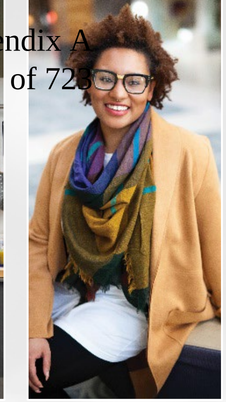




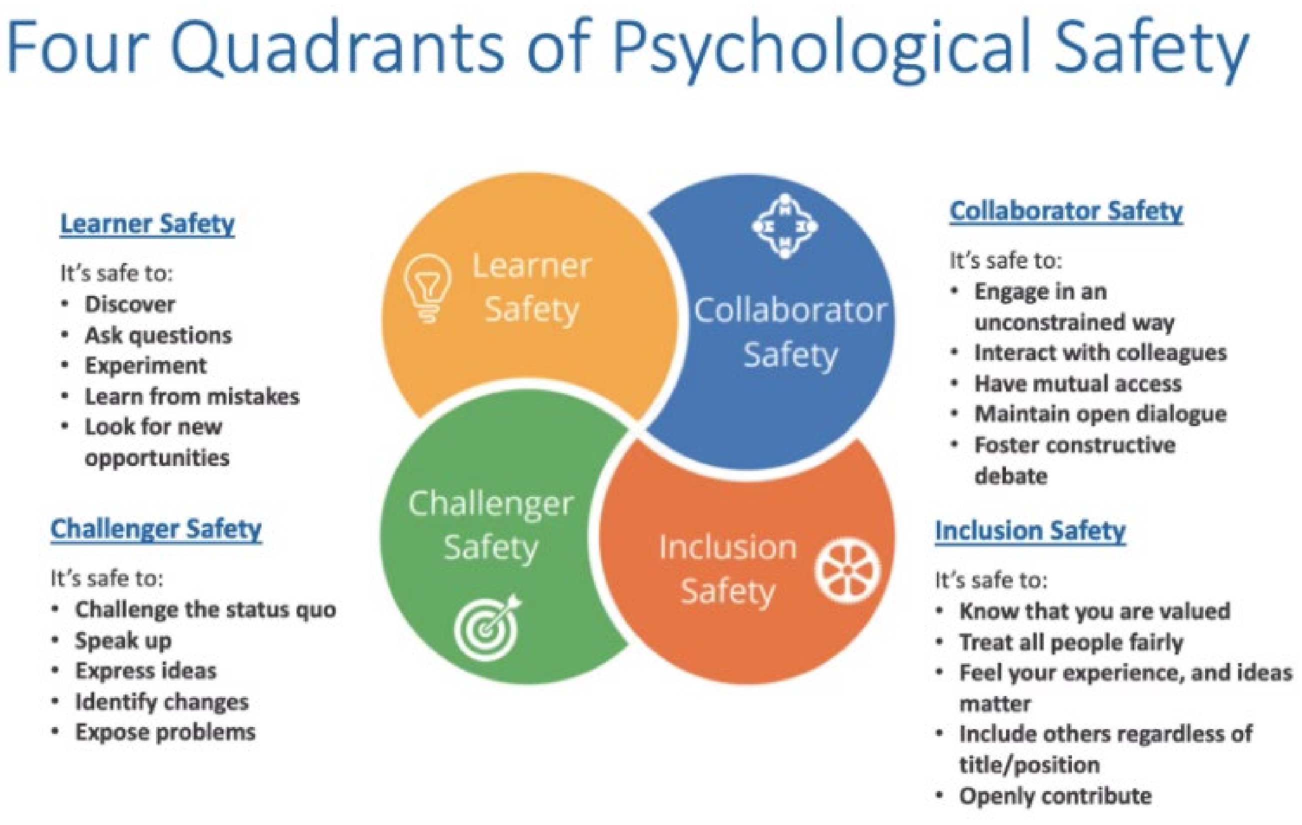

2021 NIPSCO Integrated Resource Plan

First Stakeholder Advisory Meeting

March 19th, 2021
9:00AM-2:00PM CST




SAFETY MOMENT: PSYCHOLOGICAL SAFETY



https://thriveglobal.com/stories/components-of-psychological-safety-learner-safety/

Consider two actions that will be impactful

One of these actions is to start a new behavior, and the other is to stop a behavior.

LEARNER SAFETY

STOP: Assuming everyone is on the same page
START: Self-awareness during interactions, continually improving

COLLABORATOR SAFETY

STOP: Having a narrow view of what Success is
START: Actively listening to others

CHALLENGER SAFETY

STOP: Ignoring that others influence our emotional state
START: Focus on the variety of pathways to obtain success

INCLUSION SAFETY

STOP: Disregarding impact of our own behaviors on others
START: Treat people the way <u>they</u> want to be treated

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)

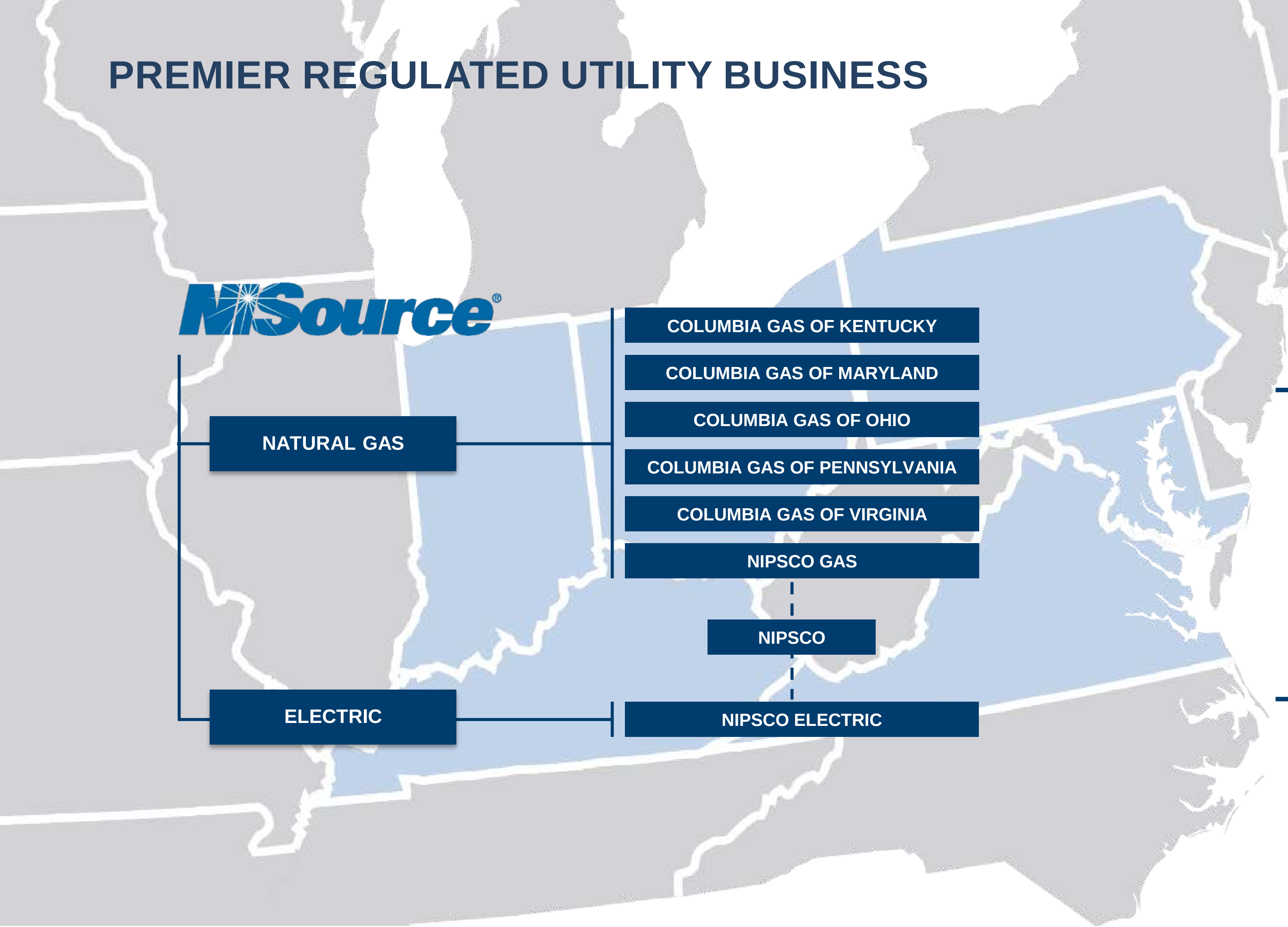
AGENDA

Time *Central Time	Topic	Speaker
9:00-9:10AM	Welcome & Introduction	Alison Becker, Manager Regulatory Policy, NIPSCO
9:10-9:20AM	Kick Off	Mike Hooper, President & COO, NIPSCO
9:20-10:20AM	2018 Short Term Action Plan Update 2021 Continuous Improvements	Fred Gomos, Director Strategy & Risk Integration, NiSource Pat Augustine, Vice President, CRA
10:20-10:30AM	Break	
10:30-11:30AM	Key Assumptions Update: Commodity Prices	Robert Kaineg, Principal, CRA Pat Augustine, Vice President, CRA
11:30-12:15PM	Lunch	
12:15-1:15PM	Key Assumptions Update: Demand Forecast	Derya Eryilmaz, Associate Principal, CRA Pat Augustine, Vice President, CRA
1:15-1:30PM	Break	
1:30-1:50PM	Treatment of Uncertainty – Introduction	Pat Augustine, Vice President, CRA
1:50-1:55PM	2021 Public Advisory Process	Erin Whitehead, Vice President Regulatory & Major Accounts, NIPSCO
1:55-2:00PM	Closing	

KICK OFF

Mike Hooper, President & COO, NIPSCO

PREMIER REGULATED UTILITY BUSINESS



NiSource®

- NATURAL GAS
  - COLUMBIA GAS OF KENTUCKY
  - COLUMBIA GAS OF MARYLAND
  - COLUMBIA GAS OF OHIO
  - COLUMBIA GAS OF PENNSYLVANIA
  - COLUMBIA GAS OF VIRGINIA
  - NIPSCO GAS
- NIPSCO
- ELECTRIC
  - NIPSCO ELECTRIC

SIGNIFICANT SCALE ACROSS 6 STATES

~3.2M

GAS CUSTOMERS

~500K

ELECTRIC CUSTOMERS

NIPSCO PROFILE

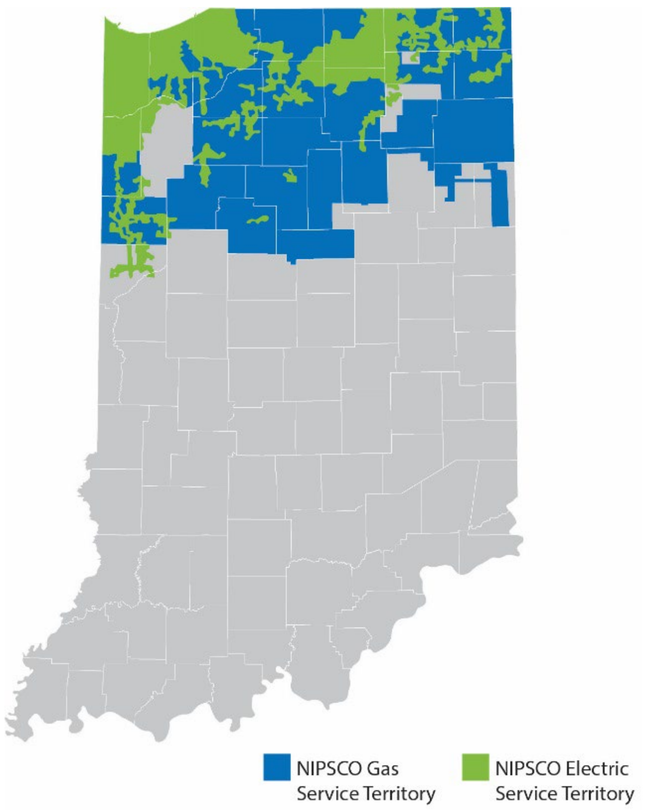
Working to Become Indiana's Premier Utility

Electric

- 460,000 Electric Customers in 20 Counties
- 3,400 MW Generating Capacity
  - 7 Electric Generating Facilities
    (2 Coal, 1 Natural Gas, 2 Hydro, 2 Wind)
  - 500 MW of New Wind Energy
    (Rosewater and Jordan Creek Wind online in Dec. 2020)
- 12,800 Miles of Transmission and Distribution
  - Interconnect with 5 Major Utilities (3 MISO; 2 PJM)
  - Serves 2 Network Customers and Other Independent Power Producers
- Electric Rates Below National Average

Natural Gas

- 820,000 Natural Gas Customers; 32 Counties
- Lowest Delivered Cost Provider in Indiana
- 17,000 Miles of Transmission and Distribution Line/Main
- Interconnections with Seven Major Interstate Pipelines
- Two On-System Storage Facilities



2,900
Employees

Merrillville, Ind.
Headquarters

PILLARS OF OUR ONGOING GENERATION TRANSITION PLAN

This plan creates a vision for the future that is better for our customers and it’s consistent with our goal to transition to the best cost, cleanest electric supply mix available while maintaining reliability, diversity and flexibility for the technology and market changes on the horizon.

Reliable and sustainable	Flexibility for the future	Local and statewide economic benefits	Best plan for customers and the company

2018 NIPSCO IRP ACTION PLAN UPDATE 2021 CONTINUOUS IMPROVEMENTS

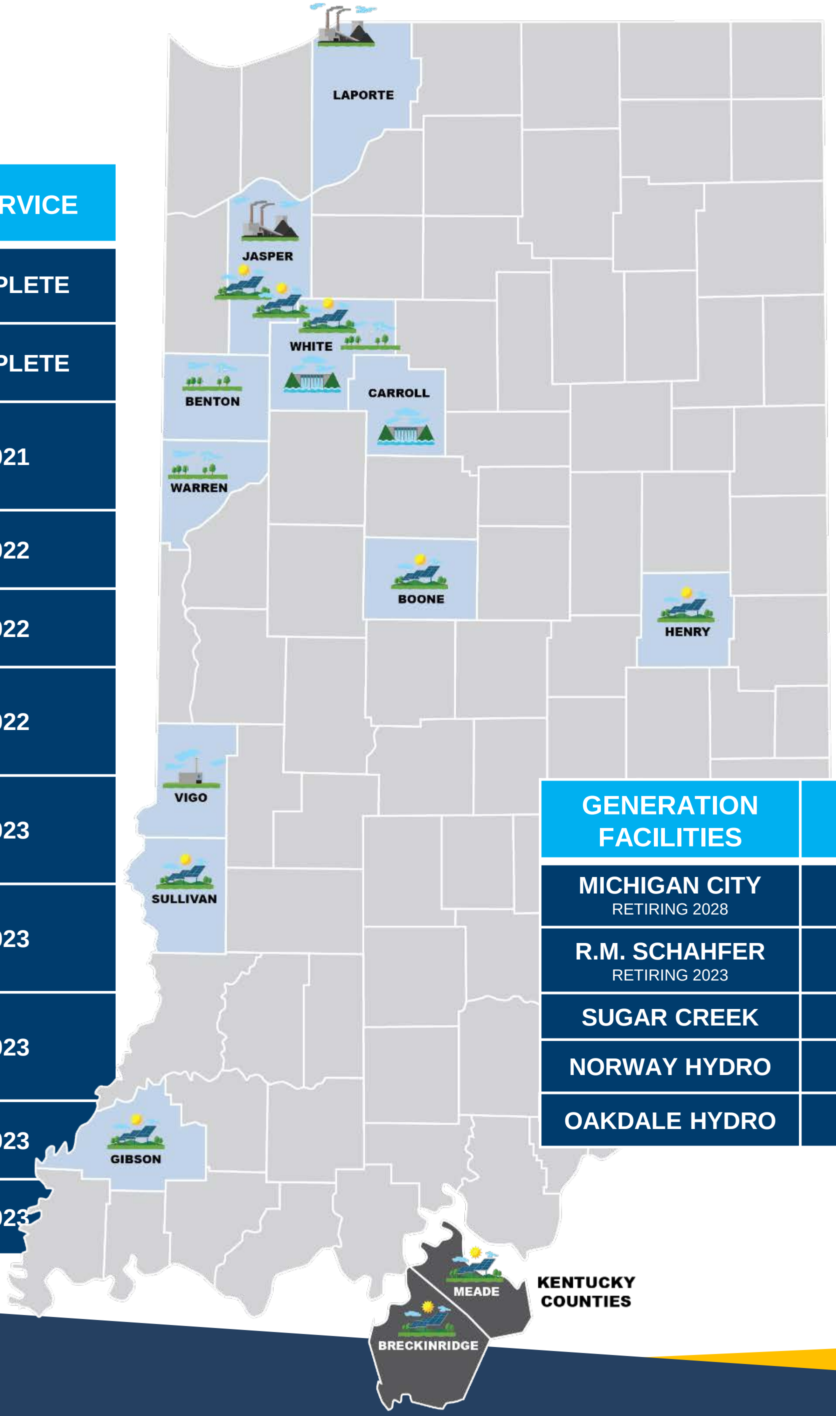
Fred Gomos, Director Strategy & Risk Integration, NiSource
Pat Augustine, Vice President, CRA

NIPSCO CONTINUES TO MAKE PROGRESS ON 2018 SHORT TERM ACTION PLAN

	2018 IRP Short-Term Action Plan	Progress To Date
Retirement	▪ Initiate retirement of R.M Schahfer coal units by 2023 ▪ Identify and Implement required reliability and transmission upgrades resulting from the retirement of the units	▪ Received approval from MISO to retire coal units by May 2023; Units 14 and 15 now expected to retire by the end of 2021; Retirement in 2021 will require another MISO approval under "Attachment Y" of MISO's Tariff ▪ Identified 6 transmission upgrade projects. To date 4 of the 6 have been completed, the remaining are expected to be completed in 2021 and 2022
Replacement	▪ Select projects from the 2018 RFP prioritizing wind resources due to expiring tax incentives ▪ File for CPCN and other necessary approvals ▪ Conduct subsequent All-Source RFP to identify preferred resource to fill remainder of 2023 capacity need (likely renewables and storage)	▪ Sought and received approval from the IURC for ~800MW of wind resources. 2 wind projects are in service and 1 is under construction ▪ Conducted subsequent RFP in late 2019. RFP yielded over 17GW of capacity resources, more than enough to meet the 2023 need. 64% of the bids represented renewables and storage ▪ 2 Solar PPA's approved by IURC, 4 BTAs and 2 PPAs currently pending. 2 PPA agreements signed and additional BTAs under negotiation
Continue and Monitor	▪ Continue implementation of filed EE programs for 2019 to 2021 ▪ Actively monitor MISO market and engage with project developers and asset owners	▪ Continued implementation of DSM plan ▪ Monitoring MISO rule changes on a range of topics, most notably, seasonal capacity constructs and change to Effective Load Carrying Capacity assessment for solar. Incorporated ELCC effects in modeling assumptions for 2019 RFP projects

NIPSCO GENERATION

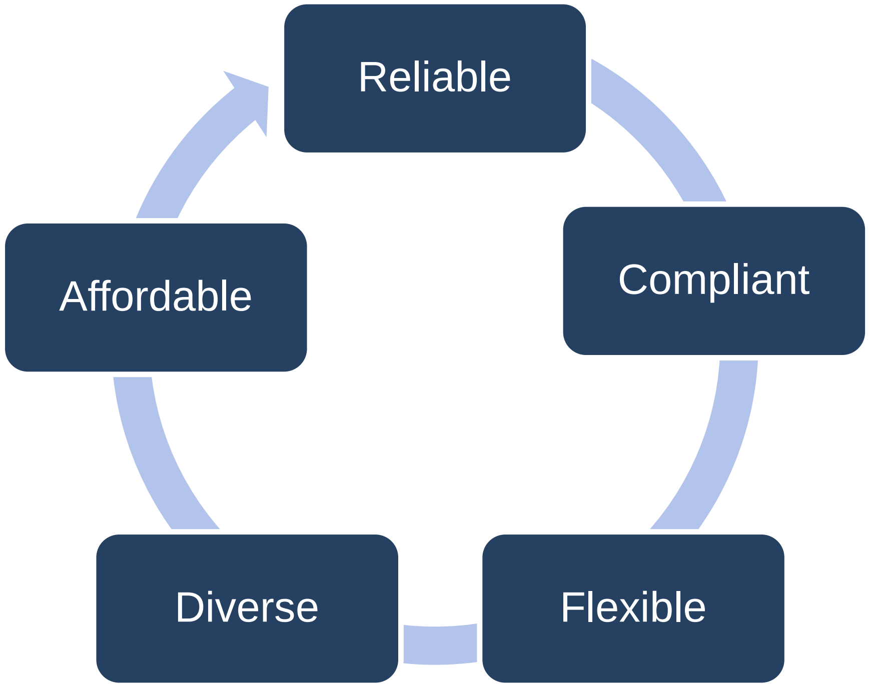
PROJECT	Installed Capacity (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102MW	WHITE	COMPLETE
JORDAN CREEK WIND	400MW	BENTON WARREN	COMPLETE
INDIANA CROSSROADS WIND	300MW	WHITE	2021
DUNNS BRIDGE SOLAR I	265MW	JASPER	2022
BRICKYARD SOLAR	200MW	BOONE	2022
GREENSBORO SOLAR	100MW +30MW BATTERY	HENRY	2022
GREEN RIVER 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



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

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)

DIRECTOR'S REPORT FEEDBACK

Category	2018 IRP Feedback	2021 Improvement Plan	Planned Deep Dive
Load Forecast	• Load forecast relies too heavily on historic methods and professional judgment. Little consideration for evaluating efficacy of current methods or new approaches • Electric Vehicle (EV) penetration not considered • Distributed Energy Resources (DERs) not evaluated sufficiently in load forecast or energy efficiency evaluation process	• Overall load forecasting process and methodology improvement, including explicit incorporation of: o DER modeling o EV modeling o Energy Efficiency	Stakeholder Meeting 1
Scenarios and Sensitivities	• Clearer scenario narratives and solicit feedback earlier from stakeholders • Ensure coverage of technology and load uncertainty	• Broader scenario ranges and earlier data exchange with stakeholders • Scenario ranges include technology (including impact of tax credit) and load (economic, industrial, DER, EV) uncertainty	Stakeholder Meeting 1 (intro) and 2 (details)
Risk Analysis	• Risk analysis focused on higher cost risk, but ignores lower cost opportunities • Reliability risk not quantified sufficiently	• Additional reliability and operational flexibility metrics to be included in NIPSCO's scorecard • Additional lower cost opportunity metric to be included in NIPSCO's scorecard • Incorporation of renewable generation output risk, correlated with power price risk in stochastic analysis	Stakeholder Meeting 1 (intro), 2 (stochastic inputs), and beyond
Market Rule Changes	• Significant burden on NIPSCO to monitor market rules changes, particularly seasonal reserve margin	• Tracking of MISO's Renewable Integration Impact Assessment ("RIIA") initiative findings and expected market responses central to IRP framework • Evaluation of preferred plan's ability to meet both the summer and winter peak • Incorporation of range of Effective Load Carrying Capability ("ELCC") trajectories over time, particularly for solar	Stakeholder Meeting 1 (overview) and beyond (portfolio development and analysis)

RELIABILITY CONSIDERATIONS FOR THE 2021 IRP

- 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
- In the 2021 IRP, NIPSCO will be:
  - Expanding its view of resource adequacy (seasonal vs. summer only)
  - Broadening its uncertainty analyses (hourly market exposure risks, ELCC credit over time)
  - Incorporating new scorecard metrics (tail risk, operational flexibility)
- 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
  - MISO has been studying the impacts of growing intermittent generation penetration in the market for the last several years through the Renewable Integration Impact Assessment (RIIA) initiative
  - The RIIA has defined three major focus areas for reliability and has identified several insights relevant to planners

MISO DEFINES THREE KEY FOCUS AREAS FOR RELIABILITY

Recent MISO Renewable Integration Impact Assessment (RIIA) provides framework for evaluating Reliability in 2021 IRP

Focus of NIPSCO's IRP

NIPSCO coordinates with MISO
Some elements beyond the purview of IRP

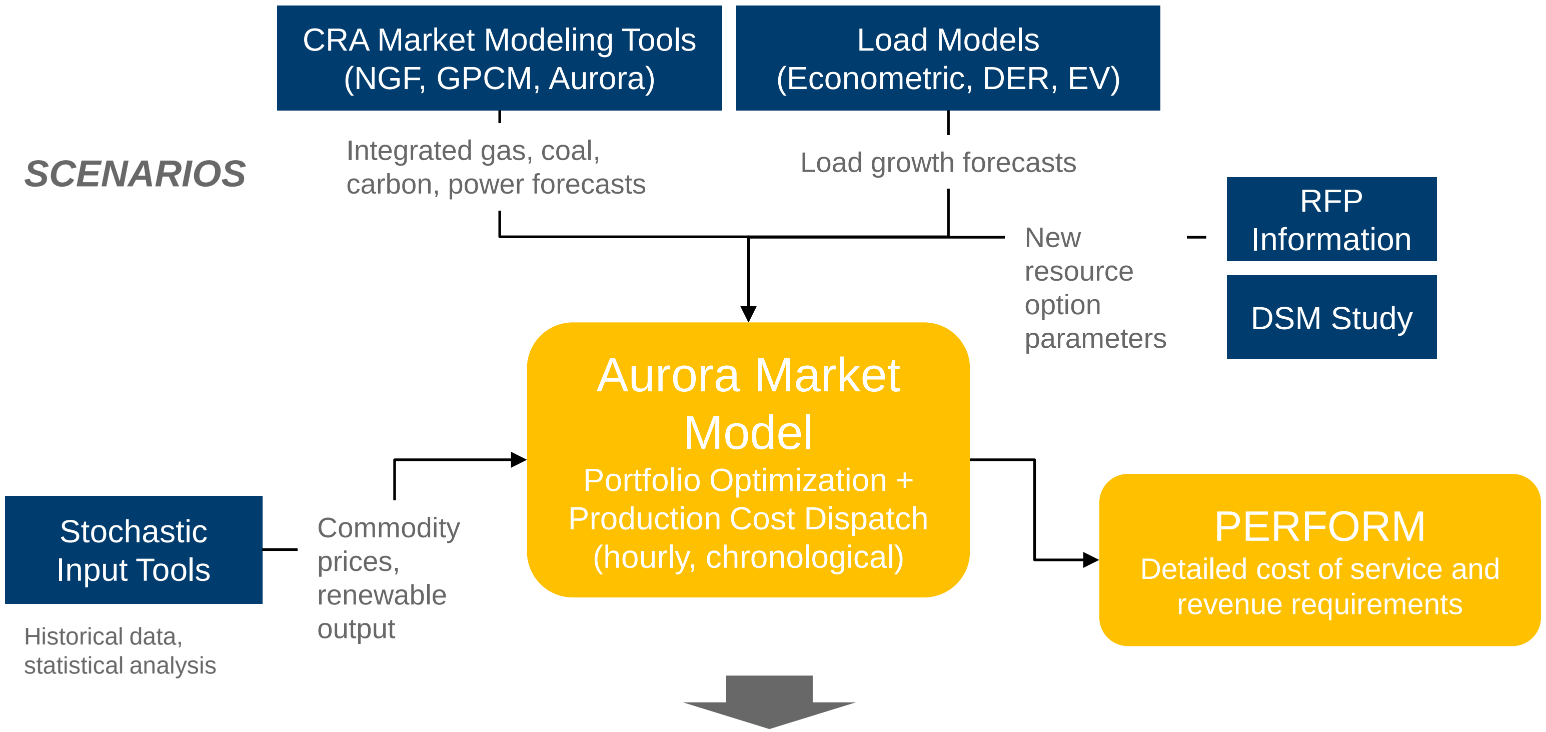
	Resource Adequacy	Energy Adequacy	Operating Reliability
Definition:	Having sufficient resources to reliably serve demand	Ability to provide energy in all operating hours continuously throughout the year	Ability to withstand unanticipated component losses or disturbances
IRP Considerations:	Ability to meet **reserve margins** in all seasons	Amount of firm, **flexible / dispatchable capacity**	Assess **ancillary services value** of resources; ensure **transmission implications** are considered

RIIA REPORT INSIGHTS PROVIDES RELEVANT RELIABILITY INSIGHTS FOR NIPSCO IRP

MISO Focus Area	RIIA Report Insight	MISO Response	Plan to Address in NIPSCO IRP
Resource Adequacy	Risk of losing load compresses into a small number of hours and shifts into the evening or winter	Market redesign, with seasonal capacity construct	Both summer and winter reserve margins will be tracked and implemented as constraints
	A system with >30% renewables will impact grid performance	ELCC capacity credit methodology to reflect changing value over time	ELCC accounting by season with a range of expected solar declines over time
	Diversity of technology and geography improves renewables' ability to serve load	Allow for technology-specific and location-specific capacity credit	Renewable output variability analysis is location specific
Energy Adequacy	With renewable penetration >40%, a greater need for ramping services will develop	Explore flexibility incentives for market redesign and assess other gas-power risks	Include "Operational Flexibility" as a metric in scorecard to measure dispatchable MW, ramp rates; consider ancillary services value
	Grid technology needs to evolve, with more integrated system planning	Explore more integrated MISO-level planning across functions, including software, process, and data needs	Incorporate DER options into IRP resource candidates; move towards integrated grid planning
	Storage paired with renewables and transmission help optimize the delivery of energy	Explore concept and ways to align benefits with outcomes	NIPSCO already pivoting to integrate storage and expects to ask for storage resources in RFP

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

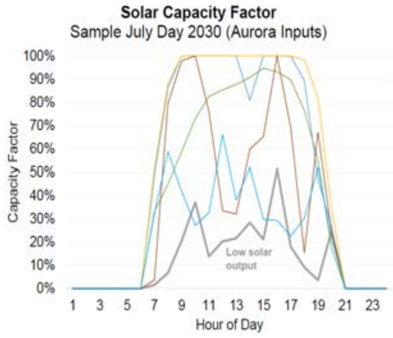
PORTFOLIO EVALUATION WILL INCORPORATE ELEMENTS OF MISO STUDY AND BROADER UNCERTAINTY ANALYSIS

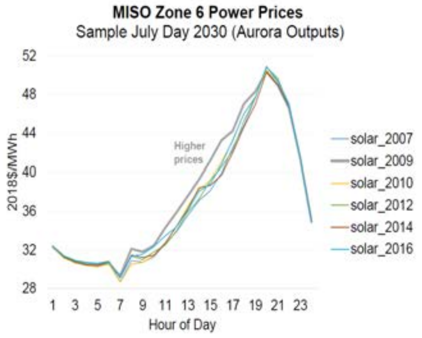
NIPSCO will be evaluating a broad range of portfolio options within a set of planning constraints in two stages

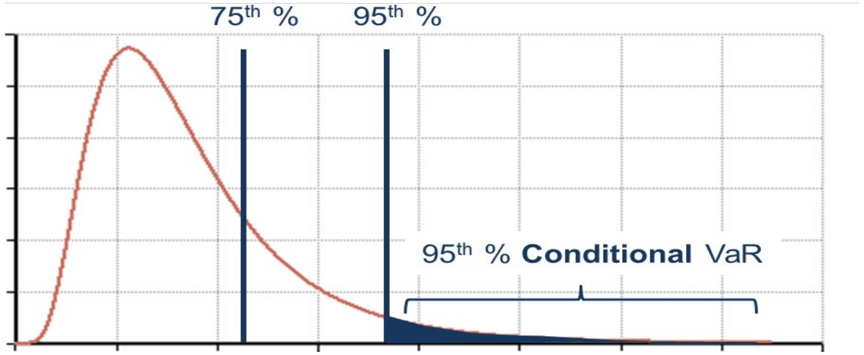
- **The Existing Fleet Review (Resource Retirements)**
- **Replacement Options**

Expanded Uncertainty Analysis Focusing On Tail Risk Outcomes

Type	Rationale
Renewable Output Variability	▪ Analysis of correlated renewable output/ power price variability is becoming more important, given the levels of intermittent generation in NIPSCO's portfolio ▪ Analysis will determine the relationship between renewable output and power prices to understand the impact at different levels of penetration
Tail Risk Exposure	▪ Metrics can vary significantly if the tail of the distribution is long ▪ By examining tail outcomes, we can understand the conditions and portfolios that expose customers to low probability, high consequence (price) events







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

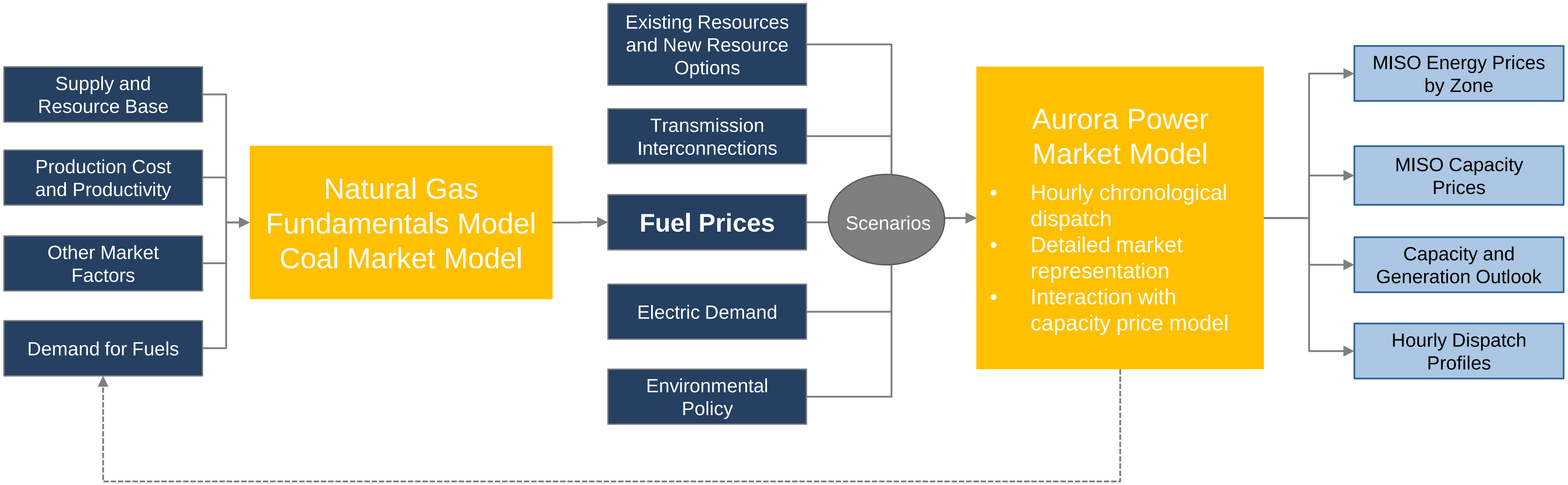
BREAK

KEY ASSUMPTIONS UPDATE: COMMODITY PRICES

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

FUNDAMENTAL MARKET MODELING STRUCTURE

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



**Note that the Aurora model will also be used in "portfolio" mode to assess NIPSCO-specific portfolio analyses*

NATURAL GAS MARKET FORECASTING

Drivers of natural gas pricing and uncertainty change as the forecast progresses in time

Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20

Markets

Expectations about weather, storage and markets drive gas price expectations in the short term

Due to composition of demand at the point, Henry Hub is now highly linked to demand for natural gas exports

Fundamentals

The cost of production, price of oil, and composition of demand drive prices in the medium term, as end-use sectors respond to prevailing prices for energy commodities

Corporate activity may also impact prices over this period if different segments of the industry are consolidated

Policy

Policies that impact economy-wide demand and access to supply will drive gas prices over the longer term

Policies that seek to lower GHG emissions in the R, C & I sectors may have a significant impact on long-term demand

NATURAL GAS MARKET OVERVIEW

- US production of natural gas has remained strong in the face of low market prices, driven by incremental cost improvements and continued production of associated gas
- Limitations on mid-stream development continue to drive significant basis differentials across US markets, with prices in the Northeast and Midwest driven in large part by access (or not) to Appalachian supply

2021 IRP Reference Case Highlights

Natural Gas Supply

- Unproven reserves estimates from the Potential Gas Committee and proved reserves data from the EIA continue to show significant supply
- The Biden administration's ban on new drilling permits on federal land has little short-term impact on supply availability, but puts modest upward pressure on prices over the medium- and long-term

Natural Gas Demand

- Accelerating coal-to-gas switching is increasing electric sector demand over the short- to medium-term, while forecasts of higher renewable penetration moderate long-term demand signals
- International liquid natural gas ("LNG") prices have fallen, and current existing US LNG and pipeline export capacity remains underutilized and planned capacity expansions face delays or cancellation

PRICE FORECASTS ARE BASED ON EXPECTATIONS FOR SUPPLY AND DEMAND

A fundamental price forecast answers the question:
"What gas price is needed to satisfy total demand and make producers whole?"

CRA Natural Gas Fundamentals Model (NGF)

Gas Supply

- Total resource in place, proved and unproven
- Resource growth over time
- Wet / dry product distribution
- Historic wells drilled and ongoing production
- Conventional & associated production
- Existing tight and coal bed methane
- Existing offshore production

Well Performance

- Drilling & completion costs
- Environmental compliance costs
- Royalties & taxes
- Initial production rates
- Changing drilling and production efficiencies over time
- Productivity decline curve
- Well lifetime
- Distribution of performance

Gas Demand

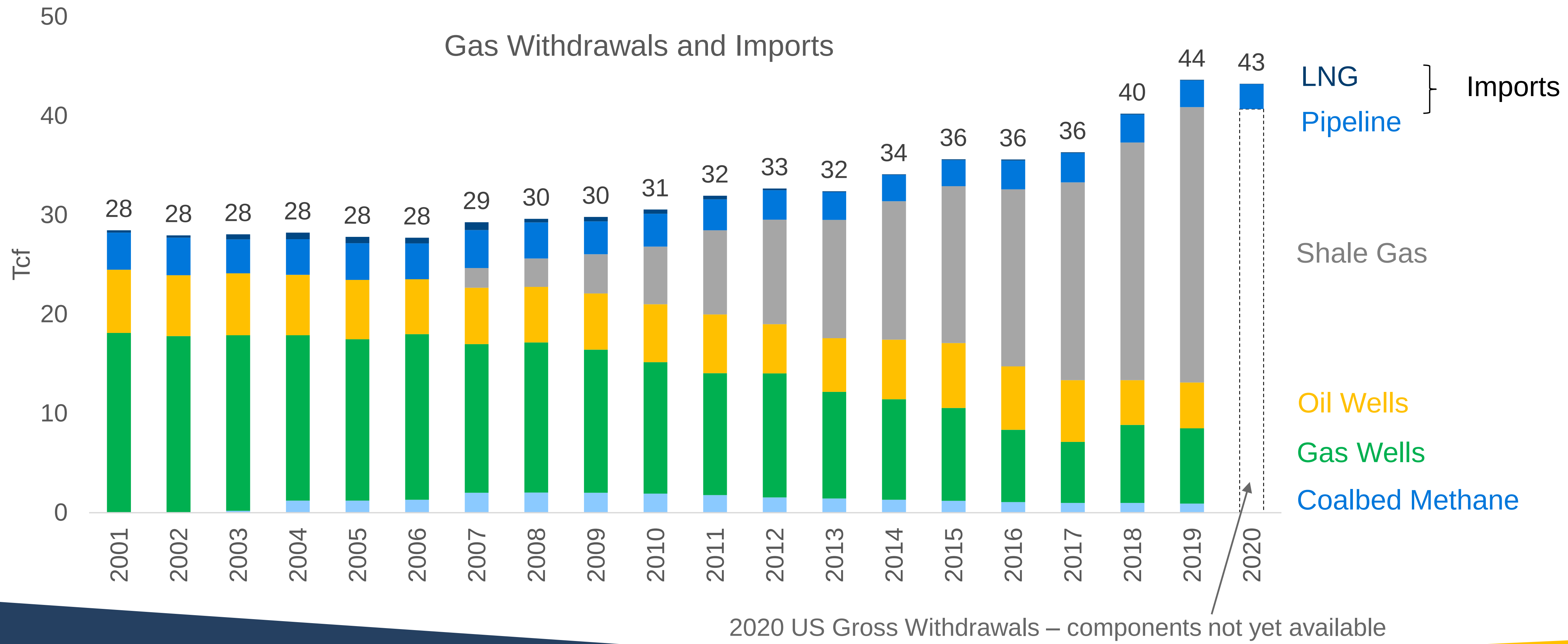
- Electric and non-electric sector demand forecast (domestic)
- International demand (net pipeline & LNG exports)

Other Market Drivers

- Value of natural gas liquids and condensates
- Natural gas storage

SHALE GAS COMPRISES THE LARGEST SHARE OF US PRODUCTION

U.S. Gas production was relatively flat from 2000-2010 until growth accelerated due to rapidly expanding shale gas production



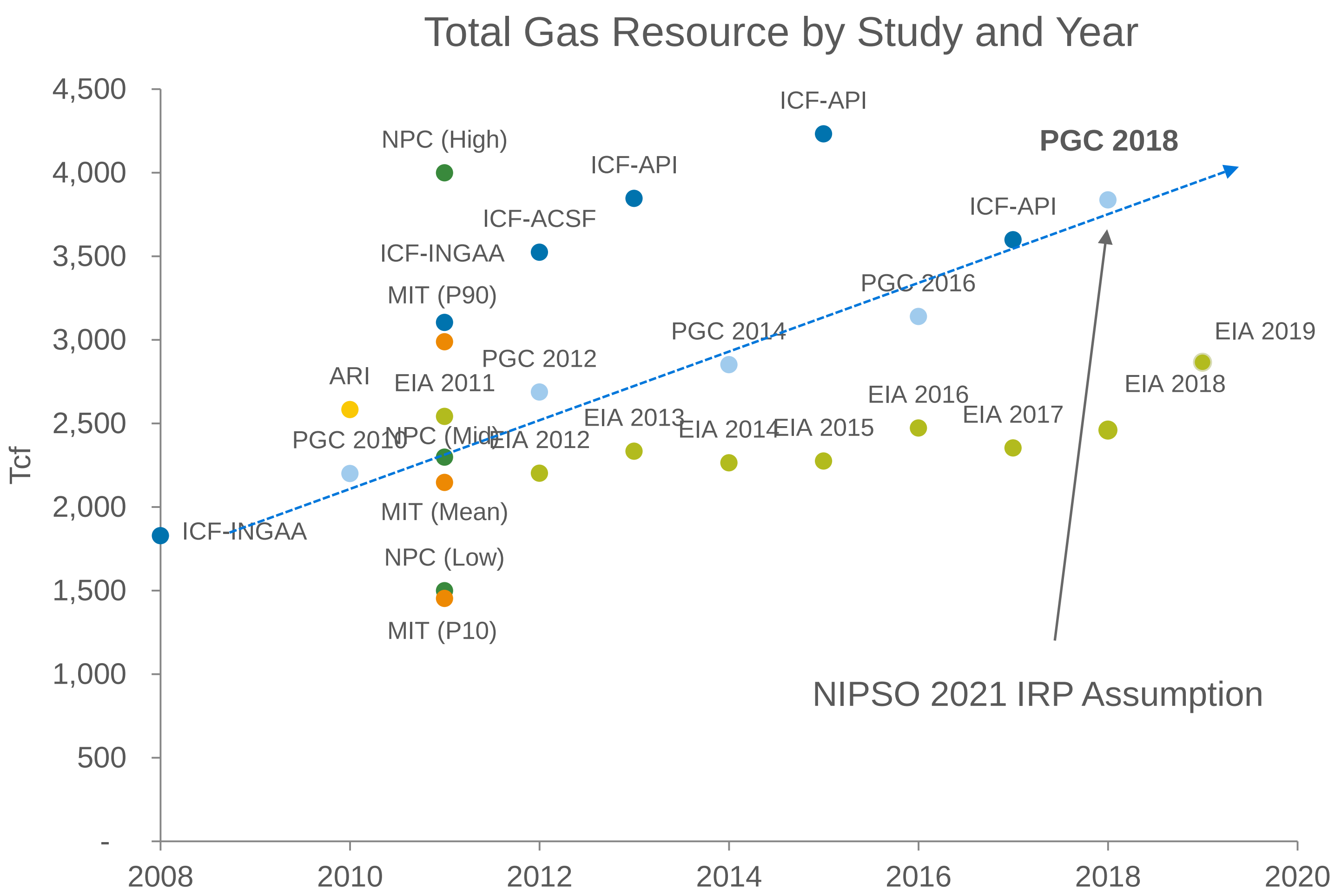
KEY DRIVERS OF THE REFERENCE CASE FORECAST

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 Annual Energy Outlook ("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 FORECAST

Driver	CRA Approach	Explanation
Domestic Demand	• Electric demand taken from AURORA base case, Residential / Commercial / Industrial 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 no further export capacity beyond projects which are already operating or which have already achieved Final Investment Decision, 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

CRA EXPECTS THE NATURAL GAS RESOURCE TO GROW OVER TIME



AEO 2021 Resource Growth Assumptions

Crude oil and natural gas resource type	EUR-Tier 1	EUR-Tier 2	EUR-Tier 2 drilling ramp-up period
Tight oil	1.00%	3.00%	6.00%
Tight and shale gas	1.00%	3.00%	6.00%
All other	0.25%	NA	NA

Source: U.S. Energy Information Administration, Office of Energy Analysis
Note: EUR = estimated ultimate recovery

EIA assumes Total Recoverable Reserves (TRR) grow over time reflecting technical improvements

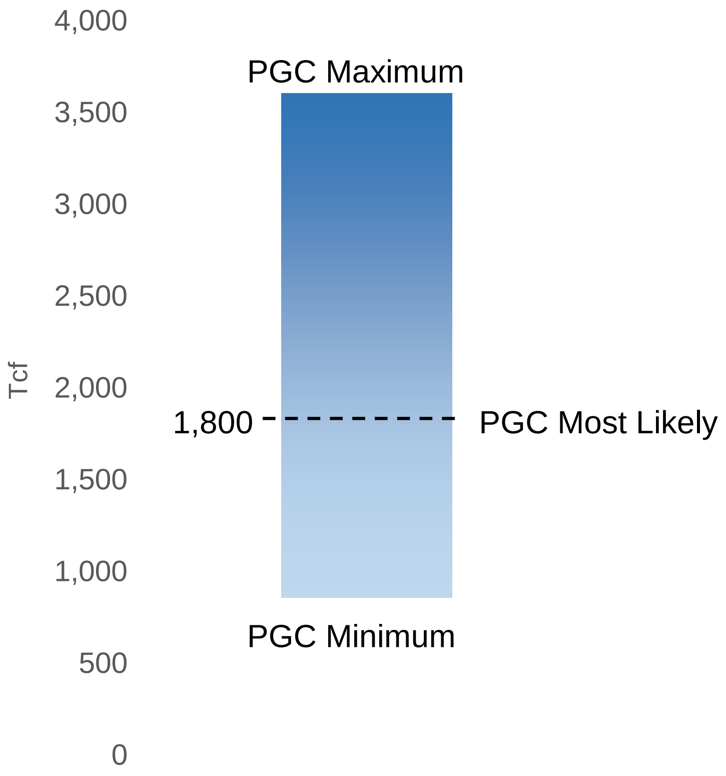
**Note: the PGC 2018 view was released in October 2019 and PGC 2020 is not expected to be available until late 2021*

CRA RELIES ON PGC'S "MOST LIKELY" VIEW OF UNPROVEN RESERVES

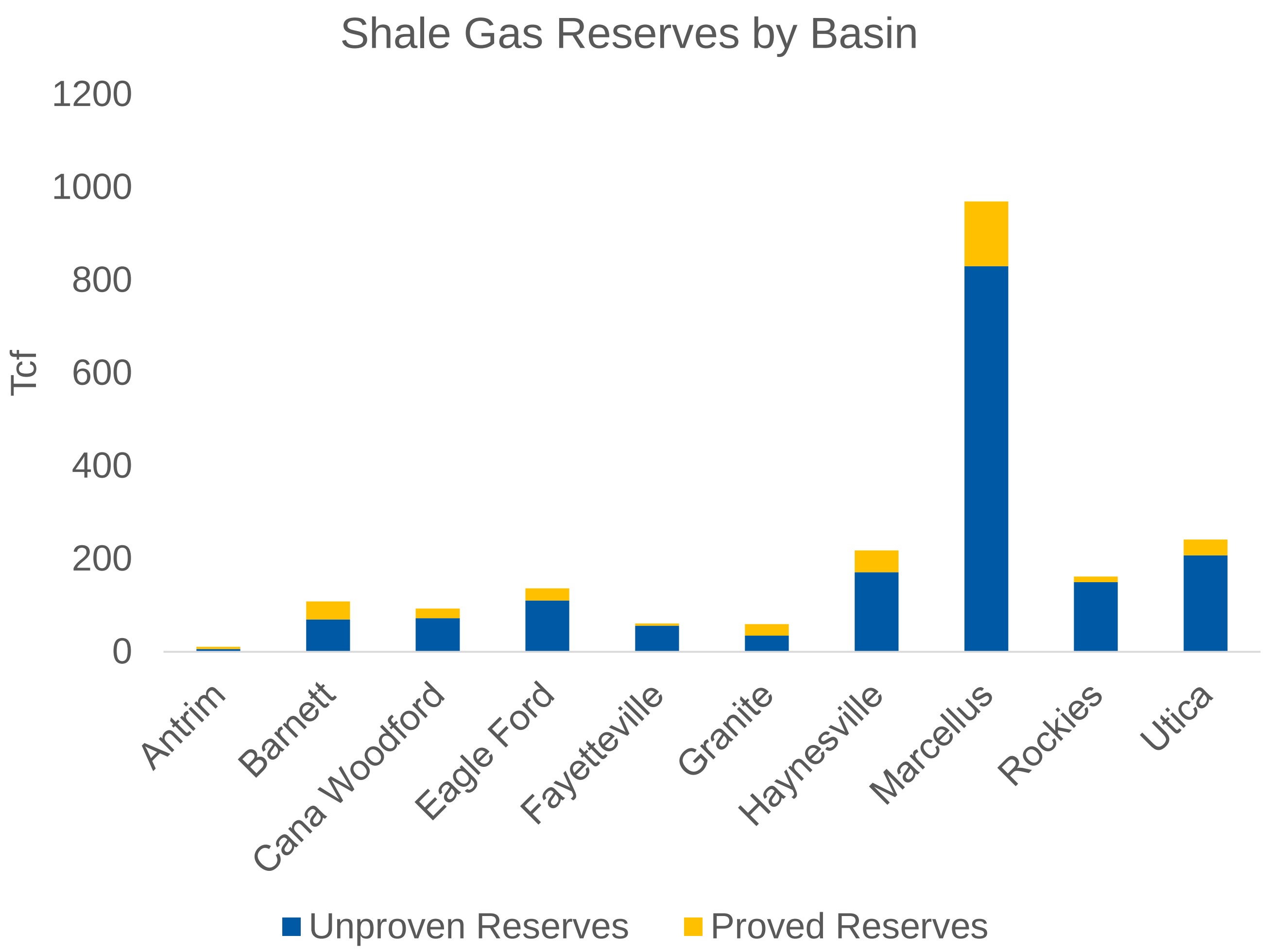
- **PGC evaluates three categories of potential resource:**
  - **Probable** – gas associated with known fields
  - **Possible** – gas outside of known fields, but within a productive formation in a productive province
  - **Speculative** – gas in formations and provinces not yet proven productive

- **PGC assigns resource to three probability categories:**
  - **Minimum** – 100% probability that state resource is recoverable
  - **Most Likely** – what is most likely to be recovered, with reasonable assumptions about source rock, yield factor, and reservoir conditions
  - **Maximum** – the quantity of gas that might exist under the most favorable conditions, close to 0% probability that this amount of gas is present

Uncertainty Range for Shale Resource in PGC 2018



CRA COMBINES UNPROVEN RESERVES FROM PGC WITH PROVED RESERVES FROM EIA

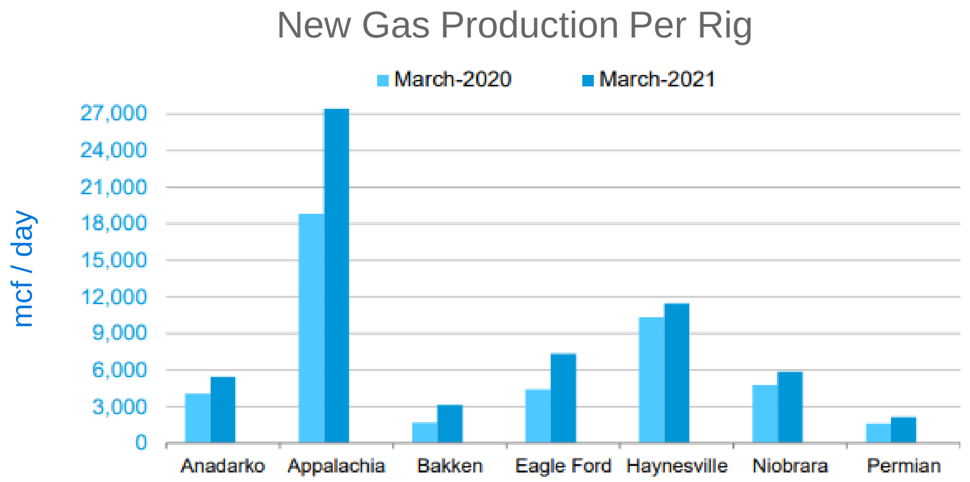


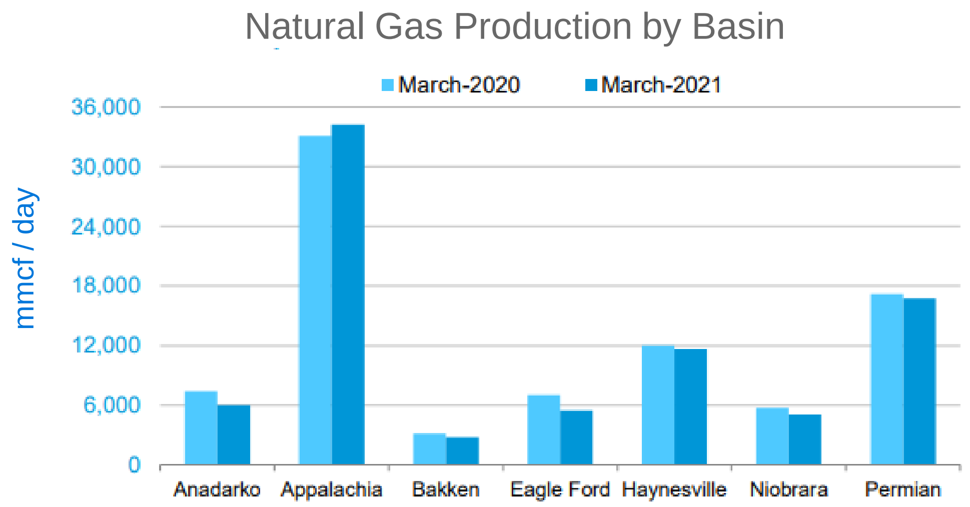
- “Proved” reserves are a known quantity and do not vary between the CRA Reference, High, and Low price views
- The quantity of “Unproven” reserves is uncertain, and varies between CRA natural gas price scenarios

PRODUCER PRODUCTIVITY

While gas producers reported improvements in average productivity in 2020, these appear to driven by focus on best producing regions, not major technical advancements

- Rig counts fell in 2020, in part due to the impacts of COVID-19 and the resulting impacts on gas prices and demand
- This results in higher observed production per rig, even as overall production was flat or declined across many shale plays
- This indicates producers are focusing drilling capital on the highest producing regions or "premium" acreage
  - Shale drillers, such as Devon Energy, confirm as much in their investor presentations, describing "improved inventory quality" as a major driver of productivity gains





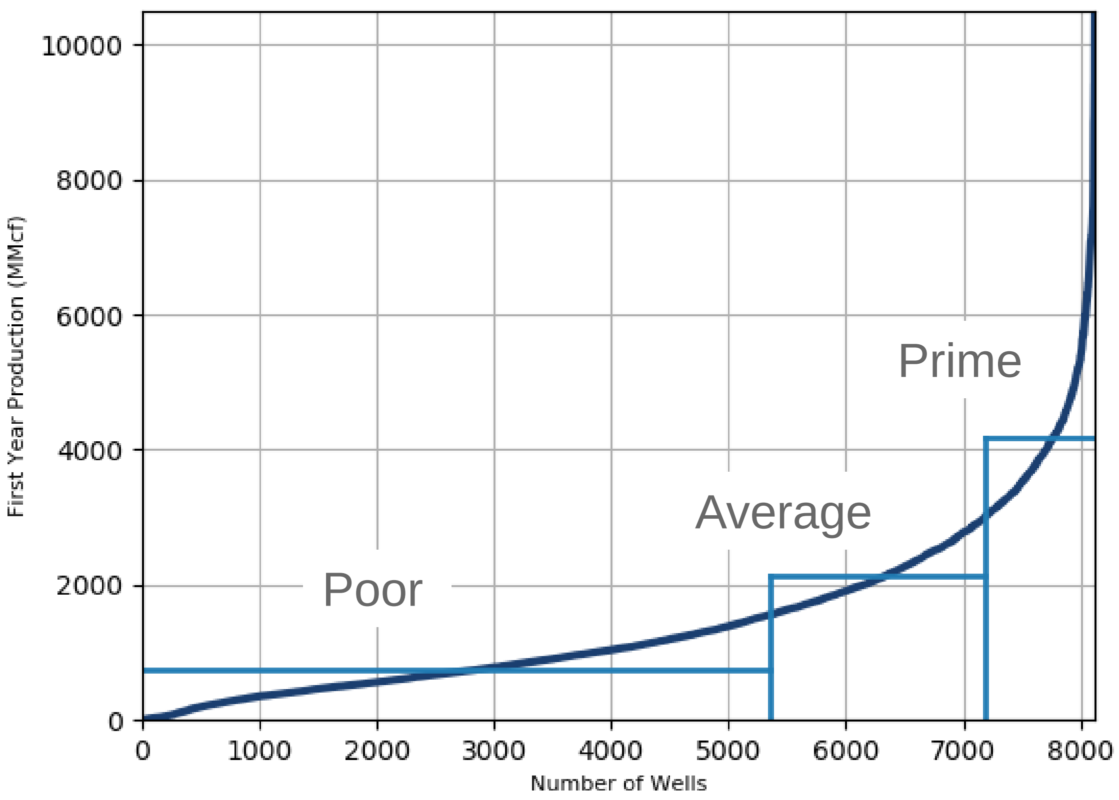
*Source: EIA Drilling Productivity Report

PRODUCER PRODUCTIVITY

CRA's natural gas forecast reflects this focus on "premium" acreage; each shale basin in NGF reflects acreage of varying quality, and a "poor-heavy" distribution is modeled in the reference case to reflect sampling bias

- CRA relies on historical drilling for completed shale wells to develop our view of basin productivity
- Our view is that this historical data has a bias towards higher producing sub-regions
  - Wells that are completed and ultimately produce gas do not reflect a random sampling of the underlying geology in each basin
  - Rather, these wells reflect areas where producers expected to find favorable geology and wells where the cost of completion was justified by the flow
- We therefore divide each basin into "Poor", "Average", and "Prime" sub-regions and adopt a "Poor-Heavy" distribution
  - This reflects the notion that remaining resource is more likely to be of lower quality over time as the premium acreage is depleted in each basin

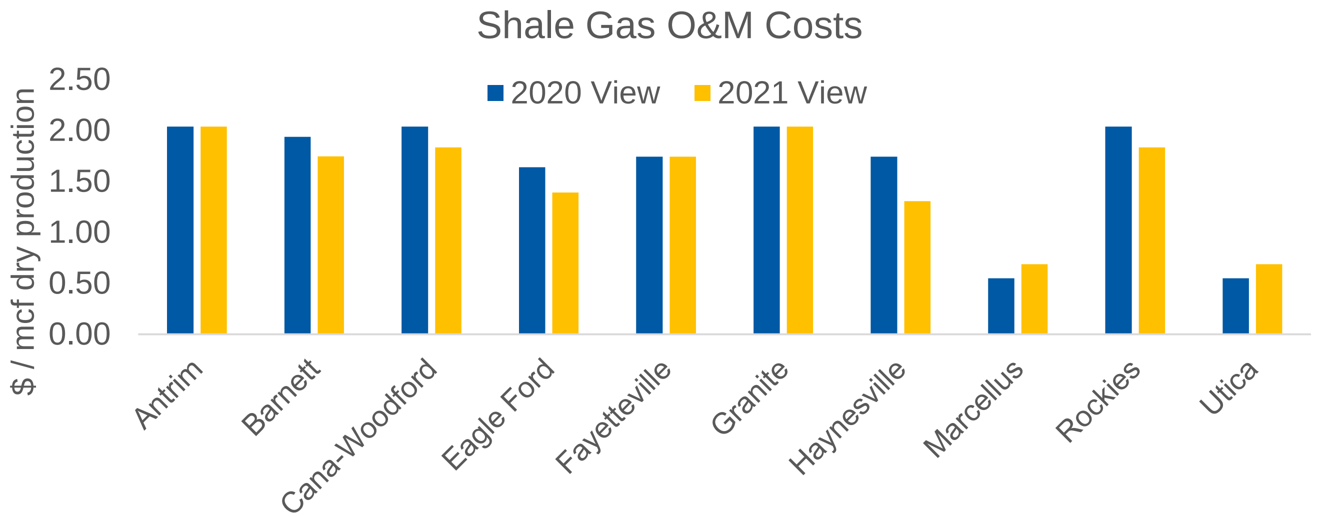
Productivity Distribution: Appalachia

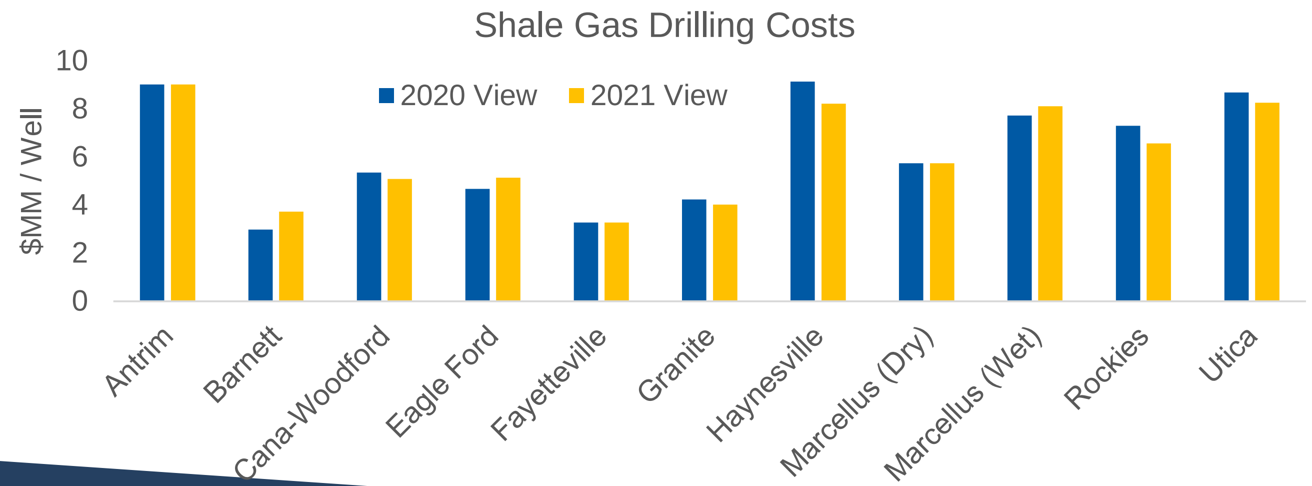


*Source: CRA analysis of Lasserdata drilling database

PRODUCTION COSTS

Producers reported improvements in drilling and O&M costs across most, but not all, shale basins in 2020 – CRA assumes these improvements continue over time





AEO 2021 Cost Improvement Assumptions

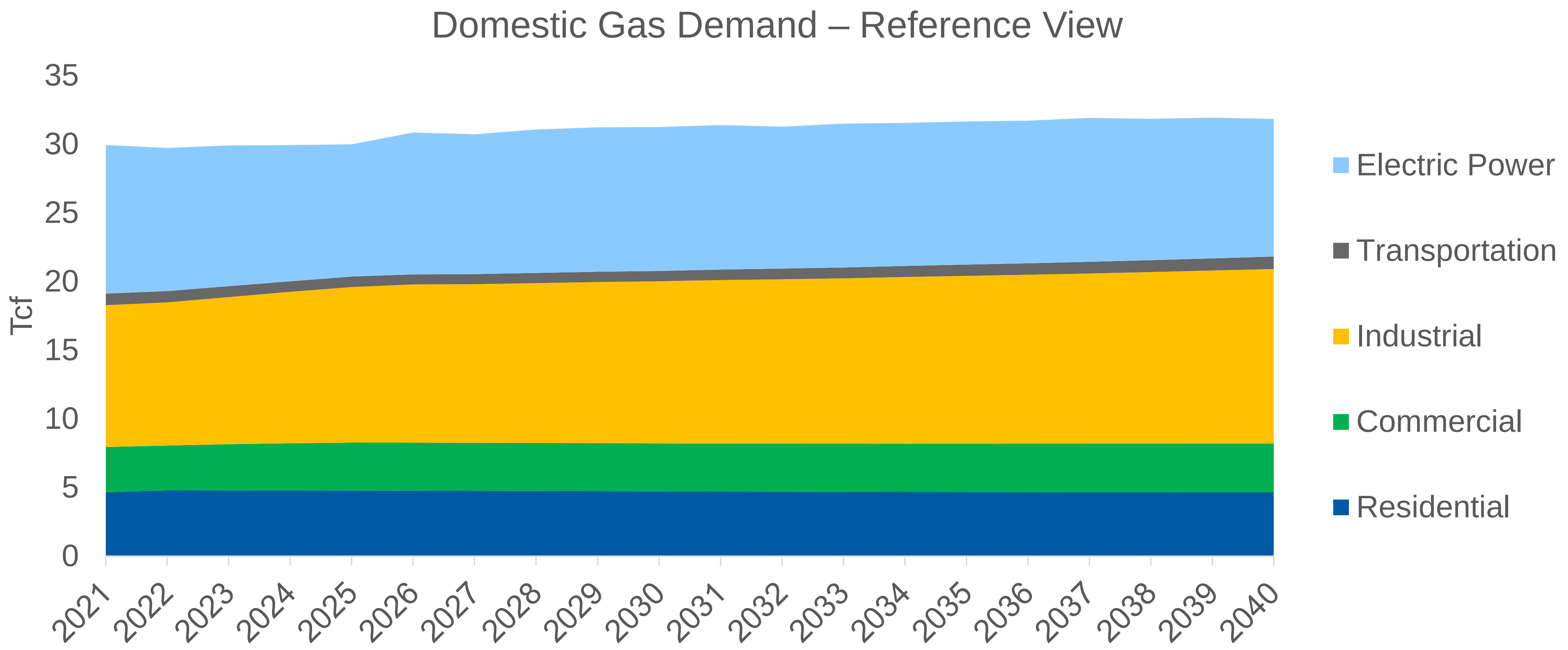
Crude oil and natural gas resource type	Drilling cost	Lease equipment and operating cost
Tight oil	-1.00%	-0.50%
Tight and shale gas	-1.00%	-0.50%
All other	-0.25%	-0.25%

Source: U.S. Energy Information Administration, Office of Energy Analysis

CRA's Reference Case assumes drilling and O&M cost improvements in line with the latest EIA outlook

DOMESTIC GAS DEMAND

Electric demand in the Reference Case comes from CRA's Aurora modeling runs, while U.S. demand from other sectors comes from AEO 2021



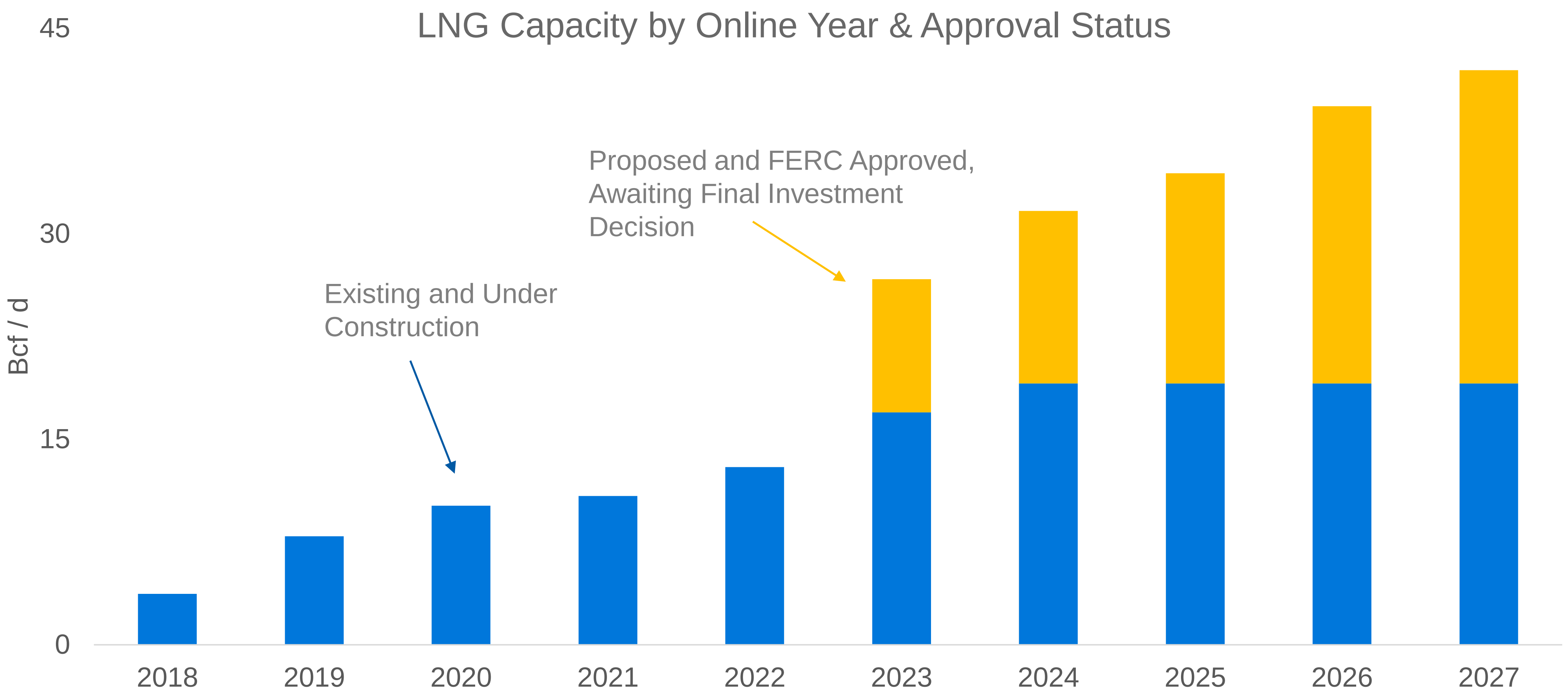
EXPORT GAS DEMAND – LNG

CRA's view is that very few, if any, projects awaiting Final Investment Decision will be completed due to increased competition and weaker export markets

	Project	Status	FTA / Non FTA	In Service	Capacity (Bcf/d)
Existing	Sabine (T1-T5)	Operating	Non-FTA		3.50
	Kenai	Operating	Non-FTA		0.20
	Cove Point (Full Terminal)	Operating	Non-FTA		0.82
	Sempra Cameron (T1-T3)	Operating	Non-FTA		2.15
	Elba/Southern LNG (T1-T10)	Operating	Non-FTA		0.35
	Freeport (T1-T3)	Operating	Non-FTA		2.13
	Corpus Christi (T1-T2) TX	Operating	Non-FTA		1.44
	Sub-total				**10.59**
Under Constr.	Corpus Christi (T3) TX	Under Const.	Non-FTA	2021	0.72
	Sabine (T6)	Under Const.	Non-FTA	2022	0.70
	Cameron Parish	Under Const.	FTA	2022	1.41
	Calcasieu Parish	Under Const.	FTA	2023	4.00
	Golden Pass	Under Const.	Non-FTA	2024	2.10
	Sub-total				**8.93**
Awaiting FID	Port Arthur (T1-T2)	Approved	FTA	2023	1.86
	Freeport (T4)	Approved	Non-FTA	2023	0.72
	Jacksonville	Approved	Non-FTA	2023	0.13
	Plaquemines Parish	Approved	Non-FTA	2023	3.40
	Rio Grande LNG Brownsville	Approved	FTA	2023	3.60
	Delfin FLNG	Approved	Non-FTA	2023+	1.80
	Annova LNG Brownsville	Approved	Non-FTA	2024	1.08
	Texas LNG Brownsville	Approved	FTA	2025	0.55
	Lake Charles LNG	Approved	FTA	2025	2.20
	Magnolia LNG	Approved	FTA	2026	1.19
	Sempra Cameron (T4-T5)	Approved	Non-FTA	2026	1.41
	Jordan Cove	Approved	Non-FTA	N/A	0.90
	Nikiski	Approved	FTA	N/A	2.63
	Sub-total				**21.47**
	Terminals (Proposed)				**3.04**
	Terminals (Pre-Filing)				**5.51**
	Grand Total				**49.54**

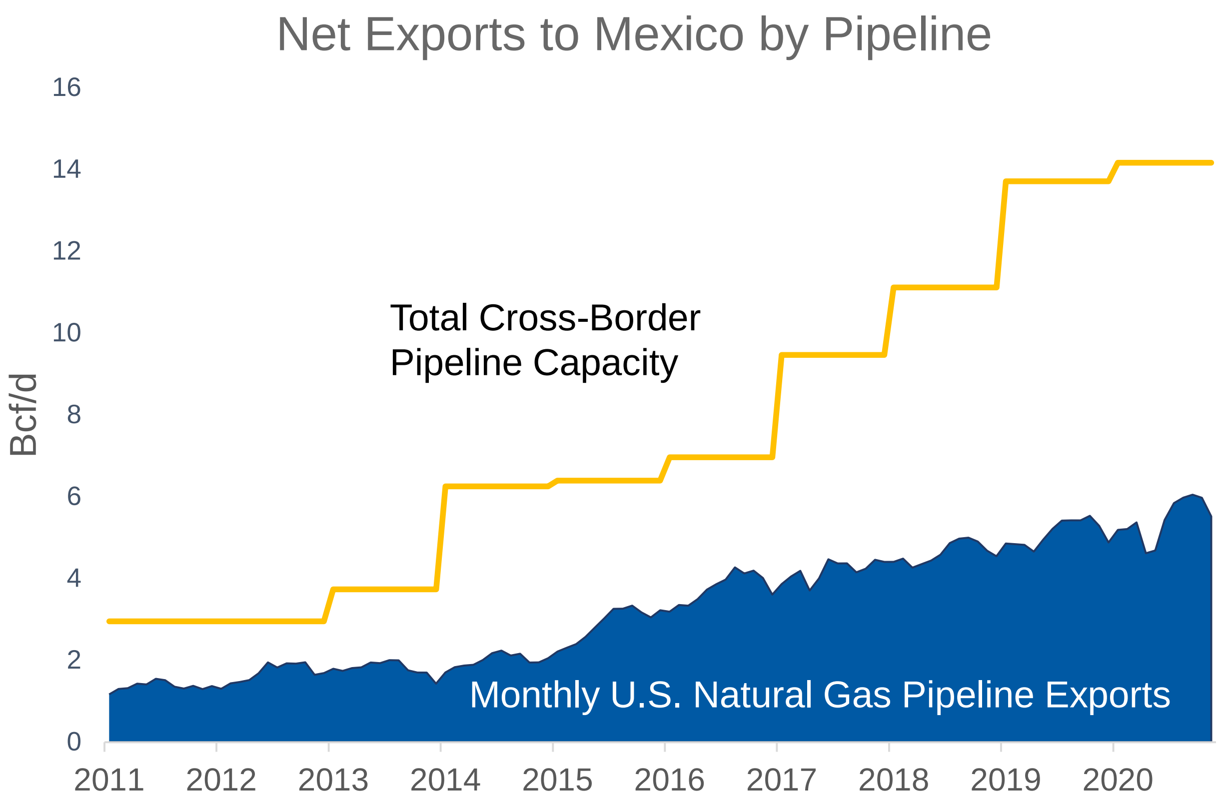
EXPORT GAS DEMAND – LNG

Due to softening prices and increase competition, CRA expects that few, if any, “proposed” LNG projects will be completed after Calcasieu Pass and Golden Pass come online in 2023 and 2024 (expected dates)



EXPORT GAS DEMAND – NET PIPELINE EXPORTS

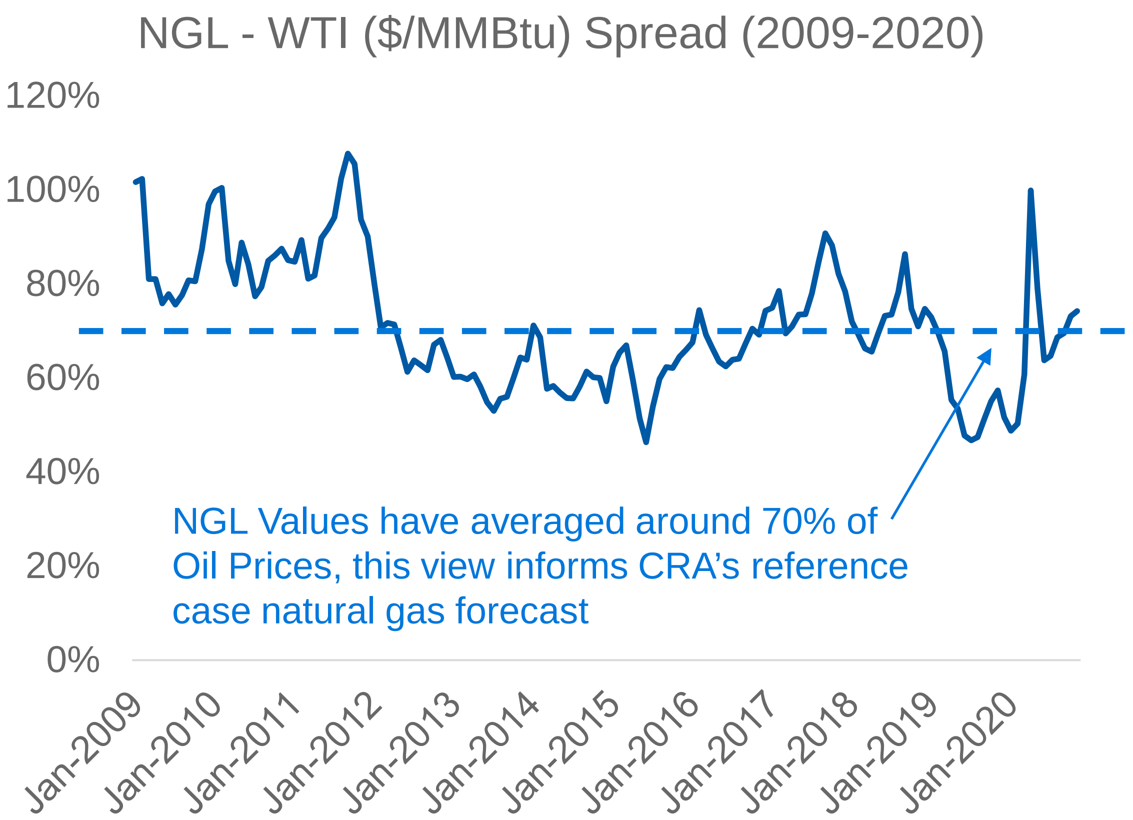
Actual shipments to Mexico from the US continue to lag behind total capacity improvements driven by recent pipeline expansion projects, and CRA expects this capacity will continue to be underutilized in the reference view

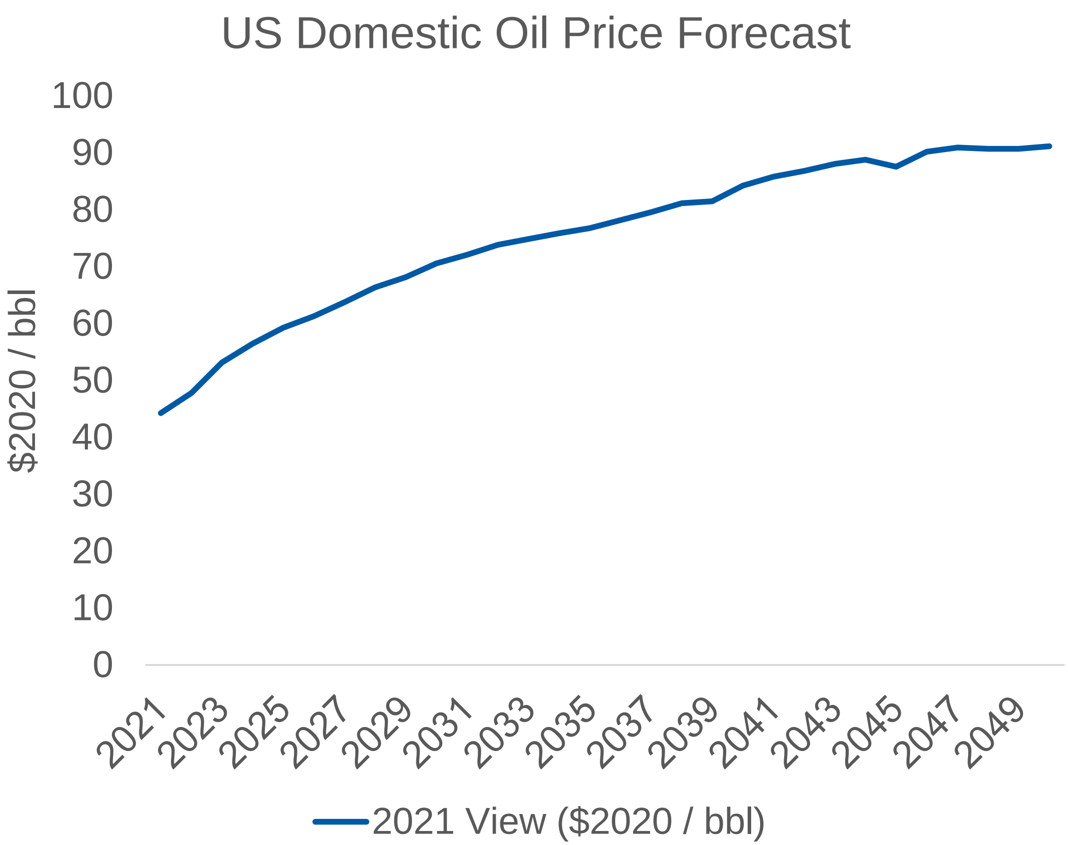


- Actual exports to Mexico have risen steadily over the last five years, but are not keeping pace with the expansion of cross-border export capacity
- Numerous pipeline projects within Mexico have faced construction delays, and completed projects are operating well below capacity
  - The 1.1 Bcf/d Comanche Trail pipeline has been utilized only 10% on average since completion in June 2017
  - The 1.4 Bcf/d Trans-Pecos pipeline completed in 2017 currently has also operated at 10-15% of total capacity since completion

NATURAL GAS LIQUIDS

Natural gas liquids and condensate are expected to supplement dry gas revenue for shale producers, but these benefits are limited by lower expected oil prices



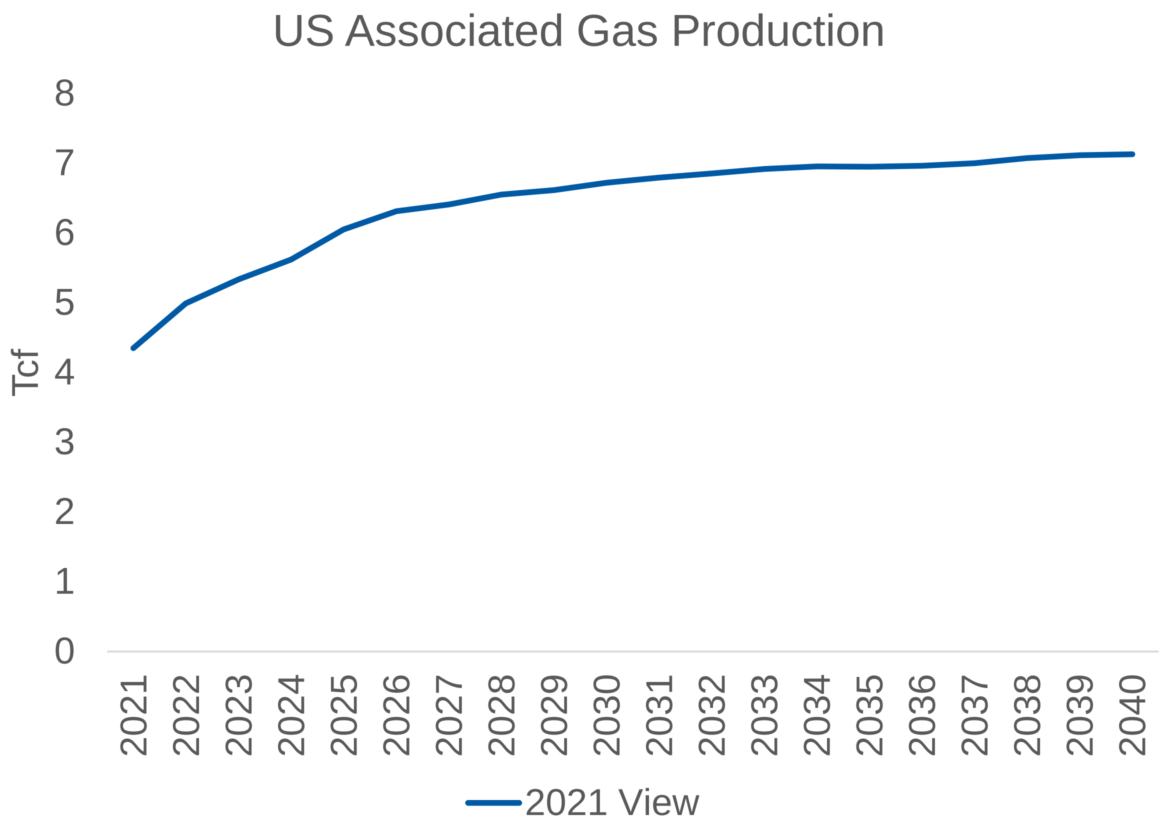


ASSOCIATED GAS PRODUCTION

Lower domestic oil prices also reduce expected volume of associated gas, particularly in the short- to medium-term

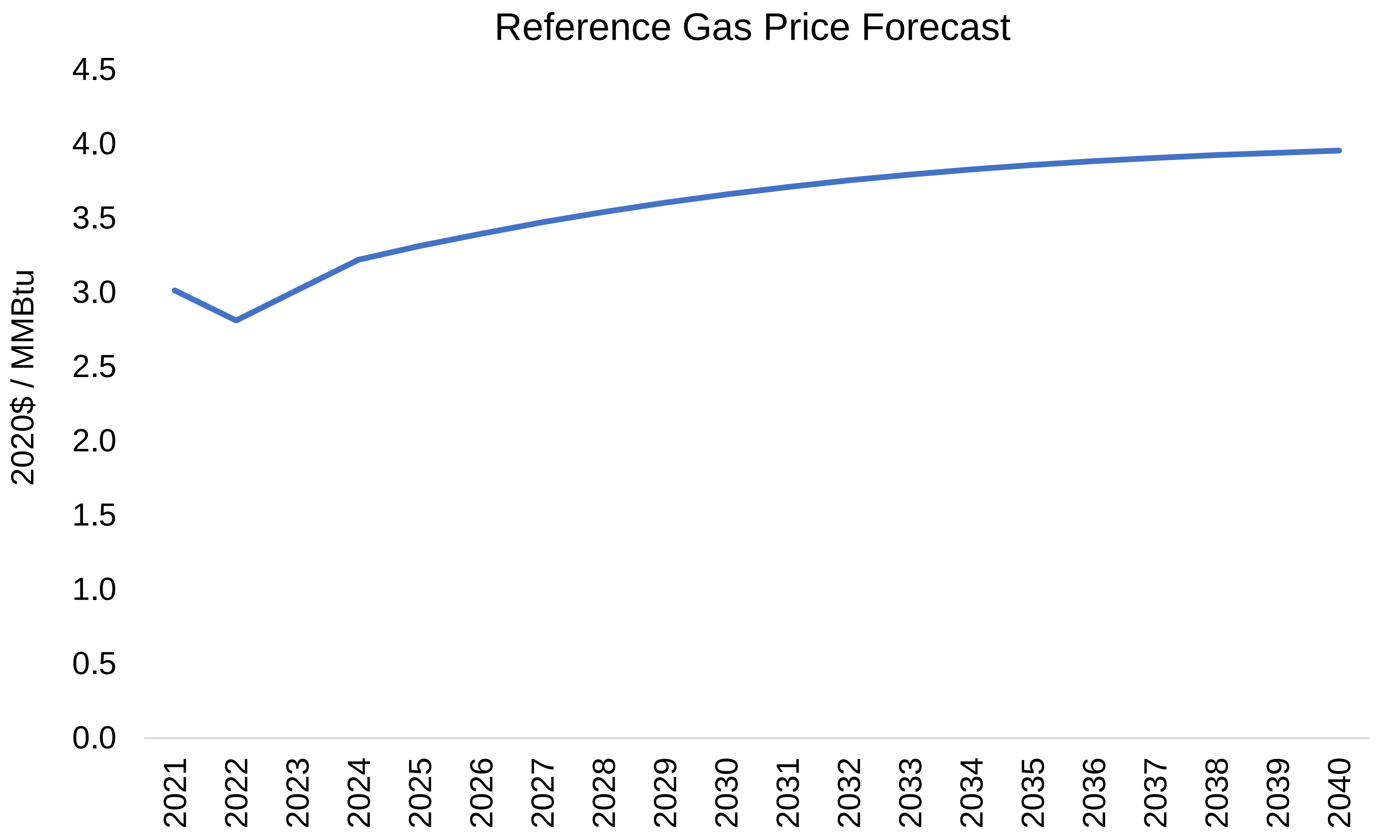
- EIA's forecast of associated gas production has fallen significantly in the 2021-2028 period relative to last year's forecast

- This reduction reflects weaker domestic oil prices and contributes to the rise in natural gas prices observed in the CRA forecast over the same period



REFERENCE CASE GAS PRICE OUTLOOK

Although the price outlook has declined in recent years, the Reference Case still expects price rises towards $4/MMBtu (real) over time

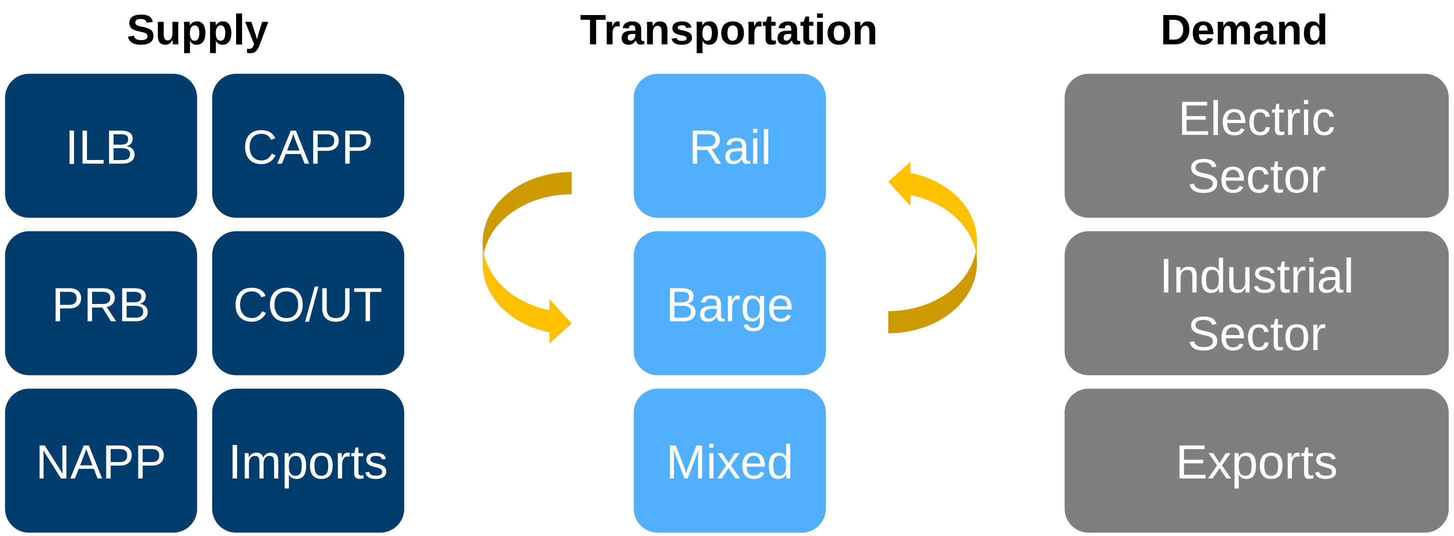


- The downward price pressure driven by improvements in drilling and O&M costs is moderated by lower domestic oil prices and associated gas volumes
- CRA observed limited productivity improvements in 2020 relative to prior years, and these seem to be primarily driven by crowding into prime regions, not technical advancements
- CRA's reference case view continues to reflect upward pressure in the medium term driven by industry consolidation as well as (modest) restrictions on supply access driven by the Biden Administration's ban on further drilling in Federal lands

COAL FORECASTING OVERVIEW

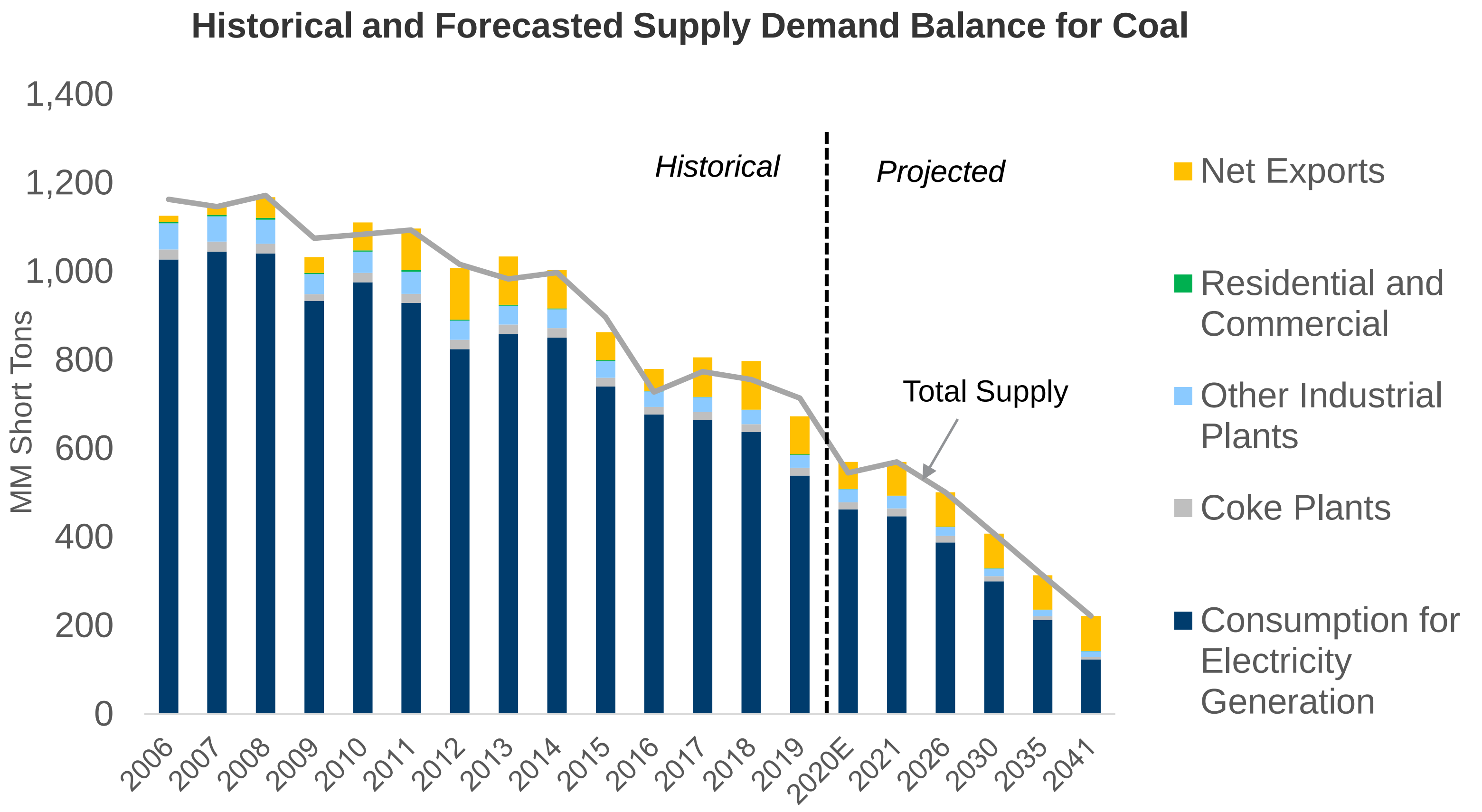
CRA forecasts coal prices based on an analysis of coal supply and demand dynamics

- CRA's process assesses future supply/demand balance for the U.S. coal market based on:
  - Macroeconomic drivers, including domestic and international demand
  - Microeconomic drivers, including trends in mining costs and production trends
- CRA iterates with the Aurora and NGF models to account for electric and gas market feedbacks



COAL MARKET OUTLOOK

The Reference Case outlook reflects declining domestic demand

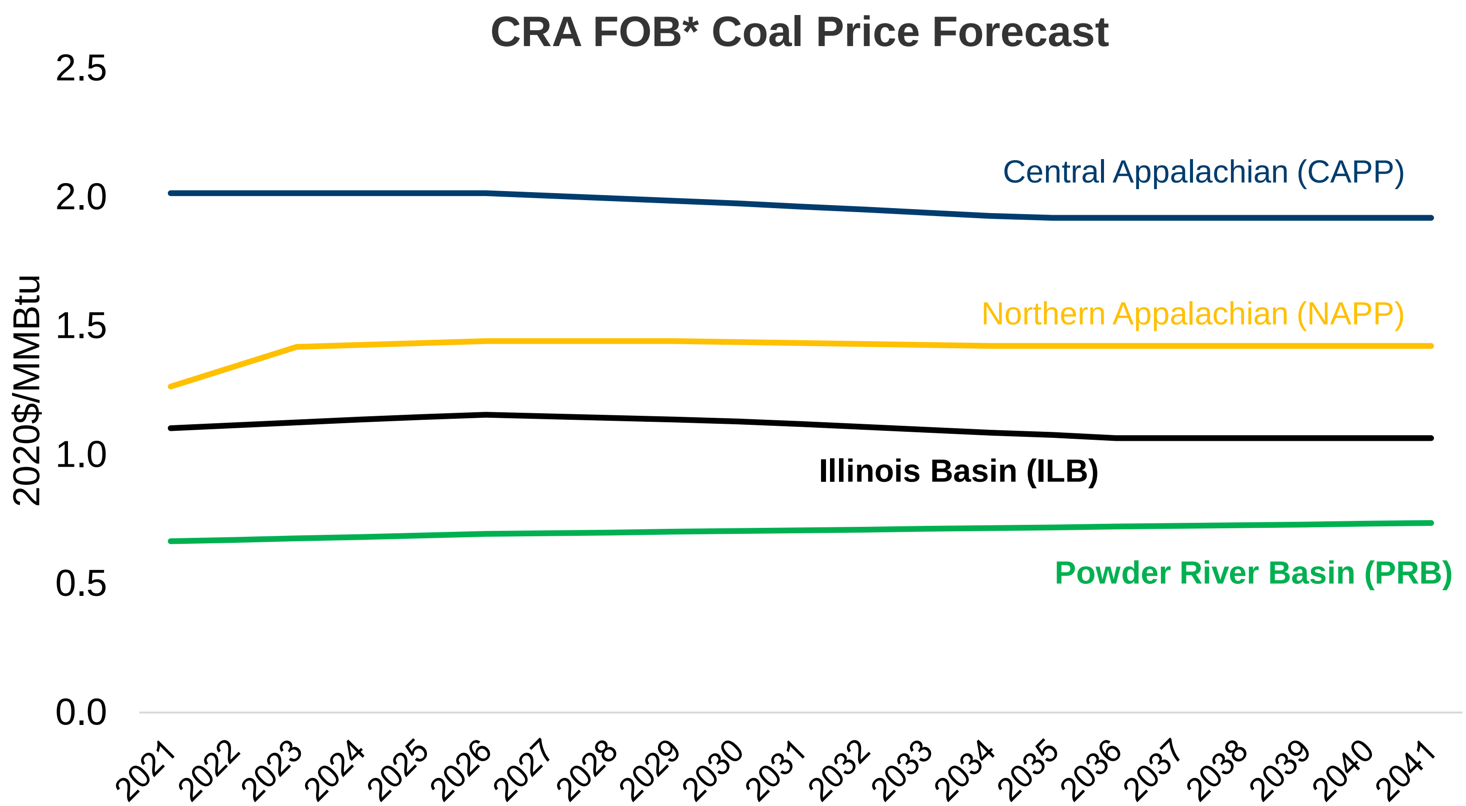


Historical: 2006-2019 data from EIA and MSHA
Forecast: CRA Analysis

- A total of 20 GW of coal capacity retired across the US in 2019 and 2020 combined.
- Low gas prices over the past few years have continued to dampen coal demand.
- A further decline in coal demand is expected with continued retirements and increasing renewable penetration across the US.

REFERENCE CASE COAL PRICE OUTLOOK

U.S. coal prices exhibit flat-to-declining trends over the long-term due to continued coal retirement expectations in the US



Flat prices reflect reduced demand offset by increased production cost.

*The Free On Board price represents the value of coal at the coal mine and excludes transport and insurance costs

REFERENCE CASE CARBON POLICY EXPECTATIONS

The Biden presidency with a narrow Democratic majority in Congress will result in new climate regulation, but successful initiatives will likely be limited in scope

Likely Executive Actions

- Re-join the Paris Accords
- Direct EPA to re-interpret CAA authority to regulate power plant CO_2 emissions (new standards or a new CPP-like effort)
- Appoint FERC commissioners who may pursue carbon pricing for wholesale markets
- Mandate reduction of emissions for federal fleets, buildings, operations, etc.
- Limit access to fossil fuel production and / or direct EPA to impose stricter standards

Potential Legislative Efforts

- Extension of tax credits (solar, wind, CCS) and introduction of new tax credits (storage)
- Direct subsidies or incentives for EE programs and electrification efforts (EVs, appliances) as part of an infrastructure / stimulus bill
- R&D spending for hydrogen, adv. nuclear, etc.
- Nationwide emissions reduction target, clean energy target, or carbon pricing initiatives

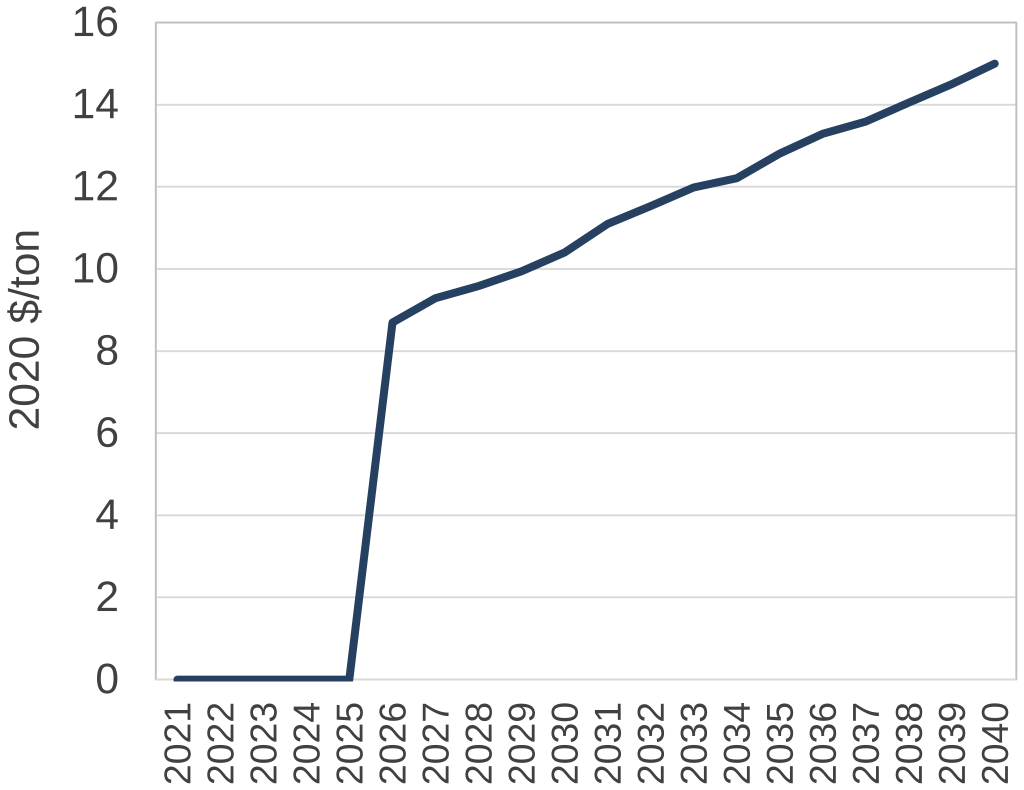
***Reference Case** with a modest carbon price in 2026 and beyond is reasonable and reflective of several pathways for regulation (legislation or executive action via EPA or FERC)*

REFERENCE CASE CARBON PRICE DEVELOPMENT

CRA has developed carbon price trajectories based on iterative power market modeling within the Aurora electricity price model

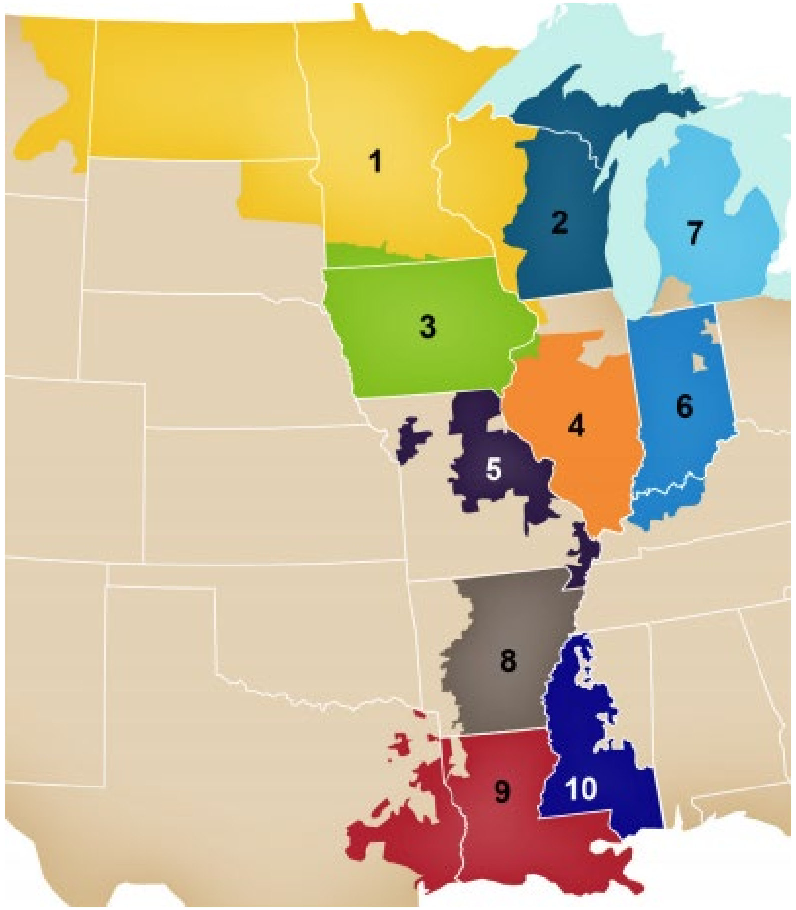
Reference Case (similar to 2018 IRP)

- Assumes new executive or legislative policy would have targets generally in line with a 30-40% reduction in CO_2 emissions from the power sector, *with a current or recent historical baseline year*
- Implications – Significant coal to gas switching and likely pressure for ~80% of the nationwide coal fleet to retire in the next 20 years; clean energy percentage likely to grow above 50%
- Price benchmark – in the range of the existing Regional Greenhouse Gas Initiative (RGGI) market price



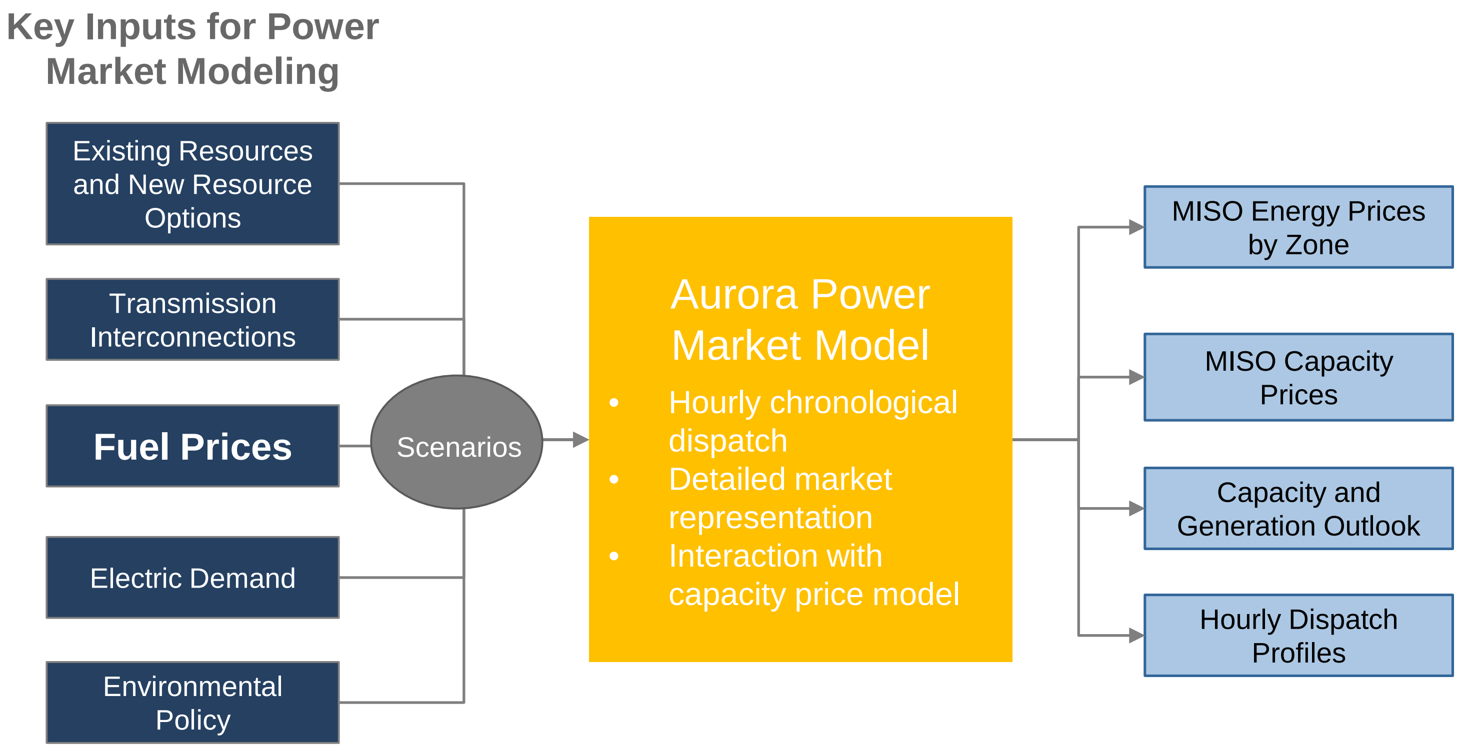
MISO OVERVIEW

- The Midcontinent Independent System Operator (MISO) is an independent, not-for-profit organization that delivers electric power across 15 U.S. states. MISO:
  - Oversees markets for energy, capacity (resource adequacy), ancillary services, and transmission rights
  - Maintains load-interchange-generation balance, coordinates reliability, operates or directs the operation of transmission facilities, and oversees transmission planning
  - Coordinates with utilities, states, and federal entities (FERC and NERC) to ensure the reliable, non-discriminatory operation of the bulk power transmission system
  - Provides approximately $3.5 billion in annual benefits to members due to efficient use of power system for resource adequacy and dispatch across a broad geographic territory
- NIPSCO territory and most resources fall within MISO's Local Resource Zone 6 (LRZ6), covering IN and parts of KY



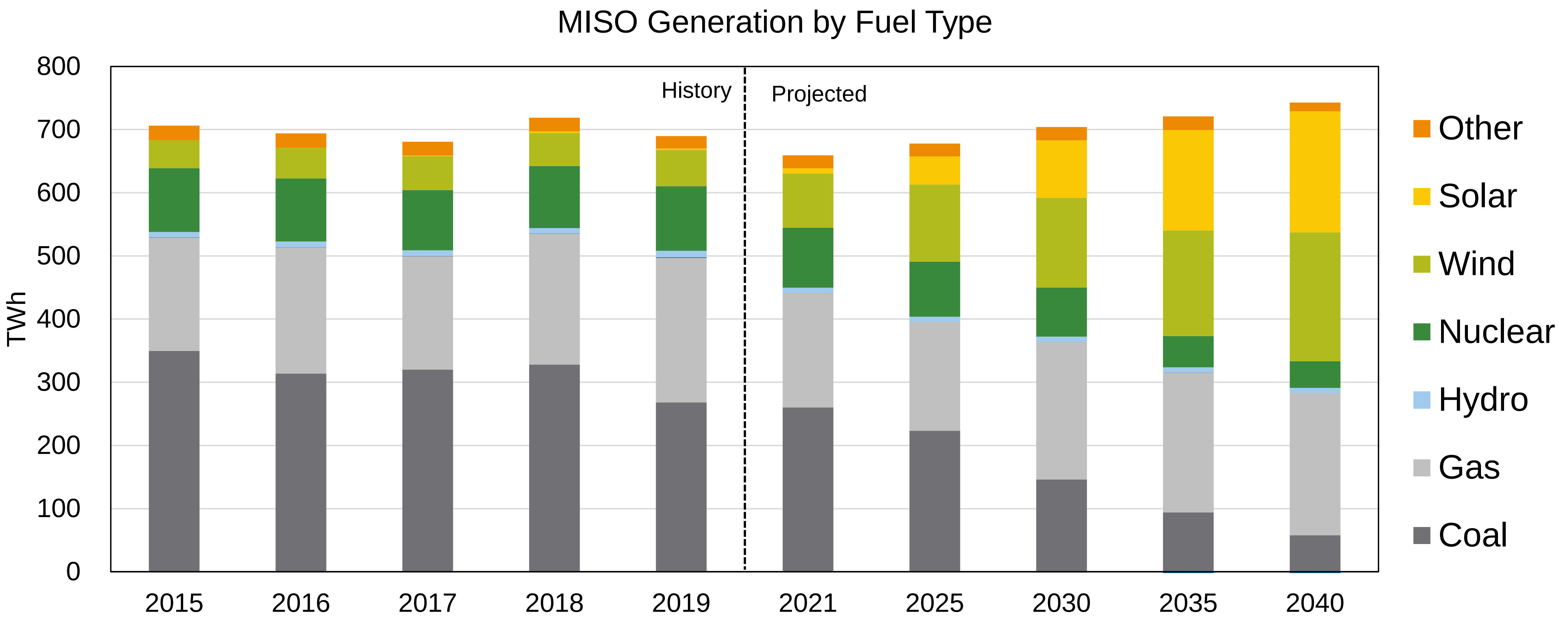
SUMMARY OF KEY MISO MARKET INPUTS FOR REFERENCE CASE

- **Fuel Prices and Environmental Policy**
  - CRA fundamental modeling and analysis (previously discussed)
- **Electric Demand**
  - MISO MTEP21 forecasts, including for DERs and EVs
- **Existing and New Resources**
  - MISO, Energy Velocity, Energy Exemplar, CRA datasets for existing
  - NIPSCO RFP data and NREL cost trajectories for new resources
- **Transmission Interconnections**
  - MISO, Energy Exemplar datasets

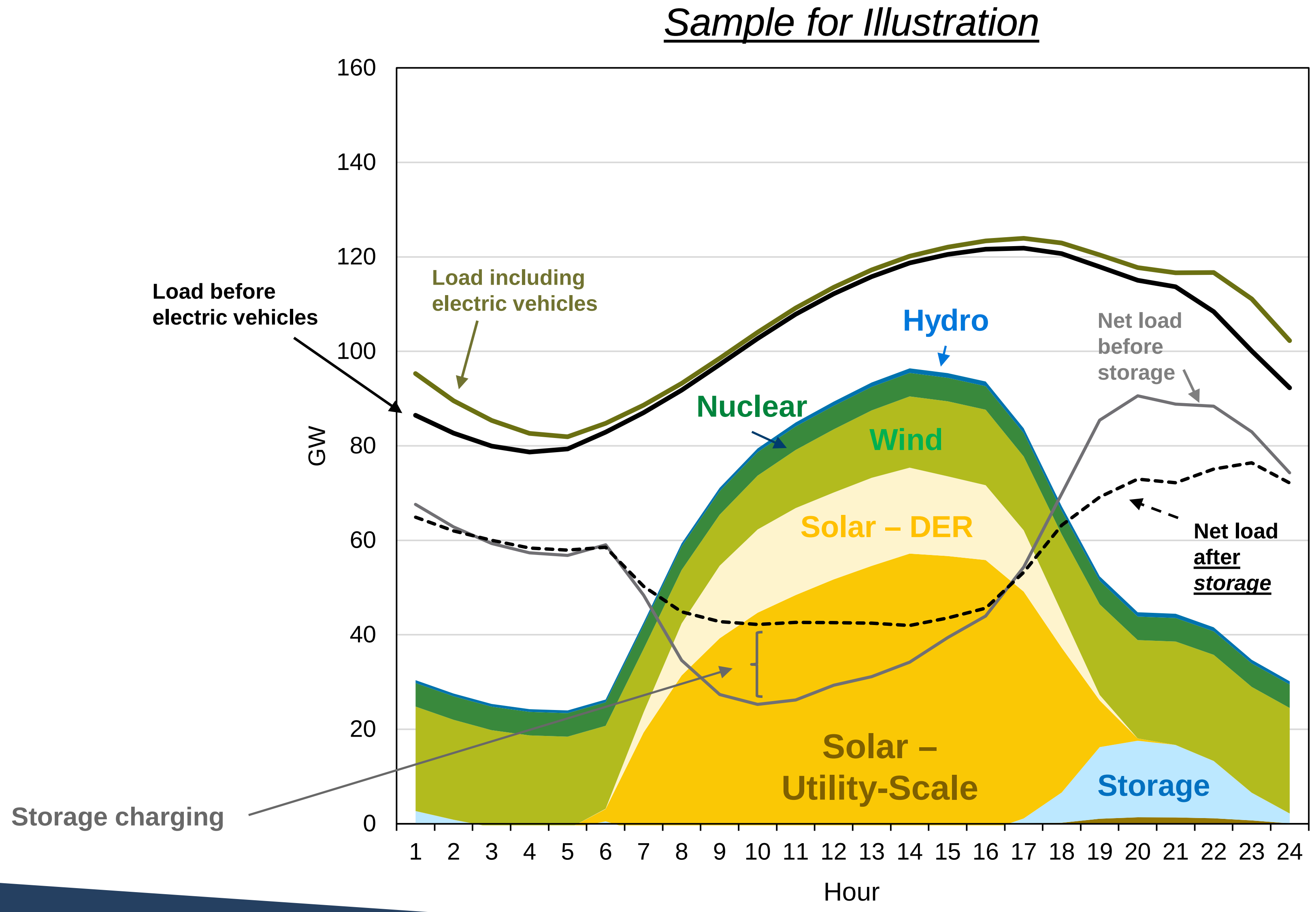


MISO ENERGY PROJECTED TO SHIFT TOWARDS RENEWABLES

- Energy from coal is expected to fall over time, with modest increases in energy from gas projected
- Growth is expected for renewables, with solar projected to grow substantially from today's very low levels



HOURLY ENERGY VIEW – MISO



Net load =

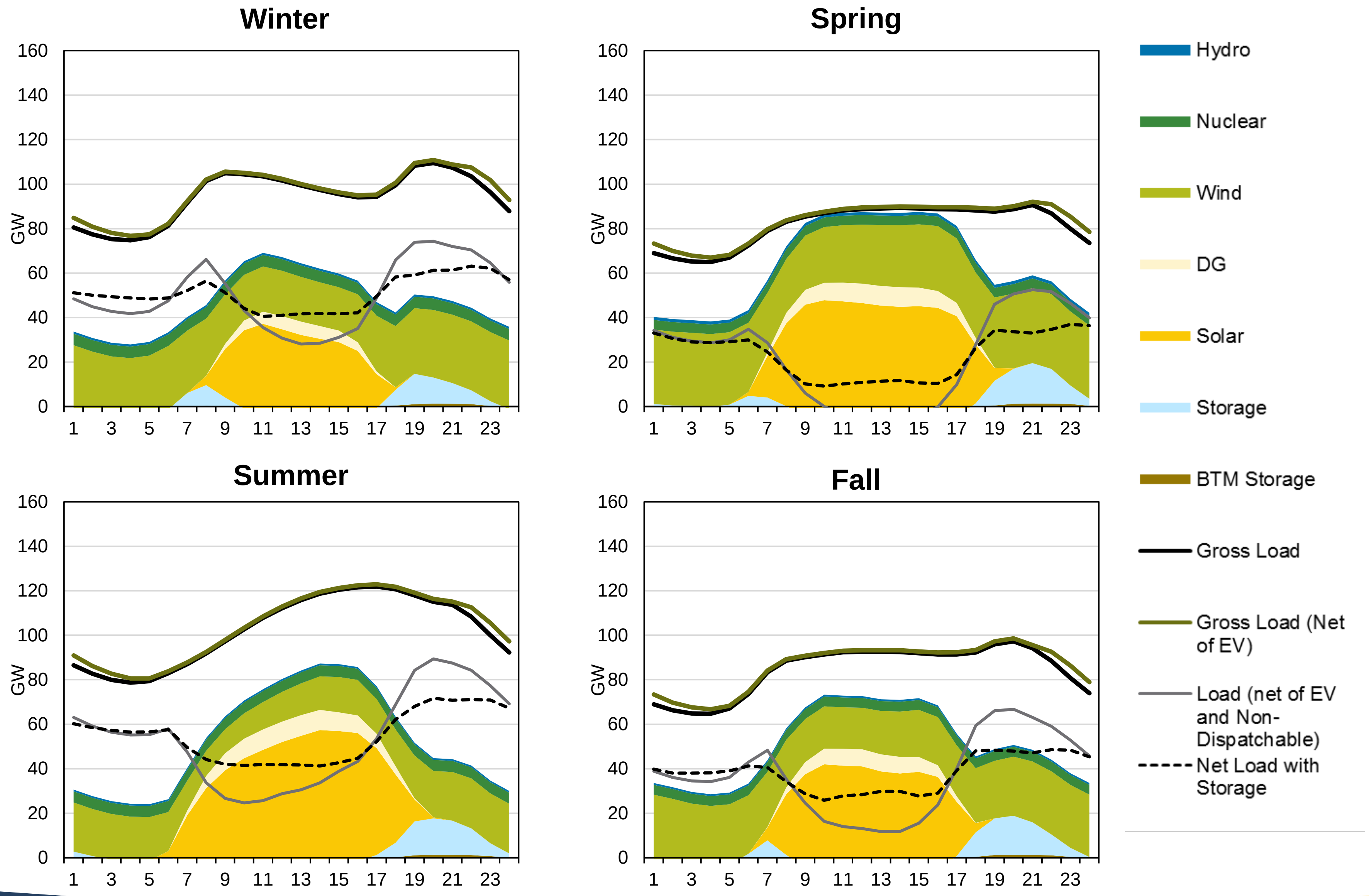
Load (including EVs)

minus

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

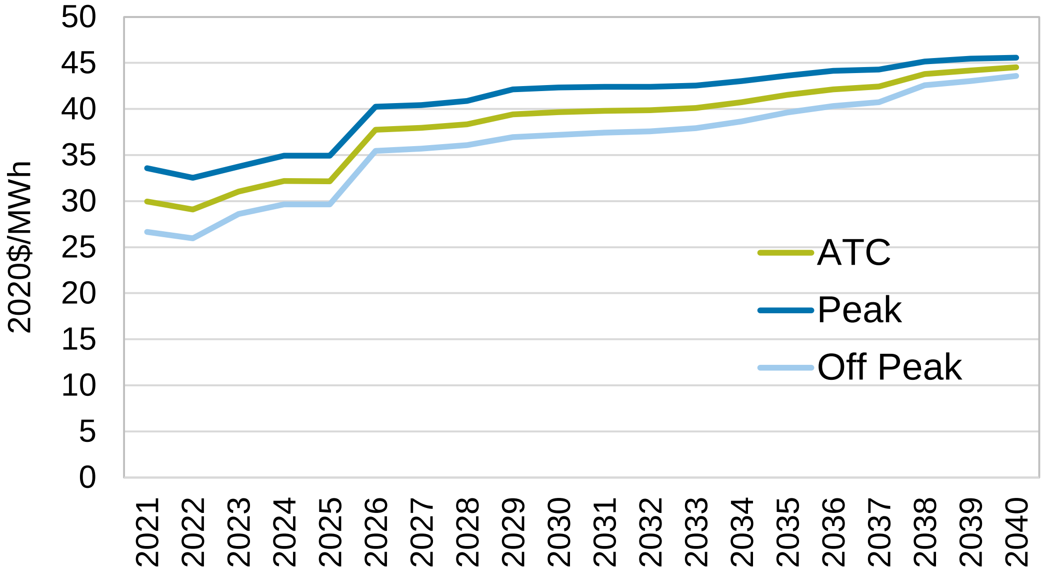
HOURLY ENERGY PROFILE – MISO 2040

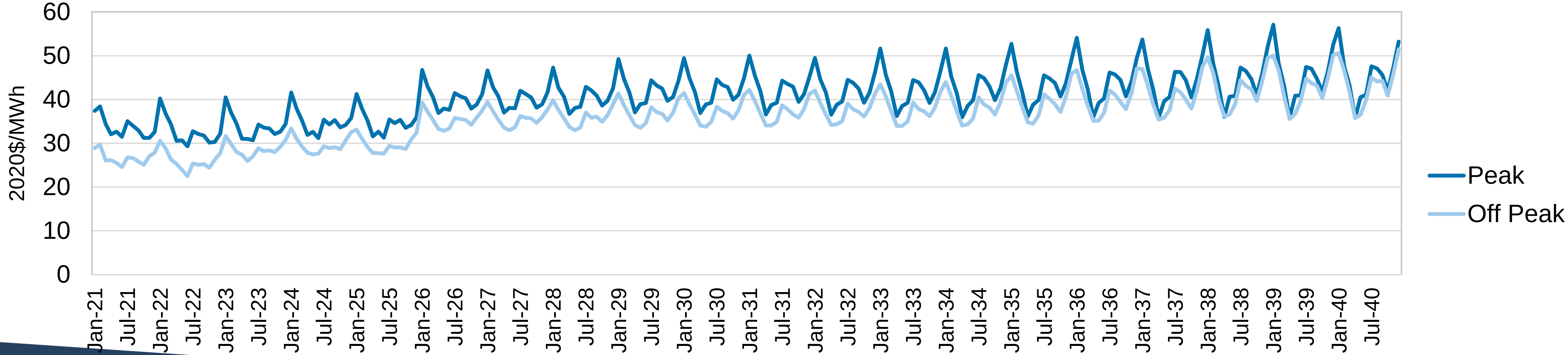
- Renewable penetration will impact resource dispatch and MISO hourly prices over time, with differences by season:
  - Mid-day hours in the spring may have sufficient generation output to meet demand
  - Summer evening peaks will require ramping support



REFERENCE CASE POWER PRICE FORECAST – MISO ZONE 6

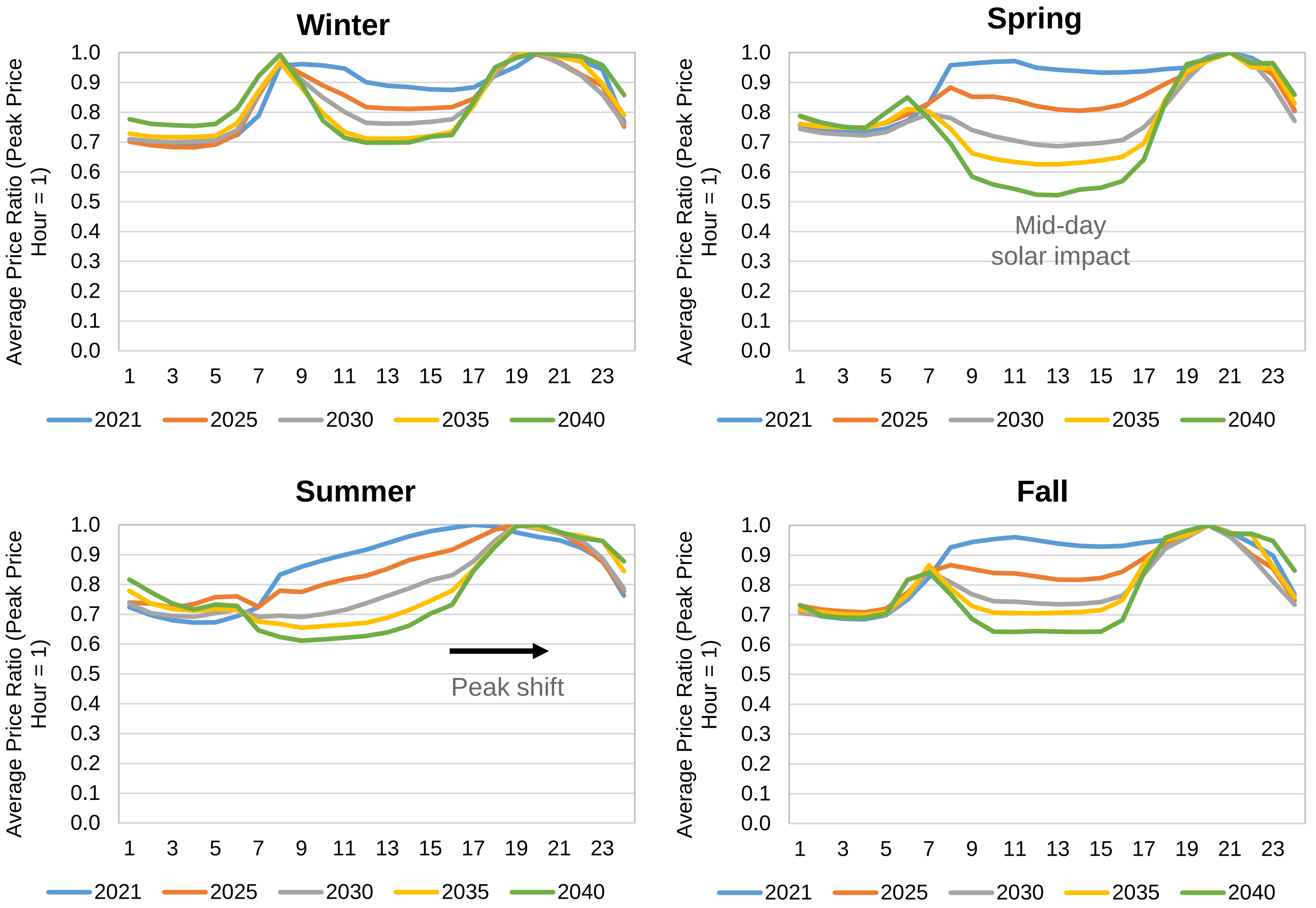
- Power prices are expected to stay relatively flat in the near-term, due to flat gas and coal prices
- Some upward pressure expected into the 2020s as a result of higher natural gas prices, although growing renewables lower the market heat rate over time
- National carbon price, starting in 2026, drives increase
- Convergence in peak and off-peak over time, largely driven by solar penetration





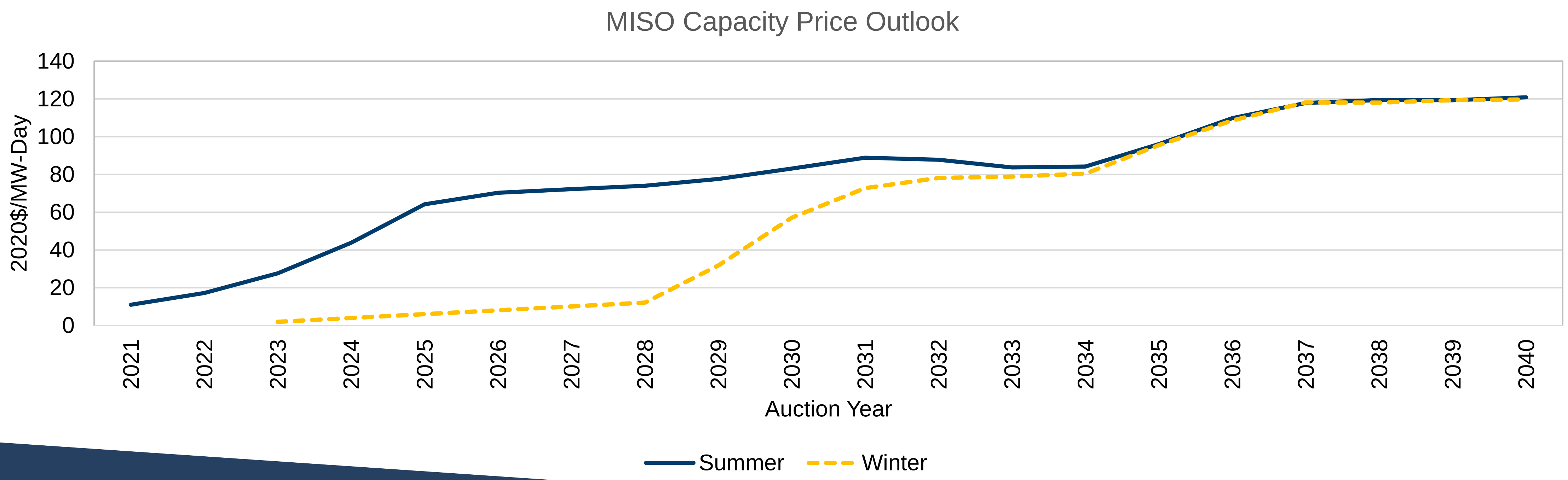
HOURLY PRICE SHAPES EXPECTED TO EVOLVE OVER TIME

- Hourly price patterns are expected to change over time, particularly as more renewables enter the system
- Mid-day prices are expected to decline as a result of solar output
- Summer peak price periods are expected to shift from mid-afternoon to evening



REFERENCE CASE 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).
- Winter reserve margins are higher than summer reserve margins in the near-term, resulting in expectations for lower prices.
- However, over time, continued fossil fuel retirement and increasing solar penetration (which gets minimal capacity credit during the winter) drive convergence between summer and winter prices.



LUNCH

KEY ASSUMPTIONS UPDATE: LOAD FORECAST

Derya Eryilmaz, Associate Principal, CRA
Pat Augustine, Vice President, CRA

LOAD FORECAST OVERVIEW

- In response to feedback from the 2018 IRP process, NIPSCO has made several enhancements to its load forecasting process for the 2021 IRP:
  - Class-level econometric analysis, assessing a range of economic variables with collaboration between internal and external experts
  - Increased transparency on econometric approach and treatment of large industrial customers under Rate 831 structure
  - Monthly, class-level projections to allow for seasonal peak planning and not just a single summer peak
  - Explicit DSM adjustments in base forecast, to facilitate supply-side modeling
  - Distributed energy resource (DER) penetration forecasts, based on economic analysis and “social network” effects
  - Electric vehicle (EV) forecasts by vehicle class, using regional and national benchmarks and NIPSCO-specific service territory data

LOAD FORECASTING METHODOLOGY OVERVIEW

Inputs | *Energy Forecast and Validation* | *Baseline Forecast Adjustments*

Data Gathering → **Weather Normalization** → **Econometric Modeling by Customer Class** → **Baseline Energy Forecast** → **Peak Load Forecast** → **DSM, DER, EV Adjustments**

Data Gathering

- Historical energy consumption and number of customers by class
- Historical DSM/EE
- Moody's macroeconomic variables (number of households, employment, personal income, etc.)
- Weather (heating/cooling degree days, temperature, humidity)

Weather Normalization / Econometric Modeling by Customer Class

- Develop weather-normalized energy sales by class (kWh/customer) for the historical period, *excluding* historical DSM program impacts
- Test all economic and demographic "driver" variables in dynamic regression system, up to three quarterly lags
- Perform post-estimation tests on econometric models' specification and forecasting performance (e.g., Systemic Mean Absolute Percentage Errors)

Baseline Energy Forecast / Peak Load Forecast

- Develop baseline customer count and energy forecasts for each NIPSCO customer rate class, *excluding* historical DSM
- Develop accompanying peak load forecasts using energy forecast and load factors by customer rate class

DSM, DER, EV Adjustments

- Adjust load forecasts to incorporate *known* DSM programs
- Adjust load forecasts for EV and DER penetration ranges

ELECTRIC SALES FORECAST – ECONOMETRIC PARAMETERS

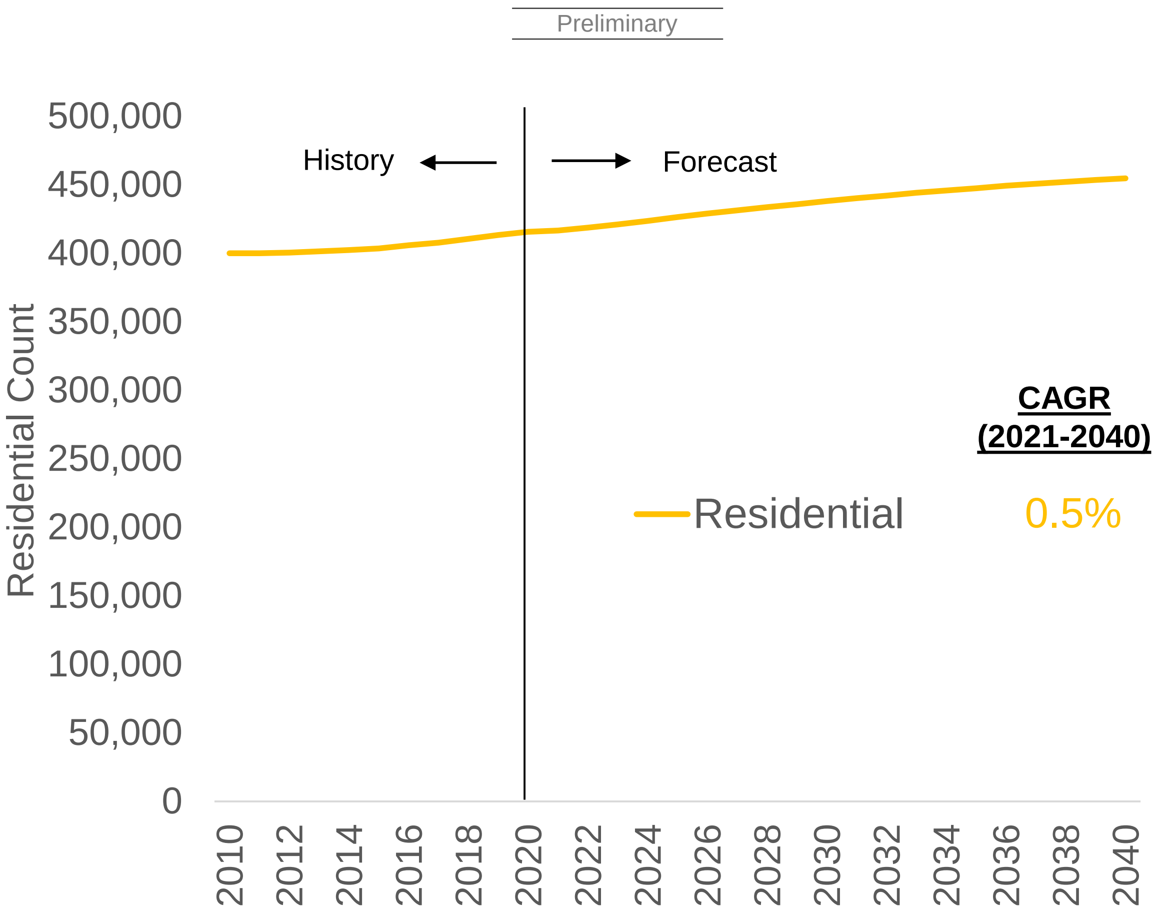
- Baseline customer count and sales per customer energy forecasts by class are projected with best fitting regional macroeconomic variables, heating and cooling degree days, seasonality factors, and expected retail rate growth trends
- CRA tested various macroeconomic variables using Moody's historical and forecast data and selected the presented model based on R-squared, adjusted R-squared and Root Mean Squared Error (RMSE) and Mean Absolute Percentage Error (MAPE)

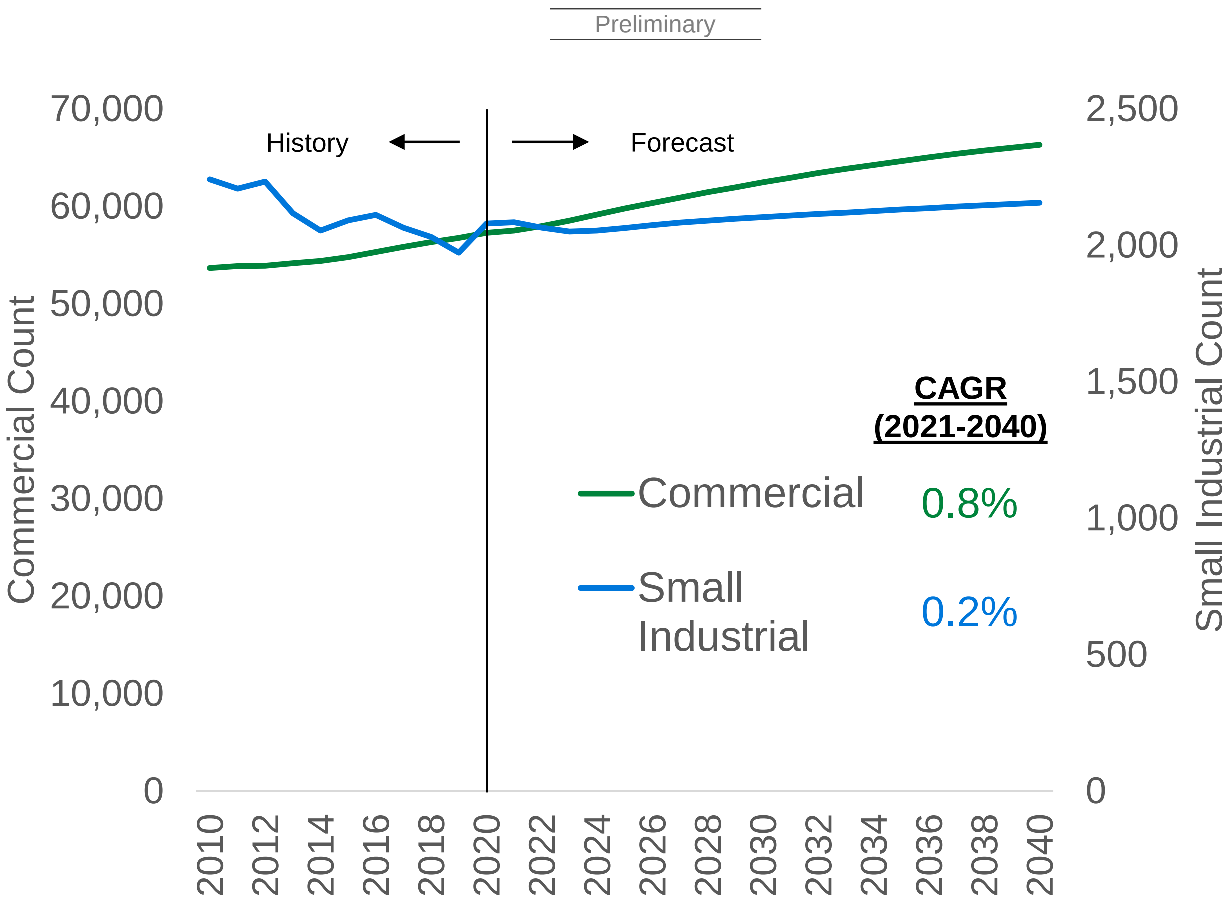
	Residential	**Commercial**	**Small Industrial**
Customer Count Forecast	*Number of households*, seasonal and annual dummies	*Number of households*, seasonal and annual dummies	*Manufacturing employment*, seasonal and annual dummies
Baseline Sales per Customer Forecast	*Real personal income*, average retail rate, HDD, CDD, seasonal monthly dummies	*Manufacturing employment*, average retail rate, HDD, CDD, seasonal monthly dummies	*Manufacturing employment*, average retail rate, HDD, CDD, seasonal monthly dummies

Note that large industrial, railroad, street lighting, public authority, and company use forecasts are based primarily on historical trends extrapolated forward

CUSTOMER COUNT FORECASTS

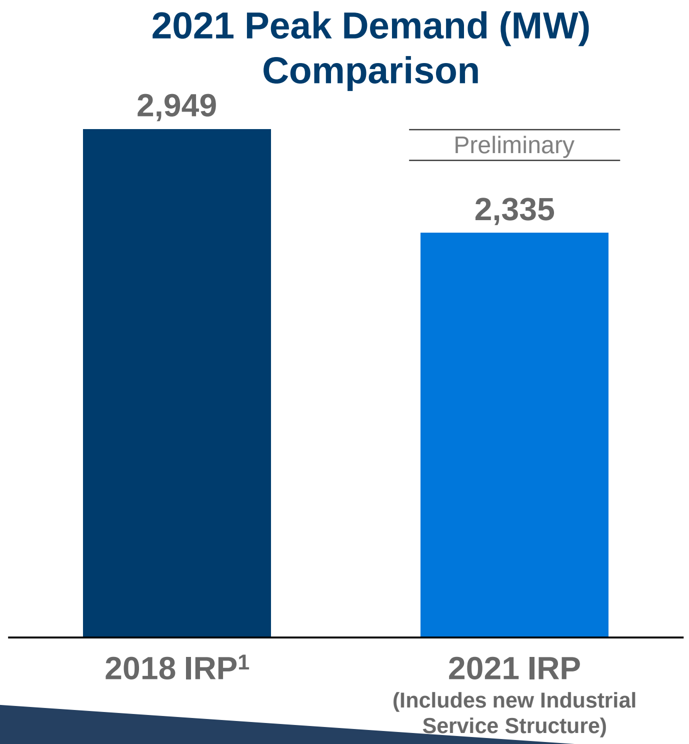
Customer count expectations are largely driven by number of households (R and C) and manufacturing employment expectations (Small I)

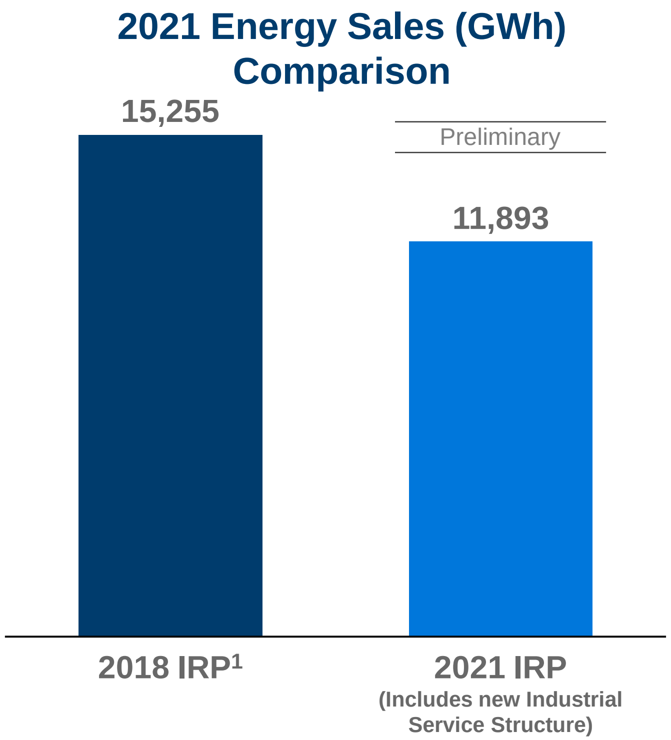




NEW INDUSTRIAL SERVICE STRUCTURE

- A new Industrial Power Service tariff was implemented in NIPSCO's 2019 Electric Rate Case (ERC) settlement
- The new tariff gives certain large industrial customers optionality in purchasing their energy and capacity needs. As a result, the new structure alters NIPSCO's demand picture from previous IRPs by reducing peak load
- The demand forecast for the 2021 IRP is the first IRP to reflect this tariff and subsequent effect on Industrial load

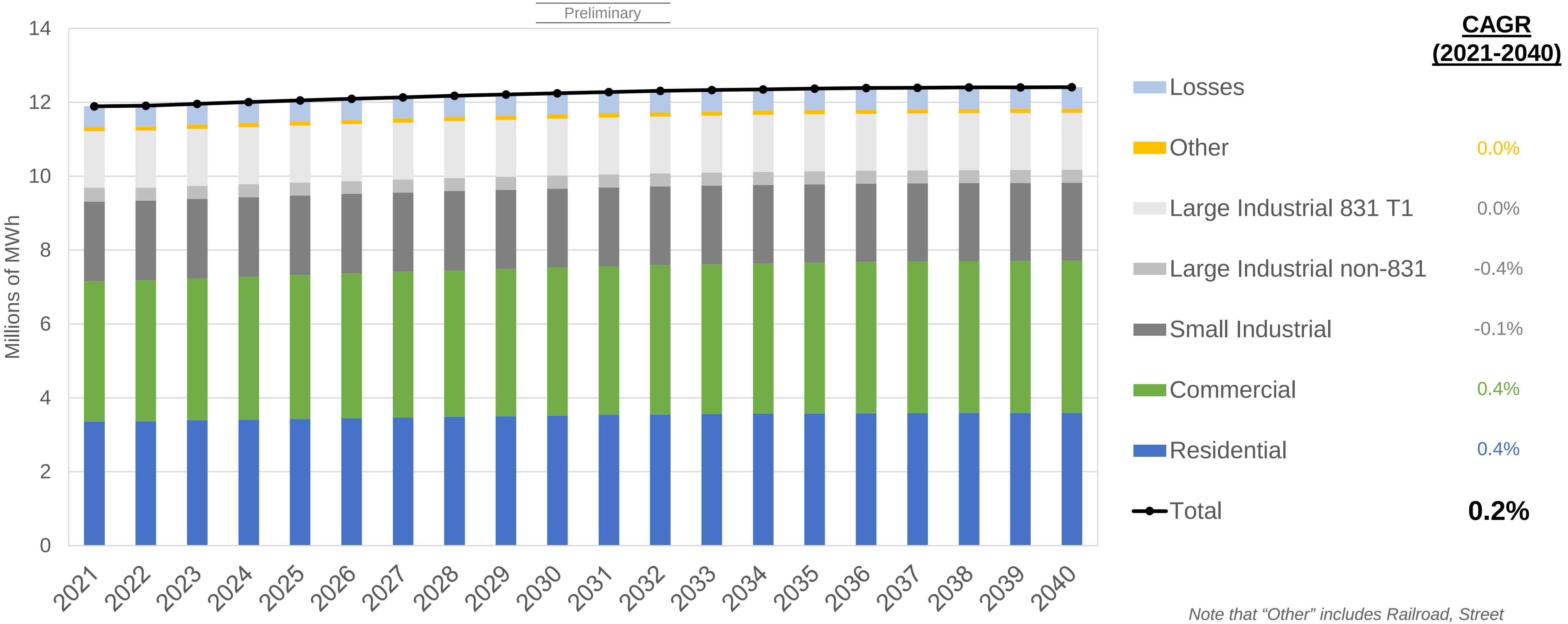




[1]Source: 2018 IRP p. 29 (Table 3-10)

SALES FORECAST

Sales forecast combines customer count outlook with econometric usage per customer forecasts by class (based on personal income and manufacturing outlooks), normalized for weather and *incorporating only prior DSM programs*



Note that "Other" includes Railroad, Street Lighting, Public Authority, and Company Use

PEAK FORECASTING – CLASS LOAD FACTORS

- Historical sample meter data provides monthly load factor data by customer class, which was used to develop monthly peak forecasts
- Customer-level load factor data for the 15 largest customers (Rate 831 T1,2,3 and Rate 832/833) was used for large industrial classes

Monthly Load Factor

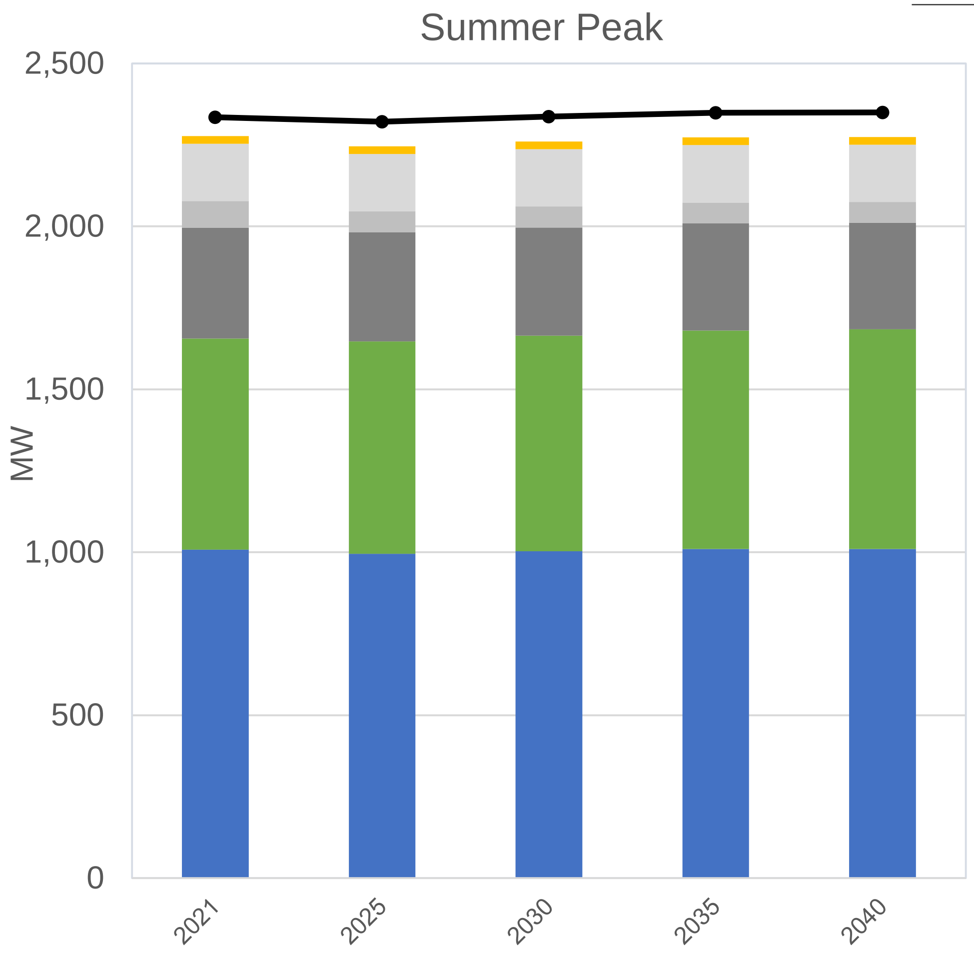
Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	84%	84%	85%	73%	62%	55%	50%	50%	55%	67%	84%	84%
Commercial	79%	79%	72%	81%	67%	79%	74%	74%	79%	82%	79%	79%
Small Industrial	88%	88%	82%	87%	82%	81%	76%	76%	81%	87%	88%	88%

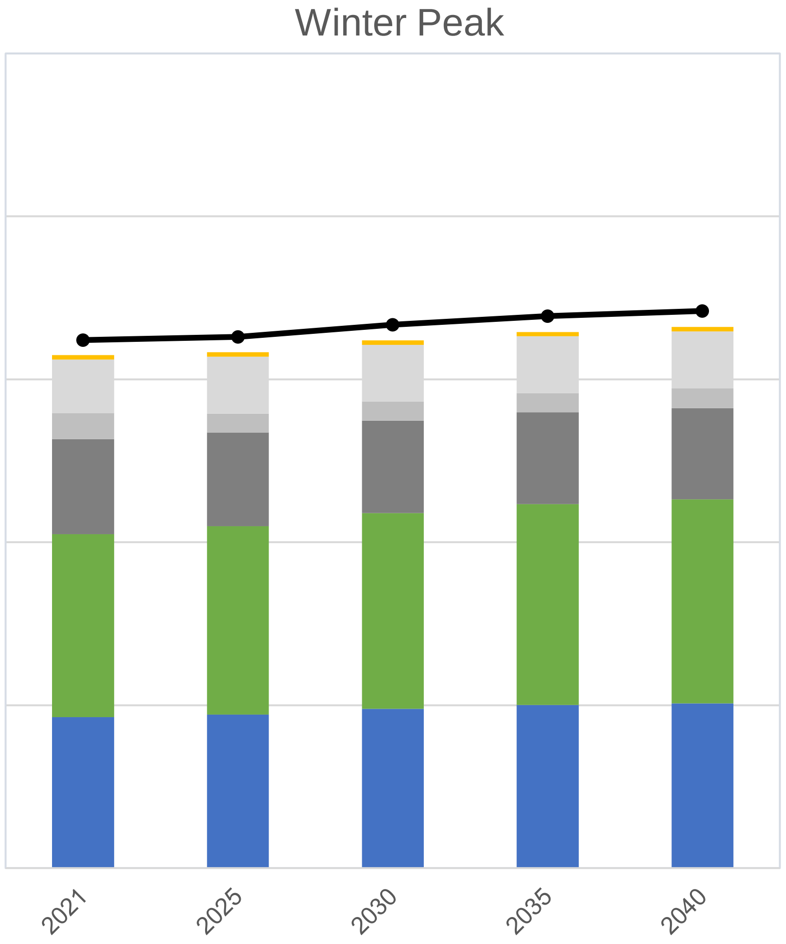
System annual peaks were calculated as the highest sum of monthly peaks, not the sum of the highest monthlies for each class (ie, a coincident peak)

PEAK LOAD FORECAST

Peak load forecast is developed at a monthly level by customer class

Preliminary





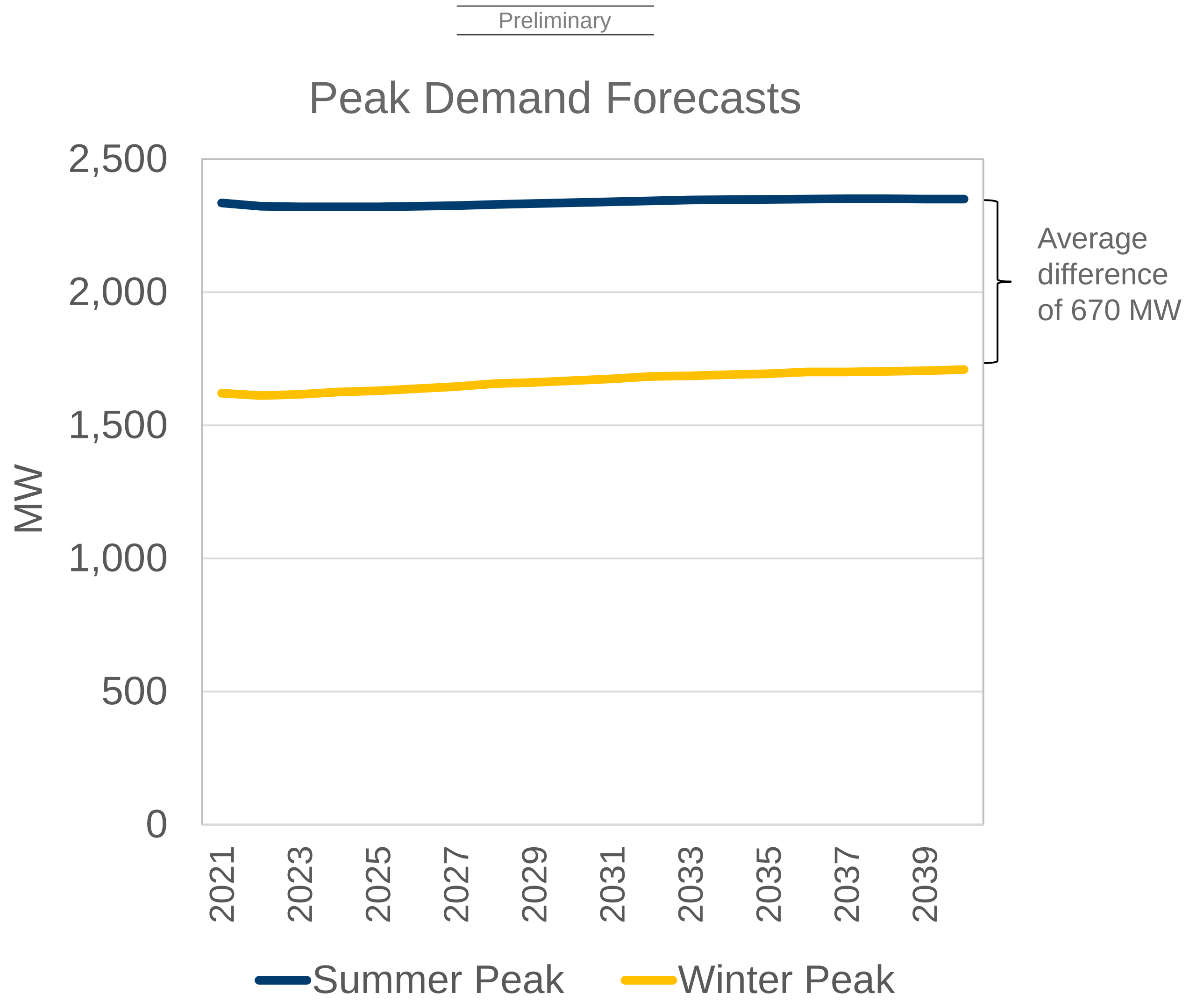
CAGR (2021-2040)

	Summer	Winter
Other	0.0%	0.0%
Large Industrial 831 T1	0.0%	0.3%
Large Industrial non-831	-1.3%	-1.4%
Small Industrial	-0.2%	-0.2%
Commercial	0.2%	0.6%
Residential	0.0%	0.5%
Winter Peak (grossed up for losses)	**0.0%**	**0.3%**

Note that "Other" includes Railroad, Street Lighting, Public Authority, and Company Use

SEASONAL PEAK FORECASTS – REFERENCE CASE

- Winter peak demand is expected to grow slightly over time, based on historical patterns and future economic forecasts
- Future uncertainties in seasonal load outlook will be evaluated through scenarios:
  – Industrial load risk
  – Customer-owned DER penetration – more impactful to summer peak
  – Electric vehicle penetration
  – Other electrification (heating, other) potential – more impactful to winter peak



INCORPORATING DISTRIBUTED ENERGY RESOURCES IN THE LOAD FORECAST

DISTRIBUTED ENERGY RESOURCE ANALYSIS: PenDER MODEL

PenDER is an Agent Based Model (ABM)

Actions (*adoption decisions*) and interactions (*via social networks*) of thousands of autonomous agents are simulated to study their effects on regional DER adoption

PenDER is Designed to:

- **Provide granular forecasting of DER adoption by demographics**
  - By socioeconomic variables (income, age, etc.) that characterize customer groups
  - By technology index of technology adoption (innovators, early adopters, laggards)
  - By region (county/neighborhood or distribution system designation)
- **Simulate adoption response to DER system costs:**
  - Cost of DER is a key determinant of adoption decisions
- **Simulate adoption response to utility pricing:**
  - Expected retail rate growth
  - Financial incentives and costs (net metering, feed-in-tariffs, grid connection costs)

METHODOLOGY OVERVIEW

The probability of adoption is based on several techno-economic variables…

- the capital cost of a solar PV system, inclusive of expected ITC benefits
- solar capacity factor, and solar system lifetime
- retail rates (for net metering) and wholesale rates
- discount rate

…which contribute to the development of the following metrics for each agent which, according to literature, are the main factors influencing the probability of adoption…

- payback period: based on the upfront capital cost, the cash flow from renewable energy incentives (i.e. net metering), discount rate, and solar PV lifetime
- household budget: based on the household income

…and ultimately help estimate the probability of an “agent” to adopt DER

- based on a logit probability function

METHODOLOGY OVERVIEW

Agent Development

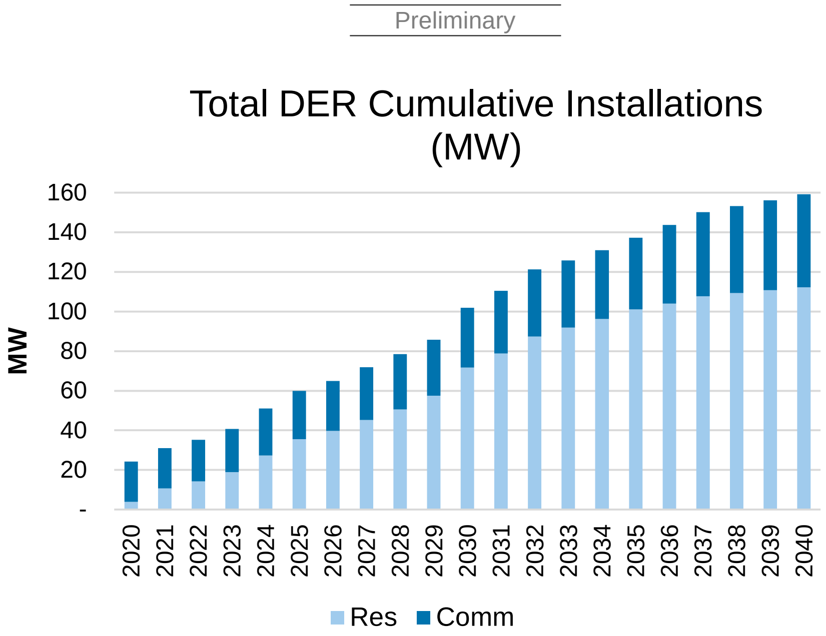
- "Agents" are modeled as representative of NIPSCO's customers, and each agent is randomly assigned a household income level based on the American Community Survey 2019 income distribution across NIPSCO counties
- Each agent is assigned a propensity to adopt new technology (bass innovation index)
- Relationships between agents are modeled through "social networks," with an average size of 13 agents belonging to one network

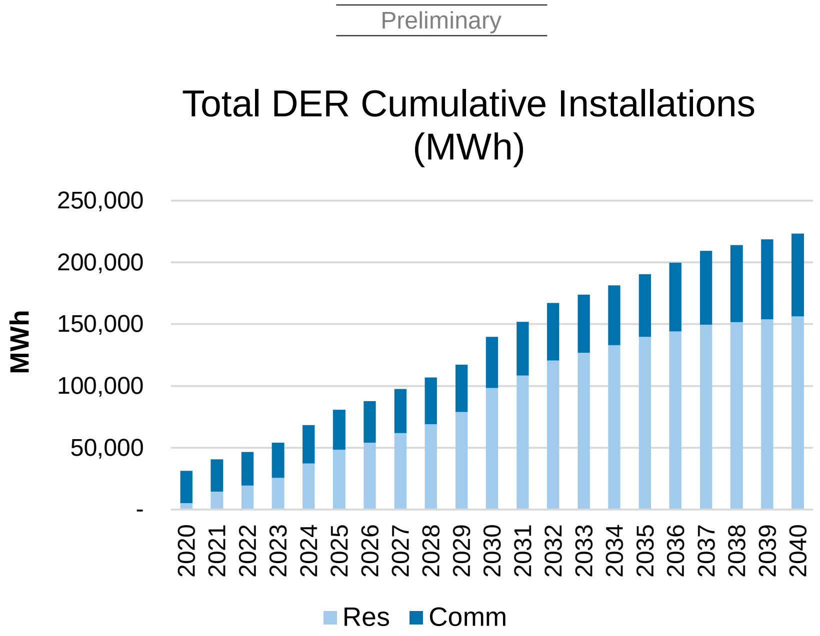
An agent will adopt DER if:

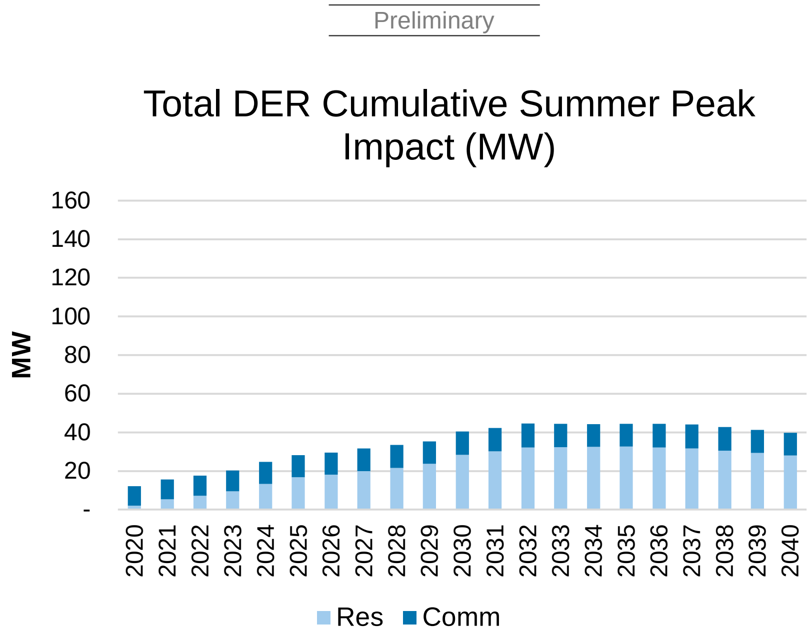
- the agent's probability of adoption is sufficiently high *(according to the economics and probability assessment from the previous slide)*
- the agent is an innovator type (bass innovation level within some threshold level) or a significant portion of the agent's network has adopted the technology

REFERENCE CASE OUTLOOK

- Net metering caps are expected to mitigate installations through the second half of the decade, but residential network effects are projected to lead to greater growth rates than the commercial sector
- A total of 160 MW of installed capacity is projected by 2040, leading to ~40 MW of summer peak impact (from a capacity credit perspective)







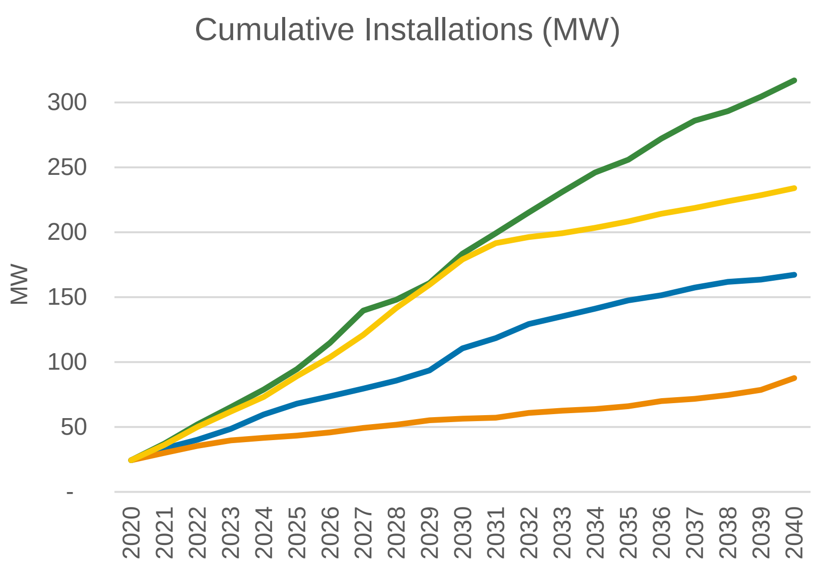
SCENARIO CONSIDERATIONS

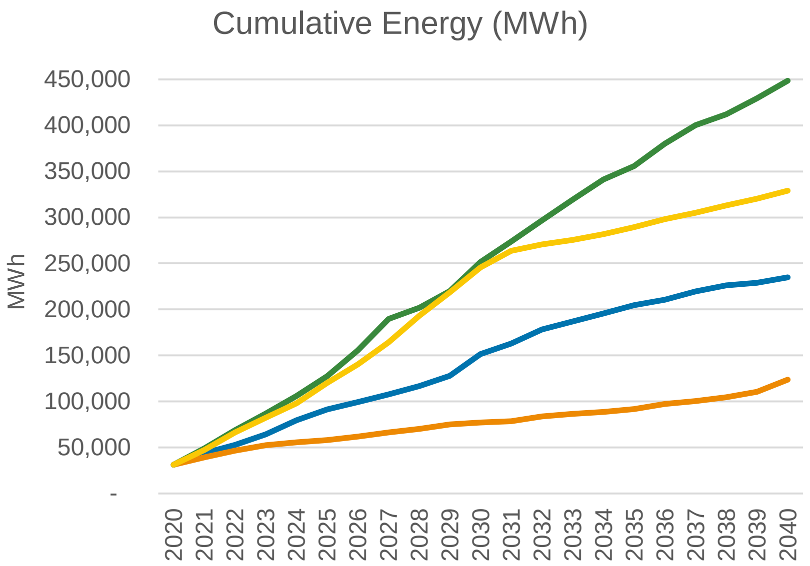
Several uncertainties are likely to drive customer payback economics over time:

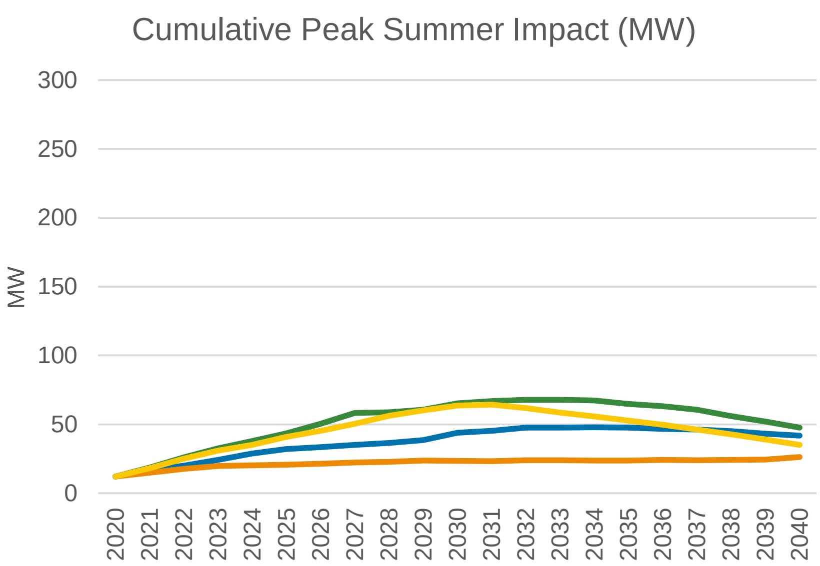
- **Capital Costs for Solar**
- **Investment Tax Credit Incentives**
- **Other Incentive Structures**
- **Retail Rate Growth Trends**

DRAFT SCENARIO RANGES FOR CONSIDERATION

- DER penetration is likely to be sensitive to a range of market and policy uncertainties, providing a range of future outcomes
- Initial projections of DER capacity ranges are from under 100 MW to over 300 MW by 2040
- Total cumulative energy production by 2040 ranges from approximately 1% to 4% of NIPSCO's current retail sales







Illustrative Ranges – to be refined in scenario work

INCORPORATING ELECTRIC VEHICLES IN THE LOAD FORECAST

ELECTRIC VEHICLES FORECAST METHODOLOGY OVERVIEW

NIPSCO has developed EV forecasts for four classes of vehicles across Low/Med/High scenarios:

- Light Duty Vehicles (Residential, *most significant*)
- Medium Duty Vehicles (Commercial, Class 2-6)
- Transit Vehicles
- Heavy Duty Trucks (Industrial, Class 7-8)

- **Growth estimates were based on and benchmarked against industry literature estimates and information specific to NIPSCO's service territory:**
  - MTEP Futures for LRZ6 total EV registrations and Bloomberg NEF Electric Vehicle Outlook
  - Known delivery fleets (i.e. Amazon) specific to NIPSCO

- **Total energy and peak demand impact were determined by:**
  - Ratio of battery electric/hybrid electric vehicles
  - Average miles driven per year
  - Fuel economy of current vehicle models
  - Energy usage improvements over time (i.e. light-weighting)
  - Charging profiles during peak/off-peak hours

KEY EV FORECAST ASSUMPTIONS AND SOURCES

1. **External EV growth forecasts/benchmarks and fleet replacement rates**
2. **Energy usage estimates from current vehicles, as well as assumptions about fuel economy improvement**
3. **Charging profiles based on actual NIPSCO data**

EV Fleet Numbers

Existing Vehicles across NIPSCO counties

- **NIPSCO EV customer database:** existing LDVs
- **NIPSCO MDV/HDV/Transit database and National Transit Database:** total vehicle counts in territory

Growth Rates

- **MTEP Futures for LRZ6:** LDV, MDV, Transit
- **Bloomberg NEF**: HDV

Vehicle Age

- **National Transit Database:** existing fleet age
- CRA/NIPSCO assumptions for LDV lifetime

Energy Usage

LDV Energy Usage (miles per day)

- **NIPSCO EV customer database**
- **EPA 2019 Automotive Trends Report**

MDV/HDV/Transit Energy Usage (miles per day)

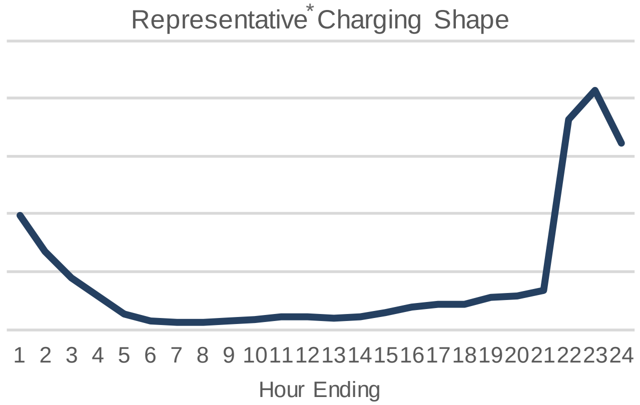
- **NIPSCO MDV/HDV/Transit database**
- **DOE 2019 "Medium- and Heavy-Duty Vehicle Electrification" Study**
- **NREL 2016 Fast-Charge Electric Bus Study**

Efficiency Improvements

- **EPRI Environmental Assessment of Full Electric Portfolio**: fuel economy improvements over time, ~0.5%/yr improvement in long-term

Charging Profiles

- **NIPSCO EV customer database**
- **NREL "Field Evaluation of Medium-Duty Plug-In Electric Delivery Trucks**

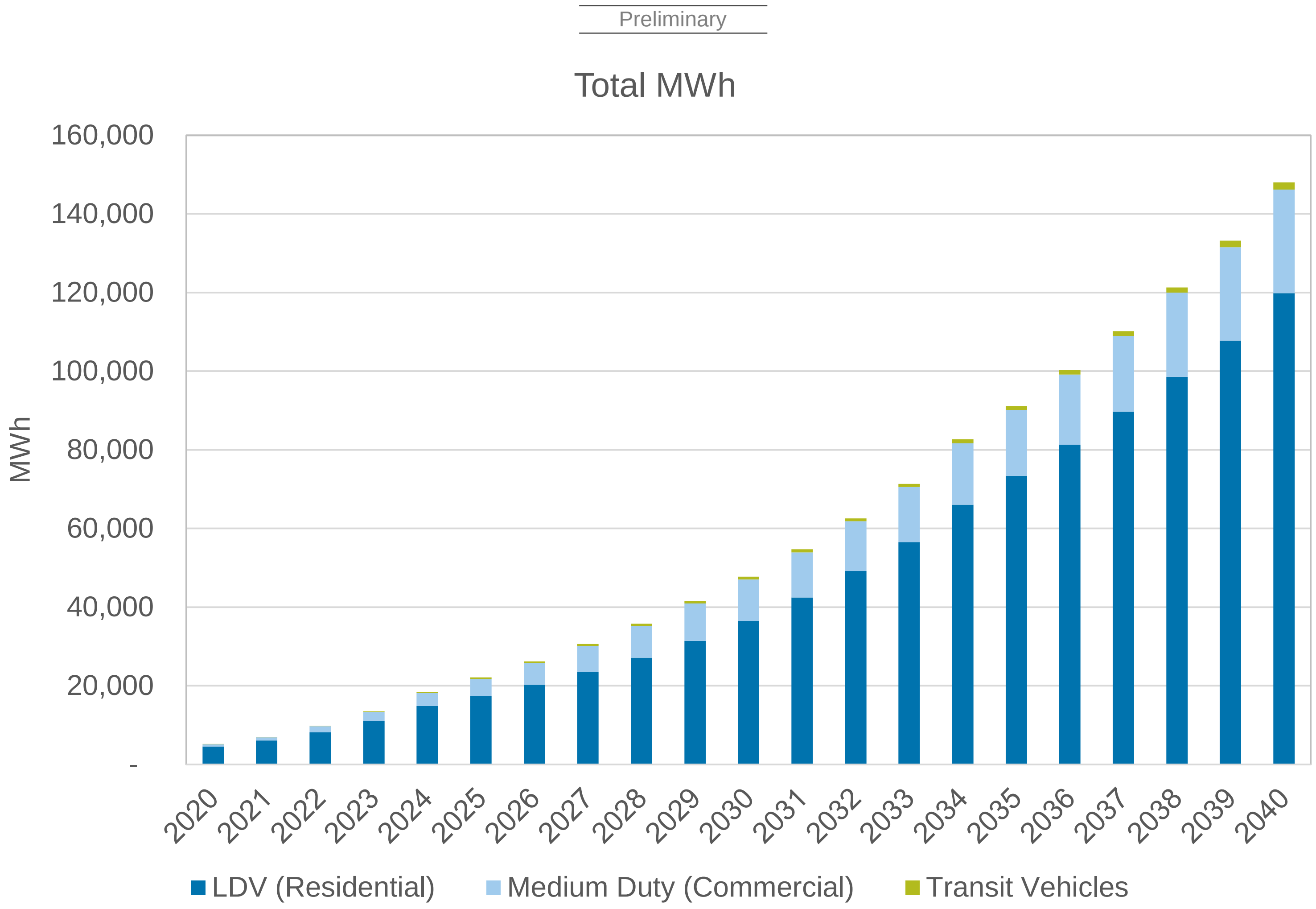


Sample shape used for LDVs/Transit in Base Case

BASE EV EXPECTATIONS

Key drivers of base case forecast:

- **LDV (Residential)**: growth assumptions based on MTEP Future I; about 10% of new sales from electric vehicles in 2040
- **Commercial**: electrification of urban delivery fleet; growth assumptions based primarily on MTEP Future I; about 15% of new sales from electric vehicles in 2040
- **Transit:** growth assumptions in proportion to passenger LDVs; about 15% of new sales from electric vehicles in 2040



SCENARIO CONSIDERATIONS

Scenario factors that drive forecast range include:

- Forecast vehicle growth numbers
- Near-term fuel economy improvements, due to increased R&D, investment, other technological advancement
- Ratio of electric-only vehicles to hybrid electric, given improvements in EV range, cultural perception, etc.

