2021 NIPSCO Integrated Resource Plan

First Stakeholder Advisory Meeting

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








SAFETY MOMENT: PSYCHOLOGICAL SAFETY

Four Quadrants of Psychological Safety

Learner Safety

It's safe to:
- Discover
- Ask questions
- Experiment
- Learn from mistakes
- Look for new opportunities

Collaborator Safety

It's safe to:
- Engage in an unconstrained way
- Interact with colleagues
- Have mutual access
- Maintain open dialogue
- Foster constructive debate

Challenger Safety

It's safe to:
- Challenge the status quo
- Speak up
- Express ideas
- Identify changes
- Expose problems

Inclusion Safety

It's safe to:
- Know that you are valued
- Treat all people fairly
- Feel your experience, and ideas matter
- Include others regardless of title/position
- Openly contribute

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 they 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

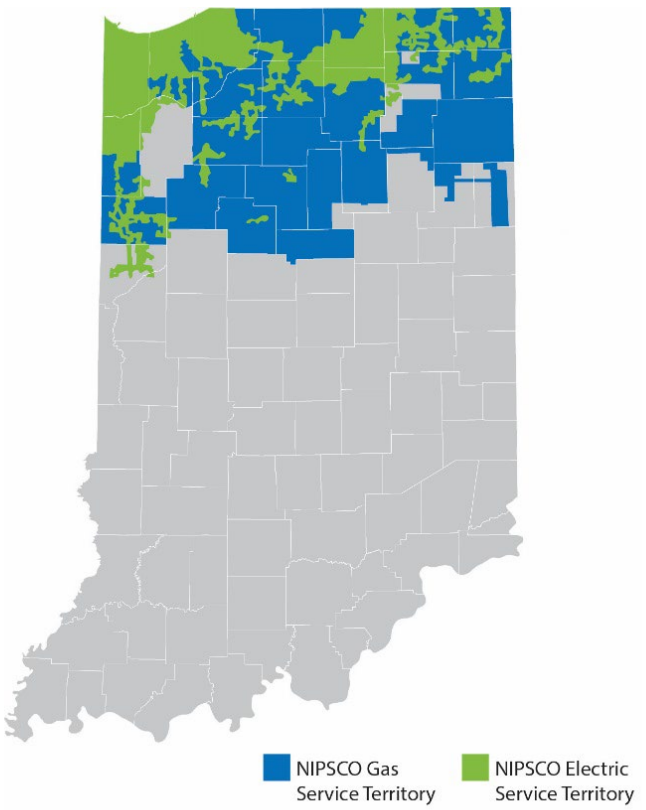
Working to Become Indiana's Premier Utility

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

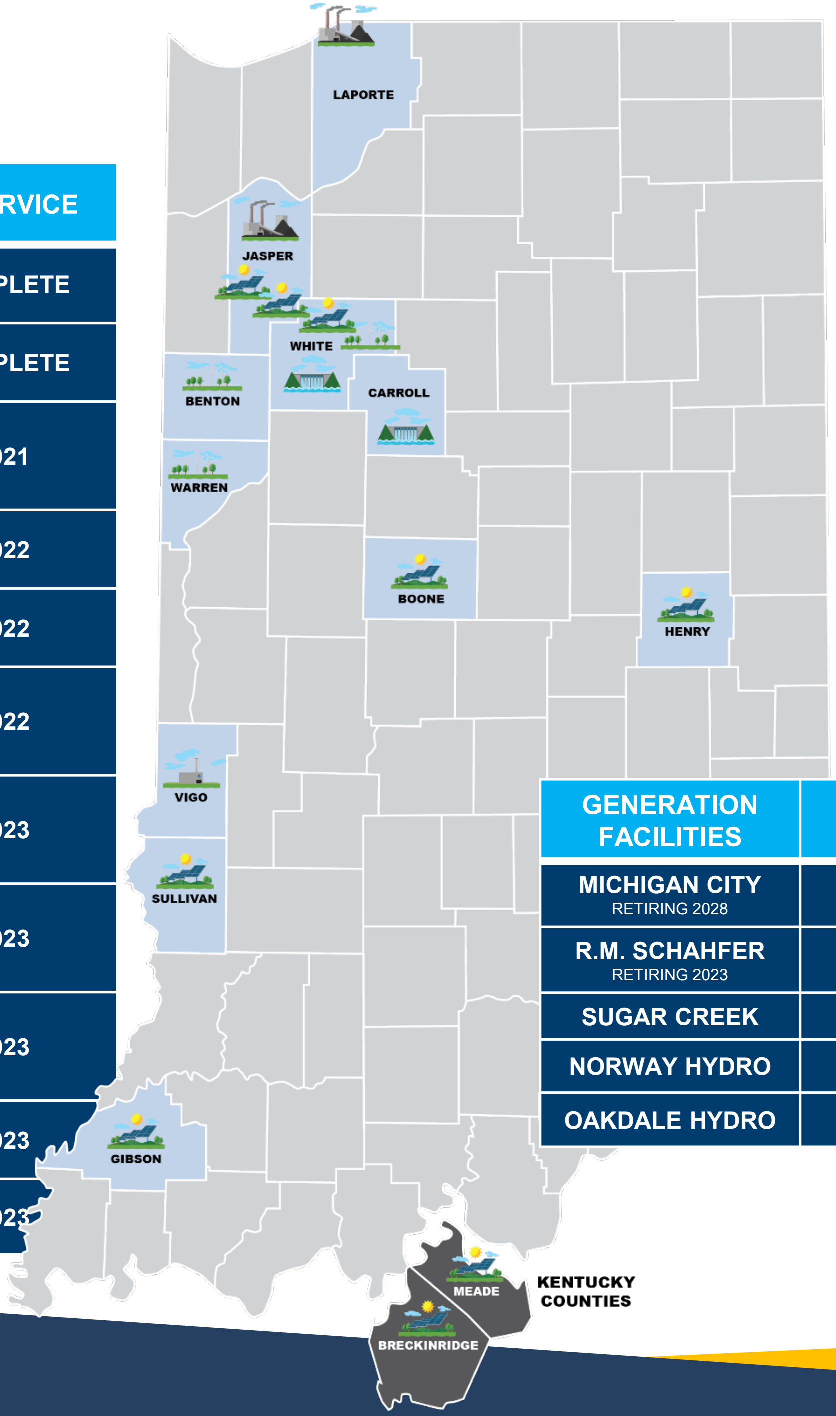
Fred Gomos, Director Strategy & Risk Integration, NiSource
Pat Augustine, Vice President, CRA

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

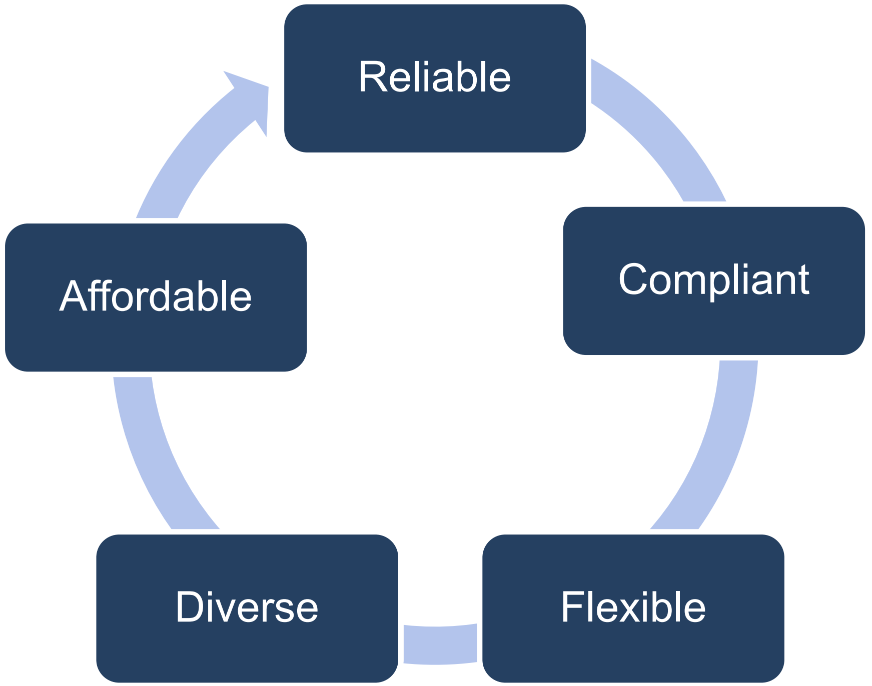
PROJECT	Installed Capacity (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102MW	WHITE	COMPLETE
JORDAN CREEK WIND	400MW	BENTON WARREN	COMPLETE
INDIANA CROSSROADS WIND	300MW	WHITE	2021
DUNNS BRIDGE SOLAR I	265MW	JASPER	2022
BRICKYARD SOLAR	200MW	BOONE	2022
GREENSBORO SOLAR	100MW +30MW BATTERY	HENRY	2022
GREEN RIVER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

