2021 NIPSCO Integrated Resource Plan

Second Stakeholder Advisory Meeting

May 20, 2021
9:00AM-2:00PM CT








SAFETY MOMENT: MAY IS STROKE AWARENESS MONTH

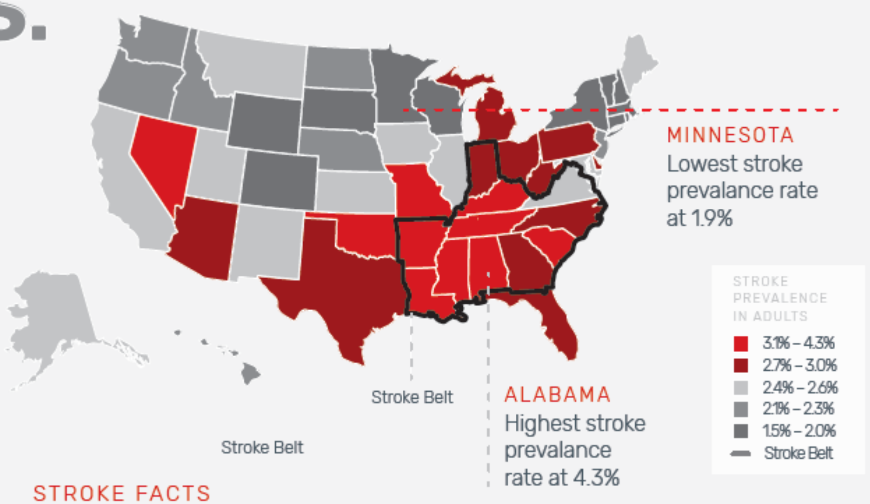
Genentech
A Member of the Roche Group

Stroke Demographics in the U.S.

Every year, close to **800,000 AMERICANS** have a stroke.

Even during a pandemic, a stroke can happen to **ANYONE**, of **ANY AGE**, at **ANY TIME**.

Learn the **STROKE SYMPTOMS** and **RISK FACTORS**.



STROKE FACTS

You can control and treat several risk factors for stroke.

Manageable risk factors of stroke include high blood pressure, atrial fibrillation (AFib), high cholesterol, smoking, diabetes, poor circulation, lack of physical activity, and obesity.

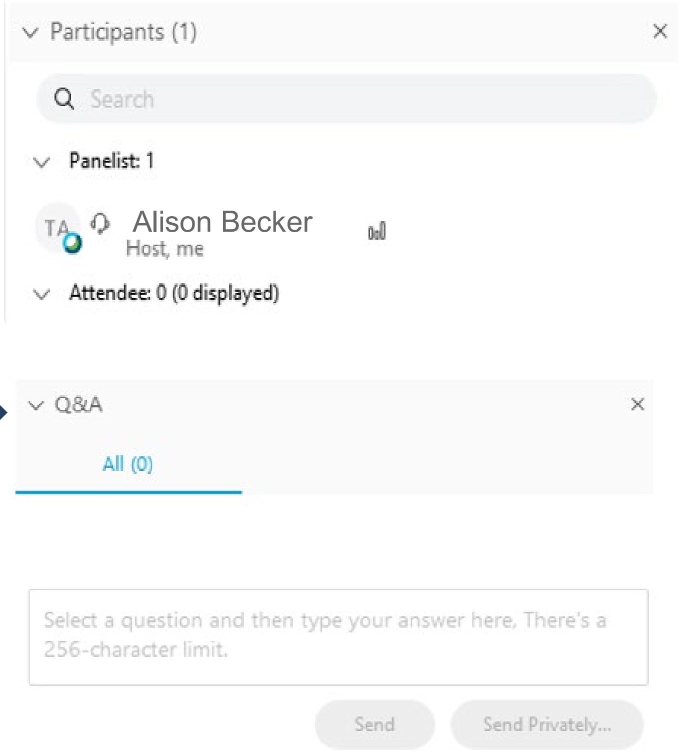
BE FAST when you suspect a stroke. Recognizing the signs and calling 911 can help a loved one get the medical attention he or she needs.

IF YOU SUSPECT STROKE, DON'T HESITATE, CALL 911 IMMEDIATELY.

STROKE CARE IS AVAILABLE AND SHOULD NOT BE DELAYED, EVEN DURING A HEALTH CRISIS. LEARN MORE AT **STROKEAWARENESS.COM**

STAKEHOLDER ADVISORY MEETING PROTOCOLS

- Your input and feedback is 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:
  - Please ask questions and make comments on the content presented
  - Please provide feedback on the process itself
- While we will mostly utilize the chat feature in WebEx to facilitate comments, we will gladly unmute you if you would like to speak. 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 Alison Becker (abecker@nisource.com)



AGENDA

Time *Central Time	Topic	Speaker
9:00-9:10AM	Webinar Introduction & Safety Moment Welcome & Stakeholder Advisory Roadmap	Alison Becker, Manager Regulatory Policy, NIPSCO Erin Whitehead, Vice President Regulatory & Major Accounts, NIPSCO
9:10-9:45AM	NIPSCO's Public Advisory Process and Updates From Last Meeting	Fred Gomos, Director Strategy & Risk Integration, NiSource Pat Augustine, Vice President, CRA
9:45-10:15AM	MISO Market Initiatives Update	Pat Augustine, Vice President, CRA
10:15-10:30AM	Break	
10:30-11:00AM	Environmental Considerations in 2021	Maureen Turman, Director Environmental Policy & Sustainability, NiSource
11:00-11:45AM	Lunch	
11:45AM-1:00PM	Modeling Uncertainty: Scenarios and Stochastic Analysis for 2021 IRP	Pat Augustine, Vice President, CRA Robert Kaineg, Principal, CRA Goran Vojvodic, Principal, CRA
1:00-1:15PM	Break	
1:15-1:45PM	2021 Request for Proposal Update	Andy Campbell, Director Regulatory Support & Planning, NIPSCO Bob Lee, Vice President, CRA
1:45-2:00PM	Wrap Up and Next Steps	Mike Hooper, President & COO, NIPSCO

2021 STAKEHOLDER ADVISORY MEETING ROADMAP

Meeting	Meeting 1 (March)	Meeting 2 (May)	Meeting 3 (July)	Meeting 4 (September)	Meeting 5 (October)
Date	3/19/2021	5/20/2021	7/13/2021	9/21/2021	10/12/2021
Location	Virtual	Virtual	Virtual	Virtual	Virtual
Key Questions	• How has NIPSCO progressed in the 2018 Short Term Action Plan? • What has changed since the 2018 IRP? • How are energy and demand expected change over time? • What is the high level plan for stakeholder communication and feedback for the 2021 IRP?	• How do regulatory developments and initiatives at the MISO level impact NIPSCO's 2021 IRP planning framework? • How has environmental policy changed since 2018? • What scenario themes and stochastics will NIPSCO explore in 2021?	• How are DSM resources considered in the IRP? • What are the preliminary RFP results?	• What are the preliminary findings from the modeling?	• What is NIPSCO's preferred plan? • What is the short term action plan?
Content	• 2018 Short Term Action Plan Update (Retirements, Replacement projects) • Resource Planning and 2021 Continuous Improvements • Update on Key Inputs/Assumptions (commodity prices, demand forecast) • Scenario Themes – Introduction • 2021 Public Advisory Process	• MISO Regulatory Developments and Initiatives • 2021 Environmental Policy Update • Scenarios and Stochastic Analysis	• DSM Modeling and Methodology • Preliminary RFP Results	• Existing Fleet Review Modeling Results, Scorecard • Replacement Modeling Results, Scorecard	• Preferred replacement path and logic relative to alternatives • 2021 NIPSCO Short Term Action Plan
Meeting Goals	• Communicate what has changed since the 2018 IRP • Communicate NIPSCO's focus on reliability • Communicate updates to key inputs/assumptions • Communicate the 2021 public advisory process, timing, and input sought from stakeholders	• Common understanding of MISO regulatory updates • Communicate environmental policy considerations • Communicate scenario themes and stochastic analysis approach, along with major input details and assumptions	• Common understanding of DSM modeling methodology • Communicate preliminary RFP results	• Communicate the Existing Fleet Review Portfolios and the Replacement Portfolios • Stakeholder feedback and shared understanding of the modeling and preliminary results. • Review stakeholder modeling and analysis requests	• Communicate NIPSCO's preferred resource plan and short term action plan • Obtain feedback from stakeholders on preferred plan

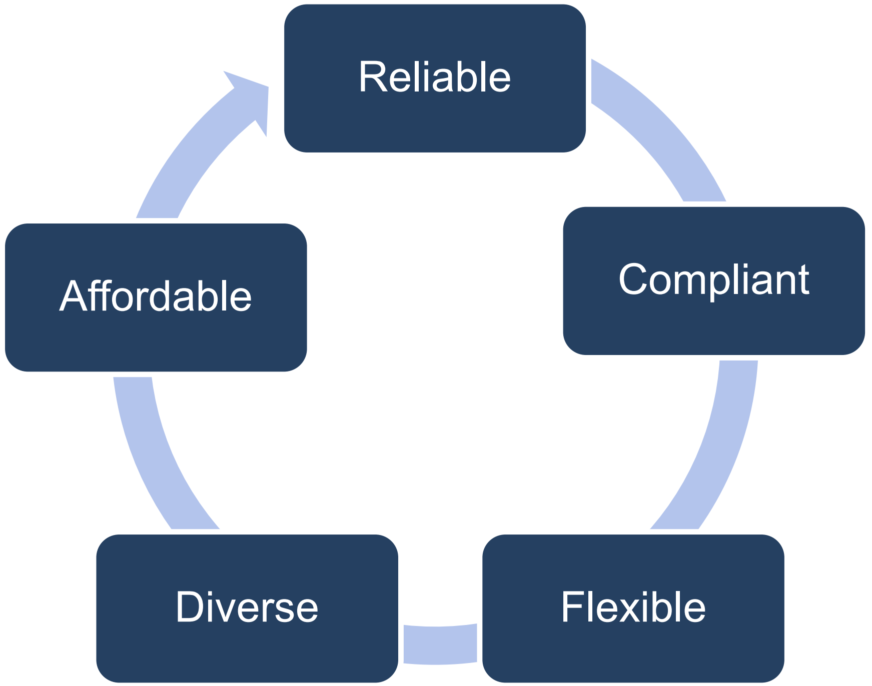
NIPSCO'S PUBLIC ADVISORY PROCESS UPDATES FROM LAST MEETING

Fred Gomos, Director Strategy & Risk Integration, NiSource

Pat Augustine, Vice President, CRA

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 IRP – is required of all electric utilities in Indiana
- The IRP process includes extensive analysis of a range of generation scenarios, with criteria such as reliable, affordable, compliant, diverse and flexible



Requires Careful Planning and Consideration for:
- NIPSCO's employees
- Environmental regulations
- Changes in the local economy (property tax, supplier spending, employee base)

STAKEHOLDER FEEDBACK SINCE MEETING #1

Theme	Stakeholders	Questions / Comments	NIPSCO Responses
Diversity, Equity & Inclusion	Citizens Action Coalition (CAC)	1. Recommend addition of diversity, equity, and inclusion (DEI) metric	1. NIPSCO welcomes interested stakeholders to engage in a one on one discussion to understand perspectives regarding DEI metrics or measures 2. NIPSCO has incorporated feedback provided in the 2018 IRP process to subsequent RFPs, including the 2021 RFP – **See the RFP section**
Cost Accounting and Revenue Requirement Modeling	CAC Reliable Energy	1. Is NIPSCO's cost methodology representing revenue requirements? 2. NIPSCO should consider reporting shorter-term Net Present Value of Revenue Requirements (NPVRRs) and not just 30-year	1. As in the 2018 IRP, NIPSCO/CRA will be deploying a financial model (PERFORM) to calculate full annual revenue requirements – **See Appendix for Slide 17 from Stakeholder Meeting #1**. While Aurora is used for capacity optimization, the full portfolio analysis includes Aurora-based dispatch and PERFORM-based revenue requirement accounting. 2. NIPSCO will produce annual revenue requirements as part of the IRP process, although the primary scorecard metric is a long-term NPVRR.
Scorecard Metrics	CAC Reliable Energy	1. The Rate Stability metrics are premised exclusively on stochastic analysis and should also consider scenario outcomes 2. The operational flexibility metric should be absorbed into economic analysis 3. The CO_2 emissions metric should not focus just on the single year of 2030	1. NIPSCO's Rate Stability metrics are not solely based on stochastic analysis. NIPSCO is planning to include scenario ranges and high and low scenario outcomes in its rate stability metric, as presented in the indicative scorecard – **See Appendix for Slide 19 from Stakeholder Meeting #1** 2. NIPSCO believes that the MISO market transition and its planned retirements of local thermal resources could require resources with high levels of dispatchability and flexibility, and such attributes are not always able to be quantified economically under current market structures. As discussed in Stakeholder Meeting #1, this metric is intended to capture one portfolio attribute and facilitate tradeoff analysis. It is just one metric of many on NIPSCO's scorecard. 3. NIPSCO will produce annual reports for emissions and will change the scorecard metric to present cumulative CO_2 emissions over the 20-year fundamental modeling period

This is a non-exhaustive list of stakeholder questions/comments received during Meeting #1 and thereafter. NIPSCO has summarized and consolidated certain comments to facilitate review and further discussion.

STAKEHOLDER FEEDBACK SINCE MEETING #1 CONTINUED

Theme	Stakeholders	Questions / Comments	NIPSCO Responses
Load Forecast (including EVs and DERs)	CAC Reliable Energy Office of Utility Consumer Counselor (OUCC) Indiana Distributed Energy Alliance (IndianaDG)	1. Load forecast should incorporate impacts of appliance standards and other natural DSM/EE 2. Consider Electric Vehicle (EV) charging patterns and dynamic pricing impacts 3. Distributed Energy Resources (DER) capacity credit could be impacted by customer behavior, including storage additions, and should account for MISO's latest view on Effective Load Carrying Capability Credit (ELCC) credit 4. Industrial load risk should be incorporated	1. NIPSCO's load forecast deploys an econometric approach, and NIPSCO, CRA, and GDS (DSM consultant) have reviewed load forecasting approaches to confirm that the IRP load forecast appropriately accounts for DSM. The 2021 IRP load forecast has declining usage per customer trends in the future (even prior to DSM program implementation) 2. NIPSCO will not be assessing price responsive EV charging in this IRP in detail, but has made adjustments to shapes in response to feedback – **See Slides 10-12** 3. NIPSCO is basing ELCC projections on MISO's latest view and has incorporated stakehold feedback to increase long-term capacity credit – **See Slides 13-14** 4. NIPSCO agrees - **See Slide 91 from Stakeholder Meeting #1**. More detail will be provided today
Uncertainty Analysis	CAC Reliable Energy	1. Stochastic analysis is over-emphasized and should be used only for select variables 2. ELCC ranges should be based on MISO's latest RIIA Summary report from February 3. Carbon regulation should not be exclusively modeled with a price 4. The natural gas forecast does not adequately address certain cost concerns	1. NIPSCO's 2021 IRP will deploy both scenario and stochastic analysis, the inputs of which will be reviewed in detail today; NIPSCO focuses its stochastic analysis on variables that can be appropriately evaluated in such a fashion (commodity prices, renewable output) 2. NIPSCO agrees and has been relying on MISO's latest ELCC studies from this report. 3. NIPSCO agrees and has constructed an alternative scenario based on a Clean Energy Standard without a carbon price - **See Slide 89 from Stakeholder Meeting #1**. Additional detail will be provided today 4. CRA's fundamental analysis is based on an integrated view of major costs and supply-demand drivers - **See Commodity Price Update section from Stakeholder Meeting #1**. Additional scenario detail will be presented today

Discussed Further

This is a non-exhaustive list of stakeholder questions/comments received during Meeting #1 and thereafter. NIPSCO has summarized and consolidated certain comments to facilitate review and further discussion.

RESPONSES TO STAKEHOLDER QUESTIONS / COMMENTS – EVs

Stakeholder Question/Comment: Could price responsive EV load affect charging shapes?

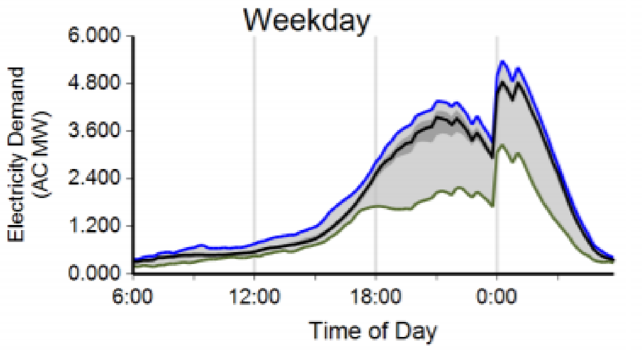
NIPSCO Response: The proposed shapes are largely consistent with the findings of the Department of Energy (DOE) study shared by stakeholders and remain appropriate. However, a shift of charging load to later overnight hours would help incorporate changing market price expectations over time

DOE Report Finding	Implications for NIPSCO 2021 IRP
Residential Level 2 home charging reflects predominant charging during night time hours	In *Low Penetration* scenarios, the IRP assumes charging predominantly at home at night: NIPSCO's Time of Use data is consistent with this finding
Public Level 2 captures charging that may occur at workplaces, parking spots, etc. and shows charging mostly during the morning/mid-day	In *High Penetration* scenarios, charging is mostly at home, but use of public facilities means more charging during morning and peak hours: NIPSCO has already been using DOE study data for its shape
No noticeable seasonality in historical data, but enabling technology could incentivize charging to lowest priced hours	NIPSCO will shift charging load to later overnight hours

RESPONSES TO STAKEHOLDER QUESTIONS / COMMENTS – EVs

DOE EV Project Study (2013)

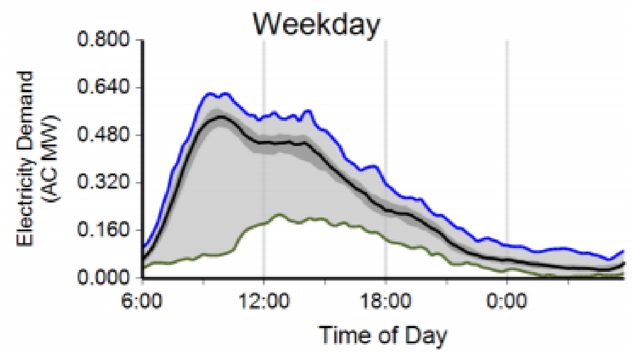
Residential Level 2



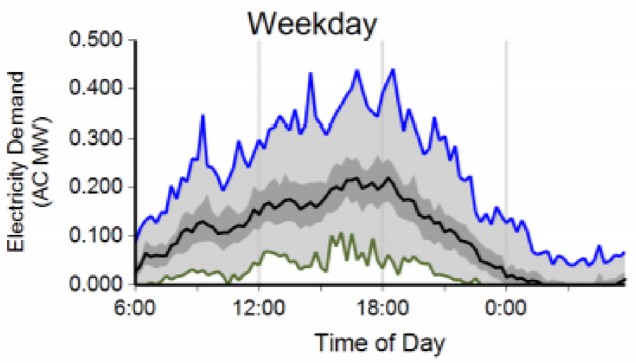
Residential shape generally conforms with NIPSCO's Time of Use Charging Shapes

Higher penetration EV scenarios suggest incorporating public (L2 and fast charging) on top of residential charging. Residential use is still primary charging pattern.

Public Level 2



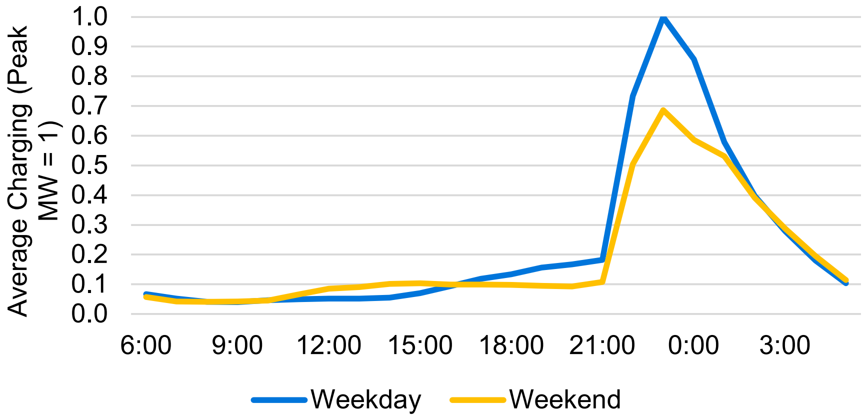
DC Fast Charger



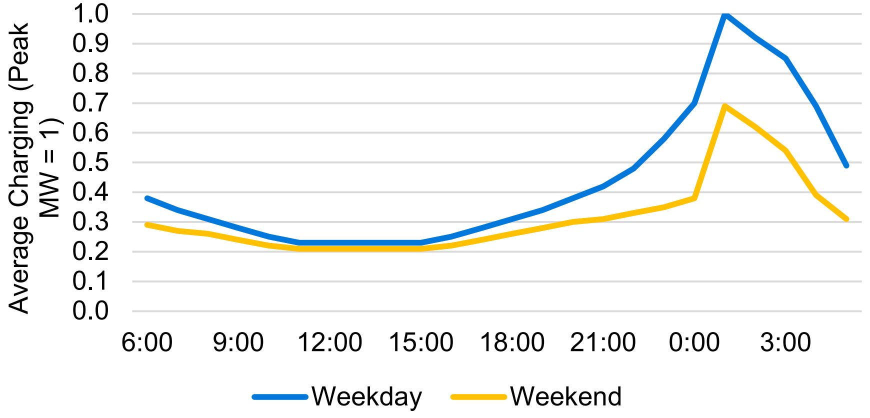
https://www.energy.gov/sites/default/files/2014/02/f8/evproj_infrastructure_q22013_0.pdf

Charging Shapes Provided in Workshop #1

Residential EV Charging Profile – Low Penetration[1] (NIPSCO Time of Use Program)



Residential EV Charging Profile – High Penetration[2] (DOE EV Project Study)

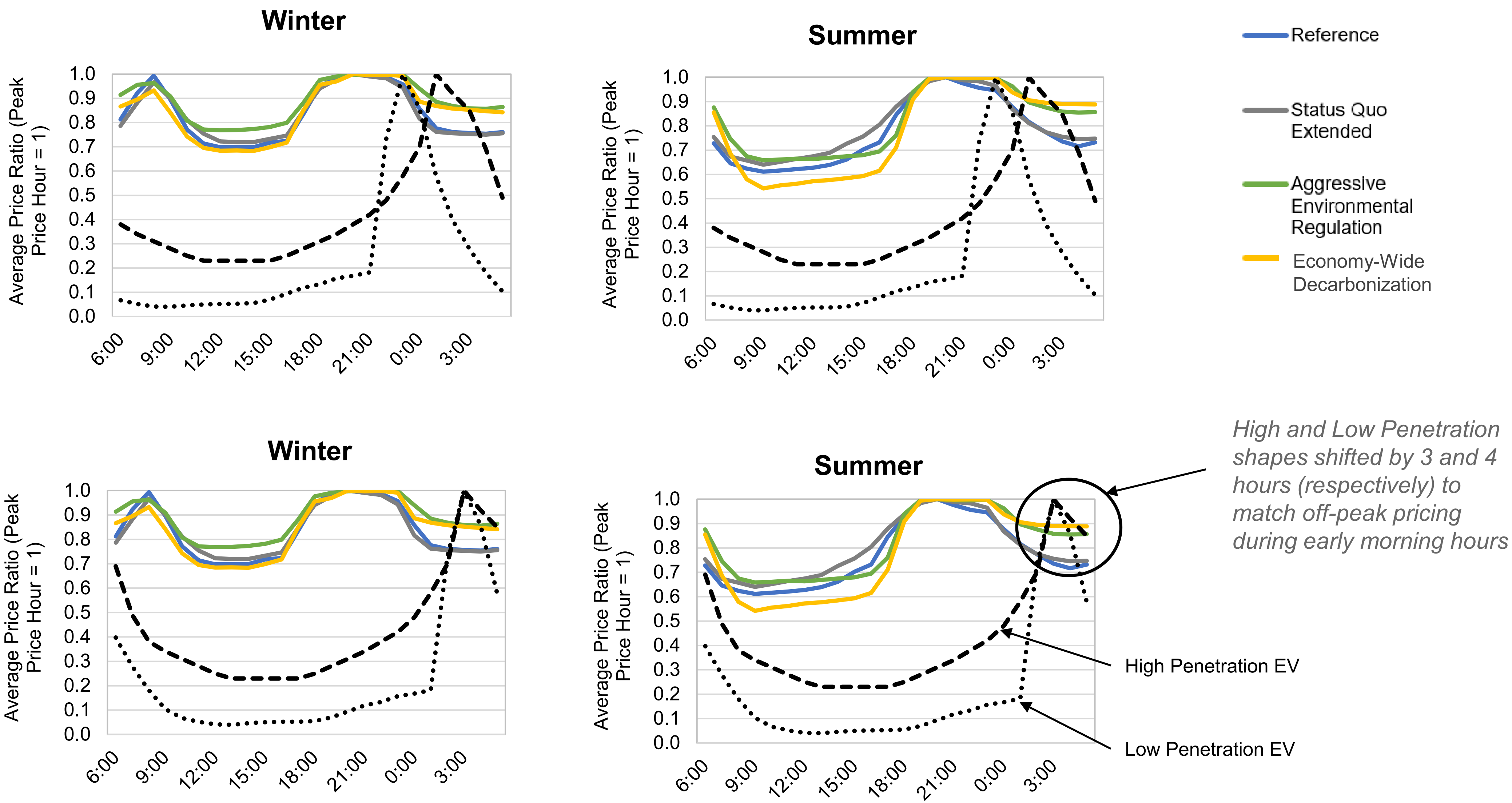


Sources
1. NIPSCO EV Pilot Program 2018 Charging Data
2. Based on DOE (2014) - https://www.energy.gov/sites/prod/files/2014/02/f8/evs26_charging_demand_manuscript.pdf
3. Based on NREL (2016) - https://www.nrel.gov/docs/fy17osti/66382.pdf

UPDATED EV CHARGING SHAPES VS. HOURLY SCENARIO POWER PRICES (2040)

Stakeholder Workshop #1

Revision for Long-Term based on Feedback (new)



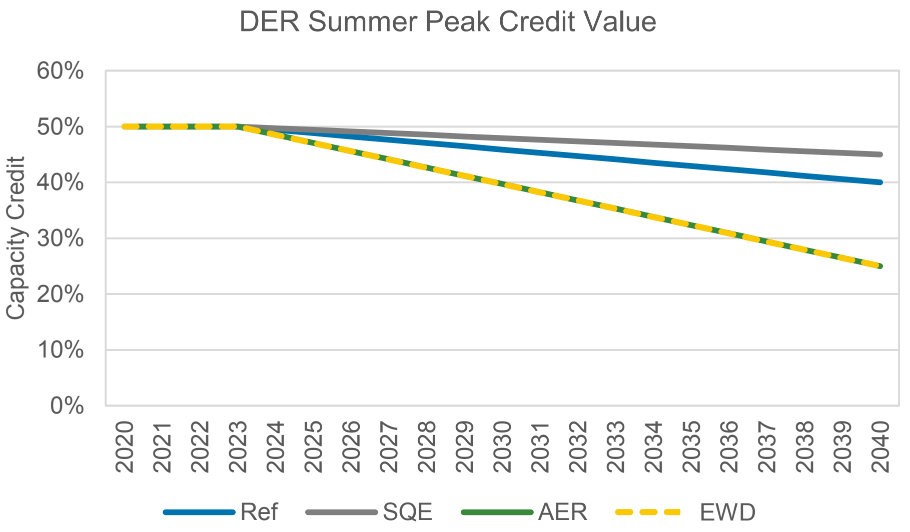
RESPONSES TO STAKEHOLDER QUESTIONS / COMMENTS – DER

Stakeholder Question/Comment: How are solar plus storage configurations or west-facing solar panels being taken into account?

NIPSCO Response: Initial DER modeling did not account for behavioral change that could maximize DER resource capacity credit, but will consider explicit integration of DER storage based on stakeholder comments.

– By storing solar energy during the day and discharging energy during peak hours, distributed storage shaves peak demand and increases effective capacity contribution.

– PenDER evaluates the adoption of DER by agents and is not set up to optimize the solar and storage pairing ratio, but assumptions regarding storage penetration can be made, especially under higher DER penetration scenarios.

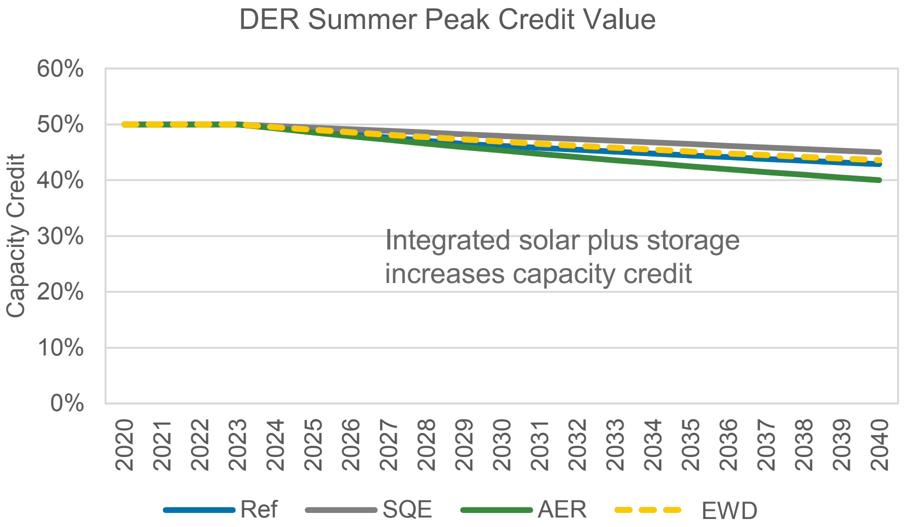


Based on: MISO RIIA Summary Report, Figure RA-18 for Distributed PV
https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

Assume greater behavioral change or integration of DER storage in scenarios with stronger policy incentives for clean energy.

Percentage of solar capacity "backed-up" by storage by 2040:

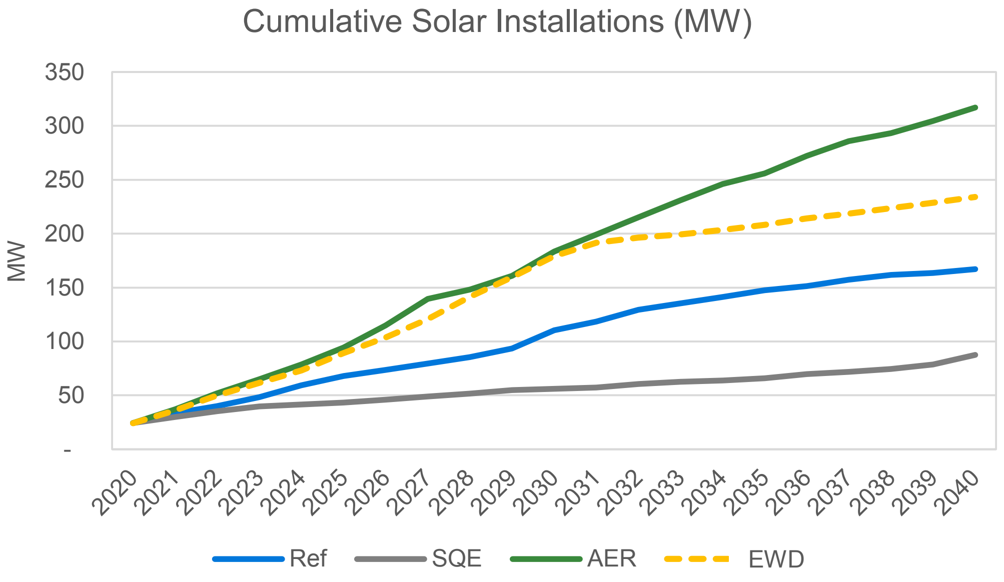
- Ref: 5%
- AER: 25%
- EWD: 33%

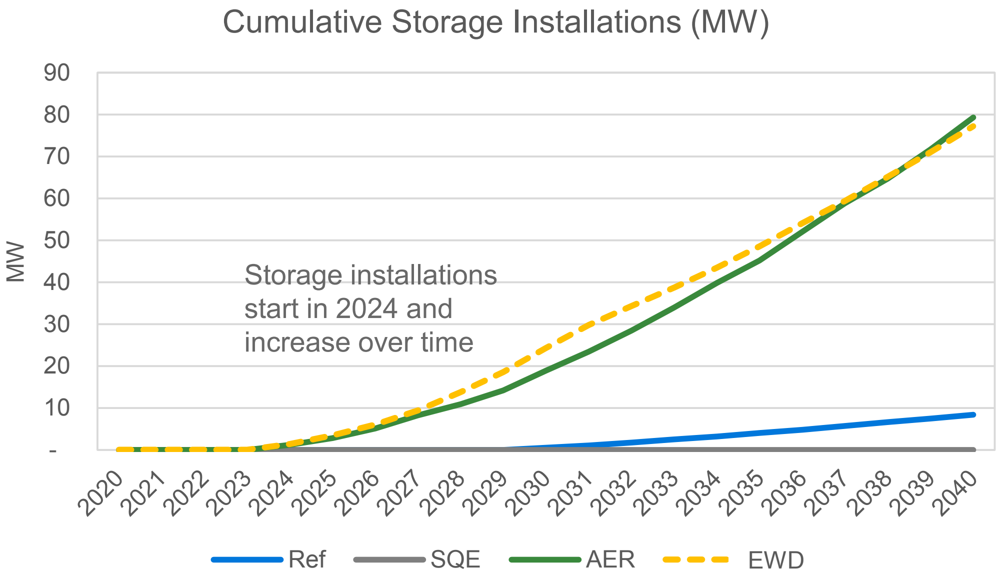


Ref = Reference; SQE = Status Quo Extended; AER = Aggressive Environmental Regulation; EWD = Economy-Wide Decarbonization

CUSTOMER-OWNED DER – UPDATED SCENARIO RANGES

Load scenario details (addressed later in scenario section of this presentation) include more information on the impacts to both summer and winter peak based on stakeholder feedback and comments from last meeting





Ref = Reference; SQE = Status Quo Extended; AER = Aggressive Environmental Regulation; EWD = Economy-Wide Decarbonization

MISO MARKET INITIATIVES UPDATE

Pat Augustine, Vice President, CRA

CONSIDERATIONS FOR LONG-TERM PLANNING WITH INTERMITTENT RESOURCES

Context

- The ongoing energy transition is transforming the way that resource planners need to think about reliability, and a power market with more intermittent resources will require ongoing enhancements to modeling approaches and new performance metrics for portfolio evaluation
- As a member of MISO, NIPSCO is not independently responsible for all elements of reliability, but must be prepared to meet changing market rules and standards

2021 IRP Approach

1 Ensure consistency with MISO rules evolution

- Seasonal resource adequacy
- Future effective load carrying capability (ELCC) accounting

2 Expand Uncertainty Analysis

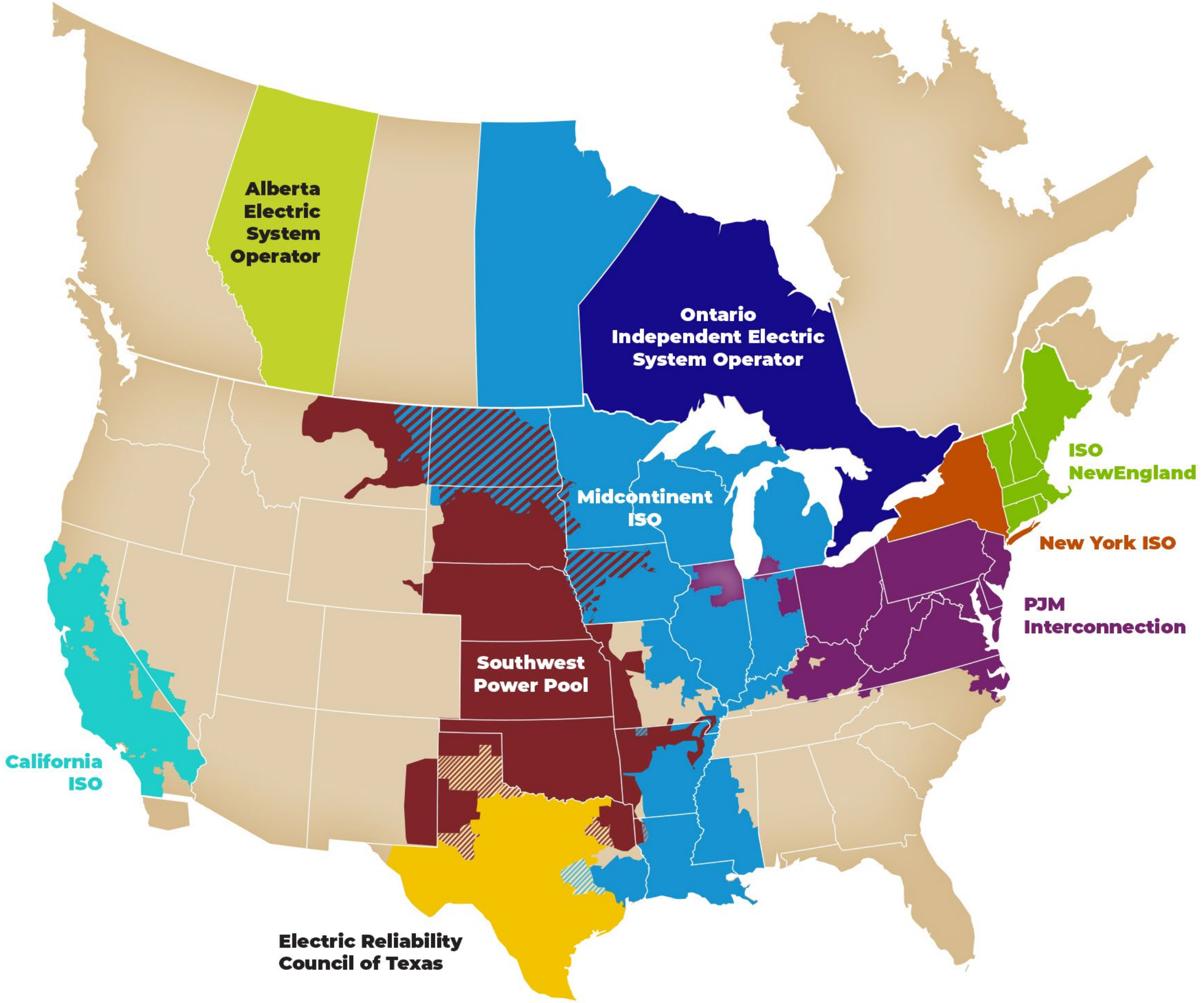
- Incorporation of renewable output uncertainty
- Broadening risk analysis to incorporate granular views of tail risk

3 Incorporate New Metrics

- Incorporating new scorecard metrics informed by stochastic analysis and capabilities of portfolio resources

ROLE OF THE INDEPENDENT SYSTEM OPERATOR (ISO)

- **Regional Transmission Organizations (RTOs)** or **Independent System Operators (ISOs)** are independent, nonprofit organizations that optimize the operation and planning of the transmission systems of their region
- ISOs have the responsibility for ensuring the reliability of the high-voltage electric transmission system to deliver low-cost energy
- ISOs are required to comply with Federal Energy Regulatory Commission (FERC) Orders and North American Electric Reliability Corporation (NERC) Reliability Standards

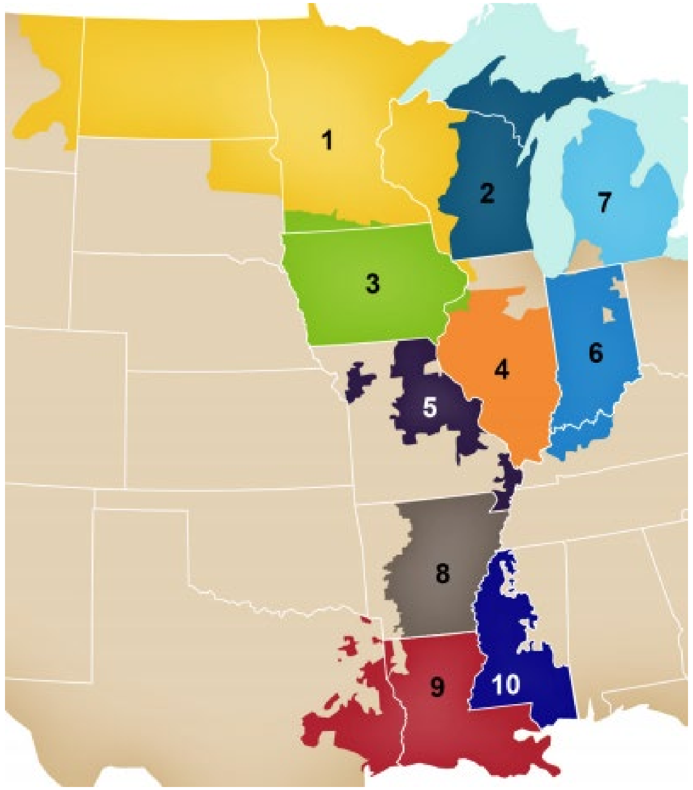


Key Functions of the ISO
• Operational authority to control transmission facilities and coordinate security for its regions to ensure reliability
• Responsible for dispatch of lowest cost generation units, ensuring the most cost-effective generation meets load

MISO VS. NIPSCO FUNCTIONS AND ROLES

NIPSCO service territory and resources fall within the Midcontinent Independent System Operator (MISO) region and are located within Local Resource Zone 6 (LRZ6), covering Indiana and northern Kentucky.

