.0% | 0 | 0.0% |
| EKPC | 2850 | 1.8% | 2,851 | 1.7% |
| HTP | 0 | 0.0% | 0 | 0.0% |
| JCPL | 6169 | 3.9% | 6,169 | 3.7% |
| ME | 3071 | 1.9% | 3,072 | 1.9% |
| Neptune | 382 | 0.2% | 383 | 0.2% |
| OVEC | 106 | 0.1% | 106 | 0.1% |
| PECO | 8479 | 5.4% | 8,479 | 5.1% |
| PENELEC | 2899 | 1.8% | 2,900 | 1.7% |
| PEPCO | 5829 | 3.7% | 5,829 | 3.5% |
| PPL | 7516 | 4.8% | 7,517 | 4.5% |
| PSEG | 10064 | 6.4% | 10,064 | 6.1% |
| RE | 427 | 0.3% | 427 | 0.3% |
| **Zone 4** | **0** | **0.00%** | **8,966** | **5.4%** |

To estimate the load-ratio share of existing regional projects, the TCIC's functionality to input a future zone's network service peak load to update future load-ratio share allocations and monthly zonal charges was utilized.

MISO Zone 4's integration to PJM proportionally reduces ComEd's portion of the load-ratio-share allocated costs for legacy and future regional projects and ComEd's cost savings are picked up by the new zone.

<u>Lower Voltage and Regional Projects - DFAX</u>

Based on CRA's interactions with PJM and review of the TCIC data, once Zone 4 joins PJM, Zone 4 will be subject to the Schedule 12 DFAX allocations for previously approved RTEP projects in subsequent years. However, Zone 4 will not be assigned the portion of costs prior to integration.

To calculate Zone 4's DFAX requirement for both future low voltage and future regional projects, CRA used ComEd's historical DFAX allocation as a proxy for the costs Zone 4 would incur, given that ComEd is similarly situated electrically on the transmission grid. Projects allocated to single entities were neglected in the calculations, as the cost allocations for such projects are likely to be the same in PJM as they would be in MISO.

---

18 Inflation is assumed to be 2.5% and the 2023 PJM load forecast is growing at a CAGR of 1.34%

ComEd historically incurred costs for low voltage projects alone, as the zone possibly contributed less than 1% per MW to flows in the DFAX assessment for regional upgrades. ComEd's share of DFAX projects is $213 million or 2.9% of PJM's total. Because ComEd's share of PJM's coincident peak load (as adjusted on Table 4 to include Zone 4 within PJM) was 12.7% compared with 5.4% for Zone 4, it was estimated that Zone 4's share of the new DFAX projects would be 0.4 times that of ComEd's or 1.24%.

Similar to regional projects, CRA assumed future low voltage projects to be the 10-year average of historic low voltage plant additions allocated to multiple entities ($685 million) and subsequently increased this base value by 3.84% each year to account for transmission growth and inflation. Zone 4's derived DFAX share of 1.24% and carrying rates were applied to estimate Zone 4's annual revenue requirement for the DFAX projects.

PJM would likely reassess the power flow implications and DFAX allocations for existing lower voltage projects once Zone 4 joins PJM. As a result, CRA calculated the annual revenue requirements for future lower voltage projects alone and neglected existing lower voltage projects, considering these cost allocations would be likely to change after Zone 4's integration into PJM. As transmission builds are designed to benefit PJM members, any net costs to Zone 4 for existing lower voltage projects are likely to be offset by ComEd's savings.

Table 5 summarizes year-over-year regional and low voltages additions for PJM and Zone 4's proportional share.

**Table 5 Cost of Future Regional and Non-Regional Transmission Projects ($ Millions)**

| Year | Cost of PJM-wide Future Regional Projects | Cost of PJM-wide Future DFAX Low Voltage Projects | Zone 4 Share of Future Regional Projects | Zone 4 Share of Future DFAX Projects |
|---|---|---|---|---|
| 2025 | 198.61 | 685.04 | 10.71 | 8.49 |
| 2026 | 206.24 | 711.35 | 11.12 | 8.82 |
| 2027 | 214.16 | 738.66 | 11.54 | 9.16 |
| 2028 | 222.38 | 767.03 | 11.99 | 9.51 |
| 2029 | 230.92 | 796.48 | 12.45 | 9.88 |
| 2030 | 239.79 | 827.07 | 12.92 | 10.26 |
| 2031 | 249.00 | 858.82 | 13.42 | 10.65 |
| 2032 | 258.56 | 891.80 | 13.94 | 11.06 |
| 2033 | 268.49 | 926.05 | 14.47 | 11.48 |
| 2034 | 278.80 | 961.61 | 15.03 | 11.92 |

Additional PJM RTEP Considerations

While PJM's documented RTEP allocations and methodology has been the key cost driver in this analysis, CRA also included additional layers to capture forecast uncertainties and other scenarios, such as accelerated grid expansion to accommodate renewables buildout driven by state clean energy targets.

PJM's Offshore Wind Transmission Study, conducted in 2021, determined enhancements to the onshore grid to reliably integrate 14 GW of announced large-scale offshore wind driven by individual state mandates to meet state RPS requirements. The study's long-term scenario estimated nearly $1.5 billion in regional project upgrades through 2035 for the reliable integration of offshore wind and other renewable resources into the PJM grid.[19]

Fifty percent of the identified regional project upgrade costs were allocated over the study period (2025-2034) to estimate PJM-wide annual plant additions. Zone 4's revenue requirement was derived by applying the appropriate carrying charge schedule and Zone 4's load-ratio share of 5.4%, which was added to the RTEP total annual revenue requirement to derive the base case for PJM transmission expansion.

Table 6 summarizes the annual revenue requirements for each of the different projects described above and the savings realized by ComEd in the *Join PJM Case.*

**Table 6: Annual Revenue Requirements for Regional and Low Voltage Projects**

| Year | Regional RTEP Approved Projects (LRS) | Regional RTEP Future Projects (LRS) | Offshore Wind Study Projects (LRS) | Low Voltage Projects (DFAX) | LRS Reduction to | Net Cost to |
|---|---|---|---|---|---|---|
| | AIC, CWLP, SIPC | | | | ComEd | Illinois |
| 2025 | 17.85 | 2.56 | 0.75 | 1.04 | (2.85) | 19.35 |
| 2026 | 17.78 | 3.90 | 1.12 | 2.12 | (3.07) | 21.85 |
| 2027 | 17.40 | 5.28 | 1.50 | 3.23 | (3.25) | 24.15 |
| 2028 | 16.98 | 6.71 | 1.88 | 4.37 | (3.44) | 26.51 |
| 2029 | 16.57 | 8.19 | 2.27 | 5.56 | (3.64) | 28.94 |
| 2030 | 16.15 | 9.71 | 2.66 | 6.78 | (3.84) | 31.46 |
| 2031 | 15.73 | 11.29 | 3.05 | 8.04 | (4.05) | 34.06 |
| 2032 | 15.32 | 12.91 | 3.45 | 9.34 | (4.26) | 36.75 |
| 2033 | 15.04 | 14.59 | 3.85 | 10.69 | (4.51) | 39.67 |
| 2034 | 14.68 | 16.33 | 4.26 | 12.08 | (4.75) | 42.60 |

Overall, transmission expansion for the State of Illinois in the *Join PJM Case* resulted in a net cost of $202.1 million (2023$ NPV) over the 2025-2034 forecast period.

## 3.3. Capacity Costs

***Background***

The utilities in Illinois rely on their respective RTOs to ensure resource adequacy at a reasonable cost based on market constructs. Each year, the utilities purchase capacity that clears in auctions. While there are many similarities in how the capacity markets operate (single clearing price auctions at zonal levels, targeted reserve margins, etc.), there are many distinctions in both market constructs and resource participation that can cause capacity prices, and therefore capacity costs, to diverge significantly between MISO and PJM. This happened recently as prices for Zone 4 in MISO reached $236.66/MW-day for the same delivery year (2022/23) that prices in the Illinois region of PJM (ComEd) were $68.96/MW-day.

Such a difference in capacity prices can lead to very different total costs for ratepayers. The total Illinois capacity requirement was over 29,000 MW for the 2022/23 delivery year. A $10/MW-day change in capacity prices would lead to $106 million difference in capacity costs

19 PJM Interconnection, 2021, “Offshore Wind Transmission Study: Phase 1 Results”, pdf pp. 2-16

in Illinois for a single year. If such a difference was sustained, the difference in capacity costs could be drastic.

Sustained differences in capacity prices can be caused by several factors that generally fall into two categories: 1) market construct, and 2) capacity and transmission developments.

Examples of impactful differences in market constructs include demand curve shapes, rules determining offer prices, capacity accreditation, seasonal versus annual constructs, and participation rules for various resource types. Examples of capacity and transmission developments include capacity resource development (leading to long or short supplies over time) and the development of transmission to support capacity imports and exports.

The PJM and MISO capacity constructs have historically gone through significant changes and are expecting more in the future as resource adequacy needs change and capacity resources evolve. As discussed previously, the capacity resource and transmission dynamics are changing significantly in both markets. It is therefore important to evaluate the capacity prices going forward to assess the capacity cost impacts of a potential move of Zone 4 to PJM.

CRA conducted an analysis of the net costs of a move to PJM by forecasting and comparing capacity costs in the *Status Quo Case* and *Join PJM Case*. The capacity prices were forecasted using CRA's proprietary capacity models, which are informed by the results of energy market modeling already presented. The models represent the PJM and MISO capacity constructs and are based on the concept of "missing money" determining capacity offers for the capacity resources. This section of the report presents a background on each of the relevant capacity markets, describes the CRA model, and presents the results of our analysis of the net capacity costs of a Zone 4 move to PJM.

### *PJM and MISO Capacity Markets*

Table 7 below highlights differences in the MISO and PJM capacity markets that are key attributes in CRA's capacity model.

**Table 7: Key Characteristics between Capacity Markets for MISO and PJM**

| | MISO Planning Resource Auction (PRA) | PJM Reliability Pricing Model (RPM) |
|---|---|---|
| Type of Resources | Dispatchable and Intermittent Resources, Energy Efficiency, Demand Response, Behind the Meter, and Stored Energy Resource Type-II | |
| Auction Scheduling | PRA is one year prior to delivery year | BRA is scheduled three years prior to delivery year, with multiple Incremental Auctions after the BRA. |
| Auction Cycle | Seasonal | Annual |
| Demand Curve Shaping | Vertical Demand Curve | Sloped Demand Curve (sloped construct recently updated) |
| CONE Reference Unit | Gas CT | Gas CC |

**MISO Capacity Auction Background**

The MISO Planning Resource Auction (PRA) ensures resource adequacy across all Local Resource Zones (LRZs). The PRA is designed by deriving the Planning Reserve Margin Requirement (PRMR). The PRMR is determined by a Loss of Load Expectation (LOLE) study targeting 0.1 day per year of reliability events, or one day in 10 years, across all four seasons and all LRZs. The minimum capacity determined by this study will serve as the PRMR for each zone. The PRMR will serve as the basis for the demand curve.

On the supply side, MISO has derived seasonal accredited capacity (SAC) values to discount the impacts of availability performance and contribution to resource adequacy. Therefore, a market participant is allowed to bid Zonal Resource Credits at the maximum level of the SAC if the resource can deliver up to its full ICAP. If the resource cannot deliver to its maximum ICAP, SACs can be converted into ZRCs that can then be bid into the market.[20] Similarly, MISO has derived seasonal effective load carrying capability (ELCC) for solar and wind capacity using historical wind and solar data to determine the impact of intermittency on resource adequacy.[21] The resulting ELCC values are also incorporated in CRA's capacity model.

MISO develops the supply curve for each LRZ through offers, import and export constraints, local clearing requirements, and other factors to derive the least cost offers. On an economics basis, each market participant may bid their units based on the net cost of new entry (CONE) including operation and maintenance costs minus any revenue from energy or ancillary services market. This bidding behavior is modeled in CRA's analysis.

If there are inadequate ZRCs offered to meet the PRMR, MISO will clear based on the approved CONE for the season. If there are not enough ZRCs at an RTO level, MISO will clear based on the lowest CONE among the LRZs for the season.[22]

**MISO Capacity Auction Reform**

Historically, the PRA was an annual auction but switched to a seasonal auction for Planning Year (PY) 2023-2024 to account for variability in reliability risk across different seasons. MISO determined the clearing price for all four seasons and released the results from their first seasonal auction in May 2023. The result of the 2023-2024 PRA auction is $10, $15, $2, and $10/MW-day across Summer, Fall, Winter, and Spring, respectively, in all MISO North Zones. The result of the most recent auction differs from the annual auction results of 2022-2023 Delivery Year PRA, which cleared at near-CONE level of $233.65/MW-day in MISO North. CONE prices are set based on gas combustion turbine units.

In the 2022/2023 Delivery Year PRA, MISO found capacity shortages across the RTO, leading to CONE-level clearing prices. The seasonal construct will cause lower overall prices due to its ability to capture seasonal variability in demand and shortages. It allows the PRMR requirements to change based on supply and demand available in the shoulder months, so winter and summer demand spikes will not drive annual prices to CONE-level. As a result, there will be significant changes to the difference in capacity costs between the *Status Quo Case* and *Join PJM* case, which will be discussed later in the results.

**PJM Capacity Auction Background**

The PJM capacity auction, known as the Reliability Pricing Model (RPM) Base Residual Auction (BRA), is scheduled every year three years prior to the beginning of the Delivery

20 Resource Adequacy Business Practice Manual (BPM-011-r27), *Midcontinent ISO*, October 2022.

21 *Id.*

22 *Id.*

Year, although the timing of recent auctions has been disrupted. There are also three Incremental Auctions which are held prior to the Delivery Year to satisfy any changes in resource needs. CRA's analysis is focused on the Base Residual Auction.[23]

PJM uses the forecast peak load, Region Reliability Requirement, and parameters used to derive the requirement for the BRA.

PJM forecasts the peak load for each zone, or locational deliverability area (LDA), and for the RTO-level in the PJM Load Forecast Report. The model includes peak load, net energy, load management, distributed generation (solar), plug-in electric vehicles, and battery storage. The load forecast examines the summer and winter peaks using historical customer data, simulated weather scenarios, and economic forecasts.[24]

The Region Reliability Requirement uses the data from the peak forecasts to calculate the required capacity, either known as Installed Reserve Margin (IRM) or Forecast Pool Requirement (FPR), that allows each LDA to satisfy the LOLE reliability criteria. PJM sets the reliability criteria for Loss of Load Expectation to one occurrence in ten years. FPR considers forced outage rates (EFORd) and is a function of unforced capacity (UCAP). The reliability requirement is expressed in terms of the unforced capacity as a percentage of peak load. The most recent auction for the 2025-2026 Delivery Year has a UCAP requirement of 23.89 GW for COMED, which is similar to the UCAP requirement of 23.86 GW in the 2024-2025 Delivery Year.[25]

PJM's supply curve is derived from capacity resource offers, similar to what was described above in the MISO capacity section. PJM's demand curve construct is slightly different than MISO. In PJM, the Variable Resource Requirement (VRR) curve is set by PJM prior to each auction and is designed to represent the value of incremental capacity.[26] The VRR curves are created for each LDA based on their specific reliability requirement and Net CONE values. Net CONE is calculated based on the gross CONE in each LDA minus net energy and ancillary services revenue (E&AS). In recent years, the net CONE has decreased due to rising E&AS. ComEd has only seen a net CONE decrease of 1.4%, while other LDAs such as BGE have seen decreases as high as 39%.[27]

**PJM Capacity Auction Reform**

In February 2023, FERC accepted PJM's quadrennial review proposal for revisions to the demand curve (Docket ER22-2984).[28] The changes will be in place for the 2026/2027 delivery auction to be run in December 2024.

One change is to adjust the reference CONE to reflect the CONE of a combined cycle power plant resource. Resources that were considered included Gas CT, Battery Storage, Hybrid PV + BESS, Utility Scale PV, Wind, EE, Plant conversions, and other emerging technologies. A combined cycle plant was chosen as the reference because it was the most economically viable solution considered and produces the lowest net CONE. It is also more likely to be built by project developers, and its cost can be estimated more accurately. This allows CONE

23 PJM Manual 18: PJM Capacity Market, *PJM Interconnection*, February 2023

24 2025/2026 RPM Base Residual Auction Planning Period Parameters, *PJM Interconnection*, June 2023,

25 *Id.*

26 Chen, Jennifer, PJM Auction Illustrates Importance of Demand Curve Fix, *NRDC*, June 2018,

27 2025/2026 RPM Base Residual Auction Planning Period Parameters, *PJM Interconnection*, June 2023

28 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, *PJM Interconnection*

values to be standardized across the other resources considered compared to other resources considered.[29]

Another key change will reduce the amount of capacity that clears each auction by adopting a steeper variable resource requirement curve along with a net CONE multiplier revised from 1.5x to 1.75x. The end effect will be a curve that is closer to vertical with a higher maximum price, making it more sensitive to changes in the supply curve, hence increasing price volatility. The higher maximum price would theoretically make higher prices possible, although given this would be near the upper limits well beyond Net CONE, it is unlikely that prices would spend enough time in the that range to have a material impact on the long-run average price.

The revisions also change the energy and ancillary services revenue offset for the reference resource used to calculate Net CONE from a backward-looking methodology to a forward-looking methodology. A forward-looking methodology will likely initially build-in higher heat rates as experienced recently in PJM compared to several years back, translating to higher E&AS revenue, lower Net CONE, and potentially lower auction prices, all else equal. However, given the small scale of the price impact, as compared to other factors, and the eventual catching-up to current conditions of the backward-looking methodology, the long-term impact on potential capacity revenues is likely to be relatively minor.

**CRA Capacity Model Methodology**

CRA quantitatively models the MISO and PJM capacity market by replicating the supply and demand structure in both markets. CRA replicates the supply and demand structure to the extent possible using simulated energy market results from the Aurora software. First, CRA calculates the 'missing money' of participating resources based on the net difference between the expected avoidable going forward costs and energy market performance. Then, depending on the expected participation behavior in the market, CRA assembles a demand curve by "stacking" the resources from lowest bids to highest bids. For the MISO capacity auction, CRA assumes the majority of the Fixed Resource Adequacy Plan (FRAP) and Self-Scheduled resources offered into the market as price takers, i.e. offered at $0/MW-day. In this step, several other components are considered, such as capacity accreditation by season, expected seasonal outages, seasonal offer behaviors, etc. In PJM, most of the participants are assumed to be merchant and enter the auction according to economics and market dynamics. CRA also considers bidding behaviors from the most recent auction and incorporates the bidding dynamics to the extent reasonable to the capacity market simulation.

Third, CRA sets the administrative demand requirement according to the expected peak demand, planning reserve margin requirements, and demand curve design for each season in MISO and for summer in PJM within the planning delivery period. As part of the step, CRA also considers the capacity import limit.

Lastly, CRA combines the demand and supply curve to fundamentally simulate the capacity market dynamics over the desired study timeframe. For MISO, CRA's price forecast is based on existing unit going forward costs in a utility-dominant market, although there may be periods of volatility between the CONE and $0 due to the vertical demand curve. CRA's approach evaluates a long-term average view of capacity value, rather than the timing of year-to-year fluctuations. Due to the volatile nature inherent in MISO's capacity market design, CRA simulates the MISO North system (MISO Zones 1 – 7) as a proxy for MISO Zone 4. For PJM, CRA to the extent possible models the parent-child structure to replicate the clearing mechanism at various levels, including the broader RTO and individual LDAs. A

29 *Id.*

Zone 4 LDA is created as part of the *Join PJM Case* to simulate how Zone 4 in PJM is likely to behave.

CRA partnered with Astrapé to calculate the ELCC used in the capacity analysis. The MISO-PJM system was simultaneously calibrated to 0.1 LOLE (the planning target for both ISOs). ELCC, or Effective Load Carrying Capability, represents the accreditation of a resource on a percentage basis relative to perfect capacity. So, for example if a 100 MW solar PV facility were to have a 60% ELCC, then the reliability contribution of the resource is equal to a 60 MW perfect generator (without outages, derates, maintenance, etc.). The mechanics through how this is performed, at a high level, are presented in Figure 3.

**Figure 3: ELCC Mechanics**


To ensure equitable and fungible accounting, this process was performed for the entire energy limited and renewable portfolio first (solar, wind, battery, demand response). Then, the process was performed for constituent resources within that portfolio. This ensures the sum of constituent resource ELCC is equal to the portfolio, and accounts for “diversity” effects amongst resource classes (e.g., solar has synergistic value with storage, storage has antagonistic value with demand response). Note this is commonly referred to average ELCC methodology which to date has been employed in ISOs such as MISO and PJM in conducting capacity markets. Average ELCCs by technology were also calculated for 2025, 2030, and 2035 based on the expansion plan buildouts for each scenario. As part of the capacity market simulation, CRA used the actual ELCCs published by MISO and PJM to simulate results over the near term as the starting point, e.g. 2023-2024 for MISO and 2025-2026 for PJM. Over time, the ELCC values converge with the benchmarks provided by Astrapé for 2030 and 2035.

The CRA methodology considers the fact that the Illinois Power Agency (IPA) procures a certain percentage of Illinois utilities’ capacity requirements to ensure the eligible retail customers meet resource adequacy requirements.[30] These “eligible retail customers” are mostly residential or small commercial fixed price customers who do not have an alternate supplier. The IPA has two procurement plans each year in the Fall and Spring. According to the 2023 Procurement Plan, the IPA will procure 50% of the forecasted requirements for the Early 2023 Auction, 75% of the requirements for the 2024-2025 Delivery Year, and 25% of the requirements for 2025-2026 Delivery Year. The procurement strategy is determined by a combination of previous auction results, load forecasts provided by the utility, and switching rates. The IPA holds their own auction to procure capacity and determines cleared prices according to their own market-based price “benchmarks.” The remaining capacity that IPA does not procure will need to be procured by AIC and ComEd in the relevant capacity markets. Importantly, the prices in the IPA auctions are heavily tied to the clearing prices in the regional capacity markets because the resources that participate have an opportunity cost

30 Electricity Procurement Plan, *Illinois Power Agency*, February 2023,

of the expected capacity price. Due to this dynamic, the CRA analysis does not separately model IPA costs as they are assumed to equal market prices over time.

**Capacity Market Results**

Differences in capacity costs between *Join PJM Case* and *Status Quo Case* are reflective of both an impact on capacity quantities and prices. Table 8 shows there is a net cost in the *Join PJM* compared to *Status Quo Case*.

**Table 8: Capacity Costs (Millions 2023$)**

| Year | Zone 4 | | | ComEd | | | Illinois | | |
|---|---|---|---|---|---|---|---|---|---|
| | Status Quo | Join PJM | Benefit (Cost) | Status Quo | Join PJM | Benefit (Cost) | Status Quo | Join PJM | Benefit (Cost) |
| 2025 | 311 | 206 | 105 | 304 | 444 | (140) | 615 | 650 | (35) |
| 2026 | 544 | 309 | 235 | 314 | 676 | (362) | 858 | 985 | (127) |
| 2027 | 630 | 415 | 214 | 554 | 945 | (391) | 1183 | 1360 | (177) |
| 2028 | 337 | 478 | (141) | 415 | 1,029 | (614) | 752 | 1507 | (755) |
| 2029 | 127 | 537 | (410) | 822 | 1,109 | (287) | 949 | 1646 | (697) |
| 2030 | 199 | 675 | (476) | 1,092 | 1,433 | (341) | 1291 | 2107 | (817) |
| 2031 | 185 | 623 | (438) | 1,088 | 1,278 | (190) | 1273 | 1901 | (629) |
| 2032 | 283 | 532 | (249) | 984 | 1,080 | (97) | 1267 | 1612 | (345) |
| 2033 | 287 | 525 | (238) | 892 | 1,054 | (162) | 1179 | 1579 | (400) |
| 2034 | 466 | 540 | (74) | 876 | 987 | (111) | 1342 | 1526 | (185) |
| NPV | (1,074) | | | (2,271) | | | (3,345) | | |

The increase in capacity costs for Zone 4 in the *Join PJM Case* can be explained by several factors, including:

- Sloped demand curve – The PJM demand curve (VRR) includes a sloped portion surrounding the planning reserve margin level of capacity. It allows for clearing at levels well above the planning reserve margin levels, though at a reduced price to represent declining marginal values of additional capacity. Still, this can lead to significantly higher quantities of capacity procured for Zone 4.
- Annual capacity product – PJM currently only procures an annual capacity product for most resource types. Since it is designed to procure sufficient capacity for the peak, which is generally in the summer, it is equivalent to purchasing summer-level capacity for the entire year. In a seasonal construct, the quantity changes by season, as does the price. In most market scenarios, the annual approach leads to higher overall capacity costs.

