



2026 NIPSCO INTEGRATED RESOURCE PLAN

Second Stakeholder Advisory Meeting

October 20, 2026

9 A.M.-3 P.M. CT

The anticipated modeling and modeled portfolios throughout the IRP are regulatory requirements made in connection with integrated resource planning that contain the company's forward-looking assumptions. The modeling remains under evaluation and such modeling and modeled portfolios are not an indication of actual future events and should not be relied upon as such.



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NAME OF **ROOM**

John Newton

CPR:

Safety Compliance Officer, Onsite Manager

SECURITY **CONTACT**

Security Compliance Officer, Portable Radio's Channel #1

LOCATION OF
NEAREST EXIT(S)

Northeast banquet room doors, gather at assembly point, grass area near Tesla charging stations

NEAREST PLACE TO
SEEK SHELTER

TORNADO: Interior restrooms and Jasper ballroom interior

FIRE: Northeast banquet room doors, gather at assembly point, grass area near Tesla charging stations

IN AN EMERGENCY,
WHO WILL DIAL 911

PRIMARY: Lisa Deak

BACKUP: Jessica Cantarelli

WHO WILL DIRECT
THE **EMERGENCY
RESPONDER(S)**

PRIMARY: Jerry Patrick, Safety/Security Compliance Officer

BACKUP: Cecilia Terrazas

LOCATION OF THE
**AUTOMATED EXTERNAL
DEFIBRILLATOR (AED)**Banquet preparation hallway located near the North banquet room doors
Owner: Jerry Patrick, Cecilia Terrazas

SAFETY MOMENT

Halloween Safety Tips

Slow down and *be alert* in residential areas

Always accompany your children

Decorate costumes and bags with **reflective tape or stickers**

Have kids carry **glow sticks or flashlights** to help them be visible

Watch for cars turning or backing up

Inspect **ALL** candy before it is consumed

Have kids walk **NOT** run from house to house

Always be **ON ALERT** and **AWARE** of your surroundings

Try to avoid ordering delivery during Trick or Treat hours

If you see something, say something!



STAKEHOLDER ADVISORY MEETING PROTOCOLS

- **Your input and feedback are critical to NIPSCO's Integrated Resource Plan (IRP) Process.**
- **The Public Advisory Process provides NIPSCO with feedback on its assumptions and sources of data. This helps inform the modeling process and overall IRP.**
- **We set aside time at the end of each section to ask questions.**
- **Your candid and ongoing feedback is key to this process:**
 - Please ask questions and make comments on the content presented
 - Please provide feedback on the process itself
- **Please identify yourself by name prior to speaking. This will help keep track of comments and follow-up actions.**
- **If you wish to make a presentation during a meeting, please reach out to Erin Whitehead (ewhitehead@nisource.com).**

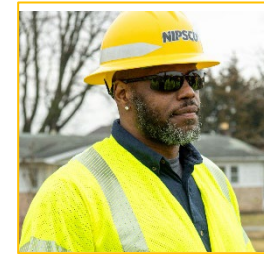
AGENDA

Time *Central Time	Topic	Speaker
9:00-9:05	Kick-Off	Erin Whitehead
9:05-9:10	Stakeholder Meeting #1 Recap & Action Items	Abe Lang
9:10-9:15	Portfolio Modeling Approach	Abe Lang
9:15-9:40	MISO Capacity Accreditation & Reserve Margin	Abe Lang
9:40-10:10	Supply-Demand Balance / Resource Adequacy Needs	Abe Lang
10:10-10:20	DSM: IRP Input Overview	Abe Lang
10:20-10:35	Break	
10:35-11:40	Market Scenario Analysis Concepts	Pat Augustine
11:40-12:25	Lunch	
12:25-12:45	Environmental: Costs & Considerations For Retirement Extension	Paul Heyborne
12:45-1:10	Incorporating New Resource Options	Abe Lang
1:10-1:25	Break	
1:25-1:45	Portfolio Concept Review	Abe Lang
1:45-1:50	Scorecard Update	Abe Lang
1:50-1:55	Calendar & Next Steps	Abe Lang
1:55-2:00	Closing Comments / Stakeholder Questions	Erin Whitehead
2:00-3:00	Stakeholder Presentations	Drew Siebenaler, Energy Futures Group



KICK OFF

Erin Whitehead, Vice President, Regulatory Policy & Major Accounts



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PREMIER REGULATED UTILITY BUSINESS



NATURAL GAS

COLUMBIA GAS OF KENTUCKY

COLUMBIA GAS OF MARYLAND

COLUMBIA GAS OF OHIO

COLUMBIA GAS OF PENNSYLVANIA

COLUMBIA GAS OF VIRGINIA

NIPSCO GAS

NIPSCO

ELECTRIC

NIPSCO ELECTRIC

SIGNIFICANT SCALE
ACROSS 6 STATES

~3.3M

GAS CUSTOMERS

~500K

ELECTRIC CUSTOMERS

NIPSCO PROFILE

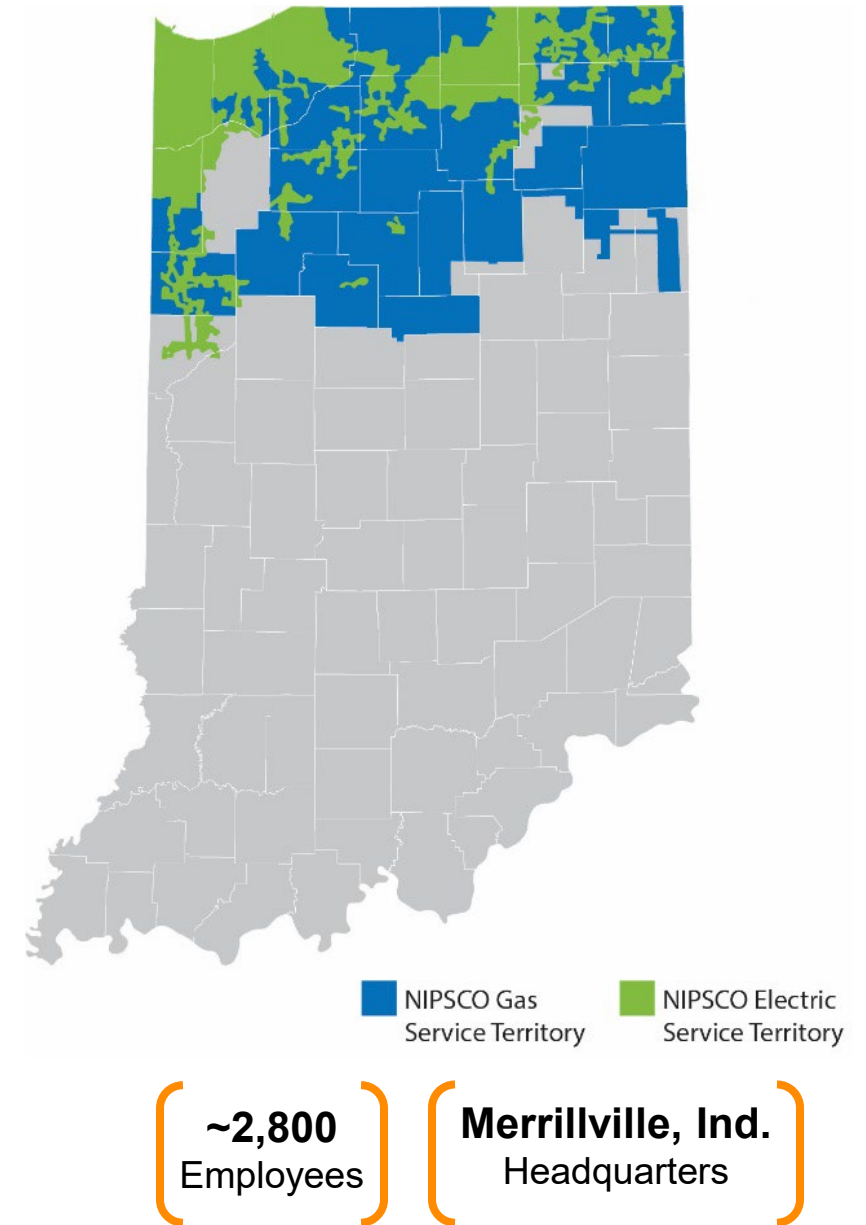
Working to Become Indiana's Premier Utility

Electric

- 496,000 electric customers in 20 counties
- +5,000 MW generating capacity
 - 17 electric generating facilities
(2 coal, 2 natural gas, 2 hydro, 5 wind, 5 solar and 2 solar-plus-storage)
 - 1,200 MW of new wind energy
(Rosewater, Jordan Creek, Indiana Crossroads Wind I & II and Carpenter online in 2020, 2021, 2023 and 2025)
 - 1,950 MW of new solar energy
(Dunns Bridge I, Indiana Crossroads solar online in 2023, Cavalry in 2024, Dunns Bridge II, Gibson, Fairbanks, Green River and Appleseed in 2025)
- ~14,600 Miles of transmission and distribution
 - Interconnect with 5 major utilities (3 MISO; 2 PJM)
 - Serves 2 network customers and other independent power producers

Natural Gas

- 878,000 natural gas customers; 32 counties
- 18,800 miles of transmission and distribution line/main
- Interconnections with seven major interstate pipelines
- Two on-system storage facilities

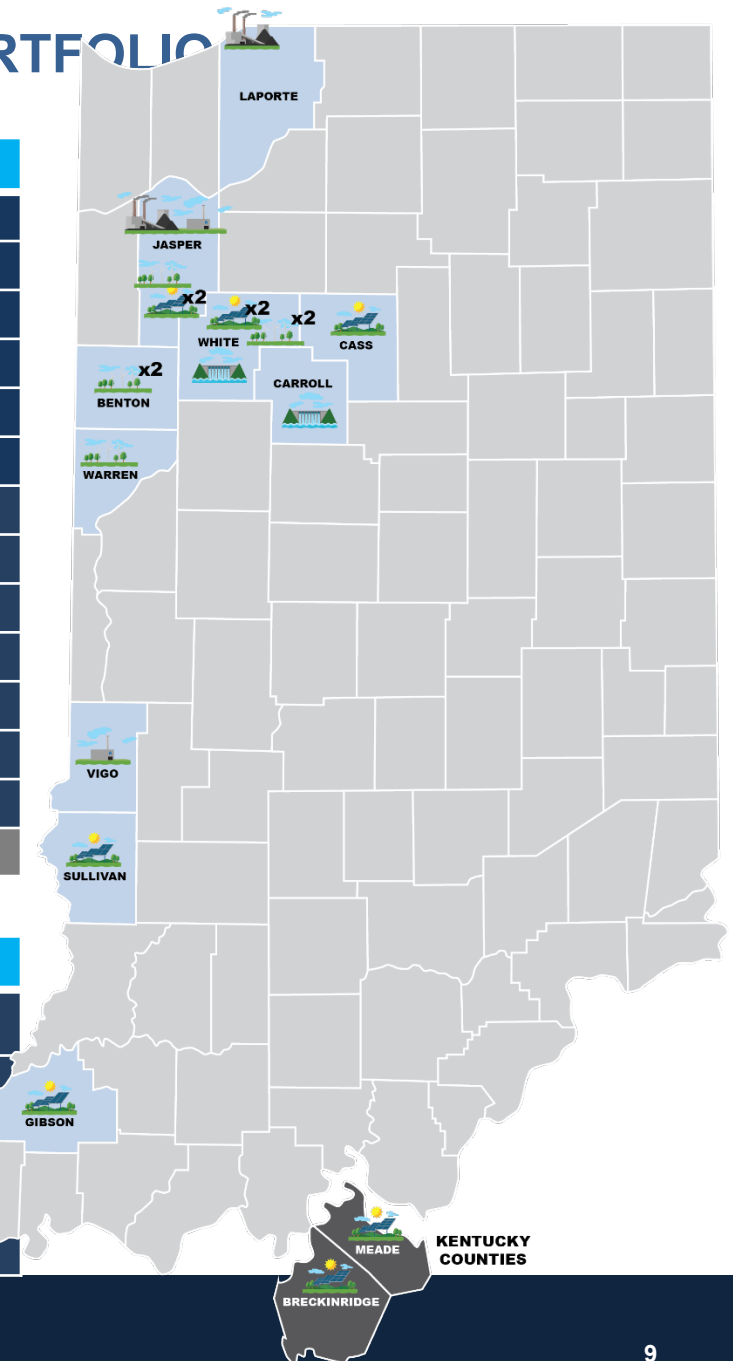


CURRENT & ANTICIPATED FUTURE NIPSCO GENERATION PORTFOLIO

Robust Renewable Investments in Indiana

NEW GENERATION FACILITIES*	INSTALLED CAPACITY (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102 MW	WHITE	2020 COMPLETE
JORDAN CREEK WIND	400 MW	BENTON & WARREN	2020 COMPLETE
INDIANA CROSSROADS WIND	302 MW	WHITE	2021 COMPLETE
DUNNS BRIDGE SOLAR I	265 MW	JASPER	2022 COMPLETE
INDIANA CROSSROADS SOLAR	200 MW	WHITE	2023 COMPLETE
INDIANA CROSSROADS II WIND	200 MW	WHITE	2023 COMPLETE
CAVALRY SOLAR	200 MW + 45 MW BATTERY	WHITE	2024 COMPLETE
DUNNS BRIDGE SOLAR II	435 MW + 56 MW BATTERY	JASPER	2025 COMPLETE
GIBSON SOLAR	200 MW	GIBSON	2025 COMPLETE
FAIRBANKS SOLAR	250 MW	SULLIVAN	2025 COMPLETE
GREEN RIVER SOLAR	200 MW	BRECKINRIDGE & MEADE, KY	2025 COMPLETE
CARPENTER WIND	195 MW	JASPER	2025 COMPLETE
APPLESEED SOLAR	200 MW	CASS	2025 COMPLETE
GAS PEAKING RESOURCE	400 MW	JASPER	2027 PRE-CONSTRUCTION

GENERATION FACILITIES	INSTALLED CAPACITY (MW)	FUEL	COUNTY
MICHIGAN CITY RETIRING 2028	455 MW	COAL	LAPORTE
R.M. SCHAHFER RETIRING 2025 (COAL) – 2028 (NG)	722 MW + 155 MW	COAL + NATURAL GAS	JASPER
SUGAR CREEK	665 MW	NATURAL GAS	VIGO
NORWAY HYDRO	7.2 MW	WATER	WHITE
OAKDALE HYDRO	9.2 MW	WATER	CARROLL

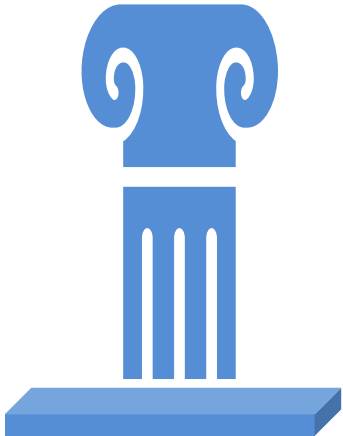


* Since 2018

HOW DOES NIPSCO PLAN FOR THE FUTURE?

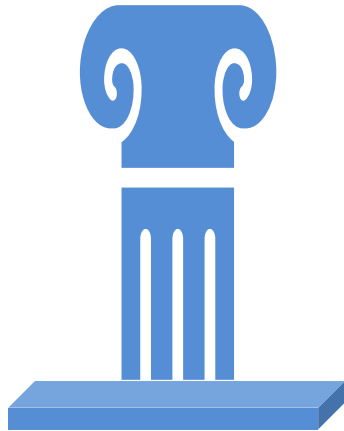
- At least every three years, NIPSCO outlines its long-term plan to supply electricity to customers over the next 20 years
- This study – known as an Integrated Resource Plan – is required of all jurisdictional electric utilities in Indiana
- The IRP process includes an extensive analysis of a range of resource options evaluated against objectives for portfolios to be reliable, affordable, sustainable, diverse and flexible

Reliability



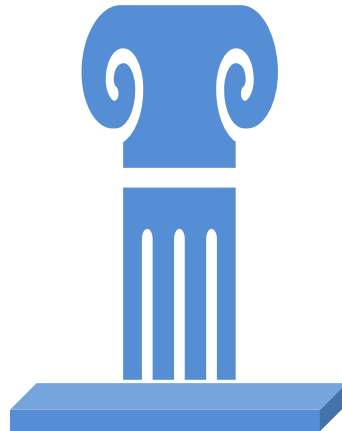
- Resource adequacy
- Operating reliability

Resilience



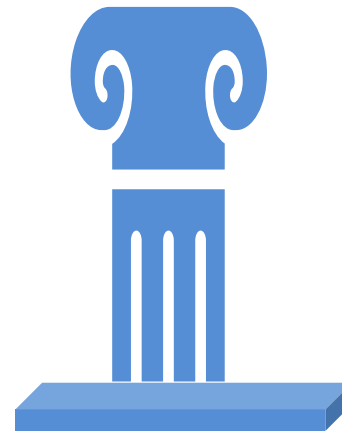
Respond to catastrophic events

Affordability



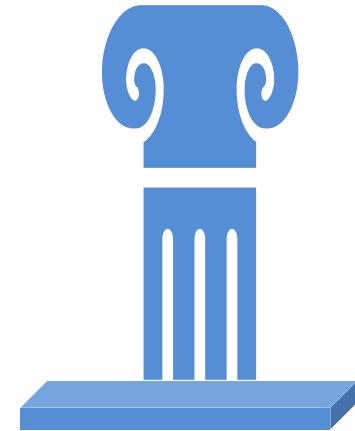
- Affordability for all customer classes
- Diverse resource mix

Stability



Ability to deliver stable electric service to all customers

Environmental Sustainability

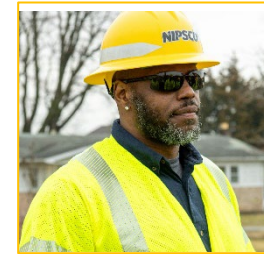


Account for both environmental regulations and consumers' demands



PORTFOLIO MODELING APPROACH

Abe Lang, Manager, Strategy & Risk

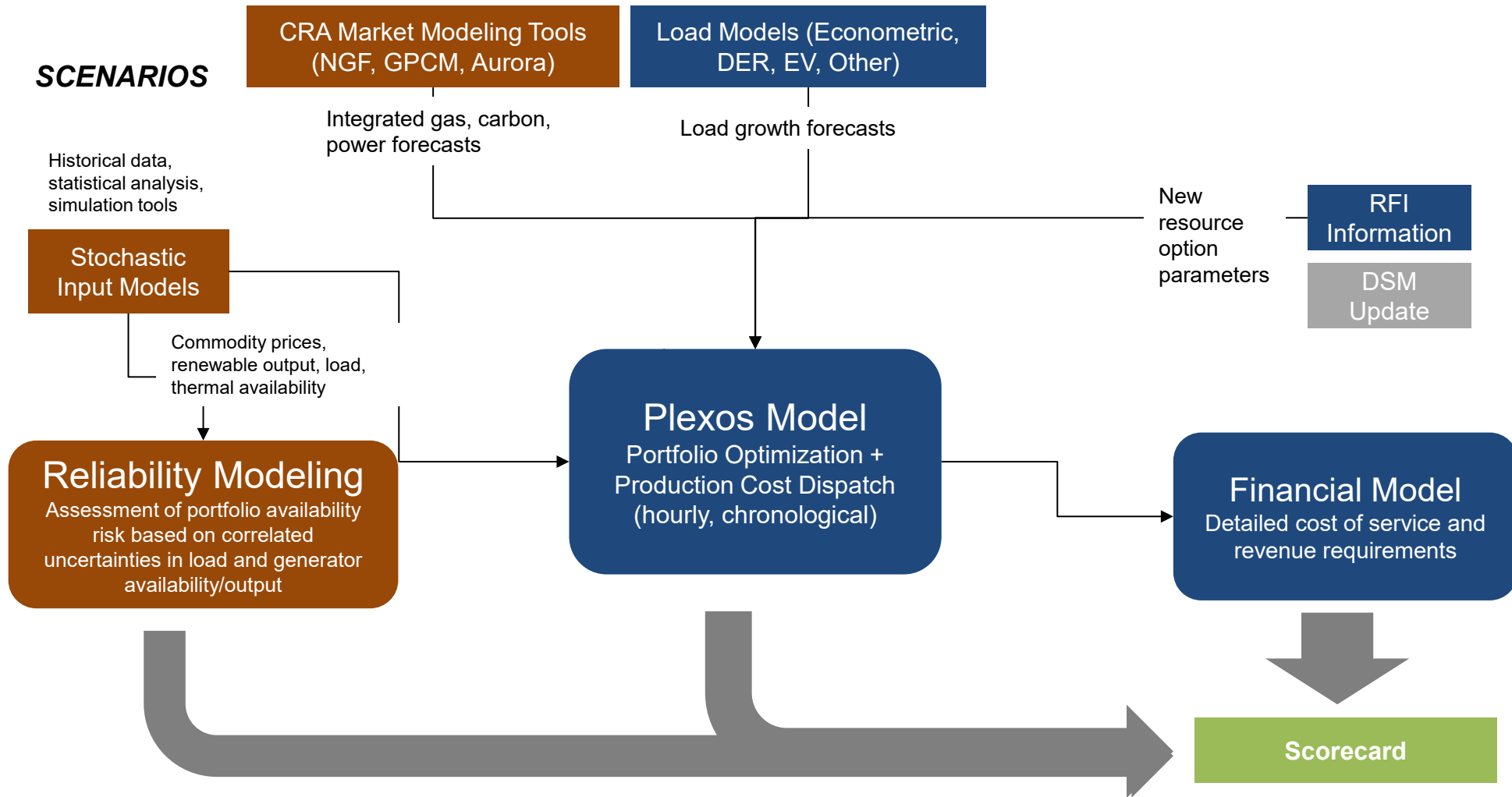


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RESOURCE PLANNING APPROACH

Key Modeling and Analysis Tools



Company

Charles River Associates

GDS / Demand Side Analytics

ANALYTICAL FRAMEWORK FOR EVALUATING FUTURE UNCERTAINTY

- Because resource decisions are generally long-lived, understanding and incorporating future risk and uncertainty is critical to making sound decisions.
- NIPSCO's IRP analysis will use both scenarios and stochastic analysis to perform a robust assessment of risk.

Portfolio Concepts

Testing specific portfolio constraints

- **Portfolio runs will test the viability of various resource constraints**
 - Changes to existing unit retirement dates
 - Minimum/Maximum associated with a particular resource type (renewables, new technology pilots)
 - Minimum/Maximum associated with energy or capacity position of the portfolio
- **NIPSCO to solicit inputs for portfolio concepts**

Today's stakeholder meeting will focus on these components of the analytical framework

Scenarios

Single, Integrated Set of Assumptions

- **Use scenarios to answer the “What if...” questions**
 - Major events can change fundamental outlook for key drivers
 - New policy or regulation (carbon emissions regulation, tax credits)
 - Fundamental gas price change
 - Major load shifts
- **Can tie portfolio performance directly to a “storyline”**

Stochastic Analysis:

Probabilistic Distributions of Inputs

- **Reliability Assessment analyzing**
 - Forced Market Exposure
 - Loss of Load
- **Can evaluate volatility and “tail risk” impacts**
 - Uncertainty in renewable resource output, generator availability and load can impact portfolio costs and key reliability metrics

To be discussed further during Stakeholder Advisory Meeting #3 after portfolio concepts are analyzed



MISO CAPACITY ACCREDITATION & RESERVE MARGIN

Abe Lang, Manager, Strategy & Risk
Pat Augustine, Charles River Associates



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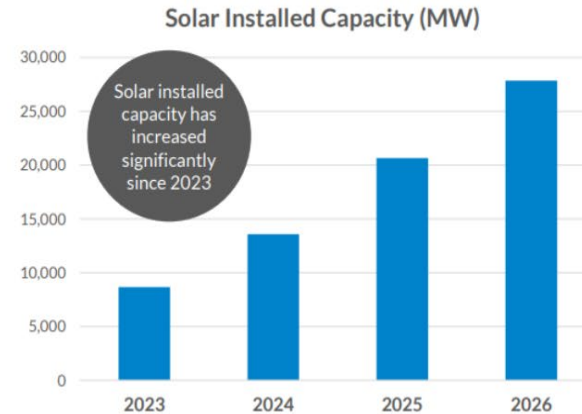


MISO RESOURCE ADEQUACY AND ACCREDITATION UNDER DLOL

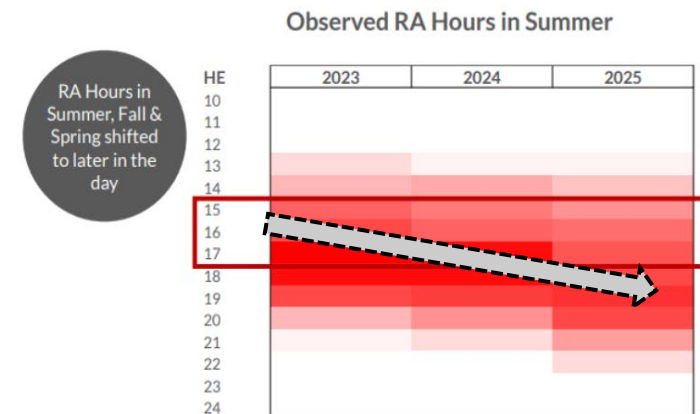
MISO grid changes required RA overhaul

Resource adequacy should ensure the **availability of resources when the system is most at risk of failure.**

- The growth in variable energy resources (mainly solar), along with changes in load and operational patterns, are **shifting the tightest hours later in the evening.**
- DLOL aims to ensure that the accredited capacity of resources reflects their **actual availability during periods of highest risk.**



Source: MISO RASC July 2026



How does DLOL address this?

DLOL combines a probabilistic and historical approach to accreditation.

- How does a **resource class** perform during **modeled Critical Hours**?
- How available was a **specific resource** during **actual tightest hours**?