Category	MISO's Role	NIPSCO's Role
Markets	Oversees markets for energy, capacity (resource adequacy), ancillary services, and transmission rights	Offers resources into markets and receives revenue; procures services from markets and pays on behalf of load
Resource Adequacy	Coordinates with utilities, states, and federal entities (FERC and NERC) to ensure the reliable operation of the bulk power transmission system by establishing rules and standards	Obligated to meet MISO rules and standards as a market participant, in coordination with the IURC
Daily Operations	Maintains load-interchange-generation balance every hour; operates or directs the operation of transmission facilities	Participates in the market in accordance with requirements and follows MISO signals and instructions; does NOT balance own supply and demand



REGULATORY EVOLUTION SINCE 2018

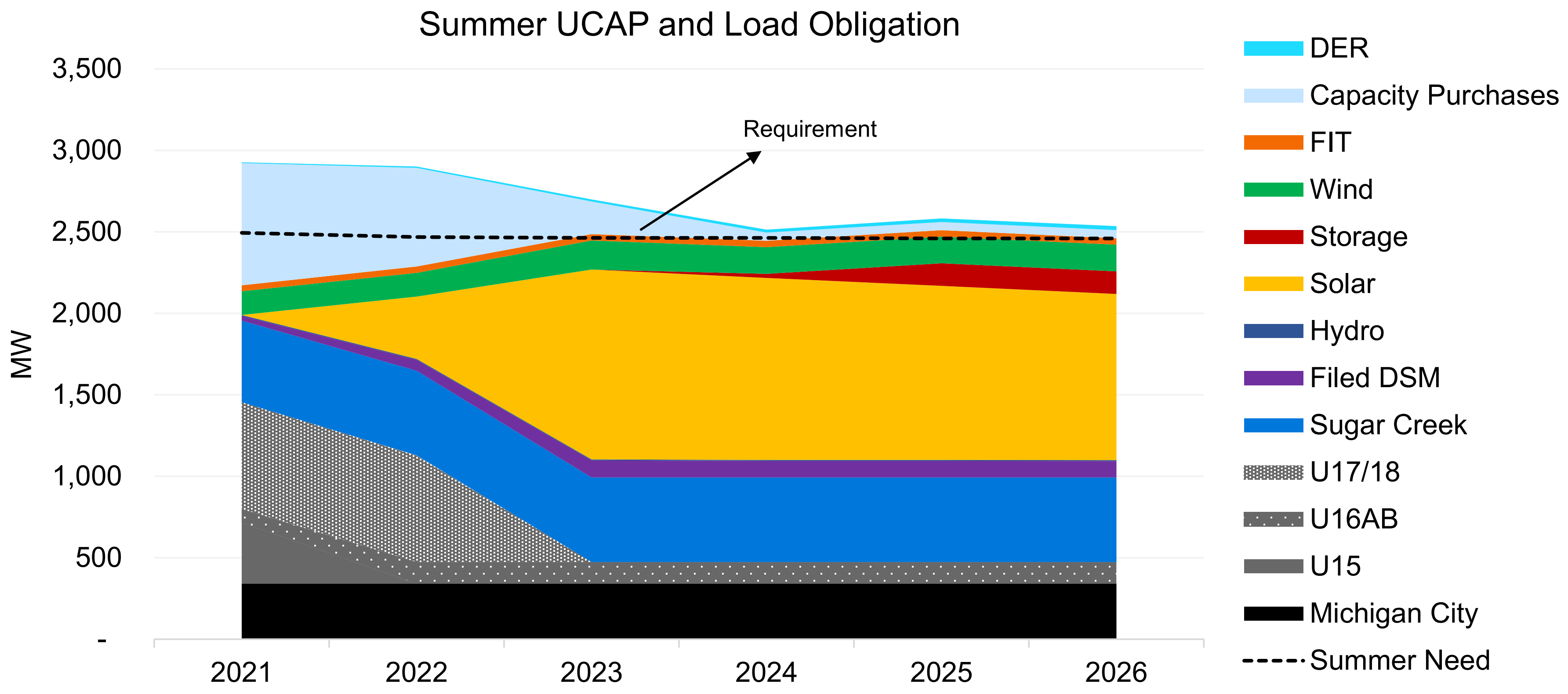
Several regulatory developments and evolving initiatives since NIPSCO's 2018 IRP will influence the way we conduct the 2021 IRP

	Initiatives and Regulatory Developments	Overview	Implications for the IRP
1	**Effective Load Carrying Capability (ELCC)**	**Renewable capacity credit** (particularly solar) is likely to decline as net peak shifts to evening hours	• Solar ELCC credit declines over time • Solar ELCC credit range across scenarios
2	**Resource Availability and Need (RAN) - Seasonal Capacity Construct**	MISO process to explore a shift to **reserve margin tracking throughout the year** (not just summer peak)	• Monthly peak load forecasting • Seasonal reserve margin planning constraints (particularly summer and winter)
3	**Renewable Integration Impact Assessment (RIIA)**	Multi-faceted review of the **impacts of growing renewable penetration** on the MISO market	• Seasonal reserve margin planning • Hourly renewable uncertainty • Operational flexibility metric • Ancillary services
4	**FERC Order 2222**	Order enabling **distributed energy resources (DER)** to participate fully in wholesale markets	• Broader view of DER ranges

RULES EVOLUTION IMPACTS NIPSCO'S FUTURE SUPPLY-DEMAND BALANCE

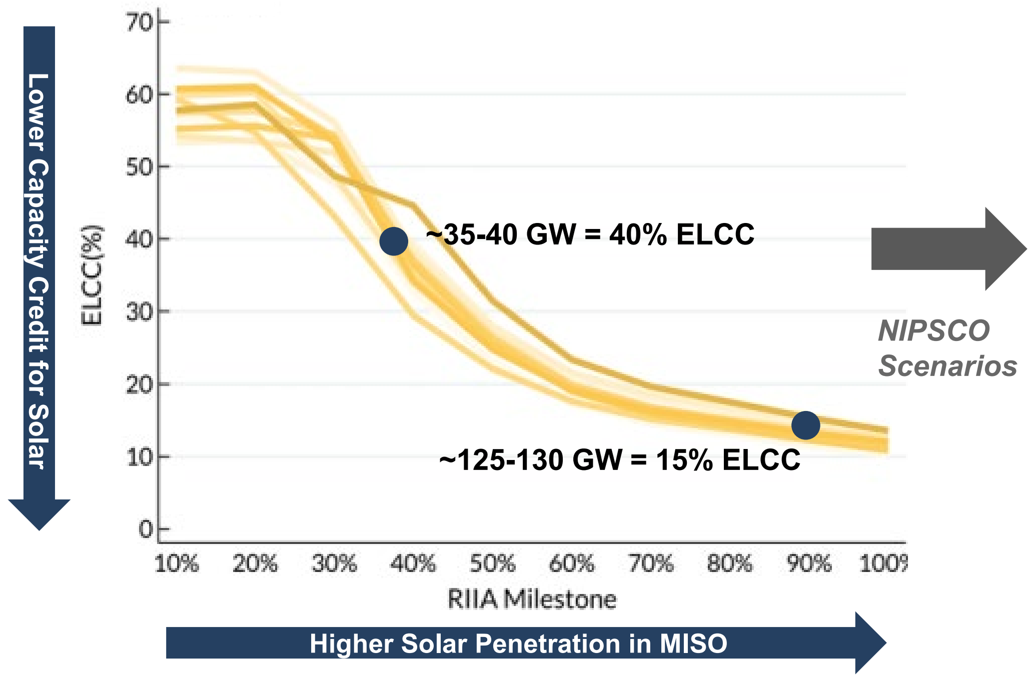
- NIPSCO's supply portfolio will be evolving significantly over the next five years
- MISO market rules changes regarding intermittent resource capacity credit accounting and seasonal reserve margin tracking will require careful evaluation in the 2021 IRP

Preliminary



1 EFFECTIVE LOAD CARRYING CAPABILITY FOR SOLAR

- 2018 IRP: "*Capacity credit will change over time with increased renewable penetration levels …NIPSCO will continue to monitor how the market evolves and incorporate it into future planning.*"
- MISO has studied the issue in more detail over the last three years and has clearer expectations for **declining summer peak credit for solar** over time



Source: Adapted from MISO's Renewable Integration Impact Assessment (RIIA), February, 2021, Figure RA-19
Note that different lines represent different historical weather years evaluated by MISO

Scenario Name	Solar Capacity (ELCC) Credit (Current → 2040)	For a 100 MW Installed Capacity (ICAP) Solar Resource
Reference Case	50% → 25%	50 MW → 25 MW
Status Quo Extended	50% → 30%	50 MW → 30 MW
Aggressive Environmental Regulation	50% → 15%	50 MW → 15 MW
Economy-Wide Decarbonization	50% → 15%	50 MW → 15 MW

Note that winter capacity credit is immediately expected to be between 5-10%

Implications for NIPSCO's 2021 IRP

- Incorporating declining solar credit for all solar resources in the portfolio over time
- Assessing a range of ELCC credits over time dependent on external market scenario

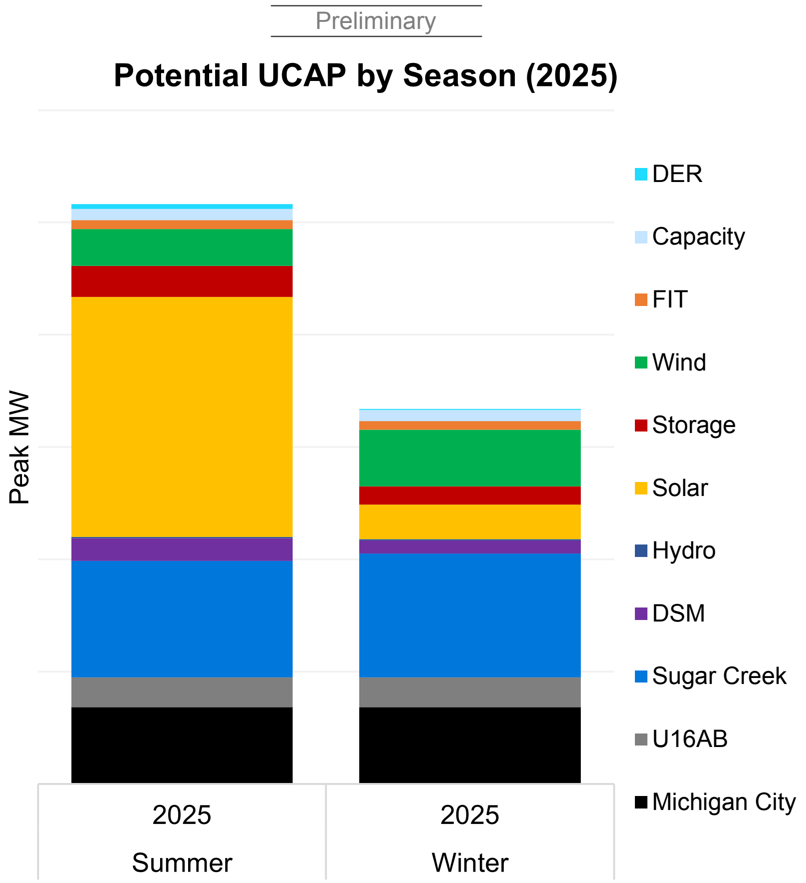
RESOURCE AVAILABILITY AND NEED – SEASONAL CAPACITY CONSTRUCT

2

NIPSCO is **currently required to only meet summer peak demand** plus a reserve margin.

However, MISO anticipates a September filing with FERC to implement a seasonal capacity construct, meaning that utilities will need to **demonstrate sufficient capacity** to meet expected demand in **all seasons**; winter planning will become more important, since **solar will receive less winter credit.**

Source: MISO RAN Reliability Requirements and Sub-annual Construct presentation from April 14, 2021



Implications for NIPSCO's 2021 IRP

- Forecasting monthly peak load expectations
- Assessing reserve margins across all seasons, particularly summer and winter

3 MISO'S RENEWABLE INTEGRATION IMPACT ASSESSMENT (RIIA)

The RIIA has defined three major focus areas for reliability and has identified several insights relevant to planners

Focus of NIPSCO's IRP (Resource Adequacy, Energy Adequacy)

NIPSCO coordinates with MISO (Operating Reliability)

Some elements beyond the purview of IRP

	Resource Adequacy	Energy Adequacy	Operating Reliability
Definition:	Having sufficient resources to reliably serve demand	Ability to provide energy in all operating hours continuously throughout the year	Ability to withstand unanticipated component losses or disturbances
Forward Planning Horizon:	Year-ahead	Day-ahead	Real-time

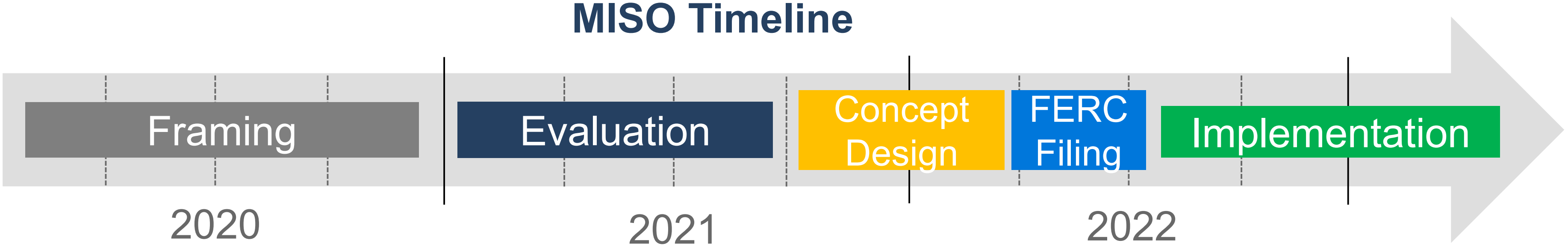
Implications for NIPSCO's 2021 IRP

- Incorporating seasonal planning (prior slide)
- Evaluating hourly renewable output uncertainty in stochastic analysis
- Including "Operational Flexibility" as a metric in scorecard to measure dispatchable MW
- Considering ancillary services value

4 FERC ORDER 2222

- FERC Order 2222 "**enables DERs to participate alongside traditional resources in the regional organized wholesale markets through aggregations**."
  - DERs are defined as "any resource located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment"
- FERC requires that "**Regional grid operators must revise their tariffs to establish DERs as a category of market participant**."
  - Although compliance filings are due this July, MISO has requested a nine-month extension
  - MISO has formed a cross-functional task force to study the issue

MISO Timeline



Implications for NIPSCO's 2021 IRP

- Evaluating a range of DER penetration scenarios

Sources: FERC Order 2222 text and accompanying Fact Sheet; MISO's Distributed Energy Resources Task Force

BREAK

ENVIRONMENTAL CONSIDERATIONS IN 2021

Maureen Turman, Director Environmental Policy & Sustainability, NiSource

NISOURCE REMAINS COMMITTED TO MEET ENVIRONMENTAL IMPACT TARGETS

NiSource projects significant emissions reductions: By 2030 – compared with a base year of 2005 – expected 90 percent reduction of greenhouse gas emissions, 100 percent reduction of coal ash generated, and 99 percent reduction of water withdrawal, wastewater discharge, nitrogen oxides, sulfur dioxide, and mercury air emissions

	PROGRESS THROUGH 2020 % REDUCTIONS FROM 2005 LEVELS	TARGET 2025 % REDUCTIONS FROM 2005 LEVELS	TARGET 2030 % REDUCTIONS FROM 2005 LEVELS
METHANE FROM MAINS AND SERVICES	39%	50% ON TARGET	50%+
GREENHOUSE GAS (NISOURCE)	63%	50%	90%
NITROGEN OXIDES (NOX)	89%	90% ON TARGET	99%
SULFUR DIOXIDE (SO2)	98%	90%	99%
MERCURY	96%	90%	99%
WATER WITHDRAWAL	91%	90%	99%
WATER DISCHARGE	95%	90%	99%
COAL ASH GENERATED	71%	60%	100%

On Target

NIPSCO CURRENT RESOURCE ENVIRONMENTAL CONTROL OVERVIEW

NIPSCO has invested in environmental controls across the fleet and plans to transition the fleet to renewable resources

Unit	Year In Service	Fuel Source	Net Demonstrated Capacity (NDC) MW	Particulate Matter (PM) Control	Sulfur Dioxide (SO_2) Control	Nitrogen Oxide (NO_x) Control	Mercury (Hg) Control	Coal Ash	*Planned Retirement
MCGS U12	1974	Coal	469	Baghouse	Dry FGD	OFA & SCR	ACI & FA	SFC	2028
RMS U14	1976	Coal	431	ESP	Wet FGD	OFA & SCR	ACI & FA	SFC	2021
RMS U15	1979	Coal	472	ESP	Wet FGD	LNB w/ OFA, SNCR	ACI & FA	SFC	2021
RMS U16A	1979	Natural Gas	78	--	--	--	--	--	--
RMS U16B	1979	Natural Gas	77	--	--	--	--	--	--
RMS U17	1983	Coal	361	ESP	Wet FGD	Advanced LNB w/ OFA	--	--	2023
RMS U18	1986	Coal	361	ESP	Wet FGD	Advanced LNB w/ OFA	--	--	2023
Sugar Creek	2002	Natural Gas	535	--	--	SCR	--	--	--
Norway	1923	Water	4	--	--	--	--	--	--
Oakdale	1925	Water	6	--	--	--	--	--	--

*As of May 20, 2021

ESP = Electrostatic Precipitator
SCR = Selective Catalytic Reduction
ACI = Activated Carbon Injection

FGD = Flue Gas Desulfurization
LNB = Low NOx Burners
FA = Fuel Additives

OFA = Over-Fire Air System
SNCR = Selective Non-Catalytic Reduction
SFC = Submerged Flight Conveyor

THE 2018 IRP PREFERRED PLAN ADDRESSED KEY NEAR TERM ENVIRONMENTAL COMPLIANCE REQUIREMENTS

RM Schahfer retirement avoids the significant capital needed to comply, while Michigan City Unit 12 is fully controlled

	CCR	ELG
Effective	October 17, 2015	January 4, 2016
Purpose	Regulates New and Existing Coal Ash Landfills and Surface Impoundments	Establishes National Standards for Treatment of Wastewater Streams
Regulated	CCRs from bottom ash, boiler slag, fly ash and certain FGD solids	Wastewater streams associated with bottom ash, boiler slag, FGD, fly ash, flue gas mercury control waste, landfill leachate, and non-chemical metal cleaning waste

Compliance Plan	Phased Compliance 2015 – 2053
	• Phase I: Separate Ponds from Generation
	• Phase II: Close CCR Ponds
	• Phase III: Implement Groundwater Remedy and Monitoring
		Compliance Plan 2018 - 2023
		• Zero Liquid Discharge
		  • Michigan City Unit 12
		  • RM Schahfer Units 14 & 15
		• Retirements
		  • RM Schahfer Units 17 & 18

Enforcement	Self Implementing	Indiana Department of Environmental Management - National Pollutant Discharge Elimination System

FEDERAL POLICY: CURRENT ADMINSTRATION'S PROPOSED INFRASTRUCTURE PLAN

Climate related regulation is a key focus of the Biden Administration and could shape the future energy landscape

Area	High Level Goals
Energy and Infrastructure	• Goal of 100% carbon-free power by 2035 • Proposing new investment tax credit incentivizing 20 gigawatts of high-voltage transmission • Eliminates tax preferences for fossil fuels • Large public investment in electric vehicles (EVs) such as expanded tax rebates
New Technology and R&D	• Proposes $50 billion to improve infrastructure resiliency • Creates a new production tax credit for hydrogen demonstration projects in distressed communities • Proposes $35 billion in climate research and development (R&D) • 10-year extension of investment tax credit (ITC) and production tax credit (PTC) for clean energy and storage
Low-income assistance and energy management	• Proposes targeted tax credits to build or retrofit one million affordable, energy-efficient and electrified housing units • Additional funding for block grants, Weatherization Assistance Program • Extending home & commercial energy efficiency (EE) tax credits to retrofit existing homes

LUNCH

MODELING UNCERTAINTY: SCENARIOS AND STOCHASTICS FOR 2021 IRP

Pat Augustine, Vice President, CRA
Robert Kaineg, Principal, CRA
Goran Vojvodic, Principal, CRA

MODELING OF UNCERTAINTY

- Because generation decisions are generally long-lived, understanding and incorporating future risk and uncertainty is critical to making sound decisions
- NIPSCO's 2021 IRP analysis uses **both scenarios and stochastic analysis** to perform a robust assessment of risk

Scenarios

Single, Integrated Set of Assumptions

- **Can be used to answer the "What if…" questions**
  - Major events can change fundamental outlook for key drivers, altering portfolio performance
    - New policy or regulation (carbon regulation, tax credits)
    - Fundamental gas price change (change in resource base, production costs, large shifts in demand)
    - Major load shifts
- **Can tie portfolio performance directly to a "storyline"**
  - Easier to explain a specific reasoning why Portfolio A performs differently than Portfolio B

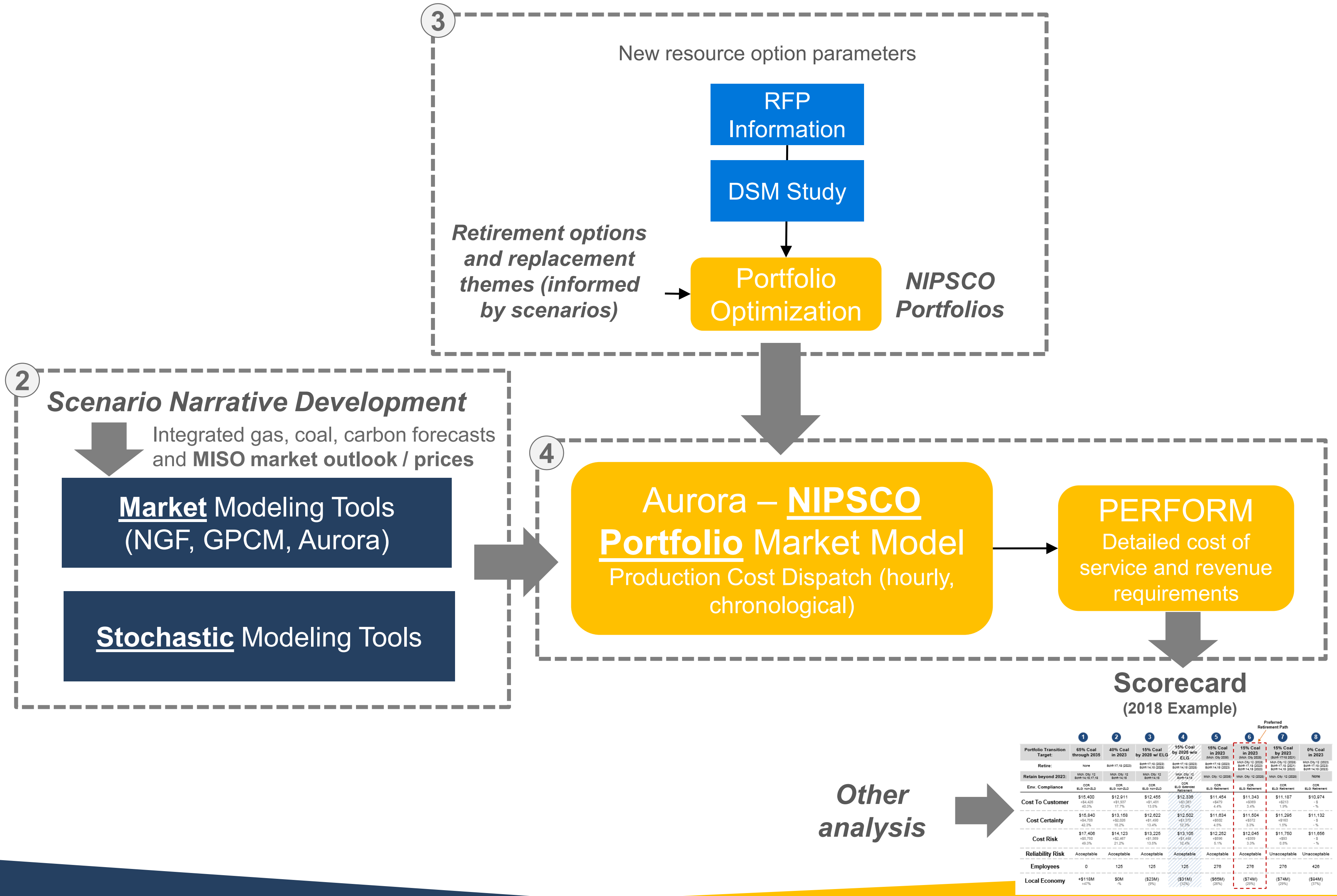
Stochastic Analysis:

Statistical Distributions of Inputs

- **Can evaluate volatility and "tail risk" impacts**
  - Short-term price and generation output volatility impacts portfolio performance
    - Granular market price volatility and resource output uncertainty may not be fully captured under "expected" conditions
    - Certain short-term extreme events are not assessed under deterministic scenarios
- **For the 2021 IRP, the stochastic analysis will be expanded to include hourly renewable availability in addition to commodity price volatility**

RESOURCE PLANNING APPROACH

	Activity		Timing
1	Identify key planning questions and themes	✓	Mar
2	Develop market perspectives (planning reference case and scenarios / stochastic inputs)	✓	Mar-May
3	Develop integrated resource strategies for NIPSCO (portfolios)		Jun-Jul
4	Portfolio modeling ▪ Detailed scenario dispatch ▪ Stochastic simulations		Aug-Sep
5	Evaluate trade-offs and produce recommendation		Sep-Oct



SCENARIO AND STOCHASTIC ANALYSIS CONTRIBUTE TO THE AFFORDABILITY AND COST STABILITY COMPONENTS OF THE SCORECARD

Preliminary & Illustrative

Objective	Indicator	Description and Metrics
Affordability	**Cost to Customer**	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Stability	**Cost Certainty**	• Certainty that revenue requirement within the most likely range of outcomes • **Metric: Scenario range NPVRR and 75th percentile of cost to customer**
	Cost Risk	• Risk of unacceptable, high-cost outcomes • **Metric: Highest scenario NPVRR and 95th percentile conditional value of risk (average of all outcomes above 95th percentile) of cost to customer**
	Lower Cost Opportunity	• Potential for lower cost outcomes • **Metric: Lowest scenario NPVRR and/or 5th percentile of cost to customer**

Scenario outcomes/ ranges *and* stochastic analysis metrics will both be reported to assess Cost Certainty, Cost Risk, and Lower Cost Opportunity

SCENARIO DEFINITION AND KEY INPUTS

SCENARIO OVERVIEW

Reference Case

- The MISO market continues to evolve based on current expectations for load growth, commodity price trajectories, technology development, and policy change (some carbon regulation and MISO rules evolution)

Status Quo Extended (“SQE”)

- Binding federal limits on carbon emissions are not implemented; natural gas prices remain low and result in new gas additions remaining competitive versus renewables, as coal capacity more gradually fades from the MISO market

Aggressive Environmental Regulation (“AER”)

- Carbon emissions from the power sector are regulated through a mix of incentives and a federal tax/cap-and-trade program that results in a significant CO2 price and net-zero emission targets for the power sector by 2040; restrictions on natural gas production increase gas prices

Economy-Wide Decarbonization (“EWD”)

- Technology development and federal incentives push towards a decarbonized economy, including through a power sector Clean Energy Standard (supporting renewables and other non-emitting technologies) and large-scale electrification in other sectors (EVs, heating, processes, etc.)

MAJOR SCENARIO PARAMETERS

Based on MISO modeling outcomes

Scenario Name	Gas Price	CO_2 Price	Federal Tech. Incentives	Load Growth	Solar Capacity (ELCC) Credit (Current → 2040)
Reference Case	Base	Base	2-year ITC extension (solar); 1-year PTC extension (60%)	Base	50% → 25%
Status Quo Extended	Low	None	No change to current policy	Lower	50% → 30%
Aggressive Environmental Regulation	High	High	5-year ITC extension (solar) plus expansion to storage; 3-year PTC extension (60%)	Close to Base	50% → 15%
Economy-Wide Decarbonization	Base	None	10-year ITC extension (solar) plus expansion to storage; 10-year PTC extension (60%); tracking further potential federal support for advanced tech including hydrogen and NG CCS	Higher	50% → 15%

Updated since last meeting

Based on CRA capacity expansion and latest MISO-wide studies from RIIA Summary Report (Figure RA-18 at https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf)

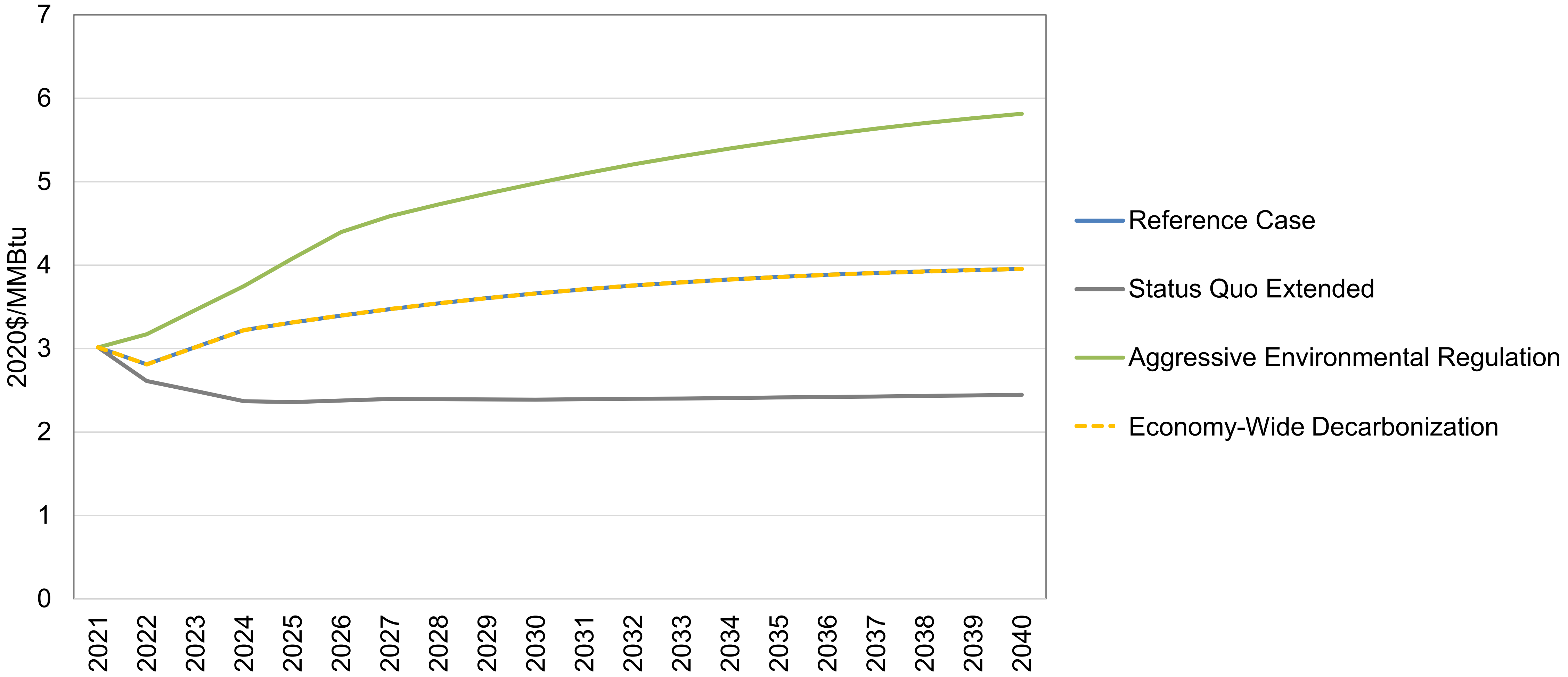
FUNDAMENTAL NATURAL GAS PRICE DRIVERS ACROSS SCENARIOS – SUPPLY

Driver	Reference Case (and EWD)	High (AER)	Low (SQE)
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• Remove resource growth resulting from policy changes (eg. drilling bans)	• Unproven resource base assumed higher
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	• Slow improvement as policy drives investment into clean energy sectors	• Accelerated improvement in well productivity
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	• Slow improvement as policy drives investment into clean energy sectors • Higher environmental costs	• Accelerated improvements in drilling technology • Lower environmental costs
NGL & Condensate Value	• Liquids valued at 70% of Annual Energy Outlook (AEO) 2021 Reference Oil Price	• Lower oil prices, given lower demand	• Base view
Associated Gas Volumes	• Natural gas from shale and tight oil plays enters the market as a price taker	• Lower, given lower oil demand	• Base view

FUNDAMENTAL NATURAL GAS PRICE DRIVERS ACROSS SCENARIOS – DEMAND

Driver	Reference Case (and EWD)	High (AER)	Low (SQE)
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	• Significant drop in power sector and other demand	• Higher power sector demand, but no change in other sectors
LNG Exports	• Under-construction projects completed and total exports rising from around 7 bcf/d in 2020 to around 14 bcf/d by 2030	• Base view, even as U.S. prices increase	• Export projects delayed due to lower price environment
Pipeline Exports	• Exports rise from 5 bcf/d in 2020 to just under 10 bcf/d by 2030	• Base view, even as U.S. prices increase	• Lower usage rates on pipelines

FUNDAMENTAL NATURAL GAS PRICE FORECAST ACROSS SCENARIOS

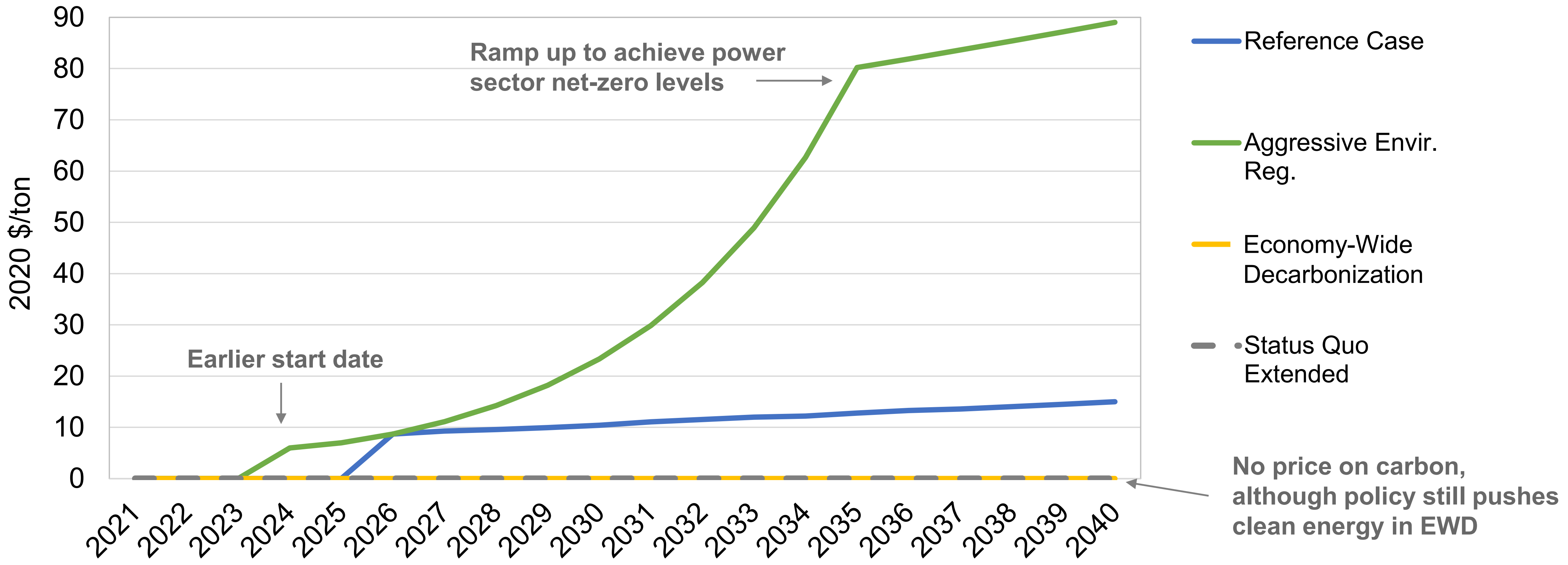


CO_2 POLICY SCENARIOS

	Status Quo Extended	Aggressive Environmental Regulation	Economy-Wide Decarbonization
Rationale	Continued hurdles in Congress stymie legislative outcomes, and federal courts limit the scope of executive actions	The current Administration / Congress lay the groundwork, and future governments implement stricter CO_2 policy to establish net zero power sector targets by 2040	Near-term policy action focuses on clean technology and electrification initiatives and initial framework for power sector clean energy mandates
Potential Outcome	States continue to advance goals, but federal legislation stops short of implementing a carbon price, and any potential EPA action is held up in the courts	Policy evolves towards a price on carbon, particularly for the power sector, with a ramp up in stringency over time to achieve net zero levels	No carbon *pricing* materializes, but economy-wide carbon reduction policy momentum includes a binding clean energy standard (100% clean with offsets) for the power sector

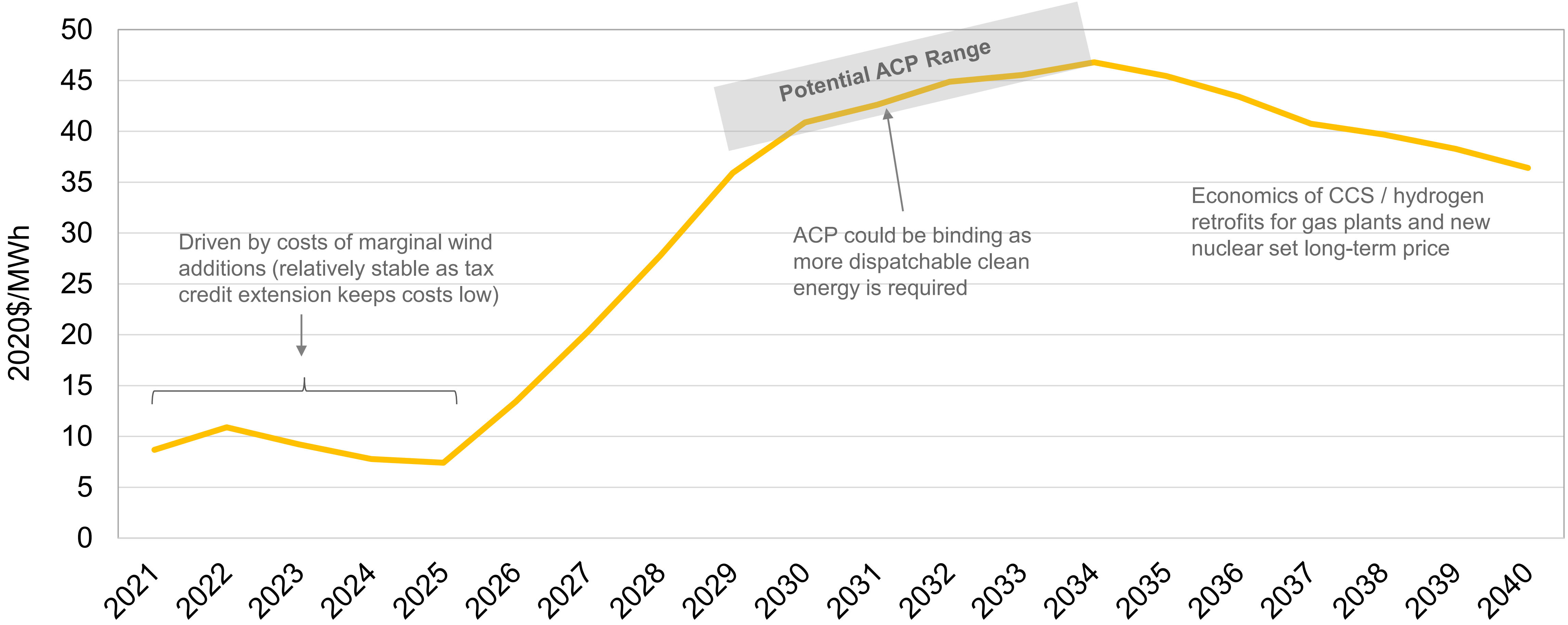
CO_2 PRICE RANGE

In the Aggressive Environmental Regulation scenario, a carbon price increase to the $80-90/ton range (resulting in long-term average power prices around $70/MWh) could make hydrogen and nuclear more attractive, achieving clean energy generation totals in the 90-95% range by 2040.



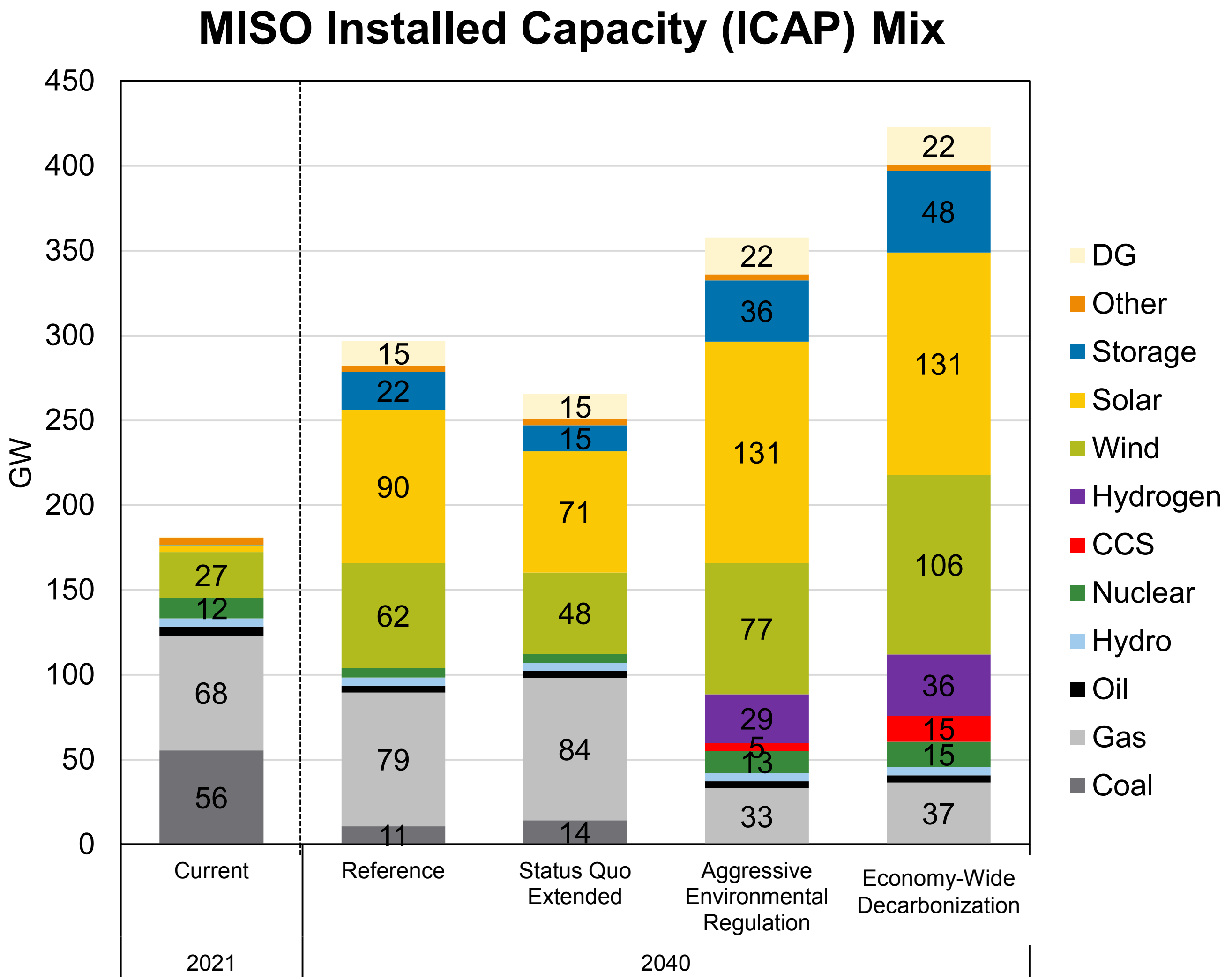
CLEAN ENERGY CREDIT PRICING

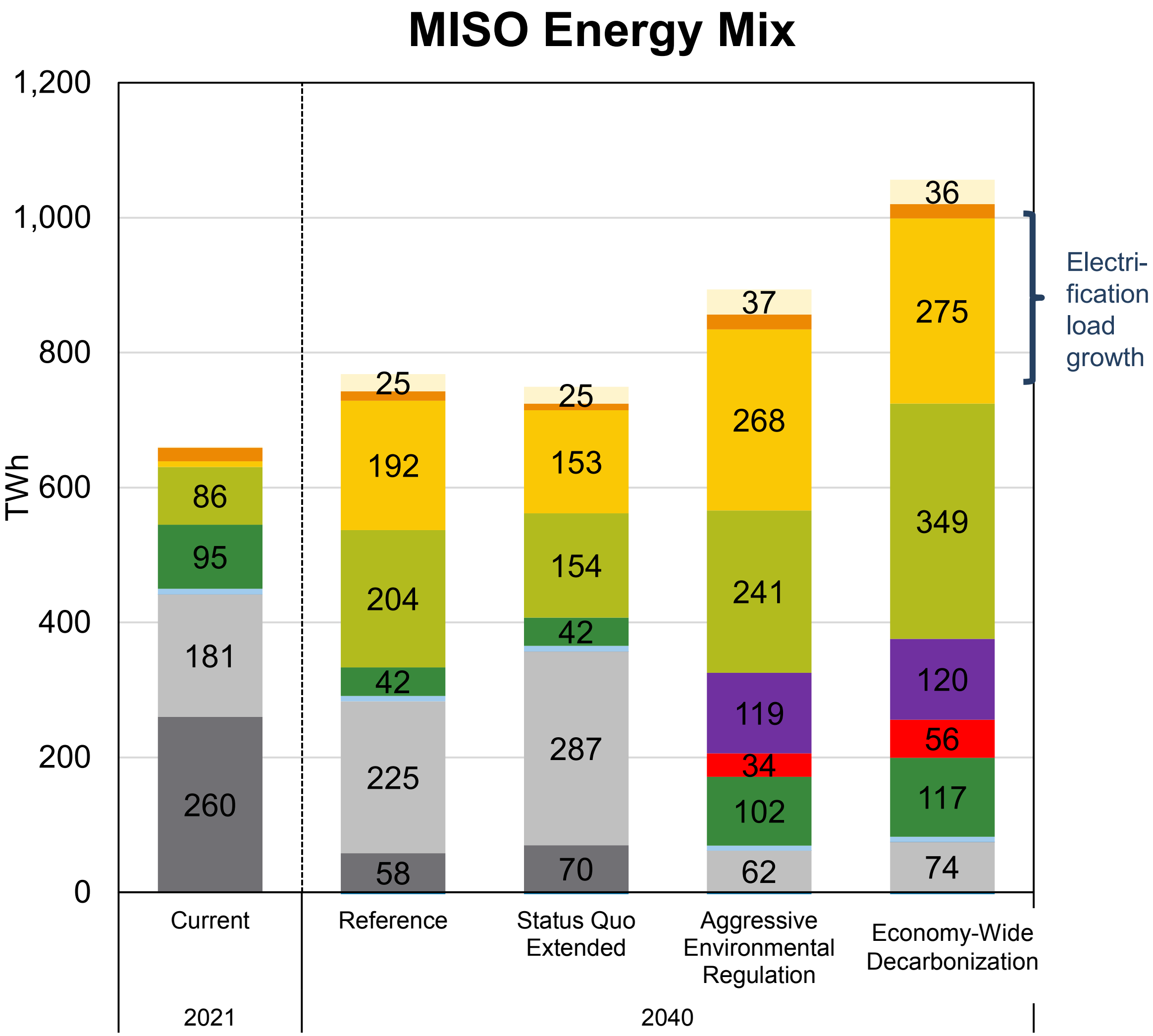
In the Economy-Wide Decarbonization scenario, a Clean Energy Standard with an Alternative Compliance Payment (ACP) would likely drive the development of a national Clean Energy Credit / Zero Emission Electricity Credit market



Note that ACP backstop price range is based loosely on provisions in the proposed CLEAN Future Act

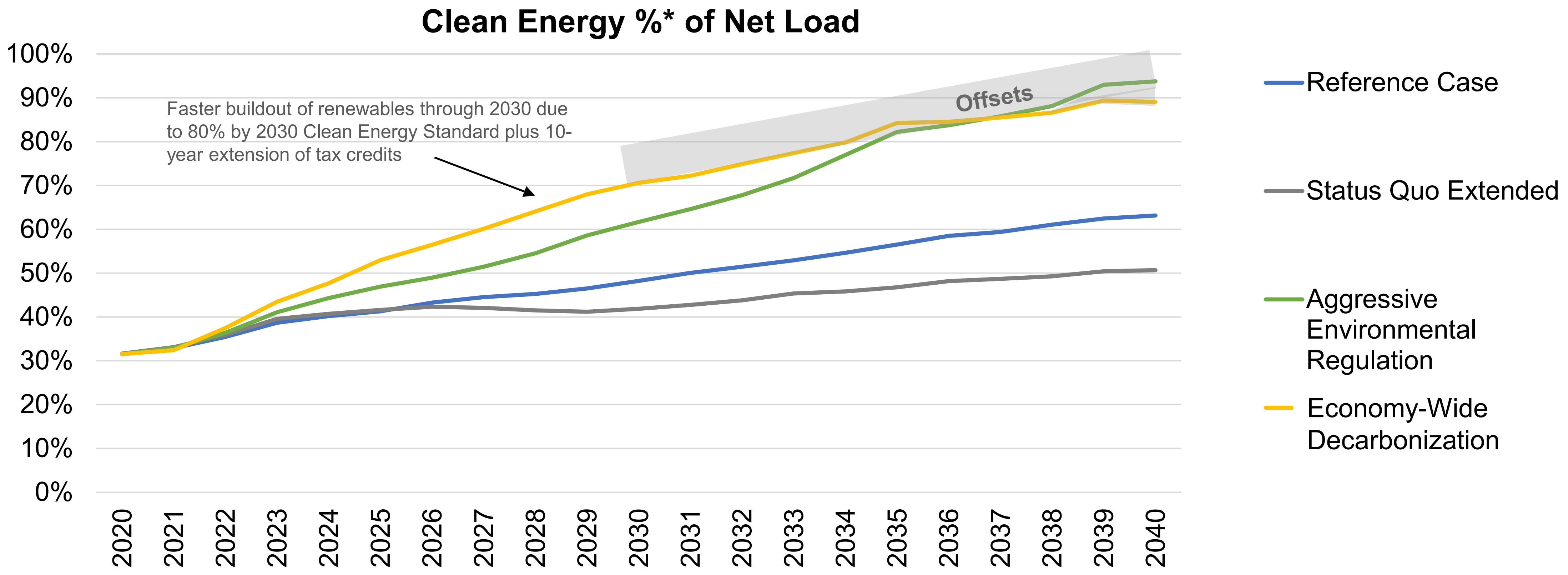
MISO CAPACITY AND ENERGY MIX OUTLOOK ACROSS SCENARIOS





CLEAN ENERGY PERCENTAGE ACROSS MISO

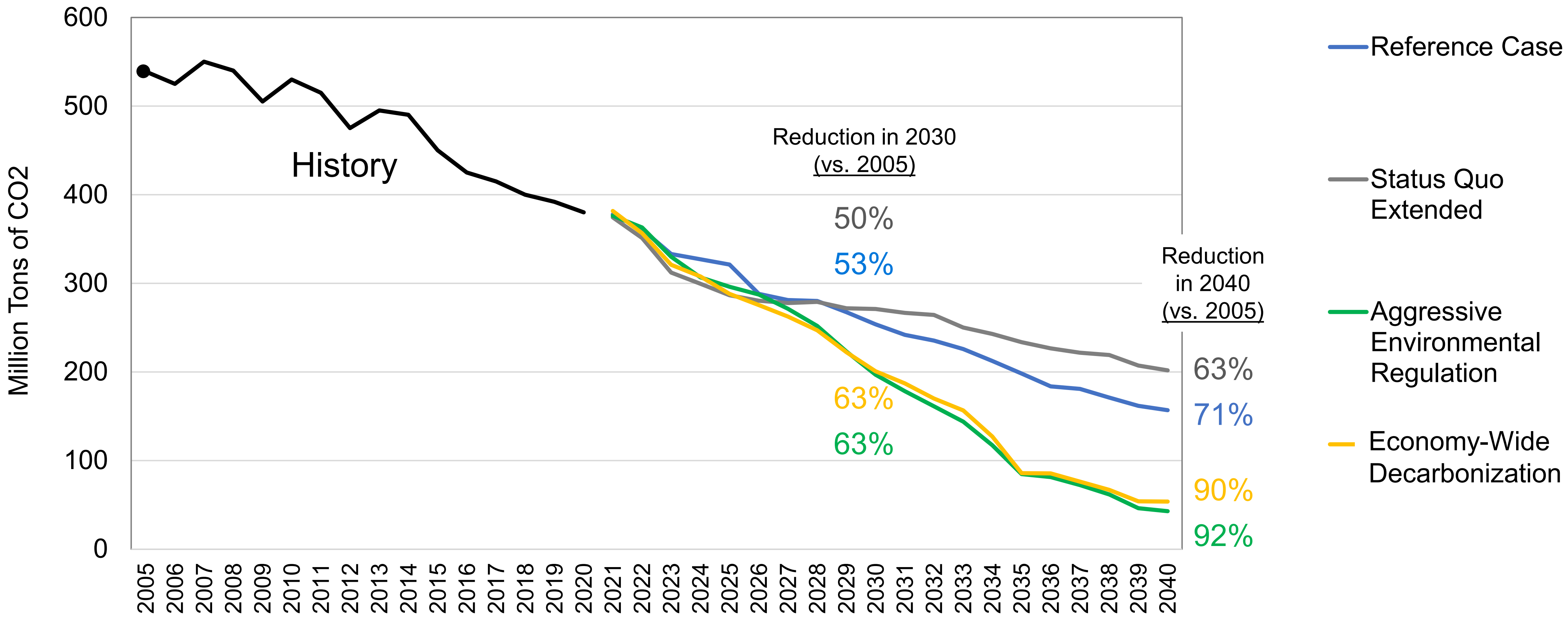
- Escalating carbon price pushes clean energy percentage to >90% in AER, while the implementation of a Clean Energy Standard achieves a very similar outcome in EWD
- Offsets outside the power sector would be expected to be available to achieve Net Zero



*This calculation is based on total MISO clean energy generation (wind, solar, hydro, other renewables, nuclear, CCS, hydrogen), adjusted for projected imports and exports, divided by MISO net load.