Light Duty Vehicles

- Adoption of LDVs influenced by factors such as capital cost of Li-ion battery, cultural perception of EVs, and prevalence of incentives
- Variation across scenarios is based on MTEP Futures forecasts

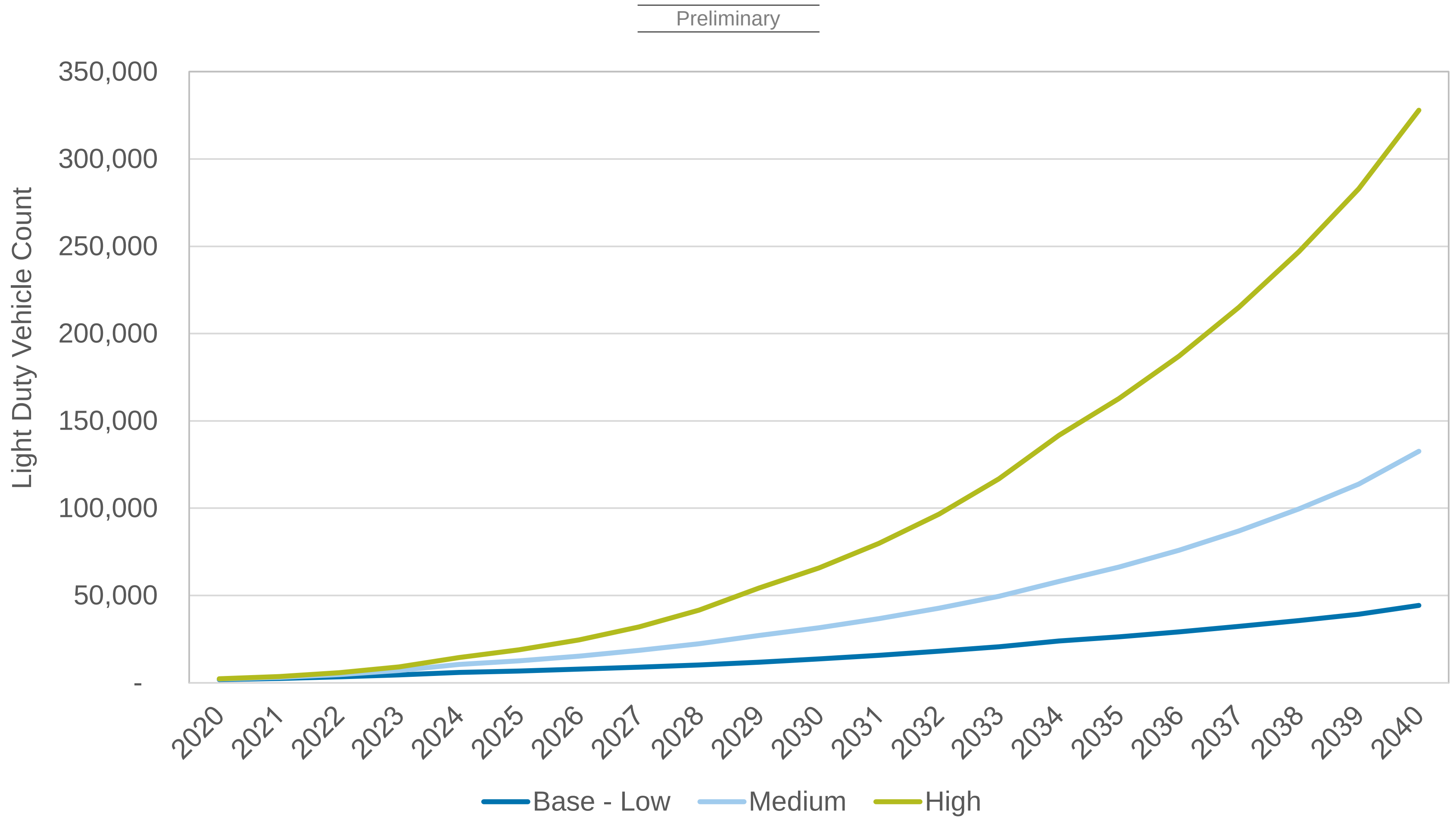
Medium & Heavy Duty Vehicles

- Electrification of urban delivery fleet and other commercial vehicles (Medium Duty) is expected in proportion to LDVs (with minor near-term adjustments for Med/High scenario).
- Industrial machinery and trucking fleet (Heavy Duty) electrification is contemplated in the High scenario

Transit Vehicles

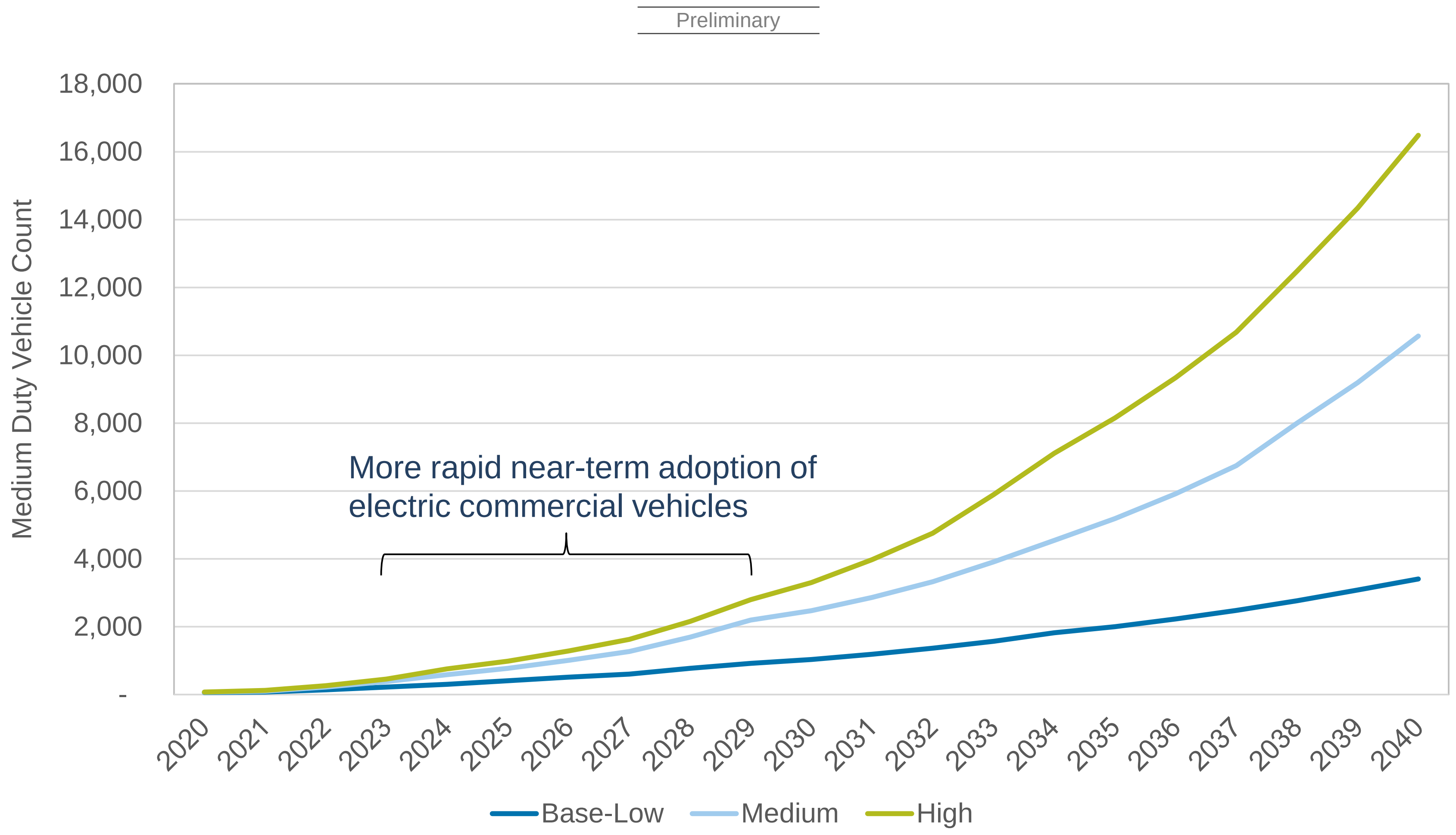
- Local transit vehicles, such as buses and shuttle buses, are expected to electrify in proportion to LDVs.
- 100% electric-only fleet expected in the High scenario

LIGHT DUTY VEHICLE FORECAST ACROSS SCENARIOS



% of New Vehicle Sales by 2040	% of Total Vehicle Stock by 2040
97%	48%
39%	19%
10%	7%

MEDIUM DUTY VEHICLE FORECAST ACROSS SCENARIOS



% of New Vehicle Sales by 2040	% of Total Vehicle Stock by 2040
77%	72%
49%	46%
12%	15%

**Note that total stock % is higher than new sales % in low case due to annual growth trajectory and relatively short assumed lifespan of vehicles*

HEAVY DUTY AND TRANSIT VEHICLE FORECAST ACROSS SCENARIOS

Heavy Duty Vehicles

- Due to the energy requirements of heavy duty vehicles (i.e. industrial hauling and highway trucks), electrification of HDVs is assumed only in the High scenario. It is possible that other low-carbon technologies, such as hydrogen fuel-cell or renewable fuels, may be alternatives in this sector which requires long hauls and high energy density
- In High scenario, additional 74 GWh of energy impact and 10 MW of peak demand in 2040 result from HDV sector
- Other industry sources (i.e. Bloomberg NEF) suggest minor penetration of electrified heavy-duty vehicles

Transit Vehicles

- Transit electrification follows LDV forecast, given similarities in passenger transport patterns
- Transit vehicles represent a far smaller impact than LDVs

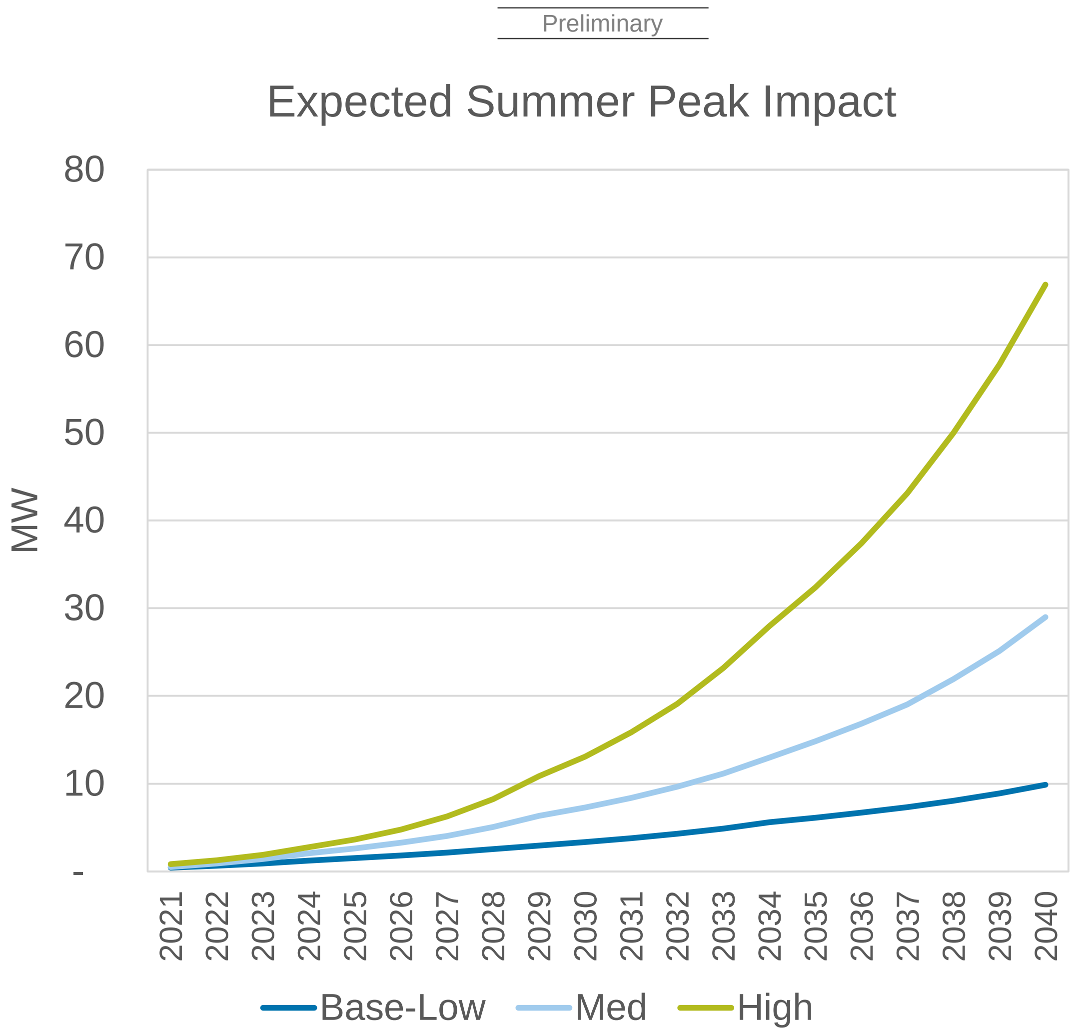
2040 estimates

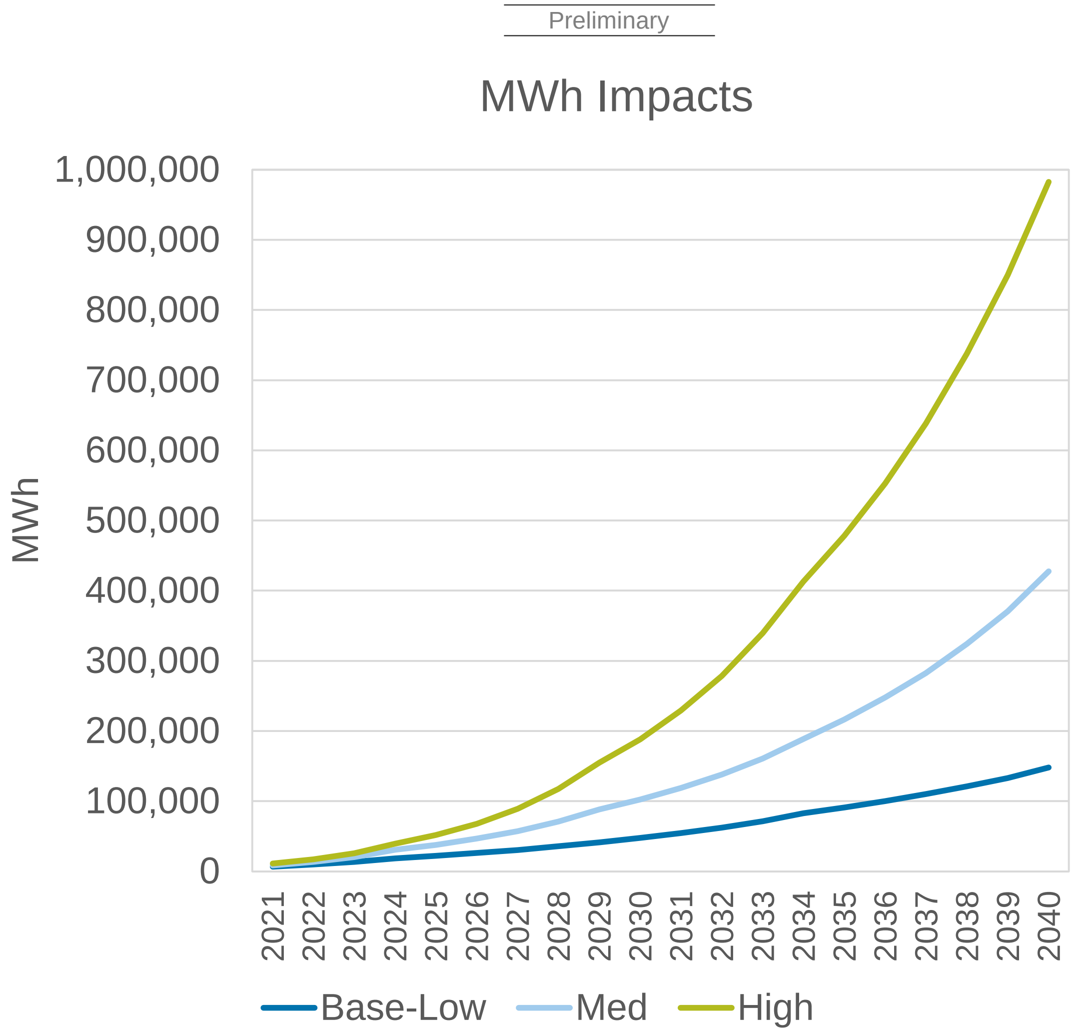
High: 10 GWh energy, 0.5 MW peak demand

Med: 2 GWh energy, 0.1 MW peak demand

Low: 1.8 GWh energy, 0.09 MW peak demand

TOTAL EV FORECAST RANGE





% of Total NIPSCO Base MWh Sales Forecast by 2040

7.9%

3.4%

1.2%

NET LOAD FORECAST

ENERGY FORECAST – REFERENCE CASE

Preliminary

- The impacts of both EVs and DERs are expected to be between 1-2% of total sales by 2040
  - Additional EV load is more than offset by expected DER penetration, resulting in minimal impact to the overall Reference Case sales forecast
- Although the overall magnitude is relatively small, annual growth rates of between 15-20% are expected for both EVs and DERs

Total MWh Sales

Year	Base Load	EV Load	DERs	All-In
2021	11,931,207	6,895	13,054	11,925,048
2022	11,945,879	9,724	22,511	11,933,092
2023	11,994,229	13,507	34,542	11,973,195
2024	12,045,292	18,421	50,631	12,013,082
2025	12,088,707	22,084	63,186	12,047,605
2026	12,131,993	26,197	71,638	12,086,552
2027	12,173,872	30,570	80,448	12,123,994
2028	12,215,153	35,726	89,686	12,161,193
2029	12,251,143	41,576	101,544	12,191,175
2030	12,286,428	47,753	126,379	12,207,801
2031	12,319,288	54,682	138,479	12,235,491
2032	12,349,786	62,573	154,566	12,257,793
2033	12,373,225	71,357	163,677	12,280,905
2034	12,391,741	82,643	172,783	12,301,602
2035	12,409,393	91,181	182,511	12,318,063
2036	12,426,237	100,276	188,733	12,337,780
2037	12,436,147	110,199	197,911	12,348,435
2038	12,442,921	121,308	204,913	12,359,316
2039	12,447,827	133,181	208,010	12,372,998
2040	12,453,040	148,022	214,101	12,386,960
2021-2040 CAGR	**0.2%**	**17.5%**	**15.9%**	**0.2%**

Preliminary

PEAK LOAD FORECAST – REFERENCE CASE

- DER growth is expected to reduce NIPSCO's summer peak obligation by about 1-2% after 2030
  - Given the expected evolution of the MISO-wide net peak to later in the evenings, the summer peak contribution of solar DER is projected to decline over time, even as total customer installations grow
- The expected impact of EV load on the summer peak is minimal, given expectations for predominantly off-peak charging
  - NIPSCO will evaluate seasonal impacts in more detail as further modeling is performed

Summer Peak MW

Year	Base Load	EV Load	DERs	All-In
2021	2,335	0	5	2,331
2022	2,323	1	8	2,315
2023	2,321	1	13	2,310
2024	2,321	1	18	2,305
2025	2,321	2	21	2,302
2026	2,323	2	23	2,302
2027	2,326	2	24	2,304
2028	2,329	3	26	2,306
2029	2,333	3	28	2,308
2030	2,337	3	33	2,307
2031	2,340	4	35	2,309
2032	2,344	4	37	2,311
2033	2,346	5	37	2,314
2034	2,348	6	37	2,316
2035	2,349	6	37	2,318
2036	2,350	7	36	2,321
2037	2,351	7	36	2,322
2038	2,351	8	35	2,324
2039	2,350	9	33	2,326
2040	2,350	10	31	2,328
2021-2040 CAGR	**0.0%**	**18.1%**	**10.4%**	**0.0%**

NEXT STEPS ON LOAD

- Prior to performing portfolio analysis, NIPSCO will likely refresh the reference case forecast with the latest Moody's economic data base case
- NIPSCO will proceed with scenario development (more detail in next section), varying key drivers in line with scenario narratives:
  - Economic growth factors – NIPSCO will use Moody's scenario ranges, which vary the outlook for the key econometric variables (households, personal income, employment)
  - Industrial load
  - Customer-owned DER penetration
  - Electric vehicle penetration

BREAK

TREATMENT OF UNCERTAINTY – INTRODUCTION

Pat Augustine, Vice President, CRA

MODELING OF UNCERTAINTY

- Because generation decisions are generally capital intensive and long-lived, understanding and incorporating future risk and uncertainty is critical to making sound decisions
- Generation 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
    - The interactions between market price volatility and resource output uncertainty are more complex than what can be assessed under "expected" conditions
    - Commodity price exposure risk is broader than single scenario ranges
- **For 2021 IRP, the stochastic analysis will be expanded to include hourly renewable availability in addition to commodity price volatility**

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

- 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

- 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 / Electrification

- 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.)

CO2 POLICY SCENARIOS

	Status Quo Extended	Aggressive Environmental Regulation	Economy-wide Decarbonization / Electrification
Rationale	Continued hurdles in Congress stymie legislative outcomes, and conservative 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 discussions 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 (75-80% by 2040) for the power sector

MAJOR SCENARIO PARAMETERS

Scenario Name	Gas Price	CO_2 Price	Federal Tech. Incentives	Load Growth	Solar Capacity (ELCC) Credit
				See next slide for details	***Based on MISO modeling outcomes DRAFT***
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/ Electrification	Base	None	8-year ITC extension (solar) plus expansion to storage; 5-year PTC extension (60%)	Higher	50% → 15%

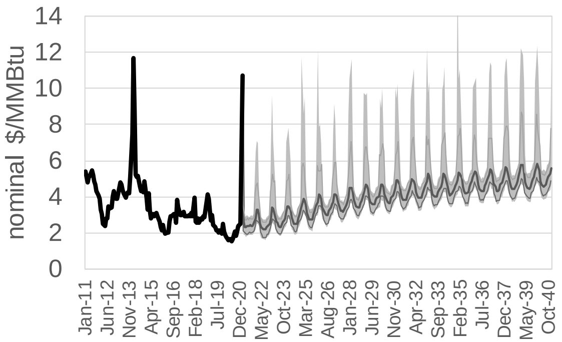
SCENARIO IMPACTS TO LOAD

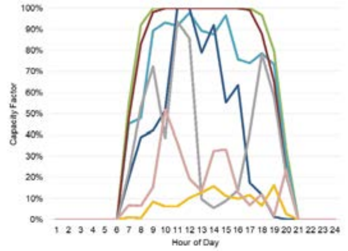
Scenario Name	Economic Growth	EV Penetration	DER Penetration	Other Electrification	NIPSCO Industrial Load
Reference Case	**Base** *Moody's Baseline forecast*	**Low** *Current trends persist (MTEP Future I)*	**Base** *Baseline expectations for continued growth, which is exponential in areas*		
Status Quo Extended	**Low** *Moody's 90th percentile downside: COVID impacts linger; lack of large fiscal stimulus, 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 / Electrification	**High** *Moody's 10th percentile upside: vaccine rollout facilitates re-openings, significant fiscal stimulus in 2021*	**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*	

STOCHASTIC VARIABLES IN THE 2021 IRP

- The 2021 IRP will expand the stochastic variables to include renewable generation output, correlated with market power prices. This will allow for a more robust risk analysis of the impacts of intermittent resources
  - Daily natural gas price volatility
  - Hourly power price volatility
  - Hourly wind and solar renewable output volatility

Input Iterations



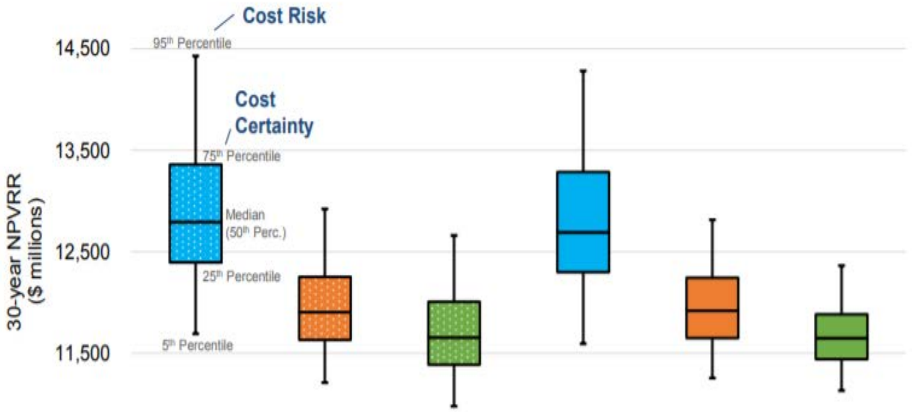


Portfolio Modeling

Aurora Power Market Model

- Hourly chronological dispatch
- Detailed market representation
- Interaction with capacity price model

Portfolio NPV Results



ILLUSTRATIVE

NEXT STEPS FOR SCENARIO AND STOCHASTIC ANALYSIS

- Developing integrated fuel, carbon, load, and power market outlooks for all four scenarios and will present detailed outcomes in the May stakeholder meeting:
  - NIPSCO load range
  - Natural gas price range
  - Carbon price range
  - MISO power price range (annual, monthly, and hourly impacts)
- Developing integrated commodity price and renewable output stochastic distributions and will share details in the May stakeholder meeting
- NIPSCO welcomes stakeholder input on proposed scenario concepts and alternative scenario requests
  - NIPSCO is open to one-on-one calls with stakeholders to discuss scenarios in more detail
  - NIPSCO asks that all stakeholder scenario requests be provided by June 30

2021 STAKEHOLDER ADVISORY PROCESS

Erin Whitehead, Vice President Regulatory & Major Accounts, 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	9/16/2021	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 has environmental policy changed since 2018? • How does NIPSCO think about reliability in the context of generation? • What scenarios 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	• 2021 Environmental Policy Update • MISO Market Rules Update, Role of the ISO, Role of the Utility • Scenarios and Stochastics	• 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	• Communicate environmental policy considerations • Common understanding of market reliability and roles • Communicate Scenario Themes and Stochastics	• 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 WILL CONDUCT AN RFP IN 2021

Similar to 2018 and 2019, NIPSCO will conduct an RFP in 2021 to help inform long term market planning and identify projects for transaction

Expert Assistance

- Continuing to retain Charles River Associates (CRA) to develop and administer RFP
- Utilizing a separate division within CRA to ensure independence from the IRP process

Approach/Design

- Currently developing the design criteria
- Once design criteria has been formulated, we will seek feedback on approach/design to ensure a robust, transparent process and result

Resource Evaluation Criteria

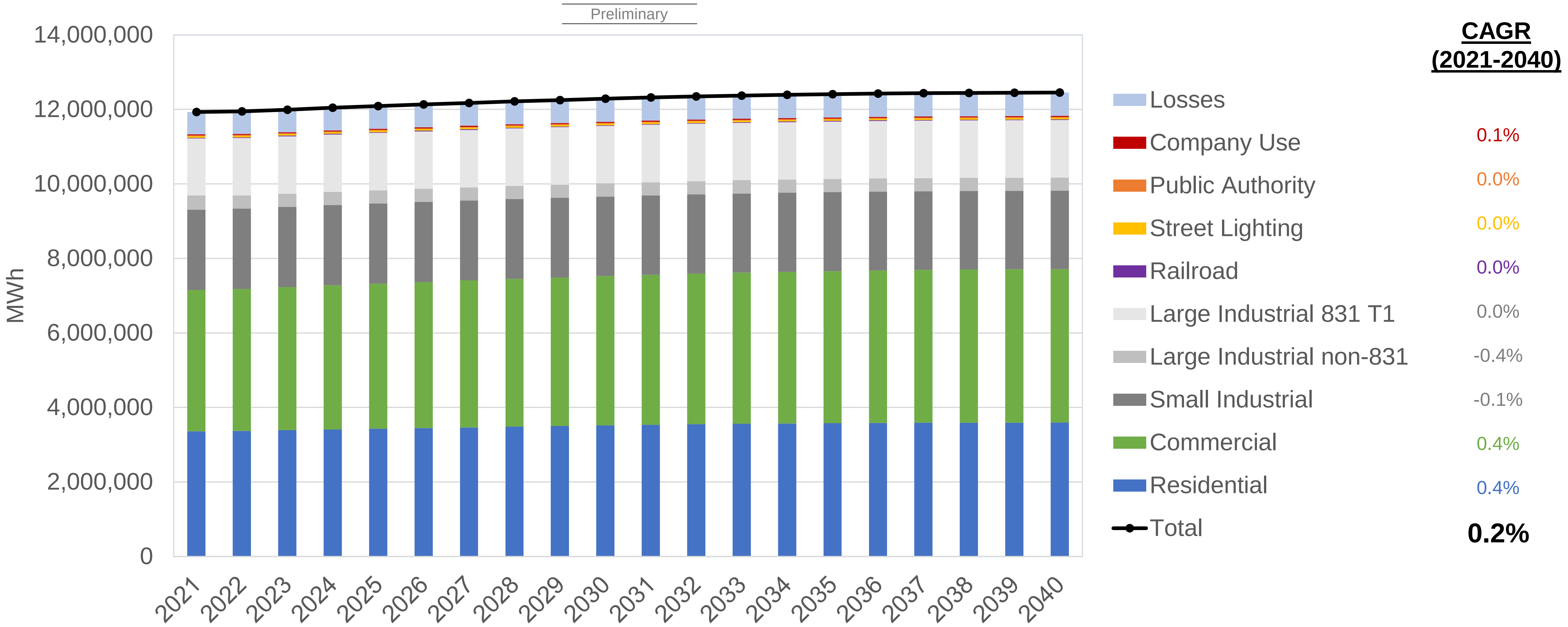
- Complimentary to the IRP portfolio analysis:
  - Cost to our customers
  - Reliability
  - Deliverability
  - Duration
  - Environmental impact
  - Employee and operational impact
  - Local community impact

CLOSING

APPENDIX

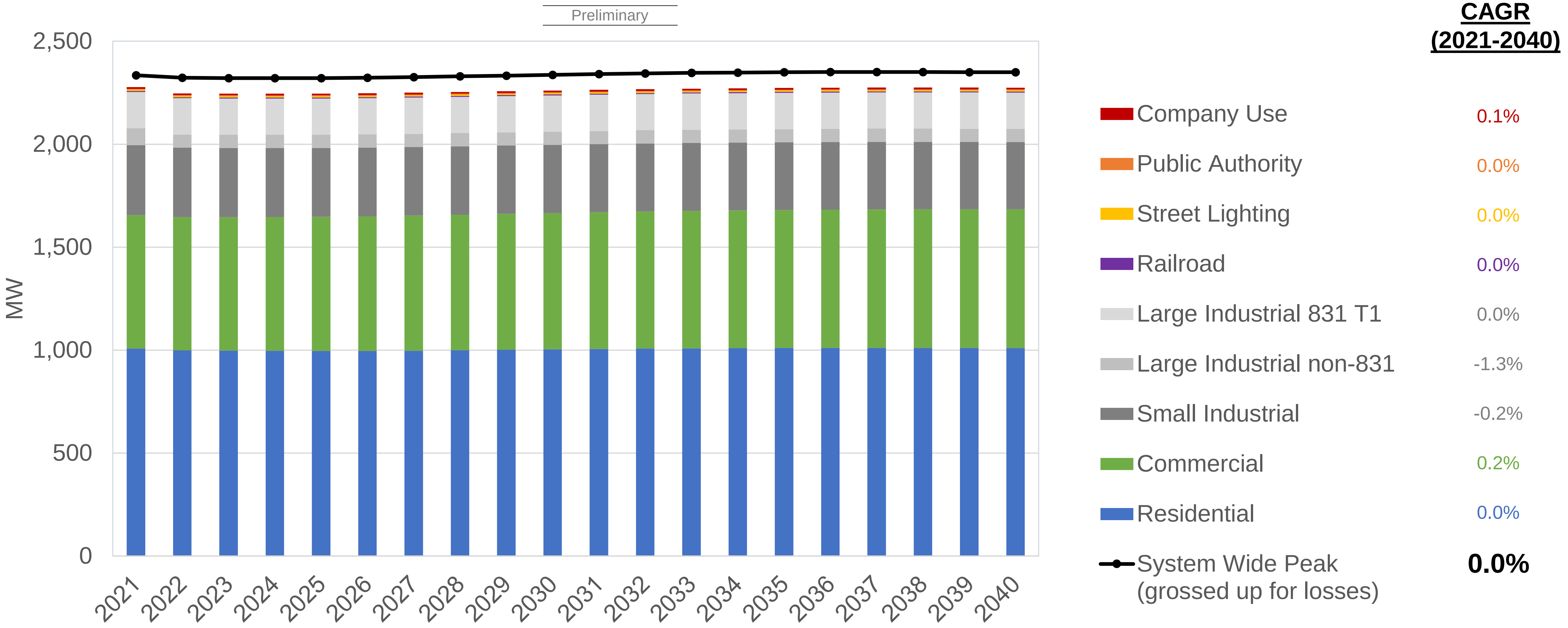
SALES FORECAST

Sales forecast combines customer count outlook with econometric usage per customer forecasts by class (based on personal income and manufacturing outlooks), normalized for weather and *incorporating only prior DSM programs*



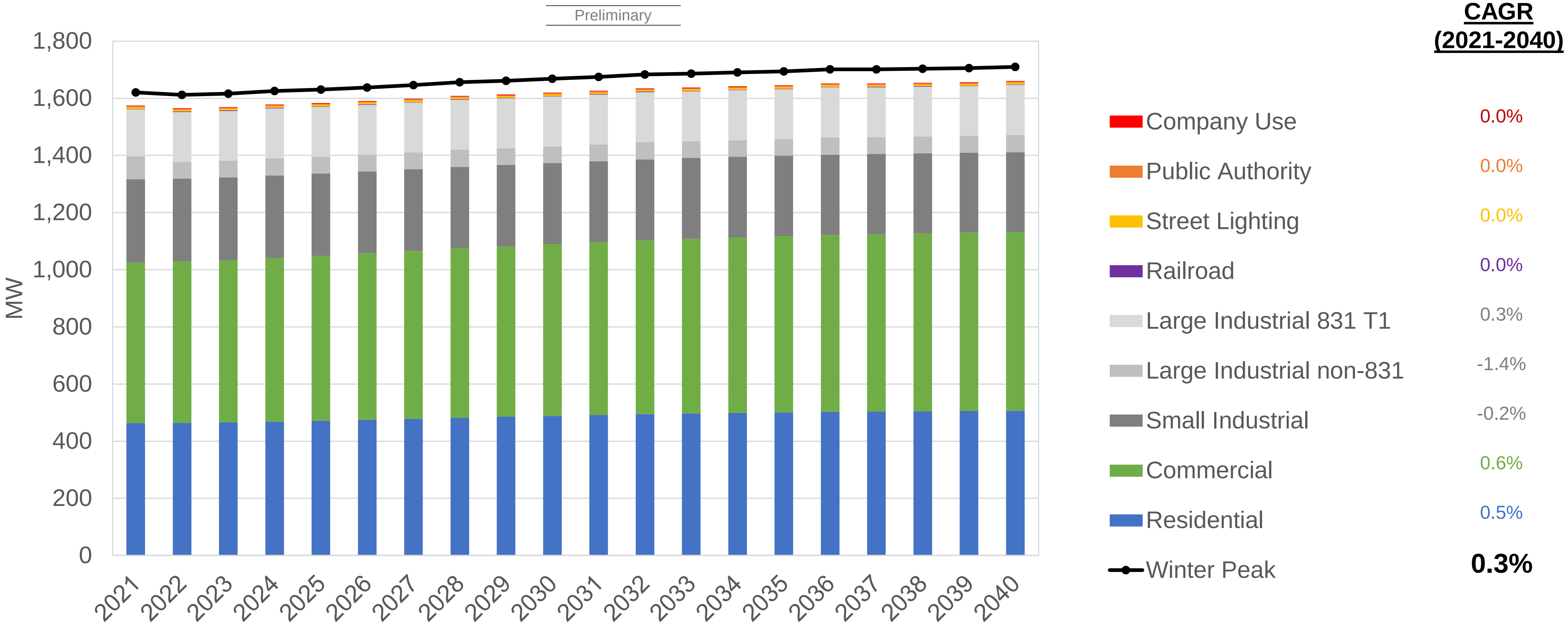
PEAK LOAD FORECAST - SUMMER

Peak load forecast is developed at a monthly level by customer class



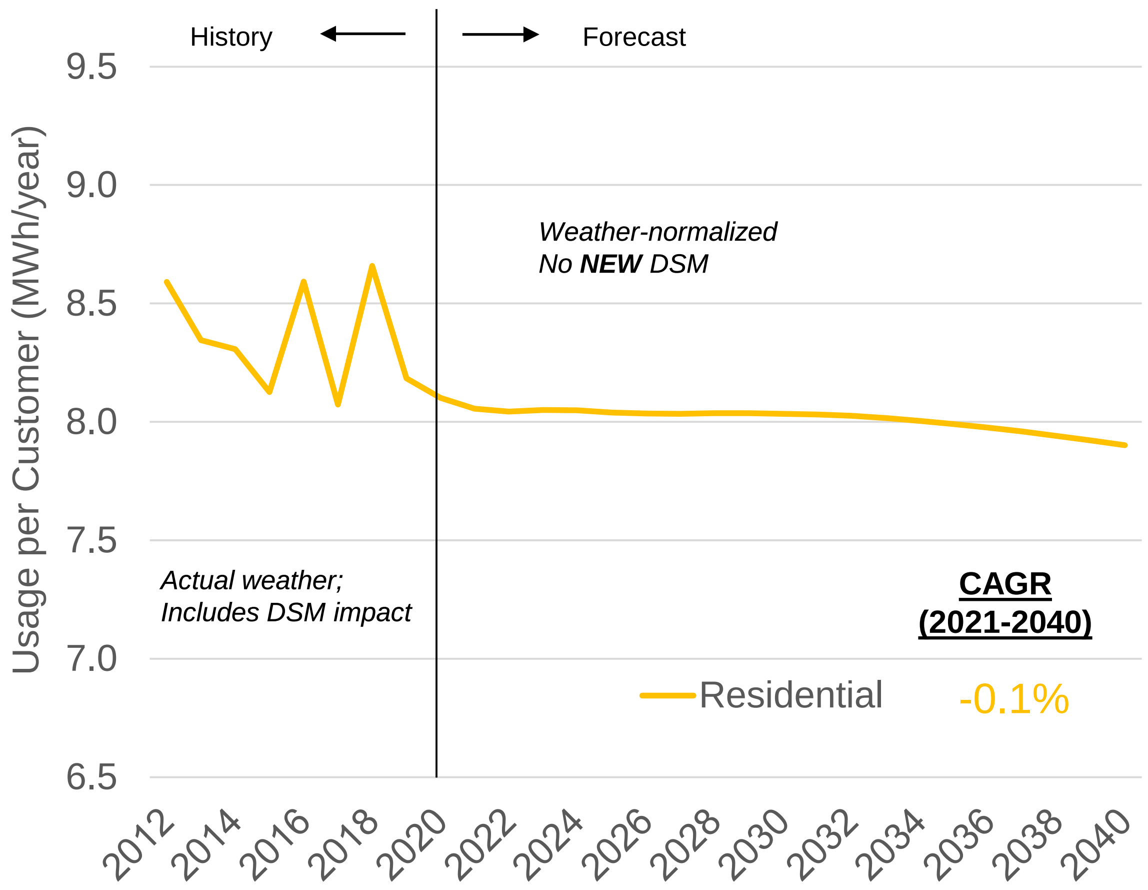
PEAK LOAD FORECAST - WINTER

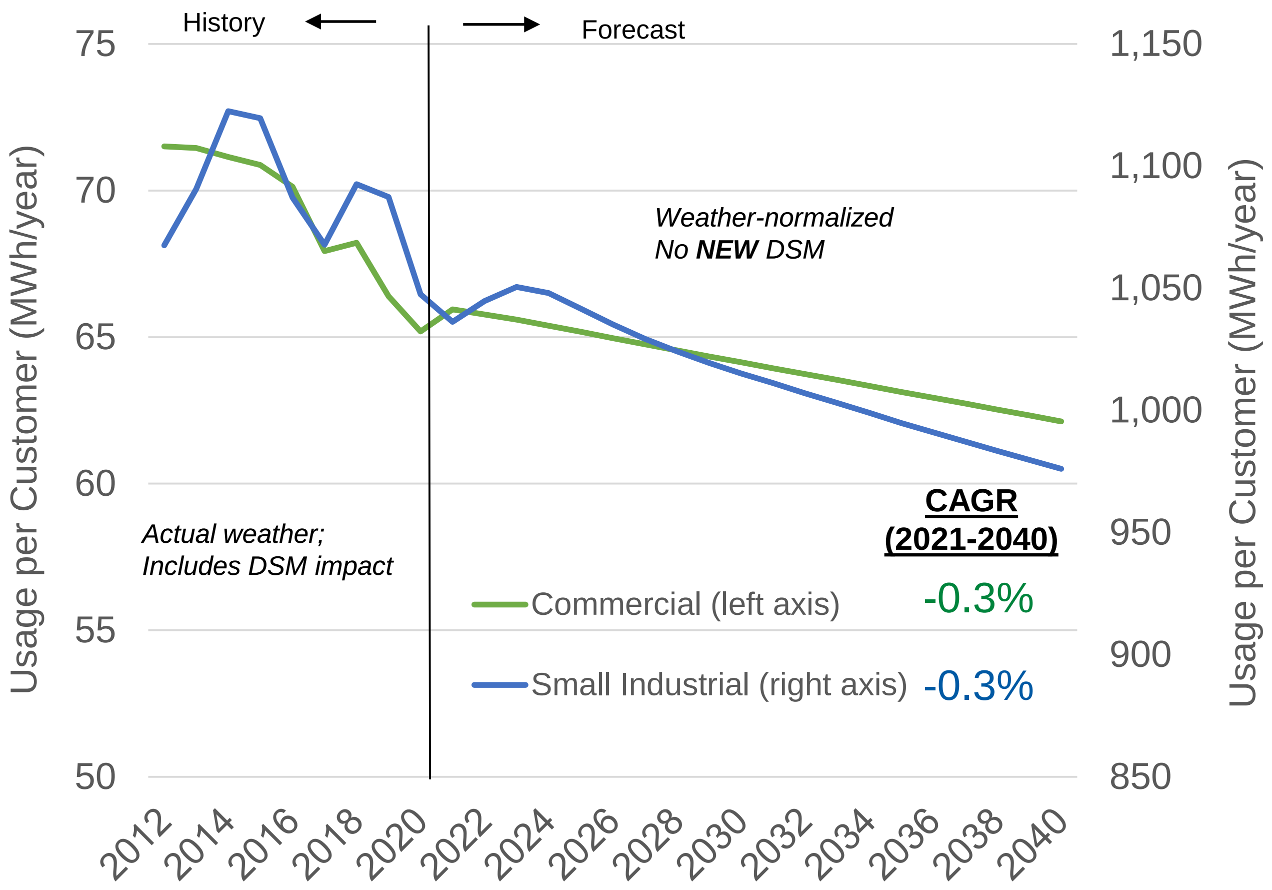
Peak load forecast is developed at a monthly level by customer class



LOAD FORECAST: USAGE PER CUSTOMER FORECASTS

Usage per customer is expected to decline, even prior to new DSM program impacts





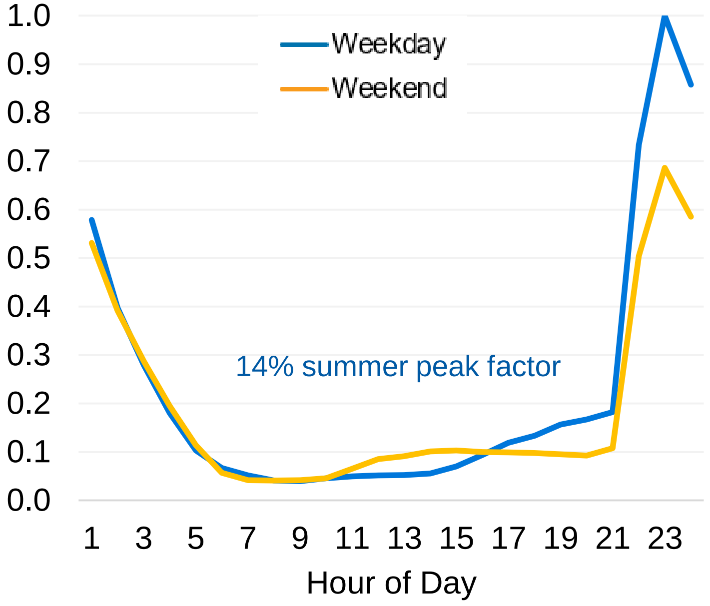
LOAD FORECAST: ACCOUNTING FOR LOSSES

- Although core historical load data is recorded at the meter, IRP modeling must include “gross-ups”
- From an energy perspective, IRP modeling must incorporate the amount of energy that needs to be generated by resources prior to facing losses associated with transmission and distribution to customers
- For MISO peak planning purposes, peak demand needs to be:
  - Inclusive of distribution losses when reporting coincident peaks
  - Grossed up for transmission losses when calculating the planning reserve margin
- Therefore, monthly loss factors based on historical data were multiplied by the projected retail sales totals by month to estimate monthly losses.

EV CHARGING PROFILE DETAILS

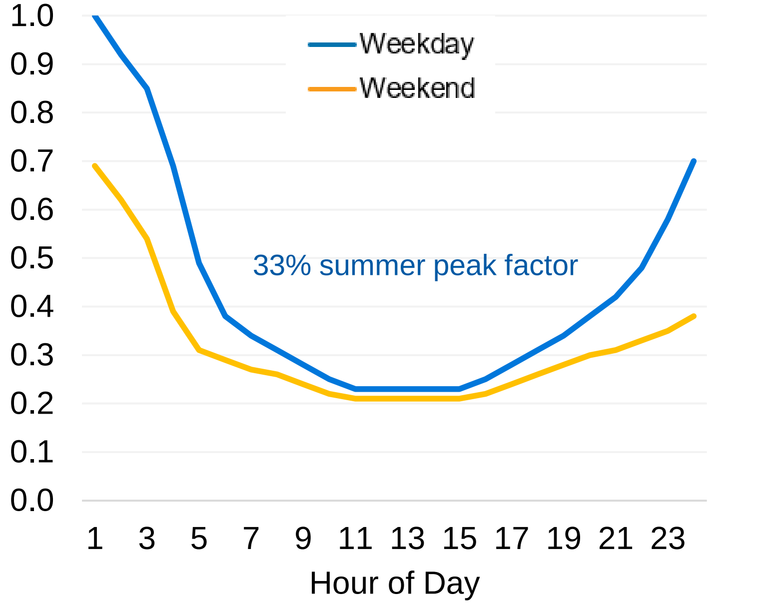
Different hourly EV charging profiles may be used according to scenario and EV class

Residential EV Charging Profile – Low Penetration[1]



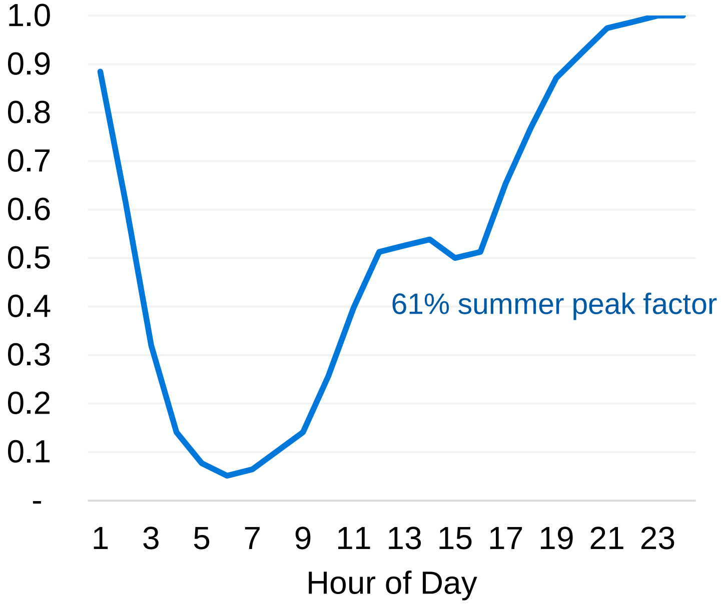
- NIPSCO's 2018 EV pilot program
- Significant off-peak demand

Residential EV Charging Profile – High Penetration[2]



- Some adopters under high penetration scenarios introduce more diversity and may not be as responsive to TOU rates or other measures

Medium & Heavy-Duty EV Charging Profile – All Scenarios[3]



- Trucks, transit vehicles, and commercial vehicles tend to have demand during the day and afternoon

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

Northern Indiana Public Service Company LLC
2021 Integrated Resource Planning
Public Advisory Meeting #1
SUMMARY

March 19, 2021

Welcome and Introductions

Ms. Alison Becker, Manager, Regulatory Policy opened the virtual meeting by providing a safety moment on psychological safety, discussing the Webex meeting protocols, and walking through the agenda. She then introduced Mike Hooper, President and COO of NIPSCO to kick off the meeting.

Overview of Public Advisory Process
Mike Hooper, President and COO, NIPSCO

Mr. Hooper began by welcoming participants and provided an overview of NiSource and NIPSCO and a high-level discussion of NIPSCO's ongoing generation transition plan.

Participants had the following questions and comments, with answers provided after:

- What does "best cost" mean?
    - It is similar to how you might think about any type of investment in your own house or business. Sometimes absolute lowest cost meets the need, but that is not always the case, so you look in a comprehensive way. For example, the lowest cost faucet may not meet the need that you have for that faucet or level or reliability or functionality and you may choose another faucet. So this is why NIPSCO is careful to say best cost and why we rely on all these pillars.

2018 NIPSCO IRP Action Plan Update / 2021 Continuous Improvements
Fred Gomos, Director Strategy & Risk Integration, NiSource
Pat Augustine, Vice President, Charles River Associates ("CRA")

Mr. Fred Gomos introduced the section by reviewing NIPSCO's 2018 IRP short-term action plan and outlining the progress to date, including actions associated with the retirement of the RM Schahfer ("Schahfer") coal plant, replacement with new renewables, and monitoring of market developments. He provided an overview of NIPSCO's existing and future generation projects, including the set of new renewable projects currently under development and before the IURC.

Mr. Gomos then provided an overview of NIPSCO's overall planning approach and a detailed review of how feedback from the 2018 IRP Director's Report motivated the 2021 IRP's improvement plan. He noted planned improvements around the load forecast, scenario and sensitivity modeling, risk analysis, and monitoring of MISO market rules changes.

Mr. Patrick Augustine expanded upon Mr. Gomos' commentary on MISO market rules changes by outlining key reliability considerations for the 2021 IRP in the context of MISO's recently released Renewable Integration Impact Assessment report.

Mr. Augustine closed the section by reviewing NIPSCO's five-step resource planning approach in more detail, including the market modeling tools that will be deployed, new enhancements associated with uncertainty modeling, and a preliminary integrated scorecard framework. He noted that enhancements to NIPSCO's IRP scorecard were likely to be made in the areas of broader accounting of costs, a broader uncertainty assessment, and expansion of the reliability metrics.

Participants had the following questions and comments, with answers provided after:

- Did last year's passage of Indiana House Bill 1414, which focused on coal plant closures, affect any NIPSCO plans to retire its plants?
  - No it did not affect our generation decisions.
- What percentage of contractors are black owned enterprises?
  - NIPSCO can follow-up with more detail on this. This has been an area we have focused on – supplier code of conduct focuses on diverse hiring. Would be happy to discuss in a 1:1.
- Do any of the requests for proposals ("RFPs") call for local hire or fair chance? Why cannot NIPSCO close Michigan City Generating Station ("Michigan City") sooner? And will the plant in fact close/retire and not convert?
  - Regarding Michigan City – that is why we step through this process. NIPSCO steps through this and allows the analysis and scorecard perspective to set the dates. Based on the 2018 IRP – the current retirement is in 2028 and the Company will test that question in this process. At the end of this process, there will be some decision with respect to Michigan City.
- When planning for the future how does NIPSCO account for community impact such as health concerns and job opportunities?
  - For health, the Company considers emissions and the ability to reduce emissions on the scorecard. NIPSCO also considers job opportunities on the scorecard, which records how many jobs are driven by the generation portfolio. The fact that the current renewable projects are home grown with local contractors is evidence of how the transition is impacting this metric. We have over 25,000 direct jobs as a result of the current plan.
- Will there be any intentionality to assure some portion of solar is built locally so vulnerable and people in need of jobs with transit challenges can be hired and work? Will you consider building solar in East Chicago, Indiana in Zone 1?
  - Certainly NIPSCO is considering local projects. Given that the Company is evaluating projects that come from developers, to some extent the Company has full control, since a project needs to be viable and cost-effective for customers. However, NIPSCO is working with developers locally, such as in La Porte County, and if there are developers or projects that are happening in East Chicago, NIPSCO is happy to hear about them. For example, a couple of years ago the Company did

collaborate on potential for community solar projects, and NIPSCO is open to discuss those with local municipalities.

- Will Michigan City retire or convert?
  - The plan is to retire Michigan City in 2028 – NIPSCO will test that question as part of this IRP.
- LaTonya: How are you working with Michigan City and Jasper County residents to ensure their needs/concerns are met during the retiring process?
  - Jasper County has been a constructive partner with respect to transition plans. The Dunn's Bridge solar and storage project will be located in Jasper County, and we are working with them and La Porte County on the transition plans.
- Does NIPSCO have a plan for utilization of the Schahfer 14 and 15 transmission rights?
  - This is to be decided. Those interconnections are tied to that facility, so NIPSCO will continue to use those interconnections and then adjust at the point of retirement. The recent news regarding earlier retirement of Units 14 and 15 does not change the approach.
- On Slide 19 under Environmental Sustainability, there is no mention of traditional pollution: soot, NOx, and SOx. These affect local communities. Should not this be explicitly acknowledged as a consideration in resource planning?
  - These pollutants are often highly correlated to CO2 emissions, which is part of NIPSCO's scorecard under the Environmental Sustainability objective. Although NOx, SO2, and particulate matter may not be included on the final scorecard, such reports can be produced as part of the portfolio analysis process and provided to stakeholders as requested.
- Are you planning to model more than one resource adequacy ("RA") construct?
  - Yes, most likely. The model may not be able to predict all the nuances associated with forthcoming changes to the capacity construct, but the Company will likely develop replacement portfolios based on different constructs. For example, there may be some portfolios that are based on the current summer-only RA construct and then look at others that also meet winter reserve margins. Although the Midcontinent Independent System Operator, Inc. ("MISO") may expand the construct to four seasons, the analysis will likely start with summer / winter. In the commodity price section that we will review later, we will show outlooks for summer and winter capacity prices.
- Can you explain a bit more what "MW weighted duration of generation commitments" means? Under Resource Optionality?
  - This was a metric introduced in 2018 as a way of proxying how flexible a portfolio is to respond to change. It is measured as the weighted average of remaining commitment years for resources within the portfolio, and the duration of commitment gives a sense of how much capacity is "locked up" over time. For example, shorter-term purchase power agreements ("PPAs") would have lower commitment durations. In general the lower the metric, the more flexible the portfolio is, but this is just one way to evaluate different strategies as part of the integrated scorecard.
- Which variables will NIPSCO sample to determine the 95th percentile conditional value of risk? Renewable output and market price?
  - That metric will be based on the 95th percentile of the net present value of portfolio revenue requirements. With regard to the stochastic variables that will feed into that analysis, NIPSCO is planning to assess commodity prices (natural gas and power)

and renewable (wind and solar) output. The idea is to have correlated stochastic inputs for those variables run through the models to calculate the corresponding portfolio costs across hundreds of iterations. This portfolio cost is what will ultimately go into the scorecard.

- How will you address inequitable harmful emission reductions, Green House Gases ("GHG")/CO2 and other emission reductions? As we look at equity how will you ensure equitable reduction so one demographic is not holding all of the CO2 versus another demographic?
    - The scorecard will take an aggregate view of CO2 (with potential separate reporting of other) emissions. Additional reports could be developed and reviewed if there is a desire to look at more granular impacts, although the IRP process tends to focus at a higher level. With NIPSCO's transition to renewables – moving us towards 90% reduction in GHG by 2030 – significant emission reductions will be happening over time. It should also be noted that CO2 is a little different than other pollutants, since it can be characterized as a global pollutant. Proximity to source is not as relevant for CO2 as it may be for other traditional pollutants, since it disperses globally.
- With regards to the economic impact metrics, would you consider including jobs at contractors, not just at NiSource? For example, I would guess a lot of the jobs related to your demand side management programs would not be counted under the current metric?
    - NIPSCO can consider that, and there may be ways to look at both NIPSCO employees and contractors. From a scorecard perspective, it is cleaner to focus on NIPSCO employees, but we can look to see if there is a way to look at a broader set of job numbers. This may be a good topic for a 1:1.
- Did NIPSCO say that CO2 is not a pollutant?
    - NIPSCO clarification[1]: That comment noted that CO2 is often characterized as a global pollutant, not a local pollutant. NIPSCO is happy to discuss this further in a 1:1.

Key Assumptions Update: Commodity Prices
Robert Kaineg and Pat Augustine, CRA

Mr. Augustine introduced the section by outlining CRA's fundamental market modeling structure, including the drivers of fundamental fuel forecasting and the overall architecture for fundamental power market modeling. He then introduced Mr. Robert Kaineg to review the fuel price fundamentals.

Mr. Kaineg provided a summary of CRA's fundamental natural gas forecasting approach, the Natural Gas Fundamentals ("NGF") model structure, and key drivers of natural gas pricing. He summarized key supply side drivers in detail, including natural gas resource size, well productivity, fixed and variable well costs, natural gas liquids and condensate value, and associated gas volumes. Mr. Kaineg then summarized key demand side drivers, including domestic demand from the power/residential/commercial/industrial sectors and international demand from LNG and pipeline exports. He then presented the reference case gas price

[1] Note that the person who asked the question indicated that she had to drop off before an answer to this question could be provided during the session, but that she would appreciate the one-on-one and the answer to the equitable CO2 reduction. NIPSCO is providing this clarification in writing as part of this meeting summary, although it was not noted verbally in the meeting.

forecast. Mr. Kaineg closed his presentation with an overview of CRA's coal forecasting process, including a coal demand outlook and the resulting coal price forecasts for major U.S. basins.

Mr. Augustine then presented CRA's reference case carbon policy expectations and the associated reference case carbon price to be used in the 2021 IRP. He then presented an overview of the MISO market and CRA's power market fundamental modeling approach. Mr. Augustine closed the section by presenting CRA's outlook for the MISO market for the reference case, including the expected evolution of the energy mix (including at an hourly level); annual, monthly, and hourly market price views; and market capacity price expectations.

Participants had the following questions and comments, with answers provided after:

- For any scenarios with either carbon emissions constraints or a carbon tax, how would that be reflected in your gas price forecasts (i.e. as a downstream impact increasing market prices and potentially decreasing gas prices (because of lower demand))? Or is there a scenario in which your model might return a concomitant, increasing price of gas and market energy?
    - There are multiple ways that CO2 constraints could impact prices. It is possible that a CO2 regulation at the wellhead could include a CO2 charge that directly increases price. However, we do not contemplate embedding such a possibility in our scenario analysis. Somewhat relatedly, a policy could regulate other parts of the natural gas production process – methane leaks for example. Carbon regulation could also restrict gas production or raise the environmental-related costs associated with gas production. Finally, carbon regulation could impact demand for gas, as you noted. To answer the final part of your question, yes, we are contemplating a scenario in which carbon prices/regulation are high and natural gas prices are high (due to increased regulatory pressure on production) even if demand for gas is lower than the reference case. This will be discussed further in the May stakeholder meeting.
- Is NIPSCO committed to a full retirement of the Michigan City, or is NIPSCO considering plans to convert the plant to fracked gas?
    - Right now, NIPSCO laid out its plan with respect to retirement of the facility in 2028. Part of this 2021 IRP process will be to evaluate that plan to either confirm or make a different decision. Right now the plan is to retire in 2028.
- How does your forecast compare to the Annual Energy Outlook ("AEO") price forecast?
    - The reference case is higher than the AEO reference case, driven largely by the "poor-heavy" view on the resource base. The price outlook is not significantly different over the long-term, but it is higher.
- Gas price forecasting – model is accounting level – not operational level. Is that correct, and how does the optimization work with Aurora?
    - Yes, there is an optimization component to meet aggregate demand into the future. For electric demand, there is an iterative process with Aurora and NGF. CRA exports the gas price forecast out of NGF and into Aurora and then re-dispatches to get gas demand that goes back into NGF to eventually arrive at convergence. Once prices stop moving significantly, CRA stops the iterations.
- How does the model treat whether there is enough capacity in the gas pipeline to transmit the gas that is demanded in Aurora optimization?

  - o The NGF model does not take into account transportation constraints, so this is not considered. NGF is purely a price model.
- How do you know whether you can transport gas during a peak event – how do you gut check that?
  - o We also use GPCM (Gas Pipeline Competition Model) to assess transportation and local gas basis. So NGF does not capture transportation constraints, but we check things through GPCM.
- How does your reference case power price forecast compare to NIPSCO's forecast in its 2018 IRP?
  - o The 2021 IRP reference case forecast is quite similar overall to the reference case forecast from the 2018 IRP, although it is a little lower. The carbon price is the same as what was used in 2018, with some minor inflation adjustments. The natural gas price forecast has come down a little bit vs. 2018, and the amount of renewables has increased. These factors both tend to reduce the power price, and more renewable generation generally results in a convergence between peak and off-peak prices. So overall, the average prices have come down by a few dollars per MWh and price shapes have changed, but the forecasts are not too fundamentally different.

Key Assumptions Update: Load Forecast
Derya Eryilmaz and Pat Augustine, CRA

After Mr. Gomos introduced NIPSCO's load forecasting enhancements for the 2021 IRP, Ms. Derya Erylilmaz provided an overview of the load forecasting methodology and a description of how the team developed the core NIPSCO load forecast. Ms. Eryilmaz provided a detailed discussion of the econometric analysis that was performed, including a summary of the economic, weather, retail rate, and demographic variables used to develop forecasts for the residential, commercial, and industrial sectors. Ms. Eryilmaz then presented customer count forecasts, the impact of NIPSCO's new industrial service structure on industrial demand, the preliminary reference case sales forecast, and the preliminary summer and winter peak demand forecasts.

Mr. Augustine then presented an overview of NIPSCO's approach to assessing customer-owned distributed energy resource penetration through CRA's PenDER model. He outlined the methodology, key model inputs, and reference case projections for distributed energy resource ("DER") installations, DER energy, and DER contribution to peak demand. He then provided a review of key drivers of DER penetration uncertainty and a range of indicative DER penetration outcomes.

Mr. Augustine then presented an overview of NIPSCO's approach to assessing electric vehicle ("EV") penetration in the service territory. He provided a review of the methodology, key assumptions and data sources, and the base case outlook. Mr. Augustine closed the section by outlining scenario considerations and providing a range of low, medium, and high EV penetration cases for the light duty vehicle (residential), medium duty vehicle (commercial), heavy duty vehicle, and transit sectors.

Participants had the following questions and comments, with answers provided after:

- Were various demand scenarios forecasted (not just reference)? It seems that EV penetration or electrification in general can have huge impacts.

- Right now, these slides describe the econometric baseline forecast; however the adjustments, including those associated with EVs and electrification, will be discussed shortly.

- For reference case what percentage of heat pump adoption by residential customers was used?
  - Again, the adjustments for electrification will be discussed later. The core forecast is based on an econometric analysis and not an end-use assessment.
- When the Citizens Action Coalition, Inc. (CAC) had a meeting with NIPSCO about this IRP, we discussed the load forecast and one concern was whether natural energy efficiency growth is accounted for in the forecast, and it sounds like it is not, unless it was embedded in in historical data. We talked about ways to try to capture that instead of as an adjustment – does CRA have a sense of what would be needed for that, and is this accurately describing your methodology?
  - CRA has explicitly removed the impact of historical energy efficiency programs from the econometric analysis and otherwise pick up trends in expected usage per customer in the regression analysis coefficients. CRA then works with DSM experts to identify future programs for evaluation.
  - Also note that we have included an appendix slide in this presentation with usage per customer forecasts. Any programmatic historical DSM has been taken out to cleanly evaluate usage per customer trends, and you will see they are generally expected to decline into the future even before new DSM programs are considered. This is shown in slide 103. However, CRA does want to evaluate whether these trajectories are reasonable and we are planning to follow up with GDS (the DSM consultant) to see if they have any further perspective or data on this topic. Note that this is a preliminary forecast and not final, so if there is reason to make small adjustments, those will be considered.
- Talking to GDS is a good idea – same data for energy consumption by NIPSCO customers would need to be accounted for in the Market Potential Study. EIA also provides energy efficiency forecasts as well.
  - Follow-up on this topic is good. CAC has been great partners as we work through the process, and to the extent another discussion is needed regarding refinements, we can. NIPSCO will work with CAC on a follow up discussion.
- NIPSCO's Order for its first Feed-in Tariff ("FIT") was July 13, 2011. Therefore, we will be approaching in the mid-term the expiration of those initial 15 year FIT contracts. How do you envision addressing those DERs?
  - Note that beyond these DER projections, the portfolio modeling will include separate FIT contract expectations. CRA does have an outlook for current customers in different categories, and those are carried through the modeling. Beyond the expiration of those tariffs, it is possible that FIT customers can fit into another tariff or otherwise deploy DER to serve their own load. Overall, the purpose of this DER analysis is to develop a range of potential outcomes based on policy, including FIT and net metering, and economic scenarios.
- On slide 70 why is solar so slow to lower net peak - roughly 4 MW of install for one MW lower peak?
  - This goes to the peak credit expectation changing over time. In the early years, the ratio is closer to 2 to 1, while in the later years, this evolves closer to 4 to 1. This is because there is an expectation that more and more solar in the broader market will result in the

MISO net peak shifting later in the day. Thus, solar resources have less value in meeting peak over time, and we expect this will be approximately 25% of nameplate capacity by 2040.

- If the compensation for net metering excess is based on time-of-day in the future, then it is possible that solar installations might be designed to face west more than south. Is that being considered?
  - No, that is not specifically being accounted for, since this framework is not intended to track specific customers by site, but is designed to capture an average perspective. Incentives could change behavior, which in turn could slightly change the net capacity credit, but probably not significantly enough to change the overall impact being assessed in the IRP scenarios.
- Regarding the PenDER tool, has CRA done any work to look at how solar-storage costs and benefits impact the system wide results? Penetration and capacity in particular.
  - To date CRA has not specifically looked at storage as part of a DER solution, but it is a real possibility that over the planning horizon, distributed storage may come into the market, and CRA is looking at evaluating how that can fit into one of the scenarios. If you assume customers are able to pair their solar with storage, they could optimize its energy and capacity value. This complexity has not been incorporated in the modeling to date, but we will consider how to fit it into the scenarios. The overall point regarding stronger capacity value over time is consistent with the last question, so CRA will look at taking this feedback into account
- Rather than fixing the shape of EV charging, would you not want to model it as a flexible load responsive to price (where possible) so that you are capturing the changing dynamics of price by hour and by season you discussed previously capturing the costs/benefits dynamics?
  - This is a valid consideration, although there are several uncertainties that make this difficult to assess. First, it is unclear how responsive how all customers would be to price signals. Second, granular price responsiveness requires smart metering infrastructure in place and rate structures to be implemented. So far, CRA has developed a few different charging shapes which are documented in the appendix of the presentation. Within these shapes, a lot of the load is already pushed to periods of time that are not likely to be highest priced. However, hourly price shapes could be different across scenarios as market prices evolve. Fully dynamic charging behavior may be difficult to deploy, but different ways of parameterizing shapes can be considered.
- The CAC committed to sending a report to CRA that touches on the price responsiveness of EV charging.
- On slide 78 it looks like the low scenario is mapped to the Base. Is that correct?
  - That is correct, and the Base is in line with MTEP Future 1. This projection is consistent with a moderate, but steady increase in EV penetration and CRA will be mapping it to the reference case. The analysis will also show medium and high cases on this slide, which will be mapped to our alternative scenarios that have stricter environmental policy pressure and a greater push towards electrification. The band covers the high end well and these ranges are best incorporated in alternative scenarios.
- For electric vehicles in general will the modeling take into account any efforts by NIPSCO to shift load to off-peak or any other type of incented behavior?

    - The pilot program referenced before was based on some time of use charging behavior, with most load shifted off-peak. Given the interest in this topic, CRA will review whether it would be appropriate to adjust charging shapes in the modeling without too much complexity.
- What is assumption for life of an EV? Is it assumed that all EVs purchased in 2021 are still around in 2040 or some fraction?
    - Light duty vehicles are deemed to have a 15-year lifespan in this analysis, while the assumed lifespan is shorter for commercial vehicles.

Treatment of Uncertainty – Introduction
Pat Augustine, CRA

Mr. Augustine opened the section with a review of NIPSCO's approach to modeling uncertainty through complementary scenario-based and stochastic analyses. He then introduced NIPSCO's four major planning scenarios for the 2021 IRP: (i) Reference Case; (ii) Status Quo Extended; (iii) Aggressive Environmental Regulation; and (iv) Economy-wide Decarbonization / Electrification. He explained the expected environmental policy drivers across scenarios and provided a broad overview of directional changes in gas prices, carbon prices, federal tax incentives, load growth, and solar capacity credit across scenarios. Mr. Augustine closed the section with a brief preview of NIPSCO's stochastic analysis approach, including the incorporation of commodity price (natural gas and power) and renewable output uncertainty.

Participants had the following questions and comments, with answers provided after:

- In the Aggressive Environmental Regulation Scenario, do you know yet what the net zero targets would be and will you model a less than zero final target or a zero target plus whatever "offsets" you think might be available?
    - The analysis is likely going to assume that some amount of offsets will be available, although it is an uncertainty about how many. In preliminary analysis, CRA is finding that between 90 and 95% of the MISO power generation will be zero emitting in the Aggressive Environmental Regulation scenario, implying that 5-10% of the generation may have to be offset, although CRA does not expect to perform a specific analysis of what offsets are available.
- How do you anticipate a net zero future affecting sales of renewable energy credits?
    - The ultimate policy construct for a net zero future could result in a carbon price, a clean energy standard, or other incentives. If a clean energy standard, this might result in new markets for renewable energy credits, including at the federal level, although CRA has not specifically analyzed prices or NIPSCO sales opportunities yet.
    - It is expected that renewable energy credit demand will go up in a scenario with a binding standard, but the availability of credits and policy design will have a huge impact on price.
- So CRA proposes to sample these variables based on historical correlations and not look at the direct drivers of price and output volatility?
    - That is partially correct. CRA is going to be developing distributions for fuel, power, and renewable output based on historical data, although this process does not necessarily attempt to assess detailed drivers such as specific weather events, plant outages, etc. However, there is limited information available regarding renewable output/power price correlation based on the relatively limited amount of renewable generation (particularly

solar) currently in the market, so the analysis will simulate correlations going forward based on fundamental market modeling. So to summarize, the analysis will combine historical statistical analysis with some forward correlation analysis to develop iterations for daily gas prices, hourly power prices, and hourly renewable output.

- That is not necessarily a bad thing because temperature for example, is not the only driver of renewable output.
  - It is difficult to identify specific drivers of renewable output or market price behavior, so the objective is to capture a range based on historical data and a forward market view. The approach aims to arrive at a happy medium between reliance on history and expectations for the future.
- The CAC indicated it might be interested in a further discussion, which NIPSCO said it was happy to facilitate.

2021 Stakeholder Advisory Process
Erin Whitehead, Vice President Regulatory & Major Accounts, NIPSCO

Ms. Erin Whitehead provided an overview of the 2021 IRP Stakeholder Advisory Meeting Roadmap by highlighting key questions, content, and meeting goals for the upcoming sessions. She then announced that NIPSCO will conduct an RFP as part of the IRP process to help inform long-term market planning and identify projects for transaction. She also thanked all of the participants for their good questions and involvement in the meeting.

Participants had the following questions and comments, with answers provided after:

- When are you issuing the 2021 RFP?
  - The target date is shortly after the second meeting, which is scheduled for May.

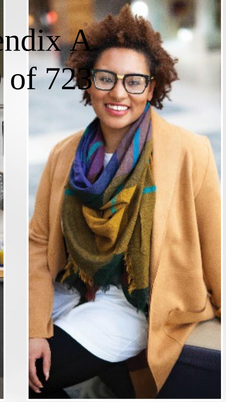
March 19, 2021 NIPSCO Public Advisory Process Meeting Registrations	
First Name:	Last Name:
Emily	Abbott
Denise	Abdul-Rahman
Lauren	Aguilar
Anthony	Alvarez
Matt	Alvarez
Sam	Anawalt
Shawn	Anderson
Linda	Anguiano
Cynthia	Armstrong
Laura	Arnold
Pat	Augustine
James	Aycock
Kim	Ballard
Vernon	Beck
Anne	Becker
Matt	Bell
Stewart	Bender
Dana	Berkes
Mahamadou	Bikienga
Marc	Blanchard
Joseph	Bocanegra
Peter	Boerger
Bradley	Borum
Wendy	Bredhold
Richard	Calinski
Andy	Campbell
Kelly	Carmichael
Morgan	Chang
MariannMariannÃ¾	Clark
John	Cleaveland
Tom	Cofer
Jeremy	Comeau
Denise	Conlon
Jordan	Covely
AnaÃ«lle	Croteau
Kim	Cuccia
Patrick	Daou
Carol	Deardorff
Peter	Djukic
Jeffery	Earl
Mike	Eckert
Lora	Fosberg
Adam	Gale
Richard	Gillingham
Fred	Gomos

March 19, 2021 NIPSCO Public Advisory Process Meeting Registrations	
First Name:	Last Name:
Doug	Gotham
Mark	Gracyk
Rob	Greskowiak
Paul	Griffin
Stacie	Gruca
Jason	Haas
Wilfred	Hackbush
Andrew	Hamilton
Joni	Hamson
Corey	Harper
John	Haselden
Ryan	Heater
Robert	Heidorn
John	Henderson
Megan	Henning
David	Hicks
Stephen	Holcomb
Scott	Houldieson
Hao	Huang
Jim	Huston
Ben	Inskeep
Andrew	Kain
Robert	Kaineg
Michelle	Kang
Will	Kenworthy
Nick	Kessler
Mickey	Koehler
Nancy	Kolasa
Stefanie	Krevda
Nicole	Kritzer
Karol	Krohn
Natalie	Ladd
Abraham	Lang
Tim	Lasocki
Robert	Leah
Shelby	Leisz
Bryan	Likins
James	Loewen
Caleb	Loveman
Allison	Lowitz
Liwei	Lu
Wendy	Lussier
Greg	Martin
Christian	Martinez
Debi	McCall

March 19, 2021 NIPSCO Public Advisory Process Meeting Registrations	
First Name:	Last Name:
Michael	McNeley
Emily	Medine
Zachary	Melda
Tony	Mendoza
Nick	Meyer
Erik	Miller
David	Nderitu
Tim	O'Hara
David	Ober
Marc	Okin
Kerwin	Olson
Patrick	Orth
April	Paronish
Richard	Pate
Bob	Pauley
Pamela	Paultre
Tim	Phillips
Mark	Pruitt
Sarah	Quinn
Dennis	Rackers
Brett	Radulovich
Brett	Radulovich
Jeff	Reed
Adam	Rickel
Robert	Ridge
Tonya	Rine
Tonya	Rine
Jonathan	Roberts
Rosalva	Robles
LouAnn	Rone
Ed	Rutter
Zach	Schalk
Cliff	Scott
Robert	Sears
Brent	Selvidge
Rob	Seren
William	Shaver
Laura	Sigward
Regiana	Sistevaris
Barbara	Smith
Jennifer	Staciwa
Karl	Stanley
Sarah	Steinberg
George	Stevens
Ronald	Talbot

March 19, 2021 NIPSCO Public Advisory Process Meeting Registrations	
First Name:	Last Name:
Margaret	Tallmadge
Susan	Thomas
LaÂ’Tonya	Troutman
Maureen	Turman
Edward	Twarok
Darian	Unruh
Will	Vance
Consuelo	Vargas
Chris	Vickery
Nathan	Vogel
John	Wagner
Nancy	Walter
Jennifer	Washburn
Erin	Whitehead
Ryan	Wilhelmus
Ashley	Williams
J. Scott	Yaeger
Paul	Yoder
Shu	Yuan
William	Zednik






NIPSCO

A NiSource Company

2021 NIPSCO Integrated Resource Plan

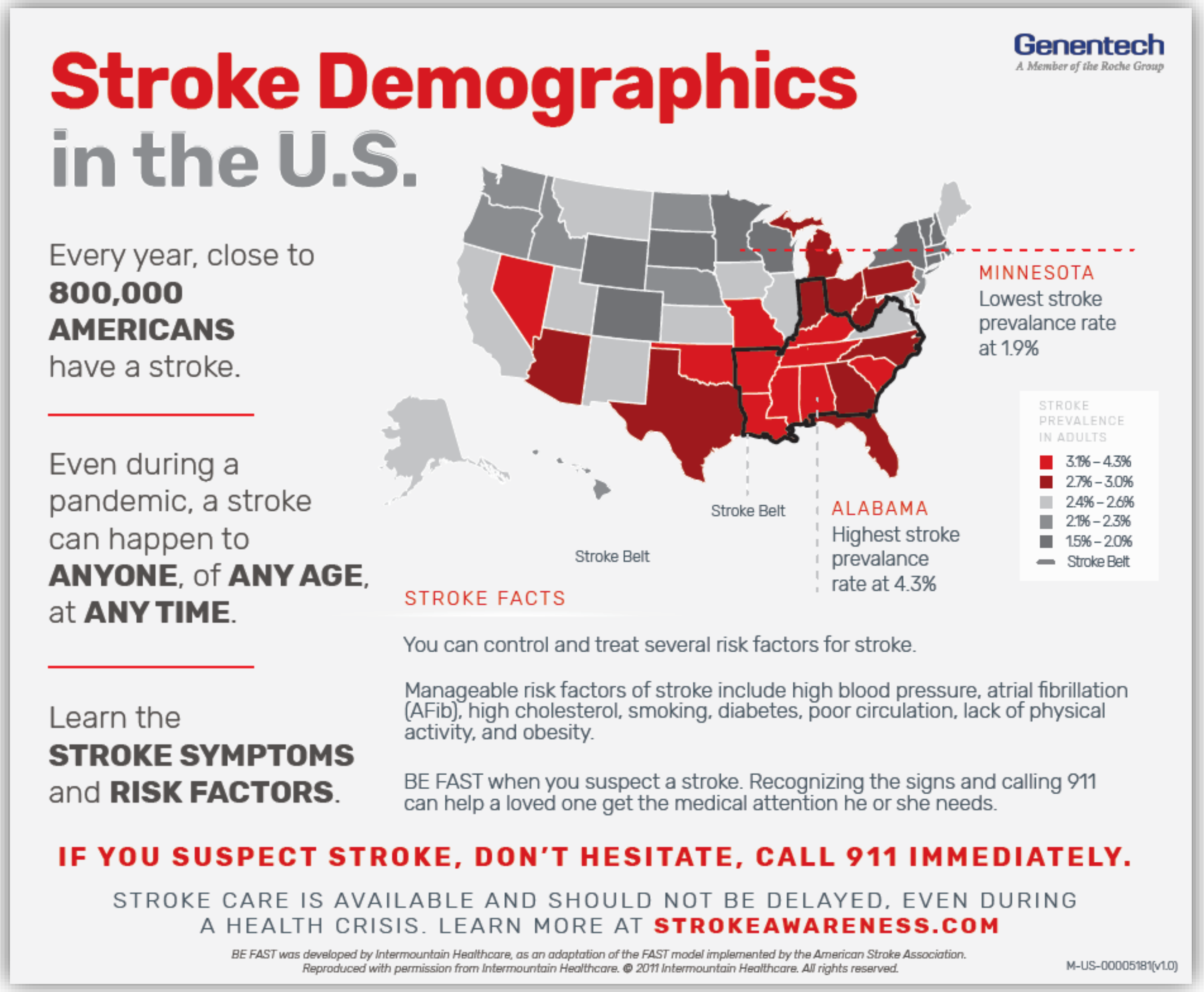
NiSource

Second Stakeholder Advisory Meeting

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

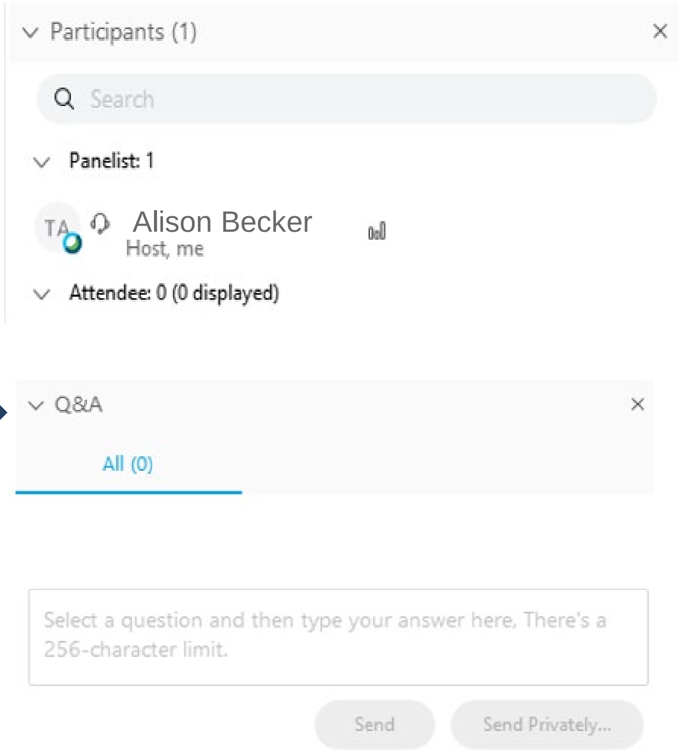



SAFETY MOMENT: MAY IS STROKE AWARENESS MONTH



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

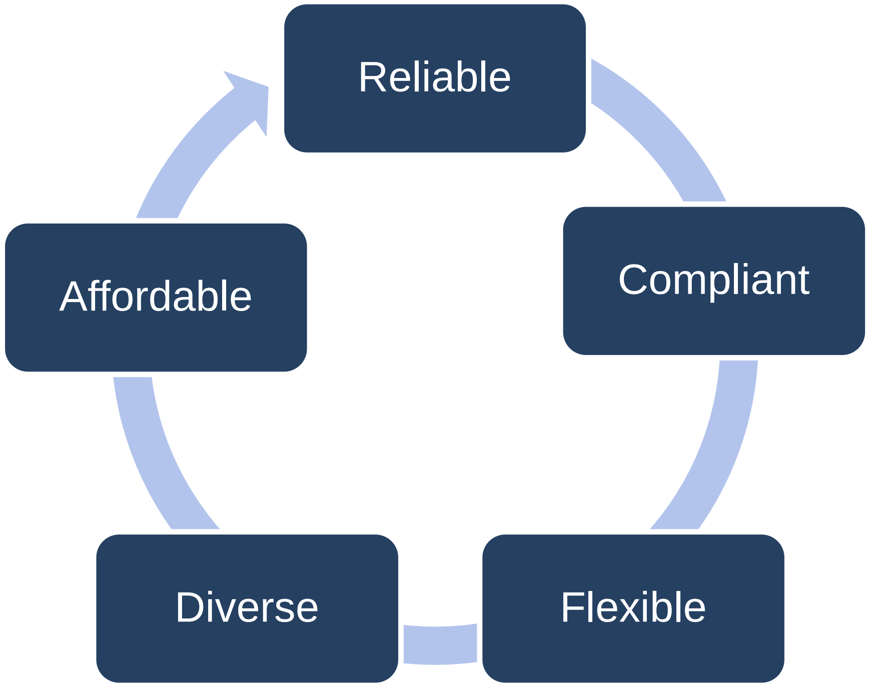
NIPSCO'S PUBLIC ADVISORY PROCESS UPDATES FROM LAST MEETING

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 CO2 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 CO2 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** **Discussed Further** 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

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?

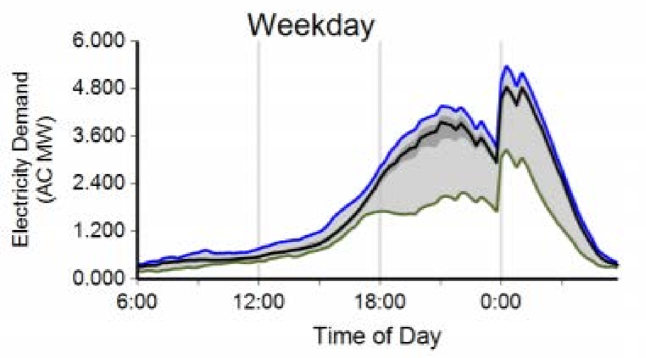
NIPSCO Response: The proposed shapes are largely consistent with the findings of the Department of Energy (DOE) study shared by stakeholders and remain appropriate. However, a shift of charging load to later overnight hours would help incorporate changing market price expectations over time

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)

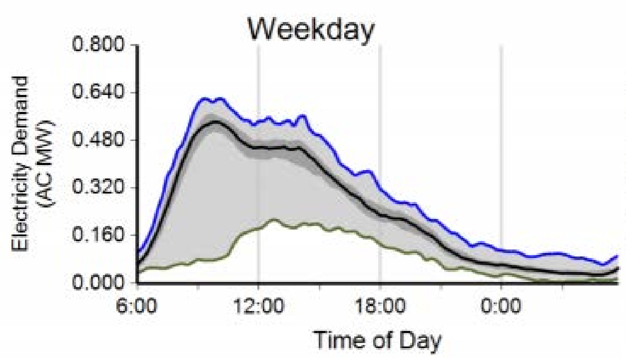
Residential Level 2



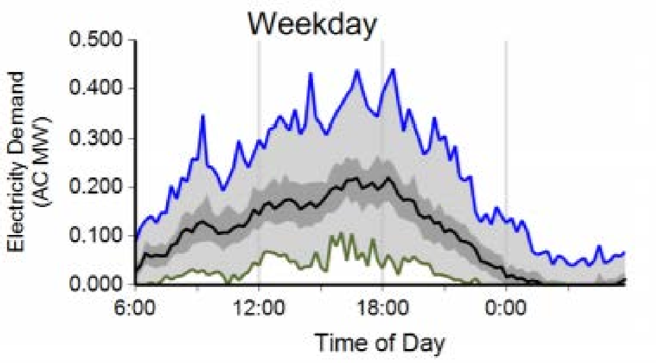
Residential shape generally conforms with NIPSCO's Time of Use Charging Shapes

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



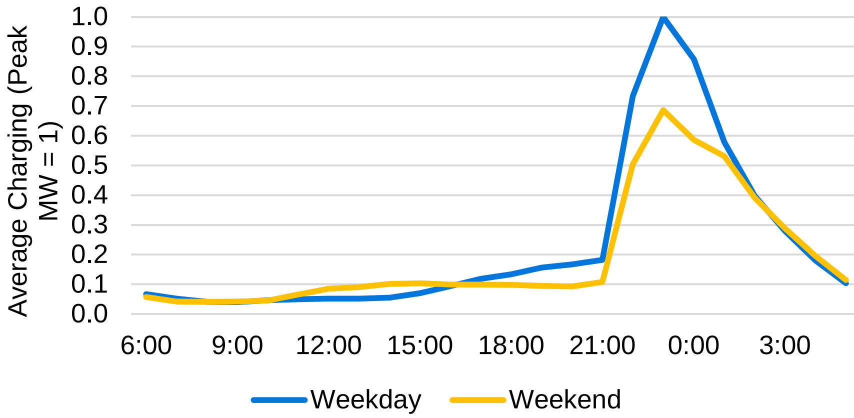
DC Fast Charger



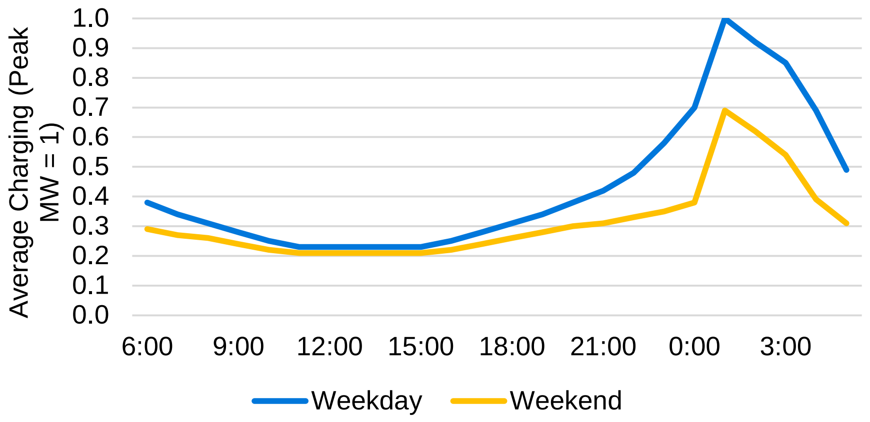
https://www.energy.gov/sites/default/files/2014/02/f8/evproj_infrastructure_q22013_0.pdf

Charging Shapes Provided in Workshop #1

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



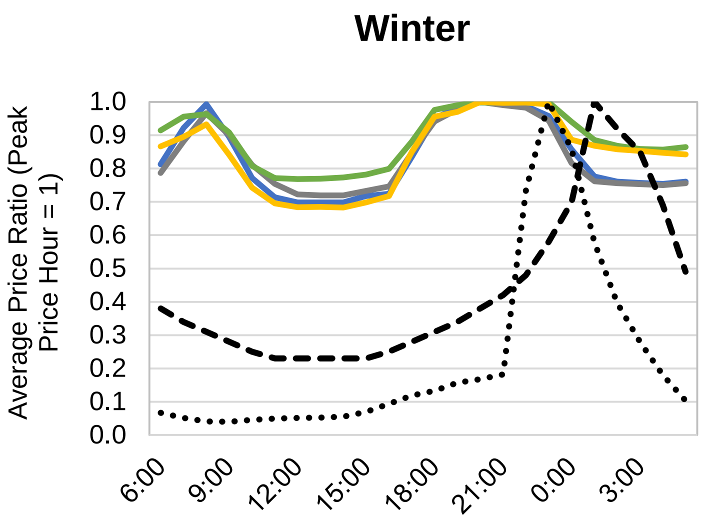
Residential EV Charging Profile – High Penetration[2] (DOE EV Project Study)

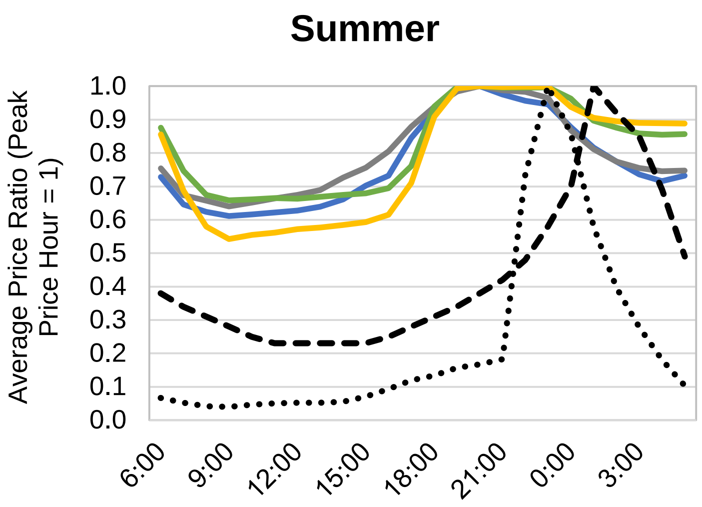


Sources
1. NIPSCO EV Pilot Program 2018 Charging Data
2. Based on DOE (2014) - https://www.energy.gov/sites/prod/files/2014/02/f8/evs26_charging_demand_manuscript.pdf
3. Based on NREL (2016) - https://www.nrel.gov/docs/fy17osti/66382.pdf

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

Stakeholder Workshop #1





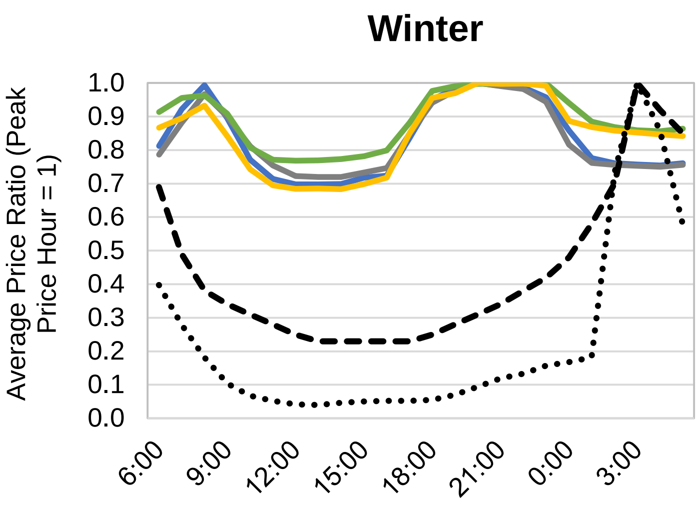
Reference

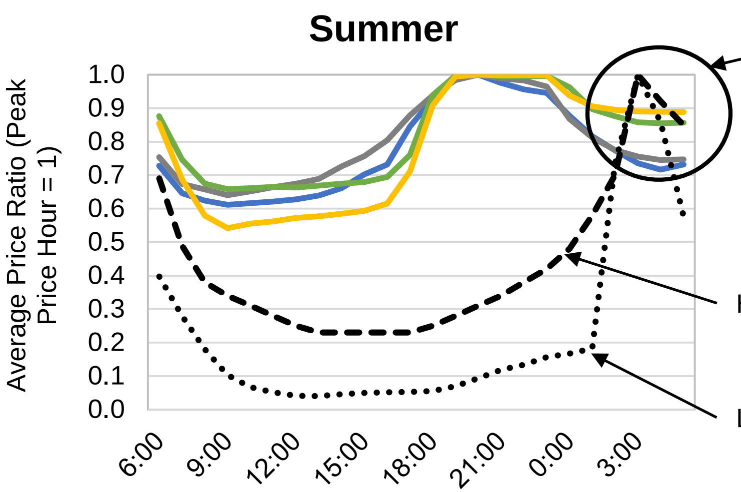
Status Quo Extended

Aggressive Environmental Regulation

Economy-Wide Decarbonization

Revision for Long-Term based on Feedback (new)





High and Low Penetration shapes shifted by 3 and 4 hours (respectively) to match off-peak pricing during early morning hours

High Penetration EV

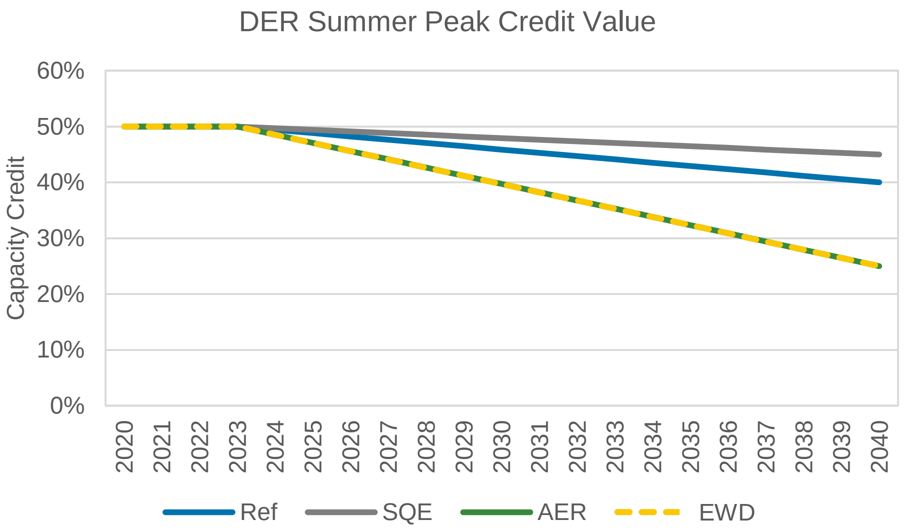
Low Penetration EV

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.

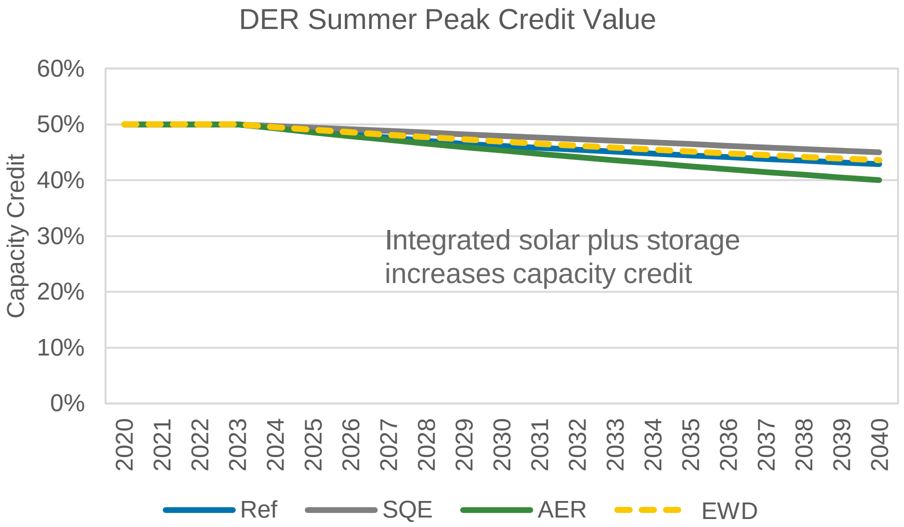


Based on: MISO RIIA Summary Report, Figure RA-18 for Distributed PV
https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

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:

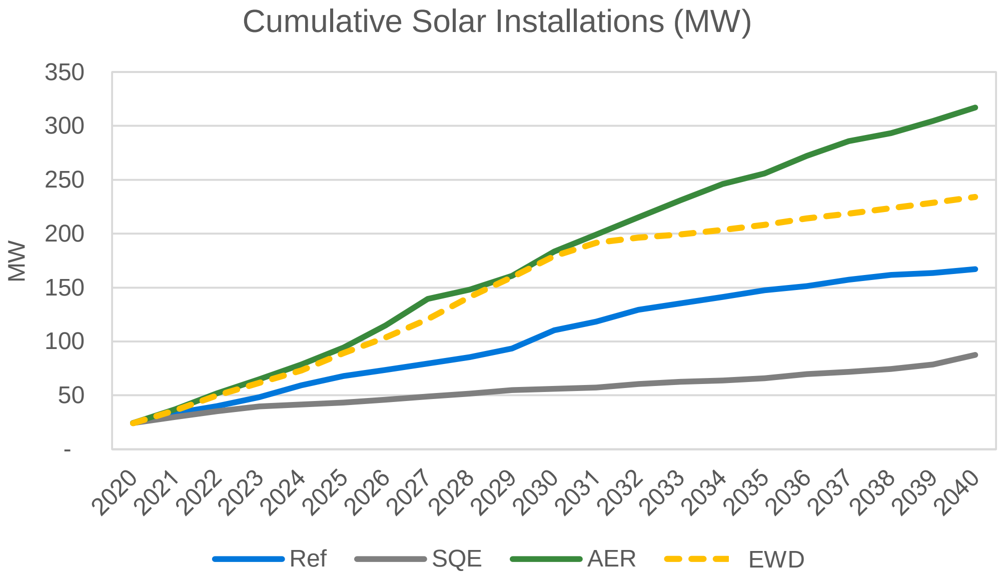
- Ref: 5%
- AER: 25%
- EWD: 33%

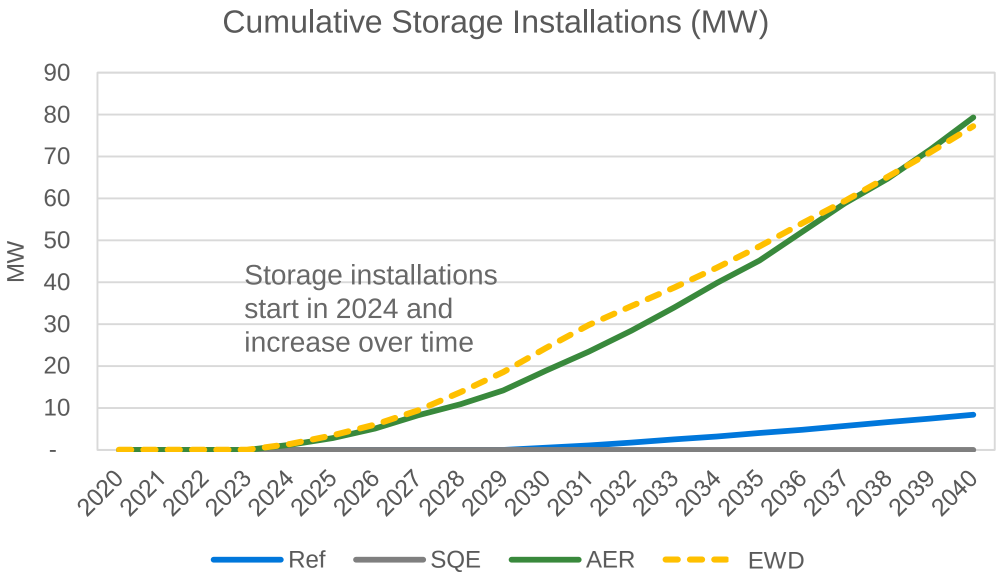


Ref = Reference; SQE = Status Quo Extended; AER = Aggressive Environmental Regulation; EWD = Economy-Wide Decarbonization

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

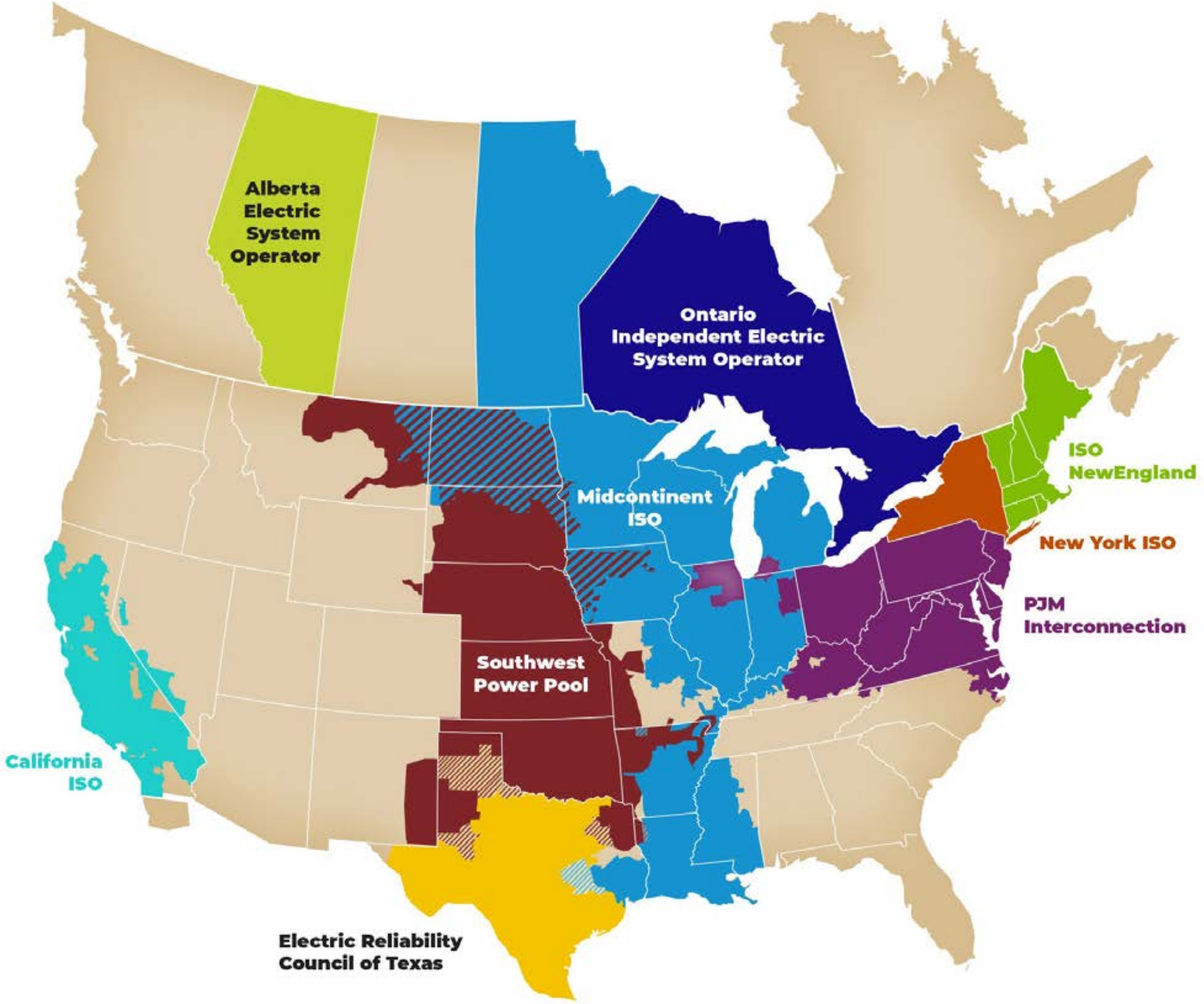
- Incorporation of renewable output uncertainty
- Broadening risk analysis to incorporate granular views of tail risk

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

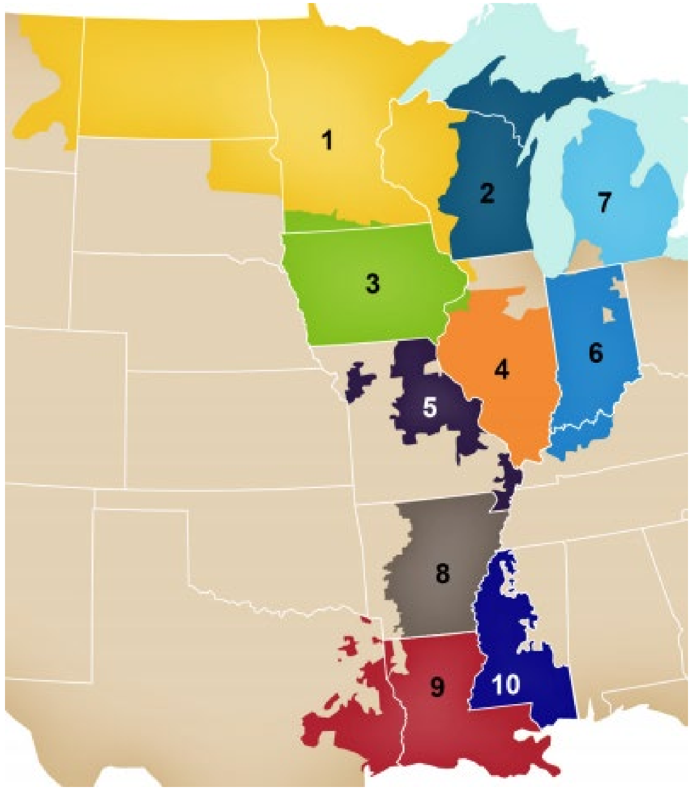


Key Functions of the ISO
• Operational authority to control transmission facilities and coordinate security for its regions to ensure reliability
• Responsible for dispatch of lowest cost generation units, ensuring the most cost-effective generation meets load

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

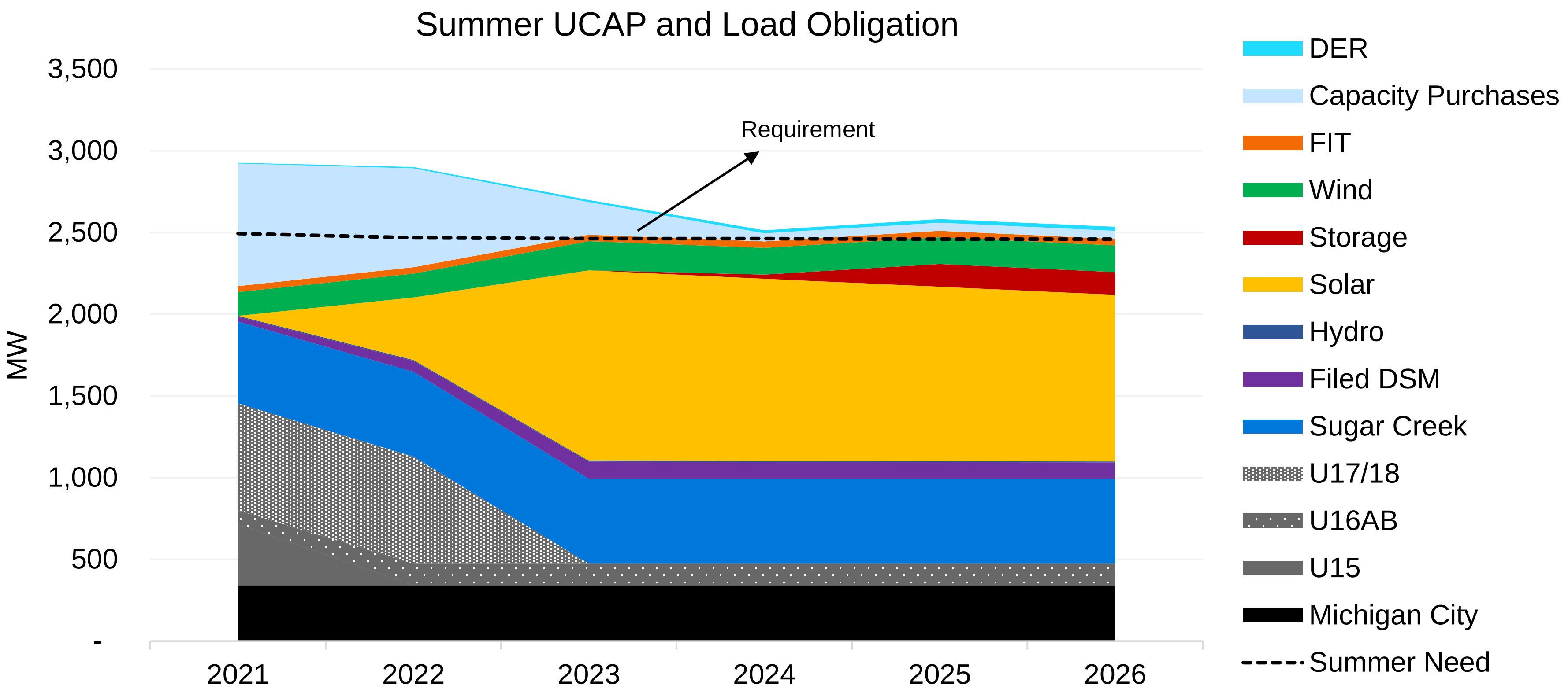
Several regulatory developments and evolving initiatives since NIPSCO's 2018 IRP will influence the way we conduct the 2021 IRP

	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

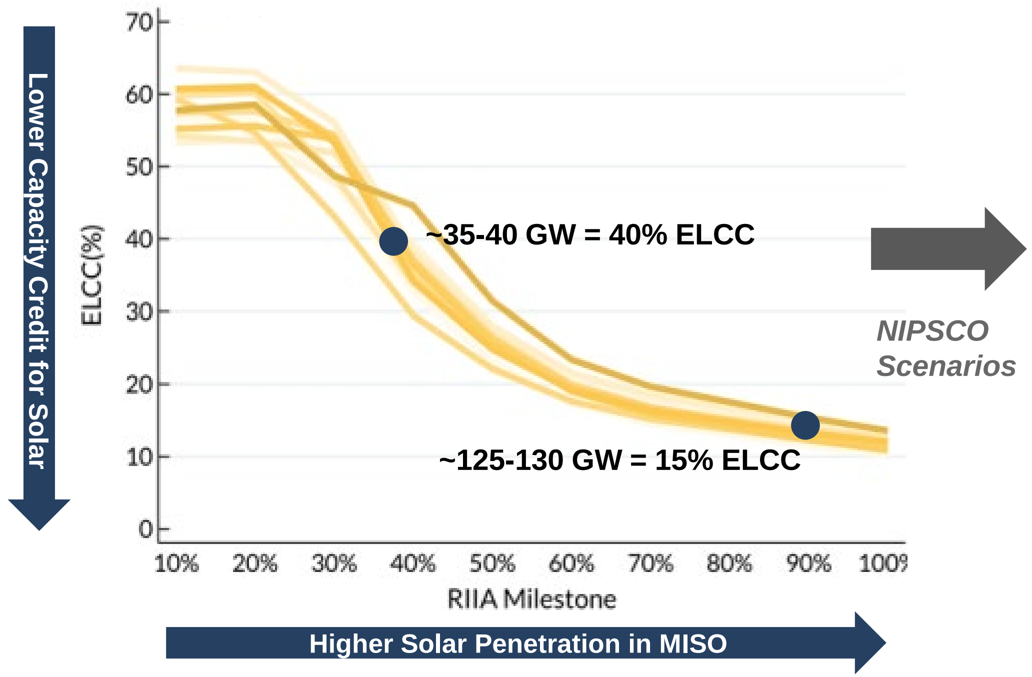
- NIPSCO's supply portfolio will be evolving significantly over the next five years
- MISO market rules changes regarding intermittent resource capacity credit accounting and seasonal reserve margin tracking will require careful evaluation in the 2021 IRP

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



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

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

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

2 RESOURCE AVAILABILITY AND NEED – SEASONAL CAPACITY CONSTRUCT

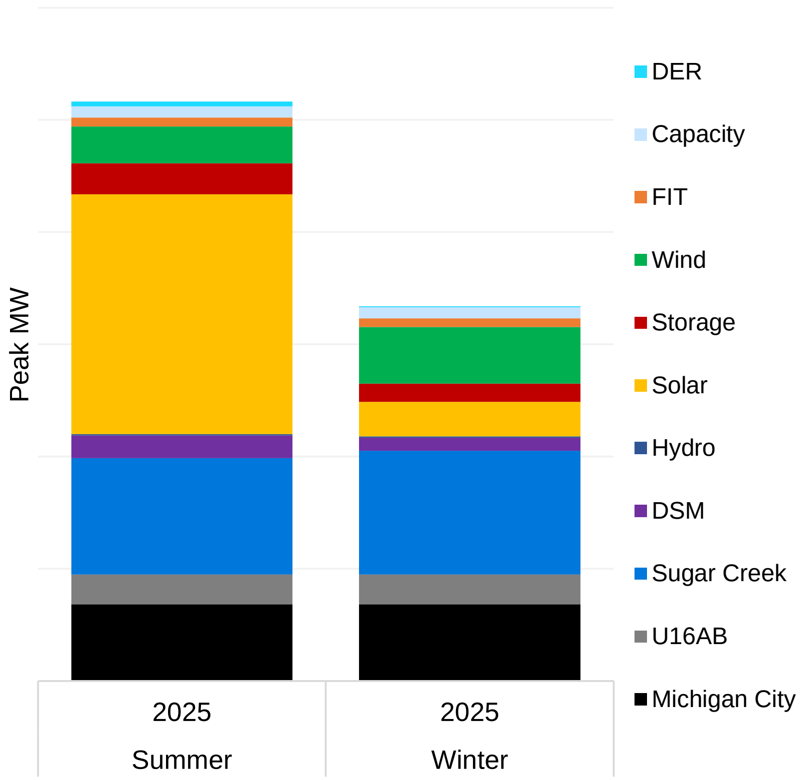
NIPSCO is **currently required to only meet summer peak demand** plus a reserve margin.

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

Preliminary

Potential UCAP by Season (2025)



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
Some elements beyond the purview of IRP (Operating Reliability)

	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

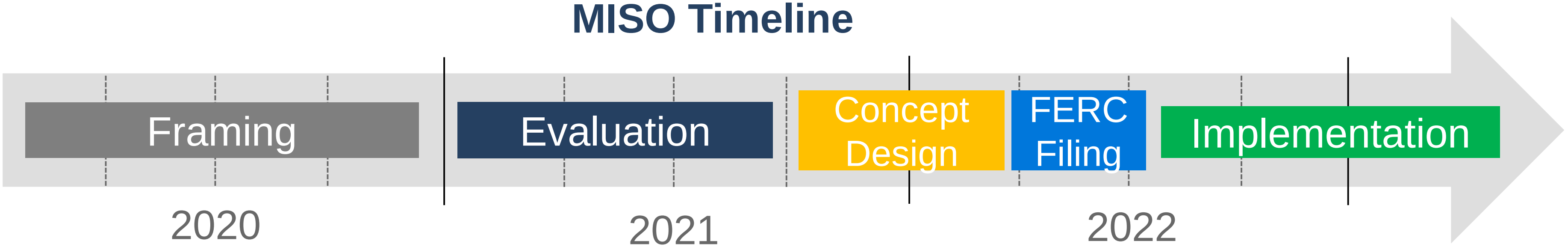
Implications for NIPSCO's 2021 IRP

- 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

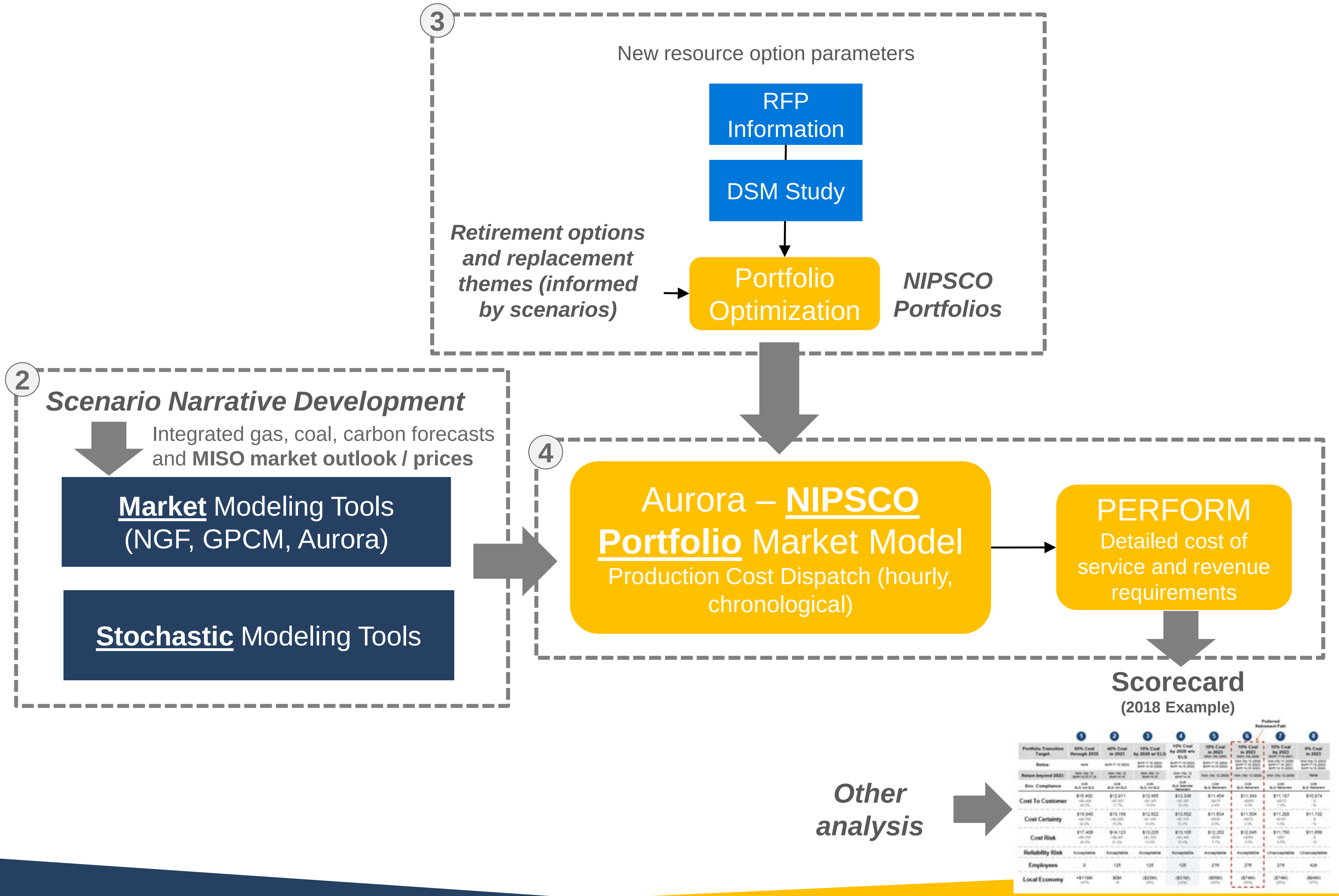
- **Can be used to answer the "What if…" questions**
  - Major events can change fundamental outlook for key drivers, altering portfolio performance
    - New policy or regulation (carbon regulation, tax credits)
    - Fundamental gas price change (change in resource base, production costs, large shifts 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 CO_2 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)

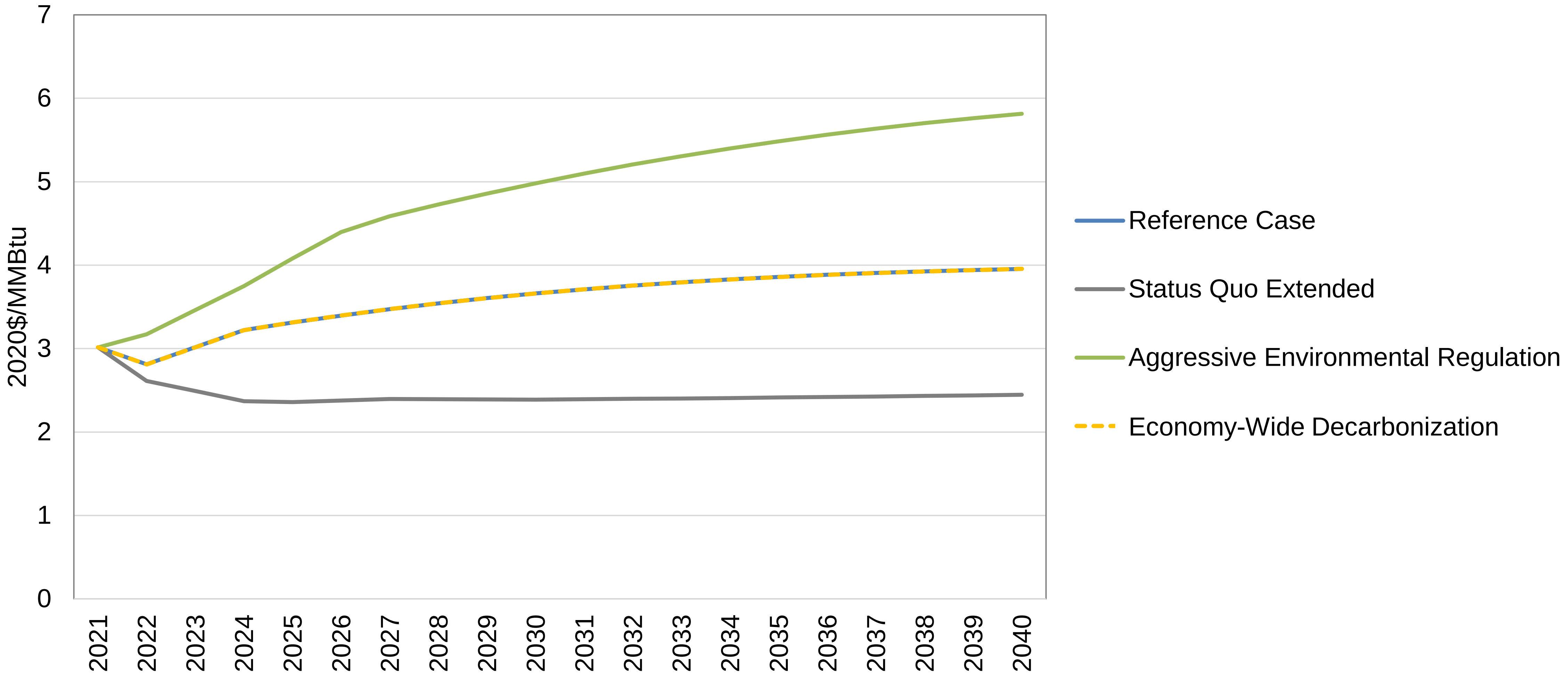
FUNDAMENTAL NATURAL GAS PRICE DRIVERS ACROSS SCENARIOS – SUPPLY

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

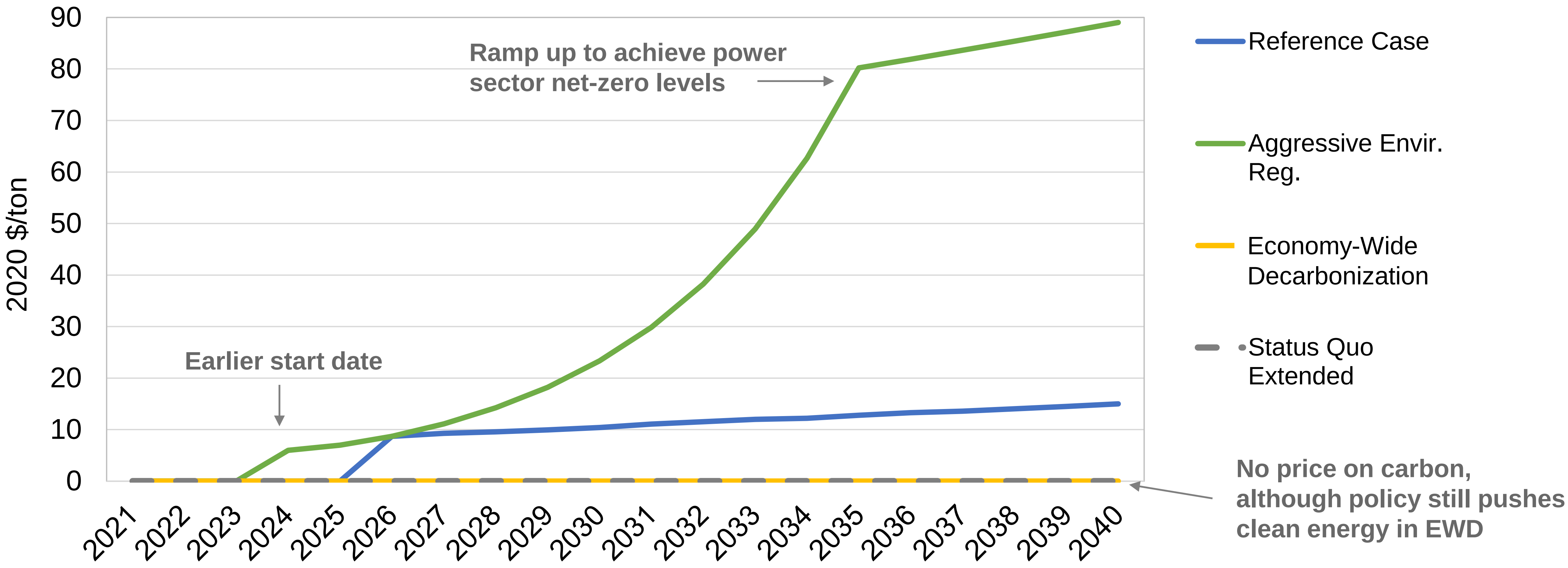


CO_2 POLICY SCENARIOS

	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

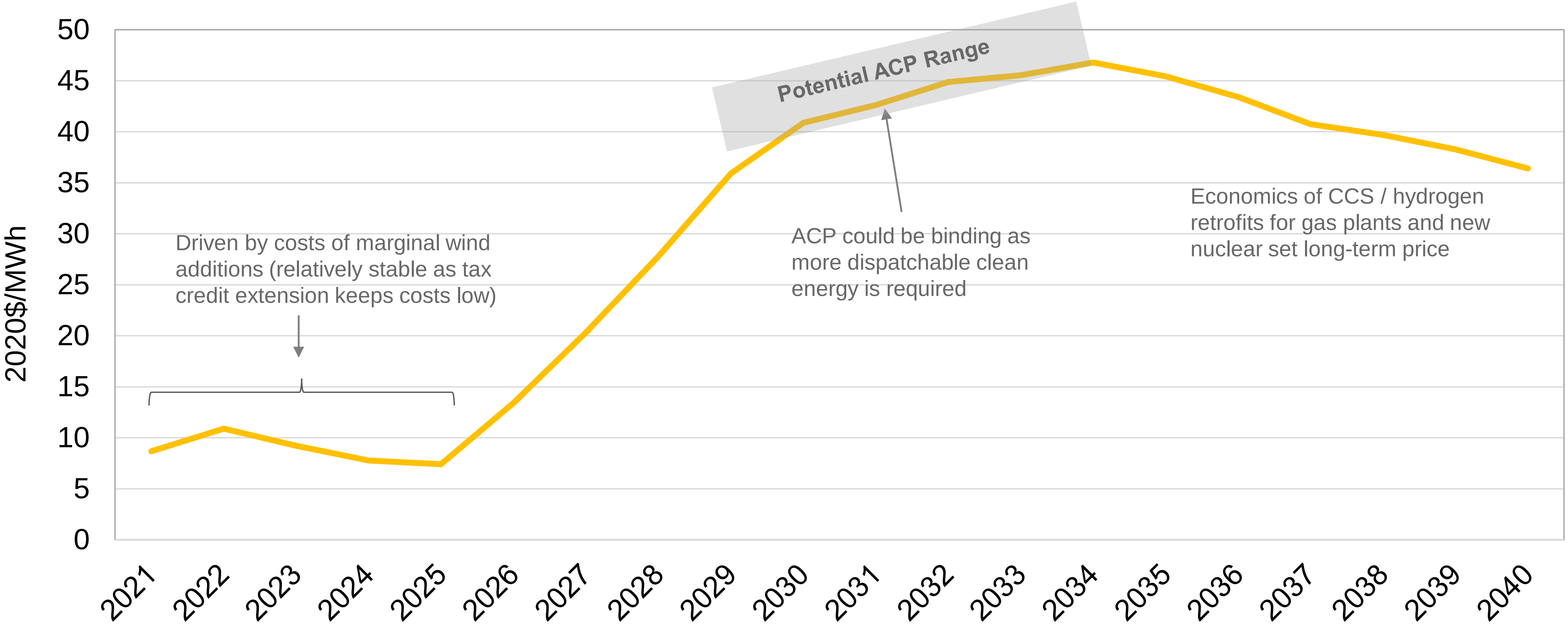
CO_2 PRICE RANGE

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.



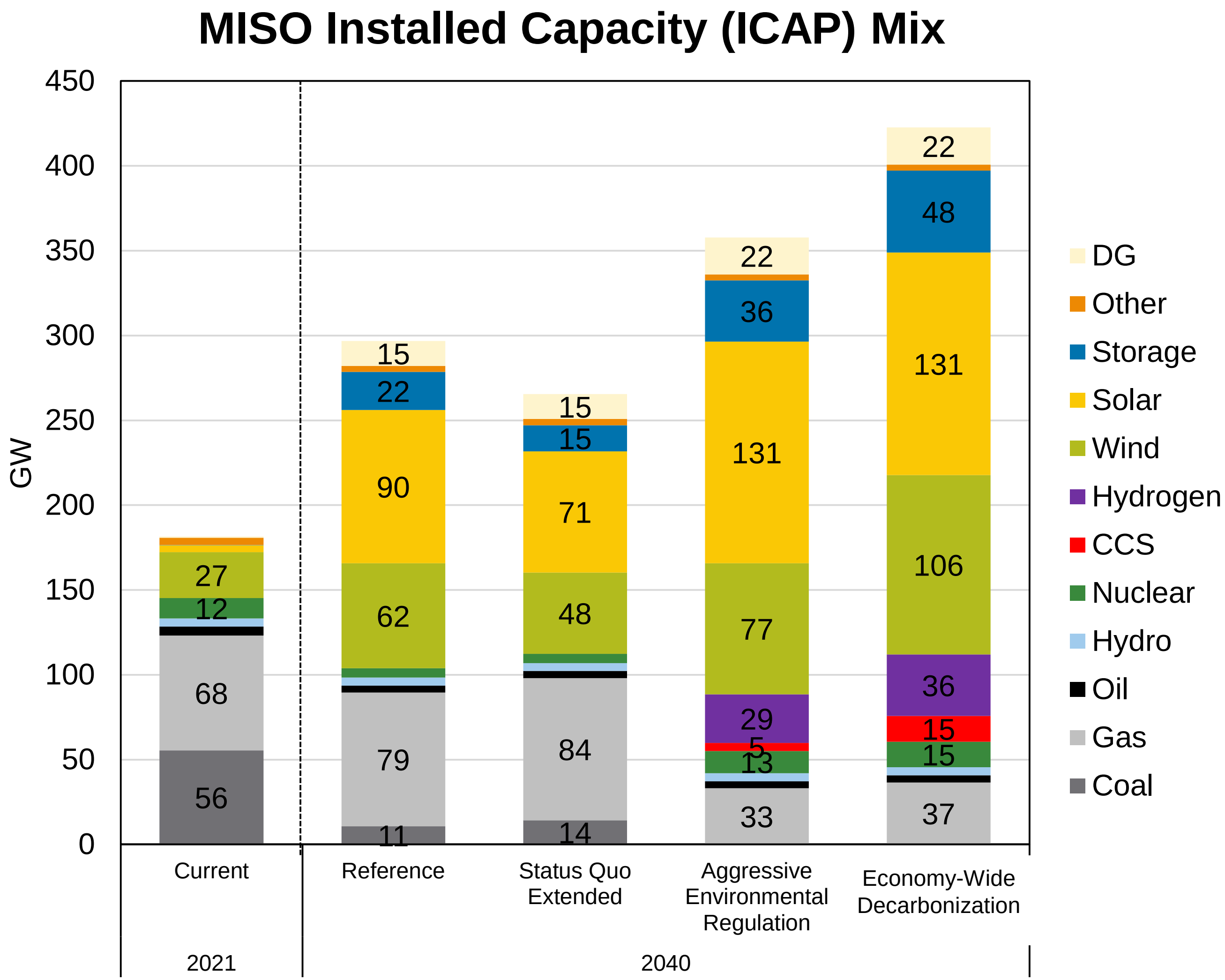
CLEAN ENERGY CREDIT PRICING

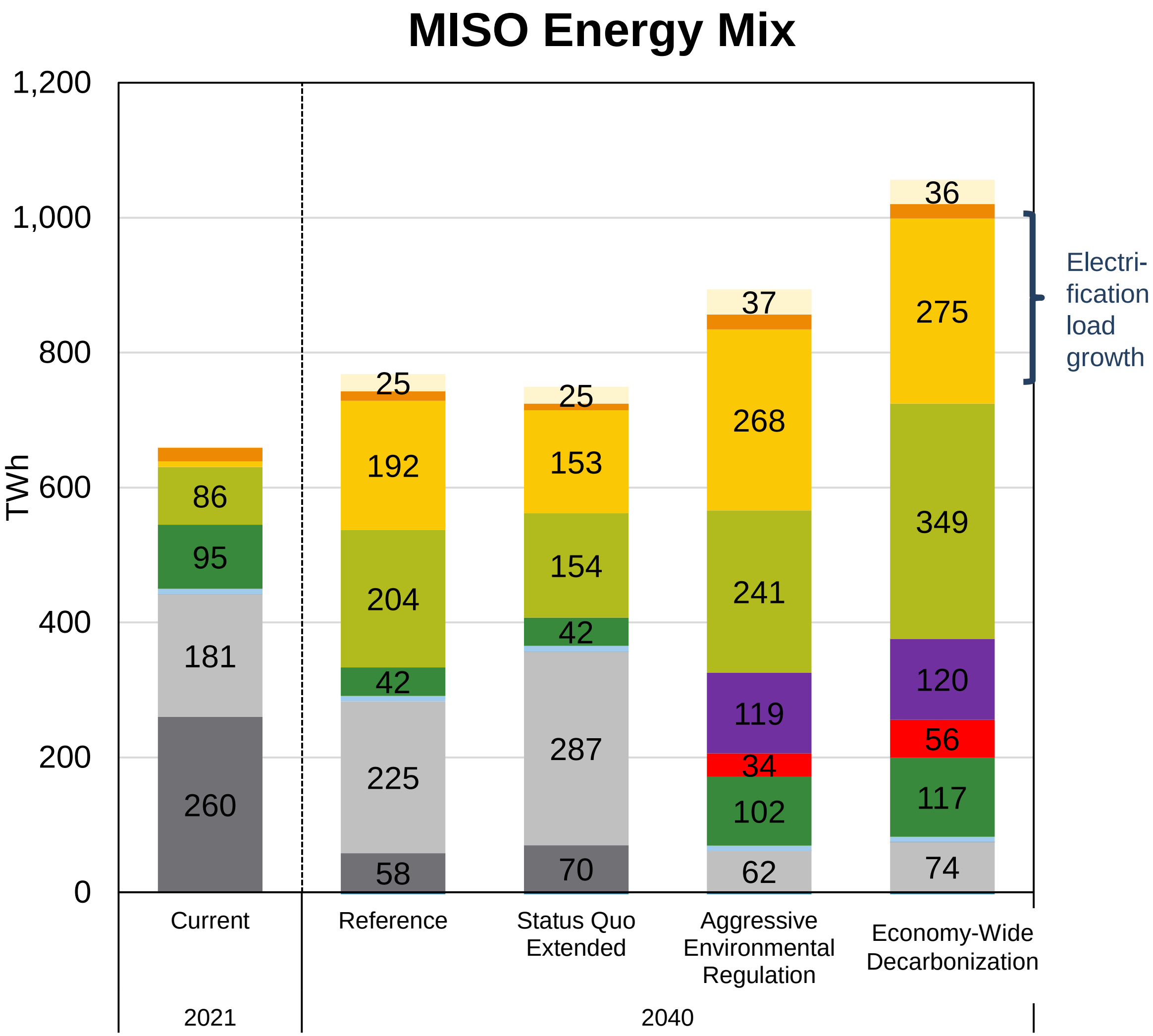
In the Economy-Wide Decarbonization scenario, a Clean Energy Standard with an Alternative Compliance Payment (ACP) would likely drive the development of a national Clean Energy Credit / Zero Emission Electricity Credit market



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

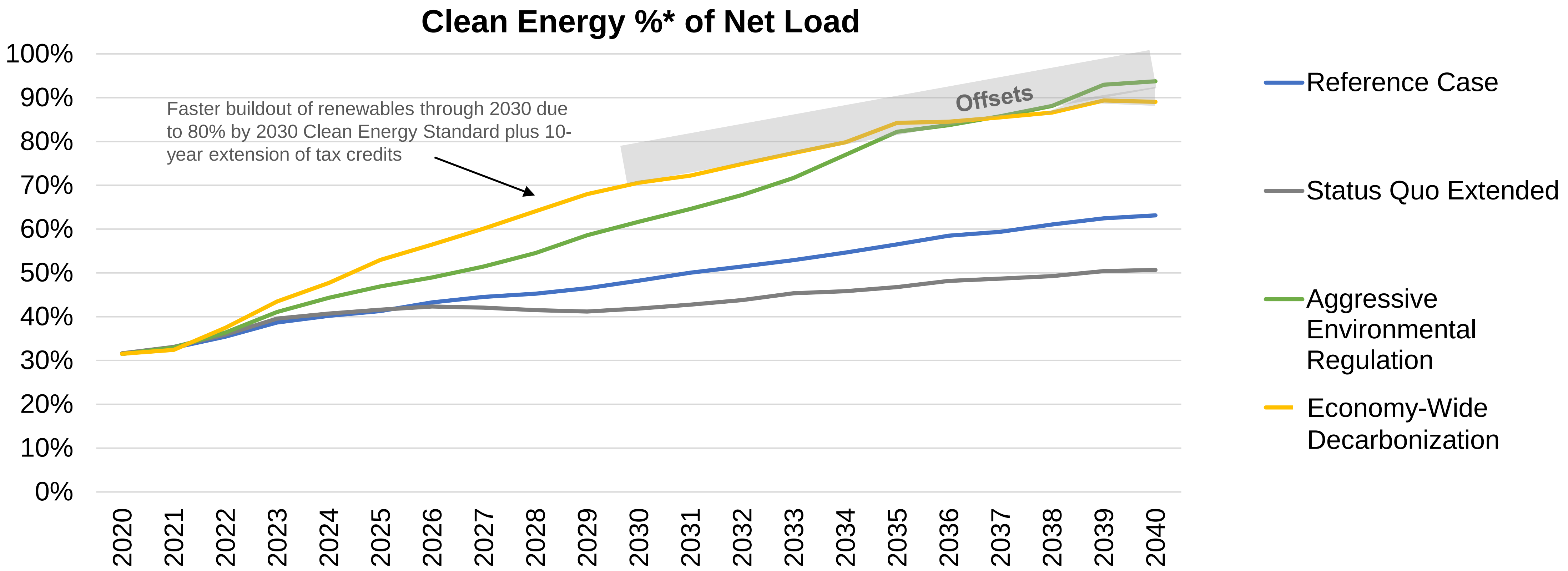
MISO CAPACITY AND ENERGY MIX OUTLOOK ACROSS SCENARIOS





CLEAN ENERGY PERCENTAGE ACROSS MISO

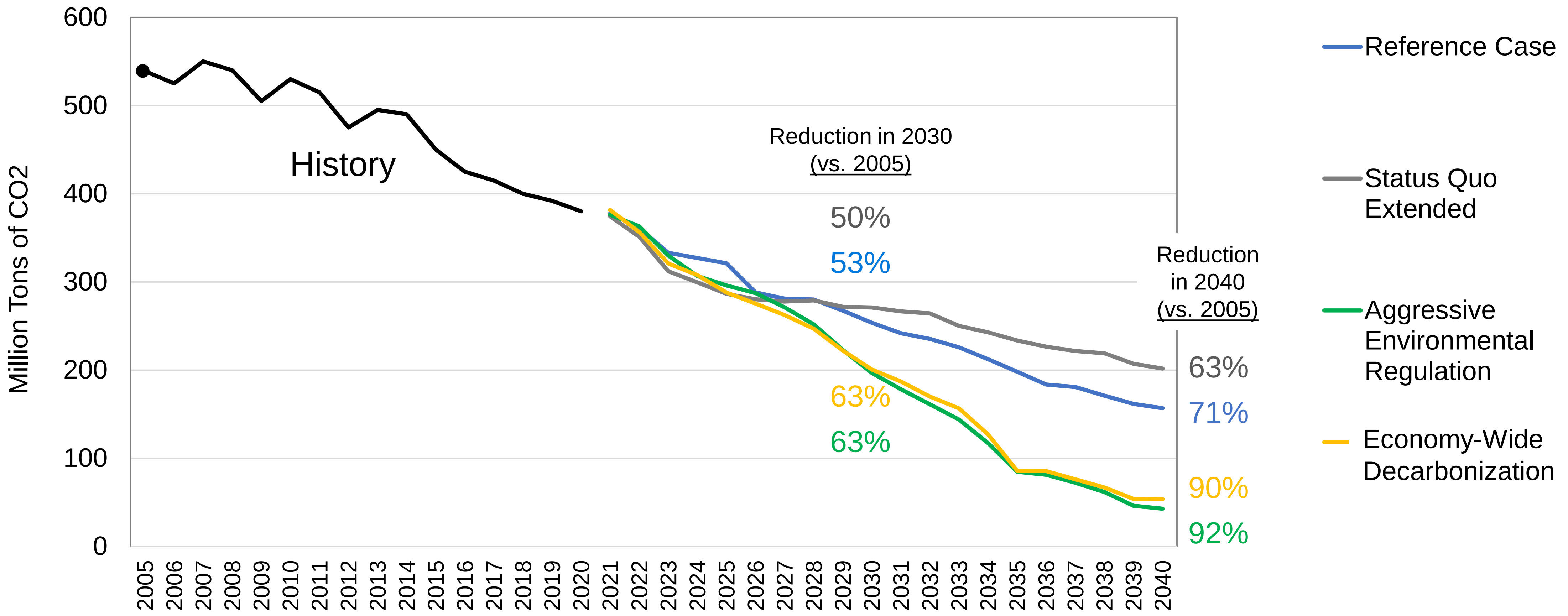
- Escalating carbon price pushes clean energy percentage to >90% in AER, while the implementation of a Clean Energy Standard achieves a very similar outcome in EWD
- Offsets outside the power sector would be expected to be available to achieve Net Zero



**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.*

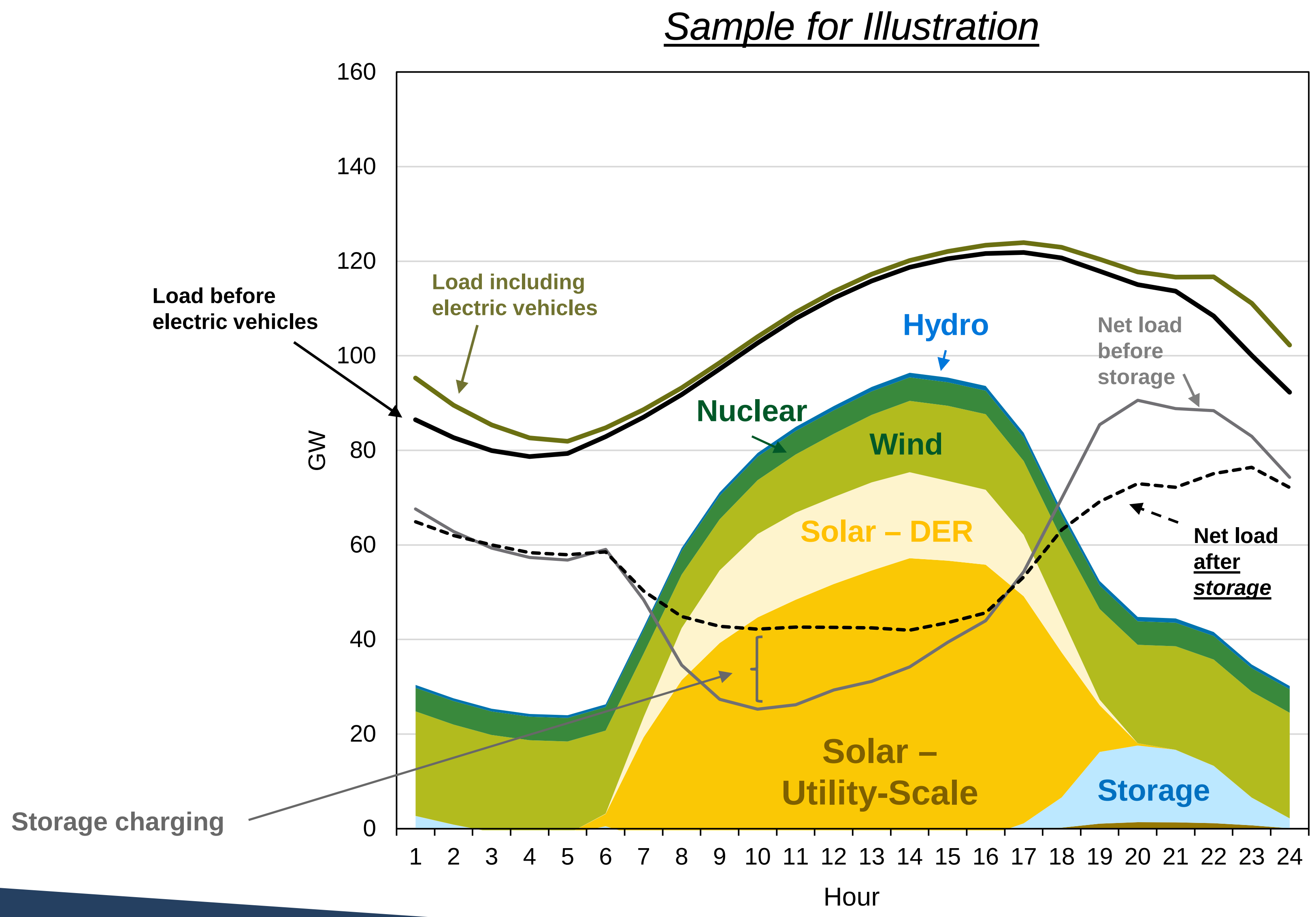
MISO CO_2 EMISSIONS

- 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



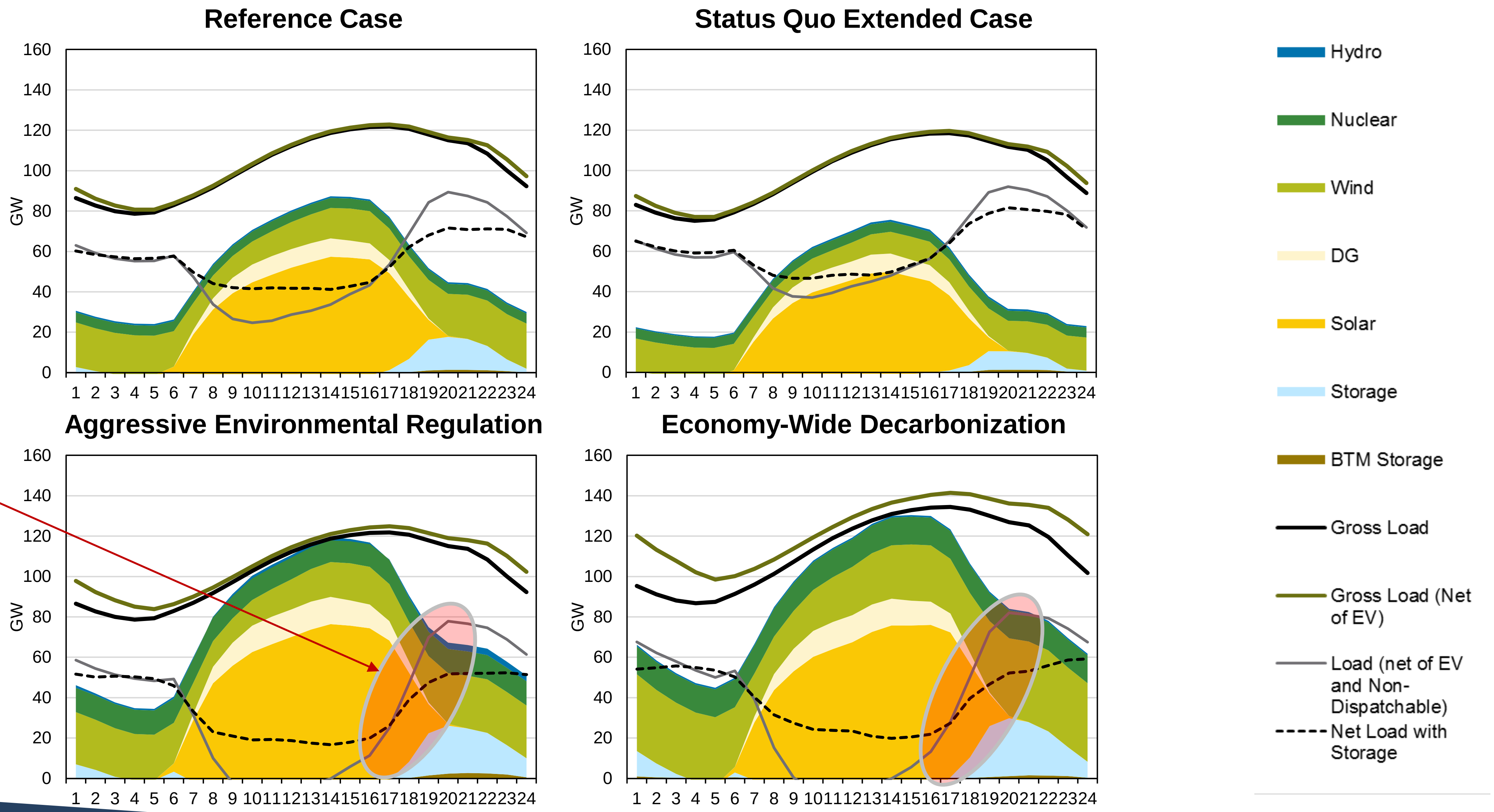
<u>Net load</u> =

Load (including EVs)

minus

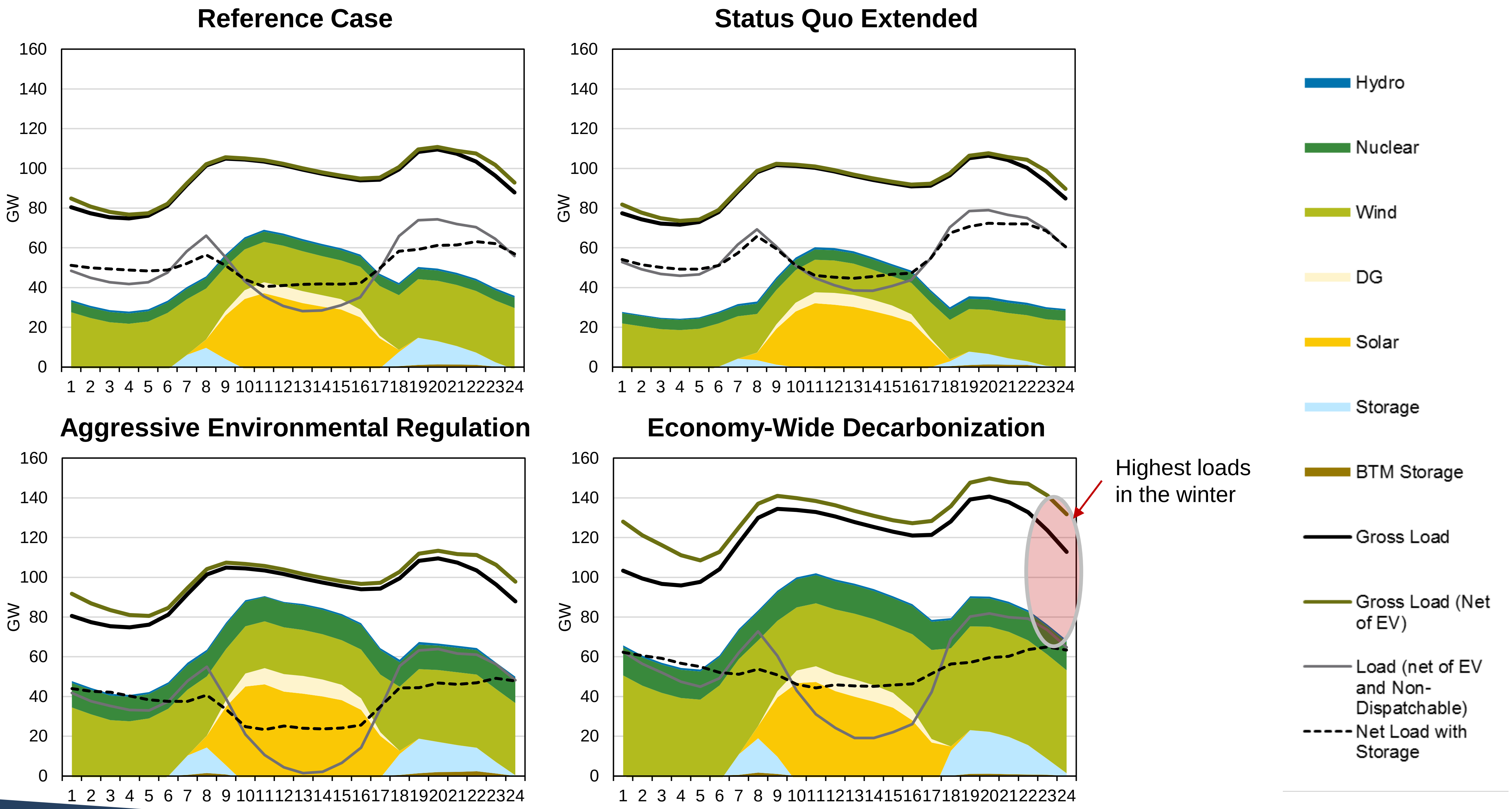
Non-dispatchable generation (wind, solar, nuclear, hydro)

SUMMER 2040



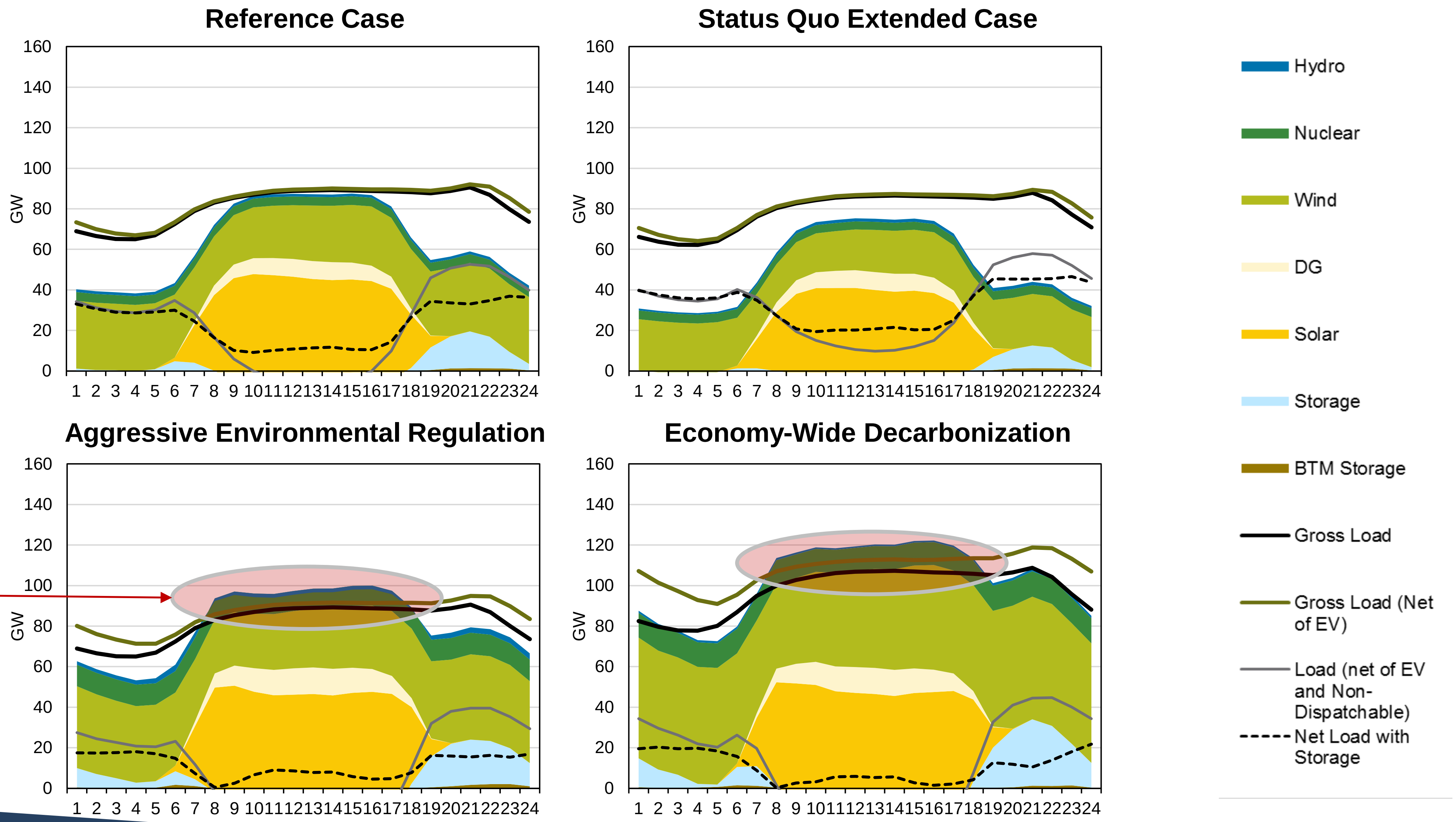
Large ramping requirements in summer evenings must be met by storage and flexible gas/H2

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

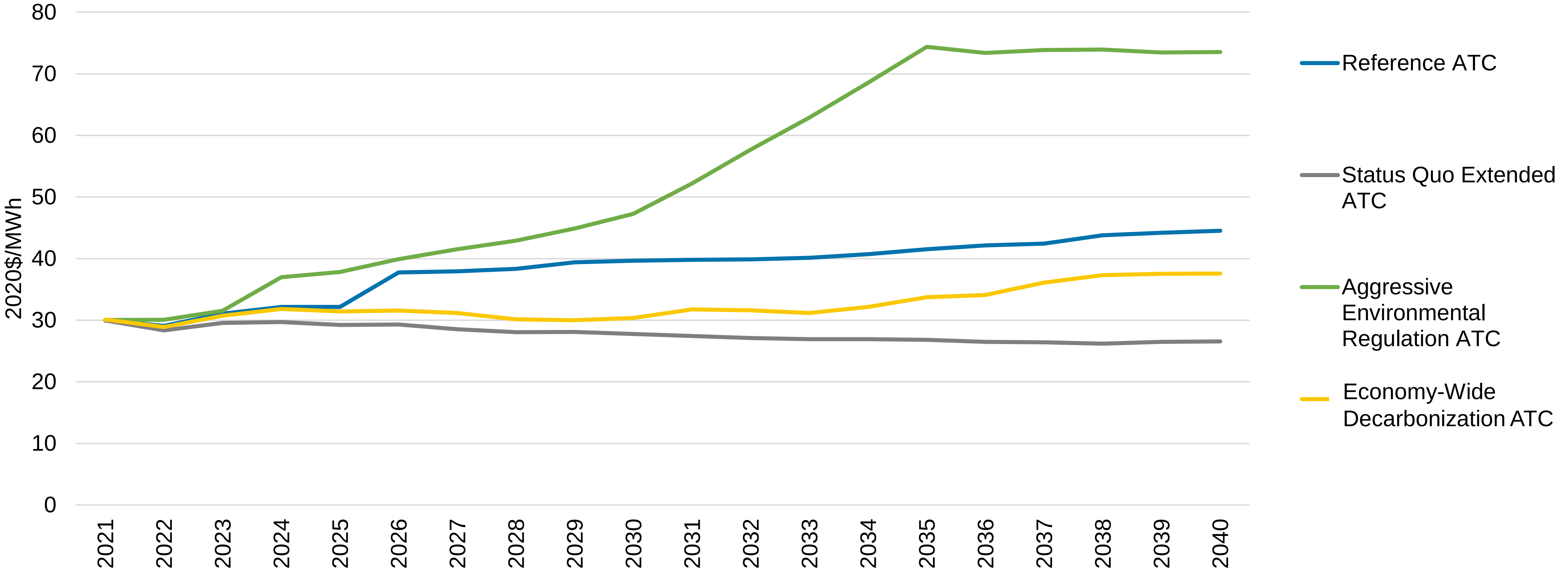


Storage needed to absorb excess renewable energy and shift to evening/ overnight or seasonally via H2;

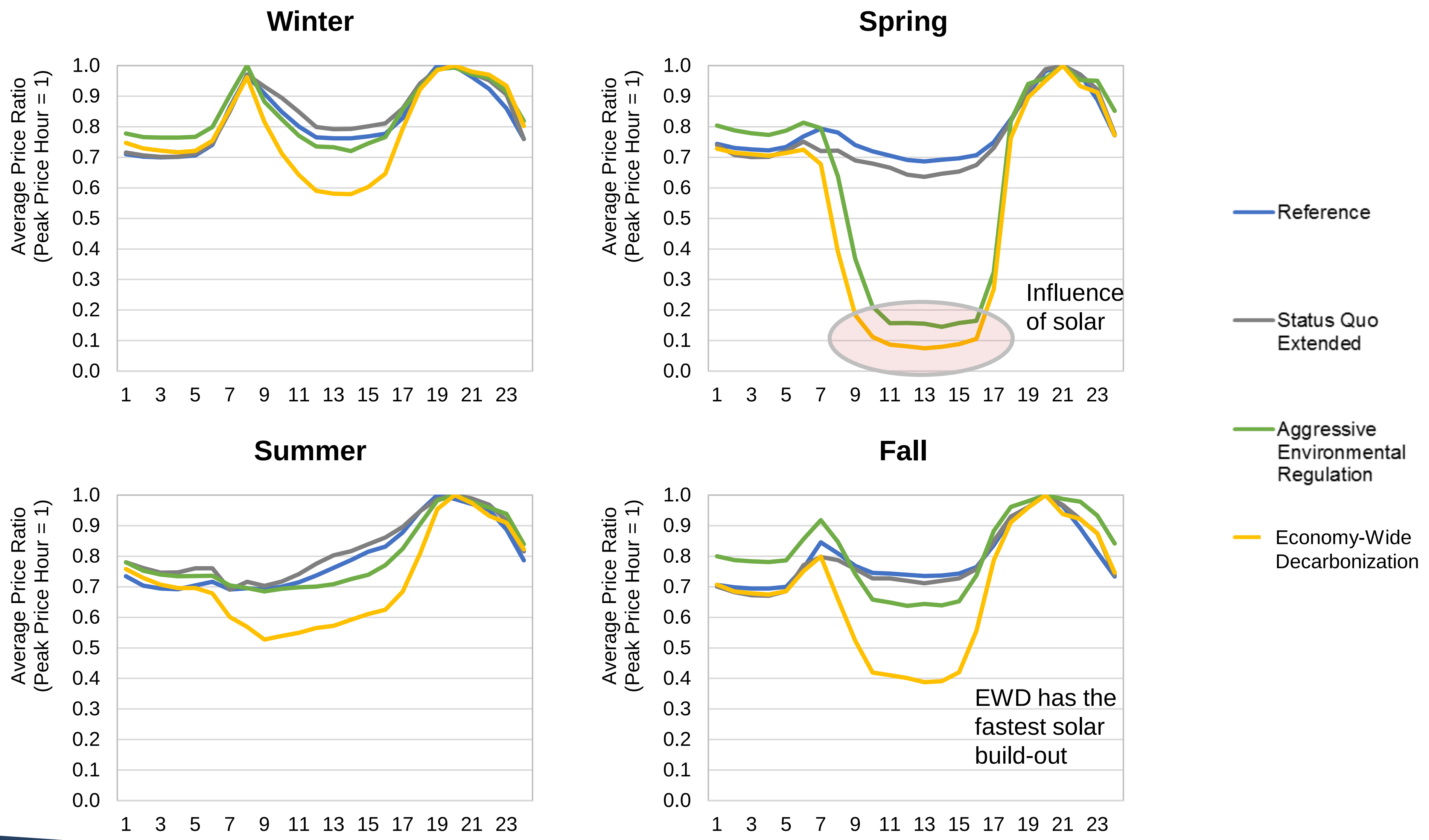
curtailment (or use of excess for electrolysis) likely on many days

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

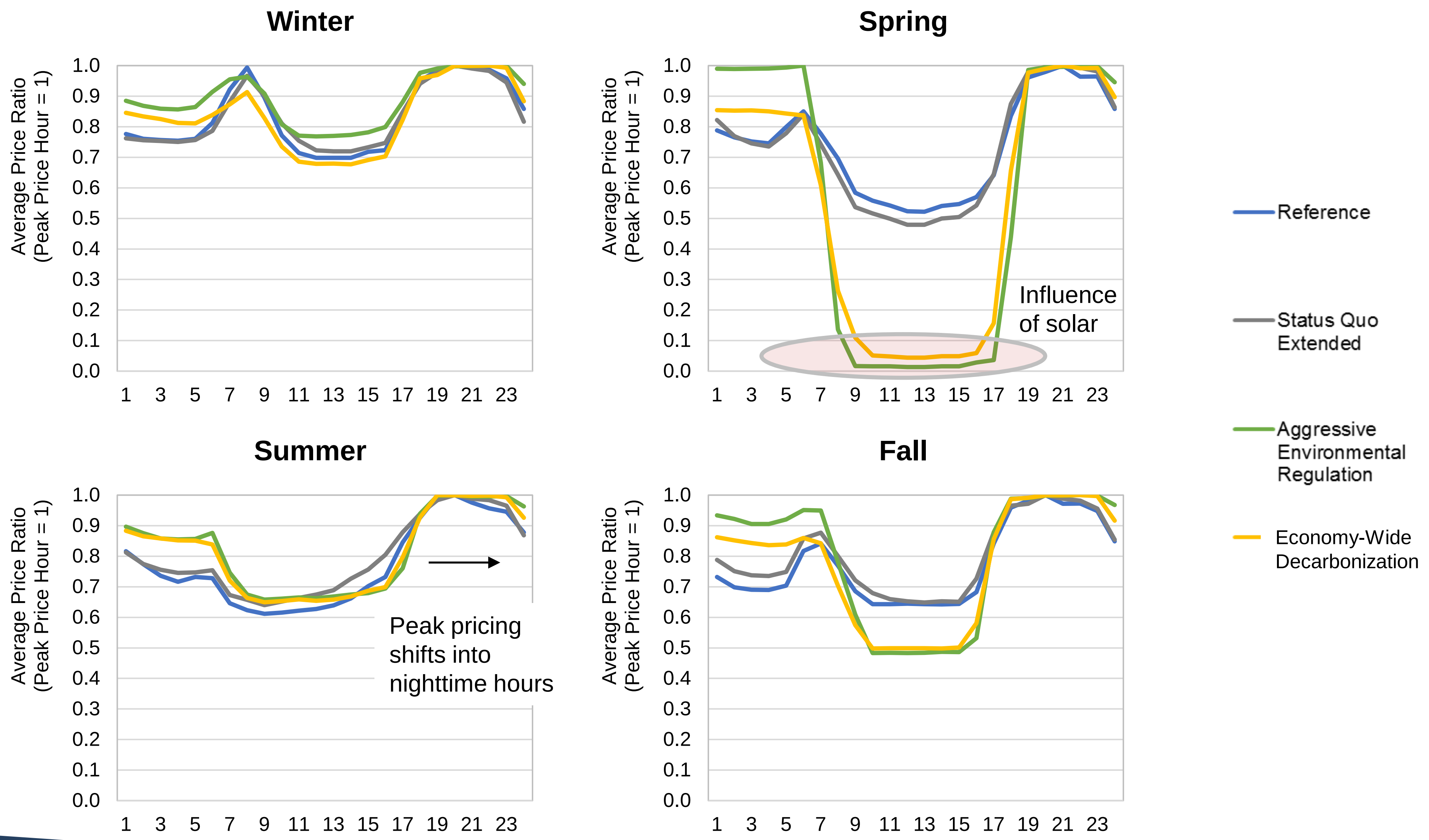
- Rising natural gas and carbon prices drive AER scenario trajectory, with long-term pricing also influenced by hydrogen commodity pricing
- Without a price on carbon, SQE and EWD scenarios have flatter pricing in real terms due to gas price expectations and growing renewable penetration



HOURLY PRICE SHAPES EXPECTED TO EVOLVE OVER TIME - 2030

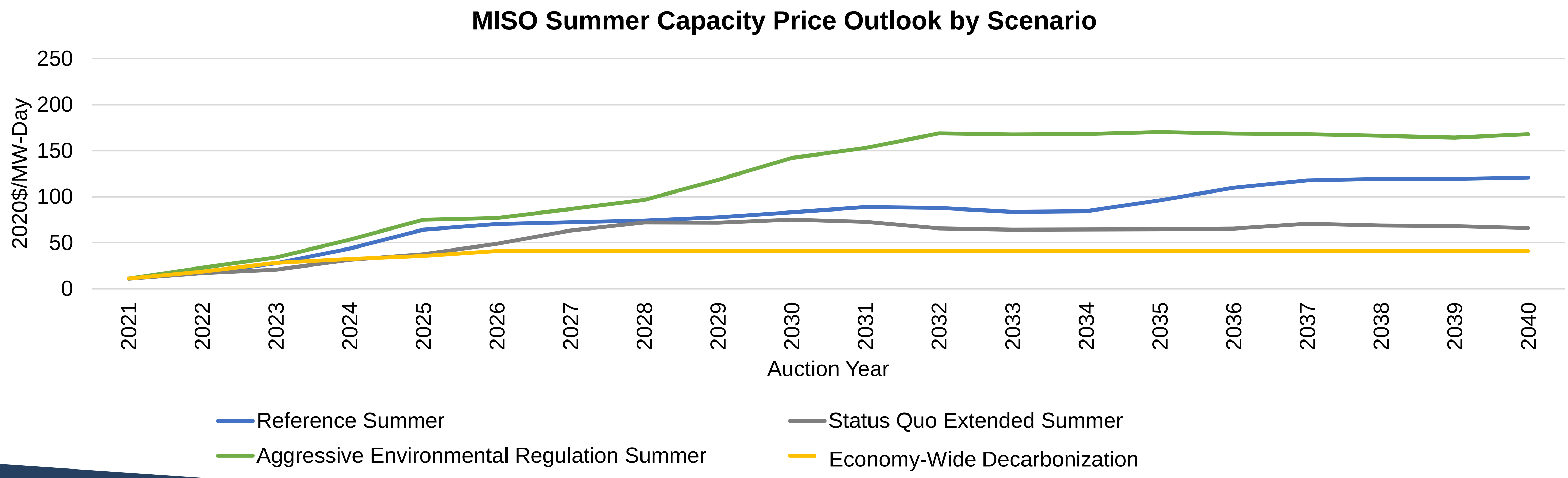


HOURLY PRICE SHAPES EXPECTED TO EVOLVE OVER TIME - 2040



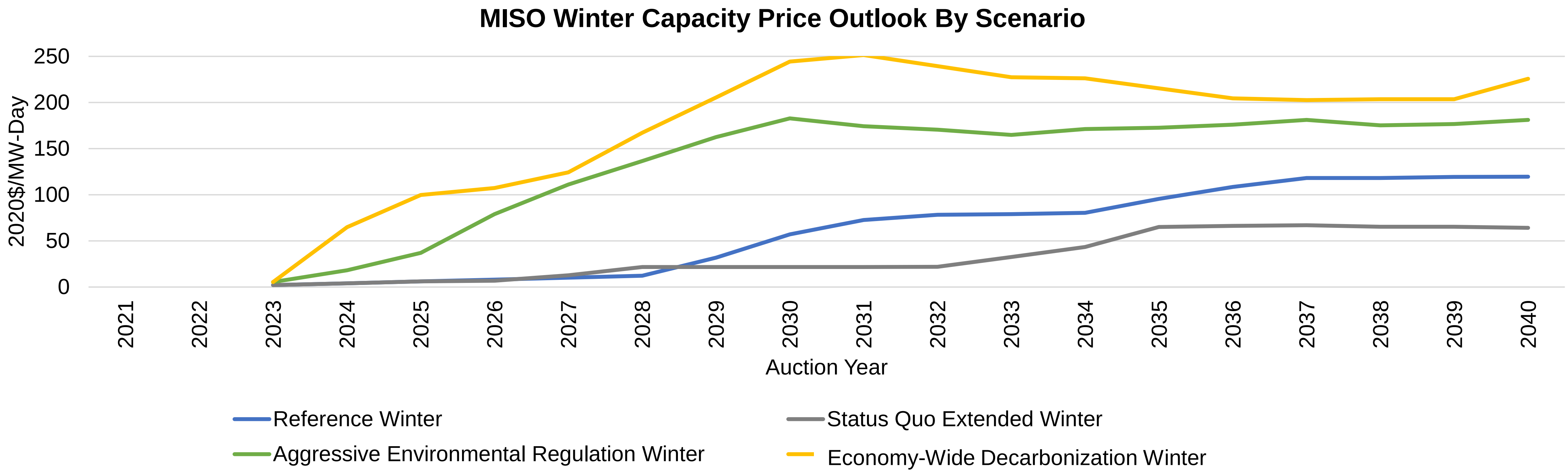
MISO SUMMER CAPACITY PRICE FORECAST

- 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

Energy Forecast and Validation

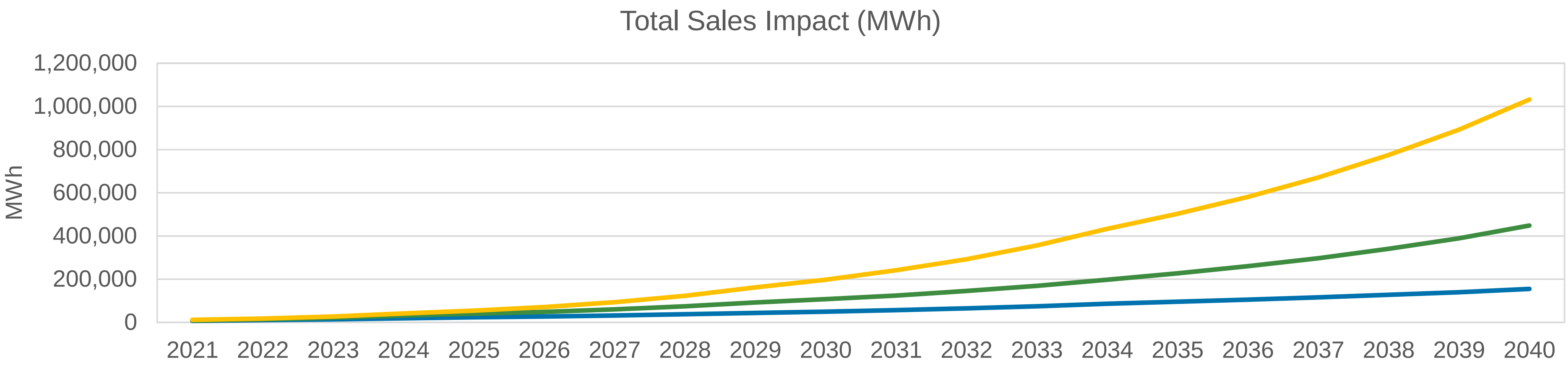
Forecast Adjustments: Base and Scenarios

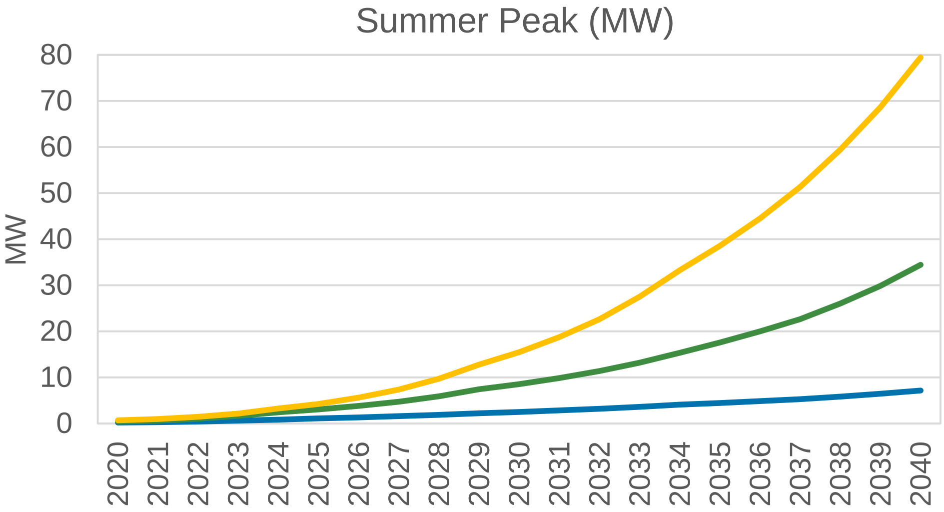
Data Gathering → **Weather Normalization** → **Econometric Modeling by Customer Class** → **Baseline Energy Forecast** → **Peak Load Forecast** → **DSM, DER, EV, Electrification, Industrial Load Adjustments**

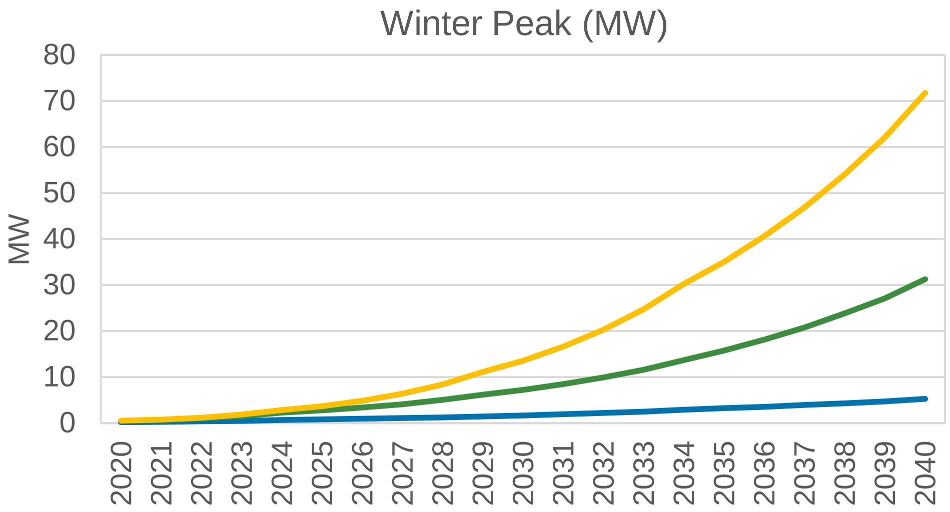
- NIPSCO reviewed the detailed process and draft forecast in Stakeholder Meeting #1
- NIPSCO and CRA have since refreshed the economic variables with the latest Moody's economic forecast:
  - Baseline Scenario
  - Upside Alternative – 10^{th} Percentile
  - Downside Alternative – 90^{th} Percentile

- 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



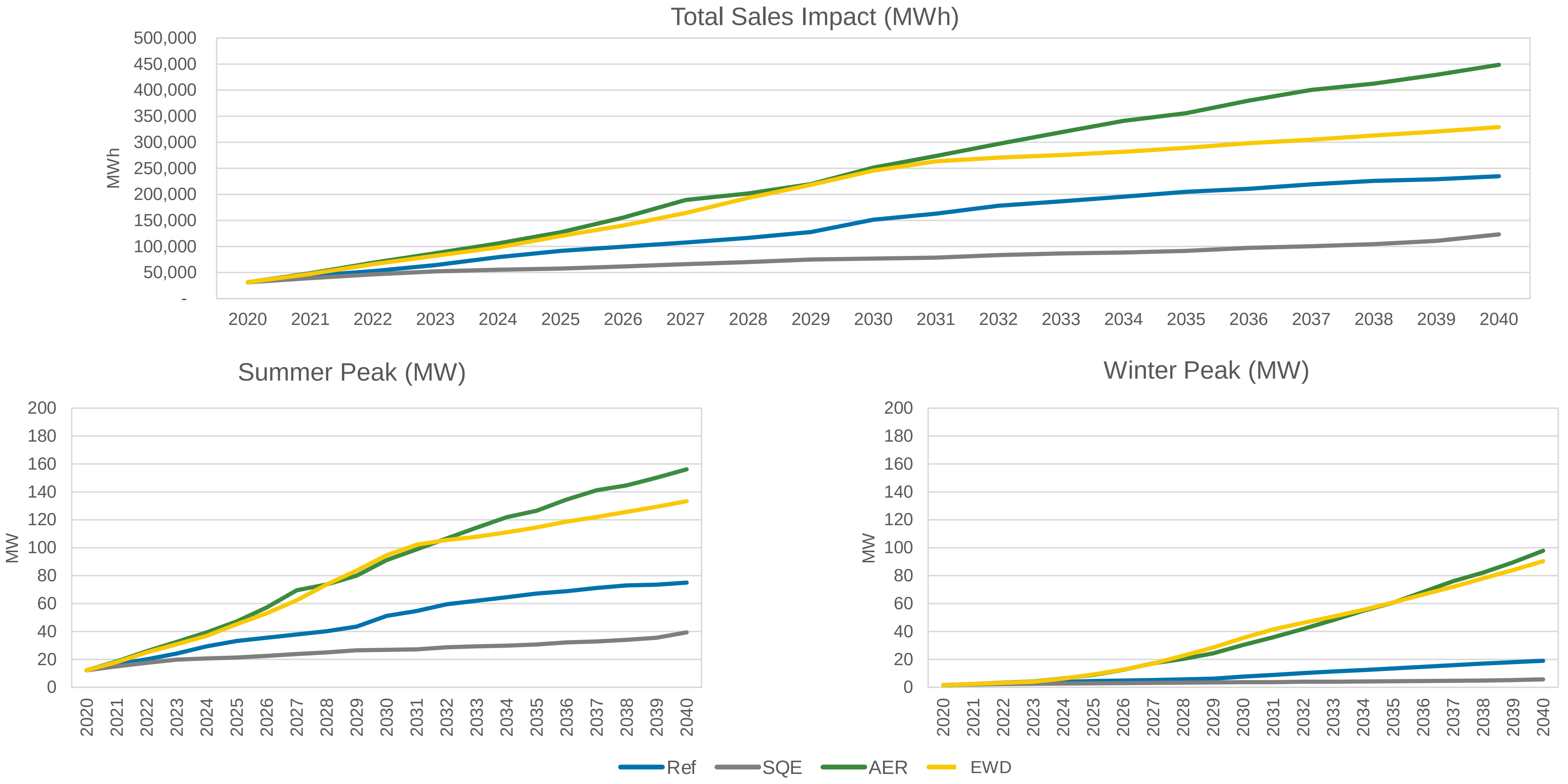




Ref / SQE AER EWD

Includes gross-up of 5% for line losses.

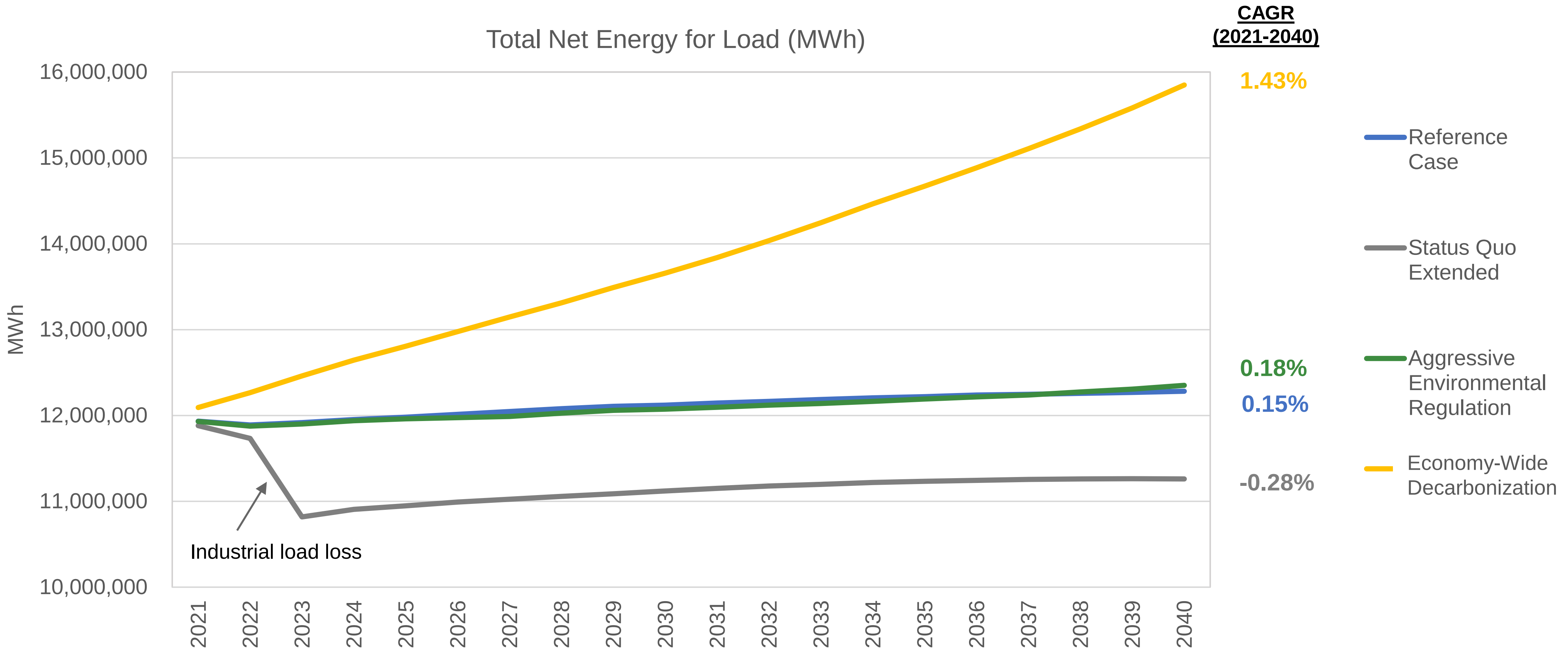
CUSTOMER-OWNED DER SCENARIO RANGE



Includes gross-up of 5% for line losses.