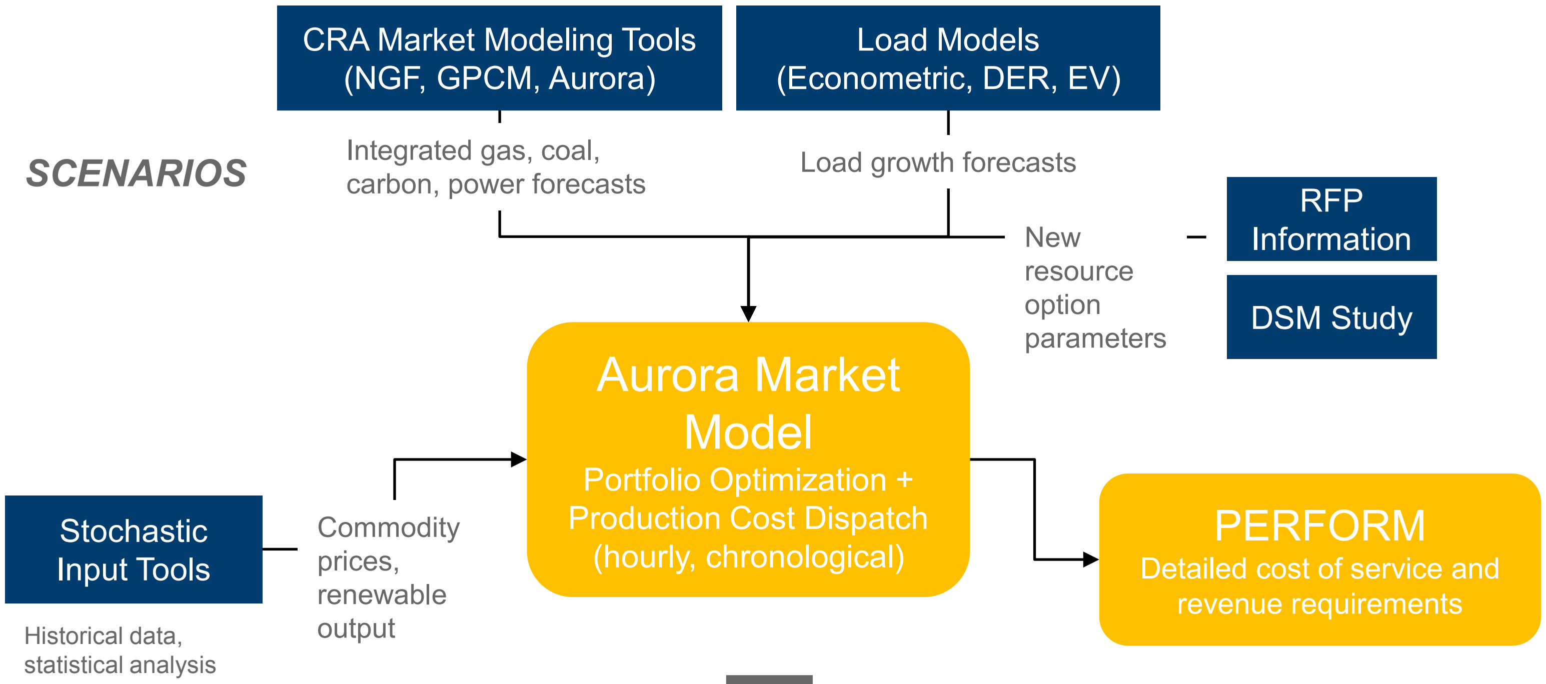
	Resource Adequacy	Energy Adequacy	Operating Reliability
Definition:	Having sufficient resources to reliably serve demand	Ability to provide energy in all operating hours continuously throughout the year	Ability to withstand unanticipated component losses or disturbances
IRP Considerations:	Ability to 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

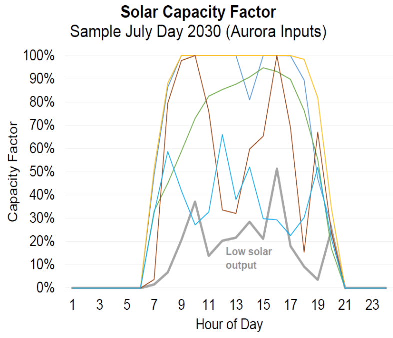
PORTFOLIO EVALUATION WILL INCORPORATE ELEMENTS OF MISO STUDY AND BROADER UNCERTAINTY ANALYSIS

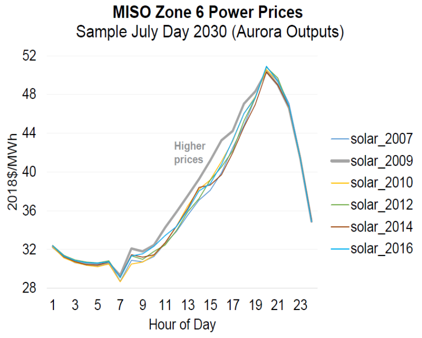
NIPSCO will be evaluating a broad range of portfolio options within a set of planning constraints in two stages

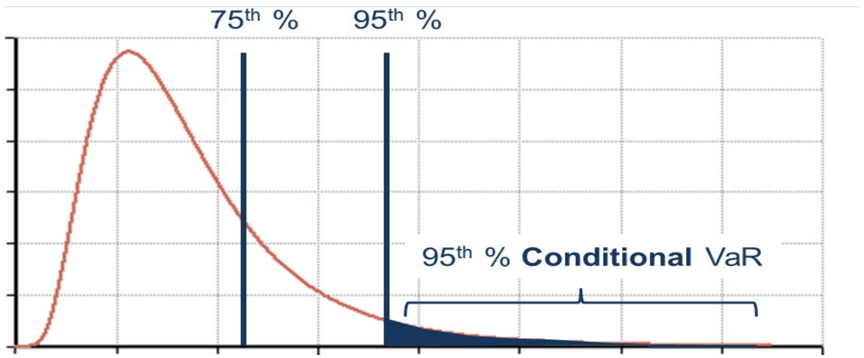
- **The Existing Fleet Review (Resource Retirements)**
- **Replacement Options**