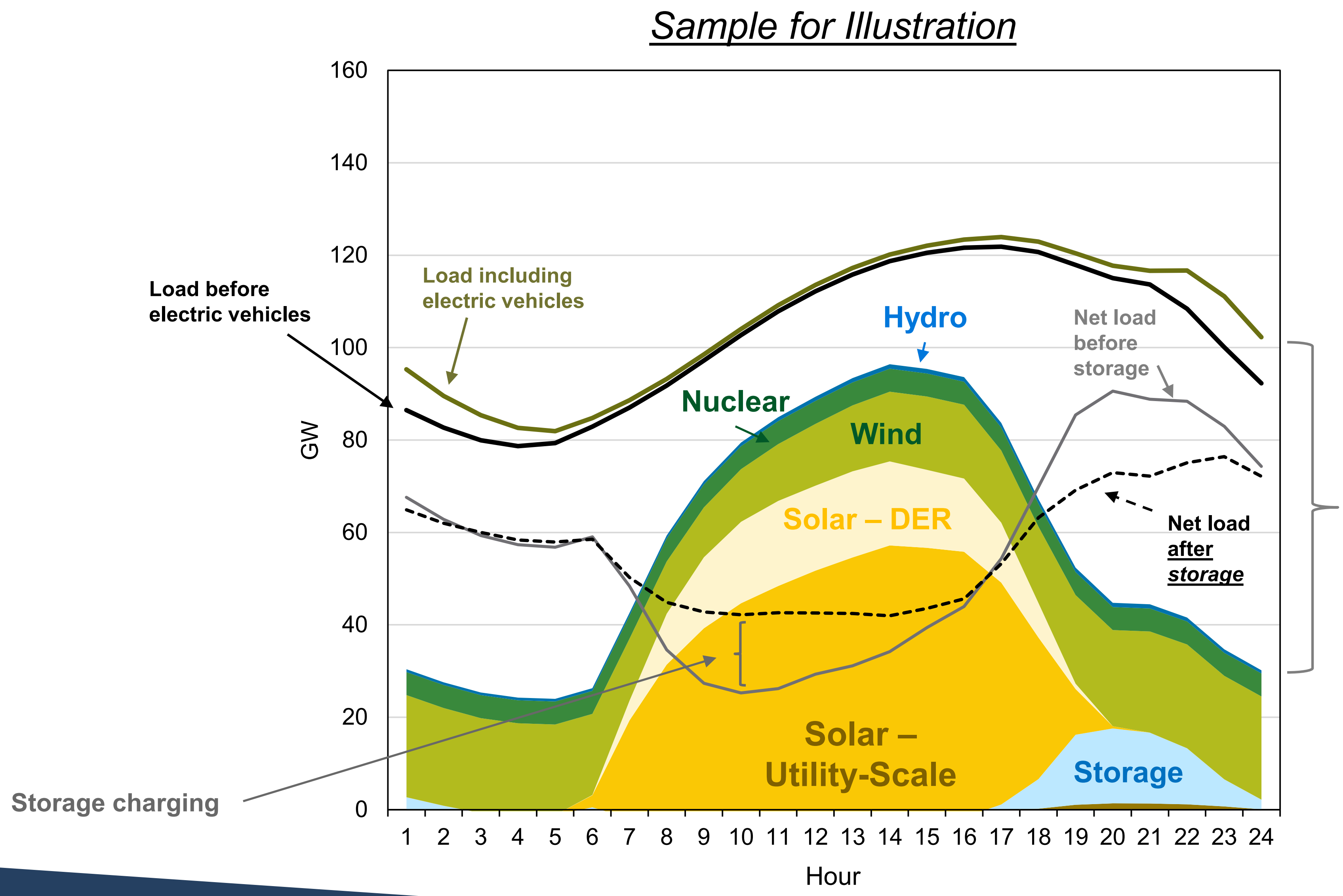
MISO CO_2 EMISSIONS

- The MISO market has already achieved a ~30% reduction in CO2 emissions relative to a 2005 baseline, with significant additional reductions projected across all scenarios



Historical data from 2005-2017 taken from MISO Futures documentation from 2020. CRA interpolated data from 2018 to first model year of 2021.

HOURLY ENERGY VIEW - MISO



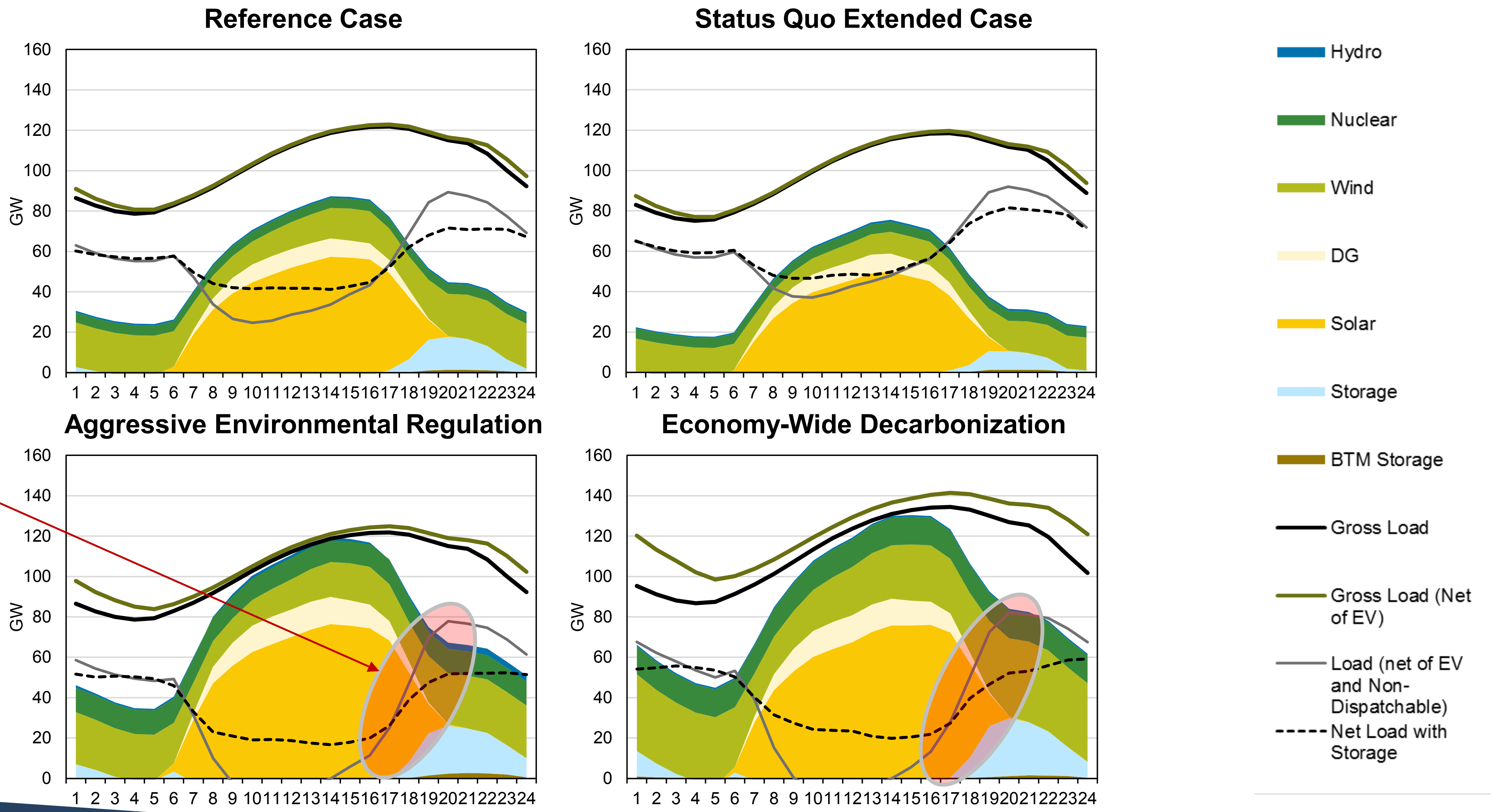
Net load =

Load (including EVs)

minus

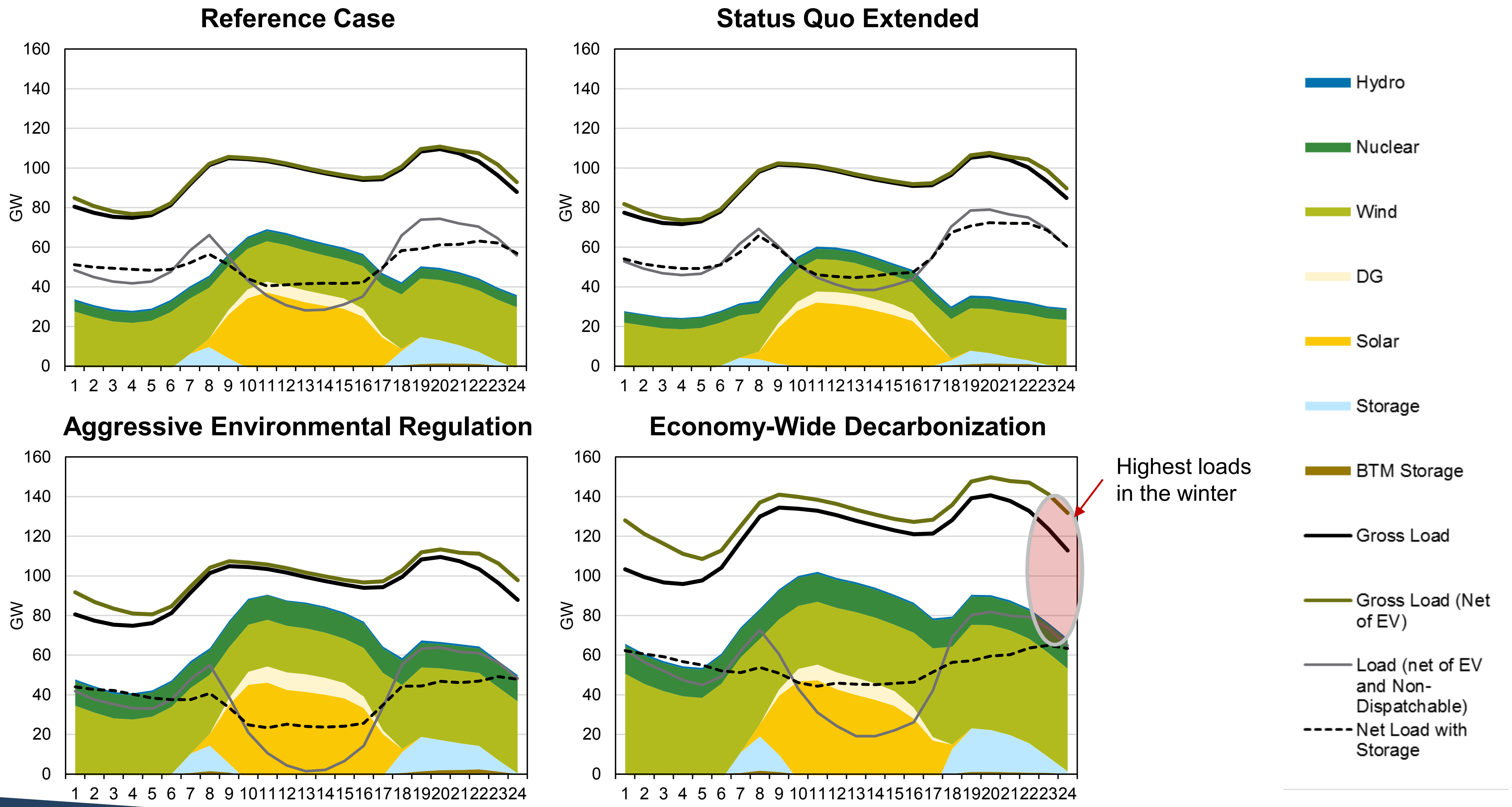
Non-dispatchable generation (wind, solar, nuclear, hydro)

SUMMER 2040



Large ramping requirements in summer evenings must be met by storage and flexible gas/H2

WINTER 2040



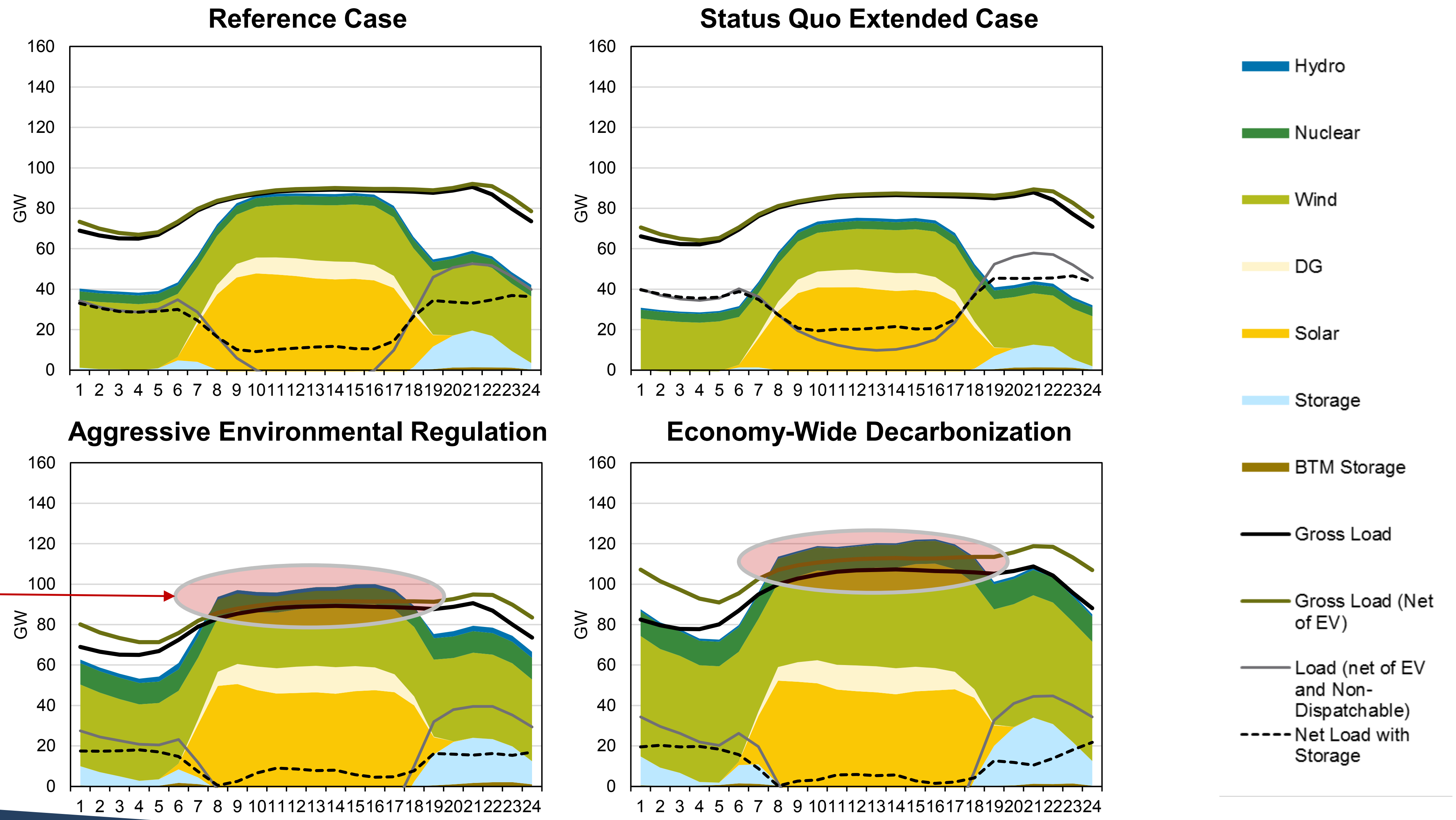
Reference Case
Status Quo Extended
Aggressive Environmental Regulation
Economy-Wide Decarbonization
GW
160
140
120
100
80
60
40
20
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Highest loads in the winter
Hydro
Nuclear
Wind
DG
Solar
Storage
BTM Storage
Gross Load
Gross Load (Net of EV)
Load (net of EV and Non-Dispatchable)
Net Load with Storage

SHOULDER MONTH (SPRING) 2040

Most spring energy needs met by renewables, particularly in AER and EWD scenarios

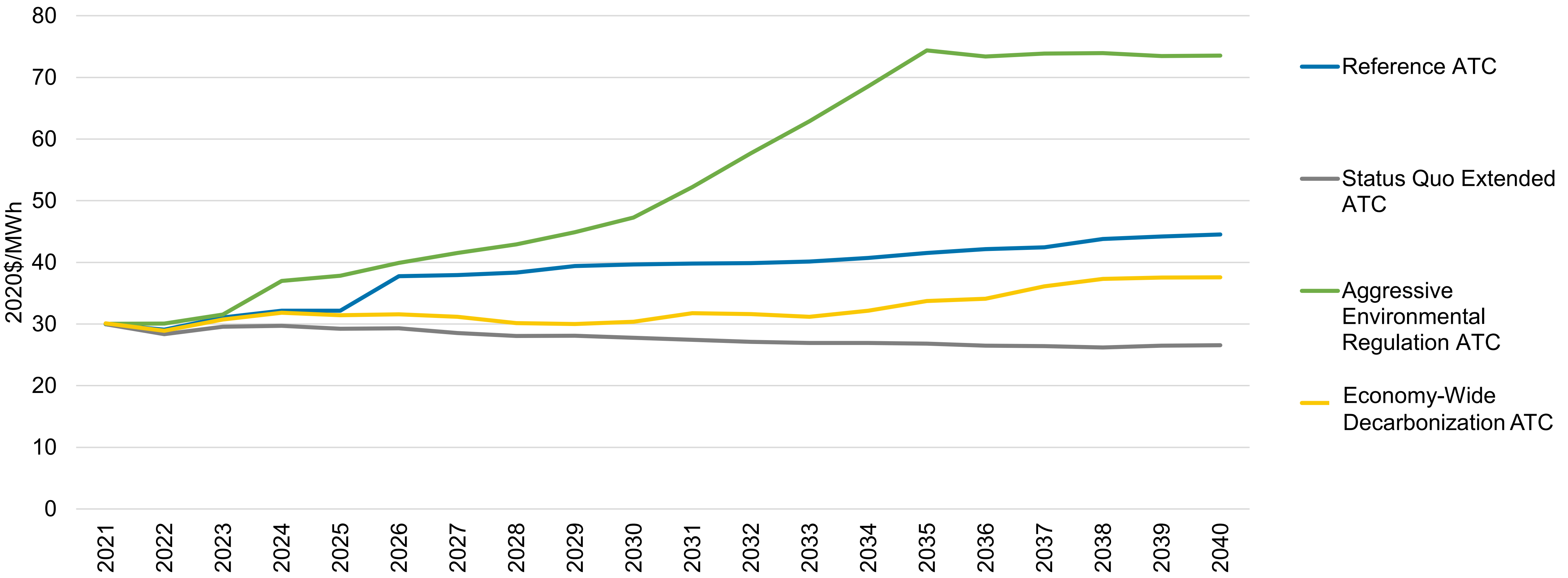
Storage needed to absorb excess renewable energy and shift to evening/ overnight or seasonally via H2;

curtailment (or use of excess for electrolysis) likely on many days

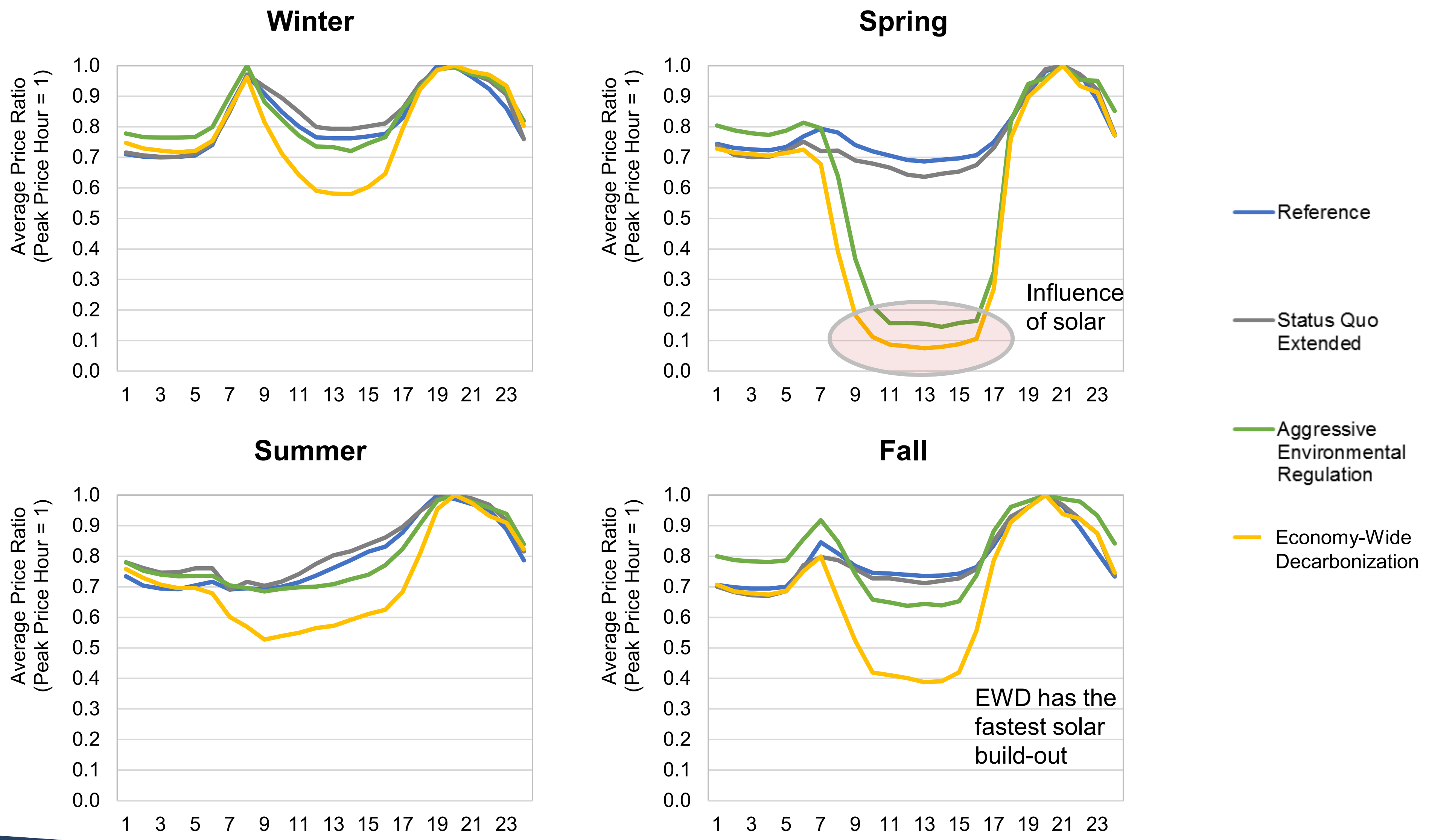


AROUND THE CLOCK ("ATC") MISO ZONE 6 PRICES BY SCENARIO

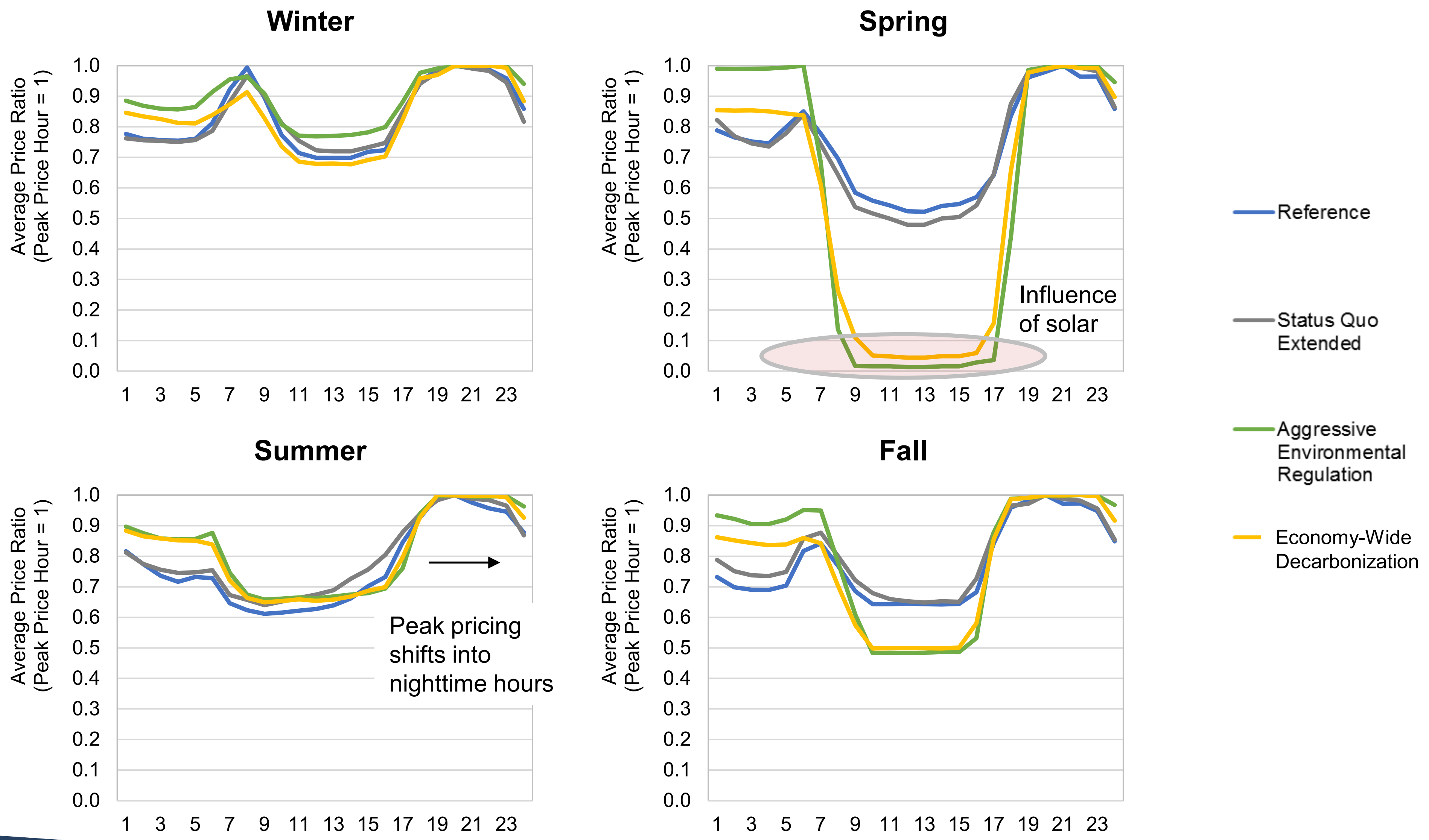
- Rising natural gas and carbon prices drive AER scenario trajectory, with long-term pricing also influenced by hydrogen commodity pricing
- Without a price on carbon, SQE and EWD scenarios have flatter pricing in real terms due to gas price expectations and growing renewable penetration



HOURLY PRICE SHAPES EXPECTED TO EVOLVE OVER TIME - 2030

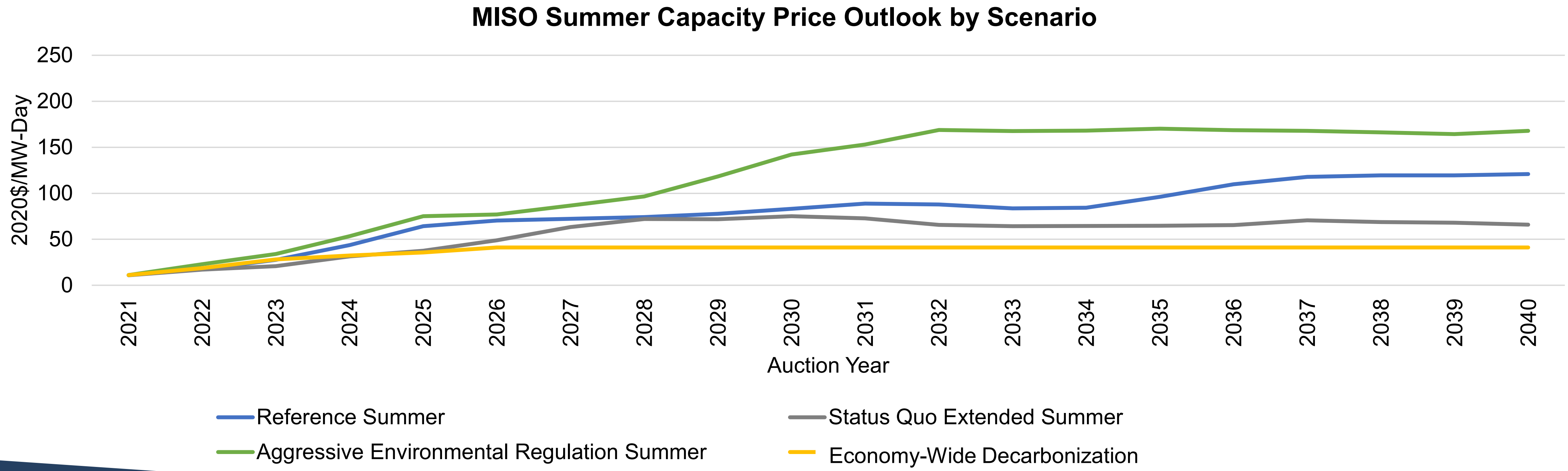


HOURLY PRICE SHAPES EXPECTED TO EVOLVE OVER TIME - 2040



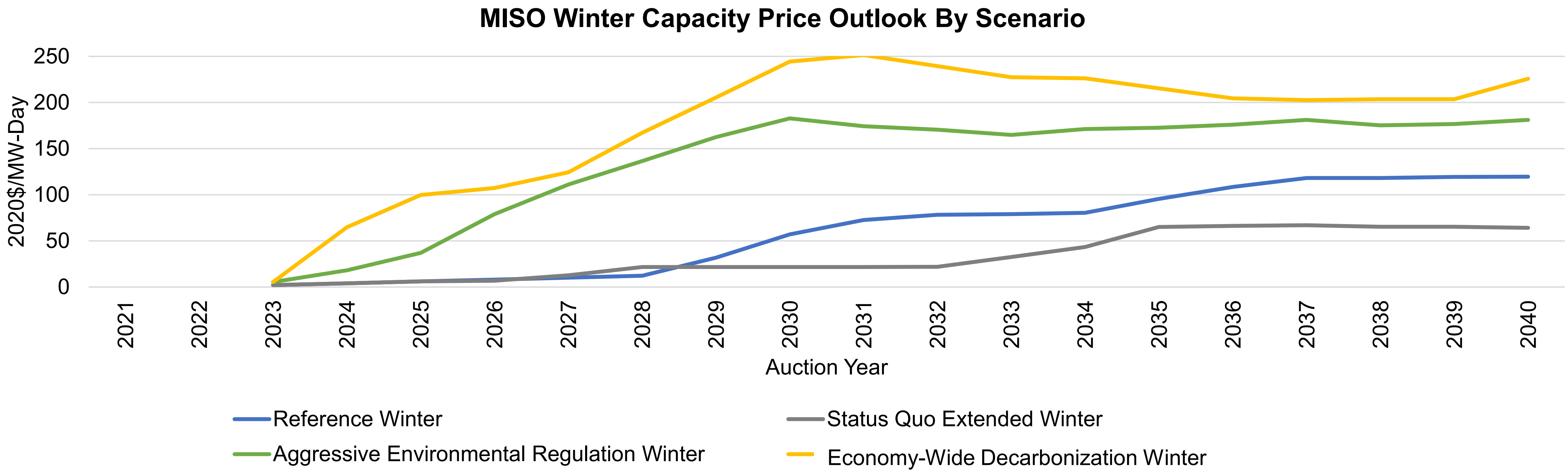
MISO SUMMER CAPACITY PRICE FORECAST

- CRA expects capacity prices to remain low in the near-term, although continued coal retirements over the 2020-2024 period are expected to tighten the system.
- The long-term price view is based on existing unit going-forward costs in a utility-dominant market, but there may be periods of volatility between the cost of new entry ("CONE") and $0 (Zone 7 cleared at CONE last year).
- Under the AER scenario, coal retirements and replacement with resources including hydrogen-enabled gas turbines and long-duration storage could push prices higher



MISO WINTER CAPACITY PRICE FORECAST

- Winter reserve margin tightening is most likely in the EWD scenario, due to clean energy targets and significantly growing winter loads from electrification
- Capacity pricing in the AER scenario is also likely to increase due to retiring capacity and replacement with a portfolio of zero-emitting resource types, as in the summer season



SCENARIO IMPACTS TO NIPSCO LOAD

Scenario Name	Economic Growth	EV Penetration	DER Penetration	Other Electrification	NIPSCO Industrial Load
Reference Case	**Base** *Moody's Baseline forecast*	**Low** *Current trends persist (MTEP Future I)*	**Base** *Baseline expectations for continued growth, which is exponential in areas*		
Status Quo Extended	**Low** *Moody's 90th percentile downside: COVID impacts linger; consumer spending lags stimulus amounts, unemployment grows again*	**Low** *Current trends persist; economics continue to favor ICE (MTEP Future I)*	**Low** *Lower electric rates decelerate penetration trends*		**Low** *Additional industrial load migration – down to 70 MW firm 831*
Aggressive Environmental Regulation	**Base** *Moody's Baseline forecast*	**Mid** *Customers respond to cost increases in gasoline, and EV growth rates increase (MTEP Future II)*	**High** *Higher electric rates and lower technology costs accelerate penetration trends*		
Economy-Wide Decarbonization	**High** *Moody's 10th percentile upside: vaccine facilitates faster re-openings, fiscal stimulus boosts economy more than expected*	**High** *Policy, technology, behavioral change drive towards high EV scenario (MTEP Future III)*	**High** *Technology-driven increase, as solar costs decline and policies facilitate installations*	**High** *MTEP Future III for R/C/I HVAC, appliances, processes*	

LOAD FORECAST PROCESS

The load forecasting process incorporates an econometric approach plus several adjustments

Inputs

Data Gathering

Energy Forecast and Validation

Weather Normalization → **Econometric Modeling by Customer Class** → **Baseline Energy Forecast** → **Peak Load Forecast**

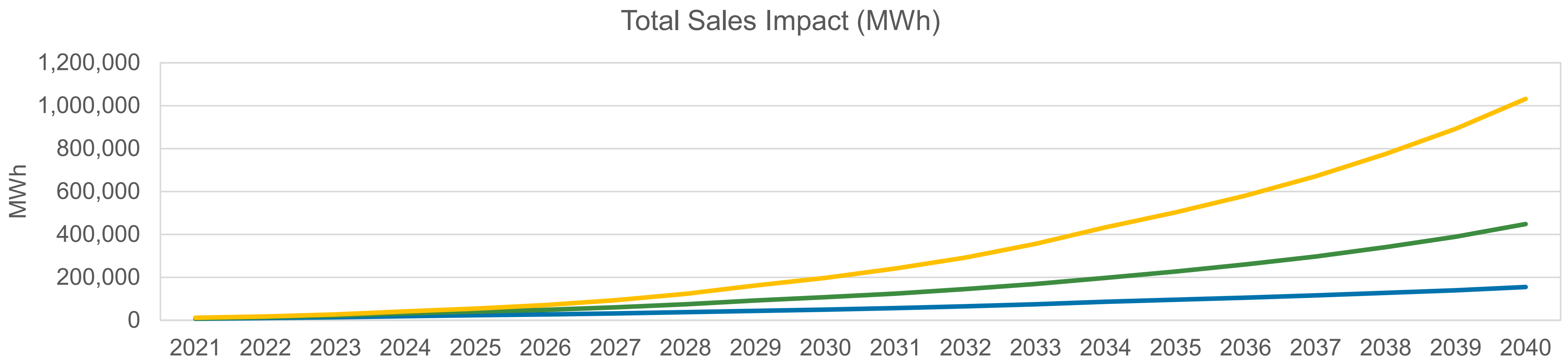
Forecast Adjustments: Base and Scenarios

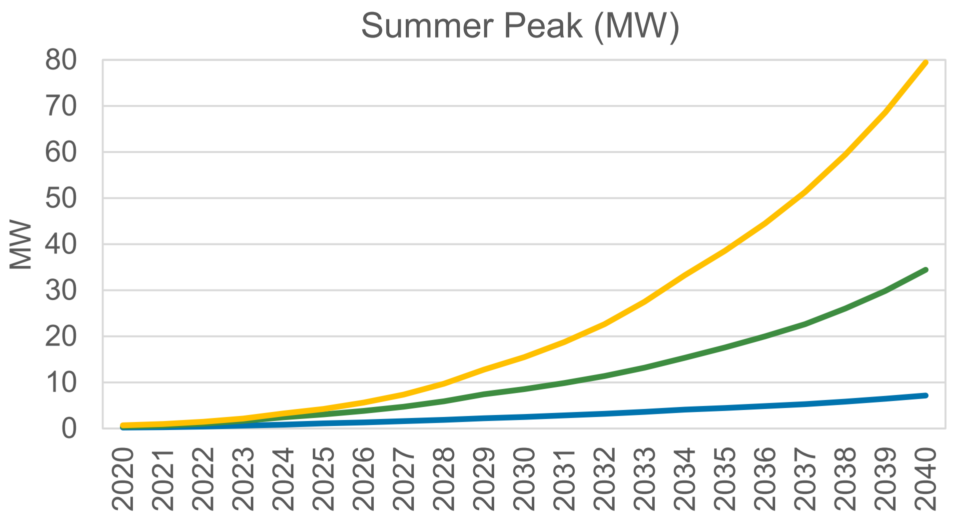
DSM, DER, EV, Electrification, Industrial Load Adjustments

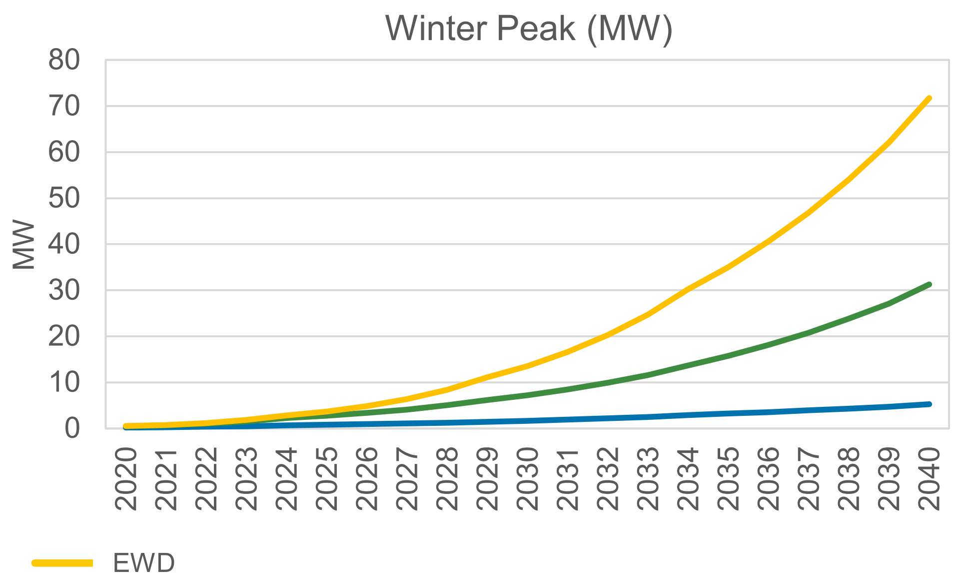
- NIPSCO reviewed the detailed process and draft forecast in Stakeholder Meeting #1
- NIPSCO and CRA have since refreshed the economic variables with the latest Moody's economic forecast:
  - Baseline Scenario
  - Upside Alternative – 10^{th} Percentile
  - Downside Alternative – 90^{th} Percentile

- Incorporate *known* DSM programs
- EV scenario ranges (From Stakeholder Meeting #1)
- DER penetration ranges (From Stakeholder Meeting #1 plus revision reviewed earlier)
- Other electrification (See subsequent slide)
- Industrial load loss (down to 70 MW firm 831 in low case)

ELECTRIC VEHICLE SCENARIO RANGE

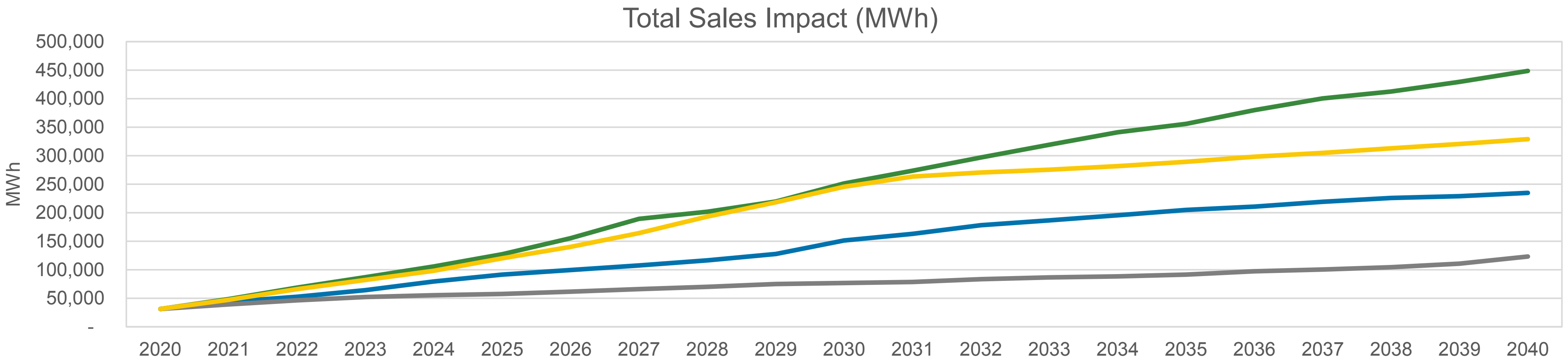


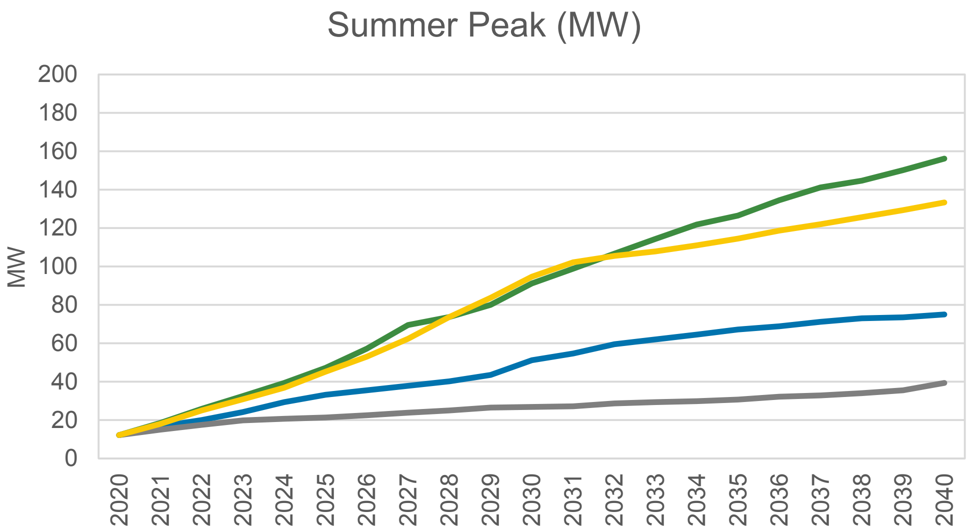


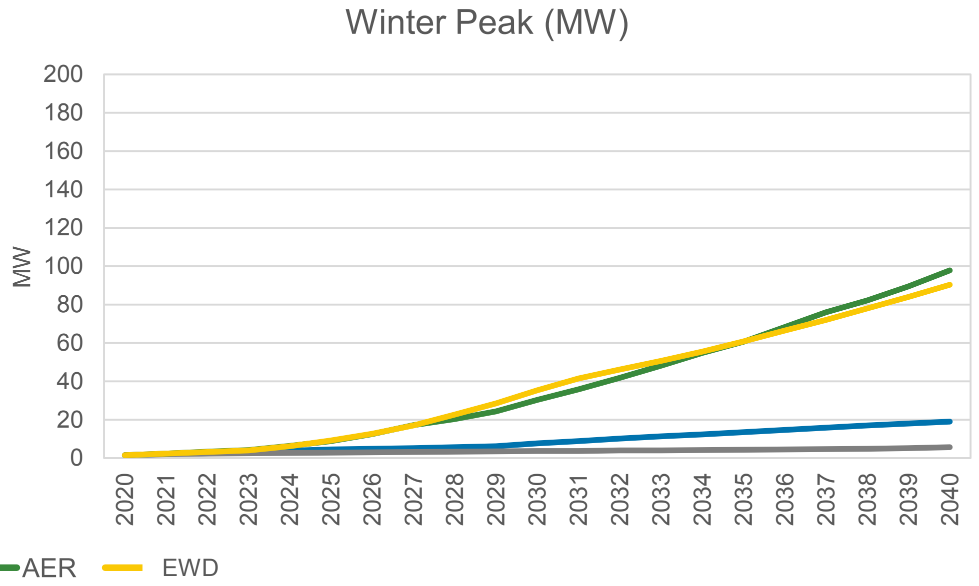


Includes gross-up of 5% for line losses.