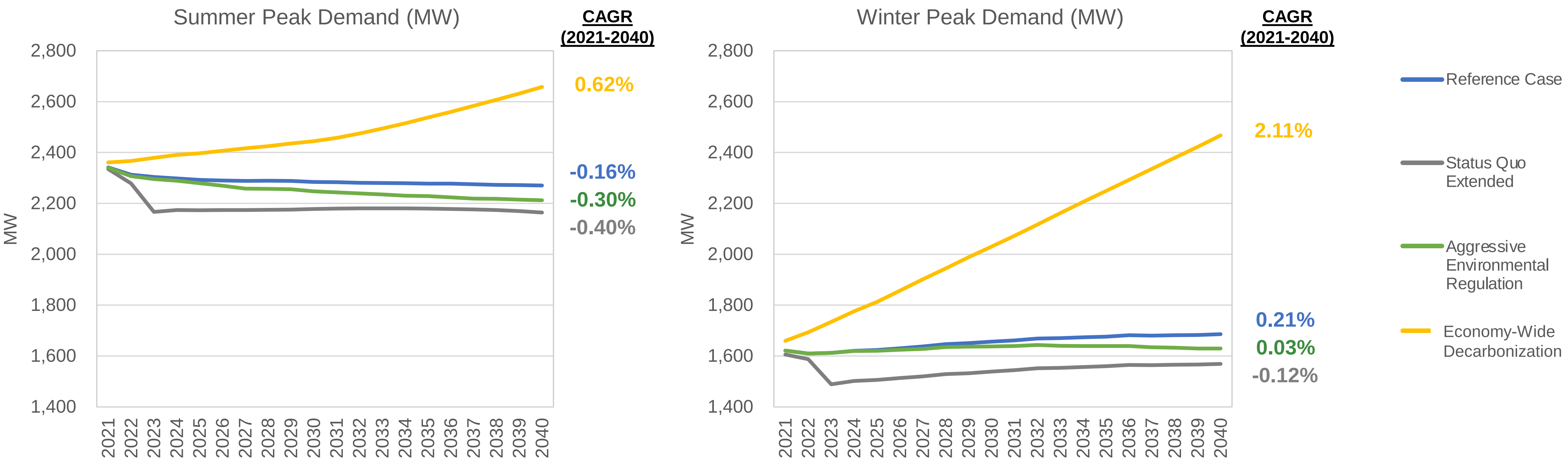
NIPSCO LOAD SCENARIO RANGES – SALES FORECAST

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



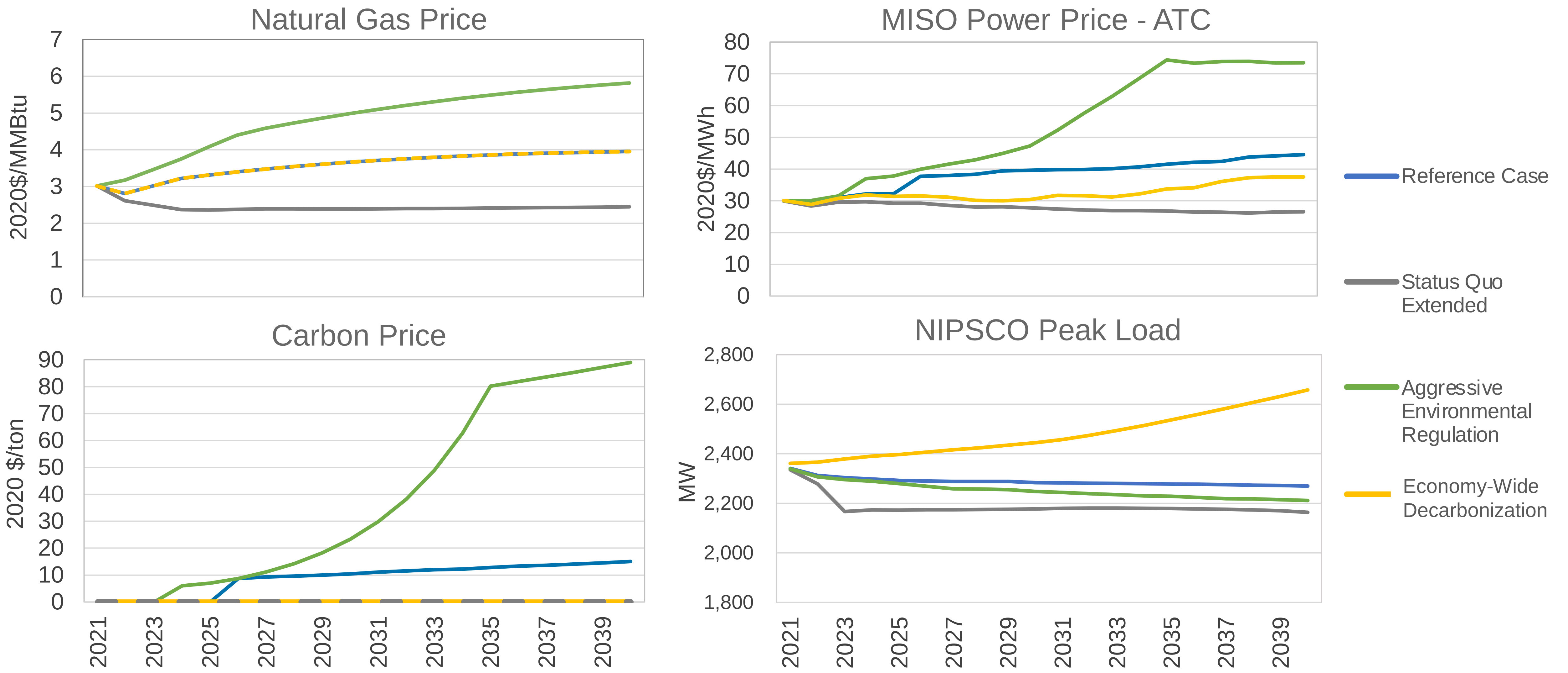
NIPSCO LOAD SCENARIO RANGES – PEAK LOAD

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

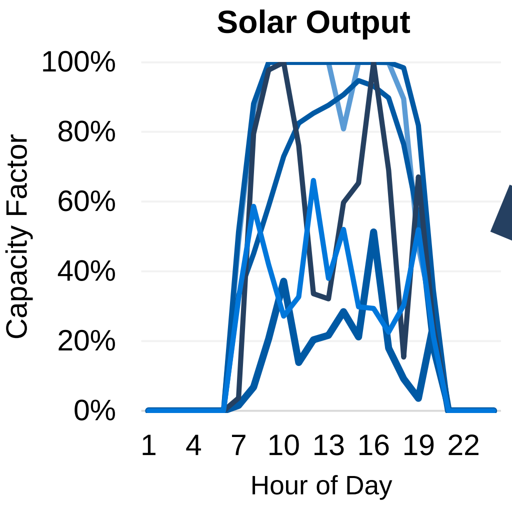
1 *Input Data Development*

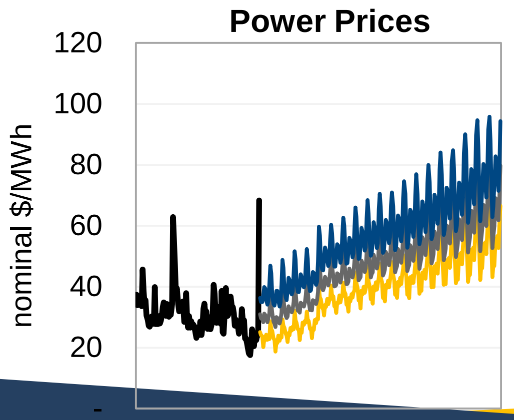
- Fundamental forecasts
- Historical price data
- Historical weather data (and corresponding renewable output)

2 *Statistical and Fundamental Analysis*

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

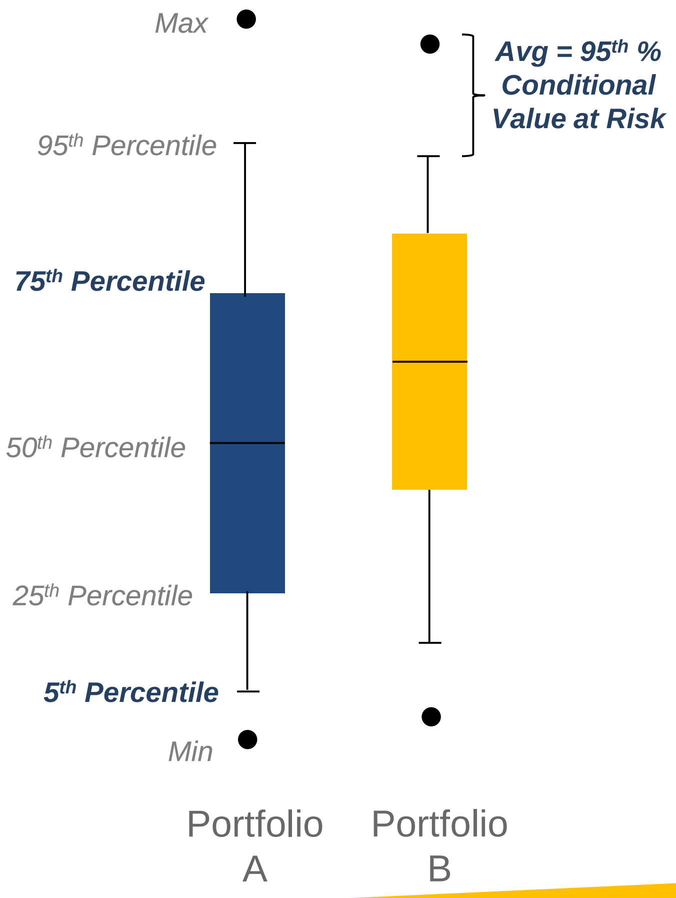
3 *Stochastic Input Development*





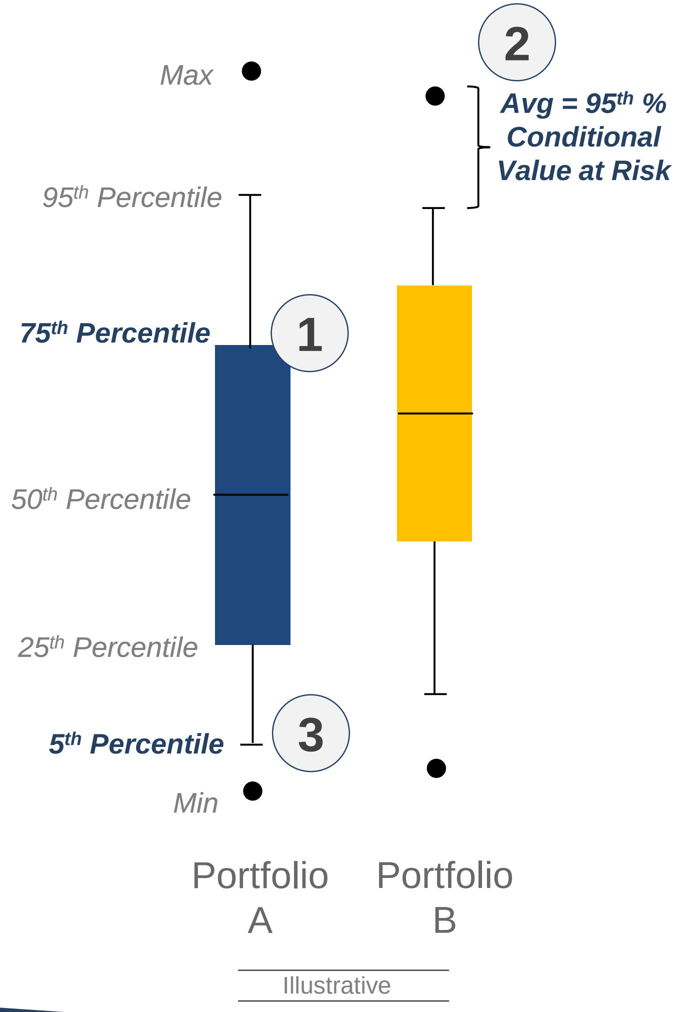
Evaluate NIPSCO portfolios hundreds of times

4 *NIPSCO Portfolio Analysis*



Illustrative

STOCHASTIC PORTFOLIO ANALYSIS RESULTS CONTRIBUTE TO SCORECARD



Preliminary & Illustrative

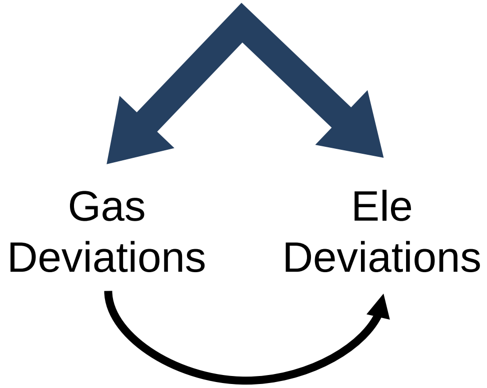
Objective	Indicator	Description and Metrics
Affordability	**Cost to Customer**	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Stability	1 **Cost Certainty**	• Certainty that revenue requirement within the most likely range of outcomes • **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)*

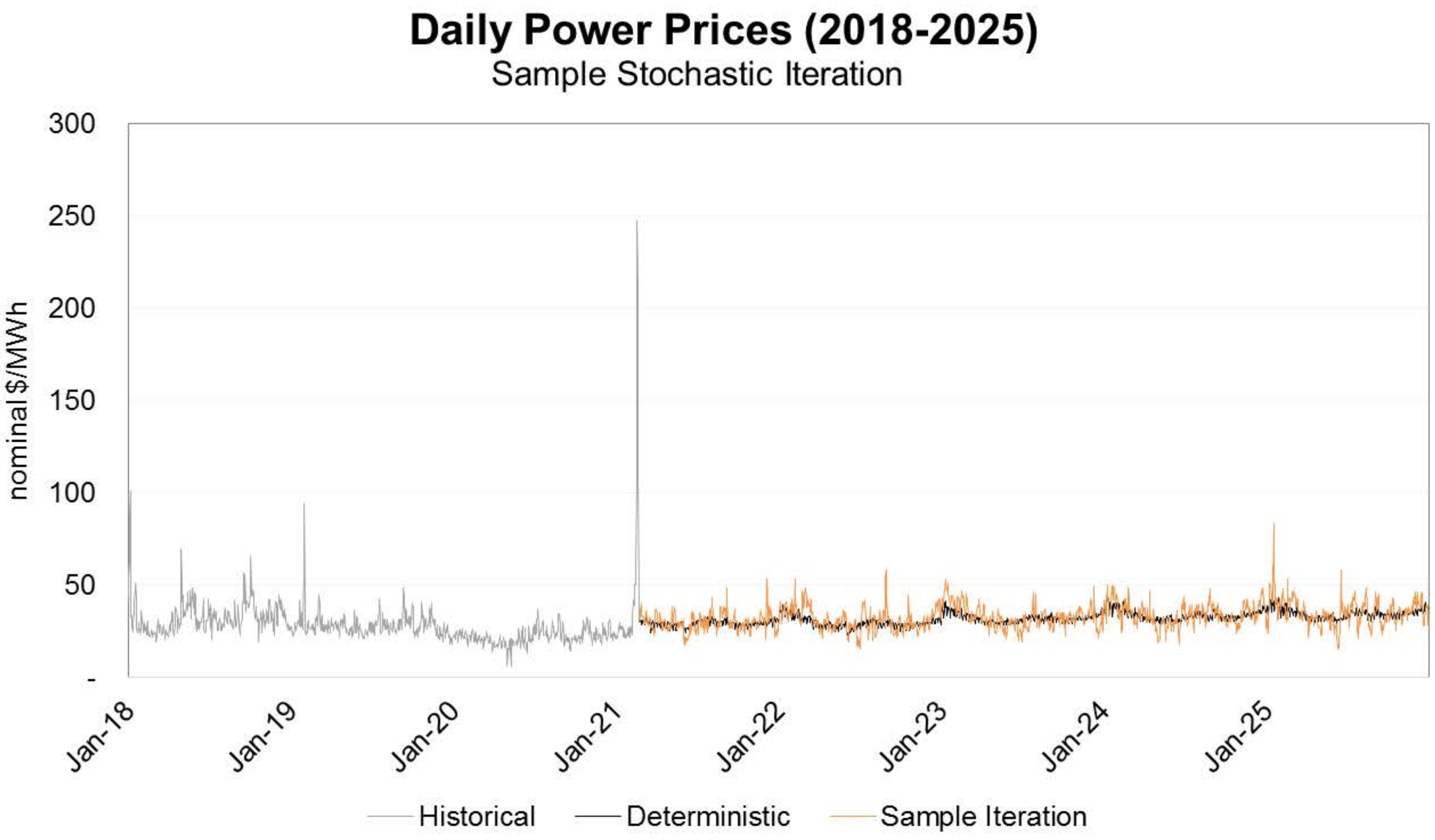


*MOSEP = Moment Simulation Energy Price Model

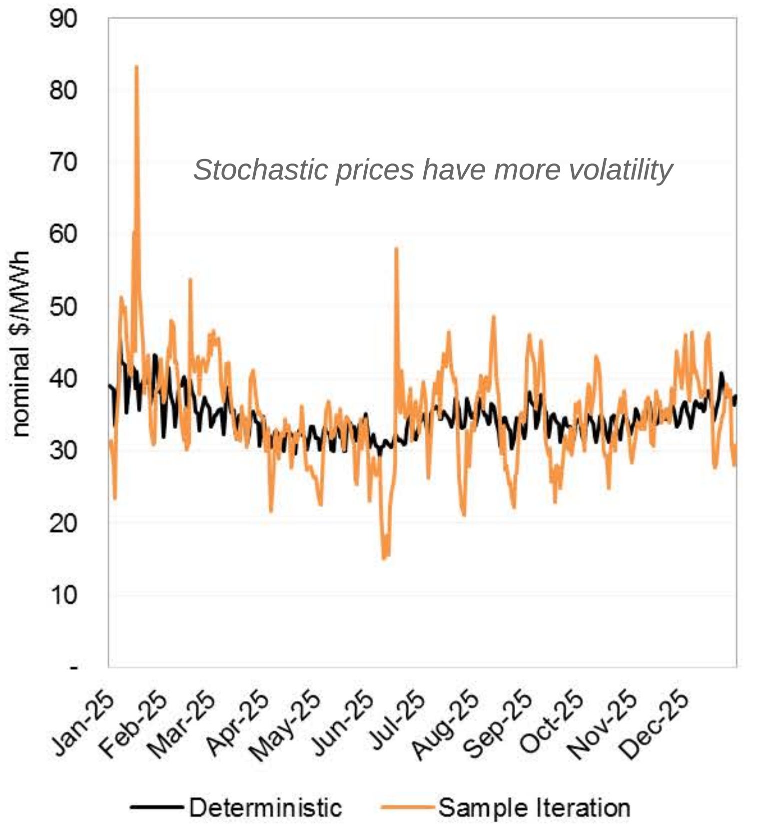
Ref Case Forecast

SAMPLE POWER PRICE ITERATIONS

Individual stochastic price iterations display more variation than deterministic forecast models



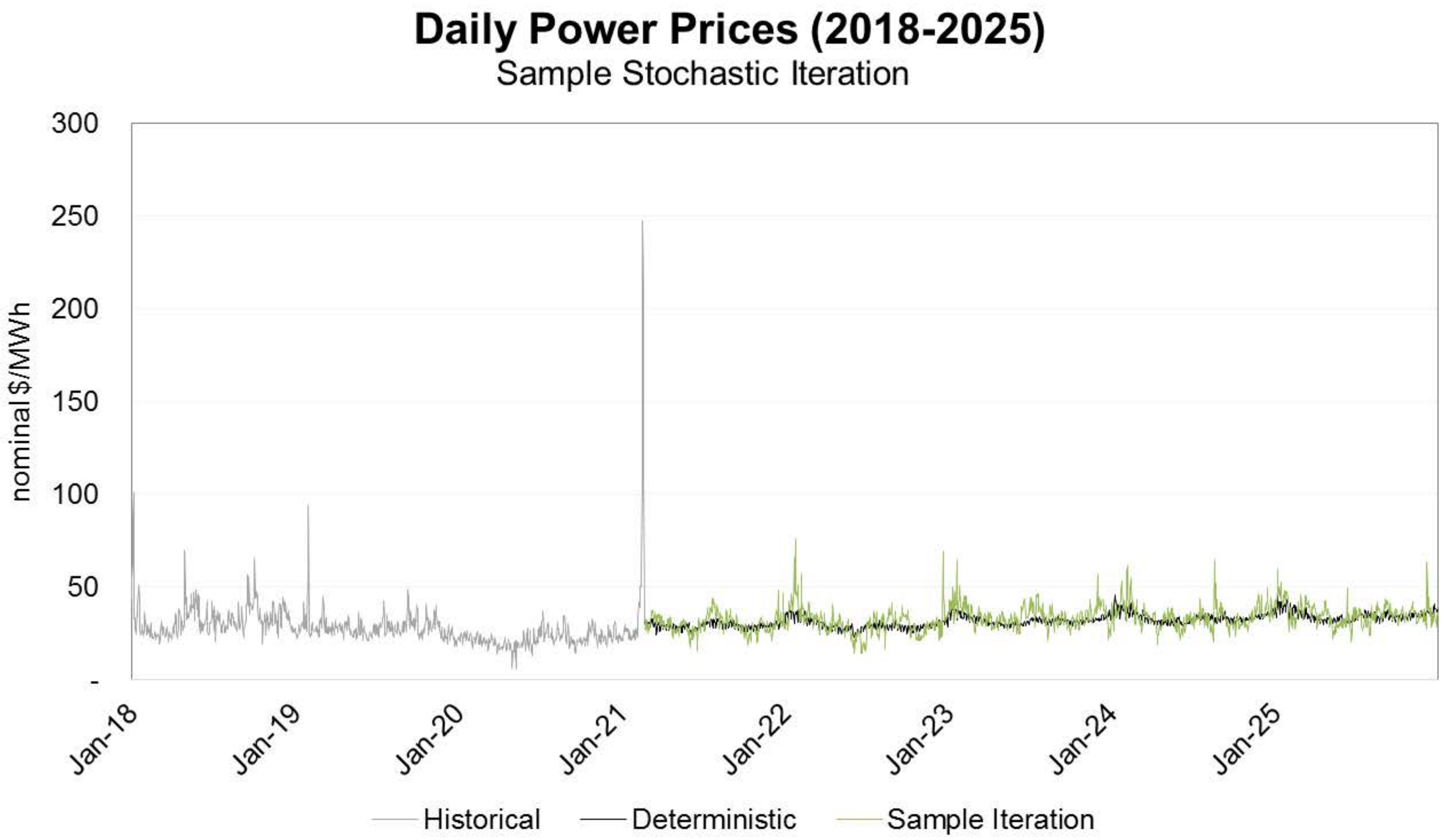
2025



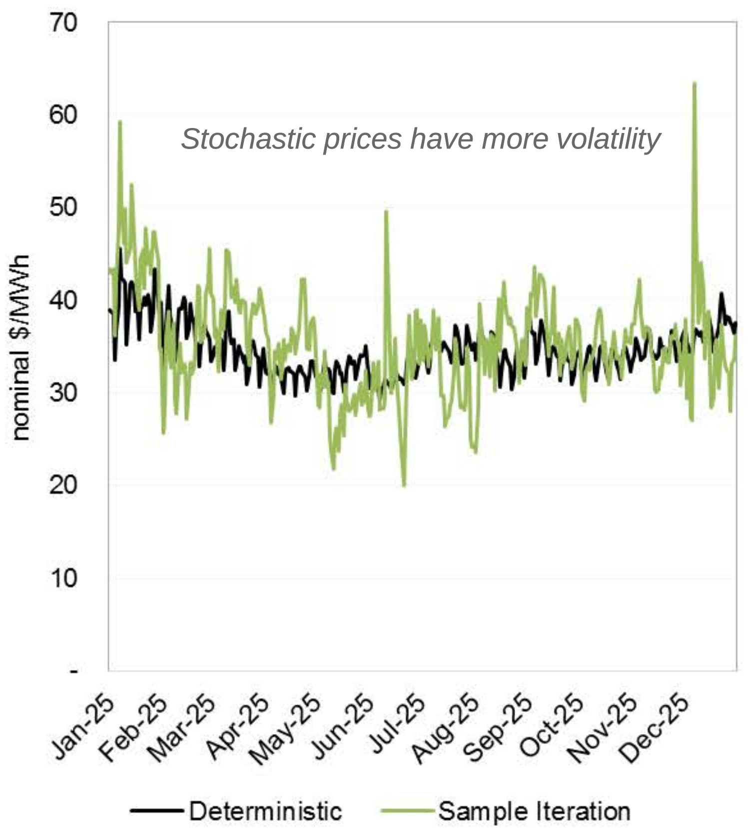
Ref Case Forecast

SAMPLE POWER PRICE ITERATIONS

Individual stochastic price iterations display more variation than deterministic forecast models

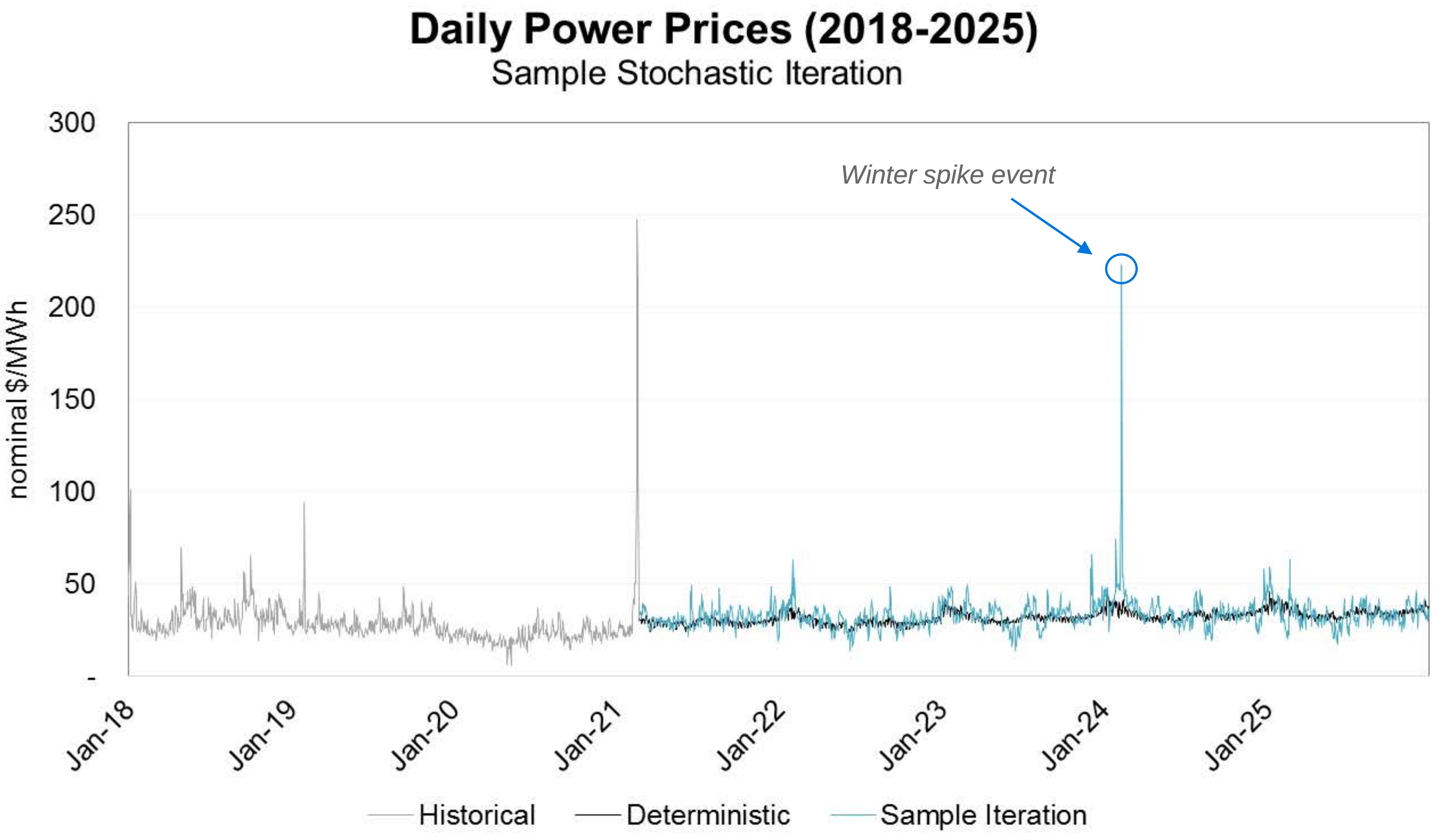


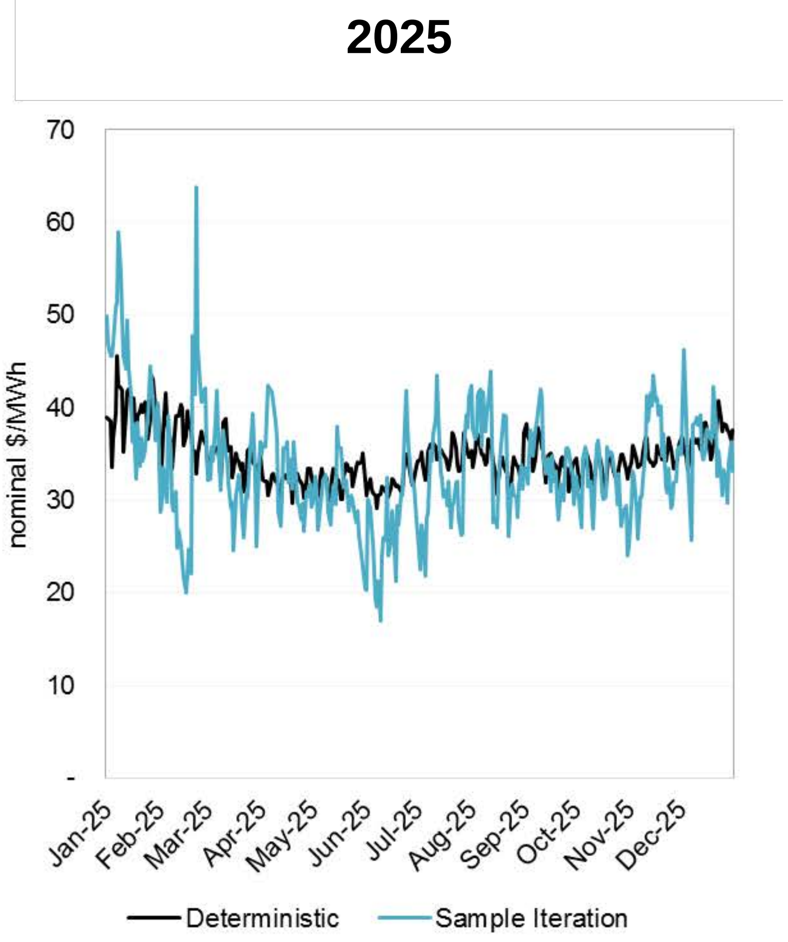
2025



SAMPLE POWER PRICE ITERATIONS

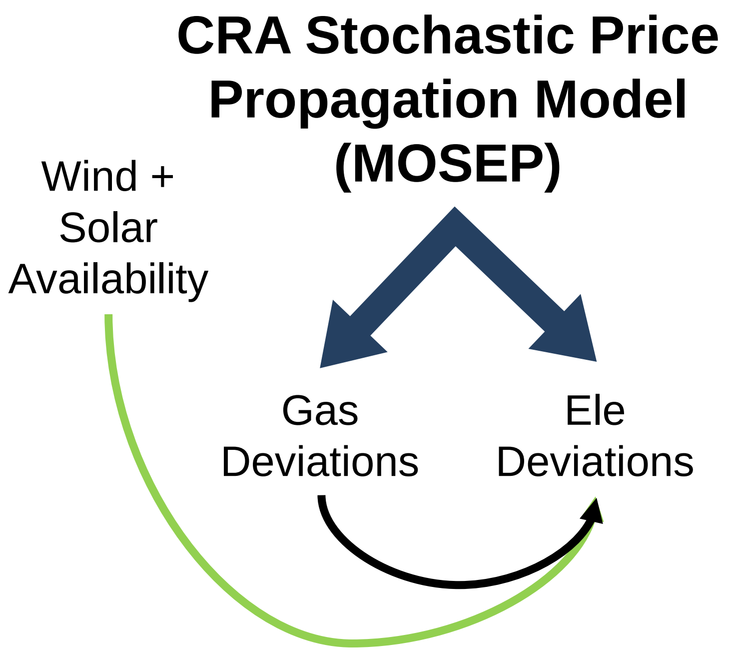
Individual stochastic price iterations display more variation than deterministic forecast models





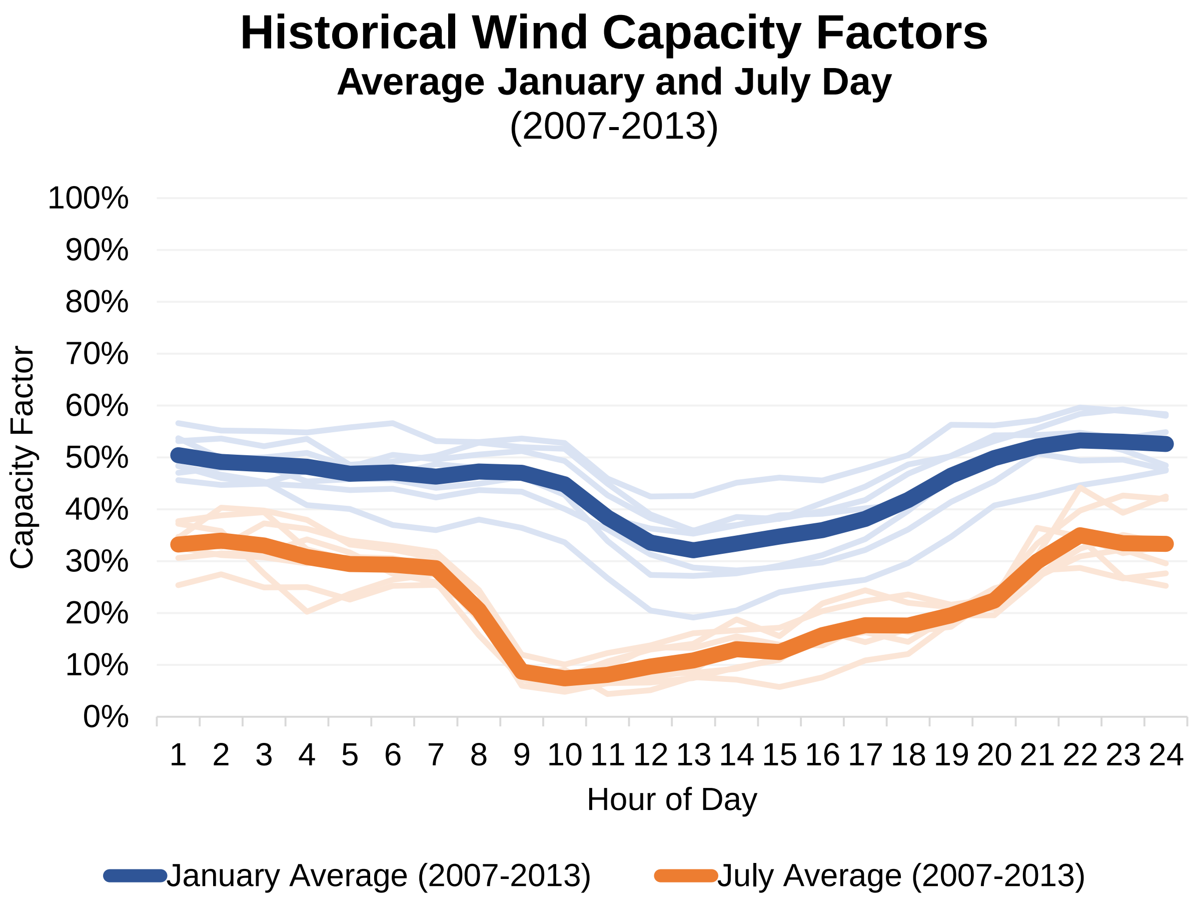
2021 IRP ENHANCEMENT – INTEGRATING RENEWABLE OUTPUT UNCERTAINTY

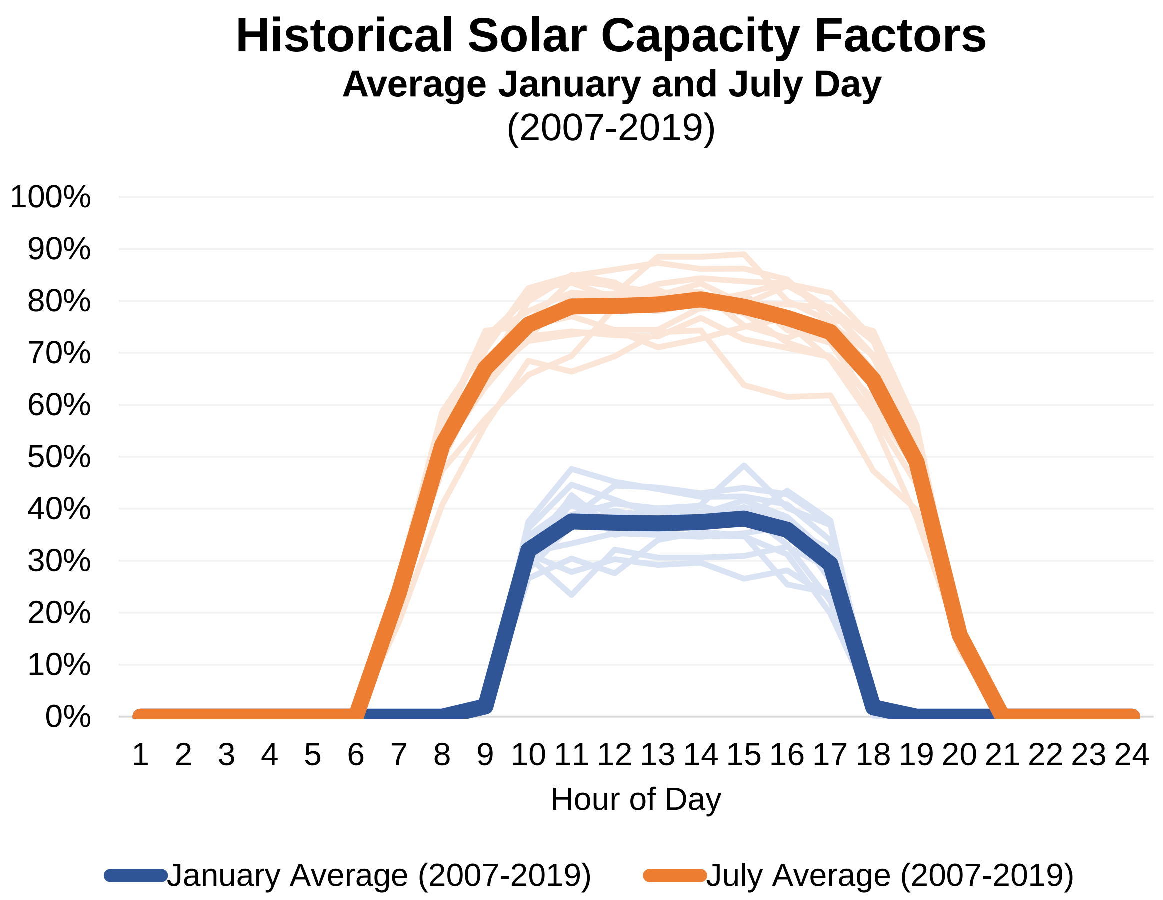
- Assuming that power prices and renewable output evolve independently of each other potentially **underestimates** the risk of growing levels of intermittent generation in NIPSCO's portfolio
- Higher levels of intermittent generation output are generally expected to depress price levels, but the magnitude 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



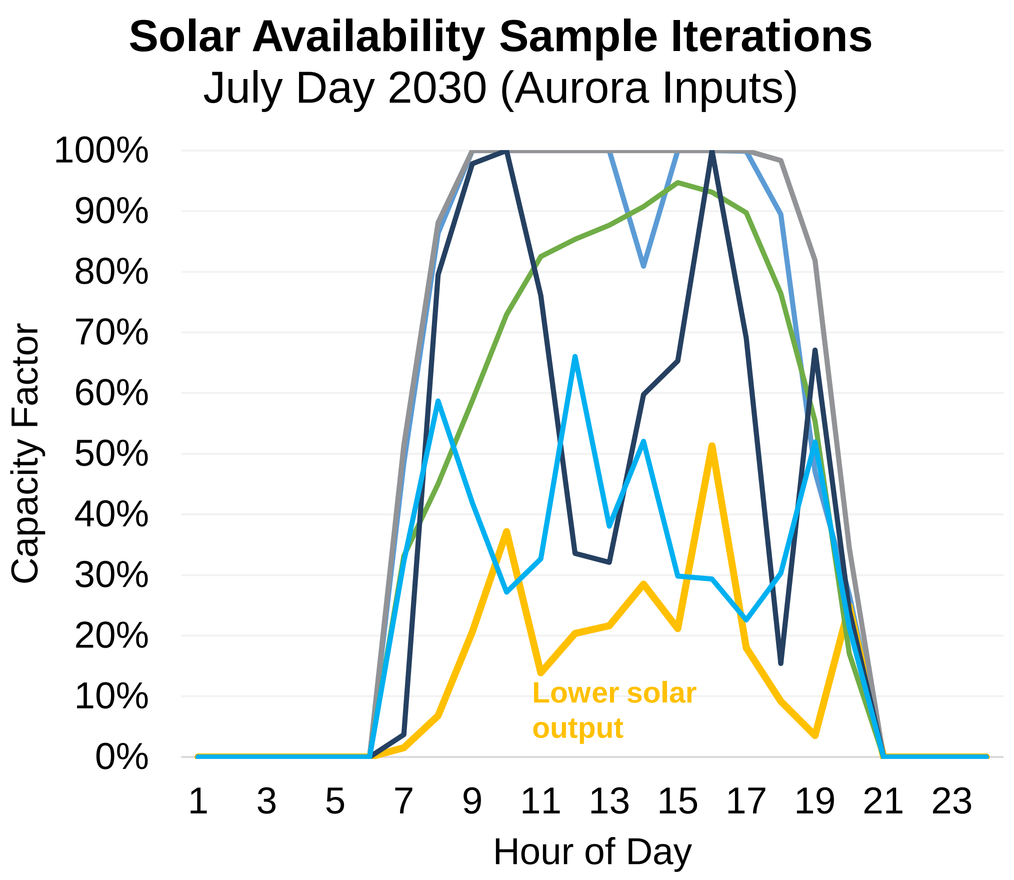


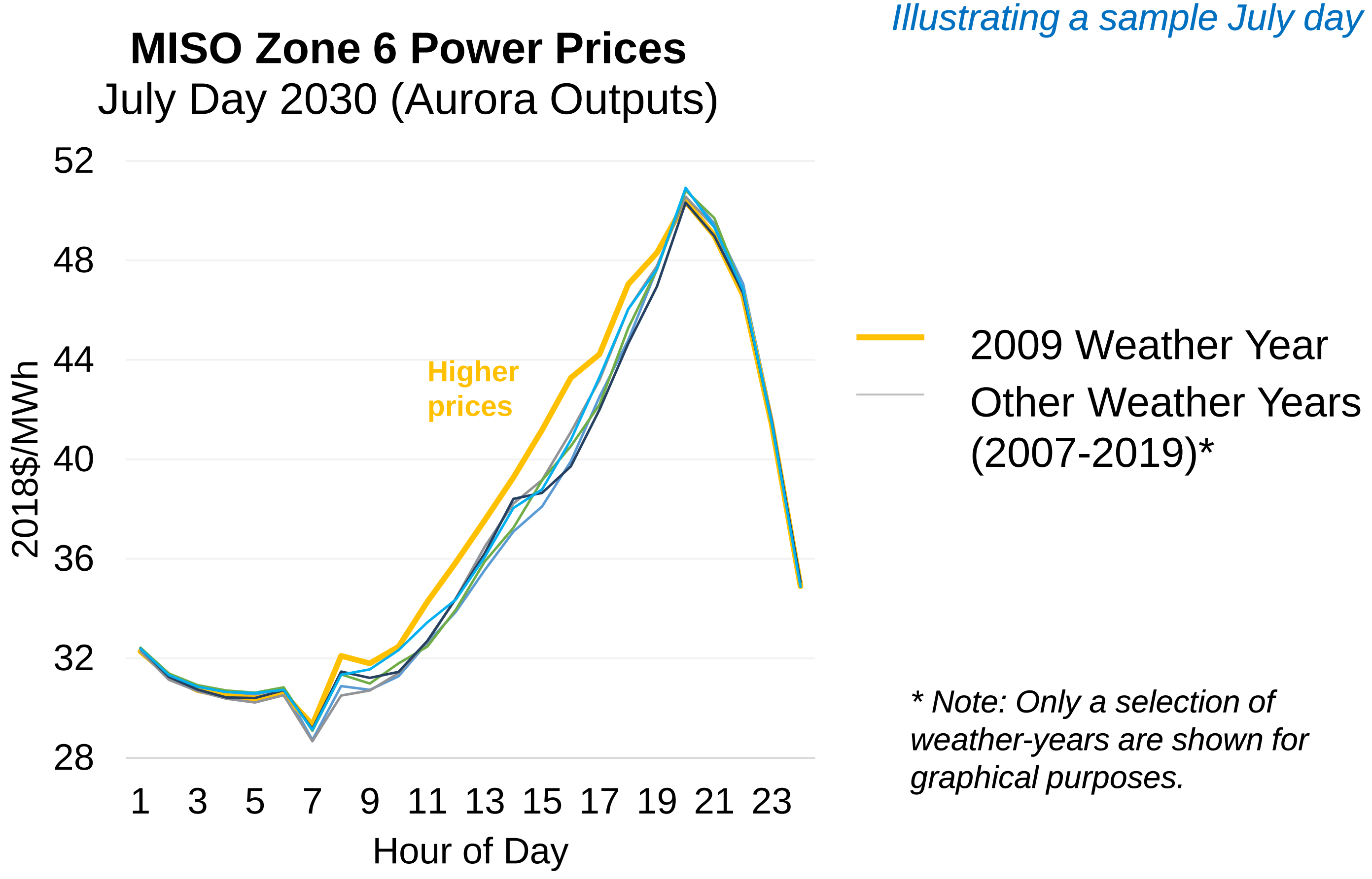
HOURLY RENEWABLE VOLATILITY AND IMPACT TO POWER PRICES

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

Ref Case Forecast

Illustrating a sample July day





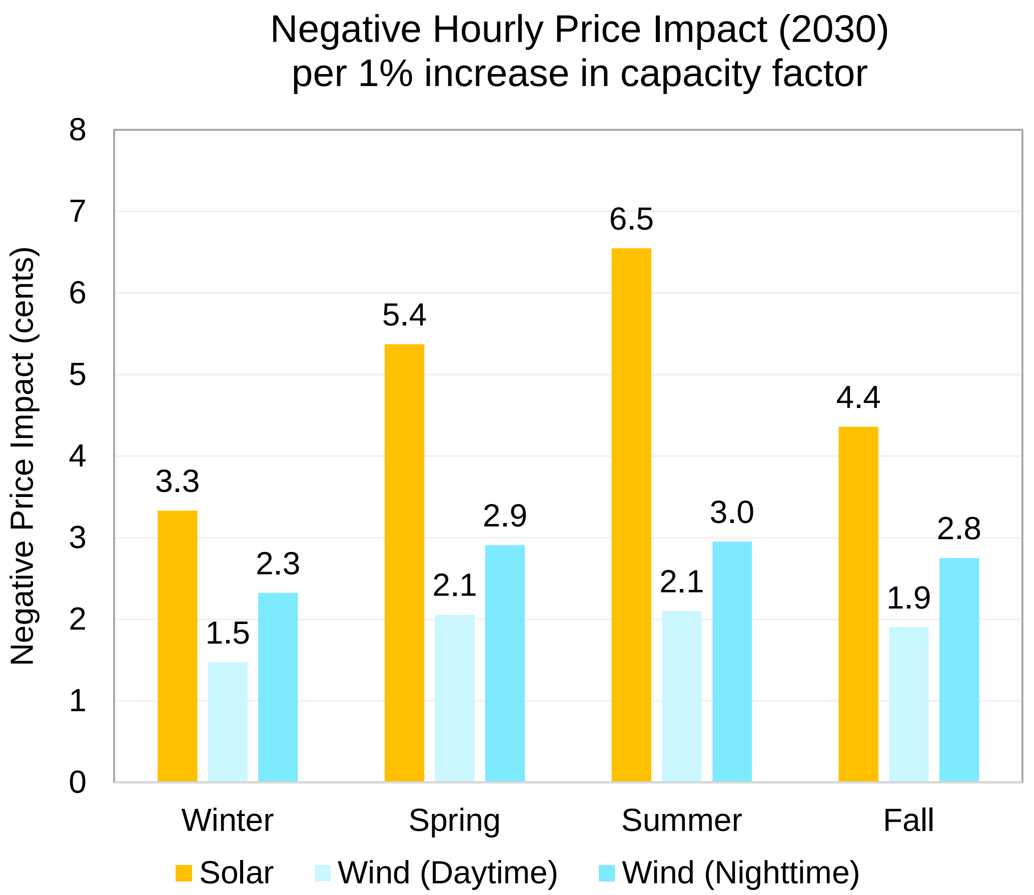
** Note: Only a selection of weather-years are shown for graphical purposes.*

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

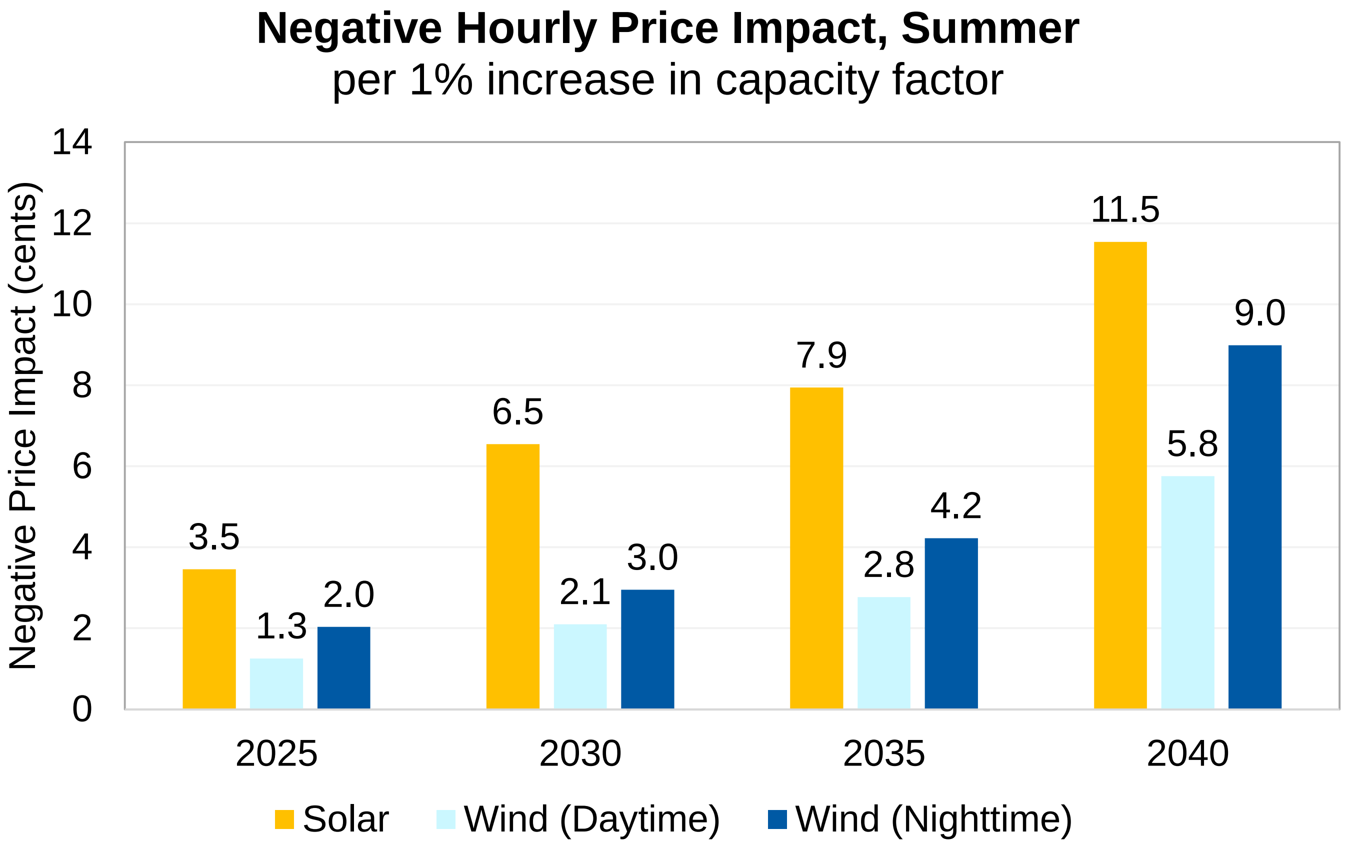


RELATIONSHIP BETWEEN RENEWABLE OUTPUT AND POWER PRICES

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

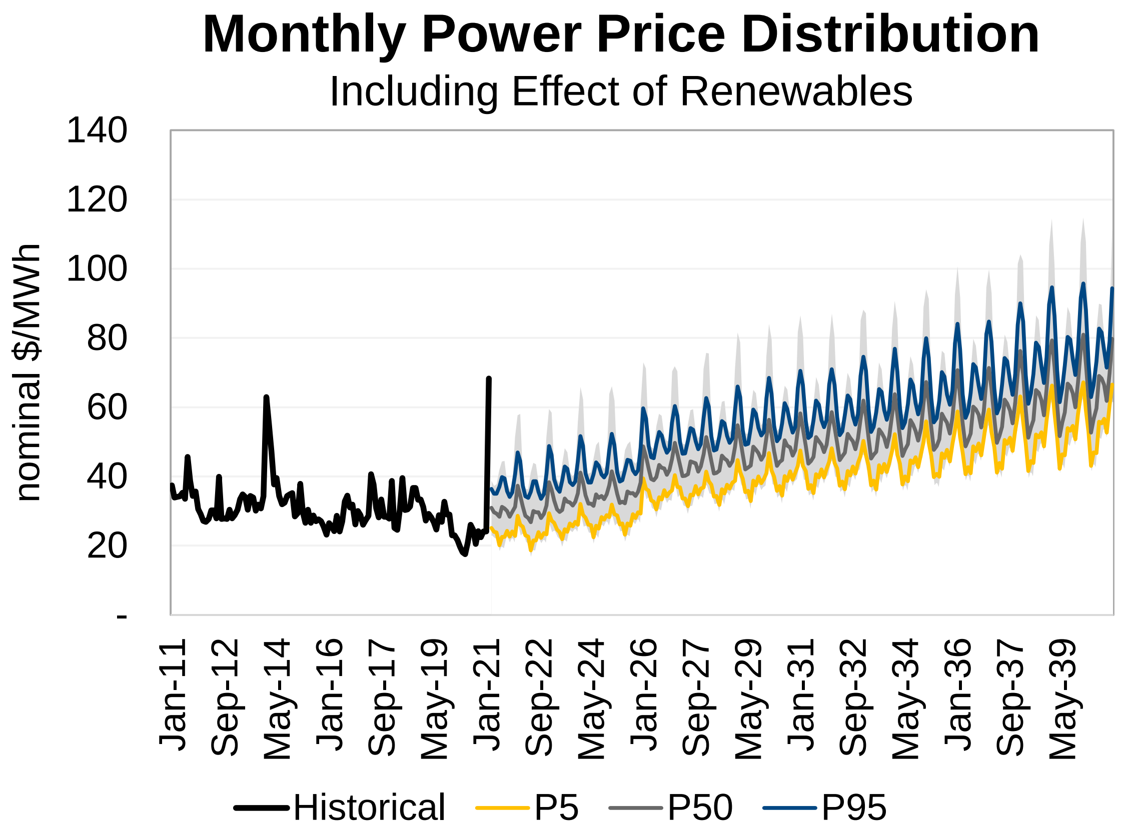
Finding #2:

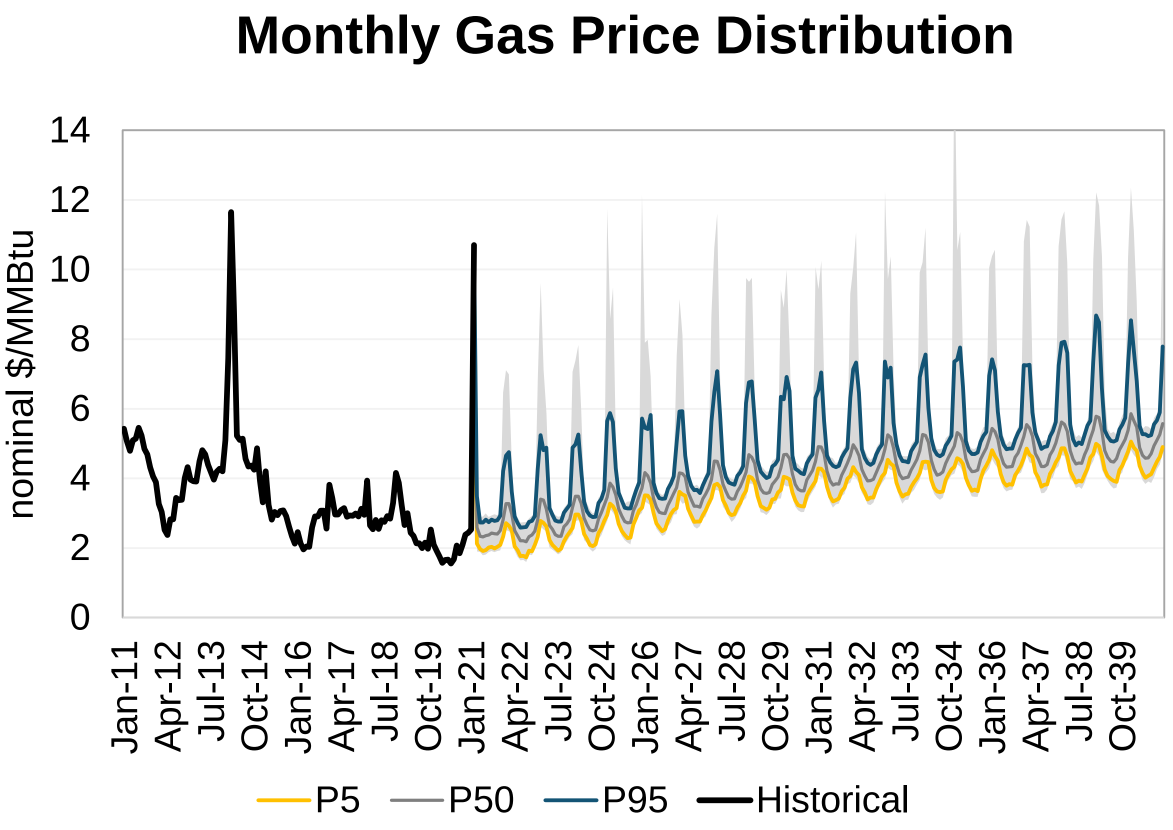
- Impact of renewable availability on power prices increases with level of renewable penetration



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*

NIPSCO 2021 RFP

Stakeholder Outreach and Feedback

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

NIPSCO 2021 RFP

Proposal Evaluation Criteria

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 13^{th}
- Reach out to Alison Becker for 1x1 meetings
- Provide requested scenarios by June 30^{th}

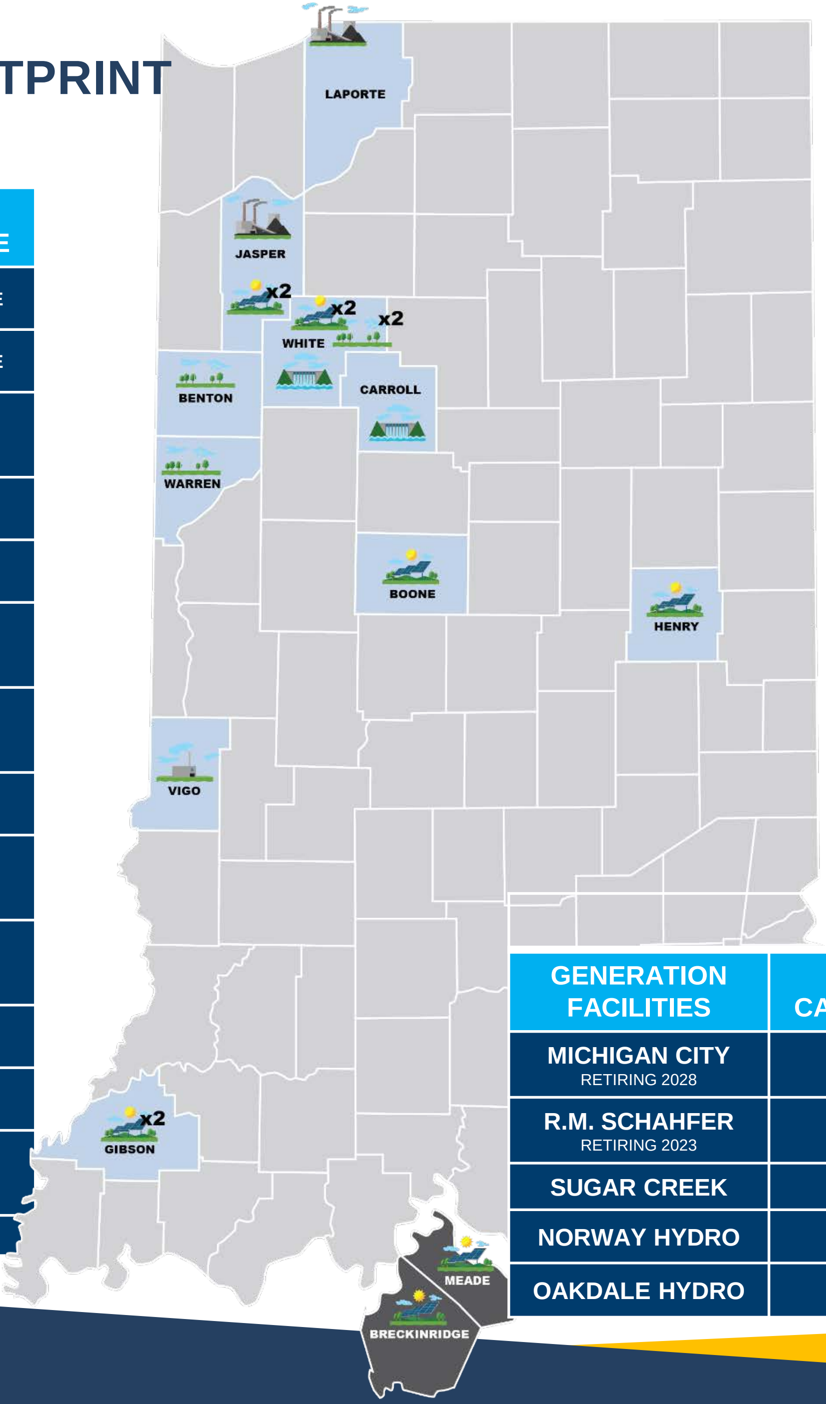
Stakeholder engagement is a critical part of the IRP process

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

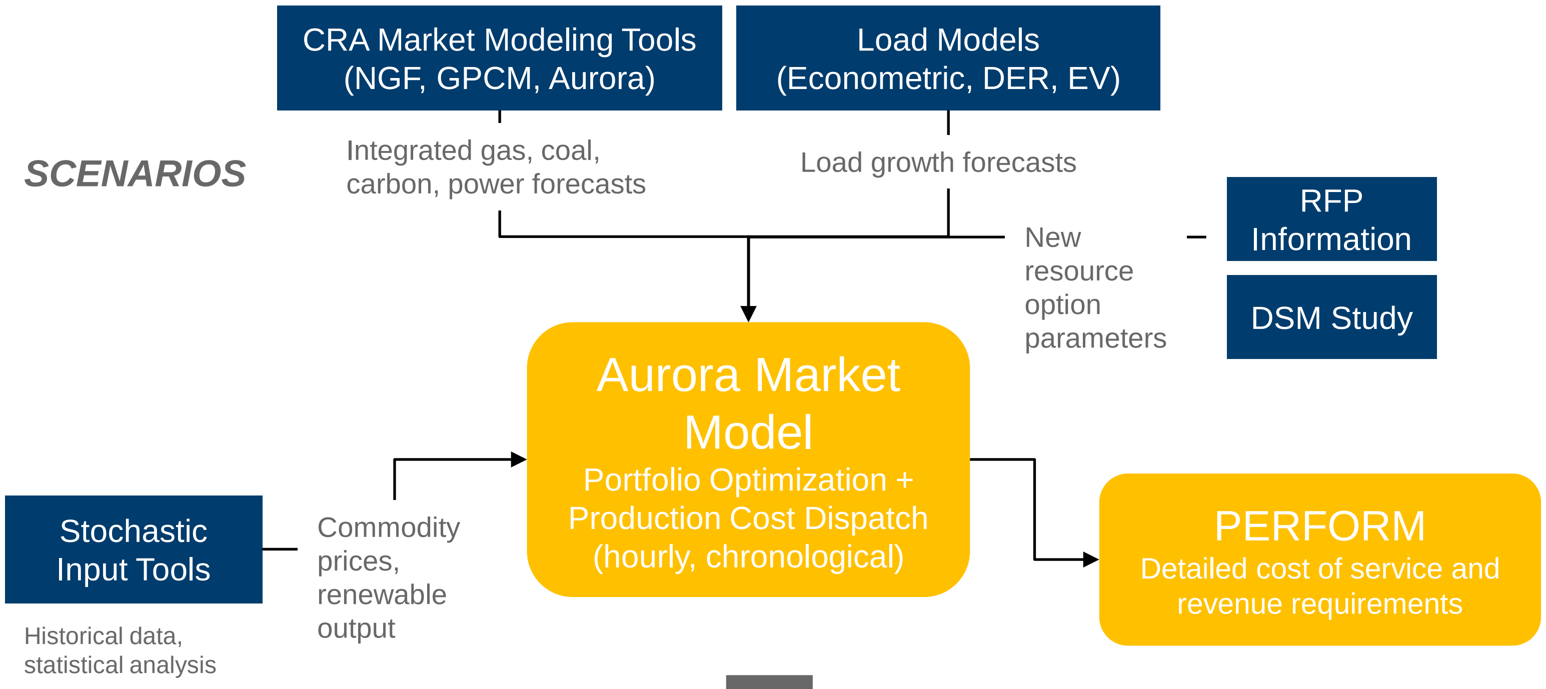
Current Facilities

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

Slide 17 from Stakeholder Meeting #1

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 delta from least	$12,985 $1,222 10.4%	$12,028 $265 2.2%	$11,769 $6 0.1%	$12,956 $1,192 10.1%	$12,121 $357 3.0%	$11,763 $0 0.0%
Cost Certainty delta from least	$13,360 $1,477 12.4%	$12,254 $371 3.1%	$12,007 $124 1.0%	$13,286 $1,403 11.8%	$12,245 $362 3.0%	$11,883 $0 0.0%
Cost Risk delta from least	$14,431 $2,067 16.7%	$12,922 $558 4.5%	$12,661 $297 2.4%	$14,284 $1,920 15.5%	$12,815 $452 3.7%	$12,364 $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 CO_2 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

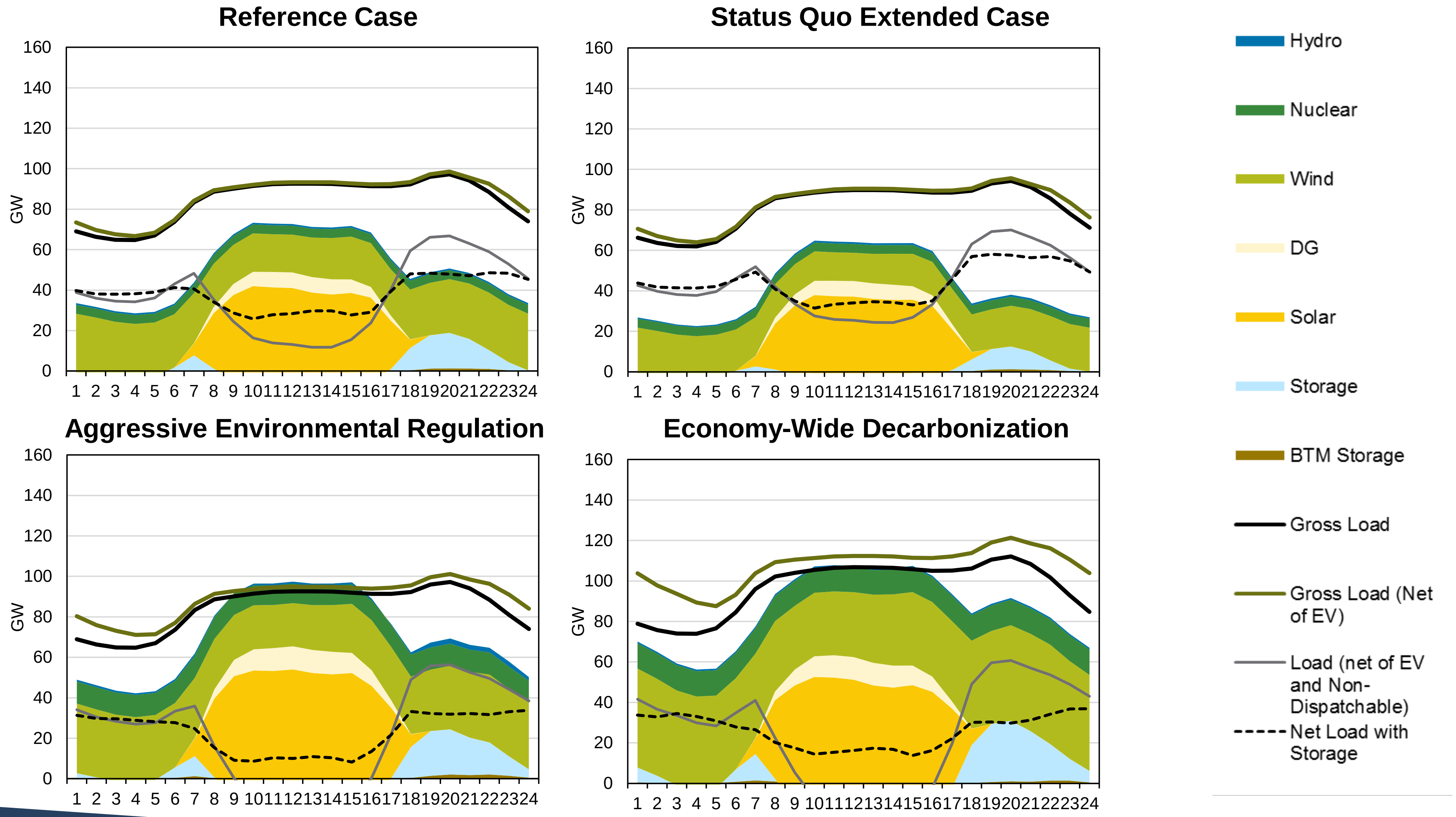
LOW CASE (STATUS QUO EXTENDED) SUPPLY DRIVERS

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

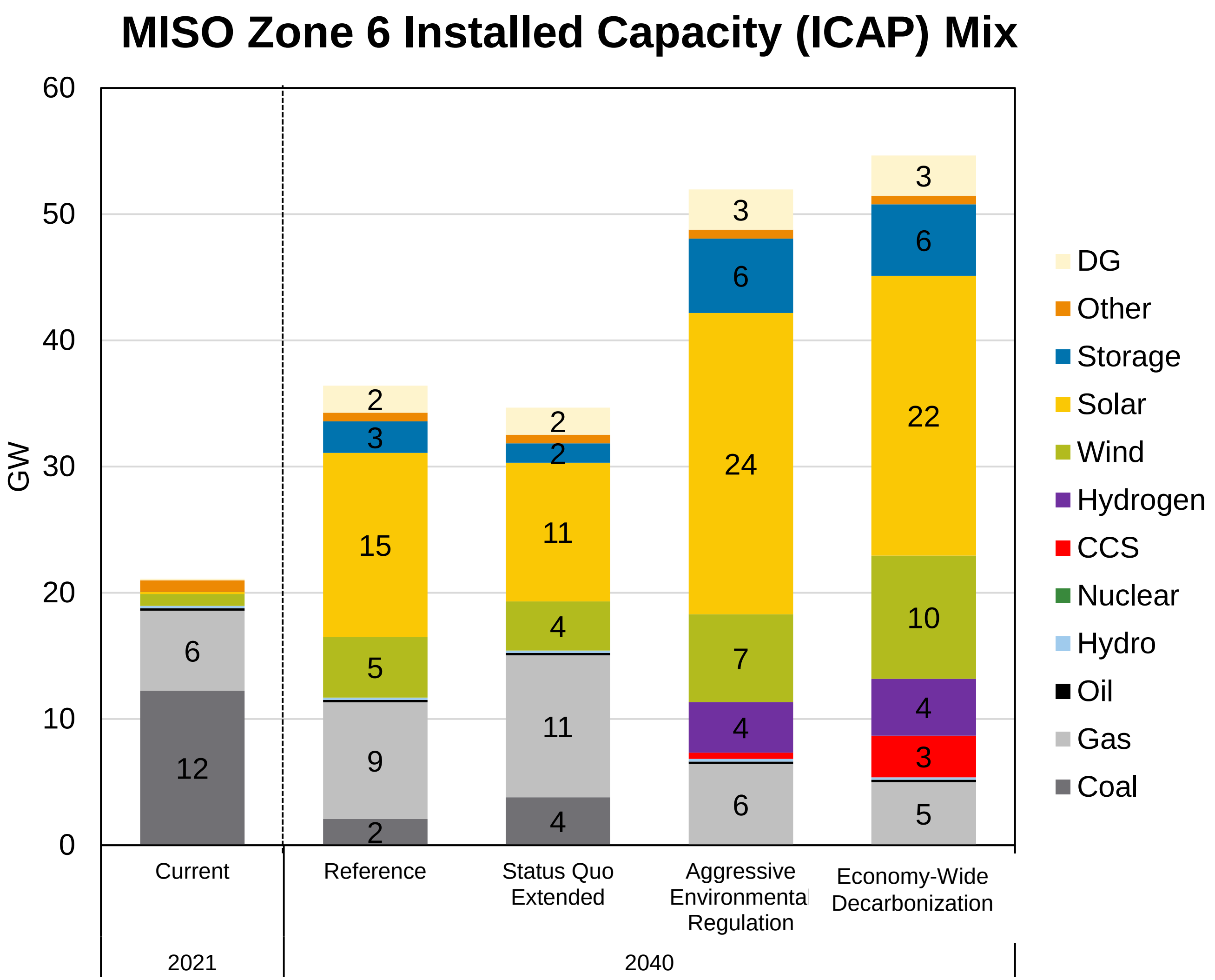
LOW CASE (STATUS QUO EXTENDED) DEMAND DRIVERS

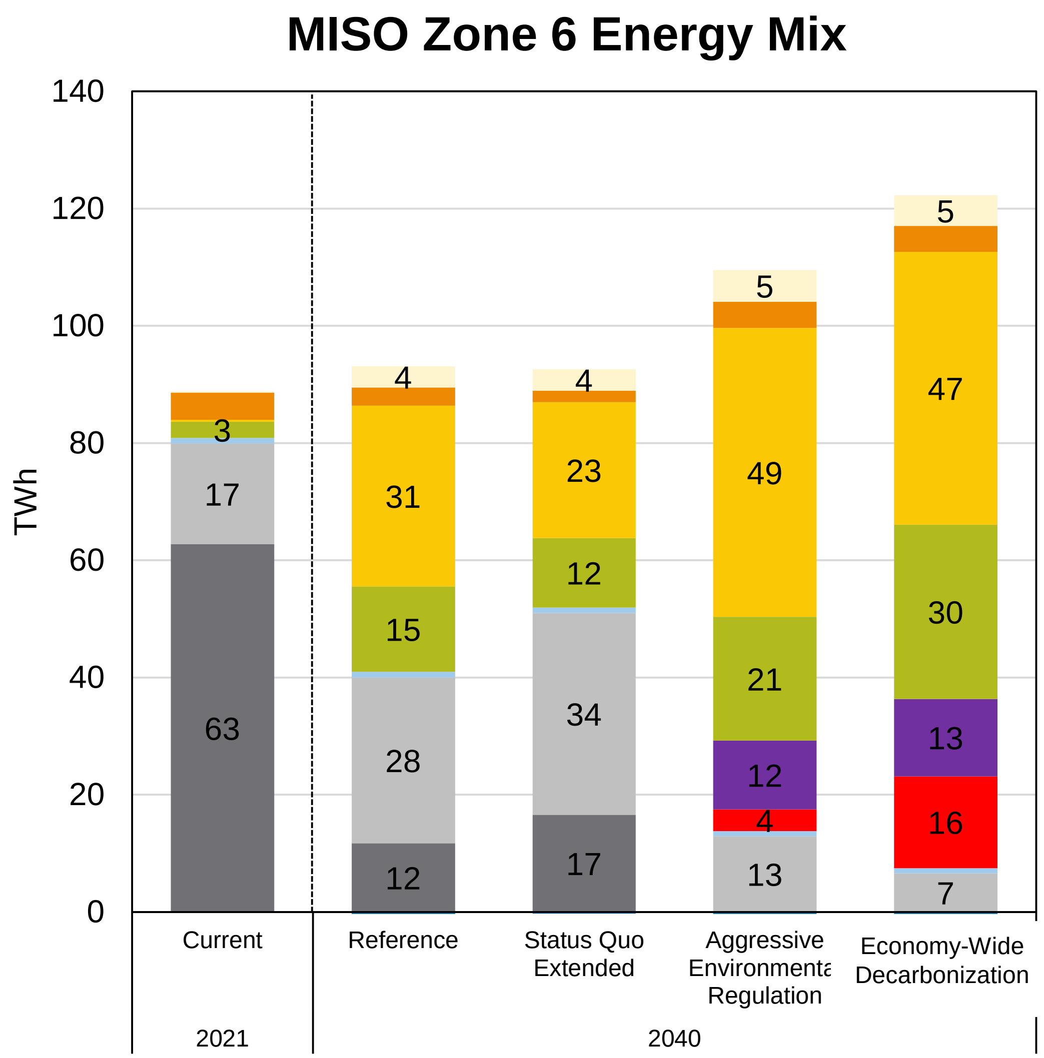
Driver	CRA Approach	Explanation
Domestic Demand	• Electric demand reflects Status Quo Extended case • No change to non-electric demand	Electric demand taken from Aurora Status Quo Extended scenario, **which is higher than Reference Case** Non-electric demand already reflects **limited transformation 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



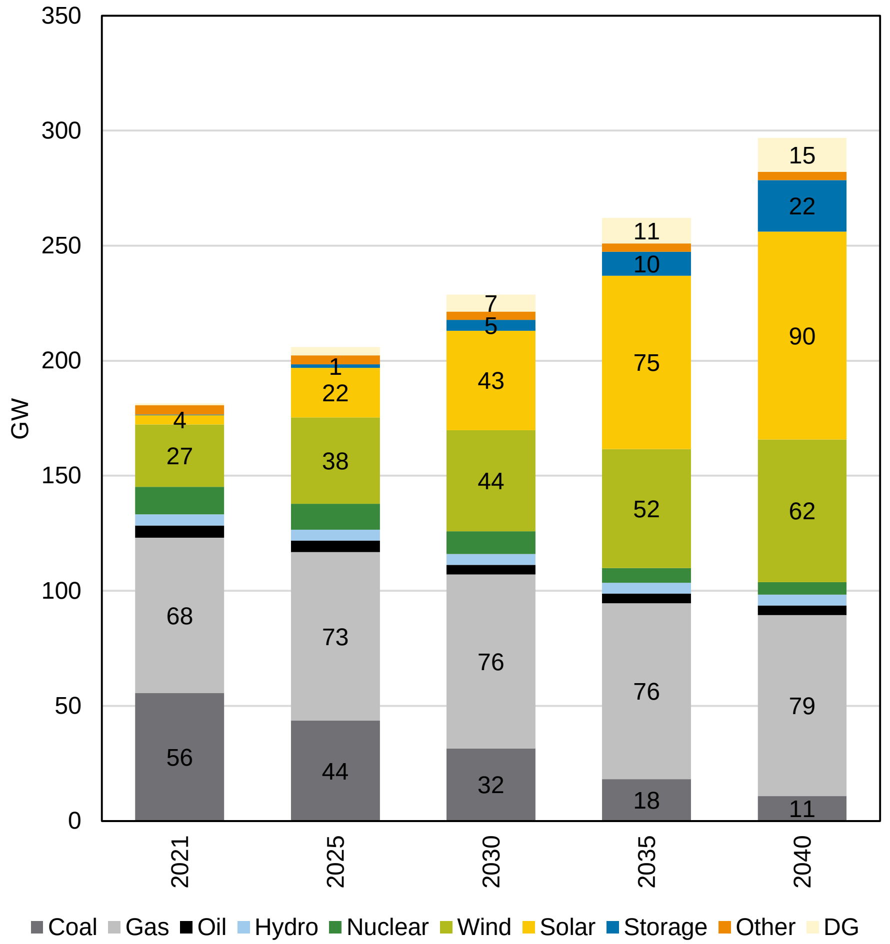
MISO ZONE 6 CAPACITY AND ENERGY MIX OUTLOOK ACROSS SCENARIOS



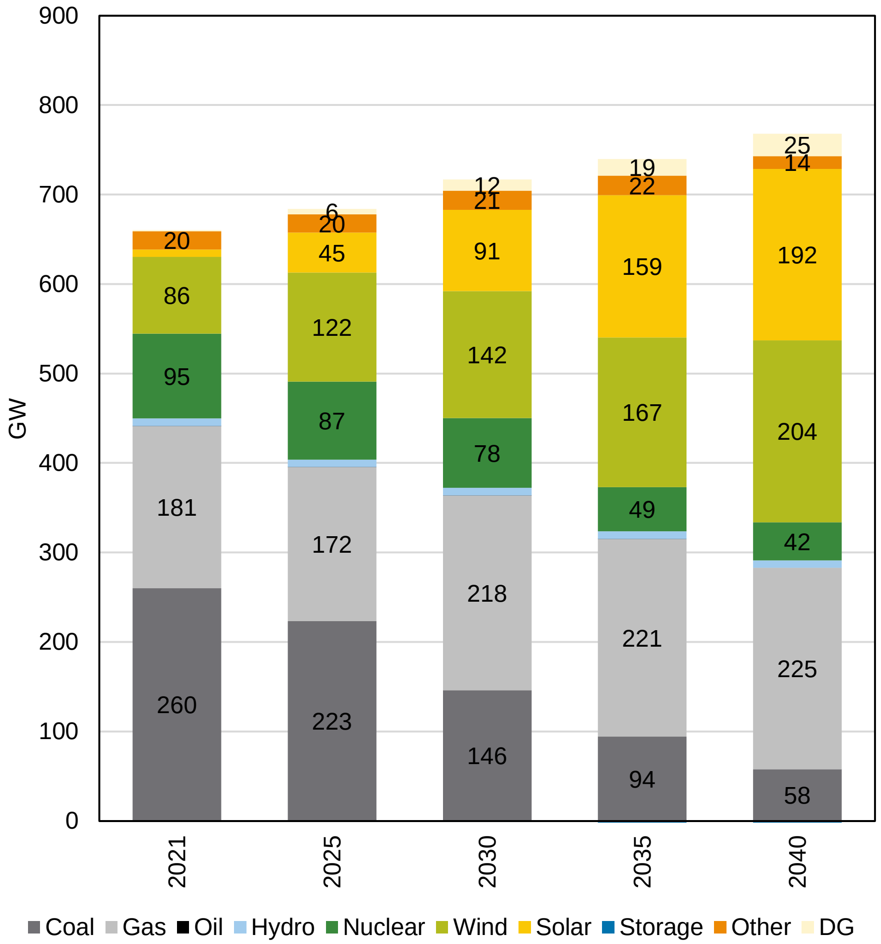


REFERENCE CASE – MISO SUPPLY MIX OUTLOOK

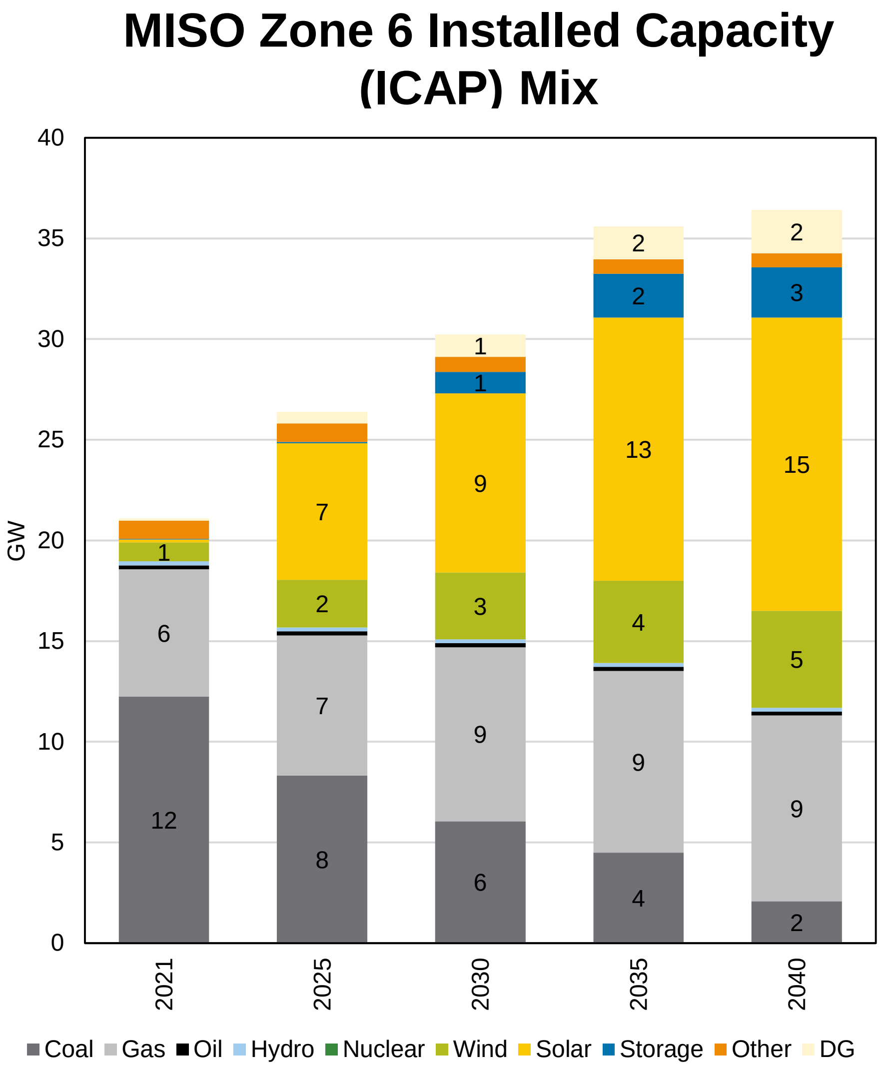
MISO Installed Capacity (ICAP) Mix

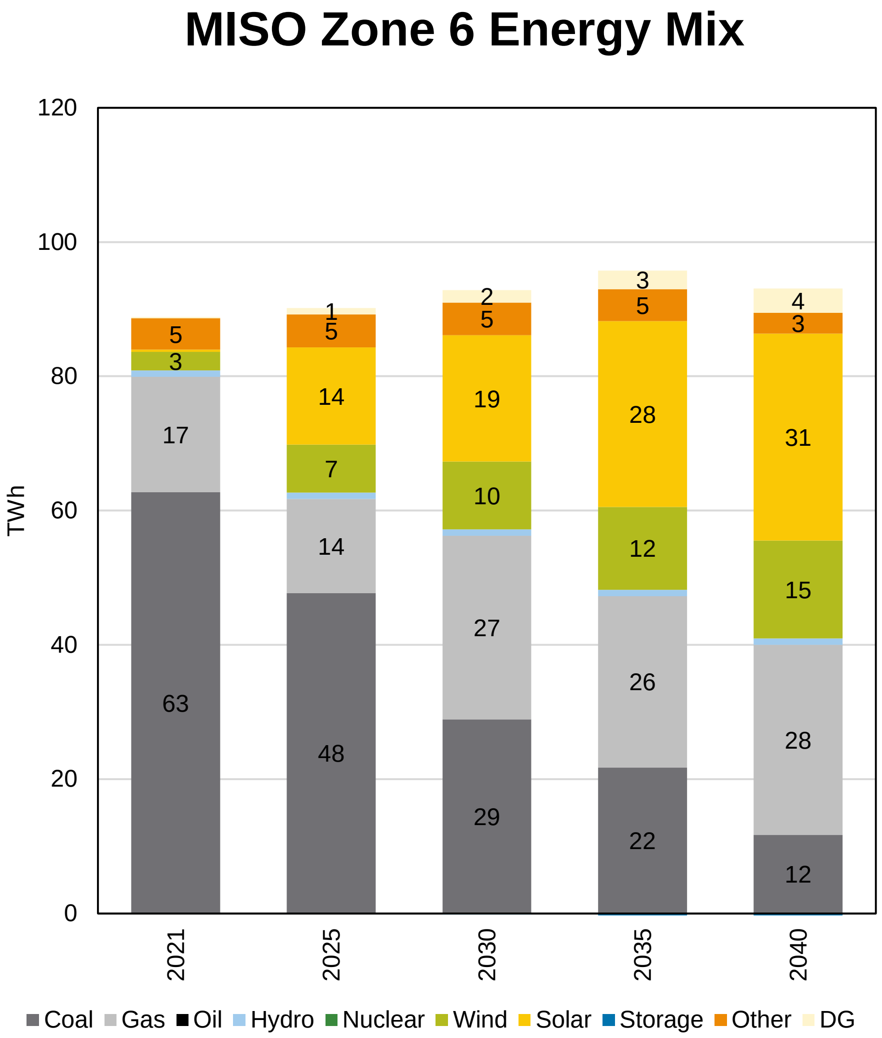


MISO Energy Mix

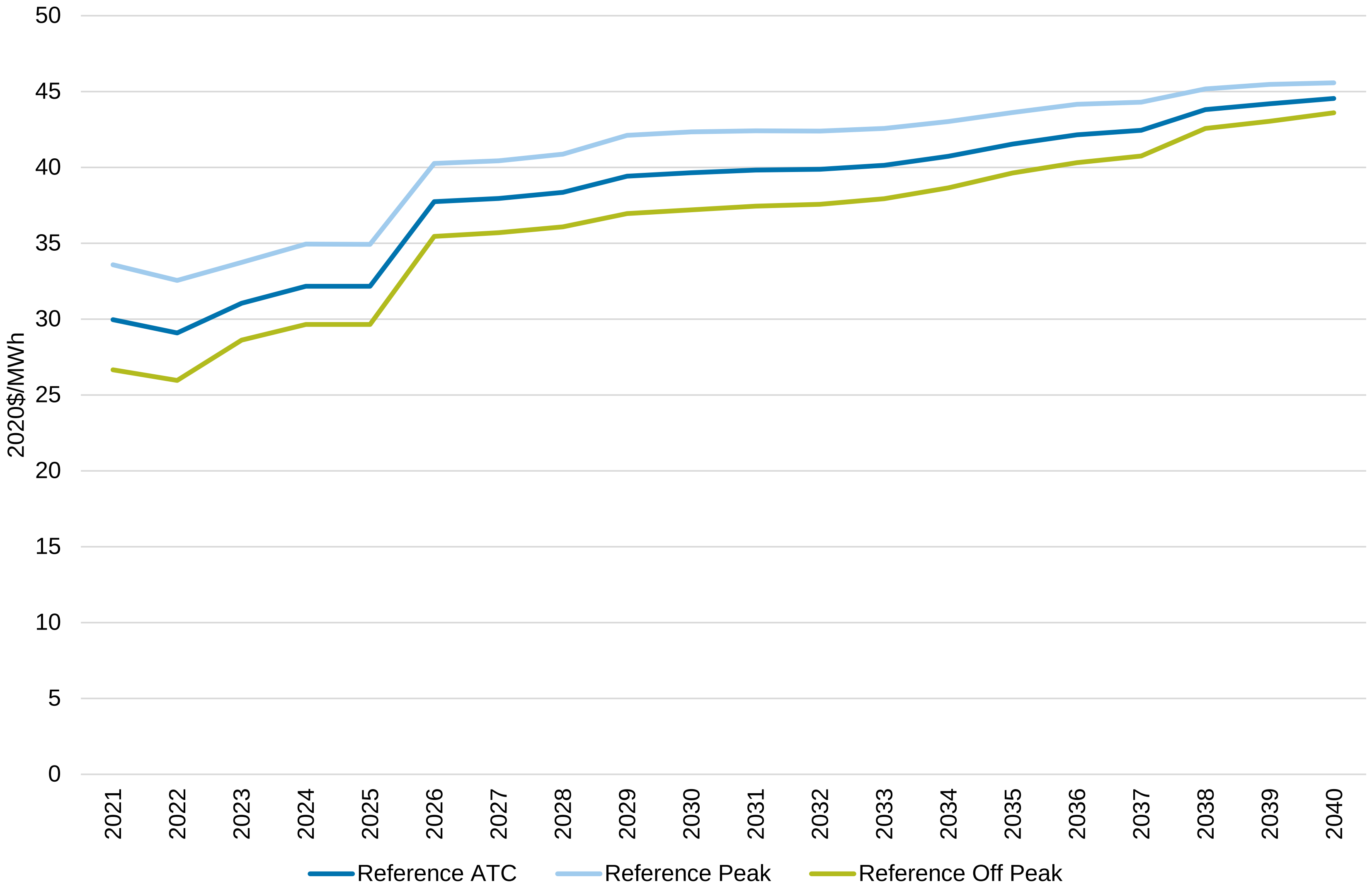


REFERENCE CASE – MISO ZONE 6 SUPPLY MIX OUTLOOK

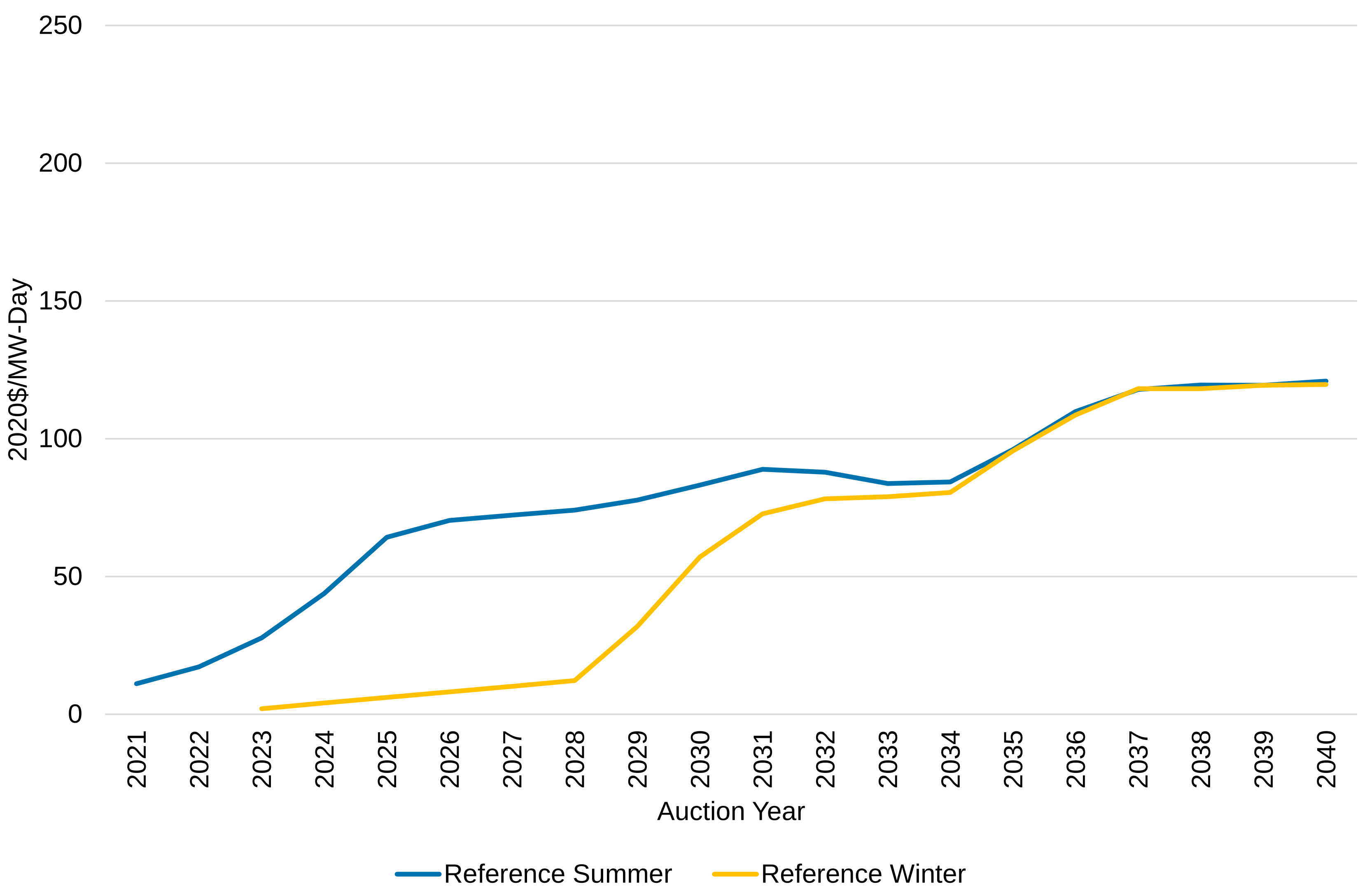




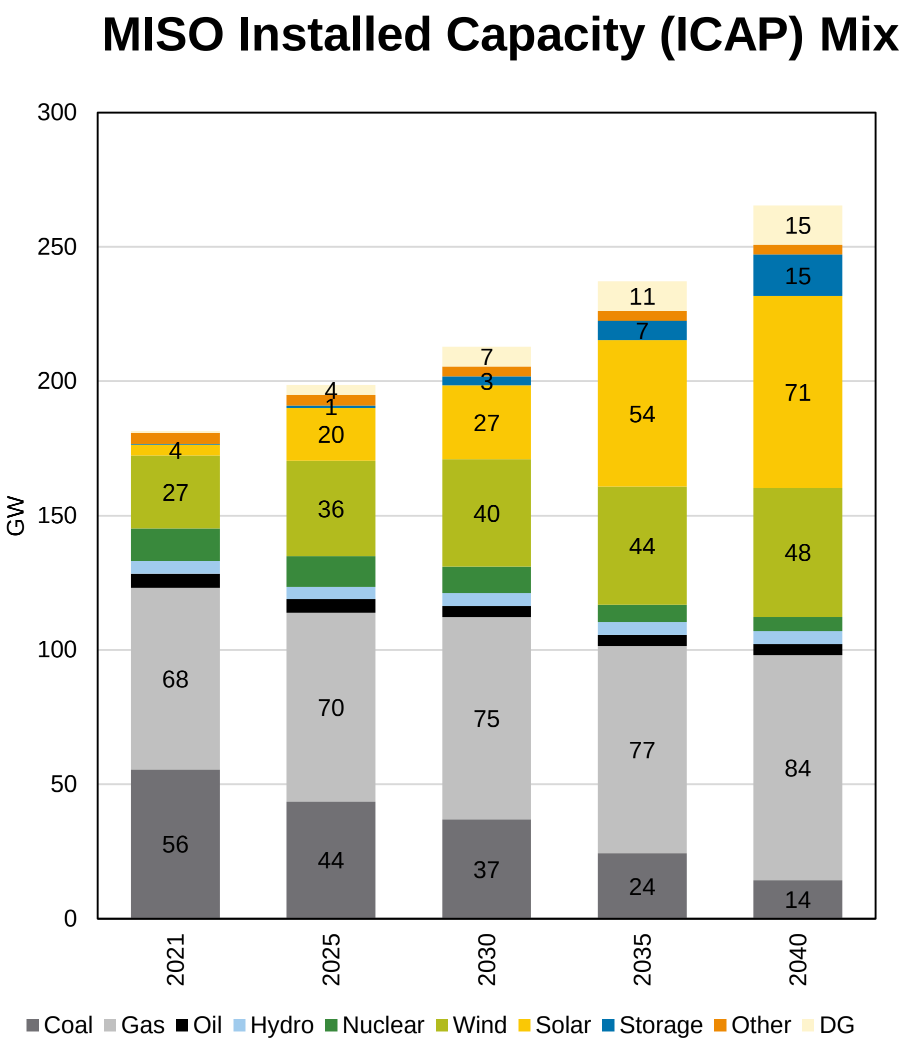
REFERENCE CASE ENERGY PRICE FORECAST

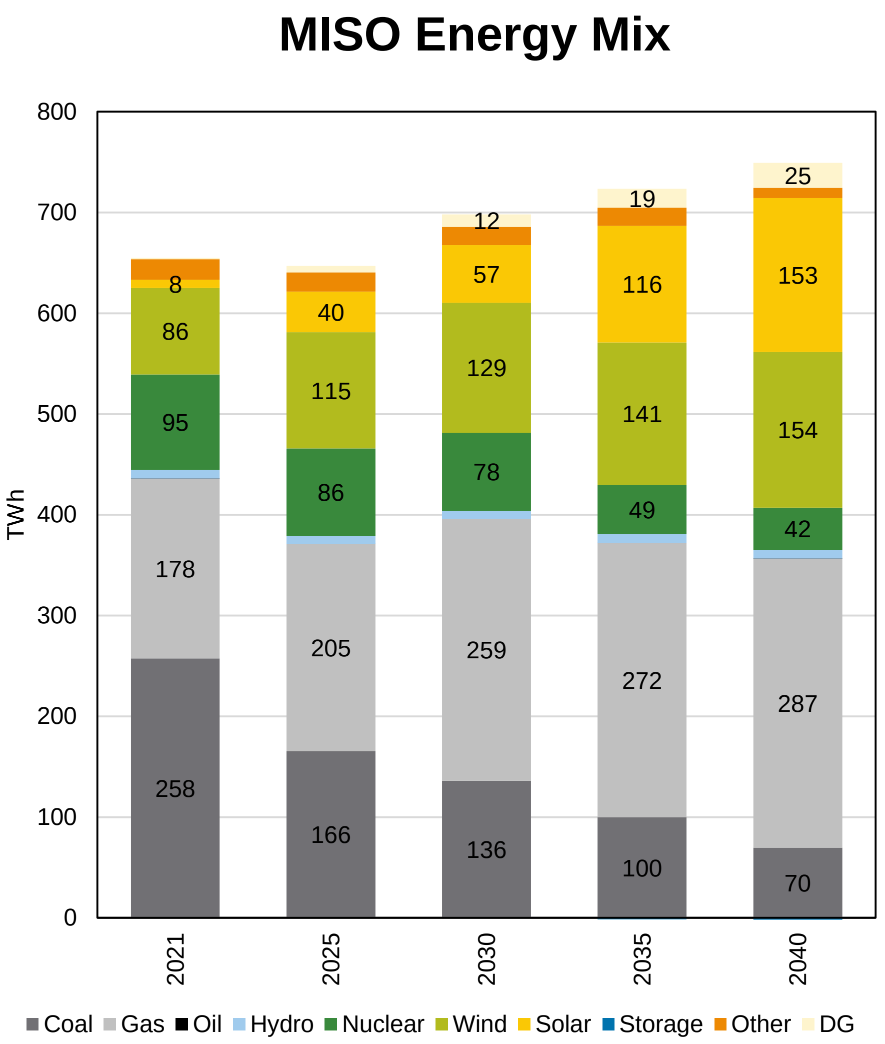


REFERENCE CASE CAPACITY PRICE FORECAST

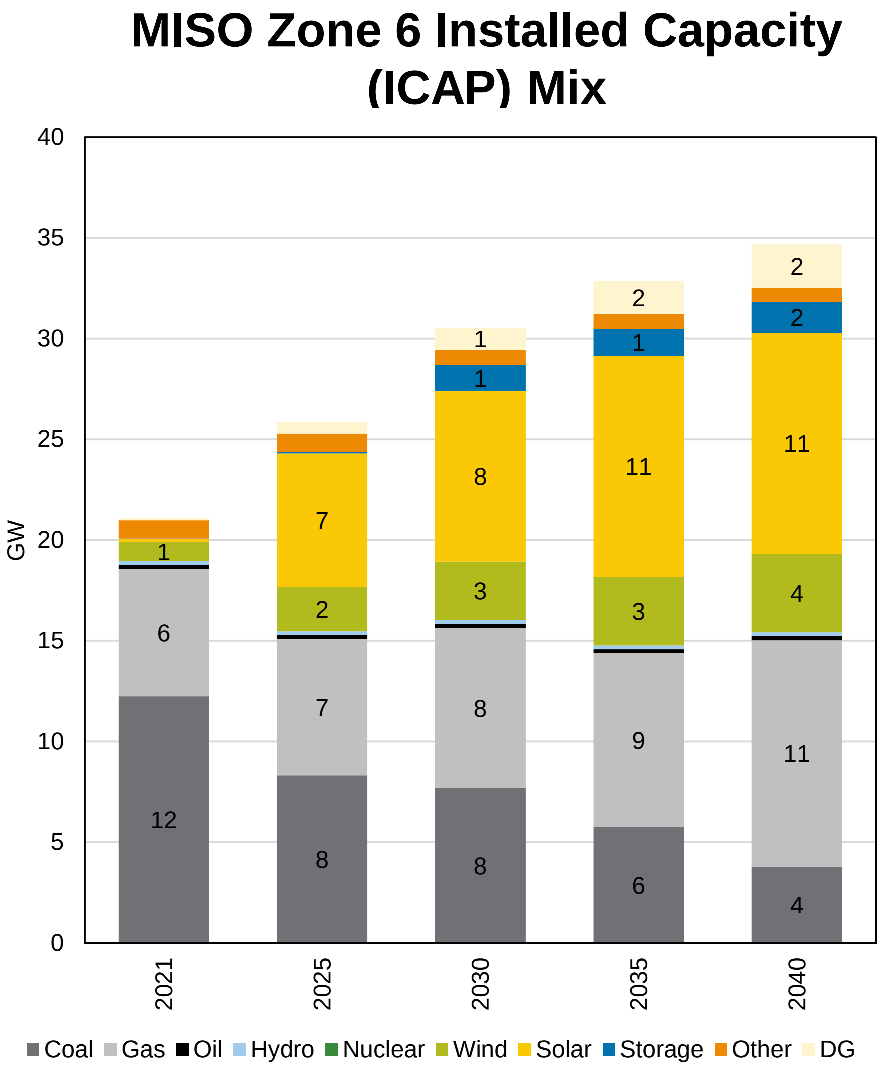


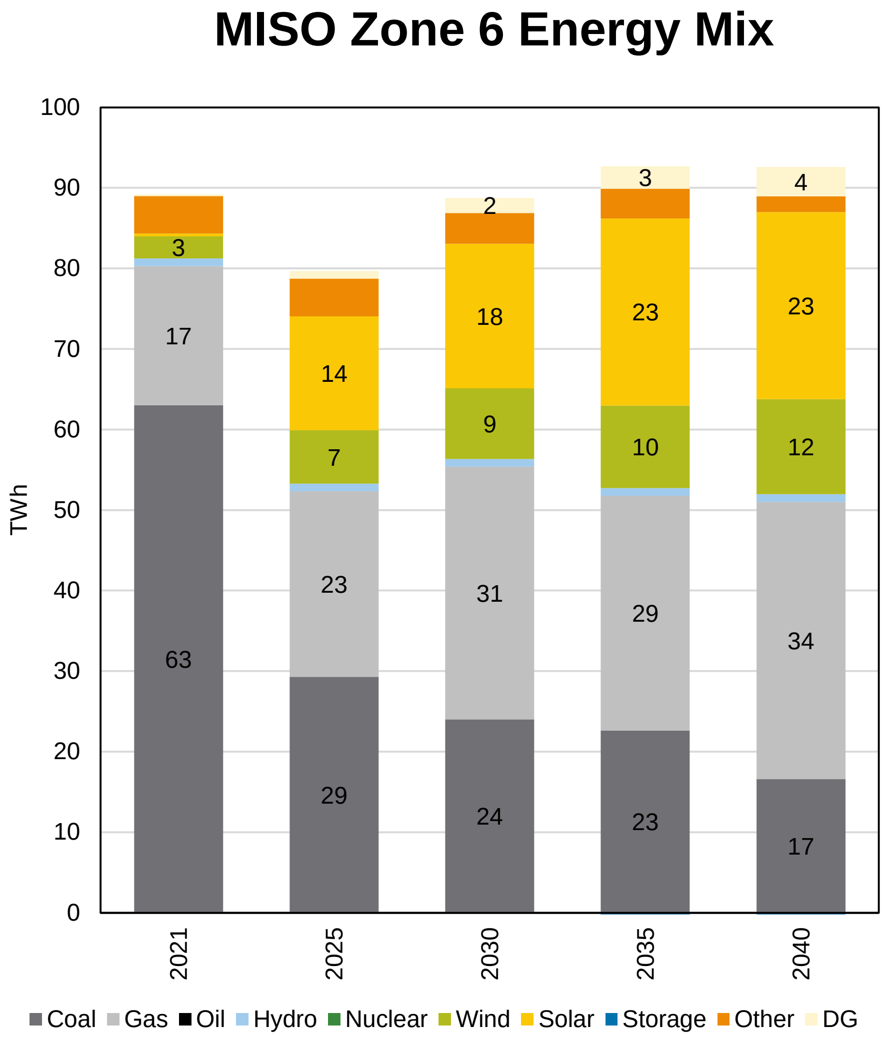
STATUS QUO EXTENDED – MISO SUPPLY MIX OUTLOOK



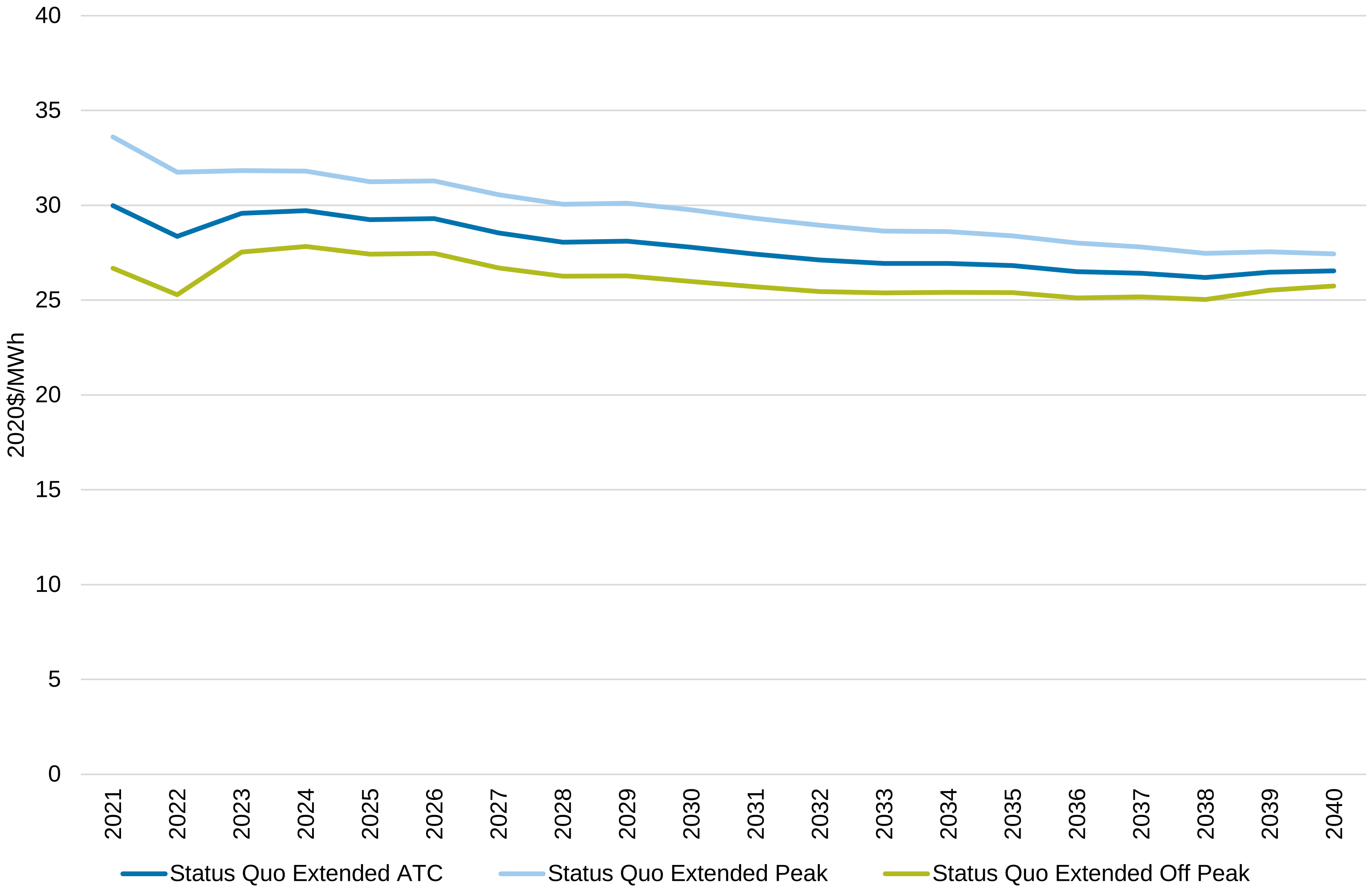


STATUS QUO EXTENDED – MISO ZONE 6 SUPPLY MIX OUTLOOK

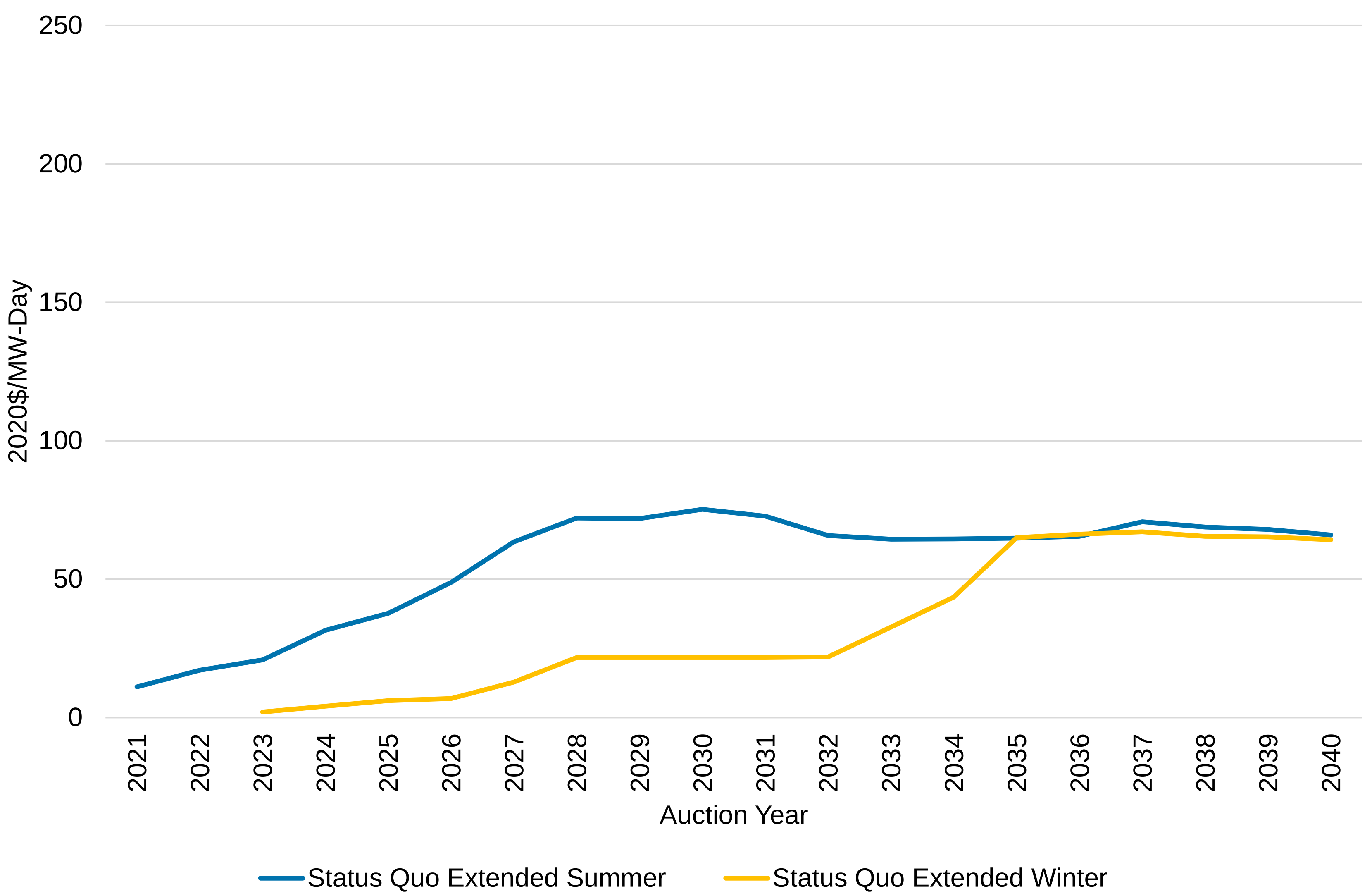




STATUS QUO EXTENDED ENERGY PRICE FORECAST

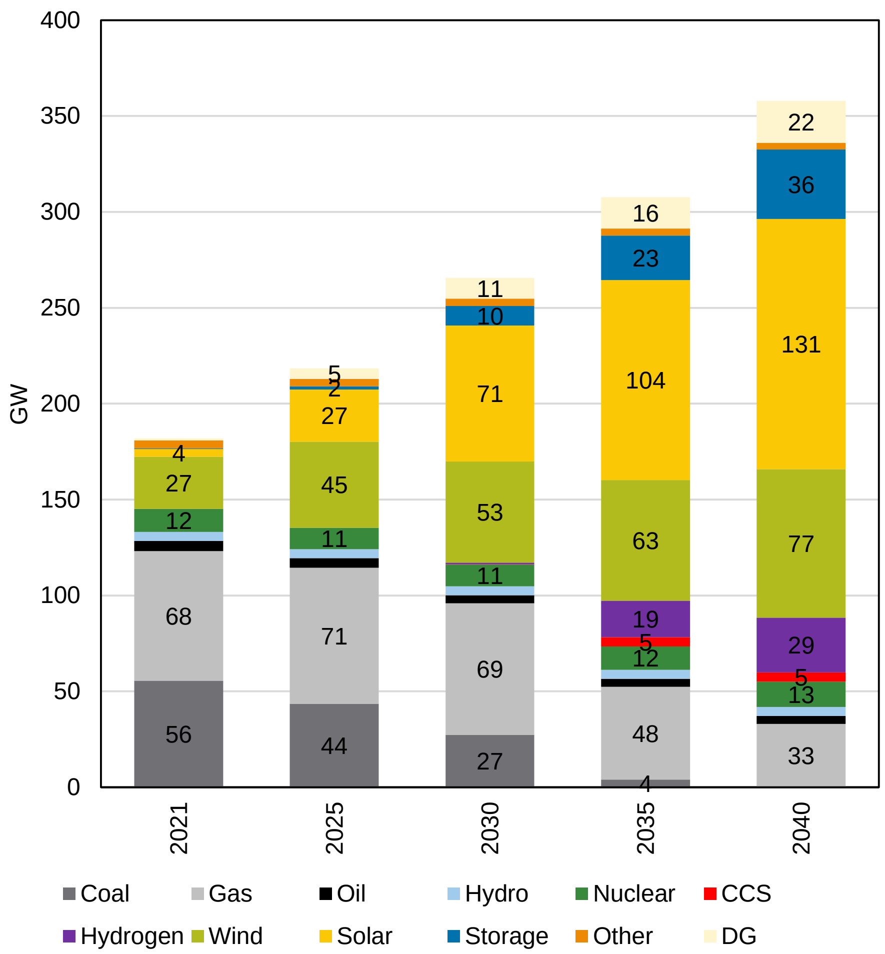


STATUS QUO EXTENDED CAPACITY PRICE FORECAST

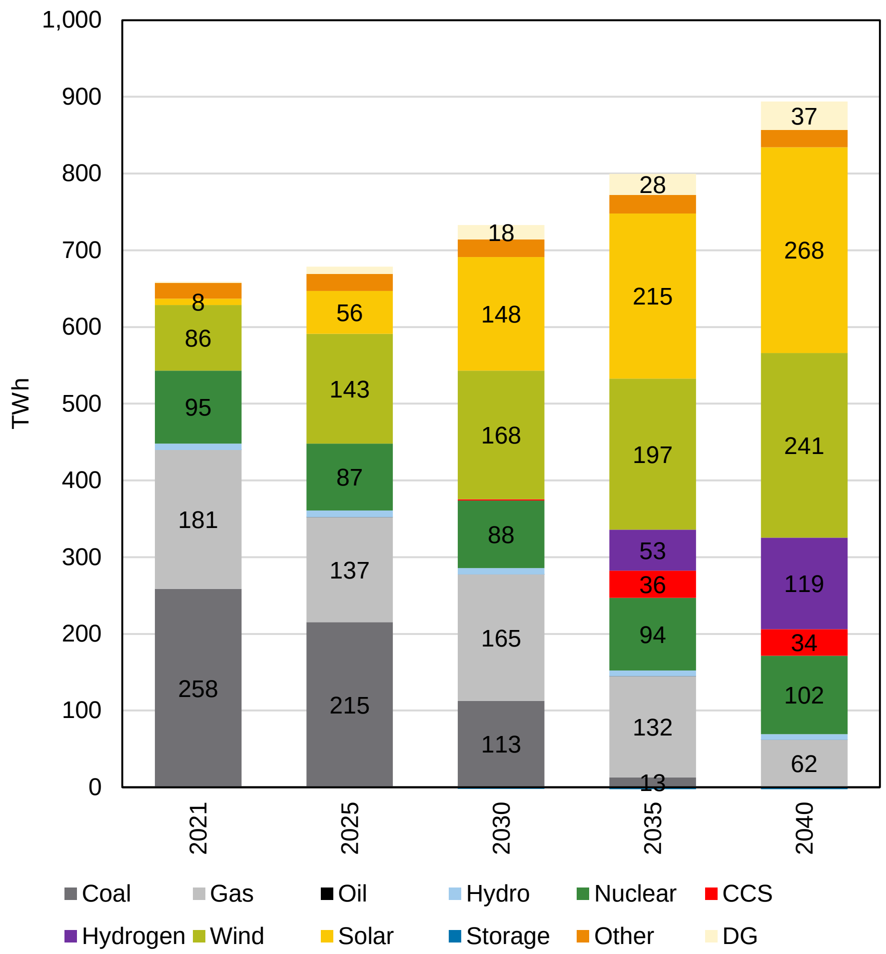


AGGRESSIVE ENVIRONMENTAL REGULATION – MISO SUPPLY MIX OUTLOOK

MISO Installed Capacity (ICAP) Mix

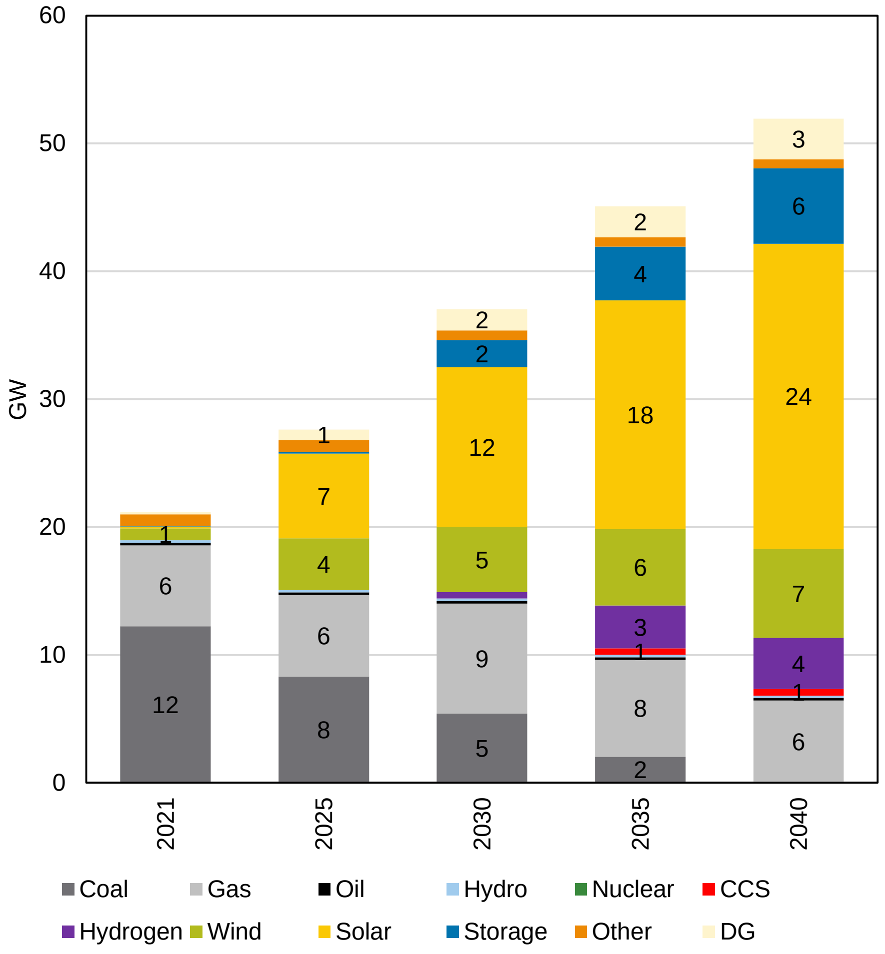


MISO Energy Mix

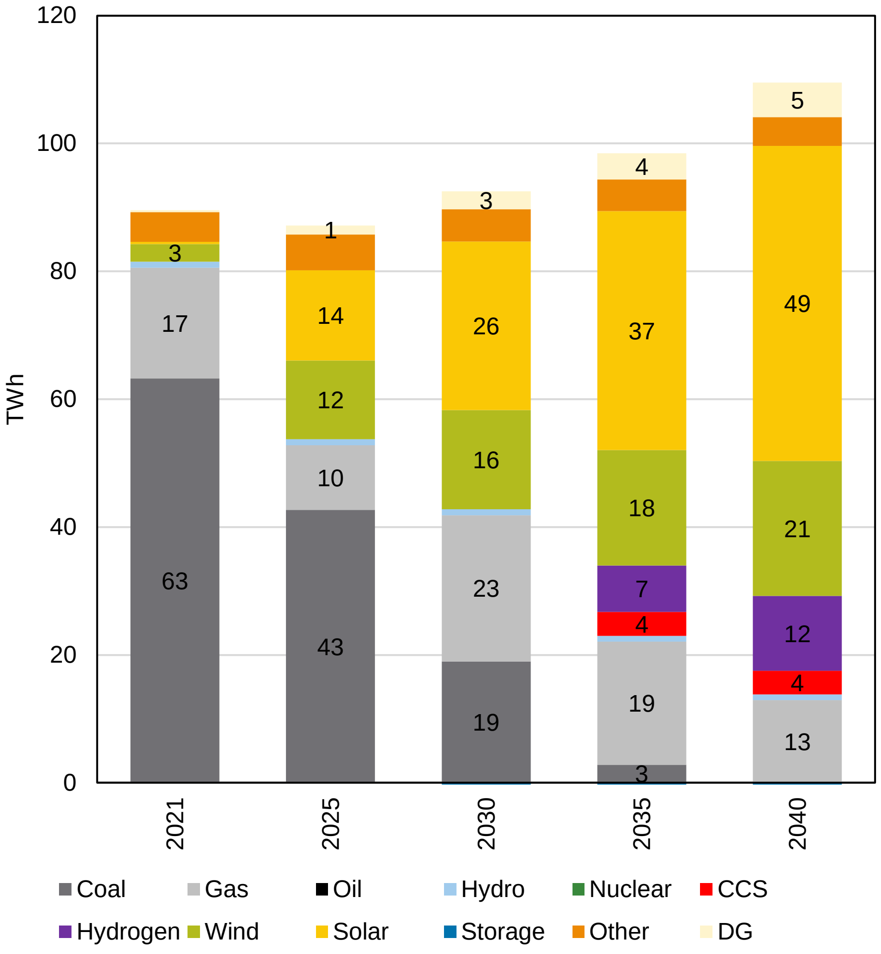


AGGRESSIVE ENVIRONMENTAL REGULATION – MISO ZONE 6 SUPPLY MIX OUTLOOK

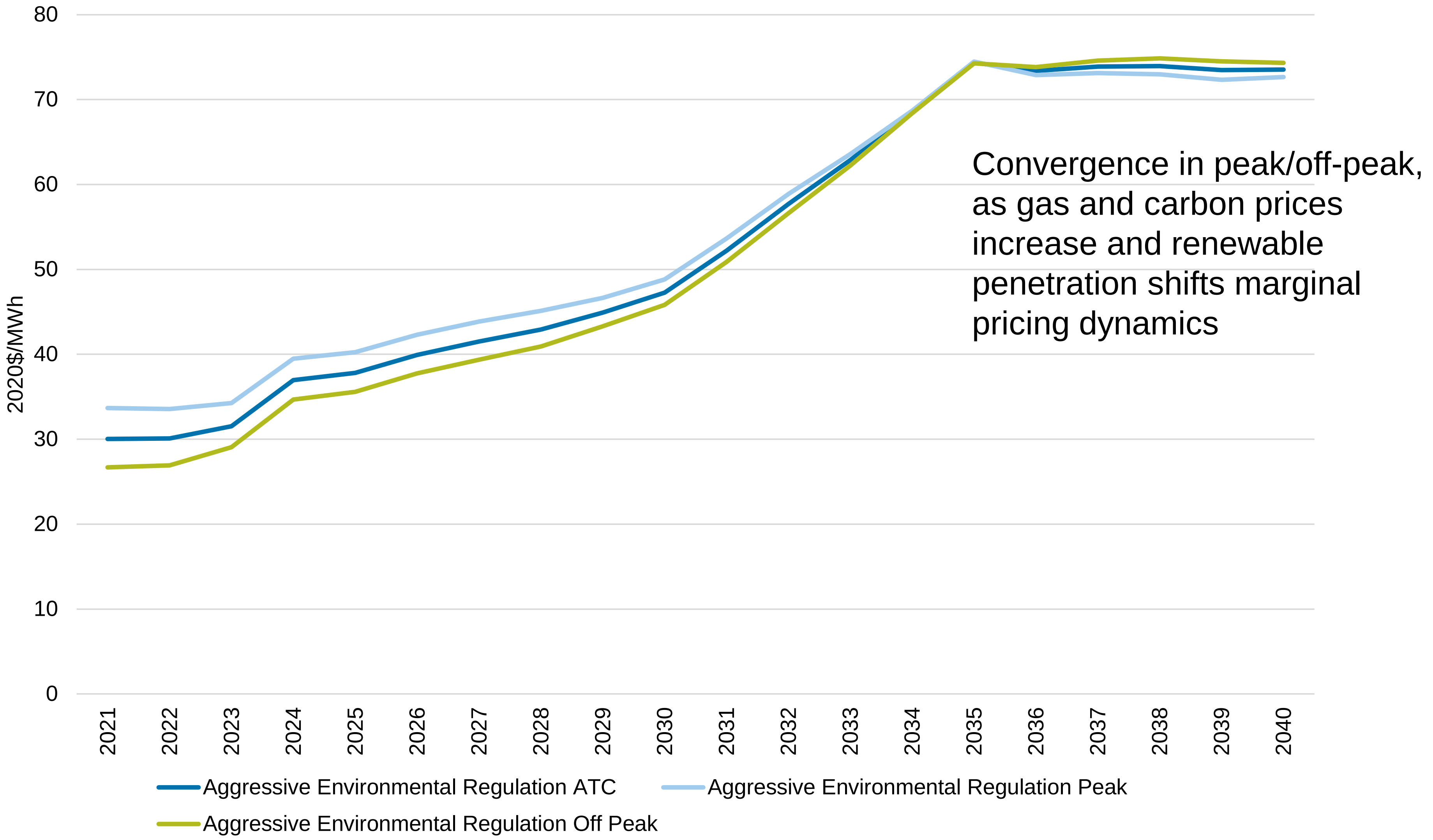
MISO Zone 6 Installed Capacity (ICAP) Mix



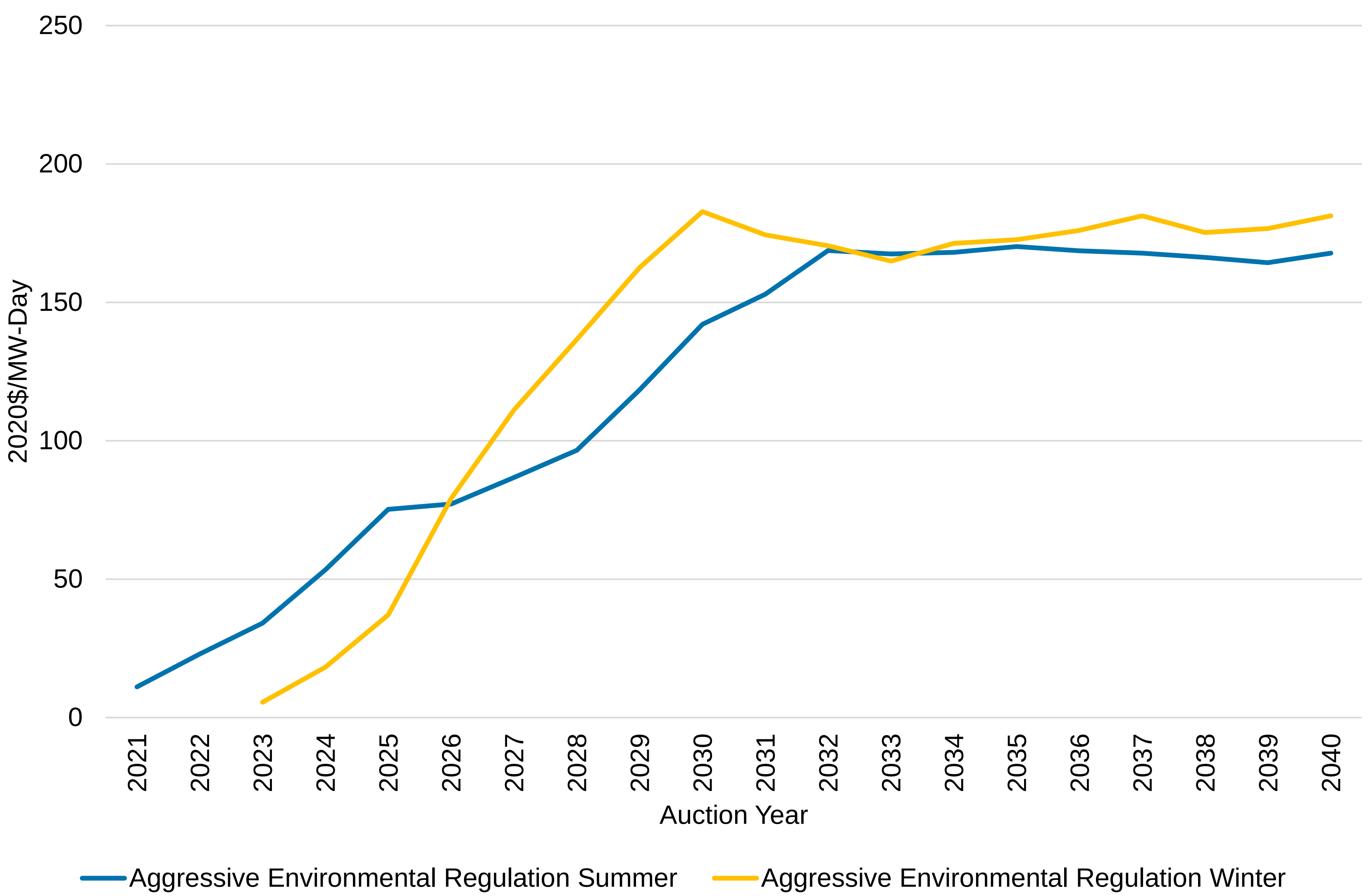
MISO Zone 6 Energy Mix



AGGRESSIVE ENVIRONMENTAL REGULATION ENERGY PRICE FORECAST

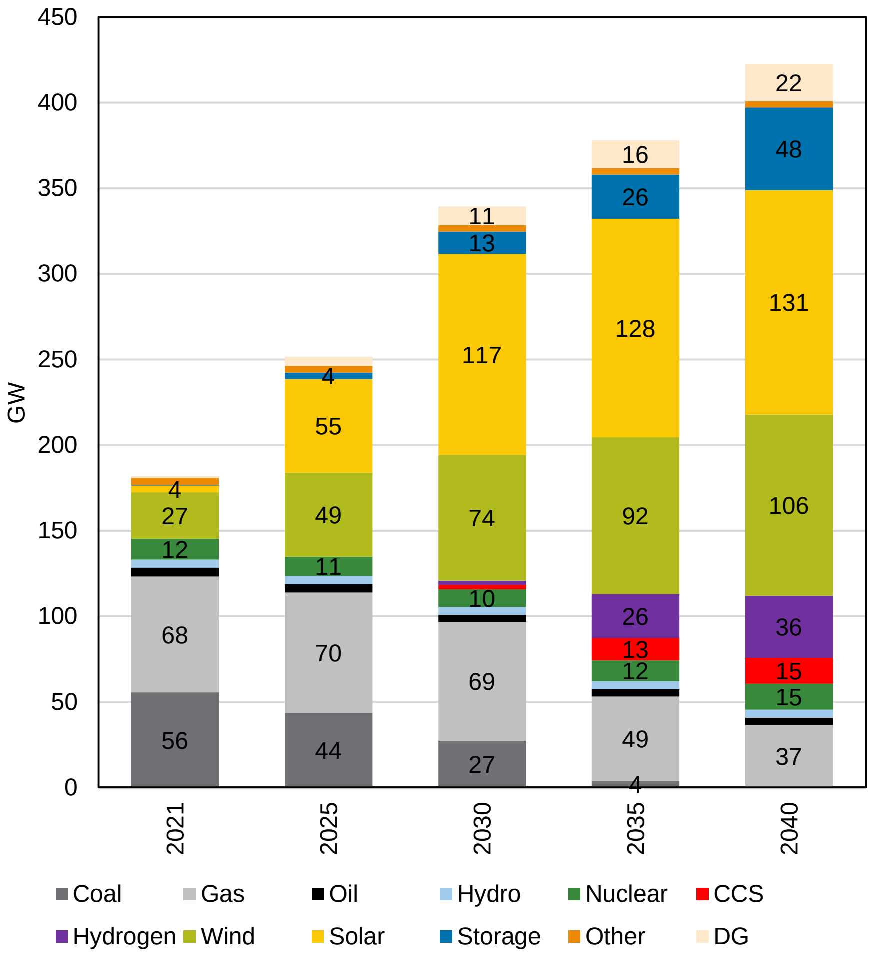


AGGRESSIVE ENVIRONMENTAL REGULATION CAPACITY PRICE FORECAST

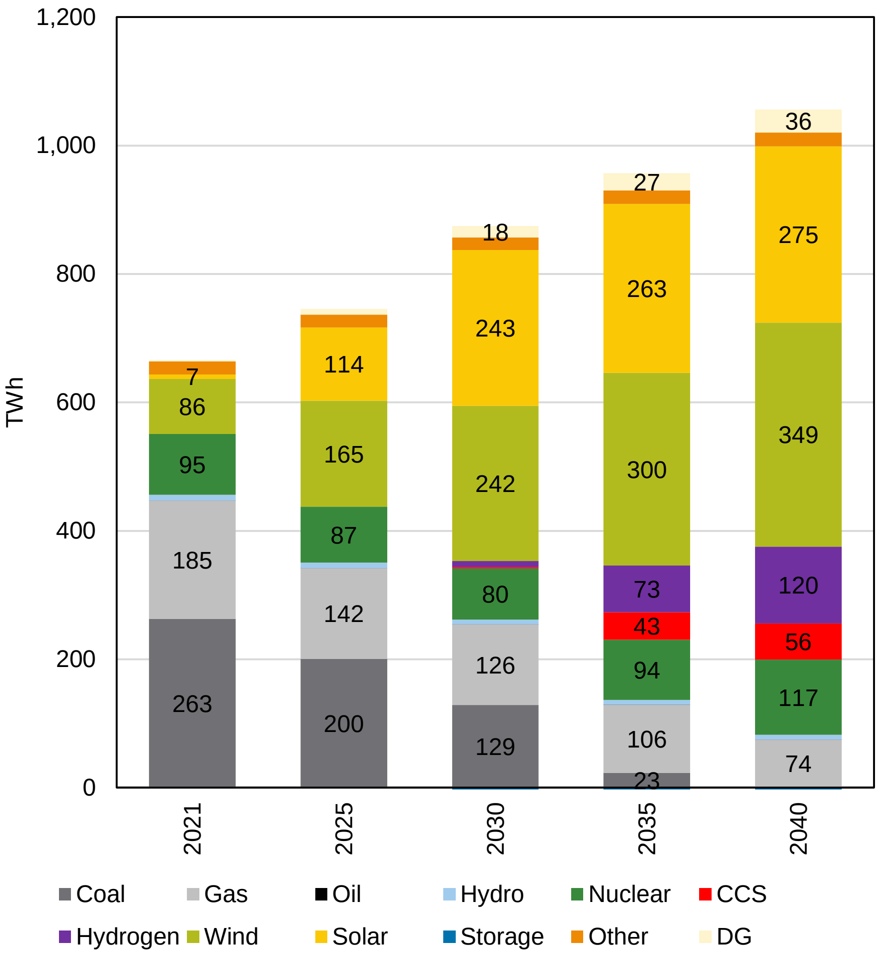


ECONOMY-WIDE DECARBONIZATION – MISO SUPPLY MIX OUTLOOK

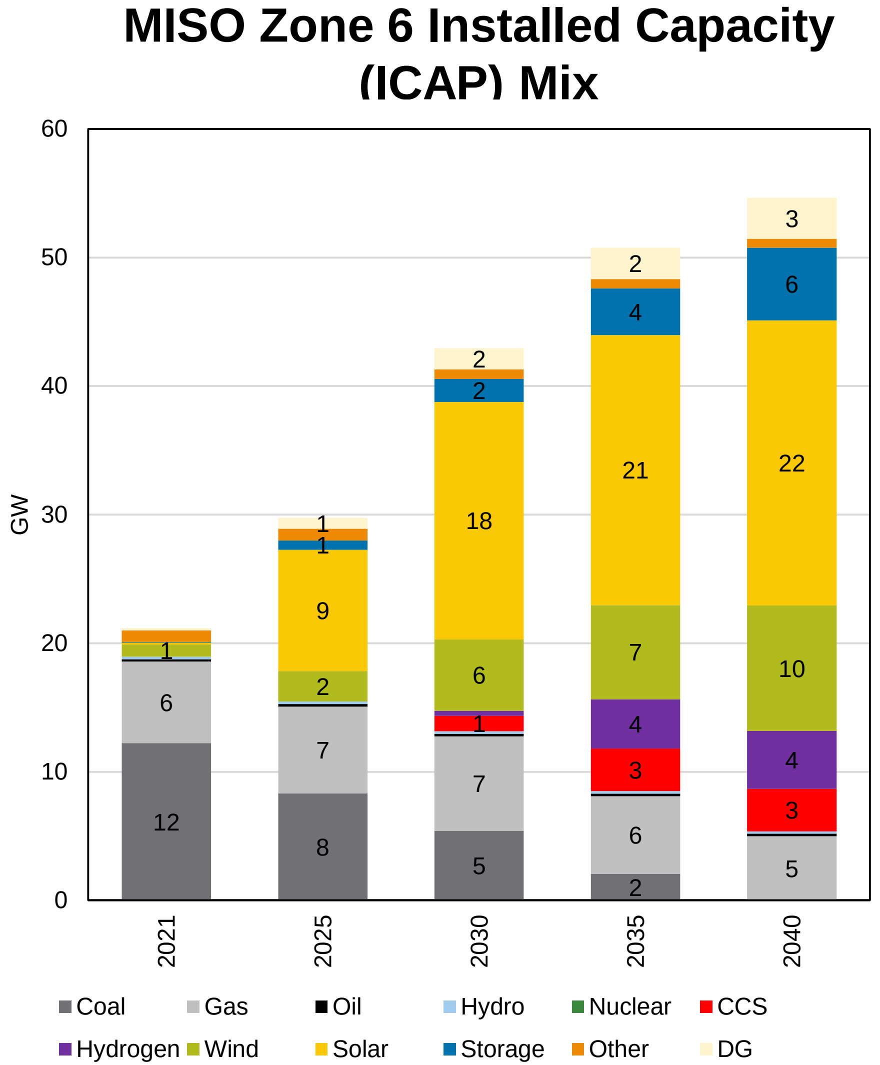
MISO Installed Capacity (ICAP) Mix

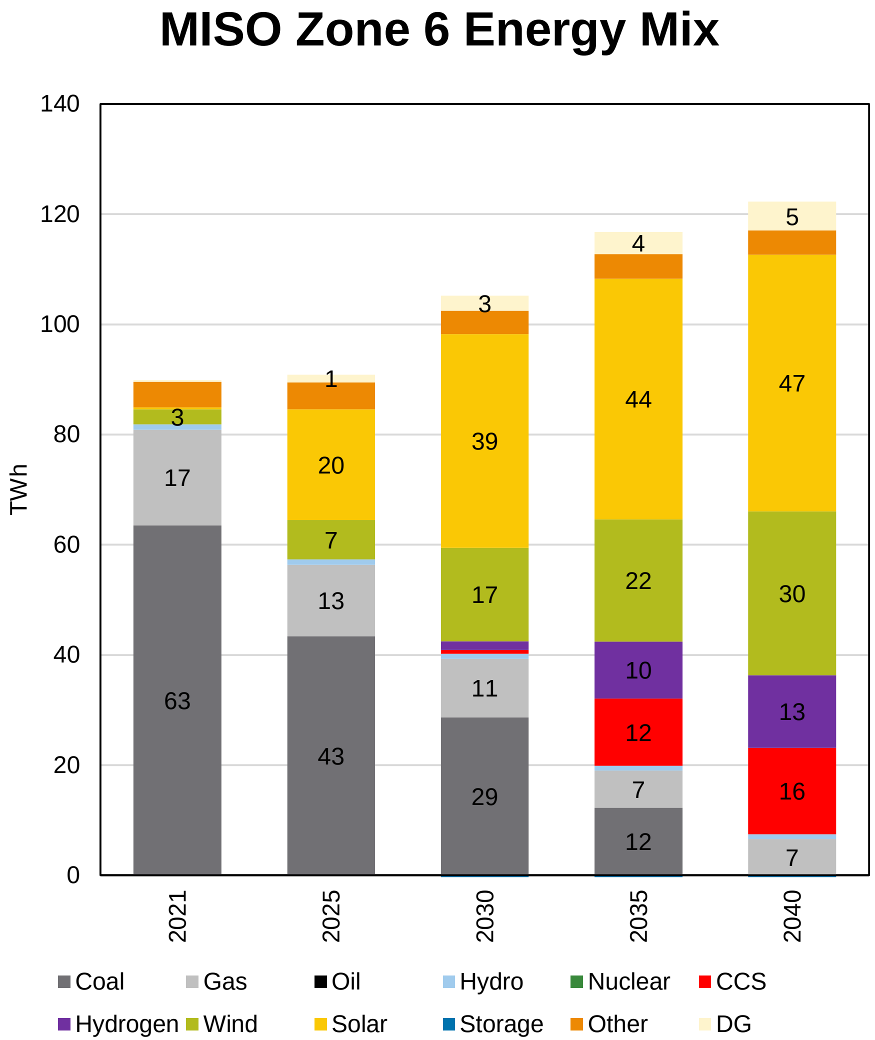


MISO Energy Mix

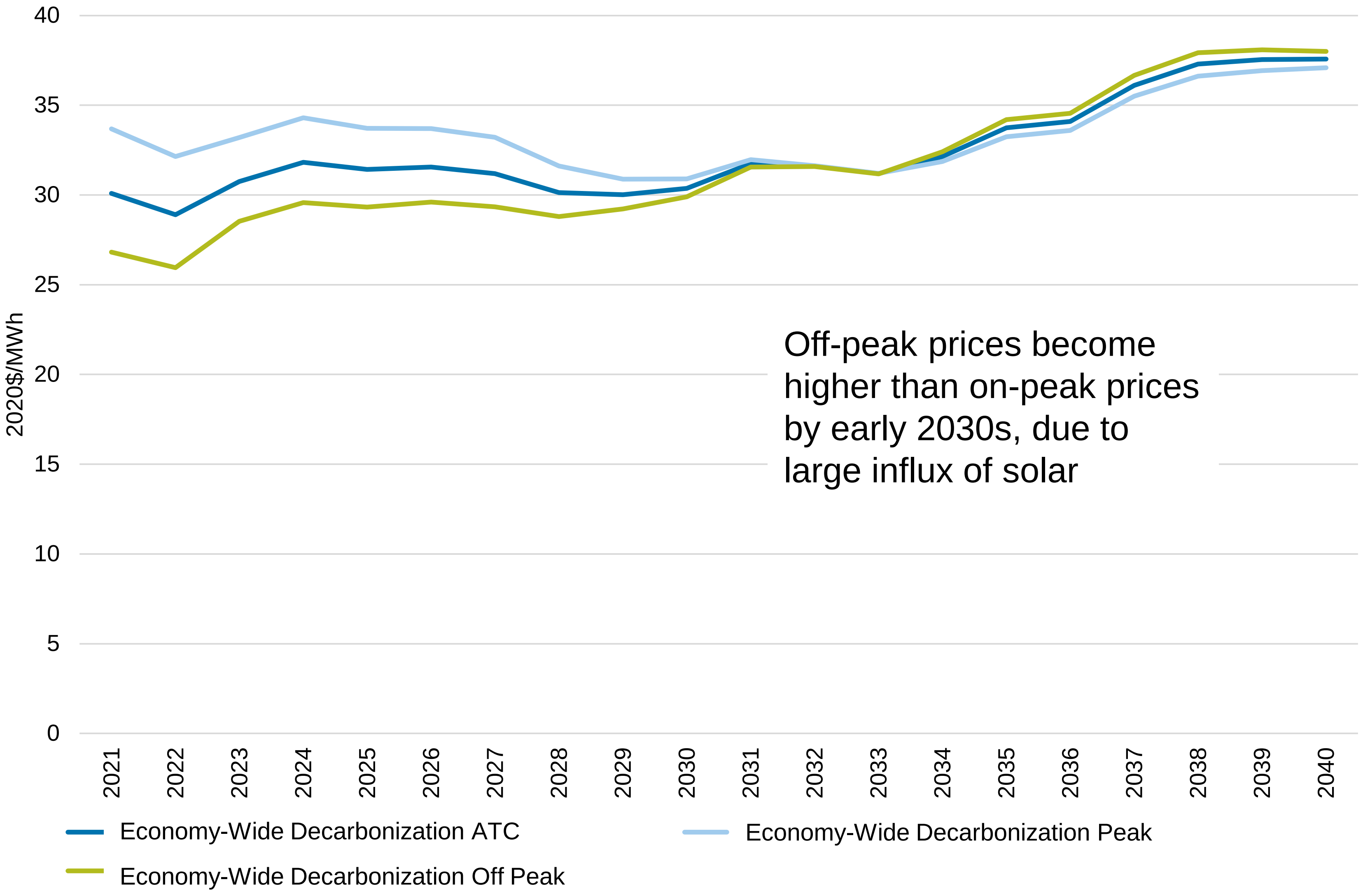


ECONOMY-WIDE DECARBONIZATION – MISO ZONE 6 SUPPLY MIX OUTLOOK

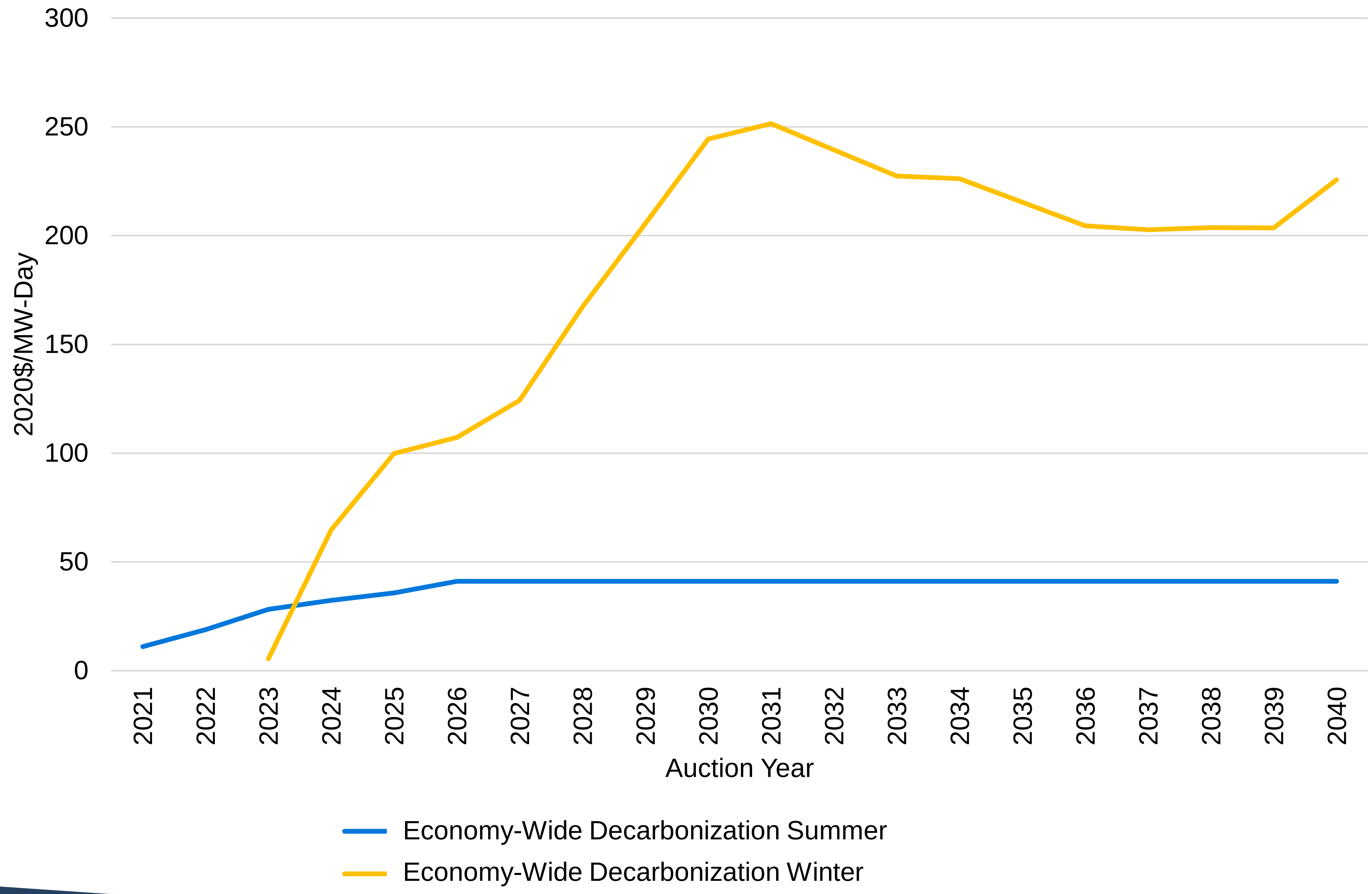




ECONOMY-WIDE DECARBONIZATION ENERGY PRICE FORECAST

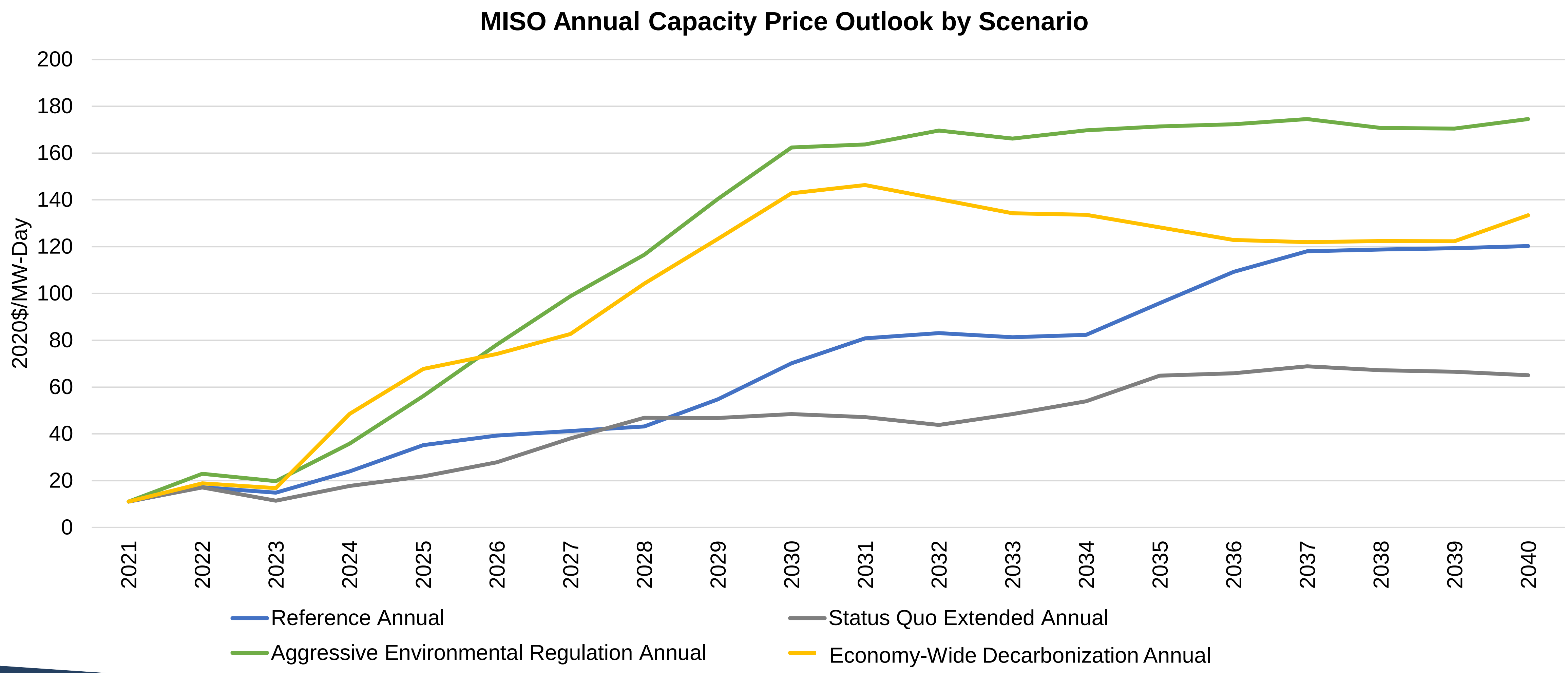


ECONOMY-WIDE DECARBONIZATION CAPACITY PRICE FORECAST



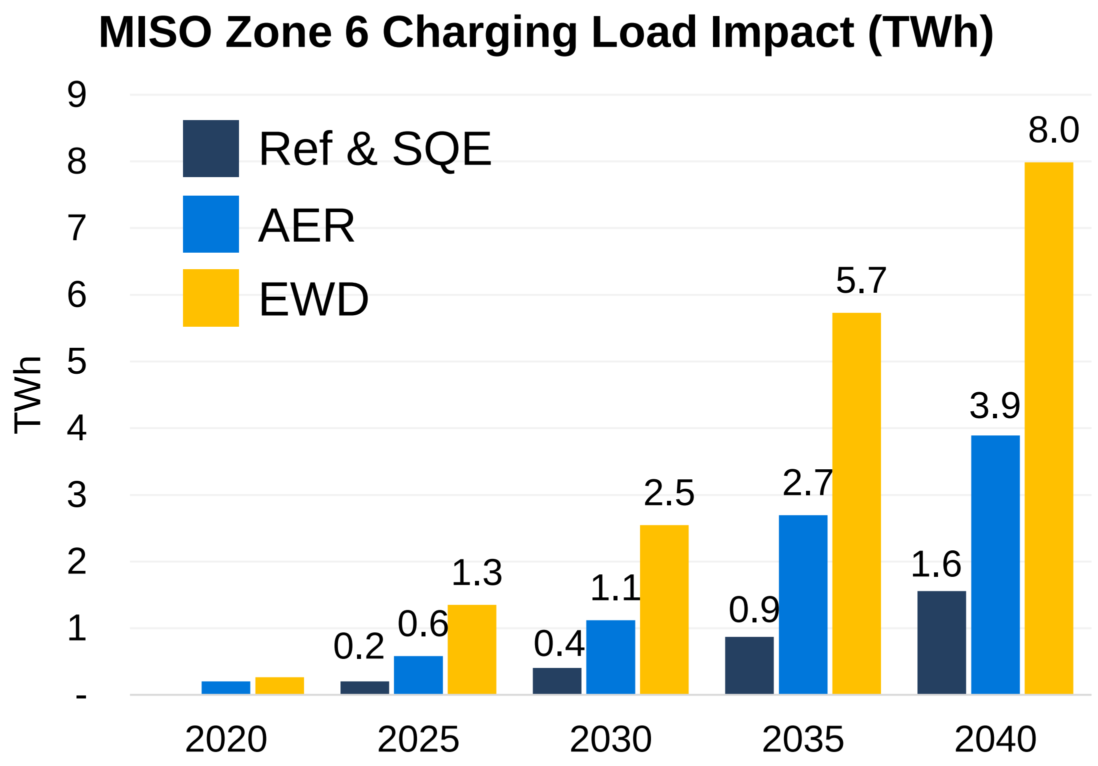
MISO ANNUAL CAPACITY PRICE FORECAST

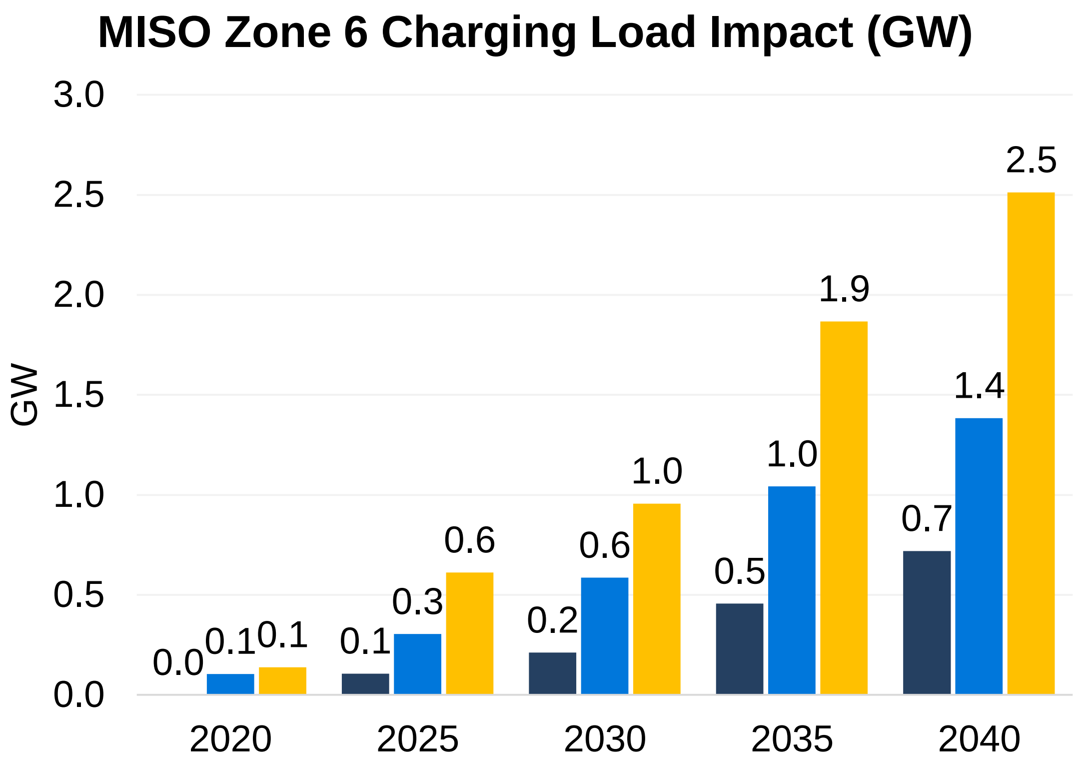
Average of summer and winter fundamental outlooks across scenarios



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

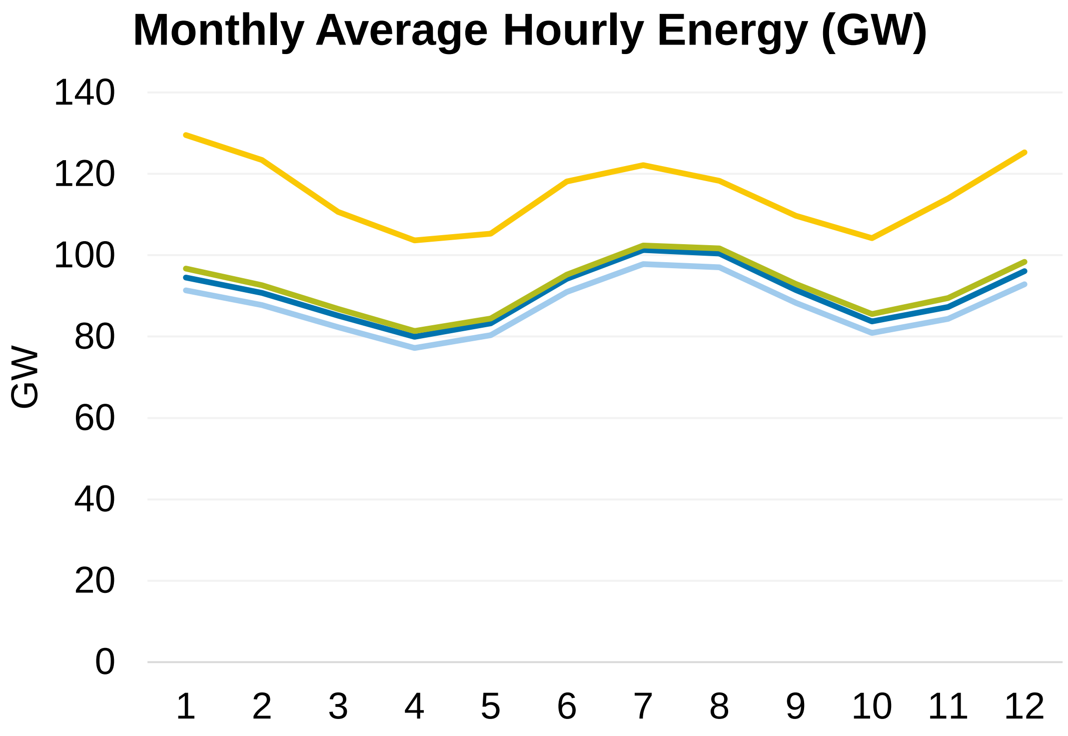
MISO BTM solar and storage penetration is based on MTEP21 assumptions

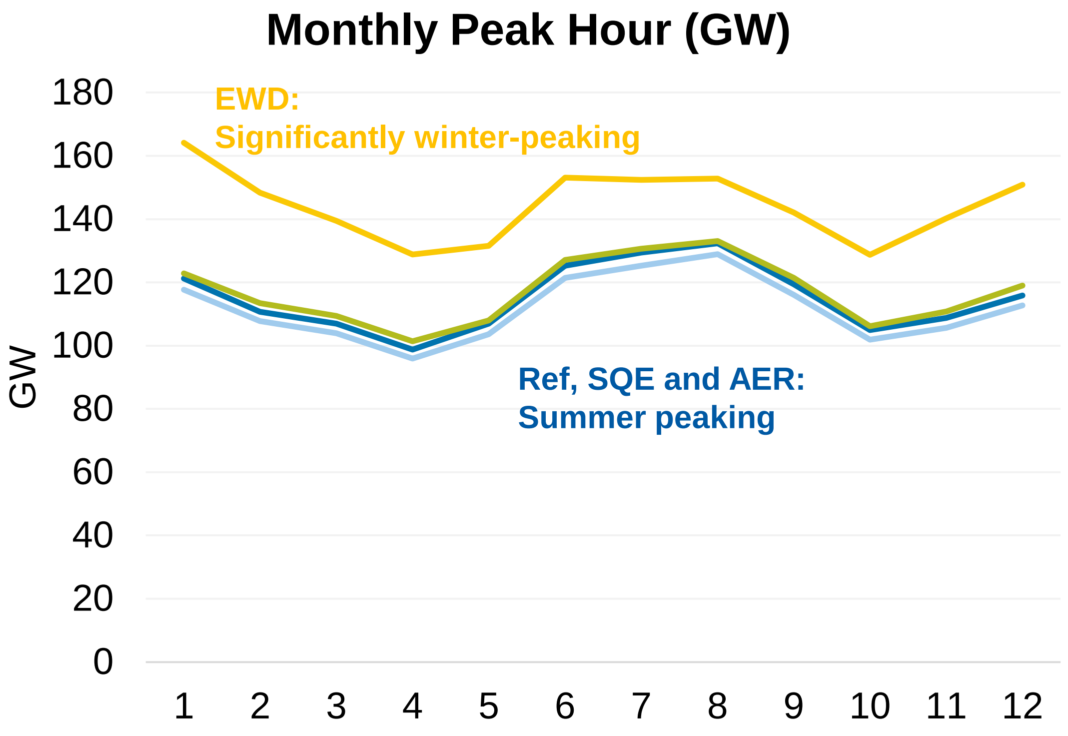
MISO market modeling incorporates DERs as "resources" within Aurora, in order to capture hourly impacts

	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

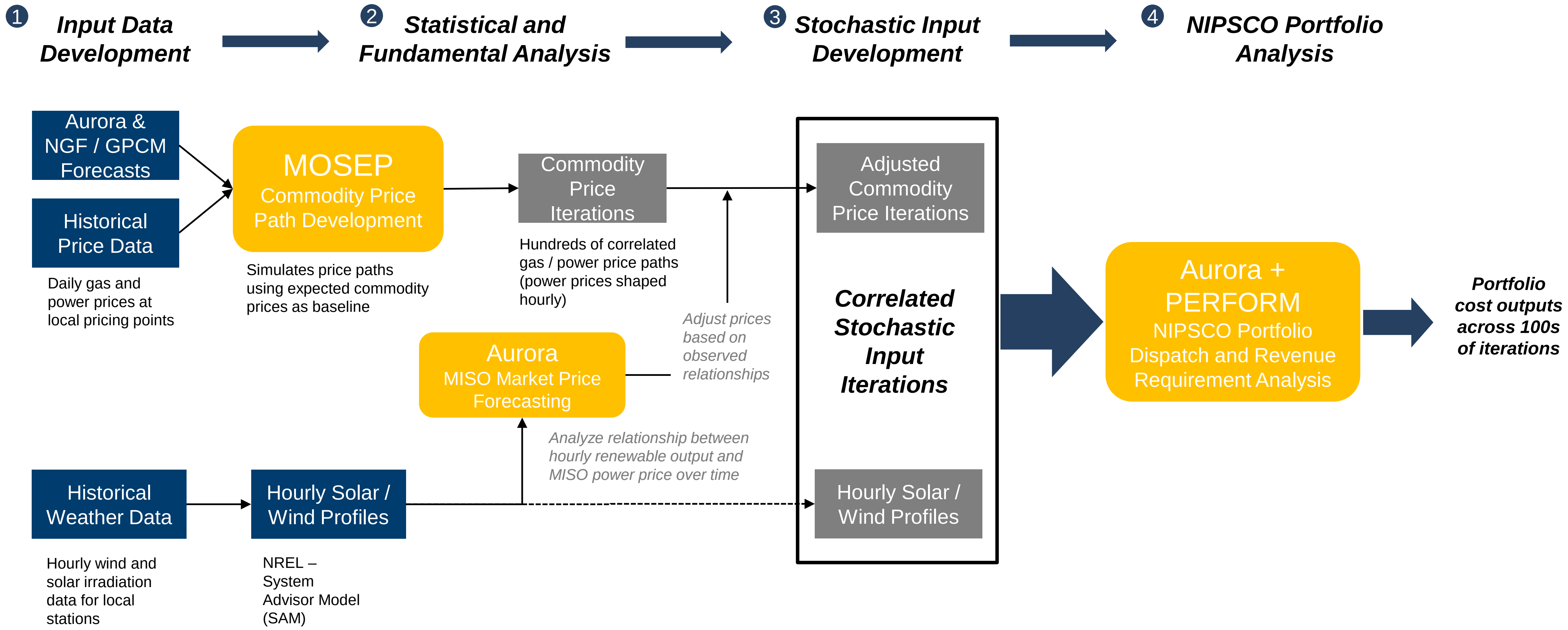
	Summer Peak (MW)				
	Base Load	EV Load	Other Electrification	DERs	All-In
2021	2,349	1	17	6	2,361
2022	2,344	1	34	14	2,367
2023	2,345	2	51	20	2,379
2024	2,344	3	69	26	2,390
2025	2,342	4	86	35	2,397
2026	2,342	6	103	43	2,407
2027	2,342	7	120	53	2,417
2028	2,342	10	137	65	2,425
2029	2,343	13	154	75	2,435
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



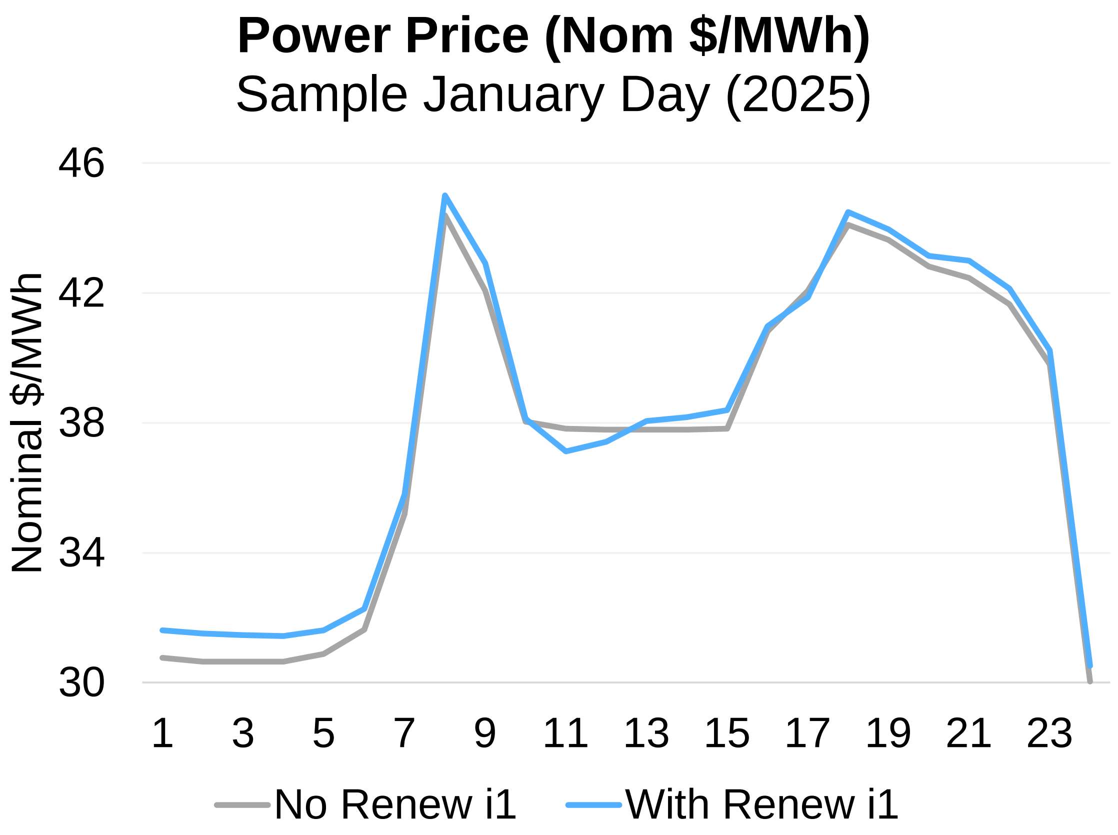
DETERMINING THE RELATIONSHIP BETWEEN RENEWABLE OUTPUT AND POWER PRICE

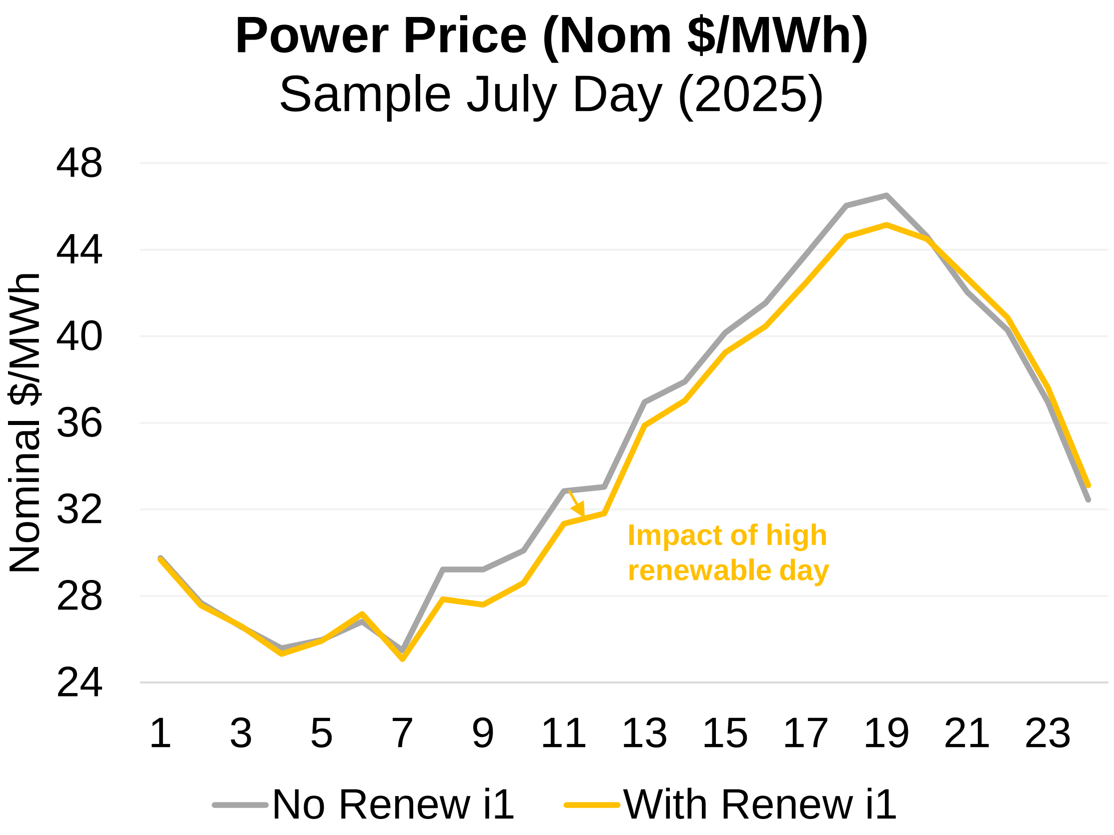
CRA Methodology

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



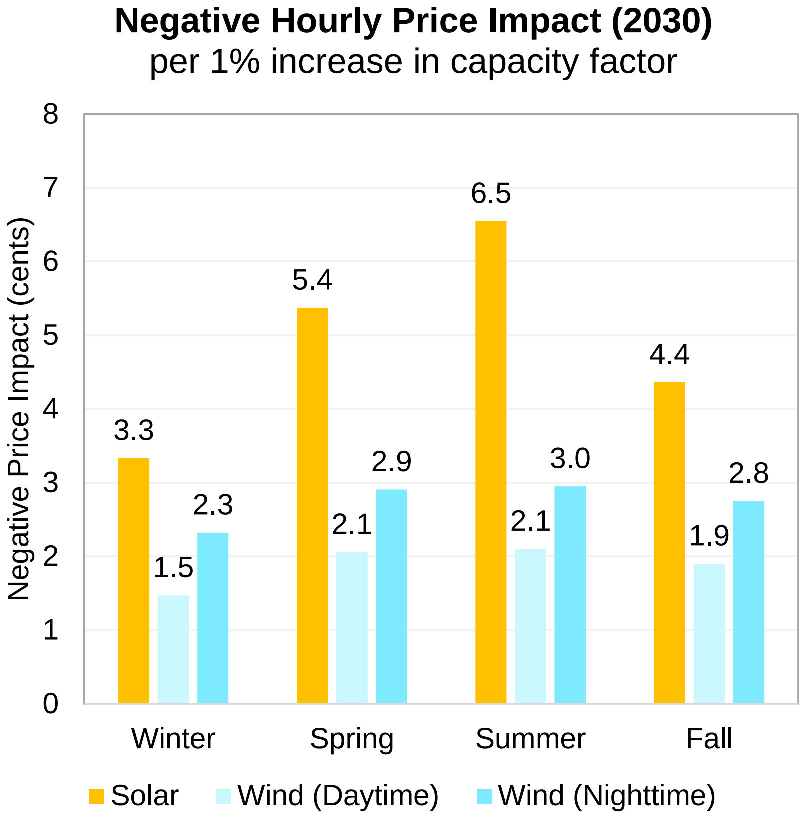


RELATIONSHIP BETWEEN RENEWABLE OUTPUT AND POWER PRICES

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)



Number of Hourly Observations (2030)

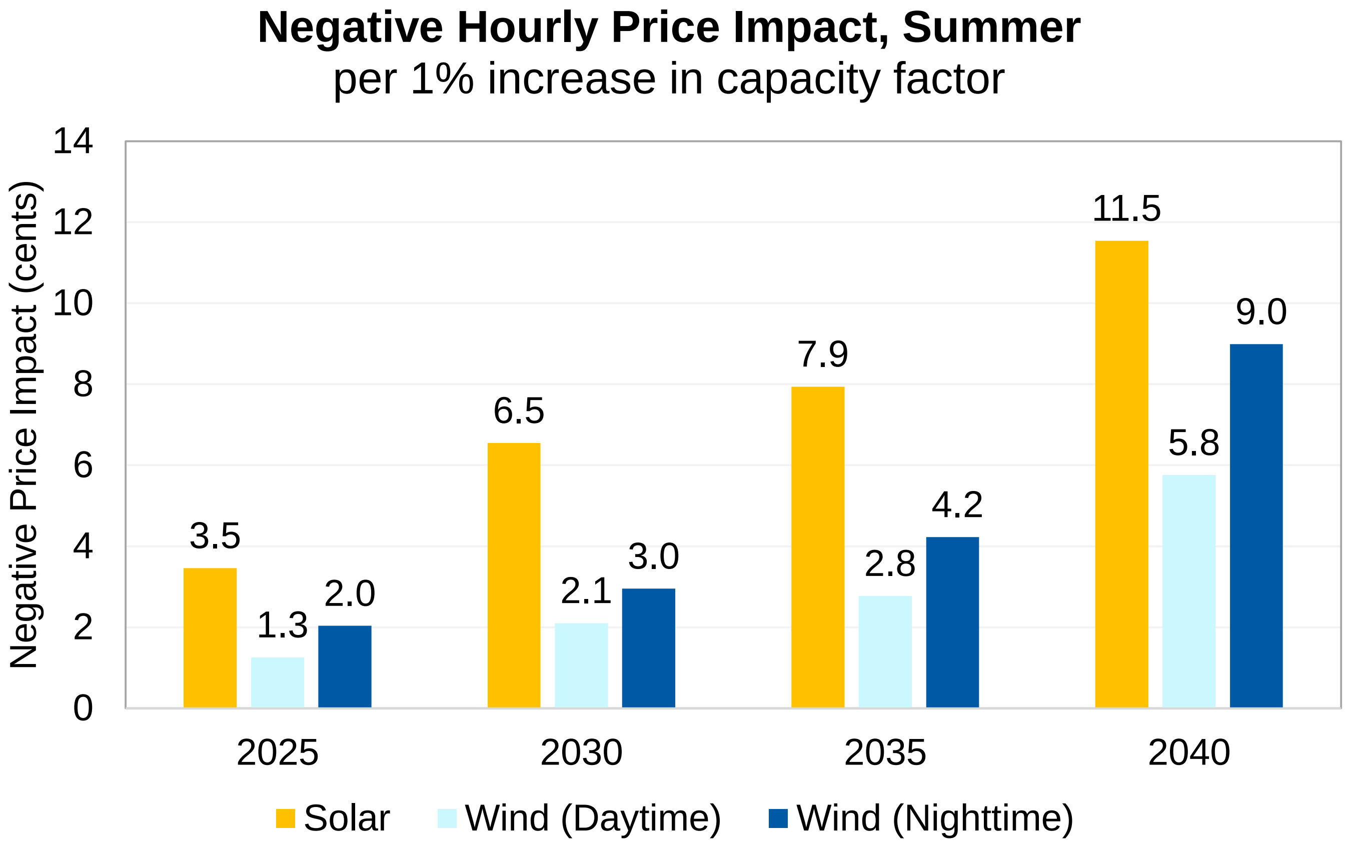
	CF Relative to "Reference Shape"	LMP Increase	LMP Decrease
Daytime	**Wind Up + Solar Up**	0	122,237
	Wind Up + Solar Down	89,699	59,649
	Wind Down + Solar Up	32,115	224,496
	Wind Down + Solar Down	179,504	0
Nighttime	**Wind Up**	0	320,769
	Wind Down	272,553	0

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*

Northern Indiana Public Service Company LLC
2021 Integrated Resource Planning
Public Advisory Meeting #2
SUMMARY

May 20, 2021

Welcome and Introductions

Ms. Alison Becker, Manager, Regulatory Policy opened the virtual meeting by providing a safety moment on Stroke Awareness Month and discussing the Webex meeting protocols. She then introduced Erin Whitehead, Vice President, Regulatory and Major Accounts NIPSCO to kick off the meeting.

Overview of Public Advisory Process
Erin Whitehead, Vice President, Regulatory and Major Accounts, NIPSCO

Ms. Whitehead welcomed participants and then reviewed the agenda and the stakeholder advisory meeting roadmap.

Participants had the following questions and comments, with answers provided after:

- Is the environmental plan still on the agenda?
    - Yes, and Maureen Turman will be speaking to that.

Updates from Public Advisory Meeting One
Fred Gomos, Director Strategy and Risk Integration, NiSource
Pat Augustine, Vice President, Charles River Associates ("CRA")

Mr. Fred Gomos, Director Strategy and Risk Integration, NiSource, began the section with an overview of NIPSCO's planning process and introduced the stakeholder feedback received since Meeting #1, which was organized across five major themes. Mr. Gomos summarized stakeholder comments and NIPSCO's responses related to Diversity, Equity, and Inclusion; Cost Accounting and Revenue Requirement Modeling; and Scorecard Metrics. He then introduced Mr. Patrick Augustine, Vice President at CRA, who summarized stakeholder comments and NIPSCO's responses related to the Load Forecast and Uncertainty Analysis. Mr. Augustine provided specific detail associated with how NIPSCO is incorporating feedback regarding Electric Vehicle and Distributed Energy Resource treatment in the load forecast.