Several other parameters lead to higher PJM costs as well. These include but are not limited to higher price caps allowing for higher prices during shortage periods and higher planning reserve margins (historically).

The increase in capacity costs for ComEd in the *Join PJM Case* is mostly explained by the addition of Zone 4, which is considered short of in-zone capacity. This has two main impacts. First, it drives up the overall PJM RTO-level capacity prices as the entire system loses some of its headroom above the planning reserve margin. Second, Zone 4 is highly connected to ComEd but is loosely tied to the rest of PJM. Depending on how PJM models Zone 4 and ComEd in its LDA construct, this could lead to price separations for the two zones together.

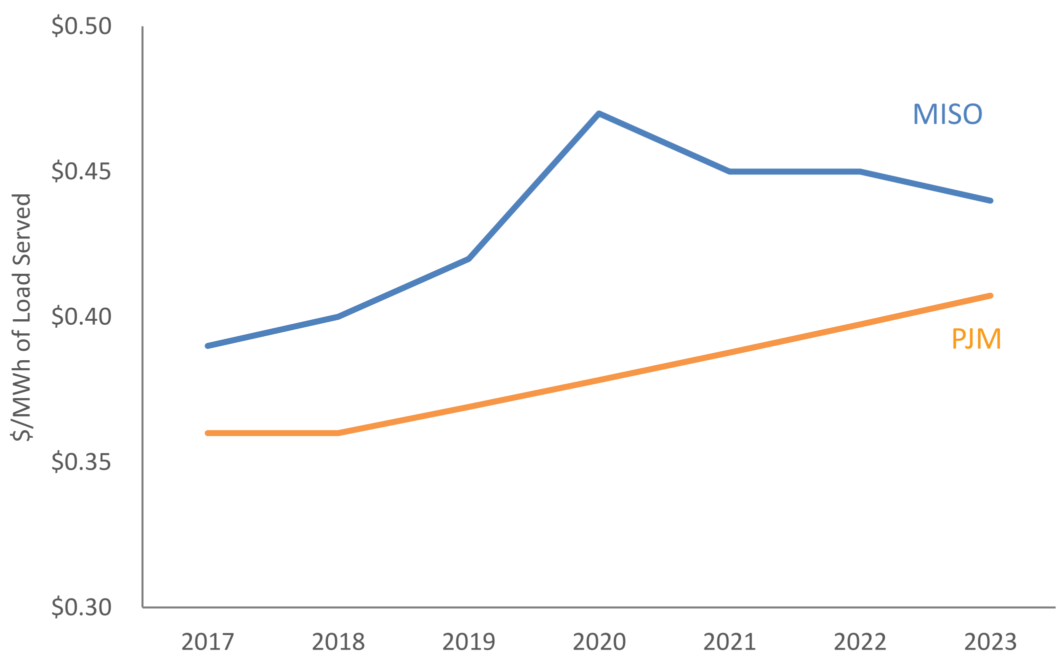
Zone 4 and ComEd would share an import constraint from the rest of RTO region, thus limiting the ability to make up for local capacity shortfalls with imports.

## 3.4. RTO Administrative Costs

PJM and MISO incur significant capital and operating costs to operate their markets and these costs are recovered through administrative charges assessed to members. PJM administrative charges are comprised of a number of Schedule 9 charges specified in the PJM OATT and MISO applies administrative charges through Schedules 10, 16, and 17 of the MISO Tariff.

To identify net costs/benefits in the *Join PJM Case,* CRA compared composite administrative rates published by the RTOs.[31] [32] Figure 4 shows composite rates of MISO and PJM from 2017-2023.

**Figure 4: PJM & MISO Composite Rates**




On average PJM administrative costs were $0.05/MWh less than those of MISO. Historically this trend has held true and CRA assumed the $0.05/MWh savings realized by joining PJM would continue through the forecast period of 2025-2034. When combined with annual load in Zone 4, this results in a savings of ~$2.6 million per year for a NPV of $17.3 million. Table 9 shows the year over year savings for AIC and SIPC/CWLP.

31 PJM Stated Rates Fact Sheet

32 MISO Audit and Finance Committee 2023 Preliminary Budget

**Table 9: Net Benefits of RTO Administrative Costs in the *Join PJM Case***

| Year | AIC Load (MWh) | SIPC/CWLP Load (MWh) | Admin. Costs Savings ($/MWh) | Net Benefits AIC ($M) | Net Benefits SIPC/CWLP ($M) | Net Benefits Zone 4 ($M) |
|---|---|---|---|---|---|---|
| 2025 | 47,432,860 | 3,096,530 | 0.05 | 2.44 | 0.16 | 2.60 |
| 2026 | 47,734,280 | 3,116,208 | 0.05 | 2.46 | 0.16 | 2.62 |
| 2027 | 48,035,356 | 3,135,862 | 0.05 | 2.47 | 0.16 | 2.63 |
| 2028 | 48,341,975 | 3,155,879 | 0.05 | 2.49 | 0.16 | 2.65 |
| 2029 | 48,649,932 | 3,175,984 | 0.05 | 2.50 | 0.16 | 2.67 |
| 2030 | 48,953,926 | 3,195,829 | 0.05 | 2.52 | 0.16 | 2.69 |
| 2031 | 49,312,596 | 3,219,244 | 0.05 | 2.54 | 0.17 | 2.70 |
| 2032 | 49,670,975 | 3,242,640 | 0.05 | 2.56 | 0.17 | 2.72 |
| 2033 | 50,030,710 | 3,266,124 | 0.05 | 2.58 | 0.17 | 2.74 |
| 2034 | 50,390,307 | 3,289,599 | 0.05 | 2.59 | 0.17 | 2.76 |

## 3.5. Exit and Integration Fees

In the *Join PJM Case,* Zone 4 will incur charges associated with exit from MISO and integration with PJM – all charges are assumed to occur in the first year of withdrawal, 2025. MISO exit fees as defined by Article Five, Section II.B of the MISO TO Agreement shall be negotiated between MISO and the withdrawing owner. The exit fee covers long-term liabilities that are normally collected through rate schedules designed to recover financial obligations incurred by MISO to support transmission service, firm transmission rights and the energy market.[33] For the purposes of this cost-benefit analysis, MISO provided an estimated exit fee of $22.6 million (2023$ NPV) for AIC. CRA assumed SIPC/CWLP would incur an exit fee proportional to their load. Overall, the exit fee for Zone 4 totaled $24 million.

Integration fees from PJM were estimated by analyzing the American Transmission Systems, Inc. (ATSI) move from MISO to PJM in 2011. In that scenario, PJM estimated integration fees to be approximately $3 million.[34] CRA assumed that integration fees would be similar for Zone 4 adjusted to 2023 dollars. Table 10 summarizes the exit and integration fees in the *Join PJM Case.*

**Table 10: Exit and Integration Fees, *Join PJM Case ($M)***

| | AIC | SIPC/CWLP | Zone 4 |
|---|---|---|---|
| Exit Fee | (22.6) | (1.5) | (24.0) |
| Integration Fee | (3.7) | (0.2) | (4.0) |
| Total | (26.3) | (1.7) | (28.0) |

33 PJM Interconnection, L.L.C., 135 FERC ¶ 61,198 (2009) (May 31, 2011 Order).

34 *Id.*

# 4. Overall Cost Benefit Results

Shown in Table 11 are the overall net costs, between the *Join PJM Case* and the *Status Quo Case*, using the components discussed in Section 3. As shown, the overall net cost to the State of Illinois is $3,407.3 million (2023 net present value) over the 2025-2034 period.

**Table 11: 2025-2034 Benefits (Costs) of Joining PJM**

*(millions of dollars; positive numbers are benefits)*

| | AIC | SIPC/CWLP | ComEd | Illinois |
|---|---|---|---|---|
| **1. Energy Trade Benefits** | 563.5 | 36.8 | (450.3) | 149.9 |
| **2. Transmission Expansion Costs** | (213.5) | (13.9) | 25.3 | (202.1) |
| **3. Capacity Costs** | (1,074.6) | 0.2 | (2,271.1) | (3,345.6) |
| **4. RTO Administrative Costs** | 17.3 | 1.1 | - | 18.5 |
| **5. Exit & Integration Fees** | (26.3) | (1.7) | - | (28.0) |
| **Net Benefits (Costs)** | (733.6) | 22.4 | (2,696.2) | (3,407.3) |

## 4.1. Ratepayer Impact

Costs and benefits incurred in the *Join PJM Case* could potentially be passed to ratepayers assuming regulatory approval. Table 12 captures the 10 year levelized residential ratepayer cost impact from joining PJM. AIC residential customers could see a 0.22 cent/KWh or ~1.25% increase in costs resulting in an average total cost of $19/year. SIPC and CWLP residential customers could expect net savings 0.11 cent/KWh (~0.6%) or $9.50/year, while ComEd residential customers could see the highest cost impact of 0.43 cent/KWh (~2.5%) or ~$37.50/year. Note that these percentage cost increases are measured against March 2023 costs per kWh and reflect neither the Illinois utilities' distribution and transmission capital expansion plans nor future fluctuations in power supply costs. All these factors, particularly costs from MISO's LRTP Tranche 1 and Tranche 2 (which are expected to be borne by AIC, SIPC, and CWLP ratepayers in both the *Join PJM Case* and *Status Quo Case*), can be expected to increase ratepayer costs per kWh over the forecast period.

**Table 12: Residential Ratepayer Impact in *Join PJM Case***

| | AIC | SIPC/CWLP | ComEd |
|---|---|---|---|
| **Levelized $/KWh Impact** | 0.0022 | (0.0011) | 0.0043 |
| **% Cost Residential Increase[35]** | 1.25% | -0.62% | 2.46% |
| **Avg. Residential Cost Per Year[36]** | $19.04 | ($9.50) | $37.52 |

35 Assumes average Illinois residential delivered electricity price of $0.1743/KWh in March 2023 from Table 5.6.A of EIA Electric Power Monthly.

36 Assumes average Illinois residential customer consumes 8736 KWh/year – 2021 EIA Data on Electric Sales, Revenue and Average Price by State.

# 5. Sensitivity Analyses

## 5.1. Scenario Construct

This study evaluated three market scenarios that describe plausible futures that might develop over time and result in different set of market conditions under which load-serving entities operating in Illinois - AIC, CWLP, SIPC, ComEd - will need to provide their service.

Each scenario is driven by a set of thematically oriented fundamental market assumptions. These scenarios are used to assess impact of uncertainties and test the boundaries of future market conditions. Table 13 summarizes the key drivers of each scenario in a matrix. Appendix B details the main assumptions on each of the scenarios.

**Table 13. RTO Scenario Assumption Matrix**

| Scenario | Load | Natural Gas | Carbon Price | New Resource Cost | Transmission |
|---|---|---|---|---|---|
| **A: Efficient Markets** | Base | Base | No National CO2 price | Base | **MISO:** all Tranche 1 projects online in 2030.<br>**PJM:** all transmission buildouts to support retirements |
| **B: Transition Bottleneck** | Base | Base | No National CO2 price | Slower Decline | **MISO:** *only assigned* Tranche 1 projects online in 2030.<br>**PJM:** transmission buildouts to support retirements |
| **C: Deep Decarbonization** | High | Base | High | Faster Decline | **MISO:** all Tranche 1 projects online in 2030 *plus Tranche 2* buildouts<br>**PJM:** all transmission buildouts to support retirements *plus incremental transmission* buildouts |

<u>Scenario A: Efficient Markets</u>

Under the “Efficient Markets” scenario, MISO and PJM markets continue to evolve based on the current outlook for load growth, commodity prices, technology development, and federal incentives and credits. Scenario A serves as the reference scenario from which all results presented in previous sections are derived from.

<u>Scenario B: Transition Bottleneck</u>

Under the “Transition Bottleneck” scenario, energy transition stalls as policy, planning, and implementation impediments hinder transmission buildout and renewable development. Restructured markets may struggle to replace retiring capacity leading to supply tightness and declining reserve margins.

<u>Scenario C: Deep Decarbonization</u>

Under the “Deep Decarbonization” scenario, economy-wide decarbonization efforts through a stringent carbon policy accelerate retirements and incentivize strong renewable entry supported by transmission reforms and faster decline in technology cost. Adoption of EVs and electrification adds to electric load growth across the RTO footprint. Additional economy-wide decarbonization pressure in the State of Illinois drives higher electrification growth.

### *Energy Trade Benefits*

Similar trends are seen in the Transition Bottleneck (Scenario B) and Deep Decarbonization (Scenario C) scenarios as compared to the Efficient Markets scenario (Scenario A) – in general Zone 4 benefits from increased imports from ComEd and increased penetration of renewables later in the forecast period. Scenario C has the greatest benefit for Zone 4 as accelerated renewable growth seen in the *Join PJM Case* is magnified by decarbonization efforts in this scenario. In all scenarios ComEd sees net costs primarily due to increased exports to Zone 4. Table 14 summarizes Energy Trade Benefits in the *Join PJM Case* across the three scenarios.

**Table 14: Energy Trade Benefits – Scenarios A, B, C**

*(2023 NPV in millions of dollars; positive numbers are benefits)*

| | Scenario A | Scenario B | Scenario C |
|---|---|---|---|
| AIC | 563.5 | 885.2 | 1,224.9 |
| SIPC/CWLP | 36.8 | 57.8 | 80.0 |
| ComEd | (450.4) | (658.8) | (570.6) |
| Illinois | 149.92 | 284.2 | 734.4 |

### *Transmission Expansion Costs*

Scenario B has lower transmission expansion costs relative to Scenario A due to the difference in assumed transmission growth in PJM. Scenario A assumes that spend on future PJM transmission grows at inflation plus load growth (3.84%/year), whereas Scenario B assumes a transition bottleneck with transmission expenditures only growing by inflation (2.5%/year).

Scenario D has higher transmission expansion costs relative to Scenario A & B, due to additional transmission expansion required in PJM under the deep decarbonization assumptions described in Appendix B. Power flow analysis identified $1.1 billion of additional projects coming online in PJM between 2030 and 2032. Annual revenue requirements were identified for these projects and applied to Zone 4 resulting in the increased transmission expansion costs.

Savings for ComEd across all three scenarios are proportional to the load ratio share assumed by Zone 4 when they join PJM. Table 15 summarizes Transmission Expansion Costs in the *Join PJM Case* across the three scenarios.

**Table 15: Transmission Expansion Costs – Scenarios A, B, C**

*(2023 NPV in millions of dollars; positive numbers are benefits)*

| | Scenario A | Scenario B | Scenario C |
|---|---|---|---|
| AIC | (213.5) | (209.0) | (341.2) |
| SIPC/CWLP | (13.9) | (13.6) | (22.3) |
| ComEd | 25.3 | 24.9 | 25.5 |
| Illinois | (202.1) | (197.8) | (338.0) |

### *Capacity Market Impacts*

Scenario B

In this scenario, both MISO and PJM are expected to face a transition bottleneck where new resources face major hurdles to be built while existing resources continue to retire as planned, except for select gas units in Illinois. With a similar thermal retirement plan to Scenario A, there is a shortage of resources due to constraints of building new renewables and dispatchable resources in both MISO and PJM. As a result, there is overall less excess capacity compared to Scenario A and overall system conditions are tighter.

The resulting analysis is a net cost of $4.36 billion for the State of Illinois in the *Join PJM Case*. Both Zone 4 and ComEd capacity prices increased, but the larger cost differential in this scenario is driven mostly by a large increase in ComEd's price differences between the *Status Quo* and *Join PJM* cases. This is because with less excess capacity, the addition of Zone 4 in the *Join PJM Case* is likely to create tightness in both Zone 4 and ComEd in aggregate to meet combined load requirements in Illinois, leading to upward pressure on capacity prices. In the *Status Quo Ccase*, ComEd's capacity prices averaged $76/MW-day compared to $123/MW-day in the *Join PJM Ccase.*

Scenario C

In this scenario, renewable generation is strongly encouraged by a changing policy landscape while load growth is the highest among the three scenarios. As a result, total capacity costs in both MISO and PJM increase to accommodate load growth, despite additional renewables and dispatchable capacity. Already tight market conditions are further stressed when Zone 4 joins PJM. As a result, capacity prices in ComEd increase from $77/MW-day to $115/MW-day between the *Status Quo* and *Join PJM* case. Additional renewable capacity provides little incremental value to the system's reliability and hence prices increase to incentivize continued penetration of dispatchable resources. The overall cost in this scenario for the State of Illinois is $4.89 billion.

Table 18 summarizes the Capacity Costs in the *Join PJM Case* across the three scenarios.

**Table 16: Capacity Market Impacts – Scenarios A, B, C**

*(2023 NPV in millions of dollars; positive numbers are benefits)*

| | Scenario A | Scenario B | Scenario C |
|---|---|---|---|
| AIC | (1,074.6) | (501.2) | (2,094.1) |
| SIPC/CWLP | (13.9) | 20.5 | (28.2) |
| ComEd | (2,271.1) | (3,875.7) | (2,771.6) |
| Illinois | (3,353.0) | (4,356.3) | (4,893.9) |

### *RTO Administrative Costs*

RTO Administrative Costs are proportional to Zone 4's annual load (MWh) used in each scenario – Appendix B covers load assumptions used in analysis. MISO MTEP 2021 Future 1 load forecast was used for Scenario A and B resulting in same net benefit for the *Join PJM Case*. To match the accelerated load growth in the Deep Decarbonization Scenario, MISO MTEP 2021 Future 3 load forecast was used resulting in increased net benefits relative to Scenario A and B as administrative costs per MWh are less in PJM relative to MISO. Table 17 summarizes RTO Administrative Costs in the *Join PJM Case* across the three scenarios.

**Table 17: RTO Administrative Costs – Scenarios A, B, C**

*(2023 NPV in millions of dollars; positive numbers are benefits)*

| | Scenario A | Scenario B | Scenario C |
|---|---|---|---|
| AIC | 17.3 | 17.3 | 19.1 |
| SIPC/CWLP | 1.1 | 1.1 | 1.2 |
| ComEd | - | - | - |
| Illinois | 18.5 | 18.5 | 20.3 |

#### *Overall Scenario Cost Benefit Results*

Table 18 summarizes the overall cost benefit results for Scenarios A, B, and C. In all instances, the *Join PJM Case* results in net costs for the State of Illinois ranging from $3.4 billion to $4.5 billion. ComEd also sees net costs in all scenarios ranging from $2.7 billion to $4.5 billion.

AIC sees net costs in Scenario A and C ($0.7 billion and $1.2 billion respectively), but, in Scenario B, sees a net benefit of $166 million. This is primarily driven by reduced capacity costs in Scenario B ($1.1 billion in Scenario A vs $0.5 billion in Scenario B). The transition bottleneck with delayed generation buildout modeled in Scenario B resulted in elevated capacity prices in both MISO and PJM reducing the delta between the *Status Quo Case* and *Join PJM Case*. MISO in particular experienced three years of capacity prices clearing at CONE (2026 - 2028). While not captured in the model, these elevated prices seen in MISO would likely incentivize new generation or delay retirements, bringing capacity prices down in MISO and subsequently increasing costs in the *Join PJM Case.* Had this effect been modeled, AIC would likely see a net cost in Scenario B as well.

SIPC and CWLP see net benefits in all scenarios, although marginal in relative magnitude compared to AIC and ComEd. These benefits are a result of lower energy prices in Zone 4 in the *Join PJM Case* not being fully offset by higher capacity prices as SIPC and CWLP can internally source most of their capacity requirement.

**Table 18: Overall Cost Benefit Results – Scenarios A, B, C**

*(2023 NPV in millions of dollars; positive numbers are benefits)*

| | Scenario A | Scenario B | Scenario C |
|---|---|---|---|
| AIC | (733.6) | 166.0 | (1,217.6) |
| SIPC/CWLP | 15.0 | 64.1 | 29.0 |
| ComEd | (2,696.2) | (4,509.6) | (3,316.6) |
| Illinois | (3,414.7) | (4,279.5) | (4,505.2) |

## 5.2. Capacity Sensitivities

The capacity import limit, or Capacity Emergency Transfer Limit (CETL), plays a vital role in driving capacity prices in Zone 4. Results presented in Section 3.3 assumed a base CETL value that incorporates the most likely CETL levels based on CRA analysis. However, this assumption is subject to the uncertainty of the CETL determination process in PJM. To determine the sensitivity of capacity costs to the CETL assumption, CRA tested three different levels of CETL limits into Zone 4, ComEd, and the Illinois LDA and assessed the possibility of resources pseudo-tying into PJM when economic. While actual CETL limits would not be determined until Zone 4 joins PJM, CRA did review its approach with PJM as part of the study.

CRA relied on Quanta to reasonably estimate a range of possible CETL limits with Zone 4 joining PJM. Quanta used power flow analysis to guide the estimation of CETL limits used in capacity modeling. The analysis attempted to replicate the specifics of Load Deliverability Study procedures defined by PJM Region Transmission Planning Process (Manual 14B).

Without CETO/CETL-specific cases, RTEP 2028 power flow models were utilized. This includes all data pertinent to contingency files and monitoring criteria. The models were verified/updated to reflect that the capacity portion of generation resources were represented accurately. The below process outlines the approach to estimate CETL Limits:

- Subsystem definitions were updated to reflect the position of Zone 4 within the PJM RTO.
- Multi-scenario thermal transfer analyses were performed that included transfers between
    a. PJM and MISO (with and without Zone 4),
    b. Rest of Illinois to Zone 4
    c. Zone 4 to Rest of Illinois
    d. MISO to Zone 4
    e. PJM to Zone 4
- Across all scenarios the maximum thermal transfer was recorded before any constraints were triggered in the broader system.
- The power flow cases at the maximum thermal transfer were evaluated through N-1 contingency analysis to identify potential voltage violations.
- If voltage violations are observed, PV transfer analysis was performed to identify the transfer level at which no more violations are recorded.
- The final transfer value achieved represents the import/export limits for use in capacity expansion modelling.

Table 19 summarizes different CETL values used to assess the sensitivity of capacity prices. With a lower CETL limit into ComEd and Zone 4, the chance of having elevated capacity prices increases, and vice versa. In the sensitivity with low CETL, CRA also analyzes the possibility of pseudo-tie resources up to 1,000 MW selling into PJM whenever economics allow. The entry of pseudo-tie resources was considered an effective measure to mitigate upward price pressure to a certain extent.

**Table 19: CETL Levels Assumptions (MW)**

| Region | Base Case | High CETL | Low CETL |
|---|---|---|---|
| ComEd | 6,393 | 7,617 | 5,170 |
| Zone 4 (Join PJM) | 5,757 | 7,627 | 3,887 |
| Illinois LDA | 7,243 | 8,602 | 5,883 |

Table 20 shows the impact of different CETL assumptions on the change in capacity costs between the *Status Quo* and *Join PJM Case* in Scenario A. In the Low CETL sensitivity net costs for the *Join PJM Case* rise to $6.7 billion for Illinois. The high CETL sensitivity does show some savings compared to the base sensitivity, but still results net cost of $3.3 billion for Illinois. The uncertainty of CETL points to level of risk that Zone 4 will be exposed to in the *Join PJM Case.*

**Table 20: Capacity Costs vs CETL Assumption**

*(2023 NPV in millions of dollars)*

| ***Status Quo Case*** | | | ***Join PJM Case*** | | | | **Net Cost** |
|---|---|---|---|---|---|---|---|
| Zone 4 | ComEd | Total Illinois | CETL Scenario | Zone 4 | ComEd | Total Illinois | Total Illinois |
| 2,801 | 5,801 | 8,602 | Base CETL | 3,875 | 8,072 | 11,974 | 3,345 |
| | | | Low CETL | 6,967 | 8,308 | 15,275 | 6,673 |
| | | | High CETL | 3,836 | 8,048 | 11,884 | 3,282 |

# 6. Qualitative Considerations

## 6.1. Emissions

CRA conducted an analysis on carbon dioxide (CO2), sulfur dioxide (SO2), and nitrous oxide (NOX) emissions. CRA's emission analysis relies on the economic dispatch model results for generation and capacity that were presented in the Energy Trade Benefits section. The analysis compares each scenario's *Status Quo Case* to the *Join PJM Case*. Key drivers of emissions are determined by increased renewable generation or fossil fuel resources. Overall, across all three scenarios, emissions decrease when Zone 4 moves to PJM due to increased generation from renewables.