CUSTOMER-OWNED DER SCENARIO RANGE



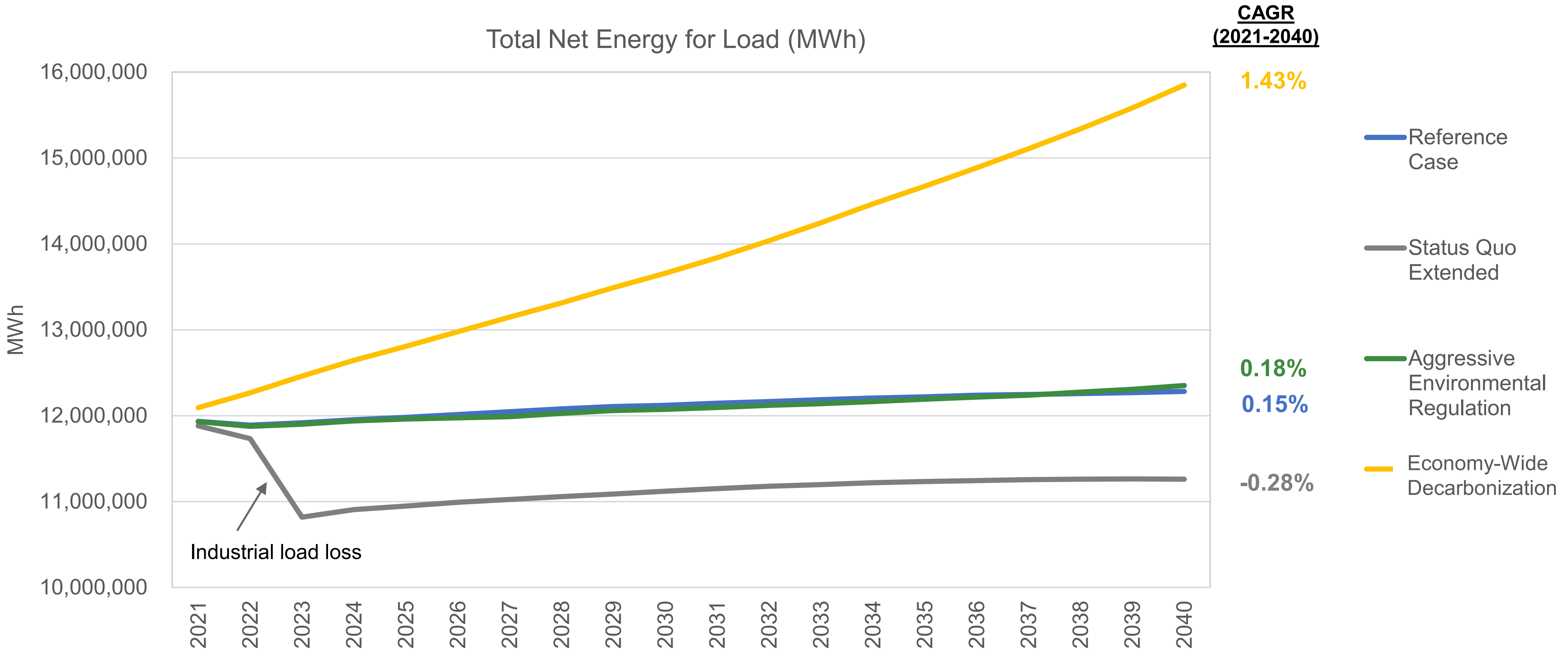




Includes gross-up of 5% for line losses.

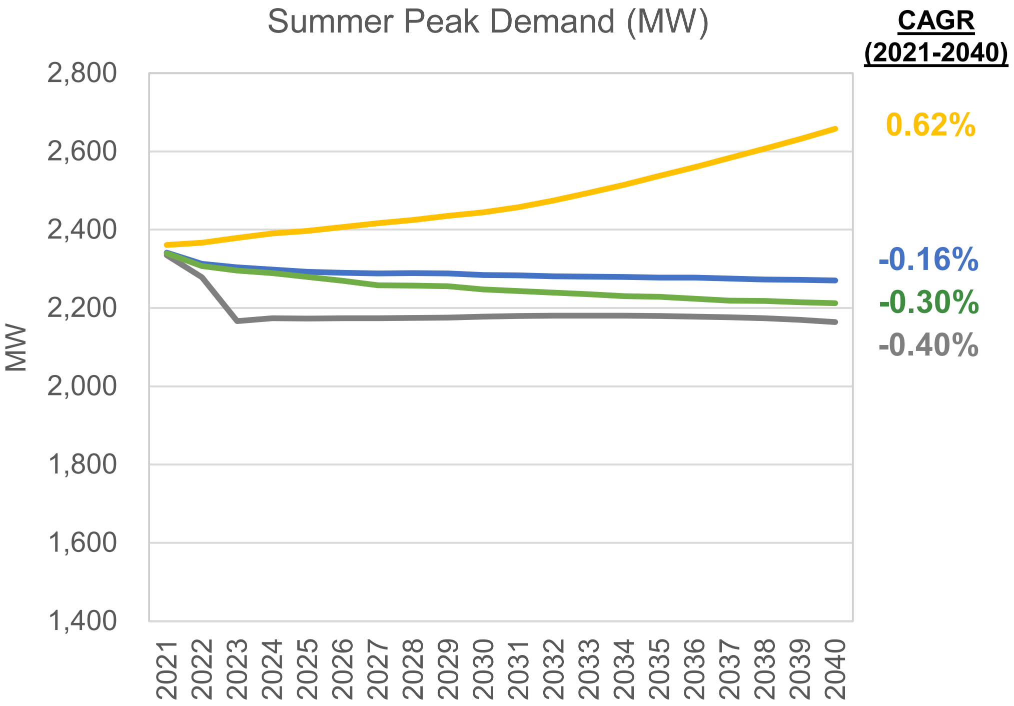
NIPSCO LOAD SCENARIO RANGES – SALES FORECAST

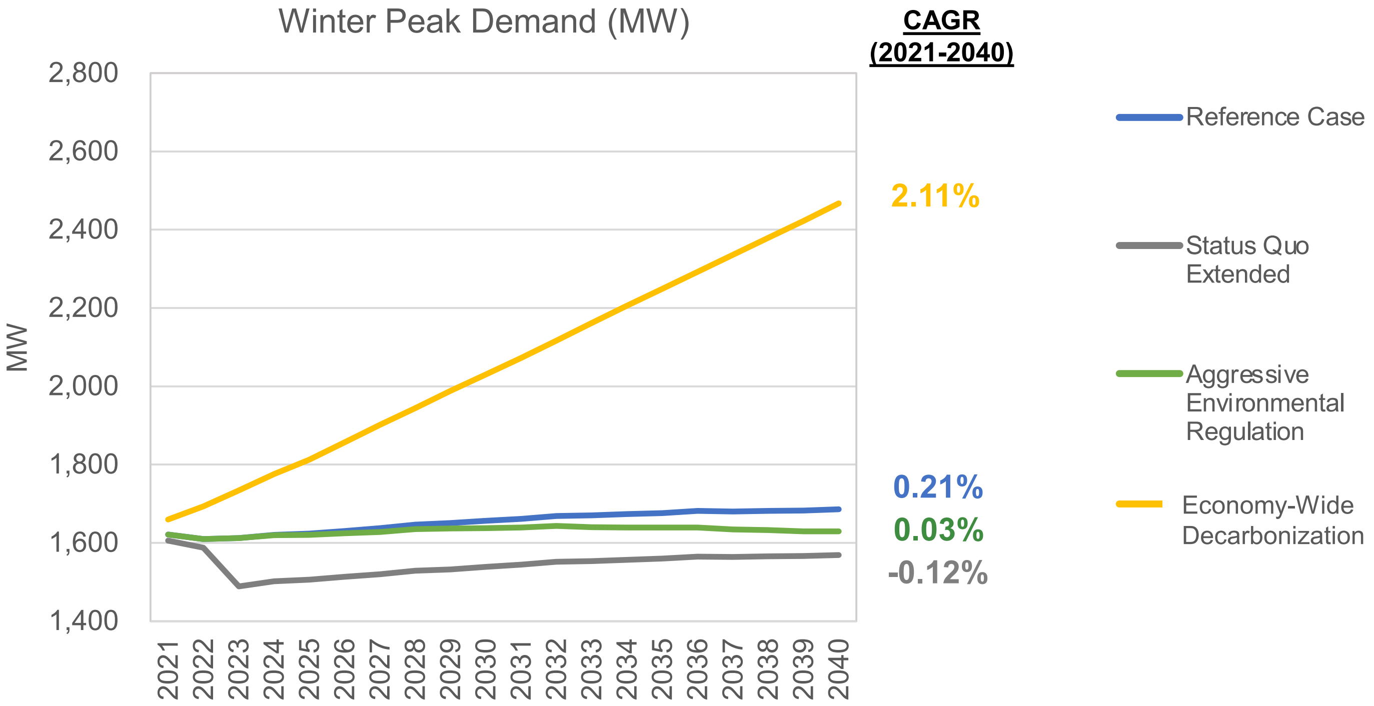
Reference case forecast is relatively flat, with broad scenario ranges driven by economic factors, potential policy drivers, and customer behavior



NIPSCO LOAD SCENARIO RANGES – PEAK LOAD

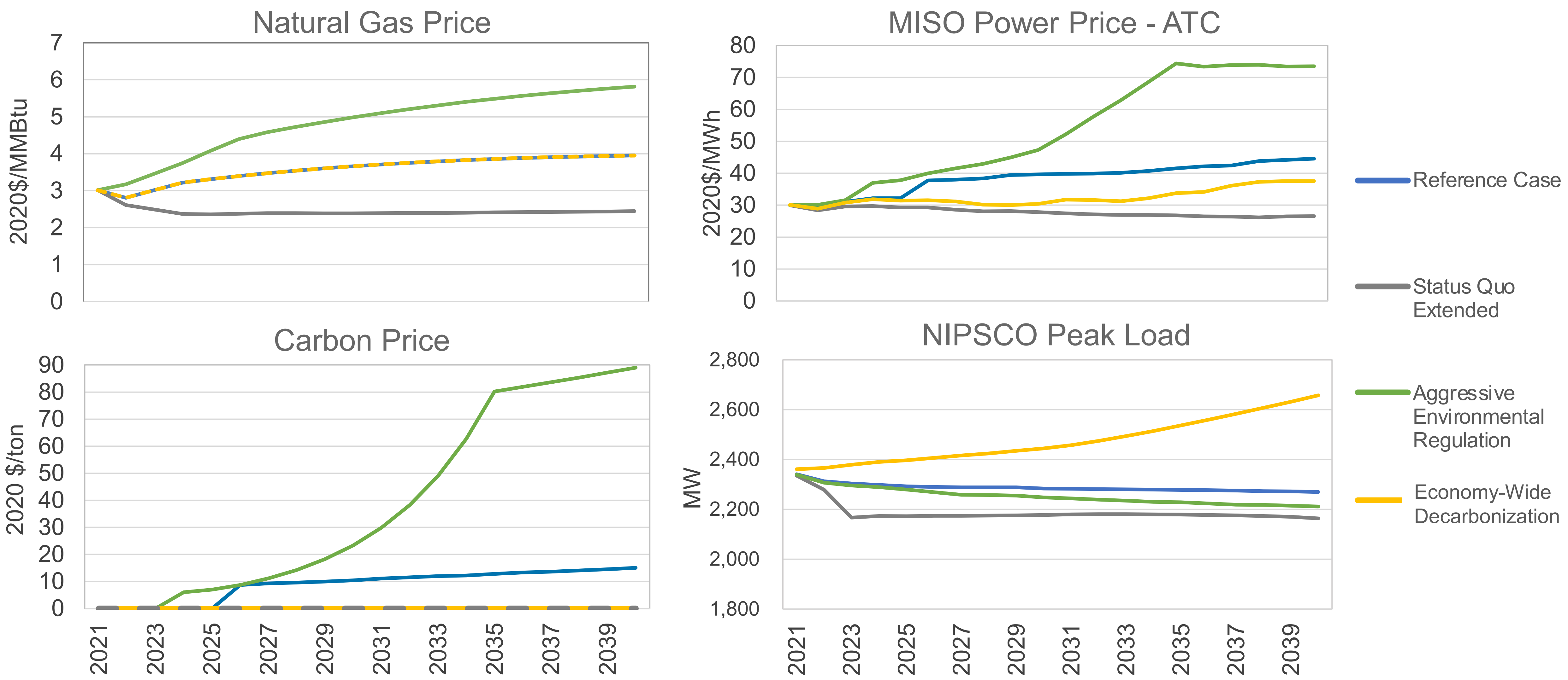
Peak load growth varies by season due to the different impacts from electrification, DER penetration, and economic growth





Note that electrification can impact the month of system peak over time.

SUMMARY RANGE OF KEY SCENARIO VARIABLES



STOCHASTIC ANALYSIS PROCESS AND KEY INPUTS

STOCHASTIC ANALYSIS APPROACH

The 2021 IRP is incorporating combined commodity price and renewable output stochastic analysis

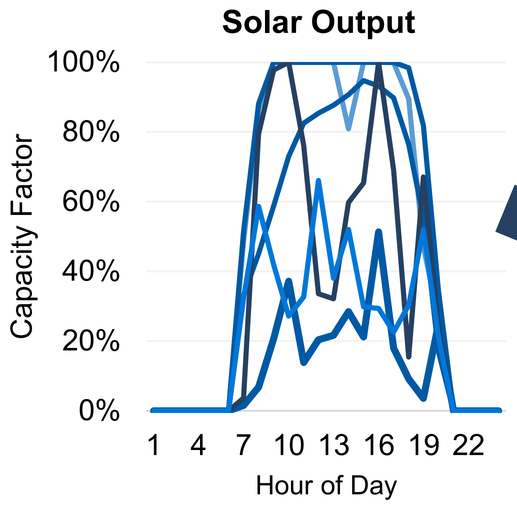
1 *Input Data Development*

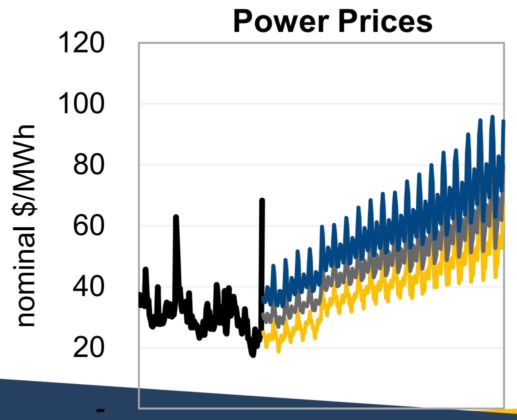
- Fundamental forecasts
- Historical price data
- Historical weather data (and corresponding renewable output)

2 *Statistical and Fundamental Analysis*

- Commodity price path simulation
- Impact analysis of renewable output on power prices

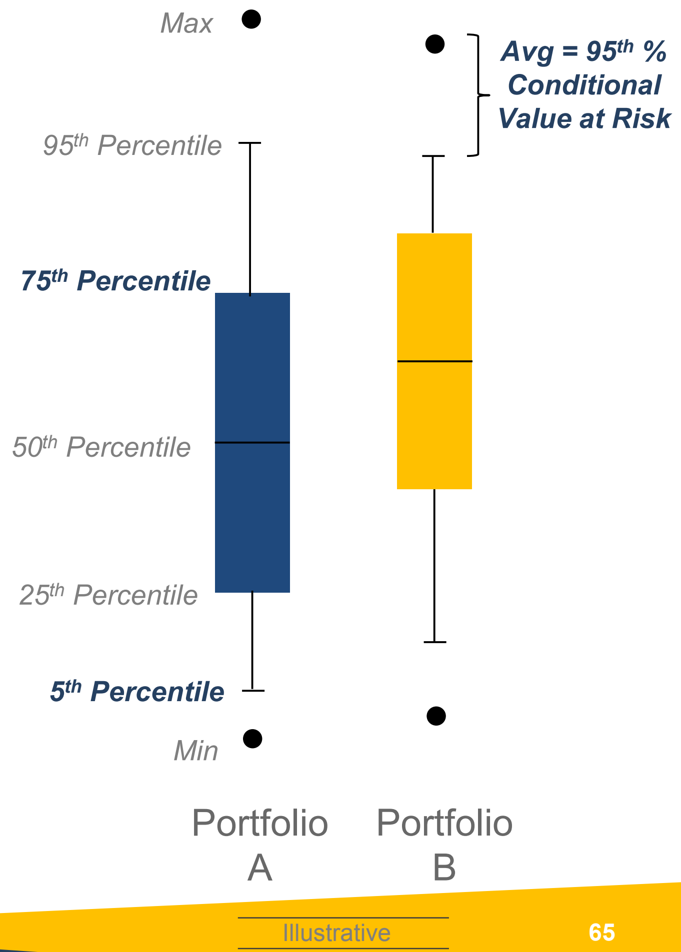
3 *Stochastic Input Development*



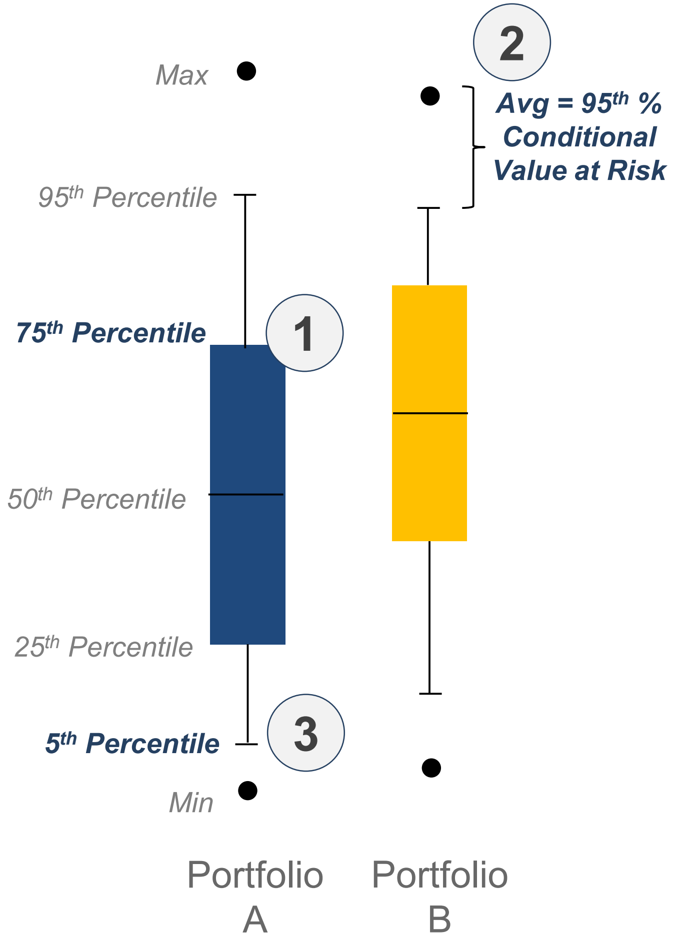


Evaluate NIPSCO portfolios hundreds of times

4 *NIPSCO Portfolio Analysis*



STOCHASTIC PORTFOLIO ANALYSIS RESULTS CONTRIBUTE TO SCORECARD



Illustrative

Preliminary & Illustrative

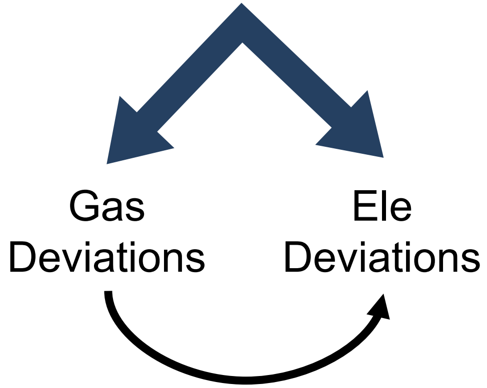
Objective	Indicator	Description and Metrics
Affordability	**Cost to Customer**	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Stability	1 **Cost Certainty**	• Certainty that revenue requirement within the most likely range of outcomes • **Metric: Scenario range NPVRR and 75th percentile of cost to customer**
	2 **Cost Risk**	• Risk of unacceptable, high-cost outcomes • **Metric: Highest scenario NPVRR and 95th percentile conditional value of risk (average of all outcomes above 95th percentile) of cost to customer**
	3 **Lower Cost Opportunity**	• Potential for lower cost outcomes • **Metric: Lowest scenario NPVRR and/or 5th percentile of cost to customer**

COMMODITY PRICE STOCHASTIC DEVELOPMENT METHODOLOGY

Consistent with 2018 IRP approach

- CRA simulates daily natural gas and power price volatility using its MOSEP simulation model
- Model parameters are calibrated to historical gas market and MISO power market price behavior (training)
- Given *expected* paths for electricity and gas prices, Monte Carlo engine simulates price deviations to yield "*actual*" or "*realized*" price paths
- Model enforces seasonal correlation between electricity and gas price deviations

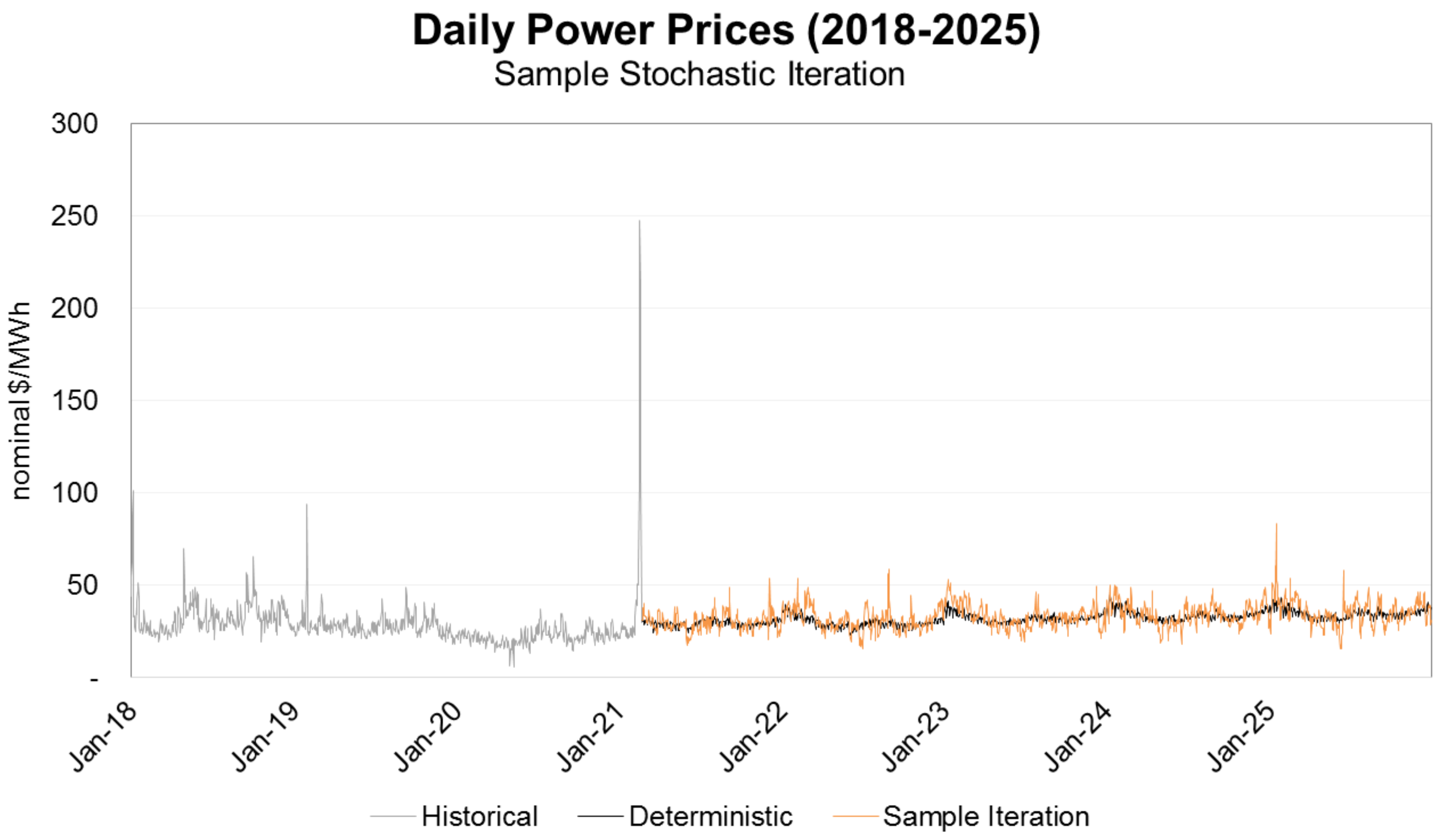
CRA Stochastic Price Propagation Model (MOSEP)*

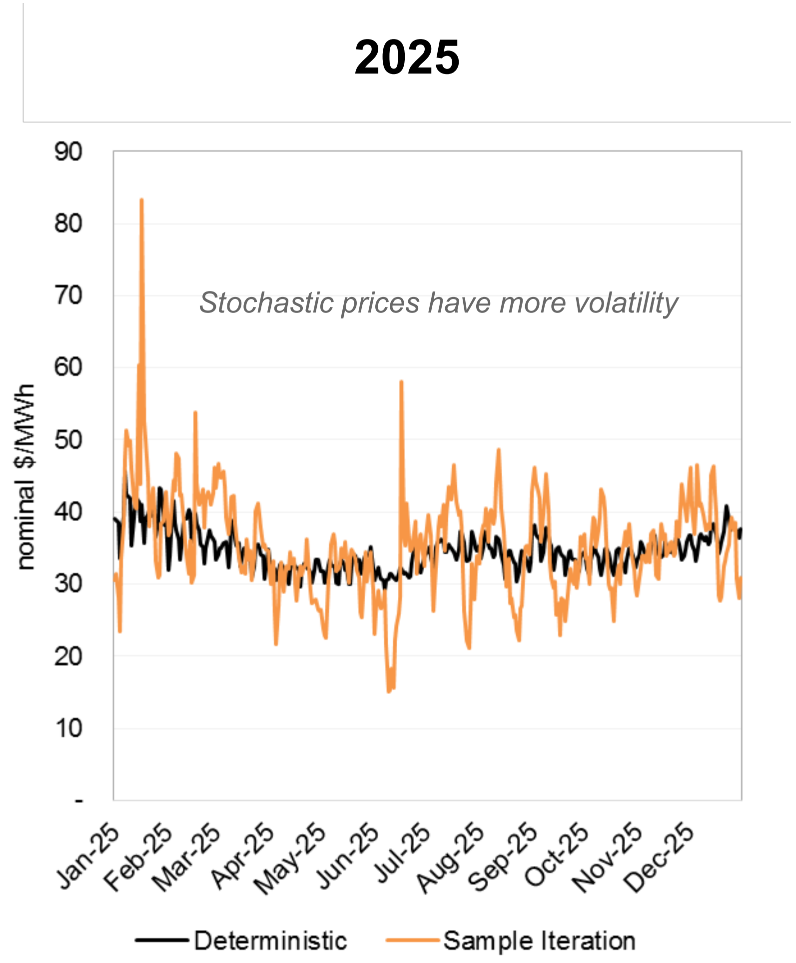


*MOSEP = Moment Simulation Energy Price Model

SAMPLE POWER PRICE ITERATIONS

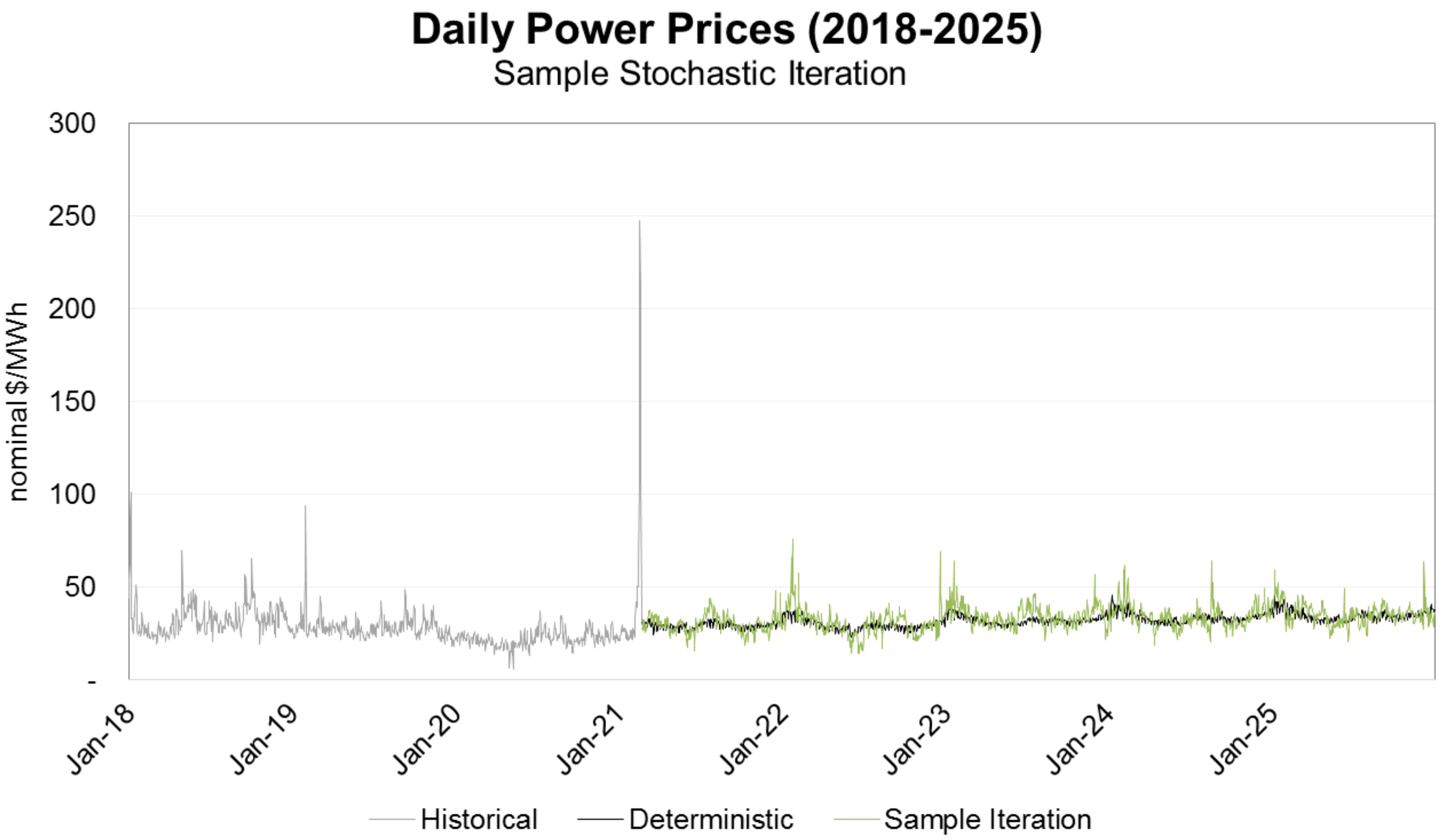
Individual stochastic price iterations display more variation than deterministic forecast models



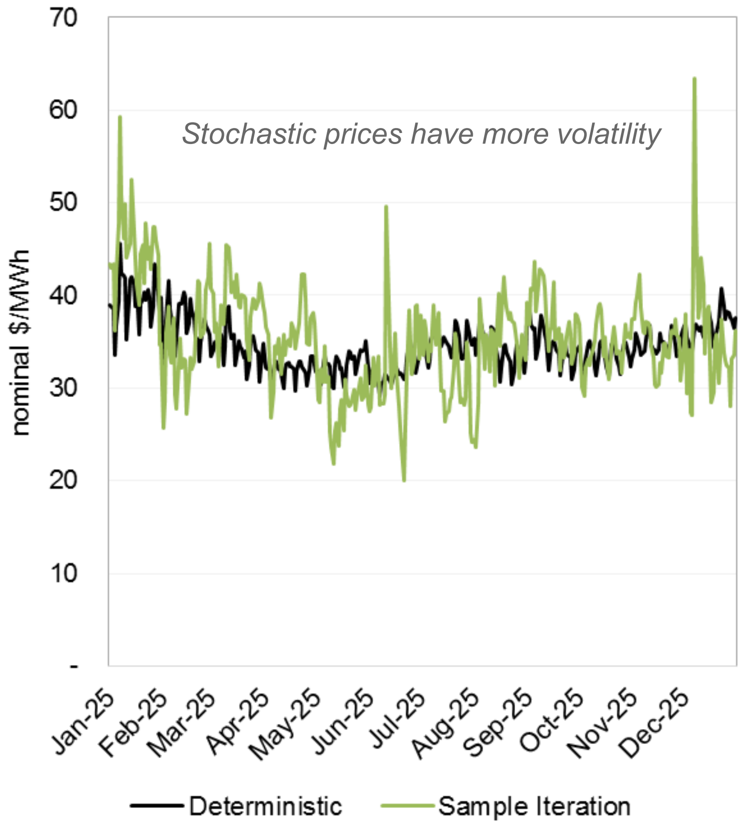


SAMPLE POWER PRICE ITERATIONS

Individual stochastic price iterations display more variation than deterministic forecast models

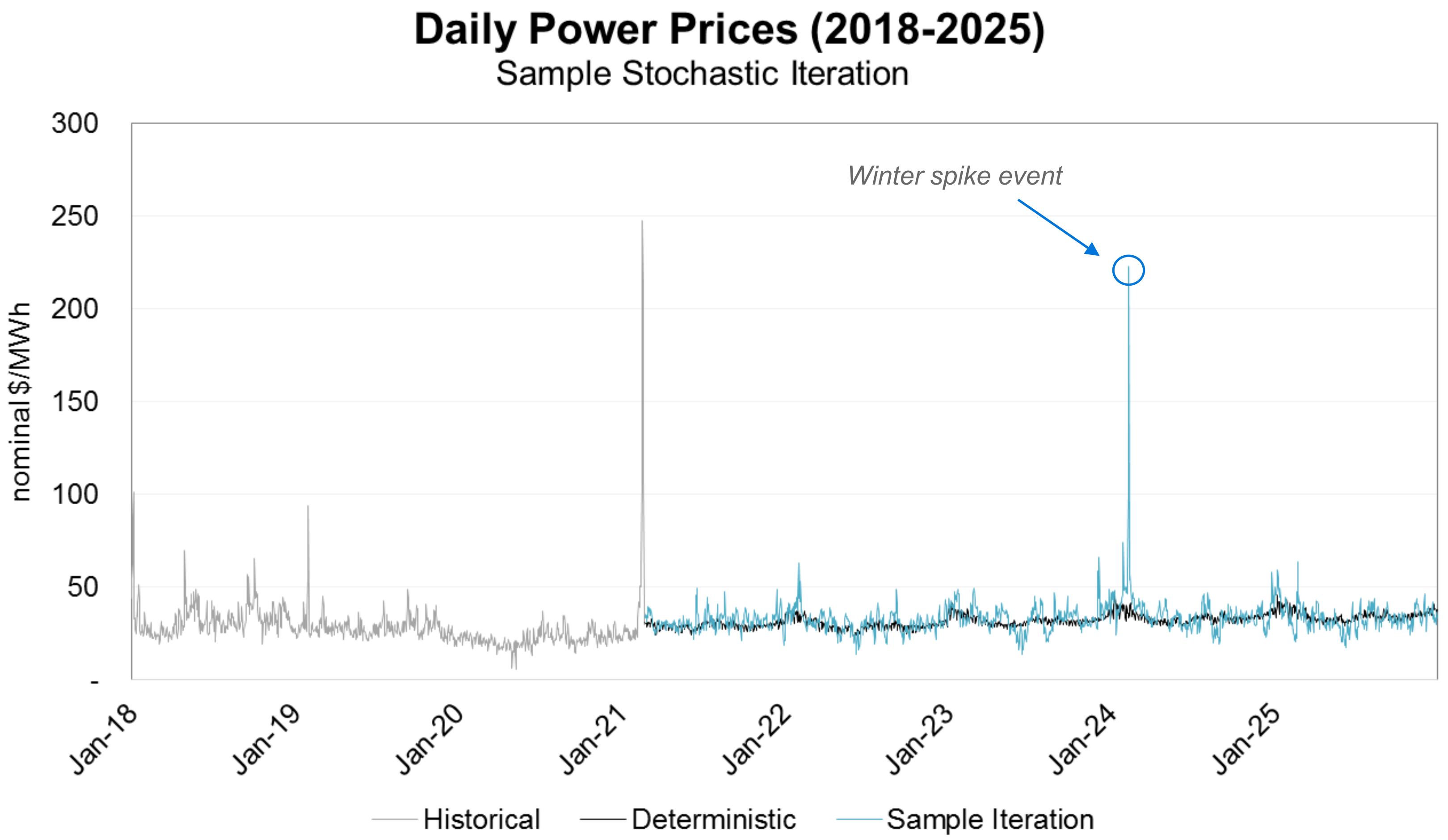


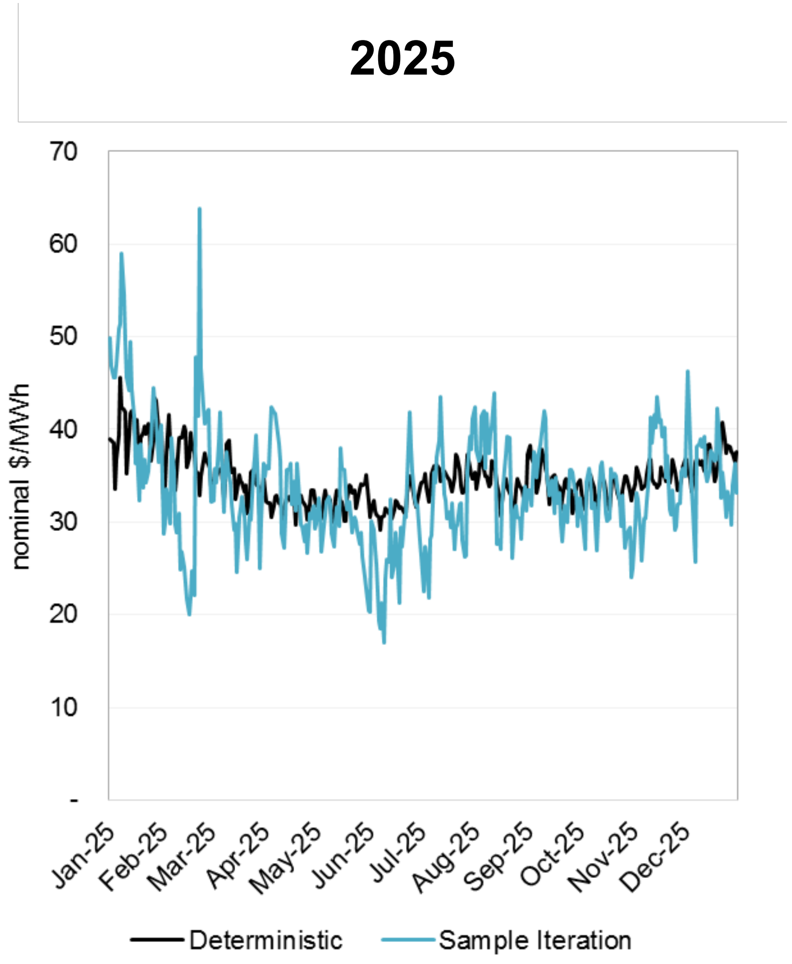
2025



SAMPLE POWER PRICE ITERATIONS

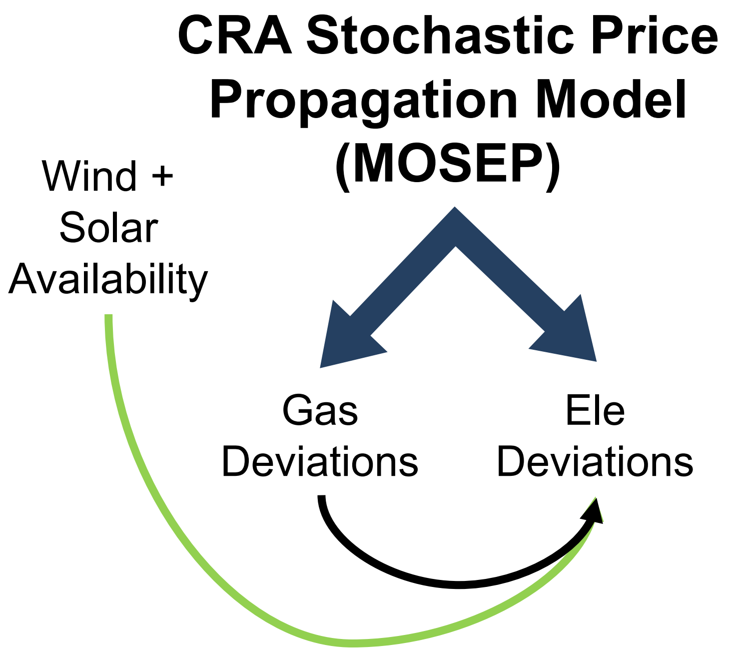
Individual stochastic price iterations display more variation than deterministic forecast models





