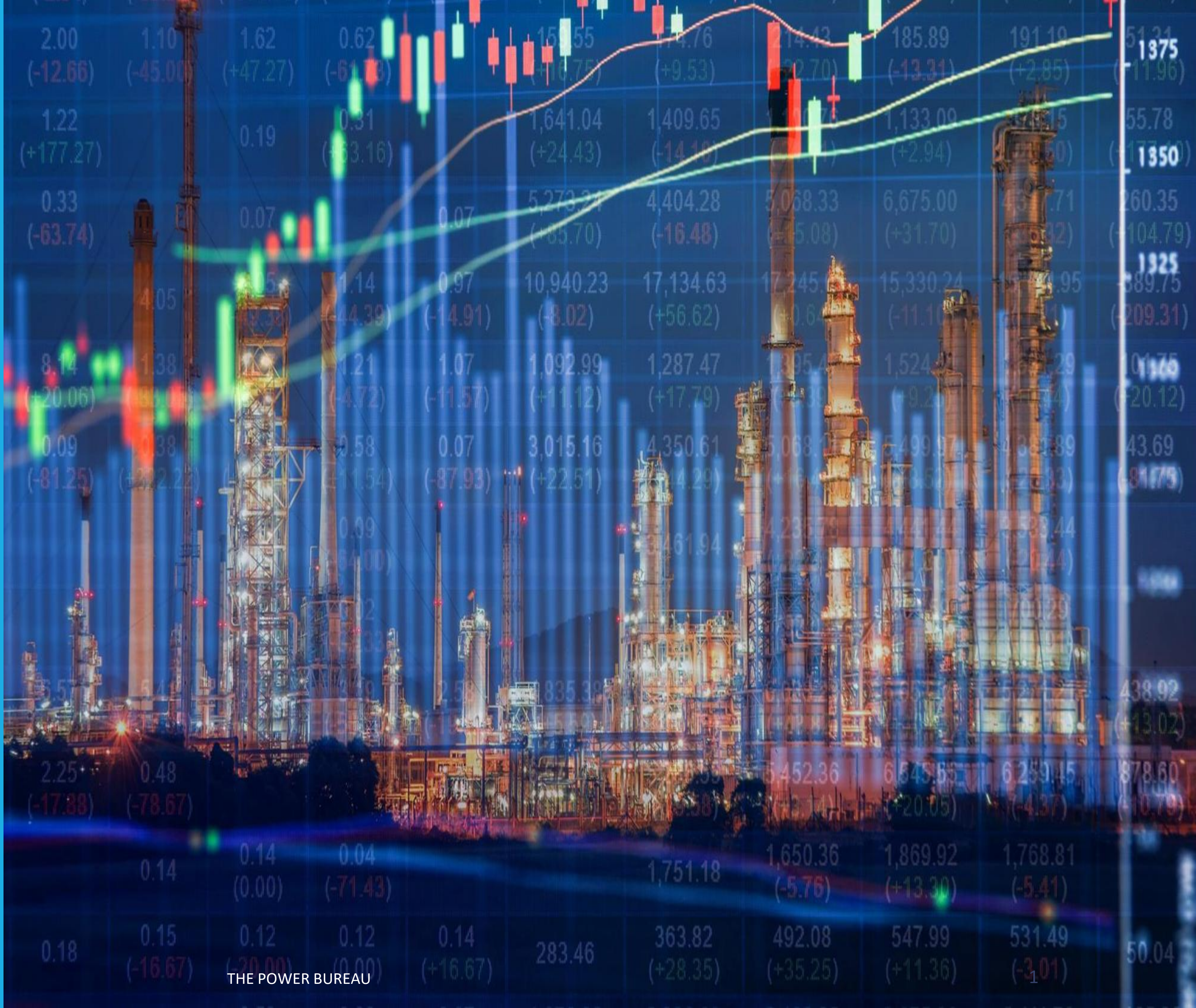
# Update to Industry Supplement to Illinois Policy Study

Update Briefing

The Power Bureau

September 2025



OVERVIEW

# Energy Storage Solution for Illinois' Energy Markets

## Current Energy Market Condition

- Rising Capacity Prices
    - ComEd ($1.6 billion in 2025/26, 2.1 billion in 2026/27))
    - Ameren Illinois ($1.3 billion in 2025/26)
- Falling Reliability
    - PJM (~800 MW of excess capacity in last auction)
    - MISO (~400 MW of excess capacity in last auction)

## Energy Storage Solution

- Cost and Benefits
    - Direct Consumer Cost – Charges that will appear on consumers' bills
        - Total Capital Costs Supported by Consumers: $ 9.8 billion
        - Energy and Capacity Sales Revenue: $10.2 billion
        - ~$0.55/month charge in year 1 eventually converting to a credit
    - Net Consumer Cost – Benefits of price suppression resulting from delivering more capacity to the PJM and MISO markets
        - Minimum consumer benefits of ~$6-$9/month
        - $34 billion in net consumer credits over 20 year of term

BRIEFING

**Capacity Market Developments**

Consumer Impact

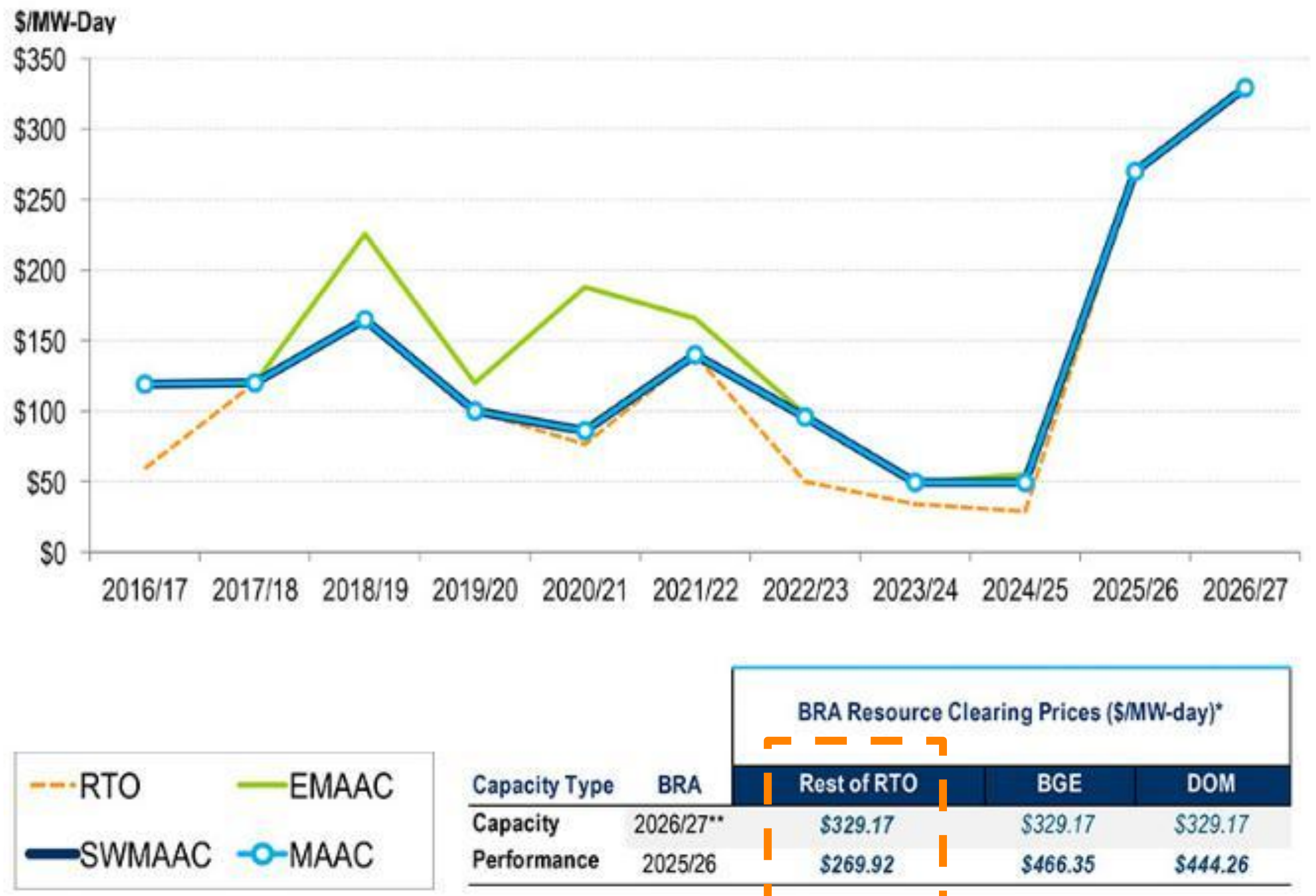
Impact of Increasing Capacity Resources

Modeling Assumptions

Modeled Monthly Billing Impact

Confirmation of Capacity Addition Impact

# PJM: Capacity Prices for 2026/27 will increase by 20% on top of the 933% increase in 2025/26




| | | BRA Resource Clearing Prices ($/MW-day)* | | |
|---|---|---|---|---|
| Capacity Type | BRA | Rest of RTO | BGE | DOM |
| Capacity | 2026/27** | $329.17 | $329.17 | $329.17 |
| Performance | 2025/26 | $269.92 | $466.35 | $444.26 |

PJM projects that a $388.57/MW-Day Capacity price would have resulted if the short-term price cap had not been in effect

# PJM: Capacity currently meets Reliability Requirements

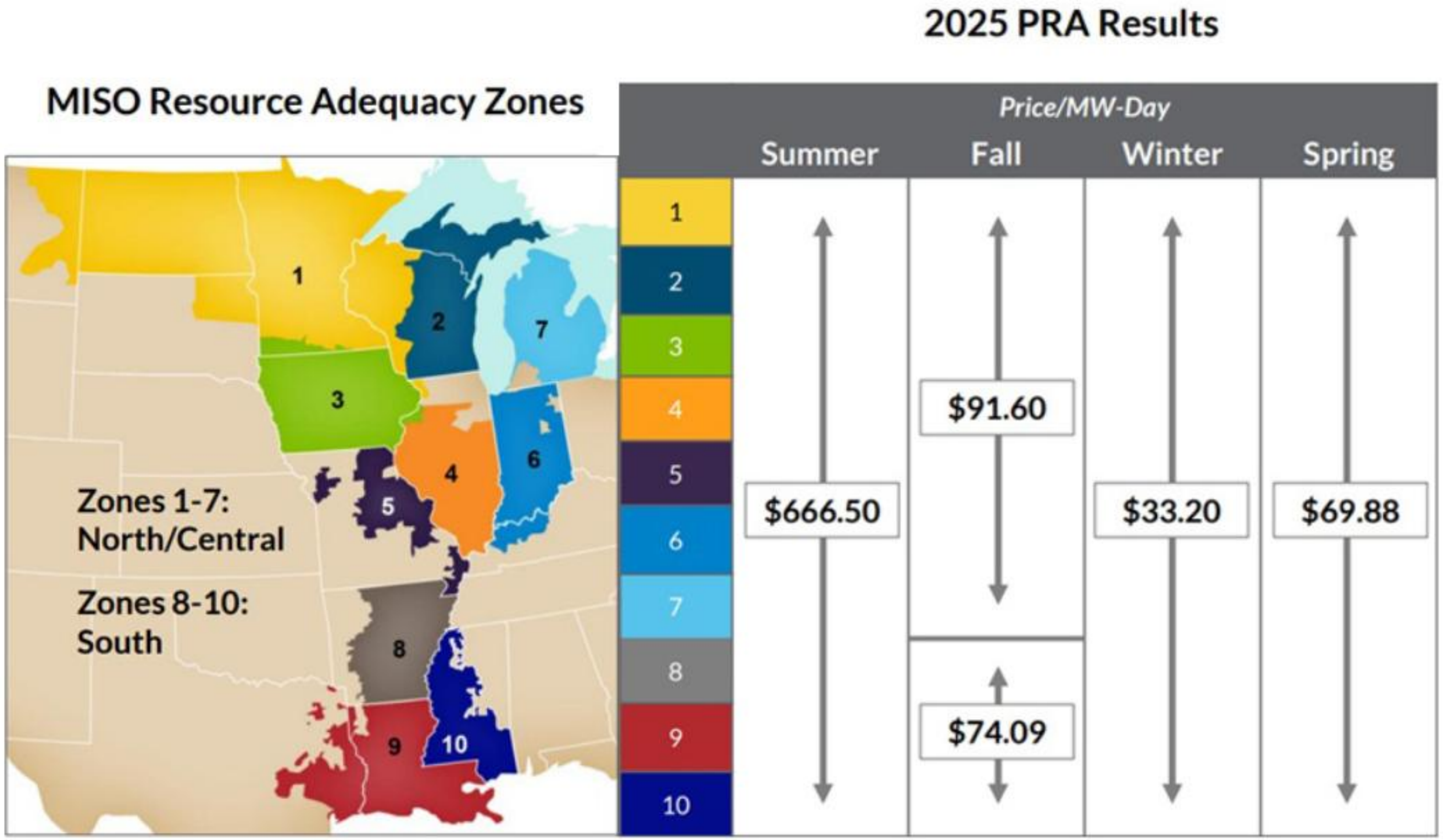
**Table 5.** Capacity Resource Offered and Cleared by Type by Delivery Year (UCAP)

| Auction Results (UCAP) | Delivery Year | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016/17 | 2017/18 | 2018/19 | 2019/20 | 2020/21* | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26** | 2026/27*** |
| Generation | 168,716.0 | 166,204.8 | 166,909.6 | 172,071.2 | 171,262.3 | 171,663.2 | 152,128.6 | 141,026.7 | 138,799.3 | 129,607.5 | 129,661.2 |
| DR | 14,507.2 | 11,293.7 | 11,675.5 | 11,818.0 | 9,846.7 | 11,886.8 | 10,513.0 | 10,116.7 | 10,146.4 | 6,084.8 | 5,530.6 |
| **Total GEN/DR Offered** | **183,223.2** | **177,498.5** | **178,585.1** | **183,889.2** | **181,109.0** | **183,550.0** | **162,641.6** | **151,143.4** | **148,945.7** | **135,692.3** | **135,191.8** |
| EE | 1,156.8 | 1,340.0 | 1,306.1 | 1,650.3 | 2,242.5 | 2,954.8 | 5,056.8 | 5,471.1 | 8,417.0 | 1,459.8 | 0.0 |
| | | | | | | | | | | | |
| Generation | 155,634.3 | 154,690.0 | 154,506.0 | 155,442.8 | 155,976.5 | 150,385.0 | 131,541.6 | 131,777.4 | 132,423.1 | 128,607.5 | 128,845.5 |
| DR | 12,408.1 | 10,974.8 | 11,084.4 | 10,348.0 | 7,820.4 | 11,125.8 | 8,811.9 | 8,096.2 | 7,992.7 | 6,064.7 | 5,530.6 |
| **Total GEN/DR Cleared** | **168,042.4** | **165,664.8** | **165,590.4** | **165,790.8** | **163,796.9** | **161,510.8** | **140,353.5** | **139,873.6** | **140,415.8** | **134,672.2** | **134,376.1** |
| EE | 1,117.3 | 1,338.9 | 1,246.5 | 1,515.1 | 1,710.2 | 2,832.0 | 4,810.6 | 5,471.1 | 7,668.7 | 1,459.8 | 0.0 |
| Uncleared GEN/DR | 15,180.8 | 11,833.7 | 12,994.7 | 18,098.4 | 17,312.1 | 22,039.2 | 22,288.1 | 11,269.8 | 8,529.9 | 1,020.1 | 815.7 |

*Note: RTO numbers include all LDAs. UCAP calculated using ELCC values for Generation Resources. DR and EE UCAP values include appropriate DR AUCAP Factor and FPR. *Starting 2020/2021: Generation, DR and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers. **Marginal ELCC accreditation implemented for all Generation Capacity Resources and Demand Resources. ***EE Eliminated.*

Only 815.7 MW of excess capacity means that future load growth cannot be supported with today's level of reliability

# MISO Capacity Auction (10x increase year-over-year)



# MISO North Regions only meet Capacity needs by importing from MISO South

## Summer 2025 PRA Results by Zone

| | Z1 | Z2 | Z3 | Z4 | Z5 | Z6 | Z7 | Z8 | Z9 | Z10 | ERZ | North | South | System |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Initial PRMR | 18,459.4 | 13,190.2 | 10,889.2 | 9,237.6 | 8,281.3 | 18,484.8 | 21,228.0 | 8,487.8 | 21,812.2 | 5,142.9 | N/A | 99,770.5 | 35,442.9 | 135,213.4 |
| Final PRMR | 18,843.5 | 13,464.4 | 11,116.0 | 9,430.10 | 8,453.5 | 18,868.9 | 21,669.2 | 8,552.6 | 21,978.8 | 5,182.3 | N/A | 101,845.6 | 35,713.7 | 137,559.3 |
| Offer Submitted (Including FRAP) | 19,732.4 | 14,569.7 | 11,321.4 | 9,328.1 | 6,737.9 | 16,123.6 | 20,883.9 | 11,517.3 | 20,498.6 | 5,543.3 | 1580.1 | 99,952.6 | 37,883.7 | 137,836.3 |
| FRAP | 4,619.2 | 10,252.6 | 456.9 | 789.4 | 0.0 | 1,080.7 | 541.3 | 494.9 | 157.5 | 1,507.7 | 46.8 | 17,779.2 | 2,167.8 | 19,947.0 |
| RBDC Opt-Out | - | - | - | - | - | - | - | - | - | - | - | 0.0 | 0.0 | 0.0 |
| Self Scheduled (SS) | 4,985.3 | 3,344.1 | 10,450.2 | 7,677.2 | 6,647.8 | 11,080.3 | 20,305.5 | 10,260.6 | 17,870.6 | 3,831.3 | 1,358.8 | 65,567.6 | 32,244.1 | 97,811.7 |
| Non-SS Offer Cleared | 10,127.9 | 973.0 | 414.3 | 861.5 | 90.1 | 3,962.6 | 37.1 | 761.8 | 2,193.5 | 204.3 | 174.5 | 16,605.8 | 3,194.8 | 19,800.6 |
| Committed (Offer Cleared + FRAP) | 19,732.4 | 14,569.7 | 11,321.4 | 9,328.1 | 6,737.9 | 16,123.6 | 20,883.9 | 11,517.3 | 20,221.6 | 5,543.3 | 1,580.1 | 99,952.6 | 37,606.7 | 137,559.3 |
| LCR | 15,696.9 | 9,719.3 | 8,049.3 | 2,577.8 | 6,071.1 | 13,051.7 | 19,681.4 | 8,487.0 | 19,615.0 | 2,523.8 | - | N/A | N/A | N/A |
| CIL | 6,025 | 4,370 | 5,555 | 8,525 | 4,117 | 8,651 | 3,569 | 2,568 | 4,361 | 4,474 | - | N/A | N/A | N/A |
| ZIA | 6,023 | 4,370 | 5,460 | 7,757 | 4,117 | 8,366 | 3,569 | 2,358 | 4,361 | 4,474 | - | N/A | N/A | N/A |
| Import | 0.0 | 0.0 | 0.0 | 101.7 | 1,715.5 | 2,745.5 | 785.5 | 0.0 | 1,757.1 | 0.0 | - | 1,893.0 | 0.0 | 1,580.1 |
| CEL | 3,991 | 4,614 | 4,618 | 4,584 | 3,939 | 6,881 | 5,726 | 6,299 | 4,286 | 2,097 | - | N/A | N/A | N/A |
| Export | 888.8 | 1105.2 | 205.5 | 0.0 | 0.0 | 0.0 | 0.0 | 2964.7 | 0.0 | 360.9 | 1,580.1 | 0.0 | 1,893.0 | - |
| ACP ($/MW-Day) | 666.50 | 666.50 | 666.50 | 666.50 | 666.50 | 666.50 | 666.50 | 666.50 | 666.50 | 666.50 | 666.50 | | | N/A |