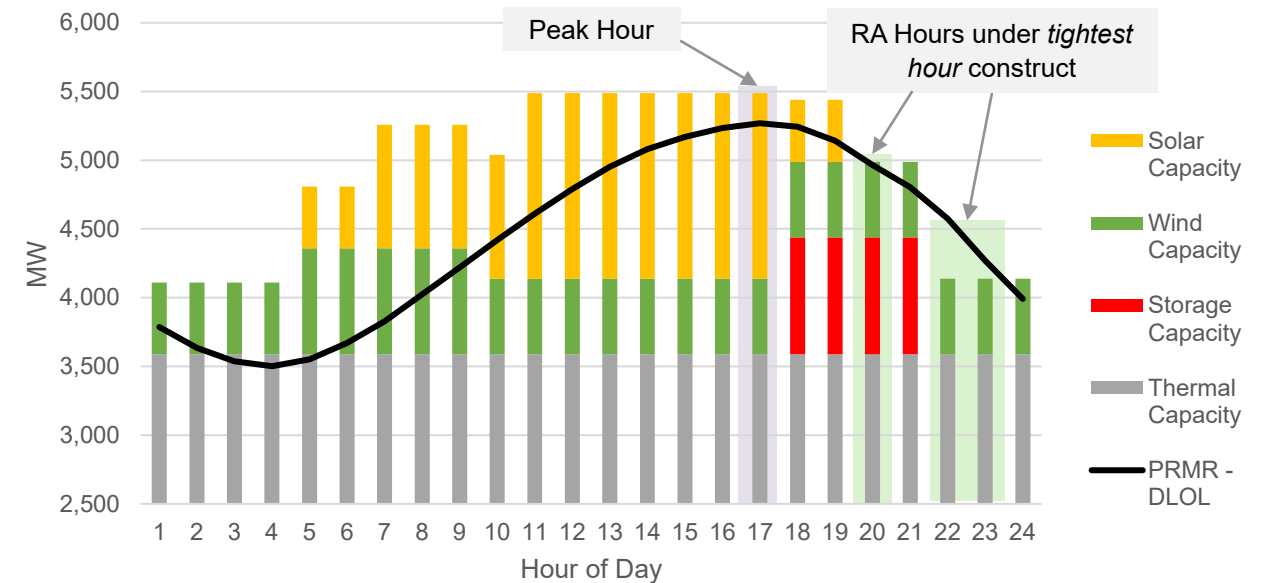
Observable impacts

At high levels of solar penetration, the tightest hour in a day becomes the hour solar is no longer available.

Planning reserve margin requirement (**PRMR**) will likely decline, since tight hours typically occur at different times than the gross peak.

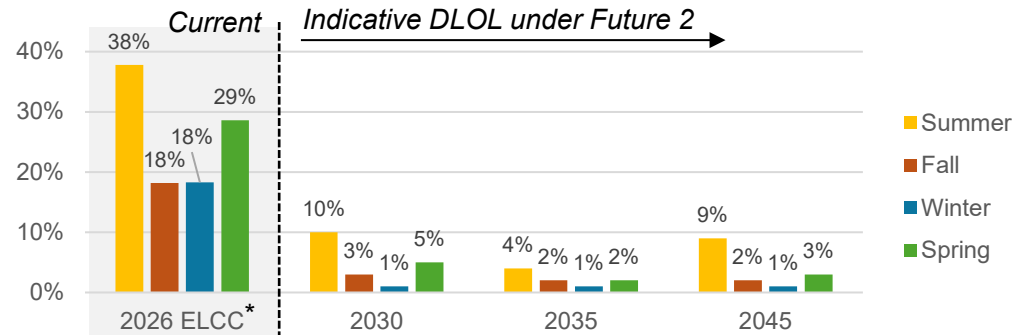
- **PRM may be close to zero or negative** due to tightest hour occurring later in the evening or during other lower load periods.

Example 24 Hour Resource Availability vs. Demand

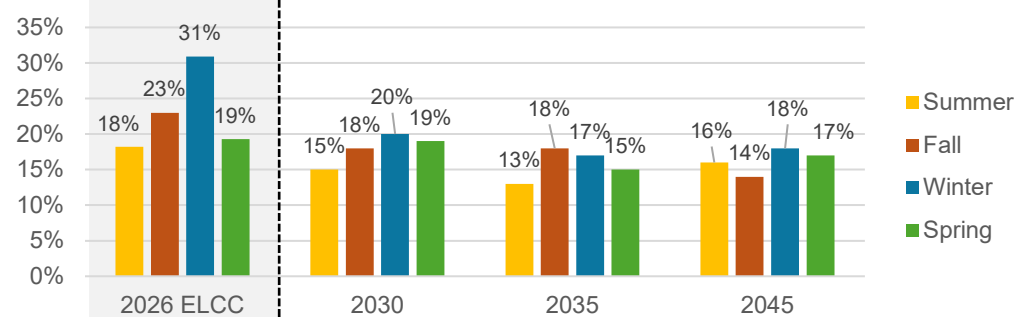


MISO RECENTLY RELEASED ACCREDITATION OUTLOOKS FOR ITS SERIES 2 FUTURES

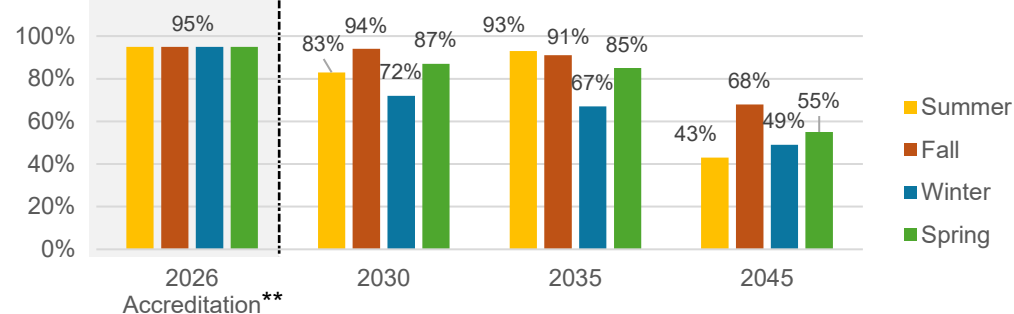
Solar



Wind



Storage 4-hr



- Thermal and nuclear accreditations will likely remain stable in the future except for aging resources with declining performance like coal.
- Solar declines to 10% or below across all seasons by 2030, though there is potential for slight long-term recovery if net load grows earlier in the evening.
- Wind accreditation is generally expected to be between 15% to 20%, although long-term trends could be impacted by evolving load shapes and shifts of stress hours to the overnight.
- MISO projects increases in summer accreditation for 4-hour storage by 2030 relative to today's indicative values (*current indicative values have been around 60% even as actual projects receive higher accreditation under current rules*). Methodological uncertainty and long-run uncertainties in market conditions make storage accreditation the most difficult to predict.

* Currently, MISO uses Solar ELCCs in calculation of PRM and PRMR but *not* the direct accreditation of solar resources

** Storage resources are assigned a default 95% accreditation due to lack of operational data

MISO ACCREDITATION ESTIMATES UNDER DLOL HAVE VARIED WIDELY

Solar

Wind

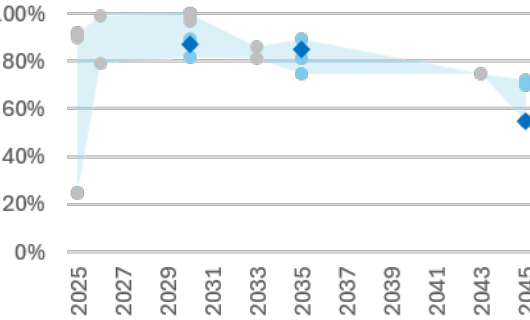
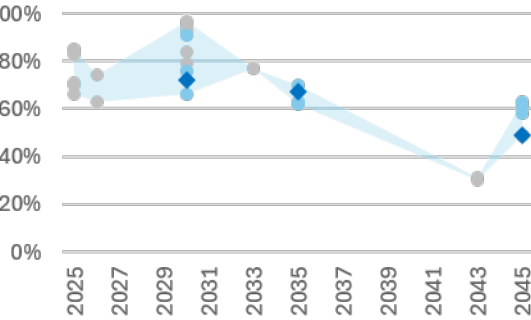
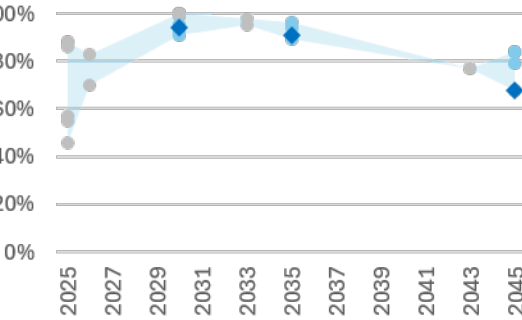
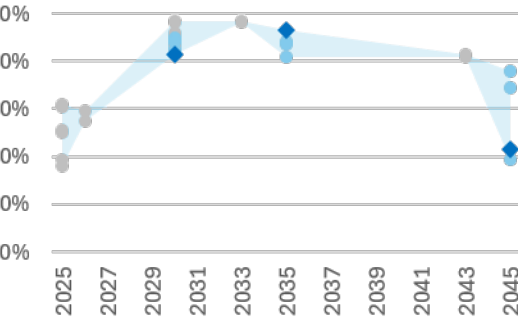
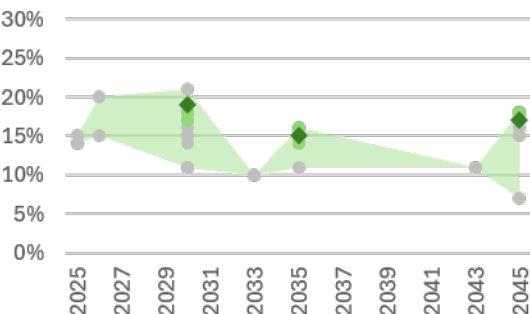
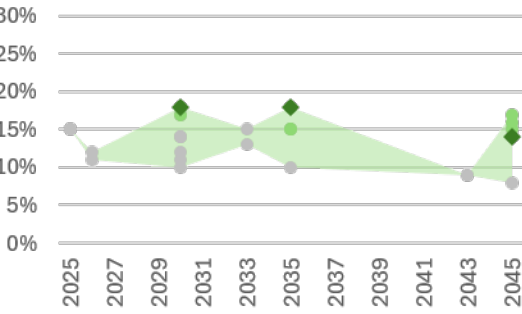
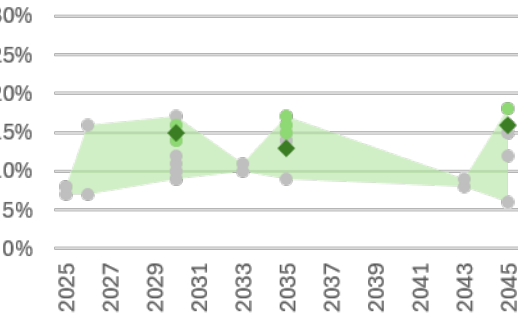
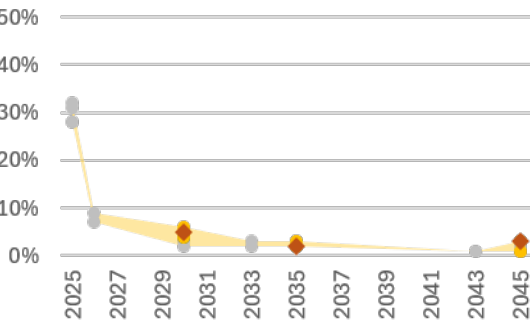
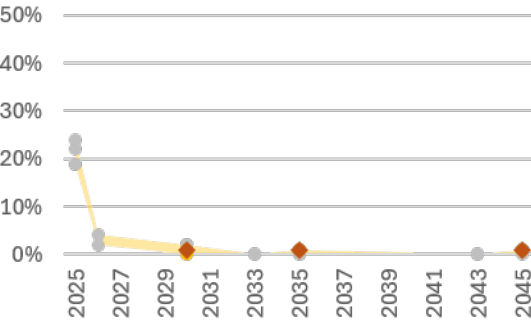
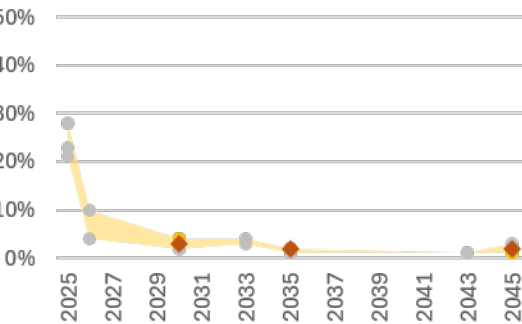
Storage 4-hr

Summer

Fall

Winter

Spring



Notes: 1. All dots represent accreditation estimates or projections under DLOL published by MISO over the last two years.
2. Colored values represent MISO Series 2 Futures (updated 9/9/26). Dark bold color indicates Future #2.
3. Storage values include Early, Blended, and Even Loss methodologies.

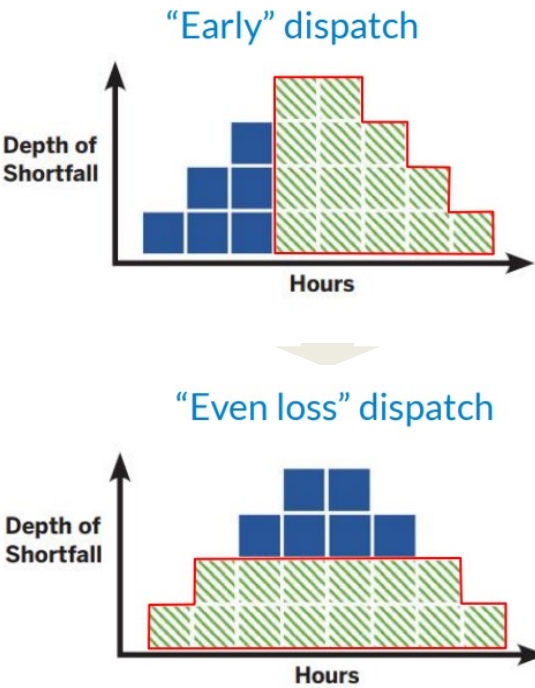
STORAGE ACCREDITATION MODELING IS COMPLEX

Calculating storage accreditation is challenging and complex, given charging and discharging dynamics and limited duration availability.

In some initial storage modeling iterations, MISO penalized storage by dispatching it in such a fashion that it would only delay shortfall events rather than providing coverage throughout them.

MISO addressed concerns by implementing an “even loss” approach:

- Adjusts storage dispatch logic to distribute unserved energy as evenly as possible across an event instead of depleting the battery resource as early as possible.
- Results in storage dispatch being able to contribute during risk hours, yielding materially different accreditation outcomes.



- Original modeling
- Use storage energy to avoid unserved energy as soon as possible
- Does not recognize the entire event

- Recognizes the entire duration of the event
- Unserved energy is distributed evenly across energy events
- Expected unserved energy (EUE) and Loss of Load Expectation (LOLE) of shortfall event remain the same, only dispatch logic changes

Key Takeaway

Storage accreditations remain highly uncertain and can change based on modeling methodology

PY25-26 Storage ELCCs assuming Early and Even-loss Dispatch

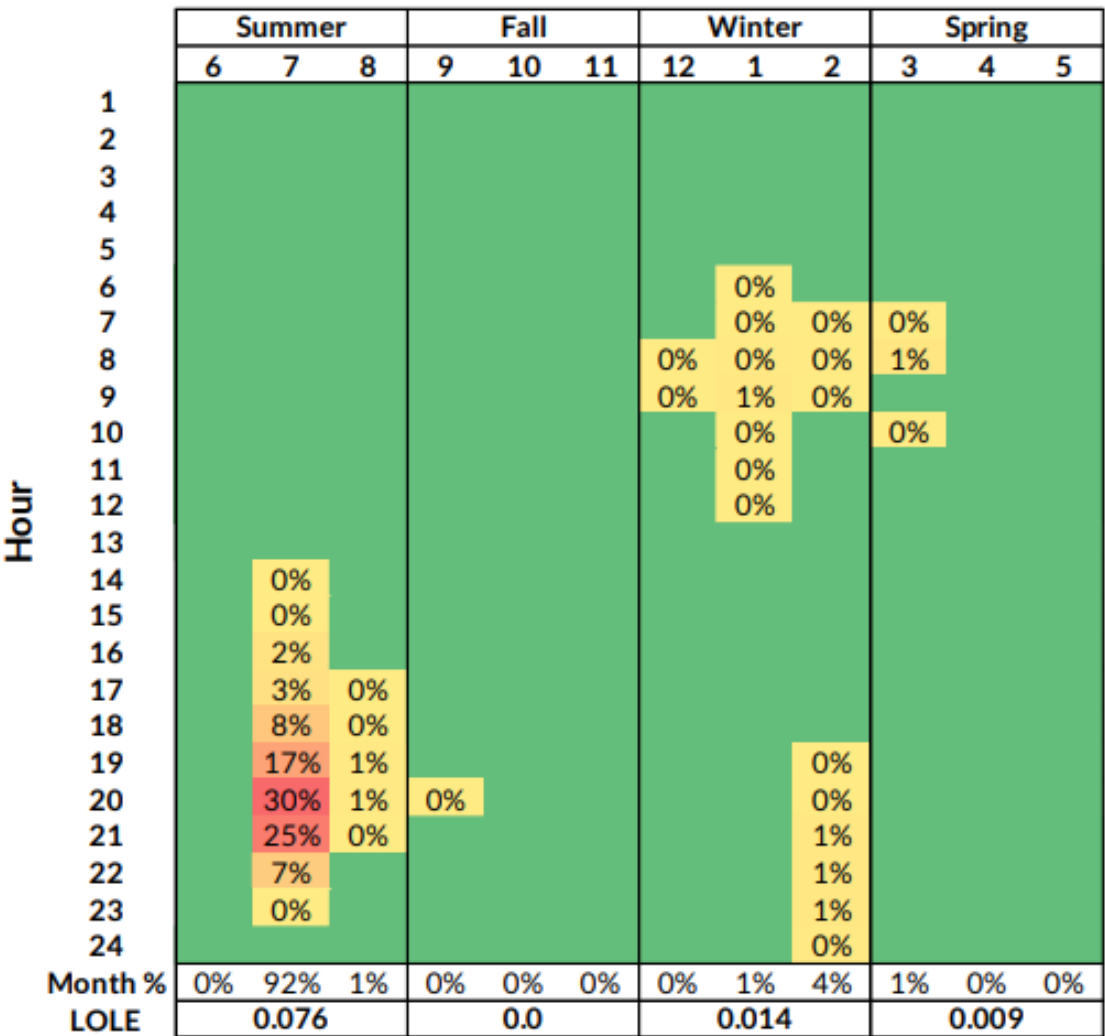
	Summer	Fall	Winter	Spring
Early (Prev. estimate)	39%	46%	66%	25%
Even Loss*	61%	88%	85%	90%

*Interim results from April 2025

MISO CURRENTLY IDENTIFIES MOST RISK HOURS IN SUMMER EVENINGS

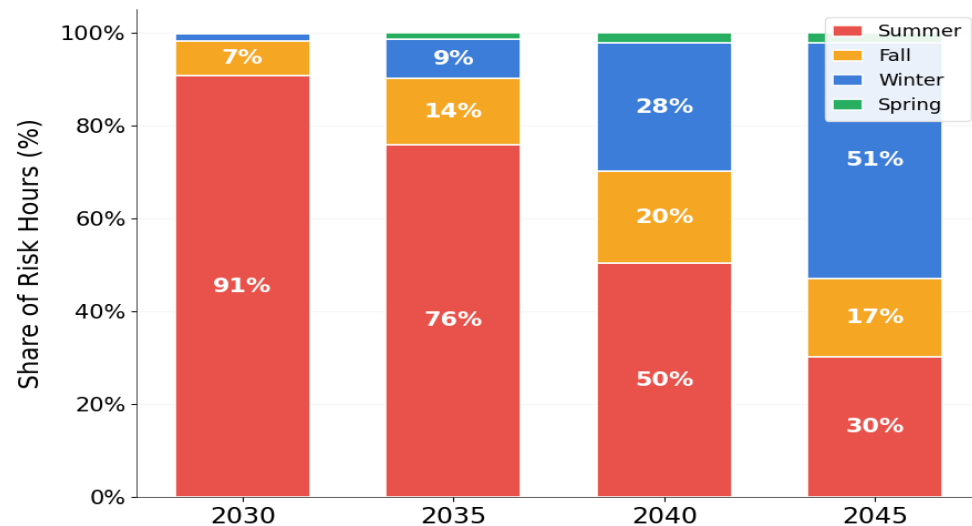
- In 2025/26, summer carried essentially all LOLE risk (~97%), and the capacity market demand curve was shaped accordingly. The construct was effectively summer-binding.
- In 2026/27, MISO reported that summer events carried 93% of the risk, with winter making up about 5%.

PY 2026/27 Annual Loss of Load Risk Distribution



STRESS-EVENT RISK ACROSS SEASONS IS LIKELY TO EVOLVE

- Winter risk is expected to grow, with risk exposure likely in the evening and the morning.
- Over time, summer risk will likely be pushed out to 8 pm or later, when solar availability drops.
- Shoulder events can occur in Fall and Spring, often due to extreme weather events combined with planned maintenance.
- Forward modeling suggests that the duration of events may lengthen over time, especially in winter months.



2045 Risk Hour Simulation

Hour	Summer			Fall			Winter			Spring		
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
1								0%	0%			
2								0%	0%			
3								0%	0%			
4									0%			
5									0%			
6									0%			
7								0%	0%			
8						0%		0%	1%	0%		
9						0%	0%	2%	2%	0%		
10							0%	1%	1%			
11								0%	0%			
12												
13												
14												
15												
16												
17								0%	0%			
18		0%		0%		2%	3%	1%	1%			
19		0%	0%	1%	0%	5%	6%	5%	3%	0%	0%	0%
20	0%	3%	4%	2%	0%	3%	3%	4%	3%	1%		0%
21	1%	9%	4%	1%	0%	1%	2%	2%	2%	0%		0%
22	0%	5%	1%	0%	0%	1%	1%	2%	2%	0%		0%
23	0%	1%	0%	0%		0%	0%	1%	1%	0%		0%
24		1%	0%	0%		0%	0%	0%	1%	0%		0%
Month %	1%	20%	9%	4%	1%	12%	16%	19%	16%	2%	0%	0%



SUPPLY-DEMAND BALANCE / RESOURCE ADEQUACY NEEDS

Abe Lang, Manager, Strategy & Risk



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REFINED SEASONAL PEAK LOAD FORECAST METHODOLOGY

Seasonal peak comparison: prior hourly allocation vs. regression forecast

WHAT CHANGED

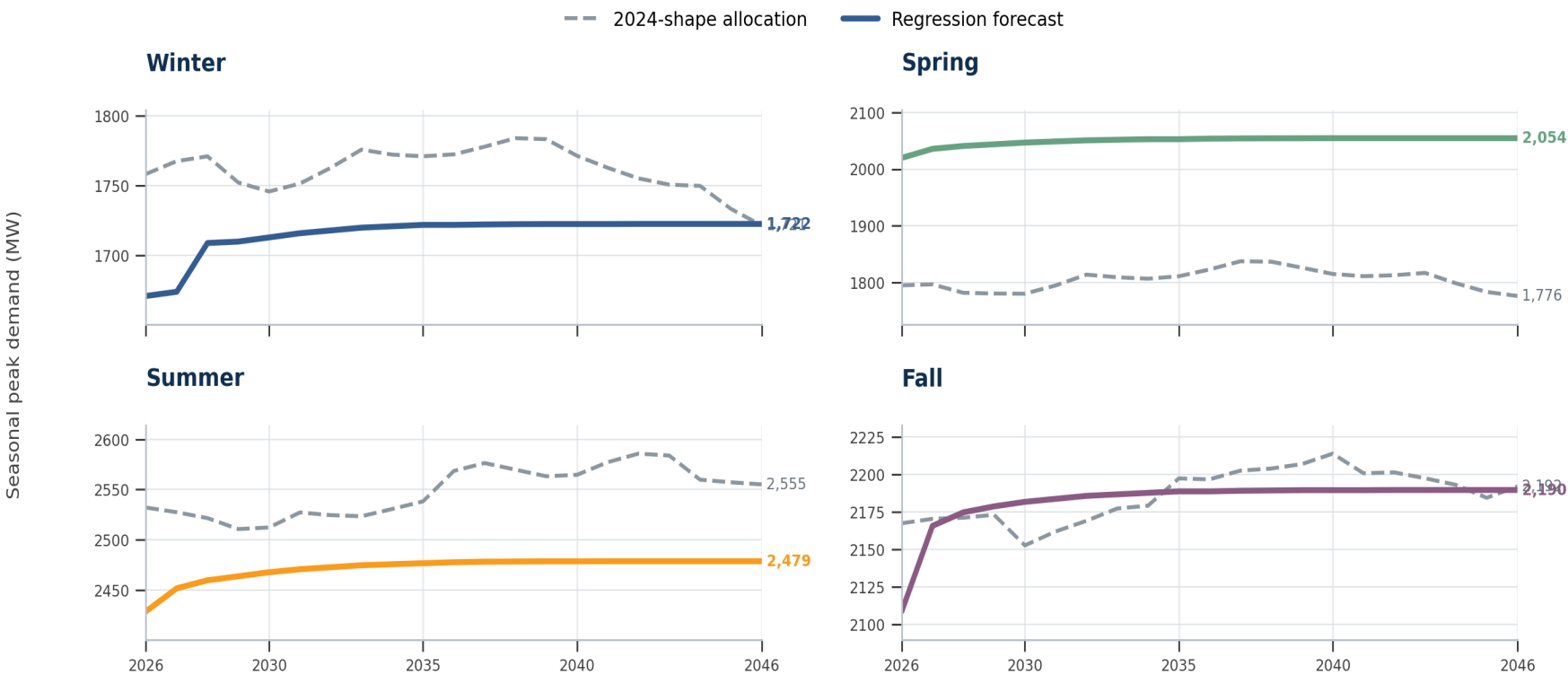
Previous approach

Seasonal peaks were derived from the hourly forecast allocated using the 2024 historical load shape.