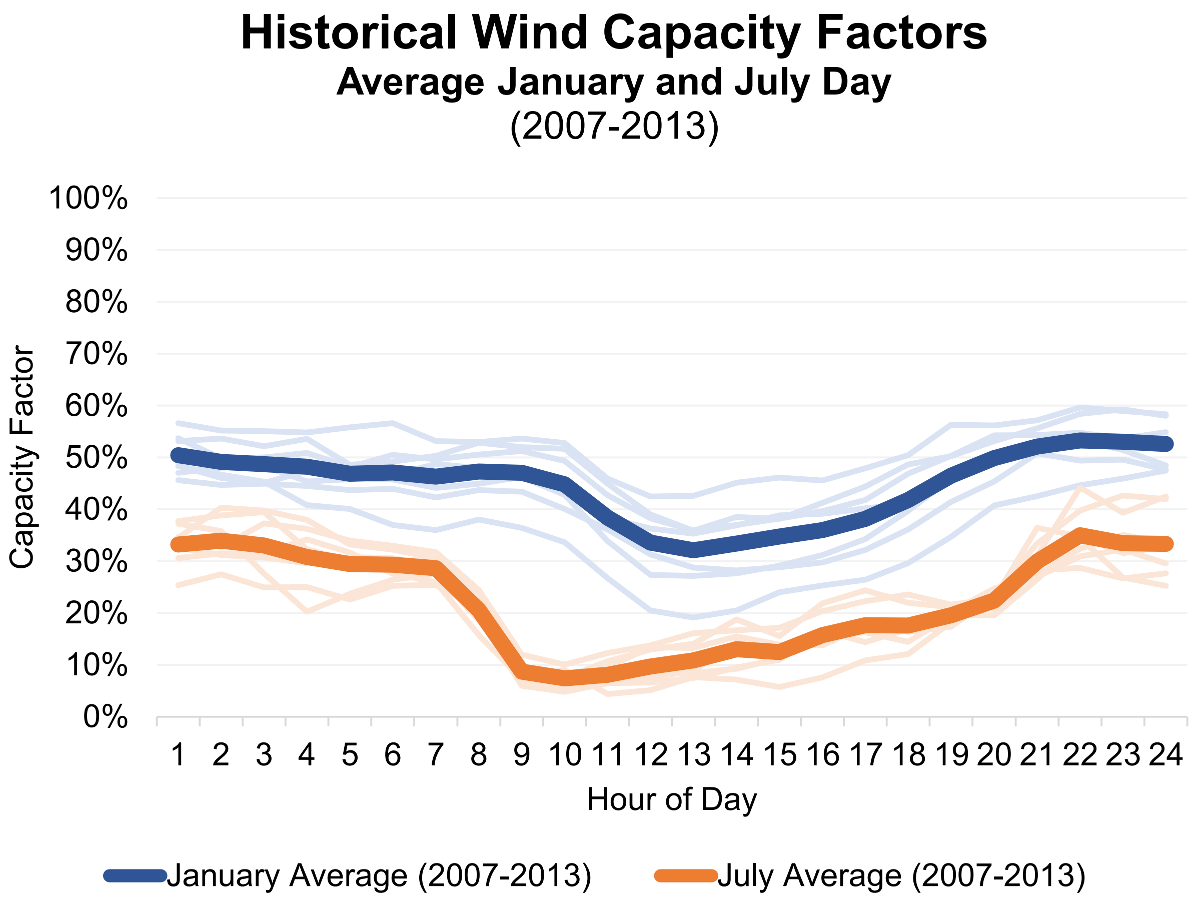
2021 IRP ENHANCEMENT – INTEGRATING RENEWABLE OUTPUT UNCERTAINTY

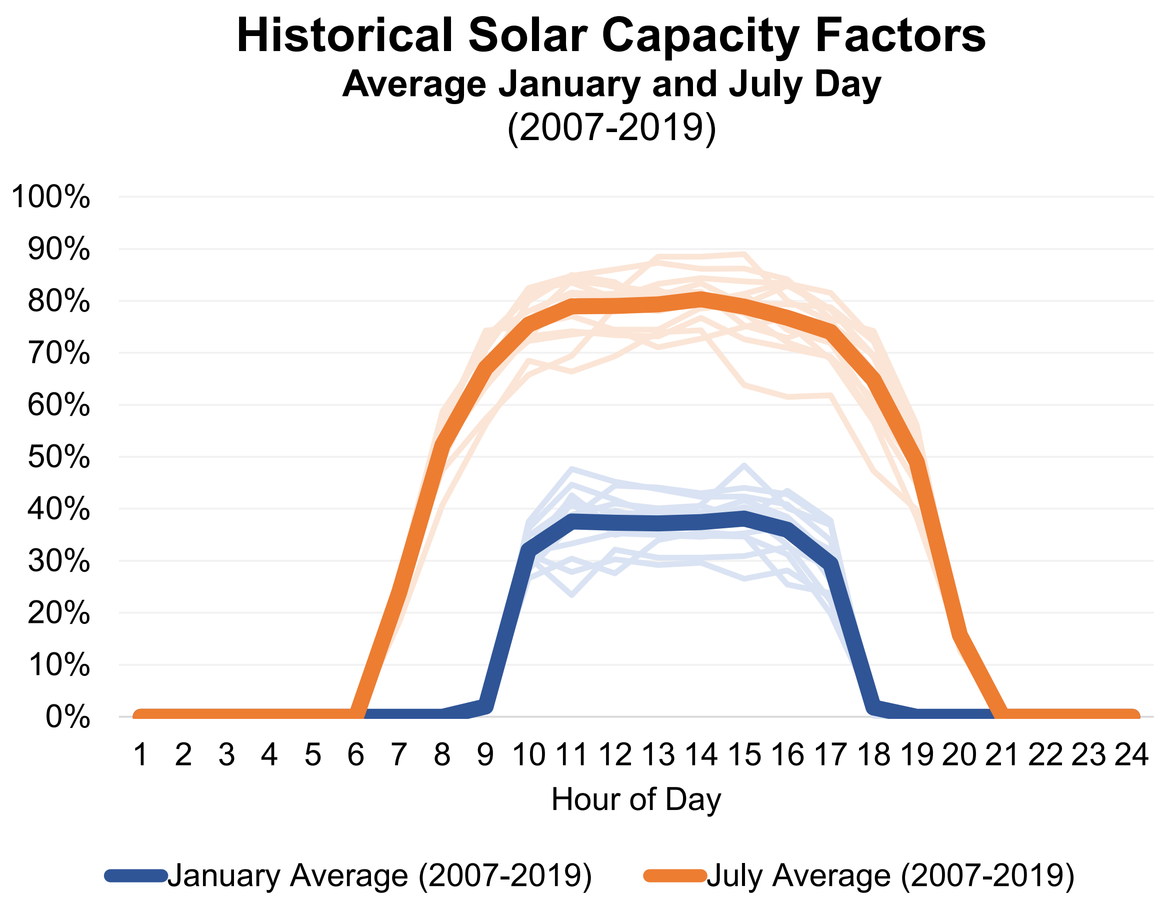
- Assuming that power prices and renewable output evolve independently of each other potentially **underestimates** the risk of growing levels of intermittent generation in NIPSCO's portfolio
- Higher levels of intermittent generation output are generally expected to depress price levels, but the magnitude of this effect is uncertain, particularly due to lack of relevant historical data
- For the stochastic analysis, the magnitude of this effect was estimated through forward power price formation using various levels of renewable penetration followed by a regression analysis to quantify the impact. Adjustments were then made to the hourly power price paths, yielding a set of power prices which are correlated with gas prices and which reflect the expected impact of varying renewable availability



HOURLY RENEWABLE OUTPUT VARIABILITY

Obtained based on historical weather data from NREL's NSRDB and WIND Toolkit databases



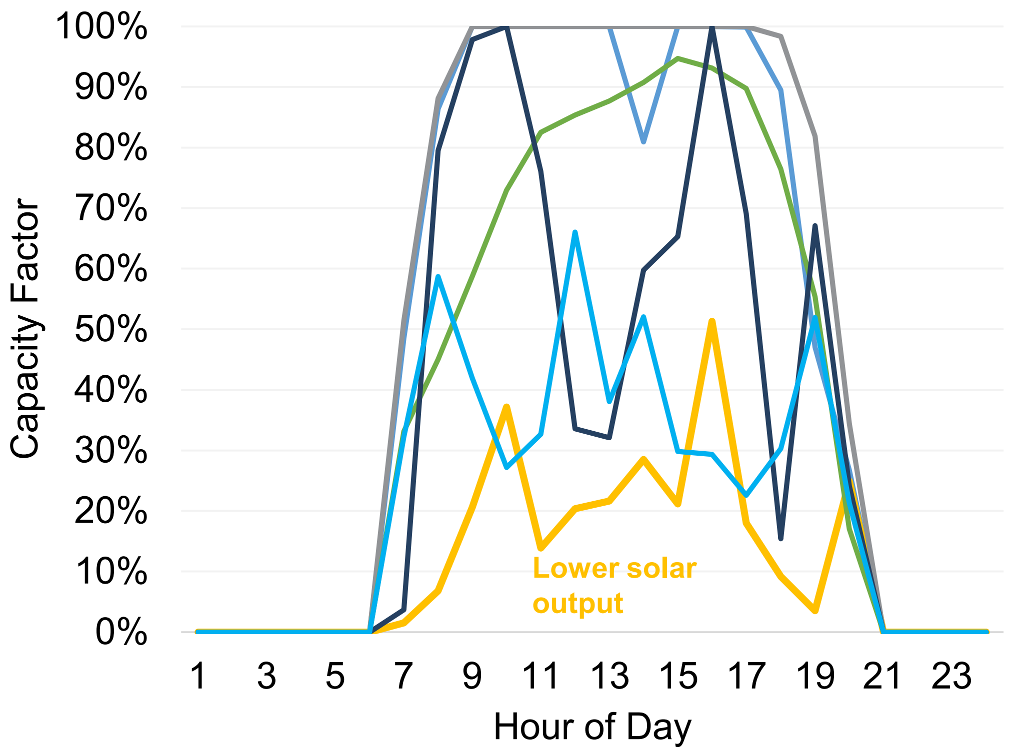


HOURLY RENEWABLE VOLATILITY AND IMPACT TO POWER PRICES

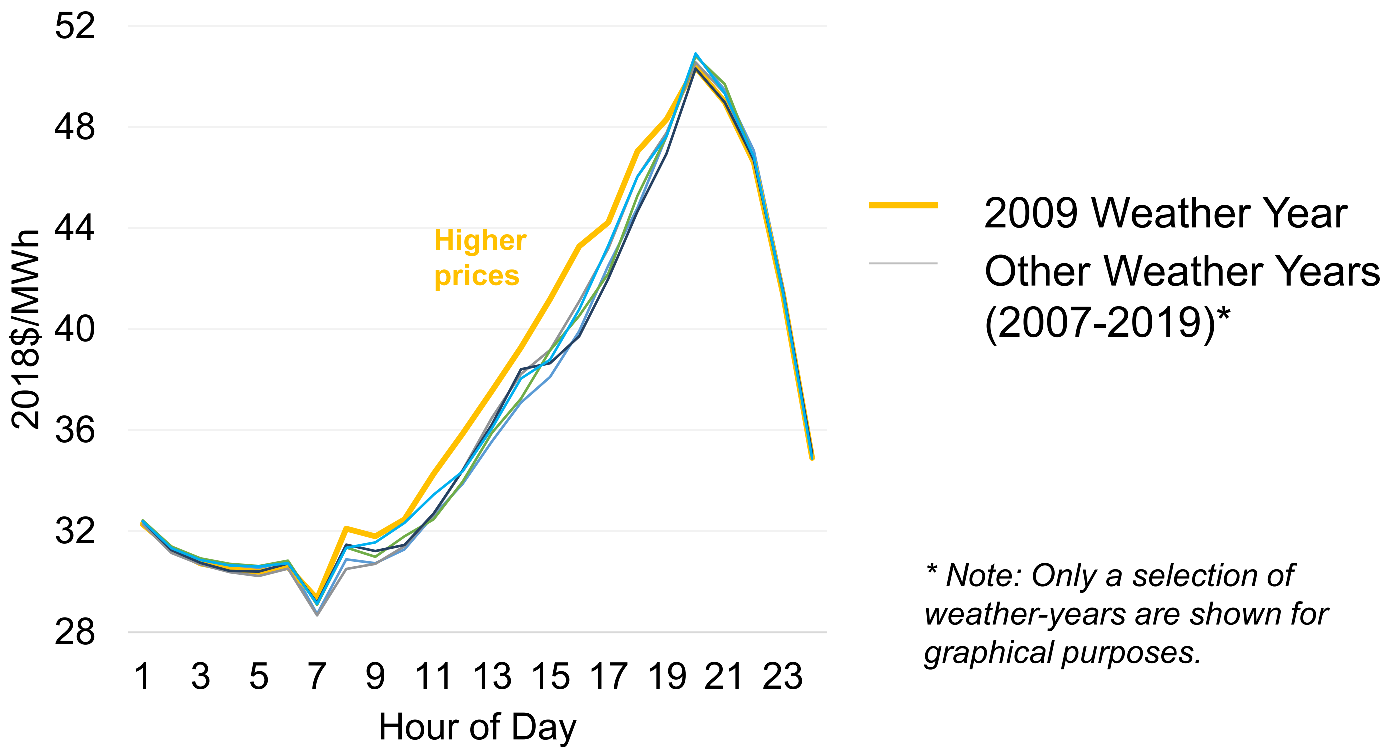
Various wind and solar availabilities from historical weather-years are modeled

Ref Case Forecast
Illustrating a sample July day

Solar Availability Sample Iterations
July Day 2030 (Aurora Inputs)



MISO Zone 6 Power Prices
July Day 2030 (Aurora Outputs)



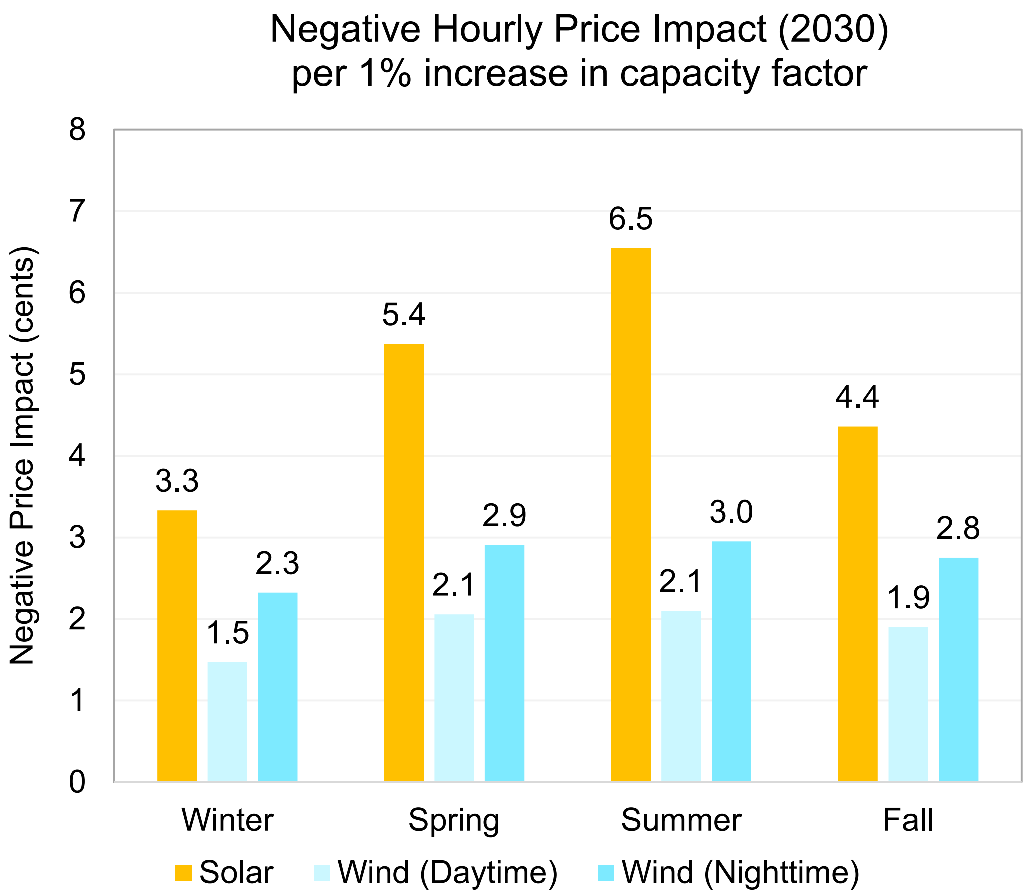
** Note: Only a selection of weather-years are shown for graphical purposes.*

RELATIONSHIP BETWEEN RENEWABLE OUTPUT AND POWER PRICES

Determined average hourly impact on prices by analyzing 20 years of hourly power prices and correlated renewable availabilities with seasonal and time-of-day variables

Finding #1:

- Renewable availability has a significant negative impact on power prices, all else equal



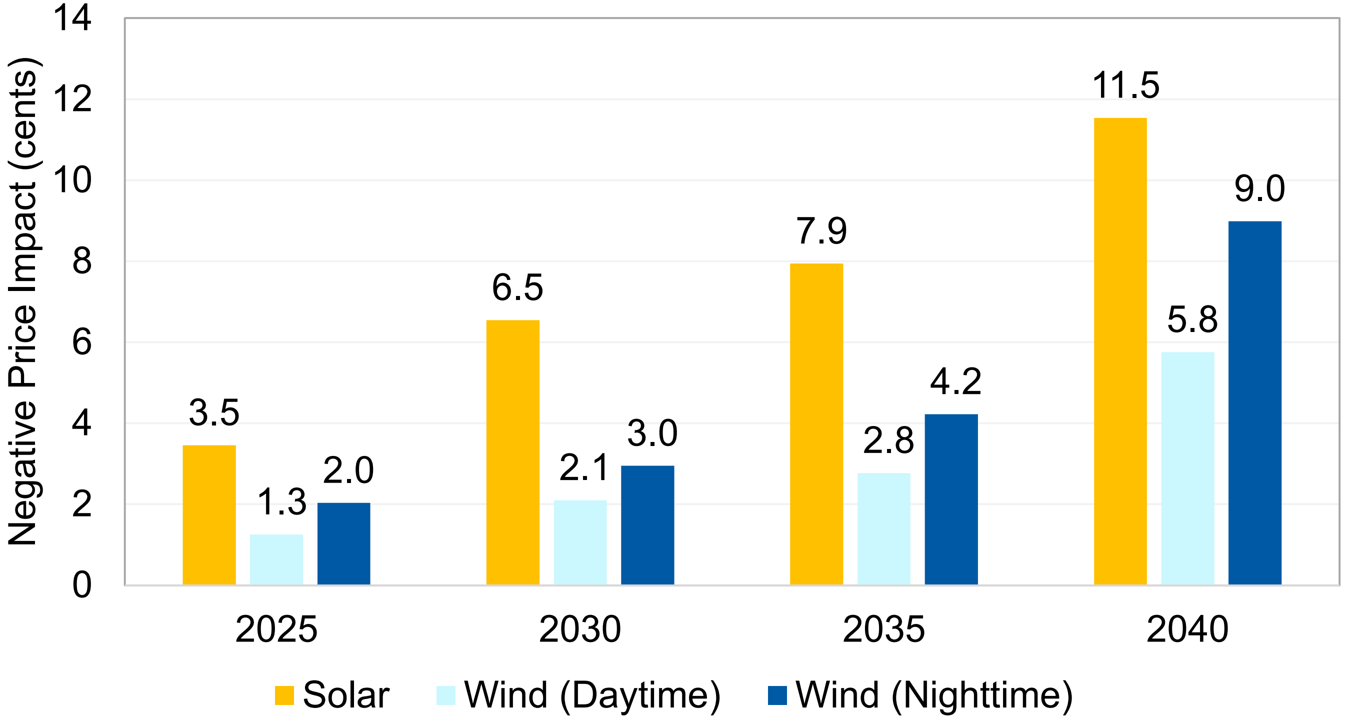
RELATIONSHIP BETWEEN RENEWABLE OUTPUT AND POWER PRICES

Conducted Aurora analysis on multiple test-years (2020, 2025, 2030, 2035, and 2040) to assess how the relationship changes with different levels of renewable penetration in MISO Zone 6

Finding #2:

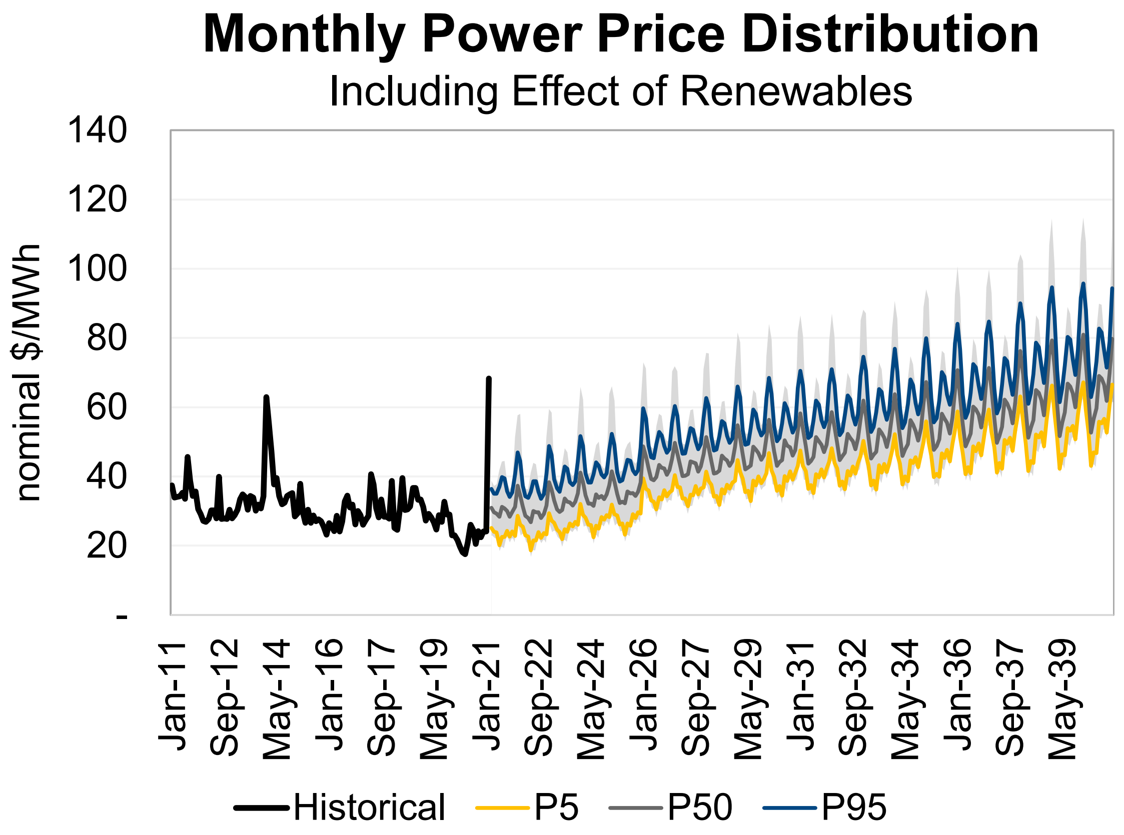
- Impact of renewable availability on power prices increases with level of renewable penetration

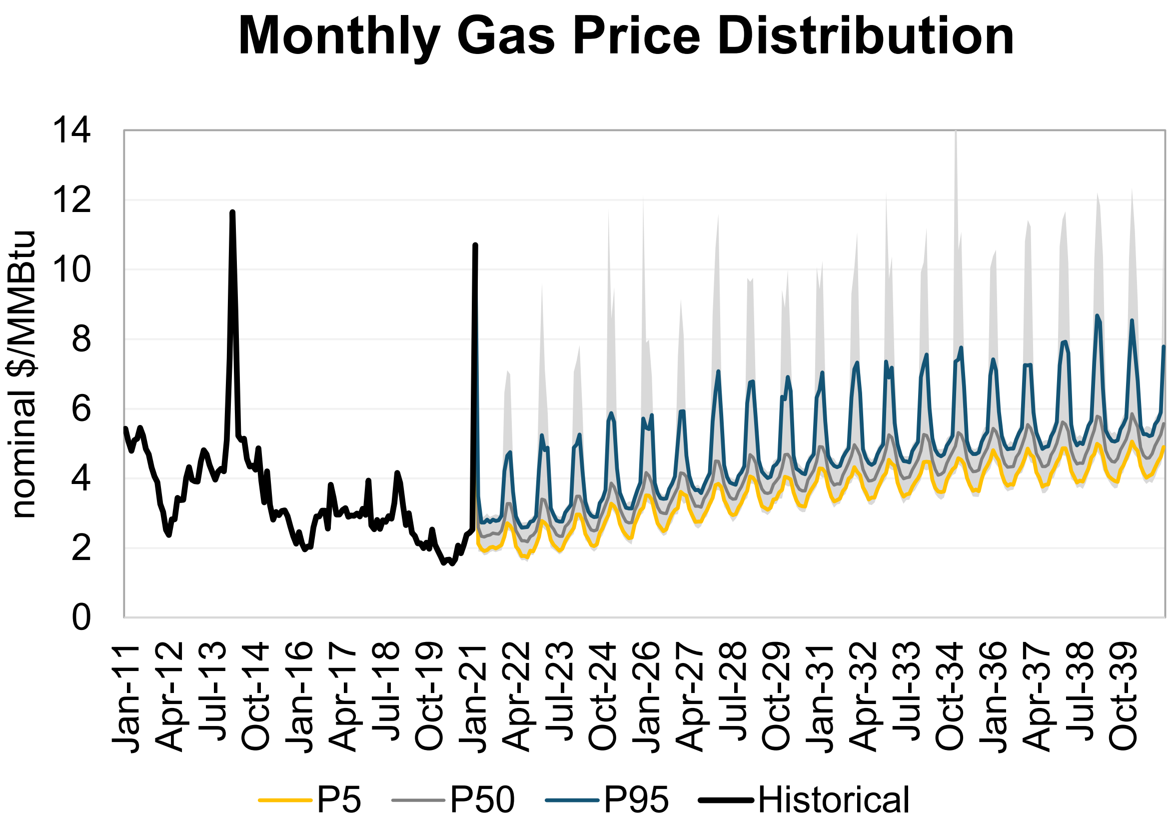
Negative Hourly Price Impact, Summer
per 1% increase in capacity factor



FINAL COMMODITY PRICE DISTRIBUTION SUMMARIES

- Hourly renewable availabilities are randomly drawn and paired with power and gas price paths and the regression-based impact is added to the power prices
- Individual paths are then analyzed through Aurora for NIPSCO portfolio analysis





BREAK

2021 REQUEST FOR PROPOSAL (RFP) UPDATE

Andy Campbell, Director Regulatory Support & Planning, NIPSCO
Bob Lee, Vice President, CRA

Northern Indiana Public Service Company LLC

2021 Request for Proposals
for Power Supply Generation Facilities
and/or Purchase Power Agreements

Second Stakeholder Advisory Meeting
May 20, 2021

Hosted by CRA International

NIPSCO 2021 RFP

Welcome

Welcome to this stakeholder advisory meeting for Northern Indiana Public Service Company's ("NIPSCO") 2021 Request for Proposals ("RFP") Process

- NIPSCO intends to conduct RFP Events ("2021 RFP") covering all-sources to help inform long-term market planning and identify potential projects for transaction
- NIPSCO will be seeking approximately 400 - 650 megawatts ("MW" – "Unforced Capacity") of 1) solar or solar paired with storage, 2) wind or wind paired with storage, and/or 3) thermal, standalone storage, emerging technologies, or other capacity resources
- NIPSCO will seek to satisfy its capacity needs through proposals for asset sales or power purchase agreements ("PPA") for delivery beginning in 2024, 2025, and 2026

- *NIPSCO does business in the State of Indiana as a regulated public utility generating, transmitting and distributing electricity for sale in Indiana and the broader Midcontinent Independent System Operator, Inc. ("MISO") regional electricity market*
- *NIPSCO currently serves approximately 468,000 electric customers in northern Indiana*
- *By November 1, 2021, NIPSCO will submit an Integrated Resource Plan ("2021 IRP") to the Indiana Utility Regulatory Commission ("IURC"), which will identify its long term capacity needs and chart a path to meet those needs*

In April 2021, NIPSCO solicited stakeholder feedback on proposed RFP design concepts and provided the RFP documents from its 2019 RFP for stakeholder feedback

- Since the 2021 RFP is the third in the series of recent RFPs, NIPSCO intends to replicate much of the 2019 RFP given the response and transaction success rates from prior events
- Stakeholders received materials on April 14, 2021 and feedback was requested by April 30, 2021
- NIPSCO reserved the right to incorporate, modify or disregard any feedback or comments received

- Below is a summary of the feedback received and incorporated by NIPSCO:
  - Three stakeholders provided comments requesting solar RFP respondents address vegetation plans and the use of pollinator-friendly vegetation
  - NIPSCO incorporated these comments by requesting solar RFP respondents provide a summary of all environmental studies and plans associated with the site including, but not limited to, impact on plant species; Respondents should note whether project(s) will meet or exceed pollinator habitat requirements
  - NIPSCO is adding an explicit reference to environmental permits, studies, or programs as a part of the Development Risk scoring criteria.
  - No other stakeholder feedback was received

NIPSCO 2021 RFP
Design Concepts

Element	2021 RFP Approach

Technology	• All solutions regardless of technology facilitated through three separate RFP
	  • Event 1: Wind and wind paired with storage
	  • Event 2: Solar and solar paired with storage
	  • Event 3: Thermal, standalone storage, emerging technologies, and other capacity resources

Event Size	• Overall size ranges from 400 – 650 MW UCAP at this time, but will be based on IRP Portfolios
Ownership Structure	• Seeking bids for new or existing asset purchase and power purchase agreements • Resource must qualify as MISO internal generation (not pseudo-tied)
Duration	• Requesting delivery beginning in 2024, 2025, and 2026 • Minimum contractual term and/or estimated useful life of 5 years
Deliverability	• Must have firm transmission delivery to MISO Zone 6 – Full Network (“NRIS”) • Must meet N-1-1 reliability criteria or show cost estimate to achieve that quality
Participants & Pre-Qualifications	• Market to broad bidder audience via trade press and today’s stakeholder meeting • Require credit-worthy counterparties to ensure ability to fulfill resource obligations

All Proposals will be evaluated consistent with the Evaluation Criteria provided in Appendix F

- The RFP will evaluate individual proposals and select the proposals to advance to the final negotiation phase based on certain evaluation criteria:
  - Levelized cost calculation for the capacity asset (300 points)
  - Reliability and deliverability for the capacity asset (300 points)
  - Development risk (250 points)
  - Additional proposal-specific benefit and risk factors (150 points)

- Examples of potential proposal-specific benefit and risk factors are listed in the RFP documents, and include, but are not limited to:
  - Impacts on local communities that NIPSCO serves
  - MBE (Minority Business Enterprise) or WBE (Women's Business Enterprise)
  - Enterprise engagement in Tier I or Tier II supplier diversity spending
  - Project specific environmental or legacy agreements
  - Black start capabilities
  - Other items not specifically addressed by economic, reliability, or development criteria

NIPSCO 2021 RFP

Information Website

Information Website for the RFP Process is http://www.nipsco-rfp.com

- Information about the RFP
- RFP documents
- RFP timeline
- Frequently Asked Questions (“FAQs”)
- Information about NIPSCO and CRA International
- Bidders may also:
  - Register to receive updates
  - Submit questions

CRA encourages all interested parties to register on the Information Website to remain informed about the RFP process

- Registrants receive any information updates about the RFP via email
  - Provide name, company name, valid email address
- Once registered, prospective bidders can submit questions

NIPSCO 2021 RFP

Inquiries

Questions regarding the RFP must be submitted to the RFP Manager

There are two ways to submit questions during the RFP:

- Via the Information Website (www.NIPSCO-RFP.com)
- Via email to the RFP Manager (NIPSCO-RFPManager@crai.com)

FAQs will be posted to the Information Website FAQ page in order to ensure that all process participants and stakeholders have equal access to information

- All questions should be submitted to the RFP manager
- Bidders and other stakeholders should not reach out to NIPSCO directly

NIPSCO 2021 RFP
Timeline

Activity	Date
Notice of Intent w/ Pre-Qualification Documents Due	Friday, June 4, 2021 (12:00 PM CPT)
Notification of Pre-Qualification	Wednesday, June 9, 2021
Proposals Due	Wednesday, June 30, 2021 (5:00 PM CPT)
Start of Bid Evaluation Period*	Tuesday, July 6, 2021
Bid Evaluation Period Complete*	Friday, August 20, 2021
Definitive Agreements Signed*	August 2021 – July 2022

*Tentative

WRAP UP & NEXT STEPS

Mike Hooper, President & COO, NIPSCO

NEXT STEPS

RFP

- RFP closes June 30th
- IRP analysis will incorporate results of the RFP

Stakeholder Process

- Next Public Stakeholder Advisory Meeting #3 is scheduled for July 13th
- Reach out to Alison Becker for 1x1 meetings
- Provide requested scenarios by June 30th

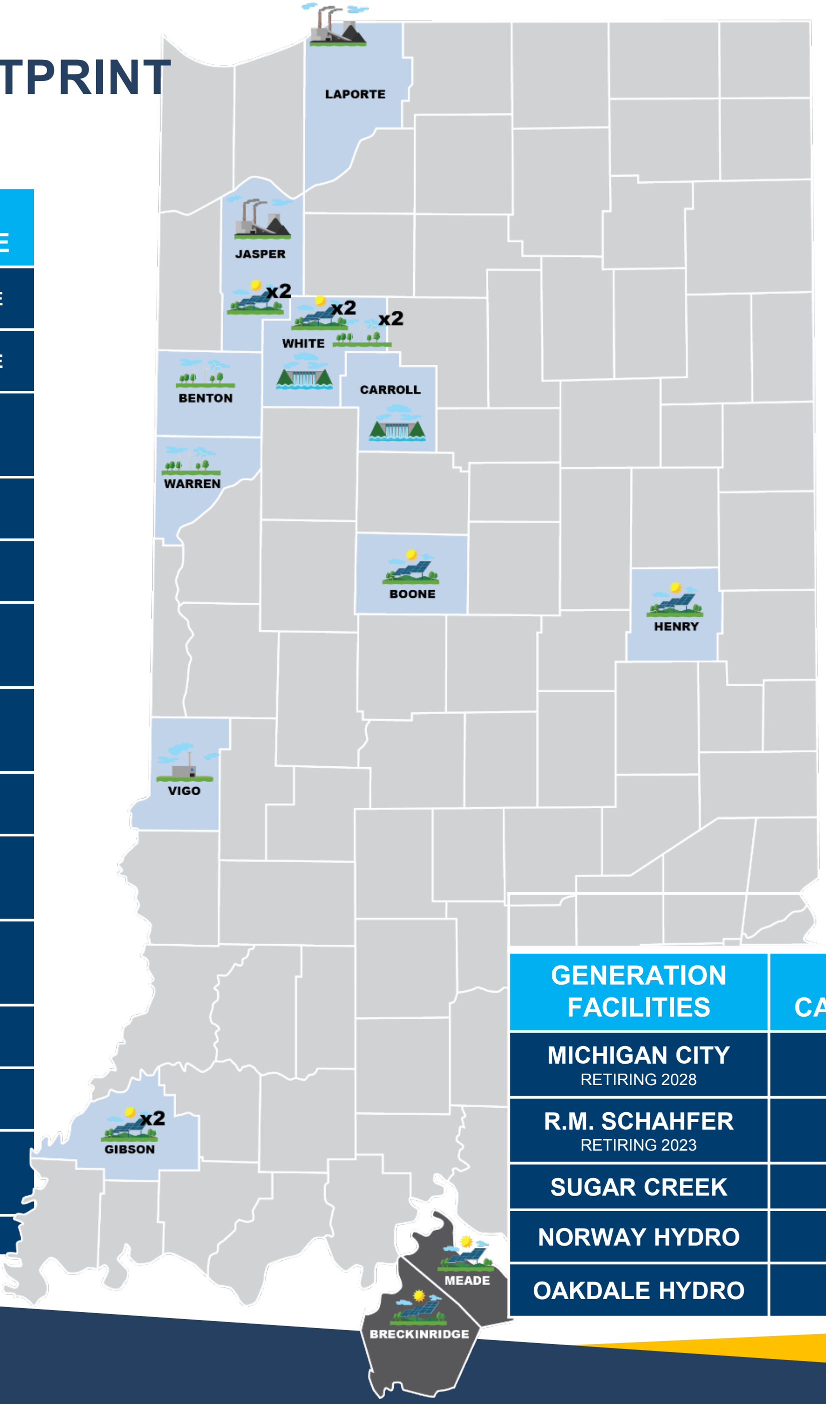
Stakeholder engagement is a critical part of the IRP process

APPENDIX

2023 ANTICIPATED GENERATION FOOTPRINT

New Generation Facilities

PROJECT	INSTALLED CAPACITY (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102MW	WHITE	COMPLETE
JORDAN CREEK WIND	400MW	BENTON WARREN	COMPLETE
INDIANA CROSSROADS WIND	300MW	WHITE	2021
DUNNS BRIDGE SOLAR I	265MW	JASPER	2022
BRICKYARD SOLAR	200MW	BOONE	2022
GREENSBORO SOLAR	100MW +30MW BATTERY	HENRY	2022
INDIANA CROSSROADS SOLAR	200MW	WHITE	2022
GREEN RIVER SOLAR	200MW	BRECKINRIDGE & MEADE (KENTUCKY)	2023
DUNNS BRIDGE SOLAR II	435MW +75MW BATTERY	JASPER	2023
CAVALRY SOLAR	200MW +60MW BATTERY	WHITE	2023
GIBSON SOLAR	280MW	GIBSON	2023
FAIRBANKS SOLAR	250MW	SULLIVAN	2023
INDIANA CROSSROADS II WIND	204MW	WHITE	2023
ELLIOT SOLAR	200MW	GIBSON	2023



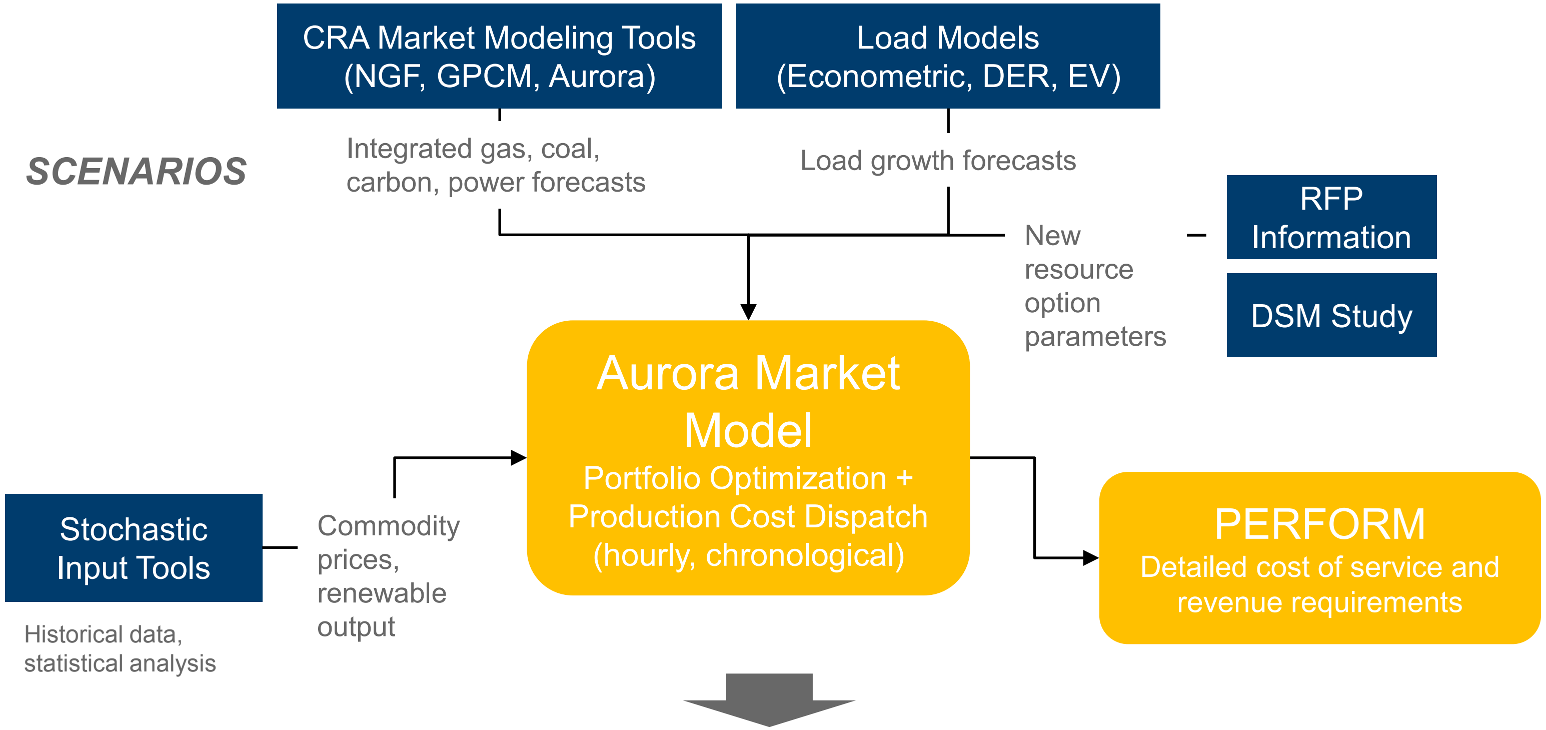
- Planned renewable resources expected to add 3,330MW installed capacity
- Additional $5 billion capital investments, much of which stays in the Indiana economy
- Generation transition plan generates more than $4 billion in cost-savings for our customers with industry-leading emissions reductions

Current Facilities

GENERATION FACILITIES	INSTALLED CAPACITY (MW)	FUEL	COUNTY
MICHIGAN CITY RETIRING 2028	469MW	COAL	LAPORTE
R.M. SCHAHFER RETIRING 2023	1,780MW	COAL	JASPER
SUGAR CREEK	535MW	NATURAL GAS	VIGO
NORWAY HYDRO	7.2MW	WATER	WHITE
OAKDALE HYDRO	9.2MW	WATER	CARROLL

RESOURCE PLANNING APPROACH

This year's process will be structurally similar to NIPSCO's 2018 IRP process, but with changes and enhancements to respond to stakeholder feedback and market change



	A	B	C	D	E	F
Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Cost to Customer	$12,985	$12,028	$11,769	$12,956	$12,121	$11,763
delta from least	$1,222 10.4%	$265 2.2%	$6 0.1%	$1,192 10.1%	$357 3.0%	$0 0.0%
Cost Certainty	$13,360	$12,254	$12,007	$13,286	$12,245	$11,883
delta from least	$1,477 12.4%	$371 3.1%	$124 1.0%	$1,403 11.8%	$362 3.0%	$0 0.0%
Cost Risk	$14,431	$12,922	$12,661	$14,284	$12,815	$12,364
delta from least	$2,067 16.7%	$558 4.5%	$297 2.4%	$1,920 15.5%	$452 3.7%	$0 0.0%
Fuel Security % non-gas capacity	45%	79%	86%	40%	72%	87%
Environmental 2030 CO_2 emissions 2005 baseline = 18.2M	2.18M	0.97M	0.97M	3.13M	2.03M	0.97M
Employees	0	0	0	<30	<30	<30
Local Economy	Dependent on project selection and location; currently under evaluation					

1. Identify key planning questions and approach
2. Develop market perspectives (planning reference case and scenarios)

Today's meeting will start

3. Develop integrated resource strategies for NIPSCO (portfolios)
4. Portfolio modeling
   - Detailed scenario dispatch
   - Stochastic simulations
5. Evaluate trade-offs and produce recommendation

Slide 19 from Stakeholder Meeting #1

PORTFOLIO PERFORMANCE WILL BE DISTILLED INTO AN INTEGRATED SCORECARD SIMILAR TO PREVIOUS IRPS

Preliminary & Illustrative

Broader Cost Elements

- Potentially incorporating additional value or avoided costs for market drivers like Ancillary Services

Broader Uncertainty Assessment

- Combination of renewable and commodity price uncertainty
- Incorporation of tail risk exposure and low cost opportunities

Expansion of Reliability Metrics

- Operational flexibility type metrics can proxy other operational requirements typically not captured in economic metrics

Objective	Indicator	Description and Metrics
Affordability	Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Rate Stability	Cost Certainty	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR and 75th percentile of cost to customer
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: Highest scenario NPVRR and **95th percentile conditional value of risk (average of all outcomes above 95th percentile)** of cost to customer
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: Lowest scenario NPVRR and/or 5th percentile of cost to customer
Environmental Sustainability	Carbon Emissions	• Carbon intensity of portfolio • Metric: Total annual carbon emissions (2030 short tons of CO_2) from the generation portfolio
Reliable, Flexible, and Resilient Supply	Operational Flexibility	• The ability of the portfolio to be controlled to provide energy "on demand," including during peak hours • Metric: % of dispatchable MW in gen. portfolio
	Resource Optionality	• The ability of the portfolio to flexibly respond to changes in NIPSCO load, technology, or market rules over time • Metric: MW weighted duration of generation commitments
Positive Social & Economic Impacts	Employees	• Net impact on NiSource jobs • Metric: Approx. number of permanent NiSource jobs associated with generation
	Local Economy	• Affect on the local economy from new development and ongoing property taxes • Metric: NPV of property taxes or land leases from the entire portfolio

RESPONSES TO STAKEHOLDER QUESTIONS / COMMENTS – EVs

Stakeholder Question/Comment: Could price responsive EV load affect charging shapes?