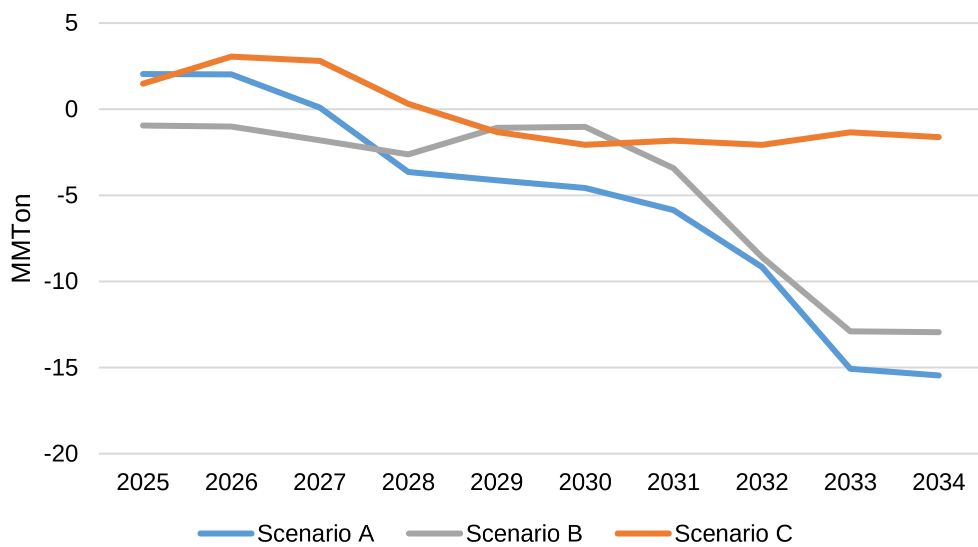
CRA's analysis compiles the hourly dispatch results to derive the emissions at the zonal level. CO2, SO2, and NOX emissions are specific to each generation asset. Emissions are estimated based on the economic dispatch of each generation asset, the fuel emission rate, and the plant heat rate. CRA then compiles the hourly dispatch and emissions by zone and year.

### *CO2 Emissions*

As shown in Figure 5, CO2 emissions in all scenarios were lower in the *Join PJM Case* compared to *Status Quo Case* at the RTO level. This is primarily driven by additional renewable buildout in the *Join PJM Case* discussed in detail in the Energy Trade Benefits section.

Scenario C had the lowest reduction of CO2 emissions. This is due to high penetration of renewables in both MISO and PJM resulting from conditions established in the Deep Decarbonization Scenario.

**Figure 5: Change in CO2 Emissions for MISO and PJM (*Join PJM – Status Quo)***




To quantify benefits from CO2 emission reductions a social cost of carbon was assumed. The Illinois Climate and Equitable Jobs Act (CEJA) uses the U.S. Interagency Working Group on Social Cost of Carbon's price at the 3% discount rate – averaging $62.34/ton for the 2025 – 2034 forecast period.[37] Monetary benefits were not included in the overall cost-benefit analysis as a price on carbon is not anticipated before 2034. Table 21 summarizes CO2 reductions in MISO and PJM and the net benefits for both RTOs and Illinois using the U.S. Interagency Working Group Social Cost of Carbon.

**Table 21: CO2 Emissions (*Join PJM – Status Quo)***

| Scenario | MISO and PJM Carbon Emissions Savings 2025-2034 | MISO and PJM Social Cost of Carbon Savings *(NPV 2023$ millions)* | Illinois Social Cost of Carbon Savings[38] *(NPV 2023$ millions)* |
|---|---|---|---|
| A – Efficient Markets | 54 million tons | 2,566.3 | 248.9 |
| B – Transition Bottleneck | 46 million tons | 2,242.5 | 217.5 |
| C – Deep Decarbonization | 2.6 million tons | 89.6 | 8.69 |

### *NOX and SO2 Emissions*

At the RTO level, local emissions (NOX and SO2) have similar trajectories as CO2 emissions, however, because NOX and SO2 have a greater health impact on local populations, these risks are concentrated in areas closer to the point of generation, as

37 U.S. Interagency Working Group on Social Cost of Greenhouses Gases, February 2021

38 Assumes savings proportional to Zone 4 and ComEd's load ratio share of MISO and PJM (~9.7%)

opposed to carbon emissions' global impact. Therefore, the analysis below focuses on Zone 4 and ComEd as well as state-wide to capture the localized pollution effects.

Table 22 and Table 23 summarize the percent change for NOX and SO2 in the *Join PJM Case* for Zone 4, ComEd, and the State of Illinois. In all scenarios, Zone 4 experiences decreased NOX/SO2 levels driven by higher levels of renewable penetration. ComEd, on the other hand, sees increased local emissions as increased exports to Zone 4 are balanced by additional fossil generation. When the two zones are aggregated, Illinois sees slight decrease in NOX/SO2 emissions overall.

**Table 22: NOX Percent Change in *Join PJM Case***

| Scenario | Zone 4 | ComEd | Illinois |
|---|---|---|---|
| A – Base Case | -8.5% | 6.2% | -1.4% |
| B – Transition Bottleneck | -8.3% | 6.1% | -1.3% |
| C – Deep Decarbonization | -12.8% | 4.7% | -4.3% |

**Table 23: SO2 Percent Change in *Join PJM Case***

| Scenario | Zone 4 | ComEd | Illinois |
|---|---|---|---|
| A – Base Case | -6.3% | 3.0% | -2.1% |
| B – Transition Bottleneck | -5.7% | 2.9% | -1.8% |
| C – Deep Decarbonization | -10.2% | 2.2% | -4.7% |

## 6.2. Environmental Justice and Equity Considerations

The following environmental justice and equity analysis reviews ratepayer, labor/employment, and health impacts for the State of Illinois.

### *Distributional Impact of Rate Changes*

As discussed in the ratepayer impact section, AIC and ComEd will experience price increases in the *Join PJM Case*. The increase of rates will affect the low-income households disproportionately, who have a higher energy burden or dedicate a greater percentage of their income towards energy bills, according to the Department of Energy.[39] The energy burden may be three times higher in certain low-income households compared to other households. This energy burden also disproportionately affects households of color, as

39 "Low-Income Household Energy Burden Varies Among States — Efficiency Can Help in All of Them," *Department of Energy*, 2018. In the DOE analysis, low-income households are defined by the census block as households that are below 80 percent of the Area Median Income, as defined by the U.S. Department of Housing and Urban Development.

studies like Hernandez et al. (2016) and Bednar et al. (2017) found that African American and Hispanic households bear higher energy costs.[40]

The EPA EJScreen tool features a map of low-income areas by national percentile.[41] In Illinois, most of the state falls within 50th percentile of the low-income qualification compared to national averages. This means that most of the neighborhoods in Illinois have income levels that are around the median national income level. Chicago, Rockford, Aurora, and Joilet, Springfield, and Peoria are some identified cities which have percentages of low-income households that qualify above the 90th percentile threshold of national low-income levels. In other words, the percentage of low-income households in these cities are higher than the rest of the U.S. The EJScreen People of Color tool also shows that these cities have people of color populations at the 90th percentile of national average.[42] As a result, these cities have a higher risk for households with significant energy burden.

Chicago and Rockford are part of ComEd's service territory, whose rate impacts are the highest among the zones in Illinois in the *Join PJM Case*, as mentioned in the Ratepayer Impact section. Therefore, these households may experience an even higher energy burden in the *Join PJM Case* on average. The effects of a rate increase compounded with high energy burden for low-income communities may bring extra financial strain on these households.

#### Labor and Employment Impact

To evaluate any labor or employment consequences, CRA tracked changes in resource additions and retirement schedules. Across all three scenarios, there are more renewable buildouts in Zone 4 and less in ComEd in the *Join PJM Case* relative to the *Status Quo Case*. This is driven by the preference to build renewables in Zone 4 as described in the Energy Trade Benefits section. Retirements, on the other hand, are largely unchanged between both cases. Overall, net impacts to the State of Illinois are neutral as additional renewable builds in Zone 4 are offset by fewer builds ComEd, however, labor and employment benefits are expected to shift from ComEd to Zone 4 in the *Join PJM Case.*

#### Local Emissions

Exposure to NOX emissions can irritate eyes, nose, throat, and lugs. High levels of NOX exposure may lead to more severe respiratory symptoms including reduced oxygenation and fluid buildup in lungs.[43] SO2 emissions also leads to detrimental impacts on health, especially the lungs and can increase respiratory problems, such as shortness of breath and chest

40 Brown et al., "Low-Income Energy Affordability: Conclusions from a Literature Review" *Oak Ridge National Laboratory,* March 2020, https://info.ornl.gov/sites/publications/Files/Pub124723.pdf

41 "Low Income Tool" in EJScreen Tool, *Environmental Protection Agency,* https://ejscreen.epa.gov/mapper/ The EJScreen tool uses census data from 2010-2014 and defines percentage low-income as households whose income is less than or equal to twice the federal Poverty Level.

42 "People of Color" in EJScreen Tool, *Environmental Protection Agency,* https://ejscreen.epa.gov/mapper/ The tool defines "People of Color" as "individuals who listed their racial status as a race other than white alone and/or list their ethnicity as Hispanic or Latino"

43 Nitrogen Oxides, *Agency for Toxic Substances and Disease Registry,* https://www.atsdr.cdc.gov/toxfaqs/tfacts175.pdf

Tightness.[44] Long term exposure can also lead to hospitalization of children and older adults with asthma.[45]

One major source of SO2 and NOX emissions is fossil fuel power plants. Residents who live near major fossil fuel plants will experience higher exposure rates and greater health risks. The EJScreen Tool's Air Toxics Respiratory Hazard Index shows greater than the 90th percentile in neighborhoods around Chicago as well as Will and Cook counties, among others. Most of the hazard risks identified in the EJScreen are located near power plants, such as in Will County, or other major emitters, such as the O'Hare airport. The high health risk in neighborhoods around Chicago may also be due to combustion of vehicles, in the heavy traffic areas around the city, as well as major power plants.

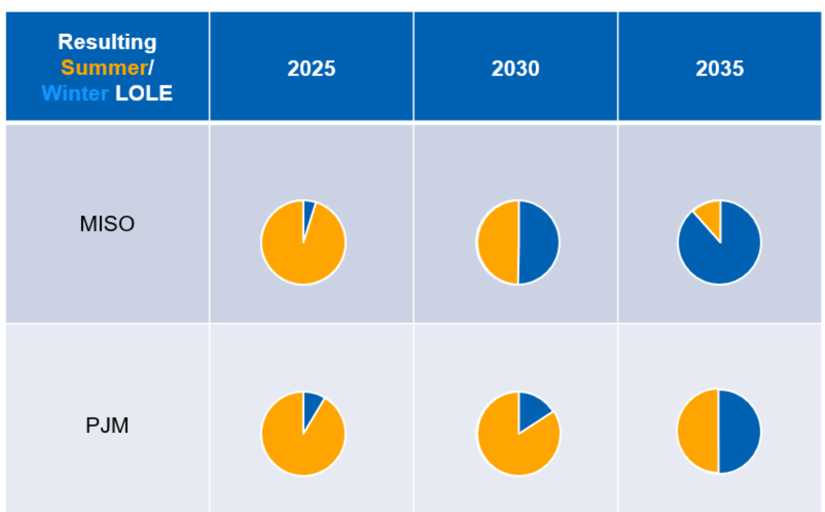
As discussed in the section above, the NOX and SO2 emissions decrease overall in the *Join PJM Case*, but the distributional effects of these emissions remain uneven across the state – Zone 4 residents generally see fewer local emissions while ComEd residents experience more. This trend is consistent with ComEd exporting more energy to Zone 4 in the *Join PJM Case.*

## 6.3. Resiliency Analysis

To complement the reliability analysis, supplemental metrics were provided for each system at 0.1 LOLE to characterize the severity of tail events. LOLE describes an expected value but does not provide information on the magnitude of load shed events or the possible length. Further, it does not quantify the economics required to withstand a severe event. Detailed below are the supplemental metrics which were monitored as part of this analysis.

To understand the composition of load shed events, first the distribution in summer or winter events was calculated by year. This was performed for three benchmark years through the study horizon – 2025, 2030, and 2035.

**Figure 6: Seasonal Risk Composition by Year**



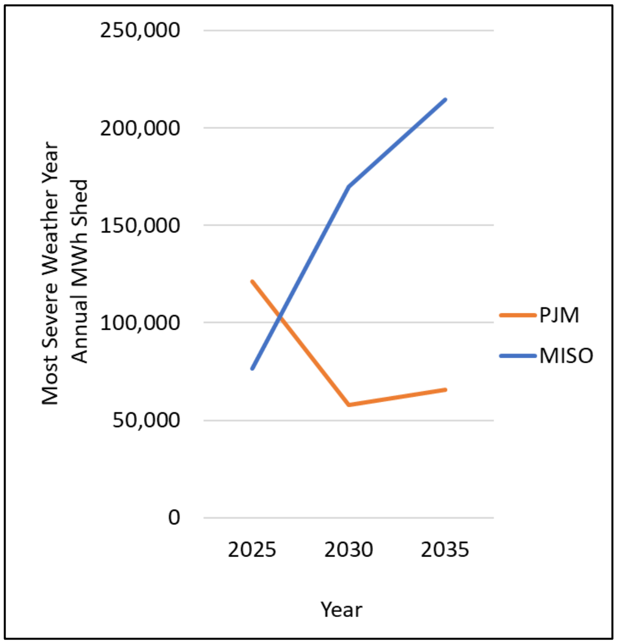

44 Sulfur Dioxide, *American Lung Association,* https://www.lung.org/clean-air/outdoors/what-makes-air-unhealthy/sulfur-dioxide

45 Id.

This indicates that, given the portfolios assessed, MISO is more subject to winter load shed events than PJM as the study years progress. The shift from summer to winter risk is driven by solar and storage penetration which provide greater reliability contribution in the summers, where the solar irradiance and the opportunity for energy arbitrage is high, compared to winter, where both are lower. It should be noted the exact ratio of summer and winter events is also driven by the degree of winter correlated forced outages assumed.

Next, the most extreme iterations were sampled from the entire distribution to understand the magnitude of MWh at risk under a 1 in 1050 combination of weather and generator performance. The results of the sampling indicate MISO is subject to more severe tail events at 0.1 LOLE as the planning horizon progresses.

**Figure 7: Severe Weather Year Events**




This is driven by the resource mix in MISO as compared to PJM by the end of the forecast period – MISO sees a more significant storage and solar portfolio which, under high demand conditions, become exhausted and unable to provide energy during the sunset to sunrise period. Overall, the results point toward PJM having a more resilient system as compared to MISO which would be a benefit in the *Join PJM Case.*

## 6.4. Risks and Other Considerations

*Capacity Cost Uncertainties*

The capacity cost analysis presented in Sections 3.3 and 5.2 was based on the assumption that market constructs would remain in their current form for the duration of the study period and that Illinois utilities would continue to either directly or indirectly rely on the capacity markets to determine their capacity costs. The current market form was assumed to be the existing construct and any changes that have been finalized and approved by FERC. This is a common assumption to make in these studies. It is also reasonable to consider the uncertainty caused by potential changes to market constructs, as well as to the form of participation by Illinois utilities.

While history suggests market construct changes are inevitable, the two potential changes that merit discussion here are a potential shift in MISO to a sloped demand curve and a change in PJM to seasonal capacity products. Both of these changes would bring the respective constructs closer together and likely reduce capacity cost separation for the *Status Quo* and *Join PJM* cases.

- MISO Sloped Demand Curve – The concept of a sloped demand curve has been proposed many times for MISO, including many times by the market monitor. MISO recently proposed a “reliability-based demand curve” or RBDC that would more accurately recognize the reliability value of capacity beyond the 0.1 LOLE standard. While the concept is proposed by MISO and seems to have stakeholder support at a high level, the details are still being worked on and the change would need FERC approval, with the earliest implementation in Q12025. If the RBDC were in effect for the most recent auction (2023/24), MISO estimates that it would have significantly raised prices (by $55/MW-day in Zone 4 region for summer 2023/24).[46]
- PJM Seasonal Construct – In response to major expected shifts in capacity resources in PJM in the coming decade, as well as to the major winter storm event in December 2022, PJM initiated a fast-tracked stakeholder process to identify resource adequacy reforms. One of the major proposed changes that PJM has proposed through that process is a shift to seasonal capacity products. Specifically, on June 14, 2023, PJM proposed, amongst a variety of changes, an annual capacity construct to separate summer and winter products. This change was motivated by an expected shift in reliability risk to winter. The likelihood of implementation remains uncertain with a stakeholder review process and FERC approval process required, in addition to sorting out details. The level of impact is uncertain. Unlike the MISO seasonal construct, the PJM proposal does not include Spring and Fall as separate products, and thus would not see the potential cost reductions from these seasons that generally face lower capacity constraints.

Another potential uncertainty is the overall level of reliance of Illinois utilities on the capacity markets for obtaining capacity. If there was a drastic shift toward capacity procurement outside of RTO capacity markets, such as a mandate of long-term capacity contracts through IPA or directly by utilities, it is possible that the capacity costs in the two scenarios would be more similar. The capacity costs in this case could be more determined by the missing money of local resources, rather than clearing prices in the MISO and PJM capacity markets. Of course, the amount of missing money even for identical capacity resources is determined by energy revenues that we have shown to be different in the two scenarios. The risk of this outcome is not seen as likely given the significant change in policy it would require. Of note - the current short-term contracts approach used by IPA do not cause the same equilibrating of capacity cost scenarios as their duration and frequency tie the prices very closely to cleared prices in the respective capacity markets (through opportunity cost economics).

#### *Operating Reserves Considerations*

In addition to energy and capacity, ancillary services are required to operate the system in a secure manner.  Ancillary services are required for normal and contingency events with

46 MISO Reliability Based Demand Curve(s), 2023

traditional ancillary services products including spinning/synchronized reserves and regulation. Ancillary services were not specifically addressed in the analysis as the ancillary service market is small relative to the size of the energy market.[47] While in the future demand for ancillary services is expected to increase, there is uncertainty whether prices will strengthen and the size of the market will grow meaningfully. There are some differences between PJM and MISO in terms of specific ancillary service products. For example, PJM offers the Regulation D product which may be beneficial for fast ramping resources such as energy storage but significant volatility has been experienced with Reg D pricing in the past. Overall, it is CRA's view that consideration of ancillary services would not materially impact the study results.

#### *Grain Belt Express*

Development of long distance of HVDC lines such as the recently approved Grain Belt Express line may impact the analysis. However, the development is expected to be in phases with full roll out expected to happen outside the 2034 study horizon.

#### *Timing of Entry*

For the purposes of this study, it was assumed that Zone 4 would be able to join PJM at the earliest date possible defined by the MISO Transmission Owners Agreement – January 2025. AIC would need to negotiate many aspects of a transfer to PJM with both RTOs. In particular, capacity arrangements would need to be made as MISO and PJM auctions procure capacity annually beginning in the month of June. Additionally, the PJM capacity auction clears three years prior to the beginning of the delivery year, so Zone 4 would have to participate in the action while still a member of MISO. While a transfer in June 2025 would not materially change the results, CRA believes a transfer earlier in January 2025 is possible as Duke Energy Ohio and Duke Energy Kentucky transferred from MISO to PJM January 2012.[48]

## 7. Conclusions

Based on the cost-benefit analysis performed, Zone 4 joining PJM would result in net costs for AIC, ComEd, and the State of Illinois overall. The results are relatively robust, driven primarily by increased capacity costs in the *Join PJM Case*. While different sensitivities and market constructs were considered, it is unlikely that changes in market dynamics would result in net benefits, especially in the forecast horizon of 2025-2034. By other measures Zone 4 joining PJM did result in some benefits, such as reduced emissions and increased resiliency, but these benefits are outweighed by the significant economic costs. Overall, the analysis concludes that it is more beneficial for AIC to remain in MISO relative to joining PJM.

---

47 MISO's regulation reserve requirements vary between 300 and 500 MW depending on reserve zone (East, West, Central, South). Spinning reserve requirements are approximately 1000 MW. PJM has two reserve zones (PJM RTO and Mid-Atlantic Dominion. Regulation requirements are imposed RTO wide with 700 MW during peak periods and 525 MW during off-peak periods. The primary reserve requirement is 150% of the largest contingency plus 190 MW or approximately 2400 MW.

48 Duke Energy Ohio, Inc., et al., 151 FERC ¶ 61,029

# Appendix A: Further Quantitative Result Details

**Table 24: Scenario A – Net Benefit (Cost) of *Join PJM Case (millions of $)***

| AIC | NPV (2023$) | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Trade Benefits | 563.5 | 93.7 | 64.9 | 58.3 | 88.1 | 92.9 | 89.1 | 95.6 | 89.5 | 74.2 | 70.1 |
| Transmission Expansion Costs | (213.5) | (20.8) | (23.4) | (25.7) | (28.1) | (30.6) | (33.1) | (35.8) | (38.5) | (41.5) | (44.4) |
| Capacity Market Impacts | (1,074.6) | 108.3 | 249.4 | 232.8 | (162.5) | (477.9) | (568.7) | (537.1) | (313.8) | (307.3) | (100.4) |
| RTO Administrative Costs | 17.3 | 2.4 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.6 | 2.6 | 2.6 |
| Exit/Integration Fees | (26.3) | (29.2) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net Benefits (Costs) | (733.6) | 154.4 | 293.4 | 267.9 | (100.0) | (413.0) | (510.2) | (474.7) | (260.3) | (272.0) | (72.2) |
| **SIPC/CWLP** | | | | | | | | | | | |
| Energy Trade Benefits | 36.8 | 6.1 | 4.2 | 3.8 | 5.8 | 6.1 | 5.8 | 6.2 | 5.8 | 4.8 | 4.6 |
| Transmission Expansion Costs | (13.9) | (1.4) | (1.5) | (1.7) | (1.8) | (2.0) | (2.2) | (2.3) | (2.5) | (2.7) | (2.9) |
| Capacity Market Impacts | 0.2 | 4.4 | 8.8 | 8.5 | (0.3) | (7.5) | (8.2) | (7.5) | (3.0) | (2.9) | 1.9 |
| RTO Administrative Costs | 1.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Exit/Integration Fees | (1.7) | (1.9) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net Benefits (Costs) | 22.4 | 7.4 | 11.6 | 10.8 | 3.8 | (3.2) | (4.4) | (3.5) | 0.5 | (0.6) | 3.7 |
| **ComEd** | | | | | | | | | | | |
| Energy Trade Benefits | (450.3) | (46.1) | (87.7) | (84.1) | (67.5) | (78.8) | (65.9) | (50.3) | (51.8) | (57.3) | (50.5) |
| Transmission Expansion Costs | 25.3 | 2.8 | 3.1 | 3.3 | 3.4 | 3.6 | 3.8 | 4.0 | 4.3 | 4.5 | 4.7 |
| Capacity Market Impacts | (2,271.1) | (150.3) | (397.7) | (440.6) | (708.2) | (338.8) | (412.9) | (236.2) | (123.0) | (212.0) | (148.5) |
| RTO Administrative Costs | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Exit/Integration Fees | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net Benefits (Costs) | (2,696.2) | (193.6) | (482.3) | (521.4) | (772.2) | (414.0) | (475.0) | (282.5) | (170.5) | (264.8) | (194.3) |
| **Illinois** | | | | | | | | | | | |
| Energy Trade Benefits | 149.9 | 53.7 | (18.6) | (21.9) | 26.4 | 20.1 | 29.0 | 51.6 | 43.6 | 21.7 | 24.2 |
| Transmission Expansion Costs | (202.1) | (19.3) | (21.8) | (24.2) | (26.5) | (28.9) | (31.5) | (34.1) | (36.8) | (39.7) | (42.6) |
| Capacity Market Impacts | (3,345.6) | (37.6) | (139.5) | (199.3) | (871.0) | (824.1) | (989.8) | (780.9) | (439.8) | (522.2) | (247.1) |
| RTO Administrative Costs | 18.5 | 2.6 | 2.6 | 2.6 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.8 |
| Exit/Integration Fees | (28.0) | (31.1) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net Benefits (Costs) | (3,407.3) | (31.8) | (177.3) | (242.8) | (868.5) | (830.2) | (989.6) | (760.6) | (430.3) | (537.4) | (262.7) |

