2025 OMS-MISO Survey Results

Furthering our joint commitment to regional resource adequacy, OMS and MISO are pleased to announce the results of the 2025 OMS-MISO Survey

June 6, 2025

Updated 6/6/2025: Slide 21

Executive Summary

The 2025 OMS-MISO Survey reinforces near-term risks and highlights key uncertainties impacting resource adequacy

- Projections result in a potential surplus ranging from 1.4 GW to 6.1 GW for summer 2026. At least 3.1 GW* of additional capacity beyond the committed capacity will be needed to meet the projected planning reserve margin forecast.
- Queue and market reforms, improved resource deployment timelines and other initiatives will help maintain resource adequacy through 2031.
    - Replacement and surplus queue projects will mitigate the impact of retirements by using existing interconnection service, supplying ~25% of new capacity additions.
- As solar penetration grows, reliability risks are spreading into winter from summer.
- Load growth, driven by economic development, is outpacing previous forecasts with a 2.2% compound annual growth rate over five years.
- Resource accreditation reforms (e.g., Direct Loss of Load in PY 2028/29) are expected to provide a clearer view of resource adequacy, system-level outlooks remain consistent with current methods.

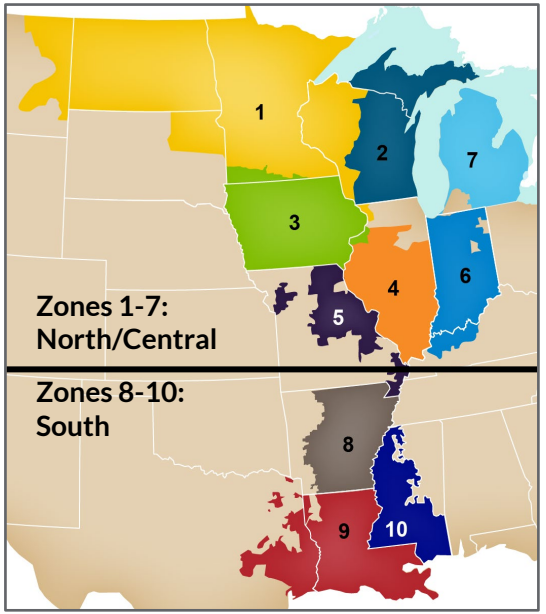
All references to capacity in this presentation indicate seasonal accredited capacity (SAC), unless noted otherwise.

*See slide 7 for data which illustrates the projected Planning Reserve Margin Requirement with Load Serving Entities' forecast (137.3 GW) minus Committed Capacity (134.2) for PY 2026/27.

The OMS-MISO Survey provides a resource adequacy view over a five-year horizon based on currently available information

The survey* results indicate the degree to which expected capacity resources satisfy planning reserve margin requirements with either a surplus or a deficit

- 91% of existing generation participated in the 2025 OMS-MISO Survey, representing 97.4% of MISO load.
- Various projected capacity scenarios and large spot-load additions highlight the increasing uncertainty and evolving risk.
- Load Serving Entities (LSEs) are expected to have adequate resources to meet load reserve requirements in each zone.
- MISO zonal views are not included this year as the annual capacity import limit and capacity export limit study will provide value updates and be reported in the Loss of Load Expectation report in November.



*The survey serves as a point-in-time analysis based on data collected during April 2025.

Additional factors can impact projected deficits or surpluses that are observed in the survey

Downside Risks

- Winter reliability risk intensifies due to low solar accreditation during the season
- Rapid industrial and commercial growth adds pressure on resource adequacy
- Continued backlog and uncertainty in generation queue (296 GW) complicates timely resource additions
  - 54 GW of signed Generation Interconnection Agreements (GIAs) not yet online (71% of which are wind and solar)
- Accelerated pace of resource retirements is driven by regulatory pressures, economic pressures and aging infrastructure
- Persistent supply-chain disruptions, labor constraints and permitting challenges delay new resource deployments

Upside Possibilities

- Market reforms, including Reliability-Based Demand Curve and accreditation updates, provide clearer and stronger investment signals
- Enhanced forecasting methods recognizing replacement/ surplus units improve accuracy and confidence
- Queue reforms reduce speculative projects and streamline resource integration processes
- Retirement deferrals offer a potential short-term reliability buffer against seasonal projected capacity shortfalls
- Easing of supply, labor, or permitting constraints could speed deployments

Summer Seasonal Accreditation Values

Resource Category	2025 Survey	2024 Survey
Potentially Unavailable Resources	• No Changes	• Indicated as "Low Certainty" in survey results by market participants • Includes potential retirements or suspensions • Assumes resources will **not** be used to meet PRMR
Potential New Capacity – *New Point of Interconnection*	• **Historical Projection:** Results in **3.5 GW/yr** • *Driven by 2022-2024 actuals* • **Emerging Projection:** Results in **6.2 GW/yr** average • *Informed by member responses to OMS-MISO Survey request, these members represent 97% of the load in the footprint* • *Fuel mix of new resources indicated by OMS-MISO Survey member responses*	• **Using 3-Year Historical Average:** Capacity addition (2.3 GW/yr) based on the average new capacity built in Planning Years 2020-2022 • **Using Alternative Projection:** Informed by timing estimates from interconnection customers with signed Generator Interconnection Agreement projects* (6.1 GW/yr) • Assumes resources **will** be used to meet PRMR
Replacement/ Surplus Project Impact Potential New Capacity – *Existing Point of Interconnection*	• **Replacement Impact Highlighted:** Results in additional "new resources" to offset the impacts of retirements • **Historical Replacement** : Valued at **1.2 GW/yr** • *50% replacement & surplus queue adoption* • **Emerging Replacement:** Valued at **2.4 GW/yr** • *100% replacement & surplus queue adoption* • *The replacement queue is not directly part of MISO's queue cycle methodology, and until recently the adoption rate of future replacement resources was unknown*	• Not included
Committed Capacity	• No Changes	• Existing generation resources • External resources with firm contracts to MISO load • Assumes resources will be used to meet PRMR

PRMR: *Planning Reserve Margin Requirement*
Committed Capacity: *Resources committed to serving MISO's load*
Potentially Unavailable Resources: *May be available to serve MISO's load but may not have firm commitments*

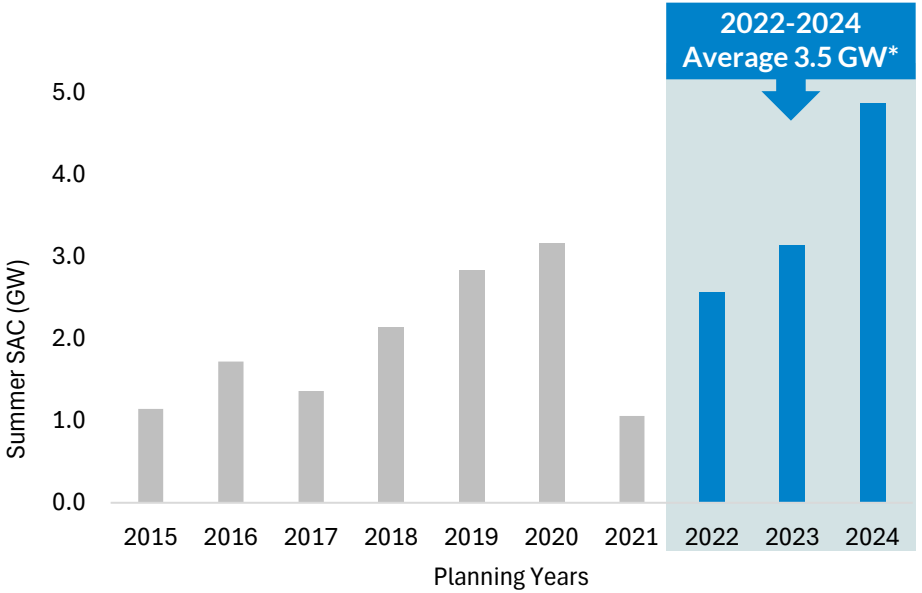
Trends and market pressures related to new capacity additions suggest that refinements are needed to better reflect uncertainty

Previously, MISO used probability-adjusted estimates for projects in various queue phases. Due to the significantly larger queue and constraints on projects with signed Generation Interconnection Agreements (GIAs), this approach no longer applies. As in 2024, the 2025 survey employs two estimates:

1. **Three-Year Historical Average:** based on the historical rate of additions per planning year*
2. **Emerging Projection:** based on member submittals to the OMS-MISO Survey

These projections are combined with the MISO Surplus and Replacement Queues to create bookend capacity forecasts for the MISO footprint.

The scale and pace of new resource additions have varied over time

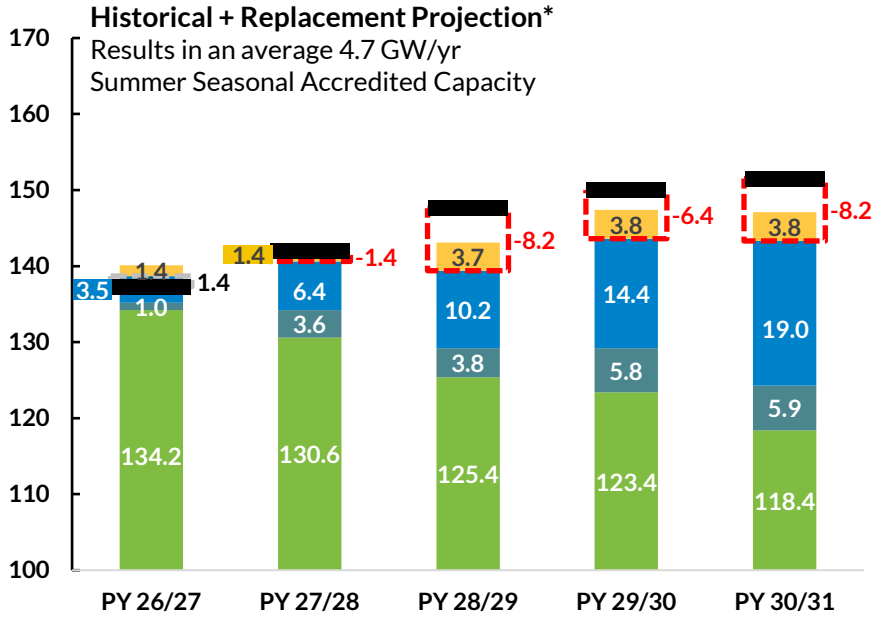


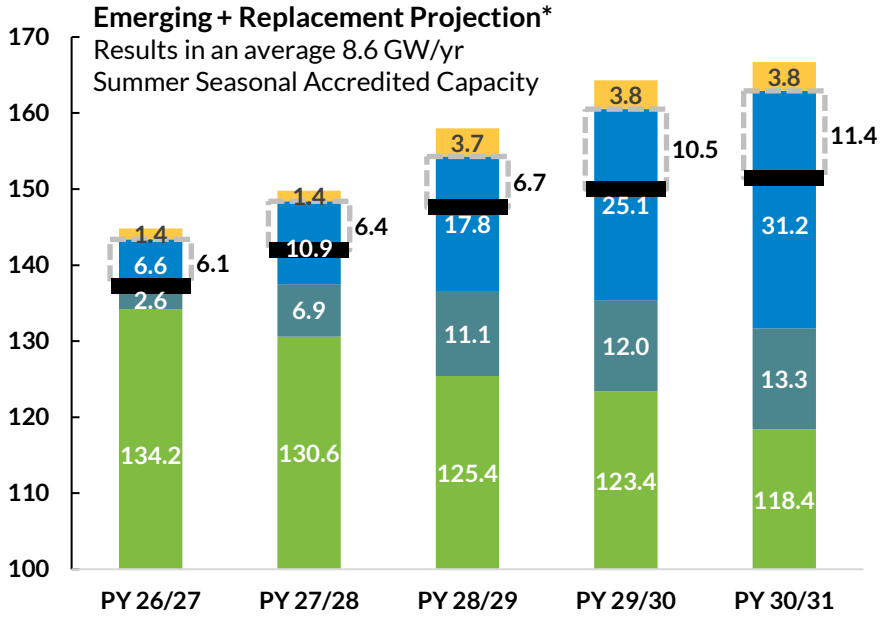
Queue applications: Nameplate 296 GW Queue & 54 GW Signed GIAs not yet online (as of 5/14/25)

**Summer seasonal accredited potential new capacity based on 2022-24 actuals*

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projections – Summer





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

Using methods for potential New Capacity described on Slide 5

***PRMR:** Planning Reserve Margin Requirement*

Red border values indicate the additional potential deficit against the Projected PRMR
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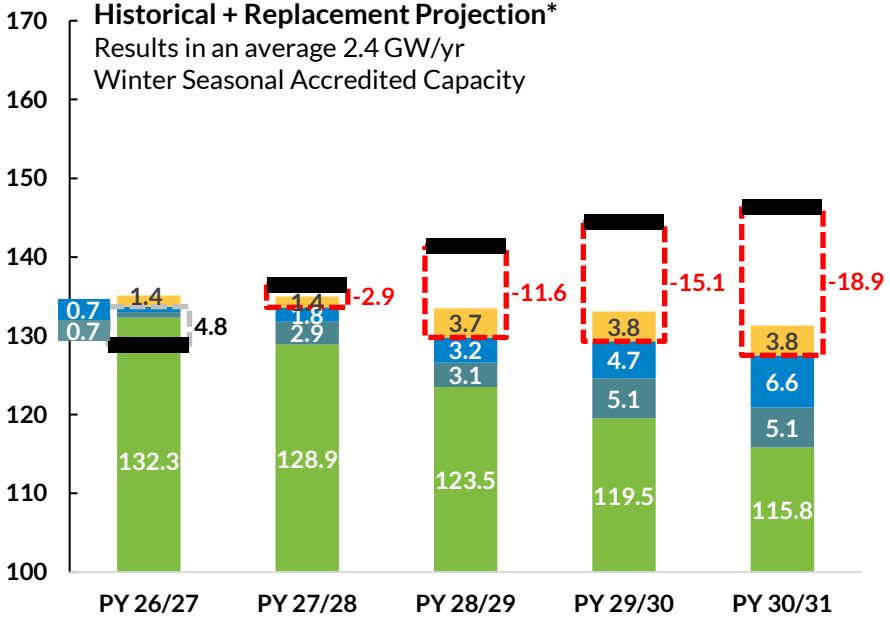
Winter Seasonal Accreditation Values

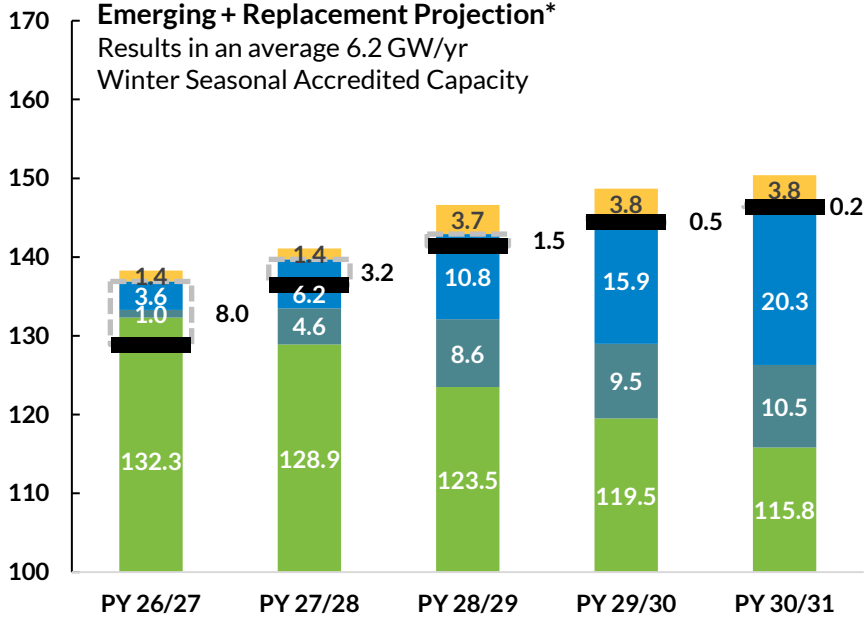
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Historical + Replacement & Emerging + Replacement Projections vs PRMR
~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter





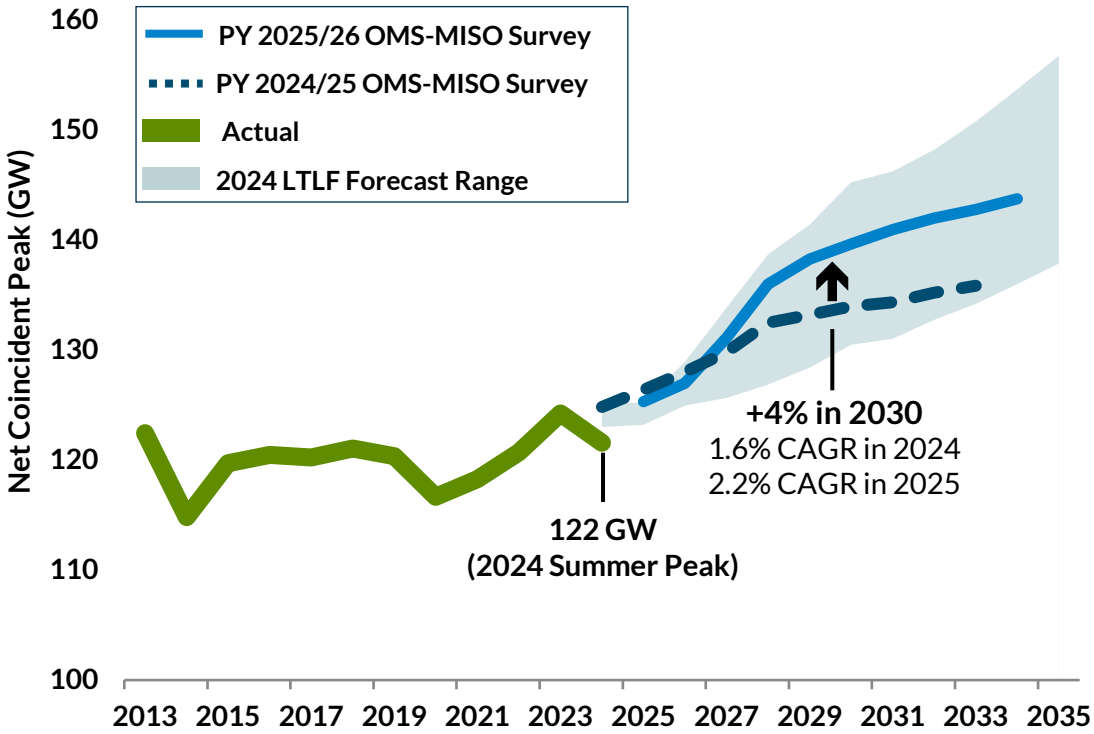
Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

Using methods for potential New Capacity described on Slide 8
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- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

OMS-MISO Survey responses show increasing load forecasts year-over-year and are close to the high end of MISO Long-Term Load Forecast



- Load growth through 2035 will exacerbate capacity shortfall and operational risks
- Many new loads will require additional firm, controllable resources

Anticipated Impact in MISO's region
2024-44 Growth TWh Low-High*



Data Centers (149-241)

Electric Vehicles (54-91)

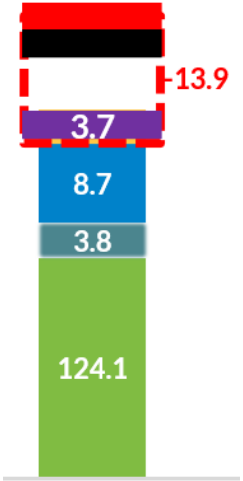
Industry Development & Offshoring (21-105)

Hydrogen (25-95)

Building Electrification (36-43)

LTLF: Long-Term Load Forecast, 2024 Long-Term Load Forecast White Paper; **CAGR:** Compound Annual Growth Rate
**Level of certainty based on expected likelihood of load growth materializing*

NEW: The 2025 OMS-MISO Survey includes sensitivities considering a range of new, large spot-load additions



PY 28/29

Illustrative example: PY 2026/27 using three-year historical average

PRMR based on Long-Term Load Forecast "High Trajectory"

- Models higher load-growth scenario per Long Term Load Forecast[1]
- Red dashed border values = deficit; gray dashed border values = surplus

PRMR based on LSE submitted load forecast

- LSE-submitted Non-Coincident Peak Forecast (NCPF) converted to Coincident Peak Forecast (CPF) using MISO-posted coincidence factors
- Transmission losses added
- PRMR calculated using out year PRM% from PY 2025/26 LOLE Study

PRMR based on Long-Term Load Forecast "Current Trajectory"

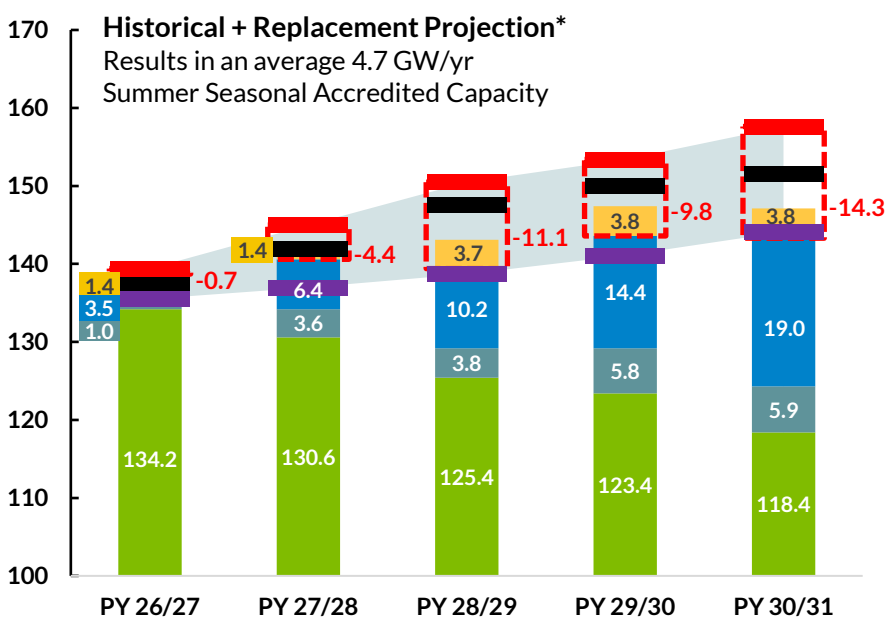
- Models lower load-growth scenario per Long-Term Load Forecast[1]

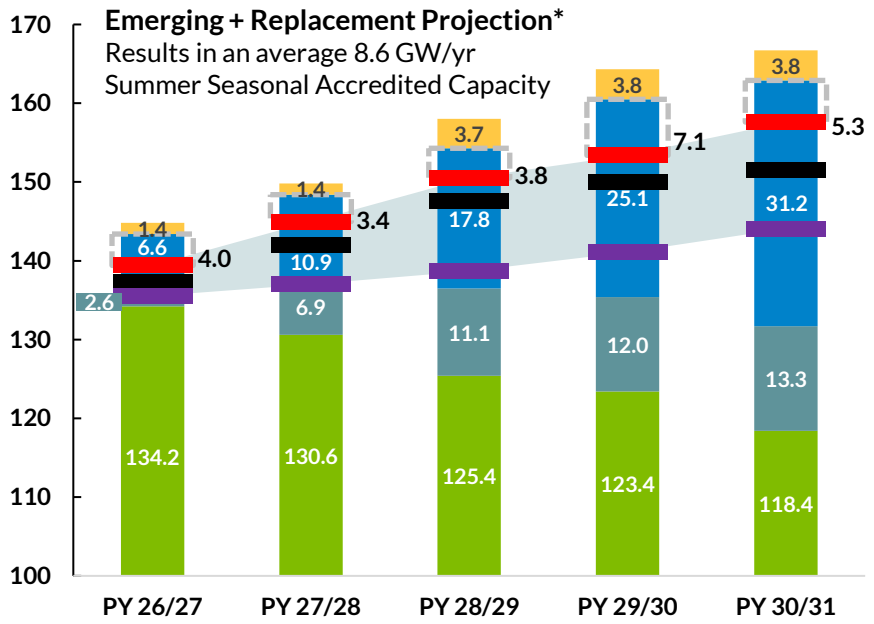
[1] MISO Long-Term Load Forecast White Paper, December 2024

PRMR: *Planning Reserve Margin Requirement* ***LSE:*** *Load Serving Entity* ***LOLE:*** *Loss of Load Expectation*

Capacity deficits continue to grow in the near and long term under a large spot-load additions scenario

MISO Resource Adequacy Projections – Summer





Planning Reserve Margin

- Projected PRMR for 'High Trajectory' scenario
- Projected PRMR for 'Current Trajectory' scenario
- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

- Shaded area indicates spread between projected PRMR for "Current Trajectory" and "High Trajectory" scenario from Long-term Load Forecast
- Red border values indicate the additional potential deficit with "High Trajectory" scenario case
- Gray border values indicate the potential surplus with "High Trajectory" scenario case
- Capacity accreditation values and Planning Reserve Margin projections based on current practices

**Using Potential New Capacity as described on Slide 5.*

***PRMR:** Planning Reserve Margin Requirement*

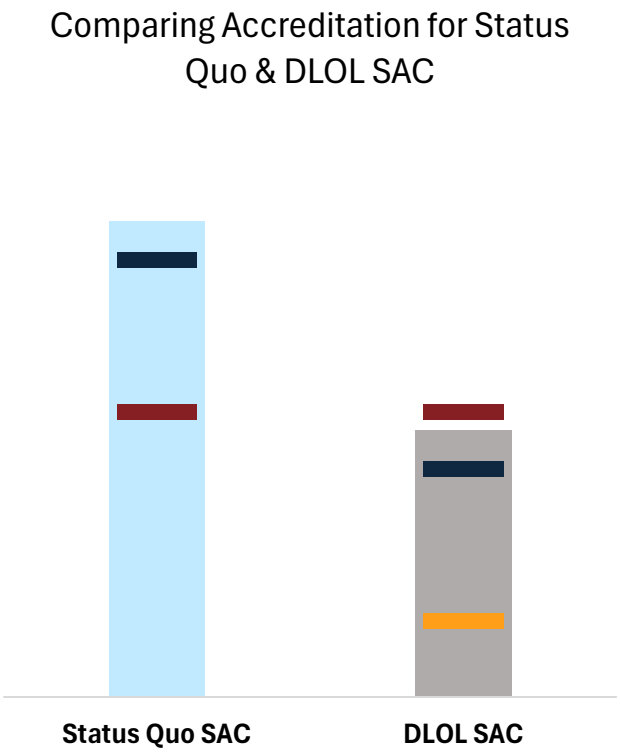
MISO's existing accreditation methods can overstate a resource's capacity value during the highest risk periods, especially as the region's risk profile changes, leading to understated risk

- Increased reliance on wind, solar and storage, projected large-load additions and electrification, and frequent large-scale weather events are decoupling periods of risk from periods of high demand.
- These drivers are upending traditional methods for establishing reliability requirements and resource accreditation.
- MISO's resource accreditation methodology* (Direct Loss of Load) will value a resource's marginal contribution to reliability during the highest risk periods.

MISO's accreditation reforms, targeted for implementation in PY 2028/29, will better measure a resource's contribution to reliability.

*See Resource Accreditation White Paper, published March 2024

High Level Description of Status Quo vs Direct Loss of Load



Peak Load Forecast
- Submitted annually by members

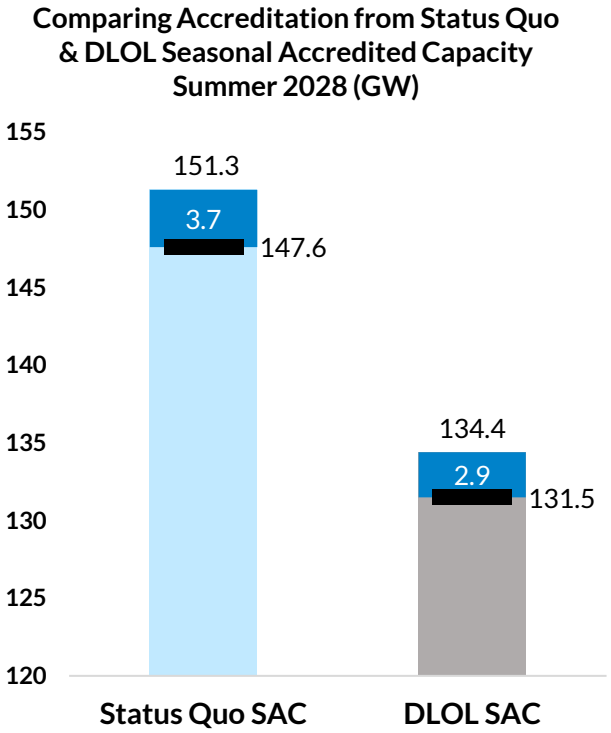
Critical Hours Load Forecast
- Illustrative only, not collected

Planning Reserve Margin Requirement (PRMR) at
- Status Quo: Peak Load
- DLOL: critical hours

Status Quo SAC value of Resources during MISO peak to meet PRMR

DLOL SAC value of Resources during critical hours to meet PRMR

Status Quo vs Direct Loss of Load Accreditation for summer 2028



- In principle, surplus/deficit moving from status quo to DLOL SAC should remain unchanged
- Modeled load and resource mix that is misaligned from OMS-MISO Survey results will cause deviations in surplus/deficit
- PY 2028/29 was most comparable in load and resource mix, which is why DLOL view is only shown for one year

Planning Reserve Margin Requirement (PRMR)
Surplus (Nearly equivalent between Status Quo & DLOL)
Status Quo SAC value of Resources during MISO peak to meet PRMR
DLOL SAC value of Resources during critical hours to meet PRMR

MISO has acted on many Reliability Imperative initiatives to address resource adequacy challenges, but there's more to be done

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Intermittent nature of new resource additions
- Delays of new resource additions
- More frequent extreme weather

Completed Initiatives

- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal June 2025)*
- ✓ Approved over $30 billion in new transmission lines

Initiatives In Progress

- ❑ Implement interim Expedited Resource Addition Study (ERAS) process *(2025)*
- ❑ Implement Direct Loss of Load (DLOL)-based accreditation *(PY 2028/29)*
- ❑ Enhance resource adequacy risk modeling
- ❑ Reduce queue cycle times through automation
- ❑ Demand Response and Emergency Resource reforms
- ❑ Enhance allocation of resource adequacy requirements

Key Takeaways

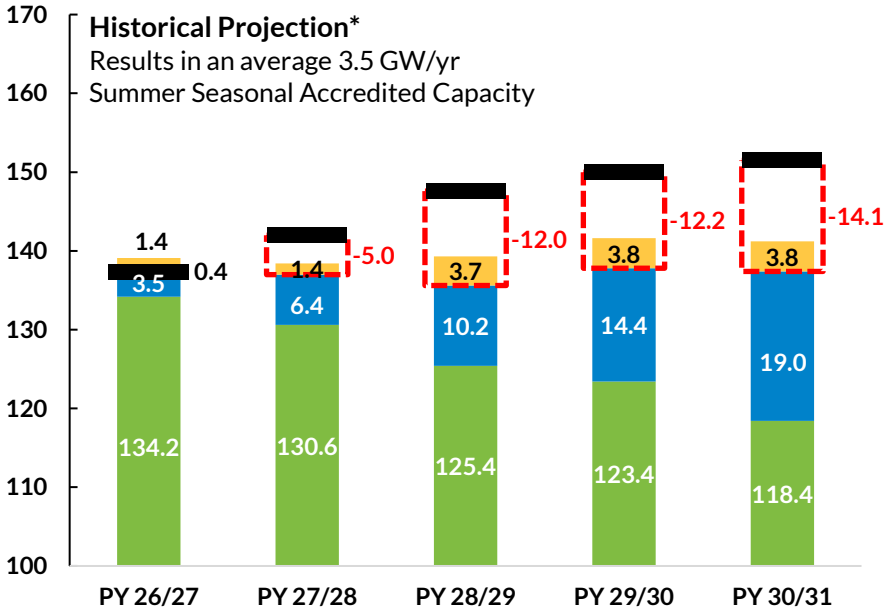
The 2025 OMS-MISO Survey emphasizes that decisions made today by utilities, regulators, MISO and its members will critically shape future resource adequacy

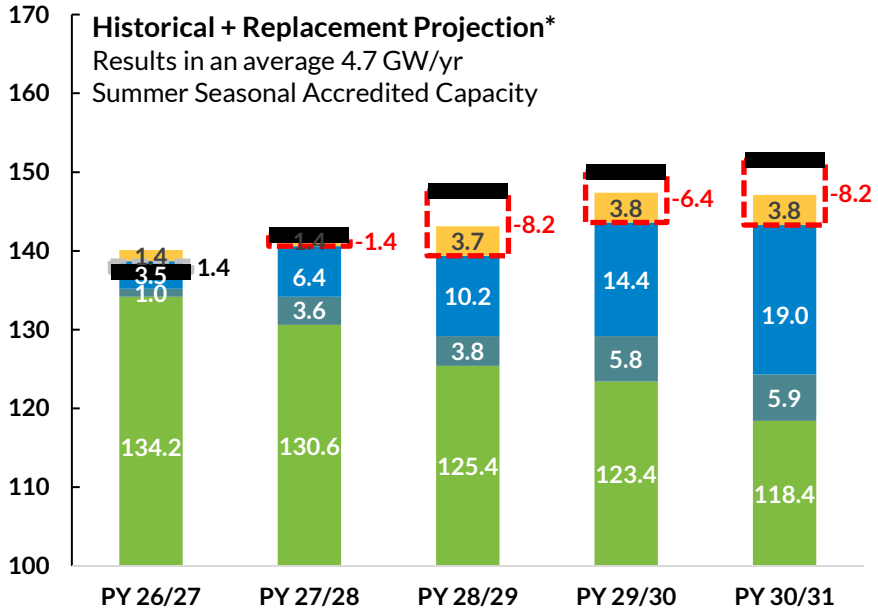
- This year's survey highlights significant uncertainty in projected resource adequacy, underscoring the urgent need for accelerated resource additions, strategic retirement planning, and proactive management of increasing load growth.
- Ongoing collaboration between OMS and MISO remains essential to address intensifying reliability risks, particularly as seasonal challenges, especially in winter, grow increasingly complex.
- Continued and immediate actions are required to streamline the addition of new capacity, align resources effectively with new load demands.
- MISO's ongoing resource adequacy reforms remain critical and responsive, directly addressing evolving reliability challenges.

Appendix

Historical & Historical + Replacement Projections vs PRMR
~3.5 GW & 4.7 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projection – Summer





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

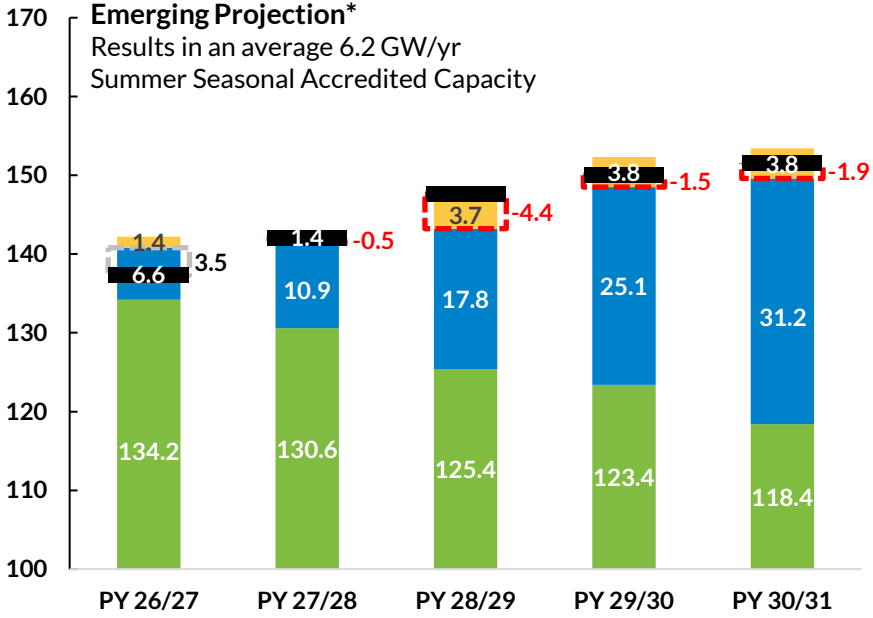
Using methods for potential New Capacity described on Slide 5
***PRMR:** Planning Reserve Margin Requirement*

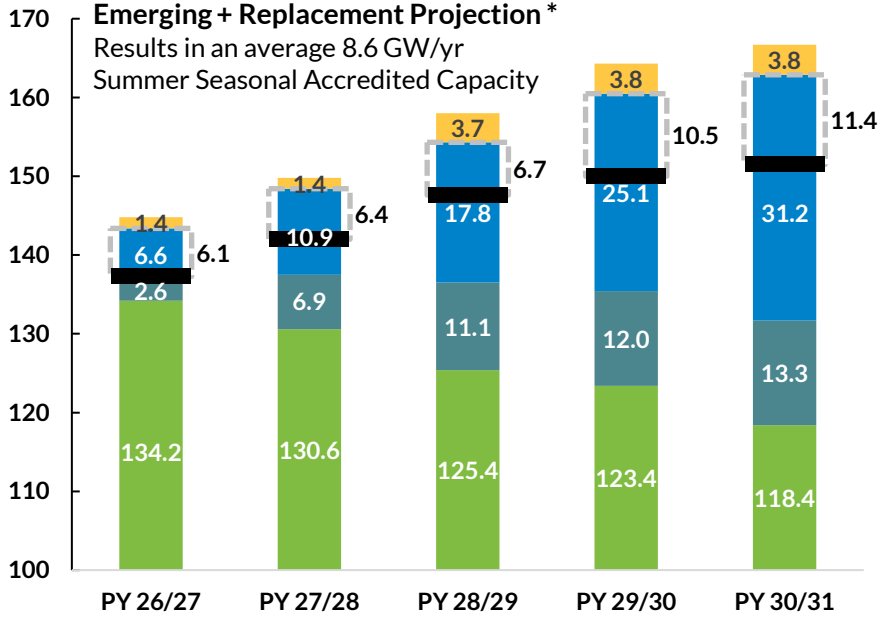
Red border values indicate the additional potential deficit against the Projected PRMR
Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Emerging & Emerging + Replacement Projections vs PRMR
~6.2 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projection – Summer





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

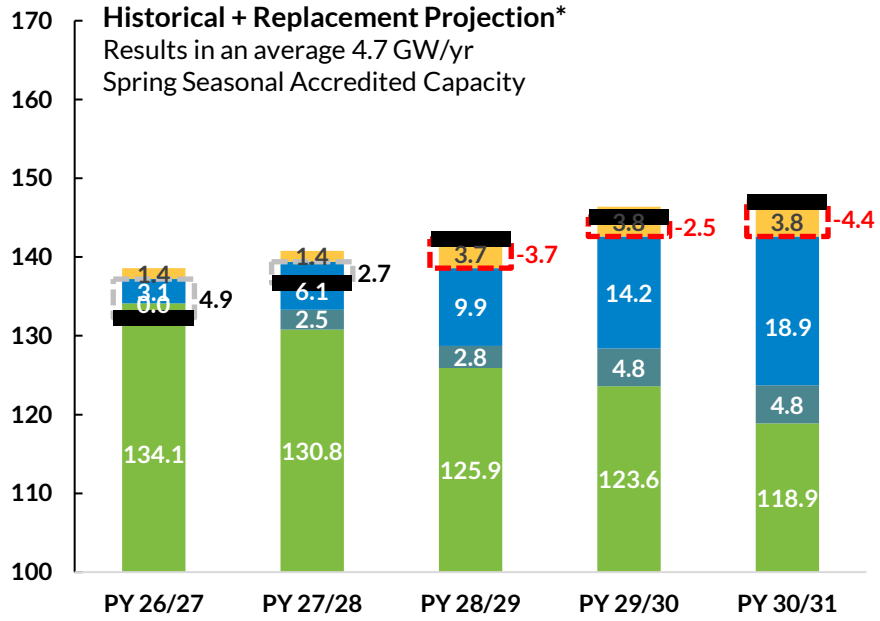
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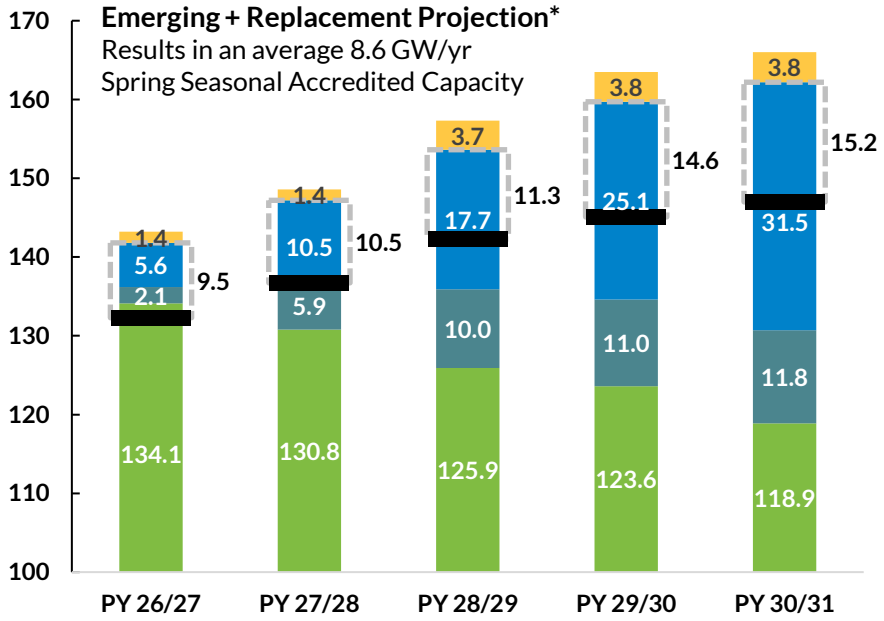
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Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Fall SAC Installation Rate

MISO Resource Adequacy Projection – Fall





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

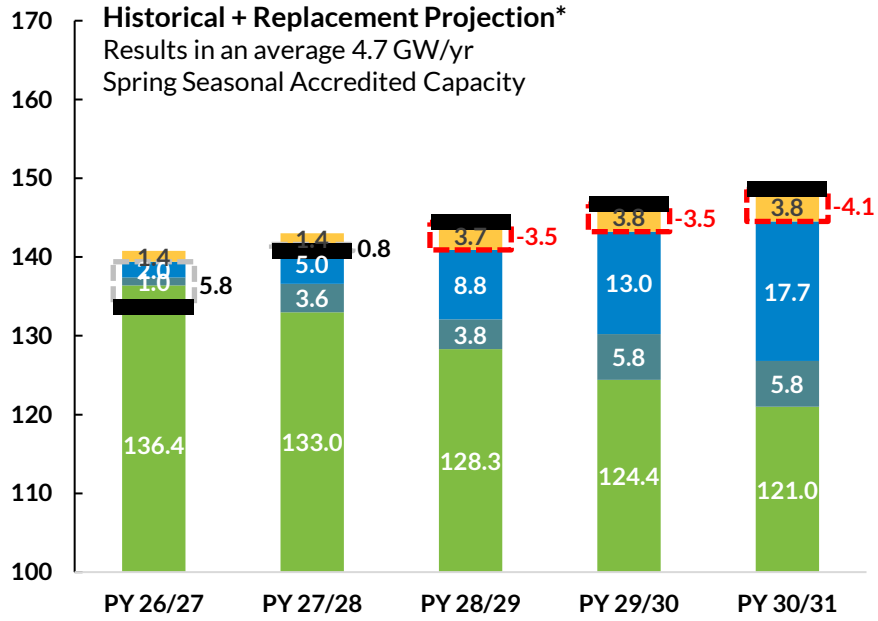
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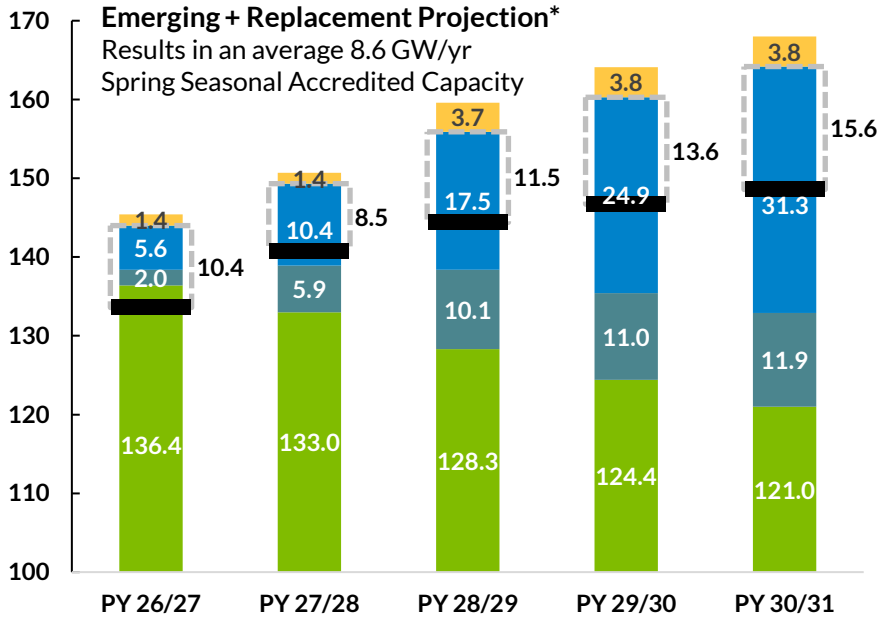
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Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Spring SAC Installation Rate

MISO Resource Adequacy Projection – Spring





Projected PRMR with LSE forecast
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Value of Replacement/Surplus Projects
Committed Capacity

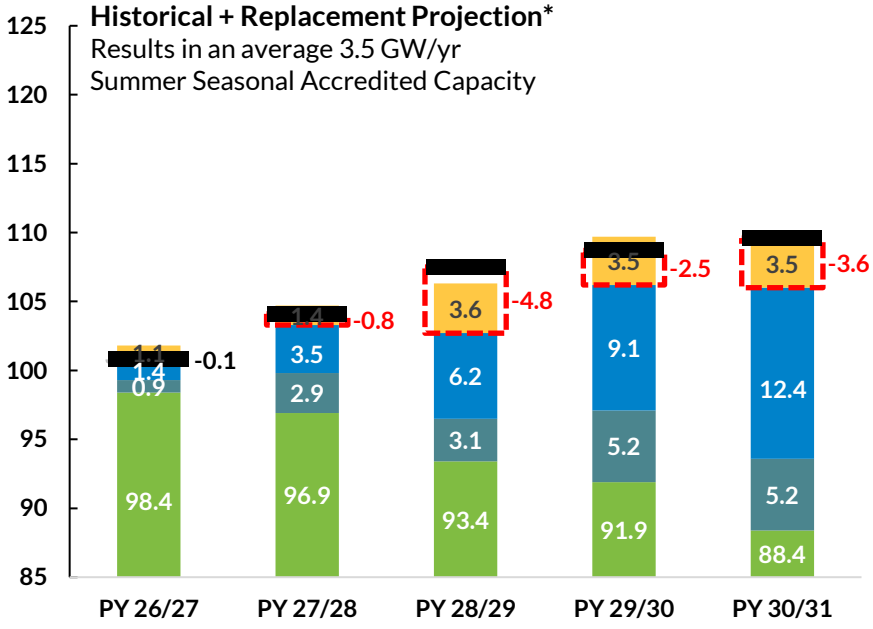
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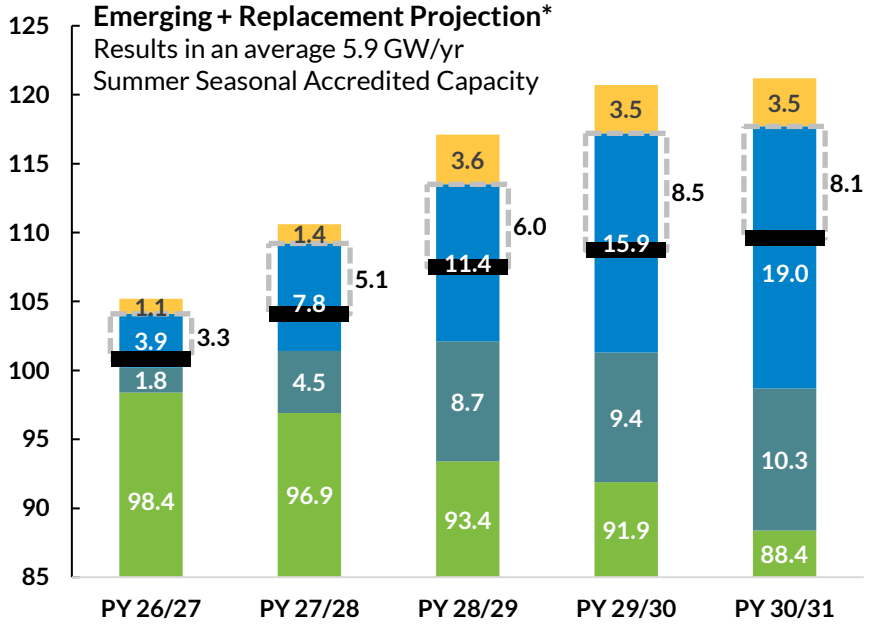
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Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projections – Summer MISO North/Central





- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

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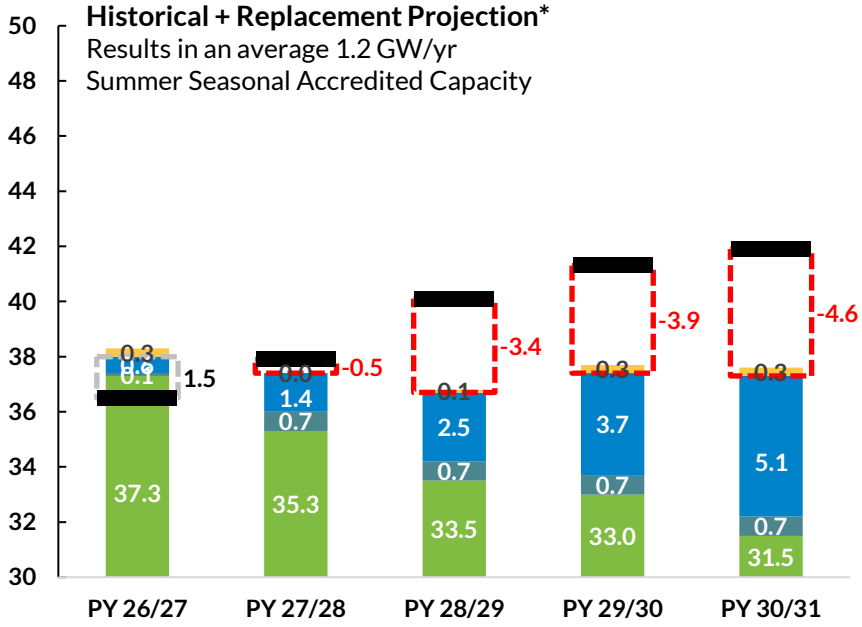
Red border values indicate the additional potential deficit against the Projected PRMR

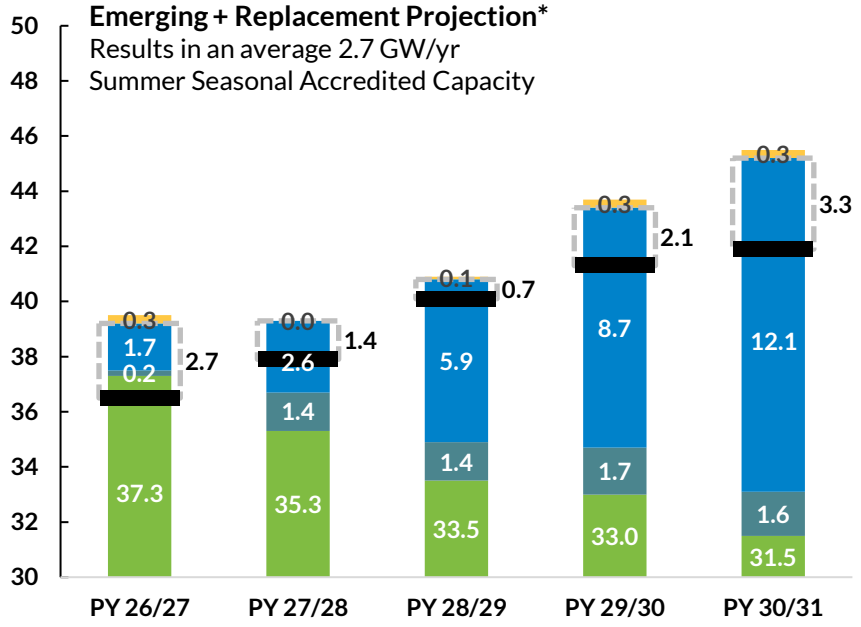
Gray border values indicate the potential surplus against the Projected PRMR

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Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projections – Summer MISO South





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

Using methods for potential New Capacity described on Slide 5

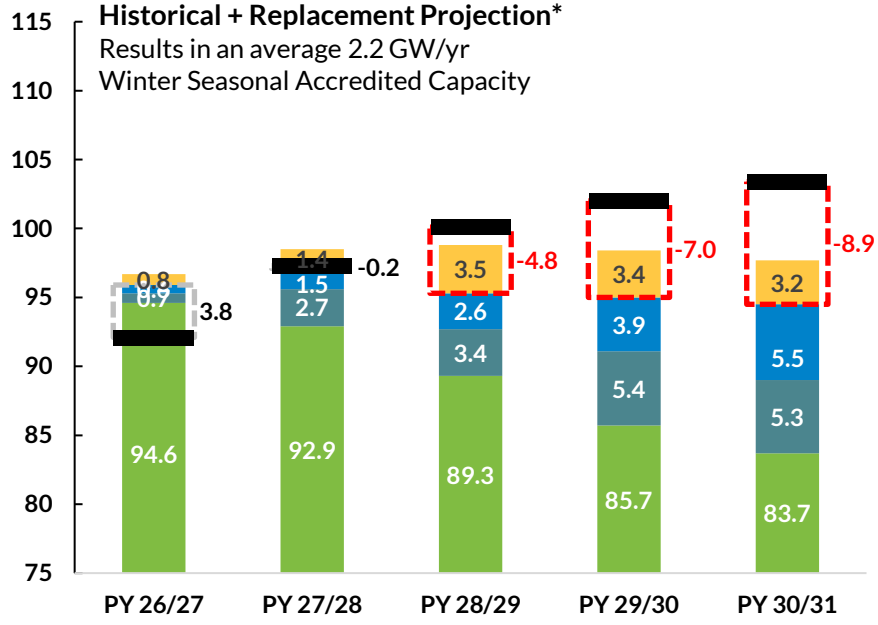
***PRMR:** Planning Reserve Margin Requirement*

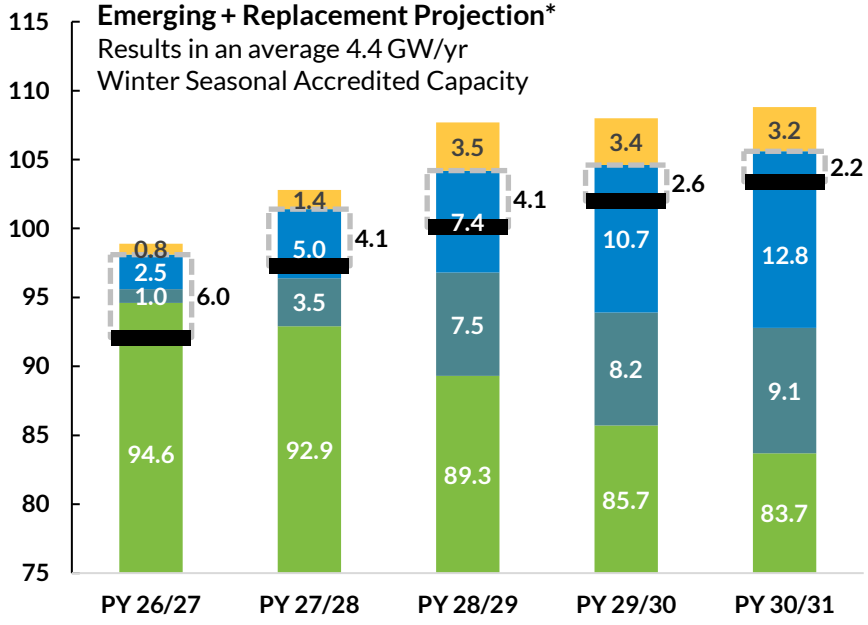
Red border values indicate the additional potential deficit against the Projected PRMR
Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR
~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter MISO North/Central





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

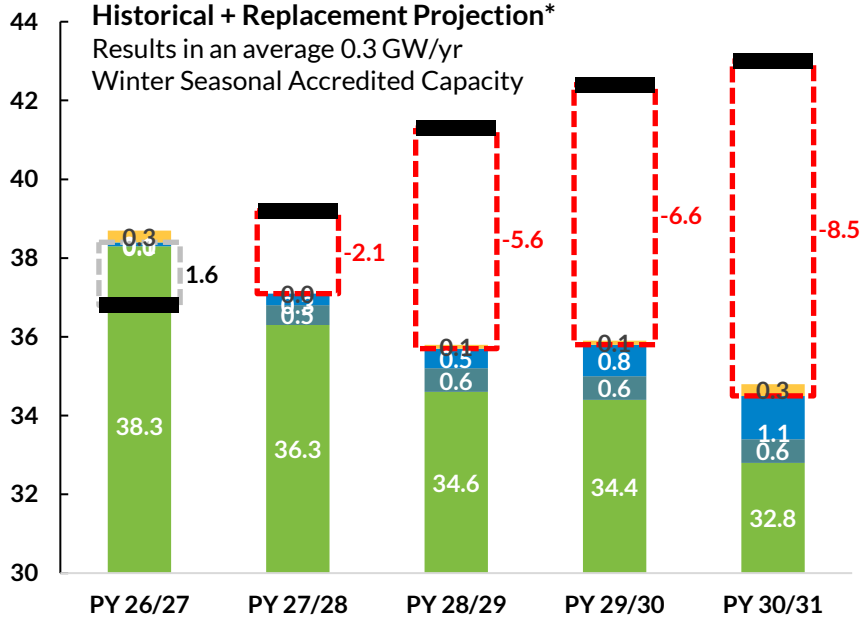
Using methods for potential New Capacity described on Slide 8
***PRMR:** Planning Reserve Margin Requirement*

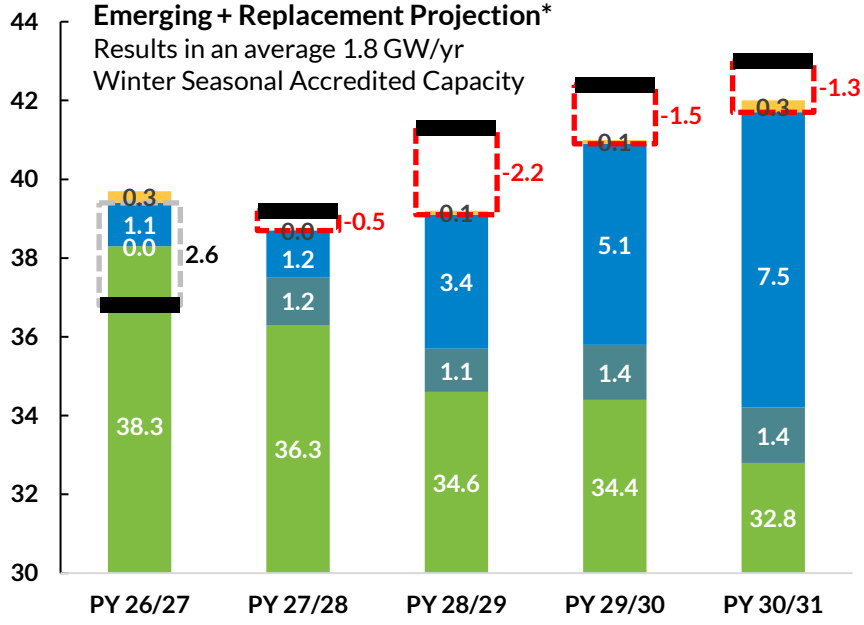
Red border values indicate the additional potential deficit against the Projected PRMR
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- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter MISO South





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

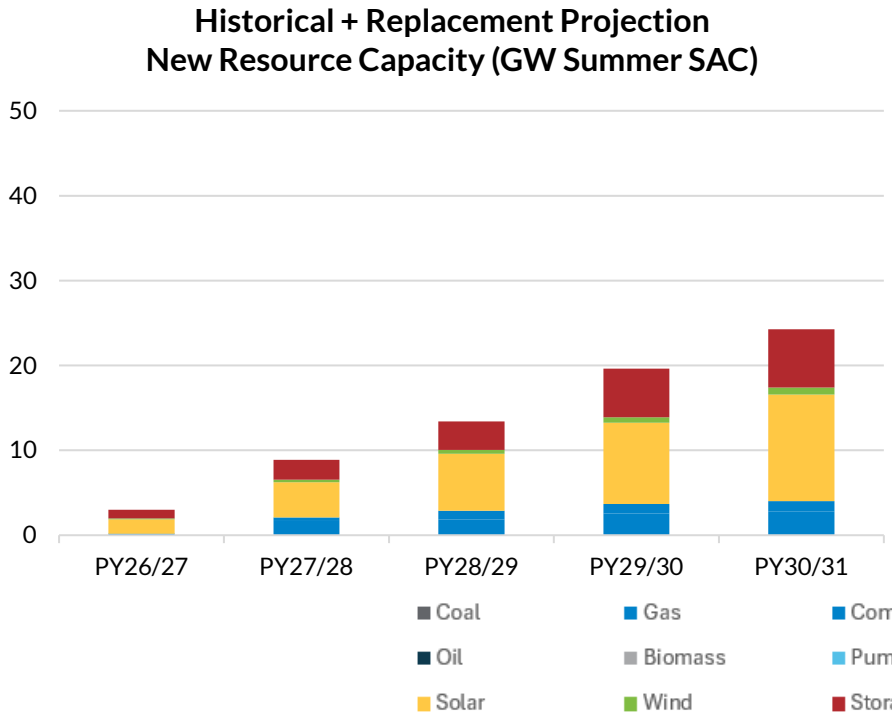
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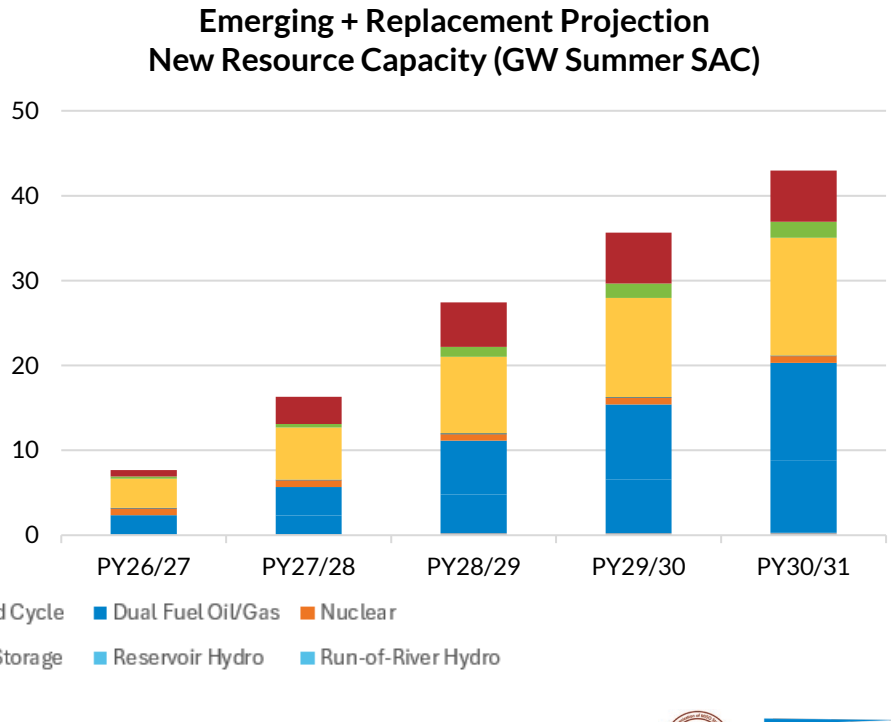
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- Capacity accreditation values and Planning Reserve Margin projections based on current practices
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OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Summer



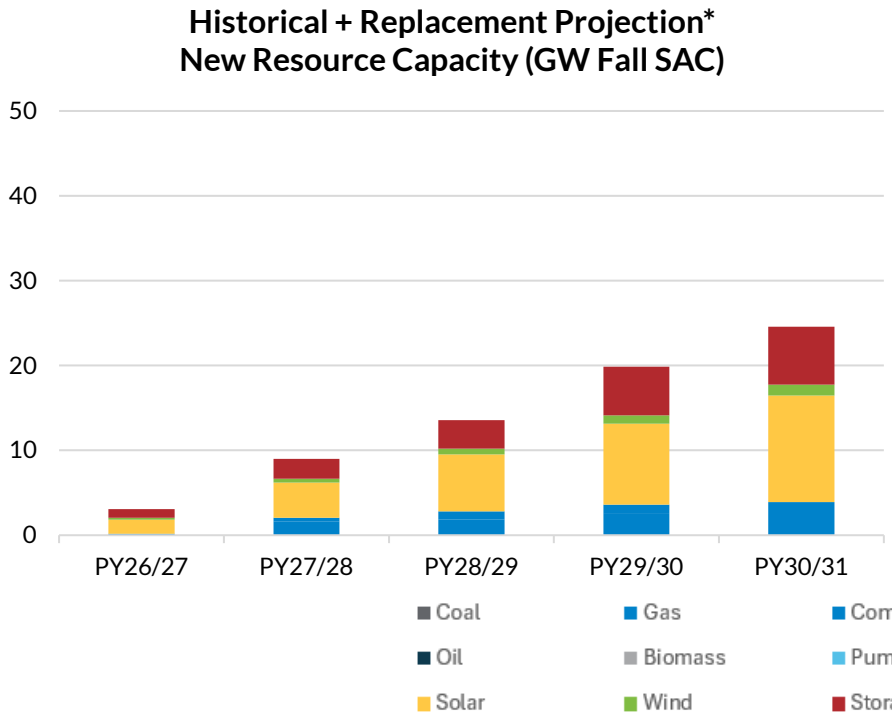


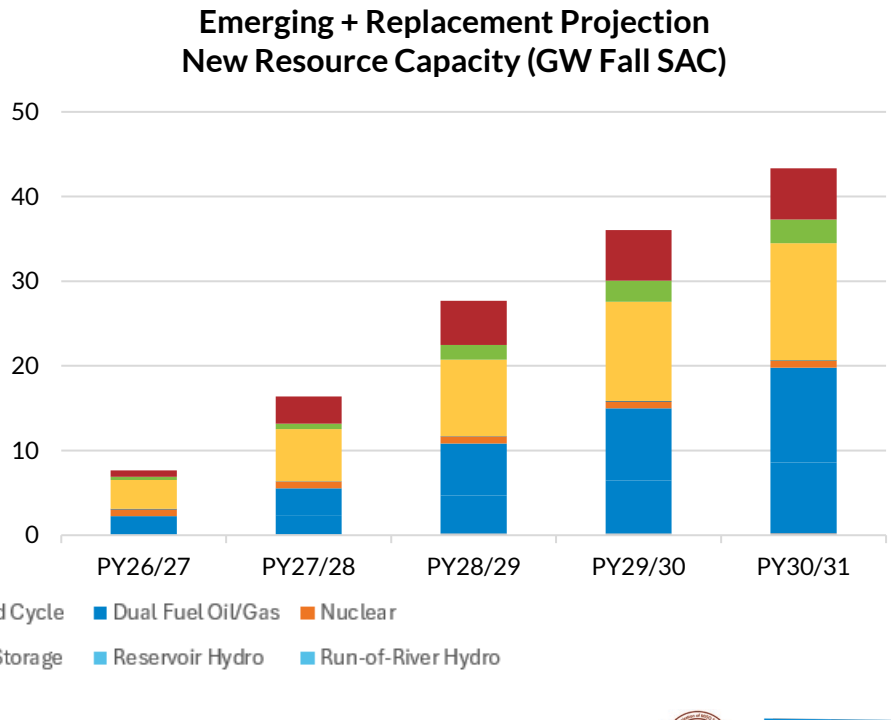
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

SAC: *Seasonal Accredited Capacity*
All values are cumulative, and are based upon average fuel type resource accreditation from Planning Year 2025/26

OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Fall



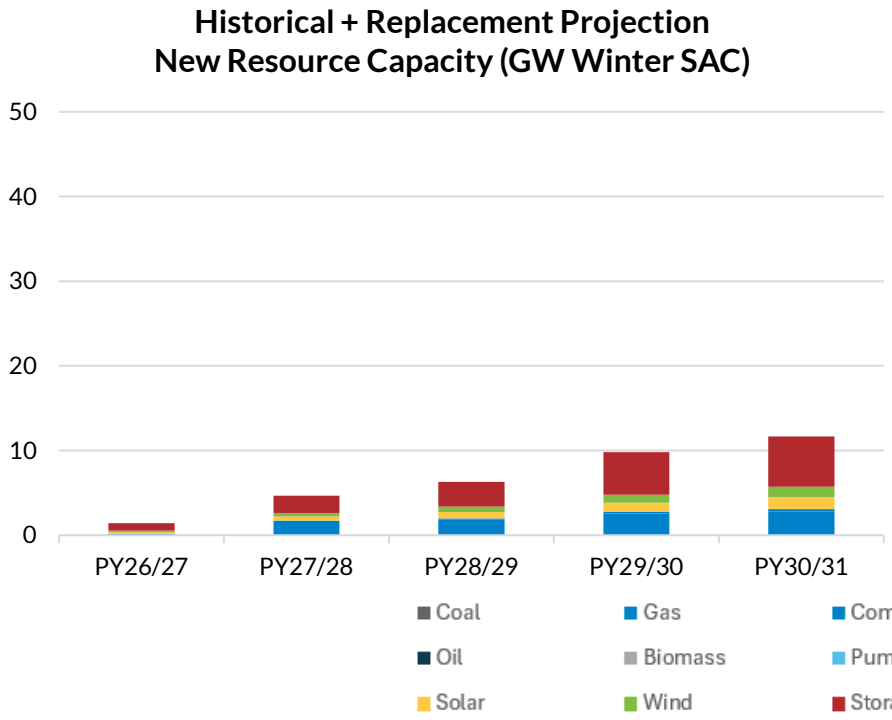


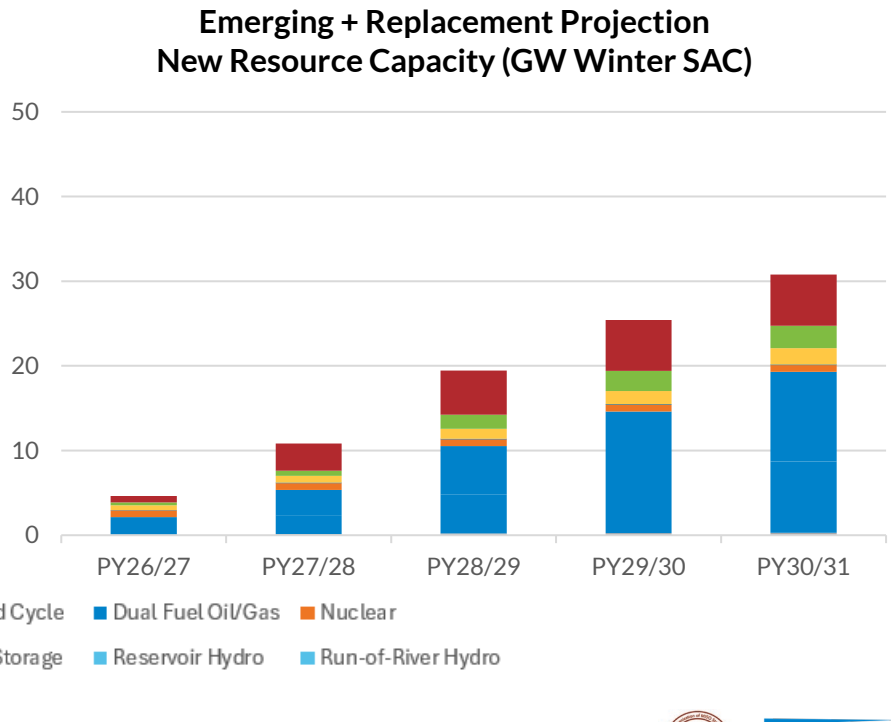
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OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Winter



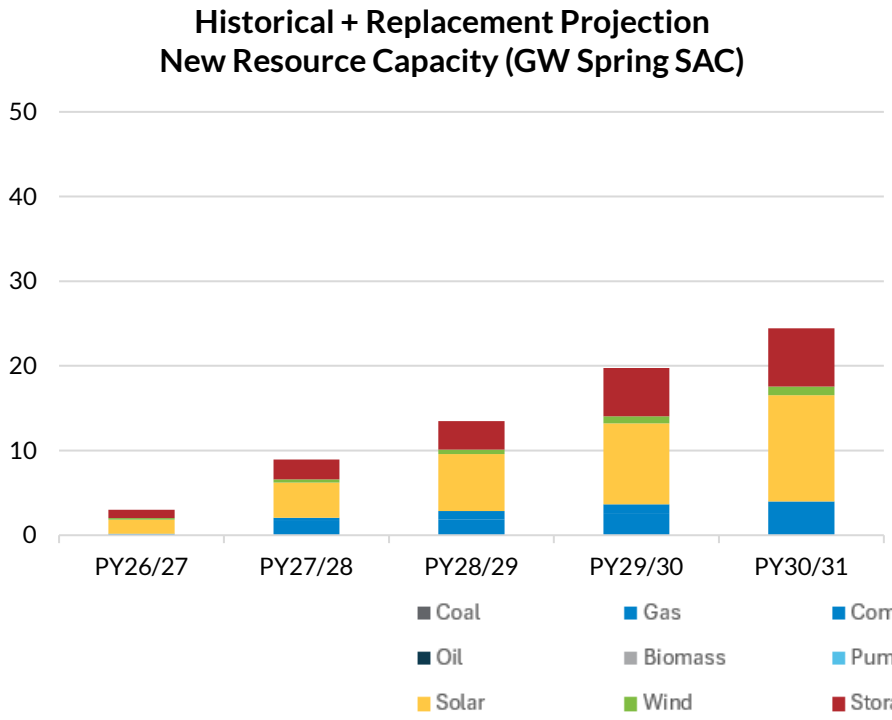


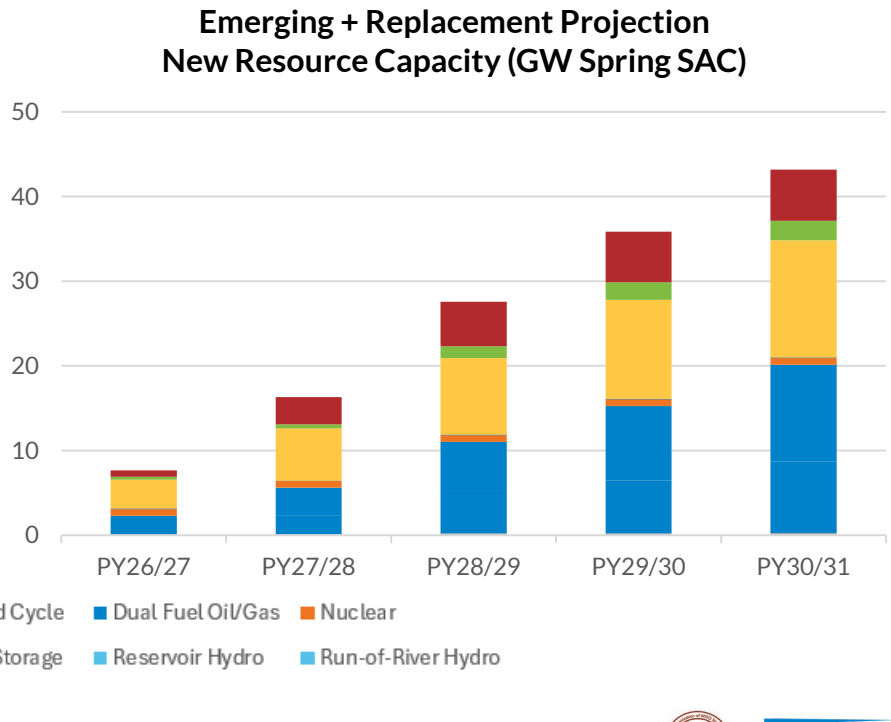
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Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
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All values are cumulative, and are based upon average fuel type resource accreditation from Planning Year 2025/26

OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Spring



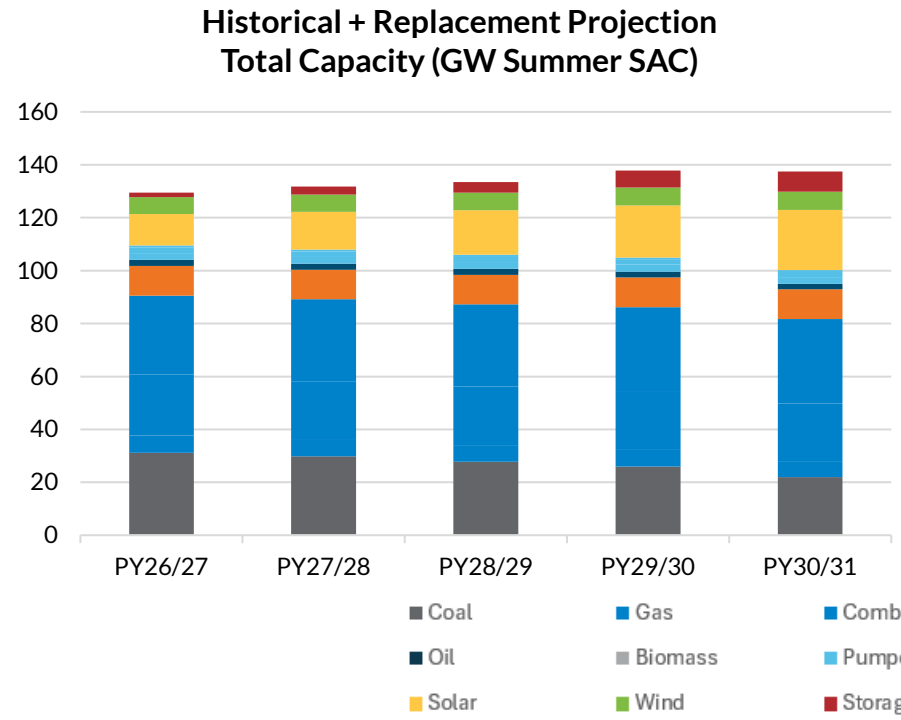


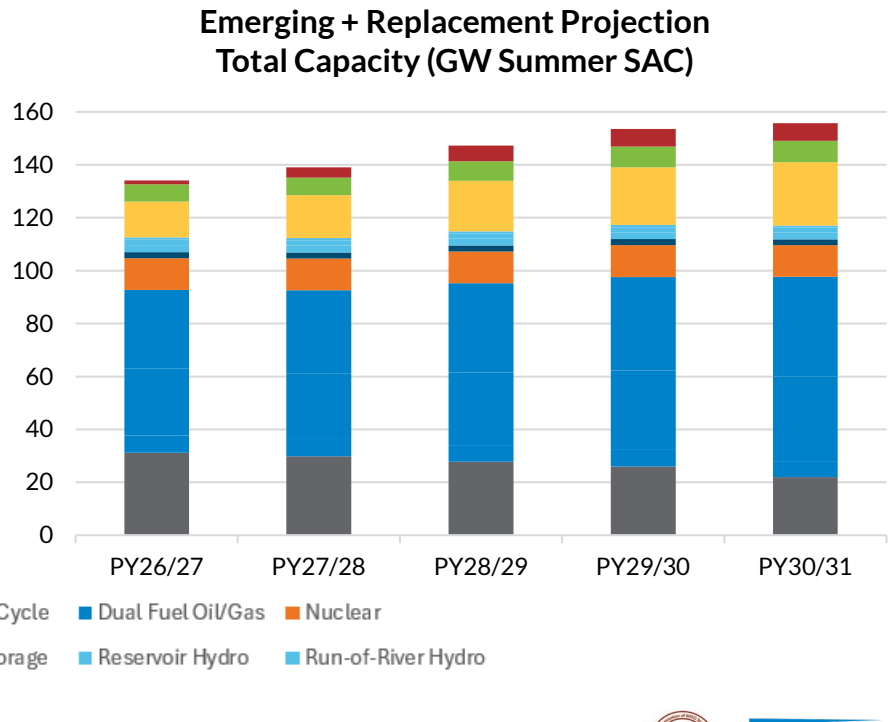
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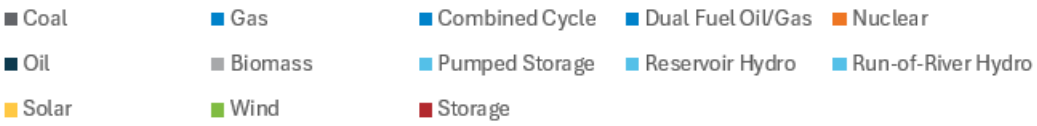
SAC: *Seasonal Accredited Capacity*
All values are cumulative, and are based upon average fuel type resource accreditation from Planning Year 2025/26

OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Summer



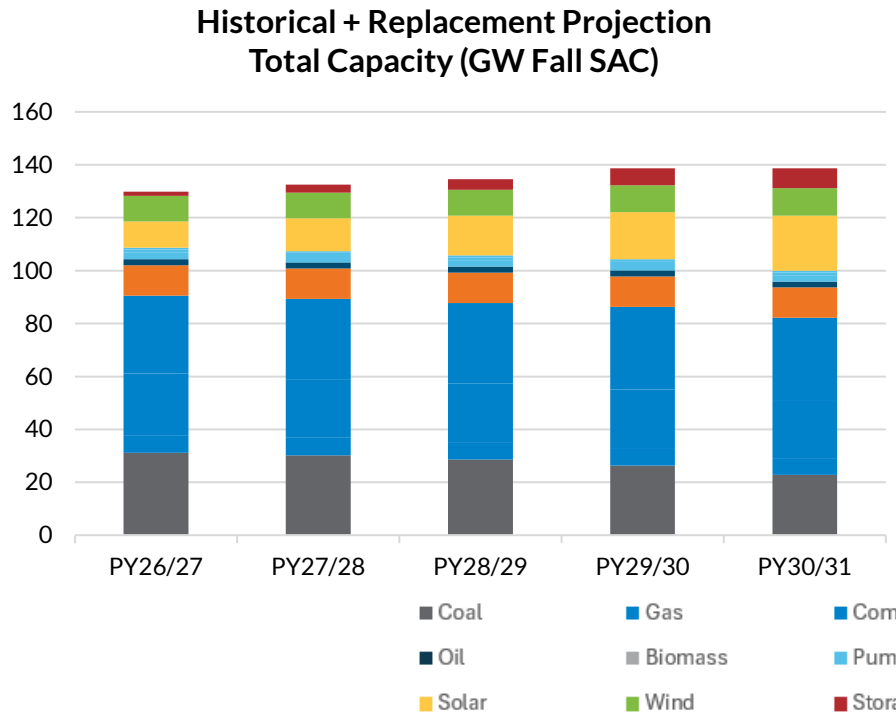


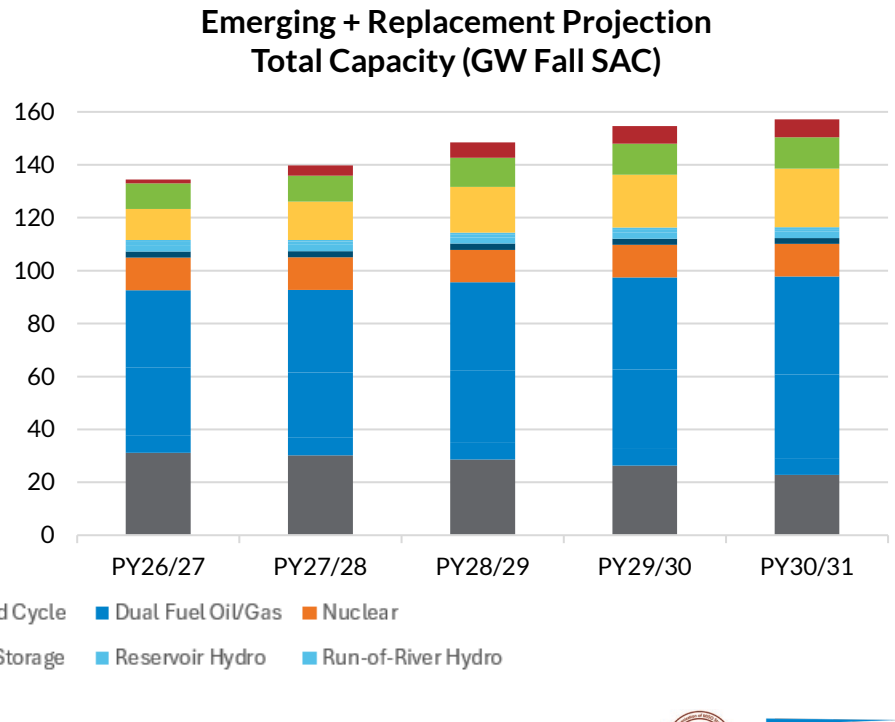


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New resources are based upon average fuel type resource accreditation from Planning Year 2025/26, existing based on seasonal Status Quo SAC

OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Fall



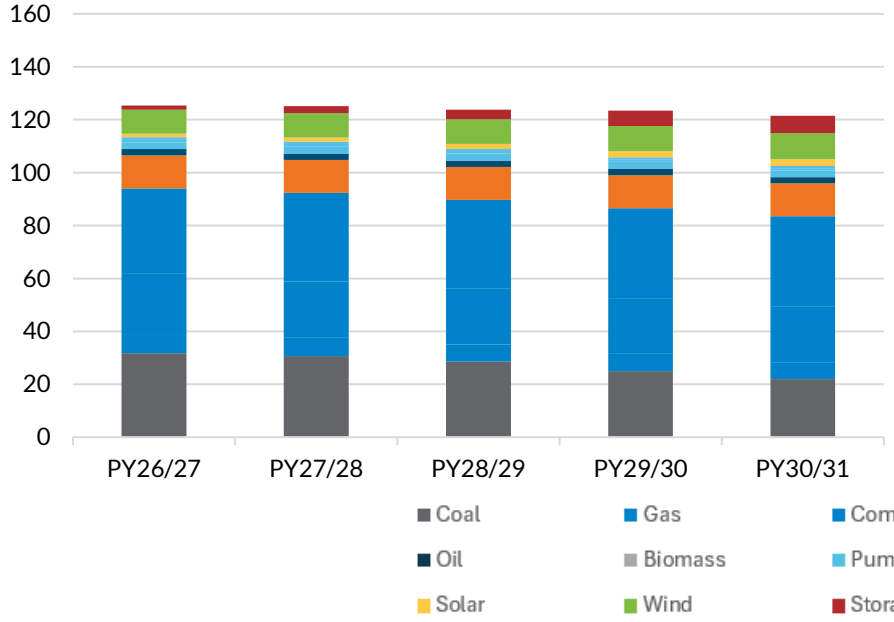


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New resources are based upon average fuel type resource accreditation from Planning Year 2025/26, existing based on seasonal Status Quo SAC

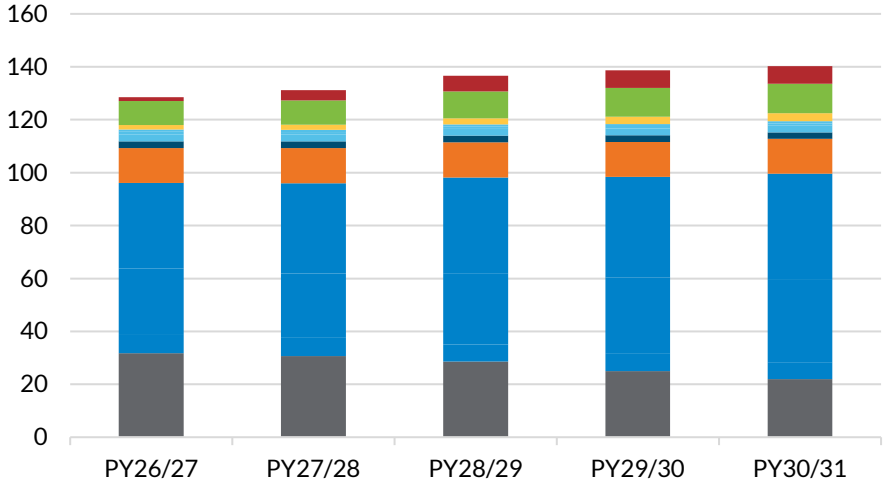
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Winter

Historical + Replacement Projection
Total Capacity (GW Winter SAC)



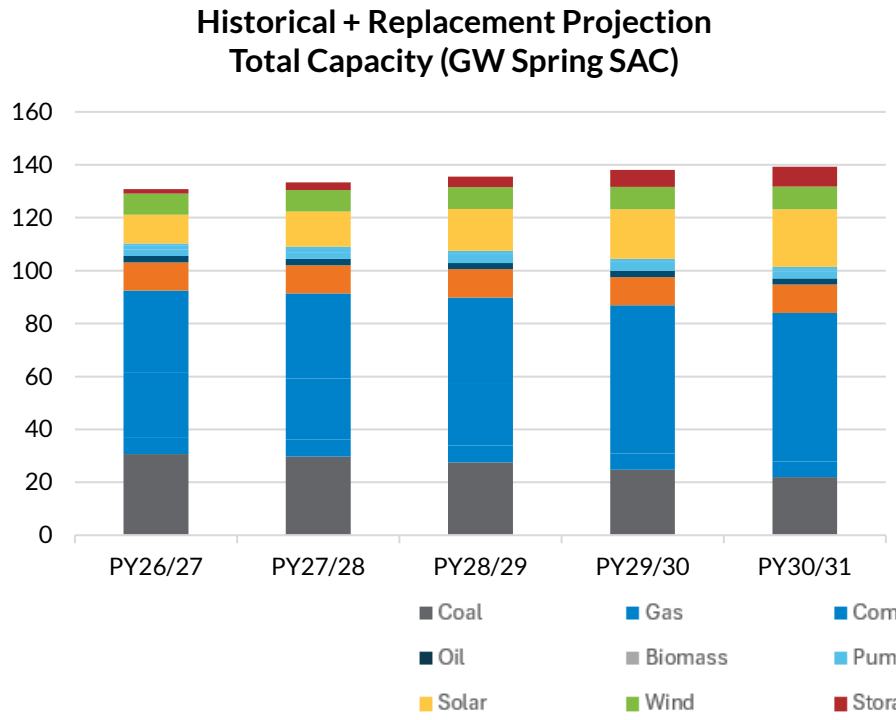
Emerging + Replacement Projection
Total Capacity (GW Winter SAC)

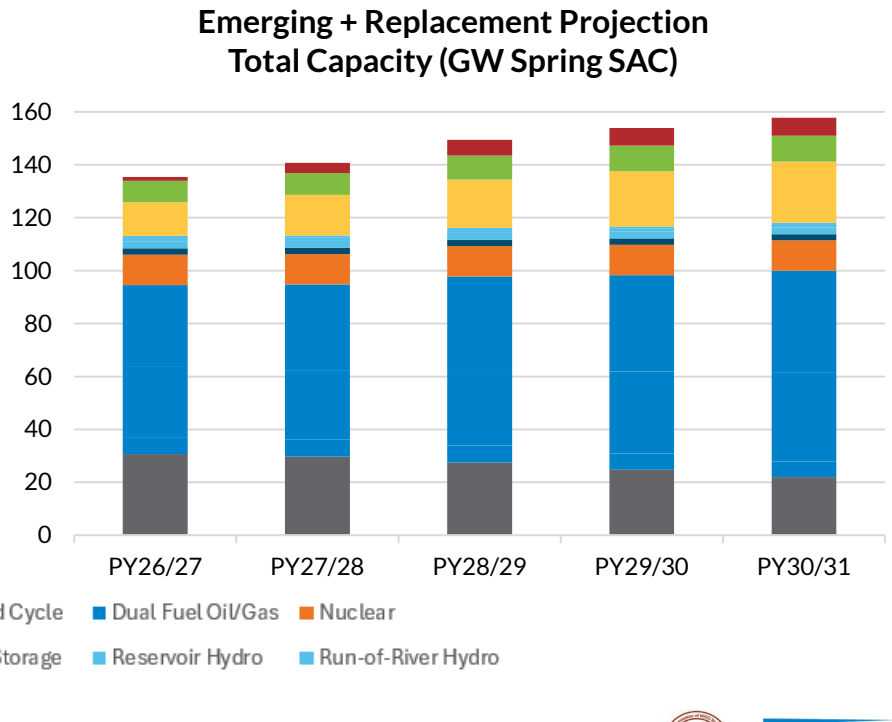


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New resources are based upon average fuel type resource accreditation from Planning Year 2025/26, existing based on seasonal Status Quo SAC

OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Spring



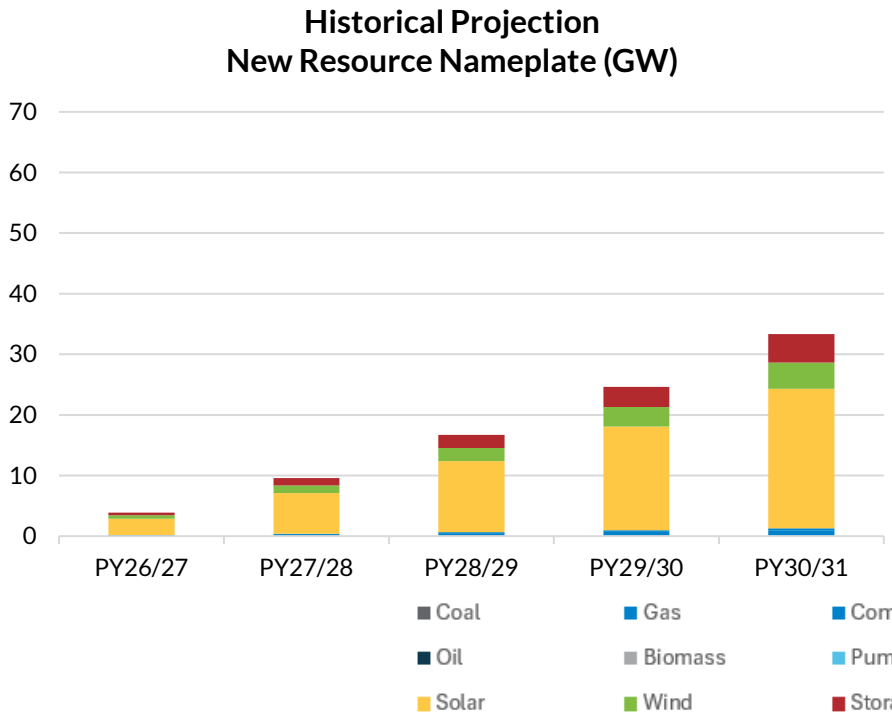


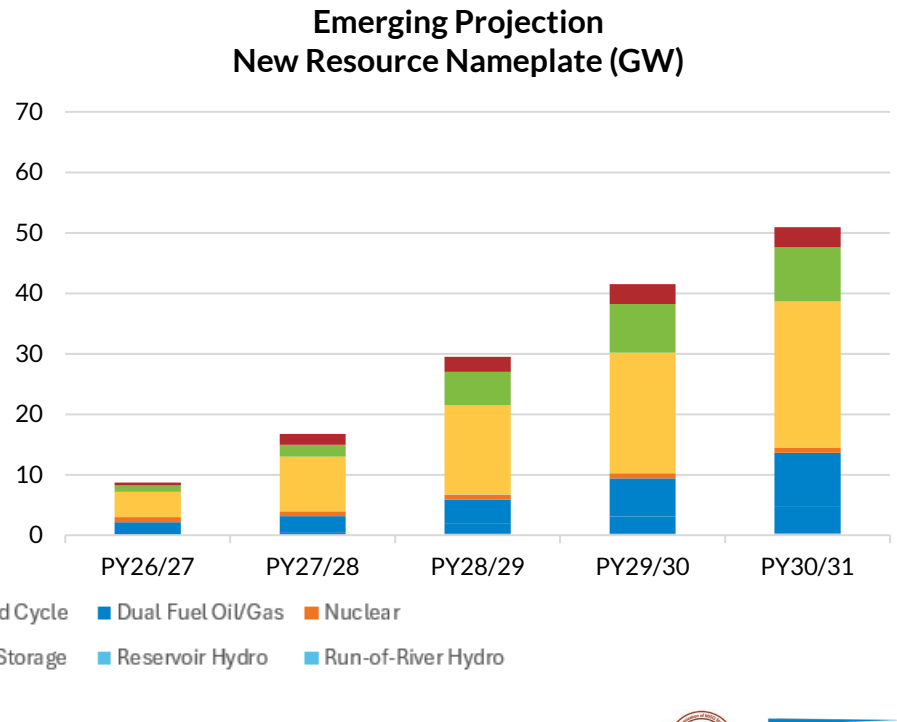
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OMS-MISO Survey projections of new resource deliverable nameplate

Combined Projections of Fuel Mix, New Resource Nameplate Only (ICAP)





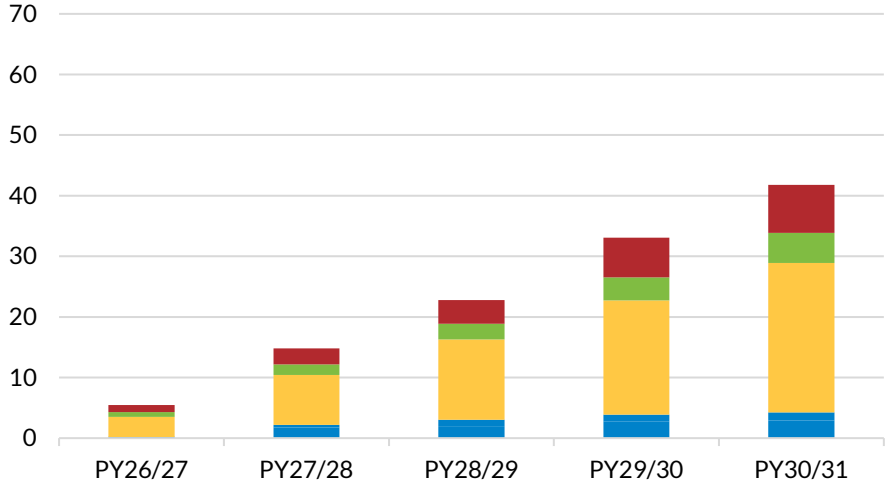
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

ICAP: *Installed Capacity*
All values are cumulative, and are based on projected nameplate installation for each fuel type

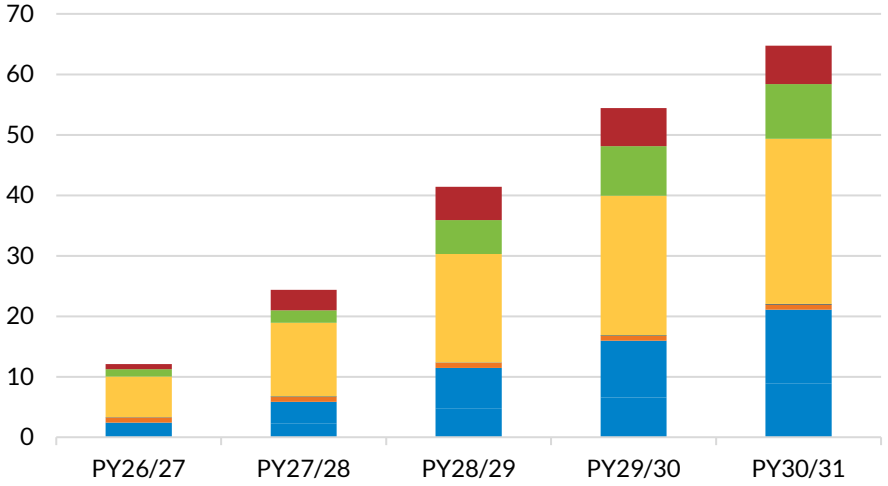
OMS-MISO Survey projections of new resource deliverable nameplate

Combined Projections of Fuel Mix, New Resource Nameplate Only (ICAP)

Historical + Replacement Projection
New Resource Nameplate (GW)



Emerging + Replacement Projection
New Resource Nameplate (GW)

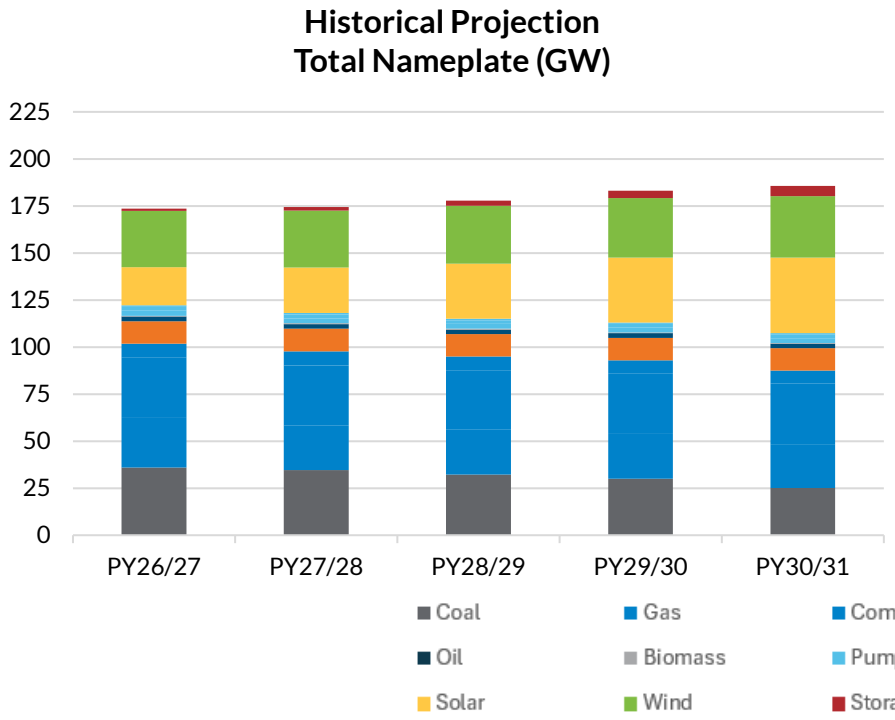


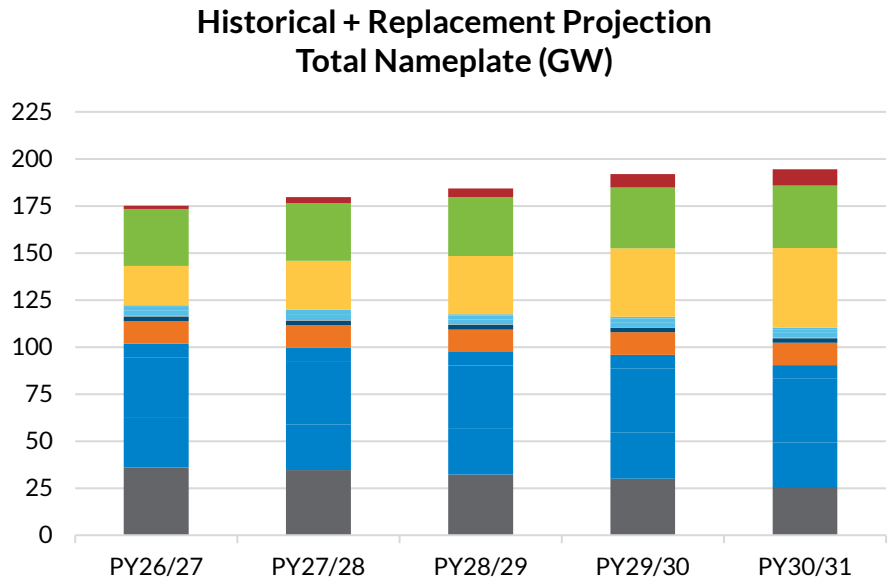
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ICAP: *Installed Capacity*
All values are cumulative, and are based on projected nameplate installation for each fuel type

OMS-MISO Survey projections of fleet total deliverable nameplate

Combined Projections of Fuel Mix, Fleet Composition by Nameplate (ICAP)

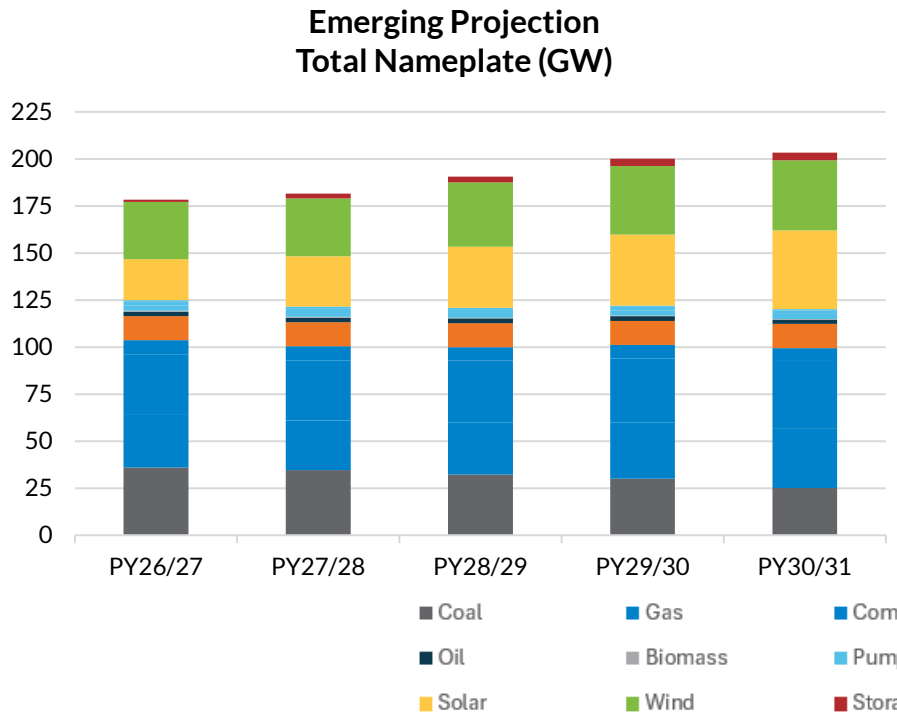


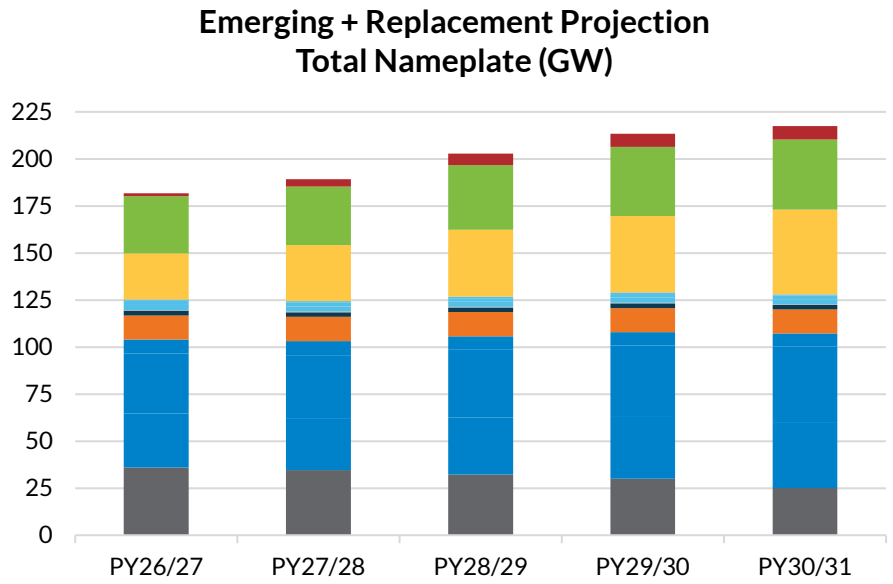


ICAP: *Installed Capacity*

OMS-MISO Survey projections of fleet total deliverable nameplate

Combined Projections of Fuel Mix, Fleet Composition by Nameplate (ICAP)





ICAP: *Installed Capacity*

Planning Resource Auction
Results for Planning Year 2025-26

April 2025

CORRECTIONS

Reposted 05/29/25

Slides Updated: 7, 11, 18-20, 23, 32-34

MISO met the planning year 2025/26 resource adequacy requirements, but pressure persists with reduced capacity surplus across the region and is reflected through improved price signals in this year's auction

Summer
$666.50
—
Fall
$91.60 (North/Central)
$74.09 (South)
—
Winter
$33.20
—
Spring
$69.88
—
Annualized
$217 (North/Central)
$212 (South)

- MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond the seasonal Planning Reserve Margin (PRM) target
  - For example, the auction cleared 1.9% above the 7.9% summer PRM target
- Summer price reflects the lowest available surplus capacity
  - Fall price varied slightly due to transfer limitations between the North and South
- Consistent with past years, most Load Service Entities (LSEs) self-supplied or secured capacity in advance and are hedged with respect to auction prices
- Surplus above the target PRM dropped 43% compared to last summer, despite the slightly lower PRM target (7.9% vs. 9.0% last year)
  - New capacity additions did not keep pace with reduced accreditation, suspensions/retirements and slightly reduced imports
- The results reinforce the need to increase capacity, as demand is expected to grow with new large load additions

Auction outcomes are consistent with the design intent of the Reliability-Based Demand Curve (RBDC), and MISO and its members can expect more stable and predictable capacity pricing, especially in surplus situations

In the 2025 PRA, the RBDC…

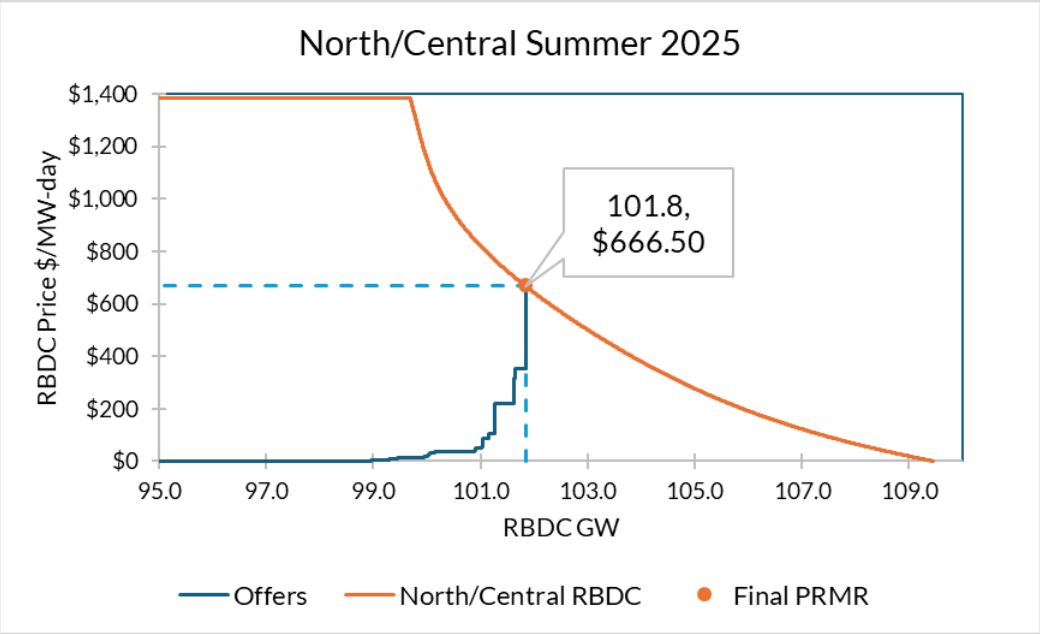
- Delivers competitive prices aligned with seasonal risks and tightening surplus
    - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
    - Clears capacity above target Planning Reserve Margin based on its reliability value in each season
- Stabilizes prices in non-summer seasons, avoiding extreme volatility

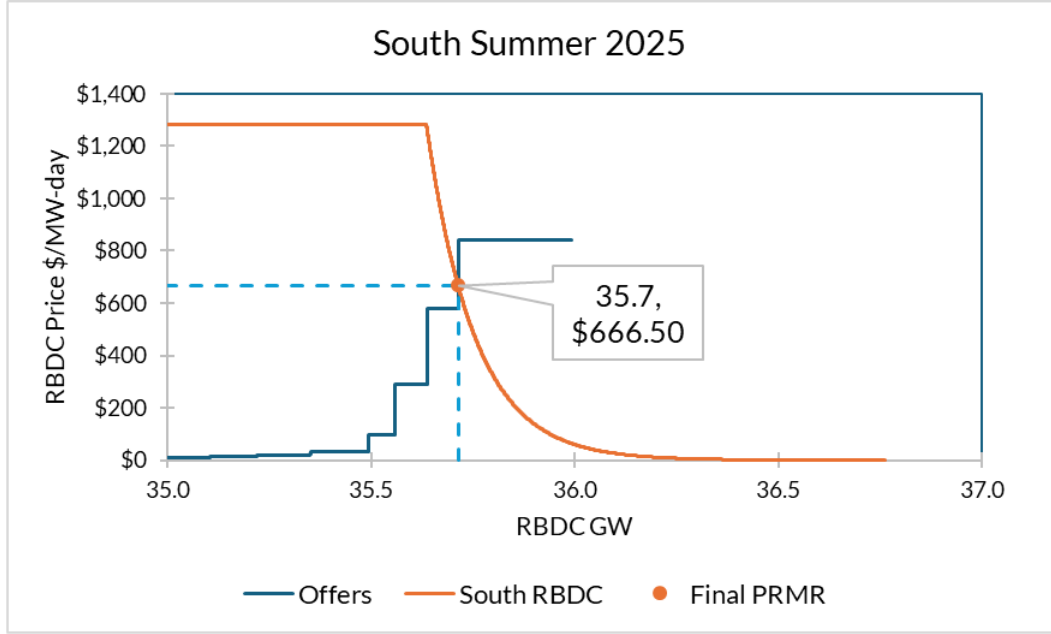
Why it Matters

- Sends clear and stable investment signals across the system, including to external resources
- Provides transparent value for capacity that exceeds the Planning Reserve Margin target
- Reflects subregional capacity needs and clears accordingly across all seasons

LOLE: Loss of Load Expectation

Auction pricing outcomes with the Reliability-Based Demand Curve (RBDC) better reflect value of capacity and resource adequacy risk across seasons





- Summer clearing of $666.50 reflects highest reliability risk and reducing surplus capacity year-over-year
  - Surplus capacity in the summer has reduced from approximately 6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW in 2025
- Incremental capacity cleared beyond the target Planning Reserve Margin based on the value it adds to reliability (e.g., North/Central "effective" summer margin at 10.1% and South at 8.7% vs. target 7.9%)
  - A small quantity of capacity, that was offered at a price higher than the reliability value indicated through the demand curve, did not clear

LOLE: Loss of Load Expectation

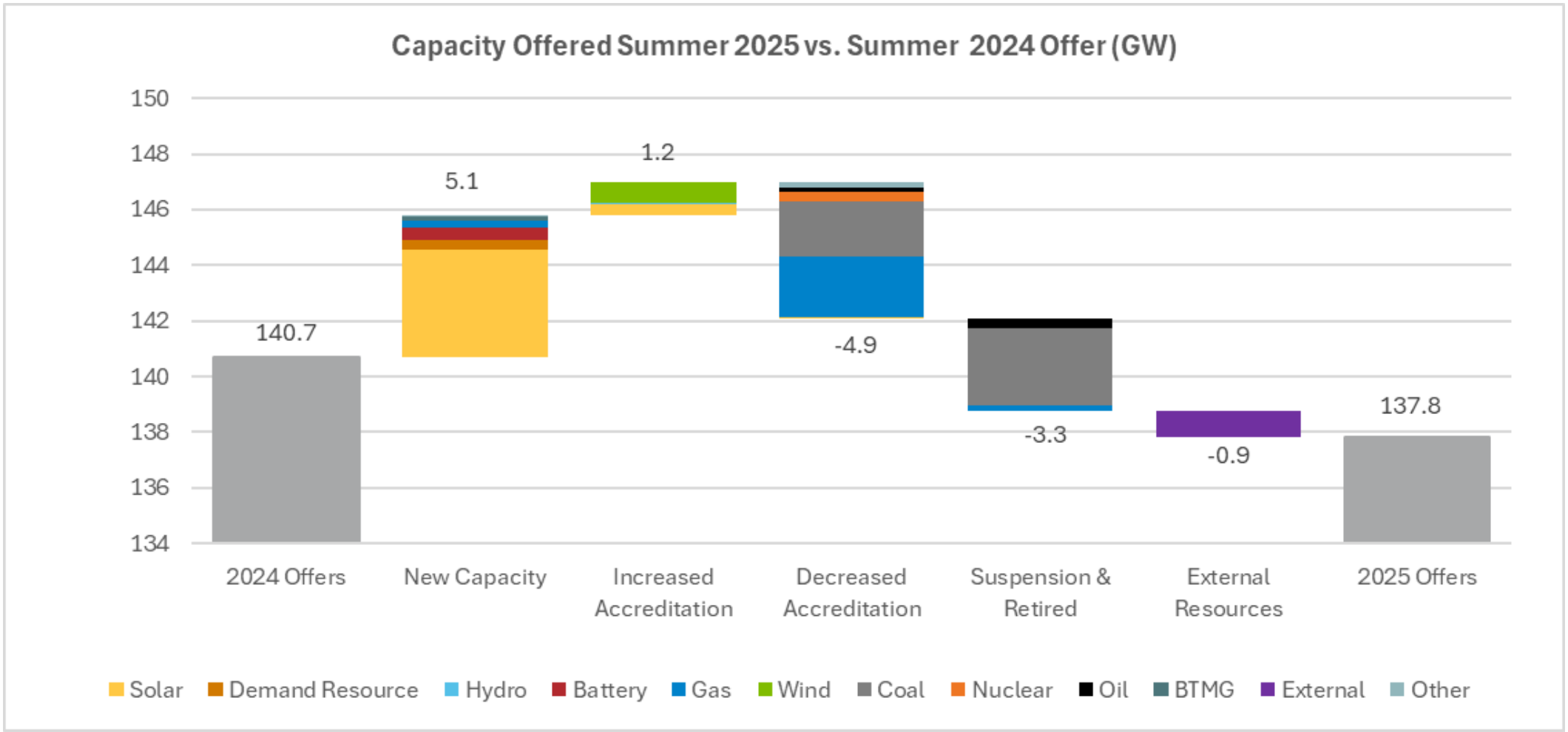
MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond seasonal reliability targets

- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices

	2025 Planning Resource Auction Initial Target vs. Final Cleared	Additional Reliability	Auction Clearing Price
Summer	Initial, 7.90% Cleared, 9.80%	+1.9%	$666.50
Fall	Initial, 14.90% Cleared, 17.50%	+2.6%	$91.60 N/C $74.09 S
Winter	Initial, 18.40% Cleared, 24.50%	+6.1%	$33.20
Spring	Initial, 25.30% Cleared, 26.80%	+1.5%	$69.88 ***Annualized*** **$217** (North/Central) **$212** (South)

PRM: Planning Reserve Margin

New capacity additions did not keep pace with decreased accreditation, suspensions/ retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

MISO has taken action on many Reliability Imperative initiatives to address resource adequacy challenges, but there's more to be done

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Majority of new resources with variable, intermittent output and high weather correlation
- Delays of new resource additions
- More frequent extreme weather

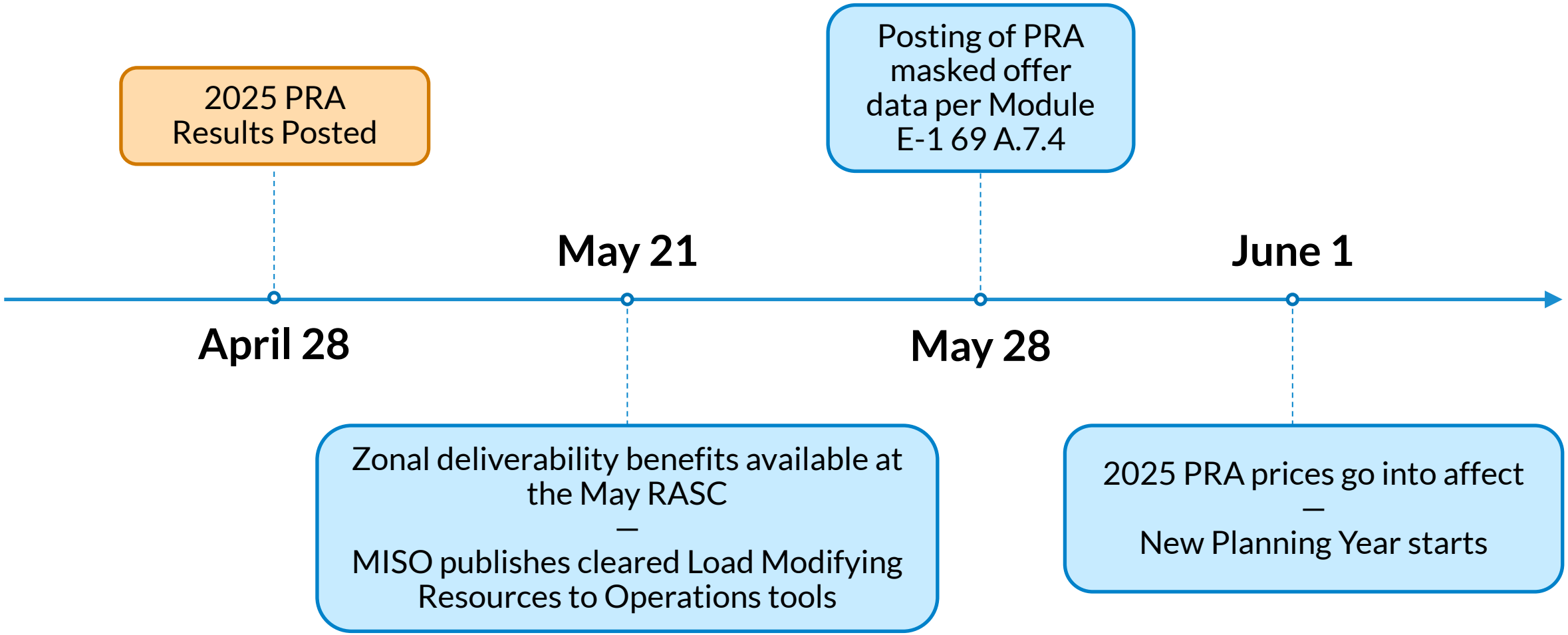
Completed Initiatives

- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Non-emergency resource accreditation *(effective PY 2028/29)*
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal coming June 2025)*
- ✓ Approved over $30 billion in new transmission lines

Initiatives In Progress

- ❑ Implement Direct Loss of Load (DLOL)-based accreditation
- ❑ Enhance resource adequacy risk modeling
- ❑ Reduce queue cycle times through automation
- ❑ Implement interim Expedited Resource Addition Study (ERAS) process *(June 2025)*
- ❑ Demand Response and Emergency Resource reforms
- ❑ Enhance allocation of resource adequacy requirements

Next Steps


2025 PRA Results Posted
April 28
May 21
Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools
Posting of PRA masked offer data per Module E-1 69 A.7.4
May 28
June 1
2025 PRA prices go into affect
—
New Planning Year starts

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Acronyms

ACP: Auction Clearing Price

ARC: Aggregator of Retail Customers

BTMG: Behind the Meter Generator

CIL: Capacity Import Limit

CEL: Capacity Export Limit

CONE: Cost of New Entry

CPF: Coincident Peak Forecast

DLOL: Direct Loss-of-Load

DR: Demand Resource

ELCC: Effective Load Carrying Capability

EE: Energy Efficiency

ER: External Resource

ERAS: Expedited Resource Addition Study

ERZ: External Resource Zones

FRAP: Fixed Resource Adequacy Plan

ICAP: Installed Capacity

IMM: Independent Market Monitor

LBA: Load Balancing Authority

LCR: Local Clearing Requirement

LOLE: Loss of Load Expectation

LMR: Load Modifying Resource

LRR: Local Reliability Requirement

LRZ: Local Resource Zone

LSE: Load Serving Entity

OMS: Organization of MISO States

PO: Planned Outage

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement

RASC: Resource Adequacy Sub-Committee

RBDC: Reliability-Based Demand Curve

SAC: Seasonal Accredited Capacity

SREC: Sub-Regional Export Constraint

SRIC: Sub-Regional Import Constraint

SRPBC: Sub-Regional Power Balance Constraint

SS: Self Schedule

UCAP: Unforced Capacity

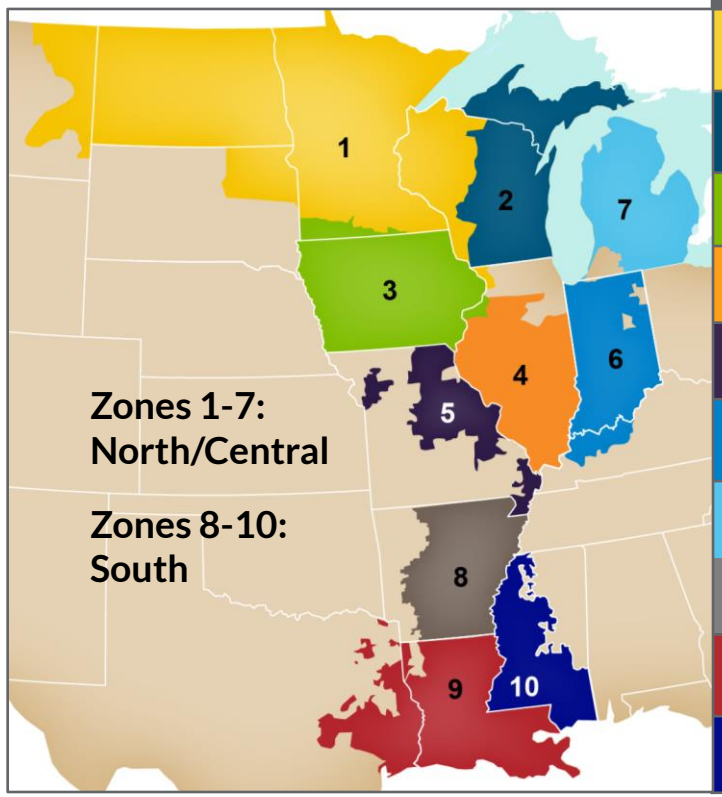
ZIA: Zonal Import Ability

ZRC: Zonal Resource Credit

The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance

2025 PRA Results

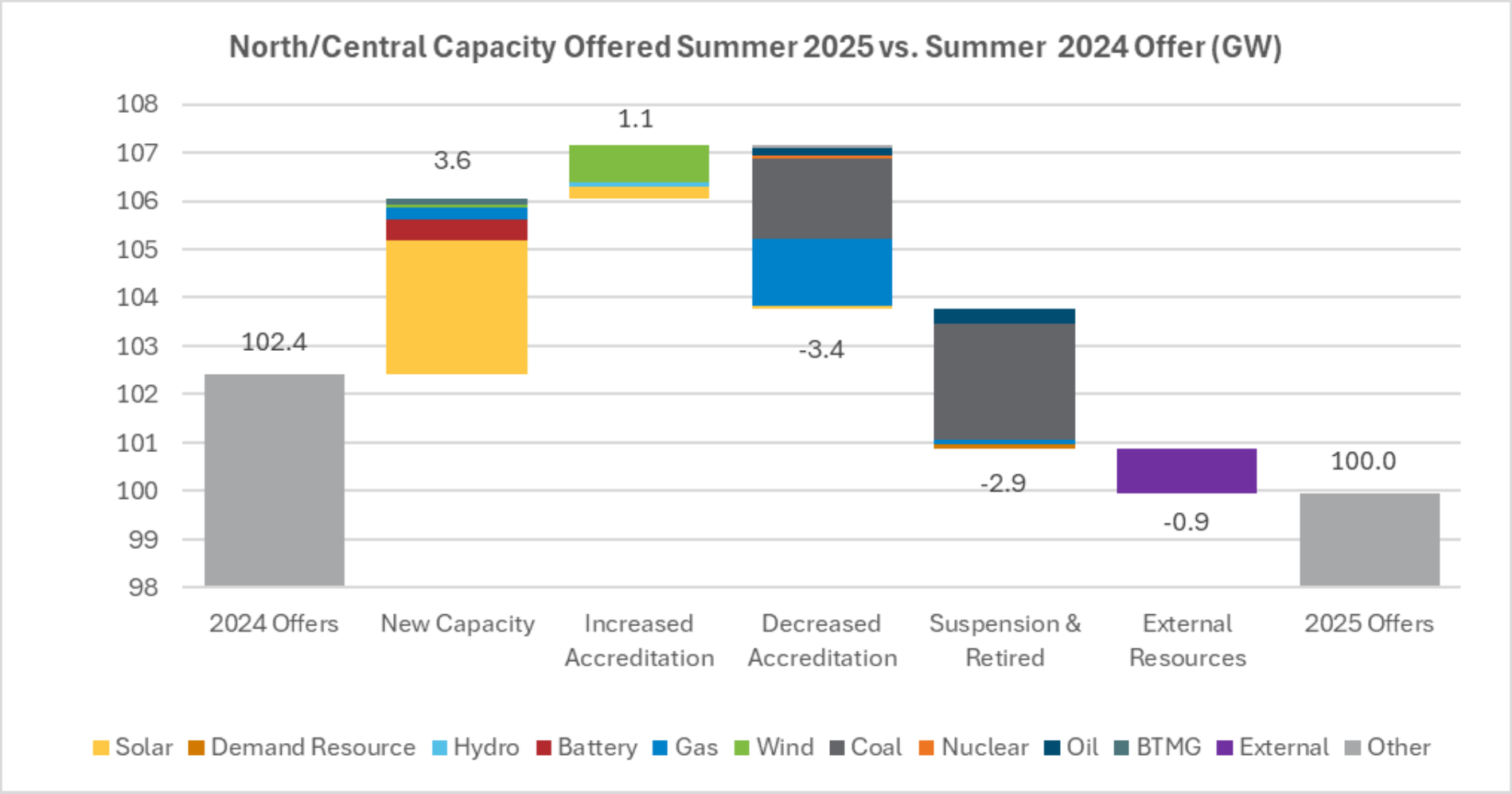
MISO Resource Adequacy Zones



	Price/MW-Day			
	Summer	Fall	Winter	Spring
1	$666.50	$91.60	$33.20	$69.88
2				
3				
4				
5				
6				
7				
8		$74.09		
9				
10				

Annualized
$217 (North/Central)
$212 (South)

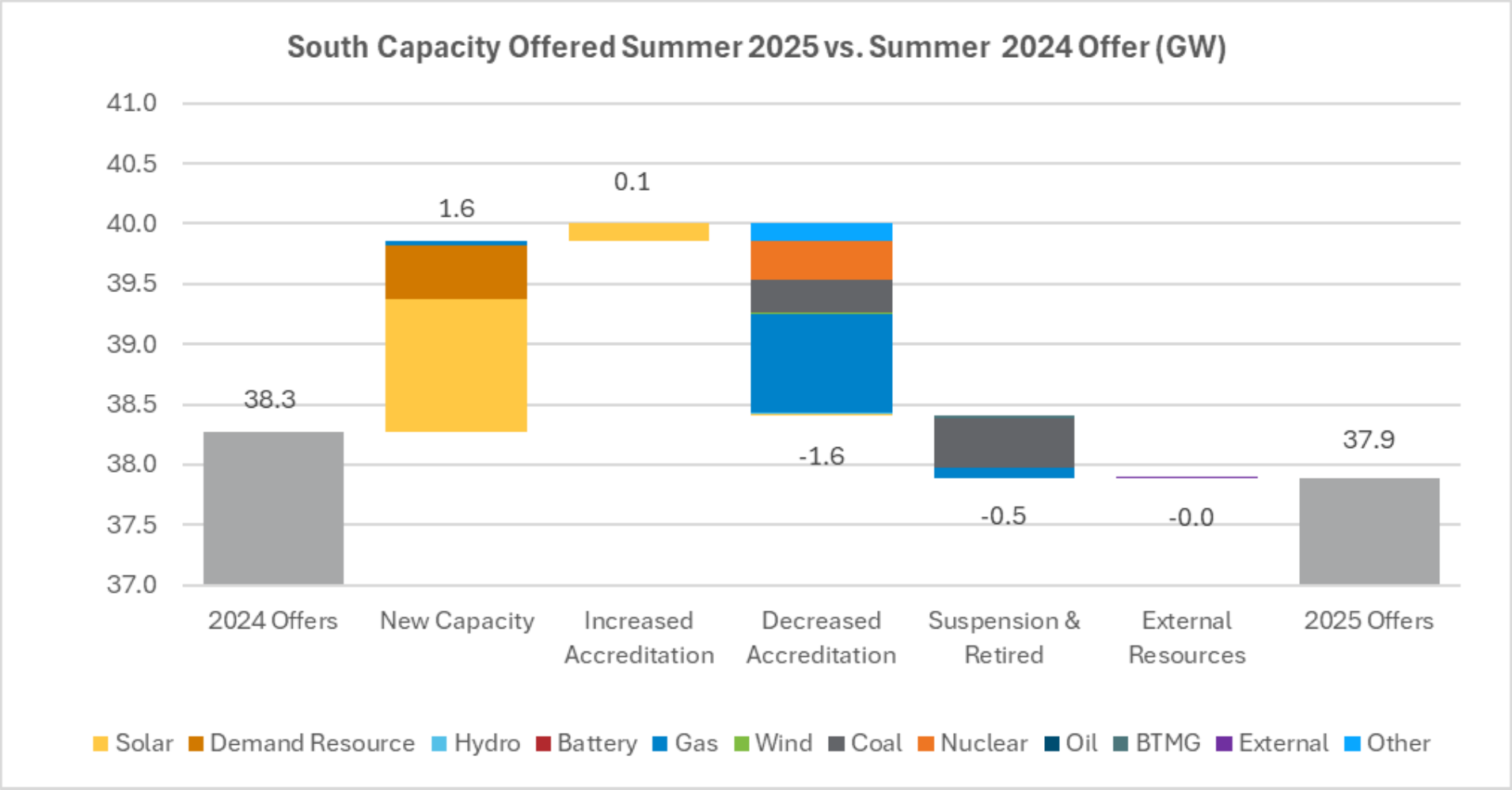
For North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

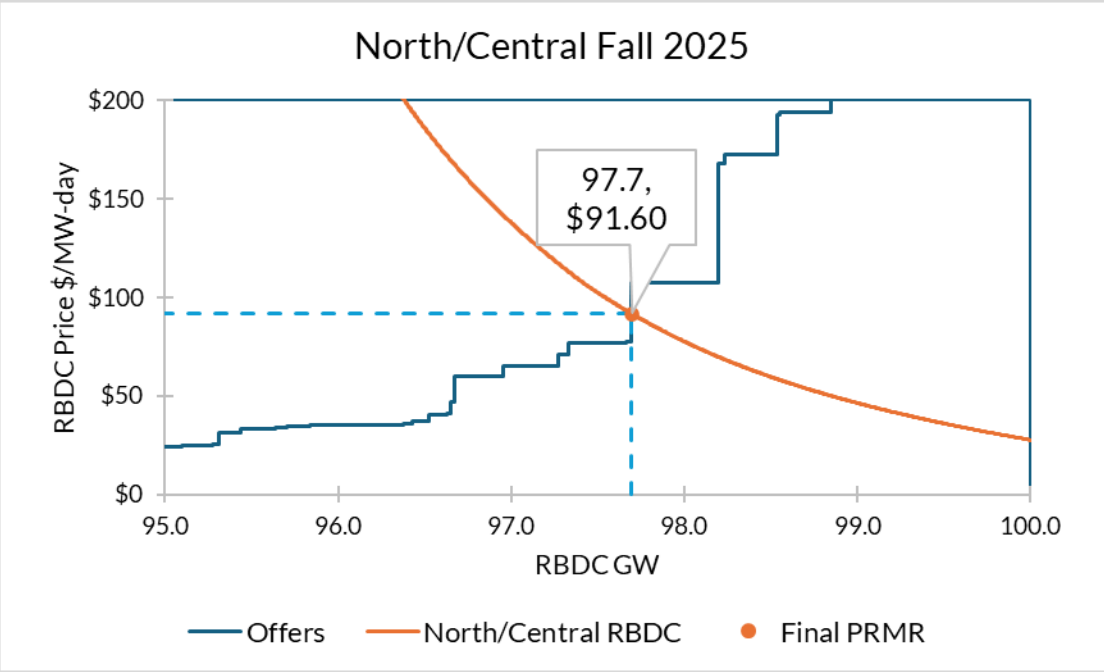
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

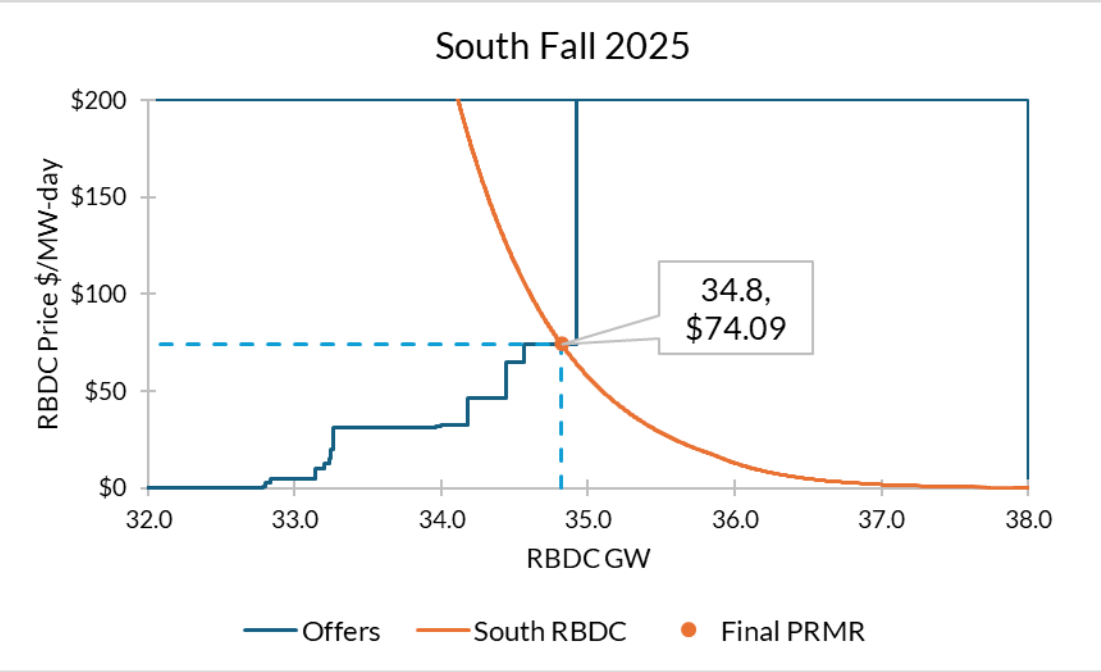
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

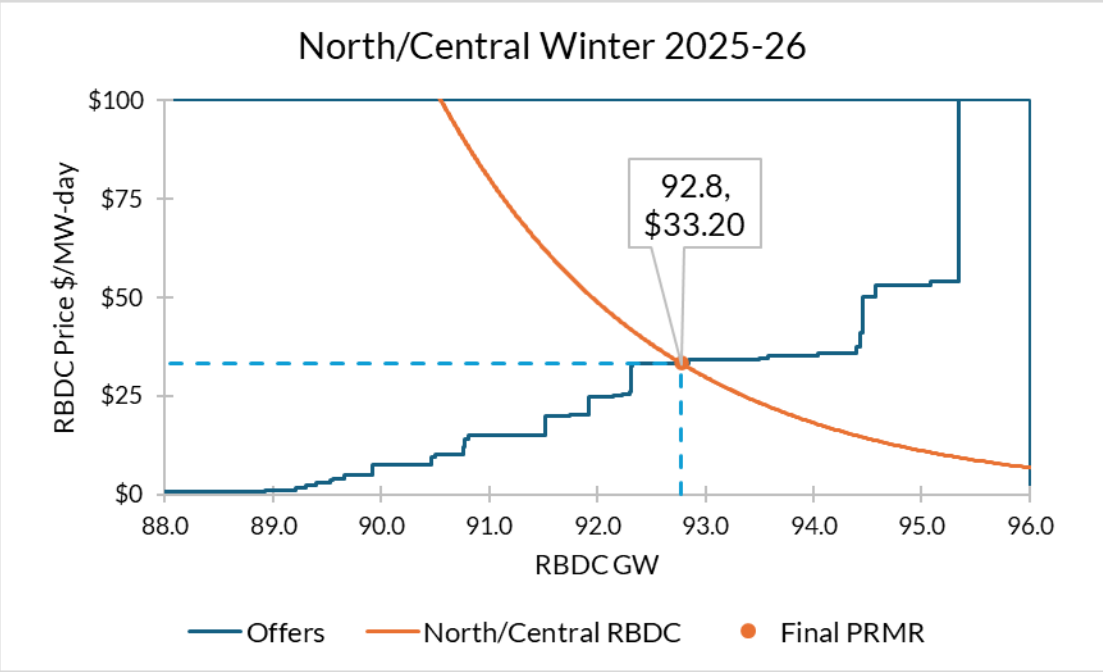
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

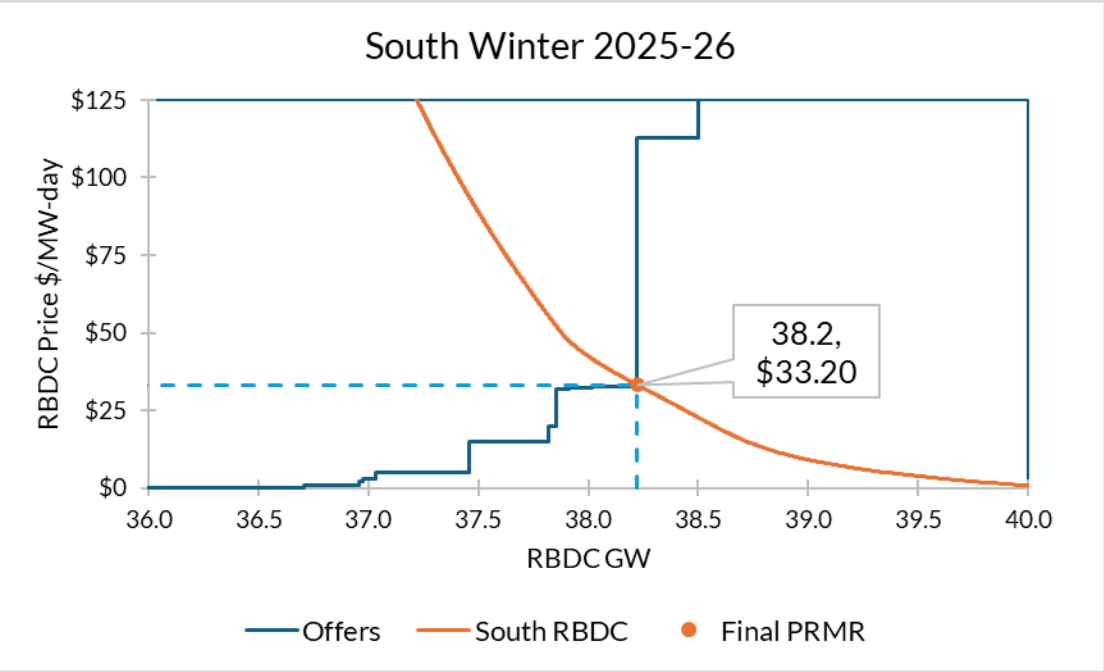




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
  - ACP for North subregion is $91.60, and $74.09 South subregion
  - A marginal resource in the South sets the price in that subregion
- In fall season, "effective" margin for North/Central subregion is at 18.4% and 15.2 % for South subregion vs. target of 14.9%

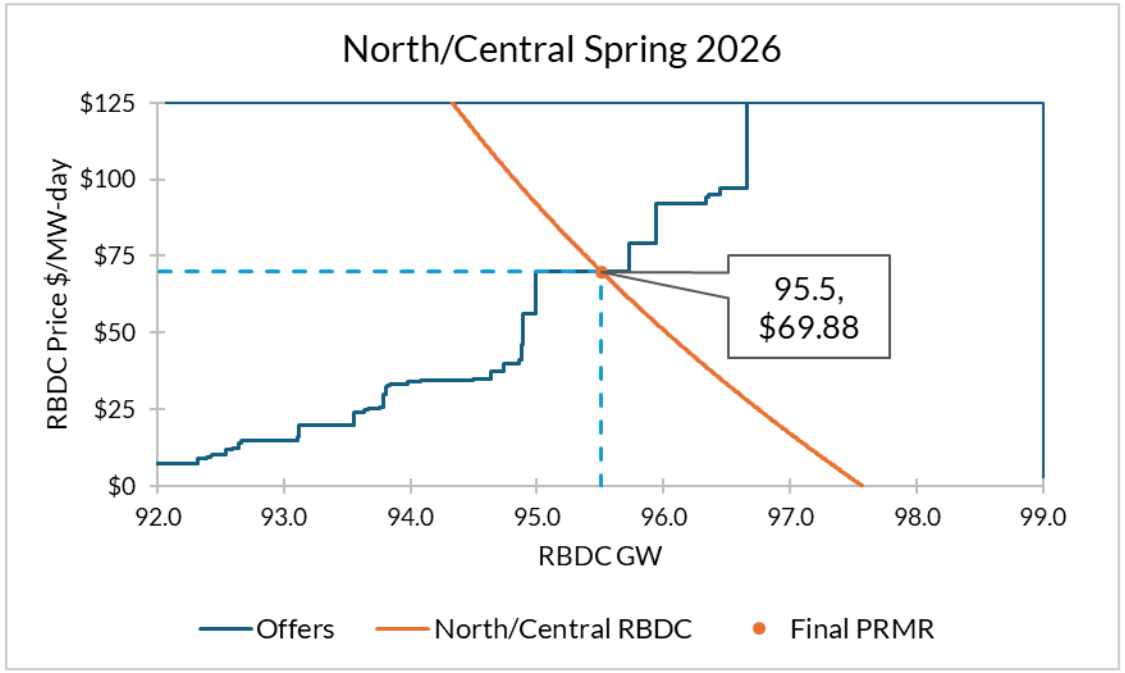
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

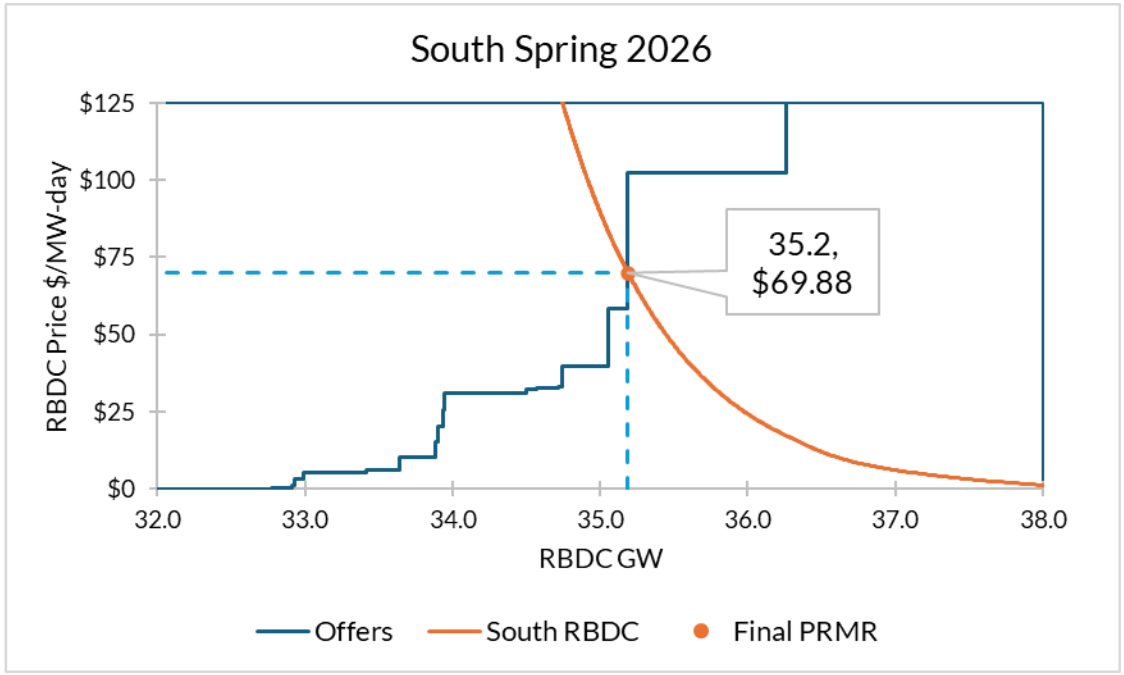




- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in winter
  - ACP for both subregions is $33.20
  - Multiple marginal resources, cleared *pro rata*, sets the price
- In winter, "effective" margin for North/Central subregion is at 23.3% and $27.3% for South subregion vs. target of 18.4%

Spring 2026 Reliability-Based Demand Curve, Offer Curves and Auction Clearing





- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in spring
  - ACP for both subregions is $69.88
  - A marginal resource sets the price
- In spring, "effective" margin for North/Central subregion is at 27.5% and 25% for South subregion vs. target of 25.3%

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

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Fall 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,290.4	12,086.4	10,179.1	8,950.4	7,898.3	17,939.5	20,493.9	8,019.3	21,578.1	5,142.6	N/A	94,838.0	34,740.0	129,578.0
Final PRMR	17,811.9	12,450.7	10,486.0	9,220.4	8,136.0	18,480.2	21,111.9	8,037.4	21,627.1	5,154.2	N/A	97,697.1	34,818.7	132,515.8
Offer Submitted (Including FRAP)	18,893.1	14,291.7	13,615.9	8,887.5	6,839.6	15,518.1	19,517.6	11,000.8	21,112.5	5,516.6	1,582.1	98,835.3	37,940.2	136,775.5
FRAP	4,233.2	9,259.1	582.7	773.3	0.0	983.1	533.1	459.4	153.4	1,518.3	44.6	16,402.6	2,137.6	18,540.2
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,646.8	3,423.5	10,580.4	7,036.0	6,706.5	10,590.4	16,911.4	9,029.4	17,788.1	3,286.3	1,208.0	60,831.1	30,375.7	91,206.8
Non-SS Offer Cleared	9,019.0	834.8	2,452.8	1,078.2	133.1	3,728.7	1,089.1	1,512.0	2,406.6	254.9	259.6	18,563.3	4,205.5	22,768.8
Committed (Offer Cleared + FRAP)	17,899.0	13,517.4	13,615.9	8,887.5	6,839.6	15,302.2	18,533.6	11,000.8	20,348.1	5,059.5	1,512.2	95,797.1	36,718.7	132,515.8
LCR	14,691.0	6,591.1	6,331.4	2,588.7	4,857.2	11,725.4	18,196.1	5,006.3	18,963.6	2,577.6	-	N/A	N/A	N/A
CIL	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508	-	N/A	N/A	N/A
ZIA	5,688	6,537	7,704	7,013	4,679	8,672	5,115	5,675	4,741	4,508	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	332.8	1,296.8	3,178.0	2,578.2	0.0	1,278.9	94.7	-	1,900.0	0.0	1,512.2
CEL	6,115	4,259	5,831	4,309	5,816	5,191	5,168	4,055	4,173	3,164	-	N/A	N/A	N/A
Export	87.2	1,066.8	3,129.9	0.0	0.0	0.0	0.0	2,963.3	0.0	0.0	1,512.2	0.0	1,900.0	-
ACP ($/MW-Day)	91.60	91.60	91.60	91.60	91.60	91.60	91.60	74.09	74.09	74.10	83.24-91.60			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Winter 2025/26 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,823.8	10,789.8	9,889.1	8,549.5	7,954.8	17,939.1	16,123.6	8,545.6	21,864.3	5,136.1	N/A	89,069.7	35,546.0	124,615.7
Final PRMR	18,565.8	11,238.7	10,300.9	8,905.1	8,285.9	18,685.7	16,794.7	9,189.0	23,511.0	5,522.7	N/A	92,776.8	38,222.7	130,999.5
Offer Submitted (Including FRAP)	19,750.7	13,217.2	12,059.1	7,547.1	6,339.9	14,679.5	19,957.3	10,751.9	22,273.0	5,939.7	1,746.5	94,964.8	39,297.1	134,261.9
FRAP	4,683.9	8,342.7	479.4	513.4	0.0	1,176.6	566.3	441.6	130.9	1,822.6	16.1	15,771.2	2,402.3	18,173.5
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	5,835.8	3,156.0	10,468.3	6,685.7	6,188.7	9,146.2	18,640.6	10,018.6	18,579.3	4,046.0	1,550.8	61,380.9	32,935.1	94,316.0
Non-SS Offer Cleared	7,977.9	1,062.6	1,044.5	271.5	99.9	4,008.7	397.0	291.7	3,105.5	71.1	179.6	15,007.6	3,502.4	18,510.0
Committed (Offer Cleared + FRAP)	18,497.6	12,561.3	11,992.2	7,470.6	6,288.6	14,331.5	19,603.9	10,751.9	21,815.7	5,939.7	1,746.5	92,159.7	38,839.8	130,999.5
LCR	13,462.0	5,951.6	8,008.4	1,371.4	3,644.7	11,074.8	15,500.2	8,014.7	20,593.7	3,534.1	-	N/A	N/A	N/A
CIL	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458	-	N/A	N/A	N/A
ZIA	5,575	6,435	5,785	6,457	4,922	7,690	4,762	3,432	4,418	3,458	-	N/A	N/A	N/A
Import	68.0	0.0	0.0	1,434.8	1,997.3	4,354.1	0.0	0.0	1,695.2	0.0	-	617.1	0.0	1,746.5
CEL	2,991	4,706	7,388	4,756	4,814	1,674	5,712	3,602	3,618	2,028	-	N/A	N/A	N/A
Export	0.0	1,322.6	1,691.5	0.0	0.0	0.0	2,809.2	1,562.8	0.0	416.9	1,746.5	0.0	617.1	0.0
ACP ($/MW-Day)	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Spring 2026 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,866.7	12,149.2	10,152.2	8,304.0	7,707.9	17,858.6	19,853.2	7,977.8	22,139.8	5,167.9	N/A	93,891.8	35,285.5	129,177.3
Final PRMR	18,174.5	12,358.6	10,327.0	8,447.2	7,841.0	18,166.7	20,195.5	7,955.2	22,076.1	5,157.7	N/A	95,510.5	35,189.0	130,699.5
Offer Submitted (Including FRAP)	18,662.6	14,525.3	12,333.3	9,178.5	6,118.7	15,824.7	19,451.0	11,495.2	21,064.7	5,864.0	1,542.6	97,313.7	38,746.9	136,060.6
FRAP	4,560.6	9,393.4	529.5	629.6	0.0	1,212.4	512.5	475.3	142.1	1,464.3	45.9	16,877.1	2,088.5	18,965.6
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,600.8	3,602.8	10,816.2	7,415.0	5,968.5	9,967.6	17,621.9	8,476.0	16,778.9	4,073.9	1,260.8	60,972.6	29,609.8	90,582.4
Non-SS Offer Cleared	8,578.5	1,069.5	589.6	1,133.9	150.2	4,001.0	719.2	1,470.2	2,947.5	325.8	166.1	16,372.9	4,778.6	21,151.5
Committed (Offer Cleared + FRAP)	17,739.9	14,065.7	11,935.3	9,178.5	6,118.7	15,181.0	18,853.6	10,421.5	19,868.5	5,864.0	1,472.8	94,222.5	36,477.0	130,699.5
LCR	12,239.1	6,737.5	5,014.7	1,823.8	4,700.3	10,377.1	16,453.6	4,243.1	19,790.5	3,178.8	-	N/A	N/A	N/A
CIL	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365	-	N/A	N/A	N/A
ZIA	6,396	6,439	7,726	7,373	4,453	9,176	5,166	6,085	4,855	4,365	-	N/A	N/A	N/A
Import	434.5	0.0	0.0	0.0	1,722.2	2,985.6	1,341.9	0.0	2,210.8	0.0	-	1,288.0	0.0	1,472.8
CEL	5,083	6,119	5,936	5,111	5,797	6,425	5,499	3,520	4,146	3,072	-	N/A	N/A	N/A
Export	0.0	1,707.2	1,608.0	731.2	0.0	0.0	0.0	2,465.6	0.0	710.3	1,472.8	0.0	1,288.0	-
ACP ($/MW-Day)	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Summer Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Summer 2023**	**Summer 2024**	**Summer 2025**	**Summer 2023**	**Summer 2024**	**Summer 2025**
Generation	122,375.6	123,395.6	121,015.6	116,989.7	119,479.2	120,738.6
External Resources	4,514.6	4,430.4	3,505.9	4,072.5	4,309.8	3,505.9
Behind the Meter Generation	4,175.2	4,180.2	4,282.8	4,129.4	4,143.5	4,282.8
Demand Resources	8,303.5	8,660.2	9,004.4	7,694.6	8,109.4	9,004.4
Energy Efficiency	5.0	22.5	27.6	5.0	22.5	27.6
Total	**139,373.9**	**140,688.9**	**137,836.3**	**132,891.2**	**136,064.4**	**137,559.3**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Fall 2023**	**Fall 2024**	**Fall 2025**	**Fall 2023**	**Fall 2024**	**Fall 2025**
Generation	121,403.5	119,745.3	122,283.4	111,713.8	111,791.5	118,309.5
External Resources	4,095.4	4,366.8	2,833.5	3,979.6	3,990.2	2,763.6
Behind the Meter Generation	3,874.2	3,877.9	3,646.8	3,842.8	3,789.7	3,646.8
Demand Resources	6,999.2	6,866.1	7,983.7	6,254.4	5,957.5	7,767.8
Energy Efficiency	4.9	22.5	28.1	4.8	22.5	28.1
Total	**136,377.2**	**134,878.6**	**136,775.5**	**125,795.4**	**125,551.4**	**132,515.8**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Winter 2023-2024	Winter 2024-2025	Winter 2025-2026	Winter 2023-2024	Winter 2024-2025	Winter 2025-2026
Generation	124,632.7	133,457.4	120,225.1	114,886.6	118,253.8	117,392.0
External Resources	3,937.1	3,973.0	2,808.7	3,334.6	3,313.3	2,793.7
Behind the Meter Generation	3,257.8	3,111.5	3,082.9	3,173.9	2,957.3	3,082.6
Demand Resources	7,644.4	7,866.4	8,112.3	6,702.4	6,822.7	7,698.3
Energy Efficiency	6.7	29.7	32.9	6.7	29.7	32.9
Total	**139,478.7**	**148,438.0**	**134,261.9**	**128,104.2**	**131,376.8**	**130,999.5**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Spring 2024**	**Spring 2025**	**Spring 2026**	**Spring 2024**	**Spring 2025**	**Spring 2026**
Generation	119,254.7	121,303.8	120,780.6	110,195.8	113,091.4	115,724.7
External Resources	3,794.1	3,481.8	2,640.1	3,409.1	3,406.5	2,570.3
Behind the Meter Generation	4,096.4	4,201.6	4,133.5	4,058.9	4,180.5	4,133.5
Demand Resources	7,282.9	7602.9	8,475.9	6,720.0	7,087.2	8,240.5
Energy Efficiency	5.3	25.0	30.5	5.3	25.0	30.5
Total	**134,433.4**	**136,615.1**	**136,060.6**	**124,389.1**	**127,790.6**	**130,699.5**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