**Capacity Needed**

**Capacity Offered**

**Capacity Imports to MISO North**

**Capacity Exports from MISO South**

Only 277 MW of excess capacity means that future load growth cannot be supported with today's level of reliability

# Consumer Impact: PJM Capacity Costs Directly Impact ComEd Consumers

| Commonwealth Edison | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | PJM Capacity Price and Adjustments | | | | | | |
| Customer Delivery Classes | Average PLC[1] (kW) | Number of Days in a Year | Auction Clearing Price ($/MW-Day) | Obligation Peak Load Scaling Factor | Base Zonal RPM Scaling Factor | Adjusted Capacity Rate ($/MW-Day) | Annual Capacity Cost | Average Monthly Capacity Cost | Increase over 2024-2025 |
| | A | B | C | D | E | F=C*D*E | G=(A*B*F)/ 1000 | H=G/12 | |
| **2024-2025** | | | | | | | | | |
| Residential Single Family Without Electric Space Heat Delivery Class | 3.30 | 365 | $28.92 | 1.1168 | 1.0913 | $35.25 | $42.42 | $3.54 | **0.0%** |
| Residential Multi Family Without Electric Space Heat Delivery Class | 1.29 | 365 | $28.92 | 1.1168 | 1.0913 | $35.25 | $16.65 | $1.39 | |
| Residential Single Family With Electric Space Heat Delivery Class | 3.24 | 365 | $28.92 | 1.1168 | 1.0913 | $35.25 | $41.70 | $3.47 | |
| Residential Multi Family With Electric Space Heat Delivery Class | 1.33 | 365 | $28.92 | 1.1168 | 1.0913 | $35.25 | $17.10 | $1.43 | |
| **AVERAGE** | **2.29** | **365.00** | **$28.92** | **1.1168** | **1.0913** | **$35.25** | **$29.47** | **$2.46** | |
| **2025-2026** | | | | | | | | | |
| Residential Single Family Without Electric Space Heat Delivery Class | 3.30 | 365 | $269.92 | 1.0159 | 1.0223 | $280.33 | $337.41 | $28.12 | **695.3%** |
| Residential Multi Family Without Electric Space Heat Delivery Class | 1.29 | 365 | $269.92 | 1.0159 | 1.0223 | $280.33 | $132.42 | $11.04 | |
| Residential Single Family With Electric Space Heat Delivery Class | 3.24 | 365 | $269.92 | 1.0159 | 1.0223 | $280.33 | $331.65 | $27.64 | |
| Residential Multi Family With Electric Space Heat Delivery Class | 1.33 | 365 | $269.92 | 1.0159 | 1.0223 | $280.33 | $136.03 | $11.34 | |
| **AVERAGE** | **2.29** | **365.00** | **$269.92** | **1.0159** | **1.0223** | **$280.33** | **$234.38** | **$19.53** | |
| **2026-2027** | | | | | | | | | |
| Residential Single Family Without Electric Space Heat Delivery Class | 3.30 | 365 | $329.17 | 1.0159 | 1.0223 | $341.86 | $411.47 | $34.29 | **869.9%** |
| Residential Multi Family Without Electric Space Heat Delivery Class | 1.29 | 365 | $329.17 | 1.0159 | 1.0223 | $341.86 | $161.49 | $13.46 | |
| Residential Single Family With Electric Space Heat Delivery Class | 3.24 | 365 | $329.17 | 1.0159 | 1.0223 | $341.86 | $404.45 | $33.70 | |
| Residential Multi Family With Electric Space Heat Delivery Class | 1.33 | 365 | $329.17 | 1.0159 | 1.0223 | $341.86 | $165.89 | $13.82 | |
| **AVERAGE** | **2.29** | **365.00** | **$329.17** | **1.0159** | **1.0223** | **$341.86** | **$285.82** | **$23.82** | |

[1] **Average PLC = Average Peak Demand for customer class between June and September 2018-2024 (ComEd)**

Cost Increase (2025/26 over 2024/25): $1.6 billion
Cost Increase (2026/27 over 2024/25): $2.1 billion

# Consumer Impact: MISO Capacity Costs Directly Impact Ameren Illinois Consumers

| Ameren Illinois | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Customer Delivery Classes** | **Season** | **Average PLC (kW)** | **Number of Days in a Sesaon** | **Auction Clearing Price ($/MW-Day)** | **Period Capacity Cost** | **Average Monthly Capacity Cost** | **Increase over 2024-2025** |
| | | **A** | **B** | **C** | **D=(A*B*C)/1000** | **E=D/Months** | |
| **2024-2025** | | | | | | | |
| Residential Single Family, No Space Heat (DS-1) | Summer | 3.30 | 92 | $30.00 | $8.95 | $2.98 | |
| | Fall | 1.72 | 91 | $15.00 | $8.03 | $2.68 | |
| | Winter | 1.65 | 90 | $0.75 | $0.50 | $0.17 | |
| | Spring | 3.03 | 92 | $34.10 | $12.52 | $4.17 | |
| | **Annual** | **2.42** | **365** | **$16.03** | **$30.00** | **$2.50** | |
| **2025-2026** | | | | | | | |
| Residential Single Family, No Space Heat (DS-1) | Summer | 3.30 | 92 | $666.50 | $198.75 | $66.25 | |
| | Fall | 1.72 | 91 | $91.60 | $49.06 | $16.35 | |
| | Winter | 1.65 | 90 | $33.20 | $22.08 | $7.36 | |
| | Spring | 3.03 | 92 | $69.88 | $25.67 | $8.56 | |
| | **Annual** | **2.42** | **365** | **$157.93** | **$295.56** | **$24.63** | |
| **Variance** | | | | | | | |
| Residential Single Family, No Space Heat (DS-1) | Summer | 3.30 | 92 | $636.50 | $189.80 | $63.27 | |
| | Fall | 1.72 | 91 | $76.60 | $41.03 | $13.68 | |
| | Winter | 1.65 | 90 | $32.45 | $21.58 | $7.19 | **885.1%** |
| | Spring | 3.03 | 92 | $35.78 | $13.14 | $4.38 | |
| | **Annual** | **2.42** | **365** | **$141.90** | **$265.55** | **$22.13** | |

Cost Increase (2025/26 over 2024/25): $1.3 billion

# Capacity Prices are Set by Auction

BRIEFING

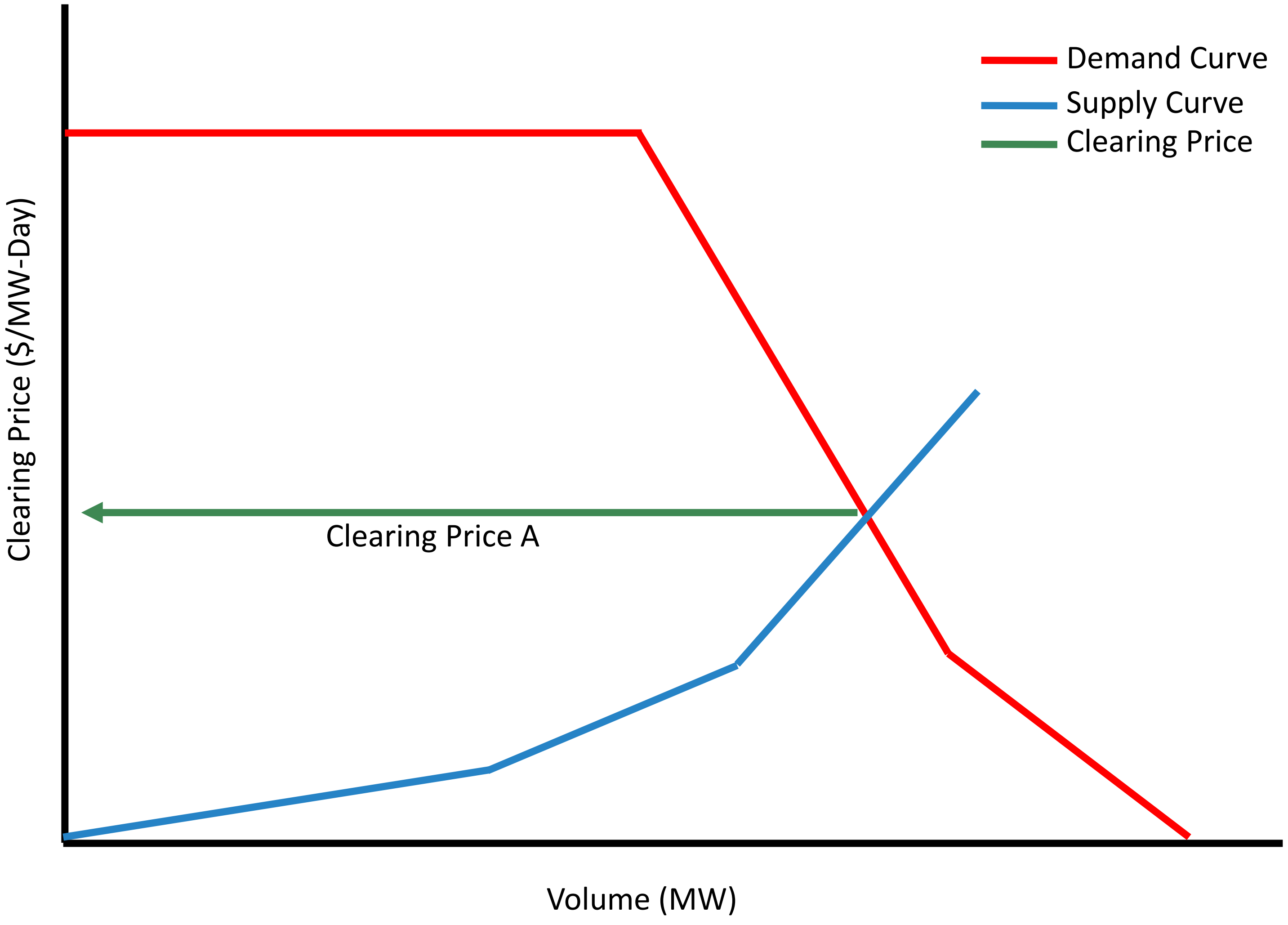
Capacity Market Developments

Consumer Impact

**Impact of Increasing Capacity Resources**

Modeling Assumptions

Modeled Monthly Billing Impact



BRIEFING

Capacity Market Developments

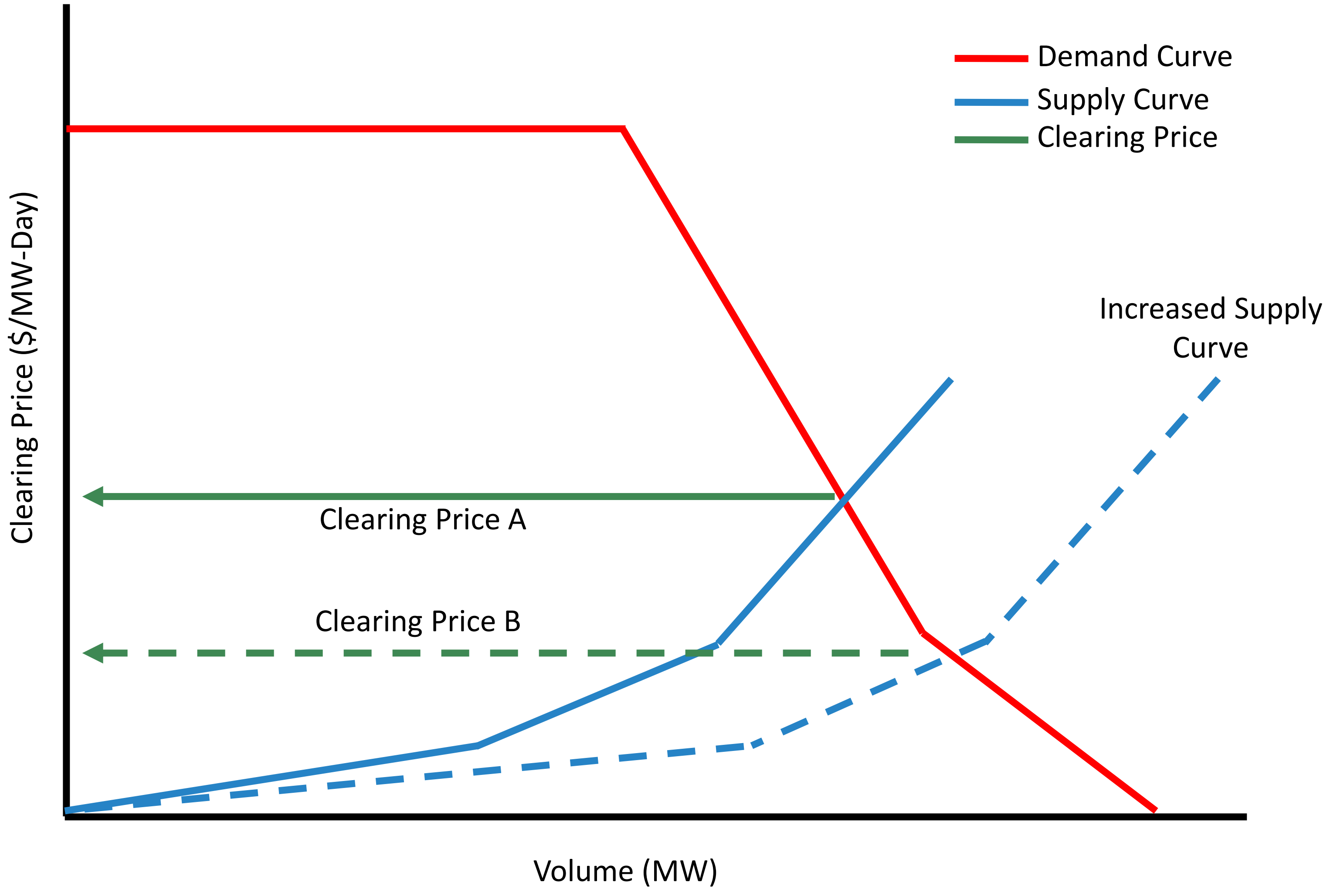
Consumer Impact

**Impact of Increasing Capacity Resources**

Modeling Assumptions

Modeled Monthly Billing Impact

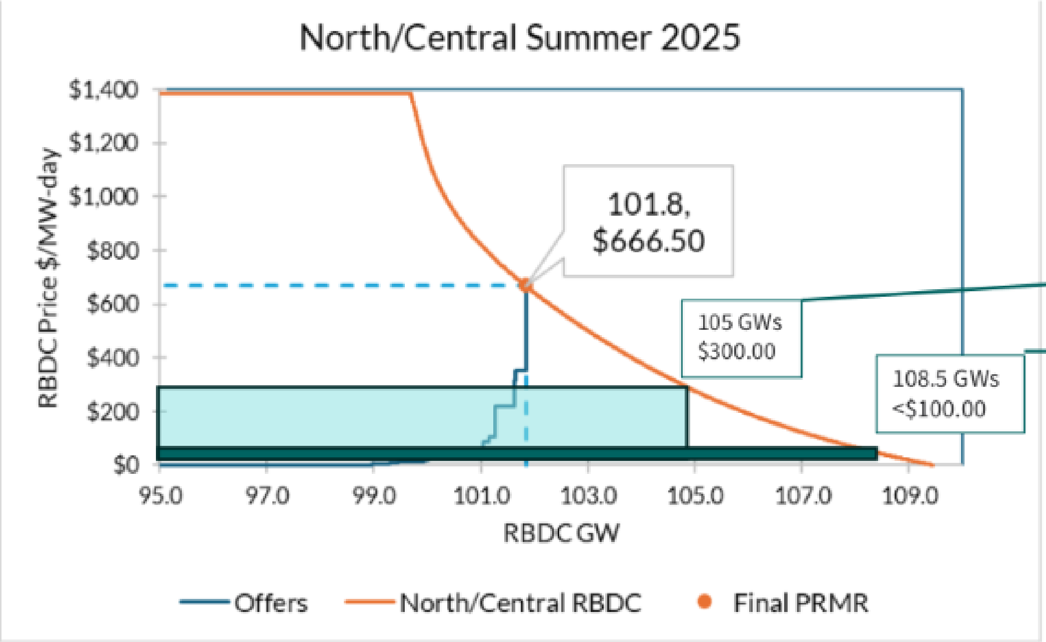
# Increasing Capacity Volumes Reduces Clearing Prices



# Confirmation: Lower Costs Resulting from More Capacity is Recognized by all Parties

## MISO North Summer Analysis

MISO North Cleared Every ZRC Offered in 2025 Summer Season, with 101.8 GWs in Supply Stack




Supply-side Gain Attributable to Market Disequilibrium

- Internally, MISO North is short of internal capacity supply by more than 3 GWs.
- Final MISO North resource was offered around $400/MW-day, with MISO South setting price for footprint, including Illinois/Zone 4.
- Today, new ESRs are provided with 95% capacity credit. Going forward under MISO's DLOL regime ESRs are likely to receive a 61% capacity factor in summer season.
- If Illinois added 3.5 GWs of ESRs, MISO would have 3.3 GWs of new ZRCs from new ESRs, reducing the ACP to ~$300/MW-day in the summer.
- If Illinois adds 7.0 GWs of ESRs, MISO would have an additional 6.6 GWs of new ZRCs from new ESRs, reducing the ACP to less than $100/MW-day.
- As MISO transitions to DLOL, more installed capacity will be needed to address upcoming capacity needs. Illinois should look to install 12 GWs of ESRs
  - Illinois should support 12 GWs of ESRs to integrate 7.3 GWs of new ESRs by 2030

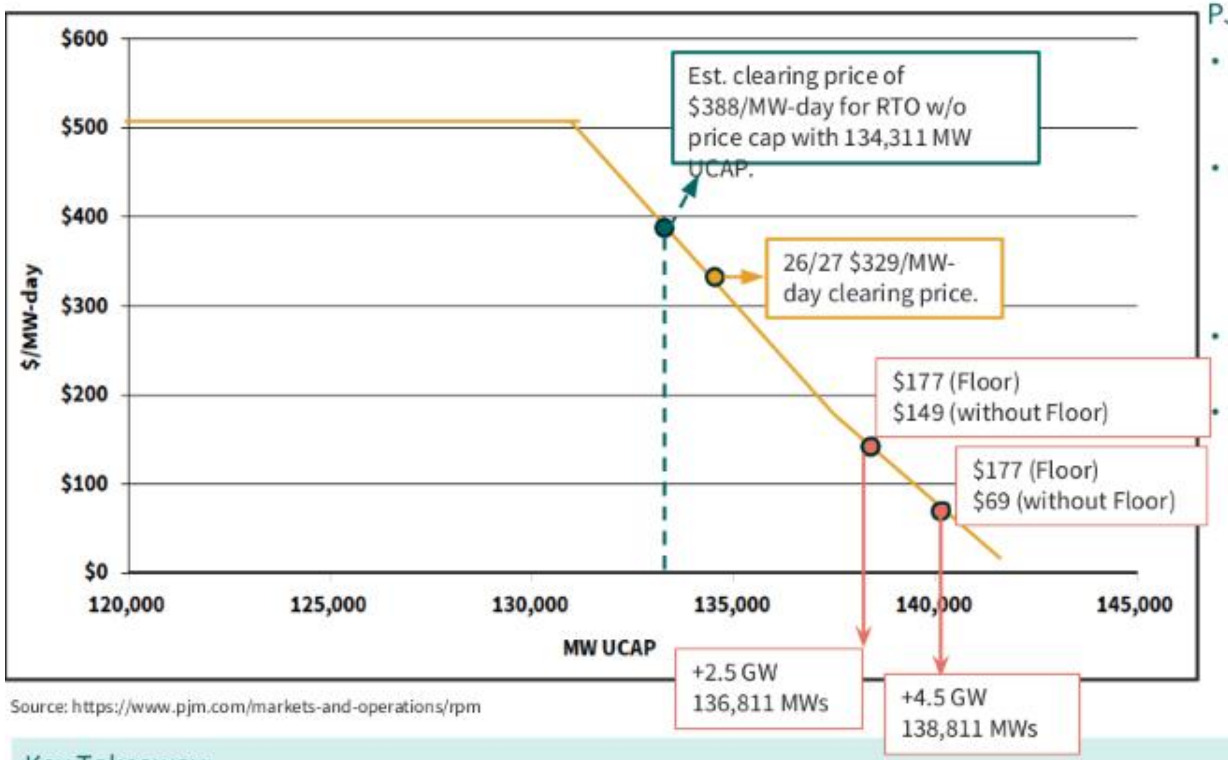
**Key Takeaway:**

- New ESRs in Illinois will meaningfully drive down the capacity price for the entire MISO footprint if 3.5 GWs of ESRs are added; MISO PRA ACP is substantially lowered if 12 GWs or more ESRs are added to Illinois portion of footprint
- New load integration likely requires more capacity for MISO Zone 4, increasing the value delivered to customers by having ESRs quickly deployed within the state.