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

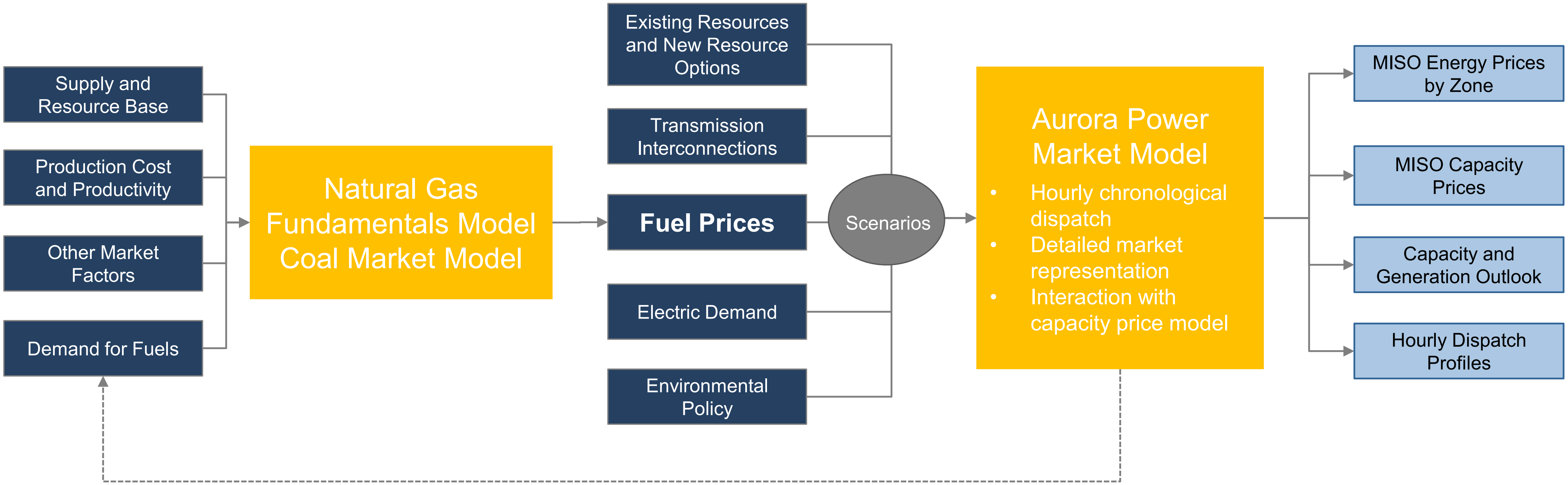
KEY ASSUMPTIONS UPDATE: COMMODITY PRICES

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

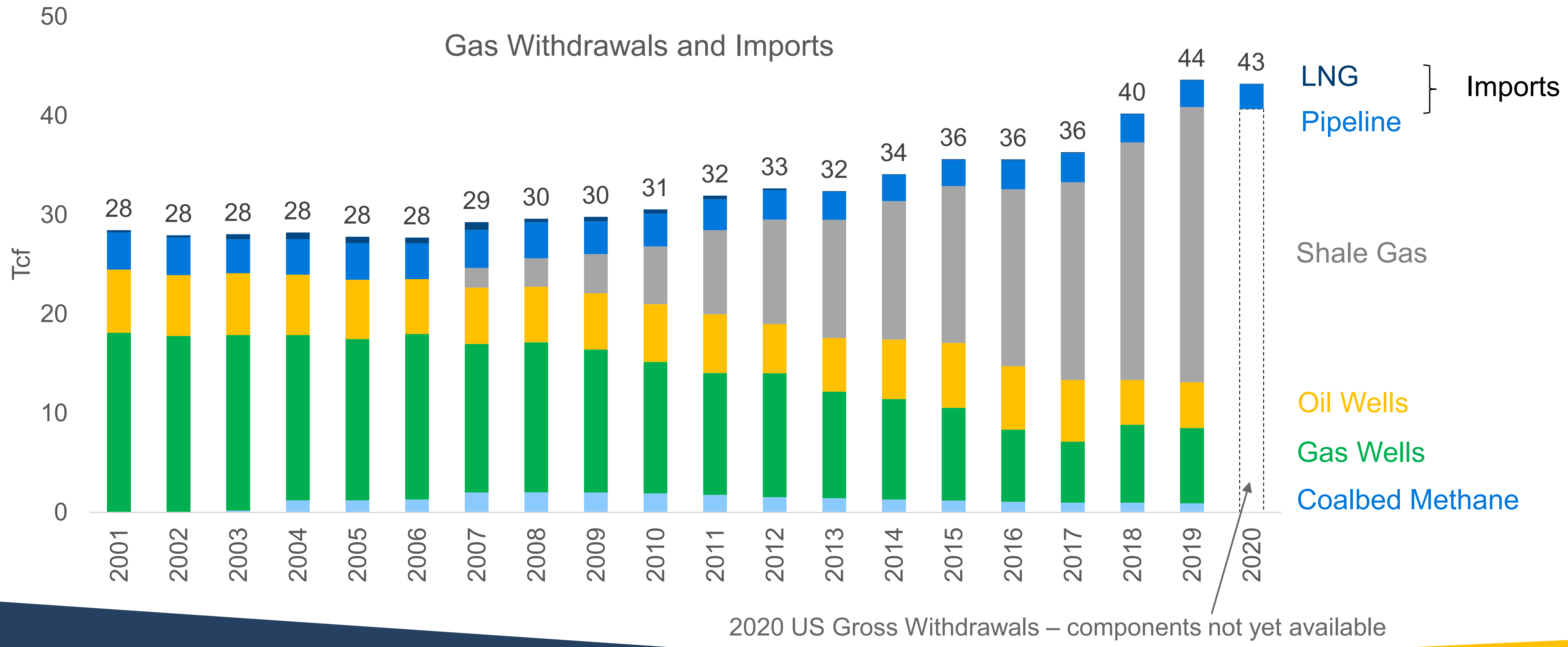
- Electric and non-electric sector demand forecast (domestic)
- International demand (net pipeline & LNG exports)

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



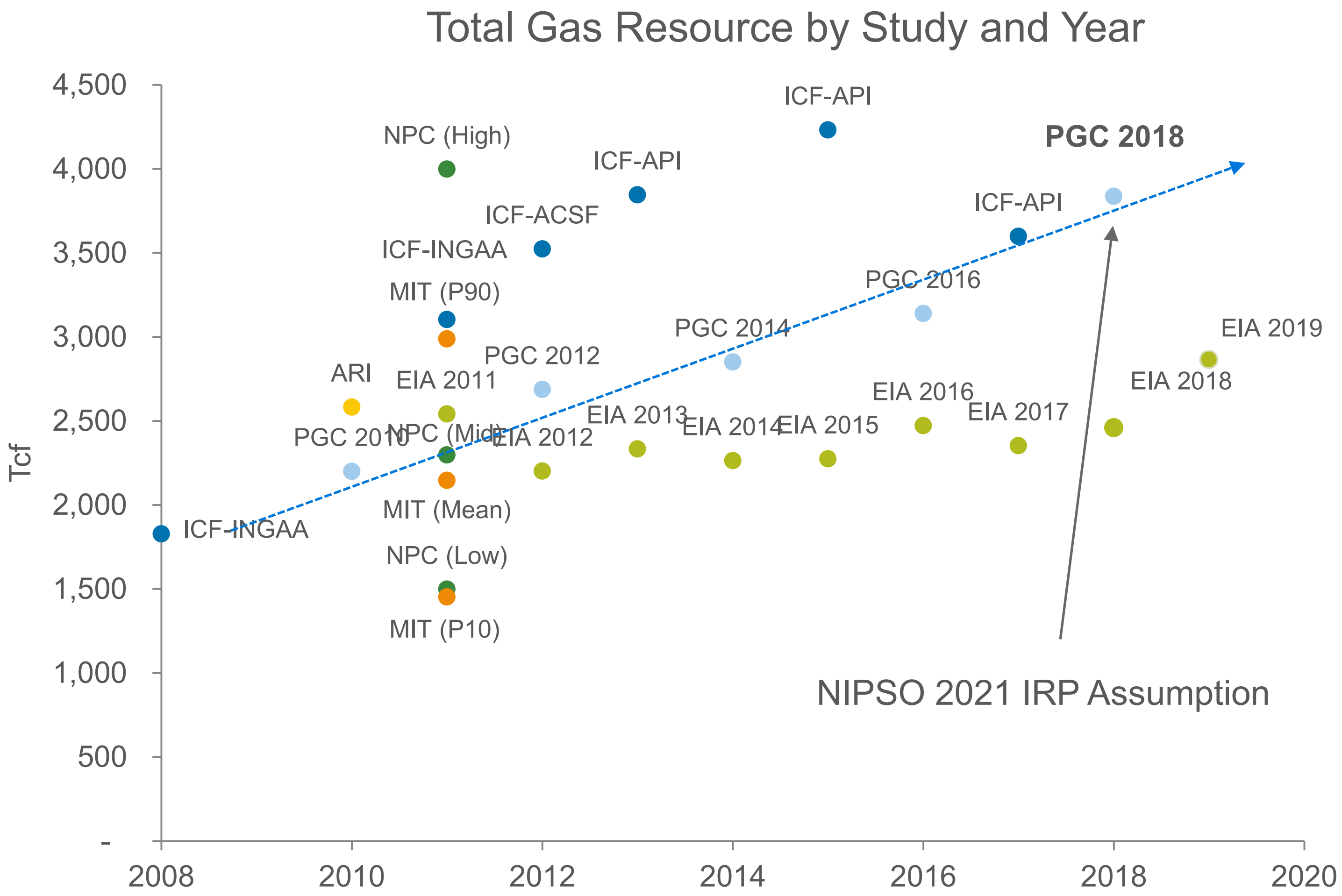
KEY DRIVERS OF THE REFERENCE CASE FORECAST