- Stakeholders shared a DOE report based on the 2011-2013 “EV Project” study across 16 cities and over 6,000 EVs suggest, which concludes that EV charging shapes vary, depending on the charging infrastructure
  - Residential Level 2 captures home charging and reflects predominant charging during night time hours. This pattern aligns well with NIPSCO’s Time of Use data.
  - Public Level 2 captures charging that may occur at workplaces, parking spots, etc. and shows charging mostly during the morning/mid-day.
  - DC Fast Charger captures public stations. Passengers may use fast charging for a variety of reasons, such as topping-up before a ride home, daily usage, or occasional use for a long-trip.
  - Overall, EV charging shapes did not exhibit noticeable seasonality.
- NIPSCO is using two shapes to evaluate a range of different average charging behaviors (as shown in Stakeholder Workshop #1 appendix).
  - In the **Low Penetration scenarios** (Reference and Status Quo Extended), EV charging is predominantly performed at home.
  - In the **High Penetration scenarios** (Aggressive Environmental Regulation and Economy-Wide Decarbonization), EV charging is mostly performed at home, although with more usage of public facilities (L2 and fast charging). Public charging occurs during morning and peak hours. This shape is based on the same DOE study, taking the charging pattern across all vehicles studied in the year 2011.
  - Case studies from countries with higher EVs per capita and fast-charging infrastructure (such as Norway) reveal that residential charging is still the dominant mode; this finding is reflected in the High Penetration charging shape.
- **Based on stakeholder questions and feedback, NIPSCO believes that proposed shapes remain appropriate, although a shift of charging load to later overnight hours would help incorporate changing market price expectations over time**

APPENDIX: SCENARIOS

KEY DRIVERS OF THE REFERENCE CASE NATURAL GAS FORECAST

Driver	CRA Approach	Explanation
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	CRA assumes a starting point of PGC 2018 "Minimum" resource, and grows the resource base to achieved PGC 2018 "Most Likely" volumes by 2050 to reflect pace of incremental discoveries over time
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	CRA based individual well productivity on historic data analyzed for each producing region, IP rates improve annually consistent with EIA assumptions The "Poor Heavy" resource base reflects CRA's view that the sampled production data is biased, reflecting the geology that producers expected to be most productive
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	CRA starts from drilling and operating costs reported by major producers in each supply basin, cost improvements over time are based on latest EIA assumptions
NGL & Condensate Value	• Liquids valued at 70% of AEO 2021 Reference Oil Price	On average since 2011, NGL prices have been around 70% of US oil prices on an MMBtu basis
Associated Gas Volumes	• Natural gas from shale and tight oil plays enters the market as a price taker	AEO21 revised EIA's forecast of domestic oil prices and production lower relative to AEO20; this pull-back in turn lowers volumes of associated gas, particularly in the short-term

KEY DRIVERS OF THE REFERENCE CASE NATURAL GAS FORECAST

Driver	CRA Approach	Explanation
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	CRA expects natural gas demand in the power sector to be relatively stable to modestly declining under Reference Case conditions; gas and renewable generation is likely to replace coal and some nuclear generation plus incremental load growth
LNG Exports	• Under-construction projects completed and total exports rising from around 7 bcf/d in 2020 to around 14 bcf/d by 2030	CRA expects few, if any, additional export terminals beyond projects already operating or that have already achieved FID due to weaker international prices and increased competition from suppliers with lower production costs or located closer to demand centers Completed facilities, on aggregate, operate at between 60-75% utilization once completed, consistent with historical operations
Pipeline Exports	• Exports rise from 5 bcf/d in 2020 to just under 10 bcf/d by 2030	CRA expects modest growth in pipeline exports to Mexico as utilization rates increase from current levels to 70% over time, reflecting growing gas demand as the energy transition continues

HIGH CASE (AGGRESSIVE ENVIRONMENTAL REGULATION) SUPPLY DRIVERS

Driver	Driver Change	Explanation
Resource Size	• Remove resource growth over time	Instead of assuming that available gas supply grows over time, we assume that future exploration is **limited by policy actions (e.g. drilling bans)**
Well Productivity	• Slow improvement (50%)	Improvements in technology slow, **as interest rotates into clean energy sectors due to changing policy incentives**
Fixed & Variable Well Costs	• Slow improvement (50%) • Environmental costs higher	Improvements in technology slow, **as interest rotates into clean energy sectors due to changing policy incentives** Environmental costs increase to reflect **additional regulation of emissions from producing sectors**
NGL & Condensate Value	• Oil prices lower – same 70% value	Transition from internal combustion engine (ICE) vehicles to EVs **lowers petroleum demand**, and fuel prices fall as CO2 prices add to final consumer costs
Associated Gas Volumes	• Fall relative to base case	Transition from ICE vehicles to EVs **lowers petroleum demand and prices fall**

HIGH CASE (AGGRESSIVE ENVIRONMENTAL REGULATION) DEMAND DRIVERS

Driver	CRA Approach	Explanation
Domestic Demand	• Electric demand reflects Aggressive Carbon price View • Non electric demand falls	Electric demand taken from Aurora Aggressive Environmental Regulation scenario reflects **significant drop in sector demand** RCI demand falls relative to the Base Case view
LNG Exports	• Remain at base view	International gas demand remains at base levels even as US prices increase
Pipeline Exports	• Remain at base view	International gas demand remains at base levels even as US prices increase

CRA HIGH GAS PRICE VS. AEO 2021

The scenario development process has created a plausible high-price scenario that takes a conservative view across key model drivers:

- AEO 21 values are used primarily to reflect a conservative case of oil-market drivers in the CRA natural forecast, including:
  - Lower associated gas volumes entering the market as a price taker
  - Less value for natural gas liquids, affecting economics of “wet” plays

- Other drivers of the High Gas Price forecast reflect others conservative outlooks that drive towards a high-price scenario relative to the Base Case:
  - CRA assumes no resource growth beyond current levels of proven and unproved reserves in the High Gas view
  - CRA impose additional environmental costs on drillers
  - CRA assumes slower rates of productivity and cost improvement
  - CRA assumes sustained export demand even at higher prices

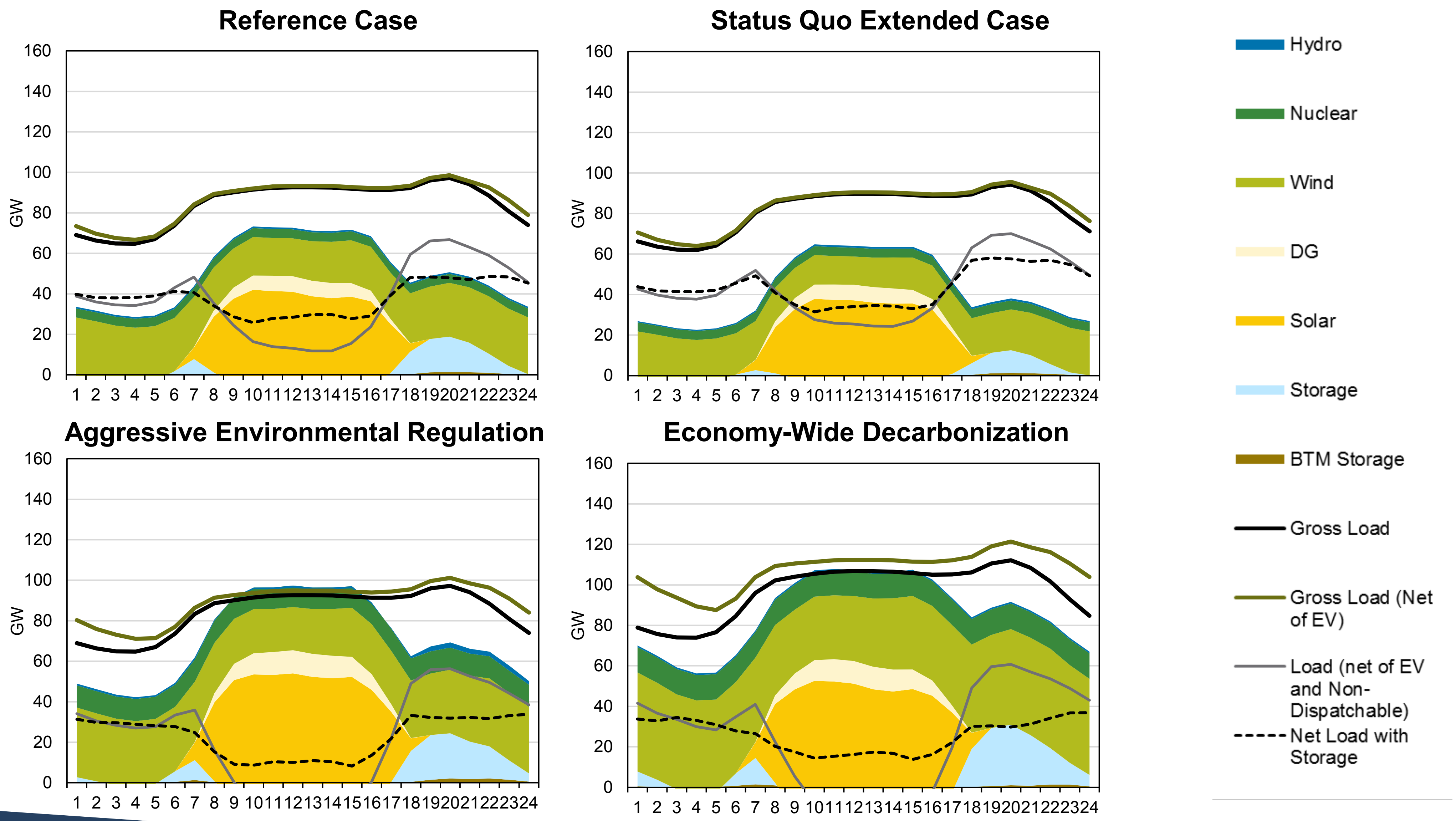
LOW CASE (STATUS QUO EXTENDED) SUPPLY DRIVERS

Driver	Driver Change	Explanation
Resource Size	• Starting unproven resource is higher than the Base Case	PGC and other forecasts have consistently shown growth in resource from year to year. In the Low case, the starting unproven resource **anticipates the growth in resources expected in the upcoming PGC 2020**. This 15% increase is well within the range of uncertainty from the 2018 unproven PGC estimates.
Well Productivity	• Fast improvement (accelerated)	**Improvements in well productivity are realized more quickly**, but stall in the 2040s after achieving long-term targets from the Base case
Fixed & Variable Well Costs	• Fast improvements (accelerated) • Environmental costs lower	**Improvements in drilling technology occur more quickly**, but stall in the 2040s after achieving long-term targets from the Base case **Environmental costs decrease** to reflect lower CO2 pressure than base case
NGL & Condensate Value	• Base Case View	Oil prices in base case already reflect status quo outlook for petroleum demand and price
Associated Gas Volumes	• Base Case View	Oil prices in base case already reflect status quo outlook for petroleum demand and price

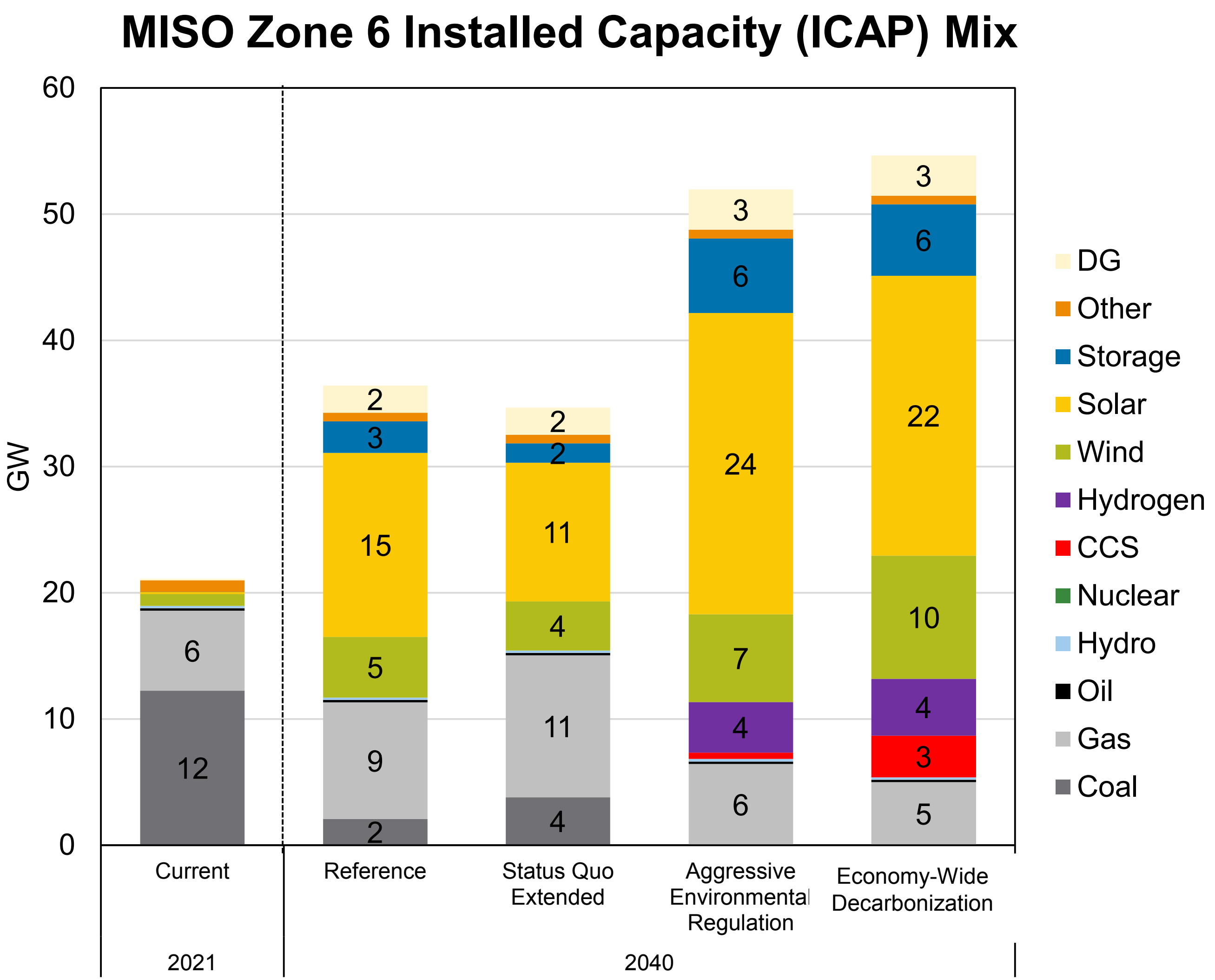
LOW CASE (STATUS QUO EXTENDED) DEMAND DRIVERS

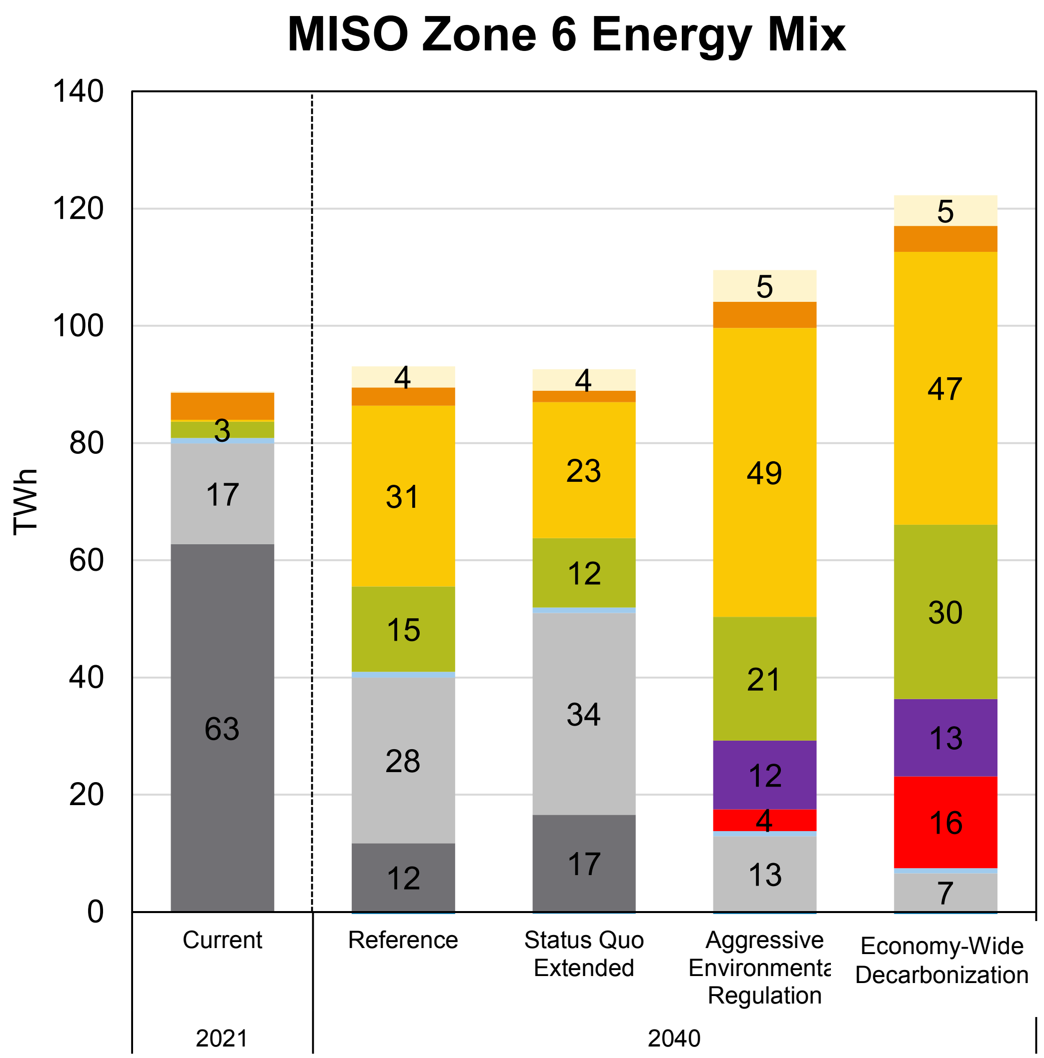
Driver	CRA Approach	Explanation
Domestic Demand	• Electric demand reflects Status Quo Extended case • No change to non-electric demand	Electric demand taken from Aurora Status Quo Extended scenario, **which is higher than Reference Case** Non-electric demand already reflects **limited transformation in end-use sectors**
LNG Exports	• Project Delays • Low capacity factors	**Under construction projects delayed** due to low prices and lack of demand Capacity factors stay around 60% levels due to low prices and demand
Pipeline Exports	• Low capacity factors	**Long term capacity factor of 50%**, down from 70% in base view