2025 PRA pricing compared with Independent Market Monitor (IMM) Conduct Threshold and Cost of New Entry (CONE)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs	System CONE (Seasonal)	North/Central CONE (Seasonal)	South CONE (Seasonal)
Summer 2025	$666.50											$1,353.84	$1,384.36	$1,282.61
Fall 2025	$91.60							$74.09			$83.24-$91.60	$1,368.71	$1,399.58	$1,296.70
Winter 2025-26	$33.20											$1,383.92	$1,415.13	$1,311.11
Spring 2026	$69.88											$1,353.84	$1,384.36	$1,282.61
Cost of New Entry (Annual)	$127,720	$125,090	$121,220	$126,040	$136,170	$124,360	$130,930	$118,960	$117,710	$117,330	$136,170			
IMM Conduct Threshold*	$34.99	$34.27	$33.21	$34.53	$37.31	$34.07	$35.87	$32.59	$32.25	$32.15	-			

- *Zonal Auction Clearing Prices (ACP) shown in $/MW-day*

**Zonal Resource Credit (ZRC) offers that impact pricing should generally stay below the IMM Conduct Threshold and applies to all seasons.*

ERZ: External Resource Zones

Historical Summer Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2015-2016	$3.48			$150.00	$3.48			$3.29		N/A	N/A
2016-2017	$19.72	$72.00						$2.99			N/A
2017-2018	$1.50										N/A
2018-2019	$1.00	$10.00									N/A
2019-2020	$2.99						$24.30	$2.99			
2020-2021	$5.00						$257.53	$4.75	$6.88	$4.75	$4.89-$5.00
2021-2022	$5.00							$0.01			$2.78-$5.00
2022-2023	$236.66							$2.88			$2.88-236.66
Summer 2023	$10.00										
Summer 2024	$30.00										
Summer 2025	$666.50										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
Fall 2025	$91.60							$74.09			$83.24-$91.60

- Auction Clearing Prices shown in $/MW-Day
- Price separation present in Fall 2025 between the North and South subregions since the Sub-Regional Import Constraint (SRIC) / Sub-Regional Export Constraint (SREC) bound

ERZ: External Resource Zones

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

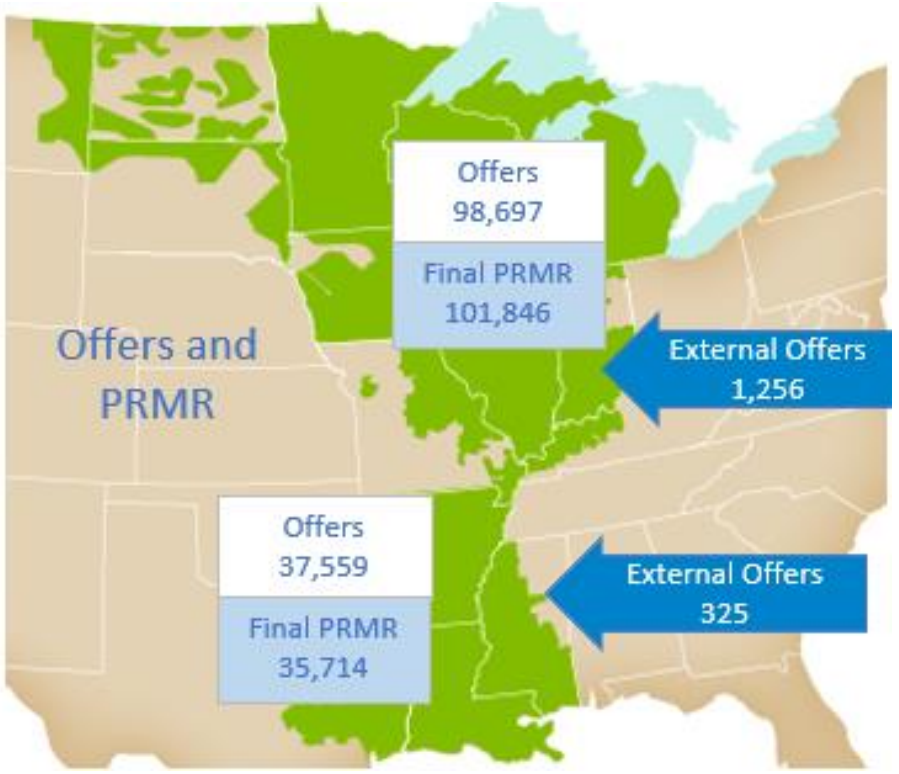
PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										

- Auction Clearing Prices shown in $/MW-Day

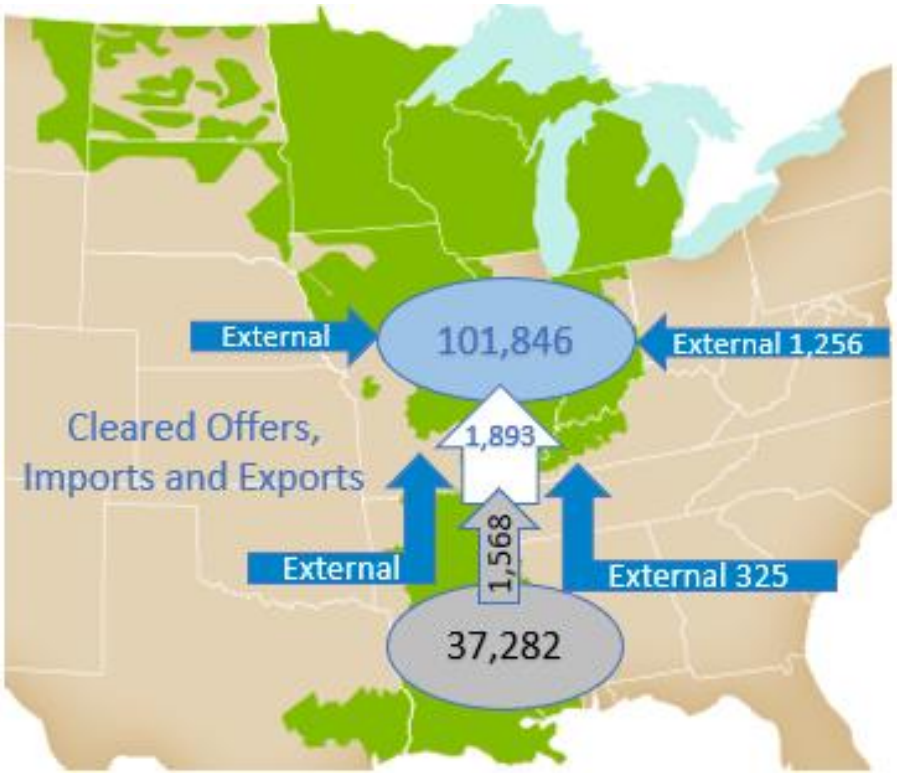
ERZ: External Resource Zones

Summer 2025 Capacity

Offered Capacity & Final PRMR (MW)



Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall 2025 Capacity

Offered Capacity & Final PRMR (MW)



Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter 2025/26 Capacity

Offered Capacity & Final PRMR (MW)



Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring 2026 Capacity

Offered Capacity & Final PRMR (MW)



Cleared Capacity, Imports & Exports (MW)



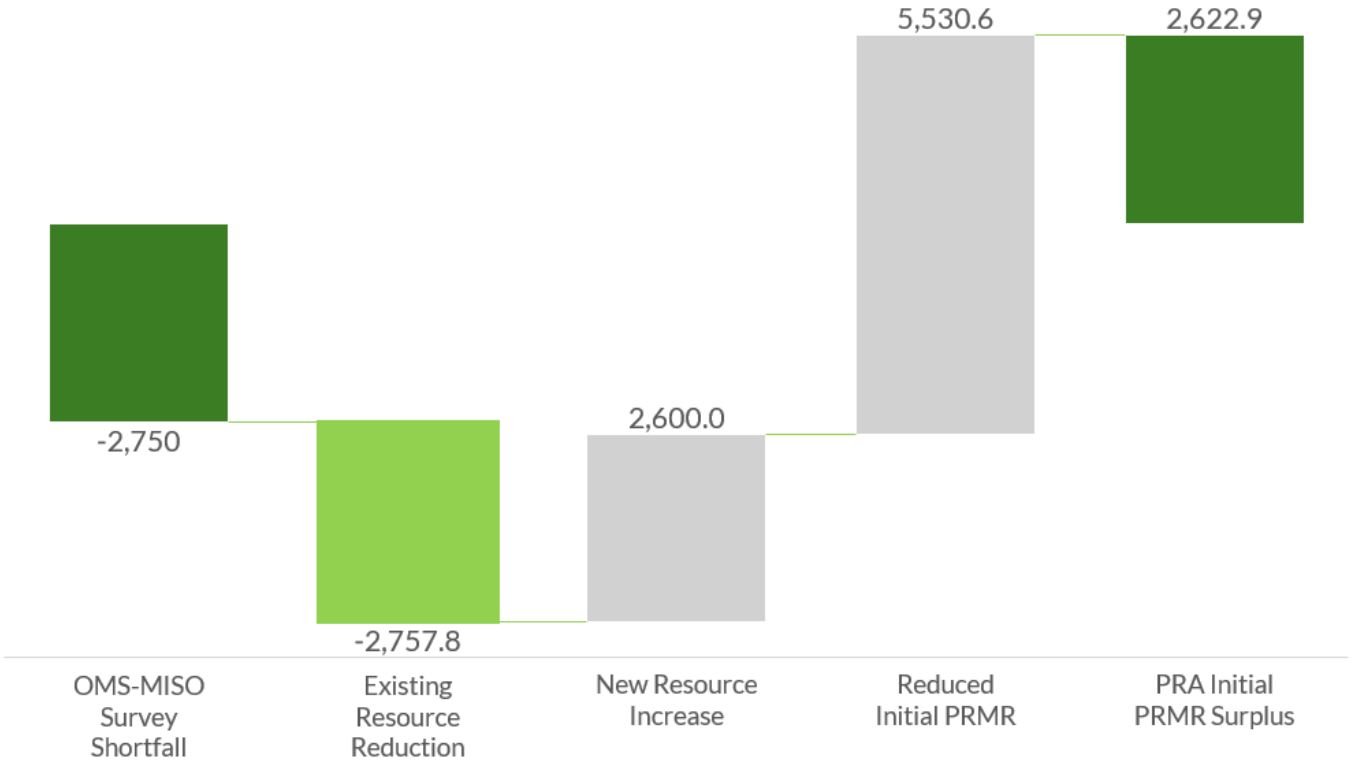
PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

The 2025 auction resulted in a surplus compared to the PRMR target, in contrast to the 2024 OMS-MISO Survey projection of a shortfall

Summer 2025 auction outcomes vs. 2024 OMS-MISO Survey projection for 2025

- Resource offers in the auction were comparable to "High Certainty" values projected in the OMS-MISO Survey
- Incremental accreditation reductions in the auction were offset by incremental increases in new resource additions
- Notably, initial PRMR was lower (5.5 GW) than projected in the OMS-MISO Survey

2024 OMS-MISO Survey Projection vs.
2025 PRA Actual PRMR Surplus (MW)

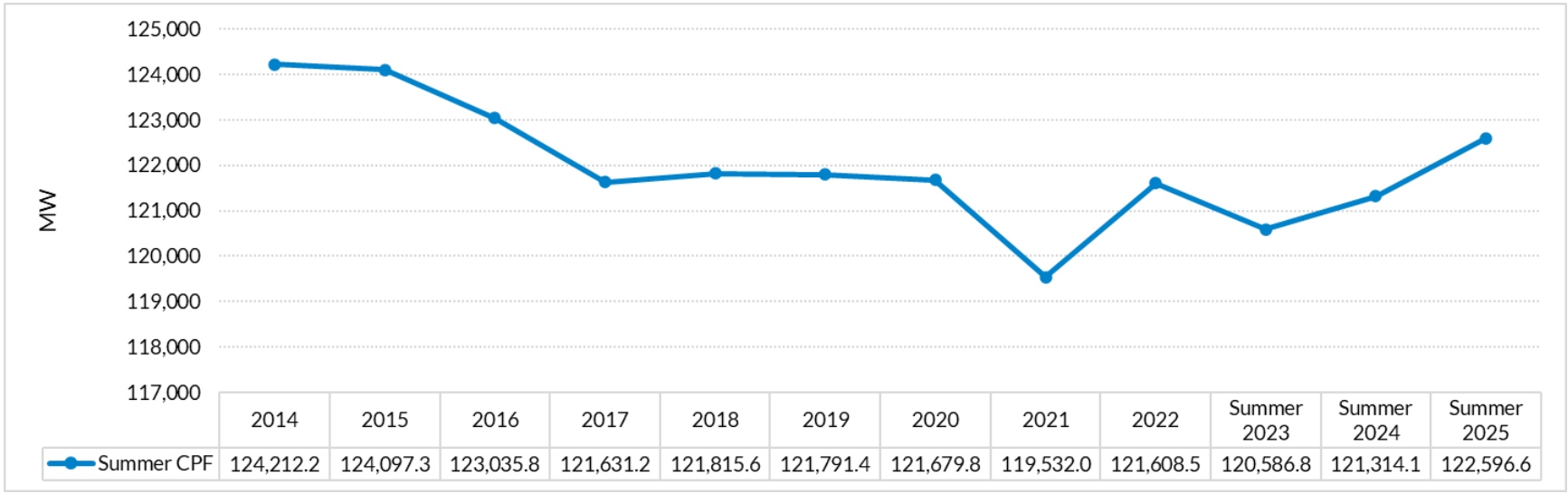


*PRA Shortfall/Surplus relative to Initial PRMR | PRMR: Planning Reserve Margin Requirement

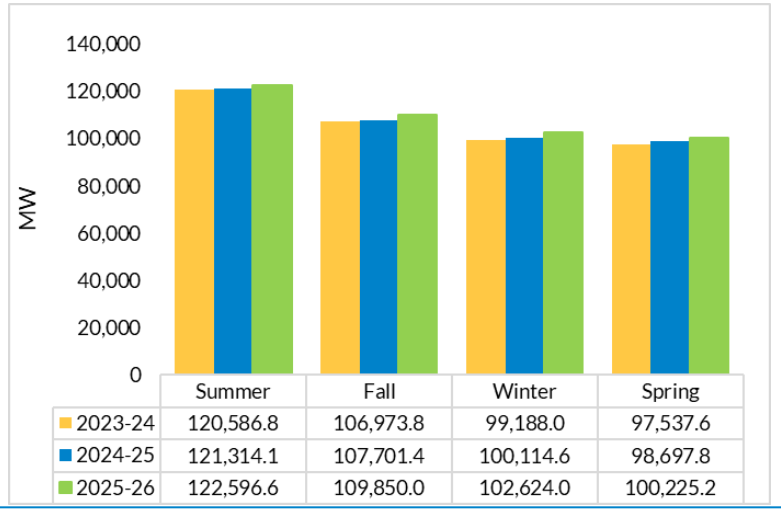
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Coincident Peak Forecast

Year over year the Summer CPF (+1.3 GW), PRM (-1.1%) and Final PRMR (+1.5 GW) are higher.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
Summer CPF	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6

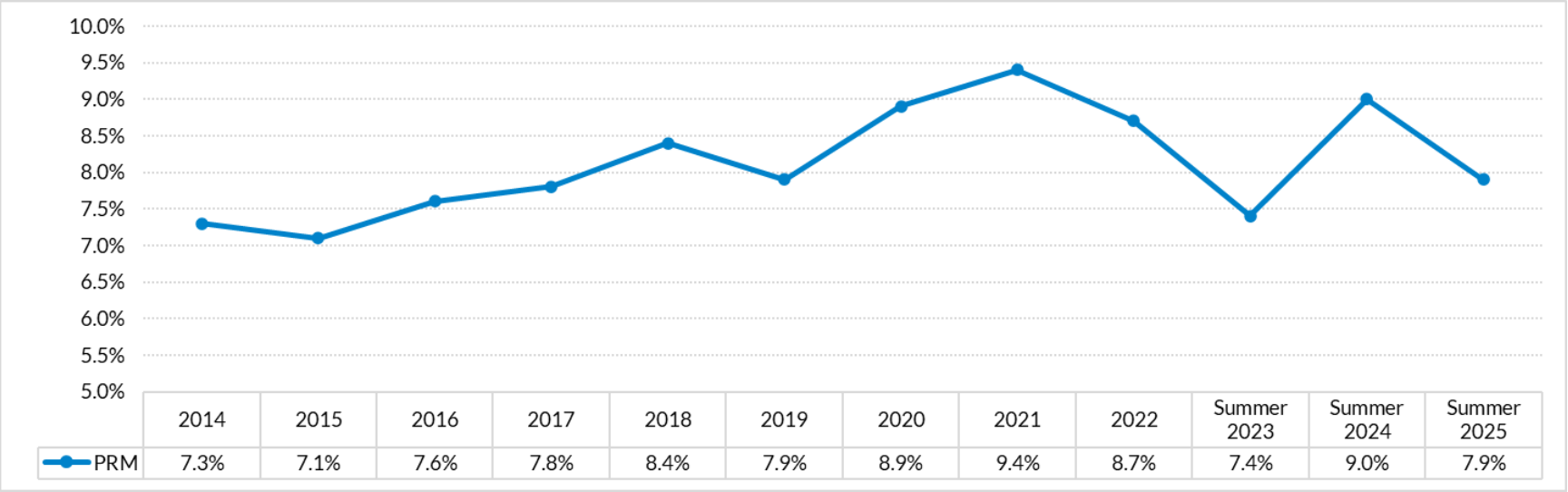


	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

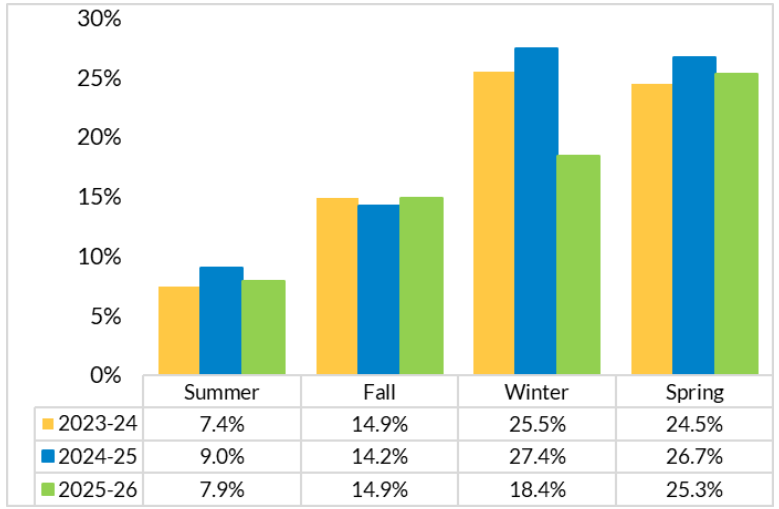
PRMR: Planning Reserve Margin Requirement

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Planning Reserve Margin (%)

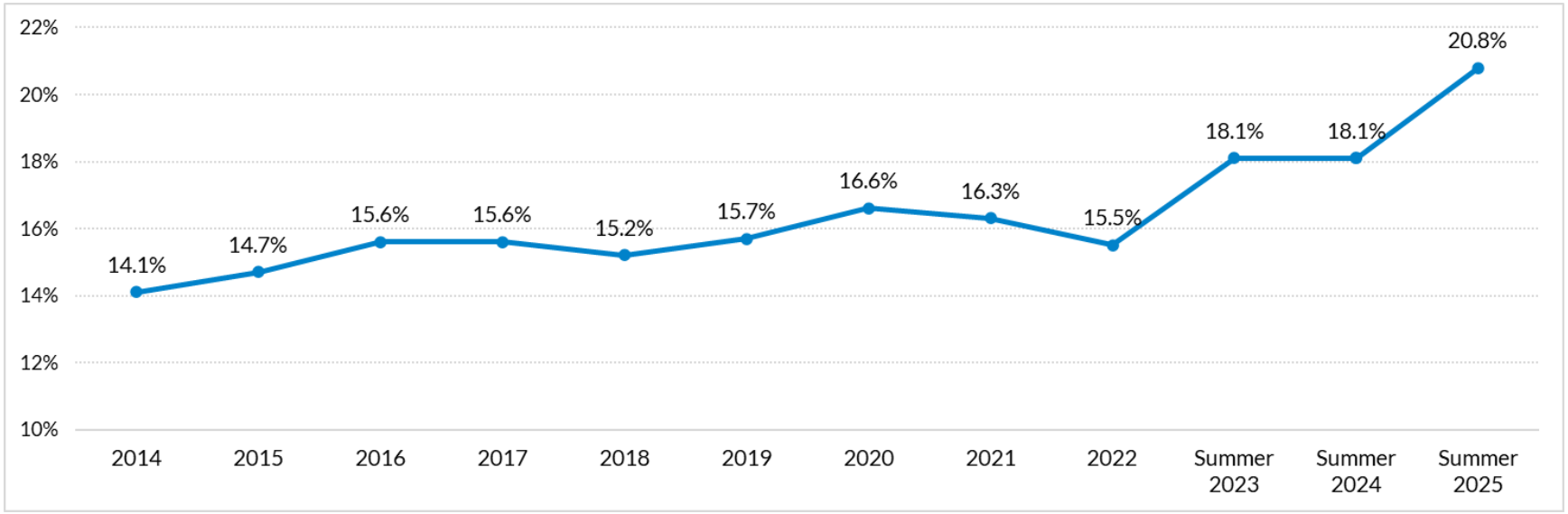


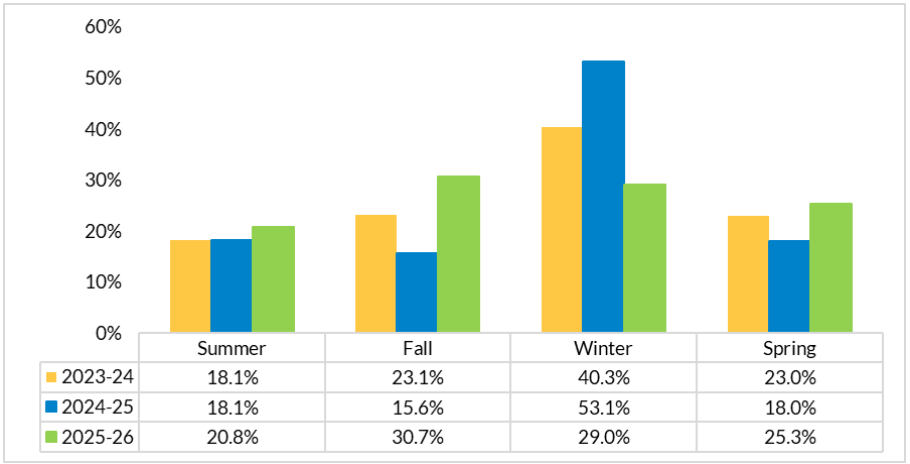
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	Summer	Fall	Winter	Spring
2023-24	7.4%	14.9%	25.5%	24.5%
2024-25	9.0%	14.2%	27.4%	26.7%
2025-26	7.9%	14.9%	18.4%	25.3%

Wind Effective Load Carrying Capacity (%)



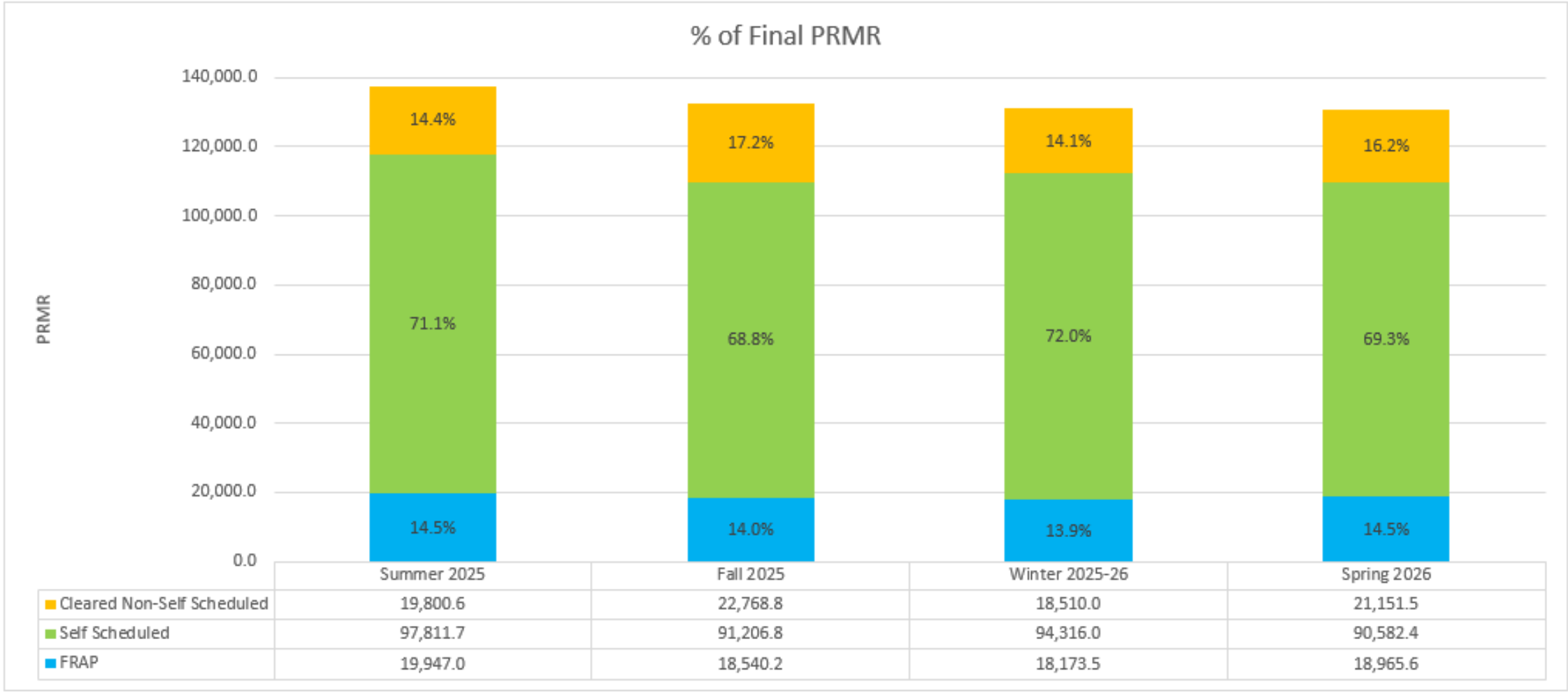


	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%
2025-26	20.8%	30.7%	29.0%	25.3%

- No change to wind or solar accreditation methodology from previous years.
- Methodology applied on a seasonal basis.
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar class average
  - Summer, fall, spring 50%
  - Winter 5%

ELCC: Effective Load Carrying Capability LOLE: Loss of Load Expectation

2025/26 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons

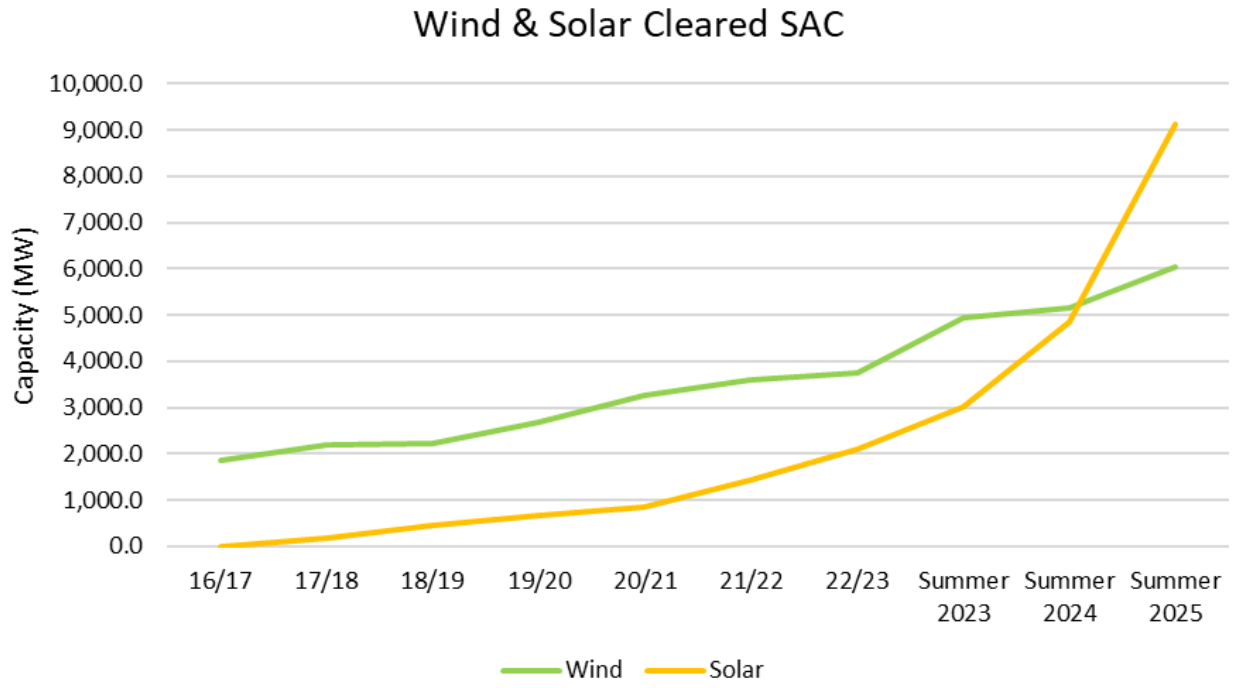


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

Although conventional generation still comprises most of the capacity, wind and solar continue to grow

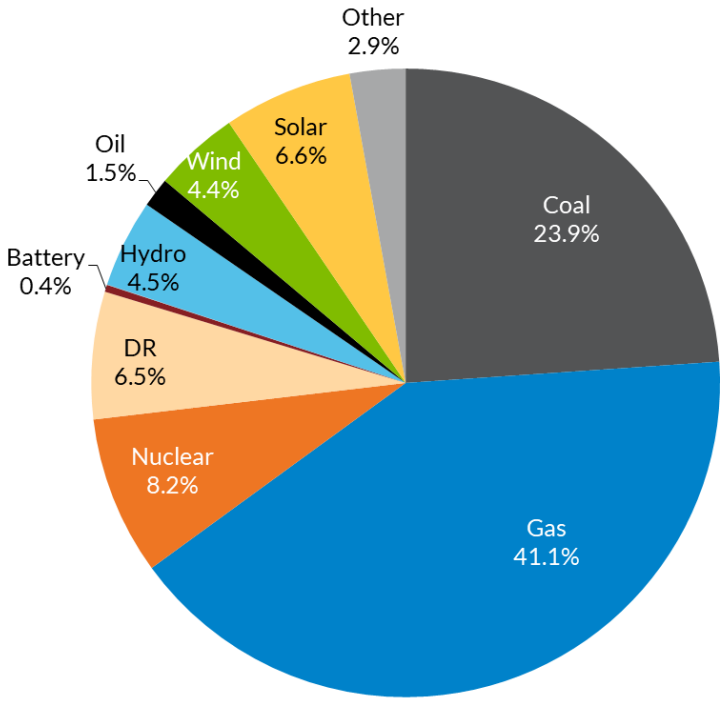
- 9.1 GW of solar cleared this year's auction, an increase of 88% from Planning Year 2024/25 (4.9 GW)
- 6 GW of wind cleared this year, an increase of 17% compared to last year (5.2 GW)



05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter final PRMR is 6.6 GW (4.8%) lower than the summer with fewer solar resources to meet final PRMR in the winter versus the summer

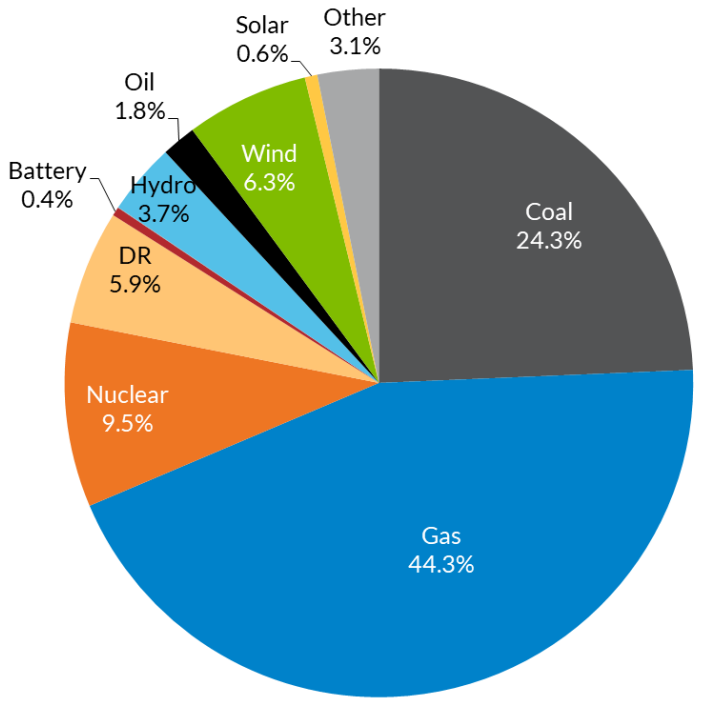
Summer 2025



MISO-wide

Cleared ZRC	Summer 2025	Winter 2025/26	Difference
Coal	32,909.6	31,887.2	1,022.4
Gas	56,470.0	57,990.5	-1,520.5
Nuclear	11,232.1	12,416.7	-1,184.6
DR	9,004.4	7,698.3	1,306.1
Battery	499.2	588.5	-89.3
EE	27.6	32.9	-5.3
Hydro	6,231.3	4,823.7	1,407.6
Oil	2,088.8	2,315.7	-226.9
Wind	6,039.1	8,282.9	-2,243.8
Solar	9,122.8	847.3	8,275.5
Misc	3,934.4	4,115.8	-181.4
PRMR	137,559.3	130,999.5	6,559.8

Winter 2025/26

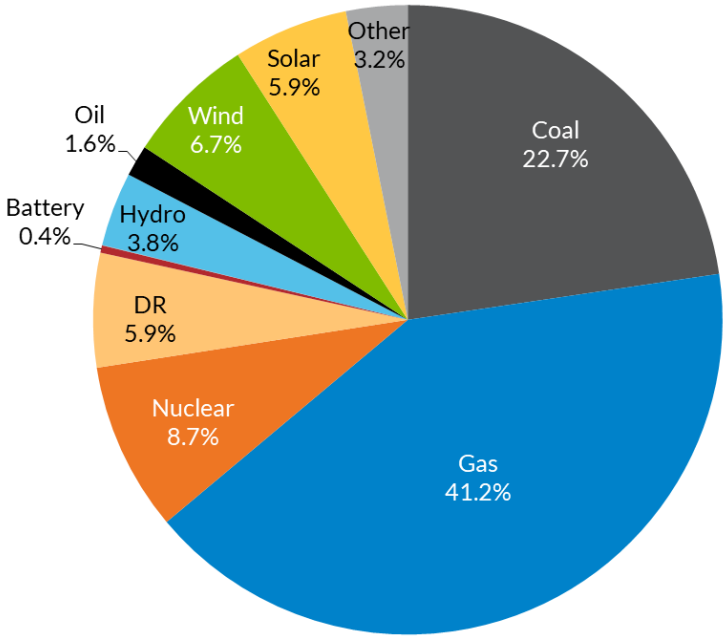


PRMR: Planning Reserve Margin Requirement

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

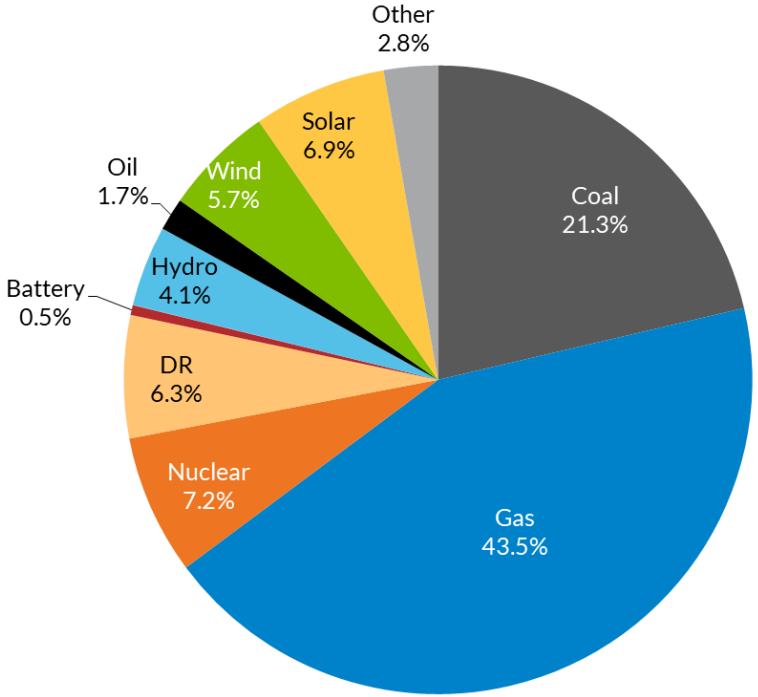
Fall 2025



MISO-Wide

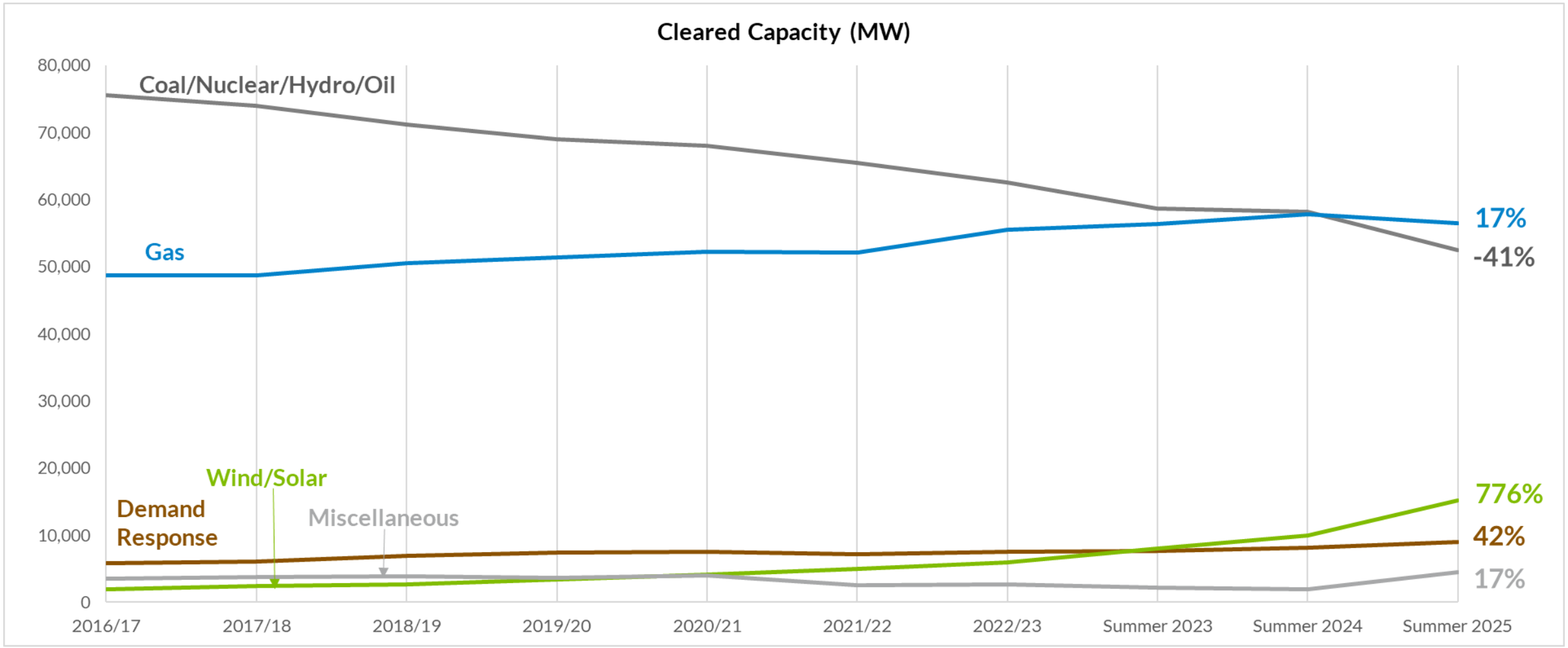
Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

Spring 2026



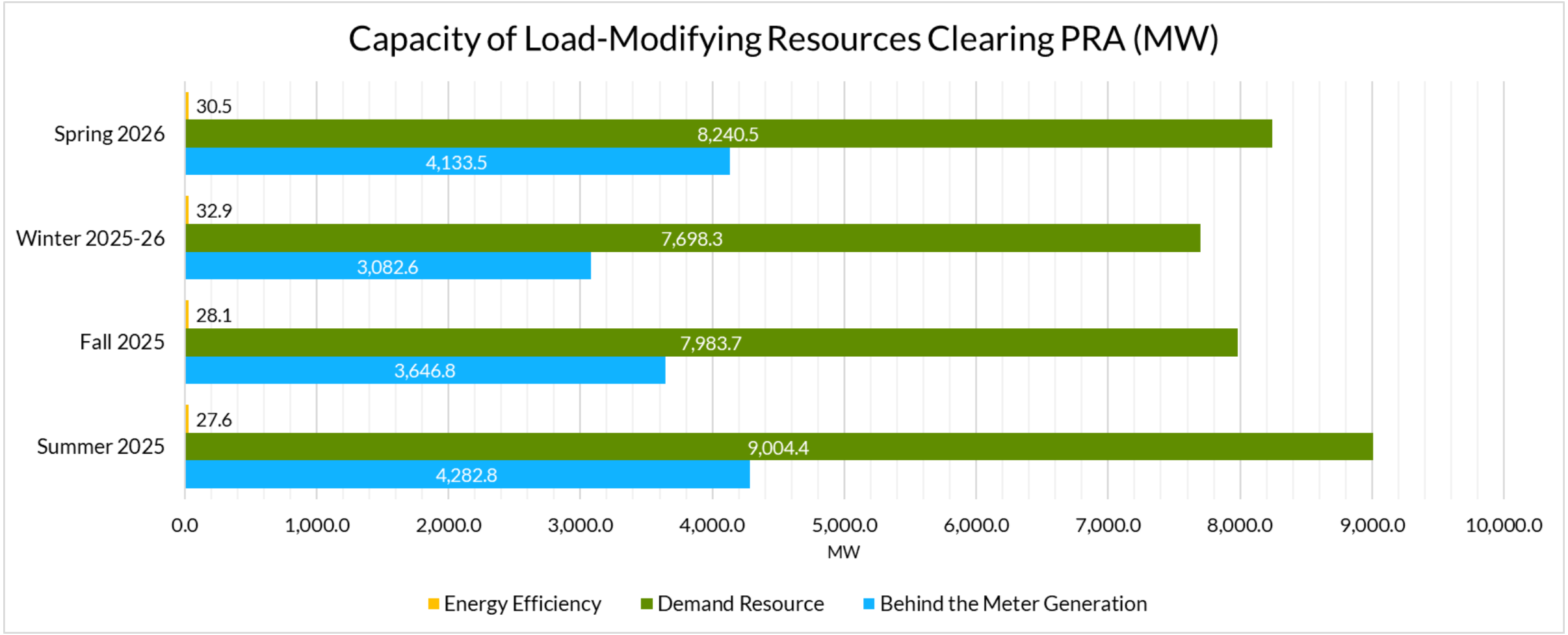
PRMR: Planning Reserve Margin Requirement

The planning resource mix shows the continuation of a multi-year trend towards less coal/nuclear/hydro/oil and increased gas and non-conventional resources

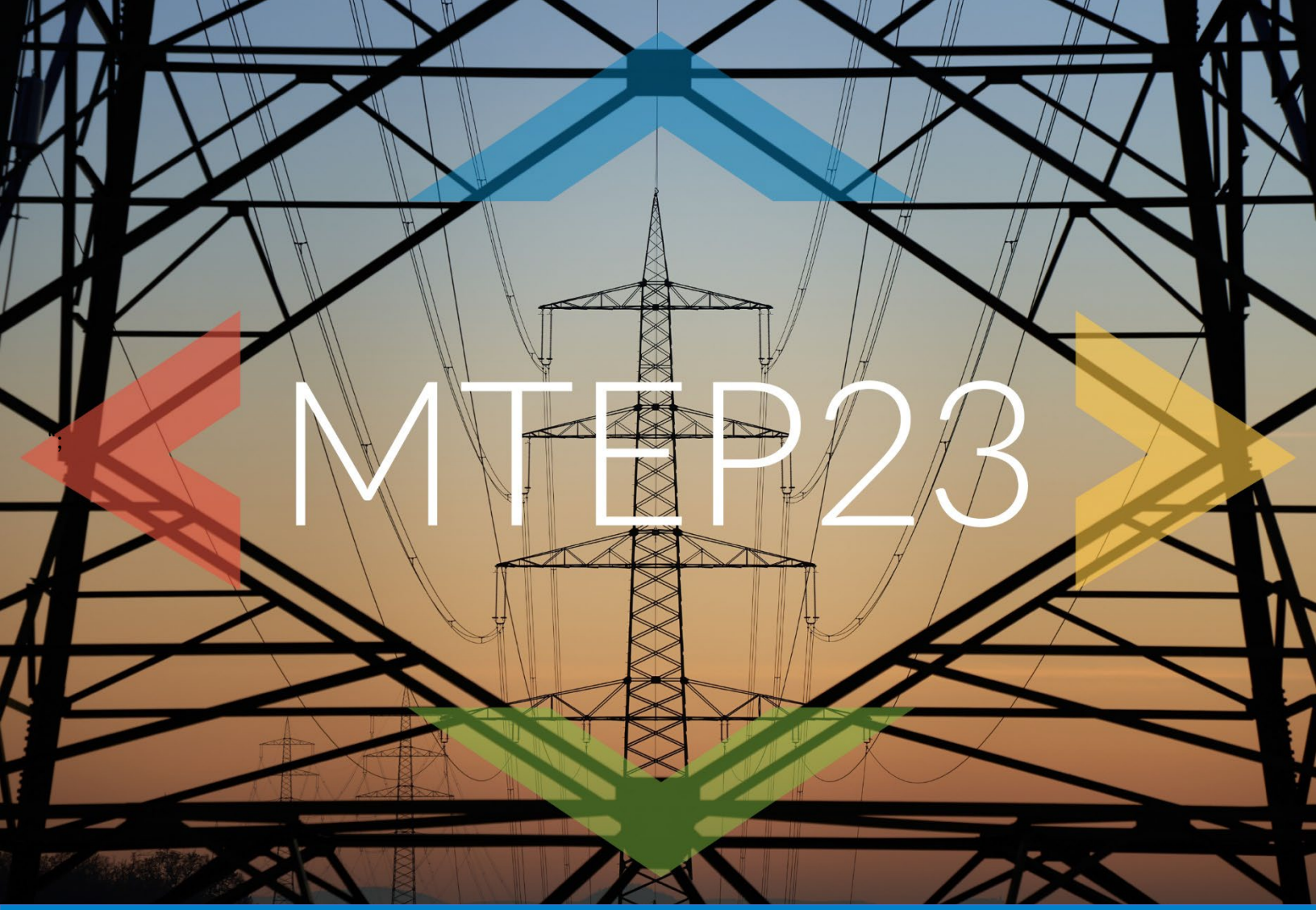


05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

2025/26 Seasonally Cleared Load Modifying Resources Comparison



Visit MISO's Help Center
for more information
https://help.misoenergy.org/



MTEP23 REPORT

Highlights

- 572 new projects with an estimated $9 billion investment
- $34 billion in projects constructed in the MISO region since 2003
- Grid evolution drove significant records in MTEP23

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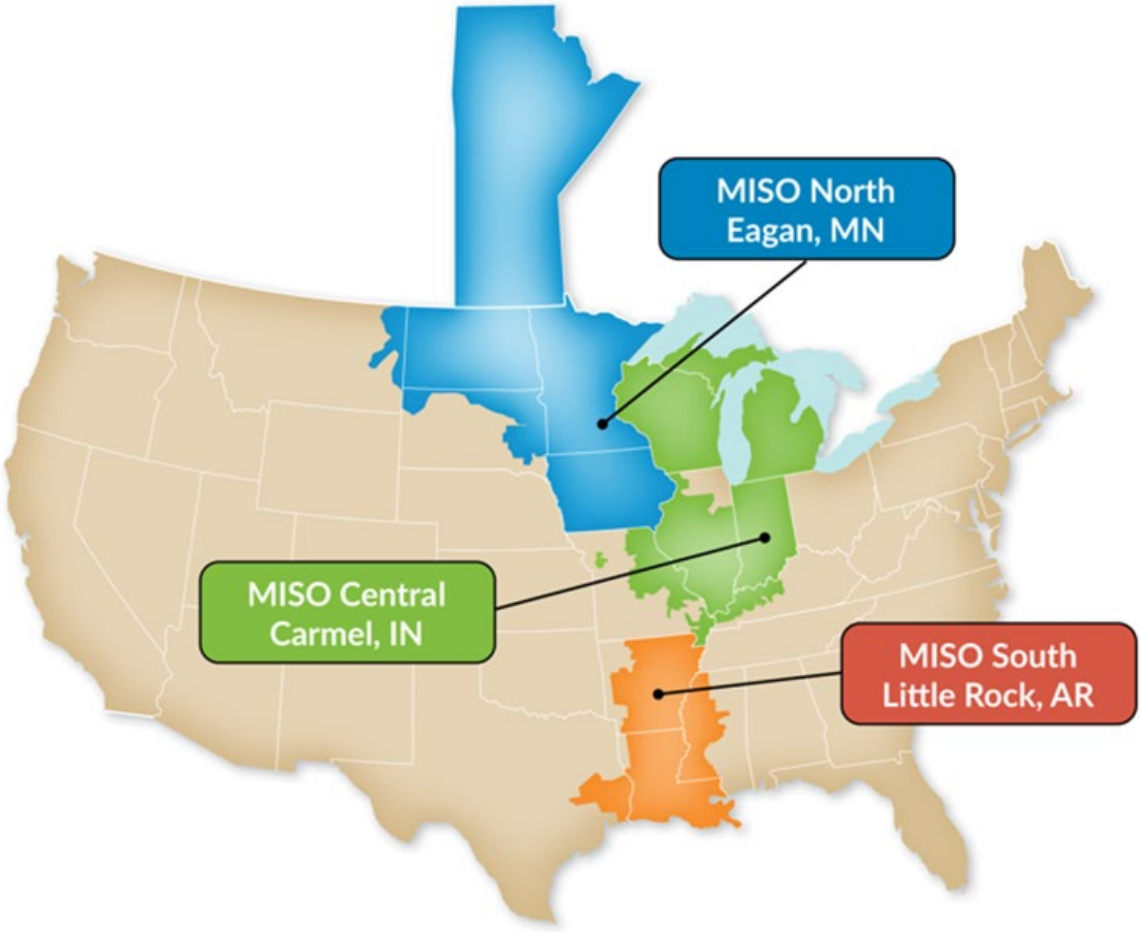
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About MISO

Midcontinent Independent System Operator (MISO) is an independent, 501(c)(4) not-for-profit, member-based organization, approved as a Regional Transmission Organization (RTO) by FERC in 2001, with responsibility for keeping the power flowing across its region reliably and cost effectively. The system MISO manages is the largest in North America based on geographical scope, with 471 market participants serving approximately 45 million people across all or part of 15 states and one Canadian province. The MISO energy markets are also among the largest in the world, with more than $40 billion in annual gross market charges.

MISO Reliability Footprint and Regional Control Center Locations



Currently, the MISO region contains nearly 75,000 miles of high-voltage transmission, as well as roughly 199,000 megawatts of electricity generating capacity. MISO does not own any of these assets. Instead, with the consent of our asset-owning members and in accordance with our FERC-approved tariff, MISO exercises functional control over the region's transmission and generation resources with the aim of managing them in the most reliable and cost-effective manner possible. The MISO region is predominantly comprised of traditionally structured, state-regulated utilities.

KEY FACTS

Area Served	15 U.S. States and Manitoba, Canada
Population Served	45 Million
Transmission Line**	75,000 Miles
Generating Units*	6,800+
Record Demand	127.1 GW 7/20/2011
Wind Peak	24.1 GW 11/30/2022
Solar Peak	2.2 GW 8/31/2022
Members	57 Transmission Owners 135 Non-transmission Owners
Market Participants	500+
Carbon Reduction	Approximately 32% since 2014



Corporate data as of August 2023
**Network Model*
***Market Footprint*

CHAPTER 1: TRANSMISSION PLANNING OVERVIEW

1.1 Planning for the Future

Since MISO's articulation of the Reliability Imperative, its members have accelerated the rate of fleet change, demonstrating a need for a stronger, regionally coordinated transition plan. Flexible, thermal resources are retiring more rapidly than expected along with attributes which have historically helped to ensure reliability.

At the same time, regulations, policies and economics create an uncertain environment for the future of thermal generators. Potential future technologies that can provide flexible attributes, such as hydrogen, long-duration storage and small modular nuclear reactors, are not yet commercially available nor deployed at scale. The interconnection queue is predominantly weather-based resources, and resources with interconnection agreements are requesting delays of 36 months and more due to supply chain and regulatory issues, among others.

The MISO region needs a coordinated transition plan to ensure an orderly, efficient transition and the ability to manage the risks associated with a massive change in resources. At the same time, the region is facing an increase in the number and intensity of severe weather events, which further magnify the need to coordinate the transition.

During this time, MISO remains focused on working with states, regulators and stakeholders on the response to the Reliability Imperative, which is designed to:

- Ensure the totality of the resource portfolio can be operated reliably under all conditions;
- Enable the construction of appropriate transmission to integrate changing resources;
- Redesign the market to ensure proper signals are sent to all market participants to inform efficient investment and reliable operations; and
- Transform its systems and processes in anticipation of the regional needs.

Resource Adequacy

While resource sufficiency was demonstrated through this year's Planning Resource Auction, the first conducted under the new seasonal construct, it was primarily achieved through resource decisions that are difficult to repeat. These include delayed resource retirements, new firm imports committed to MISO load, accreditation increases for wind resources, a lower Planning Reserve Margin Requirement, and decline in summer peak load.

Looking forward, there is a continued risk of resources retiring faster than replacement resources are able to come online due to supply chain delays and permitting constraints. Additionally, new, replacement resources will need to bring sufficient characteristics to balance the system. Further, additional work may be needed to ensure that future load estimates that apply to transmission planning and resource adequacy processes reflect actual load increases. And the concept of "resource adequacy" must be expanded to not only include capacity but also the various grid services that different technologies and resource types can bring to the system.

Acceleration of the fleet transition

MISO continues to work with its members to better understand the future resource fleet and the pace at which this change will occur. Policy goals made in public announcements and Integrated Resource Plans, verified through interviews with member utilities, are reflected through MISO's most recent projection of the fleet transition, known as Future 2A (Figure 1.1-1). This Future, reflecting current trajectory of member carbon and renewable energy goals, is accordingly more ambitious than MISO's earlier Future 2. Significant growth in renewable generation (with subsequent modest growth in accredited capacity owing to lower capacity factors of wind and solar generators compared to legacy resources), retirements of thermal resources, and load growth owing to electrification are hallmarks of this new future. Some 250 GW (installed capacity) of resource additions, mostly renewable, are expected.

Put into perspective, MISO's interconnection queue process has historically added 2 to 2.5 GW installed capacity of resources to the system each year. To reach the buildout suggested in Future 2A, such additions to the system would require additions five to ten times that size each year over the course of twenty years. The approximately 50 GW of approved resources in the current queue, which have delayed commercial operation by an average of 650 days (owing primarily to supply chain, regulatory and contractor issues), suggest that existing approval processes and supply chains are already strained.

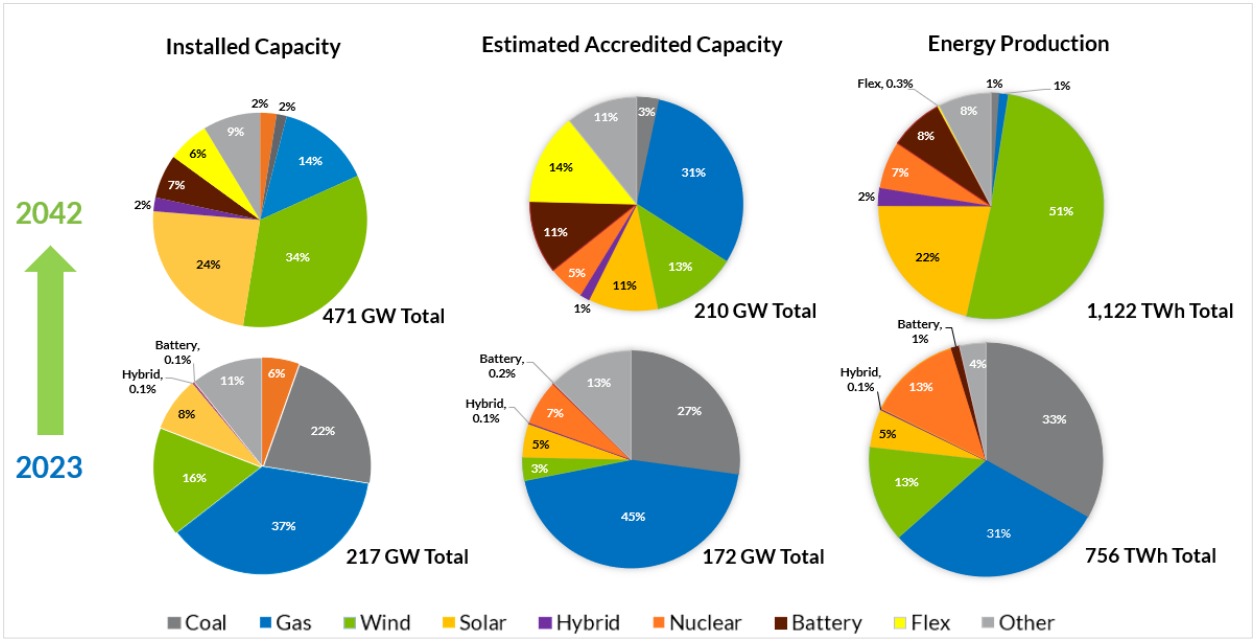


Figure 1.1-1: MISO's Future 2A anticipates significant renewable additions, controllable retirements and load growth. [1]

In addition to the magnitude of the resource shift, the timeline in which these changes are to be realized has shortened. Future 2A suggests that renewable penetration milestones will be achieved much sooner than initial estimates (Figure 1.1-2). MISO's earlier Renewable Integration Impact Assessment (RIIA) found that in annual energy penetrations above 30%, operational complexity dramatically increases and local reliability issues become more widespread as energy adequacy and system stability risks grow (see below.) Further adding to uncertainty are future load growth projections. For example, multiple load additions totaling 100+

[1] Data as of April 26, 2023. Futures do not account for all operational-level reliability needs and attributes that may require different levels of dispatchable resources. Resource additions may be subject to adjustment based on new accreditation rules. "Other" includes biomass, geothermal, hydro, oil, pumped hydro storage, demand response, non-solar distributed generation, and energy efficiency. Battery energy production includes battery discharging only. However, overall energy production pie graph includes the energy required to charge storage.

MW have been submitted through the Expedited Review Process throughout MTEP23. An accelerated pace of change suggests that work to prepare for the implications must also hasten.

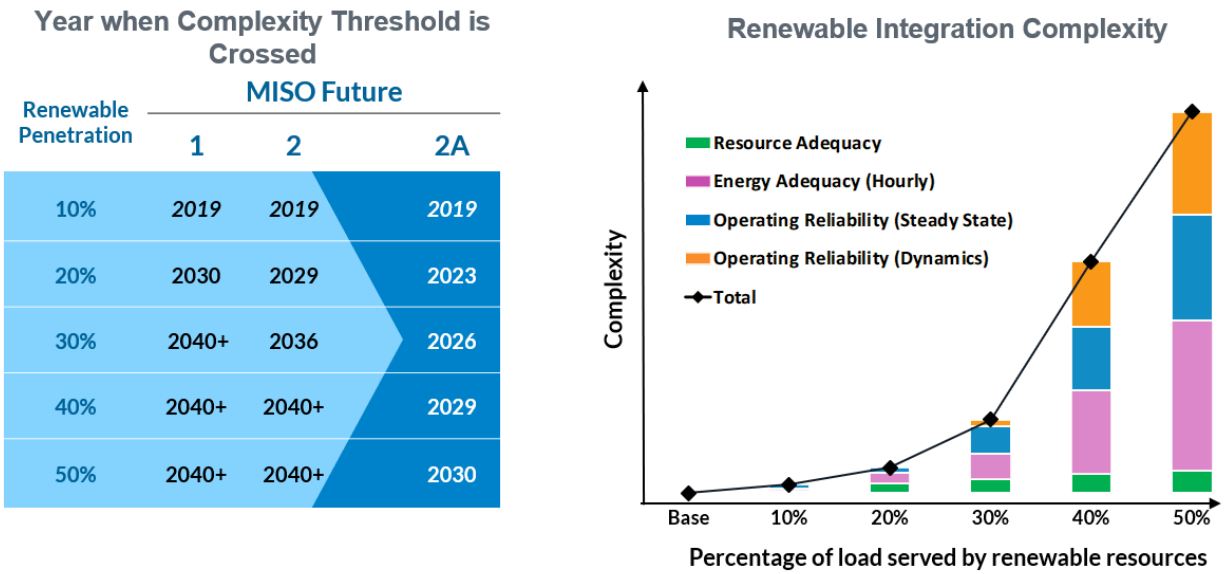


Figure 1.1-2: Reaching renewable penetration milestones more quickly than initial models implies greater system integration complexity earlier than anticipated. Left – MISO Future 2A shows renewable penetration milestones accelerated. Right – Renewable Integration Impact Assessment (RIIA) shows that as penetrations exceed 30%, integration complexity on the system dramatically increases.

Energy Adequacy

Weather is impacting resources in ways not previously experienced, and energy adequacy is becoming a growing concern. Recent weather events, including Storms Uri, Elliott and this summer's heat, are increasingly frequent, and are having broader impacts on the fleet, often in the form of correlated outages. Wind output varies significantly between weather events, as it did between Winter Storms Uri and Elliott. Gas resources see numerous unplanned outages, as they did during Winter Storm Elliott, in which almost half of those reported were due to fuel supply or transportation issues. Load volatility has also proven to be an emerging issue as models without similar historic weather data can be prone to significant forecast errors, as occurred during Storm Elliott.

Results from the recent 2023 OMS-MISO Survey also point to ongoing energy adequacy concerns. The first survey, conducted on a seasonal basis following the implementation of the seasonal resource adequacy construct, showed a 1.5 GW capacity surplus for the 2024/25 planning year. However, like the Planning Resource Auction results, these gains were made by actions that will be difficult to replicate in the coming year. Additional resources with the necessary attributes and other changes – like market rules – are needed to avoid potential capacity shortfalls in the future.

Looking forward, significant growth in resources that are either variable or energy-limited in the MISO footprint, inaccuracies in long-term load forecasts along with changing weather impacts and operational practices, are shifting risk profiles in highly dynamic ways with implications to resource adequacy and system planning. Ongoing analysis and enhancements are critical to ensure that the resources with needed capability and attributes will be available during the highest risk periods across the year. It is in this context that the MTEP23 transmission planning efforts are undertaken to ensure a reliable and efficient system.

1.2 Planning Process

The MISO Transmission Expansion Plan (MTEP) report must identify and support development of cost-effective transmission infrastructure that is sufficiently robust to meet reliability needs, enable a competitive energy market, support policy goals, and allow for competition among transmission developers in the assignment of transmission projects. MTEP must be created through an inclusive, independent, open process which allows opportunities for stakeholders to participate and provide input on the transmission system. MISO works with its stakeholders and Board of Directors to adopt MISO's Planning Guiding Principles. The most recent Principles, which were reviewed and approved by the Board of Directors in June 2023, are shown below in Figure 1.2-1.



Figure 1.2-1: MISO's Planning Guiding Principles (as adopted June 2023) are shaped by state and federal policy, stakeholder needs and cost efficiency targets.

System Planning

These principles are enacted through MISO's value-based planning approach (Figure 1.2-2), which ensures that local needs are integrated with regional requirements. Its processes consider a range of issues and viewpoints, including analyzing:

- For **local planning,** review and provide transparency on member plans, evaluate system against reliability standards, consider alternatives and verify needs as applicable
- The long-term, broader system needs through MISO's **regional planning** processes, including its Long Range Transmission Planning efforts

- The impact of policies on the transmission system and resource mix in **policy studies**
- System changes needed to accommodate new resources in **resource planning, and**
- Planning issues shared with its neighbors in **interregional planning**

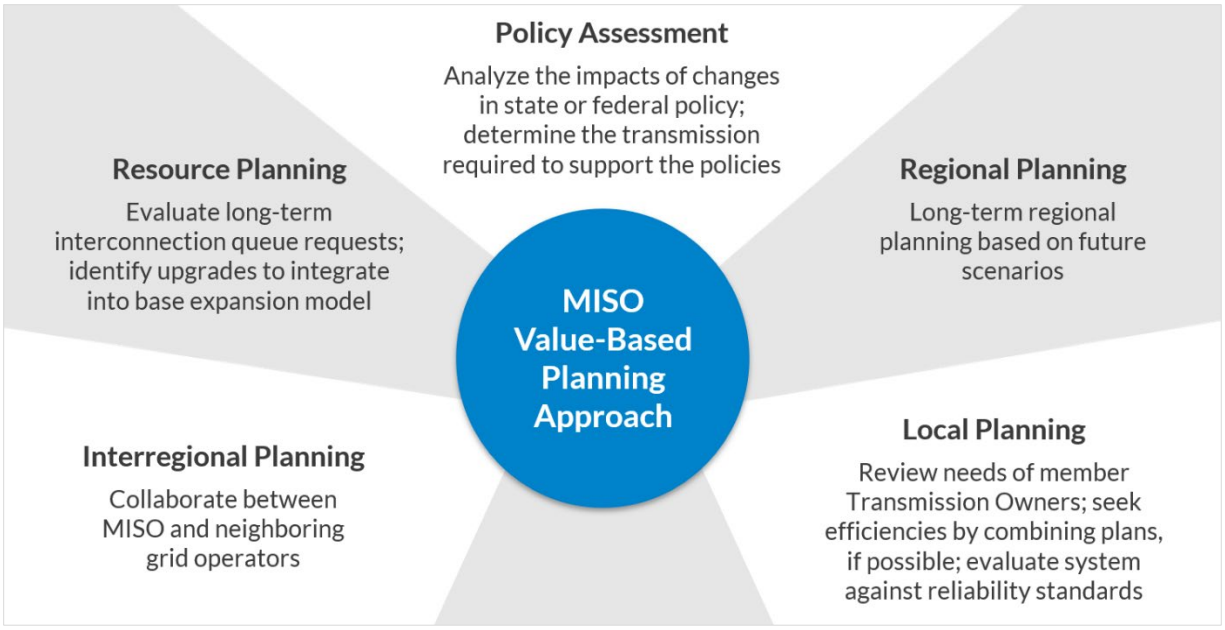


Figure 1.2-2: MISO's Value-Based Planning Approach

MISO's various planning approaches cannot operate independently of each other. The goal of the transmission planning process is to identify a least-regrets outcome that meets its member plans, provides reliable power delivery, and appropriately balances local versus regional solutions to ensure a cost-effective outcome for customers.

MISO's comprehensive planning process spans short to long term horizons depending on study objectives and need drivers (see Figure 1.2-3). The process encompasses multiple planning functions that address different timelines and aspects of transmission and resource planning. Each process informs the others to cover the entire planning horizon.



Figure 1.2-3: MISO Value-Based Planning Approach Study Horizons

Transmission Planning & Coordinated Process

MISO develops this annual regional expansion plan, which is known as the MISO Transmission Expansion Plan ("MTEP"), based on expected use patterns and analysis of the performance of the Transmission System in meeting both reliability needs and the needs of the competitive bulk power market, under a wide variety of contingency conditions. MISO uses both a near-term and long-term planning horizon in its processes with the near-term planning horizon (i.e., less than 10 years) mainly focused on local reliability planning, while the long-term planning horizon (i.e., up to 20 years) is focused on broader regional planning. This recommended plan is then subjected to stakeholder scrutiny and feedback to refine it further before it is eventually presented to the MISO Board of Directors ("MISO Board") for review and approval.

MISO strategically set up our local planning processes to assume FERC Order 890 transparency requirements for Transmission Owner submissions, with MISO's role ranging from alternative assessment, need validation, no-harm tests and/or transparency depending on the project submissions. MISO's transmission planning rules are set forth in Attachment FF of the Tariff, which contains MISO's transmission expansion planning protocol, and Appendix B of the MISO Agreement, which contains MISO's planning framework. In addition, MISO maintains a Business Practices Manual ("BPM") that covers the transmission expansion planning processes, which is known as BPM-020, including the study approaches applied by MISO. Finally, some of MISO's local planning approach is driven by North American Electric Reliability Corporation (NERC) reliability standards and reliability standards adopted by Regional Reliability Organizations integrated as part of MISO's role as a Planning Coordinator.

Project Input and Stakeholder Coordination

The planning process, in conjunction with an inclusive, transparent stakeholder process, must identify and support development of a sufficiently robust transmission infrastructure to meet local and regional reliability standards as well as enable competition among wholesale capacity and energy suppliers. Each planning cycle commences with regional model development (see Figure 1.2-4 for MISO footprint planning regions); identification of potential expansions from the local planning processes of the Transmission Owners; identification of transmission issues driven by reliability (e.g., NERC criteria), economic, and public policy requirements; and identification by stakeholders or MISO staff of potential expansions that address

the transmission issues. Each cycle concludes with recommendations to the MISO Board of Directors of recommended solutions to the transmission issues evaluated.

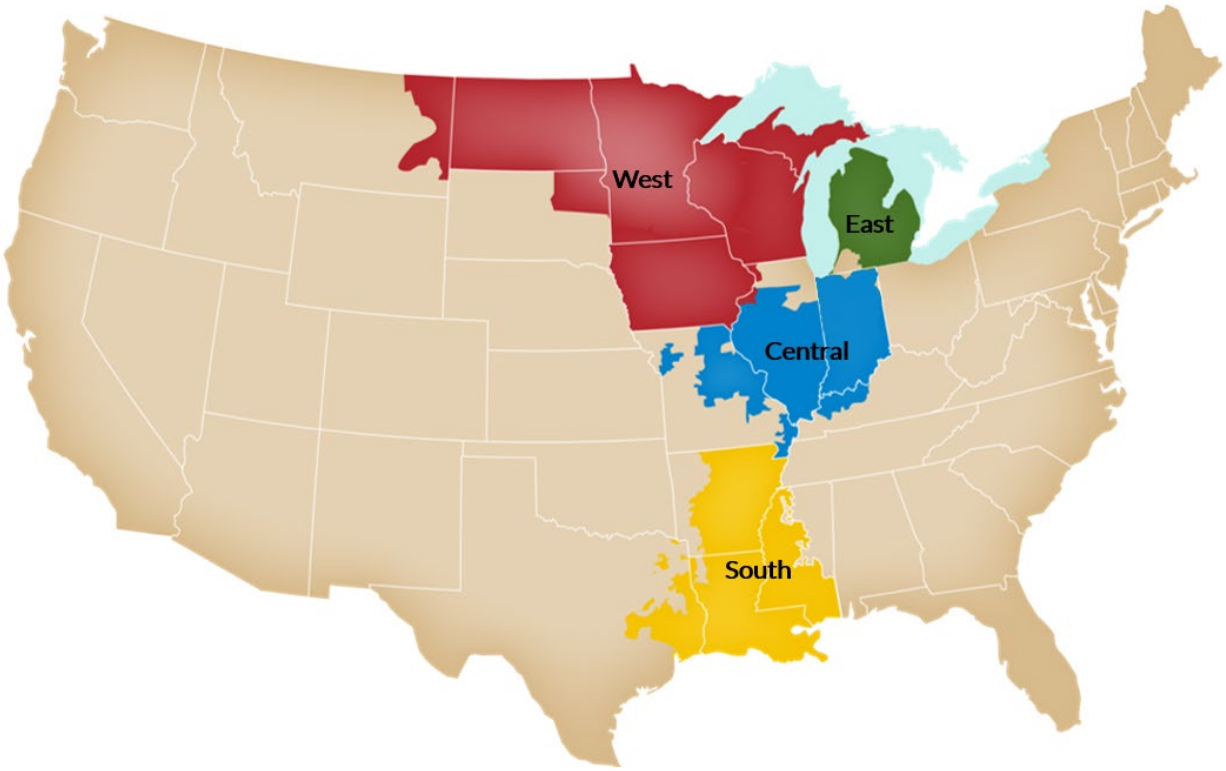


Figure 1.2-4: MISO footprint planning regions

Transmission Owner plans developed through local planning processes are included in the beginning of each regional planning cycle as potential solutions to local transmission issues identified by the Transmission Owners to meet the FERC Order 890 transparency requirements.

MISO's regional planning process makes evaluations — with stakeholder input from the Sub-regional Planning Meetings, the Planning Subcommittee, and the Planning Advisory Committee — throughout the cycle to develop expansion plans to meet the needs of the system. This multi-party collaborative process allows analysis of all projects with regional and inter-regional impact for their combined effects on the Transmission System. Moreover, the design of this collaborative process ensures that the MTEP addresses transmission issues within the applicable planning horizon in an efficient and cost-effective manner, while considering the input of stakeholders.

These various planning functions occur at different times and begin the year before an MTEP report is finalized (see Figure 1.2-5). For example, assessments of generator interconnection and retirements occur on a continuous basis. Others repeat on a regular cycle, but the actual MTEP report is produced once every 12 months. Each MTEP cycle's scope definition actually begins in the summer of the prior year. The months of in-depth research and analysis, combined with many interactions between various work streams and stakeholders culminates in Appendix A.

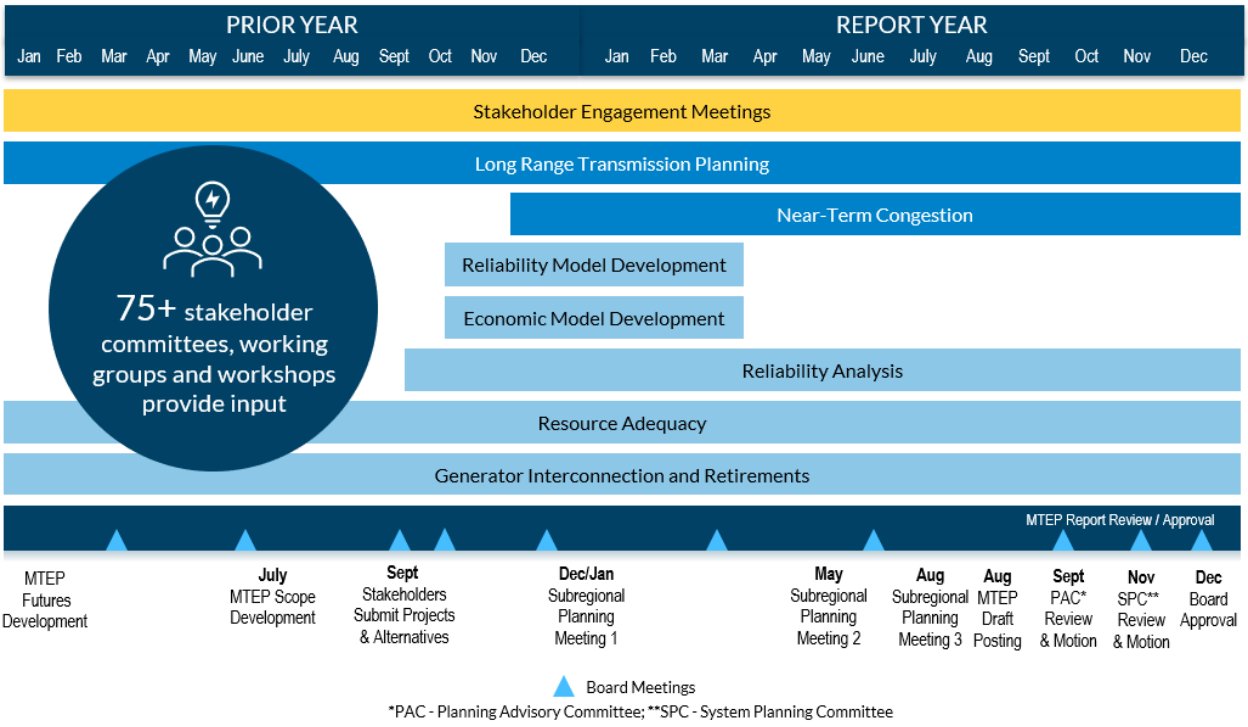


Figure 1.2-5: Typical MTEP cycle is developed in overlapping cycles and delivered annually

Planning Analysis Methods

Planning analyses performed by MISO test the transmission system under a wide variety of conditions using standard industry applications to model key items, such as steady state power flow, voltage stability, and economic parameters, as determined appropriate by MISO to be compliant with applicable criteria and the Tariff. MISO collaborates with Transmission Owners, other transmission providers, transmission customers, and other stakeholders to develop appropriate planning models that reflect expected system conditions for the planning horizon. The local reliability planning process relies on known and committed inputs into the process, while the long-term planning process considers projected inputs (Figure 1.2-6).



Figure. 1.2-6: Summary of inputs into reliability and long-term planning processes

Models are available to stakeholders with security measures as provided for in the Transmission Planning Business Practices Manual. MISO provides the opportunity for stakeholders to review and comment on the posted models before commencing planning studies.

MISO's review of projects varies depending on project drivers, system needs, opportunities for alternatives, and other factors. Specific to local planning MISO may verify the need, complete a no-harm analysis, or post information for stakeholders.

- **Verify need**: Confirmation of system need identified in project submission, including to meet compliance with applicable National Electric Reliability Organization reliability standards and reliability standards adopted by Regional Reliability Organizations, and applicable within the Transmission Provider Region. MISO must verify the need for alternatives to adequately examine their effectiveness.
- **No harm**: Ensure a submitted project does not create a system issue. Includes projects that create model changes like contingency definitions, line ratings, or line impedances.
- **Post only**: Provided for FERC Order 890 transparency provisions. May include controls equipment to communicate remotely with the facility. This information is not able to be represented with model changes.

Additionally, alternative assessments for projects may be completed by Transmission Owners prior to project submission to MISO, proposed by MISO, or proposed through stakeholder submissions. In MTEP23, MISO identified and evaluated alternatives for facilities that are larger in cost and/or have higher potential impact on the system; staff also evaluates alternatives provided by stakeholders. For example, projects that propose new lines are prioritized for analysis because MISO's experience shows that addressing existing infrastructure is typically a more cost-effective investment than building new lines. Alternatives would be assessed in this situation to ensure that the additional benefits justify the potential higher cost. Some of the criteria to select an alternative considers cost comparisons, feasibility to construct and how reliability needs are resolved. Alternatives do not always result in one project replacing another, but instead tend to be additive to the original project, even when submitted with the thought that they would directly compete. MISO considers alternatives in multiple forms, including like-for-like replacement, regional reliability projects, the combination of multiple local solutions, and other options identified through either MISO analysis or submitted by stakeholders.

Long Range Transmission Planning

Long Range Transmission Planning (LRTP) is an essential element of planning the regional grid to be reliable and efficient with a focus on the long-term (i.e., 20 years) planning horizon. LRTP efforts are launched periodically when needed to address significant changes to future conditions that the grid must be prepared to address. Long Range Transmission Planning results in projects that are regional backbone facilities needed to move bulk power between geographically dispersed areas within MISO. While they provide for a reliable and efficient grid based on forecasted resource developments, they are not intended to resolve all connection issues associated with precise siting of future generation or load.

Long Range Transmission Planning follows MISO's well-established seven-step value-based planning process and is part of MISO's overall MTEP process. Outlined below are the high-level descriptions of each step:

1. **Develop Future Scenarios** – develop scenario-based Futures with resource forecast and siting
2. **Develop Resource Plan and Site Future Resources** – development of planning models utilizing Futures
3. **Identify Transmission Issues** – identify potential transmission issues
4. **Integrated Transmission Development** – proposals for solutions to issues
5. **Transmission Solution Evaluation** – evaluate the effectiveness of various solutions
6. **Project Recommendation and Justification** – recommend preferred solutions for MTEP implementation
7. **Project Cost Allocation** – apply appropriate cost allocation

MISO is working to identify potential grid needs in support of the resource transformation underway and as contemplated under our member's resource plans and defined in the MISO Futures. This extensive stakeholder process includes regularly scheduled workshops, periodic discussions at the Planning Advisory Committee, plus additional stakeholder meetings addressing cost allocation through the Regional Expansion Criteria and Benefits Working Group. Project recommendations resulting from this process will then be presented for Board of Director review and approval over several MTEP cycles as analyses proceed and recommendations are developed.

Details of MISO's Long Range Transmission Planning study progress are summarized in Section 3.1 of the MTEP23 Report.

Project Types and Approval

MTEP Appendix A projects are vetted by MISO through the planning process and project types are determined by criteria in MISO's Tariff. Below is an overview of Tariff-defined project types [2]:

- **Baseline Reliability Project (BRP) -** Projects are Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable National Electric Reliability Organization reliability standards and reliability standards adopted by Regional Reliability Organizations, and applicable within the Transmission Provider Region. Baseline Reliability Project costs are allocated to the local Transmission Pricing Zone(s) and recovered through Attachment O by the Transmission Owner(s) developing the projects.
- **Generator Interconnection Project (GIP) -** Projects are New Transmission Access Projects that are associated with interconnection of new generation or the capacity modification of existing generation. Costs are primarily paid for by the interconnection customers with certain exceptions as specified in Attachment FF. Costs of network upgrades rated at 345 kV and above are eligible for 10 percent cost recovery from load on a system-wide basis.
- **Market Efficiency Project (MEP)** - Projects meet Attachment FF requirements for reduction in market congestion and are eligible for regional cost allocation. Projects qualify as Market Efficiency Projects based on cost and voltage thresholds and are developed to produce a benefit-to-cost ratio of 1.25 or greater. Costs are distributed to benefiting pricing zones, in accordance with Attachment FF of the Tariff.

[2] Additional details on project types are in Section 2.3.1 of the Business Practice Manual.

- **Market Participant Funded Project (MPFP)** - Projects are defined as Network Upgrades fully funded by one or more market participants but owned and operated by a Transmission Owner.

- **Multi-Value Project (MVP)** - Projects meet Attachment FF requirements to provide regional or sub-regional public policy, economic and/or reliability benefits. Costs are shared with loads and export transactions in proportion to energy withdrawals or export schedules.

- **Other** - Projects to address local reliability issues and/or provide local economic benefit, which do not qualify as Baseline Reliability Projects, New Transmission Access Projects, Targeted Market Efficiency Projects, Market Efficiency Projects, or Multi-Value Projects. Project costs are allocated to the local Transmission Pricing Zone(s) and recovered through Attachment O by the Transmission Owner(s) developing the projects.

- **Targeted Market Efficiency Project (TMEP) -** Projects are designed to alleviate historical market-to-market congestion between MISO and PJM Interconnection, while meeting certain cost and construction requirements. The costs of Targeted Market Efficiency Projects are allocated first between MISO and PJM Interconnection by the ratio of each RTO's Day-Ahead and Excess Congestion Fund congestion, offset by historical market-to-market payments. The MISO share of costs for the project is then allocated to beneficiaries using historical nodal load congestion contribution data.

- **Transmission Delivery Service Project (TDSP) -** Projects are required to satisfy a transmission service request. The costs are generally assigned to the requestor.

MISO staff formally recommends a set of projects to the MISO Board of Directors for review and approval after all projects have been posted for transparency. MISO has completed its independent review of proposed projects for need or no-harm as applicable, and staff has addressed any stakeholder feedback received. These projects make up Appendix A of the MTEP report and represent the preferred solutions to the identified transmission needs of the MISO transmission planning process.

Proposed transmission upgrades with sufficient lead times are included in Appendix B for further review in future planning cycles.

Interregional Coordination and Planning Studies

On an annual basis MISO works with the neighboring transmission planning regions, Southwest Power Pool (SPP) and PJM Interconnection (PJM), to identify issues on the seams, perform studies, and jointly evaluate transmission solutions that may be more efficient or cost effective than a corresponding regional solution. While MISO has a separate Joint Operating Agreement (JOA) with both SPP and PJM that details specific processes and criteria, the high-level interregional coordination activities are similar on each seam:

1) Exchange modeling data and other system information (typically performed in Q4).
2) Review identified issues on the seam (typically performed in Q1).
3) Evaluate whether to perform an interregional study based on the identified issues.

MISO performs joint coordinated system plan (CSP) studies with SPP and PJM on a regular basis, in accordance with the timelines and frequencies dictated in their respective JOAs. A CSP study may have a targeted scope or a more complex scope requiring a longer study period, and can include reliability, economic and/or public policy issues. All interregional issues and CSP study efforts are coordinated through a public Interregional Planning Stakeholder Advisory Committee (ISPAC) consisting of representatives and interested parties from each RTO community.

In addition to the joint study efforts with SPP and PJM, MISO performs studies as needed with neighboring entities of the Southeastern Regional Transmission Planning (SERTP) group and the Independent Electricity System Operator of Ontario (IESO). While the study process is less formal, MISO and these entities still meet regularly to review interregional issues and possible areas of collaboration.

Details on planning procedures, on-going studies and stakeholder meetings can be found on the Interregional Coordination page of the MISO public website (misoenergy.org).

New Planning Portal

In October 2023, MISO will deploy a new MTEP Project Portal that will be accessed through the Help Center. This will replace the current Project Portal, accessed through the Market Portal. This new portal will provide a robust user-friendly experience that will support the submission and management of MTEP projects throughout their lifecycle while enabling the integration capabilities for future MISO technologies (see Figure 1.2-7 for a list of enhancements).

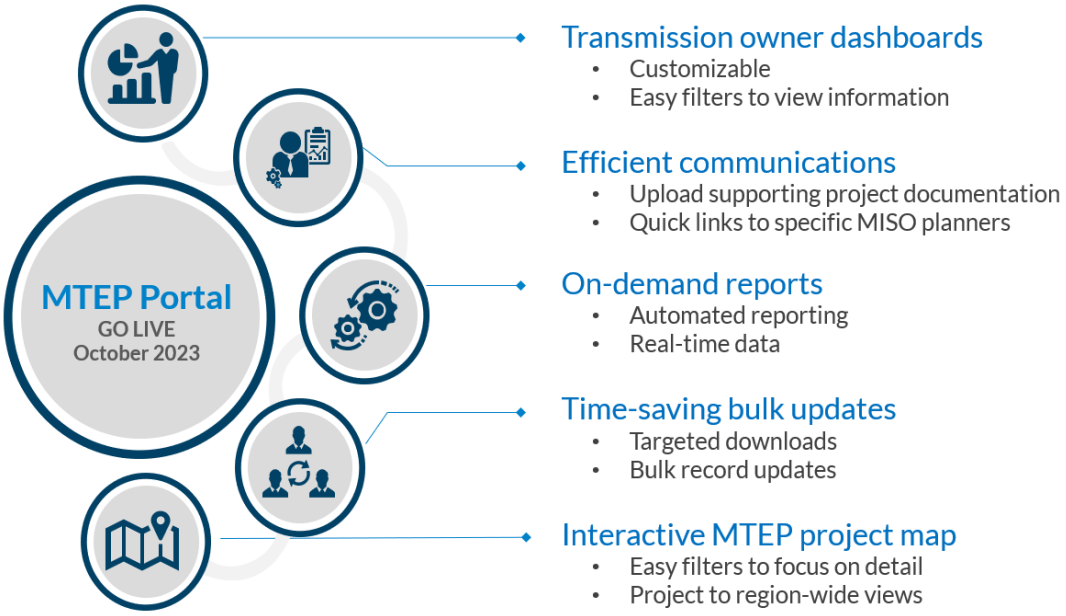


Figure. 1.2-7: Enhancements coming soon with the new MTEP Planning Portal

1.3 Historical Background

MISO Transmission Infrastructure Investment

This iteration of the MTEP report, MTEP23, builds and expands on the 19 prior years of projects since 2003 totaling over $58 billion of investment in the United States (Figure 1.3-1). MISO's proposed new projects for this MTEP cycle would add an additional estimated $9 billion and are detailed in Section 1.4, Chapter 4, and Appendix A of this report.

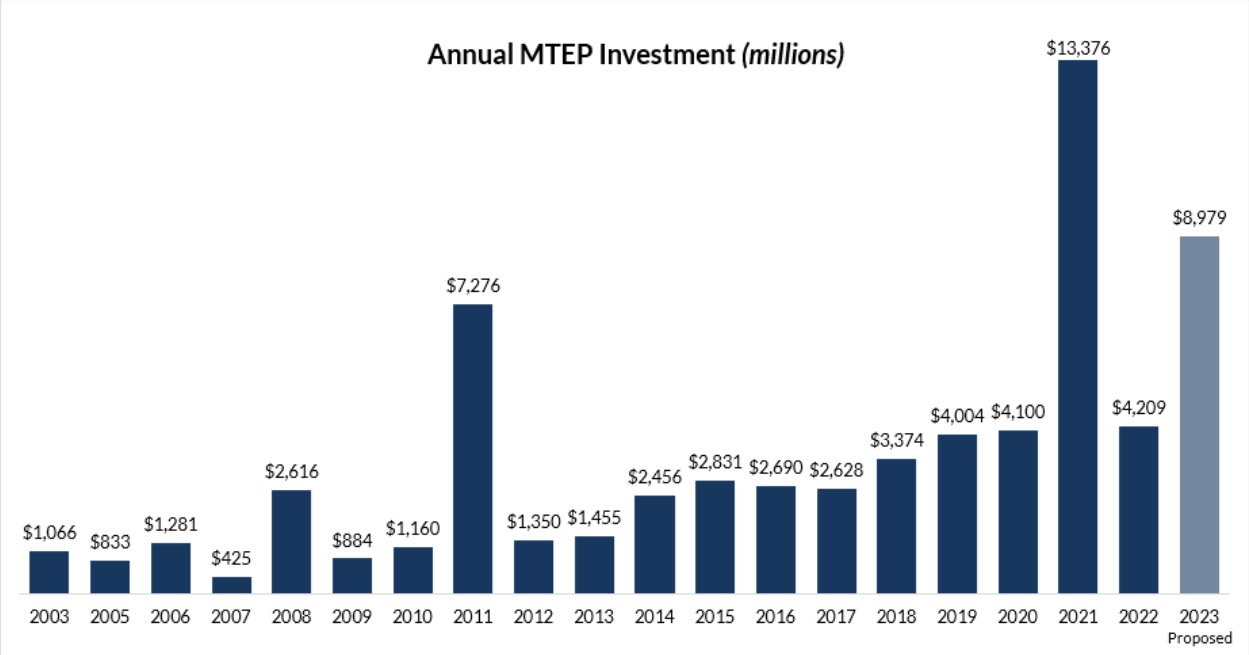


Figure 1.3-1: MTEP annual investment

Highlights in prior MTEP cycles include:

- MTEP11 reflects the approval of the Multi-Value Project portfolio, which accounts for the significantly higher investment totals compared to other MTEPs.
- MTEP14 reflects the inclusion of the new MISO South region projects.
- MTEP21 reflects the MTEP21 Addendum approval of the LRTP Tranche 1 portfolio, which accounts for $10.3 billion of the total.

MISO's transmission planning responsibilities include the monitoring of previously approved Appendix A projects. MISO surveys all Transmission Owners and Selected Developers every quarter to determine the progress of each project. These status updates are reported to the MISO Board of Directors and posted quarterly to the MISO Transmission Expansion Plan page at misoenergy.org [3].

MTEP Approved Projects Status

Since MTEP03, over $34 billion of investment has gone into service and nearly $24 billion of approved projects are yet to be fully placed into service (Figure 1.3-2).

[3] MISO Transmission Expansion Plan website address: https://www.misoenergy.org/planning/planning/

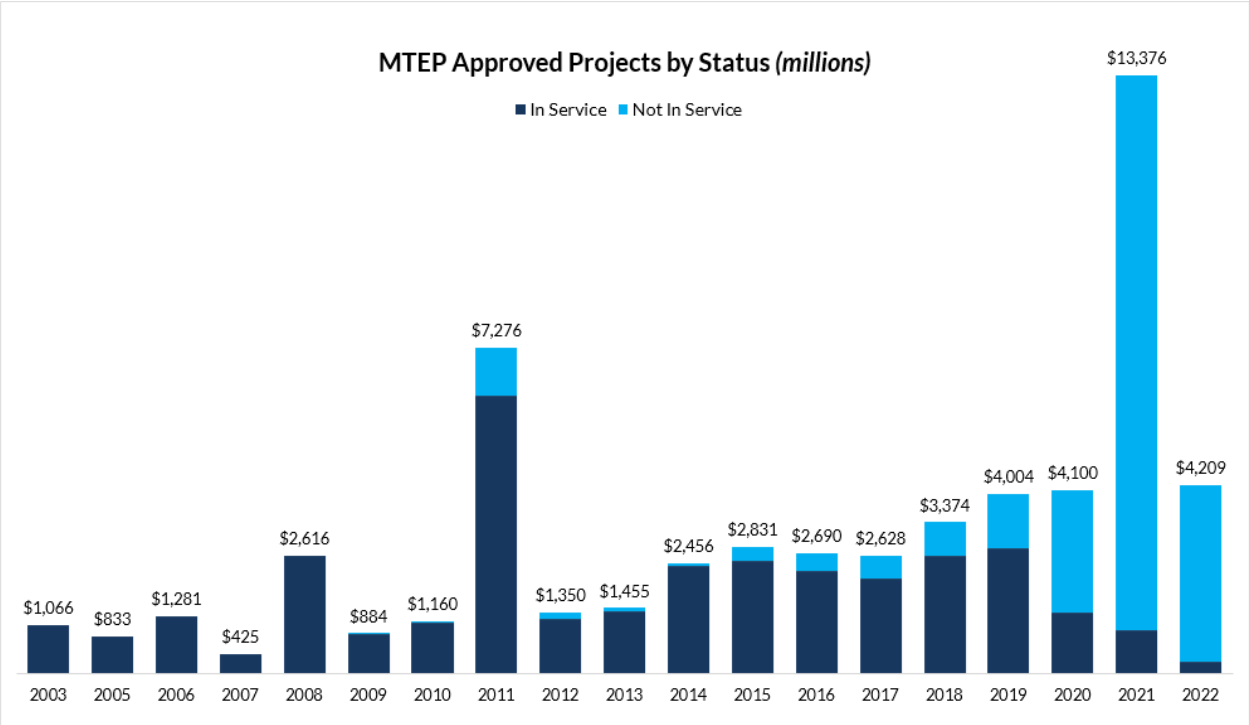


Figure 1.3-2: Appendix A project status (excluding withdrawn)

LRTP Investment Status – Tranche 1

The $13.4 billion investment in MTEP21 as shown above was the result of MISO approval of Tranche 1 of its Long Range Transmission Planning Study comprised at an estimated cost of $10.3B (2022$). Table 1.3-1 reflects those 18 approved projects as of October 2023. Going forward, as engineering and construction plans are finalized and applicable regulatory proceedings complete, MISO anticipates receiving more substantive quarterly project updates from the constructing Transmission Owners, including updates on project cost and in-service dates. Transmission Owners will continue to provide quarterly project updates until the project is placed into service.

MVP No.	Project Name	State	Estimated in Service Date		Status		Cost		Explanation
			MTEP Approved	Current Date	State Regulatory Status	Construction	MTEP Approved ($M)	Current Cost ($M)	
1	Jamestown - Ellendale	ND	12/31/2028	12/31/2028	○		$439	$439	
2	Big Stone South - Alexandria - Cassie's Crossing	SD/MN	6/1/2030	6/1/2030	◐ ○		$574	$574	
3	Iron Range - Benton County - Cassie's Crossing	MN	6/1/2030	6/1/2030			$970	$970	
4	Wilmarth - North Rochester - Tremval	MN/WI	6/1/2028	6/1/2028	○		$689	$689	
5	Tremval - Eau Clair - Jump River	WI	6/1/2028	6/1/2028	○		$505	$505	
6	Tremval - Rocky Run - Columbia	WI	6/1/2029	6/1/2029	○		$1,050	$1,050	
7	Webster - Franklin - Marshalltown - Morgan Valley	IA	12/31/2028	12/31/2028	○		$755	$755	
8	Beverly - Sub 92	IA	12/31/2028	12/31/2028	○		$231	$231	
9	Orient - Denny - Fairport	IA/MO	6/1/2030	6/1/2030	○		$390	$390	
10	Denny - Zachary - Thomas Hill - Maywood	MO	6/1/2030	6/1/2030	○		$769	$769	
11	Maywood - Meredosia	MO/IL	6/1/2028	6/1/2028	○		$301	$301	
12	Madison - Ottumwa - Skunk River	IA	6/1/2029	6/1/2029	○		$673	$673	
13	Skunk River - Ipava	IA/IL	12/31/2029	12/31/2029	○		$594	$594	
14	Ipava - Maple Ridge - Razewell - Brokaw - Paxton East	IL	6/1/2028	6/1/2028	○		$572	$572	
15	Sidney - Paxson East - Filman South - Morrison Ditch	IL	6/1/2029	6/1/2029	○		$454	$454	
16	Morrison Ditch - reynolds - Burr Oak - Leeburg - Hiple	IL/IN	6/1/2029	6/1/2029	○		$261	$261	
17	Hiple - Duck Lake	IN/MI	6/1/2030	6/1/2030	○		$696	$696	
18	Oneida - Nelson Rd.	MI	12/31/2029	12/31/2029	○		$403	$403	
						Total	$10,324	$10,324	

State Regulatory Status Indictor Scale		
○ Pending	◐ In regulatory process or partially complete	● Regulatory process complete or no regulatory process requirements

Table 1.3-1: LRTP Tranche 1 approved project status dashboard as of Oct. 2023.

Future Line Miles Appendix A Projects

Spanning from 2023 -2030, there are approximately 6,250 circuit-miles of planned new or upgraded transmission lines projected in Appendix A (Figure 1.3-3).

- 3,915 circuit-miles of upgraded transmission line on existing corridors are planned of which 59% are ≤230 kV and 41% are ≥345 kV.
- 2,335 circuit-miles of new transmission line on new corridors are planned of which 37% are ≤230 kV and 63% are ≥345 kV.

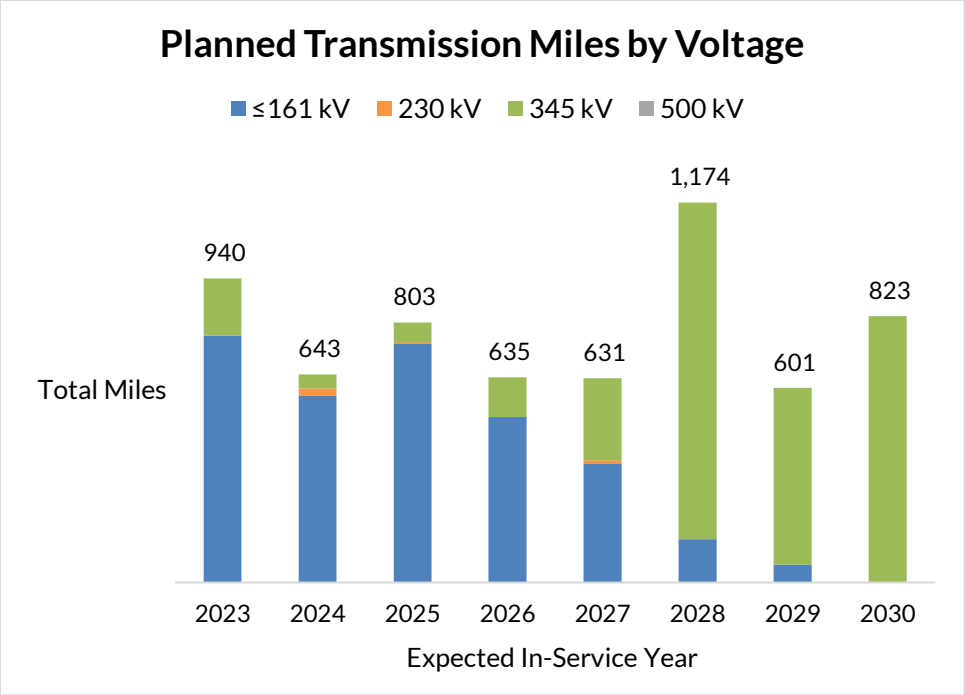


Figure 1.3-3: Active, not yet in-service, project circuit line miles by voltage and expected in-service year.

Existing Line Miles Summary

MISO has approximately 75,000 circuit-miles of transferred functional control transmission lines serving as the backbone of the footprint (Figure 1.3-4) in the United States. Currently, the West region holds 45% of total footprint line miles, the South region holds 22%, the Central region holds 20%, and the East holds 13%.

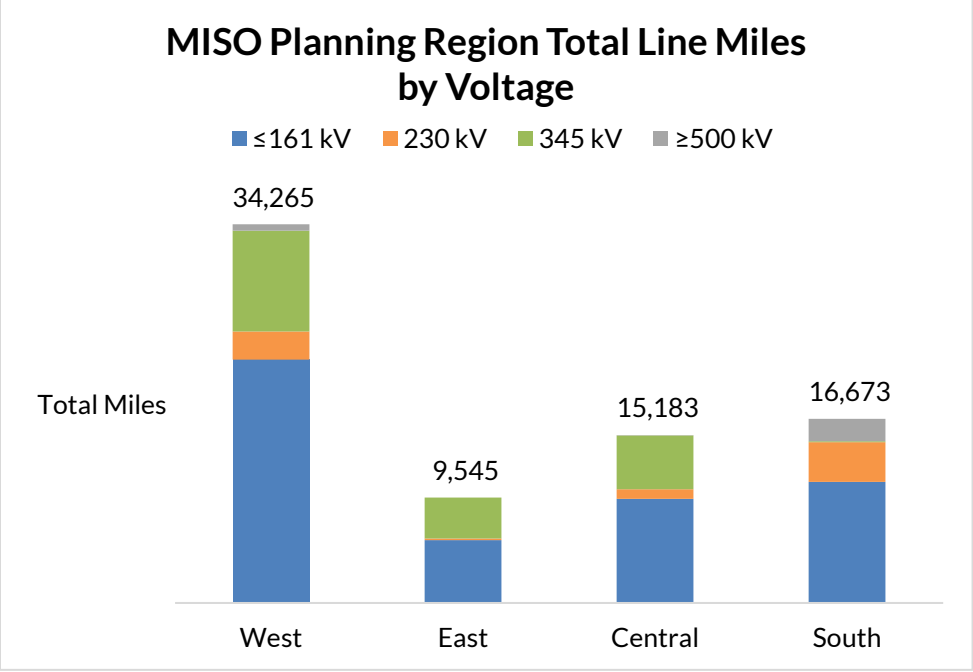


Figure 1.3-4: 2023 in-service transferred circuit miles by voltage class

Transmission Facility Investment

Of the over $58 billion total investment that remains active or in-service, $29 billion of that investment, or 50%, has occurred in the last five MTEP cycles. In the first 13 MTEP cycles, the predominant investment was in new line assets at 53% or $15.3B. There was a shift in investment in the last 6 cycles (MTEP17-MTEP22), including the approval of the Tranche 1 portfolio of projects, with the leading investments in substation (38%) and line upgrades (35%), and new lines only representing 27% of the total investment. Looking back in total (MTEP03-MTEP22), Figure 1.3-5 below reflects the current asset investments at substations representing 34%, new lines at 39% and line upgrades at 27% of the total investment.

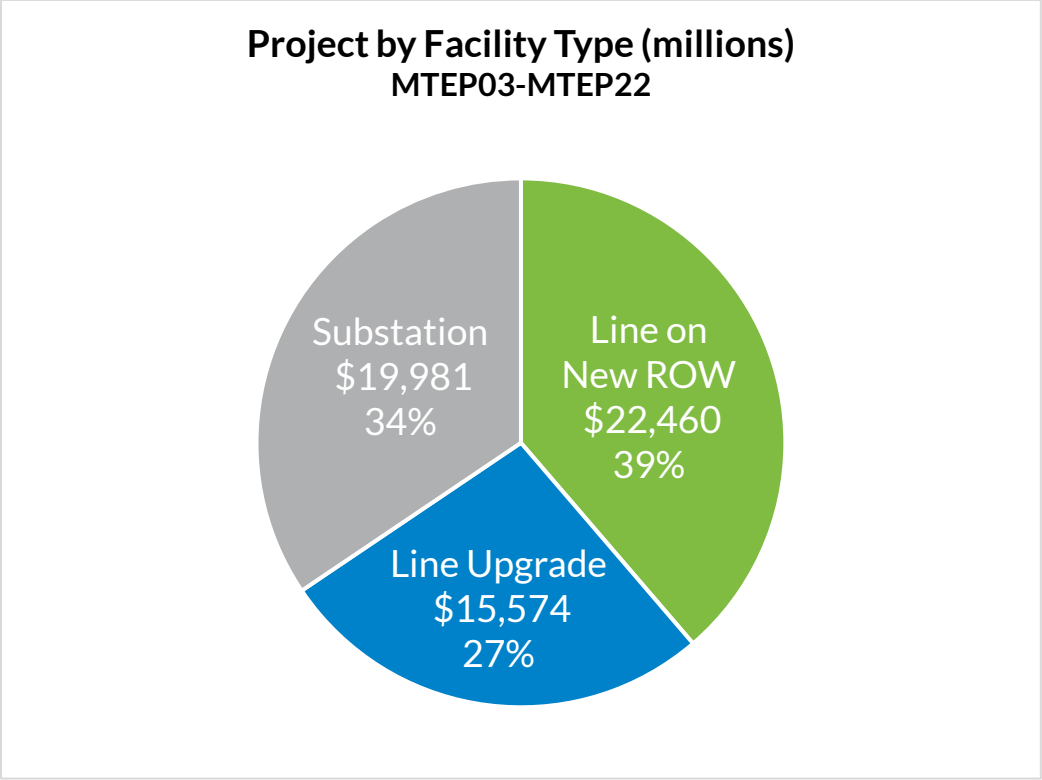


Figure 1.3-5: Appendix A project facility investment dollars in all MTEP cycles.

Full archived files of previous MTEP Reports can be accessed via the MISO Transmission Expansion Plan page at misoenergy.org.

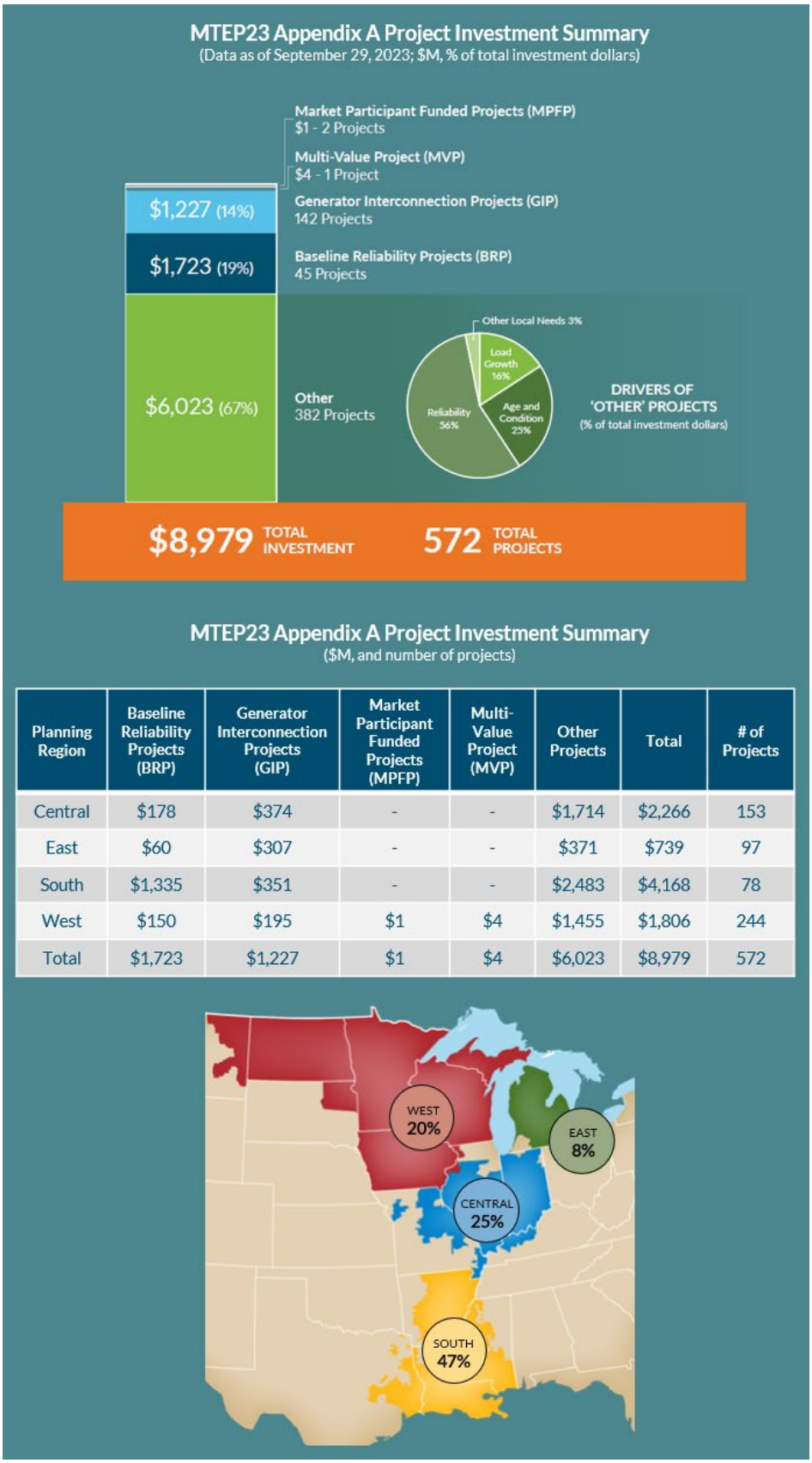
1.4 MTEP23 Investment Summary

The MTEP23 cycle proposes 572 new Appendix A projects (Figure 1.4-1) and represents roughly $9 billion in transmission infrastructure investment for the MISO region. If approved, this will be the largest investment in MISO's history, except for the two MTEP cycles that included Multi-Value Project portfolios, due to significant projects to serve new load. Forty-seven percent of the investment is located in the South region.

Of the 572 new Appendix A projects proposed in MTEP23, 382 are classified as Other projects, 142 as Generator Interconnection Projects, 45 as Baseline Reliability Projects, two as Market Participant Funded Projects, and one Multi-Value Project. The single Multi-Value Project is a like-for-like replacement of communication equipment for a MTEP11 Multi-Value Project.

Of the roughly $6.0 billion investment in Other projects, 56% are driven by reliability issues, including those caused by a reliability of load additions and generation retirements, and 25% by age and condition. The majority of Other projects address localized reliability issues that are due to load serving needs, local specific reliability needs, and aging transmission infrastructure.

Except for the larger than usual 47% share of total investment dedicated to projects in the South subregion, the distribution of investment across MISO's footprint is generally consistent with recent MTEP cycles – 25% of the total Central subregion projects, 20% for the West and 8% for the East.



MTEP23 Appendix A Project Investment Summary
($M, and number of projects)

Planning Region	Baseline Reliability Projects (BRP)	Generator Interconnection Projects (GIP)	Market Participant Funded Projects (MPFP)	Multi-Value Project (MVP)	Other Projects	Total	# of Projects
Central	$178	$374	-	-	$1,714	$2,266	153
East	$60	$307	-	-	$371	$739	97
South	$1,335	$351	-	-	$2,483	$4,168	78
West	$150	$195	$1	$4	$1,455	$1,806	244
Total	$1,723	$1,227	$1	$4	$6,023	$8,979	572

Figure 1.4-1: Appendix A project investment summary (data as of 9-29-2023)

MISO considered alternatives (see Figure 1.4-2) and verified the need for a portion of the Other projects in addition to verifying the need for all the Baseline Reliability Projects.

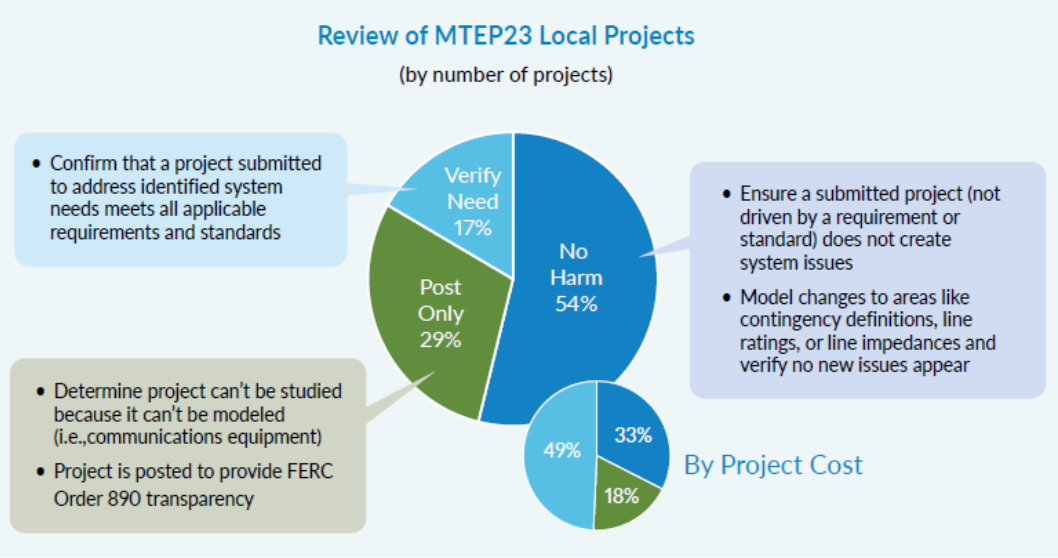


Figure. 1.4-2: Types of reviews MTP23 local projects went through.

Analysis of twelve MTEP projects for alternative solutions resulted in the re-submission of one project to address a larger set of needs, one lower-cost project, and one project that is pending further analysis.

Within MTEP23 proposed projects, the top ten projects represent roughly 43%, or $3.9 billion of the total $9 billion investment (Figure1.4-3).

Top 10 Projects in MTEP23 Appendix A

Rank	Project Name	Project Driver	Cost *(millions)*
1	Amite South Reliability Project - Phase 1 - Alternative	Other – Reliability	$1,700
2	Southeast Texas Area Reliability Project	Baseline Reliability	$1,111
3	Amite South Reliability Project - Phase 2	Other – Reliability	$290
4	New Baldwin Area Reactive Support	Other – Reliability	$170
5	New South Central Illinois Transmission Expansion	Other – Reliability	$168
6	New Slugger 138 kV Load	Other – Load Growth	$124
7	New Kokomo Fusion Phase 1 – 230/69 kV Substation	Other – Load Growth	$92
8	Rebuild Sioux-Meppen North-Hull 138 kV Line	Other – Age and Condition	$78
9	New Seminary – Wittenberg – Grand Tower 138 kV	Baseline Reliability	$68
10	Southland Expansion and Upgrades	Other – Load Growth	$58

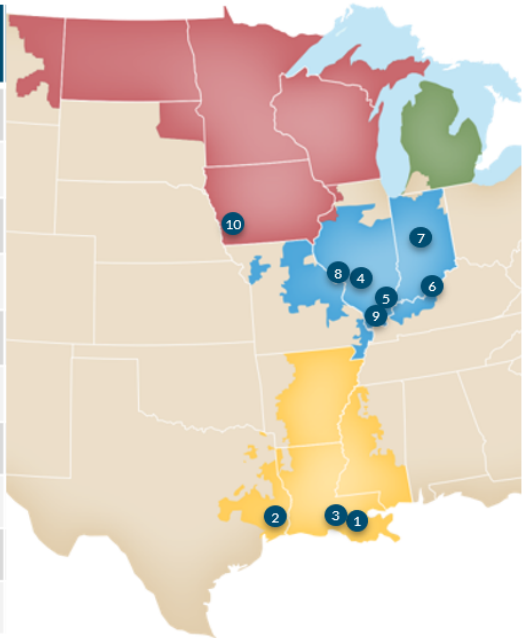


Figure 1.4-3: List of top ten proposed MTEP23 projects as of September 29, 2023, blanket renewal projects excluded from ranking.

Of the total projects proposed for MTEP23, over 70% percent are projected to go into service within the next three years (Figure 1.4-4).

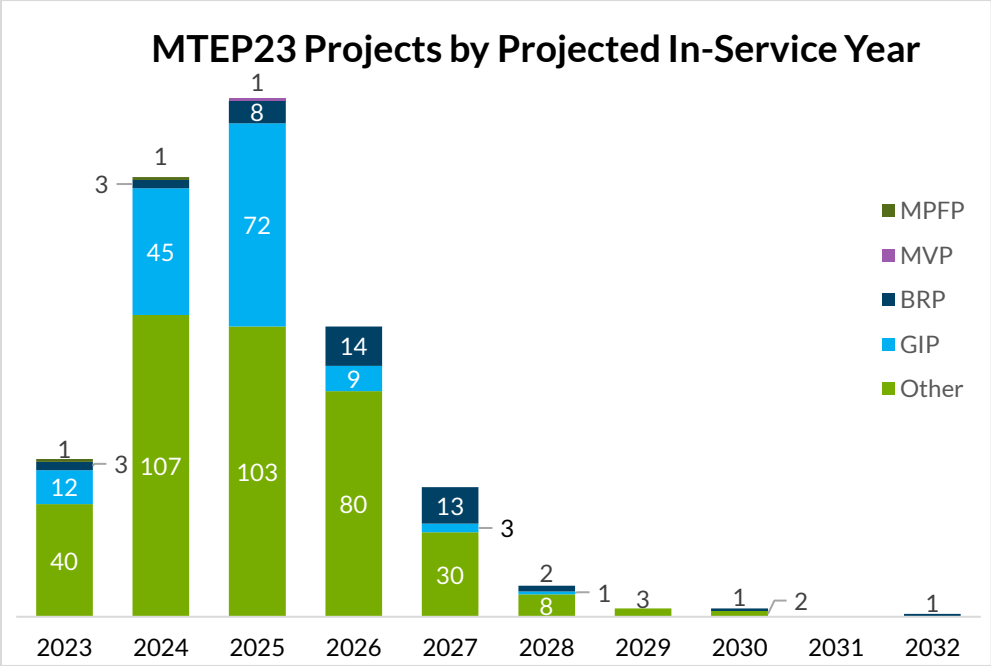


Figure 1.4-4: MTEP23 Projects by In-Service Year (data as of 9-29-23)

New Appendix A projects are spread over 14 states, with two states in the south scheduled for approximately $3.9 billion in new investment (Figure 1.4-5). These geographic trends vary greatly year to year as local planning dictates blanket asset renewal programs or as existing transmission capacity in other parts of the system is consumed and new build becomes necessary.

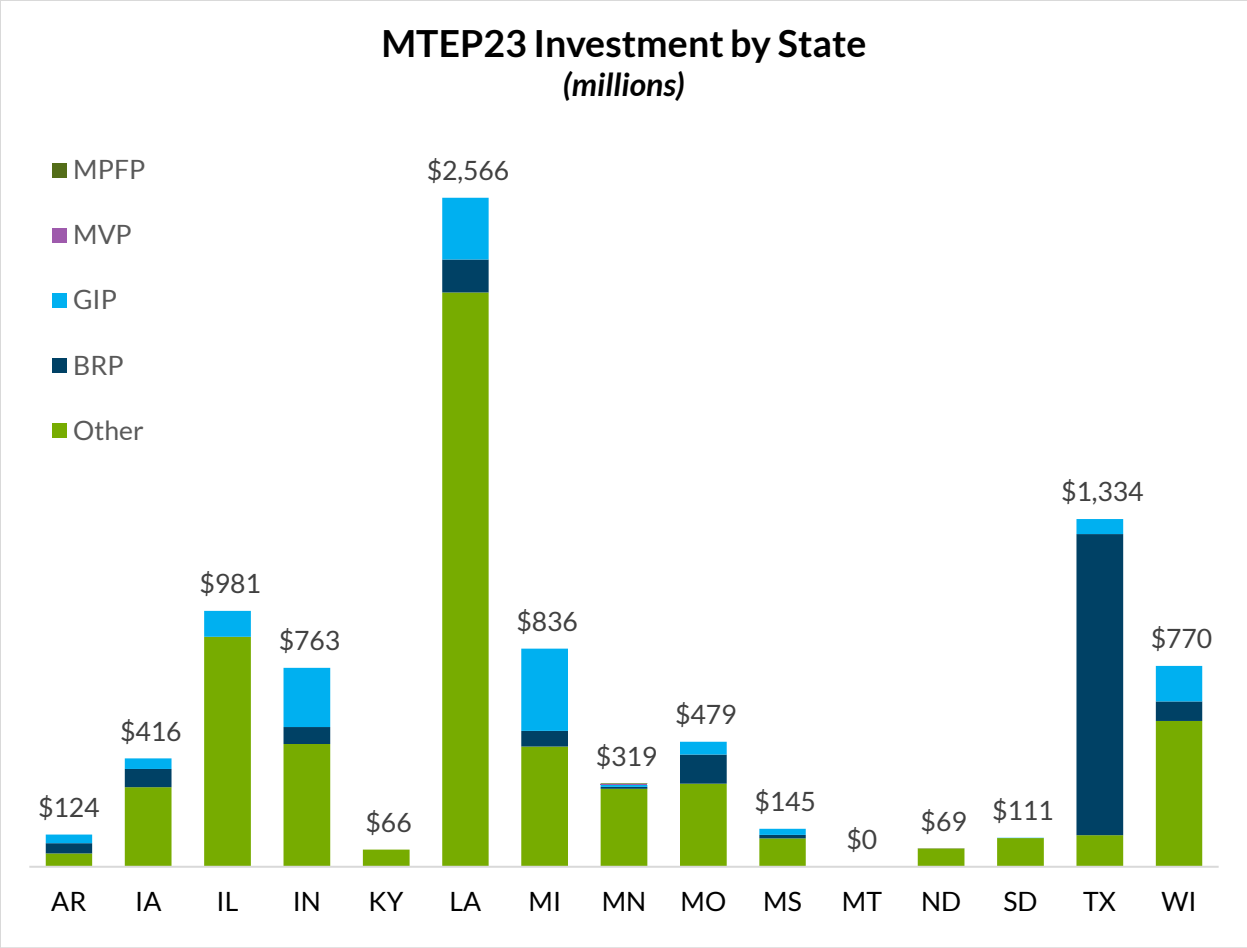


Figure 1.4-5: MTEP23 Appendix A investment categorized by state (data as of 9-29-23)

Facility Type

Each MTEP project is composed of one or more facilities, where each facility represents an individual element of the project. Examples of facilities include substations, transformers, voltage devices, circuit breakers or various types of transmission lines (Figure 1.4-6).

The largest share (44%) of facility investment in the MTEP23 cycle is dedicated to new lines on new right-of-way in MISO. Thirty percent is dedicated to substation or switching station related construction and maintenance. This includes completely new substations as well as terminal equipment work, circuit breaker additions and replacements. Twenty percent is dedicated to line upgrades which includes rebuilds, conversions, and relocations. The remaining six percent of facility costs are dedicated to voltage devices, transformers, and miscellaneous categories.

MTEP23 Transmission Investment by Facility Type

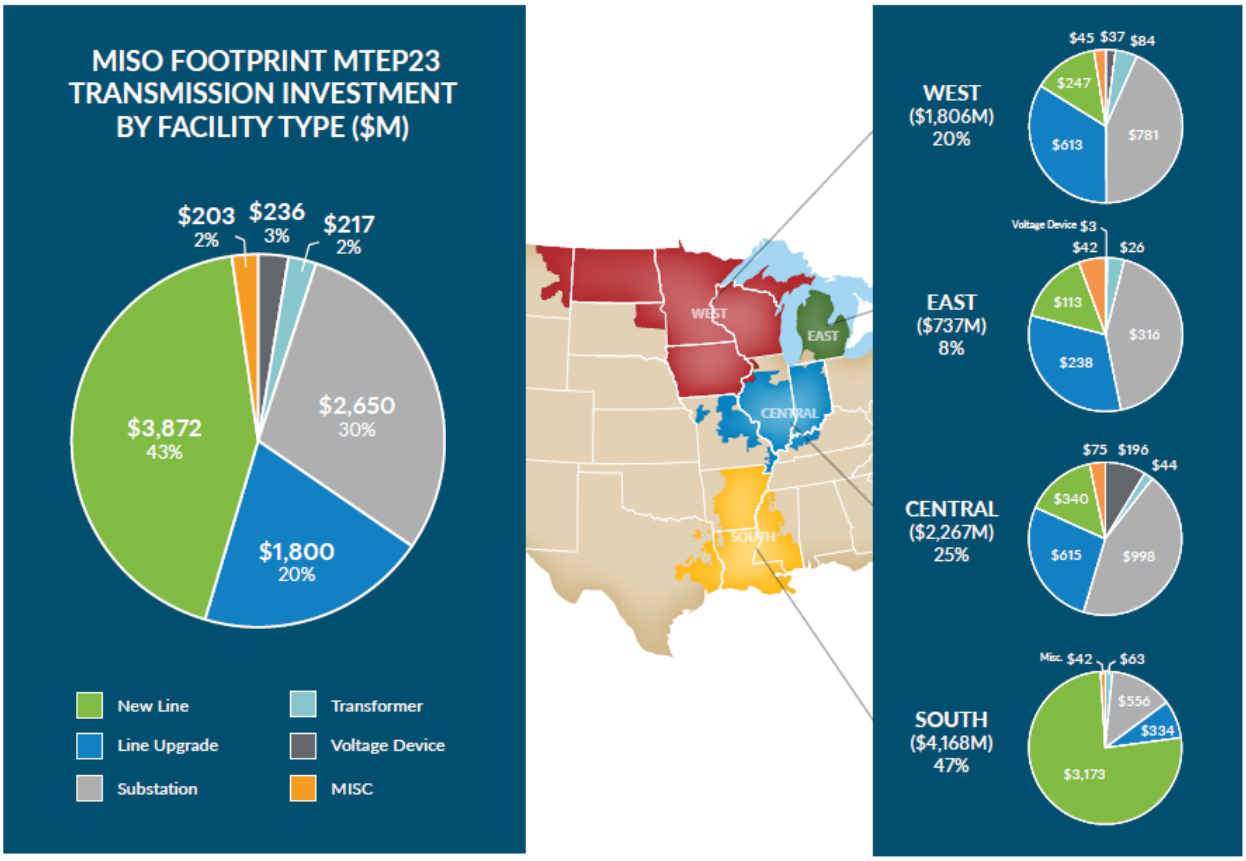


Figure 1.4-6: Facility type investment for new MTEP23 Appendix A projects by planning region (data as of 9-29-23)

MISO receives projects each year, each project has multiple facilities and the facilities determine the impact a project may have on a powerflow model (which is what we use to assess system impact) and our ability to review alternative solutions. MISO considers the facilities that make up a project to understand what type of analysis may be required, including verifying a project's need, ensuring the project does not create reliability concerns (e.g., no harm), or providing transparency (e.g., post only). In general, post only projects consider miscellaneous and substation projects that do not impact the physics of the transmission system. Alternative analysis is targeted primarily at larger projects in areas with multiple future need drivers; smaller projects to serve radial load or 'like for like' replacements are unlikely to have economic alternatives. Alternatives analysis also requires a defined reliability need, as MISO must verify this need to adequately examine alternatives and their effectiveness. The remaining projects include a combination of projects verifying needs and no harm.

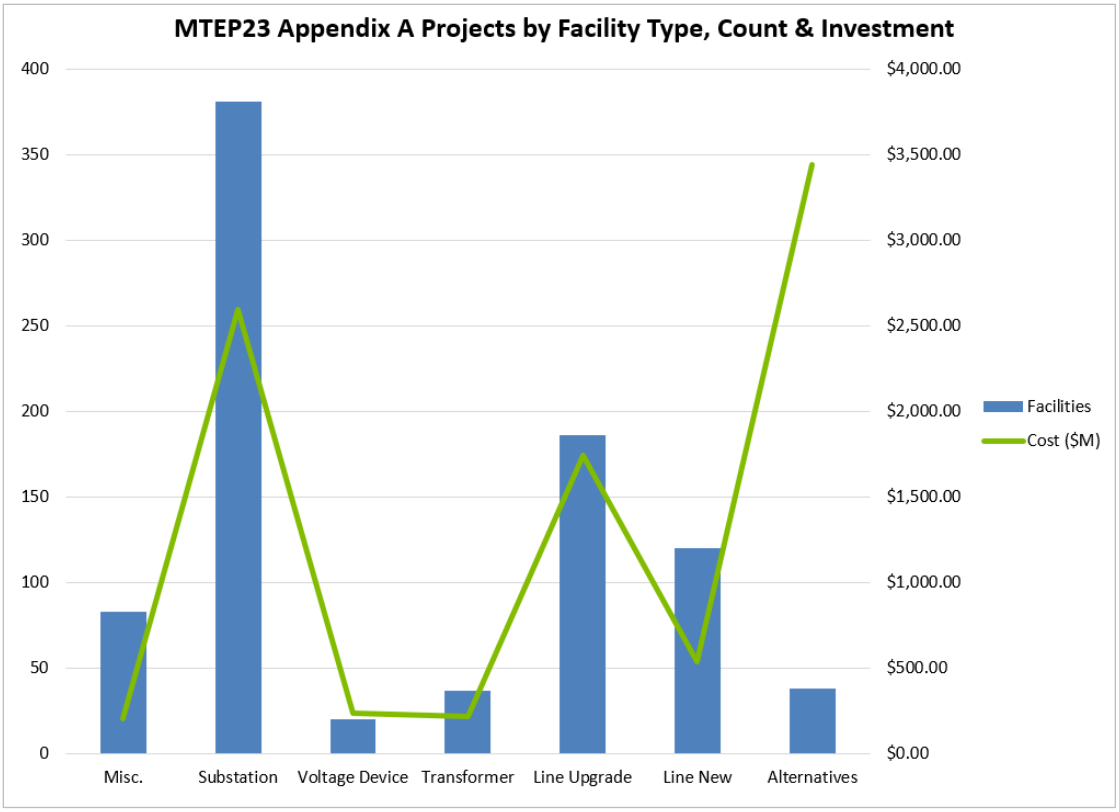


Figure 1.4-7: MTEP 23 Appendix A projects by facility type, count and investment

In addition to system adjustments allowed by NERC, MISO focuses analysis for alternative solutions on facilities that are larger in cost and in their potential impact on the system. Figure 1.4-7 demonstrates this as a small number of facilities with a large total investment of $3.4 billion are analyzed for alternative solutions resulting in alternatives selected for two projects.

MTEP23 New and Upgraded Line Miles

MTEP23 Appendix A projects total approximently 742 miles of new or upgraded lines (shown in Figure 1.4-8). Of the total, fifty-five percent of new or upgraded line miles will go into service within the next three years, or 86% within five years. There are 643 line miles, or 87% of the total line miles, that are 161 kV or below. Seventy-six line miles are projected at 230 kV or above.

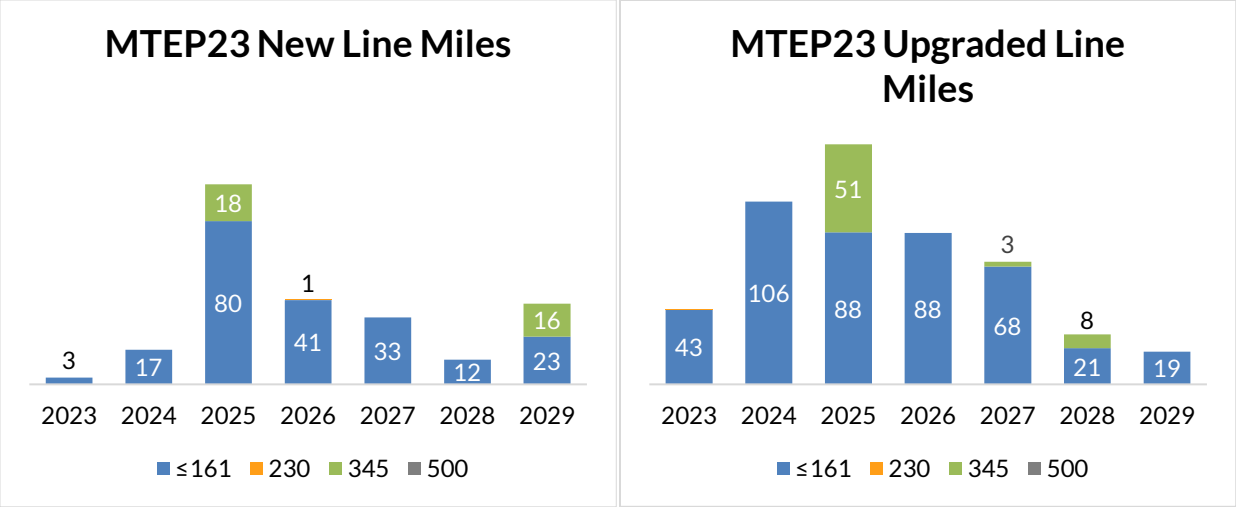


Figure 1.4-8: New and upgraded line miles proposed in MTEP23 Appendix A (data as of 9-29-23)

Allocation of Costs

MTEP23 includes a total of 62 new cost-share eligible Generator Interconnection Projects (GIPs) for Appendix A. GIP costs are primarily paid for by the interconnecting customer (generator), however, a portion of the costs for certain network upgrades are eligible for regional cost allocation under Attachment FF of the MISO Tariff. Detailed allocations by pricing zone are provided in Appendix A1.

Indicative rates related to past MTEP cost-shared projects are calculated on an annual basis. Please refer to the reports (indicative forecasts of annual charges) posted on the MISO public website[4].

MTEP Appendix B

MTEP Appendix B contains all projects that have been validated by MISO as the preferred solution to address an identified system need based on current information and forecasts, but where it is prudent to defer the final recommendation of a solution to a subsequent MTEP cycle.

This generally occurs when the preferred project does not yet need a commitment based on anticipated lead-time and there is still some uncertainty as to the prudence of selecting this project over an alternative project given potential changes in projected future conditions. MTEP Appendix B is limited to Baseline Reliability Projects and Other Projects and will be reviewed by MISO in subsequent cycles.

[4] Cost Allocation updates web address: https://www.misoenergy.org/planning/planning/schedule-26-and-26a-indicative-reports/

CHAPTER 2: PORTFOLIO EVOLUTION

2.1 MISO Futures

To perform analysis on the bulk electric system twenty years into the future, many assumptions must be made to bridge what is known about the system today to what it could be two decades from now. Complicating matters is the uncertainty of future developments.

MISO has developed a method to address this uncertainty—the use of forward-looking scenarios to provide a range of future outlooks. Within MISO, these forward-looking scenarios are called the "Futures". These Future scenarios establish ranges of economic, policy, and technological possibilities—such as load growth, electrification, decarbonization, generator retirements, renewable energy levels, fuel prices, and generation capital costs—over a twenty-year period.

Future Scenarios

MISO Futures are the inputs for multiple MTEP cycles, the LRTP initiative, and other planning studies. These Futures form the basis for the Reliability Imperative, such that MISO and its stakeholders can plan to a consistent set of scenarios across transmission, markets, and operations. In 2023, MISO introduced a new naming convention for the MISO Futures. Cohorts of Futures are now referred to by series.

The Series 1 MISO Futures developed in 2019-20 culminated an 18-month joint effort between MISO and its stakeholders. This effort aligned Futures development with the ongoing fleet transformation and incorporated the plans of MISO's members and states, while also creating future scenarios that can be utilized over several years. Therefore, the Series 1 MISO Future scenarios were used in LRTP Tranche 1.

Within this context, no new Future scenarios were developed specifically for MTEP23. Rather, within the framework of LRTP Tranche 2, the development of Series 1A commenced in Summer 2022. Originally known as the Futures Refresh, Series 1A focused on refreshing certain input data around generation and economics while maintaining the load, number, and definition of Futures established in Series 1. Specifically, LRTP Tranche 2 will develop a portfolio that meets the needs of Future 2A (F2A) within Series 1A.

The following figures show effects from refreshed input data in F2A. Driven largely by updated member plans, F2A illustrates the continuing impacts of the energy transition, with significant acceleration in thermal retirements, renewable capacity buildout and energy production, and decarbonization.

Series 1A and subsequent Futures Series will continue to capture transformation within the MISO footprint, reflecting the system's evolution and serving as the foundation for forthcoming MISO initiatives. Iterations of Futures are a product of continued collaboration between MISO and its stakeholders.

More information on the MISO Futures, including reports and Series 1A assumptions, is found here. Additionally, the 2023 Series 1A Futures Report will be incorporated once published.

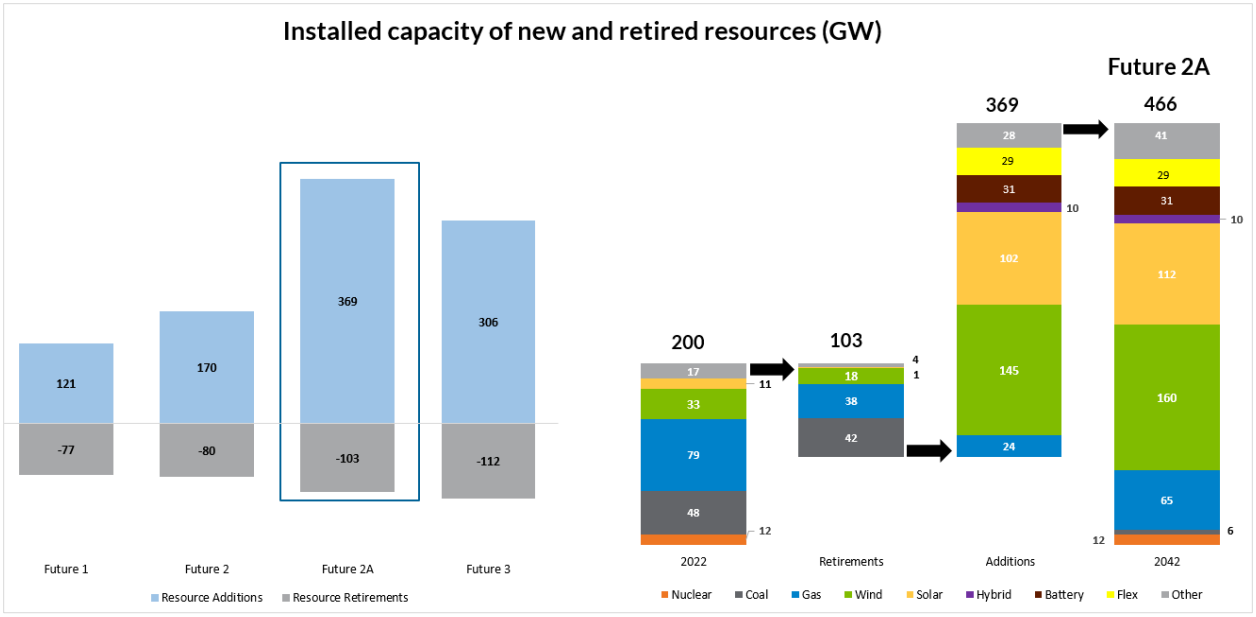


Figure 2.1-1: This figure from Future 2A analysis shows that F2A's expansion surpasses those of Series 1 Future 3, while F2A's retirements approaches those of F3.[5]

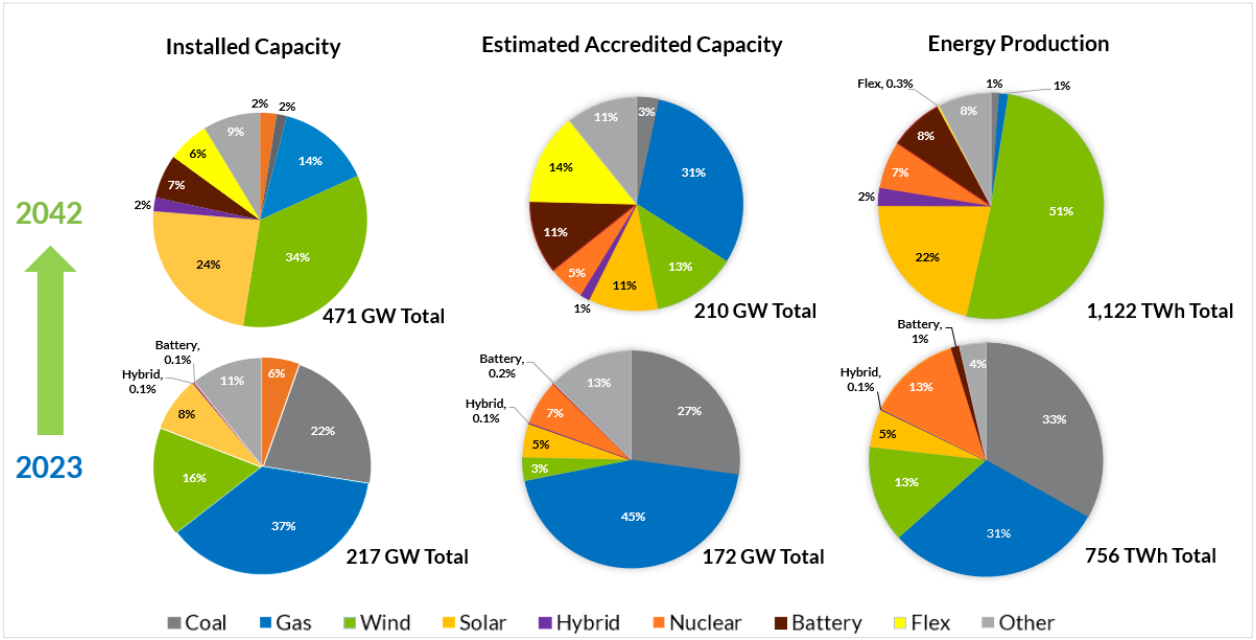


Figure 2.1-2: This figure from Future 2A analysis shows the changing energy and capacity mix as the generating fleet continues to evolve.[5]

[5] Data as of April 26, 2023. Futures do not account for all operational-level reliability needs and attributes that may require different levels of dispatchable resources. Resource additions may be subject to adjustment based on new accreditation rules. "Other" includes biomass, geothermal, hydro, oil, pumped hydro storage, demand response, non-solar distributed generation, and energy efficiency. Battery energy production includes battery discharging only. However, overall energy production pie graph includes the energy required to charge storage.

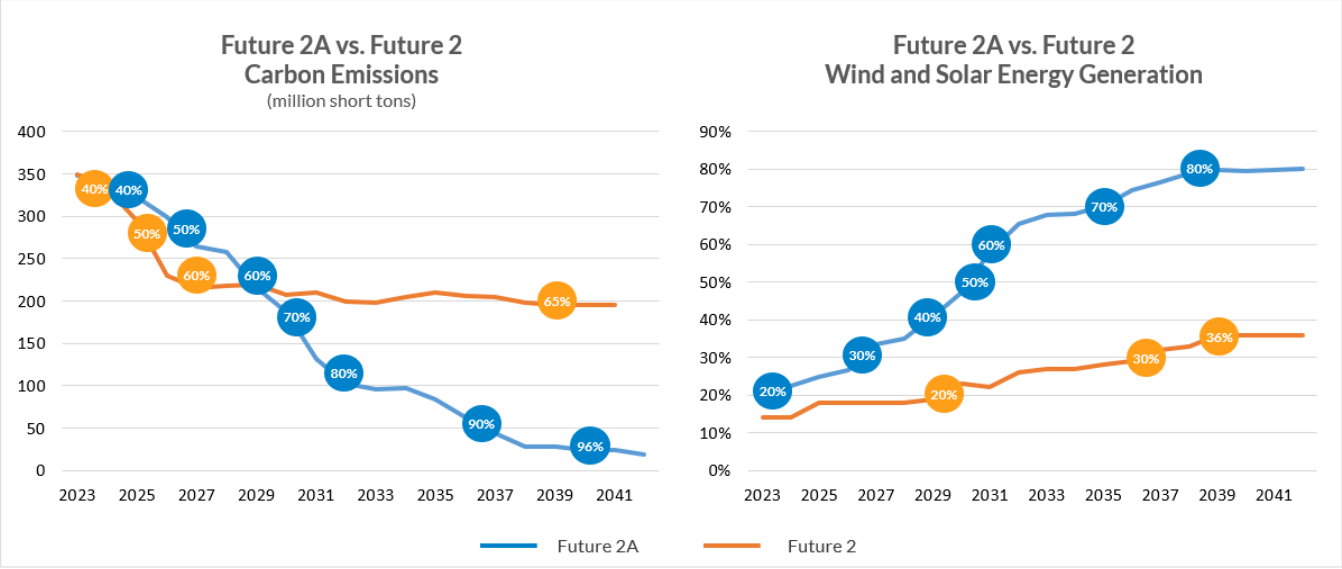


Figure 2.1-3: This figure from Future 2A analysis shows that F2A's decarbonization and renewables generation far outstrips that of Series 1 Future 2. [6]

2.2 Retirement Trends and Future Outlook

One aspect of resource evolution that MISO assists its membership in managing is the retirement of generation facilities, to ensure that the broader MISO footprint remains reliable after resources are removed from service. Through the process articulated in Module C Section 38.2.7 of the MISO Tariff, resource owners submit a request to retire generation resources for MISO approval, which triggers an assessment into the impact that the requested resource would cause once it is retired from service. As a result of these analyses, any reliability issues are addressed through transmission reinforcements or other needed mitigation measures. If the reliability issue cannot be addressed prior to the planned retirement date, MISO may require the resource to remain in service as a system support resource (SSR) until the upgrade is complete, or mitigation is available. As the generation mix continues to evolve, more generating resources are expected to retire, increasing the number of Attachment Y requests MISO receives. This may increase the need for SSR-designated units. Since September 2022, MISO has established two SSR units to maintain reliability of the region.

In 2022, MISO proposed improvements to the Attachment Y process. These improvements were accepted by FERC, which extended the advance notice timeline from 26 to at least 52 weeks to allow MISO more time to process the increased number of Attachment Y requests. MISO also proposed and gained approval for a quarterly study period system. These changes better allow for forecasting workload internally. MISO made other proposals around the studies included in the retirement process and the mitigations used in the studies have reduced reliance on load shed and redispatch. While MISO has not proposed any new studies for the base reliability study process, the extended advance notice timeline will allow for additional studies as situationally necessary. Lastly, MISO appreciates the need for greater transparency into the retirement process while maintaining a great deal of confidentiality for its members. As part of the Attachment Y improvements, MISO will be communicating the number of requests received by quarter and the number of megawatts requesting suspension or retirement.

[6] Data as of March 7, 2023. Futures do not account for all operational-level reliability needs and attributes that may require different levels of dispatchable resources. Resource additions may be subject to adjustment based on new accreditation rules.

Aging coal-fired generating resources have experienced increased retirements in recent years due to cost pressures of operation and competition from gas-fired generation. Renewable generating resources have become more economically and environmentally attractive sources of generation in recent years, putting further pressure on carbon-based generation. Since 2010, MISO has experienced the retirement of 30.8 GW, of which 21.9 GW was coal-based (Figure 2.2-1). The age of generating facilities retired in 2021 declined to an average of 32 years compared to an average of 44 years in 2011. Advancements in technology and interest in renewables are expected to continue the current trend.

A trend since 2020 is the utilization of the new Generating Facility Replacement process. This process was approved by FERC in 2019 to allow the owners of an existing facility to use their existing interconnection service to replace the existing generator with a new generating facility at the same injection point without going through the MISO Generator Interconnection queue. Since 2020, MISO has received 32 generator replacement requests to replace a total of 6.1 GW of existing generation, which otherwise would have been retired through the traditional resource retirement process.

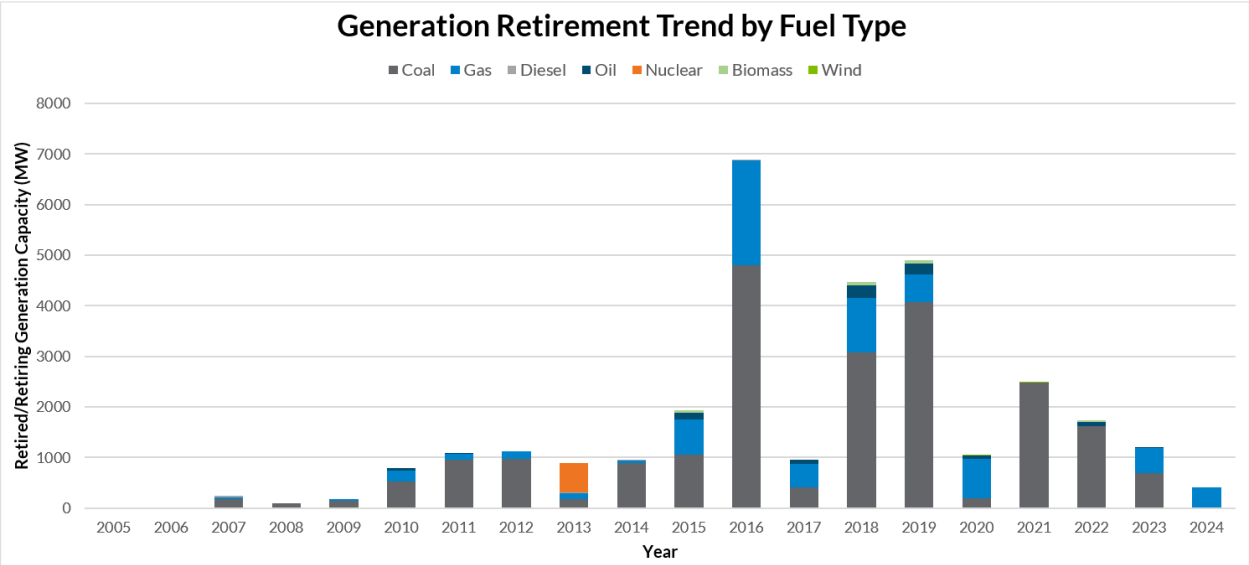


Figure 2.2-1: MW Generation Retirement by Fuel Type

2.3 Resource Outlook

Load Serving Entities (LSEs) in the MISO region must have sufficient resources to meet their forecasted demand plus their required levels of reserves. Every year, MISO administers a Planning Resource Auction (PRA) that LSEs may use to purchase or sell resources for that purpose. LSEs can also opt out of the PRA and use their own resources or negotiate bilateral contracts with other entities. Regardless of how LSEs procure their needed resources, all this information is rolled up into the PRA to demonstrate whether the region will be resource-adequate for the upcoming MISO Planning Year, which runs from June 1 to May 31 of the following year.

This year's PRA was the first to reflect MISO's new four-season resource adequacy construct, which is designed to plan for and address risks beyond the traditional summer peak-load months. This first-ever seasonal PRA demonstrated that all parts of the MISO region have adequate resources for the 2023-2024 Planning Year. More details on this year's PRA results are available here.