**Table 25: Scenario B – Net Benefit (Cost) of *Join PJM Case (millions of $)***

| AIC | NPV (2023$) | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Trade Benefits | 885.2 | 94.8 | 67.5 | 62.0 | 89.4 | 91.7 | 85.3 | 138.6 | 196.2 | 255.0 | 322.8 |
| Transmission Expansion Costs | (209.0) | (20.8) | (23.3) | (25.5) | (27.8) | (30.1) | (32.4) | (34.8) | (37.3) | (39.9) | (42.5) |
| Capacity Market Impacts | (501.2) | 270.7 | 491.2 | 523.4 | 317.9 | (138.3) | (717.8) | (843.3) | (576.5) | (550.0) | (160.0) |
| RTO Administrative Costs | 17.3 | 2.4 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.6 | 2.6 | 2.6 |
| Exit/Integration Fees | (26.3) | (29.2) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net Benefits (Costs) | 166.0 | 317.9 | 537.9 | 562.4 | 382.0 | (74.1) | (662.4) | (737.0) | (415.0) | (332.4) | 122.9 |
| **SIPC/CWLP** | | | | | | | | | | | |
| Energy Trade Benefits | 57.8 | 6.2 | 4.4 | 4.0 | 5.8 | 6.0 | 5.6 | 9.0 | 12.8 | 16.6 | 21.1 |
| Transmission Expansion Costs | (13.6) | (1.4) | (1.5) | (1.7) | (1.8) | (2.0) | (2.1) | (2.3) | (2.4) | (2.6) | (2.8) |
| Capacity Market Impacts | 20.5 | 8.4 | 14.7 | 16.3 | 12.1 | 1.7 | (10.9) | (14.2) | (8.3) | (6.4) | 3.3 |
| RTO Administrative Costs | 1.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Exit/Integration Fees | (1.7) | (1.9) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net Benefits (Costs) | 64.1 | 11.5 | 17.7 | 18.8 | 16.3 | 5.9 | (7.2) | (7.2) | 2.3 | 7.8 | 21.7 |
| **ComEd** | | | | | | | | | | | |
| Energy Trade Benefits | (658.8) | (38.6) | (84.2) | (78.3) | (83.8) | (101.2) | (122.9) | (124.8) | (123.1) | (119.4) | (119.5) |
| Transmission Expansion Costs | 24.9 | 2.8 | 3.1 | 3.2 | 3.4 | 3.6 | 3.8 | 4.0 | 4.1 | 4.4 | 4.6 |
| Capacity Market Impacts | (3,875.7) | (145.8) | (434.4) | (546.6) | (767.0) | (548.6) | (649.0) | (755.5) | (754.8) | (633.1) | (587.0) |
| RTO Administrative Costs | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Exit/Integration Fees | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net Benefits (Costs) | (4,509.6) | (181.5) | (515.5) | (621.7) | (847.4) | (646.2) | (768.2) | (876.4) | (873.8) | (748.1) | (701.9) |
| **Illinois** | | | | | | | | | | | |
| Energy Trade Benefits | 284.2 | 62.4 | (12.3) | (12.2) | 11.4 | (3.4) | (32.0) | 22.9 | 85.9 | 152.3 | 224.4 |
| Transmission Expansion Costs | (197.8) | (19.3) | (21.7) | (24.0) | (26.2) | (28.5) | (30.8) | (33.2) | (35.6) | (38.2) | (40.7) |
| Capacity Market Impacts | (4,356.3) | 133.3 | 71.5 | (6.9) | (437.0) | (685.1) | (1,377.7) | (1,613.0) | (1,339.6) | (1,189.6) | (743.7) |
| RTO Administrative Costs | 18.5 | 2.6 | 2.6 | 2.6 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 | 2.8 |
| Exit/Integration Fees | (28.0) | (31.1) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net Benefits (Costs) | (4,279.5) | 147.9 | 40.1 | (40.5) | (449.1) | (714.4) | (1,437.9) | (1,620.5) | (1,286.5) | (1,072.7) | (557.3) |

**Table 26: Scenario C – Net Benefit (Cost) of *Join PJM Case (millions of $)***

| AIC | NPV (2023$) | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Trade Benefits | 1224.9 | 133.5 | 112.5 | 126.1 | 164.7 | 169.0 | 157.0 | 193.9 | 230.2 | 261.2 | 324.2 |
| Transmission Expansion Costs | (341.2) | (20.9) | (23.4) | (25.8) | (28.3) | (30.8) | (45.2) | (63.2) | (100.9) | (103.7) | (106.4) |
| Capacity Market Impacts | (2094.1) | 532.3 | 497.8 | 63.8 | (356.5) | (739.2) | (1413.0) | (990.4) | (747.2) | (472.4) | (36.8) |
| RTO Administrative Costs | 19.1 | 2.5 | 2.6 | 2.6 | 2.7 | 2.8 | 2.8 | 2.9 | 2.9 | 3.0 | 3.1 |
| Exit/Integration Fees | (26.3) | (29.2) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net Benefits (Costs) | (1217.6) | 618.2 | 589.4 | 166.8 | (217.4) | (598.3) | (1298.4) | (856.8) | (615.0) | (311.8) | 184.1 |
| **SIPC/CWLP** | | | | | | | | | | | |
| Energy Trade Benefits | 80.0 | 8.7 | 7.3 | 8.2 | 10.8 | 11.0 | 10.2 | 12.7 | 15.0 | 17.1 | 21.2 |
| Transmission Expansion Costs | (22.3) | (1.4) | (1.5) | (1.7) | (1.8) | (2.0) | (2.9) | (4.1) | (6.6) | (6.8) | (6.9) |
| Capacity Market Impacts | (28.2) | 14.1 | 16.9 | 6.2 | (5.8) | (15.9) | (35.7) | (24.0) | (16.7) | (5.8) | 13.2 |
| RTO Administrative Costs | 1.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Exit/Integration Fees | (1.7) | (1.9) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net Benefits (Costs) | 29.0 | 19.7 | 22.9 | 12.9 | 3.3 | (6.7) | (28.2) | (15.3) | (8.1) | 4.7 | 27.6 |
| **ComEd** | | | | | | | | | | | |
| Energy Trade Benefits | (570.6) | (52.6) | (108.9) | (113.2) | (113.8) | (125.4) | (110.8) | (74.0) | (33.8) | (32.4) | (23.0) |
| Transmission Expansion Costs | 25.5 | 2.9 | 3.1 | 3.3 | 3.5 | 3.7 | 3.9 | 4.1 | 4.3 | 4.6 | 4.8 |
| Capacity Market Impacts | (2771.6) | 13.8 | (198.3) | (281.6) | (642.1) | (294.8) | (655.5) | (539.4) | (457.6) | (566.1) | (704.4) |
| RTO Administrative Costs | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Exit/Integration Fees | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net Benefits (Costs) | (3316.6) | (35.9) | (304.2) | (391.5) | (752.4) | (416.6) | (762.4) | (609.3) | (487.0) | (593.9) | (722.6) |
| **Illinois** | | | | | | | | | | | |
| Energy Trade Benefits | 734.4 | 89.6 | 10.9 | 21.2 | 61.7 | 54.6 | 56.4 | 132.5 | 211.4 | 245.9 | 322.4 |
| Transmission Expansion Costs | (338.0) | (19.4) | (21.9) | (24.2) | (26.7) | (29.2) | (44.2) | (63.2) | (103.2) | (105.8) | (108.6) |
| Capacity Market Impacts | (4893.9) | 560.2 | 316.4 | (211.6) | (1004.4) | (1050.0) | (2104.3) | (1553.8) | (1221.5) | (1044.2) | (728.0) |
| RTO Administrative Costs | 20.3 | 2.7 | 2.8 | 2.8 | 2.9 | 2.9 | 3.0 | 3.1 | 3.1 | 3.2 | 3.3 |
| Exit/Integration Fees | (28.0) | (31.1) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net Benefits (Costs) | (4505.2) | 602.0 | 308.1 | (211.8) | (966.5) | (1021.6) | (2089.1) | (1481.4) | (1110.2) | (901.0) | (510.9) |

# Appendix B: Zonal Modeling Assumptions

## Overview

All financial assumptions specified in this appendix are expressed in real 2023 US dollars, unless otherwise noted.

To assess the energy trade benefits, CRA relied on the Aurora model to perform this analysis. This licensed model performs regional long-term capacity expansion analysis and produces hourly MISO and PJM market prices at a zonal level based on a fundamental dispatch of the markets. Market inputs for the Aurora model include fuel prices, emission prices, regional load forecasts, existing resource parameters and announced regional capacity additions and retirements, and costs and operational parameters for new technology resource options. CRA also deploys a capacity market model, which produces an internally consistent capacity price outlook based on MISO and PJM market rules (See Section 3.3).

The Aurora model is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation. The database includes approximately 25,000 electricity generating facilities in the contiguous United States (U.S.), Canada, and Baja Mexico. These generating facilities include wind, solar, biomass nuclear, coal, natural gas and oil. A licensed data provider, ABB Velocity Suite, provides up-to-date information on markets, entities, and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the Aurora model.

## Market Scenarios

This study evaluated three market scenarios that describe plausible futures that might develop over time and result in different set of market conditions under which load-serving entities operating in Illinois - AIC, CWLP, SIPC, ComEd - will need to provide their service.

Each scenario is driven by a set of thematically oriented fundamental market assumptions. These scenarios are used to test the boundaries of future market conditions. Table 13 summarizes the key drivers of each scenario in a matrix. Appendix B details the main assumptions on each of the scenarios.

**Table 27. RTO Scenario Assumption Matrix**

| Scenario | Load | Natural Gas | Carbon Price | New Resource Cost | Transmission |
|---|---|---|---|---|---|
| **A: Efficient Markets** | Base | Base | No National CO2 price | Base | **MISO:** all Tranche 1 projects online in 2030.<br>**PJM:** all transmission buildouts to support retirements |
| **B: Transition Bottleneck** | Base | Base | No National CO2 price | Slower Decline | **MISO:** *only assigned* Tranche 1 projects online in 2030.<br>**PJM:** transmission buildouts to support retirements |
| **C: Deep Decarbonization** | High | Base | High | Faster Decline | **MISO:** all Tranche 1 projects online in 2030 *plus Tranche 2* buildouts<br>**PJM:** all transmission buildouts to support retirements *plus incremental transmission* buildouts |

Scenario A: Efficient Markets

Under the “Efficient Markets” scenario, MISO and PJM markets continue to evolve based on the current outlook for load growth, commodity prices, technology development, and federal incentives and credits. Scenario A serves as the reference scenario from which all results presented in previous sections are derived from.

Scenario B: Transition Bottleneck

Under the “Transition Bottleneck” scenario, energy transition stalls as policy, planning, and implementation impediments hinder transmission buildout and renewable development. Restructured markets may struggle to replace retiring capacity leading to supply tightness and declining reserve margins.

Scenario C: Deep Decarbonization

Under the “Deep Decarbonization” scenario, economy-wide decarbonization efforts through a stringent carbon policy accelerate retirements and incentivize strong renewable entry supported by transmission reforms and faster decline in technology cost. Adoption of EVs and electrification adds to load growth across the RTO footprint. Additional economy-wide decarbonization pressure in the State of Illinois drives higher electrification growth.

### Cases by Scenario

In Aurora, for each of the scenarios developed for this study, CRA has performed simulations run annually, for 10 years (2025-2034). Each scenario consists of two cases, the *Status Quo Case* and the *Join PJM Case*:

1. *Status Quo Case:* Zone 4, including AIC, SIPC, and CWLP, continues to operate as part of MISO.
2. *Join PJM Case:* Zone 4 joins PJM as an LDA connected to ComEd, and to the AEP service territories in Indiana and Michigan. Seams charges no longer apply between Zone 4 and the rest of PJM and are established between Zone 4 and MISO.

## Load Growth

CRA used a “base” load forecast used in Scenario A and Scenario B. Although the focus area of the study is the state of Illinois, the analysis of energy trade benefits requires the load forecast for each load-serving entity (LSE) in the Eastern interconnection system. For each year of the planning horizon, monthly peak load and average energy, and an hourly load profile are entered into Aurora.

For PJM, the peak load and energy forecast for CRA’s “base” view is taken from the 2023 PJM load forecast.[49] Under the “base” view, energy demand in PJM is expected to grow by 1.4% per year over the 10-year study period (2025-2034). Summer peak demand is expected to grow at a rate of 0.8% per year, while winter peak load grows at a faster pace at 1% per year.

For MISO, the primary source for the load growth forecast is the MISO MTEP Futures report, which develops future states-of-the-world for many key power market variables and each MISO future (“F1”, “F2”, and “F3”) considers different levels of electrification, electric vehicle (EV) adoption, and distributed energy resource (DER) deployment, among other

49 Based on 2023 PJM Load Forecast

assumptions.[50] CRA's "base" view aligns with Future 1 (F1) load assumptions with modest electrification growth (all from EV adoption), resulting in a 0.5% growth rate per year over the 10-year study period (2025-2034) for energy demand, 0.4% growth per year for summer peak load, and 0.5% growth for winter peak demand.

For PJM and MISO, a summary of the 10-year compound annual growth rate (CAGR) assumptions for the "Base" view load forecast are illustrated in Figure 8; and the peak load and energy forecast values used are presented in Table 28.

**Figure 8: Base View PJM and MISO Energy and Seasonal Peak Demand Growth Rates (2025-2034)**

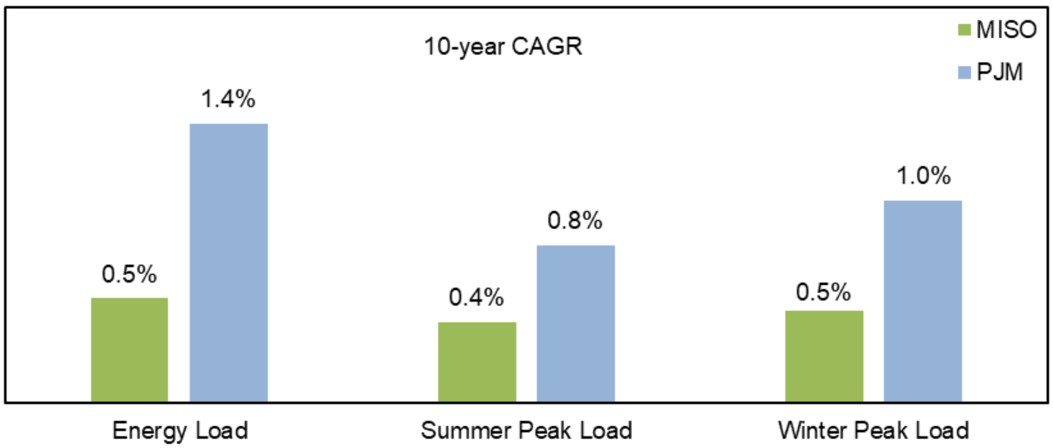



**Table 28: Peak Load and Energy Forecast at the RTO Level**

| MISO Load Forecast \ Year | 2025 | 2030 | 2034 |
|---|---|---|---|
| Summer Peak Load (MW) | 122,718 | 125,068 | 127,301 |
| Winter Peak Load (MW) | 102,292 | 104,766 | 106,664 |
| Energy (GWh) | 699,608 | 716,924 | 733,580 |
| **PJM Load Forecast \ Year** | **2025** | **2030** | **2034** |
| Summer Peak Load (MW) | 150,924 | 157,899 | 162,095 |
| Winter Peak Load (MW) | 134,140 | 142,271 | 147,000 |
| Energy (GWh) | 810,251 | 878,461 | 919,148 |

Focusing on the load-serving entities operating in the State of Illinois included in the study, Figure 9 illustrates the 10-year CAGR for the "base" view of the load forecast; and Table 29 presents the summer and winter peak load and energy forecast numbers for MISO Zone 4 and ComEd. Under the "Base" view forecast energy demand for Zone 4 is expected to grow by 0.7% per year, while energy demand in ComEd is expected to decline by 0.1% per year. Summer peak load is expected to grow 0.5% per year in Zone 4 and to decrease 0.5% per year for ComEd. Finally, the winter peak load grows 0.6% per year for Zone 4 and 0.1% per year for ComEd.

50 MISO 2022 MTEP & MISO Futures Report

**Figure 9: Base View Zone 4 and ComEd Energy and Seasonal Peak Demand Growth Rates (2025-2034)**

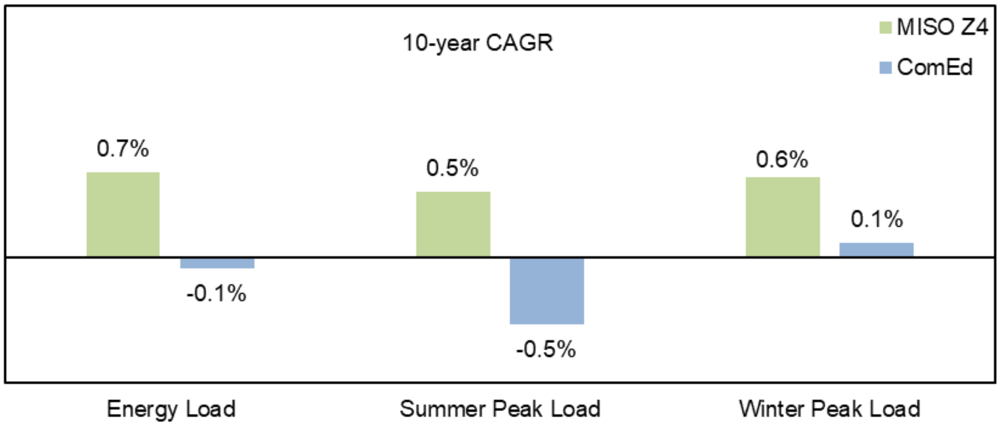



**Table 29: Base View Peak Load and Energy Forecast at the Zonal Level**

| MISO Zone 4 Load Forecast \ Year | 2025 | 2030 | 2034 |
|---|---|---|---|
| Summer Peak Load (MW) | 8,926 | 9,170 | 9,354 |
| Winter Peak Load (MW) | 7,604 | 7,828 | 8,050 |
| Energy (GWh) | 50,529 | 52,150 | 53,680 |
| **ComEd Load Forecast \ Year** | **2025** | **2030** | **2034** |
| Summer Peak Load (MW) | 20,206 | 19,839 | 19,252 |
| Winter Peak Load (MW) | 14,372 | 14,625 | 14,523 |
| Energy (GWh) | 90,708 | 91,157 | 90,006 |

For peak load and energy for other load-serving entities outside MISO and PJM, CRA uses the latest FERC Form 714 load forecast data where available. If any of these forecasts do not project load through 2034, CRA uses the compound annual growth rate by forecast area to extrapolate peak load and energy through 2034.

Hourly load profiles are drawn from hourly actual demand, as published in FERC Form 714 submissions and on the websites of Independent System Operators (ISOs) and NERC reliability regions.[51] These hourly load shapes, combined with forecasts for monthly peak load and average energy for each company, are used by Aurora to develop a complete load shape for each load-serving entity for each forecast year.

While Scenarios A and B load growth expectation are derived from CRA's "Base" view load forecast, Scenario C adjusts customer load higher to reflect changes in the broader economy. Under Scenario C, load grows more quickly than under the base view load forecast driven by

51 It is important to note that all hourly load profiles use the same year for all areas. It is also important that the hourly load profiles and hourly wind profiles are time-synchronized, especially for high wind potential areas. This is because both load and wind are heavily correlated to weather patterns.

increased economic growth, deployment of electric vehicles, and greater building electrification.

For MISO's load growth expectations, the "high" view, for Scenario C is based on MISO MTEP's Future 3, which incorporates an aggressive amount of EV and electrification growth contributing to the higher CAGR, resulting in approximately 129 TWh of incremental load, for MISO RTO, compared to the "base" view. For PJM, CRA's "high" view assumes that in addition to increased EV adoption, a high percentage of residential heating is electrified by 2035. Overall, PJM's high load view assumes approximately 79 TWh of incremental load compared to the "base" view. Figure 10 presents the comparison between the "base" and "high" views load forecast at the RTO level.

**Figure 10: Base and High views Energy and Peak Load Forecast at the RTO level**

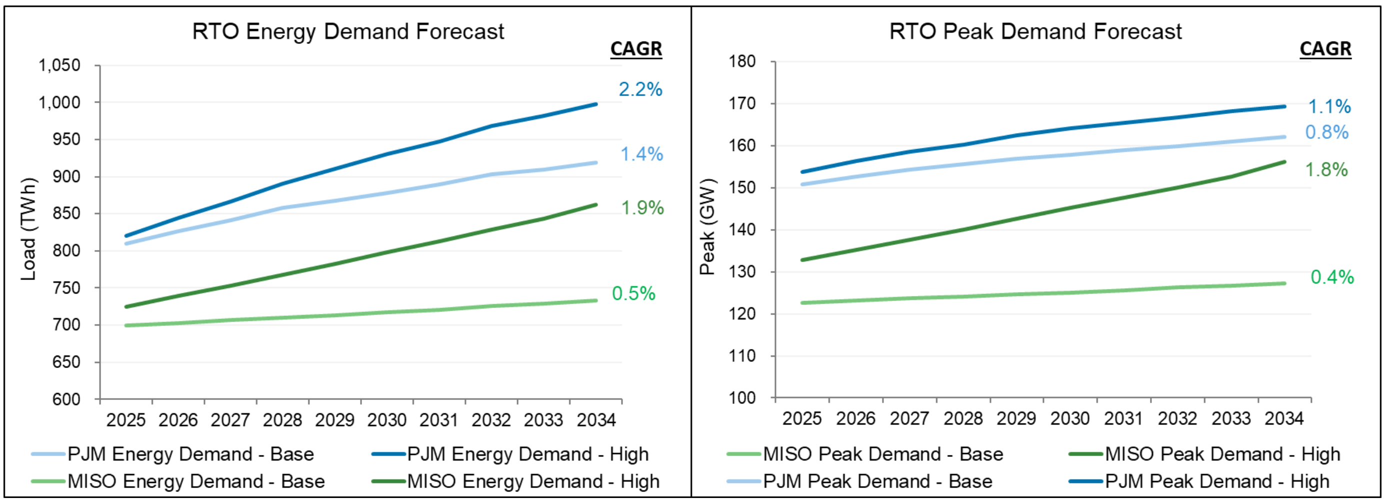



Figure 11 and Table 30 presents the comparison between the "base" and "high" views load forecast at the zonal level.

**Figure 11: Zonal Base and High views Energy and Peak Load Forecast**

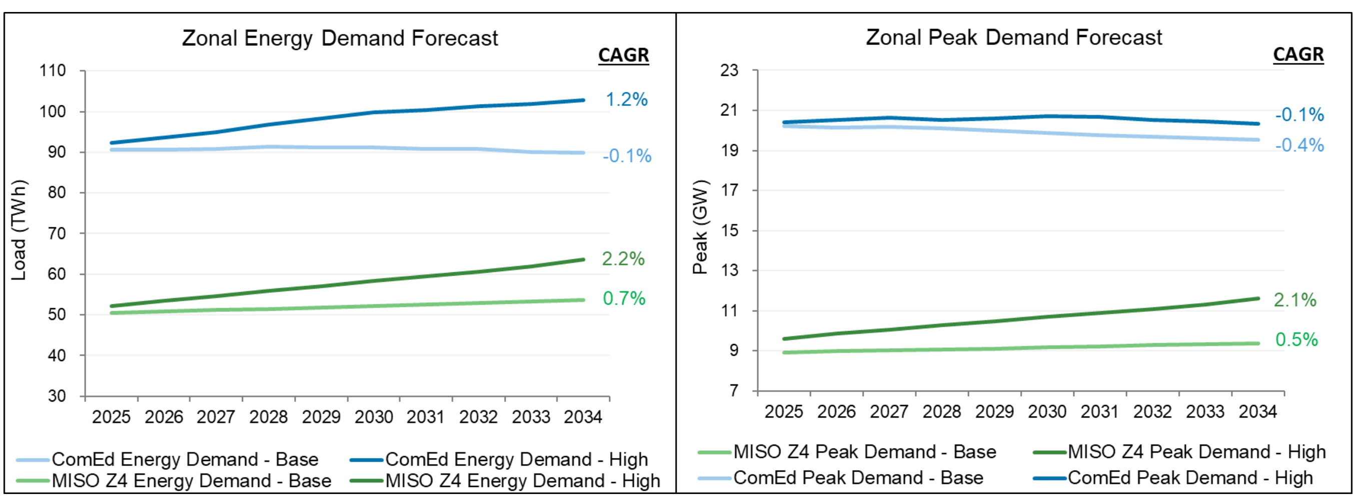


**Table 30: High View Peak Load and Energy Forecast at the Zonal Level**

| MISO Zone 4 Load Forecast \ Year | 2025 | 2030 | 2034 | CAGR |
|---|---|---|---|---|
| Summer Peak Load (MW) | 9,602 | 10,687 | 11,613 | 2.1% |
| Winter Peak Load (MW) | 7,972 | 9,113 | 10,047 | 2.6% |
| Energy (GWh) | 52,211 | 58,279 | 63,543 | 2.2% |
| **ComEd Load Forecast \ Year** | **2025** | **2030** | **2034** | **CAGR** |
| Summer Peak Load (MW) | 20,421 | 20,704 | 20,319 | -0.1% |
| Winter Peak Load (MW) | 14,903 | 16,472 | 17,089 | 1.5% |
| Energy (GWh) | 92,345 | 99,767 | 102,751 | 1.2% |

## Existing Resources

Aurora includes a detailed model of thermal generation to accurately simulate operational characteristics and project realistic hourly dispatch and prices. Modeled characteristics include fuel type, heat rate value, capacity, fixed and variable non-fuel operations and maintenance costs, startup costs, forced and planned outage rates, minimum up and down times.