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

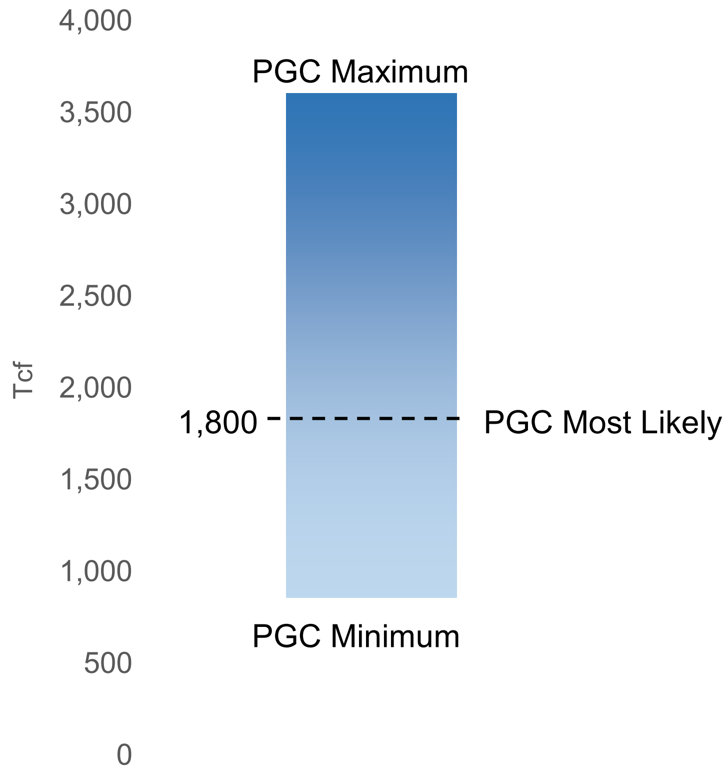
**Note: the PGC 2018 view was released in October 2019 and PGC 2020 is not expected to be available until late 2021*

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

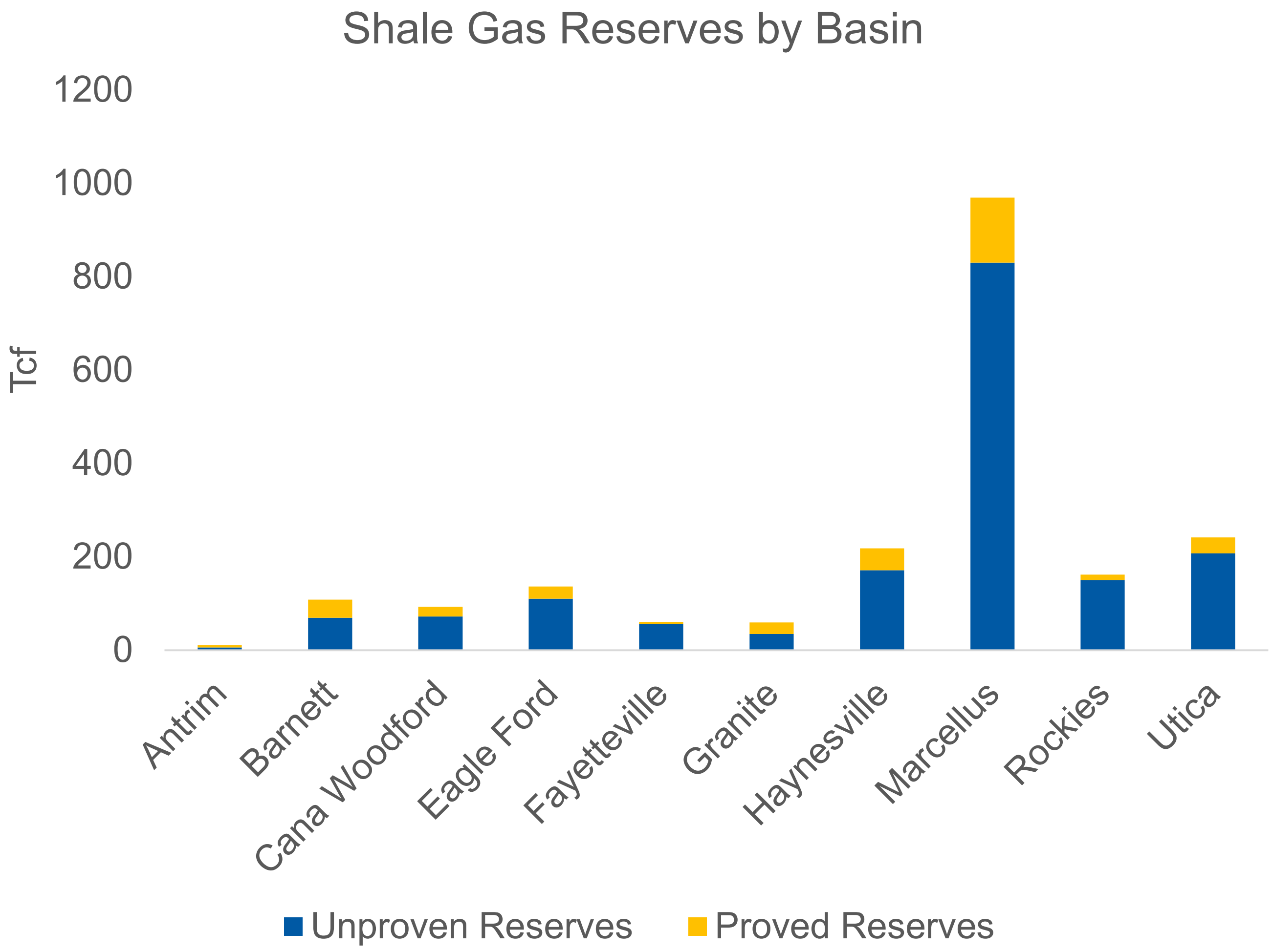
- **PGC evaluates three categories of potential resource:**
  - **Probable** – gas associated with known fields
  - **Possible** – gas outside of known fields, but within a productive formation in a productive province
  - **Speculative** – gas in formations and provinces not yet proven productive

- **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



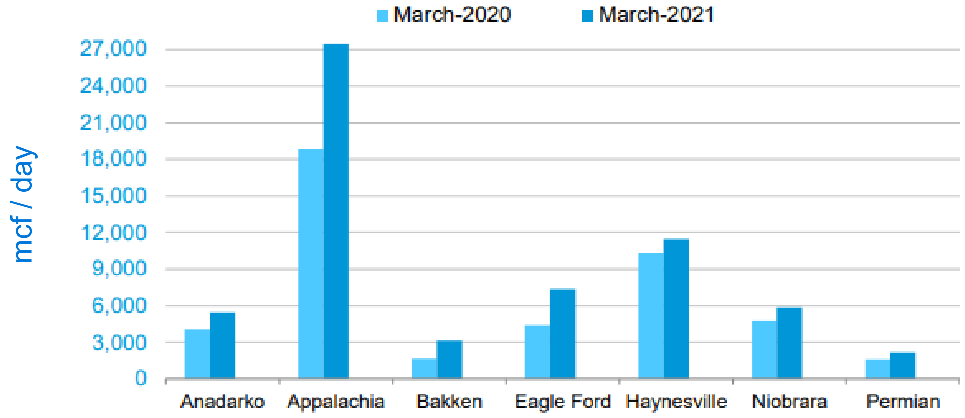
- "Proved" reserves are a known quantity and do not vary between the CRA Reference, High, and Low price views
- The quantity of "Unproven" reserves is uncertain, and varies between CRA natural gas price scenarios