It is important to note that demonstration of adequate capacity for the 2023-2024 Planning Year does not imply that the region will continue to have adequate resources going forward. Actions taken by LSEs such as delaying some previously announced resource retirements, and the region obtaining additional capacity via imports contributed to the positive results this year. Such actions may not be repeatable over the longer-term. Therefore, unless more generation is built—especially controllable resources that have the attributes the system needs—the risks of capacity shortfalls and other reliability issues will continue to grow.

OMS-MISO Survey

The region's forward-looking resource picture is further illustrated by a planning tool called the OMS-MISO Survey, which asks LSEs to provide information on demand forecasts, new generation they plan to build and existing resources they plan to retire. MISO administers the survey once a year in partnership with the Organization of MISO States (OMS), which consists of state regulatory agencies in the region. The survey is a "snapshot in time" instrument that focuses on a five-year forward view, but it also includes 10-year forward data with an understanding that uncertainty increases in the latter five years.

In recognition that forward-looking resource plans can and do change, the survey allows LSEs to indicate different levels of certainty to the information they provide. Taking that uncertainty into account, the survey shows how anticipated resource levels compare to the Planning Reserve Margin Requirement (PRMR) across MISO as a whole and in each of the region's 10 Local Resource Zones (LRZs). Like this year's PRA, this year's survey reflects MISO's new four-season resource adequacy construct. Survey results are expressed in terms of seasonal PRMRs and Seasonal Accredited Capacity (SAC), which reflects the availability of resources during times of highest reliability need in each of the summer, fall, winter, and spring seasons.

This year's survey indicates the MISO region as a whole will have sufficient resources for the 2024-2025 Planning Year, with a surplus of 1.5 GW in the summer (expressed in terms of SAC, as described above). Similar to this year's PRA results, the survey's forecasted surplus in the 2024-2025 Planning Year is based on actions such as delayed retirements and increased imports that may not occur again going forward. In the figure below, the survey shows the region could have a capacity deficit of 2.1 GW (SAC) in the summer of the 2025-2026 Planning Year, with that deficit increasing in subsequent years, which supports the view that actions taken this year to provide capacity may not be available in the future.

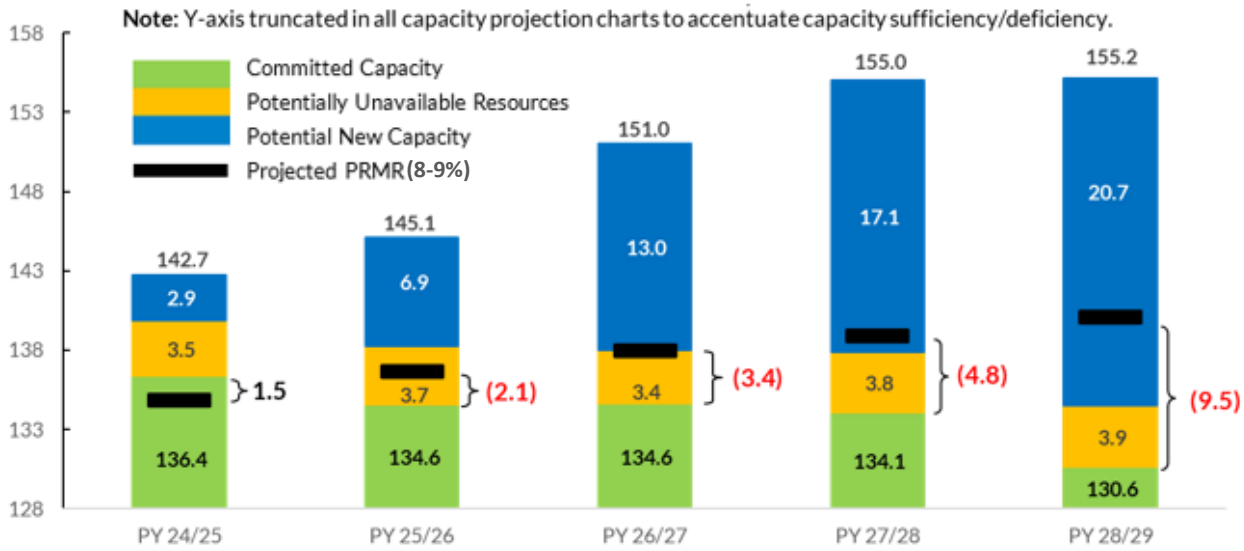


Figure 2.3-2: 2023 OMS-MISO Survey - 5-Year Summer Results

More details about this year's OMS-MISO Survey are available here, including projected capacity levels for the fall, winter, and spring seasons, as well as LRZ-level results.

Regional Resource Assessment

Another tool MISO uses to develop a holistic, forward-looking view of the grid is the Regional Resource Assessment (RRA). The RRA is a recurring study that models how the region's fleet of generating resources might evolve based on the goals that utilities and states have publicly announced to reduce their carbon emissions and/or increase their use of renewable energy. The RRA also models public announcements that utilities and states make to retire specific existing resources and to build new resources going forward.

While the RRA is similar to the OMS-MISO Survey in some regards, there are key differences in their respective designs, purposes, and modeling assumptions. For example, while the OMS-MISO Survey primarily focuses on the next five years, the RRA looks out 20 years. Another difference is that the RRA allows LSEs to submit information about their aspirational decarbonization and/or renewable energy goals. The RRA then uses computer modeling software to "predict" what resources LSEs might build to meet their goals when they have not yet publicly identified enough actual resources. The OMS-MISO Survey does not perform this type of resource-expansion modeling, and instead only includes resources that LSEs specifically identify themselves.

The most recent iteration of the RRA (published in November 2022) yielded findings and insights that align with the results of this year's PRA and OMS-MISO Survey. The key findings of the 2022 RRA are as follows:

- The 2022 snapshot of MISO member plans indicates an increase in the overall amount of installed capacity, but a decline in accredited capacity compared to current levels.
- The RRA modeling indicates a continued near-term capacity risk, highlighting the urgent need for coordinated resource planning and additional investment.
- Wind and solar generation are projected to serve 60% of MISO's annual load by 2041, which would reduce emissions by nearly 80% relative to 2005 levels, but also sharply increase the complexity of reliably operating and planning the system.

- As the solar generation fleet grows, the system will have a much greater need for controllable ramp-up capability. Maximum short-duration up-ramps increase by three times by 2031 and four times by 2041 compared to current levels.

- The capacity contribution of solar generation is forecast to decline rapidly as more solar capacity is added to the system, impacting the region's overall capacity outlook. The contribution of wind generation remains relatively stable as more wind capacity is added.

2.4 Current State of the Queue

The MISO Generator Interconnection (GI) queue provides an active and competitive mechanism to enable resource interconnections that will serve future energy and capacity needs. Projects submitted in the annual queue cycle are evaluated by MISO through an iterative study process to determine the reliability impacts and to identify transmission upgrades needed to support resource integration. Project viability is often tied to the costs of network upgrades, with the most viable candidates successfully executing a Generator Interconnection Agreement (GIA).

The Generator Interconnection queue has experienced extremely high volume over the last several years. In 2022, MISO received 956 individual project requests. Solar, storage, and hybrid applications make up the bulk of the queue.

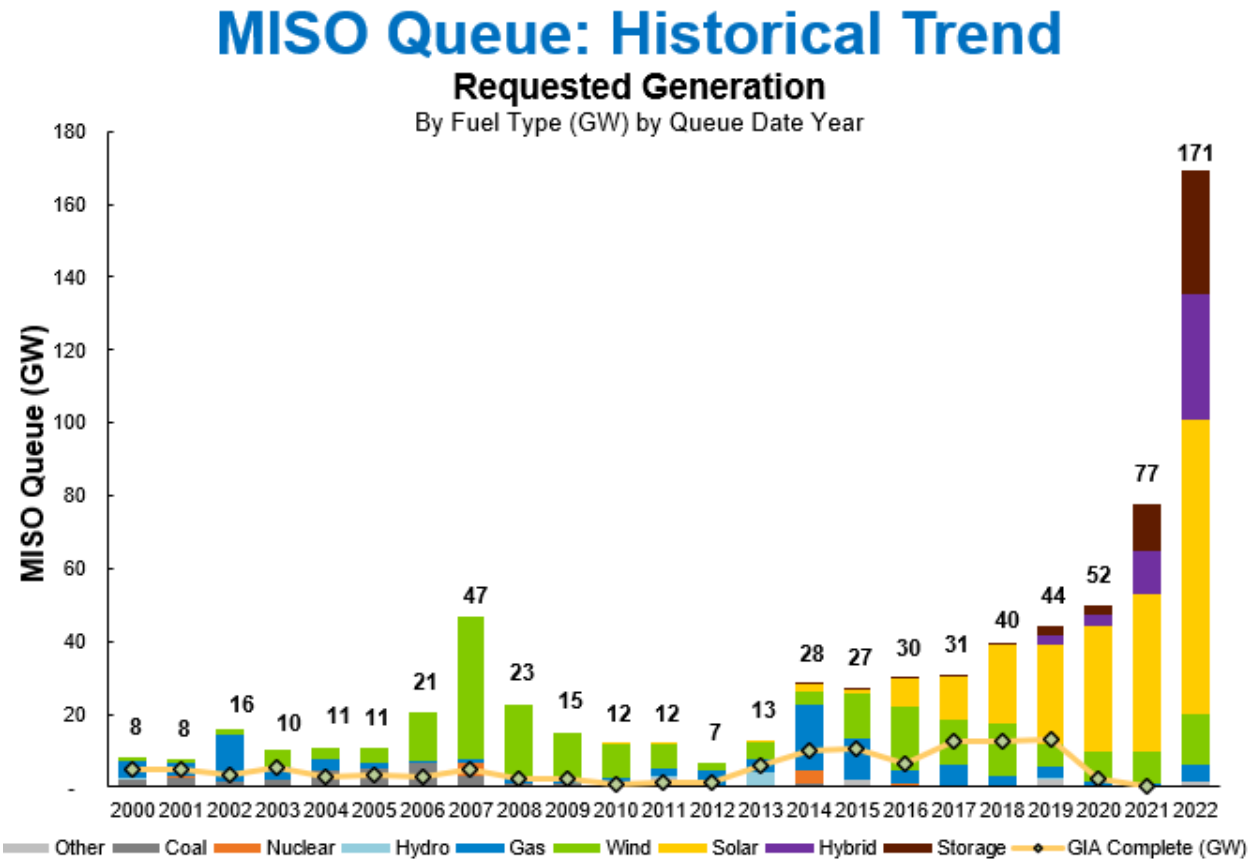


Figure 2.4-1: As of August 2023, the current state of the queue has 1,365 projects representing 235.23 GW of total capacity.

The MISO Active Queue by study area and fuel type (Figure 2.3-2) is available on the MISO website under the GIQ Web Overview link on the Generator Interconnection Queue page. A list of all active projects can also be reviewed on the page. The five study regions in the GI queue currently have 24 active cycles in various stages of the process from the start of the Definitive Planning Phase (DPP) to GIA negotiations.

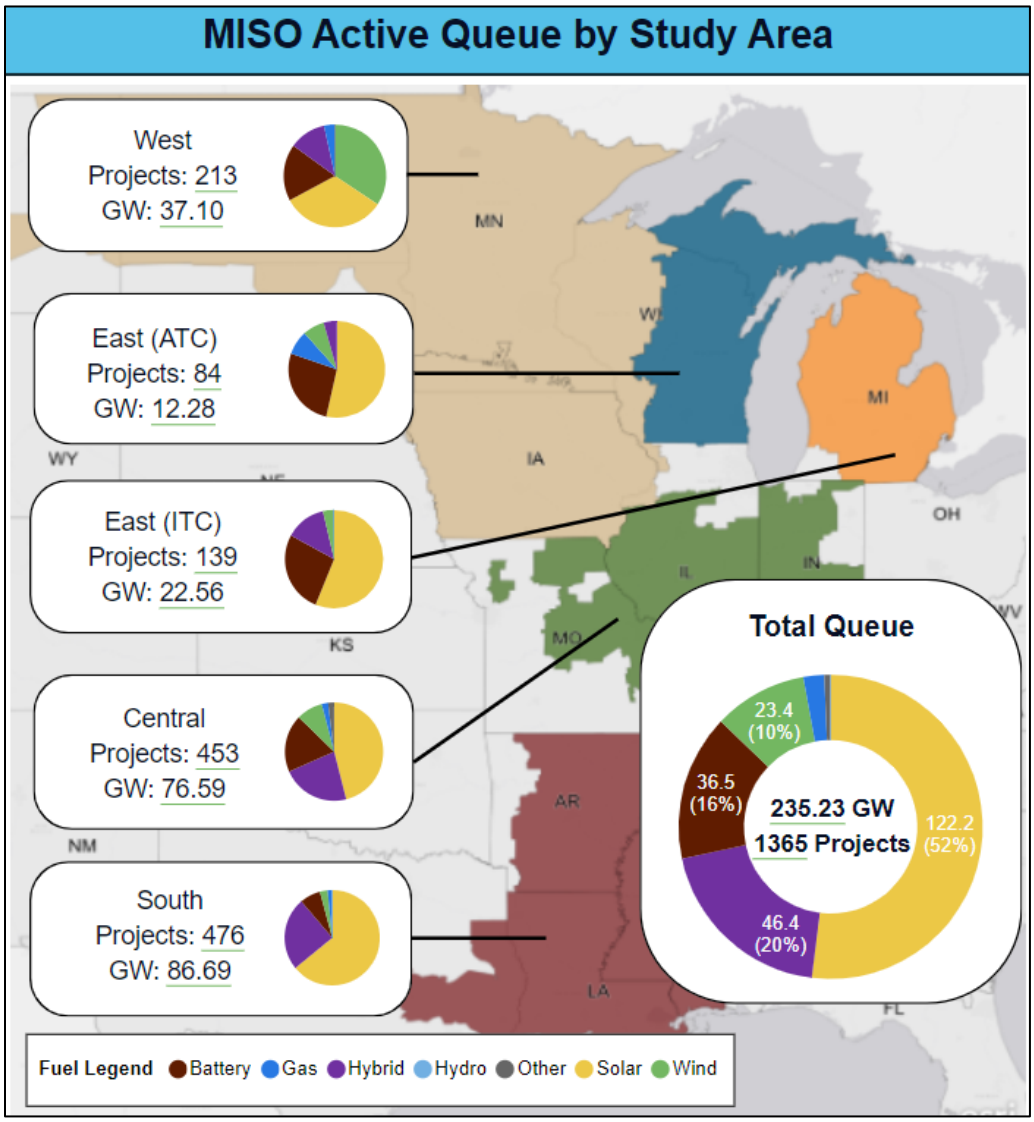


Figure 2.4-2: Active Generation Interconnection Queue by Fuel Type as of August 8 ,2023

Since the pandemic, a troubling new trend has emerged for generators that exit the queue with a GIA. Supply chain and regulatory issues have increased the time it takes for new generators to be built and reach commercial operations. As of August 2023, MISO has nearly 50 GW of new generators with a GIA and not yet online. MISO expects this number to increase to as much as 63 GW by end of 2023. Interconnection Customers and Transmission Owners report that supply chain issues on both the generator and transmission equipment are the main reason for the extended timelines. MISO will continue to track this trend and work with stakeholders on these issues, as this generation will be necessary to support potential resource adequacy shortfalls in the future.

MISO Seeking Additional Queue Reforms

MISO's queue process is constantly being assessed and refined to make improvements and has undergone eight substantive reforms since being instituted. These reforms have made the queue process quicker, more efficient, and less burdensome to our members. In fact, MISO has the shortest end-to-end queue time within our tariff among our peer RTOs and ISOs.

In March 2022 FERC approved MISO's last reform, which reduced the MISO queue timeline schedule from 505 days to either 373 or 463 days, depending on whether a Network Upgrade Facilities Study (NUFS) is conducted in parallel with or prior to the Generator Interconnection Agreement (GIA) negotiation and execution. In either case, the NUFS must be completed before interconnection takes place. Achieving these timelines is contingent upon MISO Transmission Owners completing their studies on time and our neighboring regions completing their Affected System Study (AFS) on schedule. To date, MISO and its TOs have been unsuccessful in meeting these timelines due to the sheer volume of requests in the queue.

In addition to implemented improvements, MISO is now tackling additional reforms to improve entry and exit into the queue to further streamline the GI process and MISO's need to bring new resources onto the system quickly. In May 2023, MISO introduced the need to pursue additional queue reforms in advance of the 2023 queue cycle. Without additional improvements, the 2023 queue cycle could well exceed the record 171 GW that entered the queue in 2022.

MISO continues to work with stakeholders on what rules should be adjusted and what the specifics of those rules should be. The current proposal before stakeholders is to increase the milestone payments needed to enter and stay in the queue, improve site control requirements around the point of interconnection, adjust the calculations around penalty free withdrawal, introduce a mandatory penalty schedule if a project withdraws, and introduce a cap on the size of each queue cycle. These new rules are expected to be filed with FERC within Q4 of 2023 and apply only to new queue submissions. MISO will not announce the 2023 queue submission deadline until after FERC's action on the future filing.

In addition to these future reforms, MISO is also reviewing the recent FERC Order 2023 to improve generator interconnection rules. Order 2023 will certainly improve the interconnection procedures in non-market areas of the United States that have yet to adopt cluster studies. MISO believes the Order does not go far enough, as most of the rules FERC adopted are ones that MISO already uses, but are not as prescriptive as MISO's Tariff. Because of this, MISO believes our additional queue reforms are still needed to further refine our requirements to ensure the efficient processing of the future requests.

CHAPTER 3: REGIONAL AND INTERREGIONAL PLANNING STUDIES

3.1 Long Range Transmission Planning

The Reliability Imperative focuses on preparing the region for industry transformation as the grid evolves toward increased decarbonization goals and renewable resources. As a critical part of this effort, Transmission Evolution assesses the region's future transmission needs and associated cost allocation holistically, including transmission to support member plans and state goals for existing and future generation resources. Long Range Transmission Planning (LRTP) is part of this effort.

The LRTP initiative is MISO's response to the current and future resource evolution that has and continues to affect the bulk electric system. The scale and pace of these changes require prompt attention to develop the most efficient, cost-effective investments that will ensure grid reliability in the future. LRTP sets out to proactively identify key regional backbone transmission projects to support the resource change. This requires MISO to balance regional issues which should be addressed now as part of the LRTP study versus those more localized issues which should be addressed in the future through the interconnection process or in future MTEP cycles as specific load and generation locations are determined. Ultimately, the objective of the LRTP study is to identify a least-regrets transmission build-out evaluated against multiple scenarios to manage uncertainty that achieves member goals, maintains reliability, and minimizes costs.

LRTP Tranche 1 Update

On July 25, 2022, MISO approved Tranche 1 of its LRTP study, which included 18 transmission projects with a total estimated cost of $10.3B (2022$). In the first year after project approval, Transmission Owners have continued to work on more detailed engineering design and construction plans and some Transmission Owners are starting to make regulatory filings with the applicable government agencies. As project updates have been available, Transmission Owners have provided those to MISO for its project reporting, which are shared on MISO's public website.

Additionally, as applicable, MISO has solicited proposals and selected developers for transmission projects in Tranche 1 eligible for the Competitive Transmission Process. Five Request for Proposals for Competitive Transmission Projects resulted from Tranche 1, all which MISO issued within one year of Board approval. In May 2023, MISO selected Republic Transmission to develop a competitive transmission project located in Indiana. In October 2023, MISO will select a developer for a competitive transmission project located in Missouri, and in February and April 2024, MISO will select a developer for each of the remaining three competitive transmission projects. MISO looks forward to future collaboration with Transmission Owners as the transmission projects in Tranche 1 are further designed, constructed, and placed in service.

LRTP Tranche 2 Status

Currently, MISO has moved to the next phase of the LRTP work, referred to as Tranche 2. This next Tranche will continue the work of Tranche 1 focusing on the Midwest Subregion of the MISO footprint. An important distinction from Tranche 1 is that Tranche 2 will utilize Future 2A of the recently developed Series 1A Futures to ensure transmission is available in a timely manner and meets member objectives.

In the time between the start of the Series 1 Futures (2019) and the end of the LRTP Tranche 1 effort (2022), significant changes occurred, namely acceleration of membership decarbonization and renewable plans and State policies. This acceleration drove the need to refresh the Futures and hence the Series 1A was developed.

Tranche 2 kicked off in quarter three of 2022 with the refresh of the MISO Futures. Along the way, many LRTP Workshops have been held as well as discussions at the MISO Planning Advisory Committee (PAC) to engage stakeholders in the LRTP process. Furthering stakeholder communication efforts, MISO also developed a set of Frequently Asked Questions (FAQ) to provide a broad base of information on various LRTP topics. The first key deliverable in the LRTP Tranche 2 study was completion of the updated Future 2A expansion and siting, which is the foundation for the current work on the economic and reliability models. Additional near-term key focus areas include:

- Reliability dispatch methodology and scenarios, see Reliability Modeling Whitepaper for more detail
- Issues identification using economic and reliability models
- Portfolio development to resolve regional issues
- Continued definition and refinement of robustness scenarios to ensure identification of least-regrets solutions
- Identification of benefit metrics for Tranche 2 to demonstrate multiple distinct types of value from the portfolio

Stakeholder engagement will continue throughout the process as transmission system models are completed, analysis is performed and issues identified, necessary grid enhancement solutions are developed, scenarios are analyzed, and benefits of a proposed portfolio are quantified. Tranche 2 efforts are expected to be completed with BOD approval in 2024.

LRTP Tranche 3 Status

MISO's Long Range Transmission Planning (LRTP) effort has multiple workstreams to support the different Tranches going on in parallel. Namely, MISO's current focus is on execution of the competitive process for Tranche 1, modeling and analysis for Tranche 2, and cost allocation discussions for Tranche 3.

In the most recent FERC filing to support the bi-furcated sub-regional MVP cost allocation for Tranches 1 & 2, MISO committed to exploring an alternative cost allocation approach for Tranche 3 focused on MISO South. To effectively pursue adjustments to the methodology, MISO and its stakeholders are actively engaged in evaluating options. These conversations are centered around three main criteria:

- Granularity – alignment on definition and scope of granularity and how it is considered in benefit calculation and allocation methodology
- Feasibility - evaluation tools and techniques available to determine beneficiaries
- Consistency – recognition that benefits and beneficiaries may change over time and applying a cost allocation methodology that remains just and reasonable over time

Ongoing conversations can be monitored in the Regional Expansion and Criteria Working Group (RECBWG). Additionally, we appreciate the ongoing effort of OMS' Cost Allocation Principles Committee (CapCom), Entergy Regional State Committee Working Group (ERSCWG) and other stakeholder groups in the development of a cost allocation approach for use with Tranche 3 focused on MISO South.

3.2 Interregional Studies

MISO-SPP Joint Targeted Interconnection Queue (JTIQ) Study

Introduction and Background

The JTIQ Study is a result of MISO and SPP's cluster study observations which show that transmission systems at the seams are at capacity. While the addition of generation resources and transmission along the SPP-MISO seam provides benefits to the markets, current Tariff and Joint Operating Agreement (JOA) mechanisms do not provide a cost-sharing approach that can facilitate the construction of the large-scale transmission needed to interconnect expected levels of new generation near the seam. Process, criteria, and schedule differences between the respective RTOs contribute to study delays and introduce questions on study results. The JTIQ Study takes these various barriers into consideration.

JTIQ aims to provide cost and timing certainty for generator interconnection customers as affected system costs will be known at the beginning of the MISO or SPP queue studies in addition to the elimination of Affected System Studies (AFS) needed between MISO and SPP. Moreover, this concept will identify more optimized network upgrades as compared to individual AFS clusters in the current process. The full report is available here .

Study Results

Through collaboration between the MISO and SPP Regional Transmission Organizations (RTOs), the study identified a five-transmission-project JTIQ portfolio with a planning level estimated cost of $1.06B required to address the significant transmission limitations restricting the opportunity to interconnect new generating resources near the MISO-SPP seam.

The recommended JTIQ Portfolio is expected to fully address the set of transmission constraints evaluated in the JTIQ Study as being significant barriers to the development of new generation along the MISO-SPP seam. In addition to these substantial reliability benefits, economic analysis conducted by the RTOs show customers can anticipate an Adjusted Production Cost (APC) benefit over a 10-year period of $55.7 million in the MISO footprint and $132.9 million in the SPP region. An estimated 28.7 GW of improved interregional generation enablement would be available to new generator interconnection projects near the seam.

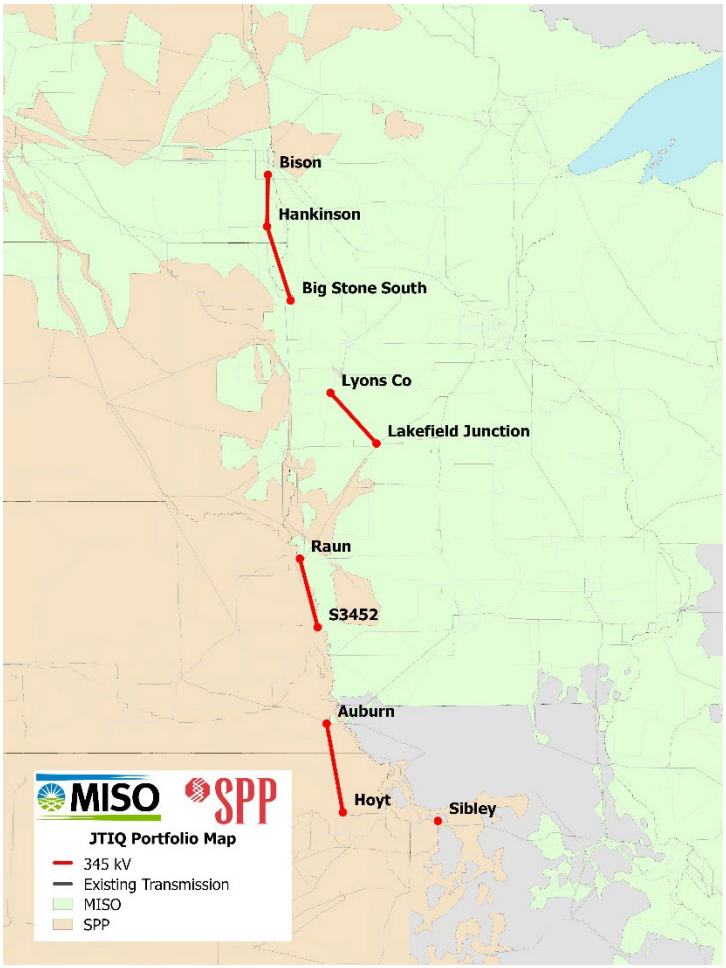


Figure 3.2.1-1: JTIQ Portfolio Map

JTIQ Portfolio	Location by RTO	Cost ($M)
Bison – Hankinson – Big Stone South 345 kV	MISO	476
Brookings Co (*moved to Lyons Co.) – Lakefield 345 kV	MISO	331
Raun – S3452 345 kV	MISO - SPP	144.4
Auburn – Hoyt 345 kV	SPP	90.5
Sibley - 345 kV Bus Reconfiguration	SPP	18.8
Total Cost of Portfolio of Projects	**MISO - SPP**	**1,060.7**

Table 3.2.1-1: List of projects comprising the JTIQ Portfolio

JTIQ Portfolio Update

The original portfolio included the Brookings Co-Lakefield 345 kV JTIQ project which will be replaced by a shorter Lyons Co-Lakefield 345 kV project in the updated JTIQ portfolio due to an approved MISO MTEP 22 project, Brookings Co-Lyons Co 345 kV second circuit on existing structures. MISO and SPP are working on updating the 2023 cost estimates and APC benefit calculations based on the updated model. RTOs will share this information once the data is available.

Cost Allocation and Cost Sharing

Projects in the JTIQ Portfolio are Generator Interconnection Projects, at the 345 kV voltage level, and, accordingly, the costs will be allocated consistent with the existing cost allocation method for Generator Interconnection Projects 345 kV and above. Each generator interconnection customer included in the group and allocated costs of the JTIQ Portfolio will pay their share of capital costs based on the size of their facility in proportion to the total enabled MWs of the portfolio. Non-capital costs associated with the generator interconnection customer's share will be allocated consistent with each RTO's current regional Tariff. MISO and SPP will allocate the share attributable to load based on application of the Adjusted Production Cost metric and each RTO will recover those costs consistent with its regional Tariff.

Department of Energy (DOE) – Grid Resilience and Innovative Partnership Program (GRIP)

In collaboration with SPP, Minnesota Department of Commerce, Minnesota Commission, Transmission Owners and Great Plains Institute, MISO supported the application for partial funding of the JTIQ projects through the DOE Grid Innovation Program. Below is a timeline of this year's activities.

JTIQ Concept Paper Submission	January 2023
DOE Notification to Submit Full Application	March 2023
Application Submitted	May 2023
DOE Notification of Award	Pending

Pending the DOE decision, the GRIP award could match up to 50% of the JTIQ portfolio. MISO and SPP do not anticipate this decision to impact current processes and will work with the DOE and interested parties to integrate any funding as appropriate.

Joint Operating Agreement (JOA) and Tariff updates

The MISO-SPP JOA captures changes in the planning processes, Affected System Study process, and allocation of costs between the two RTOs. MISO and SPP are collaborating with the stakeholders on updating the JOA redlines.

Summary of MISO Tariff Changes:

- Attachment X and related Appendices will be modified and potential new agreements added to incorporate the JTIQ Portfolio consistent with the MISO-SPP JOA changes
- Module A and Attachment FF are clarified and augmented to capture that the existing Generator Interconnection Project category and cost allocation applies to the JTIQ Portfolio of Generator Interconnection Projects
- New Attachments and Schedules will detail how costs will be charged to generator interconnection customers and MISO load, and how costs will be recovered and paid between the two RTOs

3.2.2 MISO-SPP Coordinated System Planning

In Q1 of 2023, MISO and SPP held an Annual Issues Review with the Interregional Planning Stakeholder Advisory Committee (IPSAC) to help determine whether to perform a Coordinated System Plan (CSP) study in 2023. After careful consideration and stakeholder discussion, MISO and SPP mutually determined not to initiate a CSP study based on the following rationale:

- No significant interregional congestion drivers were identified for consideration

- Forgoing 2023 CSP will better allow for the coordination of filing Targeted Market Efficiency Projects (TMEPs) in the MISO-SPP Joint Operating Agreement following the 2022 CSP, which involved developing the TMEP process and completing the first TMEP study with stakeholders
- No appropriate reliability constraints or public policy drivers were identified or planned at this time

3.2.3 MISO-PJM Coordinated System Planning

In Q1 of 2023, MISO and PJM held an Annual Issues Review with the Interregional Planning Stakeholder Advisory Committee (IPSAC) to help determine whether to perform a Coordinated System Plan (CSP) study in 2023. After careful consideration and stakeholder discussion, MISO and PJM mutually determined not to initiate a CSP study based on the following rationale:

- No interregional congestion drivers were identified for consideration as a part of an Interregional Market Efficiency Project study
- A Targeted Market Efficiency Project study was conducted in 2022, MISO and PJM recommended waiting another year before considering completing another study in order to have a full two years of new historical data to utilize
- No appropriate reliability constraints or public policy drivers were identified or planned at this time

3.3 Near-Term Congestion Study Update

Introduction and Background

MISO production cost analysis has traditionally focused on the medium- to long-term planning horizons with past Market Congestion Planning and Long-Range Transmission Planning initiatives. While MISO continues to prepare for the rapidly changing energy landscape of the future, some MISO stakeholders expressed interest in additional analysis focused on the near-term time horizon.

After reviewing the proposed issue in the MISO Interconnection Process Working Group and MISO Market Subcommittee, the issue was eventually assigned to the MISO Planning Advisory Committee (PAC) under PAC-2021-1: Address Congestion at Existing Resources and delegated to the Planning Subcommittee (PSC) for further stakeholder technical discussion. Additional information on stakeholder discussions and presentations on this issue can be found on the MISO website at PAC-2021-1 Address Congestion At Existing Resources.

Stakeholders proposed a similar process to the existing MISO-PJM Targeted Market Efficiency Project (TMEP) study process. TMEPs are quick-hit, low-cost interregional projects to address specific interregional market-to-market congestion issues. Notably for TMEPs, the evaluation process is limited to only a review of historical day-ahead (DA) market data rather than production cost modeling or simulation. To accommodate a more robust analysis of the MISO region (versus the limited Market-to-Market historical-only data review), MISO staff proposed a hybrid approach that would use traditional production cost modeling and simulation to evaluate issues, with a focus on the issues driving historical top congested flowgates.

MISO recreated the top identified flowgates in an available model. To better understand key drivers, additional assumption and model tweaks will be tested prior to determining final study recommendations.

Study Objectives and Scope

The primary objective of this study was to provide insight into recent top congestion issues seen in the MISO Day-Ahead market and identify the challenges of near-term economic modeling. MISO does not plan to recommend projects for approval based on the results of this informational study. Voluntary pursuit of

any project proposals by stakeholders based on the study results should be performed in accordance with the planning processes and timelines outlined in the MISO Transmission Planning Business Practice Manual (BPM-020) and the MISO-PJM Joint Operating Agreement (MISO-PJM JOA Article IX). Cost allocation outside of market participant funding for any specific upgrades are not in scope for this effort.

Flowgates studied were determined using the following process:

- Screening Criteria:
  - Historical Day-Ahead market data from 2021 and 2022
  - Congestion cost, binding hours, and shadow prices
  - Data included Market to Market (M2M) flowgates, but was limited to MISO-only facilities
- Flowgates were organized by their binding element and ranked by total congestion cost
- Facilities were removed from consideration using the following criteria:
  - Project went in-service during study window which had a noticeable positive effect on congestion cost
  - Project is planned to be in-service in the near-term at the facility
  - Facility was examined extensively as part of other MISO studies (JTIQ, LRTP, TMEP, etc.) and solutions were identified

Model was developed under the following assumptions:

- We used the following Hitachi PROMOD[7] releases
  - Fall 2021 gen updates and economic data
  - Spring 2022 coal prices
  - PROMOD 11.5 engine
- MTEP23 No Futures Assumptions model
  - Hartburg – Sabine was removed
  - Out of cycle projects were added if in-service date was before study window
- MTEP22 Year 2027 Summer Peak TA powerflow
- Resource utilization – generators with signed GIA additions and finalized retirement studies were included.

Study

Initial Analysis

Ten flowgates were identified for this study based on their historical congestion from 2021-2022 (see Table 3.3-1). Project testing was conducted by running the base case model, then evaluating whether historical day-ahead congestion was duplicated under the Year 5 assumptions. Only one flowgate, the Marblehead North 161/138 kV transformer, was identified as being congested in the base case model.

Monitored Facility	State	Owner	Total MISO DA Congestion Cost ($)	Base Economic Model Congestion Cost* (Year 2027)
Marblehead North 161/138 kV Transformer	IL	Ameren	103,084,055	$283,232
Johnson Junction – Graceville 115 kV	MN	GRE	71,148,820	

[7] PROMOD, Hitachi Energy owned, is a chronological security constrained unit commitment and economic dispatch tool that adheres to a wide variety of operating constraints.

Monitored Facility	State	Owner	Total MISO DA Congestion Cost ($)	Base Economic Model Congestion Cost* (Year 2027)
Cayuga 345/230 kV Transformer	IN	Duke	39,638,357	
Irvine – Beacon 161 kV	IA	Alliant West	39,602,576	
Jefferson County – Woody 161 kV	IA	Alliant West	30,763,191	
Cayuga – Hillsdale North 230 kV	IN	Duke	29,928,665	
Murphy Creek – Hayward 161 kV	MN	SMMPA/ALTW	28,681,570	
Stone Lake 345/161 kV Transformer	WI	Xcel	28,385,411	
Fox Lake – Rutland 161 kV	MN	SMMPA/ALTW	23,485,327	
Woody – Appanoose	IA	Alliant West	23,098,944	

Table 3.3-1: Top 10 List of Most Congested MISO Flowgates in 2021-2022
*Annual average shadow prices x number of binding hours

Outage Analysis

Congestion at each binding facility was further reviewed to identify outage driven congestion. MISO noted congestion that may be driven by outages due to a significant number of nearby outages during similar periods of congestion. Transmission Owners of the monitored facilities in the study provided additional insight into the impacts of outages or general cause of congestion (see Table 3.3-2).

Monitored Facility	MISO Identified Outage Impacts	Additional Information from Facility Owner
Marblehead North 161/138 kV Transformer	X	
Johnson Junction – Graceville 115 kV	X	The Johnson Junction to Graceville congestion issue was directly related to the planned construction outage on the Johnson Junction to Morris line which occurred between Oct 1,2021 and Feb 1, 2022. The normally open line segment north of Graceville was closed in to accommodate this construction outage leading to congestion on the Johnson Junction to Graceville line. Thus, the congestion correlates the construction of the Johnson Junction-Morris construction outage and grid reconfigurations. It is understood that when upgrading transmission facilities to accommodate the changing grid, it is often necessary to alter the normal operations of the transmission system which can lead to temporary economic congestion in order to ensure continued grid reliability. (GRE)

Monitored Facility	MISO Identified Outage Impacts	Additional Information from Facility Owner
Cayuga 345/230 kV Transformer	X	Congestion was likely related to Cayuga Unit 1 outage and MTEP Project 22226 is expected to relieve this congestion. (Duke)
Irvine – Beacon 161 kV		Congestion was highly correlated to several outages including MEC Diamond Trail-Hills 345 kV, MEC Montezuma-Ottumwa 345 kV, and ITC Beacon-Tri County 161 kV line upgrade outages. Ottumwa Generation outages may have also increased congestion on the line. (ITC)
Jefferson County – Woody 161 kV		Congestion was likely related to MEC Diamond Trail-Hills 345 kV line and Ottumwa Generation outages. (ITC)
Cayuga – Hillsdale North 230 kV	X	Congestion was likely related to Cayuga Unit 1 outage and MTEP Project 22226 is expected to relieve this congestion. (Duke)
Murphy Creek – Hayward 161 kV	X	Congestion was likely related to XCL Crandall-Wilmarth 345 kV line upgrade outage and ITC Adams 161 kV bus outage to connect a new generator. (ITC)
Stone Lake 345/161 kV Transformer		Facility owner confirmed minimal outage impacts. Congestion may have some relation to Manitoba Hydro flows. Congestion in 2023 has not been as extensive likely due to the refurbishment of the Eau-Claire - Arpin 345 kV line. MTEP Project 20229 is expected to further reduce binding on this line. (Xcel)
Fox Lake – Rutland 161 kV	X	Congestion was likely related to XCL Crandall-Wilmarth 345 kV and ITC-Lakefield-Dickinson County 161 kV line upgrade outages. (ITC)
Woody – Appanoose		Congestion was likely related to MEC Diamond Trail-Hills 345 kV line and Ottumwa Generation outages. (ITC)

Table 3.3-2: Outage Analysis of Study Flowgates

Final Results

The final results for the 2023 Near-Term Congestion study, as shown in Table 3.3-3, provides the changes in Adjusted Production Costs (APC) when ratings are increased for the identified flowgates.

Monitored Facility	State	Owner	APC Change ($M) *
Marblehead North 161/138 kV Transformer	IL	Ameren	-5.053
Johnson Junction – Graceville 115 kV	MN	GRE	-
Cayuga 345/230 kV Transformer	IN	Duke	2.064
Irvine – Beacon 161 kV	IA	Alliant West	0.396
Jefferson County – Woody 161 kV	IA	Alliant West	-0.139

Monitored Facility	State	Owner	APC Change ($M) *
Cayuga – Hillsdale North 230 kV	IN	Duke	0.487
Murphy Creek – Hayward 161 kV	MN	SMMPA/ALTW	1.021
Stone Lake 345/161 kV Transformer	WI	Xcel	0.159
Fox Lake – Rutland 161 kV	MN	SMMPA/ALTW	0.469
Woody – Appanoose	IA	Alliant West	0.382

Table 3.3-3: Final Results of Near-Term Congestion Study
*Positive numbers represent an economic benefit and negative numbers represent an economic loss

There were three flowgates of note in the final results of this study: Marblehead North 161/138 kV Transformer, Johnson-Junction-Graceville 115 kV, and the Cayuga 345/230 kV Transformer.

- Upgrades to the Marblehead North 161/138 kV Transformer create economic losses of approximately $5 million for the system in this study. Results also show that PJM and SPP see combined economic benefits of about $3 million from the upgrade at this transformer. Additional analysis is needed to understand the results and identify opportunities for coordination with MISO interregional and JTIQ teams.
- Upgrades to the Johnson Junction-Graceville 115 kV line result in no economic changes to the system. Analysis showed this line is located between two other limiting elements on the system that are preventing increased flow on the line even with an upgrade. Additional analysis of those nearby elements is needed to assess congestion relief opportunities for this line.
- Upgrades to the Cayuga 345/230 kV Transformer result in about $2 million of economic benefits. The upgrade allowed for reduced renewable curtailment on the system. PROMOD did not identify the Cayuga 345/230 kV as a binding constraint in the base model. Additional analysis is needed to identify how the PROMOD solution did not identify congestion but did find economic benefits to upgrading the facility.

Study Takeaways

The MISO economic planning process is geared towards long-term planning horizons rather than near-term planning horizons. In addition to adjustments that are needed in model development to better reflect the near-term, topology changes can shift or eliminate congestion making it challenging to use historical data to identify near-term issues and solutions.

Working with stakeholders to forecast future congested flowgates outside of historical day-ahead congestion may provide additional value. Additional analysis and coordination with MISO interregional and JTIQ may also provide some insight into issues identified in the 2023 Near-Term Congestion Study.

In 2023 Q4 MISO will publish a separate Near-Term Congestion Study Report with additional insight and context on the study process.

CHAPTER 4: RELIABILITY STUDIES

4.1 Reliability Assessment and Compliance

MISO, in collaboration with its transmission-owning members and stakeholders, performs annual reliability assessments to identify transmission infrastructure upgrades needed to ensure the continued system reliability in compliance with applicable local and regional reliability standards. The reliability assessment process for MTEP23 (shown in Figure 4.1-1) began with a roll-up of issues and potential solutions from the NERC assessment of the prior MTEP cycle and from the local planning processes of TOs. Following this step, MISO conducted an independent reliability assessment to evaluate and integrate the TO local planning information into the development of the overall MTEP.

MISO closely coordinates the annual reliability assessment with other planning efforts to ensure the transmission expansion plan is identified in an efficient and cost-effective fashion. A variety of factors are considered as part of MISO's transmission expansion plan development, including but not limited to, urgency of needs, cost effectiveness of solutions, system performance of solution alternatives to address identified transmission issues, and other considerations such as lead time to develop a project, right-of-way (ROW) or substation impacts, expandability, operational flexibility, etc.

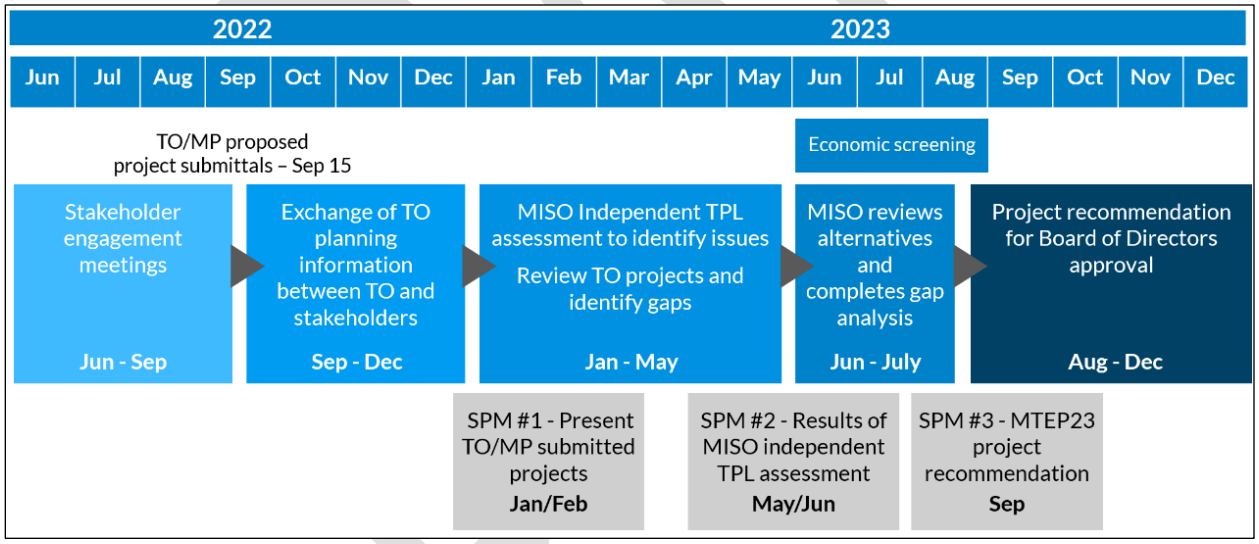


Figure 4.1-1: MTEP23 reliability assessment process

In conjunction with the MTEP planning process, an inclusive, transparent stakeholder process is utilized to facilitate open discussions and allow stakeholders to provide early and meaningful inputs into the development of transmission solutions in each planning cycle. The results of MISO's independent reliability assessments, along with proposed solution alternatives, are presented to stakeholders through a series of public Sub-regional Planning Meetings (SPM), and additional Technical Study Task Force (TSTF) meetings as needed, for each of the four MISO planning sub-regions: Central, East, South, and West.

MISO strategically set up our local planning processes to assume FERC Order 890 transparency requirements for Transmission Owner submissions resulting in different study approaches based on the types of projects submitted by Transmission Owners.

- **Verify need:** Confirmation of system need identified in project submission including to meet compliance with applicable National Electric Reliability Organization reliability standards and reliability standards adopted by Regional Reliability Organizations, and applicable within the Transmission Provider Region. MISO must verify the need for alternatives to adequately examine their effectiveness.
- **No harm:** Ensure a submitted project does not create a system issue. Includes projects that create model changes like contingency definitions, line ratings, or line impedances.
- **Post only:** Provided for FERC Order 890 transparency provisions. May include controls equipment to communicate remotely with the facility. This information is not able to be represented with model changes.

Alternatives for projects may be completed prior to submission to MISO by the Transmission Owners, proposed by MISO, or proposed by stakeholders. Alternative criteria considers cost comparisons, feasibility to construct and how reliability needs are resolved. Alternatives do not always result in one project replacing another, instead they tend to be additive to the original project, even when submitted with the thought that they would directly compete. MISO considers alternatives in multiple forms, including like-for-like replacement, regional reliability projects, the combination of multiple local solutions, and other options identified through either MISO analysis or submitted by stakeholders.

After MISO completes its independent review of all proposed projects and associated alternatives and addresses stakeholder feedback received through SPM discussions, MISO staff formally recommends a set of projects to the MISO Board of Directors for review and approval. These projects make up Appendix A of the MTEP report and represent the preferred solutions to the identified transmission needs of the MISO reliability assessments. Proposed transmission upgrades with sufficient lead times are included in Appendix B for further review in future planning cycles.

The complete results of MTEP23 reliability assessments are detailed in Appendices D3-D10 of the MTEP23 report, which are available on the MISO ShareFile site and subject to Critical Energy Infrastructure Information (CEII) and non-disclosure agreements. These results serve as compliance evidence for a variety of NERC planning standards listed on the MISO public website.

As appropriate, an executive summary of results for the appendix will be available on the MISO website under the Appendices tab.

Appendix	Title
D3	Steady State CEII
D4	Voltage Stability CEII
D5	Transient Stability CEII
D6	Generator Deliverability CEII
D7	Contingency Coverage CEII
D8	Nuclear Plant Interface Coordination CEII
D9	Planning Horizon Transfer Capability CEII
D10	Short Circuit Analysis CEII

MTEP23 project recommendations

As the result of the MTEP23 reliability assessments, 45 Baseline Reliability Projects totaling $1.7 billion are included in the MTEP23 proposed Appendix A, accounting for 19% of total transmission infrastructure investment in MTEP23. The vast majority of the recommended projects are driven by reliability (either baseline or local reliability), load growth and age and condition, and are expected to be in service within three years.

Out of the 572 MTEP23 projects submitted in this cycle, MISO Planning Engineers received and evaluated 35 Expedited Project Review (EPR) requests which is double the requests received last year. These expedited projects were submitted by Transmission Owners who determined that system conditions warrant the urgent development of system enhancements within the current MTEP cycle. New load interconnections account for over 60% of the EPR requests submitted.

Project justification details of the recommended Appendix A projects are summarized in the following subsections for each of the four MISO planning sub-regions. Figure 4.1-2 provides a quick glance into MTEP23 Appendix A project investment summary by category and planning region.

Planning Region	Baseline Reliability Projects (BRP)	Generator Interconnection Projects (GIP)	Market Participant Funded Projects (MPFP)	Multi-Value Project (MVP)	Other Projects	Total
Central	$178	$374	-	-	$1,714	**$2,266**
East	$60	$307	-	-	$371	**$739**
South	$1,335	$351	-	-	$2,483	**$4,168**
West	$150	$195	$1	$4	$1,455	**$1,806**
Total	**$1,723**	**$1,227**	**$1**	**$4**	**$6,023**	**$8,979**

Figure 4.1-2: MTEP23 Appendix A new project investment by category and planning region (data as of 9-29-2023)

In the following pages, the majority of the region's MTEP23 projects are categorized into three categories, Baseline Reliability, Other, and Generator Interconnection. The definition of each of these categories are detailed below.

Baseline Reliability Projects

According to Attachment FF of the MISO Tariff, "Baseline Reliability Projects are Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable national Electric Reliability Organization (ERO) reliability standards and reliability standards adopted by Regional Reliability Organizations and applicable within the Transmission Provider Region."

MISO identifies the need (verifies the need) or violations (noted in tables with "Limiting Element") that are required to be resolved per NERC Transmission Planning Standards and reliability standards adopted by

Regional Entities. MISO then reviews the effectiveness of the identified solution that resolves the violations. This is completed by reviewing the impacts to a powerflow model with and without the project. Sometimes the needs or violations were identified in a previous MTEP cycle. All costs for Baseline Reliability expansion projects are recovered through Attachment O by the Transmission Owner(s) developing such projects.

Other Projects

The "Other" projects category are projects that do not meet the criteria to be considered as Baseline Reliability Projects (BRP), New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. Other projects may include projects to satisfy Transmission Owner and/or state and local planning criteria other than NERC or regional reliability standards, interconnection of new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plant, improve operational performance or address other operational issues, address service reliability issues with end-use consumers, improve aesthetics including but not limited to undergrounding overhead transmission facilities, address localized economic issues, and address other miscellaneous localized needs. The tables of project information are broken down by four general categories of project drivers; Local Reliability, Age and Condition, Load Growth, and Other Local Need, but note that these four drivers are not defined in the MISO Tariff.

MISO generally completes a "no-harm" analysis for Other projects, this means that the project information is added to a powerflow model and a test is performed to see if the addition of the project causes a new violation or "harm" for the reliability of the system. If there are no new violations created by the addition of the project, the project is able to move forward. If violations exist, then those will need to be resolved. Some projects, such as improving aesthetics or communication equipment do not result in changes to information applied to powerflow models and are not analyzed and are posted only for FERC Order 890 transparency. All costs for Other projects are recovered through Attachment O by the Transmission Owner(s) developing such projects, unless other cost recovery agreements are entered into.

In MTEP23, there were a few Other projects that required analysis beyond "no-harm" to verify that the projects resolved the identified system needs, or consideration of an alternative project submitted by stakeholders. Figure 4.1-3 highlights the projects and what type of review MISO completed.

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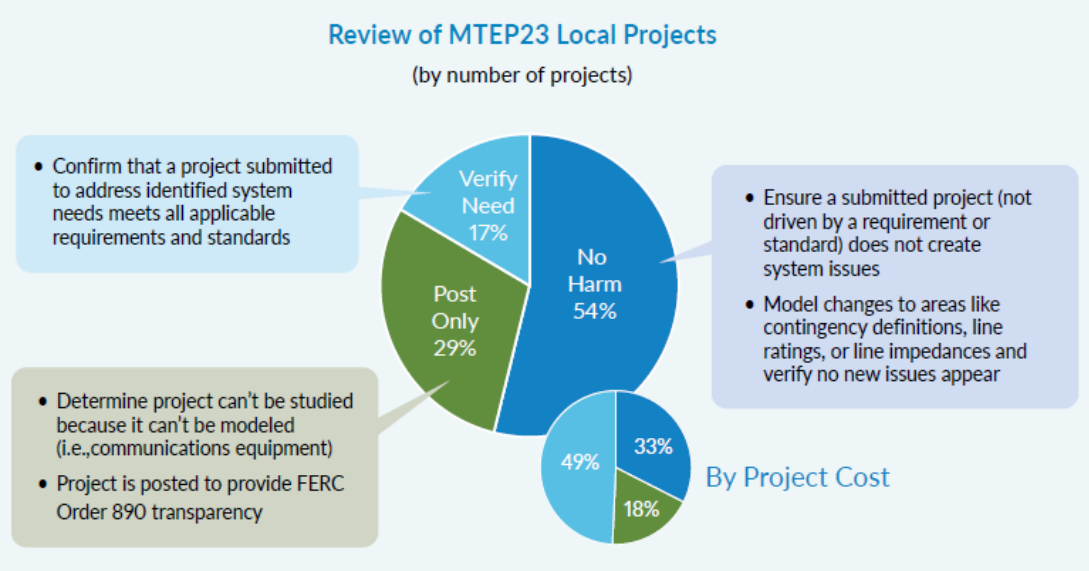


Figure 4.1-3: Types of reviews MTEP23 local projects went through

Generator Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generator Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." These represent facilities necessary to physically interconnect the generation resource to the transmission system as well as network upgrades required to facilitate reliable delivery of the output to ultimate load.

The Generator Interconnection Projects (GIPs) noted in the following sections of this chapter have been evaluated through the Generator Interconnection Queue and the associated Generator Interconnection Agreements (GIAs) have been signed. Similar to the process for "Other" projects a no-harm analysis is completed for Generator Interconnection Projects (GIPs).

Generator Interconnection Projects are network upgrades associated with interconnection of new, or increase in generating capacity of existing, generation under Attachment X and FF of the Tariff. These projects are driven by interconnection study procedures and agreements. The Interconnection Customer is responsible for 100% of the costs of network upgrades rated below 345 kV and 90% of the costs of network upgrades rated at 345 kV and above (with the remaining 10% being recovered on a system-wide basis).

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1.5 4.2 Project Justifications – Central Region

Central Region Overview

The MISO Central planning region consists of seventeen Transmission-Owning members spanning four states: Missouri, Illinois, Indiana, and Kentucky. These Transmission Owners are:

American Electric Power Service Corporation (AEP)

Ameren Illinois (AMIL)

Ameren Missouri (AMMO)

Big Rivers Electric Corp. (BREC)

City of Columbia, Mo. (CWLD)

City of Springfield, Ill. (CWLP)

Duke Energy Corp. (DEI)

GridLiance Heartland LLC (GLH)

Henderson Municipal Power & Light (HMPL)

Hoosier Energy REC Inc. (HE)

Indianapolis Power & Light (IPL)

Northern Indiana Public Service Co. (NIPSCO)

Pioneer Transmission (PTx)

Prairie Power Inc. (PPI)

Republic Transmission (RTx)

Southern Indiana Gas & Electric (SIGE)

Southern Illinois Power Cooperative (SIPC)

Wabash Valley Power Association Inc. (WVPA)

The Bulk Power System (BPS) within these states consists of an extensive 765 kV, 345 kV, 230 kV, 161 kV, and 138 kV networked transmission system. The 345 kV network spans Missouri, Illinois, and Indiana, both north to south and east to west. The 230 kV network spans through Indiana, both north to south and east to west. The 161 kV network spans north to south and east to west in Missouri, Illinois, and Kentucky, and the 138 kV networks span both north and south, and east to west in Illinois, Indiana, and Kentucky. All of Ameren, BREC, CWLD, CWLP, GLH, HMPL, and SIPC belong entirely in the SERC Region. All of DEI, HE, IPL, NIPSCO, PTx, RTx and SIGE belong entirely in the ReliabilityFirst Region. Wabash Valley is split between both ReliabilityFirst and SERC Regions.

Major load pockets in the MISO Central planning region are St. Louis, MO; Peoria, IL; Springfield, IL; Evansville, IN; and Indianapolis, IN (shown in Figure 4.2-1).

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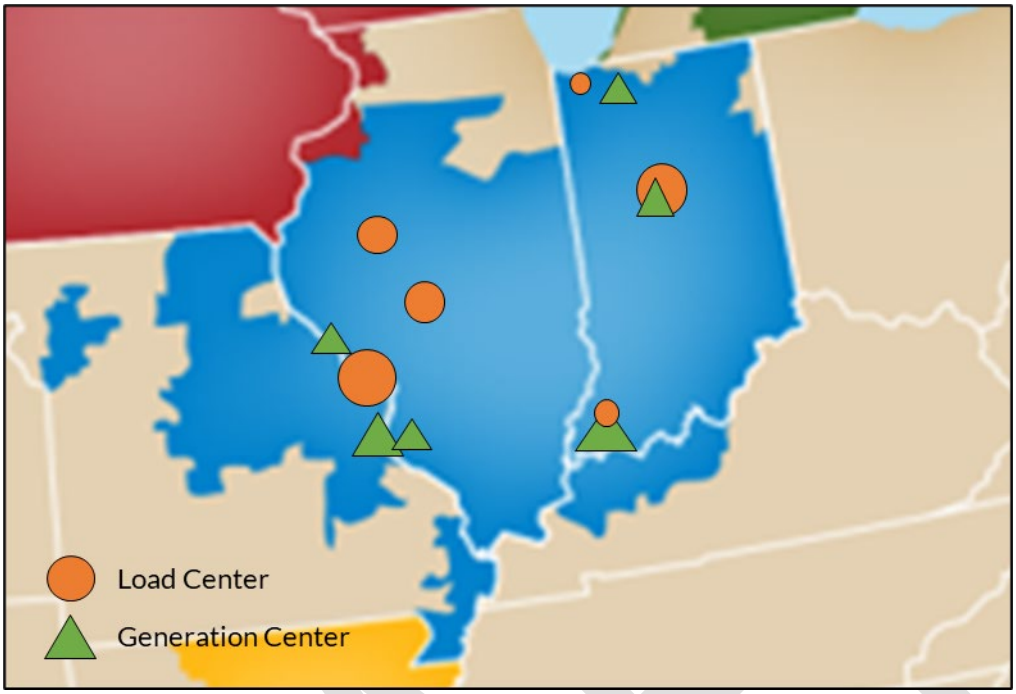


Figure 4.2-1: Generation and load centers in the Central planning region

For MTEP23, MISO Transmission Planning is recommending 153 projects from the Central region for inclusion in Appendix A at an estimated cost of $2.3 billion. Of these, 12 are Baseline Reliability Projects (BRP), 36 are Generator Interconnection Projects (GIP), and 105 are Other Projects. MISO considered alternatives for some projects in the Central region including the New South Central Illinois Transmission Expansion project. The alternative proposed transmission projects were determined to be less cost-effective than the original project.

Of the 153 projects within the Central region that are being recommended in MTEP23, 13 have an estimated cost of less than $1 million, 50 have an estimated cost between $1 million and $5 million, and the remaining 90 projects are estimated to cost greater than $5 million (indicated in Figure 4.2-2 below).

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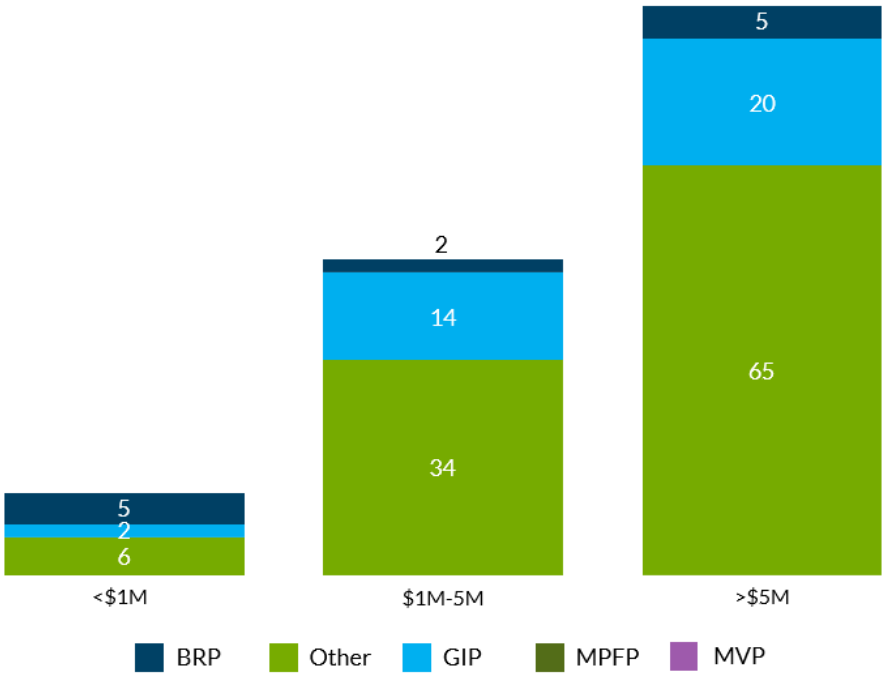


Figure 4.2-2: Project counts by cost category of MISO Central region MTEP23 projects (data as of 9-29-2023)

The majority of the projects in the MISO Central planning region are expected to go in service in the next three years (shown in Figure 4.2-3).

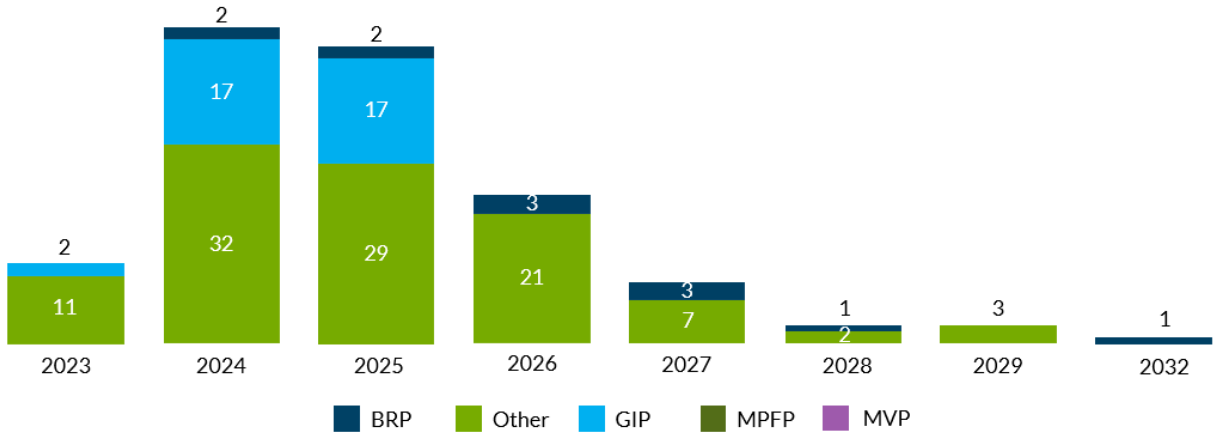


Figure 4.2-3: Central region MTEP23 projects by in-service date (data as of 9-29-2023)

In accordance with Attachment FF of the tariff, in the event a Transmission Owner determines that system conditions warrant the urgent development of system enhancements, an expedited review of the impacts of the project can be requested. MISO shall use a streamlined approval process for reviewing and approving projects proposed by the Transmission Owner(s) and decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO unless a longer review period is mutually agreed upon. During the MTEP23 cycle, generally due to voltage issues associated with the Rush Island generator retirement, MISO received the following projects through the Expedited Project Review (EPR) process:

1. Project 23971, Upgrades at Hannibal W and Effingham NW-Neoga 138 kV line
2. Project 22813, Coffeen N-Roxford 345 kV Rebuild
3. Project 23632, New Beehive – Dupo Ferry 138 kV line
4. Project 22946, New Alta-Pioneer 138 kV line
5. Project 24172, Re-route HMPL Sub 4 to HMPL Sub 4 Tap 161 kV Transmission Line

Also, in accordance with Attachment FF Section VIII.A.3, none of the projects were identified as an Immediate Need Reliability Project and excluded from the competitive developer selection process. The ten largest project investments in the MISO Central region represent $890 million (39%) of the $2.3 billion total recommended projects for the Central region in MTEP23, or 10% of the $9 billion total recommended in the MISO footprint. The locations of these projects are shown in Figure 4.2-4 and the investment is spread across the Central planning region. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

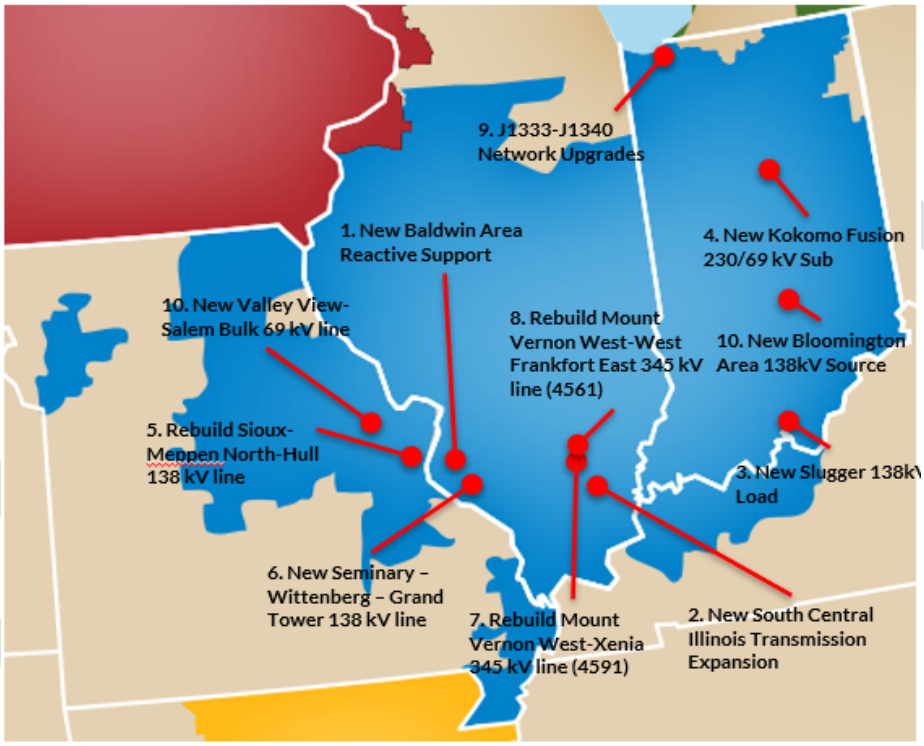


Figure 4.2-4: Central region top ten projects by cost (data as of 9-29-2023)

4.2.1 American Electric Power Service Corporation (AEP)

American Electric Power Service Corporation did not submit any new projects for MTEP23.

4.2.2 Ameren Illinois

After MISO's independent reliability analysis, MISO and Ameren Illinois recommend 47 projects at an estimated cost of $957.4 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Baseline Reliability Project, 26 are Other Projects, and 20 are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 23846 – New Seminary – Wittenburg – Grand Tower 138 kV line

Project Description: This project will include building a new Perryville (Seminary) - Wittenberg - Grand Tower 138 kV line that crosses the Missouri/Illinois Border. The total estimated cost of this project is $68 million and has an expected in-service date of December 31, 2026.

Project Need: This project is needed to mitigate multiple Transmission System Planning Performance Requirements for (TPL-001) low voltage violations.

Alternatives Considered: No alternatives were considered.

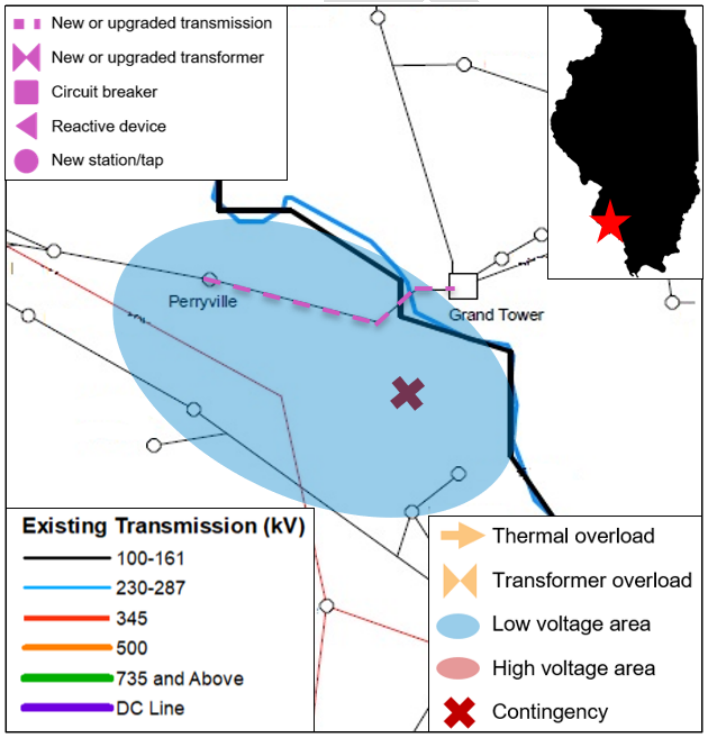


Figure 4.3.1-1: P23846 Geographic transmission map of project area

Cont Type	Limiting Element	Rating (pu)	Pre-Project Loading (pu)	Post-Project Loading (pu)
P6	[AMMO] Seminary 138 kV	0.95	0.8623	0.9921
P6	[AMMO] New Bourbon 138 kV	0.95	0.8951	0.9881

Table 4.3.1-1: P23846 voltage loading drivers

Other Projects

Project 23026 South Central Illinois Transmission Expansion

Project Description: Construct a new 138 kV substation as an ultimate six-position ring bus

requiring one 3000 A 138 kV breaker initially adjacent to the Continental Tire facility. Construct approximately a 3.5-mile 138 kV line from Mt. Vernon 42nd St. to the new substation ~0.3 miles NE of the Continental Tire facility with minimum 2,000 Amp summer emergency capability. Add a new 3,000 Amp 138 kV breaker at Mt. Vernon 42nd St. for this new 138 kV line position.

Estimated Cost: $167.85 M

Expected ISD: June 1, 2028

Alternative Considered: Double Circuit line to Mt. Vernon could be utilized and is longer than the proposed path to 42nd Street. Note: This option was not chosen because the longer path would require additional conductor and therefore, cost more than the proposed option on an already high-cost project.

Estimated Alternative Cost: Increased cost due to additional conductor required for the further connection point.

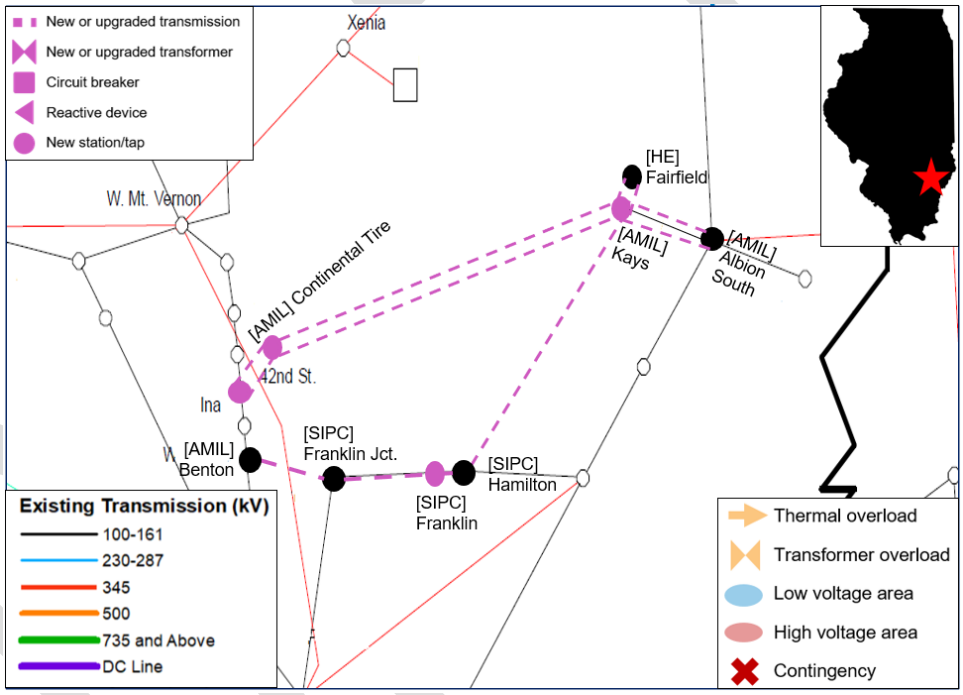


Figure 4.3.2-1: P23026 Geographic transmission map of project area

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22186	Upgrade South Ottawa 138 kV Substation to Ring Bus	Create a 5 position 6 ultimate ring bus at the existing South Ottawa substation.	6/1/2025	$9.3
22667	New PPI – Forest City 138 kV Interconnection	Construct a new 138 kV substation in ring bus configuration on the existing Ameren Havana-Cincinnati-1352 138 kV line. A	12/1/2025	$8.5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		position will feed PPI Forest City 138/69 kV.		
22728	Reconfigure Decatur North 27th St. 138 kV substation	Rebuild this station to a 7 position BAAH, minimum 8 position ultimate BAAH. New name is Boxcar.	6/1/2025	$19.8
22848	Rebuild Hutsonville-Heath 138 kV line (1311)	Rebuild the Hutsonville-Heath-1311 138 kV line from Hutsonville-Str. 95 with conductors capable of 2000 amps at Summer Emergency and OPGW.	6/1/2025	$12.5
22888	Upgrade Edwards 345 kV substation	Install a new 345 kV Ring Bus near Edwards Switchyard to support the transmission system in the Peoria area. Reroute ~0.75 miles of the existing Mapleridge-Tazewell-4528 345 kV line on the west side of Edwards Switchyard to avoid conflicts with the existing 138 kV crossings. Remove the existing failed 345 kV underground cable between Str. 123 and 124. Design and build the rerouted line to support 2 - 345 kV circuits to support MISO planning needs. All new conductors should be minimum 3000 amp Summer Emergency rated.	6/1/2027	$32
22891	Rebuild Tibbs-Steeleville 138 kV line	Repair issues found during inspections. Replace existing 477 ACSR conductor in line.	12/1/2024	$37
22946	New Alta - Pioneer 138 kV Line	Construct a new 138 kV line from Alta to Pioneer. Rebuild Alta 138 kV substation as a 4-position initial, 6-position ultimate 138 kV ring bus. Rebuild Pioneer 138 kV substation as 5-position initial, 6-position ultimate 138 kV ring bus. TP5161 was created to rebuild Pioneer as a ring bus to address aging infrastructure. The aging infrastructure will be addressed by this project.	12/1/2025	$26.7
22966	New Baldwin Area Reactive Support	Add 4 138 kV dynamic reactive 250 MVAR each located at Turkey Hill, Moro, Jarvis, and Granite City 23rd Street.	6/1/2027	$170

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23971	Upgrade Effingham NW-Neoga 138 kV line	Upgrade terminal equipment at Hannibal West, replace two structures and shunts in Neoga – Effingham NW 138 kV line. These are Non-SSR related needs.	12/1/2024	$1.75
23072	Rebuild Newton-Tanner 345 kV line	Rebuild the Newton-Tanner 345 kV line with conductors capable of 3000 amps Summer Emergency rating and two OPGWs.	12/1/2026	$29
23207	Rebuild Mattoon West-Tuscola West 138 kV line	Rebuild the 24.6-mile Mattoon West-Tuscola West-1 138 kV Transmission Line with T2 conductor rated at 2,000 amps Summer Emergency Conditions and 2 EA 72-Fiber OPGW shield wires.	12/1/2025	$18.5
23504	Rebuild Castro-Canton-138 kV line	Rebuild the 11.4-mile Vermillion-Tilton Energy Center-1572 138 kV Transmission Line with T2 conductor rated at 2,000 amps Summer Emergency Conditions and 2 EA 72-Fiber OPGW shield wires.	6/1/2024	$13
23632	New Beehive-Dupo Ferry 138 kV line	Install new Beehive to Dupo Ferry 138 kV line. Add breaker to new Dupo Ferry ring bus. Add position at Beehive.	12/1/2024	$6.3

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23286	New [PPI] Paragon 138 kV substation	Add interconnection point to the Pana substation for PPI's new bulk substation which will be called Paragon.	6/1/2025	$0.9

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22266	Rebuild Clinton-Oreana and Clinton-Goose Creek 345 kV lines	Rebuild existing double-circuit towers on the Clinton-Oreana 345 kV and Clinton-Goose Creek 345 kV line due to deteriorated conditions.	6/1/2024	$34

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22789	Upgrade Canton South 138 kV substation	Create ring bus, add high side interrupting devices.	6/1/2026	$3.25
22813	Reconductor Coffeen North-Roxford 345 kV line	Reconductor the 51 mile Coffeen North-Roxford-4551 345 kV line with conductor capable of carrying 3,000 amps during Summer Emergency conditions.	12/1/2025	$25
22816	Rebuild Louisville – Newton 138 kV line	Replace the 134 original vintage wood structures on the Louisville-Newton 138 kV line due to age and condition.	12/1/2023	$32
22817	Rebuild Mount Vernon West-Xenia 345 kV line (4591)	Rebuild the Mount Vernon West-Xenia 345 kV line (37 miles) to replace decayed and severely woodpecker damaged wood poles.	12/1/2026	$51
22851	Rebuild Mount Vernon West-West Frankfort East 345 kV line (4561)	Rebuild the Mount Vernon West-West Frankfort East 345 kV line (36 miles).	6/1/2025	$48
22868	Upgrade Quincy South 138 kV substation	Insulators – Strain Bus Suspension (18) – replace.	12/2/2024	$3
23088	Upgrade Quincy East 138 substation	Replace Breaker 1442. Replace switch 1456.	6/1/2024	$1.5
23505	Relocate Bosco 138 kV substation (fka Murdock)	Relocate station due to contamination, build a ring bus at a new location.	6/1/2025	$14.4
23844	Replace Pole and Insulator Program – MTEP23	Pole and Insulator Replacement requested by Maintenance.	12/1/2025	$20
23845	Replace Breakers and Relays Program – MTEP23	Breaker and Relay Upgrades Requested by Maintenance (Missouri and Illinois).	12/1/12025	$5

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23367	New Lincoln Land Energy Center 345 kV substation (J955)	Project will connect to the existing Austin substation. This requires us to install a new 345 kV breaker position. This is a 1165 MW combined cycle project.	12/1/2024	$2.7

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23431	Upgrade Decatur-Main St. 138 kV line (J955)	Replace two wood structures and re-frame 3 others to increase capacity of the Decatur - Main St. 138 kV line.	12/1/2024	$0.5
23635	New Baldwin Solar Interconnection (J1202)	Install one 345 kV terminal in the Baldwin substation. The terminal will consist of all necessary terminal equipment to connect the J1202 lead line to the Baldwin substation 345 kV bus.	6/1/2024	$0.15
23637	New Hennepin Solar Interconnection (J1200)	Install one 138 kV terminal in the Putnam substation. The terminal will consist of all necessary terminal equipment to connect the J1200 lead line to the Putnam substation 138 kV bus. Install upgrades at Putnam substation. Raise existing PUTN-HKOK-1556, PUTN-HENN-1771, PUTN-HENN-1765, PUTN-ESK-1757, and PUTN-BURE-1552 transmission lines.	6/1/2024	$1.8
23676	New Coffeen Solar Interconnection (J1201)	Install one 138 kV terminal in the Coffeen North substation. The terminal will consist of all necessary terminal equipment to connect the J1201 lead line to the Coffeen North substation 138 kV bus. Raise existing Coffeen North-Pana 345kV Transmission line. 44.2 MW solar generator.	6/1/2024	$1.5
23678	New Duck Creek Solar Interconnection (J1199)	Install one 345 kV terminal in the Duck Creek substation. The terminal will consist of all necessary terminal equipment to connect the J1199 lead line to the Duck Creek substation 345 kV bus. Upgrade control and relay fiber panel at the Duck Creek substations as well as the remote end substation.	6/1/2024	$2.5
23982	New Newton Solar Interconnection (J1198)	Install one 345 kV terminal in the Newton substation. The terminal will consist of all necessary terminal equipment to connect the J1198 lead line.	12/1/2025	$1.5
23983	New Bison 345 kV Substation for J1289 Lotus Wind E&P	A 200 MW wind project interconnecting the Ameren Illinois	11/1/2024	$12

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		system along the Turner - Austin 345 kV line.		
24052	New Nile 138 kV Substation for J1208-J1209 Chariot Solar I & II	A 160 MW solar project connecting to a new switching station in Saline County, Illinois.	12/1/2025	$9.25
24133	J1360 Goose Creek Wind PGIA	A 300 MW wind project connecting at the existing Goose Creek substation in McLean County, IL. Install Gas circuit breaker and relocate Rising Line terminal. Newly terminate the Goose Creek-Rising 345 kV transmission line to provide a position for J1360.	6/1/2024	$4.2
24695	New Fauna 345 kV Sub for Flora Solar (J1679)	125 MW solar generation project J1679. Interconnection at Fauna sub on Xenia - Mt Vernon West 345 kV Line 4591.	12/1/2025	$11
24718	New Quotient 345 kV Substation for Casey Fork Solar(J1241)	Construct a new 345 kV Quotient switching station in Jefferson County, IL to provide a Point of Interconnection for the Generating Facility. The new J1241 Interconnection Switching Station will split the existing Xenia – Mt Vernon West 345 kV transmission line.	12/1/2025	$11
24779	New Hoot 138 kV Substation (J1266)	Hoots J1266 Interconnection Switching Station will cut the existing Kinmundy – Salem West 138 kV transmission line.	12/1/2025	$10.5
24780	Fayetteville Bee Hollow Substation (J1311)	The Fayetteville Bee Hollow Substation will be rebuilt to a 4 position (6 position ultimate) 138 kV ring bus to allow J1311 interconnection.	12/1/2025	$8
24781	New Greenwave 138 kV Substation (J1232)	The J1232 Generating Facility will interconnect at the Greenwave substation cutting the Mattoon West-Arland-1539 138 kV Transmission Line.	12/1/2025	$8
24840	New Zeke 345 kV J1263 Interconnection Switching Station	New 345 kV Switching Station on Casey West – Kansas 345 kV for the Generating Facility J1263.	12/1/2025	$10

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24859	Casey West 345 kV- New Position for Union Center Solar(J1204)	A new 345 kV position will be constructed at Casey West Substation to serve as the Point of Interconnection for Union Center Solar, LLC under GIA J1204. The CSYW-NWTY-1 line position will also be moved from the southwest corner of the substation to the southeast corner to avoid line crossing with the IC.	12/1/2025	$1.2
24878	Ashley-IL 138 kV New Position for Ashley Solar (J1216)	This project will tap into the existing Ashley 138 kV 3-position ring bus to serve as the Point of Interconnection for the Interconnection Customer's Generating Facility, Ashley Solar, LLC. The existing ASHL-JORD-1536 138 kV transmission line will be raised to provide adequate space for the new interconnection line. The 138 kV lead line from Ashley Solar, LLC will terminate into the third position.	12/1/2025	$1
24900	Ipava 138 kV New Position (J1383)	Interconnection Facilities shall consist of one 138 kV terminal in the Ipava substation to connect the J1383 lead line.	12/1/2025	$1
24901	Morganfield 138 kV New Position (J1302)	Add 138 kV terminal in the Morganfield substation to connect the J1302 and J1096 lead line to the Morganfield substation.	12/1/2025	$1

4.2.3 Ameren Missouri

After MISO's independent reliability analysis, MISO and Ameren Missouri recommend 30 projects at an estimated cost of $352 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Baseline Reliability Project, 22 are Other Projects, five are Generator Interconnection Projects with signed Generator Interconnection Agreements, and two are Generator Interconnection projects with Provisional Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

P22869 – Rebuild Clark 138/161 kV Substation to 138 kV Breaker and a Half

Project Description: Rebuild Clark 138/161 kV Substation to have a 138 kV BAAH bus with 8 positions (4 existing lines, 2 Transformers, bring in another line) and a 161 kV ring bus with 6

positions (2 existing lines, 2 Transformers, and new line position to Viburnum). The total estimated cost of this project is $44 million and has an expected in-service date of December 1, 2027.

Project Justification: The Mines area transmission network is a 161 kV loop that is supplied by Clark 138/161 kV transformer and Fletcher (AECI) 345/161 kV transformer. The P6 events of losing either transformer combines with certain lines on the loop lead to under voltage issues on 161 kV and distribution buses. This is in violation of TPL-001-4.

Alternatives Considered: There were no alternatives for this project proposal.

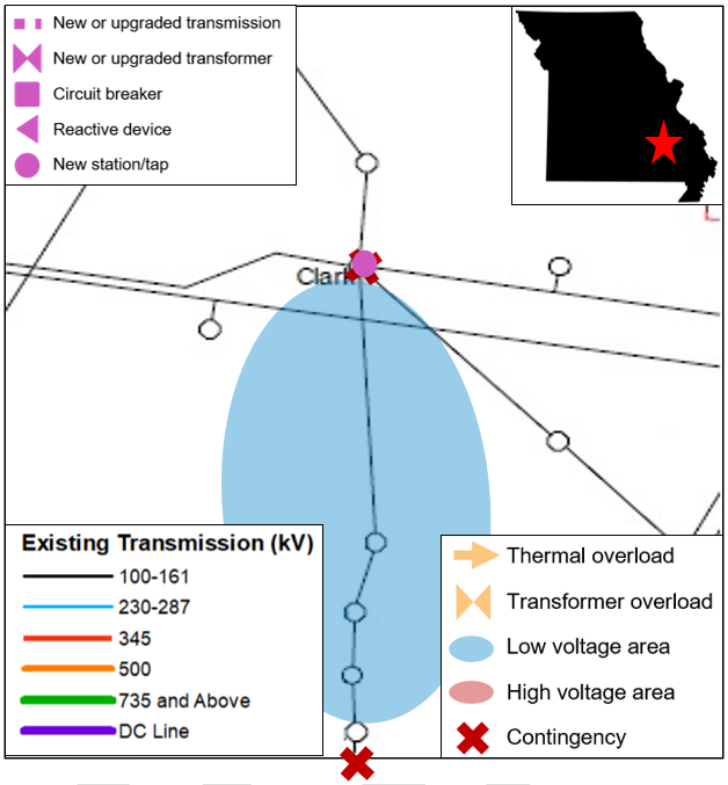


Figure 4.2.3-1: P22869 Geographic transmission map of project area

Cont.Type	Limiting Element	Rating (pu)	Pre-Project Loading (pu)	Post-Project Loading (pu)
P6	[AMMO] Clark 161 kV	0.95	0.9286	0.9975
P6	[AMMO] Viburnum 161 kV	0.95	0.9308	0.9945
P6	[AMMO] Galena 161 kV	0.95	0.9341	0.9938
P6	[AMMO] Buick Mane 161 kV	0.95	0.9341	0.9923
P6	[AMMO] Fletcher 161 kV	0.95	0.9353	0.9869

Table 4.2.3-1: P22869 Project contingency drivers

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22066	Replace Mason 345/138 kV Transformer No. 1	Replace Mason 345/138 kV Transformer #1 with a 700 MVA Unit.	12/1/2026	$7.8
22787	Upgrade Warson 161 kV substation	Line BKRs on 4-line terminals, High Side interrupting devices on XFMRs 1,2,3,4, Add bus tie 2-3 BKR.	12/1/2026	$8
22790	Reconfigure Moreau 161 kV substation	Construct a four position (six ultimate) 161 kV ring bus at Moreau. New name is Jays.	12/1/2026	$8.5
22791	New McBaine 161 kV substation	New switching station at McBaine tap off LYMT-OVRT-3. New name is Katy.	12/1/2026	$14.4
22806	Upgrade Rush Island 345 kV Substation	Upgrade the Rush Island 345 kV bus to 3000A capability.	4/1/2024	$1.5
22814	Upgrade Guthrie 161 kV substation	Add a 161 kV line breaker to the 161 kV GUTH-LYMT-3 line at Guthrie.	12/1/2024	$2
22866	Upgrade St Francois 345 kV substation	Install a new circuit breaker at St. Francois 345 kV Sub position V43 to complete the ring bus. Replace 138 kV breakers. Upgrade relaying.	6/1/2027	$12.7
22870	Reconfigure Mason-Carrollton-Sioux 138 kV lines	Split the ~2-mile Mason-Carrollton-8/Carrollton-Sioux-8 138 kV lines into two separate circuits to avoid the loss of a single structure causing a long-term outage on both Carrollton supplies.	6/1/2025	$5
22873	Upgrade Oran 161 kV substation	Add 161 kV ring bus to split the Kelso-Morley-3 line into two lines.	6/1/2026	$7.8
22890	Upgrade Selma 161 kV substation	Add line breakers to Selma-Rivermines-2 & DPFE-Selma-1. Add High Side Interrupting devices to XFMR 1 & 2.	12/1/2025	$3
22947	Upgrade Lakeshire 138 kV substation	Add line breaker to Pos. J (Baum-Wat-1).	12/1/2025	$3.4
22926	Upgrade Dardenne 161 kV substation	Add line breakers to Dardenne.	12/1/2027	$5
23006	Upgrade Pilot Knob 161 kV substation	Add circuit switcher for XFMR 1 and line breaker for 161 kV FLET –PKNB -2.	12/1/2025	$4
23087	Rebuild Troy-Pike 161 kV line	Add Dual OPGW to the TROY-PIKE-1 Line from Pike to the Auburn tap (Structure 309 or so). Adding OPGW to the TROY-PIKE-1 line	12/1/2024	$16

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		will require the line to be rebuilt. Since the line is being rebuilt, dual OPGW is to be added. At the Auburn tap the OPGW will be terminated to allow a connection to the AECI Fiber on their portion of the TROY-PIKE-1 line and brought the rest of the way to the new Harley Substation.		
23306	Rebuild Stoddard-Essex 161 kV line	Rebuild the 5.4-mile Stoddard-Essex-3 161 kV Transmission Line with T2 conductor rated at 2,000 amps Summer Emergency Conditions and 2 EA 72-Fiber OPGW shield wires.	6/1/2025	$3.3
23351	New Bugle 138 kV Capacitor (120 MVAR)	120 MVAR Capacitor at Bugle.	12/1/2024	$26
23526	Reconfigure Warrenton 161 kV substation	Install a 161 kV Ring bus at Warrenton Substation.	12/1/2024	$15

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23152	New Copley 138-12 kV Substation	Build a new four position 138 kV Ring bus needed to connect two 13/12 kV transformers.	12/1/2024	$20

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22801	Rebuild Sioux-Meppen North-Hull 138 kV line	Rebuild the Sioux-Meppen North-4 from Str. 180-Meppen North and the entire Meppen North-Hull-1494 138 kV line to upgrade aging infrastructure and improve system reliability.	12/1/2026	$77.7
22815	Upgrade Hunter 161 kV Substation	Add line breakers and high side transformer interrupting devices.	12/1/2025	$3
22846	Upgrade Sioux 138 kV substation	Upgrade 15H position to higher ampacity to increase available capacity of the 700MVA Auto Transformer.	12/1/2026	$10.5
22927	Convert Viaduct 115 kV facilities to 161 kV	Convert 115 kV facilities at Viaduct to 161 kV.	12/1/2024	$5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		Eliminate Viaduct 161 to 115 kV transformer T1 by bypassing it, and by changing the taps on Viaduct Transformer 1 from 115 to 161 kV. Replace 115kV OCB #5210 with a 161 kV puffer breaker.		

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22706	New Huck Finn Solar 345 kV	Connect a 200MW solar farm via 345 kV lead line from Interconnection Customer collector substation to existing Spencer Creek switching station.	6/1/2024	$4.2
23388	New Firebrick Wind Farm (J1026)	J1026 is seeking interconnection service for 380 MW for Wind facility. The Connection will be made at the 345 kV Spencer Creek Substation.	6/1/2024	$1.7
23430	New Zachary generation interconnection FCAs (J1025-J1182)	Install a 2nd Zachary 345/161 kV transformer, construct a 2nd Zachary - Adair 161 kV transmission line, and re-route existing Appanoose-Adair 161 kV Transmission line.	12/1/2025	$17
23470	New Northeast Missouri Wind interconnection (J1025)	Construct the new 345 kV Fabius substation in Knox County, Missouri to provide a Point of Interconnection for the Generating Facility with a terminal that will consist of all necessary terminal equipment to connect the J1025 lead line to 345kV Fabius substation bus. J1025 is a 300 MW Wind project interconnecting to the Zachary-Maywood 345 kV liner.	6/1/2024	$11
23500	New Morris Solar interconnection (J1182)	One 345 kV terminal in the Zachary substation. The terminal will consist of all necessary terminal equipment to connect the J1182 lead line to the Zachary substation bus. J1182 is a 250 MW Solar project interconnecting to the Zachary substation 345 kV bus.	11/1/2024	$2.593
24696	New Vanhorn 345 kV Substation for Wolf Creek Solar (J1352)	Construct the Interconnection Facilities at the J1352 Interconnection Switching Station, line cut-in and relay upgrades. Vanhorn sub on Montgomery-Spencer Creek 345 kV line.	6/1/2025	$11

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24860	Bullion 161 kV Add Breaker Position for Kelso 2 Solar (J1299)	This project will construct a new Point of Interconnection for the Interconnection Customer's Generating Facility, Kelso 2 Solar LLC, to the Bullion Switching Station. The 161 kV lead line from Kelso 2 Solar LLC will terminate into the fourth position.	12/1/2025	$1

4.2.4 Big Rivers Electric Corporation (BREC)

After MISO's independent reliability analysis, MISO and Big Rivers Electric Corporation recommend two Other Projects at an estimated cost of $6.2 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23569	New [BREC] McCracken-[GLH] Joppa 161 kV Tie Line	The project will construct one additional terminal at an existing Big Rivers' substation, 2 miles of 161 kV transmission line (Big Rivers owned), and a three-bay switching station (GLH owned). The project will address TPL violations caused by extreme weather and/or a small load increase. In addition to the TPL violation relief and providing needed capacity in the western part of Big Rivers' system, the proposed project will alleviate the need to purchase transmission service from TVA.	7/2/2025	$5.3

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19007	Upgrade Kansas 69 kV line	Create double circuit from existing radial 69 kV tap.	10/1/2024	$0.9

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4.2.5 City of Columbia, MO (CWLD)

City of Columbia, MO, (CWLD) did not submit any new projects for MTEP23. MISO has not identified any issues in CWLD area.

4.2.6 City of Springfield, IL (CWLP)

City of Springfield, IL, (CWLP) did not submit any new projects for MTEP23. MISO has not identified any issues in CWLP area.

4.2.7 Duke Energy Corporation (DEI)

After MISO's independent reliability analysis, MISO and Duke Energy Corporation recommend 33 projects at an estimated cost of $467 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, six are Baseline Reliability Projects, 23 are Other Projects, and four are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 23406 - Upgrade [DEI] Bedford 138 kV Bus 9

Project Description: The project will upgrade [DEI] Bedford 138 kV Bus 9. This upgrade will mitigate the overload on the [DEI] Bedford - [DEI] Bedford bus section #3 138 kV line for P6-1-1 NERC defined contingency events of Bulk Electric System (BES) elements. The total estimated cost of this project is $0.53 million and has an expected in-service date of June 1, 2027.

Project Need: The [DEI] Bedford - [DEI] Bedford bus section #3 138 kV line becomes overloaded to one hundred two (102%) percent in year 2024 for a NERC defined category P6-1-1 contingency event of BES elements. Upgrading [DEI] Bedford 138 kV Bus 9 will increase the summer emergency rating of the line from 301 MVA to 511 MVA.

Alternatives Considered: No other alternatives considered; this breaker replacement project is the best and cheapest option to address this reliability issue.

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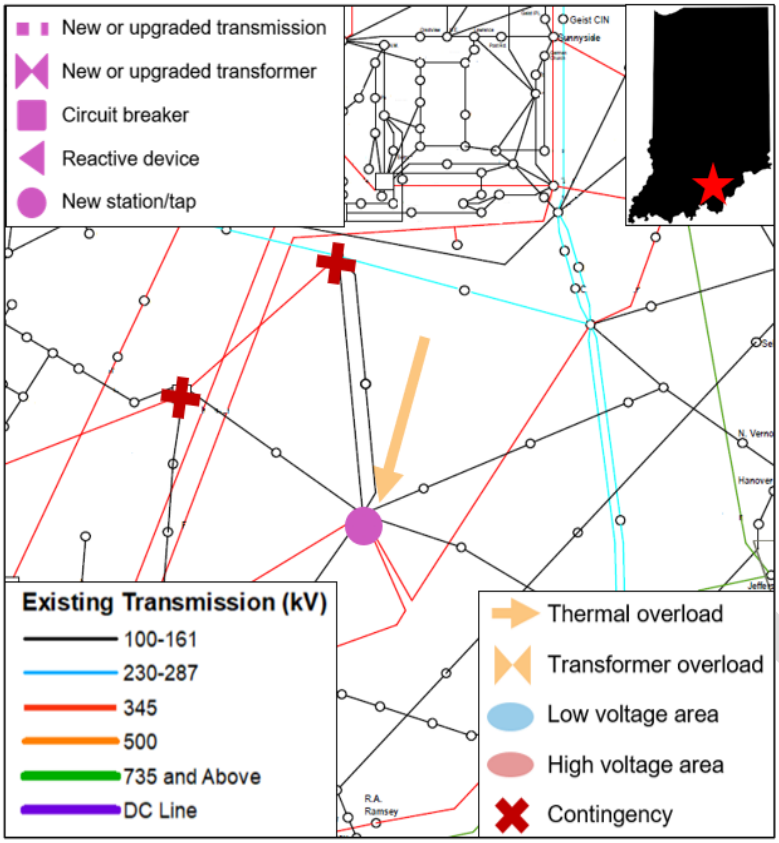


Figure 4.2.7-1: P23406 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project (post-cont.) Loading (%)	Post-project (post-cont.) Loading (%)
P6	[DEI] Bedford—[DEI] Bedford bus section #3 138 kV line	511	99	51

Table 4.2.7-1: P23406 Thermal loading drivers

Project 23407 – Upgrade [DEI] Bloomington 230 – Bk1 138 kV Bus

Project Description: The project will upgrade the [DEI] Bloomington 230/138 kV transformer. This upgrade will mitigate the overload on the [DEI] Bloomington 230/138 kV transformer for P6-1-1 contingency events of BES elements. The total estimated cost of this project is $0.39 million and has an expected in-service date of June 1, 2024.

Project Need: The [DEI] Bloomington 230/138 kV transformer becomes overloaded to one hundred five (105%) percent in year 2024 for a NERC defined category P6-1-1 contingency event. Upgrading [DEI] Bloomington 230/138 kV transformer will increase the summer emergency rating of the transformer from 151 MVA to 165 MVA.

Alternatives Considered: No other alternatives considered; this breaker replacement project is the best and cheapest option to address this reliability issue.

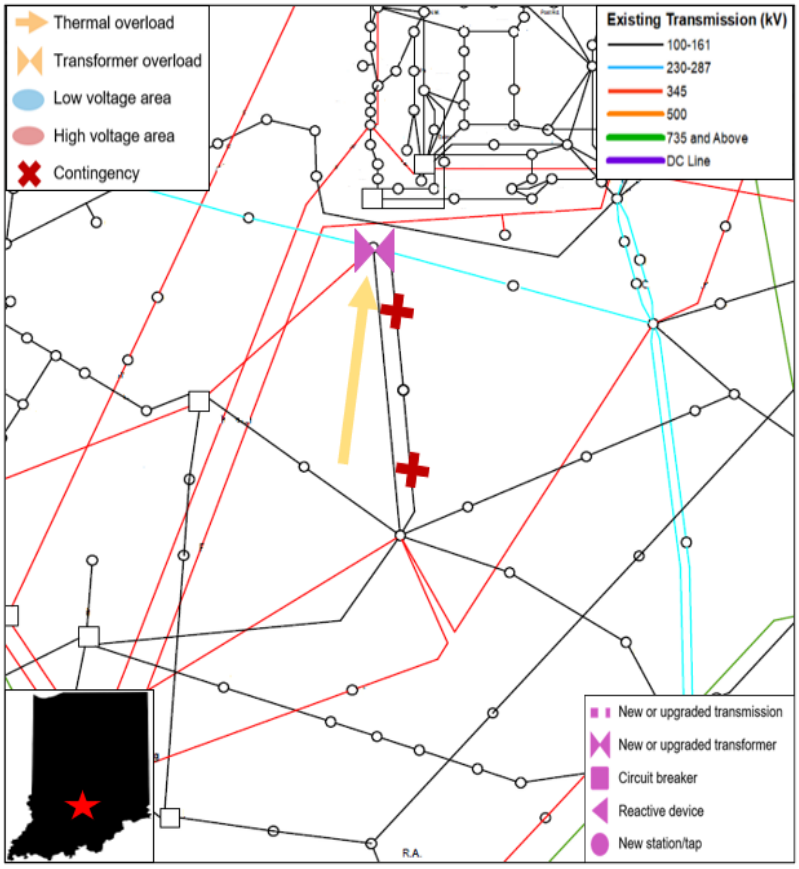


Figure 4.2.7-2: P23407 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	[DEI] Bloomington 230/138 kV transformer	165	100	91

Table 4.2.7-1: P23407 Thermal loading drivers

Project 23861 – Upgrade [DEI] Columbus 345 kV Substation Breakers

Project Description: The project will replace (3) 138 kV Circuit Breakers on transformer Banks 1, 2, and 3 with higher fault interrupting capacity at [DEI] Columbus 345 kV substation. The total estimated cost of this project is $1.5 million and has an expected in-service date of December 31, 2026.

Project Need: These Circuit Breakers were identified in the annual DEI 2022 short circuit study for replacement/upgrade as required by TPL 001-4.

Alternatives Considered: No alternatives were considered.

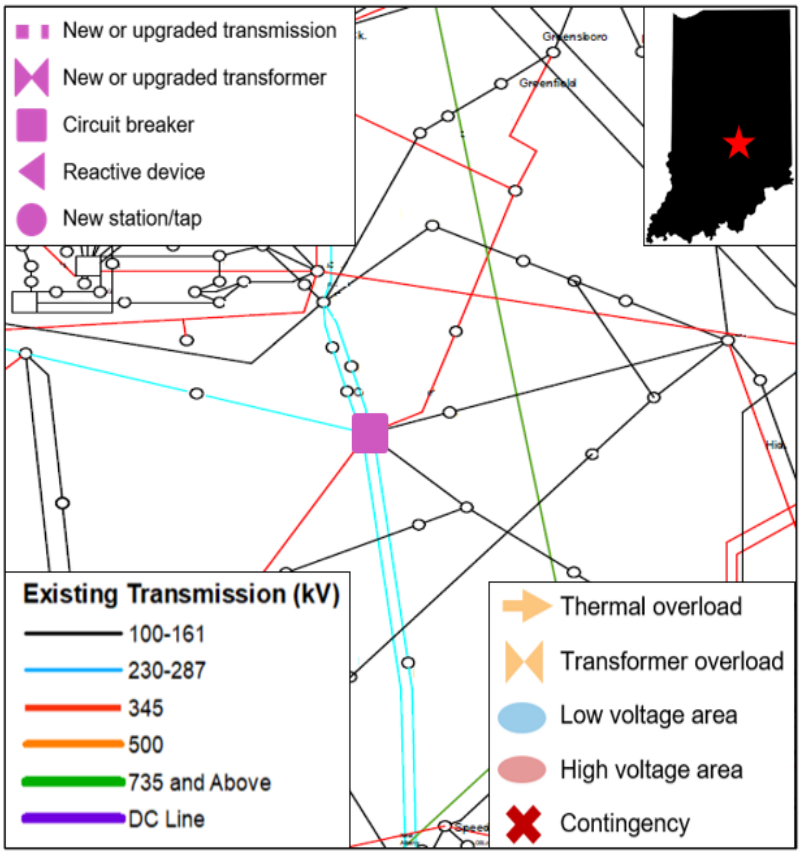


Figure 4.2.7-4: P23861 Geographic transmission map of project area

Project 23862 – Upgrade [DEI] Bedford 345 kV Sub – 138-138 Bus Tie line

Project Description: The project will Upgrade [DEI] Bedford 345/138 kV Bus Tie line. This upgrade will mitigate the overload on the [DEI] Bedford to [DEI] Bedford bus section #2 138 kV line for P6-1-1 contingency events of BES elements. The total estimated cost of this project is $0.7 million and has an expected in-service date of April 1, 2032.

Project Need: The [DEI] Bedford bus section #1 to [DEI] Bedford bus section #2 138 kV line becomes overloaded to one hundred one (101%) percent in year 2032 for a NERC defined category P6 contingency event. Upgrading this line section will increase the summer emergency rating of the line from 573 MVA to 747 MVA.

Alternatives Considered: No other alternatives were considered. This new substation project is the best and cheapest option to address these reliability issues.

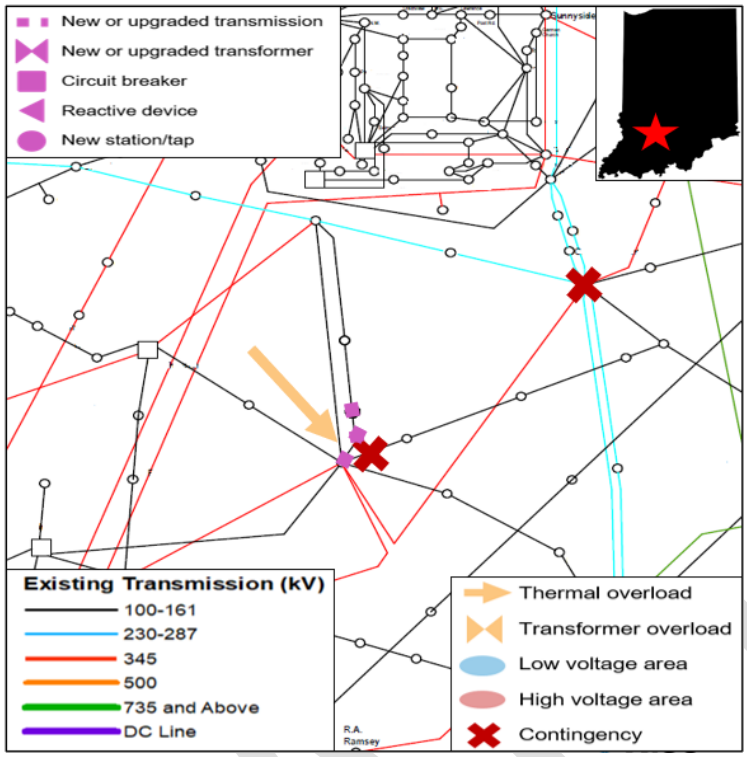


Figure 4.2.7-5: P23862 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project Loading (%)	Post-project Loading (%)
P6	[DEI] Bedford bus section #1 – [DEI] Bedford bus section #2 138 kV line	747	97	69

Table 4.2.7-5: P23862 Thermal loading drivers

Project 23863 – Upgrade [DEI] Cayuga to [DEI] Nucor 345 kV line

Project Description: The project will Upgrade [DEI] Cayuga to [DEI] Nucor 345 kV line. This upgrade will mitigate the thermal overload on the [DEI] Cayuga to [DEI] Nucor 345 kV line for P6-1-1 contingency events of BES elements. The total estimated cost of this project is $0.32 million and has an expected in-service date of April 1, 2027.

Project Need: The MTEP23 result shows the overload on [DEI] Cayuga to [DEI] Nucor 345 kV line to one hundred one (101%) percent in year 2027 for a NERC defined category P6 contingency event. Upgrading [DEI] Cayuga to [DEI] Nucor 345 kV line will increase the summer emergency rating of the line from 1279 MVA to 1374 MVA.

Alternatives Considered: No other alternatives were considered. This new substation project is the best and cheapest option to address these reliability issues.

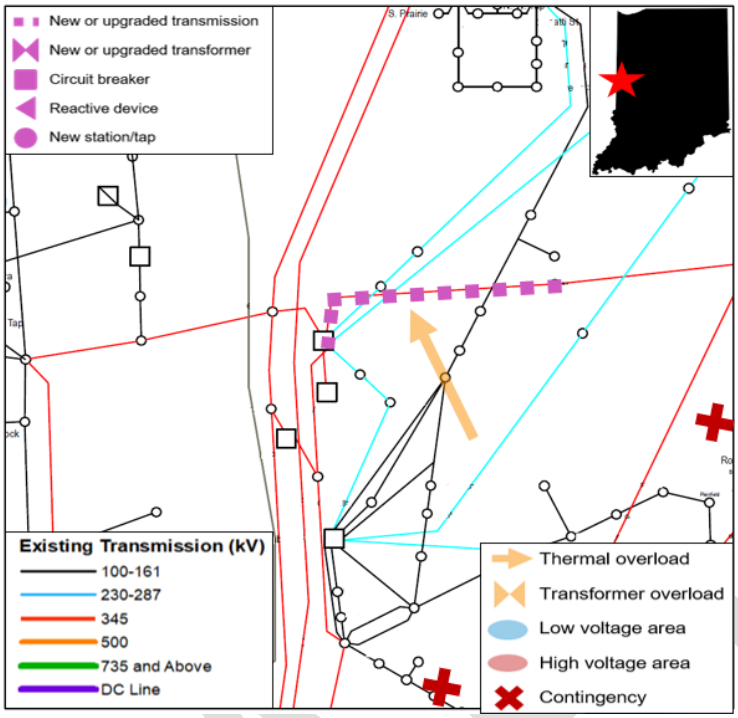


Figure 4.2.7-6: P23863 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project Loading (%)	Post-project Loading (%)
P6	[DEI] Cayuga – [DEI] Nucor 345 kV line	1374	98	93

Table 4.2.7-6: P23963 Thermal loading drivers

Project 23864 – [DEI] New Bloomington Area 138 kV Source

Project Description: The project will Construct a new [DEI] Bloomington 345/138 kV substation on the west side of Bloomington with one 138 kV line to [DEI] Bloomington Rogers St. This New Substation will mitigate multiple thermal overloads serving [DEI] Bloomington area for multiple P6-1-1 contingency events of BES elements. The total estimated cost of this project is $44.5 million and has an expected in-service date of June 1, 2028.

Project Need: MTEP23 results showed BES facilities serving the Bloomington area are overloaded beyond one hundred (100%) percent for multiple TPL contingency events. New Bloomington Area 138 kV Source will reduce the overload on these BES lines and transformers during the summer peak season.

Alternatives Considered: No other alternatives were considered. This new substation project is the best and cheapest option to address these reliability issues.

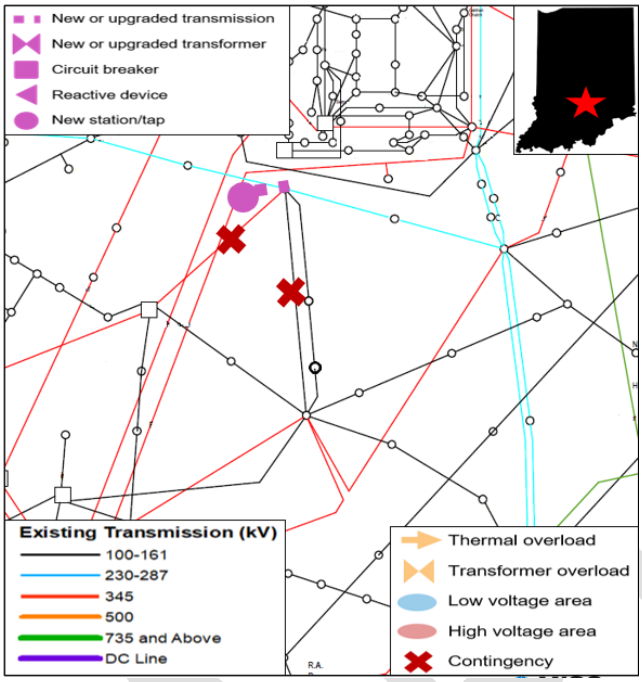


Figure 4.2.7-6: P23864 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project Loading (%)	Post-project Loading (%)
P6	[DEI] Bedford – [DEI] Harrodsburg 138 kV line	243	98	57
P6	[DEI] Bloomington Rogers St – [DEI] Bloomington Rockport Road 138 kV line	198	103	53
P6	[DEI] Bloomington Rockport Rd - [DEI] Bedford bus section #3 138 kV	198	109	58
P6	[DEI] Bloomington 230/138 kV transformer	151	111	48
P6	[DEI] Bloomington – [DEI] Bloomington NW 138 kV line	151	106	44

Table 4.2.7-6: P23864 Thermal loading drivers

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23833	New Edinburgh Industrial Park 69/12 kV sub	DEI to construct high-side and loop 69 kV lines into a new IMPA-owned Edinburgh Industrial Park substation; one 69/12 kV 20MVA transformer;	6/1/2025	$4.6

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		SCADA controlled MOLB 69 kV line switches; two 69 kV buses with a manually operated 69 kV bus tie switch; 69 kV connections from the 6950 and 69146 circuits.		
23848	Rebuild WVPA Montclair to Montclair Jct. 69 kV	WVPA Montclair to Montclair Jct. 69134 69 kV Rebuild: rebuild 69 kV line section.	12/18/2023	$8.9
23850	Rebuild WVPA Lee Hanna to Lee Hanna Jct 69 kV (Phase 3)	Rebuild 5.6 miles of 69 kV to match line conductor for Fortville to Mohawk line. (954 ACSR)	10/31/2023	$3.3
23868	New WVPA IPC to 69162 Tap loop 69 kV	Build 69 kV from IPC to 69162 Tap 2.8 miles. Add 2 ATO switches at IPC tap & 3 switches at 69162 line tap. 90 amps minimum. 477 ACSR.	12/31/2023	$6
23892	Rconfigure Shelbyville Northeast 138 kV Ring bus	Shelbyville Northeast: build 138 kV ring bus; replace CIR 6946, 6976, 69183, 13803, 13865 relays, replace OCBs 6946, 6976, 69183, 69138-1, 13803, replace Bank 1 ground switch with circuit switcher, and station battery.	6/30/2026	$10.8
23923	New WVPA Vandalia 69/12 kV Substation	Vandalia (Fillmore) Substation - Incorporate SCADA operated 69 kV flow-through switches into 6996 line between Greensboro and Amo.	7/15/2024	$5.5
23962	Rebuild 6958 Line 69 kV for FAA	6958 Line Rebuild as required by FAA - Rebuild 39 Structures and replace conductor from HE Whitehall to structure 815-1069-01. Replace individual poles 815-1060 and 815-1061. Install monitored FAA warning lights on 37 of the poles. Install 36 marker balls on the static wire.	6/1/2025	$3.4
23966	Reconfigure Greensburg 138 kV Ring Bus	Greensburg 138 kV expand sub and reconfigure to (4) breaker ring bus.	6/1/2023	$5.9
23970	Rebuild 69100 Greensfork to HE Jacksonburg Jct 69 kV	Rebuild 69100 from Greensfork #1 switch (pole #862-3176) to Jacksonburg Jct switch (pole #862-3074) using light duty steel poles, 477ACSR and OPGW.	10/9/2025	$10.8
23978	New Bargersville North 69 kV Switching Station	Build new Bargersville North 69 kV three breaker ring bus switching station in the 69102 line.	12/31/2025	$11.7

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23979	New Trafalgar 69 kV Ring Bus	Convert the existing Trafalgar 69 kV switching station to a three-breaker ring bus.	3/3/2026	$10
23980	New Glenwood West 10.5MVA 69/12 kV Sub	Glenwood West (new) - Install 10.5MVA, 69-12kV non-LTC transformer; build/re-route the existing 6920 line to loop through the new substation with ATO/TLS switches.	12/29/2023	$1.4
23981	New Saint Paul Northwest 10.5MVA 69/12 kV Sub	Saint Paul Northwest (new) - Install 10.5MVA, 69-12 kV non-LTC transformer; build/re-route the existing 6937 line to loop through the new substation with ATO/TLS switches	11/6/2025	$1.4

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23867	Rebuilding WVPA Anderson Grain 69/12 kV Sub	Relocate transmission and add in&out with SCADA switches for new Anderson Grain substation. Install 69 kV circuit switcher and relaying for high side protection.	8/7/2024	$1.75
23922	Rebuild WVPA Bringhurst 69/12 kV Sub	Rebuild Bringhurst 69/12 kV substation. 4.5MVA loading on 6.25MVA existing bank. Possibly bring #1 & #2 sectionalizing line switches inside of substation for an in&out. WVPA owns the loop through portion of the substation.	4/3/2024	$5.8
23953	Rebuild WVPA Greencastle 69/12 kV Substation	Rebuild the existing 69-12.47 kV Greencastle Substation with 69 kV flow-through in another location due to size of site. Replace bank with 14.4 MVA.	5/31/2024	$4.83
23965	Replace 13832 Line Structure 138 kV	Replace 14 structures in the 13832 line: 849-2103 thru 2106, and 849-2113 thru 2122	5/1/2024	$2.57

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Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23871	New WVPA NSC Lick Creek 69/12 kV Sub.	Build new WVPA NSC (Ninestar Connect) Lick Creek substation; Install 22.4MVA 69/12 kV sub with 3-way switches at line jct.; preliminary plan is to be fed from the 69198 circuit.	10/31/2026	$6.9
23925	New Slugger 138 kV Load	Project Slugger - large new customer load - early phases to be served from 138 kV system followed by 345/138 kV transformation as load projections increase.	12/31/2029	$123.5
23964	New Kokomo Fusion 230/69 kV Sub	Kokomo Project Fusion new 230/69 kV substation for large new customer load: inserted in the 23022 circuit. with 4-CB ring (between Greentown and Kokomo Webster St.); (2) 150MVA -230/69 kV transformers; (14) 69 kV breakers in a breaker and one-half layout; loop 69172 circuit. (Between Kokomo East and Kokomo Chrysler North) through new sub; also loop the 69174 circuit. (Between Kokomo Touby Pike Tap 1 and Chrysler North Jct.); (3) 60MVA - 69/34.5 kV transformers .	6/1/2025	$92.1
23968	New Greensfork East 69/12 kV Sub	Greensfork East new 69/12 kV - 22.4MVA Sub: looped-through feed from 69100 circuit.	8/8/2028	$1.4
23969	New Williamsport 69/12 kV Sub	Williamsport new 69/12 kV - 22.4MVA sub: looped-through feed from the 6936 circuit.	10/2/2026	$3.2

Projects Driven by Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
3382	Vincennes Vigo St. 138 kV Dist Sub	Build new radial 138 kV line and add breaker at Vincennes 138 kV sub to convert Vigo St. sub from 34 kV to 138 kV.	7/14/2026	$10.9

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Generator Interconnection Projects:

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23886	New J1234 - J1235 IN Solar 1	J1234 - J1235 IN Solar 1 – 150 MW net solar farm (100 MW for J1234 and 50 MW for J1235).	12/31/2023	$17.2
23887	J1378 Crossroads Solar	J1378 Crossroads Solar – 200 MW: 230 kV connection at existing Veedersburg West sub.	11/15/2024	$6
23963	Rebuild 6932 Potato Creek to Thorntown 69 kV	6932 Rebuild Potato Creek to Manson Jct to Clarks Hill to Thorntown with 954ACSR conductor.	5/17/2024	$41.8
23967	J1295 Gibson Solar	J1295 Gibson Solar farm 280 MW +/- w/ 345kV POI between Gibson and Francisco in circuit 34516 (3-breaker ring); Includes required relay work at Gibson.	6/1/2024	$17.7

4.2.8 GridLiance Heartland LLC (GLH)

After MISO's independent reliability analysis, MISO and GridLiance Heartland LLC recommend three Other Projects at an estimated cost of $59.7 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23827	New 3-breaker ring bus substation	Build new 3-breaker ring bus switching station near Heath, KY bisecting Joppa - Shawnee 161 kV circuit 1 line with one terminal for connection with Big Rivers Electric McCracken station. Additionally, add 1-161 kV breaker at Joppa TS station and remove existing Joppa - Joppa TS - Shawnee 161 kV circuit 1 three terminal in Illinois by bringing line in and out of Joppa TS station.	12/31/2026	$15.9

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Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23765	Rebuild Joppa-Joppa TS-Grahamville 161 kV line (854)	Rebuild the GridLiance Heartland portion of Joppa - Joppa TS - Grahamville 161 kV circuit 854 three terminal line.	12/31/2026	$21.9
23826	Rebuild Joppa - Grahamville 161 kV line (804)	Rebuild the GridLiance Heartland portion of Joppa - Grahamville 161 kV circuit 804 line.	12/31/2026	$21.9

4.2.9 Henderson Municipal Power & Light (HMPL)

After MISO's independent reliability analysis, MISO and Henderson Municipal Power & Light recommend one Other Project at an estimated cost of $0.16 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24172	Re-route HMPL Sub 4 to HMPL Sub 4 Tap 161 kV Transmission Line	HMPL to reroute the HMPL Sub 4 to HMPL 4 Tap 161 kV transmission line due to BREC Pratt Paper Project. HMPL is required to proceed with engineering/construction of the affected transmission line to meet BREC project schedule.	7/1/2023	$0.16

4.2.10 Hoosier Energy REC, Inc. (HE)

After MISO's independent reliability analysis, MISO and Hoosier Energy REC, Inc. recommend one joint Other Project with AMIL and SIPC at an estimated cost of $167.9 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023. Further details are provided in Section 4.2.2 Ameren Illinois.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23026	New South Central Illinois Transmission Expansion	Construct a new 138 kV substation as an ultimate six-position ring bus requiring one 3000 A 138 kV breaker	12/1/2025	$167.9

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		initially adjacent to the Continental Tire facility. Construct a ~3.5-mile 138 kV line from Mt. Vernon 42nd St. to the new substation ~0.3 miles NE of the Continental Tire facility with minimum 2000 A summer emergency capability. Add a new 3000 A 138 kV breaker at Mt. Vernon 42nd St. for this new 138 kV line position.		

4.2.11 Indianapolis Power & Light Company (IPL)

After MISO's independent reliability analysis, MISO and Indianapolis Power & Light Company recommend 11 projects at an estimated cost of $161 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, two are Baseline Reliability Projects, seven are Other Projects, and two are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects:

Project 23568 – Replace [IPL] Southwest 138 kV #16 Breaker

Project Description: The project will replace one (1) #6 breaker at [IPL] Southwest 138 kV. The total estimated cost of this project is $0.9 million and has an expected in-service date of December 31, 2025.

Project Need: Breaker fault violation at [IPL] Southwest 138 kV for outages of BES elements were identified in the annual IPL 2022 short circuit study for replacement/upgrade as required by TPL 001-4.

Alternatives Considered: No other alternatives were considered.

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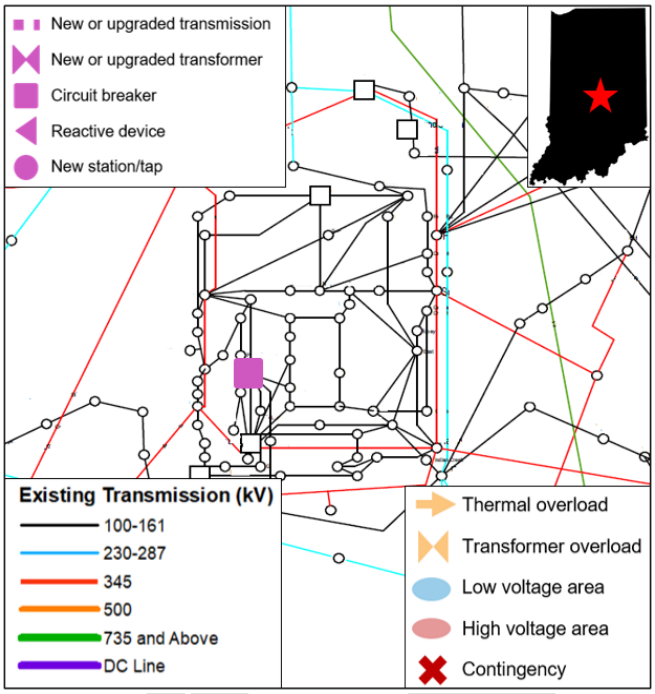


Figure 4.2.7-6: P23568 Geographic transmission map of project area

Project 23825 – Reconfigure Rockville 138 kV Substation

Project Description: The project will convert [IPL] Rockville 138 kV Substation to a ring bus configuration. This substation reconfiguration will mitigate multiple thermal overloads for spare equipment contingency events of BES elements. The total estimated cost of this project is $8.5 million and has an expected in-service date of December 1, 2024.

Project Need: The BES buses become overloaded beyond one hundred (100%) percent in year 2024 for unavailability of Long-Lead Time equipment of [IPL] Thompson Substation autotransformer in combination with Internal Breaker Fault at [IPL] Rockville Substation. Reconfiguring the [IPL] Rockville 138 kV Ring Bus will reduce the overload on the BES lines during the summer peak season.

Alternatives Considered: Purchase of a spare autotransformer for Thompson Substation; Reconductor AES Indiana 138 24 Mooresville to Eagle Valley Transmission. This alternative was not selected, because Reconfiguring Rockville 138 kV substation to ring bus configuration was cheaper than purchasing spare autotransformer and reconductoring the transmission line.

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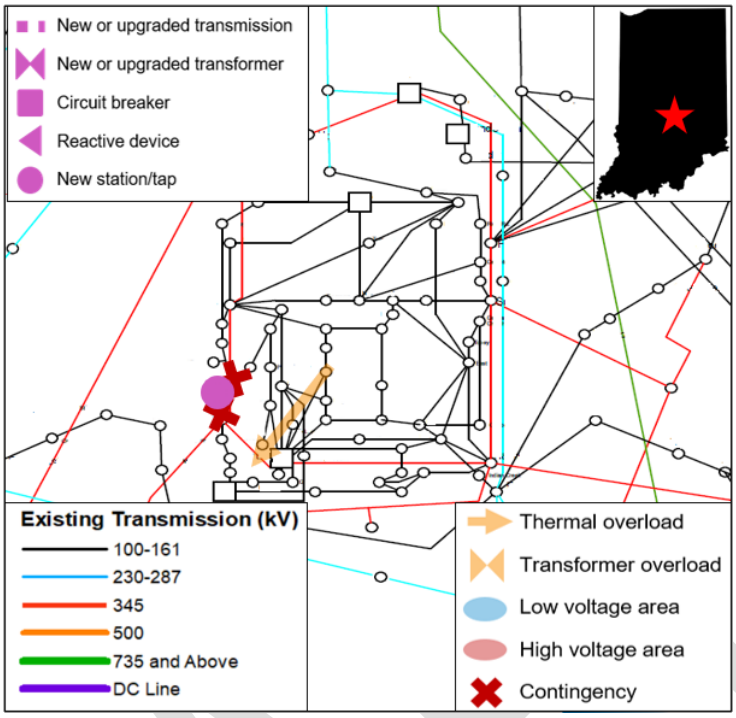


Figure 4.2.7-6: P23825 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project Loading (%)	Post-project Loading (%)
Spare Equipment	[IPL]Heartland Crossing Tap – [IPL] Eagle Valley 138 kV line	242	106	57
Spare Equipment	[IPL]Heartland Crossing Tap – [IPL] Mooresville 138 kV line	242	103	54

Table 4.2.7-6: P23825 Thermal loading drivers

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23766	New IU Health Substation 138 kV	New 138 kV, two 40 MVA transformer, three-breaker straight bus substation to serve customer load.	12/31/2023	$15
23831	New Gillette 138 kV Substation	New 138 kV, two 40 MVA transformer, three-breaker straight bus substation to serve customer load.	11/1/2024	$15

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23832	New 138/13.2 Transformer at Thompson Substation	One new 138/13.2 kV 40 MVA distribution transformer with one new 138 kV breaker.	11/1/2023	$16
23834	New Valley Avenue 138 kV Substation	New 138 kV, two 40 MVA transformer, three-breaker straight bus substation to serve customer load.	12/31/2024	$15
23893	New Winding Ridge 138 kV Substation	New 138 kV, two 40 MVA transformers, 8 breaker, breaker and a half substation to serve AES-IPL customer load and provide transmission service to TOs whom have requested as such.	12/31/2024	$15
24273	New – 138 kV - Airtech Substation	New 138 kV, two 20 MVA transformer, three-breaker substation.	12/31/2026	$10.7
24293	New - 138 kV - New Pleasant Acres Substation	New 138 kV, two 40 MVA transformers, 4 breaker, ring bus substation to serve WVPA load.	12/31/2025	$10

Generation Interconnection Projects:

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23107	New J993 Brickyard Solar 345 kV	Interconnection Customer shall install a 217 MVA solar facility.	12/1/2023	$20
23852	New Petersburg Energy Center 138 kV (R1011)	Interconnection Customer shall install a 279.45 MVA generator facility.	12/31/2025	$35

4.2.12 Northern Indiana Public Service Company (NIPSCO)

After MISO's independent reliability analysis, MISO and Northern Indiana Public Service Company recommend five projects at an estimated cost of $97.3 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, two are Baseline Reliability Projects and three are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects:

Project 23471 – Upgrade [NIPS] Roxana to [NIPS] Mittal 138 kV Line

Project Description: The project will Upgrade [NIPS] Roxanna to [NIPS] Mittal Steel Indiana Harbor West 138 kV line. This upgrade will reconduct two miles of [NIPS] Roxanna to [NIPS] Mittal 2 138 kV line. The upgrade will mitigate the overload on [NIPS] Roxanna to [NIPS] Mittal Steel Indiana Harbor West 138 kV line for multiple events of BES elements. The total estimated cost of this project is $5.65 million and has an expected in-service date of May 31, 2025.

Project Need: The [NIPS] Roxanna—[NIPS] Mittal Steel Indiana Harbor West 138 kV line becomes overloaded to one hundred twenty-five (125%) percent in year 2024 for multiple NERC defined contingency events. Upgrading The [NIPS] Roxanna—[NIPS] Mittal Steel Indiana Harbor West 138 kV line will increase the summer emergency rating of the line from 158 MVA to 286 MVA.

Alternatives Considered: No alternatives were considered.

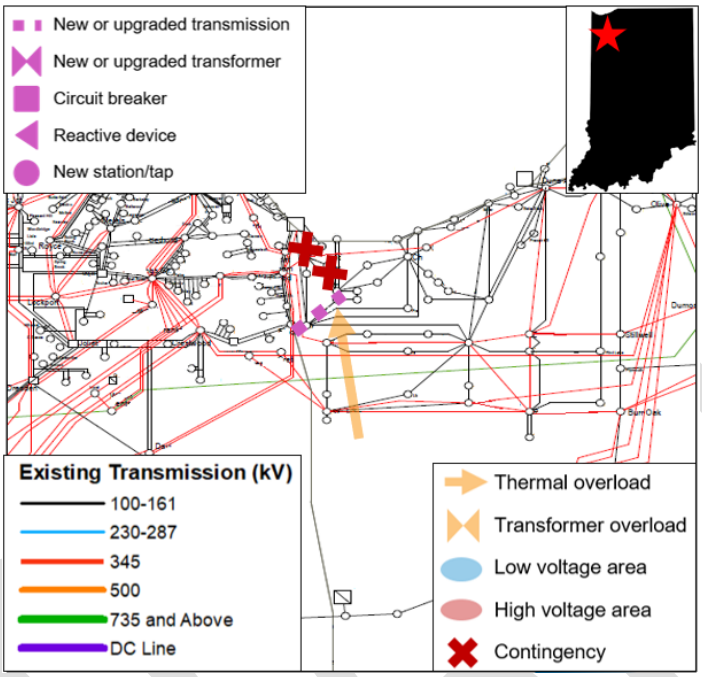


Figure 4.2.7-6: P23471 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project Loading (%)	Post-project Loading (%)
P6	[NIPS] Roxanna – [NIPS] Mittal Steel Indiana Harbor West 138 kV line	286	124	76

Table 4.2.7-6: P23471 Thermal loading drivers

Project 23472 – Upgrade [NIPS] Leesburg Substation 138 kV

Project Description: The project will Upgrade [NIPS] Leesburg 138 kV Substation. This upgrade will eliminate common breaker at [NIPS] Leesburg 138 kV Substation. The upgrade will mitigate the overload on [NIPSCO] Goshen Junction to [NIPSCO] Forrest G. Hiple 138 kV line for NERC defined P2-3 contingency events of BES elements from MTEP22. The total estimated cost of this project is $2.4 million and has an expected in-service date of December 31, 2026.

Project Need: Voltage drops in multiple BES buses and thermal overload on [NIPSCO] Goshen Junction to [NIPSCO] Forrest G. Hiple 138 kV line to one hundred sixteen (116%) percent in year 2027 for P2-3 NERC defined contingency events. Upgrading [NIPS] Leesburg 138 kV Substation will address the voltage drops and thermal overloads caused by P2-3 contingency events.

Alternatives Considered: No alternatives were considered.

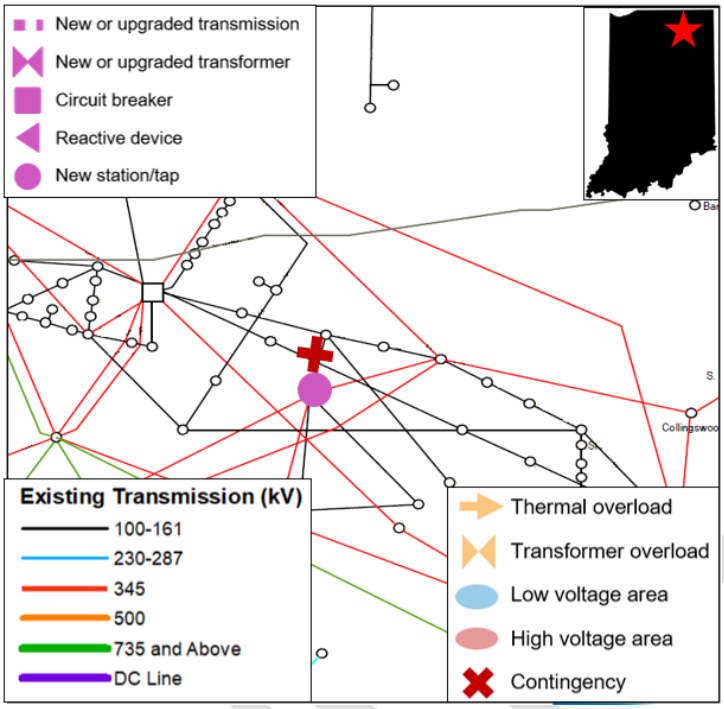


Figure 4.2.7-6: P23472 Geographic transmission map of project area

Cont. Type	Limiting Element	Summer Emergency Rating (MVA)	Pre-project Loading (%)	Post-project Loading (%)
P2-3	[NIPS] Goshen junction – [NIPS] Forrest G. Hiple 138 kV line	253	127	44
P2-3	[NIPS] Kosciusko – [NIPS] Leesburg 138 kV line	138	102	42

Table 4.2.7-6: P23472 Thermal loading drivers

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-project Voltage (pu)	Post-project Voltage (pu)
P2-3	[NIPS] Kosciusko 138 kV bus	0.9	0.87	1.00
P2-3	[NIPS] Leesburg 138 kV bus	0.9	0.89	1.00

Table 4.2.7-6: P23472 Voltage drivers

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22809	J1058 Network Upgrades 345 kV	New Substation (Dinwiddie) and 345 kV line to Connect J1058 to NIPSCO's Schahfer to St. John line.	6/1/2025	$24.1
24032	Upgrade J1482 Network 138 kV	138 kV substation and line work to connect J1482 to Springboro to Monticello 138 kV line.	5/1/2024	$17.9
24562	J1333 -J1340 Network Upgrades	Greenfield 345 kV double breaker double bus station named Hinshaw.	6/1/2024	$47.3

4.2.13 Pioneer Transmission, LLC

Pioneer Transmission, LLC did not submit any new projects for MTEP23. MISO has not identified any issues in the Pioneer Transmission area.

4.2.14 Prairie Power, Inc. (PPI)

After MISO's independent reliability analysis, MISO and Prairie Power, Inc. recommend eight Other Projects at an estimated cost of $70.4 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19947	New Allen - Mason City 69 kV Line	New Allen-Mason City 556 ACSR 69 kV Line in MEC.	12/31/2027	$6.37
19948	New Mason City - Middletown 69 kV Line	New Mason City-Middletown 556 ACSR 69 kV Line in MEC.	12/31/2027	$9.2
23350	New Forest City - Allen Tap 69 kV Line	New Forest City-Allen Tap 556 ACSR 69 kV Line in MEC.	12/31/2027	$2.88
23427	New Disco - Carthage 69 kV Line	New Disco-Carthage 336 ACSR 69 kV line in WIEC.	12/31/2026	$8.32
23428	New Golden - Denver 69 kV Line	New Golden-Denver 336 ACSR 69 kV line connecting AEC to WIEC.	12/31/2026	$12.8

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23429	Upgrade Fieldon 69 kV Substation	Two new motor-operated SCADA-controlled switches on the Hardin Tap to Eldred 69 kV line.	7/1/2023	$0.1
23532	New Pleasant View-Ishi 69 kV Line	New Pleasant View to Ishi 69 kV line in SEC. This line has three-line segments: 1) New Pleasant View to Moweaqua 336 ACSR 69 kV 3.6-mile Line. 2) New Moweaqua to Yantisville 336 ACSR 69 kV 18-mile Line. 3) New Yantisville to ISHI 336 ACSR 69 kV 7.6-mile Line and 1 mile rebuild.	12/31/2029	$23.5

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23567	Rebuild Pearl – Kampsville 69 kV Line	Rebuild Pearl-Kampsville 69 kV line in IEC from 4/0 to 336.4 ACSR.	12/31/2029	$7.29

4.2.15 Republic Transmission, LLC (RTx)

Republic Transmission did not submit any new projects for MTEP23. MISO has not identified any issues in the area.

4.2.16 Southern Indiana Gas & Electric Company (SIGE)

After MISO's independent reliability analysis, MISO and Southern Indiana Gas & Electric Company recommend seven Other Projects at an estimated cost of $37.1 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23751	Replace Maryland 69/12 kV T1 and New 69/12 kV T2 transformers	Replace existing 69/12 kV distribution T1 at Maryland due to age and add new 69/12 kV T2 for	12/31/2024	$3.9

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		distribution system contingency support.		
23757	New Garvin 69/12 kV Transformer	Add second 69/12 kV distribution transformer to provide distribution system support and contingency.	12/31/2024	$2.5
23758	New Bergdolt 138/12 kV Transformer	Add second 138/12 kV distribution transformer at the Bergdolt sub to provide distribution system and contingency support.	12/31/2024	$2.5

Projects Driven by Local Need

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23748	Rebuild Y74-1 NE – Modification 69 kV	Rebuild ~1.75 miles of 69 kV line to increase rating for local operational flexibility and contingency support.	12/31/2024	$0.71

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23749	Rebuild Y39 Cato - Winslow 69 kV	Rebuild ~9.5 miles of 69 kV due to aging infrastructure and pole condition (conductor size not changing).	12/31/2024	$14.13
23755	Replace Point Dist. 69/12 kV Transformer	Replace existing 69/12 kV distribution transformer due to age and condition.	12/31/2024	$12.26
23756	Replace Yankeetown 69/12 kV Transformer	Replace existing 69/12 kV distribution transformer T1 due to age and condition.	12/31/2024	$1.1

4.2.17 Southern Illinois Power Cooperative (SIPC)

Southern Illinois Power Cooperative did not submit any new projects for MTEP23. MISO has not identified any issues in the SIPC area.

4.2.18 Wabash Valley Power Association, Inc. (WVPA)

After MISO's independent reliability analysis, MISO and Wabash Valley Power Association, Inc. recommend six Other Projects at an estimated cost of $57.1 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
21927	New Kinsey 69/12 kV Substation	Construct New Kinsey 69/12 kV Substation (5/7 MVA). (Within AmerenMO location by TO).	2/6/2025	$1.2
21928	New Valley View-Salem Bulk 69 kV line	Construct New Valley View-Salem Bulk 69 kV line. Construct 69 kV from Salem Bulk 69 kV Substation to Kinsey substation. Construct with 477 kcml ACSR, 21 miles total. (Within AmerenMO location by TO).	2/6/2025	$44.52
23715	New Charmin Bulk 161 kV Sub. Breakers	Add breakers to Charmin Bulk to have two separate 161 kV feeds from Trail of Tears.	2/28/2024	$4.49
23780	Relocate T23 69 kV for Ameren Wittenberg-Whipple Line	Relocate T23 69 kV to allow for Ameren's new 138 kV Line (Wittenberg - Whipple).	12/31/2023	$4.59

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23714	Rebuild Citizens 69 kV Line (Groups C & E)	Rebuild 69 kV line group on CEC 69 kV System - Phase 2.	12/31/2024	$0.68
23779	Rebuild Citizens 69 kV Line (Groups A & B)	Rebuild 69 kV line group on CEC 69 kV System - Phase 1.	12/31/2023	$1.6

4.3 Project Justifications – East Region

East Region Overview

The MISO East Planning Region consists of six Transmission-Owning members within Michigan. These Transmission Owners are:

ITC Transmission (ITCT)

Michigan Electric Transmission Co. (METC)

Wolverine Power Supply Cooperative Inc. (WPSC)

Michigan Public Power Agency (MPPA)

Michigan South Central Power Agency (MSCPA)

Lansing Board of Water & Light (LBWL)

The region contains 9,830 circuit miles of transmission lines ranging from 120 kV to 345 kV. It also contains 1216 circuit miles of 69 kV sub-transmission system. The MISO East Region is interconnected with non-MISO systems: Hydro One Networks Inc. and American Electric Power to the east.

The 2023 Summer Peak planning model indicates the region contains more than 30.3 GW of generation. Installed generation capacity in the region consists mostly of coal, gas, and wind. Figure 4.3-1 shows the major load centers and generation pockets within the East Region. The load centers are typically found around larger cities in the region, i.e., Detroit, Lansing, and Grand Rapids. According to the 2023 Summer Peak planning model, the region's load exceeds 20.56 GW.

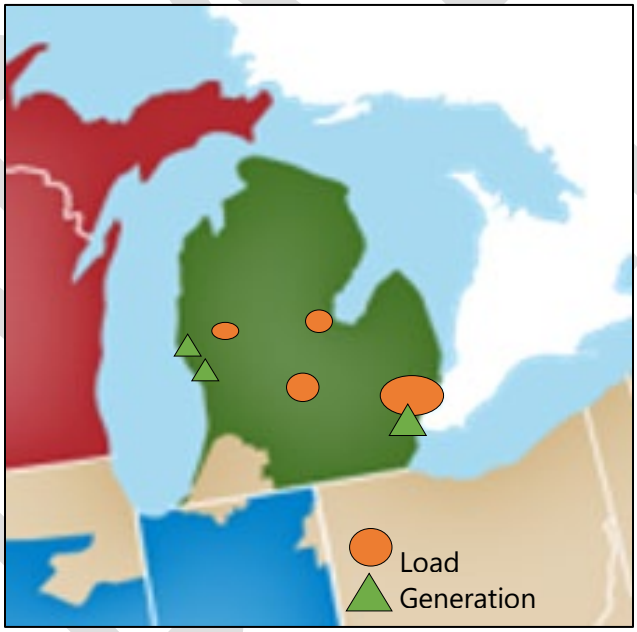


Figure 4.3-1: Generation and load centers in the East planning region

For MTEP23, MISO Transmission Planning is recommending 97 projects from the East region for inclusion in Appendix A at an estimated cost of $739 million. Of these, nine are Baseline Reliability Projects, 47 are Generator Interconnection Projects, and the remaining 41 projects are classified as Other Projects. MISO considered alternatives for one project in the East region, the Elephant Load Interconnect. The partial alternative was determined to be more cost-effective when incorporated into the original project. The combined project is detailed below.

Of the 97 projects, that are being recommended to be included in MTEP23, 30 have an estimated cost of less than $1 million, 23 have an estimated cost between $1 million and $5 million, and the remaining 44 projects are estimated to cost greater than $5 million (shown in Figure 4.3-2).

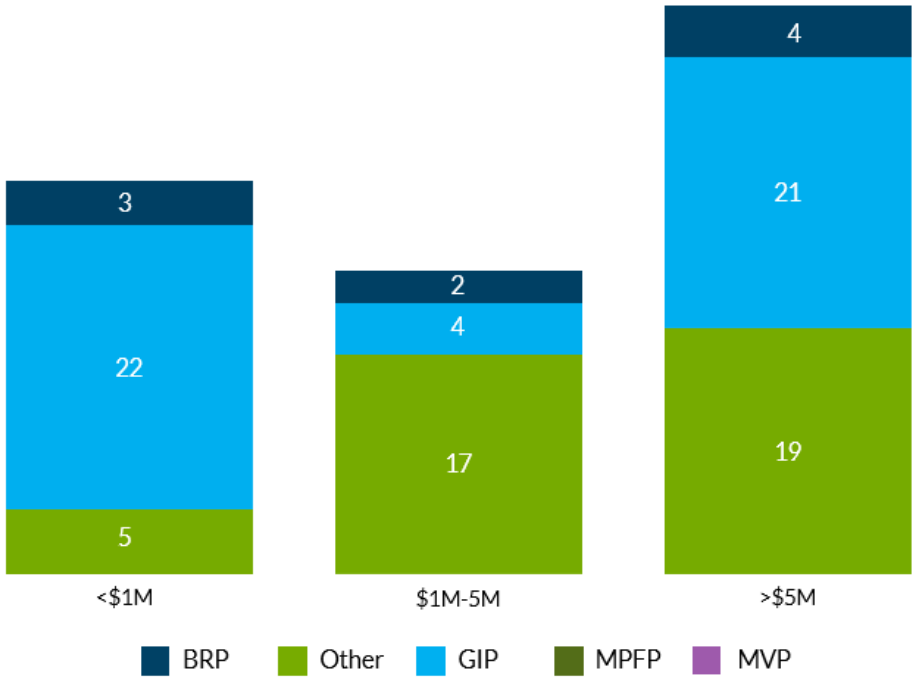


Figure 4.3-2: Project counts by cost category of MISO East region MTEP23 projects (data as of 9-29-2023)

The majority of projects in the MISO East planning region are expected to go into service in the next five years as shown in Figure 4.3-3. There are four GIP projects and two Other projects that are being approved in MTEP23 with an in-service date in 2023. Some projects and in-service dates are still being determined.

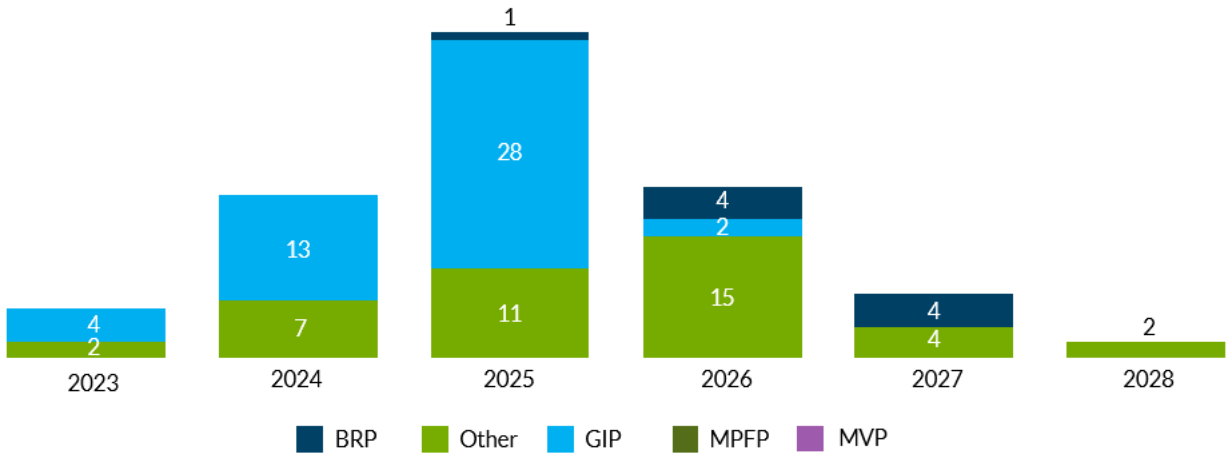


Figure 4.3-3: East region MTEP23 projects by in-service date (data as of 9-29-2023)

In accordance with Attachment FF of the MISO tariff, if a Transmission Owner determines system conditions warrant the urgent development of system enhancements, MISO will perform an expedited review of the impacts of the project. MISO shall use a streamlined approval process for reviewing and approving such projects proposed by the Transmission Owner(s) so that decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO, unless a longer review period is mutually agreed upon. During the MTEP23 cycle, generally driven by load growth and construction relocations, MISO received the following projects through the Expedited Project Review (EPR) process:

1. Project 24673, Project Hickory Load connection
2. Project 25038, Murphy-Orr Road #3 138 kV
3. Project 24115, Mack – Northeast UG Cable Relocation Project
4. Project 24393, I 375 UG Cable Relocation Project
5. Project 24466, MDOT I-96 Construction – Cody – Nolan Structure Relocation
6. Project 24593, GM Orion Plant Expansion
7. Project 23865, METC Elephant – Phase 1

Also, in accordance with Attachment FF Section VIII.A.3, none of the projects were identified as an Immediate Need Reliability Project and excluded from the competitive developer selection process. The ten largest project investments in the MISO East region represent $347million (47%) of the $739 million total recommended projects for the East region in MTEP23, or 4% of the $9 billion total recommended in the MISO footprint. The locations of these projects are shown in Figure 4.3-4 with the investment spread across the East Planning region. Projects that are blanket expenditures (such as relays, physical security, etc.) are excluded from this list.

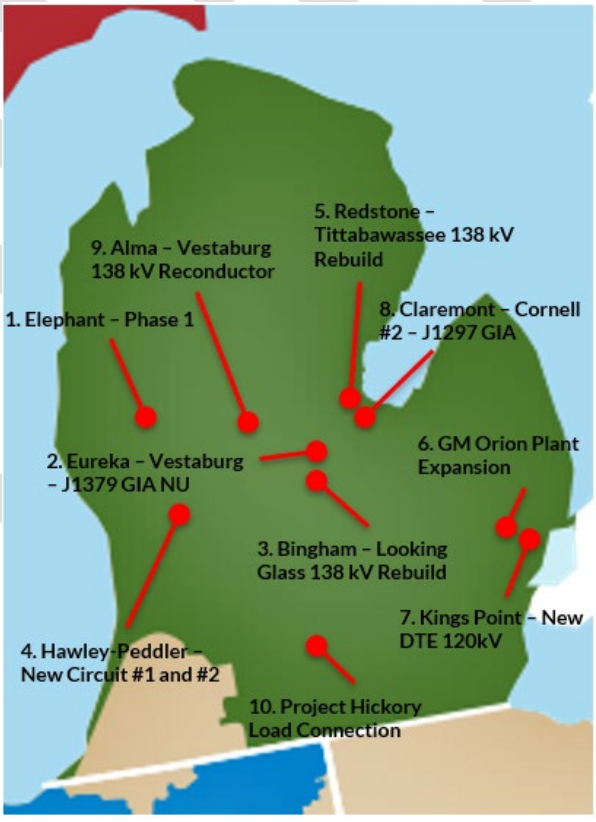


Figure 4.3-4: East region top ten projects, by cost (data as of 9-29-2023)

4.3.1 ITC Transmission (ITCT)

After MISO's independent reliability analysis, MISO and ITC Transmission recommend 27 projects at an estimated cost of $179 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, three are Baseline Reliability Projects, 14 are Other Projects, and 10 are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

ITCT 21725 - Horn - Trenton Channel 120 kV Sag Remediation

Project Description: Fully remediate the sag on the Horn – Trenton Channel 120 kV circuit up to the conductor limit. Upgrade station equipment at Trenton Channel position HG. The total estimated cost of this project is $0.32 million and has an expected in-service date of December 31, 2026.

Project Need: The Horn – Trenton Channel 120 kV circuit is projected to be overloaded for P6 contingency during peak and off-peak load conditions. The identified overloaded equipment on this circuit is the sag limit and station equipment at Trenton Channel.

Alternatives Considered: No alternatives were considered.

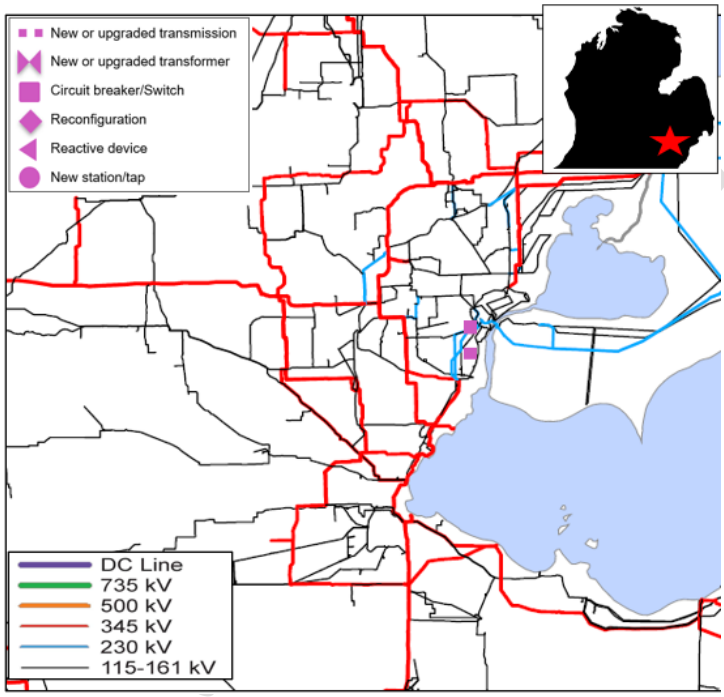


Figure 4.3.1-1: P21725 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	[ITCT] Horn – [ITCT] Trenton Channel 120 kV Ckt 1	283	98	<90

Table 4.3.1-1: P21725 Thermal loading drivers

Project 23828 – Hurst 120 kV 33.3 MVAR Capacitor

Project Description: Install a 33.3 MVAR capacitor at bus 102, position HJ, with a new 120 kV, 40 kA synchronous breaker and associated disconnect switch. Install a 3000 A, 40 kA breaker at position HK on the Hurst – Genoa 120 kV circuit. The total estimated cost of this project is $3.1 million and has an expected in-service date of June 1, 2025.

Project Need: This project is the alternative to the project P#15887 Durant 120 kV 33.3 MVAR Capacitor. The Durant buses are projected to experience low voltages for a shutdown-plus-contingency that takes out Genoa – Madrid 120 kV and Durant – Placid 120 kV lines.

Alternatives Considered: No alternatives were considered.