## Fuel And $CO_2$ Prices

For all three scenarios (A, B, and C) CRA used its “reference” view for natural gas and coal price forecasts. These forecasts of spot prices, at regional hubs, were used to represent the expected conditions for the broader PJM and MISO markets.

Scenarios A and B assume that policymakers do not enact a national CO2 price, therefore prices are assumed to be zero throughout the study period. However, there is the potential that future emissions reduction policy could implemented and that the level of policy pressure could be materially high, as represented in the high CO2 price forecast used in Scenario C.

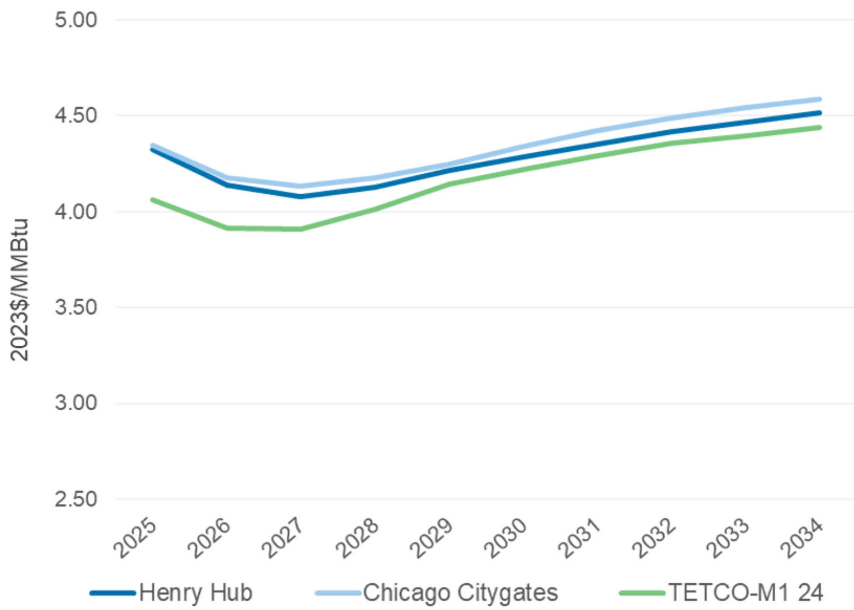
### Natural Gas Prices

CRA develops a Henry Hub outlook relying on forwards for the near-term transitioning to fundamental modeling in the long-term. For the long-term fundamental view, CRA uses the Gas Pipeline Competition Model (GPCM), a licensed model based upon the principles of market clearing economics i.e., the balance between supply and demand, to develop credible long-term estimate for natural gas pricing. GPCM accounts for natural gas production, pipeline and storage utilization, deliveries to local markets and sectors, and prices at points throughout the North American gas market. Some GPCM forecast outputs include: production at major gas basin throughout North America; prices at over 80 commonly traded market hubs as well as many non-traded locations; pipeline receipts from producers by zone.

In the near-term (2023-2025), the “reference” view price forecast is set equal to Amerex future prices for natural gas at Henry Hub as of the closing of November 08, 2022. In the mid-term (2025-2028), the forecast results from blending of near-term, future prices, and long-term fundamental CRA forecast. The long-term (2029-2035) fundamental forecast are derived from the GCPM.

CRA forecasts natural gas prices on a regional basis following major pipeline traded pricing points. Regional forecasts are derived by adding two factors, the basis differential by region (using the GCPM) and local delivery change by state, to the Henry Hub gas price. Figure 12 illustrates the annual Henry Hub, Chicago Citygate and TETCO M1(24-inch) spot prices.

**Figure 12: Reference View Natural Gas Price Forecast**



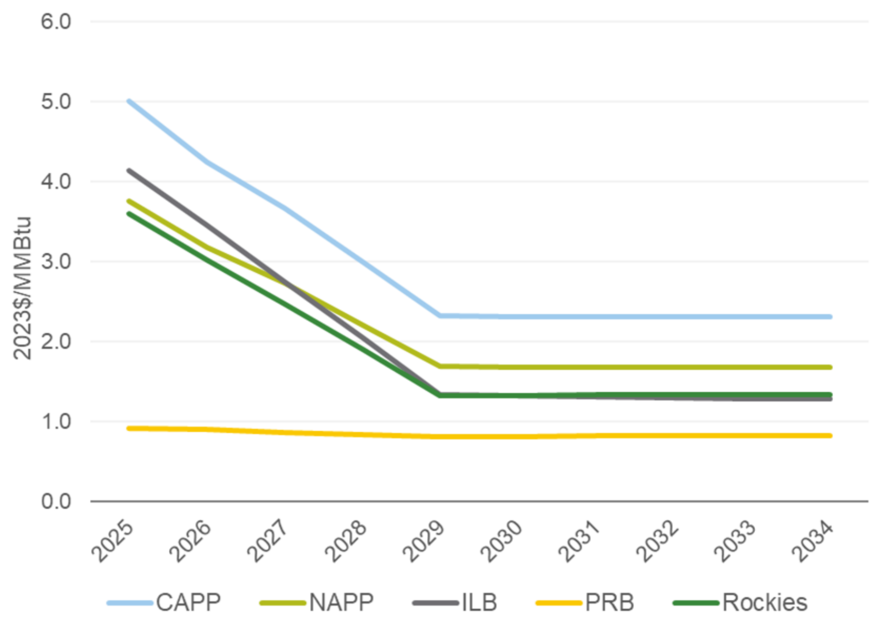

## Coal Prices

CRA's "reference" view coal price forecast was driven by a fundamental view of the major supply and demand dynamics for each of the major coal basins in the United States and the expected evolution of the power sector over time. The core forecasting process incorporates perspectives on coal supply, demand, and transportation to deliver fuel to plants throughout the United States. CRA assess the future supply/demand balance for the U.S. coal market based on macroeconomic drivers, such as domestic and international demand, and microeconomic drivers, including trends in mining costs and production.

In the near-term (2023-2025), the "reference" view price forecast is set equal to coal price forwards prices as of the closing of November 2022. In the mid-term (2025-2027), the forecast trends from near-term, forward prices, and long-term fundamental CRA analysis. Figure 13 illustrates the "reference" view FOB[52] coal price outlook by coal basin.

[52] The Free On Board (FOB) price represents the value of coal at the coal mine and excludes transport and insurance costs

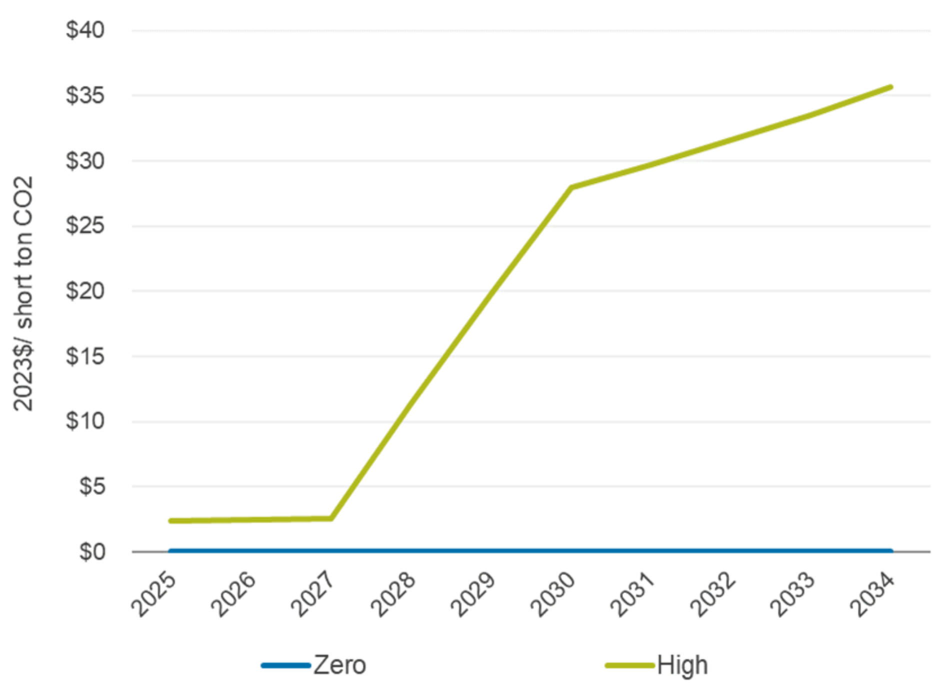
**Figure 13: Reference View Coal Forecast by Basin**




## $CO_2$ Prices

Figure 14 below illustrates how the zero CO2 price in Scenarios A and B compare to the high CO2 price view used in Scenario C. Under the high CO2 price forecast, a national price on carbon is instituted starting in 2025 with prices starting at approximately $2.3/Short Ton (real $2023) and rising linearly to around $28/Short Ton by 2030 and to $36/Short Ton by 2034.

**Figure 14: High and Zero CO2 Price Forecast ($2023/short Ton)**



## Technology Capital Costs

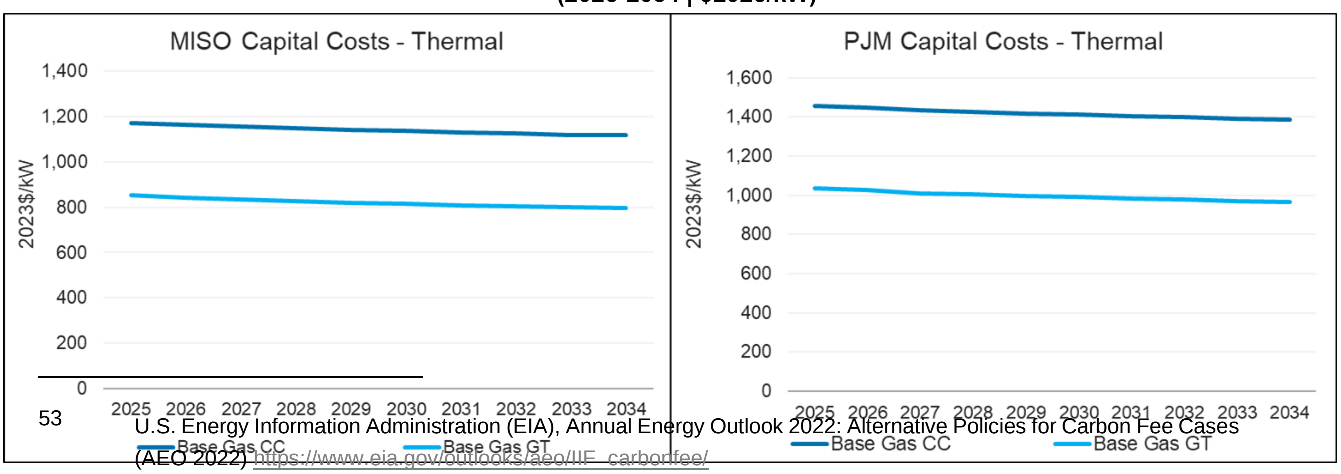
CRA relied on EIA's 2022 AEO[53] as the starting point for the technology cost and performance assumptions for new utility scale generation in the PJM and MISO footprint.[54] CRA assumes that under all scenarios, federal tax credits for new renewable generation and grid energy storage reflect current law and the schedules enacted in the Inflation Reduction Act (IRA) of 2022.

For Scenario A, changes to technology cost and performance over time are based on the moderate case of the 2022 National Renewable Energy Laboratory's (NREL) annual technology baseline (ATB) report.[55] Under Scenario B, new unit costs remain elevated as short-term shocks to the supply chain are not fully resolved over the forecast period, therefore, capital costs trajectory follow the "conservative" NREL ATB case learning rates, resulting in costs that are materially higher throughout the forecast period. Finally, in Scenario C rapid deployment of new renewable technologies combined with higher levels of policy support cause the cost of these technologies to decline more quickly. Capital costs follow the "advanced" NREL ATB case learning rates, resulting in costs that are materially lower throughout the forecast period.

**Figure 15, Figure 16,**

Figure 17, and Figure 18 compare the forecast of expected capital costs for each region, for each of the new technologies considered in this study, from NREL's moderate case used in Scenario A, the conservative case used in Scenario B and the advanced case costs used in Scenario C.

**Figure 15: MISO and PJM Comparison of Capital Costs Outlooks for Thermal Technologies[56] (2025-2034 | $2023/kW)**




53 U.S. Energy Information Administration (EIA), Annual Energy Outlook 2022: Alternative Policies for Carbon Fee Cases (AEO 2022) https://www.eia.gov/outlooks/aeo/IIF_carbonfee/

54 Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf In this report, Table 1 show the costs for a typical facility for each generating technology before adjusting for regional cost factors. Table 2 shows a full listing of the overnight costs for each technology and electricity region if the resource or technology is available to be built in the given region. In this study MISO Zone 4 capital costs are derived from the "MISC" electricity region and ComEd costs are taken from the "PJMW" electricity region as specify in Table 2.

55 NREL Electricity Annual Technology Baseline (ATB) 2022. https://atb.nrel.gov/electricity/2022/data

56 NREL ATB's Moderate, Advanced, and Conservative learning curves for thermal technologies are the same.

**Figure 16: MISO and PJM Comparison of Capital Costs Outlooks for Solar Technologies**

**(2025-2034 | $2023/kW)**

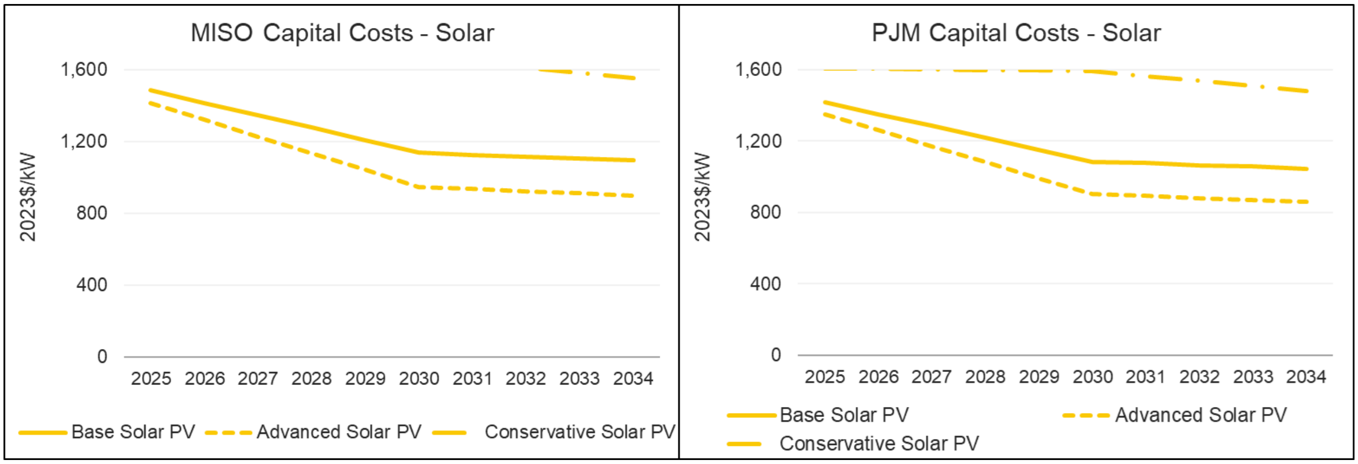



**Figure 17: MISO and PJM Comparison of Capital Costs Outlooks for Wind Technologies**

**(2025-2034 | $2023/kW)**

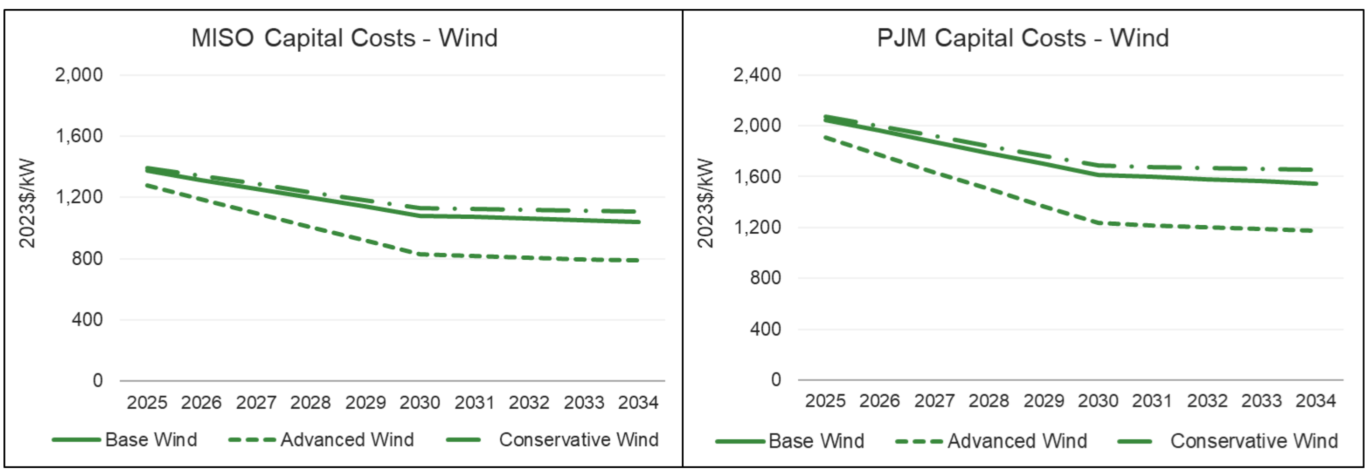
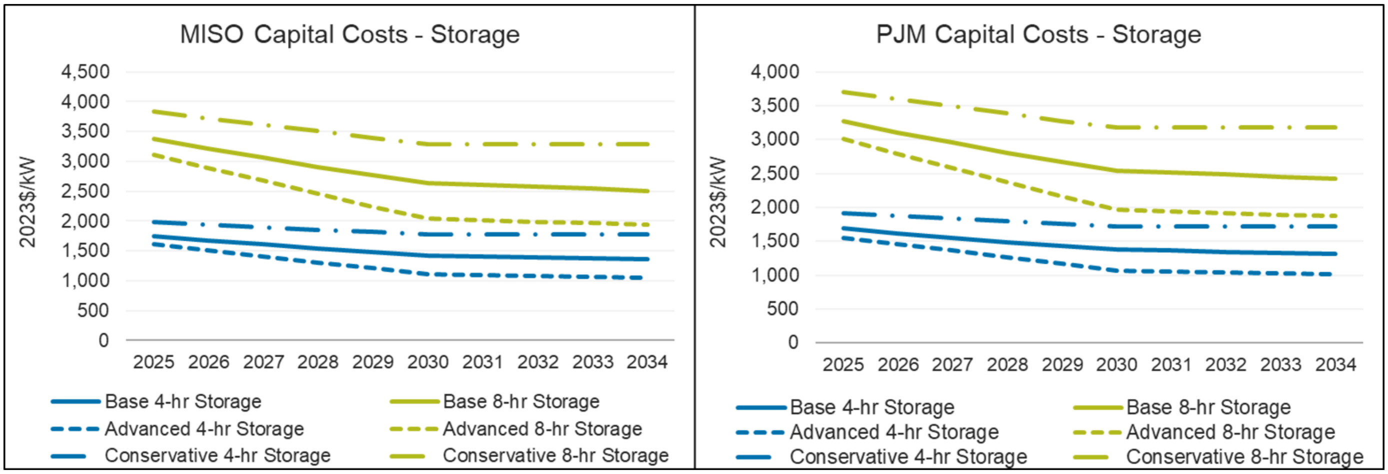


**Figure 18: MISO and PJM Comparison of Capital Costs Outlooks for Storage Technologies (2025-2034 | $2023/kW)**

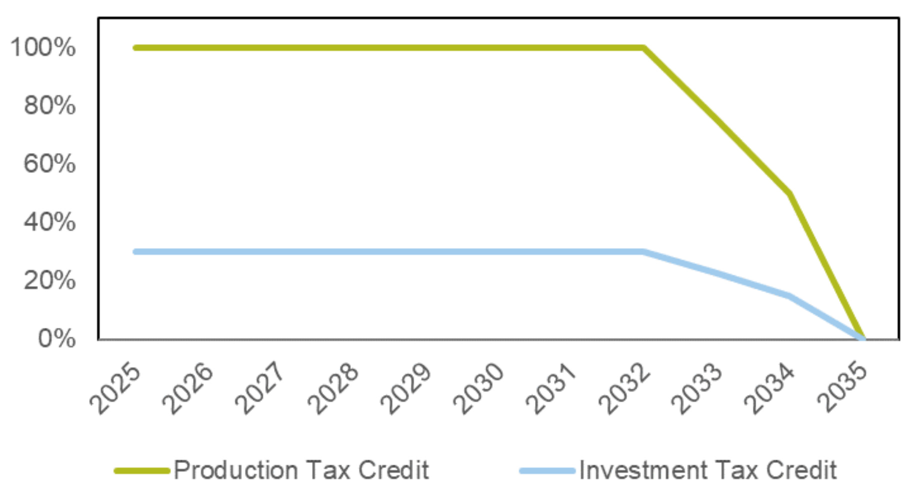



## Federal Tax Credits for Renewable Energy

The Inflation Reduction Act of 2022 (IRA) provides federal tax credits for clean energy, energy storage, clean hydrogen, and CCS. CRA modeled the IRA as part of this study.

The primary provisions under the IRA are made available through the production tax credit (PTC) and investment tax credit (ITC). These benefits are adopted for all scenarios. Figure 19 below illustrates how these benefits are assumed to decline over time. The PTC value in Figure 19 represents the multiplier applied to the statutorily defined value of the credit (e.g., in 2025 it is assumed that new wind and solar units will receive 100% of the defined credit value). By contrast, the ITC value represents the percent of capital cost that can be recovered through the credit (e.g., in 2025 it is assumed that new storage will receive a 30% credit on capital costs).

**Figure 19: Federal Tax Credit Assumptions Used in the study (2025-2034)**



### Transmission & Distribution Facilities

Transmission and distribution facilities were modeled by Quanta with PROMOD. The baseline production cost models used for this analysis were obtained from the MISO MTEP 2021 cycle with a nodal representation of the network down to the 60kV system. The models also include a representation of the entire Eastern Interconnection, including PJM.

In Scenario A, all MTEP Tranche 1 projects were included in the analysis. For Scenario B, to simulate the transition bottleneck only non-competitive Tranche 1 projects were modeled.

Scenario C was more complex as additional transmission had to be modeled to meet load growth assumptions driven by decarbonization.

In MISO, Tranche 2 projects were modeled and identified by:

- Transmission projects proposed by stakeholders and MISO during Tranche 1 but were ultimately not selected for approval.
- Preliminary overlays of Tranche 2 transmission projects presented at stakeholder meetings.
- Stakeholder comments and feedback documented through Planning Advisory Committee (PAC) meetings.