Participants had the following questions and comments, with answers provided after:

- I would like to see an additional goal to these five that your product (energy) is both environmentally friendly and healthy regardless of, and perhaps beyond the regulations.
    - The feedback is appreciated and will be taken into account.

- Is this presentation provided to stakeholders? Will it be available after the meeting?
    - Yes to both. The presentations are always posted a week ahead of time at NIPSCO.com/IRP. It is sent out to everyone who registered at least a week in advance of the meeting as well. Because of the influx of registrations after the announcement of the request for proposal ("RFP") release, not everyone may have received it. However, all materials are always available on the website.
- Environmental concerns must be at the forefront of the decision-making process. This will have an impact on future generations of Hoosiers, as well as the health and well-being of people throughout the world. Is Environmental Sustainability weighted, therefore, more heavily? One could definitely argue that this will impact the Positive Social and Economic Impacts as well.
    - NIPSCO appreciates that comment. We do not develop specific weightings for each metric on the scorecard. Instead, the Company looks at all of the portfolios that will be developed and assesses the key tradeoffs as an organization. Certainly if you look at the scorecard, NIPSCO has metrics around emissions as a proxy for environmental sustainability. Later in the agenda, we will talk about NIPSCO's trajectory from an emissions standpoint. The current plan will get us to 90% emissions reduction by 2030. It is pretty significant and the Company is driving towards that. And as noted earlier, the carbon dioxide ("CO2") emissions metric will not focus on a single year of 2030. The Company has changed the scorecard metric to present cumulative CO2 emissions over the 20-year fundamental modeling period.
- It's critical that MISO continues to have reliability as a key component in your selection process. It is clearly known renewables need units which are scheduleable/callable to be effective.
    - NIPSCO appreciates that comment. Later in the presentation, we will spend time covering the evolution of MISO rules and how such developments will impact this IRP. Many of these rules specifically address how intermittent resources will be valued in the market vs. other types of resources. This will be a key consideration to the whole analysis framework here.
- The Volkswagen mitigation trust fund is making awards as we speak for DC fast charging installation. How will NIPSCO take those additional loads into account?
    - NIPSCO has not built out electric vehicle (EV) scenarios specifically based on any one set of policy outcomes or specific to the Volkswagen trust that may be subsidizing public/semi-public installations. The EV penetration scenarios were laid out during first meeting and they will be discussed in summary form with the load forecast later in the meeting. There is a pretty wide range of outcomes and scenarios based largely on MISO's MTEP ranges, supplemented by specific customer information NIPSCO is aware of for light / medium duty vehicles. So although NIPSCO is not attempting to model the trust fund's subsidization of new charging infrastructure, the Company has spent a lot of time building a broader range of potential load outcomes in this IRP, including an assumption in the high case that nearly all new light duty vehicles sold by 2040 are electric.
    - In addition, most studies have shown that 80% of charging occurs in the home. With DC fast charging stations, it is less about load impacts and more about grid impacts on the distribution system. The level of utilization for public charging stations is low so far. Therefore, the distribution of the stations will be more important than the total number, and NIPSCO will be continually tracking such impacts on total and local loads.
- Will the WebEx be shared?

- o No, but the meeting minutes will be available at nipsco.com/irp approximately two weeks from the meeting date.

MISO Market Initiatives Update
Pat Augustine, CRA

Mr. Augustine introduced the section with an overview of the major considerations NIPSCO is taking into account while performing a long-term planning exercise with significant amounts of intermittent resources. He then provided an overview of Independent System Operator functions, and compared MISO's role and NIPSCO's role with regard to long-term planning and market operations. Mr. Augustine then identified four major regulatory changes related to MISO market operations since NIPSCO's 2018 IRP: (i) Effective Load Carrying Capability (ELCC); (ii) the Resource Availability and Need (RAN) initiative and the seasonal capacity construct; (iii) the Renewable Integration Impact Assessment (RIIA); and (iv) FERC Order 2222. He then proceeded to detail how each change impacts NIPSCO's IRP modeling and associated assumptions.

Participants had the following questions and comments, with answers provided after:

- How do you handle Zone Resource Credits ("ZRCs") deliverable and delivered to any MISO Local Resource Zone?
    - o This topic may be addressed further later in the day when the RFP is discussed. From a planning perspective, zonal resource credits are means of tracking resource adequacy throughout the MISO territory. NIPSCO's load is within Load Resource Zone ("LRZ") 6, and NIPSCO resources therefore need to help ensure there is sufficient capacity within that resource zone. As noted in the question, that capacity is tracked with zonal resource credits. When considering the supply / demand balance, the analysis focuses on that geographic distinction. Having deliverability and ZRCs in Zone 6, either as owned resources or contracts, is an important criteria due to the resource adequacy constraint.
- Is NIPSCO considering time of production rates for customer owned DERs such as rooftop solar?
    - o That likely will not be considered within the context of the IRP. From an IRP context, the analysis is not considering specific rate-making provisions, although this might be a good topic for a 1-1 conversation.
- Have you identified a number to use for expected solar capacity accreditation in winter? If so, what will you be using?
    - o Yes, there is a footnote at the bottom of slide 21 noting that the winter capacity credit is expected to be between 5-10%. Based on NIPSCO's preliminary analysis of the coincidence of solar output with its coincident winter peak loads, the IRP analysis is planning to use 6.6% for the winter solar capacity credit. This number will be further reviewed based on hourly solar shapes that NIPSCO has from its planned solar projects and any future data received in the 2021 RFP. To arrive at the preliminary 6.6% number, CRA looked at the top 10-20 winter peak hours and noted that those tend to occur during the early morning and evening hours. On average, the solar output during those hours was approximately 6.6% of nameplate capacity. While geographic diversity could help improve that number in aggregate, and while different projects are likely to have different ratings, this is the general range for what will be used for the winter credit in this IRP.

- Is NIPSCO planning to model the two or three seasonal construct proposed by MISO? Will NIPSCO be modeling this for all scenarios in the IRP?
  - The short answer is yes. This topic came up in March 19 meeting as well. During that discussion, NIPSCO committed to consider, from a NIPSCO portfolio perspective, to look at a portfolio that only has to meet the summer peak requirement since this proposed rule is not in force yet. However, MISO is expected to make a filing in September with FERC to implement the seasonal capacity construct with four seasons. Therefore, it is prudent to look at a seasonal requirement in all scenarios and to build portfolios that can meet the requirement. So given the developments at MISO and anticipation of the filing in a few months, the long term view will be to focus on the four season requirement with special attention on summer and winter, which NIPSCO has found will be most binding for its portfolio. As discussed in March, NIPSCO's load is lower in the winter than the summer, but the impact of fewer firm solar MWhs during winter peak hours is important to plan for. It is important across scenarios, but the analysis can test portfolios focused on summer reserve margins for cost comparisons.
- Is there a reason that the feed-in tariff ("FIT") information on the slide 22 on UCAP is not broken out by technology, i.e. solar and biomass?
  - It was not broken out for consolidation purposes. There is solar, biomass, and some wind in the FIT. While it was consolidated for reporting purposes, the data is available if there is interest in seeing it.
- Is it possible in all future presentations to separate out biofuels from green energies since biofuels are not green for several reasons and should not be lumped together with green energies?
  - Yes, that can be taken into account. There are very few biofuels in the NIPSCO generation portfolio. To the extent there is some biomass that is part of the FIT that the prior question was referencing, this would be the only existing resource that would fall into this category. While the general comment is appreciated, it is not a significant change in anything that is presented here or going forward.
- Has NIPSCO evaluated the winter capacity credit for wind resources?
  - That is being considered and MISO has recently been studying that issue. The latest MISO report indicates that wind capacity credit during the winter from a system-wide perspective will be close to 25%, whereas the summer tends to be closer to 15%. The assumption in the analysis currently is a slight premium in winter versus summer for wind resources, and as NIPSCO gets more project-specific data going forward, that number will be refined in the future.

Environmental Considerations in 2021
Maureen Turman, Director, Environmental Policy and Sustainability, NiSource

Ms. Maureen Turman, Director, Environmental Policy and Sustainability, opened the section with an overview of NiSource's environmental impact targets. She then provided an overview of the environmental controls present on NIPSCO's generation fleet and summarized how the 2018 IRP's preferred portfolio addressed CCR and ELG compliance requirements. She closed the section with an overview of the Biden Administration's climate-related initiatives within its proposed infrastructure plan.

Participants had the following questions and comments, with answers provided after:

- The corroded wall on Lake Michigan (built in the 1940s) is holding back more coal ash than all ponds designated for excavation at Michigan City Generating Station ("MCGS").

Is that wall slated for repair or replacement? What about the coal combustion residual fill there, is it leaching into Lake Michigan? What is your plan if that wall blows?
    - That wall is part of NIPSCO's facility and it is maintained as a critical piece of infrastructure. The wall is inspected on a regular basis, and NIPSCO has engineering reports that say that wall is in serviceable condition. The engineering firm made recommendations to NIPSCO for maintenance on the wall, and NIPSCO has taken action on those recommendations. NIPSCO has confidence in that wall and continues to maintain it.
- Can you provide the engineering report?
    - Yes, anyone who would like a copy can request it.
- On Slide 29 I would appreciate having the acronyms CCR and ELG spelled out, along with a statement of what authority issued them.
    - CCR = Coal combustion residuals, which is the ash left after coal is burned.
      ELG = Effluent limitation guidelines, associated with water discharge
      Both rules lay out industry-specific standards that the United States Environmental Protection Agency ("EPA") puts in place to regulate waste water discharge.
- Are those EPA rules?
    - Yes.

Modeling of Uncertainty: Scenarios and Stochastics for 2021 IRP
Pat Augustine, CRA, Robert Kaineg, Principal, CRA, and Goran Vojvodic, Principal, CRA

Mr. Augustine introduced the section by providing an overview of how the 2021 IRP will perform both scenario and stochastic analysis, and he noted the reasons for performing both types of assessments. He then recapped NIPSCO's resource planning approach and how scenario and stochastic analysis development fits into the broader analysis framework and the ultimate scorecard metrics. Mr. Augustine then introduced NIPSCO's four planning scenarios and provided an overview of the key variable drivers within each one. He then introduced Mr. Robert Kaineg, Principal at CRA, to discuss the natural gas markets.

Mr. Kaineg provided a review of the fundamental drivers of CRA's Reference Case natural gas price forecast from Meeting #1 and discussed how each of the fundamental supply and demand drivers were flexed across the scenarios in CRA's fundamental modeling. He closed his section with an overview of the natural gas price forecast range.

Mr. Augustine then introduced the CO2 policy drivers across the scenarios relative to the Reference Case and provided a summary of the CO2 price and Clean Energy Credit pricing expectations. He then detailed the projected MISO market outcomes for each scenario, with summaries related to capacity and energy mixes, clean energy percentage, CO2 emissions, hourly energy output, annual and hourly price forecasts, and capacity price projections. Mr. Augustine then discussed the details of NIPSCO's load forecast across scenarios, including the impacts of economic drivers, electric vehicle penetration, distributed energy resource penetration, industrial load loss risk, and other electrification.

Mr. Augustine then provided an overview of NIPSCO's approach to stochastic analysis in the 2021 IRP and how it will impact portfolio cost accounting and ultimately contribute to NIPSCO's scorecard. He then introduced Mr. Goran Vojvodic, Principal at CRA, to discuss the stochastic input development in more detail. Mr. Vojvodic reviewed CRA's process for developing commodity price stochastic price paths and provided several examples. He then explained an enhancement to the 2021 IRP process to incorporate renewable output uncertainty and its associated impacts on hourly MISO power prices. He closed the section by providing a summary of the distributions to be used for natural gas prices, power prices, and wind and solar generation output.

Participants had the following questions and comments, with answers provided after:

- Under the Economy-Wide Decarbonization ("EWD") Scenario, Why would there be an extension of the investment tax credit ("ITC") and the production tax credit ("PTC")? It seems to be unnecessary under a clean energy standard approach.
    - NIPSCO is aiming to capture a scenario that would be somewhat consistent with the Biden Administration's framework. As Maureen Turman outlined on slide 30, that framework calls for a 100% clean power sector by 2035 and proposes a 10 year extension in the ITC and PTC. One could certainly make an argument that a clean energy standard could be sufficient to meet the stated goals, but the idea in the EWD scenario, and in the Administration's framework proposal, would be that a long-term extension of those tax credits would accelerate renewable development prior to the clean energy standard driving investment in new technologies later on.
- On Slide 42, why does the EDW scenario not include a carbon price/market?
    - That comes down to policy design. What we talked about on slide 44 is the heart of the answer. The idea is that carbon regulation does not have to be performed just through a price, something that NIPSCO has heard from a few stakeholders. The construct is that federal policy would establish a national target (for example, x% clean energy by certain date) without a carbon tax or cap-and-trade mechanism. As a result of the target, different market mechanisms would develop, such as a clean energy credit or zero emission electricity credit market to help compensate those resources that might need to come into market to achieve the target. It is all about the policy design and the desire to test a range of potential outcomes that could impact the markets in very different ways.
- It looks like the lion's share of MISO gas and coal capacity in the future across all scenarios is a carryover of current capacity. Is that the case? If so, does your model require these resources to cover their embedded fixed costs in order to keep operating, or does the model only require them to cover variable costs to continue to be available to the market?
    - It is the case that no new coal capacity would be built over time across the scenarios, but there is some new gas capacity. For reference, on slide 45, current gas capacity is 68 GW and in two of the four scenarios, that number increases to 79 and 84 GWs, respectively. That means net new gas capacity is entering the market. There may be some retirement of older units, but on balance, new capacity would be entering to meet future capacity needs and in response to economic signals. In response to the second part of the question, the economic modeling evaluates things from a system-wide perspective, seeking to minimize costs and meet load or environmental constraints. Generally this means that resources are covering all variable and fixed costs. However, it is possible that an existing unit may not be fully covering its fixed costs if it is cheaper to continue operating than it is to build a new plant that may have even more difficulty covering all capital and fixed costs.
- How is carbon capture and storage ("CCS") a capacity resource? And should there not be a feedstock associated with the CCS, like coal, gas, hydrogen? Or does it assume that the feedstock is irrelevant since the assumption is zero carbon because it's being captured?
    - There is a feedstock and NIPSCO could provide details on the breakdown of the capacity in the MISO market modeling if requested. On slide 45, in the AER scenario,

with high gas and CO2 prices, all of that CCS is coal-based, so the feedstock would be coal. In the EWD scenario, the generically-labeled CCS is a mix of coal and some gas-fired carbon capture and sequestration. As noted, if interested, the details can be carved out.

- Do you model the effects of increased electricity prices on the demand for electricity? It would seem that some scenarios would have higher effects on electricity prices and thus more effect on demand, which might be useful to capture in the modeling.
    - The load forecasting exercise does this partially. The retail rate is a variable in the econometric analysis, and this is explicitly evaluated in the base case forecast. As the question implies, higher retail rates tend to result in modestly lower electricity consumption. However, to the extent that the scenarios result in materially different retail rates than the baselines, NIPSCO has not gotten into that level of detail. There is uncertainty regarding how all the drivers associated with each of the four scenarios impact all the elements that drive retail rates. The MISO power market, for instance, might capture part of it, but in some of the scenarios, there might be different outcomes for transmission and distribution cost components, which also impact rates. Since the analysis has not gone into that level of detail across the scenarios, we may be under-estimating potential load feedbacks in certain areas. However, price elasticity likely has a smaller impact than all of the other elements of load uncertainty that are being captured, such as electric vehicle or distributed energy resource penetration. Nevertheless, this is a good point and something that NIPSCO may need to consider more qualitatively and in more detail in the future.

2021 RFP Update
Andy Campbell, Director, Regulatory Support and Planning, NIPSCO
Bob Lee, Vice President, CRA

Andy Campbell, Director Regulatory Support and Planning introduced the section by presenting an overview of NIPSCO's RFP, including the specifics of each event, the range of capacity being requested, duration expectations, and other details. He then introduced Bob Lee, Vice President at CRA, who discussed the evaluation criteria, RFP logistics, and the timeline.

Participants had the following questions and comments, with answers provided after:

- For the Thermal RFP, would you be interested in participating in demand response programs?
    - This RFP is not specifically looking for demand response programs. However, there may be circumstances where it fits the criteria under other capacity resources. For example, distributed energy resources are moving through system, FERC issued guidance and RTOs are required to put forth a plan and MISO is working on that. There could be some instances where a distributed energy resource coupled with demand response could be partially or fully qualified.
- Can you elaborate on your answer on the RFP website to the question about accepting aggregation of DERs? How will you address this given that MISO's implementation on FERC Order 2222 has received an extension of time?
    - DERs or aggregation of such resources are emerging technologies and developmental technologies themselves. NIPSCO recognizes a lot can change between now and the in service years being considered (2024 -2026). The Company understands

implementation of the Order is delayed. That does not mean NIPSCO cannot effectively evaluate options given where we are in the timeline relative to in-service dates. Bidders should clearly state assumptions associated with their bid and the number of ways that the FERC Order can be implemented. NIPSCO will have to wait and see how things develop with the rest of the market.

Wrap Up and Next Steps
Mike Hooper, President and Chief Operating Officer, NIPSCO

Mike Hooper, President and COO of NIPSCO, closed the session by thanking attendees for their participation and reminding stakeholders about key dates associated with the RFP and other requested feedback.

May 20, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Emily	Abbott	Invenergy
Denise	Abdul-Rahman	NAACP Indiana
Jason	Abiecunas	FlexGen Power Systems, Inc.
Susan	Adams	
Ravi	Adibhatla	CMS Enterprises Company
Lauren	Aguilar	Indiana Office of Utility Consumer Counselor
Thomas	Ahn	Apex Clean Energy Inc
Anthony	Alvarez	OUCC
Cynthia	Armstrong	Indiana Office of Utility Consumer Counselor
Laura	Arnold	Indiana Distributed Energy Alliance (IndianaDG)
Pat	Augustine	Charles River Associates
James	Aycock	AES Indiana
Kim	Ballard	IURC
Ed	Baptista	GEG Renewables
Ed	Baptista	GEG Renewables
Mitchell	Bauer	AES Clean Energy
Vernon	Beck	Nipsco
Matt	Bell	Reliable Energy, Inc.
Dana	Berkes	NIPSCO
Greg	Berning	NiSource
Mahamadou	Bikienga	NiSource
Tom	Bitting	Hoosier Solar
Tom	Bitting	Hoosier solar
Rosann	Bloom	NextEra Energy Resources, LLC
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	Indiana Utility Regulatory Commission
Mary Jane	Both	Clenera LLC
Matt	Boys	GlidePath Power Solutions
Wendy	Bredhold	Sierra Club Beyond Coal Campaign
Allen	Brisch	Ecoplexus
Justin	Brown	Clenera
George	Bultmann	GE Renewable Energy.
Rebecca	Campbell	NRG Curtailment Solutions, Inc.
Brian	Carr	Grid One Solutions, LLC.
Gilles	Charriere	Sierra Club/ NIPSCO customer
Julie	Christy	Plus Power
Deborah	Chubb	League of Women Voters
John	Cleaveland	NIPSCO
Homer	Cobb	NAACP
Tom	Cofer	C21 Affiliated
Elaine	Coffey	
Denise	Conlon	NIPSCO
Joseph	Conn	CONN
Alex	Cooley	NiSource
Jeffrey	Corder	St. Joseph Energy Center

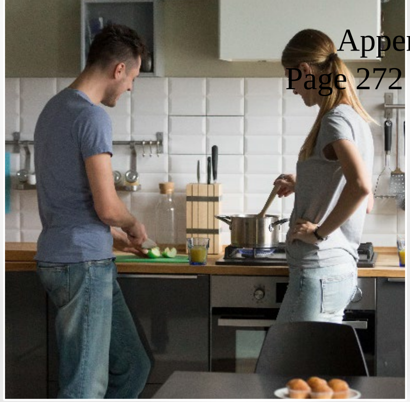
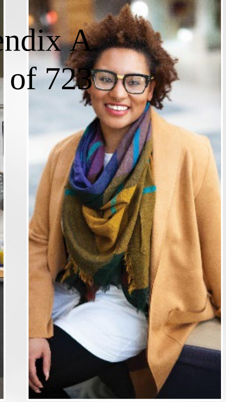
May 20, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Jordan	Covely	Inovateus Solar LLC
Ben	Crandall	Uplight
Anaelle	Croteau	AdvantageCapital
Kelley	Davies	NIPSCO
Roy	Dell'Aquila	7701 LEGACY DRIVE
Marla	DeMoss	Oracle
Ronald	DiFelice	Southern Current
Lou	Donkle	
Cory	Dutcher	General Electric Company - Power Division
Jeffery	Earl	Reliable Energy
Michael	Eckert	OUCC
Ian	Edwards	
Gregory	Ehrendreich	Midwest Energy Efficiency Alliance (MEEA)
Suzanne	Escudier	Origis Energy
Lisa	Evans	Earthjustice
Daniel	Farrell	Retired
Marjorie	Filiatreault	Dunsky Energy Consulting
William	Fine	Indiana Office of Utility Consumer Counselor
Michael	Fortini	DTE
Bill	Fowler	Shell Energy North America (US), L.P.
Steve	Francis	SEED
Sarah	Freeman	Indiana Utility Regulatory Commission
Cinthia	Galvez	OUCC
Blake	Gardiner	
Nick	Gates	Galehead Development LLC
Richard	Gillingham	Hoosier Energy
Fred	Gomos	Nisource
Lana	Gonoratsky	Enbala
Doug	Gotham	State Utility Forecasting Group
Abby	Gray	Indiana Office of Utility Consumer Counselor
Robert	Greskowiak	Invenergy LLC
Paul	Griffin	Indeck Energy Services
Jack	Groves	ENERGY SOUTHWEST INC.
Stacie	Gruca	Indiana Office of Utility Consumer Counselor
Tim	Gusick	Eastern Generation, LLC
Bryce	Gustafson	Citizens Action Coalition
Sean	Haas	Reserve
Rebecca	Halford	AES
Andrew	Hamilton	Ranger Power
Joni	Hamson	EDF Renewables
Deidre	Hansen	Indiana Utility Regulatory Commission
Barbara	Hargrove	
John	Haselden	Indiana Office of the Utility Consumer Counselort
Ryan	Heater	Indiana Utility Regulatory Commission
Robert	Heidorn	NiSource

May 20, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
John	Hejkal	Tenaska, Inc.
Max	Henderson	NiSource
Joseph	Hero	Attorney-Engineer
Jaime	Holland	NextEra Energy - Formerly Florida Power & Light
Chelsea	Hotaling	Energy Futures Group
Darrel	Hughes	DLH Consulting LLC
Jim	Hummel	Duke Energy
Sergio	Hunt	Indiana OUCC
Jim	Huston	Indiana Utility Regulatory Commission
Ben	Inskeep	EQ Research
Jeff	James	Savion, LLC
Sam	Johnson	Longroad Energy, LLC
Steve	Johnson	Tenaska
David	Johnston	Indiana Utility Regulatory Commission
Robert	Kaineg	Charles River Associates
Michelle	Kang	Charles River Associates
Teresa	Kanter	Duke Energy Renewables
Mike	Kelly	Tri Global Energy, LLC
William	Kenworthy	Vote Solar
Nick	Kessler	CenterPoint Energy
Shawn	Kestler	Kestler Energy Consulting, LLC.
John	Kinnamon	EmberClear
Cameron	Kirby	Lightsource bp
Andrea	Kong	Telamon Enterprise Ventures
Nathan	Krieger	Solarpack Development, Inc.
Karol	Krohn	Office of Utility Consumer Counselor
Jeremy	Kuhre	Clenera
Angela	Kvasnica	
Natalie	Ladd	NiSource
Willard	Ladd	Development Partners
Jonathan	Landy	Duke Energy
Tim	Lasocki	Orion Renewable Energy Group LLC
Philip	Lehmkuhler	Solential Energy
Anne	Lenzen	Opower
Bryan	Likins	NIPSCO
James	Loewen	Everspring Energy
Greg	Long	Cleveland-Cliffs Steel
Russell	Lovelace	Shell Energy North America
Caleb	Loveman	Indiana Office of Utility Consumer Counselor
Allison	Lowitz	Galehead Development
Liwei	Lu	SUFG
Wendy	Lussier	NIPSCO
Nicole	Makela	
Greg	Martin	BP
Cyril	Martinand	Cleveland-Cliffs

May 20, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Clyde	Mason	Unity Electric Discount, LLC
Ben	Mathes	Hecate Energy
Martha	Maust	
Cassandra	McCrae	Earthjustice
Kalin	McGowan	CRA
Caroline Mead	Mead	ENGIE North America
Emily	Medine	EVA
Matan	Meital	Eos Energy Enterprises
Tony	Mendoza	Sierra Club
Nick	Meyer	Nisource
Erik	Miller	AES
Alan	Mok	Duke Energy
Tim	Montague	Contintental Energy Solutions
Jeremy	Morgan	PPMS
Walter	Mueller	retired
David	Nderitu	SUFG
Richard	Nelson	Linde Inc.
Jim	Northrup	Integrated Resource Planning
David	Ober	Indiana Utility Regulatory Commission
Christian	Okolski	Leeward Renewable Energy
Kerwin	Olson	Citizens Action Coalition of IN
Justin	Painter	East Point Energy
Elizabeth	Palacio	PDA CALUMET INDIANA
April	Paronish	Indiana Office of Utility Consumer Counselor
Richard	Pate	Pate & Associates
Bob	Pauley	IURC
Juan	Pena	X-ELIO North America Inc.
Tim	Phillips	State Utility Forecasting Group
Matthew	Plante	Voltus, Inc.
Tim	Powers	Inovateus Solar LLC
Melanie	Price	Duke Energy
Melanie	Price	Duke Energy
Cody	Rajewski	Bierlein Companies
Tolaver	Rapp	Cleveland-Cliffs
Jeff	Reed	Indiana Office of Utility Consumer Counselor
Kevin	Reeves	BP Energy Company Â– North America Gas & Power
Ryan	Ren	Tri Global Energy
ADam	Rickel	NextEra Energy Resources
Robert	Ridge	NIPSCO
Tonya	Rine	CenterPoint Energy
Chad	Ritchie	TRC
Rosalva	Robles	NIPSCO
Stephen	Rodocanachi	Hartree Partners
Mike	Rodriguez	ibV Energy Partners
LouAnn	Rone	NiSource

May 20, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Roland	Rosario	CenterPoint Energy
Edward	Rutter	London Witte
Jamalyn	Sarver	Sunrise Coal LLC
Zach	Schalk	Solar United Neighbors
Julian	Schwab	Ares Managment
Cliff	Scott	NIPSCO
Robert	Sears	NIPSCO
Brent	Selvidge	AES Indiana
Rob	Seren	NIPSCO
Brad	Shearson	National Grid Renewables
Mark	Simons	MCSimons Inc.
Regiana	Sistevaris	I&M
Radha	Soorya	Longroad Energy
Pauline	Sotiroski	NIPSCO
Daniel	Spellman	Orion Renewable Energy Group LLC
Jennifer	Staciwa	NIPSCO
Karl	Stanley	NiSource
Sarah	Steinberg	Advanced Energy Economy
George	Stevens	I.U. R. C.
John	Storm	Wood Environment and Infrastructure Solutions
Ronald	Talbot	NIPSCO
Maggie	Tallmadge	Ranger Power
Cyrus	Tashakkori	OPEN ROAD RENEWABLES
Dan	Tavani	EPRI
Marco	Terruzzin	Energy Vault Inc
Dale	Thomas	IURC
Susan	Thomas	Just Transition NWI
Elias	Toshiro	Tyr Energy, Inc.
LaTonya	Troutman	NAACP
Maureen	Turman	NiSource
Michal	Tvrdon	Solar Provider Group
Edward	Twarok	NiSource
Laurel	Udenberg	ALLETE, Inc dba Minnesota Power
Darian	Unruh	Utility Regulatory Commission
Gregory	Van Horssen	Van Horssen Law & Government, PLLC
Jeffrey	Vance	Vistra Corp
Chris	Vickery	
Nathan	Vogel	Inovateus Solar LLC
Goran	Vojvodic	Charles River Associates
Nancy	Walter	Just Transition Northwest Indiana
Jennifer	Washburn	CAC
Kyle	Wattenbarger	Hitachi ABB
Patrick	Welch	X-Elio North America
Amanda	Wells	Duke Energy
Denzil	Welsh	Indiana-Michigan Power Company

May 20, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Erin	Whitehead	NIPSCO
Ryan	Wilhelmus	CenterPoint Energy
Ashley	Williams	Just Transition NWI
J. Scott	Yaeger	Southern Illinois Generation Company
William	Zednik	
Tom	Zelina	AEP
Ivan	Zyla	Advanced Power


NIPSCO
A NiSource Company

2021 NIPSCO Integrated Resource Plan

NiSource

Stakeholder Advisory Meeting #3

July 13th, 2021
9:00AM-2:00PM CT




SAFETY MOMENT

Parking Lot Safety

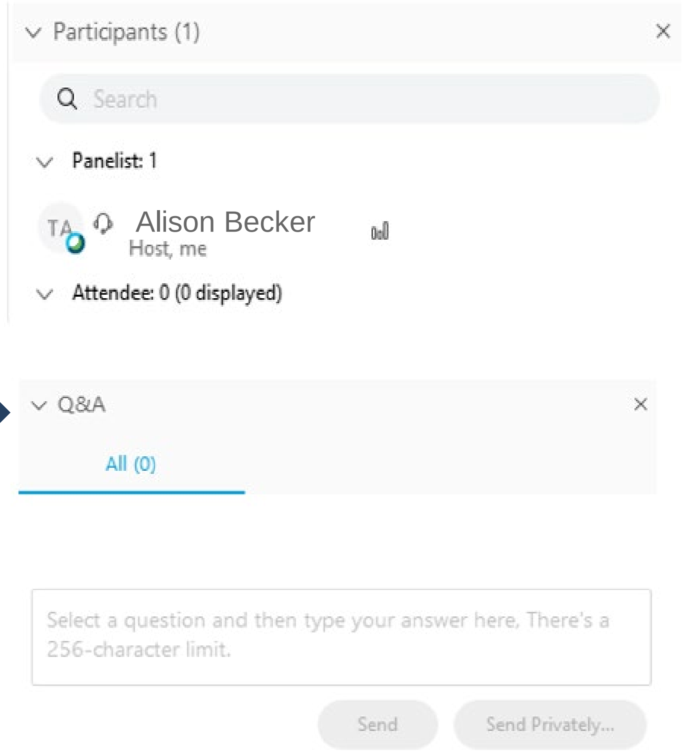
Don’t be fooled by slow-moving vehicles: 1 in 5 accidents occur in a parking lot

- Don’t become distracted by your cell phone or headphones.
- Be aware of your surroundings. Walk with confidence to buildings and to your car.
- Keep your car locked, even if you are running a quick errand.
- Park near the building in a visible and well-lit area.
- Look twice for pedestrians, bicycles, and other vehicles.
- Drive slowly and obey posted speed limits and signs.
- Stay in lanes and avoid cutting across lots.

Source: [Oceaneering]

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
9:00-9:05AM	Webinar Introduction, Safety Moment, Meeting Protocols, Agenda	Alison Becker, Manager Regulatory Policy, NIPSCO
9:05-9:10AM	Welcome	Mike Hooper, President & COO, NIPSCO
9:10-9:30AM	NIPSCO's Public Advisory Process and Updates From Last Meeting	Fred Gomos, Director Strategy & Risk Integration, NiSource
9:30-10:30AM	Developing the Demand Side Management (DSM) Study	Alison Becker, Manager Regulatory Policy, NIPSCO Jeffrey Huber, Managing Director – Energy Efficiency, GDS Pat Augustine, Vice President, CRA
10:30-10:45AM	Break	
10:45-11:15AM	Supply-Side Distributed Energy Resource (DER) Considerations	Pat Augustine, Vice President, CRA
11:15AM-12:00PM	Lunch	
12:00-1:00PM	2021 Request for Proposals (RFP) Results Overview	Andy Campbell, Director Regulatory Support & Planning, NIPSCO Bob Lee, Vice President, CRA
1:00-1:55PM	Incorporating RFP Results Into The IRP	Fred Gomos, Director Strategy & Risk Integration, NiSource Pat Augustine, Vice President, CRA
1:55-2:00PM	Wrap Up & Next Steps	Erin Whitehead, Vice President Regulatory & Major Accounts, NIPSCO

WELCOME

Mike Hooper, President & COO, NIPSCO

WHERE WE ARE IN THE 2021 IRP PROCESS

Appreciate The Stakeholder Engagement

- Thank you for your participation and level of engagement
- Third stakeholder meeting with over 100 participants registered
- 33 unique bidders into our 2021 RFP

Progress on Generation Transition Plan

- 2 wind facilities operational (Jordan Creek and Rosewater) and 1 under construction (IN Crossroads)
- Approval for 11 of the 14 projects we have filed with the Commission

Next Steps for the IRP

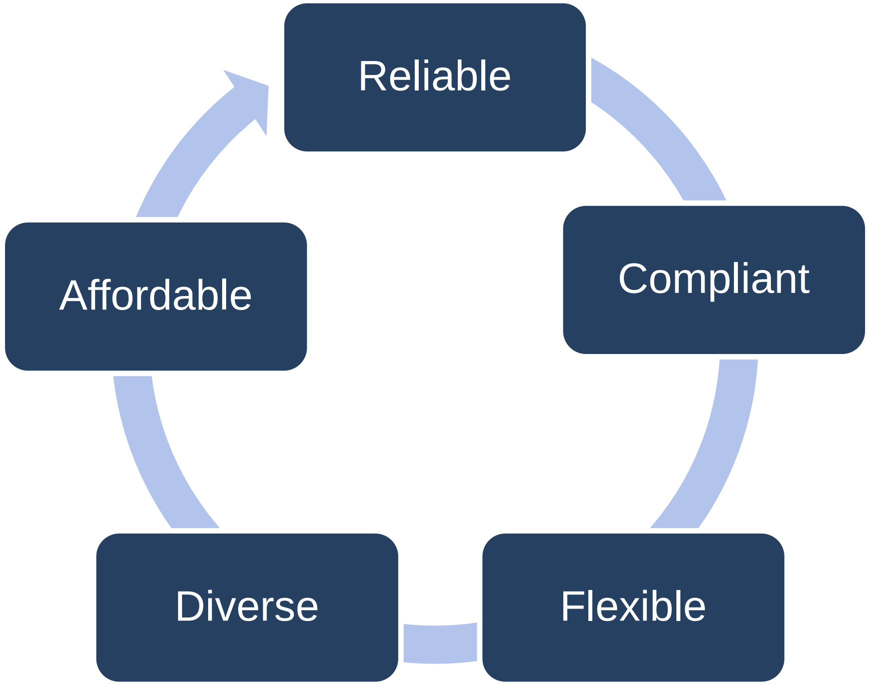
- Integrate RFP results into our analysis
- Perform portfolio modeling and evaluate all potential options
- Share directional results in the September Stakeholder meeting and get feedback on that preliminary plan

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)

2021 STAKEHOLDER ADVISORY MEETING ROADMAP

Meeting Date Location	Meeting 1 (March) 3/19/2021 Virtual	Meeting 2 (May) 5/20/2021 Virtual	Meeting 3 (July) 7/13/2021 Virtual	Meeting 4 (September) 9/21/2021 Virtual	Meeting 5 (October) 10/12/2021 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? • How will NIPSCO evaluate potential DER options? • 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 • DER Inputs • 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 • Explain next steps for portfolio modeling	• 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

RESOURCE PLANNING APPROACH

Focus of Today's Meeting

	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

3

New resource option parameters

DSM Study

RFP Information

Retirement options and replacement themes (informed by scenarios)

Portfolio Optimization

NIPSCO Portfolios

2

Scenario Narrative Development

Integrated gas, coal, carbon forecasts and **MISO market outlook / prices**

Market Modeling Tools (NGF, GPCM, Aurora)

Stochastic Modeling Tools

4

Aurora – **NIPSCO Portfolio** Market Model
Production Cost Dispatch (hourly, chronological)

PERFORM
Detailed cost of service and revenue requirements

Scorecard
(2018 Example)

Other analysis

PROGRESS SINCE LAST MEETING

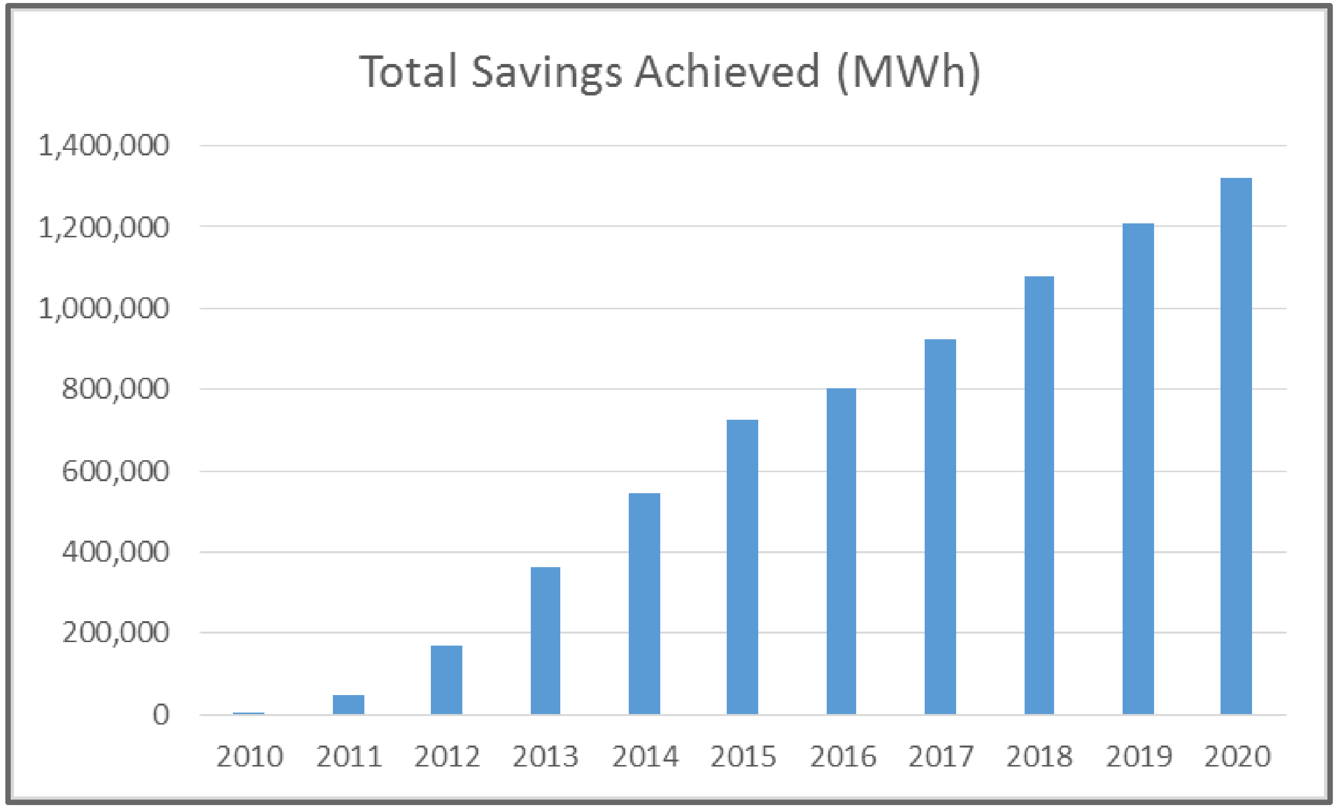
- **The 2021 RFP was launched after Stakeholder Meeting #2 and closed on June 30th**
  - The RFP team is currently reviewing and organizing bids
  - A preliminary summary will be shared later today
- **NIPSCO portfolio modeling is well underway**
  - Detailed MISO scenario and stochastic inputs (from Stakeholder Meeting #2) have been finalized
  - DSM and DER resource option inputs (to be discussed later today) have been setup
  - RFP tranche development is currently in progress

DEVELOPING THE DEMAND SIDE MANAGEMENT (DSM) STUDY

Alison Becker, Manager Regulatory Policy, NIPSCO
Jeffrey Huber, Managing Director – Energy Efficiency, GDS
Pat Augustine, Vice President, CRA

DSM AT NIPSCO – ENERGY EFFICIENCY AND DEMAND RESPONSE

- NIPSCO has had a robust history of actively promoting and implementing energy conservation and efficiency to both its employees and customers since 2010



DSM AT NIPSCO – ENERGY EFFICIENCY AND DEMAND RESPONSE

- NIPSCO actively works with its Oversight Board (“OSB”) to provide direction of both implementation and evaluation of NIPSCO energy efficiency programs
- NIPSCO and the OSB work with a third party administrator, TRC Companies, to offer cost-effective energy efficiency programs for customers
- Although NIPSCO previously offered an air conditioning cycling program, the demand response programs were historically focused on interruptible rate programs with NIPSCO’s largest customers, which now directly participate in the MISO demand response markets as part of the Rate 831 Industrial Customer Service Structure
- NIPSCO is currently seeking approval for the 2022-2023 Gas and Electric energy efficiency programs, and the 2021 IRP will plan for potential continued and new programs starting in 2024 (with a filing scheduled for November 2022)

NIPSCO MARKET POTENTIAL STUDY FOR DSM RESOURCES – ENERGY EFFICIENCY AND DEMAND RESPONSE

- To support the development of the 2021 IRP, the NIPSCO OSB worked with GDS Associates to develop a **market potential study ("MPS")** to assess the potential level of energy efficiency and demand response savings opportunities and the associated costs
- NIPSCO's MPS developed residential and commercial & industrial portfolio demand side management market potential and costs over the planning horizon for:
  - Utility-sponsored Energy Efficiency
  - Demand Response
    - Smart Thermostats
    - Direct Load Control
    - Tariff-based dynamic rates and load curtailment potential
- The MPS estimates the **maximum achievable potential (MAP)** and **realistic achievable potential (RAP)** for energy efficiency and demand response for the residential and commercial & industrial customer segments, along with the cost of acquiring the two levels of achievable potential
- The outputs of the MPS analysis will be used as inputs to be incorporated by CRA into the portfolio evaluation phase of the IRP

DEMAND SIDE MANAGEMENT MODELING STEPS

Step 1	Step 2	Step 3
Market Potential Study	**Identify "bundles" based upon market segments and savings potential**	**Evaluate DSM bundles in IRP portfolio models**
• Evaluate detailed energy efficiency and demand response program-level opportunities in NIPSCO service territory • Identify energy efficiency and demand response program impacts and associated costs	• Aggregate detailed measures into bundles of measures at the residential and commercial & industrial segment at the RAP and MAP levels • Produce bundles with detailed energy and demand savings characteristics and costs	• Allow DSM bundles to be selected in optimization analysis, along with other supply-side candidates • Evaluate alternative DSM portfolios (ie, specific bundles or RAP vs. MAP) within the IRP scenario and stochastic analysis process
GDS NIPSCO DSM Team (Steps 1–2)		CRA NIPSCO IRP Team

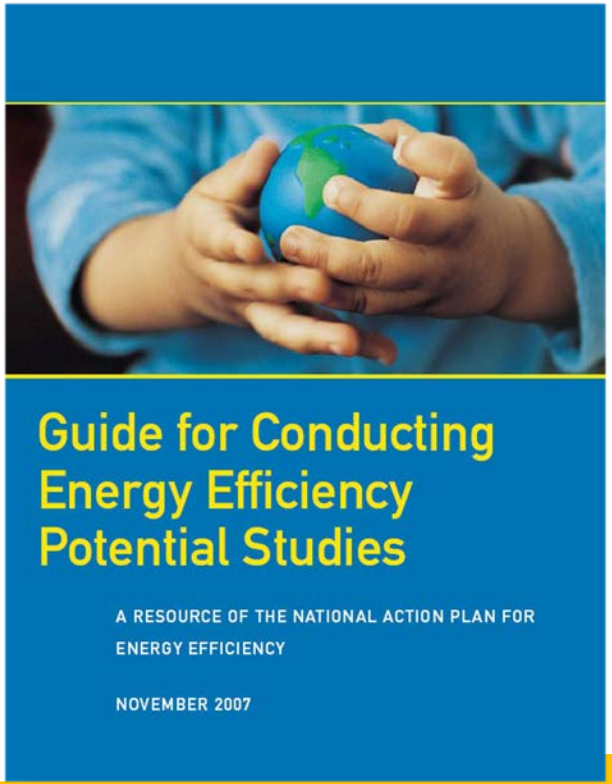
MARKET POTENTIAL STUDY OVERVIEW

WHAT IS A MARKET POTENTIAL STUDY?

Step 1	Step 2	Step 3
Market Potential Study	Identify "bundles" based upon market segments and savings potential	Evaluate DSM bundles in IRP portfolio models

Simply put, a potential study is a quantitative analysis of the amount of energy savings that either exists, is cost-effective, or could be realized through the implementation of energy efficiency programs and policies.

-National Action Plan for Energy Efficiency



TYPES OF POTENTIAL

TECHNICAL POTENTIAL

All technically feasible measures are incorporated to provide a theoretical maximum potential.

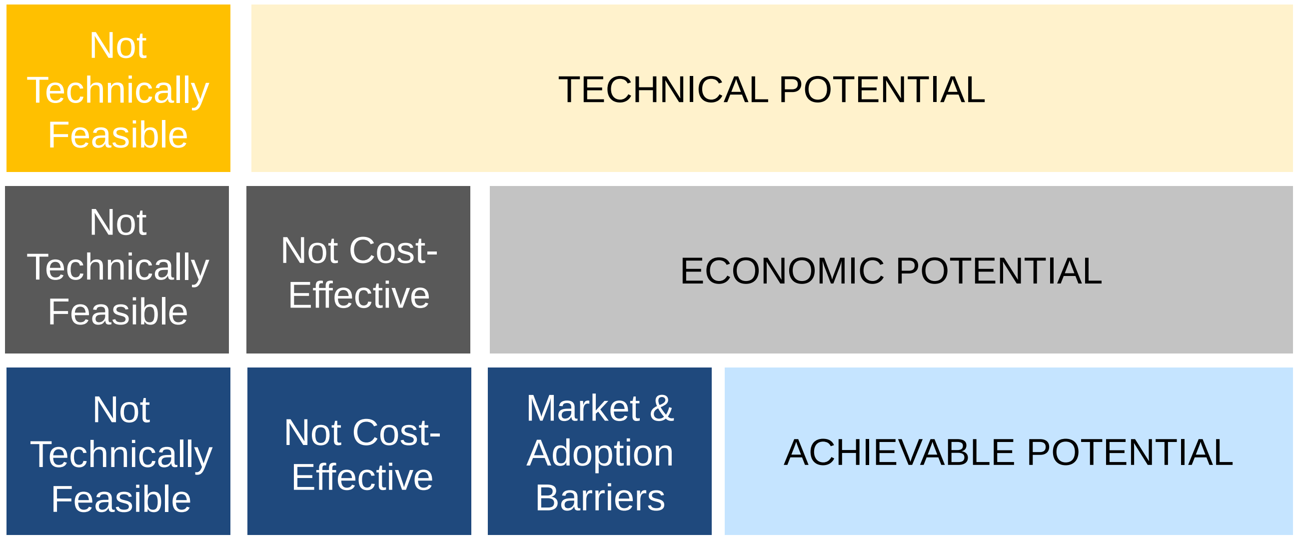
ECONOMIC POTENTIAL

All measures are screened for cost-effectiveness using the UCT Test. Only cost-effective measures are included.

ACHIEVABLE POTENTIAL

Cost-effective energy efficiency potential that can practically be attained in a real-world program delivery case, assuming that a certain level of market penetration can be attained.

Types of Energy Efficiency Potential



Two achievable scenarios

Maximum Achievable Potential (MAP) assumes 100% incentives and more aggressive adoption levels

Realistic Achievable Potential (RAP) assumes incentives that align with current levels

HOW DOES THE MARKET POTENTIAL STUDY INTERACT WITH THE IRP?

The MPS represents the starting point for developing inputs for the IRP modeling

The savings potential from this analysis will be used to create DSM resources and levels to be modeled in the IRP

DSM selections from the IRP will be used to create NIPSCO's DSM plan for 2024-2026

MARKET RESEARCH OVERVIEW

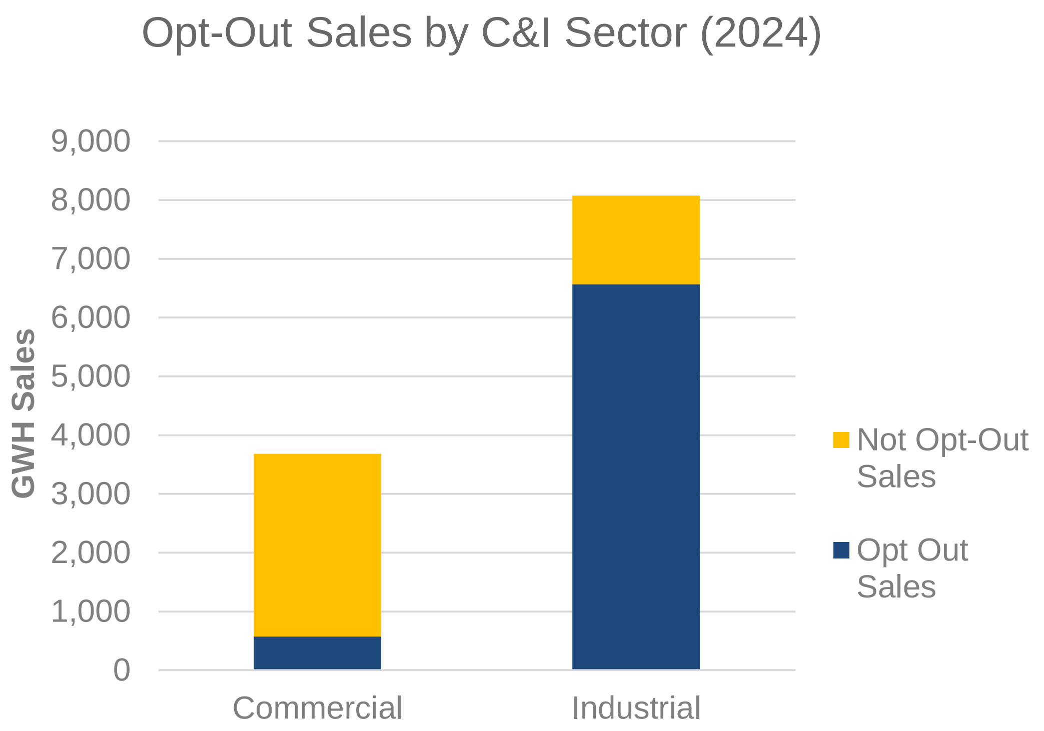
KEY GLOBAL INPUTS AND DATA SOURCES

NIPSCO Electric Load Forecast*	Forecasts of Avoided Costs	Inflation Rate	Discount Rate
Planning Reserve Margin	Line Loss Assumptions	Energy efficiency and demand response measure costs, kWh and kW savings, useful lives	Market Characteristic Data*

** To be discussed in more detail*

NIPSCO ELECTRIC LOAD FORECAST

- **NIPSCO's internal sales forecast was modified for use in the MPS**
  - Adjustment removed embedded assumptions about future energy efficiency based on historical DSM performance.
  - MPS also removed sales of current opt-out customers from eligible sales forecast (see graphic to the right)

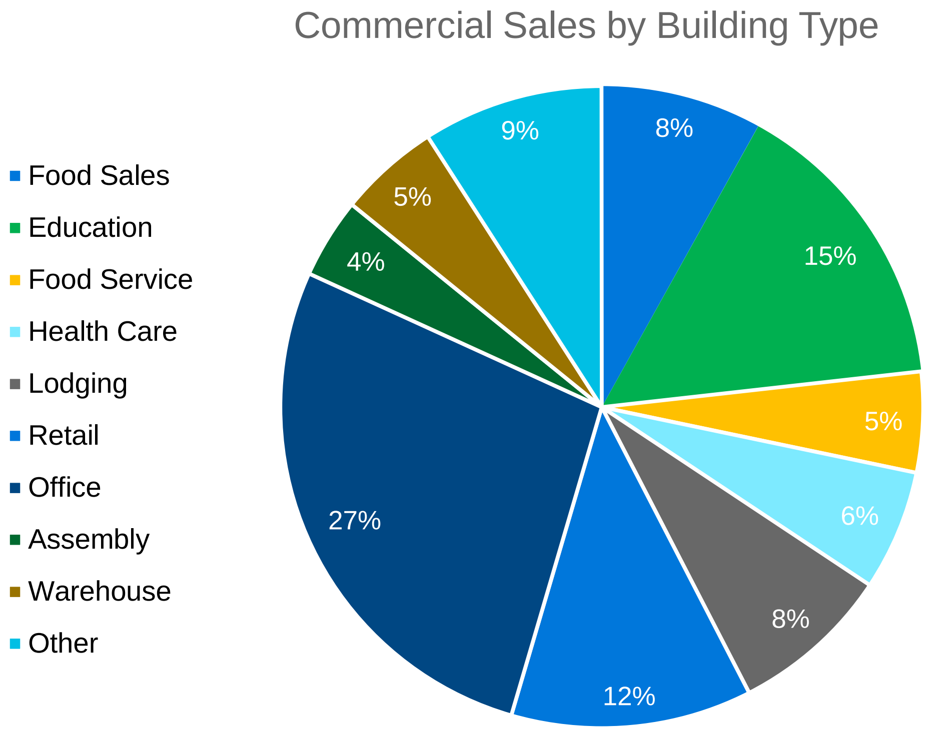


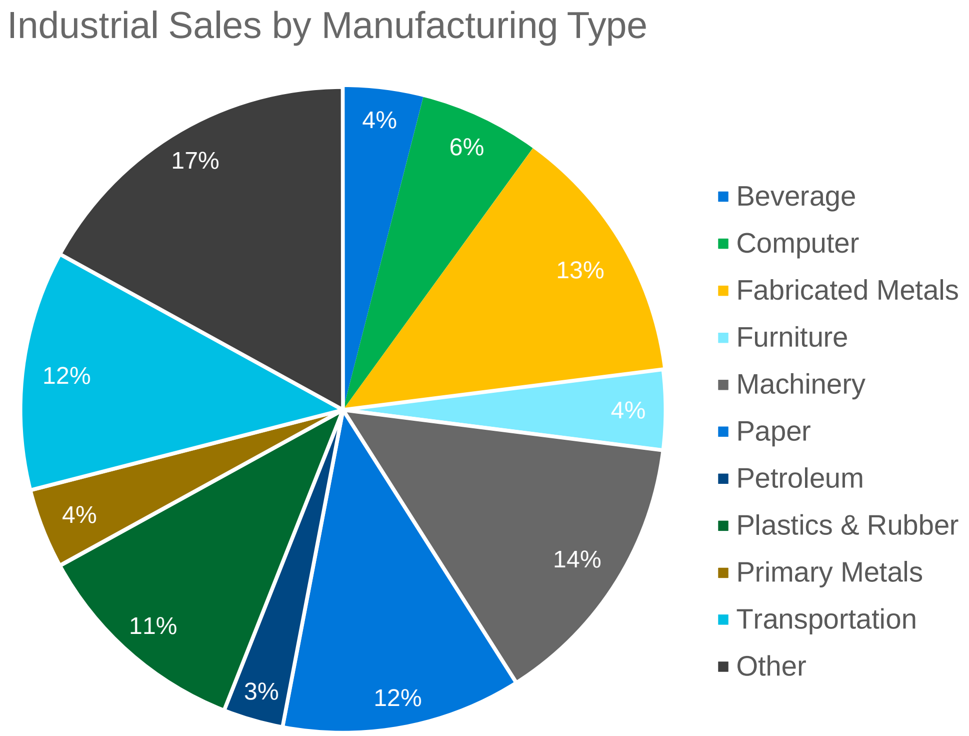
**Note that the industrial load shown here includes some non-firm Rate 831 customers. The non-firm component, however, is not included in NIPSCO's IRP load forecast, since NIPSCO is not obligated to serve that load.*

MARKET CHARACTERISTICS DATA

- **To fill in a data gap surrounding equipment characteristics and saturation data, GDS collected primary market research at residential homes and non-residential facilities**
  - Residential sector included both internet/mail surveys, as well as a smaller subset of on-site data collection
  - Commercial sector included on-site survey research
- **Data collection activities also included:**
  - Detailed segmentation of the commercial and industrial sectors from full NIPSCO customer datasets
  - Willingness to participate (WTP) research to inform adoption rates to be used in the assessment of achievable potential

MARKET CHARACTERISTICS DATA





Nonresidential sector analysis uses a top-down approach; understanding sales by building/industry type is a critical component of the top-down approach.

MARKET CHARACTERISTICS DATA

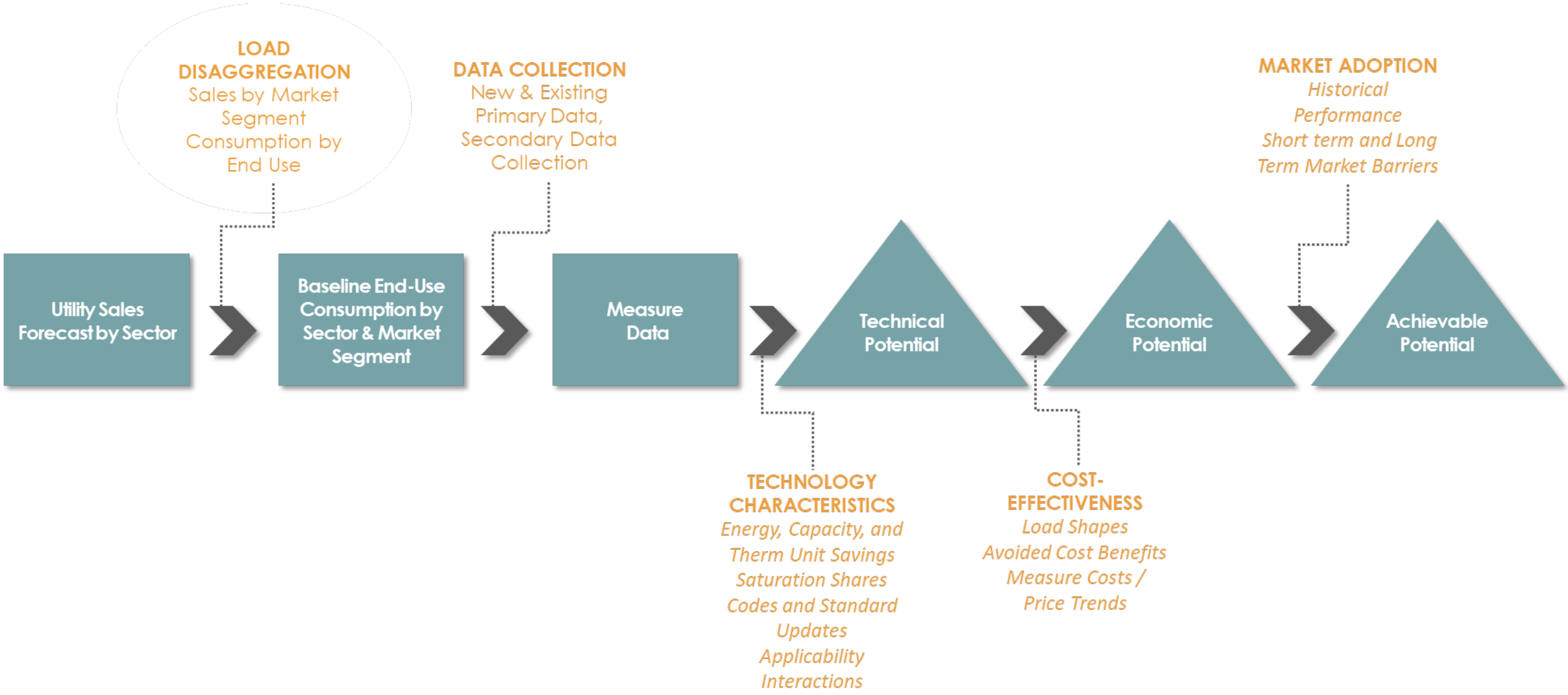
End Use	0% Incentive	25% Incentive	50% Incentive	75% Incentive	100% Incentive
Refrigeration	25.3%	43.2%	78.8%	78.8%	97.5%
Insulation	14.3%	48.3%	72.0%	72.0%	97.8%
HVAC	23.0%	57.3%	76.8%	76.8%	96.7%

Investment Type	10 Year Payback Period	5 Year Payback Period	3 Year Payback Period	1 Year Payback Period	0 Year Payback Period
Major Investment	42.8%	58.1%	67.6%	74.6%	81.2%
Minor Investment	41.0%	56.1%	65.7%	73.1%	80.8%

- The Willingness-to-Participate survey is used to inform long-term adoption rate estimates in the achievable potential scenarios.
- Surveys asked residential homeowner and commercial business/property managers their likelihood to participate across various incentive/payback performance levels and end-use/investment types.
- Adoption rates help transition from economic potential (100% adoption) to more achievable levels.
- In addition to WTP estimates (tables on left), the long-term adoption rates included an estimate of program awareness that varied by achievable potential scenario (60%-100%)
  - WTP * Awareness Factor = Long-Term Adoption Rate

ENERGY EFFICIENCY

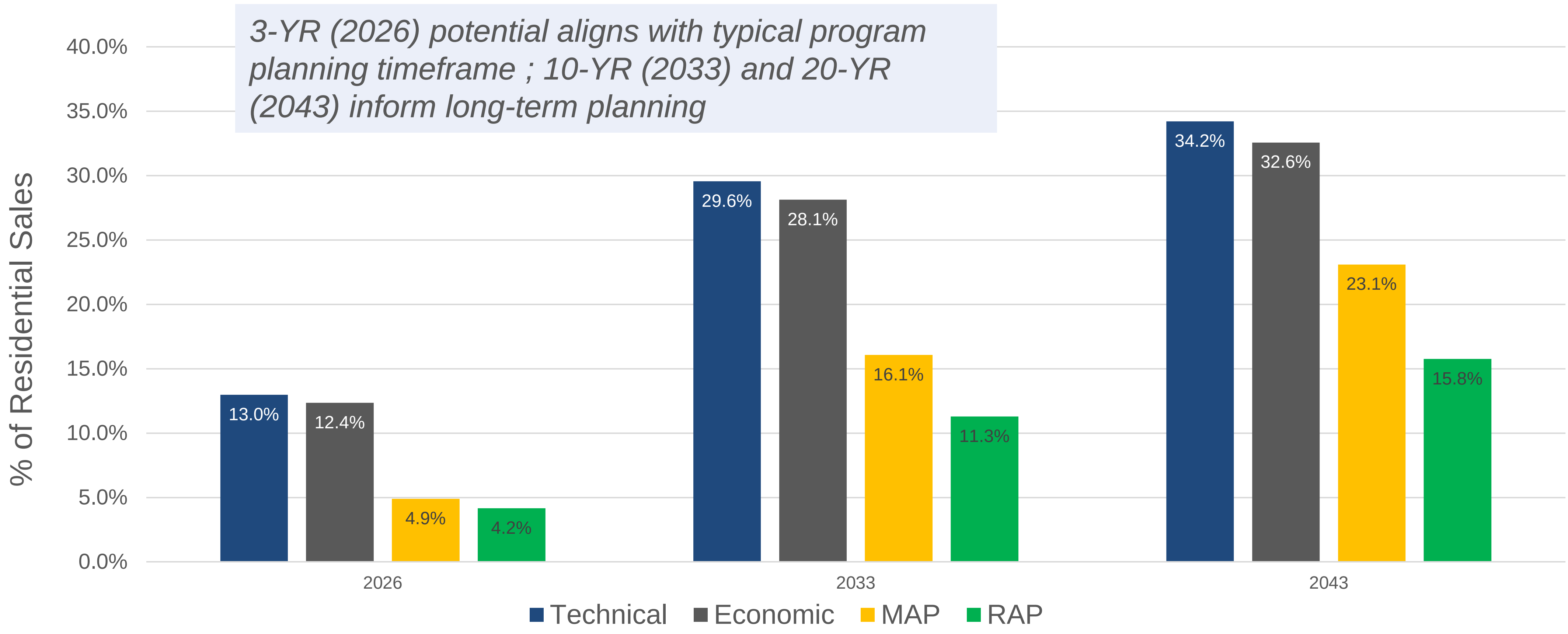
ENERGY EFFICIENCY METHODOLOGY – STUDY APPROACH



ENERGY EFFICIENCY METHODOLOGY – KEY CONSIDERATIONS

1. Measure list included all current offerings as well as additional emerging measures/technologies
   a. MPS does limit potential from residential general service lightbulbs based on discussions with NIPSCO program administrators and the NIPSCO Oversight Board.
2. Industrial sector potential excluded opt-out customers
3. The Utility Cost Test (UCT) was used to screen measure cost-effectiveness
4. Two achievable scenarios: Maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP)
5. Estimates of technical, economic, and achievable potential are gross (i.e., not adjusted for free-riders and/or spillover)

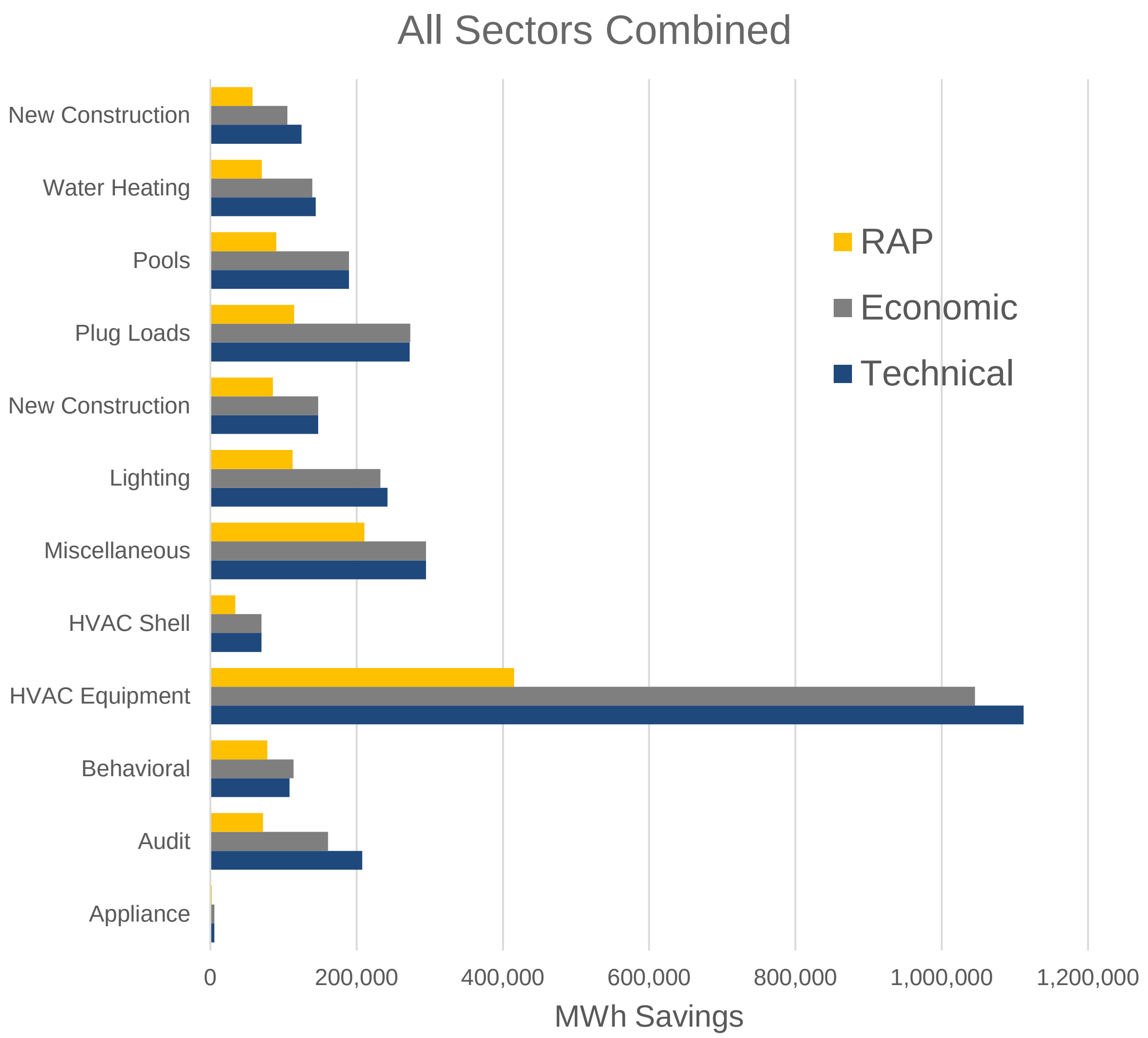
ENERGY EFFICIENCY POTENTIAL SUMMARY



Results in chart show ***cumulative annual*** savings

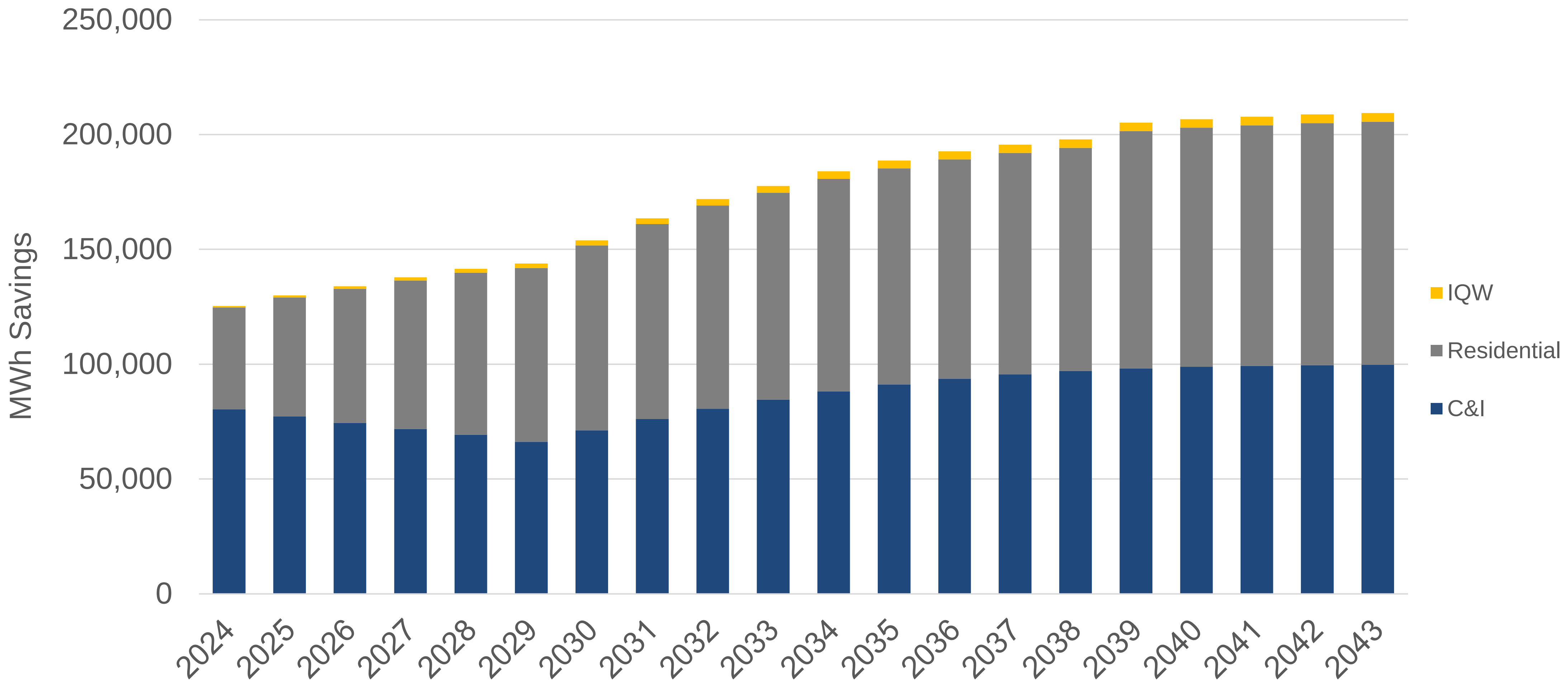
- *Cumulative Annual savings in Year X represent both the incremental (new) savings achieved in that year, as well as any sustained savings from measures installed in prior years that have not yet reached the end of their effective useful life (EUL)*

20-YEAR CUMULATIVE ANNUAL POTENTIAL BY END USE



- There is a large amount of technical and economic potential in the HVAC End Use
  - HVAC includes Heating, Cooling, Ventilation Equipment and Building Shell measures
- Lighting is primary in the C&I sector; there is very limited potential for lighting in the residential sector due to assumptions about general service LED market transformation
- Behavioral savings are slightly higher in economic potential (compared to technical) due to fewer interactive effects

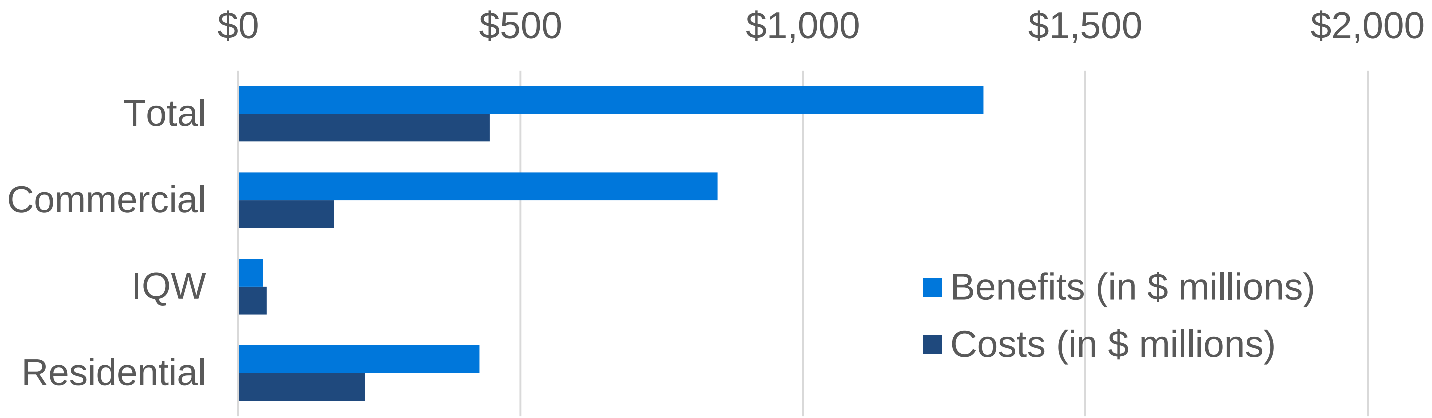
INCREMENTAL RAP BY SECTOR



C&I NPV COSTS AND BENEFITS BY PROGRAM

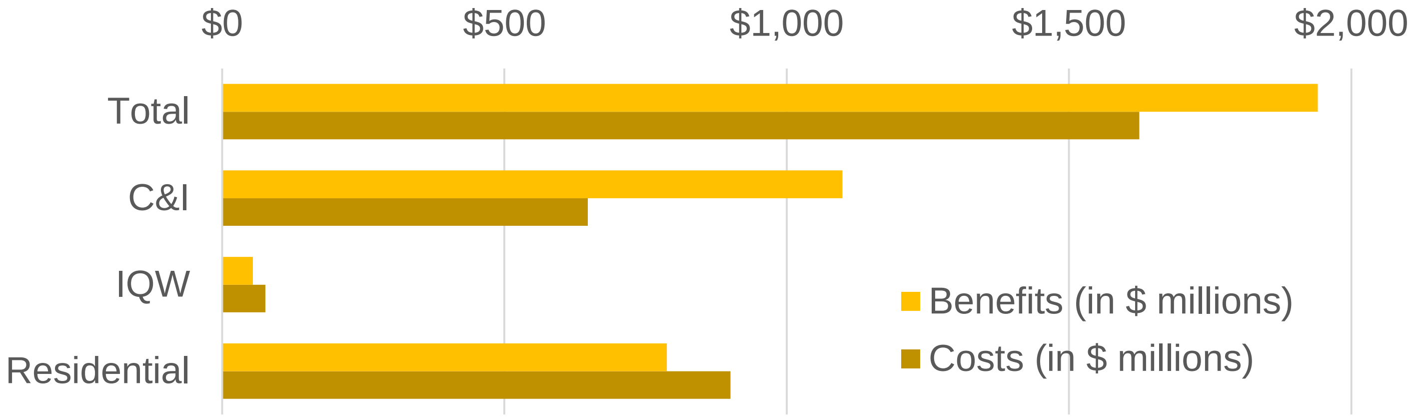
All values shown are 20-year net present values (NPV) in 2024$ for the 2024-2043 time period

RAP



Levelized $/kWh
$0.045
$0.025
$0.212
$0.075

MAP



Levelized $/kWh
$0.116
$0.076
$0.236
$0.174

ALTERNATE AVOIDED COST SCENARIO – ENERGY EFFICIENCY

- GDS analyzed an alternate avoided cost scenario for both energy efficiency and demand response
  - Base avoided cost of generation capacity is based on a natural gas CC unit and totals $164/kW-year in 2024 for G+T+D
  - The alternate avoided cost scenario reduces the total avoided cost to $115/kW-yr in 2024 and is based on a CT (peaking) unit
- The alternate avoided costs led to **slightly reduced potential in the residential sector**
  - 0.11% reduction
- The alternative avoided costs led to **no change in the commercial and industrial sector.**
- ***Energy Efficiency cost-effectiveness is typically dependent on avoided energy costs and less impacted by generation capacity costs.***

DEMAND RESPONSE

HISTORICAL AND CONTEMPLATED PROGRAMS

Prior DR Programs

- **Residential AC cycling:** program suspended in 2015
- **Rate 831 (large industrial customers) interruptible loads:** no longer part of the NIPSCO DR portfolio
  - Prior to the 2018 rate case, NIPSCO offered ~675 MW of Rate 831 interruptible loads to MISO as a load modifying resource (LMR)
  - Since the 2018 rate case, NIPSCO is only required to serve firm load for Rate 831 customers of roughly 167 MW
  - <u>~675 MW Rate 831 interruptible load is not included in this study as DR</u>
- **NIPSCO does not currently have any other DR offerings**

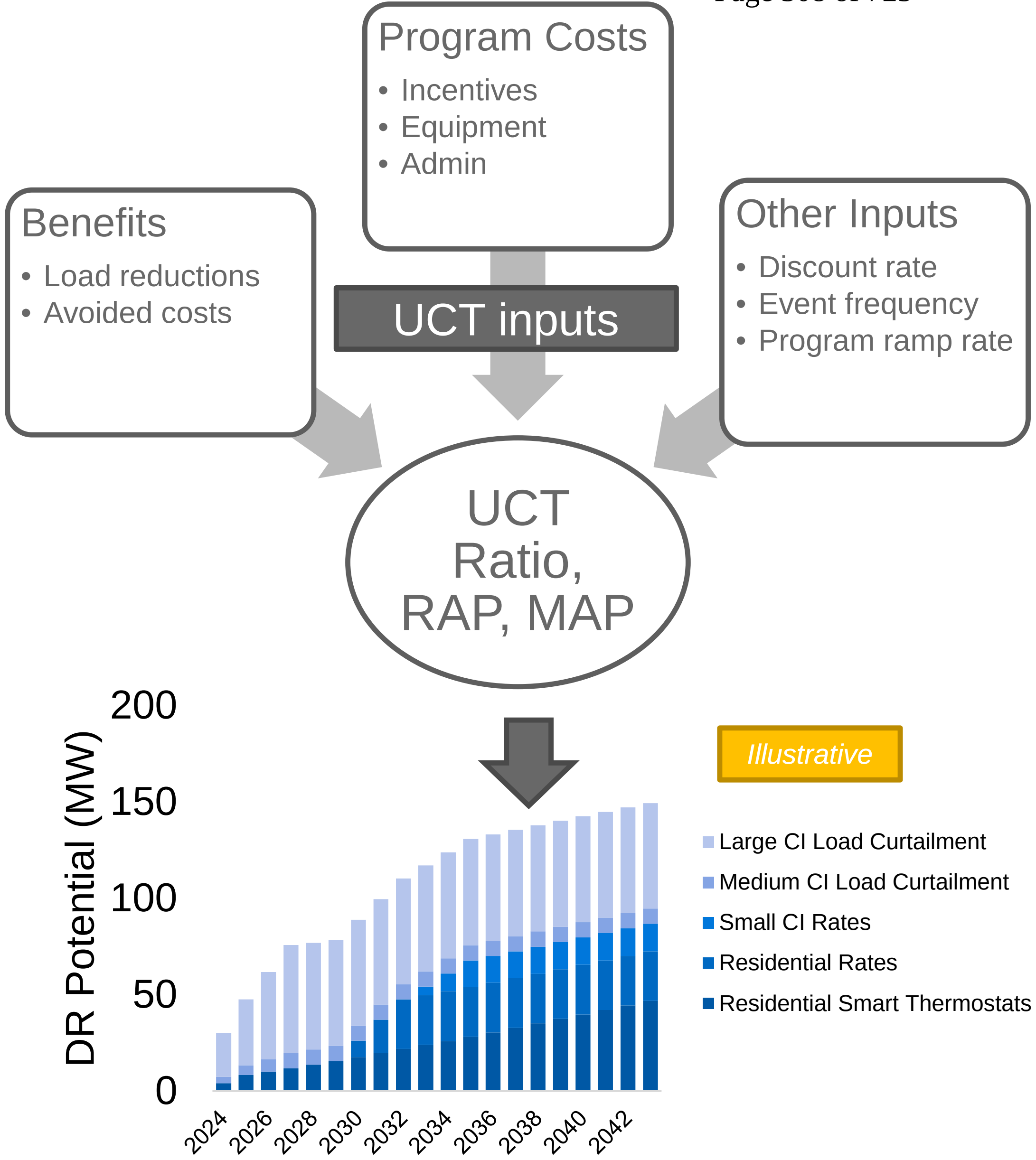
Programs Considered for Study

- **Residential smart (Wi-Fi enabled) thermostats**
  - Allow NIPSCO to control customer AC usage during event windows to reduce loads
  - Designed as add-on to smart thermostat EE rebate measure and uses EE RAP and MAP; also recruit from customers who already have smart thermostats
- **Residential electric water heaters**
  - Devices are controlled via Wi-Fi signal
- **Residential and small C&I dynamic rates**
  - Event-based critical peak pricing program that greatly increases cost of electricity during event hours
  - Enabling AMI assumed to be in place by 2030, but AMI costs are not included in program costs
- **Medium and large C&I load curtailment**
  - Customers earn a payment in exchange for reducing load with day-of notification

METHODOLOGY OVERVIEW

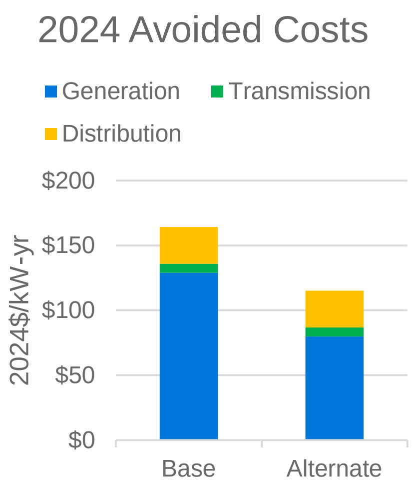
- Programs are evaluated for cost-effectiveness using the Utility Cost Test (UCT)
  - UCT = ratio of NPV benefits to NPV costs per program over 20-year lifespan
  - Only programs with UCT > 1 (benefits exceed costs) are included in RAP and MAP

- MPS contains two DR Potential scenarios:
  1. **RAP (Realistic Achievable Potential):** A “realistic” projection of future cost-effective DR
  2. **MAP (Maximum Achievable Potential):** An “aggressive” projection of future cost-effective DR, achieved by offering more generous incentives or establishing programs as opt-out (default)



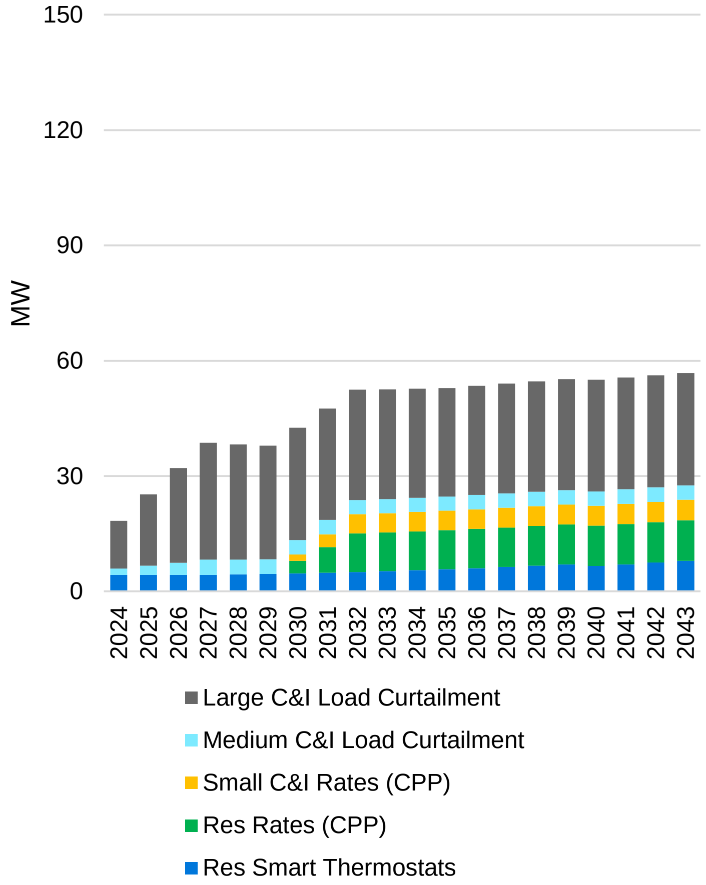
KEY ASSUMPTIONS

- All programs start in 2024 except dynamic rates in 2030 (NIPSCO does not have necessary AMI today)
  - Economic results for dynamic rates programs do not include AMI meter costs
  - All programs incorporate two or three-year ramp-up period
- All reported NPV values are in 2024$
  - Assume a 6.38% nominal discount rate and 2.1% inflation rate
- All impacts are reported in system-level MW
  - Impacts include line losses and customer opt-outs
- The avoided cost of generation capacity is based on a natural gas CC unit and totals $164/kW-year in 2024 for G+T+D
  - The alternate avoided cost scenario reduces the total avoided cost to $115/kW-yr in 2024
- Large C&I customers receive avoided generation and transmission costs only
  - Do not receive avoided distribution costs
- All programs are designed to receive 100% capacity credit under MISO LMR accreditation rules (FERC docket ER20-1846)
  - Programs have a notification times of six hours or less and may be called at least 10 times per year (we assume they are dispatched <u>on average</u> six times per year over a four-hour event)
  - We assume a constant load impact over the duration of the event

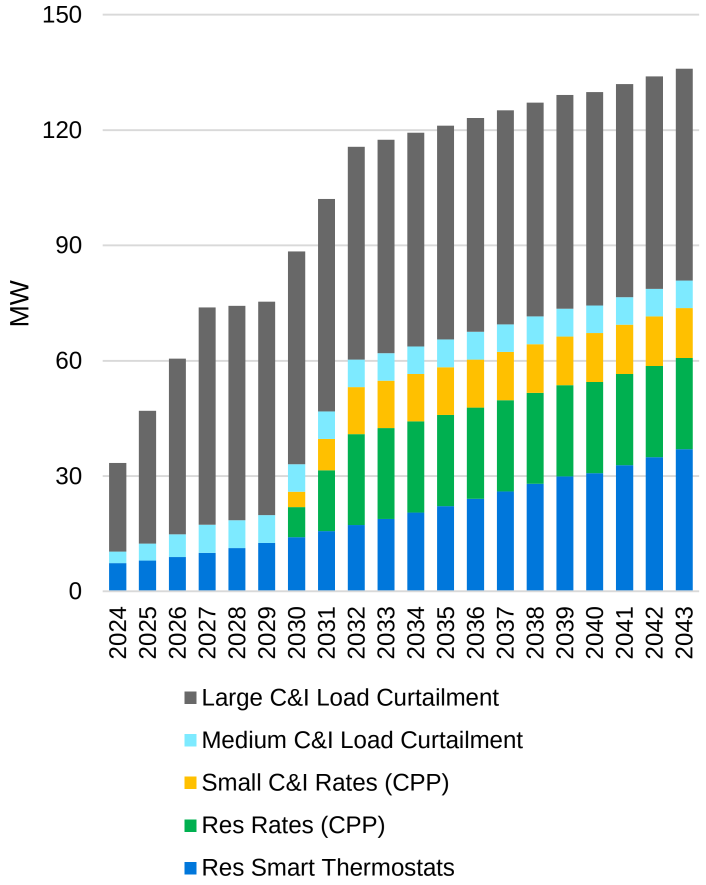


BASE CASE: RAP AND MAP TOTAL 57 MW AND 136 MW BY 2043

RAP



MAP



Program	2043 RAP MW	2043 MAP MW
Residential Smart Thermostats	8	37
Residential Rates (CPP)	11	24
Res Water Heaters[1]	0	0
Small C&I Rates (CPP)	5	13
Medium C&I Load Curtailment	4	7
Large C&I Load Curtailment	29	55
Total	**57**	**136**

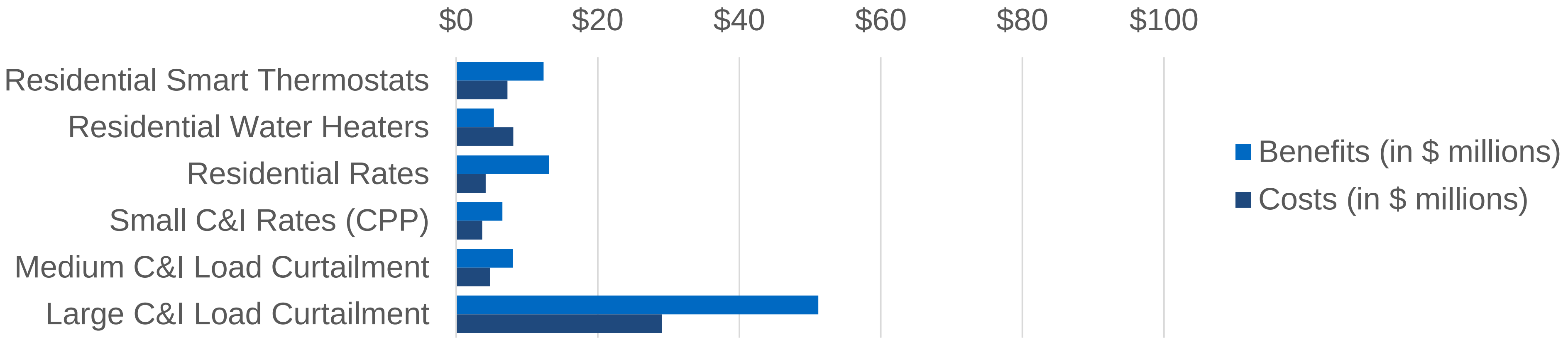
Totals may not add up due to rounding
[1] RAP and MAP are zero because program is not cost-effective

- Large C&I load curtailment is the program with highest DR potential
- Rates program start in 2030
- Rate 831 LMRs (~675 MW) are not included in these values

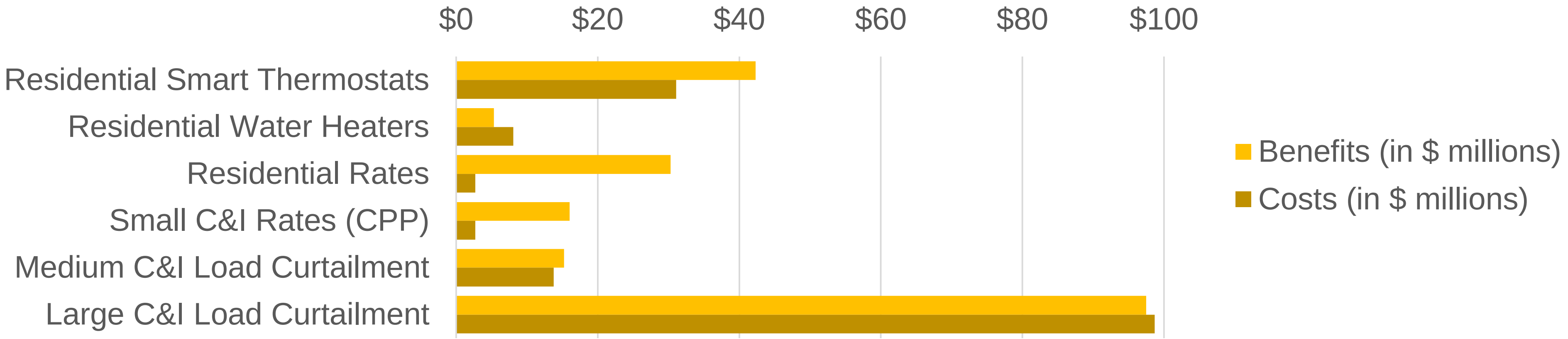
BASE CASE: NPV COSTS AND BENEFITS BY PROGRAM

All values shown are 20-year net present values (NPV) in million 2024$ for the 2024-2043 time period

RAP



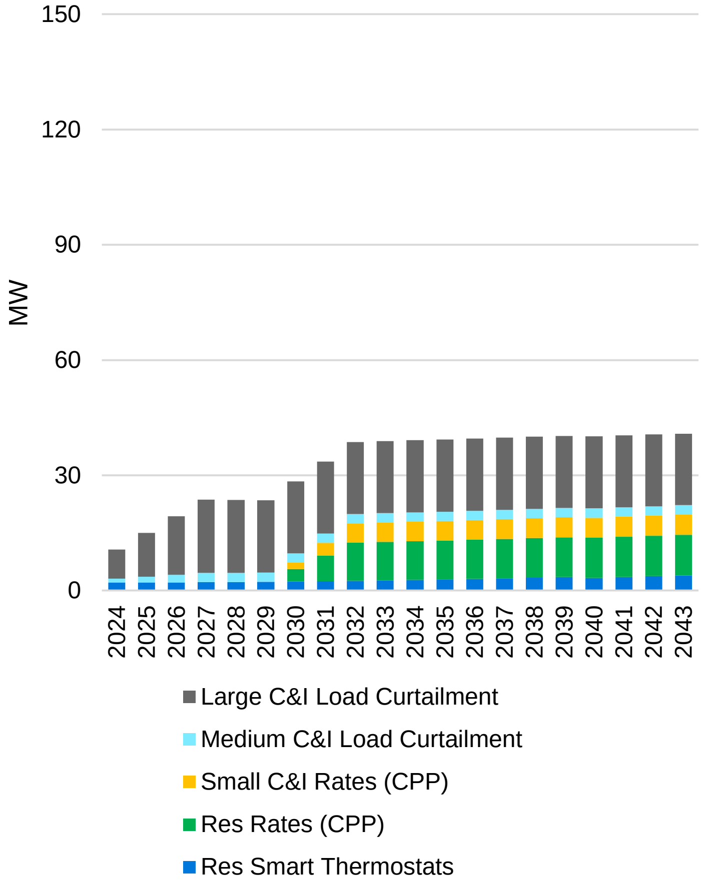
MAP



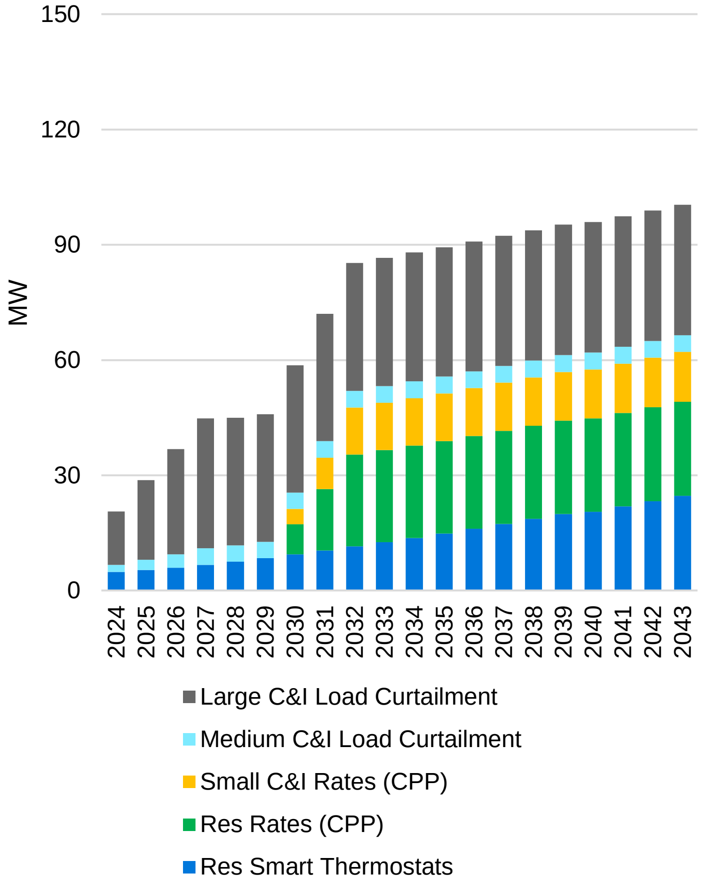
ALTERNATE SCENARIO: RAP AND MAP REACH 41 MW AND 100 MW IN 2043

Alternate avoided cost reduces RAP and MAP by 26% and 28% respectively

RAP



MAP



Program	2043 RAP MW	2043 MAP MW
Residential Smart Thermostats	4 (8)	25 (37)
Residential Rates (CPP)	11 (11)	24 (24)
Res Water Heaters[1]	0 (0)	0 (0)
Small C&I Rates (CPP)	5 (5)	13 (13)
Medium C&I Load Curtailment	2 (4)	4 (7)
Large C&I Load Curtailment	19 (29)	34 (55)
Total	**41 (57)**	**100 (136)**

Totals may not add up due to rounding
[1] RAP and MAP are zero because program is not cost-effective

Results from base case shown in parentheses

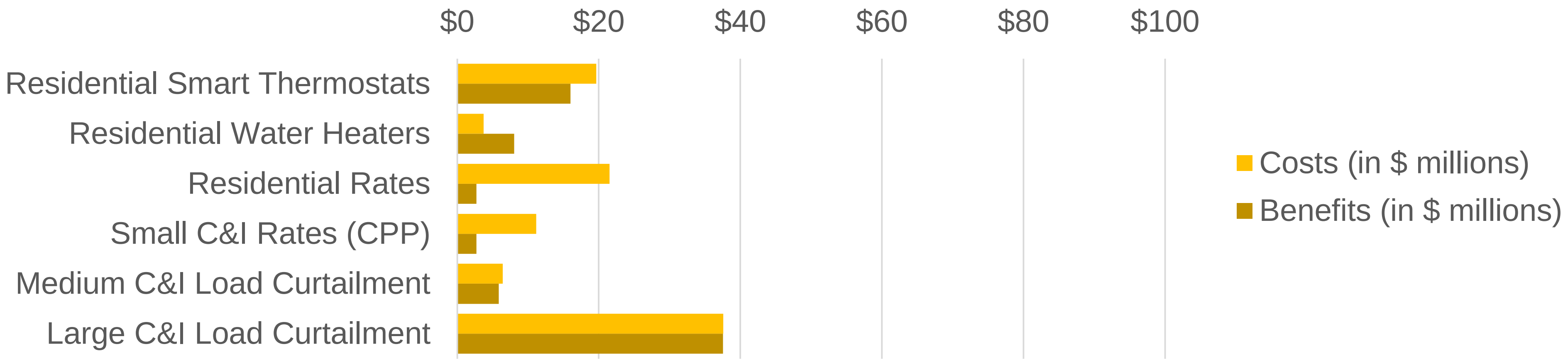
- Large C&I load curtailment is program with higher DR potential
- Rates program start in 2030
- Rate 831 LMRs (~675 MW) are not included in these values

ALTERNATE SCENARIO: NPV COSTS AND BENEFITS BY PROGRAM

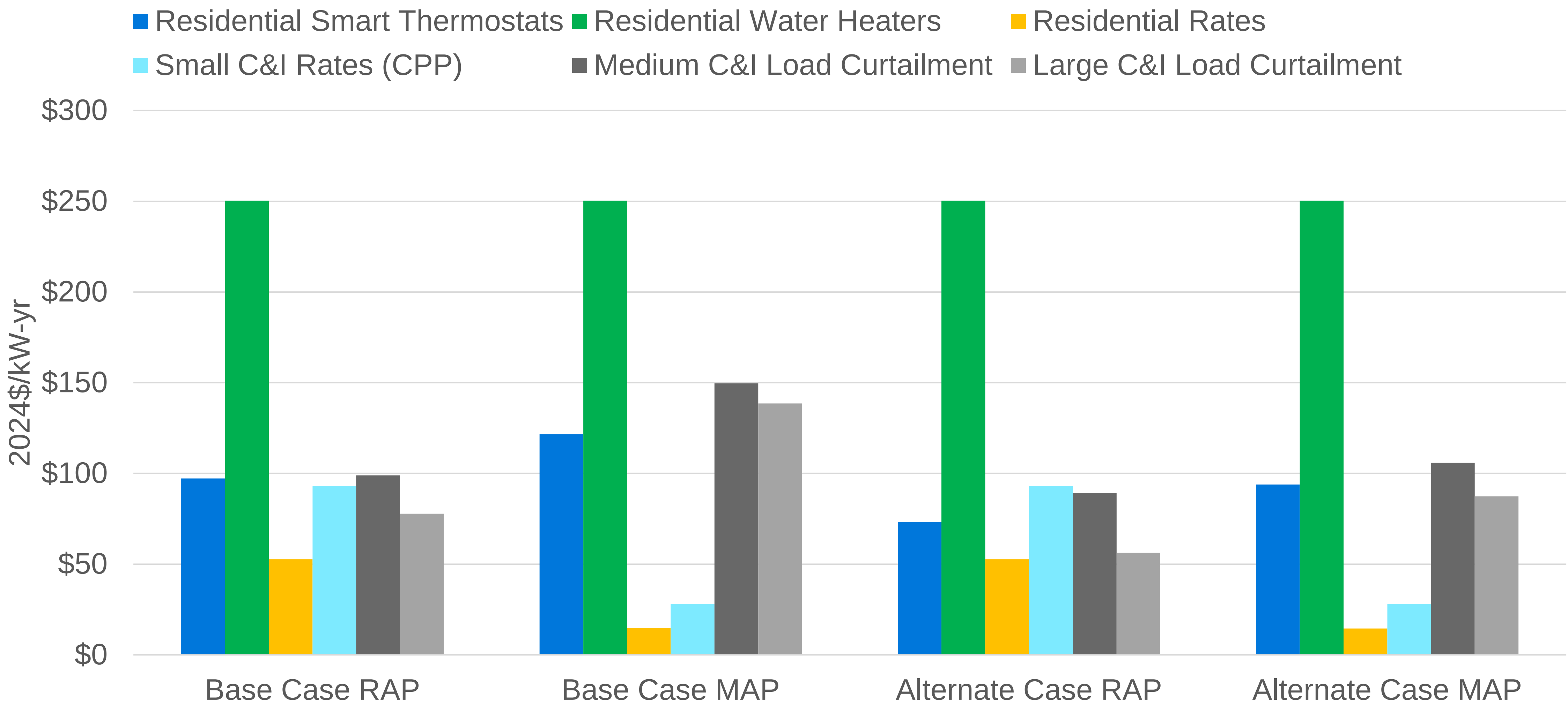
All values shown are 20-year net present values (NPV) in 2024$ for the 2024-2043 time period

RAP

MAP



LEVELIZED COSTS BY SCENARIO



Residential and Small C&I Rates have lower costs in MAP scenarios because program is designed as default with no incentive, whereas RAP is designed as opt-in with incentive

EE/DR MODELING IN IRP

MARKET POTENTIAL STUDY SAVINGS AND DSM INPUTS FOR IRP

Step 1	Step 2	Step 3
Market Potential Study	Identify "bundles" based upon market segments and savings potential	Evaluate DSM bundles in IRP portfolio models

- NIPSCO will model DSM impacts (EE & DR) based on the results from the 2021 Market Potential Study
- EE and DR estimates for IRP modeling are aggregated at the sector level:
  - Both MAP and RAP levels
  - Both the base and alternate avoided cost scenarios
  - Three vintage blocks: 2024-2029, 2030-2035 and 2036-2041 (2022 and 2023 DSM levels are informed by the current approved DSM Plan)

MARKET POTENTIAL STUDY SAVINGS AND DSM INPUTS FOR IRP

Energy Efficiency

- RAP and MAP Potential Savings were provided for input into the IRP with the following adjustments:
  - Income Qualified Program savings are constrained to align with current program budgets *(held constant in real dollars)*
  - Due to concerns about overall residential program costs, residential inputs were split into two tiers for IRP modeling.
  - DSM Inputs are based on net savings (not gross)
  - Each sector bundle has its own 8,760 shape based on measure mix

Demand Response

- RAP and MAP were provided for three categories – Rates, Residential, and C&I – for base case and alternate scenario
- DR resources will be modeled as supply, with peak capacity contribution plus limited energy duration availability

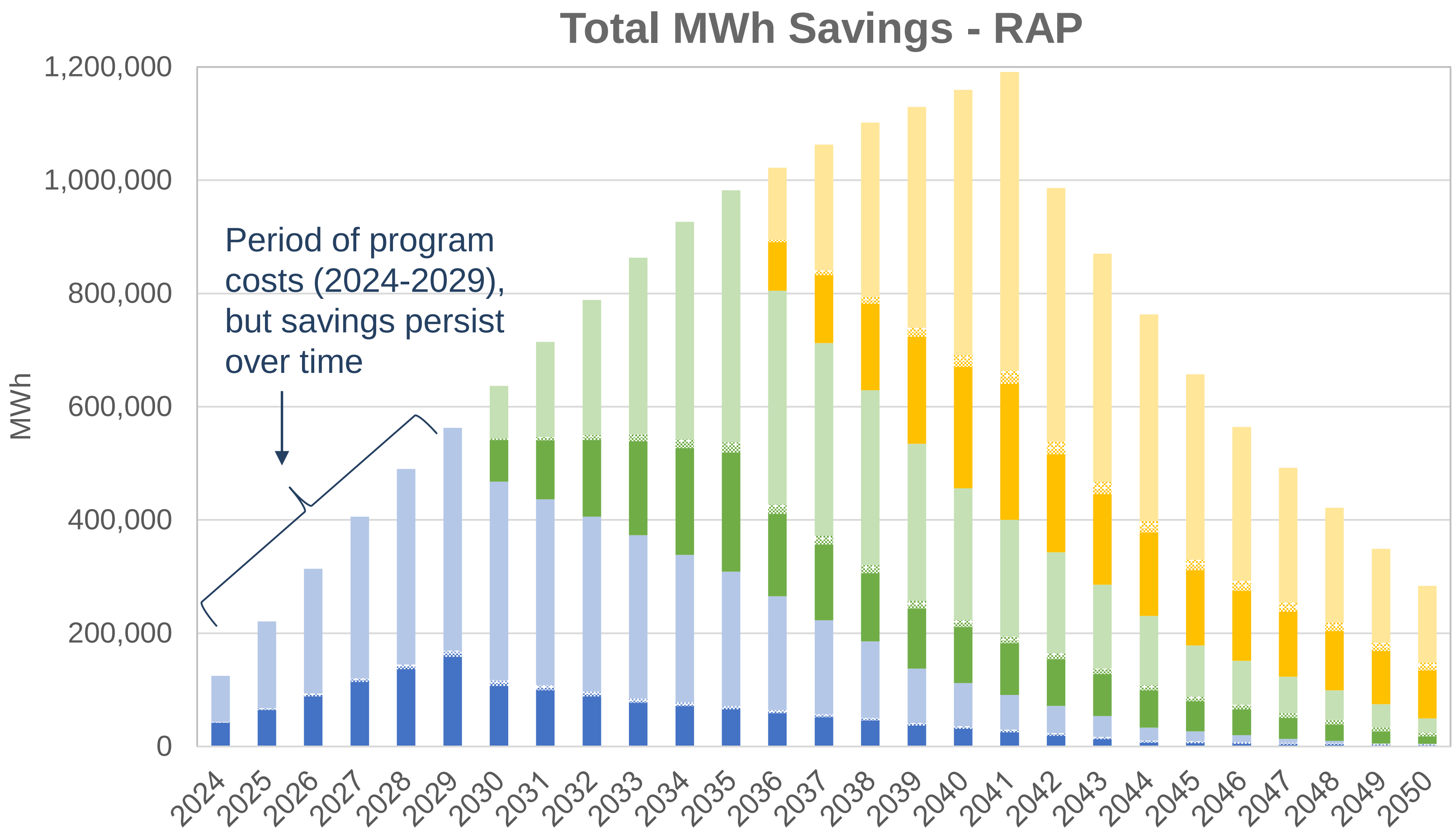
DSM BUNDLE EVALUATION IN IRP PORTFOLIO MODELING

Step 1	Step 2	Step 3
Market Potential Study	Identify "bundles" based upon market segments and savings potential	Evaluate DSM bundles in IRP portfolio models

- NIPSCO and CRA will be incorporating the DSM bundles into the portfolio development process, which will allow for portfolio selection from several resource options:
  - EE and DR bundles
  - DER resources, beyond customer-owned DERs that impact the load forecast (to be discussed later)
  - RFP supply resources (to be discussed later)
- As NIPSCO conducts the portfolio analysis, specific DSM evaluation will likely occur beyond the portfolio optimization process:
  - Assessment of the impact of various bundles if not selected through optimization
  - Assessment of the differences in the RAP vs. MAP portfolios or different avoided costs for DR

ENERGY EFFICIENCY BUNDLES FOR IRP MODELING

- DSM bundling approach allows for a representation of potential program duration over time, with differentiation across customer type and costs
- Annual costs and savings (inclusive of marginal line losses) are incorporated

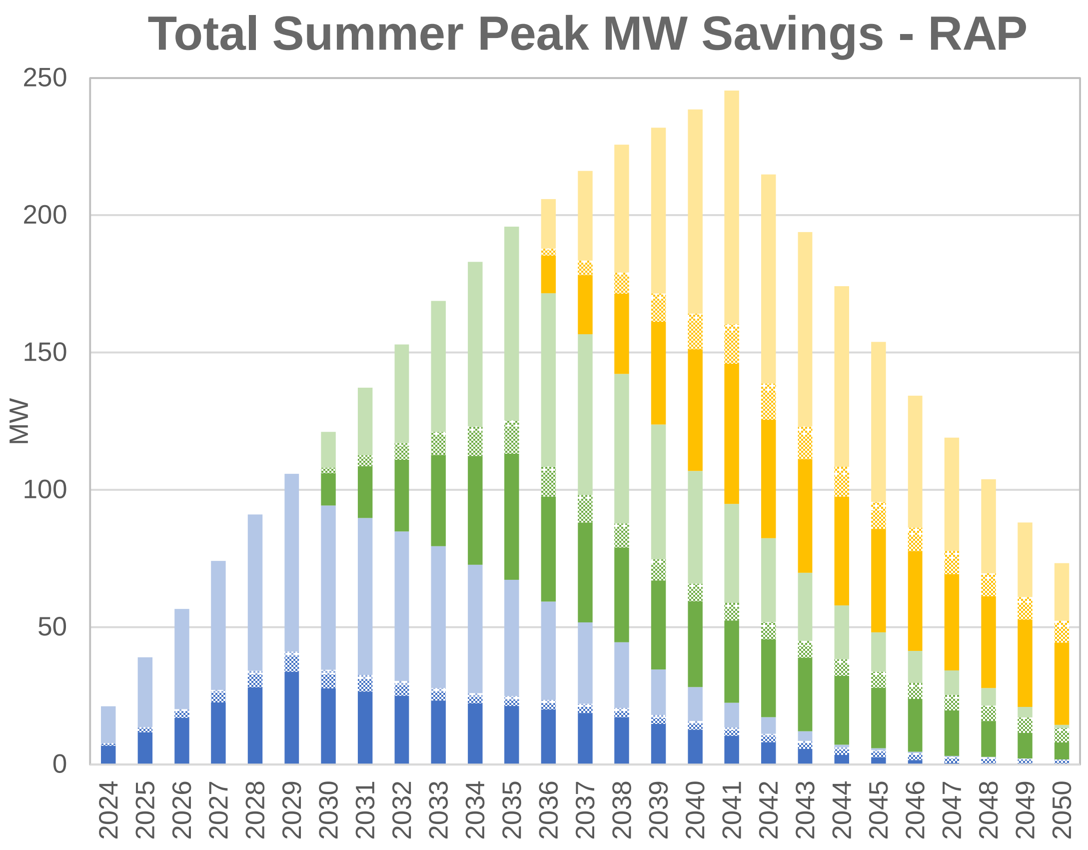


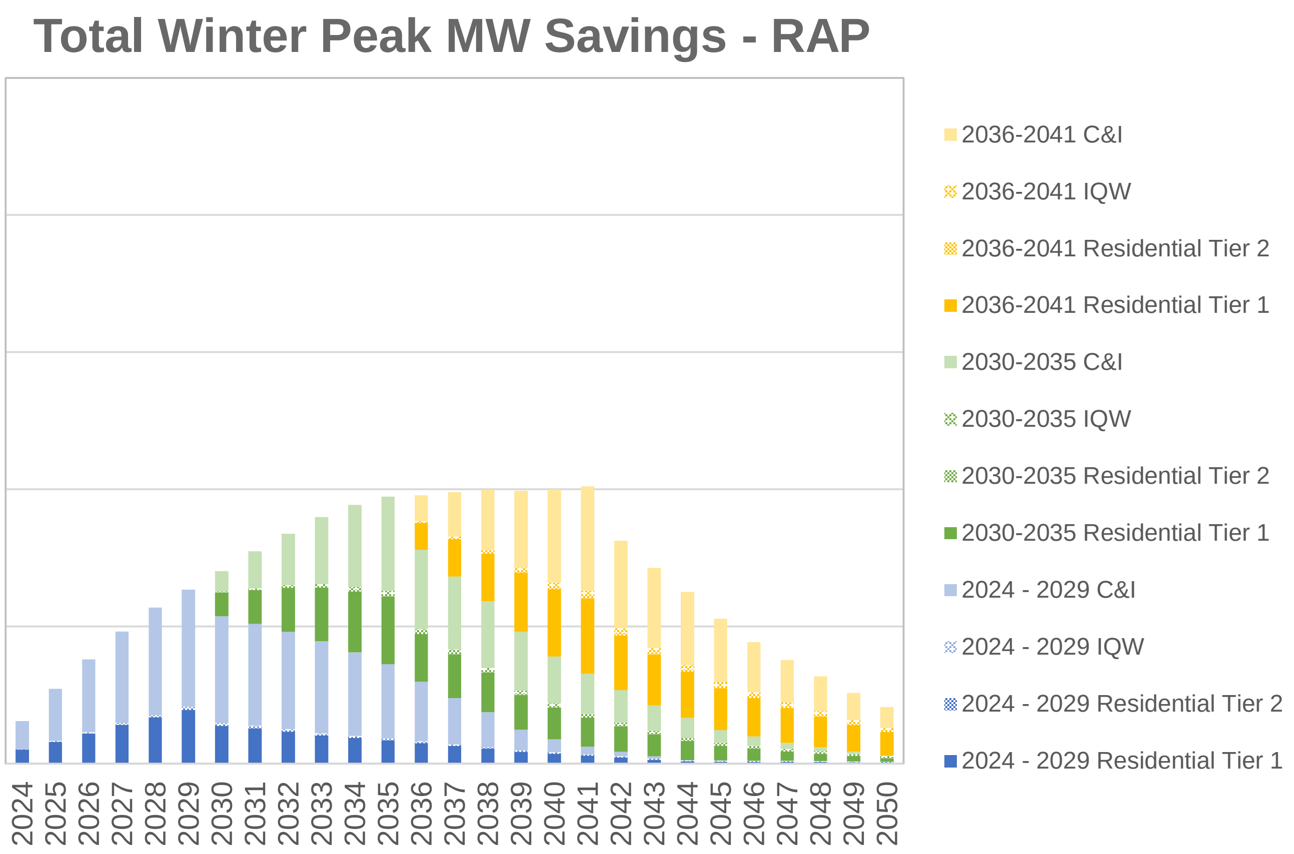
Bundle	Levelized Cost ($/MWh)
2036-2041 C&I	29
2036-2041 IQW	138
2036-2041 Residential Tier 2	253
2036-2041 Residential Tier 1	65
2030-2035 C&I	28
2030-2035 IQW	140
2030-2035 Residential Tier 2	244
2030-2035 Residential Tier 1	60
2024 - 2029 C&I	25
2024 - 2029 IQW	146
2024 - 2029 Residential Tier 2	231
2024 - 2029 Residential Tier 1	53

IQW = Income Qualified Weatherization

ENERGY EFFICIENCY BUNDLES FOR IRP MODELING

- Peak program impact is captured for the summer and winter seasons

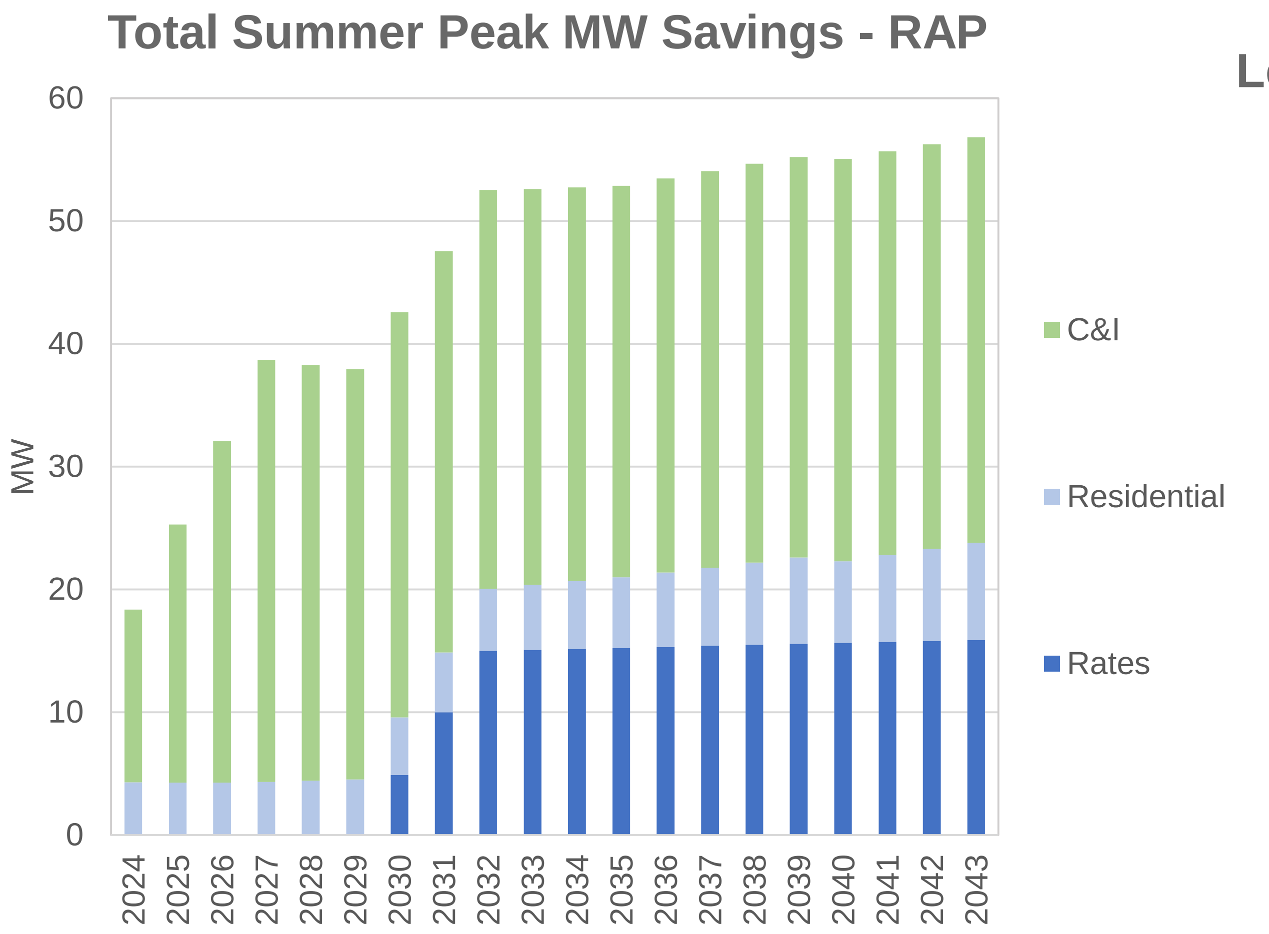


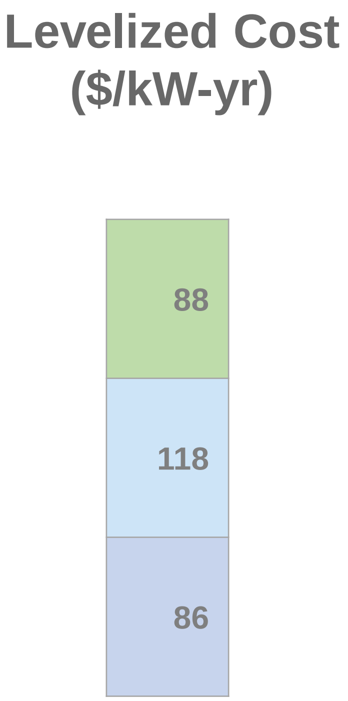


IQW = Income Qualified Weatherization

DEMAND RESPONSE BUNDLES FOR IRP MODELING

- Demand response (DR) programs are being evaluated in three total bundles for rates, Residential, and C&I customers
- DR programs provide summer peak savings, but minimal winter peak and energy value to the portfolio





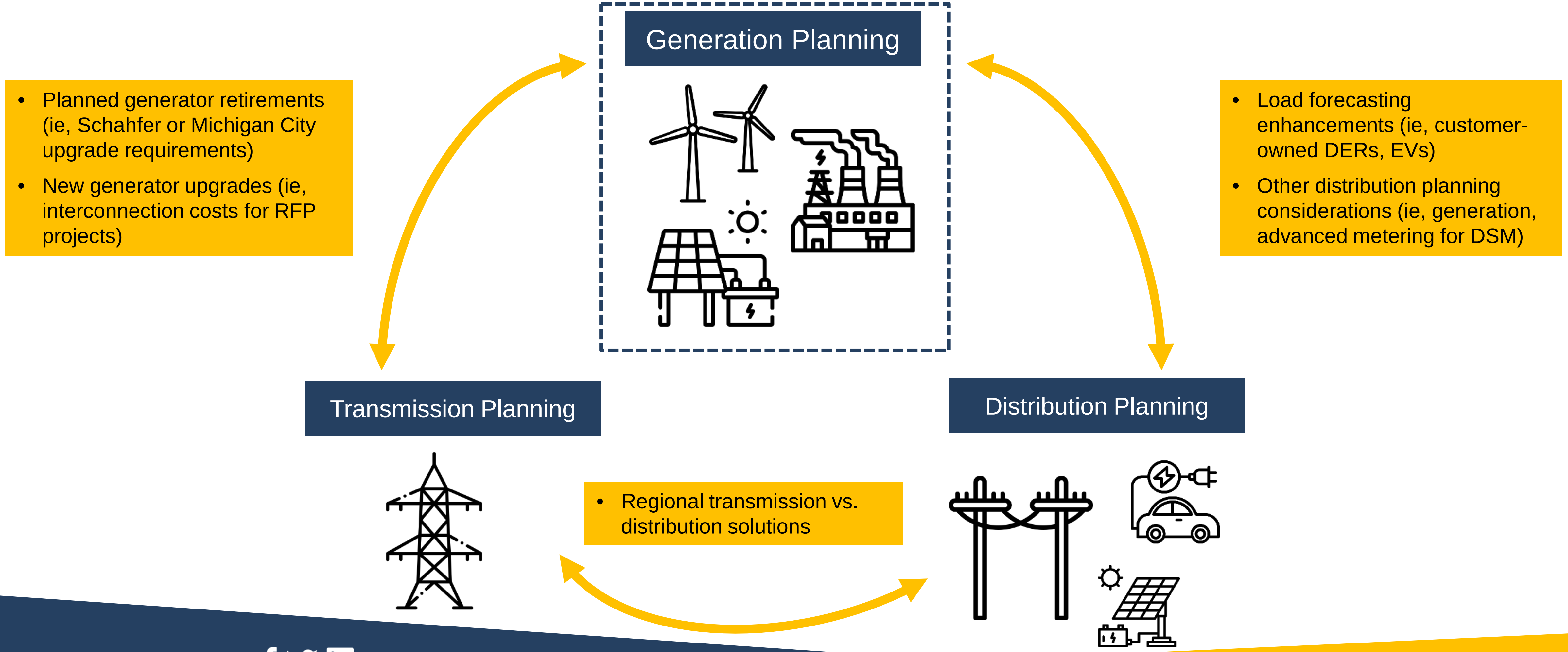
BREAK

SUPPLY-SIDE DISTRIBUTED ENERGY RESOURCE (DER) CONSIDERATIONS

Pat Augustine, Vice President, CRA

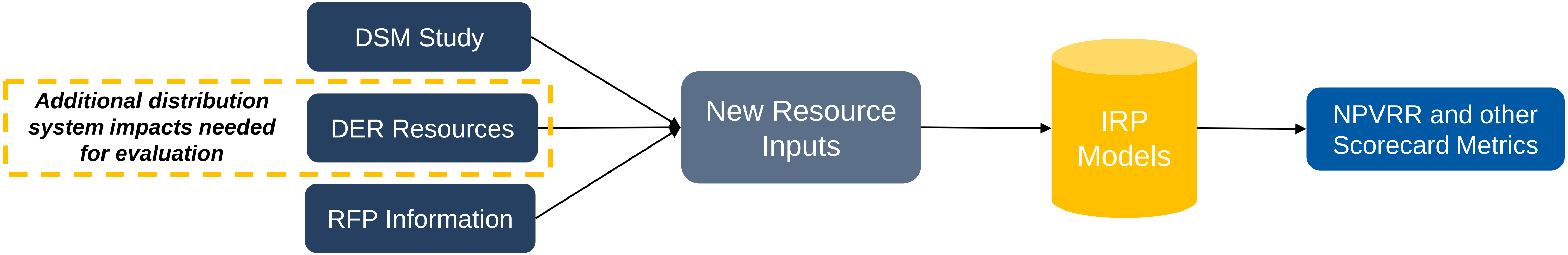
GENERATION PLANNING IS EVOLVING

- IRP has historically been centered on Generation Planning, although NIPSCO has integrated relevant T&D considerations in prior IRPs
- Technology and regulatory change is motivating a closer connection across all planning segments



INTEGRATING DER OPTIONS INTO NIPSCO'S 2021 IRP

- **Why evaluate DER?**
  - Technology costs for solar and storage have declined, making distributed options cost-competitive
  - Regulatory developments like FERC Order 2222 (See Stakeholder Meeting #2 slides) will establish new market structures for integration
- **How is NIPSCO evaluating DER in the 2021 IRP?**
  1. NIPSCO's **load forecast** incorporates a range of customer-owed DERs across scenarios (See Stakeholder Meeting #1 and Stakeholder Meeting #2 slides)
  2. Additional **supply-side** DER options (inclusive of distribution system impacts) will be evaluated against other resources



CONSIDERATIONS FOR DER RESOURCE MODELING IN THE IRP

	Utility-scale	DER
Costs	• Significant cost data and transparency from RFP bids	• Generally a cost premium to utility-scale, but may depend on specific project
T&D Impacts	• Transmission interconnection costs are incorporated in analysis	• Lowered line losses through T&D system • Strategic siting can defer upgrades on the D system
Storage duration	• ISO rules generally pointing towards 4-hour storage for capacity credit	• Storage duration *can* be shorter and optimized around utility system peaks
Peak planning and pairing with solar	• Higher solar to storage ratios generally preferred, given primary focus on summer peak needs and overall energy value	• Peak requirements may be location/circuit-specific, and lower solar to storage ratios often preferred for capacity value
Ancillary services	• Clear access to wholesale A/S markets	• Current participation options are sometimes unclear, but market rules evolution (i.e. FERC Order 2222) requires tracking

EVALUATION OF DEFERRED DISTRIBUTION INVESTMENT OPPORTUNITIES

- NIPSCO's distribution planning team has assessed *near-term* *(within the next 5 years)* system upgrade requirements across the distribution system, with an eye towards how strategically sited generation alternatives could defer substation and other distribution system investment
- NIPSCO identified several locations on the system that will require capacity improvement investments in the next five years and assessed the following* for each location:
  - Estimated distribution upgrade project cost
  - Potential battery storage and paired solar+storage additions that could defer the distribution upgrade, with consideration given for the availability of nearby land to site capacity
  - Estimated years of deferral of the distribution upgrade project that could be achieved with the generation addition
- Based on each location's deferred upgrade cost, potential capacity addition, and estimated investment deferral, an NPV of **deferred investment on a $/kW basis was developed for each location**

**Note that all estimates are based on planning-level information to support IRP analysis. Potential future project execution would require further engineering diligence.*

DER BUNDLES FOR IRP MODELING

- NIPSCO and CRA categorized the projects identified by the distribution planning team into High, Medium, and Low bundles of deferred distribution investment costs
- These resource options will be available for selection and analysis in the portfolio assessment phase:
  - *Near-term opportunities only*, to defer required distribution system investments currently identified
  - Distribution-level cost premiums to be assessed relative to larger scale projects
  - NPV of deferred distribution investment will be effectively subtracted from capital cost of the resource options

Deferral Cost Bundle	Resource	Battery Storage MW	Solar MW	Range of Potential NPV of Deferred Investment ($/kW)
High	Solar + Battery	7.0	2.7	**700 – 900**
Mid	Solar + Battery	7.0	9.1	**200 – 300**
Low	Solar + Battery	2.0	2.7	**10 – 100**

Indicative ranges, subject to change for actual projects

- The IRP will aim to identify the *types of DER projects and characteristics of candidate locations* that may be attractive, with additional project-specific evaluation required in the future
- NIPSCO intends to continue assessing DER options in more detail in future IRPs as integrated planning advancements are made and as MISO makes its filings in response to FERC Order 2222 (See Stakeholder Meeting #2 slides for more information)

LUNCH

2021 RFP RESULTS OVERVIEW

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

Stakeholder Advisory Meeting
July 13, 2021

CRA International

NIPSCO 2021 RFP

Participating Bidders

NIPSCO | CRA Charles River Associates

- Development Partners
- Invenergy
- lightsource bp
- Hartree®
- HOOSIER SOLAR
- MITSUBISHI POWER
- Origis Energy®
- APEX CLEAN ENERGY
- TENASKA®
- GLIDEPATH®
- Capital Dynamics TRULY INVESTED.
- ST. JOSEPH energy center
- bp
- Blue Steel Energy, LLC
- SIGC SOUTHERN ILLINOIS GENERATION COMPANY
- CORDELIO POWER
- EASTERN GENERATION LLC
- RANGER POWER
- Ørsted
- edp renewables
- ORION RENEWABLE ENERGY GROUP LLC
- nationalgrid renewables
- Primary Energy®
- ENERGY VAULT Enabling a Renewable World
- ibV energypartners an ib vogt company
- Swift Energy Storage Holdings, LLC
- Clēnera
- NEXTera ENERGY
- INDECK®
- EDF renewables
- HALLADOR ENERGY COMPANY
- GALE HEAD DEVELOPMENT
- BRIGHTNIGHT
- REDEUX

NIPSCO 2021 RFP

Overview of Proposals Received

- **2021 RFP generated a tremendous amount of bidder interest**
- **182 total proposals were received across a range of deal structures**
- **78 individual projects across five states with ~15 GW (ICAP) represented**
  - Many of the proposals offer variations on pricing structure and term length
  - Several instances of renewables paired with storage
  - Majority of the projects are in various stages of development

Count of Proposals by Technology and Deal Structure

Preliminary

Technology	Solar	Solar + Storage	Storage	Thermal	Wind	Hydrogen Enabled	Other	Total
Asset Sale	1	2	6	4	-	-	-	13
PPA	15	20	8	10	7	2	4	66
Both	37	60	-	2	-	-	4	103
Total	53	82	14	16	7	2	8	182
Locations	IN, IL, KY	IN, IL, KY, WI	IN, WI	IN, IL, KY	IN, IL, MO	IN	MISO	

NIPSCO 2021 RFP

Overview of Projects Received

Preliminary

Project MW ICAP by State and Technology

State	Solar	Solar + Storage	Storage	Thermal	Wind	Hydrogen Enabled	Other	Total
Illinois	150	473	-	1,074	465	-	-	2,162
Indiana	3,413	3,141	1,169	2,522	200	213	-	10,658
Kentucky	100	431	-	650	-	-	-	1,181
Missouri	-	-	-	-	670	-	-	670
MISO	-	-	-	-	-	-	100	100
Wisconsin	-	200	100	-	-	-	-	300
Total	3,663	4,245	1,269	4,246	1,335	213	100	$\boxed{15,071}$

NIPSCO 2021 RFP

Distribution of Projects Received

Preliminary

6	MISO
2	Wisconsin
2	Missouri
53	Indiana
10	Illinois
5	Kentucky

Note: Blue area represents MISO territory

NIPSCO 2021 RFP

PPA Overview

Proposal MW ICAP by PPA Term Length (PPA or Both) and Technology

Preliminary

Duration	Solar	Solar + Storage	Storage	Thermal	Wind	Hydrogen Enabled	Other	Total
10 Years	125	-	-	300	-	-	100	525
12 Years	125	-	-	-	-	-	-	125
15 Years	4,303	2,374	450	1,430	1,035	-	-	9,592
20 Years	4,055	7,056	400	2,716	500	213	-	14,940
25 Years	400	4,832	213	-	-	-	-	5,445
30 Years	400	1,000	-	136	-	-	-	1,536
Total	9,408	15,262	1,063	4,582	1,535	213	100	32,163

NIPSCO 2021 RFP

Storage Overview

NIPSCO | CRA Charles River Associates

Preliminary

- NIPSCO received bids for storage both as standalone projects and integrated with solar facilities
- MW totals for "Solar + Storage" reflect the solar capacity only but the storage component adds value and functionality to the integrated facility

Storage Project MW ICAP by Type	
Storage Integrated with Solar	1,763
Standalone Storage	1,269

- Integrated options for solar exist in several locations within MISO but like standalone options are concentrated within the target LRZ6 region

Storage Project MW ICAP by State and Type

State	Storage Integrated with Solar	Standalone Storage
Illinois	235	-
Indiana	1,238	1,169
Kentucky	190	-
Missouri	-	-
MISO	-	-
Wisconsin	100	100
Total	1,763	1,269

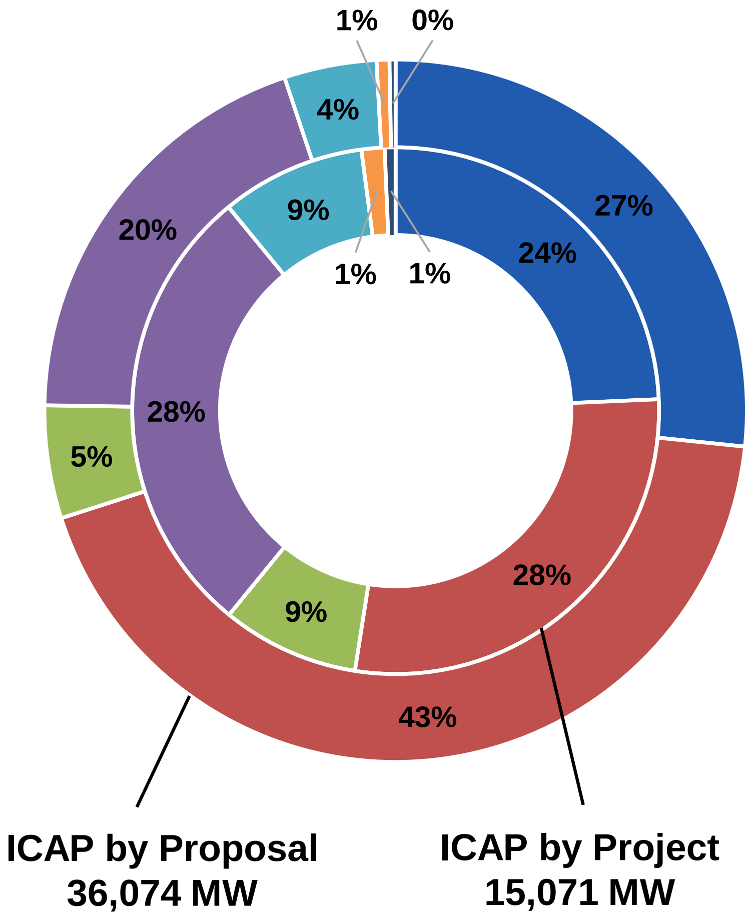
NIPSCO 2021 RFP

Allocation of Proposals and Projects by Technology

Allocation by Technology (MW ICAP)

Preliminary

Technology	ICAP by Project		ICAP by Proposal	
	MW	%	MW	%
Solar	3,663	24%	9,608	27%
Solar + Storage	4,245	28%	15,661	43%
Storage	1,269	9%	1,875	5%
Thermal	4,246	28%	7,082	20%
Wind	1,335	9%	1,535	4%
Hydrogen Enabled	213	1%	213	1%
Other	100	1%	100	0%
Total	15,071	100%	36,074	100%



NIPSCO 2021 RFP

Summary of Pricing

NIPSCO CRA Charles River Associates

Average Weighted Pricing by Technology & Deal Structure

Preliminary

Technology	Asset Sale		Power Purchase Agreement			Comments
	$/kW	Count	PPA $/MWh	$/kW-Mo	Count	
Solar	$1,467	38	$41.31	-	52	Many projects were bid as both PPA and Asset Sales as well as several PPA structures
Solar + Storage	$1,719	62	$42.77	$3.86	80	Typical PPA structure for integrated solar and storage includes both a fixed and variable component
Storage	$965	6	-	$12.93	8	
Thermal	$1,075	6	$0.36	$7.95	12	Thermal bids also typically would include pass through costs for startup and fuel
Wind	-	-	$39.63	-	7	
Hydrogen Enabled	-	-	-		2	Hydrogen pricing not reported due to limited bid count and fundamental differences in the bids received
Other	-	4	$21.83	$2.81	8	Other includes a range of structures that may or may not include both energy and capacity

- Average bid prices shown for ‘Asset Sale’ represent capital costs and exclude on-going fuel, O&M and CapEx (where applicable)
- Figures shown are for representation and do not purport competition between technologies; Separate short-listed assets are created for each RFP event

NIPSCO 2021 RFP

Next Steps in RFP Evaluation Process

- **Tuesday, July 6, 2021:** Start of Bid Evaluation Period (currently in progress)
- **Friday, August 20, 2021:** Bid Evaluation Period Completed (tentative)
- **August 2021 – July 2022:** Definitive Agreements Signed with Bidders (tentative)

- Bid evaluation considers both cost and non-cost factors
  - Asset Cost - levelized cost of energy (“LCOE”) or levelized cost of capacity (“LCOC”)
  - Facility Reliability and Deliverability
  - Development Risk
  - Asset Specific Benefit and Risk Factors

- Representative cost and performance characteristics by technology were developed based on RFP bids and provided to the IRP team for portfolio optimization modeling
- IRP to determine the preferred portfolio for execution

INCORPORATING RFP RESULTS INTO THE IRP

Fred Gomos, Director Strategy & Risk Integration, NiSource
Pat Augustine, Vice President, CRA

HOW DO THE RFP RESULTS INFORM THE IRP ANALYSIS?

The responses to the all-source RFP provide insight into the supply and pricing of alternatives available to NIPSCO and are fed into the existing fleet and replacement analysis

- **Existing Fleet Analysis**
  - RFP results provide known and visible replacement costs and volumes
  - Representative project groups/tranches will be constructed from RFP results, assembled by technology and ownership, for use in the IRP analysis
  - Existing fleet analysis will be run using the representative RFP projects as selected by the optimization model
- **Replacement Analysis**
  - RFP results provide visibility into executable alternatives for NIPSCO
  - Replacement analysis will be run using the representative project groups/tranches

	Existing Fleet Analysis	Replacement Analysis
Core Questions	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?* *Is the portfolio flexible and adaptable to address changes in market rules and energy policy?*	*What are the replacement resource portfolio options?* *How do different replacement themes compare with regard to cost, risk, environmental sustainability, and reliability?*
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

WHY ORGANIZE BIDS INTO REPRESENTATIVE GROUPS OR TRANCHES?

- The IRP is intended to select the best resource mix and future portfolio concept, and *not* select specific assets or projects
  - While highly informed by current and actionable RFP data, the IRP is meant to develop a planning-level recommended resource strategy
  - Asset-specific selection requires an additional level of diligence (full assessment of development risk, locational considerations such as congestion risk, transmission system impacts, etc)
- The IRP is a highly transparent and public process that requires sharing of major inputs
  - There would be confidentiality concerns with showing and analyzing asset-level options, which would contain specific cost bids and detailed technology data
- The IRP modeling is complex, and resource grouping improves the efficiency of the process
  - Resource evaluation requires organizing large amounts of operational and cost data into IRP models, so a smaller data set improves the efficiency of setup and run time

IRP ANALYSIS: TRANCHE DEVELOPMENT AND ASSESSMENT

A three-step process to incorporate RFP data and run the IRP models

**Additional screening focus in 2021 to inform tranche development

1 Tranche Development

Screen Bids

- High-level bid review by RFP team to confirm compliance w/ requirements and overall viability

Aggregate Bids into Groupings by Type

- Bids are organized by:
  - Technology
  - Asset sale or PPA
  - Commitment duration
  - Costs
  - Oper. characteristics
- Aggregated cost and operational information compiled in Aurora

2 Portfolio Optimization

Select Portfolios

- Based on portfolio concepts (retirement / replacement), capacity need, and other constraints, identify which tranches (or portions of tranches) are selected for the portfolio through Aurora optimization

Confirm Reasonableness

- Confirm that optimization model is selecting feasible block sizes and options based on resource-specific data

3 Portfolio Modeling

Refine Portfolio Details

- Adjust model setup as necessary to cover full range of retirement and replacement options

Analyze Portfolios

- Evaluate each portfolio across range of scenarios and stochastic inputs
- Report portfolio costs and other metrics to support scorecard development

TRANCHE DEVELOPMENT

2018 IRP Example

- **Bids will be aggregated and similar resources combined into representative tranches**
  - Bids sorted by bid type (PPA or asset sale), technology type, duration, online year, and cost
  - Price and operational characteristics for the tranche are calculated using weighted average of individual bids within the tranche
  - Certain tranches may contain only one bid, if the bid had unique characteristics that make it difficult to aggregate

PPA Solar Tranche Example

Bid Name	Bid Type	ICAP (MW)*	Online Year	PPA Term (years)	Price*	Capacity Factor
Bid 1	Solar	-	2023	20	$27.xx	-
			…			
Bid 9	Solar	275	2023	20	$32.00	24%
Bid 10	Solar	100	2023	20	$34.00	24%
Bid 11	Solar	75	2023	20	$34.00	23%
Bid 12	Solar	25	2023	20	$35.00	24%
Bid 13	Solar	500	2023	25	$35.00	25%
			…			
Bid 26	Solar	-	2023	20	$73.xx	-

Tranche Name	Tranche Type	# of Resources	ICAP (MW)	Online Year	PPA Term (weighted average years)	Price (weighted average)	Capacity Factor (weighted average)
Indiana Solar #3	Solar	5	975	2023	23	$33.93	24.2%

*Capacity and bid prices are rounded to the nearest 25 MW and dollar respectively to preserve confidentiality.

INFORMATION WILL BE USED IN THE IRP TO DEVELOP NIPSCO'S PREFERRED PORTFOLIO

- The IRP is designed to select **the preferred resource/technology mix** and will **not identify specific projects**

	Existing Fleet Analysis	Replacement Analysis
Core Questions	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?* *Is the portfolio flexible and adaptable to address changes in market rules and energy policy?*	*What are the replacement resource portfolio options?* *How do different replacement themes compare with regard to cost, risk, environmental sustainability, and reliability?*
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

SETTING THE CONTEXT FOR ASSESSING RELIABILITY IN THE IRP

Previous Reliability Assessments

- In the 2018 IRP, NIPSCO began including reliability risk metric in the scorecard used to evaluate the performance of various resource portfolios

2018 Retirement Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO's 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

- As part of the 2020 Portfolio Analysis to support NIPSCO renewable filings, the reliability criteria were further expanded to consider operational flexibility

2020 Portfolio Analysis

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 34 year NPV of revenue requirement (Base scenario deterministic results)
Long term Optionality	• Flexibility resulting from combinations of ownership, duration, and diversity • Metric: MW weighted duration of generation commitments
Capital Requirement	• Estimated amount of capital investment required by portfolio • Metric: 2020 -2023 capital needs
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 UCAP MW sourced from non-gas resources)
Environmental	• Carbon intensity of portfolio / Total carbon emissions • Metric: Total annual carbon emissions (2030 short tons of CO_2) from the generation portfolio
Operational Flexibility	• The ability of the portfolio to be controlled in manner to respond to changes in load (dispatchable) • Metric: % of 2025 Controllable MW in gen. portfolio

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

CORE ECONOMIC MODELING CAN CAPTURE ELEMENTS OF RELIABILITY

- Many elements of reliability will be incorporated in the core portfolio analysis and will ultimately contribute to the cost and risk metrics used in the scorecard

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

NIPSCO coordinates with MISO (Operating Reliability)

	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 or Emergency
Reliability Factors:	Reserve margin, ELCC and energy duration	Dispatchability, energy market risk exposure	Real Time Balancing System
IRP Modeling Approach:	Portfolio development constraints, with ELCC and seasonal accounting	Hourly dispatch analysis, including with stochastic risk	Ancillary services analysis (regulation, reserves), with sub-hourly granularity

ECONOMIC ANALYSIS OF REAL-TIME MARKET DYNAMICS + ANCILLARY SERVICES

- CRA's Energy Storage Operations (ESOP) model is an optimization program that estimates the value of storage and other flexible resources in the **real-time and ancillary services (A/S) markets**, offering an estimate of **the incremental value** such resources offer beyond what can be estimated in the day-ahead hourly production cost framework of Aurora
- NIPSCO and CRA will assess the economic value of candidate resource types (based on RFP bids) in the ESOP model for incorporation in the full portfolio revenue requirement analysis in Aurora and the PERFORM financial tool

Category	Aurora Portfolio Tool	ESOP
Market Coverage	Day-ahead energy	Real-time arbitrage plus A/S (frequency regulation and spinning reserves)
Time Granularity	Hourly, chronological	5-minute intervals, chronological
Time Horizon	20 years	Sample years (ie, 2025, 2030, 2035, 2040)
Pricing Inputs	MISO-wide fundamental analysis feed NIPSCO-specific portfolio dispatch	Historical data drives real-time and A/S pricing; specific asset types dispatched against price
Asset Parameters Used	Hourly ramp rate, storage cycle and depth of dispatch limits, storage efficiency	Sub-hourly ramp rate, storage cycle and depth of discharge limits, storage efficiency
Outputs	Portfolio-wide cost of service	Incremental real-time and A/S value for specific asset type

ECONOMIC ANALYSIS ALONE DO NOT CAPTURE THE FULL VALUE OF RESOURCES

- NIPSCO participates in the Midcontinent Independent System Operator (MISO) in a variety of roles with various compliance standards and responsibilities
- These responsibilities and standards are met in part by existing resources

Role	Definition
Energy, Capacity, and Ancillary Services Market Participant	Offers resources into markets and procures services on behalf of load to ensure adequate provision of energy, capacity, and ancillary services to support system reliability
Transmission Owner (TO)	Owns and maintains transmission facilities
Transmission Operator (TOP)	Responsible for the reliability of its local transmission system, and that operates or directs the operations of the transmission facilities

- As a TOP, NIPSCO is <u>required</u> to comply with a variety of NERC standards, particularly those that govern the reliable operation of the Bulk Electric System
    - For example, EOP-005-3 governs system restoration from Black Start Resources. Part of NIPSCO's compliance plan relies on resources that currently exist within the portfolio and the NIPSCO TOP area
- Any resource decisions (retirement or replacement) will need to consider the implications for NIPSCO's ability to comply with NERC and MISO standards and procedures now and into future

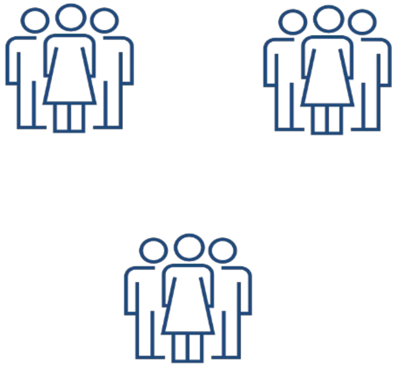
An expanded scoring criteria can account for these additional considerations

RELIABILITY ASSESSMENT PROCESS OVERVIEW

1 Define Initial Assessment Criteria

Collaborated with NIPSCO transmission planning and system operations group to develop initial framework and criteria

2 Obtain Stakeholder Feedback



We will seek feedback from interested stakeholders who want to learn more about the assessment criteria and provide input and feedback

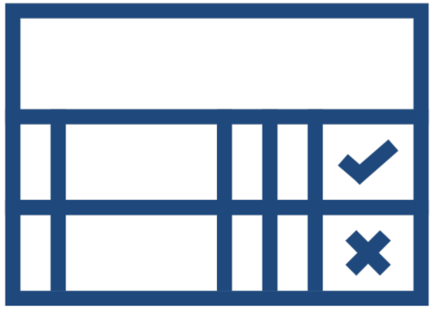
July

3 Engage 3rd Party Reviewer

Engage a qualified 3rd party expert to review the assessment criteria, develop the scoring methodology and score and rank the various resource technologies under consideration

August

4 Incorporate into IRP Analysis Scorecard(s)



Engage a qualified 3rd party expert to review the assessment criteria, develop the scoring methodology and score and rank the various resource technologies under consideration

September

INITIAL RELIABILITY ASSESSMENT CRITERIA

Preliminary

	Criteria	Description	Rationale	Normal Operation	Potential to Capture in Economic Analysis (Normal Op)	Islanded Operation (Black-out Restoration)	NERC Standard IEEE Standard
1	Blackstart	Resource has the ability to be started without support from the wider system or is designed to remain energized without connection to the remainder of the system, with the ability to energize a bus, supply real and reactive power, frequency and voltage control	In the event of a black out condition, NIPSCO must have a blackstart plan to restore its local electric system	N/A	N/A	✓	EOP-005-3
2	Energy Duration	Resource is able to meet energy and capacity duration requirements. In emergency conditions, resource is able to supply full or near full output continuously for up to a week or more independent of the electric system, except for auxiliary load needs	NIPSCO must have long duration resources for emergency procedures and must assess economic value risk for energy duration attributes over time	Various durations provide different value	✓ Hourly dispatch, capacity value, A/S value	✓	EOP-005-3
3	Dispatchability and Automatic Generation Control	The unit will respond to directives from system operators regarding its status, output, and timing. The unit has the ability to be placed on Automatic Generation Control (AGC) allowing its output to be ramped up or down automatically to respond immediately to changes on the system	MISO provides dispatch signals under normal conditions, but NIPSCO requires AGC attributes under emergency restoration procedures	✓	✓ Regulation A/S value	✓	BAL-001-2
4	Operational Flexibility and Frequency Support	Ability to provide an inertial energy reservoir or a sink to stabilize the system. The resource can adjust its output to provide frequency support or stabilization. The resource must have the capability of ranging from 0.85 lagging to 0.95 leading power factor	MISO provides market construct under normal conditions, but NIPSCO must have the ability to maintain operation during under-frequency conditions in emergencies	✓	✓ Regulation A/S value	✓	MOD-025 Attach. 1 BAL-003-2
5	VAR Support	The resource can be used to deliver VARs out onto the system or absorb excess VARs and so can be used to control system voltage under steady-state and dynamic/transient conditions. The resource can provide dynamic reactive capability (VARS) even when not producing energy. The resource must have Automatic voltage regulation (AVR) capability	NIPSCO must retain resources on the transmission system to provide this attribute in accordance with NERC and IEEE Standards	✓	X	✓	VAR-001-5 VAR-002-4.1 IEEE 1453 - 2004
6	Geographic Location Relative to Load	The resource will be located in NIPSCO's footprint (electric/Transmission Operator Area) in Northern Indiana near existing NIPSCO 138kV or 345kV facilities and is not restricted by fuel infrastructure. The resource can be interconnected at 138kV or 345kV	MISO requires locational capacity resources and runs an LMP market to provide locational energy signals; under emergency restoration procedures, a blackstart plan reliant on external resources would create a significant compliance risk	Location drives some energy and capacity value	✓ LRZ6 for capacity; project-specific congestion as needed	✓	

INTEGRATING SCORING INTO THE IRP ANALYSIS

1. Gain stakeholder feedback
2. Engage a qualified third party to develop scoring methodology utilizing the metrics identified for individual technologies and in aggregate on a portfolio level and score and rank various generation resource technologies bid into the RFP across these metrics
3. Show preliminary scoring in the September Public Stakeholder meeting

WRAP UP & NEXT STEPS

Erin Whitehead, Vice President Regulatory & Major Accounts, NIPSCO

NEXT STEPS

Portfolio Modeling (July – September)

- IRP analysis will incorporate results of the RFP

Stakeholder Process

- Next Public Stakeholder Advisory Meeting #4 is scheduled for September 21st
- Reach out to Alison Becker (abecker@nisource.com) for 1x1 meetings

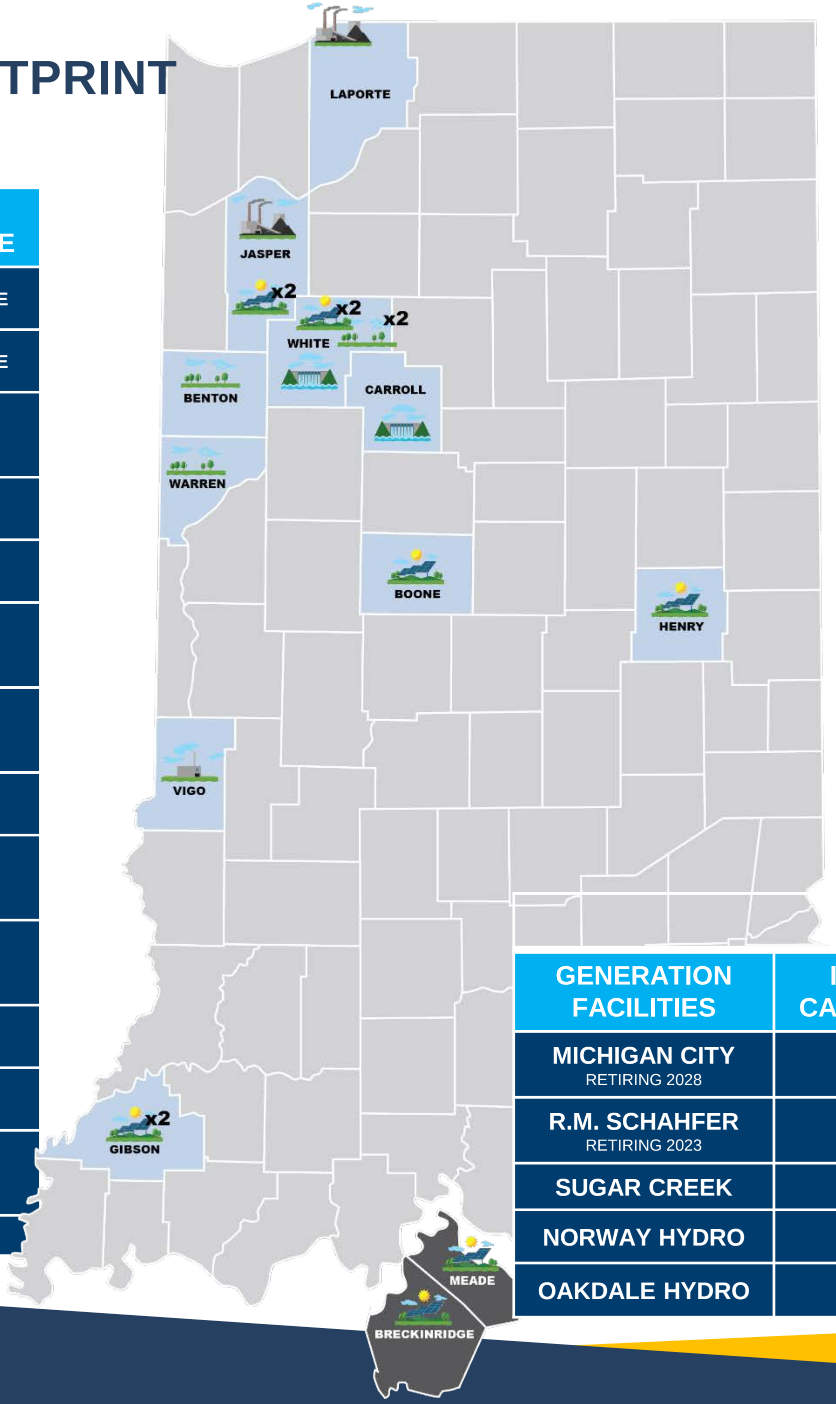
Stakeholder engagement is a critical part of the IRP process

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

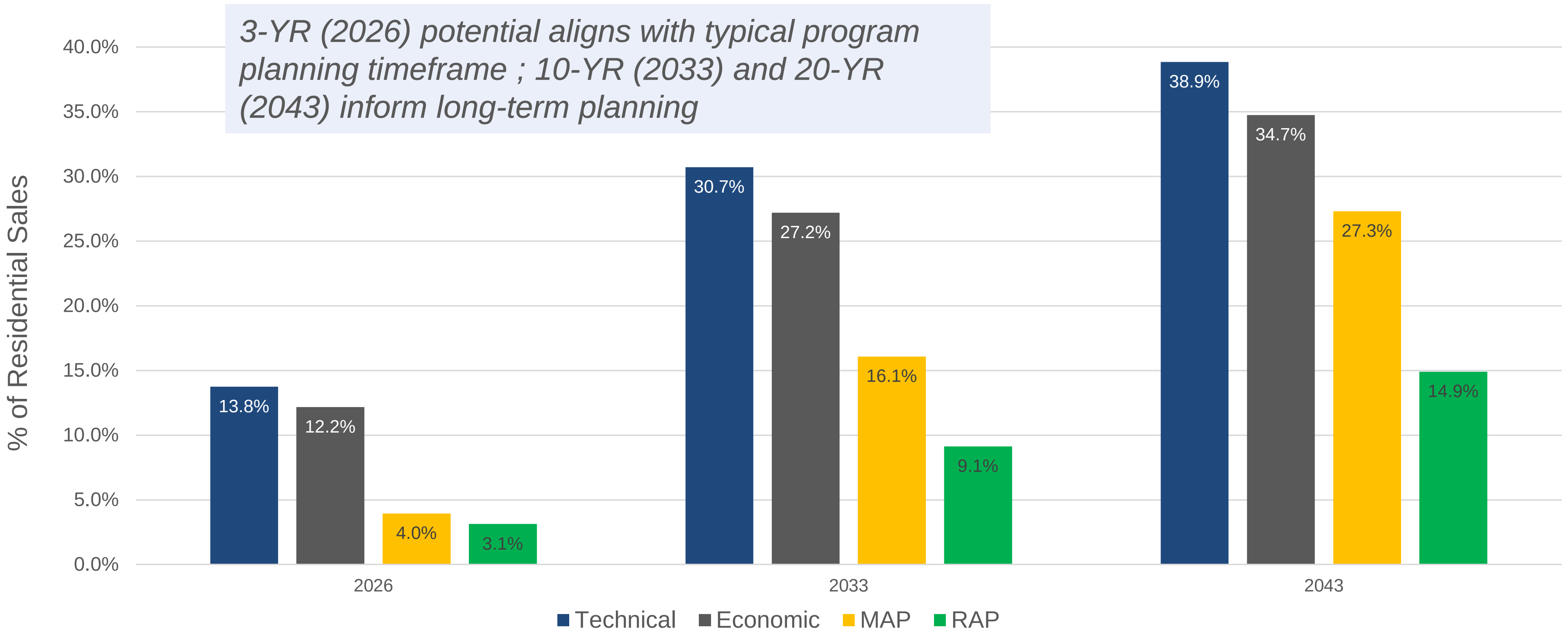


- Planned renewable resources expected to add 3,330MW installed capacity
- Additional $5 billion capital investments, much of which stays in the Indiana economy
- Generation transition plan generates more than $4 billion in cost-savings for our customers with industry-leading emissions reductions

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

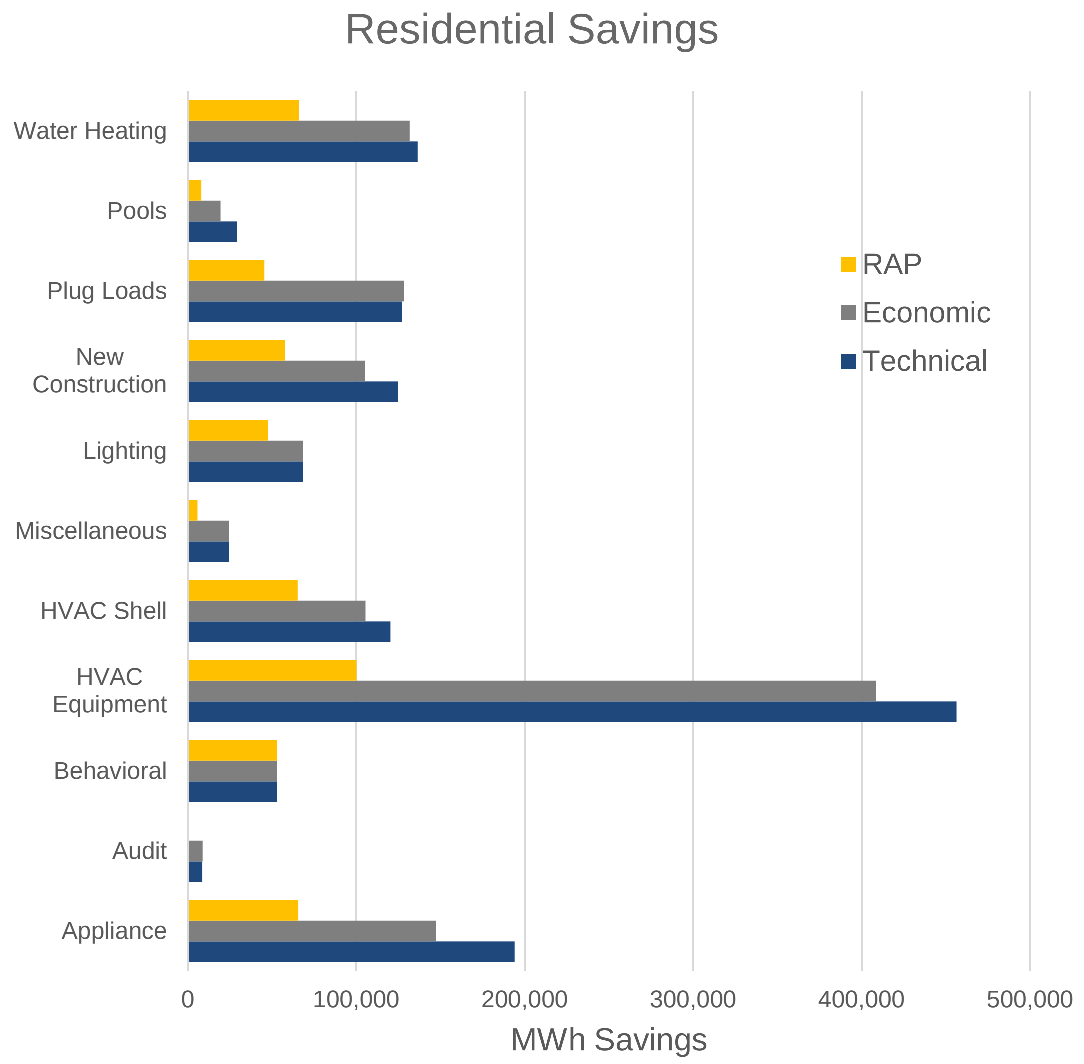
RESIDENTIAL ENERGY EFFICIENCY POTENTIAL SUMMARY



Results in chart show ***cumulative annual*** savings

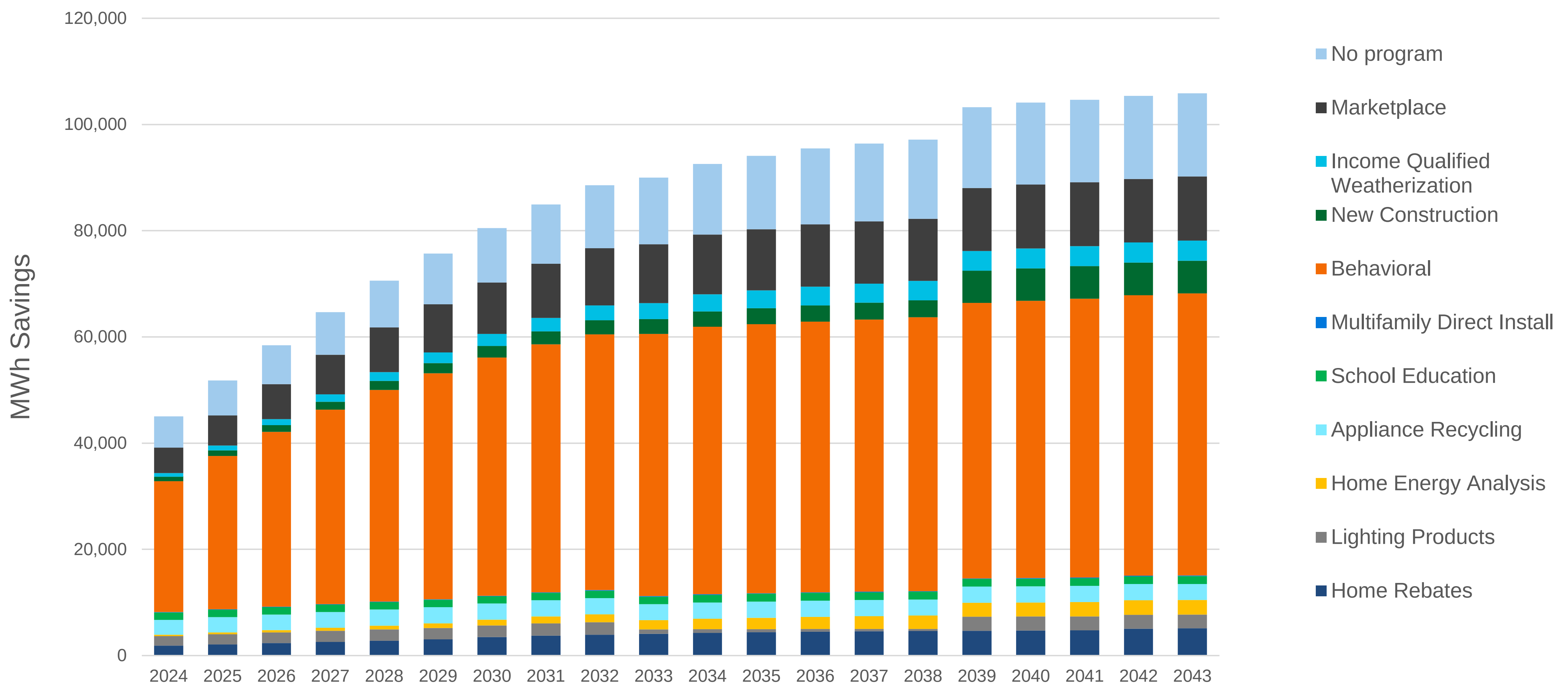
- *Cumulative Annual savings in Year X represent both the incremental (new) savings achieved in that year, as well as any sustained savings from measures installed in prior years that have not yet reached the end of their effective useful life (EUL)*

20-YEAR CUMULATIVE ANNUAL RESIDENTIAL POTENTIAL BY END-USE



- Large amount of technical and economic potential in the HVAC Shell and HVAC Equipment end uses
- Balanced contribution by HVAC Equipment / Shell, New Construction, Water Heating and Appliances in the RAP level

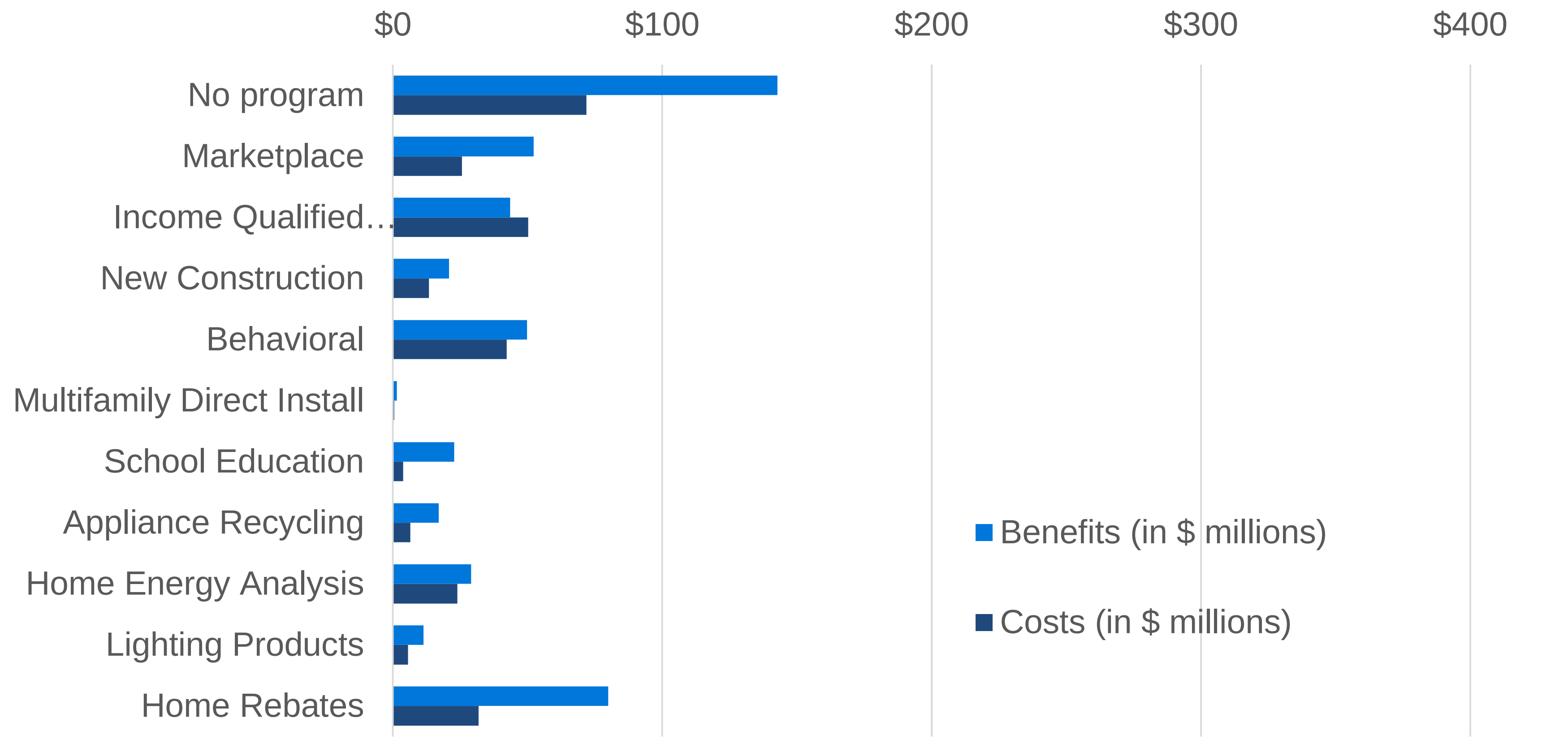
RESIDENTIAL INCREMENTAL RAP BY PROGRAM TYPE



RESIDENTIAL NPV COSTS AND BENEFITS BY PROGRAM

All values shown are 20-year net present values (NPV) in 2024$ for the 2024-2043 time period

RAP

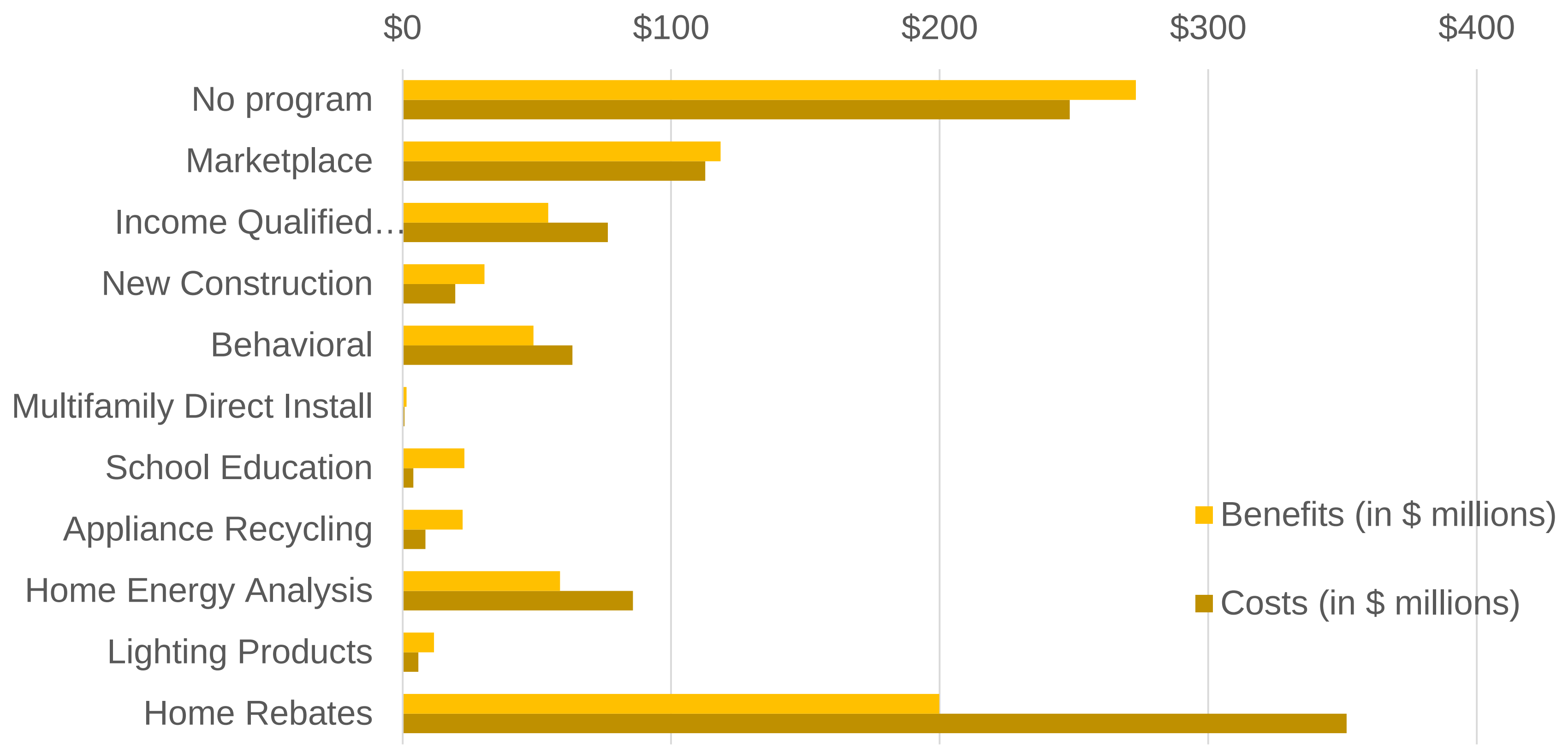


Levelized $/kWh
$0.07
$0.16
$0.21
$0.08
$0.08
$0.04
$0.03
$0.03
$0.17
$0.03
$0.13

RESIDENTIAL NPV COSTS AND BENEFITS BY PROGRAM

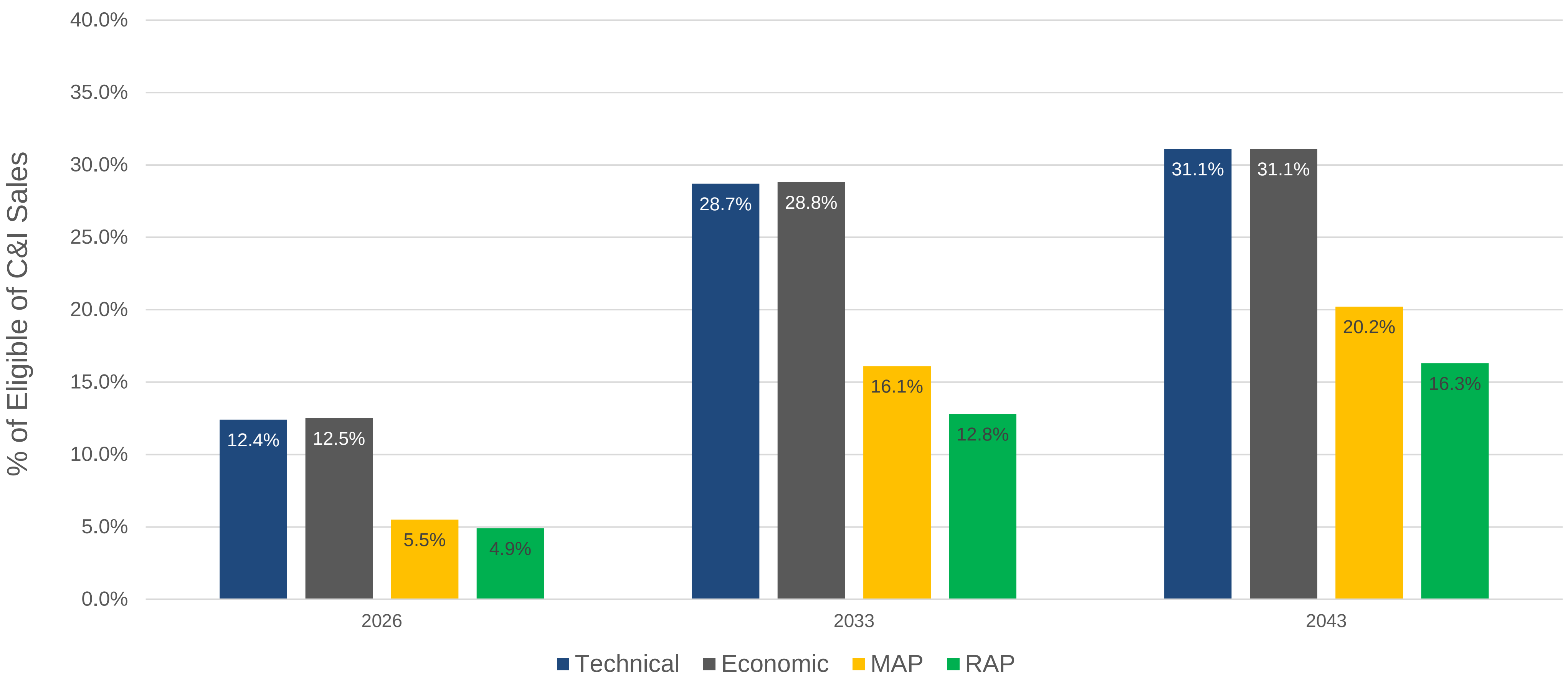
All values shown are 20-year net present values (NPV) in 2024$ for the 2024-2043 time period

MAP



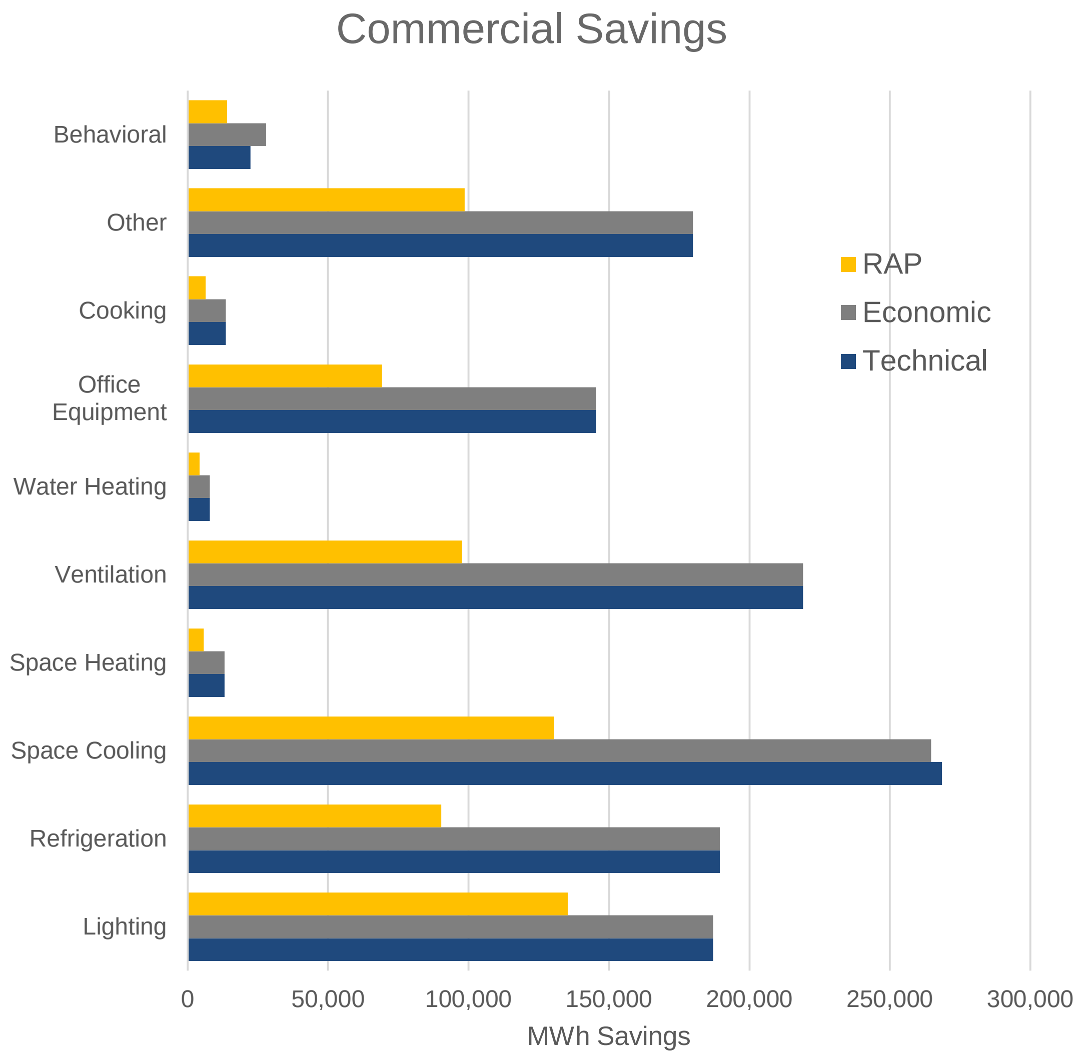
Levelized $/kWh
$0.13
$0.12
$0.24
$0.08
$0.13
$0.07
$0.03
$0.03
$0.28
$0.04
$0.53

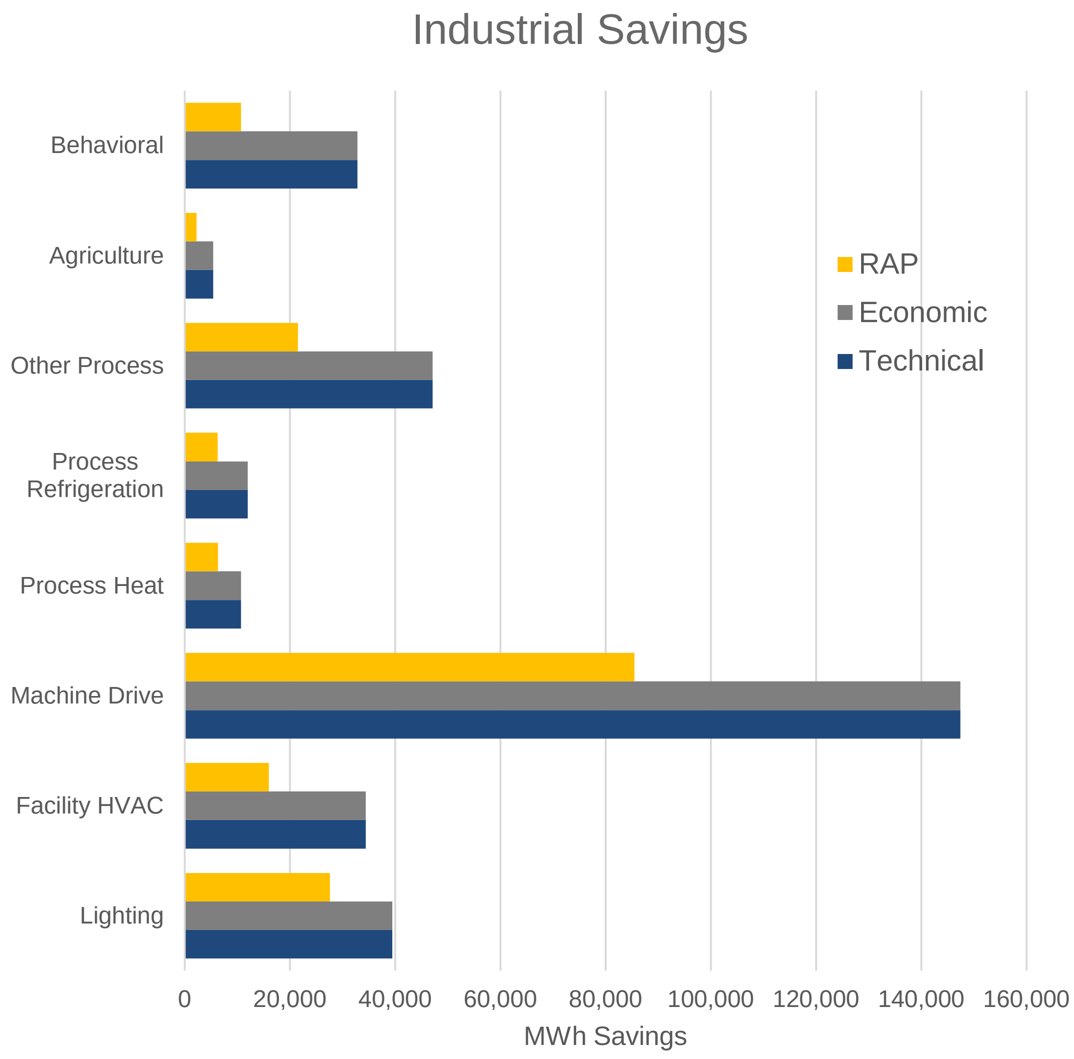
C&I ENERGY EFFICIENCY POTENTIAL SUMMARY



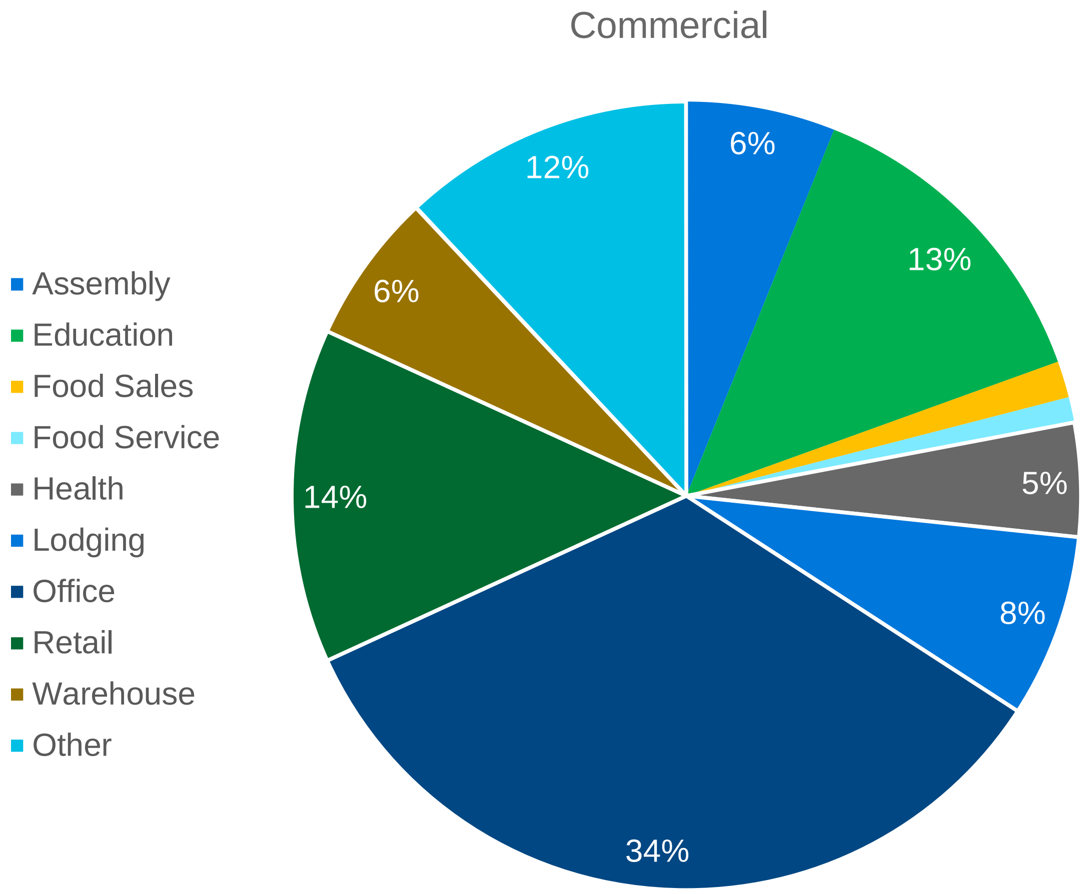
DSM Modeling

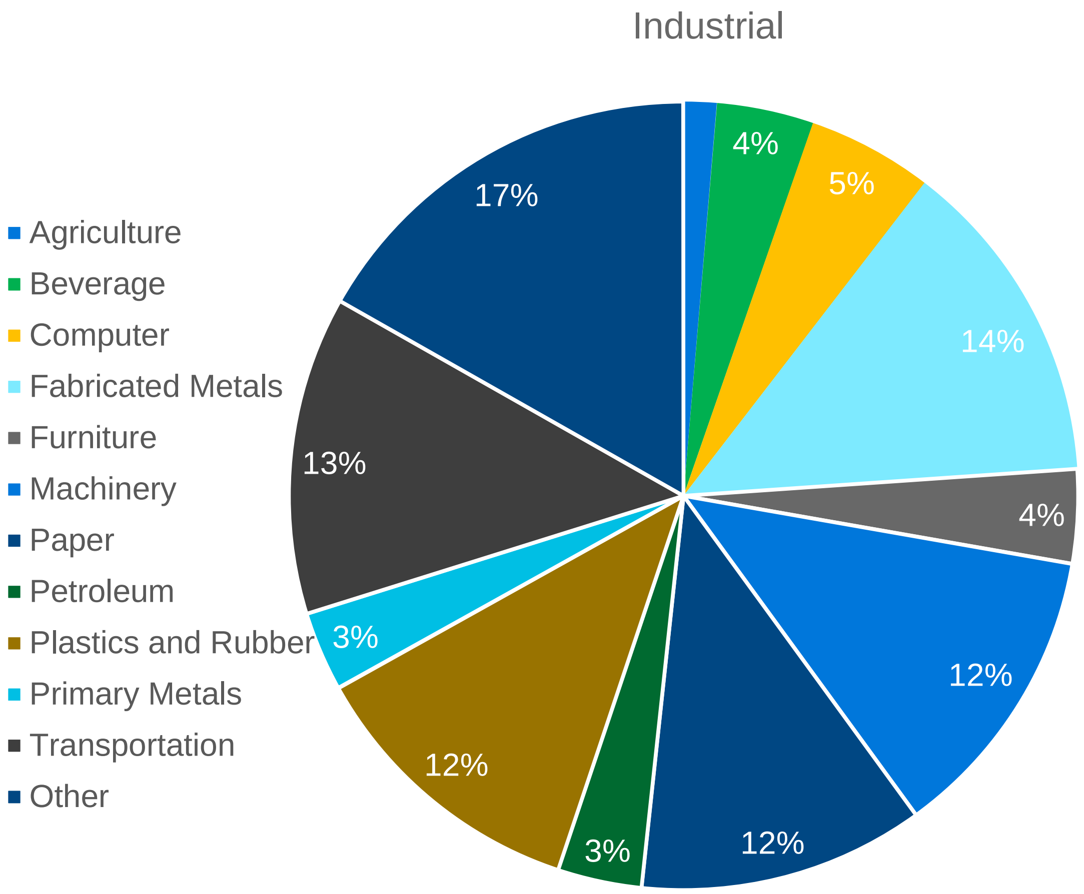
20-YEAR CUMULATIVE ANNUAL C&I POTENTIAL BY END-USE





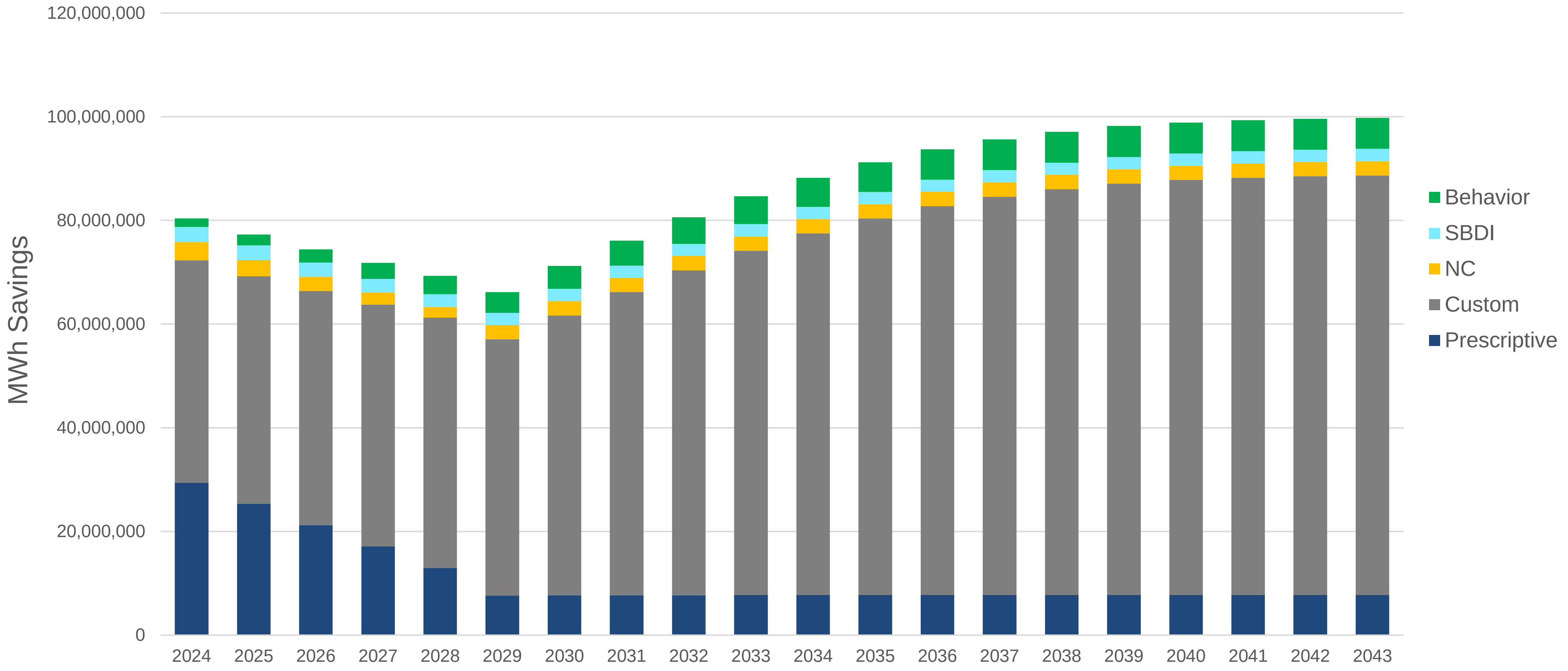
20-YEAR CUMULATIVE ANNUAL C&I POTENTIAL BY BUILDING/INDUSTRY TYPE





Data labels for building/industry types with less than 3% of savings were removed for presentation purposes.