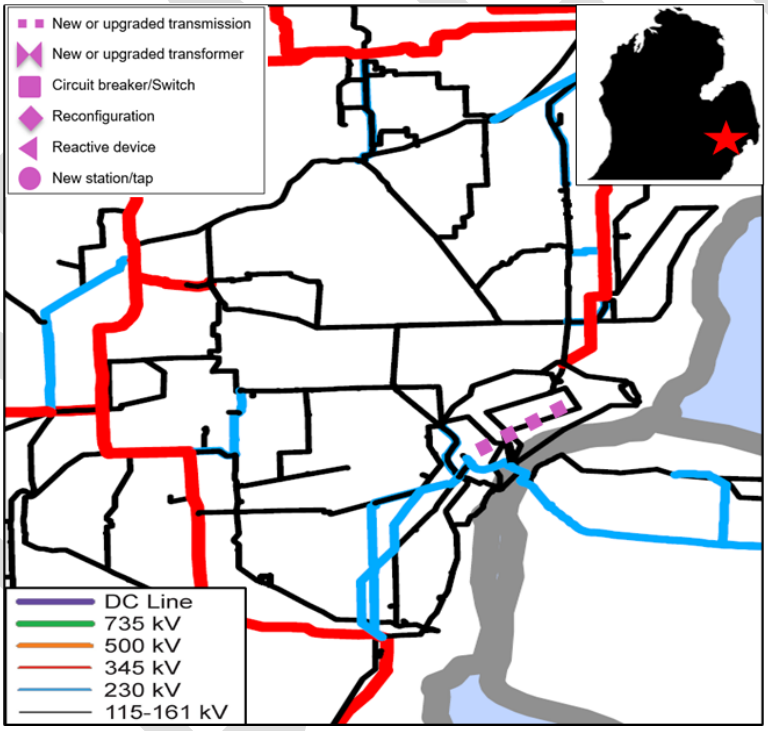


Figure 4.3.1-2: P21745 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (p.u.)	Pre-Project Loading (p.u.)	Post-Project Loading (p.u.)
P6	[ITCT] 19DURANT1 120.0	0.92	0.9089	0.9468

Cont. Type	Limiting Element	Rating (p.u.)	Pre-Project Loading (p.u.)	Post-Project Loading (p.u.)
P6	[ITCT] 19DURANT2 120.0	0.92	0.9089	0.9468

Table 4.3.1-2: P23828 Voltage loading drivers

Project 23697 – Beck – Stephens 120 kV Sag Remediation

Project Description: Remediate the sag limit on the Beck - Stephens 120 kV circuit up to a minimum summer emergency rating of 242 MVA. The total estimated cost of this project is $0.54 million and has an expected in-service date of December 31, 2026.

Project Need: The Beck - Stephens 120 kV circuit is expected to marginally overload for a P24 contingency.

Alternatives Considered: No alternatives were considered.

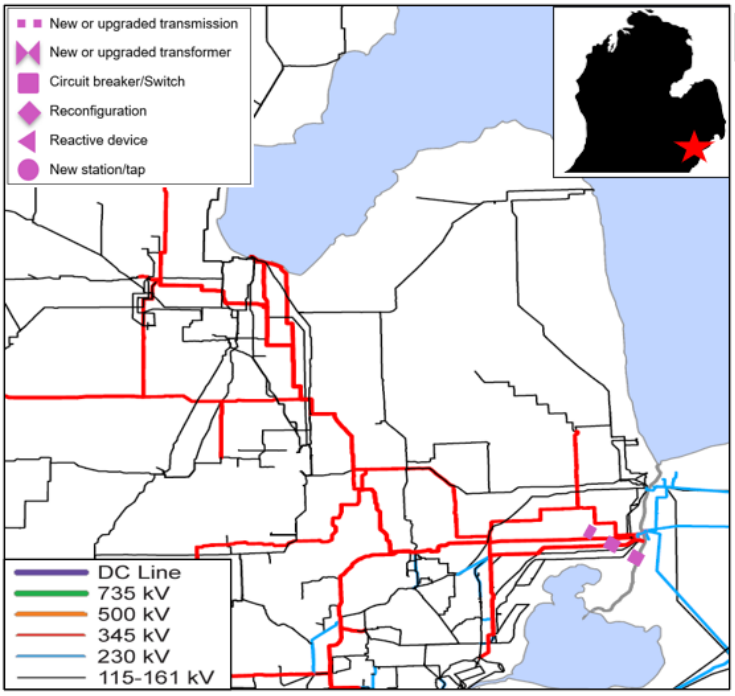


Figure 4.3.1-3: P23697 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P24	[ITCT] 19BECK1 120.00 – [ITCT] 19STEPH3 120.00 ckt 1	230	100.3	<90

Table 4.3.1-3: P23697 Thermal loading drivers

Other Projects

Projects Driven by Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
15872	Brownstown-Monroe #2 345 kV Sag Remediation	Remediate the sag on the Brownstown - Monroe #2 345 kV line to at least 1400 MVA and upgrade switches at Monroe "FT" and "FM" positions.	12/31/2026	$2.58
23880	2023 ITCT Line Relocation Blanket	Relocation portions of transmission lines located in public right of way at the government entities mandate.	12/31/2023	$2.4
24115	Mack - Northeast 120 kV UG Cable Relocation	Relocation and replacement of 1230 ft. of 1500kcmil CU cable with 2100 ft. of 2500kmil CU cable of the Mack-Northeast 120 kV circuit to accommodate future interstate infrastructure improvements directed by the Michigan Department of Transportation (MDOT).	6/03/2024	$5.54
24393	MDOT I-375 Construction - Underground Cable Relocation	Relocate a portion of the Alfred-St. Antoine and Esset-St. Antoine 120 kV underground cables currently located in the Larned I-375 bridge to accommodate the reconstruction of I-375 in downtown Detroit as directed by the Michigan Department of Transportation (MDOT).	12/31/2024	$8.2
24466	MDOT I-96 Construction - Cody - Nolan Structure Relocation	Relocate five structures on the Cody – Nolan 120 kV line that are in conflict with the reconstruction and rehabilitation project along US-23 at the I-96/Grand River intersection.	8/01/2024	$1.25

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22014	ITCT Pole Top Switch Additions/Replacement Program 2024	Installing pole-top switches, or replacing them as appropriate, at tap points of circuits will provide the operational flexibility to sectionalize parts of the line to isolate faults or perform maintenance work on it without having to shut down the entire circuit. This significantly reduces service interruptions to the customers	12/31/2024	$2.4

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		during planned maintenance work or restoration from the aftermath extreme weather events.		
23976	ITCT Pole Top Switch Additions/Replacement Program 2025	Install or replace an existing pole top switch with a new 138 kV, 1-way full-load-break pole top switch at tap points.	12/31/2025	$2.4
24072	Resource Equipment Removal and Bypass	Remove ITC assets at Resource substation. Bypass Resource substation to form a direct Alfred to Frisbie 120 kV circuit.	12/31/2026	$3.5

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23853	Wayne Transformer 301 Replacement	Replace 345/120kV transformer 301 at Wayne station with a new transformer rated at least 750 MVA for summer emergency.	12/31/2026	$5.6
23884	2025 ITCT Transmission Asset Replacement Program	Replace aging and outdated equipment on a cycle that will ensure each piece of equipment is replaced near its expected end of life. Modern equipment can improve reliability, use state of the art technology, and typically will allow for longer maintenance intervals. New equipment is also commonly equipped with better monitoring and alarming functionality giving improved remote supervision. All of this will help to reduce overall maintenance costs.	12/31/2025	$44
23894	Jewell 301 Transformer Replacement	Replace the 345/230 kV transformer #301 at Jewell with a new, standard transformer of similar size.	12/31/2026	$6.6

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22847	Kings Point – New DTE 120 kV Interconnection	DTE requested a new LDC 120 kV substation interconnection, called Kings Point. ITCT will construct a new 120 kV station and cut the Boyne - Golf 120 kV	3/31/2027	$20

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		line in to accommodate this new interconnection. The configuration for ITCT's 120 kV station will be a straight bus station with one 40 kA section breaker and two 40 kA line breakers. ITCT will relocate a ~ 2.1 miles section of the Boyne-Golf 120 kV circuit by utilizing DTE's existing 40 kV circuit on the North side of 21 Mile Rd, East side of N. Gratiot Ave, and South side of Hall Rd to rebuild this ~2.1 miles to 120 kV with 40 kV underbuilding to loop the Boyne-Golf line into the new 120 kV substation.		
23947	2026 ITCT Customer Interconnections	ITCT will individually evaluate each request to ensure it does not adversely impact reliability. Projects that result in a system solution where the cost estimate is less than $2.5 Million that have an in-service date within the year 2026 will be associated with this project. When Customer Interconnection projects are evaluated to amount in a cost greater than $2.5 Million a separate project will be submitted for approval.	12/31/2025	$2.5
24593	GM Orion Plant Expansion	At Sunbird, expand the existing substation to include 3-120 kV line breakers, 1-120 kV section breaker, and create bus 103. Construct a 2nd Pontiac-Sunbird 120 kV line and install 2-120 kV pole top switches on the Colorado taps on the Pontiac-Sunbird #1 and Sunbird-Bloomfield 120 kV lines. At Pontiac, bypass the existing series reactor and install a line breaker on the new Pontiac-Sunbird #2 line position. Install OPGW between Pontiac and Sunbird.	5/31/2025	$25.8

Generator Interconnection Projects:

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23171	J1319 Generator Interconnection	J1319 generator will utilize the existing POI established for J327 Deerfield Wind Energy at the ITCT Rapson 120 kV substation.	6/01/2023	$0

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23481	S1007 Surplus Generator Interconnection	S1007 Surplus generator will utilize the existing POI established for J202 Starkey Wind Farm at the ITCT Dixon 120 kV substation.	6/01/2023	$0
24280	Greenwood – J1331 GIA NU	Add row P and install two 120 kV breakers rated at 40 kA and four disconnect switches at Greenwood Substation.	2/28/25	$2.88
24299	J1196 Generator Interconnection TOIF	Install required entrance structures and 345 kV disconnect switch at the new Wedge station.	3/3/2025	$0
24313	Greenwood-Rapson (Banner)-J1196 GIA (Wedge) NU	Construct new Wedge 345 kV station. Install three 345 kV breakers rated at 40 kA with associated disconnects and two new bus sections. Cut the ITCT Greenwood – Rapson(Banner) 345 kV circuit into the new Wedge station.	3/3/2025	$12.62
24333	Majestic-Milan – J1224 & J1329 GIA (Neblo) NU	Build a new 345 kV 3 Breaker ring substation cut in from the Majestic-Milan 345 kV line. System changes will require relay upgrades at Majestic 345 kV and Milan 345 kV stations.	12/29/2025	$13.16
24376	Majestic Milan – J1224 & J1329 GIA (Neblo) TOIF	Install a line entrance structure and switch for the generator to connect to position CQ at the Neblo (J1224&J1329) 345 kV station.	12/29/2025	$0
24417	J1350 Generator Interconnection Network Upgrades	Build a new 345 kV 3 Breaker ring substation and cut in the Milan – Lulu 345 kV 345 kV line. System changes will require relay upgrades at Milan 345 kV station.	5/16/2025	13.38
24418	J1350 Generator Interconnection TOIF	Install a line entrance structure and a switch shunt for the generator to connect at position CI.	5/16/2025	$0
24441	J1331 Generator Interconnection TOIF	Install required entrance structures and 120 kV disconnect switch at Greenwood Substation.	2/28/2025	$0

4.3.2 Michigan Electric Transmission Co. (METC)

After MISO's independent reliability analysis, MISO and METC recommend 54 projects at an estimated cost of $506 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, six are Baseline Reliability Projects, 11 are Other Projects, and 37 are Generator Interconnection Projects with signed

Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 15752 - Redstone – Tittabawassee 138 kV Rebuild

Project Description: Rebuild ~13.4 miles of the ~21.5 mile-long Redstone – Tittabawassee 138 kV line from 336 ACSR to 1431 ACSR using future double-circuit construction with OPGW. The total estimated cost of this project is $22 million and has an expected in-service date of June 1, 2027.

Project Need: The Redstone - Tittabawassee 138 kV line was shown as overloaded in MISO's MTEP23 Generator Deliverability study. METC's 2022 internal assessment also identified this overload for various contingencies, including N-1.

Alternatives Considered: No alternatives were considered.

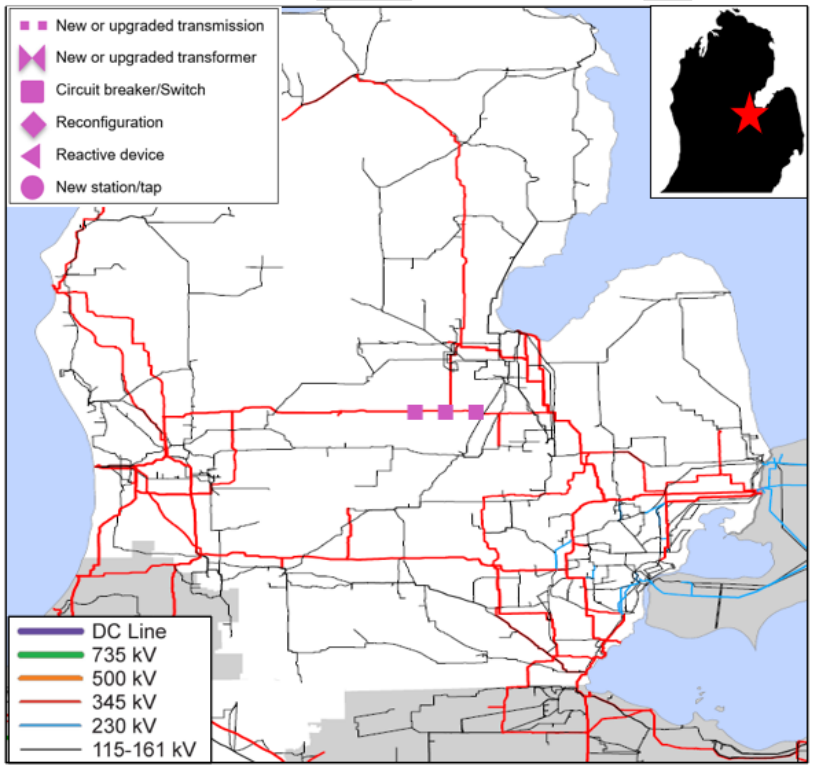


Figure 4.3.2-1: P15752 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P1	[METC] 18TITBAW 138 [METC] 18REDSTONE 138 1	372	154	TBD
P6	[METC] 18TITBAW 138 [METC] 18REDSTONE 138 1	372	128	TBD

Table 4.3.2-1: P15752 Thermal loading drivers

Project 23704 – Abbe Jct – Mio 138 kV Sag Remediation

Project Description: Remediate sag on the 266.8 ACSR to meet or exceed 106 MVA (445 A) on the Abbe Jct. – Mio Dam section of the Airport – Mio Dam 138 kV circuit. The total estimated cost of this project is $1.7 million and has an expected in-service date of December 31, 2026.

Project Need: Abble to Mio Dam 138 kV line is projected to be overloaded for category P6 contingencies in off peak and pumping condition.

Alternatives Considered: No alternatives were considered.

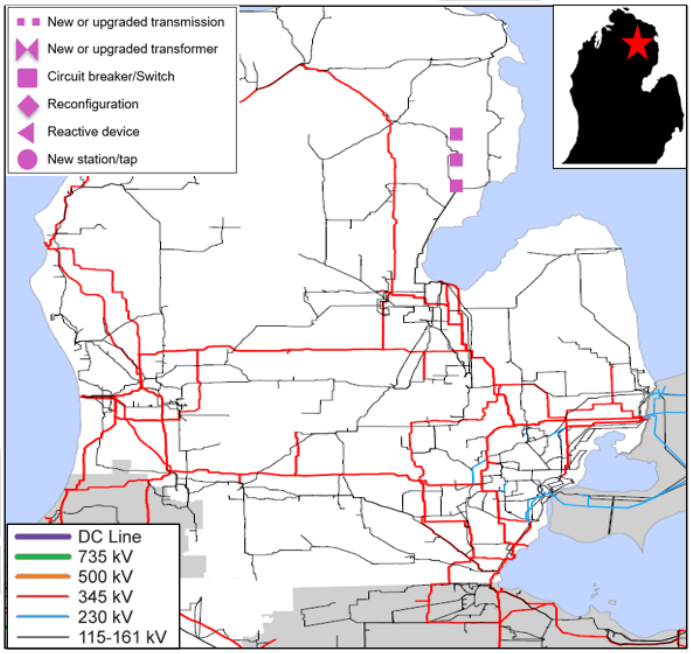


Figure 4.3.2-2: P23704 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P1	[METC] 18ABBEJ 138 [METC] 18MIO 138 1	122	110	TBD
P6	[METC] 18ABBEJ 138 [METC] 18MIO 138 1	122	104	TBD

Table 4.3.2-2: P23704 Thermal loading drivers

Project 23709 – Campbell – Blendon 138kV Loop Into Tyler

Project Description: Loop the Campbell - Blendon 138 kV line into Tyler to create Campbell - Tyler and Tyler - Blendon 138 kV lines. Install (3) new breakers at Tyler and OPGW from Port Sheldon to Campbell. The total estimated cost of this project is $6.9 million and has an expected in-service date of June 1, 2027.

Project Need: The Campbell - Tyler 138 kV #1 line is project to overload for the P6 contingencies during peak and off-peak condition.

Alternatives Considered: No alternatives were considered.

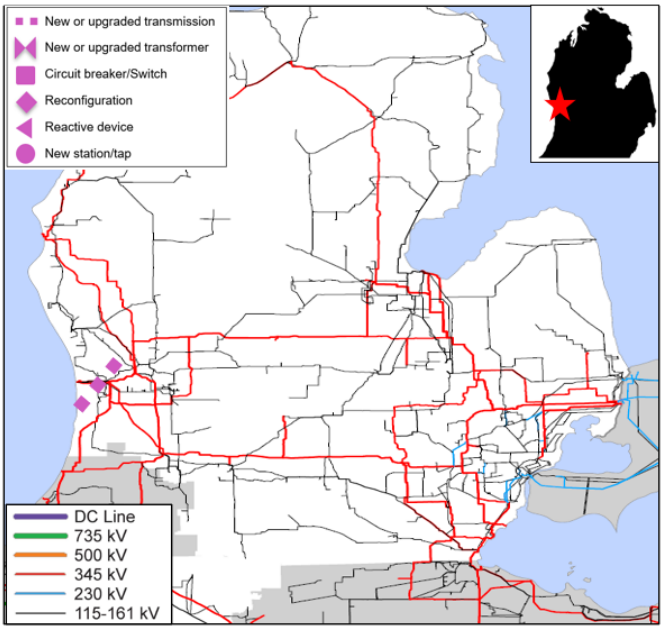


Figure 4.3.2-1: P23709 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	[METC] 18CAMPBELLW 138 [METC] 18TYPLER 138 1	337	112	TBD

Table 4.3.2-1: P23709 Thermal loading drivers

Project 23743 – Deja Junction – Vestaburg 138 kV Rebuild

Project Description: Rebuild 4.3 miles section between Deja Jct. and Vestaburg of the Eureka - Vestaburg 138 kV line. The total estimated cost of this project is $8.8 million and has an expected in-service date of June 1, 2027.

Project Need: The Deja Jct. - Vestaburg section of the Eureka - Vestaburg 138 kV circuit are projected to overload for various contingencies. The identified overloaded equipment on this circuit is the conductor. The thermal violation is only found on off peak pumping condition.

Alternatives Considered: No alternatives were considered.

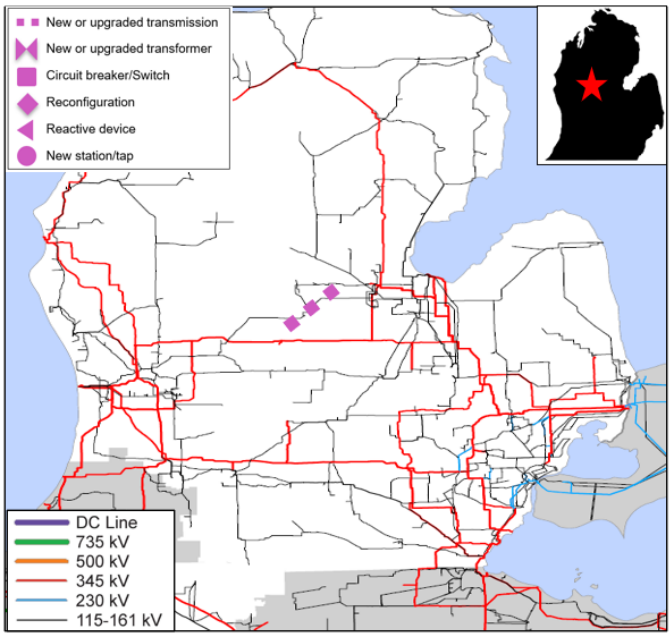


Figure 4.3.2-2: P23743 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
N1	[METC] 18DEJAJ 138 [METC] 18VESTABURG 138 1	288	331	TBD
P6	[METC] 18DEJAJ 138 [METC] 18VESTABURG 138 1	288	345	TBD

Project 23807 – Alma – Vestaburg 138 kV Reconductor

Project Description: Reconductor from Vestaburg to structure #2W8472 (~16.24 miles) from 954 ACSR to 954 ACSS. Also, upgrade 1590 SAC buses and 1200A switches at Alma position "477" to at least 455 MVA for summer emergency rating. The total estimated cost of this project is $16.7 million and has an expected in-service date of June 1, 2027.

Project Need: The Alma-Vestaburg 138 kV circuit is projected to overload for various contingencies, including N-1 in METC's 2022 internal assessment.

Alternatives Considered: No alternatives were considered.

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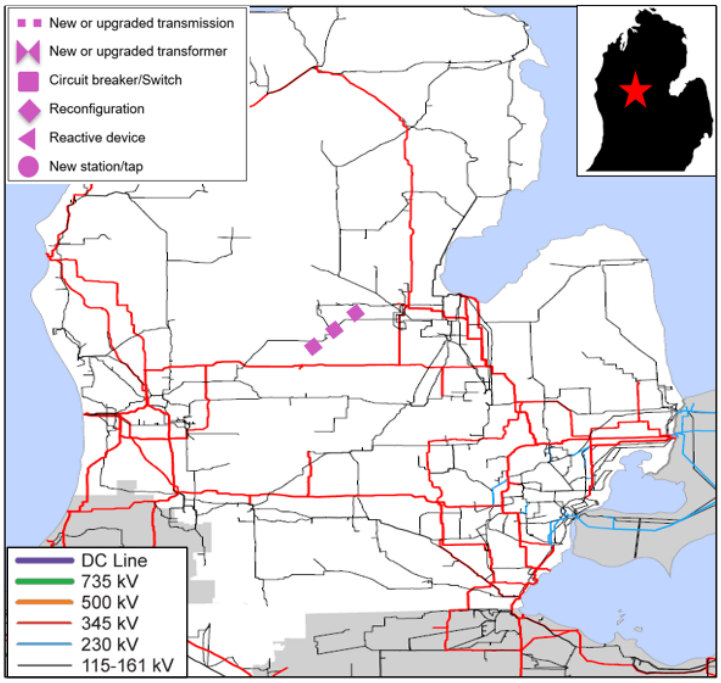


Figure 4.3.2-1: P23807 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
N1	[METC] 18ALMA 138 [METC] 18VESTABURG 138 1	445	104	TBD
P6	[METC] 18ALMA 138 [METC] 18VESTABURG 138 1	445	100	TBD

Table 4.3.2-1: P23807 Thermal loading drivers

Project 23830 – MCV 138 kV Station Equipment Upgrade

Project Description: Upgrade thermal relay at position "3141" to at least 620 MVA. The total estimated cost of this project is $0.19 million and has an expected in-service date of December 31, 2026.

Project Need: The bus-tie section at MCV position "3141" is projected to overload in METC's internal assessment under P21 contingencies.

Alternatives Considered: No alternatives were considered.

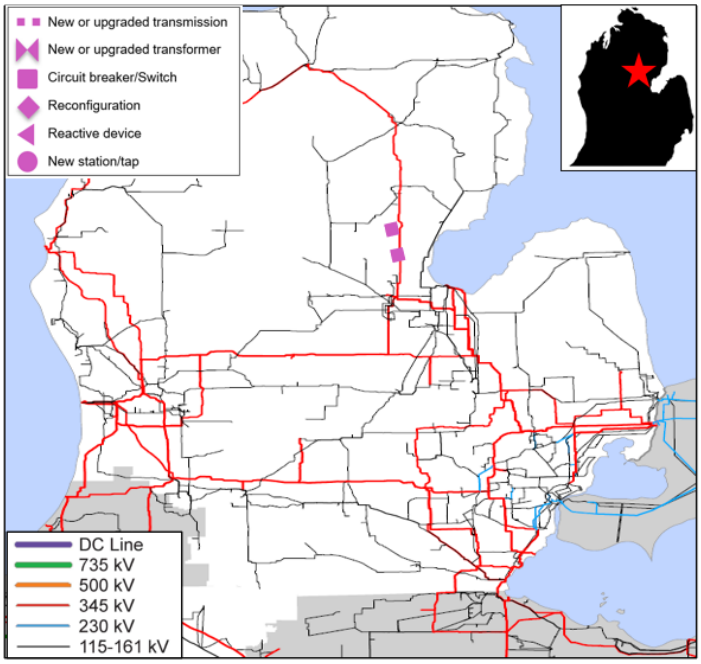


Figure 4.3.2-2: P23830 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
N1	[METC] 18MCV41 138 [METC] 18DOW1 138 1	57	140	TBD

Table 4.3.2-2: P23830 Thermal loading drivers

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23885	2026 METC Customer Interconnections	METC will individually evaluate each request to ensure it does not adversely impact reliability. Projects that result in a system solution where the cost estimate is less than $2.5 Million that have an in-service date within the year 2026 will be associated with this project. When Customer Interconnection projects are evaluated to amount in a cost greater than $2.5 Million a separate project will be submitted for approval.	12/30/2026	$2.5
23950	2023 METC Line Relocation Blanket	Relocation of portions of transmission lines located in public right of way at the government entity's mandate.	12/31/2023	$2.4

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23865	Elephant - Phase 1 (with WPSC Alternative Project 24414)	CE has requested a new 103 MW (expanding to 206 MW) Industrial interconnection near METC's Mecosta substation. To accommodate this request, METC would install a new, 3-row, 138 kV substation near the customer site, and loop the existing Chase-Mecosta 138 kV line approx. 1.5 miles into the new substation. A 138 kV, 54 MVAR cap bank would be installed at the new substation. METC would also rebuild the entire Chase-Mecosta 138 kV circuit (approx. 17.6 miles), and rebuild a 7.8 mile segment of the Croton-Mecosta 138 kV line. WPSC selected Alternative Project discussed in section 4.3.4	3/1/2025	$56
24673	Project Hickory Load connection (EPR)	METC will construct the new 138 kV, 3-row, breaker and a half Charge substation to be fed by looping the existing Highfield-Brooks Industrial 138 kV line approximately 0.2 miles into the new substation.	5/31/2024	$16.6

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23872	Kraft 138 kV Station Equipment Upgrade	Upgrade existing 500 circuit switcher, two line switches with new breakers at Kraft 138 kV station and remove N.O. 3317 PTS.	12/31/2026	$6

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23829	Tompkins 345/138 kV Transformer #1 Replacement	Replace the 345/138 kV transformer #1 at Tompkins with a new, standard transformer of similar size.	12/31/2026	$5.23
23835	Pere Marquette Transformer 2 Replacement	Replace 345/138 kV transformer 2 at Pere Marquette with a new, standard transformer of similar size. Install a 345 kV breaker and associated switch on the high side of the transformer.	12/31/2026	$8.5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		Also, install a 138 kV switch on the low side of the transformer.		
23847	Bingham – Looking Glass 138 kV Rebuild	Rebuild approximately 19.3 miles of the Bingham – Looking Glass 138 kV circuit to 1431 ACSR conductor utilizing 138 kV double- circuit structures with OPGW. Leave the East side of the double-circuit structures vacant. Connect OPGW at Bingham 138 kV position WM6.	12/31/2026	$35.4
23948	2025 METC Asset Replacement Program	Replace aging and outdated equipment on a cycle that will ensure each piece of equipment is replaced near its expected end of life. Modern equipment can improve reliability, use state of the art technology, and typically will allow for longer maintenance intervals. New equipment is also commonly equipped with better monitoring and alarming functionality giving improved remote supervision. All of this will help to reduce overall maintenance costs.	12/31/2025	$41.8
23949	METC Pole Top Switch Additions/Replacement Program 2025	Install or replace an existing pole top switch with a new 138 kV, 1-way full-load-break pole top switch at tap points.	12/31/2025	$2.4

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
25038	Murphy - Orr Road #3 138 kV Line (EPR)	Construct a 3rd 138 kV circuit from Murphy to Orr Rd utilizing 954 ACSR on the open side of the existing structures currently carrying the Orr Rd-Murphy #2 138 kV circuit. This scope will potentially add some structures at Murphy and Orr Road station ends to terminate the new 138 kV line. Install OPGW on the new circuit and terminate it at both ends. Install a new breaker at Murphy Pos. 4B7, and install a new breaker at Orr Road Pos. 6B7.	3/31/2025	$7.6

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Generator Interconnection Projects:

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22147	Blackstone-Stable-J1310 Generator Interconnection	Build a new 138 kV 3 Breaker ring substation cut in from the Blackstone – Stable 138 kV line. System changes will require relay upgrades at Stable 138 kV and Blackstone 138 kV stations.	10/1/2024	$14.65
22165	Brooks Industrial Mud Lake – J1430 Interconnection – NU	Build J1430 interconnection station as a breaker and half station with three breakers in a ring bus configuration. Brooks Industrial – Mud Lake 138 kV line will be extended to loop in the J1430 Interconnection 138 kV station. Relay upgrades will be required at Mud Lake, Stable, Marshall, and Brooks Industrial 138 kV stations.	8/1/2023	$8.61
23329	R1009 Replacement Generator Interconnection	R1009 generator will replace existing Hillman generating unit and utilize the existing POI established for Hillman Cogeneration connected at the METC Airport-Mio Dam 138 kV line (Progress Street Tap).	12/31/2023	
23785	J1550 Generator Interconnection	Install a new 138 kV switching station. Install five 138 kV breakers rated at 40 kA and two bus sections. Cut the METC Batavia – Barton Lake and Batavia – J1320 (Coldwater) 138 kV circuits into the new 138 kV switching station.	3/3/2025	$15.67
24275	Morocco – J1226 GIA NU	Install two 345 kV breakers rated at 40 kA and associated disconnect switches to complete row 36 in Morocco Substation. Install one 345 kV breaker rated at 40 kA and associated disconnect switch to complete row 34 in Morocco Substation.	06/6/2024	$4.26
24276	Vergennes – Marquette – J1255 GIA (Hawley) NU	J1255 is a 200 MW solar project connecting in Keene Township on the Vergennes – Marquette 138 kV. Build the J1255 Interconnection 138 kV station as a breaker and half station with three 40 kA breakers in a ring bus configuration. Extend the Marquette-Vergennes 138 kV line to loop in the station. Connect the generators at position WM12 as TOIF. Generators are part of the DPP 2019 Cycle 1.	12/31/2025	$6.94

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24277	Gaines – Thompson Road 138 kV – J1292 GIA (Peddler) NU	Build a new 138 kV 3 breaker ring substation cut in from the Gaines – Thompson Road 138 kV line	12/31/2025	$6.93
24279	Claremont – Cornell #2 – J1297 GIA (Hathon) NU	J1297 is a 170 MW solar project interconnecting in Venice Township, Shiawassee, MI. METC will need to build a new 138 kV breaker and half station with three 40 kA breakers. METC will need to extend the Claremont – Cornell #2 138 kV line 0.1 miles to loop in the J1297 Interconnection station for transmission service. Loop in the Cornell – Goss 138 kV line to mitigate anti-islanding at Bell Road. J1297 is queued within the DPP 2019 Cycle 1.	1/28/2026	$18.11
24282	Leoni – Parr Road – J1472 GIA (Vargo) NU	J1472 is a generator interconnection request for a 100 MW Solar Power Plant proposing to connect to the METC Leoni – Parr Road 138 kV Line. J1472 is queued within the DPP 2019 Cycle 1.	11/29/2024	$7.13
24294	Mio Dam – Twining – J1210 GIA (Quarry) – NU	Construct new Quarry 138 kV station. Install five 138 kV breakers rated at 40 kA, associated disconnects, and two new bus sections. Loop in the Mio Dam – Twinning circuit to the new Quarry station. Loop in the Iosco – Karn circuit to the new Quarry station. Remove Twinning 177 sparing and install approximately 4.3 miles of fiber on the Quarry – Twinning circuit.	3/31/2025	$11.05
24295	Marshall – Blackstone (Stable) – J1248 GIA (Bearcat) NU	J1248 is a 100.9 MW solar farm connecting on the Marshal – Stable 139kV line in Calhoun County, MI. Construct J1248 as a breaker and half station with three 40kA breakers in a ring bus configuration. Construct BM14 as a TOIF to connect J1248. Generator is part of the DPP 2019 Cycle 1.	11/30/2025	$9.71
24300	J1320 Generator Interconnection TOIF	Install required line entrance structures and 138 kV disconnect at new Byers switching station.	12/10/2025	
24301	Leoni – Parr Road – J1472 GIA (Vargo) TOIF	Install a line entrance structure and a switch for the generator to connect at position WM13.	11/29/2024	

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24314	Thetford-J1203 GIA NU	Install three 345 kV breakers rated at 40 kA and associated disconnect switches and complete row 29 in the METC Thetford Substation.	5/5/2025	$4.25
24317	DuPont – Cobb – J1375 GIA (Lamos) NU	Construct the new Lamos 138 kV station. Extend the White Lake – DuPont – Cobb 138 kV line to loop in the new Lamos 138 kV station. Install three 138 kV breakers rated at 40 kA and two new bus sections at the new Lamos station. Loop the White Lake – Du Pont – Cobb 138 kV line into the White Lake 138 kV station. Install approximately 3.1 miles of fiber from White Lake to Lamos Switching Station. Implement anti-islanding protection for identified islanding scenarios. Replace an existing bus at White Lake Substation. Install new bus and 500 tie-breaker with associated disconnects at White Lake Substation. Install 677 and 777 breakers with associated disconnects at White Lake Substation. Cut White Lake – Cobb circuit and reconnect to the new bus at White Lake.	5/12/2025	$15
24318	Eureka Vestaburg – J1379 GIA NU	Install a new 138 kV switching station. Install four 138 kV breakers rated at 40 kA and two bus sections. Cut the METC Eureka – Vestaburg 138 kV circuit into the new 138 kV switching station. Rebuild the METC Eureka – Vestaburg 138 kV line from Deja to Eureka. Rebuild the METC Eureka – North Belding 138 kV line. Add a new 138 kV line from the new switching station to North Belding.	5/31/2024	$50.09
24319	Delhi-Thompkins #2 J1399 (Edgar) NU	J1399 Interconnection is a 90 MW solar project in Lesli Township, MI. Build the J1399 Interconnection station as a breaker and half station with three 40 kA breakers in a ring bus configuration. Extend the Delhi – Tompkins 138 kV line to loop in the J1399 Interconnection station. J1399 is queued within the DPP2019 Cycle 1.	12/31/2025	$10.01

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24377	Coldwater – Byers Rebuild (J1320) – Network Upgrade	Rebuild entire J1320 – Coldwater 138 kV line with OPGW. Replace existing 336 and 477 ACSR conductor with 954 ACSR.	12/23/2024	$7.3
24395	Luce – Summerton Line Reconductor (J1379) – Network Upgrade	Reconductor the entire ~10.5 mile-long Luce – Summerton 138 kV line with OPGW. Replace the existing 336 ACSR conductor with new 795 ACSS conductor. Replace any structures as necessary.	11/26/2025	$9.68
24396	J1210 Generator Interconnection TOIF	Install required line entrance structures and 138 kV disconnect switch at the new Quarry station.	3/31/2025	
24419	J1320 Generator Interconnection Network Upgrades	Construct new Byers switching station. Install three 138 kV breakers rated at 40 kA and two new bus sections. Loop in the Batavia – Coldwater circuit to the new Byers station. Remove existing X and Z phase wave traps and tuners at Batavia and Coldwater. Install approximately 6 miles of fiber from Byers Switching Station to Batavia and approximately 2 miles of fiber from Byers Switching Station to Coldwater.	12/10/2025	$14.61
24420	Cobb – Peterson Tap Sag Remediation (J1375) – Network Upgrade	Remediate the sag on the 336 ACSR conductor on the Cobb – Peterson Tap 138 kV line section to meet or exceed a rating of 125 MVA Summer Emergency.	12/23/2024	$0.42
24433	Vergennes – Marquette – J1255 GIA (Hawley) TOIF	Install WM14 line position and disconnect at the Hawley station to interconnect J1255 generation.	12/31/2025	
24434	J1203 Generator Interconnection TOIF	Install required entrance structures and 345 kV disconnect switch at METC Thetford Substation.	5/5/2025	
24435	J1226 Generator Interconnection TOIF	Install required entrance structures and 345 kV disconnect switch at Morocco station.	6/6/2024	
24436	J1375 Generator Interconnection TOIF	Install required line entrance structures and 138 kV disconnect at new Lamos station.	5/12/2025	
24437	Delhi-Thompkins #2 J1399 (Edgar) TOIF	Install a line entrance structure and a switch for the generator to connect at position BM14.	12/31/2025	

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24438	J1401 Generator Interconnection Network Upgrades	Install one 138 kV breaker rated at 40 kA and associated disconnects.	4/5/2024	$1.05
24439	J1401 Generator Interconnection TOIF	Install a line entrance and 138 kV disconnect switch at Wagner Station.	4/5/2024	
24448	Murphy-Styx – J1389 Generator Interconnection – Network Upgrades	Build a new 345 kV 3 Breaker ring substation (Palomino) cut in from Murphy – Styx (J984) 345 kV line.	10/31/2025	$12.38
24453	Hawley-Peddler – New Circuit #1 and #2 (J1255, J1292) – Common Use Network Upgrade	Install two breakers at positions 8B7 and 8W8 at J1292, and two breakers at positions at positions 8W8 and 10B7. Install about 15 miles of 954 ACSR DCT in new Right-of-Way to connect J1292 Interconnection Station to J1255 Interconnection Station.	12/31/2025	$27.72
24454	Leoni – Lark 138 kV Sag Remediation (J1310, J1472) – Network Upgrade	Remediate the sag on the 477 ACSR conductor on the Leoni – Washtenaw Tap 138 kV segment to meet or exceed a summer emergency rating of 179 MVA.	4/5/2024	$0.66
24455	Verona – Mud Lake #1 Rebuild (J1248, J1310, J1430) – Network Upgrade	Replace existing 336 ACSR conductor on the Verona – Mud Lake #1 138 kV line with 954 ACSR including one 48 count OPGW ~ 3.6 Miles. Any new 138 kV towers should be expandable to double circuit in the future.	12/23/2024	$8.77
24456	Marshall – Blackstone (Stable) – J1248 GIA (Bearcat) TOIF	Stable – Install a line entrance structure and switch for the generator to connect at position WM14.	11/30/2025	
24459	J1379 Generator Interconnection TOIF	Install an entrance structure and 138 kV disconnect switch at the new switching station.	5/31/2024	
24493	Claremont – Cornell #2 – J1297 GIA (Hathon) TOIF	Install a line entrance structure and a switch from the generator to connect at position BM10.	1/31/2026	
24514	Murphy-Styx – J1389 Generator Interconnection – TOIF	Install a line entrance structure and a switch for the generator to connect at position RH31.	1/29/2024	

4.3.3 Wolverine Power Supply Cooperative Inc. (WPSC)

After MISO's independent reliability analysis, MISO and Wolverine Power Supply Cooperative Inc. recommend 16 Other Projects at an estimated cost of $54 million to be approved for inclusion in MTEP23

Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23575	Pellston Relocation and Upgrades	Project will replace capacity limiting equipment and existing protection system at the Pellston substation and relocate the Pellston to Cross Village line to improve reliability on that line.	12/31/2027	$1.6
23613	2025 WPSC Fiber Retrofit	Installation of fiber on recently rebuilt (post 2006) 138 kV structures utilizing ADSS (All Dielectric Self Supporting) and OPGW (Optical Ground Wire).	12/31/2025	$5
23618	Lake County Protection System Upgrade	Upgrade Lake County Protection system with new line relays.	12/31/2024	$0.08

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23574	Pellston to Cross Village	Rebuild and upgrade 9 miles of 69 kV line to 138 kV standard with steel poles, 336ACSS conductor, and OPGW.	12/31/2027	$9.5
23594	Scottville RTU Upgrade	Replace communication equipment at the Scottville substation.	12/31/2025	$0.04
23595	Weidman TRU Upgrade	Replace communication equipment at the Weidman substation.	12/31/2025	$0.04
23612	Altona Protection System Upgrade	Replace the control building to install modern digital relays and install an additional circuit breaker to increase reliability on Altona to Morley transmission line.	12/31/2026	$1.5
23614	Casnovia to Cedar Springs Rebuild	Rebuild and upgrade 11 miles of 69 kV line to 138 kV standard with steel poles, 795ACSS conductor, and OPGW.	12/31/2027	$9.25
23615	Copemish Protection System Upgrade	Replace the circuit breaker and its associated controls and protective relaying, bringing the station to Wolverine's standard for 138 kV transmission operation.	21/31/2026	$1.5

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23616	Gaylord Protection System Upgrade	Upgrade existing electromechanical relays with digital relays.	12/31/2026	$0.8
23617	Hayes Junction to Hayes Rebuild	Rebuild and upgrade 12 miles of 69 kV line to 138 kV standard with steel poles, 336 ACSS conductor, and OPGW.	12/31/2026	$11.85
23619	Mulliken Jct to Grand Ledge Rebuild	Rebuild and upgrade 4 miles of 69 kV line to 138 kV standard with wood poles, 336ACSS conductor, and OPGW.	12/31/2027	$4.25
23620	North Shade Protection System Upgrade	Upgrade existing electromechanical relays with digital relays.	12/31/2026	$1.25
23621	Redwood TRU Upgrade	Replace communication equipment at the Redwood substation.	12/31/2024	$0.15
23631	Petosky Protection System Upgrade	Upgrade existing electromechanical relays with digital relays.	12/31/2026	$1

Projects Driven by Local Need

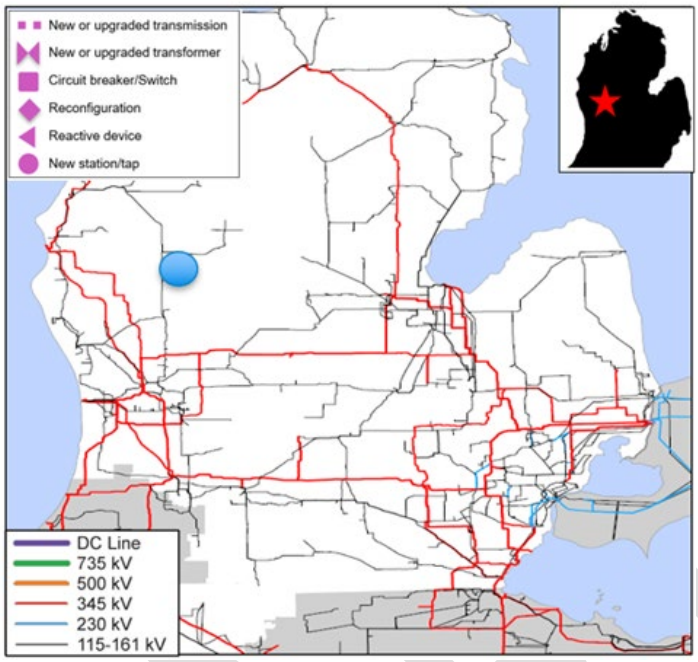
Project 24414- WPSC Elephant Interconnection (Project 23865 Partial Alternative)

Project Description: Consumers Energy Company (CE) has requested a new 103 MW (expanding to 206 MW) Industrial interconnection near METC's Mecosta substation. To accommodate this request, METC would install a new, 3-row, 138 kV substation near the customer site, and loop the existing Chase-Mecosta 138 kV line approx. 1.5 miles into the new substation. A 138 kV, 54 MVAR cap bank would be installed at the new substation. METC would also rebuild the entire Chase-Mecosta 138 kV circuit (approx. 17.6 miles). Wolverine's portion of the project will be to will cut in the Hersey to White Cloud by building four miles of double circuit 138 kV on new ROW. The total estimated cost of this project is $6 million and has an expected in-service date of March 1, 2025.

Project Need: CE requested a new interconnection on METC's Chase-Mecosta 138 kV circuit.

Alternatives Considered: The project is an alternative to the original Project 23865 submitted by METC. Wolverine's Alternative to tie into new Elephant substation eliminates the need to rebuild 7.8 miles of the Croton-Mecosta 138 kV line. The partial alternative was determined to be more cost-effective, reducing the overall cost by $9 million.

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Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	CROTON-NINETEEN MILE ROAD J-138kV	288	102	<99

Table 4.3.3-1: P24414 Thermal loading drivers

4.3.4 Michigan Public Power Agency (MPPA)

Michigan Public Power Agency did not submit any new projects for MTEP23. MISO has not identified any open issues in the MPPA area.

4.3.5 Lansing Board of Water and Light (LBWL)

Lansing Board of Water and Light did not submit any new projects for MTEP23. MISO has not identified any open issues in the LBWL area.

4.3.6 Michigan South Central Power Agency (MSCPA)

Michigan South Central Power Agency did not submit any new projects for MTEP23. MISO has not identified any open issues in the MSCPA area.

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4.4 Project Justifications – South Region

South Region Overview

The MISO South Planning Region consists of eleven Transmission-Owning members spanning four states, Arkansas, Louisiana, Mississippi, and parts of Texas. These Transmission Owners are:

Arkansas Electric Cooperative Corporation (AECC)
City of Alexandria (AXLA)
CLECO Power LLC (CLEC)
Cooperative Energy (SMEPA)
East Texas Electric Cooperative (ETEC)
Entergy Arkansas LLC (EAL)
Entergy Louisiana LLC (ELL)
Entergy Mississippi LLC (EML)
Entergy New Orleans LLC (ENO)
Entergy Texas Incorporated (ETI)
Lafayette Utilities Systems (LAFA)
City Water and Light Jonesboro (CWLT)

The region contains approximately 16,500 circuit miles of transmission lines ranging from 115 kV to 500 kV. There is also a significant 69 kV sub-transmission network interspersed across the footprint.

In the 2023 Summer Peak planning model, the region contains more than 38.1 GW of generation. The MISO South generation profile consists of mostly combined cycle, nuclear, gas, and coal fuel types, serving major load centers such as Little Rock, New Orleans, etc. Approximately 53% (20.2 GW) of the South region's generation capacity is made up of combined cycle (CC) units. Major generation centers are in central Arkansas, lower Louisiana, and western Mississippi (Figure 4.4-1).

Major load centers are typically found around larger cities in the region such as Little Rock, Jonesboro, and Pine Bluff in Arkansas; Monroe, Alexandria, Lake Charles, Lafayette, New Orleans, and Baton Rouge in Louisiana; Jackson, Hattiesburg, Natchez, Vicksburg, and Greenville in Mississippi. Texas major load centers in the Western load pocket include Bryan and the Woodlands area. The major load center in the WOTAB load pocket portion of Texas is in South Beaumont and the Port Arthur Area (Figure 4.4-1). According to the 2023 Summer Peak planning model, the regional load is over 36.1 GW.

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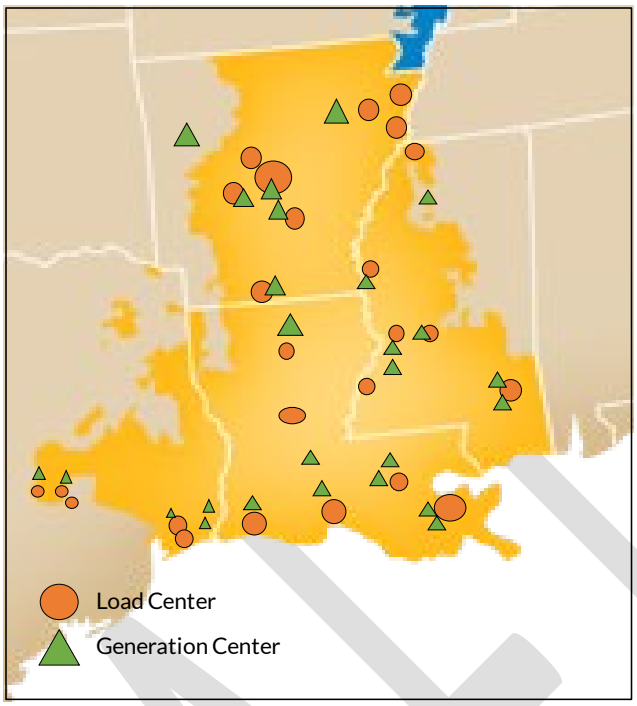


Figure 4.4-1: Generation and load centers in the South planning region

For MTEP23, MISO Transmission Planning is recommending 78 projects from the South region for inclusion in Appendix A at an estimated cost of $4.2 billion. Of these, 15 are Baseline Reliability Projects, 31 are Generator Interconnection Projects, and the remaining 32 projects are classified as Other projects. MISO considered alternatives for multiple projects in the South region. After studying alternatives alongside their corresponding projects, one alternative is selected for the Amite South Phase 1 Alternative project, in place of the Amite South Phase 1, and DSG Reliability & Resiliency projects. All other alternatives were determined to be infeasible, or inferior to the proposed projects. More detail on alternatives studied for each project is available in following sections.

Of the 78 projects, that are being recommended to be included in MTEP23, nine have an estimated cost of less than $1 million, 17 have an estimated cost between $1 million and $5 million, and the remaining 52 projects have an estimated cost greater than $5 million (Figure 4.4-2).

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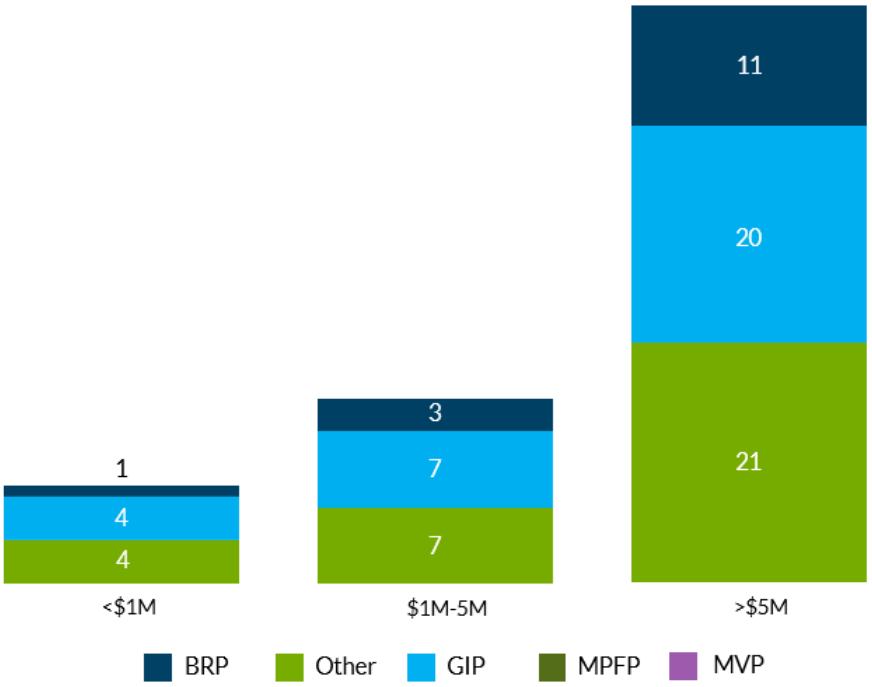


Figure 4.4-2: Project counts by cost category of MISO South region MTEP23 projects (data as of 9-29-2023)

The majority of the projects in the MISO South planning region are expected to go in service in the next three years. (Figure 4.4-3). A few projects and in-service dates are still being determined.

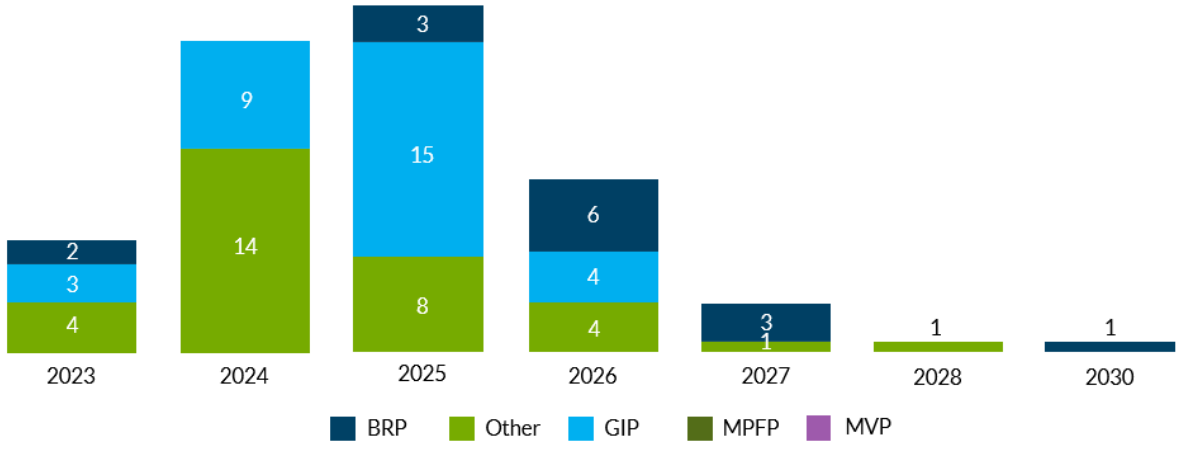


Figure 4.4- 3: South region MTEP23 projects by in-service date (data as of 9-29-2023)

In accordance with Attachment FF of the tariff, in the event a Transmission Owner determines that system conditions warrant the urgent development of system enhancements, an expedited review of the impacts of the project can be requested. MISO shall use a streamlined approval process for reviewing and approving projects proposed by the Transmission Owner(s) and decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO unless a longer review period is mutually agreed upon. During the MTEP23 cycle, MISO received eleven projects in the South planning region through the Expedited Project Review (EPR) process. Nine of these EPRs were needed to meet load growth:

1. Project ID 23348 Grenada Industrial 115 kV: New Station
2. Project ID 23820 Gloster Delivery Point
3. Project ID 24938 Driver - Hybar 230 kV: New transmission line
4. Project ID 24920 Cole Road 138 kV New Customer Station
5. Project ID 24460 Coldspring 138 kV Load Addition
6. Project ID 24415 Ragely Substation
7. Project ID 24192 UIG Load Increase
8. Project ID 24134 Mustang 138 kV New Customer Substation
9. Project ID 24152 Moscow 138 kV Customer Load Addition Project

Two EPRs were needed for Other Local Needs:

1. Project ID 12222 Maxie Delivery Point
2. Project ID 25094 Commerce to Ringier 69 kV Relocation

Also, in accordance with Attachment FF Section VIII.A.3, no MTEP23 projects were identified as Immediate Need Reliability Projects and excluded from the competitive developer selection process.

The 10 largest project investments in the MISO South region represent $3.3 billion (80%) of the $4.2 billion total recommended projects for the South region in MTEP23, or 37% of the $9 billion total recommended in the MISO footprint. The locations of the 10 most expensive projects are shown in Figure 4.4-4 and it is seen that they are spread across the southern part of the South planning region. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

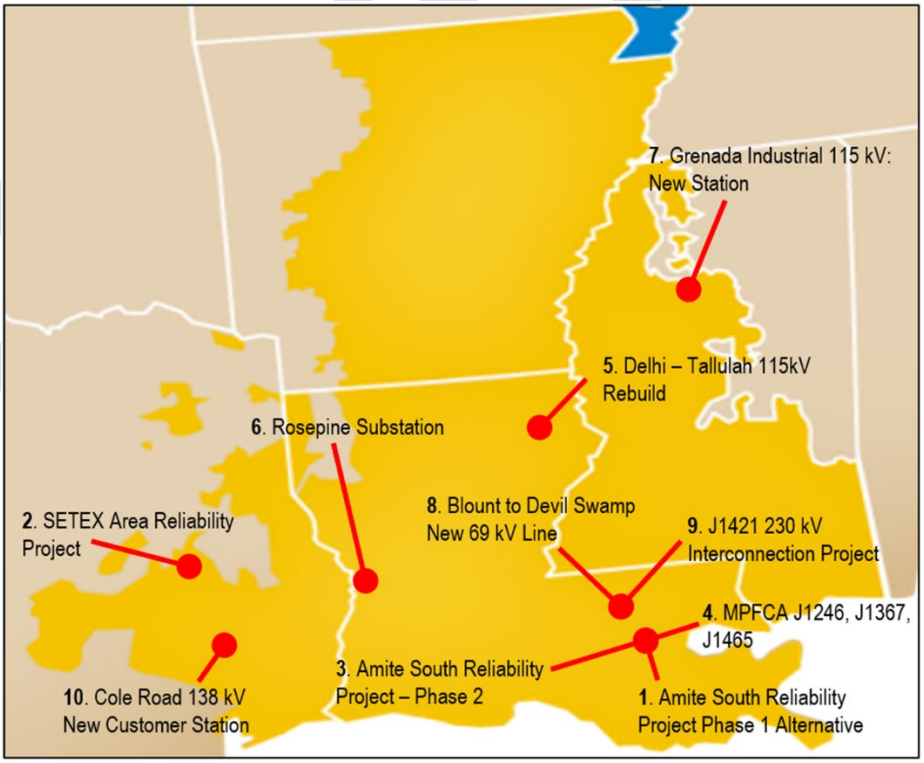


Figure 4.4-4: South region top ten projects by cost (data as of 9-29-2023)

4.4.1 Arkansas Electric Cooperative Corporation (AECC)

After MISO's independent reliability analysis, MISO and Arkansas Electric Cooperative Corporation recommend one Other Project at an estimated cost of $0 million to be approved for inclusion in MTEP23 Appendix A. All costs for this project will be paid by Mississippi County Electrical Cooperative, so there is no investment required by AECC. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24192	UIG	AECC and Mississippi County Electric will be building out the AECC Barfield substation by adding a new 25 MVA; 161/13.8 kV transformer to support 20 MW of new load. AECC and Mississippi County Electric will also be building out the AECC Hickman North substation by adding a new 40 MVA; 161/13.8 kV transformer to support 30 MW of new load.	4/1/2025	$0

4.4.2 City of Alexandria (AXLA)

City of Alexandria did not submit any new projects for MTEP23. MISO has not identified any open issues in the City of Alexandria area.

4.4.3 CLECO Power LLC (CLEC)

After MISO's independent reliability analysis, MISO and CLECO Power LLC recommend six projects at an estimated cost of $89 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Baseline Reliability Project, one is an Other Project, and four are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 24416- Rosepine Substation 230 kV

Project Description: Build a new 230 kV substation Rosepine tapped into the existing Leesville to Cooper 138 kV line 11.5 miles from Leesville. Build a new 230 kV line 3.4 miles from Rosepine to Deridder. This substation and line will be energized at 138 kV. The total estimated cost of this project is $35.6 million and has an expected in-service date of July 15, 2027.

Project Need: In this area, P6 contingencies involving Nelson to Longville, Cooper to Deridder or Coughlin to Pine Prairie create low voltage and potential overloads when two of the three lines mentioned above are outaged. This issue has resulted in reconfiguration for outages and limited ability to perform maintenance in this area except during times of lower loading. This project adds a fourth line into the area eliminating the P6 issues.

Alternatives Considered: No alternatives were considered.

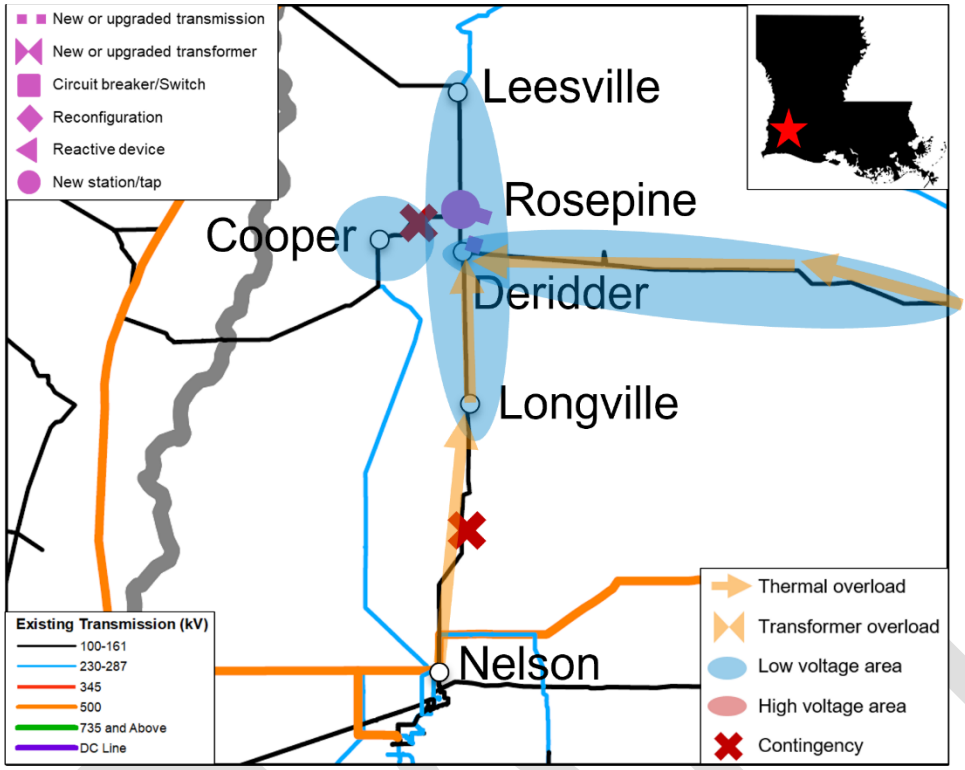


Figure 4.4.3-1: P24416 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Nelson – Longville 138 kV	243	157	36
P6	Deridder – Longville 138 kV	262	104	2
P6	Caney – Oakdale 138 kV	283	146	40
P6	Caney – Pine Prairie 138 kV	287	147	44
P6	Centennial – Deridder 138 kV	286	110	11
P6	Centennial – Perkins 138 kV	287	110	11
P6	Coughlin – Pine Prairie 138 kV	286	154	50
P6	Oakdale – West Bay 138 kV	284	120	20
P6	Perkins – West Bay 138 kV	287	108	10

Table 4.4.3-1: P24416 Thermal loading drivers

Cont. Type	Limiting Element	Rating (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	Caney 138 kV	0.9	0.757	1.0129
P6	Centennial 138 kV	0.9	0.583	1.0027
P6	Deridder 138 kV	0.9	0.512	0.9911
P6	Longville 138 kV	0.9	0.47	0.9673
P6	Oakdale 138 kV	0.9	0.738	1.0109
P6	Perkins 138 kV	0.9	0.599	1.0048
P6	Pine Prairie 138 kV	0.9	0.86	1.0170
P6	West Bay 138 kV	0.9	0.684	1.0076
P6	J1205 Substation 138 kV	0.9	0.599	1.0050

Table 4.4.3-2: P24416 Voltage Performance drivers

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24033	J1286 Manuel Expansion	Expand Manuel Substation for the interconnection of J1286 Generation Plant.	4/1/2025	$2.8
24112	J1205 Perkins Substation	Tap the existing Centennial to West Bay 138 kV line and build a new Perkins Substation. J1205 Generation Plant will interconnect to this substation.	10/31/2023	$2.6
24113	J1424 Singer Substation	Tap the existing Cooper to Penton 230 kV line and add Singer Substation. This substation is needed for J1424's generator interconnection.	9/15/2024	$2.95
24114	J1367 Caneland Expansion	Expand Caneland 230 kV substation for the interconnection of J1367 Generation Plant	9/29/2024	$5.1

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24415	Ragely Substation	Tap the existing 138 kV line between Nelson and Longville 11.3 miles from Longville. At this location build a new 138 kV Substation Turps. Build a new 6.1 mile 138 kV line from Turps to a new substation Ragley. This project will also add a 14 MVAR cap bank at Ragley.	7/15/2024	$40

4.4.4 Cooperative Energy (SMEPA)

After MISO's independent reliability analysis, MISO and Cooperative Energy recommend six projects at an estimated cost of $48 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Baseline Reliability Project, four are Other Projects, and one is a Generator Interconnection Project with a signed Generator Interconnection Agreement. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 23786 – Ft Redwood - Rawhide 115 kV Line

Project Description: Tap the Entergy MS owned Flowers - Tinsley 115 kV line and construct a new Cooperative Energy owned 115 kV breaker switching station near Rawhide Road in Warren, MS. Construct a new 115 kV line from a new Cooperative Energy owned breaker 115 kV switching station near the Ft Redwood substation to the new Cooperative Energy owned switching station near Rawhide Road. Rebuild the existing Cooperative Energy owned Redwood - Ft Redwood 115 kV line to support the industrial customer's full load during unplanned on-site generation outages. The total estimated cost of this project is $13.5 million and has an expected in-service date of June 1, 2026.

Project Need: A Cooperative Energy member distribution cooperative serves an industrial customer that has behind the meter on-site generation at its Ft Redwood substation. When the industrial customer's on-site generation has unplanned outages, multiple thermal overloads and voltage violations occur during P1/P2 events on the surrounding area when supporting the full load.

Alternatives Considered: Add a 10 MVAR capacitor at the 115 kV Redwood Substation. This alternative was not selected due to voltage issues still arising in the 28 Spring case and 2028 Shoulder, Average wind case. The Original project provides greater long-term reliability as it adds another transmission path in the area and alleviates all voltage concerns.

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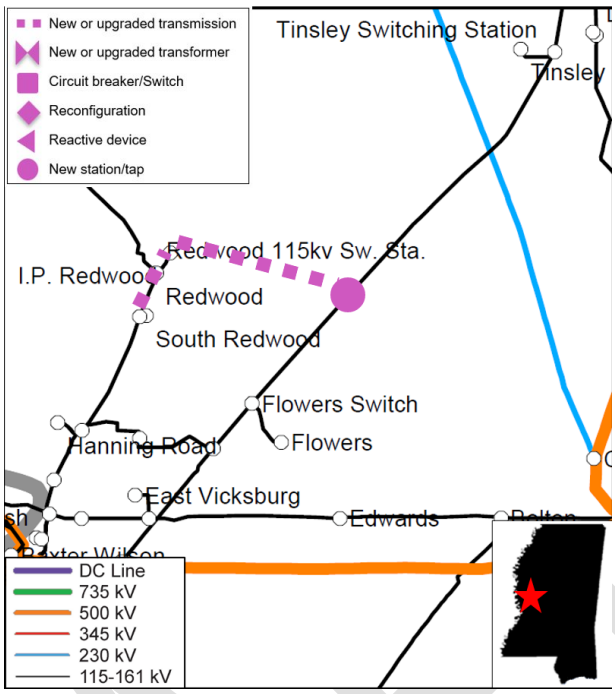


Figure 4.4.4-1: P23786 Geographic transmission map of project area

Cont. Type	Limiting Element	Low Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P3	EES-EMI-3REDWOOD+ 115 kV	0.95	0.91	0.98

Table 4.4.4-1: P23786 Voltage drivers

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23820	Gloster 13.8 kV Delivery Point	A new 13.8 kV feeder breaker will be added at the Entergy Mississippi LLC owned Gloster substation in order to serve Cooperative Energy's distribution member's new customer.	6/1/2024	$0.48

Projects Driven by Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
12210	South Hattiesburg Industrial Delivery Point	In order to serve the South Hattiesburg and Hattiesburg Industrial delivery points economically and reliably, service will be established by tapping L161 and constructing a 161 kV breaker switching station. A new distribution station will be constructed adjacent to the 161 kV switching station and the existing distribution feeders from both delivery points will be routed to the new station.	6/1/2025	$13.8
23941	Silver Creek Delivery Point	In order to serve the Silver Creek delivery point economically and reliably, service will be established by tapping the Cooperative Energy owned Line 571 115 kV line. A 115 kV GOAB will be installed at the tap point and a new 115 kV tap line will be constructed to the delivery point.	12/1/2024	$2
12222	Maxie Delivery Point	In order to serve the Maxie delivery point economically and reliably, service will be established by a short transmission feed by tapping the Cooperative Energy Lines 37 and 38 that are near the delivery point.	6/1/2023	$2

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23126	J1249 Morrow Repower	A single steam turbine unit will be repowered at Plant Morrow for combined cycle operation utilizing a new natural gas fired combustion turbine (CT).	3/1/2023	$16

4.4.5 East Texas Electric Cooperative (ETEC)

After MISO's independent reliability analysis, MISO and East Texas Electric Cooperative recommend one Other Project at an estimated cost of $3.7 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

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Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24460	Coldspring Load Addition	Phase I - Reconductor a 4.25-mile distribution circuit from the 138 kV Coldspring Substation to the customer facility to serve 5 MW of new load. Phase II - Adds power transformer and distribution bay to serve an additional 16.2 MW of new load.	Phase I: 5/31/2023 Phase II: 7/31/2024	Phase I: $1.3 Phase II: $2.4

4.4.6 Entergy Arkansas LLC (EAL)

After MISO's independent reliability analysis, MISO and Entergy Arkansas recommend 12 projects at an estimated cost of $123 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, five are Baseline Reliability Projects, three are Other Projects, and four are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 19911 – Dumas – Reed 115 kV: Rebuild Line

Project Description: Rebuild the 15-mile 115 kV line from Dumas - Reed to a minimum through path rating of 259 MVA. The total estimated cost of this project is $18.6 million and has an expected in-service date of June 1, 2025.

Project Need: Thermal overloads on the Dumas - Reed 115 kV line for the loss of the Sterlington - El Dorado 500 kV or Sterlington - El Dorado 500 kV/Sterlington - El Dorado East 115 kV double circuit. (NERC TPL P1.2 and P7.1 events)

Alternatives Considered: No alternatives were considered.

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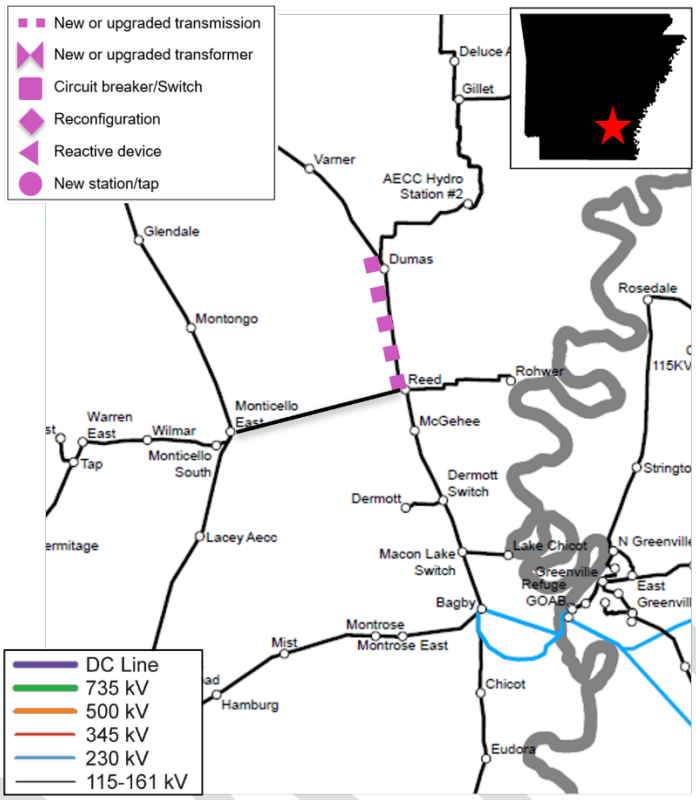


Figure 4.4.6-1: P19911 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P1-2	Dumas – Reed 115 kV	106	119	<99
P7-1	Dumas – Reed 115 kV	106	115	<99

Table 4.4.6-1: P19911 Thermal loading drivers

Project 21807 – Brinkley East Autos: Change Tap Settings 230/115 kV

Project Description: Change the high side taps on the Brinkley East 230/115 kV Auto to 242 kV (230 kV Auto completed on 3/8/2022). The total estimated cost of this project is $0.02 million and has an expected in-service date of March 1, 2023.

Project Need: These tap setting changes are needed to mitigate high voltage around the Brinkley area for the loss of the Walnut Bend Solar plant and the Brinkley East - Marianna 115 kV line section. This is a P2.3 contingency.

Alternatives Considered: No alternatives were considered.



Figure 4.4.6-2: P21807 Geographic transmission map of project area

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P2-3	Brinkley 115 kV Bus	1.05	1.07	1.00

Table 4.4.6-2: P21807 Voltage drivers

Project 23855 – Keo 500 kV Bus Reconfigure

Project Description: Reconfigure the Keo 500 kV substation so that the Keo – White Bluff & Keo - Wrightsville 500 kV lines are not lost for a P2.3 internal breaker fault. The total estimated cost of this project is $15.02 million and has an expected in-service date of December 1, 2027.

Project Need: The P2.3 internal breaker fault resulting in the simultaneous loss of the Keo – White Bluff & Keo - Wrightsville 500 kV lines cause thermal overloads on the Conway S. – Ranchette 161 kV, Jacksonville North – Holland Bottom 115 kV, and Jacksonville North – Sylvan Hill 115 kV line sections as well as near thermal overload on the Fourche – LR East 115 kV line section. Compliance with NERC TPL 001-5.

Alternatives Considered: No alternatives were considered.

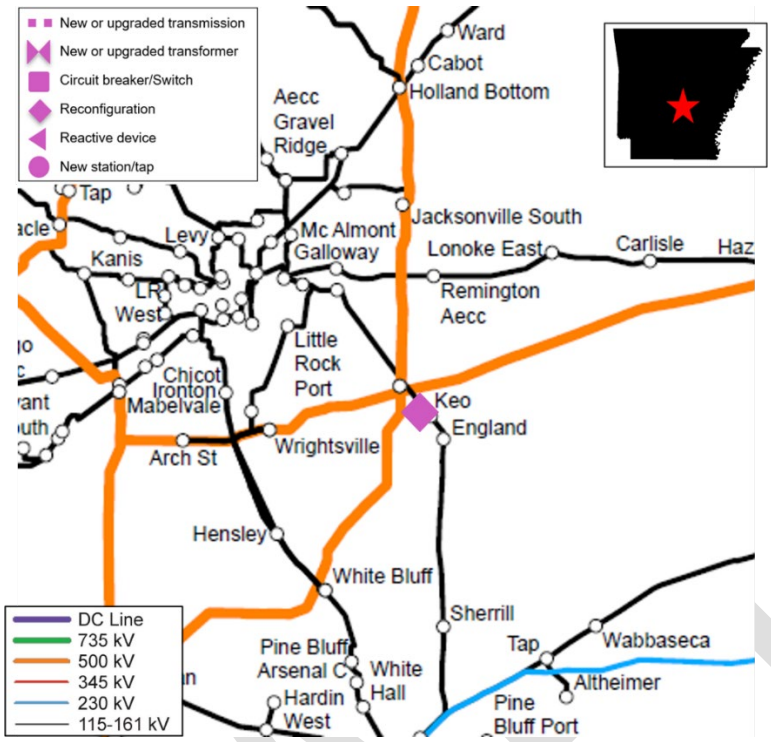


Figure 4.4.6-3: P23855 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P2-3	Jacksonville North – Holland Bottom 115 kV	298	101	<99

Table 4.4.6-3: P23855 Thermal loading drivers

Project 23898 – McNeil 500 kV Relay Improvement SPOF

Project Description: Ensure the McNeil – El Dorado 500 kV line, the McNeil 500/115 kV auto and the McNeil – Etta 500 kV line have redundant high-speed protection. This includes protection schemes with independent CT and PT winding inputs. Ensure dual battery installations or monitoring sufficient to FERC 754 guidelines. The total estimated cost of this project is $3.97 million and has an expected in-service date of December 1, 2026.

Project Need: Potential for up to ~7 GW of generation trip (ANO 1&2, Union CCGT, Ouachita CCGT, Perryville CCGT, Murray Hydro, etc.) for a 3PH fault on the McNeil 500 kV bus with non-redundant relay failure for the McNeil – El Dorado 500 kV line protection, McNeil 500/115 kV auto protection, or the McNeil – Etta 500 kV line protection.

Alternatives Considered: No alternatives were considered.

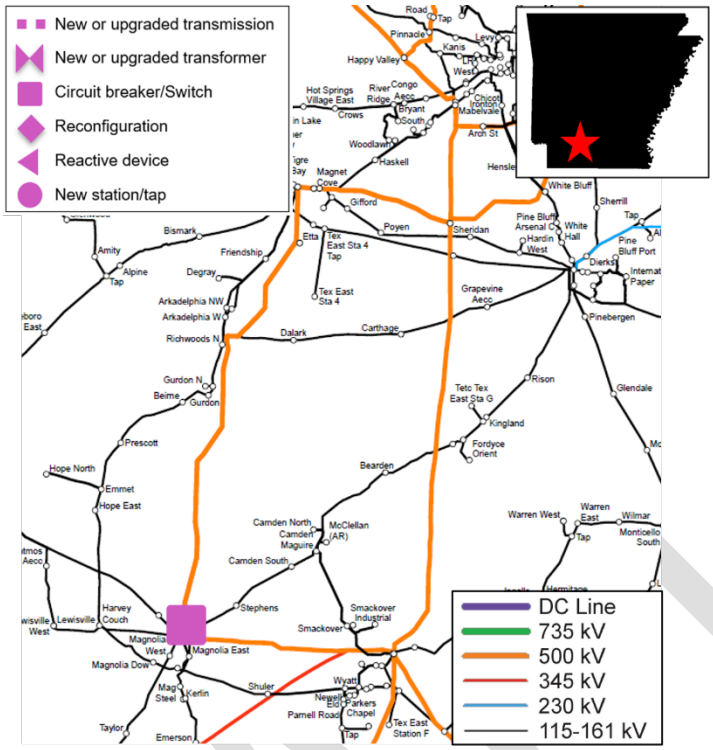


Figure 4.4.6-4: P23898 Geographic transmission map of project area

Project 23900 – Dell 161 kV Breaker Upgrades

Project Description: Upgrade Dell 161 kV Breakers B2240, B2205, and B2235 with a 63 kA breaker. The total estimated cost of this project is $2.52 million and has an expected in-service date of June 1, 2025.

Project Need: The Dell 161kV Breakers B2240, B2205 and B2235 are underrated. This project is to maintain compliance with NERC TPL-001-5 and Entergy's Local Transmission Criteria.

Alternatives Considered: No alternatives were considered.

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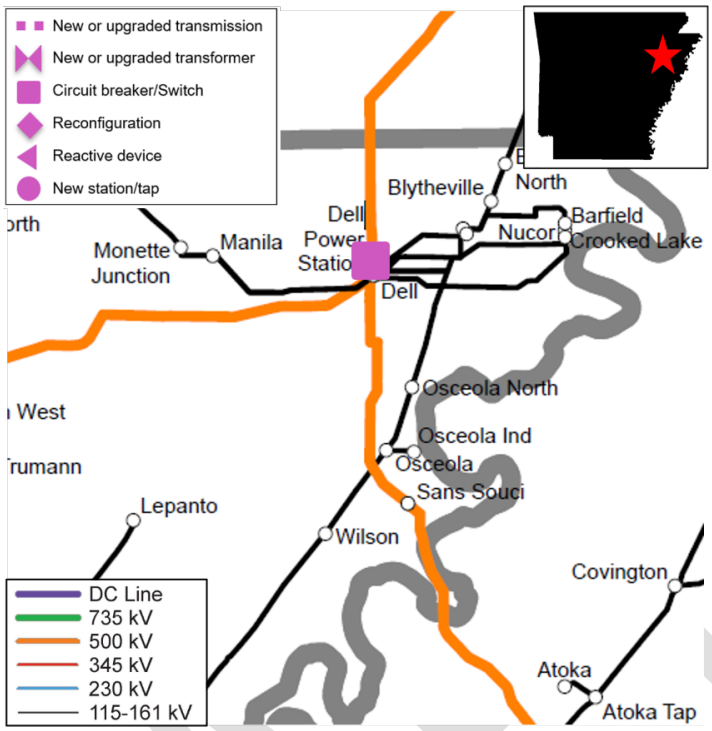


Figure 4.4.6-5: P23900 Geographic transmission map of project area

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
12055	Gum Springs 115 kV: Build Breaker Station	Create a new 115 kV switching station by tapping the Arkadelphia North – Richwood 115 kV and the Arkadelphia West – Dalark 115 kV line sections.	6/1/2026	$14.95

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24938	Driver - Hybar 230 kV: New transmission line	Entergy Arkansas will build a new 2 mile 230 kV radial transmission line from the Driver 230kV substation to a new customer build Hybar 230 kV substation. A new circuit breaker and relay upgrades will be needed at Driver 230 kV substation. Two 500 kV transmission lines will be raised for the new 230 kV line crossing.	5/1/2025	$10.63

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23899	2024 EAL Asset Renewal Program	The AM renewal asset program is to address aging and failing transmission assets across EAL's territory.	12/31/2024	$24.64

Generator Interconnection Projects:

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24697	Aurelle 115 kV: POI for J1612	A new point of interconnection for J1612 100 MW solar project. The interconnection customer will install the SANU. Network Upgrades at El Dorado 115 kV and Sterlington 115 kV will be installed by Entergy as well as the transmission line cut in. New underground fiber will be installed between Strong and Huttig tap stations.	11/27/2024	$13
24879	Prairie Creek 161 kV: POI for J1816	A new interconnection three breaker ring-bus substation will be constructed on the Fisher - Cherry Valley 161 kV transmission line. Line protection and breaker control panels will be installed at Newport and Parkin 161 kV stations. The existing wave trap will be removed from Pecan Street 161 kV station. New underground fiber will be installed between Prairie Creek and Cherry Valley 161 kV substation.	11/1/2025	$12.6
24898	Flat Lake 161 kV J1562: Cut-in Switching Station	The interconnection customer will self-build the switching station needed to interconnect J1562 200 MW solar project. The cut-in will connect the new POI station to the existing Blytheville I-55 and AECC Blytheville North 161 kV line section. Entergy will install a new line protection panel and breaker control panel at Blytheville I-55 161 kV substation and AECC Blytheville North 161 kV substation. Two existing breakers at Blytheville Elm St. 161 kV will also be replaced with new surge arresters, line protection and breaker control panels and a new RTU. New underground fiber will be installed between the new POI station to	1/31/2025	$5.2

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		Blytheville I-55 and AECC Blytheville North substations.		
24918	Hamrick 161 kV J1842: Cut-in Switching Station	The Hamrick 161 kV switching station will be constructed for the 135 MW wind farm (J1842) per the terms of the executed GIA. The wind farm will be connected by a four-mile 161 kV gen-tie line to the new Hamrick 161 kV SS that will be constructed by the Interconnection Customer. Entergy Arkansas will construct the 161 kV cut-in as well as relay settings updates at the remote end stations. New underground fiber will also be installed between Hamrick and Wynne South 161 kV.	10/31/2024	$2.1

4.4.7 Entergy Louisiana LLC (ELL)

After MISO's independent reliability analysis, MISO and Entergy Louisiana recommend 32 projects at an estimated cost of $2.5 billion to be approved for inclusion in MTEP23 Appendix A. Of these projects, five are Baseline Reliability Projects, 12 are Other Projects, and 15 are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects:

Project 12098 - Delmont to Hazel 230 kV: Upgrade Line

Project Description: Upgrade the Delmont to Hazel 230 kV conductor, bus work at both the stations, line bay bus, jumpers and any station equipment to a minimum of 1600 A. The total estimated cost of this project is $15.6 million and has an expected in-service date of June 1, 2026. This project meets the criteria requirements to be a potential immediate need reliability project (INRP) being a 230 kV BRP, costing more than $5 million dollars, and in service within 36 months. The project has a low lead time due to being a short path to upgrade (1.9 miles).

Project Need: NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines and Criteria. For the P3.2 loss of the Exxon to Downtown 230 kV line with the loss of Waterford 3 generation the Delmont to Hazel 230 kV line overloads. P6 Willow Glen-Pecue 230 kV with Willow Glen to Harelson 230 kV will overload the Delmont to Hazel 230 kV.

Alternatives Considered: No alternatives were considered.

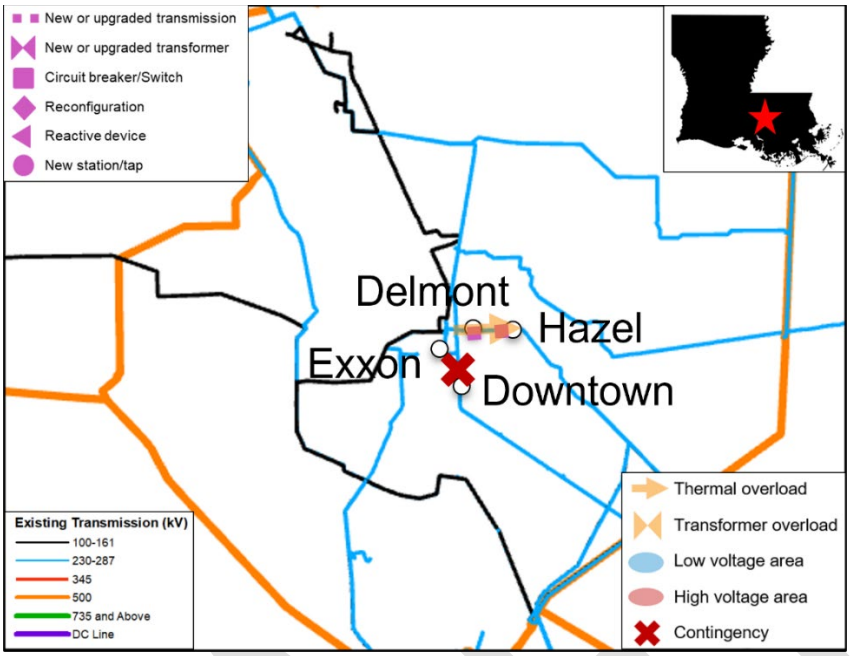


Figure 4.4.7-1: P12098 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P3	Delmont – Hazel 230 kV	361	79	41
P6	Delmont – Hazel 230 kV	361	108	61

Table 4.4.7-1: P12098 Thermal loading drivers

Project 15654 - Delhi - Tallulah 115 kV rebuild

Project Description: Rebuild 20.7 miles of 115 kV line from Delhi to Tallulah. Operate the series reactor at Delhi as normally open. The total estimated cost of this project is $39.9 million and has an expected in-service date of December 1, 2026.

Project Need: NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines and Criteria. The P1 loss of Perryville to Baxter Wilson 500 kV line and the P3 loss of the Baxter Wilson - Perryville 500 kV line coupled with the loss of Grand Gulf generation overloads the Delhi to Tallulah 115 kV line.

Alternatives Considered: No alternatives were considered.

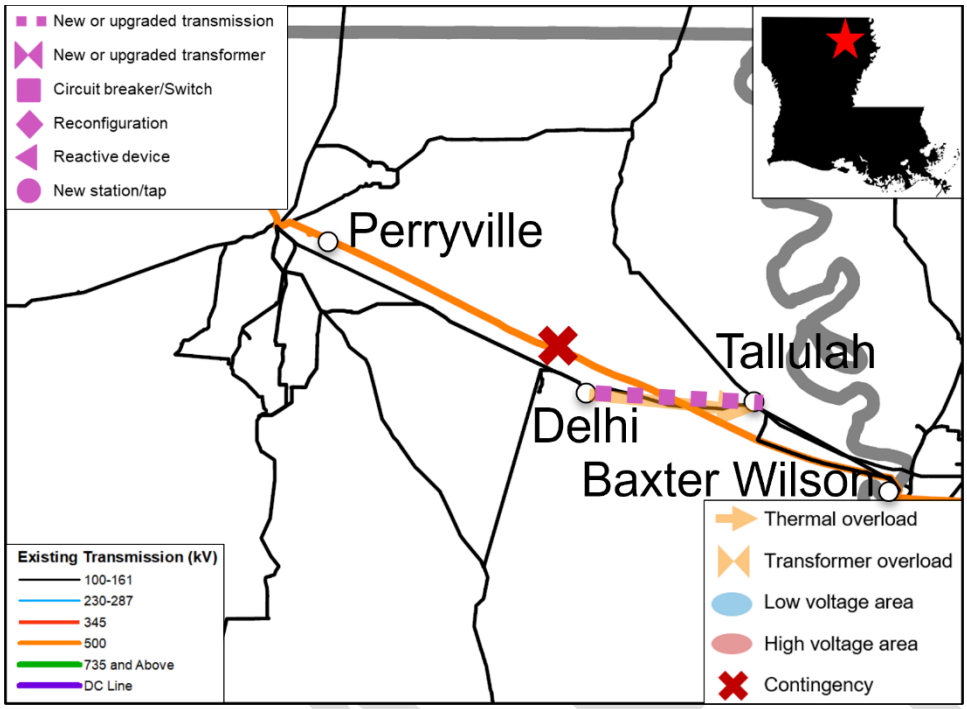


Figure 4.4.7-2: P15654 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P3	Delhi– Tallulah 115 kV	80	126	35

Table 4.4.7-2: P15654 Thermal loading drivers

Project 18236 - Winnsboro to Gilbert 115 kV: Rebuild Line

Project Description: Rebuild approximately 9.5 miles of 115 kV line from Winnsboro to Gilbert. The total estimated cost of this project is $20.9 million and has an expected in-service date of December 1, 2026.

Project Need: NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines and Criteria. P7 category event resulting in the loss of Perryville to Baxter Wilson 500 kV & Baxter Wilson to Tallulah 115 kV double circuit lines causes high loading on the Winnsboro to Gilbert 115 kV line in North Louisiana.

Alternatives Considered: No alternatives were considered.

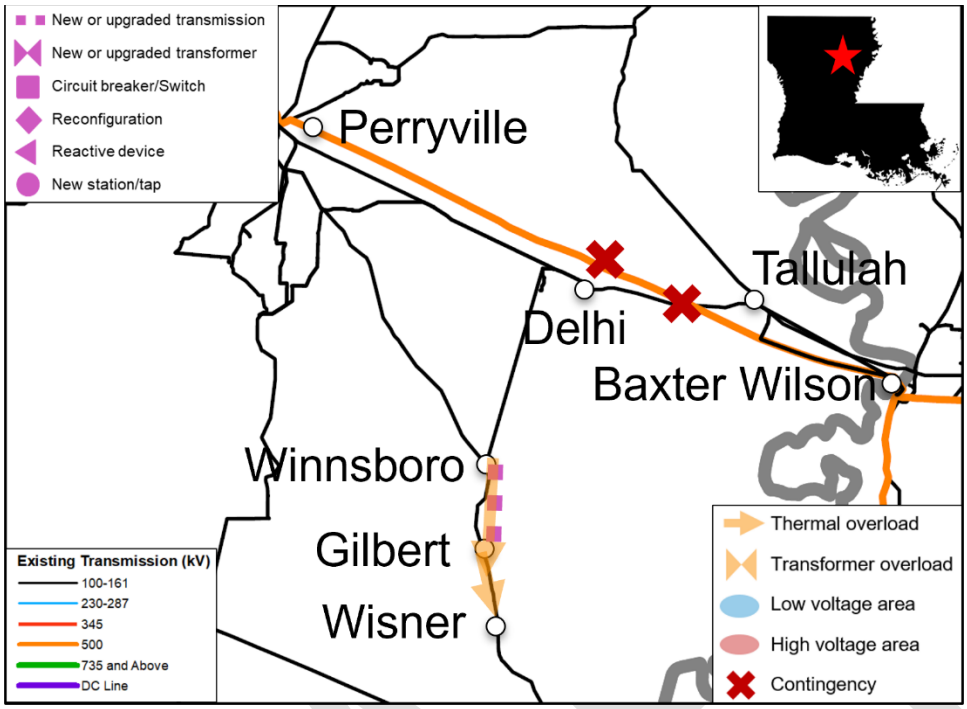


Figure 4.4.7-3: P18236 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P7	Winnsboro – Gilbert 115 kV	111	106	46

Table 4.4.7-3: P18236 Thermal loading drivers

Project 18247 - Gilbert to Wisner 115 kV: Rebuild Line

Project Description: Rebuild Gilbert to Wisner 115 kV line. The line will be built using a double circuit configuration but only strung on one side. The unused side will be reserved for a future 230 kV line. The total estimated cost of this project is $11.9 million and has an expected in-service date of December 15, 2027.

Project Need: NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines and Criteria. P7.1 loss of Perryville to Baxter Wilson 500 kV and Tallulah to Baxter Wilson 115 kV line overloads the Gilbert to Wisner 115 kV line.

Alternatives Considered: No alternatives were considered.

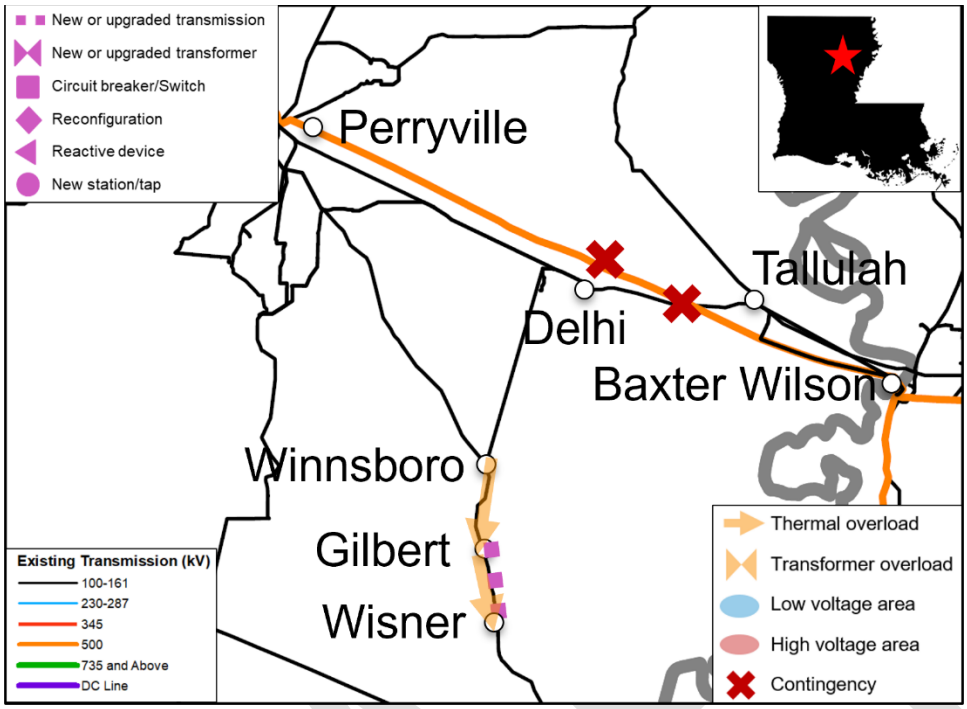


Figure 4.4.7-4: P18247 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P7	Gilbert – Wisner 115 kV	115	97	44

Table 4.4.7-4: P18247 Thermal loading drivers

Project 23937 - Willow Glen 138 kV Reconnect Bus

Project Description: Construct rigid bus to tie in the Willow Glen 138 kV southwest bus and southeast bus together. The total estimated cost of this project is $2.9 million and is currently in service.

Project Need: NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines and Criteria. P2 Internal breaker fault at Willow Glen 138 kV causes thermal overload on Willow Glen to Alchem 138 kV line and near overload on Geigy to Stauffer 138 kV.

*In the MTEP22 2025 Summer peak model, Willow Glen – Alchem 138 kV was at 100% loading during the P2 event.

Alternatives Considered: No alternatives were considered.

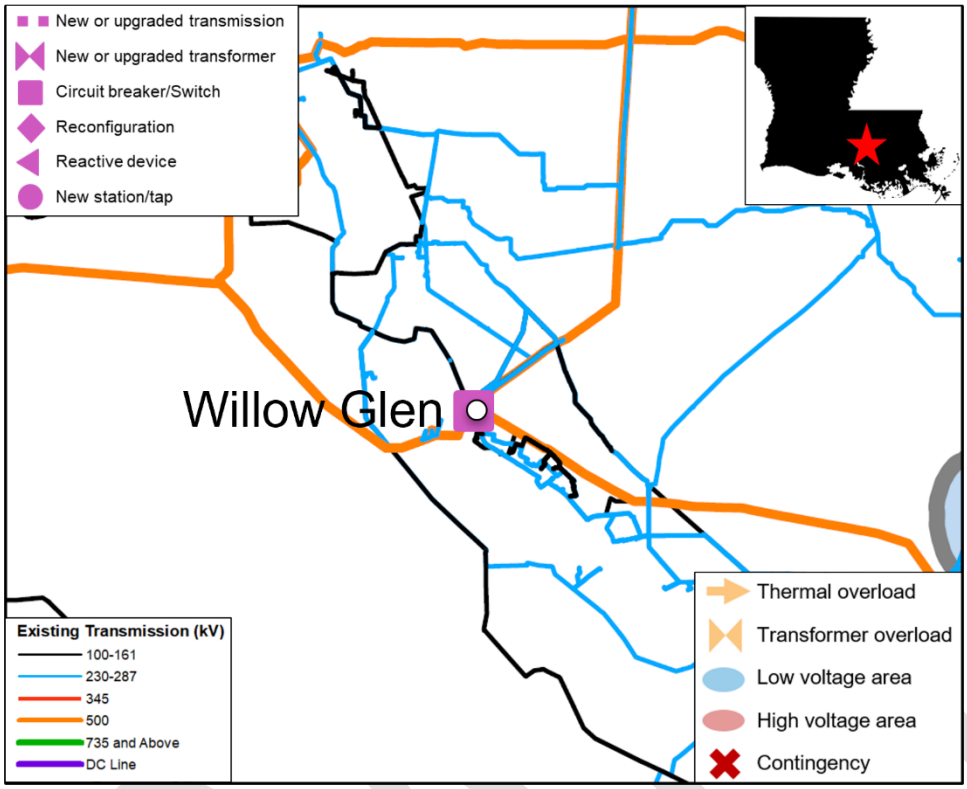


Figure 4.4.7-5: P23937 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P2	Willow Glen – Alchem 138 kV	282	84*	N/A

Table 4.4.7-5: P23937 Thermal loading drivers

Other Projects

Project 25242 - Amite South Reliability Project - Phase 1 Alternative 500/230 kV

Project Description: This project was selected as an alternative to projects 23935 – DSG Reliability and Resiliency and 23954 – Amite South Reliability Project. The scope of the project:

- Construct 500/230 kV Commodore station near the existing Derrick 230 kV Station
  - Cut in Derrick to Iberville and Richardson to Wise 230 kV lines.
  - Cut in the Webre to Bayou Labutte 500 kV line
  - Install one 500-230 kV Autotransformer
  - Commodore 230 kV station will be a breaker and half station
  - Commodore 500 kV station will be a 4 breaker ring

- Construct a new ~60 mile 230 kV line between Commodore and Waterford.
- Construct a new ~85 mile 500 kV line between Commodore and Churchill.
- Expand Waterford 500 kV into a three-breaker ring. Add additional bay at Waterford 230 kV to accommodate the new 230 kV line.
- Construct a new 500 kV four-breaker ring at Churchill, to accommodate two 500 kV lines and two Autotransformers. Install two 500-230 kV Autotransformers.
- Convert existing Waterford to Churchill 230 kV to 500 kV operation.

The total estimated cost of this project is $1.7 billion and has an expected in-service date of July 1, 2028.

Project Need: Improved extreme event resilience - Provides two EHV paths between Baton Rouge and Waterford. Location of line provides geographic diversity that can be useful in restorations during Extreme Weather Events.

Operational flexibility and preparing for future of generation in Amite South/DSG - Addressing generation retirements in Amite South, which could be accelerated by proposed EPA rules. Offers the opportunity to cut multiple sources into existing stations serving customers.

Meet Local Planning Criteria for load serving capability - Increases Load Serving Capability in Amite South. Helps meet needs of increased block load requests on the west bank of the river by providing a new 500 kV and 230 kV path. Only one 230 kV path exists today.

Entergy provided MISO with future generation retirements and future load growth assumptions that do not meet the requirements to be studied through the normal MTEP process. In order to test the reliability of the system, MISO created a set of sensitivity models that included the future generation retirements and load growth assumptions and applied them to the MTEP23 models. MISO verified that this project was needed to alleviate several thermal issues to reliably serve load in the sensitivity models.

Alternatives Considered: Two alternatives, outlined below, were considered for this project. Alternative 2 was determined to be infeasible due to restrictions at the Bayou Labutte station that prevented expansion and was not chosen. Alternative 1 also replaces the DSG Reliability & Resiliency Project and is comparable to the Amite South Phase 1 and DSG projects in terms of cost and feasibility. This project grows the load serving capability in the Amite South and DSG load pockets more effectively than the two projects that it replaces by providing an extended 500 kV circuit through both the Amite South and DSG load pockets and tying the 500 kV and 230 kV systems together at two stations instead of one. Alternative 1 was ultimately selected over the other options.

Alternative 1:

- Construct 500/230 kV Commodore station near the existing Derrick 230 kV Station. Install one 500-230 kV Autotransformer.
- Cut in Derrick to Iberville and Richardson to Wise 230 kV lines. Cut in the Webre to Bayou Labutte 500 kV line.
- Construct a new 60-mile 500 kV line with 230 kV under build between Commodore and Waterford.

- Install a second 500-230 kV Autotransformer at Waterford.

Alternative 2:

- Construct a new 80-mile 500 kV line between Bayou Labutte and Churchill.
- Install two 500-230 kV Autotransformers at Churchill.
- Construct a new 27-mile 500 kV line between Churchill and Waterford.

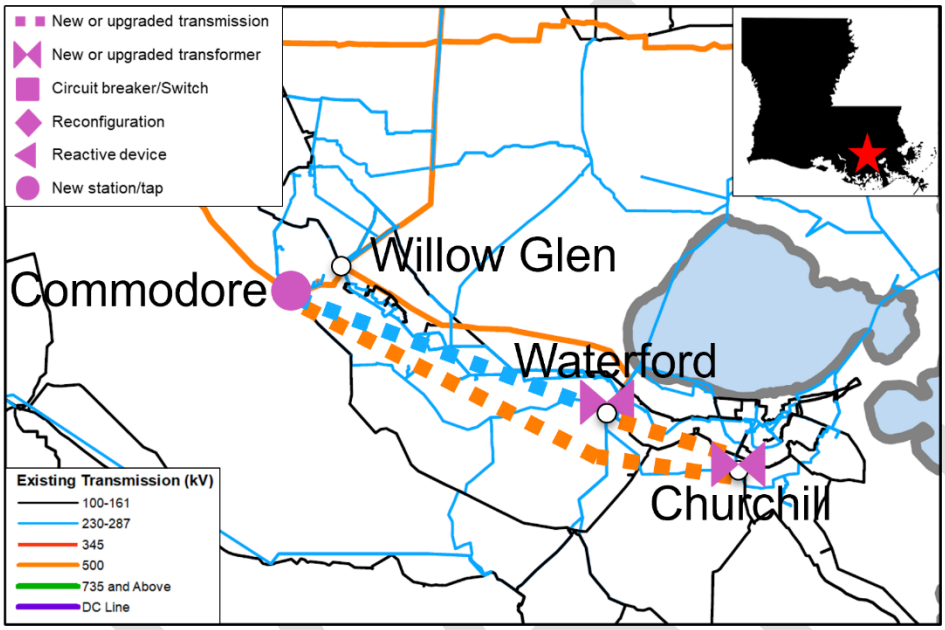


Figure 4.4.7-6: P23954 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P12	Nelson – Gooseport 128 kV	213	100.4	<99
P5	AAC Corp – Luce 230 kV	685	108	<99
P23	Bogalusa – Barkers Corner 230 kV	459	108	<99
P71	Bogalusa – Barkers Corner 230 kV	459	106	<99
P12	Bogalusa – Barkers Corner 230 kV	459	104	<99
P11	Bogalusa – Barkers Corner 230 kV	459	103	<99
P0	Donaldsonville – Bayou Everett 230 kV	459	126	<99
P71	Dow Meter – Tiger 230 kV	429	116	<99
P21	Dow Meter – Tiger 230 kV	429	105	<99

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P12	Dow Meter – Tiger 230 kV	429	105	<99
P23	Dow Meter – Tiger 230 kV	429	105	<99
P12	Evergreen – Wise 230 kV	519	162	<99
P22	Evergreen – Wise 230 kV	519	137	<99
P23	Evergreen – Wise 230 kV	519	136	<99
P11	Fancy Point – Riverbend 230 kV	1194	102	<99
P71	Northline – Cohen 230 kV	361	100	<99
P0	St. James – Sidney 230 kV	456	100.3	<99
P23	Talisheek – Bogalusa 230 kV	641	103	<99
P12	Talisheek – Bogalusa 230 kV	641	102	<99
P12	Vacherie – Waterford 230 kV	640	123	<99
P23	Vacherie – Waterford 230 kV	640	122	<99
P71	Vacherie – Waterford 230 kV	640	121	<99
P12	Waterford Tap – Waterford 230 kV	1195	102	<99
P0	Welcome – St. James 230 kV	418	205	<99
P23	Wise – Bayou Labutte 230 kV	1195	124	<99
P23	Bayou Labutte 500/230 kV	1195	119	<99
P21	Barkers Corner – Ramsay 230 kV	478	106	<99
P23	Barkers Corner – Ramsay 230 kV	478	100.5	<99

Table 4.4.7-6: P23954 Thermal loading drivers

Project 23957 - Amite South Reliability Project - Phase 2 500/230 kV

Project Description: Construct a 14-mile 230 kV line from the Willow Glen substation to the Conway substation. Station work at both Willow Glen and Conway including additional breakers to accommodate the new line. Construct a new 500 kV Station near Conway and install a 1200 MVA 500-230 kV Autotransformer. Build approximately five miles of 500 kV to cut the Willow Glen to Waterford 500 kV station into the new Conway 500 kV station. The total estimated cost of this project is $290 million and has an expected in-service date of June 30, 2026.

Project Need:

- Improved extreme event resilience - Provides an additional hardened path in the Industrial Corridor, that can be useful in restorations during events like a Hurricane. Reduces risk of extreme event involving Gypsy corridor.
- Operational flexibility and preparing for future of generation in Amite South - Addressing generation retirements in Amite South/DSG, which could be accelerated by proposed EPA rules. Provides opportunity to reduce radial exposure to industrial customers during outages.
- Meet Local Planning Criteria for load serving capability - Adds an additional source on the east bank of the river to address growing needs of new block load requests. Increases Load Serving Capability in Geismar area and Amite South.
- Entergy provided MISO with future generation retirements and future load growth assumptions that do not meet the requirements to be studied through the normal MTEP process. In order to test the reliability of the system, MISO created a set of sensitivity models that included the future generation retirements and load growth assumptions and applied them to the MTEP23 models. MISO verified that this project was needed to alleviate several thermal issues to reliably serve load in the sensitivity models.

Alternatives Considered: Two alternatives, outlined below, were considered for this project. Alternative 1 was not chosen due to the higher cost of the river crossing. Planning engineers determined that alternative 2 did not resolve the reliability violations as well as the Amite South Phase 2 project. Neither alternative was determined to be a viable replacement for the proposed project, so neither was selected.

Alternative 1:

- 500 kV tap + Commodore – Conway 230 kV line.
- Scope: Tap the Willow Glen – Waterford line (new 500 kV sub.), five mi. 500 kV line, 500/230 kV AT, expand Conway 230 kV substation, 20 mi. 230 kV line from Commodore to Conway, River Crossing.

Alternative 2:

- Construct a new 500/230 kV substation near Panama 230 kV.
- Add one 500/230 kV transformer.
- Build approximately six miles of 500 kV to cut the Willow Glen to Waterford 500 kV station into the new 500 kV station.

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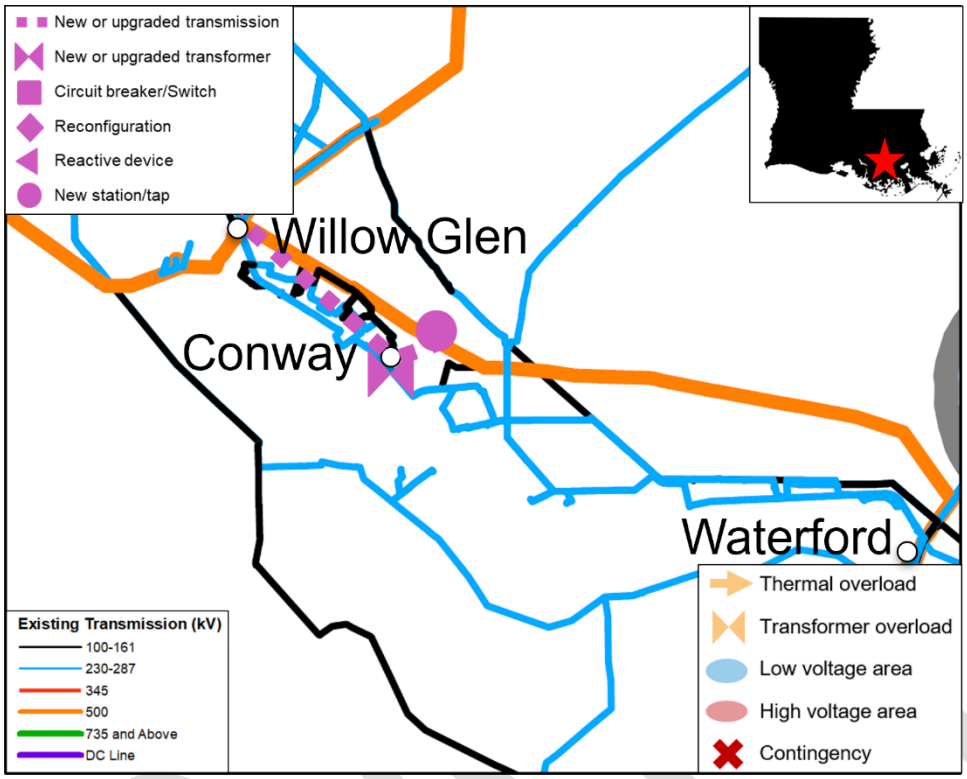


Figure 4.4.7-7: P23957 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P5	AAC Corp – Luce 230 kV	685	108	<99
P23	AAC Corp – Luce 230 kV	685	107	<99
P12	AAC Corp – Luce 230 kV	685	103	<99
P71	Addis – Northline 230 kV	361	104	<99
P12	Bogalusa – Barkers Corner 230 kV	459	102	<99
P23	Bogalusa – Barkers Corner 230 kV	459	101	<99
P71	Dow Meter – Tiger 230 kV	429	105	<99
P21	Dow Meter – Tiger 230 kV	429	105	<99
P12	Dow Meter – Tiger 230 kV	429	105	<99
P23	Dow Meter – Tiger 230 kV	429	105	<99
P71	Northline – Cohen 230 kV	361	100.2	<99
P23	South Port – Ninemile 230 kV	780	100.4	<99

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P5	Vacherie – Waterford 230 kV	640	104	<99
P12	Vacherie – Waterford 230 kV	640	103	<99
P22	Vacherie – Waterford 230 kV	640	103	<99
P23	Vacherie – Waterford 230 kV	640	103	<99
P23	Barkers Corner – Ramsey 230 kV	478	100.5	<99

Table 4.4.7-7: P23957 Thermal loading drivers

Project 23959 - Amite South Reliability Project - Phase 3 230 kV

This project and its alternatives are still under evaluation by MISO and will seek approval after December 2023.

Project Description: Construct a 40-mile 230 kV line from the Adams Creek substation to the Robert substation. Station work at both Adams Creek and Robert including additional breakers to accommodate the new line. The total estimated cost of this project is $260 million and has an expected in-service date of November 16, 2027.

Project Need: Meet Local Planning Criteria for load serving capability - Increases Load Serving Capability in Amite South.

Operational flexibility and preparing for future of generation in Amite South - Addressing generation retirements in Amite South, which could be accelerated by proposed EPA rules.

Improved extreme event resilience - Provides an additional hardened path into Amite South, that can be useful in restorations during Hurricane and other extreme weather events.

Entergy provided MISO with future generation retirements and future load growth assumptions that do not meet the requirements to be studied through the normal MTEP process. In order to test the reliability of the system, MISO created a set of sensitivity models that included the future generation retirements and load growth assumptions and applied them to the MTEP23 models. MISO verified that this project was needed to alleviate several thermal issues to reliably serve load in the sensitivity models.

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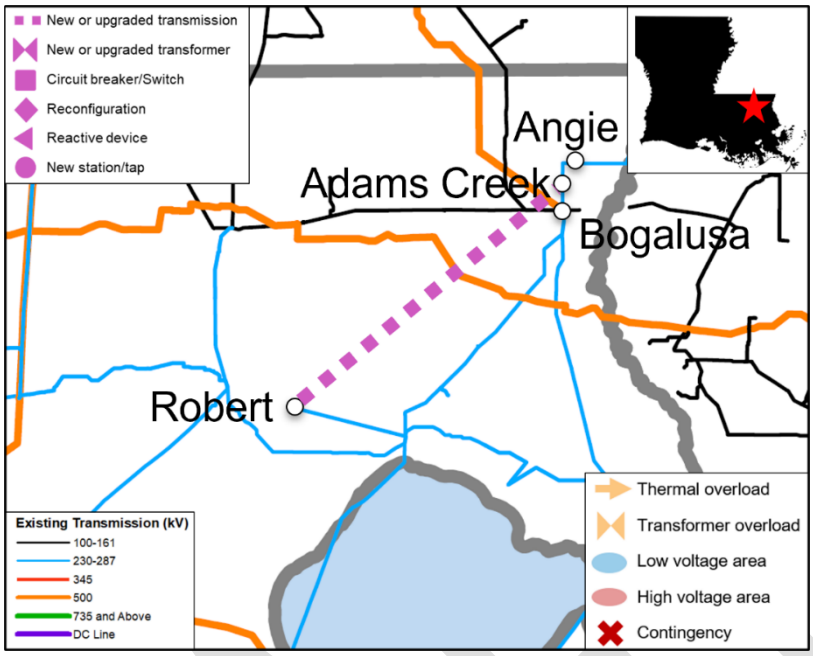


Figure 4.4.7-8: P23959 Geographic transmission map of project area

Alternatives Considered: Two alternatives are being considered for this project.

Alternative 1:

- McKnight/Daniel Tap – Michoud 500 kV line.
- Scope: Expand 500 kV Bogalusa, New 500 kV Bogue Chitto sub, 11 mi. 500 kV line from Bogalusa – Bogue Chitto, Bogue Chitto – Michoud land 27 mi., Bogue Chitto – Michoud lake 18 mi., 500/230 kV AT at Michoud, new 500 kV Michoud sub.

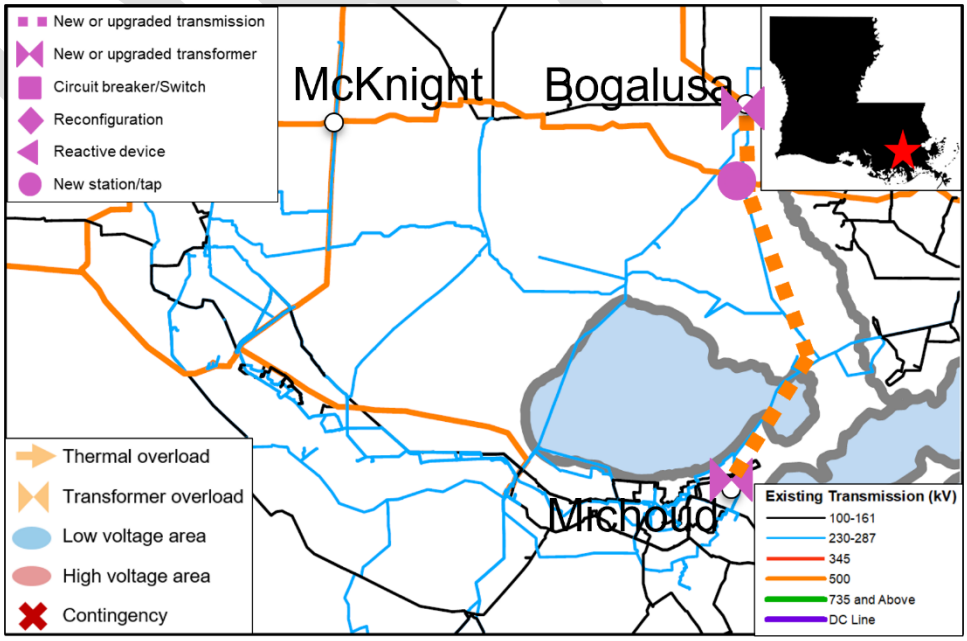


Figure 4.4.7-9: P23959 Alternative 1 Geographic transmission map of project area

Alternative 2:

- Tap McKnight to Daniel 500 kV to create a new substation (Bogue Chitto).
- Build a new 500 kV line between Bogue Chitto and Bogalusa.
- Build a new 500 kV line between Bogue Chitto and Little Gypsy.

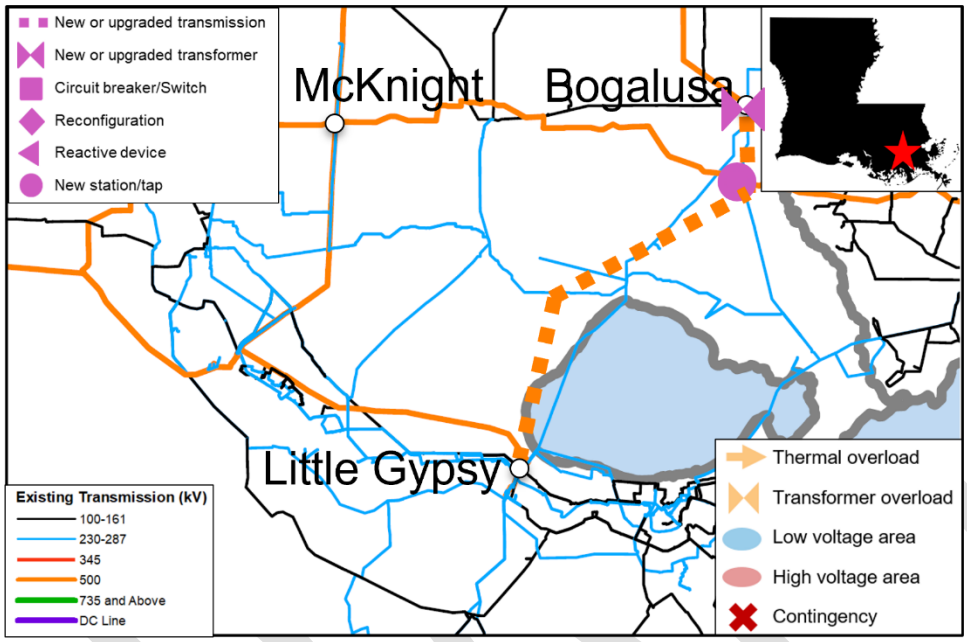


Figure 4.4.7-10: P23959 Alternative 2 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P12	Adams Creek – Bogalusa 230 kV	883	114	<99
P23	Adams Creek – Bogalusa 230 kV	883	113	<99
P23	Bogalusa – Barkers Corner 230 kV	459	120	<99
P71	Bogalusa – Barkers Corner 230 kV	459	120	<99
P21	Bogalusa – Barkers Corner 230 kV	459	120	<99
P12	Bogalusa – Barkers Corner 230 kV	459	120	<99
P5	Bogalusa – Barkers Corner 230 kV	459	116	<99
P12	Dow Meter – Tiger 230 kV	429	100.3	<99
P71	Northline – Cohen 230 kV	361	100.2	<99
P23	Talisheek – Bogalusa 230 kV	641	111	<99

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P12	Talisheek – Bogalusa 230 kV	641	110	<99
P71	Talisheek – Bogalusa 230 kV	641	110	<99
P12	Vacherie – Waterford 230 kV	640	100	<99
P71	Vacherie – Waterford 230 kV	640	100	<99
P23	Barkers Corner – Ramsay 230 kV	478	113	<99
P71	Barkers Corner – Ramsay 230 kV	478	112	<99
P12	Barkers Corner – Ramsay 230 kV	478	110	<99

Table 4.4.7-8: P23959 Adams Creek to Robert 230kV Thermal loading drivers

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
9764	Dixie Baker to Baker 69 kV: Reconductor Line	Upgrade the Dixie Baker to Baker 69 kV line section. This includes a reconductor/rebuild and upgrading substation equipment.	6/1/2026	$12.8
12084	Dixie Baker to Zachary 69 kV: Upgrade Line	Upgrade the ~3.3 mile long line section.	6/1/2027	$18.9
23881	Holiday to Lafayette 69 kV: Reterminate into Elks	Re-terminate the Holiday to Lafayette 69 kV line into the LUS Elks 69 kV substation, creating an Elks to Holiday 69 kV path. Demolish the unused portions of the Holiday - Lafayette 69 kV line. Upgrade/Rebuild Holiday to Elks line.	6/1/2025	$29.4
23882	Barnett Oil Mill 69 kV Relocation	Build new 69 kV T-line from Barnett Oil Mill Sub to a tap point on the existing CLECO Guidry to South Park 69 kV line. Install new 3-way motor operated GOAB switch cut-in to CLECO T-line. Demolish the L-658 69 kV T-line from the BROM Tap to the Barnett Oil Mill substation. Some of the L-658 structures support CLECO distribution facilities. That distribution will be relocated and/or rebuilt.	6/1/2025	$23.7

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23924	Mossville 69 kV Upgrade Breaker 17955	Breaker number 17955 at the Mossville 69 kV substation will be replaced due to the short circuit analysis.	6/1/2024	$3.6
23938	Port Hudson - Jackson 69 kV: Switch upgrades	This project is to upgrade switches on the Port Hudson to Jackson 69 kV line to increase the through path rating of the line.	12/1/2024	$3.9
23939	Blount to Devil Swamp New 69 kV line	Construct new 2.8 mile line from the existing Blount to Devil Swamp 69 kV stations.	6/1/2025	$32.3
23940	Tiger 69 kV: Bus upgrades	Upgrade the Tiger 69 kV bus tie, including breakers and switches, to increase through path rating.	6/1/2025	$1.5

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23934	2024 ELL Asset Renewal Program	This project is for the ELL Asset Renewal Program that will be executed in 2024. The asset renewal programs replace aged and/or degraded transmission line and transmission substation assets. Entergy continuously reviews asset health to prioritize those replacements and the specifics for the 2024 asset renewal plans have not yet been finalized.	12/31/2024	$43.9
23946	MTEP23 ELL Capacitor Bank Retirements	Retire the Snakefarm 115 kV and Jaguar 69 kV capacitor banks.	12/31/2023	$0.0

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24053	J1431 Interconnection Project at Vacherie 230 kV	Facilities required for the interconnection of J1431 at the existing Vacherie 230 kV substation.	5/1/2024	$1.4

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24094	J1463 Interconnection: Bueche 230 kV Station	This project is to support the interconnection of solar project J1463 at the new Bueche 230 kV station on the 230 kV line 731 (Addis to Big Cajun).	11/1/2023	$0.1
24252	MPFCA J1246, J1367, J1465: Install 2nd Bayou Labutte 500-230 kV Autotransformer and Construct New Wise to Bayou Labutte 230 kV Line	Install 2nd 500-230 kV Autotransformer at Bayou Labutte 500 kV, including all associated station and relay work. Construct new Wise to Bayou Labutte 230 kV line, including all associated station and relay work.	9/20/2025	$45.2
24253	MPFCA J1246, J1421, J1463: Willow Glen 230 kV Breaker Replacements	Replace sixteen 230 kV breakers at Willow Glen 230 kV station with IPO circuit breakers rated at 80 kA.	8/9/2025	$16.5
24254	J1465 138 kV Interconnection Station	This project is to support the interconnection of J1465 on 138 kV line between existing Livonia and Colonial Springs stations.	6/1/2025	$14.4
24272	J1421 230 kV Interconnection Project	This project is to support the interconnection of solar project J1421 at a new station cut in between Colfel and Moler 230 kV stations. Convert Moler 230 kV into a four-breaker ring bus. Upgrade the Coly to Moler 230 kV line as identified during the MISO DPP cycle.	3/1/2026	$32.3
24861	J1583 Interconnection on Evergreen to Donaldsonville 230 kV	Facilities required for the interconnection of J1583 on the Evergreen to Donaldsonville 230 kV.	6/1/2025	$5.0
24862	J1644 Generator Interconnection on Champagne to Plaisance 138 kV	Facilities required for the interconnection of J1644 on the Champagne to Plaisance 138 kV.	12/15/2024	$4.3
24985	J1827 Generator Interconnection Bastrop Tap 115 kV	Facilities required for the interconnection of J1827 at the Bastrop Tap 115 kV station.	4/1/2026	$18.5
24986	J1795 Generator Interconnection on Richard to Bayou Cove 138 kV(Ln 258)	Facilities required for the interconnection of J1795 on the Richard to Bayou Cove 138 kV Line 258.	12/4/2025	$17.7
25083	J1794 Generator Interconnection on Richard to Scott 138 kV	Facilities required for the interconnection of J1794 on the Richard to Scott 138 kV.	5/6/2025	$12.8

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
25101	J1564 Generator Interconnection on the Bogalusa to Talisheek 230 kV	Facilities required for the interconnection of J1564 on the Bogalusa to Talisheek 230 kV.	12/22/2025	$18.8
25122	J1542 Generator Interconnection on Vacherie to Chackbay 230 kV	Facilities required for the interconnection of J1542 on the Vacherie to Chackbay 230 kV.	6/1/2026	$19.3
25140	J1669 Generator Interconnection on Lake Charles Bulk to Henning 138 kV	Facilities required for the interconnection of J1669 on the Lake Charles Bulk to Henning 138 kV.	12/4/2025	$16.9
25143	J1602 Generator Interconnection at Rilla 115 kV	Facilities required for the interconnection of J1602 at Rilla 115 kV. The J1602 battery will be interconnected behind the main step up transformer for J1239 (Rilla 115 kV POI).	10/25/2024	TBD

4.4.8 Entergy Mississippi LLC (EML)

After MISO's independent reliability analysis, MISO and Entergy Mississippi recommend six projects at an estimated cost of $97.3 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, three are Other Projects and three are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
15708	North Jackson 115 kV: Install Circuit Breakers	Install Transmission Breakers at North Jackson 115 kV substation.	12/1/2025	$7.3

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23348	Grenada Industrial 115 kV: New Station	Entergy is proposing to construct a new 115 kV substation (Grenada Industrial	12/1/2024	$32.6

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		115 kV Substation) which will serve the industrial customer's 10 MW of new load and future area load growth in Grenada, MS and the industrial park. Entergy will construct a new (4) breaker ring bus substation with (1) – 40 MVA, LTC 115/13.8 kV transformer. The new substation will have (1) main and (3) feeder breakers. The new substation will cut into the current Grenada – Tillatoba 115 kV line.		

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23932	2024 EML Asset Renewal Program	The asset renewal programs replace aged and/or degraded transmission line and transmission substation assets. Entergy continuously reviews asset health to prioritize those replacements and the specifics for the 2024 asset renewal plans have not yet been finalized. Install a 69 kV capacitor bank configuration and associated automatic control features at Vinburn SS.	12/31/2024	$50.4

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24480	Cotton Blossom 230 kV: Solar Interconnection (J1747)	Interconnect a 50 MW solar generation facility to the Cotton Blossom 230 kV substation.	7/31/2024	$0.7
24899	Twinkletown 230 kV: Solar Interconnection (J1748)	Interconnect a 100 MW generation facility to the Twinkletown 230 kV substation.	7/31/2024	$0.7
25086	Tinnin Road 230 kV: Solar Gen Interconnection (J1672)	Interconnect a 150 MW generation facility to the Tinnin Road 230 kV substation.	11/16/2025	$5.5

4.4.9 Entergy New Orleans LLC (ENO)

After MISO's independent reliability analysis, MISO and Entergy New Orleans recommend one Other Project at an estimated cost of $2.2 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23960	2024 ENOL Asset Renewal Program	This project is for the ENOL Asset Renewal Program that will be executed in 2024. The asset renewal programs replace aged and/or degraded transmission line and transmission substation assets. Entergy continuously reviews asset health to prioritize those replacements and the specifics for the 2024 asset renewal plans have not yet been finalized.	12/31/2024	$2.2

4.4.10 Entergy Texas, Inc. (ETI)

After MISO's independent reliability analysis, MISO and Entergy Texas recommend 12 projects at an estimated cost of $1.3 billion to be approved for inclusion in MTEP23 Appendix A. Of these projects, three are Baseline Reliability Projects, five are Other Projects, and four are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects:

Project 18266 – New Long John to Dayton 138 kV: Rebuild line

Project Description: Rebuild New Long John to Dayton Bulk 138 kV line. The total estimated cost of this project is $24.9 million and has an expected in-service date of June 1, 2026.

Project Need: NERC TPL-001-5 Reliability Standards and Entergy's Planning Guidelines. The N-1-1 contingency involving the loss of the Lewis Creek to Security and Cleveland to Jacinto 138 kV lines results in up to 200 MW of non-consequential load loss.

Alternative Considered: Reconductor Crystal to 45L555T50 138 kV. The alternative was not selected as the alternative was not compatible with the contingency.



Figure 4.4.10-1: P18266 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	New Long John to Dayton 138 kV	99	259	<99

Table 4.4.10-1: P18266 Thermal loading driver

Project 21844 – Deer to Doucette 138 kV: Upgrade Station Equipment and Line

Project Description: Rebuild the ~6 mile Deer to Doucette 138 kV line. The total estimated cost of this project is $18.4 million and has an expected in-service date of December 1, 2025.

Project Need: NERC TPL-001-5: The G-1 N-1 contingency involving the loss of Montgomery County Power Station and the Rocky Creek to Crockett 345 kV line results in overloads of Deer – Doucette 138 kV line.

Alternatives Considered: No alternatives were considered.

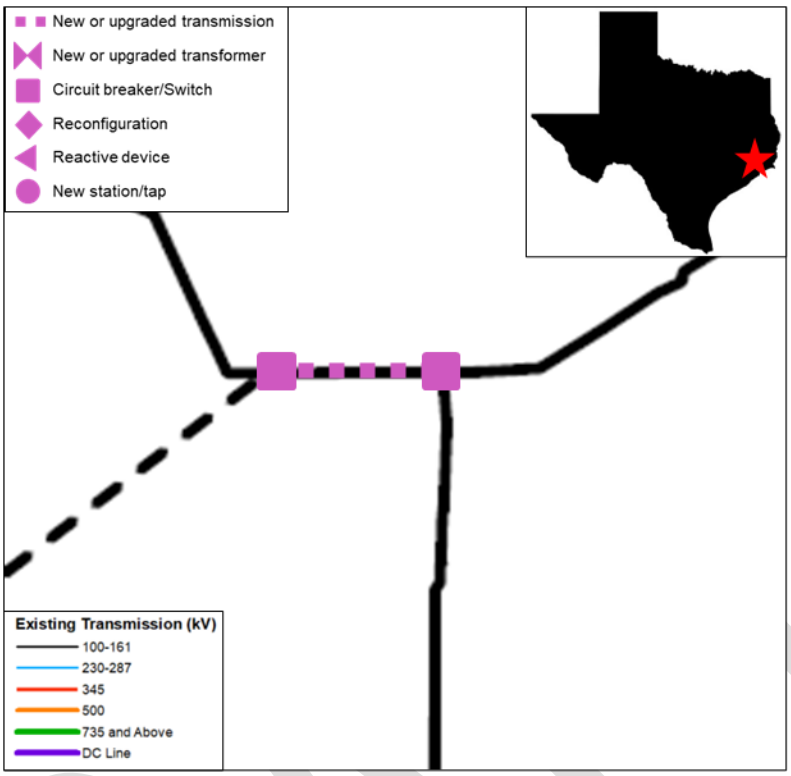


Figure 4.4.10-2: P21844 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P3	Deer to Doucette 138 kV	134	137	<99

Table 4.4.10-2: P21844 Thermal loading drivers

Project 23952 – Southeast Texas Area Reliability Project

Project Description: Construct Babel, a new 500 kV four breaker ring substation on the Layfield to Hartburg 500 kV line near the Toledo Bend Reservoir. Install two 70 MVAR Reactors. East of Lewis Creek, construct a 500-230-138 kV Station named Running Bear. Install a 500-230 kV and 230-138 kV Autotransformer. Cut the Lewis Creek to Peach Creek and Lewis Creek to Porter 230 kV lines into Running Bear 230 kV. Cut the Lewis Creek to Texas, Lewis Creek to Sheawill, and Lewis Creek to Caney Creek 138 kV lines into Running Bear 138 kV. Upgrade Running Bear to Caney Creek 138 kV. Construct a new ~150-mile 500 kV line from Babel 500 kV to Running Bear 500 kV station. The total estimated cost of this project is $1.1 billion and has an expected in-service date of December 19, 2030.

Project Need: The loss of Montgomery County Power Station and Hartburg to Cypress 500 kV overloads multiple elements. The loss of Montgomery County Power Station and Rocky Creek to Crocket 345 kV overloads multiple elements.

Alternatives Considered: Babel to Grimes 500 kV line; Double circuit Rocky Creek to Crockett 345 kV. The alternatives were not selected because the proposed project more completely resolved the limiting element violations resulting from the thermal loading drivers.

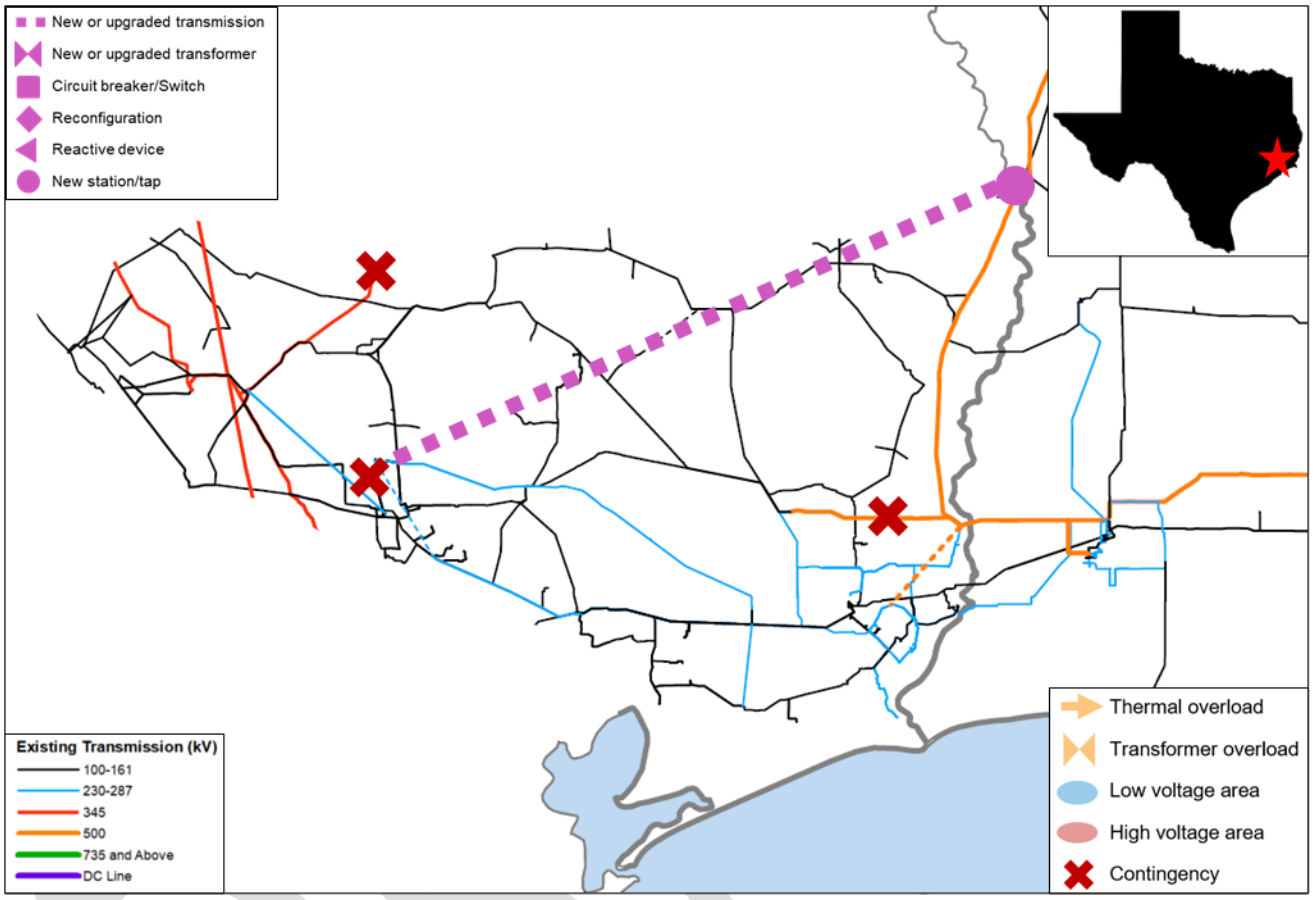


Figure 4.4.10-3: P23952 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P3	Fork Creek to Rayburn 138 kV	137	135.5*	<99
P3	Fork Creek to Rayburn 138 kV	137	137.9*	<99

Table 4.4.10-3: P23952 Thermal Loading drivers (*Case experiences voltage collapse)

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23933	Sabine 230-138 kV Auto Upgrade	Replace the existing 300 MVA 230-138 kV Sabine Autotransformer with a 500 MVA unit.	6/1/2026	$15.5

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23870	This project is for the ETI Asset Renewal Program that will be executed in 2024	Address aging and failing equipment such as structures, breakers, relay panels, RTU's, arresters, circuit switchers, etc.	12/31/2024	$34.2

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24134	Mustang 138 kV New Customer Substation	Entergy is proposing to construct a new 138 kV substation called Mustang, which will serve an industrial customer's 150 MW of new load near Orange, TX. The new Mustang 138 kV station is being laid out as a four bay breaker and a half station with twelve breakers initially installed and cut in on the existing Orange to Bunch Gully 138 kV circuit.	10/30/2024	$28.0
24152	Moscow 138 kV Customer Load Addition Project	Entergy is proposing to construct new 138 kV transmission facilities at the existing Moscow 138 kV substation which will serve an existing industrial customer's new load. The proposed new facilities include installing two 138 kV breakers at the Moscow substation and a new capacitor bank.	6/30/2023	$10.47
24920	Cole Road 138 kV New Customer Station	Entergy is proposing to construct a new 138 kV transmission station called Cole Road 138 kV which will serve a new industrial customer's 10 MW of load near Cleveland, TX. Cole Road 138 kV station will be cut into the Jacinto to Splendora 138 kV line.	10/31/2024	$29.6

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Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24298	J1442 Interconnection Project on Livingston to Rich 138 kV line	This project is to construct the interconnection station for the solar project J1442 on the Livingston to Rich 138 kV line.	5/1/2025	$15.59
24839	J1671 230 kV Interconnection Project (Rocky Creek to Veteran)	Facilities required for the interconnection of J1671 on the Rocky Creek to Veteran 230 kV.	12/4/2025	$18.85
24984	J1760 Generator Interconnection on Plum Grove to Colony 230 kV	Facilities required for the interconnection of J1760 on the Plum Grove to Colony 230 kV.	6/1/2026	$16.3
25102	J1709 Generator Interconnection at Grimes 138 kV	Facilities required for the interconnection of J1709 at the Grimes 138 kV station.	2/1/2025	$7.2

4.4.11 Lafayette Utilities System (LAFA)

Lafayette Utilities System, LAFA did not submit any new projects for MTEP23. MISO has not identified any open issues in the LAFA area.

4.4.12 City Water and Light Jonesboro (CWLT)

After MISO's independent reliability analysis, MISO and City Water and Light Jonesboro recommend one Other Project at an estimated cost of $0.32 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
25094	Commerce to Ringier 69 kV Relocation	ARDOT currently has a contract to widen and expand the existing Hwy. 18S. CWLT is required to relocate the Commerce Ringier 69 kV Line.	9/30/2023	$0.32

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4.5 Project Justifications – West Region

West Region Overview

The MISO West Planning Region consists of 20 Transmission-Owning members spanning eight states in the upper Midwest. It includes Iowa, Minnesota, Wisconsin, and parts of North Dakota, South Dakota, Montana, Michigan, and Illinois. These Transmission Owners are:

American Transmission Company (ATC)

Cedar Falls Utilities (CFU)

Central Minnesota Municipal Power Agency (CMMPA)

City of Ames, IA (COA)

Dairyland Power Cooperative (DPC)

Great River Energy (GRE)

ITC Midwest (ITCM)

MidAmerican Energy Company (MEC)

Minnesota Municipal Power Agency (MMPA)

Minnesota Power (MP)

Missouri River Energy Services (MRES)

Montana-Dakota Utilities Co. (MDU)

Muscatine Power and Water (MPW)

Northwestern Wisconsin Electric (NWEC)

Otter Tail Power Company (OTP)

Rochester Public Utilities (RPU)

Southern Minnesota Municipal Power Agency (SMMPA)

Wilmar Municipal Utilities (WMU)

WPPI Energy (WPPI)

Xcel Energy (Northern States Power, XEL/NSP)

The West planning region contains approximately 27,300 miles of transmission ranging from 57 kV to 500 kV. In the 2023 Summer Peak planning model, the region contains more than 67.2 GW of generation. Installed generation capacity in the region consists mostly of coal, gas and wind. Approximately 33.4 percent (22.5 GW) of the West region's generation capacity is made up of wind units. Major generation centers are located in central North Dakota; the Twin Cities in Minnesota; and the Quad Cities in Iowa and Illinois, with wind generation located in the eastern Dakotas and western Iowa and Minnesota (Figure 4.5-1).

Major load centers are typically found around larger cities in the region: Minneapolis/Saint Paul, Milwaukee, and Des Moines. According to the 2023 Summer Peak planning model, the regional load exceeds 42.2 GW. Power generally flows from generation-rich areas in the western portion of the region through Minnesota,

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Iowa, and Wisconsin, toward large load centers in the east. This is especially prevalent in times of high wind output.

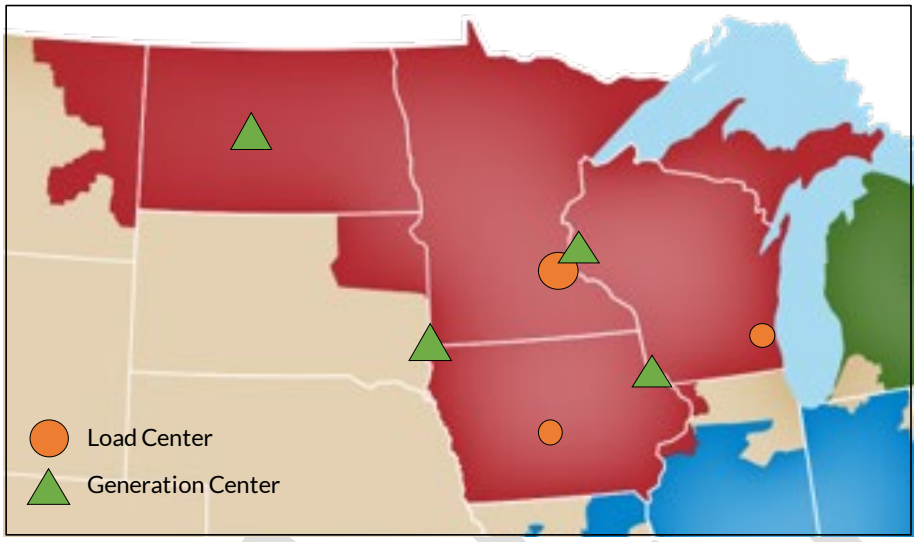


Figure 4.5-1: Generation and load centers in the West Planning Region

For MTEP23, MISO Transmission Planning is recommending 244 projects from the West region for inclusion in Appendix A at an estimated cost of $1.8 billion. Of these, nine are Baseline Reliability Projects, 28 are Generator Interconnection Projects, two are Market Participant Funded Projects, one is a Multi-Value Project, and the remaining 204 projects are classified as Other Projects. MISO considered alternatives for two projects in the west region. The original proposed projects were selected as the results of the alternative analysis.

Of the 244 projects being recommended to be included in MTEP23, 56 have an estimated cost of less than $1 million, 86 have an estimated cost between $1 million and $5 million, and the remaining 102 projects are estimated to cost greater than $5 million (Figure 4.5-2).

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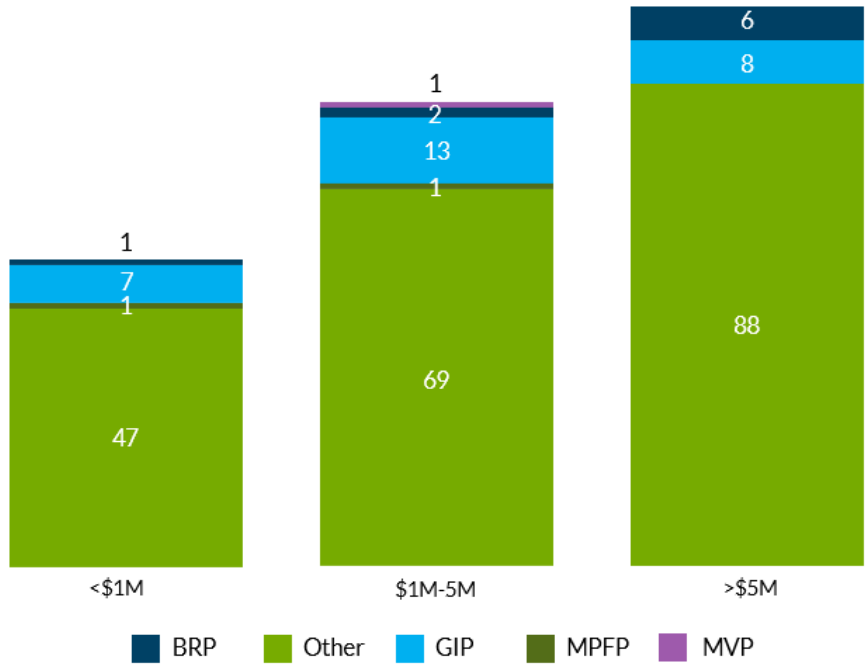


Figure 4.5-2: Project counts by cost category of MISO West region MTEP23 projects (data as of 9-29-2023)

The majority of the projects in the MISO West planning region are expected to go in service in the next three years (Figure 4.5-3). There are around 37 projects that have already went into service or are expected to be in-service by the end of 2023. A couple of projects were transmission network upgrades (GIP) correlated with generation projects that were justified by a separate Generator Interconnection process. Others fit into a bucket of timing or constructability considerations. Examples of these are the retirement of catastrophic failure devices, load additions which required short time frames to come online, or those that take advantage of outages already scheduled and planned the upgrade accordingly to meet the compliance.

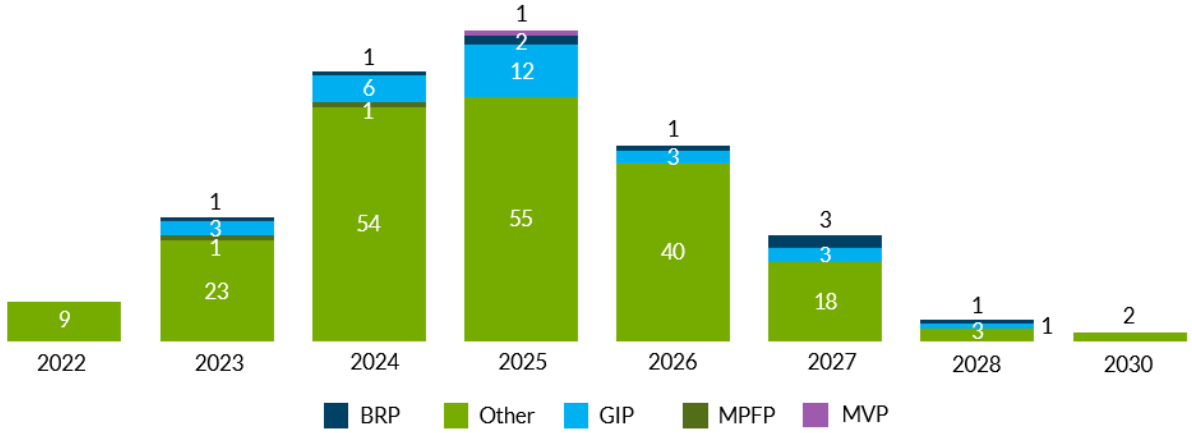


Figure 4.5-3: West region MTEP23 projects by in-service date (data as of 9-29-2023)

In accordance with Attachment FF of the tariff, in the event that a Transmission Owner determines that system conditions warrant the urgent development of system enhancements that would be jeopardized unless MISO performs an expedited review of the impacts of the project, MISO shall use a streamlined

approval process for reviewing and approving projects proposed by the Transmission Owner(s) so that decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO unless a longer review period is mutually agreed upon. During the MTEP23 cycle, MISO received the following projects through the Expedited Project Review (EPR) process:

1. Project ID 23806, OTP Lake Preston, Load Addition
2. Project ID 23936, OTP Milbank, Load Addition
3. Project ID 25256 OTP Jamestown, ND Load Addition 115 kV
4. Project ID 24740, ITCM Commercial (JCE) 69 kV Substation
5. Project ID 24513, ITCM CIPCO Maquoketa 161 kV Sub Rebuild
6. Project ID 24464, ITCM Eagle to Tharp 69 kV Line Relocation
7. Project ID 24449, ITCM Nevada Area Load Interconnections
8. Project ID 25060, ITCM Grant Milford Interconnection
9. Project ID 23919, MRES Morris to Grant County to East Fergus Fall 115 kV Upgrade
10. Project ID 24978, MDU Tatanka Load Addition
11. Project ID 22871, GRE Cedar Lake Line Rebuild
12. Project ID 24999, MEC Southland Expansion & Upgrades

Also, in accordance with Attachment FF Section VIII.A.3, none of the projects were identified as an Immediate Need Reliability Project and excluded from the competitive developer selection process. The ten largest project investments in the MISO West region represent $400 million (22%) of the $1.8 billion total recommended projects for the West region in MTEP23, or 4% of the $9 billion total recommended in the MISO footprint. The locations of these projects can be seen in Figure 4.5-4 and the investment is spread across the West Planning region. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

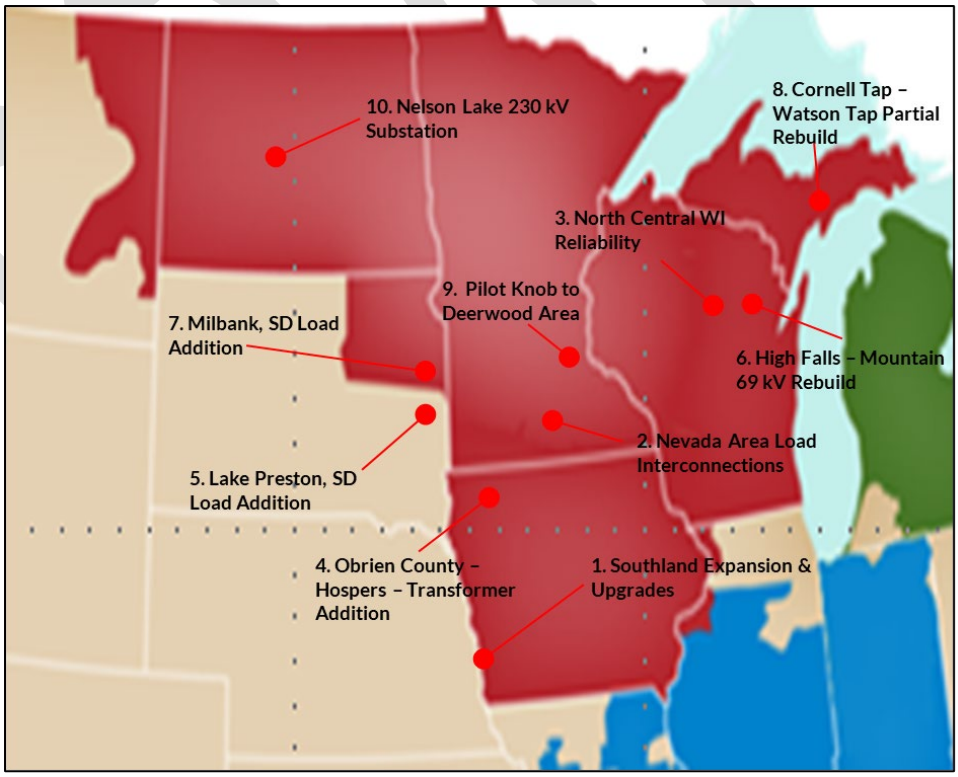


Figure 4.5-4: West region top ten projects by cost (data as of September 29, 2023)

4.5.1 American Transmission Company (ATC)

After MISO's independent reliability analysis, MISO and American Transmission Company recommend 55 projects at an estimated cost of $742 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, three are Baseline Reliability Projects, 39 are Other Projects, and 13 are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 22587 North Central WI Reliability Project

Project Description: Address reliability concerns in the 115 kV system in North Central Wisconsin for multiple P6 outage combinations. Scope includes the following:

- Construct new 115 kV source between Hilltop and Pine substations
- OPGW to be installed on new line
- Asset renewal work on relays at Hilltop, Maine, and Pine substation
- Upgrade Pine SS Bus #51 to match rating of new line

The total estimated cost of this project is $47.9 million and has an expected in-service date of June 1, 2028.

Project Need: NERC Category P6 Contingency causes overloads on the 115 kV system in Central WI. Bringing a second source into the area will prevent the need for system reconfiguration.

Alternatives Considered: No alternatives were considered.

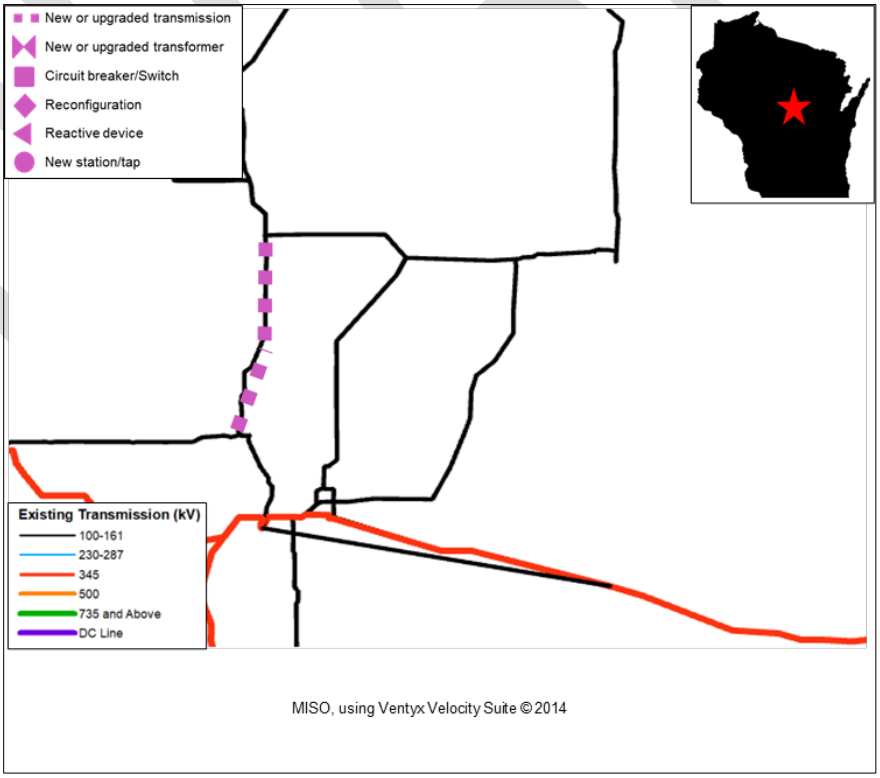


Figure 4.5.1-1: P22587 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	'ACKLEY' 115 - 'KELLY' 115 1	173	104	56

Table 4.5.1-2: P22587 Thermal Loading drivers

Project 23912 East Krok SS Transformer Replacement

Project Description: This project will replace the existing East Krok Transformer 1 with a new 138/69 kV 100 MVA transformer. The total estimated cost of this project is $8.7 million and has an expected in-service date of December 31, 2027.