# Confirmation: Lower Costs Resulting from More Capacity is Recognized by all Parties

## PJM 2026/27 RTO Base Residual Auction Results and Analysis

PJM was short UCAP MW while utilizing FRR surplus to meet overall Reliability Requirement under price cap.




Source: https://www.pjm.com/markets-and-operations/rpm

### PJM Agreed to Administrative Cap/Floor Prices

- PA Governor Shapiro and PJM agreed to implement a cap/floor for the 2026/27 and 2027/28 auctions. The values are created from a formula and the cap for 2026/27 was $329.17 and the cap for 2027/28 is $333.14.
- Illinois remains within the ComEd territory that cleared with the RTO in the PJM Base Residual Auctions(BRA), as did all areas within PJM. PJM cleared one single price of $329.17 (cap) for all UCAP MWs. However, PJM was short meeting its reliability requirement by 200 MW UCAP and used Fixed Resource Requirement (FRR) surplus resources to meet PJM's overall requirement.
- Effective Load Carrying Capability (ELCC) reduces storage's capacity another 5% from 2025/26 to 50% for a 4-hour battery.
- Additional GWs into the RTO could reduce the BRA clearing prices, pending offer price and combination of the cap prices. Presumed all offers at $0/mw-day.

| MW UCAP | MW ICAP | Est. RTO Price ($/MW-day) | Delta to Est. $388 Price |
|---|---|---|---|
| 2,500 | 5,000 | $177 | $(152) |
| 4,500 | 9,000 | $177 | $(152) |

### Key Takeaway:

- Removing the administrative floor/cap on prices and adding additional MW UCAP will result in lower capacity prices in RTO, including COMED and COMED will remain an exporting LDA into PJM.
- PJM requires more supply on the grid to meet its reliability requirement and adding ESR fulfills that need and continues to provide the capacity benefits to Illinois.
- By adding either 2.5 GWs or 4.5 GWs of additional UCAP supply, the BRA would have cleared at the administrative floor price of $177/MW-day. The 2.5 GW and 4.5 GW additions would result in respective clearing prices of $149/MW-day and $69/MW-day if no administrative price floor was set for the market.

Gabel Associates, Inc. 5

# Estimating Impact of Increased Capacity with Battery Energy Storage Systems in Illinois

## Direct Consumer Cost

**Consumer Costs for Supporting BESS Deployments**

- Market-based charges will appear on consumers' monthly bills based on formula similar to the Carbon Free Resource Adjustment – CFRA under CEJA
  - Contract Strike Price (set by competitive bidding process);
  - ***minus*** the value of Energy Sales by the BESS assets;
  - ***minus*** the value of Capacity Sales by the BESS assets;
  - ***Equals*** Direct Consumer Costs

**Direct Consumer Costs (2028-2047)**

| | |
|---|---|
| Sum of Contract Strike Prices | ($9.8 billion) |
| – Value of Energy Sales | ($3.2 billion) |
| – Value of Capacity Sales | ($7.1 billion) |
| **= Direct Consumer Cost/(Savings)** | **(-$0.4 billion)** |

## Net Consumer Cost

**Price Suppression Benefits Consumers**

- Increasing volumes of new capacity resources will reduce auction clearing prices for energy and capacity
  - Direct Consumer Cost/Savings;
  - ***minus*** Energy Auction Price Suppression;
  - ***minus*** Capacity Auction Price Suppression;
  - ***Equals*** Net Consumer Costs

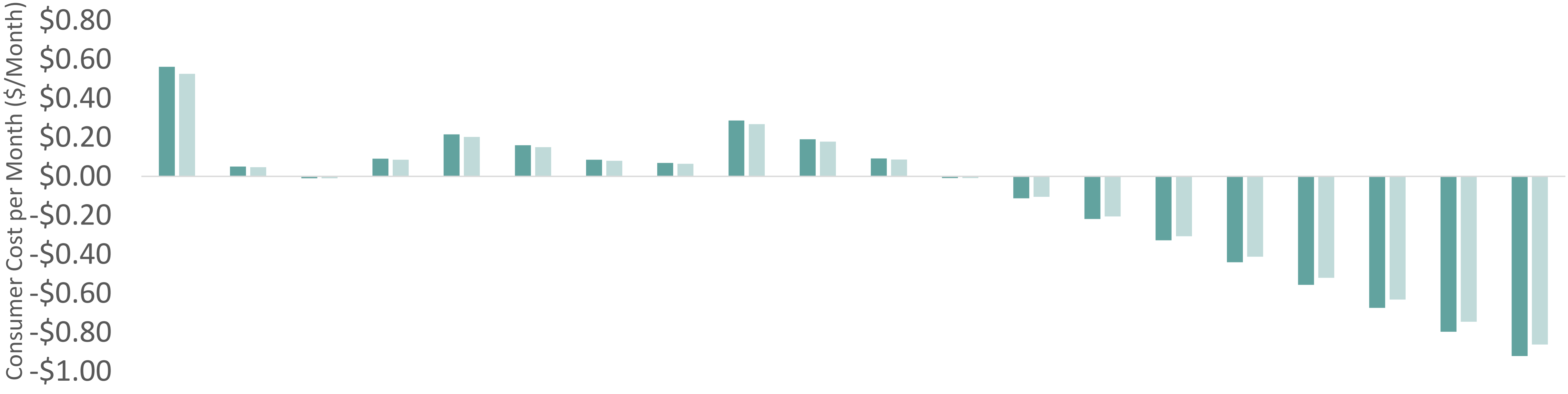
**Net Consumer Costs (2028-2047)**

| | |
|---|---|
| Direct Consumer Cost/(Savings) | (-$0.4 billion) |
| – Value of Energy Auction Price Suppression | (-$4.1 billion) |
| – Value of Capacity Auction Price Suppression | (-$29.7 billion) |
| **= Direct Consumer Cost/(Savings)** | **(-$34.2 billion)** |

# Monthly Energy Storage Resource Incentive Charge for Residential Customers

## Monthly Energy Storage Resource Incentive Charges switch to Credits starting in 2032 when deemed Energy and Capacity Revenues Exceed Direct Incentive Costs

### Direct On-Bill Charge for Energy Storage Resource Incentive ($/Month, Average Residential Account)



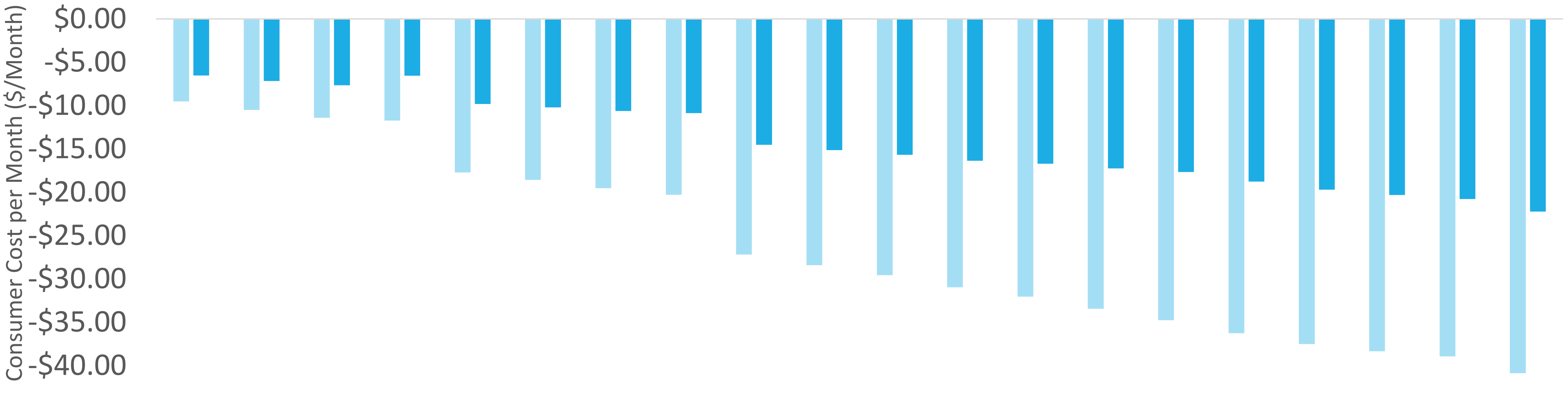

| | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ameren Illinois | $0.56 | $0.05 | -$0.01 | $0.09 | $0.22 | $0.16 | $0.08 | $0.07 | $0.29 | $0.19 | $0.09 | -$0.01 | -$0.11 | -$0.22 | -$0.33 | -$0.44 | -$0.56 | -$0.67 | -$0.80 | -$0.92 |
| ComEd | $0.53 | $0.05 | -$0.01 | $0.09 | $0.20 | $0.15 | $0.08 | $0.06 | $0.27 | $0.18 | $0.09 | -$0.01 | -$0.11 | -$0.20 | -$0.31 | -$0.41 | -$0.52 | -$0.63 | -$0.75 | -$0.86 |

Ameren Illinois ComEd

# Net Monthly Consumer Costs/Benefits for Residential Customers

## Net Consumer Costs become Net Credits after 2030 in both PJM and MISO as Energy Storage Assets Begin Suppressing Capacity Prices

### Net Consumer Cost Impact of Energy Storage Program
### (Monthly Direct On-Bill Charges + Market Price Suppression)




| | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ameren Illinois | -$9.52 | -$10.51 | -$11.41 | -$11.73 | -$17.71 | -$18.58 | -$19.53 | -$20.30 | -$27.19 | -$28.42 | -$29.58 | -$30.96 | -$32.05 | -$33.45 | -$34.76 | -$36.26 | -$37.51 | -$38.34 | -$38.95 | -$40.89 |
| ComEd | -$6.53 | -$7.16 | -$7.67 | -$6.56 | -$9.82 | -$10.20 | -$10.61 | -$10.87 | -$14.52 | -$15.14 | -$15.67 | -$16.37 | -$16.70 | -$17.24 | -$17.67 | -$18.78 | -$19.71 | -$20.33 | -$20.79 | -$22.24 |

Ameren Illinois ComEd

# THANK YOU

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# Cost and Benefit Analysis of Energy Storage Resource Deployment in Illinois

A program to support the deployment of 8,500 MW of energy storage resources in Illinois is projected to:

- Improve the reliability of energy supply for Illinois residents and businesses.
- Provide Illinois consumers with $2.3-3.0 billion in utility cost savings.
- Ensure that Illinois can meet its 100% clean energy goals by 2050.

The Power Bureau, 2024

# Contents

## Executive Summary

A capacity shortage occurs when a regional power grid cannot meet peak electricity demand on the hottest summer days or the coldest winter nights. The regional power grids that serve Illinois project capacity shortages to occur in the near term. For Illinois, this outlook indicates a lower level of system reliability and increased costs for Illinois consumers.

To mitigate the negative impacts of capacity shortages in Illinois, legislation to support the deployment of energy storage resources in Illinois is under consideration.[1] The legislation proposes to provide incentives for the installation and operation of energy storage resources. These energy storage resources would serve to i) collect electricity during periods of excess generation (e.g., "off-peak" hours during weekday evenings and early morning hours), and ii) deliver that stored energy to the regional power system during period of high energy demand (e.g., "peak" hours during weekday daytime hours). Additionally, to the extent the legislation results in the acquisition of long-duration energy storage systems, energy can be stored for use across many hours or days, to help handle grid stress events that last for extended periods.

This study examines the implications of the proposed program that considered four threshold questions:

- **How reliable is the Illinois power grid?**
  The outlook for power grid reliability in Illinois is uniformly negative. Federal, regional, and state energy regulators all identify that capacity shortages will occur in Illinois.

- **How can we improve Illinois power grid reliability?**
  Achieving significant increases in new capacity resources in Illinois is the only approach to offsetting the eventual loss of existing capacity resources (e.g., retirements of fossil-fueled power plants) and continued growth in electricity demand (e.g., datacenter development, electrification, etc.).

- **When would an energy storage resources program need to begin?**
  Immediate action is required to allow existing transmission infrastructure at retiring power plants in Illinois to be repurposed to support the deployment of large volumes of energy storage resources before projected shortages occur prior to 2030.

- **What are the consumer cost impacts of an energy storage program in Illinois?**
  Illinois consumers would realize between a net reduction of $3 billion in utility bill savings because of deploying 8,500 ME of energy storage. Based on current estimates, the average single-family utility account served by Ameren Illinois would realize an average cost savings of $7/month over 20 years and the average ComEd single family residential account would realize an average cost savings of $4/month.

The Study identifies that significant economic benefits would result from deploying at least 8,500 MW of energy storage resources in Illinois between 2030 and 2049. Figure 1 below conveys the direct customer costs and macro-economic benefits associated with the proposed energy storage program.

[1] Senate Bill 3481

Figure 1: Direct Consumer Cost Impacts and General Economic Benefits of Proposed Energy Storage Resource Program for Illinois (2030-2049)

| CONSUMER AND MACRO ECONOMIC IMPACTS OF ENERGY STORAGE PROGRAM | (COST) / BENEFIT |
|---|---|
| **DIRECT CONSUMER COST IMPACTS (2030-2049)** | |
| **Energy Storage Resource Incentive Cost**. Direct consumer cost of the energy storage resource incentives. | ($6.4) billion |
| **Wholesale Energy Price Suppression.** Energy cost reductions resulting from lower clearing prices for energy due to increasing energy supply during daily peak hours with energy storage resources. | $0.5 billion |
| **Wholesale Capacity Price Suppression.** Capacity cost reductions resulting from lower clearing prices for capacity due to increasing in-state capacity with energy storage resources to meet system peak demand. | $8.6 billion |
| **Wholesale Transmission Cost Avoidance.** Cost reductions in utility delivery rates resulting from lower capital investment requirements. | Undefined |
| **Utility Distribution System Capital Cost Avoidance.** Cost reductions in utility delivery rates resulting from lower capital investment requirements. | $25 million |
| **NET DIRECT CONSUMER COST BENEFITS** | **$3.0 billion** |
| **MACRO ECONOMIC BENEFITS (2030-2049)** | |
| **Value of Reliability.** Avoided economic losses resulting from reducing 1 day of blackouts every 10 years in Illinois between 2030 and 2049 due to the reliability enhancements provided by additional energy storage resources. | $7.3 billion |
| **Value of Reduced Emissions.** Avoided economic costs of emissions resulting from meeting peak hour energy demand with energy storage instead of fossil-fuel powered peaking power plants. | $0.76 – $4.9 billion |
| **Value of Increased Economic Activity.** Incremental increases of wages and other economic activity associated with deploying new energy storage resources throughout Illinois. | $3.75 – 16.2 billion |
| **TOTAL MACRO ECONOMIC BENEFITS** | **$11.8 to $28.4 billion** |

The Study also identifies significant general economic benefits would result from deploying at least 8,500 MW of energy storage resources in Illinois between 2030 and 2049.

- **Avoided cost of power outages.** Energy storage resource deployments to Illinois would reduce the probability of power outages from the current level of 1 to 0 days every ten years to 0 days every ten years. Between 2030 and 2049 the economic value of these avoided power outages in Illinois is projected to be $5.8 billion.
- **Reduced cost of emissions.** Energy storage resources are projected to reduce the use of peaker power plants while increasing the utilization of new wind and solar resources to meet Illinois' peak energy needs. This shift in resource use would reduce emissions from carbon-emitting power stations in Illinois between 2030 and 2049 with a value ranging from $531 million to $4.8 billion.

- **Increased economic activity.** Constructing and operating energy storage resources would increase employment in Illinois by 32,417 and 115,329 full-time equivalent years and support an increase of between $3.9 billion to $16.3 billion in value-added activity in Illinois.

In sum, the proposed energy storage resource program would improve the reliability of the wholesale power supply that supports the Illinois economy while delivering material and ongoing net cost savings to Illinois consumers and economic benefits to the Illinois economy between 2030 and 2049.

## Question 1: How Reliable is the Power Supply in Illinois?

The need for reliable power is acknowledged in the first sentence of the Illinois Public Utility Act:

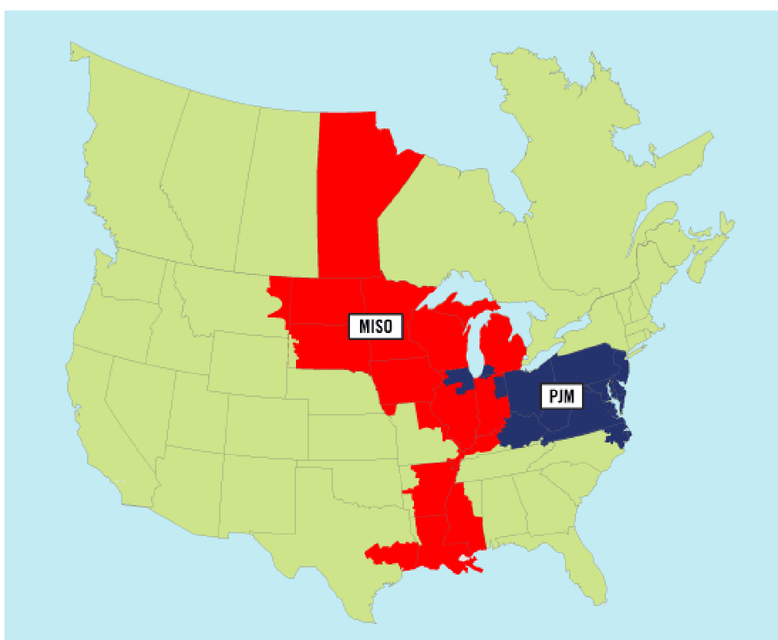
> "The General Assembly finds that the health, welfare, and prosperity of all Illinois citizens require the provision of ***adequate***, efficient, ***reliable***, environmentally safe and least-cost public utility services at prices which accurately reflect the long-term cost of such services, and which are equitable to all citizens. It is therefore declared to be the policy of the State that public utilities shall continue to be regulated effectively and comprehensively." (220 ILCS 5/1-102).

Unfortunately, the current outlook for the reliability of the regional power grids that serve Illinois is poor.

Reliable power supply in Illinois depends on the regional power grids maintaining an adequate amount of Accredited Capacity. Accredited Capacity is the maximum amount of power demand that can be delivered with a high-level of confidence through a combination of regional power stations, local demand response, and power imports from neighboring regional power systems. [NOTE: additional background on Capacity issues can be found in Attachment A].

Accredited Capacity in Illinois. PJM Interconnection (PJM) and Midcontinent ISO (MISO) are separate not-for-profit authorities which operate under the authority of the Federal Energy Regulatory Commission (FERC) to manage the regional power grids that serve Illinois. Figure 2 identifies the geographic regions served by PJM and MISO. The primary mission for PJM and MISO is to ensure regional grid reliability.