SHOULDER MONTH (FALL) 2040



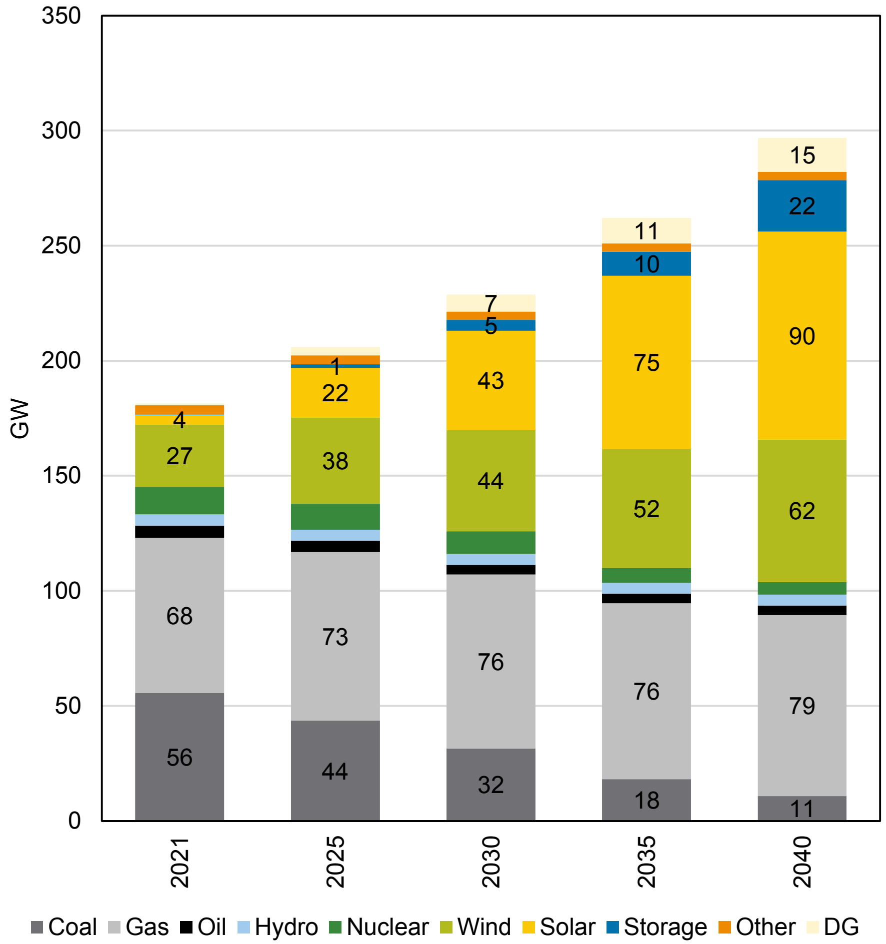
MISO ZONE 6 CAPACITY AND ENERGY MIX OUTLOOK ACROSS SCENARIOS



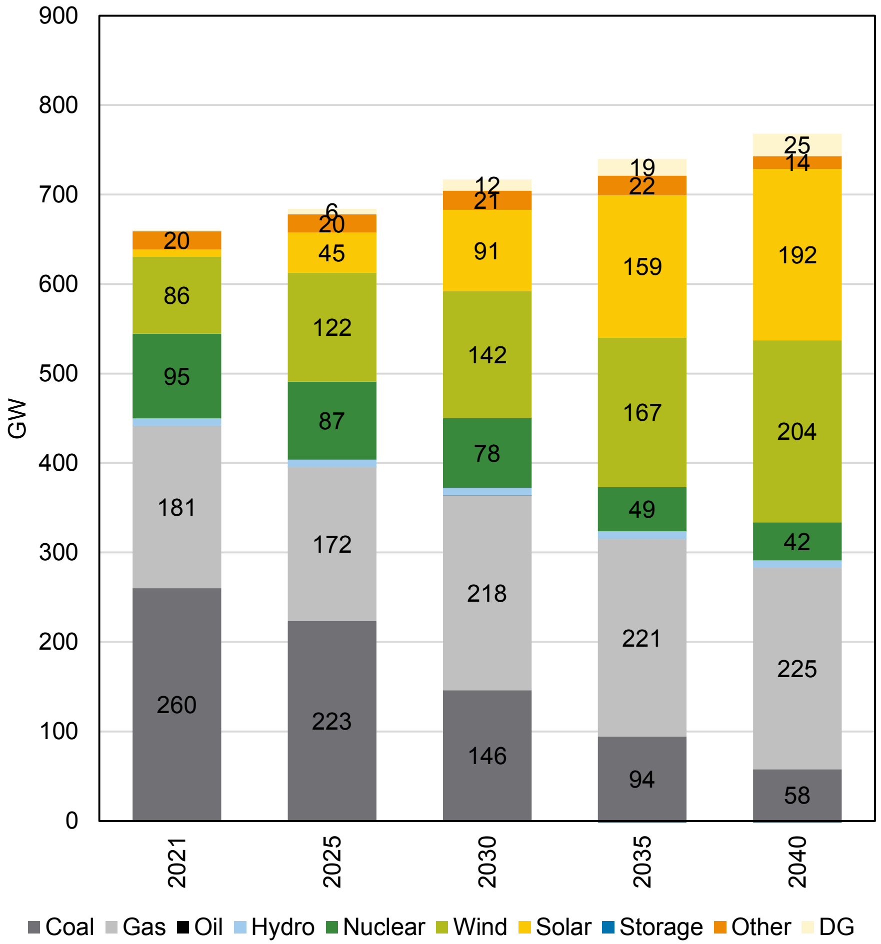


REFERENCE CASE – MISO SUPPLY MIX OUTLOOK

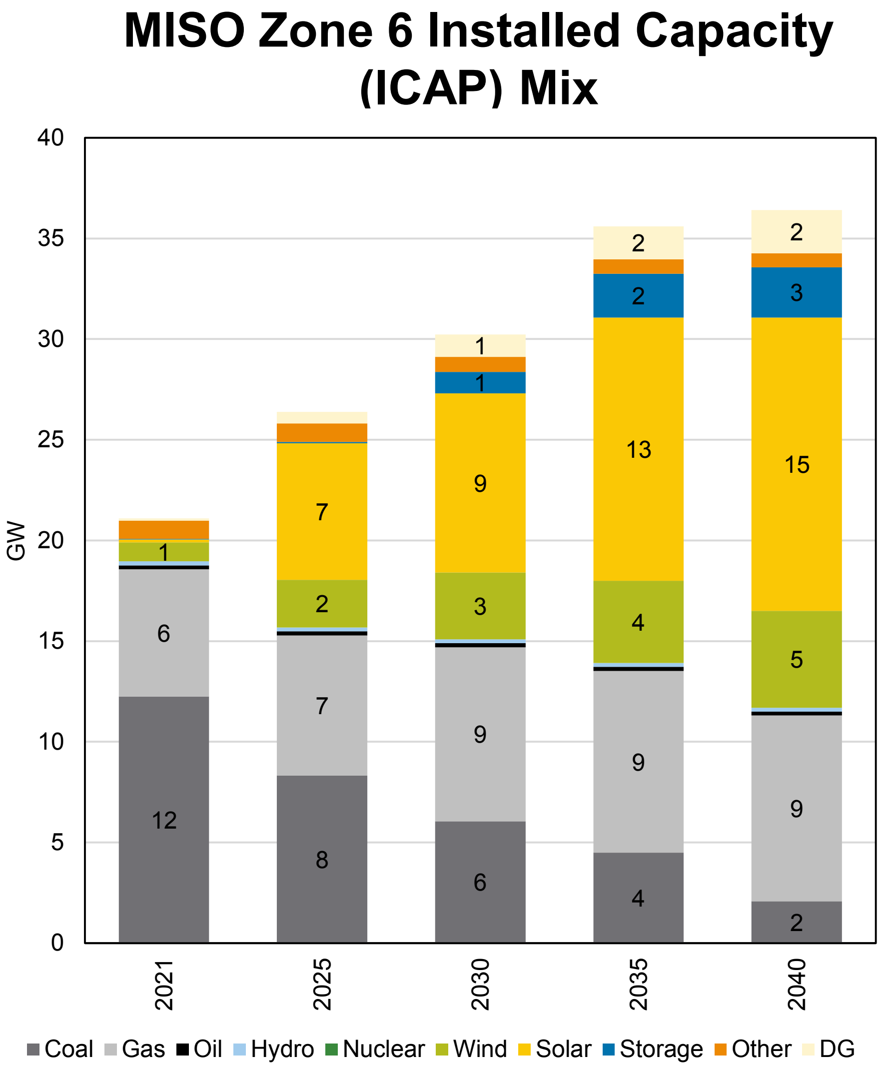
MISO Installed Capacity (ICAP) Mix

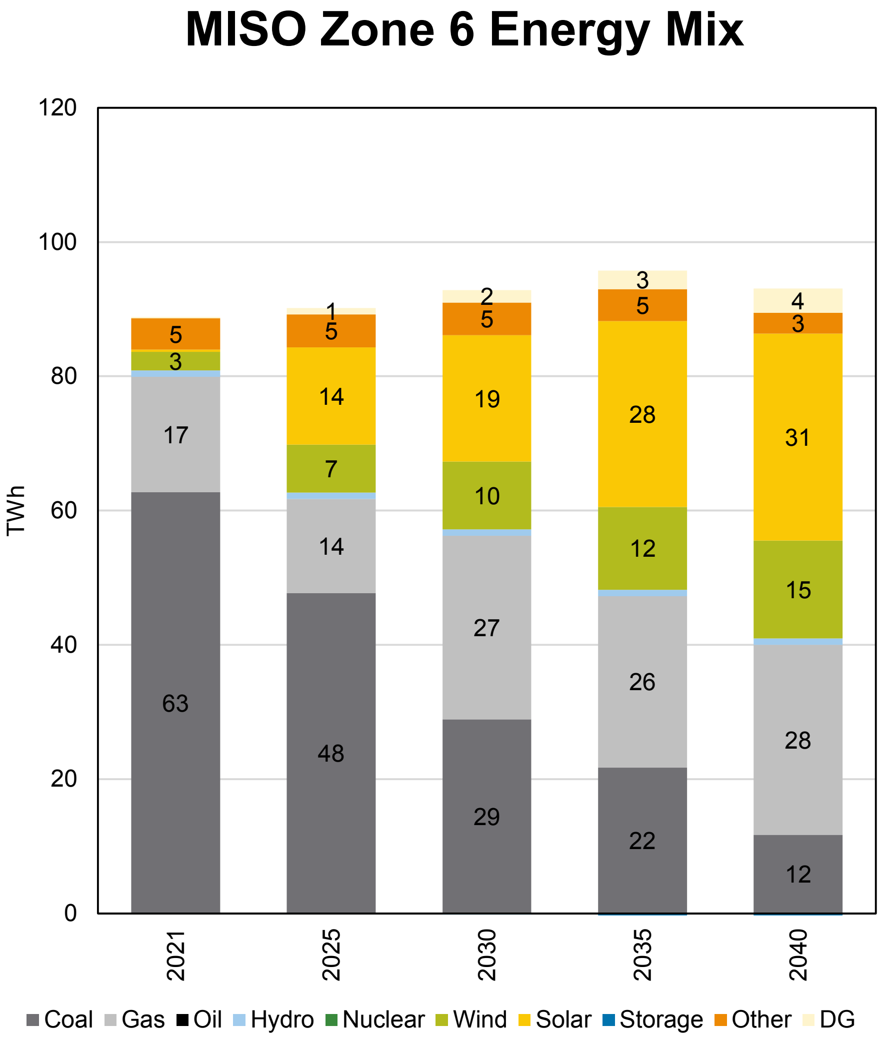


MISO Energy Mix

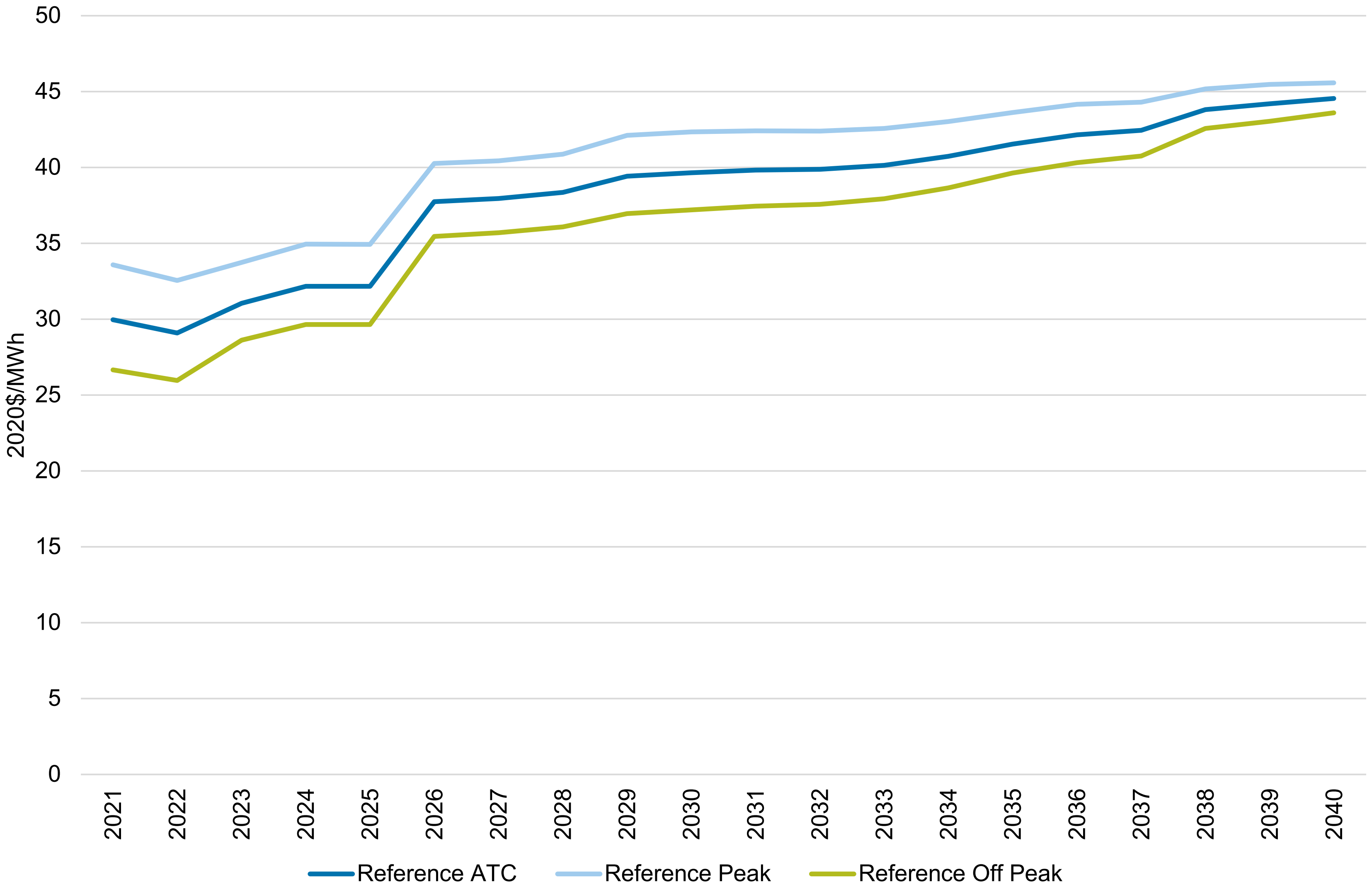


REFERENCE CASE – MISO ZONE 6 SUPPLY MIX OUTLOOK

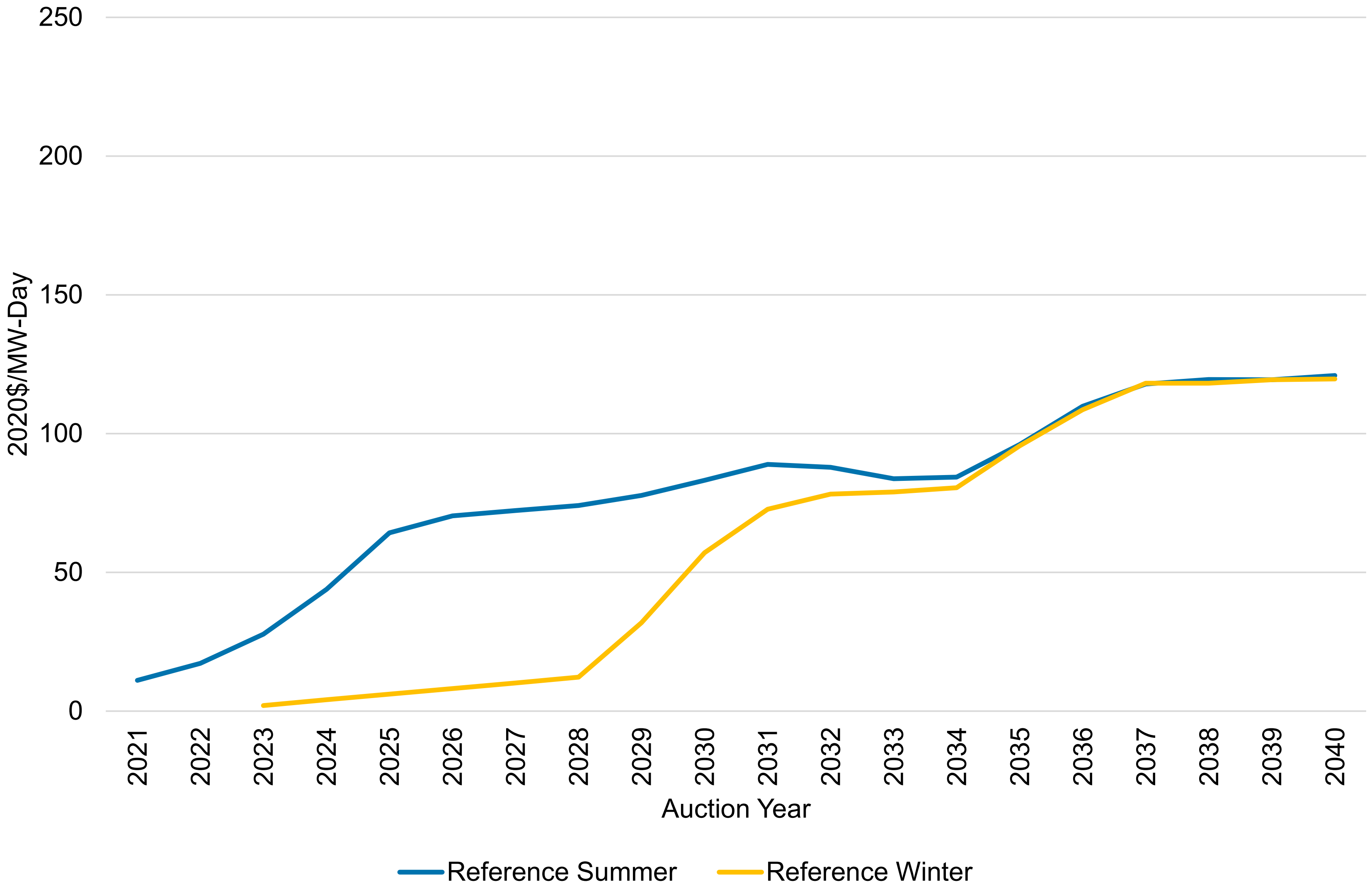




REFERENCE CASE ENERGY PRICE FORECAST

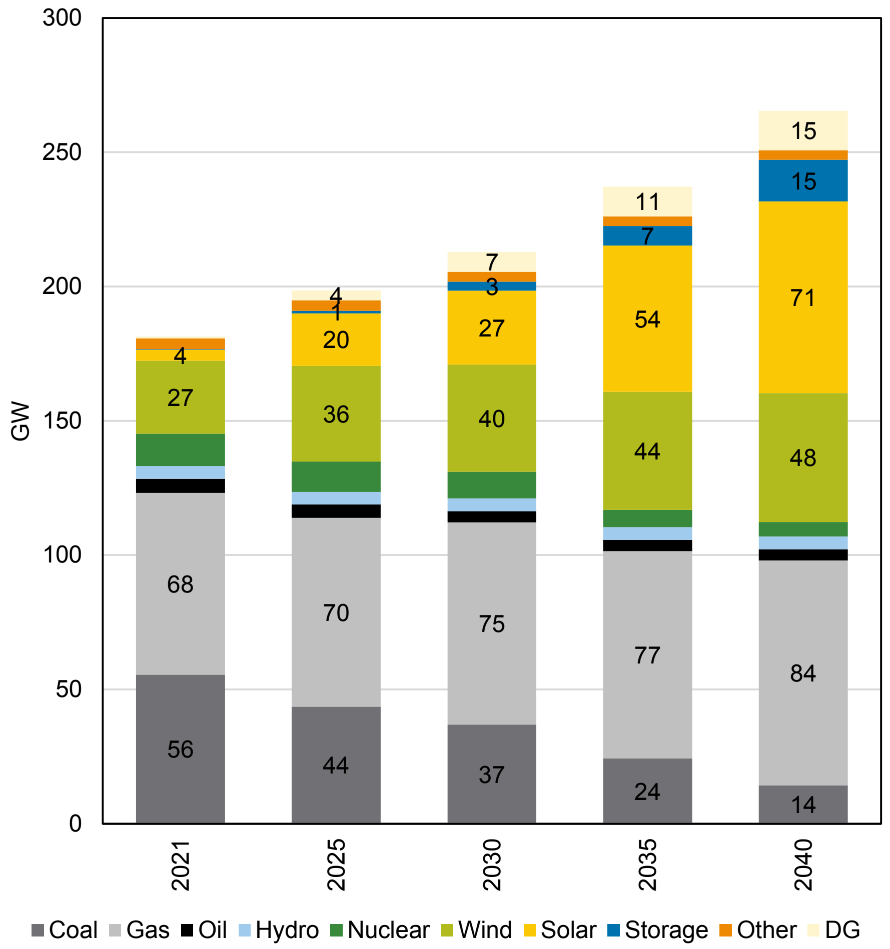


REFERENCE CASE CAPACITY PRICE FORECAST

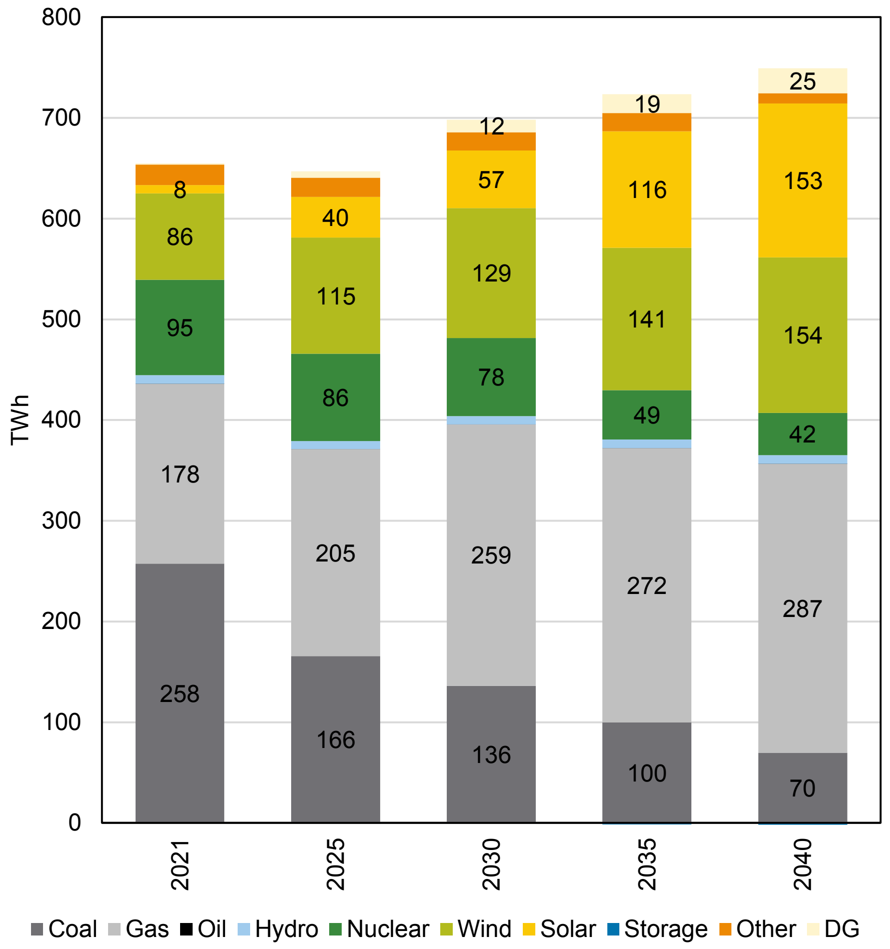


STATUS QUO EXTENDED – MISO SUPPLY MIX OUTLOOK

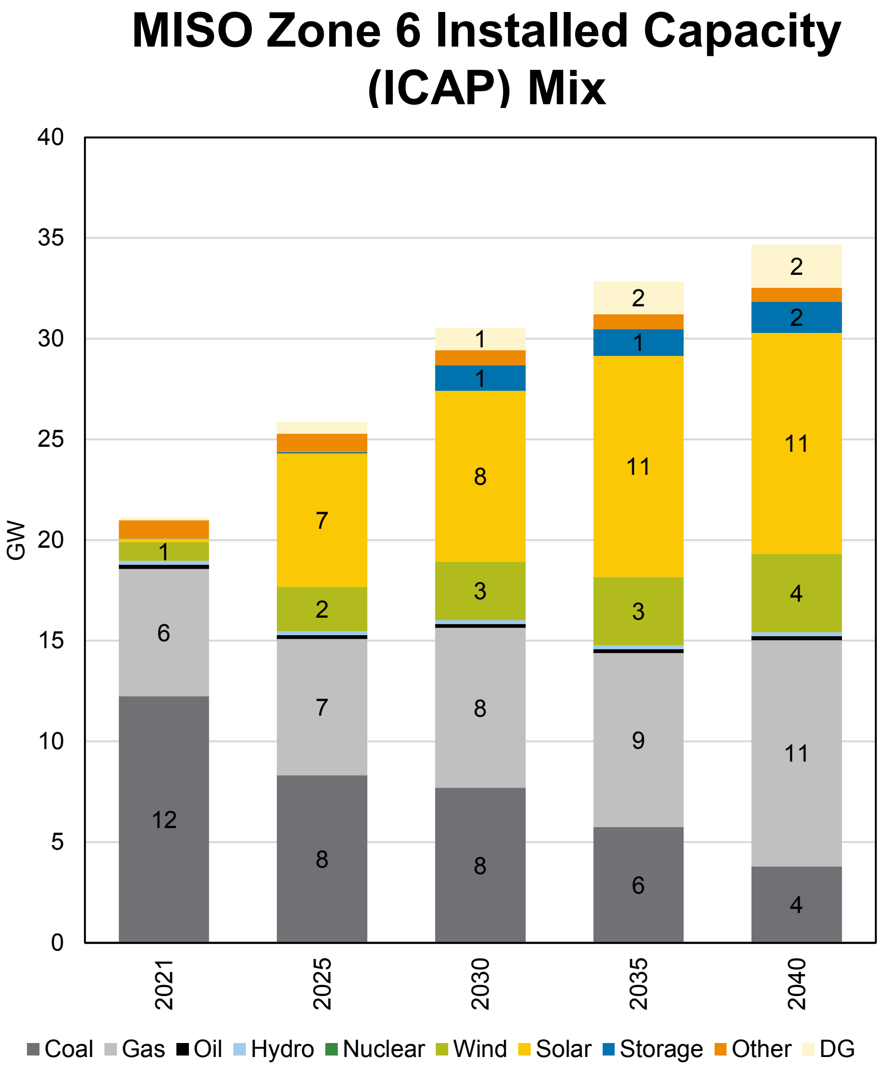
MISO Installed Capacity (ICAP) Mix

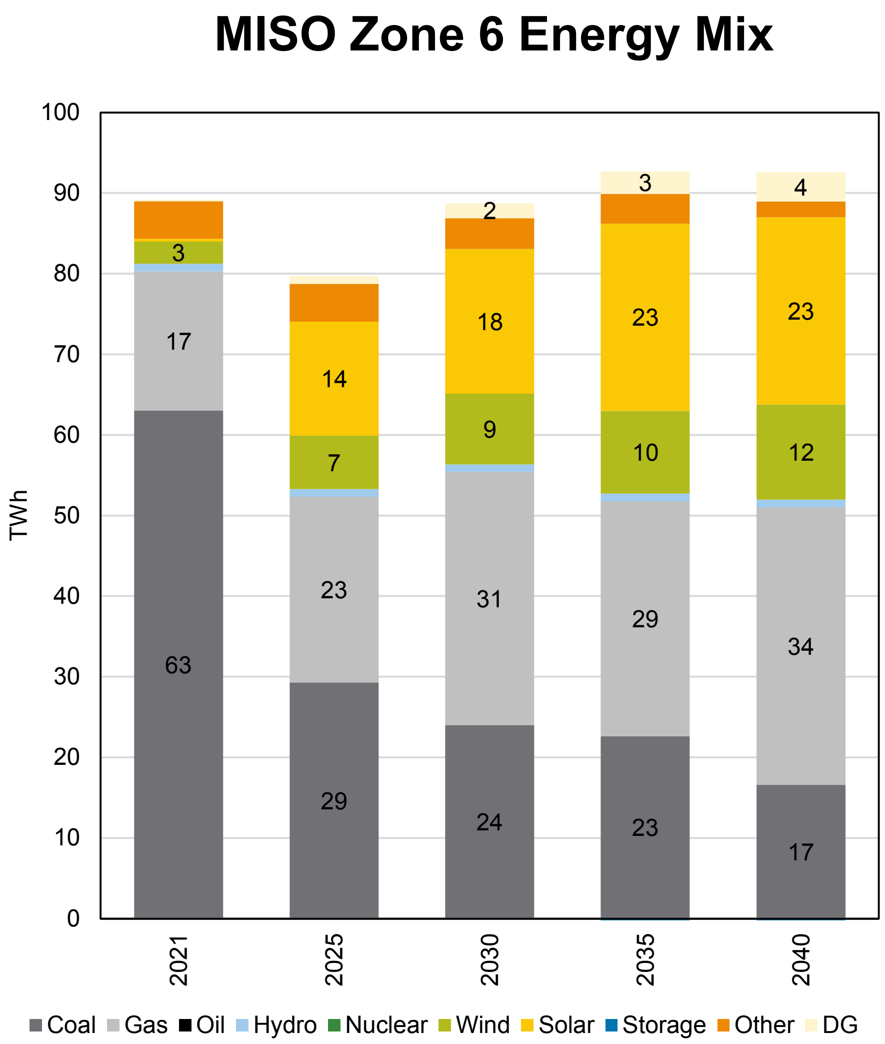


MISO Energy Mix

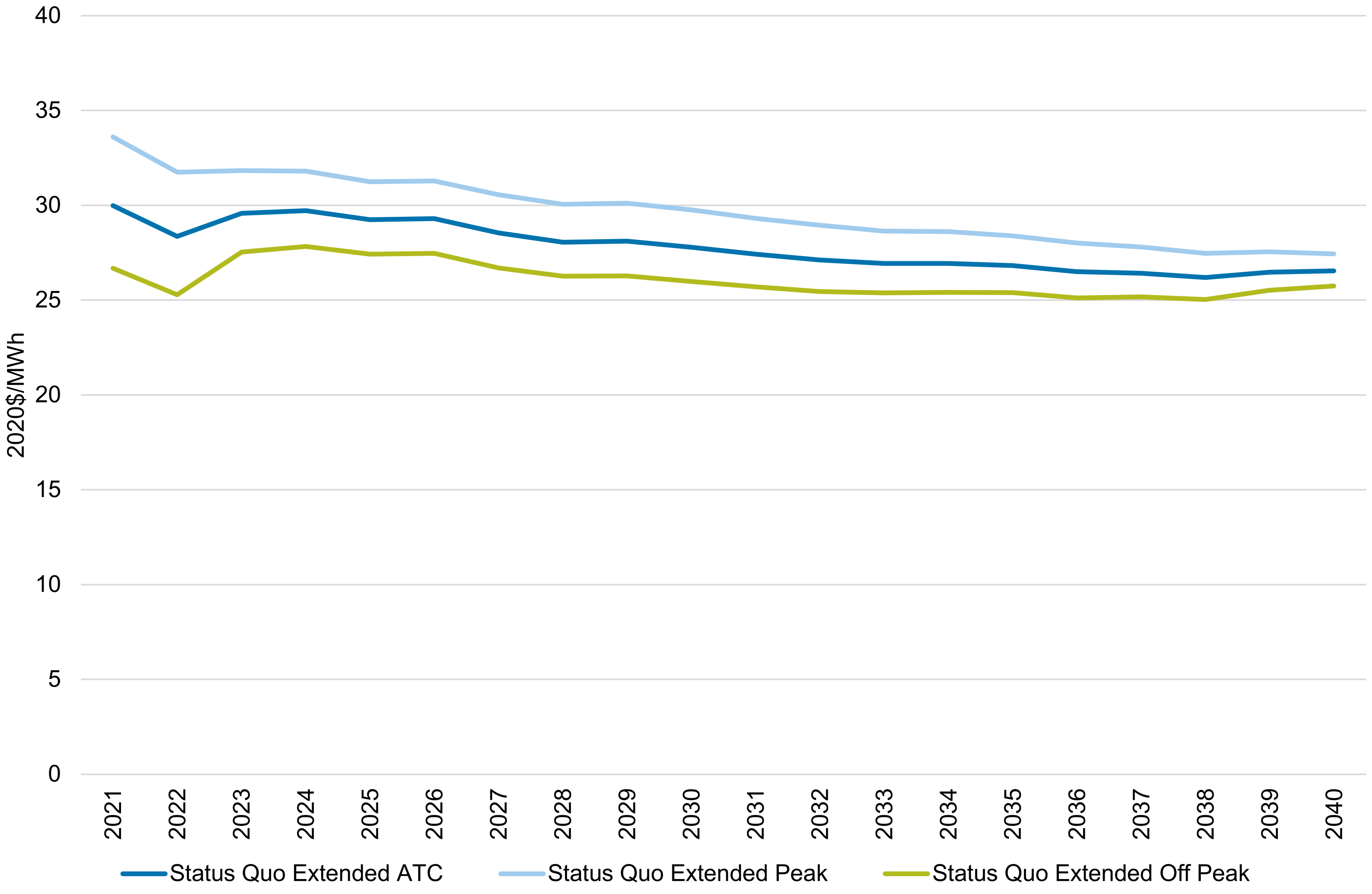


STATUS QUO EXTENDED – MISO ZONE 6 SUPPLY MIX OUTLOOK

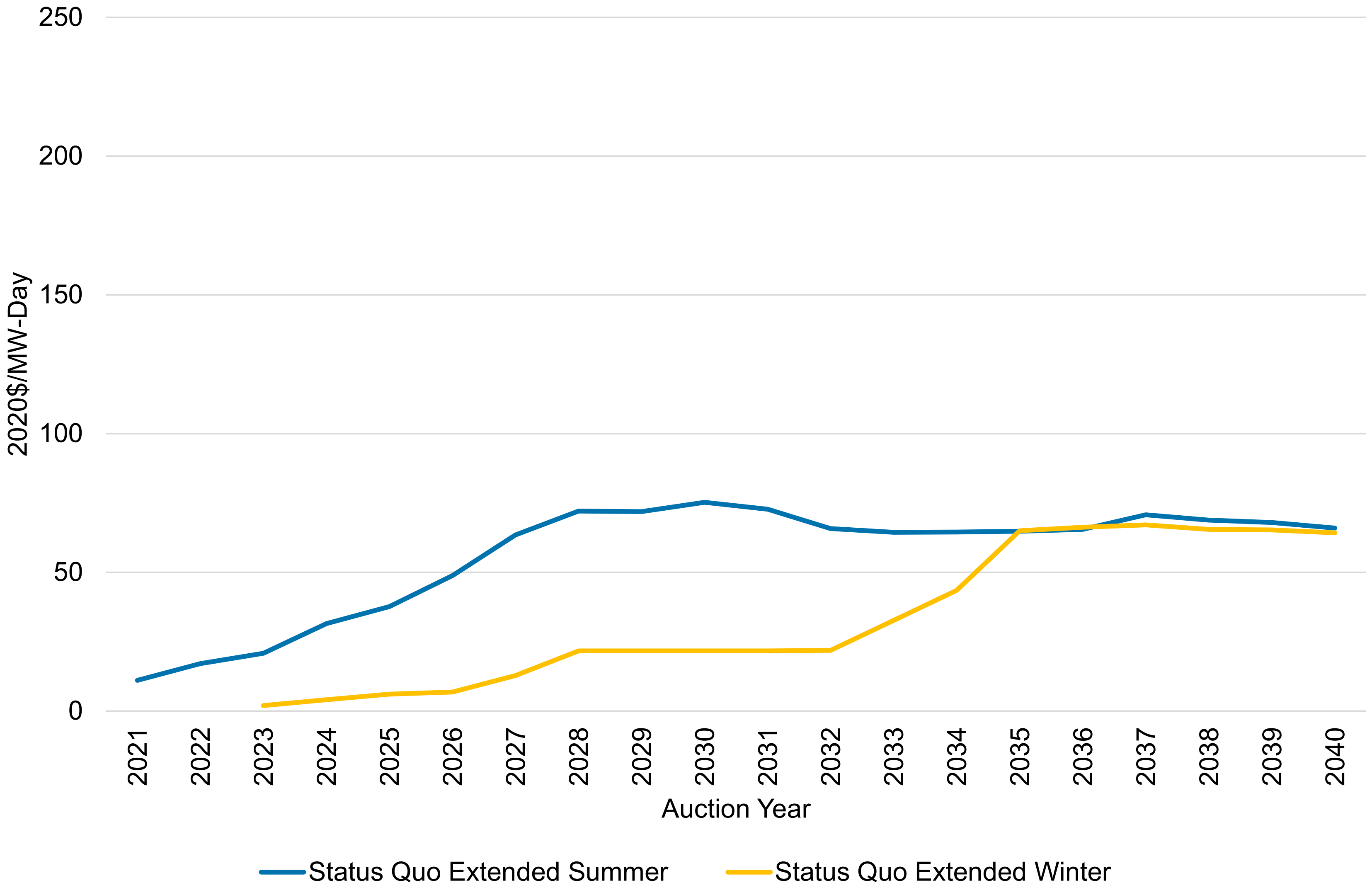




STATUS QUO EXTENDED ENERGY PRICE FORECAST

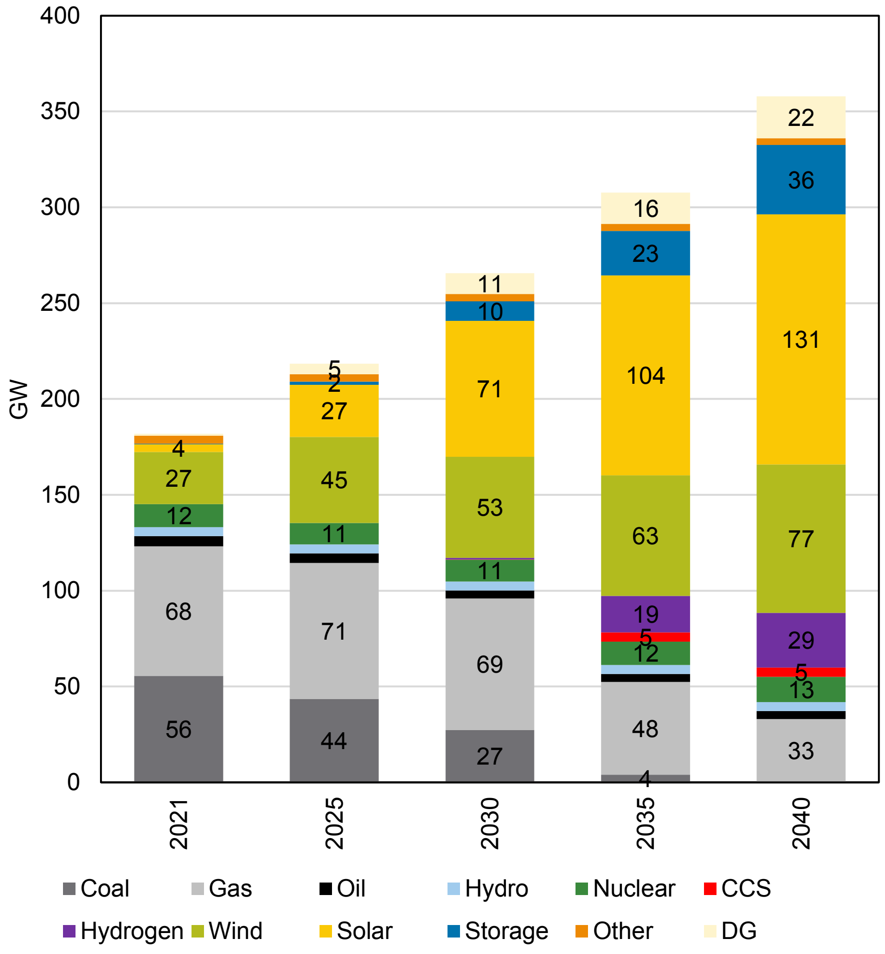


STATUS QUO EXTENDED CAPACITY PRICE FORECAST

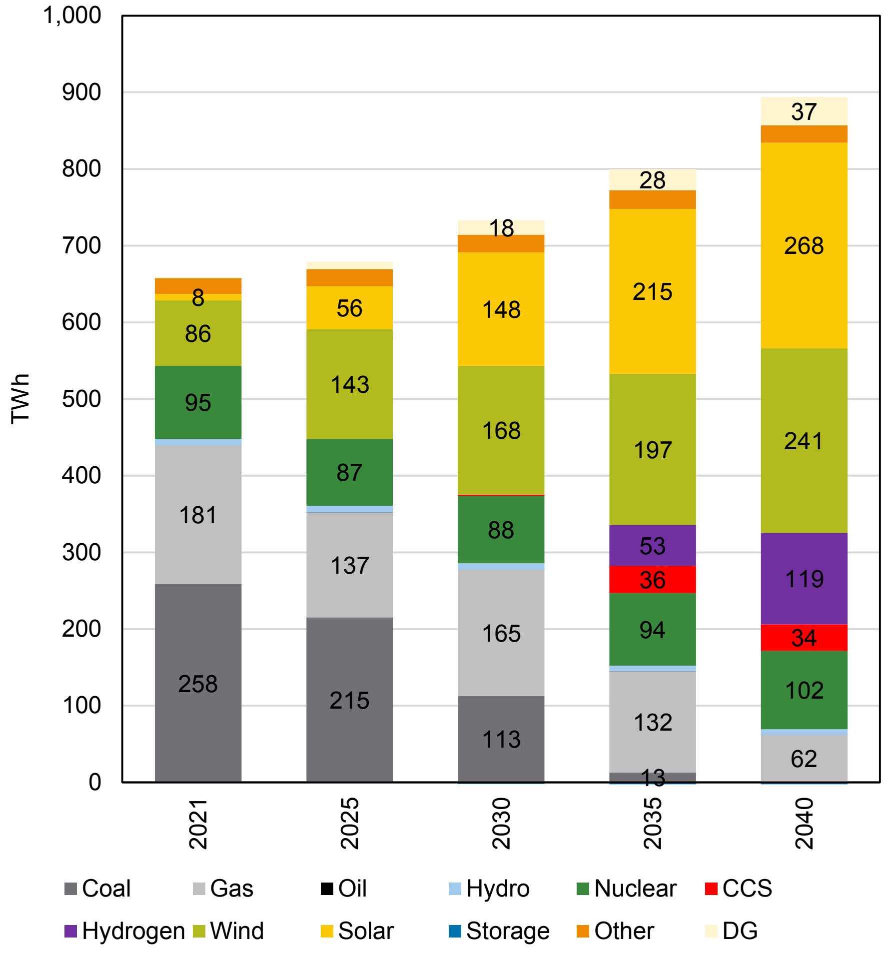


AGGRESSIVE ENVIRONMENTAL REGULATION – MISO SUPPLY MIX OUTLOOK

MISO Installed Capacity (ICAP) Mix

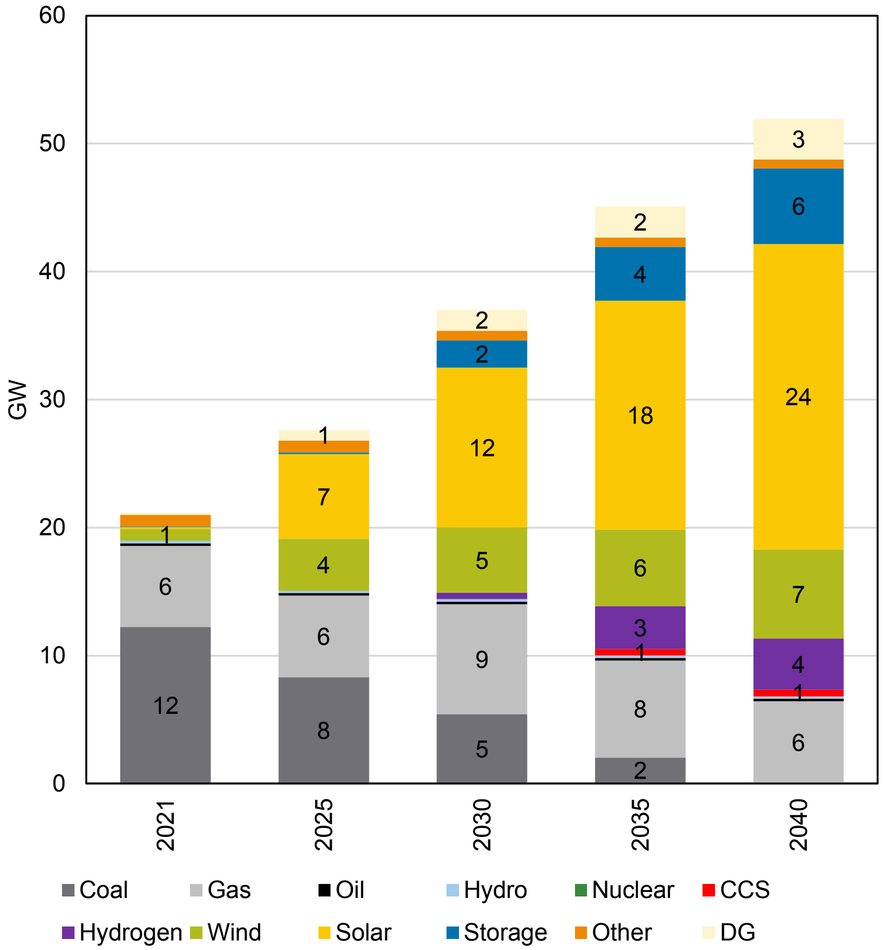


MISO Energy Mix

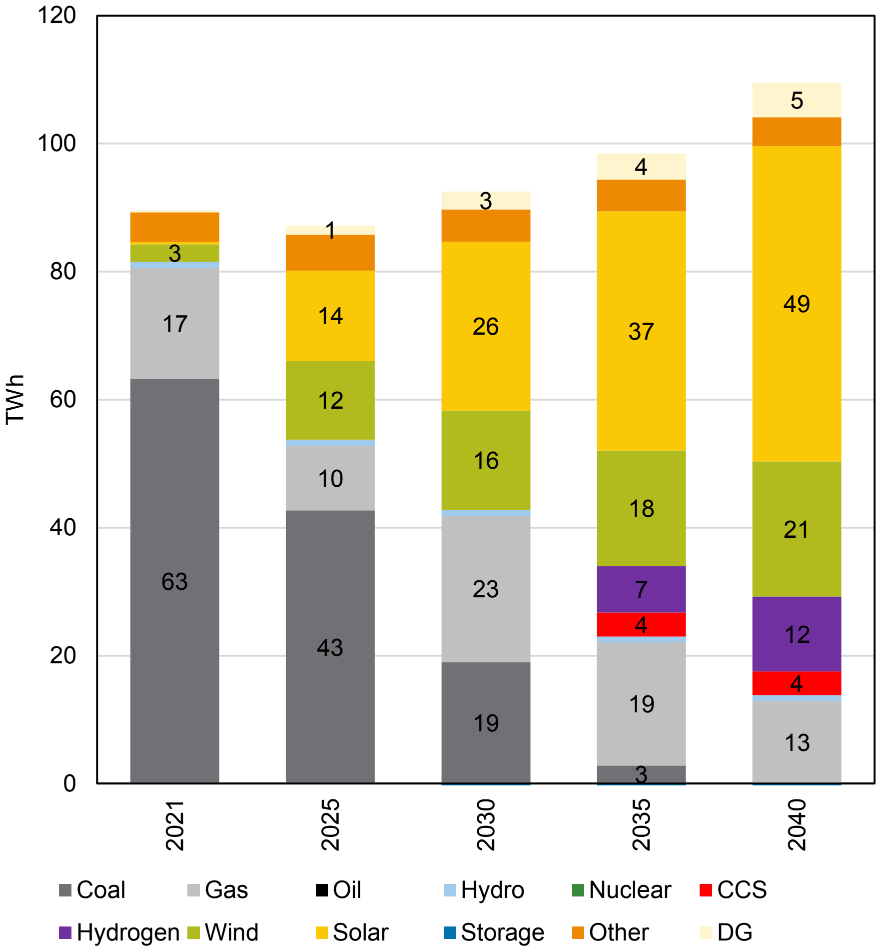


AGGRESSIVE ENVIRONMENTAL REGULATION – MISO ZONE 6 SUPPLY MIX OUTLOOK

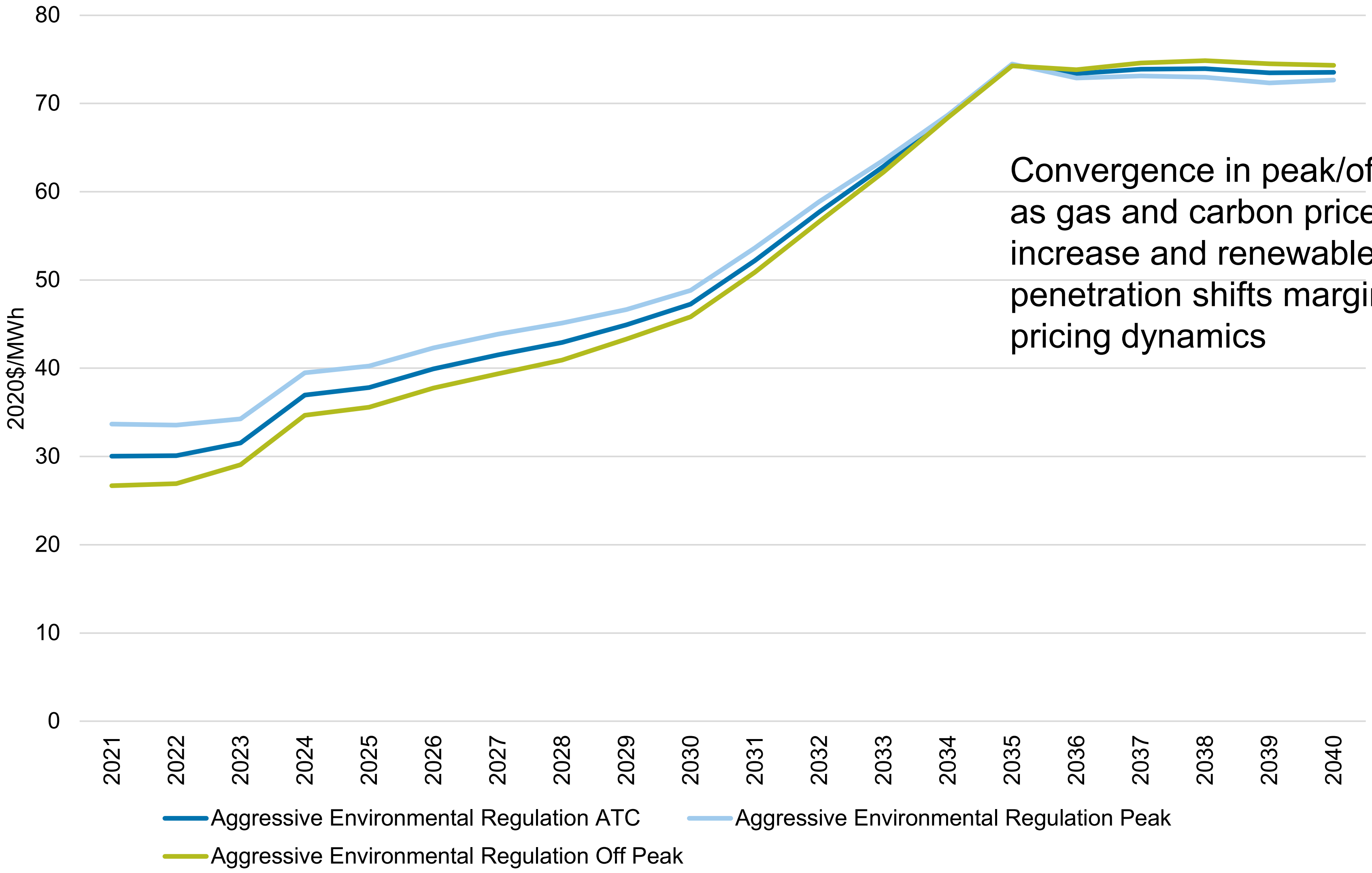
MISO Zone 6 Installed Capacity (ICAP) Mix



MISO Zone 6 Energy Mix

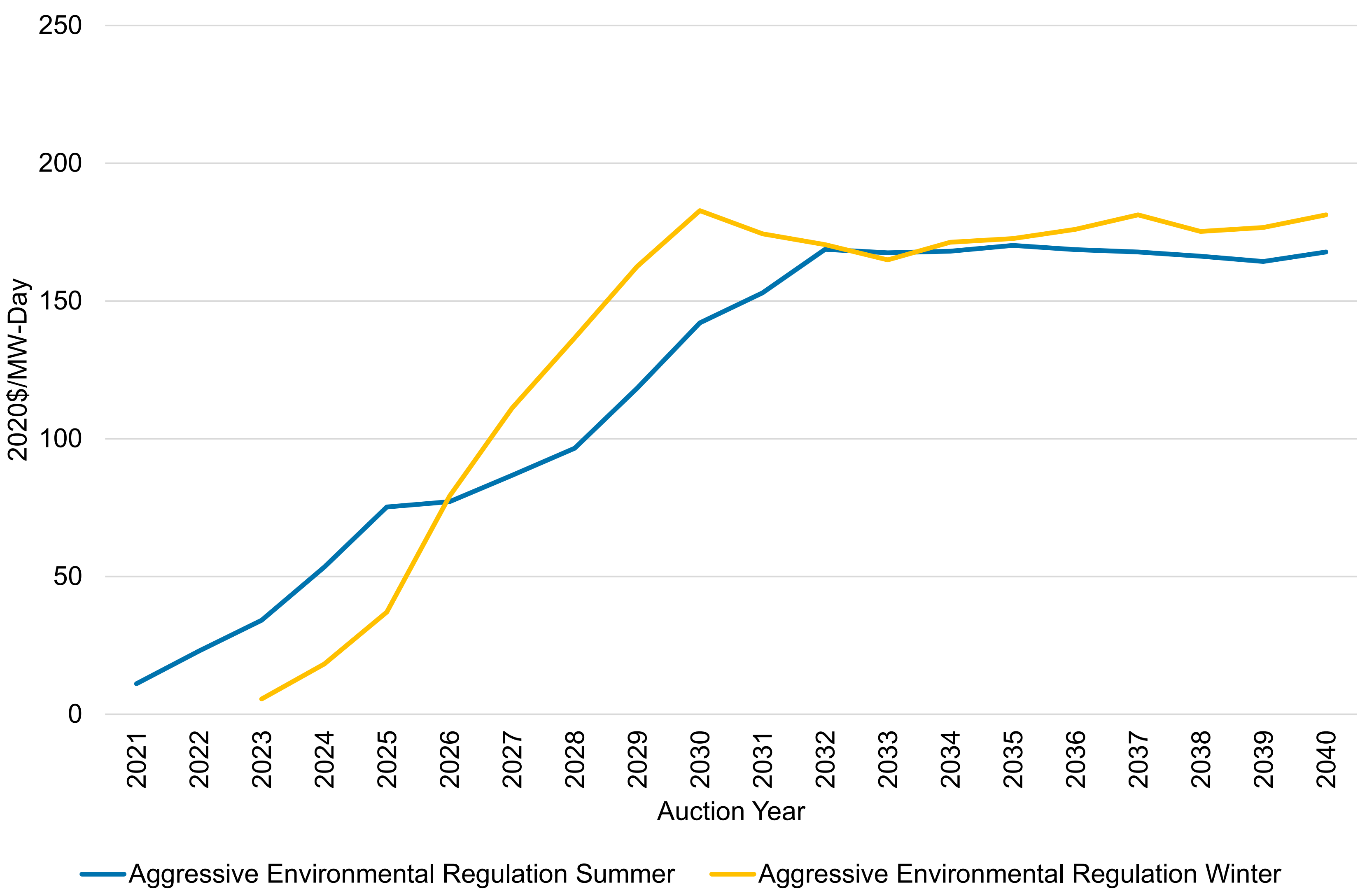


AGGRESSIVE ENVIRONMENTAL REGULATION ENERGY PRICE FORECAST



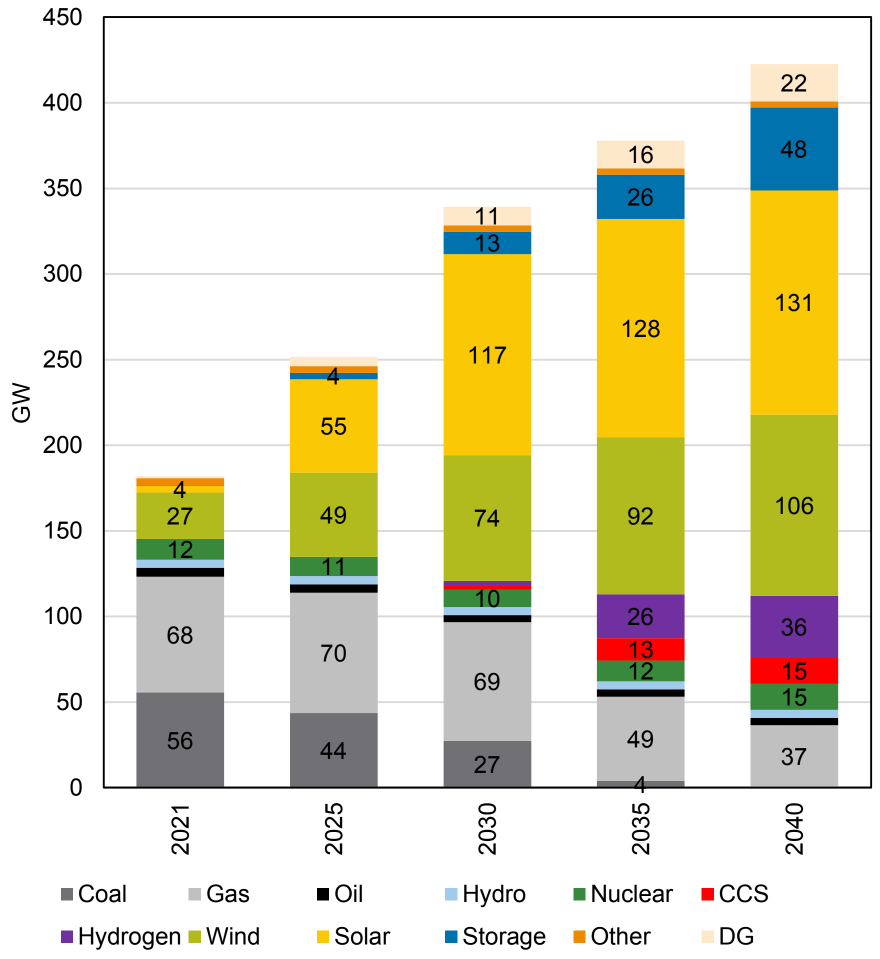
Convergence in peak/off-peak, as gas and carbon prices increase and renewable penetration shifts marginal pricing dynamics