PRODUCER PRODUCTIVITY

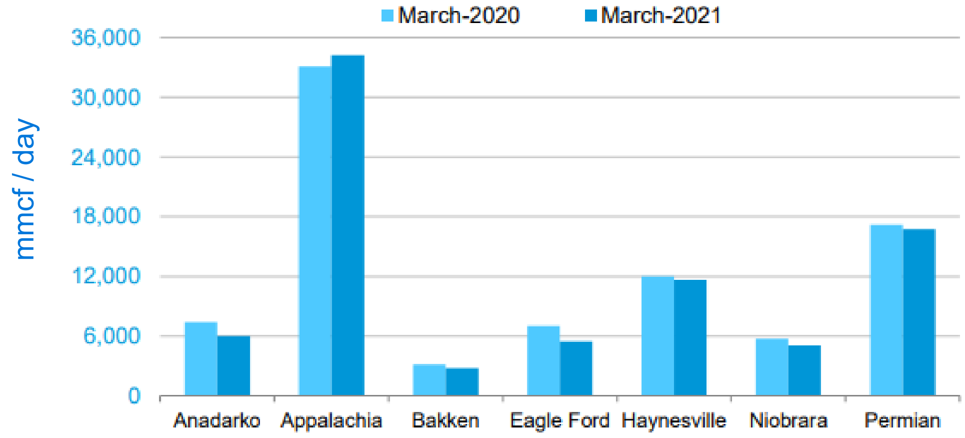
While gas producers reported improvements in average productivity in 2020, these appear to driven by focus on best producing regions, not major technical advancements

- 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

New Gas Production Per Rig



Natural Gas Production by Basin



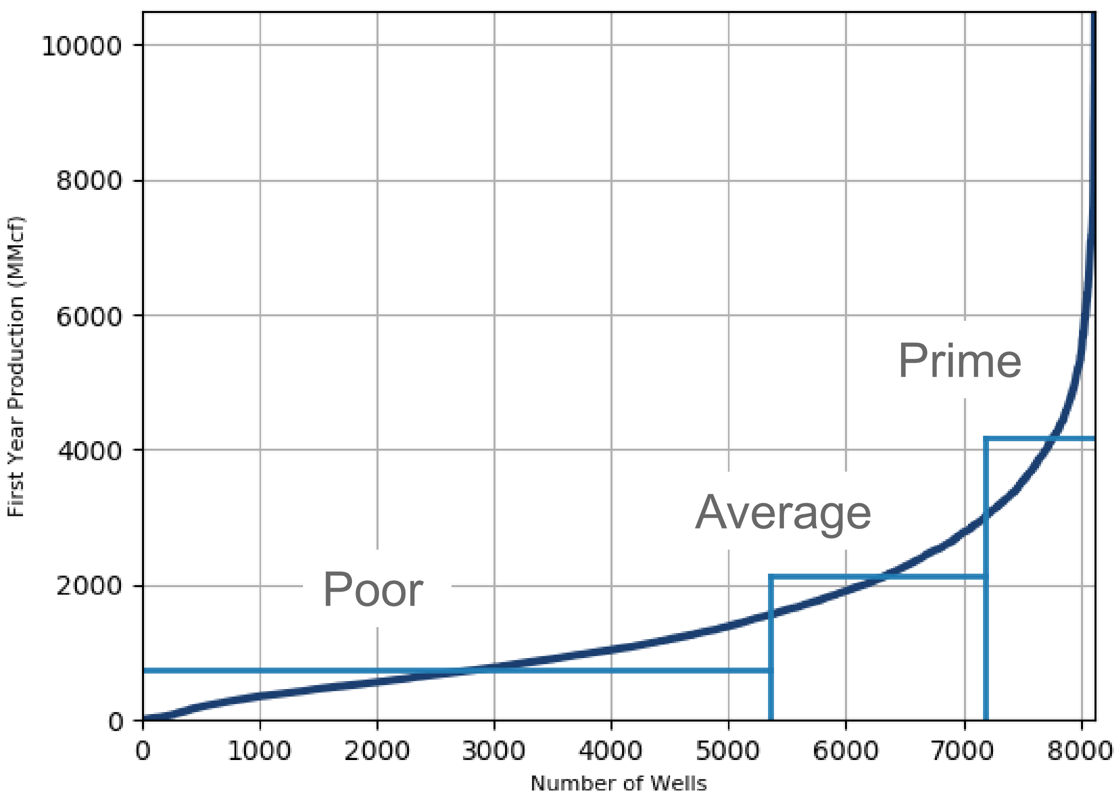
*Source: EIA Drilling Productivity Report