Figure 2: Regions Served by PJM Interconnection and Midcontinent ISO




Source: PJM and MISO Joint and Common Market

To ensure a minimum level of power grid reliability, PJM and MISO establish capacity agreements with the owners of power generating resources that ensure that their power generating resources will be available to generate at a maximum level of output if called upon to meet consumer electricity demand. The minimum levels of capacity required for PJM and MISO are set by the North American Electric Reliability Corporation (NERC) and is called the Planning Reserve Margin (e.g., the volume of available Capacity that exceeds the maximum demand for energy within a regional power system)

PJM and MISO utilize auctions to select the power stations that receive capacity agreements. The clearing prices set through the PJM and MISO capacity auctions establish an annual cost for Accredited Capacity for the region which is then passed through to load serving entities (e.g., utilities, retail energy suppliers, etc.). The cost of Accredited Capacity is passed through to consumers in the price paid for their electricity supply. The amount of Accredited Capacity required for a consumer is based on the consumers' contribution to system peak demand in the prior delivery year.

PJM and MISO capacity auctions yield variable prices for Accredited Capacity that change over time in relation to regional supply and demand. Consequently, low volumes of Accredited Capacity relative to regional Peak Demand will cause Capacity process to be higher. Figure 3 conveys the historical volatility in Capacity prices and resulting costs for Illinois consumers served by Ameren Illinois and ComEd. We note that Illinois consumers have been exposed to periods with elevated capacity costs in the past, and that projected capacity shortages in the future would result in more severe price escalations.

Figure 3: Historical Capacity Costs for Single-Family Residential Account served by Ameren Illinois

| DELIVERY YEAR | AMEREN ILLINOIS | | | | COMMONWEALTH EDISON | | | |
|---|---|---|---|---|---|---|---|---|
| | CAPACITY REQUIREMENT FOR A SINGLE FAMILY HOME (MW) | MISO CAPACITY RATE ($/MW-DAY) | DAYS/YEAR | ANNUAL CAPACITY COST | CAPACITY REQUIREMENT FOR A SINGLE FAMILY HOME (MW) | MISO CAPACITY RATE ($/MW-DAY) | DAYS/YEAR | ANNUAL CAPACITY COST |
| | A | B | C | D=A*B*C | E | F | G | H=E*F*G |
| 2015-16 | 0.005 | $150.00 | 365 | $273.75 | 0.005 | $136.00 | 365 | $248.20 |
| 2016-17 | 0.005 | $72.00 | 365 | $131.40 | 0.005 | $59.37 | 365 | $108.35 |
| 2017-18 | 0.005 | $1.50 | 365 | $2.74 | 0.005 | $120.00 | 365 | $219.00 |
| 2018-19 | 0.005 | $10.00 | 365 | $18.25 | 0.005 | $215.00 | 365 | $392.38 |
| 2019-20 | 0.005 | $2.99 | 365 | $5.46 | 0.005 | $202.77 | 365 | $370.06 |
| 2020-21 | 0.005 | $5.00 | 365 | $9.13 | 0.005 | $188.12 | 365 | $343.32 |
| 2021-22 | 0.005 | $5.00 | 365 | $9.13 | 0.005 | $195.55 | 365 | $356.88 |
| 2022-23 | 0.005 | $236.66 | 365 | $431.90 | 0.005 | $68.96 | 365 | $125.85 |
| 2023-24 | 0.005 | $15.00 | 365 | $27.38 | 0.005 | $34.13 | 365 | $62.29 |
| 2024-25 | 0.005 | $30.00 | 365 | $54.75 | 0.005 | $28.92 | 365 | $52.78 |

## Regulator Warnings about Accredited Capacity Conditions in Illinois.

Federal, regional, and state energy regulators project that Illinois will lack sufficient levels of Accredited Capacity to meet NERC's Planning Reserve Margin targets. As a result, Illinois consumers are likely to pay more for Accredited Capacity in the future (see above) while being exposed to lower levels of regional power grid reliability.

- NERC. In its most recent Summer Reliability Assessment, NERC identifies that multiple regions with either Elevated or High Risk of wholesale power shortfalls. The assessment identifies the extent to which regions meet or exceed their Planning Reserve Margin (e.g., the net balance of local Capacity plus inter-regional imports against the projected peak demand in a regional power system).

  Figure 4 shows that NERC identifies that MISO (which serves central-southern Illinois) as being at High Risk to reliability in the event of above-normal conditions. NERC's assessment indicates that power gird reliability in MISO could threatened in the summer of 2024 in cases of "above-normal summer peak load and extreme generator outage conditions".

Figure 4: NERC Seasonal Risk Assessment for Summer 2024

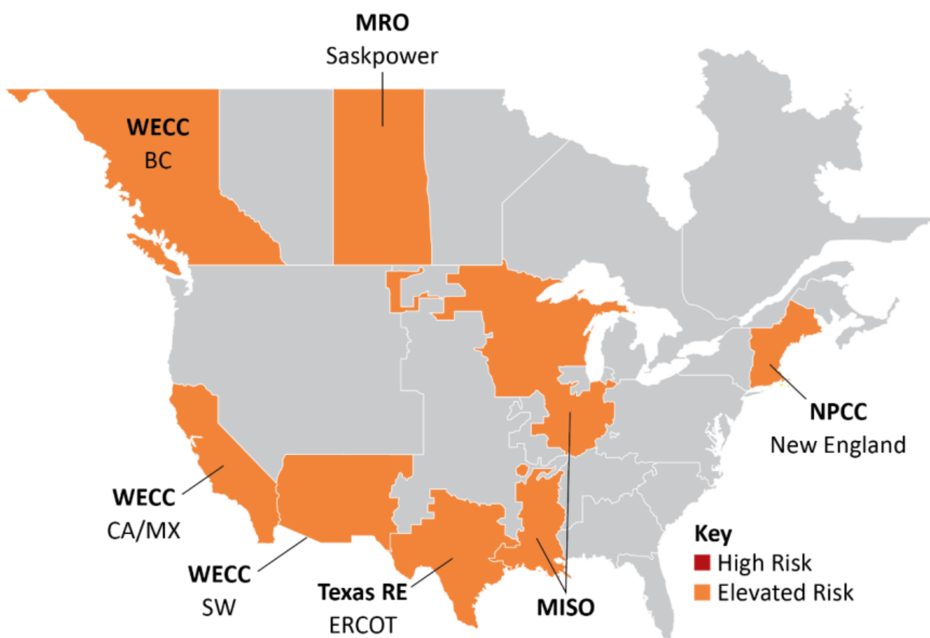



**Figure 1: Summer Reliability Risk Area Summary**

| Seasonal Risk Assessment Summary | |
|---|---|
| High | Potential for insufficient operating reserves in normal peak conditions |
| Elevated | Potential for insufficient operating reserves in above-normal conditions |
| Normal | Sufficient operating reserves expected |

Source: NERC Summer Reliability Assessment (2024)

Figure 5 conveys NERCs assessment that both MISO and PJM showed Elevated reliability risks during the Winter of 2023-24. In sum, NERC's assessments indicate that both MISO and PJM face escalating levels of risk to reliable wholesale electricity supply. In its report, NERC notes the following concerning PJM: "Forecasted peak demand has risen while resources have decreased since 2022 when Winter Storm Elliot caused energy emergencies in PJM and surrounding areas" indicating that reliability is less than robust. Of MISO, NERC notes: "Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and energy emergency alerts (EEA). Load shedding is unlikely but may be needed under wide-area cold weather events."

Figure 5: NERC Planning Reserve Margin Forecast for PJM

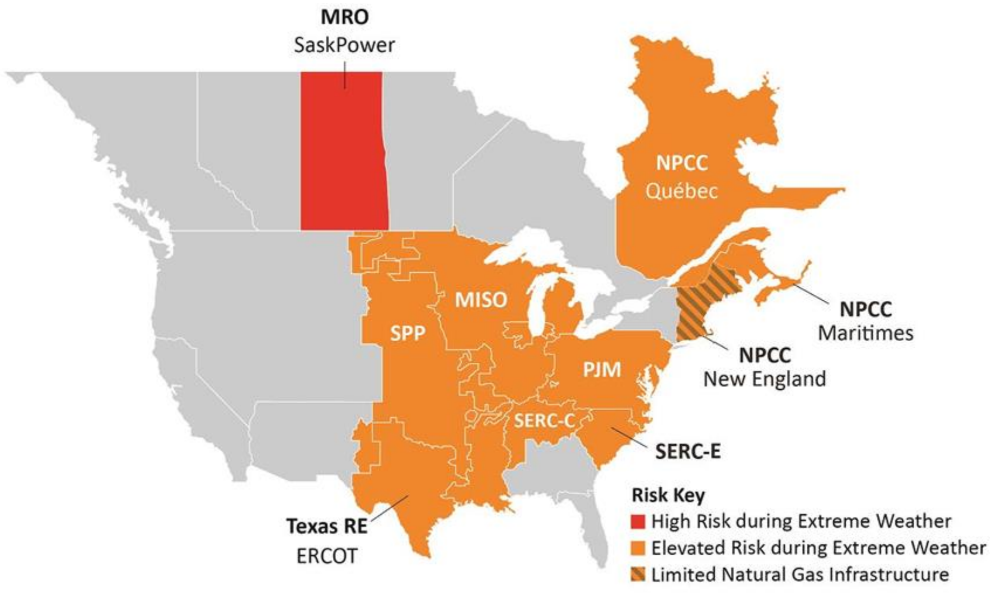



**Figure 1: Winter Reliability Risk Area Summary**

| Seasonal Risk Assessment Summary | |
|---|---|
| **High** | Potential for insufficient operating reserves in normal peak conditions |
| **Elevated** | Potential for insufficient operating reserves in above-normal conditions |
| **Low** | Sufficient operating reserves expected |

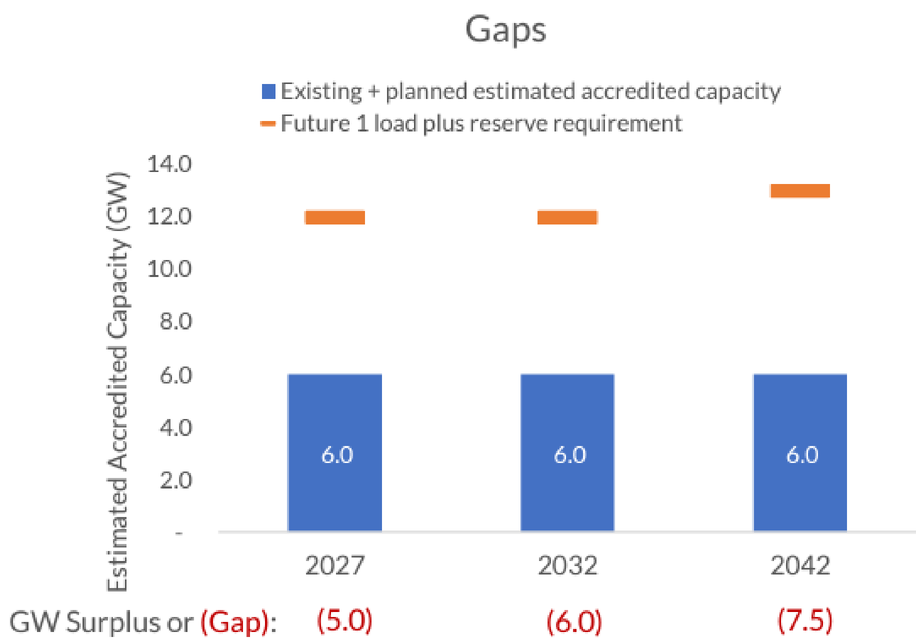
Source: [NERC Winter Reliability Assessment (2023-24)]

In sum, NERC identifies that Accredited Capacity in MISO and PJM is potentially insufficient to ensure grid reliability in the event of hotter than normal summer weather, colder than normal winter weather and unexpected outages at key regional power generating resources.

- Midcontinent Independent System Operator (MISO). MISO recently identified that central and southern Illinois ("MISO Zone 4") will not maintain even 50% of the Accredited Capacity required to meet minimum reliability standards. Figure 6 conveys the annual levels of projected Accredited Capacity requirement for Zone 4 in 2027, 2032 and 2042 (horizontal orange lines), the amount of Accredited Capacity that is anticipated in each of those years (blue columns), and the resulting projected shortfall in Accredited Capacity (red letter parenthetical value). As noted, by 2042, MISO projects that central and southern Illinois will be short 7,500 MW of Accredited Capacity which equates to seven (7) Clinton nuclear power stations.

  MISO identifies that the reliability of the regional power grid serving central and southern Illinois is in decline and projected to further deteriorate.

Figure 6: MISO Projects at Least a 50%+ Shortfalls in Accredited Capacity for the Ameren Illinois Region (Zone 4)




Source: [2023 Regional Resource Assessment, A Reliability Imperative Report, November 2023]

- PJM Interconnection (PJM). Like MISO, PJM projects annual Planning Reserve Margins for future periods. Figure 7 below conveys PJM's projected Reserve Margin for the years 2023 through 2030 under two consumer demand scenarios (e.g., the standard load forecast from 2023, and a separate scenario which assumes elevated levels of electrification within the PJM) and two scenarios regarding the amount of new Capacity that is deployed in the PJM system (e.g., Low and High volumes). PJM notes that its Reserve Margin drops below NERC's 15% Reserve Margin requirement under the Low Level of new Capacity deployment scenario starting in 2026 (assuming high electrification) and 2027 (assuming low electrification). Similarly, PJM identifies that its Reserve Margin drops below NERC's Reserve Margin requirement under the High Level of new Capacity deployment scenario starting in 2029 (assuming high electrification) and 2030 (assuming low electrification).

  Specific to northern Illinois, ComEd communicated to FERC that Accredited Capacity in the ComEd region could turn negative starting in 2030 because of retirements of most thermal generation stations in the area.

  > "The ComEd region currently has approximately 26,800 MW of generation capacity and approximately 1,400 MW of demand response capability, which means ComEd's current total internal capacity is approximately 28,200 MW. Subtracting the expected retirements of 9,661 MW to the approximate current capacity of ComEd, 28,200 MW, ***the ComEd region will likely face a shortfall of 680 MW by 2030 if the Reliability Requirement and CETL values remain constant."*** (PJM Letter to FERC, "Proposal to Establish a Fifth Cost of New Entry Area" November 21, 2023)

Figure 7: PJM Projected Planning Reserve Margin for 2023 through 203 Under Standard and High Electrification Scenarios

**Table 1.** Reserve Margin Projections Under Study Scenarios

| Reserve Margin | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| **Low New Entry** | | | | | | | | |
| 2023 Load Forecast | 23% | 19% | 17% | 15% | 11% | 8% | 8% | 5% |
| Electrification | 22% | 18% | 16% | 13% | 10% | 7% | 6% | 3% |
| **High New Entry** | | | | | | | | |
| 2023 Load Forecast | 26% | 23% | 21% | 19% | 17% | 16% | 17% | 15% |
| Electrification | 25% | 22% | 20% | 18% | 15% | 14% | 14% | 12% |

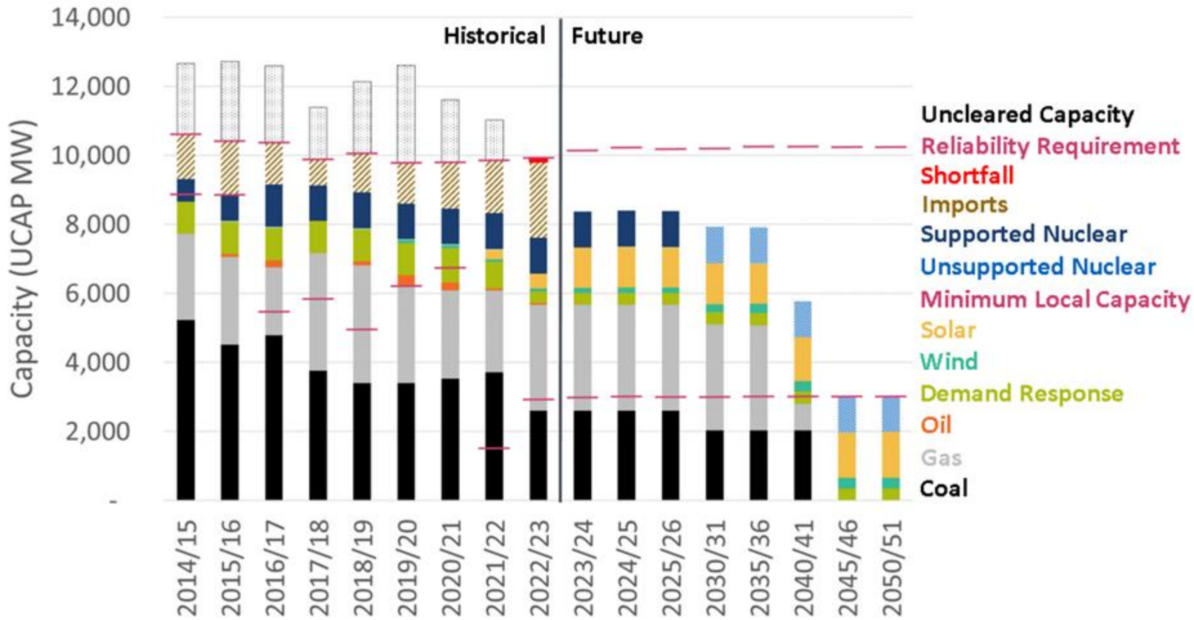
Source: Energy Transition in PJM: Resource Retirements, Replacements & Risks Feb. 24, 2023

While not as dire as the situation in MISO, PJM identifies that the reliability of the regional power grid serving northern Illinois is also in decline and can accelerate depending on the level of load growth within the region. Commonwealth Edison further identifies that the accelerated retirements of existing power generating asset in northern Illinois could cause a nominal shortage in accredited capacity by 2030.

- Illinois Commerce Commission (ICC). The ICC has recently concluded its Renewable Energy Access Plan Docket 22-0749. In that proceeding, ICC staff prepared forward projections of capacity sources to support reliability for consumers located within the portions of Illinois served by MISO and PJM regional power girds. Those projections are noted in Figures 8 and 9.

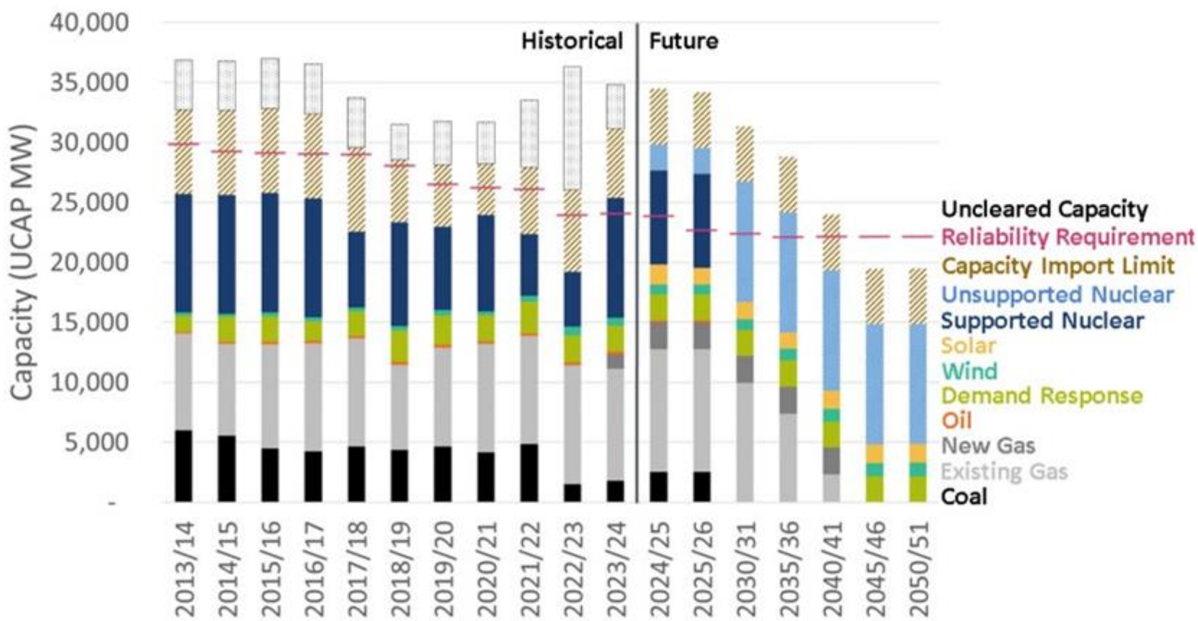
  As noted by the ICC, the portion of Illinois served by MISO encounters capacity shortfalls in the early 2030's which extend through the 2040's due to the retirement of coal and natural gas power stations in the region. Though delayed and less severe, a similar pattern was observed for the portion of Illinois served by PJM.