The transmission overlays for PJM were obtained through power flow analysis:

- PJM RTEP 2028 power flow models were utilized, as obtained from PJM. The models were updated to include the buildout of resources in Illinois and neighboring states.
- Generation Deliverability studies were performed by including Ameren Illinois within the PJM Export and Import definitions.
- Generation Deliverability study procedures consistent with the PJM tariff procedures and Manual 14B were applied. Power Gem's TARA-based PJM Generation Deliverability modules were used for this assessment.
- Thermal and voltage violations that affected facilities greater than 200kV were reviewed.
- Transmission overlays were developed to minimize the impacts on affected facilities. The overlays included the buildout of new greenfield and brownfield scope of projects.
- The proposed projects were used to update the models, and Generation Deliverability studies were rerun to verify performance.
- All studies were performed under summer peak, Winter peak, and Light Load conditions.
- Costs for new transmission was based on values from the MISO Transmission Cost Estimation Guide.[57]
    - 345kV Double Circuit: $5.20/mile
    - 345kV Single Circuit: $3.20/mile

57 Exploratory cost estimate for Illinois. Section 4.1 Transmission Cost Estimation Guide.

# Appendix C: Nodal Modeling Assumptions

## Overview

For the energy trade benefits assessment, CRA relied on Quanta to perform a nodal market analysis to better capture transmission flows and constraints for Zone 4 and ComEd. Quanta used PROMOD for this analysis, employing Aurora's zonal input assumptions and the resulting capacity expansion plan for each case, under each scenario.

PROMOD is a production cost modeling tool used in electric market simulation and developed by Hitachi Energy (formerly ABB). The economic dispatch solver minimizes costs while simultaneously adhering to a wide variety of operating constraints, including generating unit characteristics, transmission limits, fuel usage, environmental considerations, external market transactions, and customer demand. PROMOD performs an 8760-hour forecast of hourly energy prices, unit generation, revenues, fuel consumption, transactions, and transmission losses at the nodal level.

PROMOD provides a geographically and electrically detailed representation of the topology of the electric power system, including generation resources, transmission resources, and load. This detailed representation allows the model to capture the effect of transmission constraints on the ability to flow power from generators to load and thus calculates Locational Marginal Prices (LMPs) at individual nodes within the system. It can also perform and support various reliability analyses, including calculating loss-of-load probability, expected unserved energy, and effective capacity support.

The baseline production cost models used for this analysis are obtained from the MISO MTEP 2021 cycle with a nodal representation of the network down to the 60kV system. The models include a representation of the entire Eastern Interconnection, including PJM.

## Zonal Inputs and Nodal Results Process

Zonal inputs for MISO and PJM were translated to PROMOD to achieve an equivalent model at the nodal level. The inputs were originally designed for zonal simulations using the Aurora model. Typically, the nodal models include a hierarchy scheme wherein each node is a component of a zone, and each zone is a component of an ISO/RTO definition. The dissemination process to the nodal level was initiated after verification of consistency in zonal attributes against the input data.

The zonal inputs include annual load, peak load, generating capacity, interregional transmission upgrades, and unit retirements. Additional commodity inputs were provided based on economic forecasts conducted by CRA. These inputs include dispatch seams charges, production tax credits, business energy investment tax credits, carbon pricing, and natural gas prices.

The PROMOD models were also verified and updated to include major approved transmission projects from the PJM RTEP cycle, MISO MTEP cycle, and Tranche 1 approved projects. The resulting capacity expansion plan for Scenario C required incremental transmission developed through market research and power flow studies.

The following inputs required additional analysis to convert the model from zonal to nodal properly:

- Load forecasts were converted from zonal to utility-level based on load ratio shares identified in the MTEP21 base model.
- New capacity additions were made at the nodal level using information from the interconnection queues and the status of project in-service dates. To the extent

reasonable, MISO-identified Regional Resource Forecasted (RRF) units were adjusted to meet required capacity targets.

- Load modifiers, including electrification and DER, were treated as hourly resources with their characteristic shape.
- The fuel price forecasts were adjusted to ensure consistency in translating Henry Hub gas prices to major gas delivery points in the nodal model.

A benchmarking exercise was performed to verify consistency in trends and outputs between the zonal and nodal models. Following this, PROMOD simulations were performed for 2025, 2030, and 2035. Outputs were analyzed to evaluate load-weighted prices, generation-weighted prices, emissions, and transmission constraints.

### Power Flow Analysis and Additional Transmission Projects, Scenario C

Power flow analysis was performed for Scenario C to identify the high-level transmission expansion required to support scenario buildout.

The transmission overlays for MISO were compiled from the following sources:

1. Transmission projects proposed by stakeholders and MISO during Tranche 1 but were ultimately not selected for approval.
2. Preliminary overlays of Tranche 2 transmission projects presented at stakeholder meetings.
3. Stakeholder comments and feedback documented through Planning Advisory Committee (PAC) meetings.

The transmission overlays for PJM were obtained through power flow analysis:

1. PJM RTEP 2028 power flow models were utilized, as obtained from PJM. The models were updated to include the buildout of resources in Illinois and neighboring states.
2. Generation Deliverability studies were performed by including Ameren Illinois within the PJM Export and Import definitions.
3. Generation Deliverability study procedures consistent with the PJM tariff procedures and Manual 14B were applied. Power Gem's TARA-based PJM Generation Deliverability modules were used for this assessment.
4. Thermal and voltage violations that affected facilities greater than 200kV were reviewed.
5. Transmission overlays were developed to minimize the impacts on affected facilities. The overlays included the buildout of new greenfield and brownfield scope of projects.
6. The proposed projects were used to update the models, and Generation Deliverability studies were rerun to verify performance.
7. All studies were performed under summer peak, winter peak, and Light Load conditions.

### Identifying Import/Export Limits for Capacity Market Modeling

Power flow analysis was performed to guide the determination of import/export limits for use in the capacity market model. The analysis attempted to replicate the specifics of Load Deliverability Study procedures defined by Manual 14B.

Without CETO/CETL-specific cases, Quanta used RTEP 2028 power flow models. This includes all data pertinent to contingency files and monitoring criteria. The models were verified/updated to reflect that the capacity portion of generation resources are represented accurately. The following analysis was performed:

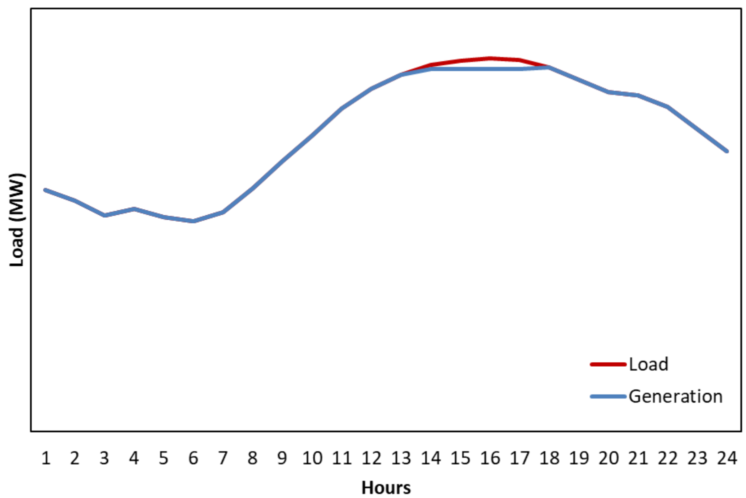
- Subsystem definitions were updated to reflect the position of Ameren Illinois within the PJM RTO.
- Multi-scenario thermal transfer analyses were performed that included transfers between
    a. PJM and MISO (with and without Ameren Illinois)
    b. Rest of Illinois to Ameren Illinois
    c. Ameren Illinois to Rest of Illinois
    d. MISO to MISO Zone 4
    e. PJM to MISO Zone 4
- Across all scenarios- the maximum thermal transfer was recorded before any constraints were triggered in the broader system.
- The power flow cases at the maximum thermal transfer were evaluated through N-1 contingency analysis to identify potential voltage violations.
- If voltage violations are observed, PV transfer analysis was performed to identify the transfer level at which no more violations are recorded.
- The final transfer value achieved represents the import/export limits for use in capacity expansion modelling.

# Appendix D: Reliability Assessment Assumptions

## Overview

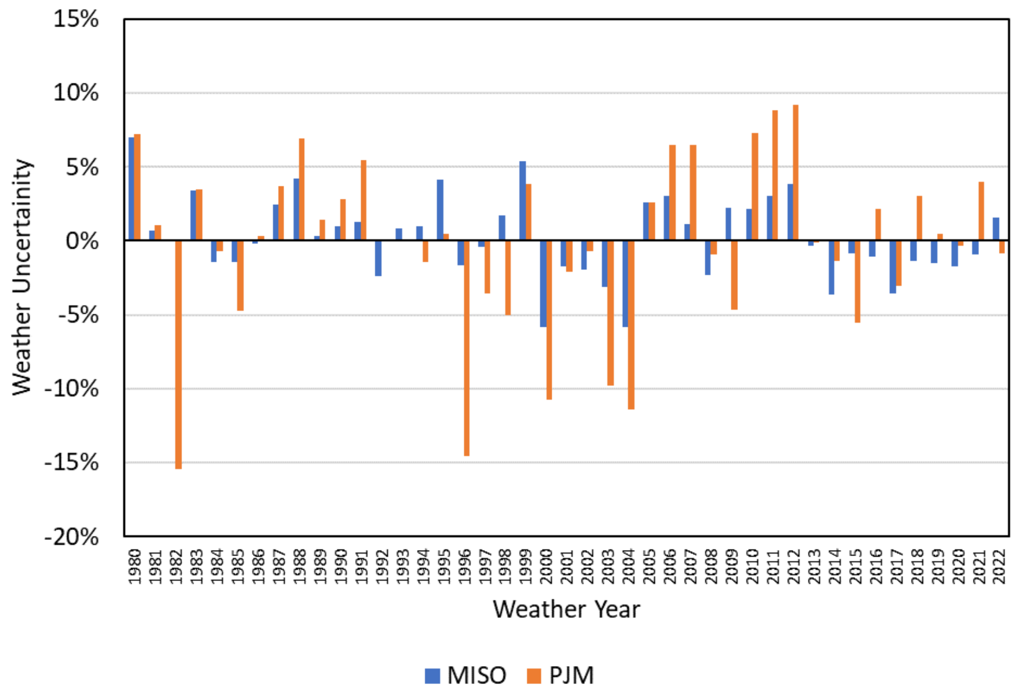
Astrapé used its Strategic Energy & Risk Valuation Model (SERVM) to perform the reliability assessment, including resource adequacy analysis, for this study. SERVM is a probabilistic tool which optimizes the hourly commitment and dispatch of resources subject to maximizing reliability at minimum cost. The reliability target used for this analysis was Loss of Load Expectation (LOLE), defined as the number of loss-of-load events due to capacity shortages, calculated in days per year. Figure 20 shows an example of a capacity shortfall which typically occurs across the peak of a day.

**Figure 20: LOLE Day Illustration**




The loss-of-load events are driven by a variety of factors but are particularly correlated to concurrent random forced outage events, severe weather, or a combination thereof. To properly characterize the possible severe weather outcomes, SERVM utilizes a "weather year" framework. Under this framework, the system is simulated given forty-three possible annual weather patterns (1980-2022) consisting of hourly temperature, wind profiles, solar irradiance, load, and hydro conditions. The purpose of the weather year framework is to address the response of the system under study given historic conditions. The impact to peak demands of simulating different weather years is visualized in Figure 21 – any particular year may be more mild or more severe than the expected, with values up to 9% greater than the annual load forecast being possible under severe summer conditions (see weather year 2010).

**Figure 21: Weather Uncertainty in the Study Regions**




The weather years are multiplied with 5 load forecast errors and 5 different iterations yielding a total of 1,075 yearly annual simulations per assessment. LOLE represents the weighted average expected number of shortage events across all these conditions.

The framework described was used to calculate the LOLE for future different study years of the MISO and PJM buildouts produced by the expansion planning models utilized by the CRA team. Study years 2025, 2030, and 2035 were simulated in SERVM to ensure the expansion plans were reliable for each scenario. This provided a feedback loop to the CRA team to add or remove effective capacity from the final portfolios.

## Overview ELCC Modeling Methodology

Once the MISO-PJM system was simultaneously calibrated to 0.1 LOLE (the planning target for both ISOs), the ELCC, or Effective Load Carrying Capability, study could be performed. ELCC represents the accreditation of a resource on a percentage basis relative to perfect capacity. So, for example if a 100 MW solar PV facility were to have a 60% ELCC, then the reliability contribution of the resource is equal to a 60 MW perfect generator (without outages, derates, maintenance, etc.). Figure 22 illustrates, at a high level, the mechanics through the ELCC calculation process.

**Figure 22: ELCC Study Process**

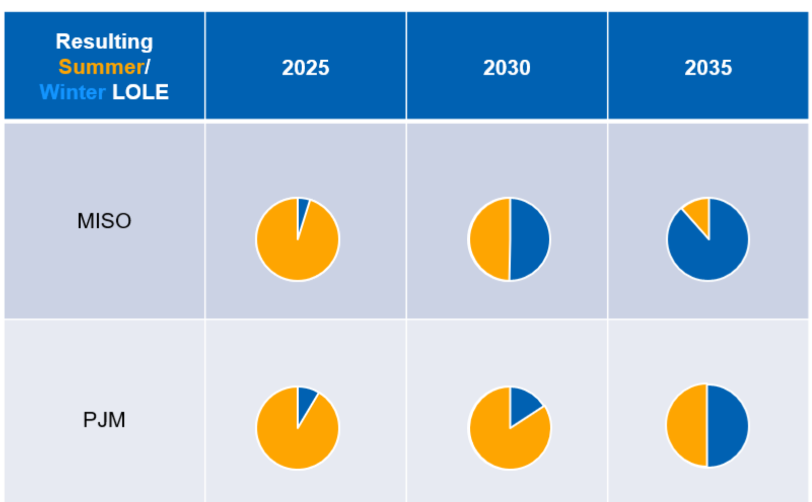

To ensure equitable and fungible accounting, first, this process was performed for the entire energy limited and renewable portfolio first (solar, wind, battery, demand response), then, for constituent resources within that portfolio. This ensures that the sum of constituent resource ELCC is equal to the portfolio, and accounts for "diversity" effects amongst resource classes (e.g., solar has synergistic value with storage, storage has antagonistic value with demand response). Note this is commonly referred to average ELCC methodology which to date has been employed in ISOs such as MISO and PJM in conducting capacity markets. Average ELCCs by technology were also calculated for 2025, 2030, and 2035 based on the expansion plan buildouts for each scenario.

## Resiliency Analysis and Results

To complement the study year reliability analysis, supplemental metrics were provided for each system at 0.1 LOLE to characterize the severity of tail events. LOLE describes an expected value but does not provide information on the magnitude of load shed events or the possible length. Further, it does not quantify the economics required to withstand a severe event. Figure 23 and Figure 24 provide the results of supplemental metrics analyzed for this resiliency analysis.

To understand the composition of load shed events, first the distribution in summer or winter events was calculated by year. This was performed for three benchmark years through the study horizon – 2025, 2030, and 2035.

**Figure 23: Seasonal Risk Composition by Study Year**

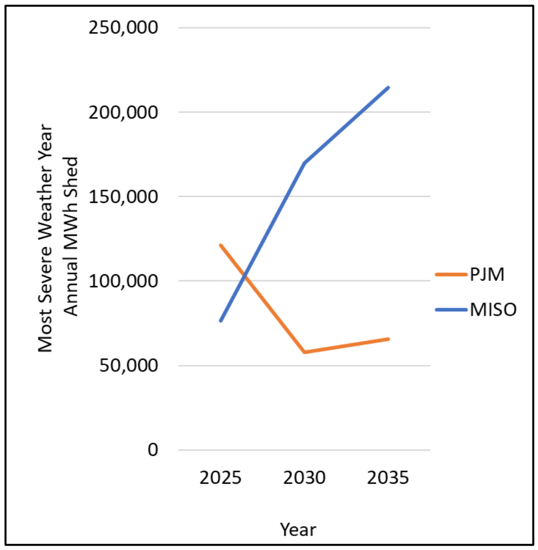


This indicates that, given the portfolios assessed, MISO is more subject to winter load shed events than PJM as the study years progress. The shift from summer to winter risk is driven by solar and storage penetration which provide greater reliability contribution in the summers, where the solar irradiance is and the opportunity for energy arbitrage is high, compared to winter, where both are lower. It should be noted the exact ratio of summer and winter events is also driven by the degree of winter correlated forced outages assumed.

Next, the most extreme iterations were sampled from the entire distribution to understand the magnitude of MWh at risk under a 1 in 1050 combination of weather and generator performance.

The results of the sampling indicate MISO is subject to more severe tail events at 0.1 LOLE as the planning horizon progresses.

**Figure 24: Severe Weather Year Events**




This is driven by the resource mix in MISO as compared to PJM by 2035 – MISO sees a more significant storage and solar portfolio which, under high demand conditions, become exhausted and unable to provide energy during the sunset to sunrise period.

## Reliability Analysis Methodology and Results Scenarios A, B, & C

SERVM was utilized to assess the reliability of portfolios produced using expansion planning models. Generally, expansion planning models consider reliability using ELCC and a Planning Reserve Margin (PRM) target – within the co-optimization, the tool ensures sufficient capacity credits are procured to ensure the PRM is met on an annual basis and thus reliability is ensured at the desired standard, in this case, 0.1 LOLE. Since ELCC and PRM are themselves proxies of a reliability model, it is beneficial that reliability standards are being met particularly as resource portfolios continue to evolve and include an increasingly diverse array of resource types.

### Conventional Resources

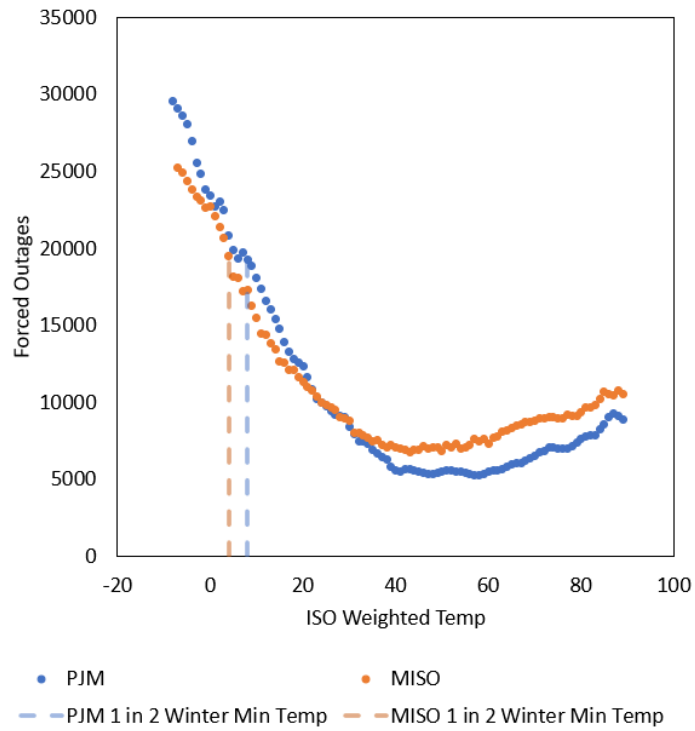
To assess portfolio reliability, the loads and resources must be appropriately characterized and modeled. SERVM utilizes a unit-level characterization of resources, quantifying their heat rates, minimum and maximum capacities, forced outage rates, weather correlation, monthly availability and so forth on a unit level scope of granularity. Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, outage probability distributions are created for each unit and SERVM randomly draws from this distribution for each unit to simulate outages. Outage distributions were scaled to an expected EFOR informed by EFORd values provided by CRA. Outage distributions are constructed using the following variables:

- Full Outage Modeling
    - Time-to-Repair Hours
    - Time-to-Fail Hours
    - Start Probability
- Planned Outages
    - Maintenance Outage Rate

The Planned Outage Rate describes the fraction of time in a month that the unit will be on planned outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

In addition to random and planned outages, weather correlated outages were included within the analysis. The Astrapé study of cold weather outages within MISO was used as a starting point as illustrated in Figure 25. The MISO outage as a function of temperatures curves were scaled up to PJM load and applied similarly. The modeled 1 in 2 Winter Minimum Temperatures are also plotted for comparison of typical winters between the two zones. At the time of this analysis, PJM had not explicitly modeled forced outages and de-rates by temperature and as such the data was not as readily available as the MISO data.

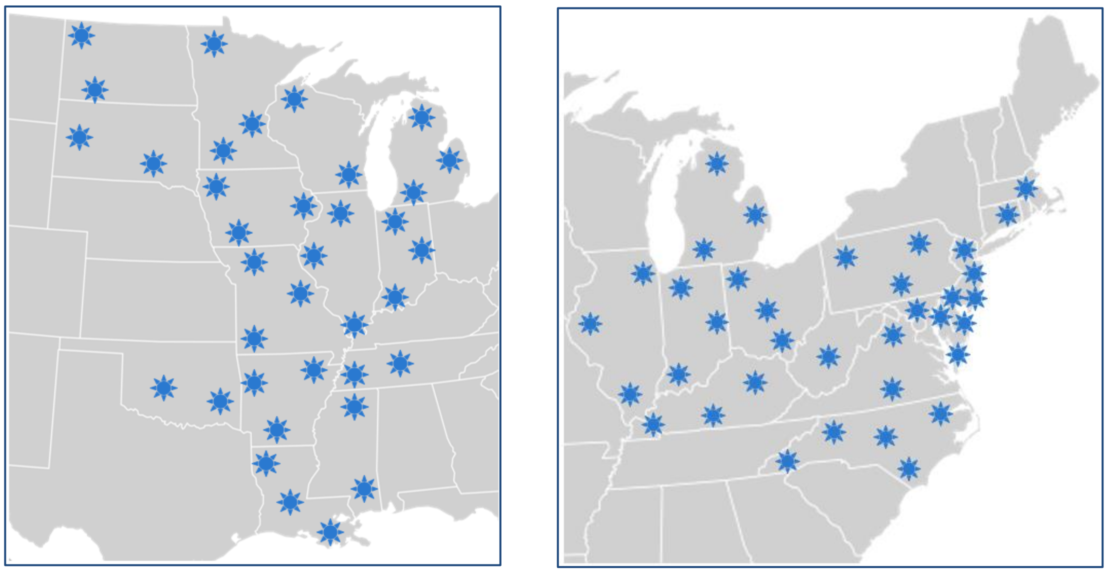
**Figure 25: MISO and PJM Cold Weather Outages**



### Solar Modeling

Data was downloaded from the NREL National Solar Radiation Database (NSRDB) Data Viewer using the latitude and longitude locations for 51 locations and technology combinations visualized below for the years 1980 through 2022. The candidate sites are visualized Figure 26 for MISO and PJM, some locations were filtered for being distant from load serving entity footprints.

**Figure 26: Solar Locations assessed in MISO (left) and PJM (right)**



By using 51 locations, the modeling incorporates diversity among future solar projects. Historical solar data from the NREL NSRDB Data Viewer included variables such as temperature, cloud cover, humidity, dew point, and global solar irradiance. The data obtained from the NSRDB Data Viewer was input into NREL's System Advisory Model (SAM) for each year and location to generate the hourly solar profiles based on the solar weather data for fixed and tracking solar PV plants. Inputs in SAM included the DC to AC ratio of the inverter module and the tilt and azimuth angle of the PV array. Data was normalized by dividing each point by the input array size. This served as the basis for solar profiles for the years 1980-2022. Solar Profiles for 1980-1997 were constructed from the 1998-2018 data by developing correlations between daily load shapes and solar profiles. The daily load shapes in the 1980-1997 were compared to daily load shapes in the 1998-2022 data and where close correlations were found, the solar shapes from those days were used.

This process was repeated for each of the 51 locations, shown below. Solar resources located within the respective zone had a weather profile randomly assigned to it based on the final list of candidate sites.

### Wind Profiles

Wind profiles were produced using historic actual data between 2019 and 2022. To construct wind shapes back to 1980, random days were selected from the 2019 to 2022 dataset based on aggregate ISO load. This process maintains the correlation in wind output to load correlation as seen in the historic data (see Figure 27). Furthermore, it was noted that MISO and PJM daily wind production was relatively correlated (Pearson's R value of 0.75) and as seen in Figure 28. This correlation was also maintained in the production of novel wind shapes.