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

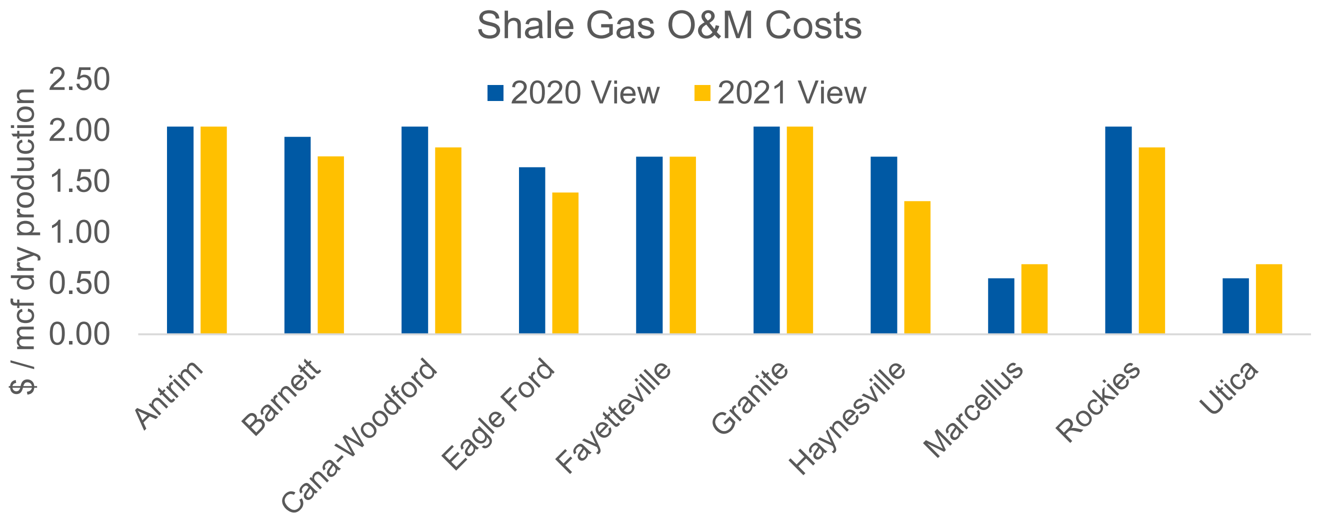
Productivity Distribution: Appalachia

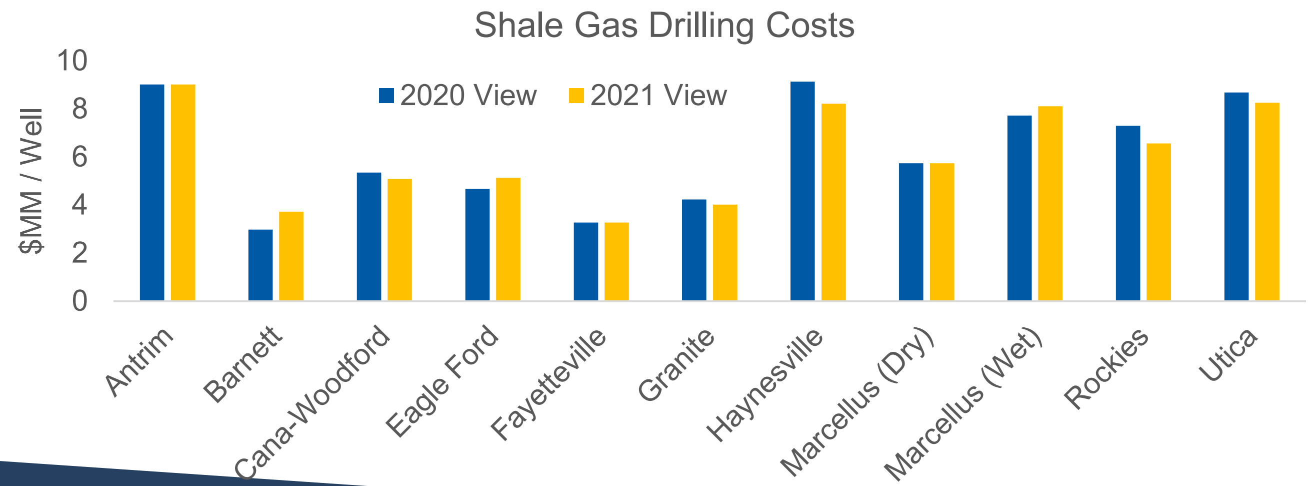


*Source: CRA analysis of Lasserdata drilling database

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

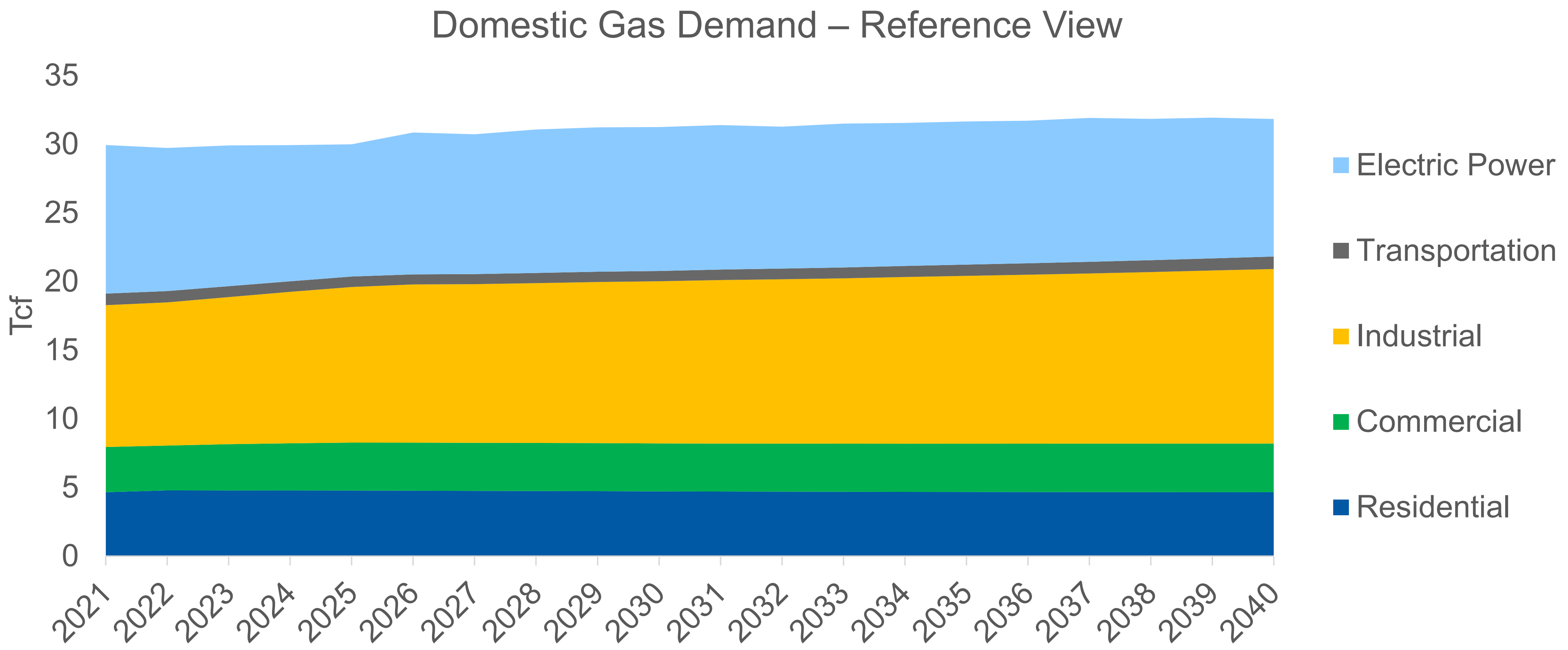
Crude oil and natural gas resource type	Drilling cost	Lease equipment and operating cost
Tight oil	-1.00%	-0.50%
Tight and shale gas	-1.00%	-0.50%
All other	-0.25%	-0.25%