Project Need: Various outages cause the East Krok Transformer 1 to overload. Replacement of this transformer will minimize need for system reconfiguration.

Alternatives Considered: No alternatives were considered.

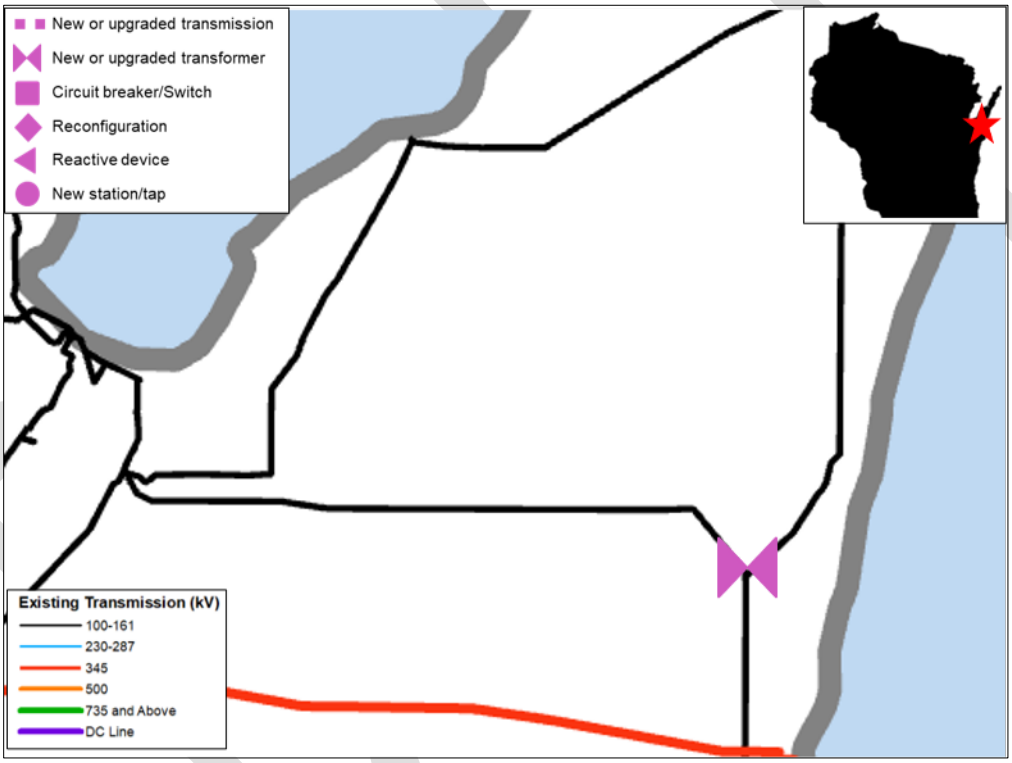


Figure 4.5.1-3: P23912 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	'EAST KRK' 69 - 'EAST KRK' 138 1	60	106	64
P6	'EAST KRK' 69 - 'EAST KRK' 138 1	60	105	63
P6	'EAST KRK' 69 - 'EAST KRK' 138 1	60	106	64

Table 4.5.1-4: P23912 Thermal Loading drivers

Project 24093 Rocky Run SS T2 and T4 Power Transformer Replacement

Project Description:

Planning Scope:

- Remove Rocky Run 345/115kV transformers T2 and T4. Replace with on-site spare 500MVA 345/115kV transformer in the T4 position.
- Upgrade two (2) 345kV bus switches and five (5) 115kV bus switches.
- Remove breaker 4-2 and shorten 345kV ring bus.
- Purchase new 500MVA 345/115kV system spare.

Asset Renewal Scope:

- Replace W-8 secondary relay SEL-321 (component replacement).
- Replace all physical security cameras.

The total estimated cost of this project is $17.6 million and has an expected in-service date of June 1, 2027.

Project Need: T4 loading exceeds the emergency rating for the NERC Category P6 contingency.

Alternatives Considered: No alternatives were considered.

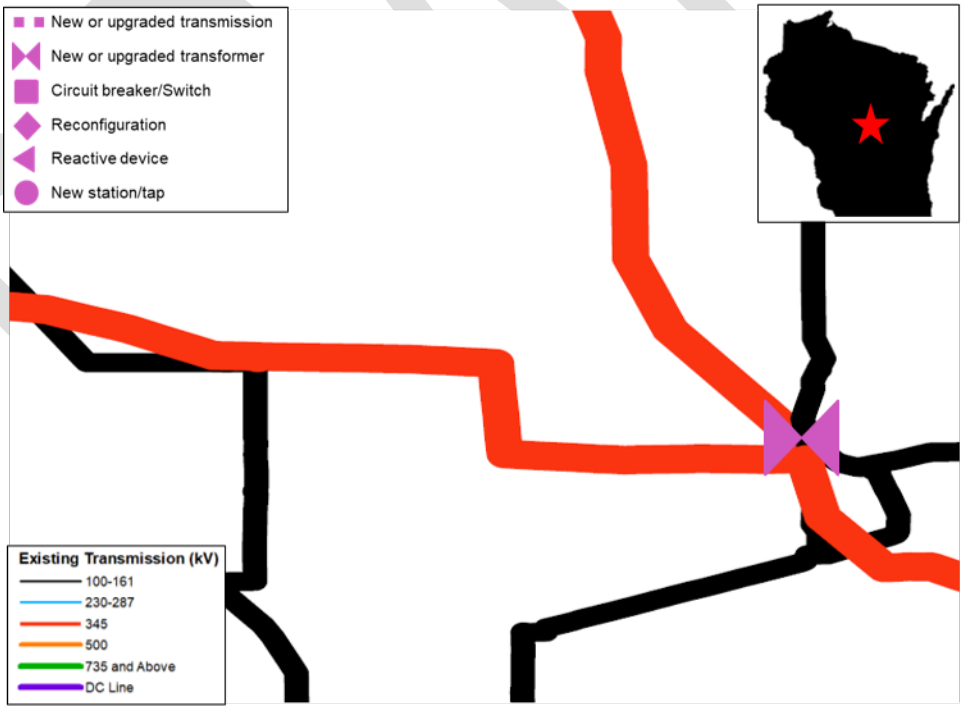


Figure 4.5.1-3: P24093 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	'ROCKY RN B4' 345 - 'ROCKY RN' 115 3	200	110	44

Table 4.5.1-5: P24093 Thermal Loading drivers

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20202	Communication Reliability Program 2024	Communications network system upgrades typically require limited infrastructure modifications and additions with shorter project life cycles. Substation Communications Reliability Upgrade projects are typically (but not limited to): - OPGW additions, replacements, relocations, or removals. - Project drivers typically are communications support for SCADA, Relay protection, Security systems, Small communications network upgrades, and Telecom industry market transitions. These projects have limited scope and cost. Initial capital spend for this program expected in 2024.	6/30/2026	$11
23858	Wick Drive – Black Earth 69 kV, (Y-62), OPGW Addition & Partial Rebuild	Installation of 6 miles OPGW with (57) Structure Replacements and (2.2) miles of new (T2-477 HAWK) conductor added to scope between the Wick Drive to Mazomanie Tap substations. 55 replacements assumed due to engineering usage analysis of 1985 and earlier structures. Of the 55 replacements, 22 also are legacy with asset renewal condition need. 2 additional structures from WKS-MAZT to replace due to ground clearance for new T2-477. OPGW Termination from Wick Drive and Black Earth substation Dead-End structures into the control houses. Substation Router Configuration to route SCADA and Relay communications on to ATC's private fiber network infrastructure	12/31/2026	$7

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		Real Estate Easements Required to address gaps and areas of inadequate width. (~$500k)		
24465	Walworth - Brick Church (Y-159), OPGW Addition & Partial Rebuild	OPGW Addition on the Walworth - Brick Church (Y-159) line and partial transmission line rebuild.	6/30/2026	$4.6
25154	CRP Substation Ethernet Migration (Phase 2)	The telecommunication companies will construct fiber infrastructure to the substation locations. This fiber will extend from the road right of way to a telecommunications handhole located outside of the fence. When a handhole does not exist outside of the fence, a new ATC owned handhole will be installed. The telecommunication companies will install fiber from this handhole through existing conduit and into the control house. The telecommunication companies will install a network interface device (NID) and any other needed associated equipment on the telecommunications board to terminate their fiber. ATC will power the NID from at least one direct current (DC) circuit and will coordinate turn up of the new ethernet circuit with the telecommunication companies. ATC will coordinate with AT&T for the decommissioning of the existing T1 service. ATC will replace the substation router at 14 locations. Some of these locations will also require a cellular router and cell booster to be installed as the backup communications medium, replacing the existing plain old telephone service (POTS). ATC will install Voice over Internet Protocol (VoIP) phones at ATC owned control houses with existing analog phones.	6/30/2024	$5.5

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20203	Line Clearance Mitigation Program 2024	Line Clearance Mitigation projects have shorter project life cycles. Projects are driven by the ongoing assessment and analysis of field line	6/30/2026	$10.0

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		clearances using Light Detection and Ranging (LiDAR) technology. Clearance mitigation work immediately follows data assessments and issue identification to maintain safety and system reliability. Initial capital spend for this program expected in 2024.		
23836	Perch Lake - National 138 kV (468) Partial Retirement Project	Reconfigure 138 kV line 468, from Perch-Lake to Presque Isle, by terminating into National SS to establish a new Perch Lake – National line. The remaining 23 miles of line from National to Presque Isle will be retired.	11/1/2025	$10.4
24785	Pleasant Prairie 345 kV Capacitor Bank Addition	Install four 345 kV 75 MVAR capacitor banks at Pleasant Prairie substation.	6/30/2025	$7.6
24819	Racine 345 kV Capacitor Bank Addition	Install two 345 kV 75 MVAR capacitor banks at Racine substation.	6/30/2025	$8.4
24296	Valders SS, New 138/69 kV Substation	Construct a new 138/69 kV Valders Substation with 100 MVA transformer looping in Forest Junction - Howards Grove 138 kV (971K51) and Custer - St Nazianz - New Holstein 69 kV (P-68) lines.	07/31/2028	$24.2
25207	Forsyth-Empire (Forsyth) 138 kV, Rerate	Rerate Line Forsyth conductor for the Forsyth to Empire section to keep up with the system demand. The thermal study identified 18 clearance issues needed to be fixed to bring the rating up to meet Operations/Planning's needs.	10/20/2024	$5

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19963	Kirkwood SS, Power Transformer and Breaker Asset Renewal	Replace T31, a 1974 vintage 138/69 kV 93 MVA power transformer with the onsite 138/69 kV 100 MVA system spare. Replace station service transformers of 100 kVA. Replace all relays, RTU, batteries and charger and install new DC panel in existing building.	12/31/2026	$14.1

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		Install battery monitoring solution instead of dual batteries to fit in existing building. Install new 138 kV and 69 kV bus tie breakers and associated disconnect switches. Replace two 69 kV and two 138 kV oil circuit breakers and replace with SF6 gas breakers. Remove and retire disconnect switches no longer in use and bypass switches. Replace one 69 kV disconnect switch due to condition. Replace capacitor cans and protection voltage transformers on existing 19.2 MVAR bank. Install new 138 kV 16.33 MVAR capacitor bank. Install new 138 kV bus PT's and new 69 kV bus PT's. Install new line side disconnects. Replace existing CCVT and wave trap. Replace brown glass insulation. Add corona rings to existing line dead-end polymer insulators.		
20201	Small Capital Project and Asset Renewal Program 2024	Asset replacements and upgrades typically require limited infrastructure modifications and additions with shorter project life cycles. Transmission Line Projects typically (but not limited to): - Structure, Cross-arm, Insulator, Surge-arrester, and Pole hardware replacements. Substation Projects typically (but not limited to): - Relays, Circuit breakers, Switches, Instrument Transformers (CTs & PTs etc.), Batteries, RTUs, and IT/OT/Communications hardware replacements. Project drivers may be Asset Renewal or small system limit upgrades. These projects have limited scope and cost. Initial capital spend for this program expected in 2024.	6/30/2026	$47

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
21921	Groenier – Rosholt (ALTE) Tap, 69 kV (Y-71), Partial Rebuild and Rerate	Sectionalize of tap near existing Rosholt (ALTE) Substation with 3-Way T-Line switch. Assumed rebuild section off center due to radial connection. Bury distribution to resolve rerate issues.	12/31/2025	$16.5
21985	Chandler-Delta 69 kV (Delta1), Rebuild and OPGW	Rebuild approximately 5.5 miles of 69 kV line Delta1 from Delta SS to Chandler SS and install OPGW.	6/30/2026	$11.6
23837	Northeast - Revere Dr. 69 kV (C-103), Uprate or Rebuild	Scope to include partial rebuild. Substation scope is for Revere Drive. Fiber optic installation.	1/31/2030	$8.6
23838	High Falls – Mountain 69 kV (Y-77), Rebuild & OPGW	Rebuild ~16.4 miles with new wire mesh wrapped wood pole structures and steel poles on foundation. - T2 4/0 Conductor and 48 Fiber OPGW. Conductor would meet and exceed planning needs. - Assumed to obtain Certificate of Authority (CA) application by rebuilding off center (30' shift) and obtaining new 80' easements typically. This is due to radial connection and uncertainty at this time if outage and distribution could be taken out for a period of time. This may not be necessary once project gets into details and could result in savings as listed under alternatives. Real Estate, Environmental, Vegetation - Majority of existing easements are 80' in width with vegetation management and access rights. 2 DNR parcels will require permit/easement. - Project assumes new easements at $800k due to shift in ROW, rest through NEPA permit. - Shifting centerline will require going through the NEPA process (schedule impacts), likely an Environmental Assessment (EA), with a resulting Special Use Permit from the Chequamegon-Nicolet National Forest. - Federal forest lands currently limit herbicide spray, resulting in brush growing up along the Rights-of-Way. Within two years of next cycle and in decent shape with prior aerial saw work.	12/31/2028	$33.0

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23856	Benson Lake SVC SCM Layer Asset Renewal	Replace hardware and software of the Benson Lake SVC plant System Control and Monitoring (SCM) Layer with supported hardware and software with a design life of 10 years.	12/1/2026	$4.5
23857	Pine Hy Tap – Pine Hy 69 kV (ASPY31-1), Rebuild & OPGW	Install 6.3 miles of new single circuit line on existing ROW.	12/31/2027	$11.5
23874	Harrison Tap – Iola 69 kV (Y-70), Rebuild & OPGW	Rebuild approximately 11 miles of 69 kV with new wood monopoles wrapped with mesh.	12/31/2026	$16.0
23875	Madison Area Relay Projects	Asset Renewal of Blount control building and contents. Retire the existing 69 kV control building at Sycamore. Install new relaying at Blackhawk (MGE), Blount, East Campus, Ruskin, Sycamore, Walnut GIS and Wingra SS.	12/1/2026	$21.9
23876	Cornell Tap – Watson Tap 69 kV (Chandler), Partial Rebuild	Rebuild approximately 18 miles of 69kV Chandler line between Cornell Tap and Watson Tap.	12/31/2026	$30.0
23895	McCue SS Control House and Relay Asset Renewal	Replace control building and contents. Install relay panels, no remote end work needed. Replace Siemens Station Manager RTU. Replace 69 kV OCB Westinghouse model 690-GS-2500. Replace existing 69 kV cap bank with 16.3 MVAR in the same bus position, replace zero crossing breaker. Retire or replace 796-A when reconductoring the 69 kV bus. Provisions to meet battery standard TPL-001-5 requirements with either dual battery or monitoring. Install 138 kV line side disconnects if practical. Install 138 kV line breaker and relaying for the section of 138 kV bus that leaves the McCue yard to feed Kennedy SS Replacement of 954.0 kcmil AAC 37 Magnolia bus and jumpers in MCU 69 kV Bus 1 and 2.	12/1/2026	$9.5
23897	Ohmstead SS Control House and Relay Asset Renewal	Replace control building and contents Install approximately five relay panels, no remote end work needed	12/1/2026	$5.7

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		Replace Siemens Station Manager RTU Replace one Bus power potential Transformer. Add four new 138 kV line side disconnects. Provisions to meet battery standard TPL-001-5 requirements with either dual battery or monitoring.		
23901	Shoto SS, Power Transformer Asset Renewal	Replace T1, a 1972 vintage 69/138 kV 84 MVA power transformer with a new 69/138 kV 100 MVA replacement. Install oil containment system for the new transformer. Install online monitoring to the new transformer and existing T2 transformer. Replace fuses and assemblies, capacitors, protection voltage transformers, and reactors on existing capacitor bank and rack for a life extension of the existing asset. Investigate and provide mitigation as needed to existing ground grid per current guidelines.	12/1/2026	$6.2
23902	SS Physical Security Switch and SS Asset Renewal Enhancement	Replace the existing Cisco 2520 switches at approximately 28 substation control house locations including dedicated firewall additions at the enhanced security sites. Replace the existing Cisco 3750/3850 physical security switches at approximately 56 control house locations. Install station wi-fi functionality at approximately 67 control house locations. Replace the existing network speakers and network door video stations at approximately 67 control house locations. Migrate mission critical equipment from AC inverted power to the station DC power at approximately 67 control house locations. Implement rogue device detection at approximately 67 control house locations.	12/1/2025	$10
23903	North Beaver Dam SS Asset Renewal	Reconfigure 138 kV bus layout. Install a fire wall between ATC and Alliant power transformers. Install online monitoring per approved 2020 program to T31 power transformer. Replace one 1980's vintage 138 kV circuit	12/1/2026	$16.1

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		switcher with a circuit breaker. Replace control building which will include relay replacements, RTU replacement, and battery replacement. Replace 69 kV 10.8 MVAR fused capacitor bank with a 12.25 MVAR fuseless bank. Install future 138 kV bus-tie disconnect switches and a set of 138 kV bus PTs to allow for bus sectionalizing. Install new line side disconnect switch on the X-47 terminal, does not currently exist. Upgrade jumpers per Planning requirements on the Y-59 line to meet future transmission line renewal needs. Upgrade strain bus in the 69 kV bus per Planning requirements to meet future needs.		
23904	South Beaver Dam – North Beaver Dam, 69 kV (Y-59) Line Rebuild & OPGW	Rebuild line and install OPGW on 4.1 miles and install 0.9 miles of OPGW on remaining section. Assumes newer legacy vintage structures can remain.	12/31/2026	$11.2
23905	Waupun - South Fond du Lac 69 kV, (Y-25) Partial Rebuild	Replace remaining legacy monopoles poles (~60%) as ~40% were replaced in 2011. Replace conductor and static with new material.	12/31/2026	$22.6
23906	South Fond du Lac SS, Power Transformer and Breaker Asset Renewal	South Fond du Lac: Replace two power transformers with new single larger voltage transformer. Install new bus for auxiliary station service. - Install new motor operated switches. - Relocate one gas circuit breaker to a new position to support new transformer location. - Retire three CCVTs and relocate one CCVT. - Install motor operators on two line disconnect switches. - Retire one oil circuit breaker and replace with gas breaker. - Replace portions of strain bus with rigid bus and replace bus PTs to support new transformer location. - Retire a portion of strain bus and replace bus PTs.	12/1/2026	$9.5

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		- Replace eight disconnect switches to support bus rebuilds and breaker replacement. - Replace four disconnect switches Columbia: - Purchase a new spare transformer.		
23911	Shoto – Northeast 69 kV (K-11), Rebuild	Line rebuild. Substation work at Northeast. Fiber optic installation.	10/31/2030	$5.4

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20204	Load Interconnection Program 2024	Load Interconnection Project life cycles are customer need driven and typically have shorter project life cycles. These Load Interconnections typically require limited infrastructure modifications and additions. These projects have limited scope and cost. Initial capital spend for this program expected in 2024.	6/30/2025	$16.0
23913	Northern Adams County Area Network Improvement Project	Construct 9.2 miles of 69 kV single circuit transmission line (5 miles between Badger West and Y-302, and 4.2 miles between Y-302 and Colburn). Expand Badger West substation with three 138 kV breakers, a 138/69 kV, 100/167/187 MVA base transformer, a new ATC control building and one 69 kV line breaker. Modify X-43 at Badger West to cross over the new 69 kV t-line.	5/1/2027	$39.9
23915	Delta County, DIC, Upgrades	ATC will construct a 138 kV, four-breaker ring configuration substation, with ultimate provisions for a six-position 138 kV ring bus. ATC will loop the existing Holmes-Old Mead Rd 138 kV line (OMDG81) into the new 138 kV substation, raising the OMDG81 line over the existing Old Mead Rd-Delta OMDY51 line.	1/31/2027	$21.0

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		ATC will retire a portion of the existing Old Mead Rd-Mead Paper 69 kV line (OMDY71), retire OMDY51/OMDY71 bypass equipment and retire the remaining portion of OMDY71 in place. ATC will remove a 69 kV breaker and OMDY71 line MOD at Old Mead Rd. ATC will replace 31 structures on the Arnold-Perkins 138 kV double circuit lines (ARNG81/29051). ATC will implement reverse power blocking and/or LTC tap limiting on the Chandler and Old Mead Rd 138/69 kV transformer LTC controls.		
24373	Manogue Rd SS DIC, New Substation	New tapped substation to serve 4.3 MVA motor load between the existing Edgerton Business Park and Russell substations on the 138 kV Line X-31. Line breakers will be installed at the Edgerton Business Park Substation on the Rockdale-Edgerton Business Park-ANR Manogue Rd-Russell 138 kV (X-31) line due to high network flow.	8/1/2025	$7.1
24473	Rock River SS, DIC, Additional Transformer	Expanding Rock River 138 kV Bus 3 to interconnect a distribution transformer.	7/1/2024	$3.0
24475	Tommy's Turnpike DIC, New Sub	ATC will construct an approximately 0.3 mile 115 kV double-circuit transmission line extension from the Whiting Ave – Okray 115kV line (B-106) to interconnect the proposed T-D substation. ATC will construct a 115 kV loop-through straight bus with line switches, bus-tie switches, and space reserved for potential line and bus-tie breakers. WPS to construct a new substation site, install two new 115/24.9 kV 33/38 MVA transformers with high side breaker protection for each and other supporting equipment.	12/31/2025	$7.7
24575	DPC Germantown Jct Tap, New T-T	New T-T interconnection to Council Creek-Hilltop 69 kV (Y-74), and constructing a new 69 kV loop-through substation near New Lisbon Tap with three line breakers to replace an existing three-way GOAB.	6/1/2026	$11.1

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24783	Hodag SS, DIC, Add Additional Transformer	Expand and reconfigure substation to a loop through straight bus configuration.	12/31/2024	$2.7
24784	Ellisville SS, DIC, New Substation	ATC will construct approximately 0.7 miles of 138 kV double-circuit transmission line extension from line M-39 to interconnect the proposed T-D substation. ATC will construct a 138 kV loop-through straight bus with two-line breakers and provisions for a future bus-tie breaker.	6/1/2025	$10.2

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24445	J1374 Ebenezer SS Network Upgrades and Interconnection Facilities	Wind Turbine generating Facility located in Grant County, Wisconsin.	8/1/2024	$1.6
24446	J1251 Summer Meadow Switching Station Network Upgrades and Interconnection Facilities	A 100 MW solar farm located in Marquette County, Michigan.	6/12/2025	$8.0
24447	J1483 Hill Valley SS Network Upgrades and Interconnection Facilities	Wind farm in Iowa County, Wisconsin.	9/1/2026	$2.3
24613	J1214 J1326 Rockdale SS Network Upgrades and Interconnection Facilities	Solar development with energy storage in Dane County, Wisconsin.	6/1/2025	$4.1
24758	J1410 J1411 North Arlington Swt St MPFCA & Network Upgrades	J1410 is a solar facility located in Dane County, Wisconsin. J1411 is an energy storage facility co-located in Dane County with J1410.	6/3/2026	$22.0
24782	J1304 J1305 J1460 MPFCA Network Upgrades	Transmission owner will reconductor one of the two segments of the line UNIG52.	12/31/2025	$4.9
24799	J1377 Blitz SS Network Upgrades and Interconnection Facilities	Solar generating facility in Rock County, WI.	11/12/2026	$14.6
24801	J1253 El Dorado SS Network Upgrades and Interconnection Facilities	Solar generating facility along with substation and network upgrades in Fond du Lac County, Wisconsin.	11/12/2027	$50.5

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24802	J1460 Sunrise SS Network Upgrades and Interconnection Facilities	Solar generating facility and substation upgrades in Rock County, WI.	12/27/2025	$4.5
24838	J1316 Paris SS Network Upgrades	J1316 is an energy storage facility interconnected at the same location as J878, a solar facility located in Kenosha County, WI.	12/29/2028	$22.4
24841	J1214 J1326 J1377 J1410 J1411 MPFCA Network Upgrades	Network upgrades to support new interconnections J1214 (solar), J1326 (storage), J1377 (solar), J1410 (solar), J1411 (storage).	5/30/2025	$1.3
24858	J1253 J1410 J1411 MPFCA Network Upgrades	Network upgrades to support new interconnections J1253 (solar), J1410 (solar), and J1411 (energy storage).	12/30/2025	$0.1
25262	J1305 Norwegian Creek SS Network Upgrades and Interconnection Facilities	Solar generating facility in Green County, Wisconsin.	11/08/2023	$8.1

4.5.2 Cedar Falls Utilities (CFU)

After MISO's independent reliability analysis, MISO and Cedar Falls Utilities recommend one Other Project at an estimated cost of $2 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for this project is provided as of September 29, 2023.

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23993	Streeter-Wida Rebuild	Rebuild of the eastern half of CFU's part of the Streeter Switch Substation to MEC's WIDA substation. This will include reconductor and structures.	4/1/2024	$2.0

4.5.3 Central Minnesota Municipal Power Agency (CMMPA)

Central Minnesota Municipal Power Agency did not submit any new projects for MTEP23. MISO has not identified any issues in CMMPA's area.

4.5.4 City of Ames, IA (COA)

City of Ames, IA did not submit any new projects for MTEP23. MISO has not identified any issues in COA area.

4.5.5 Dairyland Power Cooperative (DPC)

Dairyland Power Cooperative did not submit any new projects for MTEP23. MISO has not identified any issues in DPC's area.

4.5.6 Great River Energy (GRE)

After MISO's independent reliability analysis, MISO and Great River Energy recommend 33 projects at an estimated cost of $105.5 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, two are Baseline Reliability Projects, 29 are Other Projects, and two are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project #23718: Rush City Ring Bus Upgrade

Project Description: This project will establish a 230 kV ring bus topology at Rush City. For GRE to address the rating exceedances experienced with the current shared breaker position, GRE will add breakers and associated equipment/relaying/etc. to the 230-kV Rush City bus between the Linwood, Red Rock, and Rock Creek lines. The total estimated cost of this project is $4.01 million and has an expected in-service date of March 27, 2025.

Project Need: Currently, both the Red Rock 230 kV and Rock Creek 230 kV lines share a common breaker position in the Rush City 230 kV bus and will both trip for any fault along the approximately 70 miles of exposure currently. Under prior outage of Blaine to Bunker Lake 230 kV, loss of both of these transmission lines simultaneously leaves the Blaine, Linwood, and Rush City substations without 230 kV system support, which can cause exceedances of ratings on the Blaine-Parkwood 69 kV path.

Alternatives Considered: No alternatives were considered.

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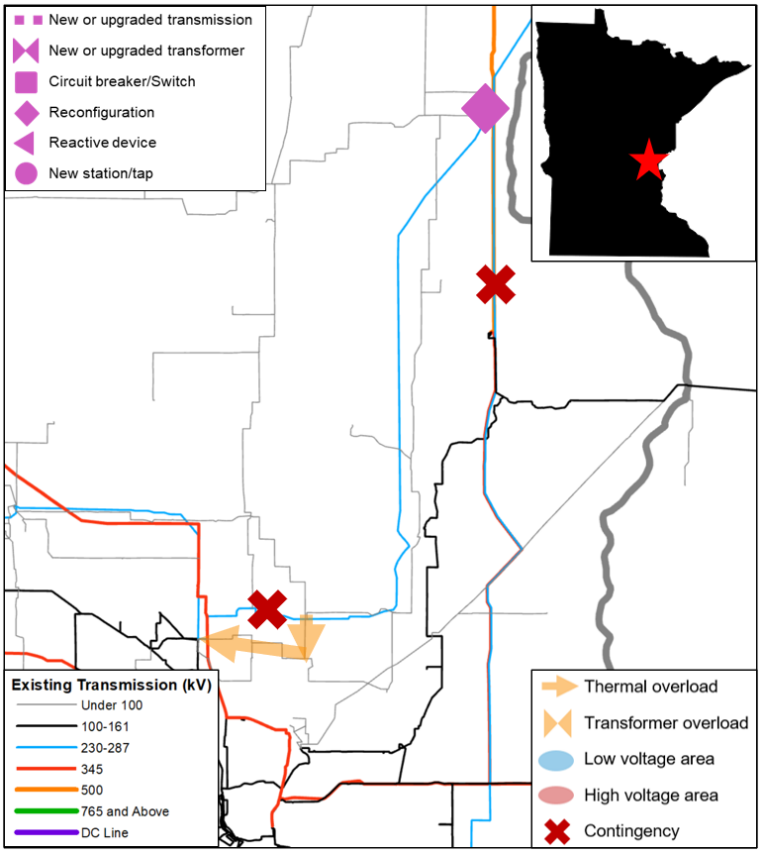


Figure 4.5.6-1: P23718 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	GRE-LXNGTN 8 - GRE-HWY65SW8 69 kV	58.8	106	64
P6	GRE-HWY65SW8 - GRE-SPRLKPK8 69 kV	58.8	107	64

Table 4.5.6-1: P23718 Thermal loading drivers

Project #23803: Big Swan Capacitor Bank Addition

Project Description: Add a new 40 MVAR capacitor on the extended 115 kV bus and replace 69 kV bus relaying, station power, and battery bank. The total estimated cost of this project is $2.63 million and has an expected in-service date of November 1, 2024.

Project Need: The Hutchinson area study identified low voltage concerns in the 115 kV system that is between Hutchinson, Wakefield, and Crow River. NERC category P6 contingencies involving prior outages, such as McLeod – Hutchinson 115 kV line, Crow River – Brooks Lake 115 kV line and Wakefield – Stockade 115 kV line causes low voltage problems at 115 kV side of GRE member substations. The Hutchinson area study also identified low voltage concerns in the 69 kV transmission system for the loss of the Hutchinson 115/69 kV transformer. Installation of a capacitor bank at Big Swan will improve the 115 kV system post contingent voltage.

Alternatives Considered: No alternatives were considered.

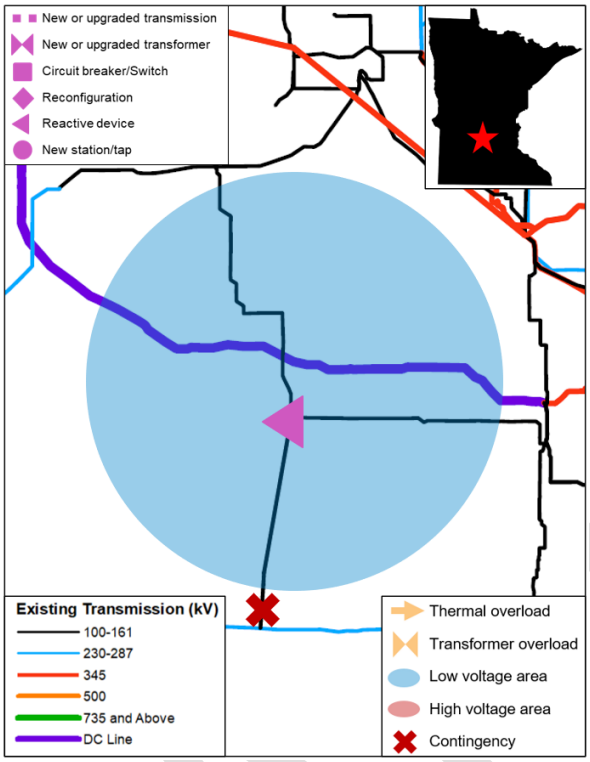


Figure 4.5.6-2: P23803 Geographic transmission map of project area

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	GRE-BIGSWAN7 115 kV	0.95	0.921	0.967
P6	GRE-SWAN LK7 115 kV	0.95	0.929	0.970
P6	GRE-BROOKSL7 115 kV	0.95	0.921	0.966
P6	HUC-HUTCHMN7 115 kV	0.95	0.915	0.956
P6	HUC-HUTCH3M7 115 kV	0.95	0.914	0.955

Table 4.5.6-2: P23803 Voltage performance drivers

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22871	Cedar Lake Line Rebuild	Relocate the existing Cedar Lake tap line to a new route to accommodate Hampton Corners - Helena 345 kV addition to the Hampton Corners - Chub Lake - Helena structures.	8/1/2025	$12.8

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23682	Princeton Breaker Addition	Add breaker and relaying to address incomplete topology and relaying load limit issue at Princeton. The plan to accommodate this work is to bring the OL line around to the west bay of the four structure and place breaker in PT occupied bay. Bus PT's will be replaced and relocated to a different location on site to accommodate the breaker addition in west bay. This project will also require that we rebuild to OL line tapping into the north by bringing it in to the west bay with the characteristics of the new line rebuild plan of the OL line.	6/21/2024	$0.76
23762	Trimont Substation Retirement	Retire GRE assets in the Trimont SMEC distribution substation.	4/30/2024	$0.24
23784	Blackberry Breaker Addition	Remove existing switch 20NSM1 from Blackberry and replace with a circuit breaker and disconnect. OR Retain existing switch 20NSM1 at Blackberry and add a circuit breaker between the 115/69 kV transformer and switch 20NSM1.	9/1/2025	$0.71
23805	Searles Capacitor Bank Retirement	Retire the 5.4 MVAR Searles Capacitor Bank and associated components.	8/31/2023	$0.12
23821	Penelope Capacitor Bank Retirement	Retire the 5.4 MVAR Penelope Capacitor Bank and associated components.	8/18/2023	$0.12
23823	Burnsville Capacitor Bank Retirement	Remove existing cap bank and 5M201. Relocate breaker 5M198 to 5M201 location. Leave A3 for future termination.	12/31/2025	$1.02

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23681	Riverton Breaker Replacement	This project will remove 69 kV bus differential relaying, replace GE-T60 with SEL-487E using existing panel 7, protect the 69 kV bus zone with the transformer relays, replace Riverton	6/30/2024	$0.85

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		IR8600 RTU with Cybectec RTU, replace Westinghouse 3-phase 115 kV PT with 3 single phase CCVTs on 115 kV bus, and replace the 115 kV 25WB1 oil breaker. In addition to this work, there will also be some 69 kV and 115 kV bus work and jumper modifications.		
23764	Stinson Breaker Addition	Add low side breaker and SEL-487E secondary transformer relay. Move 69 kV line relays to the 69 kV CTs. New panel will be installed with SEL-487E and breaker controls.	9/2/2025	$0.66
23781	Shannon Breaker Addition	Add low side breaker and SEL-487E secondary transformer relay. Move 69 kV line relays to the 69 kV CTs. New panel will be installed with SEL-487E and breaker controls. Replace RTU. Replace two (2) 69 kV Bus PTs (G.E. Superbute).	10/15/2024	$0.59
23800	Gilman - Milaca 69 kV Line Rebuild	Rebuild the JC line (18.93 miles) and switch SS2888 to 69 kV with 477 ACSS.	8/21/2026	$12.1
23801	Cotton Substation Tap Rebuild	LCP is rebuilding the existing Cotton Distribution site to the north, the 115 kV (TT Line) will need to adjust to terminate on LCP's new high side structure. The EEE from Goodland distribution substation will be placed at the new Cotton substation.	9/29/2023	$0.47
23804	Kimball Substation Tap	Install a 3-way 69 kV, 1200 A switch on Xcel Energy's Kimball – Watkins 69 kV line and construct about 2 miles of 69 kV line with 477 ACSR conductor to the high side of Meeker's new Kimball area distribution substation.	7/29/2025	$1.04
23824	Virginia Breaker Addition	Add low side breaker and SEL-487E secondary transformer relay. Move 69 kV line relays to the 69 kV CTs. New panel will be installed with SEL-487E and breaker controls. Replace RTU. Replace three (3) 69 kV Bus Pts (G.E. Superbute).	11/11/2024	$0.56
23849	Big Swan - Wakefield Storm Structures	Install (2) new storm structures every 5 miles along the ME-BW line between structures 306 and 415 as there are no	10/31/2024	$0.53

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		full stop dead ends in this section of line. Possible locations are structures 340 or 349 and 374 or 383.		
23920	Missouri River Line Crossing Relocation	Replace/relocate 5 towers and reconductor the river crossing to avoid structure/line segments from falling into Missouri river.	10/13/2023	$3.12

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23679	Cromwell Breaker Replacement	Replace 115 kV circuit breakers 13L and 26L.	11/1/2023	$1.36
23680	Frog Creek Breaker Replacement	Replace Circuit Switcher FC161-10 at Frog Creek substation with breaker and add disconnect switches. Replacement of Panel #2 relaying to also be included.	1/31/2025	$1.03
23717	Deer River Breaker Replacement	Replace breakers 21NB1,2 & 3. Oil containment and SSVT relocation project is be combined with this project to create more efficiencies with project execution. Replace bus PTs as well due to relay prioritization recommendation. Replace single phase 115 kV CCVT with 3 single-phase CCVTs. Move Zemple line relays to the 115 kV CTs (current transformers) and CCVTs. Replace EEE and internal equipment, address bus work and jumper issues, and fix wood high side dead-end.	4/9/2025	$3.82
23782	Dotson Corners Breaker Replacement	Replace 69 kV oil breakers 860, 861, and 862 and associated equipment.	7/18/2026	$0.78
23783	Maple Lake Breaker Replacement	Replace 69 kV relaying & Breakers 1NB4 & 5 at the Maple Lake sub and associated equipment.	2/28/2025	$1.16
23799	Benton County Breaker Replacement	Replace 115 kV breakers 5N52 and 5N53.	11/16/2023	$0.53
23822	Matawan - St. Olaf Lake 69 kV Rebuild	Rebuild SW-MB line segments 1 and 2 (11.01 miles) (Matawan switches to St. Olaf Lake switches) to 69 kV minimum conductor size 477 ACSR would meet	9/7/2026	$7.31

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		voltage and thermal considerations per planning.		
23869	Ramsey Breaker Replacement	Replace breaker 33RB1.	6/28/2024	$0.47
23921	Pilot Knob to Deerwood Area Projects	Rebuild the Pilot Knob Substation to a breaker and a half configuration due to age and condition of the current equipment. Upgrade the DA-PD line from Deerwood to Pilot Knob substation to increase the capacity. Upgrade to be built to 115 kV standards but operated at 69 kV. Retire the underground portion of the DA-PLX at Pilot Knob and replace with overhead. Retire the DA-RE line from Pilot Knob Road to Black Hawk Road. Retire the DA-PKX from Pilot Knob to Cliff Road. Retire SS-2820 and replace with a turning structure. Retire SS-2819.	5/21/2027	$29.6

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23761	NW Litchfield Substation Tap	Tap Xcel's Grove City – Litchfield Mun 69 kV line and Construct about 3 miles of 69 kV radial line to the high side of Meeker's new NW Litchfield distribution substation. Install metering and telecom at the new sub.	1/4/2027	$2.97
23763	Laketown Substation Tap	Install 3-way MOD 2000 A 115 kV switch on GRE's MV-VTT and construct about 3 miles of 115 kV transmission line from the three-way switch to the high side of MVEC's Laketown distribution substation.	9/26/2028	$6.31
23802	West Otsego Substation Tap	Install a 3-way 69 kV switch on GRE's Otsego to Albertville 69 kV line and construct about 0.5 miles of 69 kV tap line to the high side of Wright Hennepin's West of Otsego area substation.	10/31/2025	$1.28

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23819	Eidswold Substation Tap	New 115/12.47 kV substation for Dakota Electric Association (DEA) in the Elko New Market area.	11/22/2024	$0.21

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23883	Cedar Mountain Capacitor Bank Addition	Installation of two 75 MVAR capacitor banks, installation of three new 345 kV breakers to complete the breaker and a half.	5/31/2024	$4.03
24285	Benton County Solar Farm	The existing 115 kV Benton County substation is built as a two-row breaker-and-a-half breaker station. A new breaker and a half row would be built out to accommodate the interconnection of the 100 MW solar farm for J1426. The network upgrades at the substation will include the installation of a new 115 kV Breaker, Line arrestors, line CCVTs, Primary/Secondary Relay Panels, Metering, new metering CTs, and disconnects in the breaker-and-a-half row.	8/1/2025	$2.39

4.5.7 ITC Midwest (ITCM)

After MISO's independent reliability analysis, MISO and ITC Midwest recommend 19 projects at an estimated cost of $167.2 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, 12 are Other Projects and seven are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23546	Jefferson County 161 kV Substation Rebuild	The relaying and SCADA equipment at the Jefferson County substation is nearing the end of its useful lifespan. In addition, the existing 161/69 kV	12/31/2025	$7.92

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		transformer does not have a high side protective device, there is not adequate space to add it, and the existing 161 kV bus configuration does not allow the flexibility needed. Due to this, ITC will rebuild the 161 kV bus at Jefferson to a 3-position ring bus configuration and will replace all existing relays at the station except on two 69 kV lines going towards NEMO. ITC will also replace and upgrade existing SCADA equipment and add 69 kV line PTs on all lines except those going towards NEMO.		
24513	Maquoketa (CIPCO) 161 kV Sub Rebuild	CIPCO has notified ITC that they will be rebuilding the 161 kV portion of their Maquoketa substation to a ring bus. ITC will need to relocate the Grand Mound – Maquoketa and Maquoketa – Sale 161 kV lines into new bus positions at Maquoketa to accommodate the new layout of the substation. T2-636 ACSR should be used for new conductor for the new line taps.	5/30/2024	$2.03
24464	Eagle to Tharp 69 kV Line Relocation	A 0.75 section of the Eagle - Tharp 69 kV line is required to be moved to a new permanent location by the Iowa DOT due to a project to rebuild the I-380 and Wright Bros Blvd interchange. Thirteen new wooden poles, three new steel poles, and new T2-477 ACSR cabling is to be constructed as shown in the sketched figures. PTS 1158 is to be retired and PTS 1114 is to have the jumpers remade to face towards Eagle. PTS 1114 will remain in this configuration until the switch is retired with the Kitty Hawk rebuild.	5/1/2024	$1.62
25060	Grant Milford Interconnection	Rebuild approximately 4 miles of existing 34.5 kV line to 69 kV construction standards to interconnect new IPL Grant Milford substation and facilitate future area conversion to 69 kV operation as part of CIPCO's SW IA 34.5 to 69 kV conversion plans.	06/30/2025	3.48

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Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23464	Abbott-Traer 161 kV 15 miles Rebuild	Due to aging condition, ITC will rebuild the Abbott – Traer 161 kV circuit with T2-Grosbeak. New control building as this is an IPL owned site.	12/31/2027	$16.84
23510	Rock Creek T3 Replacement	The existing Rock Creek T3 transformer is at the end of its useful life and in need of replacement. T3 will be replaced with a new 150 MVA 161/69 kV transformer with LTC. In addition, there is an 800-amp relay thermal limit on T3, so the existing relaying needs to be upgraded to remove the 800-amp thermal limit to allow full use of the 150 MVA transformer rating.	12/31/2025	$4.27
23677	ITC Midwest Asset Replacement Program 2025	Replace aging and outdated equipment on a cycle that will ensure each system is replaced near its expected end of life. Modern equipment can improve reliability, use state of the art technology, and will typically use longer maintenance intervals which reduces maintenance costs. Equipment is commonly equipped with better monitoring and alarming functionality giving improved remote supervision.	12/31/2025	$38.40

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23511	Grinnell South 69 kV Substation & 20 MVAR Cap	IPL has notified ITC that they will be rebuilding the Grinnell South substation in a new location directly south of the existing substation location which will replace the existing Grinnell South substation. ITC will construct the 69 kV portion of Grinnell South in the new location including two busses, two-line breakers, and a bus tie breaker. ITC will also install a new 69 kV capacitor bank at the new Grinnell South substation to provide improved area voltage support for existing and potential additional future load growth in the area.	12/31/2025	$5.64

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23636	ITCM Customer Interconnects (short lead time) 2025	These projects are being done at the request of an interconnection customer to facilitate new load, re-distribute existing load, improve the performance of the sub-transmission and distribution systems, or to accommodate a new Transmission-to-Transmission connection request.	12/31/2025	$3.60
23684	Kittyhawk 69 kV Substation Interconnection	IPL has notified ITC that they will be rebuilding the Kittyhawk substation in the existing location to allow the addition of a second IPL distribution transformer. ITC will construct the 69 kV portion of Kittyhawk which will include two busses/single box structures, two-line breakers, and a bus tie breaker.	12/31/2025	$3.90
24449	Nevada Area Load Interconnections	ITCM will construct new transmission substations and network them to the existing 161 kV transmission system at Ames, NE Ankeny, and Fernald. The project will support load interconnections in the Ames/Nevada and increase transmission reliability for the city of Ames, IA.	12/31/2024	$56.52
24740	Commercial (JCE) 69 kV Substation	For ITC's portion of the Commercial Substation ITC will install a new 69 kV substation with two 69 kV line breakers, one distribution transformer position, and one mobile transformer position. All the ITC equipment will be capable of 600A or greater.	6/1/2024	$3.80

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23483	J1175 GIA - Bluebill TOIF	A new Bluebill 345 kV switching station will be constructed to interconnect projects J1174 and J1175. The Bison – Colby 345 kV line will be tapped and re-routed to new positions in the Bluebill station. The TOIF will include dead-end,	6/30/2025	$0.86

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		disconnect switch, arresters, PT's, relay panel, and associated equipment.		
23485	J1174 & J1175 MPFCA - Network Upgrades	A new Bluebill 345 kV switching station will be constructed to interconnect projects J1174 and J1175. The Bison – Colby 345 kV line will be tapped and re-routed to new positions in the Bluebill station. ITC will TO self-fund the Network Upgrades and will earn a return of and return on investment under a FSA for 90% of the cost. 10% of the Network Upgrades costs will be recovered under Attachment GG.	6/30/2025	$16.22
23611	J982 Affected System Upgrades	MISO Facilities Study for Affected System upgrades for project J982, a 300 MW wind-powered generating facility with proposed interconnection on MEC's Obrien County – Kossuth 345 kV circuit. The system impact study has indicated the interconnection of project J982 will require sag mitigation on the Fox Lake to Rutland 161 kV circuit.	9/1/2023	$0.34
23693	J1132 GIA Network Upgrades	Expansion of the Creston Roundhouse 69 kV bus with an additional box structure.	6/1/2024	$0.32
23701	J1135 GIA TOIF	Install equipment dedicated to the J1135 generating facilities. The J1135 line will be connected to a new breaker position on the Hunt Woods 69 kV bus.	6/1/2024	$0.56
23722	J1132 GIA TOIF	TOIF includes facilities and equipment dedicated to the Generating Facility including 69 kV switch.	6/1/2024	$0.04
23484	J1175 GIA - Bluebill TOIF	A new Bluebill 345 kV switching station will be constructed to interconnect projects J1174 and J1175. The Bison – Colby 345 kV line will be tapped and re-routed to new positions in the Bluebill station. The TOIF will include dead-end, disconnect switch, arresters, PT's, relay panel, and associated equipment.	6/30/2025	$0.86

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4.5.8 MidAmerican Energy Company (MEC)

After MISO's independent reliability analysis, MISO and MidAmerican Energy Company recommend 42 projects at an estimated cost of $269 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, three are Baseline Reliability Projects, 35 are Other Projects, and four are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 23686 Obrien County 345-161 kV Transformer Addition & Hospers 161-69 kV Transformer Addition

Project Description: Construct new 161 kV line from Obrien County Substation to Hospers Substation, expand Obrien County Substation to install 345-161 kV, 560 MVA transformer and 161 kV bus and expand Hospers Substation to install 161-69 kV, 167 MVA transformer and 161 kV bus. The total estimated cost of this project is $45 million and has an expected in-service date of December 1, 2026.

Project Need: Thermal and voltage issues can occur following N-1-1 230 kV contingencies at Eagle Substation.

Alternatives Considered: No alternatives were considered.

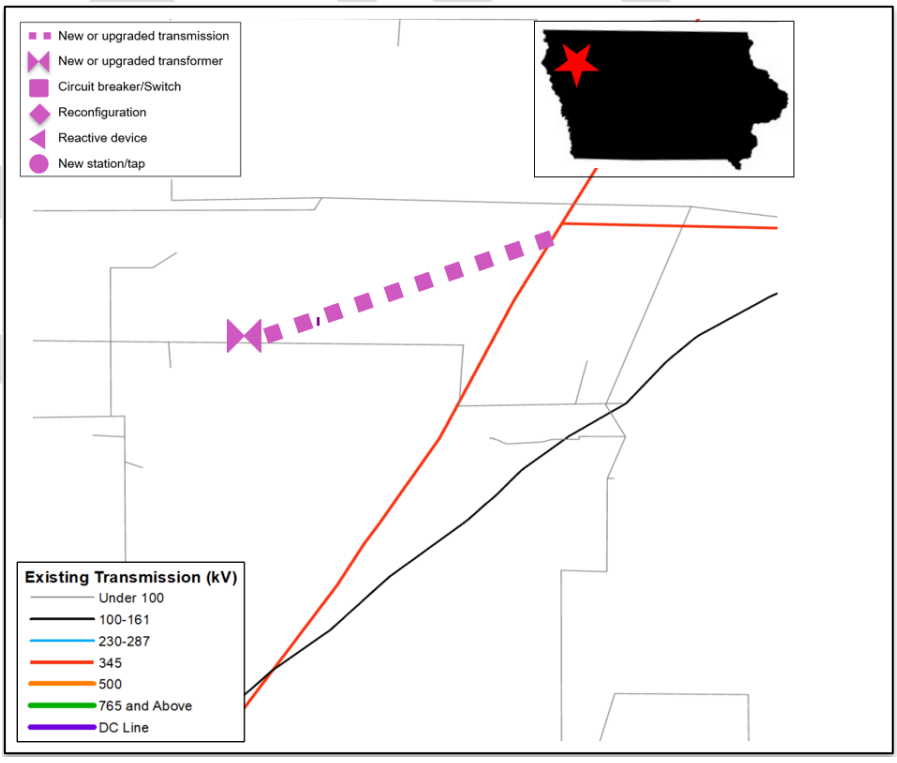


Figure 4.5.8-1: P23686 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	HOSPERS8' 69.000	0.95	0.6367	1.006
P6	MARCUS 8	0.95	0.7405	0.9715
P6	MERIDEN8	0.95	0.8260	0.9846
P6	SANBRN CRNR8	0.95	0.8061	0.9646
P6	K224MEAD-NI8	0.95	0.6899	0.999

Table 4.5.8-1: 23686 Voltage performance drivers

Project 23688 Macksburg - Winterset 161 kV Reconductor

Project Description: Reconductor the 161 kV line from Macksburg to Winterset. Line identified as a constraint in the MTEP22 generator deliverability analysis. The total estimated cost of this project is $12.5 million and has an expected in-service date of June 1, 2027.

Project Need: Line identified as a constraint in the MTEP22 generator deliverability analysis.

Alternatives Considered: No alternatives were considered.

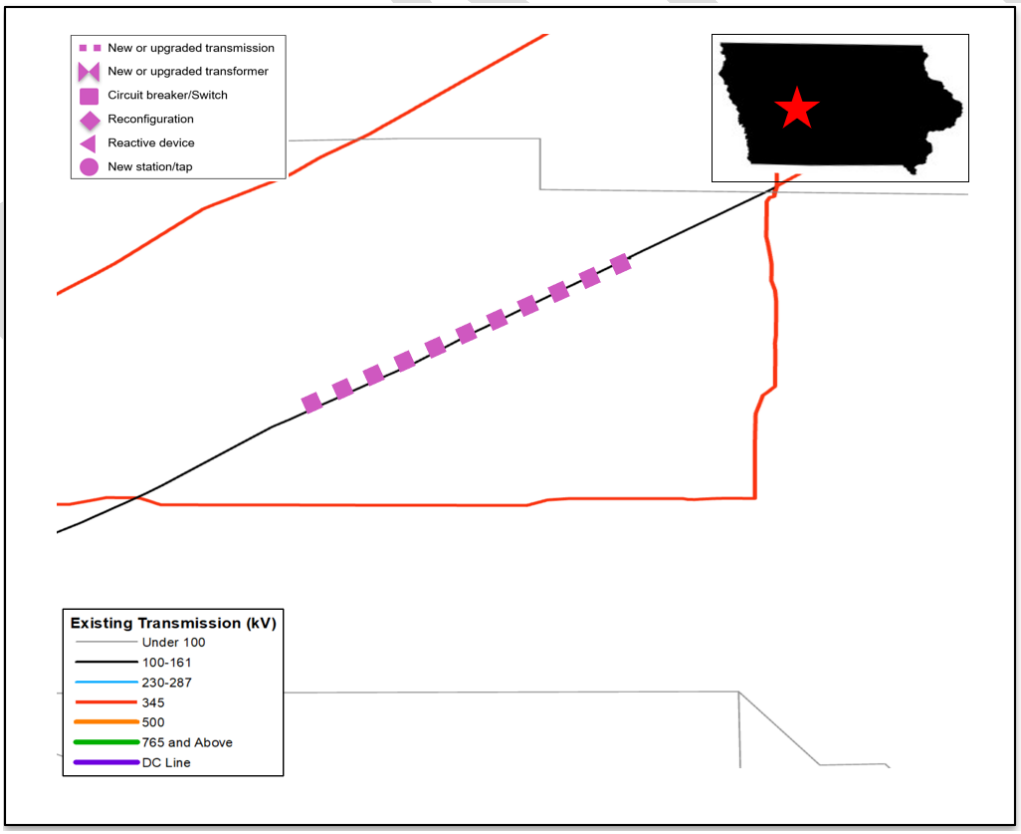


Figure 4.5.8-2: P23688 Geographic transmission map of project area

Project 23720 Hickory Avenue-Sioux Center 69 kV Line & Substation Line Terminals

Project Description: Construct new 69 kV line from Hickory Avenue Substation to Sioux Center Substation. Expand Hickory Avenue and Sioux Center Substations to install new 69 kV line terminals. The total estimated cost of this project is $12 million and has an expected in-service date of June 1, 2025.

Project Need: Mitigates thermal and voltage issues following N-1-1 69 kV contingencies at maintenance load levels.

Alternatives Considered: No alternatives were considered.

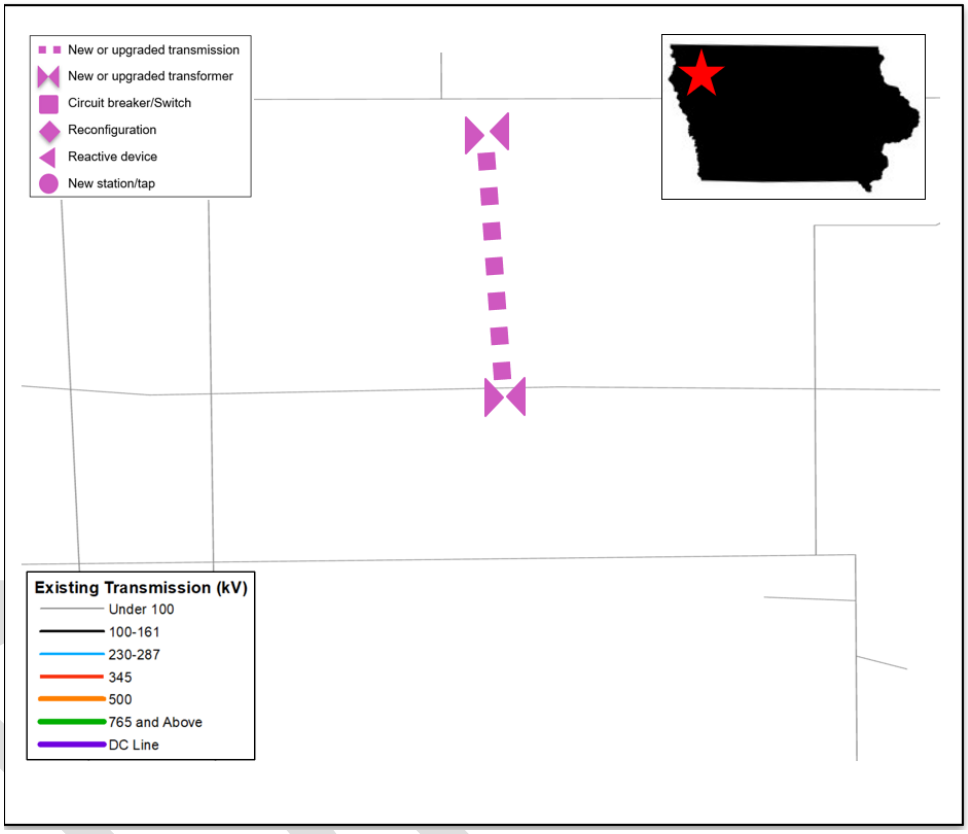


Figure 4.5.8-3: P23720 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	635370 SHELDON8 - 635372 SANBRN CRNR8	44	107	49
P6	635372 SANBRN CRNR8 - 635373 MAP SANBORN8	44	112	51
P6	635373 MAP SANBORN8 – 656573 WISDOM G	44	172	54

Table 4.5.8-2: P23720 Thermal loading drivers.

Cont. Type	Limiting Element	Rating (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	SANBRN CRNR8 69 kV	0.95	0.6482	0.9810
P6	MAP SANBORN8 69 kV	0.95	0.6623	0.9818
P6	DOON TAP8 69 kV	0.95	0.4585	0.9789
P6	BOYDEN 8 69 kV	0.95	0.4825	0.9865
P6	HICKORY AVE8 69 kV	0.95	0.4620	0.9894
P6	GEORGE 8 69 kV	0.95	0.4970	0.9777

Table 4.5.8-3: P23720 Voltage performance drivers

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23572	Franklin: Replace 161 kV Breaker 9210	Franklin: Replace 161 kV Breaker 9210.	12/01/2023	$0.50
23694	Wall Lake 161 kV Terminal Equipment Upgrades	Replace limiting jumpers on Wright - Wall Lake and Wall Lake - Franklin 161 kV line terminals.	12/31/2026	$0.10
23740	Webster: Replace 161 kV Breaker 9250	Replace 161 kV breaker 9250 in Webster substation.	12/31/2026	$0.30
23741	Wright 161 kV Terminal Equipment Upgrades	Replace 1200A substation terminal equipment on Webster - Wright and Wall Lake- Wright 161 kV line terminals.	12/31/2026	$0.15
24212	Badger Creek Substation	Construct Badger Creek Substation that will bisect the existing Arbor Hill-Raccoon Trail 345 kV line. Construct a new 345 kV line from Badger Creek Substation to the Raccoon Trail Substation.	12/1/2025	$0.00

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23571	Humboldt 69 kV Reconfiguration	Network Humboldt Central Substation and establish tie with Corn Belt's Weaver Switching Station.	12/1/2026	$9.90

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23573	Black Hawk: 161-69 kV, 167 MVA Transformer	Replace existing 161-69 kV, 50 MVA Transformer.	12/1/2025	$9.0
23590	Granger Substation 161 kV Line Breakers	Install 161 kV line breakers and associated relaying.	12/1/2026	$2.10
23592	Floyd Substation: Add 69 kV Bus PTs, Remove Wave Trap, and Incorporate Fiber	Add 69 kV Bus PTs; remove wave trap and employ fiber for Floyd-Emery 161 kV line relaying.	12/31/2024	$0.35
23593	Charles City North add 69 kV Breakers	Charles City North Add 69 kV Breakers.	12/1/2027	$0.80
23608	E. 29th & Hubbell 69 kV Expansion and Line Tap	Expand substation steel for a second 69 kV line tap.	06/01/2024	$0.50

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23609	Delaware Substation 161 kV Line Breakers	Install 161 kV line breakers and associated relaying.	6/1/2025	$1.90
23610	Washburn: 161-69 kV, 125 MVA Transformer	Replace existing 161-69 kV, 50 MVA Transformer	12/1/2026	$7.50
23628	Waverly Junction: Reconfigure 69 kV Terminals	Reconfigure 69 kV line terminals to eliminate tapped substation transformer.	6/1/2024	$1.30
23675	Avoca: Install 69 kV Breaker on 161-69 kV Transformer 8T3 and 161 kV & 69 kV Breaker Replacements	Install a 69 kV breaker on the low-side of Avoca 161-69 kV Transformer 8T3, replace/relocate Avoca Breakers 622 and 623 to accommodate new 69 kV breaker and replace Breakers 801, 802 and 620 due to condition.	12/1/2025	$4.10
23690	Quad Cities Enron Substation: Install 161 kV Line Switches	Install new 161 kV line switches on both sides of the QEN Quad City Enron substation to increase switching flexibility.	12/31/2025	$0.50
23691	Riverdale 161-13.2 kV Substation	Construct new 161-13.2 kV substation and 161 kV line taps.	12/31/2026	$4.10

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23692	Sub 28 Add 161 kV Line Breakers and Install New Control Building	Install new 161 kV line breakers and new control building to replace existing control enclosure.	12/31/2027	$3.70
23719	Oakland: Add 69 kV, 12 MVAR Capacitor Bank and 69 kV Line Breakers	Install 69 kV, 12 MVAR capacitor bank and install 69 kV line breakers at Oakland Substation.	6/1/2026	$5.0
23721	Monona: Replace 161 kV Transformer	Replace the existing Monona 161-69 kV transformer with a 125 MVA unit. Convert Monona 161 kV bus to a ring bus configuration. Also, replace two 69 kV breakers and upgrade associated terminal equipment.	12/1/2025	$7.0
23723	Edgington 161-13.2 kV Substation	Construct new 161-13.2 kV sub and 161 kV line taps. Install fiber for communication and protective relaying.	12/31/2027	$10.50
23739	Sub 42: Install 69 kV Line Switches	Install new 69 kV line switches on both sides of the Sub 42 substation to increase switching flexibility.	12/31/2027	$0.80

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23570	Valley Trail 161 kV Substation	Construct Valley Trail 161-13.2 kV Sub and Line Taps.	6/1/2026	$9.50
23687	Storm Lake Industrial 69 kV Line Taps	Construct 69 kV line taps into new Storm Lake Industrial 69-13.8 kV Substation.	12/1/2026	$0.80
23699	Gifford Road 161-13.2 kV Substation and 161 kV Line Taps	Construct Gifford Road 161-13.2 kV Sub and Line Taps.	9/1/2026	$5.50
24999	Southland Expansion & Upgrades	Expand 345 kV bus at existing Southland Substation to serve new customer load. Construct new 345 kV line from Overland Trail to Pony Creek Substation, reroute the existing Pony Creek-Rolling Hills 345 kV line into Southland Substation and rebuild the existing CBEC-Pony Creek 345 kV line.	5/31/2024	$58.0

Projects Driven by Age and Conditions

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23591	Nashua Tap-Plainfield Junction 69 kV Rebuild	Replace conductor on section of Nashua Tap-Plainfield Junction 69 kV line using existing right of way.	12/31/2024	$2.50
23629	Charles City South-Nashua Tap 69 kV Rebuild	Charles City South-Nashua Tap 69 kV Rebuild.	12/1/2025	$7.70
23630	Wida-Streeter 69 kV Rebuild	Replace conductor on MidAmerican section of Wida-Streeter 69 kV line.	4/1/2024	$1.00
23655	Shenandoah: Replace 69 kV Breakers 601 & 602	Replace 69 kV breakers at Shenandoah Substation.	12/1/2024	$0.60
23683	Sheldon: 69 kV Breaker and Relay Replacements	Replace Sheldon 69 kV Breakers 7730, 7740, 7880 and 7890 and associated disconnect switches and relaying.	10/1/2024	$2.80
23685	Neal North-Southbridge Tap-Knox-State Steel Tap 69 kV Line Rebuild	Rebuild approximately 9 miles of line.	12/5/2024	$8.60
23689	Sub 93 Louisa: Replace 345 kV Breaker 934	Replace 345 kV breaker in Sub 93 (Louisa) ring.	4/7/2023	$0.39
23724	Pomeroy 161 kV Substation 69 kV Breaker Replacement and Addition	Replace 69 kV breaker 7290. Convert 34.5 kV system to 69 kV due to condition. Expand Pomeroy 69 kV bus to accommodate additional 69 kV line terminal and add 69 kV bus differential relaying.	12/31/2023	$0.60
24923	Sidney-Percival 69 kV Line Rebuild	Replace due to condition.	6/1/2025	$9.10

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23703	J982 POI New 345 kV Interconnection Substation and 345 kV Line Taps	Construct new 345 kV POI substation and 345 kV line taps for J982 wind farm.	6/1/2025	$15.25
23725	Palo Alto 345 kV Substation Expansion for J877	Add one new 345 kV line terminal at Palo Alto substation for J877 solar farm generator tie line.	7/1/2025	$3.80
23726	Raun - Remsen 345 kV Line Uprate for DPP 2018	Replace line structures to increase line rating.	12/01/2024	$1.20

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23727	Sub 56 161 kV Substation Expansion for J1131	Add one new 161 kV line terminal at Sub 56 for J1131 solar farm generator tie line.	9/1/2027	$2.03

4.5.9 Minnesota Municipal Power Agency (MMPA)

Minnesota Municipal Power Agency did not submit any new projects for MTEP23. MISO has not identified any issues in MMPA's area.

4.5.10 Minnesota Power (MP)

After MISO's independent reliability analysis, MISO and Minnesota Power recommend five Other Projects at an estimated cost of $51 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23707	Maturi Expansion	The Maturi Expansion Project will add three circuit breakers to allow for the transmission line to be looped in and out of the Maturi Substation.	12/31/2025	$3.6

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23877	Nelson Lake 230 kV Substation	New 230 kV switching station tying together MP Square Butte East - Bison and GRE Square Butte - Stanton 230 kV lines.	6/1/2023	$25

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22909	40 Line Rebuild	Rebuild Badoura - Dog Lake 115 kV Line, new 795 ACSR and OPGW will be installed.	12/31/2024	$17

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23708	Mahtowa Expansion	The Mahtowa Expansion project will add 3-115 kV circuit breakers to reconfigure the existing Mahtowa Substation into a 3-position ring bus.	12/31/2025	$2.5

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
22885	Brainerd Crypto	Mitigation solutions to accommodate a 70 MW Load addition at Brainerd 115 kV bus, including a second 20 MVAR capacitor bank and thermal upgrade of the Brainerd - Riverton 115 kV Line.	12/31/2024	$2.8

4.5.11 Missouri River Energy Services (MRES)

After MISO's independent reliability analysis, MISO and Missouri River Energy Services recommend three projects at an estimated cost of $3.5 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Market Participant Funded Project and two are Other Projects. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Market Participant Funded Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23919	Morris to Grant County to East Fergus Falls Upgrade	Increase the rating of 115 kV lines from Morris to Grant County to East Fergus Falls.	7/1/2024	$1.34

Other Projects

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23710	Atlantic 161 kV Breaker Replacement	Replace two 161 kV oil filled breakers with SF6.	1/1/2024	$0.8

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24232	ALP SE Substation	Alexandria Light & and Power (ALP) will build a new distribution substation on the southeast part of town. The substation will tap and existing 115 kV line with an in and out substation. The substation will have a 115 kV to distribution transformer.	12/31/2025	$1.36

4.5.12 Montana-Dakota Utilities Co. (MDU)

After MISO's independent reliability analysis, MISO and Montana-Dakota Utilities Co. recommend five projects at an estimated cost of $45.3 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Market Participant Funded Project and four are Other Projects. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Market Participant Funded Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24092	Baker upgrades MP funded	Market Funded project to upgrade terminal equipment at Baker.	12/31/2023	$0.05

Other Projects

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23596	Glenham Rebuild	Rebuilding the current Glenham substation 230/115/41.6 kV.	10/31/2025	$23.5
23634	Wishek Rebuild	Will be expanding the 230 kV to add new wind farm and rebuilding the 115 and 41.6 kV.	12/31/2025	$18.7

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23633	Ellendale Load Addition	MDU has new customer requesting service at Ellendale, ND for total demand of 180 MW. MDU will serve the customer from the existing Ellendale 2 transformer's 34.5 kV tertiary. An overhead line will be built from	2/15/2023	$3.06

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		the tertiary of the transformer to the customers sub.		
24978	Tatanka Load Addition	MDU will be signing an agreement to serve 100 MW of load at the Tatanka Wind Farm collector substation off the Tatanka South Substation. There will be no cost to MDU to serve the customer.	12/1/2023	$0

4.5.13 Muscatine Power and Water (MPW)

Muscatine Power and Water did not submit any new projects for MTEP23. MISO has not identified any issues in MPW area.

4.5.14 Northwestern Wisconsin Electric (NWEC)

Northwestern Wisconsin Electric did not submit any new projects for MTEP23. MISO has not identified any issues in NWEC area.

4.5.15 Otter Tail Power Company (OTP)

After MISO's independent reliability analysis, MISO and Otter Tail Power Company recommend 18 projects at an estimated cost of $100.6 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, 16 are Other Projects and two are Generator Interconnection Projects with signed Generator Interconnection Agreements. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23860	OTP Grenville - Veblen 41.6 kV	Rebuild of 41.6 kV line between Grenville 41.6 kV and Veblen 41.6 kV.	11/30/2025	$4.6
23943	OTP Pickert - McVille 41.6 kV	Rebuild portions of the 41.6 kV line between Pickert 41.6 kV and McVille 41.6 kV.	11/30/2024	$3.8
23917	OTP Fordville - Fordville Jct. 41.6 kV	Rebuild of 41.6 kV line between Fordville 41.6 kV and Fordville Jct. 41.6 kV.	11/30/2025	$1.5
23977	OTP Cooperstown 41.6 kV	Reroute and rebuild 5 miles of 41.6 kV line near Cooperstown 41.6 kV.	11/30/2024	$1.2
23842	OTP Wilmot - Peever Jct. 41.6 kV	Rebuild 4 miles of 41.6 kV line between Wilmot 41.6 kV and Peever Jct. 41.6 kV.	12/31/2024	$1.1

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23859	OTP Granville - Granville Station 41.6 kV	Rebuild of 41.6 kV line between Granville 41.6 kV and Granville Station 41.6 kV.	12/31/2023	$1
23918	OTP Michigan - Mapes 41.6 kV	Rebuild of the 41.6 kV line between Michigan 41.6 kV and Mapes 41.6 kV.	12/31/2023	$1
23942	OTP Gackle - Jamestown 41.6 kV	Reconductor and rebuild sections of the 41.6 kV line between Gackle 41.6 kV and Jamestown 41.6 kV.	11/30/2024	$1
23944	OTP Wabek - Parshall 41.6 kV	Rebuild and Reconductor the 41.6 kV line between Parshall 41.6 kV and Wabek 41.6 kV	12/31/2027	$0.9
23955	OTP Wilton 41.6 kV Breaker Addition	Install a new line sectionalizing 41.6 kV breaker at Wilton, ND.	12/31/2024	$0.3

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23866	OTP Veblen 41.6 kV Breaker Replacement	Replacement of Veblen 41.6 kV breaker.	12/31/2023	$0.5

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23896	OTP Devils Lake, ND 115 kV Delivery	OTP is converting the 4.16 kV distribution system in the town of Devils Lake, ND to a 12.5 kV system. With this conversion, the town will be removed from our 41.6 kV system and be served via the 115 kV system. In order to move the town to the 115 kV system, a new 115 kV delivery will be established by tapping the Devils Lake East to Sweetwater 115 kV line with a two-way switch. Two miles of 115 kV line will be constructed from the new switch over to the town of Devils Lake where a new 115/12.5 kV distribution substation will be established which will include a 115 kV	12/31/2026	$1.6

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		breaker on the high side of the 115/12.5 kV transformer.		
23129	OTP Casselton 115 kV Capacitor Addition	The project consists of expanding the existing 115 kV bus at OTP's Casselton, ND substation with two additional 115 kV breakers to allow for another position in the substation. A new 115 kV 15 MVAR capacitor and breaker will be added into the new position created in the Casselton 115 kV bus.	06/01/2024	$1.2
25256	OTP Jamestown Load Expansion	Add a 115/41.6 kV transformer to the 115 kV bus at OTP's Jamestown 345 kV substation to serve a 10 MW expansion of an existing customer's load. The new transformer will also be connected to OTP's existing 41.6 kV transmission system for backup service via a normally open breaker.	06/01/2024	$3.25
23806	OTP Lake Preston, Load Addition	OTP will serve a new customer load in SD by extending a 115 kV line from our Hetland 115 kV substation to a new Lake Preston 115/34.5 kV substation. A new 115 kV line will be extended from the new Lake Preston 115/34.5 kV substation to Xcel's Brookings County 345/115 kV substation to create a 115 kV looped network. Capacitors will be installed at the new Lake Preston 115/34.5 kV substation for additional voltage support. The Facilities will consist of Hetland 115 kV substation termination addition, a 9.5 mile 115 kV line from Hetland 115 kV substation to a new Lake Preston 115/34.5 kV substation, a new Lake Preston 115/34.5 kV substation with capacitors installed at the 115 kV level, and a 45 mile 115 kV line from the new Lake Preston 115/34.5 kV substation to Xcel's Brookings County 345/115 kV substation.	12/31/2024	$42.6
23936	OTP Milbank, Load Addition	OTP will serve a new 4.5 MW load at Milbank, SD and support the	12/31/2026	$32.3

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		conversion of a 9.5 MW electric boiler moving from non-firm service to firm service by expanding the Big Stone 115 kV bus to accommodate an additional 115 kV termination, create a new approximately 12.5 mile 115 kV line from Big Stone 115 kV substation to a new Milbank 115/12.5 kV substation, adding a new Milbank 115/12.5 kV substation, adding a new approximately 18.5 mile 115 kV line from the new Milbank 115/12.5 kV substation to a new 115 kV breaker station located on the Big Stone - Marietta 115 kV line, adding a new 115 kV breaker station on the Big Stone - Marietta 115 kV line, and adding a new 115 kV tap along the new 115 kV line from the new Milbank 115/12.5 kV substation to the new 115 kV breaker station to convert an existing distribution substation to the 115 kV system. The surrounding area is no longer reliably sufficient to serve the load.		

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23146	OTP Big Stone Network Upgrades - J722	J722, a 200 MW wind project, has requested to interconnect into OTP's Big Stone South 230 kV substation as part of the MISO August 2017 DPP study cycle. J722 has been assigned to complete the following network upgrades on OTP's transmission system to interconnect at Big Stone South 230 kV. 1. Increase capacity on the Big Stone South - Big Stone 230 kV circuits #1 and #2. 2. Increase capacity on the Big Stone - Blaire 230 kV circuit.	5/31/2023	$1.8
24457	OTP Bagley Jct. 115 kV Capacitor Addition	Expand the Bagley Jct. 115 kV switching station to allow for the installation of a single step 20 MVAR 115 kV capacitor	7/31/2024	$1.2

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		bank. The project will consist of the addition of two 115 kV breakers, three disconnect switches, a single 20 MVAR 115 kV capacitor bank, and other associated equipment to allow for the installation of a 20 MVAR 115 kV capacitor bank.		

4.5.16 Rochester Public Utilities (RPU)

Rochester Public Utilities did not submit any new projects for MTEP23. MISO has not identified any issues in RPU area.

4.5.17 Southern Minnesota Municipal Power Agency (SMMPA)

After MISO's independent reliability analysis, MISO and Southern Minnesota Municipal Power Agency recommend one Other Project at an estimated cost of $8.9 million to be approved for inclusion in MTEP23 Appendix A. The expected in-service date and estimated cost of this project is provided as of September 29, 2023.

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
25252	Fairmont, MN Area 69 kV Transmission Expansion	Building of a new 69/12.5 kV distribution substation "West Industrial Park" (WIP) west of Fairmont, construction of a new 69 kV SMMPA breaker station and construction of two 69 kV transmission lines, one from WIP to the SMMPA's Fairmont Energy Station (FES) substation (approx. 2 mi) and one from WIP which will tap Great River Energy's 69 kV line between Rutland substation and the Fairmont 10th Street Substation (0.5mi).	3/01/2024	$8.92

4.5.18 Wilmar Municipal Utilities (WMU)

Wilmar Municipal Utilities did not submit any new projects for MTEP23. MISO has not identified any issues in WMU area.

4.5.19 WPPI Energy (WPPI)

WPPI Energy did not submit any new projects for MTEP23. MISO has not identified any issues in WPPI area.

4.5.20 Xcel Energy (Northern States Power)

After MISO's independent reliability analysis, MISO and Xcel Energy recommend 62 projects at an estimated cost of $311.2 million to be approved for inclusion in MTEP23 Appendix A. Of these projects, one is a Baseline Reliability Project, one is a Multi-Value Project, and 60 are Other Projects. The expected in-service date and estimated cost for these projects are provided as of September 29, 2023.

Baseline Reliability Projects

Project 24278 – Edina Switch Replacement

Project Description: Project will replace 115 kV switch at Edina, which is limiting the rating of the Edina - St. Louis Park 115 kV line. The total estimated cost of this project is $0.14 million and has an expected in-service date of December 31, 2023.

Project Need: This project remediates overloads on the Edina - St. Louis Park 115 kV line identified in MTEP22.

Alternatives Considered: No alternatives were considered.

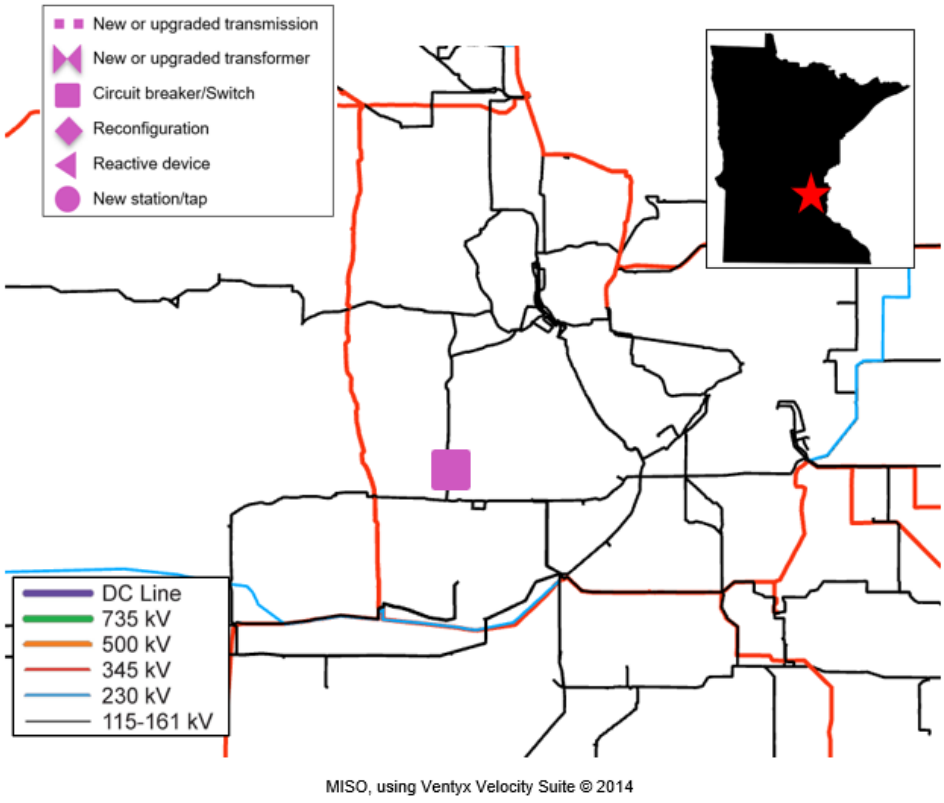


Figure 4.5.20-1: P24278 Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Edina – St. Louis Park 115 kV	308.6	127	90
P7-1	Edina – St. Louis Park 115 kV	308.6	127	90

Table 4.5.20-1: P24278 Thermal loading drivers

Multi-Value Projects:

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
24902	Brookings - Lyon, Hampton - Helena OPGW Replacement	This project will replace the aging OPGW on the Brookings - Lyon County and Hampton - Helena 345 kV lines. This project will be performed in tandem with the installation of the Brookings - Lyon County and Hampton - Helena 2nd circuit installation project.	9/1/2025	$4.0

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23347	Blue Lake Substation - FRM13	Replace ammeter on Blue Lake 345 kV breaker 8M33 to increase rating on the Blue Lake - Scott County 345 kV line.	9/2/2022	$0.1
23447	W3441 Extension to W3510	Extend the line from Birchwood substation to the east to connect to Xcel line W3510 in the vicinity of the town of Wieger, a distance of about 13 miles. Install motor operated switches at Birchwood to sectionalize the line. Install manual switches at the connection to W3510. The line would initially be operated as a normally open second source to Birchwood.	12/1/2025	$9.0
23450	STY Install TR3 & 115 kV Bus Tie	Install new 115 kV bus tie and associated disconnect switches and bus work and re-terminate 0818/5529 at Rogers Lake Sub.	12/15/2024	$5.3
23451	Pine Lake - Stanton 69 kV Rebuild	Rebuild 16.1 miles from Pine Lake - Stanton to 69 kV standard.	9/1/2023	$9.5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23453	Line 0811 - Riverside Substation - FRM13	Replace switches 5M330B, 5M331B, 5M329A, 5M330A, 5M329B, 5M331A, aux current transformers on 5M304 and 5M305, and two sections of busbar.	12/31/2022	$0.9
23454	Line 0838 - Red Rock Substation - FRM13	Replace bushing current transformers on breaker K2, switches K2B1, 946B, K2B2, 946A, and meters on 946 and K2.	12/31/2022	$0.7
23463	Nighthawk Breaker Station	New 4-line terminal breaker station connecting to Minnesota Valley – Troy 69 kV transmission line (0724), Crook's substation, and the SMBSC plant.	6/1/2024	$5.0
23468	Chisago County Substation - FRM13	Replace primary and secondary 115 kV bus 1 differential relays for TR05 and TR06.	8/1/2022	$0.2
23469	Scott County Substation - FRM13	Replace busbar.	12/31/2022	$0.2
23486	Inver Hills Substation - FRM13	Replace busbar.	3/1/2023	$0.2
23487	Kohlman Lake Substation - FRM13	Replace meter on breaker 5P106.	12/31/2022	$0.1
23488	Prairie Substation - FRM13	Replace meter on breaker 5G8.	12/31/2022	$0.1
23489	Wilmarth Substation - FRM13	Replace bushing current transformer on breaker 5S11 as well as switches 8S26B1, 8S25B, 8S25A, 8S26B1.	12/31/2022	$0.6
23501	Line 0840 Elliot Park Pumping Plants	Upgrades to pumping station for HPFF.	6/1/2025	$5.0
23509	Junction Mill Substation	Build new Junction Mill substation near 3-terminal 115 kV connection with Glenmont, River Falls and Crystal Cave lines. In addition, this substation will install a new 115/69 kV transformer and change the operating voltage of the River Falls tap to 69 kV. The transformation at the River Falls substation will be removed as well as any 115 kV equipment.	6/1/2024	$12.0
23513	Emerald Substation	Line W3209 – Replace 3-way switch with new 161 kV to 115 kV substation. Rebuild 1 mile of double circuit 161-115 kV line to single circuit 115 kV line. Retire Pine Lake 161 kV to 115 kV yard.	6/15/2025	$12.0

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23515	Eau Claire TR09 Replacement	Upgrade Eau Claire TR09.	6/1/2025	$8.0
23712	Lyon County Substation - FRM13	Replace 5N130 actuator secondary current limitation to increase TR9 rating back up to its transformer limits.	9/1/2023	$0.3
23760	Nobles County Substation - FRM13	Upgrade flexible busbar to increase ratings of TR9 and TR10.	9/1/2023	$0.5
24374	Steep Bank Lake Line Swap	Move J460 Steep Bank Lake interconnection to new 34 5kV second circuit being built between Brookings County - Lyon County (MTEP ID 23452).	9/2/2025	$0.3

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23446	W3502 Rebuild and Connection to W3503	Construct a new line from the end of the existing line W3502 to Xcel's W3503 1.3 miles to the east. The new connection would be made with a group of one-way pole mounted switches. The new connection will allow the sections between the substations to be sequentially rebuilt. The existing line W3502 will be rebuilt to serve as a redundant connection.	6/15/2024	$3.0
23448	W3430 Rebuild	Rebuild 2 ¼ miles from Luck - Luck (DPC) to 69 kV standard.	6/1/2023	$1.0
23449	W3429 Clear Lake to STR 214 Rebuild	Rebuild 10 miles of line W3429 from Clear Lake to Structure 214 to 69 kV standard and add OPGW.	7/31/2024	$5.3
23455	Parkers Lake TR09 ELR	Replace Parkers Lake 345/115 kV TR09 (3 phases).	12/31/2025	$6.0
23456	Lake Yankton TR02 ELR	Replace Lake Yankton 115/69 kV TR02.	12/31/2026	$1.5
23457	Hydro Lane TR05 ELR	Replace Hydro Lane 115/69 kV TR05.	12/31/2026	$3.0
23458	Line 0893 NSS-BCK Rebuild	Rebuild 3.4 miles of 115 kV line between North Star Steel and Battle Creek substations. Portions of this line are double circuited with 0892, this project will separate the two circuits.	12/15/2023	$3.4

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23459	Line 0749 Waseca - ITC Tap Rebuild	Rebuild 6.7 miles of 69 kV line 0749 from Waseca - ITC Tap and add OPGW.	6/15/2024	$6.0
23460	Line 0714 Medelia - Watonwan Rebuild	Rebuild 22 miles of line 0714 69 kV from Medelia - Watonwan.	12/31/2024	$11.0
23461	Line 0708 STR 78 to 476 Rebuild	Rebuild 16 miles of line 0708 69 kV from Eagle Lake - Waterville and add OPGW.	12/31/2024	$9.0
23462	Line 0718 Arlington - Winthrop Rebuild	Rebuild 15 miles line 0718 69 kV from Arlington - Winthrop.	6/15/2024	$9.0
23466	W3351 88 kV Rebuild STR 336 to Saxton Pump	Rebuild line W3551 from structure 336 to Saxton Pump. Design the 88 kV circuit to be 115 kV capable. Include provision for a 34.5 kV under build circuit to connect to W3628 north of Saxton Pump.	12/31/2024	$8.0
23467	Line 0859 Str 16 to Chemolite rebuild	Rebuild 6.9 miles of line 0859 115 kV from Chemolite substation to structure 16.	12/31/2024	$9.0
23473	Line 0892 RRK-BCK Rebuild	Rebuild 3.4 miles of 115 kV line between Red Rock and Battle Creek substations. Portions of this line are double circuited with 0893, this project will separate the two circuits.	12/15/2023	$5.2
23474	Line 0736 Arden Hills - Lawrence Creek Rebuild	Rebuild 33 miles of line 0736 69 kV from Arden Hills - Lawrence Creek and add OPGW.	12/31/2025	$20.0
23475	Line 0721 STR 71 to 476 Rebuild	Rebuild 22 miles line 0721 69 kV from Structure 71 - Structure 476.	12/31/2025	$11.0
23476	Line 0822 Empire to STR 107 Rebuild	Rebuild 7 miles of line 0822 115 kV from Empire to Str 107 and add OPGW.	12/31/2024	$6.0
23477	Line 0772 Prairie to MNPC Connection Rebuild	Rebuild 12 miles of line 0772 69 kV from Prairie - Emerado.	12/31/2025	$6.0
23479	Iron River Substation Rebuild	Rebuild the existing Iron River substation to include a 115 kV ring bus and new 115/34.5 kV transformer.	6/1/2024	$7.0
23490	Crystal Cave TR01 ELR	Replace Crystal Cave 161/115 kV TR01.	12/31/2024	$3.5
23491	Parkers Lake TR10 ELR	Replace Parkers Lake 345/115 kV TR10 with a single 3 phase transformer.	12/31/2022	$3.5

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Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23492	Pine Lake TR03 ELR	Replace Pine Lake 161/115 kV TR03.	12/31/2027	$3.5
23493	Monticello TR06 & TR10 ELR	Replace Monticello 345/230 kV TR06 and 345/115 kV TR10.	9/16/2025	$7.0
23494	Prairie Island TR10 ELR	Replace Prairie Island 345/161 kV TR10	12/15/2024	$3.5
23495	Pipestone TR05 & TR06 ELR	Replace Pipestone TR05 and TR06 115/69 kV transformers.	12/31/2024	$3.0
23496	Inver Grove TR02 ELR	Replace Inver Grove 115/69 kV TR02.	12/31/2025	$2.5
23497	Lake Pulaski TR05 ELR	Replace Lake Pulaski 115/69 kV TR05.	12/31/2026	$2.5
23498	Minnesota Valley TR11 ELR	Replace Minnesota Valley 115/69 kV TR11.	12/31/2027	$2.5
23499	Osprey TR05 ELR	Replace Osprey 115/69 kV TR05.	12/31/2027	$3.5
23502	Line 0771 Rebuild	Rebuild 2 miles of line 0771 from Young America - Carver County 69 kV substations and add OPGW.	6/30/2024	$1.5
23503	Line 0719 Winthrop to STR 45 Rebuild	Rebuild 1.5 miles of line 0719 69 kV from Winthrop - Structure 45.	12/31/2025	$2.0
23506	Gingles TR05 ELR	Replace Gingles 115/69 kV TR05.	12/31/2025	$2.5
23508	Line 5503 Cherry Creek - Great Plains - West Sioux Falls Rebuild	Rebuild 2 miles 115 kV Cherry Creek - Great Plains. Rebuild 1 mile 115 kV Great Plains - West Sioux Falls (single circuit portion) as bifurcated double circuit. Rebuild 0.7 mile 115 kV Great Plains - West Sioux Falls (double circuit portion).	6/1/2024	$5.0
23512	Prairie View Substation	Rebuild the Wheaton Substation on a new location with a 4-row breaker and a half 161 kV configuration in order to separate it from the Generation facility.	6/1/2026	$17.0
23527	Line W3428 Clear Lake - New Richmond Rebuild	Rebuild 19.8 miles of line W3428 from Clear Lake - New Richmond.	3/15/2023	$10.0
23528	Gaiter Lake Substation	Build new Gaiter Lake substation in Waseca to pick up load off of Clarks Grove, Meridan, and Waseca substations. Retire Clarks Grove and Meridan substations.	10/15/2025	$7.8

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Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
23514	Sauk Centre North Interconnection	Build three one-way switches on line 0794 to accommodate new Sauk Centre Municipal distribution substation.	12/31/2024	$0.8
23547	21829 - South Dayton Interconnection	New GRE interconnection (MTEP ID 21829). Xcel will own high side of new sub with an in-and-out configuration on the Elm Creek - Champlin Tap 115 kV line.	6/15/2023	$5.0
23728	Owen Area Substation	Install new Owen Area Substation and convert Owen Distribution to 23.9 kV.	10/15/2026	$7.9
24315	Dubay Lake Substation	Install new 115/34.5 kV substation in the Dayton area to meet area load growth.	6/16/2025	$12.4

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 Long-Term Reliability Assessment

December 2024

Corrected July 11, 2025



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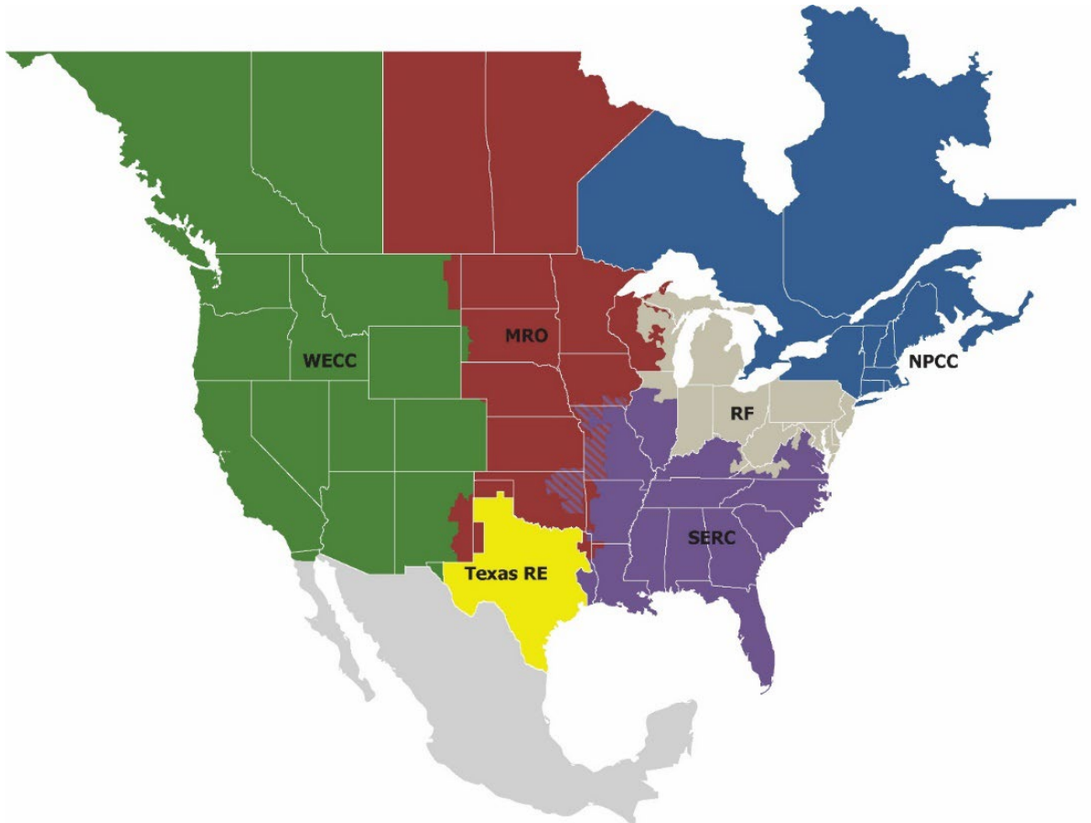
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the *Long-Term Reliability Assessment* (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2024 about known system changes with updates incorporated prior to publication. This *2024 LTRA* assessment period includes projections for 2025–2034; however, some figures and tables examine data and information for the 2024 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section of this report. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; it is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

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[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] ERO Reliability Assessment Process Document

Assumptions

In this *2024 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2024. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

In the *2024 LTRA*, NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

This *2024 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next 10 years; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used both a probabilistic assessment and a reserve margin analysis to assess the risk of future electricity supply shortfalls. Both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development.

Areas categorized as **High Risk** fall below established resource adequacy criteria in the next five years. High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Extreme weather, producing wide-area heat waves or deep-freeze events, poses an even greater threat to reliability. **Elevated-Risk** areas meet resource adequacy criteria, but analysis indicates that extreme weather conditions are likely to cause a shortfall in area reserves. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions. The results of the risk assessment are depicted in **Figure 1**.

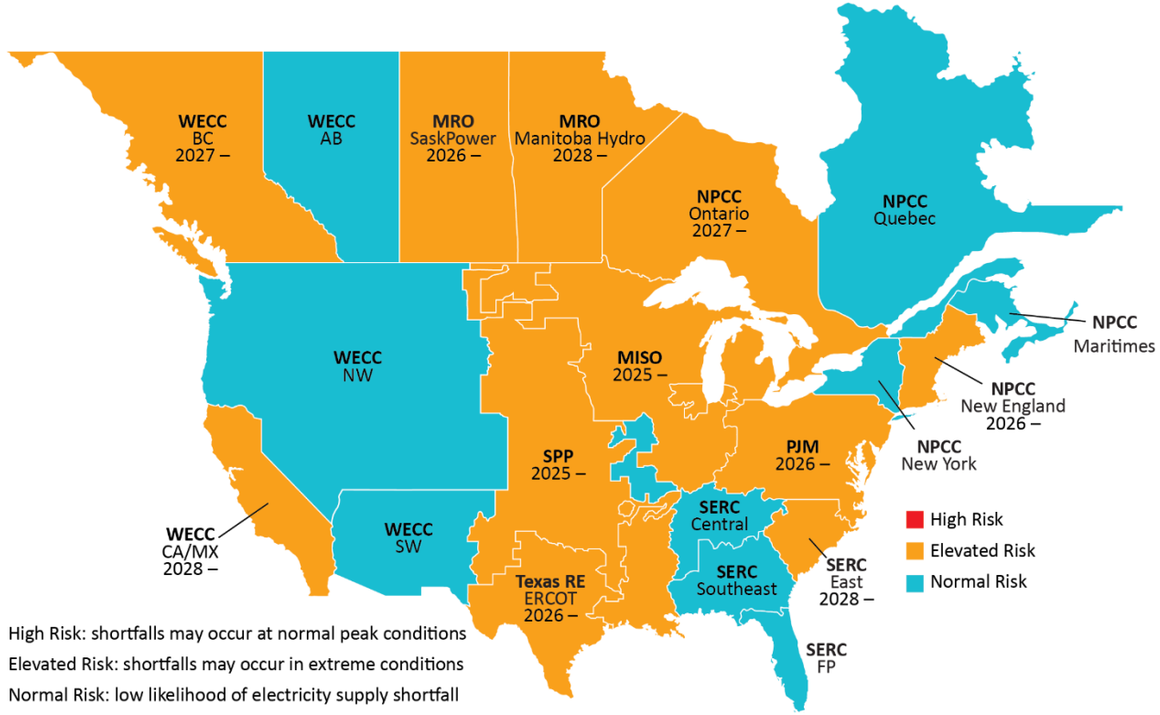


Figure 1: Risk Area Summary 2025–2029 (Corrected July 2025)

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 20 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic Assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Table 1: Capacity and Energy Risk Assessment Area Summary (Corrected June 2025)			
Area	**Risk Level**	**Years**	**Risk Summary**
MISO	Elevated	2025 -	Uncertainty around new resource additions and existing generator retirements results in resource adequacy risks. Above-normal generator outages during extreme weather can result in unserved energy or load loss.
Manitoba	Elevated	2028 -	Potential resource shortfalls in low-hydro conditions, driven by rising demand.
SaskPower	Elevated	2026 -	Risk of insufficient generation during fall and spring when more generators are off-line for maintenance.
Southwest Power Pool (SPP)	Elevated	2025 -	Potential energy shortfalls during peak summer and winter conditions arise from low wind conditions and natural gas fuel risk.
New England	Elevated	2026 -	Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of supply shortfalls in extreme winter conditions.
Ontario	Elevated	2027 -	Reserve margins fall below RMLs as nuclear units undergo refurbishment and some current resource contracts expire. Demand growth is also adding to resource procurement needs.
PJM	Elevated	2026 -	Resource additions are not keeping up with generator retirements and demand growth. Winter seasons replace summer as the higher-risk periods due to generator performance and fuel supply issues.
SERC-East	Elevated	2028 -	Demand growth and planned generator retirements contribute to growing energy risks. Load is at risk in extreme winter conditions that cause demand to soar while supplies are threatened by generator performance, fuel issues, and inability to obtain emergency transfers.
ERCOT	Elevated	2026 -	Surging load growth is driving resource adequacy concerns as the share of dispatchable resources in the mix struggles to keep pace. Extreme winter weather has the potential to cause the most severe load-loss events.
California-Mexico	Elevated	2028 -	Demand growth and planned generator retirements can result in supply shortfalls during wide-area heat events that limit the supply of energy available for import.
British Columbia	Elevated	2027 -	Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Risk from Additional Generator Retirements

Plans for generator retirements continue at similar pace and scale to levels reported in the *2023 LTRA*. Confirmed generator retirements (52 GW by 2029 and 78 GW over the 10-year period) are accounted for in the Capacity and Energy Risk Assessment above. Economic, policy, and regulatory factors spur further fossil-fired generators to retire in the 10-year horizon. Announced retirements, which include many generators that have not begun formal deactivation processes with planning entities, total 115 GW over the 10-year period. The effect of all retirements on the assessment area Planning Reserve Margins (PRM) can be seen in **Figure 2**. On-peak reserve margins fall below RMLs; the levels required by jurisdictional resource adequacy requirements) in the next 10 years in almost every assessment area, signaling an accelerating need for more resources.

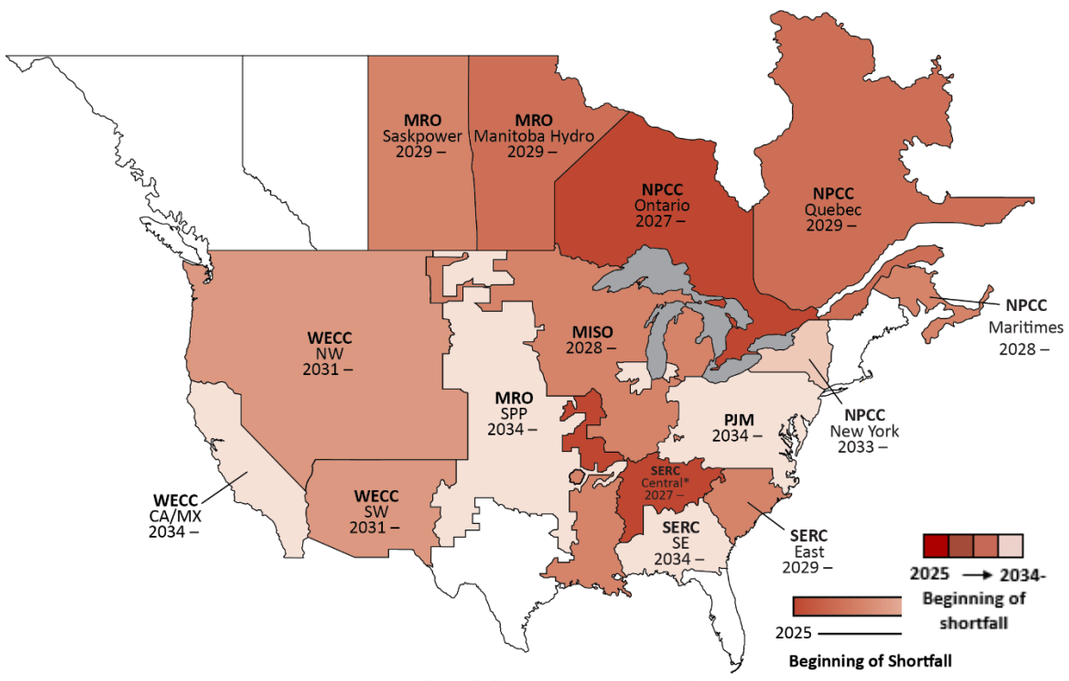


Figure 2: Projected Reserve Margin Shortfall Areas with Announced Generator Retirements (Corrected July 2025)

Changing Resource Mix and Reliability Implications

New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the *2023 LTRA* with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.

As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.

Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb; demand growth is now higher than at any point in the past two decades. Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. Additionally, the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America. The aggregated BPS-wide projections for both winter and summer have increased massively over the 10-year period:

- The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 GW this LTRA up from over 80 GW in the *2023 LTRA*.
- The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the *2023 LTRA*.

Transmission Trends

For the first time in recent years, transmission projections reported for the LTRA reflect a significant increase in transmission development. This year's cumulative level of 28,275 miles of transmission (>100 kV) in various stages of development for the next 10 years is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning stages of development.

New transmission projects are being driven to support new generation and enhance reliability. Transmission development continues to be affected by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, 68 projects totaling 1,230 miles of new transmission are delayed by siting and permitting issues, according to data collected for the LTRA. Questions of cost allocation and recovery can also challenge transmission development when the benefits apply to more than one area, as often occurs with projects that enhance interregional transfer capability.

In NERC's separate Interregional Transfer Capability Study (ITCS), which was performed to meet requirements contained in the Fiscal Responsibility Act of 2023, NERC found that an additional 35 GW of transfer capability across the United States would strengthen energy adequacy under extreme conditions. Increasing transfer capability between neighboring transmission systems has the potential to alleviate energy shortfalls in some areas identified in this LTRA's **Capacity and Energy Risk Assessment**. Conversely, when resource plans are developed that address these same energy shortfalls, such as through resource additions, demand-side management initiatives, or changes to generator retirement plans, the need for increased transfer capability will also change. Planners have options for reducing energy adequacy risks from extreme weather. Selecting the best course of action will depend on weighing these options against various engineering, economic, policy, reliability, and resilience objectives.

The ITCS provides foundational insights that facilitate stakeholder analysis and actions; it is not a transmission plan. In the future, NERC will extend the study beyond the congressional mandate to include transfer capabilities from the United States to Canada and among Canadian provinces.

Emerging Issues

The **Emerging Issues** section discusses developments and trends that have the potential to substantially change future long-term demand and resource projections, resource availability, and reliable operations of the BPS. Topics include data centers and large industrial loads, battery energy storage systems, electric vehicles and load, and energy drought. NERC's RSTC has formed new task forces where needed to address emerging issues.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Carefully manage generator deactivations.** Independent System Operator/Regional Transmission Organizations (ISO/RTOs) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be developed and placed in service.

2. **NERC and Regional Entities: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To be more effective in using energy criteria and outputs of probabilistic analysis, NERC must specify consistent methods and assumptions for assessment areas to follow in preparing the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy. Finally, NERC should work with the Regional Entities to perform wide-area energy analysis with modeled interregional transfer capability. Wide-area energy analysis will support the evaluation of extreme weather and regional fuel supply issues on an interconnection level.

3. **Regulators and Policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, delays from siting and permitting activities will need to be reduced. These are the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

4. **Regulators, electric industry, and gas industry member organizations: Implement a framework for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** Various initiatives were launched in the past year to address the reliability needs that arise from the complexity of interconnecting natural gas and electric infrastructure. Voluntary actions taken by the natural gas industry in response to the North American Energy Standards Board (NAESB) Forum report are a positive step toward improving winter readiness. The National Association of Regulatory Utility Commissioners (NARUC) launched its Gas-Electric Alignment for Reliability (GEAR) task force this year and recently created the Natural Gas Readiness Forum. For its part, NERC continues to collaborate extensively with industry and policymakers. NERC has enhanced its Reliability Standards requiring generators to prepare for winter extremes, implement training, and establish communication protocols between generators and grid operators. Current standards projects encompass extreme weather planning and energy assurance requirements. NERC will continue to provide full support to initiatives aimed at achieving a reliable interconnected energy system and urges regulators and policymakers to support needed avenues of coordination between the two sectors.

5. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure essential reliability services are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[7] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary** section.

[7] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Capacity and Energy Assessment

The resource mix transformation is making traditional capacity-based adequacy criteria obsolete. Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure sufficient resources are available to meet demand. In their application, current capacity-based adequacy criteria were not designed to differentiate between the scenarios, size, frequency, duration, and timing of energy shortfalls. This has become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. Therefore, supplemental criteria must be adapted to properly assess system adequacy and help determine appropriate solutions. This year's LTRA includes probabilistic indices to measure these additional dimensions of risk and provide a more robust approach to understanding risk of inadequacy in future plans.

Assessment Approach

NERC is using two approaches in this LTRA to assess future resource capacity and energy risk; both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high-risk periods and potential energy constraints resulting in load-loss events. The 2024 ProbA is performed for each assessment area and examines the system as planned for the years 2026 and 2028. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as RML) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

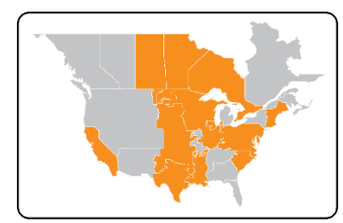
See the **Demand Assumptions and Resource Categories** for further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

Risk Categories

An assessment area is **high risk** when established resource adequacy targets or requirements are not met during this assessment period. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See the **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area**. Recently, regulators and policymakers in many states and market areas have begun considering or developing resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.[8] High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Unusual heat waves or deep-freeze events pose an even greater threat to reliability.

For the *2024 LTRA*, assessment areas are classified as high risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA.
- Annual normalized EUE exceeds 0.002% (20 ppm) for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are not met.

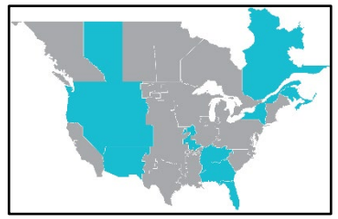


An assessment area is considered an **elevated risk** when it meets the established resource adequacy target or requirement, but probabilistic or deterministic analysis of conditions that are plausible but more extreme than normal seasonal peaks are likely to cause shortfall in area reserves. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. Simply put, elevated-risk areas meet resource adequacy requirements but may face challenges meeting load under extreme conditions. For the *2024 LTRA*, assessment areas are classified as elevated risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA.

[8] See the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid*.

- Annual normalized EUE is less than 0.002% (20 ppm) but non-zero for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.



NERC assesses areas as **normal risk** when resource adequacy criteria are met and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme[9] conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2024 LTRA*, assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is negligible or zero.
- Resource adequacy target(s) established by regulatory authority or market operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from probabilistic assessments performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In this year's LTRA, NERC incorporated new probabilistic assessment criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid* alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

Elevated-Risk Area Details

The below areas are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the **Regional Assessments Dashboards** section.

MISO

MISO has experienced slower resource additions due to market pressures and constraints faced by projects with signed interconnection agreements. MISO has highlighted uncertainties with a large number of new resources that have signed interconnection agreements (Tier 1 additions) and are expected to come on-line in the next several years.[10] Resource adequacy risks could grow over time absent the new capacity reflected in the Tier 1 additions and the deferral of announced retirements (see **Risk from Additional Generator Retirements**).

PRMs in MISO with resource additions are shown in **Figure 3** and **Figure 4**. MISO reports 56 GW of nameplate generating capacity, predominantly solar and batteries, with signed generation interconnection agreements (qualifying as Tier 1 and reflected in the ARM in **Figure 3** and **Figure 4**) as of July 2024 that can help meet resource adequacy needs if connection is completed. If resource additions remain at or near historically average levels (approximately 2.3 GW/year average over the last 3 years), PRMs in MISO will fall below the RML reserve margin requirements much faster. Summer PRMs with average resource additions are shown in **Figure 3** as **Reserve Margin-Avg Addition**.

[9] Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide Area Heat Dome.
[10] See results from the 2024 Organization of MISO States (OMS)-MISO Survey.

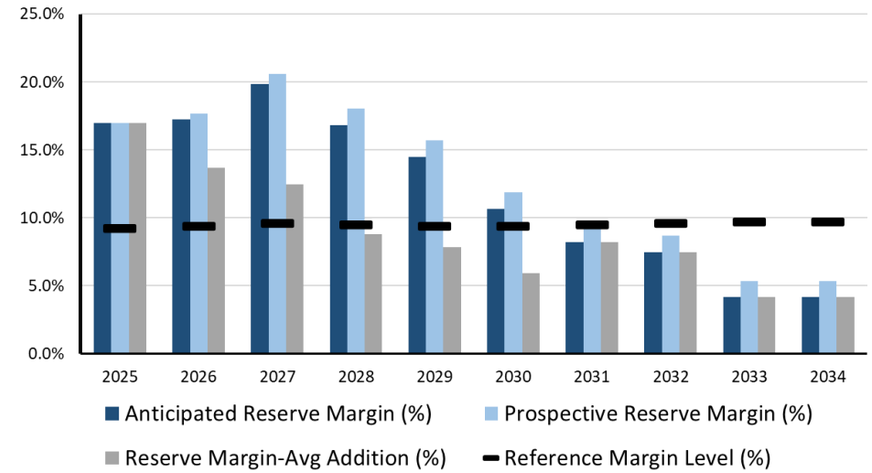


Figure 3: MISO Planning Reserve Margin–Summer

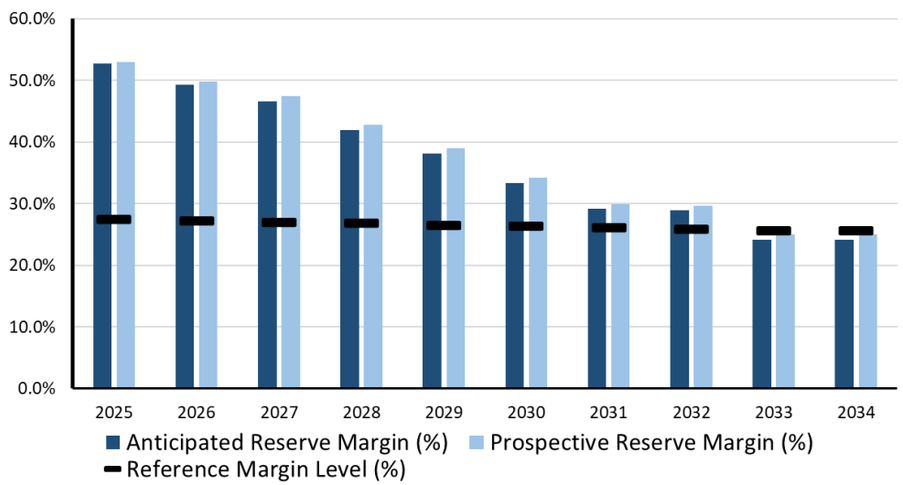


Figure 4: MISO Planning Reserve Margin–Winter

To establish the RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. The study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they define the minimum PRM that will meet an LOLE of 1 day in 10 years. See the **MISO** assessment area pages.

MISO is an elevated risk in the *2024 LTRA* because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below RMLs within the next five years.

MRO-Manitoba Hydro

The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of electric vehicles. Resource projections have not changed significantly.

As in prior probabilistic assessments, Manitoba Hydro's 2024 ProbA indicates that there is some risk of load loss and unserved energy associated with very low hydro conditions (see **Table 2**). Electricity demand peaks in winter, making this the higher-risk season. However, electricity supplies could fall short during either peak summer or winter conditions should an extreme and prolonged drought affect hydro production.

Table 2: MRO-Manitoba Hydro ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	7.23	**4.71**	**68.87**
EUE (PPM)	0.29	**0.18**	**2.50**
LOLH (hours per year)	0.01	**0.06**	**0.91**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SaskPower

Resource projections for Saskatchewan over the 10-year period have increased since the *2023 LTRA*, rising to just over 1 GW and include two new 377 MW gas-fired generation facilities, expansion of existing gas-fired generation facilities, and new geothermal resources. The peak demand forecast growth rate (1.35% annually) has changed little since the *2023 LTRA*.

The ProbA for SaskPower indicates there is some risk of load loss and unserved energy that diminishes with the new resource additions that are planned for 2027 (**Table 3**). Saskatchewan is a winter-peaking system; however, the unserved energy risks are more closely associated with the planned outages of large generators that typically occur in the fall and spring shoulder periods. The months of September and October are the highest risk periods because of the potential for high temperatures to unexpectedly extend beyond summer and into the maintenance period.

Table 3: MRO-SaskPower ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	117.0	**75.64**	**8.55**
EUE (PPM)	4.4	**2.81**	**0.30**
LOLH (hours per year)	0.9	**0.54**	**0.08**
Operable On-Peak Margin	24.6%	**24.8%**	**30.8%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SPP

New resource capacity in the interconnection queue—primarily solar, battery, and wind—is currently projected to keep up with rising peak demand forecasts. DR programs are also increasing over the next 10 years. Resource adequacy issues can arise, however, if generators retire earlier than anticipated or new resource additions connect more slowly. Currently, there are over 8 GW of coal and gas-fired generators that have indicated that they may retire within the next 10 years, making the resource outlook unclear. SPP's summer reserve margins, based on installed generator capacity, remain above RMLs through 2029 (see **Figure 5**).

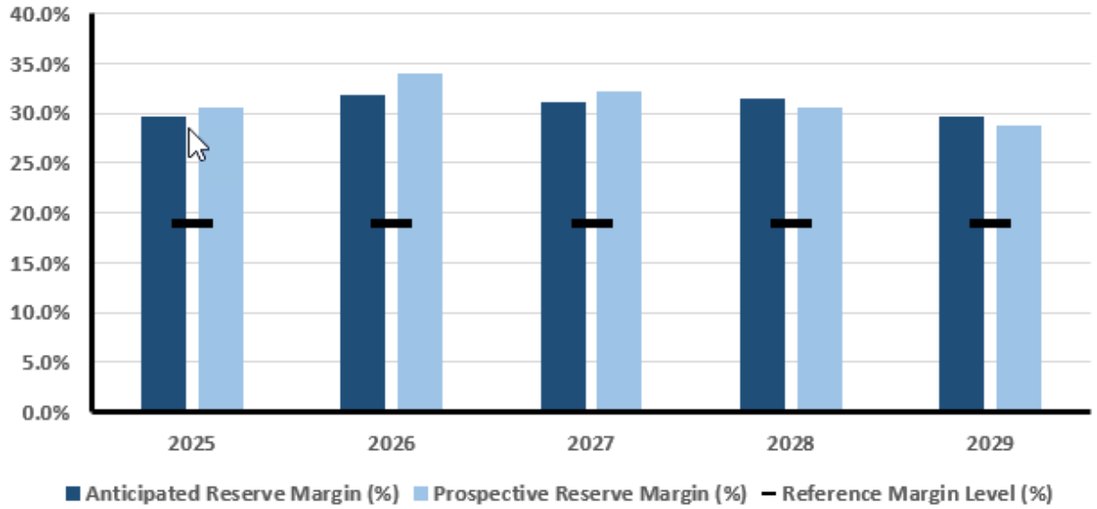


Figure 5: MRO-SPP Five-Year Planning Reserve Margin–Summer

All-hours probabilistic analysis performed by SPP shows that resource adequacy challenges are shifting from summer (when area demand is at its highest) to winter months (when the new resource mix is less capable of performing reliably). Annual results of the ProbA are in **Table 4** below. SPP's 2023 loss-of-load expectation (LOLE) study results indicate that a separate RML and seasonal resource capacity contributions are needed for the summer and winter seasons to effectively provide for resource adequacy.

Table 4: MRO-SPP ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.84	**0.00**	**6.61**
EUE (PPM)	0.00	**0.00**	**0.02**
LOLH (hours per year)	0.00	**0.00**	**0.01**
Operable On-Peak Margin	19.6%	**19.5%**	**16.0%**

** Year 2026 Results from the 2022 ProbA provided for trending*

NPCC-New England

New England is forecasting unprecedented demand growth driven by electrification of heating and transportation. Wind, solar, and batteries make up the projected resource additions, along with growth in distributed energy resources. Since the *2023 LTRA*, the peak demand forecast is relatively unchanged. New England has among the strongest winter demand forecast growth rates of any assessment area, rising over 7 GW in the 10-year period, or 35% from its current peak demand forecast.

The 2024 ProbA for NPCC-New England reveals increasing risk of load loss and unserved energy compared to the 2022 ProbA (see **Table 5**). Higher-demand forecast and replacement of dispatchable resources with more VERs contribute to this trend. In the ProbA modeling, supply shortfall risk is limited to the summer months and is associated with periods of above-normal demand and low resource output (e.g., low wind, solar, or high thermal outages).

Table 5: NPCC-New England ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.55	**10.69**	**67.40**
EUE (PPM)	0.00	**0.09**	**0.06**
LOLH (hours per year)	0.00	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

While NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months, a persistent concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk but were not within the scope of the 2024 ProbA.

NPCC-Ontario

Near- and long-term resource adequacy challenges continue in the NPCC-Ontario assessment area as the Independent Electricity System Operator (IESO) manages lengthy refurbishment outages at nuclear generators and demand growth driven by agriculture and electrification. The beginning of projected shortfalls occurs in 2027 when some contracts for firm capacity are set to expire (see **Figure 6**). However, a number of resources with expiring contracts between 2026 and 2029 are anticipated to be re-committed for five-year terms through the IESO's second medium-term procurement, which is underway. As such, Ontario's Anticipated Reserve Margins (ARM) and Prospective Reserve Margins shown in **Figure 6** (which do not include this set of expiring resources) are conservative. Recommitment of these resources is expected to raise margins above the reference level in 2029 and help maintain reliability through the end of the decade. In May 2024, the IESO finalized long-term commitments for new-build battery storage facilities (1,784 MW) and new-build natural gas and biogas facilities (411 MW). Early operation incentives anticipated to bring a portion of these resources online as early as 2027 could help alleviate the reserve margin gap. The IESO also launched procurements for new capacity and energy-producing resources to be online as early as 2029. In addition, the IESO finalized an agreement with Hydro-Québec for capacity sharing in November 2024, providing 600 MW of firm imports to Ontario starting in Summer 2025 through Summer 2031. This capacity is also expected to help alleviate shortfalls indicated in 2027.

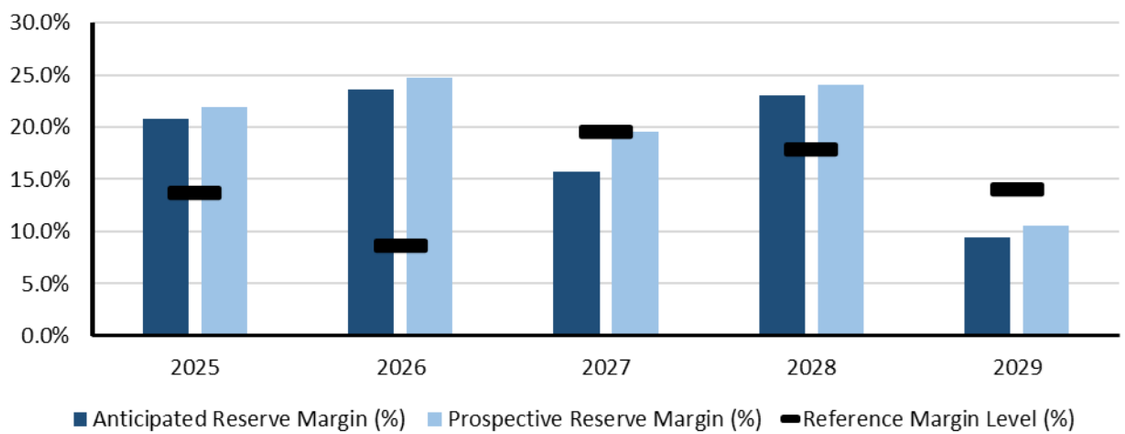


Figure 6: NPCC-Ontario Five-Year Planning Reserve Margin–Summer

The probabilistic assessment for Ontario performed by NPCC provides further insights into the potential for load loss and unserved energy. There is negligible risk of unserved energy and load loss in 2026 and earlier years; however, a small risk of load loss (< 0.01 hours) emerges after 2026 (Table 6). The 2024 ProbA study included only years 2026 and 2028, both of which have projected capacity surpluses above RMLs (see Figure 6). If 2027 and 2029 had been included in the ProbA, it can be expected that there would have been higher amounts of LOLH and unserved energy. ProbA results are also helped by the inclusion of electricity transfers from neighboring areas and modeling for some operating procedures used to manage supply shortfalls.

Table 6: NPCC-Ontario ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

** Year 2026 Results from the 2022 ProbA provided for trending*

PJM

PJM's projections for generator additions in 2025 and 2026 are scaled back dramatically from the *2023 LTRA* while demand forecasts continue to rise. As a result, ARMs for future years have fallen by as much as nine percentage points from last year. The trends in demand growth and resource additions create resource adequacy and system planning challenges for PJM as it carefully manages generator deactivation requests from the aging fossil and nuclear fleet.

PJM's ProbA results provide indication of the increasing resource adequacy risk to the system (see Table 7). EUE and LOLH are found in both ProbA assessment years (2026 and 2028) with risk concentrated in the winter months (especially January). The risk occurs on days where temperatures are very low across the entire PJM area, which results in high loads. While normal resource performance can meet these demand forecasts, resource performance from thermal resources on very cold days has historically been below normal due to freezing and fuel supply issues. Furthermore, solar resources are not likely to contribute during some of the coldest hours, resulting in very low total electricity supply and thus projections of load loss. ProbA analysis shows some summer load-loss and unserved energy risk but at much lower levels. Summer shortfall events are most likely to occur during wide-area heat events that coincide with low wind and low solar output, or very high outage and derates in the thermal generation.

Table 7: PJM ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1,043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.12**	**0.22**
Operable On-Peak Margin	29%	**17.8%**	**17.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

SERC-East

The addition of solar resources is helping to raise summer on-peak reserve margins in the assessment area, despite rising demand forecasts and additional coal-fired generator retirements. Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024. An additional 2 GW of solar PV resources are in the process of connecting. The summer peak demand forecast has also risen since the *2023 LTRA*, increasing by 2.8 GW (6.3%) over last year's projection. The area reserve margins have increased in the near term as a result of the solar resource additions then drop off after 2028 due to higher demand forecasts and planned generator retirements.

Despite these resource additions and higher summer reserve margins, the 2024 ProbA reveals growing resource adequacy risk in SERC-East (see Table 8). Measures of unserved energy and load-loss have increased since the 2022 ProbA as demand has risen and the resource mix has changed. SERC-East has changed from a summer-peaking area to one with peak electricity demand occurring in both the summer and winter seasons. This change is the result of added solar PV generation that shaves off summer peak demand and trends toward electrification in heating that drives up winter peak demand. The ProbA shows that the risk of unserved energy and load loss is concentrated in winter (January–February) months when wide-area extreme cold weather can affect electricity demand, generator performance, generator fuel supplies, and the availability of electricity imports. Based on current forecasts, resource adequacy risk will increase in SERC-East after 2028 due to the planned retirement of over 1,800 MW in coal-fired generation and continued load growth.

Table 8: SERC-East ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.40	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

** Year 2026 Results from the 2022 ProbA provided for trending*

Texas RE-ERCOT

ERCOT is forecasting explosive demand growth, driven by data center projects, Bitcoin operations, development in oil- and natural-gas-producing areas, and industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. Substantial amounts of solar PV and battery resources are being added to help meet rising demand, but there are significant reliability challenges to address during this period of rapid growth. Resource adequacy risks are mounting as fewer dispatchable resources comprise the resource mix. One of the strategies to address this risk is state implementation of a dispatchable resource generation loan program called the Texas Energy Fund. Furthermore, the forecasted growth in loads and resources poses significant challenges for transmission system planners.

Load growth and the characteristics of the resource mix are contributing to higher levels of unserved energy and load loss in probabilistic analysis (see **Table 9**). In the 2024 ProbA, EUE for the analyzed 2026 ERCOT system has risen to 19 ppm (0.0019 %) of the total annual supplied energy compared to the same analysis in the 2022 ProbA. The 2024 ProbA shows an improving trend in the analyzed 2028 ERCOT system, enabled by additional generation capacity from ERCOT scenarios developed to support rapid growth in large loads.[11]

A deeper analysis of the probabilistic assessment results reveals the unique characteristics of winter and summer risk. While peak winter loads can persist for 48 hours or longer, peak summer periods generally only last for a few hours. This is manifested in the duration and depth of the winter firm load-shed events that appear in the ProbA and has significant implications for the reliability contribution of energy-limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and up to 29 GW in load loss. In contrast, most summer unserved energy events were 1–2 hours in duration.

Table 9: Texas RE-ERCOT ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

** Year 2026 Results from the 2022 ProbA provided for trending*

A key conclusion from the Texas RE-ERCOT 2024 ProbA is that matching the area's demand growth with a resource mix that is more variable and less fully dispatchable is increasing the risk of supply shortfalls that can result in load loss and unserved energy. When the seasonal characteristics of demand and resources are considered, Resource Planners can appropriately focus efforts to reduce the risk of potentially severe, long-duration winter shortfall events. The Public Utility Commission of Texas established a Reliability Standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude.

WECC-CA/MX

Resource additions continue to improve the overall resource adequacy outlook for the WECC California-Mexico assessment area. Since the 2022 ProbA, the planned extension of the Diablo Canyon nuclear plant (2.2 GW) and resource additions (over 5 GW nameplate in batteries, 3.3 GW nameplate in solar PV, and 0.2 GW in natural-gas-fired and geothermal generation) have alleviated supply shortfalls that were driving unserved energy and load-loss metrics in year 2026, as shown in the results of the 2024 ProbA performed by WECC (see **Table 10**).

Table 10: WECC-CA/MX ProbA Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.72	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

** Year 2026 Results from the 2022 ProbA provided for trending*

Demand growth and planned generator retirements cause energy adequacy risks to re-emerge in future years. With a resource portfolio that includes a substantial amount of solar PV, the risk of supply shortfall is associated with summer evening periods when demand is high and solar output is diminished. WECC's analysis for the 2024 ProbA found only a small occurrence (<1 hour) of resources falling below margin levels for reliability in the 2028 study year. WECC further observed that load-loss and unserved energy risk was localized in the Mexico portion of the assessment area, reflecting localized resource and transmission system constraints.

[11] Due to the inclusion of an additional 20 GW of large loads based on newly signed interconnection agreements, study-year 2028 included additional generation capacity from the "High Large Load Adoption" scenario of the ERCOT 2024 Long-Term System Assessment (LTSA), which included 22 GW of combustions turbines (CT) and 4 GW of combined cycles (CC).

The CA/MX 2028 system analyzed by WECC for the 2024 ProbA reflects the continued rapid transformation of the power grid. The analysis assumes forecasted demand growth of 3.5 GW, substantial resource additions (4.6 GW of solar PV, 7.6 GW in batteries, and 0.8 GW of natural-gas-fired generation imported from repowered coal units in Utah), and the retirement of over 3 GW of gas-fired generation. As demand grows and the resource mix becomes increasingly variable, periods of supply shortfalls can emerge. Battery additions and transfers help make up for energy shortfalls that can arise during evening solar down ramps.

WECC-BC

BC has a predominantly hydroelectric generation system with vast amounts of energy storage provided by its reservoirs. Winter peak demand in the province is forecast to grow modestly over the next 10 years, from 11,966 MW this winter to 12,305 MW at the end of the 10-year period. Since the *2023 LTRA*, the winter peak demand compound annual growth rate (CAGR) has fallen from 1.0% to 0.3%. Growth rate and reserve margins are higher. While the overall resource adequacy outlook has improved, the 2024 ProbA indicates the area continues to be at an elevated risk of supply shortfall during extreme conditions. Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Western Interconnection-wide probabilistic analysis performed by WECC for the 2024 ProbA reveals that risk of reserve shortages emerges after 2026, potentially resulting in unserved energy and load-loss events during extreme weather. WECC's analysis identified over five hours in 2028 when high demand and low supply from WECC-BC's internal resources were not able to be remedied with imports from neighboring areas experiencing similar conditions (see **Table 11**). In contrast, 2026 had no unserved energy or load-loss periods. An examination of hourly results showed that imports from neighbors were more available in 2026 to cover periods of potential shortfalls in BC Hydro's internal resources.

Table 11: WECC-BC ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	24	**0**	**103,132**
EUE (PPM)	0.71	**0**	**1,456**
LOLH (hours per year)	0.00	**0**	**5.52**
Operable On-Peak Margin	12.7%	**16.9%**	**9.4%**

** Year 2026 Results from the 2022 ProbA provided for trending*

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

BC's supply margins relative to demand are lowest during winter peak demand periods. Imports from neighbors in the U.S. Northwest are common during these periods, and often during the overnight hours of 23:00 to 4:00 local. WECC's analysis shows the need for imports growing year to year throughout most of the LTRA forecast horizon. A widespread, extreme cold weather event in the Northwest that limits transfer capability is thus a risk to BC. Even though WECC-BC is expecting only moderate demand growth and relatively few retirements, diminished surplus capacity in neighboring areas is negatively affecting the resource adequacy outlook.

Normal-Risk Area Details

All other assessment areas (see **Figure 1**) are assessed as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance).

Resource and Demand Projections

The **Capacity and Energy Assessment** section in this LTRA is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to continue rising dramatically over the *2024 LTRA* assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that, in the future, the risk assessment map will expand with more elevated and high-risk areas.

Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, and nuclear generators can have a profound and negative effect on the resource adequacy and reliability of the BPS in the next 10 years. In this preceding **Capacity and Energy Assessment** NERC accounted for nearly 79 GW of fossil-fired and nuclear generator retirements that are anticipated through 2034. Environmental regulations and energy policies have the potential to influence generators to seek deactivation during the 10-year assessment period.[12] An additional 43 GW of fossil-fired generators have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. These retirements, along with the confirmed retirements, contribute to declining reserve margins in the assessment areas over the next 10 years (see **Table 12**). As a result of demand growth and generator retirements, ARM is projected to fall below RML in 18 of the 20 assessment areas by 2034. While forecasts such as this factor into resource planning and market mechanisms to obtain resources needed for resource adequacy, it underscores the significant resource growth needed across North America. The lack of dispatchable resources and diverse generator fuel types in the interconnection processes makes the future resource mix look alarmingly unreliable. The potential for capacity and energy shortfalls and a higher-risk resource mix is heightened by economic and policy factors that place pressure on existing thermal generators.

The yearly projections of future retirements and an assessment area view are provided in the **Risk from** Additional Generator Retirements section.

[12] The Environmental Protection Agency (EPA) issued a final rule on May 9, 2024, establishing Greenhouse Gas Standards and Guidelines for Power Plants (the "GHG Rule"). This rule was released concurrently with three other EPA regulations that impact fossil-fueled power generation: Coal Combustion Residuals, Effluent Limitations Guidelines, and Mercury and Air Toxics Standards. Collectively, these four new regulations impose considerable financial and operational challenges on coal-fired generators.

Table 12: Anticipated Reserve Margins with Announced Retirements											
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MISO[13]	17.7%	10.3%	10.3%	13.2%	8.6%	7.1%	10.6%	8.2%	7.5%	4.2%	-2.5%
MRO-Manitoba	12.5%	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
MRO-SaskPower	28.9%	27.8%	26.6%	31.1%	29.4%	7.0%	28.8%	28.0%	26.7%	26.8%	1.2%
MRO-SPP	28.3%	26.7%	26.0%	25.0%	20.8%	19.1%	26.7%	24.9%	23.5%	22.4%	8.1%
NPCC-Maritimes	18.9%	20.6+%	25.5%	25.1%	18.6%	3.9%	23.4%	20.7%	19.1%	17.7%	-1.5%
NPCC-New England	20.4%	25.0%	25.0%	26.3%	24.9%	23.5%	22.0%	20.1%	19.7%	17.1%	14.6%
NPCC-New York	18.4%	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
NPCC-Ontario	22.5%	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
NPCC-Quebec	12.5%	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
PJM	29.8%	34.9%	35.7%	28.1%	21.4%	18.2%	23.1%	21.6%	20.1%	18.5%	10.3%
SERC-C	28.2%	18.9%	18.9%	15.0%	16.0%	15.2%	17.3%	17.1%	18.4%	21.1%	11.8%
SERC-E	30.4%	27.3%	25.8%	24.6%	20.6%	14.4%	14.3%	10.2%	6.3%	4.6%	-2.2%
SERC-FP	27.0%	25.4%	26.0%	23.2%	22.1%	20.9%	18.4%	22.0%	20.4%	18.2%	16.0%
SERC-SE	44.9%	39.9%	35.9%	31.5%	24.5%	21.4%	27.7%	25.8%	24.7%	23.7%	13.0%
TRE-ERCOT	24.3%	30.2%	32.5%	29.7%	25.6%	25.4%	27.8%	28.0%	28.4%	28.9%	24.9%
WECC-AB	36.3%	35.8%	35.7%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
WECC-BC	20.9%	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
WECC-CA/MX	38.6%	45.5%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
WECC-NW	34.5%	40.3%	38.9%	35.6%	30.7%	24.5%	18.3%	12.2%	10.2%	8.1%	5.9%
WECC-SW	28.6%	37.0%	35.6%	31.6%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-9.6%

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the Executive Summary.

[13] MISO reserve margins in this table reflect MISO Seasonal Accredited Capacity for summer. Adjustments and derates are applied to account for factors affecting expected resource output, resulting in unforced capacity (UCAP) reserve margins that are lower compared to installed capacity (ICAP) values. For more information see the **MISO assessment area** page.

Resource Mix Changes

Capacity Versus Energy: Changes in the Way to Plan for Resource Adequacy

Industry's methods of planning for resource adequacy need to change. The modern power system requires the enhancement of assumptions and supplementation of risk information for a better characterization of the risk. Historically, the resource adequacy criterion has been based on the LOLE metric, which should be no more than 1 event-day in 10 years when the generating resources are less than load (commonly known as "1-day-in-10"). This has been a design basis for the U.S. electric grid for at least 70 years (with its first formal mention in a 1951 American Institute of Electrical Engineers paper by C. W. Watchorn) and has historically served the industry well. Two important related but separate discussion topics include considerations for assumptions in the calculation of LOLE and other metrics and the establishment of the resource adequacy criteria (i.e., traditionally in terms of LOLE-1-day-in-10). The 1-day-in-10 LOLE criterion is commonly converted into a minimum capacity requirement resulting in a target or RML. In doing this, planners determine the minimum PRM required to maintain a 1-day-in-10 LOLE level. Historically, systems with an actual PRM above the minimum generally have sufficient resources and provide adequate energy and ERSs that operators need to reliably operate the BPS. Issues can arise in resource adequacy planning processes when planners solely rely on the RML comparison as the system transforms from an era of certain to more uncertain fuel sources and load behavior. In recent years, NERC has documented warnings of potential energy shortages in its reliability assessments, while in many cases the RML comparison indicates no shortfall. Substantial uncertainty has been introduced into planning the system with the addition of energy-constrained resources (variable energy resources such as wind and solar, and, at times, just-in-time fuels such as natural gas) that are highly dependent on weather and environmental conditions. Uncertainty in energy sufficiency is increasing as the types of resources change, leaving fewer resources that can be dispatched (dispatchable resources) in response to the variable resource availability and greater exposure to constraints in fuel supplies, reservoir levels, or battery discharge capabilities. Historical generator reliability assumptions based on the idea of well-maintained, well-invested units with an anticipated long life are no longer adequate. This increases uncertainty as a greater proportion of fossil-fueled resources continue to be retired, often with little notice to system planners. Nameplate values of variable energy resources are not as meaningful as projected energy availability, and environmental conditions can adversely impact the simultaneous availability of thousands of megawatts.

Probabilistic analysis enhances deterministic transmission planning from an energy adequacy standpoint given the following factors:

- Considers likelihood of events: It uses historical data to estimate how often different outages and weather conditions might occur.
- Provides more information: It calculates the average impact of these events, including how often and how long power outages might last.
- Helps compare options: It enables the selection of the upgrade(s) that provide the best balance between cost and reliability over time to be chosen.

Detailed recommendations are included in a recently published NERC report:
Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report, June 2024

Changes in Existing BPS Resource Capacity

Thermal generator retirements and new resource additions continue at a rapid pace. Since the *2023 LTRA*, over 8 GW of coal-fired generation has been retired, while substantial solar and battery resources have connected to the grid (see **Table 13**). From a strictly on-peak capacity perspective, there has been little change (8,348 MW is 0.8% of the total BPS summer on-peak resource capacity.)

Table 13: Existing BPS Resource On-Peak Capacity

	2023 Capacity (MW)	2024 Capacity (MW)	Difference (MW)
Coal	188,856	180,402	-8,454
Petroleum	32,107	30,987	-1,120
Natural Gas	483,391	484,148	757
Biomass	7,273	7,381	108
Solar[14]	52,998	66,293	13,295
Wind[15]	32,320	31,370	-950
Geothermal	4,319	3,881	-438
Conventional Hydro	103,368	105,792	2,424
Run of River Hydro	1,565	2,047	482
Pumped Storage	19,463	19,422	-41
Nuclear	106,173	105,385	-788
Hybrid & Battery	5,593	9,909	4,316
Other	2,217	774	-1,443
Total	1,039,643	1,047,791	8,348

This year-on-year change in on-peak capacity continues the general trend of declining baseload and dispatchable generation—which includes coal-fired, natural gas, and nuclear generators—and rising VERs. **Figure 7** shows the trend continuing through 2034, where 20% of the generating capacity will be provided by VERs. Focusing on the relatively small change in total on-peak capacity since 2023 can mask risks to reliability that result when important attributes of the retiring generation resources are not inherent in the replacement resource mix. Thermal generation resources, such as coal-fired generators, have the capability to be dispatched when needed and provide system inertia, dynamic reactive support, and frequency response for stable grid operation. Most types of replacement resources have limited or none of these attributes. Further, retirements in the thermal generator fleet are making the resource mix less effective in meeting winter energy needs.

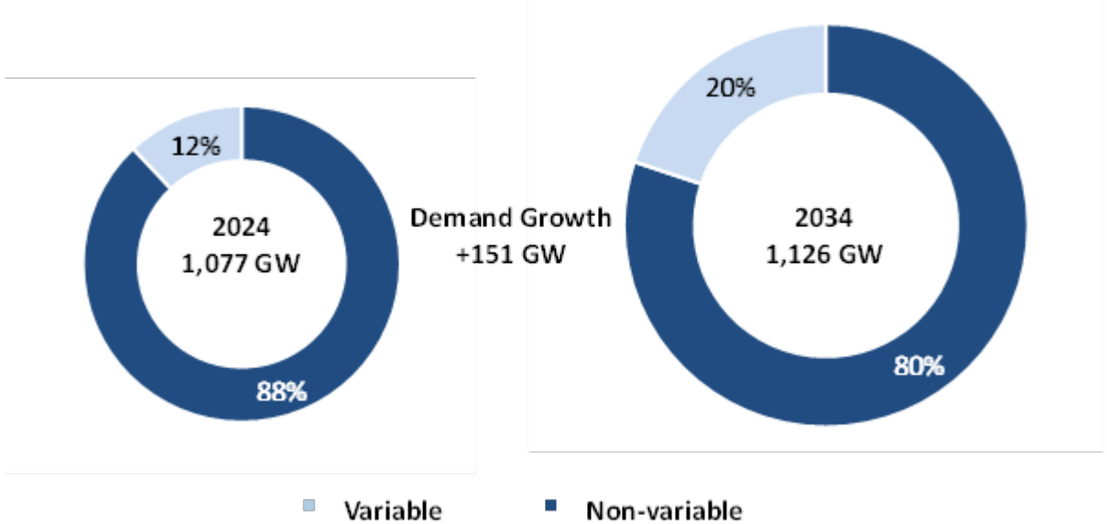


Figure 7: North America Total Generation Capacity in 2024 and 2034

Capacity Additions

New generation is added to the BPS through the area interconnection planning processes. Solar PV is the overwhelmingly predominant generation type being added to the BPS, followed by battery and natural-gas-fired generators, wind turbines, and hybrid resources. Batteries are now the second most predominant resource in the North America BPS interconnection queues. A summary of generation resources in the interconnection planning queues is shown in **Figure 8**.

Capacity in planning has grown since the *2023 LTRA* by over 44 GW (12%). In general, **Tier 1** resources are in the final stages for connection, while **Tier 2** resources are further from completion (see text box). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. While interconnection queues continue to swell, considerable uncertainty

[14] The capacity values in this table represent the on-peak contribution of solar resources. The total installed (nameplate) capacity of BPS solar in 2024 is 111,102 MW. See Table 11.
[15] The capacity values in this table represent the on-peak contribution of wind resources. The total installed (nameplate) capacity of BPS wind in 2024 is 176,636 MW. See Table 11.

surrounds the timing and amount of resource additions. (See an analysis of projected and actual additions on the next page).

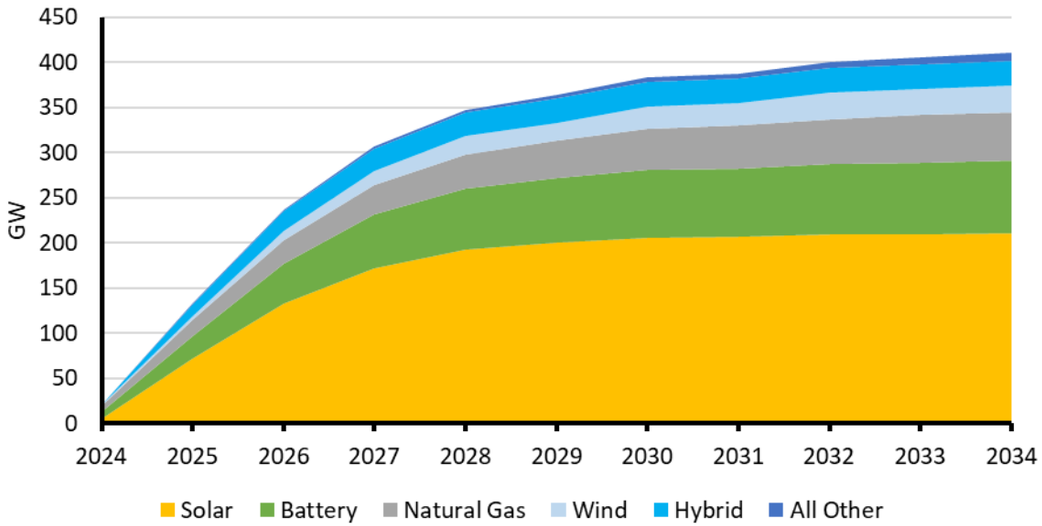


Figure 8: Tier 1 and 2 Planned Resources Projected Through 2034

Solar PV and wind nameplate capacity, both existing and planned, vary widely by area. Figure 9 and Figure 10 show current solar PV and wind installed capacities and the capacity in the planning process through 2034 for assessment areas with significant amounts. In addition, hybrid generation resources, which combine energy storage with a generating plant (i.e., a wind or solar farm), are connecting to the grid in parts of North America, and many more projects are in BPS planning processes.

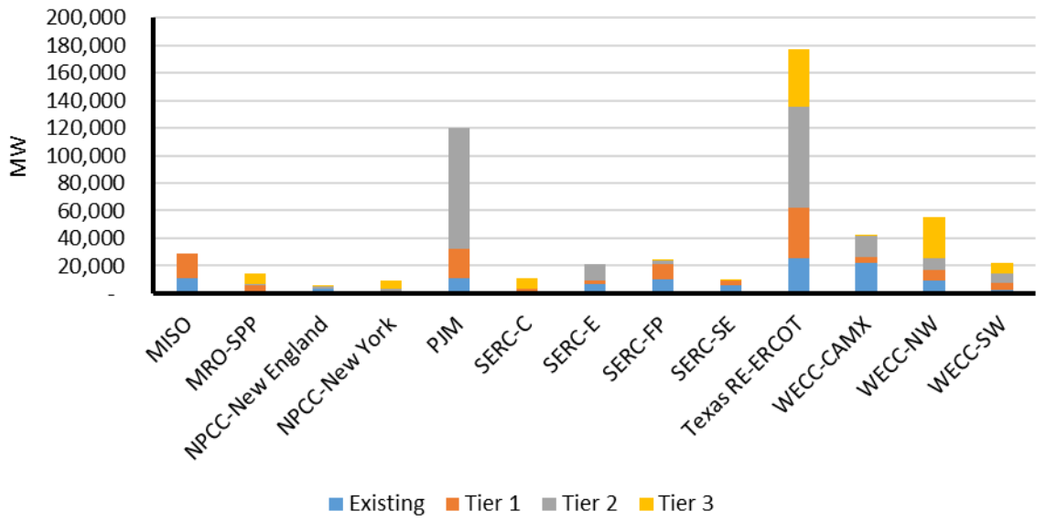


Figure 9: Solar Nameplate Capacity Existing and Planned through 2034

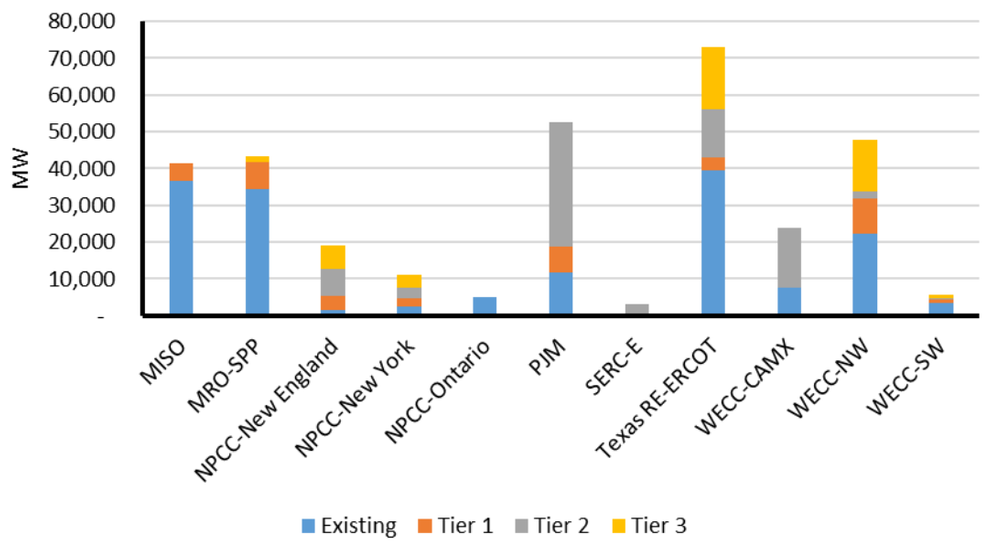
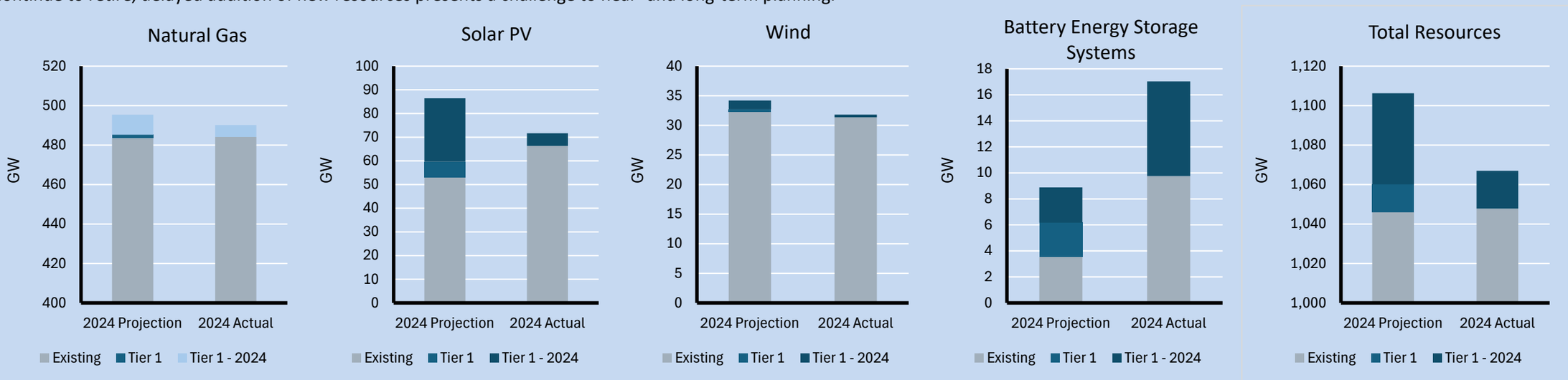


Figure 10: Wind Nameplate Capacity Existing and Planned through 2034

Resource Additions – How Much and When?

The added resource capacity on the BPS over the past year fell short of industry's projections, raising concerns that demand growth has the potential to outpace supply resources. The figures below compare the *2023 LTRA* projection of this year's installed capacity against the actual current installed capacity derived from data collected for this LTRA. Natural gas, solar PV, and wind resources were all over-projected last year. This gives evidence to industry reports of construction delays that prevented the expected interconnection of new resources. To a lesser extent, project withdrawals prior to commercial operation also contributed to lower-than-expected resource additions. One key exception—battery energy storage systems (BESS)—came in higher than last year's projections. As baseload and dispatchable generation continue to retire, delayed addition of new resources presents a challenge to near- and long-term planning.



Comparison of Projected Capacity from the 2023 LTRA to the Actual Capacity in the *2024 LTRA*

The sluggish rate at which new generation moves through the interconnection queue and begins service has been a cause for concern for long-term reliability planning. The Lawrence Berkeley National Laboratory published the results of an interconnection queue study in April 2024 assessing that less than one-fifth of generation capacity projects seeking interconnection between 2000 and 2018 actually came to fruition by the end of 2023.[16] Wait times have also been on the rise: According to the same study, the time from initiating a request for interconnection to the start of commercial operations has increased from less than two years, as was the case from 2000–2007, to more than four years from 2018–2023. The delay in bringing new generation capacity online in assessment areas that are anticipating steady or accelerated thermal capacity retirements, as well as increased demand, presents a significant reliability risk.

In recognition of the interconnection backlog risk, some regional transmission organizations have taken steps to address the lagging completion rates. MISO has assigned multiplication factors to generator requests based on the study phase and the likelihood of that resource coming on-line to more accurately gauge the likely incremental capacity in its footprint.[17] MISO also continues to advance the Joint Targeted Interconnection Queue (JTIQ) with SPP to resolve binding constraints that have delayed the interconnection process. PJM analyzed the completion rate of its interconnection queue and reported that less than 16% of resources submitted into the queue between 1999 and 2023 went into operation. The ISO has also applied a reduction to the nameplate capacity of value of Tier 1 resources to reflect the historical addition rate of new generation. PJM's interconnection process subcommittee is working on enhancements for new generation to interconnect as a capacity resource. These measures and others are examples of the broader effort to streamline generator additions and thus offset retiring capacity.

Offshore wind plants are increasingly entering interconnection queues, located around the Northeastern United States. **Figure 11** shows the current planned capacity in the planning process through 2034 by assessment area. Currently, the existing offshore wind nameplate capacities are small in comparison: a single 29 MW plant in NPCC-New England and a 12 MW plant in PJM.

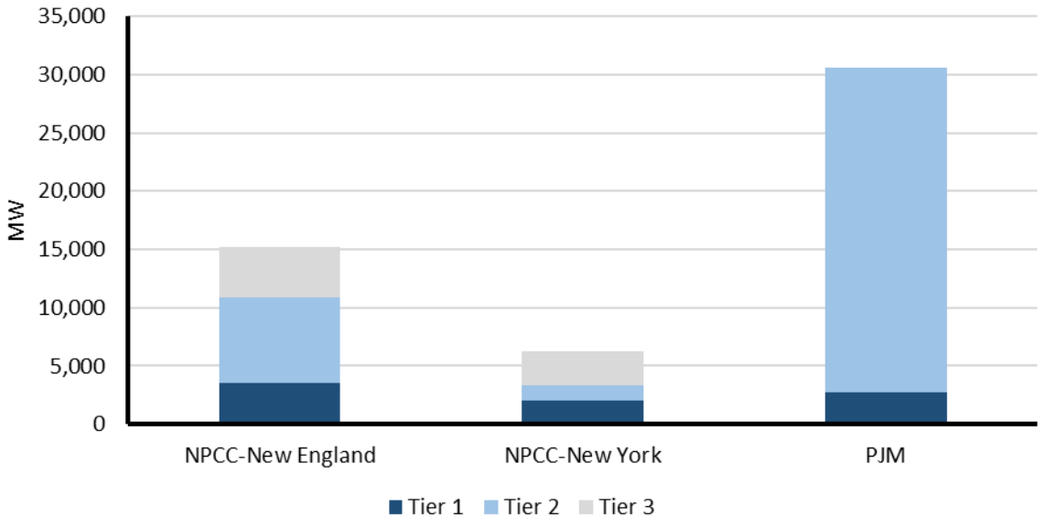


Figure 11: Offshore Wind Capacity Planned through 2034

Battery Resources

As the BPS increases the share of energy provided by VERs, the ability to provide energy by BESS or hybrid-solar PV and wind plants is increasingly important. While currently installed capacity totals just over 17 GW, an additional 306.5 GW of BESS are in planning. **Figure 12** shows the nameplate capacity of BESS resources currently in operation and in planning for connection to the BPS through 2034.