Updated approach

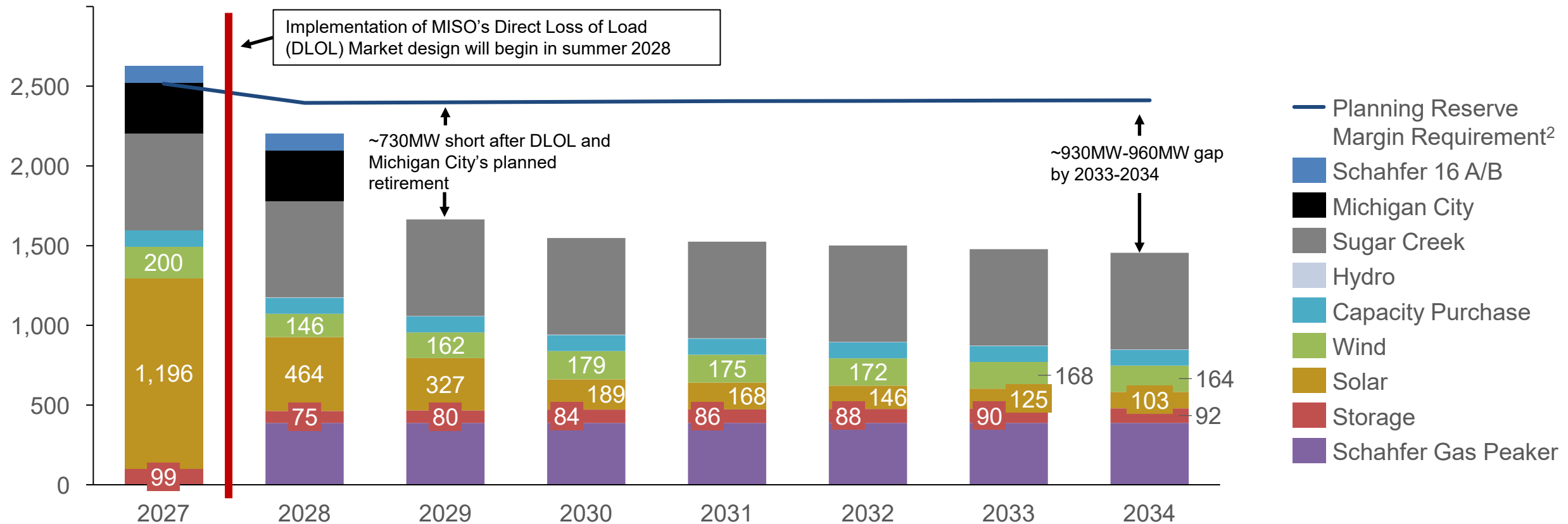
A regression model now forecasts monthly peak demand directly. The hourly forecast is aligned to the modeled peak rather than allowing the donor load shape to determine it.



The regression forecast produces a smoother long-term outlook and changes peak levels differently by season.

NIPSCO IRP STARTING CAPACITY POSITION – SUMMER SEASON¹

NIPSCO's Summer 2029 incremental accredited capacity need will require ~730MW of accredited capacity and grow to over 930MW of accredited capacity by the mid 2030s



1. Renewable and storage accreditation based on MISO's Series 2, Futures 2 accreditation class averages, pg. 58 →

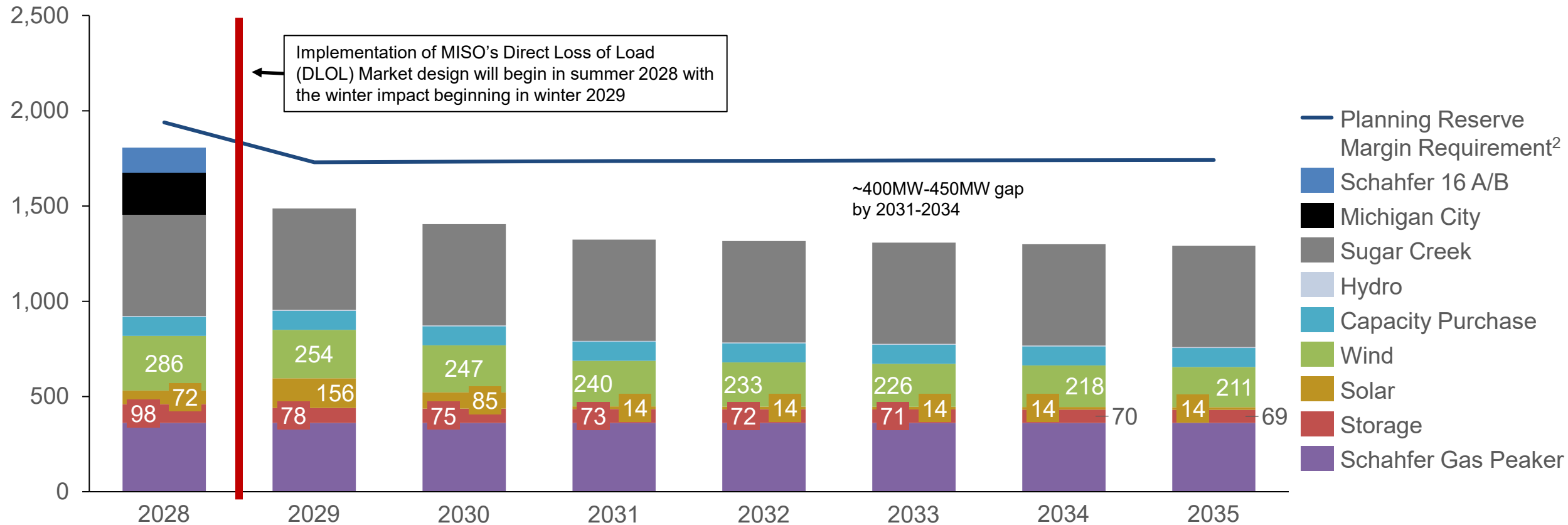
<https://cdn.misoenergy.org/MISO%20Futures%20Report%20Series%20202766529.pdf>

2. Planning reserve margin requirements are based off of MISO UCAP PRM % from the "Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) Results, pg. 4 →

<https://cdn.misoenergy.org/Indicative%20DLOL%20Results%20PY%202025-2026667100.pdf>

NIPSCO IRP STARTING CAPACITY POSITION – WINTER SEASON¹

NIPSCO's winter capacity position is impacted less by DLOL but incremental capacity needs grow to between 400MW and 450MW in the 2030s



1. Renewable and storage accreditation based on MISO's Series 2, Futures 2 accreditation class averages, pg. 58 →

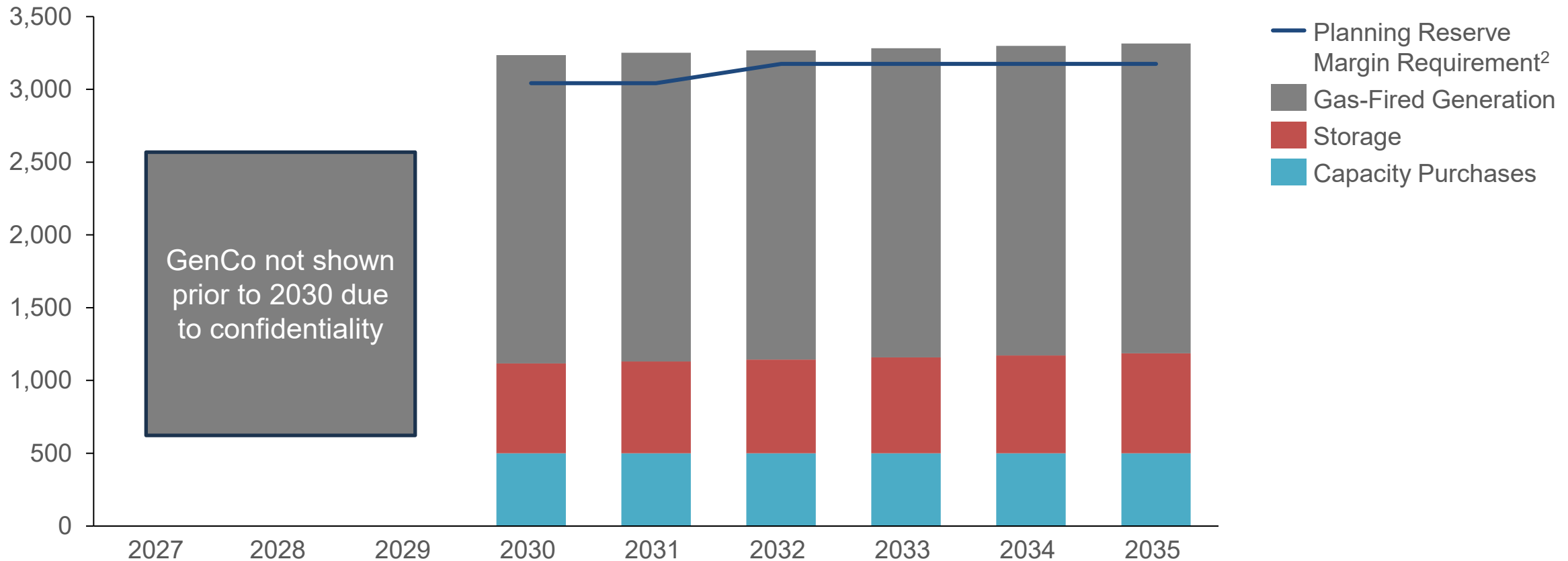
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GENCO IRP STARTING CAPACITY POSITION – SUMMER SEASON^{1,2}

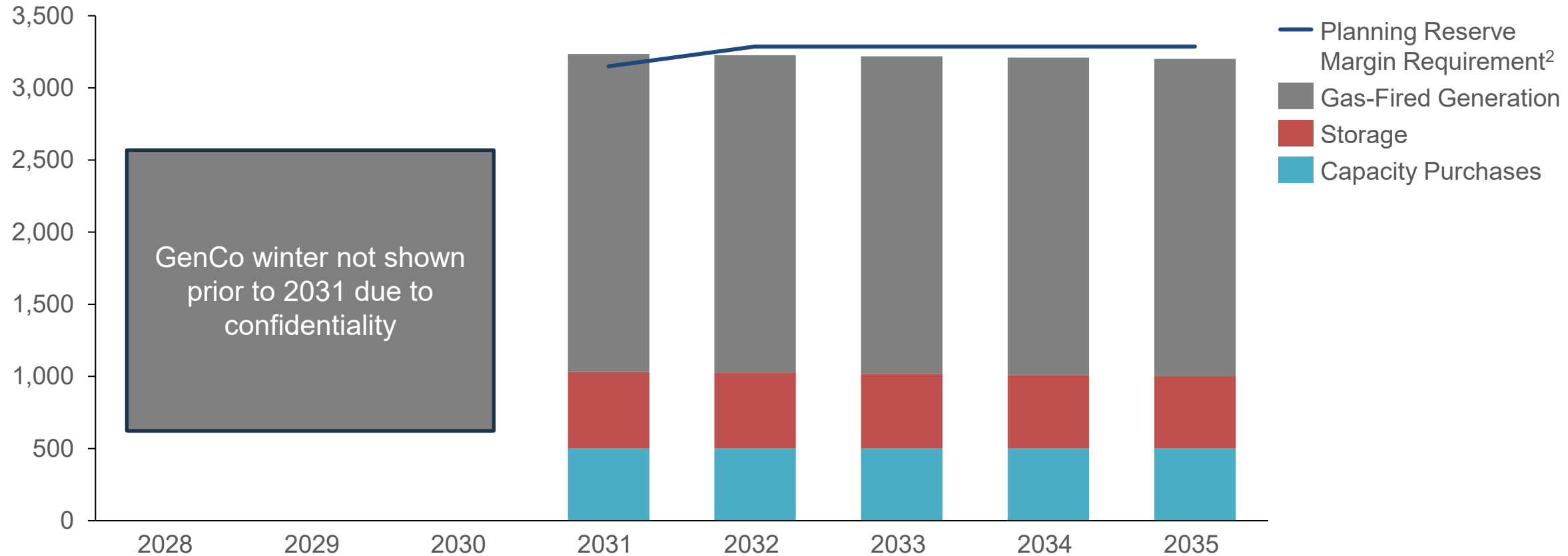
GenCo is currently expected to meet resource adequacy requirements for the summer season through 2035



1. Genco will be responsible for solving any capacity shortfalls that may occur, and GenCo will be responsible for bearing any costs associated with solving these shortfalls
2. Resource accreditation based on MISO's Series 2, Futures 2 accreditation class averages, pg. 58 → <https://cdn.misoenergy.org/MISO%20Futures%20Report%20Series%202766529.pdf>
3. Planning reserve margin requirements are based off of MISO UCAP PRM % from the "Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) Results, pg. 4 → <https://cdn.misoenergy.org/Indicative%20DLOL%20Results%20PY%202025-2026667100.pdf>

GENCO IRP STARTING CAPACITY POSITION – WINTER SEASON^{1,2}

GenCo has~ 60-80MW of incremental accredited capacity need starting in 2032 for the winter season



1. Genco will be responsible for solving any capacity shortfalls that may occur, and GenCo will be responsible for bearing any costs associated with solving these shortfalls
2. Resource accreditation based on MISO's Series 2, Futures 2 accreditation class averages, pg. 58 → <https://cdn.misoenergy.org/MISO%20Futures%20Report%20Series%202766529.pdf>
3. Planning reserve margin requirements are based off of MISO UCAP PRM % from the "Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) Results, pg. 4 → <https://cdn.misoenergy.org/Indicative%20DLOL%20Results%20PY%202025-2026667100.pdf>



DSM: IRP INPUT OVERVIEW

Abe Lang, Manager, Strategy & Risk



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ENERGY PARTNER



CHANGES TO INPUTS AND ASSUMPTIONS SINCE THE 2024 MPS AND IRP

Updated data came from two main sources:

Updated Data from NIPSCO

- **Overall Sales, Peak Load Forecast, and Customer Forecasts**
- **EV Forecast**
 - Lower than the prior study; lowers EV charging potential
- **Solar Forecast**
 - Lower than prior study; affects battery storage DR potential
- **NIPSCO Program Planning Assumptions**
 - EE: Used 2026 Plan incentives and non-incentive cost assumptions
 - DR: Smart Thermostat values used exactly (2027-2029 Plan)
 - DRL C&I DR values used as a guide rather than explicitly (2027-2029 Plan)
- **Data Centers are Excluded for both EE & DR**
 - Previously only excluded for EE
- **General Assumptions like Inflation and WACC**
- **Economic Assumptions**
 - Increase in avoided generation capacity
 - Minor changes to avoided energy cost, inflation rates, and WACC (discount rate)

Updated Data from Other Sources

- **Updated MISO Resource Adequacy hours**
 - Using 2026 update
- **Seasonal End-Use Load Shapes from NREL**
 - DR: Using 2026 shapes for Smart Thermostats (heating and cooling), EV Charging, Water Heating
- **Battery Cost Assumptions from NREL**
 - 2026 battery cost assumptions are lower than the ones used in the prior study
- **Refreshed the price elasticity of supply for C&I DR**
 - Based on historic PJM auction results
 - Same source as 2024, just more data

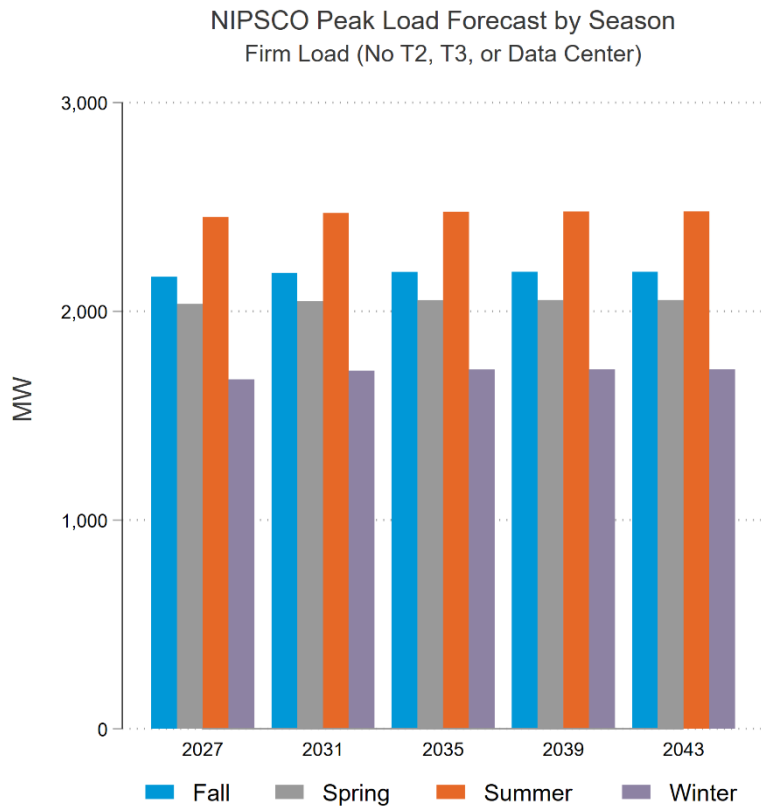
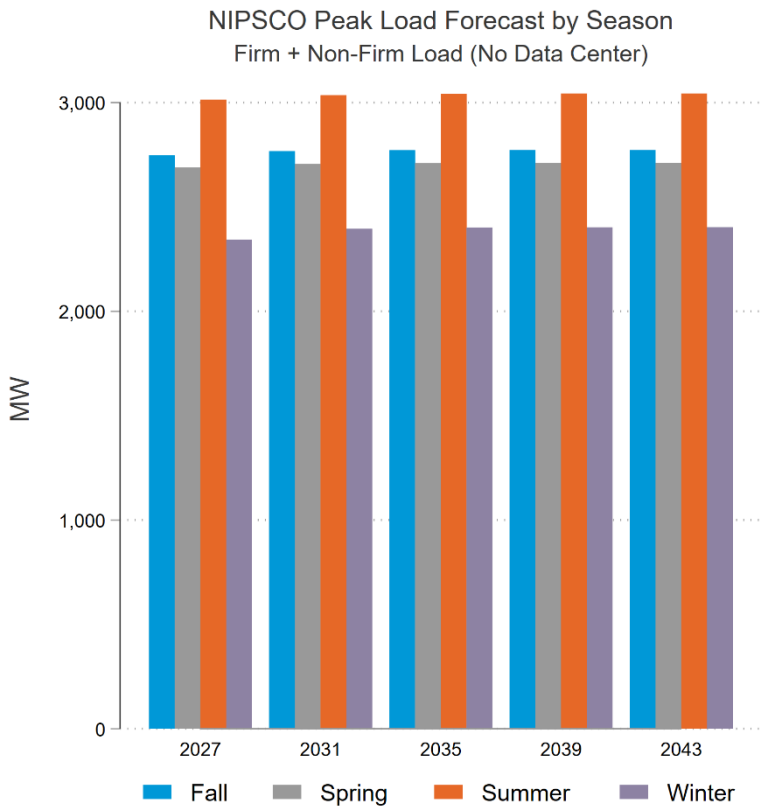
The accelerated development of IRP inputs did not allow for models to be redesigned, new measures to be added, or changes to the achievable potential scenarios

THE MODELING APPROACH AND OTHER KEY INPUTS STAYED THE SAME

- **Each season is modeled independently in case it is a binding constraint in the IRP (DR)**
- **Avoided cost of T&D capacity**
- **Line loss factors**
- **No material changes to market segmentation outside of updated forecasts**
- **Guiding principles of RAP, Enhanced RAP, and MAP**
 - No change to long-term adoption rate data and achievable potential scenario methodology
- **IRP inputs include offerings that do not pass UCT screening (DR)**
 - EE measures are screened for cost-effectiveness
- **Time-varying rates become available in 2030 (DR)**
 - RAP is a default peak time rebate offering
 - MAP is default TOU with opt-in CPP

STUDY PEAK DEMAND FORECAST BY SEASON

We assume no DR potential for the firm load on Rate 531 (T2 or T3)



Season	Peak Type
Summer	Cooling
Fall	Cooling
Winter	Heating
Spring	Cooling

Spring was modeled as a heating peak in the 2024 MPS

DSM BUNDLE IN THE IRP

Energy Efficiency

- **Sector-based bundles**
 - Residential: Low/Medium Cost Bundle, High-Cost Bundle, & Behavior
 - Income-Qualified (IQ)
 - Overall C&I
- **Residential and C&I Bundles are selectable ; IQ Bundle is treated as a going-in resource**
- **2027-2029 bundle is based on 2027-2029 NIPSCO Program Plan filing ; 2030-2032 and 2033-2046 bundles are based on updated MPS results**
- **RAP and Enhanced Bundles**

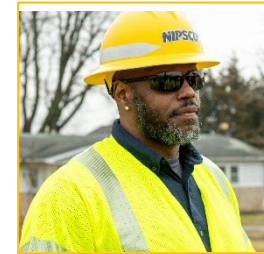
Demand Response

- **Each modeled DR program offerings is available for selection (modeled independently)**
- **2027-2029 DR impacts are not directly tied to the 2027-2029 NIPSCO Program Plan filing**
- **Program Costs exclude net lifetime T&D benefits (same for EE)**



MARKET SCENARIO ANALYSIS CONCEPTS

Pat Augustine, Charles River Associates



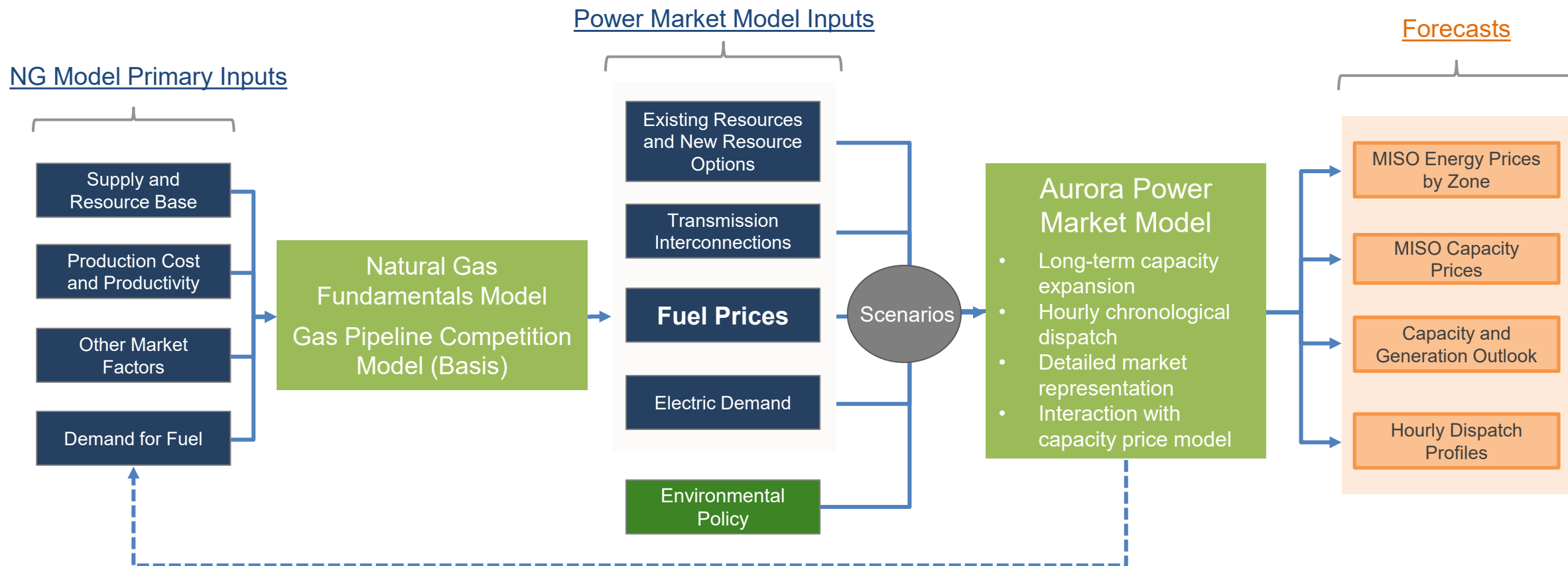
OUR VISION IS TO BE A
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ENERGY PARTNER





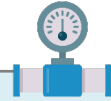
FUNDAMENTAL MARKET MODELING STRUCTURE

CRA's fundamental market models simulate the fuel and power markets to produce integrated outlooks for commodity prices, environmental policy and power market outcomes.