Figure 8: Projected Capacity Sources and Shortfalls for Ameren Illinois Service Region




Source: [Renewable Energy Access Plan, Illinois Commerce Commission]

Figure 9: Projected Capacity Sources and Shortfalls for ComEd Region




Source: [Renewable Energy Access Plan, Illinois Commerce Commission]

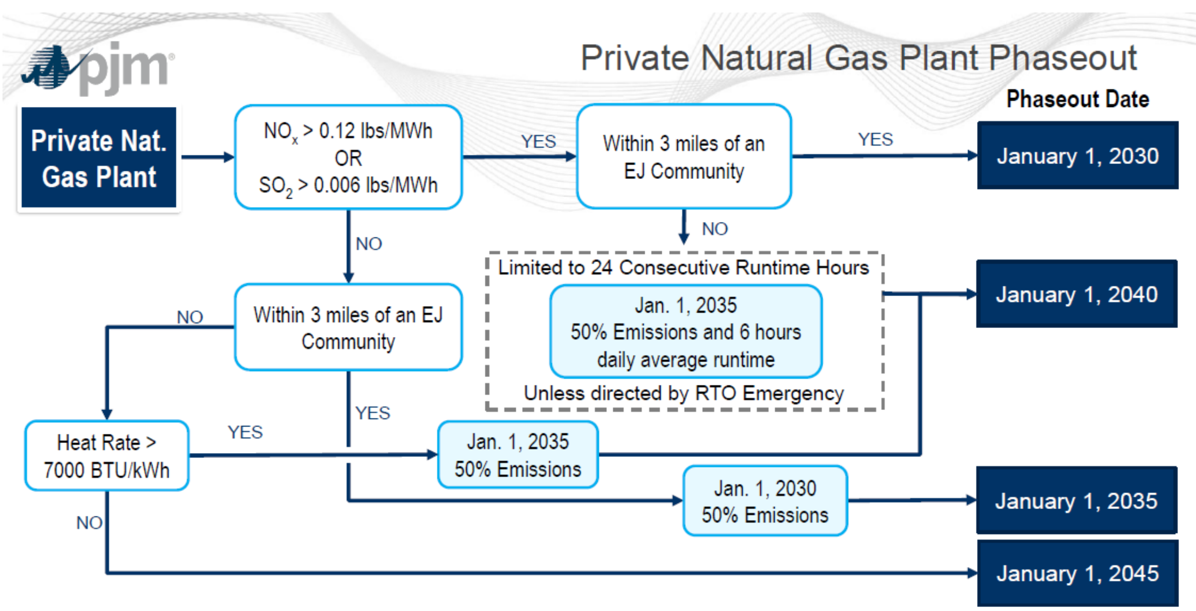
- Illinois Power Agency (IPA). In its recently completed Policy Study, the IPA identified that adding 7,500 MW of utility-scale energy storage in Illinois would improve the reliability of the PJM and MISO regional grids to the benefit of Illinois consumers:

> "The proposed 7,500 MW of utility-scale energy storage would have an impact on generation and resource adequacy. Against a base case of a 0.1 LOLE level, in 2030, LOLE would drop to 0.01, and in 2040, the LOLE would drop to 0. ***In other words, utility-scale energy storage could be expected to eliminate the likelihood of a loss of load event in 2040.*** In 2030, the proposed levels of energy storage would not yet be fully deployed, and thus the impact is not fully realized. Similarly, the ELCC for the deployment of utility-scale energy storage would be 94% in 2030 and 64% in 2040, indicating that a sizable portion of the energy delivered by utility-scale energy storage systems would contribute to generation and resource adequacy."[2]

Options for Increasing Accredited Capacity in Illinois. For decades, Illinois has enjoyed the benefits of a reliable regional grid that resulted from hosting surplus levels of Accredited Capacity. However, current market conditions and regulatory constraints require Illinois to address a pending capacity shortage.

- **Accelerating Capacity Retirements.** Under CEJA, all power stations assets larger than 25MW will be required to either reduce their emissions or cease operations by 2045 (see Figure 10). This means that thousands of MW of Accredited Capacity will no longer be available to support system reliability needs in the next few years.

Figure 10: Emissions Reduction Schedule for Privately Owned Natural Gas Power Assets in Illinois under CEJA




(source: Illinois Clean Energy Jobs Act Fossil Fuel Generation Phaseout, PJM, 2021)

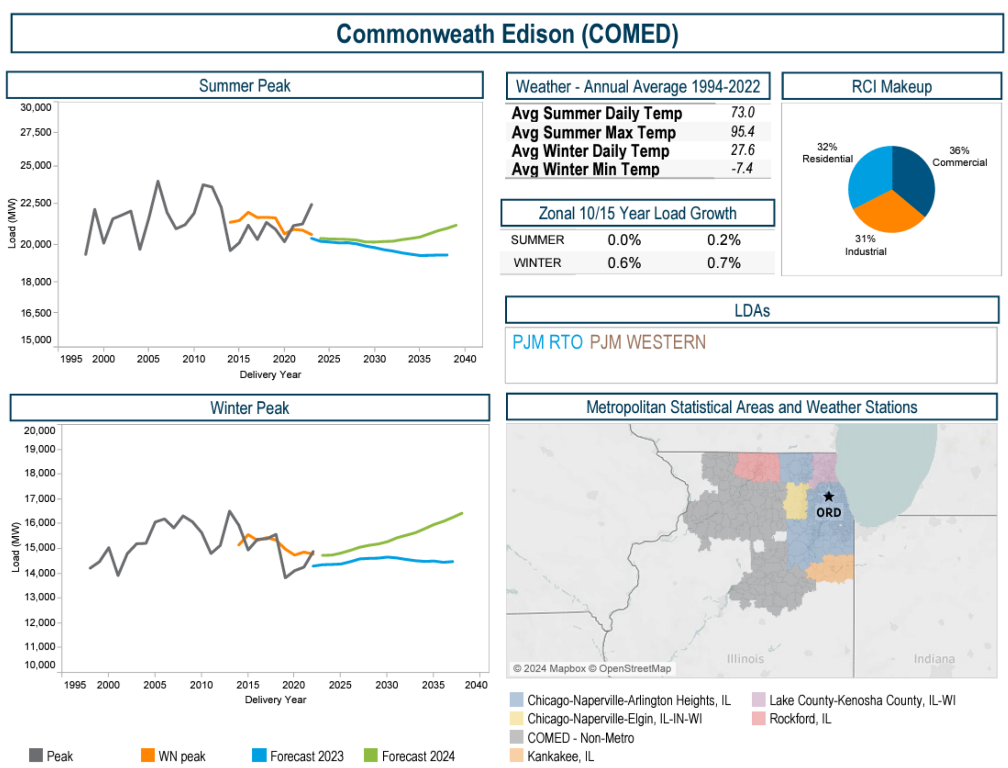
[2] Illinois Power Agency Policy Study (Page 95)

- **Limited New Capacity Options.** With the constraints on fossil fuel generation under CEJA it is unlikely that developer will site new natural gas plants in Illinois. Many renewable energy project deployments are delayed in receiving interconnection agreements with PJM and MISO or are facing project financing challenges.
- **Projected Increases in Energy Demand.** In addition to general efforts towards electrification, datacenter development in Illinois is projected to significantly increase overall demand on the regional power system. As noted recently in the press:

> "25 data center projects that would consume around 5 gigawatts of power total — *roughly equivalent to the output of five nuclear plants* — are undergoing engineering studies in Exelon unit Commonwealth Edison Co.'s territory, Butler said. That compares with about 400 megawatts of data center demand currently on its system. Butler expects up to 80% of the planned developments to be completed. " (AI-Driven Power Demand Is Set to Jump 900% in Chicago Area, Exelon CEO Says, Mark Chediak and Josh Saul, April 18, 2024, Bloomberg)

The impacts of expanding datacenter and electrification are occurring outside of Illinois as well. Figure 11 conveys a recent peak demand forecast for the ComEd region by PJM. Even greater upward adjustments in summer and winter peak demand forecasts have been made for other portions of the PJM region. This is relevant because increasing demand patterns across all of PJM can indicate potential limits to the amounts of Capacity that are available to be imported into the ComEd region.

Figure 11: PJM's Increases Peak Demand Projections for the ComEd Region




Source: PJM Load Forecast Report January 2024

## Key Considerations.

1. Capacity is the maximum amount of output that a power resource can deliver to the regional power system. Accredited Capacity is the amount of Capacity that a collection of power resources could be expected to deliver to the regional grid on demand net of physical and operational constraints. The Planning Reserve Margin is a measure of the extent by which Accredited Capacity exceeds the maximum consumer demand in a regional power system.

2. The North American Reliability Corporation (NERC) mandates that regional power girds secure Accredited Capacity at least equal to a minimum Planning Reserve Margin. Maintaining more Accredited Capacity than the minimum level established by the Planning Reserve Margins increases reliability by reducing the risk of cascading system failures that can result from extreme weather and other emergencies.

3. PJM Interconnection (PJM)) and Midcontinent ISO (MISO) secure Accredited Capacity through market-based competitive auction to ensure a minimum level of reliability for Illinois consumers.

4. All federal, regional, and state energy regulators (NERC, PJM, MISO, ICC, IPA) project falling levels of Accredited Capacity for Illinois which will negatively impact system reliability and energy affordability for Illinois residents.

5. Energy storage may be one of the few options available to Illinois to maintain high system reliability at a reasonable cost to consumers.

## Question #2: How much energy storage does Illinois need?

Proposed legislation targets the deployment of 8,500 MW of energy storage in Illinois (7,500 MW of utility-scale energy storage resources plus 1,000 MW of distributed-scale energy storage resources). However, scenario analysis indicates that as much as 15,000 MW of energy storage capacity would be needed to ensure the reliability of the regional grids that serve Illinois.

Our analysis considered the following scenarios:

- **Scenario A (Business-as-Usual).** The Business-as-Usual scenario serves as a benchmark to assess the extent to which the Ameren Illinois and ComEd regions can meet Planning Reserve Margins under the following assumptions:

  - **Capacity Requirements.** Planning Reserve Margins for each year of the analysis were calculated based on the current forward projections of system peak summer demand using current MISO and PJM forecasts and adjusted to reflect system losses.

  - **Capacity Resources.** An annual portfolio of capacity resources for each region was calculated based on the following groupings of resources:

    i. Existing Capacity. All currently operating power generation (e.g., nuclear, coal, natural gas, renewables, energy storage), demand response resources, and capacity import capabilities) as identified by the Energy Information Administration and the relevant utilities.

    ii. Retirements. All announced retirements as well as anticipated retirements of facilities in accordance with the schedules specified under the requirements of CEJA.

    iii. New Resources. All non-energy storage power resources identified in the current interconnection queues of PJM and MISO were included in the analysis. Based on historical values, 15% of proposed resources identified in the PJM and MISO queues were assumed to successfully deploy.[3] These resources were assumed to be deployed equally over the 10-year period between 2030 and 2039.

  The above projections were then compared to establish the extent to which Capacity Resources met or exceeded Capacity Requirements for each region in each year between 2030 and 2039.

  **Scenario B (Decreased Renewable Energy Deployments).** We adjusted the Business-as-Usual Scenario by decreasing the projected volumes of new renewable energy resource deployments in the Ameren Illinois and ComEd regions by 10% per year to reflect the ongoing challenges in requesting and receiving interconnection approvals from PJM and MISO, ongoing regional transmission constraints, and the elevated cost of capital. These projections were compared to establish the extent to which Capacity Resources met or exceeded Capacity Requirements for each region in each year between 2030 and 2039.

  **Scenario C (Increased Demand for Electricity).** we amended the Business-as-Usual Scenario by increasing annual peak load requirements for both Ameren Illinois and ComEd by 1.0% year-over-year for the modeling period. To reflect PJM's recent upward adjustment of Peak Demand for the ComEd

[3] "Tracking Progress of Proposed Power Plants or New Facilities", PJM Inside Lines (June 19, 2019)

region, and comments from ComEd's CEO that datacenter expansions in the ComEd service region will accelerate over time (causing a resulting increase in peak demand). This estimated growth level is conservative compared to other recent projections of over 3% annual growth in demand which consider electrification schedules that are fully aligned with CEJA. These projections were compared to establish the extent to which Capacity Resources met or exceeded Capacity Requirements for each region in each year between 2030 and 2039.

The results of these scenarios are presented in Figure 12 below.

Figure 12: Planning Reserve Margin Projections for Ameren Illinois and ComEd

| SCENARIOS | YEAR | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 |
| **AMEREN ILLINOIS PLANNING RESERVE MARGIN - MW SURPLUS/(DEFICIT)** | | | | | | | | | | |
| Scenario A (Business As Usual) | 4,722 | -2,868 | -3,071 | -3,302 | -3,460 | -5,708 | -5,873 | -6,042 | -6,215 | -6,392 |
| Scenario B (Decreased Renewable Deployments) | -3,070 | -2,887 | -3,095 | -3,329 | -3,494 | -5,748 | -5,920 | -6,096 | -6,275 | -6,458 |
| Scenario C (Increased Demand for Electricity) | -3,553 | -3,890 | -4,262 | -4,669 | -5,010 | -7,447 | -7,809 | -8,182 | -8,566 | -8,961 |
| **COMMONWEALTH EDISON PLANNING RESERVE MARGIN - MW SURPLUS/(DEFICIT)** | | | | | | | | | | |
| Scenario A (Business As Usual) | 662 | 698 | 641 | 470 | 419 | -2,320 | -2,498 | -2,676 | -2,807 | -2,983 |
| Scenario B (Decreased Renewable Deployments) | 662 | 694 | 634 | 460 | 407 | -2,335 | -2,516 | -2,698 | -2,831 | -3,011 |
| Scenario C (Increased Demand for Electricity) | -692 | -892 | -1,188 | -1,607 | -1,907 | -4,902 | -5,355 | -5,815 | -6,227 | -6,699 |
| **STATEWIDE** | | | | | | | | | | |
| Scenario A (Business As Usual) | 5,383 | -2,170 | -2,430 | -2,832 | -3,041 | -8,028 | -8,371 | -8,719 | -9,022 | -9,375 |
| Scenario B (Decreased Renewable Deployments) | -2,408 | -2,193 | -2,461 | -2,869 | -3,087 | -8,083 | -8,437 | -8,794 | -9,106 | -9,469 |
| Scenario C (Increased Demand for Electricity) | -4,246 | -4,782 | -5,450 | -6,276 | -6,917 | -12,349 | -13,164 | -13,997 | -14,793 | -15,660 |

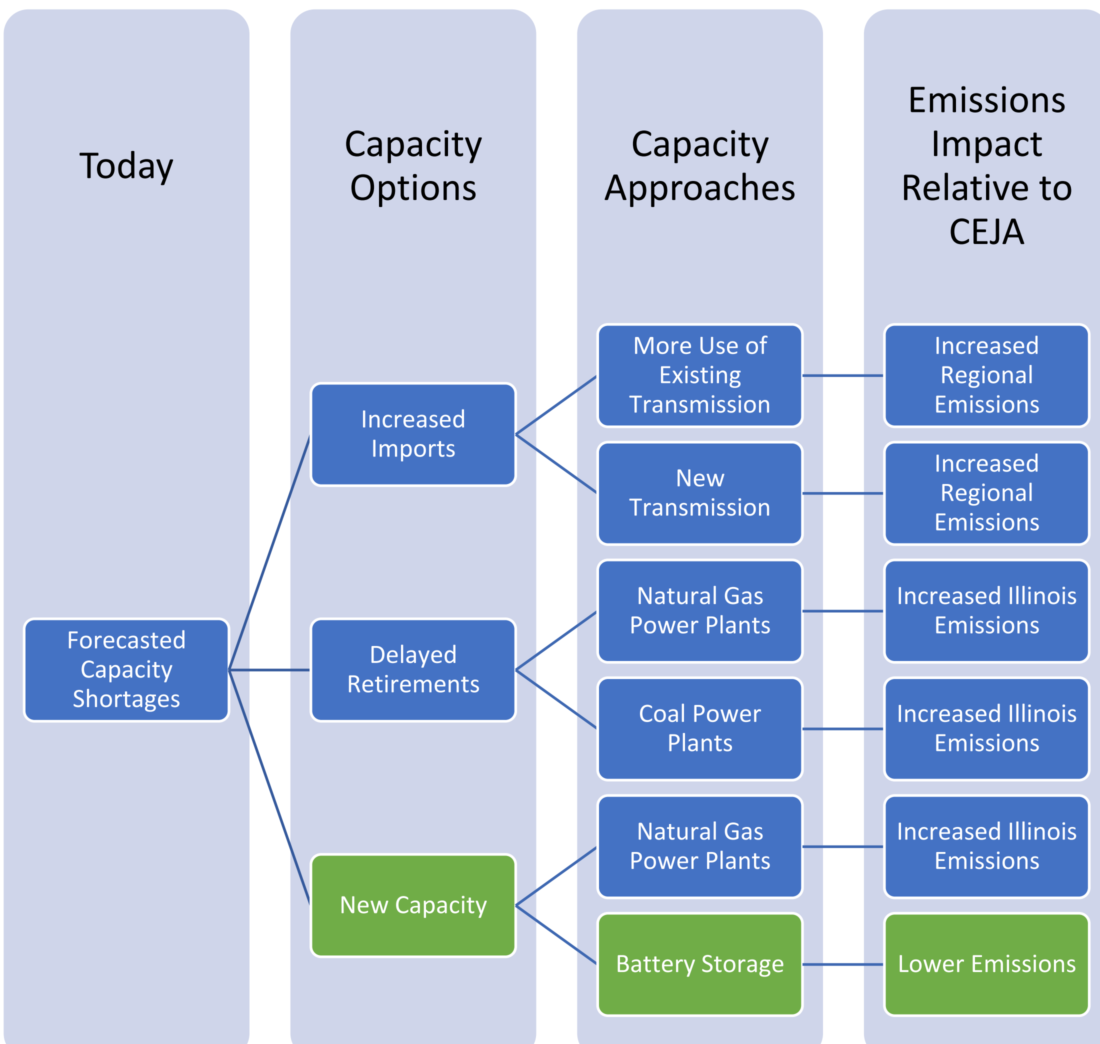
Under the Business-as-Usual scenario, Capacity Resources fail to meet Capacity Requirements in the Ameren Illinois region by 2031. In the ComEd region, Capacity Resources hover near the minimum Capacity Requirements levels until 2035 before turning decidedly negative. The Business-as-Usual scenarios demonstrate findings that are very much in line with those of NERC, PJM, MISO, the ICC, and the IPA.