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



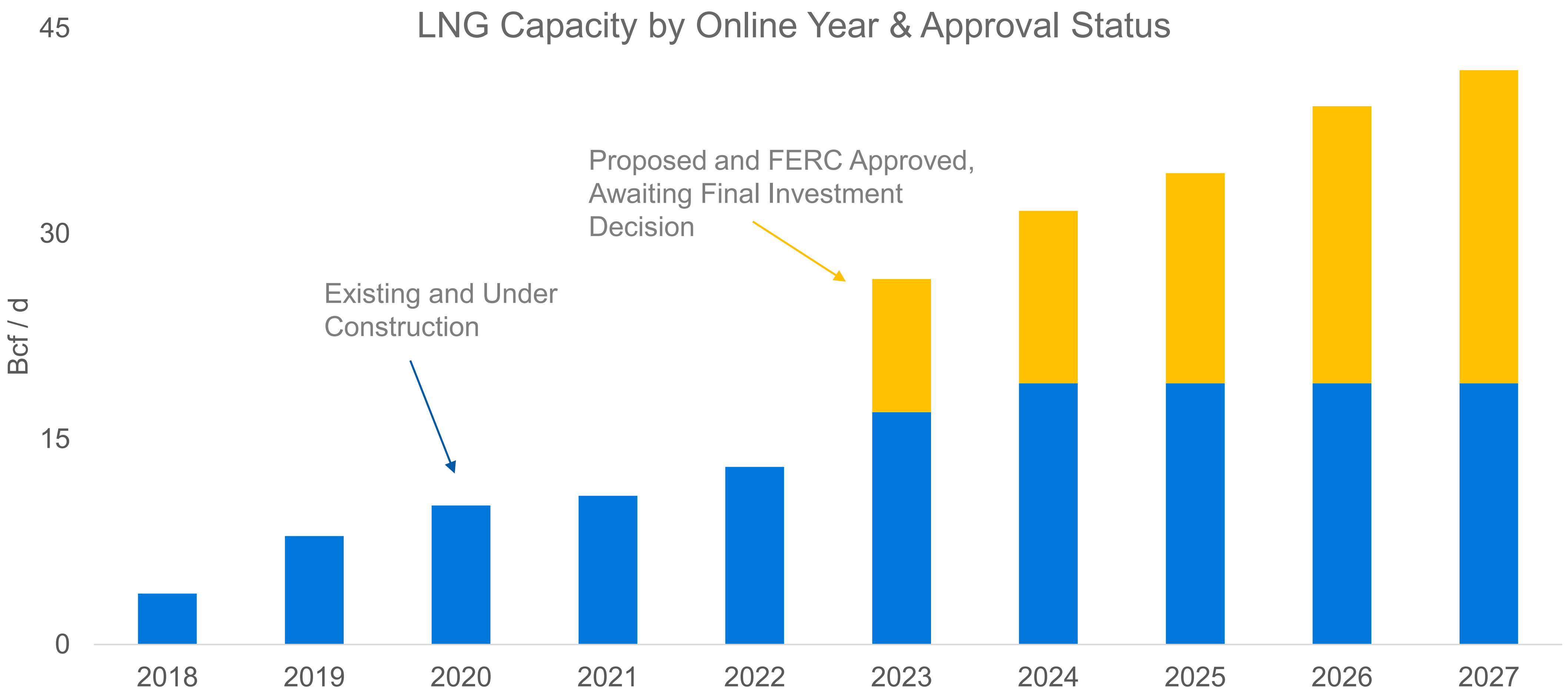
EXPORT GAS DEMAND – LNG

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**

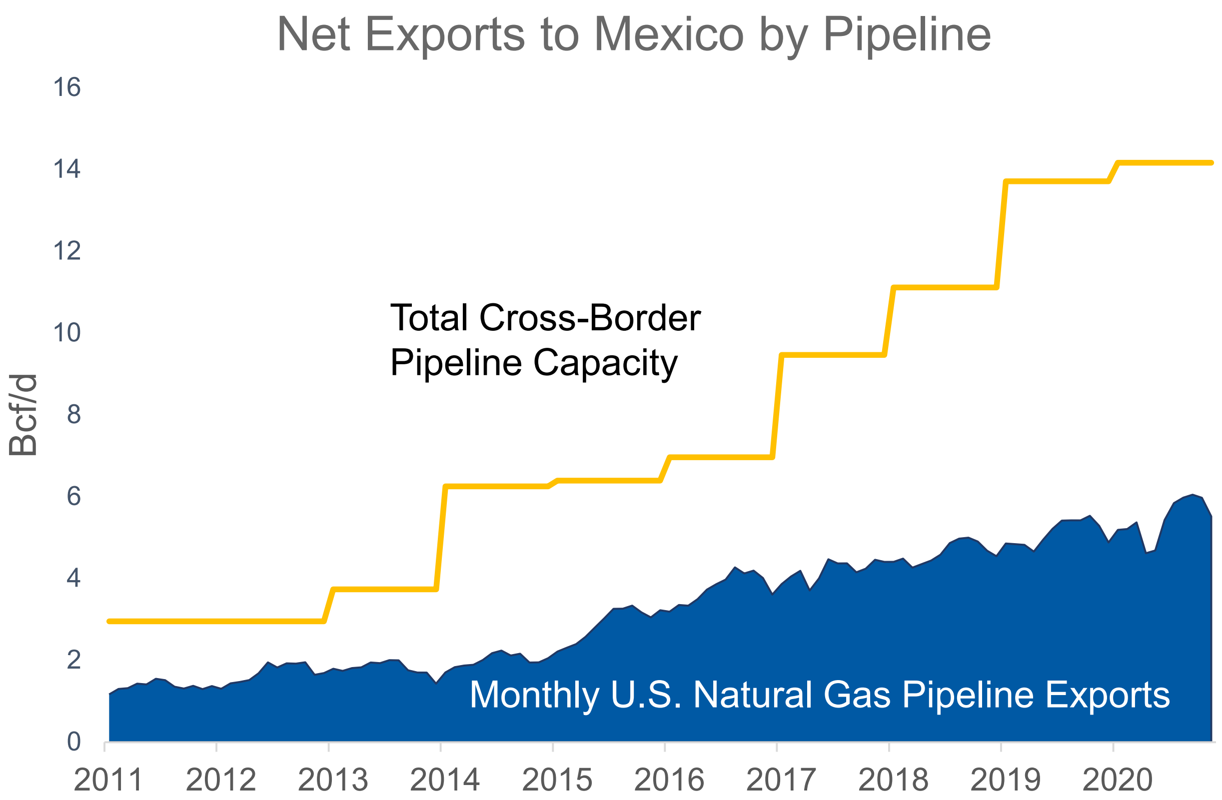
EXPORT GAS DEMAND – LNG

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

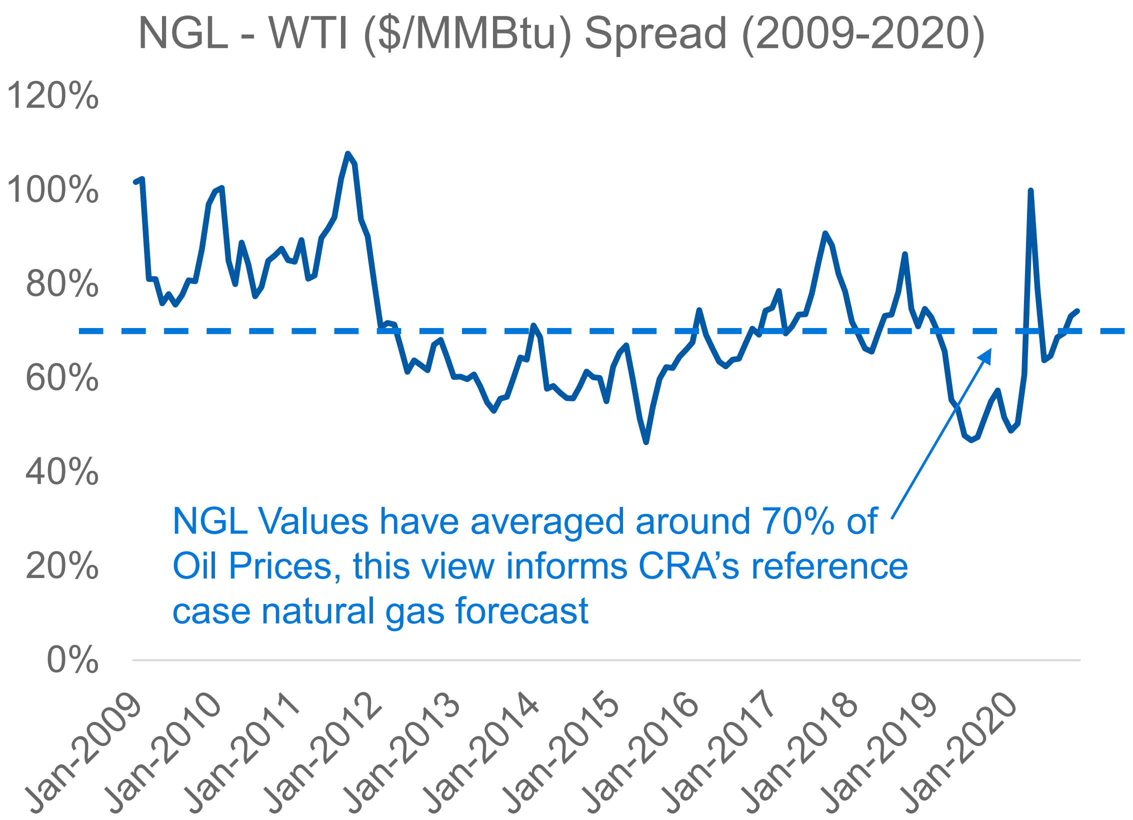
Actual shipments to Mexico from the US continue to lag behind total capacity improvements driven by recent pipeline expansion projects, and CRA expects this capacity will continue to be underutilized in the reference view

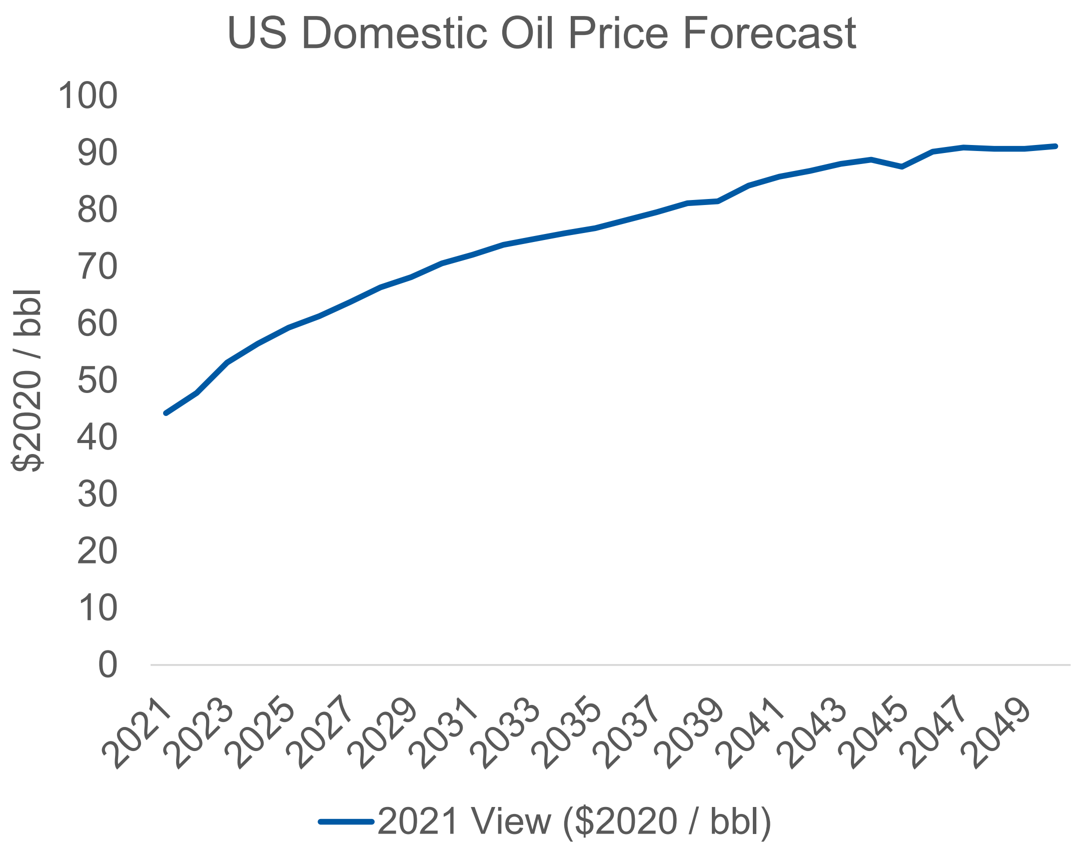


- Actual exports to Mexico have risen steadily over the last five years, but are not keeping pace with the expansion of cross-border export capacity
- Numerous pipeline projects within Mexico have faced construction delays, and completed projects are operating well below capacity
  - The 1.1 Bcf/d Comanche 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