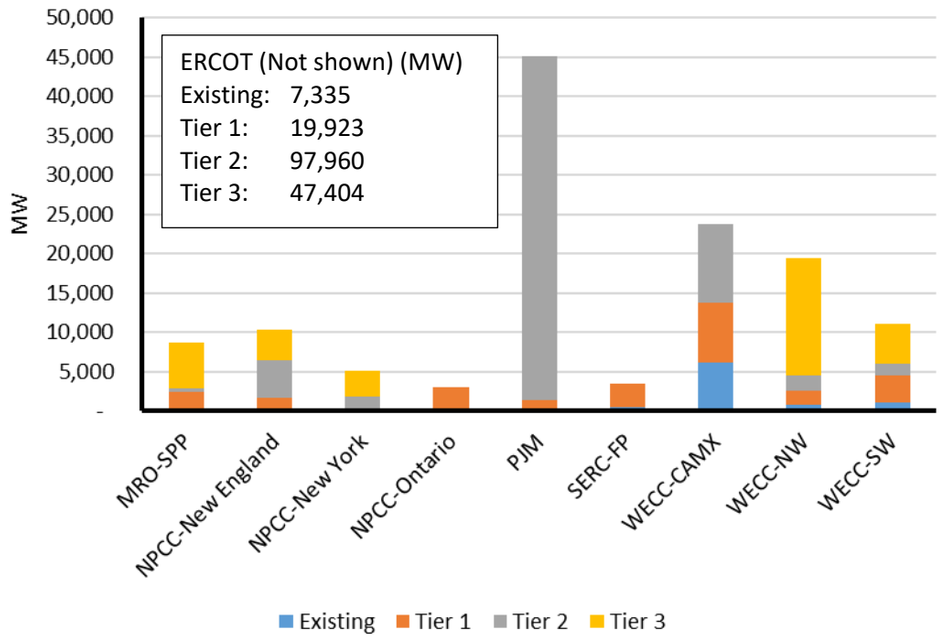


Figure 12: Battery Resource Capacity Existing and Planned through 2034

BESS are improving reliability by helping to offset the variability and uncertainty of inverter-based resources (IBR). BESS are, however, a relatively new type of grid resource with unique operating characteristics. The joint *NERC-WECC Staff Report: 2022 California Battery Energy Storage System Disturbances*[18] highlights an event when a BESS, like some other IBRs, failed to properly ride through a normal system fault. This indicates that BESS must be included in the currently underway strategies to address IBR performance issues.

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. **Table 14** shows the nameplate value and the capacity contribution of existing wind, solar PV, hydro, and energy storage systems resources at the peak demand hour for each assessment area. During risk periods after peak demand (e.g., U.S. assessment areas in WECC), contributions of solar PV resources output is diminished during evening periods and additional resources are needed.

[18] NERC–WECC *2022 California Battery Energy Storage System Disturbances*

Table 14: BPS Wind, Solar, Hydro, and Battery Generation Resources by Assessment Area Year 2024												
Assessment Area	Wind			Solar			Hydro			Energy Storage Systems		
	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)
MISO	41,349	5,715	13.8%	30,502	5,305	17.4%	2,450	1,576	64.3%	401	84	21.0%
MRO-Manitoba Hydro		52	-	-	-	-	6,434	5,704	88.7%	-	-	-
MRO-SaskPower	815	164	20.1%	30	-	-	864	862	99.8%	-	-	-
MRO-SPP	34,475	5,134	14.9%	703	275	39.1%	5,633	4,079	72.4%	2	2	100%
NPCC-Maritimes	-	261	-	-	5.1	-	1,361	1,312	96.4%	-	-	-
NPCC-New England	2,548	127	5.0%	3,361	308	9.2%	1,917	1,469	76.6%	26	9	34.9%
NPCC-New York	2,706	461	17.1%	1,039	240	23.1%	4,915	3,736	76.0%	60	30	50.2%
NPCC-Ontario	4,943	1,364	28%	478	-	0.0%	8,748	6,215	71.0%	18	-	0.0%
NPCC-Québec	3,820	1,375	36.0%	10	-	0.0%	40,907	39,354	96.2%	-	-	-
PJM	11,701	1,760	15.0%	10,735	4,808	44.8%	3,071	2,367	77.1%	222	100	44.8%
SERC-C	982	172	17.5%	2,308	771	33.4%	4,995	3,364	67.4%	100	50	50.0%
SERC-E	-	-	-	6,777	4,753	70.1%	3,170	3,016	95.1%	15	6	38.4%
SERC-FP	-	-	-	10,121	5,618	55.5%	-	-	-	538	523	97.2%
SERC-SE	-	-	-	7,267	5,414	74.5%	3,293	3,260	99.0%	115	40	34.9%
Texas RE-ERCOT	39,532	11,062	28.0%	31,058	19,098	61.5%	583	458	78.6%	10,720	-	0.0%
WECC-AB	5,559	1,867	33.6%	3,042	-	0.0%	894	285	31.9%	270	264	97.8%
WECC-BC	776	279	36.0%	2	-	0.0%	16,902	12,623	74.7%	-	-	-
WECC-CA/MX	7,694	1,158	15.0%	24,905	14,641	58.8%	10,211	3,582	35.1%	11,883	11,155	93.9%
WECC-NW	23,518	3,489	14.8%	12,787	6,877	53.8%	41,257	21,168	51.3%	1,909	1,231	64.5%
WECC-SW	3,784	628	16.6%	5,944	2,527	42.5%	1,025	721	70.3%	2,997	2,592	86.5%

Solar PV Distributed Energy Resource Growth

Behind-the-meter (BTM) solar PV generators are solar PV resources connected on the distribution system, such as residential rooftop solar systems. The rapid growth of BTM solar PV continues with cumulative levels expected to reach over 123 GW by the end of this 10-year assessment period (up from 89 GW reported in the *2023 LTRA*, an increase of 38%). There are currently 58.7 GW of installed BTM solar PV across the North American BPS.

BTM solar PV generators, like grid-connected solar PV, are also VERs. In large penetrations, their predictable change in output from the time of day contributes to steep ramps in demand. As the sun sets and output diminishes, grid resources must make up for the decrease in solar generation and increase in demand that was being served. The opposite ramp occurs during morning hours; it may be less impactful to reliability but can be challenging for grid-connected generator scheduling and dispatch. **Figure 13** shows the current and projected BTM solar PV by area through 2034.

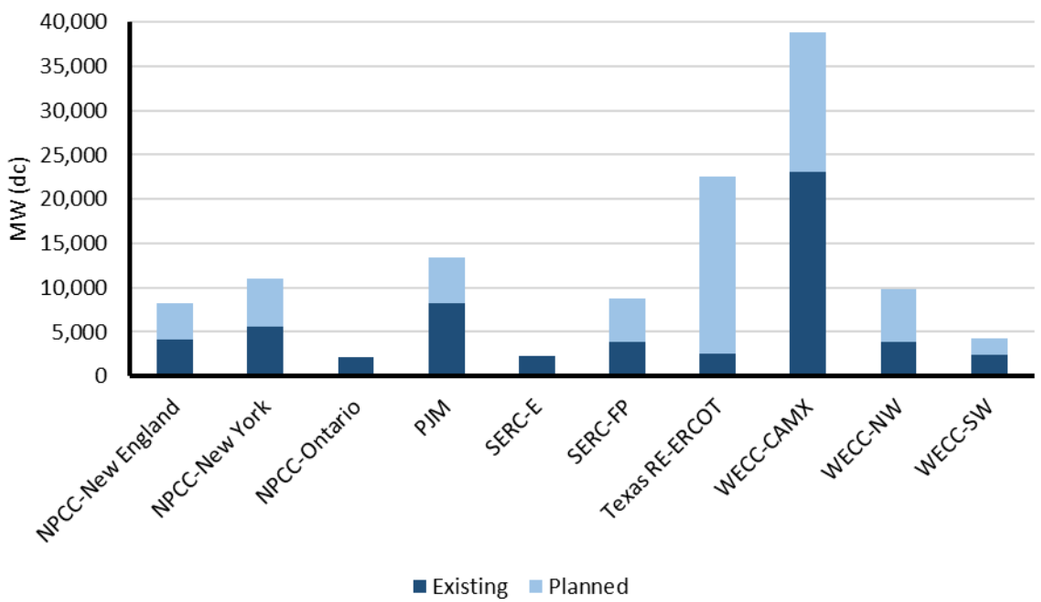


Figure 13: Solar PV DER Capacity Existing and Planned through 2034

Generation Retirements

The total capacity of traditional baseload generation fuel types will continue to decline as older generators retire. Generators become confirmed for retirement according to various processes in place in the Interconnections, such as regional planning tariffs in the wholesale electricity market areas or the integrated resource planning process in vertically integrated states. Properly designed mechanisms can prevent generators from retiring before planners can study and address reliability issues that could occur.

Currently, over 79 GW of fossil-fired and nuclear generating capacity is being retired over this assessment period (see **Figure 14**), a small decrease from the 83 GW in retirements reported in the *2023 LTRA*. This capacity includes generators that are confirmed for retirement through retirement planning processes or that have indicated plans to retire to an ISO/RTO or Planning Coordinator.

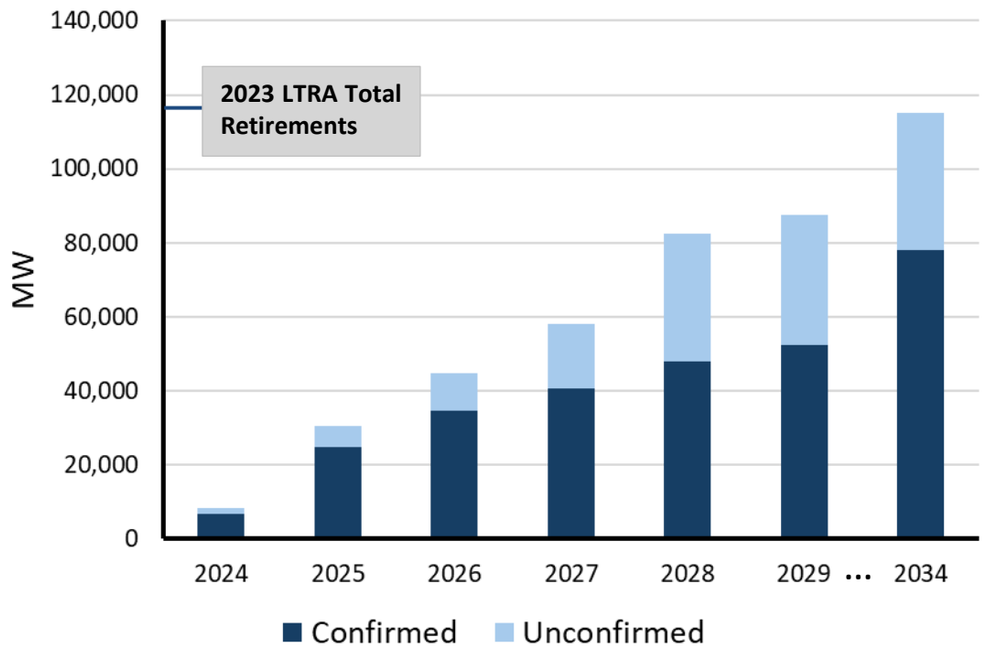


Figure 14: Projected Generation Retirement Capacity through 2034

Additional fossil-fired generator retirements are expected and would result in further loss of existing capacity. Generator Owners often announce plans to retire generator units before initiating the

interconnection planning process, and the announced plans or timing may be subject to change before the retirement is confirmed. Wholesale electricity market areas, where merchant electric generators make up a large part of the generating fleet, have more uncertainty around future generator retirements, making resource planning and adequacy assessment difficult. **Figure 15** shows the total capacity of reported retirements (i.e., reported to ISO/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[19] This total of confirmed and announced-potential retirements over the next 10 years is over 115 GW (3 GW lower than 10-year projections in the *2023 LTRA*).

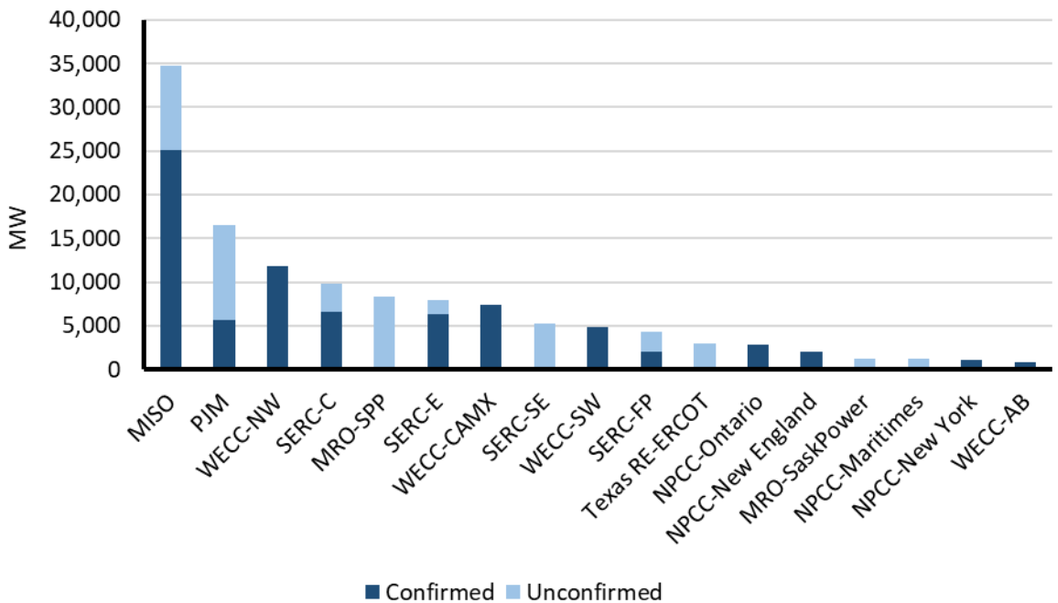


Figure 15: Projected Capacity Retirements of Nuclear and Fossil Generation 2024–2034

Natural Gas Fuel Reliance Trends

Natural-gas-fired generators are and will remain a critical resource for BPS reliability in many areas over the 10-year assessment period, especially during winter. These generators provide many necessary reliability attributes that are exiting the system as traditional generators retire and inverter-based renewable resources take their place in the resource mix. Natural-gas-fired generators are dispatchable and provide the ERSs of inertia, frequency response, and ramping flexibility. In winter, when peak demand in most areas occurs during early morning hours, natural-gas-fired generation is at its highest contribution to the resource mix in many areas. Severe winter weather events in 2021 and 2022 provided stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure supplies during times of extreme electricity demand.

As the generation resource mix evolves and becomes more weather-dependent, fuel assurance becomes increasingly critical when conducting reliability assessments. Until recently, comparing seasonally available capacity to a predetermined PRM level has sufficed as a means to assess resource adequacy. However, resource adequacy is now only the first step of a meaningful reliability assessment. Energy adequacy must now be layered on top to assess the risk that available capacity may be rendered unavailable due to phenomena including low wind or solar output and/or natural gas supply and transportation issues.

This year, the Energy Information Administration (EIA) projected that more than 40% of delivered natural gas would be consumed by power generators, more than 0.6 Bcf/d higher than was consumed by power generators in 2023 and 7% higher than what the EIA had projected for 2024 in the fall of last year. Natural-gas-fired power plants generated 42% of the electrical energy consumed by end-use electricity customers in 2023 and are on track to maintain that share of generation this year. A significant percentage of natural-gas-fired power plants rely upon as-available, non-firm gas supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas by both generators and natural gas distribution companies (generally firm shippers) can at the same time dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability, and when winter weather impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can put at risk even firm pipeline customers as preparatory linepack is rapidly depleted.

[19] Confirmed generator retirements are reported to NERC by each assessment area in this *2024 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

The *2024 LTRA* projects that an additional 6,500 MW of new natural-gas-fired generation will be added in North America over the next five years. While some assessment areas project net decreases in natural-gas-fired capacity, other areas report increases ranging from 3% to over 50%.

In the United States, 8 out of 13 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to over 10 GW of new natural-gas-fired power capacity. Altogether, those additions translate to an increase in natural gas use for power generation of more than 84 Bcf (245 MMcf/d). Whether this increase in natural gas generation capacity is sufficient to meet the increase in net internal demand projected for these same assessment areas remains to be seen, but based on the capacity additions alone, some areas are set to see an insufficient increase in gas pipeline capacity, as per the EIA's database of nationwide U.S. gas pipeline projects. (see **Figure 16**).

PJM is one such area, projected to see a 3% increase in natural-gas-fired generation capacity (+2,500 MW). Net internal electricity demand in PJM is forecasted to rise by 25 GW over the planning horizon at the same time that non-variable resources are expected to shrink their share of the capacity mix from 96% to 88%. To the extent that variable resources are uncertain during times of peak stress on the grid, there is a risk of gas delivery capacity being insufficient for the amount of natural gas supply that could be required to meet the demand increase. SPP is another assessment area where natural-gas-fired power capacity is set to rise, by 5%, or roughly 1,500 MW. In both PJM and SPP, there is a risk of a shortfall in natural gas pipeline capacity that could facilitate delivery of the additional fuel that is necessary to meet their capacity expansion plans.

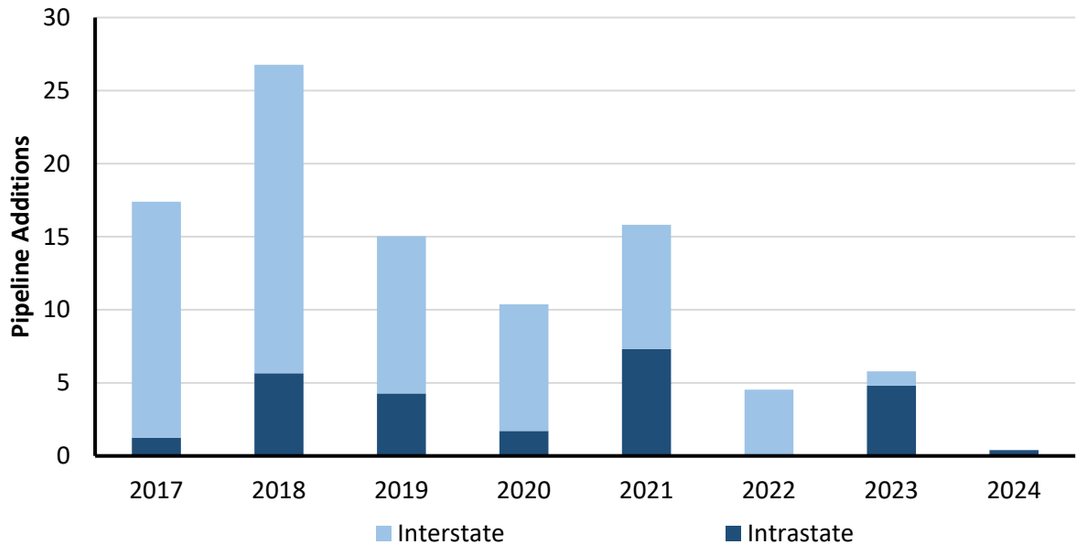


Figure 16: Annual U.S. Natural Gas Pipeline Capacity Additions by Type (2017–2024) Bcf/d (Source: U.S. Energy Information Administration)

Reliability Implications

The addition of variable resources, primarily wind and solar PV, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. With electricity supplies coming increasingly from VERs and natural-gas-fired generators, there is a growing risk that supplies can fall short of demand during some periods. Geographically diverse wind and solar resources and loads can help reduce these risks, but they require robust transmission networks, comprehensive energy and transfer capability analysis, and effective operating procedures and market mechanisms.

Maintaining ERSs for Grid Support

For the grid to operate reliably, it needs resources that are not only sufficient for meeting demand and energy requirements but also capable of controlling voltages, maintaining stable frequency across the system, and flexibly ramping up or down to dispatch control at all times. Conventional generators, such as nuclear, coal, and natural gas-fired generators, provide much of the ERSs that support reliable operation today. New resources on the grid are almost all IBRs, which have different physical and operating characteristics that affect the level of ERSs that they can provide. Without the spinning mass or traditional excitation systems providing the voltage control of a hydroelectric or thermal generator,

most IBRs have limited capability for maintaining system voltages and stability. Batteries, with their fast response time, have some ERS capability that wind and solar do not. They are useful in regulating system frequency and are helping to balance variability from VERs in ERCOT and California where wind and solar make up a large portion of the resource mix.[20] As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

Accelerated generator retirements, especially unanticipated requests for deactivation, can cause ERS-related reliability issues in parts of the system due to the future loss of the generator's reliability attributes. This reduction in the level of ERSs can result in voltage violations or system instability. System planning and generator deactivation processes evaluate these changes to the system and ensure plans proceed only when reliability criteria, including ERS-related considerations, are met. For example, PJM's deactivation process identified reliability concerns to the system as a result of the requested deactivation of the Brandon Shores power plant (1,280 MW) in 2023. Until necessary system upgrades are completed to address identified system voltage and other reliability issues that would occur with the deactivation, PJM has requested that the Brandon Shores generators at the plant remain in service through the reliability-must-run process.[21]

To ensure the future system can operate reliably, market operators, system planners, regulators, and policymakers need to ensure effective mechanisms are in place to provide for the ERS needs of the future system. Long-term activities can provide incentives to generators with needed reliability attributes. Effective backstops will also be needed to prevent the loss of critical generators when analysis finds deactivation would violate reliability criteria.

Specific and actionable recommendations are contained in the **Recommendations and ERO Actions Summary** section of this report.

[20] See the *2023 Special Report on Battery Storage* from the California ISO.
[21] Information on this and other proposed deactivations in PJM are found on PJM's Generator Deactivations page.

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. The aggregated assessment area summer peak demand forecast is expected to rise by over 132 GW, and aggregated winter peak demand forecasts are increasing by 149 GW. The growth rates of forecasted peak demand (see **Figure 17**) and energy (see **Figure 18**) continue to rise sharply since the 2022 LTRA, reversing an almost two-decade trend of falling or flat growth rates. See **Figure 17** for seasonal peak demand growth over the current and prior assessment periods and **Figure 18** for net energy growth. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in **Figure 19**.

Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2023 LTRA*, peak season CAGR has risen in all assessment areas except two: NPCC-Maritimes' winter CAGR fell from 0.98% to 0.63% and WECC-BC's winter CAGR fell from 1.05% to 0.28%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

Large Commercial and Industrial Loads

Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. Emerging large loads, such as data centers (including crypto and AI) and hydrogen fuel plants, present unique challenges to forecasting and planning for increased demand. Earlier this year, NERC's RSTC established a Large Loads Task Force to better understand the reliability implications of growth in large loads and develop solutions.

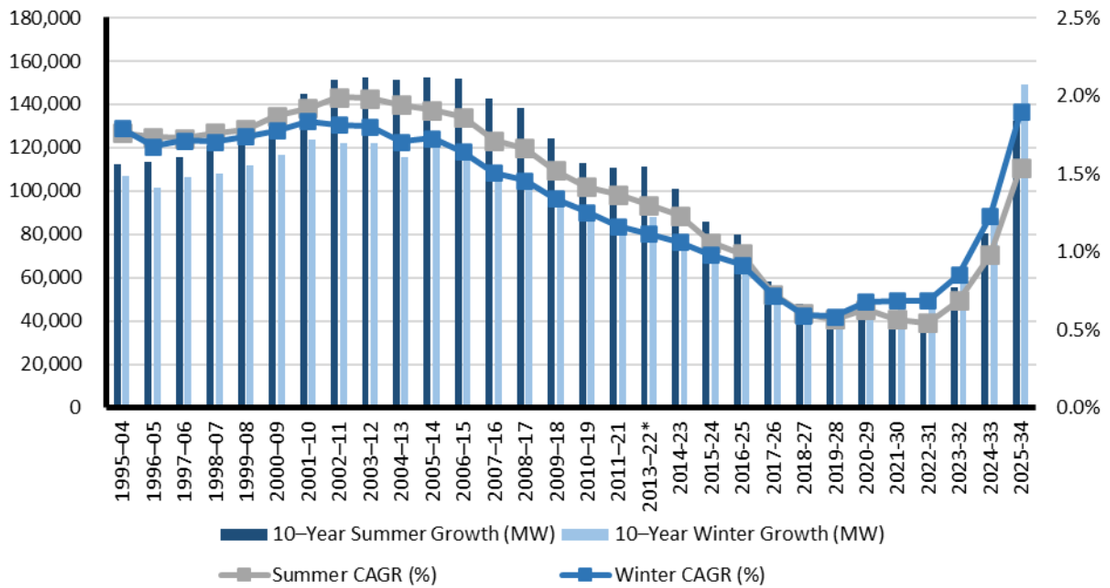


Figure 17: 10-Year Summer and Winter Peak Demand Growth and Rate Trends



Figure 18: Net Energy for Load Growth and Rate Projections

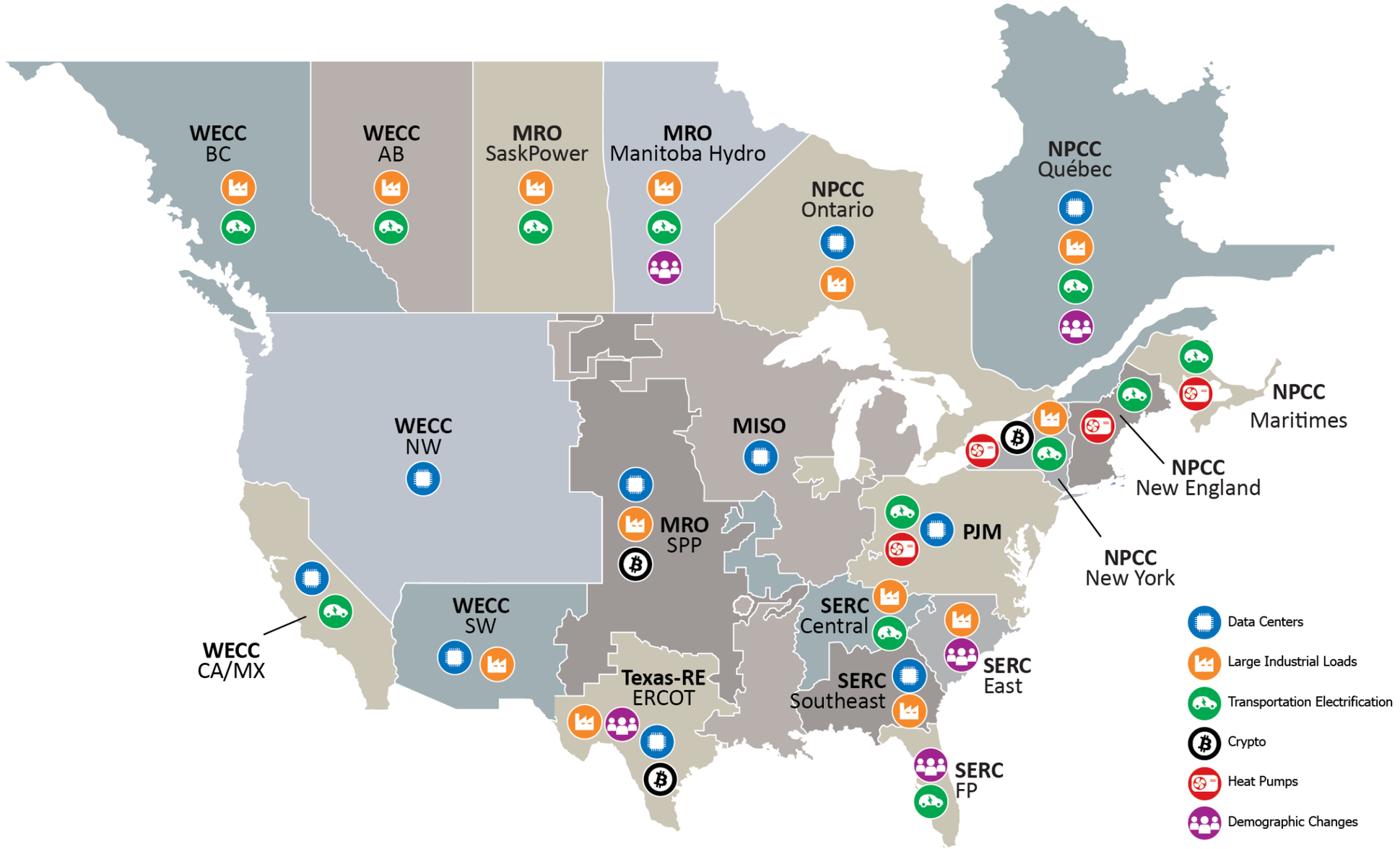


Figure 19: Primary Demand Drivers by Assessment Area

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of electric vehicles (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output and fuel risks are significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from a summer-peaking system to a winter-peaking (or dual-season peaking) system and the approximate year of the transition:

- NPCC-New England (mid-2030s)
- NPCC-New York (mid to late-2030s)
- NPCC-Ontario (2030)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer.

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and distributed energy resource performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating large commercial and industrial loads, electrification, electric vehicle adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year had a noticeable effect on resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Transmission Development and Interregional Transfer Capability

Transmission Projects

This year's cumulative level of 28,275 miles of transmission (>100 kV) in construction or stages of development for the next 10 years (see **Figure 20**) is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

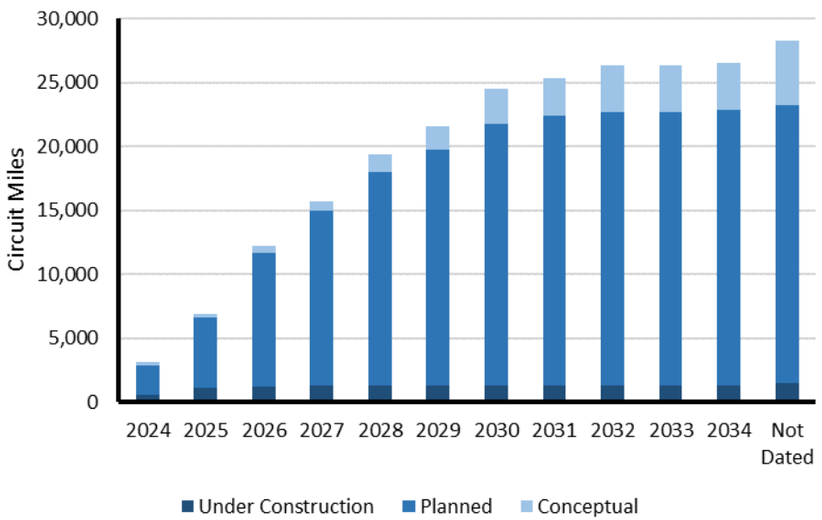


Figure 20: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. **Figure 21** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria. Some substantial new projects to integrate renewable generation are also in development or are entering planning processes. Nearly 70 of the 1,160 transmission projects in development are for tie-lines and tie-line upgrades, which support transfer capability between neighboring Balancing Authority areas. See the transmission summaries at the end of each assessment area's pages (in the **Regional Assessments Dashboards**) for current transmission development details.

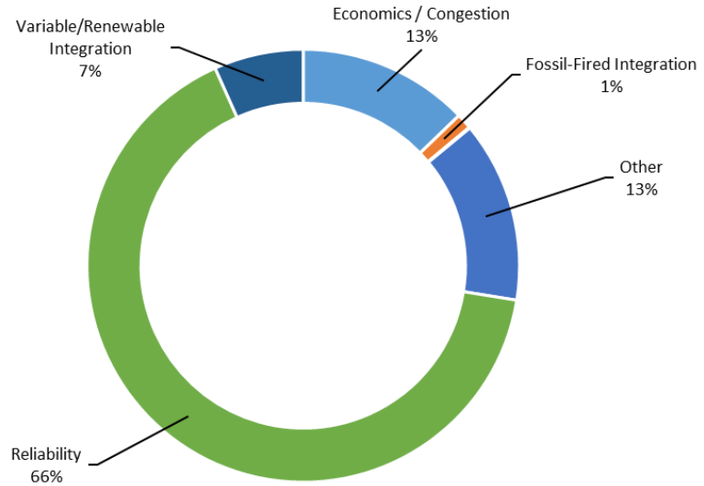


Figure 21: Future Transmission Circuit Miles by Primary Driver

Transmission development in some areas is hampered by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, over 110 projects are currently delayed from their expected in-service dates. Siting and permitting issues are the most common cause for delays, affecting 68 projects (totaling 1,230 miles of new transmission). Other reasons for delays include economic impacts, planning and construction issues, or changing needs.

Interregional Transfer Capability Study (ITCS)

The Fiscal Responsibility Act of 2023[22] required NERC to conduct a comprehensive study of existing and future interregional transfer capability between each Transmission Planning Region[23] (TPR) to make recommendations for prudent additions to the amount of power that can be moved or transferred between neighboring TPRs and to make recommendations on how to meet and maintain transfer capability. In addressing this legislation, NERC identified additions to transfer capability that could support energy adequacy.[24] NERC filed the completed study report with FERC on November 19, 2024.[25]

Transfer Capability is the measure of the ability of the interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all the transmission lines (or paths) between those areas under specific system conditions. The units of transfer capability are in terms of electric power, generally expressed in MW.

To provide further opportunities for stakeholder engagement and consultation, the project was divided into several stages, each with an accompanying report.

- **Overview of Study Need and Approach[26]:** Provided background and context regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. (published in June 2024)
- **Transfer Capability Analysis (Part 1)[27]:** Addressed the first part of the congressional directive, which mandated a transfer capability analysis between each pair of neighboring TPRs, as well as the simultaneous import capability of each TPR. (published in August 2024)
- **Prudent Additions Recommendations (Part 2) and Meet/Maintain Recommendations (Part 3)**: Contained an energy margin analysis and resulting recommendations for prudent[28] additions to the transfer capability between neighboring TPRs to improve energy adequacy during, for example, extreme weather events. It also discussed how to meet and maintain transfer capability as enhanced by these prudent additions.
- **Canadian Analysis:** Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces.[29]

Transfer Capability Analysis (Part 1)

Adequate transfer capability is fundamental to the reliable operation of the BPS. Balancing Authorities may rely on their neighbors to supply energy for various purposes, including economic or policy reasons. Transfer capability is also essential under stressed operating conditions, allowing Balancing Authorities to maintain reliability by importing needed energy from their neighbors. As the resource mix becomes increasingly dependent on just-in-time and weather-dependent fuel and energy for wind and solar, the ability to transfer electrical energy from areas of surplus to areas experiencing fuel or energy constraints has become essential to maintaining reliable delivery of electricity to end-use customers.

The ITCS is a congressionally mandated study to evaluate transfer capability and recommend additions to strengthen reliability.

A holistic view of the interconnected system and a thorough understanding of its behavior are essential when calculating or increasing transfer capability. When neighboring TPRs transfer energy over a highly interconnected system, the energy flows over many different lines based on the electrical characteristics, or impedance, of traveling each route, unless there is specific equipment used to control flows. As a result, energy typically flows not only across the tie lines that directly connect the exporting (source) TPR to the importing (sink) TPR but over many routes, some of which

[22] H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress
[23] For the purposes of the ITCS, this term refers to the study regions as described in ITCS Overview of Study Need and Approach, Chapter 2.
[24] As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.
[25] NERC filing of the Interregional Transfer Capability Study, FERC Docket AD25-4-000.
[26] The ITCS Overview of Study Need and Approach can be found here.
[27] The ITCS Transfer Capability Analysis (Part 1) report can be found here.
[28] FERC defines prudence as the determination of whether a reasonable entity would have made the same decision in good faith under the same circumstances at the relevant point in time. See, e.g., New England Power Co., 31 FERC ¶61,047 at p. 61,084 (1985); and PotomacAppalachian Transmission Highline, LLC, 140 FERC ¶61,229 at P 82 2012 (Sept. 20, 2012).
[29] The ITCS Part 1 evaluated transfer capability from Canada into the United States.

may be running through third-party systems. The way electrical energy flows has broad implications for calculating and using transfer capability in an interconnected system, especially when traveling over long distances. For example, maintaining and increasing transfer capability may be highly dependent on the system conditions within the source and sink TPRs as well as surrounding areas. Likewise, transfer capability does not correlate one-to-one with the rating of new or upgraded transmission facilities.

Part 1 Key Findings

- Transfer capability varies seasonally and under different system conditions that limit transmission loading—it cannot be represented by a single number.
- Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.
- Observed transfer capabilities are generally higher in the West Coast, Great Lakes, and Mid-Atlantic areas but relatively lower in the Mountain States, Great Plains, Southeast, and Northeast. There is limited transfer capability between interconnections

The transfer capability results in the Part 1 report reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. This study used a set of cases representative of stressed system conditions most relevant for the Part 2 analysis. As such, the study did not attempt to maximize transfer capability values for each interface through optimal generation re-dispatch, system topology changes, or other operational measures. Consequently, higher transfer capabilities may be available under different conditions. Changes to future resource additions, resource retirements, load forecast changes, and/or transmission expansion plans have the potential to significantly alter the study results.

Recommendations for Prudent Additions (Part 2) and to Achieve Transfer Capability (Part 3)

Part 2 of the ITCS evaluated the energy adequacy of the BPS should past weather conditions occur again in 2033. Specifically, the study applied 12 past weather years to the 2033 loads and resource mix using the current transfer capabilities as calculated in Part 1. The Part 2 study then evaluated the impact that additional transfer capability could have in mitigating the identified resource deficiencies[30] during extreme events, thereby improving energy adequacy. Using a six-step process, the ITCS developed a list of recommended additions to transfer capability. **Figure 22** shows the existing and potential new interfaces where additional transfer capability is recommended. While there are several factors that Transmission Planners consider, including reliability, economics, and policy objectives, given NERC's role as the ERO, the ITCS focused solely on reliability, specifically in terms of energy adequacy, for these recommendations.

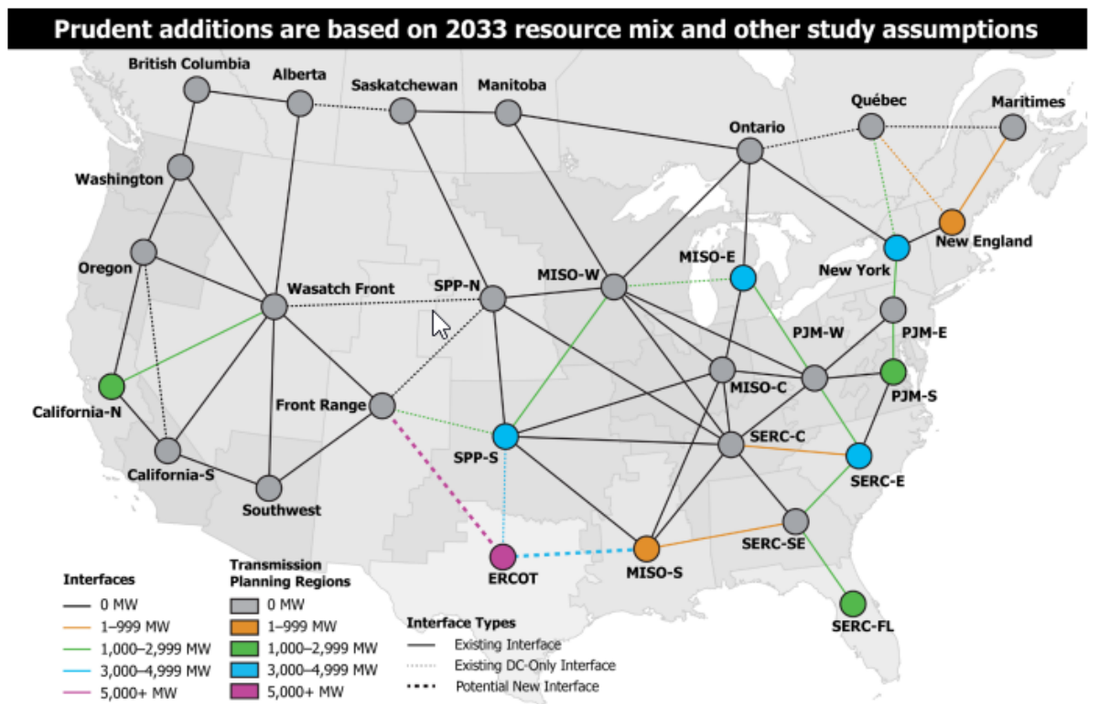


Figure 22: Prudent Additions to Transfer Capability

[30] For the purposes of this study, "resource deficiency" is used to describe instances where available resources, including energy transfers from neighbors, are insufficient to meet the projected demand plus minimum margin level.

The resulting recommendations for prudent additions to transfer capability (Part 2 study) were published in a report along with recommendations to meet and maintain transfer capability as enhanced by the prudent additions (Part 3).[31] Planners have multiple options for reducing the energy adequacy and extreme weather risks. In addition to the transmission enhancements that were in scope for the ITCS, due consideration should also be given to constructing local generation and storage, demand-side management approaches, and grid resilience projects. The ITCS recommended that planners consider all options and balance reliance on external resources vs. internal resources, noting that there may be better options than an over-reliance on one or the other.

Part 2 Key Findings

- Import capability required to reliably serve customers during extreme conditions varied significantly across the country, so a one-size-fits-all requirement would be inefficient and ineffective.
- Transmission limitations and the potential for energy inadequacy were identified in all 12 years studied.
- 35 GW of additional transfer capability is recommended across the United States to improve energy adequacy under extreme conditions.
- Some identified transmission needs could be alleviated by projects already in the planning, permitting, or construction phases. If completed, these projects could mitigate several risks highlighted by the ITCS, reinforcing their importance for grid resilience.
- The ITCS provides foundational insights for further discussion, and decisions. Transmission upgrades alone will not fully address all risks, and a broader set of solutions should be considered, emphasizing the need for local resources, energy efficiency, demand-side, and storage solutions.

See the *ITCS Final Report* for Detailed Key Findings

[31] The ITCS report *Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)* can be found here.

Emerging Issues

While developing this LTRA, NERC and the industry considered trends and developments that have the potential to impact the future reliability of the BPS over the next 10 years and beyond. Discussed below are emerging issues and trends not previously covered in this report that have the potential to impact future long-term projections or resource availability and operations.

Data Centers and Large Industrial Load

Growth in large load parcels like data centers and industrial facilities pose various challenges for system planners and operators, in addition to fueling rapid demand growth discussed elsewhere in this report. **Figure 23** shows one estimate of data center growth in the United States by 2027.[32] Other types of large industrial loads include smelters, manufacturing centers, hydrogen electrolyzers, and future electrified mass transit or shipping charging stations. Adding large parcels of load on the system can add new uncertainties to peak and hourly load forecasting. For example, data centers have longer operating hours and require more heating and cooling than other commercial buildings. In Texas, crypto mining facilities have connected in recent years that scale their operations (and thus electricity demand) depending on electricity prices. The behavior of large data centers during normal grid faults is also an emerging concern because customer-initiated automatic disconnecting of sizeable load can cause operating issues. Sudden and unexpected disconnecting load during a grid fault is analogous to well-known IBR performance issues and poses similar reliability risks. Planners and operators need to consider the characteristics of these loads as they begin to proliferate and support NERC RSTC's Large Loads Task Force to share best practices.

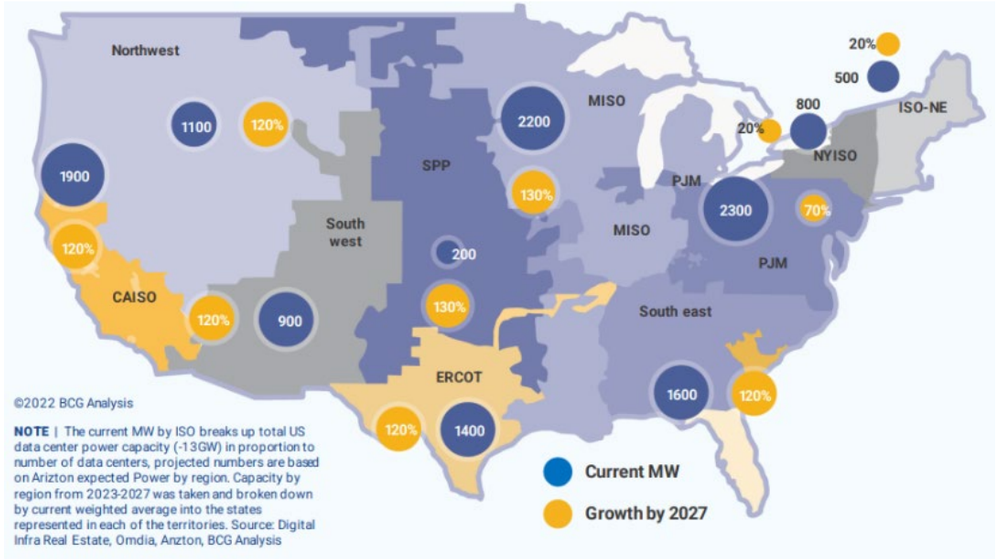


Figure 23: Projected Growth in Data Centers in the United States

Battery Energy Storage Systems

Planners and operators are focused on requirements to model, study, and operate the BPS with increased BESS and hybrid resources. BESS are increasingly being relied upon in areas with substantial amounts of solar PV resources to reduce ramping requirements on other resources by discharging in late afternoon as solar PV output rapidly declines. BESS are also often used for ancillary services, such as frequency response. Accurately accounting for BESS in operating and planning studies is a challenge because it requires assumptions and modeling capabilities for battery charging and discharging behavior. In real-time operations, system operators often do not have visibility into battery state-of-charge, a necessary condition for reliably integrating batteries into system operating plans. Without such information, operators may be surprised should battery resources fail to deliver when needed. In Texas, where battery resource growth is among the highest in North America, ERCOT uses a battery storage data collection program to obtain operational information and is pursuing market rules for state-of-charge accounting in unit commitment processes. System planners in many areas will be counting on new BESS facilities to manage variability and demand and resources. Obtaining the benefits of these resources requires careful integration into operating, planning, and market designs.

[32] *Grid Strategies: The Era of Flat Power Demand is Over*: https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

Electric Vehicles and Electric Load

With increased adoption of electric vehicles (EV), which use batteries to store energy, there is a need to understand the impact of battery charging on system performance. EV forecasting is important for resource adequacy and system planning to account for changing load and load patterns. It is also important for system studies to include EV modeling and parameterization that account for the behavior of battery charging systems on system performance. In January 2024, NERC released the *EV Charging Study*, noting that the behavior of large amounts of EV chargers in operation can affect the BPS response to common outages. The RSTC established an EV Task Force to promote collaboration among the electric power industry and automotive representatives on areas of grid reliability.

Energy Drought

More reliance on wind, solar, and hydro resources in the resource mix has the potential to expose the electric system to supply shortages under abnormal weather patterns. When two or more resource types are simultaneously affected by conditions that cause below-normal resource output, operators can face challenges in meeting demand. Analysis of U.S. historical hourly generator data indicates that there are regional patterns to energy drought that can be expressed in terms of duration, magnitude, and seasonality (See **Figure 24**). There is also a higher likelihood for energy droughts to be more likely occur during high-load periods than at other times, underscoring the importance in considering such events in planning for resource and storage needs.[33]

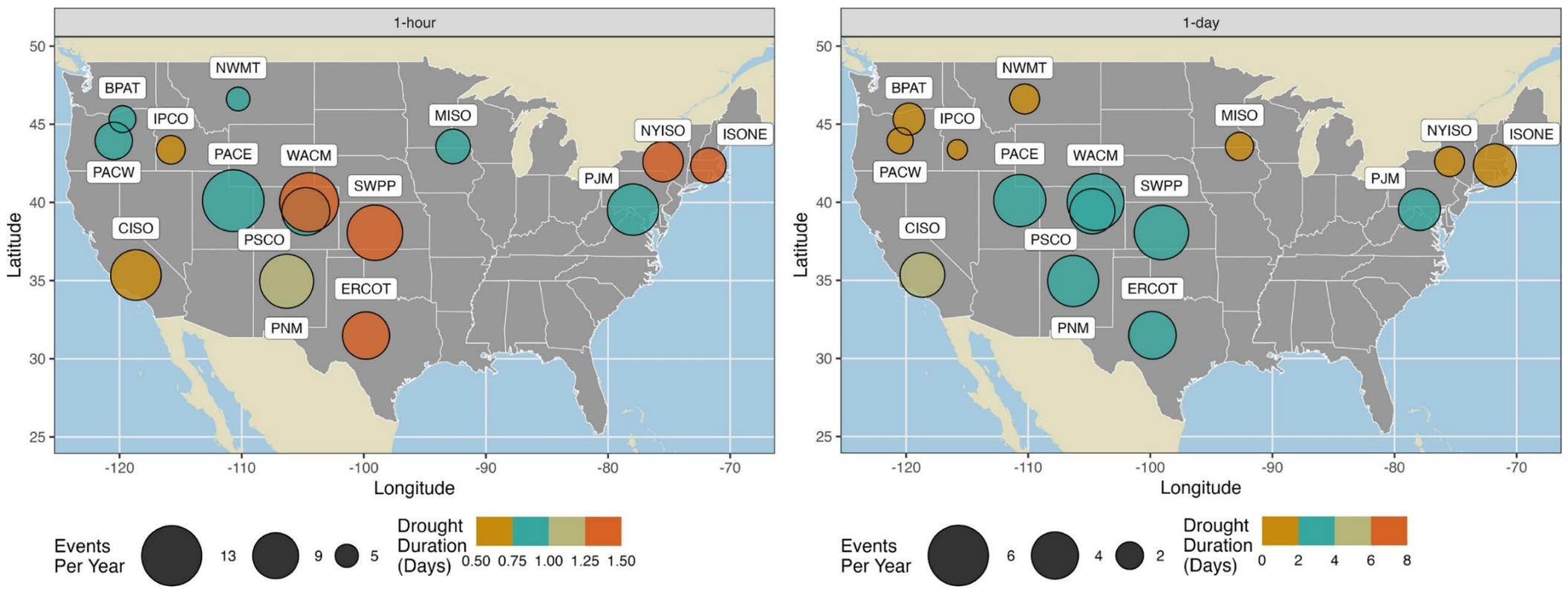
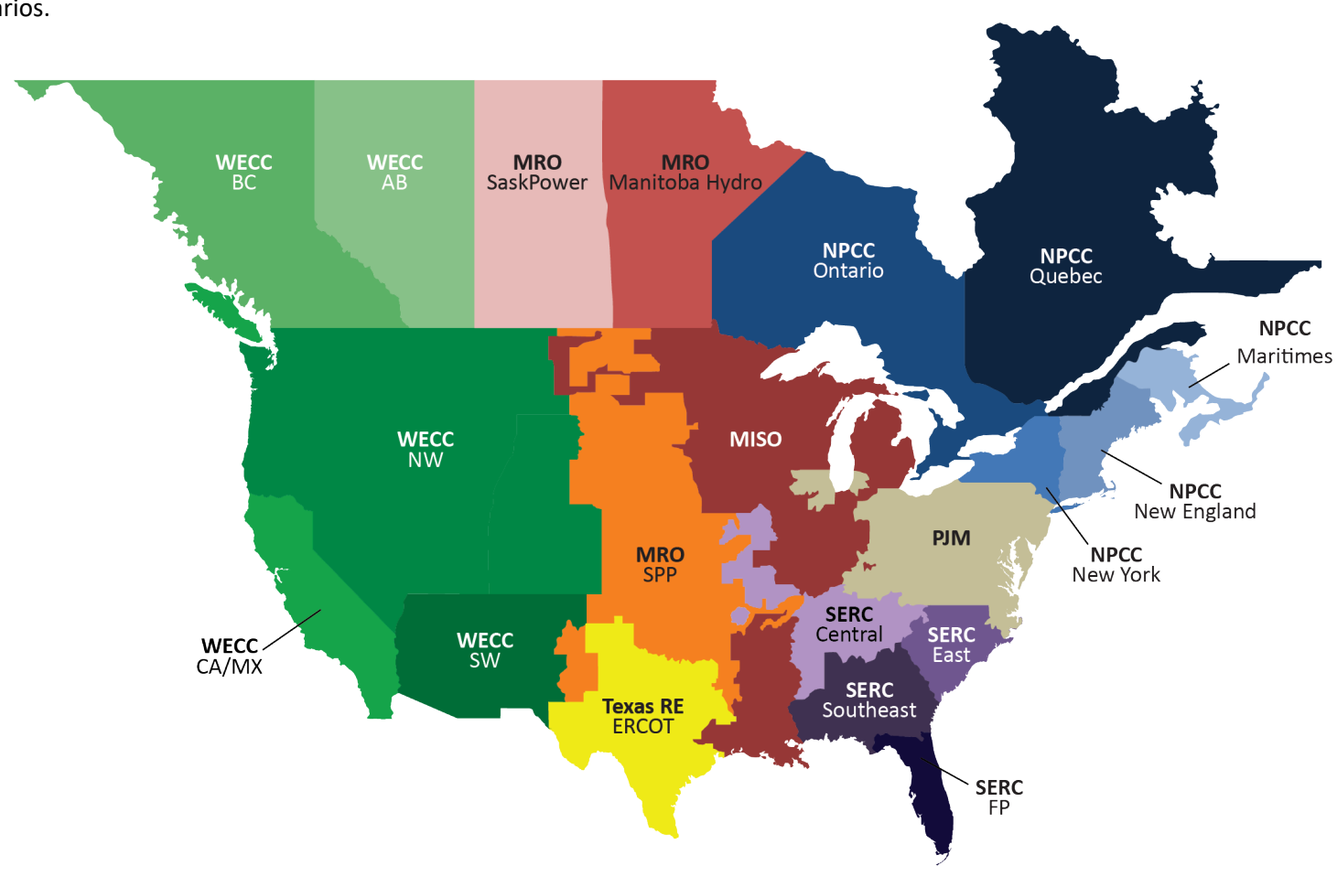


Figure 24: Frequency and Duration of Hourly (Left Panel) and Daily (Right Panel) Energy Droughts. Source: Pacific Northwest National Laboratory

[33] See Standardized benchmark of historical compound wind and solar energy droughts across the Continental United States

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Demand Assumptions and Resource Categories** table. On-Peak Reserve Margin bar charts show the ARM compared to the RML established for the area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the Demand and Resource Tables), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the Demand and Resource Tables) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.



- MISO *(Midcontinent Independent System Operator)*
- PJM

MRO – Midwest Reliability Organization
- MRO-Manitoba Hydro
- MRO-SaskPower
- MRO-SPP

NPCC – Northeast Power Coordinating Council
- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

SERC – SERC Reliability Corporation
- SERC-Central
- SERC-East
- SERC-Southeast
- SERC-Florida Peninsula

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT *(Electric Reliability Council of Texas)*

WECC
- WECC-AB *(Alberta)*
- WECC-BC *(British Colombia)*
- WECC-CA/MX *(California/Mexico)*
- WECC-NW *(Northwest)*
- WECC-SW *(Southwest)*



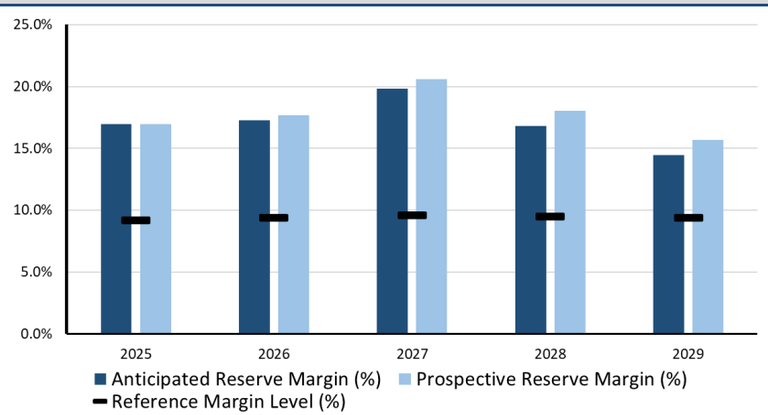
MISO

Midcontinent Independent System Operator, Inc. (MISO) is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

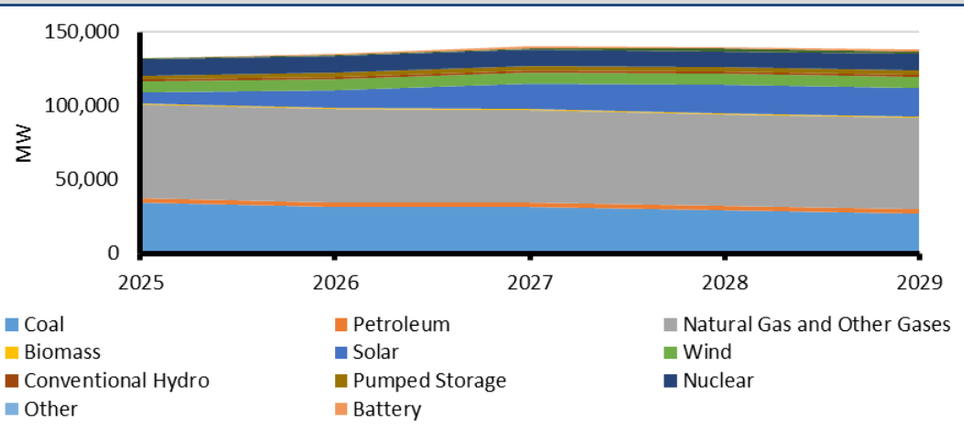
Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	122,328	124,343	126,073	128,700	129,401	130,120	130,493	131,327	131,952	131,952
Demand Response	8,205	8,221	8,058	8,065	8,074	8,077	8,079	8,075	8,075	8,075
Net Internal Demand	114,122	116,122	118,015	120,635	121,327	122,043	122,414	123,252	123,877	123,877
Additions: Tier 1	4,959	11,376	18,275	21,501	22,205	22,205	22,205	22,205	22,205	22,205
Additions: Tier 2	19	464	916	1,486	1,486	1,486	1,486	1,486	1,486	1,486
Additions: Tier 3	803	3,686	8,252	13,017	15,546	16,399	16,542	16,608	16,659	16,659
Net Firm Capacity Transfers	1,320	1,270	1,165	925	855	750	549	549	549	549
Existing-Certain and Net Firm Transfers	128,520	124,787	123,153	119,397	116,669	112,823	110,273	110,273	106,838	106,838
Anticipated Reserve Margin (%)	17.0%	17.3%	19.8%	16.8%	14.5%	10.6%	8.2%	7.5%	4.2%	4.2%
Prospective Reserve Margin (%)	17.0%	17.7%	20.6%	18.0%	15.7%	11.9%	9.4%	8.7%	5.4%	5.4%
Reference Margin Level (%) (Summer)	9.2%	9.4%	9.6%	9.5%	9.4%	9.4%	9.5%	9.6%	9.7%	9.7%

Note: See **Figure 3** for summer reserve margins with historically average resource additions in MISO based on results from the 2024 Organization of MISO States (OMS)-MISO Survey.



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MISO's capacity resource turnover continues to occur with coal unit contributions being primarily replaced by solar, wind, and battery facilities. Furthermore, generation installation delays result in uncertainty throughout the assessment timeframe. As a result of these factors, MISO is facing capacity shortfalls in the next five years.
- MISO's reduction in capacity resources since the *2023 LTRA* has primarily been in the coal fleet with a reduction of 6,200 MW in the first year of the assessment.
- MISO has continued the seasonal capacity auction construct and has found growing evidence of risk in non-peak (e.g., spring and fall) seasons. Countering the risk during these off-peak seasons requires more resources to be available, and this can result in less opportunity for generators to pursue their maintenance needs. During peak seasons when high levels of generator availability are expected, short-notice unplanned outages and higher forced outages could occur as a result of deferred maintenance and challenge reliability.

MISO Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	34,637	31,706	31,618	29,067	26,841
Coal*	27,450	24,362	23,203	17,977	16,744
Petroleum	3,065	3,058	3,060	3,050	3,050
Petroleum*	2,992	2,990	2,992	2,992	2,992
Natural Gas	63,051	62,977	62,616	62,394	62,009
Natural Gas*	62,576	61,543	62,396	62,394	62,009
Biomass	577	571	553	481	481
Solar	8,091	12,538	17,318	19,174	19,763
Wind	6,954	7,236	7,536	7,632	7,660
Conventional Hydro	1,527	1,527	1,527	1,527	1,527
Pumped Storage	2,528	2,528	2,578	2,578	2,578
Nuclear	11,027	11,127	11,127	11,127	11,127
Other	72	72	72	72	72
Battery	208	582	1,011	1,358	1,377
Total MW	132,159	134,892	140,263	139,973	138,018
Total MW*	124,423	126,048	131,562	128,826	127,864
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to MISO are removed from the resource projection where marked.					

MISO Assessment

Planning Reserve Margins

The planning reserves across the MISO footprint in the summer are projected to fall below reserve margin requirements as new generation coming on-line could be insufficient to make up for generator retirements and load growth. It is important to note that there is 56 GW of generation with signed generation interconnection agreements that are yet to come on-line as of July 5, 2024, so there is an opportunity to accelerate installation speeds. However, if resource additions remain at or near historically average levels (approximately 2.3 GW/year average over the last 3 years), PRMs in MISO will fall below the RML reserve margin requirements much faster. Summer PRMs with average resource additions are shown in **Figure 3** as **Reserve Margin-Avg Addition**.

Increased coordination between MISO and its members will be critical to ensuring reliability throughout this resource transition of integrating new intermittent resources and continuing to retire conventional resources. Resource adequacy is a key function of MISO, and the MISO annual planning resource auction (PRA) provides a mechanism for capacity sellers to provide resources that meet the needs of load-serving entities for each of the four seasons in the upcoming year. MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy.

Note: Capacity values for existing resources in tables on p. 41–42 reported by MISO reflect the Seasonal Accredited Capacity (SAC) for Summer. Adjustments and derates are applied to account for factors affecting expected resource output. The RML in the Demand, Resources, and Reserve Margins table on p. 41 is the Unforced Capacity (UCAP) RML, consistent with the reported capacity values.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The introduction of the seasonal PRA and inputs to the process provide more granularity and reliability planning for non-peak hour times during the year. In addition to that change, MISO conducts seasonal resource assessments evaluating generation availability, outage rates, and forecasted load variation across all four seasons. Refer to MISO's Resource Adequacy page.

Probabilistic Assessments

To establish RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. In recent years, MISO improved its LOLE study modeling by including seasonal outage rates, correlated cold weather outage adder profiles, a probabilistic distribution of non-firm support, and 30 years of hourly wind and solar profiles. The LOLE study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they prescribe the minimum PRM that will meet an LOLE of 1 day in 10 years. For more information on the seasonal LOLE Study, visit: https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf.

MISO also performed a probabilistic analysis for the 2024 ProbA. Because MISO used the same model for both the ProbA and the LOLE study, transmission limitations were not included explicitly in the simulations. It is appropriate for MISO to make this assumption for the LOLE study and for determining capacity needs in the MISO system because MISO accounts for transmission limitations elsewhere in the resource adequacy process. However, for an adequacy assessment like the ProbA, the assumption can overvalue resource performance by not accounting for transmission constraints on the deliverability of energy resources. The resulting 2024 ProbA metrics in the table below can understate the risk of unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	68.8	**0.000**	**0.000**
EUE (PPM)	0.108	**0.000**	**0.000**
LOLH (hours per year)	0.393	**0.000**	**0.000**
Operable On-Peak Margin	13.9%	**11.3%**	**11.3%**

* Provides the 2022 ProbA Results for Comparison

MISO is an elevated risk in the *2024 LTRA* because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. All-hours probabilistic studies of the MISO system performed apart from the 2024 ProbA show that shortfall risks can also occur during spring and fall in months that are not peak demand seasons for MISO. The 2022 NERC ProbA Regional Risk Scenario Sensitivity Case included seasonal forced-outage rates and correlated cold weather outages instead of annual average outage rates. MISO found that not only did EUE increase in this sensitivity, but it was also spread throughout the year. Since this study, MISO implemented enhancements to its LOLE study and PRA to address seasonal resource needs.

Demand

The peak demand forecast has increased from the *2023 LTRA* by close to 3 GW (~2.5%), and, while the load forecasts still vary across year to year, the load at the end of the study horizon is ~5 GW higher (~4%). Load-serving entities do not include DR resources in the load forecast, and MISO does not have much insight into the amount of electrification built into the load forecasts. There are other studies at MISO investigating electrification and transportation industry impacts to load forecasts

through the MTEP report. MISO contracted with Applied Energy Group (AEG) to evaluate the MISO footprint's electrification potential. This is documented in the report and has been utilized to update the MISO Futures Report.

Demand-Side Management

DR programs continue to play a significant role in providing capacity to MISO. DR is steady around 8 GW in the summer and 6.5 GW in the winter and is projected to remain constant during the study horizon. MISO's transition to seasonal auctions highlights accreditation of DR and availability during non-summer seasons.

Distributed Energy Resources

Behind-the-meter generation (BTMG) resources contribute about 4.2 GW of capacity across the study horizon, of which ~1.2 GW are distributed PV. MISO's transition to seasonal auctions highlights the availability of DERs across the four seasons, and MISO is working with stakeholders to derive adequate methods of aggregating, reporting, and allowing DER participation in MISO markets.

Generation

The departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years. Solar continues to rise in capacity contributions with a growth of 1,200 MW since the *2023 LTRA* and growth of 3,200 MW in the first year of the study.

There are ~56 GW installed capacity (ICAP) of generation (predominantly solar and battery) with signed generation interconnection agreements in MISO that are projected to come on-line over the next few years. There have been some supply chain and tariff issues that have delayed the commercial operation of these resources.

Due to the large size in the MISO interconnection queue, in the 2022 LTRA (similarly to the OMS-MISO Survey), prospective generation in the queue gets multiplied by a factor based on the study phase and likelihood of that resource coming on-line and gets added into the footprint over time. This reduction is utilized to minimize the impact of prospective generation projects that will not come to fruition through the queue cycle. MISO continues to pursue queue reform efforts to expedite the process by ensuring projects being studied are of adequate certainty.

Transmission

The MISO Transmission Expansion Plan (MTEP) 2021 included the Long-Range Transmission Plan (LRTP) tranche 1 projects totaling $10.3 billion in investment for reliability and economic benefits estimated at $23–52 billion across the MISO footprint while also facilitating the integration of ~53 GW of new resources. In MTEP22, $4.3 billion in transmission projects were approved with $550 million going toward integrating new resources, $550 million going toward baseline reliability projects, and the age and condition category for the rest. MTEP23 includes a further $9 billion investment into the MISO footprint to address the local needs of the region. MISO is also pursuing LRTP tranche 2 with an expected investment of $18-23 billion to implement a 765 kV backbone into the northern portion of the footprint. These projects are expected to be included as part of MISO's MTEP24 project portfolio. In MTEP24, $6.7 billion in transmission projects have been submitted for board approval. MISO is also pursuing LRTP tranche 2.1 with an expected investment of $21.8 billion to implement a 765 kV backbone into the midwestern portion of the footprint. Tranche 2.1 brings reliability and economic benefits estimated at $51.7–101 billion across the MISO Midwest footprint, facilitating integration of ~115.7 GW of new resources.

Energy Storage

MISO's energy storage resources are still primarily in the future with only 84 MW of on-line storage. The MISO interconnection queue does have a significant amount of energy storage upcoming, but these are primarily Tier 3 resources at present.

Capacity Transfers

MISO benefits from significant transfer capacity with neighboring assessment areas due to the geographic location. MISO and SPP continue to finalize the Joint Targeted Interconnection Queue (JTIQ) portfolio to resolve the binding constraints that have traditionally delayed the interconnection process. MISO's utilization of capacity transfers is identified in the LOLE report and memorialized through the MISO PRA.

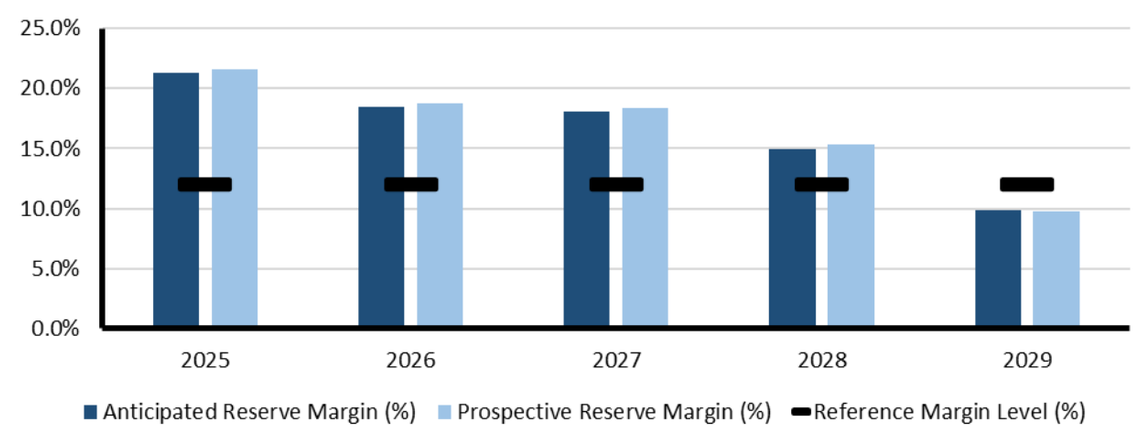


MRO-Manitoba Hydro

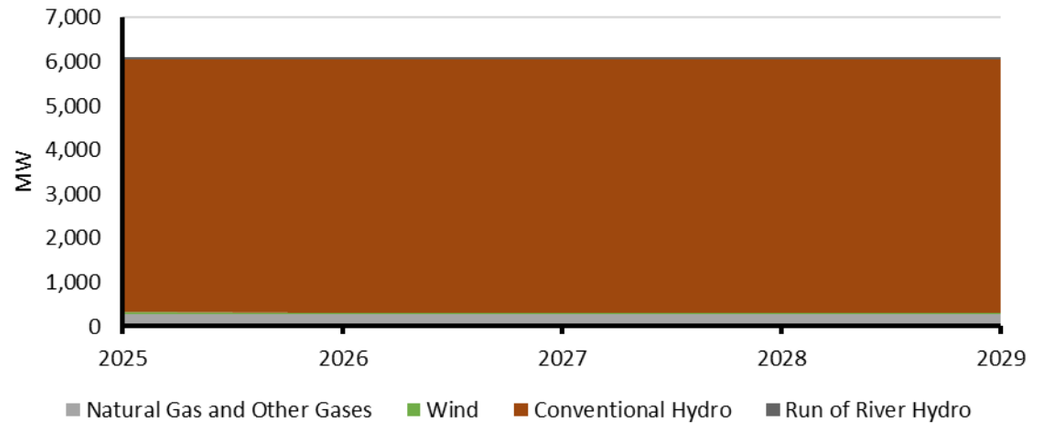
Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 616,000 electric customers in Manitoba and provides approximately 296,000 customers with natural gas in southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Additions: Tier 1	30	51	64	64	64	64	64	64	64	64
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-113	-113	-93	-167	-172	-565	-565	-565	-565	-565
Existing-Certain and Net Firm Transfers	5,786	5,780	5,800	5,726	5,721	5,328	5,328	5,328	5,328	5,328
Anticipated Reserve Margin (%)	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
Prospective Reserve Margin (%)	21.6%	18.8%	18.4%	15.3%	9.8%	0.5%	-0.6%	-1.7%	-3.0%	-4.2%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of EVs. Resource projections have not changed significantly.
- The ARM falls below the RML of 12% beginning in Winter 2029–2030 due to load growth and the reduction of winter import capacity transfers. Manitoba Hydro is performing analysis to inform its integrated resource plan and support future decisions for resources.

MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Natural Gas	278	278	278	278	278
Wind	52	31	31	31	31
Conventional Hydro	5,705	5,726	5,739	5,739	5,739
Conventional Hydro*	5,705	5,726	5,739	5,739	5,721
Run of River Hydro	856	856	856	856	856
Total MW	6,094	6,094	6,107	6,107	6,107
Total MW*	6,094	6,094	6,107	6,107	6,089
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The winter ARM falls below the Reference Margin Level of 12% in 2029–2030. No resource adequacy issues are anticipated until Winter 2029–2030. A Tier 1 project to replace eight older and smaller hydro units is being planned for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project (PREP), approximately 50 MW, replaces the original hydro units that were mothballed or retired based on economics/end of life after about 100 years of operation. No Tier 2 or Tier 3 resources have been assumed to come into service during the assessment period.

The ARM falls below the Reference Margin Level of 12% beginning in Winter 2029–2030 due to net load growth and the reduction of winter import capacity transfers. Manitoba Hydro's Integrated Resource Plan was published in Summer 2023. Further analysis is underway and will help inform Manitoba Hydro's future resource decisions for resources in the 2029 timeframe.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Under normal water conditions, over 95% of the generation in Manitoba Hydro's system is from renewable energy—primarily hydro generation and wind generation. As the operator of a predominantly hydro system, Manitoba Hydro frequently performs an all-hours energy adequacy analysis of the near-term through seasonal time periods to manage reservoir energy storage and meet system demand. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements for maintaining Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to coincide with peak demand hours**.**

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance, such as the water resource conditions, energy and capacity exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast and load variation profiles, demand responses, wind penetration, and generation fleet availability. Most of Manitoba Hydro's generating facilities are use-limited or energy-limited hydro units. The annual energy output of these facilities is mostly dependent on the availability of the water resource. In the 2024 ProbA, Manitoba Hydro examines the impact of the most significant factor over the long run—variations in water conditions.

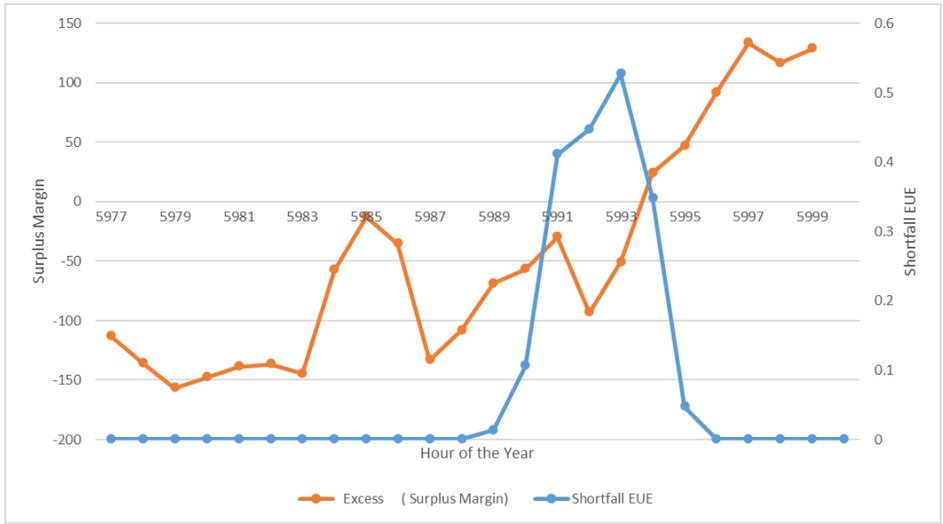
Nonzero LOLH and EUE are observed for both reporting years of 2026 and 2028 and shown in the table below. The LOLH and EUE indices are higher compared to the 2022 assessment mainly due to the increase in the forecast peak demand. Water flow conditions of 10th percentile or lower tend to increase the LOLH and EUE. As a small winter-peaking system on the northern edge of a large summer peaking system (MISO), there generally is assistance available, particularly in MISO's off-peak hours, to provide energy to supplement hydro generation in low-flow conditions in winter. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water flow conditions.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	7.23	**4.711**	**68.870**
EUE (PPM)	0.29	**0.176**	**2.504**
LOLH (hours per year)	0.01	**0.059**	**0.914**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

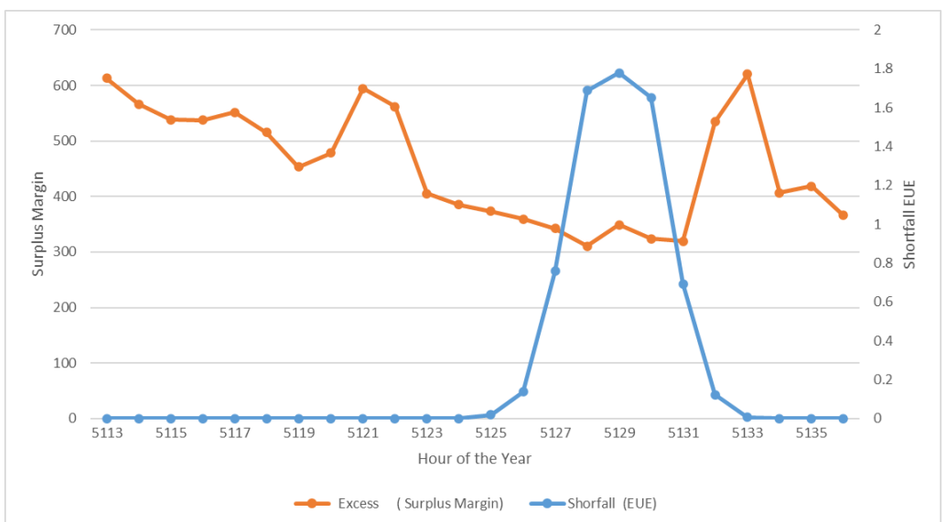
* Provides the 2022 ProbA Results for Comparison

The Monthly EUE and LOLH for 2026 and 2028 show that the highest LOLH and EUE contribution are from July and November, respectively, for 2026 and 2028.

The two graphs below show the hourly energy availability on the Manitoba Hydro system during the ProbA's highest risk days in 2026 and 2028. Surplus energy and shortfall EUE are plotted for the day when the highest loss of load event happens in the ProbA analysis. The Probability Weighted Average (PWA) surplus margin is negative, which indicates possible loss of loads for 2026. However, the PWA surplus energy is higher for 2028 during the day when the highest loss of load event is observed. This is because the surplus is an average for different water year data and the average surplus may not represent the event when loss of load occurs.

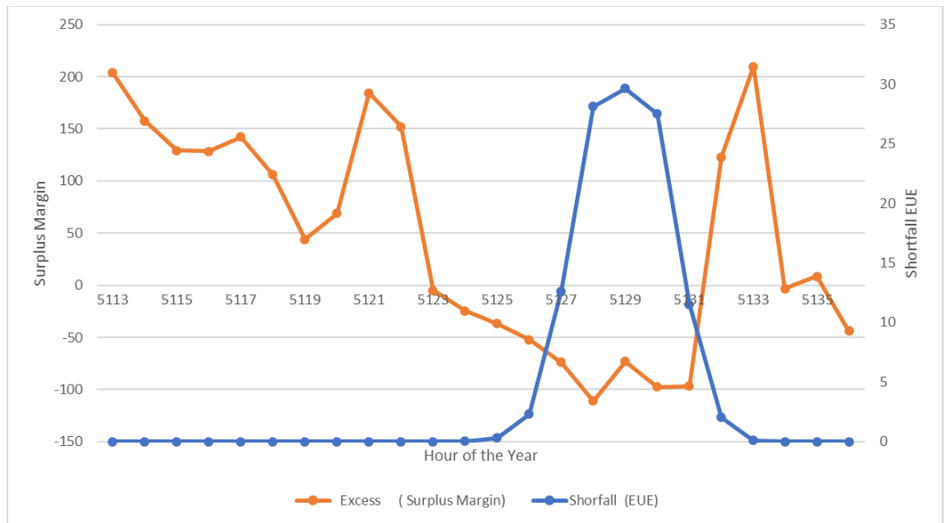


Hourly PWA Surplus Margin and Shortfall EUE for 2026 Representative Risk Day (Summer)



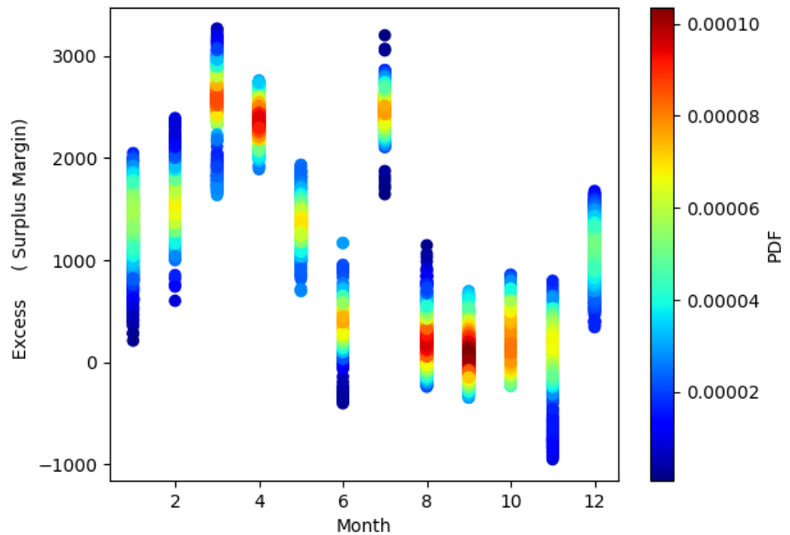
Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer)

The figure below shows the surplus margin and shortfall EUE for 2028 under extreme drought conditions. It can be seen that the loss-of-load event occurs when the surplus margin becomes negative. This surplus energy shown in the figure is the average value for this hour for the entire simulation. It may not represent each individual loss-of-load event during simulation. By plotting the hourly surplus and unserved energy for the low-water years, it is possible to see what risk periods are likely to emerge during extreme drought.



Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer) During Extreme Drought Condition

The scatter plots of surplus energy vs. month for 2026 and 2028 are shown in the figures below. In the months of June and August to November, the PWA surplus energy is relatively lower compared to the other months due to less import from MISO. The PWA surplus energy in July 2026 is high due to higher hydro energy availability for July. However, since PWA is the result of averaging, positive surplus energy does not mean that there will be no loss-of-load events.



PWA Surplus Energy Versus Month for 2026

Demand

Manitoba Hydro's load-growth forecast is up around 3.2% over the assessment period in comparison with the forecast used for the *2023 LTRA*. Factors considered in load-growth projections include economic activity, EV adoption, and demand-side management programs in Manitoba operated by Efficiency Manitoba. EV adoption in Manitoba is being driven in part by proposed federal regulations that are expected to require that at least 20 percent of new vehicles sold in Canada will be zero-emission by 2026, at least 60 percent by 2030, and 100 percent by 2035.

Manitoba Hydro is anticipating load growth of 1.3% over the last half of the assessment period. Limited surplus firm generation resources (resource adequacy) have the potential to slow the connection of very large new industrial loads. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

Demand-Side Management

Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five minutes notice. The program is intended for peak load management. In addition, one product provides 50 MW of contingency reserves, also on five minutes' notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Distributed Energy Resources

Manitoba is not currently experiencing large additions of wind and solar resources being seen in other regions; hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated in the next five years. Additions of energy storage resources in the next 10 years are not anticipated at this time. There is a potential for significant solar DER resources in the latter half of the assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar DER may be dependent on solar PV subsidies and/or incentives.

Generation

Manitoba Hydro is monitoring federal and provincial policy/strategies/regulations related to electricity/energy. The Canadian federal government is considering significant carbon emission regulations. Through Environment and Climate Change Canada, it is taking multiple steps to develop clean electricity regulations that aim for Canadian electricity generation to achieve net-zero greenhouse gas emissions by 2035 by requiring generating units to meet a stringent emissions intensity standard (measured in tons CO2 equivalent per GWh) and pay a price for any remaining emissions. The proposed regulations are still in development and not proposed to be fully implemented until 2035, so it is too early to determine any potential impacts. The Province of Manitoba is developing a provincial energy strategy/policy which may be released in Fall 2024. As details are not yet available, it is too early to determine any potential impacts.

Energy Storage

Manitoba Hydro currently has no energy storage resources, and none have been committed to over the next 10-year period.

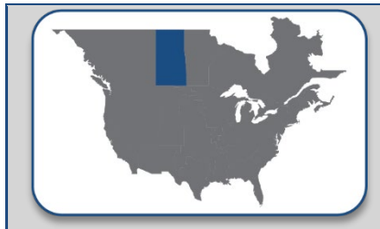
The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources online are hydro generation resources which therefore serve most operational, reliability, and economic functions.

Capacity Transfers

Manitoba Hydro has coordination and tie-line agreements with neighboring assessment areas, such as MISO, SaskPower, and the IESO. In accordance with these agreements, planning- and operating-related issues are discussed and coordinated through respective committees. In addition to this planning and operating committee work, Manitoba Hydro engages with the neighboring utilities of Minnesota Power, Xcel Energy, Otter Tail Power, Minnkota Power Cooperative, SaskPower, and Hydro One regularly to share information, discuss issues, and coordinate activities. Manitoba Hydro also coordinates planning studies (for example, transmission service request studies and requests for generation interconnections) with its neighboring assessment areas. In addition, capacity transfers are verified from a resource adequacy perspective with adjacent regions/entities. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only in extreme conditions occurring simultaneously.

Transmission

Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue that is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end of life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

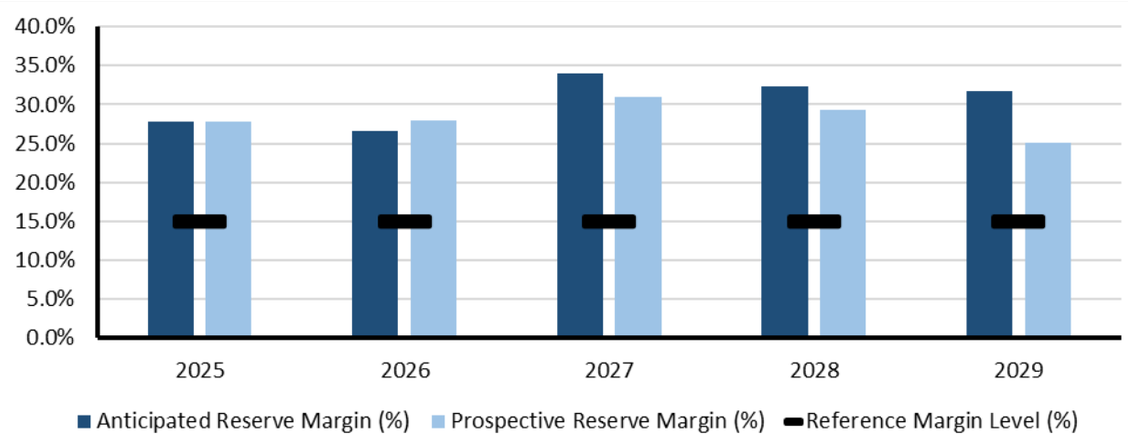


MRO-SaskPower

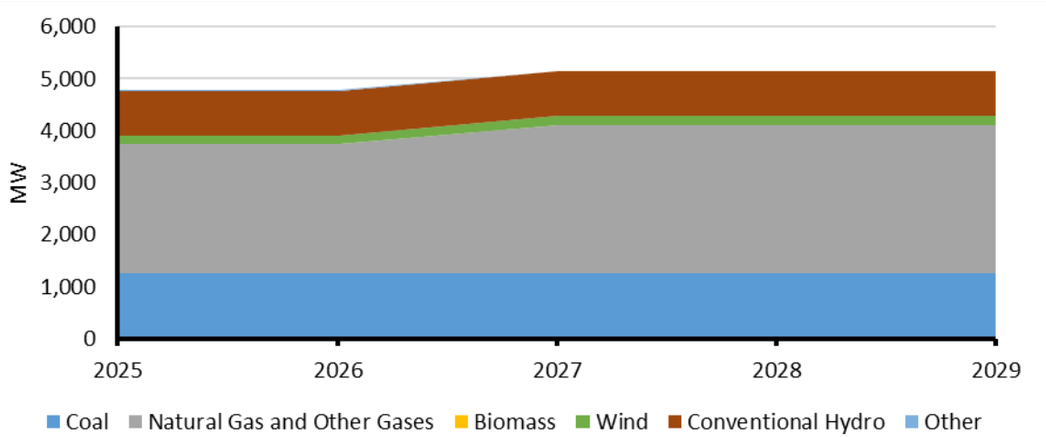
MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles), with a population of 1.2 million and approximately 550,000 customers. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown Corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	3,917	4,025	4,149	4,189	4,210	4,242	4,271	4,315	4,359	4,408
Demand Response	72	72	72	72	72	72	72	72	72	72
Net Internal Demand	3,845	3,953	4,077	4,117	4,138	4,170	4,199	4,243	4,287	4,336
Additions: Tier 1	507	507	883	883	883	883	883	883	883	883
Additions: Tier 2	0	55	175	175	928	928	928	928	928	928
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	290	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,407	4,497	4,582	4,566	4,566	4,489	4,490	4,490	4,552	4,566
Anticipated Reserve Margin (%)	27.8%	26.6%	34.0%	32.4%	31.7%	28.8%	28.0%	26.6%	26.8%	25.7%
Prospective Reserve Margin (%)	27.8%	28%	31.0%	29.3%	25.1%	22.3%	20.8%	19.5%	19.8%	18.7%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- SaskPower's ARM is above the RML throughout the assessment period. No resource adequacy issues are anticipated.
- Saskatchewan is adding approximately 1,064 MW of generation under Tier 1 within the next five years. This includes a 200 MW wind generation facility, two new 377 MW gas generation facilities, and the expansion of two existing natural gas facilities totaling 90 MW. The remaining capacity addition comes from geothermal and flare gas.

MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Coal	1,249	1,249	1,249	1,249	1,249
Coal*	1,249	1,249	1,088	1,088	188
Natural Gas	2,487	2,487	2,863	2,863	2,863
Biomass	3	3	3	3	3
Wind	164	164	162	162	162
Conventional Hydro	856	856	856	856	856
Other	22	17	17	1	1
Total MW	4,781	4,775	5,150	5,134	5,134
Total MW*	4,781	4,775	4,989	4,973	4,073
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-SaskPower Assessment

Planning Reserve Margins

Saskatchewan uses a criterion of 15% as the reference reserve margin and has assessed its PRM for the upcoming 10 years considering the summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available demand response for each year. Saskatchewan's ARM ranges from approximately 19% to 34% and does not fall below the Reference Margin Level.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. Saskatchewan evaluates non-peak hour risks and diminishing capacity credits associated with higher penetration levels of VERs as part of the long-term planning process.

Results of the 2024 ProbA are provided in the table below. Based on the deterministic calculations within this assessment, Saskatchewan's ARM is 27.8% and 34.0% for years 2026 and 2028, respectively. Since the 2022 ProbA, the reported forecast reserve margin for 2026 has remained consistent. The minor variation in the reserve margin is due to a slight change in the schedule of generator outages. EUE is also comparable to the 2022 ProbA, with some variation attributed to updated hydro energy dispatch, which is able to reduce the EUE in the months where it was highest in the prior ProbA.

Base Case Summary of Results			
	2026*	2026	2026
EUE (MWh)	117.0	**75.641**	**8.553**
EUE (PPM)	4.4	**2.807**	**0.300**
LOLH (hours per year)	0.9	**0.547**	**0.078**
Operable On-Peak Margin	24.6	**24.4%**	**30.5%**

* Provides the 2022 ProbA Results for Comparison

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix consists of baseload and fast ramping generation resources, with little penetration of VERs. The main factor contributing to EUE is the amount of planned generator outages. When these short-term reliability issues are identified in advance, they can be mitigated by rescheduling the maintenance. The hourly EUE heat maps in the following figures show that risk of unserved energy is at its highest in the summer months. Risk can also be found in months before or after summer and be driven by unseasonable temperatures driving above-normal demand that coincides with generator maintenance periods. Winter risks of shortfall are associated with extreme cold weather and unexpected generator outages.

Hourly EUE Heat Map : 2026

EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Feb-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-26	1.2	1.2	1.1	1.2	1.2	1.3	1.3	1.3	1.4	1.5	1.6	1.8	1.8	1.7	1.7	1.6	1.6	1.6	1.5	1.5	1.5	1.6	1.5	1.3
Jun-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jul-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0
Sep-26	0.5	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.7	0.8	0.9	1.2	1.2	1.3	1.4	1.5	1.5	1.6	1.4	1.5	1.7	1.3	1.0	0.7
Oct-26	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.4	0.3	0.3
Nov-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Dec-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.1

Hourly EUE Heat Map : 2028

EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feb-28	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-28	0.0	0.0	0.0	-	-	-	-	0.0	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jun-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Jul-28	0.0	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sep-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oct-28	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1
Nov-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Dec-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0

Hourly EUE Heat Maps (in MWh)

Demand

Saskatchewan experiences its peak-season in the winter. Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. The average annual summer and winter peak demand growth is expected to be approximately 1.35% throughout the assessment period.

Demand-Side Management
Saskatchewan's EE and energy conservation programs include incentive-based and education programs focusing on installed measures and products that provide verifiable, measurable, and permanent reductions in electrical energy, and demand reductions during peak hours.

Saskatchewan's DR consists of contracts with industrial customers for interruptible load based under conditions specified in demand response programs. The first of these programs provides a curtailable load, currently up to 72 MW, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours notification time.

Distributed Energy Resources
The current BTM DER installed capacity in Saskatchewan is approximately 50 MW, which includes approximately 48 MW of solar PV and the remaining approximately 2 MW of distributed wind projects. An additional 25 MW of DER solar PV are expected to be added in the next five years. BTM DER installations are incorporated into the load forecast models, which are used in supply and transmission planning study models.

Small power producers contribute an additional 5 MW installed DER capacity (non-BTM) in Saskatchewan. There is currently an existing 8 MW and a potential for up to 20 MW of DERs being added in the next 2 years based on the currently approved Power Generation Partner program. These projects are included as generation additions, but currently their capacity is not considered in reliability planning.

Generation
Saskatchewan is adding approximately 1,064 MW into its resource mix of generation under the Tier 1 category within the next five years. The includes a 200 MW wind generation facility, expansion of two existing natural gas facilities totaling 90 MW, two new natural gas facilities totaling 754 MW, 15 MW of flare gas generation, and 5 MW of geothermal generation.

Under Tier 2, over 1,717 MW of new generation is projected in the assessment period. This includes 754 MW of natural gas, 600 MW of wind generation, 300 MW of utility-scale solar generation, and 63 MW of co-generation.

Generating resources being planned as Tier 2 and Tier 3 will replace generators planned for retirement prior to deactivation. Therefore, Saskatchewan is not expecting any long-term reliability impacts due to generation retirements.

Energy Storage
SaskPower currently has its first battery storage system, a 20 MW/20 MWh unit, under commissioning. There are plans to expand this site by an additional 60 MW/60MWh capacity. The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/voltage control, primary frequency control, and blackstart.

Capacity Transfers
SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is the largest of the three interfaces and is the only interface with long-term firm contracts. Capacity transfers from Manitoba would be limited in the event of a prior outage of tie lines between SaskPower and Manitoba Hydro, as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger generating units in Saskatchewan. Risk mitigation is in place through SaskPower's emergency operating procedure that will allow one or more measures such as short-term imports from other available interfaces (for example Alberta or SPP), initiating demand response and short-term load shedding.

Transmission
SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 650 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 kilometers of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, and installation of two phase-shifting transformer interfaces and two static var systems are being added.

The remaining other transmission projects (approximately 460 circuit kilometers) are under the planning and conceptual phase in the 5-to-10-year planning horizon. These projects are driven by load growth, new generation additions, and reliability needs.

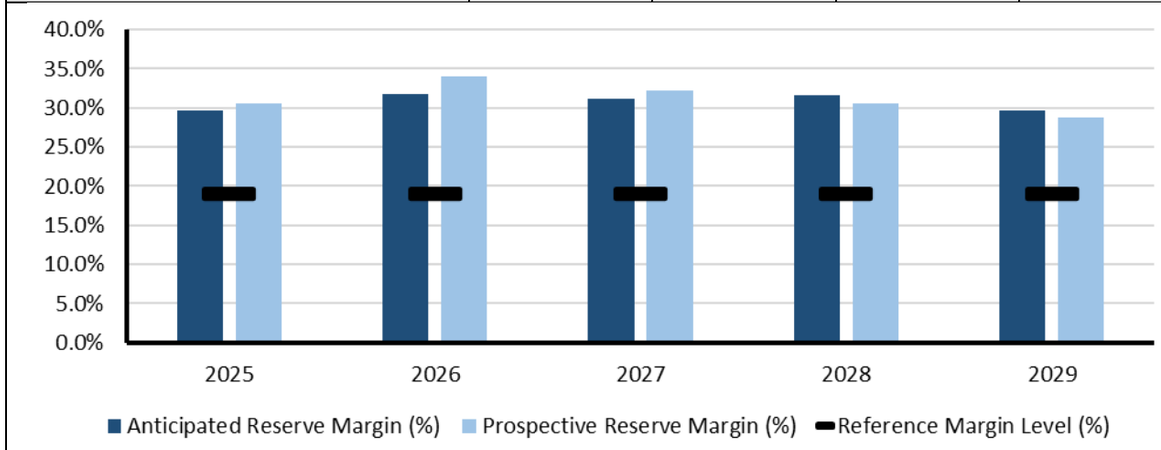


MRO-SPP

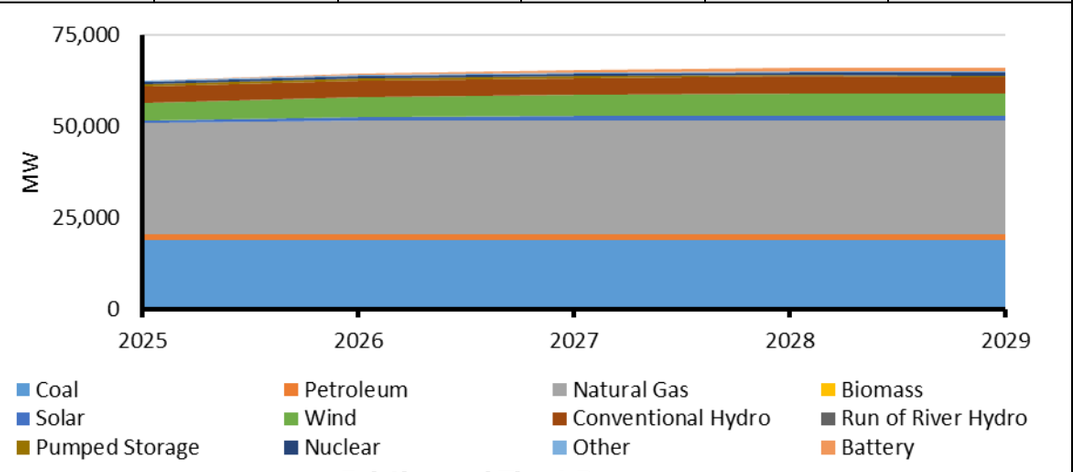
The Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	55,669	57,171	59,031	59,764	60,596	61,963	62,490	63,287	63,764	64,172
Demand Response	1,463	1,771	2,057	2,124	2,172	2,222	2,259	2,465	2,467	2,472
Net Internal Demand	54,206	55,400	56,975	57,640	58,424	59,741	60,231	60,822	61,297	61,700
Additions: Tier 1	2,123	4,966	6,750	7,843	7,957	7,957	7,957	7,957	7,957	7,957
Additions: Tier 2	1,239	2,454	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756
Additions: Tier 3	6,823	16,770	22,655	28,948	28,948	28,948	28,948	28,948	28,948	28,948
Net Firm Capacity Transfers	-1,097	-1,077	-1,136	-1,131	-1,131	-1,131	-1,131	-1,133	-1,133	-1,133
Existing-Certain and Net Firm Transfers	68,157	68,039	67,981	67,984	67,799	67,749	67,253	67,175	67,055	67,094
Anticipated Reserve Margin (%)	29.7%	31.8%	31.2%	31.6%	29.7%	26.7%	24.9%	23.5%	22.4%	21.6%
Prospective Reserve Margin (%)	30.6%	34.1%	32.2%	30.6%	28.7%	25.2%	23.3%	22.0%	20.6%	19.6%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- There are over 8 GW of coal and gas-fired generators that have indicated they plan to retire over the next 10 years in SPP. Without sufficient dispatchable generation, SPP can experience energy shortages when output from wind resources is low.

MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	18,952	18,952	18,919	18,919	18,919
Coal*	17,934	16,647	16,614	14,062	14,062
Petroleum	1,629	1,629	1,631	1,631	1,631
Petroleum*	1,629	1,629	1,575	1,575	1,575
Natural Gas	30,471	31,098	31,098	31,098	31,098
Natural Gas*	29,896	30,220	29,924	29,812	29,812
Biomass	20	20	20	20	20
Solar	495	864	1,149	1,283	1,283
Wind	4,974	5,456	5,928	6,117	5,909
Conventional Hydro	4,526	4,541	4,573	4,605	4,628
Pumped Storage	472	472	472	472	472
Nuclear	769	769	769	769	769
Other	281	281	281	281	281
Battery	41	290	555	930	1,044
Total MW	62,630	64,370	65,392	66,124	66,053
Total MW*	61,037	61,188	61,858	59,925	59,855
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked.					

MRO-SPP Assessment

Planning Reserve Margins

The Existing-Certain and Net Firm Transfers Reserve Margin for the SPP assessment area is projected to fall below the current coincident summer season RML of 19% in 2027. The current summer season reserve margin target for SPP is 15%, but that is based on the non-coincident peak demand of load-responsible entities (LRE) in the SPP assessment area. For purposes of NERC assessments, the 15% target is converted, along with forecasted demand values, to an SPP coincident peak representation based on the latest calculated diversity factor. This results in an RML of 19%. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to be above the 19% RML for the 10-year horizon.

Like the generation unavailability scenario in NERC's *2024 Summer Reliability Assessment*, SPP shows the potential to utilize all the current projected capacity and there could be times of capacity shortfall based on performance impacts during high-load periods. While the potential to all available capacity has a lower probability, the assumptions and projections are based around historical unavailability during peak periods. Current LTRA projections are based on the latest resource adequacy data submittals, which are provided by the LREs and Generator Owners in SPP.

SPP performs a biennial LOLE study to establish a reserve margin target such that the LOLE for the applicable planning year (3- and 6-year study) does not exceed 1 day in 10 years, or 0.1 day per year. The target is determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand with load uncertainty to ensure that the LOLE does not exceed 0.1 day per year.

SPP's 2023 LOLE study results indicate that separate PRMs and capacity requirements are needed for the summer and winter seasons to recognize the seasonal balance of risk. Also, as colder temperature outages increase with the incorporation of additional wind and solar resources, the loss-of-load risk shifts to the winter season. Due to the shift in seasonal risk, it would be appropriate to consider a maximum LOLE threshold for the winter season or incorporation of an EUE reliability metric to complement the LOLE metric.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

As the resource mix continues to change from a standard base load conventional thermal and hydro resources to VERs and short-term energy storage resources (ESR), SPP is incorporating energy adequacy metrics (i.e., EUE) in the determination of PRMs, RMLs, additional reliability policies, and resource accreditation enhancements.

SPP will begin performing a yearly energy adequacy assessment and assessment of reliability attributes (inertia, primary frequency response, ramp, regulation, contingency reserves, voltage and reactive support capability, fuel assurance, flexibility, and blackstart capability). Results of the analysis will be presented annually to SPP stakeholders. The results will also be used to identify needs for new market products, changes to market functionality, or changes to resource adequacy policies and requirements.

The 2024 ProbA performed for the NERC LTRA used assumptions and methods that reflect SPP's Loss of LOLE studies. Results are shown in the following table.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.84	0.00	6.61
EUE (PPM)	0.00	0.00	0.02
LOLH (hours per year)	0.00	0.00	0.01
Operable On-Peak Margin	19.6%	19.5%	16.0%

*Provides the 2022 ProbA Results for Comparison

With the current SPP fleet, there was no loss of load for the 2026 study that included Tier 1 resource additions and 600 MW in generator retirements. The 2028 analysis included both Tier 1 and Tier 2 resource additions and 2,700 MW in generator retirements. The result was a small amount of EUE (6.61MWh) and LOLH (0.01hr/year). The loss of load/hour occurred mostly during the summer season (0.007hr/yr), while the winter season had 0.0004hr/yr. SPP is a summer-peaking region, and the results also supported that. The demand was highest in the afternoons between 13:00 and 19:00 during July and August.

Study improvements for 2024 from the previous NERC ProbAs include additional weather years, seasonal forced-outage modeling, and incremental cold weather outages.

SPP uses the Strategic Energy & Risk Valuation Model (SERVM) for the ProbA. It is a production-cost modeling tool that uses the Monte Carlo method to solve LOLE. Each weather year was simulated 300 times to simulate a multitude of random forced outage draws. Taking 300 draws for each weather year (43) and multiplying by 8,760 hours gets to a total of over 113 million simulated hours, from 1980 to 2022. Each iteration was performed on an 8,760-hour basis.

The study input model consisted of multiple modeling assumptions including multiple historical weather years (1980–2022); hourly load, solar, and wind profiles; load forecast uncertainty; random forced outages draws and variability; physical and economic resource parameters; resource retirements; future resource additions; zonal transmission limitations; and incremental conventional resource forced outages due to extreme cold temperature.

The generating resources modeled in the Probabilistic Assessment reflect the data supplied in the *2024 LTRA*. Existing and projected resources were included in the Probabilistic Assessment along with reported confirmed retirements. As mentioned previously, wind and solar resources, as well as historical weather years, were modeled at historical hourly values using 2012 to 2022 weather years. There were six study zones, and SPP modeled a projected 8,760 hourly demand profile for each area to provide load variability and volatility for chronological hours during simulation. Each local resource zone was modeled with an import and export limit based on a separate power flow transfer analysis. SPP used unit-specific outage rates within the analysis based on NERC Generation Availability Data System (GADS) data from 2015 to 2022. External assistance only included firm contracts from external entities with firm transmission service.

Demand

SPP peak load occurs during the summer season; the 2024 net internal demand forecast is projected to peak at 53,094 MW, which is projected to increase compared to the previous year's LTRA forecast for the 2022 summer season. The diversity factor used to convert the non-coincident peak demand forecast to an SPP coincident peak demand forecast was consistent with the ~3.5% applied in the *2023 LTRA*. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment timeframe. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has observed.

Demand-Side Management

SPP's energy efficiency (EE) and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in EE and DR across the assessment area. In addition, SPP is constructing a new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

Distributed Energy Resources

The SPP Model Development, Economic Studies, and Supply Adequacy working groups are developing policies and procedures around DERs. SPP resource adequacy implemented policies for DERs that mandate certain testing, reporting, and document requirements for resources and programs not registered in the SPP Integrated Market. Accreditation methodology policies are being constructed and are planned to be approved in late 2024.

Generation

SPP currently has approximately 900 MW of installed solar generating facilities. In the ARM calculation, SPP is reporting nameplate capacity of approximately 11 GW of Tier 1, 2, and 3 wind resources, approximately 18 GW of Tier 1, 2, and 3 solar resources, approximately 9.8 GW of Tier 1, 2, and 3 battery resources and approximately 2.7 GW of Tier 1, 2, and 3 gas resources.

In 2024, SPP filed conventional based performance accreditation and effective load carrying capability (ELCC) methodology for wind and solar resources. The goal is for these policies to become effective in the 2026/2027 timeframe for both the summer and winter seasons.

There are concerns of drought conditions impacting the Missouri River and other water sources for generation resources that rely on once-through cooling processes. Low water can impact the generation's capacity output and reduce its ability to support congestion management and serve load. An additional concern could be the impact of river conditions on coal shipments, which could cause generators to run at a derated level to conserve supplies.

Energy Storage

Currently, SPP is studying approximately 17,000 MWs of energy storage and hybrid resource projects in the generator interconnection queue process. There are approximately 50 MWs of energy storage under contract by SPP members. These resources are being modeled as generation in the planning assumptions both near and long term.

Capacity Transfers

The SPP assessment area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. On an annual basis during the model build season, SPP staff coordinate the modeling of transfers between Planning Coordinator footprints. The modeled transactions are fed into the models created for the SPP planning process.

SPP and ERCOT executed a Coordination Plan that superseded the prior coordination agreement. The Coordination Plan addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the

Coordination Plan based on the latest discussions and business decisions, and it was updated in June 2024.

Transmission

In the 2023 ITP Assessment, SPP approved 44 transmission projects, including 150 miles of new transmission. Additionally, the study calls for 93 miles of transmission to be rebuilt.

SPP is observing a number of transmission projects that are currently delayed. SPP is actively tracking these projects and discussing them throughout its stakeholder process. Many delays are driven by supply chain issues or increasing length of construction times. The delays of these transmission projects do not currently seem to be driving reliability issues.

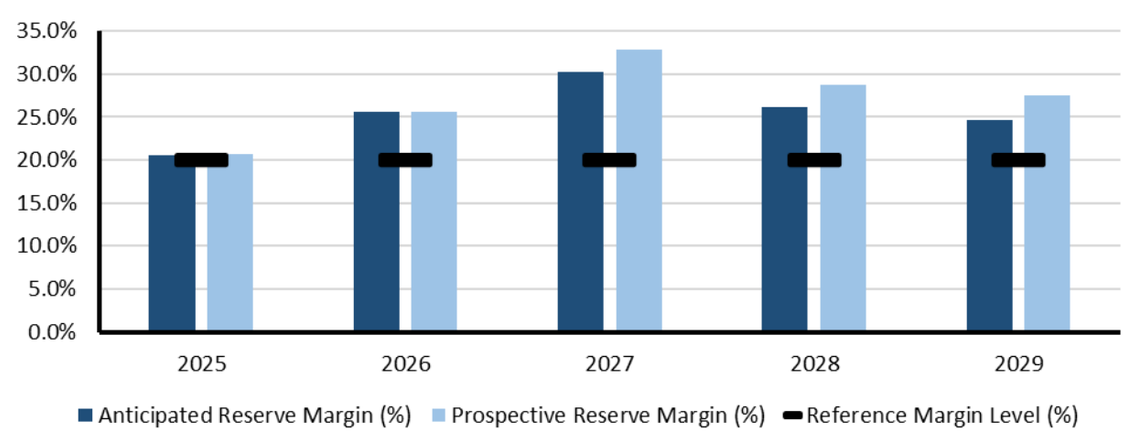


NPCC-Maritimes

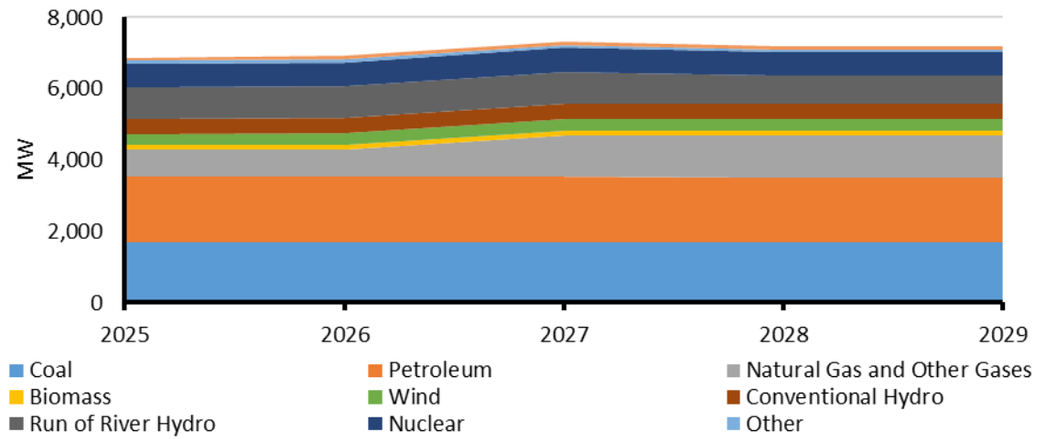
The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two Balancing Authority Areas (New Brunswick and Nova Scotia). It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI) and the northern portion of Maine (NM), which is radially connected to NB. The area covers 58,000 square miles with a total population of 2 million people.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	6,201	6,056	6,095	6,141	6,216	6,272	6,331	6,398	6,474	6,560
Demand Response	274	293	309	317	317	317	317	317	317	318
Net Internal Demand	5,927	5,763	5,786	5,825	5,899	5,954	6,014	6,081	6,157	6,242
Additions: Tier 1	108	171	579	579	579	579	579	579	579	579
Additions: Tier 2	6	4	447	600	1,398	1,398	1,398	1,398	1,398	1,398
Additions: Tier 3	0	13	80	127	197	255	267	279	291	291
Net Firm Capacity Transfers	289	322	215	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	7,038	7,063	6,959	6,771	6,771	6,771	6,679	6,665	6,665	6,752
Anticipated Reserve Margin (%)	20.6%	25.5%	30.3%	26.2%	24.6%	23.4%	20.7%	19.1%	17.7%	17.4%
Prospective Reserve Margin (%)	20.7%	25.6%	32.8%	28.8%	27.5%	26.3%	23.5%	21.9%	20.4%	20.1%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Since the *2023 LTRA*, the overall resource outlook has improved with expected new natural-gas-fired generators coming into service in 2027. Winter peak demand forecasts for this assessment area have risen through 2030; however, ARMs are currently projected to remain above the RML of 20% until 2031 when the ARM dips to 19.7%.

NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Coal	1,696	1,696	1,696	1,696	1,696
Coal*	1,696	1,696	1,396	1,248	467
Petroleum	1,831	1,831	1,825	1,819	1,819
Natural Gas	757	757	1,157	1,157	1,157
Biomass	148	148	148	148	148
Solar	5	5	5	5	5
Wind	293	321	329	329	329
Conventional Hydro	412	412	412	412	412
Run of River Hydro	902	902	902	791	791
Nuclear	663	663	671	671	671
Other	77	77	77	77	77
Battery	72	99	99	99	99
Total MW	6,856	6,911	7,321	7,204	7,204
Total MW*	6,856	6,911	7,021	6,756	5,975
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

NPCC-Maritimes Assessment

Planning Reserve Margins

The NPCC-Maritimes assessment area is comprised of NB, NS, PEI, and NM. The RML for the assessment area is 20%; however, this reserve margin is not mandated. The ARM over the study period for the Maritimes area ranges between 17% and 30% during the winter period and between 88% and 93% during the summer period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

During off-peak hours, the Maritimes area has surplus generation and no constraints with converting the capacity to energy.

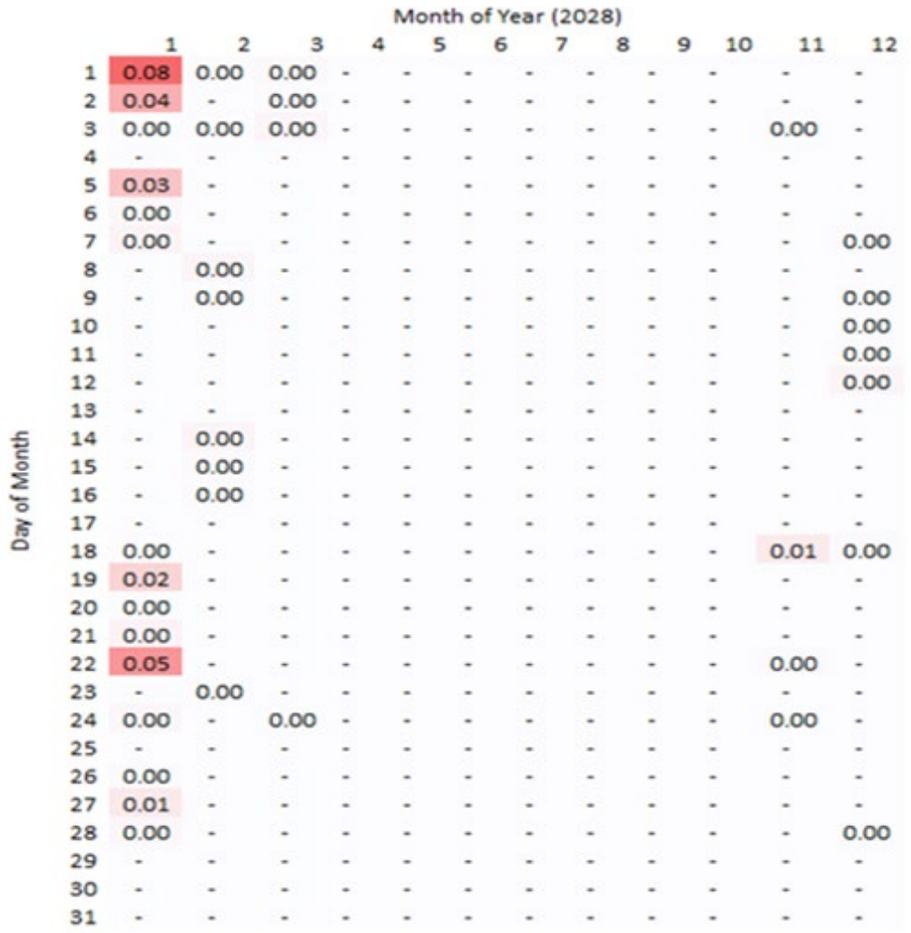
Probabilistic Assessments

Two Balancing Authorities within the Maritimes area are members of NPCC and jointly prepare annual probabilistic assessments that cover three- to five-year forward-looking periods and evaluate the adequacy of the Maritimes' transmission system and resources. In addition, the Maritimes area also supports NERC's annual seasonal ProbAs, which provides an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves. Results of the 2024 ProbA are in the table below.

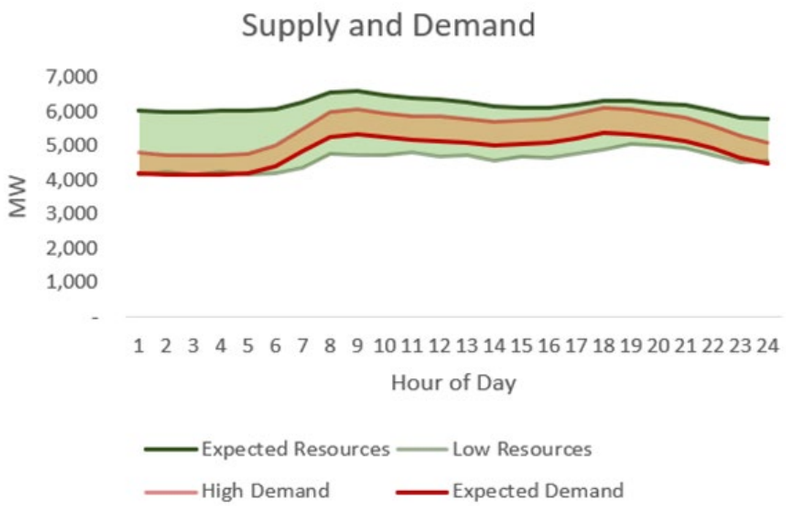
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	3.87	**5.02**	**0.28**
EUE (PPM)	0.14	**0.17**	**0.01**
LOLH (hours per year)	0.07	**0.09**	**0.02**
Operable On-Peak Margin	22.9%	**17.9%**	**29.0%**

* Provides the 2022 ProbA Results for Comparison

The following table of LOLH for 2028 provides a depiction of risks across the calendar year and highlights the concentration of risk in winter. Most load-loss risk occurs in winter months of December–February, with some additional risk occurring in shoulder months. 2026 has a similar risk distribution.



Hourly demand and resource projections for a typical risk-day in 2026 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, the greatest risk for this assessment area is in the form of lower-than-expected resource contributions. If this were to occur, expected demand for all hours would not be met. This risk would be exaggerated by the addition of a higher-than-expected demand event. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period. The area peak loads are expected to increase by 4.2% during summer and by 6.4% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.4% in summer and 0.6% in winter. The Maritimes Area annual energy forecasts are expected to increase by a total of 5.9% during the 10-year assessment period for an average growth of 0.6% per year.

Demand-Side Management

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 20 MW to 169 MW while the annual amounts for winter peak demand reductions rise from 168 MW to 629 MW.[34]

Distributed Energy Resources

The DER installed capacity in NS is approximately 245 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff, and BTM solar.

LTRA wind capacity for NB, NS, and PEI is derated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. BTM solar is assumed to have an ELCC of 0% during winter period. The Maritimes area has shown embedded BTM solar PV projections of 149 MW in 2024 rising to 881 MW by 2034. These projects include distributed small-scale solar (mainly rooftop) that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of the area's system peak, which occurs either before sunrise or after sunset in the winter period.

Generation

NB assumes extending 28 MW of diesel-fired generator starting in 2025 and recently upgraded 290 MW of natural-gas-fueled resource completed in 2023. There are 25.2 MW of wind power purchase agreements (PPA) also slated to start in 2025. An anticipated replacement PPA contract, a long-term firm energy contract from a neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

NB Tier 1 resources include 71 MW of wind and 400 MW of combustion turbines. Tier 2 resources include 200 MW of wind resources and Tier 3 includes 400 MW of wind.

In NS, Tier 1 resources include wind projects with a total nameplate capacity of 473 MW phased in from 2024–2027 with an ELCC of 10%, 150 MW battery storage, 4 MW tidal power, 2 MW biomass unit, and a small 0.14 MW solar farm. Tier 2 resources in NS include 250 MW of battery storage (2026–2032), 600 MW of combustion turbines (2027–2033), a 150 MW conversion of a coal-fired unit to natural gas (2028), 450 MW in conversion of coal-fire units to oil (2030), 220 MW of solar generation,

[34] Current and projected energy efficiency effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

and 416 MW of wind generation. Tier 3 resources in NS include natural gas additions (combustion turbines) of 50 MW in 2029 and new wind generation with a nameplate capacity of 850 MW phased in from 2026–2033. These Tier 3 resource additions are anticipated to facilitate the retirement of additional coal-fired generation by 2030. However, these retirements have not been included in the assessment due to their uncertainty.

Small amounts of new solar generation capacity (Tier 1) of up to 21 MW were being installed in PEI in 2024, along with 10 MW of new hybrid energy storage (Tier 1). PEI also has 30 MW of Tier 2 wind, 111 MW Tier 3 wind, and 140 MW of Tier 3 petroleum-based generation and 10 MW of Tier 3 batteries.

NB derates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI derate wind capacity to 18% and 17%, respectively, of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid-based solar is estimated at zero since the Maritimes area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource phased in from 2026 through 2032. This grid-scale project will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 1 resource starting summer of 2024 and another 10 MW nameplate capacity energy storage system as a Tier 3 resource. This project will provide a storage option for the output from the 10 MW solar facility that is planned to come online during the same time frame. This project will provide fuel savings and may assist in providing additional reliability if a generation outage occurs.

NB Power has not included any energy storage resources in the *2024 LTRA* submission; however, the value of energy storage options is expected to increase as the technology improves and as NB's smart grid network develops. NB Power issued a request for expressions of interest for new renewable generation sources including 200 MW of wind, 15 MW of solar, 5 MW of tidal, and 50 MW of 4-hour duration battery storage in February 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources, such as wind, to provide additional flexibility to the system.

Capacity Transfers

ProbA studies show that the Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission

NS has multiple new transmission line projects compared to the *2023 LTRA*; most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

Reliability Issues

The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual fuel oil/gas, tie benefits, and biomass with no single one type feeding more than about 27% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges for resources during this assessment period.



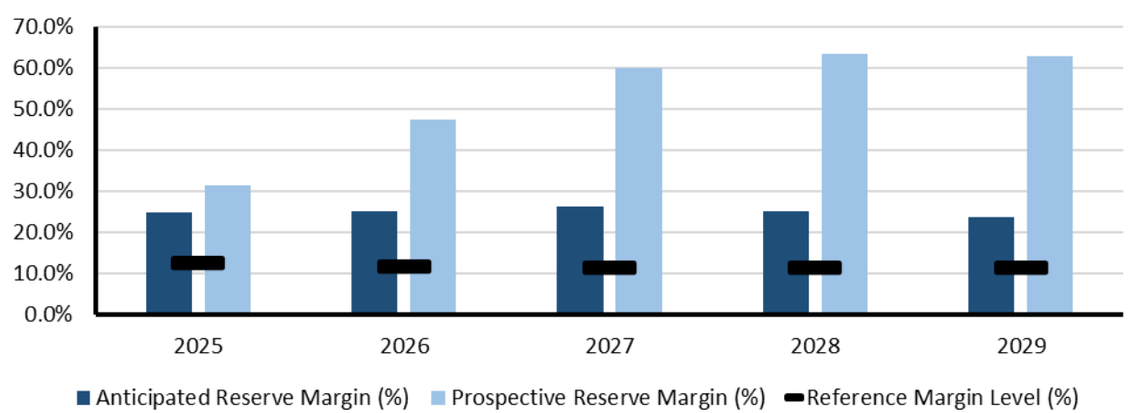
NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England Inc. (ISO-NE). ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. Note: Northern Maine is not directly connected to the transmission system administered by ISO-NE.

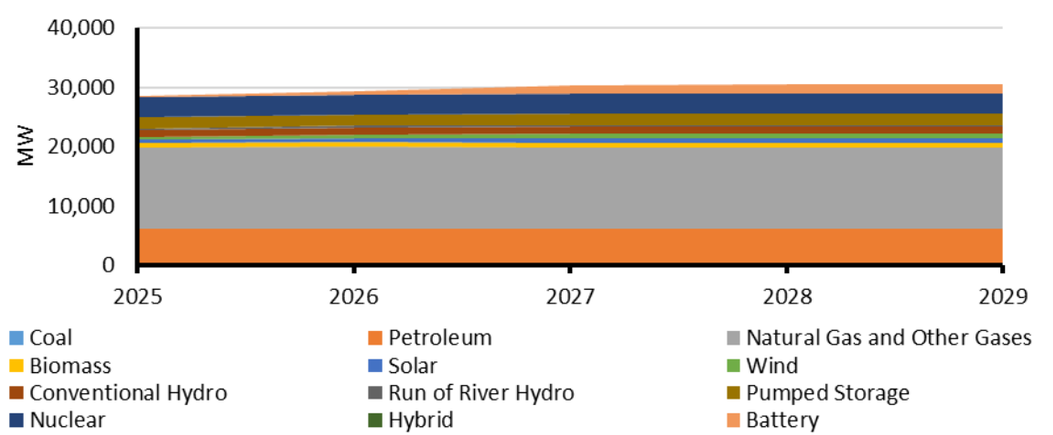
The New England BPS serves approximately 15.1 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	24,579	24,702	24,845	25,076	25,364	25,706	26,100	26,547	27,052	27,567
Demand Response	566	588	544	544	544	544	544	544	544	544
Net Internal Demand	24,013	24,114	24,301	24,532	24,820	25,162	25,556	26,003	26,508	27,023
Additions: Tier 1	660	1,492	2,374	2,748	2,748	2,748	2,748	3,168	3,168	3,168
Additions: Tier 2	337	3,089	5,911	7,084	7,425	7,766	7,766	7,766	7,766	7,766
Additions: Tier 3	1,404	1,765	5,106	7,906	9,221	9,355	9,721	10,432	10,432	10,432
Net Firm Capacity Transfers	1,248	567	465	84	84	84	84	84	0	0
Existing-Certain and Net Firm Transfers	29,354	28,658	28,327	27,946	27,946	27,946	27,946	27,946	27,862	27,862
Anticipated Reserve Margin (%)	25.0%	25.0%	26.3%	25.1%	23.7%	22.0%	20.1%	19.7%	17.1%	14.8%
Prospective Reserve Margin (%)	31.4%	47.3%	60.1%	63.3%	62.8%	62.0%	59.5%	58.3%	55.0%	52.0%
Reference Margin Level (%)	12.7%	11.8%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- New England is forecast to have sufficient ARMs to meet consumer demand for electric energy for the first five years (2025–2029) of the assessment period and not require any Tier 2 resources.
- ISO-NE is addressing the issues brought on by grid transformation through several planning, operational, and market measures. A significant project is the redesign of the capacity market from a forward, annual auction to a prompt, seasonal auction with resource accreditation. The Capacity Auction Reforms (CAR) project began in Q2 2024 and is expected to be in place for the 19th Capacity Commitment Period (CCP 19) beginning on June 1, 2028. Additionally, New England has made tariff modifications to its Longer-Term Transmission Planning process to facilitate the New England states' achievement of their policy-based goals by enabling the development of transmission infrastructure. ISO-NE is also working with regional stakeholders to develop a regional energy shortfall threshold (REST) that defines the region's tolerance for energy shortfalls during low-probability extreme weather conditions.

NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW)[35]					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	541	541	541	541	541
Coal*	445	445	445	7	7
Petroleum	5,703	5,703	5,687	5,687	5,687
Natural Gas	13,651	13,724	13,708	13,708	13,708
Biomass	780	780	780	780	780
Solar	533	663	663	663	663
Wind	391	594	819	819	819
Conventional Hydro	1,209	1,209	1,209	1,209	1,209
Run of River Hydro	289	289	289	289	289
Pumped Storage	1,860	1,860	1,860	1,860	1,860
Nuclear	3,331	3,331	3,331	3,331	3,331
Hybrid	34	35	35	35	35
Other	74	74	74	74	74
Battery	159	584	1,242	1,616	1,616
Total MW	28,553	29,385	30,237	30,611	30,611
Total MW*	28,458	29,290	30,141	30,077	30,077
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to ISO-NE are removed from the resource projection where marked.					

[35] MW totals reflect Existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

NPCC-New England Assessment

Planning Reserve Margins

ISO-NE's installed capacity requirement (ICR) is based on the capacity needed to meet the ISO-NE and NPCC resource adequacy reliability criterion of an LOLE of 0.1 day/year. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period. The latest ICR calculations result in an annual RML of 12.70% in 2025, 11.82% in 2026, and 11.33% in 2027, expressed in terms of the annual 50/50 peak demand forecast published in the *2024 Capacity, Energy, Loads, and Transmission (CELT) Report*. For the years 2028 through 2034, which are beyond the current forward capacity market timeframe, ISO-NE continued to use the last available RML value of 11.33%. The ISO-NE RML is relatively low compared to other regions due to the impact of reflecting external assistance from neighboring control areas and the continued increase in BTM solar facilities.

Non-Peak Hour Risk, Energy Assurance, and Probabilistic-Based Assessments

ISO-NE routinely prepares 21-day energy forecasts. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the forecasted regional supply/demand balance is negative, projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential energy shortfalls is expected to inform market participants such that actions can be taken to increase the expected availability of generating resources as needed.

ISO-NE recently completed work with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. This tool is a framework that has three major steps (weather modeling, risk screening/scenario generation, and 21-day energy assessment), which were subsequently applied to assess the summers and winters of 2027 and 2032.

Probabilistic Assessments

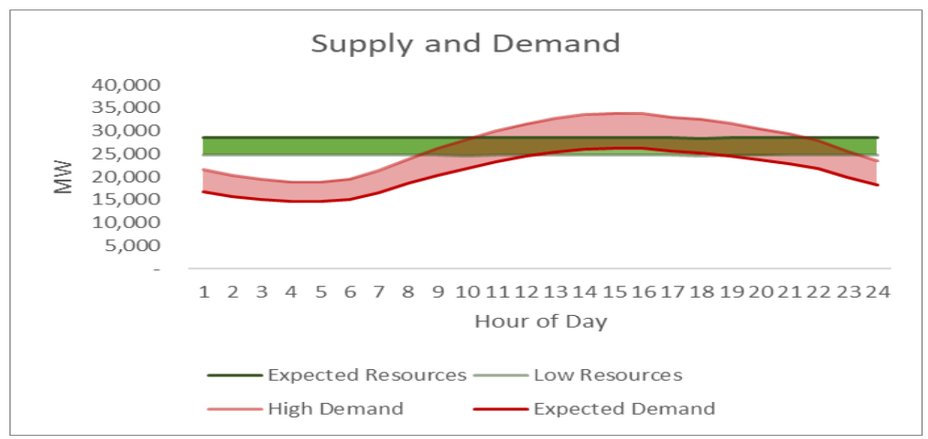
ISO-NE conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC/NERC reliability requirements. In the transmission assessment domain, revisions to ISO-NE planning processes reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated planning activities with neighboring systems will continue and help support the New England states' policy objectives of providing access to a greater diversity of clean resources to meet environmental compliance obligations. Results from the 2024 ProbA, shown in the table below, reveal a slight increase in load-loss and unserved energy risk from the 2022 analysis, but values remain small. ISO-NE is considered to have sufficient resources for the planning horizon to meet NPCC resource adequacy criteria.

Base Case Summary 2024 ProbA of Results			
	2026*	2026	2028
EUE (MWh)	0.551	**10.69**	**7.40**
EUE (PPM)	0.004	**0.09**	**0.06**
LOLH (hours per year)	0.002	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

* Provides the 2022 ProbA Results for Comparison

NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months (June–August).

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contributions meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 25–30% higher than expected, which could cause strain on the system from the hours beginning 10:00 a.m. through 10:00 p.m. Also, below-normal resource performance from unexpected generator outages or low solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from the hour beginning 12:00 p.m. through 7:00 p.m. on a typical peak day. Reliance on external assistance may be necessary in these extreme conditions. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Fuel availability during extreme winter conditions is a persistent reliability concern in New England that is not modeled in detail in the ProbA. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk and were not modeled in the 2024 ProbA.

Demand

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,988 MW from 24,579 MW in 2025 to 27,567 MW in 2034 (roughly 2% decrease from the 2023 forecast in the later years). The corresponding net internal winter peak demand increases by 7,342 MW from 20,639 MW in 2025–2026 to 27,981 MW in 2034–2035 (roughly a 2.5% decrease from the 2023 forecast). Net energy for load is forecast to grow by 24,701 GWh from 119,285 GWh in 2025 to 143,986 GWh in 2034 (roughly 10% decrease from the 2023 forecast). The changes from the 2023 forecast were in part due to continued enhancements of the heating and transportation electrification forecasts.

The higher winter peak growth rate due to anticipated electrification results in significant convergence with summer peak projections by the end of the 10-year period, such that New England's transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by this time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

Demand-Side Management

For the summer of 2025, ISO-NE forecasts 566 MW of controllable and dispatchable demand-side management (DSM) resources, and that amount is projected to decrease by 22 MW to 544 MW by 2034. For the summer of 2025, ISO-NE forecasts 1,873 MW of passive DSM resources (EE and conservation). Demand-side resources are projected to peak in 2030 at 2,117 MW and then begin to decrease to 1,978 MW by 2034. This decrease in the later years is due to expiring EE measures outpacing new passive DSM additions.

Distributed Energy Resources

For summer months, the BTM PV forecast is incorporated as estimated reductions to the ISO-NE gross demand forecast. In 2025, New England forecasts 1,141 MW of peak load reduction (4,533 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,299 MW of peak load reduction (8,217 MW nameplate) by 2034. The BTM PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day. The BTM peak load reduction decreases from 25.2% of nameplate in 2025 to 15.8% in 2034.

ISO-NE recently adopted a new planning procedure (PP12) to formalize and standardize data collection for DERs. Under this procedure, distribution providers would be responsible for providing installation-level data on DERs connected to their system. Additionally, transmission providers would be responsible for providing basic data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits that this procedure will lead to is "*proper accounting for the location, size, and type of DER which will lead to more accurate study outcomes.*"

Generation

The largest change that will impact New England's generation fleet is ISO-NE's CARs.

Specifically, to better ensure power system reliability and cost efficiency as New England's resource mix evolves, ISO-NE is proposing a CAR that would transition the capacity market from a forward/annual market to a prompt/seasonal market with accreditation reforms. This initiative has three primary components that would be in place for the Capacity Commitment Period (CCP) scheduled to start on June 1, 2028.

- Prompt auction: Instead of taking place three years in advance, the capacity auction would take place shortly before the CCP, reflecting more accurate information about projected electricity supply and demand.
- Seasonal CCP: The CCP changes from annual to sub-annual (seasonal) commitment periods to better address the distinct reliability challenges of winter and summer, as well as variations in resource performance from season to season.
- Accreditation reforms: Work began in 2022 via the former "Resource Capacity Accreditation in the Forward Capacity Market" project to identify and implement methodologies that will more accurately reflect resource contributions to resource adequacy in the capacity market. It is critical to the reliable and efficient clean-energy transition that the accreditation methodologies are updated to reflect resources' capabilities and how those capabilities contribute to resource adequacy. This work continues through CAR in the context of the proposed market constructs.

Energy Storage

New England currently has a total of 1,899 MW of energy storage capacity. This number includes about 39 MW of battery storage (BESS) and hybrid solar/battery storage. The largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,860 MW of quick-start 10-minute operating reserve capability, and with full reservoirs, and can deliver over 11,800 MWh of energy to the BPS.

Over the next five years (2025–2029), the nameplate capacity of energy storage devices (BESS, integrated-hybrid, and co-located-hybrid) are projected to increase significantly (Tier #1 [1,607 MW], Tier #2 [5,047 MW], and Tier #3 [4,955 MW]). No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase from the five-year projection. All the above capacity totals reflect summer seasonal claimed capability ratings.

Capacity Transfers

New England is interconnected with the three BAs of Québec, the Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to reduce the installed capacity requirement to meet the regional resource adequacy criterion. Assumed assistance from tie benefits ranges from 1,830 MW in 2025 to 2,115 MW in 2027. Aside from such assistance, ISO-NE's firm capacity imports are projected to range from a maximum of 1,248 MW in the summer of 2025 down to 465 MW in the summer of 2027. There is one long-term firm import contract of 84 MW that extends through the summers of 2028 through 2032. There are currently no firm imports projected for the summers of 2033 and 2034. In addition, there are no firm exports identified over the 10-year assessment.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs using IBRs, and changes to mandatory planning criteria promulgated by NERC, NPCC, and regional stakeholders have driven the need for longer-term transmission assessments.

The future reliable and economic performance of the BPS is expected to be maintained as a result of approximately $1.5 billion of planned transmission upgrades over the next 10 years. Generator retirements, the integration of many DERs and VERs, the use of IBR technologies, and issues rising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. Interregional import capability will also increase with the completion of the 1,200 MW HVdc New England Clean Energy Connect (NECEC) tie line between Québec and Maine, scheduled to be in service by the beginning of 2026.

In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. Transmission assessments and resultant plans are being developed throughout the region to meet these future system needs.

Reliability Issues

New England's BPS is transitioning to a system with unprecedented demand growth, due to electrification of heating and transportation, and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE is engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall BPS reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected in service dates for system upgrades due to supply chain issues. In these cases, ISO-NE develops operating plans to work around any issues caused by these delays. Additionally, the New England Transmission Owners have indicated that supply chain issues are causing a notable increase in project costs.

New England has already experienced constraints on electric energy production due to constraints on fuel infrastructure that have an impact on the power sector during winter. In response, ISO-NE has been a key player at the national level in promoting BPS reliability through sharing of lessons learned, best practices, and, more recently, through the performance of more detailed and in-depth BPS energy assessments. Additionally, to address winter energy security challenges, ISO-NE and regional stakeholders developed and put in place a two-year program to compensate certain resources that provide energy security during the winters of 2023–2024 and 2024–2025 (from December to February). ISO-NE's Inventoried Energy Program (IEP) is a voluntary program designed to provide incremental, winter-period compensation for participants that maintain inventoried energy for their assets during extreme cold periods when energy security is most stressed.

The just-in-time delivery of a generator's fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy—either through long-term energy storage solutions that can capture and store renewable power or through the use of dispatchable resources.

ISO-NE is actively working on numerous major projects to prepare for the clean energy transition and ensure continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

- **CAR Project**
- **Operational Impacts of Extreme Weather Events**
- **Regional Energy Shortfall Threshold**
- **Day-Ahead Ancillary Services Initiative**
- **Economic Planning for the Clean Energy Transition (EPCET)**
- **Extended-Term Transmission Planning Tariff Changes**
- **Longer-Term Transmission Studies**
- **Storage As Transmission Only Asset (SATOA)**
- **FERC Order No. 1920 Project**
- **FERC Order No. 2023 & 2023-A Project**
- **FERC Order No. 2222 Project**
- **FERC Order No. 881 Project**

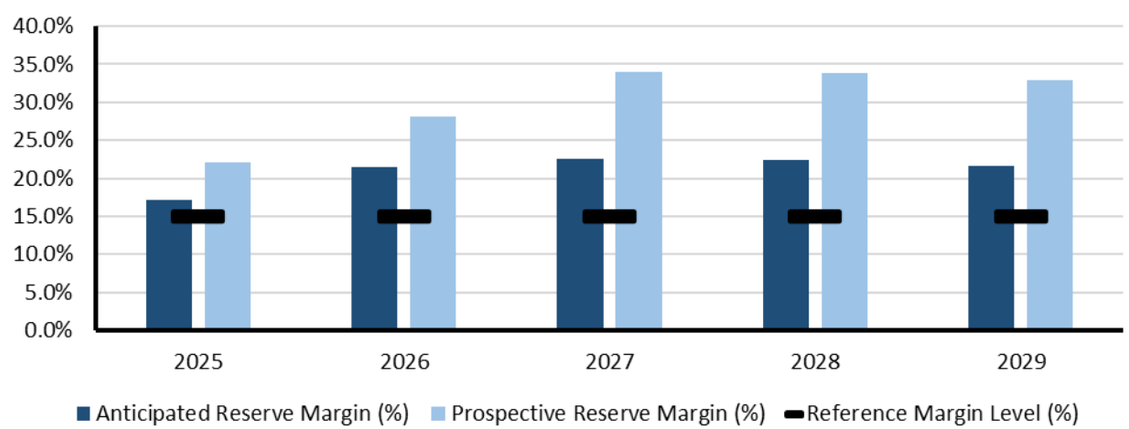


NPCC-New York

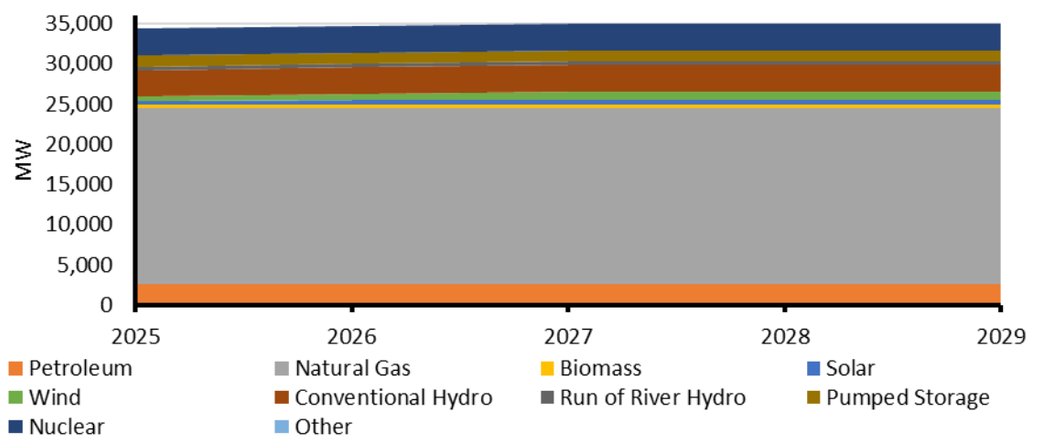
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). The NYSRC approved the 2025–2026 IRM at 24.4%.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	31,650	31,900	32,110	32,130	32,340	32,580	32,880	33,320	33,830	34,210
Demand Response	897	897	897	897	897	897	897	897	897	897
Net Internal Demand	30,754	31,004	31,214	31,234	31,444	31,684	31,984	32,424	32,934	33,314
Additions: Tier 1	495	858	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Additions: Tier 2	1,558	2,090	3,572	3,572	3,572	3,572	3,572	3,572	3,572	3,572
Additions: Tier 3	1,381	4,384	6,384	7,928	8,383	8,383	8,383	8,383	8,383	8,383
Net Firm Capacity Transfers	1,600	2,880	3,186	3,186	3,186	3,186	3,186	3,186	3,186	3,186
Existing-Certain and Net Firm Transfers	35,511	36,790	37,096	37,097	37,097	37,097	36,687	36,687	36,687	36,687
Anticipated Reserve Margin (%)	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
Prospective Reserve Margin (%)	22.1%	28.2%	34.0%	33.9%	33.0%	32.0%	29.5%	27.7%	25.7%	24.3%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Public policies, such as New York state's 2019 Climate Leadership and Community Protection Act (CLCPA), are driving rapid changes in New York's electric system, impacting how electricity is produced, transmitted, and consumed. The transition to a cleaner grid in New York is leading to an electric system that will be increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation.
- Recent assessments reveal that reliability margins are shrinking. Electrification programs are increasing the demand for electricity and placing New York on a trajectory to be a winter-peaking system in the future. Largely in response to public policies, fossil fuel generators are retiring at a faster pace than new renewable supply is entering service. The potential for delays in construction of new supply and transmission, higher than forecasted demand, and extreme weather could threaten reliability and resilience of the New York grid.
- NYISO's reliability studies identified actionable reliability needs starting 2025 in New York City. The reliability need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by state legislation and regulations promulgated by the New York State Department of Environmental Conversation, commonly known as the Peaker Rule,[36] to limit emissions. Following a solicitation for proposed solutions to the reliability need, NYISO retained several plants in New York City that would have otherwise been deactivated to comply with the Peaker Rule. NYISO's 2024 Reliability Needs Assessment (RNA), targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations.
- Driven by public polices, new supply, large loads, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection process balances developer needs with grid reliability. Efforts are underway to make this process more efficient while protecting grid reliability. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway in NYISO's Public Policy Transmission Planning Process.
- To achieve the mandates of the CLCPA, new dispatchable emission-free resources (DEFR) with the necessary reliability services will be needed to replace the capabilities and attributes of today's generation. These types of resources, which can achieve the necessary attributes by a combination of solutions, must be significant in capacity and have attributes similar to traditional generation plants, such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, provide ERSs, and adapt to meet rapid, steep ramping needs. Such new emission-free supply is not yet available on a commercial scale.
- New wholesale electricity market rules are supporting the grid in transition. These markets are critical for a reliable transition. Wholesale electricity markets are open to significant investment in wind, solar, and battery storage as well as distributed energy resources. Demand management programs are also under development as a measure to facilitate achievement of CLCPA targets. By lowering the peak load and avoiding system buildout to serve the highest demand hour, fewer DEFRs will be needed and fewer fossil fuel-fired plants will be needed to meet lower peaks during the transition.

[36] Subpart 227-3 of Title 6 of the New York Codes, Rules an3,323d Regulations.

NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Petroleum	2,631	2,631	2,631	2,631	2,631
Petroleum*	2,628	2,628	2,628	2,628	2,628
Natural Gas	21,907	21,907	21,907	21,907	21,907
Biomass	334	334	334	334	334
Solar	545	586	586	586	586
Wind	461	785	1,070	1,070	1,070
Conventional Hydro	3,323	3,323	3,323	3,323	3,323
Run of River Hydro	413	413	413	413	413
Pumped Storage	1,410	1,410	1,410	1,410	1,410
Nuclear	3,330	3,330	3,330	3,330	3,330
Battery	50	50	50	50	50
Total MW	34,405	34,769	35,054	35,054	35,054
Total MW*	34,401	34,765	35,051	35,051	35,051
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to NYISO are removed from the resource projection where marked.					

NPCC-New York Assessment

Planning Reserve Margins

The LTRA anticipated and prospective margins are above 15% with the exception of year 9 (2033) and year 10 (2034). However, the system margins are narrowing throughout the assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's 2024 Reliability Needs Assessment, which is underway and targets completion in Q4 2024, will likely identify reliability criteria violations.

NYISO also provides support to the NYSRC in conducting an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the NPCC and NYSRC resource adequacy criterion of "1 day in 10 years." The current IRM for the 2024–2025 capability year is 22% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 22%. Additionally, the NYISO performs an annual study to identify the locational minimum installed capacity requirements (LCR) for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

New York State's CLCPA mandates to decarbonize span over all major industries and are a main driver for the electric system changes. NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, the system will need dispatchable emission-free resources (DEFR) and long-duration resources to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource adequacy studies through NYISO's reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments, including a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO's Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement and certain combined cycle gas units participate in a "Minimum Oil Burn" program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and Other Studies)

NYISO performs probabilistic assessments using GE's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes as well as to determine annual IRM LCRs. NYISO also pursued capacity accreditation market rules to more accurately reflect capacity market suppliers' contributions to resource adequacy. These new market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors (CAF) for various capacity accreditation resource classes. The groundbreaking proposal was accepted by FERC in May 2022. The CAFs will reflect the marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

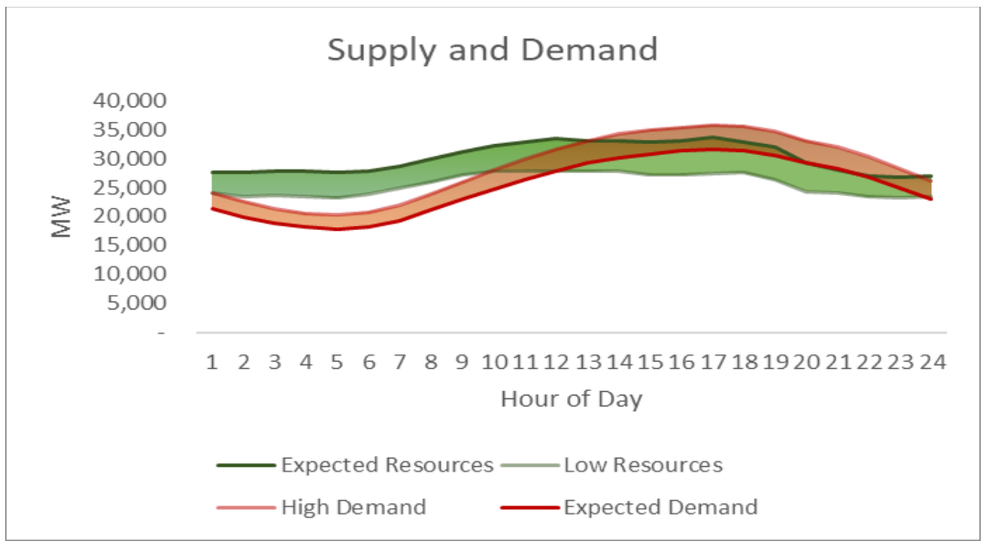
Additionally, NPCC provides results into NERC's ProbA process under the LTRA. The results from the ProbA performed in 2024 by NPCC are shown below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.06	1.91	1.30
EUE (PPM)	0.00	0.01	0.01
LOLH (hours per year)	0.00	0.01	0.01
Operable On-Peak Margin	16.7%	14.0%	15.0%

* Provides the 2022 ProbA Results for Comparison

Most load-loss and unserved energy risk is in the summer months of late June through August.

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contribution is enough to meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 10–13% higher than expected, which could cause strain on the system from the hours beginning 2:00 p.m. through 11:00 p.m. Also, below-normal resource performance from unexpected generator outages or low-solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from hour beginning 12:00 p.m. through 12:00 a.m. on a typical peak day. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

NPCC's Directory 1 defines a compliance obligation for the NYISO, as a Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning horizon. NYISO delivers a report every year under this study process to verify the system against the 1-day-in-10-years LOLE criterion, which is usually based on NYISO's latest available reliability assessment results and assumptions. NYSRC Reliability Rules have recently included a requirement defining NYISO's obligation to deliver a Long-Term Resource Adequacy Assessment Report every year during which the NYISO publishes a Reliability Needs Assessment (RNA) and an annual update in the intervening year between RNAs.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York Control Area (NYCA). The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak is projected to shift into the evening as additional BTM solar is added to the system and as EV charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the forecast horizon, BTM solar generation becomes less coincident with the NYCA peak hour, and BTM solar coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the Climate Impact Study Phase I report are included in NYISO's end-use models and are reflected in the baseline, policy scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The 10-year annual average energy (+1.7%) and summer peak demand (+0.8%) growth rates are higher than last year's forecast. Increases in growth rates relative to the prior forecast are primarily attributed to the significant impacts of interconnecting large load projects. Baseline energy and coincident peak demand increase significantly throughout the 30-year forecast period, driven largely by large load project growth in the early forecast years and electrification of space heating, non-weather sensitive appliances, and EV charging in the outer forecast years. New York is projected to become winter-peaking in future decades due to space heating electrification and EV penetration. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

Demand-Side Management

NYISO is working on developing market concepts to encourage the participation of flexible load, which will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy policies. Many of New

York's utilities are piloting several load management programs (e.g., smart EV charging, home-thermostat use, and integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

DR participation for the summer capability period has increased slightly from 1,234 MW to 1,281 MW since the *2023 LTRA*. There are currently 425 MW of DR participating in ancillary services programs and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

NYISO has implemented in 2024 a plan to integrate DERs, including DR resources, into the markets it administers. The DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, provides a single participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO deployed its DER participation model in 2024.

Generation

The pace of renewable project development and existing generation retirement is unprecedented and driving a need to increase the pace of transmission expansion, clean dispatchable generation, and demand management programs development. In general, resource and transmission expansion take many years from development to deployment. Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. Significant new resource development will be required to achieve energy targets under the CLCPA. The total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply. The sheer scale of resources needed to satisfy system reliability and policy requirements within the next 20 years is unparalleled.

Currently, NYISO's interconnection process contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

For the 2024 RNA, gas availability is derated during winter to further account for cold weather risks.

To achieve the CLCPA mandate of an emission-free grid by 2040, DEFRs must be developed and deployed throughout New York. DEFRs that provide sustained on-demand power and system stability will be essential to meeting policy objectives while maintaining a reliable electric grid. While essential to the grid of the future, such DEFR technologies are not commercially available today.

ERSs usually provided to the system by synchronous fossil generation will continue to be necessary. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities, as well as DEFRs, will likely be part of this transformation. In May 2023, the New York State Public Service Commission (PSC) initiated a process to examine the need for resources to ensure the reliability of the CLCPA mandate for a zero-emissions electric grid by 2040. The PSC seeks to identify innovative technologies to ensure the reliability of a zero-emissions electric grid. Numerous other initiatives at both state and federal levels are in progress and may impact the grid of the future.

Energy Storage

Storage resources can help to fill in voids created by reduced output from renewable resources. However, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-Located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is developing a model for hybrid storage resources to allow multiple technologies at the same point of interconnection to participate in the market as a single resource. Additionally, the resource adequacy simulation tools (such as GE's MARS) used in system planning by NYISO and for setting the IRMs were enhanced to include energy-limited resources models that allow for charging and discharging and also include temporal constraints (e.g., hours/days or hours/month).

Capacity Transfers

The models used for NYISO's reliability planning studies include firm capacity transactions (purchases and sales) with the neighboring systems as a base-case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVdc line from Québec to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO employs limiting emergency assistance from neighbors by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighbors.

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York's imports and exports of energy could vary significantly due to the resulting changes in neighboring grids. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York's and other regions' grids evolve, continuous monitoring and collaboration with our neighboring states will be required.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest.

Key transmission projects under development and accounted for in the reliability models include the following:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City
- The AC Public Policy Transmission Projects that consist of upgrading transmission corridors in central New York and the lower Hudson Valley, which projects target completion of the majority of the components by December 2023
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new dc tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emissions-free resources while maintaining the reliability of New York's electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state's electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York's clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC's consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

Reliability Issues

The 2024 RNA, targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations. Accounting for these factors, the planned bulk power transmission system will not be able to securely and reliability serve the forecasted demand in New York City. When accounting for forecasted economic growth and policy-driven increases in demand, the New York City (Zone J) will be deficient starting in summer 2033 by as much as 17 MW for 1 hour and increasing to 97 MW for 3 hours in summer 2034 on the peak day during expected weather conditions. The Reliability Need occurs within the transmission district owned by Consolidated Edison Company of New York, Inc. ("Con Edison"). Con Edison is designated as the Responsible Transmission Owner in the NYISO's transmission planning process and required to submit a regulated backstop solution to address the need, which may be triggered if sufficient market-based solutions do not materialize.