Under the Decreased Renewable Energy Deployments Scenario, Capacity Resources fail to meet Capacity Requirements in the Ameren Illinois region one year earlier in 2030. Delays in deployments of renewable energy resources are more muted in the ComEd region but do contribute to a deeper Planning Reserve Margin deficit starting in 2035. The Decreased Renewable Energy Deployments Scenario demonstrate that continued delays in renewable deployments within MISO and PJM worsen the reliability outlook for all of Illinois.

Under the Increased Demand for Electricity Capacity scenario shows a decidedly more negative impact in the Ameren Illinois region where Capacity Resources fall more than 9,000 MW below the projected Capacity Requirements by 2039. A similarly negative trend is observed in the ComEd region where increased demand for electricity drives the Planning Reserve deficit to over 6,000 MW by 2039. The Increased Demand for Electricity Capacity indicates that Illinois will not have the resources necessary to meet native load growth or to fully participate fully in either electrification or the growing wave of datacenter development.

The results of the scenario analyses indicate that material shortages in Accredited Capacity could be evident in Illinois as early as 2030 and increase to as much as 15,000 MW statewide by 2039. Mitigating the loss of grid reliability associated with this capacity deficit can be achieved through different capacity options and approaches. Figure 13 below maps out the immediately available capacity options and approaches for Illinois along with the potential impact on regional emissions relative to the emissions goals for Illinois set in CEJA.

Figure 13: Capacity Deficit Mitigation Options for Illinois



Descriptions of the capacity options and approaches are as follows:

- **Increased Capacity Imports.** Illinois is connected to the PJM and MISO regional grids and can import some level of Accredited Capacity through transmission lines. The pathway to the most immediate source of incremental Accredited Capacity is to increase utilization of existing transmission system of import capacity from neighboring regions into Illinois. Over time, new transmission assets could be deployed to import greater volumes of Accredited Capacity into Illinois. Imported capacity would be sourced from fossil-fueled power plants. This situation would be like the circumstances in New Jersey where Accredited Capacity from domestic fossil-fueled power plants has been replaced by imported Accredited Capacity – some of which is sourced from fossil-fuel power plants.
- **Delayed Power Plant Retirements.** The planned retirements of power plants in Illinois could be delayed maintaining minimum levels of grid reliability in Illinois. MISO and PJM have no authority to order power plants to continue operating, but they may pay plant owners to continue operating while transmission upgrades necessary to maintain reliability are completed. Transmission upgrades can require years to complete, this option may be in place for an intermediate or longer term. Alternately, the state could follow the policy path set by California where the state elected to extend the operations of fossil fuel power plants scheduled for retirement to ensure grid reliability.[4]
- **New Capacity.** The scale of pending capacity deficit indicates that new capacity must be deployed to ensure reliability in Illinois. CEJA established a schedule for the reduction of emissions from all fossil-fuel power generating assets with nameplate capacity greater than 25 MW. Based on this, new capacity from single cycle or combined-cycle natural gas power plants seems unlikely. Illinois policymakers could follow other states which have authorized new fossil-fuel capacity deployments to ensure reliability despite having adopted aggressive emissions goals.[5] Alternatively, Illinois policymakers could support the deployment of new capacity in the form of energy storage resources.

## Key Considerations.

1. Accredited Capacity must meet or exceed peak energy demand to ensure reliability.
2. The statewide capacity shortage could be as much as 15,000 MW by 2039.
3. Illinois can increase levels of Accredited Capacity by increasing capacity imports from power plants outside of Illinois, the majority of which would be sourced from fossil-fuel power plants.
4. Illinois could experience delays in the retirement of certain fossil fuel plants of those retirements threaten the reliability of the regional grid.
5. New capacity will be required to reverse Illinois' capacity deficit. Illinois could follow other states that have elected to allow deployment of new natural gas generation to ensure reliability despite emissions goals or support the deployment of a sufficient level of energy storage to meet Illinois' reliability needs.

[4] "Despite climate goals, California will let three gas plants keep running", Sammy Roth, Los Angeles Times, August 15, 2023

[5] "California to Build Temporary Gas Plants to Avoid Blackouts", Mark Chediak | Naureen S Malik, Bloomberg, August 19, 2021.

## Question #3: Is an Energy Storage Program needed now?

The prior section applied scenario analysis to identify the severity of the potential capacity shortfall in Illinois. This section applies a similar set of scenario analyses to establish the extent to which the timing of capacity shortfalls in Illinois change in relation to potential market conditions.

The analysis considered the following scenarios:

- **Scenario A (Business-as-Usual).** The Business-as-Usual scenario noted in the above section was utilized with the same assumptions.
- **Scenario B (Accelerated Fossil-Fuel Plant Retirements)**. The Business-as-Usual Scenario was amended to accelerate by 2 years the retirement of fossil fuel power stations in Illinois during the modeling period to reflect the impact of the potential for early retirement of fossil-fuel power resources in Illinois ahead of the schedule established in CEJA.
- **Scenario C (Delayed Deployments of Renewable Energy Resources).** the Business-as-Usual Scenario was amended to delay by 1 year the deployment volume of anticipated renewable energy resources in the Ameren Illinois and ComEd regions for the modeling period to reflect slow rate of deployment of renewable energy resources in Illinois.

The results of these scenarios are presented in Figure 14 below.

Figure 14: Planning Reserve Margin Projections for Ameren Illinois and ComEd (Base Scenarios)

| SCENARIOS | YEAR | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 |
| **AMEREN ILLINOIS PLANNING RESERVE MARGIN - MW SURPLUS/(DEFICIT)** | | | | | | | | | | |
| Scenario A (Business As Usual) | 4,722 | -2,868 | -3,071 | -3,302 | -3,460 | -5,708 | -5,873 | -6,042 | -6,215 | -6,392 |
| Scenario B (Decreased Renewable Deployments) | -3,070 | -2,887 | -3,095 | -3,329 | -3,494 | -5,748 | -5,920 | -6,096 | -6,275 | -6,458 |
| Scenario C (Increased Demand for Electricity) | -3,553 | -3,890 | -4,262 | -4,669 | -5,010 | -7,447 | -7,809 | -8,182 | -8,566 | -8,961 |
| **COMMONWEALTH EDISON PLANNING RESERVE MARGIN - MW SURPLUS/(DEFICIT)** | | | | | | | | | | |
| Scenario A (Business As Usual) | 662 | 698 | 641 | 470 | 419 | -2,320 | -2,498 | -2,676 | -2,807 | -2,983 |
| Scenario B (Decreased Renewable Deployments) | 662 | 694 | 634 | 460 | 407 | -2,335 | -2,516 | -2,698 | -2,831 | -3,011 |
| Scenario C (Increased Demand for Electricity) | -692 | -892 | -1,188 | -1,607 | -1,907 | -4,902 | -5,355 | -5,815 | -6,227 | -6,699 |
| **STATEWIDE** | | | | | | | | | | |
| Scenario A (Business As Usual) | 5,383 | -2,170 | -2,430 | -2,832 | -3,041 | -8,028 | -8,371 | -8,719 | -9,022 | -9,375 |
| Scenario B (Decreased Renewable Deployments) | -2,408 | -2,193 | -2,461 | -2,869 | -3,087 | -8,083 | -8,437 | -8,794 | -9,106 | -9,469 |
| Scenario C (Increased Demand for Electricity) | -4,246 | -4,782 | -5,450 | -6,276 | -6,917 | -12,349 | -13,164 | -13,997 | -14,793 | -15,660 |

As noted earlier, under the Business-as-Usual scenario Capacity Resources fail to meet Capacity Requirements in the Ameren Illinois region by 2031 indicating that peak electricity demand could trigger emergency procedures to prevent blackouts. The ComEd region maintains marginally more Capacity

Resources than Capacity Requirements until 2035 when the balance turns negative indicating that regional plus imported capacity would not be sufficient to meet peak electricity demand.

Under the Accelerated Fossil Fuel Retirement Scenario, Capacity Resources fail to meet Capacity Requirements one year earlier in 2030 in Ameren. In ComEd, the scenario indicates that Capacity Resources fail to meet Capacity Requirements two years earlier in 2033.

The Increased Delayed Renewable Energy Resource Deployment scenario shows an even more significant negative impact in the Ameren Illinois region with Capacity Resources failing to meet Capacity Requirements by 3,000 MW in 2030. The ComEd region is less impacted and shows a marginally deeper deficit between Capacity Resources and Capacity Requirements starting in 2035.

The results of the scenario analyses indicate that material shortages in Accredited Capacity could be evident in Illinois as early as 2030. Using the historical experience of utility-scale renewable energy procurement and development in Illinois as a guide, we infer that deploying sufficient volumes of utility-scale energy storage resources would require at least five (5) years of lead time prior to the delivery of operable energy storage resources. As material shortages in Accredited Capacity could be in evidence as early as 2030, then an energy storage initiative would need to commence no later than 2025 to mitigate the risks of those capacity shortages.

We note that the scenarios analyzed above rely on existing commercially available battery technology, and assume 4-hour energy storage systems, available in the form of Lithium-ion batteries. The legislation introduced in Illinois also recognizes and accounts for the fact that emerging technologies hold the potential for extended durations of as much as multiple days. Energy storage systems with extended duration could play a significant role in ensuring reliability of Illinois' power grid, especially as the state relies on intermittent renewable generation and energy storage as a replacement for both the capacity and energy needs that have historically been provided by thermal plants. These extended duration systems could ease constraints around using storage to stand in for thermal plants, offer new opportunities to store energy for dispatch during multi-day grid stress events, such as multi-day extreme weather, and may be able to lower the overall needed installed capacity of generation plant needed to meet the state's loads. Those dynamics are not modeled in this study. The legislation that has been introduced calls for utility-scale pilot projects that utilize such technologies and requires a "firm energy resource procurement plan." This plan would evaluate and then incorporate long-duration energy storage technologies into the procurement process to support reliability and the deployment of renewable resources in accordance with state policy.

## Key Considerations.

1. Accredited Capacity should meet or exceed peak energy demand to ensure reliability within a regional power grid.

2. Analysis indicate that material capacity shortages could appear at or even before 2030 in the Ameren Illinois region and 2033 for the ComEd region.

3. The near-term timing of the projected capacity shortfalls indicates that an immediate start in the planning and deployment of energy storage resources in Illinois would be required to guarantee sufficient reliability in Illinois between 2030 and 2039.

## Question #4: What are the consumer cost impacts of incentivizing energy storage resource deployments in Illinois?

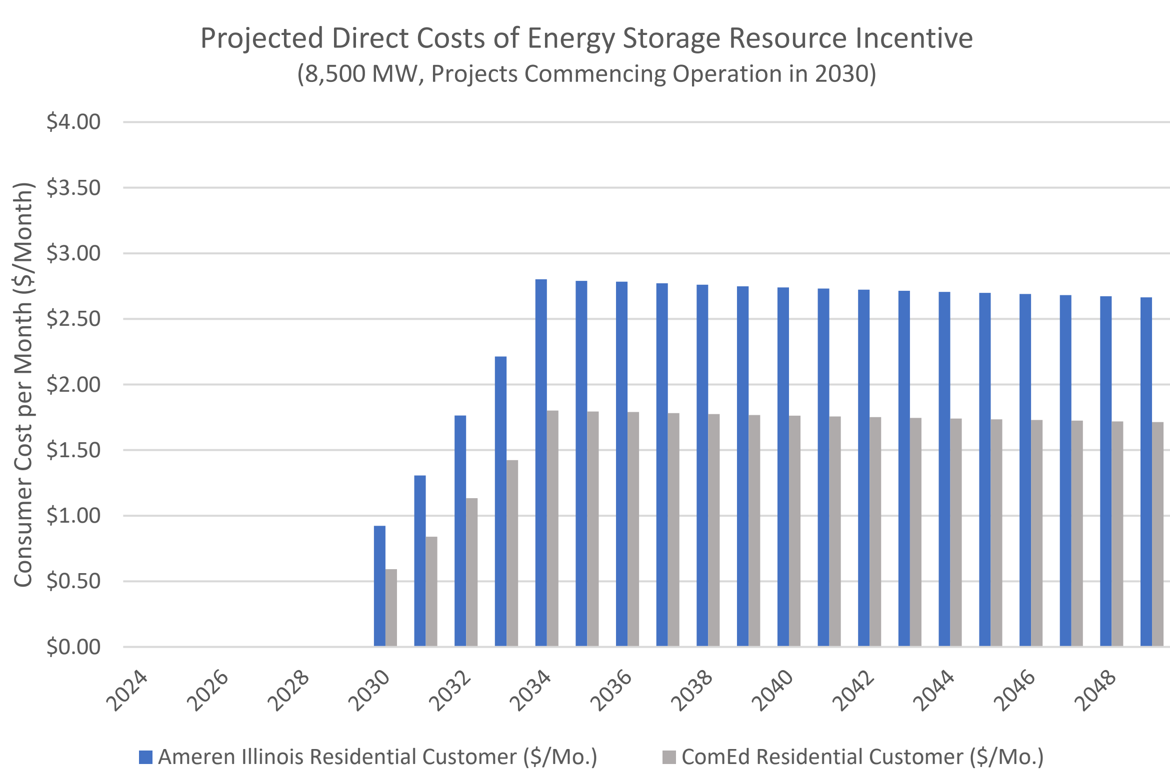
Deploying energy storage resources in Illinois will have associated cost impacts for consumers that will bear the direct costs associated with paying the incentives for the energy storage resources. However, these direct costs will be more than offset by resulting market price suppression for energy and capacity (which will flow to consumers) as well as various indirect and general market benefits such as reduced emissions, added economic activity and avoided blackouts.

### Consumer Cost Impacts of 8,500 MW of Energy Storage Resources ($3 billion benefit).

Between 2030 and 2049, the deployment of 8,500 energy storage resources is projected to add $6.4 billion of on-bill charges to Illinois consumers. During that same period, Illinois consumers are projected to realize lower energy and capacity prices which would result in approximately $9.4 billion in lower total energy costs. Combined, deploying 8,500 MW of energy storge resources in Illinois would result in a net cost savings of approximately $3 billion for Illinois consumers.

- Net Incentive Cost ($6.4 billion cost). The IPA Policy Study projected the gross cost for the energy storage resource incentive program of $24.9 billion for the period between 2030 and 2049. That gross cost would then reduce by $18.5 billion to reflect the market value of the sales of energy and Capacity that energy storage resource owners would earn during that same period. This resulted in a Net Incentive Cost for consumer of $6.4 billion. Because incentives will only be paid to successfully deployed energy storage resources, on-bill charges for the program will not occur until 2030 when

Figure 15: Projected Monthly Consumer Cost for Energy Storage Incentive for 8,500 MW Program Size



energy storage resources are expected to begin operating in Illinois. Figure 15 conveys the timing and scale of the estimated monthly costs for the energy storage resource incentive for the average single-family residential utility accounts served by Ameren Illinois and ComEd.

- Wholesale Energy Price Suppression Benefit ($533 million benefit). The IPA Policy Study projected that the introduction of large volumes of utility-scale energy storage resources would suppress wholesale electricity prices by increasing available energy supply in the PJM and MISO auction processes. The resulting reduction in wholesale prices resulting from introducing 7,500 MW of utility-scale energy storage resources between 2030 and 2049 was projected to be $452 million.

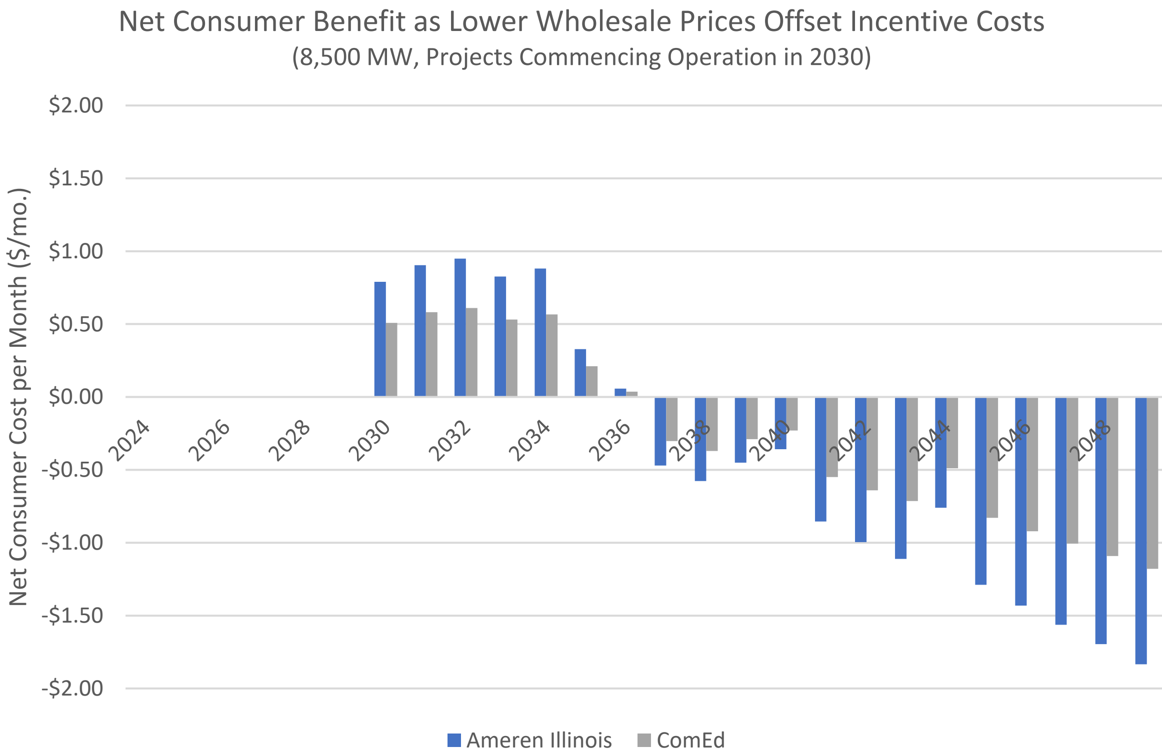
  Additionally, the IPA Policy Study identified that deploying 1,000 MW of distributed-scale energy storage resources would suppress wholesale electricity prices by reducing peak demand for electricity and thus reducing clearing prices for energy and capacity in the PJM and MISO auction processes. The resulting reduction in wholesale prices resulting from utility-scale energy storage resources between 2030 and 2049 was projected to be $81 million.

- Wholesale Capacity Price Suppression Benefit ($8.6 billion benefit). In a manner like that noted in the IPA Study above, deploying 7,500 MW of utility-scale energy storage resources between 2030 and 2049 will increase the supply of Accredited Capacity available to bid into the PJM and MISO Capacity auctions and thereby result in lower clearing prices, which will reduce the cost of Capacity prices for all ComEd and Ameren Illinois customers. Details on the methodology used to calculate the Wholesale Price Suppression Benefit can be found in Attachment B to this paper.

- Net Consumer Cost ($3 billion benefit). Deploying 8,500 MW of energy storge resources in Illinois would result in direct costs of $6.4 billion to consumers which would be offset by $9.4 billion in lower energy and capacity prices. These lower energy and capacity prices would result from the increased energy supply available to bid into the hourly PJM and MISO energy markets during peak periods, and increased energy capacity resource being available to bid into the annual PJM and MISO capacity auctions.

- Net Rate Impact for Consumers. Figure 16 conveys the timing and scale of the estimated monthly net costs for the energy storage resource incentive for the average single-family residential utility accounts served by Ameren Illinois and ComEd. As shown, an incentive program to support the deployment of 8,500 MW of energy storage resources in Illinois would cause a modest rate impact for consumers in the first years of the program as energy storage resources come online (approximately $1/month for the average Ameren Illinois customer and $0.60/month for the average ComEd consumer). Those monthly costs would then be offset by lower energy and capacity prices as the energy storage resources resulting from the program begin bidding into the PJM and MISO energy and capacity markets thus causing lower clearing prices. These lower wholesale clearing prices for energy and capacity would result in lower energy supply charges for consumers and eventually grow to a level that is greater than the monthly energy storage program charges.