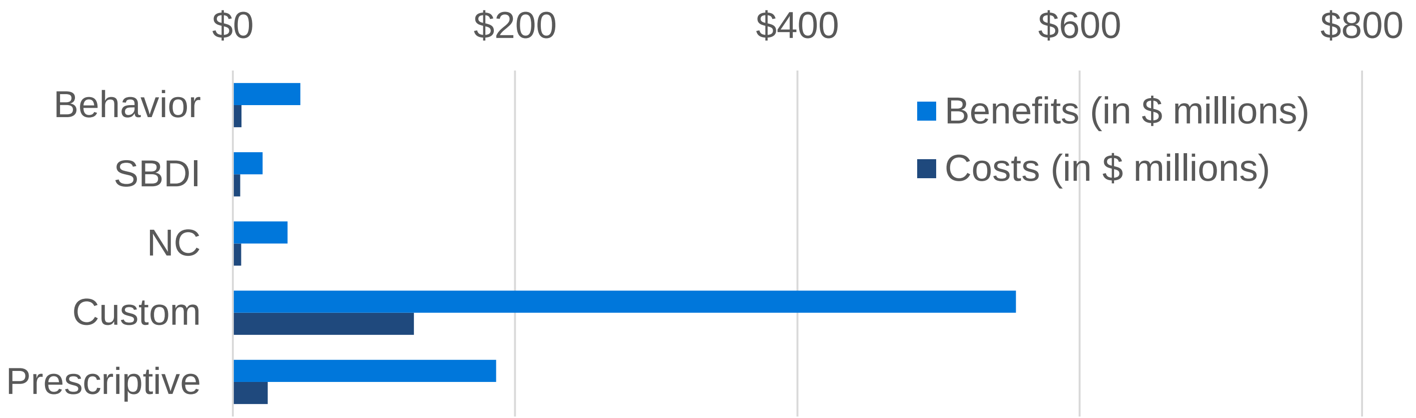
C&I INCREMENTAL RAP BY PROGRAM TYPE



C&I NPV COSTS AND BENEFITS BY PROGRAM

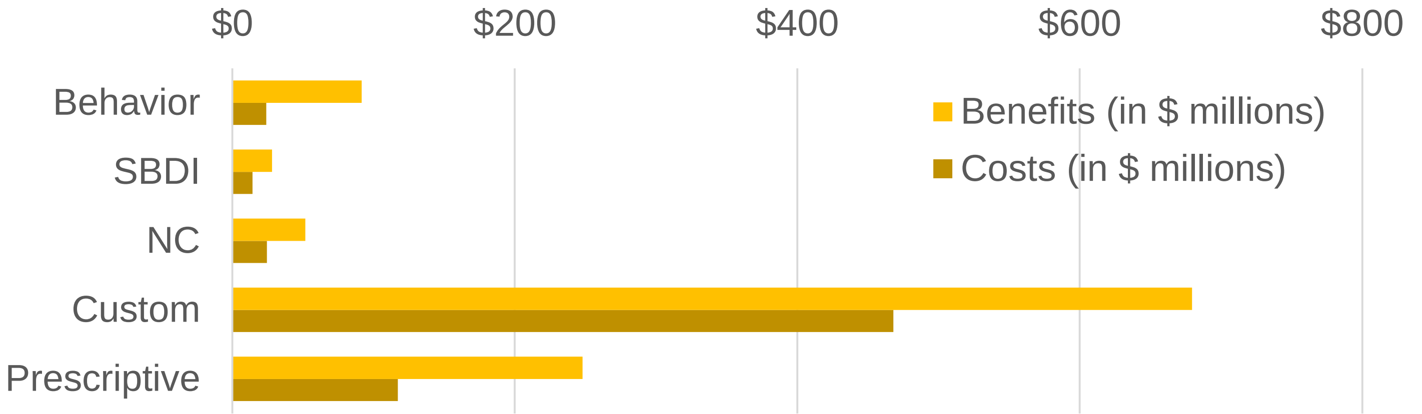
All values shown are 20-year net present values (NPV) in 2024$ for the 2024-2043 time period

RAP



Levelized $/kWh
$0.03
$0.03
$0.02
$0.03
$0.02

MAP



Levelized $/kWh
$0.07
$0.06
$0.06
$0.08
$0.07

PREVIOUS RELIABILITY ASSESSMENTS

2018 Retirement Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO's 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

2020 Portfolio Analysis Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 34 year NPV of revenue requirement (Base scenario deterministic results)
Long term Optionality	• Flexibility resulting from combinations of ownership, duration, and diversity • Metric: MW weighted duration of generation commitments
Capital Requirement	• Estimated amount of capital investment required by portfolio • Metric: 2020 -2023 capital needs
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 UCAP MW sourced from non-gas resources)
Environmental	• Carbon intensity of portfolio / Total carbon emissions • Metric: Total annual carbon emissions (2030 short tons of CO_2) from the generation portfolio
Operational Flexibility	• The ability of the portfolio to be controlled in manner to respond to changes in load (dispatchable) • Metric: % of 2025 Controllable MW in gen. portfolio

Northern Indiana Public Service Company LLC
2021 Integrated Resource Planning
Public Advisory Meeting #3
SUMMARY

July 13, 2021

Welcome and Introductions

Ms. Alison Becker, Manager, Regulatory Policy opened the virtual meeting by providing a safety moment on Parking Lot Safety and discussing the Webex meeting protocols. She then introduced Mike Hooper, President and Chief Operating Offcer of NIPSCO to kick off the meeting.

Mr. Hooper welcomed participants and thanked them for the level of participation, noting this was the third meeting with over 100 participants registered. Mr. Hooper thanked the numerous bidders and the robust response to NIPSCO's 2021 request for proposals ("RFP"). He then discussed NIPSCO's progressing generation transition plan, project construction, and progress on the renewables projects filed with the Indiana Utility Regulatory Commission. He discussed the next steps for the 2021 IRP – integrating the RFP results into the analysis, portfolio modeling to analyze all options, and directional results, which will be discussed at the next stakeholder meeting in September. Ms. Becker then reviewed the agenda for the day.

Public Advisory Process and Updates from Last Meeting
Fred Gomos, Director, Strategy and Risk Integration, NiSource

Mr. Fred Gomos, Director Strategy and Risk Integration, NiSource, began the section with an overview of NIPSCO's planning process and key planning considerations. He discussed the Stakeholder Advisory Meeting Roadmap and reminded participants of NIPSCO's Resource Planning Approach. He then outlined RFP and portfolio modeling progress since the last meeting and fielded participant questions.

Participants had the following questions and comments, with answers provided after:

- Does the reference to "portfolio optimization" mean that NIPSCO will use Aurora's portfolio optimization tool?
  - Yes, if you go back to slide 10, you see there are a number of models, but Aurora is the main dispatch and portfolio optimization tool used in the modeling. The portfolio optimization function will be used for portfolio development, but standard dispatch mode is also used during the scenario and stochastic analysis.
- As a follow up, is it correct that the Portfolio Optimization in Aurora relaxes the integer constraints on new resources? Just trying to understand why Portfolio Optimization would be used instead of long-term capacity expansion ("LTCE").

    - The primary reason for the use of the portfolio optimization functionality is run time and efficient integration with the portfolio calculation tool. It takes market prices as an input, so instead of solving against load like the LTCE does, the portfolio optimization functionality solves much faster.
- So NIPSCO cannot dispatch against price using LTCE?
    - It can by setting up the model in a different fashion, but the portfolio optimization tool performs the same functions as LTCE and is better integrated with the other portfolio analysis that will be performed. We would be open to discussing these details further in a one-on-one meeting.

Developing the Demand Side Management ("DSM") Study
Alison Becker, Manager, Regulatory Policy, NIPSCO
Jeffrey Huber, Managing Director—Energy Efficiency, GDS Associates, Inc. ("GDS")
Patrick Augustine, Vice President, Charles River Associates ("CRA")

Ms. Becker provided an initial overview of NIPSCO's history implementing energy efficiency and demand programs, and coordination with the NIPSCO Oversight Board ("OSB") on both the implementation and evaluation of these offerings.

Ms. Becker then discussed the role of a market potential study ("MPS") to assess the future of energy efficiency and demand response ("DR") savings and provide DSM inputs for NIPSCO's IRP. NISPSO worked with GDS to develop the MPS.

Mr. Jeffrey Huber, Managing Director – Energy Efficiency, GDS, reviewed the types of potential estimated in the MPS. GDS assessed potential at the following levels: technical potential, economic potential, and achievable potential. GDS assessed two types of achievable potential: maximum achievable potential ("MAP") and realistic achievable potential ("RAP").

Mr. Huber reviewed two key inputs into the MPS: the NIPSCO load forecast and market characteristics data. He also provided an overview of the primary market research conducted to better inform the MPS and allowed GDS to disaggregate the commercial and industrial sales forecast into building/industry type and by end-use. The market research also helped to inform expected technology adoption rates for assessing achievable potential.

Mr. Huber then reviewed the results of the MPS. Technical and economic potential for energy efficiency was estimated to be 34% and 33% of NIPSCO sales in 2043, respectively. Similar levels of technical and economic potential suggest that nearly all measures were found to be cost effective under the Utility Cost Test ("UCT"). Maximum achievable is 23% of NISPCO sales in 2043, and realistic achievable was estimated at 16% of NIPSCO sales in 2043. GDS reviewed the potential savings by end-use, overall MAP and RAP benefits and cost, as well as the levelized cost per kWh for each sector.

Mr. Huber reviewed the results of the DR potential analysis. He noted that future potential appears less than prior assessments of DR potential because Rate 831 (large industrial customers) interruptible loads are no longer part of NIPSCO's load obligation and DR portfolio. The current DR analysis focused on residential smart thermostats, residential electric water heaters, residential and small commercial and industrial ("C&I) dynamic rates, and medium and large C&I load curtailment.

Like the Energy Efficiency Potential assessment, the DR Potential analysis screened for cost-effectiveness using the UCT and looked at both MAP and RAP. The 20-year RAP potential is roughly 57 MW of DR, and the 20-year MAP was 136 MW of DR Potential. In both RAP and MAP, large C&I load curtailment is the program with the highest DR Potential.

The DR Potential analysis performed a sensitivity analysis using an alternate avoided cost of generation assumption. The base avoided cost of generation capacity was based on a natural gas combined cycle unit. The alternate avoided cost scenario assumed a combustion turbine unit and a reduced avoided cost. The alternate avoided cost reduced RAP and MAP by 26% and 28% respectively. Mr. Huber noted that the energy efficiency analysis also considered the alternative avoided cost scenario, but that the overall impact on the future potential was negligible.

Following a review of the MPS results, Mr. Huber discussed how the results of the MPS were used to create the DSM inputs for the IRP. Based on coordination between GDS, CRA, NIPSCO, and the NIPSCO OSB, GDS provided DSM bundles for IRP modeling based on aggregate potential at the sector level. The IRP DSM inputs were informed directly by the MPS with a few minor adjustments.

Mr. Patrick Augustine, Vice President at CRA, then presented a summary of how the energy efficiency and demand response bundles would be modeled in the portfolio analysis phase. He explained that 12 total EE bundles were developed by GDS across three discrete time periods (2024-29, 2030-35, 2036-41) and across four different categories (two residential bundles, one C&I bundle, and one bundle for income qualified weatherization). He noted that the costs for the bundles would be assessed in the program years, with savings persisting over time. Mr. Augustine then displayed the three DR bundles, broken into residential, C&I, and rates categories.

Participants had the following questions and comments, with answers provided after:

- Thanks for a very great process at the Oversight Board ("OSB") level. The Citizens Action Coalition of Indiana, Inc. ("CAC") would be interested in talking to NIPSCO more about third party aggregators to get participation from the medium/small commercial and industrial customers in interruptible tariffs. The former interruptible tariff was a good example.
    - NIPSCO and the CAC agreed to schedule a one-on-one.
- What is the knowledge of installers regarding incentive rates and general awareness of programs?
    - As part of the process, GDS looked at additional market research, including JD Power, and there was not a consistent awareness factor across the board (different awareness types for small business vs non-small business). However, based on feedback, installers are aware of the programs.
- What drives the jump in residential costs from $0.075 in the realistic achievable potential ("RAP") scenario to $0.174 in the maximum achievable potential ("MAP")?
    - The incentive increases all the way to 100% of measure cost, driving the cost up.
- Please elaborate on the 2030 rate program?
    - That is a critical peak pricing program. Under such a rate program, a customer enrolled would face a lower rate during off-peak hours, but would face a much higher rate on certain peak days/hours based on a defined pricing structure.

Customers would be expected to shift usage out of peak times to save costs, which under this scenario would be the default tariff for residential customers. It is important to note that this is only a study at this point, and NIPSCO has not made any final decision on such a rate program. For RAP, the program is voluntary, but for MAP, the tariff would be default, with an ability to opt-out.

- If these bundles are going to be modeled with the integer constraints on them relaxed, would it not make more sense to condense the potential into all RAP (less Income Qualified Weatherization ("IQW") and all MAP (less IQW)? This is because the model could take a partial of amount of each bundle under linear optimization.
    - NIPSCO can consider this, although residential and commercial & industrial programs are generally considered somewhat separate. Note that the three time periods were designed to allow for the potential for different bundle selection amounts over time. We can also discuss this further during a one-on-one.
- Regarding slide 48, what is the optimization period? If it goes beyond 2041, will you not have an end-effects issue if the assumption is that no new energy efficiency occurs after 2041?
    - The optimization period will run out a full 30 years, including the end effects period. The DSM bundles will be modeled on a levelized cost basis to account for all costs and benefits and to keep all resource options on an equal footing.
- Did the market potential study consider possible opportunities for commercial and industrial customers to reduce electric usage with combined heat and power ("CHP") projects?
    - The MPS did not include CHP as a resource.
- The CAC would like to talk to you about extending EE through 2050. That is really important because the IRP will not capture the totality of the end effects issue otherwise.
    - The analysis only incorporates specific programs through 2041, but it does account for all savings for those programs through 2050 and beyond in the optimization. We can certainly discuss this further in a one-on-one.
- Will you model the avoided costs that cannot be explicitly represented in the IRP as reduction in costs to the DSM bundles, such as avoided transmission and distribution ("T&D")?
    - Avoided T&D costs are accounted for in the DSM screening and will be accounted for in the portfolio analysis phase. For example, on slide 38, the stacked bar of avoided costs associated with T&D (~$30 kW/year) will be included in the calculation of benefits. GDS will work with CRA to ensure that these savings are appropriately captured as offsets in the Aurora modeling, and we can review this further in a one-on-one setting.

Supply-Side Distributed Energy Resource ("DER") Considerations
Pat Augustine, CRA

Mr. Augustine introduced the section on supply-side DER options by providing an overview of how utility planning is evolving with regard to the interactions between generation planning and transmission and distribution planning. He summarized the interactions that NIPSCO accounts for in its planning work and noted that the 2021 IRP is including an explicit consideration of supply-side DER options due to declining technology costs and regulatory developments such as FERC Order 2222. He noted that NIPSCO would be evaluating DER options as supply-side options on equal footing with DSM and RFP resources, incorporating key considerations such as DER project costs and deferred T&D investments. Mr. Augustine then outlined NIPSCO's approach to identifying DER options and summarized the three supply-side DER bundles for use in the IRP. These bundles included solar and storage capacity and a net present value calculation of deferred distribution system investment that would be netted off of resource costs in the portfolio analysis.

Participants had the following questions and comments, with answers provided after:

- Thanks for putting the effort into thinking about how to better capture supply-side DERs. Can you share the analysis?
    - Yes, NIPSCO can share much of the analysis, which includes details on the distribution-level locations which were analyzed.
- What will the operating profile of the hybrid systems look like on the generation side of the resource offered?
    - There is unlikely to be a consistent ratio of solar and storage pairing across all DER sites. From a modeling perspective, the bundle summaries show that a certain amount of solar and a certain amount of battery storage will be analyzed together. The storage components will be allowed to dispatch optimally to meet peak requirements and take advantage of energy arbitrage opportunities.
- Is NIPSCO actively building out utility scale projects?
    - The short answer is yes. Slide 86 shows the projects that came out of the 2018 IRP and NIPSCO's two previous requests for proposals. These include wind, solar, and solar plus storage projects.

2021 RFP Results Overview
Andy Campbell, Director, Regulatory Support and Planning, NIPSCO
Bob Lee, Vice President, CRA

Mr. Andrew Campbell, Director of Regulatory Support & Planning for NIPSCO, opened the discussion on the results of the 2021 RFP. He summarized that NIPSCO's latest RFP solicitation garnered a robust response with more than 30 bidders submitting offerings for consideration by NIPSCO. Before turning it over to CRA to review the initial results, he noted that the information at this point is informative and preliminary and that there will be no conclusions until the conclusion of the IRP process

Mr. Bob Lee, Vice President at CRA, then summarized the responses to the 2021 RFP. He noted that the RFP responses generated 182 proposals spread throughout Indiana, Illinois, Kentucky, Missouri, and MISO with the overwhelming response centralized in MISO Zone 6, which encompasses Indiana and part of northern Kentucky. The RFP generated just over 15 GW (installed capacity, or "ICAP") of projects and proposals from those projects covering over 32 GW (ICAP). Mr. Lee also summarized preliminary average costs within the RFP bids. He concluded by informing the meeting attendees that the RFP asset tranches have been shared with the IRP team at CRA and that the bid evaluation phase is expected to be complete in late August followed by the possibility of definitive agreements thereafter dependent on the outcomes of the 2021 IRP preferred portfolio.

Participants had the following questions and comments, with answers provided after:

- Two questions related to Michigan City. Will the coal ash on the lake stay there indefinitely? Has NIPSCO read the recent report on the Great Lakes, and will the Company use it in making decisions related to the closure at Michigan City?
  - NIPSCO is coordinating with the Indiana Department of Environmental Management regarding the Michigan City plant's plan to close the ash pond and remove the coal ash after retirement. The ash will be extracted and taken down to the landfill at the Schafer location. This will be done in compliance with the United States Environmental Protection Agency ("EPA") rule that oversees all facilities. It was requested that the individual asking the question send a copy of the referenced report.
- For thermal, is the purchase power agreement ("PPA") $/MWh $0.36/MWh or $36/MWh?
  - It is $0.36/MWh for only the variable operations and maintenance ("VOM") cost components specified in the bids that are aggregated here. Note that fuel and emission costs are generally assumed to be separately passed through to NIPSCO and would be *additive* to this VOM when the portfolio modeling is performed.
- I understand now that a lot of operating costs are excluded from the $0.36/MWh for thermal. With that said, is there an apples-to-apples way to compare thermal to other sources? Can thermal be expressed as $/MWh as well?
  - It would be hard to do that for thermal bids. You would need to make a lot of assumptions around natural gas prices and future emission costs. In addition, a $/MWh price is sensitive to plant heat rate, market prices for energy, and other factors. Such analysis will be performed in the IRP modeling when it establishes the preferred portfolio.
- What kinds of technologies are in the "other" category? Are those the same as the emerging technologies you mentioned earlier?
  - No, they tend to be system power arrangements and are sometimes not tied to an individual facility. So it is a "catch all" category for bids like these.
- Is there a plan in place to reach out first to hosting coal plant communities with clean job opportunities as part of environmental reparations? Also The NAACP is requesting a carve-out for community owned solar. Is that a foreseeable possibility?
  - NIPSCO would be happy to have a one-on-one with the NAACP to discuss options for community solar. Please reach out to Alison Becker (abecker@nisource.com) to set up a meeting. Regarding the jobs created, that is considered both as part of reviewing the RFP responses as well as throughout NIPSCO's Your Energy, Your Future initiative. The Company is happy to continue conversations.
- Can NIPSCO elaborate on what you were referring to by "emerging technologies"?
  - This primarily includes hydrogen-enabled thermal resources. This is a new emerging area that NIPSCO wants to consider, and the Company also wants to cast a wider net around other developmental technologies, including storage options or small scale nuclear. While we did not get bids for all types of potential emerging technologies, the outreach is allowing NIPSCO to start discussions with developers for further consideration. While some bids in this area are not actionable, they may be considered for long-term portfolio modeling, particularly for managing carbon risks.

- Does the pricing provided by respondents include the cost of any required MISO network upgrades as a pass through cost to NIPSCO? Did NIPSCO require respondents to estimate their own network upgrade costs if the respondent didn't already have those reported by MISO?
  - The RFP did ask bidders who they are assuming is responsible for interconnection costs, and the bids fall into three categories: developers are on hook for all costs, which are included in their price; a cap on such costs is included in the bid, and higher costs might trigger adjustments to pricing; and the third assumes that NIPSCO will be responsible for all such costs.
- How will NIPSCO's assets/portfolio concept be impacted in terms of redevelopment opportunities if toxic coal ash is allowed to sit indefinitely on the lake front at the Michigan City Generating Station? How valuable will that property be for redevelopment if the coal ash remains in place?
  - The coal ash will not remain in place, as noted earlier. The other questions fall into the realm of how changes in the portfolio will impact property tax, employee base, etc. The Company is in compliance with all environmental issues at Michigan City, and there is no threat to human health from the facility as it stands. However, we have noted that NIPSCO has more actions to take, and no final decisions on the plant's future have been made.
- What is your plan for revitalizing the Michigan City Generating Station once it's closed?
  - No decisions have been made on that yet.

Incorporating RFP Results into the IRP
Fred Gomos, NiSource
Pat Augustine, CRA

Mr. Gomos began the section with an introduction of how the RFP results inform the IRP analysis. He outlined how NIPSCO will be performing both an existing fleet analysis and a replacement analysis using detailed information from the RFP. He then introduced Mr. Augustine, who provided the rationale for why individual RFP bids are organized into tranches for portfolio modeling. Mr. Augustine then outlined NIPSCO's three step process for analysis, which included (i) tranche development, (ii) portfolio optimization, and (iii) portfolio modeling.

Mr. Gomos then transitioned to a review of NIPSCO's assessment of reliability in the 2021 IRP, including the focus on resource adequacy, energy adequacy, and operating reliability. He described the way that NIPSCO evaluates each of these elements in the IRP portfolio analysis, and Mr. Augustine then provided a detailed overview for how NIPSCO will quantitatively assess real-time energy and ancillary services value at a five-minute level of granularity in CRA's Energy Storage Operations (ESOP) model. Mr. Augustine then noted that not all reliability metrics can be captured in economic analysis, and Mr. Gomos closed the section with a review of how NIPSCO is planning to perform additional reliability analysis on six specific criteria. He noted that NIPSCO is open to stakeholder feedback on the topic and will be engaging a qualified consultant to develop scoring methodology utilizing the metrics identified for individual technologies and in aggregate on a portfolio level and score and rank various generation resource technologies bid into the RFP across these metrics.

Participants had the following questions and comments, with answers provided after:

- Can you talk more about how the analysis will measure energy market risk exposure?

    - Risk metrics will come out of the scenario and stochastic analysis, and when NIPSCO eventually gets to the scorecard, it will include measures of uncertainty and tail risk. Energy market risk exposure will not be a standalone metric, but the uncertainty analysis, particularly the stochastic component, will evaluate hourly portfolio costs, including exposure to the energy market. Different portfolio constructs will have different exposure.
- Will the metric be annual sales/purchases or will it look at particular seasons or conditions?
    - The risk metrics will be summarized on an annual basis, although more granular portfolio analysis data will be available and will ultimately be driving the annual summaries. There is no defined metric at the scorecard level for seasonal sales and purchases, since such risk exposure is captured in the broader uncertainty metrics.
- Will the Real Time ("RT") and ancillary services ("A/S") value of flexible resources from ESOP then be a reduction in their cost for purposes of use in Portfolio Optimization or just to reduce the present value of revenue requirements ("PVRR")?
    - The RT and A/S values will be incorporated as a reduction in the cost of relevant resources (such as storage or flexible thermal resources) in the portfolio optimization and full portfolio analysis phases of the IRP. This will then be rolled into the full PVRR analysis.
- Do you have a list of resources to meet these criteria?
    - No, we haven't established a full list of resources that meet these criteria. However, we will be looking at specific resource types that participated in the RFP and we will be engaging a third party reviewer to support this task.
- For Ancillary services, can they provide the list for them to provide feedback?
    - Yes, spinning reserve and regulation (both up and down, which is a combined product in MISO) will be evaluated in this exercise.
- Is NIPSCO planning to stratify resources by service provided?
    - It is not binary, as some resources have the ability to provide multiple attributes for energy and ancillary services, as well as other reliability values. The analysis will look to incorporate that, so in some sense there is some level of stratification to ensure all value attributes are accounted for.
- It is possible that some of the reliability services you've outlined may not be needed at all or under certain conditions, meaning that they may not actually provide value to ratepayers. For example, grid-forming inverters are coming quicker than realized and they may provide some of these services. In addition, it's not clear why Automatic Generation Control ("AGC") is necessary when NIPSCO is in MISO. Finally, the need for some of these ancillary services can get saturated very quickly. One concern is that you're ranking portfolio options against criteria that may not be always needed.
    - We certainly agree that the space is moving fast, and this is why we want to get someone who is familiar with the details to review our metrics and scoring. The Company also wants to be sure that it is not assessing things that are not applicable. MISO is dynamic and will continue to evolve, but what NIPSCO is trying to do here is recognize that there are MISO products, NERC standards, and required compliance plans to ensure reliability under a variety of system conditions. For example, there are normal market mechanisms that will likely not be available during a blackout condition, so NIPSCO needs to ensure resources would be in place to maintain grid stability. These factors are critical considerations as we retire Schafer and Michigan City, so while looking at

resource replacements, we want to make sure we have resources that provide needed services under normal conditions and during emergency conditions.

- What voltage are Schahfer Units 16AB connected to?
  - Units A & B are connected to the 138 kV system.
- Could you please discuss assumptions for Largest Single Hazzard ("LSH") evaluations? Are there any special considerations in selection criteria for this future heavily intermittent weighted portfolio?
  - The Company does not have an answer at this time, but we will consider this question when reviewing reliability criteria further.
- Are these assessment criteria going to be used to evaluate whether or not a resource should be included or will it be used to assess a portfolio of resources after the fact to see whether these criteria are met given the overall mix of resources in the portfolio that was modeled?
  - This is evolving, but the Company wants to perform this review on a portfolio basis. Individual resources will be scored and the impact on a full portfolio will be assessed. We don't intend to eliminate any resources from consideration as part of this process, but use it to score a range of candidate portfolios.

Wrap Up and Next Steps
Erin Whitehead, Vice President, Regulatory and Major Accounts, NIPSCO

Ms. Whitehead, Vice President, Regulatory and Major Accounts for NIPSCO, closed the session by thanking attendees for their participation and feedback. She then outlined key next steps in the IRP process and invited participants to reach out for one on one discussions.

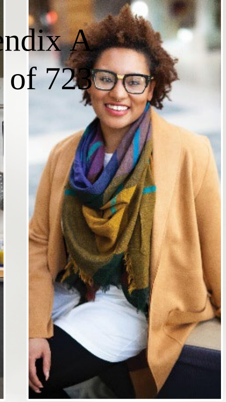
July 13, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Emily	Abbott	Invenergy
Denise	Abdul-Rahman	NAACP Indiana
Cynthia	Armstrong	Indiana Office of Utility Consumer Counselor
Pat	Augustine	Charles River Associates
Kim	Ballard	IURC
Vernon	Beck	Nipsco
Matt	Bell	Reliable Energy, Inc.
Greg	Berning	NiSource
Bradley	Borum	Indiana Utility Regulatory Commission
Shane	Bradford	CenterPoint Energy
Wendy	Bredhold	Sierra Club Beyond Coal Campaign
Andy	Campbell	NIPSCO
John	Cleaveland	NIPSCO
Tom	Cofer	C21 Affiliated
Jeremy	Comeau	IURC
Alex	Cooley	NiSource
Jordan	Covely	Inovateus Solar LLC
Ben	Crandall	Uplight
Anaelle	Croteau	AdvantageCapital
Mason	Daumas	EDP Renewables
Cory	Dutcher	General Electric Company - Power Division
Jeffery	Earl	Reliable Energy
Daniel	Farrell	Retired
Bill	Fine	Indiana Office of Utility Consumer Counselor
Neil	Fitzharris	EDP Renewables North America
Michael	Fortini	DTE
Bill	Fowler	Shell Energy North America (US), L.P.
Nick	Gates	Galehead Development LLC
Richard	Gillingham	Hoosier Energy
Fred	Gomos	Nisource
Doug	Gotham	State Utility Forecasting Group
Courtland	Grangier	
Robert	Greskowiak	Invenergy LLC
Paul	Griffin	Indeck Energy Services
Jack	Groves Pe	ENERGY SOUTHWEST INC.
Stacie	Gruca	Indiana Office of Utility Consumer Counselor
Sean	Haas	Reserve
Andrew	Hamilton	Ranger Power
John	Haselden	Indiana Office of the Utility Consumer Counselort
Ryan	Heater	Indiana Utility Regulatory Commission
Robert	Heidorn	NiSource
Max	Henderson	NiSource
Joseph	Hero	Attorney-Engineer
Chelsea	Hotaling	Energy Futures Group
Sarah	Howdeshelt	AES Indiana

July 13, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
James	Hummel	Duke Energy
Sergio	Hunt	Indiana OUCC
Jim	Huston	Indiana Utility Regulatory Commission
Andrew	Kain	Purdue
Michelle	Kang	Charles River Associates
Will	Kenworthy	Vote Solar
Nick	Kessler	CenterPoint Energy
Andrea	Kong	Telamon Enterprise Ventures
Stefanie	Krevda	Indiana Utility Regulatory Commission
Karol	Krohn	Office of Utility Consumer Counselor
Reagan	Kurtz	Citizens Action Coalition of Indiana
Natalie	Ladd	NiSource
Tim	Lasocki	Orion Renewable Energy Group LLC
Robert	Leah	National Grid Renewables
Ali	Lehman	WeSolar, consultant for NAACP IN
Anne	Lenzen	Opower
Bryan	Likins	NIPSCO
James	Loewen	Everspring Energy
Simon	Lomax	Better Jobs Coalition (consultant)
Greg	Long	Cleveland-Cliffs Steel
Caleb	Loveman	Indiana Office of Utility Consumer Counselor
Liwei	Lu	SUFG
Wendy	Lussier	NIPSCO
Cyril	Martinand	Cleveland-Cliffs
Tara	McElmurry	NIPSCO
Kalin	McGowan	CRA
Emily	Medine	EVA
Erik	Miller	AES
Sophia	Miller	Ranger Power
Alan	Mok	Duke Energy
Tim	Montague	Contintental Energy Solutions
Danny	Musher	Key Capture Energy
David	Nderitu	SUFG
Mark	Noll	Demand Side Analytics
Mark	Noll	Demand Side Analytics
David	Ober	Indiana Utility Regulatory Commission
Kerwin	Olson	Citizens Action Coalition of IN
April	Paronish	Indiana Office of Utility Consumer Counselor
Richard	Pate	Pate & Associates
Bob	Pauley	IURC
Kattie	Penn	
Tim	Phillips	State Utility Forecasting Group
Brett	Radulovich	NiSource
Brett	Radulovich	NiSource
Jeff	Reed	Indiana Office of Utility Consumer Counselor

July 13, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Matt	Rice	CenterPoint Energy
Adam	Rickel	NextEra Energy Resources
Robert	Ridge	NIPSCO
Tonya	Rine	CenterPoint Energy
Trina	Robinson	NAACP
Rosalva	Robles	NIPSCO
Stephen	Rodocanachi	Hartree Partners
LouAnn	Rone	NiSource
Jamalyn	Sarver	Hallador Energy Company
Cliff	Scott	NIPSCO
Robert	Sears	NIPSCO
Brent	Selvidge	AES Indiana
Rob	Seren	NIPSCO
Laura	Sigward	bp
Regiana	Sistevaris	I&M
Barbara	Smith	OUCC
Anna	Sommer	EFG
Theodore	Sommer	LWG CPa's and advisors
Pauline	Sotiroski	NIPSCO
Daniel	Spellman	Orion Renewable Energy Group LLC
Jennifer	Staciwa	NIPSCO
Sarah	Steinberg	Advanced Energy Economy
Saif	Syed	
Ryan	Tedeschi	NIPSCO
Marco	Terruzzin	Energy Vault Inc
Leah	Thill	MACOG
Dale	Thomas	IURC
Susan	Thomas	Just Transition NWI
La'Tonya	Troutman	NAACP
Maureen	Turman	NiSource
Ed	Twarok	NiSource
Darian	Unruh	Utility Regulatory Commission
Greg	Van Horssen	Van Horssen Law & Government, PLLC
Will	Vance	AES Indiana
Marco	Velastegui	
Chris	Vickery	
Nathan	Vogel	Inovateus Solar LLC
Jennifer	Wagner	
John	Wagner	NIPSCO
Michael	Wallace	BrightNight Power
Nancy	Walter	Just Transition Northwest Indiana
Jennifer	Washburn	CAC
Amanda	Wells	Duke Energy
Erin	Whitehead	NIPSCO
Ryan	Wilhelmus	CenterPoint Energy

July 13, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Ashley	Williams	Just Transition NWI
Jean	Williams	Duke Energy
Katherine	Zoellmer	






NIPSCO
A NiSource Company

NiSource

2021 NIPSCO Integrated Resource Plan

Stakeholder Advisory Meeting #4

September 21st, 2021
9:00AM-2:00PM CT




SAFETY MOMENT

FIVE TIPS TO IMPROVE YOUR MENTAL HEALTH

PHYSICAL

Exercise (think "baby steps!"... even a short walk helps), drink lots of water, see your doctor, eat foods that make you healthier, take time to stretch throughout the day

MINDFUL

Try yoga, meditation, make a list of three things you are grateful for, engage in random acts of kindness, spend time in nature or outdoors when possible

SOCIAL

Try something new and creative, call a friend/family member, send a card/note, organize lunch/dinner over video chat with friends or family

EMOTIONAL

Focus on the present moment, not what might happen; increase positive self-talk—be a cheerleader for yourself or a friend, find activities that relieve stress and tension, journal, try therapy or support group

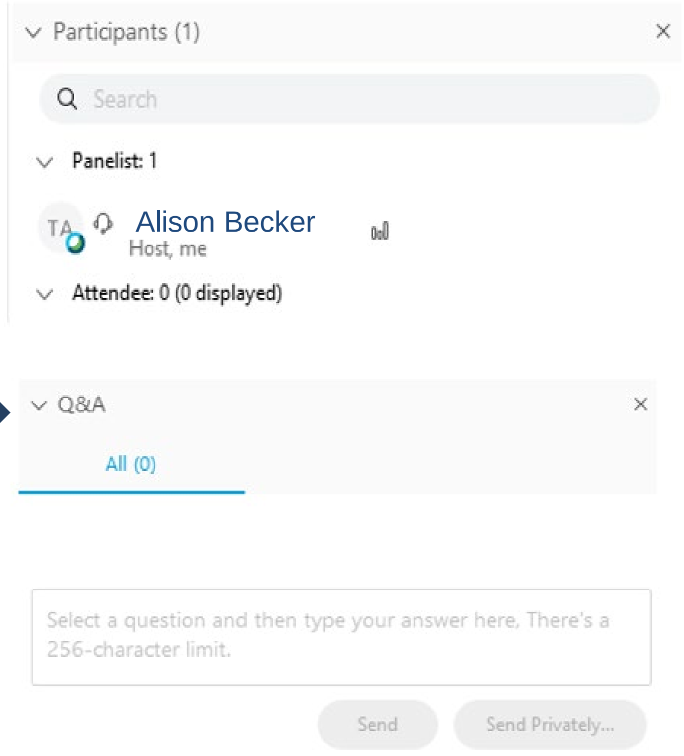
MENTAL

Try something new and creative, call a friend/family member, send a card/note, organize lunch/dinner over video chat with friends or family

Cummins

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
9:00-9:05AM	Webinar Introduction, Safety Moment, Meeting Protocols, Agenda	Alison Becker, Manager Regulatory Policy, NIPSCO
9:05-9:15AM	Welcome	Mike Hooper, President & COO, NIPSCO
9:15-9:45AM	NIPSCO's Public Advisory Process and Updates From Last Meeting	Fred Gomos, Director Strategy & Risk Integration, NiSource
9:45-10:45AM	Resource Planning Activity Review	Fred Gomos, Director Strategy & Risk Integration, NiSource Pat Augustine, Vice President, CRA
10:45-11:30AM	Lunch	
11:30AM-12:30PM	Existing Fleet Analysis & Results	Fred Gomos, Director Strategy & Risk Integration, NiSource Pat Augustine, Vice President, CRA
12:30-12:45PM	Break	
12:45-1:55PM	Replacement Analysis & Results	Fred Gomos, Director Strategy & Risk Integration, NiSource Pat Augustine, Vice President, CRA
1:55-2:00PM	Analysis Next Steps	Erin Whitehead, Vice President Regulatory & Major Accounts, NIPSCO

WELCOME

Mike Hooper, President & COO, NIPSCO

PILLARS OF OUR ONGOING GENERATION TRANSITION PLAN

This plan creates a vision for the future that is better for our customers and it's consistent with our goal to transition to the best cost, cleanest electric supply mix available while maintaining reliability, diversity and flexibility for the technology and market changes on the horizon.

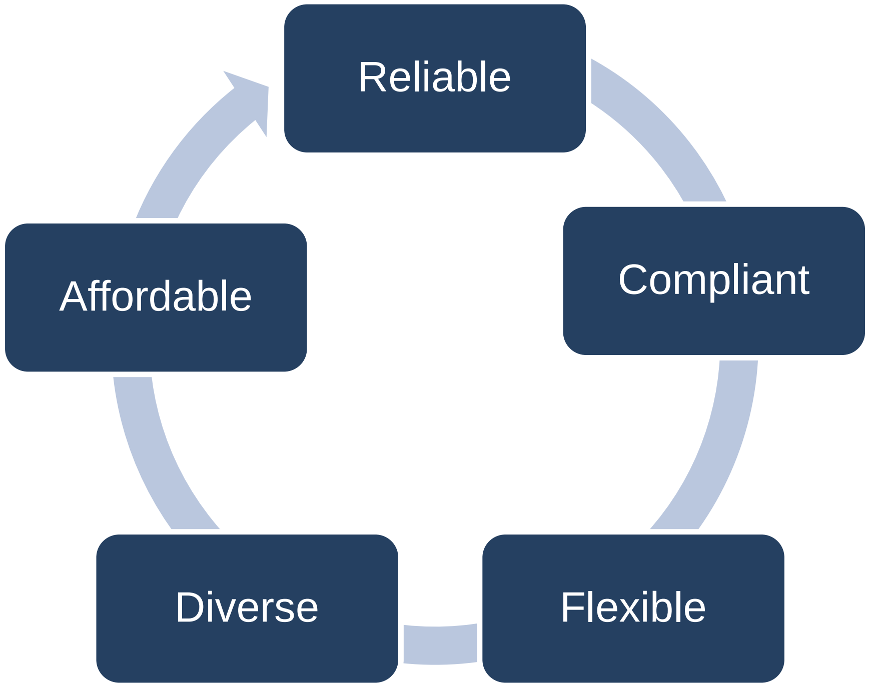
Reliable and sustainable	Flexibility for the future	Local and statewide economic benefits	Best plan for customers and the company

NIPSCO'S PUBLIC ADVISORY PROCESS UPDATES FROM LAST MEETING

Fred Gomos, Director Strategy & Risk Integration, NiSource

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)

Technical Webinar focused on Reliability Assessment 10/12/2021

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	10/21/2021
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? • How will NIPSCO evaluate potential DER options? • 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 • DER Inputs • 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 • Explain next steps for portfolio modeling	• Communicate the Existing Fleet Portfolios and the Replacement Portfolios • Develop a shared understanding of economic modeling outcomes and preliminary results to facilitate stakeholder feedback	• Communicate NIPSCO's preferred resource plan and short-term action plan • Obtain feedback from stakeholders on preferred plan

ONE ON ONE INTERACTIONS SINCE JULY STAKEHOLDER MEETING

- NIPSCO met with stakeholders to discuss a variety of IRP topics, share feedback/perspective, and help provide answers to questions

Stakeholder	Date	Subject Area/Discussion Topic
Citizens Action Coalition of Indiana (CAC)	7/23	• Follow up from topics presented in the July stakeholder meeting • Topics included portfolio optimization, portfolio modeling, DSM, reliability criteria, supply-side DER
	9/7	• Reliability criteria approach discussion, including third-party and NIPSCO subject matter experts
Indiana Office of Utility Consumer Counselor (OUCC)	9/15	• Topics included IRP recap, supply demand picture, reliability criteria approach

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

3

New resource option parameters

DSM Study

RFP Information

Retirement options and replacement themes (informed by scenarios)

Portfolio Optimization

NIPSCO Portfolios

2

Scenario Narrative Development

Integrated gas, coal, carbon forecasts and **MISO market outlook / prices**

Market Modeling Tools (NGF, GPCM, Aurora)

Stochastic Modeling Tools

4

Aurora – **NIPSCO Portfolio** Market Model

Production Cost Dispatch (hourly, chronological)

PERFORM

Detailed cost of service and revenue requirements

Scorecard

(2018 Example)

Other analysis

RESOURCE PLANNING ACTIVITY REVIEW

Fred Gomos, Director Strategy & Risk Integration, NiSource
Pat Augustine, Vice President, CRA

1 IDENTIFY KEY PLANNING QUESTIONS AND THEMES

- The ongoing fleet transition in MISO makes it critical for NIPSCO's IRP to capture several changing dynamics to allow NIPSCO to remain flexible
- Over the course of the IRP, NIPSCO has discussed or will be discussing these topics:

Topic		Stakeholder Meeting
Retirement Timing for Existing Coal and Gas Units	Assessing the retirement timing of the remaining generating fleet after the Schahfer coal units retire, which includes Michigan City Unit 12, Schahfer Units 16A and 16B, and Sugar Creek	Meeting 4
Flexibility & Adaptability of The Portfolio	Incorporating evolving capacity credit expectations for resources and an imminent seasonal resource adequacy requirement	Meetings 1-3
Long-Term Reliability Implications	Understanding system reliability implications of a portfolio that will have significant intermittent resources, in light of the MISO market evolution and NIPSCO's operational responsibilities	Meeting 2, 3
Carbon Emissions & Regulation/Incentives	Assessing diverse portfolio options in the context of increased policy conversations that push for 100% decarbonization of the power sector by the middle of the next decade	Meeting 2

1 IDENTIFY KEY PLANNING QUESTIONS AND THEMES

As in the 2018 IRP, multiple objectives and indicators are summarized across portfolios in an integrated scorecard framework against which to test portfolios and evaluate the major planning questions

Objective	Indicator
Affordability	Cost to Customer
Rate Stability	Cost Certainty
	Cost Risk
	Lower Cost Opportunity
Environmental Sustainability	Carbon Emissions
Reliable, Flexible, and Resilient Supply	Reliability
	Resource Optionality
Positive Social & Economic Impacts	Employees
	Local Economy

- The scorecard is a means of reporting key metrics for different portfolio options to transparently review tradeoffs and relative performance; it does not produce a single score or ranking of portfolios, but serves as a tool to facilitate decision-making
- NIPSCO has identified **5 major planning objectives** and multiple metrics within **9 key indicator categories**
- The Existing Fleet Analysis scorecard focuses on scenario costs, carbon emissions, and impact on NIPSCO employees and the local economy
- The Replacement Analysis scorecard incorporates broader perspectives on risk (stochastic analysis) and reliability than the Existing Fleet Analysis scorecard

2 DEVELOP MARKET PERSPECTIVES (REF CASE, SCENARIOS / STOCHASTIC INPUTS)

- 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

2 DEVELOP MARKET PERSPECTIVES (REF CASE, SCENARIOS / STOCHASTIC INPUTS)

- NIPSCO has developed four integrated market scenarios or “future states of the world”
  - Scenarios incorporate a range of future outcomes for load, commodity prices, technology, and policy
  - The 2021 IRP includes two distinct policy frameworks for achieving net-zero emission trajectories for the broader power market
- Stochastic inputs have been developed for key components of quantifiable stochastic risk
  - For the 2021 IRP, the stochastic analysis has been expanded to include hourly renewable availability in addition to commodity price volatility

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”)

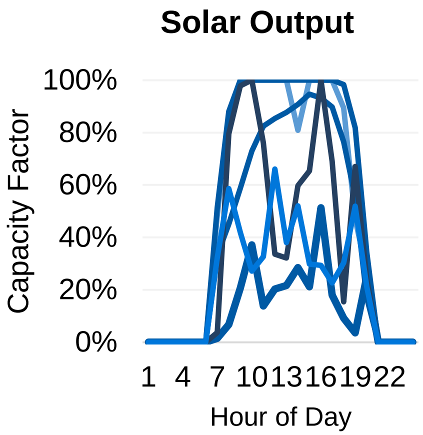
- Binding federal limits on carbon emissions are not implemented; natural gas prices remain low and result in new gas additions remaining competitive versus renewables, as coal capacity more gradually fades from the MISO market

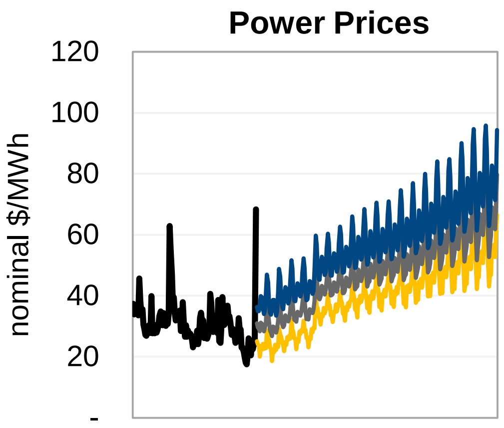
Aggressive Environmental Regulation (“AER”)

- 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.)



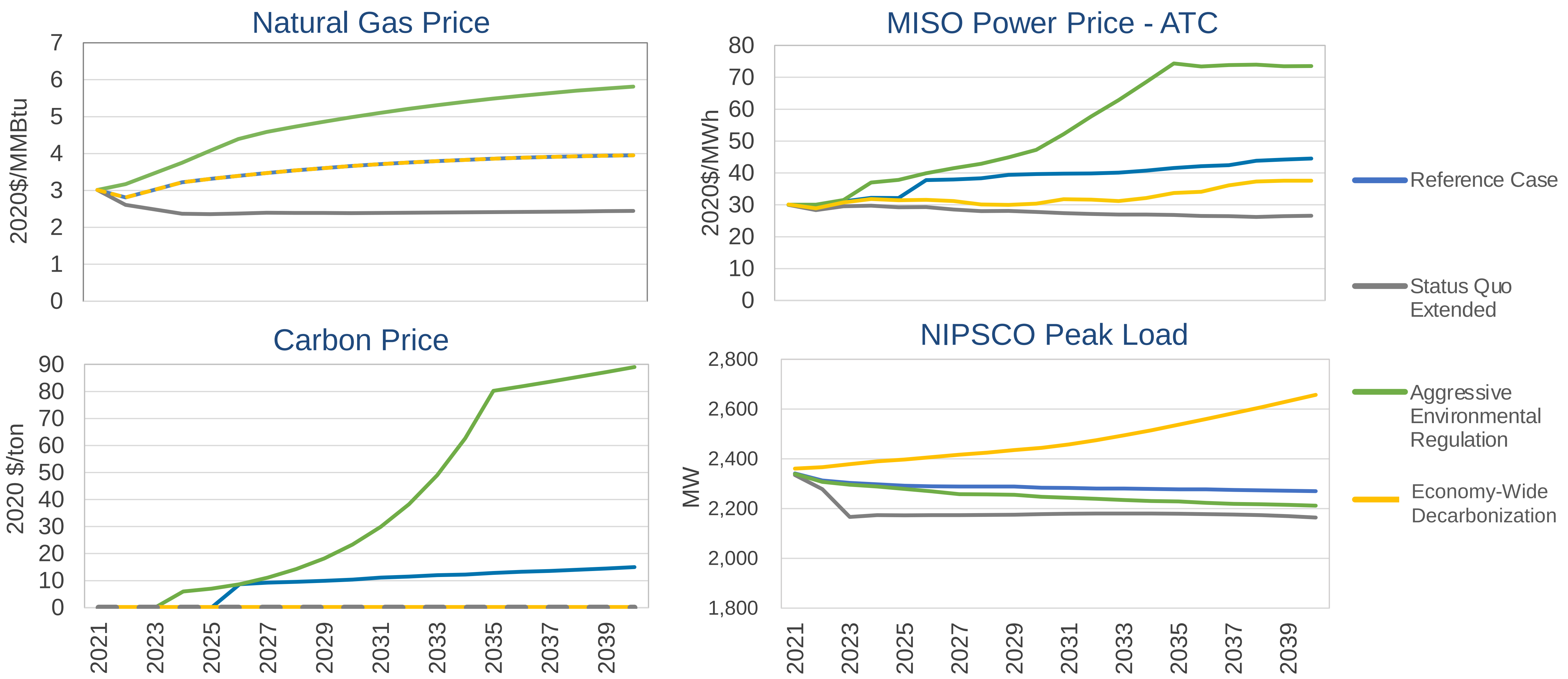


2 MAJOR SCENARIO PARAMETERS

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%

*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)

2 SUMMARY RANGE OF KEY SCENARIO VARIABLES



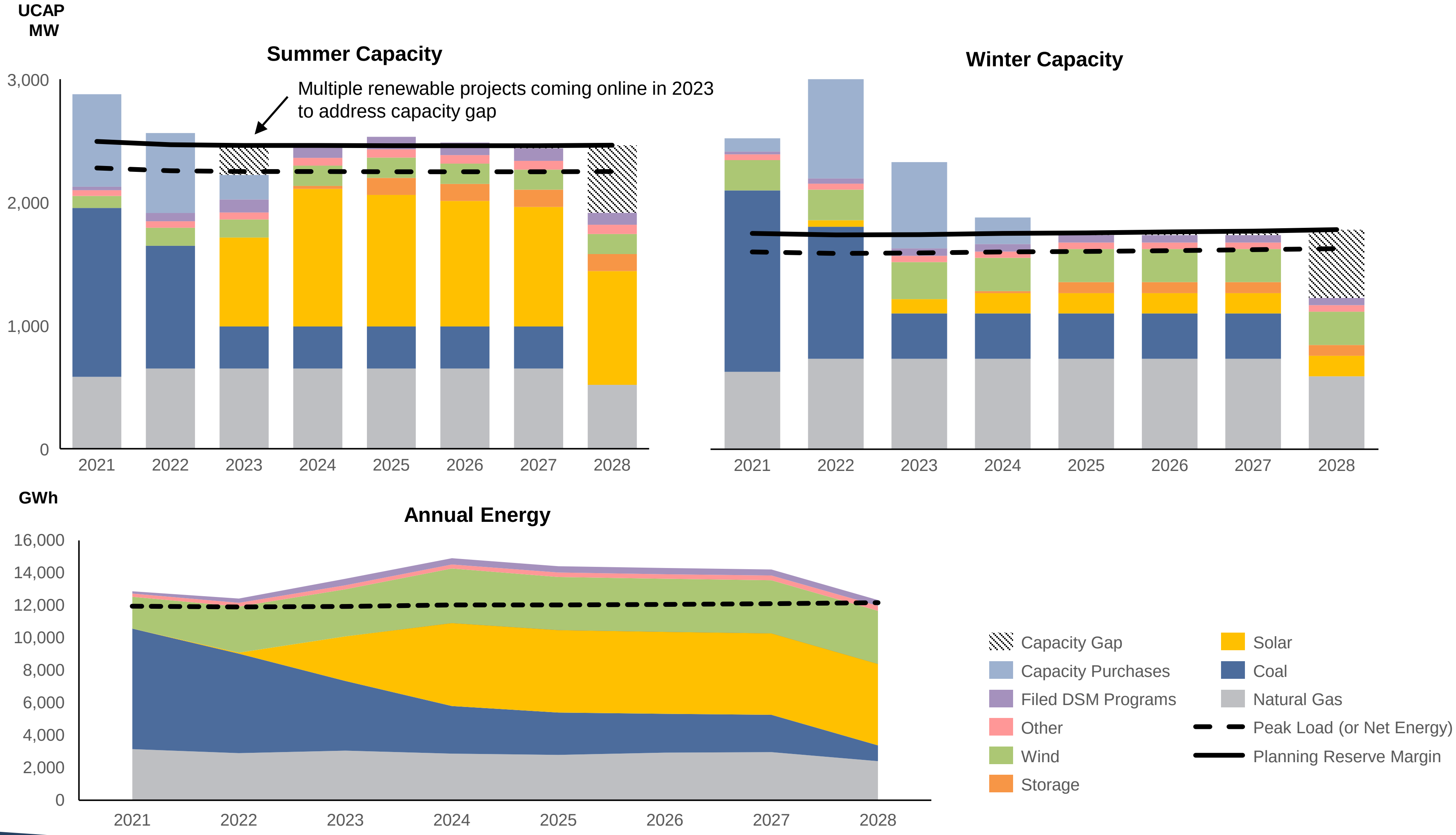
3 DEVELOP INTEGRATED RESOURCE STRATEGIES FOR NIPSCO

- NIPSCO has identified several future resource options (**reviewed in Stakeholder Meeting #3**):
  - Demand Side Management resources (Energy Efficiency and Demand Response)
  - Distributed Energy Resources (DERs)
  - Resources from the Request for Proposal (RFP) process

- Based on NIPSCO's starting capacity and energy position, the IRP analysis constructs a range of portfolio options (**to be reviewed in detail today**) that will:
  - Assess different Existing Fleet retirement timing options
  - Evaluate different Replacement portfolio themes

3 STARTING NEAR-TERM CAPACITY AND ENERGY BALANCE

NIPSCO is now monitoring summer and winter reserve margins plus the annual energy balance

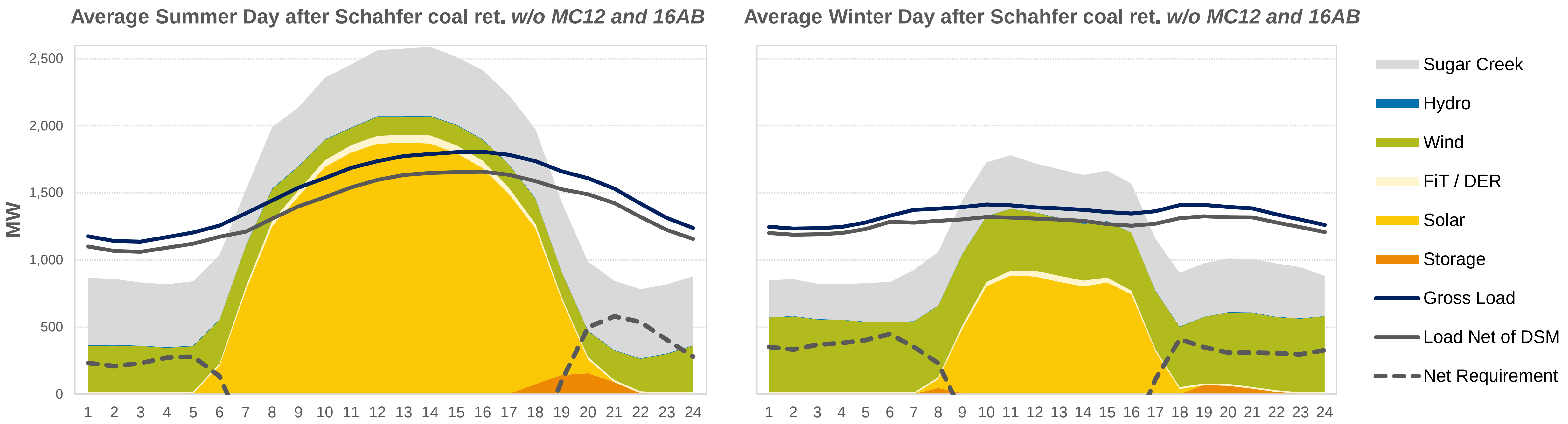


Key Points

- The capacity credit for some of the 2023 projects are not reflected until 2024 due to in service date timing;
- Capacity credit for some storage resources is not reflected until 2025 (after a full year of operations) due to plant configuration
- While winter loads are lower, the lower capacity credit in the winter for solar resources results in a similar reserve margin
- On an annual basis, the net energy position for the portfolio is long, driven by the energy value and economic dispatch advantage of wind and solar resources. However, the tight capacity position may create hourly gaps, particularly in the winter mornings and evenings when solar resources ramp down (next slide)

3 STARTING ENERGY BALANCE VARIES ON AN HOURLY BASIS

- There are hours of the day where renewable resources are not available (ex: overnight for solar). Furthermore, solar resources may experience steep production declines in the evening hours
- Currently, Sugar Creek (natural gas CC), Schahfer 16AB (natural gas peaker), and Michigan City 12 (coal) are part of the portfolio, and when economic, NIPSCO can purchase from the MISO market
- As 16AB and MC12 retire, the portfolio will require new resources to be available to mitigate against specific hourly energy exposure



LUNCH

EXISTING FLEET ANALYSIS

Fred Gomos, Director Strategy & Risk Integration, NiSource
Pat Augustine, Vice President, CRA

ANALYTICAL FRAMEWORK REMINDER

- The IRP analysis is performed in two phases; the first phase examines current and future resource additions to confirm timing of retirement for existing units with retirement dates falling within the IRP horizon
- Insight and conclusions from existing fleet analysis inform replacement concepts to evaluate. Once a preferred existing portfolio is established, future replacements are evaluated across a range of objectives

	Existing Fleet Analysis	Replacement Analysis
Core Questions	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?* *Is the portfolio flexible and adaptable to address changes in market rules and energy policy?*	*What are the replacement resource portfolio options?* *How do different replacement themes compare with regard to cost, risk, environmental sustainability, and reliability?*
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

CONSTRUCTED RETIREMENT PORTFOLIOS TO COVER THE RANGE OF TIMING POSSIBILITIES FOR REMAINING FOSSIL UNITS

	1	2	3	4	5	6	7	7H
Portfolio Transition Target:	**15% Coal through 2032** MC 12 Through Book life	**15% Coal through 2028** 2018 IRP Preferred Plan	**15% Coal through 2026** Early Retirement of MC 12	**15% Coal through 2024** Early Retirement of MC 12	**15% Coal through 2028** 2018 IRP Preferred Plan + 2025 16AB retirement	**15% Coal through 2026** Early Retirement of MC 12 + 2025 16AB retirement	**15% Coal through 2028 Fossil Free by 2032** 2018 IRP Preferred Plan + 2025 16AB ret. + 2032 SC ret.	**15% Coal through 2028 Option for Fossil Free by 2032** 2018 IRP Preferred Plan + 2025 16AB ret. + 2032 SC conv.
Retain beyond 2032	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Michigan City 12	**Retire** **2032**	**Retire** **2028**	**Retire** **2026**	**Retire** **2024**	**Retire** **2028**	**Retire** **2026**	**Retire** **2028**	
Schahfer 16AB	**Retire** **2028**				**Retire** **2025**			
Sugar Creek	**Retain**						**Retire** **2032**	**Convert to H2** **2032**

Short term (Portfolios 1–6)

Longer term (Portfolios 7 and 7H)

Not a viable pathway due to implementation timing

Key Points

- Portfolio construction is necessarily broad to fully address tradeoffs
- Portfolios 1-4 focus on the timing of the Michigan City retirement
- Portfolios 5 and 6 focus on the replacement timing for Schahfer 16AB. Units are not retained beyond 2028 in any portfolio given current condition and age
- Portfolio 7 and 7H are assessing implications of carbon free portfolio pathways

EXISTING FLEET ANALYSIS SELECTIONS ARE DRIVEN BY ECONOMIC OPTIMIZATION

Resource options include RFP tranches, DSM bundles, DER options, and an opportunity to uprate capacity at Sugar Creek

- Driven by a binding winter reserve margin and the energy resources already obtained from the 2018 IRP Preferred Plan, the indicative ordering of model selection preference favors resources that offer greater levels of firm capacity
- This is not NIPSCO's replacement resource selection or plan, but an optimized set of additions to facilitate evaluation of the various existing fleet strategies

COST-EFFECTIVENESS: More → Less

Portfolio 1 — MC12 Through Book Life

Technology	ICAP MW	Year
NIPSCO DER	10	2026
Sugar Creek Uprate	53	2027
DSM*	68	2027*
Thermal Contract	50	2024
Thermal Contract	100	2026
Gas Peaker	300	2032
Storage	135	2027
Total	**693**	

Portfolios 2 | 3 | 4 — 2018 IRP (MC 2028) | MC 2026 | MC 2028

Technology	ICAP MW	Year P2	Year P3	Year P4
NIPSCO DER	10	2026	2026	2026
Sugar Creek Uprate	53	2027	2027	2027
DSM*	68	2027*	2027*	2027*
Thermal Contract	50	2024	2024	2024
Thermal Contract	100	2026	2026	2026
Gas Peaker	300	2028	2026	2024
Storage	135	2027	2027	2025
Solar	100 / 200^	2026	2026	2026
Total	**793 / 893^**			

^ P2/3 have 100 MW of solar; P4 has 200 MW

Portfolios 5 | 6 — Portfolio 2 w/ 16AB 2025 | Portfolio 3 w/ 16AB 2025

Technology	ICAP MW	Year P5	Year P6
NIPSCO DER	10	2026	2026
Sugar Creek Uprate	53	2027	2027
DSM*	68	2027*	2027*
Thermal Contract	50	2024	2024
Thermal Contract	100	2026	2026
Gas Peaker	300	2028	2026
Storage	135	2025	2025
Solar	100	2026	2026
Wind	200	N/A	2026
Total	**993**		

Portfolio 7 — Fossil Free By 2032

Technology	ICAP MW	Year
NIPSCO DER	10	2026
DSM*	68	2027*
Storage	235	2025
Storage	100	2026
Storage	235	2027
Solar	250	2026
Wind	200	2026
Total	**1,020**	

Portfolio 7H — Fossil Free Option by 2032 w/ SC Conversion (incl. capital costs)

Technology	ICAP MW	Year
NIPSCO DER	10	2026
Sugar Creek Uprate	53	2027
DSM*	68	2027*
Storage	235	2025
Storage	135	2027
Solar	250	2026
Wind	200	2026
Hydrogen-Enabled Gas Peaker	193	2025
SC Electrolyzer Pilot	20	2026
Total	**1,131**	

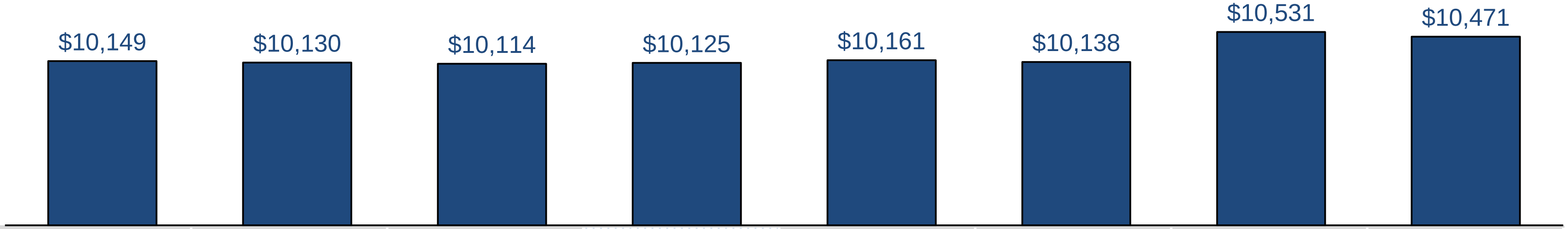
*DSM includes the cumulative impact of both Residential and Commercial programs by 2027, with Commercial being most cost effective. DSM is reported on a summer peak basis. Note that the winter impact is ~46MW.

Notes: Portfolios were optimized against winter reserve margin constraints (9.4%), followed by summer to ensure compliance with both.
A maximum net energy sales limit of 30% during the fleet transition (2023-2026), falling to 25% in 2030+, was also enforced.
Wind outside LRZ6 was not included in optimization analysis, given lack of capacity deliverability to LRZ6 and significant congestion risk.

EXISTING FLEET ANALYSIS: DETERMINISTIC COST TO CUSTOMERS RESULTS

Net Present Value of Revenue Requirement

(2021-2050, $M)



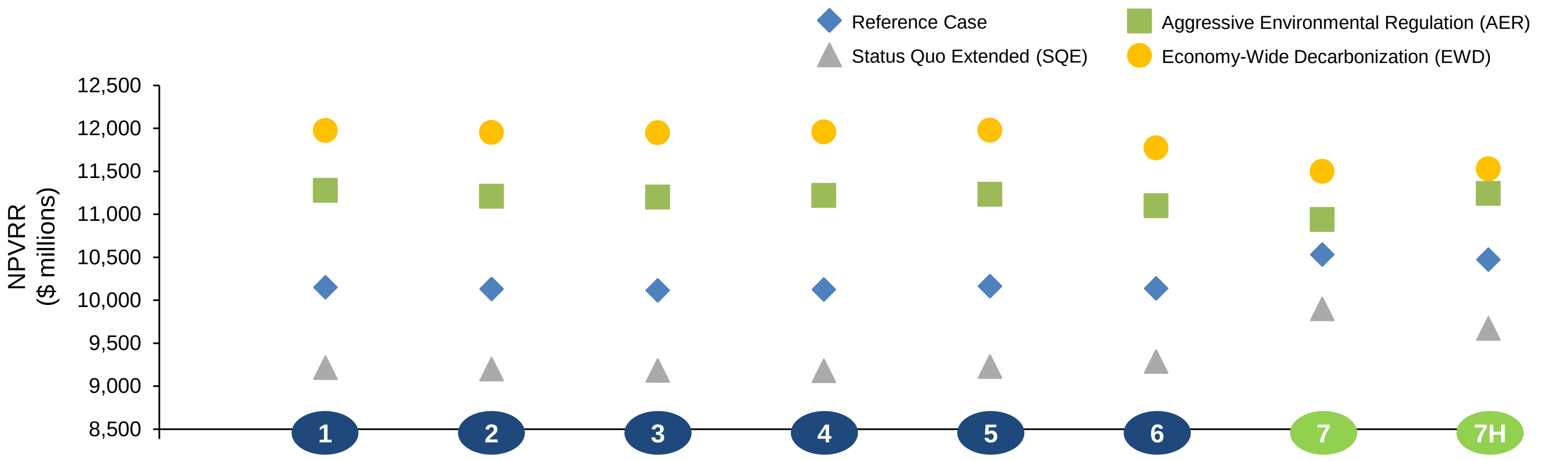
Portfolio Transition Target:	15% Coal through 2032 (1)	15% Coal through 2028 (2)	15% Coal through 2026 (3)	15% Coal through 2024 (4)	15% Coal through 2028 (5)	15% Coal through 2026 (6)	15% Coal through 2028 Fossil Free by 2032 (7)	15% Coal through 2028 Option for Fossil Free by 2032 (7H)
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Rank (1=Least Cost)	5	3	1	2	6	4	8	7
Delta from Least Cost	$35M 0.3%	$16M 0.2%	-	$10M 0.1%	$47M 0.5%	$24M 0.2%	$417M 4.1%	$357M 3.5%

Not a viable pathway due to implementation timing

Observations

- The difference in NPVRR from the highest cost to lowest cost portfolio is approximately $430 million
- Consistent with NIPSCO's prior IRP findings, early retirement of coal is generally cost effective for customers, although the difference in cost across several portfolios is small, since much of the remaining portfolio is fixed and small changes in retirement dates are now being assessed
- Retaining Units 16A/B until 2028 may be cost effective, given the portfolio's capacity needs. However, this is contingent on the operational condition of these older vintage units, and the cost impacts of earlier retirement are well less than 1% in NPVRR

EXISTING FLEET ANALYSIS: SCENARIO RESULTS



	Portfolio Transition Target:	15% Coal through 2032	15% Coal through 2028	15% Coal through 2026	15% Coal through 2024	15% Coal through 2028	15% Coal through 2026	15% Coal through 2028 Fossil Free by 2032	15% Coal through 2028; Option for Fossil Free by 2032
	Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
	Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Reference Case	**Delta from Lowest Cost to Customer**	$35 0.3%	$16 0.2%	- -	$10 0.1%	$47 0.5%	$24 0.2%	$417 4.1%	$357 3.5%
Status Quo Extended	**Delta from Lowest Cost to Customer**	$36 0.4%	$18 0.2%	$2 0.0%	- -	$49 0.5%	$108 1.2%	$720 7.8%	$492 5.4%
Aggressive Env. Reg.	**Delta from Lowest Cost to Customer**	$336 3.1%	$269 2.5%	$259 2.4%	$277 2.5%	$292 2.7%	$157 1.4%	- -	$303 2.8%
Econ-Wide Decarbonization	**Delta from Lowest Cost to Customer**	$477 4.1%	$454 3.9%	$449 3.9%	$459 4.0%	$478 4.2%	$276 2.4%	- -	$29 0.3%

Not a viable pathway due to implementation timing

*Note that a $0.50/kg H2 subsidy is assumed in AER and EWD

Observations

- MC12 retirement in 2026 has a small cost benefit (<$20M) relative to retirement in 2028 across all scenarios
- MC 12 retirement in 2032 is always higher cost than earlier retirement, with the largest difference in the AER scenario (high carbon price)
- Portfolio 2 is slightly lower cost than Portfolio 5, although additional renewable additions with early 16AB retirement (Portfolio 6) lower costs under high carbon regulation scenarios
- Portfolios 7 and 7H have the smallest range, as their future renewable, hydrogen, and storage investments hedge against high-cost power market outcomes

EXISTING FLEET ANALYSIS SCORECARD

Objective	Indicator	Description and Metrics
Affordability	**Cost to Customer**	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	**Cost Certainty**	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: Highest scenario NPVRR
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: Lowest scenario NPVRR
Environmental Sustainability	**Carbon Emissions**	• Carbon intensity of portfolio • Metric: Cumulative carbon emissions (2024-40 short tons of CO_2) from the generation portfolio
Reliable, Flexible, and Resilient Supply	**Reliability**	• *To be addressed in Replacement Analysis stage*
	Resource Optionality	
Positive Social & Economic Impacts	**Employees**	• Net impact on NiSource jobs • Metric: Approx. number of permanent NiSource jobs associated with generation
	Local Economy	• Net effect on the local economy (relative to 2018 IRP) from new projects and ongoing property taxes • Metric: NPV of existing fleet property tax relative to 2018 IRP

Additional risk metrics will be included in the Replacement Analysis, when broader set of resource types are evaluated

Key Points

- Two closely related, but distinct scorecards are used for the Existing Fleet Analysis and the Replacement Analysis
- The Existing Fleet Analysis focuses on scenario costs, carbon emissions, and impact on NIPSCO employees and the local economy
- The Replacement Analysis expands the risk assessment to include a stochastic assessment and introduces reliability metrics to assess a broader range of future resource options

EXISTING FLEET ANALYSIS SCORECARD

Preliminary	1	2	3	4	5	6	7	7H
Portfolio Transition Target:	15% Coal through 2032	15% Coal through 2028	15% Coal through 2026	15% Coal through 2024	15% Coal through 2028	15% Coal through 2026	15% Coal through 2028 Fossil Free by 2032	15% Coal through 2028 Fossil Free by 2032
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Cost To Customer 30-year NPV of revenue requirement (Ref Case)	$10,149 +$35 0.3%	$10,130 +$16 0.2%	$10,114 - -	$10,125 $10 0.1%	$10,161 +$47 0.5%	$10,138 +$24 0.2%	$10,531 +$417 4.1%	$10,471 +$357 3.5%
Cost Certainty Scenario Range (NPVRR)	$2,759 +$1,161 72.6%	$2,754 +$1,156 72.3%	$2,766 +$1,167 73.0%	$2,777 +$1,179 73.8%	$2,747 +$1,149 71.9%	$2,487 +$889 55.6%	$1,598 - -	$1,855 +$257 16.1%
Cost Risk Highest Scenario NPVRR	$11,974 +$477 4.1%	$11,951 $454 3.9%	$11,947 +$449 3.9%	$11,957 +$459 4.0%	$11,976 +$478 4.2%	$11,773 +$276 2.4%	$11,498 - -	$11,527 +$29 0.3%
Lower Cost Opportunity Lowest Scenario NPVRR	$9,215 +$36 0.4%	$9,197 +$18 0.2%	$9,181 +$2 0.0%	$9,179 - -	$9,229 +$49 0.5%	$9,287 +$108 1.2%	$9,899 +$720 7.8%	$9,671 +$492 5.3%
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)	43.3 +22 102%	33.7 +12 57%	28.5 +7 33%	23.0 +2 8%	33.7 +12 57%	28.5 +7 33%	21.4 - -	30.9 +9 44%
Employees Approx. existing gen. jobs compared to 2018 IRP*	+127	0	-127	-127	-4	-131	-34	-4
Local Economy NPV of existing fleet property tax relative to 2018 IRP	+$13	$0	-$10	-$23	$0	-$10	-$16	+$13

Not a viable pathway due to implementation timing

*Adding replacement projects could have an impact on net jobs

PORTFOLIO-LEVEL OBSERVATIONS

- Retaining Michigan City 12 beyond the currently planned retirement date of 2028 (**Portfolio 1**) is higher cost than the alternatives across all four scenarios
- Retirement of Michigan City 12 in 2024 (**Portfolio 4**) is higher cost than later retirement in three out of the four scenarios and is not a viable pathway given insufficient timing to secure replacement capacity
- Retirement of Michigan City 12 in 2026 (**Portfolio 3**) has the lowest Cost to Customer under the Reference Case and in three out of four scenarios and achieves the most significant CO_2 reductions of the viable portfolios testing coal retirement
- Retirement of Michigan City in 2028 (**Portfolio 2**) is very close to Portfolio 3 on all cost metrics, while also preserving some NIPSCO jobs and local property tax benefits for two additional years
- Acceleration of the Schahfer 16A/B retirement to 2025 (**Portfolios 5 and 6**) is slightly higher cost than retaining the units until 2028, but early retirement could be influenced by unit operational condition and other external policy and technology factors, since additional renewable energy replacement (**Portfolios 6**) provides lower costs under scenarios with significant carbon regulation (AER and EWD)
- A retirement of Sugar Creek in the 2030s (**Portfolio 7**) offers the lowest carbon emission profile and, along with potential retrofit to reduce CO_2 emissions (**Portfolio 7H**), provides a hedge against significant environmental regulations that would otherwise raise portfolio costs

OVERARCHING EXISTING FLEET ANALYSIS OBSERVATIONS

- Portfolios 2 (2028 MC12 retirement) and 3 (2026 MC12 retirement) tend to be lowest cost amongst viable portfolios testing Michigan City and Schahfer 16AB retirement dates
  - Preserving optionality for the MC12 retirement date will allow NIPSCO to perform full due diligence on RFP projects to confirm timing and costs, monitor ongoing market design and environmental policy changes, and react to technology evolution
  - Schahfer 16AB may provide relatively low-cost capacity through 2028, but NIPSCO is likely to be flexible with retirement timing based on MC12 retirement plans and 16A/B operational conditions and to efficiently pursue replacement opportunities that may cost-effectively cover capacity needs for all retiring resources as technology and policy evolves

- Portfolios 7 and 7H are higher cost under currently expected conditions, but retirement or conversion of Sugar Creek in the 2030s, with additional early renewable additions, would be lower cost than continuing to operate the unit fully on natural gas in the event of a high carbon price or other aggressive clean energy policies
  - NIPSCO can keep such options open regardless of retirement date for Michigan City
  - These portfolio concepts remain part of the Replacement Analysis phase for broader study

BREAK

REPLACEMENT ANALYSIS

Fred Gomos, Director Strategy & Risk Integration, NiSource
Pat Augustine, Vice President, CRA

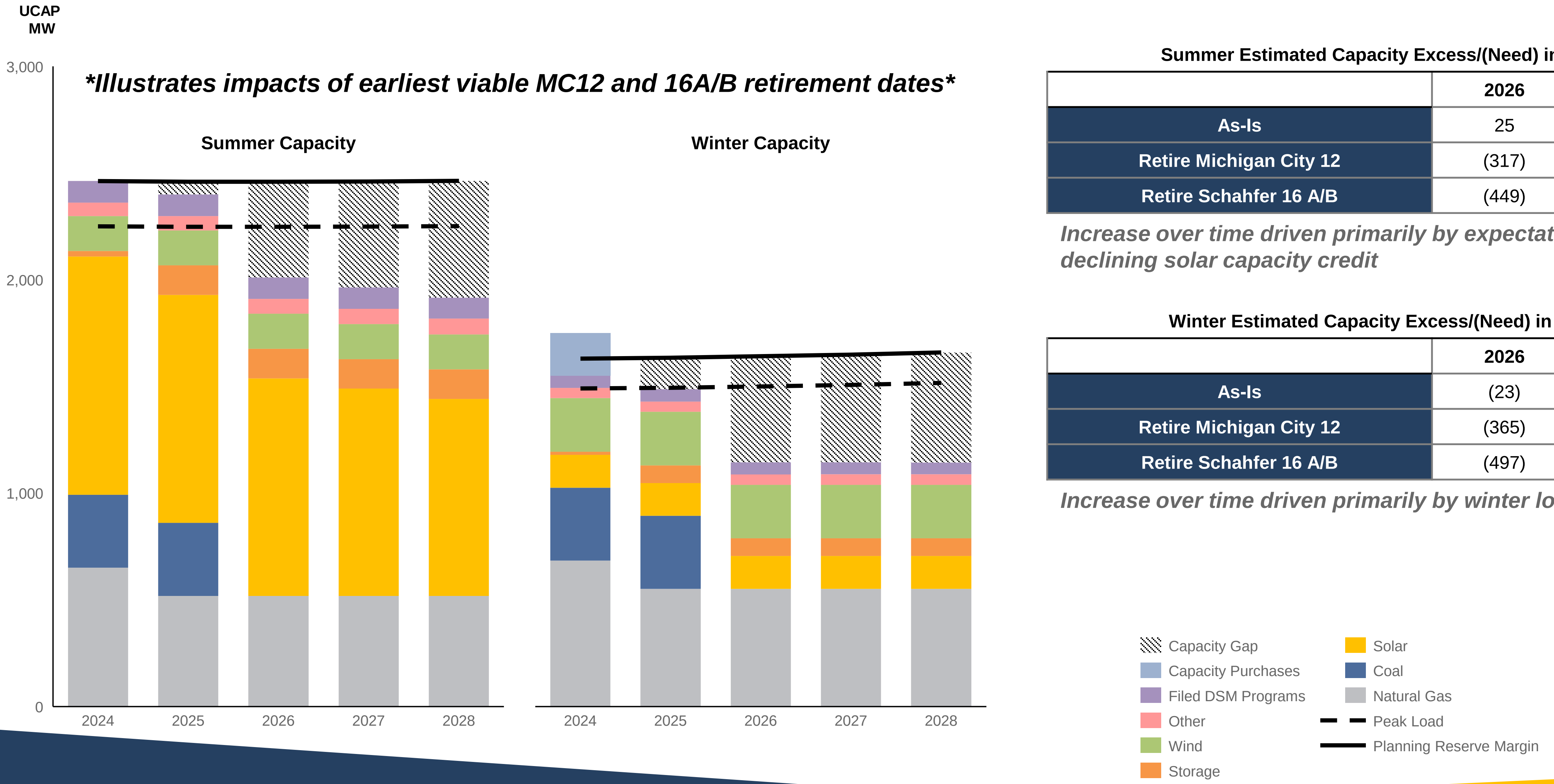
ANALYTICAL FRAMEWORK REMINDER

- The IRP analysis is performed in two phases; the first phase examines current and future resource additions to confirm timing of retirement for existing units with retirement dates falling within the IRP horizon
- Insight and conclusions from existing fleet analysis inform replacement concepts to evaluate. Once a preferred exiting portfolio is established, future replacements are evaluated across a range of objectives

	Existing Fleet Analysis	Replacement Analysis
Core Questions	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?* *Is the portfolio flexible and adaptable to address changes in market rules and energy policy?*	*What are the replacement resource portfolio options?* *How do different replacement themes compare with regard to cost, risk, environmental sustainability, and reliability?*
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

A CAPACITY GAP OPENS UPON RESOURCE RETIREMENTS

Uncertainty in the capacity gap is driven by future load growth, MISO planning reserve margin targets, and realized renewable resource capacity credit



Summer Estimated Capacity Excess/(Need) in MWs

	2026	2028
As-Is	25	(73)
Retire Michigan City 12	(317)	(415)
Retire Schahfer 16 A/B	(449)	(547)

Increase over time driven primarily by expectations for declining solar capacity credit

Winter Estimated Capacity Excess/(Need) in MWs

	2026	2028
As-Is	(23)	(41)
Retire Michigan City 12	(365)	(383)
Retire Schahfer 16 A/B	(497)	(515)

Increase over time driven primarily by winter load growth

REPLACEMENT ANALYSIS PORTFOLIOS HAVE BEEN DEVELOPED ACROSS NINE CONCEPTS

The concepts are informed by the IRP themes, findings from Existing Fleet Analysis, and additional optimization testing

- For the Replacement Analysis, **Portfolio 3** from the Existing Fleet analysis has been used to assess portfolio selection under the earliest possible retirement of MC12, noting that Portfolio 2 would have similar results, with small changes in resource addition timing. This approach does not imply that NIPSCO has determined a specific MC12 retirement date
- Resource combinations are constructed based on RFP projects (tranches) and other opportunities to explore a range of emissions profiles and dispatchability under current and proposed market rules

Dispatchability

Emissions	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Higher Carbon Emissions	Thermal PPAs, solar and storage **A**	Non-service territory gas peaking (no early storage) **B**	Natural gas dominant (CC) **C**
Mid Carbon Emissions	No new thermal resources; solar dominant w/ storage **D**	Thermal PPAs plus storage and solar **E**	Local gas peaker, plus solar and storage **F**
Low Carbon Emissions	Solar dominant w/ storage, plus retire Sugar Creek **G**	All renewables and storage, plus retire Sugar Creek (Portfolio 7) **H**	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H) **I**

Sugar Creek is retained through modeling horizon

Sugar Creek Retires or converts to H2

Net Zero Concepts

ICAP ADDITIONS– RFP PROJECTS AND OTHER NEAR-TERM OPPORTUNITIES

- Several resource additions are common across all themes, *when allowed*: **R&C DSM programs**, **Thermal PPAs, attractive NIPSCO DER, SC uprate**
- A range of solar, storage, gas, wind, and hydrogen-enabled resources are incorporated across portfolios

ICAP Additions through 2027 Planning Year

Dispatchability

Emissions	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Higher Carbon Emissions	**A** NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 135MW Solar+Storage 450MW* Solar 250MW	**B** NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 443MW Thermal PPA 150MW Solar 250MW	**C** NIPSCO DER 10MW SC Uprate 53MW Gas CC 650MW *Portfolio violates normal net long energy sales constraints enforced in optimization*
Mid Carbon Emissions	**D** NIPSCO DER 10MW SC Uprate 53MW Storage 135MW Solar+Storage 450MW* Solar 400MW	**E** NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 470MW Solar 250MW	**F** NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 300MW Thermal PPA 150MW Storage 135MW Solar 100MW
Low Carbon Emissions	**G** NIPSCO DER 10MW Storage 135MW Solar+Storage 450MW* Solar 450MW	**H** NIPSCO DER 10MW Wind 200MW Storage 570MW Solar 250MW	**I** NIPSCO DER 10MW SC H2 Electrolyzer 20MW SC Uprate 53MW H2 Enabled Peaker 193MW Wind 200MW Storage 370MW Solar 250MW

Sugar Creek is retained through modeling horizon

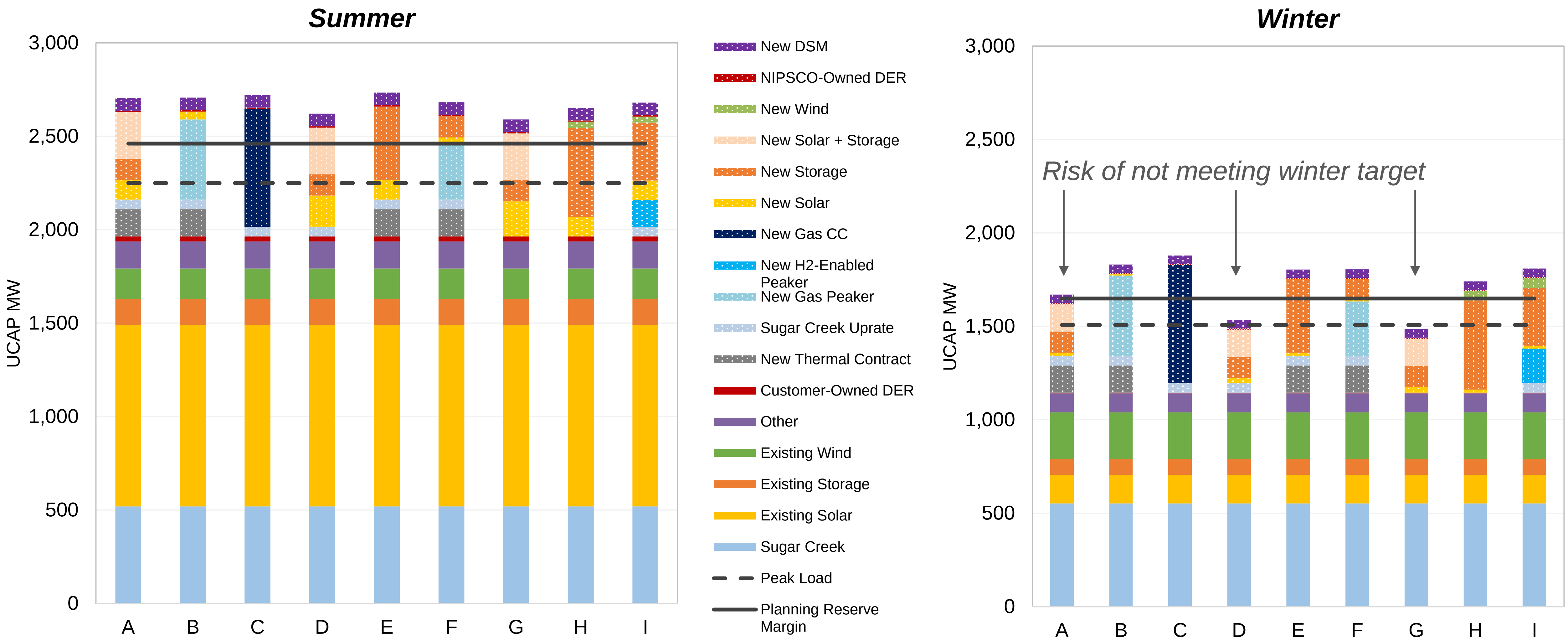
Sugar Creek Retires or converts to H2

Net Zero Concepts

Note: Residential/Commercial DSM universally selected across portfolios
**Represents 300 MW of solar and 150 MW of storage*
***Gas peaker in Portfolio B represents an out-of-service territory PPA; Gas peaker in Portfolio F represents asset sale proposal*

2027 SUPPLY-DEMAND BALANCE WITH NEW RESOURCE ADDITIONS

Assumes Michigan City 12 and Schahfer 16AB are retired for illustration

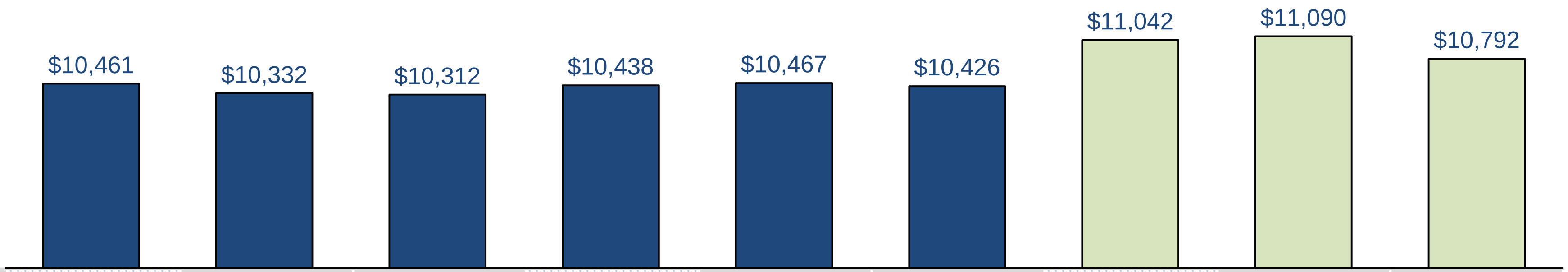


RESULTS: COST TO CUSTOMER REFERENCE CASE

Net Present Value of Revenue Requirement

(2021-2050, $M)

- Sugar Creek continues to operate
- Sugar Creek retires/converts in 2032



Replacement Theme	A: Thermal PPAs, solar and storage	B: Non-service territory gas peaking (no early storage)	C: Natural gas dominant (CC)	D: No new thermal resources; solar dominant w/ storage	E: Thermal PPAs plus storage and solar	F: Local gas peaker, plus solar and storage	G: Solar dominant w/ storage, plus retire Sugar Creek	H: All renewables and storage, plus retire Sugar Creek (Portfolio 7)	I: New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	5	2	1	4	6	3	8	9	7
Delta from Least Cost	$150 1.5%	$21 0.2%	-	$126 1.2%	$156 1.5%	$115 1.1%	$730 7.1%	$778 7.5%	$480 4.7%

Not a viable pathway due to not meeting winter planning reserve margins

Observations

- Portfolios A through F are all within ~$150 million NVPRR
- Portfolios A and D (solar dominant that only meet summer RM) are not tenable options given potential market rule changes
- Portfolio C develops a very net long position and is higher cost than several alternatives over a 20-year period, as economics are driven by long-term “merchant” margins
- Portfolios with significant storage (E in particular) have potential value in ancillary services markets
- Portfolios G, H, and I (net zero concepts) are higher cost, with Portfolio I retaining the optionality to burn natural gas at Sugar Creek under Reference Case conditions

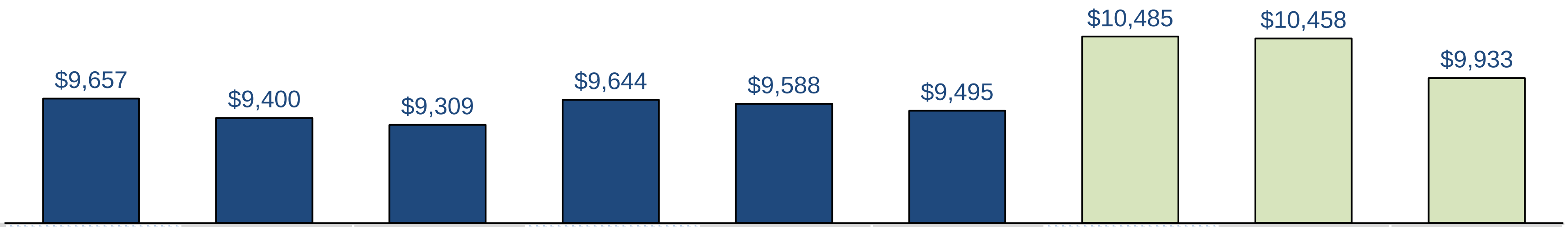
SCENARIO RESULTS: COST TO CUSTOMER STATUS QUO EXTENDED (SQE)

Net Present Value of Revenue Requirement

(2021-2050, $M)

Sugar Creek continues to operate

Sugar Creek retires/converts in 2032



Replacement Theme	A: Thermal PPAs, solar and storage	B: Non-service territory gas peaking (no early storage)	C: Natural gas dominant (CC)	D: No new thermal resources; solar dominant w/ storage	E: Thermal PPAs plus storage and solar	F: Local gas peaker, plus solar and storage	G: Solar dominant w/ storage, plus retire Sugar Creek	H: All renewables and storage, plus retire Sugar Creek (Portfolio 7)	I: New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	6	2	1	5	4	3	9	8	7
Delta from Least Cost	$347 3.7%	$91 1.0%	-	$334 3.6%	$278 3.0%	$186 2.0%	$1,176 12.6%	$1,149 12.3%	$684 7.3%

Not a viable pathway due to not meeting winter planning reserve margins

Observations

- With no carbon regulation and low natural gas prices, portfolios with more gas generation (particularly C) are lower in cost
- The cost of pursuing a net zero strategy in this environment increases, with the spread from the lowest to highest cost portfolios widening to over $1 billion in NPVRR

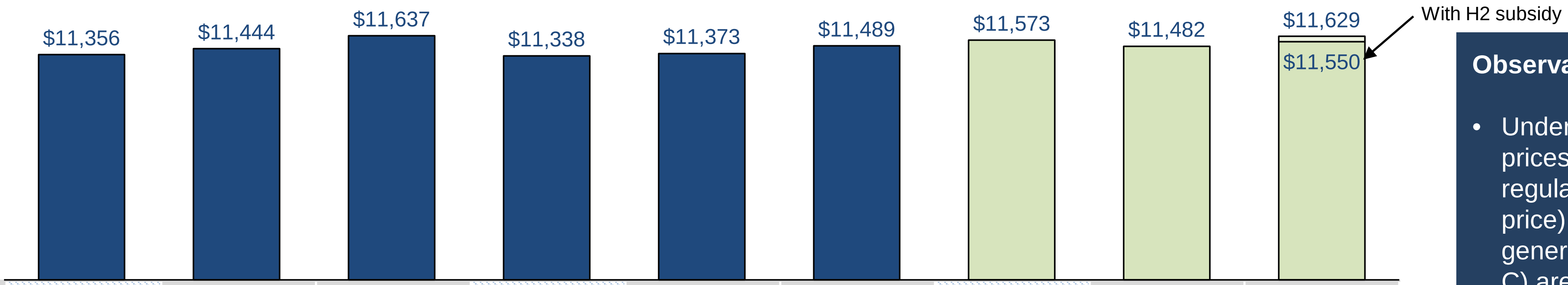
SCENARIO RESULTS: COST TO CUSTOMER AGGRESSIVE ENVIRONMENTAL REGULATION (AER)

Net Present Value of Revenue Requirement

(2021-2050, $M)

Sugar Creek continues to operate

Sugar Creek retires/converts in 2032



	A	B	C	D	E	F	G	H	I
Replacement Theme	**Thermal PPAs, solar and storage**	**Non-service territory gas peaking (no early storage)**	**Natural gas dominant (CC)**	**No new thermal resources; solar dominant w/ storage**	**Thermal PPAs plus storage and solar**	**Local gas peaker, plus solar and storage**	**Solar dominant w/ storage, plus retire Sugar Creek**	**All renewables and storage, plus retire Sugar Creek (Portfolio 7)**	**New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)**
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	2	4	9	1	3	6	8	5	7
Delta from Least Cost	$18 0.2%	$106 0.9%	$299 2.6%	-	$35 0.3%	$151 1.3%	$235 2.1%	$144 1.3%	$212 1.9%

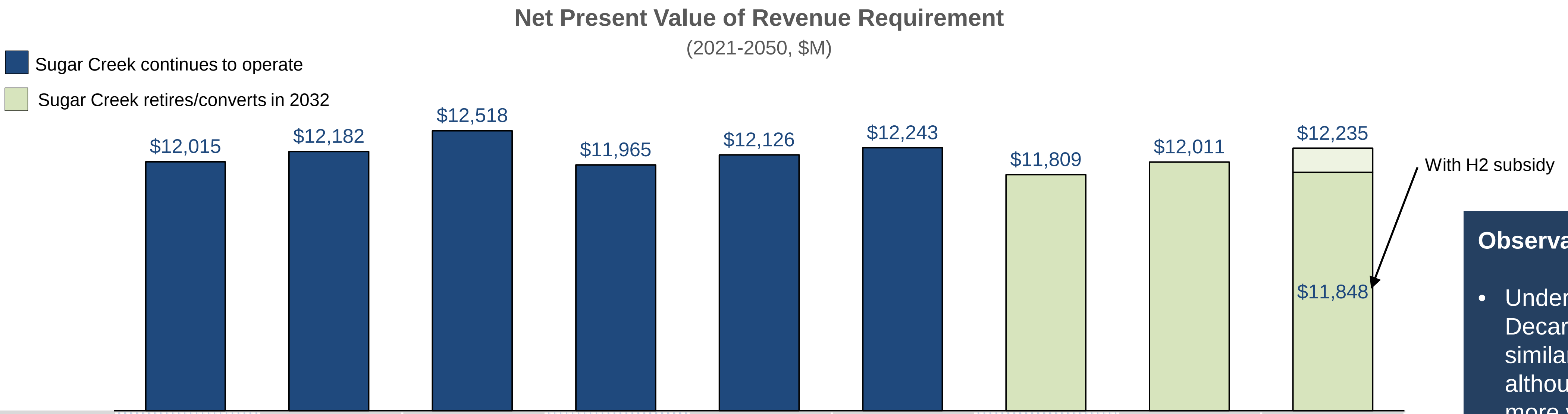
Not a viable pathway due to not meeting winter planning reserve margins

*Note: Rank and Delta from Least Cost utilize 3I **with** the H2 subsidy at $0.50/kg.

Observations

- Under a scenario with rising gas prices and strict environmental regulation (through a carbon price), portfolios with more gas generation (particularly Portfolio C) are higher cost
- Among viable options, Portfolio E (storage and solar, with no new gas capacity additions) is lowest cost

SCENARIO RESULTS: COST TO CUSTOMER ECONOMY-WIDE DECARBONIZATION (EWD)



	A	B	C	D	E	F	G	H	I
Replacement Theme	**Thermal PPAs, solar and storage**	**Non-service territory gas peaking (no early storage)**	**Natural gas dominant (CC)**	**No new thermal resources; solar dominant w/ storage**	**Thermal PPAs plus storage and solar**	**Local gas peaker, plus solar and storage**	**Solar dominant w/ storage, plus retire Sugar Creek**	**All renewables and storage, plus retire Sugar Creek (Portfolio 7)**	**New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)**
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	5	7	9	3	6	8	1	4	2
Delta from Least Cost	$207 1.7%	$373 3.2%	$709 6.0%	$156 1.3%	$317 2.7%	$434 3.7%	-	$202 1.7%	$39 0.3%

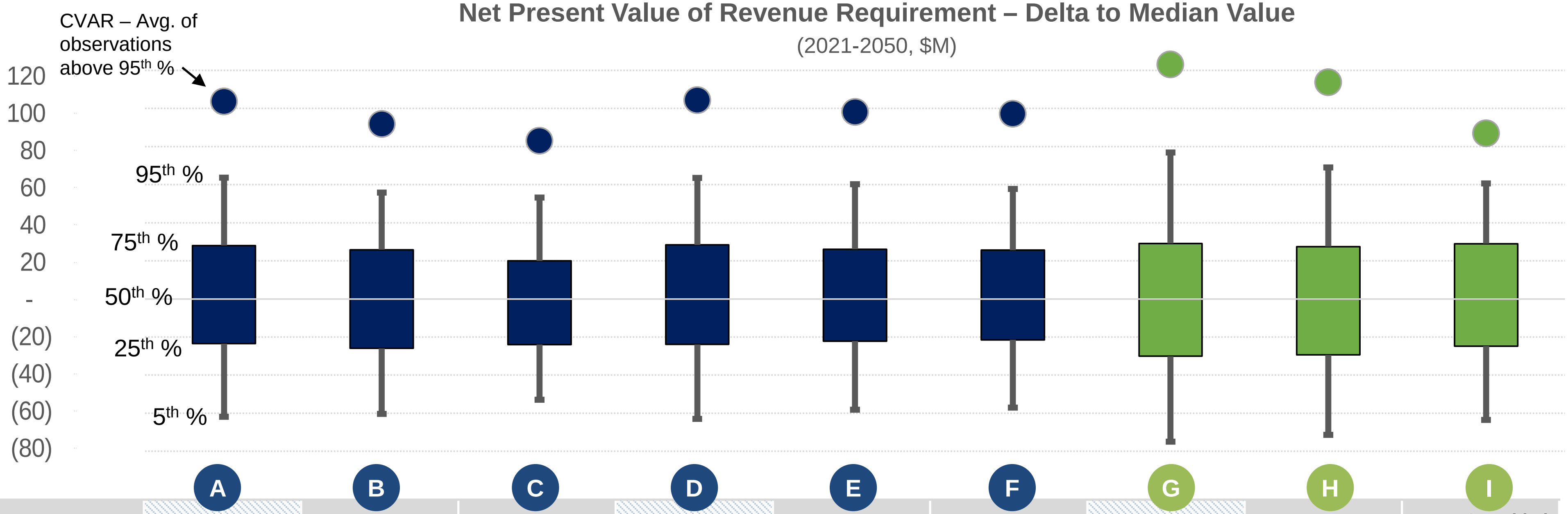
Not a viable pathway due to not meeting winter planning reserve margins

*Note: Rank and Delta from Least Cost utilize 3I **with** the H2 subsidy at $0.50/kg.

Observations

- Under the Economy-Wide Decarbonization scenario, similar trends are evident, although clean energy has more value under the Clean Energy Standard construct, resulting in Portfolio I (assuming a future H2 subsidy) having lowest costs among viable portfolios.

RESULTS: STOCHASTIC ANALYSIS



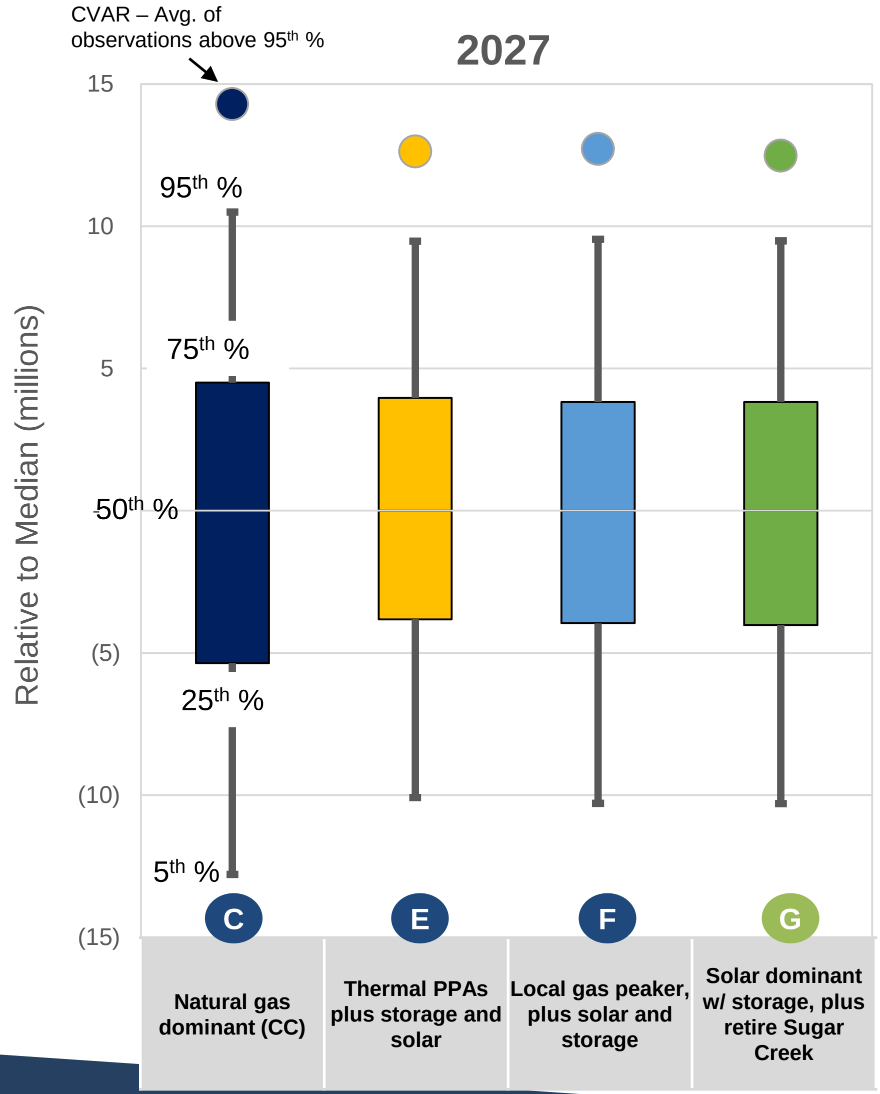
Replacement Theme	Thermal PPAs, solar and storage	Non-service territory gas peaking (no early storage)	Natural gas dominant (CC)	No new thermal resources; solar dominant w/ storage	Thermal PPAs plus storage and solar	Local gas peaker, plus solar and storage	Solar dominant w/ storage, plus retire Sugar Creek	All renewables and storage, plus retire Sugar Creek (Portfolio 7)	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
95th % CVAR Delta from Low	21	9	-	21	15	14	40	31	4
75th % Delta from Low	8	6	-	8	6	6	9	7	9
5th % Delta from Low	13	15	22	12	17	18	-	4	11

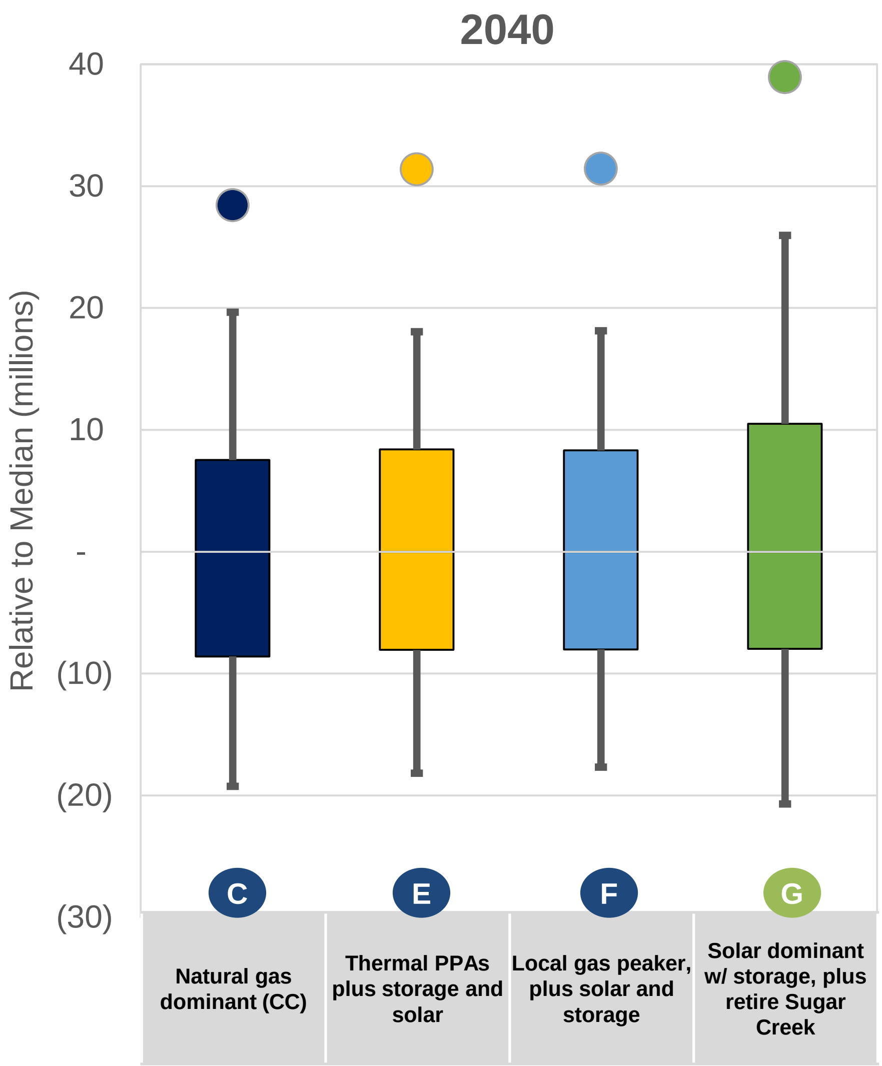
Observations

- The stochastic analysis evaluates short-term volatility in commodity prices (natural gas and power) and hourly renewable (solar and wind) output
- The overall magnitude of cost distributions across portfolios is narrower than the scenario range, suggesting that stochastic risk for these portfolio options is less impactful than the major policy or market shifts evaluated across scenarios
- Over the 30-year time horizon, dispatchability serves to mitigate tail risk, as portfolios that retain SC or add gas (including with hydrogen enablement) or storage capacity perform best at minimizing upside risk
- The lowest downside range is observed in renewable-dominant portfolios

THE RISK PROFILE CHANGES OVER TIME

Sample of Portfolios – 2027 and 2040



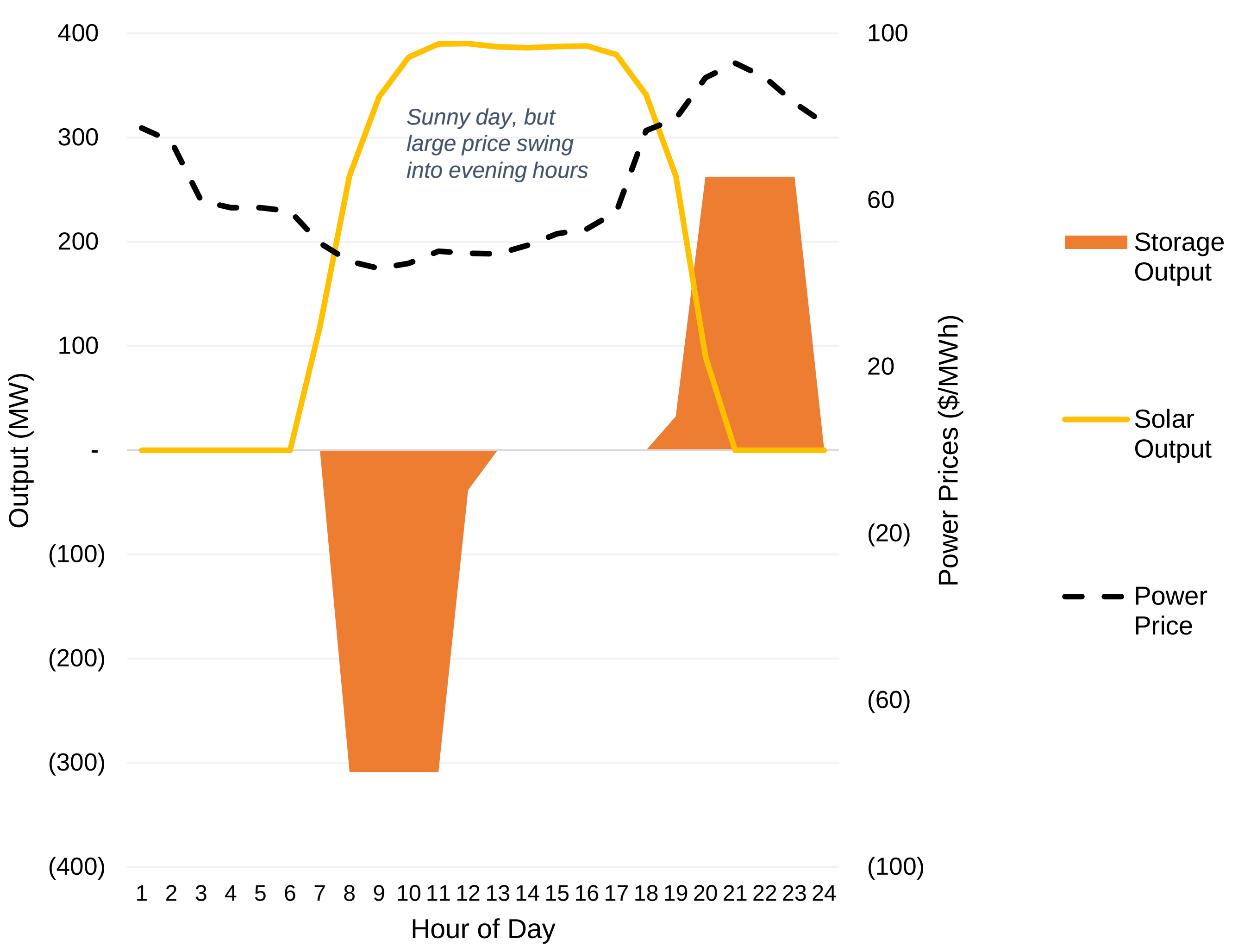


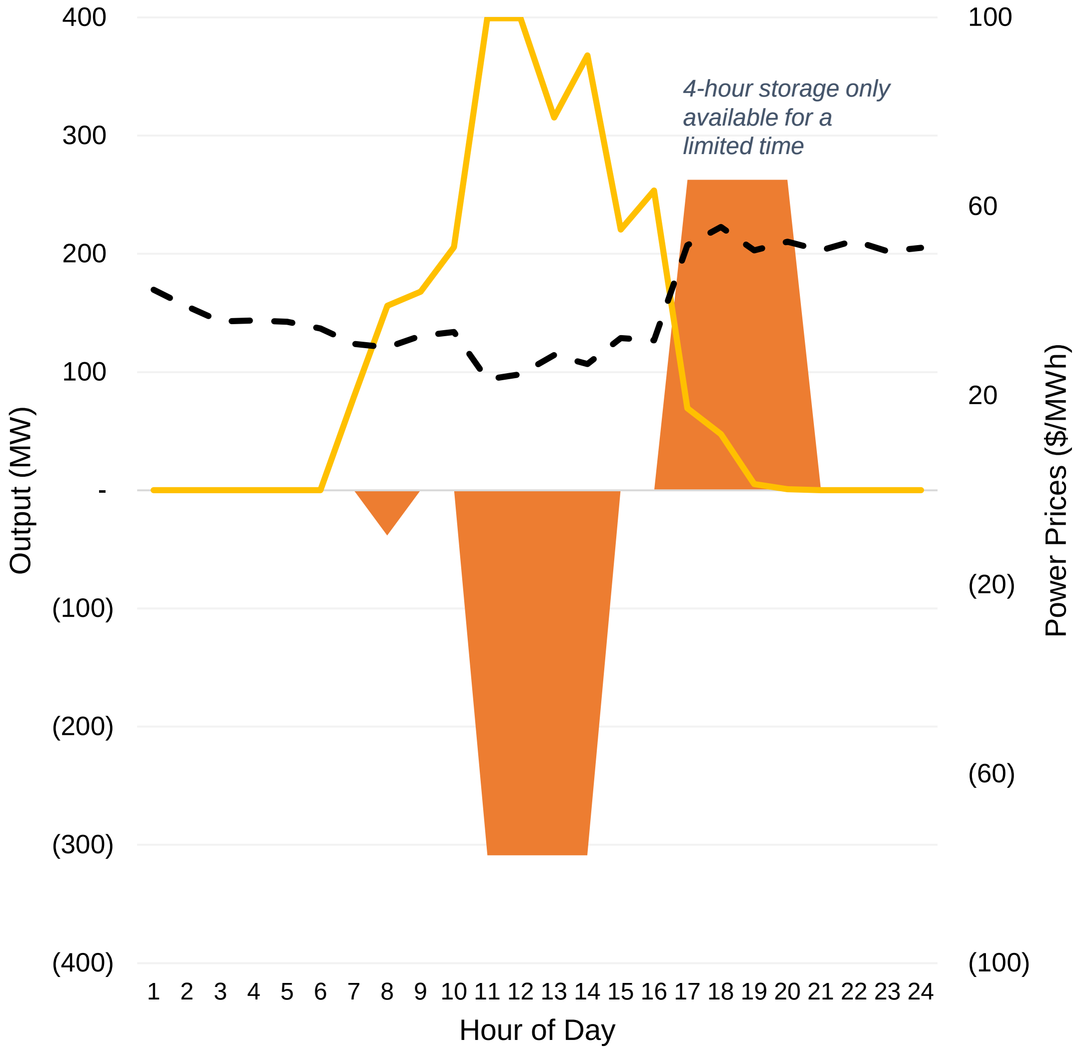
Observations

- In the early years, additional gas capacity (particularly the combined cycle in Portfolio C) adds risk to the portfolio given natural gas volatility and long energy position
- Over time, as the MISO market evolves to include more intermittent renewable capacity, renewable output uncertainty becomes more correlated to power prices, exposing renewable-dominant portfolios (particularly G) to more uncertainty
- Portfolios that integrate some level of dispatchable capacity in the form of peaking or storage resources (Portfolios E and F) perform similarly from a risk perspective over time and hedge against both near-term and long-term stochastic risk exposure

SAMPLE SUMMER DAYS – 2040 STOCHASTIC ANALYSIS

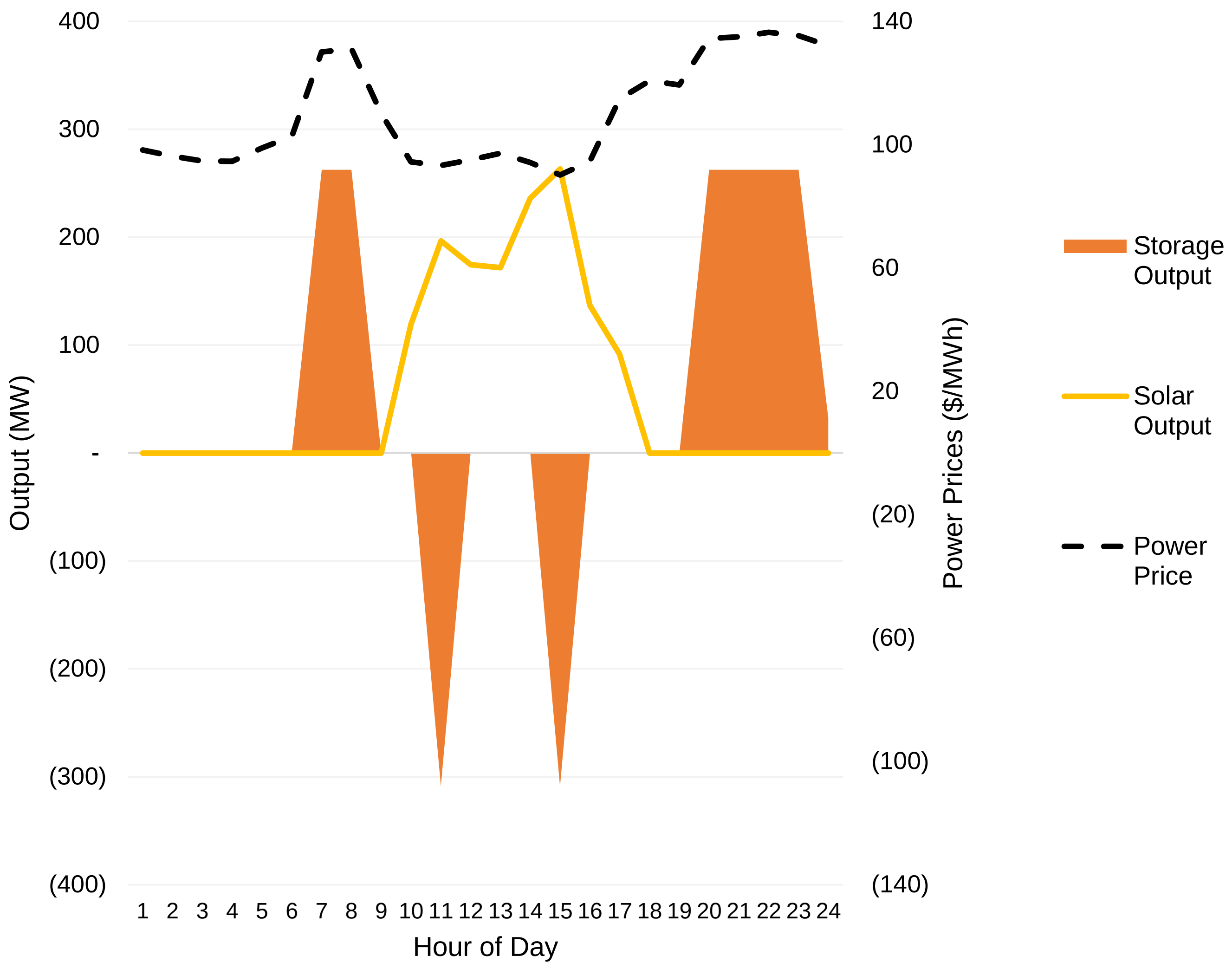
Over time, solar output is likely to correspond to lower price periods of the day, with storage (or gas peakers) able to dispatch when prices are high

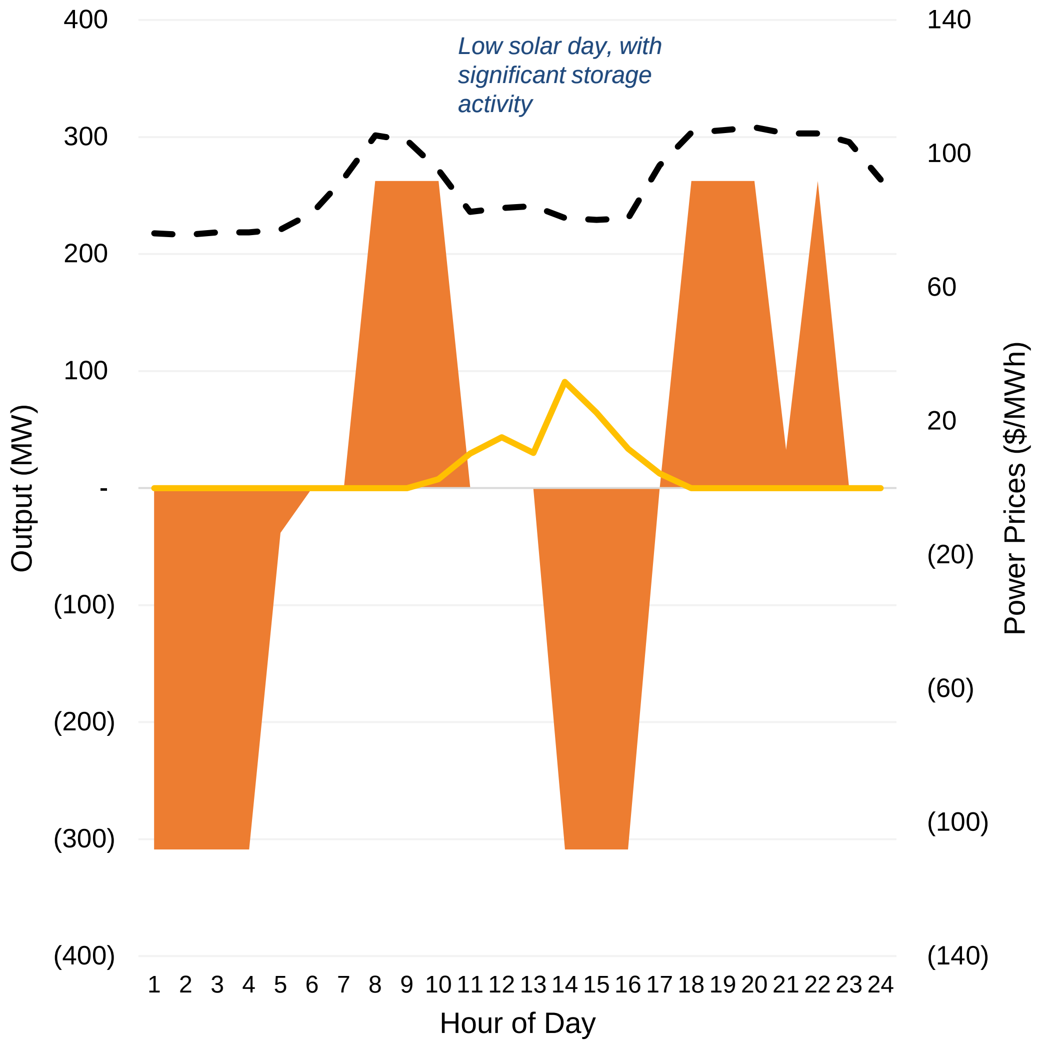




SAMPLE WINTER DAYS – 2040 STOCHASTIC ANALYSIS

Solar output tends to be lower in the winter, with dual price peaks in the morning and evening





REPLACEMENT ANALYSIS SCORECARD

Objective	Indicator	Description and Metrics
Affordability	**Cost to Customer**	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	**Cost Certainty**	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR and 75^{th} % range vs. median
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: Highest scenario NPVRR and 95^{th} % conditional value at risk (average of all outcomes above 95^{th} % vs. median)
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: Lowest scenario NPVRR and 5^{th} % range vs. median
Environmental Sustainability	**Carbon Emissions**	• Carbon intensity of portfolio • Metric: Cumulative carbon emissions (2024-40 short tons of CO_2) from the generation portfolio
Reliable, Flexible, and Resilient Supply	**Reliability**	• The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules • Metric: *Sub-hourly A/S value impact and additional scoring (under development)*
	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 (UCAP – 2027)
Positive Social & Economic Impacts	**Employees**	• *Addressed in Existing Fleet Analysis for existing generation assets; employee numbers will be dependent on specific asset replacements*
	Local Economy	• Effect on the local economy from new projects and ongoing property taxes • Metric: NPV of property taxes from the entire portfolio

Key Points

- As in the 2018 IRP, multiple objectives and indicators are summarized across portfolios in an integrated scorecard framework
- The Replacement Analysis scorecard incorporates broader perspectives on risk (stochastic analysis) and reliability than the Existing Fleet Analysis scorecard

REPLACEMENT ANALYSIS SCORECARD

Preliminary

	A	B	C	D	E	F	G	H	I
Replacement Theme	Thermal PPAs, solar and storage	Non-service territory gas peaking (no early storage)	Natural gas dominant (CC)	No new thermal resources; solar dominant w/ storage	Thermal PPAs plus storage and solar	Local gas peaker, plus solar and storage	Solar dominant w/ storage, plus retire Sugar Creek	All renewables and storage, plus retire Sugar Creek (Portfolio 7)	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Cost To Customer 30-year NPV of revenue requirement (Ref Case) $M	$10,461 +$150	$10,332 +$21	$10,312 -	$10,438 +$126	$10,467 +$156	$10,426 +$115	$11,042 +$730	$11,090 +$778	$10,792 +$480
Cost Certainty Scenario Range (NPVRR) $M	$2,359 +$1,035	$2,782 +$1,458	$3,208 +1,885	$2,322 +$998	$2,538 +$1,215	$2,748 +$1,424	$1,324 -	$1,553 +$229	$1,855 +$531
Cost Risk – Highest Scenario NPVRR $M	$12,015 +$207	$12,182 +$373	$12,518 +$709	$11,965 +$156	$12,126 +$317	$12,243 +$434	$11,809 -	$12,011 +$202	$11,848 +$39
Cost Risk – Stochastic 95% CVAR – 50%	$104 +$21	$92 +$9	$83 -	$104 +$21	$98 +$15	$97 +$14	$123 +$40	$114 +$31	$87 +$4
Lower Cost Opp. Lowest Scenario NPVRR $M	$9,657 +$347	$9,400 +$91	$9,309 -	$9,644 +$334	$9,588 +$278	$9,495 +$186	$10,485 +$1,176	$10,458 +$1,149	$9,933 +$684
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)	27.3 +11.3	30.4 +14.4	47.2 +31.2	27.3 +11.3	27.3 +11.3	28.5 +12.4	16.1 -	16.1 -	25.2 +9.2
Reliability	*To be added in final scorecard*								
Resource Optionality MW-weighted duration of 2027 generation commitments (yrs.)	20.01 +3.0	20.53 +3.5	23.55 +6.6	20.37 +3.4	21.15 +4.2	22.12 +5.1	17.00 -	18.19 +1.2	21.46 +4.5
Local Economy NPV of property taxes	$420 -$66	$388 -$98	$451 -$35	$417 -$69	$413 -$73	$416 -$70	$486 -	$477 -$9	$421 -$65

*Note: Appendix contains more detailed scorecard data

PORTFOLIO-LEVEL OBSERVATIONS

- Portfolios that have the highest solar additions and meet only the summer reserve margin target (**Portfolios A, D, G**) perform best under high environmental regulation scenarios (AER and EWD), but are higher cost in other scenarios and are not feasible, given expected market rules changes
- Although adding new combined cycle capacity (**Portfolio C**) results in lowest costs under the Reference and SQE scenarios and provides a new dispatchable energy resource to mitigate future intermittency risk, this strategy carries the highest scenario cost exposure and uncertainty, results in the highest CO2 emissions, and reduces future resource optionality
- While a portfolio approach that retires all thermal resources by 2032 and relies solely on renewables and storage (**Portfolio H**) provides a high level of scenario cost certainty, the lowest emission profile, and significant additional local economic investment, it has the highest cost under Reference scenario conditions and exposes the portfolio to high stochastic tail risk, given high levels of intermittent resources
- While portfolios that retain Sugar Creek and add some amount of new peaking and storage resources (**Portfolios B, E, and F**) do not score best on any single metric, they minimize cost risks, continue NIPSCO down a path of significant CO2 emission reductions, and allow for flexibility and optionality
- A portfolio that includes additional renewables and storage, as well as options to pursue hydrogen at existing and new thermal facilities (**Portfolio I**), produces lower CO2 emissions than B, E, and F, performs better under scenarios with high environmental regulation/incentives (particularly EWD), and mitigates stochastic tail risk

OVERARCHING REPLACEMENT ANALYSIS INITIAL OBSERVATIONS

- Certain resources that provide near-term capacity (Sugar Creek uprate, attractive DER opportunities, and thermal capacity contracts) appear to be cost-effective additions to the portfolio to firm up the capacity position in the near-term and in anticipation of future retirements
- Storage and gas peaking resources appear to be economic replacement options for Michigan City and Schahfer 16AB
  - The quantities and characteristics of storage and gas peaking resource additions likely require further study to assess reliability tradeoffs, understand the value of each resource type given ongoing and potential market and policy changes, and monitor technology change
- Integrating dispatchable capacity into the portfolio over the long term (without materially increasing gas-fired energy exposure and CO2 emissions through a combined cycle) tends to mitigate cost risk associated with intermittent resources; additionally, it appears impossible to meet seasonal reserve margin requirements with only renewable (without storage) resources
- Short-term acquisition of capacity resources will still allow NIPSCO the optionality to monitor technology and policy trends to inform future action and maintain a pathway to a Net Zero portfolio over the long term, including with emerging technology like hydrogen

PREFERRED PORTFOLIOS INFORM THE ACTION PLAN

- Replacement Portfolios B, E, F, & I could be preferred under different, but plausible future scenarios
- These various portfolios will inform the preferred plan and both the short-term and long-term action plans

ICAP Additions through 2027 Planning Year

Dispatchability

Emissions	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Higher Carbon Emissions	**A** NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 135MW Solar+Storage 450MW* Solar 250MW	**B** NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 443MW Thermal PPA 150MW Solar 250MW	**C** NIPSCO DER 10MW SC Uprate 53MW Gas CC 650MW
Mid Carbon Emissions	**D** NIPSCO DER 10MW SC Uprate 53MW Storage 135MW Solar+Storage 450MW* Solar 400MW	**E** NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 470MW Solar 250MW	**F** NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 300MW Thermal PPA 150MW Storage 135MW Solar 100MW
Low Carbon Emissions	**G** NIPSCO DER 10MW Storage 135MW Solar+Storage 450MW* Solar 450MW	**H** NIPSCO DER 10MW Wind 200MW Storage 570MW Solar 250MW	**I** NIPSCO DER 10MW SC H2 Electrolyzer 20MW SC Uprate 53MW H2 Enabled Peaker 193MW Wind 200MW Storage 370MW Solar 250MW

Sugar Creek is retained through modeling horizon

Sugar Creek Retires or converts to H2

Net Zero Concepts

Note: Residential/Commercial DSM universally selected across portfolios
**Represents 300 MW of solar and 150 MW of storage*
***Gas peaker in Portfolio B represents an out-of-service territory PPA; Gas peaker in Portfolio F represents asset sale proposal*

BREAK

CORE ECONOMIC MODELING CAPTURES SOME ELEMENTS OF RELIABILITY

Additional analysis and assessment is required for a fuller perspective

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

NIPSCO coordinates with MISO (Operating Reliability)

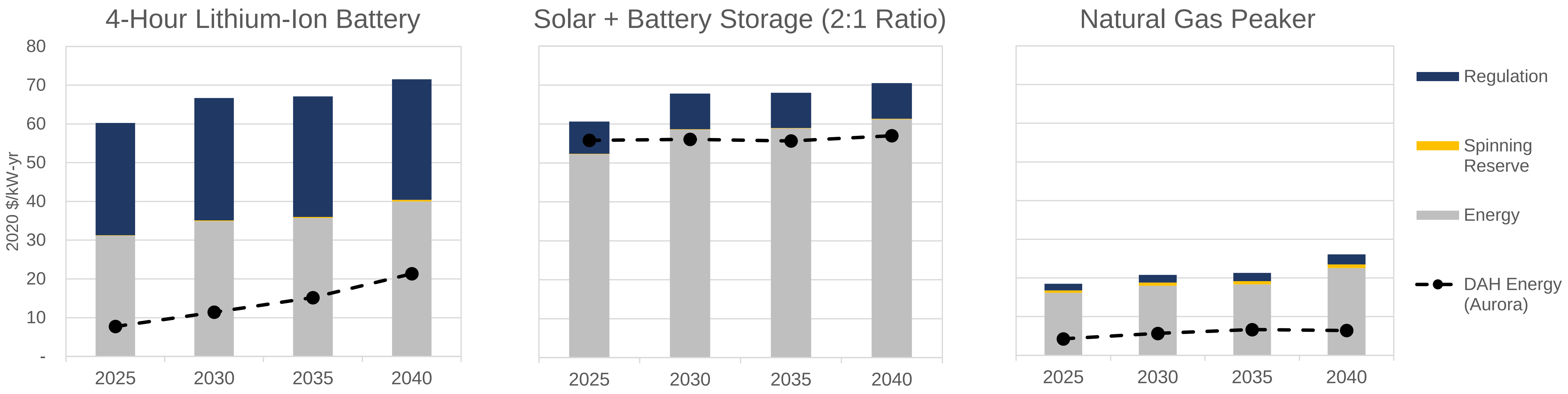
	Resource Adequacy	Energy Adequacy	Operating Reliability
Definition:	Having sufficient resources to reliably serve demand	Ability to provide energy in all operating hours continuously throughout the year	Ability to withstand unanticipated component losses or disturbances
Forward Planning Horizon:	Year-ahead	Day-ahead	Real-time or Emergency
Reliability Factors:	Reserve margin, ELCC and energy duration	Dispatchability, energy market risk exposure	Real Time Balancing System
IRP Modeling Approach:	Portfolio development constraints, with ELCC and seasonal accounting	Hourly dispatch analysis, including stochastic risk	**Ancillary services analysis (regulation, reserves), with sub-hourly granularity**

SUB-HOURLY ENERGY AND ANCILLARY SERVICES EVALUATION

- While most of NIPSCO's existing portfolio (including new renewables) realize nearly all value from energy and capacity contributions, highly flexible resources that do not provide a lot of energy to the portfolio may still provide value in the form of ancillary services and in their ability to respond to changing market conditions in real time at sub-hourly granularity:
  - The MISO market currently operates markets for spinning reserves and regulation
  - FERC Order 841 also requires ISOs to redesign markets to accommodate energy storage
- Long-term market developments are uncertain, and fundamental evaluation of sub-hourly ancillary services markets is challenging, but the 2021 IRP has performed an analysis, incorporating:
  - 5-minute granularity for energy and ancillary services based on historical data observations and future energy market scenario projections
  - Operational parameters for various storage and gas peaking options
  - ***Incremental value, above and beyond what is picked up in the Aurora-based hourly energy dispatch, is assessed and summarized on a portfolio level***

SUB-HOURLY ANALYSIS INDICATES POTENTIAL UPSIDE FOR STORAGE ASSETS

Reference Case

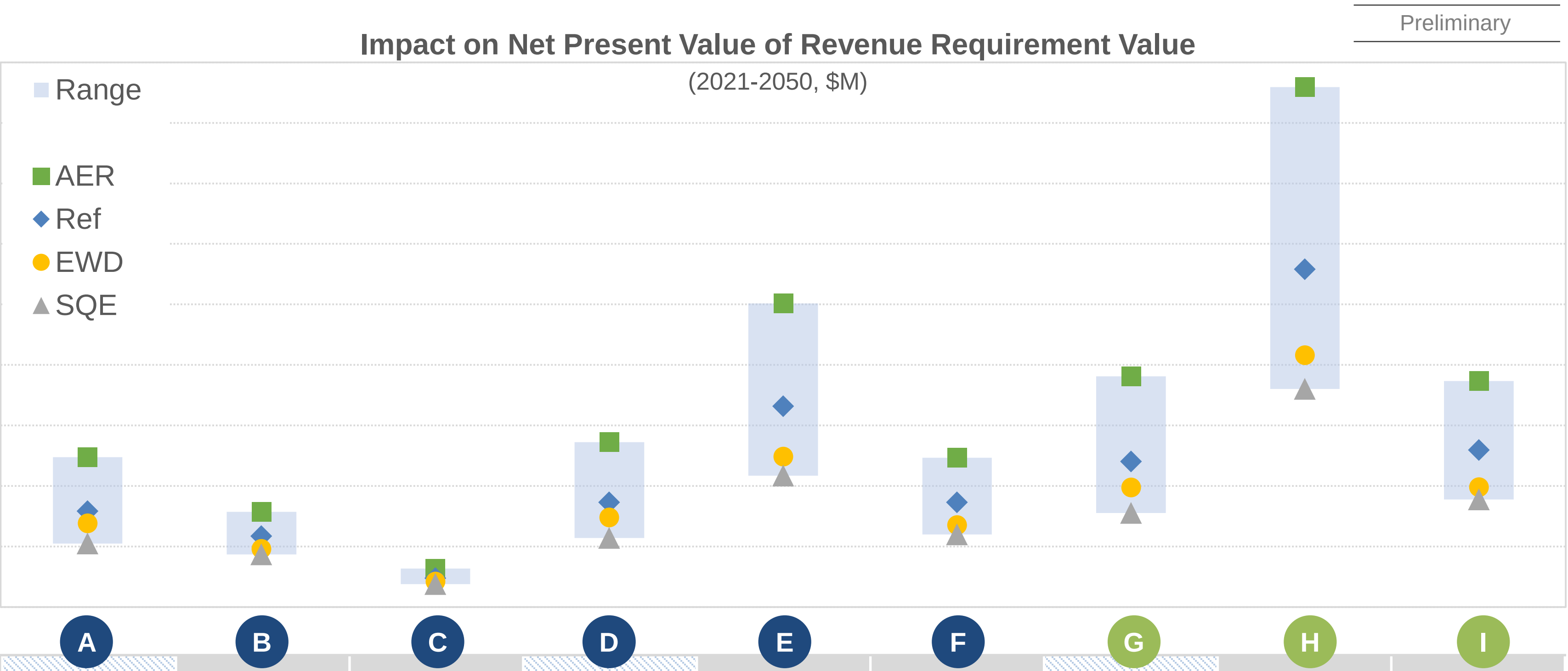


- Highly flexible battery able to respond in real time to changing price signals
- Can participate regularly in the regulation market (providing up and down service, given charging and discharging capabilities)

- Solar component provides significant energy value, which is also captured in fundamental modeling
- Investment tax credit rules limit the battery's flexibility and ability to take advantage of the regulation market (must charge predominantly from the solar)

- Real-time volatility is greater than day ahead hourly dispatch value, providing value upside compared to Aurora modeling
- Regulation opportunities are only available when the unit is already operating for energy

RANGE OF ADDITIONAL VALUE OPPORTUNITY (NPVRR COST REDUCTION) BY PORTFOLIO



	A	B	C	D	E	F	G	H	I
Replacement Theme	**Thermal PPAs, solar and storage**	**Non-service territory gas peaking (no early storage)**	**Natural gas dominant (CC)**	**No new thermal resources; solar dominant w/ storage**	**Thermal PPAs plus storage and solar**	**Local gas peaker, plus solar and storage**	**Solar dominant w/ storage, plus retire Sugar Creek**	**All renewables and storage, plus retire Sugar Creek (Portfolio 7)**	**New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)**
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)

Observations

- *Additional value is uncertain and dependent on market rules evolution, MISO generation mix changes, and market participant behavior*
- Portfolios with the largest amounts of storage (E and H) have the greatest potential to lower NPVRR by capturing flexibility value that may manifest in the sub-hourly energy and ancillary services markets
- A wide range of value is possible, with higher prices and price spreads in the AER scenario driving higher estimates

RELIABILITY ASSESSMENT PROCESS OVERVIEW

1. Define Initial Assessment Criteria
2. Obtain Stakeholder Feedback
3. Engage 3rd Party Reviewer
4. Incorporate into IRP Analysis Scorecard(s)

Collaborated with NIPSCO transmission planning and system operations group to develop initial framework and criteria

We will seek feedback from interested stakeholders who want to learn more about the assessment criteria and provide input and feedback

Engage a qualified 3rd party expert to review the assessment criteria, develop the scoring methodology and score and rank the various resource technologies under consideration

Incorporate the scoring and ranking results of the assessment into the IRP Analysis Scorecard(s)

August-September

September-October

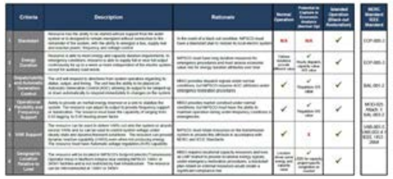
RELIABILITY ASSESSMENT AND RANKING UPDATE

Assess NIPSCO's Reliability Needs

- Power Ramping
- Frequency Response
- Short Circuit Strength
- Flicker
- Black Start

Near Completion

Review & Map Reliability Needs to Existing Reliability Metrics



In Progress

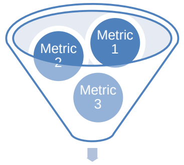
Apply a Series of Reliability Filters to IRP Portfolios

In Progress

Scoring Criteria

In Progress

Ranking Portfolios



In Progress

INITIAL RELIABILITY ASSESSMENT CRITERIA

Preliminary – Updated from Last Stakeholder Meeting

	Criteria	Description	Rationale	Normal Operation	Potential to Capture in Economic Analysis (Normal Op)	Islanded Operation (Black-out Restoration)	NERC Standard IEEE Standard
1	Blackstart	Resource has the ability to be started without support from the wider system or is designed to remain energized without connection to the remainder of the system, with the ability to energize a bus, supply real and reactive power, frequency and voltage control	In the event of a black out condition, NIPSCO must have a blackstart plan to restore its local electric system.	N/A	N/A	✓	EOP-005-3
2	Energy Duration	Resource is able to meet energy and capacity duration requirements. In emergency conditions, resource is able to supply full or near full output continuously for up to a week or more independent of the electric system except for auxiliary load needs	NIPSCO must have long duration resources for emergency procedures and must assess economic value risk for energy duration attributes over time	Various durations provide different value	✓ Hourly dispatch, capacity value, A/S value	✓	EOP-005-3
3	Dispatchability and Automatic Generation Control	The unit will respond to directives from system operators regarding its status, output, and timing. The unit has the ability to be placed on Automatic Generation Control (AGC) allowing its output to be ramped up or down automatically to respond immediately to changes on the system	MISO provides dispatch signals under normal conditions, but NIPSCO requires AGC attributes under emergency restoration procedures	✓	✓ Regulation A/S value	✓	BAL-001-2
4	Operational Flexibility and Frequency Support	Ability to provide inertial energy reservoir or a sink to stability the system. The resource can adjust its output to provide frequency support or stabilization in response to frequency deviations with a droop of 5% or better	MISO provides market construct under normal conditions, but NIPSCO must have the ability to maintain operation during under-frequency conditions in emergencies	✓	✓ Regulation A/S value	✓	MOD-025 Attach. 1 BAL-003-2
5	VAR Support	The resource can be used to deliver VARs out onto the system or absorb excess VARs and so can be used to control system voltage under steady-state and dynamic/transient conditions. The resource can provide dynamic reactive capability (VARs) even when not producing energy. The resource must have Automatic voltage regulation (AVR) capability. The resource must have the capability ranging from 0.85 lagging to 0.95 leading power factor	NIPSCO must retain resources on the transmission system to provide this attribute in accordance with NERC and IEEE Standards	✓	X	✓	VAR-001-5 VAR-002-4.1 IEEE 1453 - 2004
6	Geographic Location Relative to Load	The resource will be located in NIPSCO's footprint (electric/Transmission Operator Area) in Northern Indiana near existing NIPSCO 138kV or 345kV facilities and is not restricted by fuel infrastructure. The resource can be interconnected at 138kV or 345kV	MISO requires locational capacity resources and runs an LMP market to provide locational energy signals; under emergency restoration procedures, a blackstart plan reliant on external resources would create a significant compliance risk	Location drives some energy and capacity value	✓ LRZ6 for capacity; project-specific congestion as needed	✓	

ANALYSIS NEXT STEPS

Erin Whitehead, Vice President Regulatory & Major Accounts, NIPSCO

STAKEHOLDER FEEDBACK

Seeking Feedback

- Seeking feedback regarding the modeling results presented today
- Reach out to Alison Becker (abecker@nisource.com) for 1x1 meetings

Upcoming Stakeholder Meetings

- Converted the **October 12th** stakeholder meeting to a **Technical Webinar** focused on the Reliability Assessment
- Final Public Stakeholder Advisory Meeting #5 is scheduled for **October 21st**

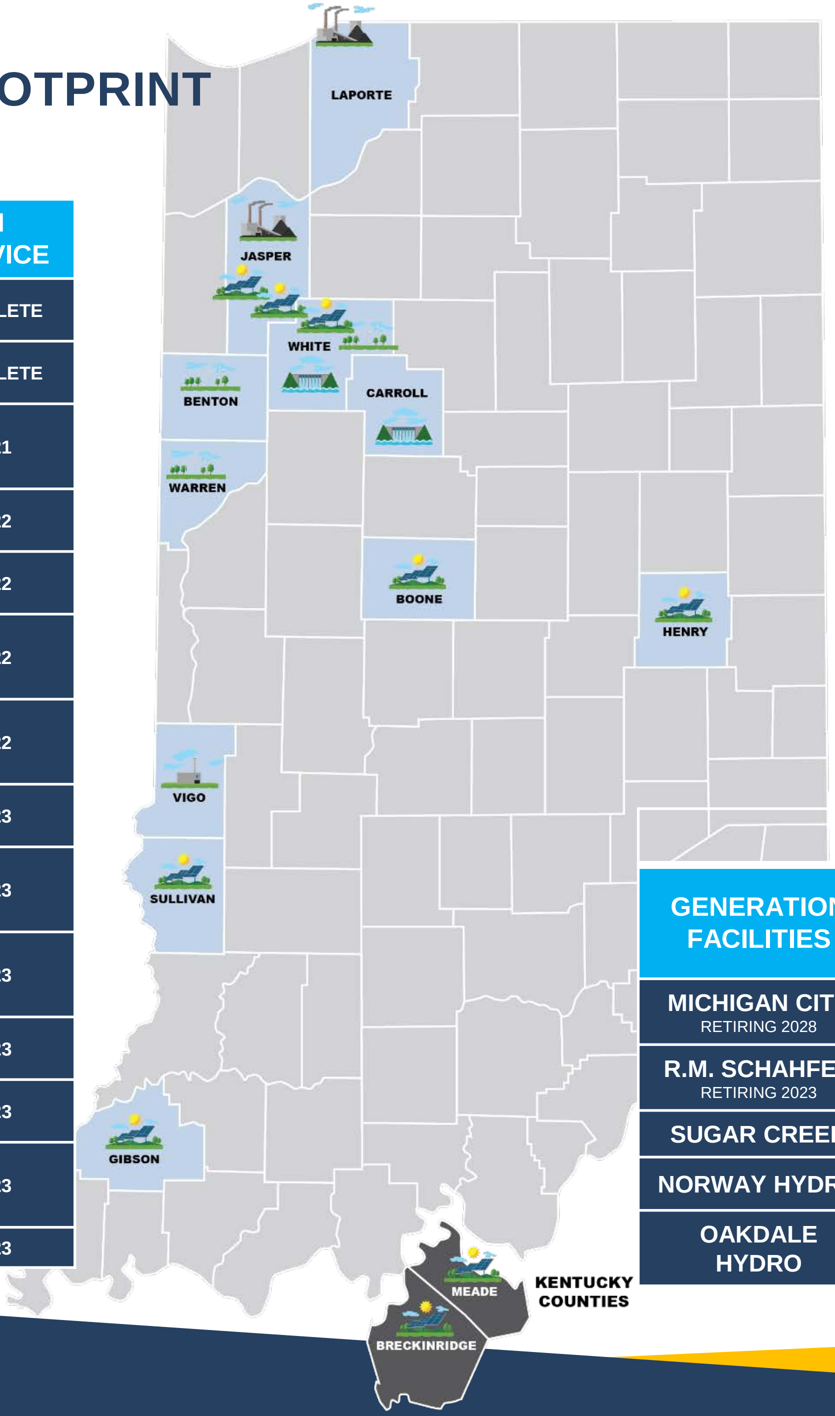
Stakeholder engagement is a critical part of the IRP process

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

CONSIDERATIONS FOR LONG-TERM PLANNING WITH INTERMITTENT RESOURCES

As we established in the previous 3 stakeholder meetings, reliability is a key focus for the 2021 IRP

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

REGULATORY EVOLUTION SINCE 2018

Several regulatory developments and evolving initiatives since NIPSCO's 2018 IRP 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

PREVIOUS RELIABILITY ASSESSMENTS

2018 Retirement Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75^{th} percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95^{th} percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO's 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

2020 Portfolio Analysis Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 34 year NPV of revenue requirement (Base scenario deterministic results)
Long term Optionality	• Flexibility resulting from combinations of ownership, duration, and diversity • Metric: MW weighted duration of generation commitments
Capital Requirement	• Estimated amount of capital investment required by portfolio • Metric: 2020 -2023 capital needs
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 UCAP MW sourced from non-gas resources)
Environmental	• Carbon intensity of portfolio / Total carbon emissions • Metric: Total annual carbon emissions (2030 short tons of CO_2) from the generation portfolio
Operational Flexibility	• The ability of the portfolio to be controlled in manner to respond to changes in load (dispatchable) • Metric: % of 2025 Controllable MW in gen. portfolio

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”)

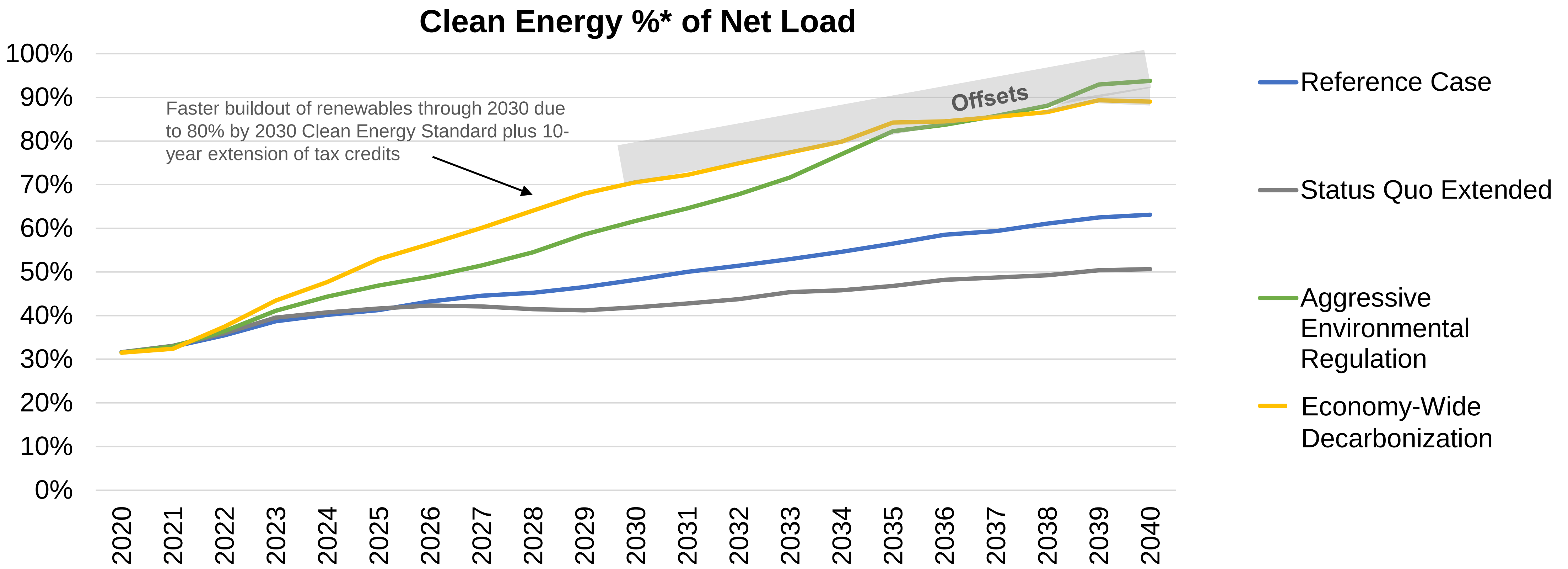
- Technology development and federal incentives push towards a decarbonized economy, including through a power sector Clean Energy Standard (supporting renewables and other non-emitting technologies) and large-scale electrification in other sectors (EVs, heating, processes, etc.)

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*	

CLEAN ENERGY PERCENTAGE ACROSS MISO

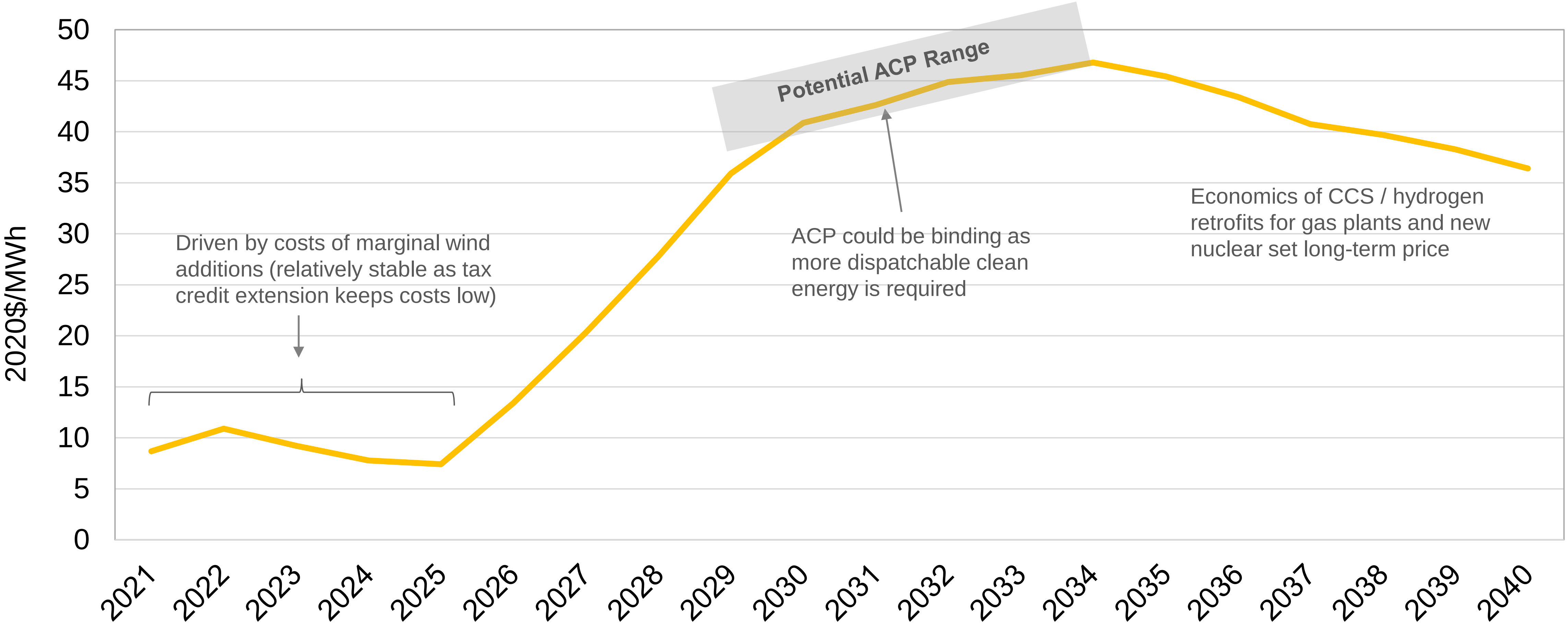
- Escalating carbon price pushes clean energy percentage to >90% in AER, while the implementation of a Clean Energy Standard achieves a very similar outcome in EWD
- Offsets outside the power sector would be expected to be available to achieve Net Zero



**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.*

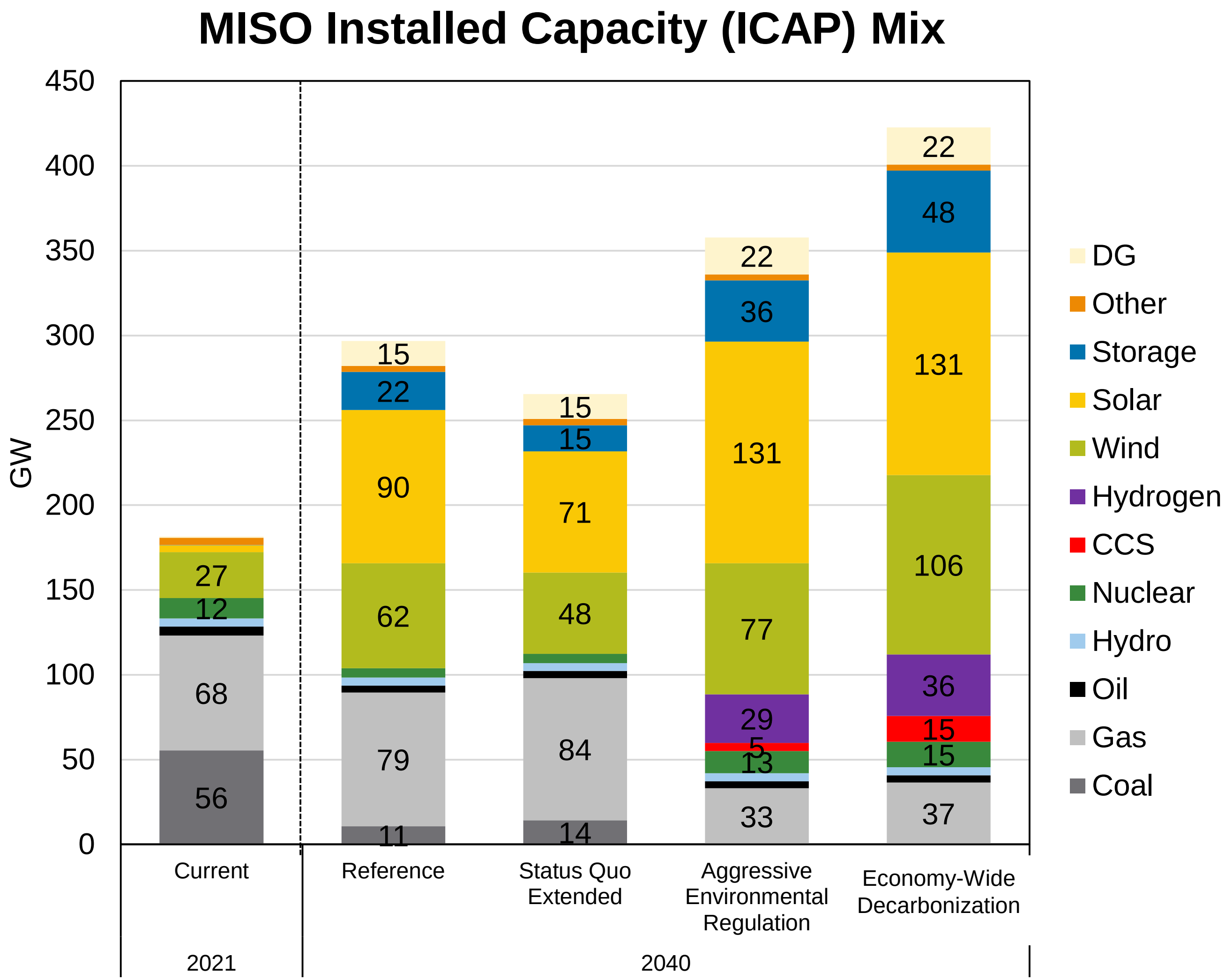
CLEAN ENERGY CREDIT PRICING

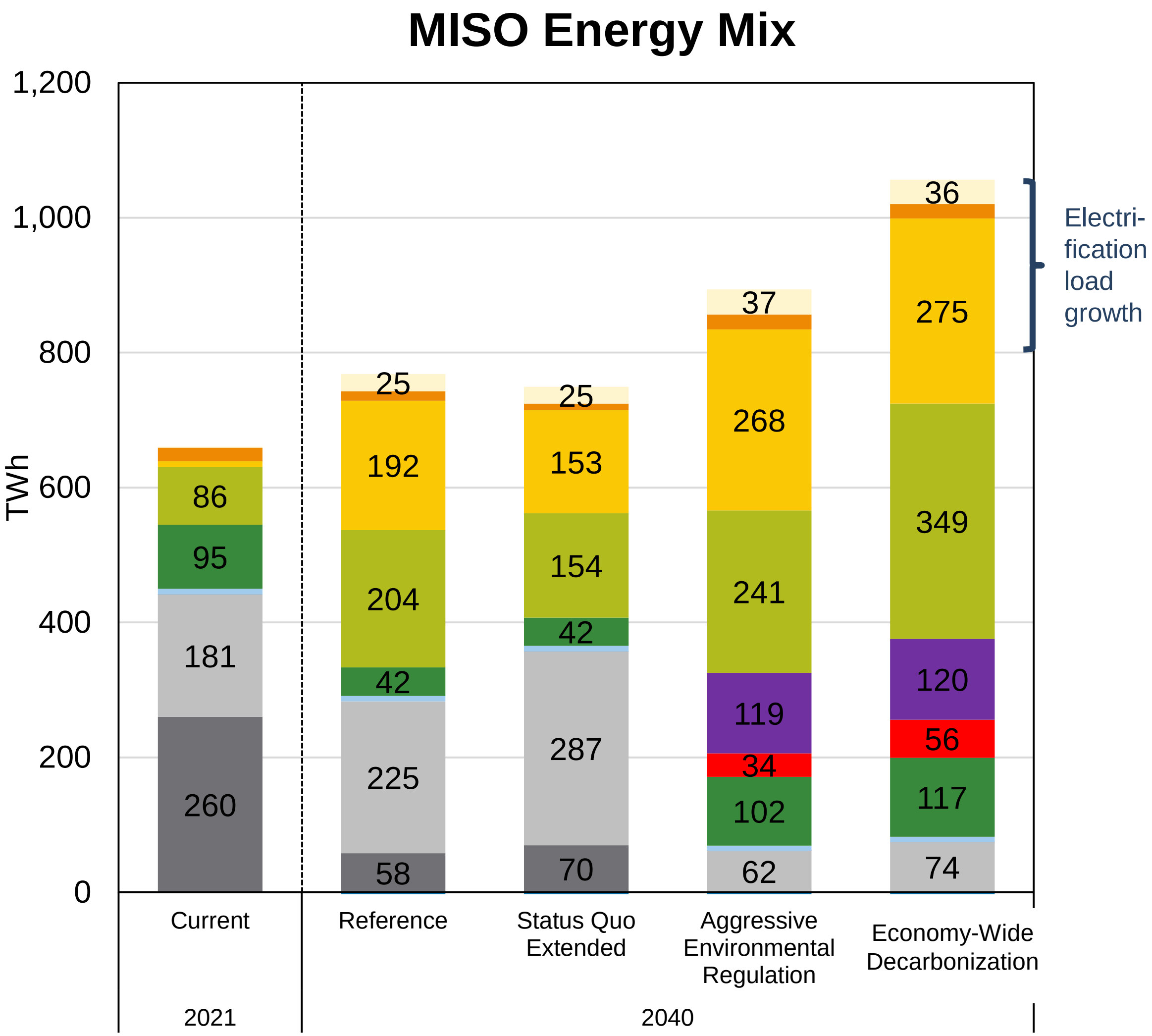
In the Economy-Wide Decarbonization scenario, a Clean Energy Standard with an Alternative Compliance Payment (ACP) would likely drive the development of a national Clean Energy Credit / Zero Emission Electricity Credit market



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





STOCHASTIC ANALYSIS APPROACH

The 2021 IRP has incorporated commodity price and renewable output stochastic analysis

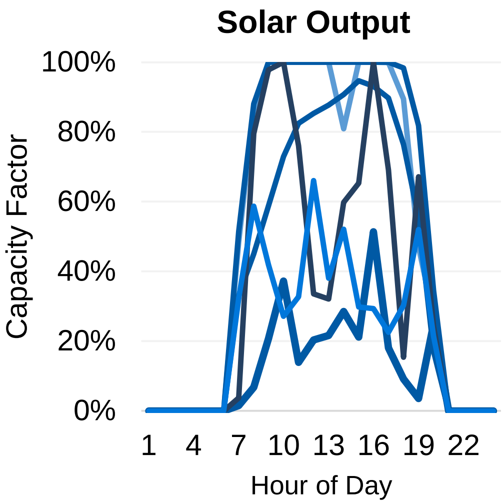
1 *Input Data Development*

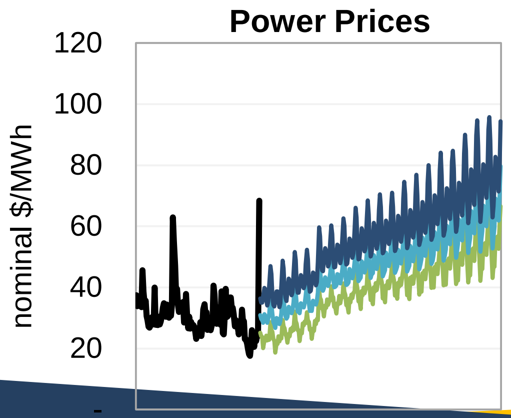
- Fundamental forecasts
- Historical price data
- Historical weather data (and corresponding renewable output)

2 *Statistical and Fundamental Analysis*

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

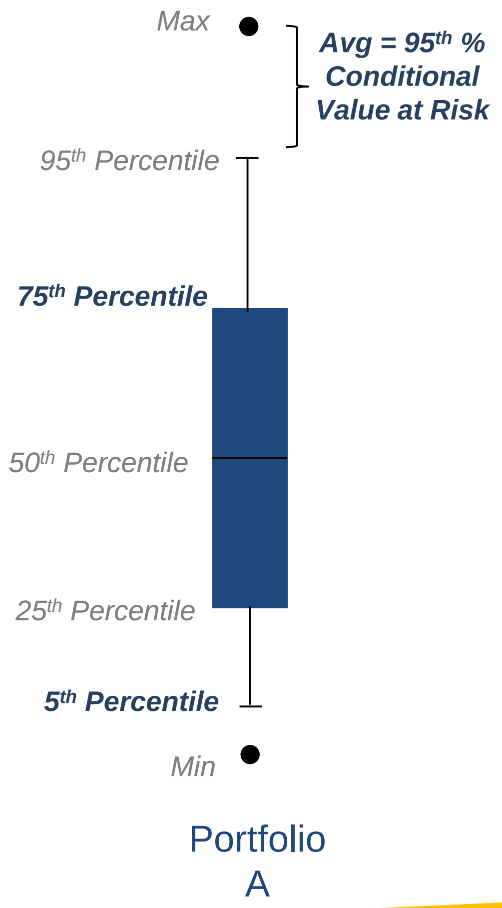
3 *Stochastic Input Development*





Evaluate NIPSCO portfolios 500 times

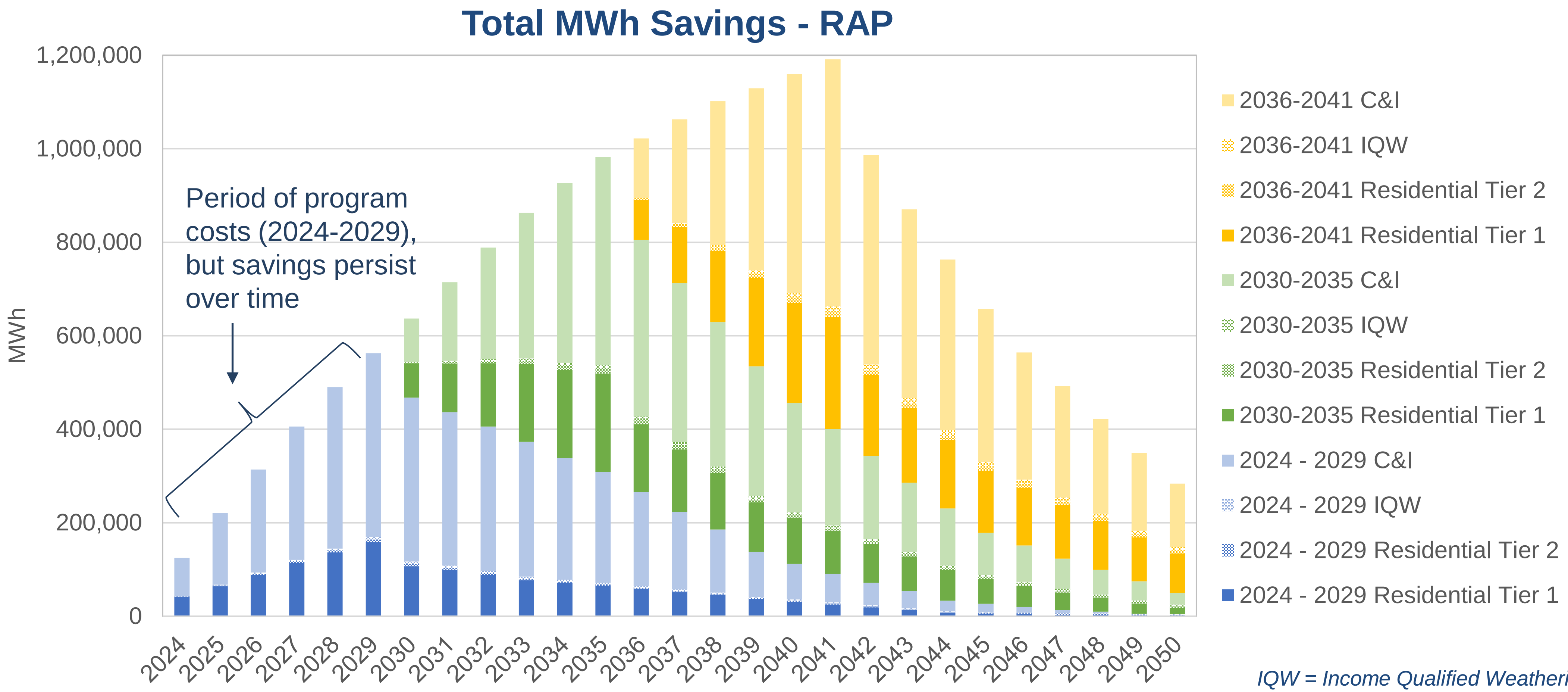
4 *NIPSCO Portfolio Analysis*



Illustrative

ENERGY EFFICIENCY BUNDLES FOR IRP MODELING

- DSM bundling approach allows for a representation of potential program duration over time, with differentiation across customer type and costs
- Annual costs and savings (inclusive of marginal line losses) are incorporated



Levelized Cost ($/MWh)

Bundle	Levelized Cost ($/MWh)
2036-2041 C&I	29
2036-2041 IQW	138
2036-2041 Residential Tier 2	253
2036-2041 Residential Tier 1	65
2030-2035 C&I	28
2030-2035 IQW	140
2030-2035 Residential Tier 2	244
2030-2035 Residential Tier 1	60
2024 - 2029 C&I	25
2024 - 2029 IQW	146
2024 - 2029 Residential Tier 2	231
2024 - 2029 Residential Tier 1	53

IQW = Income Qualified Weatherization

DISTRIBUTED ENERGY RESOURCES

- NIPSCO and CRA categorized the projects identified by the distribution planning team into High, Medium, and Low bundles of deferred distribution investment costs
- These resource options were available for selection and analysis in the portfolio assessment phase:
  - *Near-term opportunities only*, to defer required distribution system investments currently identified
  - Distribution-level cost premiums assessed relative to larger scale projects
  - NPV of deferred distribution investment effectively subtracted from capital cost of the resource options

Deferral Cost Bundle	Resource	Battery Storage MW	Solar MW	Range of Potential NPV of Deferred Investment ($/kW)
High	Solar + Battery	7.0	2.7	**700 – 900**
Mid	Solar + Battery	7.0	9.1	**200 – 300**
Low	Solar + Battery	2.0	2.7	**10 – 100**

Indicative ranges, subject to change for actual projects

- The IRP aims to identify the *types of DER projects and characteristics of candidate locations* that may be attractive, with additional project-specific evaluation required in the future
- NIPSCO intends to continue assessing DER options in more detail in future IRPs as integrated planning advancements are made and as MISO makes its filings in response to FERC Order 2222 (See Stakeholder Meeting #2 slides for more information)

RFP INFORMATION: TRANCHE DEVELOPMENT

A three-step process to incorporate RFP data and run the IRP models

Additional screening focus in 2021 to inform tranche development

1 Tranche Development

Screen Bids

- High-level bid review by RFP team to confirm compliance w/ requirements and overall viability

Aggregate Bids into Groupings by Type

- Bids are organized by:
  - Technology
  - Asset sale or PPA
  - Commitment duration
  - Costs
  - Oper. characteristics
- Aggregated cost and operational information compiled in Aurora

2 Portfolio Optimization

Select Portfolios

- Based on portfolio concepts (retirement / replacement), capacity need, and other constraints, identify which tranches (or portions of tranches) are selected for the portfolio through Aurora optimization

Confirm Reasonableness

- Confirm that optimization model is selecting feasible block sizes and options based on resource-specific data

3 Portfolio Modeling

Refine Portfolio Details

- Adjust model setup as necessary to cover full range of retirement and replacement options

Analyze Portfolios

- Evaluate each portfolio across range of scenarios and stochastic inputs
- Report portfolio costs and other metrics to support scorecard development

TRANCHE SUMMARY – PPA OPTIONS

Tranche	ICAP (MW)	Heat Rate (Btu/kWh)	Energy Price ($/MWh)	Capacity Price ($/kW-mo)	First Eligible Start Year**	PPA Term (years)	Escalation Rate
Wind P1	500		$48.37		2025	20	0%
Wind P2 (Non-LRZ 6)	835		$33.28		2024	15	0%
Solar P1	825		$49.73		2024	20	0%
Solar P2	588		$37.50		2024	17	0.9%
Solar + Storage P1	300:150^		$39.00	$7.43	2025	15	0%
Solar + Storage P2	1,135:478^		$44.49	$6.14	2023	20	0%
Storage P1	863			$11.95	2025	19	0.2%
Gas Peaking P1	443	10,244	*	$6.47	2026	20	0%
Gas Peaking P2	193	10,238	*	**$8 – $9**	2025	20	2.1%
Gas CC P1	1,365	6,627	$0.98*	$8.89	2024	20	0.1%
Other Thermal P1	50	12,500	**$2 – $3***	**$5 – $6**	2024	10	
Other Thermal P2	150			**$3 – $4**	2026	10	2.0%
Hydrogen P1 – Enabled Peaker	193	10,238	*	**$9 – $10**	2025	20	
Hydrogen P2 – Electrolyzer Pilot	20			**$25 – $30**	2026	20	

Notes: **Red-colored** price information shown as a range to protect confidentiality when tranches are composed of a limited number of bids.
^Capacity for Solar + Storage tranches is represented in the format of "Solar:Storage."
*Fuel and emission variable costs are additive to the Energy Price and are incorporated in the portfolio modeling for the Gas Peaking P1, Gas Peaking P2, Gas CC P1, Other Thermal P1, and Hydrogen P1 tranches.
**First Eligible Start Year indicates the first year some part of the tranche is expected to be available, although capacity is available to start in subsequent years according to bidder information; this is incorporated in the portfolio modeling.