AGGRESSIVE ENVIRONMENTAL REGULATION CAPACITY PRICE FORECAST

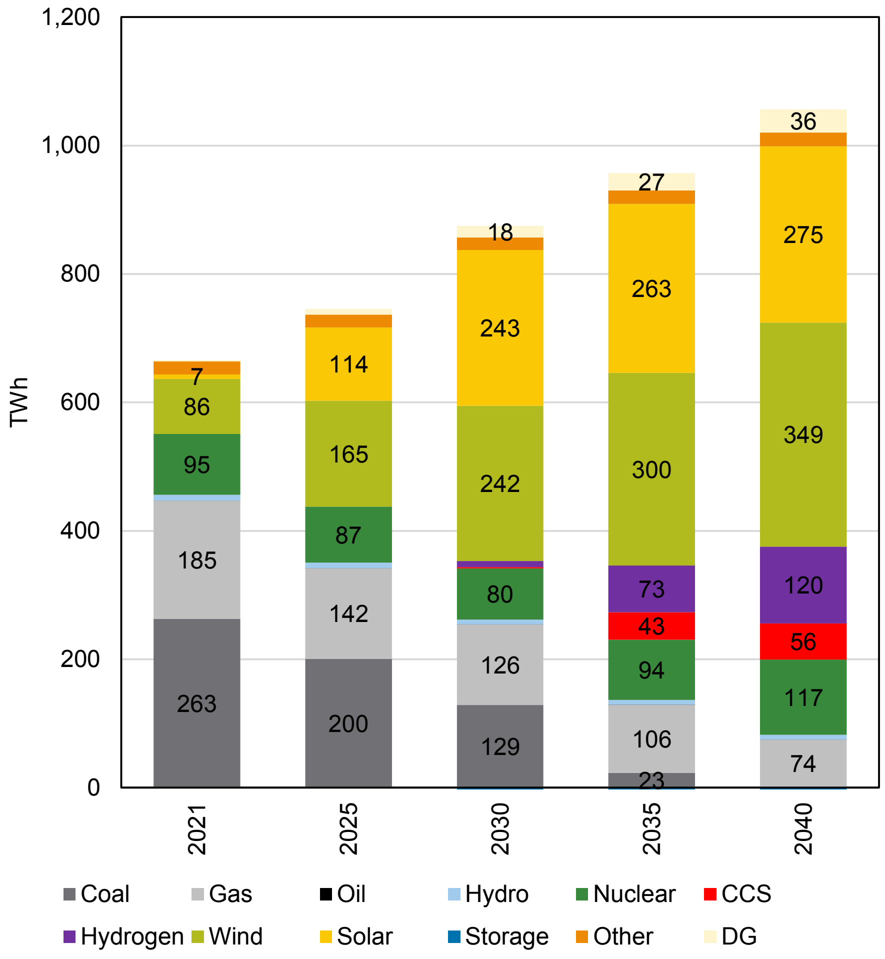


ECONOMY-WIDE DECARBONIZATION – MISO SUPPLY MIX OUTLOOK

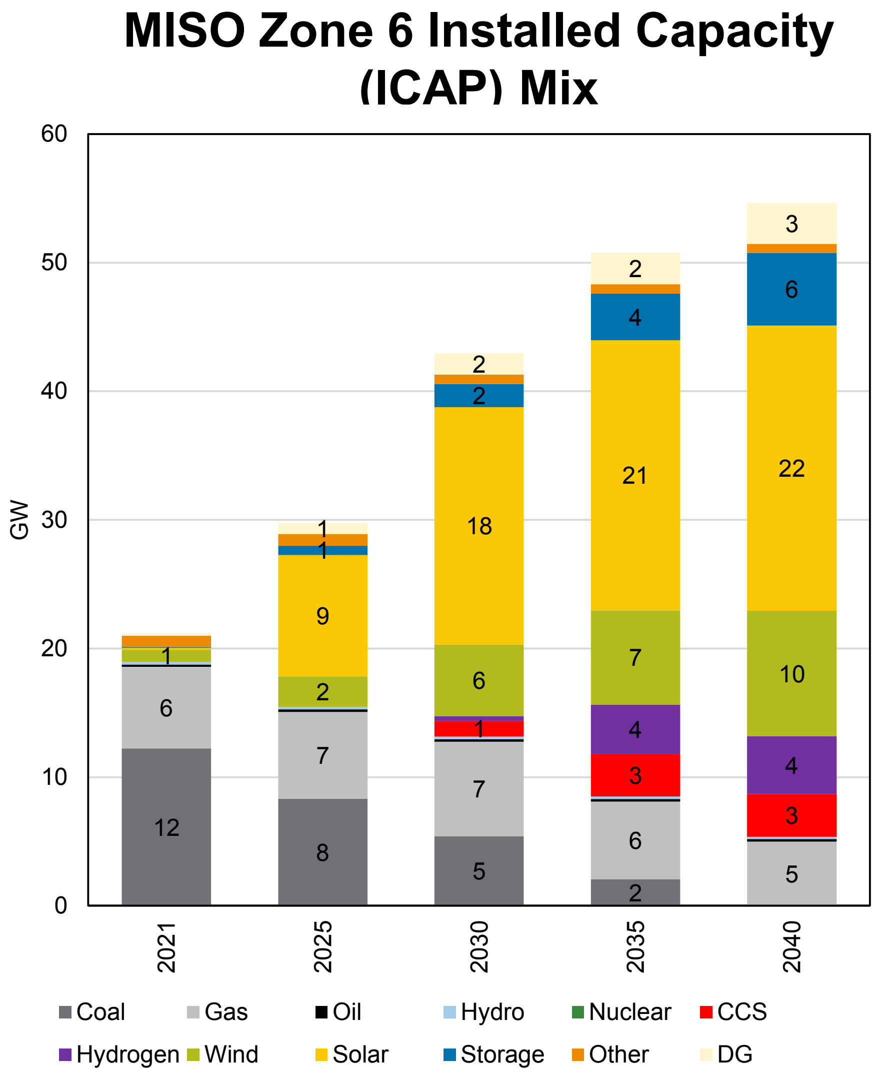
MISO Installed Capacity (ICAP) Mix

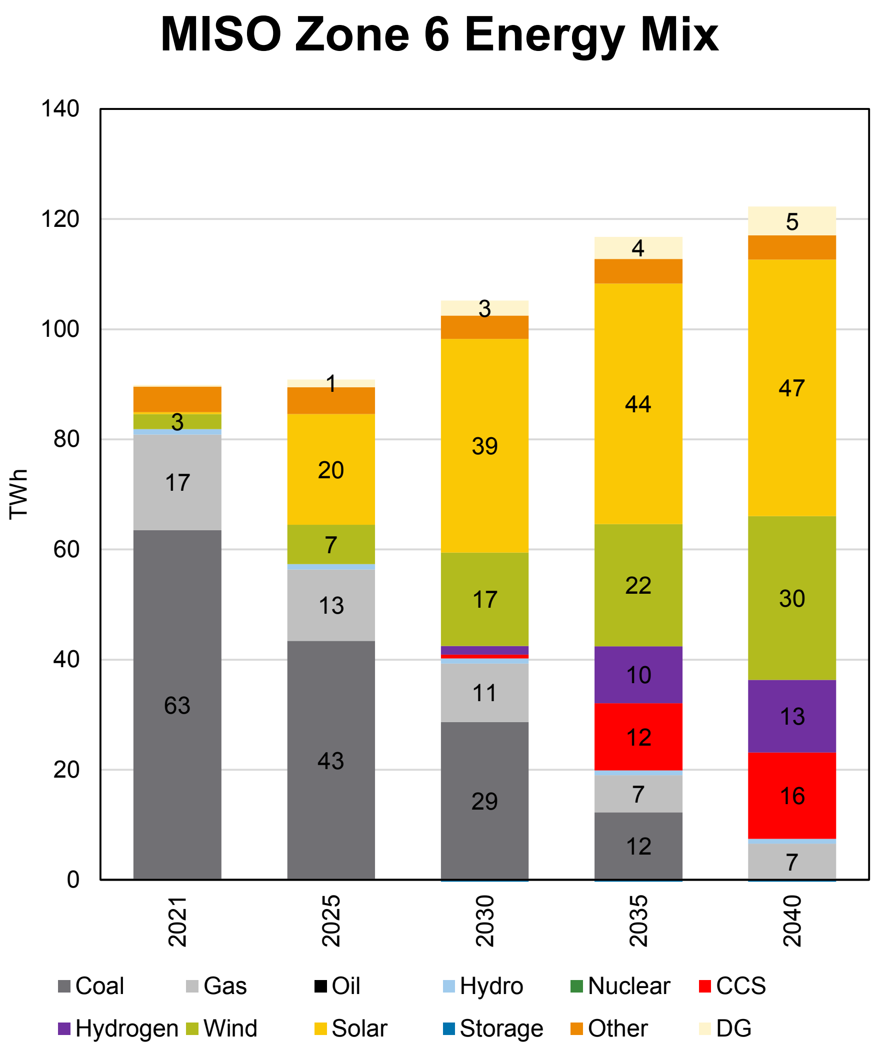


MISO Energy Mix

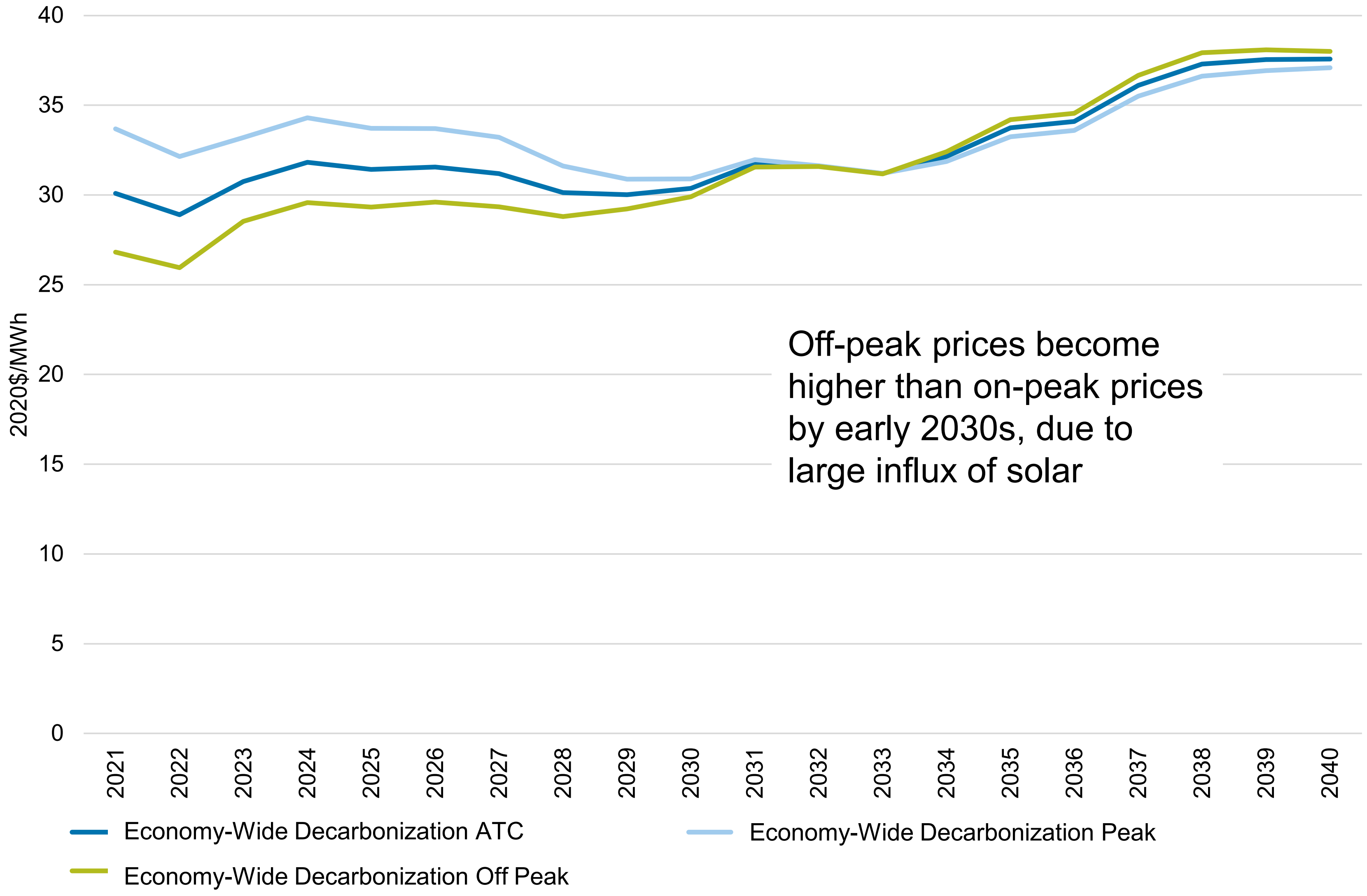


ECONOMY-WIDE DECARBONIZATION – MISO ZONE 6 SUPPLY MIX OUTLOOK

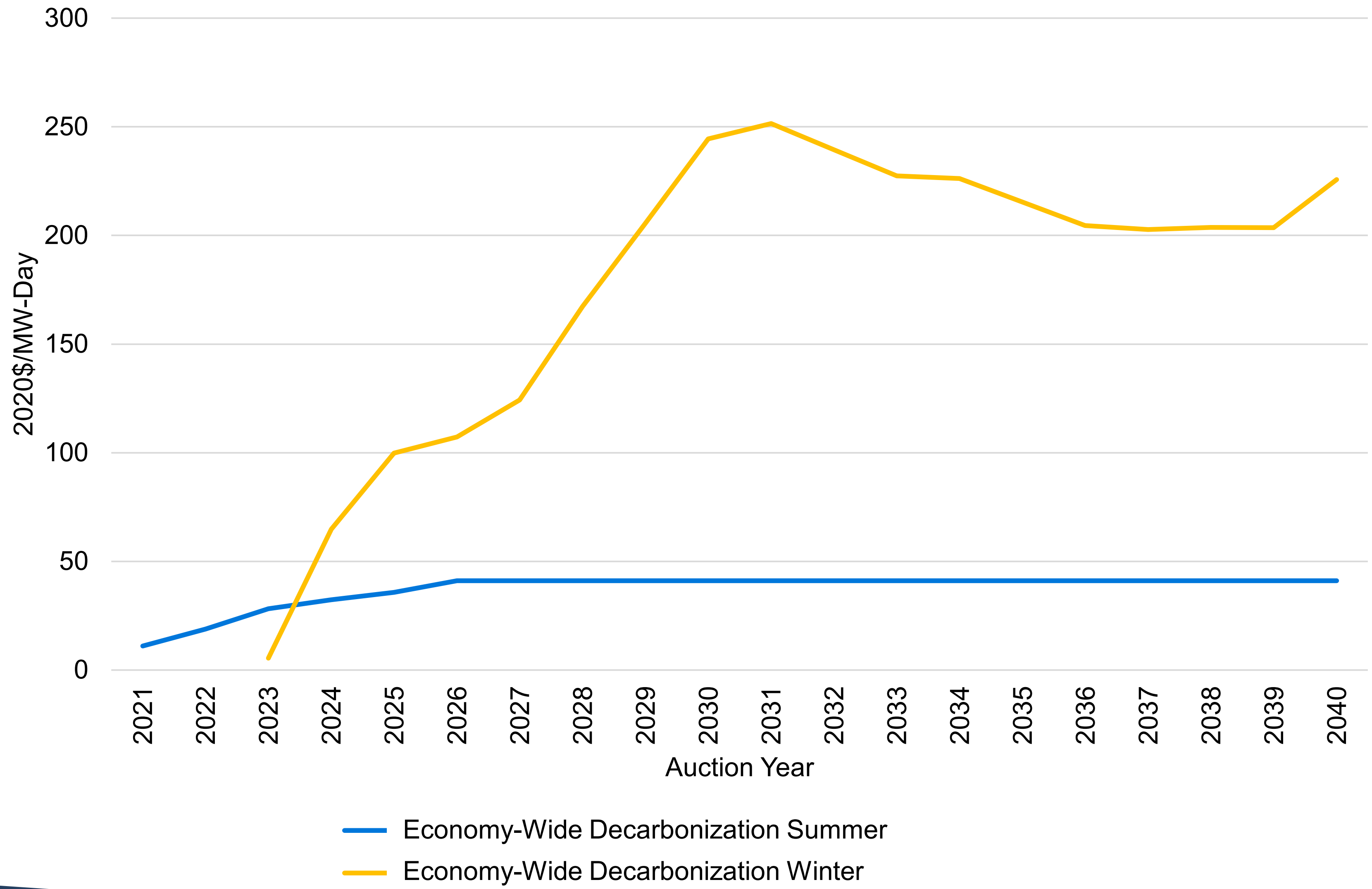




ECONOMY-WIDE DECARBONIZATION ENERGY PRICE FORECAST

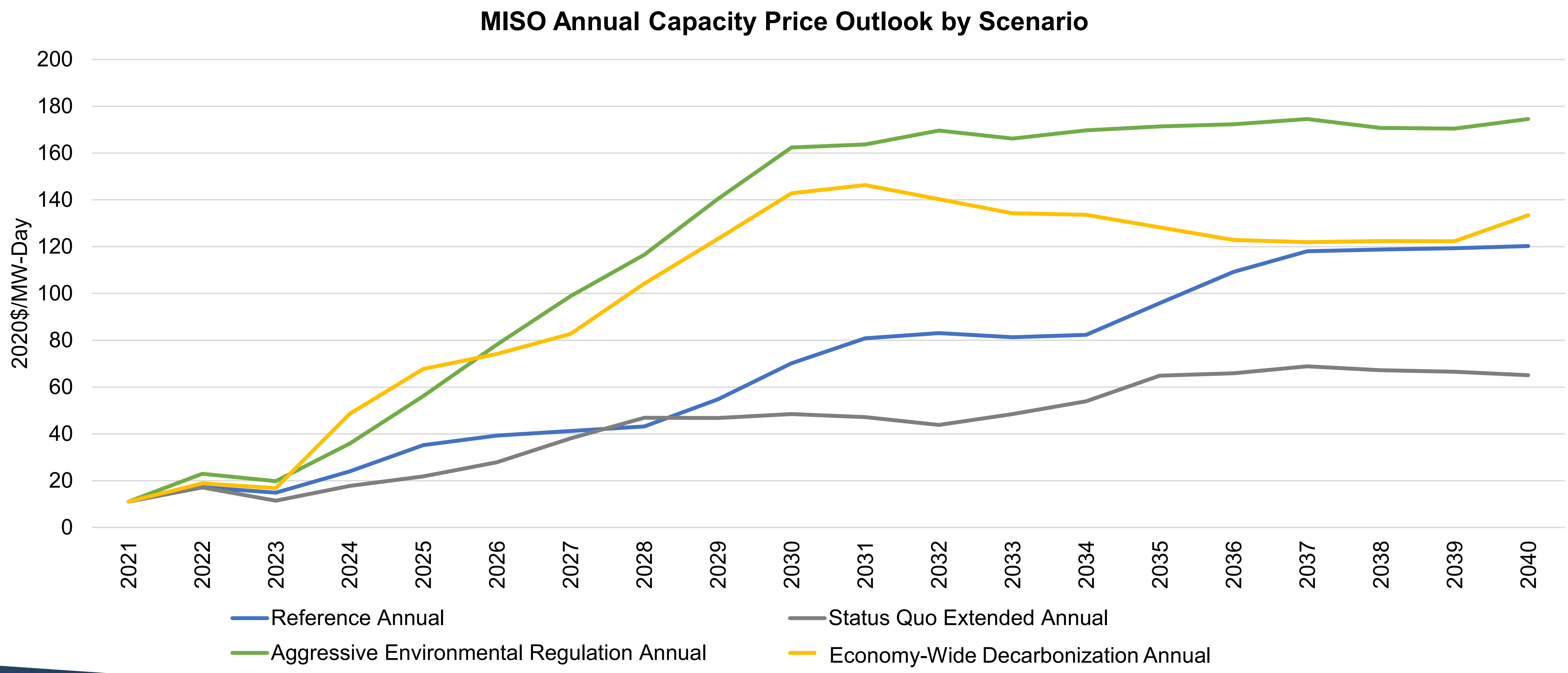


ECONOMY-WIDE DECARBONIZATION CAPACITY PRICE FORECAST



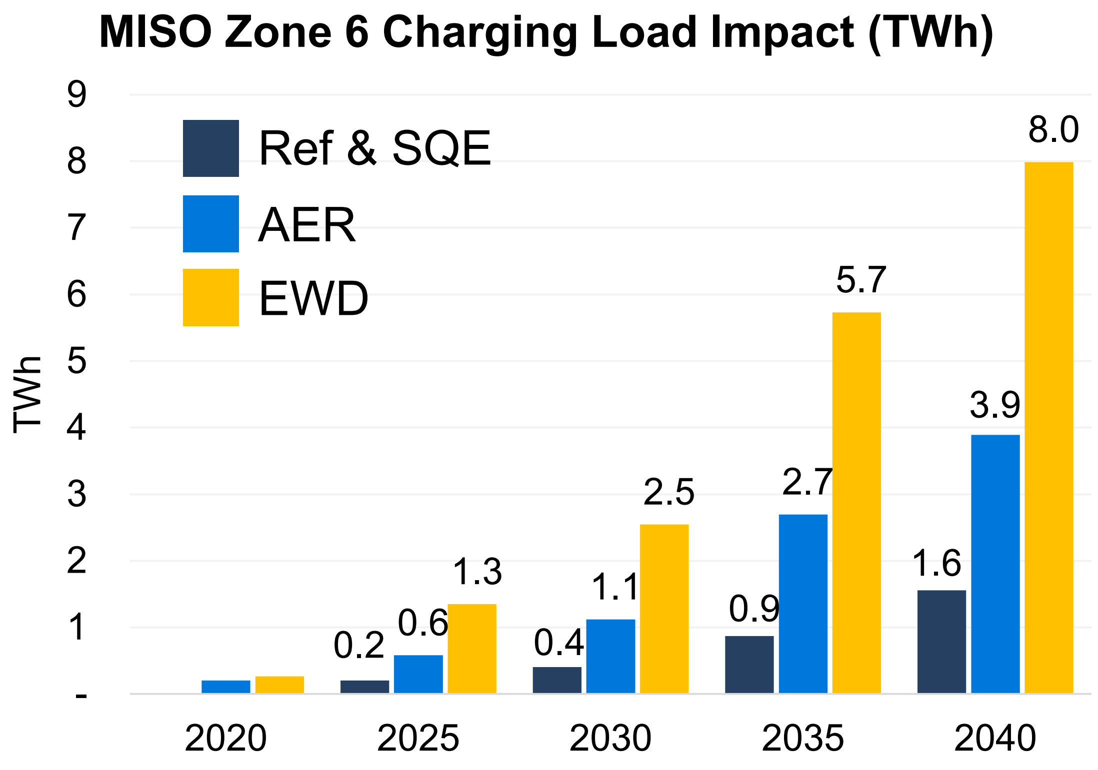
MISO ANNUAL CAPACITY PRICE FORECAST

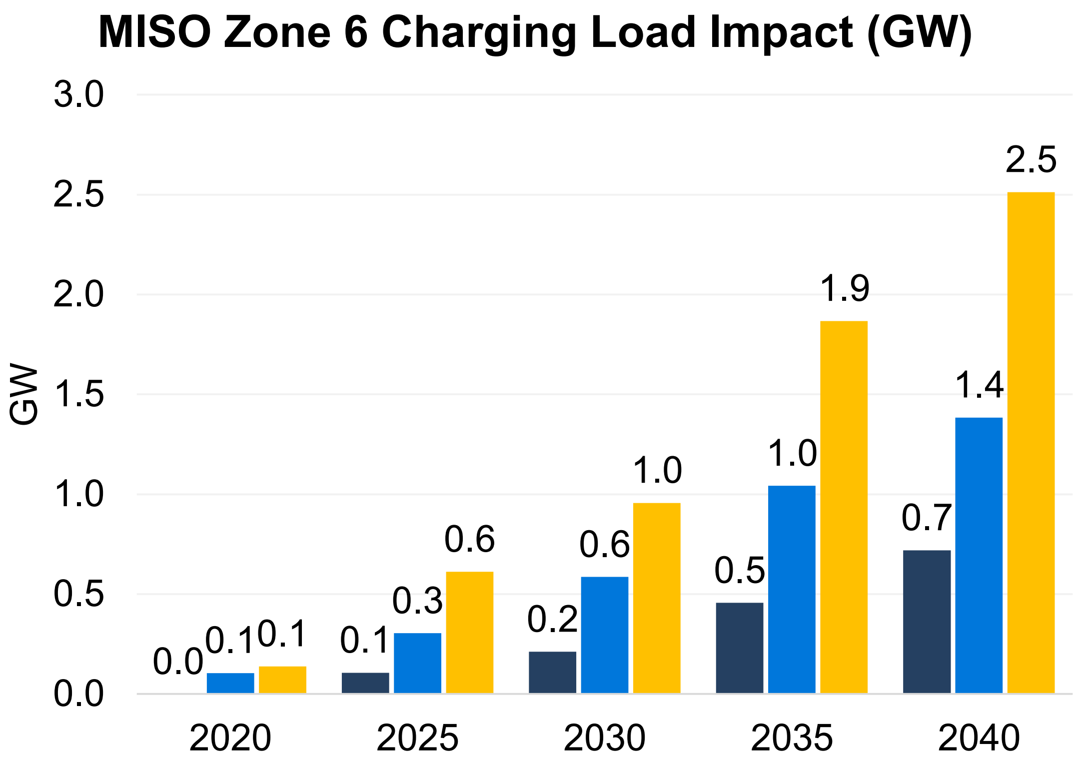
Average of summer and winter fundamental outlooks across scenarios



MISO SCENARIO DETAILS: EV LOAD IMPACT BY MISO LOAD ZONE

EV count by scenario was based on MTEP21 Futures, then translated into energy and peak impacts based on CRA assumptions for MWh per car and hourly charging profiles





Note: Energy impact based on an assumption of 15,000 annual miles per car and kWh/mile efficiency improvements over time (varies by Future)

MISO SCENARIO DETAILS: DER PENETRATION

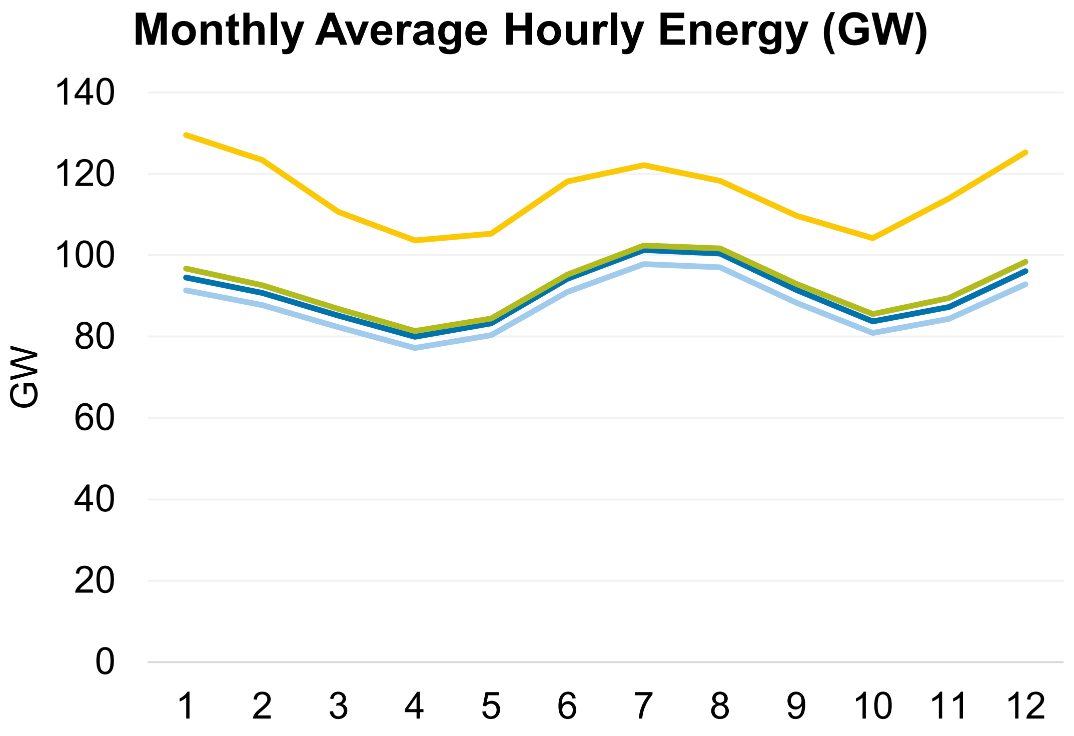
MISO BTM solar and storage penetration is based on MTEP21 assumptions

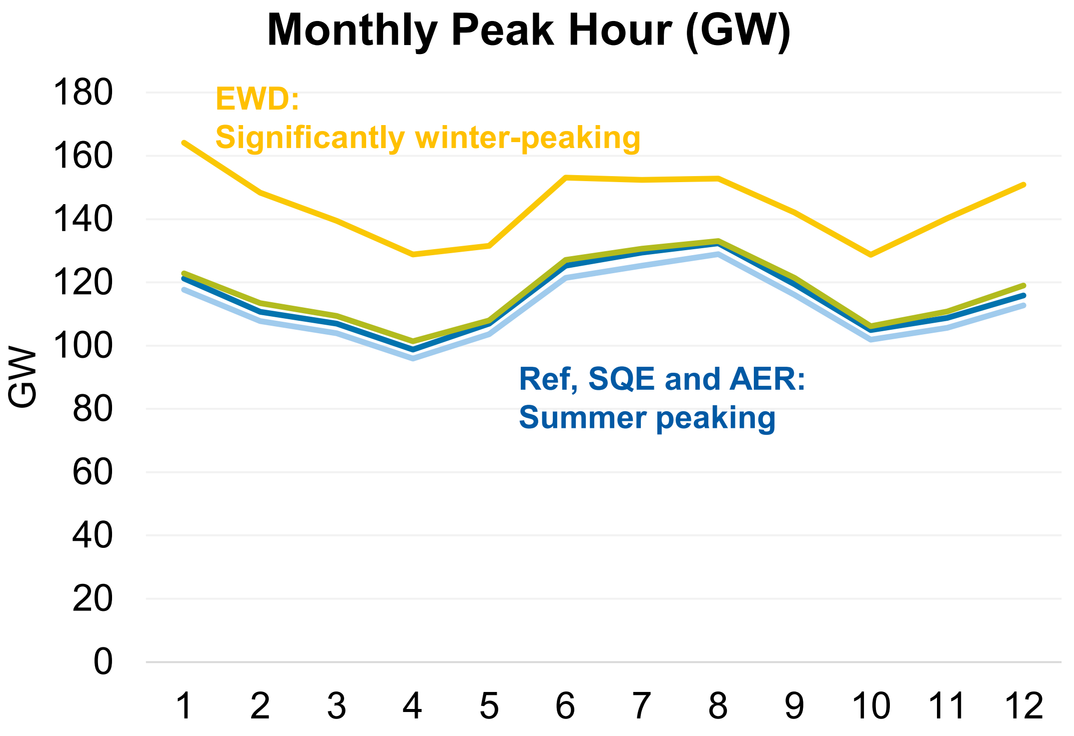
MISO market modeling incorporates DERs as "resources" within Aurora, in order to capture hourly impacts

	BTM Solar	BTM Storage
Base (Ref, SQE)	14.7 GW 20% CF	1.47 GW
High (AER, EWD)	21.8 GW 19-20% CF	3.27 GW

MISO SCENARIO DETAILS: NET IMPACTS ON SEASONAL LOAD SHAPES

Higher electrification has significant impacts on seasonal system energy and peak due to electrification of building heating load





Note: Graphics represent Net Load, defined as (Gross Load – DG – EV – BTM Storage)

MISO SCENARIO DETAILS: NET PEAK LOAD GROWTH

Electrification drives the major differences, with less significant impacts associated with EE and DERs

Scenario	MISO Footprint		MISO Zone 6	
	Total Energy Sales (2020-2040 CAGR)	Coincident Peak (2020-2040 CAGR)	Total Energy Sales (2020-2040 CAGR)	Coincident Peak (2020-2040 CAGR)
Reference	0.6%	0.5%	0.3%	1.0%
SQE	0.5%	0.3%	0.2%	0.8%
AER	0.7%	0.5%	0.4%	0.9%
EWD	1.8%	1.6%	1.4%	2.0%

NIPSCO REFERENCE CASE LOAD DETAILS

	MWh Sales			
	Base Load	EV Load	DERs	All-In
2021	11,940,087	7,239	13,054	11,934,273
2022	11,902,413	10,211	22,511	11,890,112
2023	11,938,227	14,183	34,542	11,917,868
2024	11,985,631	19,342	50,631	11,954,342
2025	12,021,815	23,188	63,186	11,981,817
2026	12,058,173	27,507	71,638	12,014,041
2027	12,094,192	32,099	80,448	12,045,843
2028	12,131,648	37,512	89,686	12,079,475
2029	12,165,047	43,655	101,544	12,107,158
2030	12,197,613	50,140	126,379	12,121,374
2031	12,226,902	57,416	138,479	12,145,839
2032	12,254,112	65,701	154,566	12,165,247
2033	12,275,076	74,924	163,677	12,186,324
2034	12,291,826	86,776	172,783	12,205,819
2035	12,307,652	95,740	182,511	12,220,881
2036	12,322,461	105,290	188,733	12,239,018
2037	12,330,264	115,709	197,911	12,248,062
2038	12,335,196	127,374	204,913	12,257,657
2039	12,338,219	139,840	208,010	12,270,049
2040	12,341,572	155,423	214,101	12,282,894
2021-2040 CAGR	**0.2%**	**17.5%**	**15.9%**	**0.2%**

NIPSCO REFERENCE CASE LOAD DETAILS

	Summer Peak (MW)			
	Base Load	EV Load	DERs	All-In
2021	2,346	0	5	2,341
2022	2,321	0	8	2,313
2023	2,316	1	13	2,304
2024	2,315	1	18	2,298
2025	2,313	1	22	2,292
2026	2,313	1	25	2,290
2027	2,314	2	27	2,289
2028	2,317	2	30	2,289
2029	2,319	2	33	2,289
2030	2,322	3	41	2,284
2031	2,325	3	45	2,283
2032	2,328	3	50	2,281
2033	2,329	4	53	2,281
2034	2,330	4	55	2,279
2035	2,331	4	58	2,278
2036	2,332	5	60	2,277
2037	2,332	5	62	2,275
2038	2,331	6	64	2,273
2039	2,330	6	65	2,272
2040	2,329	7	66	2,270
2021-2040 CAGR	**0.0%**	**18.6%**	**14.8%**	**-0.2%**

	Winter Peak (MW)			
	Base Load	EV Load	DERs	All-In
2021	1,622	0	1	1,621
2022	1,611	0	1	1,610
2023	1,614	0	2	1,612
2024	1,622	1	2	1,620
2025	1,626	1	3	1,624
2026	1,633	1	3	1,630
2027	1,640	1	4	1,637
2028	1,650	1	4	1,647
2029	1,654	1	5	1,651
2030	1,661	2	6	1,656
2031	1,667	2	8	1,662
2032	1,676	2	9	1,669
2033	1,678	2	10	1,670
2034	1,682	3	11	1,673
2035	1,686	3	13	1,676
2036	1,692	4	14	1,682
2037	1,692	4	15	1,681
2038	1,694	4	16	1,682
2039	1,695	5	17	1,683
2040	1,699	5	18	1,686
2021-2040 CAGR	**0.2%**	**17.3%**	**19.4%**	**0.2%**

NIPSCO STATUS QUO EXTENDED LOAD DETAILS

	MWh Sales			
	Base Load	EV Load	DERs	All-In
2021	11,882,769	7,239	8,236	11,881,772
2022	11,738,319	10,211	15,906	11,732,624
2023	10,826,820	14,183	22,246	10,818,757
2024	10,912,600	19,342	25,380	10,906,562
2025	10,953,440	23,188	27,900	10,948,728
2026	10,995,558	27,507	31,901	10,991,164
2027	11,030,105	32,099	36,777	11,025,427
2028	11,062,811	37,512	40,947	11,059,377
2029	11,091,495	43,655	45,904	11,089,245
2030	11,119,554	50,140	48,002	11,121,692
2031	11,144,181	57,416	49,616	11,151,981
2032	11,167,627	65,701	54,992	11,178,337
2033	11,182,358	74,924	58,036	11,199,247
2034	11,192,656	86,776	60,095	11,219,336
2035	11,201,372	95,740	63,549	11,233,563
2036	11,209,985	105,290	69,477	11,245,797
2037	11,211,709	115,709	72,598	11,254,820
2038	11,210,581	127,374	77,193	11,260,762
2039	11,206,908	139,840	83,400	11,263,348
2040	11,202,183	155,423	96,983	11,260,623
2021-2040 CAGR	**-0.3%**	**17.5%**	**13.9%**	**-0.3%**

Note that "Base Load" column includes industrial load loss in 2023

NIPSCO STATUS QUO EXTENDED LOAD DETAILS

	Summer Peak (MW)			
	Base Load	EV Load	DERs	All-In
2021	2,338	0	3	2,335
2022	2,284	0	6	2,279
2023	2,174	1	8	2,167
2024	2,182	1	9	2,174
2025	2,182	1	10	2,173
2026	2,184	1	11	2,174
2027	2,185	2	12	2,174
2028	2,187	2	14	2,175
2029	2,189	2	15	2,176
2030	2,191	3	16	2,178
2031	2,193	3	16	2,180
2032	2,195	3	17	2,180
2033	2,195	4	18	2,181
2034	2,195	4	19	2,180
2035	2,194	4	19	2,180
2036	2,194	5	21	2,178
2037	2,193	5	22	2,176
2038	2,191	6	23	2,174
2039	2,188	6	25	2,170
2040	2,186	7	29	2,164
2021-2040 CAGR	**-0.4%**	**18.6%**	**12.6%**	**-0.4%**

	Winter Peak (MW)			
	Base Load	EV Load	DERs	All-In
2021	1,606	0	0	1,606
2022	1,588	0	1	1,588
2023	1,490	0	1	1,489
2024	1,503	1	1	1,502
2025	1,507	1	1	1,506
2026	1,514	1	1	1,513
2027	1,520	1	2	1,520
2028	1,529	1	2	1,529
2029	1,533	1	2	1,533
2030	1,539	2	2	1,539
2031	1,545	2	2	1,544
2032	1,552	2	3	1,552
2033	1,554	2	3	1,554
2034	1,557	3	3	1,557
2035	1,560	3	3	1,560
2036	1,565	4	3	1,565
2037	1,564	4	3	1,564
2038	1,565	4	3	1,566
2039	1,565	5	4	1,566
2040	1,568	5	4	1,569
2021-2040 CAGR	**-0.1%**	**17.3%**	**13.5%**	**-0.1%**

Note that "Base Load" column includes industrial load loss in 2023

NIPSCO AGGRESSIVE ENVIRONMENTAL REGULATION LOAD DETAILS

	MWh Sales			
	Base Load	EV Load	DERs	All-In
2021	11,940,087	8,848	18,353	11,930,582
2022	11,902,413	14,117	39,460	11,877,069
2023	11,938,227	21,643	58,513	11,901,358
2024	11,985,631	32,279	78,351	11,939,558
2025	12,021,815	39,750	101,219	11,960,346
2026	12,058,173	49,150	130,630	11,976,693
2027	12,094,192	60,357	166,489	11,988,060
2028	12,131,648	74,624	179,303	12,026,969
2029	12,165,047	92,524	198,380	12,059,191
2030	12,197,613	107,422	231,625	12,073,410
2031	12,226,902	124,827	255,225	12,096,504
2032	12,254,112	145,101	279,276	12,119,936
2033	12,275,076	169,022	302,984	12,141,114
2034	12,291,826	197,883	326,113	12,163,596
2035	12,307,652	227,408	341,534	12,193,525
2036	12,322,461	260,245	366,863	12,215,843
2037	12,330,264	296,570	388,403	12,238,432
2038	12,335,196	340,450	400,873	12,274,772
2039	12,338,219	388,899	418,854	12,308,264
2040	12,341,572	448,747	439,145	12,351,174
2021-2040 CAGR	**0.2%**	**23.0%**	**18.2%**	**0.2%**

NIPSCO AGGRESSIVE ENVIRONMENTAL REGULATION LOAD DETAILS

	Summer Peak (MW)			
	Base Load	EV Load	DERs	All-In
2021	2,346	1	7	2,340
2022	2,321	1	14	2,308
2023	2,316	2	21	2,296
2024	2,315	2	29	2,289
2025	2,313	3	37	2,280
2026	2,313	4	47	2,269
2027	2,314	5	60	2,258
2028	2,317	6	65	2,258
2029	2,319	7	71	2,255
2030	2,322	9	83	2,248
2031	2,325	10	91	2,244
2032	2,328	11	100	2,239
2033	2,329	13	108	2,235
2034	2,330	15	115	2,230
2035	2,331	18	120	2,229
2036	2,332	20	129	2,223
2037	2,332	23	136	2,219
2038	2,331	26	140	2,218
2039	2,330	30	145	2,215
2040	2,329	34	152	2,212
2021-2040 CAGR	**0.0%**	**23.5%**	**17.8%**	**-0.3%**

	Winter Peak (MW)			
	Base Load	EV Load	DERs	All-In
2021	1,622	1	1	1,621
2022	1,611	1	2	1,610
2023	1,614	2	3	1,612
2024	1,622	2	5	1,619
2025	1,626	3	8	1,621
2026	1,633	3	11	1,625
2027	1,640	4	16	1,628
2028	1,650	5	20	1,635
2029	1,654	6	24	1,637
2030	1,661	7	30	1,638
2031	1,667	8	36	1,640
2032	1,676	10	42	1,643
2033	1,678	12	49	1,640
2034	1,682	14	56	1,640
2035	1,686	16	62	1,639
2036	1,692	18	70	1,640
2037	1,692	21	78	1,634
2038	1,694	24	85	1,633
2039	1,695	27	93	1,630
2040	1,699	31	101	1,629
2021-2040 CAGR	**0.2%**	**22.5%**	**28.3%**	**0.0%**

NIPSCO ECONOMY-WIDE DECARBONIZATION LOAD DETAILS

	MWh Sales				
	Base Load	EV Load	Other Electrification	DERs	All-In
2021	11,959,772	11,797	138,288	16,823	12,093,034
2022	12,009,527	18,051	276,575	36,768	12,267,385
2023	12,073,746	27,243	414,863	53,629	12,462,223
2024	12,120,588	41,410	553,150	70,244	12,644,904
2025	12,156,297	54,220	691,438	93,435	12,808,519
2026	12,191,556	71,300	829,726	114,783	12,977,798
2027	12,225,301	93,545	968,013	140,008	13,146,853
2028	12,254,438	123,199	1,106,301	170,374	13,313,564
2029	12,279,724	162,557	1,244,588	196,880	13,489,991
2030	12,302,917	197,831	1,382,876	225,617	13,658,008
2031	12,323,055	240,823	1,521,164	244,397	13,840,644
2032	12,337,897	292,523	1,659,451	251,846	14,038,025
2033	12,349,912	356,629	1,797,739	256,836	14,247,444
2034	12,358,681	433,600	1,936,027	263,625	14,464,683
2035	12,366,646	502,271	2,074,314	271,449	14,671,782
2036	12,373,769	580,771	2,212,602	280,740	14,886,402
2037	12,374,300	670,186	2,350,889	288,030	15,107,346
2038	12,372,805	774,588	2,489,177	296,379	15,340,190
2039	12,369,171	892,267	2,627,465	304,262	15,584,640
2040	12,364,591	1,031,805	2,765,752	313,157	15,848,992
2021-2040 CAGR	**0.2%**	**26.5%**		**16.6%**	**1.4%**

NIPSCO ECONOMY-WIDE DECARBONIZATION LOAD DETAILS

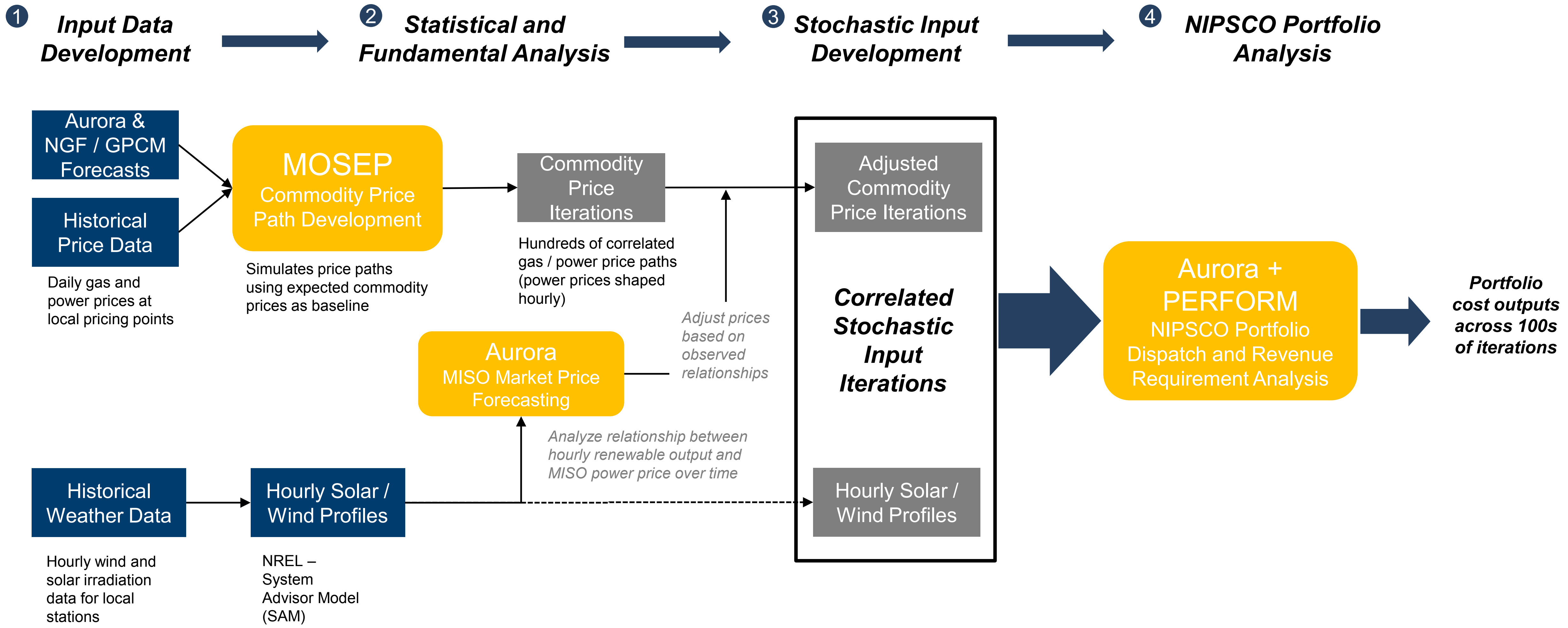
	Summer Peak (MW)				
	Base Load	EV Load	Other Electrification	DERs	All-In
2021	2,349	1	17	6	2,361
2022	2,344	1	34	14	2,367
2023	2,345	2	51	20	2,379
2024	2,344	3	69	26	2,390
2025	2,342	4	86	35	2,397
2026	2,342	6	103	43	2,407
2027	2,342	7	120	53	2,417
2028	2,342	10	137	65	2,425
2029	2,343	13	154	75	2,435
2030	2,344	15	172	87	2,444
2031	2,345	19	189	95	2,458
2032	2,345	23	206	98	2,475
2033	2,345	28	223	101	2,494
2034	2,280	33	305	104	2,515
2035	2,279	39	327	108	2,537
2036	2,278	45	349	112	2,560
2037	2,277	51	371	116	2,583
2038	2,275	59	393	120	2,607
2039	2,272	69	415	123	2,632
2040	2,269	79	436	128	2,658
2021-2040 CAGR	**-0.2%**	**26.0%**		**17.3%**	**0.6%**

	Winter Peak (MW)				
	Base Load	EV Load	Other Electrification	DERs	All-In
2021	1,626	1	34	1	1,660
2022	1,626	1	68	2	1,693
2023	1,633	2	102	3	1,734
2024	1,641	3	137	5	1,776
2025	1,611	4	206	8	1,813
2026	1,617	5	247	12	1,857
2027	1,623	6	288	16	1,902
2028	1,629	8	330	22	1,945
2029	1,635	11	371	28	1,988
2030	1,640	14	412	36	2,030
2031	1,645	17	453	42	2,073
2032	1,649	20	494	47	2,116
2033	1,653	25	536	52	2,161
2034	1,656	30	577	57	2,206
2035	1,659	35	618	62	2,249
2036	1,661	41	659	68	2,292
2037	1,663	47	700	74	2,336
2038	1,664	54	741	80	2,379
2039	1,665	62	783	87	2,423
2040	1,665	72	824	93	2,467
2021-2040 CAGR	**0.1%**	**27.0%**		**28.3%**	**2.1%**

APPENDIX: STOCHASTIC ANALYSIS

STOCHASTIC ANALYSIS APPROACH

The 2021 IRP is incorporating combined commodity price and renewable output stochastic analysis



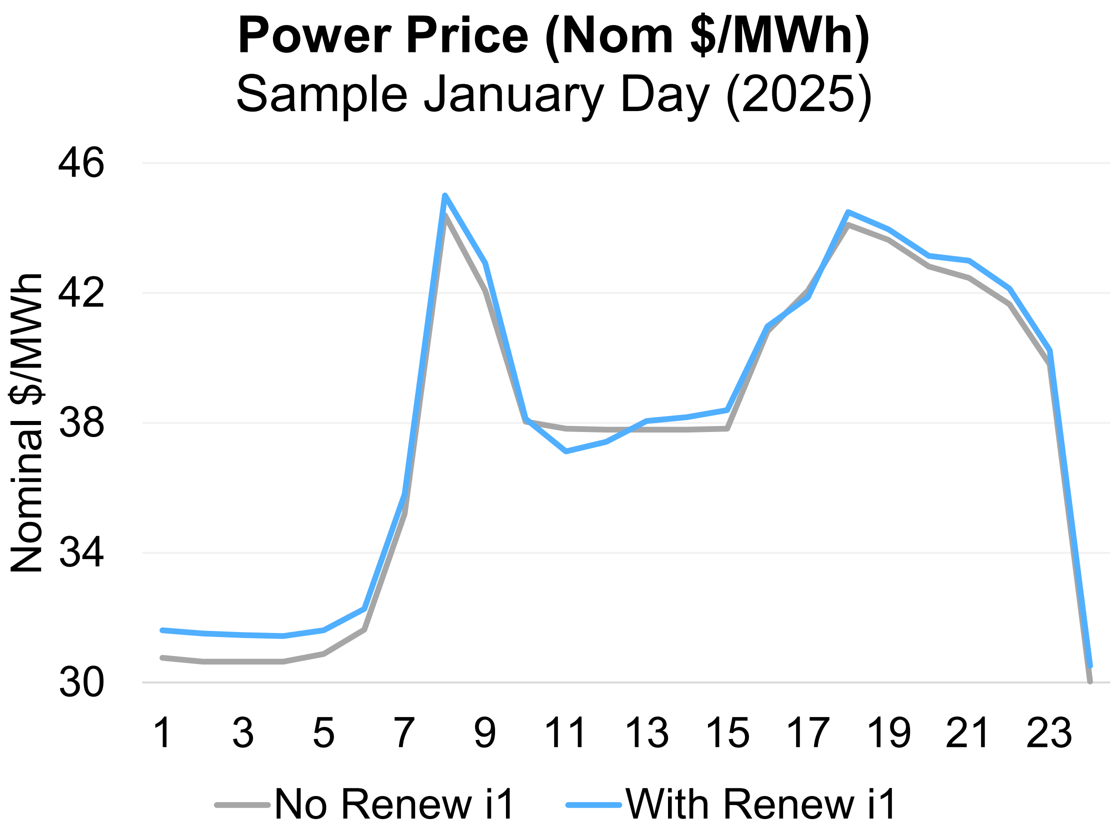
DETERMINING THE RELATIONSHIP BETWEEN RENEWABLE OUTPUT AND POWER PRICE

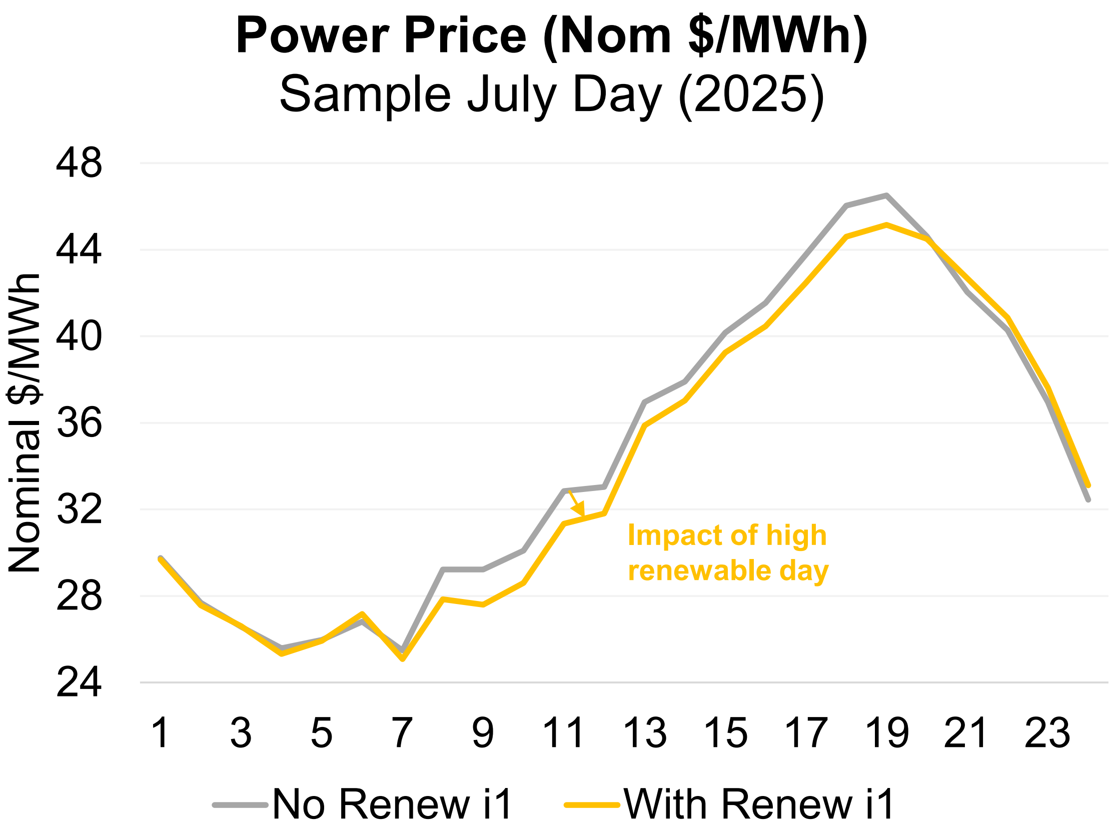
CRA Methodology

1. **Obtain "historical" hourly renewable (wind and solar) availability for the relevant MISO location**
   - Since 10 years' worth of actual renewable project generation data is not available, CRA used 10 years of historical weather data to proxy for "historical" renewable generation data using NREL's System Advisor Model (SAM) resource performance models
2. **Determine the hourly impact of renewable availabilities on power prices by:**
   1. Running Aurora price formation multiple times with various renewable generation scenarios as inputs
   2. Then, performing a regression to model and quantify the relationship between price and renewable output
3. **Enforce the relationship between renewable availability and power prices in CRA's stochastic power price propagation model, MOSEP, based on our regression equation**
4. **Generate MOSEP results, producing, for each stochastic iteration, 20 forecast years of hourly power prices that include the impact of intermittent renewable generation**

MOSEP OUTPUT SAMPLES

Base Case Forecast
Illustrating a sample iteration





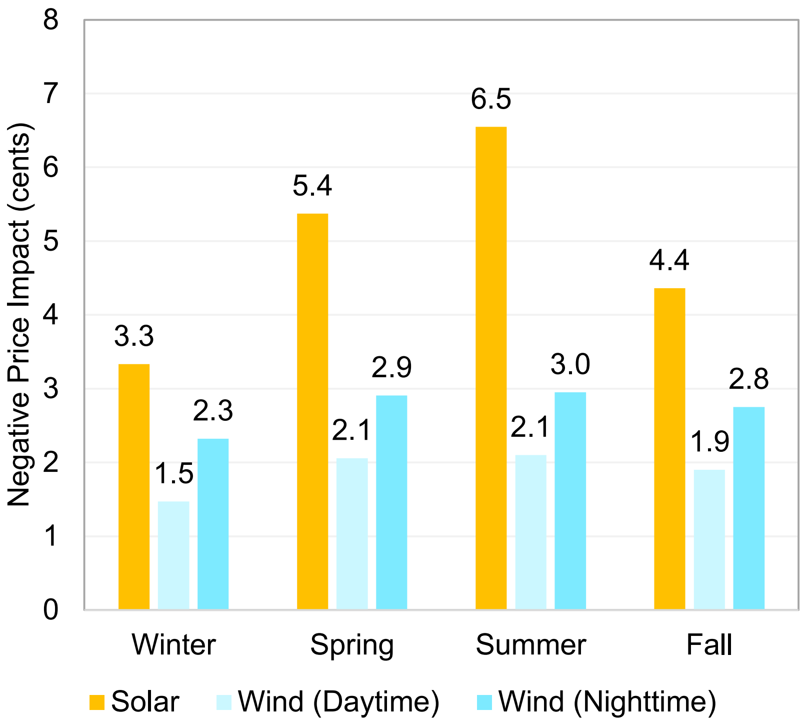
RELATIONSHIP BETWEEN RENEWABLE OUTPUT AND POWER PRICES

Determined average hourly impact on prices by analyzing 20 years of hourly power prices and correlated renewable availabilities with seasonal and time-of-day variables

Finding #1:

- Renewable availability has a significant negative impact on power prices, all else equal
- Regression coefficients are found to be statistically significant (>99.99% confidence)

Negative Hourly Price Impact (2030)
per 1% increase in capacity factor



Number of Hourly Observations (2030)

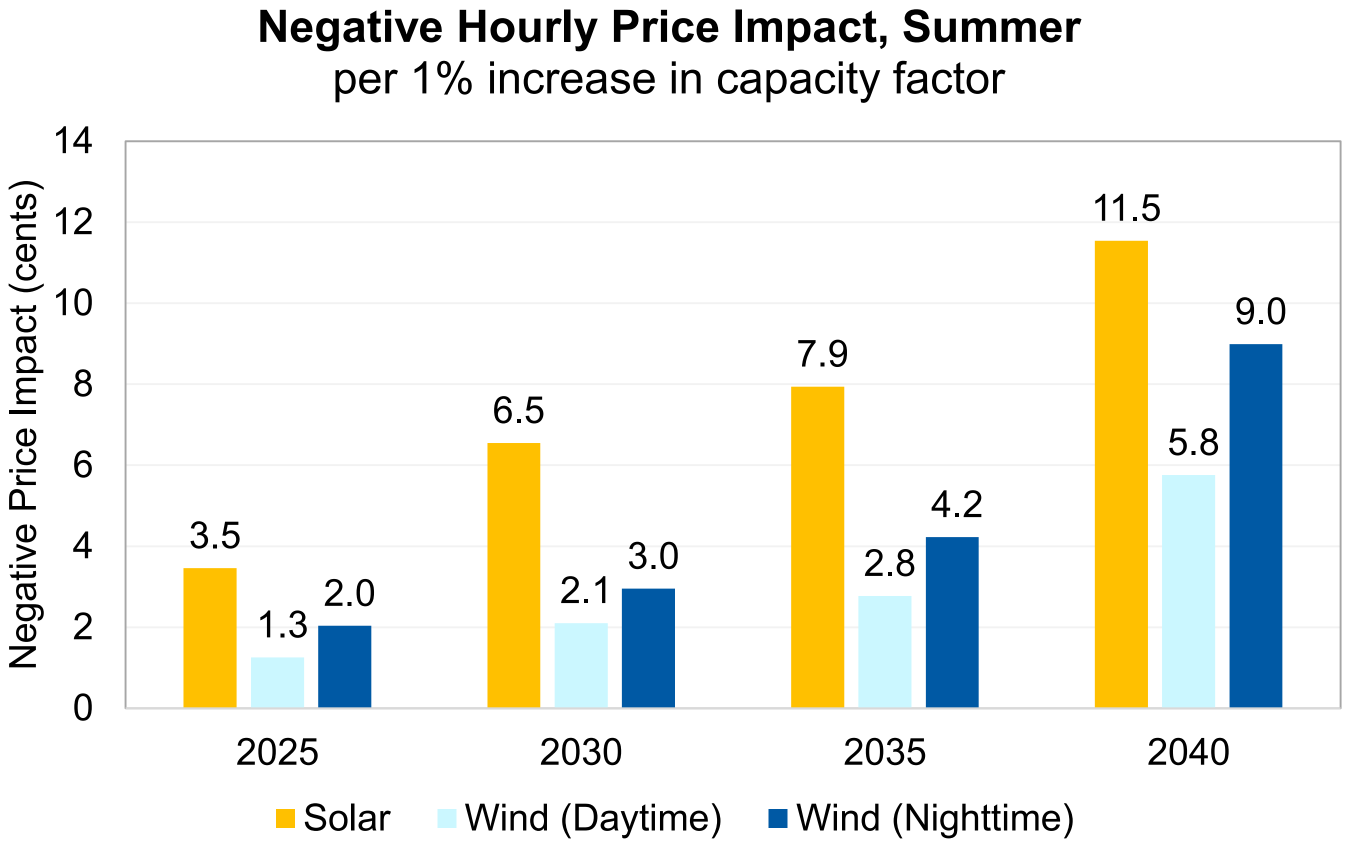
	CF Relative to "Reference Shape"	LMP Increase	LMP Decrease
Daytime	**Wind Up + Solar Up**	0	122,237
	Wind Up + Solar Down	89,699	59,649
	Wind Down + Solar Up	32,115	224,496
	Wind Down + Solar Down	179,504	0
Nighttime	**Wind Up**	0	320,769
	Wind Down	272,553	0

RELATIONSHIP BETWEEN RENEWABLE OUTPUT AND POWER PRICES

Conducted Aurora analysis on multiple test-years (2020, 2025, 2030, 2035, and 2040) to assess how the relationship changes with different levels of renewable penetration in MISO Zone 6

Finding #2:

- Impact of renewable availability on power prices increases with level of renewable penetration
  - E.g. In a given hour in summer 2025, a 1% increase in solar availability decreases power prices by 3.5 cents, on average
  - Impact of a 1% increase in solar availability increases to 11.5 cents in 2040 given assumed Reference Case renewable penetration levels



* *Note: Summer impacts and standalone solar / wind impacts shown only; impact of interaction effects between wind and solar availability on power prices was also determined but is not shown here*