Prior to the 2024 RNA, the NYISO completed the 2023 Q2 STAR on July 14, 2023. This assessment found a reliability need beginning in summer 2025 in New York City primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by the New York Department of Environmental Conservation (DEC) Peaker Rule. The reliability need is a deficiency in the transmission security margin. Specifically, the New York City zone is deficient by as much as 446 MW for a duration of nine hours on the peak day during expected weather conditions (95 degrees Fahrenheit) when accounting for forecasted economic growth and policy-driven increases in demand. To ensure the continued reliability of electric service in New York City, NYISO designated the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges as necessary for reliability to temporarily remain in operation after the Peaker Rule compliance date until permanent solutions to the need are in place, for an initial period of up to two years (May 1, 2027).

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future. The

system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York's current reliance on neighboring systems is expected to continue through the next 10 years. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest.

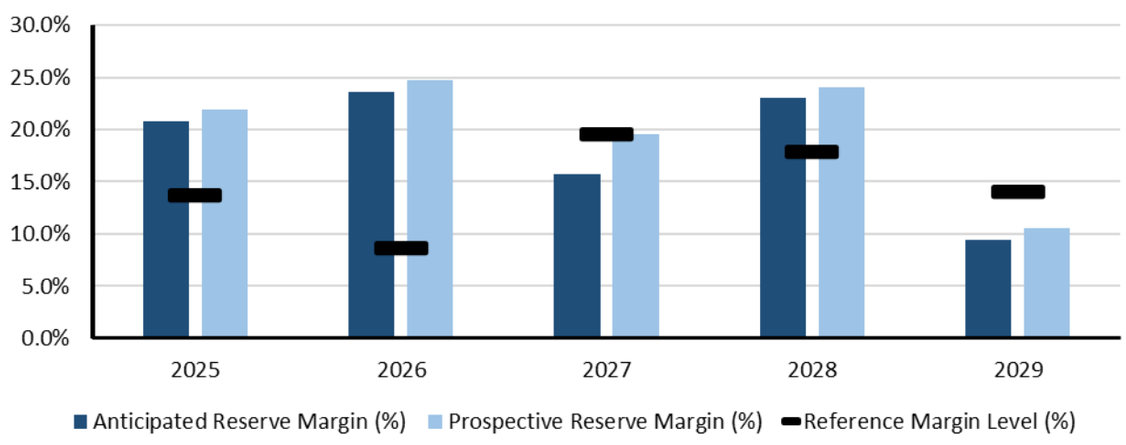


NPCC-Ontario

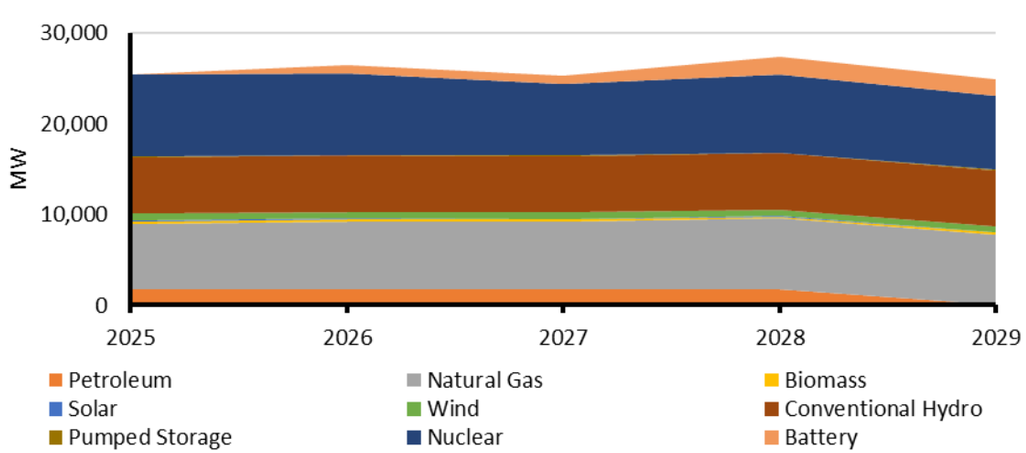
NPCC-Ontario is an assessment area in the Ontario province of Canada. The IESO is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	23,385	23,860	24,264	24,627	25,248	26,038	26,473	27,373	27,974	28,789
Demand Response	1,791	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914
Net Internal Demand	21,594	21,946	22,350	22,713	23,333	24,123	24,559	25,458	26,060	26,875
Additions: Tier 1	617	1,737	1,735	3,012	3,302	3,300	3,843	4,385	4,384	5,128
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	600	600	500	600	600	600	600	0	0	0
Existing-Certain and Net Firm Transfers	25,470	25,394	24,133	24,924	22,242	22,051	20,660	20,705	20,671	20,257
Anticipated Reserve Margin (%)	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
Prospective Reserve Margin (%)	22.0%	24.8%	19.5%	24.1%	10.5%	6.1%	0.8%	-0.5%	-2.9%	-4.6%
Reference Margin Level (%)	13.7%	8.6%	19.5%	17.8%	14.1%	9.4%	17.2%	8.1%	6.8%	8.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- While potential reserve margin shortfalls are forecast for 2027 and 2029, they are mainly driven by changes in the IESO's resource adequacy assessment methodology since the *2023 LTRA*. Last year, reserve margin calculations included the continuation of existing resources (following contract expiry) for the entire outlook period. For this LTRA, reserve margins reflect the contribution of existing resources only until the end of their contract or commitment period. This change to the methodology is more conservative and helps to better identify system needs in the IESO's planning assessments to establish resource acquisition targets and address anticipated needs.
- The IESO has two capacity sharing agreements with Hydro-Québec providing firm summer capacity, which will help to address future shortfalls this decade.
- The IESO has completed a broad set of actions to secure new capacity for this decade to ensure that Ontario's power system needs are met during a period of nuclear retirements and refurbishments and economy-wide demand growth. This includes securing long-term commitments amounting to 2,195 MW of new capacity to be on-line by 2028, with early operation incentives anticipated to bring a portion on-line as early as 2027 to help alleviate the reserve margin gap.
- The annual capacity auction, which helps to meet needs in the short term by securing capacity for up to one year at a time, has historically secured more capacity than targeted. Trends suggest that this should continue, as the November 2024 auction (which will help to ensure reliability through summer 2025 and winter 2025–2026) also secured more capacity than targeted.
- The IESO is taking steps that will address future shortfalls around the end of this decade and heading into the 2030s. The next round of medium- and long-term procurements was recently launched to ensure that capacity and energy needs continue to be met. The second medium-term procurement aims to re-commit existing resources with contracts expiring over the 2026–2029 period, while the second long-term procurement aims to secure capacity and energy from new resources (to be online as early as 2029), to meet needs emerging in the early 2030s.
- The IESO is also responsible for implementing new provincial policy as outlined in the Ontario government's July 2023 Powering Ontario's Growth report, which includes developing new nuclear projects, transmission expansions, and expanded conservation and demand management programs. The IESO will also incorporate changes stemming from the federal release of the final Clean Electricity Regulations, anticipated toward the end of 2024.

NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Petroleum	1,695	1,695	1,695	1,695	5
Natural Gas	7,275	7,465	7,465	7,847	7,761
Biomass	297	294	257	209	209
Solar	100	100	100	100	100
Wind	743	722	711	711	602
Conventional Hydro	6,215	6,212	6,212	6,212	6,202
Pumped Storage	38	38	38	38	38
Nuclear	9,008	9,008	7,895	8,639	8,142
Battery	118	998	996	1,886	1,885
Total MW	25,487	26,531	25,368	27,336	24,944

Planning Reserve Margins

The ARM falls below the RML starting in 2027. While expected nuclear retirements, the ongoing nuclear refurbishment program, and demand growth are resulting in increased needs this decade, the reserve margin shortfalls indicated in 2027 and 2029 are primarily driven by the change in the IESO's resource adequacy assessment methodology described above.

Mid-decade capacity needs that were identified in the 2022 *Annual Acquisition Report* have been met through a series of competitive procurements. Since May 2023, the IESO has secured over 3,600 MW of new capacity from battery storage, natural gas, and biogas facilities, expected to come on-line between 2025 and 2028. In addition, the 2023 capacity auction secured 1,867 MW of summer capacity and 1,311 MW of winter capacity above targets of 1,400 and 850 MW, respectively. The IESO continues to actively procure existing and new resources to meet longer-term needs, using the mechanisms in the Resource Adequacy Framework.

Ongoing refurbishments at Bruce Nuclear Generating Station (NGS) and Darlington NGS will see between one and three reactors concurrently off-line through Summer 2033. Refurbishments remain on or ahead of schedule and outages continue to be managed to limit impacts to the grid. Following the return to service of refurbished units at Bruce, each unit is expected to be uprated, with the additional capacity anticipated to be available in the early 2030s.

The Ontario government has also announced a plan to deliver three additional small modular reactors in addition to the 300 MW unit already underway (anticipated on-line in 2029). The provincial government's July 2023 Powering Ontario's Growth plan directed the IESO to conduct an impact assessment on potentially adding 4,800 MW of large-scale nuclear capacity to Bruce NGS. Approval was granted from the federal nuclear regulator in October 2024 to extend operation of four units at Pickering NGS (previously scheduled for decommissioning in 2025) through September 2026. The government is also supporting the refurbishment of the four units at Pickering, with refurbishment of the first unit anticipated to be completed in 2031.

To address resource adequacy needs emerging mid-decade due to the combined effect of nuclear retirements and refurbishments, as well as expiring generation contracts, the IESO has employed competitive acquisition mechanisms from the Resource Adequacy Framework in part via the capacity auction referenced above. The IESO's first long-term procurement concluded in May 2024 and secured long-term commitments from 10 battery storage facilities for 1,784 MW of new capacity and three natural gas/biogas facilities for 411 MW of new capacity. Facilities are anticipated to be in service as early as May 2027.

The IESO calculates the reserve margin requirement on an annual basis and publishes this in the Annual Planning Outlook (APO). The requirement is calculated for each year for net demand at the time of the annual demand peak to provide an LOLE that is at or below 0.1 days per year. The reserve margin requirement in the *2024 LTRA* is derived from the capacity requirement in the 2024 APO, plus any material changes to demand and supply following APO publication.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Energy adequacy assessments are conducted annually for the APO by using a deterministic approach in the IESO's economic dispatch model. In addition, the IESO's capacity adequacy assessments consider the system's ability to serve load in all hours of the year (i.e., during peak hours as well as non-peak load hours).

As demand requirements increase, nuclear refurbishments continue, and some units at the Pickering NGS retire in 2024, Ontario's energy needs are expected to be met this decade by the resources secured through the IESO's recently completed procurements. The second medium-term procurement, which was recently launched, aims to secure capacity and energy from existing resources reaching contract end; this is expected to help alleviate energy risks in the latter half of this decade. The second long-term procurement that is underway aims to acquire new capacity and energy-producing resources and is anticipated to alleviate energy risks in the early 2030s.

Factors that could increase energy adequacy risks include aging resources and the potential for decreased performance, market exit of resources reaching contract end, extreme weather, and decarbonization policies and risks presented by new resources, including in-service delays or a high risk of forced outages during the initial period of operation. Deliverability challenges for new resources and long lead times required to build new transmission may also increase energy adequacy risks. Demand-side factors include materialization of data centers, increased industrial automobile production and EV supply chain loads, and climate change impacts on weather-sensitive load.

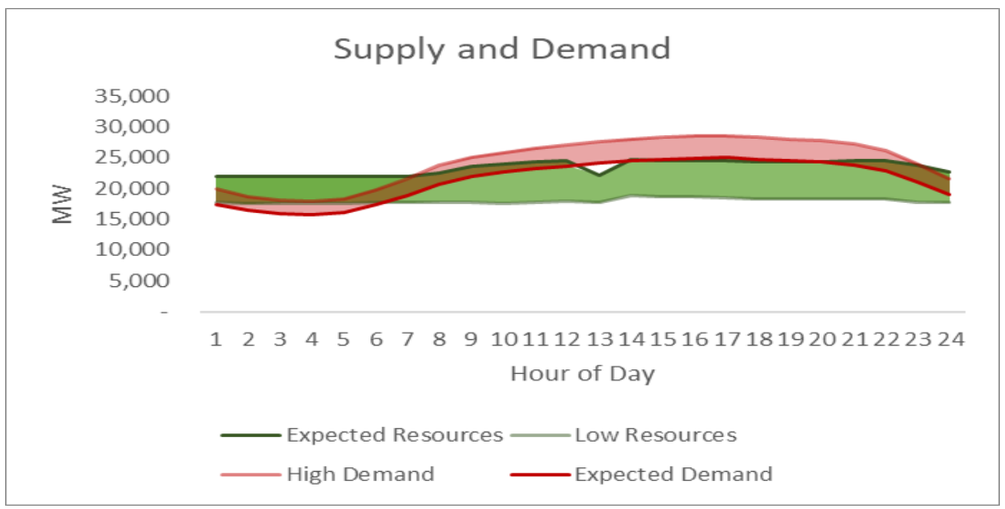
Looking forward, with the federal government's proposed Clean Electricity Regulations to decarbonize Canada's electric system by 2050, the IESO is assessing the role of natural gas generation as a flexible resource in the interim as new sources of non-emitting supply are added to the system.

The IESO conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table on the next page. The low risk of unserved energy is concentrated in the summer peak period, which typically occurs in late August.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

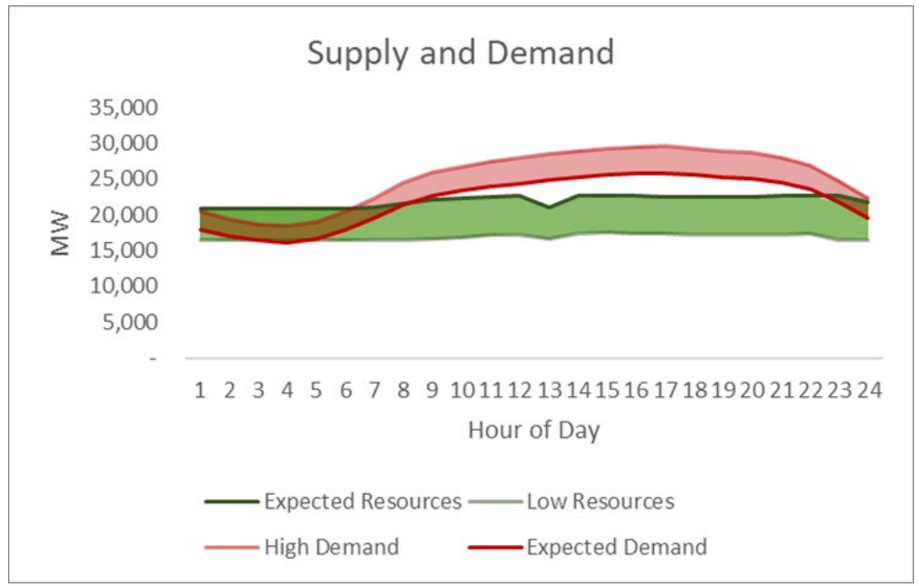
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a representative summer risk-day in 2026 are shown in the figure below. Expected resource contributions are not sufficient to meet expected demand on the risk day. The risk could be exacerbated by either a lower-than-expected resource contribution event or a higher-than-expected demand event, with greater risk being due to a larger variability in resource contribution. There is expected strain on the system from the hours beginning 12:00 p.m. through 8:00 p.m. If resource contributions are less than expected, strain on the system at expected demand conditions could be seen for almost all hours of the day beginning at 7:00 a.m. Reliance on external assistance may be necessary during peak conditions.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

In 2028, the EUE and LOLH are higher than 2026. Risk occurs during the same summer peak period but also during winter peak conditions in December. Demand growth that is forecasted to occur between 2026 and 2028 contributes to higher loss-of-load risk compared to the 2026 result. The risk day in 2028 has the same drivers as the 2026 result noted above.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2028

Demand

Forecasted demand for this *2024 LTRA* outlook period (relative to the *2023 LTRA* outlook period) indicates 10% higher annual energy demand, 8% higher summer peak demand, and 9% higher winter peak demand.

With an expanding agricultural and greenhouse sector, along with increasing electricity use for home heating and transportation, summer and winter peaks are anticipated to converge over the forecast period, leading Ontario to be dual-peaking by 2030. In the near term, the peak magnitude is expected to increase slightly as the province exits the remnants of the post-pandemic inflationary cycle, and new industrial projects supporting decarbonization begin commercial operation. Over this assessment period, the IESO projects total internal demand growth to increase at a compound annual growth rate of 2.34% for summer and 2.75% for winter. Offsetting the growth in demand are reductions from conservation, including savings from EE programs and codes and standards regulations, electricity price responsiveness and increased output by embedded generation.

Ontario's Industrial Conservation Initiative (ICI) acts as a critical peak pricing program leading to reductions in demand at peak and is expected to reduce around 1,500 MW if the hour of annual system peak demand occurs in the summer or around 1,000 MW if it occurs in the winter. It is expected to scale based on increased industrial growth in future years, with reductions in 2034 of 2,000 MW for a summer peak demand hour and over 1,400 MW for a winter peak demand hour.

Demand-Side Management

DR capacity, from both dispatchable loads and hourly DR resources (e.g., residential or commercial and industrial load), is procured through the IESO's annual capacity auction. Starting with the 2023 capacity auction, the IESO implemented a capacity qualification process for all resource types eligible to participate, which applies resource-specific calculation methodologies to determine the amount of unforced capacity (UCAP) each resource is eligible to offer into the auction.

In June 2023, the IESO launched Peak Perks, a residential DR program where participants help reduce demand by up to 150 MW through brief, time-limited thermostat adjustments during periods of peak electricity demand in the summer months.

In July 2023, the IESO launched an interruptible rate pilot to provide large-load customers with an interruptible rate in exchange for agreeing to temporarily reduce demand when directed by the IESO. The pilot spans a three-year period and up to 15 events of up to four-hour duration can be called, primarily in the day-ahead timeframe but also on shorter notice.

Forecast savings from the IESO's 2021–2024 Conservation and Demand Management Framework were included in the forecast and resulted in a decrease in demand. Savings from the 2021–2024 CDM framework are expected to persist beyond the end of 2024. In February 2024, Ontario's minister of energy asked the IESO to examine options and analysis for a post-2024 EE framework and programs.

Distributed Energy Resources

The IESO estimates that contracted DERs contributed more than 3,400 MW of capacity and 5.3 TWh of energy in 2023, more than half of which is solar PV, one-third wind, and modest contributions from hydroelectric and biomass resources. While the IESO has little insight into uncontracted DERs, it has observed energy contributions of approximately 2 TWh in 2023.

Generation

Recent generation procurements are provided in the PRM section.

The transmission-connected supply mix in Ontario has shifted over the past decade from having only synchronous generation facilities to one with more IBRs including wind, solar, and storage. Previous assessments performed by the IESO indicate that Ontario is expected to have sufficient inertia and frequency response to ensure stable operation up to 2025.

Going forward, the addition of over 2,900 MW of new battery storage resources in the next few years will increase the proportion of IBRs on the system. With the shift toward a higher proportion of IBRs, further areas that will be explored include the sufficiency of the resource mix to provide system inertia, primary frequency response, operating reserve, ramping capability, reactive support, and voltage control. If needs are identified, the IESO's procurements may be used as one avenue to acquire resources that can provide the required services.

The IESO has also been taking a proactive approach to dealing with challenges posed by IBRs. This includes working to optimize the location of IBR resources acquired through the IESO's procurements to minimize performance issues and initiating a review of the IESO's Market Rules to align with the latest IEEE 2800 standard, which aims to establish uniform technical minimum requirements for interconnection, capability, and lifetime performance of IBRs.

Energy Storage

By May 2028, over 2,900 MW of new battery storage resources are expected to come on-line, including the 250 MW/1,000 MWh Oneida battery storage facility (expected to be operational in June 2025), and 2,714 MW of battery storage resources secured through the IESO's first set of long-term procurements. Of this, 930 MW is expected to reach commercial operation by May 2026 and the remaining 1,784 MW by May 2028. These standalone battery storage resources (with a minimum four-hour duration) are expected to support the reliable operation of Ontario's electric system through the ability to be dispatched by the IESO and ramp up and down quickly. The resources are also located in areas of Ontario where transmission security or resource adequacy needs were identified.

Newly acquired energy storage facilities through the IESO's first set of long-term procurements will be required to be available during peak hours.

Capacity Transfers

Firm capacity imports and exports with neighboring jurisdictions are included in the IESO's planning studies. For non-firm imports, the IESO assumes a limited amount for the purposes of its reliability assessments. Non-firm imports are assumed to be 250 MW for summer and 240 MW for winter, an amount considered likely to flow throughout the year, including under tight supply conditions and prices.

In November 2024, the IESO and Hydro-Québec finalized a new capacity sharing agreement for a swap of a minimum of 600 MW of capacity per season. Under this agreement, the IESO will deliver capacity

to Québec during the winter period and Hydro-Québec will deliver capacity to Ontario during the summer period. The agreement commences in the Winter 2024–2025 season and runs to October 2031, with an option for an extension for an additional three years. Other terms of the agreement are expected to include the option for the IESO to increase the minimum amount provided to Québec each year and to bank any amount of the 600 MW from Québec for use in a future summer period over the term of the agreement.

The 2023 capacity auction secured 300 MW of system-backed imports from Québec for the Summer 2024 obligation period. As part of the 2016 capacity sharing agreement between Ontario and Québec, the IESO may call on a total of 500 MW of firm imports from Hydro-Québec, which may be requested all in one summer or in smaller amounts over multiple summers. The IESO's recent assessments indicate the intention to utilize the 500 MW of firm imports from June to September 2027 to help meet resource adequacy needs. However, depending on the outcomes of the ongoing procurements and changes to Ontario's resource adequacy outlook, the IESO may choose to utilize this capacity in another year.

Transmission

The existing transmission system in northeastern Ontario has insufficient capability to reliably supply forecasted load growth; as such, the IESO has recommended several new transmission reinforcements in the region to address this need. Several of the recommended reinforcements are in the early project development stage and one is undergoing a transmitter selection process.

The IESO recently recommended additional transmission reinforcements in southwest Ontario to support the area's medium-term needs, including a double circuit, 230 kV line from Lambton transmission station to Chatham substation, expected in-service by 2028, and a new 500 kV transmission line connecting Longwood and Lakeshore transmission stations, to be in-service by 2030. These projects will ensure that transfer capability continues to be sufficient as additional load continues to connect in the area.

Reliability Issues

Nuclear refurbishment over the next decade is a major resource risk that requires additional attention. The IESO has regular meetings with nuclear operators to assess probable delays and take appropriate mitigation actions.

For long-term planning purposes, the IESO carries an additional level of nuclear refurbishment reserve to account for the risk of refurbishment delays and increased forced outage rates pre- and post-refurbishment. In addition, advanced outage approvals are provided solely when Ontario is adequate under extreme weather.

Other factors that may pose reliability risks include supply chain issues, conditions in neighboring jurisdictions, extreme weather, decarbonization-driven changes to supply and demand, policy and regulatory uncertainty, asset health, and potential market exit of existing resources.

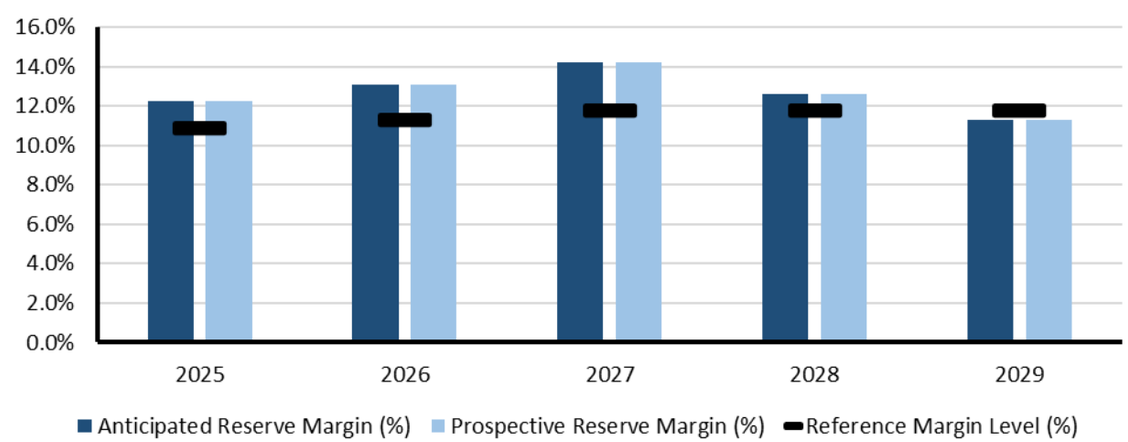


NPCC-Québec

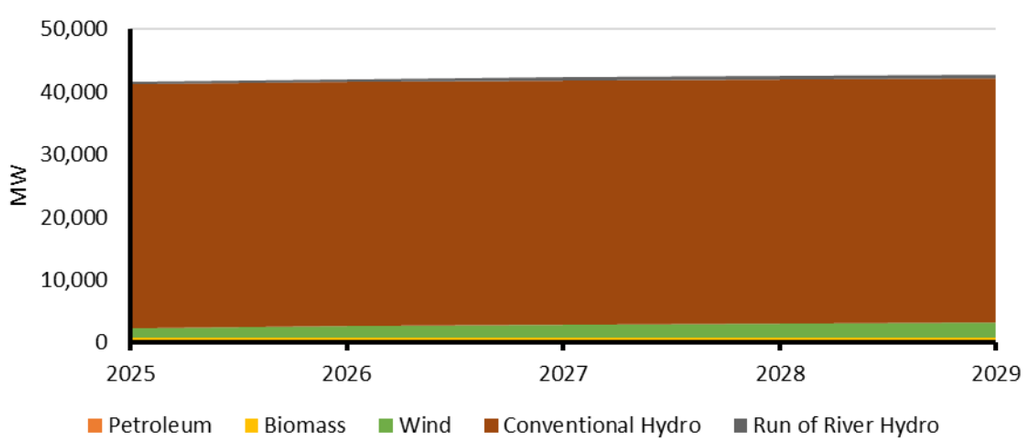
The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVdc ties, radial generation, or load to and from neighboring systems.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	41,497	41,954	42,476	43,385	44,070	44,784	45,577	46,635	47,828	49,041
Demand Response	4,732	4,896	5,068	5,258	5,322	5,377	5,388	5,388	5,388	5,388
Net Internal Demand	36,765	37,058	37,408	38,127	38,748	39,408	40,189	41,247	42,440	43,652
Additions: Tier 1	73	469	665	835	1,016	1,016	1,016	1,016	1,016	1,016
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-390	-145	455	455	455	600	0	0	0	0
Existing-Certain and Net Firm Transfers	41,185	41,429	42,066	42,103	42,103	42,256	41,656	41,656	41,656	41,656
Anticipated Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Prospective Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Reference Margin Level (%)	10.9%	11.3%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM and PRM remain above the RML until 2029 (winter 2029–3030).
- A total of 4,048 MW wind generation capacity (1,016 MW capacity value at peak time) is expected to be in service by 2030.
- Two new transmission projects connecting Québec with New England and New York are expected to be in service by the end of 2025 and May 2026, respectively.

NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Petroleum	429	429	429	429	429
Biomass	400	400	400	400	400
Wind	1,449	1,807	2,002	2,173	2,354
Conventional Hydro	38,925	38,962	38,999	39,036	39,036
Run of River Hydro	446	446	446	446	446
Total MW	41,648	42,043	42,276	42,483	42,664

NPCC-Québec Assessment

Planning Reserve Margins

The ARM is based on existing and anticipated generating capacity and firm capacity transfers. The Québec area projects an ARM above the RML over the first five winters of the assessment period (2024–2025 to 2028–2029). The ARM is under the RML for the winters 2029–2030 to 2034–2035 mainly due to the demand growth.

The RML is derived from the NPCC 2023 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on December 5, 2023. The demand uncertainty captured in the reserve ratio reflects both weather and economic uncertainty. The methods and assumptions can be found in the *Comprehensive Review* report available on the NPCC website.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2023 Supply Plan update, which was filed with the Régie de l'énergie on November 1, 2023.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

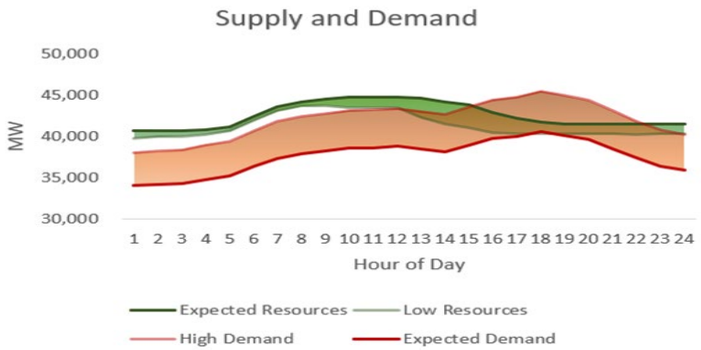
The main energy risk for the Québec area is associated with a series of dry years, hence the energy reliability criterion established by the Régie de l'énergie. This risk surpasses the energy risk associated with the other renewable resources over the horizon of this study. The potential impact of climate change on the water inflows could be an issue for energy reliability and is therefore the subject of various ongoing internal studies.

Hydro-Québec conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table below. The low risk of unserved energy is concentrated in the winter peak period, which typically occurs in late January to early February.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**8.21**	**4.97**
EUE (PPM)	0.00	**0.04**	**0.03**
LOLH (hours per year)	0.00	**0.01**	**0.01**
Operable On-Peak Margin	-2.3%	**9.8%**	**11.9%**

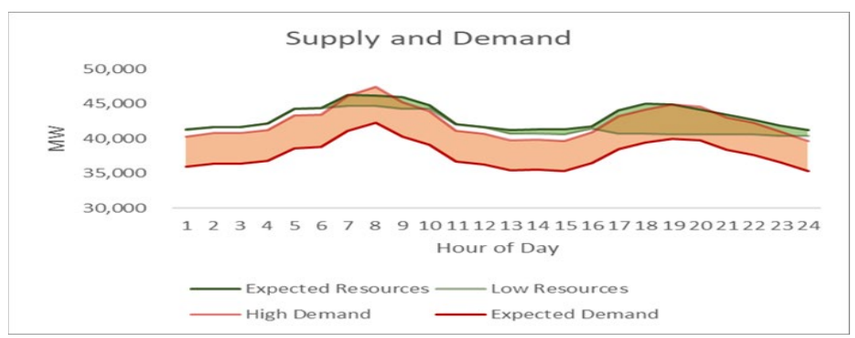
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a typical winter risk day in 2026 are shown in the figure below. Although expected resource contribution is expected to be enough to meet expected demand, there is risk that above-normal demand could exceed resources. Demand could be 10–15% higher than expected, which could strain the system from the hours beginning 3:00 p.m. through 10:00 p.m. Also, if resource contributions are less than expected, the peak hour beginning at 6:00 p.m. could lead to a loss-of-load situation. Reliance on external assistance may be necessary in these events.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Hourly demand and resource projections for a typical winter risk day in 2028 are shown in the figure below.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Demand

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand.

Demand-Side Management

The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 2,784 MW on winter 2024–2025 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will grow from 611 MW in 2024–2025 to 889 MW by the end of the period study. Another similar program for residential customers is in operation and should gradually rise from 166 MW for Winter 2024–2025 to 621 MW for Winter 2028–2029.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 371 MW for Winter 2024–2025 and 445 MW for Winter 2034–2035. Moreover, data centers specializing in blockchain applications are required to reduce their demand during peak hours at Hydro-Québec's request. Their contribution as a resource is expected to be around 269 MW over the study period. Finally, another DR resource consists in a voltage reduction scheme allowing for a 250 MW peak demand reduction. EE and conservation programs are integrated in the assessment area's demand forecasts.

Distributed Energy Resources

Total installed BTM capacity (solar PV) is expected to increase to 862 MW in 2035. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter-peaking area, DERs' on-peak contribution ranges from 2 MW for Winter 2024–2025 to 5 MW for the last winter period. No potential operational impacts of DERs are expected in the Québec area considering their low contribution.

Generation

Four wind projects with a total installed capacity of 4,000 MW are expected to be commissioned during the assessment period. The first project, Apuiat (204 MW), is expected to be commissioned in 2024–2025. The second project (1,144 MW divided into 6 wind farms) is expected to be commissioned in December 2026. The third project is Des Neiges (1,200 MW) and is divided into three phases (400 MW each). The first phase is expected to be operational in the winter of 2026–2027. The second and third phases are expected to be in service for the 2027–2028 and 2028–2029 winters, respectively. The fourth project is made of 1,500 MW divided into 8 wind farms, which are expected to be operational in the winters of 2027–2028, 2028–2029 and 2029–2030, depending on the location.

In addition to wind projects, unit replacement projects at existing hydroelectric facilities are being studied. Up to 2,000 MW of capacity could be added by replacing generating units with most recent models, as outlined in Hydro-Québec's Action Plan 2035.

Energy Storage

No energy storage facilities are planned to be commissioned during the assessment period.

Capacity Transfers

The governments of Québec and Ontario have signed an MOU of an agreement that allows a seasonal capacity exchange between the two areas for the next seven years except for the year 2027 (no exchange is allowed). The technical details of the agreement will be completed by Fall 2024 and will be in place from Winter 2024–2025 to winter 2030–2031. This agreement will be firm and allow Québec to import 600 MW from November to April. In summer, Québec will export 600 MW of firm capacity to Ontario from May to October.

Transmission

Appalaches-Maine Interconnection

This project, expected to increase transfer capability between Québec and Maine by 1,200 MW, has resumed construction. The project will connect to the New England Clean Energy Connect project (NECEC) in Maine. It involves the construction of a ±320 kV dc transmission line about 100 kilometers (62 miles) long from the Des Appalaches 735/230 kV substation to the Canada-United States. border. From the international border crossing, the dc transmission line will be extended 145 miles to a substation in Lewiston, ME, where the power will be converted from dc to ac. The project in Québec also includes the construction of an dc to dc converter at the Des Appalaches substation and triggers the need of thermally upgrade two 735 kV lines in the south of the system. The project is expected to be in service in December 2025.

Hertel-New York Interconnection (CHPE)

This project, expected to increase transfer capability between Québec and New York by 1,250 MW, is under construction. It involves the construction of a ±400 kV dc underground transmission line about 60 kilometers (37 miles) long from the Hertel 735/315 kV substation just south of Montréal to the Canada-United States border. The project will connect to the Champlain Hudson Power Express project (CHPE) in New York state. From the international border crossing, the dc transmission line will be extended 339 miles to a substation in Astoria, NY, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at the Hertel substation. The project is expected to be in service in May 2026.

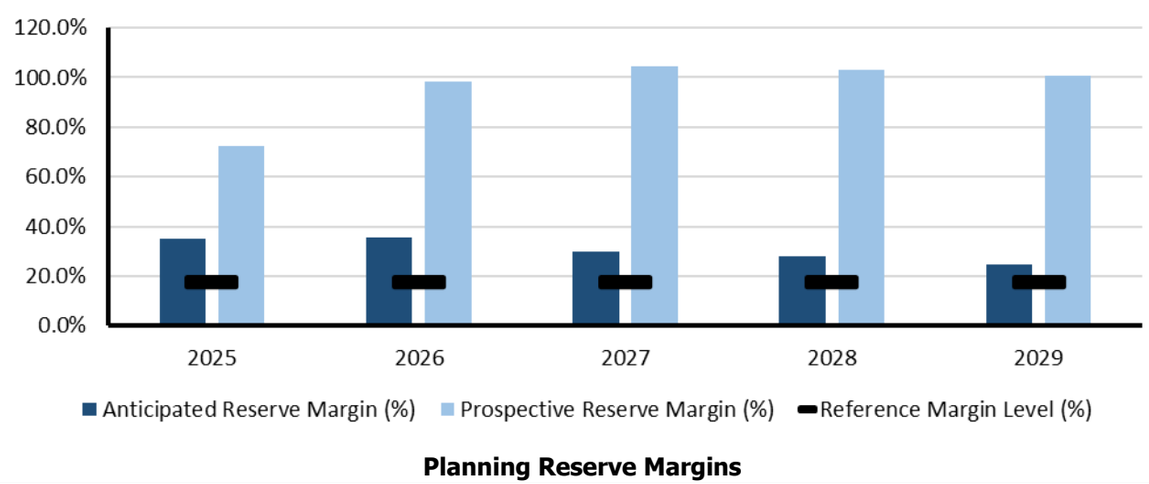


PJM

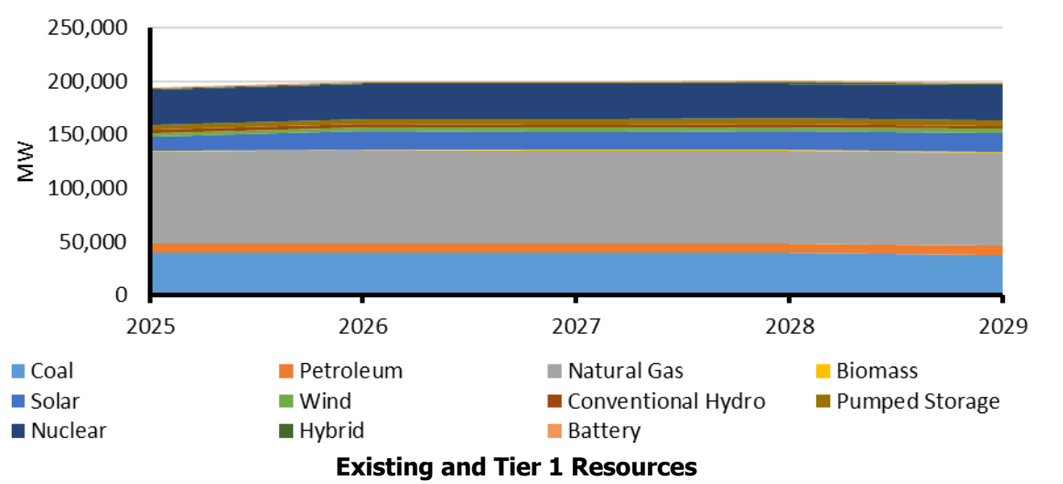
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	153,493	156,803	159,859	162,972	165,681	167,873	170,008	172,109	174,366	176,822
Demand Response	7,554	7,693	7,808	7,913	8,000	8,083	8,162	8,230	8,312	8,400
Net Internal Demand	145,939	149,110	152,051	155,059	157,681	159,790	161,846	163,879	166,054	168,422
Additions: Tier 1	11,056	17,047	17,139	17,784	17,911	18,155	18,155	18,155	18,155	18,155
Additions: Tier 2	55,112	93,845	112,827	122,781	127,059	131,113	131,287	133,652	133,652	133,652
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	4,502	4,347	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	185,828	185,270	180,552	180,552	178,577	178,577	178,577	178,577	178,577	178,577
Anticipated Reserve Margin (%)	34.9%	35.7%	30.0%	27.9%	24.6%	23.1%	21.6%	20.0%	18.5%	16.8%
Prospective Reserve Margin (%)	72.4%	98.3%	104.7%	103.3%	100.5%	96.5%	94.1%	92.9%	82.1%	79.5%
Reference Margin Level (%)	17.7%	17.7%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2034 when it falls below the 17.6% RML level.
- PJM implemented a number of changes to the 2023 load forecasting process to improve model accuracy, switching from an annual to monthly end-use model for PJM's sector models to better determine heating, cooling, and other non-weather-sensitive load and moving to an hourly model to better capture new technologies and peak shifting. Additionally, higher expectations for data center loads now incorporate 15-year forecasts from impacted electric distribution companies (EDC).
- PJM's review of recent policies (e.g., state laws and federal environmental initiatives) indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by these state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generation to comply or retire. Conversely, there are multiple mandates with renewable portfolio standards (RPS) that account for the majority of over 150 GWs submitted projects.

PJM Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	39,735	39,735	39,325	39,325	37,747
Coal*	39,394	39,394	33,313	28,240	25,124
Petroleum	8,810	8,514	8,514	8,514	8,117
Natural Gas	85,541	87,245	87,245	87,245	87,245
Natural Gas*	85,541	87,245	87,228	87,228	87,228
Biomass	928	928	928	928	928
Solar	13,349	16,770	16,908	17,621	17,754
Wind	3,017	3,512	3,507	3,507	3,507
Conventional Hydro	2,934	2,922	2,934	2,934	2,944
Pumped Storage	5,189	5,189	5,189	5,189	5,189
Nuclear	32,535	32,535	32,535	32,535	32,535
Hybrid	1,315	1,742	1,739	1,739	1,739
Battery	393	982	982	994	994
Total MW	193,747	200,074	199,807	200,532	198,699
Total MW*	193,406	199,733	193,779	189,430	186,060
*** Capacity with additional generator retirements.** Generators that are forecasted to retire by PJM are removed from the resource projection where marked.					

PJM Assessment

Planning Reserve Margins

The ARM does not fall below the RML in PJM until 2034. PJM's growing demand profile and a change in resource mix that favors VERs, however, present a new level of risk.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

PJM is forecasting around 30% installed reserves (including expected committed demand resources), which is well above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. Due to the current low penetration of energy-limited and VERs in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand. To address future reliability concerns due to growing VER penetration and limitations associated with the performance of those resources, PJM's Effective Load Carrying Capability methodology calculates the reliability and energy contribution of limited and variable resources.

Some of PJM's assumptions for determining the resource mix to use in the ProbA differ from those used in developing the LTRA. Only a portion of the Tier 1 resource additions are used in the ProbA to more accurately reflect historical rates of development. Additionally, more generator retirements are used in the ProbA based on PJM's generator forecasting. These assumptions are more consistent with the assumptions included in official studies performed by PJM to support its capacity market. In addition, the information in the ProbA for winter seasons refers to the Winter 2026–2027 and Winter 2028–2029 because PJM's studies are based on "delivery years," which start on June 1 of a year and end on May 31 of the subsequent year.

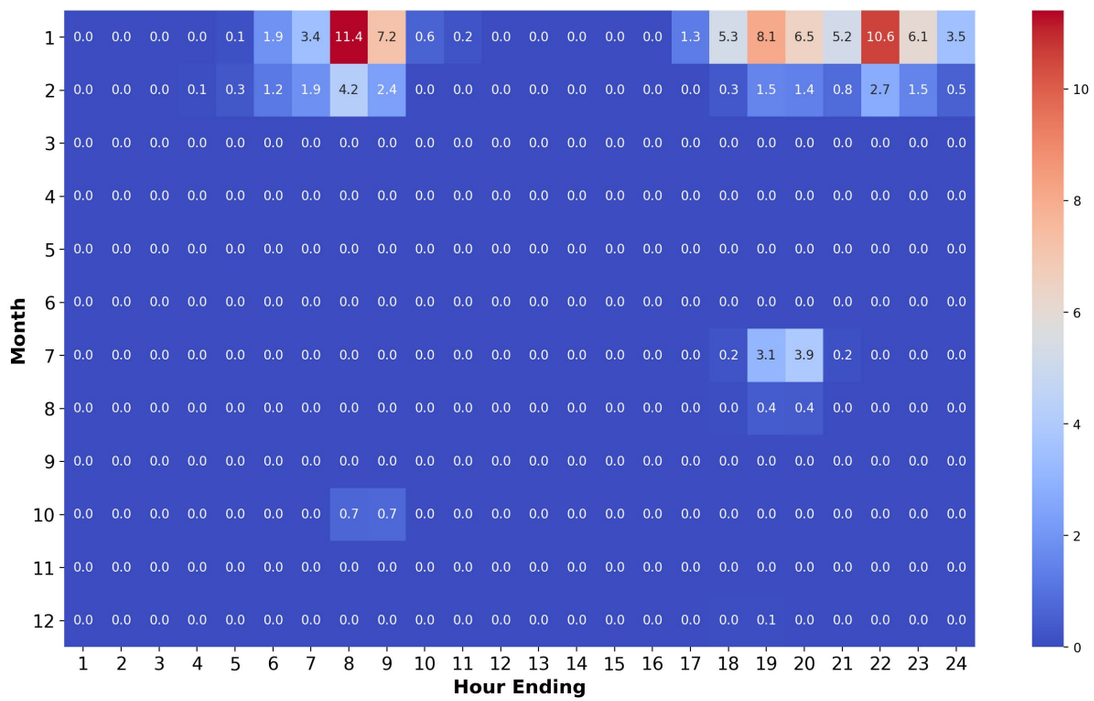
Results of the 2024 ProbA are provided in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.11**	**0.22**
Operable On-Peak Margin	29.0%	**17.8%**	**17.7%**

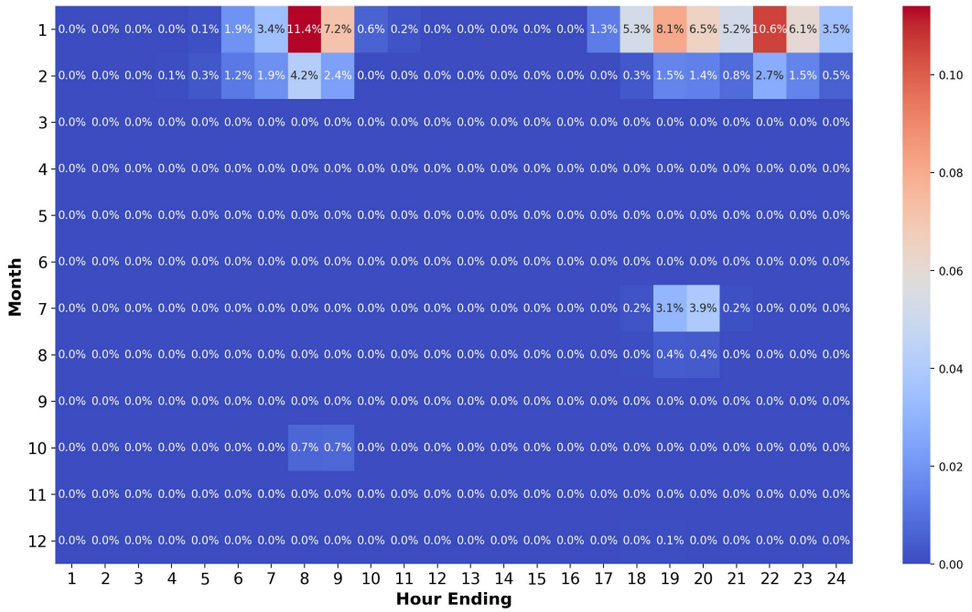
* Provides the 2022 ProbA Results for Comparison

In both 2026 and 2028, most EUE and LOLH are concentrated in the winter months (especially January), as shown in the following EUE heat maps. The risk occurs in days when temperatures are very low, which results in high loads across the assessment area. If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.

The smaller shares of EUE and LOLH observed in the summer period for 2026 and 2028 are associated with high temperatures and high loads across the assessment area that drive load-loss events in the evening (hours ending 19 and 20) as grid-connected and BTM solar resource output declines. Low performance of wind resources and, to a lesser extent, slightly worse performance of thermal resources, also contribute to the load-loss events in the analysis.



2026 EUE Heat Map (Share of Annual EUE in %)



2028 EUE Heat Map (Share of Annual EUE in %)

PJM implemented capacity reforms (approved by FERC) at the start of 2024, which include using the loss-of-load model employed to perform the ProbA, as well as accreditation reforms based on the risk patterns identified by said model, for the capacity auctions starting with delivery year 2025–2026.

Demand

PJM is experiencing large growth in data centers that are in turn driving higher demand forecasts. Loudoun County, Virginia, in the PJM assessment area, is home to "Data Center Alley," the largest concentration of data centers in the world. Electrification in transportation, heating, and industrial sectors is also spurring demand growth.

The PJM Interconnection produces an independent peak load forecast of total internal demand using econometric regression models with daily load as the dependent variable and independent variables including calendar effects, weather, economics, and end-use characteristics. PJM annually reviews its load forecast methodology and implements changes when improvements are identified.
Summer peak load growth in PJM is projected to average 1.6% per year over the next 10-year period and 1.6% over the next 15 years. The PJM summer peak is forecasted to be 176,822 MW in 2034, a 10-year increase of 25,575 MW, and reaches 190,752 MW in 2039, a 15-year increase of 39,505 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.5% with a median of 0.5%.

Winter peak load growth for PJM is projected to average 1.9% per year over the next 10-year period and 1.8% over the next 15 years. The PJM regional transmission organization winter peak load in 2033–2034 is forecasted to be 163,069 MW, a 10-year increase of 28,410 MW, and reaches 176,195 MW in 2038–2039, a 15-year increase of 41,536 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.0% with a median of 0.7%.

Net energy for load growth for PJM is projected to average 2.3% per year over the next 10-year period and 2.2% over the next 15 years. Total PJM energy is forecasted to be 1,021,955 GWh in 2034, a 10-year increase of 208,627 GWh, and reaches 1,120,928 GWh in 2039, a 15-year increase of 307,600 GWh. Annualized 10-year growth rates for individual zones range from 0.1% to 7.3% with a median of 0.7%.

Demand-Side Management

DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during summer peak season from 7,550 MW in 2025 to 8,400 MW in 2034.

Distributed Energy Resources

PJM expects 4,470 MW of solar DERs at the time of the peak in 2029 and 5,103 MW in 2034. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

Generation

Overall, new generation is coming on-line slower than anticipated. Generator retirements are outpacing the new generation replacing them. As a result, PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load. PJM could be at risk of facing resource adequacy challenges if these trends continue. PJM has applied an 11% reduction to the nameplate value of Tier 1 resources to reflect the historical rate of slower-than-anticipated addition of new generation.

PJM reviews the progression of generation interconnection to understand overall developer trends more fully and their impact on the interconnection process. Of new and expanded generation resources submitted in Queue A (1999) through December 31, 2023, 74,294 MW (or 15.8%) reached commercial operation, 33,166 MW (or 7%) were withdrawn from the interconnection process after Interconnection Service Agreement (ISA) execution, and 1,560 MW (or 0.3%) were withdrawn after wholesale market participant agreement (WMPA) execution but before construction. Overall, 20.4% of projects that requested uprates to existing capacity reached commercial operation.

Stakeholders at the June 6, 2023, Interconnection Process Subcommittee meeting approved an issue charge to examine how to enhance transfer of CIRs, which allow new generation to interconnect as a capacity resource, from deactivating resources to new generation. The goal is to develop a solution that both improves the efficiency of the process and clarifies that it applies to all energy-injecting capacity resource types. The existing provisions in the PJM Tariff, and related defined terms included in the Reliability Assurance Agreement (RAA), governing the CIR transfer process will be clarified to reduce confusion as to which capacity resource types the transfer process applies.

PJM's existing installed capacity reflects a fuel mix consisting of approximately 48% natural gas, 22% coal, and 18% nuclear. Hydro, wind, solar, oil, and waste fuels constitute the remaining 12%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility. Totaling nearly 125,000 MW of CIRs, renewable and hybrid fuels are changing the landscape of PJM's interconnection process. Solar energy makes up 40% of the new service requests in PJM's generation interconnection queue. State policies encouraging renewable generation are contributing to the rise in solar generation interconnection requests.

PJM's review of recent policies indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generators to comply or retire. See *Energy Transition in PJM: Resource Retirements, Replacements, and Risks* (February 2023). Conversely, there are multiple mandates with RPS that account for the majority of over 150 GWs in submitted projects. Growing levels of intermittent and limited duration resources, such as wind, solar, and battery storage, do not replace conventional large-scale generation installations megawatt-for-megawatt but rather require multiple megawatts to replace one megawatt of dispatchable generation due to their limited availability in certain hours of the day and seasons of the year. Many megawatts from a range of generation technologies, available at different times, are required to replace a megawatt of thermal generating capacity. Looking out over the next 8 to 10 years of the energy resource transition, maintaining an adequate level of generation resources with operational and physical characteristics that support reliability will be crucial for PJM's ability to serve electrical demand reliably.

Energy Storage

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy (DOE) national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

Today, there are approximately 177 GWs of solar, wind, battery, and hybrid in the PJM interconnection queue. Hybrid resources make up approximately 26 GWs and standalone storage makes up approximately 28 GWs.

Some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land but each has its own connection to the grid) or hybrid (in which the storage facility and generator share a common connection to the grid).

Capacity Transfers

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if transfers were dropped to zero.

Transmission

PJM's Regional Transmission Expansion Plan (RTEP) continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by new wind and solar generating units driven by federal and state renewable incentives, generating plant deactivations, and market impacts introduced by DR and EE programs. As of December 31, 2023, renewable resources continue to represent a significant portion of PJM's new services requests.

The PJM board approved 48 new baseline projects during 2023 at an estimated $6.6 billion to ensure that fundamental system reliability criteria across the grid are met. The board also approved the inclusion of 93 new network transmission projects at an estimated $180 million into the RTEP.

Reliability Issues

PJM's 2023 *Load Forecast Report* addressed the impact of industry changes that are reshaping system hourly loads. As a result, the level and timing of coincident peak and non-coincident peak demands across PJM have begun to shift. Solar-power penetration, expected impacts of EVs, state electrification programs, home battery storage, and a significant increase in data center loads are markedly increasing the complexity of PJM's load forecasting process. Driven by discrete and localized load growth, like Data Center Alley in Loudoun County, Virginia, in 2022, PJM and stakeholders conducted a review of data center load growth and identified growth rates of over 300% in some instances. As a result, the 2023 PJM *Load Forecast Report* incorporates adjustments to specific zones for data center load growth.

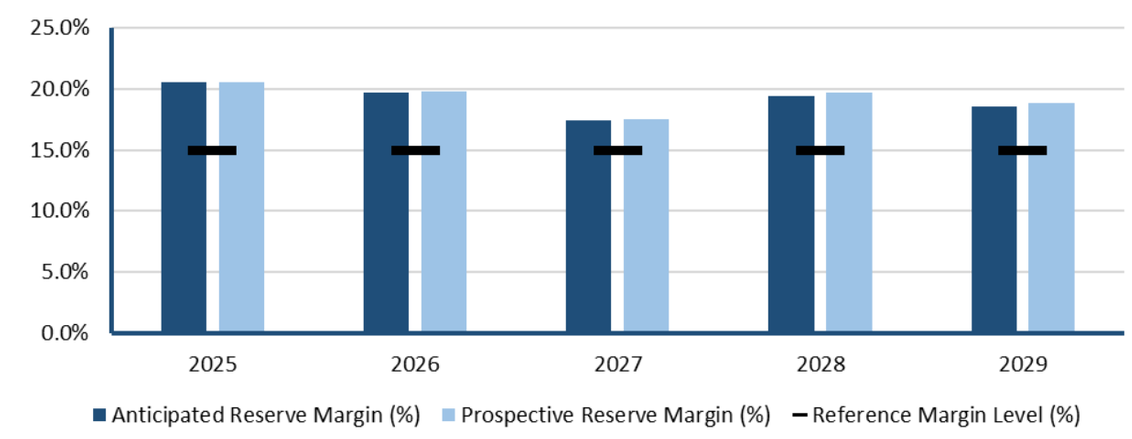


SERC-Central

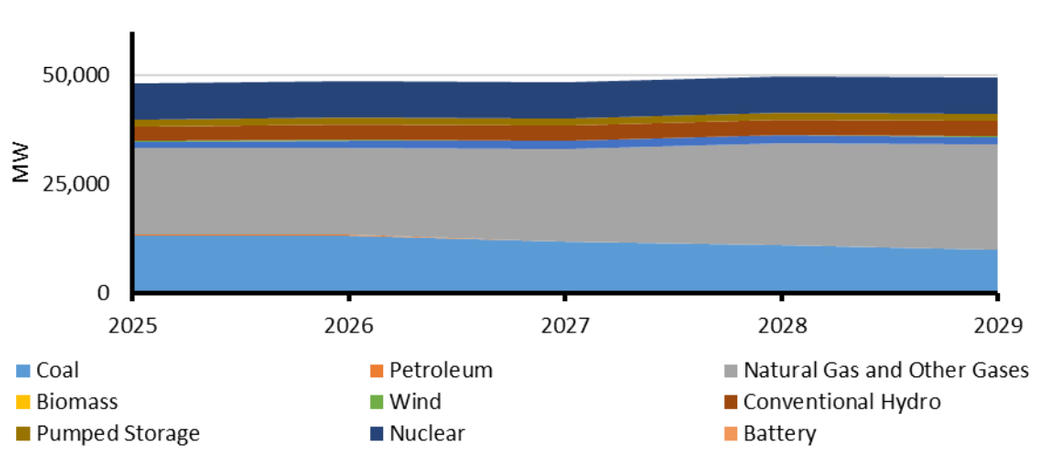
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	42,983	43,202	43,399	43,384	43,440	43,636	43,725	43,913	44,077	44,316
Demand Response	1,859	1,856	1,852	1,849	1,847	1,844	1,842	1,840	1,839	1,837
Net Internal Demand	41,124	41,346	41,547	41,535	41,593	41,792	41,883	42,074	42,239	42,479
Additions: Tier 1	1,123	1,540	2,970	4,983	5,841	5,841	5,841	7,609	8,935	9,598
Additions: Tier 2	20	20	20	120	120	120	120	120	120	120
Additions: Tier 3	135	263	415	1,118	3,395	4,198	4,965	5,368	5,745	6,198
Net Firm Capacity Transfers	1,240	765	190	-288	-288	-288	-288	-287	-287	-287
Existing-Certain and Net Firm Transfers	48,437	47,962	45,813	44,608	43,478	43,191	43,191	42,224	42,224	41,153
Anticipated Reserve Margin (%)	20.5%	19.7%	17.4%	19.4%	18.6%	17.3%	17.1%	18.4%	21.1%	19.5%
Prospective Reserve Margin (%)	20.8%	20.0%	17.7%	19.7%	18.9%	17.6%	17.4%	18.8%	21.4%	19.8%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.
- New transmission line additions total 209 miles through 2028. The entities also plan to upgrade 185 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,348	13,348	11,774	11,047	9,917
Coal*	13,048	13,348	11,146	10,013	8,883
Petroleum	148	148	148	148	148
Natural Gas	19,857	19,857	21,287	23,300	24,158
Natural Gas*	19,476	19,476	20,906	22,919	23,777
Biomass	36	36	36	36	36
Solar	1,338	1,706	1,706	1,706	1,706
Wind	172	172	172	172	172
Conventional Hydro	3,393	3,393	3,393	3,393	3,393
Pumped Storage	1,673	1,673	1,673	1,673	1,673
Nuclear	8,280	8,280	8,280	8,280	8,280
Battery	75	125	125	125	125
Total MW	48,319	48,737	48,593	49,879	49,607
Total MW*	47,639	48,356	47,584	48,464	48,192
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Central Assessment

Planning Reserve Margins
The future reserve margins are above the RML for SERC-Central.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load-loss. Analysis of detailed ProbA outputs shows that that this negligible risk occurring in 2026 is associated with hot summer conditions and upper levels of economic load forecast models.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.10**	**0.00**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.00**	**0.00**
Operable On-Peak Margin	18.4%	**13.2%**	**14.9%**

* Provides the 2022 ProbA Results for Comparison

Demand
Drivers of load growth are commercial expansion, electrification of heating and transportation, and growth in residential load. Entities expect to continue to have increased economic growth that will drive both population and employment to the SERC-Central assessment area, but these gains in employment are slightly offset by improvements in efficiency.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation
Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.

Generator retirements are carefully managed by entities in the SERC-Central assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers
Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission
The entities reported a total addition of 209 miles of new transmission lines until 2028. The entities are also planning to upgrade 185 miles of transmission lines in the next 10 years to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

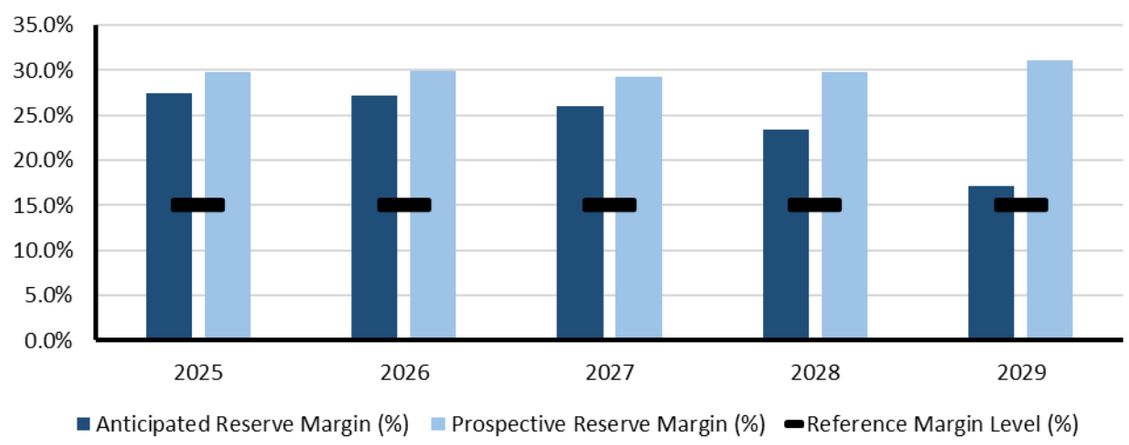


SERC-East

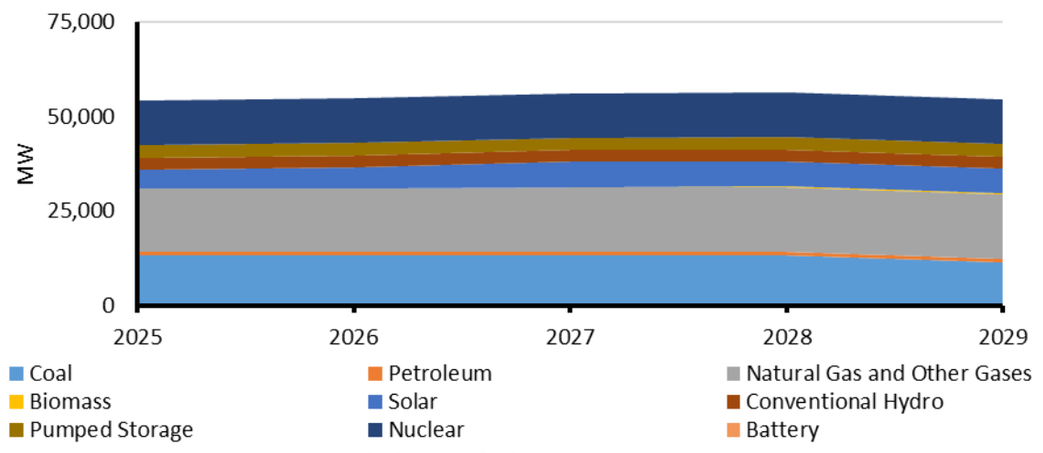
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	44,099	44,789	46,308	47,378	48,286	49,533	50,349	50,896	51,741	52,155
Demand Response	1,092	1,186	1,214	1,225	1,228	1,229	1,230	1,231	1,232	1,233
Net Internal Demand	43,007	43,603	45,094	46,153	47,058	48,304	49,119	49,665	50,509	50,922
Additions: Tier 1	772	1,330	2,777	2,818	2,818	2,818	2,818	2,818	2,818	2,818
Additions: Tier 2	38	217	506	1,975	5,577	8,032	9,766	11,595	13,978	16,767
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	593	593	593	593	593	593	593	593	593	593
Existing-Certain and Net Firm Transfers	54,039	54,129	54,045	54,118	52,301	52,395	51,316	49,998	49,998	48,636
Anticipated Reserve Margin (%)	27.4%	27.2%	26.0%	23.4%	17.1%	14.3%	10.2%	6.3%	4.6%	1.0%
Prospective Reserve Margin (%)	29.8%	30.0%	29.3%	29.8%	31.1%	33.0%	32.1%	31.7%	34.2%	35.9%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2030 when it falls below the 15.0% RML level.
- Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024.

SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,150	13,150	13,150	13,150	11,333
Coal*	13,108	12,564	12,564	11,910	10,093
Petroleum	1,044	1,044	992	992	992
Petroleum*	1,044	1,044	868	868	868
Natural Gas	16,627	16,717	17,061	17,121	17,121
Natural Gas*	16,601	16,691	17,061	17,121	17,121
Biomass	176	176	176	176	176
Solar	4,995	5,553	6,624	6,665	6,665
Conventional Hydro	3,102	3,102	3,102	3,102	3,102
Pumped Storage	3,324	3,324	3,324	3,324	3,324
Nuclear	11,795	11,795	11,795	11,808	11,808
Battery	6	6	6	6	6
Total MW	54,218	54,866	56,229	56,343	54,526
Total MW*	54,150	54,254	55,519	54,979	53,162
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-East Assessment

Planning Reserve Margins
The ARM falls below the RML starting in 2030 for SERC-East. Projected demand is expected to increase around 8.75% from 2024 to 2028 in the footprint.

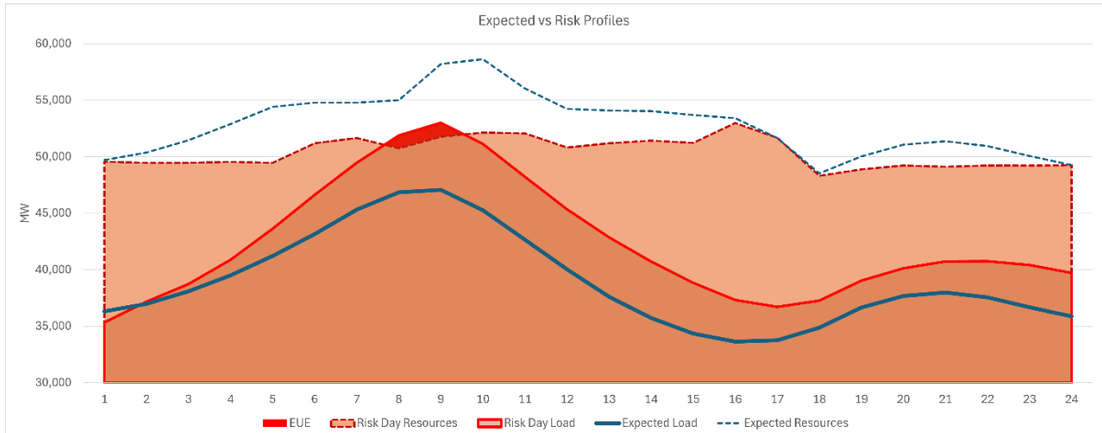
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
SERC-East has an elevated risk of energy shortages based on results of the 2024 ProbA shown in the table below.

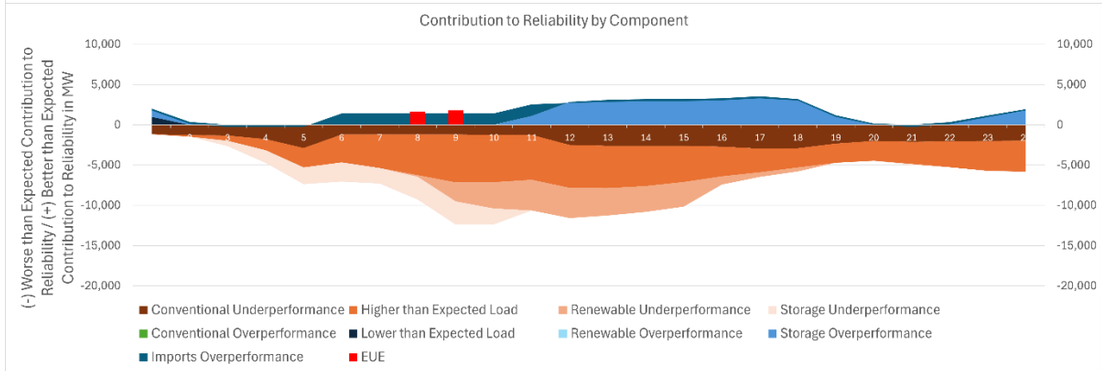
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.39	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

* Provides the 2022 ProbA Results for Comparison

SERC-East has changed from a summer-peaking assessment area to a dual-peaking assessment area, with both a summer and winter peak. The addition of solar PV generation shaves off summer peak demand, and a trend toward electrification of heating drives up winter peak demand. The ProbA results for 2026 indicate some risk for SERC-East in the winter months of January and February. The annual EUE is 143.35 MWh but for a very short, expected duration of 0.09 hours. The risk occurs during winter morning hours around 8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. For extreme cold weather events that might impact a wide geographical footprint, there is also a limit on imports from neighboring areas.

For 2028, SERC-East continues to show winter risk with 207.26 MWh of EUE and 0.17 hours of LOLH. The load is expected to grow by over 2%. The load-loss events in the analysis are for very few hours and short duration, occur around 8:00 a.m., and are tied to extreme weather, higher forecasted load levels, and lower resource performance. This can be seen in the following figures showing the risk profile and resource performance for a likely event-day.





Demand
Population growth is driving demand forecast increases in SERC-East. Entities expect faster-than-average growth in the urban areas and overall increasing energy and demand in the 10-year forecast. While the economic indicators used in the forecast have growth rates that vary during each year, the economic outlook will contribute to increased energy and demand over the 10-year forecast. Some entities project their EE adoption to impact roughly 1% of annual retail sales (after opt-outs) during the 10-year forecast.

There are also many large commercial/industrial loads accounted for in the forecast that have been announced or in discussions with the entities to locate in the service territory. If the large sites come to fruition, it will drive significant increases in energy and demand during the later part of the 10-year forecast.

The projected EV adoptions are driving energy and demand increases during the later part of the 10-year forecast window. EVs are currently the most significant contributor of all electrification sources (e.g., heating, industrial) in the 10-year forecast.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 286 miles of new transmission lines through 2028. The entities are also planning to upgrade 515 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

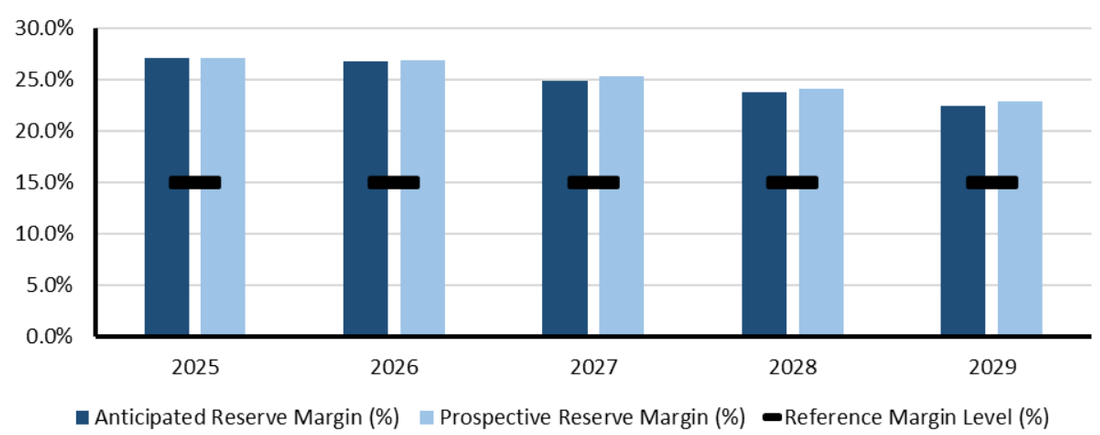


SERC-Florida Peninsula

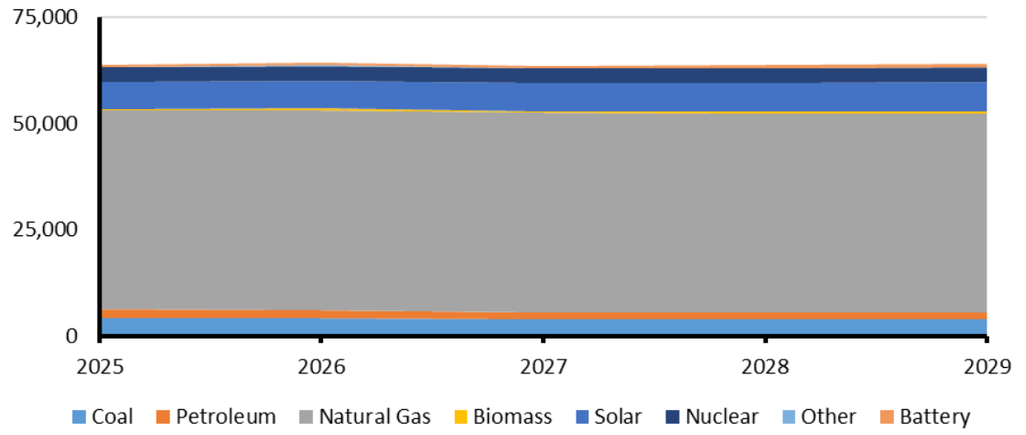
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	53,509	53,795	54,015	54,551	55,250	55,879	56,593	57,612	58,631	59,679
Demand Response	2,840	2,834	2,837	2,820	2,806	2,795	2,783	2,771	2,761	2,748
Net Internal Demand	50,669	50,961	51,178	51,731	52,444	53,084	53,810	54,841	55,870	56,931
Additions: Tier 1	871	1,497	1,573	1,785	2,018	3,421	3,927	4,545	4,547	4,549
Additions: Tier 2	0	40	200	200	200	200	200	200	200	200
Additions: Tier 3	0	39	39	39	39	39	39	39	39	39
Net Firm Capacity Transfers	494	293	293	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	63,521	63,121	62,366	62,230	62,230	61,725	61,725	61,493	61,493	61,493
Anticipated Reserve Margin (%)	27.1%	26.8%	24.9%	23.7%	22.5%	22.7%	22.0%	20.4%	18.2%	16.0%
Prospective Reserve Margin (%)	27.1%	26.9%	25.3%	24.1%	22.9%	23.1%	22.4%	20.8%	18.6%	16.4%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 459 MW in the next 10 years. Tier 1 additions include 484 MW of natural gas, 1,560 MW of BESS, and 1,792 MW of solar generation over the next 10 years.
- New transmission line additions total 668 miles through 2030. The entities also plan to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,367	4,367	3,908	3,908	3,908
Coal*	3,341	3,779	2,851	2,851	2,851
Petroleum	1,957	1,852	1,724	1,724	1,724
Petroleum*	1,892	1,786	1,477	1,477	1,477
Natural Gas	46,860	47,012	46,844	46,801	46,801
Biomass	310	310	310	310	310
Solar	6,255	6,635	6,711	6,853	6,997
Nuclear	3,502	3,502	3,502	3,502	3,502
Other	9	9	9	9	9
Battery	638	638	638	708	797
Total MW	63,898	64,324	63,646	63,815	64,048
Total MW*	62,807	63,671	62,343	62,512	62,745
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Florida Peninsula Assessment

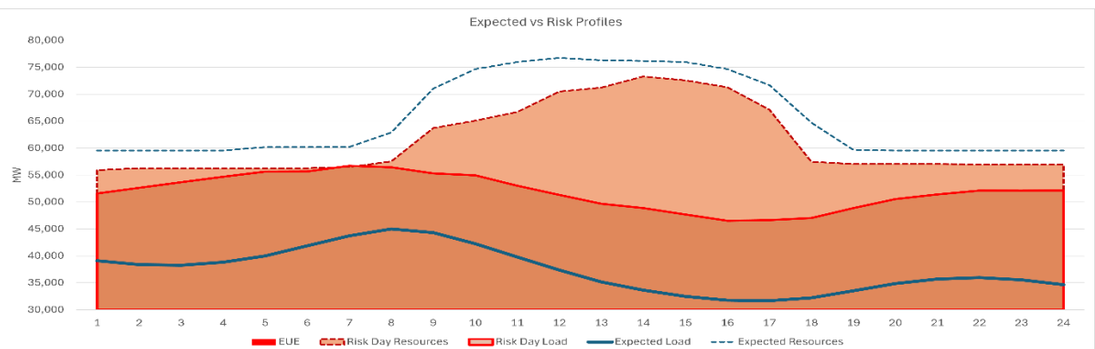
Planning Reserve Margins
The ARM is not expected to fall below the RML for any period of the assessment period.

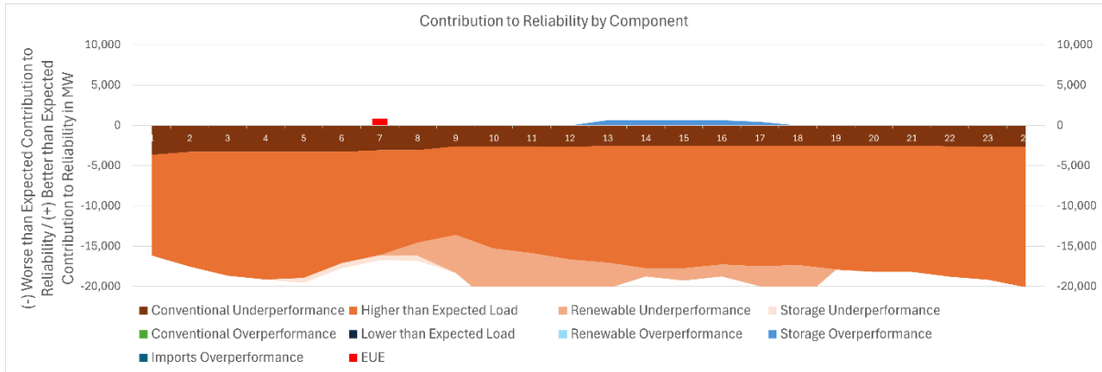
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss. Analysis of detailed ProbA outputs shows that that the negligible risk in year 2026 is associated with hot late-summer or early fall conditions, high generator forced outages, and upper levels of economic load forecast models. The risk occurs in evening hours around 7:00 p.m. when contribution from solar generation is limited.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1.13	**2.18**	**16.28**
EUE (PPM)	0.00	**0.01**	**0.06**
LOLH (hours per year)	0.00	**0.01**	**0.02**
Operable On-Peak Margin	18.6%	**19.2%**	**16.3**

* Provides the 2022 ProbA Results for Comparison

For study year 2028, the ProbA results shows very low risk with 16.28 MWh of EUE and 0.02 LOLH hours. The driver of the risk is mainly extreme winter weather, similar to conditions from 1989, when Florida experienced one of the worst winter freezes on record. With higher load levels and lower resources in 2028, the low risk shifts to late December, occurring in morning hours when contribution from solar generation is limited, and is associated with winter freeze events that limit imports.





Demand
The individual entities within the FL-Peninsula Subregion develop their load forecasts and the Florida Reliability Coordinating Council (FRCC) then aggregates these forecasts to calculate a non-coincident seasonal peak for the subregion. Each entity adjusts their forecasts annually to account for their actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and energy efficiency efforts, and electric appliances usage patterns. Based on the data reported in the 2023 FRCC Regional Load and Resource Plan, the net energy for load (NEL) and summer peak demands are forecasted to grow when compared to previous forecasts. The current average annual growth rate for the NEL is 0.97% per year. Firm summer and winter peak demand growth are expected to increase to 1.19% and 1.17%, respectively.

Demand-Side Management
Controllable DR from interruptible and dispatchable load management programs within the FL-Peninsula Subregion is treated as a load-modifier, and it is projected to be constant at approximately 6% of the summer and winter total peak demands for all years of the assessment period.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Florida Peninsula assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Energy Storage

Electricity storage (ES) is still a growing capacity contributor in the assessment area. Over the next 10 years, a total of approximately 2,900 MW of ES generation is projected to be in service by 2032 and is included in the utilities' 10-year site plans (approximately 775 MW by 2029).

Individual entities in the assessment area that have installed or are projecting the installation of ES are developing operating protocols on the use and dispatch of these facilities. ES units are studied as part of the normal generation interconnection process and included in other FRCC studies and processes with members providing individual dispatch profiles and study levels in order to identify potential operational impacts.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 668 miles of new transmission lines through 2030. The entities are also planning to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

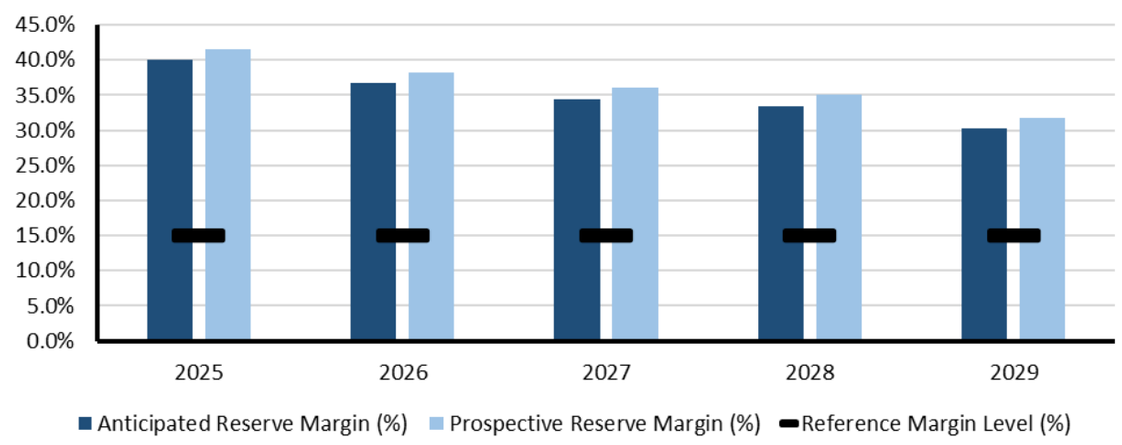


SERC-Southeast

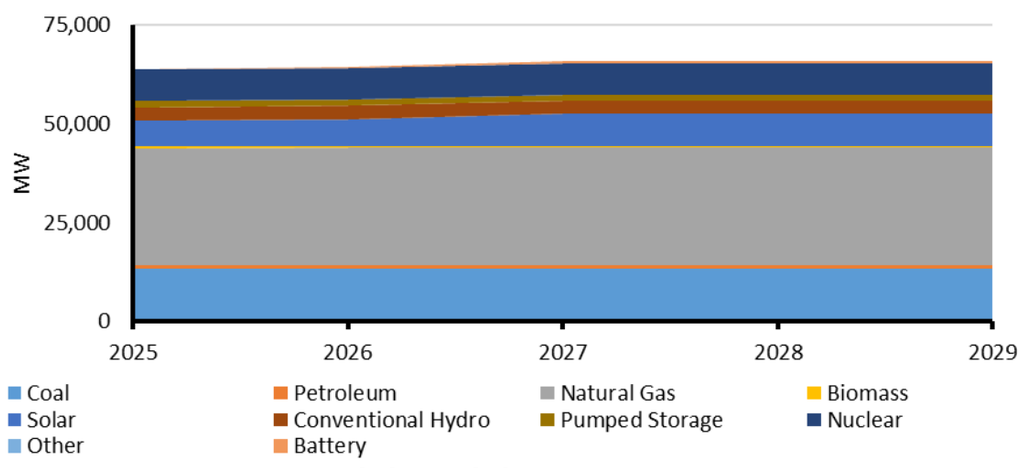
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	46,984	48,384	50,467	50,852	51,974	53,031	53,794	54,233	54,677	55,078
Demand Response	1,633	1,666	1,723	1,755	1,875	1,876	1,875	1,875	1,876	1,876
Net Internal Demand	45,351	46,718	48,744	49,097	50,099	51,155	51,919	52,358	52,801	53,202
Additions: Tier 1	1,248	1,486	3,050	3,050	3,050	3,129	3,129	3,129	3,129	3,129
Additions: Tier 2	105	105	218	218	218	218	218	218	218	218
Additions: Tier 3	366	366	366	366	366	366	366	366	366	366
Net Firm Capacity Transfers	-392	-392	-392	-392	-684	-684	-684	-684	-684	-684
Existing-Certain and Net Firm Transfers	62,257	62,413	62,472	62,472	62,180	62,180	62,180	62,180	62,180	62,180
Anticipated Reserve Margin (%)	40.0%	36.8%	34.4%	33.5%	30.2%	27.7%	25.8%	24.7%	23.7%	22.8%
Prospective Reserve Margin (%)	41.5%	38.2%	36.0%	35.0%	31.7%	29.2%	27.3%	26.2%	25.1%	24.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,275	13,275	13,275	13,275	13,275
Coal*	13,275	13,275	12,271	10,321	10,321
Petroleum	915	915	915	915	915
Petroleum*	915	915	915	899	899
Natural Gas	29,639	29,795	29,854	29,854	29,854
Natural Gas*	29,564	29,387	29,446	28,426	28,426
Biomass	424	424	424	424	424
Solar	6,597	6,835	8,021	8,021	8,021
Conventional Hydro	3,293	3,293	3,293	3,293	3,293
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	105	105	483	483	483
Total MW	63,897	64,291	65,914	65,914	65,914
Total MW*	63,822	63,883	64,502	61,516	61,516
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Southeast Assessment

Planning Reserve Margins

The future reserve margins are above the RMLs for SERC-Southeast.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.00**	**0.00**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.00**	**0.00**
Operable On-Peak Margin	30.8%	**29.6%**	**25.6%**

* Provides the 2022 ProbA Results for Comparison

Demand

Data centers, cryptocurrency facilities, and large commercial and industrial load are driving demand forecast growth in the assessment area. Metro areas are experiencing a higher growth rate compared to rural areas.

Demand-Side Management

Entities within the SERC-Southeast assessment area use a variety of controllable and dispatchable DR programs to reduce peak demand. One entity manages a voluntary DSM water heater program designed to allow system operators to control the appliances' usage during peak demand periods. Another entity monitors and dispatches DR programs commensurate with contract terms. Annual ELCC simulations are performed to determine the capacity value for each unique and active DR program. An adjustment to that capacity value is then made based on predicted customer response when the program is called or dispatched.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Southeast assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 1,078 miles of new transmission lines in the next 10 years. The entities are also planning to upgrade 694 miles of transmission lines during this time to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

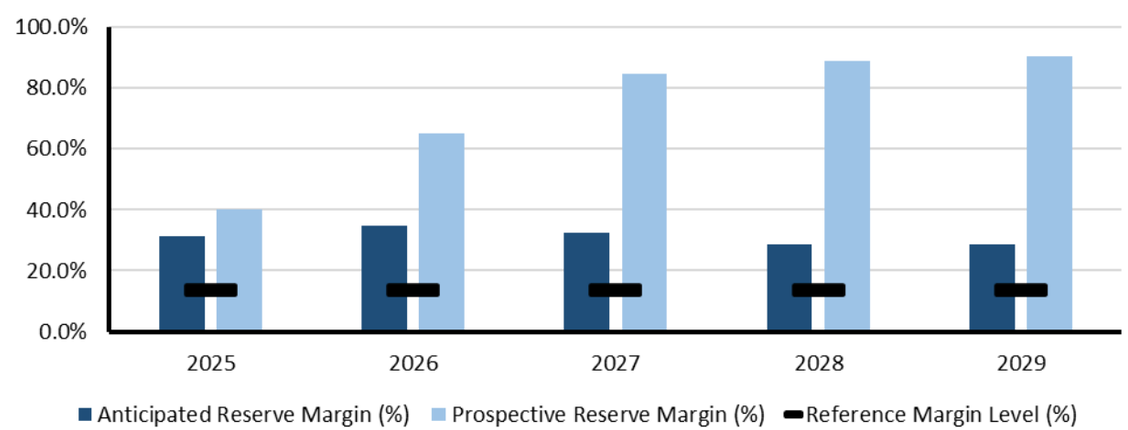


Texas RE-ERCOT

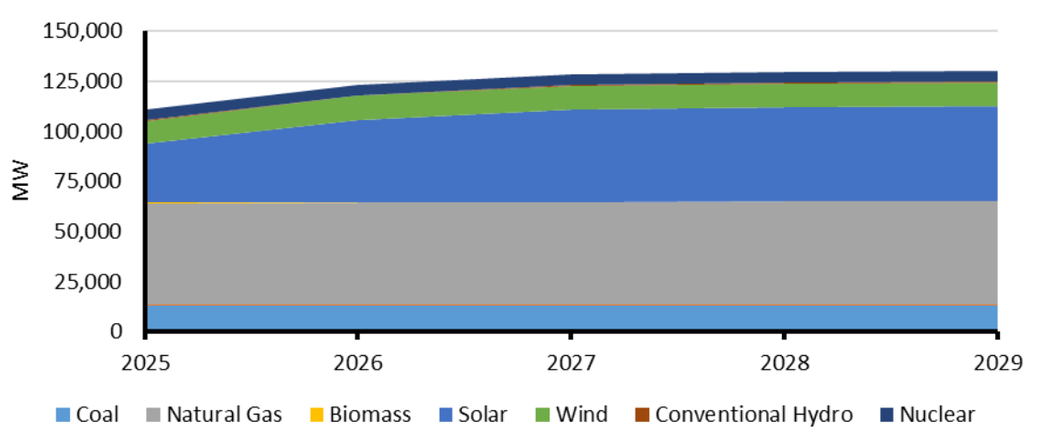
The Electric Reliability Council of Texas (ERCOT) is the ISO for the Texas Interconnection and is located entirely in the state of Texas; it operates as a single BAand performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	88,873	95,721	101,405	105,417	106,365	106,951	106,772	106,463	106,062	106,961
Demand Response	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652
Net Internal Demand	86,220	93,069	98,753	102,765	103,713	104,298	104,119	103,811	103,410	104,309
Additions: Tier 1	11,187	23,684	28,725	29,226	29,903	29,903	29,903	29,903	29,903	29,903
Additions: Tier 2	7,281	27,876	51,414	62,225	65,786	65,939	65,939	65,939	65,939	65,939
Additions: Tier 3	7,252	17,627	29,082	41,174	45,318	47,062	47,062	47,062	47,062	47,062
Net Firm Capacity Transfers	20	20	20	20	20	20	20	20	20	20
Existing-Certain and Net Firm Transfers	101,906	101,645	102,003	103,088	103,338	103,338	103,338	103,338	103,338	103,338
Anticipated Reserve Margin (%)	31.2%	34.7%	32.4%	28.8%	28.5%	27.8%	28.0%	28.3%	28.8%	27.7%
Prospective Reserve Margin (%)	40.3%	65.2%	84.6%	88.8%	90.3%	88.8%	89.1%	89.7%	90.4%	88.8%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Generation resources, primarily solar PV, continue to be added to the grid in Texas in large quantities, increasing ARMs but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation. The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV.

- The Public Utility Commission of Texas (PUCT) established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. ERCOT will begin performing reliability assessments required by the new standard in 2026.

- ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities.

Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	13,568	13,568	13,568	13,568	13,568
Coal*	13,568	13,568	12,913	12,353	12,353
Petroleum	10	10	10	10	10
Natural Gas	50,568	50,694	50,845	51,458	51,458
Natural Gas*	49,709	49,928	48,823	49,436	49,436
Biomass	163	163	163	163	163
Solar	29,557	41,201	45,984	46,485	47,163
Wind	11,332	11,908	12,166	12,166	12,166
Conventional Hydro	458	458	458	458	458
Nuclear	4,973	4,973	4,973	4,973	4,973
Total MW	110,628	122,975	128,167	129,281	129,958
Total MW*	109,769	122,208	125,490	126,044	126,721
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Texas RE-ERCOT Assessment

Planning Reserve Margins

The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV. However, the high reserve margin belies concerns over the continuing trend toward less fully dispatchable resources and more IBRs like solar PV and wind. While thermal resource availability and adequate gas supplies are still concerns during extreme winter weather events, the fleet performed well during Winter Storm Heather in January 2024, indicating that new weatherization standards, fully implemented in 2023, are effective.

Non-Peak Hour Risk and Energy Assurance

The PUCT established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. The latter two measures have an "exceedance tolerance," which is the maximum acceptable percentage frequency of loss-of load events that exceed the permissible thresholds based on a probabilistic simulation.

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at hour ending (HE) 9:00 p.m.—based on probabilistic modeling of monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. The summer peak load hour continues to be 5:00 p.m. For winter, the peak load hour is HE 8:00 a.m. Risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 a.m. to 9:00 a.m.) as well as the early evening hours.

ERCOT is experiencing transmission limitations as a result of load growth and resource development that affect energy delivery. On March 1, 2024, ERCOT introduced four new Interconnection reliability operating limits (IROL) in the South Texas region. This consists of two South Texas import constraints and two South Texas export constraints, which, if violated, could result in a thermal cascading condition. This is the first thermal IROL that could lead to a cascading condition in the Texas RE-ERCOT Region and has been attributed to the increase in generation capacity in South Texas and the rapid load growth in central Texas. To manage the South Texas export constraint, generation in South Texas must be curtailed to maintain transmission line flows below 100% of the impacted lines' thermal ratings. The risk of such curtailments, which is highest for the hours with the highest net peak loads (early evening), is included in the monthly probabilistic reserve risk assessments. ERCOT has approved two San Antonio Reliability projects that are expected to be completed in 2027 and should help alleviate some of risk drivers associated with these IROLs.

Probabilistic Assessment

Results of the 2024 ProbA are shown in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

* Provides the 2022 ProbA Results for Comparison

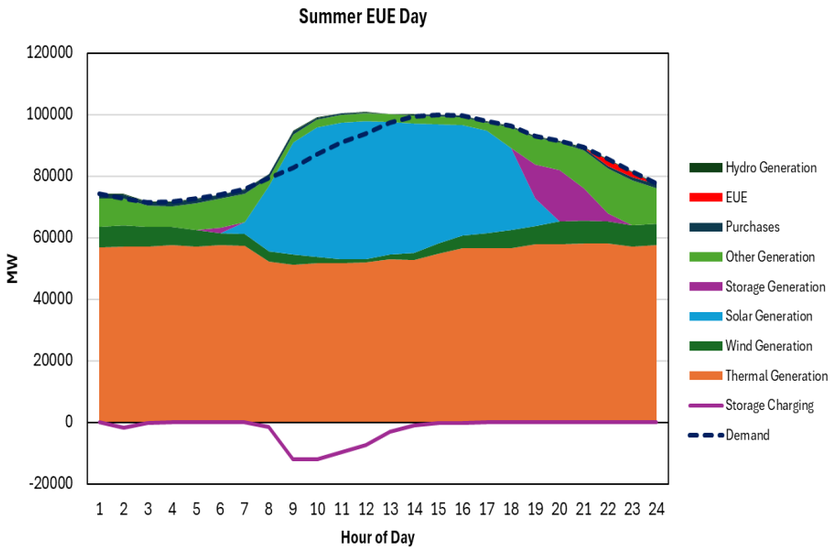
Increasing reliability risk in ERCOT is primarily driven by increasing large load demand anticipated from data centers, Bitcoin operations, continued load growth in oil and gas-producing areas (such as the Permian Basin), and growth in industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. ERCOT also anticipates 1,860 MW of fossil-fueled plant capacity to be retired by Summer 2028. New planned units are primarily renewable and storage, which exhibit declining marginal reliability contributions. The reliability forecasts provided by this ProbA assessment for 2028 include resource capacity contributions from expansion planning analysis conducted for ERCOT's 2024 *Long-Term System Assessment*. While there is uncertainty around the deployment of these resources, the large load demand growth is also uncertain and large loads are subject to various requirements for being integrated into the grid.

All SERVM simulations for ERCOT and surrounding regions impose all relevant generator temporal constraints, including operating limitations on conventional units as well as state-of-charge on batteries, so this assessment accounts for energy adequacy. However, this assessment does assume fuel for conventional units will be available when needed.[37]

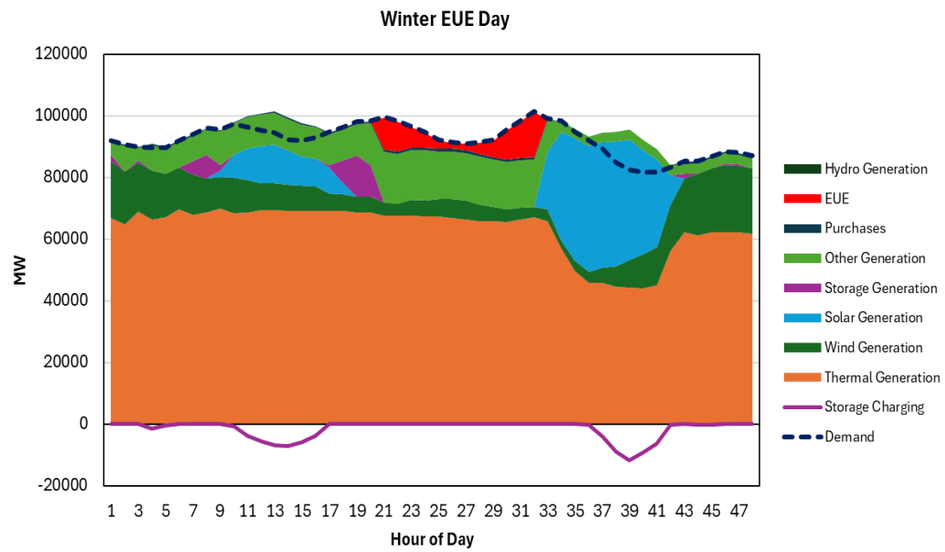
The unique characteristics of winter risk vs. summer risk can be seen in the following charts of a representative risk day. While peak winter loads can persist for 48 hours or longer, peak summer

[37] ERCOT and several other entities used SERVM software tool to perform the ProbA. Information about SERVM can be found at the company's website.

periods generally only last for a few hours. This has significant implications for the duration and depth of firm load-shed events in the winter as well as for the reliability contribution of energy limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and 29 GW in depth. The illustration below indicates a winter EUE event with duration >12 hours while most summer events were 1–2 hours in duration.



Metric	2026 Summer	2026 Winter	2028 Summer	2028 Winter
LOLE (days/year)	0.38	0.51	0.05	0.04
LOLH (hours/year)	1.41	1.57	0.18	0.16
EUE (MWh)	10,985	11,090	857	781
Max Hourly EUE (MWh)	29,124	29,266	17,762	16,851
Max EUE Duration (Hr)	15	16	12	11



From the hourly event data, ERCOT provided a multi-metric summary of the largest event showing the highest magnitude and longest-duration, as shown in the following figure.

Demand

ERCOT's long-term load forecast consists of the following individual components: (1) a base forecast that uses an econometric model with estimation data comprising 15 historical weather years, economic drivers, calendar information, and historical loads, (2) a roof-top PV forecast, (3) an EV forecast, a large flexible load forecast (crypto-mining facilities), and new "large loads" with a signed interconnection contract with their transmission or distribution service provider. Forecasts are provided for eight weather zones as well as system coincidental and non-coincidental demands. ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In

comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities. (A negligible amount of new contracted loads reported by transmission service providers occur past 2029). The base peak load, which excludes these new contracted loads as well as load reductions due to rooftop solar installations, grows at a more modest 1.4%.

A major load forecasting change from last year is a new Texas Legislature requirement to include non-contracted loads in transmission planning studies. Non-contracted loads lack a signed Interconnection or facility expansion agreement. ERCOT's previous practice had been to exclude these more speculative loads from the load forecast. The non-contracted loads total about 3.6 GW for summer 2025 and reach about 31.7 GW by 2029. The non-contracted loads are not included in the LTRA's peak load forecast. ERCOT is evaluating how these non-contracted forecasted loads will be handled for future resource adequacy and other planning activities.

Demand-Side Management

Most of the demand-side resources available to ERCOT are dispatchable in the form of noncontrollable load resources providing responsive reserve service and ERCOT's Emergency Response Service. The ERCOT Emergency Response Service consists of 10- and 30-minute ramping DRs and distributed generation that can first be deployed when physical responsive reserves drop to 3,000 MW and are not projected to be recovered above 3,000 MW within 30 minutes following the deployment of non-spin reserves. Responsive reserve is provided by industrial loads and is procured on an hourly basis in the day-ahead market. During 2023, load resources started to participate in two other ancillary services, the Non-Spinning Reserve Service and ERCOT Contingency Reserve Service (ECRS), which are used to help balance the system during periods when there may be net-load ramps that cannot be met with conventional supply-side resources.

The remaining dispatchable DR available to ERCOT is from the transmission and distribution service providers' (TDSP) load management programs. These programs provide price incentives for voluntary load reductions from commercial, industrial, and residential loads during energy emergency alert events.

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member TDSPs to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year timeframe.

A bill was approved in the 88th Texas Legislature (HB 3390) that outlines new DER reporting responsibilities. The bill authorizes ERCOT to require TDSPs to provide unregistered DER information that ERCOT deems necessary for grid reliability assessment. ERCOT is now developing annual data collection and maintenance processes.

A multi-phase aggregated DER (ADER) pilot program was implemented in 2022. As of May 2024, there were two ADERs with 13 MW of dispatchable capability actively participating in the pilot project with another nine ADERs in various stages of registration/qualification.

Generation

Natural-gas-fired generation makes up approximately 45% of the available generation inside the ERCOT footprint. Approximately 6% of the natural-gas-fired generation demonstrates firm fuel capabilities as part of ERCOT's Firm Fuel Supply Service required by the PUCT.

ERCOT has established formal working relationships with grid generators' fuel suppliers to gather operational and delivery information useful for its control room operators. ERCOT has focused the efforts on two fronts: (1) obtaining real-time (or near real-time) information on the health of the natural gas systems that serve the generators and (2) maintaining communication with pipelines to notify ERCOT of any planned or unplanned events that could impact deliveries to generators.

After the 2021 Odessa event, ERCOT intensified its efforts to find corrective measures to enhance the ride-through performance of IBRs and improve overall system resilience. The study, which recommended installing synchronous condensers at six locations in West Texas, has been completed, and the ERCOT board of directors endorsed the project in December 2023. The project is expected to be in service in 2027.

ERCOT has proposed new grid code requirements for IBRs to improve voltage ride-through (VRT) performance to align with IEEE Standard 2800. The proposed grid code requirements are continuing to go through ERCOT's stakeholder approval process. Until new rules go into effect, IBRs will be expected to maximize VRT capability and address existing performance failures (such as by reducing maximum output).

To provide an incentive to build new dispatchable resources, the PUCT adopted a new rule to establish a generation loan program, one of four incentive programs under the recently established Texas Energy Fund (TEF). The other three programs within the TEF include completion bonus grants for new dispatchable generation projects that consistently provide power generation over a 10-year period, grants for companies to establish or secure backup power resources, and grants to improve the resiliency and availability of electric utility service outside the ERCOT region. The TEF has $5 billion

available for all four programs. These loans and grants have thus far resulted in 72 applications seeking funding under the TEF loan program. The PUCT staff-recommended portfolio represents 9,781 MW in potential new generation if all recommended applicants were to execute a loan agreement at the requested loan amounts.

Energy Storage

The current installed BESS capacity is 9,149 MW. These systems participate in ERCOT's Energy and Ancillary Service markets. Most have durations in the one-to-two-hour range. ERCOT is seeing an increase in longer-duration systems (three to four hours) to take advantage of energy-shifting and capacity-firming opportunities arising from continued high renewable generation penetration. For the first half of 2024, energy storage provided 87% of ERCOT's regulation up and 91% of responsive reserve service from primary frequency response (RRS-PFR). In June 2023, ERCOT implemented a new ancillary service, the ERCOT Contingency Reserve Service (ECRS), which, in part, is designed to address the ramping needs of the system. This ancillary service product provides additional opportunities for BESS ancillary service participation. To support larger BESS penetration levels, ERCOT submitted new proposed rules for state-of-charge accounting in energy dispatch and reliability unit commitment that are planned for implementation this year.

Based on the latest developer information for projects that are in the interconnection queue, ERCOT expects about 10,500 MW of additional battery energy storage capacity to be operational by year-end 2025. This capacity constitutes projects for which developers have posted financial security to build the interconnection facilities. By year-end 2029, the additional cumulative Tier 1 planned capacity reaches about 20,000 MW.

ERCOT currently assigns a 0% on-peak contribution for battery energy storage. ERCOT has changed its rule to adopt an ELCC methodology for battery storage of various durations. Extending the proposed ELCC methodology for BESS to current and forecasted resources in ERCOT would improve the anticipated reserve margins in the future.

Capacity Transfers

ERCOT has coordination plans in place with neighboring grids. These plans cover dc tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers.

Transmission

In September, the PUCT approved ERCOT's Permian Basin Reliability Plan. The plan consists of new and upgraded local transmission projects as well as building new import paths to load centers in other areas of the Texas RE-ERCOT region, including options for extra high voltage (EHV) infrastructure operating at 345 kW or 765 kV. The plan supports Permian Basin load growth that is currently expected to reach 24 GW by 2030 and over 26 GW by 2038.

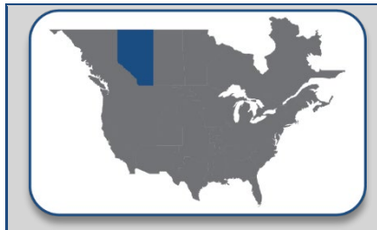
ERCOT's 2023 Regional Transmission Plan (RTP) identified 173 reliability projects, with the majority consisting of 138 kV and 345 kV system upgrades. The 2023 RTP also included an economic assessment of the ERCOT transmission system for years 2025 and 2028 using production cost savings and generator revenue reduction tests.

The substantial increase in new loads from a year ago is expected to present challenges for transmission planning. The forecasted pace of the load growth could exceed the pace at which transmission capacity can be built to support it. ERCOT is working on major changes to its transmission planning process to address these challenges. For example, ERCOT is investigating a "generation hub" concept to indicate optimal generation location to address regional load growth and optimize transmission investments.

A new biennial report on grid resiliency—the Grid Reliability and Resiliency Assessment—evaluates extreme weather scenarios considering different levels of thermal and renewable generation availability and the potential outages caused by extreme weather conditions. The assessment also includes proposed transmission projects that may mitigate regional resiliency risks. The first report will be released by December 31, 2024.

New minimum deliverability criteria were included in ERCOT's 2023 RTP to ensure the deliverability of 100% of generation resource capacity and energy storage resources with a duration greater than or equal to two hours. For storage systems with a duration less than two hours, a prorated deliverability was ensured. Corrective action plans (CAP) were proposed to address any reliability violations under the contingencies defined for the minimum deliverability criteria.

ERCOT has also started implementing the PUCT's amended rules relating to certification criteria and is in the process of integrating a new congestion cost savings test for economic projects evaluation.

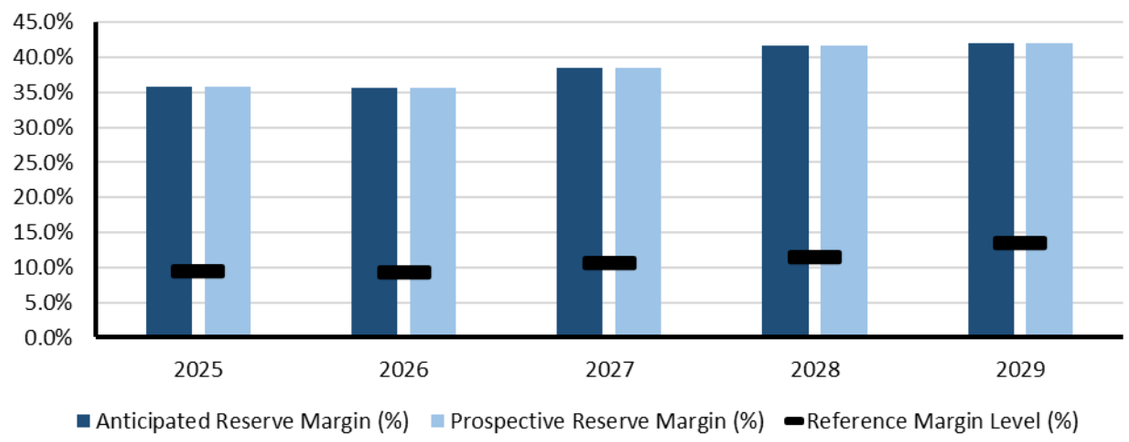


WECC-AB

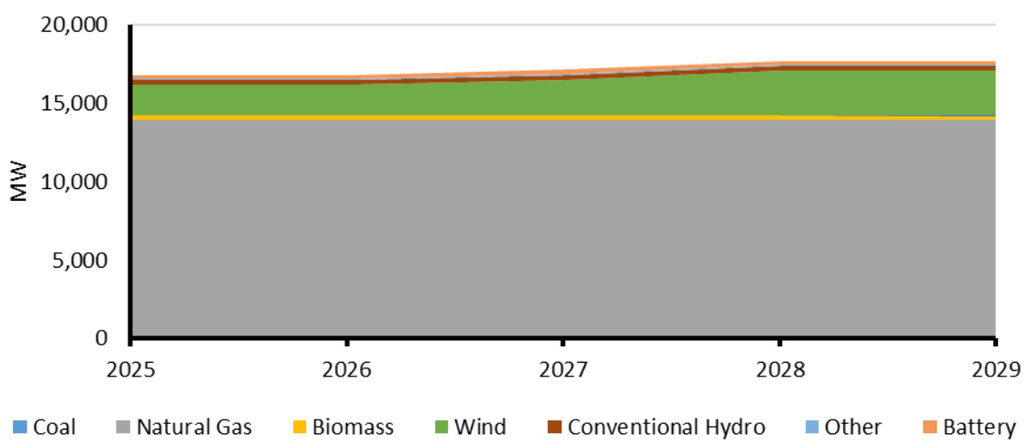
WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Additions: Tier 1	3,275	3,275	3,405	3,541	3,537	3,342	3,537	3,441	3,273	3,273
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	1,031	1,680	1,824	2,247	2,700	2,502	3,068	3,096	2,744	2,744
Net Firm Capacity Transfers	43	96	69	0	68	396	409	0	0	0
Existing-Certain and Net Firm Transfers	13,578	13,631	13,822	14,182	14,244	13,931	14,585	13,867	13,330	13,330
Anticipated Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Prospective Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Reference Margin Level (%)	9.4%	9.4%	10.6%	11.5%	13.6%	9.2%	13.2%	11.3%	9.0%	9.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- The peak hour of demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's.
- Despite low resource adequacy risk, operational risk is still present. Ensuring sufficient frequency response capability has been identified as the region's highest priority. Frequency response has been declining in the region due to the increasing share of IBR resources and declining baseload resources. This under frequency load shedding risk is exacerbated in islanded or near-islanded situations.
- Alberta's two remaining coal-fired generators completed their conversion to natural gas this year.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	13,932	13,932	13,941	13,930	13,920
Biomass	336	336	336	336	336
Wind	1,912	1,912	2,232	2,811	2,799
Conventional Hydro	285	285	303	302	312
Other	81	81	81	81	81
Battery	264	264	264	264	263
Total MW	16,810	16,810	17,157	17,723	17,713

WECC-AB Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. From the 2032–2033 winter onward, Alberta shows a shortfall of existing-certain and net firm transfers. This indicates that imports may be necessary during this timeframe if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the one-day-in-ten-year (ODITY) level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

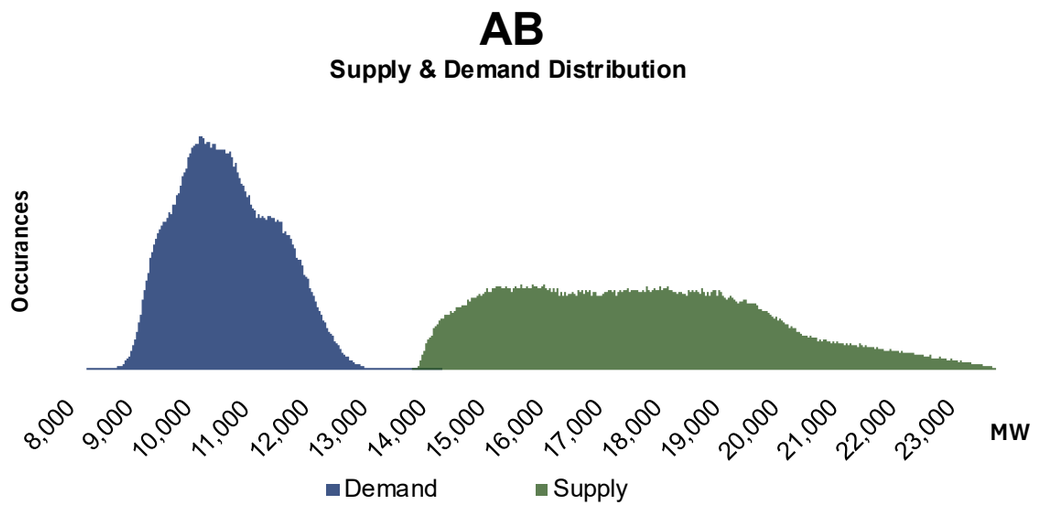
Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0	0	0
EUE (PPM)	0	0	0
LOLH (hours per year)	0	0	0
Operable On-Peak Margin	26.1%	41.6%	42.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the Multi-Area Variable Resource Integration Convolution (MAVRIC) model. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. WECC also produces an annual reliability assessment called the *Western Assessment of Resource Adequacy* (WARA).[38]

The availability and demand distributions in the ProbA simulations do not overlap, indicating an extremely low probability of Alberta not being resource adequate over the next four years. For 2026 and 2028, the peak hour occurs in December at HE 18:00. Alberta does not show LOLH nor EUE in the LTRA forecast horizon. The gap between the demand distribution and the supply distribution shown in the figure below emphasizes that there is minimal resource adequacy risk in Alberta. The ARM appears to further validate this, as it is far above the RML for 2026 and 2028.



Demand

Peak demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's. Near-term load growth is driven by industrial loads, such as oil sands production, pulp and paper mills, and gas and oil processing. Long-term demand growth is driven by electrification of transportation and buildings as well as potential growth in emerging industries, such as hydrogen production.

[38] See WECC Reliability Assessments.

Distributed Energy Resources
BTM DERs are difficult to measure due to data gathering barriers. AESO released its updated 2022 Plan for DER Roadmap Integration Activities.

Generation
Over 6 GW of nameplate capacity are being added in Alberta through the end of 2028. There is significantly more solar, wind, and energy storage in this year's planned capacity additions than in the last LTRA. Additionally, several states and provinces in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions. Alberta's two remaining coal units have been converted to natural gas this year.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
In WECC's analysis, Alberta is not showing significant changes to capacity transfers. There is a slight increase in exports between 5:00 p.m. and 10:00 p.m. and in the later years of the assessment period.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

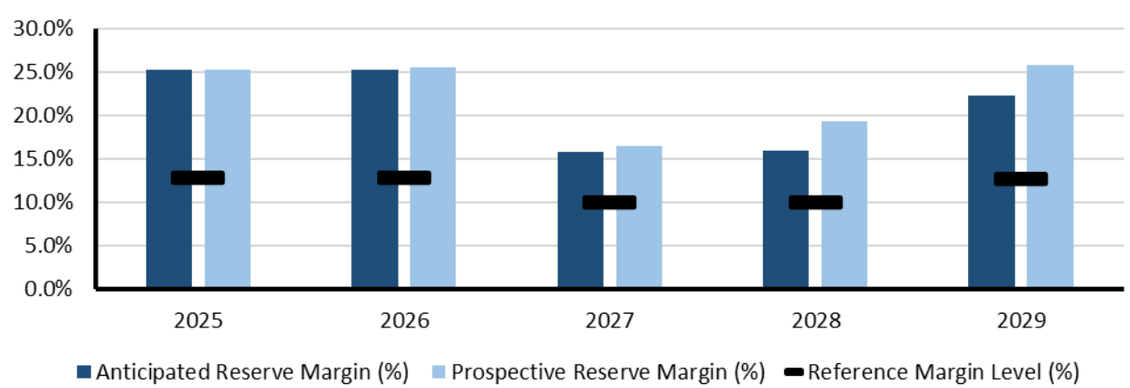


WECC-BC

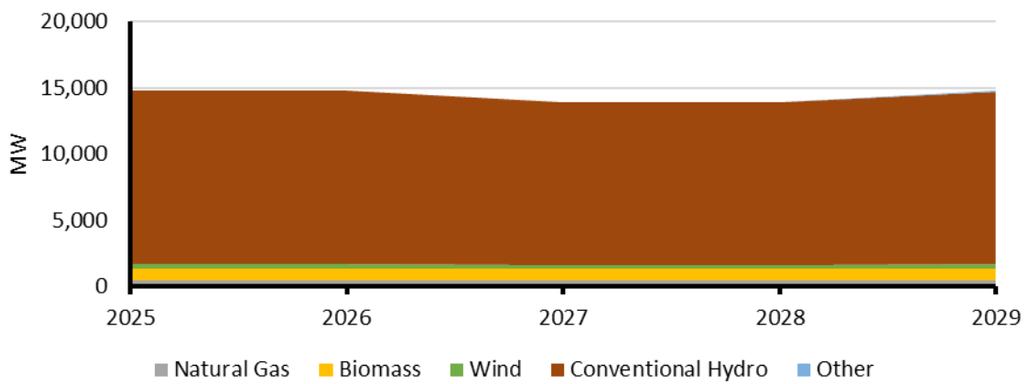
WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of BC, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Additions: Tier 1	956	956	893	893	956	956	956	956	893	956
Additions: Tier 2	0	41	79	398	419	748	1,077	1,077	1,012	1,405
Additions: Tier 3	0	5	5	5	6	6	59	59	56	59
Net Firm Capacity Transfers	184	188	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	14,054	14,022	13,019	12,998	13,812	13,795	13,795	13,795	12,982	13,795
Anticipated Reserve Margin (%)	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
Prospective Reserve Margin (%)	25.2%	25.6%	16.5%	19.2%	25.8%	28.3%	30.5%	30.0%	21.7%	31.3%
Reference Margin Level (%)	12.8%	12.8%	10.0%	10.0%	12.7%	12.7%	12.6%	12.6%	9.8%	12.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from the winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.
- The peak hour of demand for BC occurs in the winter. BC shows the lowest demand growth rate in the west. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the previous LTRA forecast. This is an average annual growth rate of 0.28%, and a 2.8% load growth over the forecast horizon.
- BC is showing hours of demand at risk that are not fully mitigated by the addition of Tier 3 resources. Supply chain performance will play a significant role in BC's ability to reliably meet energy needs. Seasonal and daily fluctuations of hydro resource availability is also a risk. LOLH and EUE correlate with periods when river flows are at their lowest.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	459	459	456	456	459
Biomass	920	920	914	914	920
Wind	279	279	268	268	279
Conventional Hydro	13,145	13,110	12,253	12,232	13,087
Other	22	22	22	22	22
Total MW	14,825	14,790	13,912	13,891	14,768

WECC-BC Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. In 2028, however, WECC's analysis identified over five hours where resources, including imports from neighbors, fall below margins for system reliability.

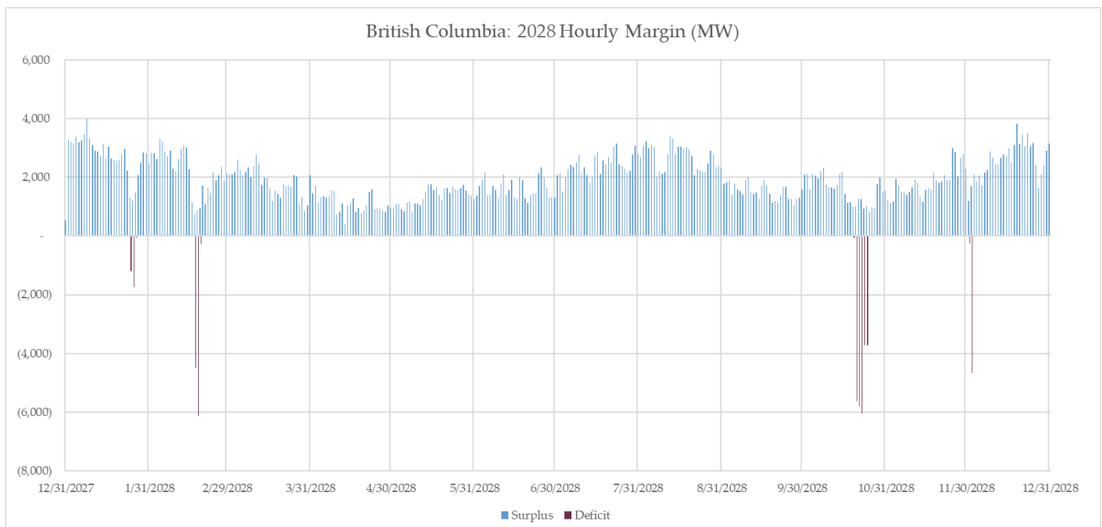
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	24	0	103,132
EUE (PPM)	0.71	0	1,457
LOLH (hours per year)	0.002	0	5.52
Operable On-Peak Margin	12.7%	16.9%	9.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

For both 2026 and 2028, the peak hour occurs in December at HE 19:00. LOLH and EUE are not forecast in 2026 but do appear in 2028. No LOLH or EUE occurs at the peak hour. 88% of the EUE in 2028 occurs overnight between the hours of 23:00 and 4:00.

In 2026, the peak summer hour is HE 17:00 in September, and in 2028 the peak hour is HE 17:00 in August. There is no LOLH projected for 2026 or during peak hours. LOLH occurs in 2028 between the hours of 17:00 and 20:00.



Icicle Plot with Hourly Surplus and Deficits for British Columbia in 2028

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

	1	2	3	4	5	6	7	8	9	10	11	12
0	(0)	(5)	-	-	-	-	-	-	-	(10)	-	-
1	(1)	(5)	-	-	-	-	-	-	-	(12)	-	-
2	(1)	(6)	-	-	-	-	-	-	-	(20)	-	-
3	(3)	(5)	-	-	-	-	-	-	-	(14)	(0)	-
4	(0)	(1)	-	-	-	-	-	-	-	(0)	(0)	-
5	-	(0)	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	(0)	-	-
8	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
9	(0)	(0)	-	-	-	-	-	-	-	-	-	(0)
10	-	(0)	-	-	-	-	-	-	-	-	-	(0)
11	-	-	-	-	-	-	-	-	-	-	-	(1)
12	-	-	-	-	-	-	-	-	-	-	-	(3)
13	-	(0)	-	-	-	-	-	-	-	-	-	(5)
14	-	-	-	-	-	-	-	-	-	-	-	(1)
15	-	(0)	-	-	-	-	-	-	-	-	-	(0)
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-	-
20	-	(0)	-	-	-	-	-	-	-	-	-	-
21	-	(0)	-	-	-	-	-	-	-	-	-	-
22	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
23	-	(2)	-	-	-	-	-	-	-	(5)	-	-

2028 Heat Map EUE (GW) - British Columbia

Demand

BC's average annual load growth in its forecast has fallen to a rate below Alberta's. The peak hour total internal demand for BC occurs in the winter. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the last forecast. This is an average annual growth rate of 0.28% and a 2.8% load growth over the forecast horizon. BC's load growth is lower due to updated monthly profiles that reflect current trends and aggressive DSM which it includes as a demand reduction in the demand forecasts provided to WECC. Load growth in BC is primarily driven by EV and gas sector load growth and is partially offset by a decline in demand from the forestry sector.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. BC Hydro has net metering. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

Across WECC, several states and provinces as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

In BC, hydro and wind resources are being added to the system. The BC Hydro Authority (BCHA) is taking steps to mitigate risks associated with climate change by improving coastal watershed inflow forecasting to an hourly level and increasing investment in capital projects to increase the resiliency of its hydro-dominant portfolio. Drought conditions in BC have led to water conservation measures, such as encouraging generation at facilities located in less drought-impacted areas, revising discharge plans at storage capable sites, and importing power when available to reduce water consumption.

Capacity Transfers

WECC's probabilistic analysis indicates that BC's need for imports is increasing during the assessment period.

Transmission

Three transmission projects with voltage design of 500 kV and higher are planned in the BC region.

Reliability Issues

WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

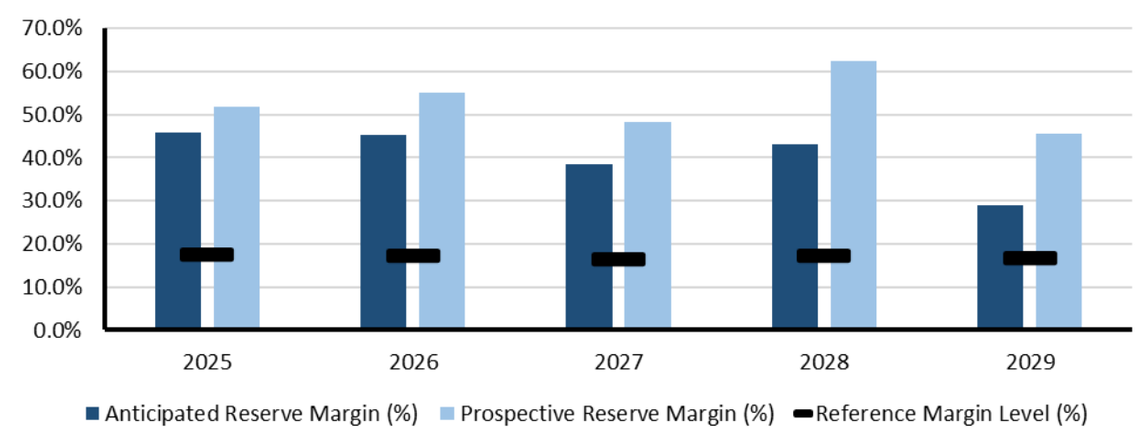


WECC-CA/MX

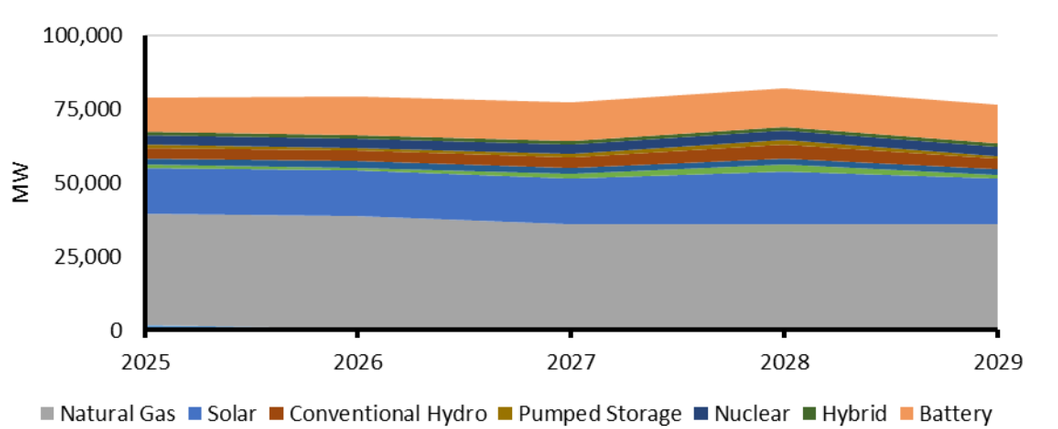
WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	56,619	57,274	59,291	60,131	61,289	61,067	62,336	65,876	67,251	69,064
Demand Response	795	797	793	793	793	794	794	794	794	794
Net Internal Demand	55,824	56,477	58,499	59,338	60,496	60,273	61,542	65,082	66,457	68,269
Additions: Tier 1	9,700	11,074	11,128	11,546	11,074	11,990	11,990	12,437	12,047	11,990
Additions: Tier 2	3,349	5,628	5,727	11,483	10,121	17,017	17,017	22,135	23,212	24,650
Additions: Tier 3	9	19	19	22	19	321	321	326	322	321
Net Firm Capacity Transfers	1,509	1,828	2,760	1,953	448	357	342	898	317	314
Existing-Certain and Net Firm Transfers	71,707	70,921	69,827	73,373	66,866	66,142	63,916	68,939	64,533	63,888
Anticipated Reserve Margin (%)	45.8%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
Prospective Reserve Margin (%)	51.8%	55.1%	48.2%	62.5%	45.6%	57.9%	51.0%	59.0%	50.2%	47.3%
Reference Margin Level (%)	17.4%	17.4%	16.4%	17.4%	16.6%	16.4%	16.1%	16.3%	14.9%	15.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML in Summer 2034, but the RML is covered by the PRM, which includes Tier 2 resource additions.
- Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers. However, with planned generation resource additions the shortfalls are eliminated. Imports may be necessary if the new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 2 resources and primarily correspond with the evening down ramp of solar and lingering demand after peak.
- The peak hour of demand for CA/MX occurs in the summer. Total internal demand at peak hour is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%.
- Diablo Canyon, a 2.2 GW nuclear site, will no longer be retired by 2025 and is now slated to be retired in 2030.

WECC-CA/MX Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	1,572	466	466	465	466
Coal*	1,122	16	16	15	16
Petroleum	185	185	185	184	185
Natural Gas	38,180	38,180	35,565	35,504	35,506
Biomass	726	726	727	726	726
Solar	15,464	15,464	15,501	17,990	15,464
Wind	1,158	1,158	1,428	2,144	1,158
Geothermal	2,004	2,059	2,061	2,056	2,059
Conventional Hydro	3,582	3,582	3,838	4,727	3,582
Pumped Storage	889	889	951	1,710	889
Nuclear	3,282	3,282	3,287	3,283	3,282
Hybrid	32	32	34	39	32
Other	32	32	32	32	32
Battery	12,792	14,111	14,119	14,106	14,111
Total MW	79,898	80,166	78,194	82,967	77,492
Total MW*	79,448	79,716	77,744	82,517	77,042
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The ARM falls below the RML in the summer of 2034. With the addition of Tier 2 resources, reserve margins remain above RML. Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

The California Independent System Operator (CAISO) is responsible for much of the BPS that is in CA/MX. CAISO manages the transmission system, oversees transmission planning, and operates the wholesale electricity market for its territory. Other entities in CA/MX include the Balancing Authority of Northern California (BANC), the Imperial Irrigation District (IID), and Mexico's National Center for Energy Control (CENACE), which operates the connected Baja California system.

CAISO Only: The ARM falling below the RML in Summer 2034 and the shortfall of existing-certain and net firm transfers in Summer 2029 is consistent when looking at CA/MX or solely at CAISO. The RML of CAISO averages 0.7% higher than the CA/MX region RML over the LTRA horizon. This is due to the exclusion of natural gas and coal resource energy contributions from CA/MX entities outside of CAISO. Decreasing baseload generators results in increased variability, which in turn requires a greater RML to maintain the ODITY threshold. However, the gap between the anticipated, prospective, and existing reserve margins and the RML for CAISO are greater than the broader CA/MX region. The proportion of energy availability to anticipated net internal demand is larger for CAISO, accounting for this increase.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. After 2026, however, WECC's analysis identified periods of unserved energy and load loss in CA/MX during June through October. Of note, this risk is limited to the Mexico portion of CA/MX (i.e., ProbA results for the CAISO do not indicate LOLH or EUE) until 2029, when the risk extends across the entire assessment area.

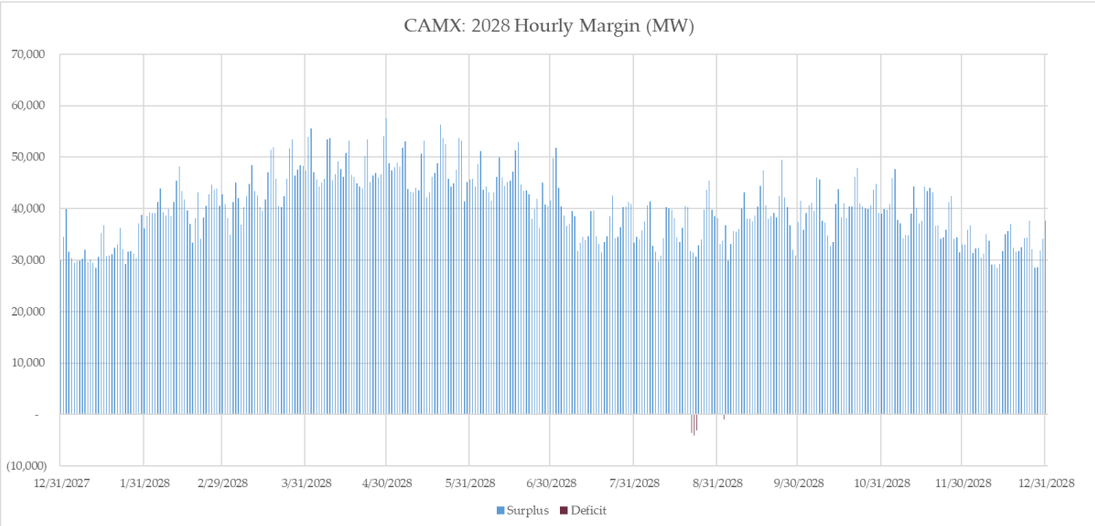
Base Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.721	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

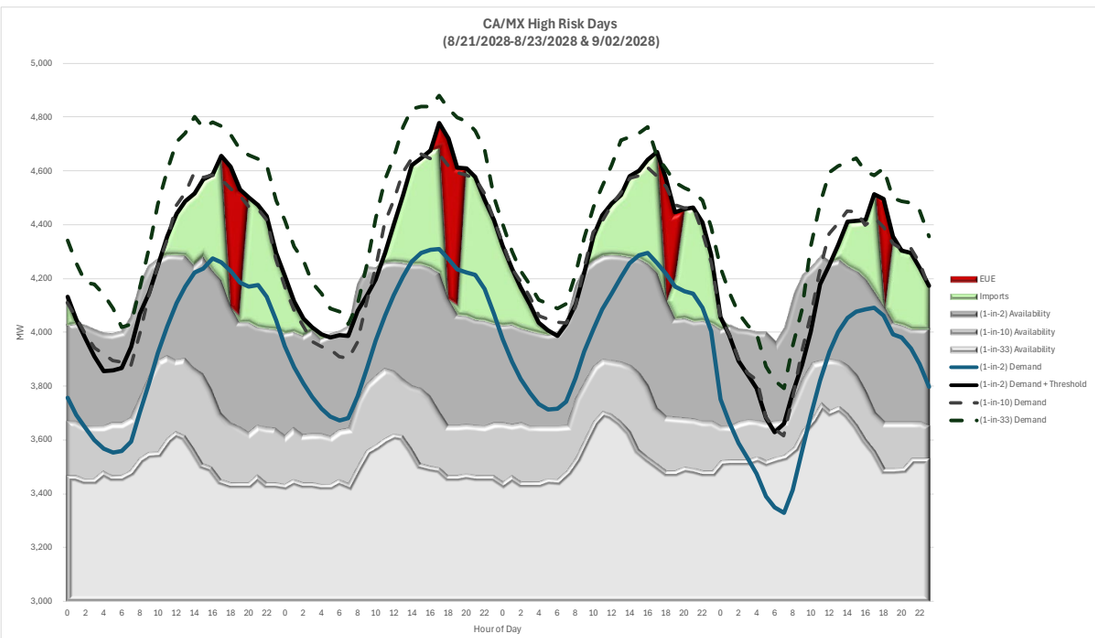
* Provides the 2022 ProbA Results for Comparison

Though the hour and month of peak demand are the same for both CAISO and the broader CA/MX region, CAISO shows the greatest amount of EUE and LOLH in September, whereas CA/MX shows the greatest amount of EUE and LOLH in August. This coincides with the seasonal reduction of solar irradiance in the fall and CAISO having a proportionally larger share of solar resources than the CA/MX region. Excluding regions external to CAISO results in a 96% reduction in LOLH events and EUE over the LTRA horizon.

The hour of peak demand in summer occurs at 5:00 p.m. The hours of highest risk, however, occur during periods after the peak demand hour as solar PV resource output diminishes. There is no LOLH projected for 2026; however in 2028, the ProbA reveals some LOLH between the hours of 5:00 and 8:00 p.m.



Icicle Plot with Hourly Surplus and Deficits for CA/MX in 2028



Demand

The peak demand for CA/MX occurs in the summer. The peak hour for total internal demand is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%. Transportation and building electrification are the primary drivers of demand growth.

CAISO Only: The demand forecast for CAISO grows at a slightly higher rate than the broader CA/MX region, with a load growth of 25.2% over the LTRA forecast horizon, and an average annual rate of 2.1%.

Demand-Side Management

A portion of the near-term decline in controllable and dispatchable DR for Summer 2024 is partly driven by regulatory changes in the CA/MX region. This includes making resource adequacy DR crediting adjustments based on historical performance and increasing DR availability requirements. The California Public Utilities Commission (CPUC) determined resource adequacy values of utility DR were overestimated during high load days. In response, the CPUC removed transmission gross-ups and some credits from utility DR resource adequacy values starting in 2024. The CPUC also directed that DR resource adequacy capacity must be available during all days the ISO calls a flex alert or issues a grid warning or on which the governor's office has issued an emergency notice, representing a significant increase in required availability. In addition, the CPUC now requires all DR capacity to be available a minimum of three days per week for at least four hours per day.

For CAISO, energy efficiency and conservation drops significantly when excluding non-CAISO entities from the CA/MX region. The entities outside of CAISO account for an average of 70% of the energy efficiency and conservation DSM for the CA/MX region for the LTRA timeframe.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. CAISO allows seven DER aggregators as market participants for energy and ancillary services. Additionally, PG&E's Partnership Pilot includes new or existing solar, storage, energy efficiency and demand response used via third party DER providers, vendors, or aggregators.

Generation

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
CA/MX is showing increasing amounts of exports to the northwest, especially during winter months.

Transmission
Seventeen transmission projects with 500 kV and higher are planned.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

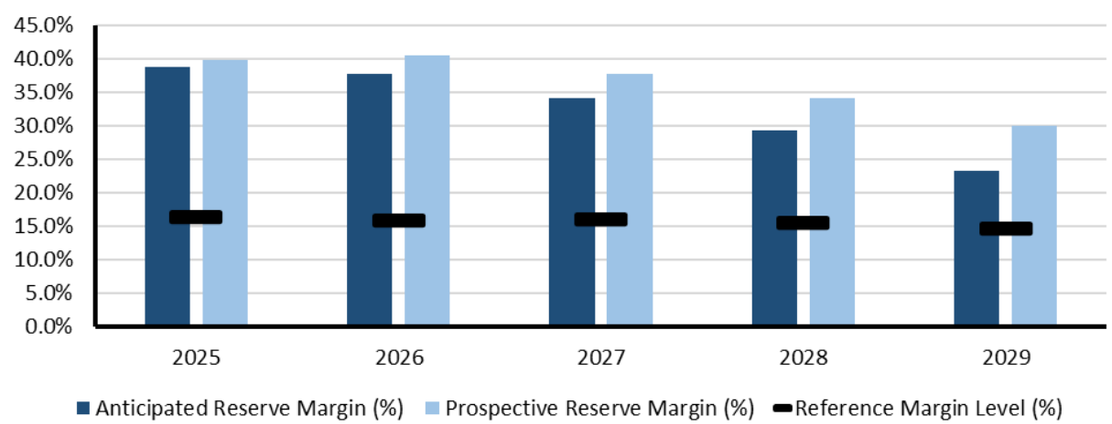


WECC-NW

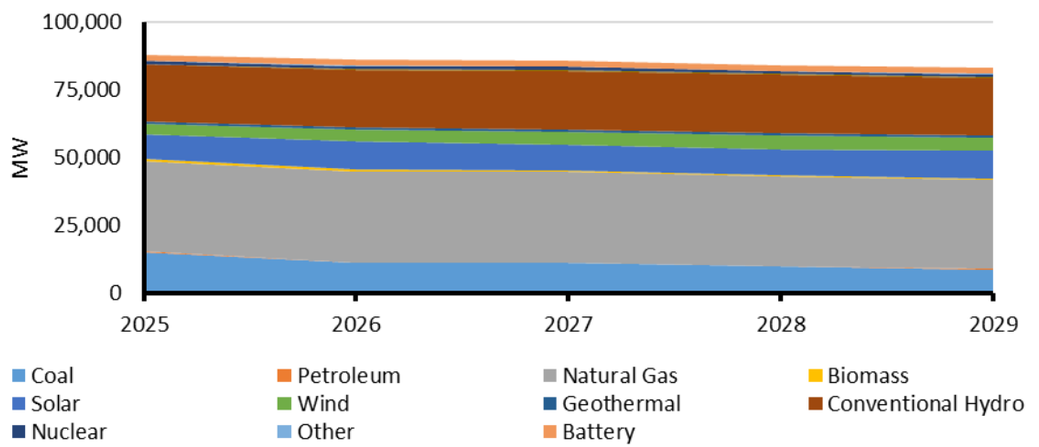
WECC-NW (Northwest) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	68,274	69,745	71,580	73,626	75,079	75,917	76,736	77,462	78,316	78,835
Demand Response	806	808	811	814	806	809	812	814	817	820
Net Internal Demand	67,469	68,936	70,768	72,811	74,273	75,108	75,925	76,647	77,499	78,016
Additions: Tier 1	7,000	9,386	9,295	9,489	9,752	9,752	10,141	10,141	9,915	10,141
Additions: Tier 2	788	1,955	2,628	3,595	5,046	6,593	7,258	7,273	6,935	7,253
Additions: Tier 3	2,945	8,874	14,008	21,247	28,296	33,802	40,239	42,260	41,876	43,809
Net Firm Capacity Transfers	5,627	8,796	9,087	9,863	8,462	6,037	2,783	2,423	2,370	2,140
Existing-Certain and Net Firm Transfers	86,609	85,564	85,605	84,618	81,788	78,094	74,003	73,297	72,810	71,446
Anticipated Reserve Margin (%)	38.7%	37.7%	34.1%	29.3%	23.3%	17.0%	10.8%	8.9%	6.7%	4.6%
Prospective Reserve Margin (%)	39.9%	40.6%	37.8%	34.2%	30.0%	25.7%	20.4%	18.4%	15.7%	13.9%
Reference Margin Level (%)	16.3%	15.8%	15.9%	15.4%	14.7%	14.5%	14.3%	14.2%	14.4%	13.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the RML for all years in the LTRA time horizon.
- Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar and wind, supported by BESS. Supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources.
- The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous LTRA. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%.

WECC-NW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	14,965	11,031	11,021	9,667	8,761
Coal*	14,661	10,223	10,607	9,349	8,060
Petroleum	321	321	319	319	316
Natural Gas	33,452	33,636	33,304	32,954	32,749
Biomass	729	723	683	683	604
Solar	9,086	10,191	9,350	9,431	10,379
Wind	3,924	4,566	4,939	4,939	4,561
Geothermal	884	934	933	1,007	997
Conventional Hydro	21,003	21,000	21,542	21,522	20,958
Pumped Storage	373	373	375	375	373
Nuclear	1,096	1,096	1,096	1,096	1,096
Other	64	64	64	64	64
Battery	2,084	2,219	2,188	2,188	2,219
Total MW	87,981	86,154	85,814	84,245	83,077
Total MW*	87,679	85,346	85,398	83,926	82,377
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-NW Assessment

Planning Reserve Margins

The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the Reference Margin for all years in the LTRA time horizon. Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,722	0	1
EUE (PPM)	4	0	0
LOLH (hours per year)	0.04	0	0
Operable On-Peak Margin	37.6%	36.1%	27.8%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

Imports to the Northwest from the CA/MX region grow throughout the LTRA forecast horizon. A calm, cloudy, extreme heat event occurring in the Northwest and CA/MX regions simultaneously poses a risk to the Northwest by limiting surplus energy in CA/MX to send northward.

Energy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio. More variability in energy output requires a greater reserve margin to maintain resource adequacy.

For 2026 and 2028, the peak hour occurs in August at HE 17:00. LOLH and EUE are not forecast in 2026 and only occur for a single hour in 2028. The LOLH occurred in August at HE 19:00, slightly after peak. The LOLH corresponds with the declining solar availability in the evening while demand remains high.

Demand

The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous plan. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%. There are significant differences between balancing areas, with some showing large load growth impacts while others showing a slight decrease in demand. Entities reporting large load growth cite new data centers as a primary driver.

Demand-Side Management

In the Northwest, Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows Idaho Power to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year to year based on factors such as the availability of water and program parameters. In 2022, the utility lengthened the season and included additional evening hours, which drove some reduction in participation that carried over to the Summer 2024 availability.

PacifiCorp states in its most recent Integrated Resource Plan (IRP) that it hopes to reach 1,123 MW of demand response by 2042 in its preferred portfolio plan, which is a 21% increase by 2042 from its previous plan. PacifiCorp's dispatchable DR programs include residential, small commercial air-conditioner load control, irrigation load management, and 203 MW of interruptible contracts.

The Public Service Company of Colorado (PSCo) also offers a wide array of DR programs, such as Saver's Switch, which is a program where the air-conditioning unit of a customer may be controlled

remotely and cycled during extreme heat events. Peak Day Partners allows for the direct load control and reduction of customers 0.5 MW or greater in size when system peaking conditions are met. The Interruptible Service Credit Option (ISOC) is a program where customers agree to reduce consumption in return for a rate discount with non-compliance being met with a fee.

Distributed Energy Resources
BTM DERs are difficult to measure due to data-gathering barriers. One example is Idaho Power's filing of annual DER Resources Status Reports by customer class and resource type, such as in 2023.

Generation
Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and BESS, further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
The Northwest is showing greatly increasing import needs over the 10-year time horizon, especially in the winter months. Most of the imports in the model simulations come from CA/MX, with a smaller portion coming from BC**.**

Transmission
Twelve transmission projects with 500 kV and higher are planned.

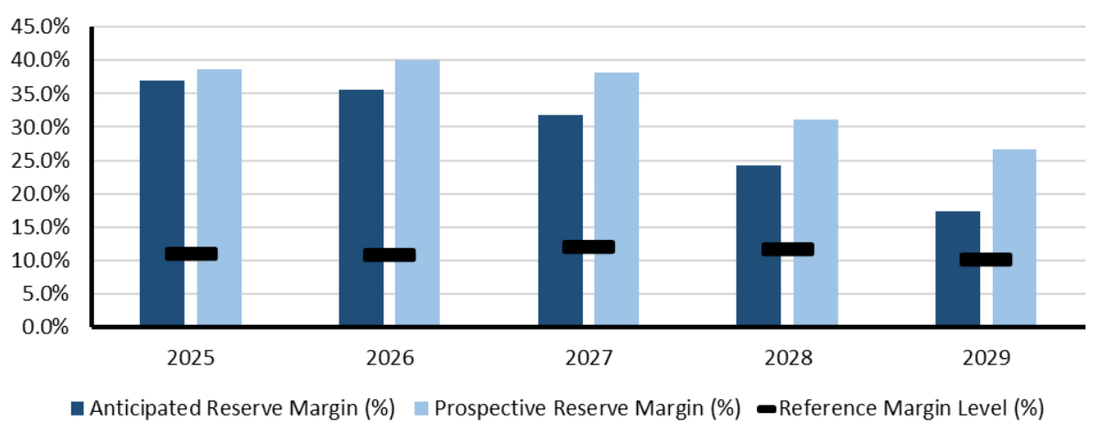


WECC-SW

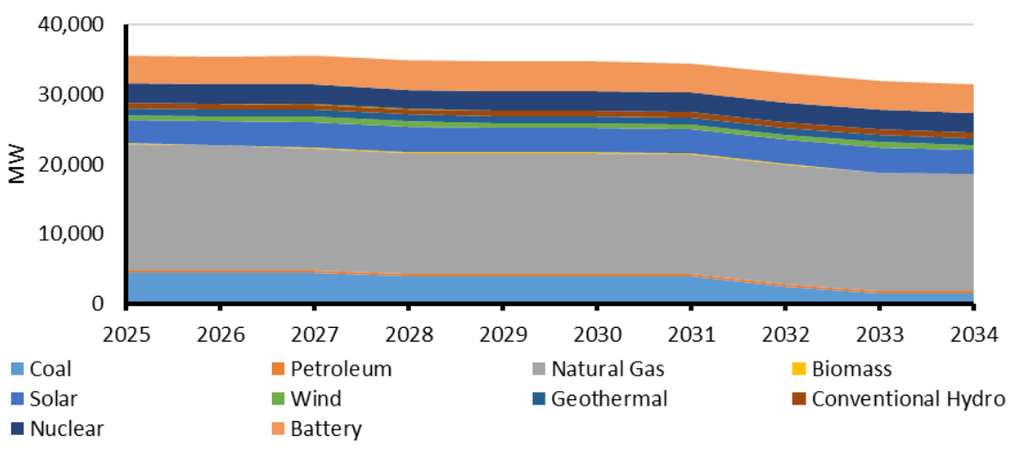
WECC-SW (Southwest) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	28,347	29,184	30,098	30,905	31,684	32,401	33,082	33,676	34,301	34,886
Demand Response	417	392	396	424	373	389	392	396	424	373
Net Internal Demand	27,930	28,792	29,702	30,481	31,311	32,012	32,690	33,279	33,876	34,512
Additions: Tier 1	5,140	5,251	5,656	5,656	5,557	5,557	5,557	5,557	5,656	5,557
Additions: Tier 2	475	1,305	1,899	2,079	2,932	2,932	2,966	2,984	3,221	2,984
Additions: Tier 3	40	677	1,148	2,589	3,113	4,438	5,734	7,479	8,960	10,027
Net Firm Capacity Transfers	2,651	3,556	3,554	2,966	2,045	928	716	320	322	0
Existing-Certain and Net Firm Transfers	33,110	33,784	33,491	32,212	31,187	30,070	29,644	27,787	26,645	25,956
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	11.0%	10.8%	12.0%	11.7%	10.2%	10.1%	9.9%	9.7%	10.8%	9.4%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032.
- Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources. Both supply chain and zoning issues have been cited as inhibiting project completion.
- The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%, which is the highest forecasted growth in the WECC region. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.
- Natural gas derates during extreme heat events are a risk for the Southwest as these resources make up a large share of the resource portfolio in the area.

WECC-SW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,436	4,436	4,432	3,939	3,941
Coal*	4,432	4,432	4,148	3,655	3,657
Petroleum	323	323	322	322	323
Natural Gas	18,165	17,933	17,520	17,323	17,343
Biomass	82	82	82	82	82
Solar	3,354	3,354	3,628	3,628	3,479
Wind	628	695	799	799	695
Geothermal	1,047	1,047	1,047	1,047	1,047
Conventional Hydro	721	721	721	721	721
Pumped Storage	104	104	104	104	104
Nuclear	2,724	2,724	2,711	2,711	2,724
Battery	4,016	4,061	4,226	4,226	4,240
Total MW	35,599	35,479	35,593	34,902	34,698
Total MW*	35,595	35,475	35,309	34,618	34,414
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-SW Assessment

Planning Reserve Margins

The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032. This indicates that imports may be necessary if new resources were to be significantly delayed, as Tier 3 resources will be required for reserve margins to meet the RML. Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	84	0	19
EUE (PPM)	1	0	0.13
LOLH (hours per year)	0.003	0	0.00
Operable On-Peak Margin	18.3%	33.8%	22.5%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. Another report produced is a WECC report called the WARA.

For 2026 and 2028, the peak hour occurs in July at HE 17:00. LOLH and EUE are not anticipated in 2026 and are minimal in 2028. LOLH was only observed in August at HE 19:00. The LOLH corresponds with the evening down ramp of solar and lingering demand after peak.

Due to the significant share of natural gas resources in the Southwest portfolio, a concern for the Southwest is natural gas derates during extreme heat events. A strategy to assist with resource planning is to construct derate curves for natural gas resources as a function of temperature. Resource procurement practices have also changed to focus on adding resources that have no dependence on temperature.

Demand

The Southwest has the highest rate of load growth in the Western Interconnection for the LTRA horizon. Large industrial and commercial load additions, such as data centers, have been cited as the reason for this growth.

The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.

Demand-Side Management

Arizona Public Service (AZPS) has numerous DSM pilots and programs, such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. In the Residential Energy Storage Pilot, residents may install a small BESS at their residence and enable it to be dispatched by AZPS in response to grid needs 100 times a year, but not below 20% of its capacity. AZPS is projecting an almost 50 MW increase in available DR from 2024 to 2025.

In 2023, the Salt River Project (SRP) subscribed 87 MW of DR capability through the installation of 76,143 smart thermostats and enrolled over 500 businesses as interruptible customers providing 41 MW of controllable DR capacity. The SRP aims to achieve 300 MW of dispatchable DR capability by 2035.

The Public Service Company of New Mexico (PNM) operates the Peak Saver and Power Saver programs. Peak Saver reduces demand from commercial customers greater than 50 kW in size during peak demand periods, and the Power Saver program cycles the compressor of air conditioners to reduce peak demand in the summer. One hundred hours of curtailment are available for both

programs with a four-hour limit per curtailment, and it was found that both programs combined reduce peak demand by an average of 45 MW per curtailment event.

El Paso Electric (EPE) operates a smart thermostat program to cycle air conditioners with the potential to achieve 50 MW of relief by 2040.

Additionally, AZPS, SRP, PNM, and EPE all offer time of use (TOU) rate structures for their customers.

Distributed Energy Resources
BTM DERs are difficult to measure due to data gathering barriers. In the Southwest, NV Energy has added DER plans to its triennial IRPs.

Generation
Southwest entities have slightly under 10 GW of nameplate capacity Tier 1 solar resources planned between 2024 and 2028. Supply chain issues resulting in project delays or failure of completion are a concern for the Southwest. Zoning issues prohibiting the construction of new solar assets are also an issue.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
The Southwest is not showing a significant increase in reliance on imports in the model, with peak exports occurring between 5:00 p.m. and 10:00 p.m.

Transmission
Twelve transmission projects with 500 kV and higher are planned.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[39] for the summer and winter of each year.[40] Projected total internal demand is based on normal weather (50/50 distribution)[41] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[42]**	**Load Forecasting Entity**
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
MRO-SPP	Summer	Noncoincident	SPP LSEs
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro-Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AB	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-BC	Winter	Noncoincident	
WECC-CA/MX	Summer	Noncoincident	
WECC-NW	Summer	Noncoincident	

[39] Glossary of Terms Used in NERC Reliability Standards.

[40] The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).

[41] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.

[42] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[42]**	**Load Forecasting Entity**
WECC-SW	Summer	Noncoincident	

Resource Categories

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.

Anticipated Resources[43]

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements[44]

Prospective Resources: Includes all "anticipated resources" plus the following:

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[45]

[43] Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

[44] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

[45] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[46]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[47]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

[46] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[47] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin (ARM): The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin (PRM): The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level (RML): The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, system planners use this metric is to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[48]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[49] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[50] which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
  - The BES does not experience instability, uncontrolled separation, cascading,[51] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[52]
  - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

[48] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms
[49] BES Definition
[50] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.
[51] NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."
[52] NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

- Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this LTRA are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's PRMs relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: The ARM is greater than RML.

Marginal: The ARM is lower than the RML and the PRM is higher than RML.

Inadequate: The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss-of-Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss-of-load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss-of-load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[53] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

Normal Risk: Negligible amounts of LOLH and EUE.

Periods of Risk: LOLH < 2 Hours and EUE < 0.002% of total annual net energy.

Significant Risk: LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically “equal probability” forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.

Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
- **Planned** (any of the following):
  - Permits have been approved to proceed
  - Design is complete
  - Needed in order to meet a regulatory requirement

- **Conceptual** (any of the following):
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as “Under Construction” or “Planned”

Other projected lines that do not meet requirements of “Under Construction” or “Planned”

[53] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	2024-2025 Summer: 9.0% Fall: 14.2% Winter: 27.4% Spring (2025): 26.7%	Planning Reserve Margin	Yes: Established Annually[54]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	15.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
MRO-SPP	19.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP Staff, Stakeholders, SPP Regional State Committee.
NPCC-Maritimes	20.0%[55]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	11.3–12.7%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[56]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	8.6–19.5%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	10.9–11.8%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro-Québec, NPCC Reliability Coordinating Committee
PJM	17.6–17.7%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard
SERC-Central	15.0%[57]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

[54] In MISO, the states can override the MISO PRM.