TRANCHE SUMMARY – ASSET SALE OPTIONS

Tranche	ICAP (MW)	Heat Rate (Btu/kWh)	First Eligible Start Year**	Asset Sale ($/kW)
Solar A1	1,250		2025	$1,282
Solar A2	1,150		2025	$1,603
Solar + Storage A1	901:305^		2024	$1,346
Solar + Storage A2	549:275^		2025	$1,167
Storage A1	406		2025	$984
Gas Peaking A1	369	11,471	2024	$575
Gas CC A1	650	6,540	2026	**$1,100 - $1,300**

Notes: **Red-colored** price information shown as a range to protect confidentiality when tranches are composed of a limited number of bids.
^Capacity for Solar + Storage tranches is represented in the format of “Solar:Storage.”
**First Eligible Start Year indicates the first year some part of the tranche is expected to be available, although capacity is available to start in subsequent years according to bidder information; this is incorporated in the portfolio modeling.

TOTAL ADDITIONS THROUGH 2040

ICAP Additions by 2040 Planning Year

Dispatchability

Emissions	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Higher Carbon Emissions	**A** NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW** **Storage 335MW** Solar+Storage 450MW* **Solar 1,650MW**	**B** NIPSCO DER 10MW SC Uprate 53MW Gas Peaker*** 443MW Thermal PPA 150MW** **Storage 200MW** **Solar 1,200MW**	**C** NIPSCO DER 10MW SC Uprate 53MW Gas CC 650MW **Storage 100MW** **Solar 500MW**
Mid Carbon Emissions	**D** NIPSCO DER 10MW SC Uprate 53MW **Storage 335MW** Solar+Storage 450MW* **Solar 1,650MW**	**E** NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW** **Storage 770MW** **Solar 1,350MW**	**F** NIPSCO DER 10MW SC Uprate 53MW Gas Peaker*** 300MW Thermal PPA 150MW** **Storage 335MW** **Solar 1,200MW**
Low Carbon Emissions	**G** NIPSCO DER 10MW **Storage 535MW** Solar+Storage 450MW* **Solar 3,150MW**	**H** NIPSCO DER 10MW Wind 200MW **Storage 1,370MW** **Solar 2,250MW**	**I** NIPSCO DER 10MW SC H2 Electrolyzer 20MW SC Uprate 53MW H2 Enabled Peaker 193MW Wind 200MW **Storage 470MW** **Solar 1,450MW**

Sugar Creek Retires or converts to H2

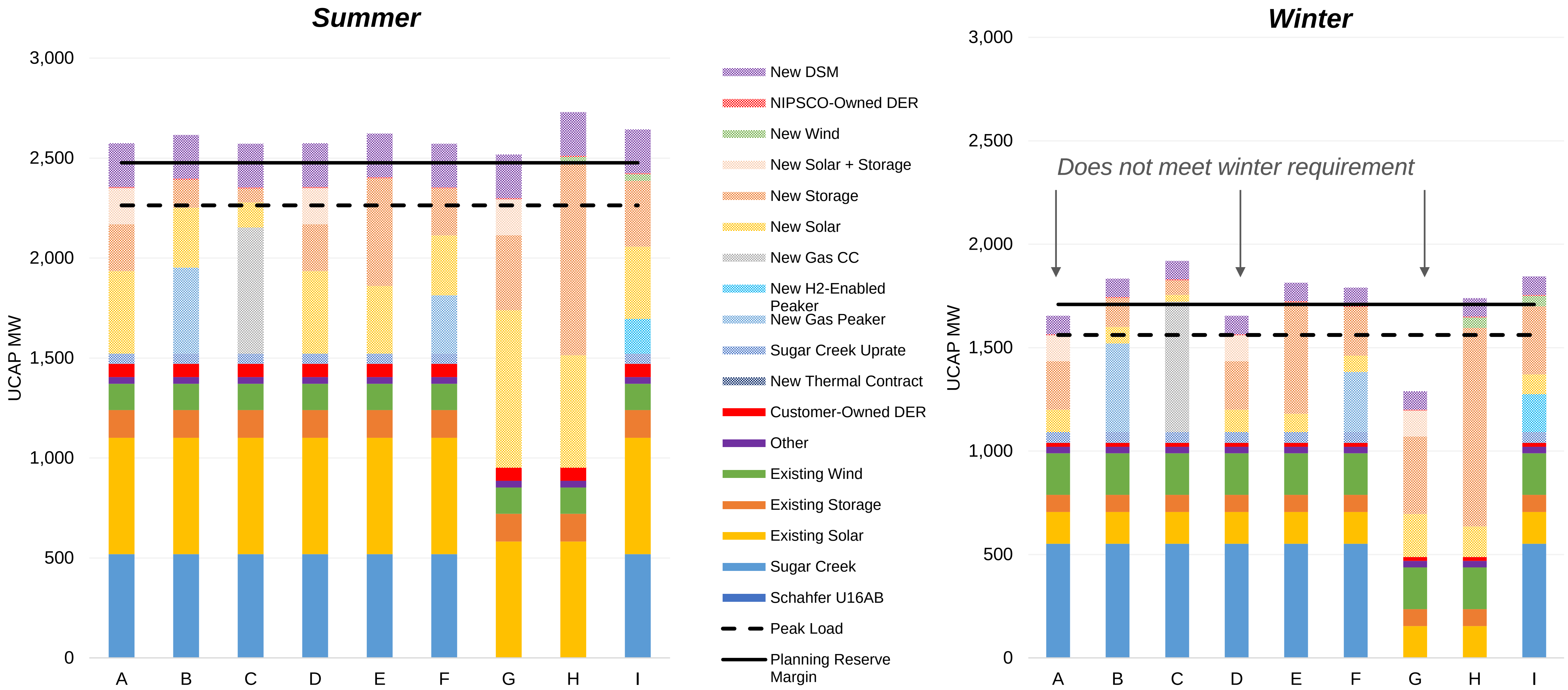
Net Zero Concepts

Observations

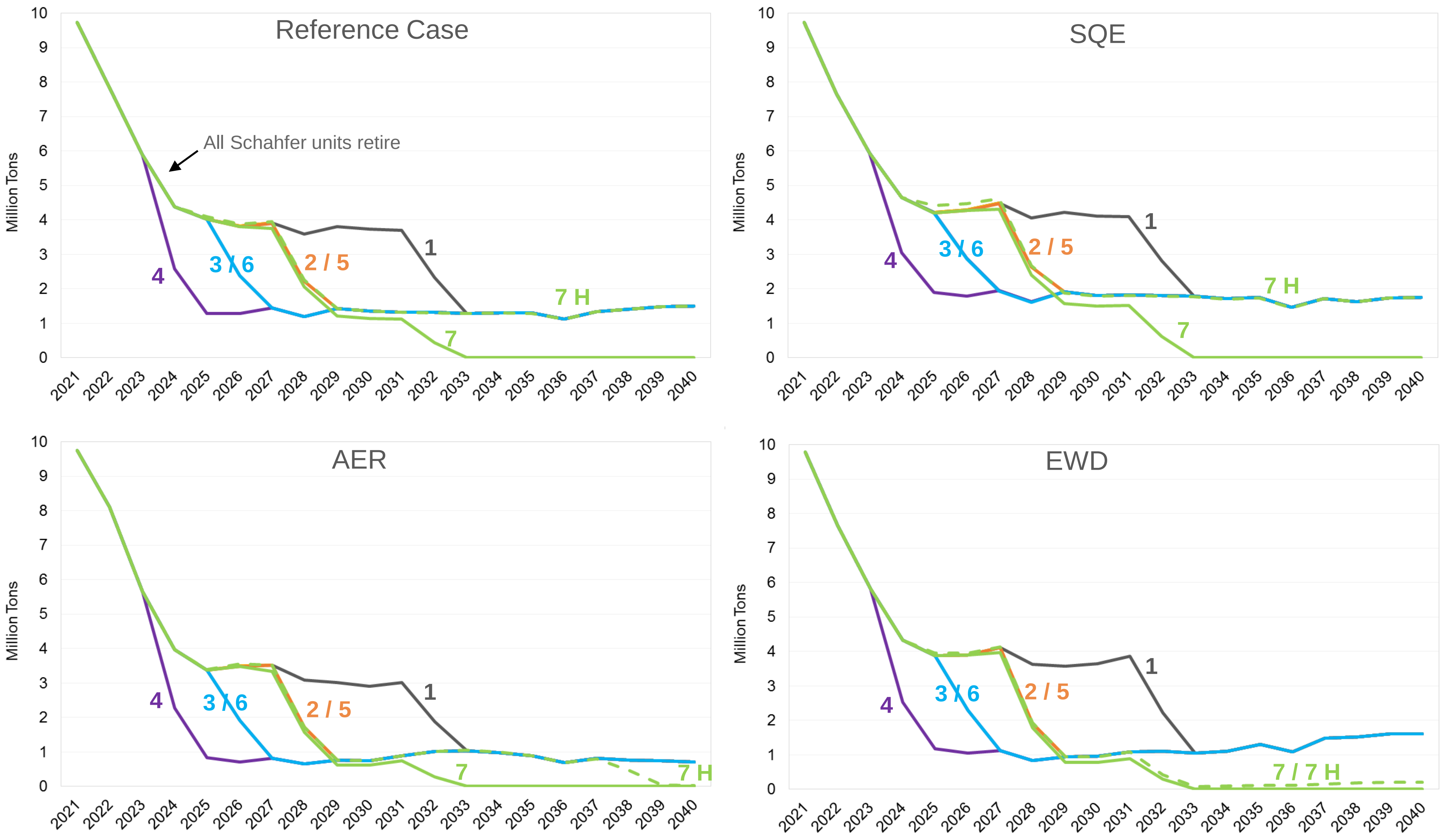
- Renewables and storage remain the most cost-effective long-term resource for the portfolio
- Over time, more energy resources are likely to be needed, as wind contracts roll off, existing solar degrades, and Sugar Creek is expected to run less
- Future IRPs will be able to refine long-term plan, just as this IRP is refining the 2018 preferred portfolio

Note: Residential/Commercial DSM plus a DR Rates program universally selected across portfolios
**Represents 300 MW of solar and 150 MW of storage*
***Ten-year PPA term would have this resource expire by mid-2030s*
****Gas peaker in Portfolio B represents an out-of-service territory PPA; Gas peaker in Portfolio F represents asset sale proposal*

2040 SUPPLY-DEMAND BALANCE



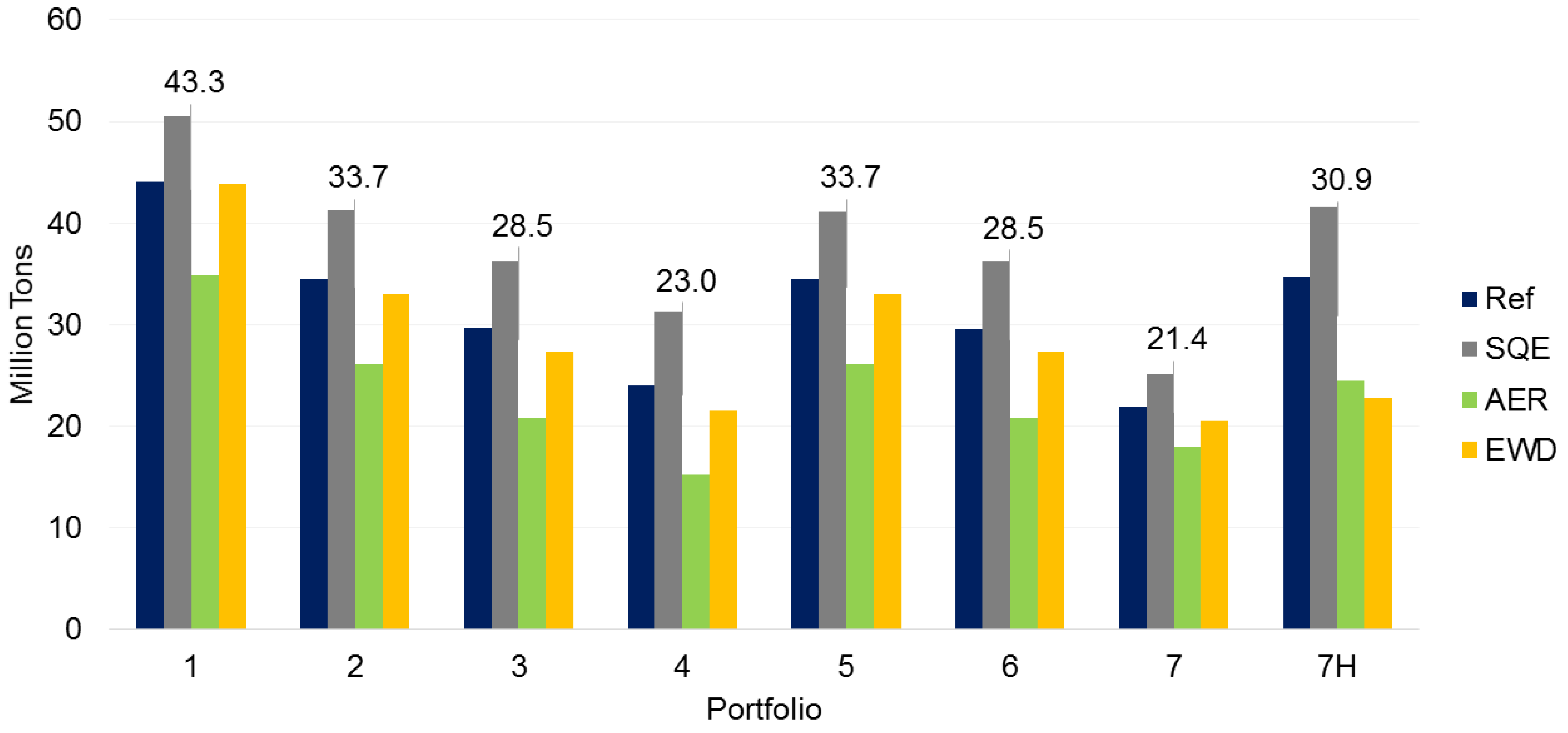
CO2 EMISSIONS – EXISTING FLEET ANALYSIS



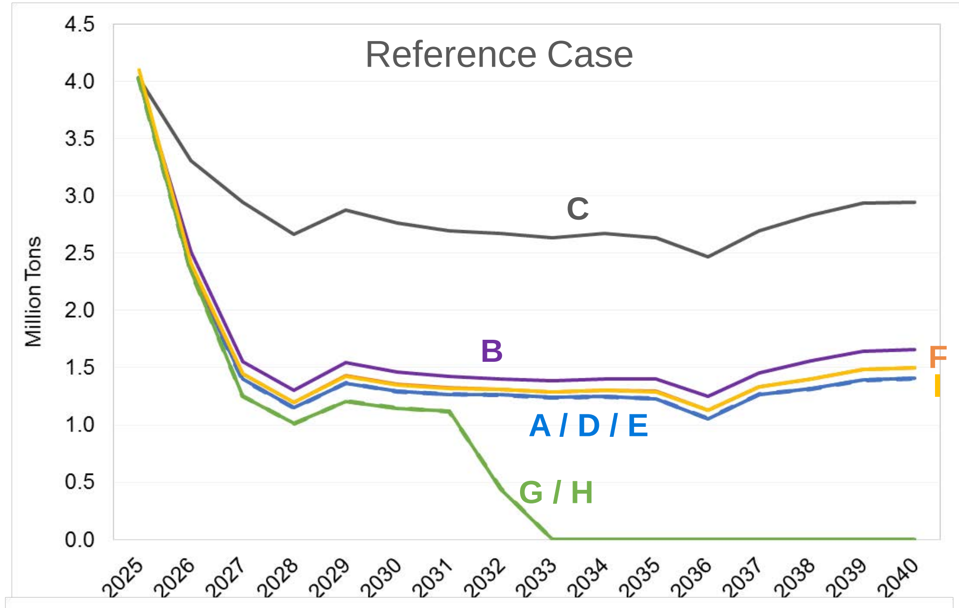
Key Points

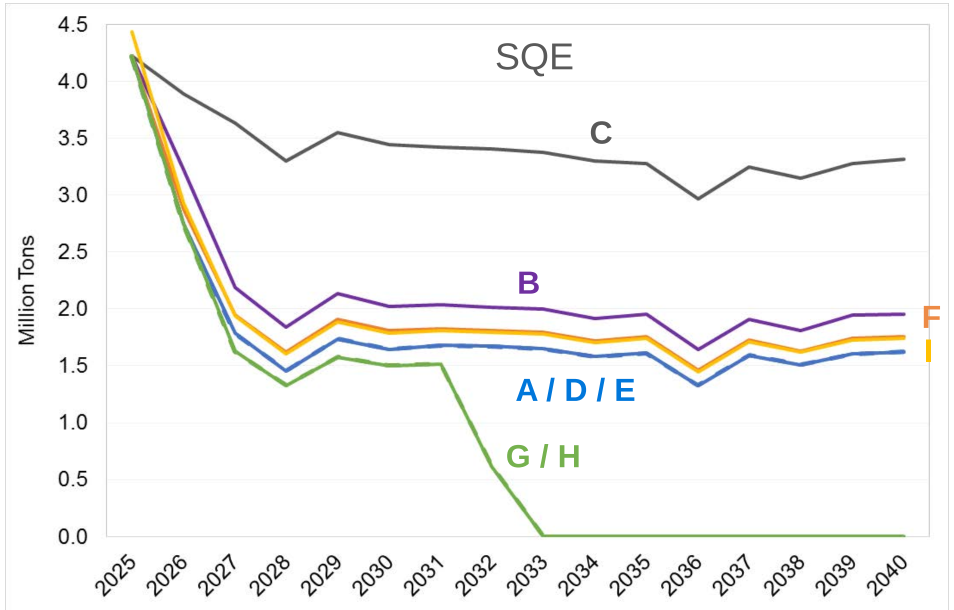
- Emission trajectories are largely driven by the Michigan City retirement date
- Portfolio 7H preserves the optionality to burn natural gas and continues to do so under Reference and SQE market conditions, while transitioning to hydrogen in AER and EWD

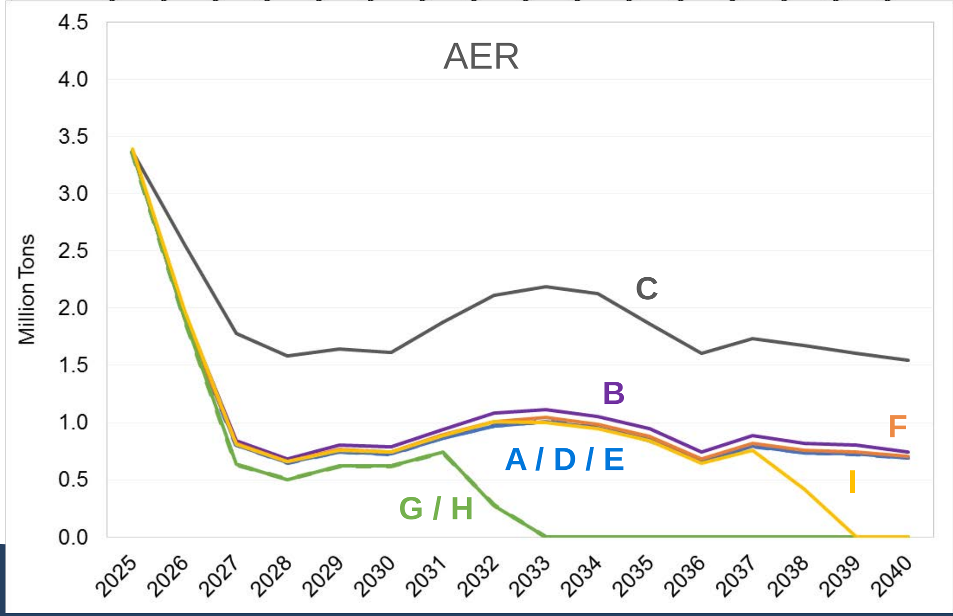
ENVIRONMENTAL STEWARDSHIP- 2024-2040 CUMULATIVE MILLION SHORT TONS OF CO2 – EXISTING FLEET ANALYSIS

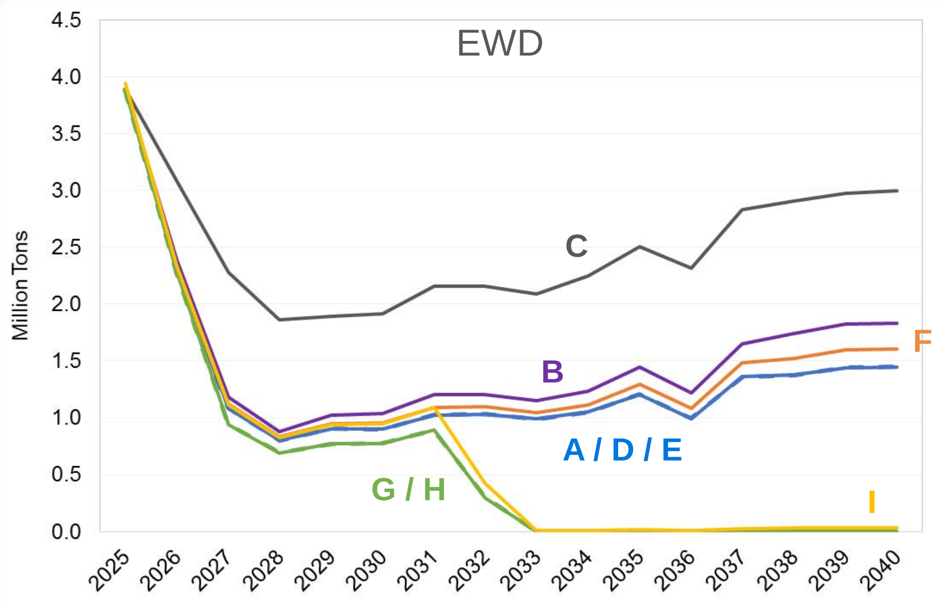


CO2 EMISSIONS – REPLACEMENT ANALYSIS





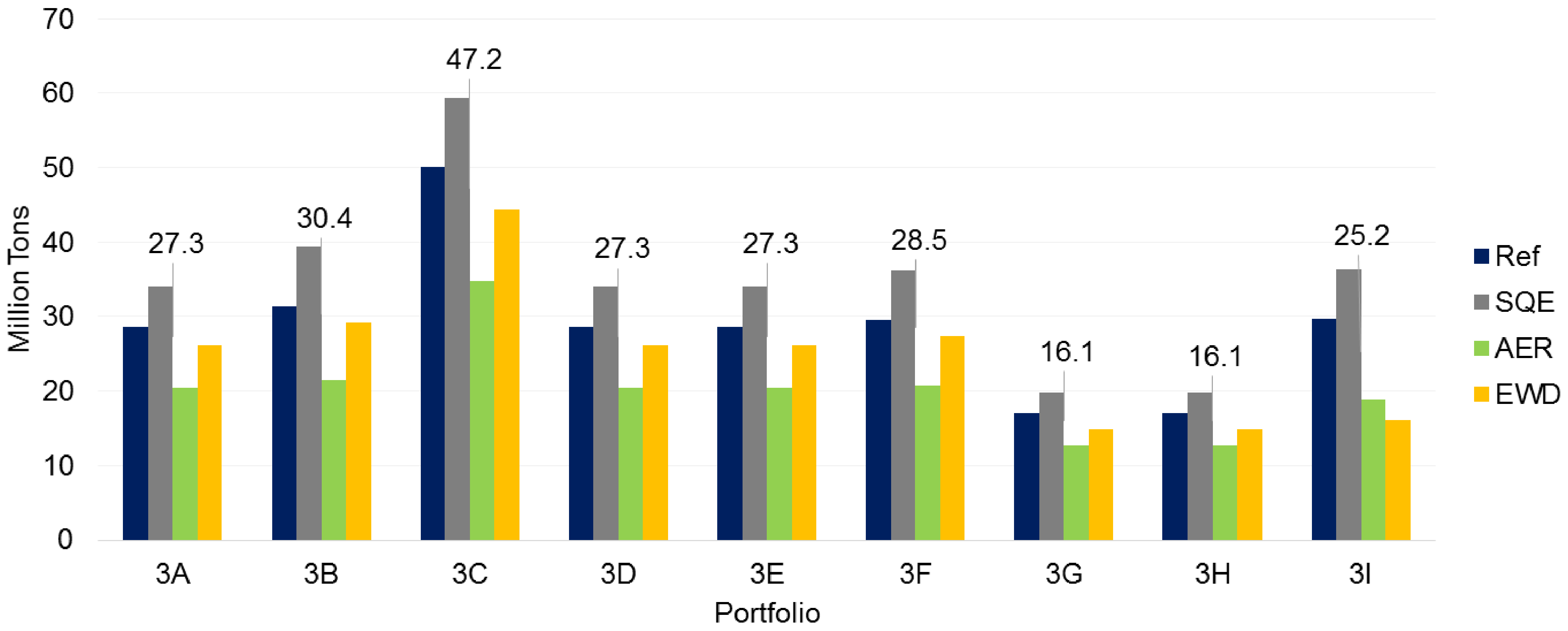




Key Points

- Gas plant dispatch varies across scenarios (due to fuel prices, carbon prices, surrounding MISO market drivers)
- Portfolio C (new CC) has the highest emissions
- Portfolio I preserves the optionality to burn natural gas and continues to do so under Reference and SQE market conditions, while transitioning to hydrogen in AER and EWD

ENVIRONMENTAL STEWARDSHIP- 2024-2040 CUMULATIVE MILLION SHORT TONS OF CO2 – REPLACEMENT ANALYSIS



KEY HYDROGEN PARAMETERS FOR MODELING

Short-Term: RFP Bids

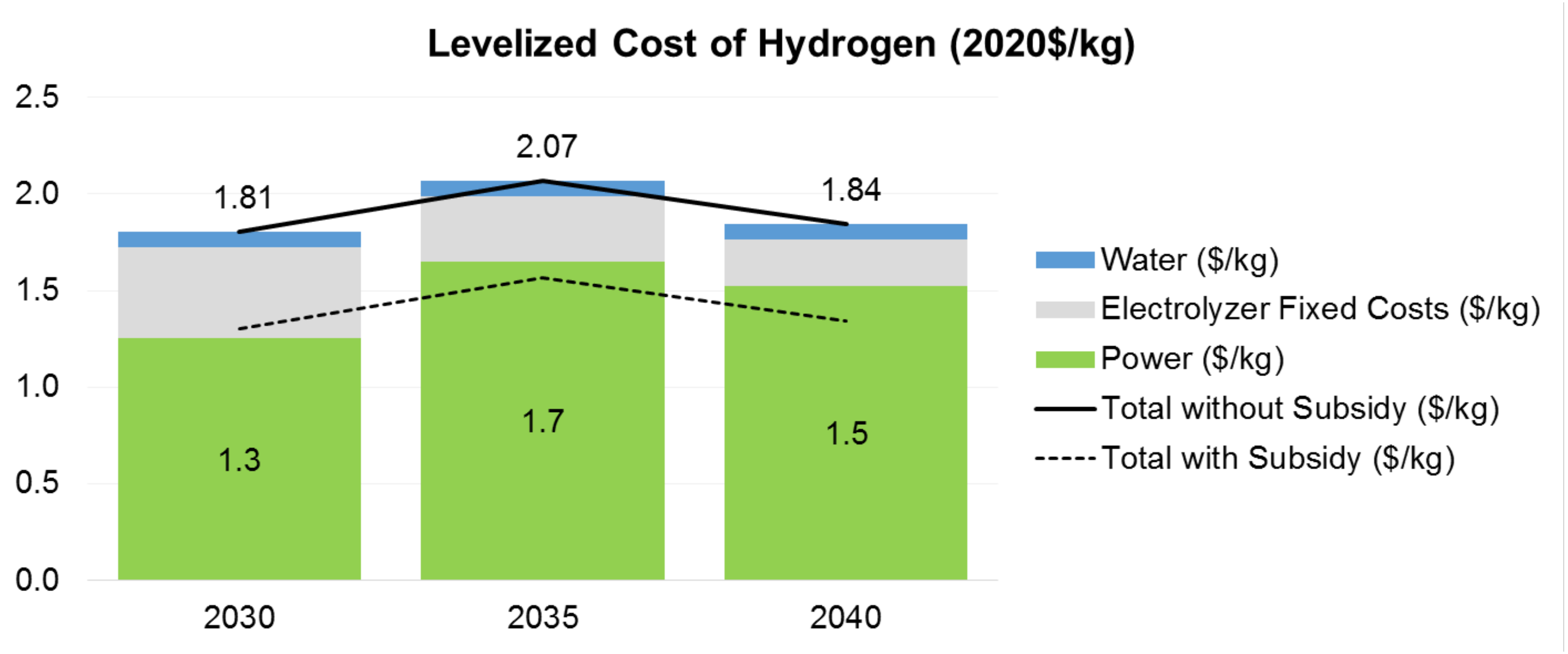
- **Sugar Creek Electrolyzer Pilot**
  - 20 MW electrolyzer at fixed PPA price starting 12/31/2025 (includes capex, FOM)
  - Daily production of 8,000 kg hydrogen, 2,920,000 kg annually (equates to less than 5% of total fuel at full capacity)
  - No additional retrofit costs at Sugar Creek required to be 5% hydrogen-enabled
- **5% Hydrogen-Enabled Peaker**
  - Additional fixed capacity payments associated with infrastructure to enable 5% hydrogen blending in *new* peaker development
  - Higher levels of hydrogen blending not contemplated and would be higher cost
  - No fuel supply (ie, NIPSCO would be responsible for delivering hydrogen to the plant)

Long-Term: Independent Cost Estimates

- **Long-term fuel cost trajectories were developed based on public and CRA forecasts to represent an all-in "market" cost of hydrogen production (and hence hydrogen fuel)**
  - Electrolyzer capex costs based on declining trajectory
  - Modest improvements in electrolyzer conversion efficiency to 74% by 2050
  - Electricity costs based on an optimized mix of renewables, battery storage, and market power purchases
  - Variable costs of water
  - Federal subsidy of \$0.50/kg evaluated as a sensitivity
- **Plant retrofit costs to enable Sugar Creek to blend up to 100% hydrogen**
  - ~\$300/kW investment assumed based on review of public sources and indicative turbine supplier data

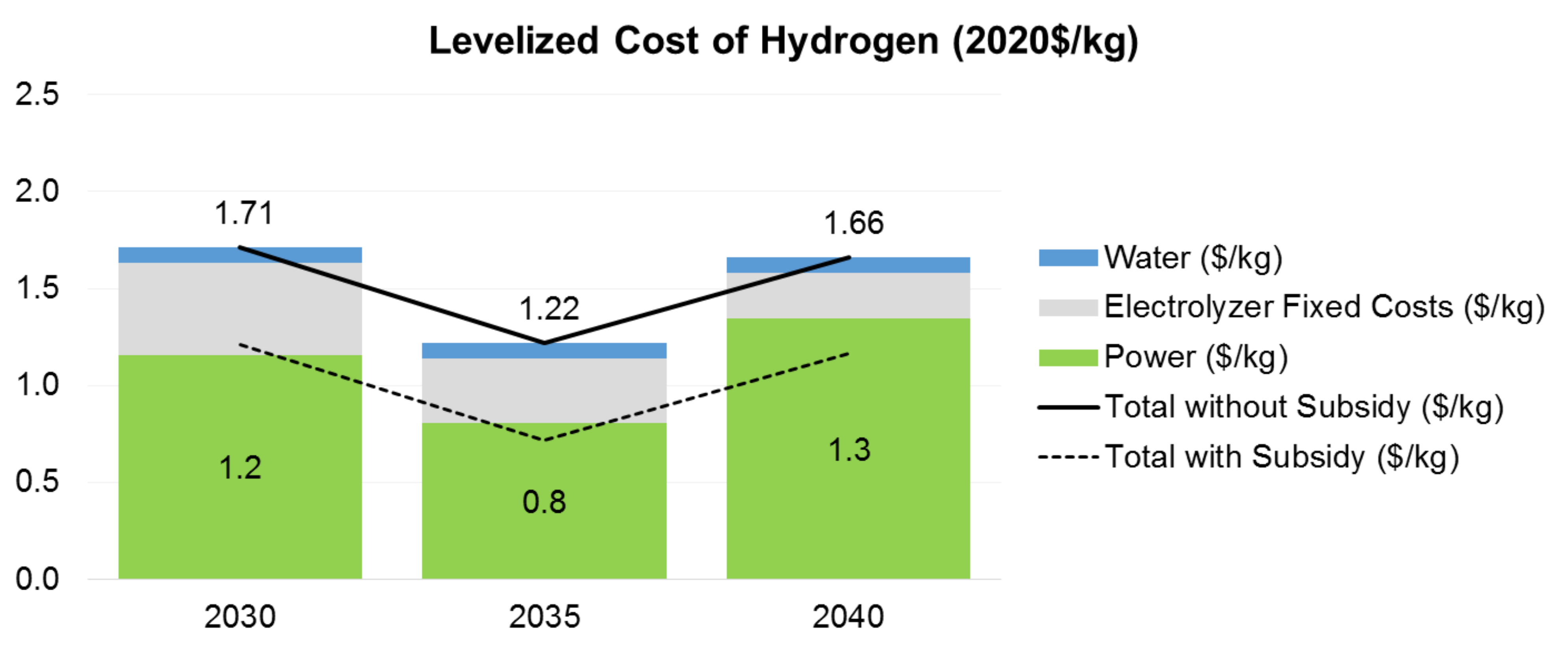
LONG-TERM GREEN HYDROGEN PRODUCTION COSTS – AER

ELECTRICITY COSTS BASED ON OPTIMIZED MIX OF RENEWABLES, BATTERY STORAGE, AND MARKET PURCHASES



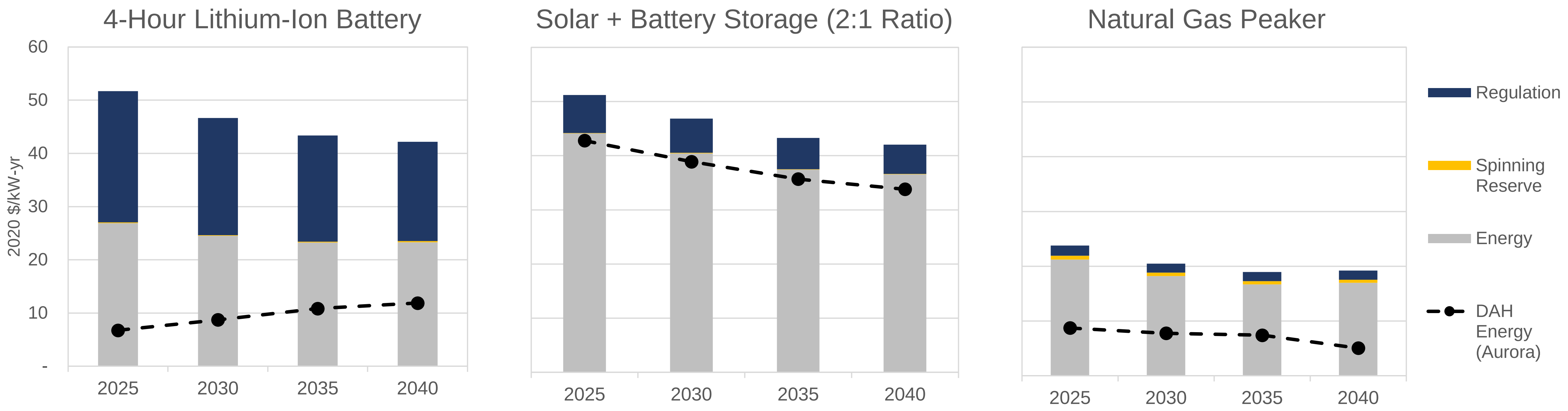
LONG-TERM GREEN HYDROGEN PRODUCTION COSTS – EWD

ELECTRICITY COSTS BASED ON OPTIMIZED MIX OF RENEWABLES, BATTERY STORAGE, AND MARKET PURCHASES



SUB-HOURLY ANALYSIS INDICATES POTENTIAL UPSIDE FOR STORAGE ASSETS

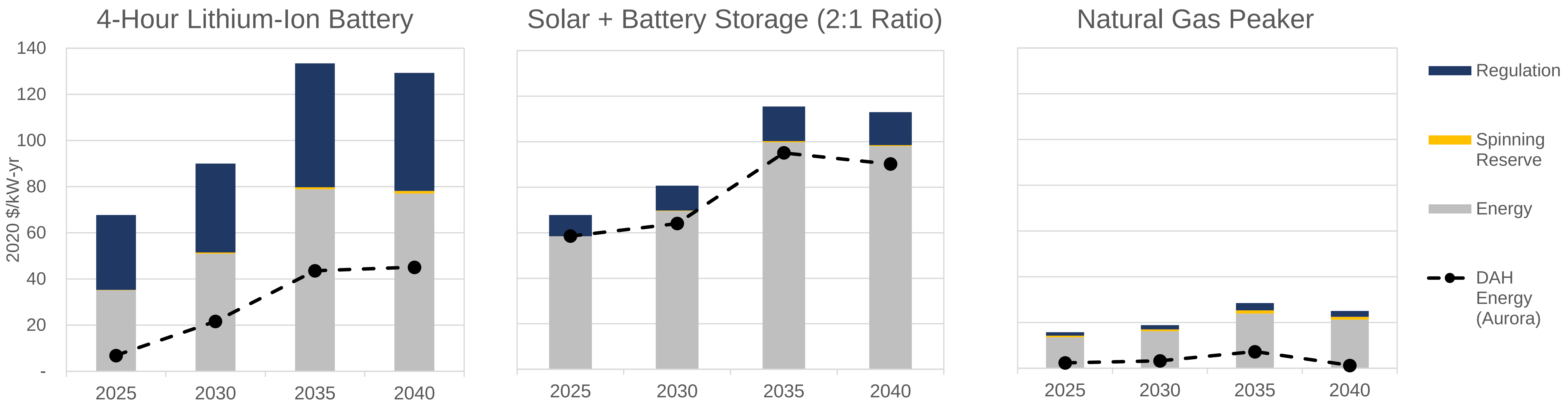
Status Quo Extended



- Lower overall power prices reduce margin expectations for all technologies, although premium between day ahead Aurora-based value and sub-hourly / ancillary services impact is comparable for solar + storage and gas peaker options
- Upside for stand-alone storage is mitigated over time as energy arbitrage opportunities are less valuable

SUB-HOURLY ANALYSIS INDICATES POTENTIAL UPSIDE FOR STORAGE ASSETS

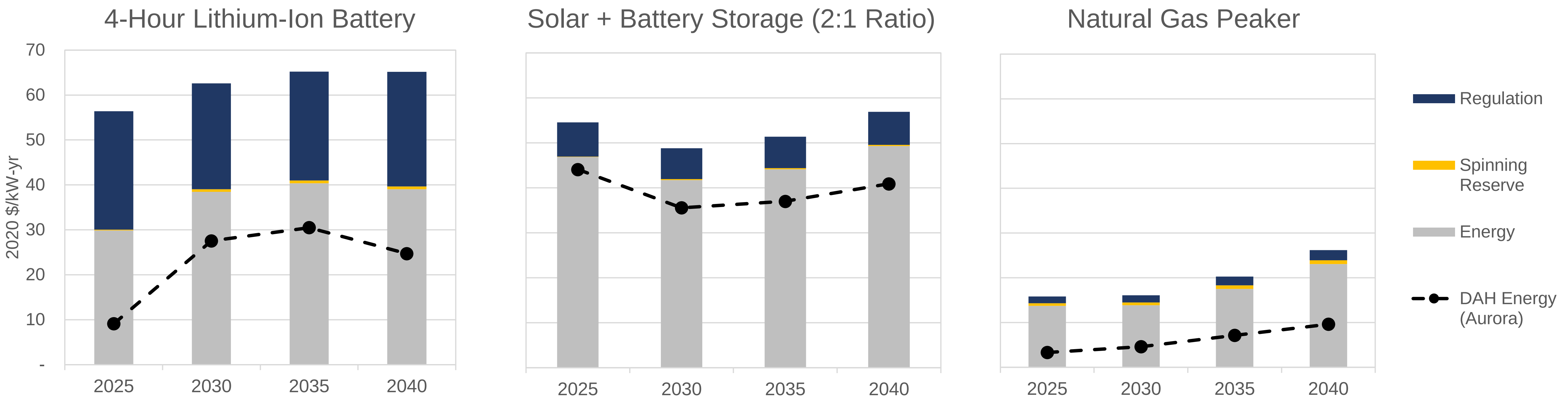
Aggressive Environmental Regulation



- Higher overall power prices increase margin opportunities, particularly for storage resources, which have significant upside potential with greater energy price spreads and higher ancillary services prices
- Natural gas peaker upside is more limited, given high carbon price and high natural gas price embedded in this scenario

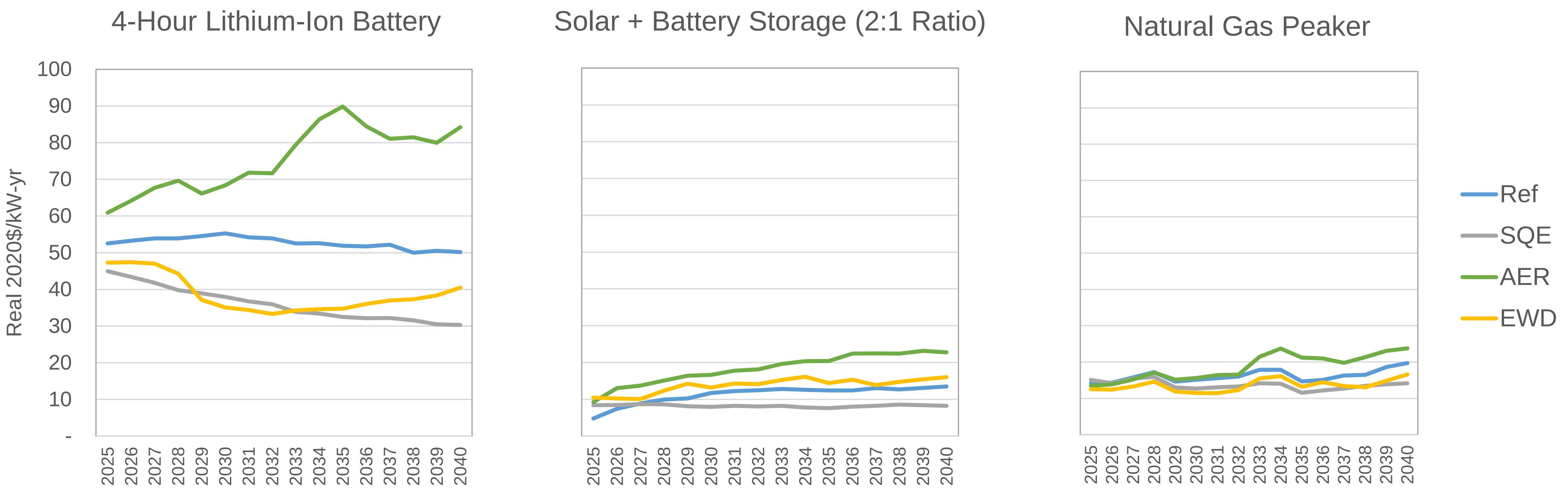
SUB-HOURLY ANALYSIS INDICATES POTENTIAL UPSIDE FOR STORAGE ASSETS

Economy-Wide Decarbonization



- Prices in the EWD scenario are lower than the Reference Case, but renewable penetration is high, resulting in sustained upside opportunities for battery resources

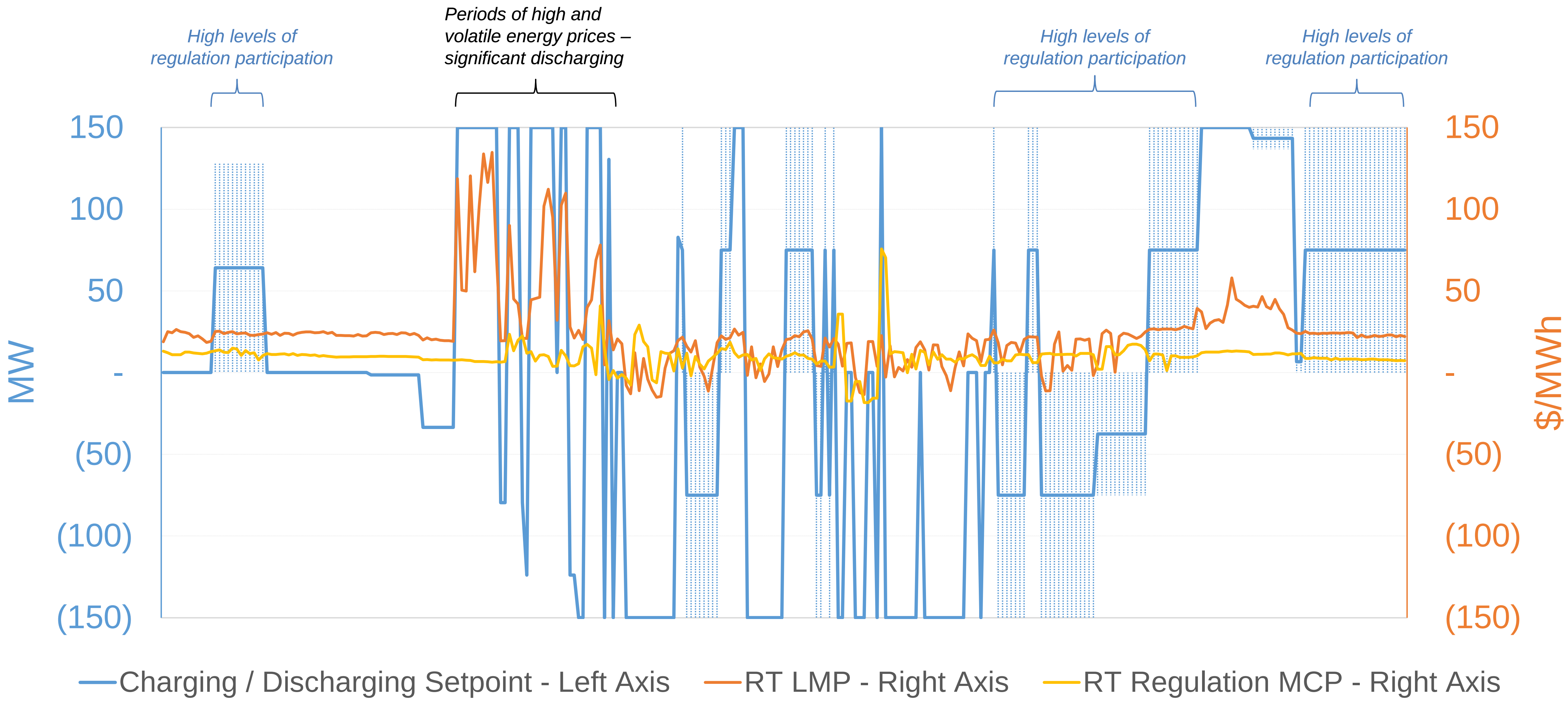
INCREMENTAL REAL TIME ENERGY AND ANCILLARY SERVICES VALUE ACROSS SCENARIOS



- Stand-alone storage resources have the largest upside opportunity in the sub-hourly real time energy and ancillary services markets
- The upside is greatest in the AER scenario, with highest prices and larger price spreads

ESOP DISPATCH EXAMPLE – SAMPLE 2025 SUMMER DAY

5-Minute Granularity across a Single Day – Reference Case



REPLACEMENT ANALYSIS SCORECARD

Preliminary	A	B	C	D	E	F	G	H	I
Replacement Theme	Thermal PPAs, solar and storage	Non-service territory gas peaking (no early storage)	Natural gas dominant (CC)	No new thermal resources; solar dominant w/ storage	Thermal PPAs plus storage and solar	Local gas peaker, plus solar and storage	Solar dominant w/ storage, plus retire Sugar Creek	All renewables and storage, plus retire Sugar Creek (Portfolio 7)	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Cost To Customer 30-year NPV of revenue requirement (Ref Case) $M	$10,461 +$150 5	$10,332 +$21 2	$10,312 - 1	$10,438 +$126 4	$10,467 +$156 6	$10,426 +$115 3	$11,042 +$730 8	$11,090 +$778 9	$10,792 +$480 7 ← Rank
Cost Certainty Scenario Range (NPVRR) $M	$2,359 +$1,035 5	$2,782 +$1,458 8	$3,208 +1,885 9	$2,322 +$998 4	$2,538 +$1,215 6	$2,748 +$1,424 7	$1,324 - 1	$1,553 +$229 2	$1,855 +$531 3
Cost Risk – Highest Scenario NPVRR $M	$12,015 +$207 5	$12,182 +$373 7	$12,518 +$709 9	$11,965 +$156 3	$12,126 +$317 6	$12,243 +$434 8	$11,809 - 1	$12,011 +$202 4	$11,848 +$39 2
Cost Risk – Stochastic 95% CVAR – 50%	$104 +$21 6	$92 +$9 3	$83 - 1	$104 +$21 6	$98 +$15 5	$97 +$14 4	$123 +$40 9	$114 +$31 8	$87 +$4 2
Lower Cost Opp. Lowest Scenario NPVRR $M	$9,657 +$348 6	$9,400 +$91 2	$9,309 - 1	$9,644 +$334 5	$9,588 +$278 4	$9,495 +$186 3	$10,485 +$1,176 9	$10,458 +$1,149 8	$9,933 +$684 7
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)	27.3 +11.3 4	30.4 +14.4 8	47.2 +31.2 9	27.3 +11.3 4	27.3 +11.3 4	28.5 +12.4 7	16.1 - 1	16.1 - 1	25.2 +9.2 3
Reliability	*To be added in final scorecard*								
Resource Optionality MW-weighted duration of 2027 generation commitments (yrs.)	20.01 3	20.53 5	23.55 9	20.37 4	21.15 6	22.12 8	17.00 1	18.19 2	21.46 7
Local Economy NPV of property taxes	$420 5	$388 9	$451 3	$417 6	$413 8	$416 7	$486 1	$477 2	$421 4

QUANTA TECHNOLOGY WILL ASSIST NIPSCO WITH THE REVIEW AND DEVELOPMENT OF METRICS, SCORING METHODOLOGY, AND RANKING OF PROJECTS AND PORTFOLIOS

Scope of Work

Review and Assessment of Metrics	•Critical assessment of existing metrics •Propose Additional metrics tailored to assure supply resilience and reliability needs of systems with high penetration of inverter-based resources (IBR)
NIPSCO's Reliability Needs & Constraints	•High-level study/assessment of NIPSCO's system constraints, reliability needs, and grid value to integrating IBRs. •Examples: Need for more reserves & inertial response; locational limits due to short circuit strength; Grid value of Non-Wire Solutions, …etc.
Scoring Methodology	•Review the existing qualitative scoring methodology •Propose "simplified" quantitative scoring of each selected reliability attribute, suitable for single/multiple technology projects.
Portfolios Scoring & Ranking	•Apply the scoring methodology to select projects or portfolios, and evaluate reasonableness of results •Develop a ranking methodology •Rank selected portfolios
Stakeholder Engagement	•Support regulatory and market outreach initiatives as requested by NIPSCO

Northern Indiana Public Service Company LLC
2021 Integrated Resource Planning
Public Advisory Meeting #4
SUMMARY

September 21, 2021

Welcome and Introductions
Alison Becker, Manager Regulatory Policy, NIPSCO

Ms. Alison Becker, Manager, Regulatory Policy, welcomed participants to the virtual meeting and provided a safety moment on Mental Health Awareness. She then discussed the Webex meeting protocols and walked through the agenda for the day. She then introduced Mike Hooper, President and Chief Operating Officer of NIPSCO, to kick off the meeting.

Welcome
Mike Hooper, President and COO, NIPSCO

Mr. Hooper welcomed participants and thanked them for the high level of participation. Mr. Hooper then highlighted the importance of the mental health safety topic, given the continued pandemic environment. He reminded participants of the generation path NIPSCO has been on and also highlighted the period of transition that NIPSCO, along with the rest of the state and country, is in. Mr. Hooper emphasized that the dynamic period makes it critical for NIPSCO to remain flexible and adaptable. Mr. Hooper also discussed that NIPSCO is focused on engaging with stakeholders to ensure continued considerations of all aspects and perspectives during this energy transition. He closed with an emphasis on the criticality of stakeholder feedback.

Participants had the following questions and comments, with answers provided after:

- What is the schedule for notifying participants as to whether or not their asset has been chosen for further negotiation?
  - NIPSCO is currently preparing a letter for those who are not moving to the next round.

Public Advisory Process and Updates from Last Meeting
Fred Gomos, Director, Strategy and Risk Integration, NiSource

Mr. Fred Gomos, Director Strategy and Risk Integration, NiSource, began the section with an overview of NIPSCO's planning process and highlighted updates to the Stakeholder Advisory Meeting Roadmap. He announced that the October 12 Public Advisory Meeting has been converted to a Technical Webinar focused on the Reliability Assessment and that the final Public Advisory Meeting will take place on October 21, with the IRP being submitted to the

Indiana Utility Regulatory Commission by November 15. Mr. Gomos then walked through one-on-one stakeholder interactions with the Citizens Action Coalition of Indiana and the Indiana Office of Utility Consumer Counselor since the July public advisory meeting. He then provided a reminder of NIPSCO's resource planning approach.

Resource Planning Activity Review
Fred Gomos, Director, Strategy and Risk Integration, NiSource
Pat Augustine, Vice President, Charles River Associates ("CRA")

Mr. Pat Augustine, Vice President at CRA, reminded participants of the five step planning process core to NIPSCO's resource planning approach. He started with an overview of the key planning questions and themes in the 2021 IRP and reviewed the major elements of the integrated scorecard framework. He then walked through NIPSCO's process of developing external market perspectives, including the use of both scenarios and stochastic analysis to perform a robust assessment of risk. He then reviewed the major scenarios and stochastic components shared in previous stakeholder meetings. Finally, Mr. Augustine discussed the development of integrated resource strategies or portfolios, sharing NIPSCO's current capacity and energy positions on both an annual and hourly basis.

Participants had the following questions and comments, with answers provided after:

- What basis did you use for the lower capacity credit (slide 17)?
    - NIPSCO relied heavily on published Midcontinent Independent System Operator, Inc. ("MISO") studies, including those summarized in the February report MISO published on its Renewable Integration Impact Assessment ("RIIA") study. NIPSCO mapped the solar additions included in the IRP's four market scenarios to numbers in MISO's RIIA report, along with accompanying capacity credit projections. It should be noted that the credits shown on slide 17 are for the summer, while solar credits for the winter were assumed to be below 10% across the modeling horizon.
- It does not seem to make sense for the federal government to offer long-term Investment Tax Credit for renewables when there is a mandate for decarbonization or aggressive regulation (slide 17).
    - That is a fair comment and part of the federal policy debate happening now. The current proposed bills being debated in Congress right now actually do both - 10 year extensions to tax credits, plus a clean electricity payment program that incentivizes significant year-to-year growth in renewables or other clean energy. Therefore, the Economy Wide Decarbonization scenario actually represents a plausible aggressive decarbonization scenario for planning purposes, although we will need to wait to see what makes its way into law.
- What summer and winter Planning Reserve Margins ("PRMs") are you using (Slide 20)?
    - We are using 9.4% for both summer and winter. Winter could be higher based on some indicative MISO evaluations, but for purposes of the IRP, 9.4% is used for both.
- Is that 9.4% adjusted for NIPSCO's coincidence factor?
    - Yes, it is adjusted to be coincident to the MISO peak, or in other words, NIPSCO's load when MISO has its peak. The coincident peak is approximately 95-97% of NIPSCO's internal peak.
- Can you talk a little about the capacity purchases on this slide in the front years? Meaning, are they forward bi-laterals or anticipated market purchases (slide 20)?

  - The capacity purchases are forward bi-lateral deals and are already committed to by NIPSCO (short-term contracts). They are tied to capacity secured in advance of Schahfer Units 14/15 retiring. In addition, some of the renewable replacement projects for the remaining units at Schahfer have in-service dates that do not line up with MISO planning years, so secured capacity is also related to that gap.
- It was mentioned that capacity was purchased to replace Units 14 & 15. What is that replacement capacity resource?
  - These bi-lateral contracts are for zonal resource credits to meet capacity obligations within MISO. They are not tied to a discrete resource. Note that those capacity costs associated with the 2021/2022 and 2022/2023 planning years will NOT be recovered from customers.
- Can you explain why the capacity costs are not being recovered from customers? Is this for a particular time, and/or amount?
  - Given that Schahfer Units 14 and 15 are still in base rates even as they retire prior to 2023, the required replacement capacity purchases will not be charged to customers.

Existing Fleet Analysis
Fred Gomos, Director, Strategy and Risk Integration, NiSource
Pat Augustine, Vice President, CRA

Mr. Gomos re-introduced the IRP's two-step analytical framework and the various reasons why the analysis is performed in two parts. Mr. Gomos walked through the composition of eight existing fleet portfolios that evaluate different retirement dates for NIPSCO's remaining fossil units. Mr. Gomos then transitioned to Mr. Augustine who walked through the existing fleet portfolio optimization results. Mr. Augustine also reviewed the deterministic cost to customer net present value of revenue requirement ("NPVRR") results and observations for all existing fleet portfolios. Next, Mr. Augustine walked through the NPVRR results and observations across the four scenarios. He then shared the existing fleet analysis scorecard framework and results. Mr. Augustine provided a detailed overview of portfolio level observations, and transitioned back to Mr. Gomos to discuss overarching existing fleet analysis observations.

Participants had the following questions and comments, with answers provided after:

- Totally get that it's iterative but I think one thing that would really help understand how you arrive at those portfolios is to also see the results of those minimally constrained runs (Slide 25).
  - The Aurora model is used to perform least cost optimization analysis within each of the eight existing fleet concepts, with the results illustrated on the next slide. We can provide additional material in spreadsheet format if stakeholders wish to review the annual capacity additions or other detail from the modeling.
- Was a carbon capture, utilization, and storage ("CCUS") retrofit assumed in 2030 in any case?
  - The eligible resources for the optimization modeling are based on projects offered through the request for proposal ("RFP") process. With respect to CCUS, no bids from that technology class were received in the RFP, so NIPSCO did not evaluate it as a replacement option in this phase of the analysis.
- The question is whether any of the environmental scenarios assumed CCUS would be required to keep a combined cycle gas turbine on line.

    - No, CCUS is not included in the NIPSCO portfolio analysis based on what was received from the RFP. However, as discussed in the May stakeholder meeting, it is possible that CCUS will be a viable long-term decarbonization option throughout the market. In addition, NIPSCO plans to document a potential CCUS option on the Sugar Creek plant in the IRP report section on emerging technology.
- What life is assumed for the capital related to the Sugar Creek update?
    - We assume a 30-year life, meaning that capital would be spread over 30 years for modeling purposes in accordance with revenue requirement accounting principles.
- What is the term of the capacity contracts?
    - Both thermal contracts are 10 years.
- I assume "SC Electrolyzer Pilot" is not a reference to a synchronous condenser, can you explain?
    - Yes, it is the Sugar Creek electrolyzer pilot. This was a 20 MW electrolyzer pilot bid into the RFP, with costs only associated with the electrolyzer. NIPSCO would have to acquire the electricity to electrolyze water into hydrogen, which would be burned at Sugar Creek. This option was effectively "forced into" Portfolio 7H. Note that the appendix includes details on assumptions for hydrogen-related costs over the long-term.
- A net present value ("NPV") analysis is not a proxy for rates. At least one other utility is now providing both an NPV and a rate impact analysis. Why not provide both?
    - Using planning-level analysis from an IRP to calculate specific customer rates by class is difficult. The NPV is a good metric, and it is based on annual revenue requirements. NIPSCO is willing to share annual revenue requirements and sales obligations, as a proxy for overall generation rates as was done in the last IRP.
- Why did you not consider retirement of Michigan City in 2025 instead of 2024? Would that be possible? Rather than consider a portfolio that is not viable?
    - The answer is the same whether it is 2024 or 2025. Transmission project completion is key, and the delta in costs between Portfolio 3 and 4 is very small anyway. 2024 was a good bookend (as soon as possible without transmission or replacement capacity considerations), and 2026 was the next window that was viable.
- Follow up on rates- customers pay bills not rates and comparing rates alone will make any activity that reduces sales look more expensive even if bills are cheaper.
    - That's a fair point, and once you layer in things like demand side management which change customer usage, the simple revenue requirement divided by sales metric may not be the best comparison.
- This discussion should be continued. Difficulty in calculation is not sufficient to not consider.
    - The difficulty is focused on translating planning-level financial modeling to specific rate structures by class. However, NIPSCO would be happy to have a one-on-one to facilitate continuing that conversation and is able to provide annual revenue requirement details so that stakeholders can assess costs over time in different ways.
- It seems like the difference between Portfolio 6 and 7 is largely driven by the "fossil free by 2032" constraint and not so much the difference in Michigan City 12's retirement date. Could you also run a variation on Portfolio 7 that retires Michigan City 12 in 2026 given that your other portfolios are showing a benefit to that earlier retirement date?

- o Yes, that has actually been done in the replacement analysis phase. Since Portfolio 3 (2026 retirement was lowest cost), NIPSCO took that and built out several more concepts, including one very similar to Portfolio 7. That will be covered in next section of the presentation.

- Why are you continuing to use a 30 year NPV when the industry norm is 20 year NPV, not to mention the high uncertainty in years 21-30.
  - o The industry norm is not necessarily 20years, as utilities often look at longer term NPVs. It is also important to note that the fundamental modeling period (with fundamental forecasts for fuel costs, carbon costs, power prices, and plant dispatch) is 20 years, with the last 10-year period being an end-effects extrapolation on variable costs, with all financial treatment of rate base accounting extended through the full 30 years.
- Why are carbon dioxide ("CO2") emissions so much higher for 7H?
  - o The CO2 emissions on the scorecard represent the average across all four scenarios. In two of the four scenarios, it will likely to be more economic for Sugar Creek to burn more natural gas than hydrogen, so Portfolio 7H is effectively the same as other portfolios that retain Sugar Creek in those cases. In addition, Portfolio 7H also retains Michigan City until 2028, so it has higher emissions associated with that plant than other portfolios that retire Michigan City earlier. There is an appendix slide with annual trajectories of CO2 emissions for all portfolios across all four scenarios that provides more detail.

Replacement Analysis
Fred Gomos, Director, Strategy and Risk Integration, NiSource
Pat Augustine, Vice President, CRA

Mr. Gomos introduced the core questions and key decisions in the replacement analysis, the second part of the two-step IRP analysis. Mr. Gomos illustrated the expected supply-demand outlook following future resource retirements and shared the replacement concepts developed across frameworks assessing differing levels of emissions and dispatchability. He explained that this framework drove the development of nine replacement portfolios, noting that resource combinations were constructed based on RFP projects. Mr. Gomos then transitioned to Mr. Augustine who provided an overview of the specific installed capacity additions in each of the nine portfolios, along with summer and winter supply-demand balance summaries. Mr. Augustine then walked through cost to customer results and observations across each of the four scenarios. Mr. Augustine also discussed stochastic results across the nine portfolios and the changing risk profile of different resource options over time. He then shared the replacement analysis scorecard framework and results. Mr. Augustine provided a detailed review of portfolio level observations and transitioned back to Mr. Gomos to discuss overarching replacement analysis observations. Mr. Gomos then pivoted to NIPSCO's approach to reliability in the IRP and shared that reliability will be discussed in more detail in the upcoming October 12 Technical Webinar. As part of that discussion, Mr. Augustine introduced the sub-hourly ancillary services analysis that was performed and that will be reviewed in more detail on October 12.

Participants had the following questions and comments, with answers provided after:

- Regarding slide 40, I'm not sure I totally follow how you went from optimized portfolios with overall similar NPVRRs (on slide 27) to now portfolios that are mostly more expensive than those optimized portfolios. Similarly, now the portfolio with the combined cycle ("CC") is the lowest cost, but a CC was not picked at all in the optimized portfolio, I do not understand that either. And it may be that looking at the modeling files would be the easiest way to unpack that.

  - NIPSCO is happy to share portfolio construction details and outputs so that you can review further. Regarding the first part of the question, these replacement portfolios are based on the same mix of resources optimized from the existing fleet analysis, but as was done in 2018, the long-term generic build-outs are specifically set to a split of purchased power agreements ("PPAs") and owned resource options, while the existing fleet analysis was based solely on extrapolated costs for PPAs. NIPSCO has typically found that on a pure cost to customer perspective, PPAs are slightly lower cost than owned assets, so this is why the long-term mix of owned and PPA resources results in slightly higher NPVRRs than the existing fleet analysis with only PPAs. With regard to the second part of the question, the CC portfolio violates the net sales energy constraint that was enforced in the existing fleet analysis. In the replacement analysis, we have allowed that constraint to be violated to specifically test a CC theme. As you will see, this portfolio is net long in the energy market and thus subject to significant scenario-based cost risk.

- Why does utility ownership raise the costs? Is this based on bids from developers or other factors like tax credit normalization?
  - In this RFP and in the past, NIPSCO has found that ownership has a slight cost premium to PPAs based on RFP bids, although there are other considerations that NIPSCO also looks at when evaluating owned vs. PPA resources. With regard to normalization, tax credits are assumed to be monetized through tax equity partnerships, which avoid utility normalization issues.
- Portfolio A meets reserve margin. Why is it cited as non-viable?
  - Portfolio A meets the summer PRM and just barely meets the winter reserve margin in the graphic shown on the slide for 2027 (slide 39). However, over time, the portfolio continues to add more solar than storage and thus does not meet the winter reserve margin, given winter load growth expectations and other portfolio changes. There is an appendix slide for 2040 that illustrates this.
- Repeating the comment "The importance of flexibility cannot be understated." Is the value of flexibility explicitly considered in these portfolios? Any consideration of small nuclear reactors ("SMRs")?
  - Flexibility is important, which is why NIPSCO considers multiple options for evaluation and assesses different scorecard metrics including one around commitment duration of the portfolio. With regard to SMRs, because the Company is constrained to the universe of RFP bids and because no SMR bids were received, they have not been explicitly evaluated. However, that does not preclude them from being long-term options as NIPSCO performs additional IRPs in the future.
- Why are you constrained on resource options to the RFP?
  - NIPSCO wants bids that can be transacted against as part of the Action Plan that comes out of the IRP. Although additional diligence needs to be performed, and although NIPSCO may run additional RFPs in the future, RFP data provides a level of commitment with somewhat binding prices and collapses uncertainty. When you introduce concepts like SMR, there is not real-world pricing that can be relied upon. However, as noted, it could be a resource in the future, and the 2021 IRP will not lock-in all future resource decisions for the next 20 years.
- Since we're talking about dispatch of resources 19 years down the road, can you also perform this analysis with flow batteries and multi-day storage?

  - We did not get a lot of bids in the RFP for such technologies, although a few conceptual offers were introduced for long-duration storage. In some sense, Portfolio I with hydrogen picks up the value of long-duration, highly dispatchable clean energy technology. In addition, storage technology is likely to evolve and inherent in that question is the theme of flexibility, so that as new technologies come forward, NIPSCO can take advantage of them. This means that the Optimized Portfolio concepts over the long-term that are developed now in 2021 do not imply that NIPSCO's preferred portfolio will be locking in such additions. Instead, as technology evolves, the Company can continue to assess it.
- Well said, that's exactly what I wanted to say. I wouldn't expect these technologies to show up now for an online date 19 years down the road.
- Why is Portfolio A considered higher carbon compared to D and E mid-carbon when all 3 have the same average carbon emissions?
  - Portfolio A has thermal PPAs, so within its dispatchability category, it was considered more carbon-intensive than the others. However it is a fair question, since these thermal PPAs are not energy resources, but simply provide capacity from thermal plants might have higher carbon emissions in the wider MISO market.

Analysis Next Steps
Erin Whitehead, Vice President, Regulatory and Major Accounts, NIPSCO

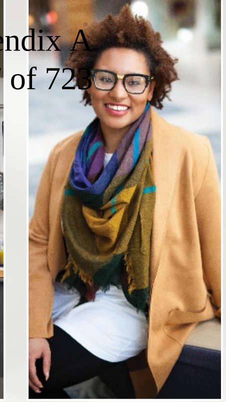
Ms. Whitehead, Vice President, Regulatory and Major Accounts for NIPSCO, closed the session by thanking attendees for their participation and feedback. She then outlined key next steps in the IRP process and invited participants to reach out for one-on-one discussions.

September 21, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Emily	Abbott	Invenergy
Anthony	Alvarez	OUCC
Shawn	Anderson	NiSource
Rahul	Anilkumar	Quanta Technology
Cynthia	Armstrong	Indiana Office of Utility Consumer Counselor
Pat	Augustine	Charles River Associates
Ed	Baptista	GEG Renewables
Vernon	Beck	Nipsco
Matt	Bell	Reliable Energy, Inc.
Greg	Berning	NiSource
Rosann	Bloom	NextEra Energy Resources, LLC
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	Indiana Utility Regulatory Commission
Matt	Boys	GlidePath Power Solutions
Shane	Bradford	CenterPoint Energy
Sean	Brady	clean grid alliance
Don	Bull	NIPSCO
Bryan	Burns	Nipsco
Andy	Campbell	NIPSCO
Kelly	Carmichael	NiSource
Gilles	Charriere	Sierra Club/ NIPSCO customer
Richard	Ciciarellie	Schonfeld
Kody	Clark	Bank of America
John	Cleaveland	NIPSCO
Tom	Cofer	C21 Affiliated
Alex	Cooley	NiSource
Jeffrey	Corder	St. Joseph Energy Center
Jordan	Covely	Inovateus Solar LLC
Cory	Dutcher	General Electric Company - Power Division
Jeffery	Earl	Reliable Energy
Suzanne	Escudier	Origis Energy
Samuel	Fazekas	nipsco
William	Fine	Indiana Office of Utility Consumer Counselor
Neil	Fitzharris	EDP Renewables North America
Michael	Fortini	DTE
Lora	Fosberg	
Bill	Fowler	Shell Energy North America (US), L.P.
Steve	Francis	SEED
Julia	Friedman	Opower/Oracle Utilities
Joene	Gileguy-Konan	Ranger Power
Richard	Gillingham	Hoosier Energy
Mike	Girata	NiSource
Fred	Gomos	Nisource
Lana	Gonoratsky	Enbala
Benjamin	Gorman	Key Capture Energy

September 21, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Doug	Gotham	State Utility Forecasting Group
Robert	Greskowiak	Invenergy LLC
Paul	Griffin	Indeck Energy Services
Jack	Groves	ENERGY SOUTHWEST INC.
Stacie	Gruca	Indiana Office of Utility Consumer Counselor
Aida	Haigh	NiSource
Andrew	Hamilton	Ranger Power
Joni	Hamson	EDF Renewables
John	Haselden	Indiana Office of the Utility Consumer Counselort
Sean	He	Verition Fund Management
Ryan	Heater	Indiana Utility Regulatory Commission
Robert	Heidorn	NiSource
John	Hejkal	Tenaska, Inc.
Max	Henderson	NiSource
Stephen	Holcomb	NiSource
Jaime	Holland	NextEra
Mike	Hooper	NIPSCO
Chelsea	Hotaling	Energy Futures Group
Jim	Hummel	Duke Energy
Jim	Huston	Indiana Utility Regulatory Commission
Ben	Inskeep	EQ Research
Matthew	Johnson	NextEra Energy Resources
Michelle	Kang	Charles River Associates
Will	Kenworthy	Vote Solar
Nick	Kessler	CenterPoint Energy
Shawn	Kestler	Kestler Energy Consulting, LLC.
Mo	Klefeker	Primary Energy
Reagan	Kurtz	Citizens Action Coalition of Indiana
Natalie	Ladd	NiSource
Willard	Ladd	Development Partners
Tim	Lasocki	Orion Renewable Energy Group LLC
Anne	Lenzen	Opower
Bryan	Likins	NIPSCO
James	Loewen	Everspring Energy
Simon	Lomax	Better Jobs Coalition (consultant)
Caleb	Loveman	Indiana Office of Utility Consumer Counselor
Caleb	Loveman	Indiana Office of Utility Consumer Counselor
Allison	Lowitz	Galehead Development
Wendy	Lussier	NIPSCO
Jamie	Mante	nipsco
Greg	Martin	BP
Christian	Martinez	Leeward Renewable Energy
Mike	McBride	Nipsco
Tara	McElmurry	NIPSCO
Emily	Medine	EVA

September 21, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Zachary	Melda	NextEra Energy
Michael	Melvin	NIPSCO
Erik	Miller	AES
Sophia	Miller	Ranger Power
Mike	Mooney	Hoosier Energy
Danny	Musher	Key Capture Energy
David	Nderitu	SUFG
Kerwin	Olson	Citizens Action Coalition of IN
April	Paronish	Indiana Office of Utility Consumer Counselor
Richard	Pate	Pate & Associates
Bob	Pauley	IURC
Bob	Pauley	IURC
Rockey	Pollard	
Rockey	Pollard	NiSource, Inc.
Timothy	Powers	Inovateus Solar LLC
Brett	Radulovich	NiSource
Jeff	Reed	Indiana Office of Utility Consumer Counselor
Adam	Rickel	NextEra Energy Resources
Robert	Ridge	NIPSCO
Tonya	Rine	CenterPoint Energy
Clayton	Robinson	Cordelio Power
Stephen	Rodocanachi	Hartree Partners
Kurt	Sangster	NIPSCO / NiSource
Jamalyn	Sarver	Hallador Energy Company
Cliff	Scott	NIPSCO
Robert	Sears	NIPSCO
Rob	Seren	NIPSCO
Brad	Shearson	National Grid Renewables
Laura	Sigward	bp
Anna	Sommer	EFG
Daniel	Spellman	Orion Renewable Energy Group LLC
Jennifer	Staciwa	NIPSCO
Karl	Stanley	NiSource
Sarah	Steinberg	Advanced Energy Economy
Dave	Strom	Primary Energy Recycling
Ron	Talbot	NIPSCO
Ryan	Tedeschi	NIPSCO
Dale	Thomas	IURC
Greg	Trewitt	TREW Energy
Maureen	Turman	NiSource
Chris	Turnure	NiSource
Edward	Twarok	NiSource
Darian	Unruh	Utility Regulatory Commission
Gregory	Van Horssen	Van Horssen Law & Government, PLLC
Will	Vance	AES Indiana

September 21, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Chris	Vickery	
Nathan	Vogel	Inovateus Solar LLC
John	Wagner	NIPSCO
Nancy	Walter	Just Transition Northwest Indiana
Jennifer	Washburn	CAC
Patrick	Welch	X-Elio North America
Amanda	Wells	Duke Energy
Erin	Whitehead	NIPSCO
Raisa	Wieser	NextEra Energy Resources
Ryan	Wilhelmus	CenterPoint Energy
J. Scott	Yaeger	Southern Illinois Generation Company
Monica	Yocum	NIPSCO

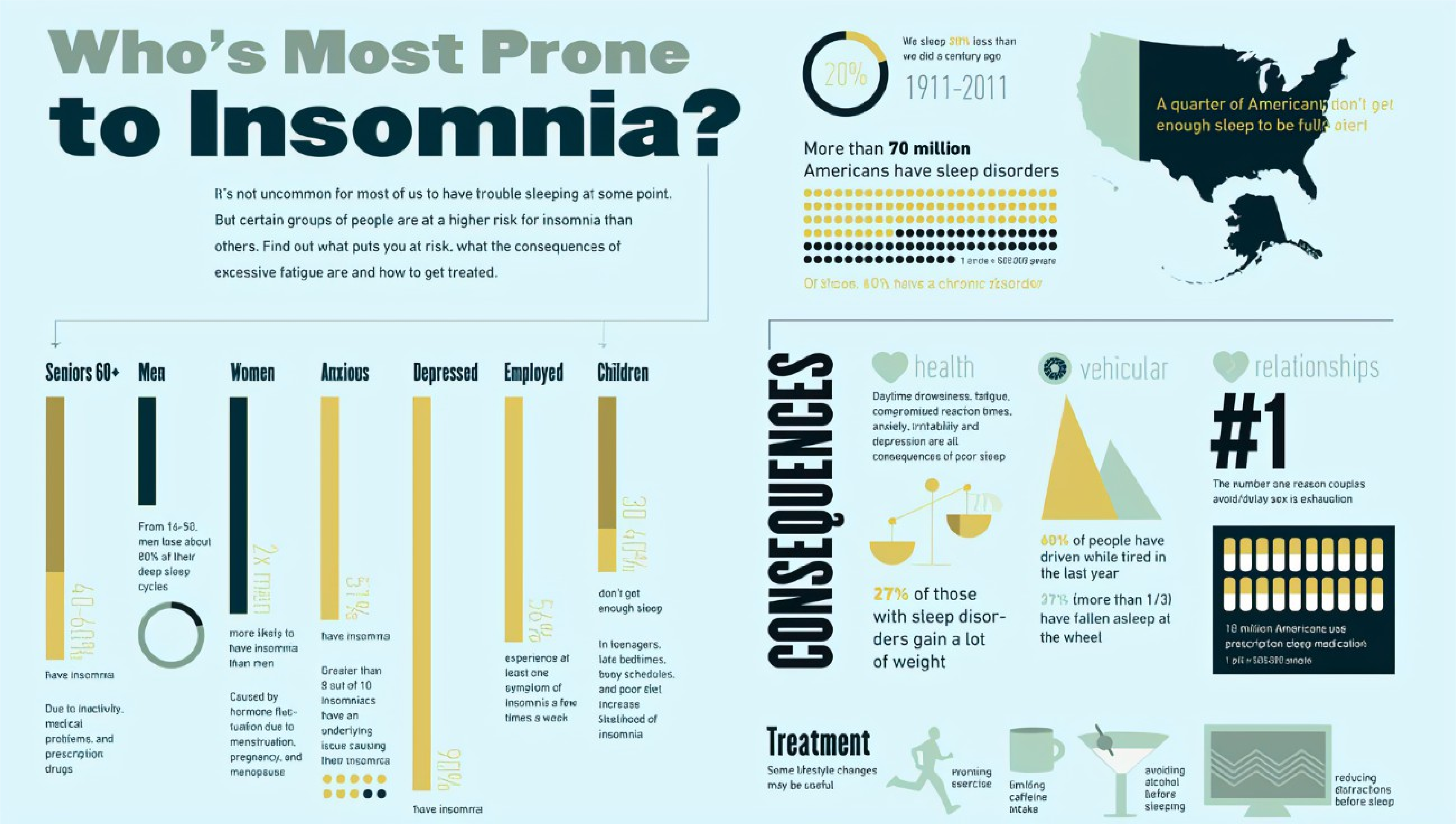
2021 NIPSCO Integrated Resource Plan

Technical Webinar

October 12th, 2021
9:00AM-12:00PM CT

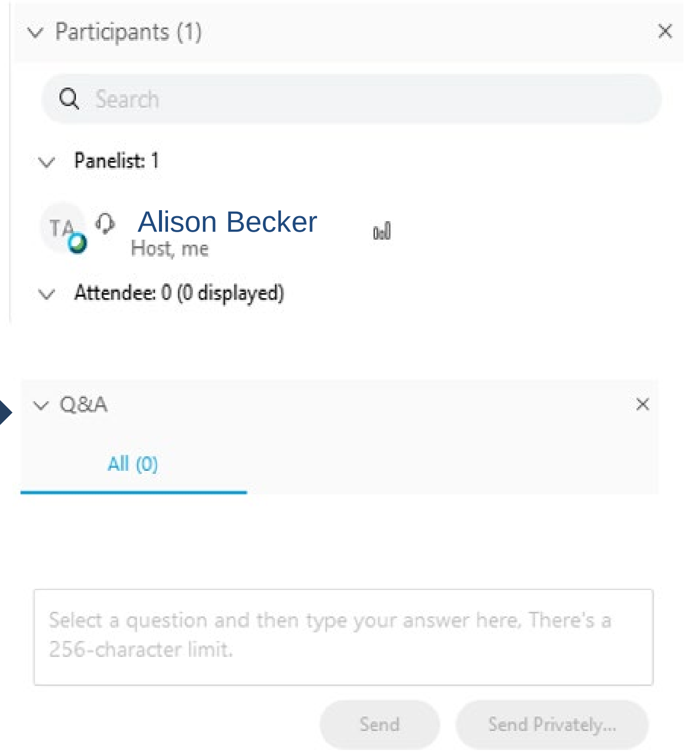



SAFETY MOMENT



TECHNICAL WEBINAR 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
9:00-9:05AM	Webinar Introduction, Safety Moment, Meeting Protocols, Agenda	Alison Becker, Manager Regulatory Policy, NIPSCO
9:05-9:15AM	Reliability Approach in the IRP	Fred Gomos, Director Strategy & Risk Integration, NiSource
9:15-9:45AM	Economic Reliability Analysis - Real-Time Market Dynamics & Ancillary Services	Pat Augustine, Vice President, CRA Goran Vojvodic, Principal, CRA
9:45-10:00AM	Break	
10:00-11:55AM	Qualitative Assessment of Reliability Attributes - Scoring Criteria & Results	Fred Gomos, Director Strategy & Risk Integration, NiSource Hisham Othman, VP, Transmission and Regulatory Consulting, Quanta Technology, LLC
11:55AM-12:00PM	Next Steps	Alison Becker, Manager Regulatory Policy, NIPSCO

RELIABILITY APPROACH IN THE IRP

Fred Gomos, Director Strategy & Risk Integration, NiSource

SETTING THE CONTEXT FOR ASSESSING RELIABILITY IN THE IRP

Previous Reliability Assessments

- In the 2018 IRP, NIPSCO began including reliability risk metric in the scorecard used to evaluate the performance of various resource portfolios

2018 Retirement Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO's 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

- As part of the 2020 Portfolio Analysis to support NIPSCO renewable filings, the reliability criteria were further expanded to consider operational flexibility

2020 Portfolio Analysis

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 34 year NPV of revenue requirement (Base scenario deterministic results)
Long term Optionality	• Flexibility resulting from combinations of ownership, duration, and diversity • Metric: MW weighted duration of generation commitments
Capital Requirement	• Estimated amount of capital investment required by portfolio • Metric: 2020 -2023 capital needs
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 UCAP MW sourced from non-gas resources)
Environmental	• Carbon intensity of portfolio / Total carbon emissions • Metric: Total annual carbon emissions (2030 short tons of CO_2) from the generation portfolio
Operational Flexibility	• The ability of the portfolio to be controlled in manner to respond to changes in load (dispatchable) • Metric: % of 2025 Controllable MW in gen. portfolio

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

CORE ECONOMIC MODELING CAPTURES SOME ELEMENTS OF RELIABILITY

Additional analysis and assessment is required for a fuller perspective

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

NIPSCO coordinates with MISO (Operating Reliability)

	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 or Emergency
Reliability Factors:	Reserve margin, ELCC and energy duration	Dispatchability, energy market risk exposure	Real Time Balancing System
IRP Modeling Approach:	Portfolio development constraints, with ELCC and seasonal accounting	Hourly dispatch analysis, including stochastic risk	**Ancillary services analysis (regulation, reserves), with sub-hourly granularity**

ECONOMIC ANALYSIS ALONE DO NOT CAPTURE THE FULL VALUE OF RESOURCES

- NIPSCO participates in the Midcontinent Independent System Operator (MISO) in a variety of roles with various compliance standards and responsibilities
- These responsibilities and standards are met in part by existing resources

Role	Definition
Energy, Capacity, and Ancillary Services Market Participant	Offers resources into markets and procures services on behalf of load to ensure adequate provision of energy, capacity, and ancillary services to support system reliability
Transmission Owner (TO)	Owns and maintains transmission facilities
Transmission Operator (TOP)	Responsible for the reliability of its local transmission system, and that operates or directs the operations of the transmission facilities

- As a TOP, NIPSCO is required to comply with a variety of NERC standards, particularly those that govern the reliable operation of the Bulk Electric System
  - o For example, EOP-005-3 governs system restoration from Black Start Resources. Part of NIPSCO's compliance plan relies on resources that currently exist within the portfolio and the NIPSCO TOP area
- Any resource decisions (retirement or replacement) will need to consider the implications for NIPSCO's ability to comply with NERC and MISO standards and procedures now and into future

An expanded scoring criteria can account for these additional considerations

ECONOMIC RELIABILITY ANALYSIS - REAL-TIME MARKET DYNAMICS & ANCILLARY SERVICES

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

SUB-HOURLY ENERGY AND ANCILLARY SERVICES EVALUATION

- While most of NIPSCO's existing portfolio (including new renewables) realize nearly all value from energy and capacity contributions, highly flexible resources that do not provide a lot of energy to the portfolio may still provide value in the form of ancillary services and in their ability to respond to changing market conditions in real time at sub-hourly granularity:
  - The MISO market currently operates markets for spinning reserves and regulation
  - FERC Order 841 also requires ISOs to redesign markets to accommodate energy storage

- Long-term market developments are uncertain, and fundamental evaluation of sub-hourly ancillary services markets is challenging, but the 2021 IRP has performed an analysis, incorporating:
  - 5-minute granularity for energy and ancillary services based on historical data observations and future energy market scenario projections
  - Operational parameters for various storage and gas peaking options
  - ***Incremental value, above and beyond what is picked up in the Aurora-based hourly energy dispatch, is assessed and summarized on a portfolio level***

FERC ORDER 841

- The Federal Energy Regulatory Commission ("FERC") issued Order No. 841 to boost competition in the storage sector and ensure that markets like MISO revise tariffs to establish participation models for storage resources, including:
  - Enablement of storage resources to provide energy and a variety of ancillary services
  - Allowance for storage resources to both receive and inject electric energy in a way that recognizes physical and operational characteristics and optimizes benefits to MISO through a single offer curve made up of both discharge segments and charge segments.
  - Ability of storage resources to participate and set prices in the Planning Reserve Auction (capacity market)
- MISO is responsible for implementing this order and has been granted an extension to June 6, 2022, to make its compliance filing
- NIPSCO will be involved in the MISO stakeholder process as the compliance filing is developed

ECONOMIC ANALYSIS OF REAL-TIME MARKET DYNAMICS + ANCILLARY SERVICES

- CRA's Energy Storage Operations (ESOP) model is an optimization program that estimates the value of storage and other flexible resources in the sub-hourly energy and ancillary services (A/S) markets, offering an estimate of the incremental value such resources offer beyond what can be estimated in the day-ahead hourly production cost framework of Aurora

Category	Aurora Portfolio Tool	ESOP
Market Coverage	Day-ahead energy	Energy plus ancillary services ("A/S") (frequency regulation and spinning reserves)
Time Granularity	Hourly, chronological	5-minute intervals, chronological
Time Horizon	20 years	Sample years (ie, 2025, 2030, 2035, 2040)
Pricing Inputs	MISO-wide fundamental analyses feed NIPSCO-specific portfolio dispatch	Historical data drives real-time and A/S pricing; specific asset types dispatched against price
Asset Parameters Used	Hourly ramp rate, storage cycle and depth of dispatch limits, storage efficiency	Sub-hourly ramp rate, storage cycle and depth of discharge limits, storage efficiency
Outputs	Portfolio-wide cost of service	Incremental value for specific asset type

RFP BID INFORMATION WAS USED FOR ASSET PARAMETERIZATION

- Generic Lithium-Ion storage and Natural Gas peaker operational parameters were developed from RFP bids
- Key parameters for sub-hourly modeling include ramp rates, cycle and state of charge limits for storage, and hours limits for the gas peaker

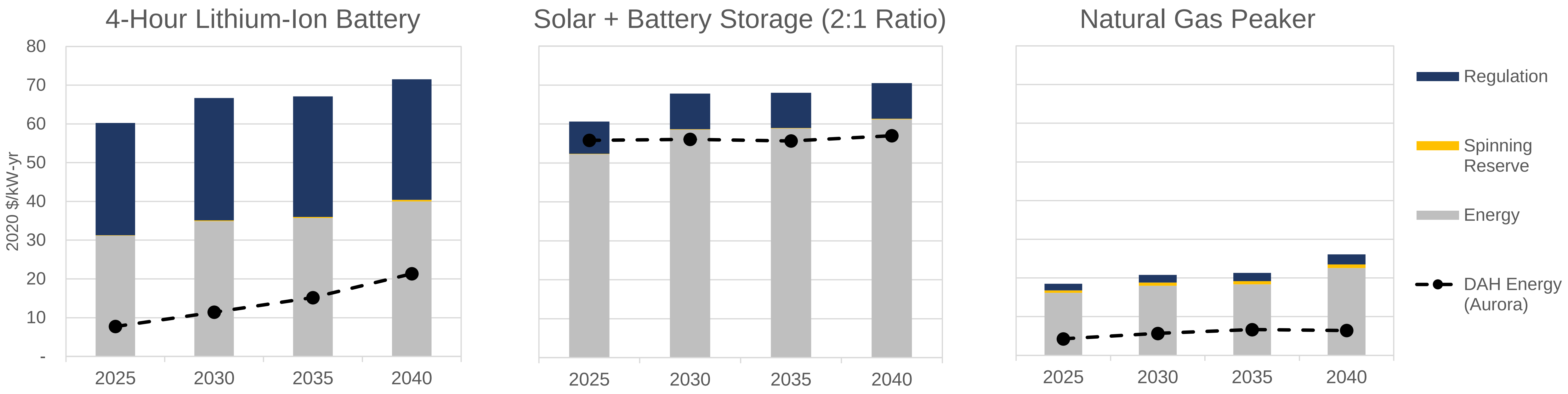
Lithium-Ion	Units	Value
Duration (Energy/Power Ratio)	hours	4
Roundtrip Efficiency	%	87%
Max Cycles per Year	#	365
Parasitic Load	%/hr	0.50%
Ramp Rate	%/min	100%
State of Charge Lower Bound*	%	0-20%
State of Charge Upper Bound*	%	80-100%
VOM	$/MWh	0

**Note that ranges were tested, but this variable had modest impact on the overall conclusions*

Gas Combustion Turbine	Units	Value
Heat Rate (Average Realized)	Btu/kWh	10,000
Ramp Rate	%/min	17%
Forced Outage	%	5.00%
Minimum Generation Percentage	%	50%
Max hours of operation / year	Hours/yr	3,000
Min Downtime	Hours	4
Min Runtime	Hours	2
Emission Rate	lb CO2/MMBtu	119
Start Costs	$/MW/start	18
VOM	$/MWh	2

SUB-HOURLY ANALYSIS INDICATES POTENTIAL UPSIDE FOR STORAGE ASSETS

Reference Case



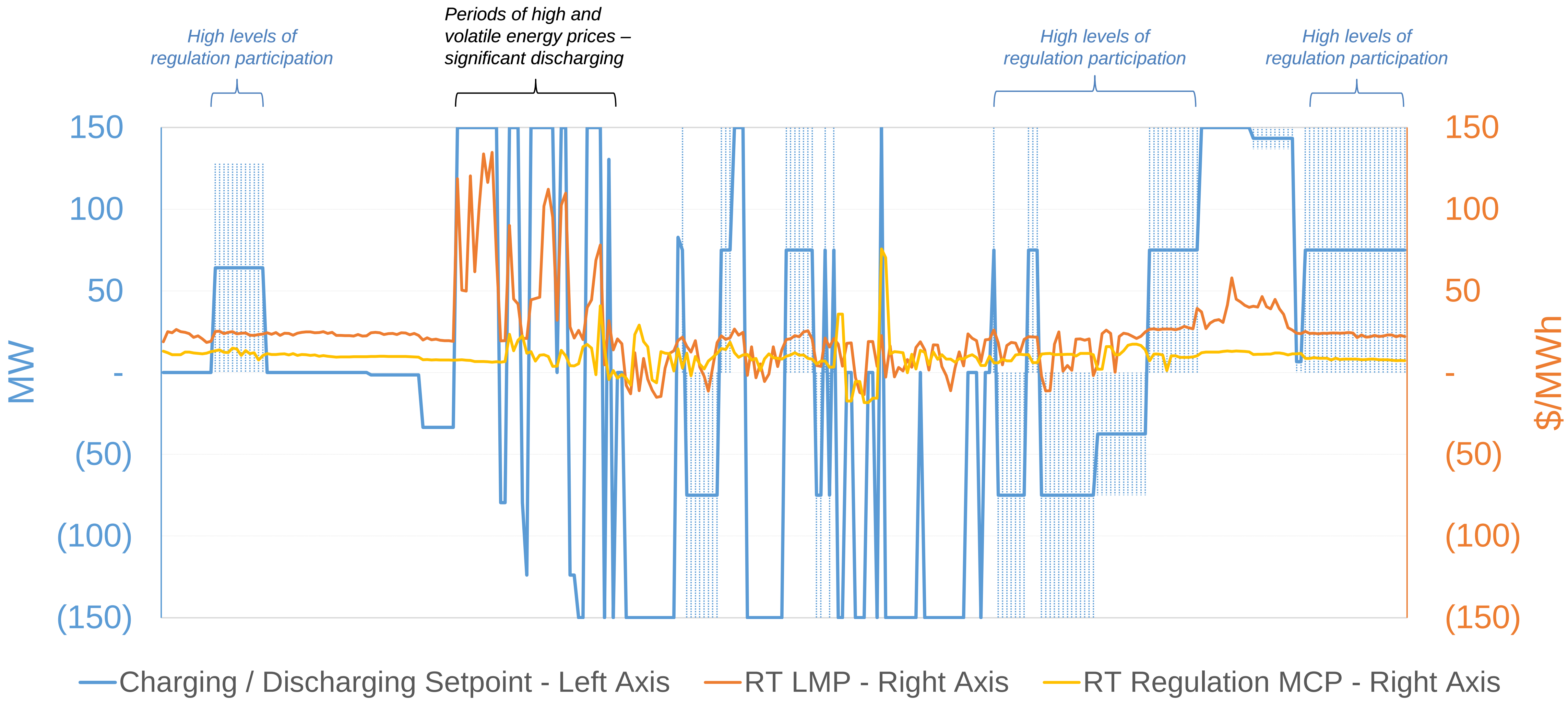
- Highly flexible battery able to respond in real time to changing price signals
- Can participate regularly in the regulation market (providing up and down service, given charging and discharging capabilities)

- Solar component provides significant energy value, which is also captured in fundamental modeling
- Investment tax credit rules limit the battery's flexibility and ability to take advantage of the regulation market (must charge predominantly from the solar)

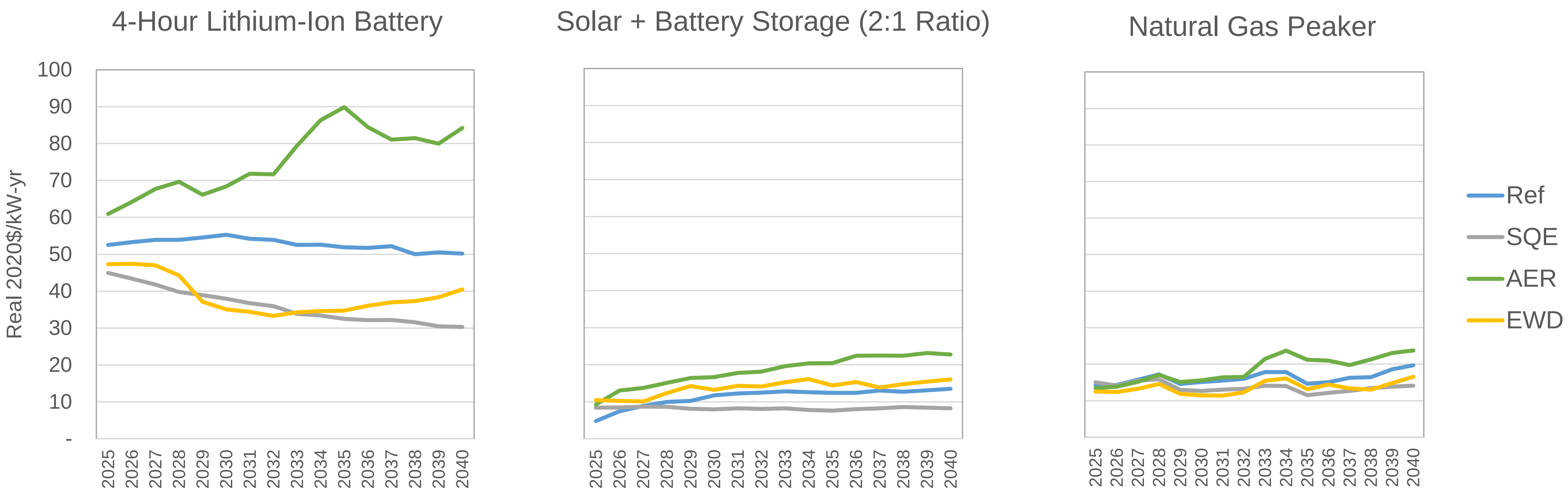
- Real-time volatility is greater than day ahead hourly dispatch value, providing value upside compared to Aurora modeling
- Regulation opportunities are only available when the unit is already operating for energy

ESOP DISPATCH EXAMPLE – SAMPLE 2025 SUMMER DAY

5-Minute Granularity across a Single Day – Reference Case



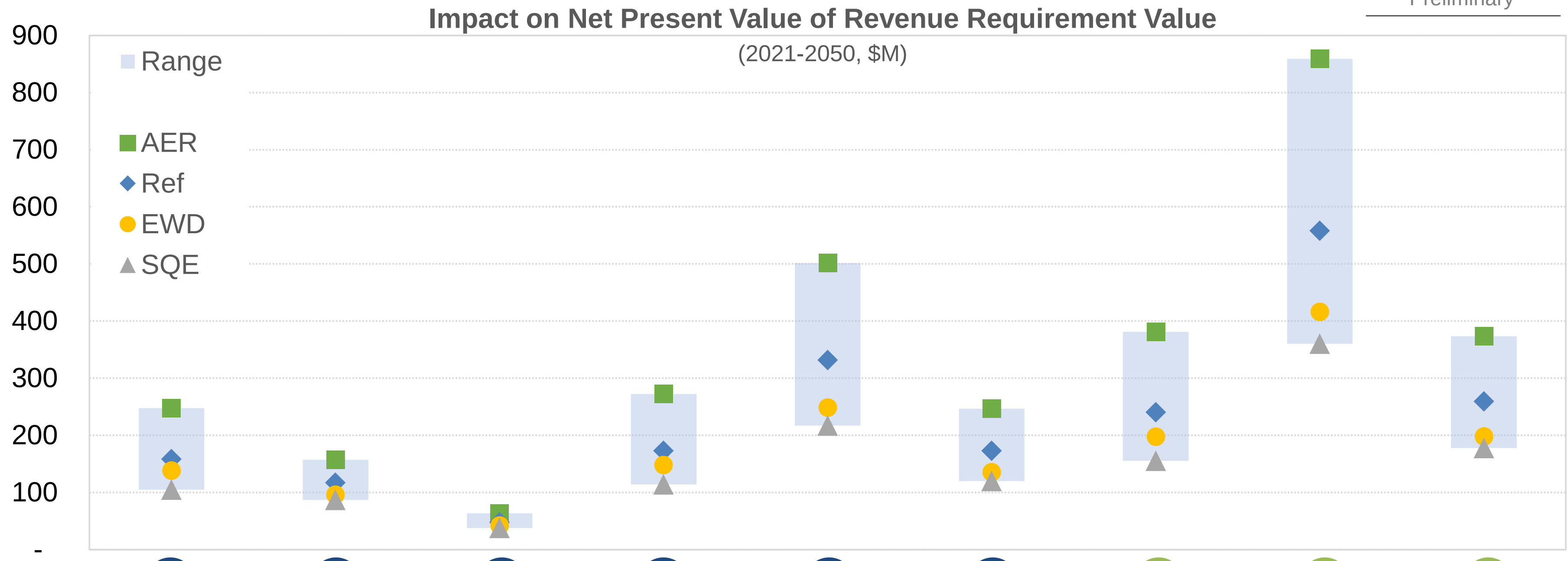
INCREMENTAL REAL TIME ENERGY AND ANCILLARY SERVICES VALUE ACROSS SCENARIOS



- Stand-alone storage resources have the largest upside opportunity in the sub-hourly energy and ancillary services markets
- The upside is greatest in the AER scenario, with highest prices and larger price spreads

RANGE OF ADDITIONAL VALUE OPPORTUNITY (NPVRR COST REDUCTION) BY PORTFOLIO

Preliminary



	A	B	C	D	E	F	G	H	I
Replacement Theme	**Thermal PPAs, solar and storage**	**Non-service territory gas peaking (no early storage)**	**Natural gas dominant (CC)**	**No new thermal resources; solar dominant w/ storage**	**Thermal PPAs plus storage and solar**	**Local gas peaker, plus solar and storage**	**Solar dominant w/ storage, plus retire Sugar Creek**	**All renewables and storage, plus retire Sugar Creek (Portfolio 7)**	**New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)**
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)

Observations

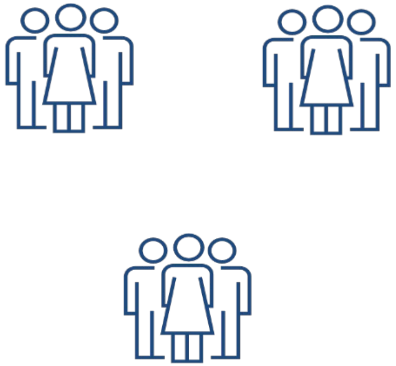
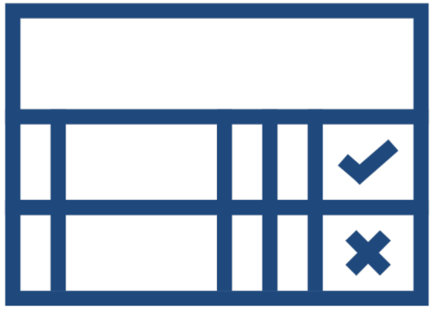
- *Additional value is uncertain and dependent on market rules evolution, MISO generation mix changes, and market participant behavior*
- Portfolios with the largest amounts of storage (E and H) have the greatest potential to lower NPVRR by capturing flexibility value that may manifest in the sub-hourly energy and ancillary services markets
- A wide range of value is possible, with higher prices and price spreads in the AER scenario driving higher estimates
- Results will be incorporated into the final replacement analysis scorecard

BREAK

QUALITATIVE ASSESSMENT OF RELIABILITY ATTRIBUTES - SCORING CRITERIA & RESULTS

Fred Gomos, Director Strategy & Risk Integration, NiSource
Hisham Othman, VP, Transmission and Regulatory Consulting, Quanta Technology, LLC

RELIABILITY ASSESSMENT PROCESS OVERVIEW

1 Define Initial Assessment Criteria	2 Obtain Stakeholder Feedback	3 Engage 3rd Party Reviewer	4 Incorporate into IRP Analysis Scorecard(s)
			
Collaborated with NIPSCO transmission planning and system operations group to develop initial framework and criteria	We will seek feedback from interested stakeholders who want to learn more about the assessment criteria and provide input and feedback	Engage a qualified 3rd party expert to review the assessment criteria, develop the scoring methodology and score and rank the various resource technologies under consideration	Incorporate the scoring and ranking results of the assessment into the IRP Analysis Scorecard(s)

RELIABILITY ASSESSMENT GUIDING PRINCIPLES

Resources Modeled	▪ The resources modeled are based on the replacement portfolios constructed for the Replacement Analysis
Transmission Upgrades	▪ Analysis incorporates planned Transmission projects
Time Period	▪ Resources are evaluated in 2030 after the Michigan City Unit 12 retirement
Evaluation	▪ The analysis is conducted at a planning level and, therefore, further evaluation and granular studies will be required in the future ▪ Individual resources from the 9 replacement portfolios are assessed based on the established reliability criteria. The score of the individual resources drive portfolio score

Goal

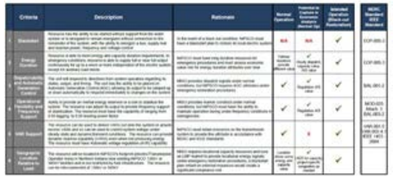
- **Understand potential reliability implications of potential resource additions to the NIPSCO portfolio**
- **Understand the range of potential mitigations required associated with different replacement portfolio strategies**

RELIABILITY ASSESSMENT AND RANKING

Assess NIPSCO's Reliability Needs

- Power Ramping
- Frequency Response
- Short Circuit Strength
- Flicker
- Black Start

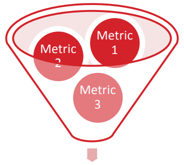
Review & Update Reliability Metrics



Apply a Series of Reliability Filters to IRP Portfolios

Scoring Criteria

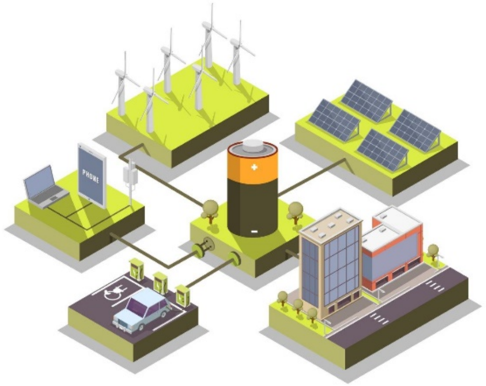
Ranking Portfolios



ESSENTIAL RELIABILITY SERVICES - OVERVIEW

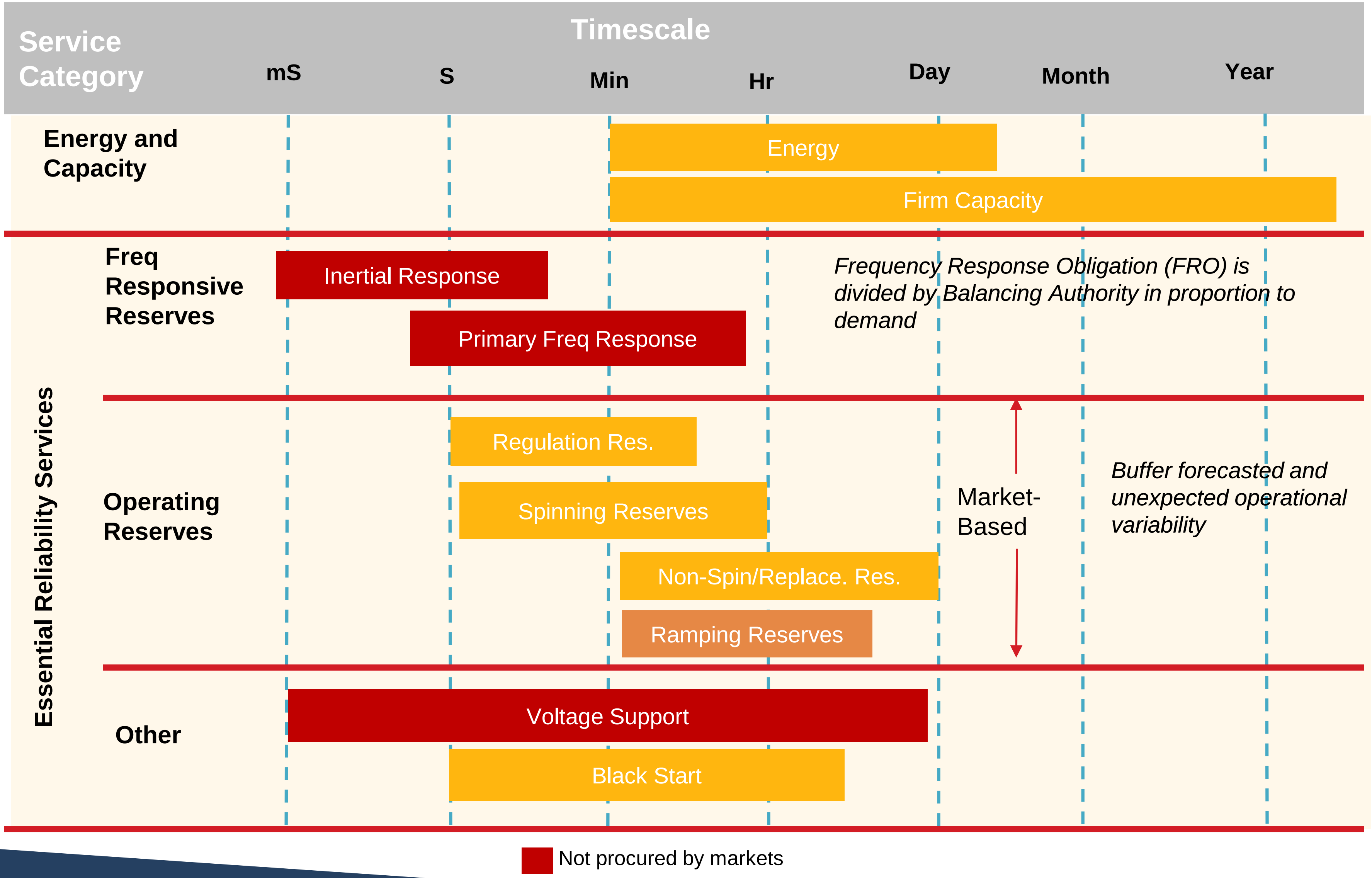
MODELING RESOURCE RELIABILITY ATTRIBUTES

- Resources have many attributes aside from energy and capacity that are critical to reliable operation.
  - Selecting a portfolio with the right attributes is crucial to ensure reliability and resilience.
  - Valuation and ranking resources should account for their reliability attributes.
  - System needs for reliability attributes increases with higher levels of inverter-based resources (IBRs).



- Reliability and Resilience Attributes/Metrics:
  - Dispatchability
  - Predictability
  - Dependability (e.g., Supply Resilience, firmness)
  - Performance Duration Limits
  - Flexibility (e.g., ramping speed, operating range)
  - Intermittency (e.g., intra-hr and multi-hr ramping)
  - Regulating Power
  - VAR support
  - Energy Profile (e.g., capacity value / ELCC)
  - Inertial Response
  - Primary Frequency Response
  - Minimum Short Circuit Ratio
  - Locational Characteristics (e.g., deliverability, resilience to grid outages)
  - Black start and system restoration support
  - Flicker
  - Harmonics
  - Sub-synchronous Resonance

ESSENTIAL RELIABILITY SERVICES



- Regulation Reserves:
  - Rapid response by generators used to help restore system frequency. These reserves may be deployed after an event and are also used to address normal random short-term fluctuations in load that can create imbalances in supply and demand.
- Ramping Reserves:
  - An emerging and evolving reserve product (also known as load following or flexibility reserves) that is used to address “slower” variations in net load and is increasingly considered to manage variability in net load from wind and solar energy. MISO sets the level based on the sum of the forecasted change in net load and an additional amount of ramp up/down (575 MW for now).

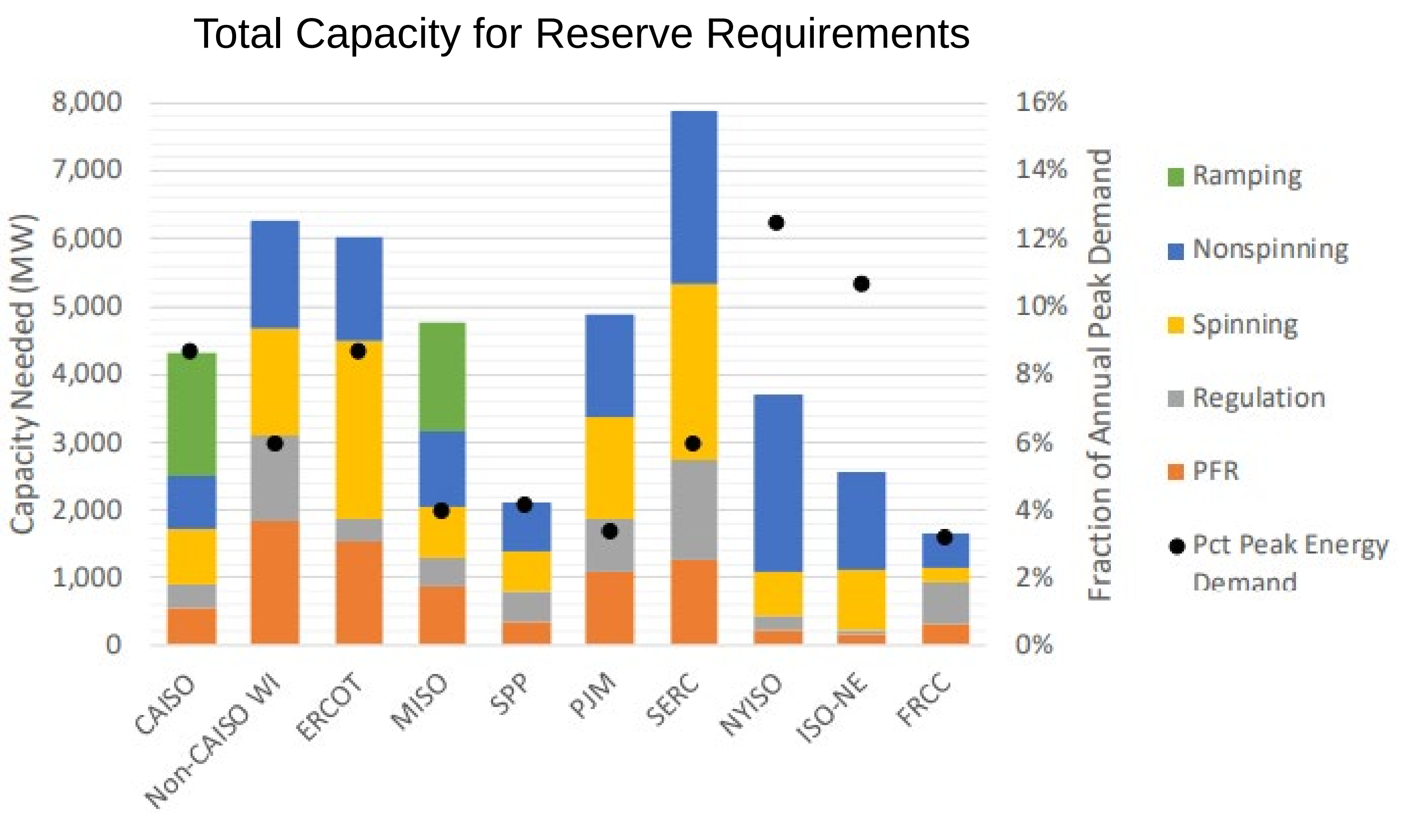
QUANTA TECHNOLOGY

ESSENTIAL RELIABILITY SERVICES - RESERVE REQUIREMENTS ACROSS WHOLESALE MARKETS

2020	MISO	CAISO	PJM	ERCOT	ISO-NE	NYISO	SPP
Peak Demand	**121.4**	53.6	147.5	73.7	26.3	32.1	52.5
Reserve Margin %	**15.80%**	16.14%	16.60%	13.75%	16.90%	15%	12%
Peak Capacity Requirement GW	**140.6**	62.3	172	83.5	30.3	36.9	58.8
Primary Freq Response Obligation							
(MW/0.1Hz)	**210**	196.5	258.3	381	38.3	49.9	
MW	**882**	550	1085	1543	161	210	
% of Peak Load	**0.70%**	1.10%	0.70%	2.20%	0.70%	0.70%	
Regulating Reserve Requirement							
Up/Down %	**0.35%**	0.64%/0.72%	0.36% offpeak; 0.55% on-peak	0.48%/0.42%	0.25%	0.73%	0.92%/0.63%
Up/Down MW	**425**	320/360	525/800	318/295	60	217	470/325
Spinning Reserve							
%	**0.61%**	1.60%	1.03%	3.76%	3.75%	2.20%	1.14%
MW	**740**	800	1504.8	2626.8	900.00	655	585
Non-Spinning Reserve							
%	**0.92%**	1.60%	1.03%	2.21%	10min 5.98% ; 30min 3.33%	10min 4.41%, 30min 8.82%	1.43%
MW	**1110**	800	1053.2	1534.5	1435/800	1310/2620	730
Ramping Reserve Requirement							
5 min MW		-300/500					
15 min MW		-1200/1800					
Hourly MW	**-1614/1554**						

ESSENTIAL RELIABILITY SERVICES

- MISO's total capacity for reserves is around 4% of peak load. This is comparable to PJM and SPP. However, is less than half of CAISO, NYISO, ERCOT, and ISO-NE.
- MISO has a ramping product.



RELIABILITY CONCERNS OF HIGH PENETRATION INVERTER-BASED RESOURCES (IBRS)

Key Consideration	System Concern
Power Ramping	• High Up and Down Intermittent "un-forecasted" Power Ramps can affect Control Area performance
Low System Inertia	• High RoCoF following a large loss causes resources to trip due to reduced synchronizing torques • Under Frequency relays respond to low frequency (nadir) by tripping load • Speed of system events faster than ability of protection system
Low Short Circuit Ratio (Weakened Grid)	• Instability in inverter controls (PLL synchronization and inner current loop low frequency oscillations) • Challenges to inverter Ride-Through and Islanding • Voltage Flicker (especially in distribution feeders) • Difficulty of voltage control due to high voltage sensitivity dV/dQ • Difficulty in energizing large power transformers
Low Fault Current Levels	• Ability of protection systems to detect faults
Low damping of system oscillations	• Synchronous machines have rotor dampers. • Use of grid forming inverters and inverter control settings to mitigate
Low Reserves	• Renewables operate at max power tracking and do not leave a headroom for reserves
Flicker	• Intermittent renewables cause fluctuations is system voltages especially when the grid short circuit strength is low. Ensure compliance with IEEE 1453 standard for flicker.
Black Start	• Ability to restart a system with predominantly inverter-based resources.

IMPACT OF INVERTER BASED GENERATION ON SYSTEM PROTECTION

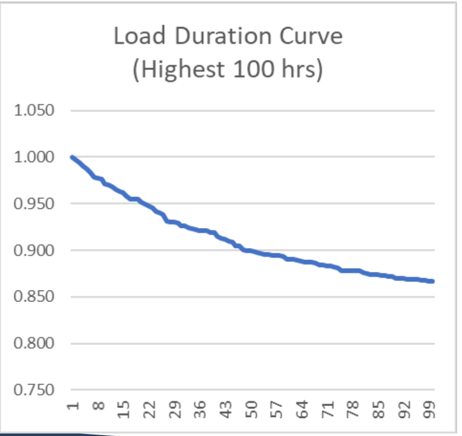
- **Declining Inertia of the power system**
  - The frequency change is important in regard to the stability of protective relays during power swing conditions.
  - In more extreme cases of system frequency changes, it may even impact the protection relay algorithms to a degree that an over or under frequency event can be erroneously caused.
  - The requirements onto maximum fault clearing time are a function of the system inertia
- **Reduced short circuit current (fault level)**
  - The inverter-based fault current contribution to short circuits is limited by the electronic controls of the inverters. The level may vary between control designs but would typically be in the order of 1.0 – 1.5 times nominal current. This will cause sensitivity issues for protective relays where they may fail to operate, or their operation will not be properly coordinated.
- **Different negative sequence fault current contribution**
  - Inverter contribution of negative- or zero-sequence current to a fault depend to inverter type and generation. Protection schemes that rely on negative sequence current are impacted. (directional elements, over current elements)
- **Changed source impedance characteristic**
  - The source impedance of an inverter-based generator during a fault is determined by the control algorithm of the inverter and does not need to be inductive. This may affect and challenge correct operation of the cross- or memory polarisation functions of protection relays.
- **Missing model of inverter-based generation**
  - The characteristic of inverters is mostly determined by the control algorithm selected and developed by the manufacturer. The behaviour of inverters from different manufacturers can be different in response to the fault current. the correct modelling of inverter-based generation inside of short circuit programs used for protection studies is challenging. This is even more a challenge for aggregated inverter-based generation that’s consist of different power sources like wind generation type 3, type 4 or solar panels.

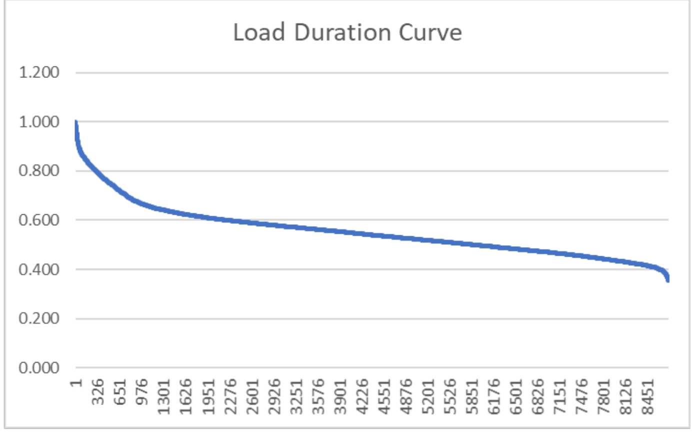
NIPSCO DEMAND AND RESOURCE DEVELOPMENT

DEMAND PROFILE

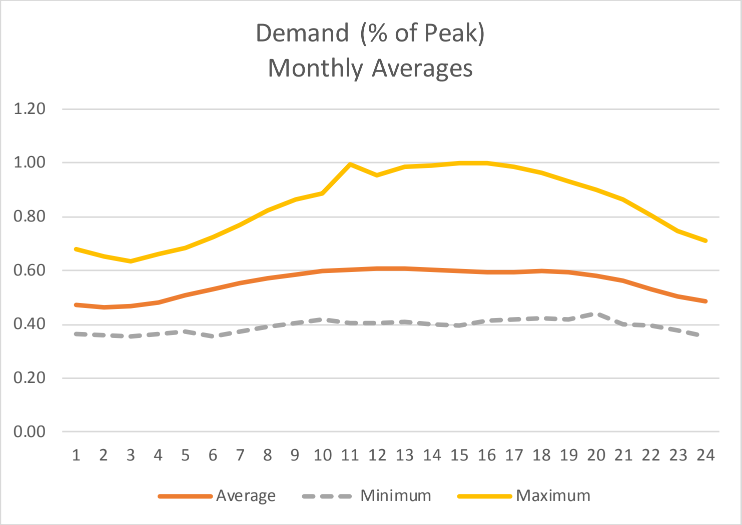
Month/Hr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0.50	0.50	0.50	0.50	0.52	0.55	0.58	0.58	0.59	0.60	0.60	0.59	0.59	0.58	0.57	0.57	0.57	0.60	0.60	0.59	0.58	0.56	0.54	0.52
2	0.49	0.49	0.49	0.49	0.52	0.55	0.57	0.58	0.59	0.59	0.59	0.58	0.58	0.57	0.56	0.55	0.56	0.58	0.58	0.58	0.57	0.55	0.52	0.50
3	0.46	0.46	0.47	0.49	0.51	0.54	0.55	0.56	0.56	0.56	0.55	0.55	0.54	0.52	0.51	0.51	0.51	0.52	0.55	0.53	0.52	0.49	0.48	0.47
4	0.43	0.43	0.44	0.46	0.49	0.51	0.53	0.54	0.54	0.54	0.54	0.54	0.52	0.51	0.51	0.50	0.49	0.50	0.51	0.51	0.50	0.47	0.45	0.44
5	0.42	0.42	0.43	0.44	0.47	0.50	0.52	0.54	0.54	0.55	0.55	0.55	0.55	0.54	0.53	0.52	0.52	0.52	0.52	0.52	0.49	0.47	0.44	0.43
6	0.46	0.45	0.45	0.47	0.48	0.51	0.53	0.56	0.58	0.60	0.62	0.63	0.64	0.64	0.64	0.63	0.62	0.61	0.60	0.59	0.57	0.53	0.50	0.47
7	0.55	0.53	0.53	0.54	0.56	0.58	0.62	0.66	0.71	0.74	0.77	0.79	0.81	0.82	0.82	0.82	0.81	0.79	0.76	0.74	0.70	0.65	0.60	0.57
8	0.51	0.49	0.50	0.51	0.54	0.56	0.59	0.62	0.65	0.68	0.71	0.73	0.75	0.75	0.76	0.76	0.75	0.72	0.70	0.68	0.64	0.60	0.56	0.53
9	0.46	0.46	0.46	0.48	0.51	0.53	0.55	0.57	0.59	0.61	0.63	0.64	0.66	0.66	0.66	0.66	0.65	0.64	0.64	0.61	0.59	0.54	0.51	0.48
10	0.43	0.43	0.44	0.46	0.49	0.52	0.54	0.55	0.55	0.55	0.55	0.56	0.55	0.54	0.53	0.53	0.53	0.54	0.54	0.53	0.50	0.48	0.45	0.44
11	0.46	0.46	0.46	0.47	0.50	0.52	0.54	0.55	0.56	0.56	0.56	0.55	0.55	0.54	0.53	0.53	0.54	0.55	0.55	0.54	0.53	0.50	0.48	0.47
12	0.48	0.47	0.47	0.47	0.49	0.52	0.55	0.56	0.56	0.56	0.56	0.55	0.55	0.55	0.54	0.54	0.56	0.57	0.57	0.57	0.56	0.54	0.51	0.49
Average	*0.47*	*0.47*	*0.47*	*0.48*	*0.51*	*0.53*	*0.56*	*0.57*	*0.59*	*0.60*	*0.60*	*0.61*	*0.61*	*0.60*	*0.60*	*0.59*	*0.59*	*0.60*	*0.59*	*0.58*	*0.56*	*0.53*	*0.50*	*0.48*
Minimum	*0.36*	*0.36*	*0.35*	*0.36*	*0.37*	*0.36*	*0.37*	*0.39*	*0.41*	*0.42*	*0.40*	*0.40*	*0.41*	*0.40*	*0.40*	*0.41*	*0.42*	*0.42*	*0.42*	*0.44*	*0.40*	*0.40*	*0.38*	*0.36*
Maximum	*0.68*	*0.65*	*0.64*	*0.66*	*0.68*	*0.72*	*0.77*	*0.82*	*0.87*	*0.89*	*0.99*	*0.95*	*0.98*	*0.99*	*1.00*	*1.00*	*0.99*	*0.96*	*0.93*	*0.90*	*0.86*	*0.80*	*0.75*	*0.71*

- The demand is Summer peaking (July), and peak hours are mid day (11AM-4PM).
- Highest 15% of peak demand occurs in only 100 hours in a year.





Month	Monthly Consumption (% of Max)
1	88%
2	80%
3	75%
4	72%
5	73%
6	81%
7	100%
8	93%
9	84%
10	74%
11	76%
12	78%



Annual Consumption pu-h	4,849
Load Factor	55.4%

EXISTING AND PLANNED GENERATION RESOURCES

- Existing Resources (2019)
  - Coal 1,995 MW
  - Combined Cycle 535 MW
  - Gas Peaker 155 MW
  - Hydro 10 MW

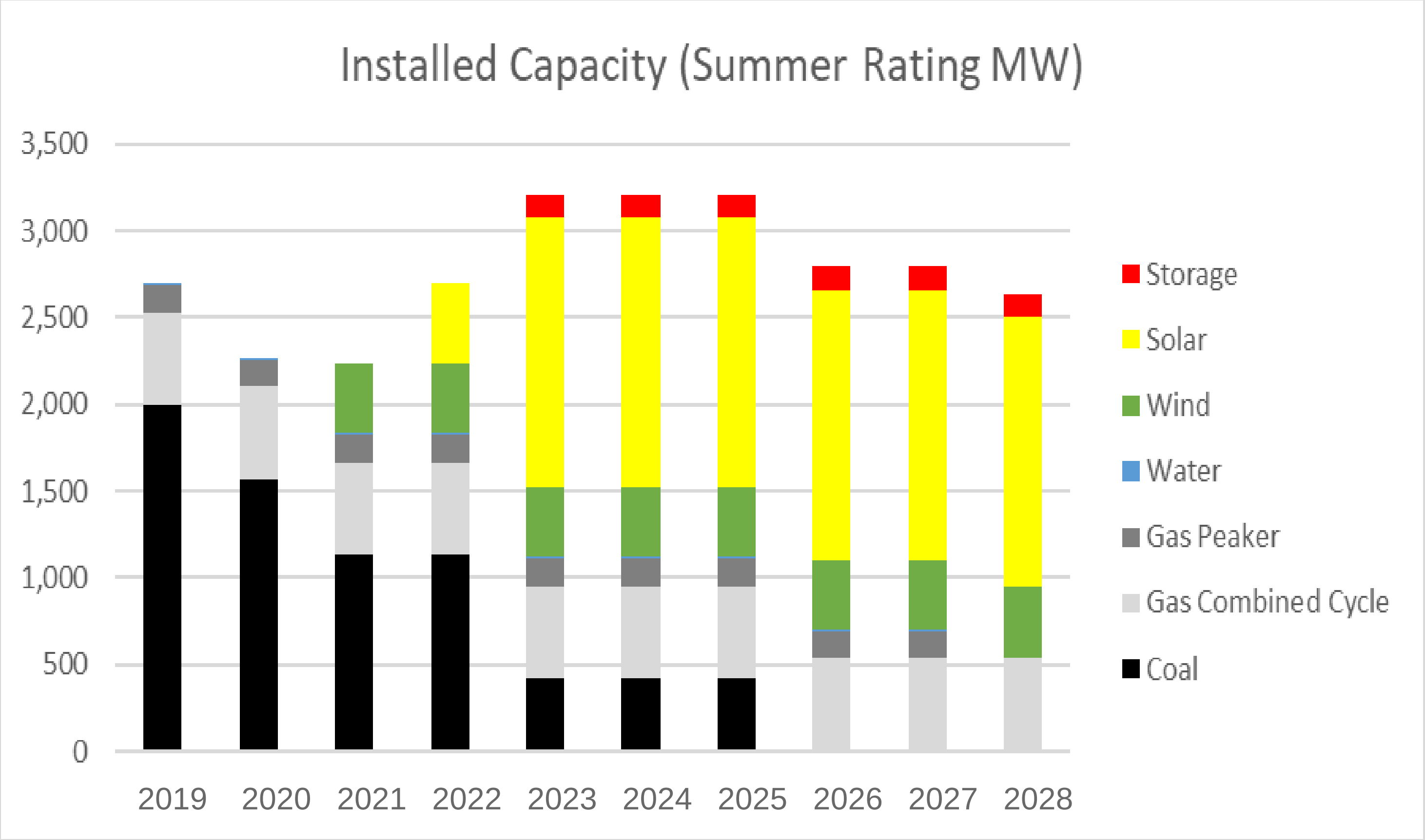
2,695 MW

- Planned Resource Additions (Owned Assets)
  - Wind (2021) 405 MW
  - Solar (2022/2023) 1,550 MW
  - Storage (2023) 135 MW

2,090 MW

- End of Life Schedule:

Coal	(2020)	425 MW
	(2021)	440 MW
	(2023)	710 MW
	(2026-2028)	420 MW
Gas Peaker	(2025-2028)	155 MW
		2,150 MW



- Significant changes in the resource mix are already planned prior to the 2021 IRP results, with a shift away from Coal towards Solar and Wind resources.

2021 IRP - CONSIDERED PORTFOLIOS

Replacement Resource Tranches

		A	B	C	D	E	F	G	H	I	Resource End Date
Sugar Creek Uprate	2027	53	53	53	53	53	53	-	-	53	
New DER	2026	10	10	10	10	10	10	10	10	10	
Wind P1	2026	-	-	-	-	-	-	-	200	200	
Solar P2	2026	250	100	-	400	250	100	450	250	250	
Solar+Storage P1	2026	450	-	-	450	-	-	450	-	-	
Storage P2	2025	-	-	-	-	-	-	-	100	100	
Storage P2	2026	-	-	-	-	100	-	-	100	-	
Storage P2	2027	-	-	-	-	100	-	-	100	-	
Storage A2	2025	-	-	-	-	135	-	-	135	135	
Storage A2	2026	-	-	-	-	-	-	-	-	-	
Storage A2	2027	135	-	-	135	135	135	135	135	135	
Gas Peaking P1	2026	-	443	-	-	-	-	-	-	-	
Gas Peaking A1	2026	-	-	-	-	-	300	-	-	-	
Gas CC A1	2026	-	-	650	-	-	-	-	-	-	
Other Thermal P1	2024	50	50	-	-	50	50	-	-	-	2034
Other Thermal P2	2026	100	100	-	-	100	100	-	-	-	2036
Hydrogen P1	2025	-	-	-	-	-	-	-	-	193	
Hydrogen P2	2026	-	-	-	-	-	-	-	-	20	

- Retirements:
  - Schahfer 17/18 - 2023
  - MC12 Retirement – Modeled as 2026; however, same resource mix as by 2028
- Other Thermal P1, P2:
  - Zonal resource contracts

	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Duration)
Higher Carbon Emissions	**A** NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 135MW Solar+Storage 450MW* Solar 250MW	**B** NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 443MW Thermal PPA 150MW Solar 250MW	**C** NIPSCO DER 10MW SC Uprate 53MW Gas CC 650MW
Mid Carbon Emissions	**D** NIPSCO DER 10MW SC Uprate 53MW Storage 135MW Solar+Storage 450MW* Solar 400MW	**E** NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 470MW Solar 250MW	**F** NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 300MW Thermal PPA 150MW Storage 135MW Solar 100MW
Low Carbon Emissions	**G** NIPSCO DER 10MW Storage 135MW Solar+Storage 450MW* Solar 450MW	**H** NIPSCO DER 10MW Wind 200MW Storage 570MW Solar 250MW	**I** NIPSCO DER 10MW SC H2 Electrolyzer 20MW SC Uprate 53MW H2 Enabled Peaker 193MW Wind 200MW Storage 370MW Solar 250MW

**Gas Peaker: Local to Service Territory in Portfolio F, while outside of territory in Portfolio B

QUANTA TECHNOLOGY

2030 PORTFOLIO MIX

- 2,150 MW of conventional resources will be retired.
- 2,090 MW of IBR resources are planned to be added (owned assets).
- In addition, Portfolios A through I will provide additional resources. The total of all resources in 2030 are summarized below. The mix of IBRs ranges between 63% (C) to 85% (H).

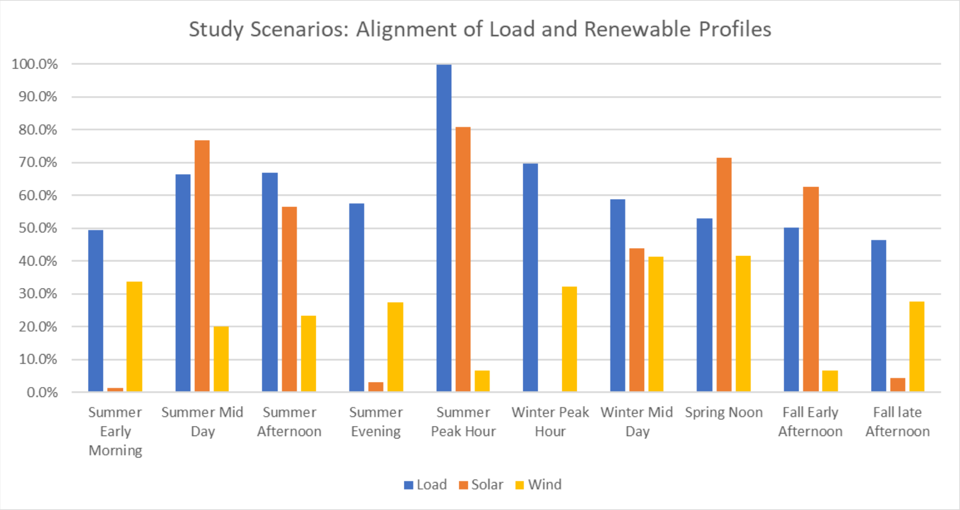
Portfolio	Solar PV MW	Wind MW	Energy Storage MW	Thermal Gen MW	Hydro MW	IBR %
A	2,100	405	420	738	10	80%
B	1,800	405	135	738	10	76%
C	1,550	405	135	1,238	10	63%
D	2,250	405	420	588	10	84%
E	1,800	405	605	738	10	79%
F	1,650	405	270	1,038	10	69%
G	2,000	405	270	535	10	83%
H	1,800	605	705	535	10	85%
I	1,800	605	505	781	10	79%

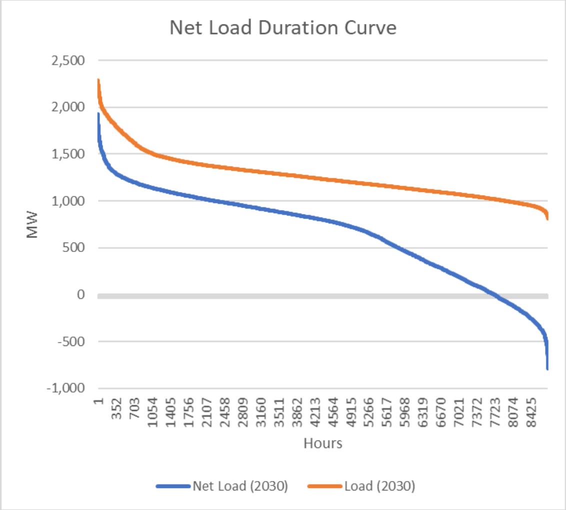
RESOURCE VARIABILITY ANALYSIS

RESOURCE VARIABILITY ANALYSIS - SUMMARY

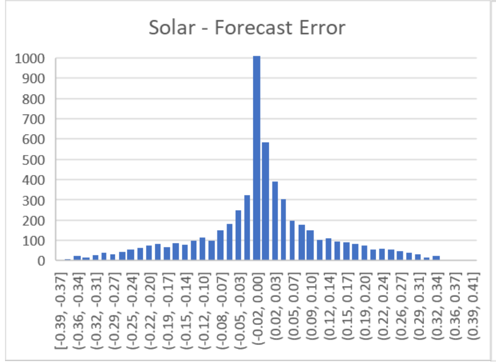
- The hourly profiles of Solar, Wind, and Solar plus Storage are characterized across two dimensions:
  - Forecast Error
  - Alignment with Load

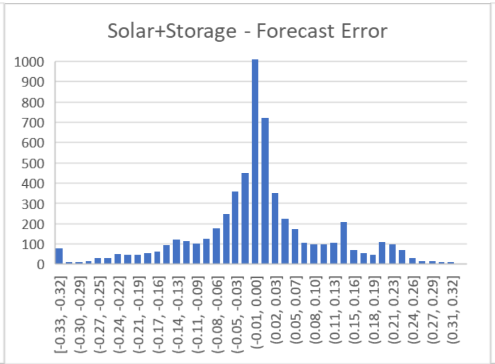
- This characterization is utilized in subsequent evaluation of portfolios of these resources.

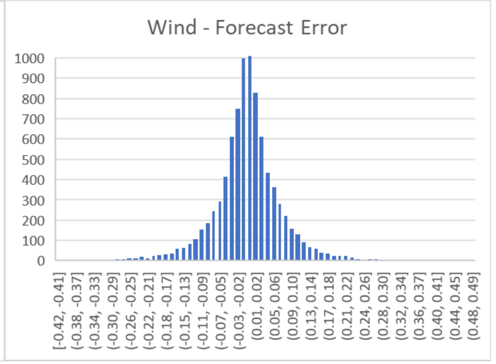




Forecast Error%	Solar	Wind	S+S
Standard Deviation	9.9%	7.5%	9.2%
min Error	-39%	-42%	-33%
max Error	39%	48%	33%
90% Percentile	19%	8%	12%







RELIABILITY CRITERIA & METRICS

RELIABILITY CRITERIA

	Criteria	Description	Rationale
1	Blackstart	Resource has the ability to be started without support from the wider system or is designed to remain energized without connection to the remainder of the system, with the ability to energize a bus, supply real and reactive power, frequency and voltage control	In the event of a black out condition, NIPSCO must have a blackstart plan to restore its local electric system.
2	Energy Duration	Resource is able to meet energy and capacity duration requirements. In emergency conditions, resource is able to supply the energy needs of critical loads.	NIPSCO must have long duration resources for emergency procedures and must assess economic value risk for energy duration attributes over time
3	Dispatchability and Automatic Generation Control	The unit will respond to directives from system operators regarding its status, output, and timing. The unit has the ability to be placed on Automatic Generation Control (AGC) allowing its output to be ramped up or down automatically to respond immediately to changes on the system.	MISO provides dispatch signals under normal conditions, but NIPSCO requires AGC attributes under emergency restoration procedures
4	Operational Flexibility and Frequency Support	Ability to provide inertial energy reservoir or a sink to stabilize the system. The resource can adjust its output to provide frequency support or stabilization in response to frequency deviations with a droop of 5% or better	MISO provides market construct under normal conditions, but NIPSCO must have the ability to maintain operation during under-frequency conditions in emergencies
5	VAR Support	The resource can be used to deliver VARs out onto the system or absorb excess VARs and so can be used to control system voltage under steady-state and dynamic/transient conditions. The resource can provide dynamic reactive capability (VARs) even when not producing energy. The resource must have Automatic voltage regulation (AVR) capability. The resource must have the capability ranging from 0.85 lagging to 0.95 leading power factor	NIPSCO must retain resources on the transmission system to provide this attribute in accordance with NERC and IEEE Standards
6	Geographic Location Relative to Load	The resource will be located in NIPSCO's footprint (electric Transmission Operator Area)in Northern Indiana near existing NIPSCO 138kV pr 345kV facilities and is not restricted by fuel infrastructure. The resource can be interconnected at 138kV or 345kV. Preferred locations are ones that have multiple power evacuation/deliverability paths, are close to major load centers, and do not deteriorate the transmission system's transfer capability headroom.	MISO requires location capacity resources and runs an LMP market to provide locational energy signals; under emergency restoration procedures, a blackstart plan reliant on external resources would create a significant risk. Location provides economic value in the form of reduced losses, congestion, curtailment risk, and address local capacity requirements. Additionally, from a reliability perspective, resources that are interconnected to buses with multiple power evacuation paths and those close to load centers are more resilient to transmission system outages and provide better assistance in the blackstart restoration process.
7	Predictability and Firmness of Supply	Ability to predict/forecast the output of resources and to counteract forecast errors.	Energy is scheduled with MISO in the day-ahead hourly market and in the real-time 5-minute market. Deviations from these schedules have financial consequences and thus the ability to accurately forecast the output of a resource up to 38 hours ahead of time for the day-ahead market and 30 minutes for the real time market is advantageous.
8	Short Circuit Strength Requirement	Ensure the strength of the system to enable the stable integration of all inverter-based resources (IBRs) within a portfolio.	The retirement of synchronous generators within NIPSCO footprint and also within MISO and replacements with increasing levels of inverter-based resources will lower the short circuit strength of the system. Resources than can operate at lower levels of SCR and those that provide higher short circuit current provide a better future proofing without the need for expensive mitigation measures.

RELIABILITY METRICS

	Criteria	Measurement Approach	Included in Minimum Interconnection Requirements	Quanta Analysis to Support Metric
1	Blackstart	• MWs with black start capability • **Qualitative Assessment of Risk of not Starting**	NO	• Blackstart Analysis ★
2	Energy Duration	• Percentage of NIPSCO's critical load (MW and Time) that can be supplied during emergencies	NO	• Energy Adequacy Analysis
3	Dispatchability and Automatic Generation Control	• MWs on AGC • Up Range / Down range • Ability for Fast Regulation • Duration of Up / Down Regulation	NO (except being on SCADA for monitoring and control)	• Increase of Regulation Requirements due to IBRs in each Portfolio • 10-min Ramp Capability of Portfolio
4	Operational Flexibility and Frequency Support	• Inertial Response Gap/Surplus • Primary Frequency Response Gap/Surplus	NO	• Inertial Repose • Primary Response
5	VAR Support	• Continuous VAR output range	YES	• Sum of VAR capability
6	Geographic Location Relative to Load	• MWs or % within NIPSCO footprint • Firmness of fuel supplies • MWs with POIs with multiple (2 or higher) secure power evacuation paths • Reduction in Existing Grid transfer capability headroom	NO	• Topology analysis
7	Predictability and Firmness of Supply	• Ability to mitigate Forecast Error of intermittent resources using fast ramping capability	NO	• Power Ramping ★
8	Short Circuit Strength Requirement	• MWs of IBRs potentially impacted by lack of short circuit strength • Need for synchronous condensers and/or grid forming inverters to ensure stable system integration	NO, 1547 and P2800 do not address	• Short Circuit Strength Analysis

★ Blackstart and Predictability and Firmness of Supply have been included as specific examples discussed on the following slides. Further details on the other criteria are found in the Appendix and will be detailed in the IRP report.

BLACKSTART

- The power industry does not have experience of black starting systems served mostly by inverter-based resources. Few success stories have been reported in news media over the past 5 years:

- **GE Completes First Battery Assisted Black Start of a GE Heavy Duty Gas Turbine**
  - Perryville Power Station, Entergy
  - GE 7F.03 150MW simple cycle
  - BESS 7.4MW
  - Feb 2020
- **Imperial Irrigation District**
  - El Centro Generating Station, Southern California
  - 44MW combined cycle
  - BESS 33MW/20MWh
  - Originally designed for grid stability and renewable smoothing
  - May 2017
- **Scottish Power**
  - Blackstart of wind power in world-first demonstration
  - Nov 2020
- **WEMAG German battery park demonstrates successful black start**
  - Schwerin, a city in northern Germany
  - Combined Cycle Plant
  - BESS 5MW/15MWh
  - Originally designed for frequency regulation and other grid balancing services
  - Feb 2017
- **Glendale Water & Power (GWP)**
  - BESS 2MW/950kWh
  - July 2017

QUANTA TECHNOLOGY

BLACK START STRATEGY

- Observations:
  - Five portfolios (A, D, E, G, H) do not have synchronous machines.
  - 4 Portfolios have synchronous machines (B, C, F, I)
  - 3 Portfolios have large aggregate MW stand-alone storage capability (E, H, I)
  - 2 Portfolios do not have stand-alone storage systems
  - System needs short circuit strength and inertia to function before energizing solar/wind resources.
  - All portfolios have large aggregate MWs of Solar plus storage

ICAP MW

Inside NIPSCO	A	B	C	D	E	F	G	H	I
Gas Resource	0	0	650	0	0	300	0	0	193
Synch Cond.	986	986	986	986	986	986	986	986	986
Solar	350	350	100	500	100	200	550	350	350
Solar+Storage	1250	800	800	1250	800	800	1250	800	800
Wind	405	405	405	405	405	405	405	605	605
Storage	135	0	0	135	470	135	135	570	370

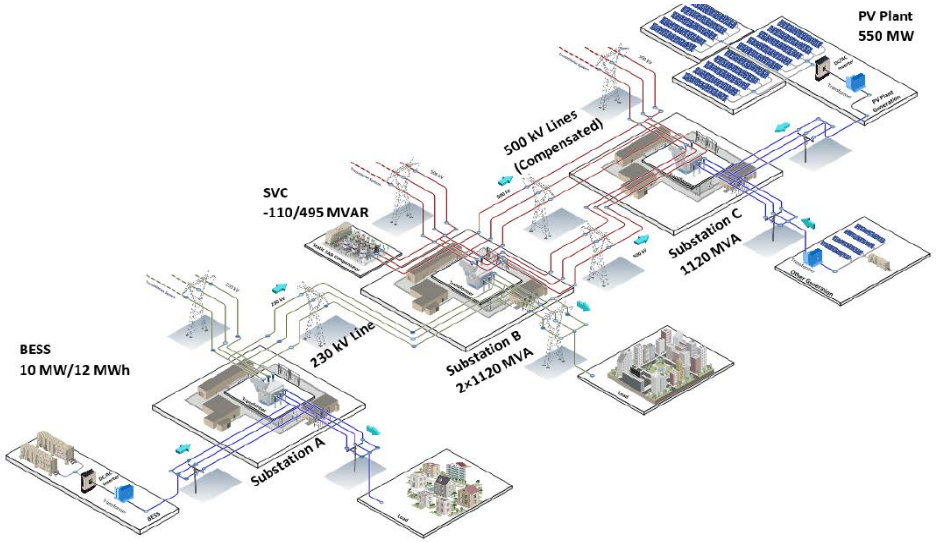
- Preliminary Black Start Strategy:
  - Energize standalone storage equipped with GFM inverters, if available
  - Portfolios C, F, and I should specify the gas resources to have black start capability
  - Find cranking paths to Synchronous Condensers and energize them.
  - Start with area around RMSGS, Babcock, Dune Acres, ..etc.
  - Energize solar plus storage sites, then solar, then wind

- Evaluation Metrics:
  - Adequacy of storage size to start the pony motors of synchronous condensers and supply the transformer inrush currents.
  - Ability of storage and synchronous condensers (real and reactive power) to black start other renewable resources (assume the auxiliary loads of these resources to be 5% of their rating, and that each farm is modular and can be started in steps).

POWER PLANT BLACK START STUDIES – KEY CONSIDERATIONS

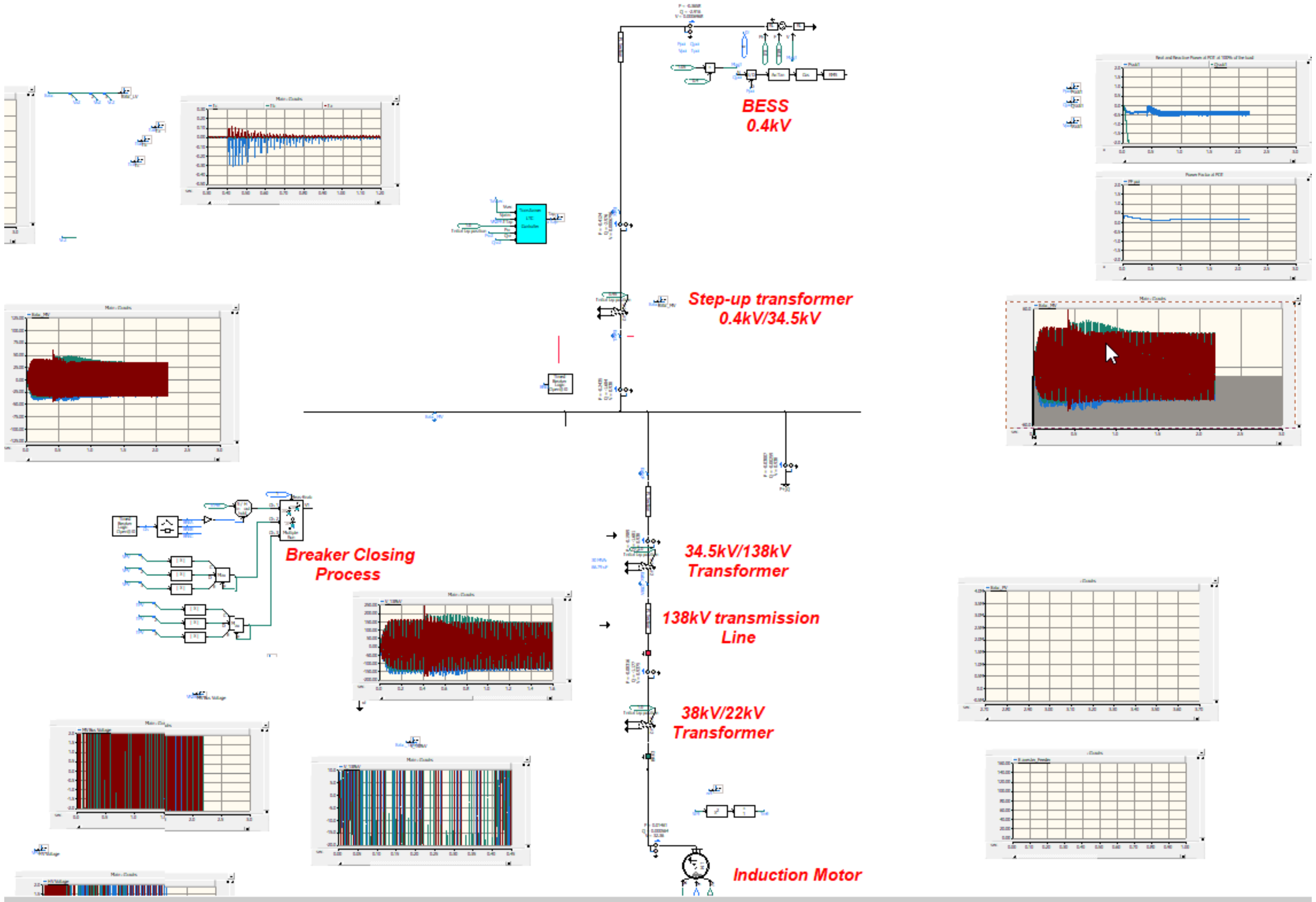
- Modeling:
  - Sequencing of Essential Motors (Startup and Shutdown)
  - Modeling of Induction Motors (dynamic characteristics)
  - Protection system Modeling
  - Fast bus transfer
  - Battery System
  - Transformers
- Analysis:
  - Transient and steady-state simulations
- Considerations:
  - Inverter short-circuit current limitations
  - Soft-start techniques
  - Dynamic interactions
  - Frequency and Voltage control
  - Protective relay operation in view of limited short circuit curren

- Results:
  - Inverter Size (MVA, PF)
  - BESS Size (MW, MWh)
  - BESS control and protection settings
  - Transformer tap settings
  - Protection setting adjustments



PORTFOLIO EVALUATION - BLACK START

- Using 135MW/150MVA battery to black start the pony motor of synchronous condensers:



BLACK START CAPABILITY - QUALITATIVE ASSESSMENT OF PORTFOLIOS

- The following are considerations for a qualitative assessment:
  - Portfolios that do not have energy storage systems with GFM inverters and do not have Peaker Plants with black start capability cannot be started. So, Portfolios B will fail.
  - Portfolios that have 135MW and higher of energy storage with GFM inverters appear (from the expedient cursory analysis) to have the capability to black start the synchronous condensers. This applies to portfolios (D-I). Portfolio C, if its peaker plant is equipped with black start capability should also be able to start.
  - Portfolios without peaker plants will have a limited time to energize the system (depending on the state of charge of the batteries). Larger batteries are better. During this period of time, they can attempt to start facilities with solar+storage first, and then solar, and then wind near the major load centers. The synch condensers provide the reactive power, and the battery stabilize the frequency.
  - From a risk perspective, it appears that the follow is the ranking of the Portfolios:
    - F and I are the best. They have both peaker plants and storage.
    - C next.
    - E, H next due their large storage size
    - G, D, A next
    - B fails to black start

Inside NIPSCO	A	B	C	D	E	F	G	H	I
Gas Resource	0	0	650	0	0	300	0	0	193
Synch Cond.	986	986	986	986	986	986	986	986	986
Solar	350	350	100	500	100	200	550	350	350
Solar+Storage	1250	800	800	1250	800	800	1250	800	800
Wind	405	405	405	405	405	405	405	605	605
Storage	135	0	0	135	470	135	135	570	370

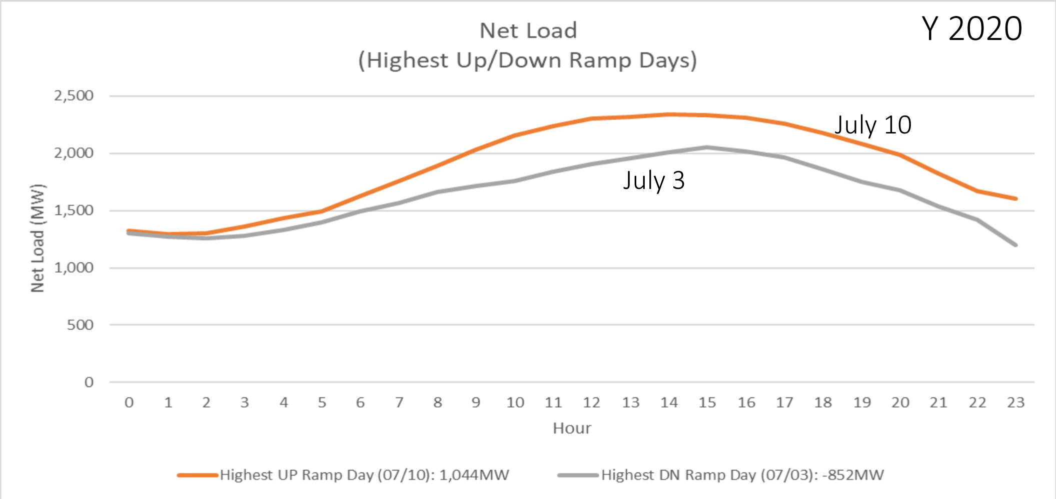
POWER RAMPS

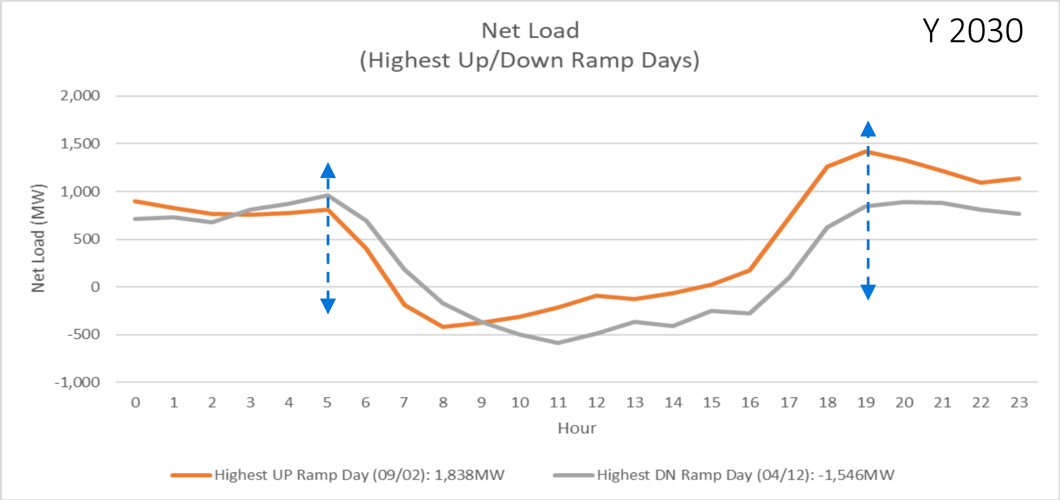
- The electric power industry has documented over the past decade an expected change in the hourly load profile as the intermittent renewable penetration of solar and wind resources increases. This has been dubbed the "Duck Curve".
- System operation is challenged during periods of high power ramp rates. This has prompted CAISO and later MISO to adopt a new ancillary service product called Ramping Product, with the objective of acquiring fast ramping resources that can be committed and dispatched rapidly to balance the system supply and demand during these periods of high power ramps.
- Power ramps can occur at different time scales:
  - Intra-hour ramping: intermittency of renewable resources due to cloud cover or wind bursts. These ramps can be quantified at a second, minute, 5-min, and 10-min basis. These ramps can be mitigated by procuring additional fast regulation reserves including energy storage.
  - Hour to hour: changes in power output between two consecutive hours.
  - Multi-Hour during a day: sustained increase or decrease in power output across multiple hours in a day.
- Hourly and daily power ramps can be partially mitigated by properly forecasting and scheduling these ramps in the day-ahead and real-time markets. However, any unscheduled hourly ramps will affect control area performance and have to be mitigated within the control area. Energy is scheduled with MISO in the day-ahead hourly market and in the real-time 5-minute market. Schedules are submitted up to 38 hours ahead of the actual hour time for the day-ahead market and 30 minutes for the real time market.

NET LOAD POWER RAMPS

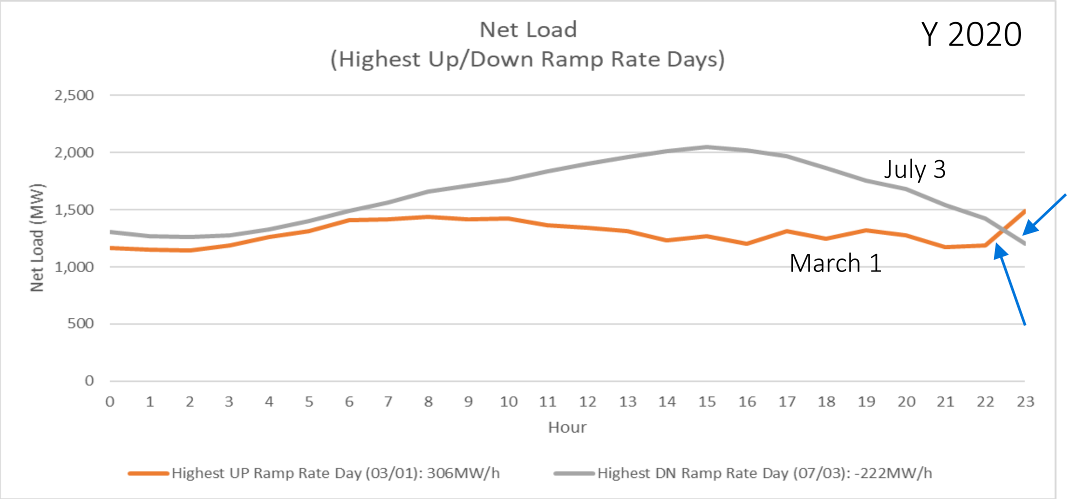
Portfolio E (without Storage/Peakers Dispatch)

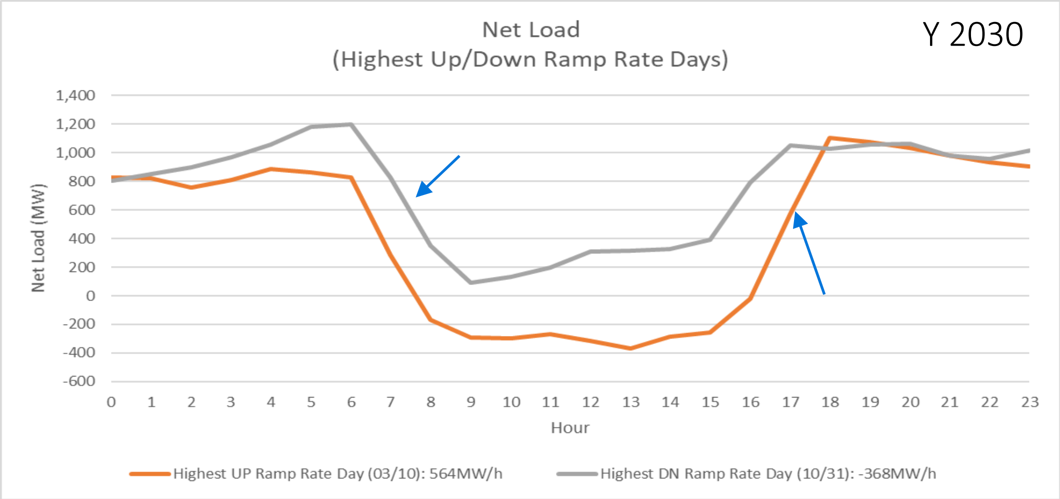
Highest Up/Down Ramp Days





Highest Up/Down Ramp Rate Hours



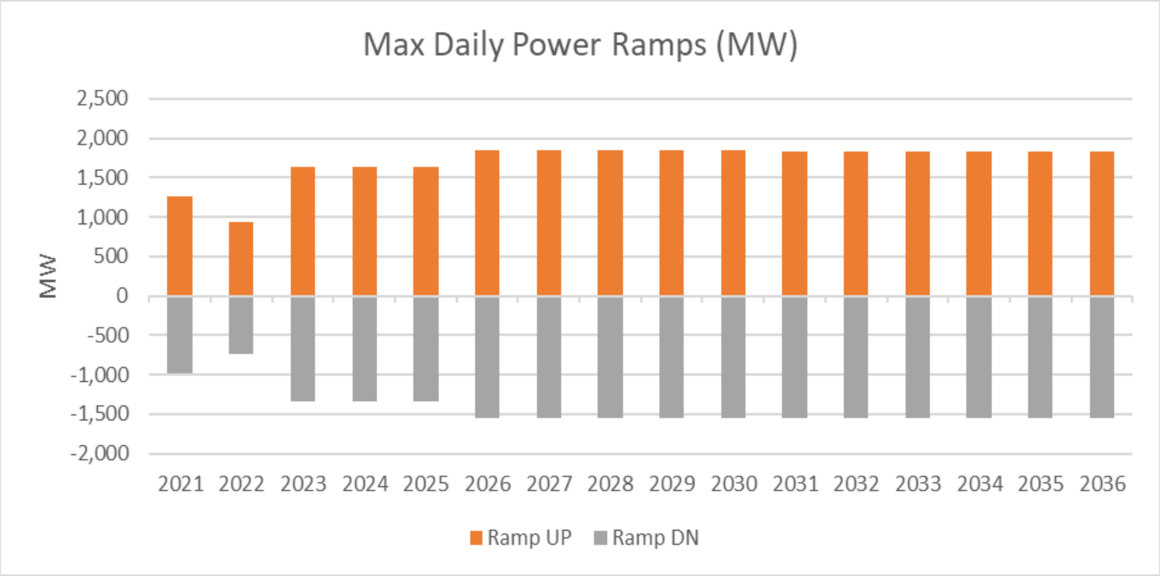


Significant change in Net Load profile from a conventional shape in 2020 to a "Duck Curve" in 2030

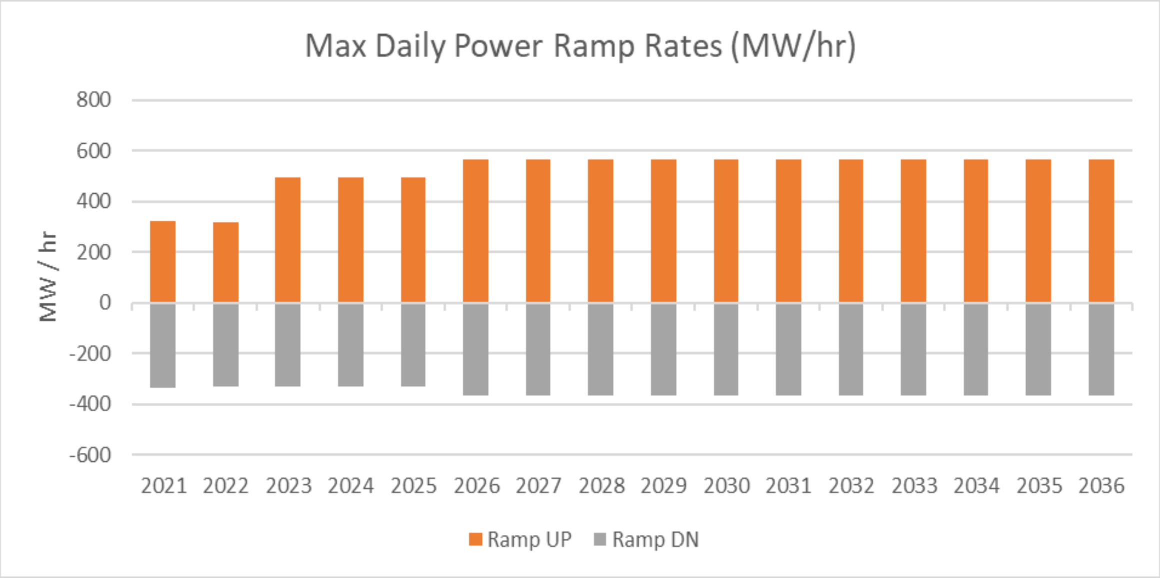
NET LOAD POWER RAMPS

Portfolio E (without Storage/Peakers Dispatch)

Year	Ramp UP	Ramp DN	Ramp Rate UP	Ramp Rate DN
2021	1,256	-982	322	-333
2022	930	-735	319	-331
2023	1,633	-1,347	494	-331
2024	1,632	-1,347	494	-330
2025	1,631	-1,347	494	-330
2026	1,839	-1,546	564	-368
2027	1,838	-1,546	564	-368
2028	1,838	-1,546	564	-368
2029	1,838	-1,546	564	-368
2030	1,838	-1,546	564	-368
2031	1,838	-1,546	564	-368
2032	1,837	-1,546	563	-368
2033	1,837	-1,546	563	-368
2034	1,837	-1,546	563	-368
2035	1,837	-1,546	563	-368
2036	1,837	-1,546	563	-368



Ramping Category	2020 MW	2020 %Peak	2030 MW	2030 %Peak	Increased MW 2030 vs 2020
1-hr Up	306	13.1%	564	24.7%	258
1-hr Down	-222	9.5%	-368	16.1%	146
Day Up	1,044	44.6%	1,838	80.5%	794
Day Down	-852	36.4%	-1,546	67.7%	694



QUANTA TECHNOLOGY

NET LOAD POWER RAMPS (Y2030 VS Y2020)

Portfolio	Solar	Wind	Solar + Storage	Day Ramping Up (MW)	Day Ramping Down (MW)	1hr Ramping Up (MW)	1hr Ramping Down (MW)	Peaker/Storage (MW)	Forecast Error 90th Percentile	Excess Ramping Capability (MW)
2020	**0**	**405**	**0**	**1,044**	**-852**	**306**	**-222**	**155**	**32**	**123**
A	1,800	405	450	1,863	-1,719	593	-397	135	428	-293
B	1,800	405	0	1,838	-1,546	564	-368	443	374	69
C	1,550	405	0	1,630	-1,346	493	-329	0	327	-327
D	1,950	405	450	1,988	-1,830	621	-426	135	457	-322
E	1,800	405	0	1,838	-1,546	564	-368	470	374	96
F	1,650	405	0	1,713	-1,426	521	-342	435	346	89
G	2,000	405	450	2,030	-1,870	630	-437	135	466	-331
H	1,800	605	0	1,844	-1,594	566	-413	570	390	180
I	1,800	605	0	1,844	-1,594	566	-413	563	390	173
90th Percentile	19%	8%	12%							

- Balancing areas are required per BAL-003 to comply with Control Performance Standard (CPS) 1 and CPS2. CPS2 is a monthly standard intended to limit unscheduled flows. It requires compliance better than 90% that the average Area Control Error (ACE) will remain below a threshold over all 10-min intervals in the month. For a balancing area with a peak load of 2500MW, the threshold is around 37MW. NIPSCO is a local balancing area under MISO but does not carry any ACE performance requirements currently.
- A small percentage (≈30%) of the hourly ramps in Net Load can be forecasted an hour ahead using a persistent forecast method and thus scheduled in the real time market. Example, Portfolio E has total 1-hour ramp up of 564MW while its forecast error is 374MW, or 66%.
- The unforecasted changes in renewable resource outputs should be mitigated using fast ramping resources.
- Portfolios ranked according to their ability to mitigate the unforecasted power ramps from best to worst: H, I, E, F, B. Other portfolios require additional flexible ramping resources to mitigate the impacts of the renewable power ramps.