SCENARIO OVERVIEW

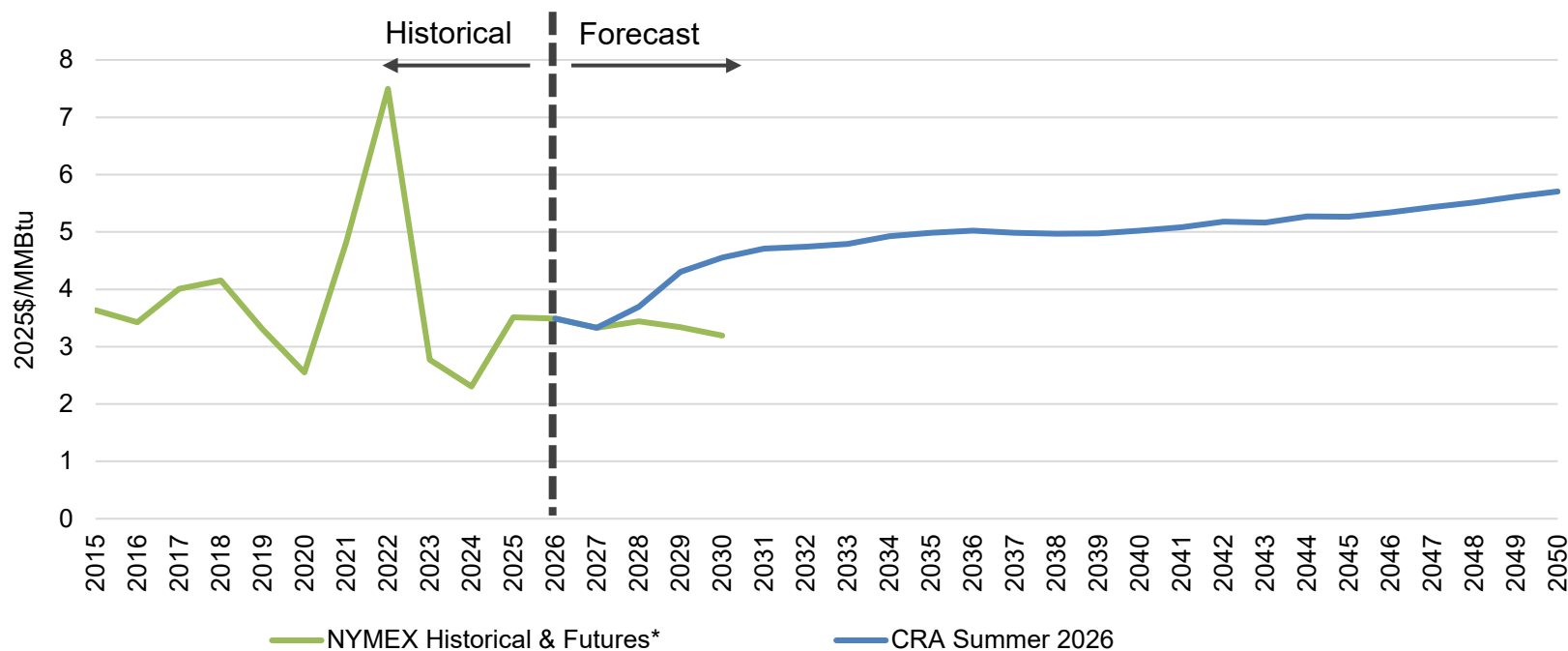


Scenario	Commodity Prices	Demand	Carbon Policy	Technology Costs
Reference Case (REF)	Base	Base	Current and Proposed Policy (No GHG Regulation)	Base
Sustained Load Growth (SLG)	Higher gas price due to strong demand 	Higher load from new data centers, industrial onshoring, EVs 	Current and Proposed Policy (No GHG Regulation) 	Growing demand for gas capacity raises capital costs 
Aggressive Environmental Regulation (AER)	Offsetting impacts from demand softening and production restrictions 	Base 	Carbon pricing begins in 2035 	Easing demand for gas capacity lowers capital costs 



RECAP: REFERENCE CASE ANNUAL HENRY HUB OUTLOOK

- Near term market forwards are lower than they were earlier in the year despite high gas prices in January 2026.
 - The war in Iran has seen an increase in associated gas production due to increased oil prices.
- Longer-term forwards have been stable, although illiquid, and CRA's fundamental market modeling suggests that rising demand will push Henry Hub prices above \$5/MMBtu in real dollar values.



* NYMEX Futures dated June 26, 2026

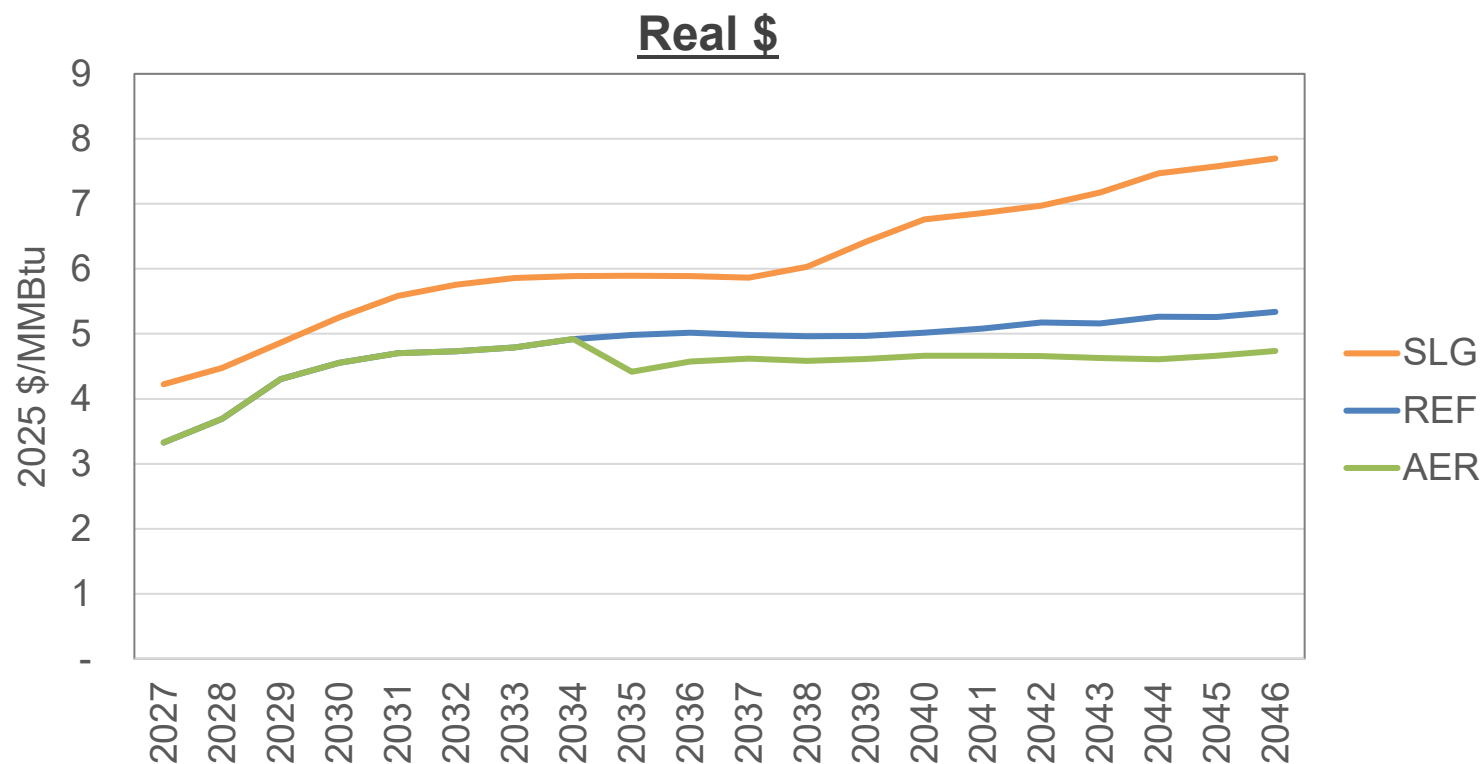


FUNDAMENTAL NATURAL GAS PRICE DRIVERS ACROSS SCENARIOS

Driver	Reference Case	Sustained Load Growth	Aggressive Environmental Regulation
Resource Size	Rely on Potential Gas Committee (PGC) “Most-Likely” unproven estimates		 Lower supply: More restrictions on drilling/gas access reduces assumed access to gas reserves
Well Productivity	- IP rates based on historic drilling data - IP improves as per EIA Tier 1 assumptions - Resource base is “Poor Heavy”		
Fixed & Variable Well Costs	- Fixed and variable costs based on reported data - Costs improve as per EIA assumptions		
Domestic Demand	- Electric demand taken from fundamental REF case, RCI demand based on AEO Reference Case - Total long-term domestic demand ~35 Tcf + ~15 Tcf exports	 Higher demand: Highest AEO electric demand outlook (+5 Tcf domestic demand by 2045)	 Lower demand: AEO low growth demand (~10 Tcf domestic demand by 2045)
Resulting Price	\$4.75-\$5.25 long-term (real 2025\$)	 \$6.50-\$7.50 long-term (real 2025\$)	 Similar to Ref near-term; \$4.50-\$4.75 long-term (real 2025\$) long-term demand reduction offsets supply restrictions



NATURAL GAS PRICE SCENARIO RANGE – HENRY HUB

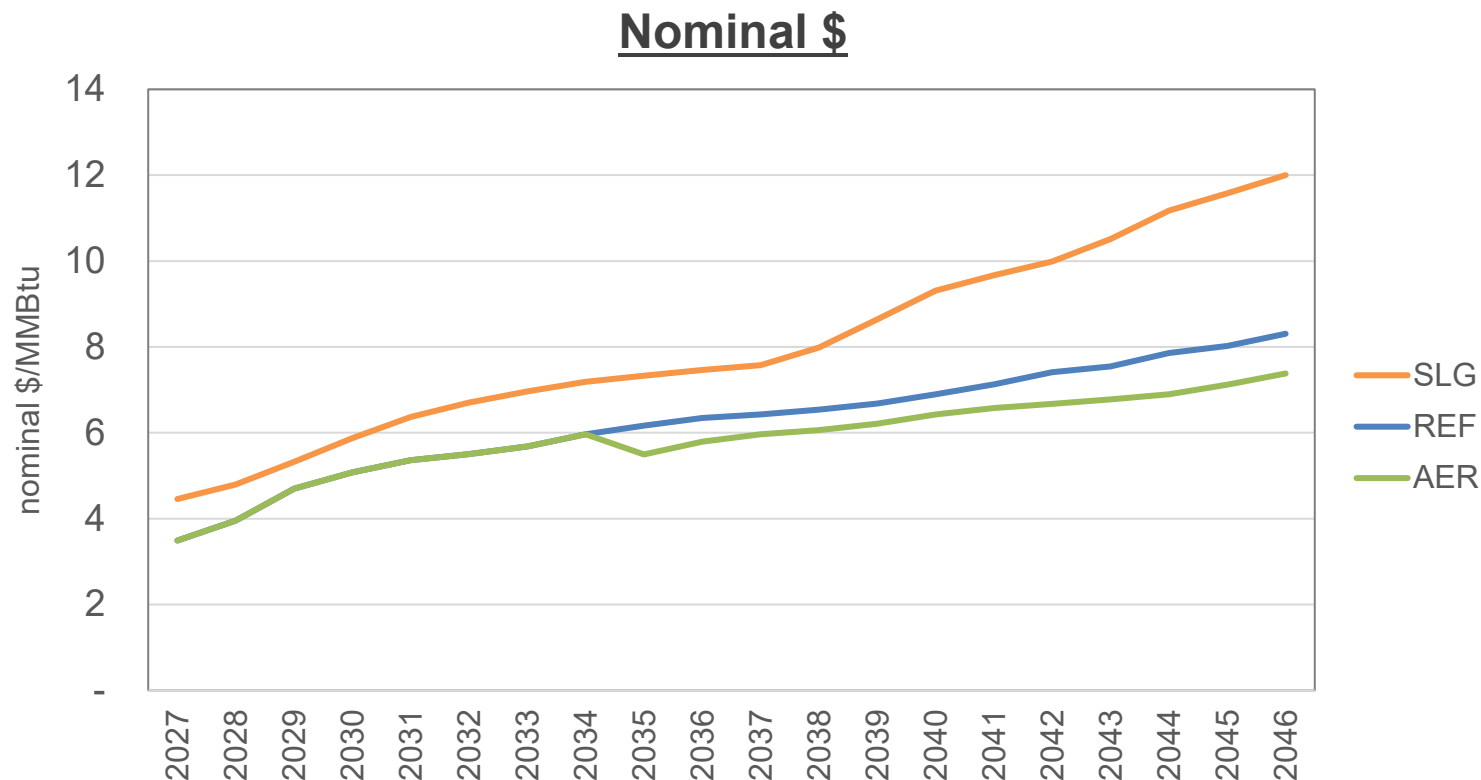


- **SLG (Sustained Load Growth)**
– Higher demand drives prices higher
- **AER (Aggressive Environmental Regulation)** –
Lower demand after the implementation of the carbon price keeps prices below \$5/MMBtu (real \$), although long-term production restrictions keep prices close to the Reference Case

	Prices (in real 2025 \$)		
	2027	2036	2046
SLG	\$4.22	\$5.89	\$7.70
REF	\$3.33	\$5.02	\$5.34
AER	\$3.33	\$4.57	\$4.73



NATURAL GAS PRICE SCENARIO RANGE – HENRY HUB



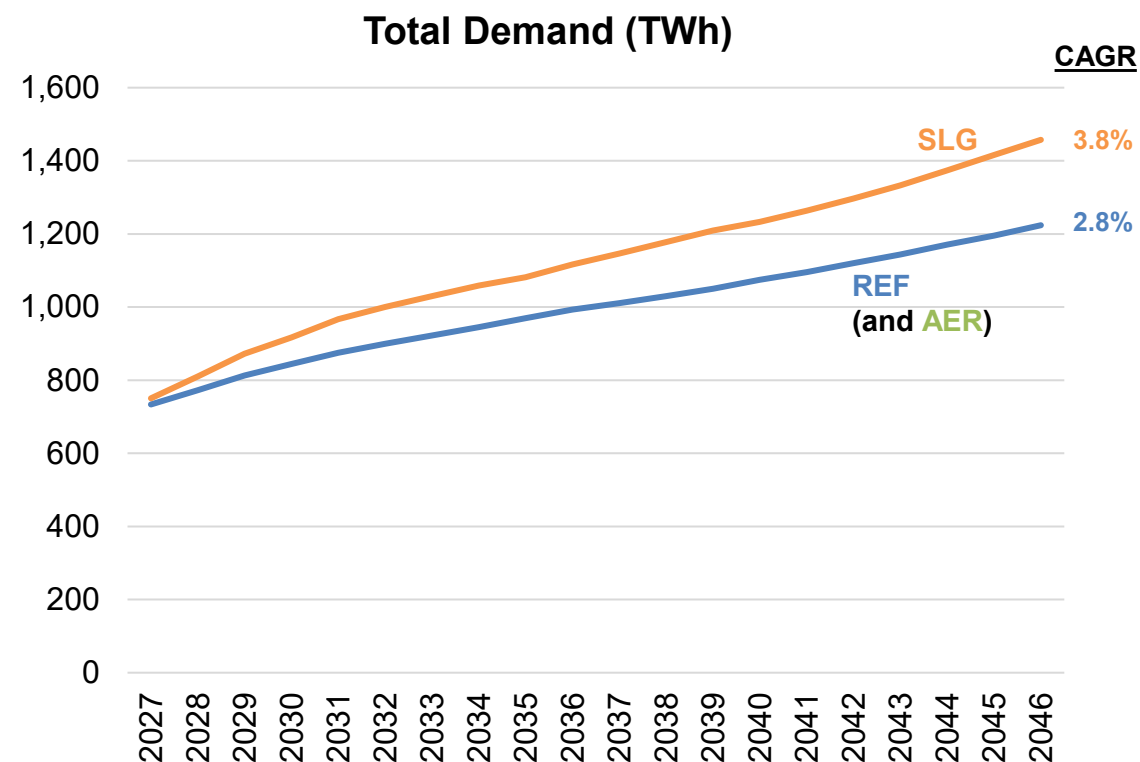
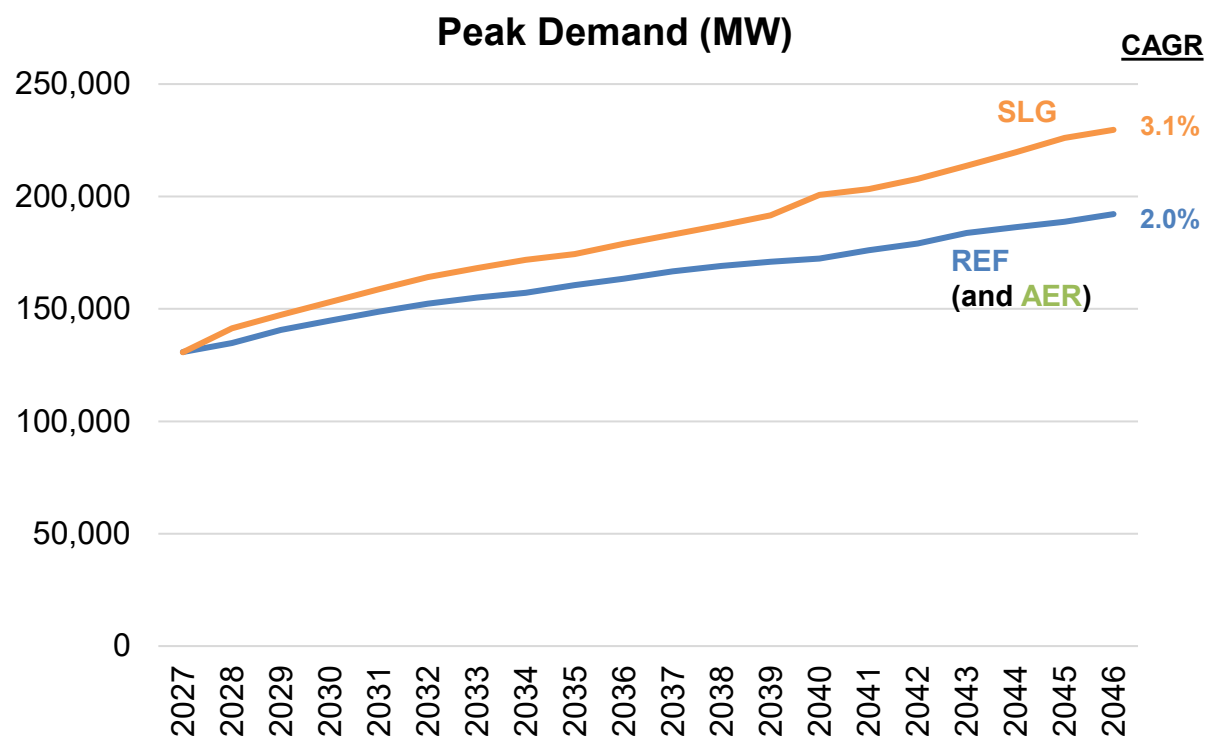
- **SLG (Sustained Load Growth)** – Higher demand drives prices higher
- **AER (Aggressive Environmental Regulation)** – Lower demand after the implementation of the carbon price drives prices down relative to the Reference Case, although long-term production restrictions keep prices close to the Reference Case

	Prices (in nominal 2025 \$)		
	2027	2036	2046
SLG	\$4.46	\$7.47	\$12.00
REF	\$3.49	\$6.35	\$8.31
AER	\$3.49	\$5.80	\$7.38



MISO LOAD GROWTH INPUTS

- The **SLG** scenario incorporates higher load growth across the MISO footprint, at the high end of MISO's recent load growth scenario range.
- The **AER** scenario has been evaluated with the same load as the Reference Case.

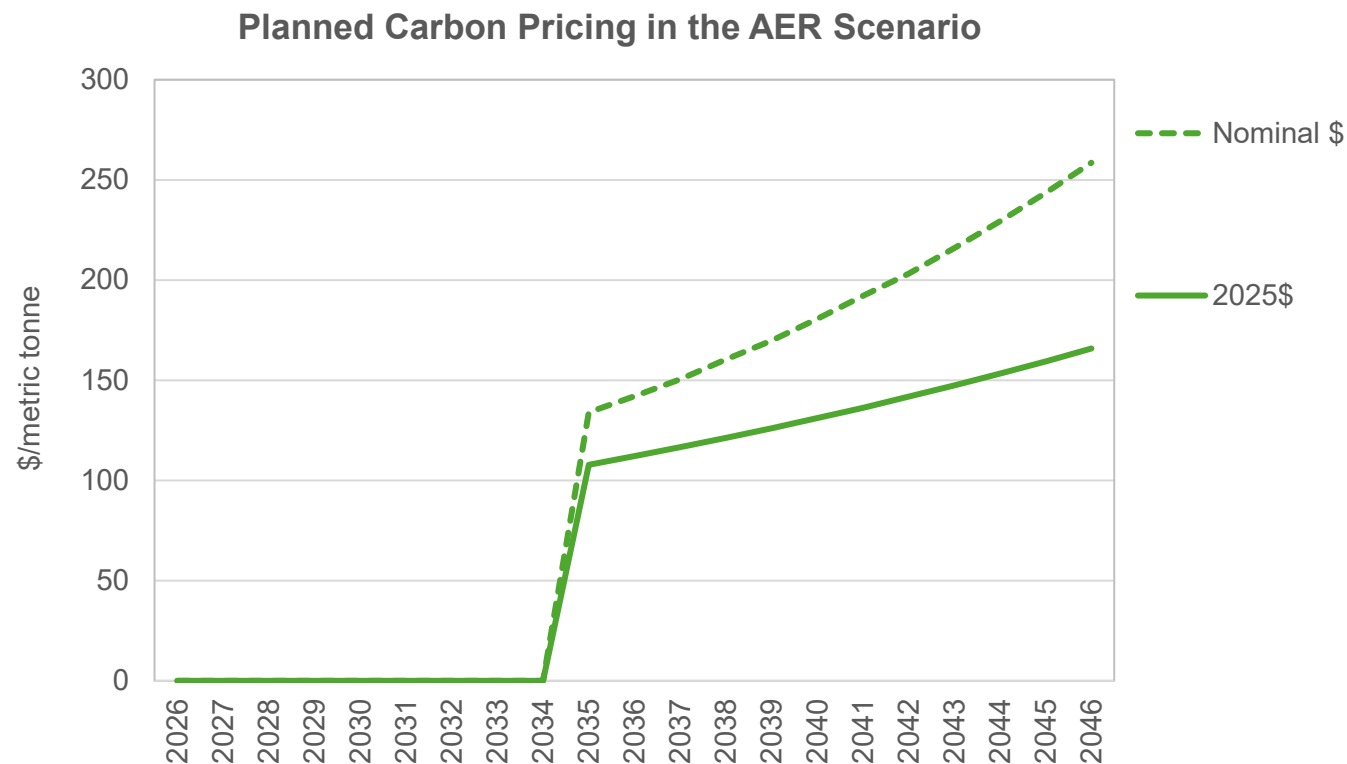




AGGRESSIVE ENVIRONMENTAL REGULATION (AER) SCENARIO ASSUMES CARBON EMISSIONS FROM THE POWER SECTOR ARE REGULATED MORE HEAVILY IN THE FUTURE

Implementation of Carbon Pricing in the AER Scenario is Consistent with the 2024 IRP

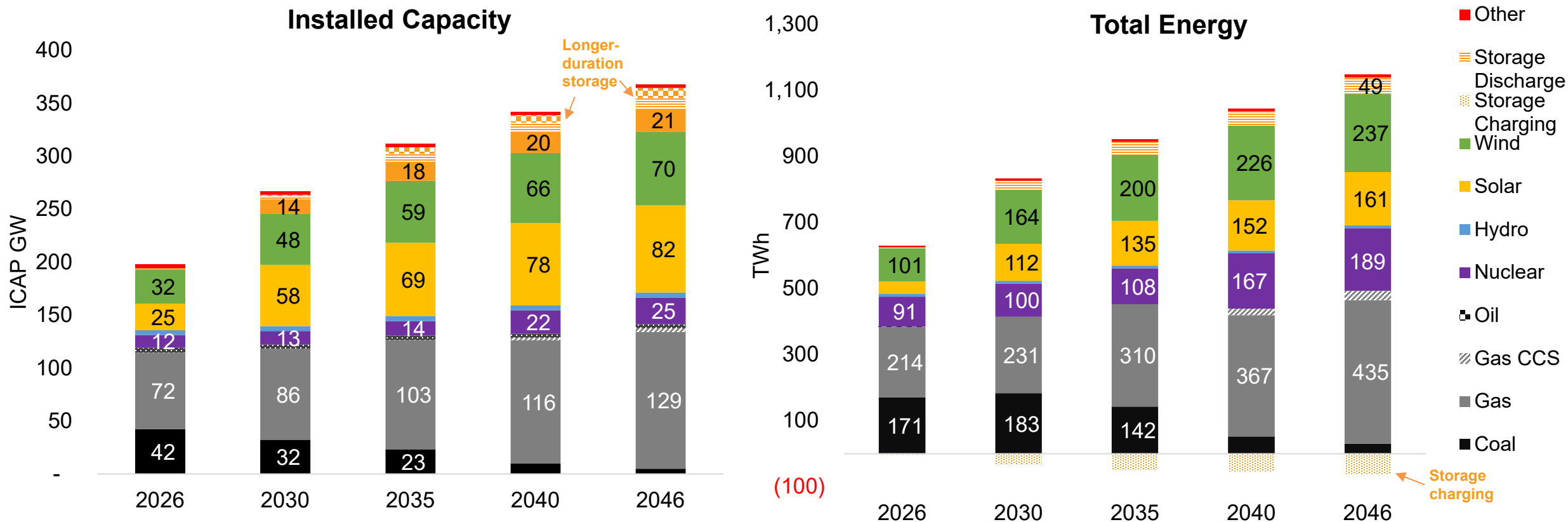
- Since 2015, greenhouse gas regulations have undergone multiple revisions, repeals and legal challenges.
- Carbon pricing is a good planning tool that helps understand how different resource portfolios perform under future policy scenarios to ensure resilient decisions.
- The cost trajectory represents a range of future potential environmental policy options that will impact the cost of emitting carbon rather than an explicit carbon tax policy.
- Carbon pricing is derived from the Brookings Institution.¹
- Consistent approach to the last IRP, with pricing beginning in 2035 instead of 2030.





RECAP: REFERENCE CASE MISO MARKET EVOLUTION

- Load growth and reliability requirements are expected to drive significant natural gas additions, with gas generation projected to double over the next 20 years as coal generation fades, albeit at a slower pace than projected in prior years.
- Renewable capacity growth is expected through the end of the decade in a race to secure tax credits, with slower but sustained growth over the long-term, driven by steadily growing energy demands, state policy, and power prices.