**Figure 27: Wind Output to Load Correlation for MISO and PJM**

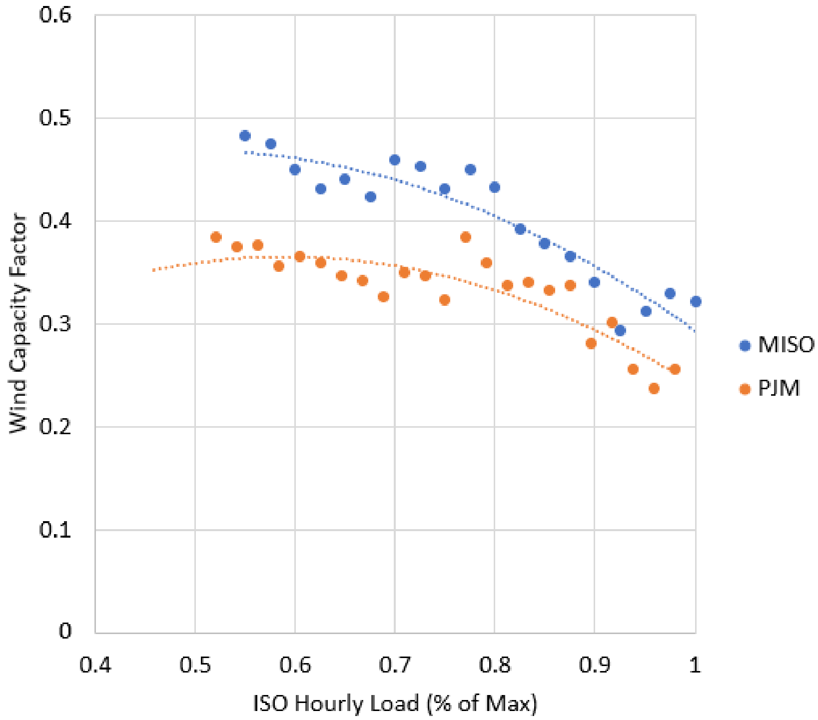
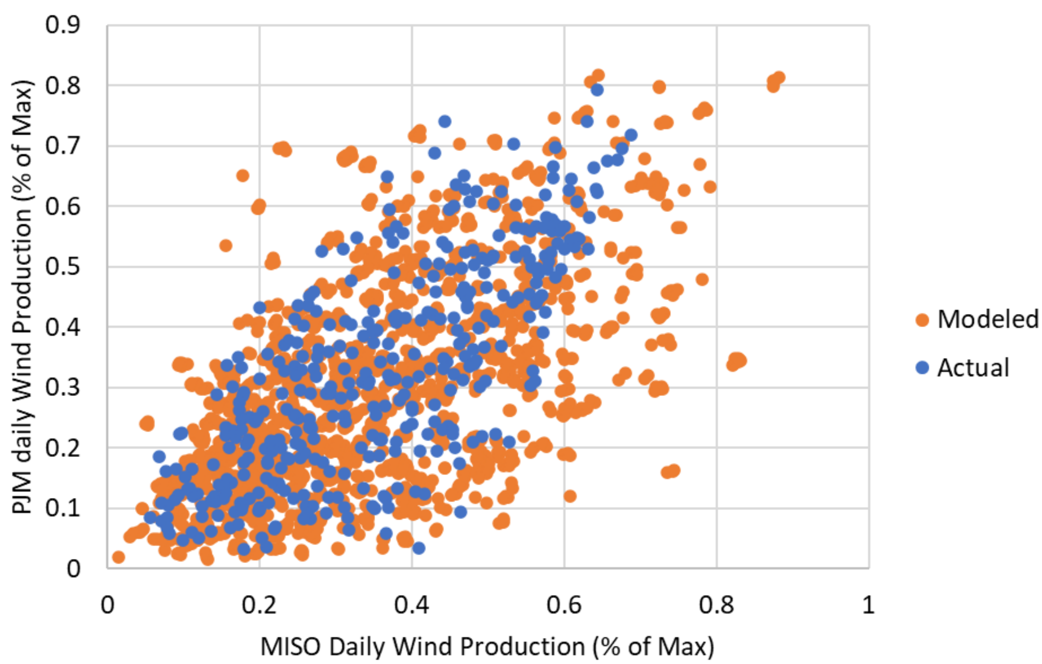
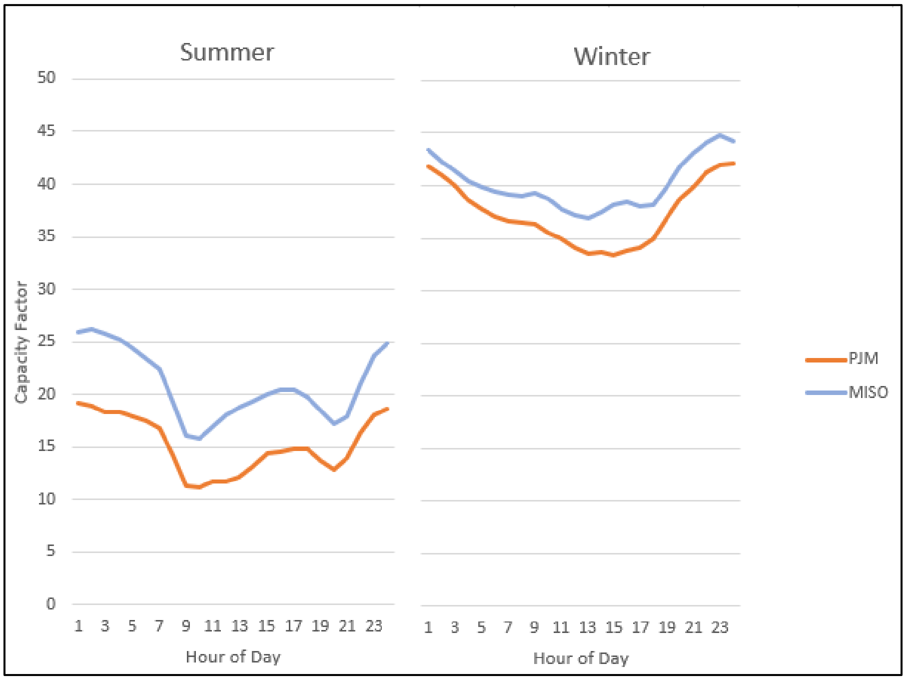



**Figure 28: Daily Wind Production Correlation between MISO and PJM**



Average hourly profiles across all weather years are illustrated in Figure 29.

**Figure 29: Aggregate Average Wind Shapes**




### Energy Limited Resource Modeling (DR and Storage)

Demand Response programs were modeled as resources in the simulations with limits including availability by season and hours per call. Table 31 provides the modeling inputs characteristics by ISO. Input characteristics were created based on publicly available information regarding demand response program obligations. Demand Response programs are intended to encapsulate all load modifying, behind the meter, and/or curtailable loads within each ISO, and are modeled as the last resource in the dispatch stack.

**Table 31: Demand Response Characteristics**

| ISO | MW | Months Available | Hours per Day | Calls per Year |
|---|---|---|---|---|
| MISO | 12,110 | 5-9 | 4 | Unlimited |
| PJM | 12,410 | 1-12 | 12 | Unlimited |

Pumped storage and battery resources were modeled as energy storage resources with appropriate max capability, MWh ponds, charging capabilities, and cycling efficiency. Energy storage technologies are economically scheduled to generate during peak conditions and pump/charge during off-peak conditions, though the dispatch can change if an unexpected event (such as a unit failure or combination of unit failures) occurs during the simulation. On high peak load days, the battery fleet was modeled to transition from maximizing energy revenue (i.e., energy arbitrage) to maximizing reliability (hold maximum stage of charge unless discharging was required to avoid load shed). In this way, the economic benefits of storage are realized while conservative operations on peak days are reflected as well.

### Load Development Processing

Unique, hourly regional load shapes were developed for each of the 43 weather years for each modeled zone as described in Table 32.

**Table 32: Summer Peak Load by Zone**

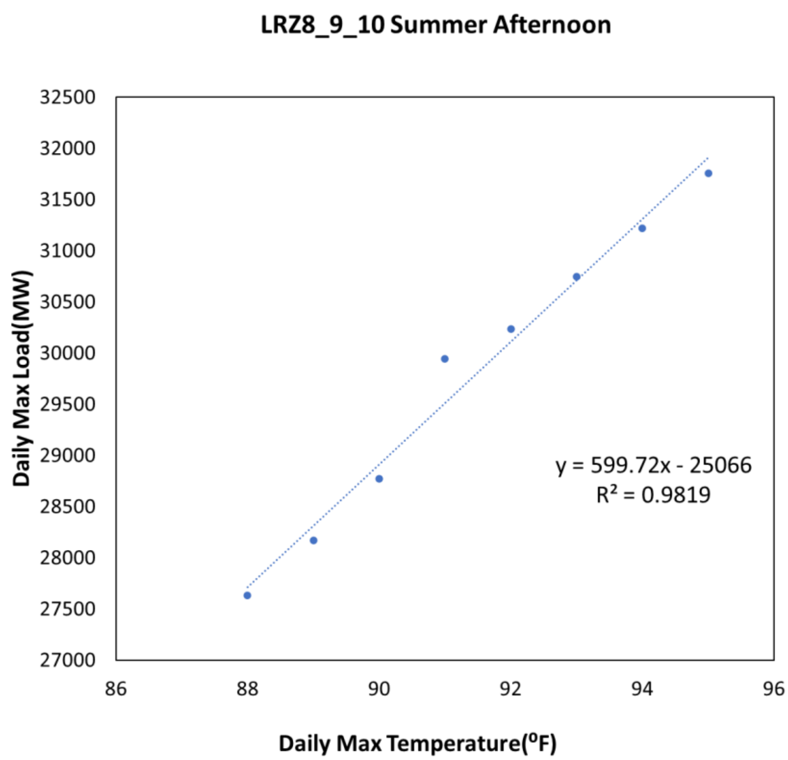
| Zone Description | 2022 Summer Peak Load (MW) |
|---|---:|
| MISO_Zone_01 | 17,592 |
| MISO_Zone_02 | 11,731 |
| MISO_Zone_03 | 9,089 |
| MISO_Zone_04 | 9,091 |
| MISO_Zone_05 | 7,977 |
| MISO_Zone_06 | 17,788 |
| MISO_Zone_07 | 20,750 |
| MISO_Zone_08 | 7,670 |
| MISO_Zone_09 | 20,243 |
| MISO_Zone_10 | 4,405 |
| PJM_AEP | 28,196 |
| PJM_APS | 8,675 |
| PJM_ATSI | 12,273 |
| PJM_COMED | 20,787 |
| PJM_DEOK | 5,239 |
| PJM_DOM | 20,424 |
| PJM_East | 55,762 |
| PJM_EKPC | 2,091 |

The following steps describe how the shapes were developed:

1. Publicly available historical hourly loads for 2017-2021 were downloaded from MISO and PJM for each region. In addition, historical hourly temperature data for 2017-2021 was downloaded from the National Oceanic and Atmospheric Administration (NOAA) such that correlations between historic temperature and loads could be determined.
2. Historical hourly load profiles were then grossed up to normalize for economic growth. To gross up these values, hourly load data was plotted as a function of ambient temperature and filtered for summer and winter peak load periods for each historical year. Multipliers were determined for each season/year to scale the distribution of hourly load values at each temperature interval such that they aligned with the economic base year (2021).
3. The grossed up 2017-2021 historical loads, along with corresponding 2017-2021 temperature data were fed into a neural network model to create seasonal “networks”. The seasons were defined as winter (December, January, and February), summer (June – August), and shoulder (all other months). The inputs for the Neural Network model were temperature, hour of week factor, and rolling average temperatures from the previous 8, 24, and 48 hours.

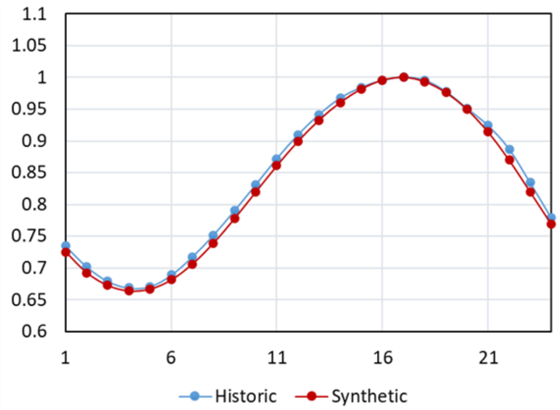
4. Historical temperatures from 1980-2022 were fed into the seasonal “networks” to create “synthetic” load profiles for each weather year.
5. Because certain extreme temperatures occur so infrequently, the trained networks were unable to develop strong correlations between extreme temperature conditions and historical loads. To improve forecast accuracy for extreme conditions, linear correlations between daily peak loads and daily maximum temperatures in summer (daily minimum temperatures for winter) were developed outside the neural network model to assess the change in load per degree change in the weather. The linear relationships were then applied to any summer daily peak load hour at or above 92-97 degrees (depending on the region) or any winter daily peak load hour at or below -11-28 degrees (depending on the region) in lieu of the of the neural network results. Additional smoothing of the daily load profile was applied to the 8 load hours before and after the extreme temperature daily peak. Figure 30 shows an example of the linear trends used in adjusting the summer daily peak loads as a function of temperature for MISO Zones 8, 9 and 10 (LRZ8_9_10).

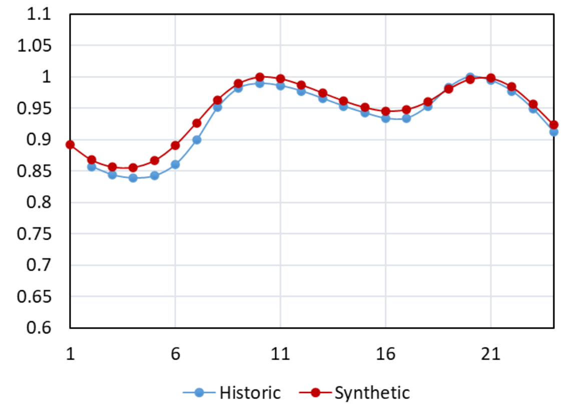
**Figure 30: Extreme Temper Analysis Example**




Loads were verified for reasonableness by comparing the average summer and winter daily load shapes from the synthetic load data to the average summer and winter daily load shapes from the actual historical data. Figure 31 shows close agreement in the average daily shapes.

**Figure 31: Load Shape Analysis and Calibration. (left) MISO Aggregate Typical Summer Day Load Shape (Normalized); (right) MISO Aggregate Typical Winter Day Load Shape (Normalized)**



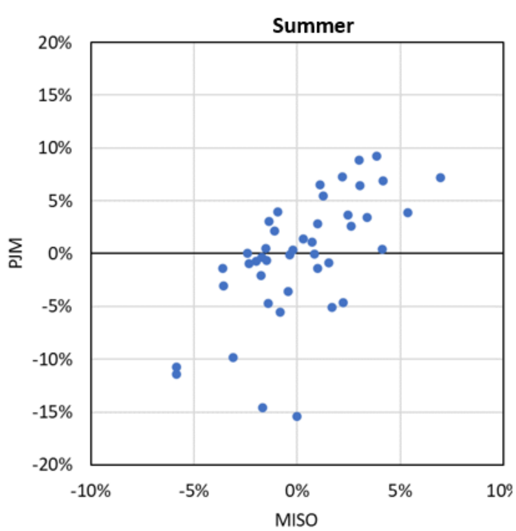

Lastly, each zone was mapped to the respective seasonal peak and energy forecast dependent upon the scenario under study. Mapping to the reference forecast zonally yields the load forecast characteristics for 2025 for each zone by season illustrated in Table 33.

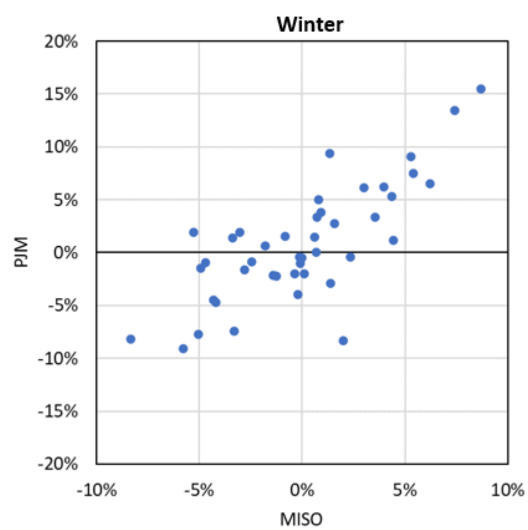
**Table 33: 2025 Peak Forecasts**

| Season | Region | 1 in 2 Peak MW | 1 in 43 Peak MW |
|---|---|---|---|
| Summer | MISO | 120,151 | 128,512 |
| | PJM | 155,174 | 169,463 |
| Winter | MISO | 101,343 | 110,138 |
| | PJM | 134,823 | 155,668 |

Taking each of the seasonal 43 peaks and plotting them by weather year results in the visualization shown in Figure 32. This indicates, in general, weather events are fairly coincident across both ISOs (hot summers are shared, severe winters are shared).

**Figure 32: Correlation in Weather Uncertainty**



### Peak Demand Forecast Uncertainty

Economic load forecast error multipliers were included to isolate the economic uncertainty that is present long-term load forecasts. To estimate economic load forecast error, the difference between Congressional Budget Office (CBO) GDP forecasts and actual data was fit to a normal distribution. Because electric load grows at a slower rate than GDP, a multiplier was applied to the raw CBO forecast error distribution.

As an illustration, 10.4% of the time, it is expected that load will be under-forecasted by 2% (Table 34). The SERVM model utilized each of the forty-three weather years and applied each of these five load forecast error points to create 215 different load scenarios. As mentioned previously, each weather year was given an equal probability of occurrence.

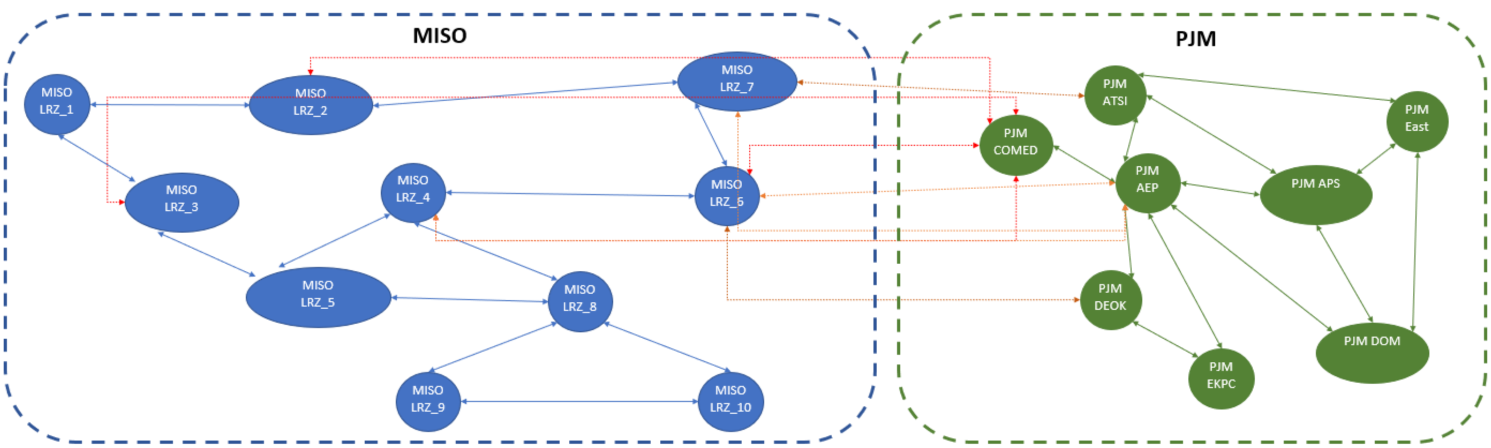
**Table 34: Economic Load Forecast Errors**

| Peak Demand Uncertainty | Probability of Occurrence |
|---|---|
| -2% | 10.4% |
| -1% | 23.3% |
| 0% | 32.6% |
| 1% | 23.3% |
| 2% | 10.4% |

### Model Topology

The Aurora zonal topology was reproduced in SERVM and is visualized below. SERVM operates as a “pipe and bubble” model where transmission constraints between zones are characterized as an interface with transfer capabilities which can change on a month-to-month basis (Figure 33). The MISO and PJM zones were separately co-dispatched and for the reliability assessment and subsequent ELCC analysis no internal constraints were reflected initially. ISO-ISO transfer constraints were reflected in the initial analysis to capture potential seams congestion. A second model run was performed where internal constraints were considered to help guide incremental resource placement, if necessary.

**Figure 33: Model Topology**




### Simulation Results

SERVM was run for all weather years and load forecast errors as defined previously for each portfolio generated via the Aurora capacity expansion process. The years 2025, 2030, and 2035 were sampled to provide snapshots of the reliability disposition of the ISOs over the planning horizon. From SERVM, the LOLE metrics were recorded for each ISO, and then each ISO was simultaneously calibrated to 0.1 LOLE by the addition of perfect capacity or the addition of block load (100% load factor). These additions of capacity or load were reported as “Short” or “Long” positions respectively and were provided to the project team for the purposes of adjusting portfolios if necessary. Deviations from 0.1 LOLE can be expected due to the nature of PRM and ELCC being approximations. As the resource mix evolves from conventional to energy limited and renewable resources, the ELCC values for resources become increasingly complex as resources have synergistic or antagonistic relations and interactive effects which each other. This concept is explored further in the ELCC section of this report.

Table 35 presents the simulation results by case for each scenario. Scenarios with “Join PJM” indicate scenarios where MISO Zone 4 has been moved into the PJM BA, the implications are that rather than being co-dispatched with MISO generation against MISO load, these loads and resources are now co-dispatched with PJM load and generation. Portfolios which were originally found to produce LOLE values above 0.1 LOLE are emphasized. In general, the ISOs are observed to be adequate in 2025, and gravitate to equilibrium as the planning horizon progresses. There are minor deviations (on the order of <3% reserve margin) from the planning target likely due to interactive effects of resources as well as the drift to winter LOLE through the study period particularly for the MISO system. As MISO sees a more aggressive solar and storage buildout than PJM, the composition of winter LOLE increases at a faster rate.  As a function of total capacity in each ISO, the adjustments necessary were not seen as significant which indicates the PRM and ELCC approximations used in Aurora are reasonable.