ASSESSMENT RESULTS

RELIABILITY METRICS

	Criteria	Potential Measurement Approaches Considered	Included in Minimum Interconnection Requirements	Quanta Analysis to Develop Metric
1	Blackstart	• MWs with black start capability • **Qualitative Assessment of Risk of not Starting**	NO	• Blackstart Analysis
2	Energy Duration	• Percentage of NIPSCO's critical load (MW and Time) that can be supplied during emergencies	NO	• Energy Adequacy Analysis
3	Dispatchability and Automatic Generation Control	• MWs on AGC • Up Range / Down Range • Ability for Fast Regulation • Duration of Up / Down Regulation	NO (except being on SCADA for monitoring and control)	• Increase of Regulation Requirements due to IBRs in each Portfolio • 10-min Ramp Capability of Portfolio
4	Operational Flexibility and Frequency Support	• Inertial Response Gap/Surplus • Primary Frequency Response Gap/Surplus	NO	• Inertial Repose • Primary Response
5	VAR Support	• Continuous VAR output range	YES	• Sum of VAR capability
6	Geographic Location Relative to Load	• MWs or % within NIPSCO footprint • Firmness of fuel supplies • **MWs with POIs with multiple (2 or higher) secure power evacuation paths** • Reduction in Existing Grid transfer capability headroom	NO	• Topology analysis
7	Predictability and Firmness of Supply	• Ability to mitigate Forecast Error of intermittent resources using fast ramping capability	NO	• Power Ramping
8	Short Circuit Strength Requirement	• MWs of IBRs potentially impacted by lack of short circuit strength • Need for synchronous condensers and/or grid forming inverters to ensure stable system integration	NO, 1547 and P2800 do not address	• Short Circuit Strength Analysis

PORTFOLIO RELIABILITY METRICS

Preliminary

	Year 2030	Metric	A	B	C	D	E	F	G	H	I
1	Blackstart	Qualitative Assessment of Risk of not Starting	25%	0%	75%	25%	50%	100%	25%	50%	100%
2	Energy Adequacy	Energy Not Served when Islanded (Worst 1-week) %	76%	79%	32%	75%	79%	56%	75%	73%	58%
3	Dispatchability	Dispatchable (%CAP, unavoidable VER Penetration)	29%	17%	57%	28%	46%	47%	27%	48%	48%
			56%	49%	40%	61%	49%	44%	63%	50%	50%
		Increased Freq Regulation Requirements (MW)	60	47	40	64	47	43	66	53	53
		1-min Ramp Capability (MW)	346	211	261	331	681	397	326	761	599
		10-min Ramp Capability (MW)	649	514	764	574	984	859	548	983	944
4	Operational Flexibility and Frequency Support	Inertia MVA-s	3,200	6,004	6,711	3,200	3,218	5,099	2,914	2,914	4,379
		Inertial Gap FFR MW	148	276	177	180	0	72	192	0	0
		Primary Gap PFR MW	258	387	380	261	0	248	262	0	20
5	VAR Support	VAR Capability	364	109	283	429	314	233	451	445	442
6	Location	Average Number of Evacuation Paths	5	2.5	N/A	4.6	4.7	4.7	4.8	5.6	5.1
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) MW	-293	69	-327	-322	96	89	-331	180	173
8	Short Circuit Strength	Required Additional Synch Condensers MVA	805	64	0	1,017	779	68	1,070	948	599

CAP: the capacity value of the portfolio including the existing and planned resources
Solar capacity credit : 50% of installed capacity; Wind capacity credit : 16.3% (based on MISO published data on system wide capacity credits)

PORTFOLIO RELIABILITY METRICS (NORMALIZED)

Preliminary

	Year 2030	Metric	A	B	C	D	E	F	G	H	I
1	Blackstart	Qualitative Assessment of Risk of not Starting	25%	0%	75%	25%	50%	100%	25%	50%	100%
2	Energy Adequacy	Energy Not Served when Islanded (Worst 1-week) %	76%	79%	32%	75%	79%	56%	75%	73%	58%
3	Dispatchability	Dispatchable (%CAP, unavoidable VER penetration%)	29%	17%	57%	28%	46%	47%	27%	48%	48%
			56%	49%	40%	61%	49%	44%	63%	50%	50%
		Increased Freq Regulation Requirement (% Peak Load)	2.6%	2.1%	1.8%	2.8%	2.1%	1.9%	2.9%	2.3%	2.3%
		1-min Ramp Capability (%CAP)	26.0%	23.5%	18.4%	23.5%	49.9%	31.6%	22.8%	50.8%	40.2%
		10-min Ramp Capability (%CAP)	48.8%	57.4%	53.8%	40.8%	72.0%	68.4%	38.3%	65.6%	63.3%
4	Operational Flexibility and Frequency Support	Inertia (s)	2.19	6.09	4.29	2.07	2.14	3.69	1.85	1.77	2.67
		Inertial Gap FFR (%CAP)	11.1%	30.8%	12.5%	12.8%	0.0%	5.7%	13.4%	0.0%	0.0%
		Primary Gap PFR (%CAP)	19.4%	43.2%	26.7%	18.6%	0.0%	19.7%	18.3%	0.0%	1.3%
5	VAR Support	VAR Capability (%CAP)	63.9%	80.7%	42.9%	66.6%	51.9%	47.1%	67.3%	60.3%	60.4%
6	Location	Average Number of Evacuation Paths	5	2.5	N/A	4.6	4.7	4.7	4.8	5.6	5.1
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW)	-14.3%	3.9%	-21.7%	-14.6%	5.5%	5.5%	-14.7%	9.2%	8.8%
8	Short Circuit Strength	Required Additional Synch Condensers (%Peak Load)	35%	3%	0%	45%	34%	3%	47%	42%	26%

VER: Variable Energy Resources (e.g., solar, wind)
CAP: Capacity credit of all resources including existing, planned, and portfolio

QUANTA TECHNOLOGY

SCORING CRITERIA THRESHOLDS

Preliminary

	Year 2030		1 (Pass)	1/2 (Caution)	0 (Potential Issue)	Rationale
1	Blackstart	Qualitative assessment of risk of not starting	>50%	25-50%	<25%	System requires real and reactive power sources with sufficient rating to start other resources. Higher rated resources lower the risk
2	Energy Adequacy	Energy Not Served when Islanded (Worst 1-week) %	<70%	70-85%	>85%	Ability of Resource to serve critical and essential part load for 1 week, estimated at 15% of total load. Adding other important load brings the total to 30%
3	Dispatchability	Dispatchable (VER Penetration %)	<50%	50-60%	>60%	Intermittent Power Penetration above 60% is problematic when islanded
		Increased Freq Regulation Requirements	<2% of peak load	2-3% of Peak Load	>3% of peak load	Regulation of Conventional Systems ≈1%
		1-min Ramp Capability	>15% of CAP	10-15% of CAP	<10% of CAP	10% per minute was the norm for conventional systems. Renewable portfolios require more ramping capability
		10-min Ramp Capability	>65% of CAP	50-65% of CAP	<50% of CAP	10% per minute was the norm for conventional systems. But with 50% min loading, that will be 50% in 10 min. Renewable portfolios require more ramping capability
4	Operational Flexibility and Frequency Support	Inertia (seconds)	>3xMVA rating	2-3xMVA rating	<2xMVA rating	Synchronous machine has inertia of 2-5xMVA rating.
		Inertial Gap FFR (assuming storage systems will have GFM inverters)	0	0-10% of CAP	>10% of CAP	System should have enough inertial response, so gap should be 0. Inertial response of synch machine ≈ 10% of CAP
		Primary Gap PFR MW	0	0 - 2% of CAP	2% of CAP	System should have enough primary response, so gap should be 0. Primary response of synch machine ≈ 3.3%of CAP/0.1Hz (Droop 5%)
5	VAR Support	VAR Capability	≥41% of ICAP	31-41% of ICAP	<31% of ICAP	Power factor higher than 95% (or VAR less than 31%) not acceptable. Less than 0.91 (or VAR greater than 41.5%) is good
6	Location	Average Number of Evacuation Paths	>3	2-3	<2	More power evacuation paths increases system resilience
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) MW	≥ 0	-10% - 0% of CAP	<-10% of CAP	Excess ramping capability to offset higher levels of intermittent resource output variability is desired
8	Short Circuit Strength	Required Additional Synch Condensers MVA	<5%	0-10% of CAP	>10% of CAP	Portfolio should not require additional synchronous condensers

PORTFOLIO RELIABILITY RANKING

Preliminary

	Year 2030		A	B	C	D	E	F	G	H	I
1	Blackstart	Qualitative assessment of risk of not starting	½	0	1	½	½	1	½	½	1
2	Energy Adequacy	Energy not served when islanded	½	½	1	½	½	1	½	½	1
3	Dispatchability	Dispatchable %	½	1	1	0	1	1	0	1	1
		Increased Freq Regulation Requirements	½	½	1	½	½	1	½	½	½
		1-min Ramp Capability	1	1	1	1	1	1	1	1	1
		10-Min Ramp Capability	0	½	½	0	1	1	0	1	½
4	Operational Flexibility and Frequency Support	Inertia	½	1	1	½	½	1	0	0	½
		Inertial Gap FFR	0	0	0	0	1	½	0	1	1
		Primary Gap PFR	0	0	0	0	1	0	0	1	½
5	VAR Support	VAR Capability	1	1	1	1	1	1	1	1	1
6	Location	Average Number of Evacuation Paths	1	½	1	1	1	1	1	1	1
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit)	0	1	0	0	1	1	0	1	1
8	Short Circuit Strength	Required Additional Synch Condenser	0	1	1	0	0	1	0	0	0

		A	B	C	D	E	F	G	H	I
1	Blackstart	0.50	-	1.00	0.50	0.50	1.00	0.50	0.50	1.00
2	Energy Adequacy	0.50	0.50	1.00	0.50	0.50	1.00	0.50	0.50	1.00
3	Dispatchability	0.50	0.75	0.88	0.38	0.88	1.00	0.38	0.88	0.75
4	Operational Flexibility and Frequency Support	0.17	0.33	0.33	0.17	0.83	0.50	-	0.67	0.67
5	VAR Support	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
6	Location	1.00	0.50	1.00	1.00	1.00	1.00	1.00	1.00	1.00
7	Predictability and Firmness	-	1.00	-	-	1.00	1.00	-	1.00	1.00
8	Short Circuit Strength	-	1.00	1.00	-	-	1.00	-	-	-
	Cumulative Score	3.67	5.08	6.21	3.55	5.71	7.50	3.38	5.55	6.42
	Percent Score (out of 8 possible points)	46%	64%	78%	44%	71%	94%	42%	69%	80%

1	Portfolio passes the screening test
½	Portfolio requires minor to moderate mitigation measures
0	Portfolio requires significant mitigation measures

1. Every metric is scored based on the criteria in the legend at the top of the page
2. Then, for criteria where there is more than one metric, the scores are averaged to create a single score for each criteria
3. All criteria scores are added to get a final portfolio score out of 8 possible points

PORTFOLIO RELIABILITY RANKINGS

	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Duration)
Higher Carbon Emissions	**A** (7) NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 135MW Solar+Storage 450MW* Solar 250MW	**B** (6) NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 443MW Thermal PPA 150MW Solar 250MW	**C** (3) NIPSCO DER 10MW SC Uprate 53MW Gas CC 650MW
Mid Carbon Emissions	**D** (8) NIPSCO DER 10MW SC Uprate 53MW Storage 135MW Solar+Storage 450MW* Solar 400MW	**E** (4) NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 470MW Solar 250MW	**F** (1) NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 300MW Thermal PPA 150MW Storage 135MW Solar 100MW
Low Carbon Emissions	**G** (9) NIPSCO DER 10MW Storage 135MW Solar+Storage 450MW* Solar 450MW	**H** (5) NIPSCO DER 10MW Wind 200MW Storage 570MW Solar 250MW	**I** (2) NIPSCO DER 10MW SC H2 Electrolyzer 20MW SC Uprate 53MW H2 Enabled Peaker 193MW Wind 200MW Storage 370MW Solar 250MW

**Gas Peaker: Local to Service Territory in Portfolio F, while outside of territory in Portfolio B

RELIABILITY ASSESSMENT RESULTS WILL BE INCORPORATED INTO THE REPLACEMENT SCORECARD

	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Duration)
Higher Carbon Emissions	A (7) NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 135MW Solar+Storage 450MW* Solar 250MW	B (6) NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 443MW Thermal PPA 150MW Solar 250MW	C (3) NIPSCO DER 10MW SC Uprate 53MW Gas CC 650MW
Mid Carbon Emissions	D (8) NIPSCO DER 10MW SC Uprate 53MW Storage 135MW Solar+Storage 450MW* Solar 400MW	E (4) NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 470MW Solar 250MW	F (1) NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 300MW Thermal PPA 150MW Storage 135MW Solar 100MW
Low Carbon Emissions	G (9) NIPSCO DER 10MW Storage 135MW Solar+Storage 450MW* Solar 450MW	H (5) NIPSCO DER 10MW Wind 200MW Storage 570MW Solar 250MW	I (2) NIPSCO DER 10MW SC H2 Electrolyzer 20MW SC Uprate 53MW H2 Enabled Peaker 193MW Wind 200MW Storage 370MW Solar 250MW

**Gas Peaker: Local to Service Territory in Portfolio F, while outside of territory in Portfolio B

Preliminary	A	B	C	D	E	F	G	H	I
Replacement Theme	Thermal PPAs, solar and storage	Non-service territory gas peaking (no early storage)	Natural gas dominant (CC)	No new thermal resources; solar dominant w/ storage	Thermal PPAs plus storage and solar	Local gas peaker, plus solar and storage	Solar dominant w/ storage, plus retire Sugar Creek	All renewables and storage, plus retire Sugar Creek (Portfolio 7)	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Cost To Customer 30-year NPV of revenue requirement (Ref Case) $M	$10,461 +$150	$10,332 +$21	$10,312 -	$10,438 +$126	$10,467 +$156	$10,426 +$115	$11,042 +$730	$11,090 +$778	$10,792 +$480
Cost Certainty Scenario Range (NPVRR) $M	$2,359 +$1,035	$2,782 +$1,458	$3,208 +1,885	$2,322 +$998	$2,538 +$1,215	$2,748 +$1,424	$1,324 -	$1,553 +$229	$1,855 +$531
Cost Risk Highest Scenario NPVRR $M	$12,015 +$207	$12,182 +$373	$12,518 +$709	$11,965 +$156	$12,126 +$317	$12,243 +$434	$11,809 -	$12,011 +$202	$11,848 +$39
Cost Risk Stochastic 95% CVAR – 50%	$104 +$21	$92 +$9	$83 -	$104 +$21	$98 +$15	$97 +$14	$123 +$40	$114 +$31	$87 +$4
Lower Cost Opp. Lowest Scenario NPVRR $M	$9,657 +$347	$9,400 +$91	$9,309 -	$9,644 +$334	$9,588 +$278	$9,495 +$186	$10,485 +$1,176	$10,458 +$1,149	$9,933 +$684
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)	27.3 +11.3	30.4 +14.4	47.2 +31.2	27.3 +11.3	27.3 +11.3	28.5 +12.4	16.1 -	16.1 -	25.2 +9.2
Reliability	*To be added in final scorecard*								
Resource Optionality MW-weighted duration of 2027 generation commitments (yrs.)	[illegible] +3.0	[illegible] +3.5	[illegible] +6.6	[illegible] +3.4	[illegible] +4.2	[illegible] +5.1	[illegible] -	[illegible] +1.2	[illegible] +4.5
Local Economy NPV of property taxes	$420 [illegible]	$388 -$98	$451 -$35	$417 [illegible]	$413 -$73	$416 -$70	$486 -	$477 -$9	$421 -$65

NEXT STEPS

Alison Becker, Manager Regulatory Policy, NIPSCO

NEXT STEPS

Scorecard Integration

- The scores from the reliability assessment will be integrated as a metric in the Replacement Analysis Scorecard

Seeking Feedback

- Seeking feedback regarding the assessment results presented today
- Reach out to Alison Becker (abecker@nisource.com) for 1x1 meetings

Final Stakeholder Meeting

- Final Public Stakeholder Advisory Meeting #5 is scheduled for **October 21st**

APPENDIX

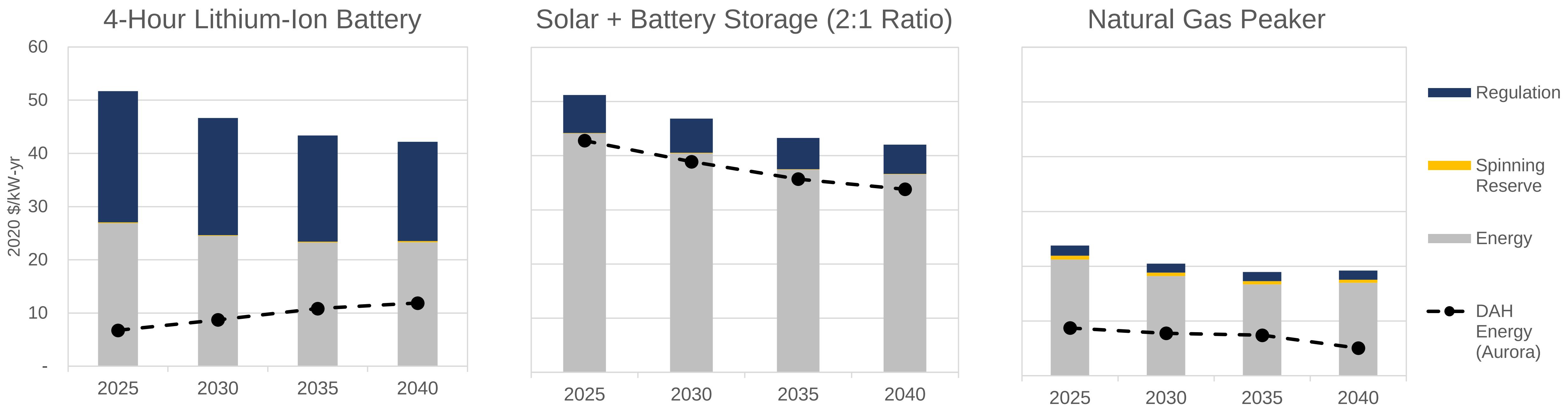
GLOSSARY

Acronym	Definition
A/S	Ancillary Services
ACE	Area Control Error
AER	Aggressive Environmental Regulation Scenario
AGC	Automatic Generation Control
BESS	Battery Energy Storage System
CRA	Charles River Associates
DER	Distributed Energy Resource
ELCC	Effective Load Carrying Capability
ESOP	Energy Storage Operations
EWD	Economy-Wide Decarbonization Scenario
FERC	Federal Energy Regulatory Commission
GFM	Grid Forming Inverters
IBR	Inverter-Based Resources
IRP	Integrated Resource Plan
MISO	Midcontinent Independent System Operator
MVA	Million Volt-Amps
NERC	North American Electric Reliability Corporation
NIPSCO	Northern Indiana Public Service Company
POI	Point of Interconnection
PPA	Purchase Power Agreement

Acronym	Definition
REF	Reference Case Scenario
RoCoF	Rate of Change of Frequency
SC	Sugar Creek
SQE	Status Quo Extended Scenario
TO	Transmission Owner
TOP	Transmission Operator
VAR	Volt-Ampere Reactive
VOM	Volt-Ohm-Meter

SUB-HOURLY ANALYSIS INDICATES POTENTIAL UPSIDE FOR STORAGE ASSETS

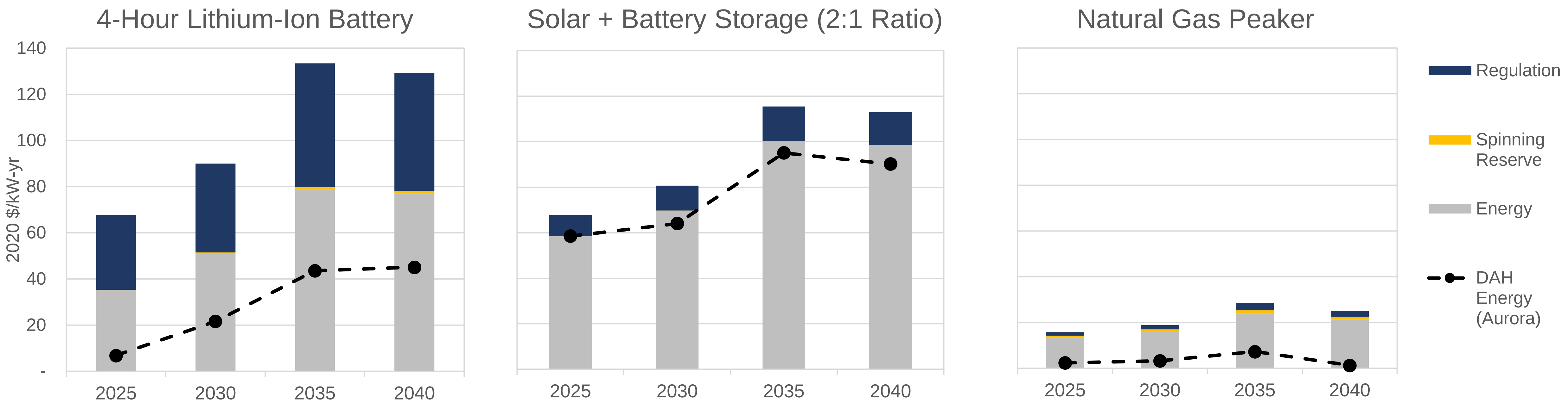
Status Quo Extended



- Lower overall power prices reduce margin expectations for all technologies, although premium between day ahead Aurora-based value and sub-hourly / ancillary services impact is comparable for solar + storage and gas peaker options
- Upside for stand-alone storage is mitigated over time as energy arbitrage opportunities are less valuable

SUB-HOURLY ANALYSIS INDICATES POTENTIAL UPSIDE FOR STORAGE ASSETS

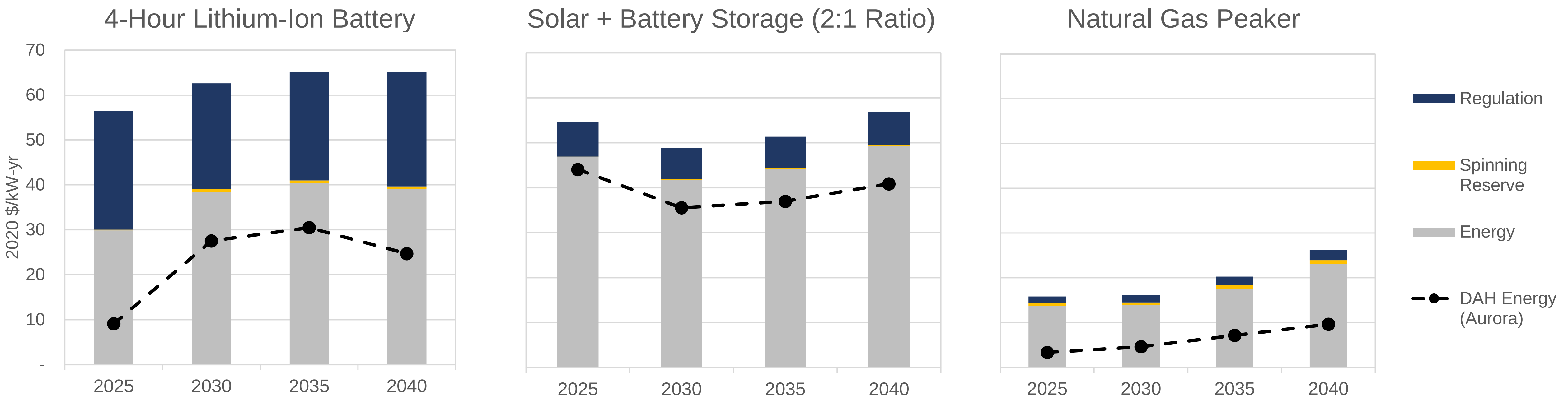
Aggressive Environmental Regulation



- Higher overall power prices increase margin opportunities, particularly for storage resources, which have significant upside potential with greater energy price spreads and higher ancillary services prices
- Natural gas peaker upside is more limited, given high carbon price and high natural gas price embedded in this scenario

SUB-HOURLY ANALYSIS INDICATES POTENTIAL UPSIDE FOR STORAGE ASSETS

Economy-Wide Decarbonization



- Prices in the EWD scenario are lower than the Reference Case, but renewable penetration is high, resulting in sustained upside opportunities for battery resources

FREQUENCY RESPONSE AND SIMPLIFIED MODEL

- **Inertial Response**
  - $\frac{2H}{f_0}\frac{df}{dt} = \Delta P$
  - ΔP = Loss of power resources due to contingency event

    + Variability of intermittent resources solar+wind resources at 1s

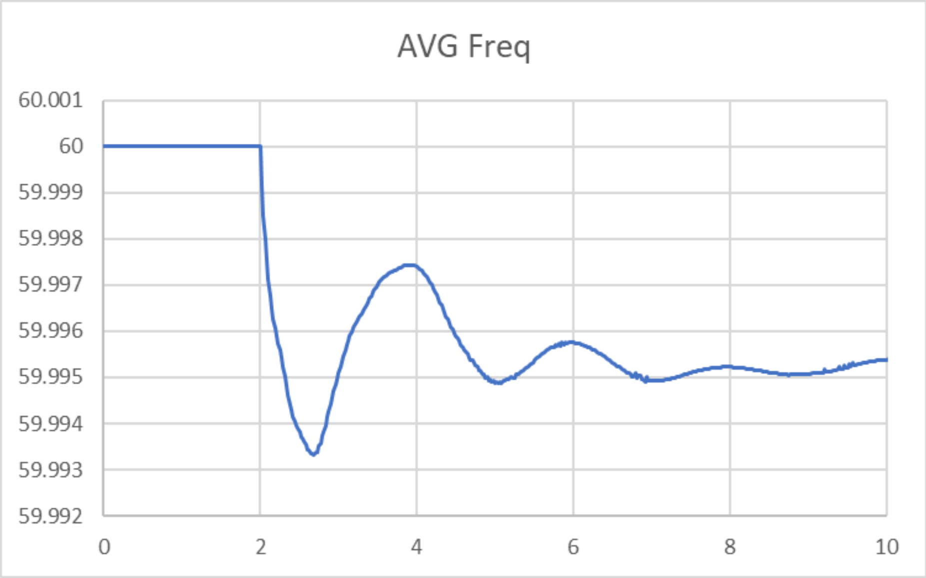
    - Virtual inertial contribution from online solar+wind resources

    - Virtual inertial contribution from battery energy storage

    - Inertial response contribution from outside areas over tie-lines
  - Inertia to limit RoCoF: H= ΔP/(2 x RoCoF Limit) f_0
  - Inertia to avoid triggering UFLS before the responsive reserves load: H=ΔP/(2 x UFLS speed) f_0 ;

    where UFLS speed = (pickup frequency – trip frequency)/delay

- **Primary Freq Response**
  - Δf(pu)= - (R .ΔP)/(D.R+1)
  - Where:
    - R is governor droop,
    - D is load damping,
    - ΔP is system disturbance, and all are in per unit using the same MW base value, such as system load level

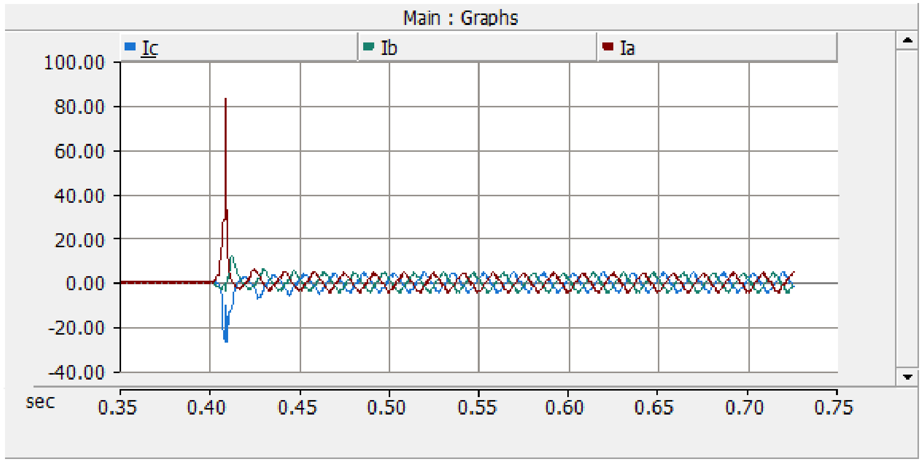


APPENDIX: MODELING THE PORTFOLIOS

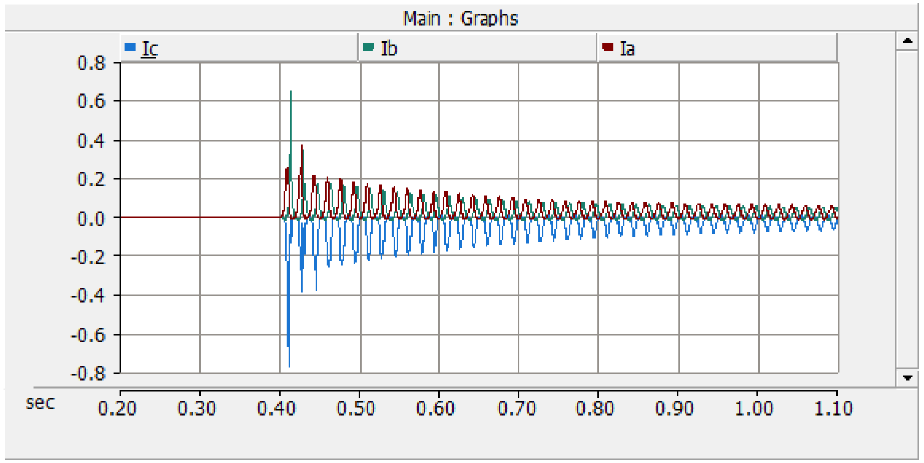
i. Energy Adequacy Analysis (Islanded Operation)
ii. Dispatchability
iii. Flexibility: Inertial Response
Flexibility: Primary Frequency Response
iv. VAR Support
v. Predictability of Supply
vi. Short Circuit Strength
vii. Black Start
viii. Locational Attributes

INRUSH CURRENTS

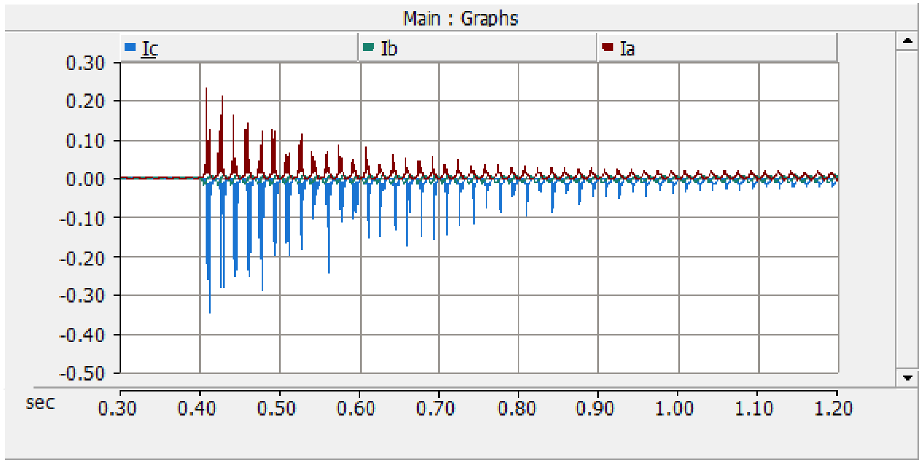
Step1: 0.4kV34.5kV XFO energization (0.4kV side)



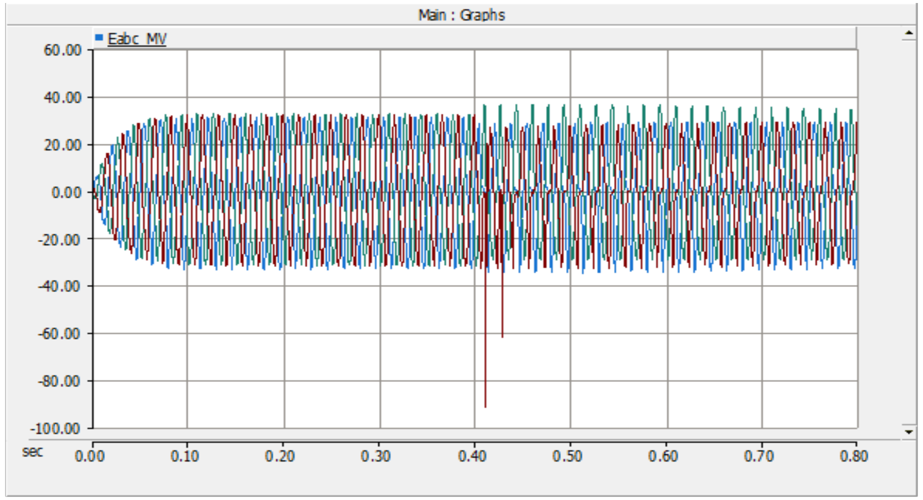
Step2 : 34.5kV/138kV XFO energization (34.5kV side)



Step3 : 138kV/22kV XFO energization (138kV side)

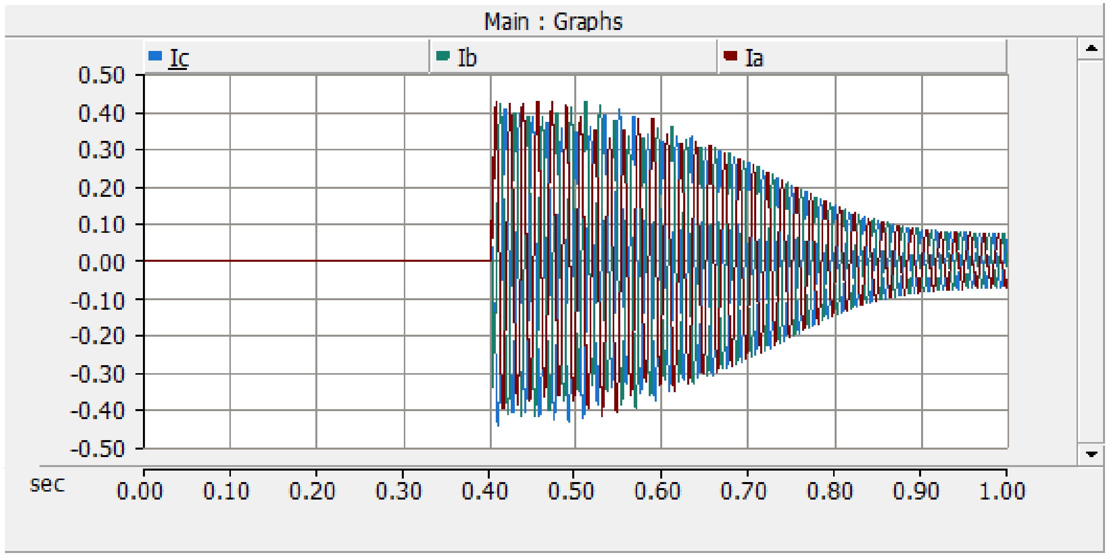


34.5kV Voltage side (TOV)

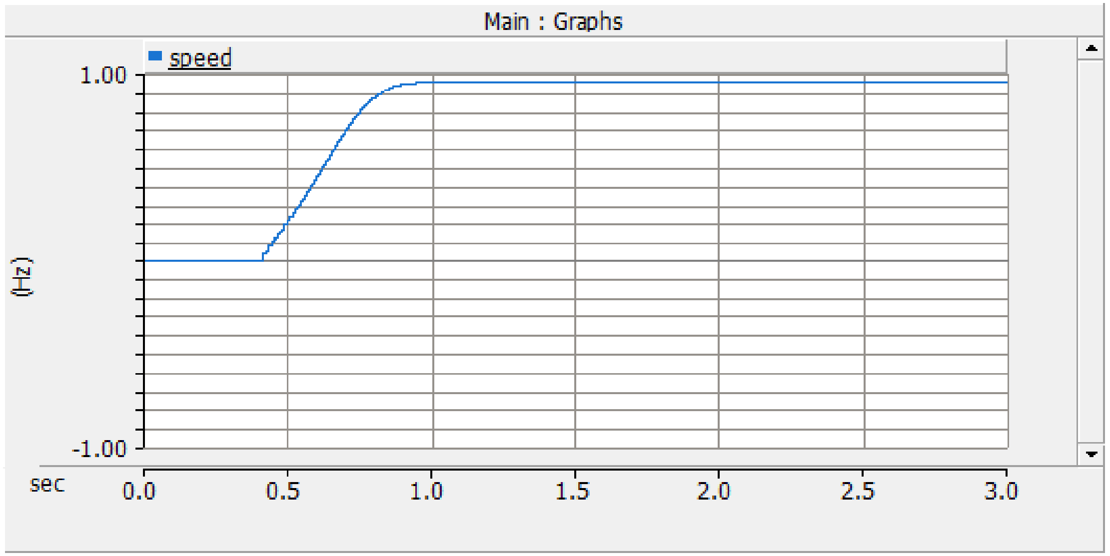


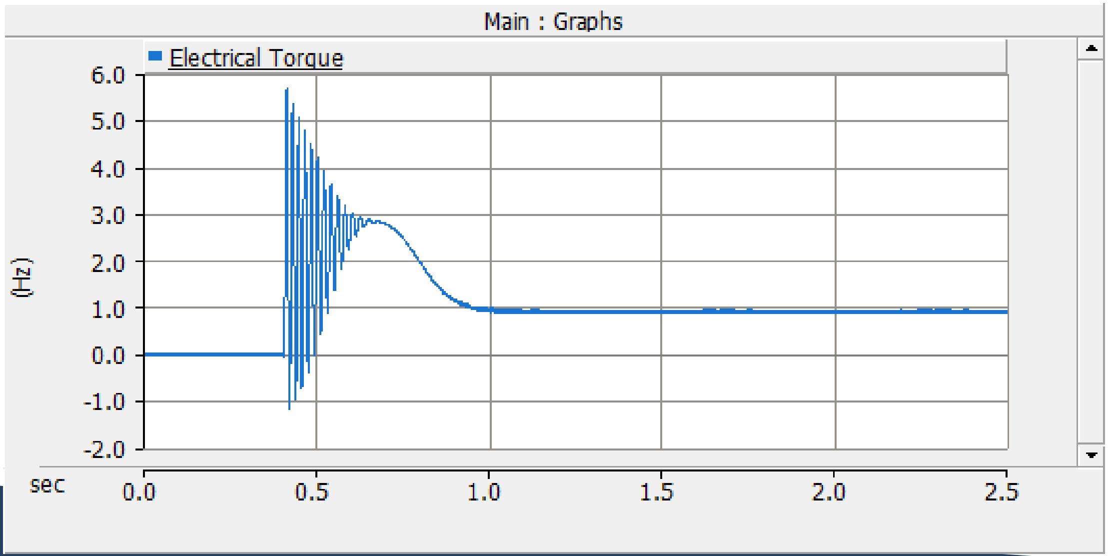
INDUCTION MOTOR (PONY)

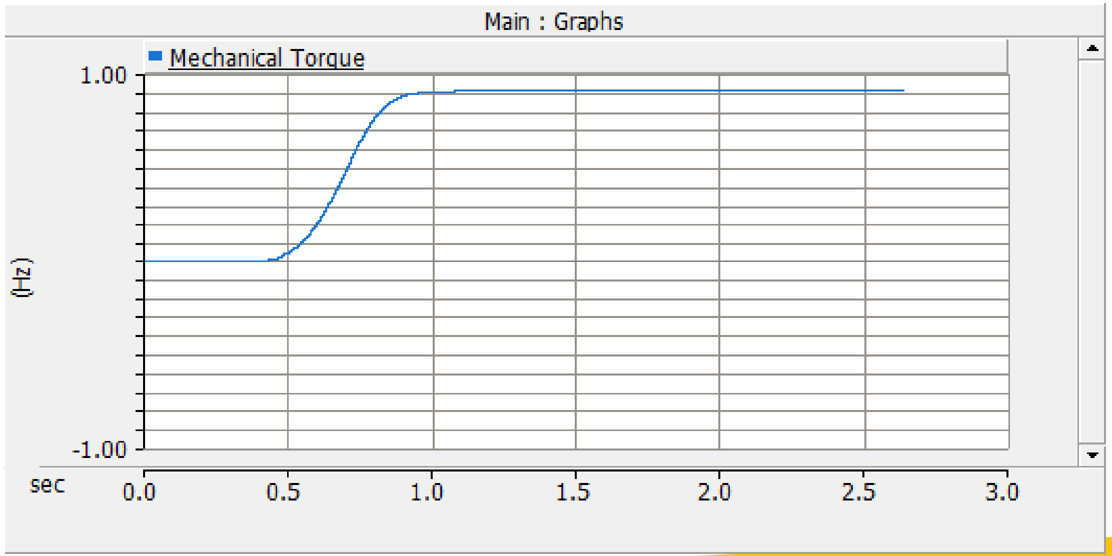
Step4 : Induction motor Inrush Current at 22kV (breaker closing)



Mechanical Speed

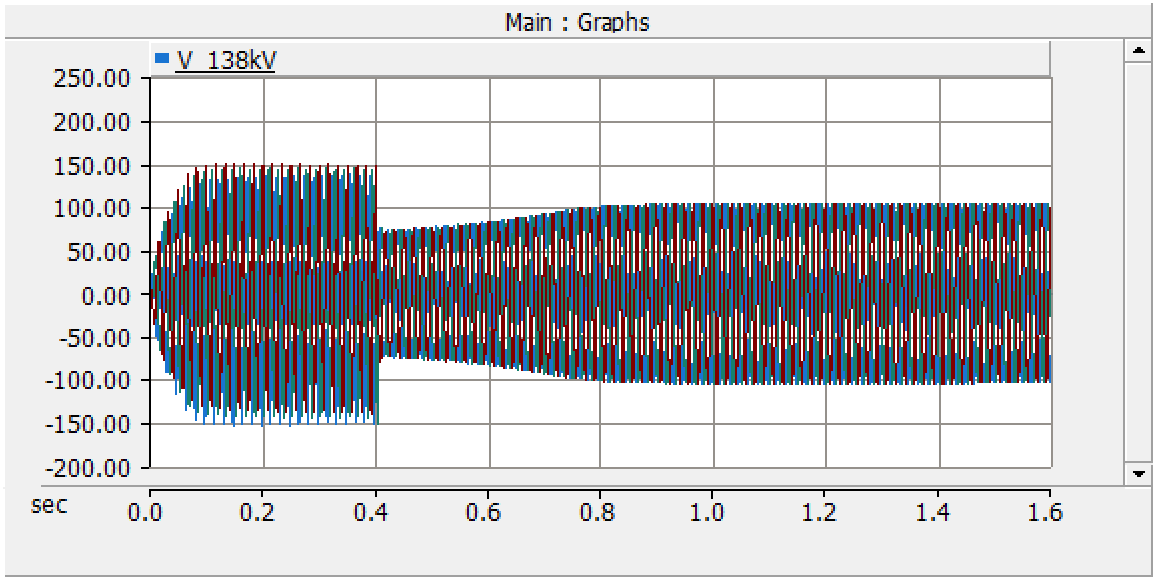






CHECK BATTERY RATINGS

- Upon closing the breaker between the battery and the 0.4/34.5k 150MVA transformer, the inrush current is around 80kA on the 0.4kV side which translate to a rating of 55MVArs from the inverters. This level of inrush current is within the capability of the system. Note that the inrush current will depend on the breaker closing time and strategy.
- The rating implications of energizing the 34.5/138kV transformer, the 18mile 138kV line, and the 138/22kV step down transformer is less, and are acceptable too.
- The motors started. There is a voltage drop on the 138kV bus.

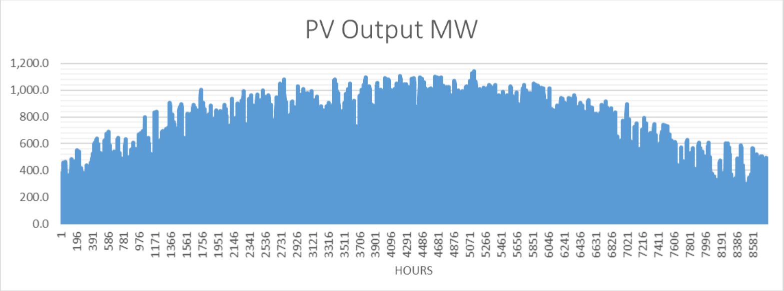


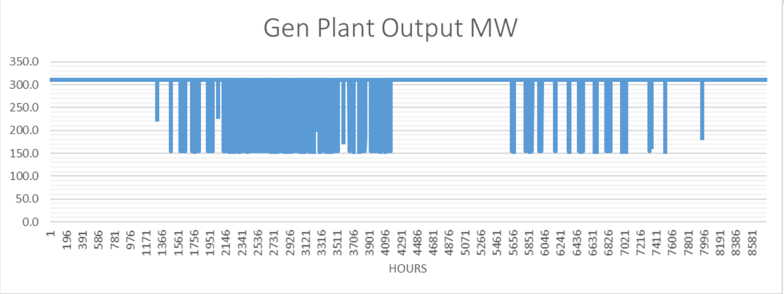
ENERGY ADEQUACY – ISLANDED OPERATION

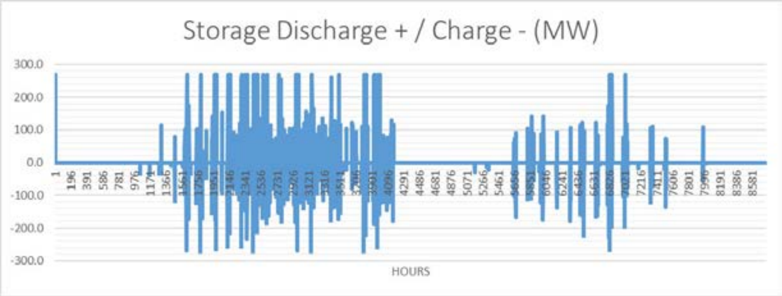
Portfolio	Solar PV MW	Wind MW	Energy Storage MW	Thermal Gen MW	Hyrdo	IBR %	Energy Not Served (GWh/Yr)	Energy Not Served 1-Yr (%)	ENS Worst 1-Week (%)	ENS Worst 1-hr (%)	Storage Avg Cycles/Day	Renewable Curtailment %
A	1,650	405	420	0	10	100%	6,079	54.8%	76.2%	99.0%	0.16	0.4%
B	1,350	405	135	0	10	99%	6,717	60.6%	78.5%	99.0%	0.06	0.2%
C	1,100	405	135	650	10	71%	2,054	18.5%	32.1%	63.2%	0.49	1.7%
D	1,800	405	420	0	10	100%	5,793	52.3%	75.0%	99.0%	0.26	1.3%
E	1,350	405	605	0	10	100%	6,711	60.5%	78.5%	99.0%	0.02	0.0%
F	1,200	405	270	300	10	86%	4,499	40.6%	55.9%	91.4%	0.11	0.2%
G	1,850	405	420	0	10	100%	5,705	51.5%	74.6%	99.0%	0.29	1.7%
H	1,350	605	705	0	10	100%	6,071	54.8%	73.4%	98.8%	0.04	0.0%
I	1,350	605	505	193	10	92%	4,476	40.4%	58.1%	88.1%	0.41	0.1%

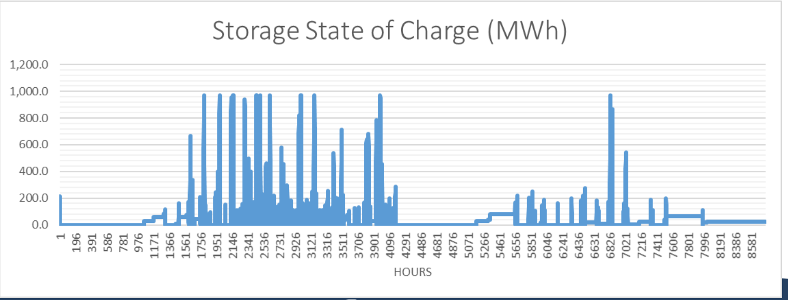
- The analysis is simulating resources (ICAP) inside the service territory (islanded operation). For additional context, the NIPSCO system has never been islanded. This analysis is testing a Black Swan event.
- The analysis simulates each portfolio in the year 2030 from an energy adequacy perspective when NIPSCO is operating in an islanded mode under emergency conditions and assesses its ability to meet the demand requirements across all 8760 hours of the year. The outcome of the simulations is the energy not served (GWh) if the system operates in islanded mode for 1 year, the worst energy not served if the islanded mode lasts for 1 week, and for 1 hour. Additional results are the average daily utilization of energy storage assets (cycles/day) and the level of renewable curtailment.
- The portfolios can be ranked as to their ability to serve the load as follows: C, I, F, G, D, H, A, E, B
- Note: All the resources in each portfolio in addition to all other existing and planned resources are assumed to continue serving NIPSCO load.

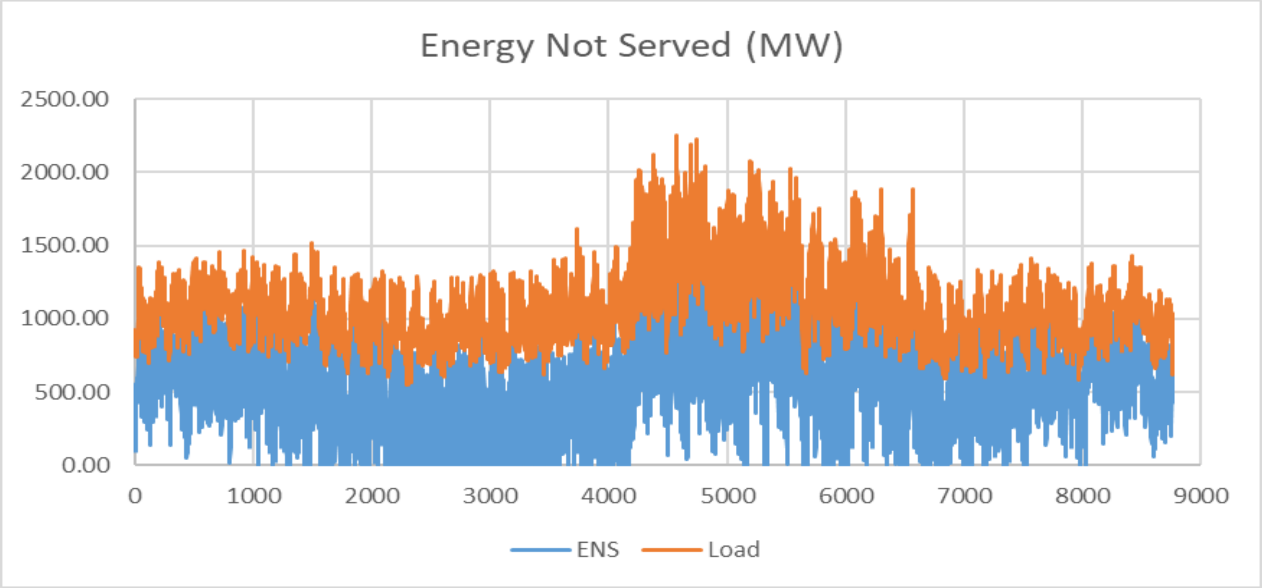
REPRESENTATIVE SIMULATION RESULTS – PORTFOLIO F











- The graph shows the hourly load profile and the energy-not-served (ENS) at each hour of the year 2030.
- The simulation dispatched the peaker plant and the energy storage assets against the net native load after deducting solar and wind outputs. Solar curtailment was enforced during periods when the storage was fully charged and the plant was at minimum output level.
- The peaker plant was assumed fully flexible (no ramp limits), but with a Pmin of 50% of its rating.
- The energy storage systems were assumed to have 4 hours of capacity, and round-trip-efficiency of 85%.

DISPATCHABILITY

Portfolio	Additional Installed Capacity (MWs) Total	Dispatchable	Non-Dispatchable	%Dispatchable	Renewable Penetration % Y2030
A	1,048	488	560	47%	53%
B	906	646	260	71%	48%
C	713	703	10	99%	43%
D	1,048	338	710	32%	56%
E	933	673	260	72%	48%
F	748	638	110	85%	45%
G	1,045	285	760	27%	57%
H	1,030	570	460	55%	53%
I	1,076	616	460	57%	53%

- Portfolios ranked by highest % of dispatchable resources: C, F, E, B, I, H, A, D, G
- Without additional resources, the renewable penetration from planned resources will reach 43% by 2030. However, adding one of the IRP portfolios will increase the penetration by as much as 14%.

INCREASE IN REGULATION REQUIREMENTS & POWER RAMPING CAPABILITY

Portfolio	Increase in Freq Regulation Requirements (MW)
A	60
B	47
C	40
D	64
E	47
F	43
G	66
H	53
I	53

- The short-term intermittency of solar and wind resources increases the need for frequency regulation. This analysis quantifies the increased level of regulation services.

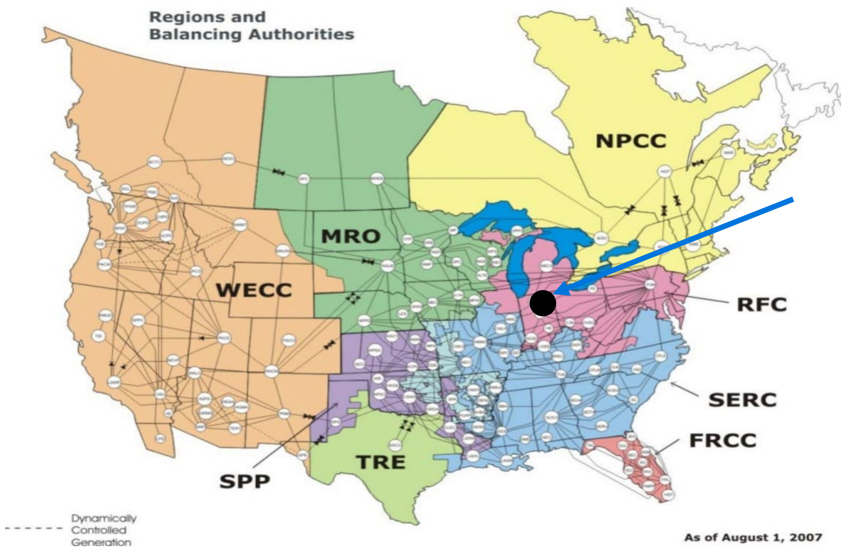
Y 2030

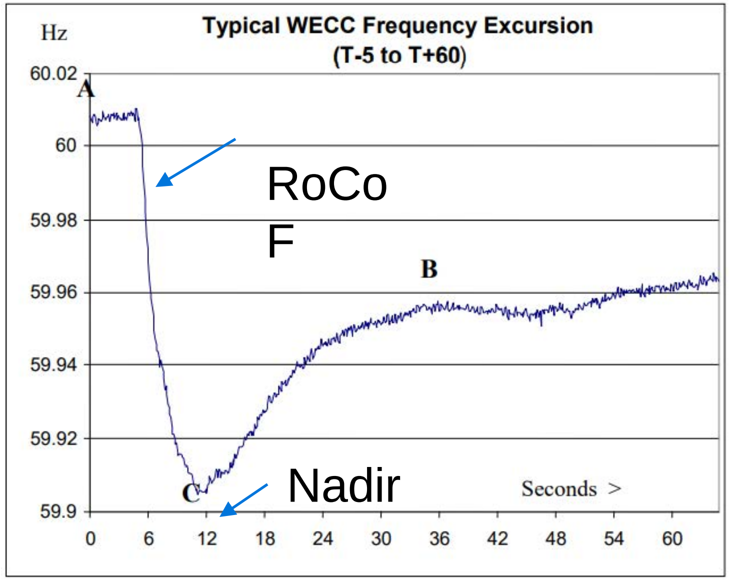
Portfolio	1-min Ramp Capability (MW)	10-min Ramp Capability (MW)
A	346	649
B	211	514
C	261	764
D	331	574
E	681	984
F	397	859
G	326	548
H	761	983
I	599	944

- The ramping capability of the system is measured at 1-min and 10-mins. The higher the ramping capability the better flexibility the system will have to respond to sudden disturbance.

FREQUENCY CONTROL - OVERVIEW

- NIPSCO operates a balancing control area, within the MISO balancing control area within the Eastern Interconnection.
- Dispatchers at each Balancing Authority fulfill their NERC obligations by monitoring ACE and keeping the value within limits that are generally proportional to Balancing Authority size.
- Generators contribute to the frequency response through Governors while loads contribute through their natural sensitivity to frequency. Frequency Response is measured as change in MW per 0.1Hz change in frequency. Governor's droop of 5% translates to a response of 3.3% while load response is typically 1-2%. Frequency Response is particularly important during disturbances and islanding situations. Per BAL-003, each balancing area should carry a frequency bias, whose monthly average is no less than 1% of peak load.
- Following the loss of a large generator, frequency drops initially at a rate (RoCoF) that depends on the level of inertia in the system. After few seconds, it will stabilize at a lower value (Nadir) due to the primary frequency response of generators and loads. Afterwards, AGC systems will inject regulation reserves that raise the frequency to within a settling range within a minute. Tertiary reserves are called upon if required to help.





Control	Ancillary Service/IOS	Timeframe	NERC Standard
Primary Control	Frequency Response	10-60 Seconds	FRS-CPS1
Secondary Control	Regulation	1-10 Minutes	CPS1– CPS2 – DCS - BAAL
Tertiary Control	Imbalance/Reserves	10 Minutes - Hours	BAAL - DCS
Time Control	Time Error Correction	Hours	TEC

QUANTA TECHNOLOGY

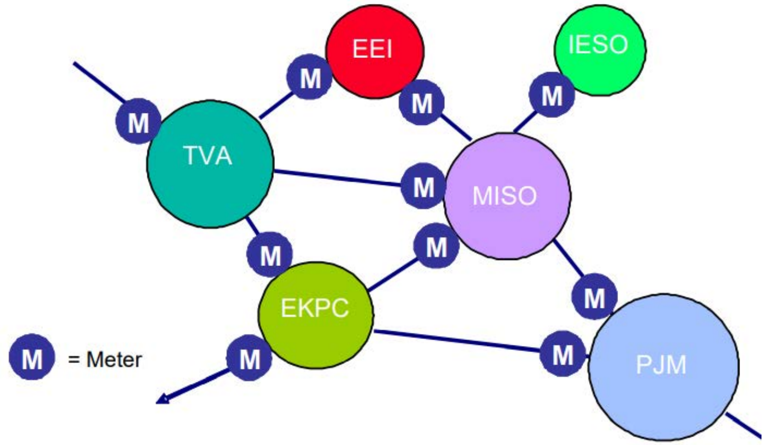
MODELING OVERVIEW

- The NIPSCO system is connected to neighboring utilities through 69-765kV lines with a total line ratings of 28GW. The simultaneous import capability is estimated at 2,650MW while the export capability is estimated at 2,350MW.

- Most of the conventional generation capacity within NIPSCO system is planned for retirement and thus the system inertia is expected to decline.

Portfolio	2021		2025		2030	
	Summer Rating MW	Inertia MVA-s	Summer Rating MW	Inertia MVA-s	Summer Rating MW	Inertia MVA-s
A	1,830	8,027	1,120	5,431	598	3,200
B	1,830	8,027	1,120	5,431	1,041	6,004
C	1,830	8,027	1,170	5,701	1,248	6,711
D	1,830	8,027	1,120	5,431	598	3,200
E	1,830	6,845	1,120	5,002	598	3,218
F	1,830	8,027	1,120	5,431	898	5,099
G	1,830	8,027	1,120	5,431	545	2,914
H	1,830	8,027	1,120	5,431	545	2,914
I	1,830	8,027	1,313	6,627	791	4,379

- The NIPSCO system will be assessed during normal operation when it is connected to the MISO system, and also under abnormal operation when it is isolated.



Sum of Tie Line Ratings	RTO	69	138	345	765	Total
Ameren Illinois	MISO		245			245
American Electric Power	PJM	94	927	12,819	2,669	16,509
Commonwealth Edison	PJM		766	7,967		8,733
Duke Energy Indiana	MISO	44	430	2,106		2,580
Michigan Electrical	MISO		215			215
Total MVA		**138**	**2,583**	**22,892**	**2,669**	**28,282**

QUANTA TECHNOLOGY

INERTIAL RESPONSE (ROCOF)

Event	Loss of 420MW Gen									
Renewable Variability	Yes					No				
NIPSCO	Islanded					Connected				
Scenario	1	2	3	4	**5**	6	7	**8**	**9**	10

Summer Peak Hour
7/21 3PM
Load 100%; PV 81%; Wind 7%

Spring Noon
April 11-1PM
Load 53%; PV 63%%;Wind 42%

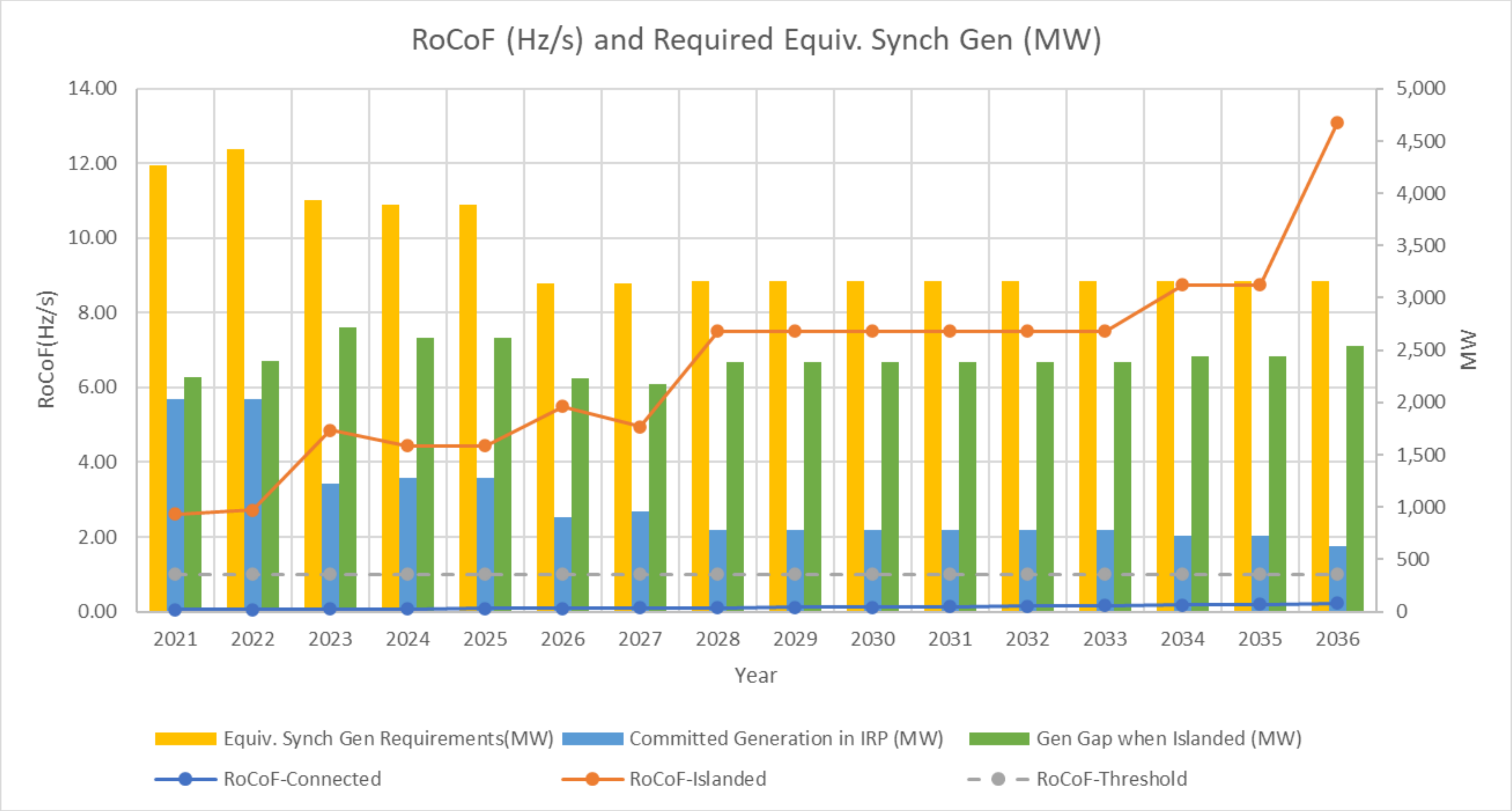
Fall Early Afternoon
10/18 1PM
Load 50%; PV 63%%; Wind 7%

Assumptions:

- No storage systems in the IRP are fitted with grid-forming inverters capable of inertial response.
- Wind can provide inertial response level of 11% of their nameplate rating.
- IBR adoption in the rest of MISO starts at 20% in 2021 and increases by 2.5% each year reaching 42.5% in 2030.
- Tie-line import capability limit connecting NIPS area of 2650 MW.
- Solar and OSW variability (1-second) of 5% of nameplate rating.

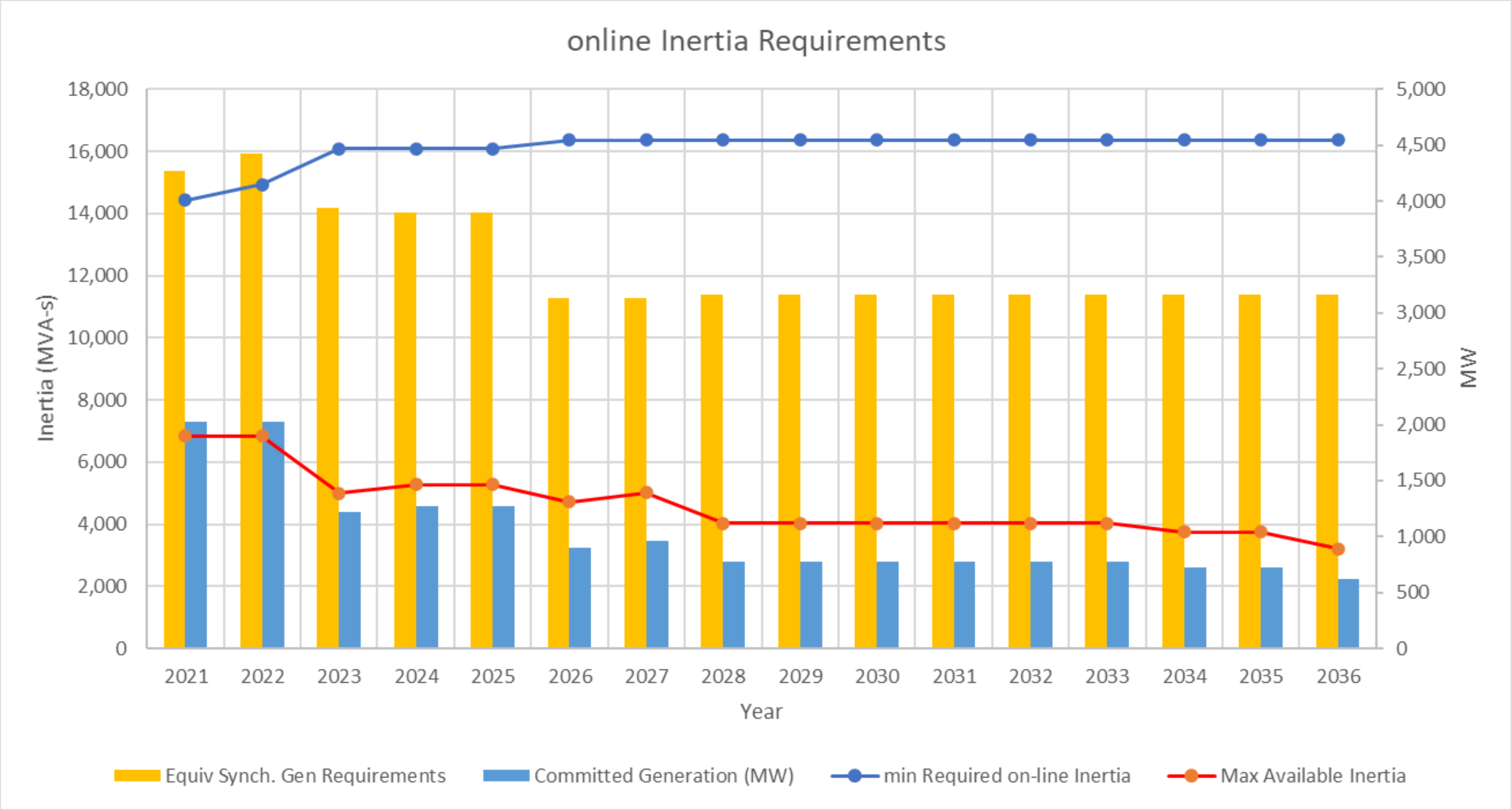
INERTIAL RESPONSE

- Using Portfolio E, the system inertial response was simulated during normal conditions when NIPSCO is connected to MISO and also during emergency conditions when it is islanded. The simulation is conducted assuming all available synchronous generation is committed.



- During normal operations when NIPSCO is connected to MISO system, RoCoF starts in 2021 at a small value of 0.05Hz/s and increases to 0.12Hz/s by 2030 and 0.38Hz/s by 2040. This increase is due to retirements of synchronous generation within NIPSCO system and also within MISO. However, it remains acceptable below 1.0Hz/s.
- When Islanded, RoCoF exceeds the acceptable threshold starting at 2.6Hz/s in 2021 and reaching 7.5Hz/s by 2028.

INERTIAL RESPONSE



- An equivalent inertia of 16,000MVA-s is required to be on-line to maintain RoCoF within 1Hz/s. This can be accomplished by either committing additional synchronous generation or synchronous condensers equipped with fly wheels reaching 2,383 MW or equipping energy storage with grid forming inverters capable of delivering a combined inertial response of 411MW.

QUANTA TECHNOLOGY

INERTIAL RESPONSE –PORTFOLIO RANKING

Portfolio	On-Line Gen MVA (Y2021)	On-Line Gen MVA (Y2030)	On-Line Inertia MVA-s (Y2021)	On-Line Inertia MVA-s (Y2030)	Energy Storage MW (Y2030)	Fast Frequency Response (MW)	RoCoF Limit Hz/s	Normal System (Connected): RoCoF Normal (Y2021)	Normal System (Connected): RoCoF Normal (Y2030)	Normal System (Connected): Gap Inertia (MVA-s)	Islanded System: RoCoF Islanded (Y2021)	Islanded System: RoCoF Islanded (Y2030)	Islanded System: Gap Inertia (MVA-s)	Islanded System: Required Mitigation BESS GFM[1] (MW)	Islanded System: Additional Required BESS GFM (MW)
A	2,236	945	6,845	4,028	270	404	1.00	0.04	0.08	0	2.61	7.61	16,568	418	148
B	2,236	945	6,845	4,028	135	269	1.00	0.04	0.08	0	2.61	7.51	16,361	411	276
C	2,236	1,573	6,845	6,729	135	359	1.00	0.04	0.07	0	2.61	3.04	16,093	312	177
D	2,236	757	6,845	3,218	270	377	1.00	0.04	0.08	0	2.61	13.45	16,729	450	180
E	2,236	945	6,845	4,028	605	739	1.00	0.05	0.12	0	2.61	7.51	16,361	411	0
F	2,236	1,358	6,845	5,927	270	468	1.00	0.04	0.08	0	2.61	3.71	16,200	342	72
G	2,236	690	6,845	2,931	270	368	1.00	0.04	0.08	0	2.61	18.33	16,783	462	192
H	2,236	690	6,845	2,931	705	803	1.00	0.04	0.08	0	2.61	17.61	16,211	443	0
I	2,236	1,013	6,845	4,397	505	652	1.00	0.04	0.08	0	2.61	6.22	16,211	394	0

[1]GFM : Battery Energy Storage equipped with Grid Forming Inverters

- The portfolios can be ranked based on the available fast frequency response capability within NIPSCO service territory: H, E, I, F, A, D, G, C, B
- All portfolios do not violate the inertial response threshold during normal interconnected operations
- During islanded operations:
  - Portfolios E, H, and I can meet the inertial threshold if 68%, 63%, and 78% of their storage is equipped with grid forming (GFM) inverters with inertial response functionality.
  - Other portfolios require additional storage in addition to equipping all their planned storage with GFIs.
- Ranking of Portfolios: I, E, H, F, A, C, D, G, B

QUANTA TECHNOLOGY

PRIMARY FREQUENCY RESPONSE

Portfolio	Installed Generation MW (Y2021)	Installed Generation MW (Y2030)	Energy Storage MW (Y2030)	On-Line Reserves MW (Y2021)	On-Line Reserves MW Y2030)	Primary Freq Response (MW)	Freq Nadir Threshold (Hz)	Islanded System: Freq Nadir Hz (Y2021)	Islanded System: Freq Nadir Hz (Y2030)	Islanded System: Required Gen Resources (MW)	Islanded System: Requied Storage Resources (MW)	Islanded System: Load Drop (MW)
A	1,830	748	270	-448	487	225	0.50	17.09	0.87	961	258	202
B	1,830	748	135	-448	151	113	0.50	17.09	1.64	1,608	387	404
C	1,830	1,248	135	-448	444	113	0.50	17.09	1.61	1,073	380	111
D	1,830	598	270	-448	461	225	0.50	17.09	0.87	1,125	261	228
E	1,830	748	605	-448	621	504	0.50	17.09	0.40	0	0	404
F	1,830	1,048	270	-448	461	225	0.50	17.09	0.87	612	248	228
G	1,830	545	270	-448	449	225	0.50	17.09	0.87	1,183	262	240
H	1,830	545	705	-448	549	588	0.50	17.09	0.35	0	0	576
I	1,830	791	505	-448	595	421	0.50	17.09	0.48	17	20	330

On-Line Reserves measured at peak load inside NIPSCO

Online Reserves include generation and energy storage resources in excess of net load inside NIPSCO area

- The portfolios were simulated to assess the level of frequency drop in response to the sudden loss of 420MW of generation. The simulations were conducted when the system was in normal interconnected modes and did not find any reliability issues with any portfolio. However, when the system was simulated under emergency operation in islanded mode, several portfolios experienced frequency violation of the nadir dropping by more than 0.5Hz potentially triggering under frequency load shedding schemes.
- The analysis continued to quantify the level of additional fast response requirements from storage systems to mitigate the reliability violations.
- Note: The analysis assumed a droop of 5% for conventional assets, and 1% for storage assets, all limited by the resource ramp rates.

QUANTA TECHNOLOGY

DYNAMIC REACTIVE POWER CAPABILITY AND DISTANCE TO LOAD

Y 2030	
Portfolio	VAR Capability (MVAr)
A	444
B	385
C	603
D	378
E	590
F	575
G	355
H	545
I	565

- A large part of NIPSCO's baseload and industrial clients are clustered around the same area. NIPSCO provides the dynamic reactive power requirements of these customers.
- The resources within NIPSCO footprint can generate dynamic reactive power. However, the given the localized nature of reactive power, the closer "electrically" the generator VARs to the load centers, the more valuable they are to the system.
- The available dynamic VArs in the system are calculated assuming all resources have the capability to operate +/- 0.9 power factor.
- The electrical distance of each resource to each load center is calculated using the Zbus matrix in the form of electrical impedance.
- Each portfolio will be evaluated based on its VARs distance from the load centers as follows:
  - The VARs of each resource will be weighted by the inverse of its distance to all load points and by the relative weight of that load point among all load points. The shorter the distance, and the higher the load served at the load point, the higher the score.
  - The portfolio VARs will be normalized by the impedance per mile of 138kV lines to yield a metric of VARs/mile distance from load centers.

IMPORTANCE AND IMPACTS OF SHORT CIRCUIT STRENGTH

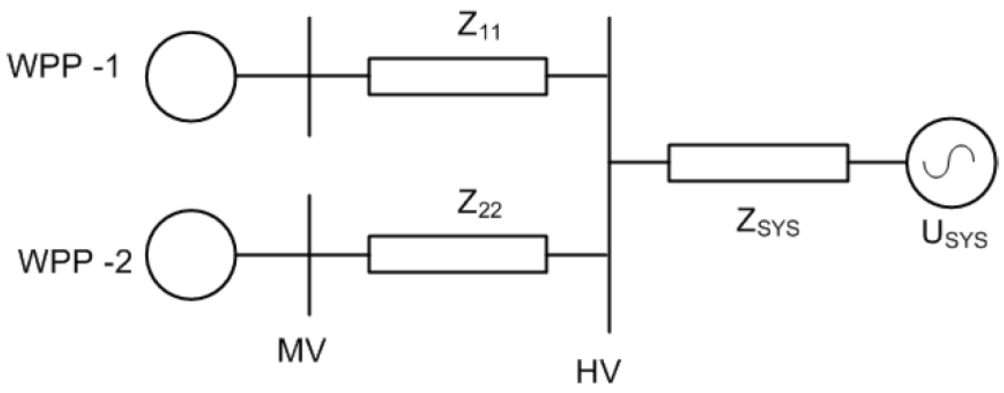
Importance:

- Short Circuit MVA (SCMVA) is a measure of the strength of a bus in a system. The larger SCMVA, the stronger the bus. That indicates the bus is close to large voltage sources, and thus it will take large injections of real or reactive power to change its voltage. SCMVA changes depending on grid configuration and on-line resources. The lowest SCMVA is usually utilized for engineering calculations.
- When IBRs are interconnected to a system, it is desirable to maintain a stable bus voltage irrespective of the fluctuation of the IBR's output. Similarly, grid following (GFL) inverters rely on stable voltage and frequency to synchronize to the grid using their phase locked loops (PLL).
- The maximum allowable size of IBR desiring to interconnect to a bus is limited to a fraction of the bus's short circuit MVA, say less than 20-50%. This is expressed as Short Circuit Ratio (SCR) of the ratio of SCMVA to the rating of the IBR. This will translate to SCR of 2-5.
- When multiple IBRs are interconnected at a close electrical distance, their controls interact, and the impact of system voltages will increase. Thus, a modified measure was adopted to be ESCR (Effective SCR) to capture this interaction.

Impact:

- When conventional power plants with synchronous generators are retired and/or the system tie-lines are severed, the short circuit currents will dramatically decline. IBRs are limited in their short circuit contribution and also the phase of their current (real) is not aligned with typical short circuit currents (reactive), and thus are not a substitute.
- Declining SCMVA and increasing IBRs will eventually violate the ESCR limits, requiring either a cessation of additional IBR interconnections, or provisioning additional mitigation measures.
- Mitigations can come in the form of optimal placement of IBRs to avoid clustering them in a manner that violates the ESCR limits, provisioning synchronous condensers, or requiring inverters to have grid-forming (GFM) capability.

SHORT CIRCUIT STRENGTH – EQUIVALENT SHORT CIRCUIT RATIO



$$ESCR_i = \frac{S_i}{P_i + \sum_j IF_{ji} * P_j}$$

where $IF_{ji} = \frac{\Delta V_j}{\Delta V_i}$ is the interaction factor between buses i and j and can be calculated using Zbus.

Pi and Pj are the inverter ratings at buses i and j respectively, while Si is the minimum short circuit MVA at bus i.

Optimal Placement of IBRs from Short Circuit perspective to avoid ESCR limitation:

$$MAXIMIZE \ \sum_{j \in buses} P_j$$

Subject to $\sum_j IF_{ji} * P_j \le \frac{S_i}{ESCR\ Threshold}$

$$P_j \ge 0$$

PLACEMENT OF IBRS IN PORTFOLIOS A TO I

- NIPSCO provided a list of locations of the planned IBRs as follows:
  - 1305MW within NIPSCO territory in addition to 450MW in Duke/Vectren territory. These 1755MW were modeled in this analysis as planned resources and thus excluded from the relative evaluation of Portfolios A-I.
  - 930MW of resources are outside of NIPSCO territory (Duke, IPL, Big Rivers, Ameren) and were not modeled.
  - The resources in each portfolio (A-I) are located at buses with Queued projects and POIs. The study distributed them among these POIs while respecting the ICAP MW to the extent possible (next slide).
  - The Sugar Creek combined cycle plant is assumed within the service territory and is modeled connected to the Reynolds 345kV bus.
  - Islanded NIPSCO system was modeled.

Portfolio	Solar PV MW	Wind MW	Energy Storage MW	Thermal Gen MW	Hyrdo MW	IBR %
A	2,100	405	420	738	10	80%
B	1,800	405	135	738	10	76%
C	1,550	405	135	1,238	10	63%
D	2,250	405	420	588	10	84%
E	1,800	405	605	738	10	79%
F	1,650	405	270	1,038	10	69%
G	2,000	405	270	535	10	83%
H	1,800	605	705	535	10	85%
I	1,800	605	505	781	10	79%

SHORT CIRCUIT STUDY PROCEDURE

- An islanded NIPSCO system is modeled including Sugar Creek and 2 synchronous condensers.
- System Zbus matrix is calculated, and the Interaction Factor matrix is derived.
- The Effective Short Circuit Ratio (ESCR) is calculated at each bus to assess the strength of the system to integrate the combined planned and Portfolio IBRs.
- If the ESCR is above 3, the Portfolio is deemed satisfactory from a short circuit strength perspective.
- Otherwise, additional synchronous condensers are placed in the system and their sizes optimized to enable full integration of the Portfolio resources (not withstanding potential violations of other planned resources outside of the portfolio).
- The portfolios are compared based on the total MVA of the synchronous condensers that will be required to mitigate short circuit strength violations.
- Three sites for synchronous condensers were selected based on the system topology:
  - 17REYNOLDS, 17SCHAHFER, and 17BURR_OAK
- NOTE: This is a screening level analysis and is indicative. Detailed system studies should be conducted by NIPSCO to assess the selected Portfolio in detail.

ESCR ANALYSIS – WITHOUT MITIGATION

- Using the an ESCR threshold of 3, the analysis shows that ESCR is violated at each bus for all Portfolios. Therefore, all portfolios will require mitigation. This analysis did not consider the combined cycle plant or Hydrogen plants in Portfolios B, C, F, and I.
- Portfolio C does not introduce additional IBRs to those already planned and thus is excluded from this comparative analysis.
- Each Portfolio is evaluated using %Pass (percentage of IBR resources) that will pass the ESCR test. The analysis is provided for all resources and again for only those introduced by the Portfolio.

Bus	Bus Name	A	B	C	D	E	F	G	H	I
255504	17J837_INXRD	F	F	F	F	F	F	F	F	F
255506	17J838_INXRD	F	F	F	F	F	F	F	F	F
3	TAP1	F	F	F	F	F	F	F	F	F
255490	17J643-	F	F	F	F	F	F	F	F	F
255510	17J847-	F	F	F	F	F	F	F	F	F
255110	17SCHAHFER	F	F	F	F	F	F	F	F	F
255205	17REYNOLDS	F	F	F	F	F	F	F	F	F
255205	17REYNOLDS	F	F	F	F	F	F	F	F	F
255205	17REYNOLDS	F	F	F	F	F	F	F	F	F
255205	17REYNOLDS	F	F	F	F	F	F	F	F	F
255205	17REYNOLDS	F	F	F	F	F	F	F	F	F
255205	17REYNOLDS	F	F	F	F	F	F	F	F	F
255106	17LEESBURG	F	F	F	F	F	F	F	F	F
255106	17LEESBURG	F	F	F	F	F	F	F	F	F
255205	17REYNOLDS	F	F	F	F	F	F	F	F	F
255130	17GREEN_ACR	F			F	F	F	F	F	F
255180	17STILLWELL	F	F		F	F		F	F	F
255151	17LUCHTMAN	F	F		F	F		F	F	F
255149	17LK_GEORGE					F		F	F	
255159	17MORRISON									
255205	17REYNOLDS	F	F	F	F	F	F	F	F	F
	Total									
	Pass (MW)	0	0	0	0	0	0	0	0	0
	Fail (MW)	2,590	2,005	1,755	2,740	2,474	1,990	2,790	2,774	2,575
	% Pass	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Portfolio Only									
	Pass (MW)	0	0	0	0	0	0	0	0	0
	Fail (MW)	835	250	0	985	719	235	1,035	1,019	820
	% Pass	0%	0%	N/A	0%	0%	0%	0%	0%	0%

ESCR ANALYSIS – WITH SC MITIGATION

- The analysis is repeated by optimizing the mitigation using 3 potential synchronous condensers (SC) to enable each Portfolio to pass the test. For Portfolios B, C, F, I, the total SC MVA will be reduced by the planned synchronous generation assets (assuming they are located at places that provide similar short circuit strength as the assumed combined 3 sites in this study).
- Portfolio C does not introduce IBRs.
- The ranking of portfolios from lowest need for mitigation are:
  - C, B, F, I, E, A, H, D, G

Portfolio	SC (Gross) MVA	Synch. Gen (MW)	SC (Net) MVA
A	805		805
B	507	443	64
C	0	650	0
D	1017		1017
E	779		779
F	368	300	68
G	1070		1070
H	948		948
I	792	193	599

ESCR ANALYSIS – WITH SC MITIGATION AND GRID FORMING ESS INVERTERS

- The analysis is repeated by assuming all storage systems will be equipped with grid forming inverters, and then optimizing the mitigation using 3 potential synchronous condensers (SC) to enable each Portfolio to pass the test. For Portfolios B, C, F, I, the total SC MVA will be reduced by the planned synchronous generation assets (assuming they are located at places that provide similar short circuit strength as the assumed combined 3 sites in this study).
- Portfolio C does not introduce IBRs.
- The ranking of portfolios from lowest need for mitigation are:
  - C, F, B, I, E, H, A, D, G

With Grid Forming Inverters for Energy Storage

Portfolio	SC (Gross) MVA	Synch. Gen (MW)	SC (Net) MVA
A	706		706
B	507	443	64
C	0	650	0
D	906		906
E	287		287
F	208	300	-92
G	947		947
H	430		430
I	393	193	200

ESCR ANALYSIS – WITH MITIGATION (CAUTION)

- The analysis reveals potential issues with planned projects that should be investigated in detail at a level deeper than this screening study level.
- These correspond to the following projects:

Bus	Bus Name	kV	Project	Type	ICAP(MW) - Power flow
255504	17J837_INXRD	0.7	Indiana Crossroads	Wind	200
255506	17J838_INXRD	0.7	Indiana Crossroads	Wind	100
255490	17J643-DUNNS	0.7	Dunn's Bridge 1	S+S	165
255510	17J847-DUNNS	0.7	Dunn's Bridge 1	Solar	100

Bus	Bus Name	A	B	C	D	E	F	G	H	I
255504	17J837_INXRD	F	F	F	F	F	F	F	F	F
255506	17J838_INXRD	F	F	F	F	F	F	F	F	F
3	TAP1	P	P	P	P	P	P	P	P	P
255490	17J643-	F	F	F	F	F	F	F	F	F
255510	17J847-	F	F	F	F	F	F	F	F	F
255110	17SCHAHFER	P	P	P	P	P	P	P	P	P
255205	17REYNOLDS	P	P	P	P	P	P	P	P	P
255205	17REYNOLDS	P	P	P	P	P	P	P	P	P
255205	17REYNOLDS	P	P	P	P	P	P	P	P	P
255205	17REYNOLDS	P	P	P	P	P	P	P	P	P
255205	17REYNOLDS	P	P	P	P	P	P	P	P	P
255205	17REYNOLDS	P	P	P	P	P	P	P	P	P
255106	17LEESBURG	P	P	P	P	P	P	P	P	P
255106	17LEESBURG	P	P	P	P	P	P	P	P	P
255205	17REYNOLDS	P	P	P	P	P	P	P	P	P
255130	17GREEN_ACR	P			P	P	P	P	P	P
255180	17STILLWELL	P	P		P	P		P	P	P
255151	17LUCHTMAN	P	P		P	P		P	P	P
255149	17LK_GEORGE					P		P	P	
255159	17MORRISON									
255205	17REYNOLDS	P	P	P	P	P	P	P	P	P
	Total									
	Pass (MW)	2,025	1,440	1,190	2,175	1,909	1,425	2,225	2,209	2,010
	Fail (MW)	565	565	565	565	565	565	565	565	565
	% Pass	78%	72%	68%	79%	77%	72%	80%	80%	78%
	Portfolio Only									
	Pass (MW)	835	250	0	985	719	235	1,035	1,019	820
	Fail (MW)	0	0	0	0	0	0	0	0	0
	% Pass	100%	100%	N/A	100%	100%	100%	100%	100%	100%

LOCATIONAL ATTRIBUTES – NUMBER OF EVACUATION PATHS

- The evacuation paths from each site are tabulated based on the grid topology.
- For each site, the number of viable paths based on the site ICAP (MW) are calculated.
- Next step is to assess the average paths for each portfolio and rank them
- For each portfolio, a metric of the average number of paths to evacuate the portfolio resources is calculated. Only resources in each portfolio are considered and not the previously planned resources.
- Portfolio A has an average of 5 evacuation paths while Portfolio B has 2.5.
- The ranking from highest evacuation paths to lowest is:
  - H, I, A, G, E/F, D, B

Evac Paths	A	B	C	D	E	F	G	H	I
7	300	300	300	300	300	300	300	300	300
2	200	200	200	200	200	200	200	200	200
2	265	265	265	265	265	265	265	265	265
6	435	435	435	435	435	435	435	435	435
8									
4									
4									
8									
7	105	105	105	105	105	105	105	105	105
7	200			200	250	100	200	250	250
5	250	250	250	250	250	250	250	250	250
3	200	200	200	200	200	200	200	200	200
7	250			250			250	200	200
3	135			135	150	135	135	150	135
3	131	131		200	131		200	131	131
2	119	119		200	125		200	125	104
9					62.5		50	162.5	
3									
2									
	Gas Peaker	CC	Solar	S+S	ESS	Wind	Sync Con.	Planned	Outside
MW-Path	4,186	631	0	4,555	3,406	1,105	5,005	5,706	4,156
Avg Paths	5.0	2.5	N/A	4.6	4.7	4.7	4.8	5.6	5.1

EXISTING/PLANNED RENEWABLE PROJECTS – POWER PURCHASE AGREEMENTS (PPAS) ONLY

Project	Technology	ICAP (MW)	Battery Capacity (MW)	Expected In-Service	Structure	In/Out of Service Territory
Barton	Wind	50	-	Existing	PPA	Out of Service Territory
Buffalo Ridge	Wind	50	-	Existing	PPA	Out of Service Territory
Jordan Creek	Wind	400	-	Existing	PPA	In Service Territory
Indiana Crossroads II	Wind	200	-	2023	PPA	Out of Service Territory
Greensboro	Solar + Storage	100	30	2022	PPA	Out of Service Territory
Brickyard	Solar	200	-	2022	PPA	Out of Service Territory
Green River	Solar	200	-	2023	PPA	Out of Service Territory
Gibson	Solar	280	-	2023	PPA	Out of Service Territory
		1,480	30			

Northern Indiana Public Service Company LLC
2021 Integrated Resource Plan
Technical Webinar
SUMMARY

October 12, 2021

Welcome and Introductions
Alison Becker, Manager Regulatory Policy, NIPSCO

Ms. Alison Becker, Manager, Regulatory Policy, welcomed participants to the virtual technical webinar and provided a safety moment on Insomnia. She then discussed the Webex meeting protocols and walked through the agenda for the day. She then transitioned to Mr. Fred Gomos, Director Strategy and Risk Integration at NiSource, to walk through NIPSCO's reliability approach in the IRP.

Participants had the following questions and comments, with answers provided after:

- Will there be the opportunity to discuss a decision around whether an asset is chosen or not with NIPSCO?
    - This topic is not on the agenda for today. However, you may contact Charles River Associates ("CRA") as the administrator of the request for proposals ("RFP"). Notifications have and are going out now.

Reliability Approach in the IRP
Fred Gomos, Director Strategy and Risk Integration, NiSource

Mr. Gomos set the context for assessing reliability in the IRP by recapping previous reliability assessments in the 2018 IRP and the 2020 Portfolio Analysis and describing how the 2021 IRP approach builds upon the previous body of work. Mr. Gomos explained the three-step approach for reliability in the 2021 IRP. He then provided an overview of how NIPSCO has been assessing reliability in its core economic modeling, anchored to the recent MISO Renewable Integration Impact Assessment report. Mr. Gomos then noted several additional non-economic reliability considerations not captured in the core economic analysis, which is driving the need for the expanded reliability assessment.

Economic Reliability Analysis – Real-Time Market Dynamics & Ancillary Services
Pat Augustine, Vice President, CRA
Goran Vojvodic, Principal, CRA

Mr. Pat Augustine, Vice President at CRA, set the stage for the sub-hourly energy and ancillary services evaluation and provided an overview of Federal Energy Regulatory Commission Order 841. He then walked through CRA's Energy Storage Operations ("ESOP") model, an optimization program that estimates the value of storage and other flexible resources in the sub-hourly energy and ancillary services markets. He then transitioned to Mr. Goran Vojvodic, Principal at CRA, who summarized the major results of the ESOP analysis by technology. Mr. Vojvodic then reviewed an example chart visualization to illustrate the type of dispatch behavior in the energy and ancillary services markets that is simulated through the modeling exercise. Mr. Augustine then concluded the section by summarizing the incremental real-time energy and ancillary service value projections by technology across the four IRP scenarios and the range of additional value opportunity (net present value revenue requirement cost reduction) at the replacement portfolio level.

Participants had the following questions and comments, with answers provided after:

- How did you determine regulation market values?
    - Five-minute price projections were based primarily on historical data and observed relationships between energy and ancillary services prices in the Midcontinent Independent System Operator, Inc. ("MISO") market. There is quite a lot of historical data available for these markets, and at least under current market conditions, regulation and energy prices are highly correlated because there is an opportunity cost of dispatching in the energy market versus being held in reserve for regulation. Functionally, the price development process entailed the following steps: (i) obtain historical five-minute price data for energy and ancillary services prices; (ii) measure the relationships between them; (iii) take these relationships and propagate them forward based on the fundamental energy forecasts that were developed across all four MISO market scenarios. This approach admittedly carries a lot of uncertainty because it uses historical data as the basis, but it is very difficult to try to fundamentally simulate a real time regulation price. Therefore, this approach allows NIPSCO to assess a range of potential future outcomes for planning purposes, and the values here are not incorporated in the core net present value revenue requirement analysis given significant long-term market uncertainty.
- MISO's symmetric REG market (one product for both up and down) results in acute constraints on both energy storage and VER (wind & solar) providing REG. There might be significant economic benefits for introducing an asymmetric REG market. Have you looked? Could you?
    - As mentioned before, in order to participate in the regulation market, a resource has to be able to regulate up and down simultaneously as the question implies. This may constrain resource participation in ways that are not present in other markets that have separate products for regulation up and down. The question's suggestion that a market design change could impact economic outcomes is fair, but we have not evaluated that. To the extent the market design changes in the future, analysis adjustments would be required.

      CRA has done some analysis in other markets which have both REG up and REG down markets, and this requires a slightly different model configuration. In the case of regulation, the modeling has to assume a number of things about whether the resource will be picked up to regulate and thus whether it has enough room to move either up or down. For example, a storage resource cannot be discharging at full output if also providing regulation service. In a reconfigured market, both up and down potential would have to be separately tracked against separate prices. In other markets, CRA is seeing REG up prices slightly higher than REG down prices, so that may impact the value for different resource types.

Qualitative Assessment of Reliability Attributes – Scoring Criteria & Results
Fred Gomos, Director, Strategy and Risk Integration, NiSource
Hisham Othman, Vice President, Transmission and Regulatory Consulting, Quanta Technology, LLC ("Quanta")

Mr. Gomos described the four-step approach to the non-economic reliability assessment and the incorporation of a third party expert. He also reviewed the guiding principles under which the assessment was performed and focused on the primary goals of the assessment: to understand reliability implications of potential resource additions to the NIPSCO portfolio and to understand the range of potential mitigations associated with different replacement portfolio strategies.

Mr. Gomos then introduced Mr. Hisham Othman, Vice President, Transmission and Regulatory Consulting at Quanta, who provided an overview of the steps Quanta took to perform the reliability assessment and ranking. Mr. Othman reviewed the elements critical to reliable operation of an electric system and provided an overview of the NIPSCO demand and resource assumptions. Mr. Othman then reviewed the eight reliability criteria identified for the assessment and the rationale for each. He then described measurement approaches for each of the eight criteria and the type of analysis that was performed to support each metric. Mr. Othman then provided detailed review of the analysis performed for two of the criteria: Blackstart and Predictability and Firmness of Supply.

Mr. Othman then summarized the overall assessment results, including metrics and the criteria thresholds used for scoring each of the metrics. The resulting ranking of each metric and the methodology to arrive at a cumulative score and rank for each portfolio were discussed. Mr. Othman then transitioned back to Mr. Gomos who concluded the discussion with the ranking of each of the nine replacement portfolios and how the scoring and ranking will be incorporated into NIPSCO's IRP scorecard.

Participants had the following questions and comments, with answers provided after:

- To what extent does NIPSCO need to plan reliability services for its own fleet and load vs. services that MISO can and/or does obtain system wide? Is there a potential disconnect between generation resources presented to the MISO market and the levels of each of the reliability services needed?
  - It depends on what service you are looking at and what North American Electric Reliability Corporation standard or MISO tariff provision is governing the particular service. For example, NIPSCO is responsible for having a blackstart plan that is approved by MISO. For other criteria, under normal system conditions, many of these services are provided and managed by MISO as the system operator. The earlier analysis on ancillary services tried to quantify some of that value. However, NIPSCO is also trying to understand the requirements for the Company under islanded conditions when the larger grid is not available. For example, for criteria like voltage support or short circuit strength, they would have to actually be within the service territory to be able to function and operate in a reliable fashion under such conditions. Other services today are not

procured in the market but they are still provided as part of the interconnection requirements.

- With NIPSCO being in the heart of the Eastern Interconnection, the largest interconnected grid in the world, the present rate of change of frequency (“RoCoF”) levels for the biggest design basis events are about an order of magnitude lower than have been problematic in small, islanded systems around the world. Is there any analysis that shows RoCoF is problematic in the foreseeable future?
    - Related to the rate of change of frequency, it is true that the larger the system, the lower the impact. It’s been a problem in island systems like Hawaii, and one of the things we look at is also the ability of the NIPSCO system to operate in an islanded fashion in order to be able to restart. So if you think of those scenarios where you need to actually reliably restart the system, those implications come into play. When connected to the rest of the MISO and the Eastern Interconnect, you are absolutely right that there are no foreseeable impacts for RoCoF. However for situations where the system needs to restart, then you also need to consider resources to have enough mitigation in place to be able to actually operate and restart the system.
- For what it’s worth, I'm of the opinion that MISO's symmetric market is an expensive anachronism. Notice in Hisham's chart that most of the independent system operators (“ISOs”) now have asymmetric REG markets now. Not urgent, but it will become more expensive. I was excited that Quanta had essentially the entire setup necessary to answer the question "what would the saving results from an asymmetric REG market". That would advise the discussion.
    - It is true that in asymmetrical markets, different resources have capabilities in one direction, while others may have capabilities in the other direction. While some Northeastern markets also have single regulation constructs like MISO, it is certainly true that other ISOs have two products, and the hypothesis that this reduces system costs overall may be correct. The reliability assessment has not been focused on a system-wide cost view, nor a scenario analysis associated with potential market design changes. However, NIPSCO appreciates the comments, and the Company will need to continue to track market design changes as it evaluates different resources in the future.
- We certainly agree that energy adequacy is critical and certainly it is more meaningful than adequacy judged by capacity value, but if I understand the appendix files this metric was judged based on performance of the portfolio dispatched as an islanded systems without any connection to MISO during one year and then picking out the worst performing week for each, is that correct? And if so, why does that Black Swan event make sense, wouldn't you want to evaluate these portfolios under representative emergency conditions?
    - Yes that is correct. The idea is that NIPSCO is under an emergency situation where the system is islanded and needs to be serving its native load. Thus we consider whether there are enough resources to serve critical load under those conditions and have not quantified the probability of such a “black swan” event happening.
- What I mean by representative emergency conditions is that, for example, if you are looking at situations in which max gen events are happening in MISO, one of the things you can observe is that load actually increases significantly and so I’m not sure why it would make sense to simulate these portfolios under typical meteorological conditions and not account for the types of factors that tend to happen under those kinds of conditions. I certainly agree that our ability to plan reliably is getting more and more

constrained and because of data we don't even understand, including the ways in which climate change is affecting the frequency and severity of weather events, but it seems like to the extent you could look backward and evaluate those things, you would want to do so under a set of assumptions that make the performance of both resources look consistent with the weather event that is actually being experienced. And I would extend that also to things like the probability of forced outage, which increases at both high and low temperature extremes and to the probability of fuel supply interaction which is also temperature-related. It just seems like that makes more sense than to kind of simulate NIPSCO as an islanded system for a period of one year and take the worst possible week, because if that was an actual scenario, that to me would imply some sort of apocalyptic conditions that happened as opposed to a severe weather event.

  - That is a very good comment we will take it into advisement. The analysis that was done does not really imply that NIPSCO would become an islanded system for a year, but is intended to evaluate what the worst week throughout the year might be. But you are right that we are not simulating weather, load, or forced outage events across a distribution of outcomes, and we will think about if we want to add another measure under that metric and if we can accomplish that within the time frame.

- Does your "energy not served" analysis use stochastic analysis drawing on the availability distributions for the various resource types? If not, what analysis did you use?
  - This analysis was not based on a statistical assessment of uncertainty. Instead, NIPSCO is taking the average profiles for solar and wind and dispatching other portfolio elements against the base load profile to assess how much energy can be served. There is clearly additional risk associated with weather conditions and the resilience of resources to those weather conditions, but that was not evaluated with this analysis.
- Another approach to reliability, rather than using islanding, would be to use energy inflows and outflows by hour? Rather than constraining NIPSCO's system to be islanded it seems like reliability risk especially as pertains to energy adequacy – when you look at the equilibrium of the Midwest energy system or the eastern interconnect and as more intermittent resources are built out system wide, it seems like the risk is really related to those hours in which say the net end loads are relatively high – those would be the hours say from the catastrophic basis drawing on the drawing on the variability of intermittent resources or even the availability of dispatchable resources. It just seems like that would be another approach to thinking about the reliability of the portfolio without having to do the islanding.
  - This is actually quite similar to what we have done in the stochastic portfolio analysis that is part of the core economic portfolio modeling. You might recall that the stochastic analysis incorporates different iterations of commodity prices and renewable output for wind and solar and evaluates, from an economic perspective, NIPSCO's exposure to the market. Keep in mind that under normal operating conditions, NIPSCO is constantly selling and buying energy to and from the market, so this exposure is economic and less about physical transmission limitations. So, in the stochastic economic analysis, energy adequacy hour by hour across 500 iterations of potential fuel, power, and renewable output outcomes were evaluated. In that analysis, NIPSCO did find that in the near term, more natural gas resources exposed the portfolio to

commodity price volatility risk, but over the long term, very heavy reliance on renewables exposed the portfolio to significant market exposure risk when prices were spiking and renewables were not available. So overall, the approach the question just laid out has largely already been picked up in the economic analysis.

From a reliability perspective, the analysis has been focusing on more technical, non-economic factors, such as frequency, our ability to regulate voltage, our ability to black start the system, etc. However, NIPSCO will consider about whether we can perform any further reviews for the reliability assessment based on your question.

- Nice blackstart analysis. I fully agree with your statements about the need for GFM (grid forming) on the energy storage to realize blackstart and other benefits. It is important to note that grid forming for batteries, while commercially proven, is not the default. Many BESS are being built without GFM today. Do you agree with those (like me) who are of the opinion that GFM should be required for all battery energy storage projects?
    - Yes, that will become a major consideration in the future. As more inverter-based resources are built, they will become the backbone of the system going forward, and trying to build them from the start with the right capability with the right specs is the right thing to do. Retrofitting later on is going to be more expensive, so prioritizing grid forming capability in the future is important. If NIPSCO looks at storage systems and at the inverter cost or the percentage of the cost relative to the inverters, adding the grid forming inverter is unlikely to swing the economics negatively, so it is better to have those capabilities up front. Not only that, inverters that can operate under a low short circuit ratio are preferable to ones that require a higher short circuit ratio to operate because that is also going to be a declining capability of the grid going forward. In addition, the analysis so far is up to the year 2030 and they could actually become even more critical if we were to advance the analysis to the year 2040.

      This analysis also informs how we engage with some of the developers that bid into the RFP, particularly storage projects. If we now know that grid forming inverters are something that would be required or highly preferred, we can go back to developers and ask if that is specified in their project or what would it cost to be included in the project. So, I think that’s an example of something this study informs for ultimate RFP project selection and execution.

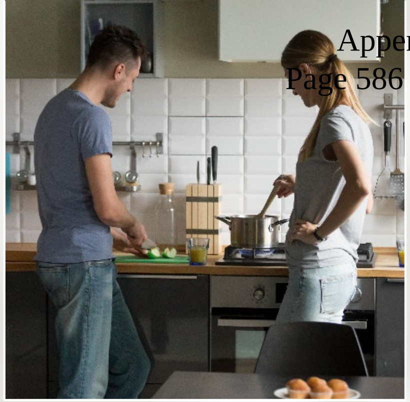
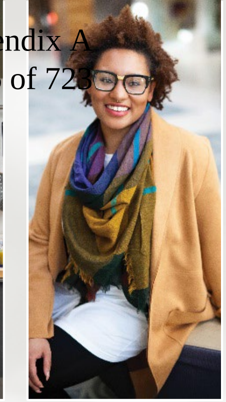
Next Steps
Alison Becker, Manager Regulatory Policy, NIPSCO

Ms. Becker closed the session by thanking attendees for their participation and feedback. She then outlined key next steps in the IRP process and invited participants to reach out for one-on-one discussions.

October 12, 2021 NIPSCO Technical Webinar Registrations		
First Name:	Last Name:	Company:
Emily	Abbott	Invenergy
Anthony	Alvarez	OUCC
Shawn	Anderson	NiSource
Rahul	Anilkumar	Quanta Technology
Pat	Augustine	Charles River Associates
Kim	Ballard	IURC
Vernon	Beck	Nipsco
Greg	Berning	NiSource
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	Indiana Utility Regulatory Commission
Matt	Boys	GlidePath Power Solutions
Sean	Brady	clean grid alliance
Don	Bull	NIPSCO
Bryan	Burns	Nipsco
Richard	Calinski	NIPSCO
Kelly	Carmichael	NiSource
Gilles	Charriere	Sierra Club/ NIPSCO customer
Richard	Ciciarelli	Schonfeld
Kody	Clark	Bank of America
John	Cleaveland	NIPSCO
Steven	Cofer	cadmus
Andrew	Colvin	
Kim	Cuccia	NiSource
Chanda	Durnford	Nextera Energy
Cory	Dutcher	General Electric Company - Power Division
Gregory	Ehrendreich	Midwest Energy Efficiency Alliance (MEEA)
Suzanne	Escudier	Origis Energy
Bill	Fowler	Shell Energy North America (US), L.P.
Steve	Francis	SEED
Sarah	Freeman	Indiana Utility Regulatory Commission
Richard	Gillingham	Hoosier Energy
Mike	Girata	NiSource
Fred	Gomos	Nisource
Benjamin	Gonin	
Doug	Gotham	State Utility Forecasting Group
Robert	Greskowiak	Invenergy LLC
Jack	Groves	ENERGY SOUTHWEST INC.
Gerardo	Guzman	McKinsey
Aida	Haigh	NiSource
Joni	Hamson	EDF Renewables
Sean	He	Verition Fund Management
Ryan	Heater	Indiana Utility Regulatory Commission
Robert	Heidorn	NiSource
John	Hejkal	Tenaska, Inc.
Megan	Henning	NIPSCO

October 12, 2021 NIPSCO Technical Webinar Registrations		
First Name:	Last Name:	Company:
David	Hicks	Indeck Energy Services, Inc.
Jaime	Holland	NextEra
Chelsea	Hotaling	Energy Futures Group
Jim	Hummel	Duke Energy
Jim	Huston	Indiana Utility Regulatory Commission
Ben	Inskeep	EQ Research
Kelsie	Johnson	ranger power
Michelle	Kang	Charles River Associates
Kelley	Karn	Duke Energy
Mo	Klefeker	Primary Energy
Stefanie	Krevda	Indiana Utility Regulatory Commission
Karol	Krohn	Office of Utility Consumer Counselor
Reagan	Kurtz	Citizens Action Coalition of Indiana
Natalie	Ladd	NiSource
Tim	Lasocki	Orion Renewable Energy Group LLC
George	Learn	
Shelby	Leisz	AES Indiana
Bryan	Likins	NIPSCO
Caleb	Loveman	Indiana Office of Utility Consumer Counselor
Jamie	Mante	nipsco
Gregory	Martin	BP
Clyde	Mason Jr	Unity Electric Discount, LLC
Shelly-Ann	Maye	
Cassandra	McCrae	Earthjustice
Tara	McElmurry	NIPSCO
Zachary	Melda	NextEra Energy
Michael	Melvin	NIPSCO
Earl	Miller	Hiler Industries
Erik	Miller	AES
Nicholas	Miller	HICKORYLEDGE LLC
Mike	Mooney	Hoosier Energy
Danny	Musher	Key Capture Energy
David	Ober	Indiana Utility Regulatory Commission
Hisham	Othman	Quanta Technology LLC
Richard	Pate	Pate & Associates
Bob	Pauley	IURC
Matthew	Piggins	
Rockey	Pollard	NiSource, Inc.
Mark	Pruitt	The Power Bureau
Brett	Radulovich	NiSource
Jeff	Reed	Indiana Office of Utility Consumer Counselor
Adam	Rickel	NextEra Energy Resources
Robert	Ridge	NIPSCO
Tonya	Rine	CenterPoint Energy
Clayton	Robinson	Cordelio Power

October 12, 2021 NIPSCO Technical Webinar Registrations		
First Name:	Last Name:	Company:
Rosalva	Robles	NIPSCO
Stephen	Rodocanachi	Hartree Partners
Roland	Rosario	CenterPoint Energy
Edward	Rutter	LWGCPA and Advisors
Kurt	Sangster	NIPSCO / NiSource
Jamalyn	Sarver	Hallador Energy Company
Robert	Sears	NIPSCO
Casey	Shull	OUCC
Anna	Sommer	EFG
Theodore	Sommer	LWG CPa's and advisors
Daniel	Spellman	Orion Renewable Energy Group LLC
Jennifer	Staciwa	NIPSCO
Karl	Stanley	NiSource
Sarah	Steinberg	Advanced Energy Economy
Dale	Thomas	IURC
Dan	Traynor	PPMS, LLC.
Maureen B	Turman	NiSource
Edward	Twarok	NiSource
Gregory	Van Horssen	Van Horssen Law & Government, PLLC
Chris	Vickery	
Nancy	Walter	Just Transition Northwest Indiana
Jennifer	Washburn	CAC
Amanda	Wells	Duke Energy
Erin	Whitehead	NIPSCO
Ryan	Wilhelmus	CenterPoint Energy
Scott	Yaeger	Southern Illinois Generation Company
Monica	Yocum	NIPSCO
Tom	Zelina	AEP


NIPSCO
A NiSource Company

2021 NIPSCO Integrated Resource Plan

NiSource

Stakeholder Advisory Meeting #5

October 21st, 2021
9:00AM-2:00PM CT




SAFETY MOMENT

Fire Safety

Be prepared for an emergency

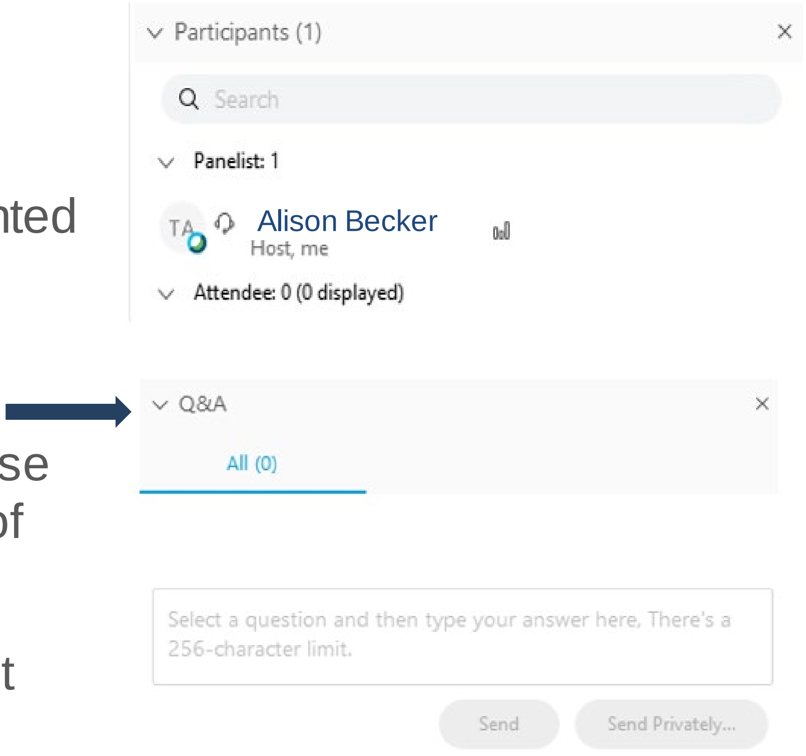
Fire facts

- In just two minutes, a fire can become life threatening.
  In five minutes, a residence can be engulfed in flames.
- Families should plan and practice a home fire escape plan at least twice a year.
- Working smoke alarms cut the risk of dying in reported fires in half.
- Two of every five home fires started in the kitchen.

OCEANEERING®

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
9:00-9:05AM	Webinar Introduction, Safety Moment, Meeting Protocols, Agenda	Alison Becker, Manager Regulatory Policy, NIPSCO
9:05-9:15AM	Welcome	Mike Hooper, President & COO, NIPSCO
9:15-9:30AM	NIPSCO's Public Advisory Process and Resource Planning Activity Review	Fred Gomos, Director Strategy & Risk Integration, NiSource
9:30-10:00AM	Existing Fleet Analysis Review	Pat Augustine, Vice President, CRA
10:00-10:15AM	Break	
10:15-11:00AM	Replacement Analysis Review	Pat Augustine, Vice President, CRA Hisham Othman, VP, Transmission and Regulatory Consulting, Quanta Technology, LLC
11:00-11:30AM	Responses to Stakeholder Feedback	Pat Augustine, Vice President, CRA
11:30AM-12:00PM	Lunch	
12:00-1:00PM	Preferred Resource Plan and Action Plan	Fred Gomos, Director Strategy & Risk Integration, NiSource Pat Augustine, Vice President, CRA
1:00-1:55PM	Stakeholder Presentations	TBD
1:55-2:00PM	Wrap Up & Next Steps	Erin Whitehead, Vice President Regulatory & Major Accounts, NIPSCO

WELCOME

Mike Hooper, President & COO, NIPSCO

PILLARS OF OUR ONGOING GENERATION TRANSITION PLAN

This plan creates a vision for the future that is better for our customers and it's consistent with our goal to transition to the best cost, cleanest electric supply mix available while maintaining reliability, diversity and flexibility for the technology and market changes on the horizon.

Reliable and sustainable

Flexibility for the future

Local and statewide economic benefits

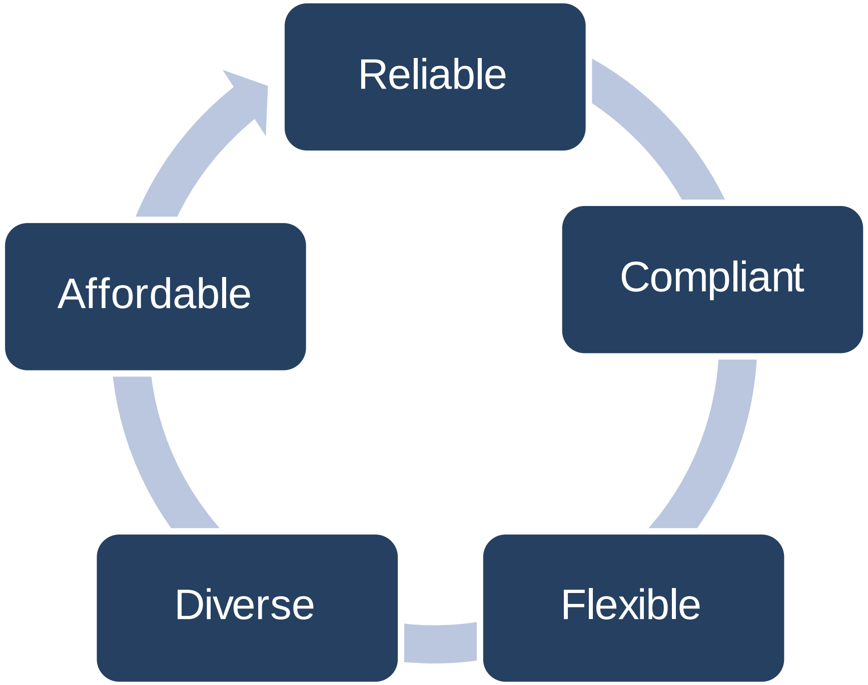
Best plan for customers and the company

NIPSCO'S PUBLIC ADVISORY PROCESS AND RESOURCE PLANNING ACTIVITY REVIEW

Fred Gomos, Director Strategy & Risk Integration, NiSource

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)

2021 STAKEHOLDER ADVISORY MEETING ROADMAP

Meeting	Meeting 1 (March)	Meeting 2 (May)	Meeting 3 (July)	Meeting 4 (September)	Technical Webinar	Meeting 5 (October)
Date	3/19/2021	5/20/2021	7/13/2021	9/21/2021	10/12/2021	10/21/2021
Location	Virtual	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? • How will NIPSCO evaluate potential DER options? • What are the preliminary RFP results?	• What are the preliminary findings from the modeling?	• What are the results of the Reliability Assessment?	• 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 • DER Inputs • Preliminary RFP Results	• Existing Fleet Review Modeling Results, Scorecard • Replacement Modeling Results, Scorecard	• Reliability Assessment	• 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 • Explain next steps for portfolio modeling	• Communicate the Existing Fleet Portfolios and the Replacement Portfolios • Develop a shared understanding of economic modeling outcomes and preliminary results to facilitate stakeholder feedback	• Common understanding of Reliability Assessment methodology • Communicate Reliability Assessment results	• Respond to key stakeholder comments and requests • Communicate NIPSCO's preferred resource plan and short-term action plan • Obtain feedback from stakeholders on preferred plan

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

3

New resource option parameters

DSM Study

RFP Information

Retirement options and replacement themes (informed by scenarios)

Portfolio Optimization

NIPSCO Portfolios

2

Scenario Narrative Development

Integrated gas, coal, carbon forecasts and **MISO market outlook / prices**

Market Modeling Tools (NGF, GPCM, Aurora)

Stochastic Modeling Tools

4

Aurora – **NIPSCO Portfolio** Market Model

Production Cost Dispatch (hourly, chronological)

PERFORM

Detailed cost of service and revenue requirements

Scorecard

(Example)

Other Analysis (e.g. Reliability Assessment, Employee Impacts, etc.)

1 IDENTIFY KEY PLANNING QUESTIONS AND THEMES

- The ongoing fleet transition in MISO makes it critical for NIPSCO's IRP to capture several changing dynamics to allow NIPSCO to remain flexible
- Over the course of the 2021 IRP, NIPSCO has discussed these topics:

Topic	
Retirement Timing for Existing Coal and Gas Units	Assessing the retirement timing of the remaining generating fleet after the Schahfer coal units retire, which includes Michigan City Unit 12, Schahfer Units 16A and 16B, and Sugar Creek
Flexibility & Adaptability of The Portfolio	Incorporating evolving capacity credit expectations for resources and an imminent seasonal resource adequacy requirement
Carbon Emissions & Regulation/Incentives	Assessing diverse portfolio options in the context of increased policy conversations that push for 100% decarbonization of the power sector by the middle of the next decade
Long-Term Planning With Intermittent Resources	Understanding system reliability implications of a portfolio that will have significant intermittent resources, in light of the MISO market evolution and NIPSCO's operational responsibilities

1 LONG TERM SYSTEM PLANNING WITH INTERMITTENT RESOURCES

2021 IRP Approach To Evaluate		Action Implemented In IRP Modeling
Ensure Consistency with MISO Rules Evolution	▪ Seasonal resource adequacy ▪ Future effective load carrying capability (ELCC) accounting	▪ Both summer and winter reserve margins tracked and implemented as constraints ▪ ELCC accounting by season with a range of expected solar declines over time
Expand Uncertainty Analysis	▪ Incorporation of renewable output uncertainty ▪ Broadening risk analysis to incorporate granular views of tail risk	▪ Stochastic analysis evaluated the relationship between hourly renewable output and power prices to estimate the impact at different levels of penetration and across the commodity price distribution ▪ Examined tail outcomes to understand the conditions and portfolios that expose customers to low probability, high consequence (price) events
Incorporate New Metrics	▪ Incorporating new scorecard metrics informed by stochastic analysis and capabilities of portfolio resources	▪ Performed ancillary services analysis (regulation, spinning reserves) with sub-hourly granularity and conducted qualitative reliability assessment with several new metrics

1 IDENTIFY KEY PLANNING QUESTIONS AND THEMES

As in the 2018 IRP, multiple objectives and indicators are summarized across portfolios in an integrated scorecard framework against which to test portfolios and evaluate the major planning questions

Objective	Indicator
Affordability	Cost to Customer
Rate Stability	Cost Certainty
	Cost Risk
	Lower Cost Opportunity
Environmental Sustainability	Carbon Emissions
Reliable, Flexible, and Resilient Supply	Reliability
	Resource Optionality
Positive Social & Economic Impacts	Employees
	Local Economy

- The scorecard is a means of reporting key metrics for different portfolio options to transparently review tradeoffs and relative performance; it does not produce a single score or ranking of portfolios, but serves as a tool to facilitate decision-making
- NIPSCO has identified **5 major planning objectives** and multiple metrics within **9 key indicator categories**
- The Existing Fleet Analysis scorecard focuses on scenario costs, carbon emissions, and impact on NIPSCO employees and the local economy
- The Replacement Analysis scorecard incorporates broader perspectives on risk (stochastic analysis) and reliability than the Existing Fleet Analysis scorecard

2 DEVELOP MARKET PERSPECTIVES (REF CASE, SCENARIOS / STOCHASTIC INPUTS)

- NIPSCO developed four integrated market scenarios or future "states of the world"
  - Scenarios incorporate a range of future outcomes for load, commodity prices, technology, and policy
  - The 2021 IRP includes two distinct policy frameworks for achieving net-zero emission trajectories for the broader power market
- Stochastic inputs have been developed for key components of quantifiable stochastic risk
  - For the 2021 IRP, the stochastic analysis has been expanded to include hourly renewable availability in addition to commodity price volatility

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")

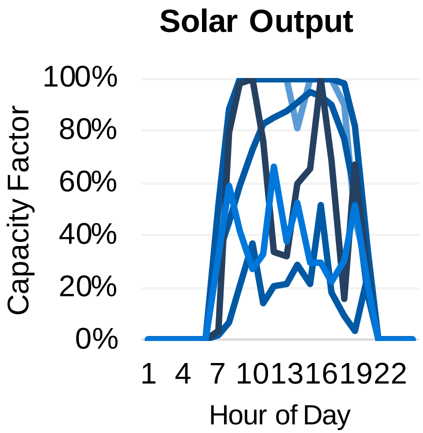
- Binding federal limits on carbon emissions are not implemented; natural gas prices remain low and result in new gas additions remaining competitive versus renewables, as coal capacity more gradually fades from the MISO market

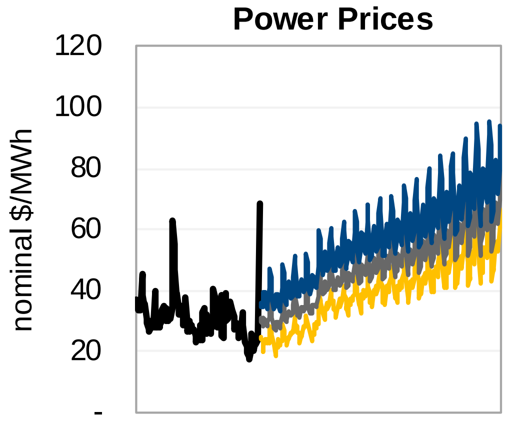
Aggressive Environmental Regulation ("AER")

- 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 CO_2 price and net-zero emission targets for the power sector by 2040; restrictions on natural gas production increase gas prices

Economy-Wide Decarbonization ("EWD")

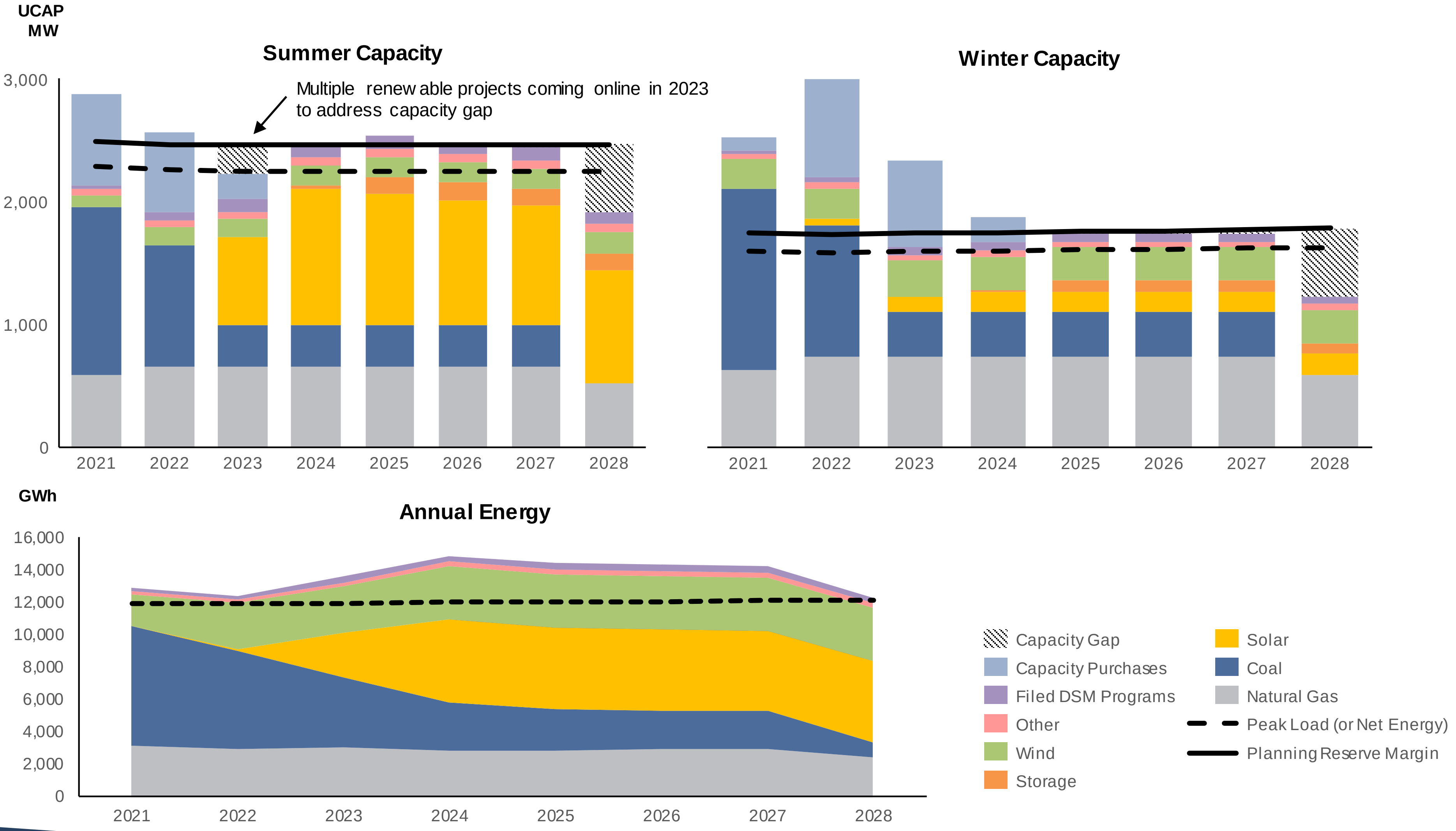
- Technology development and federal incentives push towards a decarbonized economy, including through a power sector Clean Energy Standard (supporting renewables and other non-emitting technologies) and large-scale electrification in other sectors (EVs, heating, processes, etc.)





3 STARTING NEAR-TERM CAPACITY AND ENERGY BALANCE

NIPSCO is now monitoring summer and winter reserve margins, plus the annual energy balance

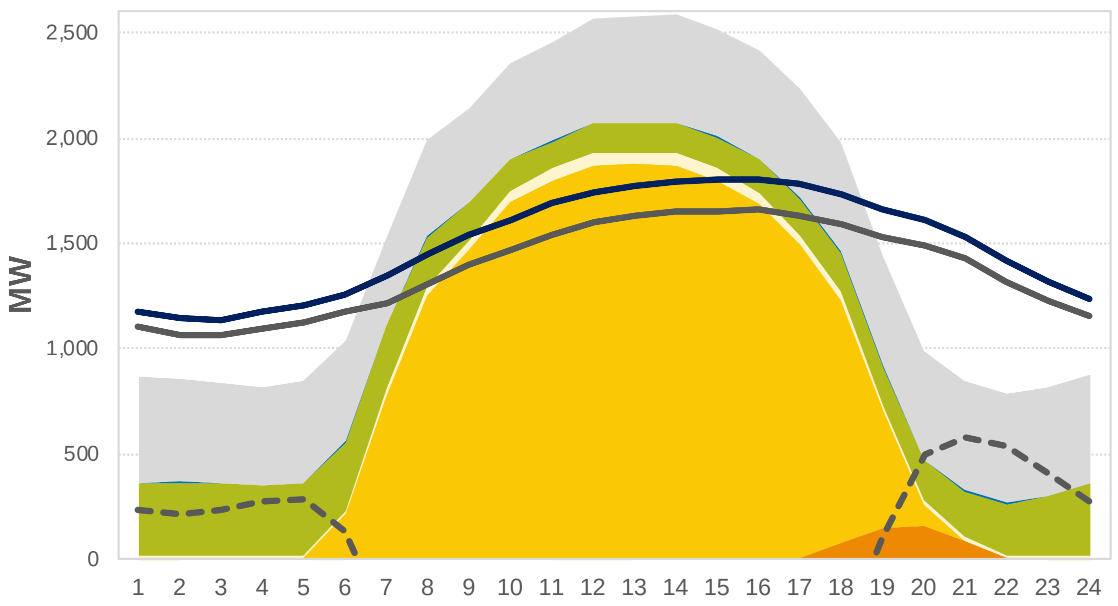


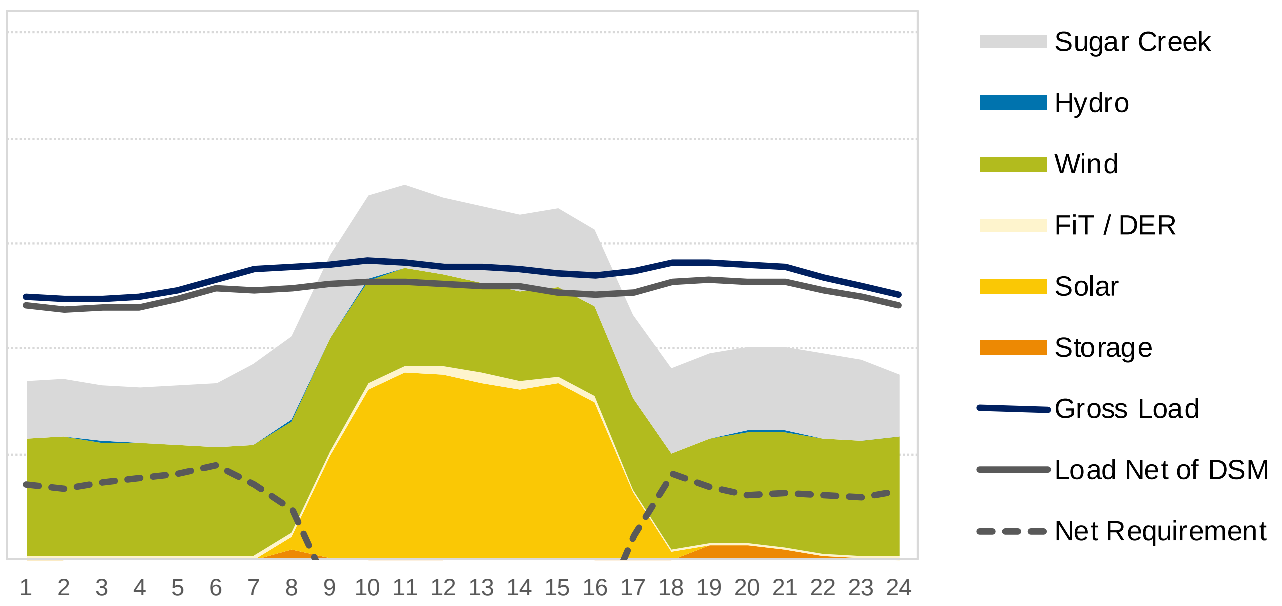
Key Points

- The capacity credit for some of the 2023 projects is not reflected until 2024 due to in-service date timing
- Capacity credit for some storage resources is not reflected until 2025 (after a full year of operations) due to plant configuration
- While winter loads are lower, the lower capacity credit in the winter for solar resources results in a similar reserve margin
- On an annual basis, the net energy position for the portfolio is long, driven by the energy value and economic dispatch advantage of wind and solar resources. However, the tight capacity position may create hourly gaps, particularly in the winter mornings and evenings when solar resources ramp down (next slide)

3 STARTING ENERGY BALANCE VARIES ON AN HOURLY BASIS

- There are hours of the day where renewable resources are not available (ex: overnight for solar). Furthermore, solar resources may experience steep production declines in the evening hours
- Currently, Sugar Creek (natural gas CC), Schahfer 16AB (natural gas peaker), and Michigan City 12 (coal) are part of the portfolio, and when economic, NIPSCO can purchase from the MISO market
- As 16AB and MC12 retire, the portfolio will require new resources to be available to mitigate against specific hourly energy exposure





EXISTING FLEET ANALYSIS REVIEW

Pat Augustine, Vice President, CRA

RECAP: ANALYTICAL FRAMEWORK

- The IRP analysis is performed in two phases; the first phase examines current and future resource additions to evaluate timing of retirement for existing units
- Insight and conclusions from existing fleet analysis inform replacement concepts to evaluate. Once a preferred existing portfolio is established, future replacements are evaluated across a range of objectives

	Existing Fleet Analysis	Replacement Analysis
Core Questions	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?* *Is the portfolio flexible and adaptable to address changes in market rules and energy policy?*	*What are the replacement resource portfolio options?* *How do different replacement themes compare with regard to cost, risk, environmental sustainability, and reliability?*
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

RECAP: CONSTRUCTED RETIREMENT PORTFOLIOS TO COVER THE RANGE OF TIMING POSSIBILITIES FOR REMAINING FOSSIL UNITS

	1	2	3	4	5	6	7	7H
Portfolio Transition Target:	15% Coal through 2032	15% Coal through 2028	15% Coal through 2026	15% Coal through 2024	15% Coal through 2028	15% Coal through 2026	15% Coal through 2028 Fossil Free by 2032	15% Coal through 2028 Option for Fossil Free by 2032
	MC 12 Through Book life	2018 IRP Preferred Plan	Early Retirement of MC 12	Early Retirement of MC 12	2018 IRP Preferred Plan + 2025 16AB retirement	Early Retirement of MC 12 + 2025 16AB retirement	2018 IRP Preferred Plan + 2025 16AB ret. + 2032 SC ret.	2018 IRP Preferred Plan + 2025 16AB ret. + 2032 SC conv.
Retain beyond 2032	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Michigan City 12	Retire 2032	Retire 2028	Retire 2026	Retire 2024	Retire 2028	Retire 2026	Retire 2028	
Schahfer 16AB	Retire 2028				Retire 2025			
Sugar Creek	Retain						Retire 2032	Convert to H2 2032

Short term (Portfolios 1–6) — Longer term (Portfolios 7, 7H)

Not a viable pathway due to implementation timing

Key Points

- Portfolio construction is necessarily broad to fully address tradeoffs
- Portfolios 1-4 focus on the timing of the Michigan City retirement
- Portfolios 5 and 6 focus on the replacement timing for Schahfer 16AB. Units are not retained beyond 2028 in any portfolio given current condition and age
- Portfolio 7 and 7H are assessing implications of carbon free portfolio pathways

RECAP: EXISTING FLEET ANALYSIS SELECTIONS ARE DRIVEN BY ECONOMIC OPTIMIZATION

Resource options include RFP tranches, DSM bundles, DER options, and an opportunity to uprate capacity at Sugar Creek

- Driven by a binding winter reserve margin and the energy resources already obtained from the 2018 IRP Preferred Plan, the indicative ordering of model selection preference favors resources that offer greater levels of firm capacity
- This is not NIPSCO's final replacement resource selection or preferred plan, but an optimized set of additions to facilitate evaluation of the various existing fleet strategies

COST-EFECTIVENESS: More → Less

Portfolio 1 — MC12 Through Book Life

Technology	ICAP MW	Year
NIPSCO DER	10	2026
Sugar Creek Uprate	53	2027
DSM*	68	2027*
Thermal Contract	50	2024
Thermal Contract	100	2026
Gas Peaker	300	2032
Storage	135	2027
Total	**693**	

Portfolios 2 | 3 | 4 — 2018 IRP (MC 2028) | MC 2026 | MC 2028

Technology	ICAP MW	Year P2	Year P3	Year P4
NIPSCO DER	10	2026	2026	2026
Sugar Creek Uprate	53	2027	2027	2027
DSM*	68	2027*	2027*	2027*
Thermal Contract	50	2024	2024	2024
Thermal Contract	100	2026	2026	2026
Gas Peaker	300	2028	2026	2024
Storage	135	2027	2027	2025
Solar	100 / 200^	2026	2026	2026
Total	**793 / 893^**			

^ P2/3 have 100 MW of solar; P4 has 200 MW

Portfolios 5 | 6 — Portfolio 2 w/ 16AB 2025 | Portfolio 3 w/ 16AB 2025

Technology	ICAP MW	Year P5	Year P6
NIPSCO DER	10	2026	2026
Sugar Creek Uprate	53	2027	2027
DSM*	68	2027*	2027*
Thermal Contract	50	2024	2024
Thermal Contract	100	2026	2026
Gas Peaker	300	2028	2026
Storage	135	2025	2025
Solar	100	2026	2026
Wind	200	N/A	2026
Total	**993**		

Portfolio 7 — Fossil Free By 2032

Technology	ICAP MW	Year
NIPSCO DER	10	2026
DSM*	68	2027*
Storage	235	2025
Storage	100	2026
Storage	235	2027
Solar	250	2026
Wind	200	2026
Total	**1,020**	

Portfolio 7H — Fossil Free Option by 2032 w/ SC Conversion (incl. capital costs)

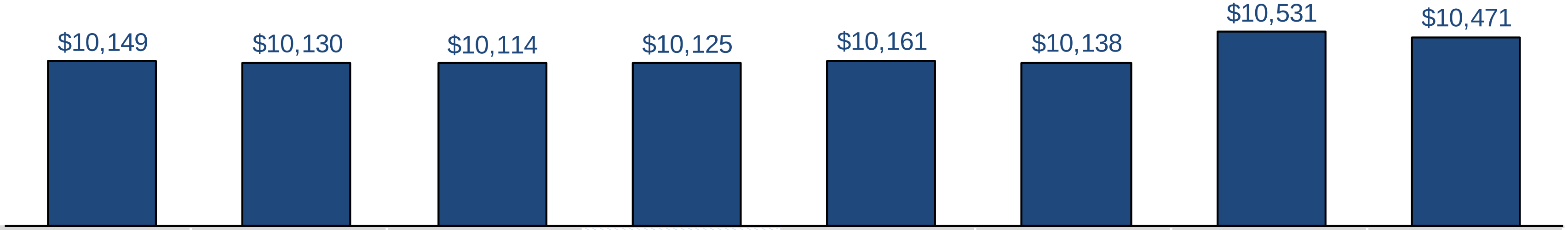
Technology	ICAP MW	Year
NIPSCO DER	10	2026
Sugar Creek Uprate	53	2027
DSM*	68	2027*
Storage	235	2025
Storage	135	2027
Solar	250	2026
Wind	200	2026
Hydrogen-Enabled Gas Peaker	193	2025
SC Electrolyzer Pilot	20	2026
Total	**1,131**	

*DSM includes the cumulative impact of both Residential and Commercial programs by 2027, with Commercial being most cost effective. DSM is reported on a summer peak basis. Note that the winter impact is ~46MW.

Notes: Portfolios were optimized against winter reserve margin constraints (9.4%), followed by summer to ensure compliance with both.
A maximum net energy sales limit of 30% during the fleet transition (2023-2026), falling to 25% in 2030+, was also enforced.
Wind outside LRZ6 was not included in optimization analysis, given lack of capacity deliverability to LRZ6 and significant congestion risk.

RECAP: EXISTING FLEET ANALYSIS - DETERMINISTIC COST TO CUSTOMERS RESULTS

Net Present Value of Revenue Requirement
(2021-2050, $M)



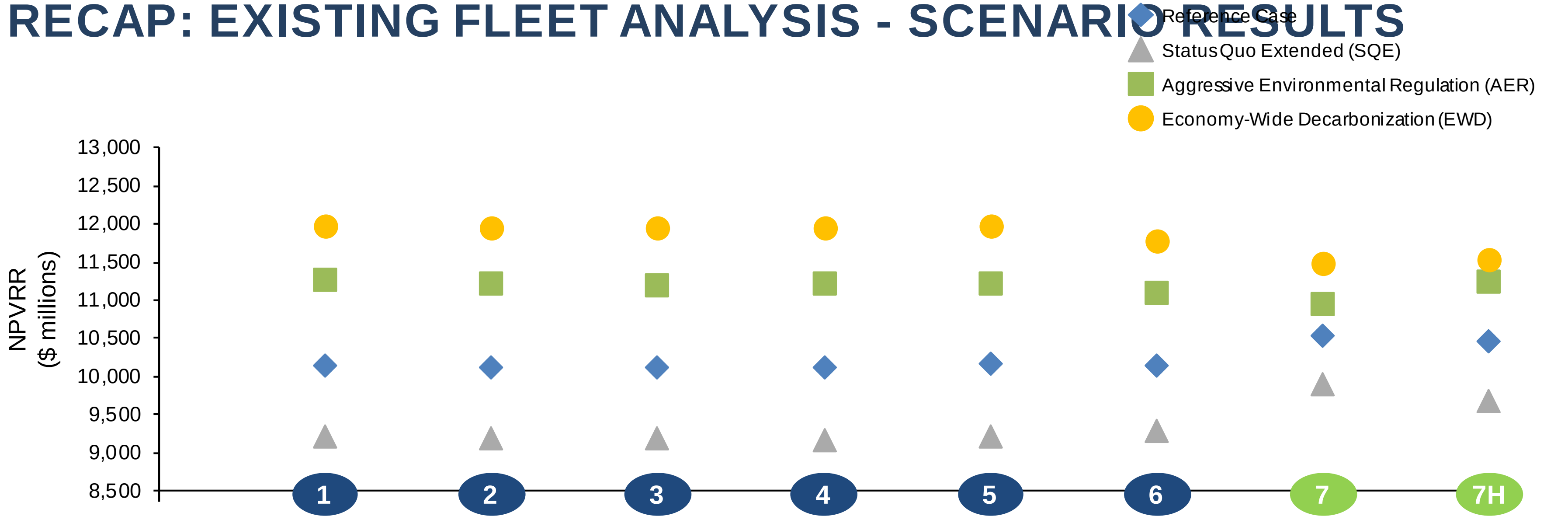
Portfolio Transition Target:	15% Coal through 2032 (1)	15% Coal through 2028 (2)	15% Coal through 2026 (3)	15% Coal through 2024 (4)	15% Coal through 2028 (5)	15% Coal through 2026 (6)	15% Coal through 2028 Fossil Free by 2032 (7)	15% Coal through 2028 Option for Fossil Free by 2032 (7H)
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Rank (1=Least Cost)	5	3	1	2	6	4	8	7
Delta from Least Cost	$35M 0.3%	$16M 0.2%	-	$10M 0.1%	$47M 0.5%	$24M 0.2%	$417M 4.1%	$357M 3.5%

Not a viable pathway due to implementation timing

Observations

- The difference in NPVRR from the highest cost to lowest cost portfolio is approximately $430 million
- Consistent with NIPSCO's prior IRP findings, early retirement of coal is generally cost effective for customers, although the difference in cost across several portfolios is small, since much of the remaining portfolio is fixed and small changes in retirement dates are now being assessed
- Retaining Units 16A/B until 2028 may be cost effective, given the portfolio's capacity needs. However, this is contingent on the operational condition of these older vintage units, and the cost impacts of earlier retirement are less than 1% in NPVRR

RECAP: EXISTING FLEET ANALYSIS - SCENARIO RESULTS



	Portfolio Transition Target:	15% Coal through 2032	15% Coal through 2028	15% Coal through 2026	15% Coal through 2024	15% Coal through 2028	15% Coal through 2026	15% Coal through 2028 Fossil Free by 2032	15% Coal through 2028; Option for Fossil Free by 2032
	Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
	Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Reference Case	**Delta from Lowest Cost to Customer**	$35 0.3%	$16 0.2%	- -	$10 0.1%	$47 0.5%	$24 0.2%	$417 4.1%	$357 3.5%
Status Quo Extended	**Delta from Lowest Cost to Customer**	$36 0.4%	$18 0.2%	$2 0.0%	- -	$49 0.5%	$108 1.2%	$720 7.8%	$492 5.4%
Aggressive Env. Reg.	**Delta from Lowest Cost to Customer**	$336 3.1%	$269 2.5%	$259 2.4%	$277 2.5%	$292 2.7%	$157 1.4%	- -	$303 2.8%
Econ-Wide Decarbonization	**Delta from Lowest Cost to Customer**	$477 4.1%	$454 3.9%	$449 3.9%	$459 4.0%	$478 4.2%	$276 2.4%	- -	$29 0.3%

Observations

- MC12 retirement in 2026 has a small cost benefit (<$20M) relative to retirement in 2028 across all scenarios
- MC 12 retirement in 2032 is always higher cost than earlier retirement, with the largest difference in the AER scenario (high carbon price)
- Portfolio 2 is slightly lower cost than Portfolio 5, although additional renewable additions with early 16AB retirement (Portfolio 6) lower costs under high carbon regulation scenarios
- Portfolios 7 and 7H have the smallest range, as their future renewable, hydrogen, and storage investments hedge against high-cost power market outcomes

Not a viable pathway due to implementation timing

*Note that a $0.50/kg H2 subsidy is assumed in AER and EWD

RECAP: EXISTING FLEET ANALYSIS SCORECARD

Objective	Indicator	Description and Metrics
Affordability	**Cost to Customer**	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	**Cost Certainty**	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: Highest scenario NPVRR
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: Lowest scenario NPVRR
Environmental Sustainability	**Carbon Emissions**	• Carbon intensity of portfolio • Metric: Cumulative carbon emissions (2024-40 short tons of CO_2) from the generation portfolio
Reliable, Flexible, and Resilient Supply	**Reliability**	• *To be addressed in Replacement Analysis stage*
	Resource Optionality	
Positive Social & Economic Impacts	**Employees**	• Net impact on NiSource jobs • Metric: Approx. number of permanent NiSource jobs associated with generation
	Local Economy	• Net effect on the local economy (relative to 2018 IRP) from new projects and ongoing property taxes • Metric: NPV of existing fleet property tax relative to 2018 IRP

Additional risk metrics will be included in the Replacement Analysis, when broader set of resource types are evaluated

Key Points

- Two closely related, but distinct scorecards are used for the Existing Fleet Analysis and the Replacement Analysis
- The Existing Fleet Analysis focuses on scenario costs, carbon emissions, and impact on NIPSCO employees and the local economy
- The Replacement Analysis expands the risk assessment to include a stochastic assessment and introduces reliability metrics to assess a broader range of future resource options

RECAP: EXISTING FLEET ANALYSIS SCORECARD

	1	2	3	4	5	6	7	7H
Portfolio Transition Target:	**15% Coal through 2032**	**15% Coal through 2028**	**15% Coal through 2026**	**15% Coal through 2024**	**15% Coal through 2028**	**15% Coal through 2026**	**15% Coal through 2028 Fossil Free by 2032**	**15% Coal through 2028 Fossil Free by 2032**
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Cost To Customer 30-year NPV of revenue requirement (Ref Case)	$10,149 +$35 0.3%	$10,130 +$16 0.2%	$10,114 - -	$10,125 $10 0.1%	$10,161 +$47 0.5%	$10,138 +$24 0.2%	$10,531 +$417 4.1%	$10,471 +$357 3.5%
Cost Certainty Scenario Range (NPVRR)	$2,759 +$1,161 72.6%	$2,754 +$1,156 72.3%	$2,766 +$1,167 73.0%	$2,777 +$1,179 73.8%	$2,747 +$1,149 71.9%	$2,487 +$889 55.6%	$1,598 - -	$1,855 +$257 16.1%
Cost Risk Highest Scenario NPVRR	$11,974 +$477 4.1%	$11,951 $454 3.9%	$11,947 +$449 3.9%	$11,957 +$459 4.0%	$11,976 +$478 4.2%	$11,773 +$276 2.4%	$11,498 - -	$11,527 +$29 0.3%
Lower Cost Opportunity Lowest Scenario NPVRR	$9,215 +$36 0.4%	$9,197 +$18 0.2%	$9,181 +$2 0.0%	$9,179 - -	$9,229 +$49 0.5%	$9,287 +$108 1.2%	$9,899 +$720 7.8%	$9,671 +$492 5.3%
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)	43.3 +22 102%	33.7 +12 57%	28.5 +7 33%	23.0 +2 8%	33.7 +12 57%	28.5 +7 33%	21.4 - -	30.9 +9 44%
Employees Approx. existing gen. jobs compared to 2018 IRP*	+127	0	-127	-127	-4	-131	-34	-4
Local Economy NPV of existing fleet property tax relative to 2018 IRP	+$13	$0	-$10	-$23	$0	-$10	-$16	+$13

*Adding replacement projects could have an impact on net jobs

Not a viable pathway due to implementation timing

BREAK

REPLACEMENT ANALYSIS REVIEW

Pat Augustine, Vice President, CRA
Hisham Othman, VP, Transmission and Regulatory Consulting, Quanta Technology, LLC

RECAP: ANALYTICAL FRAMEWORK

- The IRP analysis is performed in two phases; the first phase examines current and future resource additions to evaluate timing of retirement for existing units
- Insight and conclusions from existing fleet analysis inform replacement concepts to evaluate. Once a preferred existing portfolio is established, future replacements are evaluated across a range of objectives

	Existing Fleet Analysis	Replacement Analysis
Core Questions	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?* *Is the portfolio flexible and adaptable to address changes in market rules and energy policy?*	*What are the replacement resource portfolio options?* *How do different replacement themes compare with regard to cost, risk, environmental sustainability, and reliability?*
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

RECAP: REPLACEMENT ANALYSIS PORTFOLIOS HAVE BEEN DEVELOPED ACROSS NINE CONCEPTS

The concepts are informed by the IRP themes, findings from the Existing Fleet Analysis, and additional optimization testing

- For the Replacement Analysis, **Portfolio 3** from the Existing Fleet analysis has been used to assess portfolio selection under the earliest possible retirement of MC12. Note that Portfolio 2 would have similar results, with small changes in resource addition timing. This approach does not imply that NIPSCO has determined a specific MC12 retirement date
- Resource combinations are constructed based on RFP projects (tranches) and other opportunities to explore a range of emissions profiles and dispatchability under current and proposed market rules

Dispatchability

Emissions	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Higher Carbon Emissions	Thermal PPAs, solar and storage (A)	Non-service territory gas peaking (no early storage) (B)	Natural gas dominant (CC) (C)
Mid Carbon Emissions	No new thermal resources; solar dominant w/ storage (D)	Thermal PPAs plus storage and solar (E)	Local gas peaker, plus solar and storage (F)
Low Carbon Emissions	Solar dominant w/ storage, plus retire Sugar Creek (G)	All renewables and storage, plus retire Sugar Creek (Portfolio 7) (H)	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H) (I)

Sugar Creek is retained through modeling horizon

Sugar Creek Retires or converts to H2

Net Zero Concepts

RECAP: ICAP ADDITIONS– RFP PROJECTS AND OTHER NEAR-TERM OPPORTUNITIES

- Several resource additions are common across all themes, *when allowed*: **R&C DSM programs**, **Thermal PPAs, attractive NIPSCO DER, SC uprate**
- A range of solar, storage, gas, wind, and hydrogen-enabled resources are incorporated across portfolios

Dispatchability

ICAP Additions through 2027 Planning Year

Emissions	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Higher Carbon Emissions	**A** NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 135MW Solar+Storage 450MW* Solar 250MW	**B** NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 443MW Thermal PPA 150MW Solar 250MW	**C** NIPSCO DER 10MW SC Uprate 53MW Gas CC 650MW *Portfolio violates normal net long energy sales constraints enforced in optimization*
Mid Carbon Emissions	**D** NIPSCO DER 10MW SC Uprate 53MW Storage 135MW Solar+Storage 450MW* Solar 400MW	**E** NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 470MW Solar 250MW	**F** NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 300MW Thermal PPA 150MW Storage 135MW Solar 100MW
Low Carbon Emissions	**G** NIPSCO DER 10MW Storage 135MW Solar+Storage 450MW* Solar 450MW	**H** NIPSCO DER 10MW Wind 200MW Storage 570MW Solar 250MW	**I** NIPSCO DER 10MW SC H2 Electrolyzer 20MW SC Uprate 53MW H2 Enabled Peaker 193MW Wind 200MW Storage 370MW Solar 250MW

Sugar Creek is retained through modeling horizon

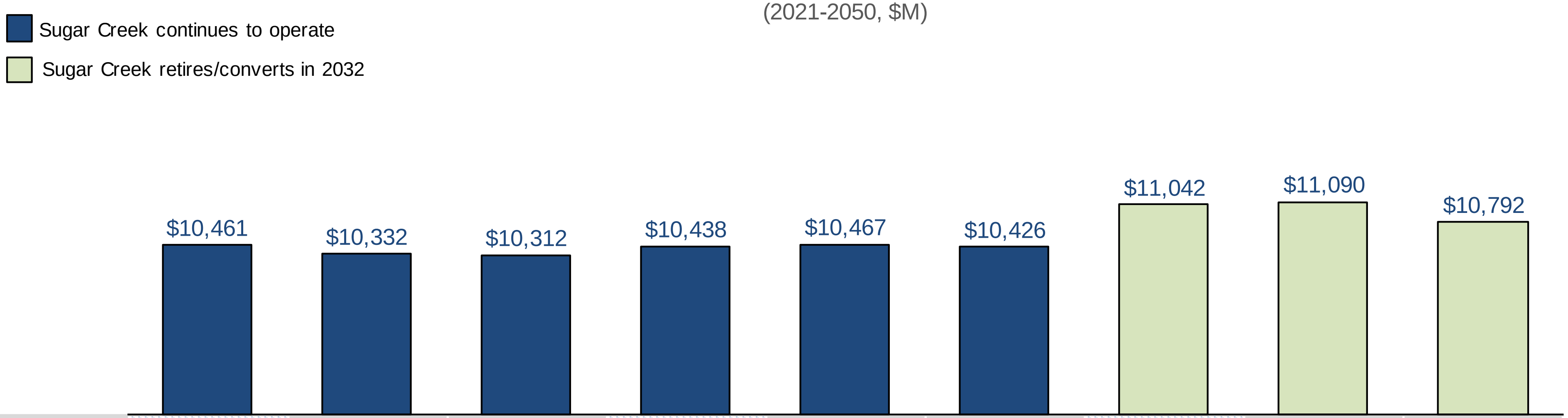
Sugar Creek Retires or converts to H2

Net Zero Concepts

Note: Residential/Commercial DSM universally selected across portfolios
**Represents 300 MW of solar and 150 MW of storage*
***Gas peaker in Portfolio B represents an out-of-service territory PPA; Gas peaker in Portfolio F represents asset sale proposal*

RECAP: RESULTS - COST TO CUSTOMER REFERENCE CASE

Net Present Value of Revenue Requirement
(2021-2050, $M)



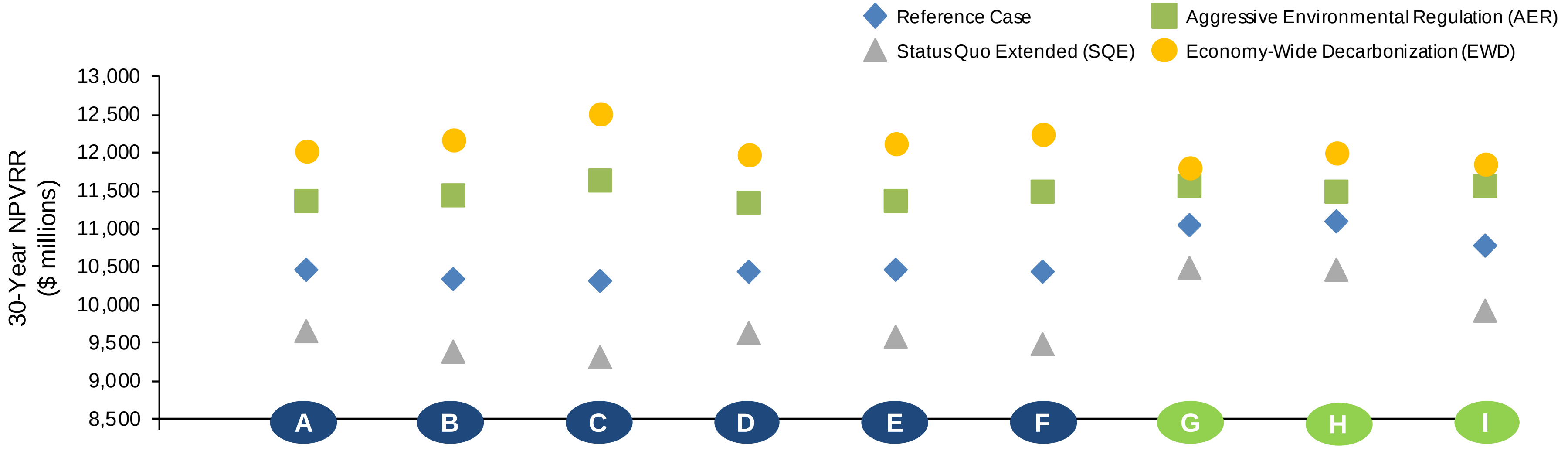
Replacement Theme	Thermal PPAs, solar and storage	Non-service territory gas peaking (no early storage)	Natural gas dominant (CC)	No new thermal resources; solar dominant w/ storage	Thermal PPAs plus storage and solar	Local gas peaker, plus solar and storage	Solar dominant w/ storage, plus retire Sugar Creek	All renewables and storage, plus retire Sugar Creek (Portfolio 7)	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
	A	B	C	D	E	F	G	H	I
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	5	2	1	4	6	3	8	9	7
Delta from Least Cost	$149 1.4%	$20 0.2%	-	$126 1.2%	$155 1.5%	$114 1.1%	$730 7.1%	$778 7.5%	$480 4.7%

Not a viable pathway due to not meeting winter planning reserve margins

Observations

- Portfolios A through F are all within ~$150 million NVPRR
- Portfolios A and D (solar dominant that only meet summer RM) are not tenable options given potential market rule changes
- Portfolio C develops a very net long position and is higher cost than several alternatives over a 20-year period, as economics are driven by long-term "merchant" margins
- Portfolios with significant storage (E in particular) have potential value in ancillary services markets
- Portfolios G, H, and I (net zero concepts) are higher cost, with Portfolio I retaining the optionality to burn natural gas at Sugar Creek under Reference Case conditions

RECAP: REPLACEMENT ANALYSIS SCENARIO RESULTS



		A	B	C	D	E	F	G	H	I
	Carbon Emissions:	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
	Dispatchability:	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Reference Case	Delta from Lowest Cost to Customer	$149 1.4%	$20 0.2%	- -	$126 1.2%	$155 1.5%	$114 1.1%	$730 7.1%	$778 7.5%	$480 4.7%
Status Quo Extended	Delta from Lowest Cost to Customer	$347 3.7%	$91 1.0%	- -	$334 3.6%	$278 3.0%	$186 2.0%	$1,176 12.6%	$1,149 12.3%	$624 6.7%
Aggressive Env. Reg.	Delta from Lowest Cost to Customer	$18 0.2%	$106 0.9%	$299 2.6%	- -	$35 0.3%	$151 1.3%	$235 2.1%	$144 1.3%	$212 1.9%
Econ-Wide Decarb.	Delta from Lowest Cost to Customer	$207 1.7%	$373 3.2%	$709 6.0%	$156 1.3%	$317 2.7%	$434 3.7%	- -	$202 1.7%	$39 0.3%

Not a viable pathway due to not meeting winter planning reserve margins

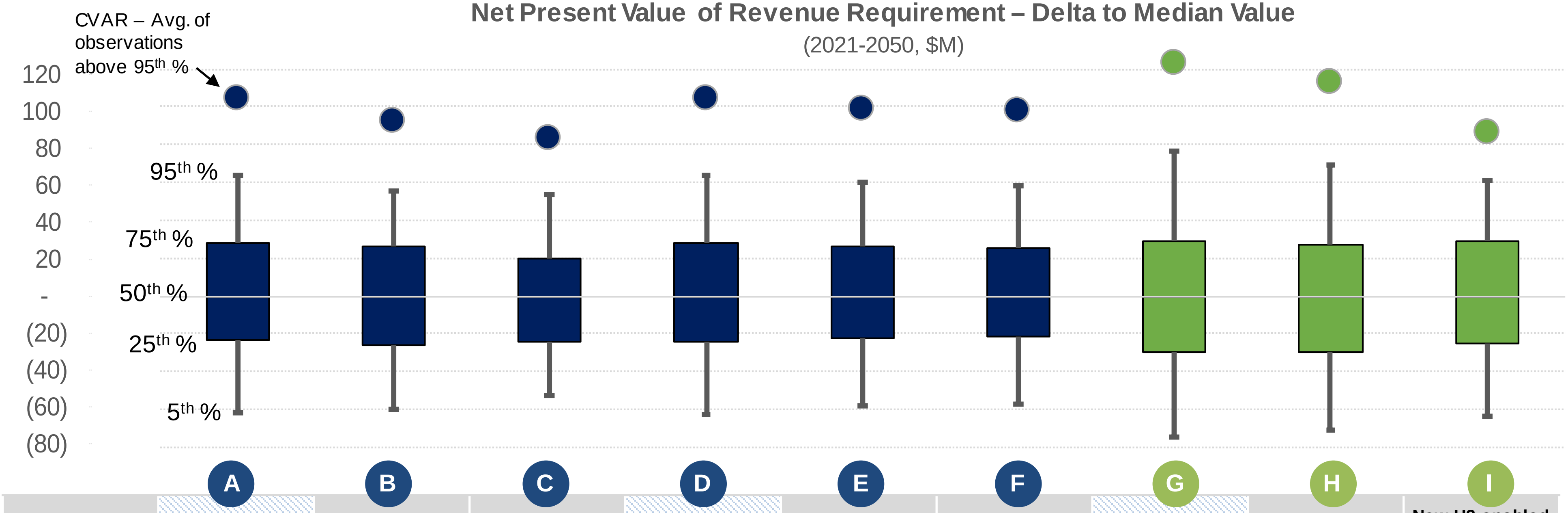
*Note that a $0.50/kg H2 subsidy is assumed in AER and EWD

Observations

- Portfolios B, C, and F have lowest costs among viable options under the Reference and SQE scenarios
- Portfolio E has the lowest cost among viable portfolios under the AER scenario, with C highest cost and H/I more competitive
- Emission free resources (clean energy) have the most value in the EWD scenario, with Portfolio I (assuming a future H2 subsidy) having the lowest cost among viable portfolios

RECAP: RESULTS - STOCHASTIC ANALYSIS

Net Present Value of Revenue Requirement – Delta to Median Value
(2021-2050, $M)



Replacement Theme	Thermal PPAs, solar and storage	Non-service territory gas peaking (no early storage)	Natural gas dominant (CC)	No new thermal resources; solar dominant w/ storage	Thermal PPAs plus storage and solar	Local gas peaker, plus solar and storage	Solar dominant w/ storage, plus retire Sugar Creek	All renewables and storage, plus retire Sugar Creek (Portfolio 7)	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
95th % CVAR Delta from Low	21	9	-	21	15	14	40	31	4
75th % Delta from Low	8	6	-	8	6	6	9	7	9
5th % Delta from Low	13	15	22	12	17	18	-	4	11

Observations

- The stochastic analysis evaluates short-term volatility in commodity prices (natural gas and power) and hourly renewable (solar and wind) output
- The overall magnitude of cost distributions across portfolios is narrower than the scenario range, suggesting that stochastic risk for these portfolio options is less impactful than the major policy or market shifts evaluated across scenarios
- Over the 30-year time horizon, dispatchability serves to mitigate tail risk, as portfolios that retain SC or add gas (including with hydrogen enablement) or storage capacity perform best at minimizing upside risk
- The lowest downside range is observed in renewable-dominant portfolios

RECAP: IN PREVIOUS SCORECARD RELIABILITY INDICATORS WERE UNDER DEVELOPMENT

Objective	Indicator	Description and Metrics
Affordability	Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	Cost Certainty	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR and 75th % range vs. median
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: Highest scenario NPVRR and 95th % conditional value at risk (average of all outcomes above 95th % vs. median)
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: Lowest scenario NPVRR and 5th % range vs. median
Environmental Sustainability	Carbon Emissions	• Carbon intensity of portfolio • Metric: Cumulative carbon emissions (2024-40 short tons of CO_2) from the generation portfolio
Reliable, Flexible, and Resilient Supply	Reliability	• The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules • Metric: *Sub-hourly A/S value impact and additional scoring (under development)*
	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 (UCAP – 2027)
Positive Social & Economic Impacts	Employees	• *Addressed in Existing Fleet Analysis for existing generation assets; employee numbers will be dependent on specific asset replacements*
	Local Economy	• Effect on the local economy from new projects and ongoing property taxes • Metric: NPV of property taxes from the entire portfolio

Key Points

- The Replacement Analysis scorecard incorporates broader perspectives on risk (stochastic analysis) and reliability than the Existing Fleet Analysis scorecard
- NIPSCO has completed the qualitative assessment of reliability and has now defined the reliability metrics which will be used in the scorecard (discussed further on following slides)

COMPLETED ANALYSES TO INFORM RELIABILITY INDICATORS

- The results presented in September did not include additional reliability considerations that were previously under development
  - Certain portfolio attributes were evaluated through additional economic analysis
  - Ohers required a technical, but non-economic review
- NIPSCO held a Technical Webinar on October 12th to review the approach, analyses, and key outcomes of the additional reliability assessment to provide an open forum for questions and discussion

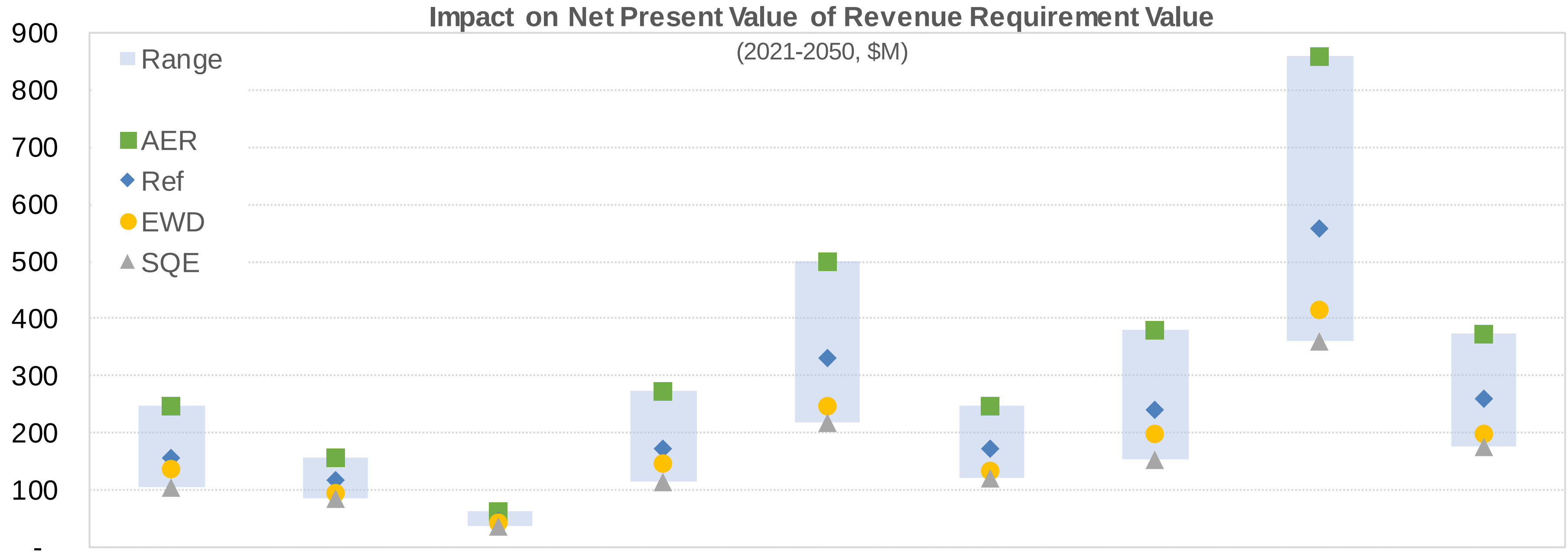
	Economic Assessment	Non-Economic Assessment
Analysis Performed	Ancillary services analysis (regulation and spinning reserves), with sub-hourly granularity	Qualitative reliability assessment performed by third-party expert Quanta Technology
Scorecard Metric	Sub-hourly energy and ancillary services value impact	Composite Reliability Assessment Score

SUB-HOURLY ENERGY AND ANCILLARY SERVICES EVALUATION

- While most of NIPSCO's existing portfolio (including new renewables) realize nearly all value from energy and capacity contributions, highly flexible resources that do not provide a lot of energy to the portfolio may still provide value in the form of ancillary services and in their ability to respond to changing market conditions in real time at sub-hourly granularity:
  - The MISO market currently operates markets for spinning reserves and regulation
  - FERC Order 841 also requires ISOs to redesign markets to accommodate energy storage

- Long-term market developments are uncertain, and fundamental evaluation of sub-hourly ancillary services markets is challenging, but the 2021 IRP has performed an analysis, incorporating:
  - 5-minute granularity for energy and ancillary services based on historical data observations and future energy market scenario projections
  - Operational parameters for various storage and gas peaking options
  - ***Incremental value, above and beyond what is picked up in the Aurora-based hourly energy dispatch, is assessed and summarized on a portfolio level***

RANGE OF ADDITIONAL VALUE OPPORTUNITY (NPVRR COST REDUCTION) BY PORTFOLIO



	A	B	C	D	E	F	G	H	I
Replacement Theme	**Thermal PPAs, solar and storage**	**Non-service territory gas peaking (no early storage)**	**Natural gas dominant (CC)**	**No new thermal resources; solar dominant w/ storage**	**Thermal PPAs plus storage and solar**	**Local gas peaker, plus solar and storage**	**Solar dominant w/ storage, plus retire Sugar Creek**	**All renewables and storage, plus retire Sugar Creek (Portfolio 7)**	**New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)**
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)

Observations

- *Additional value is uncertain and dependent on market rules evolution, MISO generation mix changes, and market participant behavior*
- Portfolios with the largest amounts of storage (E and H) have the greatest potential to lower NPVRR by capturing flexibility value that may manifest in the sub-hourly energy and ancillary services markets
- A wide range of value is possible, with higher prices and price spreads in the AER scenario driving higher estimates
- Results are incorporated into the final replacement analysis scorecard

RELIABILITY ASSESSMENT GUIDING PRINCIPLES

Resources Modeled	▪ The resources modeled are based on the portfolios constructed for the Replacement Analysis
Transmission Upgrades	▪ Analysis incorporates planned transmission projects
Time Period	▪ Resources are evaluated in 2030 after the Michigan City Unit 12 retirement
Evaluation	▪ The analysis is conducted at a planning level and, therefore, further evaluation and granular studies will be required in the future ▪ Individual resources from the 9 replacement portfolios are assessed based on the established reliability criteria. The score of the individual resources drive the portfolio score

Goal

- **Understand potential reliability implications of potential resource additions to the NIPSCO portfolio**
- **Understand the range of potential mitigations required associated with different replacement portfolio strategies**

TECHNICAL WEBINAR STAKEHOLDER FEEDBACK

Stakeholders offered several comments and questions during the Technical Webinar on 10/12.

Stakeholder	Feedback Summary	NIPSCO Response

Indiana Office of Utility Consumer Counselor (OUCC)	• Consider evaluating "energy inflows and outflows" by hour rather than constraining NIPSCO's system to be islanded.	• This has been evaluated as part of the core IRP economic modeling and analysis, including stochastic analysis:
		  • Under normal operating conditions, NIPSCO is constantly selling and buying energy to and from the market, so this exposure is economic and less about physical transmission limitations.
		  • The analysis concluded that over the long-term, portfolios with more dispatchable gas or storage are less susceptible to market risk than those dominated by renewables.
		• The reliability assessment has focused separately on energy adequacy risks under emergency conditions.

Citizens Action Coalition of Indiana (CAC)	• Consider portfolio evaluation under more representative emergency conditions rather than full islanded conditions. This might include simulation of severe weather events (which may be getting more frequent due to climate change) and associated resource availability, including renewables and other resources that may be impacted by forced outage or fuel supply unavailability.	• NIPSCO's assessment was intended to evaluate a "worst case" week and not imply islanded operations for the year. • We have not simulated weather, load, or forced outage events within the reliability assessment, but there may be an opportunity to tie elements of the stochastic analysis that was performed to additional reliability metrics in the future. Of particular focus are those that examine tail risk, as measured by CVAR in the economic analysis. • There is an industry trend towards greater focus on generation and transmission resiliency studies that aim to better quantify extreme event risk, and we will consider analysis enhancements for future IRPs and further reliability assessment.

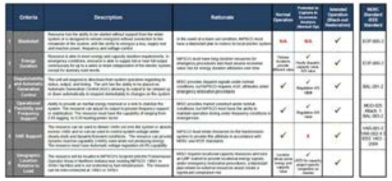
Note NIPSCO has received other comments from stakeholders and is in the process of reviewing. We will strive to incorporate feedback received into the final report.

RELIABILITY ASSESSMENT AND RANKING

Assess NIPSCO's Reliability Needs

- Power Ramping
- Frequency Response
- Short Circuit Strength
- Flicker
- Black Start

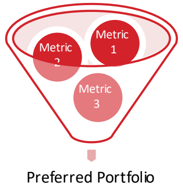
Review & Update Reliability Metrics



Apply a Series of Reliability Filters to IRP Portfolios

Scoring Criteria

Ranking Portfolios



QUANTA TECHNOLOGY

RELIABILITY CRITERIA

	Criteria	Description	Rationale
1	Blackstart	Resource has the ability to be started without support from the wider system or is designed to remain energized without connection to the remainder of the system, with the ability to energize a bus, supply real and reactive power, frequency and voltage control	In the event of a black out condition, NIPSCO must have a blackstart plan to restore its local electric system. The plan can either rely on MISO to energize a cranking path or on internal resources within the NIPSCO service territory.
2	Energy Duration	Resources are able to meet the energy and capacity duration requirements. Portfolio resources are able to supply the energy demand of customers during MISO's emergency max gen events, and also to supply the energy needs of critical loads during islanded operation events.	NIPSCO must have long duration resources to serve the needs of its customers during emergency and islanded operation events.
3	Dispatchability and Automatic Generation Control	The unit will respond to directives from system operators regarding its status, output, and timing. The unit has the ability to be placed on Automatic Generation Control (AGC) allowing its output to be ramped up or down automatically to respond immediately to changes on the system.	MISO provides dispatch signals under normal conditions, but NIPSCO requires AGC attributes under emergency restoration procedures or other operational considerations
4	Operational Flexibility and Frequency Support	Ability to provide inertial energy reservoir or a sink to stabilize the system. The resource can adjust its output to provide frequency support or stabilization in response to frequency deviations with a droop of 5% or better	MISO provides market construct under normal conditions, but preferable that NIPSCO possess the ability to maintain operation during under-frequency conditions in emergencies
5	VAR Support	The resource can be used to deliver VARs out onto the system or absorb excess VARs and so can be used to control system voltage under steady-state and dynamic/transient conditions. The resource can provide dynamic reactive capability (VARs) even when not producing energy. The resource must have Automatic voltage regulation (AVR) capability. The resource must have the capability ranging from 0.85 lagging to 0.95 leading power factor	NIPSCO must retain resources electrically close to load centers to provide this attribute in accordance with NERC and IEEE Standards
6	Geographic Location Relative to Load	The resource will be located in NIPSCO's footprint (electric Transmission Operator Area) in Northern Indiana near existing NIPSCO 138kV pr 345kV facilities and is not restricted by fuel infrastructure. The resource can be interconnected at 138kV or 345kV. Preferred locations are ones that have multiple power evacuation/deliverability paths and are close to major load centers.	MISO requires location capacity resources and runs an LMP market to provide locational energy signals; under emergency restoration procedures, a blackstart plan reliant on external resources would create a significant risk. Location provides economic value in the form of reduced losses, congestion, curtailment risk, and address local capacity requirements. Additionally, from a reliability perspective, resources that are interconnected to buses with multiple power evacuation paths and those close to load centers are more resilient to transmission system outages and provide better assistance in the blackstart restoration process.
7	Predictability and Firmness of Supply	Ability to predict/forecast the output of resources and to counteract forecast errors.	Energy is scheduled with MISO in the day-ahead hourly market and in the real-time 5-minute market. Deviations from these schedules have financial consequences and thus the ability to accurately forecast the output of a resource up to 38 hours ahead of time for the day-ahead market and 30 minutes for the real time market is advantageous.
8	Short Circuit Strength Requirement	Ensure the strength of the system to enable the stable integration of all inverter-based resources (IBRs) within a portfolio.	The retirement of synchronous generators within NIPSCO footprint and also within MISO and replacements with increasing levels of inverter-based resources will lower the short circuit strength of the system. Resources than can operate at lower levels of SCR and those that provide higher short circuit current provide a better future proofing without the need for expensive mitigation measures.