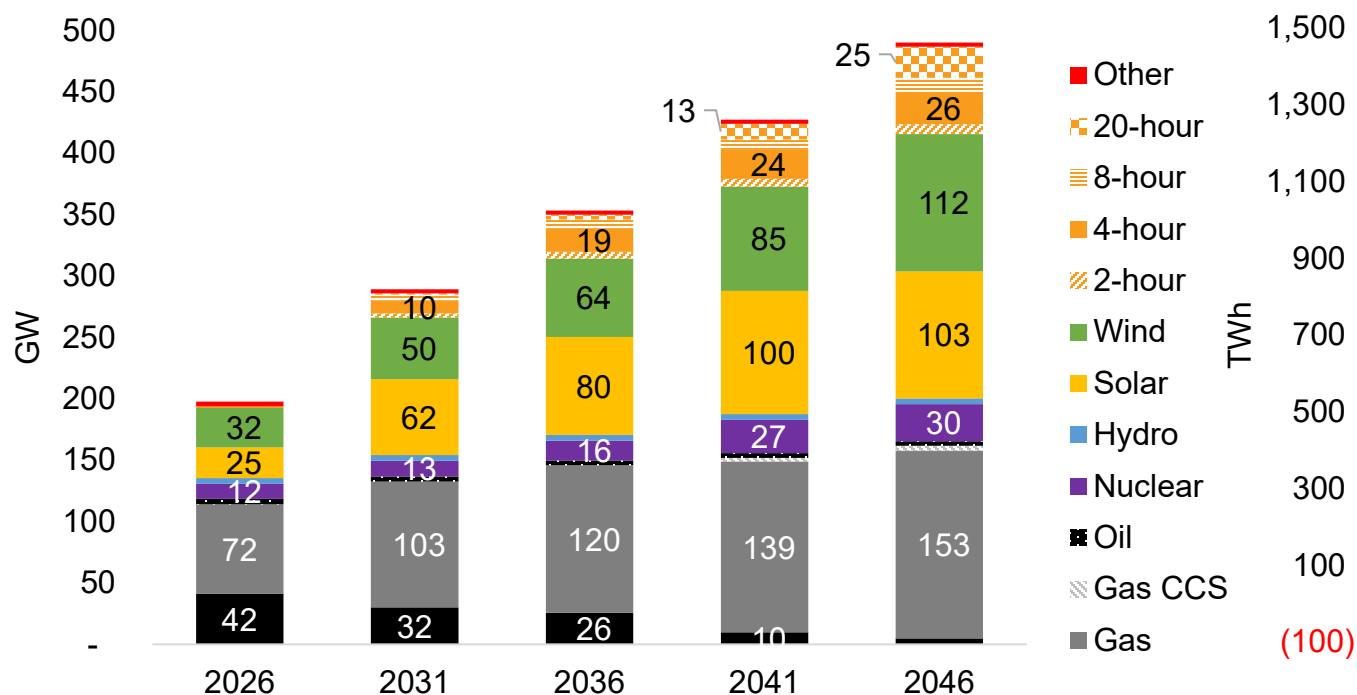




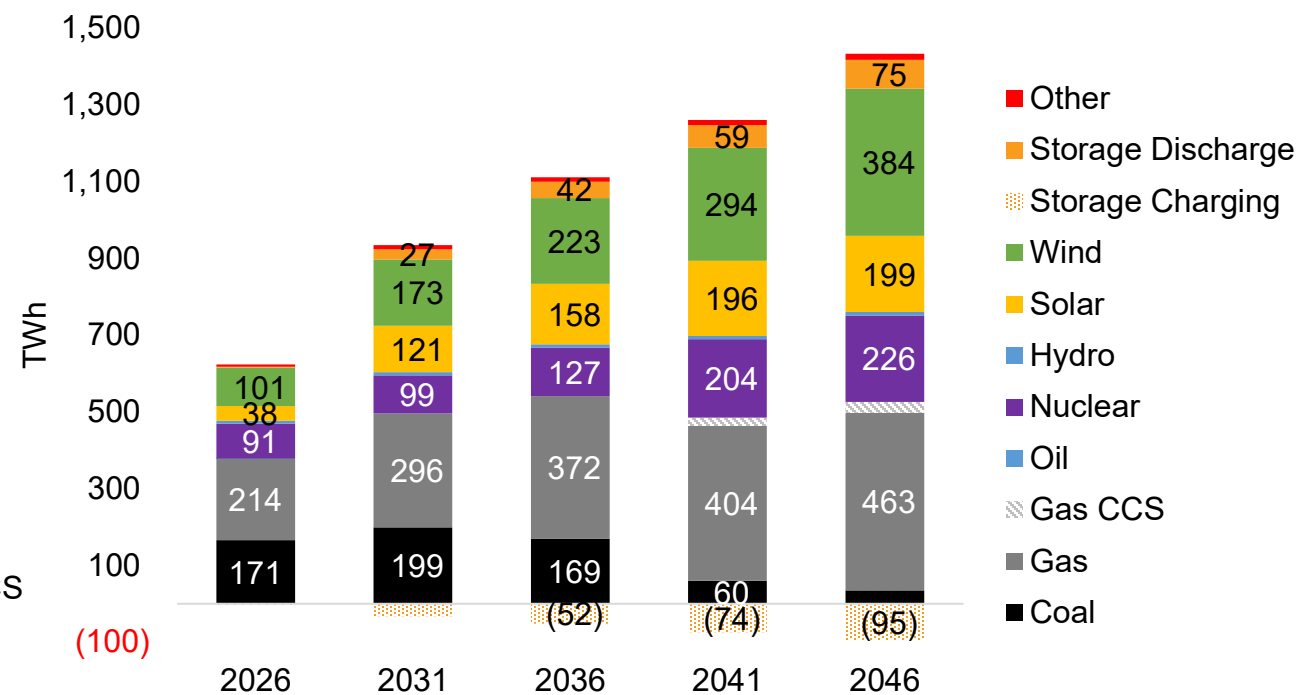
SUSTAINED LOAD GROWTH – CAPACITY AND GENERATION MIX OVER TIME

- Significant additional capacity is needed to meet incremental energy needs.
- Coal generation fades more slowly as a result of higher regional load and higher natural gas prices.
- Clean energy grows at a relatively faster rate than in the Reference Case, given higher long-term gas prices.
- Natural gas generation retains a share of about one-third of the capacity and long-term generation mix.

Installed Capacity



Total Energy

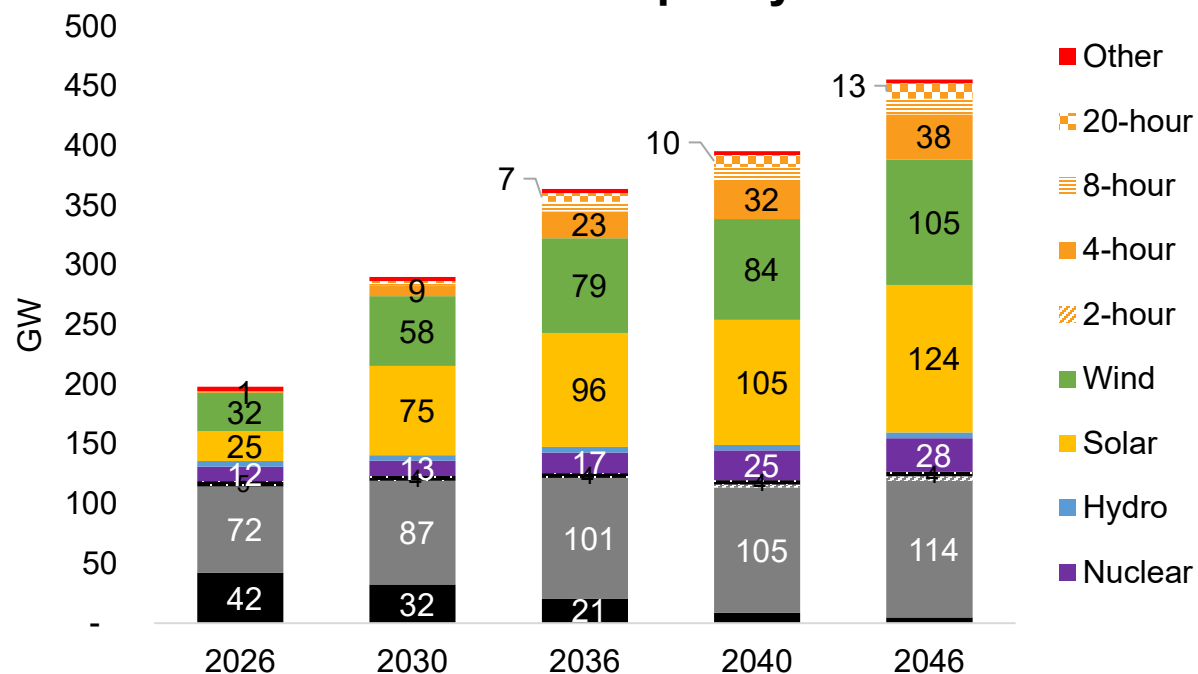




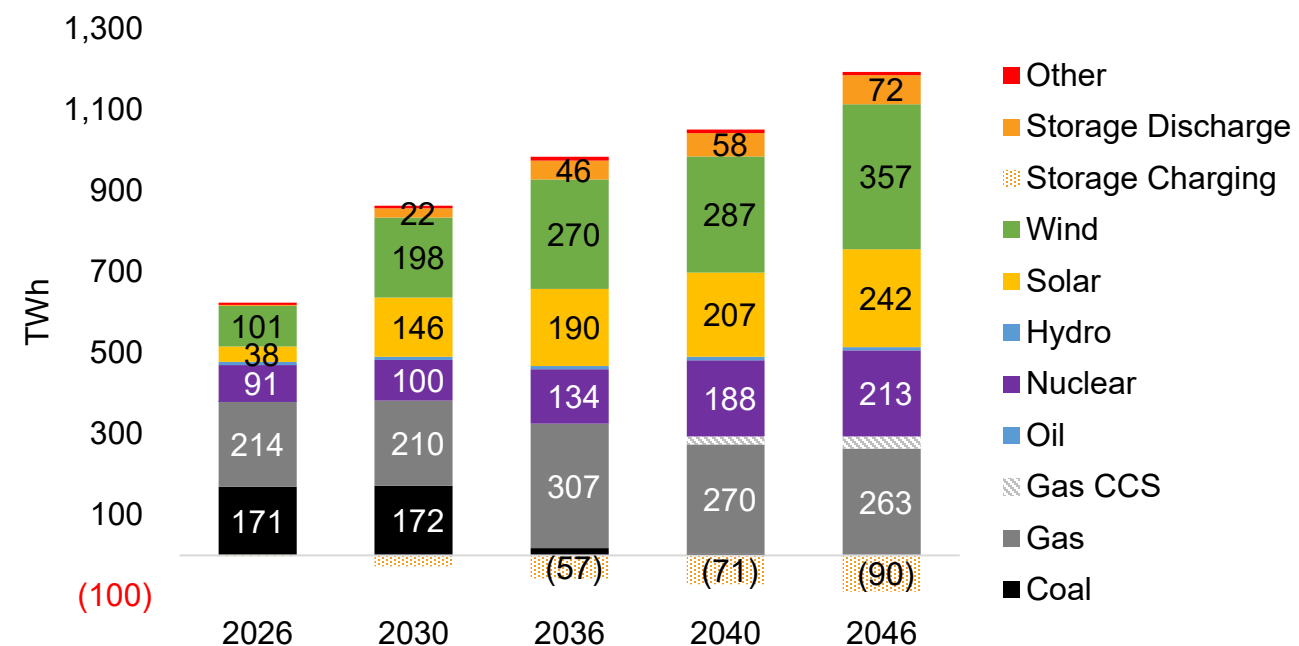
AGGRESSIVE ENVIRONMENTAL REGULATION – CAPACITY AND GENERATION MIX OVER TIME

- Coal generation approaches zero by 2036 after the implementation of the carbon price.
- By 2046, clean energy is projected to be ~75-80% of the total mix.
- Nearly 50% more storage capacity is added to the system relative to the Reference Case, although dispatchable natural gas capacity retains a role even in the face of high carbon pressure.

Installed Capacity



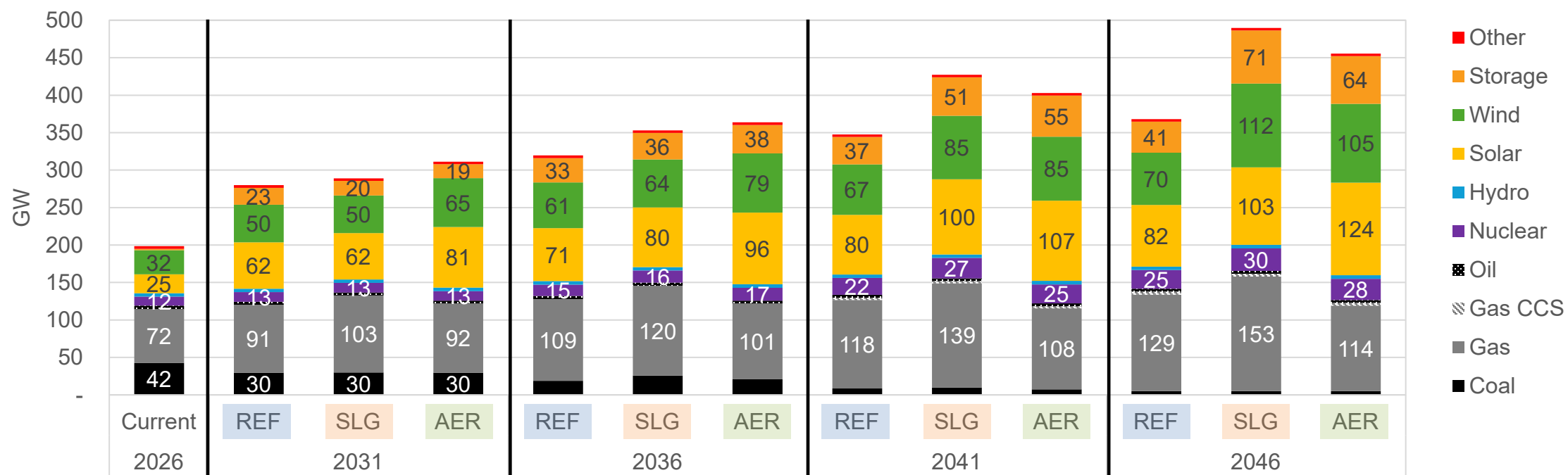
Total Energy





MISO CAPACITY MIX OVER TIME ACROSS SCENARIOS

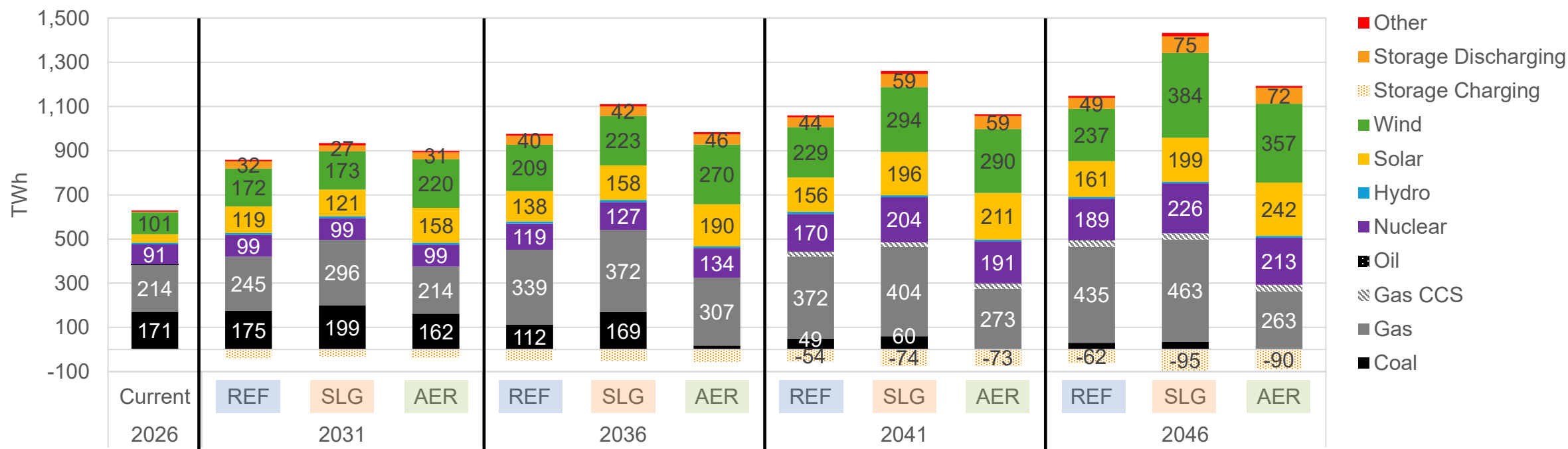
- Relative to the Reference Case, the **SLG** scenario has more capacity overall across all resource categories to meet increased regional load growth demands.
 - Higher gas prices drive smaller increases in natural gas capacity and larger increases in wind and storage, in particular.
- Relative to the Reference Case, the **AER** scenario retires coal plants earlier, has fewer natural gas additions and ~50% more wind, solar, and storage by 2046 (plus additional nuclear capacity).





MISO ENERGY MIX OVER TIME ACROSS SCENARIOS

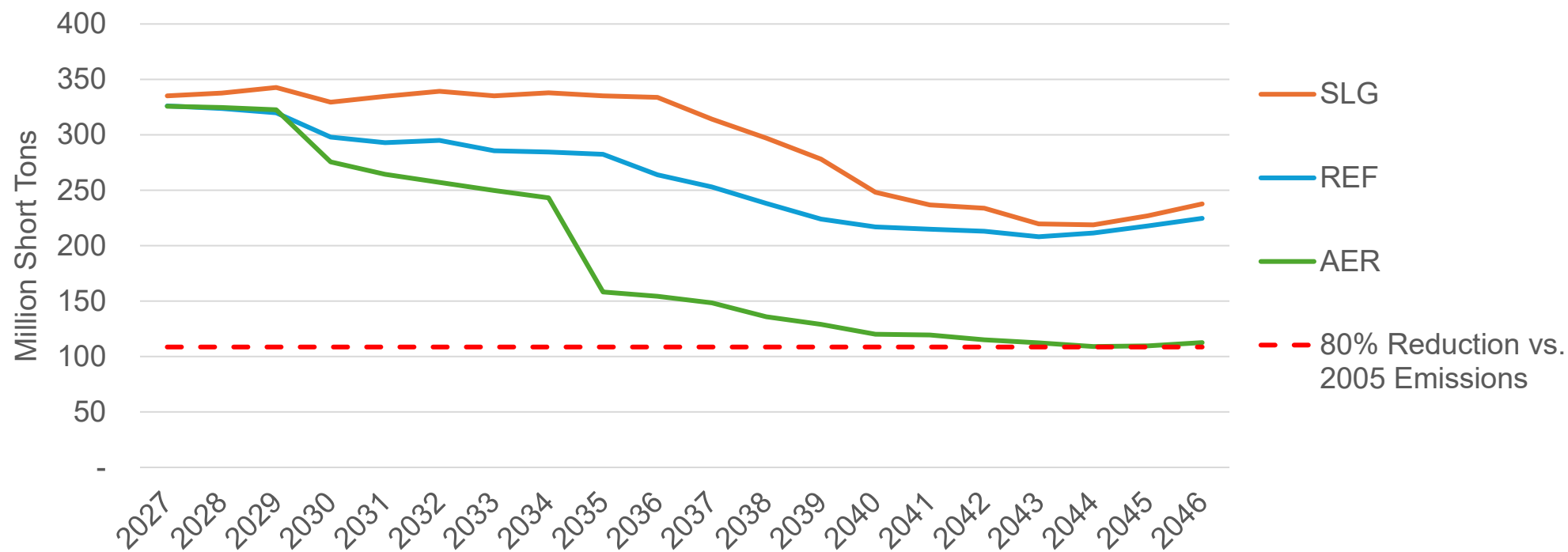
- Relative to the Reference Case, the **SLG** scenario has higher coal generation through the 2030s and significantly scaled wind, solar, and nuclear generation because of higher load growth and higher natural gas prices; long-term natural gas generation is comparable.
- Relative to the Reference Case, coal generation falls precipitously by 2036 in **AER**, with higher levels of clean energy over the long-term. Natural gas generation is ~40% lower by 2046, although the resource is still expected to be part of the overall mix, given its dispatchability characteristics.





CO2 EMISSIONS ACROSS MISO

- MISO-wide CO2 emissions are projected to remain relatively stable for the next decade under the **SLG** scenario in contrast to the ~15-20% reduction expected over that time period in the Reference Case. However, over the long-term projected emissions converge as more clean energy is added in the **SLG** scenario.
- Emissions in the **AER** scenario are projected to fall significantly with the introduction of the carbon price in 2035 and then achieve an 80% reduction relative to 2005 levels by the mid-2040s.

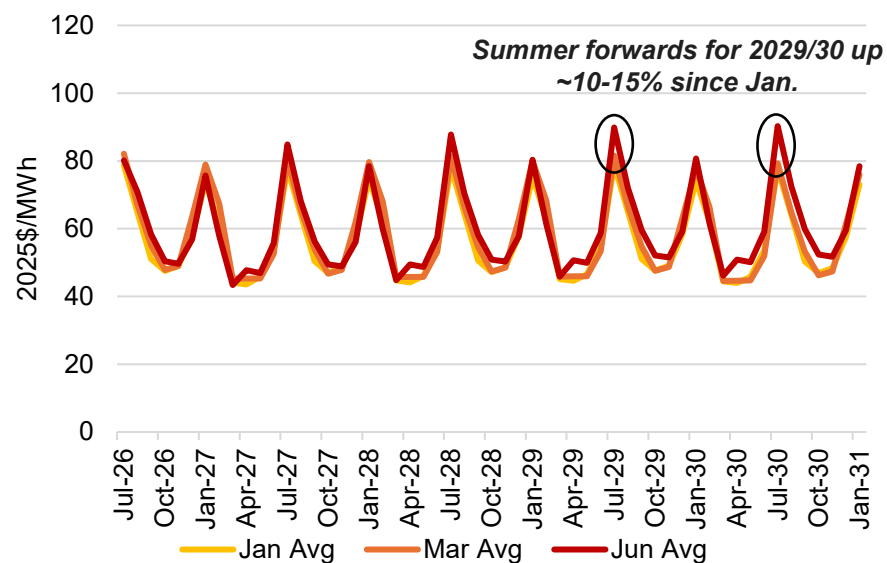




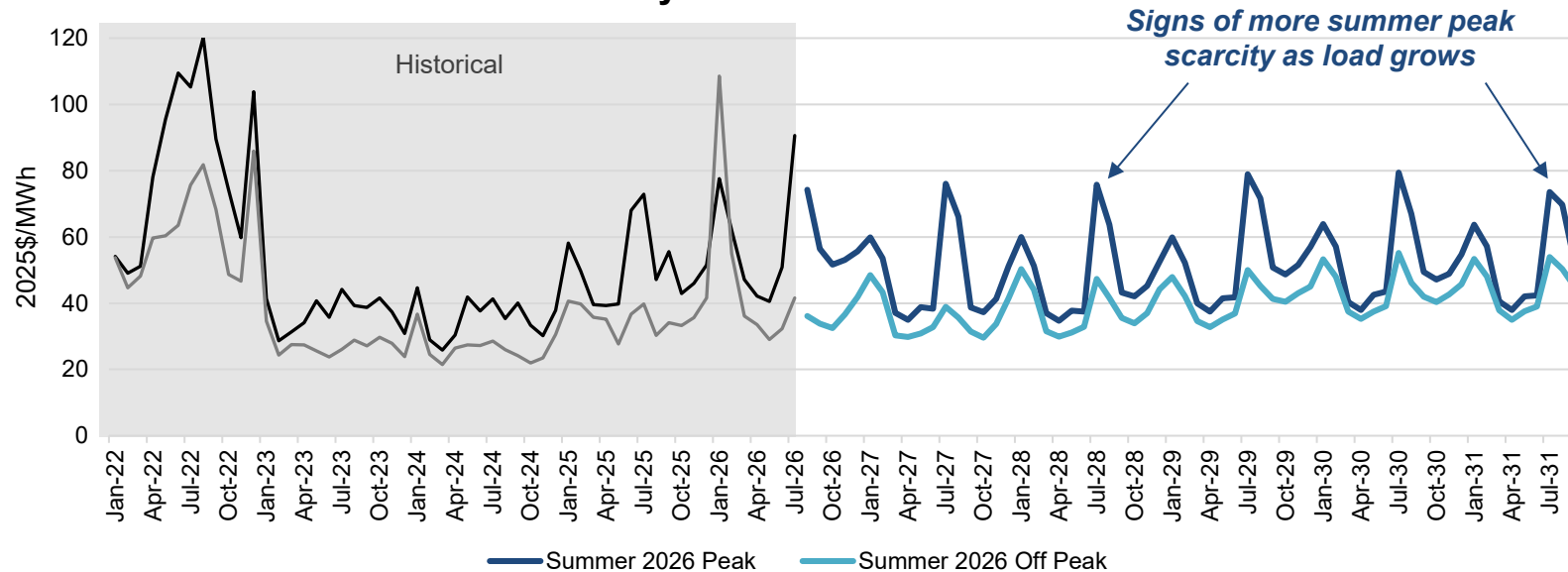
RECAP: REFERENCE CASE NEAR-TERM PRICE OUTLOOK

- Following the post-2022 fall in natural gas prices, MISO power prices experienced a two-year period of relative stability, averaging ~\$30/MWh through 2023 and 2024.
- More volatility has been observed in 2025 and 2026 as a result of extreme weather and tightening supply-demand conditions.
- Indiana Hub forwards have been trending up slightly over the last six months, reflecting expectations that demand growth will outpace supply additions. CRA's latest forecast captures such trends, particularly in summer peak periods.