[55] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

[56] The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

[57] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-East	15.0%[58]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0%[59]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[60]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustment for non-modeled market considerations	ERCOT Board of Directors
WECC-AB	9.0–13.6%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[61]
WECC-BC	9.8–12.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-CA/MX[62]	14.9–17.4%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-NW	13.8–16.3%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-SW	9.4–12.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]

[58] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[59] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[60] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[61] WECC's RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[62] California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

LTRA Recommendations and Ongoing ERO Actions

Add new resources with needed reliability attributes and make existing resources more dependable.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society.
2. **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for 85% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred in new geographic areas as recently as the summer of 2023.[63] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[64] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[65] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[66,67]
3. **Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold-weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[68] Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[69]

[63] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[64] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.
[65] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide
[66] NERC IBR Activities
[67] Order No. 901 Work Plan
[68] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*
[69] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*

LTRA Recommendations and Ongoing ERO Actions

4. **Mitigate fuel-related risks to electricity generation (fuel assurance):** In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[70]

Initiative	Description	Product/Reliability Solution
Cold Weather Reliability Standards and Activities	New cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their Reliability Coordinators, Transmission Operators, and Balancing Authorities for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation. NERC and the industry are currently developing the remaining Reliability Standard enhancements to address the staff report. Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* on NERC's standards development page.[71]	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter-Based Resources Strategy	NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The statuses of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[72] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued Order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars

[70] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

[71] Project 2021-07

[72] IBR Activities

LTRA Recommendations and Ongoing ERO Actions		
	FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered bulk power system-connected IBRs.[73] Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.	
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the RSTC. Refer to the RSTC-Approved Documents page.[74]	Reliability Guideline
Expand the transmission network to deliver supplies from new resources and locations to serve changing loads. 5. **Develop the transmission network:** ISOs and RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.		
Initiative	**Description**	**Product/Reliability Solution**
Interregional Transfer Capability Study (ITCS)	NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis will be published in 2025. See **Interregional Transfer Capability Study (**ITCS).	ERO Study and Recommendations

[73] FERC Order Issued November 17, 2022
[74] RSTC Approved Documents

LTRA Recommendations and Ongoing ERO Actions

Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

6. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.

7. **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.

8. **Maintain sufficient amounts of flexible resources and essential reliability services:** To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource Planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators. [75]

9. **Include energy risks and extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.

10. **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations. [76]

[75] NERC ERS Measure 6 Forward Tech Brief

[76] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

LTRA Recommendations and Ongoing ERO Actions		
Initiative	**Description**	**Product/Reliability Solution**
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2024 LTRA* to advise industry and stakeholders of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[77] The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls. New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[78] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather* requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[79]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The status of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[80]	Reliability Standards Reliability Guidelines Educational Webinars
4: Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

[77] ERAWG
[78] Project 2022-03
[79] Project 2023-07
[80] DER Activities

Errata

In June 2025, NERC, MRO, and MISO determined that incorrect RMLs were used in the 2024 LTRA for MISO.[81] After applying the correct RMLs, the following changes have been made:

- Figure 1 Risk Area Summary 2025–2029 (p. 6) | MISO changed from High Risk to Elevated Risk
- Table 1: Capacity and Energy Risk Assessment Summary (p. 7)| MISO changed from High Risk to Elevated Risk and Risk Summary updated
- Figure 2: Projected Reserve Margin Shortfall Areas with Announced Generator Retirements (p. 8) | MISO year of shortfall changed from 2025 to 2028 and caption updated
- High Risk Area Details and Elevated Risk Area Details (p. 12) | Removed the description of High Risk, moved relevant discussion of MISO risks to Elevated Risk Area Details, and updated text.
- Figures 3 and 4: MISO Planning Reserve Margins for Summer and Winter (p.13)| Updated with correct RMLs
- Table 12: Anticipated Reserve Margins with Announced Retirements (p. 40) | Footnote added to identify use of UCAP reserve margins for MISO
- MISO Demand, Resources and Reserve Margins (p. 41) | Updated the Reference Margin Level (%) row in the table and updated the Planning Reserve Margins bar graph with correct RMLs; added a note and reference to OMS-MISO Survey
- MISO Highlights (p. 42) | Changed MISO projected capacity shortfall from *2025* to *within the next five years* in the first bullet
- MISO Assessment (p. 43) | Removed the shortfall capacity value in the Planning Reserve Margins section and added a note on the capacity values for existing resources in the MISO tables; removed the statement of ARM falling below RML in the Probabilistic Assessments section

[81] See the *Statement on NERC's 2024 Long-Term Reliability Assessment* issued on June 17, 2025.

MISO IMM Blasts NERC Long-term Assessment, Says RTO in Good RA Spot

By Amanda Durish Cook

MINNEAPOLIS — MISO Independent Market Monitor David Patton called NERC's Long-Term Reliability Assessment inaccurate for labeling MISO a high-risk area and said he believes MISO is in a good reliability position.

"We find that it is completely inaccurate. MISO should not be colored in red," Patton said at a June 10 Markets Committee meeting of the MISO Board of Directors.

Patton faulted NERC for apparently conflating installed capacity with unforced capacity in the assessment's totals. He said NERC tallied unforced capacity values for MISO when calculating a margin that it ultimately compared to an installed capacity requirement. He said the blunder lowered the footprint's capacity sums on paper by more than 10 GW.

"I don't frankly understand how they did this," Patton said. "They basically presented an apples and oranges assessment."

NERC's Long-Term Reliability Assessment predicted MISO could be confronted with capacity shortfalls in 2025. It assumed the RTO would have 132.2 GW in generating capacity, or 124.4 GW after factoring in all retirement announcements. (See *NERC Warns Challenges 'Mounting' in Coming Decade*.)

Ahead of summer, MISO reported it has 143.1 GW in offered capacity available to it to meet a likely 123-GW annual peak. (See *MISO Prepping for Likely 123-GW Summer 2025 Peak*.) Altogether, the RTO has 203 GW of installed capacity.

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Why This Matters

MISO IMM David Patton panned the RTO's precarious standing in NERC's Long-Term Reliability Assessment. He waved away resource adequacy concerns and said NERC botched a margin-to-capacity requirement comparison, apparently mixing up unforced capacity and installed capacity.

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Patton said factoring in imports and typical planned and forced outages, MISO has a comfortable, 12.2% reserve margin. ■

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MISO's Planning Resource Auction indicates sufficient resources

Improved pricing signal more accurately highlights reliability risk

For Immediate Release

April 28, 2025

Media Contact

Brandon Morris

CARMEL, Ind. — Today, MISO released the 2025 Planning Resource Auction (PRA) results indicating adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026). While the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint.

This is the first year MISO utilized a Reliability-Based Demand Curve (RBDC), which introduces a reliability-focused pricing structure that more accurately reflects the increasing value of accredited capacity as the system approaches minimum resource adequacy targets.

"MISO's market reforms continue to assist in providing pricing signals that improve market efficiency and enhance reliability across the footprint," said Aubrey Johnson, MISO's vice president of system planning and competitive transmission. ""We developed the RBDC through extensive collaboration with the Organization of MISO states, our stakeholders and our Independent Market Monitor to ensure this proactive approach helps meet the future needs of our evolving fleet."

The seasonal Auction Clearing Prices are:

- Summer (June, July and August) $666.50/MW-day
- Fall (September, October and November)
  - $91.60/MW-day for the North/Central subregion
  - $74.09/MW-day for the South subregion
- Winter (December, January and February) $33.20/MW-day
- Spring (March, April and May) $69.88/MW-day
- Annualized, the prices are $217/MW-day for the North/Central region and $212 for the South region.

The majority of MISO's Load Serving Entities (LSEs) either self-supply or secure the capacity they need before the auction. Those that enter the auction to procure capacity must pay the Auction Clearing Price and those holding excess capacity sell it at the same clearing price. The impact on consumer costs will vary and depends on factors such as the size of any capacity shortfall and the terms of wholesale power purchase agreements or state-regulated retail rates.

"This year's results underscore MISO's proactive Market Redefinition efforts to enhance resource availability as outlined in the Reliability Imperative." Johnson continues. "MISO, our states and our stakeholders continue to make progress responding to the resource adequacy challenges we face, and these results offer valuable insights to allow members to maximize their existing resources and plan for the ongoing energy transition."

MISO's Independent Market Monitor has reviewed and agreed with the offers and results of the 2025 PRA. MISO will host the 2025 Planning Resource Auction Results meeting April, 29 at 10 a.m. ET.

##

MEDIA CONTACT:
Brandon D. Morris

About MISO

Midcontinent Independent System Operator (MISO) is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. 45 million people depend on MISO to generate and transmit the right amount of electricity every minute of every day. MISO is committed to reliable, nondiscriminatory operation of the bulk power transmission system and collaborating with all stakeholders to create cost-effective and innovative solutions for our changing industry. MISO operates one of the world's largest energy markets with more than $40 billion in annual gross market energy transactions.

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A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking

Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	
BAL-502-RFC-03	06/01/17	ReliabilityFirst Board Approved	
BAL-502-RF-03	08/10/17	NERC BOT Approved	
BAL-502-RF-03	10/16/17	FERC Approved	

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025



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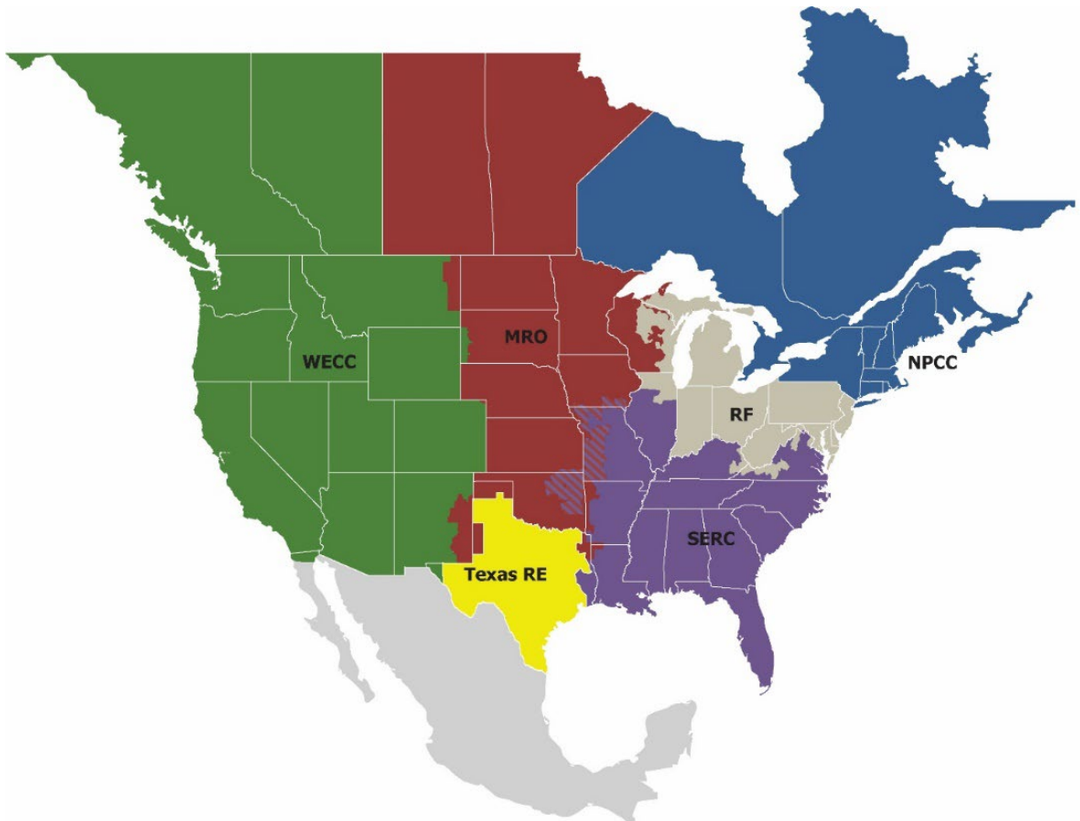
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is spans six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment (LTRA*), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

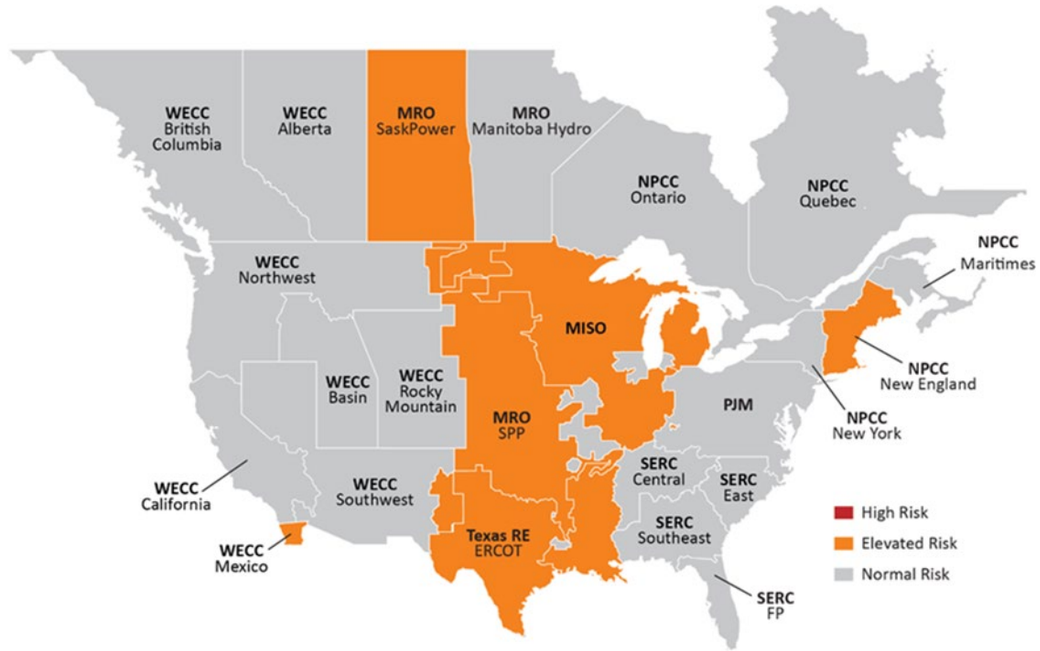


Figure 1: Summer Reliability Risk Area Summary

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

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA.* Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.

- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.

- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).

- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's 2024 *State of Reliability* report

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.
[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

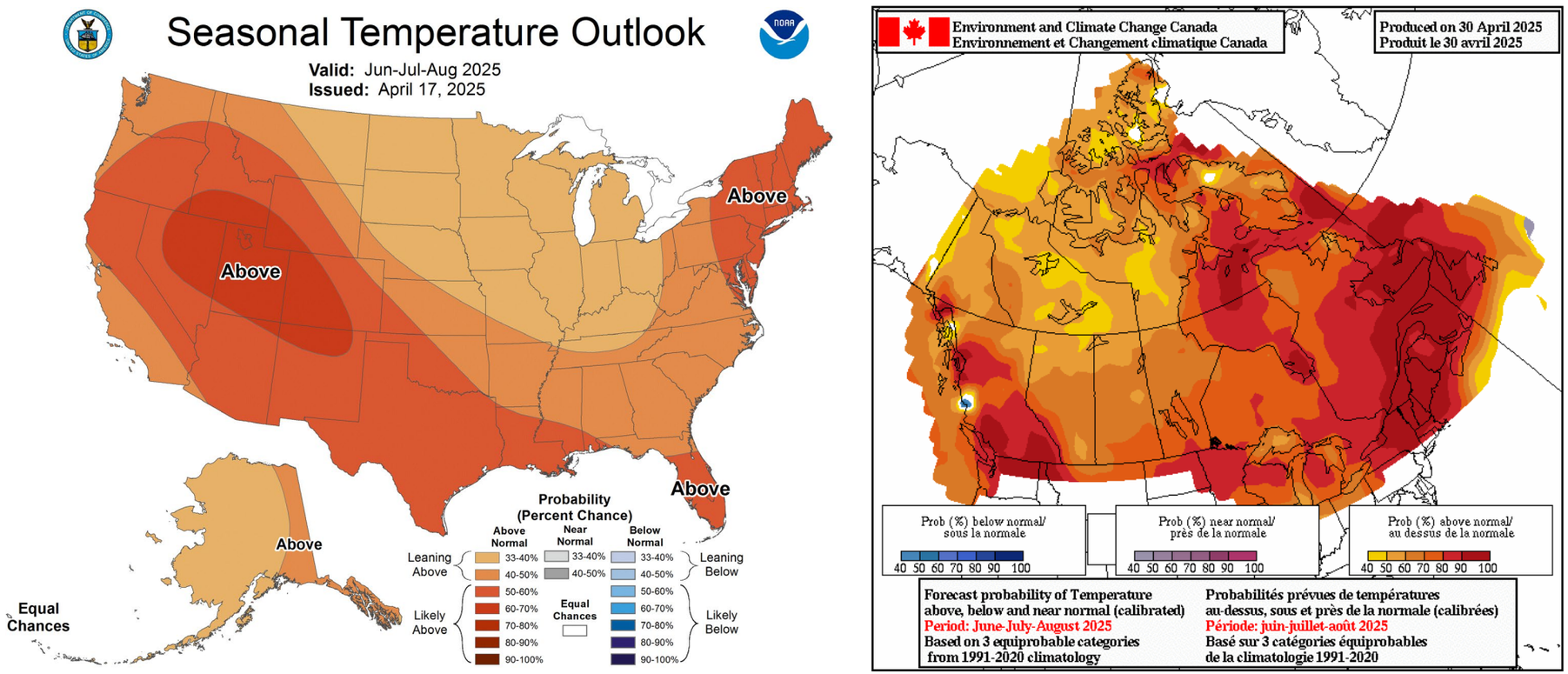


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 1.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[2] • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in Table 2.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

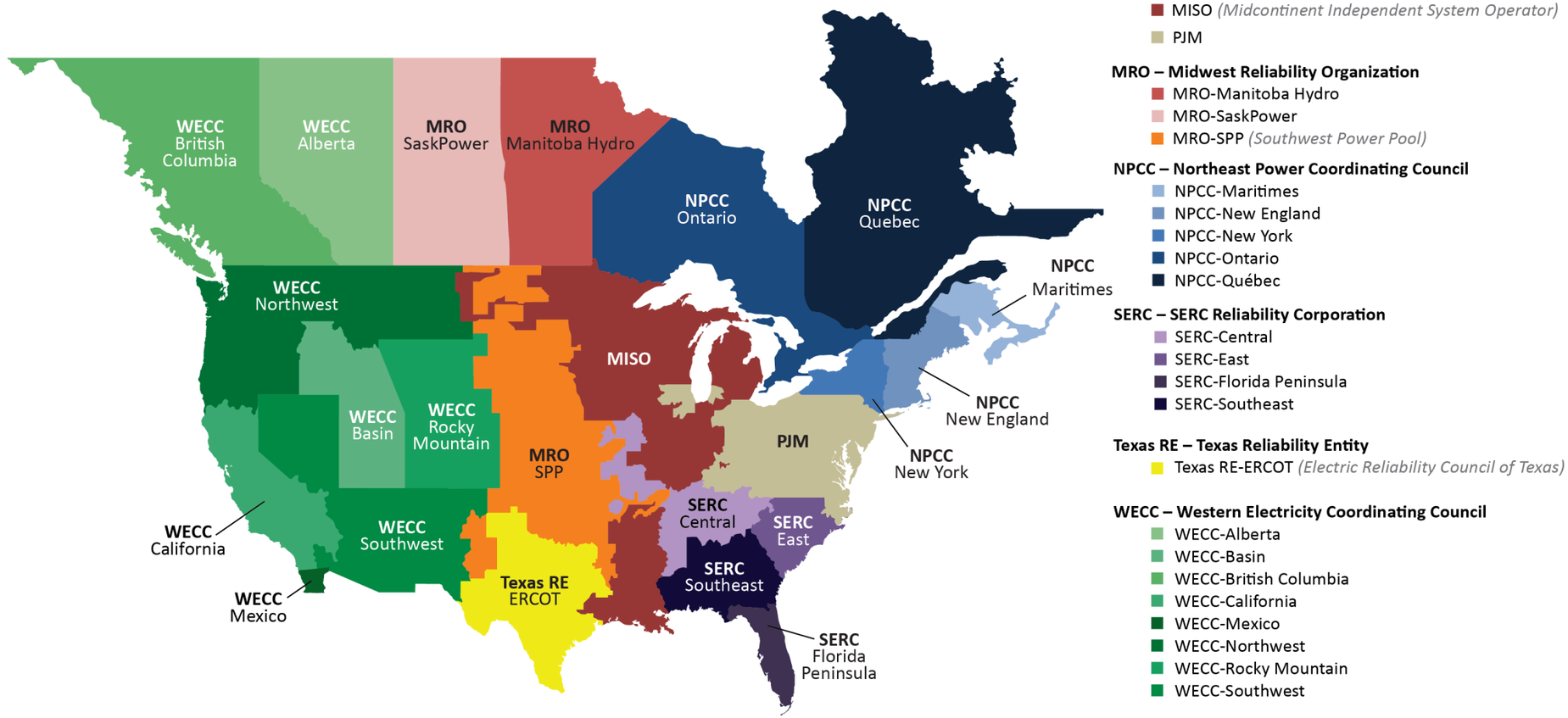
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central SERC-East SERC-Florida Peninsula SERC-Southeast	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.





MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

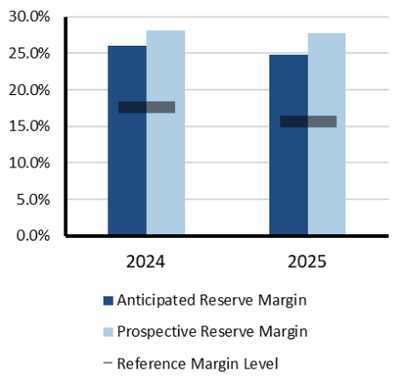
Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

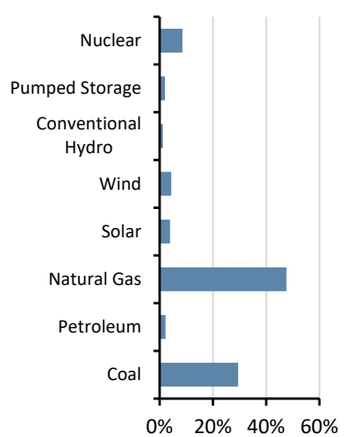
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

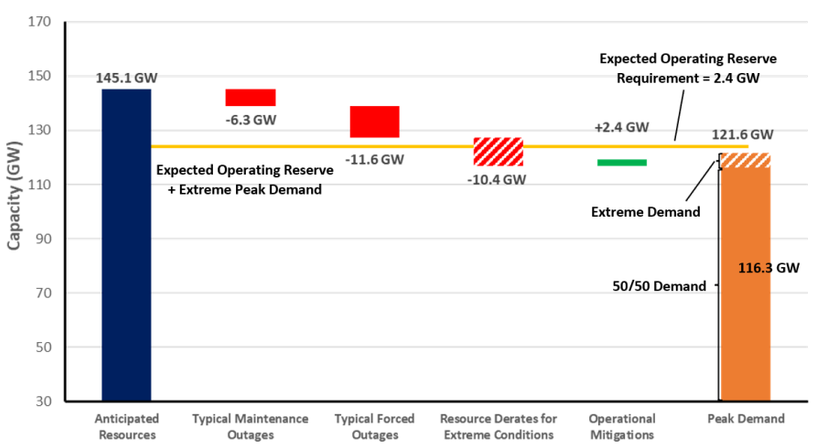
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions



MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

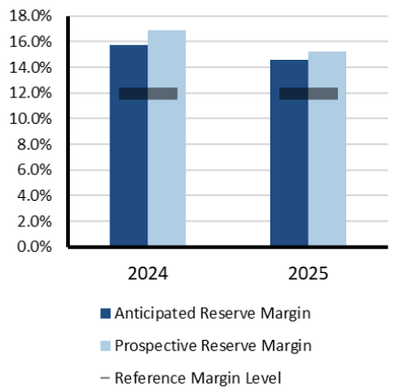
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

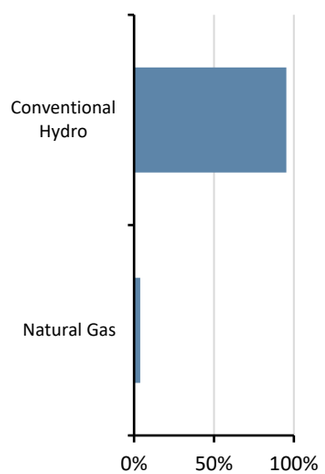
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

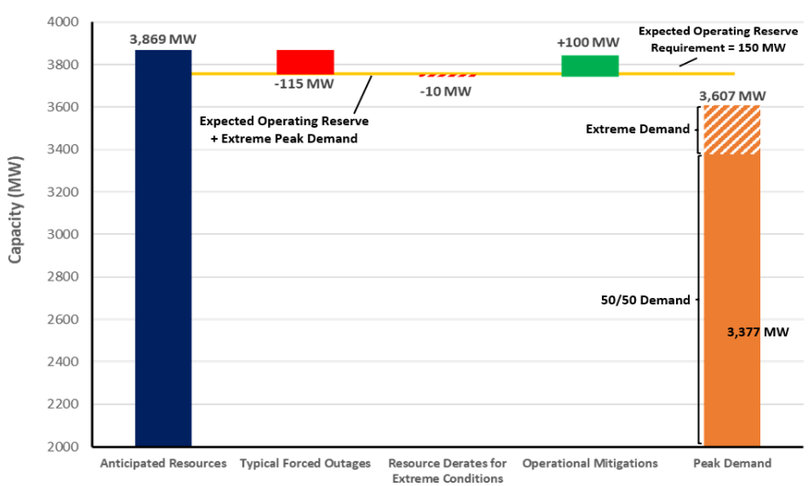
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

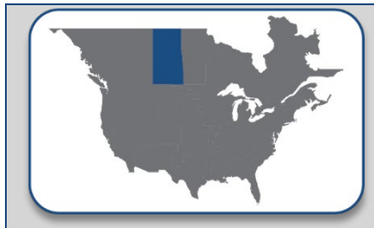
Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required



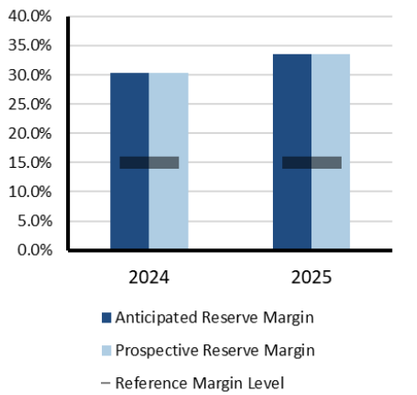
MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

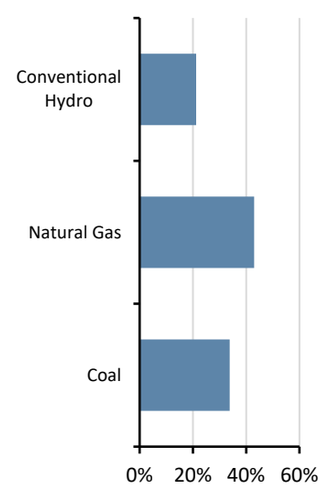
On-Peak Reserve Margin



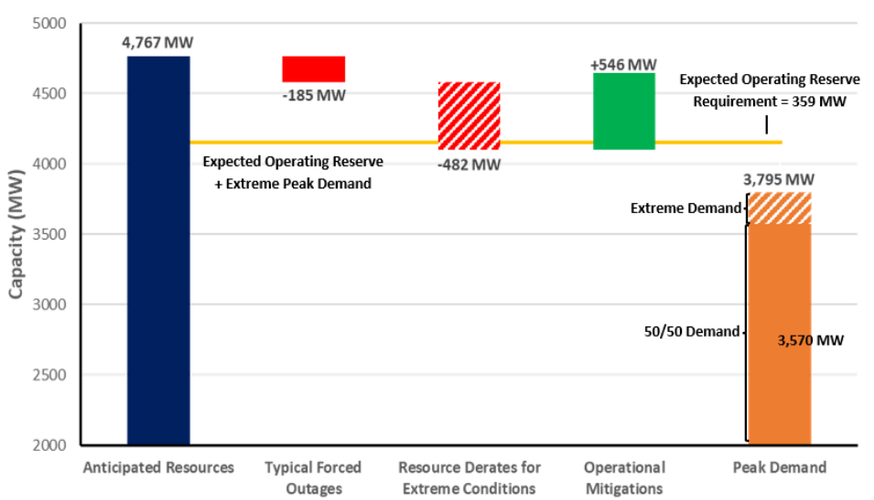
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice



MRO-SPP

SPP PC's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

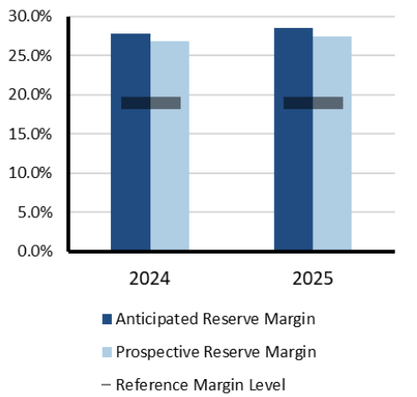
Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

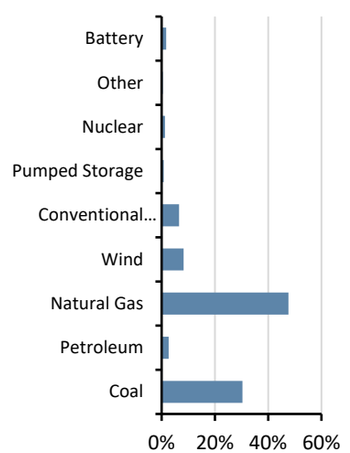
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

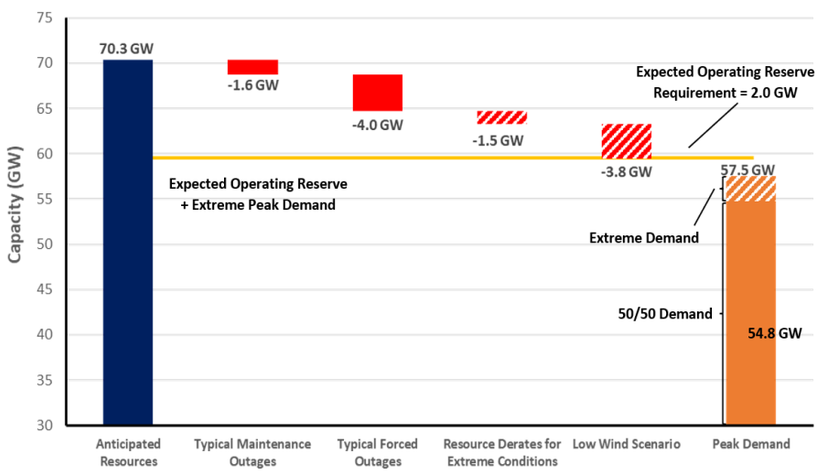
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer



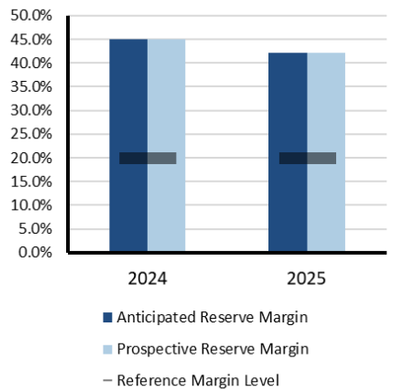
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

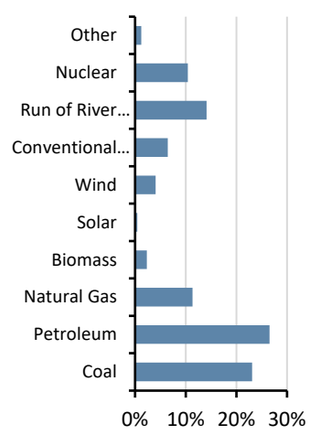
On-Peak Reserve Margin



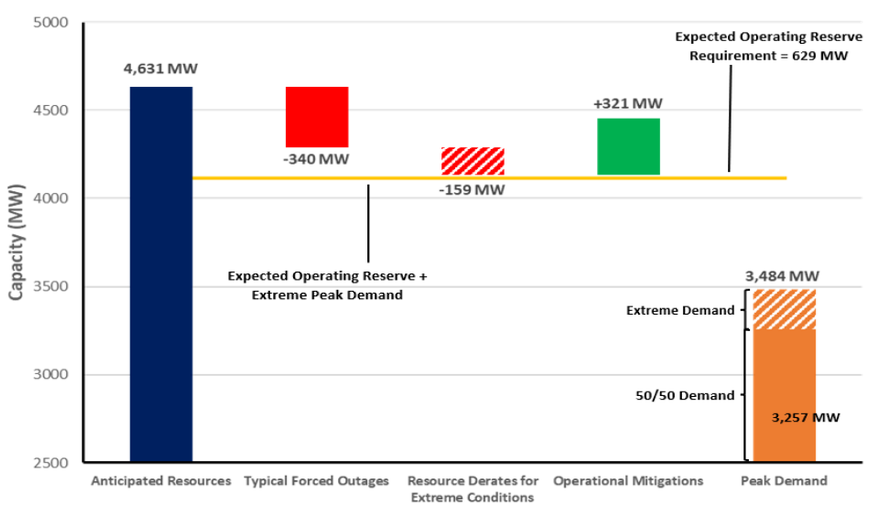
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)



NPCC-New England

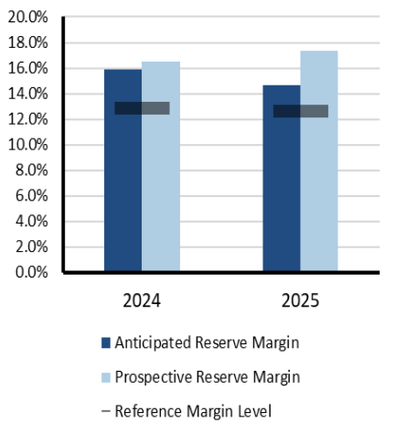
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

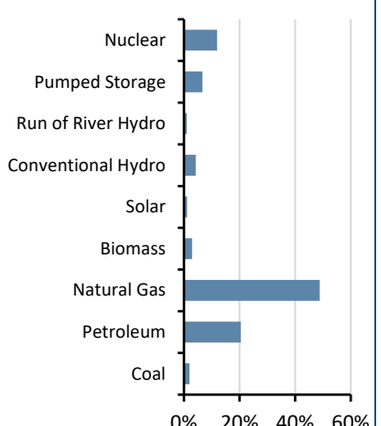
On-Peak Reserve Margin



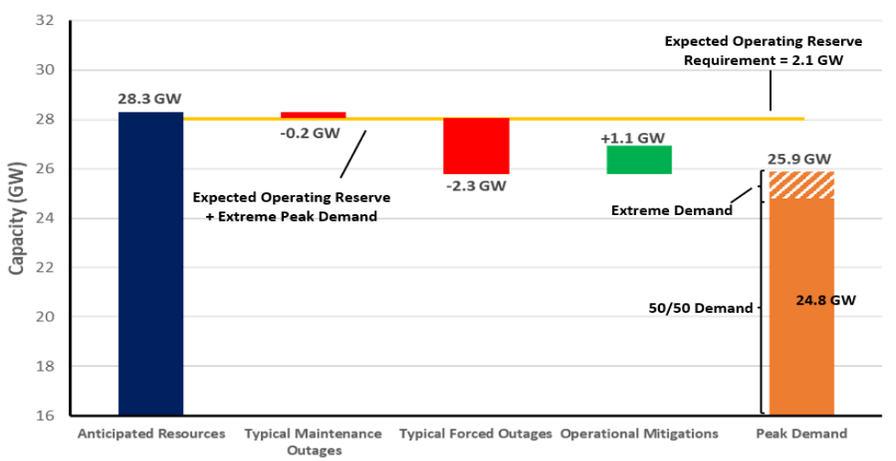
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



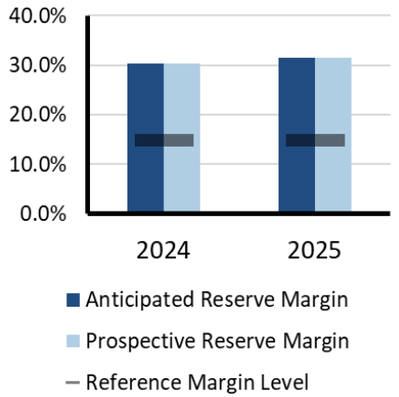
NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

Highlights

- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

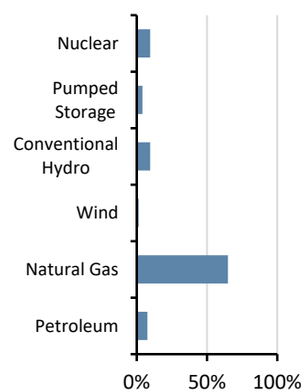
On-Peak Reserve Margin



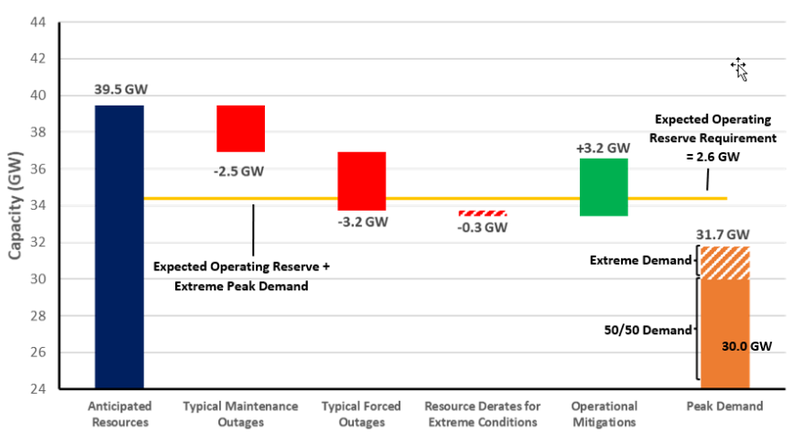
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual



NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

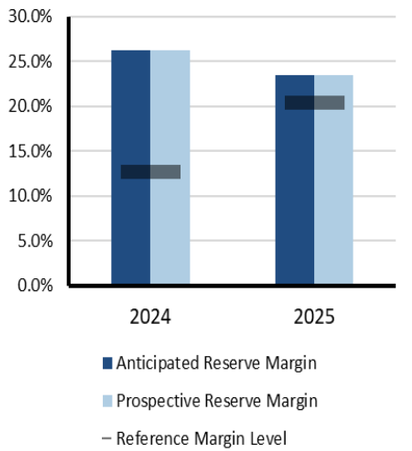
Highlights

- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

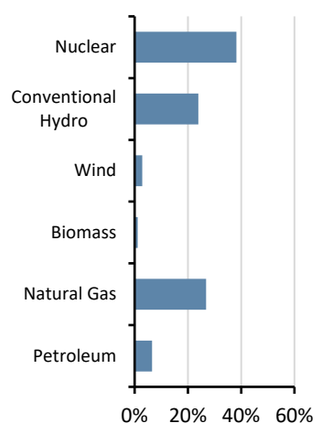
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

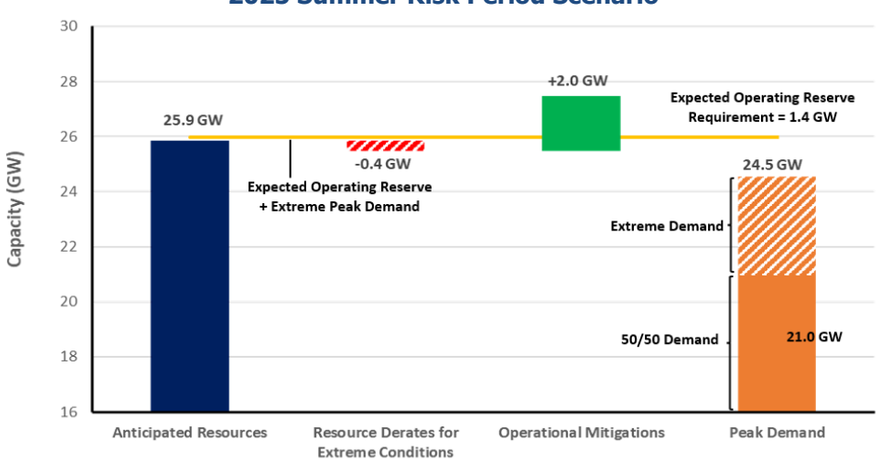
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.



NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

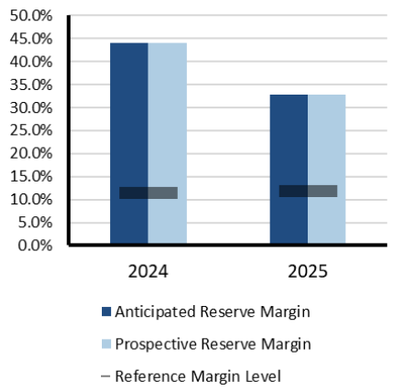
Highlights

- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

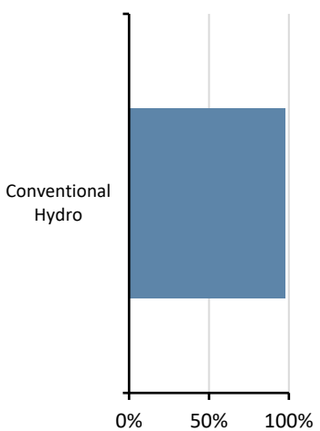
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

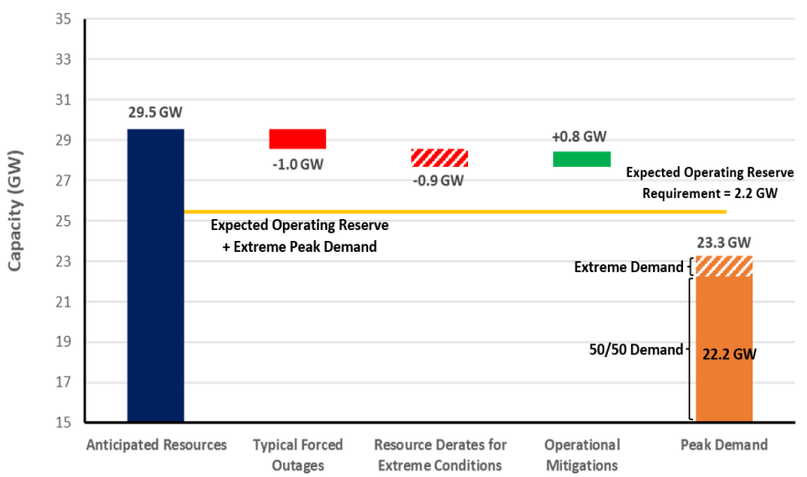
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

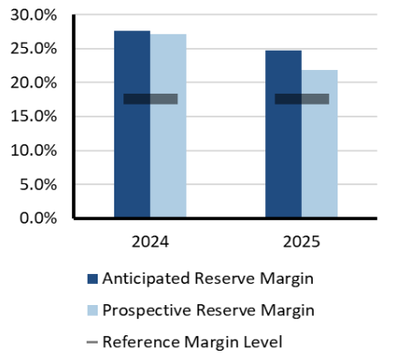
Highlights

- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

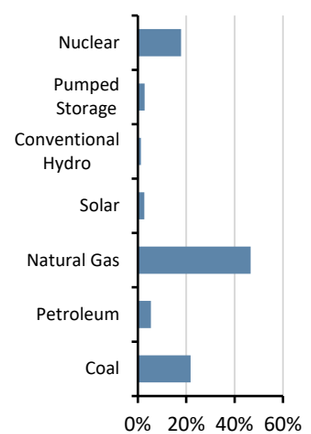
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

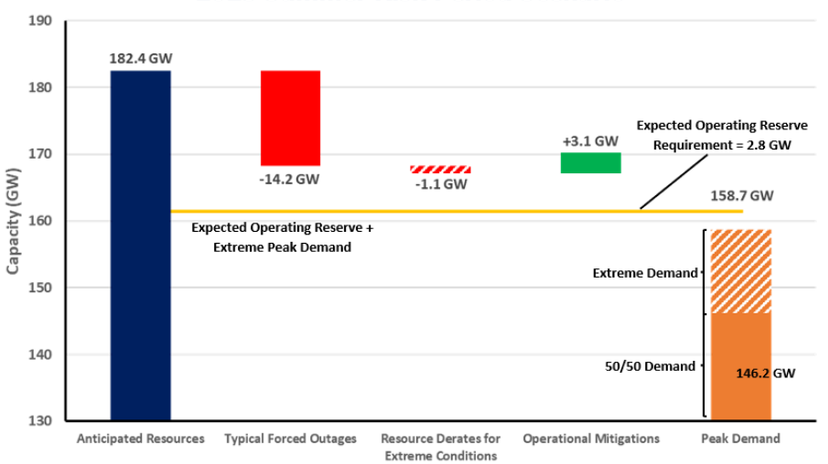
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



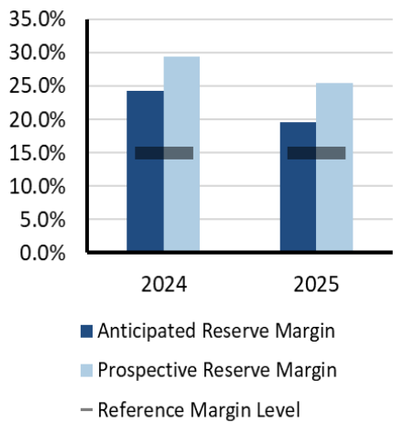
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

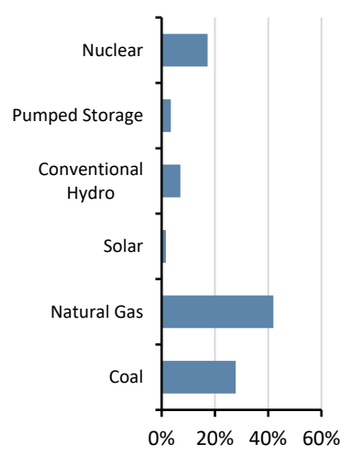
On-Peak Reserve Margin



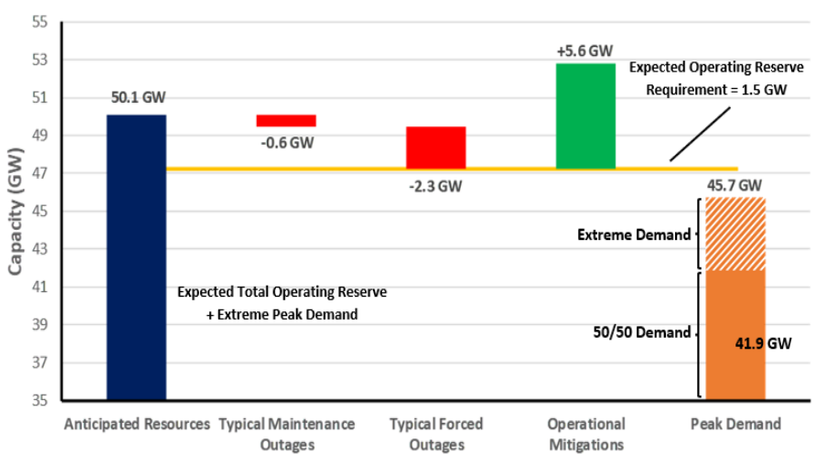
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures



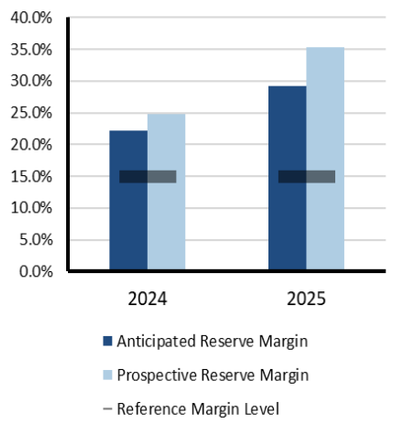
SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

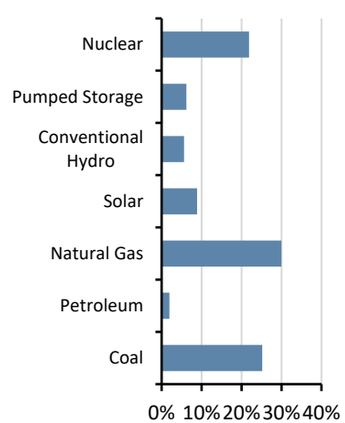
On-Peak Reserve Margin



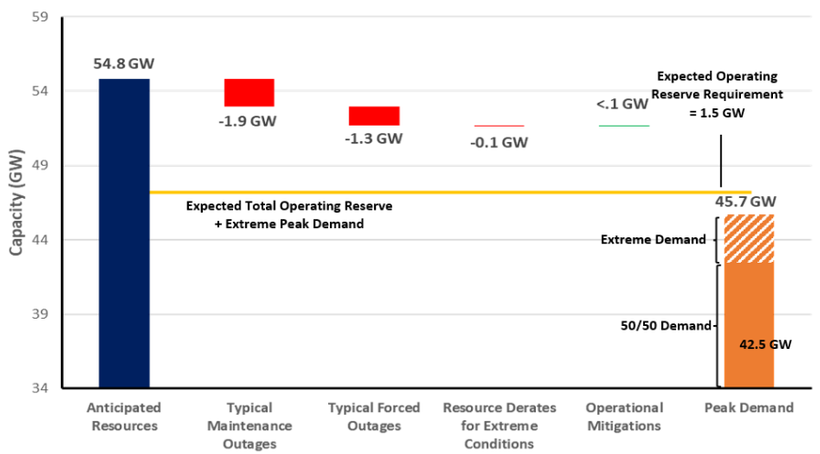
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures



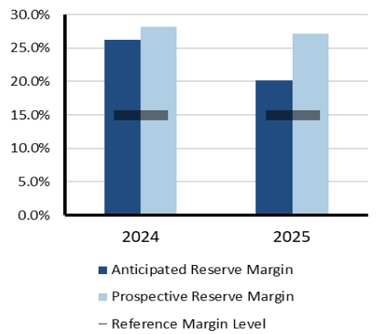
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

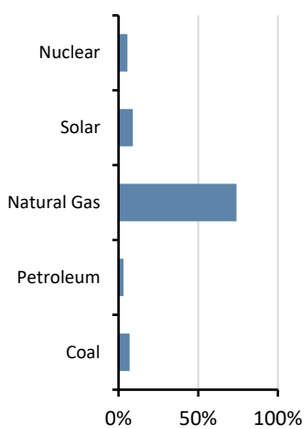
On-Peak Reserve Margin



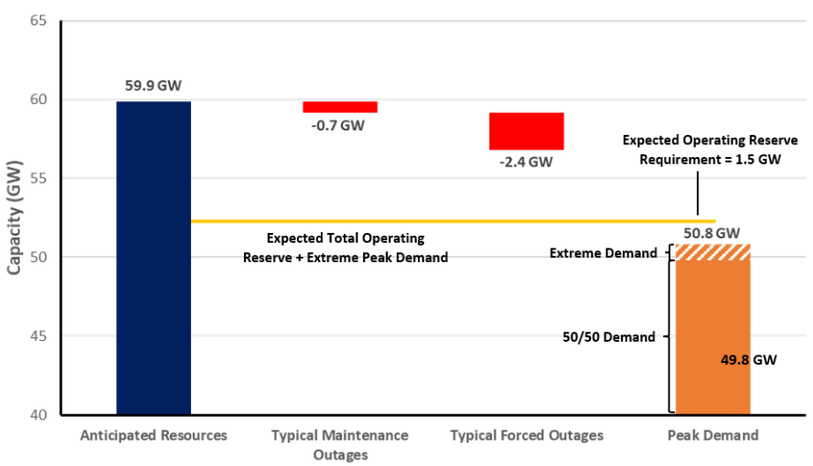
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions



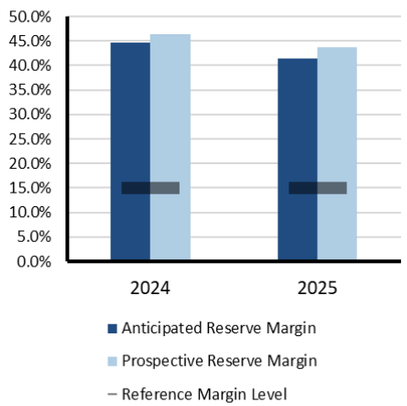
SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

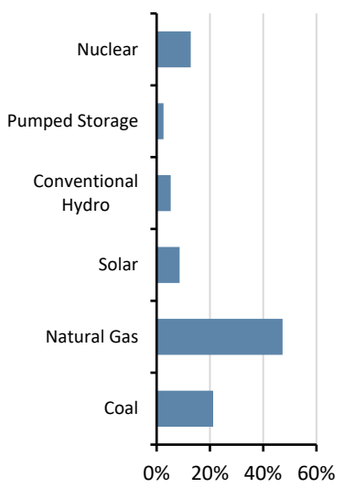
On-Peak Reserve Margin



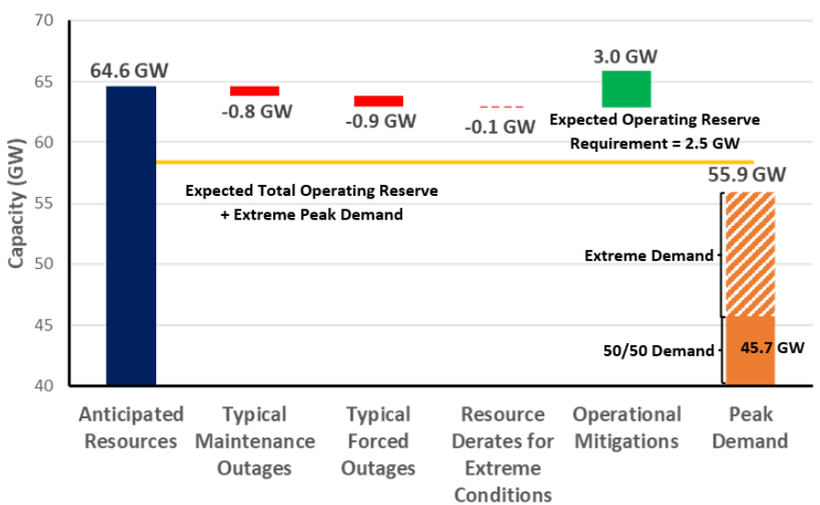
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

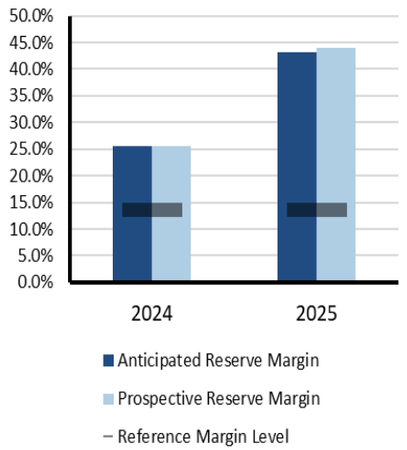
Highlights

- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

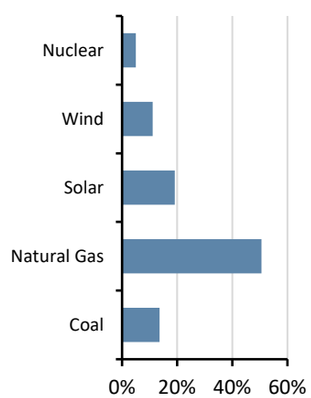
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

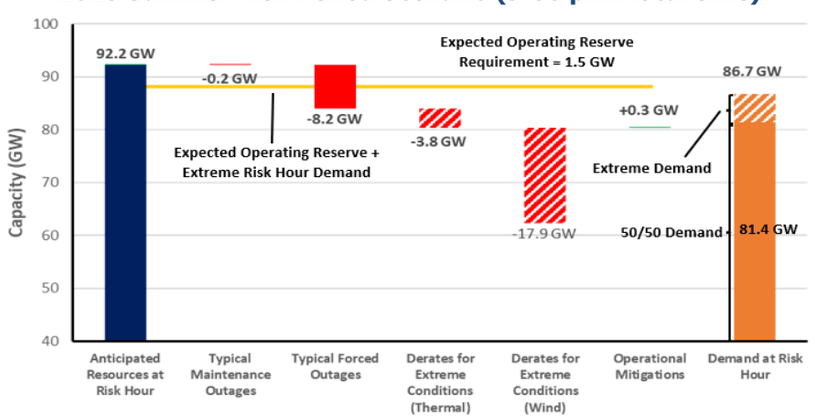
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

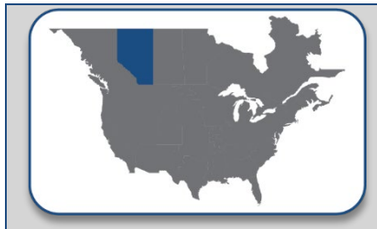
Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports



WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

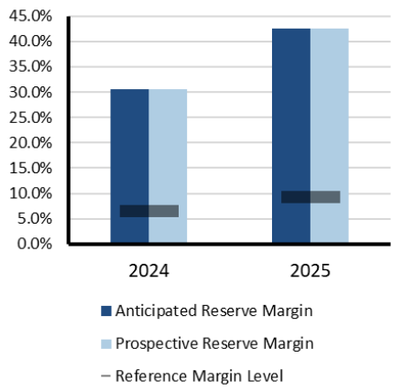
Highlights

- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

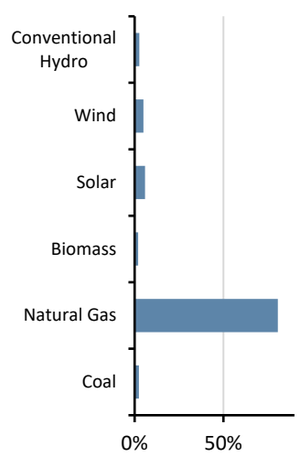
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

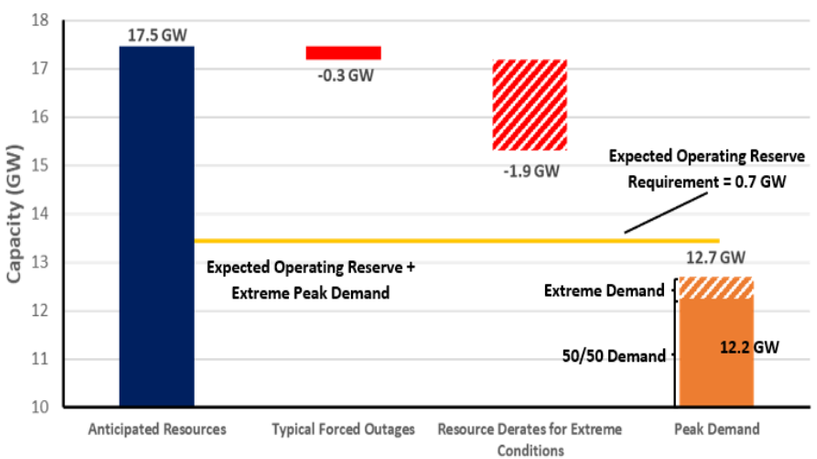
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution



WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

Highlights

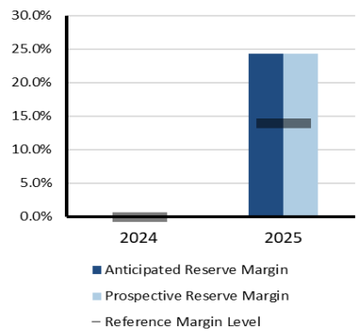
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

Risk Scenario Summary

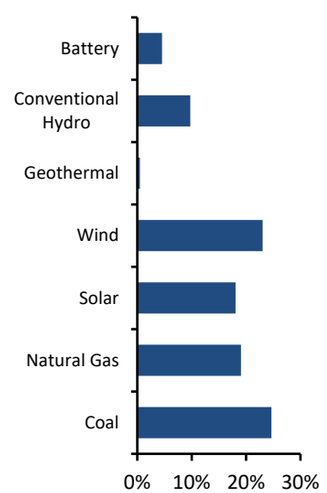
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

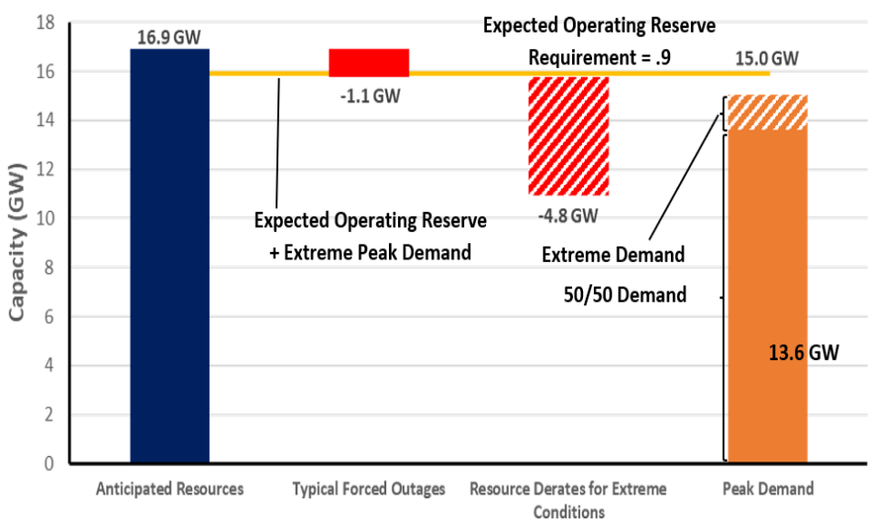
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

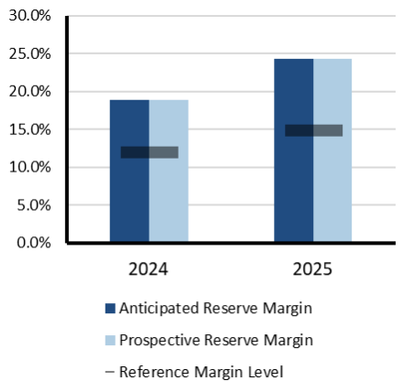
Highlights

- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

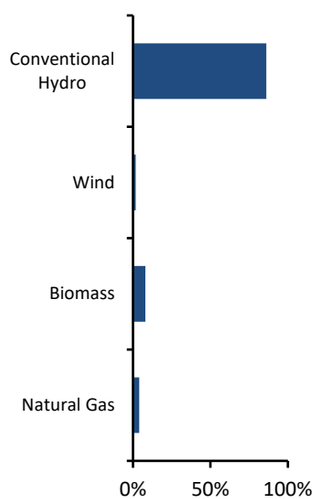
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

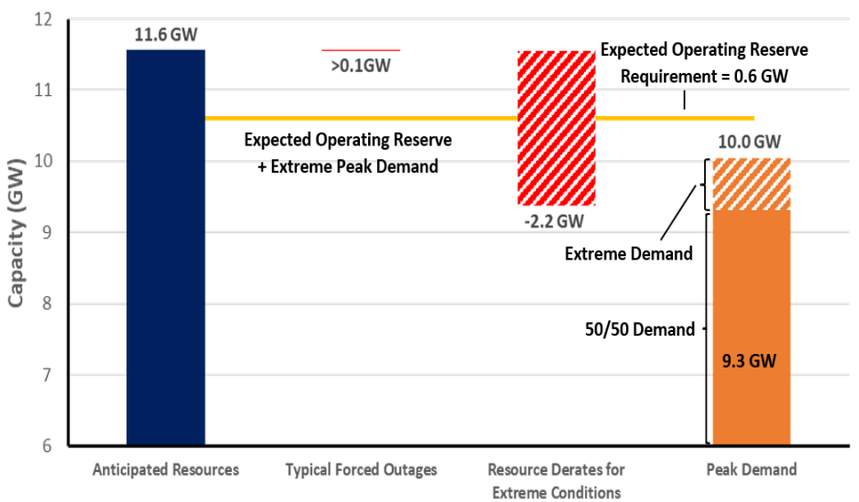
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA*.

Highlights

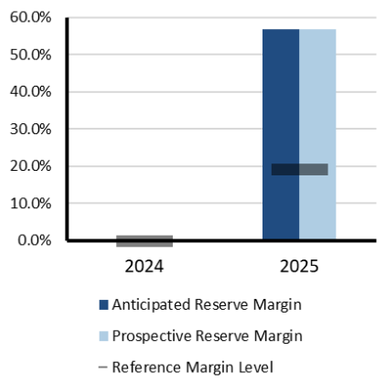
- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

Risk Scenario Summary

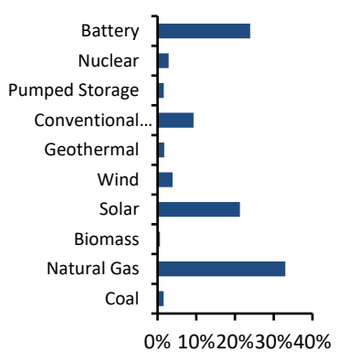
Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Reserve Margin

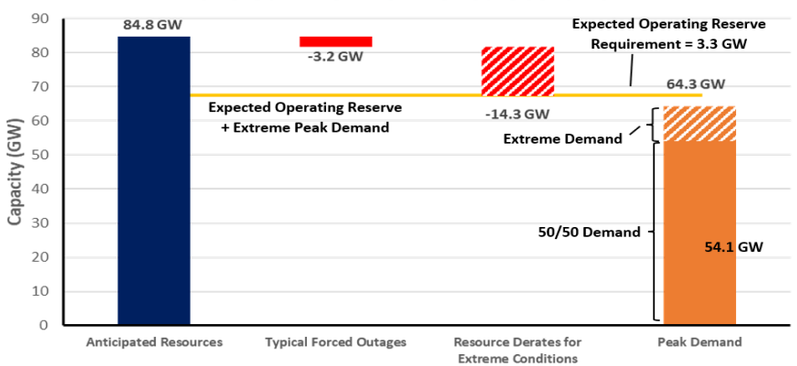
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages



WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

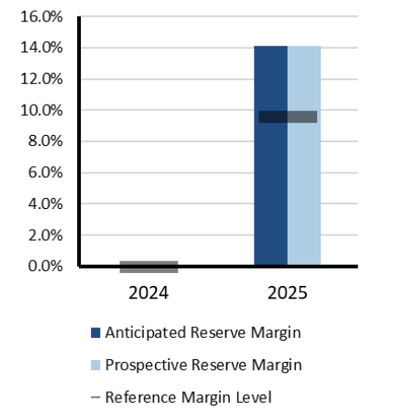
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

Risk Scenario Summary

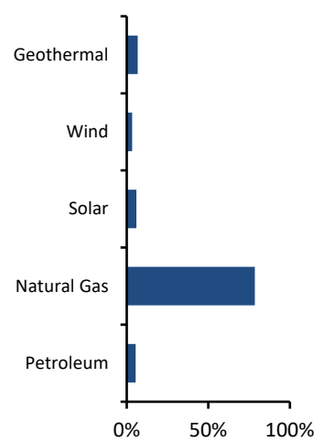
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

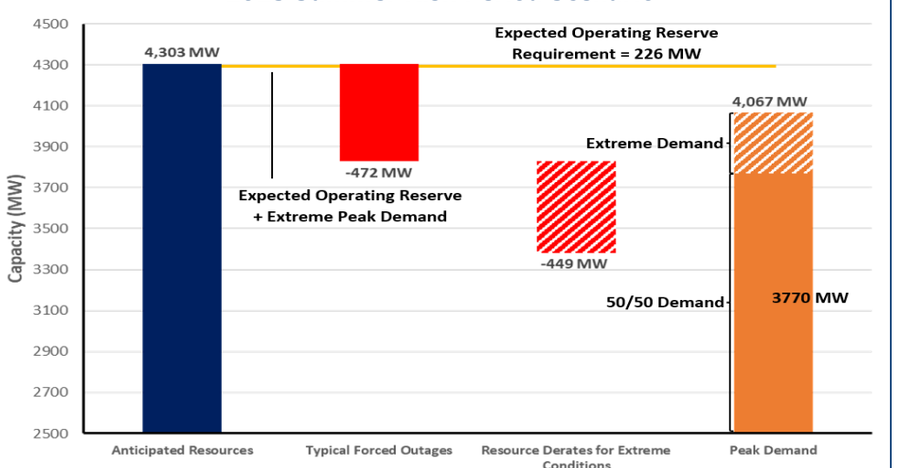
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA*.

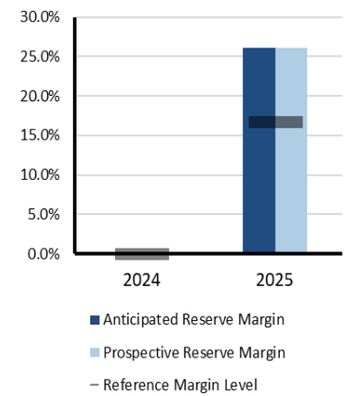
Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

Risk Scenario Summary

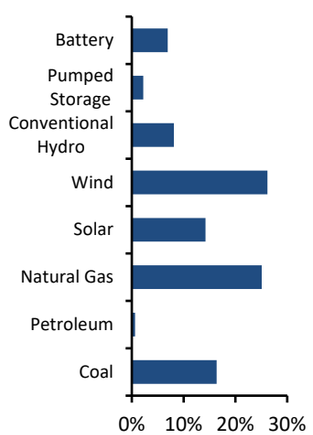
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

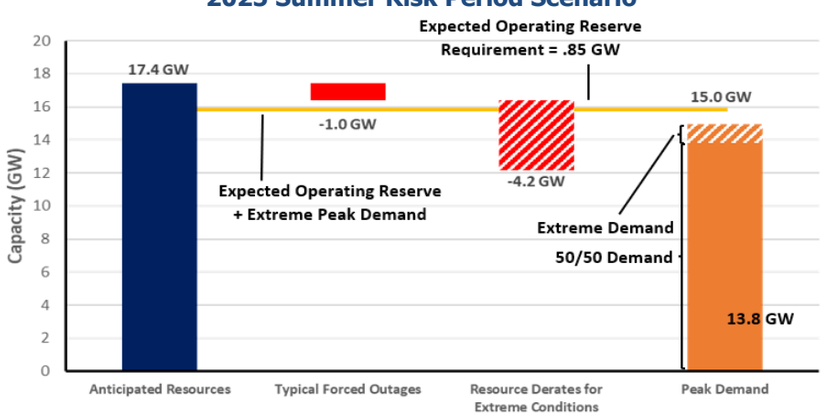


(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 SRA.*

Highlights

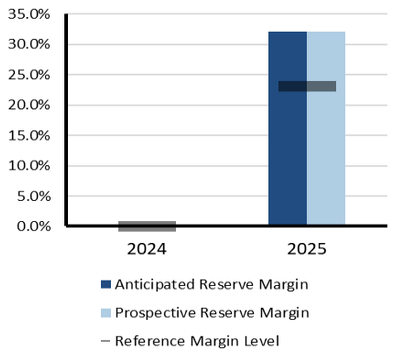
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
- Extreme heat corresponds with elevated loads, reduced transmission ratings, and temperature derates of thermal resources, which can strain resource adequacy and grid reliability.
- Seasonal hydro variability is a risk.

Risk Scenario Summary

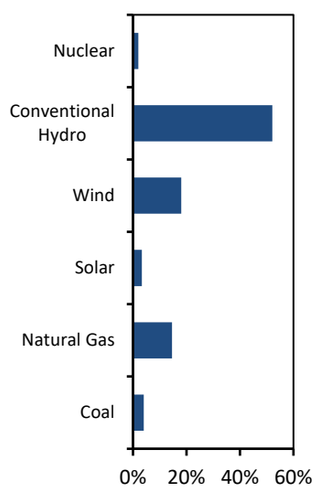
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

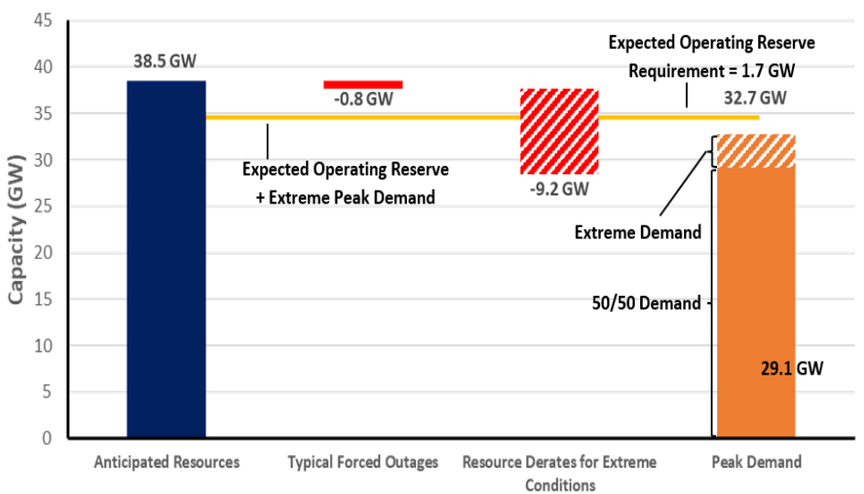
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



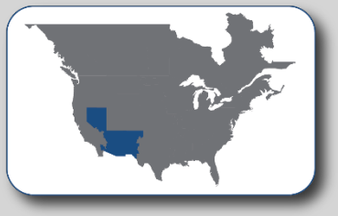
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 SRA.*

Highlights

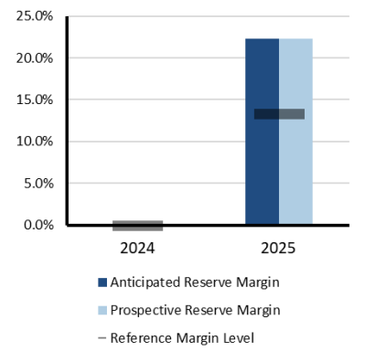
- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected to occur in early July around 5:00 p.m., when solar generation output begins to diminish.
- Wide-area heat events or wildfires that affect resource and transmission availability across the western interconnection area a reliability concern for the Southwest. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability to export to the Southwest.

Risk Scenario Summary

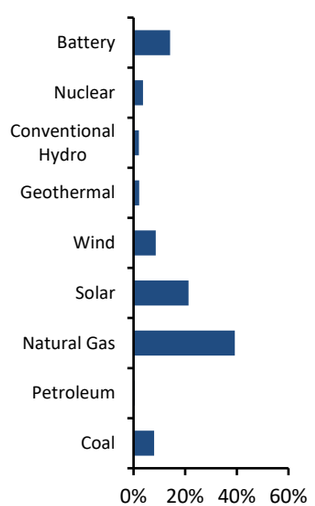
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

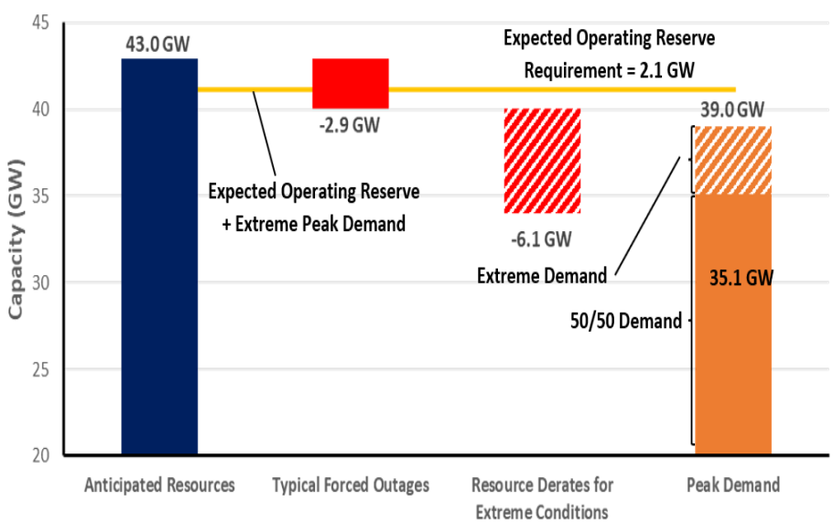
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
• Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[12] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[13] The summer season represents June–September and the winter season represents December–February.

[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin (ARM), which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the summer 2025 as shown in **Figure 4**.

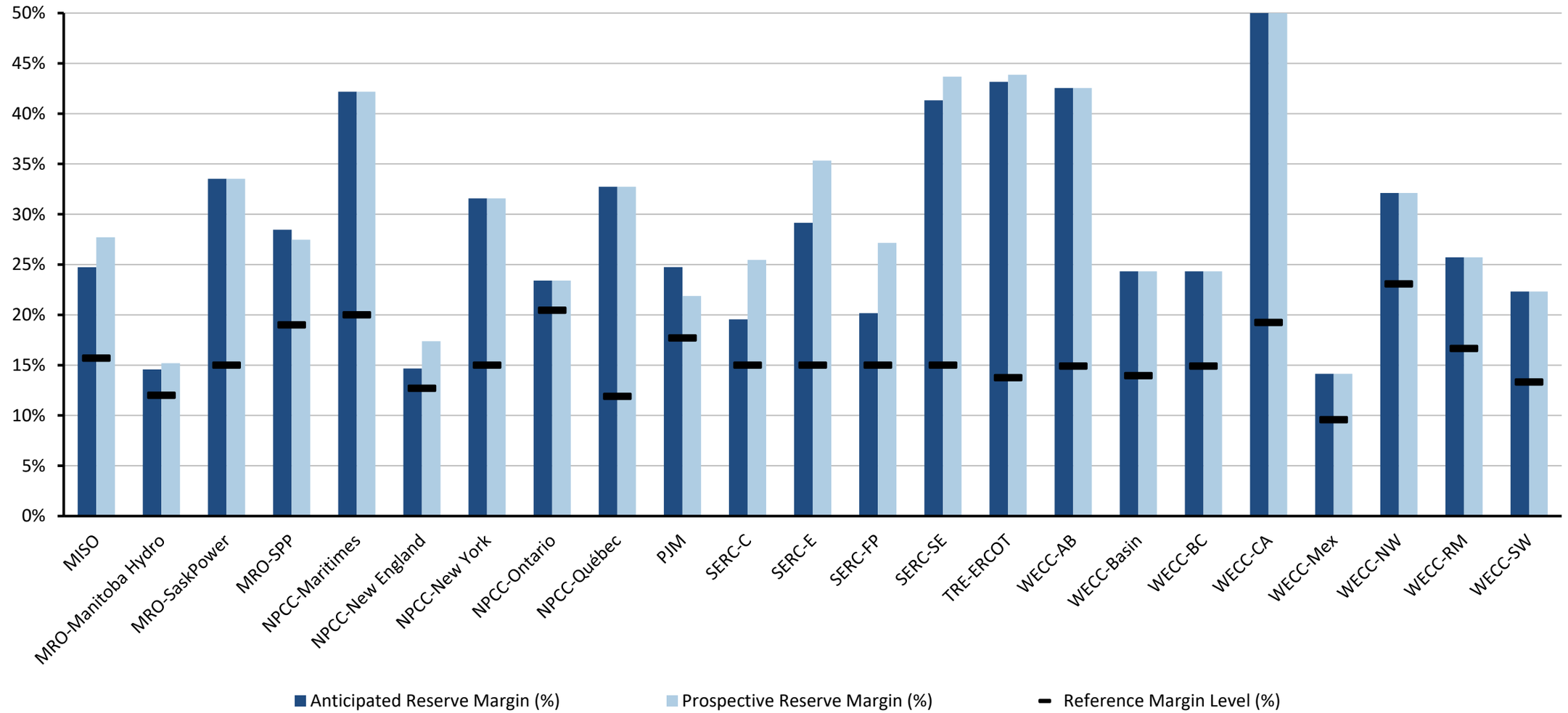


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

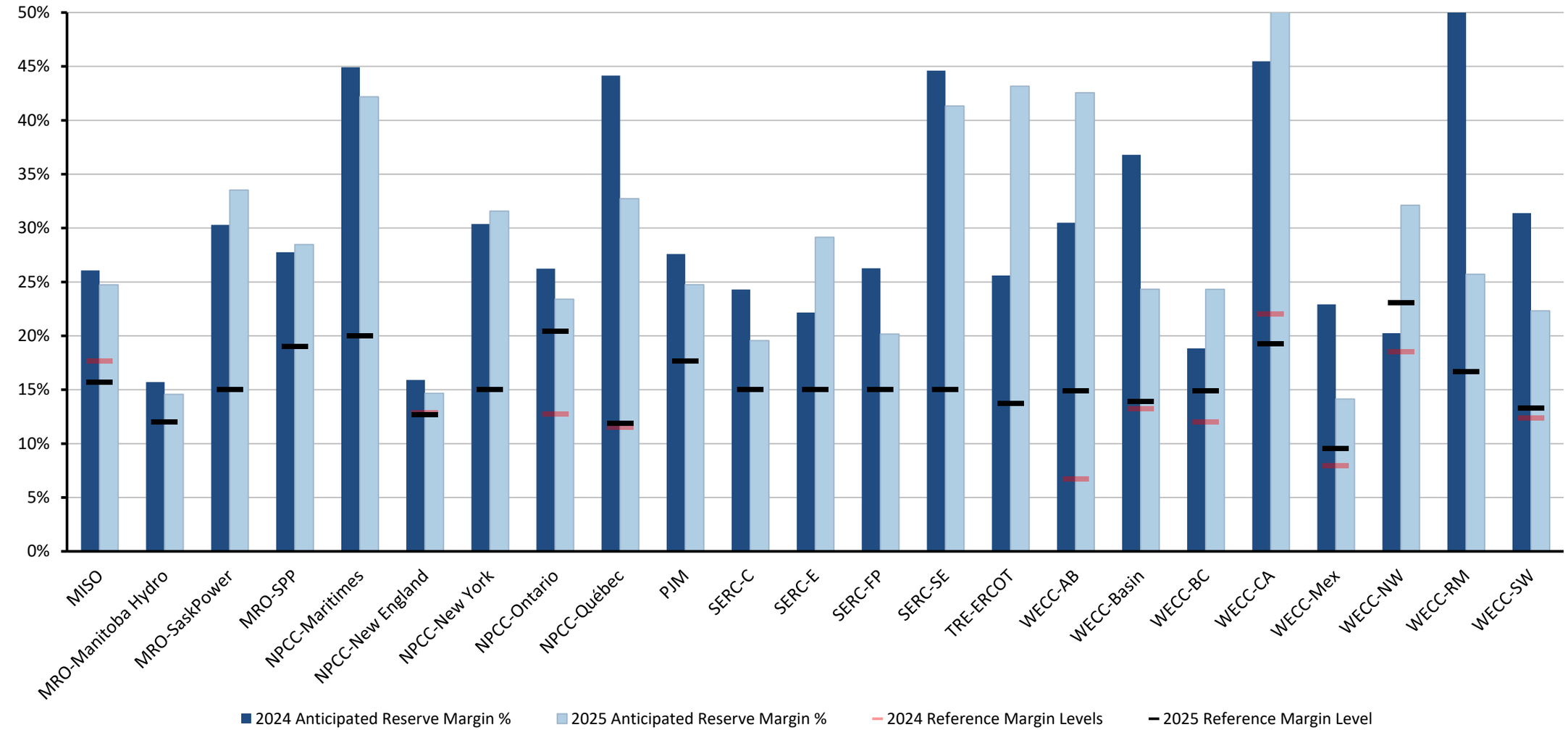


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

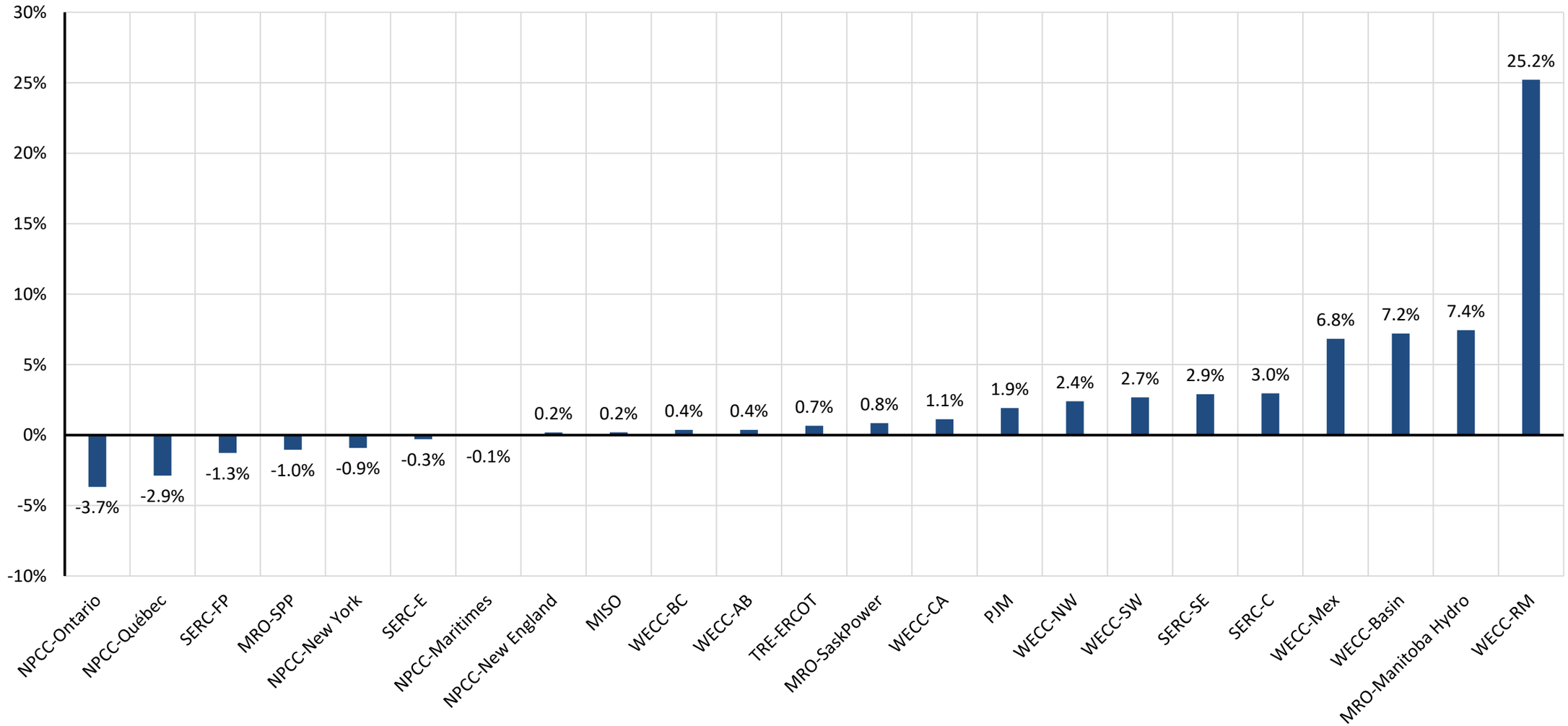


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	**175,081**	**34,774**	**20%**	**142,014**	**86,170**	**61%**	**101,959**	**65,290**	**64%**	**36,311**	**32,298**	**89%**

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta's demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.
[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2024 SRA*.
[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.
*Values include both maintenance and forced outages.
**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.



MISO'S RESPONSE TO THE RELIABILITY IMPERATIVE

- UPDATED FEBRUARY 2024 -

Living Document

This is a "living" report that is updated periodically as conditions evolve, and as MISO, stakeholders and states continue to assess and respond to the Reliability Imperative.

misoenergy.org

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A Message from John Bear, CEO



We have to face some hard realities.

There are immediate and serious challenges to the reliability of our region's electric grid, and the entire industry — utilities, states and MISO — must work together and move faster to address them.

MISO and its utility and state partners have been deeply engaged on these challenges for years, and we have made important progress. But the region's generating fleet is changing even faster and more profoundly than we anticipated, so we all must act with more urgency and resolve.

Many utilities and states are decarbonizing their resource fleets. Carbon emissions in MISO have declined more than 30% since 2005 due to utilities and states retiring conventional power plants and building renewables such as wind and solar. Far greater emissions reductions — possibly exceeding 90% — could be achieved in coming years under the ambitious plans and goals that utilities and states are pursuing.

Studies conducted by MISO and other entities indicate it is possible to reliably operate an electric system that has far fewer conventional power plants and far more zero-carbon resources than we have today. However, **the *transition* that is underway to *get to* a decarbonized end state is posing material, adverse challenges to electric reliability.**

A key risk is that many existing "dispatchable" resources that can be turned on and off and adjusted as needed are being replaced with weather-dependent resources such as wind and solar that have materially different characteristics and capabilities. While wind and solar produce needed clean energy, they lack certain **key reliability attributes** that are needed to keep the grid reliable every hour of the year. Although several emerging technologies may someday change that calculus, they are not yet proven at grid scale. Meanwhile, efforts to build new dispatchable resources face headwinds from **government regulations and policies**, as well as **prevailing investment criteria for financing new energy projects**. Until new technologies become viable, we will continue to need dispatchable resources for reliability purposes.

But fleet change is not the only challenge we face. **Extreme weather events** have become more frequent and severe. **Supply chain and permitting issues** beyond MISO's control are delaying many new reliability-critical generation projects that are otherwise fully approved. **Large single-site load additions**, such as energy-intensive production facilities or data centers, may not be reliably served with existing or planned resources. **Incremental load growth** due to electric vehicles and other aspects of electrification is exerting new pressure on the grid. And **neighboring grid systems are becoming more interdependent** and reliant on each other, highlighting the need for more interregional planning such as the Joint Targeted Interconnection Queue study that MISO conducted with Southwest Power Pool.

This report documents how MISO is addressing these risks through the **Reliability Imperative** — the critical and shared responsibility that MISO, our members and states have to address the urgent and complex challenges to electric reliability in our region. MISO first published a Reliability Imperative report in 2020, and this is the fourth time we've updated it to reflect the changing landscape.

None of the work we must do is easy, but it is necessary. The region's 45 million people are counting on MISO and its utility and state partners to get it right. Thank you for your interest in these important issues.



Executive Summary

THE CHALLENGE: A "HYPER-COMPLEX RISK ENVIRONMENT"

There are urgent and complex challenges to electric system reliability in the MISO region and elsewhere. This is not just MISO's view; it is a well-documented conclusion throughout the electric industry. The North American Electric Reliability Corporation, a key reliability entity throughout the U.S., Canada and part of Mexico, has described these challenges as a "hyper-complex risk environment." These challenges include:



Fleet change: The new weather-dependent resources that are being built, such as wind and solar, do not provide the same critical reliability attributes as the conventional dispatchable coal and natural gas resources that are being retired. While emerging technologies such as long-duration battery storage, small modular reactors and hydrogen systems may someday offer solutions to this issue, they are not yet viable at grid scale.



Regulations, policies and investment criteria: Many dispatchable resources that provide critical reliability attributes are retiring prematurely due to environmental regulations and clean-energy policies. This regulatory environment, along with prevailing investment criteria for financing new energy projects, increases the challenges to build new dispatchable generation — even if it is critically needed for reliability purposes.



Fuel assurance: Gas resources can face challenging economics to procure fuel because they share the pipeline system with residential and commercial heating and manufacturing uses. Coal plants typically keep large stockpiles of fuel onsite, but coal supplies have tightened due to changing economics, import/export dynamics, supply chain issues and other factors. Aging resources can also be more prone to outages. While renewable resources such as wind turbines do not use "fuel" per se, they are sometimes unavailable due to adverse weather conditions.



Extreme weather events: While extreme weather has always been commonplace in the MISO region, severe weather events that impact electric reliability have been increasing. The Electric Power Research Institute found that hurricanes are increasing in intensity and duration, heat events are increasing in frequency and intensity and cold events are increasing in frequency. Examples include Winter Storm Elliott in 2022, Winter Storm Uri in 2021, Hurricane Ida in 2021, and Hurricanes Laura, Delta and Zeta in 2020.



Load additions: Some parts of the MISO region are enjoying a resurgence in manufacturing and/or other types of economic growth, with companies planning and building new factories, data centers and other energy-intensive facilities. While such development is welcome from an economic perspective, it can also pose significant reliability risks if the load additions it spurs cannot be reliably served with existing or planned resources.



Incremental load growth: While electricity demand has been flat for many years, it is expected to increase due to the electrification of other sectors of the economy. Electric vehicles are growing in popularity, and the residential and commercial sectors are increasingly using electricity for heating and cooling. These trends will accelerate more due to the electrification tax credits in the 2022 Inflation Reduction Act.



Supply chain and permitting issues: Many projects that have been fully approved through MISO's Generator Interconnection Queue process are not going into service on schedule due to supply chain issues and permitting delays that are beyond MISO's control. As of late 2023, about 25 gigawatts (GW) of approved resources are signaling delays that average 650 days to commercial operation.

RELIABILITY IMPERATIVE OVERVIEW

The **Reliability Imperative** is the term MISO uses to describe the shared responsibility that MISO, its members and states have to address the urgent and complex challenges to electric system reliability in the MISO region. MISO's *response* to the Reliability Imperative consists of numerous interconnected and sequenced initiatives that are organized into four primary pillars, as shown here:

RELIABILITY IMPERATIVE PILLAR	KEY INITIATIVES *(partial list)*
MARKET REDEFINITION Enhance and optimize MISO's markets to ensure continued reliability and efficiency while enabling the changing resource mix, responding to more frequent extreme weather events, and preparing for increasing electrification	• Ensure resources are accurately accredited • Identify critical system reliability attributes • Ensure accurate pricing of energy & reserves
OPERATIONS OF THE FUTURE Focus on the skills, processes and technologies needed to ensure MISO can effectively manage the grid of the future under increased complexity	• Manage uncertainty associated with increasing reliance on variable wind and solar generation • Prepare control room operators to rapidly assess and respond to changing system conditions • Use artificial intelligence & machine learning to enhance situational awareness & communications • Evaluate interdependency of neighboring systems
TRANSMISSION EVOLUTION Assess the region's future transmission needs and associated cost allocation holistically, including transmission to support utility and state plans for existing and future generation resources	• Develop "Futures" planning scenarios using ranges of economic, policy, and regulatory inputs • Develop distinct "tranches" (portfolios) of Long Range Transmission Plan (LRTP) projects • Enhance joint transmission planning with seams partners • Improve processes for new generator interconnections and retirements
SYSTEM ENHANCEMENTS Create flexible, upgradeable and secure systems that integrate advanced technologies to process increasingly complex information and evolve with the industry	• Modernize critical tools such as the Day-Ahead and Real-Time Market Clearing Engines • Fortify cybersecurity and proactively address the rapidly evolving cyber threat landscape • Develop cutting-edge data and analytics strategies

RECENT KEY ACCOMPLISHMENTS

MISO and its stakeholders have made great progress under the Reliability Imperative in recent years. Some of our key accomplishments to date include:

Seasonal Resource Adequacy Construct: In August 2022, the Federal Energy Regulatory Commission (FERC) approved MISO's proposal to shift from its summer-focused resource adequacy construct to a new four-season construct that better reflects the risks the region now faces in winter and shoulder seasons due to fleet change, more frequent and severe extreme weather, electrification and other factors. This new construct seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.

LRTP Tranche 1: The first of four planned portfolios of Long Range Transmission Planning (LRTP) projects was approved by the MISO Board of Directors in July 2022. This tranche of 18 projects represents a total investment of $10.3 billion — the largest portfolio of transmission projects ever approved by a U.S. Regional Transmission Organization. These projects will integrate new generation resources built in MISO's North and Central subregions, supporting the reliable and affordable transition of the fleet and further hardening the grid against extreme weather events.

Reliability-Based Demand Curve: MISO's Planning Resource Auction (PRA) was not originally designed to set higher capacity clearing prices as the magnitude of a shortfall increases. This lack of a "warning signal" can mask an imminent shortfall — as occurred with the 2022 PRA. Accurate capacity pricing is also crucial to make effective investment and retirement decisions. MISO worked with its stakeholders to design a Reliability-Based Demand Curve that will improve price signals in the PRA. Full implementation is planned for the 2025 PRA, subject to FERC proceedings.

Futures Refresh: The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that "bookend" what the region's resource mix might look like in 20 years. In 2023, MISO updated its Futures to lay the groundwork for LRTP Tranche 2 and to better reflect evolving decarbonization plans of MISO members and states. The refreshed Futures also model how the financial incentives for clean energy in the 2022 Inflation Reduction Act could further accelerate fleet change. The refreshed Futures are indicated with an "A" (e.g., Future 2 was updated and renamed Future 2A).

System Enhancements: The Market System Enhancement (MSE) program made significant progress in 2023. In March, the Energy Management System upgrade was moved into service. This provides a more stable platform with improved visualization while enhancing functionality and user experience. MISO also took delivery of the Reliability Assessment Commitment for the Real-Time Market Clearing Engine, which will improve application security and reduce solution time. MISO also completed Model Manager Phase 2, which connects internal applications to improve model data propagation. MSE will continue to deliver more new products, including Day-Ahead and Real-Time Market Clearing Engine items.

MISO PRIORITIES GOING FORWARD

While far from a complete list, some of MISO's key priorities for 2024 include:

Attributes: In 2023, following an in-depth look at the challenges of reliably operating an electric system in a rapidly transforming landscape, MISO published an *Attributes Roadmap* of recommended solutions to address the potential scarcity of three priority attributes that appear to pose the most acute risks: system adequacy,

flexibility and system stability. The recommendations include further modernizing the resource adequacy construct, focusing market signals on emerging flexibility needs, and requirements for new capabilities from inverter-based resources. Next, MISO will prioritize attribute solution integration, including handoffs to MISO business units and stakeholder groups and the scoping of ongoing analysis.

Accreditation: MISO must ensure resource accreditation values reflect what we can expect to receive during high-risk periods. For non-thermal resources, MISO's recommended approach blends a probabilistic methodology with availability during tight conditions, leveraging principles from the thermal accreditation reform implemented in 2022. MISO has proposed a three-year transition to the new methodology that will be applied to all non-emergency resources following the transition period. A FERC filing is planned for 2024.

LRTP Tranche 2: Work to develop the Tranche 2 portfolio of LRTP projects is progressing, with approval by MISO's Board of Directors anticipated in 2024. Planning is complex, but MISO will continue to balance the need to plan quickly with the need to develop a robust, lowest-cost portfolio. Tranche 2 is based on the refreshed Future 2A, which reflects all decarbonization plans of MISO members and states. As with Tranche 1, MISO anticipates Tranche 2 will deliver sufficient benefits to qualify under the Multi-Value Project cost allocation mechanism, with costs allocated only to the subregion where benefits are realized.

CALL TO ACTION: WE MUST WORK TOGETHER AND MOVE FASTER

In light of the urgent and complex risks to electric reliability in the MISO region, utilities, states and MISO must all act with more urgency and more coordination to avoid a looming mismatch between the pace of adding new resources and the retirement of older resources in the MISO region. This means we must:

- Refine generation resource plans across MISO by accelerating the addition of reliability attributes and moderating retirements to avoid undue reliability risk
- Maintain transition resources as reliability "insurance" until promising new technologies become viable at grid scale
- Identify areas of risk in which electricity providers, states and MISO must coordinate

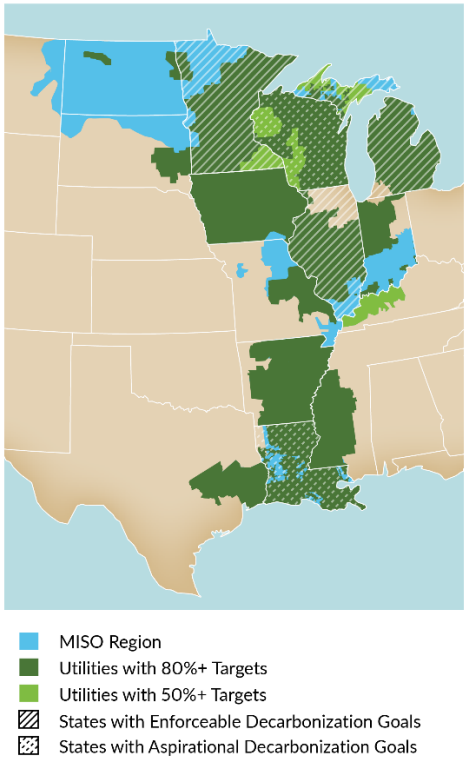
CONTINUED STAKEHOLDER INPUT IS CRUCIAL

Many of the ideas and proposals in this report reflect a great deal of technical input from MISO stakeholders. MISO appreciates stakeholder feedback on the Reliability Imperative, and we look forward to continuing the dialogue. This document is a "living" report that MISO regularly updates.

Challenges Driving the Reliability Imperative

COMPLEX POLICY LANDSCAPE

As the map indicates, many utilities and states in the MISO region have adopted policies and goals to decarbonize their resource fleets. Currently, about 75% of the region's total load is served by utilities that have ambitious decarbonization and/or renewable energy goals.



Without question, utilities and states are making remarkable progress toward their goals. Carbon emissions in MISO have already declined more than 30% since 2005, and far greater reductions are expected going forward.

Currently, wind and solar generation account for about 20% of the region's total energy. Under MISO modeling scenario Future 2A, which reflects all the clean-energy goals that utilities and states have publicly announced, wind and solar are projected to serve 80% of the region's annual load by 2042. Fleet change of that magnitude would foster a 96% reduction in carbon emissions compared to 2005 levels — which would be an extraordinary accomplishment for a region that was predominately reliant on fossil fuels not that long ago.

But at the same time, complex challenges to electric system reliability have been steadily materializing throughout the U.S. in recent years, including in MISO. These challenges are driven by a combination of economic, technological and policy-related factors along with extreme weather events. Here is a look at some of these challenges and the drivers associated with them:

TIGHTENING SUPPLY

Over the last 10-plus years, surplus reserve margins in MISO have been exhausted through load growth and unit retirements. Since 2022, MISO has been operating near the level of minimum reserve margin requirements. While MISO has implemented several reforms to help avert near-term risk, more work is urgently needed to mitigate reliability concerns in the coming years. In fact, the region only averted a capacity shortfall in 2023 because some planned generation retirements were postponed and some additional capacity was made available to MISO.

However, MISO cannot count on such actions being repeated going forward. Indeed, the North American Electric Reliability Corporation (NERC) projects the MISO region will experience a 4.7 GW shortfall beginning in 2028 if currently expected generator retirements actually occur. Notably, NERC says that shortfall will occur *even if* the 12-plus GW of new resources that are expected to come online by then actually materialize. This is because the new resources that are being built have significantly lower accreditation values than the older resources that are retiring, as is discussed in more detail below.

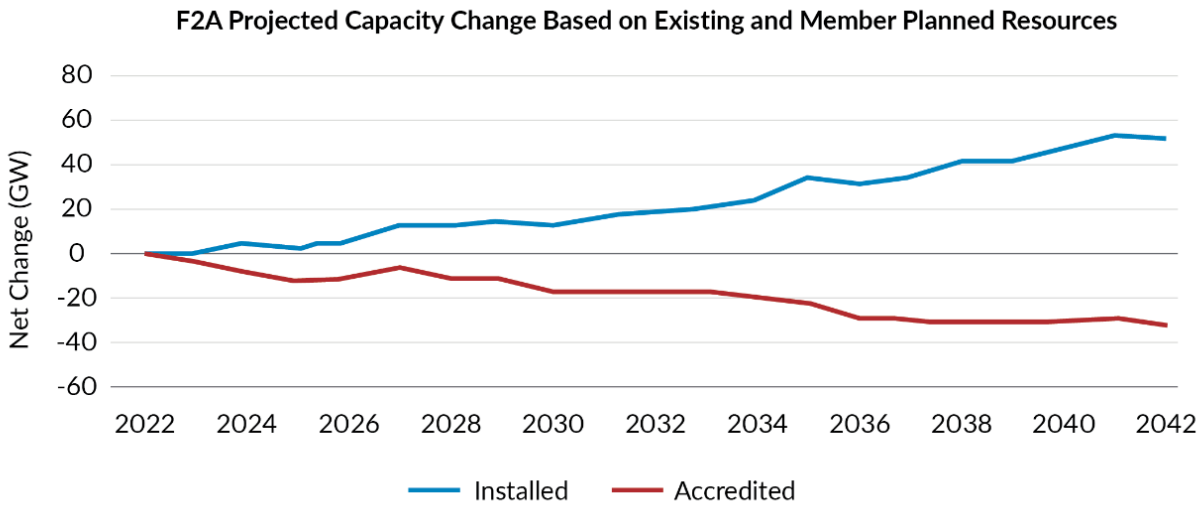
An annual planning tool called the **OMS-MISO Survey** tells a similar story. The survey compiles information about new resources utilities and states plan to build and older assets they intend to retire in the coming years. The 2023 survey shows the region's level of "committed" resources declining going forward, with a potential shortfall of 2.1 GW occurring as soon as 2025 and growing larger over time. MISO administers the survey in partnership with the Organization of MISO States (OMS), which represents the region's state regulatory agencies.

Other drivers of the region's tightening supply picture include:

- U.S. Environmental Protection Agency (EPA) regulations that prompt existing coal and gas resources to retire sooner than they otherwise would.
- Wall Street investment criteria that make it more challenging to build new dispatchable generation, even if it is critically needed for reliability purposes.
- The approximately $370 billion in financial incentives for clean-energy resources in the federal Inflation Reduction Act.

DECLINING ACCREDITED CAPACITY

Fleet change is creating a gap between the region's levels of installed and accredited generation capacity. **Installed capacity** is the maximum amount of energy that resources could theoretically produce if they ran at their highest output levels all the time and never shut down for planned or unplanned reasons. **Accredited capacity**, by contrast, reflects how much energy resources are realistically expected to produce during times when they are needed the most by accounting for their performance, which includes limiting factors such as their forced outage rates during adverse weather conditions.



The chart above is from MISO Future 2A, which reflects the publicly announced decarbonization plans of MISO-member utilities and states. As the chart shows, the region's level of *installed* capacity — the blue line — is forecast to increase by nearly 60 GW from 2022 to 2042 due to the many new resources —

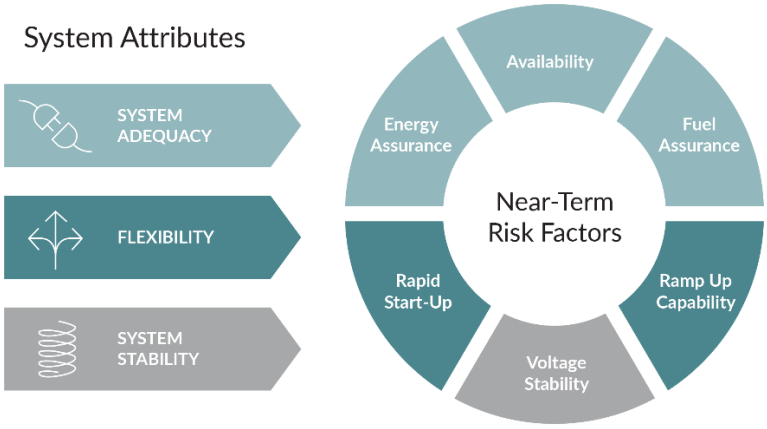
primarily wind and solar — that utilities and states plan to build in that 20-year time period.[1] But because those new wind and solar resources have significantly lower accreditation values[2] than the conventional resources that utilities and states plan to retire in the same 20-year period, the region's level of *accredited* capacity — the red line — is forecast to decline by a net 32 GW by 2042.

MISO modeling indicates that a reduction of that magnitude could result in load interruptions of three to four hours in length for 13-26 days per year when energy output from wind and solar resources is reduced or unavailable. Such interruptions would most likely occur after sunset on hot summer days with low wind output and on cold winter days before sunrise and after sunset.

NEED FOR SYSTEM RELIABILITY ATTRIBUTES

Reliably navigating the energy transition requires more than just having sufficient generating capacity; it also requires urgent action to avoid a looming shortage of broader **system reliability attributes**. In 2023, MISO completed a foundational analysis of attributes, with a focus on three priority attributes where risk for the MISO system is most acute:

- **System adequacy** is the ability to meet electric load requirements during periods of high risk. MISO focused on the near-term risk factors of availability, energy assurance and fuel assurance.
- **Flexibility** is the extent to which a power system can adjust electric production or consumption in response to changing system conditions. MISO focused on the near-term risk factors of rapid start-up and ramp-up capability.
- **System stability** is the ability to remain in a state of operating equilibrium under normal operating conditions and to recover from disturbances. MISO focused on the nearest-term risk factor of voltage stability.



No single type of resource provides every needed system attribute; the needs of the system have always been met by a fleet of diverse resources. However, in many instances, the new weather-dependent resources that are being built today do not have the same characteristics as the dispatchable resources they are replacing. While studies show it is possible to reliably operate the system with substantially lower levels of dispatchable resources, the transformational changes require MISO and its members to study, measure, incentivize and implement changes to ensure that new resources provide adequate levels of the needed system attributes.

[1] It is not a typical industry practice for utilities and states to publicly announce their resource plans a full 20 years in advance, which is the time horizon that MISO used for the MISO Futures. Thus, this forecast should be viewed as a "snapshot in time" that will change going forward as utilities and states solidify their resource plans.
[2] In the Future 2A model, retiring conventional resources are accredited at 95% or more of their nameplate capacity, while wind is accredited at 16.6% and solar declines over time to 20%. Accreditation values will vary depending on the methodologies and assumptions that were used to create them.

In December 2023, MISO published an Attributes Roadmap report that recommends urgent action to advance a portfolio of market reforms and system requirements and to provide ongoing attributes visibility through regular reporting.

EMERGING TECHNOLOGIES SHOW PROMISE BUT ARE NOT YET VIABLE AT GRID SCALE

A number of emerging technologies are being developed that could potentially mitigate the challenges described above. They include long-duration battery storage, carbon capture, small modular nuclear reactors and "green" hydrogen produced from renewables, among others.

However, while these technologies show promise for the future, they are not yet commercially viable to be deployed at scale. MISO is actively engaged in tracking the progress of these technologies and is preparing to incorporate them into the system if/when the opportunity arises.

MISO does expect the commercial viability timelines of these technologies to be accelerated by the $370 billion in financial incentives for clean energy in the 2022 Inflation Reduction Act. In recognition of that, MISO modeled those incentives in the refreshed MISO Futures. More information on emerging technologies is available in MISO's 2022 Regional Resource Assessment.

LOAD ADDITIONS ARE SURGING



Some parts of the MISO region are enjoying a resurgence in manufacturing and/or other economic growth, with companies planning and building new factories, data centers and other energy-intensive facilities. For example, in the MISO South subregion that spans most of Arkansas, Louisiana, Mississippi and a small part of Texas, there are discussions and plans to build a variety of new manufacturing plants for steel, hydrogen, liquified natural gas and other heavy industry that could add more than 1,000 megawatts (MW) of new load. The tax credits for clean-energy manufacturing in the Inflation Reduction Act are helping to drive some of these additions.

While such development is welcome from an economic perspective, it can also pose significant grid reliability risks if the large load additions it spurs cannot be reliably served with existing or planned resources.

LOAD GROWTH DUE TO INCREMENTAL ELECTRIFICATION





While year-over-year demand for electricity in MISO has been fairly flat for many years, it is expected to increase going forward due to the electrification trends in other sectors of the economy. Electric vehicles are growing in popularity, and the residential and commercial building sectors are increasingly using electricity for heating and cooling purposes — with a desire to source this new electric load from renewables. These trends will likely accelerate even more due to the substantial financial incentives in the Inflation Reduction Act for electric vehicles, rooftop solar systems and electric appliances.

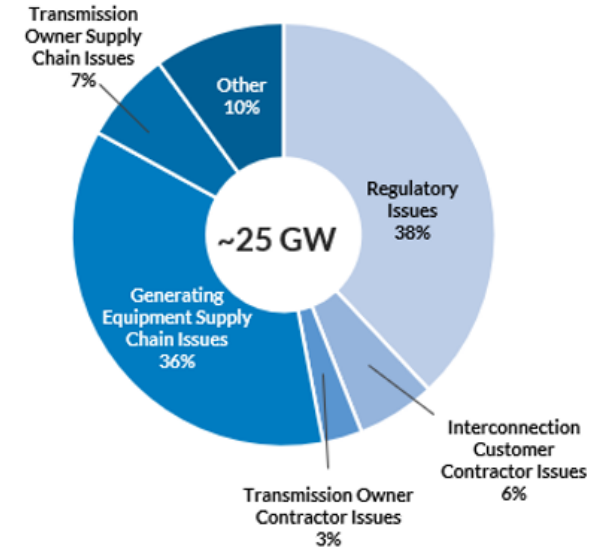
The impacts of these trends could be significant. In MISO's 2021 Electrification Insights report, MISO found that electrification could transform the region's grid from a summer-peaking to a winter-peaking system and that uncontrolled vehicle charging and daily heating and cooling load could result in two daily power peaks in nearly all months of the year.

DELAYS TO APPROVED GENERATION PROJECTS

In addition to reliability being challenged by declining accredited capacity, electrification and load additions, another concern is that a large number of fully approved and much-needed new generation projects are being delayed by supply chain issues, regulatory issues, and other external factors beyond MISO's control.

As of late 2023, about 25 GW of fully approved generation projects in MISO's Generator Interconnection Queue had missed their in-service deadlines by an average of 650 days, with developers citing supply chain and permitting issues as the two biggest reasons for the delays. An additional 25 GW of fully approved queue projects had not yet missed their in-service deadlines as of late 2023, but MISO expects many of them will also be delayed by external factors.

25 GW of fully approved & much-needed generation projects are delayed by supply chain and other issues



As the region's capacity picture continues to tighten, the possibility that upward of 50 GW of fully approved new generation projects could be delayed by external factors beyond MISO's control is deeply concerning.

FUEL ASSURANCE RISKS

The transition to a low- to no-carbon electric grid also poses risks in the realm of fuel assurance. These risks impact conventional coal and gas resources that provide reliability attributes such as system adequacy, flexibility and system stability that may be becoming scarce due to fleet change.

Coal resources have historically been considered fuel-assure because large stockpiles of fuel can be stored on-site. However, coal supplies have tightened in recent years due to a confluence of factors, including contraction of the mining and transportation sectors and supply chain issues. These factors increase the risk that coal plants will be unable to perform due to a lack of fuel availability. Coal resources can also be affected by extreme winter weather freezing onsite coal piles and/or impacting coal-handling equipment.

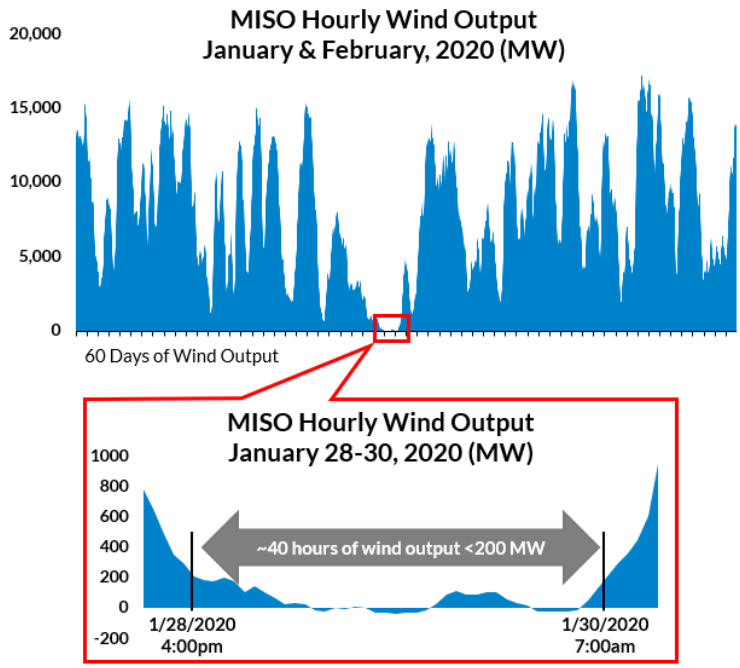
Gas-fired resources are also subject to fuel-assurance risks because they rely on pipelines to deliver gas to them. However, because the pipeline system was largely built for home-heating and manufacturing purposes, gas power plants sometimes face very challenging economic conditions to procure the fuel they need to operate. In the MISO region, this has historically occurred during extreme winter weather events that drive up home-heating needs for gas. Many gas generators in MISO do not have "firm" fuel-delivery

contracts, opting instead for less costly "interruptible" pipeline service or a blend thereof. Only about 27% of the gas generation that responded to MISO's 2023-2024 Generator Winterization Survey indicated it had firm transport contracts in place for all of their supplies during the 2023-2024 winter season. Additionally, gas power plants, gas pipelines and coal generators can be forced out of service by icing and other effects of severe winter weather — as has occurred in the MISO region and elsewhere with increasing frequency.

WIND DROUGHTS

Wind resources can experience "fuel" availability challenges in the form of highly variable wind speeds. Consequently, the energy output of wind can fluctuate significantly on a day-to-day and even an hour-by-hour basis — including multi-day periods when output drops far below average.

For example, over 60 consecutive days in January-February 2020, hourly wind output in MISO averaged more than 8,000 MW. However, as the chart shows, for 40 consecutive hours in the middle of that 60-day block, average hourly wind output dropped to less than 47 MW, and only once exceeded 200 MW in any single hour.



An even longer and broader "wind drought" occurred during Winter Storm Uri in 2021 when the MISO, Southwest Power Pool, Electric Reliability Council of Texas and PJM regions all experienced 12 consecutive days of low wind output.

Wind turbines can also be unavailable in extremely cold weather. While turbines equipped with special "cold weather packages" are designed to operate in temperatures as low as minus 22 F, they generally cut off if temperatures dip below that point. Still, it is important to keep in mind that all types of generators struggle in extreme cold, not just wind turbines.

EPA REGULATIONS COULD ACCELERATE RETIREMENTS OF DISPATCHABLE RESOURCES

While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability. In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond.

In May 2023, for example, EPA proposed a rule to regulate carbon emissions from all existing coal plants, certain existing gas plants and all new gas plants. As proposed, the rule would require existing coal and gas resources to either retire by certain dates or else retrofit with costly, emerging technologies such as carbon-capture and storage (CCS) or co-firing with low-carbon hydrogen.

MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA's optimistic timeline. If EPA's proposed rule drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised. The proposed rule may also have a chilling effect on attracting the capital investment needed to build new dispatchable resources.

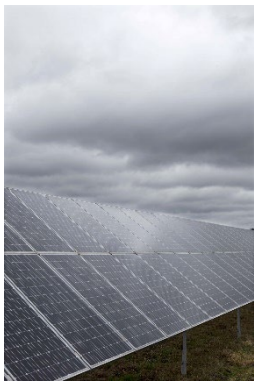
RISKS IN NON-SUMMER SEASONS

In the past, resource adequacy planning in MISO focused on procuring sufficient resources to meet demand in the peak hour of the year, which normally occurs on a hot and humid summer day when air conditioning load is very high. If utilities had enough resources to reliably meet that one peak hour in the summer, the assumption was they could operate reliably for the other 8,759 hours of the year.

That assumption no longer holds true. Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.

This changing risk profile is why MISO shifted from its annual summer-focused resource adequacy construct to a new framework that establishes resource adequacy requirements on a seasonal basis for four distinct seasons: summer (June-August); fall (September-November); winter (December-February); and spring (March-May). This new seasonal construct also seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.









Pillar 1: Market Redefinition

MISO established the energy and ancillary service markets w nearly two decades ago when the composition of, and the risks to, the energy industry were very different from today. MISO's Markets of the Future report indicates that the region's foundational market constructs will continue to be effective going forward, but only with significant revisions. Further informed by the attributes analysis completed in 2023, MISO is enhancing and optimizing its market constructs and products to ensure they continue to deliver reliability and value in the face of fleet change, extreme weather events, electrification and load additions. This work occurs under four themes within the Market Redefinition pillar of the Reliability Imperative, as discussed below.

UNCERTAINTY AND VARIABILITY

In the planning horizon, MISO is addressing the changing risk profile and enhancing market signals for new resource investments. MISO's original resource adequacy construct was designed for a conventional fleet of resources where reliability risk was concentrated during the typical summer peak period. This is no longer the case. Factors such as aging conventional resources, more frequent and severe weather events and increased reliance on weather-dependent renewables have altered the region's historic risk profile, creating new risks in non-summer months and at differing times of the day. As the generation mix further diversifies, the accreditation process of evaluating each generator's contribution to the system is a critical reliability and planning mechanism.

In 2022, FERC approved MISO's proposal to shift from the annual, summer-based resource adequacy construct to a new construct with four seasons. The new seasonal construct also aligns the accreditation of thermal resources with availability in the highest-risk periods. These changes, implemented in the 2023-2024 Planning Resource Auction (PRA), are already delivering positive market outcomes, such as more proactive outage coordination among stakeholders and incentivizing improved unit performance.

MISO completed an evaluation of potential paths for non-thermal accreditation reforms 2022. This resulted in a proposed accreditation reform that leverages the principles from the thermal accreditation reform implemented in 2022, aligning the accreditation methodology for all resource types (except for emergency-only resources). MISO has proposed a transition period to begin applying the new accreditation methodology in the 2028-2029 planning year. The design work is expected to be finished with a filing with FERC in 2024.

The PRA was not designed to set higher capacity clearing prices as the magnitude of a shortfall increases. This lack of a "warning signal" can instill a false sense of calm among PRA participants, masking an imminent shortfall — as occurred with the 2022 PRA. MISO is working with its stakeholders to enhance pricing within the capacity construct by designing a Reliability-Based Demand Curve (RBDC) to better reflect MISO's market guiding principles, reliability risk and help avoid uneconomic retirements. Full implementation is planned for the 2025-2026 PRA, subject to FERC proceedings.

While the RBDC improves price signals in the planning horizon, MISO is also working on pricing reforms in the operating horizon. These focus on **scarcity pricing** when demand and reserve requirements exceed available supply in real time, often happening during extreme events when MISO enters emergency procedures to manage challenging conditions.

MISO's reforms to scarcity pricing will help incentivize appropriate market behavior, manage congestion throughout events and value reserve shortages appropriately, ultimately providing greater transparency and minimizing manual market intervention. MISO's focus areas for 2024 are updating the value of lost load, demand curves and forced-off assets that become physically disconnected from the grid due to weather-related transmission events. MISO has been presenting ideas at the Market Subcommittee stakeholder group. These enhancements will begin in 2024, with complete implementation expected by 2025.

Lastly, informed by the analysis of critical reliability attributes and in light of the changing reliability risk profiles in the region, MISO will work with stakeholders in 2024 to reevaluate the traditional risk metrics used in the industry for resource adequacy assessments and improve the underlying risk models.

RESOURCE MODELS AND CAPABILITIES

To avoid a looming shortage of necessary voltage stability attributes, as detailed in the *Attributes Roadmap*, MISO will advance a multistep technology standard to require capabilities from inverter-based resources to support grid stability at interconnection. In January 2023, MISO embarked on a path to improve inverter-based resource performance requirements using a reliability risk-based approach to evaluate potential gaps in MISO's current tariff. MISO finalized the proposed Tariff language in November to address the highest priority performance requirements and capabilities. This proposal is Phase 1 of the recommended four-phase approach, and this cross-matrix "resource models and capabilities" project will continue in the Interconnection Process Working Group (IPWG).

Another area of focus is MISO's work toward compliance with **FERC Order 2222**, which facilitates the participation of distributed energy resources (DERs) in wholesale electricity markets. DERs are small-scale resources such as rooftop solar panels, electric battery storage systems or electric vehicles and their charging equipment. In isolation, these resources would not have much impact on the grid, but when they are aggregated into a larger block, they can be impactful. MISO is developing a plan to comply with this order through broad collaboration with stakeholders, members, regulators, distributors and DER aggregators.

IDENTIFYING LOCATIONAL NEEDS

Another critical focus associated with increased uncertainty and variability is challenging reserve deliverability due to congestion. Historically, MISO utilized reserve zones to procure and reliably deliver reserves. MISO is working to implement improved locational granularity in its reserve products to ensure deliverability. Updating the reserve zones more frequently should enhance market efficiency and system reliability since there would be better alignment between zonal definitions and system conditions.

In addition to the local deliverability of resources, MISO will explore approaches to better hedge congestion through MISO's Auction Revenue Rights (ARR) mechanism and the Financial Transmission

Rights market. Evaluation has identified gaps and is exploring potential areas of improvement, including updating approaches for allocating ARRs, more granular periods, and ways to incentivize outages that better align with day-ahead energy models.

ENHANCING COORDINATION

As operational uncertainty and complexity increase, MISO continues to improve coordination across stakeholders and external entities, including neighboring grid operators. The collaborative **OMS-MISO Survey** provides a prompt view of resource adequacy over the five-year horizon, characterizing relative levels of resource certainty. MISO's **Regional Resource Assessment** (RRA) provides a collective 20-year view of the evolution of members' resource plans. It aims to provide insights that help members, states and MISO prepare for the energy transition. MISO's *Attributes Roadmap* specifically identifies the need for evolved coordination between MISO's resource adequacy assessments and MISO state and member planning process to ensure attribute sufficiency. MISO is committed to continued analysis, transparency and collaboration in the Resource Adequacy stakeholder forum.

One example is how transmission owners and MISO are working together on **ambient-adjusted ratings (AARs)** and **seasonal ratings** on transmission lines in the region, per the requirements of FERC Order 881. While using more accurate line ratings does not diminish the need to build new transmission, having the most accurate line rating information can help ensure that the region's transmission system is fully utilized and delivers its maximum value. MISO has engaged in extensive discussions with its transmission owners and consulted with other interested stakeholders to develop a compliance approach that meets the requirements of FERC Order 881 and is consistent with MISO's Tariff.

> "Our market products and the signals they send need to evolve and reflect the new realities and trends that we are experiencing. Input and support from our stakeholders will be key in the effective and timely implementation of these changes."
>
> Todd Ramey, MISO Senior Vice President, Markets and Digital Strategy

Pillar 2: Operations of the Future

MISO's control room operations are also challenged by fleet change, extreme weather and other risk drivers. In addition to implementing lessons learned from past events such as Winter Storm Elliott, forward-looking work is underway to ensure MISO has the capabilities, processes and technology to anticipate and respond to operational opportunities and challenges. This work, termed Operations of the Future, focuses on five buckets of work: (1) operations preparedness, (2) operations planning, (3) uncertainty and variability, (4) situational awareness and critical communications and (5) operational continuity.

OPERATIONS PREPAREDNESS

Tomorrow's control room will be very different from today. Operations preparedness is critical to managing the rapidly changing system conditions, increased volumes of data and enhanced technologies and tools that operators face. To ensure that control room personnel are ready to manage reliability effectively and efficiently in this new and continually evolving environment, MISO is developing improved operations simulation tools and enhancing operator training. In the future, operator and member training and drills will leverage a robust simulator that mirrors production and can quickly incorporate and maintain real-time event scenario simulations with broad, controlled access capabilities.

> "In the past, predicting load and generation was relatively straight-forward. In the future, the operating environment will be much more variable, and we need the people, processes and technology to deal with that variability."
>
> Jennifer Curran, MISO Senior Vice President, Planning & Operations and Chief Compliance Officer

OPERATIONS PLANNING

Operations planning helps MISO to remain a step ahead of the shifting energy landscape. System operators need to quickly access insights into the future and processes that enable the continued reliable and efficient operation of the bulk electric system. In the future, it will be necessary to leverage information in new ways. The ability to quickly model and analyze realistic planning scenarios will enable operators to develop and modify operating day plans from start to execution. Operators will be better prepared to manage increased uncertainty in resource availability with operational planning processes that are centralized and streamlined and outages that are proactively scheduled leveraging predictive economic impact analysis and power system studies.

UNCERTAINTY AND VARIABILITY

The increase in variable generation such as wind and solar has introduced greater uncertainty. Today, operators leverage a variety of market products and other analytics-based tools to manage uncertainty. To help manage increasing complexity, MISO is using machine-learning to predict net uncertainty for the upcoming operating day, using probabilistic forecasts and advanced analytics. With this more complete view, operators can create daily risk assessments that — when coupled with new dynamic reserve requirements — incentivize efficient unit-commitment decisions.

In the future, operators will need to manage the grid reliably and efficiently through tight margins, high-ramping periods, and increased variability by optimizing a risk management framework that accurately provides a risk profile based on net uncertainty impacts and by leveraging predictive economic impact analysis and power system studies.

SITUATIONAL AWARENESS AND CRITICAL COMMUNICATIONS

Situational awareness and critical communications will become even more important as operating risks become less predictable and more difficult to manage in day-to-day operations. New control room technologies and capabilities, improved real-time data capabilities and more complex operating conditions, driven by new load and generation patterns, will require MISO and its members to communicate even more quickly and efficiently.

Today, MISO operations rely heavily on the expertise of its operators. While operators have access to significant amounts of data related to weather, load and more, they must manually synthesize that data into useable information. Although this has worked well historically, solutions must envision a future with more complex information and operators who may not possess the same historical knowledge.

In the future, operators will need an integrated toolset that leverages artificial intelligence and machine learning, combined with additional data and analytics. Improvements in how MISO sees and navigates will give operators important information automatically. Systems will provide situational awareness insights for operators based on their function in the control room. Operators will analyze information and create new displays in real time to quickly assess the impacts of operational situations. Dynamic views of the state of the system will ensure operators can maintain the appropriate level of situational awareness while also reducing operator burden and automating key communication requirements, especially during critical events.

Additionally, enhancements to communications protocols, such as system declarations, will ensure that control rooms have the information they need when they need it. Automated messaging triggered by specific process and procedure actions will reinforce compliance with NERC standards.

OPERATIONAL CONTINUITY

Operational continuity capabilities need to evolve to align with the changing technologies, resource portfolio and threat landscape. Improved tools and updated processes are vital to ensuring that MISO can reliably operate the grid, mitigate risks, and, if necessary, recover quickly in the event of disruptions to toolsets or control centers.

Pillar 3: Transmission Evolution

The ongoing shift in the resource fleet and the substantial projected increase in load pose significant challenges to the design of the transmission system in the MISO region. MISO's Transmission Evolution work addresses these challenges in concert with other elements of the Reliability Imperative framework.

Under Transmission Evolution, MISO holistically assesses the region's future transmission needs while considering the allocation of transmission costs. This work creates an integrated transmission plan that reliably enables member goals while minimizing the total cost of the fleet transition, inclusive of transmission and generation. It also improves the transfer capability of the transmission system — meaning its ability to effectively and efficiently move energy from where it is generated to where it is needed.

LONG RANGE AND INTERREGIONAL TRANSMISSION PLANNING

Regional Long Range Transmission Planning (LRTP) and interregional planning are important parts of the Transmission Evolution pillar. The LRTP effort is developing four tranches of new backbone transmission to support MISO member plans for the changing fleet. In July 2022, the MISO Board of Directors approved LRTP Tranche 1. The 18-project portfolio of least-regret solutions is focused on MISO's Midwest subregion, representing $10.3 billion in investment. The projects in Tranche 1 will provide a wide range of value, including congestion and fuel savings, avoided capital costs of local resources, avoided transmission investments, resource adequacy savings, avoided risk of load shedding and decarbonization.

> "We see very little risk of over-building the transmission system; the real risk is in a scenario where we have underbuilt the system. Similarly, across markets and operations, our job is to be prepared."
>
> Clair Moeller, MISO President

This transmission investment hinges on appropriate allocation of the associated costs. MISO's Tariff stipulates a roughly commensurate "beneficiaries pay" requirement that must be met while balancing the divergent needs of MISO's three subregions. Because Tranches 1 and 2 primarily benefit the Midwest subregion, costs will only be allocated there. As Tranches 3 and 4 progress, other approaches may be considered based on stakeholder discussion. Work on Tranche 2 is progressing, with an anticipated approval by MISO's Board of Directors in 2024.

Futures refresh

MISO's future scenarios, or Futures, set the foundation for LRTP. The Futures help MISO hedge uncertainty by "bookending" a range of potential economic, policy and technological possibilities based on factors such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas prices and generation capital cost over a 20-year period.

Member and state plans often do not provide resource information for the full 20-year study period covered by LRTP. Although MISO does not have authority over generation planning or resource procurement, this lack of information creates a gap in the resources needed to serve load and meet member goals. MISO fills the gap through resource expansion analysis, which seeks to find the optimal resource fleet that minimizes overall system cost while meeting reliability and policy requirements. The resulting resource expansion plans are used with their respective Future to identify transmission issues and solutions.

To lay the groundwork for Tranche 2 and to better understand potential future needs based on the most recent plans, legislation, policies and other factors, MISO refreshed its three Futures in 2023. While the defining characteristics of each Future remained the same (e.g., load forecast and retirement assumptions), updates were made to data and information that inform the potential resource mix. Among other factors, this includes state and member plans, capital costs, operating and fuel costs and defined resource additions and retirements. MISO also modeled the impacts of the clean energy tax credits in the federal Inflation Reduction Act because those incentives are expected to accelerate the transition to a decarbonized grid.

Future 2A, the focus of Tranche 2, indicates that fleet change will increase in velocity due to stronger renewable energy mandates, carbon reduction goals and other policies. Future 2A projects a 90% reduction in carbon emissions by 2042 and forecasts that wind and solar will provide 30% of the region's energy a full 10 years earlier than the previous Series 1 Futures that were used for Tranche 1.

Planning for an uncertain future

When planning for larger, regional solutions that address needs 20 years into the future, there is inherent uncertainty, which is why LRTP is designed to identify "least-regrets" transmission solutions. Appropriately managing this uncertainty is a key function of planning. In developing Future 2A, MISO leveraged the consensus on policy goals among MISO members and states about how quickly change would occur. Additionally, MISO's comprehensive processes and robustness testing demonstrate the benefits and needs of transmission solutions that achieve member goals and minimize costs, including several iterations of analyses for Future 2A and other scenarios.

Other visibility tools

As the system becomes more interdependent and interconnected, MISO provides information to members about the outcomes and impacts of their individual plans when studied in the aggregate. Anticipating and communicating changing risks and future systems needs within the planning horizon is critical to ensure continued reliability.

As described earlier in this report, the **OMS-MISO Survey** compiles information about new resources that utilities and states plan to build and older assets they intend to retire in the coming years. While this tool looks several years ahead, certainty is lower in later years when many significant risks will need to be addressed.

Because utility and state plans can be less specific and certain, cover a shorter timeframe and are not always publicly available, MISO conducts the **Regional Resource Assessment (RRA)** to capture more information and details. The RRA aggregates utility and state plans and goals — both public and private —

over a 20-year planning horizon to shed light on regional fleet evolution trends and timing. The information is then used to model potential reliability needs and gaps that may arise and may be leveraged to inform and advance analysis of resource attributes. In the future, new tools will provide stakeholders with ongoing access to RRA information for greater visibility into the impact of these future system changes.

Interregional initiatives

MISO continually works with its neighboring grid operators, Southwest Power Pool (SPP) and PJM, to address issues on the seams. Joint, coordinated, system plan studies are regularly conducted to assess reliability, economic and/or public policy issues. The studies can be more targeted in scope with a shorter study cycle or can be more complex, requiring a longer study period.



The Joint Targeted Interconnection Queue (JTIQ) initiative with SPP is an example of a recent complex study initiative. This unprecedented, coordinated effort identified a portfolio of proposed transmission projects that align with both MISO's and SPP's interconnection processes. These projects will create additional transmission capability to enable generator interconnections in both regions.

In October 2023, the U.S. Department of Energy (DOE) announced it would award $464.5 million in federal funding under the Grid Resilience and Innovation Partnerships (GRIP) program to the JTIQ portfolio. This historic opportunity significantly reduces the estimated investment for new transmission lines that will benefit seven states. A FERC filing to obtain approval of cost allocation for the JTIQ portfolio will be submitted in early 2024, and MISO Board approval will be sought thereafter. The process SPP and MISO followed to coordinate the study proved to be effective and significantly more efficient than typical Affected System Studies. Based on its success, the process will be included in the 2024 filing to enable improved coordination in the future.

PLANNING TRANSFORMATION

MISO's planning tools and processes must also evolve as the transitioning resource mix increases the complexity of transmission planning. In response, Planning Transformation, another component of the Transmission Evolution pillar, will develop aligned, adaptable and flexible processes and tools over the next five to 10 years to recognize and address emerging transmission threats and risks identified in markets and operations.

The new MISO Transmission Expansion Plan (MTEP) Portal is a major step in this transformation. The system launched in October 2023 and helps MISO staff and transmission owners manage project data more efficiently and effectively, and it will save hundreds of work hours each year. It also provides stakeholders better support for submitting, updating, tracking and managing MTEP projects and enables more transparency.

Other measures — such as the Generator Interconnection Portal and technology evaluation of resource siting — are already implemented, underway or planned for the future. These include evolving technology

for the resource transition, adapting planning criteria to enhance system resiliency and robustness, and integrating model data.

RESOURCE UTILIZATION

The Resource Utilization initiative focuses on improving resource utilization planning to include a dynamic generator retirement process, more rapid generator interconnections and resource reliability attributes that are addressed throughout the resource lifecycle.

To improve the generator retirement process, asset owners are now required to provide one-year advance notice of resource retirements, an increase from the prior 26 weeks. Quarterly retirement studies have also been instituted to better forecast the engineering workload needed to conduct analyses, and other changes are being implemented that help align retirements with MTEP processes and improve visibility of retirements to stakeholders.

MISO is also working to ensure its processes do not impede generator interconnections. Although MISO's queue processes have been effective in cycles with typical volumes, they are not sufficient for managing recent request volumes that are growing exponentially compared to historical norms. This significantly increases the time it takes MISO to complete studies, which drives more project withdrawals, provides less certainty of early study results, and, ultimately, complicates late-stage studies. These issues are compounded by many speculative projects, despite years of reforms on "first ready, first served" principles.

Improvements to customer-facing and backend operational queue processes over the past several years have enabled more efficient application processing. However, additional changes are needed to manage the dramatic growth in applications, further expedite the interconnection process and maximize transparency and certainty to customers.

As a result, MISO paused accepting interconnection applications for the 2023 cycle, with plans to resume in March 2024 after receiving FERC approval on multiple process improvements to ensure better interconnection requests are submitted. The 2024 cycle is anticipated to begin in the fall of 2024, as it has in previous years.

Tariff changes approved by FERC in January 2024 increase financial commitments and withdrawal penalties and require interconnection customers to provide greater site control for projects. FERC did deny a MISO proposal to cap the size of queue study cycles to ensure they do not exceed a certain percentage of MISO load. However, FERC provided guidance on how MISO could implement a cap in the future, as well as other improvements that will enable the dispatch of existing resources with new interconnection requests. MISO believes these changes will decrease applications and result in higher-quality, more viable projects entering the queue. A reduction in project withdrawals may ultimately reduce network upgrades between studies and provide greater planning certainty for customers and MISO.

In July 2023, FERC issued Order 2023 to ensure that generator interconnection customers can interconnect to the transmission system in a reliable, efficient, transparent, timely and nondiscriminatory manner. The order is mostly consistent with the queue changes MISO has already implemented and

intends to implement going forward. MISO is reviewing the order to assess potential changes and compliance needs.

Lastly, as described in the Resource Models And Capabilities section of this report, MISO is advancing a multistep technology standard to require capabilities from inverter-based resources to support grid stability through the Interconnection Process Working Group. This cross-matrix work is further described in MISO's *Attributes Roadmap* report as a solution to mitigate the potential shortage of system stability attributes.

Delays outside of MISO's control

Despite improvements MISO has made to its Generator Interconnection Queue, many fully approved projects are not going into service on schedule due to supply chain issues and permitting delays that are beyond MISO's control. As of late 2023, about 25 gigawatts (GW) of resources that were fully approved through MISO's queue process had missed their in-service deadlines by an average of 650 days, with developers citing supply chain and permitting issues as the two biggest reasons for the delays. An additional 25 GW of fully approved queue projects had not yet missed their in-service deadlines as of late 2023, but MISO expects many of them will also be delayed by external factors.









Pillar 4: System Enhancements

Continual system enhancements and modeling refinements are the bedrock of MISO's response to the Reliability Imperative. The ongoing complexities of the electric industry landscape necessitate paramount upgrades to facilitate reliability-driven market improvements. The Market System Enhancement (MSE) program stands out as a visionary endeavor, focusing on upgrading, building and launching new systems with improved performance, security and architectural modularity. This strategic emphasis enhances MISO's capability to respond swiftly and efficiently and deliver new market products that align with the evolving industry landscape.

MISO places strategic importance on enabling a mature hybrid cloud capability to future-proof the technological infrastructure and foster a resilient and adaptable organizational framework. Simultaneously, the commitment to fostering a flexible work environment amplifies MISO's readiness for ongoing technological changes. This dynamic approach, centered on securely harnessing hybrid cloud technology, optimizes the work environment, positioning MISO for future advancements. The integration of these strategies underlines MISO's forward-looking approach and establishes its leadership in embracing advanced technologies for safeguarding operations.

MARKET SYSTEM ENHANCEMENT (MSE) PROGRAM

The MSE program, initiated in 2017, is a transformative force in reshaping MISO's market platform. Its focus on creating a more flexible, upgradeable and secure system underscores its pivotal role in accommodating the region's evolving portfolio and technology changes. The achievements in 2023 highlight the program's commitment to continuous improvement. The upgrade of the Energy Management System, completion of Phase 2 Core Development, and advancements in the Day-Ahead Market Clearing Engine and Real-Time Market Clearing Engine showcase MSE's impact on improving functionality, user experience, business continuity and security posture. This program is not merely a technological upgrade; it is a strategic initiative that positions MISO to meet the demands of the future electric grid.

> "For MISO to continue to deliver on our mission, we must prioritize our plan to address the right strategic drivers that will enable us to accommodate the region's evolving portfolio and technology changes. The work we do in System Enhancements supports the transformational efforts across the Reliability Imperative and will increase value to our stakeholders."
>
> Todd Ramey, Senior Vice President, Markets and Digital Strategy

WORK ANYWHERE

MISO's strategic move toward future-proofing its technological infrastructure involves enabling and maturing hybrid cloud capabilities. This initiative goes beyond technology; it embraces the transformative strategy of realizing a flexible work environment that transcends conventional boundaries. The delicate balance between the freedom to work remotely and stringent adherence to security and compliance requirements signifies a definitive change in how MISO approaches work. This shift sets the stage for a more agile and responsive workforce, enhancing productivity and embracing the evolving nature of work. Simultaneously, adopting a well-managed hybrid cloud platform forms the backbone of MISO's technological evolution, allowing seamless operations between on-premises data centers and the public cloud. This combination fortifies organizational resilience and propels MISO into a future where adaptability is the key to sustainable success.

SECURITY OF THE FUTURE

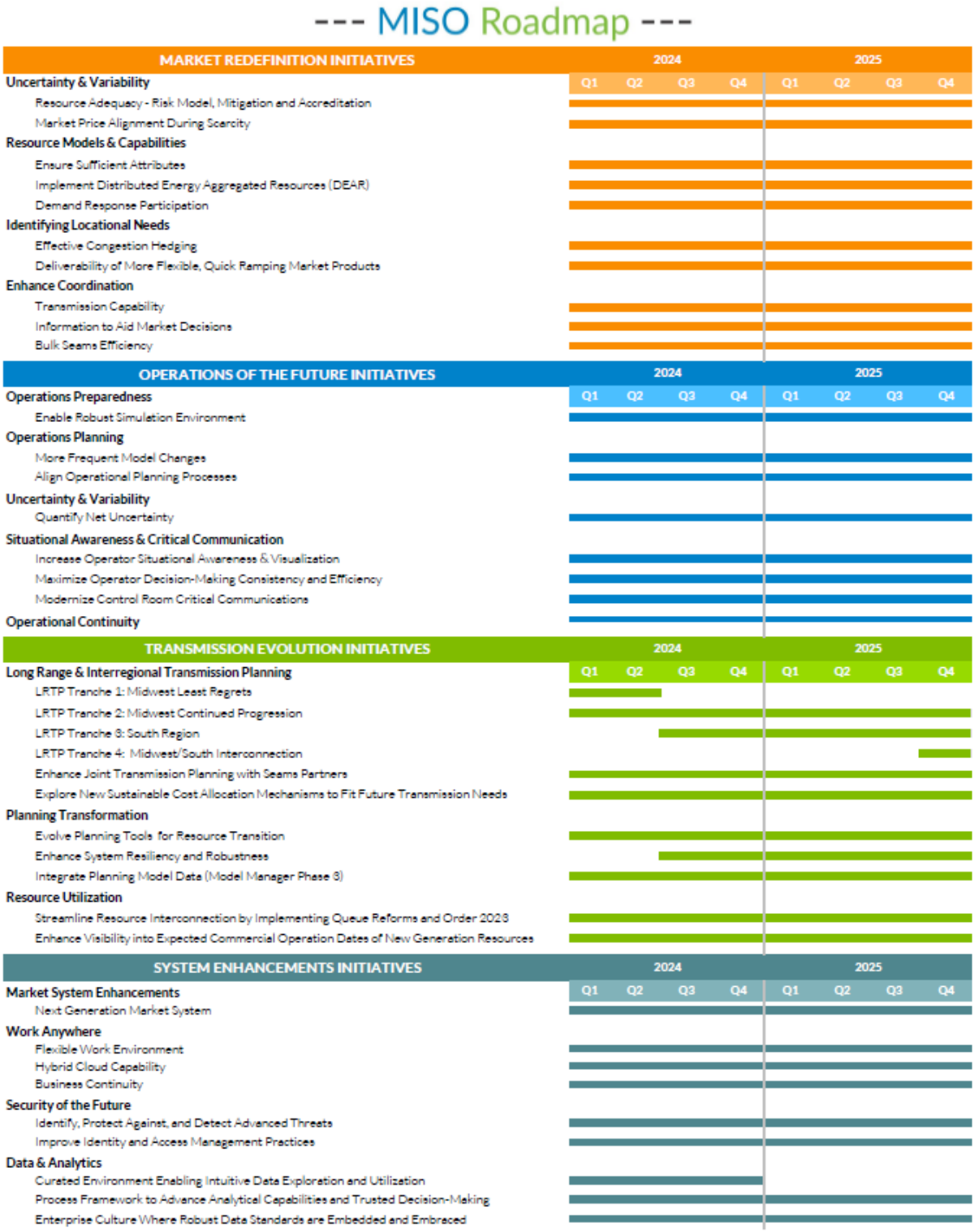
MISO's commitment to seamlessly integrating cutting-edge technologies is underpinned by a dedication to security, reliability and efficiency. This includes initiatives designed to fortify MISO's approach to cybersecurity. Refining identity and access management practices, adopting a proactive zero-trust approach and transforming asset management data quality and timeliness demonstrate MISO's proactive stance against the evolving cyber threat landscape. The commitment extends beyond external threats to assessing security best practices for the internal environment. The ongoing thorough review to evaluate and implement the latest security protocols, conduct regular audits and stay abreast of emerging threats exemplifies MISO's dedication to securing tomorrow.

DATA AND ANALYTICS

MISO's data strategy is a comprehensive framework that goes beyond a simple upgrade — it is a visionary approach to enhancing MISO's data capabilities. The three key priorities — fostering an enterprise culture, delivering a holistic process framework and providing a curated environment — fortify MISO's position as a leader in the energy sector. This strategy modernizes tools, platforms, technologies and processes and empowers teams to model, simulate, analyze and visualize data for informed decision-making. Through a focused and well-defined program, MISO is set to realize a data platform that not only meets the needs of today but is agile enough to adapt to the evolving landscape of data requirements.

MISO Roadmap

As illustrated below, the **MISO Roadmap** outlines MISO's priorities to help its members to reliably achieve their plans and goals. The MISO Roadmap resides on MISO's public website.



MISO's Role

This report is written from MISO's perspective. However, the responsibility for ensuring grid reliability and resource adequacy in the MISO region is not MISO's alone. It is shared among Load Serving Entities (LSEs), states and MISO, each of which have designated roles to play.

LSEs are utilities, electric cooperatives and other types of entities that are responsible for providing power to end-use customers. In most (though not all) of the MISO region, LSEs have designated service territories and are regulated by state agencies. LSEs have exclusive authority to plan and build new generation resources and to make decisions about retiring existing resources, with oversight from state agencies as applicable by jurisdiction.

MISO performs certain transmission planning functions but does not plan or build new generation or decide which existing resources should retire. MISO exercises functional control of its members' generation and transmission assets with the consent of its members and per the provisions of its Tariff, which is subject to approval by FERC. By operating these assets as efficiently as possible on a region-wide basis, MISO generates substantial cost savings and other reliability benefits that would not otherwise be realized.

MISO also establishes and administers resource adequacy requirements for LSEs and states, as applicable by jurisdiction. These include:

- A **Planning Reserve Margin (PRM)** that sets the level of contractually obligated resources that MISO can call into service when normally scheduled resources go offline for planned or unplanned reasons or when demand surges due to extreme weather conditions or other factors. The PRM is set through MISO's stakeholder process.
- A **Planning Resource Auction (PRA)** that LSEs can use to procure needed resources or sell surplus resources. LSEs can "opt out" of the PRA by using their own resources or negotiating bilateral contracts with other entities.
- **Resource accreditation metrics** that determine how much "credit" various types of resources receive toward meeting resource adequacy requirements based on factors such as their unplanned outage rates.
- **Locational procedures** that determine how much capacity is needed in certain parts of the MISO region for reliability purposes and how much can be imported from and exported to other locations, among other things.

MISO engages with a broad range of stakeholders to share ideas and discuss potential solutions to the challenges facing the region. The Reliability Imperative work also involves a robust, collaborative dialogue across the many forums within the stakeholder process. The collaboration that takes place in these forums has provided valuable policy and technical-related feedback, and MISO is committed to continuing that engagement.

MISO INITIATIVES ARE INTERCONNECTED AND SEQUENCED

MISO's strategic priorities are connected and build upon each other. Success in one area depends on progress in another, so efforts must be coordinated and sequenced. For example, achieving reliable and economically efficient grid operations requires new tools and processes to be developed under the Operations of the Future workstream and market enhancements to be developed under the Market Redefinition workstream.

Given the urgent and complex challenges that are facing the region, it is crucial for MISO members, states and MISO to work together to execute on the reforms that are needed.

The MISO Value Proposition

MISO creates substantial cost savings and other benefits by managing the grid system on a regional basis that spans all or parts of 15 states and one Canadian province. Before MISO was created, the system was managed by 39 separate Local Balancing Authorities (LBAs), which made the grid much more fragmented and far less economically efficient than it is today.

The benefits that MISO created in calendar year 2022 range from $3.3 billion to $4.5 billion, according to the Value Proposition study that MISO performs every year. That represents a benefit-to-cost ratio of about 12:1 when compared to the fees that utilities pay to be members of MISO. MISO creates benefits in a variety of ways, including through efficient dispatch and reduced need for assets. Since the Value Proposition study was launched in 2007, the cumulative benefits that MISO has created exceed $40 billion. And notably, that figure does not reflect all the benefits MISO creates due to the conservative approach that MISO uses to conduct the study.

While continuing to use this conservative approach, MISO anticipates that it will create even more benefits going forward by helping its members and states to achieve their decarbonization goals in a reliable manner. In June 2022, MISO looked at those anticipated future benefits in a supplemental report called the Forward View of the Value Proposition. That report estimates the value that MISO will create going forward in two ways that are not specifically reflected in the "standard" Value Proposition study: (1) the value of sharing carbon-free energy from areas with higher levels of renewables to regions with lower levels, and (2) the value of sharing flexibility attributes that are required to integrate those new renewables while maintaining reliability.

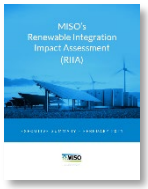
MISO found that by including these two additional value streams, MISO's total benefit-to-cost ratio would increase from approximately 12:1 today to approximately 26:1 by 2040. This illustrates that while there are indeed many challenges associated with fleet change, there are also tremendous economic benefits that utilities and states can realize by pursuing their decarbonization goals as members of MISO.

Informing the Reliability Imperative

MISO's response to the Reliability Imperative has been informed by years of conversations with stakeholders. MISO has also undertaken numerous studies to assess the region's changing risk profile and to explore how reliability is being affected by various drivers. This work includes:



Attributes Roadmap: This study looks at three key electric system attributes where near-term risk is most acute: (1) System Adequacy, (2) Flexibility and (3) System Stability. The Attributes Roadmap recommends advancing a combination of current and new proposals as well as providing ongoing attributes visibility through regular reporting.



Renewable Integration Impact Assessment (RIIA): This study assesses the impacts of integrating increasingly higher levels of renewables into the MISO system. RIIA indicates that planning and operating the grid will become significantly more complex when greater than 30% of load is served by wind and solar. However, RIIA also indicates that renewable penetrations of greater than 50% could be reliably achieved if utilities, states, and MISO coordinate closely on needed actions.



Regional Resource Assessment (RRA): The RRA is a recurring study based on the plans and goals MISO members have publicly announced for their generation resources. The RRA aggregates these plans and goals to develop an indicative view of how the region's resource mix might evolve to meet utilities' stated objectives. The RRA aims to help utilities and states identify new and shifting risks years before they materialize, creating a window to develop cost-effective solutions.



MISO Futures: The MISO Futures utilize a range of economic, policy and technological inputs to develop three future scenarios that "bookend" what the region's resource mix might look like in 20 years. The Futures inform the development of transmission plans and help MISO prioritize work under the Reliability Imperative. Series 1 was published in 2021. In 2023, MISO updated the report to Series 1A to reflect evolving member/state plans and the clean energy incentives in the Inflation Reduction Act, among other things.



Markets of the Future: This report illustrates how and when MISO's market structures will need to evolve in order to accommodate the transformation of the energy sector. The needs are presented in four broad categories: (1) Uncertainty and Variability, (2) Resource Models and Capabilities, (3) Location and (4) Coordination. This report helped establish the foundation for the work MISO is currently doing to identify critical system attributes.



The February (2021) Arctic Event: This report discusses lessons learned from Winter Storm Uri, which affected the MISO region and other parts of the country in February 2021. MISO and its members took emergency actions during the event to prevent more widespread grid failures. Uri illustrated how extreme weather can exacerbate the challenges of fleet change. Preparing for extreme weather is a major part of MISO's response to the Reliability Imperative.

Electrification Insights: This report explores the challenges and opportunities the grid could face from the growth of electric vehicles and the increasing electrification of other sectors of the economy, such as homes and businesses. The report indicates electrification could transform the MISO grid from a summer-peaking to a winter-peaking system, and that vehicle charging and daily heating and cooling load could result in two daily power peaks nearly all year.



From this groundwork, we know there are many challenges ahead. But we also believe we can respond to the Reliability Imperative in a manner that enables our members to achieve their resource plans and policy objectives. We are determined to do the hard work required to ensure our members benefit from MISO membership.

Acronyms Used in This Report

DER: Distributed Energy Resource

FERC: Federal Energy Regulatory Commission

GW: Gigawatt

JTIQ: Joint Targeted Interconnection Queue

LBA: Load Balancing Authority

LSE: Load Serving Entity

LRTP: Long Range Transmission Planning

MSC: Market Subcommittee

MISO: Midcontinent Independent System Operator

MSE: Market System Enhancement

MTEP: MISO Transmission Expansion Plan

MW: Megawatt

NERC: North American Electric Reliability Corporation

OMS: Organization of MISO States

PAC: Planning Advisory Committee

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

RBDC: Reliability-Based Demand Curve

RIIA: Renewable Integration Impact Assessment

RRA: Regional Resource Assessment

SPP: Southwest Power Pool

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