Figure 16: Projected Net Monthly Consumer Cost for Energy Storage Incentive for 8,500 MW Program Size

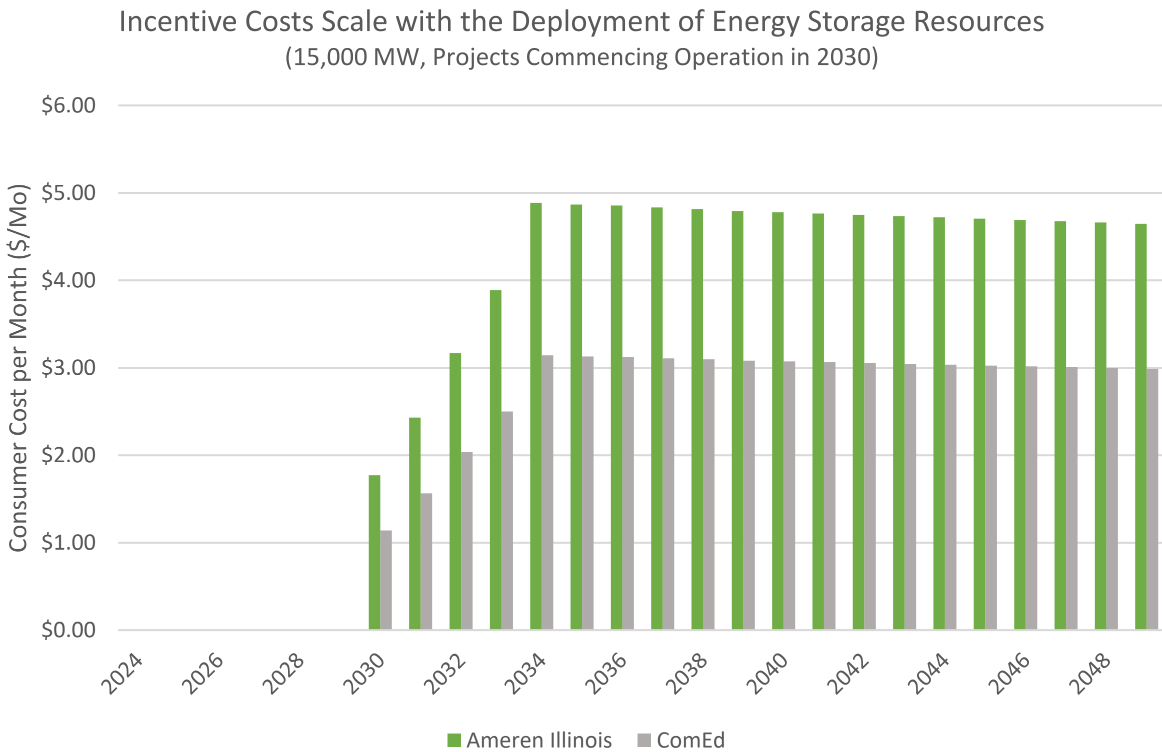



## Consumer Cost Impacts of 15,000 MW of Energy Storage Resources ($2.4 billion benefit).

Between 2030 and 2049, the deployment of 15,000 MW of energy storage resources is projected to add $11.2 billion of on-bill charges to Illinois consumers. During that same period, Illinois consumers are projected to realize lower energy costs amounting to approximately $9.383 billion. Combined, deploying 15,000 MW of energy storge resources in Illinois would result in a net cost savings of approximately $2.4 billion for Illinois consumers.

- Net Incentive Cost ($11.2 billion cost). Scaling the energy storage program to 15,000 MW would carry a projected total gross cost $45.9 billion for the period between 2030 and 2049. That gross cost would be reduced by $34.8 billion to reflect the market value of the sales of energy and capacity that energy storage resource owners would earn during that same period. This resulted in a Net Incentive Cost for consumer of $11.1 billion. Because incentives will only be paid to successfully deployed energy storage resources, on-bill charges for the program will not occur until 2030 when energy storage resources are expected to begin operating in Illinois. Figure 17 conveys the timing and scale of the estimated monthly costs for the energy storage resource incentive for the average single-family residential utility accounts served by Ameren Illinois and ComEd.

Figure 17: Projected Monthly Consumer Cost for Energy Storage Incentive for 15,000 MW Program Size




The incentive costs of the energy storage program will be more than offset by the price suppression the added energy storage resources will cause in the wholesale energy and capacity markets.

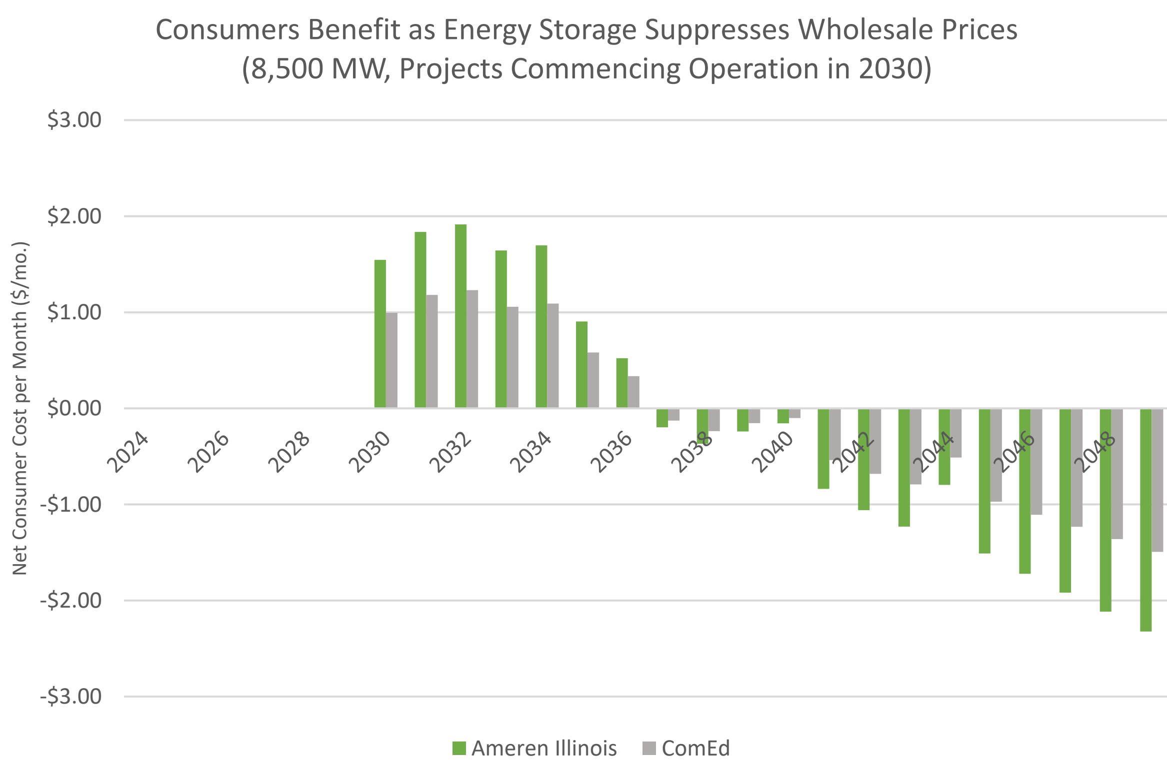
- Wholesale Energy Price Suppression Benefit ($0.8 billion benefit). The IPA Policy Study projected a price suppression effect of over $550 million for the deployment of 8,500 MW of energy storage resources in Illinois between 2030 and 2039. To account for the price suppression effect of 15,000 MW of energy storage, we scaled the IPA projection by a conservative 50% factor to reflect for diminishing price suppression effect that would be realized in the PJM and MISO wholesale energy markets resulting from the injection of additional peak hour energy supply volumes.

- Wholesale Capacity Price Suppression Benefit ($12.7 billion benefit). As noted above, deploying 15,000 MW of utility-scale energy storage resources between 2030 and 2049 will increase the supply of Accredited Capacity available to bid into the PJM and MISO Capacity auctions and thereby result in lower clearing prices. This will result in reduced Capacity prices for all ComEd and Ameren Illinois customers. Details on the methodology used to calculate the Wholesale Price Suppression Benefit can be found in Attachment B to this paper.

- Net Consumer Cost ($3 billion benefit). Deploying 15,000 MW of energy storge resources in Illinois would result in net direct costs of $11.2 billion to consumers which would be offset by $13.6 billion in lower energy and capacity prices. These lower energy and capacity prices would result from the increased energy supply available to bid into the hourly PJM and MISO energy markets during peak periods, and increased energy capacity resource being available to bid into the annual PJM and MISO capacity auctions.

- Net Rate Impact for Consumers. Figure 18 conveys the timing and scale of the estimated monthly net costs for the energy storage resource incentive for the average single-family residential utility accounts served by Ameren Illinois and ComEd. As shown, an incentive program to support the deployment of 15,000 MW of energy storage resources in Illinois would cause a modest rate impact for consumers in the first years of the program as energy storage resources come online (approximately $1.75/month for the average Ameren Illinois customer and $0.90/month for the average ComEd consumer). Those monthly costs would then be offset by lower energy and capacity prices as the energy storage resources resulting from the program begin bidding into the PJM and MISO energy and capacity markets thus causing lower clearing prices. These lower wholesale clearing prices for energy and capacity would result in lower energy supply charges for consumers and eventually grow to a level that is greater than the monthly energy storage program charges.

Figure 18: Projected Net Monthly Consumer Cost for Energy Storage Incentive for 15,000 MW Program Size




Economic Impacts of Energy Storage Resources. Deploying energy storage resources will also provide significant benefits beyond consumer bills. Based on the findings of the IPA's Policy Study and other sources, we estimate that the value of these benefits as ranging between $11.8 and $24.8 billion.

- Wholesale Transmission Cost Avoidance (Unidentified Benefit). Credible and public authorities identify that utility-scale energy storage resources reduce congestion-related transmission costs (See: National Renewable Energy Laboratory, New York ISO, California ISO, PJM Interconnection). Additionally, energy storage resources can defer or fully avoid transmission system expansions and extensions to reduce transmission costs. Estimating the scale of these benefits is beyond the scope of this study, however, policymakers and the industry may elect to examine this issue at a future time as the regional ISOs accelerate their transmission system planning processes to contend with the energy transition. For instance, PJM recently estimated that accelerating retirements of baseload power stations in Illinois could require over $1.3 billion in transmission system upgrades to ensure reliability.[6]

- Utility Distribution System Cost Avoidance ($250 million). Distributed-scale energy storage resources deliver a range of values to local utility distribution systems. Under CEJA, the value of distributed resources is $250/kW of installed capacity. Applying this rate to the proposed volume of 1,000 MW of distributed-scale energy storage resource capacity yields a consumer value of $250 million. As with the transmission cost avoidance value noted above, policymakers and the industry should examine this issue carefully to determine the extent to which distributed scale energy storage resources can further delay or avoid the costs presented in the utility Multi-Year Grid Plans that are currently under consideration in Illinois.

  When combined, these various direct consumer costs and benefits yield a net savings for consumers. As noted in Figure 18, the net cost to consumers is minor in the first years of the program (e.g., about $1.00 per month for the average single family residential customer served by Ameren Illinois, about $0.68 per month for the average single family residential customer served by ComEd). However, after the energy storage resource portfolio has been fully deployed, the value of the price suppression in the PJM and Ameren Illinois Capacity auctions will increase as other sources of Accredited Capacity retire.

- Value of Reliability ($7.3 billion). Grid operators recognize the economic value of avoiding power outages. MISO identifies the value of lost load (VOLL) as ranging between $3,500 to $23,000/MWh (LRTP Tranche 1 Portfolio Detailed Business Case, LRTP Workshop, March 29, 2022). MISO's VOLL rate indicates that avoiding just one-day of lost load in MISO Zone 4 (central and southern Illinois) would have a value of between $345 million and $2.3 billion (e.g., 98,630 MWh of average daily load * VOLL rate). The average annualized value of avoiding one day of outages every ten years in MISO Zone 4 would then be $35.5 to $230 million. PJM has not identified a VOLL range.

  To identify the value of reliability that would result from deploying 8,500 MW of energy storage resource in Illinois, we utilized a tool development by the US Department of Energy and Lawrence Berkely Lab "Interruption Cost Estimate (ICE)" calculator. The ICE calculator allows electric reliability planners at utilities, government organizations or other entities to estimate the cost-of-service interruptions and the economic benefits associated with reliability improvements. According to the outputs of the ICE calculator, the annualized value of increasing grid reliability in Illinois to avoid 1 day of outages every 10 years for a 20-year period is $7.3 billion. To be clear, consumers will not

[6] Illinois Generation Retirement Study PJM Interconnection August 3, 2022

experience a discount on their utility bills reflecting this value; however, consumers would realize the material benefits that a more reliable regional power system can provide.

- Value of Avoided Emissions ($756 million to $4.9 billion). The IPA Policy Study identified that expanding energy storage resource will result in reductions in emissions from the existing fleet of fossil-fuel generators. Figure 20 conveys the findings from the Policy Study which specifies a range of values related to reductions in $CO_2$, $SO_2$, $NO_x$ and Particulate Matter.

  As with the Value of Reliability, consumers will not experience a discount on their utility bills reflecting this value; however, the issue of avoided emissions costs could become a relevant direct consumer cost in the event of a cap and trade or carbon tax policy in future years.

- Value of Additional Economic Activity ($3.75 to 16.2 billion). The IPA Policy Study also identified that expanding energy storage resource will result in increased economic activity and local job development. Figure 21 conveys the findings from the Policy Study which specifies a range of value for incremental economic activities and job creation as they relate to the proposed deployment of energy storage resources.

Figure 20: Value of Reduced Emissions (IPA Study, 2024)

**Table 5-11: Energy Storage Range of Value of Emissions Impacts (2030-2049, Shown in 2022 Real Dollars**

| | |
|---|---|
| $CO_2$ | $423 million - $4.15 billion |
| $SO_2$ | $65 – 288 million |
| $NO_x$ | $434 -259 million |
| $PM_{2.5}$ | $9 - 85 million |

Figure 21: Projected Value of Added Economic Opportunity and Job Creation (IPA Policy Study, 2024)

**Table 5-12: Total (Direct, Indirect and Induced) Value Added**

| Case | Total Value Added | | |
|---|---|---|---|
| | $ | $/MW | $/TWh |
| Utility-Scale Energy Storage Low CapEx | $1,969,419,166 | $262,589 | $12,060,567 |
| Utility-Scale Energy Storage High Capex | $8,836,463,187 | $1,178,195 | $54,113,801 |
| Utility-Scale Energy Storage Low Opex | $1,138,331,501 | $151,778 | $6,971,052 |
| Utility-Scale Energy Storage High Opex | $4,490,941,843 | $598,792 | $27,502,172 |
| Distributed Energy Storage Low Capex | $510,450,822 | $510,451 | $23,444,703 |
| Distributed Energy Storage High Capex | $2,036,437,850 | $2,036,438 | $93,532,382 |
| Distributed Energy Storage Low Opex | $259,859,576 | $259,860 | $11,935,196 |
| Distributed Energy Storage High Opex | $1,005,621,973 | $1,005,622 | $46,187,620 |

**Table 5-13: Total (Direct, Indirect and Induced) Job Creation**

| Case | Total Job Creation | | |
|---|---|---|---|
| | FTE-Years | FTE-Years/MW | FTE-Years/TWh |
| Utility-Scale Energy Storage Low Capex | 16,473 | 2.196 | 100.877 |
| Utility-Scale Energy Storage High Capex | 62,107 | 8.281 | 380.338 |
| Utility-Scale Energy Storage Low Opex | 9,555 | 1.274 | 58.515 |
| Utility-Scale Energy Storage High Opex | 31,766 | 4.235 | 194.534 |
| Distributed Energy Storage Low Capex | 4,198 | 4.198 | 192.807 |
| Distributed Energy Storage High Capex | 14,329 | 14.329 | 658.136 |
| Distributed Energy Storage Low Opex | 2,191 | 2.191 | 100.608 |
| Distributed Energy Storage High Opex | 7,127 | 7.127 | 327.345 |

## Key Considerations.

1. Between 2031 and 2049, deploying 8,500 MW of energy storage resources in Illinois would deliver the following:

   a. $6.4 billion in consumer support between 2031-2049.

   b. $533 million in wholesale energy cost suppression and $8.6 billion in wholesale capacity costs suppression.

   c. $3.0 billion in net consumer cost reductions between 2031-2049.

   d. $5.19/month in cost savings for the average Ameren Illinois residential customer between 2030 and 2049.

   e. $3.34/month in cost savings for the average ComEd residential customer between 2030 and 2049.

2. Between 2031 and 2049, deploying 15,000 MW of energy storage resources in Illinois would deliver the following:

    a. $11.2 billion in consumer support between 2031-2049.

    b. $800 million in wholesale energy cost suppression and $12.7 billion in wholesale capacity costs suppression.

    c. $2.4 billion in net consumer cost reductions between 2031-2049.

    d. $4.37/month in cost savings for the average Ameren Illinois residential customer between 2030 and 2049.

    e. $2.81/month in cost savings for the average ComEd residential customer between 2030 and 2049.

3. Between 2031 and 2049, deploying energy storage resources in Illinois would deliver at least the following economic benefits:

    a. Deliver a Value of Reliability of $7.3 billion reflecting the value of reducing power outages in Illinois from 1 day in ten years to 0 days in ten years.

    b. Deliver general economic benefits of $756 million and $4.9 billion between 2031-2049 because of reducing emissions from fossil-fuel power stations.

    c. Support an increase in value added economic activity of between $3.75 and $16.2 billion .

## Conclusions

The deployment of a significant volume of energy storage resources will make material improvements in the reliability of energy supply in Illinois. Improved reliability will enhance the safety health and well-being of all Illinoisans and position the state of continued progress towards it economic and sustainability goals.

Importantly, the conclusions of this study align with the forecasts of all relevant energy regulators (e.g., NERC, PJM, MISO, ICC, IPA) that Illinois will experience material and persistent capacity shortfalls as early as 2030. Depending on a range of factors, Illinois could require between 9,000 and 15,000 MW of new Accredited Capacity to maintain compliance with the NERC Reserve Margin guidelines used to ensure a minimum level of regional grid reliability.

Accelerating retirements of fossil fuel power plants, delays in deployments of renewable energy resources, and the exceptionally long lead times related to delivering regional transmission solutions lead to the conclusion that delivering energy storage resources into Illinois is the approach to ensuring the reliability of the power grid in Illinois.

Deploying between 8,500 and 15,000 MW of energy storage capacity will require between $6.4 and $11.2 billion in direct consumer support. In return for this investment, consumers will realize lower wholesale energy and capacity costs which will lead to lower retail costs. These lower retail costs will exceed consumer charges by $2.4 to 3.0 billion between 2030 and 2049. Specifically, an energy storage resource program will yield long term direct and indirect consumer costs benefits including:

- An average net energy cost reduction of approximately $4/month for a typical residential customer served by Ameren Illinois between 2030 and 2049,
- An average net energy cost reduction of over $3/month for a typical residential customer served by ComEd between 2030 and 2049.

Additionally, the deployment of a significant volume of energy storage in Illinois will also generate general economic values for consumers and industry in Illinois:

- A Value of Reliability of $7.3 billion reflecting the value of reducing power outages in Illinois from 1 day in ten years to 0 days in ten years.
- Benefits of $756 million and $4.9 billion between 2031-2049 because of reducing emissions from fossil-fuel power stations.
- Value added economic activity of between $3.75 and $16.2 billion .

In short, deploying a significant energy storage program will be the necessary investment to support the stability of the regional power grid, deliver direct economic value to Illinois consumers, and continue to support the energy transition in Illinois.