Indiana Hub Forwards



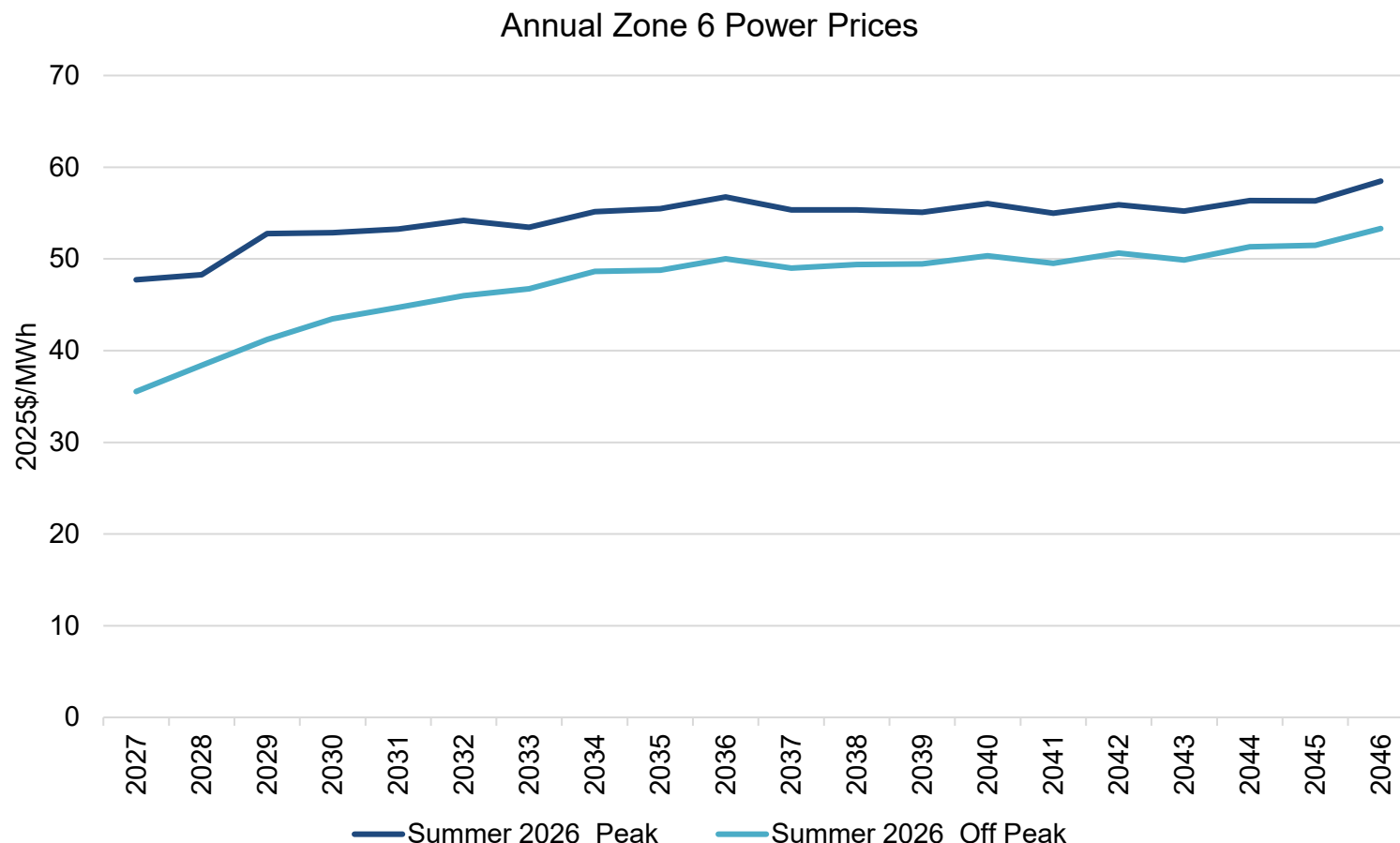
Monthly Zone 6 Power Prices





RECAP: REFERENCE CASE POWER PRICE FORECAST – MISO ZONE 6

- MISO power prices are primarily influenced by the price of natural gas and the composition of the generation fleet.
- Near-term load growth and natural gas price increases are expected to drive power price increases (in real \$) into the early 2030s.
- Supply response over the long-term, including with low variable cost advanced clean energy technology, is expected to moderate wholesale market price growth.
- Convergence in peak and off-peak prices is expected over time, largely driven by a combination of solar energy growth and evolving load shapes.

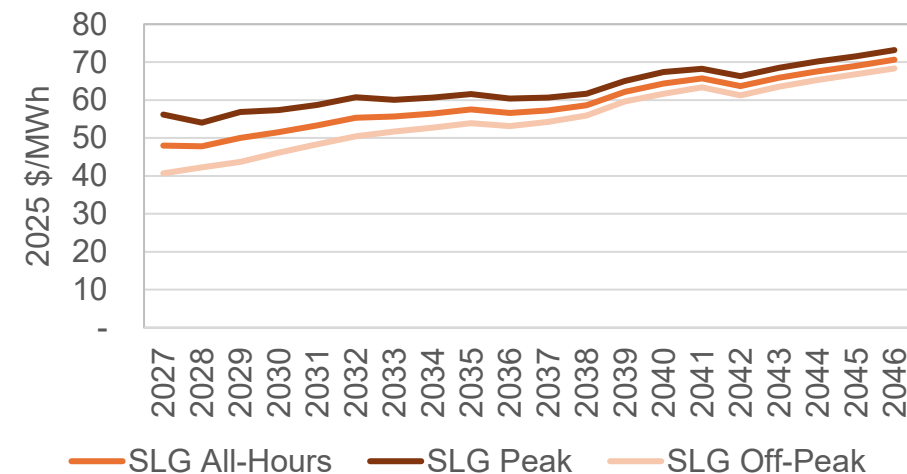




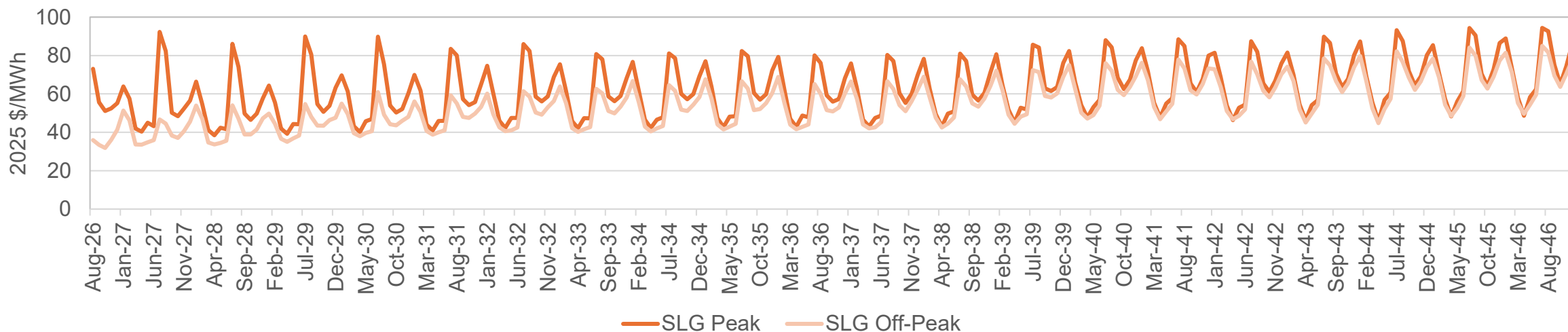
SUSTAINED LOAD GROWTH – MISO ZONE 6 POWER PRICE PROJECTIONS

- Higher projected scarcity in the near-term is expected, particularly in the summer months (close to \$90/MWh in real 2025\$), driven by faster load growth and tighter regional reserve margins.
- Long-term prices are expected to grow in real \$ (towards \$70/MWh by 2046), driven by rising natural gas prices and sustained load growth.

Annual Zone 6 Power Prices



Monthly Zone 6 Power Prices

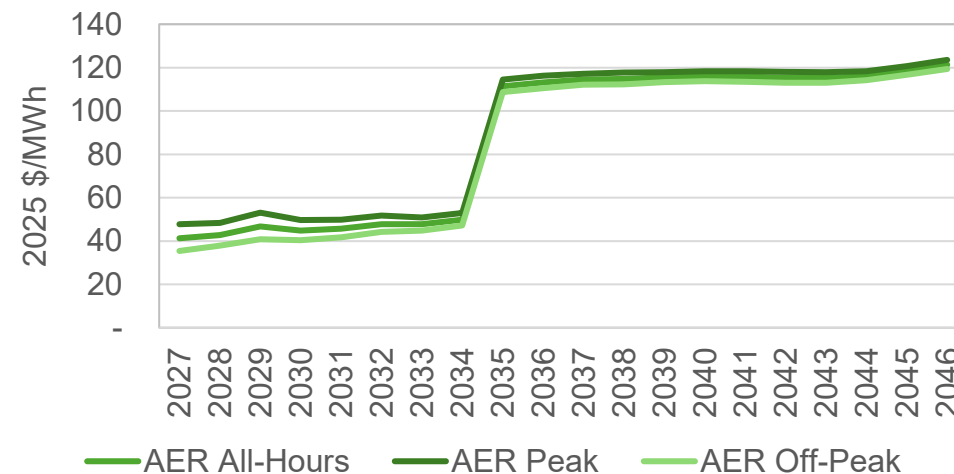




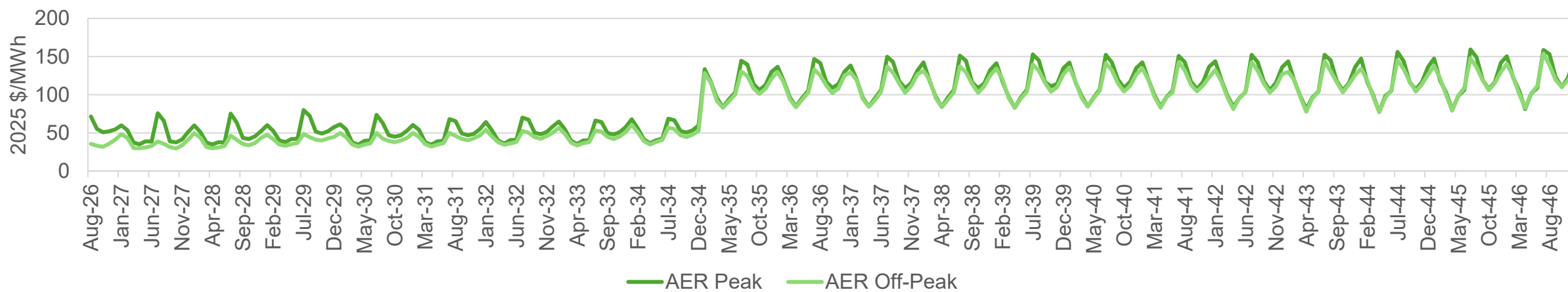
AGGRESSIVE ENVIRONMENTAL REGULATION – MISO ZONE 6 POWER PRICE PROJECTIONS

- Prices are projected to be relatively flat in real \$ for the next 8 years prior to the implementation of the carbon price, at levels that are slightly lower than those in the Reference Case because of more low variable cost resource additions.
- In 2035, power prices are projected to increase significantly in line with the carbon price, holding relatively flat thereafter as a result of growing low variable cost generation offsetting the increases in carbon prices and natural gas prices.

Annual Zone 6 Power Prices



Monthly Zone 6 Power Prices

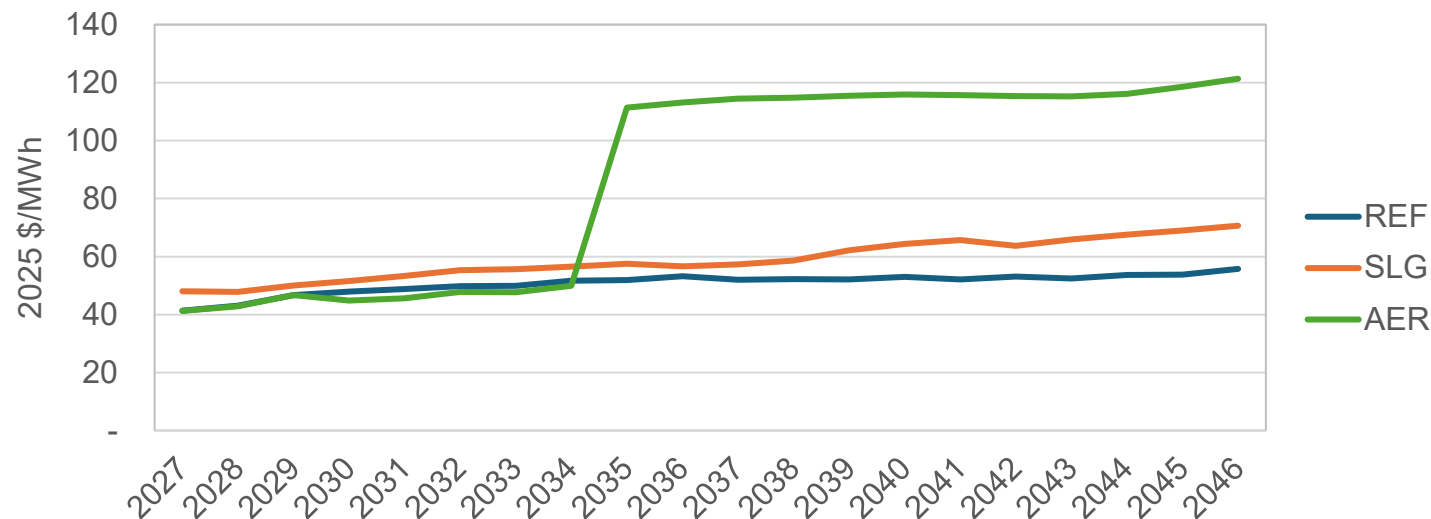




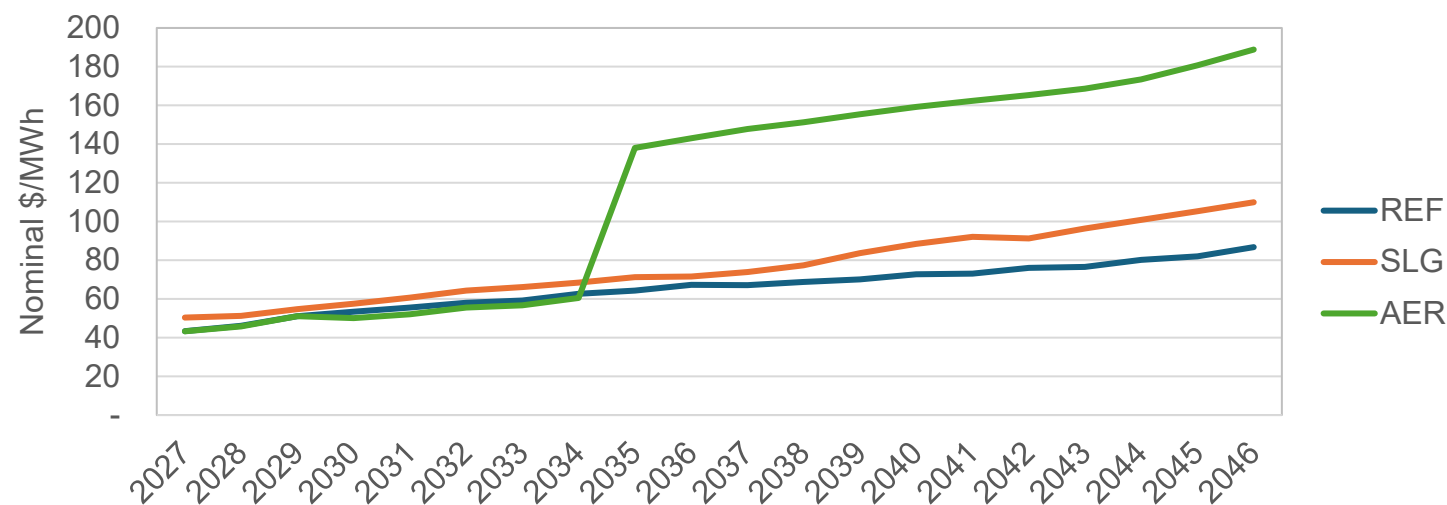
MISO ZONE 6 POWER PRICES

- The **SLG** scenario results in MISO market prices that are consistently higher than those in the Reference Case as a result of higher load growth and higher natural gas prices.
- The **AER** scenario results in MISO prices that are slightly lower than those in the Reference Case in the near term due to a slightly different resource mix, with higher long-term prices driven by assumed carbon regulation via a price.

MISO Zone 6 All Hours Pricing (Real 2025\$/MWh)



MISO Zone 6 All Hours Pricing (Nominal \$/MWh)

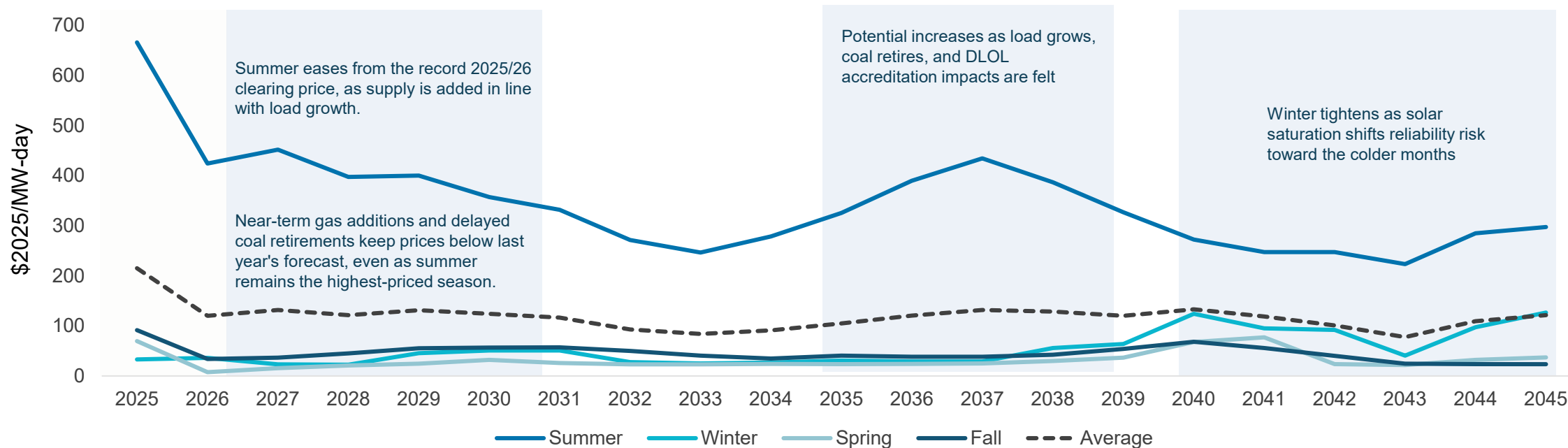




RECAP: MISO NORTH CAPACITY PRICE OUTLOOK - REFERENCE

- The 2026/27 auction cleared at \$424/MW-d for the summer season and around \$125/MW-d annually.
- CRA expects continued pressure on summer prices through the forecast period reflecting persistent pressure on the supply-demand balance. However, the forecast assumes vertically integrated utilities build to serve growing load.
 - The seasonal capacity construct could serve to dampen the year-round price impact if other seasons are not as tight as the summer. MISO maintains no annual price cap (though each season is capped at annual Gross CONE), running the risk of high year-round prices if non-summer seasons, such as winter, become short.
- Over the long-term, risks in the winter season may eventually emerge due to 24x7 load growth and solar growth, but the summer season is currently expected to continue to be priced at a premium.

Seasonal Capacity Price

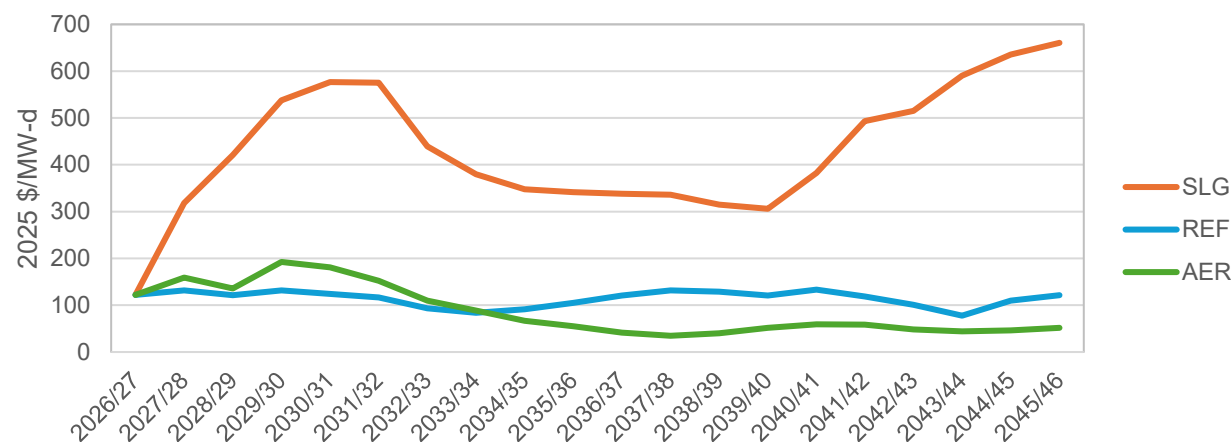




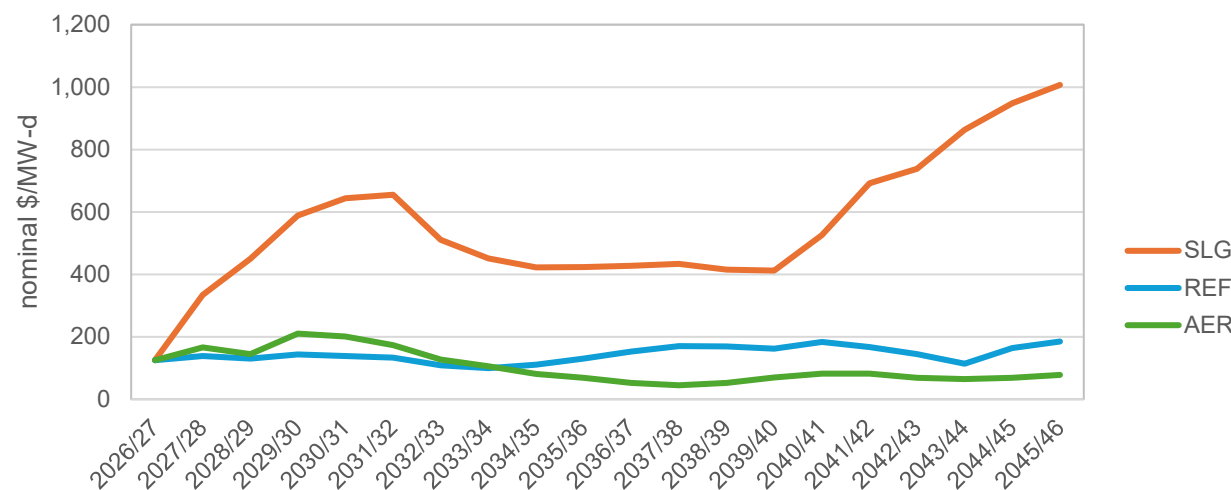
AVERAGE ANNUAL CAPACITY PRICE OUTLOOK ACROSS SCENARIOS

- Capacity price expectations are driven largely by regional reserve margins and the net cost of new entry (CONE).
- In the **SLG** scenario:
 - Supply additions are not expected to meet the scale of large load entering MISO North; thus, reserve margins in the near-term are projected to be significantly lower than those in the Reference case across all seasons.
 - Natural gas additions temporarily ease prices through the 2030s, but scheduled coal retirements starting in 2040 push prices in Summer and Winter to seasonal cap.
- In the **AER** scenario:
 - Relative to the Reference Case, capacity prices are projected to be higher in the near-term due to earlier coal retirements.
 - Over the long-term, the high carbon price drives energy prices higher, reducing the net CONE for marginal storage additions in the long-run.