**Table 35: Reliability Assessments Results**

| Scenario | Region | LOLE as Found | | | Long/(Short) MW | | |
|---|---|---|---|---|---|---|---|
| | | 2025 | 2030 | 2035 | 2025 | 2030 | 2035 |
| A – Status Quo | MISO | 0 | 0.17 | 0.37 | 2,000 | -500 | -5,500 |
| | PJM | 0 | 0.11 | 0.01 | 8,000 | -500 | 6,000 |
| A – Join PJM | MISO | 0 | 0.15 | 0.42 | 3,000 | -500 | -6,500 |
| | PJM | 0 | 0.33 | 0.05 | 10,000 | -3,000 | 4,000 |
| B – Status Quo | MISO | 0.01 | 0.04 | 0.09 | 1,500 | 3,000 | 1,000 |
| | PJM | 0 | 0.12 | 0.05 | 10,500 | -1,000 | 1,500 |
| B – Join PJM | MISO | 0.01 | 0.02 | 0.07 | 3,000 | 4,000 | 2,000 |
| | PJM | 0 | 0.18 | 0.01 | 11,000 | -2,000 | 4,000 |
| C – Status Quo | MISO | 0.03 | 0.17 | 0.29 | 1,500 | -1,600 | -4,000 |
| | PJM | 0 | 0.10 | 0.09 | 8,000 | 0 | 0 |
| C – Join PJM | MISO | 0.03 | 0.06 | 0.20 | 2,000 | 1,000 | -2000 |
| | PJM | 0 | 0.07 | 0.09 | 9,000 | 1,000 | 0 |

## ELCC Modeling Methodology and Results Scenarios A, B, And C

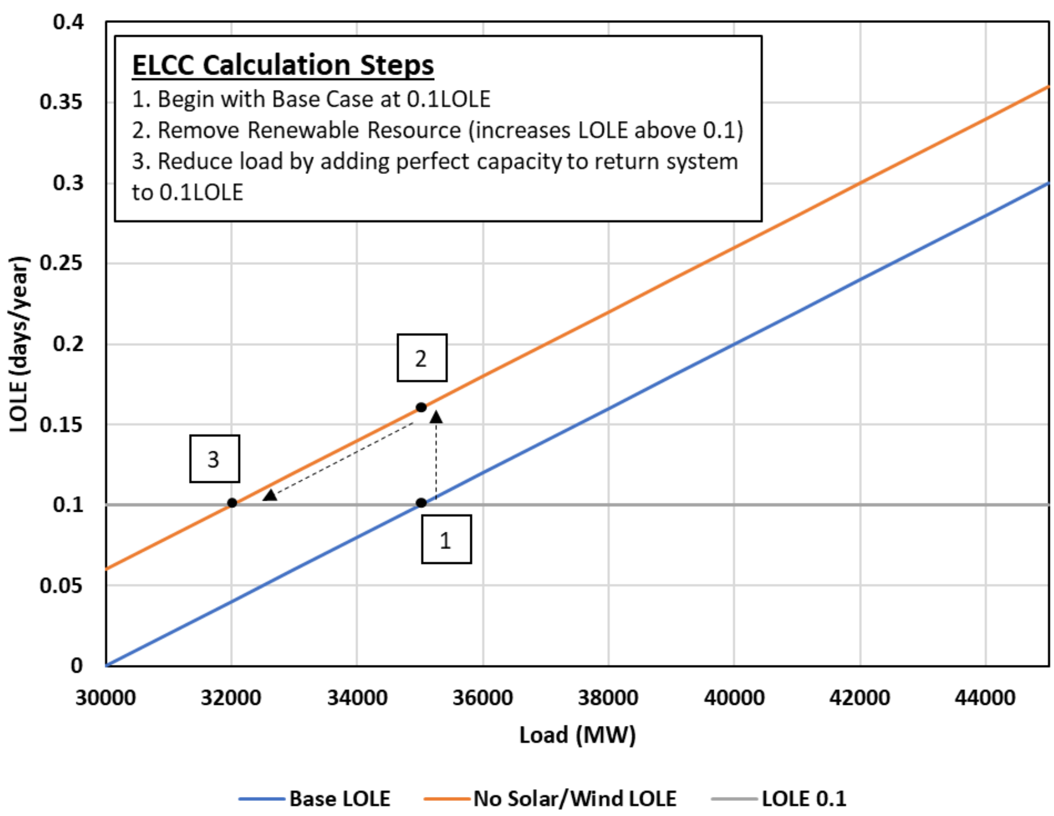
The ELCC of a resource is the capacity value (expressed in MW) associated with the resource’s reliability contribution to the system. The ELCC can also be expressed as a percentage of the calculated capacity value relative to the nameplate capacity value of the resource. Figure 34 illustrates the ELCC calculation process.

The portfolio ELCC values were calculated using the following steps:

1. Begin with a system calibrated to 0.1 LOLE.

2. Remove all resources of the unit category being tested and determine the impact on LOLE (LOLE increases due to the reduction in resources).
3. Add in perfectly available dispatchable resources until 0.1 LOLE is achieved.
4. The MW amount of perfect resources added to the system is equal to the ELCC of the tested resource portfolio.

**Figure 34: ELCC Calculation Process**




This process was repeated by aggregate resource class (i.e., solar, wind, battery, DR) as well as the aggregate energy limited and intermittent portfolio. This was performed to capture all possible synergistic and antagonistic effects between resource classes. The individual resource class ELCCs were adjusted such that the sum of all resource class ELCC was equal to the portfolio ELCC. Table 36 presents the expected synergistic relations between resources. For brevity, storage and DR are described as “ELR” or energy limited resources. The first three rows describe the diminishing returns by penetration of these resource classes (ELCC goes down with penetration). For the following three rows, increasing solar penetration likely has the effect of raising wind or ELR ELCC by narrowing peak demand hours into the late evening, allowing these resources to carry more load. There is not typically a significant relationship between wind and energy limited resources in terms of synergistic effects.

**Table 36: Expected Synergistic and Antagonistic Relations**

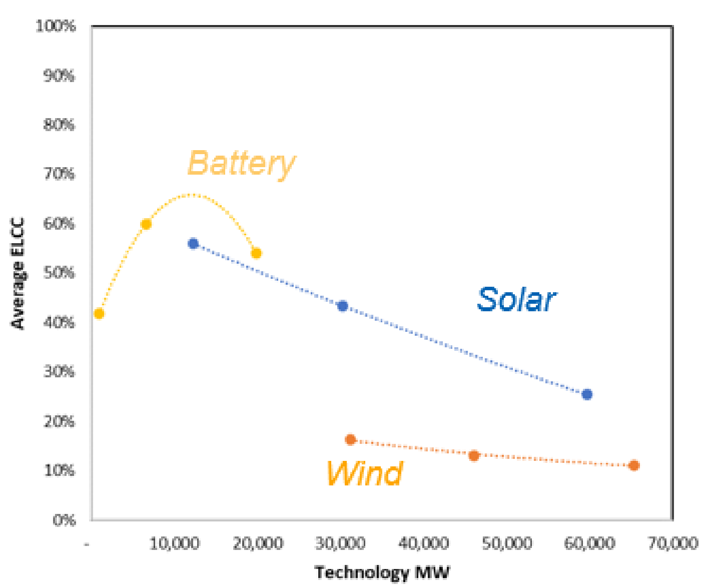
| Resource | Resource | Synergistic Effect |
|---|---|---|
| Solar | Solar | ↓ |
| Wind | Wind | ↓ |
| ELR | ELR | ↓ |
| Solar | Wind | ↑ |
| Solar | ELR | ↑ |
| Wind | ELR | ↑ / ↓ |

The ELCC analysis focused on Scenario A, and similar to the resource adequacy analysis focused on the years 2025, 2030, and 2035. The results of which are provided below by ISO. Table 37 provides the resulting MISO Summer ELCC values by resource. Figure 35 illustrated the MISO Summer average ELCC values by installed capacity.

**Table 37: MISO Summer ELCC Results by Resource**

| Summer ELCC | 2025 | 2030 | 2035 |
|---|---|---|---|
| Solar | 56% | 43% | 25% |
| Wind | 16% | 13% | 11% |
| DR | 42% | 65% | 41% |
| Battery | 42% | 60% | 54% |
| DR and Battery | 42% | 63% | 49% |

**Figure 35: MISO Summer average ELCC Results by Installed Capacity**



As MISO DR was modeled as a 4-hour product, and incremental batteries were modeled as a 4 hour product, the results for these resource classes are aggregated as their performance on critical summer days will be identical. This class of resources sees a noticeable synergistic effect by penetration that increases average ELCC at first before incremental penetration ultimately decreases the ELCC. Solar and wind see monotonically decreasing values.

Table 38 provides the resulting MISO Winter ELCC values by resource. Battery ELCC is raised slightly, as there is less penetration from DR given the availability assumptions utilized. However similar dynamics are seen where an initial increase in ELCC is offset by penetration. Figure 36 illustrated the MISO winter average ELCC values by installed capacity.

**Table 38: MISO Winter ELCC Results by Resource**

| Winter ELCC | 2025 | 2030 | 2035 |
|---|---|---|---|
| Solar | 7% | 7% | 7% |
| Wind | 39% | 31% | 28% |
| DR | 0% | 0% | 0% |
| Battery | 67% | 77% | 38% |

**Figure 36: MISO Winter average ELCC Results by Installed Capacity**

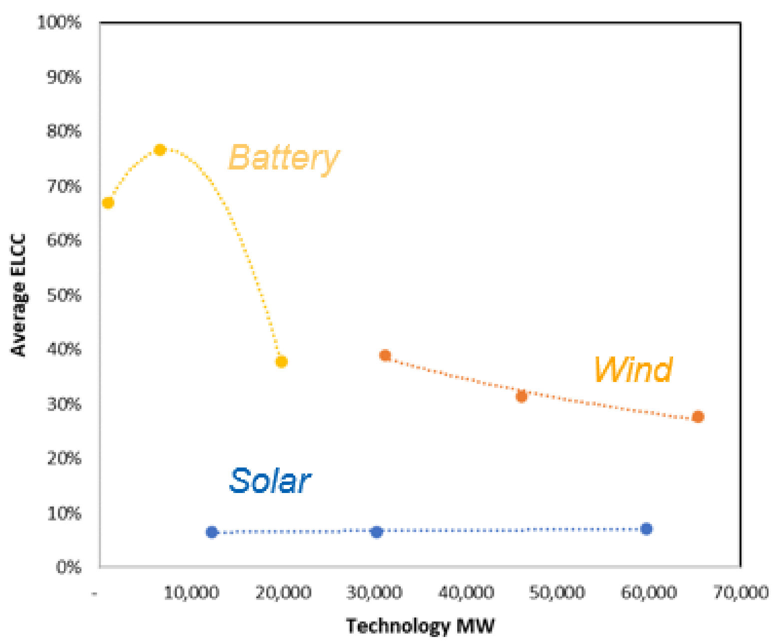
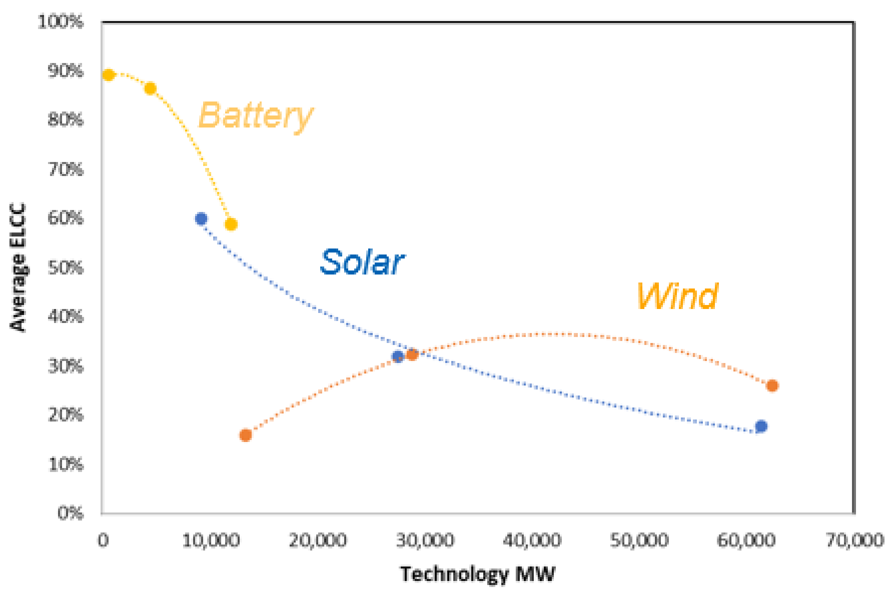



Table 39 provides the resulting PJM ELCC values by resource. PJM results are provided on an annual basis. DR sees significantly higher value due to the 12-hour duration. DR and Battery results are not aggregated as the durations for each product differ. The results of the wind ELCC are complicated by the shift to winter LOLE which generally raises the wind ELCC (note the MISO Wind ELCC in winter compared to summer), an increasing penetration of offshore wind which is expected to raise the wind fleet ELCC from higher annual production and finally the synergistic increase to wind reliability from solar penetration. Figure 37 illustrated the PJM average ELCC values by installed capacity.

**Table 39: PJM ELCC Results by Resource**

| ELCC | 2025 | 2030 | 2035 |
|---|---|---|---|
| Solar | 60% | 32% | 18% |
| Wind | 16% | 32% | 26% |
| DR | 100% | 100% | 74% |
| Battery | 89% | 86% | 59% |

**Figure 37: PJM ELCC Results by Installed Capacity**



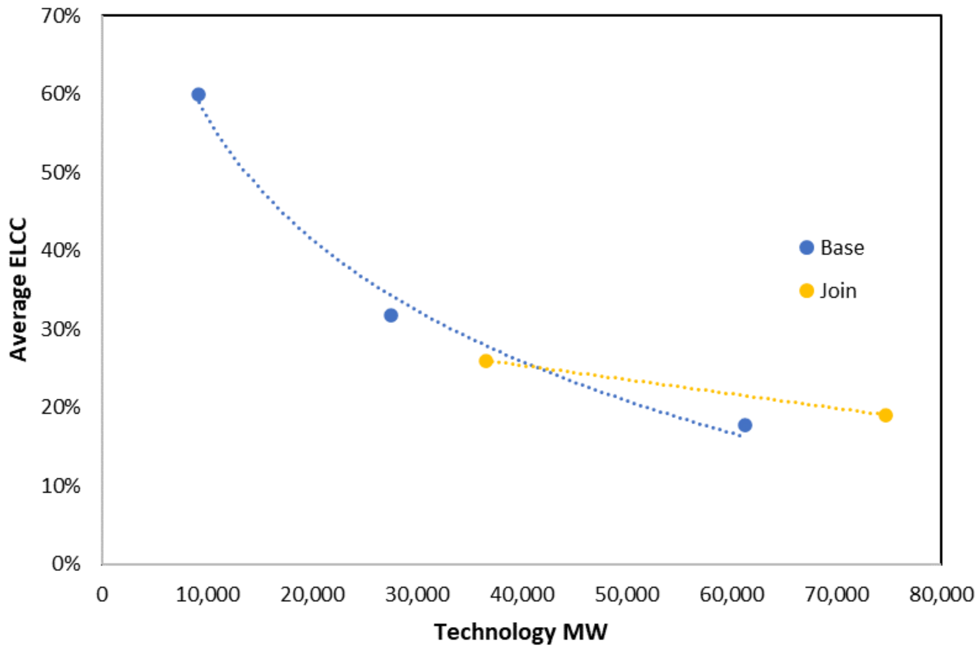

ELCC analysis was also performed for the "Scenario A – Join PJM" to understand how changes to the load and resource balance of the PJM system could impact ELCC results. Simulations were performed and results compiled for the 2030 and 2035 study years. Table 40 summarizes PJM ELCC Results for the Join PJM case for Scenario A.

**Table 40: PJM ELCC Results for Join PJM Case**

| ELCC | 2025 | 2030 | 2035 |
|---|---|---|---|
| Solar | | 26% | 19% |
| Wind | | 24% | 26% |
| DR | | 97% | 66% |
| Battery | | 90% | 47% |

A key difference in the Status Quo and Join PJM systems is the penetration of resources. Solar exhibits an increase by ~14 GW, Wind increases by ~8 GW while battery exhibits a modest decline. Notably, Figure 38 shows the comparison of the solar ELCC curves between the Status Quo and Join PJM cases. Notably, the ELCC curve is elevated slightly compared to the base case. This suggests the inclusion of most westward located solar resources have a positive impact on reliability. This is likely driven by longitudinal considerations and solar output during system peak conditions: solar resources further west will have more coincident output with load.

**Figure 38: Solar ELCC Curves between Status Quo and Join PJM Cases**



# Appendix E: Initiating Order Docket 22 -0485

A copy of the original initiating order for the AIC RTO Cost Benefit Study is included below:

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

| | | |
|---|---|---|
| Illinois Commerce Commission<br>On Its Own Motion | : | |
| -vs- | : | 22--0485 |
| Ameren Illinois Company<br>d/b/a Ameren Illinois | : | |
| Cost/benefit analysis of the utility's membership in MISO or another RTO | : | |

ORDER

By the Commission:

Ameren Illinois Company d/b/a Ameren Illinois is a transmission-owning member of the Midcontinent Independent System Operator (MISO), a regional transmission organization (RTO) that manages the electricity transmission system in 15 states and one Canadian province. In a Staff Report dated July 11, 2022, the Commission's Public Utilities Bureau recommends that an analysis be made of the relative costs and benefits of Ameren's continued membership in MISO compared to the costs and benefits of the company's membership in a different RTO.

To place this question in its proper context, the Staff Report provides a summary of the development of competitive electric markets in Illinois. In December 1997, the General Assembly enacted the Electric Service Customer Choice and Rate Relief Law of 1997, significantly restructuring the state's industry and providing a transition to competitive retail electricity markets. The new law initiated the concept of delivery services and required Illinois utilities to provide to their customers open access to delivery services on a phased-in basis. In enacting the new law, the legislature recognized that certain components of delivery service could be subject to FERC jurisdiction. Accordingly, the legislature added Section 16-108 to Public Utilities Act (the Act). Section 16-108 states in relevant part:

> An electric utility shall provide the components of delivery services that are subject to the jurisdiction of the Federal Energy Regulatory Commission at the same prices, terms and conditions set forth in its applicable tariff as approved or allowed into effect by … [FERC]. The [ICC] shall otherwise have the authority pursuant to Article IX to review, approve, and modify the

> prices, terms and conditions of those components of delivery services not subject to the jurisdiction of [FERC]. (220 ILCS 5/16-108(a).)

Furthermore, Section 16-101A(d) of the Act provides:

> The Illinois Commerce Commission should act to promote the development of an effectively competitive electricity market that operates efficiently and is equitable to all consumers.

Consistent with that mandate, the Commission continues to be actively engaged at the FERC, working to ensure that the components of delivery service over which the FERC has regulatory authority are provided at rates, terms, and conditions that are appropriate for the state's retail direct access program. Similarly, the Commission has been advocating transparent wholesale electricity markets, because transparent wholesale markets are key for the state's open access retail program to provide greater benefits to customers.

In addition to opening Illinois energy markets to competition, the 1997 legislation added Section 16-126, to the Act, requiring that certain Illinois electric utilities owning or controlling transmission facilities or providing transmission services in the state become members of a regional transmission organization approved by FERC. Section 16-126.1 of the Act, added to the Rate Relief Law in 2007, allowed large electric utilities such as Ameren to choose which RTO they wished to belong to. Section 16-126.1 provides as follows:

> The State shall not directly or indirectly prohibit an electric utility that on December 31, 2005 provided electric service to at least 100,000 customers in Illinois from membership in a Federal Energy Regulatory Commission approved regional transmission organization of its choosing. Nothing in this Section limits any authority the [Illinois Commerce] Commission otherwise has to regulate that electric utility. This Section ceases to be effective on July 1, 2022 unless extended by the General Assembly by law. 220 ILCS 5/16-126.1.

The General Assembly has not extended the life of Section 16-126.1. The statutory restriction on state oversight of RTO membership thus ended on July 1, 2022, and the question of Ameren's continued membership in MISO is now within the Commission's jurisdiction.

As noted in the Staff Report, MISO is situated almost entirely in states having non-competitive electric markets, and the utilities serving those customers remain vertically integrated, combining functions and resources for the generation, transmission, and distribution of electric power and energy. Whether MISO is a good fit for Ameren, a non-vertically integrated utility that serves a competitive market in Illinois, warrants consideration.

MISO was established in 1998. As a regional transmission organization, MISO performs numerous functions, including transmission planning, reliability coordination, and the operation of centralized wholesale electricity markets where market participants can buy and sell various energy products, including capacity. Ameren is a transmission-owning member of MISO. Ameren serves as Balancing Authority in Zone 4 of MISO and, as a Load Serving Entity (LSE), participates in MISO's energy, capacity, and ancillary service markets.

MISO defines resource adequacy as "ensuring that [LSEs] serving Load in the MISO Region have sufficient Planning Resources to meet their anticipated peak demand requirements plus an appropriate reserve margin (Planning Reserve Margin Requirement or PRMR)." Each year, MISO calculates and assigns each LSE within MISO a share of the PRMR.

As the Staff Report explains, MISO provides LSEs with three options to meet their resource adequacy capacity obligation. First, an LSE can demonstrate achievement of its assigned PRMR through the submission of a fixed resource adequacy plan (FRAP). These plans may include such resources as owned generators and bilateral purchase contracts with generating companies either inside or outside of the LSE's local resource zone. Second, LSEs can use a "self-supply" option, in which the LSE offers into MISO's annual PRA supply resources that are owned by, or committed to, the LSE. Third, an LSE can procure capacity through MISO's voluntary annual Planning Resource Auction (PRA). The amount of capacity committed through these three options determines whether sufficient Planning Resources exist to meet the PRMR for the entire MISO region.

The Staff Report recounts that MISO released its most recent PRA results for the June 1, 2022, through May 31, 2023, delivery year on April 14, 2022. In its auction report summary, MISO reported that "capacity offers fell 1,230 MW short of the PRMR in the MISO North/Central zones" and that these capacity shortfalls expose nearly 8 GWs of load in MISO's North/Central region to an auction clearing price of $236.66 MW/Day. In an accompanying press release, MISO's president and chief operating officer stated, "The reality for the zones that do not have sufficient generation to cover their load plus their required reserves is that they will have increased risk of temporary, controlled outages to maintain system reliability." MISO released additional information regarding its PRA results on May 25, 2022. At that time, MISO reported that while its PRMR is designed so that the probability of loss of load is no more than 0.1 days per year, the insufficient resources available to meet resource adequacy requirements seen in the most recent PRA results for the period of June 2022 through May 2023 showed a risk of loss of load of 0.179 days per year.

The Staff Report observes that, apart from a portion of Michigan, Illinois is the only competitive retail state in MISO. The rest of MISO is made up of LSEs that are vertically integrated, and most practice integrated resource planning. Moreover, MISO's PRA is voluntary and not intended to incentivize the development of capacity resources necessary to ensure resource adequacy. Rather, as MISO notes on its Resource Adequacy homepage, the MISO "Resource Adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy." In the case of Illinois, this means that MISO's Resource Adequacy construct must complement the state's reliance on competitive wholesale markets to discipline retail electricity prices. Given the most recent MISO PRA results and the regulatory structure of its membership, it is not clear that MISO's Resource Adequacy construct accomplishes this goal.

As noted earlier, Section 16-126.1 of the Act no longer commits an electric utility's choice of membership in a regional transmission to the utility. Given this change in law and the results of MISO's most recent PRA, the Staff Report concludes that it is appropriate to reexamine the costs and benefits of Ameren's membership in MISO and its participation in MISO markets, as opposed to the costs and benefits of membership in another regional transmission organization. This analysis will provide better information regarding whether membership in MISO continues to serve the interests of Ameren's electricity customers.

The State Report thus recommends that the Commission direct Ameren to analyze and report on the benefits and costs of continued participation in MISO (Report). In particular, Ameren should perform an analysis of the benefits and costs of participation in MISO, including consideration of the relative net benefits of participation in MISO versus participation in PJM, another regional transmission organization. The study should examine a period of no less than five and no more than 10 years from the period beginning June 1, 2024. The study should examine the costs and benefits to ratepayers, including, but not limited to, consideration of reliability, resource adequacy, resiliency, affordability, equity, the impact on the environment, and the general health, safety, and welfare of the people of the State of Illinois.

The Staff Report further recommends that Ameren should identify the analyses it believes are necessary and appropriate regarding participation in MISO. Ameren should advise and update MISO and PJM regarding that actual analysis. Because Ameren shall ultimately have responsibility for the study and will shoulder the burden of presenting it, Ameren should be entitled to maintain a level of independence and control of this study.

Finally, the Staff Report recommends that the Commission order Ameren to file its Report on a schedule developed by Ameren in consultation with Commission Staff, but in no event to exceed 12 months. The Staff Report also recommends that stakeholders be allowed a 30-day period, after the filing of the Report, to provide comments on the Report.

The Commission accepts the recommendations of the Staff Report and the suggestions and proposals made therein regarding the nature, scope, and extent of the recommended analysis and study of Ameren's continued membership in MISO.

The Commission, being fully advised in the premises, is of the opinion and finds that:

(1) the Commission has jurisdiction over the subject matter of this proceeding;

(2) Ameren Illinois Company d/b/a Ameren Illinois is an electric utility subject to the jurisdiction of the Commission;

(3) Ameren Illinois Company d/b/a Ameren Illinois should be made respondent to this proceeding;

(4) the recitals of fact set forth in the prefatory portion of this Order are supported by the record and should be adopted as findings of fact; and

(5) the Staff Report dated July 11, 2022, should be filed in this docket and made a part of the record of this proceeding.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that Ameren Illinois Company d/b/a Ameren Illinois be directed to conduct an analysis and study of its continued membership in MISO consistent with the recommendations contained in the Staff Report dated July 11, 2022.

IT IS FURTHER ORDERED that Ameren Illinois Company d/b/a Ameren Illinois be made respondent to this proceeding.

IT IS FURTHER ORDERED that the Staff Report dated July 11, 2022, be made a part of the record of this proceeding.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 21st day of July, 2022.

(SIGNED) CARRIE ZALEWSKI

Chairman