## About this Study

This study was supported by the following organizations:

- The American Clen Power Association
- The Coalition for Community Solar Access
- The Solar Energy Industries Association
- The Clean Grid Alliance

The Power Bureau is an independent consulting firms specializing in energy planning and procurement. Led by Mark Pruitt, The Power Bureau assists public and private organizations model, evaluate, and transact in wholesale and retail energy markets. Prior to his work with The Power Bureau, Pruitt served as the first Director of the Illinois Power Agency, the state agency responsible for planning and managing wholesale energy and renewable energy procurement for consumers receiving service from Ameren Illinois and ComEd through default rate service. Pruitt serves as an Associate Professor at Northwestern University where he teaches course in energy policy, markets, and regulation.

Capacity, Accredited Capacity, and Reserve Margins. If a regional power system connected one hundred power stations with a combined maximum power output of 20,000 megawatts (MW) and a transmission interconnection with a neighboring regional power system that import up to 5,000 MW of power then the Capacity of that system would be 25,000 MW. This means that if all the power assets (power stations, transmission, etc.) were fully operational at the same time, then that power system could fulfill consumer demand of up to 25,000 MW.

However, power system assets are not able to always deliver 100% of their potential output due to a range of physical and operational constraints:

- Fuel Availability. Sufficient fuel is not always available for power stations. Nuclear stations require refueling ever two years, coal piles can freeze in extreme weather, natural gas supply can be curtailed to support consumer heating needs, wind turbines require a minimum wind speed to operate, direct sunlight is required for maximum output from solar panels. seasonal water flow rates can reduce the output of hydroelectric generation, and atmospheric temperatures can reduce the output from landfill gas generating assets..
- Limited Ramp Rates Not all power stations can instantaneously start and stop in response to variable consumer demand. Nuclear plants have minimal ability to vary their output, most coal and natural gas plants sometimes require hours to increase the thermal outputs to support more power generation, and few renewable resources have consistent ramping capabilities.
- Maintenance Downtimes. Power stations require periodic and regular maintenance which require that the stations pause power delivery to the regional power system.
- Emergencies, Accidents, and Failure. All power stations can experience failures caused by extreme weather, unforeseen equipment failures, and other emergency situations which require that the stations cease power delivery to the regional power system.

Federal, regional, and state power system planners acknowledge these issues and apply a variety of approaches to account for power station constraints and to assess whether consumer demand can be met by a regional power system. Two of these approaches are core to the analysis of this Study:

- Accredited Capacity. System planners apply an Effective Load Carrying Capability (ELCC) variable to each power asset to reflect the realistic contribution to regional Capacity that power asset can provide when consumer demand peaks in the regional power system. Multiplying a power asset's maximum output by the ELCC yields the Accredited Capacity of the power resource.

  Figure A below conveys the ELCC values that PJM will apply to different power resources in an upcoming Capacity procurement. For example, if a new 100 MW onshore wind generator were to seek to provide Capacity to the PJM system, PJM would multiply the wind asset's 100MW of maximum output by the 35% ELCC to yield a 35MW Accredited Capacity value for that wind generator. Based on this, it would take 300 MW of onshore wind generator Capacity to provide 100MW of Accredited Capacity, while it would take only 105 MW of Capacity from a nuclear station to provide 100 MW of Accredited Capacity.

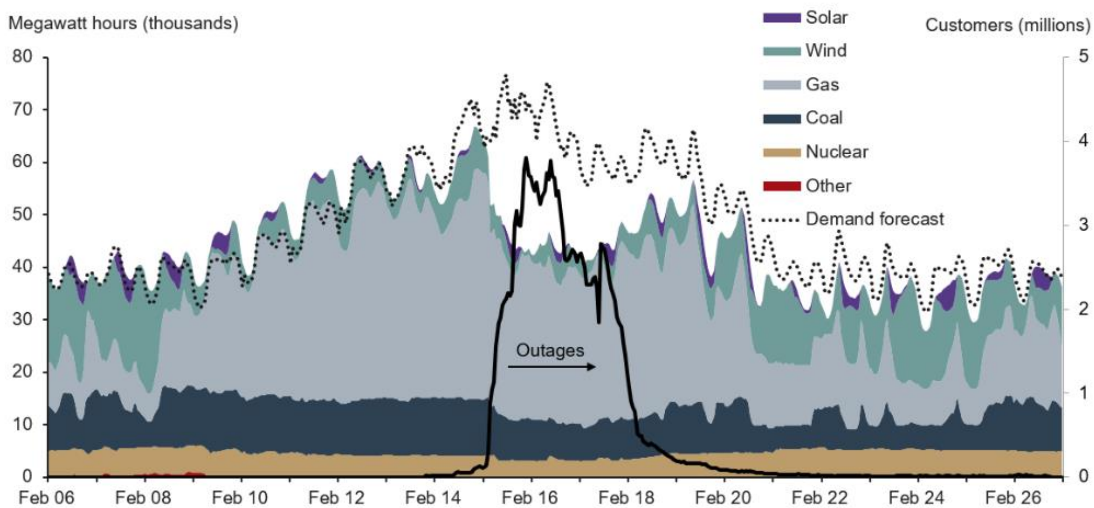
Figure A: Effective Load Carrying Capabilities of Various Generating Resources (PJM)

| | 2025/2026 BRA ELCC Class Ratings |
|---|---|
| Onshore Wind | 35% |
| Offshore Wind | 60% |
| Fixed-Tilt Solar | 9% |
| Tracking Solar | 14% |
| Landfill Intermittent | 54% |
| Hydro Intermittent | 37% |
| 4-hr Storage | 59% |
| 6-hr Storage | 67% |
| 8-hr Storage | 68% |
| 10-hr Storage | 78% |
| Demand Resource | 76% |
| Nuclear | 95% |
| Coal | 84% |
| Gas Combined Cycle | 79% |
| Gas Combustion Turbine | 62% |
| Gas Combustion Turbine Dual Fuel | 79% |
| Diesel Utility | 92% |
| Steam | 75% |

- Planning Reserve Margin. System operators seek to secure extra volumes of Accredited Capacity to guard against the risk that some Accredited Capacity may not being available for delivery to the regional power system. This extra volume of Accredited Capacity is the Planning Reserve Margin. The North American Reliability Corporation (NERC) is a not-for-profit regulatory authority empowered by the Federal Energy Regulatory Commission (FERC) to establish and enforce reliability standards for regional power system operators. NERC recommends that regional power system operators maintain a 15% Planning Reserve Margin (e.g., ensuring access to a volume of Accredited Capacity that is 15% more than the peak consumer demand would normally require).

Reliability. While these Capacity planning activities appear mundane, they are essential to ensuring reliability under all adverse conditions. For example, in February 2021, the wholesale power market manager that serves most of the state of Texas (Electric Reliability Council of Texas, ERCOT) experienced a major power crisis. Wintry weather and storms caused consumer power demand to reach historic highs while simultaneously constraining fuel deliveries and power production from all generating resources (nuclear, coal, natural gas, wind, and solar). In response, system operators implemented a rolling blackouts to prevent a total collapse of the ERCOT system. Figure B conveys the speed and severity of the power outages that triggered the system instability and resulting blackouts. The blackouts impacted more than 4.5 million homes and businesses[7]. Up to 246 deaths have been directly or indirectly attributed to the blackouts.[8] The Federal reserve Bank of Dallas estimates that the blackouts cost the Texas economy between $8 and 130 billion.[9] We note that ERCOT does not operate a Capacity market.

Figure B: Timeline of events leading to blackouts in ERCOT in February, 2021




Source: [Federal Reserve Bank of Dallas]

[7] Sullivan, Brian, K.; Malick, Nauren S. (February 16, 2021). "5 Million Americans Have Lost Power From Texas to North Dakota After Devastating Winter Storm". *Time*. Retrieved February 16, 2021.
[8] Patrick Svitek (January 2, 2022). "Texas puts final estimate of winter storm death toll at 246". *The Texas Tribune*. Retrieved January 3, 2022.
[9] Golding, Garrett; Kumar, Anil; Mertens, Karel (April 15, 2021) "Cost of Texas' 2021 deep freeze justifies weatherization" The Federal Reserve Bank of Dallas.

Capacity Price Suppression Calculation Approach. PJM and MISO utilize auctions to select the power stations that receive capacity agreements. Under these agreements, the capacity provider (e.g., power plant operator, demand response provider, etc.) is obligated to provide a maximum amount of capacity upon demand to the grid if called upon. The capacity provider receives compensation for this service and are subject to penalties for non-performance.

As market-based mechanisms, the PJM and MISO capacity auctions yield variable prices that change over time in relation to regional supply and demand. Consequently, low volumes of Accredited Capacity relative to regional Peak Demand will cause Capacity process to be higher. Alternately, higher volumes of Accredited Capacity relative to regional Peak Demand will cause Capacity process to be lower.

To estimate the price suppression effect of introducing new energy storage resources into the PJM and MISO capacity auctions we reviewed the forward capacity price projections presented in Figure C below which reflect the findings of the Illinois Policy study by the IPA.

Figure C: Projected Capacity Prices in Illinois (IPA Policy Study, '20240215 capacity prices.xls')

| YEAR | FORWARD CAPACITY PRICES ($/MW-Day) | | | |
|---|---|---|---|---|
| | PJM | | MISO CONE | |
| | COST OF NEW ENTRY (CONE) | PRICE PROJECTION | COST OF NEW ENTRY (CONE) | PRICE PROJECTION |
| 2025 | $405.00 | $68.95 | $338.25 | $130.00 |
| 2026 | $537.25 | $108.13 | $346.71 | $131.00 |
| 2027 | $556.05 | $61.78 | $355.37 | $134.00 |
| 2028 | $575.52 | $59.91 | $364.26 | $138.00 |
| 2029 | $595.66 | $96.58 | $373.36 | $131.00 |
| 2030 | $616.51 | $80.29 | $382.70 | $145.00 |
| 2031 | $638.08 | $103.01 | $392.27 | $273.54 |
| 2032 | $660.42 | $101.56 | $402.07 | $402.07 |
| 2033 | $683.53 | $199.70 | $412.12 | $412.12 |
| 2034 | $707.46 | $210.48 | $422.43 | $422.43 |
| 2035 | $732.22 | $291.93 | $432.99 | $432.99 |
| 2036 | $757.84 | $391.76 | $443.81 | $443.81 |
| 2037 | $784.37 | $609.20 | $454.91 | $454.91 |
| 2038 | $811.82 | $631.46 | $466.28 | $466.28 |
| 2039 | $840.24 | $544.93 | $477.94 | $477.94 |
| 2040 | $869.64 | $476.03 | $489.89 | $489.89 |
| 2041 | $900.08 | $679.48 | $502.13 | $502.13 |
| 2042 | $931.58 | $717.68 | $514.69 | $514.69 |
| 2043 | $964.19 | $745.67 | $527.55 | $527.55 |
| 2044 | $997.94 | $556.76 | $540.74 | $540.74 |
| 2045 | $1,032.86 | $775.76 | $554.26 | $554.26 |
| 2046 | $1,069.01 | $814.58 | $568.12 | $568.12 |
| 2047 | $1,106.43 | $847.52 | $582.32 | $582.32 |
| 2048 | $1,145.15 | $880.62 | $596.88 | $596.88 |
| 2049 | $1,185.24 | $915.04 | $611.80 | $611.80 |
| 2050 | $1,226.72 | $946.40 | $627.10 | $627.10 |

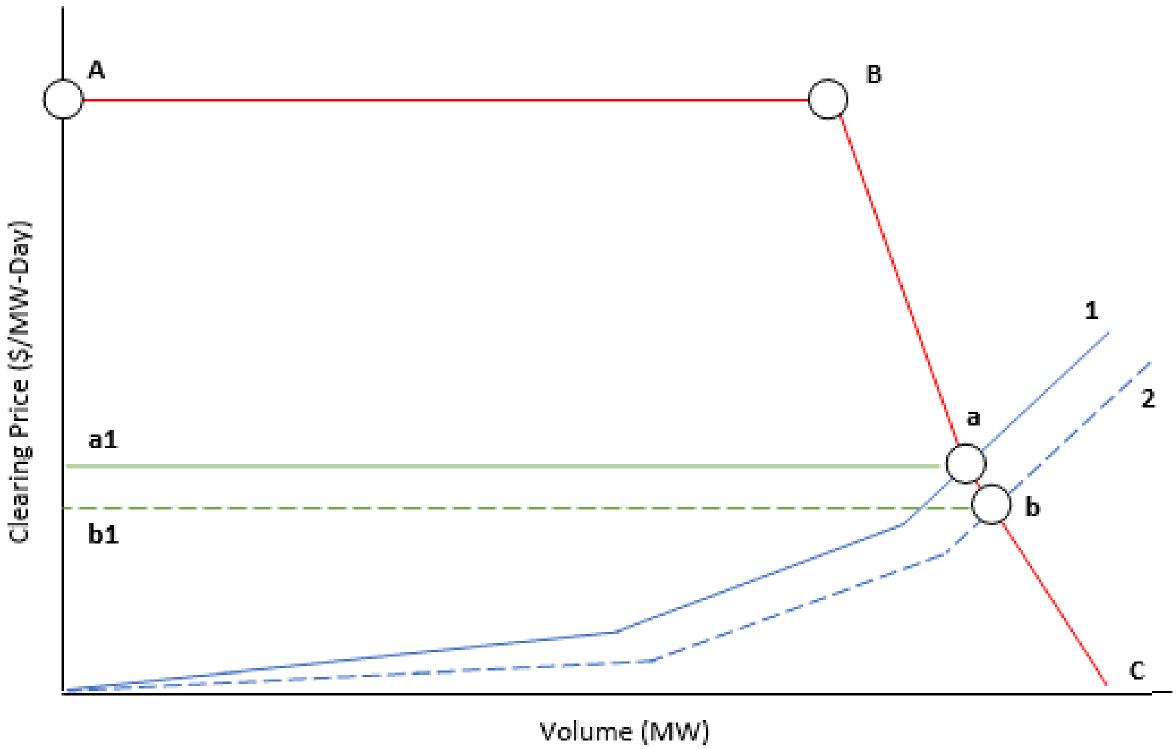
We then established a process whereby we replicated the capacity auction and bidding process that would yield the capacity values presented by the IPA. Then we adjusted the volumes in those annual bidding process models to reflect the injection of the various capacity volumes that would be delivered through the proposed program to establish a new clearing price in each period.

The level of Capacity price suppression resulting from the introduction of new capacity resources in a wholesale power market can be estimated by using the methodology described below and conveyed in Figure D:

- The ISO sets a capacity demand curve (solid red line segment “ABC”)
- Bids from generating units create the supply curve (solid blue line “1”)
- The point at which the supply and demand curve cross (point “a”) sets the auction clearing price of “a1” (solid green line).
- A secondary supply curve is created to reflect the introduction of the new Capacity that is available from the new energy storage resources (blue dashed line segment ABC) and the new supply curve (dashed blue line “2”).
- The point at which the secondary supply curve cross (point “b”) sets a new auction clearing price of “b1” (dashed green line).
- Multiplying the difference in clearing prices (a1 minus b1) by the volume of Capacity secured represents the cost savings for Capacity that would be realized by all consumers in the wholesale market region.

On a parallel analysis, further price suppression would occur in the wholesale Capacity auction as a result from deploying 1,000 MW of distributed-scale energy storage resources in Illinois. Unlike utility-scale resources, the proposed distributed-scale energy storage resources would not increase the supply of Capacity available to bid into the PJM and MISO capacity auctions. Instead, the distributed-scale energy storage resources would serve to reduce system peak demand by releasing energy during the peak hours of the day. In so doing, the regional power systems will register a lower total volume of Capacity requirements.

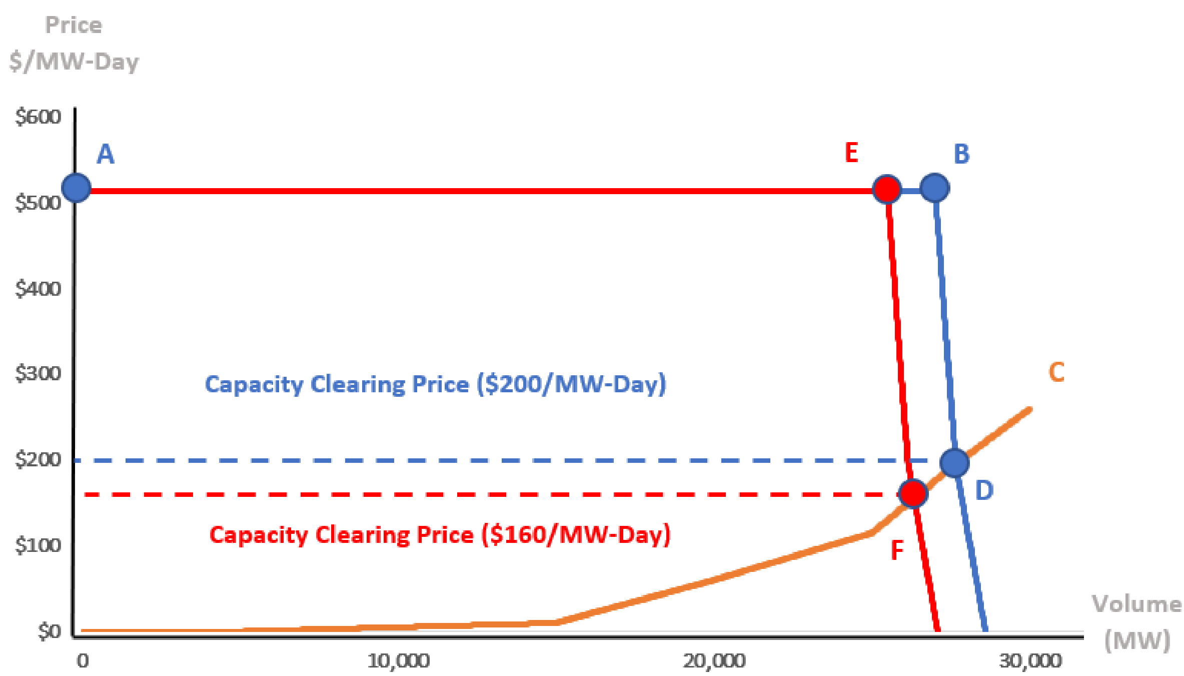
Figure D:  Price Suppression in Wholesale Capacity Market Auction Prices Resulting from Increased Supply of Accredited Capacity




The level of Capacity price suppression resulting from the introduction of distributed-scale energy storage resources in regional power markets was estimated by using the following general steps described below and conveyed in Figure D:

- The ISO sets a demand curve with a minimum Capacity requirement (segment AB)
- Generating units bid in their offers to provide Capacity to the ISO region (C)
- The clearing price for Capacity is set where Capacity supply intersects the Demand curve (D, blue dashed line)
- The use of energy storage resources to reduce peak demand within the ISO will alter the original Demand Curve (segment AE)
- Because the same generating units bid in their offers to provide Capacity to the ISO region, the supply line remains the same (segment C)
- A lower capacity clearing price occurs where the supply line intersects the new Demand curve (F, red dashed line)
- Multiplying the difference in clearing prices (a1 minus b1) by the reduced volume of Capacity secured represents the cost savings for Capacity that would be realized by all consumers in the wholesale market region.

Figure E: Capacity Market Price Suppression Effect Resulting from Additional Distributed Energy Storage Resources




This process was repeated in each of the program years (2030 to 2039) and each utility region to arrive at a projected capacity price suppression value (e.g., (IPA Capacity Price Projection) – (Adjusted Capacity Price Projection) = (Projected Price Suppression Value)). This projected capacity price suppression value was then multiplied by the annual projected volume of capacity required for the appropriate utility to yield an estimated annual capacity cost reduction value.