Annual Avg. Capacity Prices (Real 2025\$/MW-day)



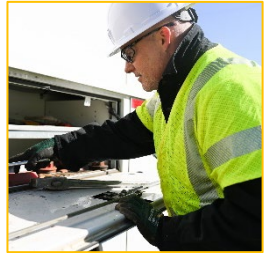
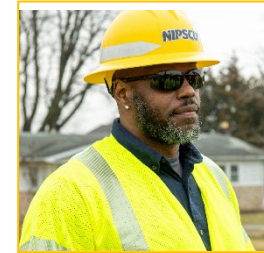
Annual Avg. Capacity Price (Nominal \$/MW-day)





ENVIRONMENTAL: COSTS & CONSIDERATIONS FOR RETIREMENT EXTENSION

Paul Heyborne, Manager, Environmental Policy & Sustainability



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ENERGY PARTNER



MICHIGAN CITY GENERATING STATION IS EXPECTED TO REQUIRE LIMITED INCREMENTAL ENVIRONMENTAL INVESTMENT FOR CONTINUED OPERATION

Best Available Pollution-Control Systems Support Compliance with Air, Water and Coal Ash (CCR) Requirements

CURRENT PLANNING VIEW

\$0

Incremental Capital Needed for
Long-Term Environmental
Compliance

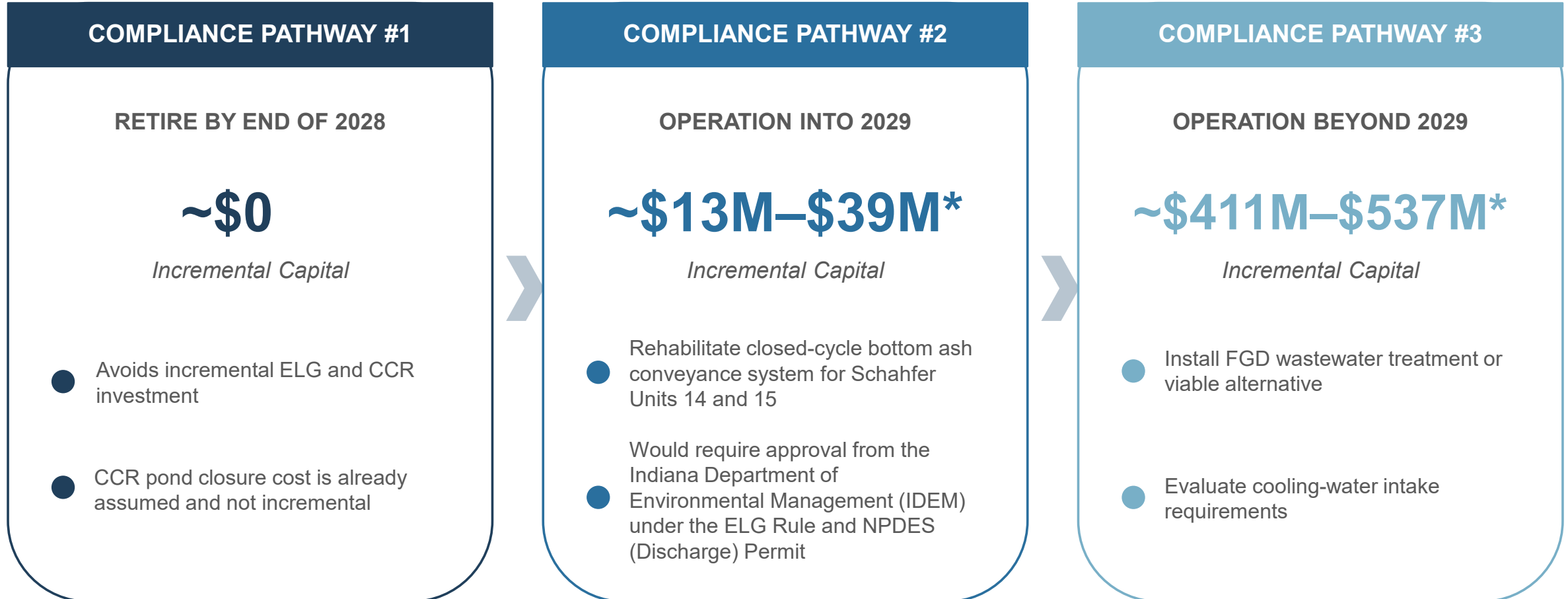
~\$7M

Planned Maintenance Capital for
Environmental Compliance if
Operating After 2028

ENVIRONMENTAL CONSIDERATION	POSITION	INCREMENTAL CAPITAL COST ASSUMED
Effluent Limitations Guidelines (ELG) Rule	Existing dry flue gas desulfurization (FGD) and closed-cycle ash systems support continued compliance	\$0
CCR Rule	CCR pond closures have been completed; Groundwater remedy, monitoring and post-closure care continue to be implemented	\$0
Other Environmental Requirements	Existing controls support continued compliance	\$0

SIGNIFICANT INCREMENTAL ENVIRONMENTAL COMPLIANCE INVESTMENT IS ASSUMED FOR OPERATING SCHAHFER UNITS 17 AND 18 BEYOND 2028

ELG and CCR Compliance are the Primary Environmental Compliance Cost Drivers

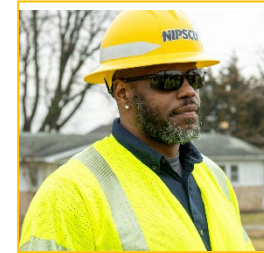


*Estimates exclude indirect costs (AFUDC and Overhead).



INCORPORATING NEW RESOURCE OPTIONS

Abe Lang, Manager, Strategy & Risk



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ENERGY PARTNER



NIPSCO 2027 IRP NEW PORTFOLIO RESOURCE OPTIONS

Single-bid, proprietary
redacted from public
version

Technology	Build Cost	PPA Price	Tolling Price	COD	Comments
	\$/kW	(\$/MWh)	(\$/kW-mo)		
Traditional					
Solar	\$2,800	\$79		Q1 2030	
Solar + Storage		\$78	\$14	Q1 2030	
Wind				Q3 2030	
Wind + Storage				Q1 2031	
Standalone Storage	\$2,000		\$15	Q2 2029	Includes six-hour duration storage; eligible for ITC
CCGT	\$3,500		\$33	Q1 2034	
CT *	\$3,000-\$4,400		\$35	Q2 2030	NIPSCO will used self-build estimates for modeling
Emerging					
Linear Generation				Q2 2030	Pilot ready, low emission resource – selected in some preliminary modeling; eligible for ITC
Nuclear (SMR)				Q2 2035	No bids received in RFI, proprietary cost information - not selected in preliminary modeling; eligible for ITC
Sodium/Iron Air (LDES)				Q2 2031	No bids received in RFI, proprietary cost information - not selected in preliminary modeling; potentially eligible for ITC

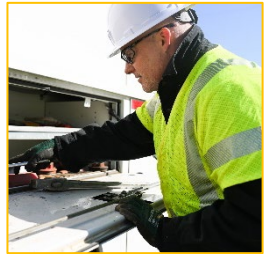
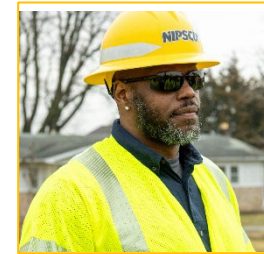
Unless otherwise noted, this table reflects proposals received (not projects). Some proposals are mutually exclusive or have been bid as both Asset Sale and PPA.

- Average bid prices shown for “Asset Sale” represent capital costs and exclude on-going fuel, O&M and CapEx (where applicable)
- Figures shown are for representation and do not purport competition between technologies



PORTFOLIO CONCEPTS

Abe Lang, Manager Strategy & Risk



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PORTFOLIO CONCEPTS: STAKEHOLDER IRP PORTFOLIO SUGGESTIONS

2027 IRP portfolio concept proposals received from stakeholders are summarized below

Requestor	Request #	Request Description	Additional Details	NIPSCO Comments
A	1	Only solar, storage, and solar + storage through 2031; No new gas until 2033	RFP/RFI resources in MISO queue get 3-year delay to anticipated COD	Plan to accommodate in initial portfolio modeling; Aligned with requestor D
B	2	2028 Coal retirement	- Assume EPA GHG returns in 2028-2029 with compliance beginning in 2036. - Assume lowest bid not average for RFP/RFI resources - Legacy ITC/PTC reinstatement - 2029-2038.	Plan to accommodate these in the initial portfolio modeling
	3	2030 Coal retirement		
	4	2032 Coal retirement		
C	5	Run MCGS U12 (M1C12) and Schahfer U17/18 (U17/18) on coal for duration	Run with underlaying load forecast - no additions.	Plan to address gas conversions in the IRP, but this will require additional study that will take longer than the initial portfolio runs;
	6	Convert MC12 to gas U17/18 continue operating on coal		
	7	Convert MC12 and U17/18 to gas		
D	8	Carbon/environmental regulations increase in mid-term - i.e. AER in 2024 IRP	Assume pilot-ready resources reach commercialization/scalability on accelerated timeline (i.e. near to mid term).	Plan to accommodate in initial portfolio modeling; Aligned with requestor A; Pilot ready resources will be included in all portfolio modeling
E	9	Evaluate a Virtual Power Plant - customer-sited DER (Distributed Energy Resources)	Examples include: solar, batteries, other dispatchable generation	Further feedback will be needed; VPP's can be considered for implementation after the IRP based on the amount of solar+storage that is selected in the preferred plan

NIPSCO PORTFOLIO CONCEPTS

NIPSCO is proposing to model the following portfolio concepts as it begins its IRP modeling with considerations for retirements, federal policy and new asset availability

Draft concepts can be refined based on feedback

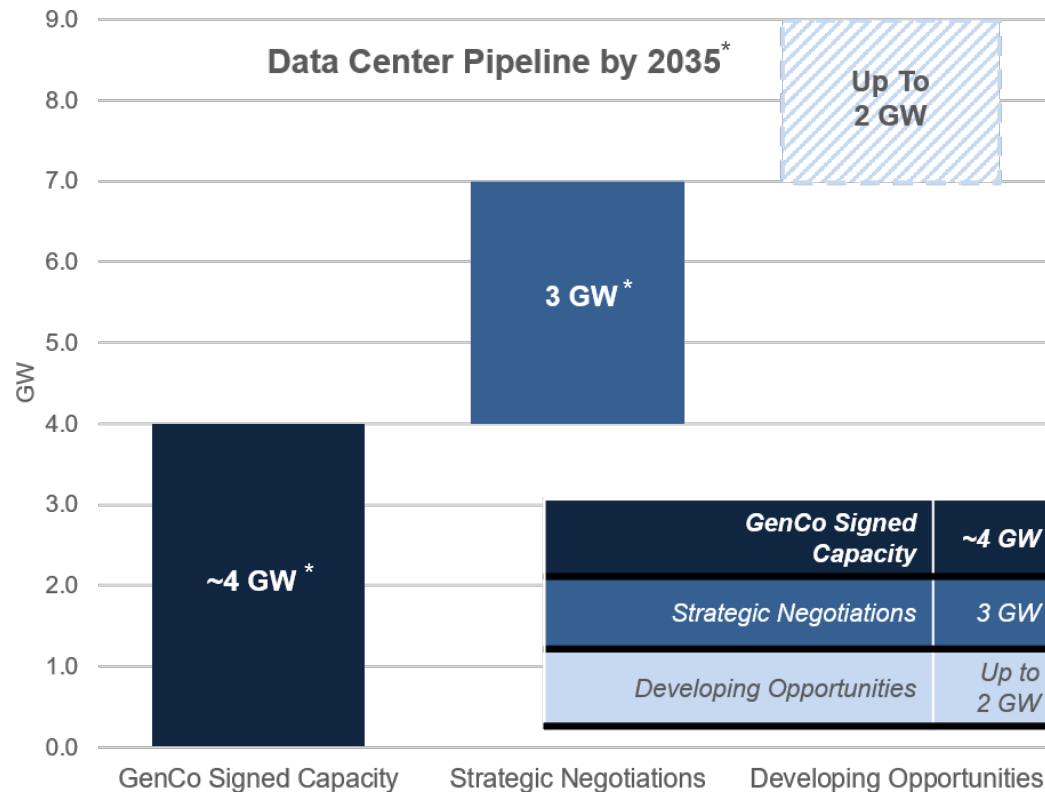
		A	B	C	D	E	F	G	H	I	J
Retirements	MCGS Retirement	2028	2028	2030	2032 Gas conversion	2032 Gas conversion	2033	2033	2039	2039	None (2040+)
	Schahfer 17/18 Retirement	N/A 202c order only	2028*	2029*	2032* Gas conversion	N/A 202c order only	N/A 202c order only	N/A 202c order only	N/A 202c order only	N/A 202c order only	N/A 202c order only
Federal Policy	EPA GHG Rules	Withdrawn	2035 compliance	Withdrawn	Withdrawn	Withdrawn	Withdrawn	2035 Compliance	Withdrawn	2035 compliance	Withdrawn
	PTC / ITC Tax Credits (solar / wind)	N/A	2029 Reinstated	N/A	N/A	N/A	N/A	2029 Reinstated	N/A	2029 Reinstated	N/A
New Asset Availability	4-hr Storage earliest COD	Q2 2029	Q2 2029	Q2 2029	Q2 2029	Q2 2029	Q2 2029	Q2 2029	Q2 2029	Q2 2029	Q2 2029
	Gas earliest COD	Q2 2030	Q2 2033	Q2 2030	Q2 2033	Q2 2033	Q2 2030	Q2 2033	Q2 2030	Q2 2030	Q2 2030
	Nuclear earliest COD	Q2 2035	Q2 2035	Q2 2035	Q2 2035	Q2 2035	Q2 2035	Q2 2035	Q2 2035	Q2 2035	Q2 2035
	Long Duration Storage (LDES) earliest COD	Q2 2031	Q2 2031	Q2 2031	Q2 2031	Q2 2031	Q2 2031	Q2 2031	Q2 2031	Q2 2031	Q2 2031

PORTFOLIO CONCEPTS: SENSITIVITIES

GenCo Load Forecast Sensitivities*

Two load sensitivities to be run off of GenCo's portfolios based on current data center pipeline:

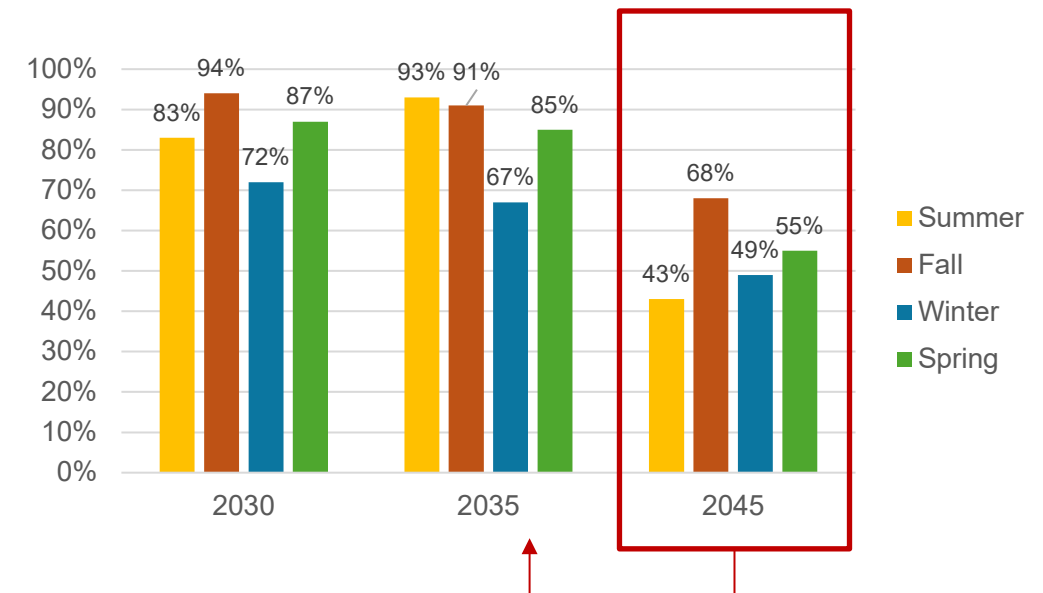
- 1) 3 GW by 2035*
- 2) 5 GW by 2035*



MISO Storage Accreditation Sensitivities

Sensitivity to be run that evaluates the acceleration of changes in MISO's storage capacity accreditation for select NIPSCO portfolios that have higher selections of storage

MISO Future 2 Storage Accreditation**



PORTFOLIOS WILL BE ANALYZED THROUGH THE SCORECARD

Proposed changes from 2024 Scorecard **highlighted in blue** focus on ensuring lower near-term customer costs

Objectives	Indicators	<u>Proposed</u> Metrics for 2026	NIPSCO / GenCo
Affordability	Cost to Customer	- Near-term and long-term Impact to customer bills Metrics: 10-year NPV of revenue requirement 20-year NPV of revenue requirement	NIPSCO
Rate Stability	Cost Certainty	- Certainty that revenue requirement within the most likely range of outcomes Metric: Scenario range NPVRR	NIPSCO
	Cost Risk	- Risk of unacceptable, high-cost outcomes Metric: Highest scenario NPVRR	NIPSCO
	Lower Cost Opportunity	- Potential for lower cost outcomes Metric: Lowest scenario NPVRR	NIPSCO
Environmental Sustainability	Carbon Emissions	- Carbon intensity of portfolio Metric: Cumulative carbon emissions / cumulative generation 2027-46 short tons CO2 per MWh	NIPSCO + GenCo
Reliable and Flexible Supply	Reliability, Flexibility	- The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules Metric: Loss of Load Expectation proxy ("Forced market exposure") metrics for NIPSCO system from probabilistic reliability analysis Metric: MW black start and fast start capability	NIPSCO
Resiliency	Resiliency	Metric: Expected unserved energy across weather years Metric: Unserved energy at the 95th-percentile	NIPSCO
Positive Social and Economic Impacts	Local Investment in Economy and Bill Credits	- The effect on the local economy from new projects and ongoing property taxes and targeted investment Metric: NPV of property taxes from the entire portfolio Data center value provided to customers Metric: Bill Credits passed back to customers	NIPSCO + GenCo

PORTFOLIO ANALYSIS APPROACH

1

Portfolio Concept Development

Define Portfolios

- For **each portfolio concept**, perform optimization analysis to identify long-term resource portfolios
- Include sensitivities on:
 - Resource accreditation
 - Load growth

Eligible Resources

- DSM bundles (EE and DR)
- RFI tranches
- Other new resource options (mid- and long-term)

2

Portfolio Evaluation

Analyze Portfolios

- Evaluate portfolios against 3 market scenarios, which vary:
 - Natural gas price
 - Environmental policy
 - MISO market price
 - NIPSCO Load
- Evaluate portfolios across stochastic distribution of key variables:
 - Commodity prices
 - Wind and solar output
 - NIPSCO Load
 - Unit outages

3

Preferred Portfolio Selection

Populate Scorecard

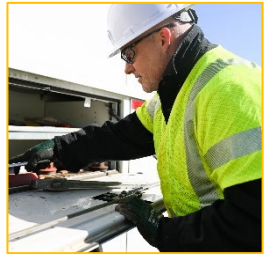
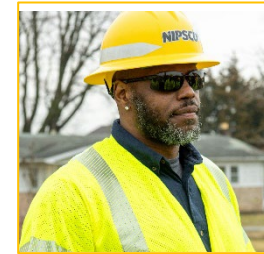
- Summarize data for scorecard
 - Costs
 - Cost risk
 - Carbon emissions
 - Reliability metrics
 - Local economy metrics
- Assess tradeoffs and identify preferred portfolio

2026 STAKEHOLDER ADVISORY MEETING ROADMAP

Meeting	Meeting 1 Sept. 23, 2026	Meeting 2 Oct. 20, 2026	Meeting 3 Jan. 13, 2027
Location	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943
Content	• Resource Planning and 2024 Continuous Improvements • 2026 Public Advisory Process • 2026 Policy Update • Update on Key Inputs/Assumptions (core demand forecast, new considerations for demand) • Emerging Technologies & RFI Results • Scorecard Overview	• Portfolio Input • Existing unit assumption Review • DSM Forecast Update • Scenario Themes • Market Pricing Scenario Analysis Sensitivities • Portfolio Concepts	• Reliability Assessment • Scorecard Results • Preferred Plan & Short-term Action Plan • DSM Planned Next Steps
Meeting Goals	• Communicate what has changed since the 2024 IRP • Communicate environmental policy considerations • Communicate the 2026 public advisory process, timing, and input sought from stakeholders • Common understanding of MISO regulatory updates • Communicate resource needs due to potential demand	• Communicate resource needs due to potential demand • Communicate updates to key inputs/assumptions • Communicate retirement constraints for existing units • Common understanding of DSM modeling methodology • Communicate commodity prices impacts • Communicate preliminary RFI results	• Common understanding of DSM modeling methodology • Communicate the rationale behind the preferred plan selection • Explain next steps for DSM in 2027



APPENDIX



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MISO HAS RECENTLY UPDATED ITS WIND MODELING UNDER D-LOL

In early 2026, MISO reported deficiencies in its wind modeling, noting that the prior approach under-represented extreme low-wind conditions and wind variability more broadly.

- The new approach uses a wind speed-based regression method to build 30-year zonal wind profiles that are meteorologically driven, rather than relying on the prior simplified methodology.

When cross-validated against historic data, new wind profiles match metered wind output more closely than the legacy profiles.

The changing wind profile affected both resource output during risk hours and the risk hours themselves.



Change to Indicative DLOL PY26-27

Season	Base Run DLOL %		New Wind Profile DLOL %		Change	
	Summer	Winter	Summer	Winter	Summer	Winter
Solar	40.00%	2.50%	39.40%	4.00%	-0.60%	+1.50%
Storage	54.70%	74.30%	58.80%	63.10%	+4.10%	-11.20%
Wind	7.30%	24.00%	15.80%	28.30%	+8.50%	+4.30%

Key Takeaway

Under DLOL, changes to a single resource's dispatch can have impacts across all classes – this is largely due to shifting risk hours and resource output.

Regression-based forecasts are backward looking - new technologies like tall wind will fundamentally change wind shapes and will result in future changes to accreditations.

CHANGING LOAD SHAPES MAY IMPACT D-LOL OUTCOMES

MISO Resource Adequacy (RA) Construct

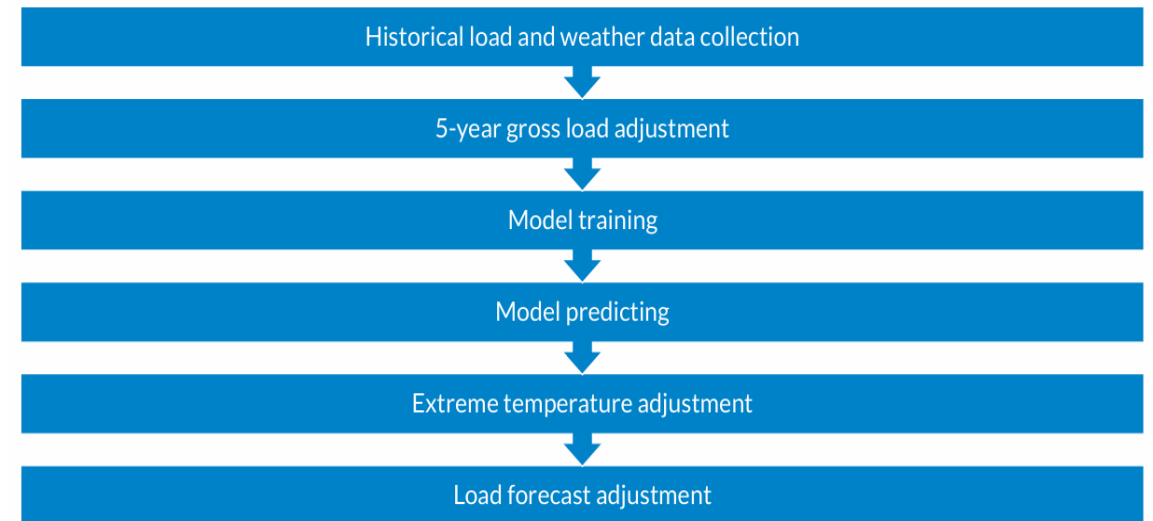
MISO includes the impact of data centers and electric vehicles on the peak load, but it is unclear if they include their impact on load shape.

Current EV charging behavior drives load growth in the evening hours. Data center load drives demand around the clock. Both could place downward pressure on renewable generation accreditation, especially solar.

Key Takeaway

DLOL values are largely assumptions driven– These assumptions may or may not accurately reflect future conditions. If future MISO load shapes vary significantly from historical data used in the DLOL models, accreditation and PRMR outcomes may differ.