RELIABILITY METRICS

	Criteria	Potential Measurement Approaches Considered	Included in Minimum Interconnection Requirements	Quanta Analysis to Develop Metric
1	Blackstart	• MWs with black start capability	NO	• Blackstart Analysis
2	Energy Duration	• Percentage of NIPSCO's critical load (MW and Time) that can be supplied during emergencies	NO	• Energy Adequacy Analysis
3	Dispatchability and Automatic Generation Control	• MWs on AGC • Up Range / Down Range • Ability for Fast Regulation • Duration of Up / Down Regulation	NO (except being on SCADA for monitoring and control)	• Increase of Regulation Requirements due to IBRs in each Portfolio • 10-min Ramp Capability of Portfolio
4	Operational Flexibility and Frequency Support	• Inertial Response Gap/Surplus • Primary Frequency Response Gap/Surplus	NO	• Inertial Repose • Primary Response
5	VAR Support	• Continuous VAR output range that can be delivered to load centers	YES	• Dynamic VAR deliverability
6	Geographic Location Relative to Load	• MWs or % within NIPSCO footprint • Firmness of fuel supplies • MWs with POIs with multiple (2 or higher) secure power evacuation paths	NO	• Topology analysis
7	Predictability and Firmness of Supply	• Ability to mitigate Forecast Error of intermittent resources using fast ramping capability	NO	• Power Ramping and Forecast Errors
8	Short Circuit Strength Requirement	• MWs of IBRs potentially impacted by lack of short circuit strength • Need for synchronous condensers and/or grid forming inverters to ensure stable system integration	NO, 1547 and P2800 do not address	• Short Circuit Strength Analysis

QUANTA TECHNOLOGY

PORTFOLIO RELIABILITY METRICS

Preliminary

	Year 2030	Metric	A	B	C	D	E	F	G	H	I
1	Blackstart	Qualitative Assessment of Risk of not Starting	0	0	1	0	1	1	0	1	1
2	Energy Adequacy	Energy Not Served when Islanded (Worst 1-week) %	76%	78%	32%	75%	78%	56%	74%	73%	58%
3	Dispatchability and Automatic Generation Control	Dispatchable (%CAP, unavoidable VER Penetration)	28%	16%	55%	27%	44%	45%	26%	47%	47%
			58%	50%	42%	63%	50%	45%	65%	51%	51%
		Increased Freq Regulation Requirements (MW)	54	41	34	58	41	37	59	46	46
		1-min Ramp Capability (MW)	331	196	261	331	666	382	326	761	599
		10-min Ramp Capability (MW)	574	439	764	574	909	784	548	983	944
4	Operational Flexibility and Frequency Support	Inertia MVA-s	3,218	3,218	6,729	3,218	3,218	5,116	2,931	2,931	4,397
		Inertial Gap FFR MW	155	283	157	160	0	79	171	0	0
		Primary Gap PFR MW	259	388	380	260	0	249	261	0	19
5	VAR Support	Dynamic VAR to load Center Capability (MVAr)	658	471	457	704	630	555	725	731	719
6	Location	Average Number of Evacuation Paths	5	3	N/A	5	5	5	5	6	5
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) MW	-228	134	-262	-257	161	154	-266	245	238
8	Short Circuit Strength	Required Additional Synch Condensers MVA	580	388	0	763	341	0	802	488	257

CAP: the capacity value of the portfolio including the existing and planned resources
Solar capacity credit: 50% of installed capacity; Wind capacity credit : 16.3% (based on MISO published data on system wide capacity credits)

QUANTA TECHNOLOGY

PORTFOLIO RELIABILITY METRICS (NORMALIZED)

Preliminary

	Year 2030	Metric	A	B	C	D	E	F	G	H	I
1	Blackstart	Qualitative Assessment of Risk of not Starting	25%	0%	75%	25%	50%	100%	25%	50%	100%
2	Energy Adequacy	Energy Not Served when Islanded (Worst 1-week) %	76%	78%	32%	75%	78%	56%	74%	73%	58%
3	Dispatchability and Automatic Generation Control	Dispatchable (%CAP, unavoidable VER penetration%)	28%	16%	55%	27%	44%	45%	26%	47%	47%
			58%	50%	42%	63%	50%	45%	65%	51%	51%
		Increased Freq Regulation Requirement (% Peak Load)	2.30%	1.80%	1.50%	2.50%	1.80%	1.60%	2.60%	2.00%	2.00%
		1-min Ramp Capability (%CAP)	24.00%	20.80%	17.80%	22.80%	47.20%	29.40%	22.10%	49.30%	39.00%
		10-min Ramp Capability (%CAP)	41.70%	46.70%	52.10%	39.60%	64.40%	60.30%	37.10%	63.70%	61.50%
4	Operational Flexibility and Frequency Support	Inertia (seconds)	2.13	3.11	4.17	2.02	2.07	3.58	1.81	1.73	2.6
		Inertial Gap FFR (%CAP)	11.20%	30.10%	10.70%	11.00%	0.00%	6.10%	11.60%	0.00%	0.00%
		Primary Gap PFR (%CAP)	18.80%	41.30%	25.90%	17.90%	0.00%	19.10%	17.70%	0.00%	1.30%
5	VAR Support	Dynamic VAR to load Center Capability (%CAP)	47.80%	50.00%	31.20%	48.50%	44.70%	42.70%	49.10%	47.40%	46.80%
6	Location	Average Number of Evacuation Paths	5	2.5	N/A	4.6	4.7	4.7	4.8	5.6	5.1
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW)	-10.00%	6.70%	-15.10%	-10.60%	8.10%	8.40%	-10.70%	11.20%	10.90%
8	Short Circuit Strength	Required Additional Synch Condensers (%Peak Load)	25%	17%	0%	33%	15%	0%	35%	21%	11%

VER: Variable Energy Resources (e.g., solar, wind)
CAP: Capacity credit of all resources including existing, planned, and portfolio

SCORING CRITERIA THRESHOLDS

Preliminary

	Year 2030	Metric	1 (Pass)	1/2 (Caution)	0 (Potential Issue)	Rationale
1	Blackstart	Ability to blackstart using Storage & SC	>50%	25-50%	<25%	System requires real and reactive power sources with sufficient rating to start other resources. Higher rated resources lower the risk
2	Energy Adequacy	Energy Not Served when Islanded (Worst 1-week) %	<70%	70-85%	>85%	Ability of Resource to serve critical part load for 1 week, estimated at 15% of total load. Adding other important loads brings the total to 30%
3	Dispatchability	Dispatchable (VER Penetration %)	<50%	50-60%	>60%	Intermittent Power Penetration above 60% is problematic when islanded
		Increased Freq Regulation Requirements	<2% of peak load	2-3% of Peak Load	>3% of peak load	Regulation of Conventional Systems ≈1%
		1-min Ramp Capability	>15% of CAP	10-15% of CAP	<10% of CAP	10% per minute was the norm for conventional systems. Renewable portfolios require more ramping capability
		10-min Ramp Capability	>65% of CAP	50-65% of CAP	<50% of CAP	10% per minute was the norm for conventional systems. But with 50% min loading, that will be 50% in 10 min. Renewable portfolios require more ramping capability
4	Operational Flexibility and Frequency Support	Inertia (seconds)	>3xMVA rating	2-3xMVA rating	<2xMVA rating	Synchronous machine has inertia of 2-5xMVA rating.
		Inertial Gap FFR (assuming storage systems will have GFM inverters)	0	0-10% of CAP	>10% of CAP	System should have enough inertial response, so gap should be 0. Inertial response of synch machine ≈ 10% of CAP
		Primary Gap PFR MW	0	0 - 2% of CAP	2% of CAP	System should have enough primary response, so gap should be 0. Primary response of synch machine ≈ 3.3%of CAP/0.1Hz (Droop 5%)
5	VAR Support	VAR Capability	≥41% of ICAP	31-41% of ICAP	<31% of ICAP	Power factor higher than 95% (or VAR less than 31%) not acceptable. Less than 0.91 (or VAR greater than 41.5%) is good
6	Location	Average Number of Evacuation Paths	>3	2-3	<2	More power evacuation paths increases system resilience
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) MW	≥ 0	-10% - 0% of CAP	<-10% of CAP	Excess ramping capability to offset higher levels of intermittent resource output variability is desired
8	Short Circuit Strength	Required Additional Synch Condensers MVA	0	0-21.9% of CAP	>21.9% of CAP	Portfolio should not require additional synchronous condensers. 500MVAr is a threshold (same size as one at Babcock)

PORTFOLIO RELIABILITY RANKING

Preliminary

	Year 2030	Metric	A	B	C	D	E	F	G	H	I
1	Blackstart	Qualitative assessment of risk of not starting	1/2	0	1	1/2	1/2	1	1/2	1/2	1
2	Energy Adequacy	Energy not served when islanded	1/2	1/2	1	1/2	1/2	1	1/2	1/2	1
3	Dispatchability	Dispatchable %	1/2	1/2	1	0	1/2	1	0	1/2	1/2
		Increased Freq Regulation Requirements	1/2	1	1	1/2	1	1	1/2	1/2	1/2
		1-min Ramp Capability	1	1	1	1	1	1	1	1	1
		10-Min Ramp Capability	0	0	1/2	0	1/2	1/2	0	1/2	12
4	Operational Flexibility and Frequency Support	Inertia	1/2	1	1	1/2	1/2	1	0	0	1/2
		Inertial Gap FFR	0	0	0	0	1	1/2	0	1	1
		Primary Gap PFR	0	0	0	0	1	0	0	1	1/2
5	VAR Support	VAR Capability	1	1	0	1	1	1	1	1	1
6	Location	Average Number of Evacuation Paths	1	1/2	1	1	1	1	1	1	1
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit)	0	1	0	0	1	1	0	1	1
8	Short Circuit Strength	Required Additional Synch Condenser	0	1/2	1	0	1/2	1	0	1/2	1/2

	Criteria	A	B	C	D	E	F	G	H	I
1	Blackstart	0.50	-	1.00	0.50	0.50	1.00	0.50	0.50	1.00
2	Energy Adequacy	0.50	0.50	1.00	0.50	0.50	1.00	0.50	0.50	1.00
3	Dispatchability	0.50	0.63	0.88	0.38	0.75	0.88	0.38	0.63	0.63
4	Operational Flexibility and Frequency Support	0.17	0.33	0.33	0.17	0.83	0.50	-	0.67	0.67
5	VAR Support	1.00	1.00	-	1.00	1.00	1.00	1.00	1.00	1.00
6	Location	1.00	0.50	1.00	1.00	1.00	1.00	1.00	1.00	1.00
7	Predictability and Firmness	-	1.00	-	-	1.00	1.00	-	1.00	1.00
8	Short Circuit Strength	-	0.50	1.00	-	0.50	1.00	-	0.50	0.50
	Cumulative Score	3.67	4.46	5.21	3.54	6.08	7.38	3.38	5.79	6.79
	Percent Score (out of 8 possible points)	46%	56%	65%	44%	76%	92%	42%	72%	85%

1	Portfolio passes the screening test
½	Portfolio requires minor to moderate mitigation measures
0	Portfolio requires significant mitigation measures

1. Every metric is scored based on the criteria in the legend at the top of the page
2. Then, for criteria where there is more than one metric, the scores are averaged to create a single score for each criteria
3. All criteria scores are added to get a final portfolio score out of 8 possible points

QUALITATIVE RELIABILITY ASSESSMENT RESULTS

	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Duration)
Higher Carbon Emissions	A (7) NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 135MW Solar+Storage 450MW* Solar 250MW	B (6) NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 443MW Thermal PPA 150MW Solar 250MW	C (5) NIPSCO DER 10MW SC Uprate 53MW Gas CC 650MW
Mid Carbon Emissions	D (8) NIPSCO DER 10MW SC Uprate 53MW Storage 135MW Solar+Storage 450MW* Solar 400MW	E (3) NIPSCO DER 10MW SC Uprate 53MW Thermal PPA 150MW Storage 470MW Solar 250MW	F (1) NIPSCO DER 10MW SC Uprate 53MW Gas Peaker** 300MW Thermal PPA 150MW Storage 135MW Solar 100MW
Low Carbon Emissions	G (9) NIPSCO DER 10MW Storage 135MW Solar+Storage 450MW* Solar 450MW	H (4) NIPSCO DER 10MW Wind 200MW Storage 570MW Solar 250MW	I (2) NIPSCO DER 10MW SC H2 Electrolyzer 20MW SC Uprate 53MW H2 Enabled Peaker 193MW Wind 200MW Storage 370MW Solar 250MW

**Gas Peaker: Local to Service Territory in Portfolio F, while outside of territory in Portfolio B

Observations

- Portfolios F and I scored the highest across the eight defined reliability criteria
- Reliability Assessment results are then incorporated into the replacement scorecard as the non-economic component of the Reliability metric

REPLACEMENT ANALYSIS SCORECARD

Objective	Indicator	Description and Metrics
Affordability	**Cost to Customer**	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	**Cost Certainty**	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR and 75th % range vs. median
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: Highest scenario NPVRR and 95th % conditional value at risk (average of all outcomes above 95th % vs. median)
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: Lowest scenario NPVRR and 5th % range vs. median
Environmental Sustainability	**Carbon Emissions**	• Carbon intensity of portfolio • Metric: Cumulative carbon emissions (2024-40 short tons of CO_2) from the generation portfolio
Reliable, Flexible, and Resilient Supply	**Reliability**	• The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules • Metric: *Composite Reliability Assessment Score and Sub-hourly A/S value impact*
	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 (UCAP – 2027)
Positive Social & Economic Impacts	**Employees**	• *Addressed in Existing Fleet Analysis for existing generation assets; employee numbers will be dependent on specific asset replacements*
	Local Economy	• Effect on the local economy from new projects and ongoing property taxes • Metric: NPV of property taxes from the entire portfolio

REPLACEMENT ANALYSIS RESULTS

	A	B	C	D	E	F	G	H	I
Replacement Theme	Thermal PPAs, solar and storage	Non-service territory gas peaking (no early storage)	Natural gas dominant (CC)	No new thermal resources; solar dominant w/ storage	Thermal PPAs plus storage and solar	Local gas peaker, plus solar and storage	Solar dominant w/ storage, plus retire Sugar Creek	All renewables and storage, plus retire Sugar Creek (Portfolio 7)	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Cost To Customer 30-year NPVRR (Ref Case) $M	$10,461 +$149	$10,332 +$20	$10,312 -	$10,438 +$126	$10,467 +$155	$10,426 +$114	$11,042 +$730	$11,090 +$778	$10,792 +$480
Cost Certainty Scenario Range NPVRR $M	$2,359 +$1,035	$2,782 +$1,458	$3,208 +1,884	$2,322 +$998	$2,538 +$1,214	$2,748 +$1,424	$1,324 -	$1,553 +$229	$1,855 +$531
Cost Risk High Scenario NPVRR $M	$12,015 +$206	$12,182 +$373	$12,518 +$709	$11,965 +$156	$12,126 +$317	$12,243 +$434	$11,809 -	$12,011 +$202	$11,848 +$39
Cost Risk Stochastic 95% CVAR – 50%	$104 +$21	$92 +$9	$83 -	$104 +$21	$98 +$15	$97 +$14	$123 +$40	$114 +$31	$87 +$4
Lower Cost Opp. Lowest Scenario NPVRR $M	$9,657 +$348	$9,400 +$91	$9,309 -	$9,644 +$335	$9,588 +$279	$9,495 +$186	$10,485 +$1,176	$10,458 +$1,149	$9,933 +$684
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)	27.3 +11.2	30.4 +14.3	47.2 +31.1	27.3 +11.2	27.3 +11.2	28.5 +12.4	16.1 -	16.1 -	25.2 +9.1
Reliability Composite reliability score (out of 8 possible points)	3.67 -3.71	4.46 -2.92	5.21 -2.17	3.54 -3.84	6.08 -1.30	7.38 -	3.38 -4.00	5.79 -1.59	6.79 -0.59
Reliability Reduction to 30-Year NPVRR (Ref Case) $M	($158) +$400	($117) +$441	($48) +$510	($173) +$385	($332) +$226	($173) +$385	($240) +$318	($558) -	($259) +$299
Resource Optionality MW-weighted duration of 2027 gen. commitments (yrs.)	20.01 +3.01	20.53 +3.53	23.55 +6.55	20.37 +3.37	21.15 +4.15	22.12 +5.12	17.00 -	18.19 +1.19	21.46 +4.46
Local Economy NPV of property taxes	$420 -$66	$388 -$98	$451 -$35	$417 -$69	$413 -$73	$416 -$70	$486 -	$477 -$9	$421 -$65

Not a viable pathway due to not meeting winter reserve margins

*Note: Appendix contains more detailed scorecard data

REPLACEMENT ANALYSIS SCORECARD FOR VIABLE PORTFOLIOS

		B	C	E	F	H	I
Replacement Theme		Non-service territory gas peaking (no early storage)	Natural gas dominant (CC)	Thermal PPAs plus storage and solar	Local gas peaker, plus solar and storage	All renewables and storage, plus retire Sugar Creek (Portfolio 7)	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions		Higher	Higher	Mid	Mid	Low	Low
Dispatchability		Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Cost To Customer 30-year NPVRR (Ref Case) $M		$10,332 +$20	$10,312 -	$10,467 +$155	$10,426 +$114	$11,090 +$778	$10,792 +$480
Cost Certainty Scenario Range NPVRR $M		$2,782 +$1,229	$3,208 +$1,655	$2,538 +$985	$2,748 +$1,195	$1,553 -	$1,855 +$302
Cost Risk	High Scenario NPVRR $M	$12,182 +$334	$12,518 +$670	$12,126 +$278	$12,243 +$395	$12,011 +$163	$11,848 -
	Stochastic 95% CVAR – 50%	$92 3	$83 1	$98 5	$97 4	$114 6	$87 2
Lower Cost Opp. Lowest Scenario NPVRR $M		$9,400 +$91	$9,309 -	$9,588 +$279	$9,495 +$186	$10,458 +$1,149	$9,933 +$684
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)		30.4 +14.3	47.2 +31.1	27.3 +11.2	28.5 +12.4	16.1 -	25.2 +9.1
Reliability	Composite reliability score (out of 8 possible points)	4.46 6	5.21 5	6.08 3	7.38 1	5.79 4	6.79 2
	Reduction to 30-Year NPVRR (Ref Case) $M	($117) +$441	($48) +$510	($332) +$226	($173) +$385	($558) -	($259) +$299
Resource Optionality MW-weighted duration of 2027 gen. commitments (yrs.)		20.53 +2.34	23.55 +5.36	21.15 +2.96	22.12 +3.93	18.19 -	21.46 +3.27
Local Economy NPV of property taxes		$388 -$89	$451 -$26	$413 -$64	$416 -$61	$477 -	$421 -$56

Delta calculated vs. lowest cost option
Metric is ranked from highest to lowest

*Note: Appendix contains more detailed scorecard data

RESPONSES TO STAKEHOLDER FEEDBACK

Pat Augustine, Vice President, CRA

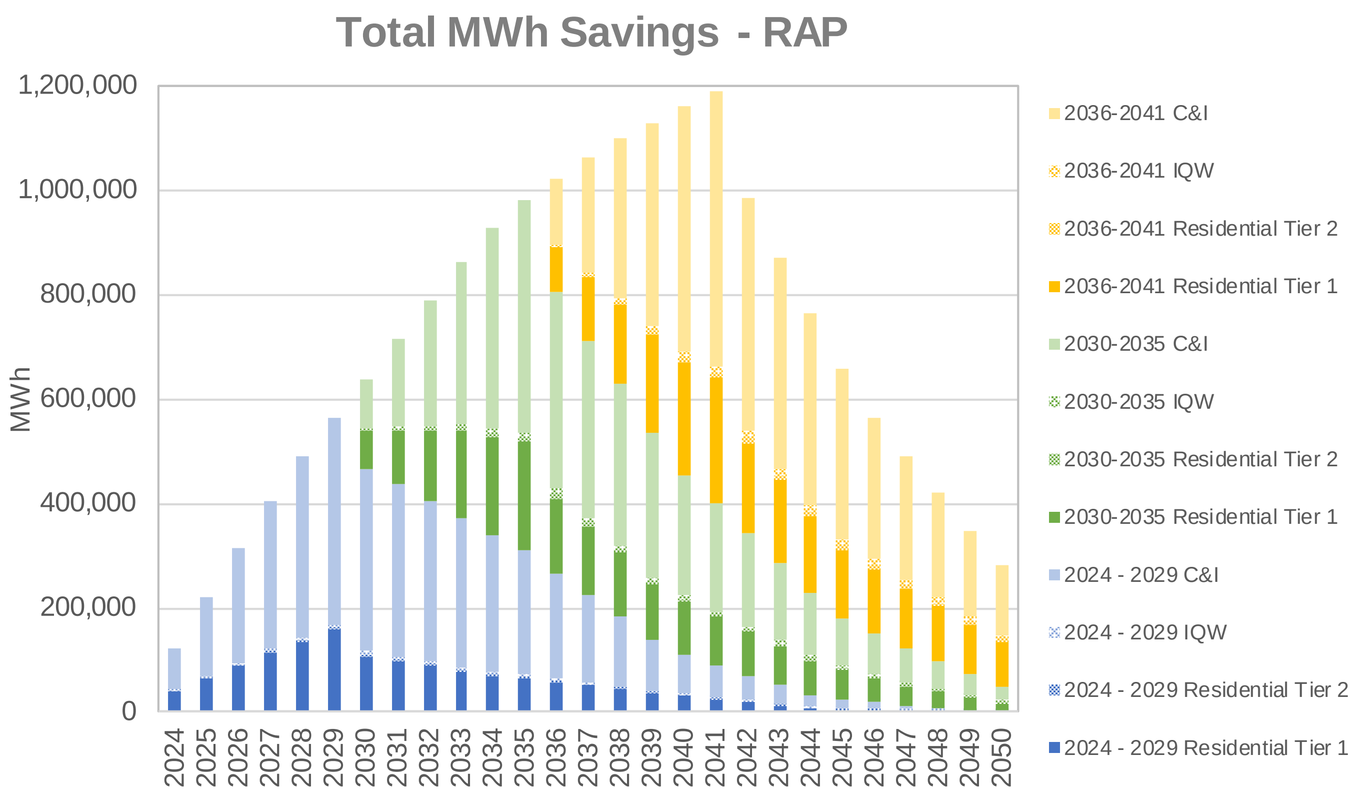
STAKEHOLDER FEEDBACK

- As part of the 2021 IRP public advisory process, NIPSCO has received some questions and requests for supplementary analysis in addition to the core portfolio results we just reviewed
- Today, we'll briefly review two follow-up topics: DSM impacts and different customer cost summaries

Stakeholder	Questions, Comments, and Requested Analysis
Citizens Action Coalition of Indiana (CAC)	• Additional Demand Side Management (DSM) evaluation to assess RAP vs. MAP impacts
Reliable Energy	• Review of 20-year NPVRRs and annual generation revenue requirements

RECAP OF KEY DSM PORTFOLIO FINDINGS

- NIPSCO's portfolio optimization analysis found DSM measures to be cost-effective throughout the entire planning horizon, with the following bundles selected:
  - Tier 1 residential energy efficiency for 2024-2029, 2030-2035, and 2036-2041
  - Commercial & industrial energy efficiency for 2024-2029, 2030-2035, and 2036-2041
  - The residential demand response rates programs after 2030
- Core portfolio analysis was performed for Realistic Achievable Potential (RAP) levels, with Maximum Achievable Potential (MAP) reserved for additional testing

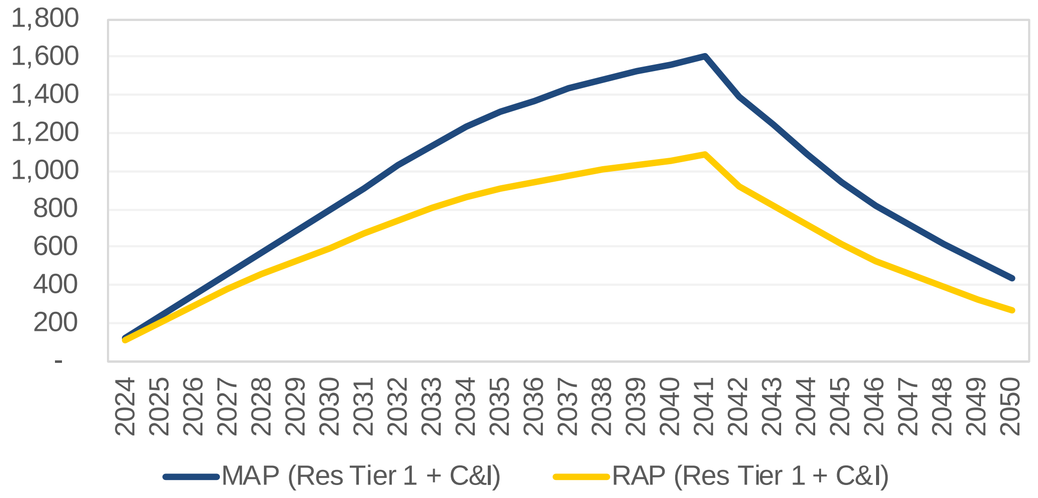


IQW = Income Qualified Weatherization

MAP VS. RAP: KEY INPUTS AND PORTFOLIO DEVELOPMENT

- MAP portfolio testing is most impactful for energy efficiency measures, with additional savings available at higher costs
- NIPSCO tested the impact of DSM at MAP for two candidate Replacement Portfolios (E and F)
  - Residential and commercial/industrial MAP energy efficiency programs "hard coded" into the portfolio model
  - Small long-term capacity adjustments (100 MW of storage in the 2030s) were made to each portfolio to reflect lower capacity requirements (winter reserve margin being more binding over the long-term)

Annual GWh Savings



Levelized Cost ($/MWh)

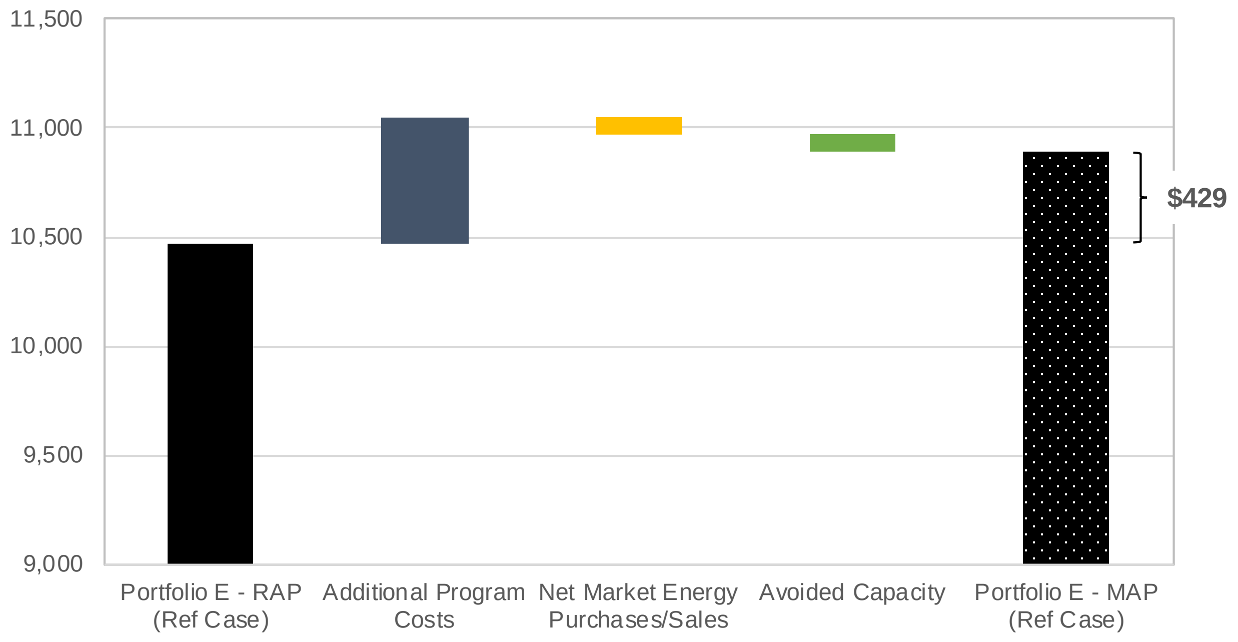
		RAP	MAP
2024-2029	Res Tier 1	53	140
	C&I	26	86
2030-2035	Res Tier 1	60	160
	C&I	30	90
2036-2041	Res Tier 1	65	165
	C&I	32	91

Note that levelized costs are presented prior to cost adjustments for avoided T&D investment

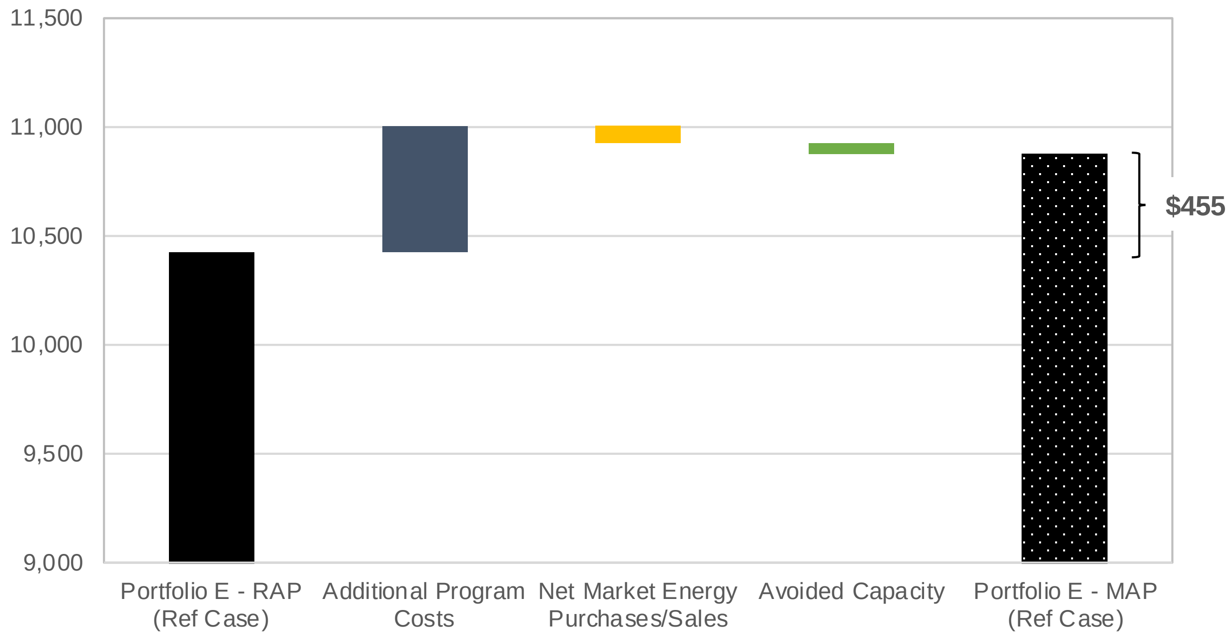
MAP VS. RAP: PORTFOLIO COST IMPLICATIONS

- Under Reference Case conditions, moving to MAP would increase the 30-year NPVRR by $429 million for Portfolio E and $455 million for Portfolio F.
- Alternative scenarios would change the impact of net market energy purchases/sales, but even under the highest scenario price conditions (AER), these savings would not offset additional program costs

Portfolio E – 30-yr NPVRR Impact



Portfolio F – 30-yr NPVRR Impact



20-YEAR NPV REVIEW: EXISTING FLEET ANALYSIS: SCENARIO RESULTS

Portfolio Transition Target:	15% Coal through 2032	15% Coal through 2028	15% Coal through 2026	15% Coal through 2024	15% Coal through 2028	15% Coal through 2026	15% Coal through 2028 Fossil Free by 2032	15% Coal through 2028; Option for Fossil Free by 2032
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Reference Case — Delta from Lowest Cost to Customer	$30 0.3%	$12 0.1%	- -	$3 0.0%	$41 0.5%	$33 0.4%	$276 3.1%	$280 3.2%
Status Quo Extended — Delta from Lowest Cost to Customer	$20 0.2%	$13 0.2%	$1 0.0%	- -	$43 0.5%	$98 1.2%	$491 6.0%	$389 4.7%
Aggressive Env. Reg. — Delta from Lowest Cost to Customer	$233 2.5%	$160 1.7%	$154 1.7%	$152 1.7%	$182 2.0%	$91 1.0%	- -	$221 2.4%
Econ-Wide Decarbonization — Delta from Lowest Cost to Customer	$431 4.6%	$395 4.2%	$394 4.2%	$386 4.1%	$418 4.5%	$264 2.8%	$24 0.3%	- -

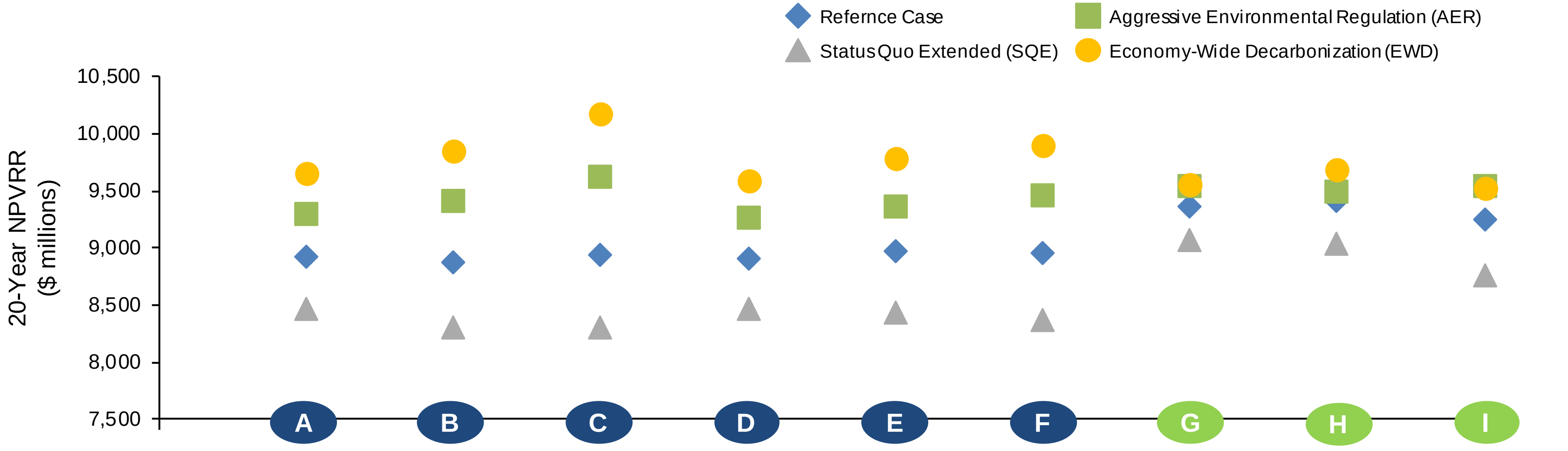
Not a viable pathway due to implementation timing

*Note that a $0.50/kg H2 subsidy is assumed in AER and EWD

Observations

- Observations from the 20-year NPVRR view are very similar to the 30-year view
- MC 12 retirement in 2026 is always slightly lower cost than retirement in 2028
- MC 12 retirement in 2032 is always higher cost than earlier retirement, with the largest difference in the AER scenario (high carbon price)
- Portfolio 2 is slightly lower cost than Portfolio 5, although additional renewable additions with early 16AB retirement (Portfolio 6) lower costs under high carbon regulation scenarios
- Portfolios 7 and 7H have the smallest range

20-YEAR NPV REVIEW: REPLACEMENT ANALYSIS: SCENARIO RESULTS



		A	B	C	D	E	F	G	H	I
	Carbon Emissions:	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
	Dispatchability:	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Reference Case	Delta from Lowest Cost to Customer	$49 0.6%	- -	$66 0.7%	$28 0.3%	$95 1.1%	$76 0.9%	$489 5.5%	$531 6.0%	$365 4.1%
Status Quo Extended	Delta from Lowest Cost to Customer	$167 2.0%	- -	$5 0.1%	$169 2.0%	$138 1.7%	$74 0.9%	$773 9.3%	$743 9.0%	$471 5.7%
Aggressive Env. Reg.	Delta from Lowest Cost to Customer	$36 0.4%	$150 1.6%	$351 3.8%	- -	$96 1.0%	$201 2.2%	$269 2.9%	$226 2.4%	$278 3.0%
Econ-Wide Decarb.	Delta from Lowest Cost to Customer	$128 1.3%	$335 3.5%	$653 6.9%	$62 0.7%	$256 2.7%	$377 4.0%	$32 0.3%	$167 1.8%	- -

Not a viable pathway due to not meeting winter planning reserve margins

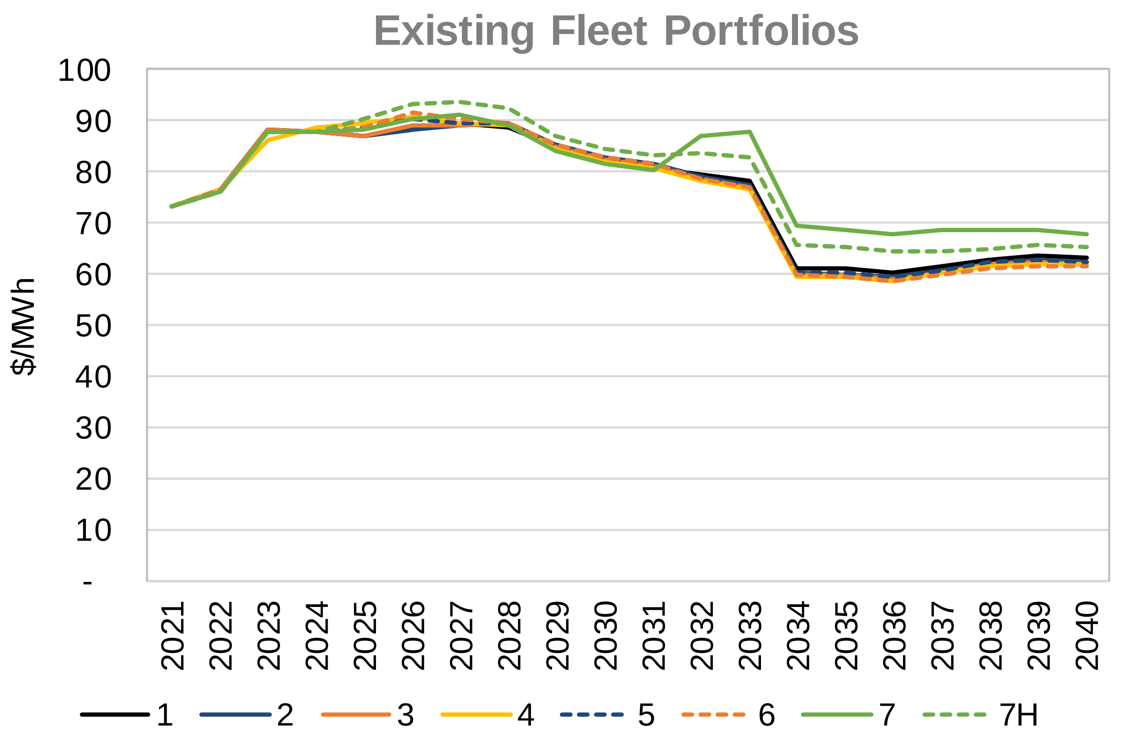
*Note that a $0.50/kg H2 subsidy is assumed in AER and EWD

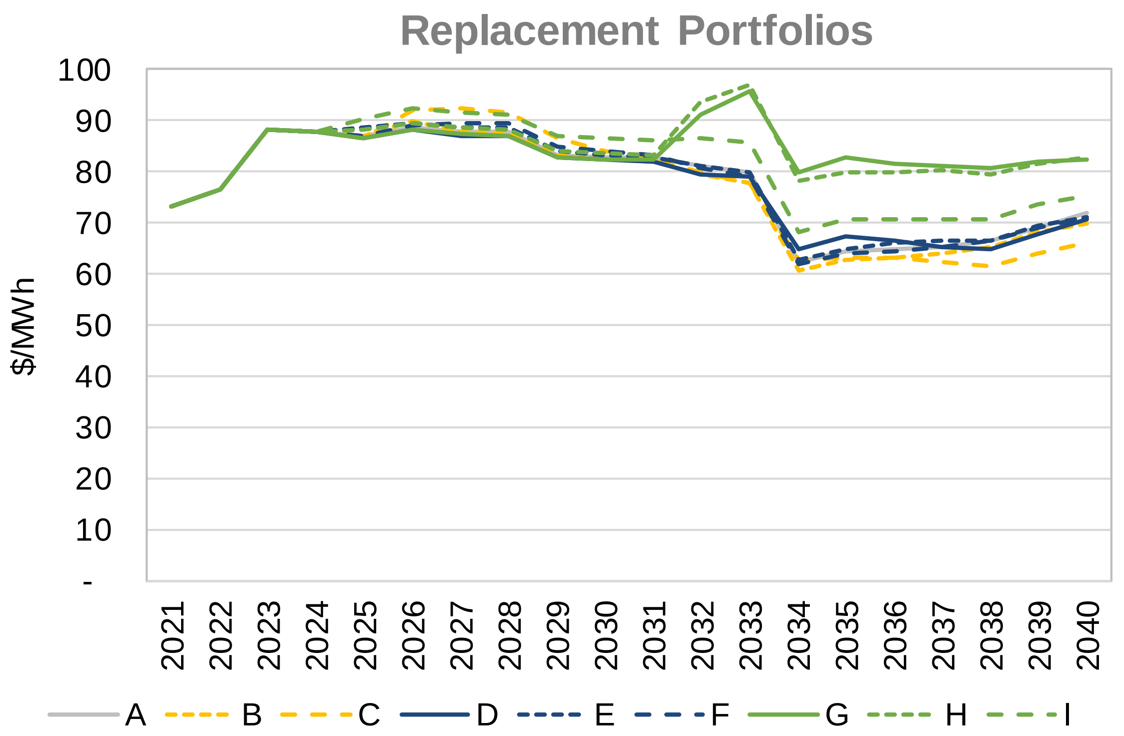
Observations

- Observations from the 20-year NPVRR view are similar to the 30-year view, with a major exception being the performance of Portfolio C (as identified by NIPSCO in the September meeting)
- Portfolios B, C, and F have lowest costs among viable options under the Reference and SQE scenarios
- Portfolio E has the lowest cost among viable portfolios under the AER scenario, with C highest cost and H/I more competitive
- Clean energy has the most value in the EWD scenario, with Portfolio I (assuming a future H2 subsidy) having the lowest cost among viable portfolios

ANNUAL GENERATION COSTS PER MWH – REFERENCE CASE

- Annual "generation rate" review confirms no significant short vs. long-term rate impact differences across portfolios that are not already evident in the NPV summaries
- Different scenarios drive different relative cost trajectories, as also evident in NPV summaries





- Portfolios 1 through 4 are within \$2.50/MWh of each over the study period, and Portfolios 1 through 6 are within \$3.50/MWh of each other

- All portfolios are within \$5/MWh of each other through 2030
- Portfolio C is higher cost in the mid-2020s, but lowest cost over the long-term

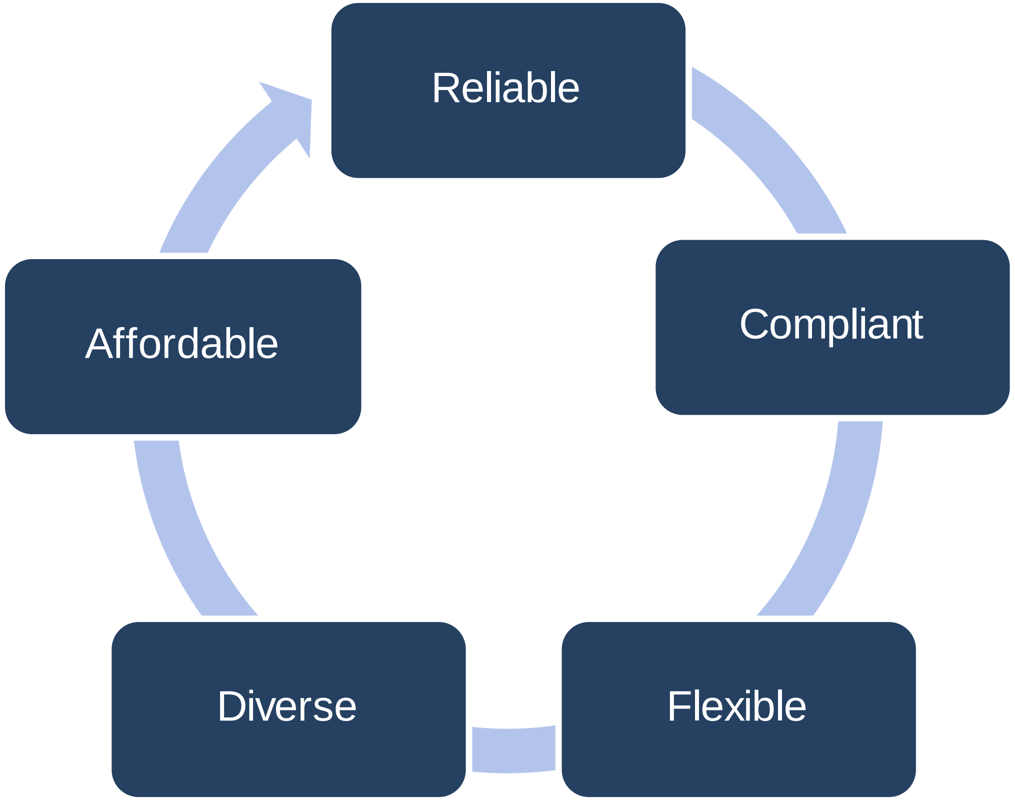
LUNCH

PREFERRED RESOURCE PLAN AND ACTION PLAN

Fred Gomos, Director Strategy & Risk Integration, NiSource
Pat Augustine, Vice President, CRA

NIPSCO PREFERRED SUPPLY PORTFOLIO CRITERIA

- Requires careful planning and consideration for all of NIPSCO's stakeholders, including the communities we serve and our employees
- The IRP is an informative submission to the IURC; NIPSCO intends to remain engaged with interested stakeholders



EXISTING FLEET ANALYSIS SCORECARD

Preferred Pathways

	1	2	3	4	5	6	7	7H
Portfolio Transition Target:	15% Coal through 2032	15% Coal through 2028	15% Coal through 2026	15% Coal through 2024	15% Coal through 2028	15% Coal through 2026	15% Coal through 2028 Fossil Free by 2032	15% Coal through 2028 Fossil Free by 2032
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Cost To Customer 30-year NPV of revenue requirement (Ref Case)	$10,149 +$35 0.3%	$10,130 +$16 0.2%	$10,114 - -	$10,125 $10 0.1%	$10,161 +$47 0.5%	$10,138 +$24 0.2%	$10,531 +$417 4.1%	$10,471 +$357 3.5%
Cost Certainty Scenario Range (NPVRR)	$2,759 +$1,161 72.6%	$2,754 +$1,156 72.3%	$2,766 +$1,167 73.0%	$2,777 +$1,179 73.8%	$2,747 +$1,149 71.9%	$2,487 +$889 55.6%	$1,598 - -	$1,855 +$257 16.1%
Cost Risk Highest Scenario NPVRR	$11,974 +$477 4.1%	$11,951 $454 3.9%	$11,947 +$449 3.9%	$11,957 +$459 4.0%	$11,976 +$478 4.2%	$11,773 +$276 2.4%	$11,498 - -	$11,527 +$29 0.3%
Lower Cost Opportunity Lowest Scenario NPVRR	$9,215 +$36 0.4%	$9,197 +$18 0.2%	$9,181 +$2 0.0%	$9,179 - -	$9,229 +$49 0.5%	$9,287 +$108 1.2%	$9,899 +$720 7.8%	$9,671 +$492 5.3%
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)	43.3 +22 102%	33.7 +12 57%	28.5 +7 33%	23.0 +2 8%	33.7 +12 57%	28.5 +7 33%	21.4 - -	30.9 +9 44%
Employees Approx. existing gen. jobs compared to 2018 IRP*	+127	0	-127	-127	-4	-131	-34	-4
Local Economy NPV of existing fleet property tax relative to 2018 IRP	+$13	$0	-$10	-$23	$0	-$10	-$16	+$13

*Adding replacement projects could have an impact on net jobs

Not a viable pathway due to implementation timing

PORTFOLIOS 3 AND 5 ARE THE PREFERRED EXISTING FLEET PORTFOLIOS

Preferred Pathways

	3	5
Portfolio Transition Target:	**15% Coal through 2026**	**15% Coal through 2028**
Retire:	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)
Retain beyond 2032:	Sugar Creek	Sugar Creek
Cost To Customer 30-year NPV of revenue requirement (Ref Case)	$10,114	$10,161
Cost Certainty Scenario Range (NPVRR)	$2,766	$2,747
Cost Risk Highest Scenario NPVRR	$11,947	$11,976
Lower Cost Opportunity Lowest Scenario NPVRR	$9,181	$9,229
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)	28.5	33.7
Employees Approx. existing gen. jobs compared to 2018 IRP*	-127	-4
Local Economy NPV of existing fleet property tax relative to 2018 IRP	-$10	$0

- The two portfolios **represent book ends** of Michigan City Unit 12 and Schahfer 16AB retirement dates
- Selecting two portfolios as preferred existing fleet pathways **preserves flexibility for customers,** given ongoing MISO rules evolution, active federal policy deliberations, and required monitoring of Schahfer 16AB's operations over the next few years
- Both portfolios provide **ample timing for transmission upgrades** needed prior to Michigan City Unit 12 retirement
- **Portfolio 3 is lowest cost to customer,** but both portfolios are within 0.5% on an NPVRR basis

Preferred Pathway F with flexibility to pivot to I over the long term

REPLACEMENT ANALYSIS SCORECARD

		B	C	E	F	H	I
Replacement Theme		Non-service territory gas peaking (no early storage)	Natural gas dominant (CC)	Thermal PPAs plus storage and solar	Local gas peaker, plus solar and storage	All renewables and storage, plus retire Sugar Creek (Portfolio 7)	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions		Higher	Higher	Mid	Mid	Low	Low
Dispatchability		Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Cost To Customer 30-year NPVRR (Ref Case) $M		$10,332 +$20	$10,312 -	$10,467 +$155	$10,426 +$114	$11,090 +$778	$10,792 +$480
Cost Certainty Scenario Range NPVRR $M		$2,782 +$1,229	$3,208 +$1,655	$2,538 +$985	$2,748 +$1,195	$1,553 -	$1,855 +$302
Cost Risk	High Scenario NPVRR $M	$12,182 +$334	$12,518 +$670	$12,126 +$278	$12,243 +$395	$12,011 +$163	$11,848 -
	Stochastic 95% CVAR – 50%	$92 3	$83 1	$98 5	$97 4	$114 6	$87 2
Lower Cost Opp. Lowest Scenario NPVRR $M		$9,400 +$91	$9,309 -	$9,588 +$279	$9,495 +$186	$10,458 +$1,149	$9,933 +$684
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)		30.4 +14.3	47.2 +31.1	27.3 +11.2	28.5 +12.4	16.1 -	25.2 +9.1
Reliability	Composite reliability score (out of 8 possible points)	4.46 6	5.21 5	6.08 3	7.38 1	5.79 4	6.79 2
	Reduction to 30-Year NPVRR (Ref Case) $M	($117) +$441	($48) +$510	($332) +$226	($173) +$385	($558) -	($259) +$299
Resource Optionality MW-weighted duration of 2027 gen. commitments (yrs.)		20.53 +2.34	23.55 +5.36	21.15 +2.96	22.12 +3.93	18.19 -	21.46 +3.27
Local Economy NPV of property taxes		$388 -$89	$451 -$26	$413 -$64	$416 -$61	$477 -	$421 -$56

Delta calculated vs. lowest cost option
Metric is ranked from highest to lowest

*Note: Appendix contains more detailed scorecard data

PORTFOLIOS F AND I ARE THE PREFERRED REPLACEMENT ANALYSIS PORTFOLIOS

Preferred Portfolio F with flexibility to pivot to I over the long term

		F	I
Replacement Theme		Local gas peaker, plus solar and storage	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions		Mid	Low
Dispatchability		Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Cost To Customer 30-year NPVRR (Ref Case) $M		$10,426	$10,792
Cost Certainty Scenario Range NPVRR $M		$2,748	$1,855
Cost Risk	High Scenario NPVRR $M	$12,243	$11,848
	Stochastic 95% CVAR – 50%	$97	$87
Lower Cost Opp. Lowest Scenario NPVRR $M		$9,495	$9,933
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)		28.5	25.2
Reliability	Composite reliability score (out of 8 possible points)	7.38	6.79
	Reduction to 30-Year NPVRR (Ref Case) $M	($173)	($259)
Resource Optionality MW-weighted duration of 2027 gen. commitments (yrs.)		22.12	21.46
Local Economy NPV of property taxes		$416	$421

- **Portfolio F** is the **preferred near-term** replacement portfolio that balances all of NIPSCO's major planning objectives
- **Both Portfolio F and Portfolio I** include near-term additions of cost-effective DSM, new DER, and an uprate at Sugar Creek
- The potential to pivot to **Portfolio I over the near-term *and* longer-term preserves flexibility** in an environment of market, policy, and technology uncertainty:
  - Additional solar (and wind) capacity may be added if environmental policy makes it more economic
  - Additional storage capacity may be added as further technology and reliability diligence is performed
  - New peaking capacity may be hydrogen-enabled as options are explored further
  - Hydrogen pilot projects and long-term hydrogen conversion pathways may be explored for Sugar Creek as policy and technology evolves

IRP PREFERRED PLAN POINTS TO NEED TO MAINTAIN FLEXIBILITY ON RETIREMENT TIMING AND REPLACEMENT RESOURCES

Evolving MISO Market rules changes and federal policy on emissions regulations are key drivers

Retirement Of Michigan City 12 and Schahfer 16AB

- Refine retirement timing of Michigan City Unit 12 to be between 2026 and 2028
- Establish retirement date for vintage peaking units at Schahfer (16A/B) to between 2025 and 2028
- The exact retirement dates will be informed by:
  - System reliability impacts
  - Policy and regulatory considerations
  - Securing replacement resources
- Flexibility in timing allows NIPSCO to optimize retirement timing of vintage peaking units (along with Michigan City 12). NIPSCO can pursue cost-effective resources that cover capacity needs for both assets
- Michigan City Unit 12 and Schahfer 16AB do not have to retire at the same time

Replacement Resources

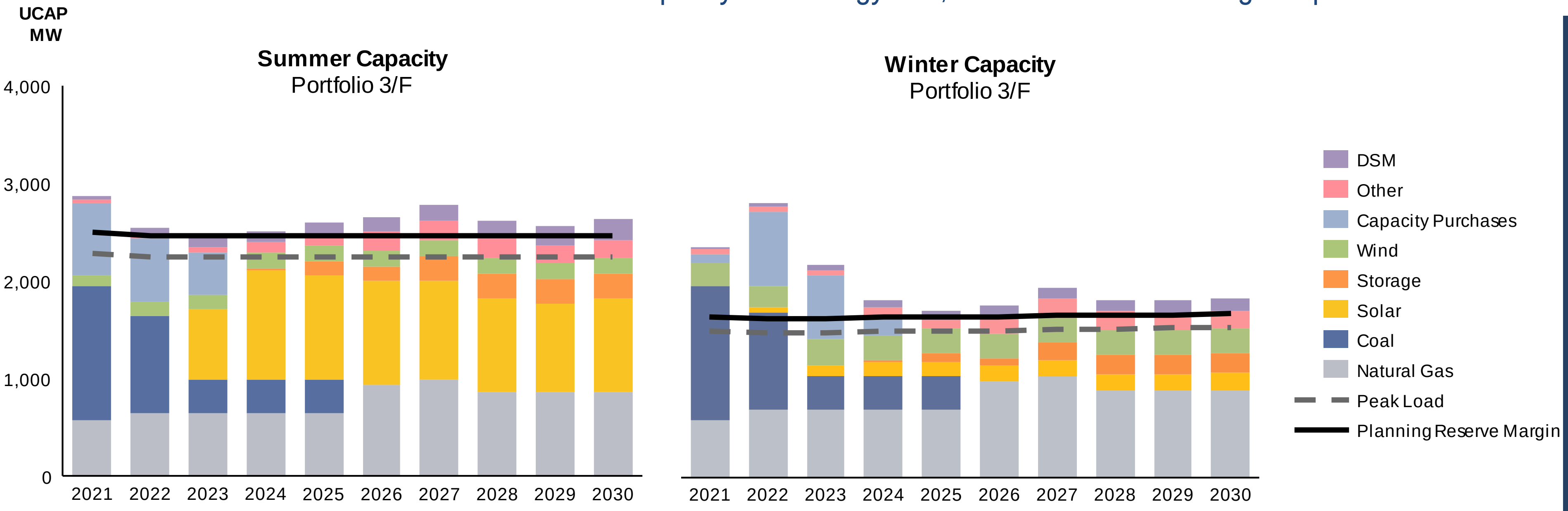
- Preferred Plan contains a diverse, flexible and scalable mix of incremental resources to add to the NIPSCO portfolio
- Large energy storage and gas peaking resources are attractive replacement options, supplemented by continued DSM expansion, new DER opportunities, and contract options to firm up the capacity position in the short term

Summary MW (ICAP) Range Of Portfolio Additions by 2028	
Sugar Creek Uprate	30 – 53 MW ICAP
Short-Term Capacity Contracts	150 MW ICAP
DSM	~68 MW at summer peak
New Solar	100 – 250* MW ICAP
New Storage	135 – 370 MW ICAP
New Gas Peaking**	Up to 300 MW ICAP

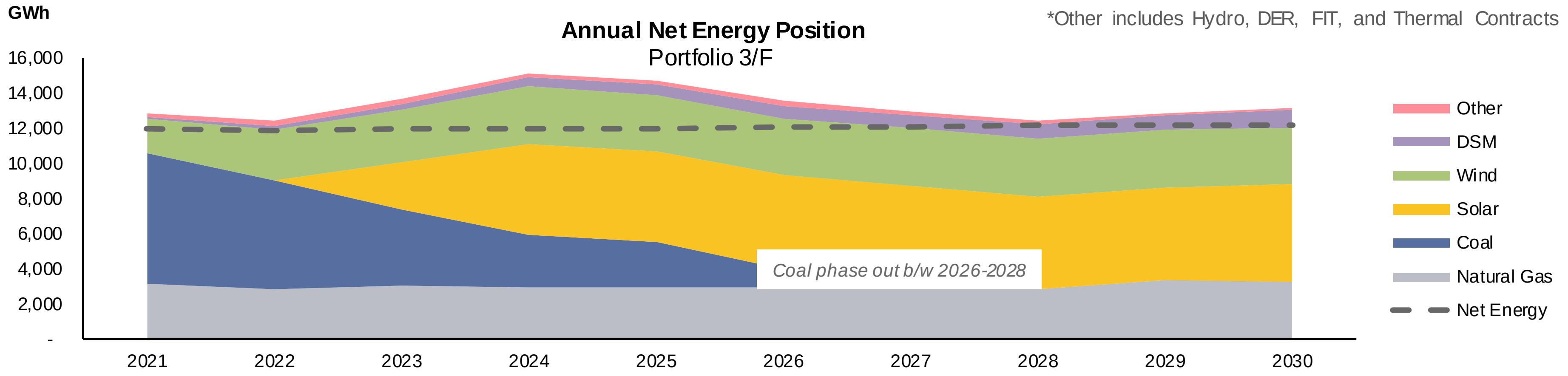
* Top end of range dependent on project sizing
**Potentially H2 enabled

PREFERRED PLAN CAPACITY AND ENERGY BALANCE

Renewable resources balance summer capacity and energy mix, with thermal and storage required for winter reserve margin compliance



*Other includes Hydro, DER, FIT, and Thermal Contracts



*Other includes Storage, Hydro, DER, FIT, and Thermal Contracts

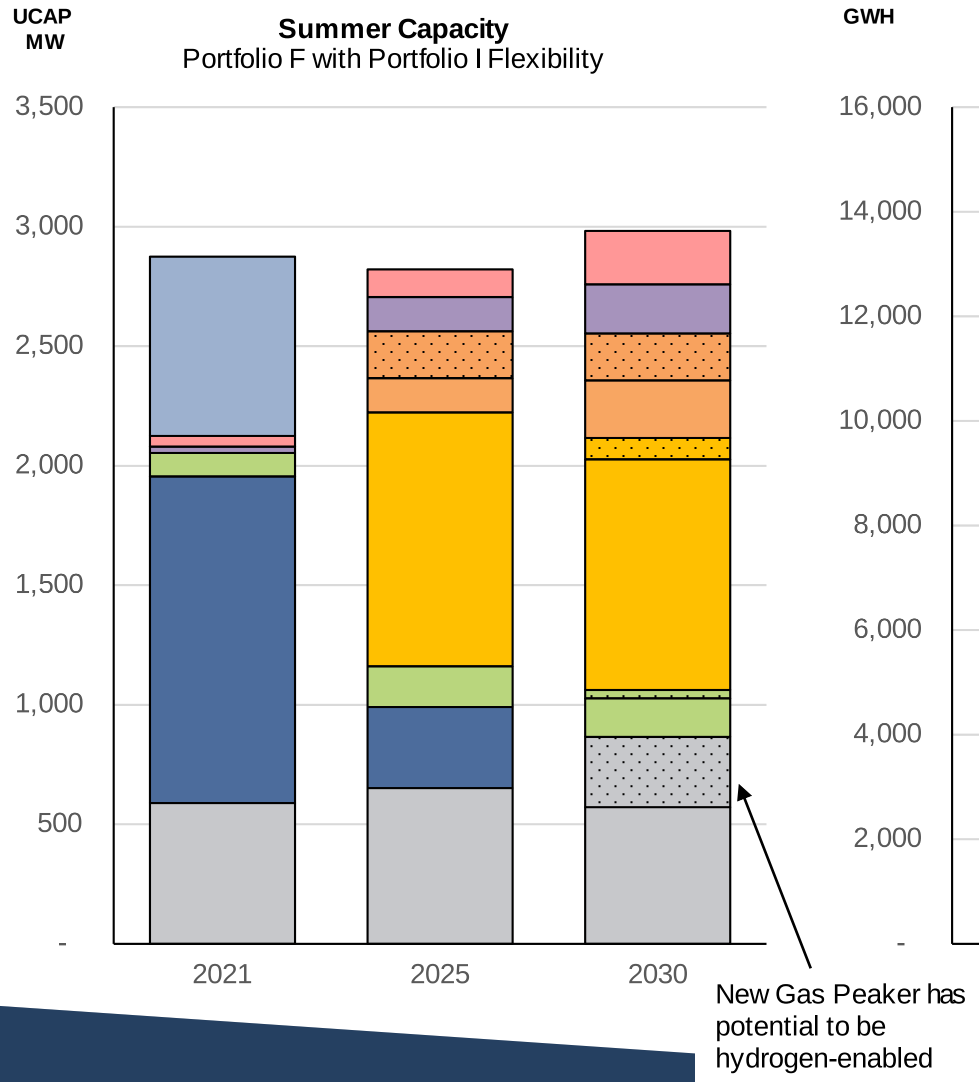
Note that storage has a net negative contribution to annual energy and reduces the size of the "Other" area in the net energy graphic

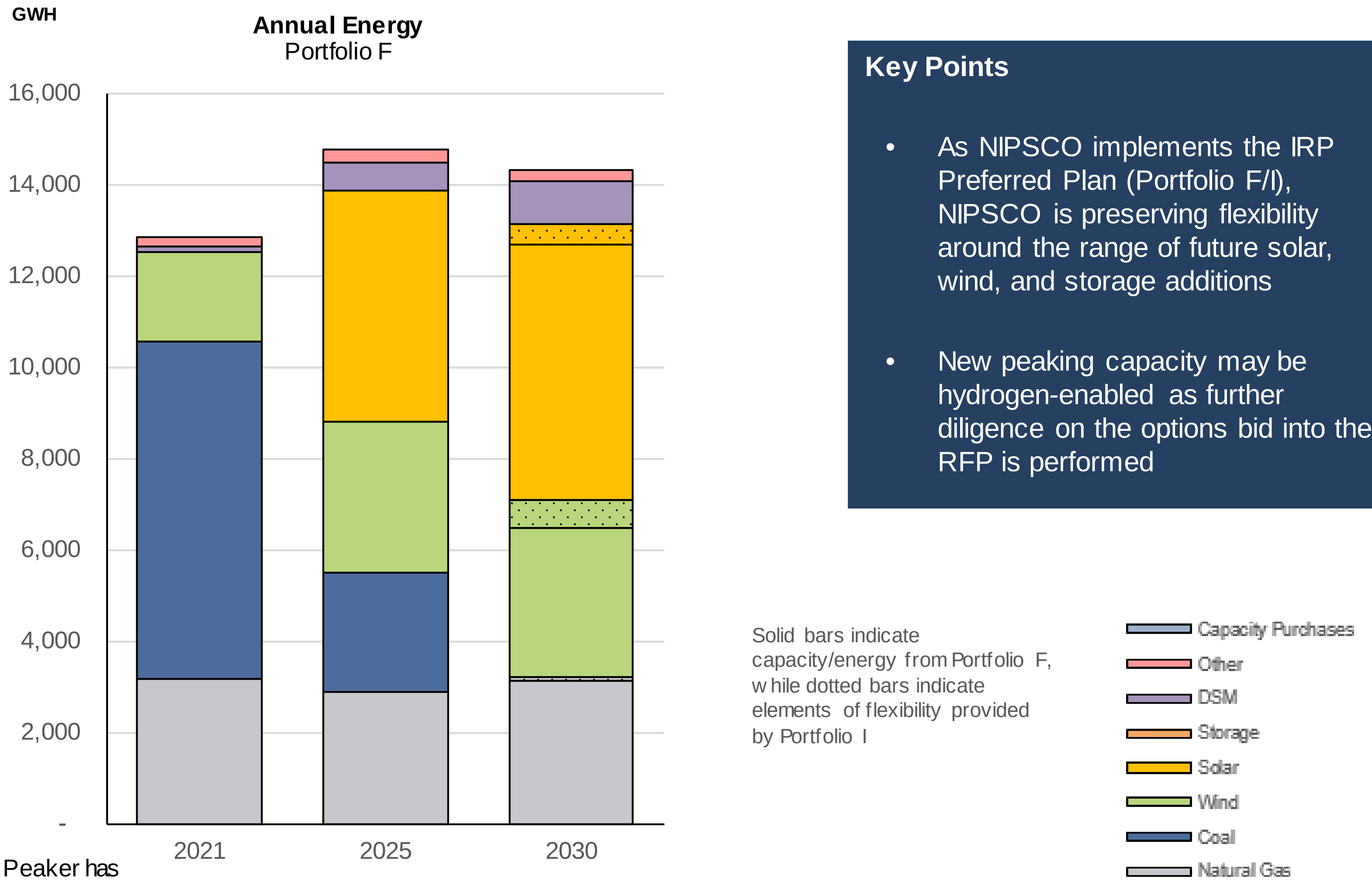
Key Points

- NIPSCO's preferred plan anticipates new capacity-advantaged resources entering into service by the middle of the decade, including storage, natural gas (SC uprate and peaking), and thermal capacity contracts
- Additional solar and new DSM programs provide additional capacity and energy benefit
- Energy from the portfolio is projected to be roughly in balance with load requirements, with flexibility around the ultimate timing of the Michigan City 12 retirement
- New storage and gas peaking resources provide limited net energy contribution on an annual basis, but support the portfolio's energy adequacy when intermittent resources are unavailable

PREFERRED PLAN PROVIDES FLEXIBILITY TO PIVOT OVER TIME

As NIPSCO implements the IRP preferred plan, there is flexibility to adjust to different resource types as market/technology/policy evolve





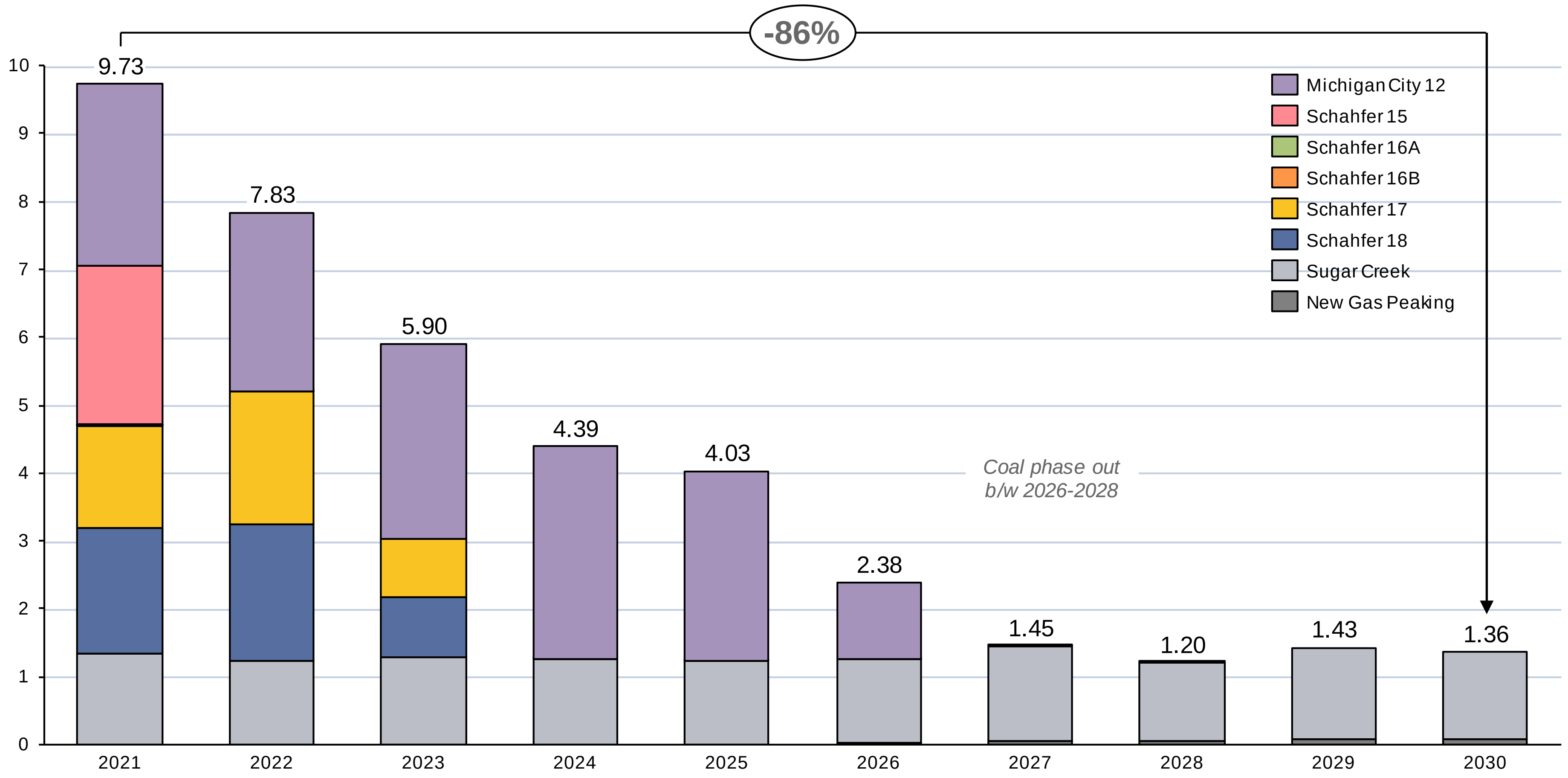
Key Points

- As NIPSCO implements the IRP Preferred Plan (Portfolio F/I), NIPSCO is preserving flexibility around the range of future solar, wind, and storage additions
- New peaking capacity may be hydrogen-enabled as further diligence on the options bid into the RFP is performed

PREFERRED PLAN CO2 EMISSIONS PROFILE

Significant emission reductions are projected by 2030, in line with NiSource overall emissions targets

Portfolio 3/F CO2 Emissions – Reference Case
Million Short Tons of CO2



Key Points

- NIPSCO's preferred plan remains on the CO2 emission reduction pathway identified in the 2018 IRP
- Emissions from coal will be phased out by the 2026-2028 time period based on the ultimate retirement date for Michigan City 12
- New gas peaking additions (modeled at 300 MW in Portfolio F) are likely to contribute emissions of around 0.05 M tons per year from 2026-2030
- The long-term emission profile is dependent on dispatch of Sugar Creek and any new peaking capacity (a product of fuel prices, environmental policy incentives, and the broader MISO market composition), as well as future potential conversion or retrofit opportunities

NIPSCO SUPPLY RESOURCE PLAN AND TIMING

	Near Term	Mid Term	Long Term
Timing	**2022-2025**	**2026-2028**	**2028 & Beyond**
NIPSCO Activity Description	• Complete and place in-service 12 remaining renewables projects filed with the IURC • Complete retirement and shutdown of remaining Schahfer coal units (17, 18) • Begin implementation of MC12-related transmission projects • Actively monitor changing federal/state policy, MISO market rules, and technology advancements • Optimize exact quantities and resource types of portfolio additions	• Full implementation of transmission projects • Retire Schahfer Units 16A/B and Michigan City Unit 12 • Secure approvals for replacement projects • Actively monitor changing federal/state policy, MISO market rules, and technology advancements • Optimize exact quantities and resource types of portfolio additions	• Identify long term pathway for future NIPSCO portfolio to achieve net-zero targets in line with current policy momentum • Monitor market and industry evolution and refine future IRP plans
Retirements	• Schahfer Units 17, 18 (by 2023)	• Schahfer Units 16A/B • Michigan City Unit 12	• N/A
Expected Capacity Additions	• ~2,845 MW*	• ~600-800 MW (ICAP)	
NIPSCO's Preferred Replacement Plan	• Demand Side Management (DSM) • NIPSCO Owned DER (up to 10 MW) • Thermal Contracts (150 MW) • Storage (135-370MW)**	• Sugar Creek Uprate (30-53 MW) • Solar (100-250 MW) • Storage (135-370MW)** • Gas Peaking (up to 300 MW) • Hydrogen Electrolyzer Pilot (20 MW)	• Solar (TBD MW) • Storage (TBD MW) • Sugar Creek Conversion • Other potential resource opportunities
Expected Regulatory Filings	• Approvals for replacement capacity contracts and pilot projects as needed • DSM Plan	• Approvals for replacement capacity resources and pilot projects as needed	• Approvals for replacement capacity projects • Future DSM Plans

*Additions also include replacement ICAP MW for approved renewables projects filed with the IURC
** Exact Storage ICAP MW to be optimized

STAKEHOLDER PRESENTATIONS

TBD

WRAP UP & NEXT STEPS

Erin Whitehead, Vice President Regulatory & Major Accounts, NIPSCO

NEXT STEPS

Seeking Feedback

- Seeking feedback regarding the plan presented today
- Reach out to Alison Becker (abecker@nisource.com) for 1x1 meetings
- NIPSCO IRP Email: nipsco_irp@nisource.com

IRP Submission

- NIPSCO will submit their 2021 IRP report to the IURC by **November 15th**
- IRP Website: www.nipsco.com/irp

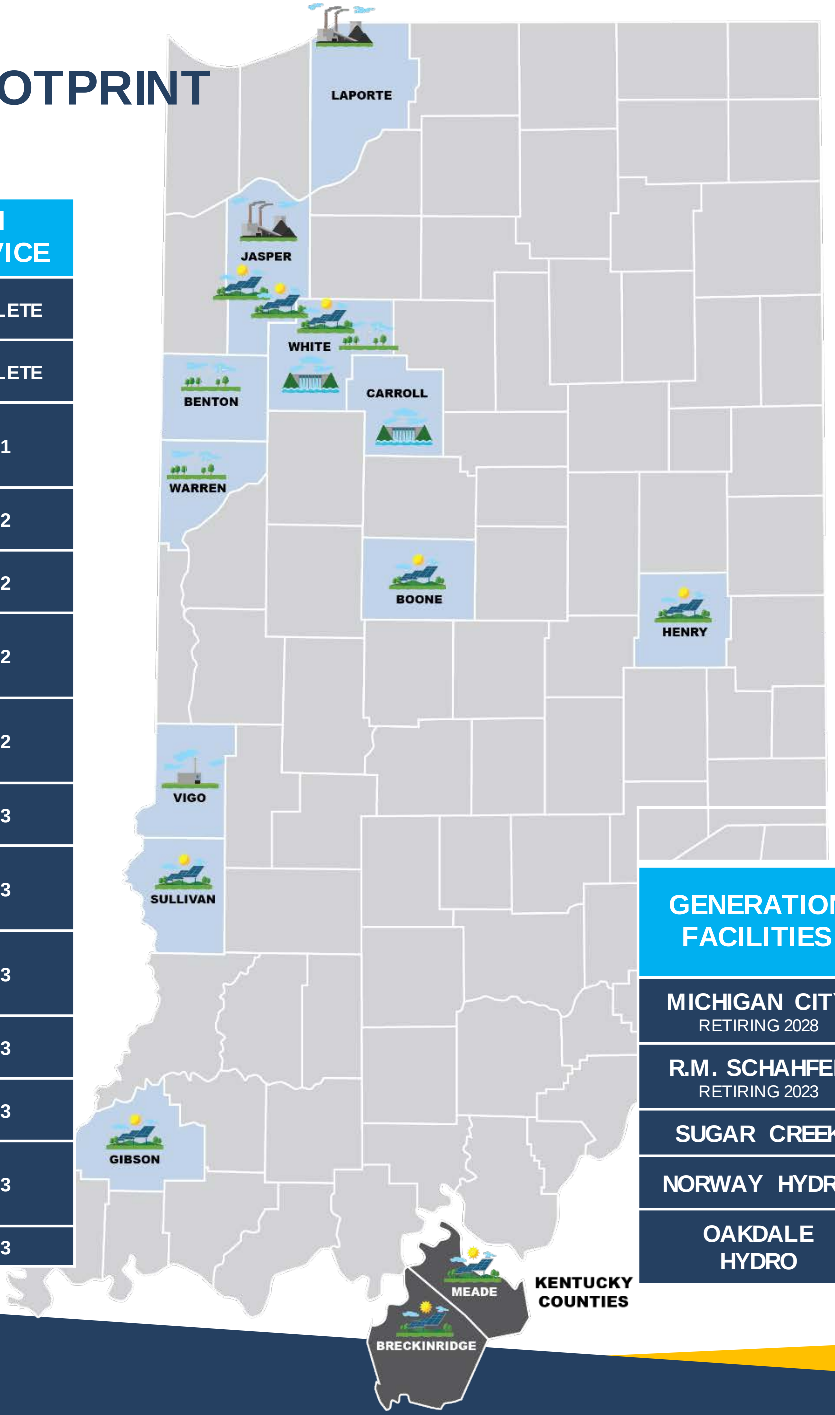
Stakeholder engagement is a critical part of the IRP process

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

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

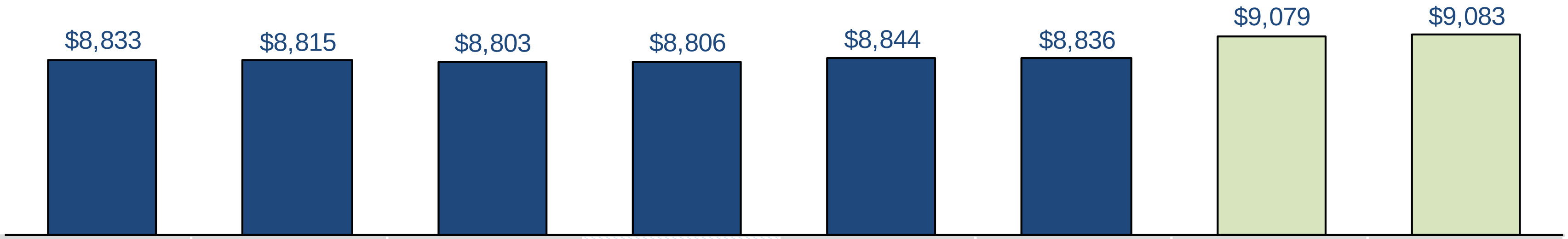
20-YEAR NPV REVIEW: EXISTING FLEET ANALYSIS: REFERENCE CASE

Sugar Creek continues to operate

Sugar Creek retires/converts in 2032

Net Present Value of Revenue Requirement

(2021-2040, $M)



Portfolio Transition Target:	**15% Coal through 2032** (1)	**15% Coal through 2028** (2)	**15% Coal through 2026** (3)	**15% Coal through 2024** (4)	**15% Coal through 2028** (5)	**15% Coal through 2026** (6)	**15% Coal through 2028 Fossil Free by 2032** (7)	**15% Coal through 2028 Option for Fossil Free by 2032** (7H)
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Rank (1=Least Cost)	4	3	1	2	6	5	7	8
Delta from Least Cost	$30M 0.3%	$12M 0.1%	-	$3M 0.0%	$41M 0.5%	$33M 0.4%	$276M 3.1%	$280M 3.2%

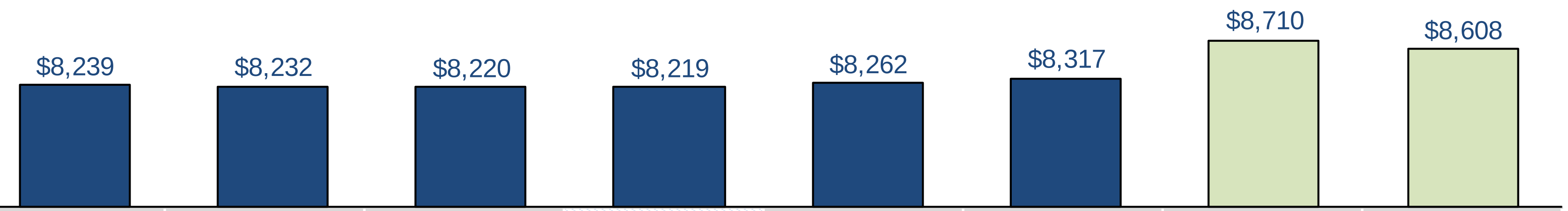
Not a viable pathway due to implementation timing

20-YEAR NPV REVIEW: EXISTING FLEET ANALYSIS: STATUS QUO EXTENDED (SQE)

Sugar Creek continues to operate

Sugar Creek retires/converts in 2032

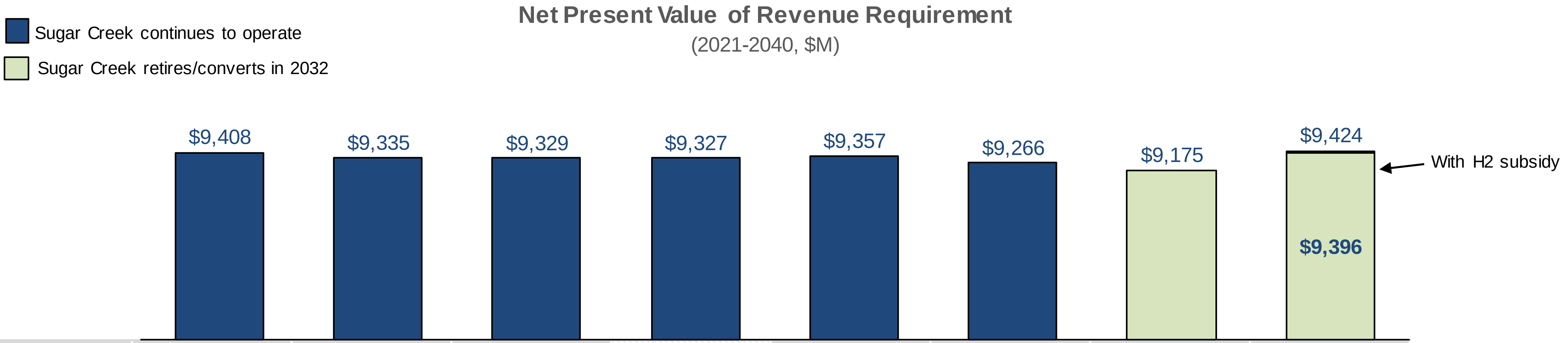
Net Present Value of Revenue Requirement
(2021-2040, $M)



Portfolio Transition Target:	**15% Coal through 2032** (1)	**15% Coal through 2028** (2)	**15% Coal through 2026** (3)	**15% Coal through 2024** (4)	**15% Coal through 2028** (5)	**15% Coal through 2026** (6)	**15% Coal through 2028 Fossil Free by 2032** (7)	**15% Coal through 2028 Option for Fossil Free by 2032** (7H)
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Rank (1=Least Cost)	4	3	2	1	5	6	8	7
Delta from Least Cost	$20M 0.2%	$13M 0.2%	$1M 0.0%	-	$43M 0.5%	$98M 1.2%	$491M 6.0%	$389M 4.7%

Not a viable pathway due to implementation timing

20-YEAR NPV REVIEW: EXISTING FLEET ANALYSIS: AGGRESSIVE ENVIRONMENTAL REGULATION (AER)

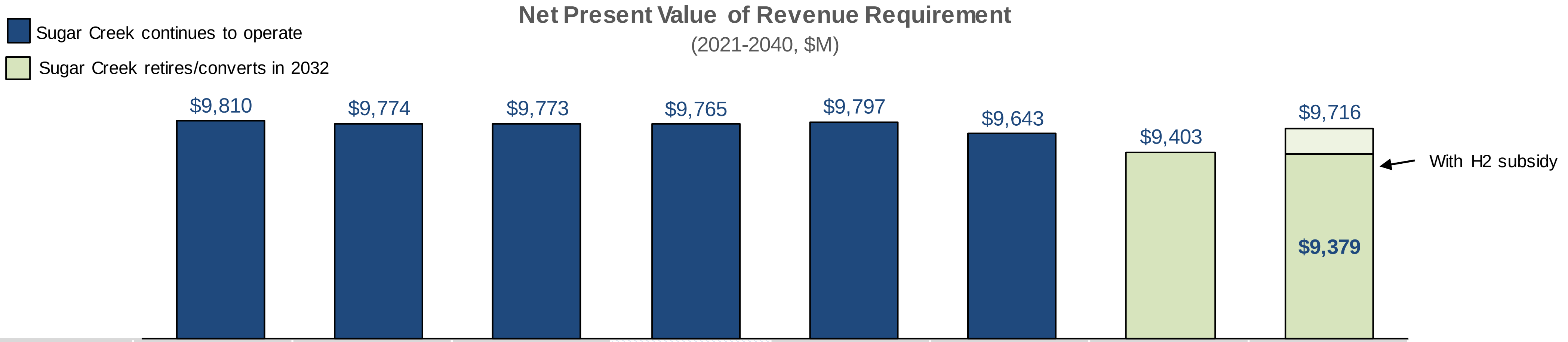


Portfolio Transition Target:	**15% Coal through 2032** 1	**15% Coal through 2028** 2	**15% Coal through 2026** 3	**15% Coal through 2024** 4	**15% Coal through 2028** 5	**15% Coal through 2026** 6	**15% Coal through 2028 Fossil Free by 2032** 7	**15% Coal through 2028 Option for Fossil Free by 2032** 7H
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Rank (1=Least Cost)	8	5	4	3	6	2	1	7
Delta from Least Cost	$233M 2.5%	$160M 1.7%	$154M 1.7%	$152M 1.7%	$182M 2.0%	$91M 1.0%	-	$221M 2.4%

Not a viable pathway due to implementation timing

*Note: Rank and Delta from Least Cost utilize 3I **with** the H2 subsidy at $0.50/kg.

20-YEAR NPV REVIEW: EXISTING FLEET ANALYSIS: ECONOMY-WIDE DECARBONIZATION (EWD)



Portfolio Transition Target:	15% Coal through 2032 (1)	15% Coal through 2028 (2)	15% Coal through 2026 (3)	15% Coal through 2024 (4)	15% Coal through 2028 (5)	15% Coal through 2026 (6)	15% Coal through 2028 Fossil Free by 2032 (7)	15% Coal through 2028 Option for Fossil Free by 2032 (7H)
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Rank (1=Least Cost)	8	6	5	4	7	3	2	1
Delta from Least Cost	$431M 4.6%	$395M 4.2%	$394 4.2%	$386M 4.1%%	$418M 4.5%%	$264M 2.8%%	$24M 0.3%%	-

Not a viable pathway due to implementation timing

*Note: Rank and Delta from Least Cost utilize 3I **with** the H2 subsidy at $0.50/kg.

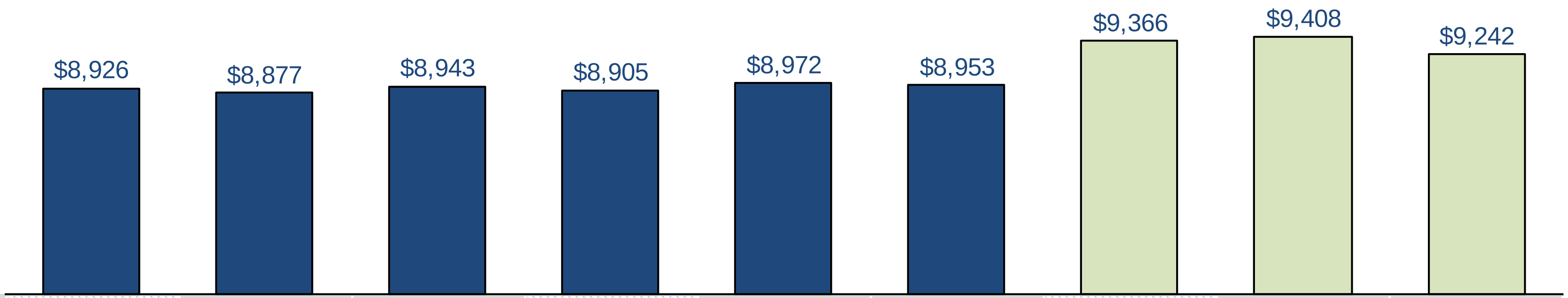
20-YEAR NPV REVIEW: REPLACEMENT ANALYSIS: REFERENCE CASE

Sugar Creek continues to operate

Sugar Creek retires/converts in 2032

Net Present Value of Revenue Requirement

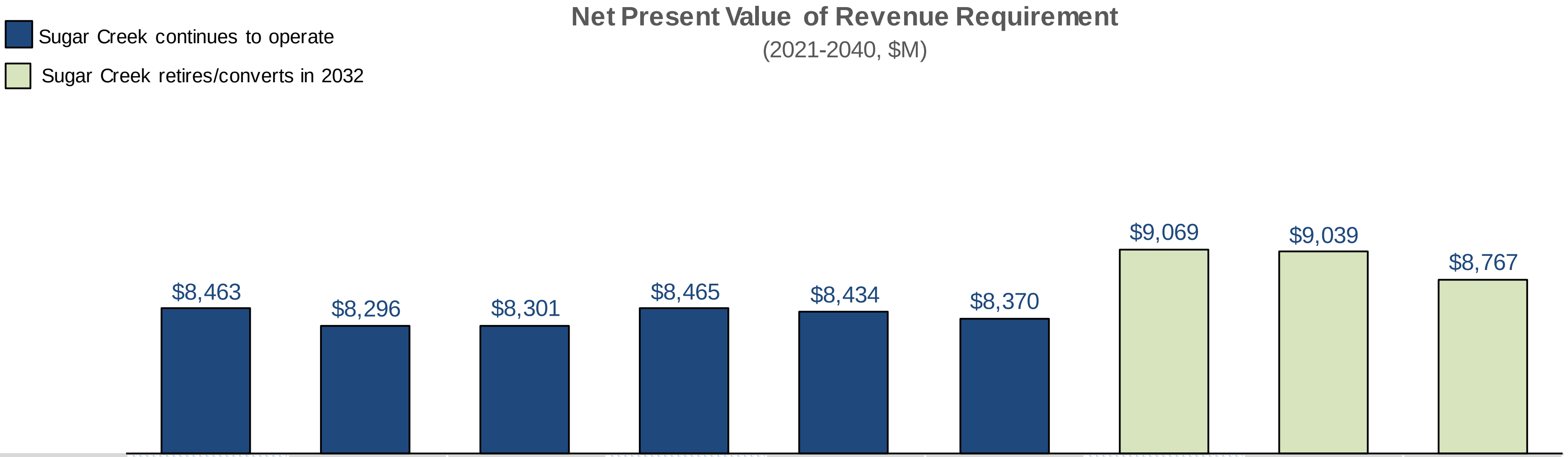
(2021-2040, $M)



Replacement Theme	A: Thermal PPAs, solar and storage	B: Non-service territory gas peaking (no early storage)	C: Natural gas dominant (CC)	D: No new thermal resources; solar dominant w/ storage	E: Thermal PPAs plus storage and solar	F: Local gas peaker, plus solar and storage	G: Solar dominant w/ storage, plus retire Sugar Creek	H: All renewables and storage, plus retire Sugar Creek (Portfolio 7)	I: New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	3	1	4	2	6	5	8	9	7
Delta from Least Cost	$49 0.6%	-	$66 0.7%	$28 0.3%	$95 1.1%	$76 0.9%	$489 5.5%	$531 6.0%	$365 4.1%

Not a viable pathway due to not meeting winter planning reserve margins

20-YEAR NPV REVIEW: REPLACEMENT ANALYSIS: STATUS QUO EXTENDED (SQE)



	A	B	C	D	E	F	G	H	I
Replacement Theme	**Thermal PPAs, solar and storage**	**Non-service territory gas peaking (no early storage)**	**Natural gas dominant (CC)**	**No new thermal resources; solar dominant w/ storage**	**Thermal PPAs plus storage and solar**	**Local gas peaker, plus solar and storage**	**Solar dominant w/ storage, plus retire Sugar Creek**	**All renewables and storage, plus retire Sugar Creek (Portfolio 7)**	**New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)**
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	5	1	2	6	4	3	9	8	7
Delta from Least Cost	$167 2.0%	-	$5 0.1%	$169 2.0%	$138 1.7%	$74 0.9%	$773 9.3%	$743 9.0%	$471 5.7%

Not a viable pathway due to not meeting winter planning reserve margins

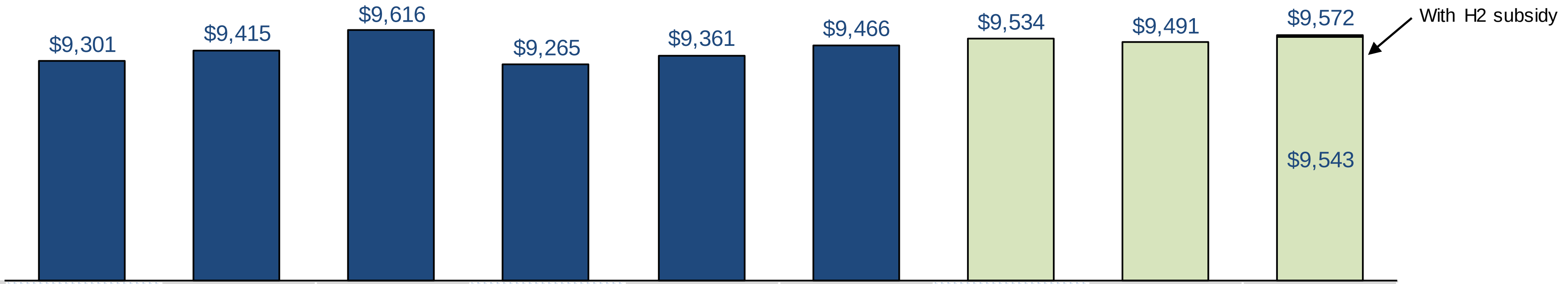
20-YEAR NPV REVIEW: REPLACEMENT ANALYSIS: AGGRESSIVE ENVIRONMENTAL REGULATION (AER)

Sugar Creek continues to operate

Sugar Creek retires/converts in 2032

Net Present Value of Revenue Requirement

(2021-2040, $M)

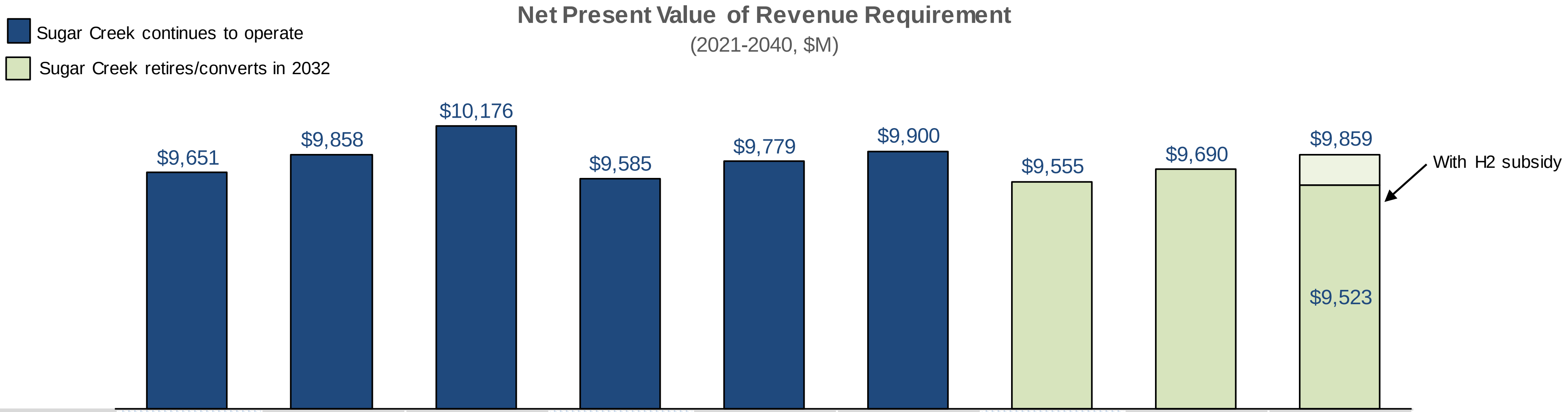


	A	B	C	D	E	F	G	H	I
Replacement Theme	**Thermal PPAs, solar and storage**	**Non-service territory gas peaking (no early storage)**	**Natural gas dominant (CC)**	**No new thermal resources; solar dominant w/ storage**	**Thermal PPAs plus storage and solar**	**Local gas peaker, plus solar and storage**	**Solar dominant w/ storage, plus retire Sugar Creek**	**All renewables and storage, plus retire Sugar Creek (Portfolio 7)**	**New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)**
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	2	4	9	1	3	5	7	6	8
Delta from Least Cost	$36 0.4%	$150 1.6%	$351 3.8%	-	$96 1.0%	$201 2.2%	$269 2.9%	$226 2.4%	$278 3.0%

Not a viable pathway due to not meeting winter planning reserve margins

*Note: Rank and Delta from Least Cost utilize 3I **with** the H2 subsidy at $0.50/kg.

20-YEAR NPV REVIEW: REPLACEMENT ANALYSIS: ECONOMY-WIDE DECARBONIZATION (EWD)



Replacement Theme	A: Thermal PPAs, solar and storage	B: Non-service territory gas peaking (no early storage)	C: Natural gas dominant (CC)	D: No new thermal resources; solar dominant w/ storage	E: Thermal PPAs plus storage and solar	F: Local gas peaker, plus solar and storage	G: Solar dominant w/ storage, plus retire Sugar Creek	H: All renewables and storage, plus retire Sugar Creek (Portfolio 7)	I: New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	4	7	9	3	6	8	2	5	1
Delta from Least Cost	$128 1.3%	$335 3.5%	$653 6.9%	$62 0.7%	$256 2.7%	$377 4.0%	$32 0.3%	$167 1.8%	-

Not a viable pathway due to not meeting winter planning reserve margins

*Note: Rank and Delta from Least Cost utilize 3I **with** the H2 subsidy at $0.50/kg.

SETTING THE CONTEXT FOR ASSESSING RELIABILITY IN THE IRP

Previous Reliability Assessments

- In the 2018 IRP, NIPSCO began including reliability risk metric in the scorecard used to evaluate the performance of various resource portfolios

2018 Retirement Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO's 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

- As part of the 2020 Portfolio Analysis to support NIPSCO renewable filings, the reliability criteria were further expanded to consider operational flexibility

2020 Portfolio Analysis

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 34 year NPV of revenue requirement (Base scenario deterministic results)
Long term Optionality	• Flexibility resulting from combinations of ownership, duration, and diversity • Metric: MW weighted duration of generation commitments
Capital Requirement	• Estimated amount of capital investment required by portfolio • Metric: 2020 -2023 capital needs
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 UCAP MW sourced from non-gas resources)
Environmental	• Carbon intensity of portfolio / Total carbon emissions • Metric: Total annual carbon emissions (2030 short tons of CO_2) from the generation portfolio
Operational Flexibility	• The ability of the portfolio to be controlled in manner to respond to changes in load (dispatchable) • Metric: % of 2025 Controllable MW in gen. portfolio

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

CORE ECONOMIC MODELING CAPTURES SOME ELEMENTS OF RELIABILITY

Additional analysis and assessment is required for a fuller perspective

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

NIPSCO coordinates with MISO (Operating Reliability)

	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 or Emergency
Reliability Factors:	Reserve margin, ELCC and energy duration	Dispatchability, energy market risk exposure	Real Time Balancing System
IRP Modeling Approach:	Portfolio development constraints, with ELCC and seasonal accounting	Hourly dispatch analysis, including stochastic risk	**Ancillary services analysis (regulation, reserves), with sub-hourly granularity**

ECONOMIC ANALYSIS ALONE DO NOT CAPTURE THE FULL VALUE OF RESOURCES

- NIPSCO participates in the Midcontinent Independent System Operator (MISO) in a variety of roles with various compliance standards and responsibilities
- These responsibilities and standards are met in part by existing resources

Role	Definition
Energy, Capacity, and Ancillary Services Market Participant	Offers resources into markets and procures services on behalf of load to ensure adequate provision of energy, capacity, and ancillary services to support system reliability
Transmission Owner (TO)	Owns and maintains transmission facilities
Transmission Operator (TOP)	Responsible for the reliability of its local transmission system, and that operates or directs the operations of the transmission facilities

- As a TOP, NIPSCO is <u>required</u> to comply with a variety of NERC standards, particularly those that govern the reliable operation of the Bulk Electric System
  - For example, EOP-005-3 governs system restoration from Black Start Resources. Part of NIPSCO's compliance plan relies on resources that currently exist within the portfolio and the NIPSCO TOP area
- Any resource decisions (retirement or replacement) will need to consider the implications for NIPSCO's ability to comply with NERC and MISO standards and procedures now and into future

An expanded scoring criteria can account for these additional considerations

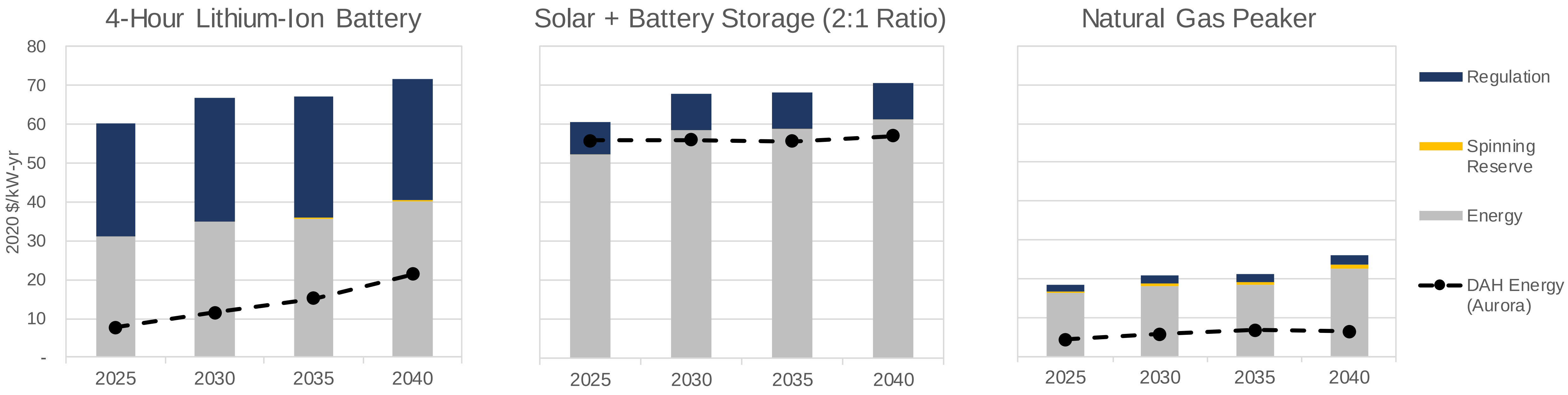
ECONOMIC ANALYSIS OF REAL-TIME MARKET DYNAMICS + ANCILLARY SERVICES

- CRA's Energy Storage Operations (ESOP) model is an optimization program that estimates the value of storage and other flexible resources in the sub-hourly energy and ancillary services (A/S) markets, offering an estimate of the incremental value such resources offer beyond what can be estimated in the day-ahead hourly production cost framework of Aurora

Category	Aurora Portfolio Tool	ESOP
Market Coverage	Day-ahead energy	Energy plus ancillary services ("A/S") (frequency regulation and spinning reserves)
Time Granularity	Hourly, chronological	5-minute intervals, chronological
Time Horizon	20 years	Sample years (ie, 2025, 2030, 2035, 2040)
Pricing Inputs	MISO-wide fundamental analyses feed NIPSCO-specific portfolio dispatch	Historical data drives real-time and A/S pricing; specific asset types dispatched against price
Asset Parameters Used	Hourly ramp rate, storage cycle and depth of dispatch limits, storage efficiency	Sub-hourly ramp rate, storage cycle and depth of discharge limits, storage efficiency
Outputs	Portfolio-wide cost of service	Incremental value for specific asset type

SUB-HOURLY ANALYSIS INDICATES POTENTIAL UPSIDE FOR STORAGE ASSETS

Reference Case



- Highly flexible battery able to respond in real time to changing price signals
- Can participate regularly in the regulation market (providing up and down service, given charging and discharging capabilities)

- Solar component provides significant energy value, which is also captured in fundamental modeling
- Investment tax credit rules limit the battery's flexibility and ability to take advantage of the regulation market (must charge predominantly from the solar)

- Real-time volatility is greater than day ahead hourly dispatch value, providing value upside compared to Aurora modeling
- Regulation opportunities are only available when the unit is already operating for energy

Northern Indiana Public Service Company LLC
2021 Integrated Resource Planning
Public Advisory Meeting #5
SUMMARY

October 21, 2021

Welcome and Introductions
Alison Becker, Manager Regulatory Policy, NIPSCO

Ms. Alison Becker, Manager, Regulatory Policy, welcomed participants to the virtual meeting and provided a safety moment on fire safety. She then discussed the Webex meeting protocols, emphasized the importance of stakeholder feedback, and walked through the agenda for the day. She then introduced Mike Hooper, President and Chief Operating Officer of NIPSCO, to kick off the meeting.

Welcome
Mike Hooper, President and COO, NIPSCO

Mr. Hooper welcomed participants and thanked them for the high level of participation and engagement. Mr. Hooper then highlighted the changing dynamics in the energy industry that are captured in the IRP: market rule changes, federal energy policy uncertainty and implications, and rapidly changing technology. Mr. Hooper then previewed NIPSCO's preferred portfolio and how it preserves the ability to adapt to expected changes in regulations, policies, and other market forces. Mr. Hooper noted that NIPSCO is well positioned to meet customers' annual energy needs with the execution of the "Your Energy, Your Future" electric generation transition plan. Mr. Hooper discussed how the 2021 preferred path provides a diverse, flexible, and scalable mix of incremental resources in the near term and direction on potential long-term solutions. He closed with an emphasis on NIPSCO's long-term strategy to provide customers with energy that is affordable, reliable, and sustainable.

Public Advisory Process and Resource Planning Activity Review
Fred Gomos, Director, Strategy and Risk Integration, NiSource

Mr. Fred Gomos began the section with an overview of NIPSCO's planning process and highlighted the Stakeholder Advisory Meeting Roadmap. He then reminded participants of the five step planning process core to NIPSCO's resource planning approach. He provided an overview of the key planning questions and themes in the 2021 IRP and reviewed the major elements of the integrated scorecard framework. He then walked through NIPSCO's process of developing external market perspectives, including the use of both scenarios and stochastic analysis to perform a robust assessment of risk. He then reviewed the major scenarios and stochastic components shared in previous stakeholder meetings. Finally, Mr. Gomos discussed the development of integrated resource strategies or portfolios, sharing NIPSCO's current capacity and energy positions on both an annual and hourly basis.

Participants had the following questions and comments, with answers provided after:

- Can you remind me what the winter wind effective load carrying capability ("ELCC") assumption was?
    - NIPSCO used a higher ELCC credit for the winter relative to the summer. Although still uncertain and subject to actual project operations, consistent with some recent MISO studies, we used 25% for winter wind capacity credit.

Existing Fleet Analysis Review
Pat Augustine, Vice President, Charles River Associates ("CRA")

Mr. Pat Augustine re-introduced the IRP's two-step analytical framework and the various reasons why the analysis is performed in two parts. Mr. Augustine presented the composition of eight existing fleet portfolios that evaluate different retirement dates for NIPSCO's remaining fossil units and then reviewed the existing fleet portfolio optimization results, including the deterministic cost to customer net present value of revenue requirement ("NPVRR") results and observations for all existing fleet portfolios. Next, Mr. Augustine summarized the results and observations across the four scenarios. He then shared the existing fleet analysis scorecard framework.

Participants had the following questions and comments, with answers provided after:

- Is the hydrogen resource zero carbon hydrogen or is it produced with fossil fuels? Commitment to green hydrogen?
    - As modeled, it is green hydrogen, meaning that it is hydrogen produced from clean renewable energy. Cost data was informed by request for proposal ("RFP") bids, including the type of upgrades that would be needed at natural gas facilities to be able to blend hydrogen with natural gas or burn hydrogen directly. Over the long term, we have modeled a cost associated with production of green hydrogen that includes electrolyzer costs, electricity costs, and other components.

Replacement Analysis
Pat Augustine, Vice President, CRA
Hisham Othman, VP, Transmission and Regulatory Consulting, Quanta Technology LLC

Mr. Augustine introduced the core questions and key decisions in the replacement analysis, the second part of the two-step IRP portfolio assessment. Mr. Augustine illustrated the expected supply-demand outlook following future resource retirements and shared the replacement concepts developed across frameworks that assess differing levels of emissions reduction and dispatchability. He explained that this framework drove the development of nine replacement portfolios, noting that resource combinations were constructed based on RFP projects. Mr. Augustine then provided an overview of the specific installed capacity additions in each of the nine portfolios, along with summer and winter supply-demand balance summaries. Mr.

Augustine presented cost to customer results and observations across each of the four scenarios. Mr. Augustine also discussed the stochastic analysis results across the nine portfolios and the changing risk profile of different resource options over time. He then shared the replacement analysis scorecard framework and described the economic and non-economic approaches to assessing reliability. He briefly reviewed the results of the economic assessment of sub-hourly ancillary services analysis that was detailed in the October 12, 2021 Technical Webinar. Mr. Augustine then introduced the non-economic assessment and introduced the guiding principles and goals of the assessment.

Mr. Augustine then introduced Mr. Othman, who reviewed feedback received during the Technical Webinar associated with the technical reliability assessment. Mr. Othman then discussed the technical reliability assessment approach and reviewed the reliability criteria, reliability metrics, thresholds, rankings, and results. He then transitioned back to Mr. Augustine who described how the reliability assessment results were incorporated into the replacement analysis scorecard.

Participants had the following questions and comments, with answers provided after:

- Pat, I had one other thought about potentially modeling representative emergency conditions. The current stochastic analysis does not vary load, but that would be really important for an extreme weather scenario. I have been mulling the idea of whether one could do regression based projections of both load and energy efficiency ("EE") performed under extreme weather, at least for the residential side. Is that something you all would entertain for next time?
    - Yes, I think so. Historically, NIPSCO has taken the view that regional load uncertainty is picked up in the power prices, and the analysis is simulating power price distributions that are associated with extreme weather events. However, when NIPSCO reliability and portfolio are viewed more granularly, there could be value in incorporating NIPSCO load uncertainty into that mix, perhaps with EE impacts, to provide a more robust view of risk. This could be done through the economic analysis or other reliability frameworks. So I think we would definitely be open to that dialogue for future enhancements.
    - This is an emerging area and NIPSCO really appreciates the sort of the thoughtfulness that you have offered with that comment and in prior one-on-one discussions. It makes a lot of sense to look at risk not only for the resource side but also the demand side as well. This might show the value of demand response and other resource attributes.
- Will the IRP more specifically articulate how you weighed the scorecard results in picking these plans? I'm curious, for example, if the reliability analysis tipped the balance towards Portfolios F and I for you?
    - NIPSCO tries not to put explicit weights behind any of these scores, because ultimately, while there are objective numbers here, when weighting it, it becomes a subjective exercise. It has been considered in the aggregate and NIPSCO has tried to balance the major objectives. Reliability is important and clearly we want to pick a portfolio that maximizes that, but economics are also important, and Portfolio F is pretty competitive relative to the other portfolios, which often have risk profiles that are disqualifying. In addition, the carbon intensity of the portfolio is also a factor, so all of those things help drive decision making. Overall, there is not one metric that overrides everything, and the decision-making process is really about driving a balance across the dimensions.

Responses to Stakeholder Feedback
Pat Augustine, Vice President, CRA

Mr. Augustine discussed stakeholder comments and responses related to two specific topics: demand side management ("DSM") and different customer cost summaries. Mr. Augustine reviewed the key DSM portfolio findings and discussed the additional DSM evaluations that were performed to assess maximum achievable potential impacts relative to realistic achievable potential levels. Mr. Augustine also reviewed 20-year NPVRRs, which were shown to be similar to the 30-year view. Finally, he summarized a sample of annual generation revenue requirements, which confirmed no significant short vs long term generation rate impact differences across portfolios that are not already present in the NPVRR summaries.

Preferred Resource Plan and Action Plan
Fred Gomos, Director, Strategy and Risk Integration, NiSource
Pat Augustine, Vice President, CRA

Mr. Gomos opened the section with a review of the preferred supply portfolio criteria. Mr. Gomos then transitioned to Mr. Augustine who highlighted the various tradeoffs in the existing fleet analysis scorecard and indicated the preferred pathways. Mr. Gomos then discussed key observations regarding the preferred existing fleet portfolios and implications for the NIPSCO fleet. Mr. Augustine then reviewed the various tradeoffs in the replacement analysis scorecard and provided an indication of the preferred pathways over both the near- and long-term. Mr. Augustine then transitioned to Mr. Gomos who discussed key observations of the preferred replacement portfolios and implications for future resources.

Mr. Gomos then summarized the key points of the preferred plan: refining the Michigan City Generating Station Unit 12 retirement date; establishing a retirement date range for Schahfer Generating Station Units 16A and B; and pursuing a diverse, flexible, scalable mix of replacement resources. Mr. Augustine then described the preferred plan's capacity and energy balance, including the elements of flexibility that could result in different mixes over time. Mr. Augustine also highlighted that the preferred plan remains on the carbon emission reduction pathway identified in the 2018 IRP. Mr. Gomos concluded the section by summarizing NIPSCO's implementation plan timing over the near-term, mid-term, and long-term, highlighting the flexible nature of the preferred pathway.

Participants had the following questions and comments, with answers provided after:

- Please explain the decision for a local build combustion turbine ("CT") plant in Portfolio F vs. thermal purchase power agreement ("PPA") in Portfolio E. Would not Portfolio F have more risk with potential natural gas price increases/carbon price and possible stranded asset risk?
    - Portfolios E and F both contain the thermal PPAs. They are short-term PPAs with attractive costs, and they help firm up the near-term capacity position. In terms of the other part of the question, as to what's driving the need for a gas peaker, the difference between Portfolio E and F for example, is really storage versus a gas peaking resource. Based on the reliability study, Portfolio F scored better, and from an emissions perspective, the peaker does not contribute much of an increase, as it only runs a limited number of hours throughout the year.
    - In terms of the risk element of that question, there are several considerations. The peaker plant in Portfolio F does not dispatch much and therefore does not expose the portfolio to significant risks associated with high gas prices or high

carbon regulations that were evident with the combined cycle in Portfolio C. On a scenario basis, Portfolio F is slightly higher cost than Portfolio E in the Economy-Wide Decarbonization ("EWD") and Aggressive Environmental Regulation ("AER") scenarios, partly due to the fact that commodity prices and carbon regulation are higher, but also due to the fact that storage investment tax credits are assumed. From the stochastic commodity and renewable risk perspective the analysis found both of these portfolios scored very similarly. While the combined cycle in Portfolio C had a lot of near-term stochastic risk associated with high commodity prices, the portfolios with a gas peaker or storage both had similar near-term risk profiles and provided similar long-term risk mitigation from a renewable output volatility perspective. So overall, there are a range of trade-offs, and it is probably not fair to say that a peaking facility substantially increases risks associated with higher carbon or gas prices.

- Is the peaker in Portfolio F likely to be outfitted with a clutch so it can be operated as a synchronous condenser?
    - Yes, and it might be addressed as the plan is implemented. One thing to note is that the IRP is picking technologies, but is not picking specific projects – that is the body of work that happens next. So there is going to be a team at NIPSCO and CRA that is going to go through all of the bids and look at all of the bidders that have been short-listed, and those are the types of evaluations to ensure that the right resources are selected to achieve the objectives outlined in the IRP.
- If a natural gas-dominant asset in NIPSCO's territory was rejected by NIPSCO, will NIPSCO re-evaluate the project if solar and batteries are added?
    - This is probably best addressed by the RFP manager. The RFP window has closed, but what NIPSCO wants to do is to continue to engage with developers and if you think that a change makes a project better, that conversation can take place in the future if that is what drove the rejection.
- What is the likely source of green hydrogen in Portfolio I?
    - From a modeling perspective, a mix of wind, solar, storage, and grid purchases at times of renewable oversupply would comprise the sources of green hydrogen. We have not specifically modeled additional wind, solar, or battery storage resources that would be devoted to electrolysis within the IRP portfolio assessment, but it has been proxied through an all-in price of hydrogen. This was done through an analysis that evaluates the optimal mix of wind, solar, storage and opportunistic grid purchases that would minimize the production costs for hydrogen on a dollar per kilogram basis or a dollar per MWh basis for use in the NIPSCO portfolio model. Going forward, there will be additional assessments required if NIPSCO were to look at large-scale hydrogen production. That would include review of specific renewable resources that would be devoted to hydrogen production; assessment of whether they may be opportunities to use some of the existing fleet's energy that might otherwise be liquidated in MISO at a low price for hydrogen production; or if there will be a larger hydrogen network where the commodity could be bought and used not only in the electric system but other parts of the broader NIPSCO gas portfolio, such as for industrial customers or other end users. So those are broader questions, but from a modeling perspective, the idea was to build up the mix of wind, solar, storage, and market purchases that would be green and come up with an all-in price of hydrogen that would be used for costing out the portfolio analysis and hydrogen plant dispatch.

- As I understand it, there are two preferred existing fleet pathways (Portfolios 3 & 5) and the replacement analysis is based on one of them (Portfolio 3). Have you looked at whether the replacement analysis would be different if it were based on Portfolio 5?
    - Not explicitly, but the optimized existing fleet portfolio mixes were nearly identical for Portfolios 3 and 5. The differences were only associated with the timing of when the gas peaking and storage capacity enters the portfolio. So the replacement analysis has not been rerun under Portfolio 5, but based on the composition of Portfolio 3 versus 5, it would be unlikely to see any difference in results. From a future execution perspective, there will be additional portfolio analysis that might be performed to confirm the ultimate retirement dates and replacement resource timings.
- Is the 300 MW CT a build-transfer unit or 2 units that NIPSCO takes title to? (Portfolio F)
    - As modeled and as based on the RFP inputs, it is a single existing unit, bid in as a build transfer.
- Back on slide 14 there is mention of the EWD scenario. This would involve a very significant load increase over the next 10 years. How does this possibility/likelihood figure into the scenarios presented here?
    - This was discussed in Stakeholder Meeting 2 with respect to potential impacts on load of electric vehicle penetration, distributed energy resources, and other electrification drivers. So that is factored into the modeling, and the analysis has shown that Portfolios I and H tend to be quite competitive from a cost to customer perspective in that state of the world.
    - From a modeling perspective, there is a higher load projection for NIPSCO in the EWD scenario, particularly in the winter season, so portfolios that have different resource mixes are going to have different market sales and purchases positions within MISO. In addition, higher load for NIPSCO means that there will be different capacity balance positions, with portfolios generally becoming shorter over time. As currently constructed, the replacement portfolios tend to exceed the minimum reserve margin requirement in the near-term, but over the long term, when demand is higher than the supply, additional market purchases are made at the prevailing capacity market price for the EWD scenario. So overall, the portfolios will have different net energy positions and different levels of long-term capacity purchases, particularly in the winter, under this scenario.
- What does 68 MW of DSM equal on an energy savings basis? Curious that same level of DSM is chosen in every portfolio. Also, did I hear you correctly earlier today that one possible missing resource/analysis is certain demand response ("DR") potential? We are interested in NIPSCO looking into third party aggregation of smaller commercial and industrial ("C&I") customers (now that Rider 775 is gone) to capture cost-effective interruptible tariff opportunities
    - It is around 500,000 MWh of new DSM savings on an energy perspective by the 2028-2030 time period. Slide 66 illustrates the different energy and capacity components. It is not very easy to see the details on the energy graphic, but the purple slice is showing DSM energy savings, and this includes both NIPSCO's filed program plus the incremental bundles that were selected. The incremental additions represent about 500,000 MWh (or about 500 GWh on this graphic) by the 2028 to 2030 time period, although once added to the filed DSM programs that are also projected, the number will be quite a bit higher in total.
    - In terms of the second comment, from a portfolio optimization and development perspective, we have evaluated whether the incremental DSM is economic relative to any other resources. It tends to look good from a cost perspective,

particularly the commercial and industrial energy efficiency bundles. The residential bundle is a little bit higher cost, but at the Tier 1 aggregation, it appears economic across the board regardless of what portfolio we evaluated.

  - With regard to the final comment, from a demand response perspective, there were a set of residential rate DR programs that came out of the GDS market potential study which are part of the preferred portfolio, but they don't come in until after 2030 or so. They also involve some other rate design and technology improvements, but from a planning cost basis, those were attractive and selected in the optimization analysis, while other DR programs were not.
  - If there are proposals, particularly associated with interruptible structures, that stakeholders have and can bring to us, NIPSCO will be happy to entertain them. The Company has struggled with making a program work for smaller C&I customers because aggregation is not very cost effective under the current Midcontinent Independent System Operator, Inc. ("MISO") construct, but NIPSCO is happy to hear about any ideas that people have or programs that have worked in other states. It will be interesting to see how MISO responds to FERC Order 2222 in the next couple of months. Some other independent system operators have come up with their respective plans and NIPSCO is looking at them now, so the Company interested in your proposals. Note that NIPSCO planned to talk about this subject as part of the October Oversight Board meeting, but the Commission's Winter Preparedness Forum was scheduled for the same day, so that topic has been moved to a later date. NIPSCO welcomes the continued input from energy efficiency parties and interested stakeholders.

- Did the rejection of the Elkhart Solar Project zoning request by the Elkhart County Commission earlier in October affect the optimism NIPSCO has about finding enough new solar capacity in the next few years?
  - The short answer is no. NIPSCO has tried to select projects that economically support our service territory first, then Indiana, and then we'll go beyond the state borders if necessary. The Company wants to site and build these projects in places where there is community benefit and the community wants the project there and wants to be a partner with us, much like the Company has over the years with other elements of our generating fleet. So to the extent that NIPSCO can continue to do that and execute that effectively, that is what the Company will lean on. There were no projects in Elkhart County, but that particular issue does not give us any concern about continuing to find viable solar projects and executing on those that are already under development.

Wrap Up and Next Steps
Erin Whitehead, Vice President, Regulatory and Major Accounts, NIPSCO

Ms. Whitehead closed the session by thanking attendees for their participation and feedback. She encouraged participants to continue to engage with feedback and invited participants to reach out for one-on-one discussions. Ms. Whitehead then closed the session confirming the plan to submit the IRP by November 15, 2021.

October 21, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Vivek	Agastya	Fortistar Capital
Shawn	Anderson	NiSource
Cynthia	Armstrong	Indiana Office of Utility Consumer Counselor
Pat	Augustine	Charles River Associates
Greg	Baacke	NIPSCO
Bipin	Balar	NIPSCO
Vernon	Beck	Nipsco
Greg	Berning	NiSource
Elizabeth	Bertke	NiSource
Bradley	Borum	Indiana Utility Regulatory Commission
Matt	Boys	GlidePath Power Solutions
Don	Bull	NIPSCO
Bryan	Burns	Nipsco
Andrew	Campbell	NIPSCO
Kelly	Carmichael	NiSource
Richard	Ciciarelli	Schonfeld
Kody	Clark	Bank of America
John	Cleaveland	NIPSCO
Steven	Cofer	cadmus
Andrew	Colvin	
Jeremy	Comeau	IURC
Alex	Cooley	NiSource
Ben	Crandall	Uplight
Kim	Cuccia	NiSource
Chanda	Durnford	Nextera Energy
Cory	Dutcher	General Electric Company - Power Division
Gregory	Ehrendreich	Midwest Energy Efficiency Alliance (MEEA)
Suzanne	Escudier	Origis Energy
Steve	Francis	SEED
Richard	Gillingham	Hoosier Energy
Benjamin	Gonin	
Doug	Gotham	State Utility Forecasting Group
Robert	Greskowiak	Invenergy LLC
Jack	Groves	ENERGY SOUTHWEST INC.
Gerardo	Guzman	McKinsey
Aida	Haigh	NiSource
Cb	Hall	Energy Futures Group
Joni	Hamson	EDF Renewables
Sean	He	Verition Fund Management
Robert	Heidorn	NiSource
John	Hejkal	Tenaska, Inc.
Jaime	Holland	NextEra
Chelsea	Hotaling	Energy Futures Group
Jim	Hummel	Duke Energy
Jim	Huston	Indiana Utility Regulatory Commission

October 21, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Ben	Inskeep	EQ Research
Kelsie	Johnson	ranger power
Michelle	Kang	Charles River Associates
Will	Kenworthy	Vote Solar
Nick	Kessler	CenterPoint Energy
Mo	Klefeker	Primary Energy
Brian	Kortum	NiSource, Inc.
Reagan	Kurtz	Citizens Action Coalition of Indiana
Natalie	Ladd	NiSource
Tim	Lasocki	Orion Renewable Energy Group LLC
Bryan	Likins	NIPSCO
Jeff	Loewe	
Jeff	Loewe	NiSource
James	Loewen	Everspring Energy
Caleb	Loveman	Indiana Office of Utility Consumer Counselor
Wendy	Lussier	NIPSCO
Zach	Manheimer	
Jamie	Mante	nipsco
Gregory	Martin	BP
Clyde	Mason Jr	Unity Electric Discount, LLC
Shelly-Ann	Maye	
Michael	Melvin	NIPSCO
Ilse	Miles	Nipsco
Earl	Miller	Hiler Industries
Erik	Miller	AES
Mike	Mooney	Hoosier Energy
Danny	Musher	Key Capture Energy
David	Nderitu	SUFG
Kerwin	Olson	Citizens Action Coalition of IN
Hisham	Othman	Quanta Technology LLC
Bob	Pauley	IURC
Tim	Phillips	State Utility Forecasting Group
Rockey	Pollard	NiSource, Inc.
Brett	Radulvoich	NiSource
Jeff	Reed	Indiana Office of Utility Consumer Counselor
Greg	Reiss	
Adam	Rickel	NextEra Energy Resources
Robert	Ridge	NIPSCO
Tonya	Rine	CenterPoint Energy
Rosalva	Robles	NIPSCO
Stephen	Rodocanachi	Hartree Partners
Roland	Rosario	CenterPoint Energy
John	Sabotnik	NIPSCO
Kurt	Sangster	NIPSCO / NiSource
Jamalyn	Sarver	Hallador Energy Company

October 21, 2021 NIPSCO Public Advisory Process Meeting Registrations		
First Name:	Last Name:	Company:
Cliff	SCott	NIPSCO
Robert	Sears	NIPSCO
Rob	Seren	NIPSCO
Casey	Shull	OUCC
Anna	Sommer	EFG
Daniel	Spellman	Orion Renewable Energy Group LLC
Jennifer	Staciwa	NIPSCO
Karl	Stanley	NiSource
Sarah	Steinberg	Advanced Energy Economy
Ron	Talbot	NIPSCO
Dale	Thomas	IURC
Dan	Traynor	PPMS, LLC.
LaTonya	Troutman	NAACP
Maureen B	Turman	NiSource
Chris	Turnure	NiSource
Edward	Twarok	NiSource
Gregory	Van Horssen	Van Horssen Law & Government, PLLC
Chris	Vickery	
Jennifer	Wagner	
Jennifer	Washburn	CAC
Keith	Weber	NiSource
Michael	Weisenburger	NiSource
Amanda	Wells	Duke Energy
Erin	Whitehead	NIPSCO
Ryan	Wilhelmus	CenterPoint Energy
Scott	Yaeger	Southern Illinois Generation Company
Monica	Yocum	NIPSCO

BOSE McKINNEY & EVANS LLP

ATTORNEYS AT LAW

Jeffery A. Earl
Of Counsel
Direct Dial: (317) 684-5207
Fax: (317) 223-0207
E-Mail: JEarl@boselaw.com

October 1, 2021

Via electronic mail only

Alison Becker
Manager Regulatory Policy
Northern Indiana Public Service Company
abecker@nisource.com

RE: Reliable Energy comments on NIPSCO IPR modeling.

Dear Alison,

Reliable Energy (RE), through its representatives, attended the most recent IRP forum. While a number of the following questions were raised during the meeting, RE feels it is important to document its concerns in writing. We would be happy to make our representatives available for one-on-one follow-up discussions if NIPSCO desires to continue this conversation.

1. NIPSCO identified five metrics that will use to evaluate the scenarios. While RE has no concerns about the objectives of the metrics, RE does have concerns about the way that NIPSCO plans to measure the metrics.

a. Affordability measures the impact to customer bills. NIPSCO and Charles River Associates (CRA) acknowledged at the last session that a 30-year net present value (NPV) of revenue requirements is not a measure of the impact on customer bills. An NPV is based on levelized costs over the entire 30-year period, but customer rates fluctuate from year to year. Scenarios may, and likely do, exist with high revenue requirements in the earlier years but lower total NPVs because of assumed lower revenue requirements in the later years. Conversely, a scenario with higher total NPVs may have low revenue requirements in the short term and higher assumed revenue requirements in later years. For affordability to be a criterion, efforts must be made to actually evaluate customer rate impacts and to focus specifically on the short- to mid-term revenue requirements of a scenario. Allowing long-term, assumed revenue requirements to drive the NPV calculation does not properly reflect the rapidly changing nature of the energy generation and consumption markets. Duke Energy Indiana has included a specific rate impact metric in its current IRP in addition to an NPV metric in recognition that these two metrics are different and distinct. We would hope that NIPSCO would do the same.

BOSE
McKINNEY
& EVANS LLP
ATTORNEYS AT LAW

RE agrees with NIPSCO that rate impact analysis is complex. RE disagrees that the complexity justifies the exclusion of a rate impact analysis. RE suggests the focus of an affordability metric should be residential customer rates and that the following should be included:

- All costs for any retired plants that NIPSCO expects to recover, including both undepreciated capital costs and ongoing operations and maintenance costs imbedded in NIPSCO's base rates until its next rate case.

- New fossil assets (including the Sugar Creek uprate) should be depreciated over a shorter period consistent with House Enrolled Act No. 1191 in the cases which assume Aggressive Environmental Regulation and Economy Wide Decarbonization.

b. Rate Stability measures cost certainty, cost risk, and lower cost opportunity. RE questions whether the methodology being used is consistent with actually identifying cost certainty, cost risk, and lower cost opportunity.

c. Environmental Sustainability simply measures carbon emissions based on the sum of carbon emissions from the generation profile. While the downstream emissions (i.e., power plant emissions) are important, the upstream emissions (i.e., production and transportation emissions) are not insignificant and should be considered. Further, the metric should not simply measure carbon emissions but should also measure other greenhouse gasses, including methane, nitrous oxide, and fluorinated gasses, on a carbon-dioxide-equivalent (CO_2e) basis. This is especially true if the goal of environmental stability is to ease the effects of climate change because these gasses may have an order of magnitude higher climate impact in the short term compared to carbon emissions. We direct you to the National Energy Technology Laboratory, which has modeling tools available to compute the upstream greenhouse gas emissions.

d. Reliable, Flexible, and Resilient Supply measures reliability and resource optionality. NIPSCO indicated in the deck it is still working on this metric, which is understandable since absent fuel inventory and extensive battery storage the system, which relies heavily on new renewable generation assets and purchased power, will likely be far from reliable. Resource optionality according to the deck is based on 2027 MW weighted UCAP commitments. At a minimum, resource optionality needs to show weighted UCAP commitments not just for 2027 but also 2030, 2035, and 2040. As discussed further below, extended terms on PPAs significantly reduce resource optionality unless the PPAs contain termination options.

BOSE
McKINNEY
& EVANS LLP
ATTORNEYS AT LAW

e. Positive Social and Economic Benefits considers employment and the local economy. The employment portion is based on "new" employment with no apparent consideration of lost employment due to closed generation facilities and the loss of generation-fuel-related jobs. The economy measurement uses the NPV of property taxes, but it is not clear how the property taxes are estimated.

2. NIPSCO continues to rely heavily on 30-year NPVs. As noted above, this is not a replacement or proxy for customer rate impacts, which NIPSCO has acknowledged. It also not appropriate for any evaluation in the context of how NIPSCO is considering replacement resources.

NIPSCO indicated it is limiting consideration of resources in its 30-year analysis to the resources bid in response to the RFP. When asked specifically, for example, about Small Modular Nuclear Reactors (SMRs), NIPSCO responded SMRs were not considered because no one had submitted a bid for SMRs. Eliminating a potential resource option is not appropriate for any long-term forecast, but especially not for an economic analysis that ostensibly continues for 30 years in the midst of a period of rapid technological change. Further, the IRP does not recognize that certain resources are not appropriately acquired through an RFP. The unknowns and the unconsidered sources are too great to allow a 30-year plan (which is not really a plan at all) to be the basis of decision-making. If NIPSCO continues to use NPVs as part of its economic analysis, the metric should be 20 years, which, as NIPSCO confirmed, is the industry standard. In addition, the NPV should be provided in five-year increments, i.e., first five years, first 10 years, etc.

3. The recent volatility in natural gas prices could be a predictor of future price volatility once significant amounts of coal capacity are retired. RE believes that the modeling to date does not capture the magnitude of this volatility. Multiple high-fuel/high-energy-price crises in the past two years have demonstrated that this is not a hypothetical possibility—it is an actuality, especially in bulk energy systems that rely heavily on renewable energy resources with natural gas baseload support. NIPSCO should re-evaluate how to reflect the potential for extreme volatility in its modeling.

4. Power Purchase Agreements (PPAs) with a term beyond 10 years pose a significant risk to ratepayers. Buyouts of PPAs are listed as the third-largest use of securitization in the power sector.[1] This is because parties that entered into PPAs without pre-negotiated termination options could be left with a non-economic source of generation with a mandatory extended term. NIPSCO

[1] https://saberpartners.com/wp-content/uploads/2019/05/Fichera-NARUC-Electricity-Comm-5-17-19-for-Printing-Indexed.pdf, page 4.

BOSE
McKINNEY
& EVANS LLP
ATTORNEYS AT LAW

should be encouraged to negotiate termination options even if the base term is at a higher cost recognizing the termination option would only be exercised if the power is no longer economic. This would be consistent with the comment of Fred Gomos, namely "the importance of flexibility cannot be understated."

5. The assumed purchased power agreements (PPAs) should be structured as leases so as not to have an adverse balance sheet impact and therefore require no debt equivalency payments.

Thank you for the opportunity to provide comments on the IRP that is under development. Reliable Energy is pleased to discuss these comments at your convenience should you have any questions or require additional explanation.

All the best,

Jeffery A. Earl

111 Monument Circle, Suite 2700 | Indianapolis, Indiana 46204 | (317) 684-5000 | (317) 684-5173 (fax) | www.boselaw.com

NIPSCO Response to Reliable Energy ("RE") Letter on IRP Modeling Dated October 1, 2021

General Response

Thank you for your thoughtful letter. NIPSCO appreciates RE's participation in the 2021 Integrated Resource Plan ("IRP"), both through attending the Public Advisory Process/ Stakeholder meetings and in putting these thoughts on paper for NIPSCO's consideration. NIPSCO has taken this feedback into account when finalizing the preferred plan as well as the report that will be submitted to the Indiana Utility Regulatory Commission ("IURC" or "Commission") by November 15, 2021. NIPSCO welcomes further discussion on these, or any other, issues with you before the report is submitted or while it is undergoing review.

Response to Comment 1

A. NIPSCO's affordability metric is based on the net present value of full generation revenue requirements. While NIPSCO's core scorecard metric should cover a long-term period to assess the full impacts of resource additions that may enter the portfolio over the next few years, RE's comments about reviewing shorter term cost impacts have merit. As noted in the September 21 Stakeholder Meeting, NIPSCO reviewed 20-year net present values (""NPVs") (RE's preferred metric) as part of its process and found broad consistency with all portfolio conclusions (with the exception of Portfolio C in the Replacement Analysis, which NIPSCO commented on in the meeting). For your reference, please find a summary of all 20-year NPVs attached, which is also included as part of the content for the Stakeholder Meeting on October 21. In addition, NIPSCO is also providing a summary of annual revenue requirement details in Excel format, consistent with those provided in the 2018 IRP process. Additional information regarding revenue requirement components will be included in the detailed appendix that will be submitted with NIPSCO's IRP.

   The net present value revenue requirement ("NPVRR") is an appropriate metric to assess the relative cost differences between different portfolio strategies. In the IURC Director's Report for the

2018 NIPSCO IRP[1], the Director provided the following response to a comment provided by the Indiana Coal Council ("ICC") regarding the use of the NPVRR metric:

ICC Comment in Blue

NIPSCO failed to consider customer rate impacts despite the IURC's requirement that the IRPs describe how the utility plans to deliver safe, reliable, and efficient electricity at just and reasonable rates." A NPV comparison is not a proxy for rate analysis. "NIPSCO should prepare an annual rate analysis for residential customers under all scenarios as part of the IRP. (Page 1 and 2 of ICC Comments)

Director's Response in (Italics):

The Director thinks that NIPSCO's calculation of projected annual revenue requirements for all scenarios and portfolios within the IRP provides a reasonable indicator of future rate levels. The purpose of a long-term resource optimization process is to compare the relative economics of different resource portfolios over many years. NPVRR is the standard industry tool to appropriately make such a comparison when combined with consideration of other characteristics that are important to resource decisions such as risks and uncertainty. The Director also disagrees with the ICC's request for NIPSCO to conduct an annual rate analysis because it is not clear what ICC means. It is possible to estimate at a high level indicative average class (residential, commercial, and industrial) rates but more specificity is problematic for reasons noted below. IRPs typically develop equations where the objective function is to minimize the NPVRR and NIPSCO's analysis addresses NPVRR and other metrics. The Director also agrees with NIPSCO that, to the best of our knowledge, the use of NPVRR as a metric was not challenged by the ICC throughout the stakeholder process. Moreover, as noted by the CAC Joint Commenters (Page 28 of Reply Comments), the algorithms that would be necessary to integrate into the IRP models to project future rates are difficult to design; especially since cost of service studies and resulting rate designs are very transitory and subject to rate cases that may produce unexpected outcomes. Even for a utility that anticipates little change in infrastructure or other costs, it is difficult to meaningfully speculate on rate design over a 20 year planning horizon. By way of examples, it is difficult to speculate on the type of rate designs that might be offered to increase energy efficiency, demand response, and DERs. For utilities, like NIPSCO, that anticipate significant changes to their infrastructure, requiring

[1] Pg.41 IURC Final Director's Report for NIPSCO 2018 Integrated Resource Plan, February 10, 2020 https://www.in.gov/iurc/files/NIPSCOs-2018-FINAL-Directors-Report-12-10-2020-1131.pdf

annual rate analysis would be extraordinarily difficult, time consuming, costly and with little merit.

NIPSCO's revenue requirement analysis already incorporates all undepreciated capital expenses associated with the coal plants consistently across all portfolios. NIPSCO assumes that each unit continues to depreciate at the same rate of 3.88% until 2033, regardless of whether the unit is retired or not. This means that each retirement portfolio has the same depreciation schedule for existing capital. Incremental fixed operations and maintenance costs that are not part of base rates are operating expenses that vary dependent on retirement date.

NIPSCO's Aggressive Environmental Regulation ("AER") and Economy-Wide Decarbonization ("EWD") scenarios do not contemplate federal phase-out of combined cycle technology, so new investment in Sugar Creek Generating Station ("Sugar Creek") should not be depreciated over a shorter life. In fact, at the Midcontinent Independent System Operator, Inc. ("MISO") market level, the scenarios incorporate potential conversion of existing natural gas capacity to use hydrogen or implement carbon capture, utilization, and storage ("CCUS") to reduce carbon emissions (See Slide 45 from NIPSCO's May 20 Stakeholder Meeting), and NIPSCO's Sugar Creek facility may be able to deploy such technology over the long-term, meaning that the plant is not necessarily an early retirement candidate in the AER and EWD scenarios. Furthermore, in portfolios where an early retirement of the plant in 2032 was modeled (Portfolio 7 and Portfolios G and H), the uprate was not an eligible resource addition. See slides 26 and 38 from the September 21 Stakeholder Meeting for additional detail regarding the composition of the various portfolios NIPSCO has evaluated. NIPSCO will continue to monitor state legislative activities, including the impacts of House Enrolled Act No. 1191, as federal policy debates continue.

B. NIPSCO's rate stability metrics have been developed across two distinct approaches for risk: scenario and stochastic analysis. This allows for a comprehensive review of different perspectives for risk, certainty, and lower cost opportunity, directly in response to stakeholder and Director's Report feedback to the 2018 IRP. Please see slides 29 and 48 from the September 21 Stakeholder Meeting for more detail on the metric definition and are open to additional feedback on other means of measuring stability.

C. Thank you for this comment. NIPSCO will continue to assess lifecycle emissions from its operating businesses as part of its efforts at the NiSource corporate level. For the 2021 IRP, NIPSCO's core metric remains scope 1 emissions from power plants, but we appreciate this perspective as the Company takes a broader review of its emissions profile. NIPSCO believes the lifecycle emissions should be evaluated for all generation resources and technologies including natural gas, coal, wind and solar amongst others.

D. Given NIPSCO's focus on developing a short-term action plan from this IRP, 2027 was selected as the most appropriate year for this metric. NIPSCO does not expect the 2021 IRP to lock in a generation portfolio that will remain unchanged over the next 30 years (see more detail in the response to Comment 2 below), so the 2027 time period is most significant as a measure of flexibility directly following the implementation of key near-term portfolio decisions that may result from the 2021 IRP. NIPSCO did evaluate the optionality metric over the full time horizon and did not find material differences in outcomes relative to what was reported for the 2027 value. Therefore, we remain confident that 2027 is the right year to use on the scorecard, although the Company agrees with the spirit of RE's comments, since flexibility over time is important.

NIPSCO also appreciates RE's comments acknowledging the complexity of reliability planning within the context of the IRP, particularly in the midst of an industry wide transition. As NIPSCO noted in the May 20 Stakeholder Meeting (slide 16), the transition will require ongoing enhancements to modeling approaches and new performance metrics for portfolio evaluation. Furthermore, it was also noted that, as a member of the (MISO organization, NIPSCO is not independently responsible for all elements of reliability planning but must coordinated with MISO and be prepared to meet changing market rules and standards.

To that end, the NIPSCO IRP has anchored its understanding of reliability around various MISO initiatives addressing multiple facets of reliability, including Effective Load Carrying Capability, Resource Availability and Need – Seasonal Capacity Construct, and the Renewable Integration Impact Assessment. Please see the May 21 Stakeholder Meeting slides (slides 15-24) for the discussion on the various MISO initiatives and implications for the NIPSCO IRP. Additionally, in the

NIPSCO
A NiSource Company

July 13 Stakeholder Meeting, NIPSCO introduced its comprehensive approach for assessing reliable, flexible and resilient supply measures in this IRP. This approach included both economic analysis of real time market dynamics, primarily through granular sub-hourly energy and ancillary services evaluation, and a qualitative technical reliability assessment. NIPSCO engaged Quanta Technology to conduct an independent assessment of the candidate portfolios across the assessment criteria. A technical workshop with stakeholders was held on October 12, 2021 where both studies were discussed in detail. NIPSCO is interested in any feedback RE may have regarding the analysis and the approach.

NIPSCO agrees that resources that have onsite fuel supply or firm supply commitments could provide a facet of resilience to the energy system. However, NIPSCO does not believe that a narrow and simplistic construct like onsite fuel supplies should be the measure by which we determine if the system is reliable or not. Abroad approach is warranted, given the complexity and dynamic nature of reliability and resilience planning.

As the Federal Energy Regulatory Commission ("FERC") stated[2] in its unanimous rejection of the 2018 U.S. Department of Energy Proposed Rule on Grid Reliability and Resilience Pricing, "Although the Proposed Rule focuses on one possible aspect of grid resilience – secure onsite fuel – we conclude that a proper evaluation of grid resilience should not be limited to that single issue, and should instead encompass a broader consideration of resilience issues, including wholesale electric market rules, planning and coordination, and NERC standards. Indeed, the efforts of RTOs and ISOs on grid resilience encompass a range of activities, including wholesale electric market design, transmission planning, mandatory reliability standards, emergency action plan development, inventory management, and routine system maintenance."

E. As discussed in the September 21 Stakeholder Meeting (and defined on slide 29 and presented on slide 30), lost employment at existing generation facilities is already the primary metric used in the Existing Fleet phase of NIPSCO's portfolio analysis. The impact on fuel-related jobs or other non-NiSource employment associated with supply chains for any resource type are not reported in the IRP.

[2] Pg. 11 FERC Grid Reliability and Resilience Pricing and Grid Resilience in Regional Transmission Organizations and Independent System Operators Docket Nos. RM18-1-000 and AD18-7-000 (issued January 8, 2018)

Similar to what was done in the 2018 IRP, property taxes are approximated as 2% of the book value of a generation asset. NIPSCO assumes that property tax will not be collected on the remaining net book value of the plant if it is retired.

Response to Comment 2

A. In the September stakeholder meeting, NIPSCO did not confirm that 20 years is industry standard for net present value analysis. In fact, NIPSCO stated the opposite, suggesting that the industry uses a variety of time horizons, with some utilities and regulatory jurisdictions requiring NPV analysis even longer than 30 years. The IURC Director's Report on the 2018 NIPSCO IRP stated the following in response to a stakeholder (ICARE) comments regarding the use of the 30-year planning Horizon

> ICARE was concerned about NIPSCO's use of a 30-year planning horizon as being too long and inconsistent with the IRP rule.
>
> *Director's Response: The Director appreciates ICARE's confusion about going beyond the IRP's required 20-year planning horizon. The Director agrees with NIPSCO's explanation discussed below:*
>
> *"[T]he use of a 30-year NPVRR is used to account for the life of assets that are depreciated over a long time horizon. As is standard practice in utility resource planning, "end-effects" extrapolations like this are often performed to extend the analysis time period in order to account for the value of long-lived assets and the relative difference in portfolio costs that have developed after 20 years of fundamental modeling." (Citation needed)*
>
> *The Director would also observe that ignoring end-effects could bias the decision against capital intensive facilities. That is, long-term resource planning models may not select a capital intensive resource near the later years of a 20-year planning horizon.*

Notwithstanding, NIPSCO agrees with RE that time periods other than just 30 years can be reviewed as part of the IRP process, as NIPSCO has done. See responses to Comment 1A for additional detail.

As communicated in the September 21 Stakeholder Meeting, NIPSCO's preferred portfolio from the 2021 IRP will not lock in a generation portfolio for the next 30 years. In fact, the purpose of

NIPSCO
A NiSource Company

continuous planning and triennial IRP updates is to allow for a process that can revisit market conditions on a regular basis and react accordingly. That is why flexibility is a guiding principle for NIPSCO. For example, after NIPSCO's 2018 IRP, it performed a 2020 portfolio analysis update which suggested that the value of storage technology (based on pending market rules changes and bids to its Phase II requests for proposals, or "RFPs") was greater than originally identified in the 2018 IRP, and NIPSCO pivoted to incorporate more paired solar plus storage capacity in its recent CPCN applications. In addition, the 2021 IRP is adjusting and refining the preferred replacement resources for the Michigan City Generating Station retirement relative to what was identified in the 2018 IRP in light of MISO market rules changes, technology evolution, and other power market trends. As a result, the 2021 IRP is finding increased value for storage, gas peaking technology, and distributed energy resources, and the preferred portfolio is likely to pivot in that direction. Similarly, although NIPSCO has laid out multiple long-term portfolio options associated with replacement or retrofit of the Sugar Creek combined cycle in the 2030s, a firm decision is not being made as part of this IRP.

NIPSCO's IRP report will review several emerging technology options, even though there is currently insufficient cost and operational performance information to model them with sufficient precision. These include small modular reactors ("SMRs"), CCUS, and long-duration storage, with additional detail on hydrogen provided above and beyond RFP bids. With respect to SMR, NIPSCO is open to receiving additional information on the technology for further analysis. While RFP bidders offered firm or indicative bid information for certain options like hydrogen and long-duration storage, no information was provided for SMR, even though outreach was conducted to a primary developer in this space. However, NIPSCO will continue to track demonstration project progress in the SMR area and will continue to solicit information for all technologies in future IRP and RFP analyses.

<u>Response to Comment 3</u>

While recent volatility in natural gas prices is a product of many factors (rapid economic growth after the severe impacts of the COVID pandemic, production limitations due to maintenance and workforce restrictions in certain global producing regions, drilling discipline in key North American basins, and weather events that have impacted renewable generation), NIPSCO agrees that natural gas volatility is a key market uncertainty that requires careful evaluation in the IRP. This is why NIPSCO has once again evaluated natural gas volatility through its stochastic analysis in the 2021 IRP. As part of this analysis, daily gas price paths are simulated across 500 iterations that then evaluated in the IRP dispatch and revenue requirement modeling to develop distributions of customer cost outcomes. NIPSCO also enhanced its stochastic modeling approach this year to assess the relationship between hourly renewable generation output and MISO price volatility. Considerable time was spent reviewing this information during NIPSCO's May 20 Stakeholder Meeting (See in particular slides 64-76). As shown in that presentation, there are iterations from the natural gas price stochastic distribution that cover the range of recent price spikes in the forward gas market for this winter.

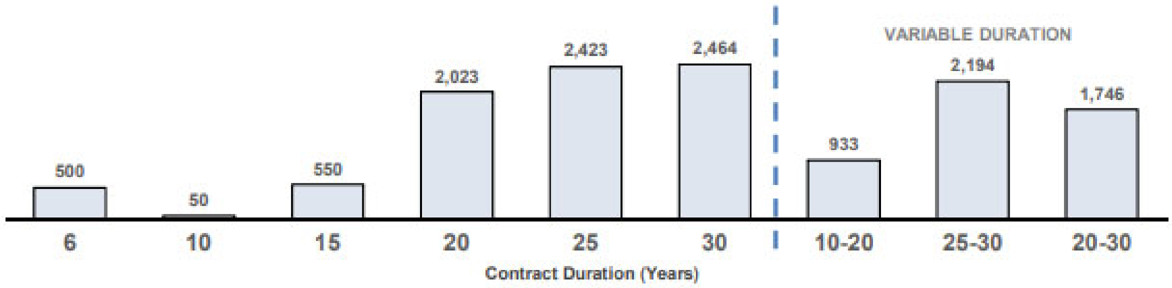
NIPSCO has also expanded the risk metrics used in its scorecard to report and evaluate the 95th percentile conditional value at risk as a measure of tail risk and extreme volatility. This metric looks at the impact of all observations from across the stochastic distribution that are above the 95th percentile and not just the 95th percentile itself. Key outputs from NIPSCO's stochastic analysis were presented in the September stakeholder meeting, leading to key conclusions that large combined cycle capacity additions would increase market risk in the near-term (supportive of RE's point that natural gas price volatility will more significantly impact portfolios with high levels of "natural gas baseload support"), and portfolios that relied heavily on intermittent renewable generation (without sufficient dispatchable capacity) would increase market risk over the long-term. In the spirit of other comments offered by RE, NIPSCO did not simply evaluate a long-term NPV when assessing stochastic risk, but looked at specific points in time in the near-term and long-term to assess the evolving risk profile.

Response to Comment 4

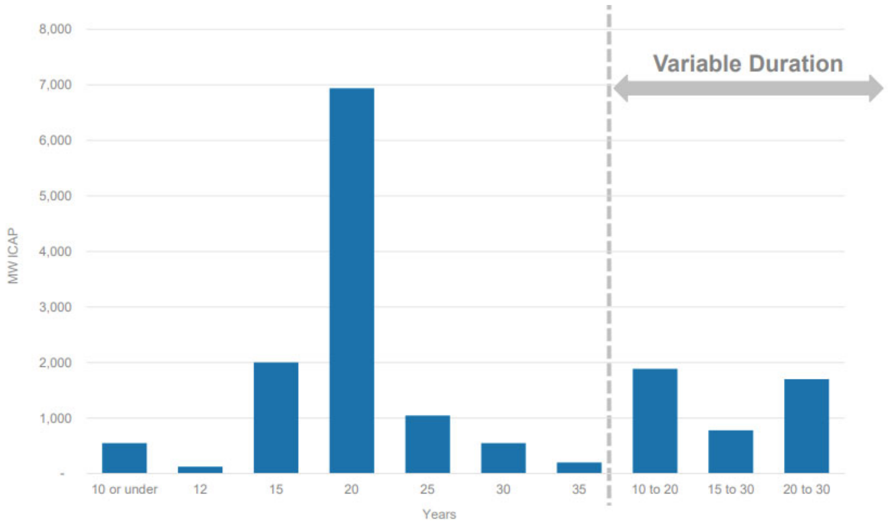
The thermal purchase power agreements ("PPAs") being evaluated are for terms of 10 years or less. PPAs for renewable technology with 15-20-year terms are beneficial for customers over their full lifetimes, and the IURC has validated this strategy with approvals of several wind and solar PPAs over the last couple of years. However, the Company does agree that over-reliance on PPAs could pose risks to customers (See recent certificate of public convenience and necessity testimony for more detailed review of the tradeoffs between owned assets and PPAs).

NIPSCO would be interested in learning more about RE's understanding of the renewable PPA market, specifically on the availability of 10-year PPAs for the types of resources NIPSCO is pursuing. NIPSCO has conducted three RFPs since 2018, and the figures below summarize the duration of PPA bids received. The Company's experience suggests that durations below 10 years are not commonplace, particularly for new renewable projects.

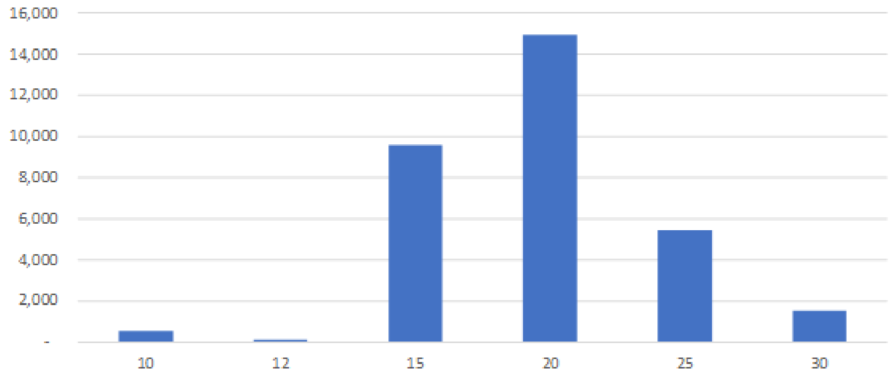
2018 All-Source RFP



2019-20 Phase II RFPs



2021 RFP Events



Response to Comment 5

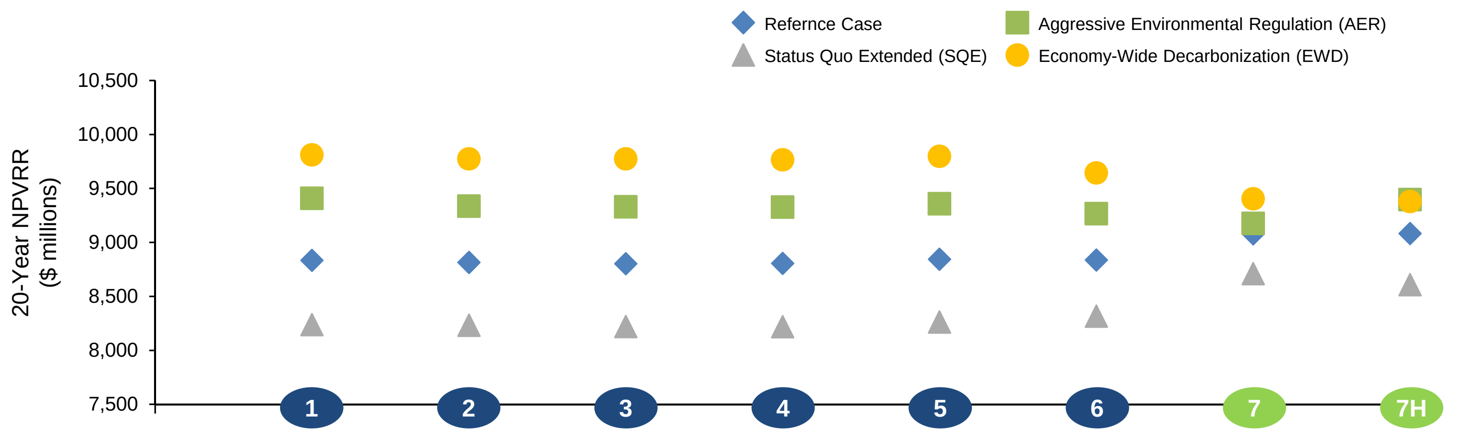
The ratings agencies that NIPSCO engages with have different standards for how they treat the impact of PPAs on the balance sheet. From our discussions with the ratings agencies, the PPAs NIPSCO has signed to date do not have a material impact on the balance sheet at this time. We will continue to monitor and evaluate the impacts associated with PPA's across a range of financial dimensions for NIPSCO and customers. The accounting determination of the treatment of PPAs will be handled in accordance with current and future accounting standards and principles. NIPSCO's current PPAs are not treated as leases.

Conclusion

Again, NIPSCO appreciates RE's attention to the Company's IRP process. As a reminder, all of the Stakeholder Meeting materials are available at nipsco.com/irp. Please contact Alison Becker at abecker@nisource.com to follow up on any of these issues or discuss any additional thoughts.

EXISTING FLEET ANALYSIS

20-YEAR NPV REVIEW: EXISTING FLEET ANALYSIS: SCENARIO RESULTS



	Portfolio Transition Target:	15% Coal through 2032	15% Coal through 2028	15% Coal through 2026	15% Coal through 2024	15% Coal through 2028	15% Coal through 2026	15% Coal through 2028 Fossil Free by 2032	15% Coal through 2028; Option for Fossil Free by 2032
	Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
	Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Reference Case	Delta from Lowest Cost to Customer	$30 0.3%	$12 0.1%	- -	$3 0.0%	$41 0.5%	$33 0.4%	$276 3.1%	$280 3.2%
Status Quo Extended	Delta from Lowest Cost to Customer	$20 0.2%	$13 0.2%	$1 0.0%	- -	$43 0.5%	$98 1.2%	$491 6.0%	$389 4.7%
Aggressive Env. Reg.	Delta from Lowest Cost to Customer	$233 2.5%	$160 1.7%	$154 1.7%	$152 1.7%	$182 2.0%	$91 1.0%	- -	$221 2.4%
Econ-Wide Decarbonization	Delta from Lowest Cost to Customer	$431 4.6%	$395 4.2%	$394 4.2%	$386 4.1%	$418 4.5%	$264 2.8%	$24 0.3%	- -

Not a viable pathway due to implementation timing

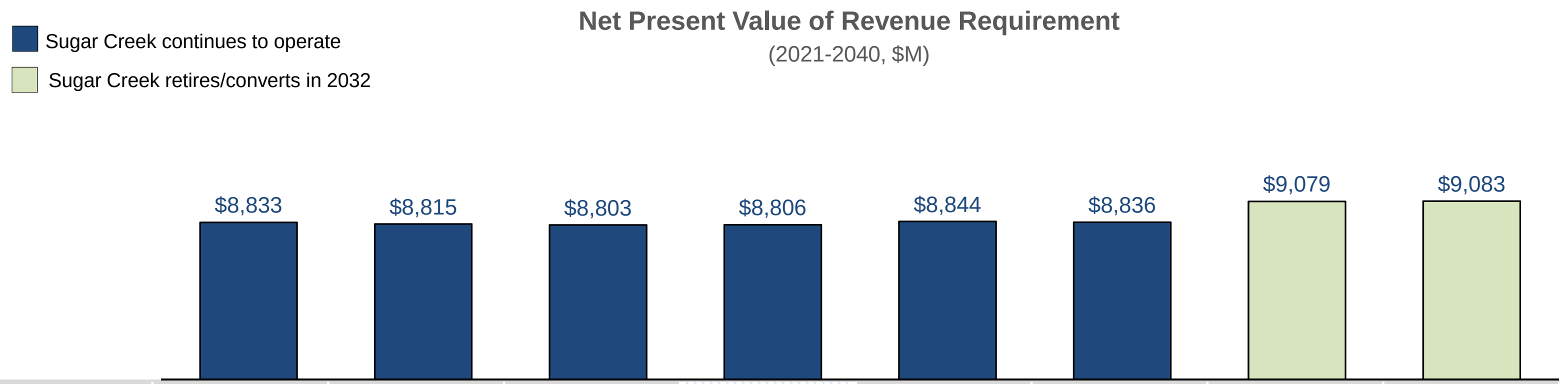
*Note that a $0.50/kg H2 subsidy is assumed in AER and EWD

Observations

- Observations from the 20-year NPVRR view are very similar to the 30-year view
- MC 12 retirement in 2026 is always slightly lower cost than retirement in 2028
- MC 12 retirement in 2032 is always higher cost than earlier retirement, with the largest difference in the AER scenario (high carbon price)
- Portfolio 2 is slightly lower cost than Portfolio 5, although additional renewable additions with early 16AB retirement (Portfolio 6) lower costs under high carbon regulation scenarios
- Portfolios 7 and 7H have the smallest range

EXISTING FLEET ANALYSIS

20-YEAR NPV REVIEW: EXISTING FLEET ANALYSIS: REFERENCE CASE



Portfolio Transition Target:	15% Coal through 2032 (1)	15% Coal through 2028 (2)	15% Coal through 2026 (3)	15% Coal through 2024 (4)	15% Coal through 2028 (5)	15% Coal through 2026 (6)	15% Coal through 2028 Fossil Free by 2032 (7)	15% Coal through 2028 Option for Fossil Free by 2032 (7H)
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Rank (1=Least Cost)	4	3	1	2	6	5	7	8
Delta from Least Cost	$30M 0.3%	$12M 0.1%	-	$3M 0.0%	$41M 0.5%	$33M 0.4%	$276M 3.1%	$280M 3.2%

Not a viable pathway due to implementation timing

EXISTING FLEET ANALYSIS

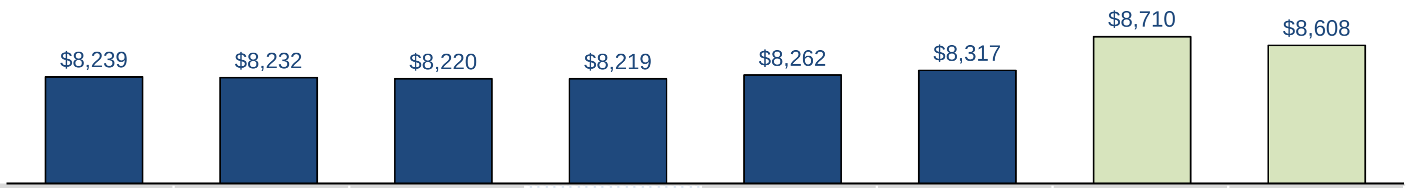
20-YEAR NPV REVIEW: EXISTING FLEET ANALYSIS: STATUS QUO EXTENDED (SQE)

Net Present Value of Revenue Requirement

(2021-2040, $M)

Sugar Creek continues to operate

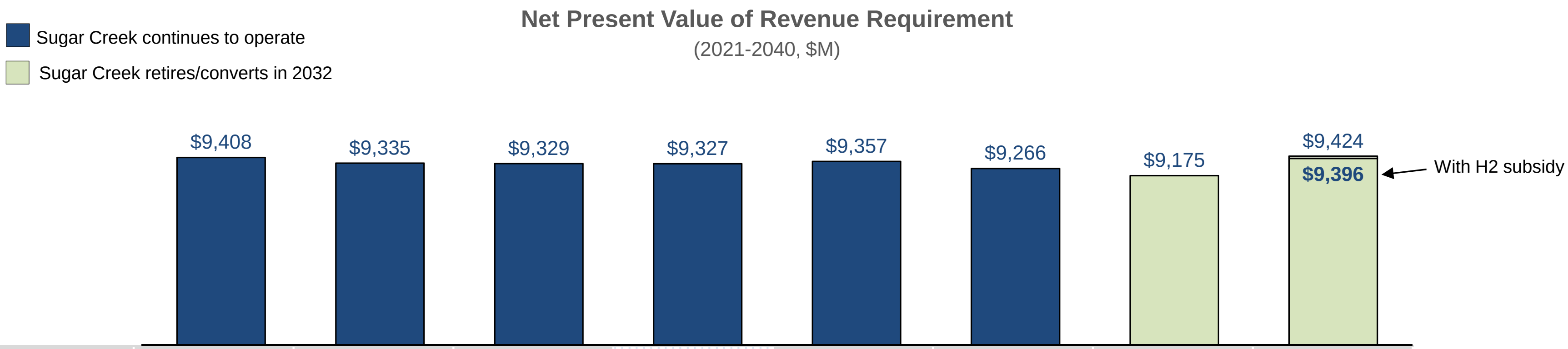
Sugar Creek retires/converts in 2032



Portfolio Transition Target:	15% Coal through 2032 (1)	15% Coal through 2028 (2)	15% Coal through 2026 (3)	15% Coal through 2024 (4)	15% Coal through 2028 (5)	15% Coal through 2026 (6)	15% Coal through 2028 Fossil Free by 2032 (7)	15% Coal through 2028 Option for Fossil Free by 2032 (7H)
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Rank (1=Least Cost)	4	3	2	1	5	6	8	7
Delta from Least Cost	$20M 0.2%	$13M 0.2%	$1M 0.0%	-	$43M 0.5%	$98M 1.2%	$491M 6.0%	$389M 4.7%

Not a viable pathway due to implementation timing

20-YEAR NPV REVIEW: EXISTING FLEET ANALYSIS: AGGRESSIVE ENVIRONMENTAL REGULATION (AER)

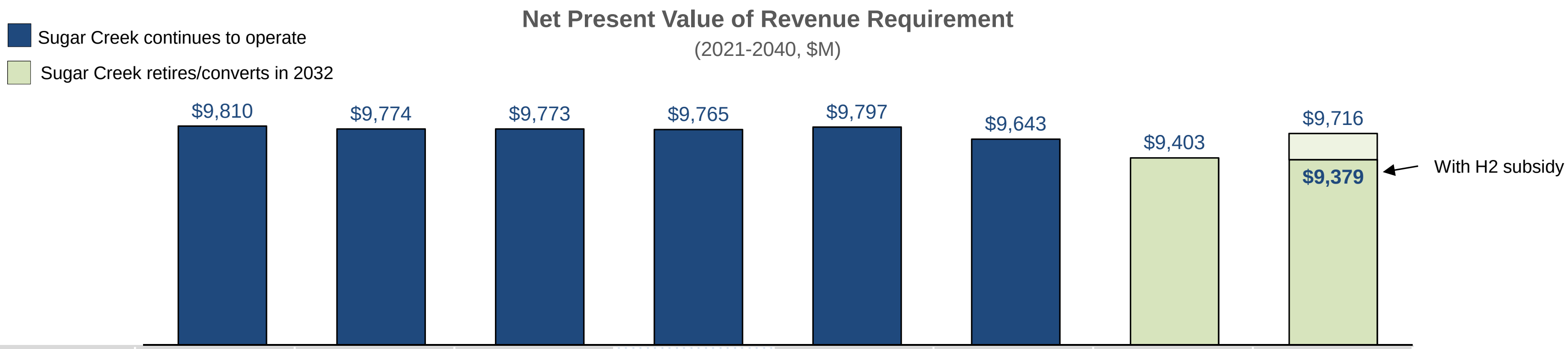


Portfolio Transition Target:	15% Coal through 2032 (1)	15% Coal through 2028 (2)	15% Coal through 2026 (3)	15% Coal through 2024 (4)	15% Coal through 2028 (5)	15% Coal through 2026 (6)	15% Coal through 2028 Fossil Free by 2032 (7)	15% Coal through 2028 Option for Fossil Free by 2032 (7H)
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Rank (1=Least Cost)	8	5	4	3	6	2	1	7
Delta from Least Cost	$233M 2.5%	$160M 1.7%	$154M 1.7%	$152M 1.7%	$182M 2.0%	$91M 1.0%	-	$221M 2.4%

Not a viable pathway due to implementation timing

*Note: Rank and Delta from Least Cost utilize 3I **with** the H2 subsidy at $0.50/kg.

20-YEAR NPV REVIEW: EXISTING FLEET ANALYSIS: ECONOMY-WIDE DECARBONIZATION (EWD)



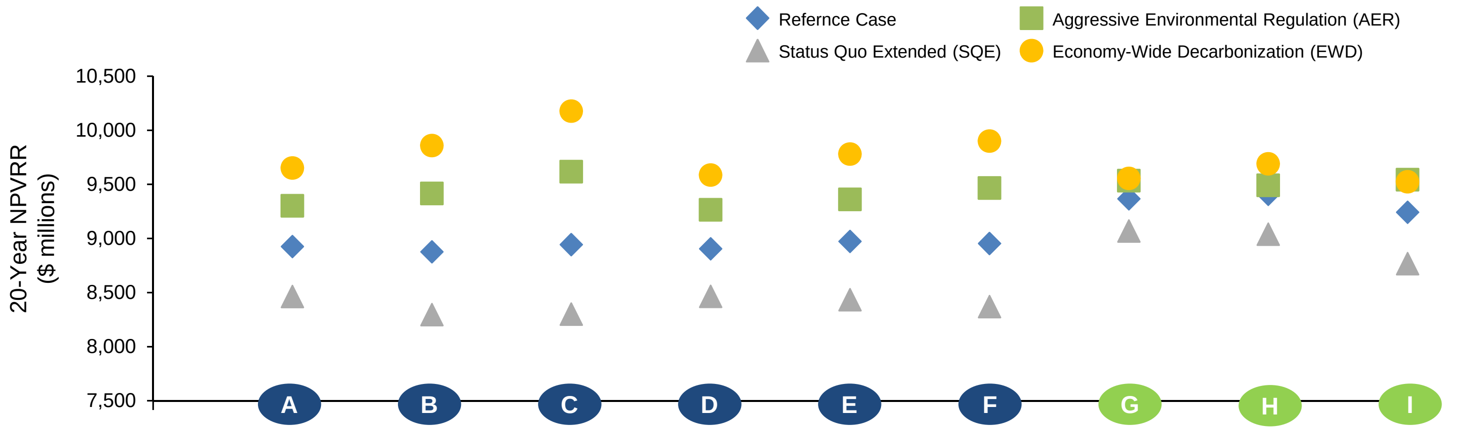
Portfolio Transition Target:	**15% Coal through 2032** 1	**15% Coal through 2028** 2	**15% Coal through 2026** 3	**15% Coal through 2024** 4	**15% Coal through 2028** 5	**15% Coal through 2026** 6	**15% Coal through 2028 Fossil Free by 2032** 7	**15% Coal through 2028 Option for Fossil Free by 2032** 7H
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Rank (1=Least Cost)	8	6	5	4	7	3	2	1
Delta from Least Cost	$431M 4.6%	$395M 4.2%	$394 4.2%	$386M 4.1%%	$418M 4.5%%	$264M 2.8%%	$24M 0.3%%	-

Not a viable pathway due to implementation timing

*Note: Rank and Delta from Least Cost utilize 3I **with** the H2 subsidy at $0.50/kg.

REPLACEMENT ANALYSIS

20-YEAR NPV REVIEW: REPLACEMENT ANALYSIS: SCENARIO RESULTS



		A	B	C	D	E	F	G	H	I
	Carbon Emissions:	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
	Dispatchability:	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Reference Case	**Delta from Lowest Cost to Customer**	$49 0.6%	- -	$66 0.7%	$28 0.3%	$95 1.1%	$76 0.9%	$489 5.5%	$531 6.0%	$365 4.1%
Status Quo Extended	**Delta from Lowest Cost to Customer**	$167 2.0%	- -	$5 0.1%	$169 2.0%	$138 1.7%	$74 0.9%	$773 9.3%	$743 9.0%	$471 5.7%
Aggressive Env. Reg.	**Delta from Lowest Cost to Customer**	$36 0.4%	$150 1.6%	$351 3.8%	- -	$96 1.0%	$201 2.2%	$269 2.9%	$226 2.4%	$278 3.0%
Econ-Wide Decarb.	**Delta from Lowest Cost to Customer**	$128 1.3%	$335 3.5%	$653 6.9%	$62 0.7%	$256 2.7%	$377 4.0%	$32 0.3%	$167 1.8%	- -

Not a viable pathway due to not meeting winter planning reserve margins

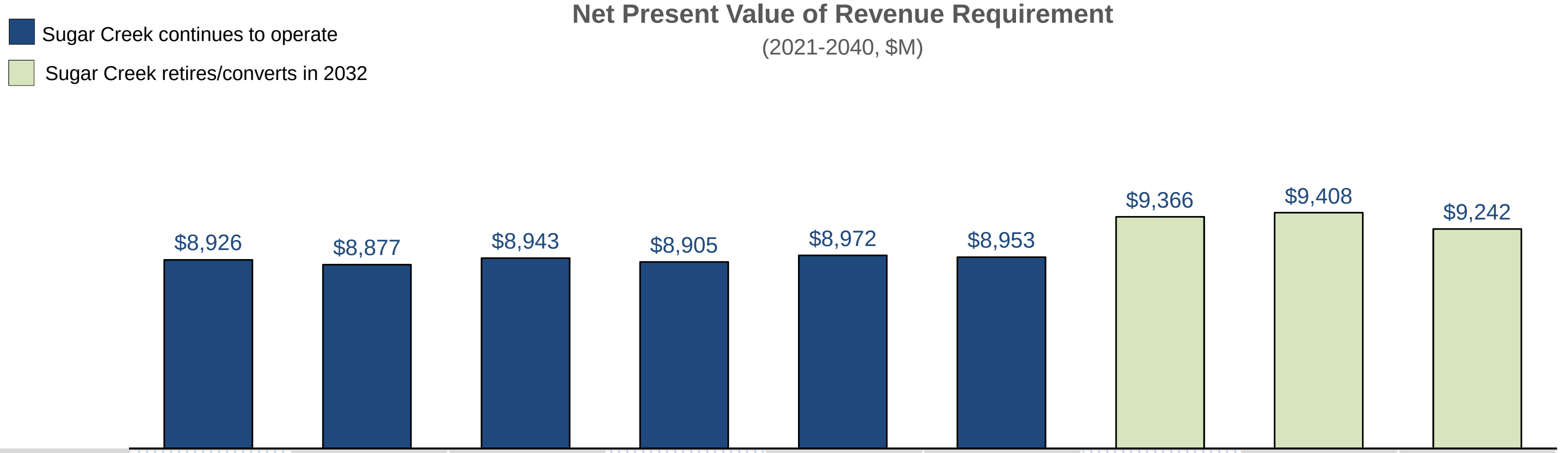
*Note that a $0.50/kg H2 subsidy is assumed in AER and EWD

Observations

- Observations from the 20-year NPVRR view are similar to the 30-year view, with a major exception being the performance of Portfolio C (as identified by NIPSCO in the September meeting)
- Portfolios B, C, and F have lowest costs among viable options under the Reference and SQE scenarios
- Portfolio E has the lowest cost among viable portfolios under the AER scenario, with C highest cost and H/I more competitive
- Clean energy has the most value in the EWD scenario, with Portfolio I (assuming a future H2 subsidy) having the lowest cost among viable portfolios

20-YEAR NPV REVIEW: REPLACEMENT ANALYSIS: REFERENCE CASE

Net Present Value of Revenue Requirement
(2021-2040, $M)



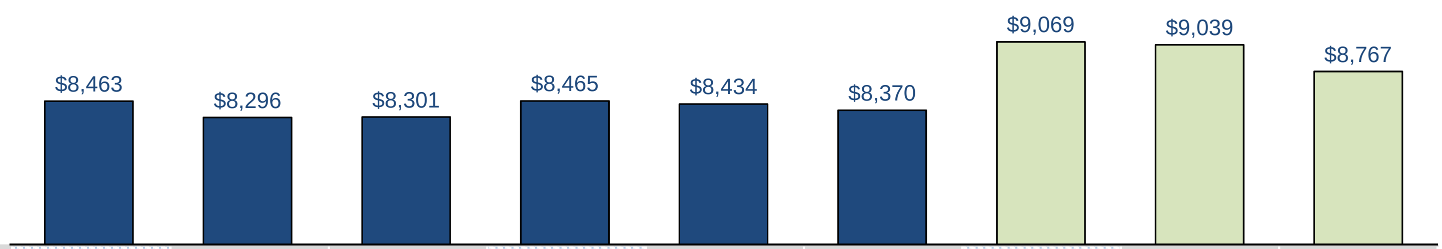
Replacement Theme	A: Thermal PPAs, solar and storage	B: Non-service territory gas peaking (no early storage)	C: Natural gas dominant (CC)	D: No new thermal resources; solar dominant w/ storage	E: Thermal PPAs plus storage and solar	F: Local gas peaker, plus solar and storage	G: Solar dominant w/ storage, plus retire Sugar Creek	H: All renewables and storage, plus retire Sugar Creek (Portfolio 7)	I: New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	3	1	4	2	6	5	8	9	7
Delta from Least Cost	$49 0.6%	-	$66 0.7%	$28 0.3%	$95 1.1%	$76 0.9%	$489 5.5%	$531 6.0%	$365 4.1%

Not a viable pathway due to not meeting winter planning reserve margins

20-YEAR NPV REVIEW: REPLACEMENT ANALYSIS: STATUS QUO EXTENDED (SQE)

Sugar Creek continues to operate
Sugar Creek retires/converts in 2032

Net Present Value of Revenue Requirement
(2021-2040, $M)

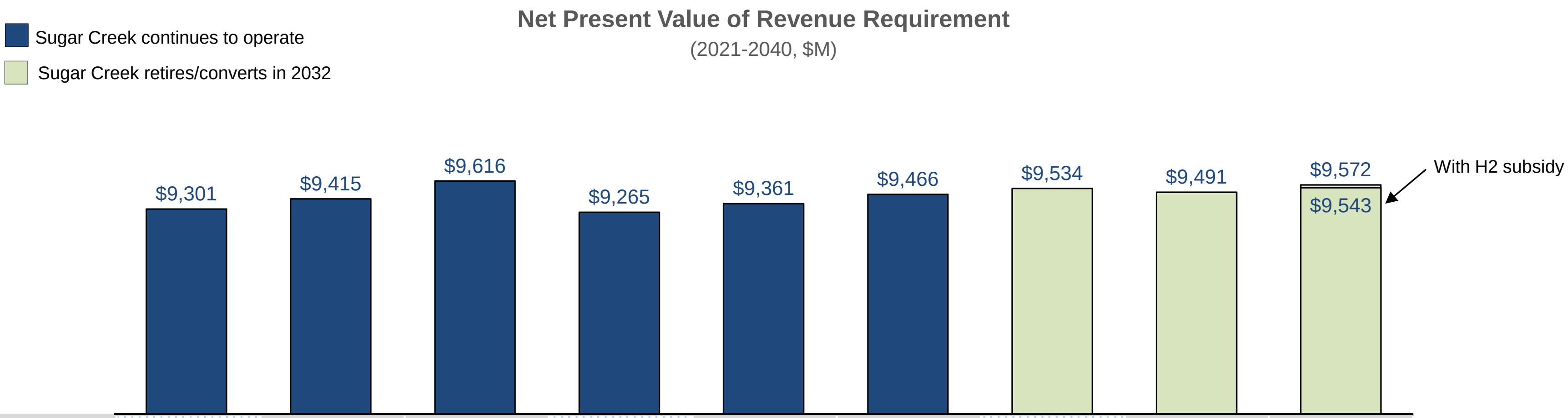


Replacement Theme	A: Thermal PPAs, solar and storage	B: Non-service territory gas peaking (no early storage)	C: Natural gas dominant (CC)	D: No new thermal resources; solar dominant w/ storage	E: Thermal PPAs plus storage and solar	F: Local gas peaker, plus solar and storage	G: Solar dominant w/ storage, plus retire Sugar Creek	H: All renewables and storage, plus retire Sugar Creek (Portfolio 7)	I: New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	5	1	2	6	4	3	9	8	7
Delta from Least Cost	$167 2.0%	-	$5 0.1%	$169 2.0%	$138 1.7%	$74 0.9%	$773 9.3%	$743 9.0%	$471 5.7%

Not a viable pathway due to not meeting winter planning reserve margins

REPLACEMENT ANALYSIS

20-YEAR NPV REVIEW: REPLACEMENT ANALYSIS: AGGRESSIVE ENVIRONMENTAL REGULATION (AER)



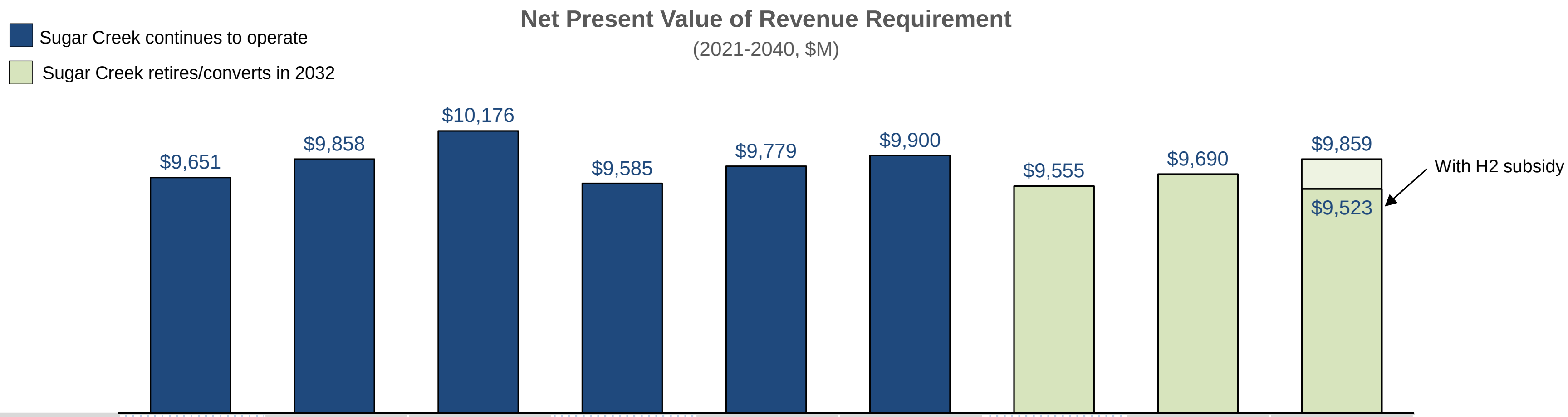
	A	B	C	D	E	F	G	H	I
Replacement Theme	**Thermal PPAs, solar and storage**	**Non-service territory gas peaking (no early storage)**	**Natural gas dominant (CC)**	**No new thermal resources; solar dominant w/ storage**	**Thermal PPAs plus storage and solar**	**Local gas peaker, plus solar and storage**	**Solar dominant w/ storage, plus retire Sugar Creek**	**All renewables and storage, plus retire Sugar Creek (Portfolio 7)**	**New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)**
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	2	4	9	1	3	5	7	6	8
Delta from Least Cost	$36 0.4%	$150 1.6%	$351 3.8%	-	$96 1.0%	$201 2.2%	$269 2.9%	$226 2.4%	$278 3.0%

Not a viable pathway due to not meeting winter planning reserve margins

*Note: Rank and Delta from Least Cost utilize 3I **with** the H2 subsidy at $0.50/kg.

REPLACEMENT ANALYSIS

20-YEAR NPV REVIEW: REPLACEMENT ANALYSIS: ECONOMY-WIDE DECARBONIZATION (EWD)



Replacement Theme	A: Thermal PPAs, solar and storage	B: Non-service territory gas peaking (no early storage)	C: Natural gas dominant (CC)	D: No new thermal resources; solar dominant w/ storage	E: Thermal PPAs plus storage and solar	F: Local gas peaker, plus solar and storage	G: Solar dominant w/ storage, plus retire Sugar Creek	H: All renewables and storage, plus retire Sugar Creek (Portfolio 7)	I: New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	4	7	9	3	6	8	2	5	1
Delta from Least Cost	$128 1.3%	$335 3.5%	$653 6.9%	$62 0.7%	$256 2.7%	$377 4.0%	$32 0.3%	$167 1.8%	-

Not a viable pathway due to not meeting winter planning reserve margins

*Note: Rank and Delta from Least Cost utilize 3I **with** the H2 subsidy at $0.50/kg.

Comments of CAC on NIPSCO's 2021 IRP October 12th Technical Meeting

Submitted to NIPSCO on October 20, 2021

Overall Thoughts[1]

Citizens Action Coalition of Indiana ("CAC") submits these comments on NIPSCO's October 12, 2021 presentation and review of the CRA/Quanta "draft material" deck. Given the tight timing, these are being provided quickly and at the expense of more careful consideration (and editing). Consequently, these comments should be regarded as advisory, and possibly incomplete.

First of all, this is good practice, and NIPSCO deserves credit for such a forward looking, innovative approach.

It is worth noting that is new ground for the industry. Much of the analysis is not firmly established art. There is plenty of room for judgment and, frankly, disagreements between reasonable people. There's no one right answer to most of the questions addressed.

To that end, these comments are primarily aimed at identifying positive refinements to what is clearly sound, well executed work.

Regulation

The section that looks at incremental value from ancillary services (particularly slides 14, 16, 17) includes a substantial focus on REG. As noted in the webinar and on slide 26, MISO has a single REG product (i.e. up and down are one service). Analysis was done on that basis, which is correct. But it is worth noting that the majority of ISOs have moved to asymmetric markets as wind and solar resources have increased. Having separate markets releases constraints on modern resources, providing benefits in several forms. When MISO eventually adopts this practice, the value of the renewable heavy portfolios, as shown for example in the center figure of slide 14, and the opportunity bars of slide 17 will increase. Both wind and solar provide an extremely high quality REG service. Field demonstrations, for example, in CAISO with both wind and solar PV plants,[2] showed that the quality of the REG response from wind and solar PV was measurably superior to thermal generation. Operating expectation (and FERC expectation) is that superior REG performance should result in reduced amounts of REG being procured, saving operating costs for all stakeholders. FERC requires that superior performance be rewarded with accompanying market signals.

Further ERCOT experience with wind plants *always* providing down primary frequency response is partly responsible for a *reduction* in the amount of REG procured by ERCOT as the amount of wind and solar generation has steadily increased. Statistical work in several systems has predicted an increase in the amount of REG needed with higher VER levels, but in practice this is usually not observed. Such behavior will likely impact the analysis here, boosting scores of the renewable heavy portfolios.

[1] These comments were prepared with the assistance of Nicholas W. Miller of HickoryLedge LLC.
[2] CAISO/NREL/FirstSolar "Using Renewables to Operate a Low-Carbon Grid: demonstration of Advanced Reliability Services from a Utility-scale Solar PV Plant"

Blackstart

This is innovative analysis and most welcome. We were confused across the scenario tables for resources (i.e. slide 33, 34, 41), so these comments are not exactly aligned with the scenarios. The deck (slide 40) includes a few up-to-date references for inverter-bases resources providing blackstart. The analysis correctly credits energy storage (assumed to be BESS) equipped with GFM as a credible resource for providing blackstart. But, there appears to be an assumption that the storage (i.e. the battery energy storage portion) of the "solar+storage" resources would not have GFM inverters, and therefore could not be used for blackstart. This appears to result in no credit and correspondingly so for the ES portion of those scenarios with solar+storage. The genesis of this assumption is not clear, but it seems to be at odds with state-of-the-art practice. For example, all of the present tranche of solar+storage projects that have been awarded and are under design now in Hawai'i include *as a contractual requirement of the project* that they have grid-forming inverters on the battery portion.[3] It is HELCO's operational expectation to rely on the grid-forming functionality of the BESS to deliver a wide range of operational benefits. This capability will affect the scoring of these solar+storage projects not only for blackstart, but for short circuit strength, inertial response, and possibly fast regulation. Should NIPSCO go forward with scenarios that include solar+storage, they should expect to demand a high level of functionality from these plants, including state-of-the-art GFM capability. The score of scenarios in the IRP evaluation should reflect that, with the expectation that they will probably improve.

VAR Support

The deck correctly points out that IBRs, including solar PV and wind, have the capability to provide reactive power and to perform voltage regulation *regardless* of whether they are generating (slide 38). BESS can provide voltage regulation regardless of whether it is charging, discharging or idle. Thus, IBR resources *that are specified accordingly* can provide this essential reliability service all the time. In comparison, thermal resources must be committed and running. For fossil generation that is expected to have a relatively low capacity factor, this means that the voltage support will be relatively rare. That benefit is only realized when the generator is running and producing MW, at least at the unit minimum. The exception is for small simple cycle combustion turbines, some types of which can be equipped with a clutch that allows operation of the generator as a synchronous condenser. This feature adds to the capital cost, but can be a significant benefit to systems where the CT is expected to run rarely. LADWP has relatively new units with this feature that are reputed to be run in condenser mode most of the time. Commercial arrangements for this function are non-standard, and the losses associated with this function are non-trivial. The capability is not commercially available on large gas generation, including combined cycle plants. It must be specified at the time of initial design (no retrofits).

[3] For example: Docket 2017-0352, Order # 36604, 10-9-2019. 'Application to HELCO for PPA for Renewable Dispatchable Generation with ENGIE 2020 Project CoHI1' before the Hawai'i PUC.

The reliability metrics on the tables of slides 51, 52 and 53 includes VAR support (line 5 of the tables). That all the options result in the same score seems at odds with the arguably better features of the IBR options. It was not clear if the totals on line 5 are correct.

Ramping

The aggregate dispatchability, and particularly the 1- and 10-minute ramping results seem unnecessarily constrained by traditional views of thermal generation as the primary resource for net load following. For example, the scenarios with energy storage but no thermal generation received quite poor scoring. This seems at odds with the reality that, properly managed, the energy storage elements alone, or the combined resources of solar plus energy storage, can be available for ramping duty every hour of every day. It is a fact that the combined constraints of sunlight and state of charge can constrain capability. Further, ITC constraints that penalize charging the batteries from the grid present an economic (though not physical) constraint that must be respected. But the resources are synchronized and ready *instantly* to provide a very high quality, fast, and finely controllable ramping response all the time. All resources that provide ramping must respect a variety of limits. Surely the fact that, under some conditions, the energy storage resource cannot draw ramping power from the grid is less constraining than the reality that a fossil plant can *never* draw power from the grid. The very high scores for the fossil resources would appear to disregard the reality that these resources must be committed and dispatched to provide ramping services in these time frames. It is the economic expectation that these plants will have relatively low capacity factors, so they will tend to not be running. The plants, and particularly the combined cycle option, are subject to minimum dispatch limitations, minimum start times, minimum run times, and minimum down times, all of which have the potential to negatively impact their ability to provide ramping when needed. This is especially the case for unexpected ramps.

Short Circuit Strength

The technical issues surrounding dropping short current strength are a legitimate concern. It is worth noting that every scenario includes synchronous condensers, which help mitigate the concern. The combined issues of sensitivity of IBRs to low short circuit levels and the potentially adverse impact of low short circuit current *from the IBRs* on protection are real. However, both issues are receiving a great deal of attention from the industry on several fronts. As with the ramping observation, the fossil resources only provide short circuit strength when they are committed. In comparison, grid forming inverters from the new energy storage (either stand-alone or in the solar+storage facilities) can expected to be synchronized all the time. Again, as an example, it is the current reality in Kaua'i and the near future reality on Hawai'i that the system can run and be protected successfully with a single synchronous condenser (Kaua'i today) or an extremely limited number of synchronous machines, relying on their solar+energy storage projects to provide the needed system support. That the end short circuit scoring resulted in such extreme (zeros and ones only) seems at odds with a more nuanced reality.

NIPSCO Response to Citizens Action Coalition of Indiana, Inc. ("CAC") Comments on NIPSCO's 2021 IRP October 12, 2021 Technical Meeting Submitted on October 20, 2021

Response to Overall Thoughts

Thank you for the timely response to the information presented during the Technical Webinar. NIPSCO appreciates the ongoing, thoughtful engagement with the CAC throughout the IRP Process. NIPSCO considered your feedback when finalizing the preferred plan as well as the report that will be submitted to the Indiana Utility Regulatory Commission ("IURC" or "Commission") by November 15, 2021.

Response to Regulation

Thank you for these comments. NIPSCO agrees that market design changes will impact ancillary services opportunities and that the implementation of an asymmetric regulation market could serve to benefit renewable resources (at least from the perspective of allowing them to monetize ancillary services revenue). While this may be worth evaluating in the future, NIPSCO's sub-hourly ancillary services analysis was primarily targeted towards the relative value of storage versus gas peaker portfolio additions. A fuller portfolio analysis with co-optimized energy and ancillary services dispatch is challenging to perform across time and against multiple scenarios and portfolios, so NIPSCO has taken the approach of performing targeted analyses to assess key resource tradeoffs. However, NIPSCO will continue to monitor Midcontinent Independent System Operator, Inc. ("MISO") market developments and welcomes continued suggestions regarding analytical frameworks that might be useful in future IRPs.

Response to Blackstart

A. The 2030 portfolio mix evaluated in the analysis includes both existing resources and the replacement resource tranches assumed to be operating in the year 2030 that are within NIPSCO's service territory.
B. The reliability analysis and portfolio scoring assumed that stand-alone storage systems will be fitted with grid-forming inverters, while the storage part of solar plus storage resources will be fitted with grid-following inverters. The solar plus storage resources are configured with the storage system operating behind the solar inverter; therefore, it is unlikely for the combined inverter to be grid forming. The CAC's comment is correct that the scoring will be impacted if a

decision is made to require grid-forming inverters also for the storage component of solar plus storage resources. However, this will only impact Portfolios A, D, and G that include 150MW of storage within the 450MW of solar plus storage capacity block.

Response to Volt-Amp Reactive ("VAR") Support

A. NIPSCO agrees with the comments regarding the relative availability of dynamic VARs from inverter-based resources and thermal resources.
B. Given the local nature of reactive power, the "VAR Support" reliability metric is designed to quantify the ability of each portfolio to deliver its dynamic VARs to load centers. The availability of dynamic VARs, however, was not considered in the evaluation due to its dependence on commitment decisions that are beyond the scope of this investigation.

Response to Ramping

A. The ramping component of the dispatchability metric quantified the MWs that each portfolio can provide within one and 10 minutes. Energy storage was assumed to have the capability to provide 100% of its rated MW capacity, while peaker and combined cycle plants were assumed to provide MWs commensurate with their technology.
B. The scores reflect the aggregate ramping capability of all resources within each portfolio. For example, Portfolio H, which does not have peaker or combined cycle plants, was assessed to have the highest ramping capability.
C. NIPSCO will continue to study this topic and take into account CAC's other comments regarding analytical approaches around reliability risk. For example, sub-hourly stochastic analyses of load, renewable output, day ahead forecast error, and other factors might be useful frameworks for assessing ramping needs at various intervals.

Response to Short Circuit Strength

A. NIPSCO appreciates CAC's acknowledgement of the importance of short circuit ratio.
B. All inverters on the market, including grid forming ones, have limited short circuit current capability, and thus are not expected to appreciably increase the short circuit strength of the grid. Compounding this limitation is the uncertain phase angle of the short circuit current (reactive or active) which appears to depend on the inverter control system and thus

NIPSCO
A NiSource Company

manufacturer specifics. Given these limitations and uncertainty, a prudent assumption was made in this study that grid forming inverters can operate successfully at low short circuit ratios and thus assumed to cause no harm. However, they were not assumed to enhance the grid short circuit strength.

C. The “Short Circuit Strength” metric quantified the size of the necessary additions of synchronous condensers in order to maintain an acceptable level of short circuit ratio at each grid-following inverter location in the grid.

Conclusion

We appreciate the CAC’s perspective and thoughtfulness regarding reliability. NIPSCO will continue to monitor MISO market developments and welcomes continued conversation regarding analytical frameworks and reliability assessments that we might consider for future IRPs. As a reminder, all of the Stakeholder Meeting materials are available at nipsco.com/irp. Please contact Alison Becker at abecker@nisource.com to follow up on any of these issues or discuss any additional thoughts.

Alison Becker, Manager of Regulatory Policy
Northern Indiana Public Service Company
150 West Market, Suite 600
Indianapolis, Indiana 46204

October 28, 2021

Re: NIPSCO's 2021 Integrated Resource Plan Public Advisory Process

Dear Ms. Becker,

Indiana Advanced Energy Economy ("Indiana AEE") respectfully submits this letter of comment regarding the preferred portfolio that the Northern Indiana Public Service Company ("NIPSCO") has selected for its 2021 Integrated Resource Plan ("IRP").

Advanced Energy Economy ("AEE") is a national business association representing companies working to make our energy system secure, clean, affordable, and reliable. AEE supports a broad portfolio of technologies, products and services that enhances U.S. competitiveness and economic growth through an efficient, high-performing energy system that is clean, secure, and affordable. AEE has been operating in the Hoosier State as Indiana AEE since 2016. In Indiana, we aim to drive the development of advanced energy by identifying growth opportunities, removing policy barriers, encouraging market-based policies, establishing partnerships, and serving as the voice of innovative companies in the advanced energy sector.

Indiana AEE appreciates the robust stakeholder process that NIPSCO has held with regard to its 2021 IRP. The Company has been thoughtful, collaborative, and receptive to feedback. We also commend NIPSCO for its leadership within the utility sector on the transition towards clean, advanced energy resources and its commitment to retiring the remainder of its coal fleet no later than 2028.

While we recognize that the energy transition introduces new uncertainties regarding future technologies, and that the intent of this IRP is to remain flexible and responsive to changing economic and policy conditions, we caution NIPSCO against the specific inclusion of new natural gas peaking resources in the mid-term. Excluding such peaking resources would be in

NIPSCO and its ratepayers' best interest because 1) there is a significant opportunity cost to waiting to add 300 MW of capacity instead of investing in and gaining experience with cost-effective and reliable advanced and distributed energy resource, especially demand-side resources, in the near-term; 2) energy storage resources, both long- and short-duration, may be receiving additional federal support in the near future; and 3) a newly built fossil resource in 2026 adds fuel price and stranded asset risk, which can be avoided with a different set of resource addition and retirement strategies.

Our recommendation is to note NIPSCO's need for approximately 300 MW of clean, firm peaking resources (Duke Energy Indiana is referring to these resources as "ZELFRs," or "Zero Emitting Load Following Resources" in its 2021 IRP stakeholder process), leave the specific capacity addition subject to future all-source Request for Proposal responses, and re-evaluate available resource options within the 2024 IRP.

1. There is a significant opportunity cost to waiting to add 300 MW of capacity instead of investing in and gaining experience with cost-effective and reliable advanced and distributed energy resources, especially demand-side resources, in the near-term.

Additional investment in demand side resources and management programs, including demand response, time varying rates that encourage off-peak energy usage, distributed generation and storage, and energy efficiency, can reduce system peaks that require the use of natural gas peaking plants. Improved management and integration of demand side resources can help utilities make better use of existing resources, improve reliability, and avoid the need for investments in new generation resources. Indiana AEE recommends that NIPSCO pursue all cost-effective energy efficiency, which includes levels beyond the market potential study's realistically achievable potential. Energy efficiency programming can also be focused on those that provide sizable demand reductions, such as behavioral energy efficiency.

Planning for meter-based pay-for-performance program designs, particularly when enabled by NIPSCO's widespread advanced metering infrastructure ("AMI") deployment expected over the next several years, can enhance the value of energy efficiency and other distributed energy resources ("DERs") by increasing the ability of utilities to rely on them to meet grid needs.[1] DER aggregation services will also become more widespread as wholesale markets, including the Midcontinent Independent System Operator ("MISO"), allow for their participation.[2] Indiana AEE recommends that the utility begin ramping up these programs in the near term to meet its

---

[1] Frick, Natalie Mims and Lisa C Schwartz. *Time-Sensitive Value of Efficiency: Use Cases in Electricity Sector Planning and Programs.* Lawrence Berkeley National Lab (2019). Available at: https://emp.lbl.gov/publications/time-sensitive-value-efficiency-use
[2] As required by FERC Order 2222 (2020).

approximate need of 300 MW incrementally. In this way, NIPSCO may be able to avoid the need to add new generation capacity and gain experience managing a system with these resources.

2. Energy storage resources, both long- and short-duration, may be receiving additional federal support in the near future.

Given the rapidly changing energy landscape, which includes declining energy storage resource costs and technological innovation, NIPSCO should remain open to alternatives that can provide similar capacity and operational flexibility as a combustion turbine, whether or not it can later be converted to run on green hydrogen. Advanced energy resources, which include large-scale and distributed renewables, short- and long-duration energy storage, and demand side resources such as energy efficiency and demand response, are cost-effective, clean, and fully capable of reliably serving electricity demand. Studies show that these resources, when used together and paired with utility programs and rates that encourage smart and managed electricity usage and demand flexibility, can replace most, if not all, of the fossil fuel generation currently serving electric customers.[3]

Utilities around the country are finding that energy storage resources are increasingly competitive (including when paired with solar and wind resources), flexible to operate, and prudent to invest in. For example, in early 2019, Arizona Public Service announced that it would procure 850 MW of battery storage to meet peak demand and replace natural gas peaking capacity.[4] Importantly, these resources may also receive additional federal support in the near future; the infrastructure bills currently being debated in Congress include a tax credit for energy storage, as well as funding for energy storage projects that enhance grid resilience and demonstrations of long-duration storage technologies and “second-life applications” of electric vehicle batteries.

3. A newly built fossil resource in 2026 adds fuel price and stranded asset risk, which can be avoided with a different set of resource addition and retirement strategies.

Furthermore, we note that natural gas plants are subject to additional uncertainties given the fuel’s inherent price risk, which may impact NIPSCO’s customers’ bills. Just recently, global natural gas prices have spiked as demand rises disproportionately to supply, and some believe

---

[3] 2035: The Report. Goldman School of Public Policy at the University of California Berkeley. June 2020. Available at: http://www.2035report.com/wp-content/uploads/2020/06/2035-Report.pdf?hsCtaTracking=8a85e9ea-4ed3-4ec0-b4c6-906934306ddb%7Cc68c2ac2-1db0-4d1c-82a1-65ef4daaf6c1

[4] APS to install 850 MW of storage, 100 MW of solar in major clean energy buy. Gavin Bade. Utility Dive, February 2019. Available at: https://www.utilitydive.com/news/aps-to-install-850-mw-of-storage-100-mw-of-solar-in-major-clean-energy-buy/548886/

that these prices mark a longer-term upward trend.[5] We also note that expensive peaker plants that are intended to run infrequently are not cost-effective when compared to other advanced energy resources.[6] This is especially true if the plant is unlikely to operate throughout its useful life, which will be necessary if NIPSCO intends to meet its goal for 100% decarbonization by the middle of the next decade. Conversion to green hydrogen (included in Preferred Pathway I) is speculative, and there is still a heightened risk of asset stranding if the technology either does not materialize or materializes at a cost that is not competitive with alternatives. Finally, there is also always a risk that forecasted demand does not materialize as modeled. Adding incremental capacity over the next several years can help mitigate against this possibility.

Rather than committing now to new natural gas generation, NIPSCO has a few alternatives to consider. Given that the date to retire the Schahfer 16A and B units remains somewhat flexible, we encourage NIPSCO to consider retiring Michigan City Unit 12 on the accelerated timeline in 2026 (as included in Preferred Pathway 3) and retaining one or both Schahfer units as it develops a set of programs and plans to procure/develop cost-effective, clean, peaking resources (or a portfolio of resources). This may, in fact, be in 2026 or earlier. As it is doing currently, NIPSCO can rely on short-term market purchases to fill any gaps as it develops its portfolio of energy storage and distributed and demand side resources. The longer NIPSCO can delay a decision to procure this natural gas capacity, the more attractive the alternative options it will be able to consider will become. It also avoids a near- or mid-term decision that could quickly prove uneconomic or become stranded, or be avoided if forecasted load does not materialize.

We appreciate the opportunity to submit these comments ahead of the filing of NIPSCO's 2021 IRP and thank the IRP team for their consideration.

Respectfully submitted,

Caryl A. Auslander
Program Director
Indiana Advanced Energy Economy

---

[5] The Era of Cheap Natural Gas Ends as Prices Surge by 1,000%. Anna Shiryaevskaya, Stephen Stapczynski, and Ann Koh. Bloomberg, August 2021. Available at: https://www.bloomberg.com/news/articles/2021-08-06/the-era-of-cheap-natural-gas-ends-as-prices-surge-by-1-000

[6] As a current example, CenterPoint's current proposal to build a natural gas combustion turbine to serve peak demand is estimated to add an average of $23/month to customer bills.

NIPSCO Response to Indiana Advanced Energy Economy ("AEE") Comments on NIPSCO's 2021 Integrated Resource Plan Public Advisory Process Submitted on October 28, 2021

General Response

Thank you for your thoughtful letter. NIPSCO appreciates AEE's participation in the 2021 Integrated Resource Plan ("IRP") process. NIPSCO has taken your feedback into account when finalizing the preferred plan as well as the report that will be submitted to the Indiana Utility Regulatory Commission ("IURC" or "Commission") by November 15, 2021.

Response to Recommendation Point 1

A. NIPSCO has specifically selected its preferred plan to preserve flexibility around resource selection and retirement dates. While we certainly expect the long-term portfolio (post-2030) additions to be revisited in subsequent IRPs (including the potential for long-duration storage, hydrogen, or other technologies such as carbon capture, utilization, and storage or small modular reactors), it is not tenable to retain a "zero-emitting load-following resource" placeholder for near-term capacity needs that will materialize upon the retirement of one or all of the Michigan City Generating Station Unit 12 and R.M. Schahfer Generating Station Units 16A and B. The analysis has assessed the cost, environmental emissions profile, risk, and reliability of several alternatives, and NIPSCO has determined a mix of storage and new thermal resources (including with potential hydrogen enablement) will be required this decade.

B. NIPSCO is committed to continued expansion of its demand side management ("DSM") program, and the preferred plan calls for cost-effective energy efficiency, including the vast majority of bundle options identified by the DSM market potential study completed in 2021. NIPSCO has worked closely with the Energy Efficiency Oversight Board to identify DSM options, and the IRP includes substantial DSM additions (all available commercial and industrial programs and all but the highest cost residential programs – See July stakeholder meeting slides for more detail). Including NIPSCO's recently approved DSM plan (see Cause No. 45456, approved by the Commission on September 1, 2021), the preferred portfolio includes nearly one million MWh of incremental DSM by the end of the decade. NIPSCO has evaluated the impacts to customer costs of levels beyond realistic achievable potential levels and has found significant cost increases. However, NIPSCO will continue to engage with stakeholders on this topic within the IRP and Oversight Board settings.

C. For the first time, NIPSCO has incorporated distributed energy resources ("DERs") into its preferred portfolio, and the IRP establishes a benchmark against which to evaluate project opportunities, particularly in light of the distribution investment deferrals that may be available. NIPSCO will continue to evaluate DER opportunities as the Midcontinent Independent System Operator, Inc. responds to the Federal Energy Regulatory Commission Order No. 2222.

D. NIPSCO agrees that an automated metering infrastructure ("AMI") deployment will enable modern energy capabilities, including the integration of customer-owned generation resources into the grid. AMI is included in NIPSCO's Transmission, Distribution, and Storage System Improvement Charge Plan currently pending before the Commission in Cause No. 45557.

Response to Recommendation Point 2

A. NIPSCO is closely tracking federal policy developments and is aware that a stand-alone storage investment tax credit may be enacted. In anticipation of this, two of NIPSCO's IRP scenarios included such a tax credit, and portfolios with more storage performed better under such conditions. This is one of the reasons why NIPSCO's preferred portfolio is designed to allow for flexibility and to pivot to more storage as policy evolves.

B. NIPSCO agrees that technology and economics continue to advance for energy storage resources. As outlined in stakeholder meetings, NIPSCO employs a scorecard approach to evaluate tradeoffs among replacement portfolios. An element of this scorecard includes a measure of reliability. As outlined in public stakeholder meetings and a technical workshop in October, NIPSCO enhanced its analysis of reliability by engaging a third-party expert, Quanta Technology, LLC, to perform a Reliability Assessment over the resources included in the replacement portfolios. The results of this analysis indicated that Portfolios F and I provided the highest reliability scores across a range of critical reliability criteria. NIPSCO's preferred resource plan calls for up to 370MW of storage additions.

Response to Recommendation Point 3

A. NIPSCO's preferred plan does not alter NIPSCO's previously stated goal of a 90 percent reduction in carbon emissions (from a 2005 baseline) by 2030. As noted in the final stakeholder meeting, the peaker plant in Portfolio F does not dispatch much and therefore does not expose

NIPSCO
A NiSource Company

the portfolio to significant risks associated with high gas prices or stringent carbon regulations that might be more material with a combined cycle addition. NIPSCO agrees that natural gas prices may be volatile and higher in the future and has reflected this in its scenario and stochastic analyses. In the stochastic analysis, while the combined cycle in Portfolio C has significant near-term risk associated with high commodity prices, the portfolios with a gas peaker or storage both had similar near-term risk profiles and provided similar long-term risk mitigation from a renewable output volatility perspective. So, overall, NIPSCO agrees that there are a range of trade-offs associated with portfolio selection, but the analysis has not found that a gas peaker facility substantially increases risks associated with higher carbon or gas prices.

Conclusion

We appreciate Indiana AEE's perspective and attention to the Company's IRP process. As a reminder, all of the Stakeholder Meeting materials are available at nipsco.com/irp. Please contact Alison Becker at abecker@nisource.com to follow up on any of these issues or discuss any additional thoughts