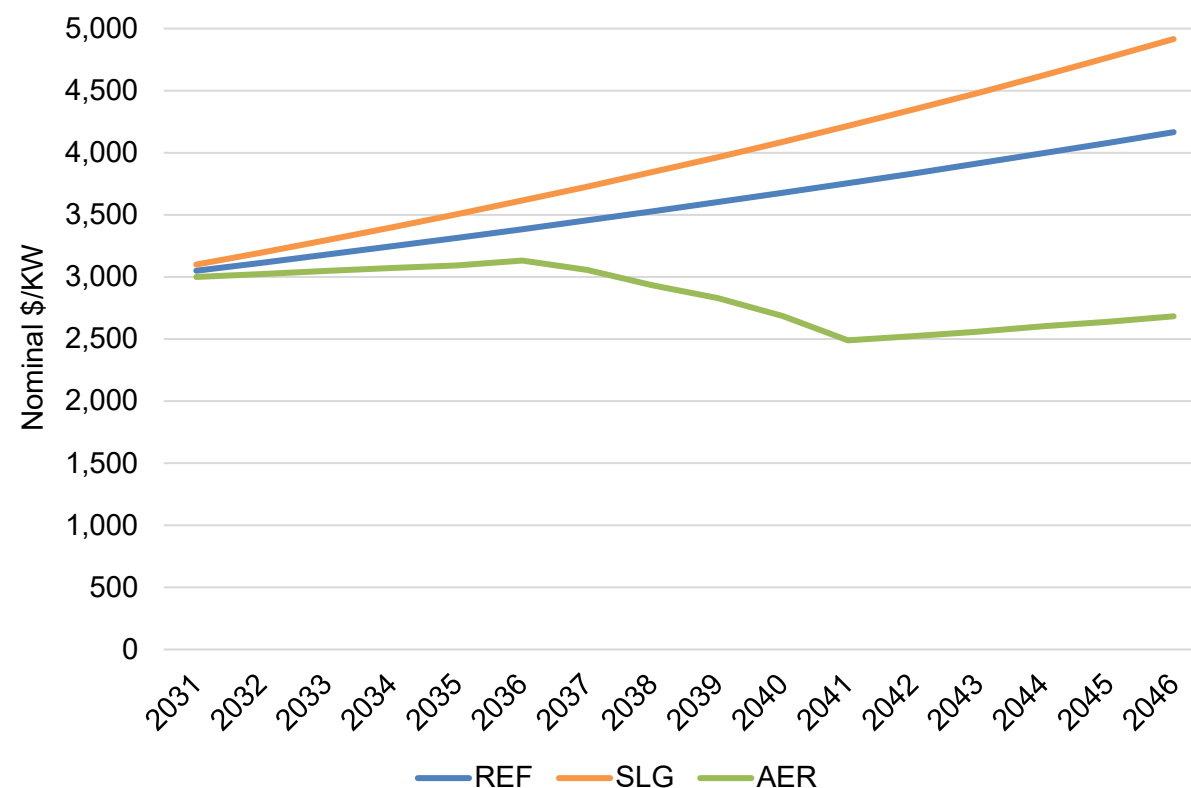
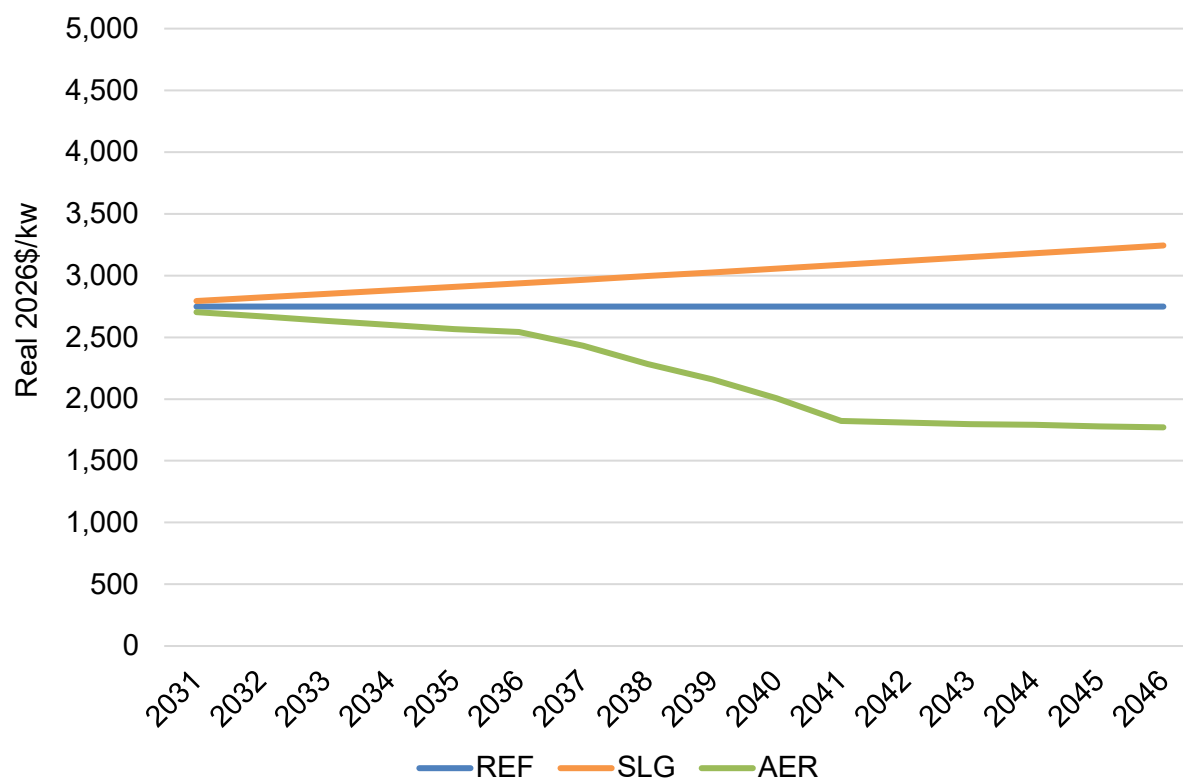
MISO's Load Shaping Process





GAS COMBINED CYCLE CAPITAL COST CHANGES ACROSS SCENARIOS

- The **SLG** scenario assumes higher demand for natural gas turbines and continued real escalation in costs relative to the Reference Case.
- The **AER** scenario assumes material reduction in gas turbine demand after the implementation of federal carbon pressure, dropping real costs by the 2040s to levels witnessed a few years ago.

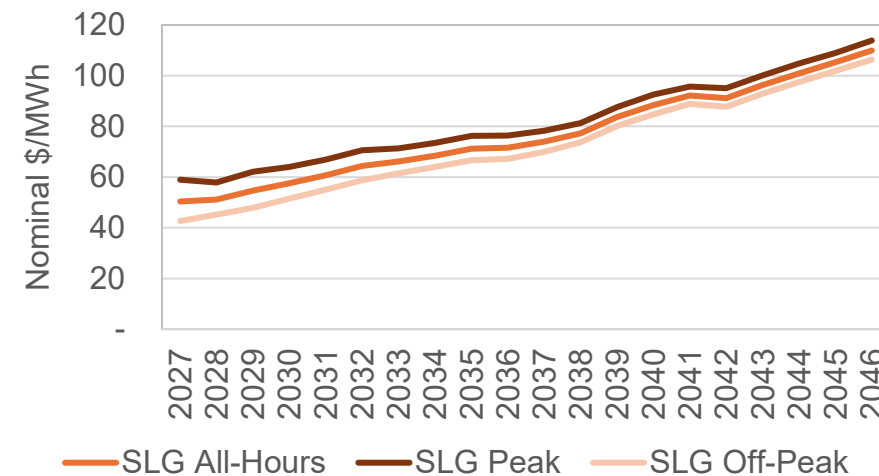




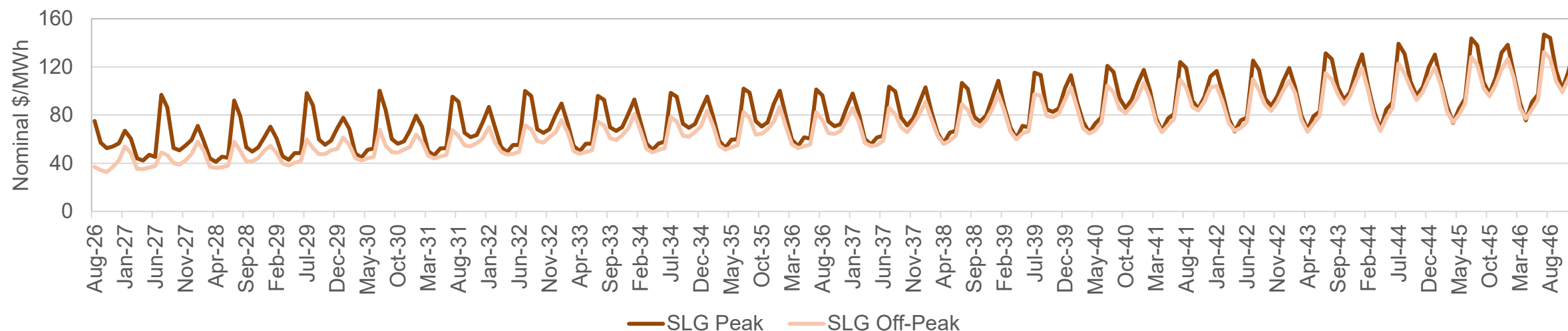
SUSTAINED LOAD GROWTH – MISO ZONE 6 POWER PRICE PROJECTIONS

- Higher projected scarcity in the near-term is expected, particularly in the summer months (close to \$100/MWh nominal \$), driven by faster load growth and tighter regional reserve margins.
- Long-term prices are expected to grow in nominal \$ (towards \$110/MWh by 2046), driven by rising natural gas prices and sustained load growth.

Annual Zone 6 Power Prices



Monthly Zone 6 Power Prices

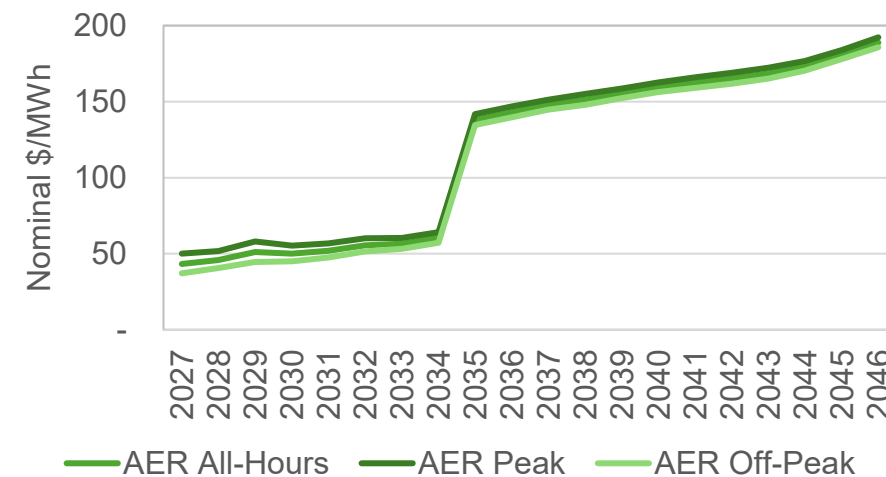




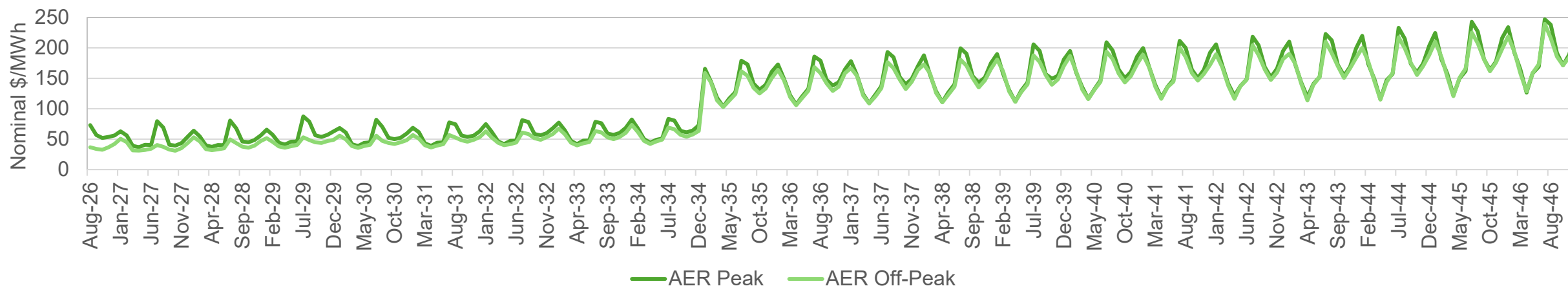
AGGRESSIVE ENVIRONMENTAL REGULATION – MISO ZONE 6 POWER PRICE PROJECTIONS

- Prices are projected to be relatively flat in real \$ for the next 8 years prior to the implementation of the carbon price, at levels that are slightly lower than those in the Reference Case because of more low variable cost resource additions.
- In 2035, power prices are projected to increase significantly in line with the carbon price, holding relatively flat thereafter as a result of growing low variable cost generation offsetting the increases in carbon prices and natural gas prices.

Annual Zone 6 Power Prices



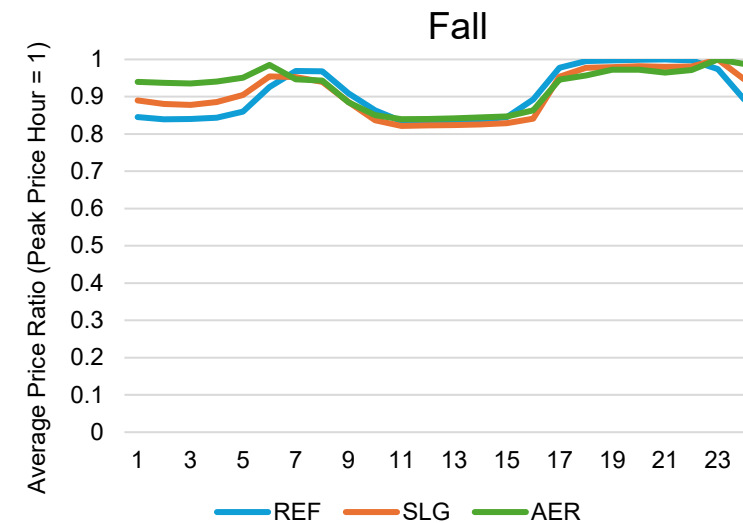
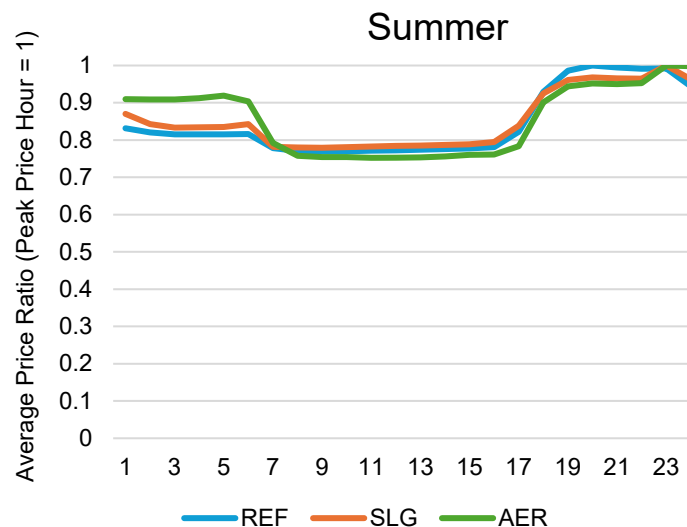
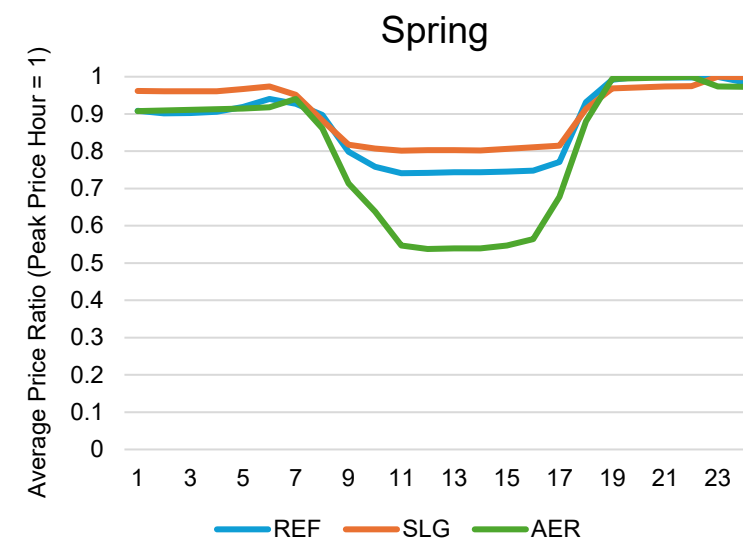
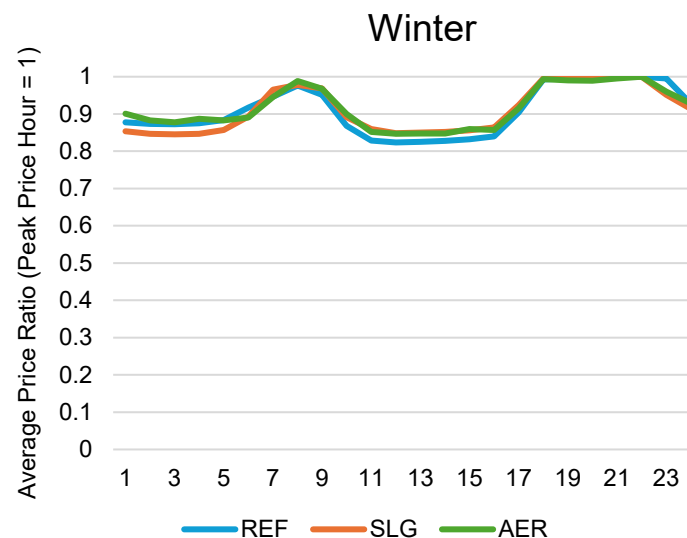
Monthly Zone 6 Power Prices





MISO ZONE 6 HOURLY SHAPES (2046)

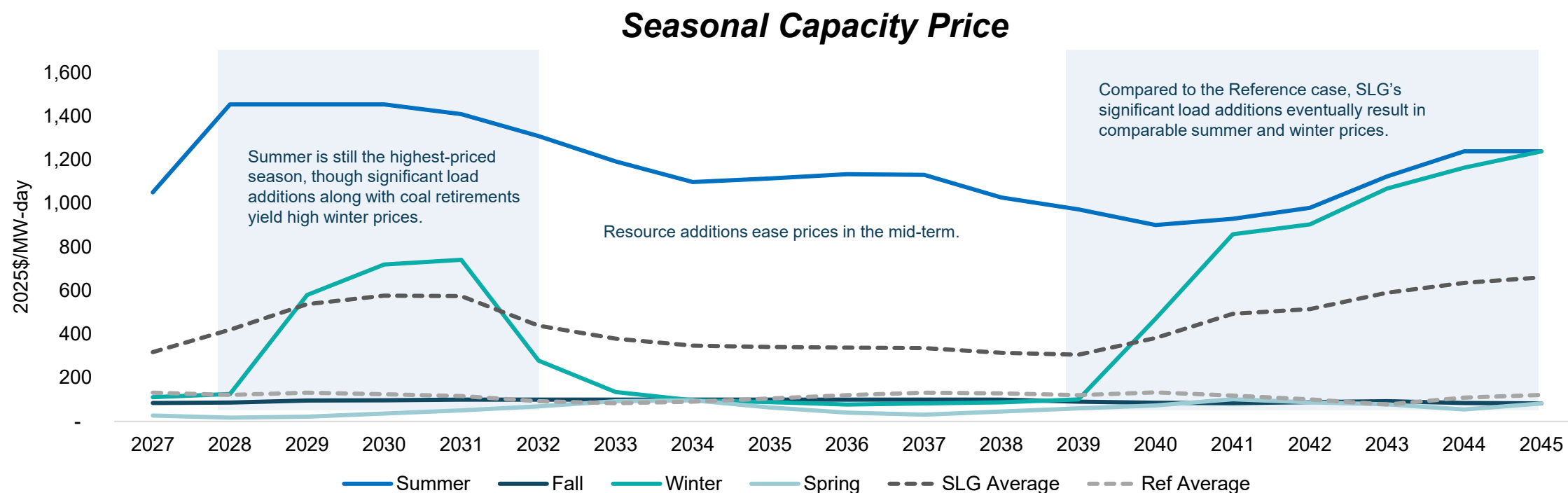
- Over the long-term, hourly price shapes are likely to shift, with mid-day solar hours having the lowest pricing throughout the year.
- Spring months with low load and high solar output tend to have the largest price spreads, particularly under the AER scenario.
- Summer price peaks are expected to be between 8-11pm.
- Early morning hours are likely to exhibit relatively high pricing across the year.





SUSTAINED LOAD GROWTH (SLG) MISO NORTH CAPACITY PRICE OUTLOOK

- Sustained load growth drives low near-term reserve margins, resulting in summer prices projected to reach the systemwide price cap of \$1,400/MW-day.
- Additions in the 2030s are projected to ease prices in the mid-term, reflecting expectations that utilities build to serve growing load.
- Over the long term, **risks in the winter season due to 24x7 load growth** drive projected winter prices higher, particularly as reserve margins remain tight.

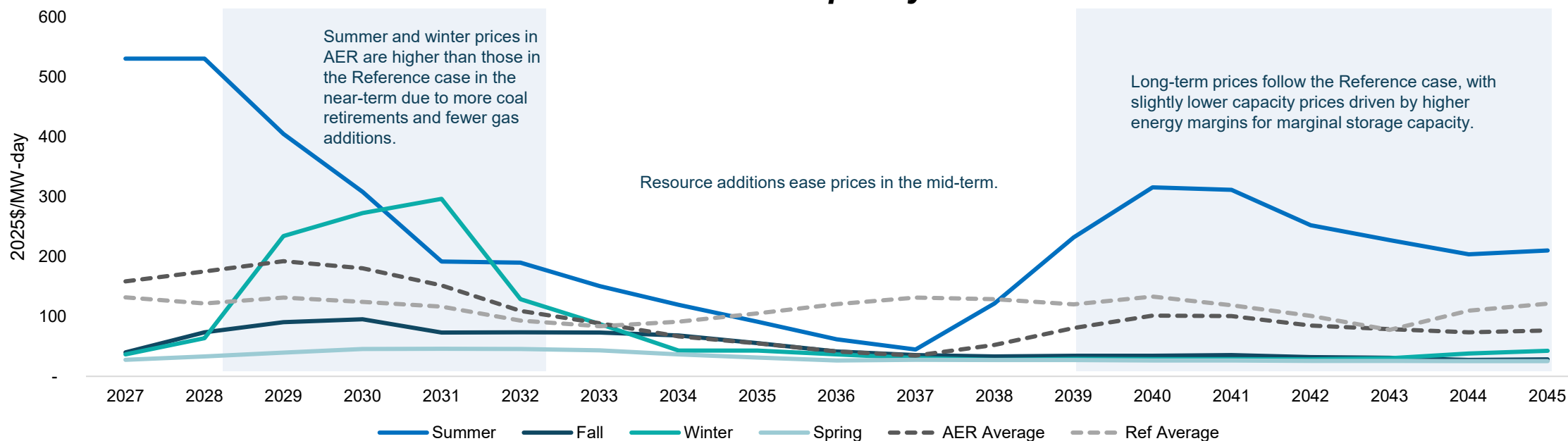




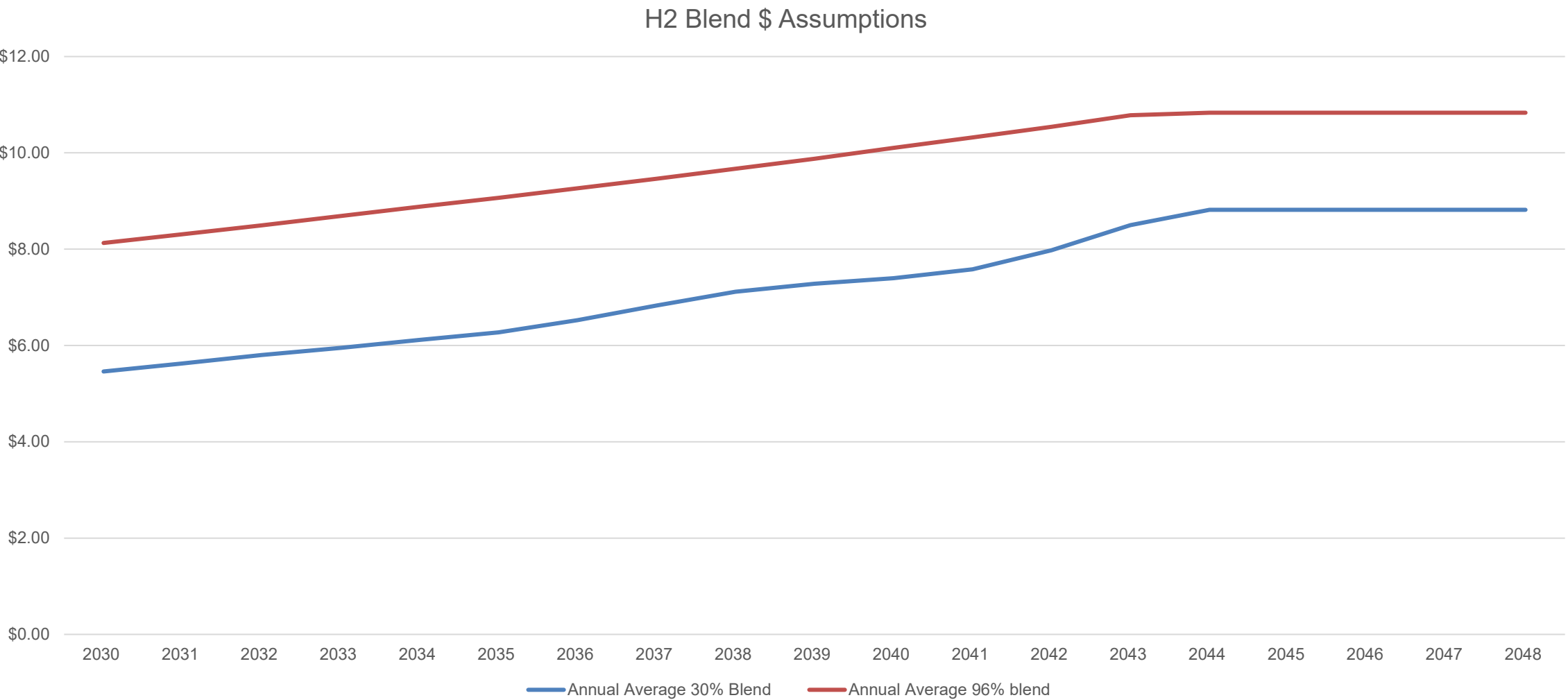
AGGRESSIVE ENVIRONMENTAL REGULATION (AER) MISO NORTH CAPACITY PRICE OUTLOOK

- Near-term AER capacity prices are projected to be higher on average than those in the Reference Case, due to accelerated coal retirements and fewer natural gas additions, reducing the amount of accredited thermal capacity in MISO North.
- The regional portfolio is projected to add significant new capacity through the mid-2030s, lowering capacity price outcomes.
- Reserve margins are generally aligned with those in the Reference Case in the later years, although the high carbon price drives increased energy margins for marginal capacity resources (particularly storage), resulting in lower capacity clearing prices.

Seasonal Capacity Price



HYDROGEN PRICE ASSUMPTIONS (2030-2048)



Same forecast as utilized in 2024 NIPSCO Integrated Resource Plan

CARBON CAPTURE UTILIZATION & SEQUESTRATION (CCUS) – RETROFIT COST AND OPERATIONAL ASSUMPTIONS

Characteristics	Units	CCUS Retrofit Cost
Net Capacity to Grid (Winter)	ICAP MW ²	585
Net Capacity to Grid (Summer)	ICAP MW ²	585
Heat Rate (Winter)	Btu/kWh ³	7,662
Heat Rate (Summer)	Btu/kWh ³	7,672
Installed Capital Cost ¹	2024\$/kW ⁴	\$1,860
Variable Operations and Maintenance Cost	2024\$/kW ⁴	\$3.34
Fixed Operations and Maintenance Cost	2024\$/kW-yr ⁵	\$46.99
CO2 Transportation Cost	2022\$/ton	\$7.50
CO2 Sequestration Cost	2022\$/ton	\$4.86
CO2 Emissions Rate	lbs/MMBtu ⁶	11.9

Notes

1. For retrofit of an existing combined cycle plant
2. Megawatts
3. British Thermal Units per Kilowatt-hour
4. Kilowatt
5. Kilowatt-year
6. Pounds per Millions British Thermal Units

Same forecast as utilized in 2024 NIPSCO Integrated Resource Plan