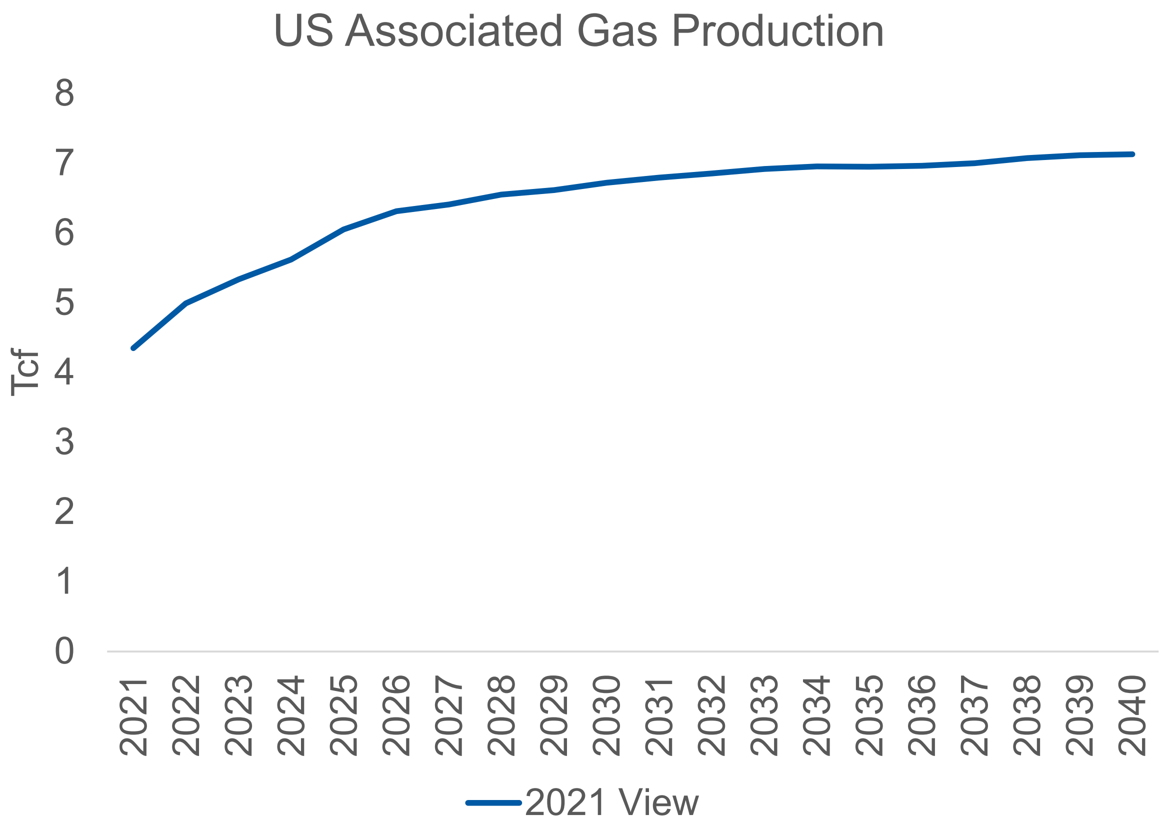


ASSOCIATED GAS PRODUCTION

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

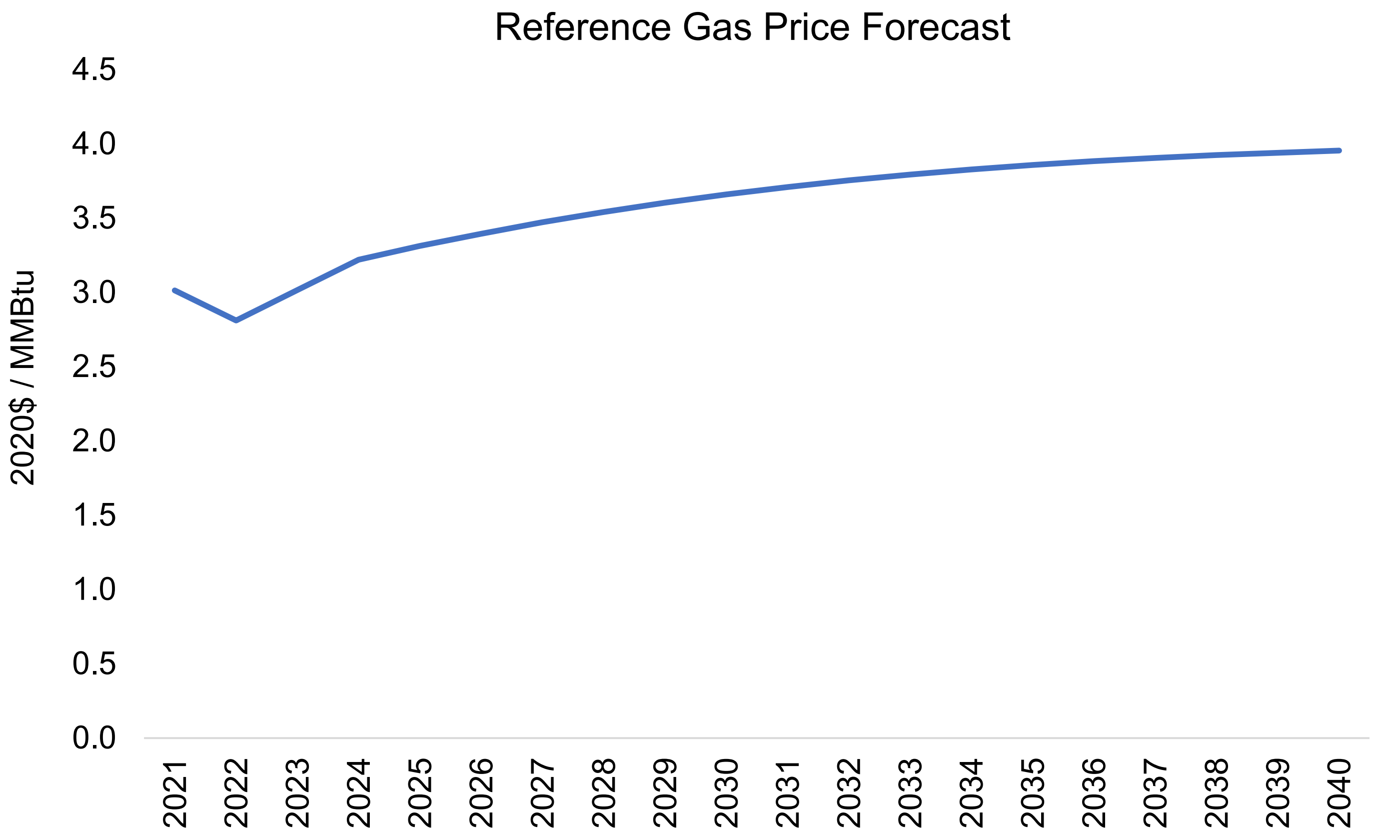
- EIA's forecast of associated gas production has fallen significantly in the 2021-2028 period relative to last year's forecast

- 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

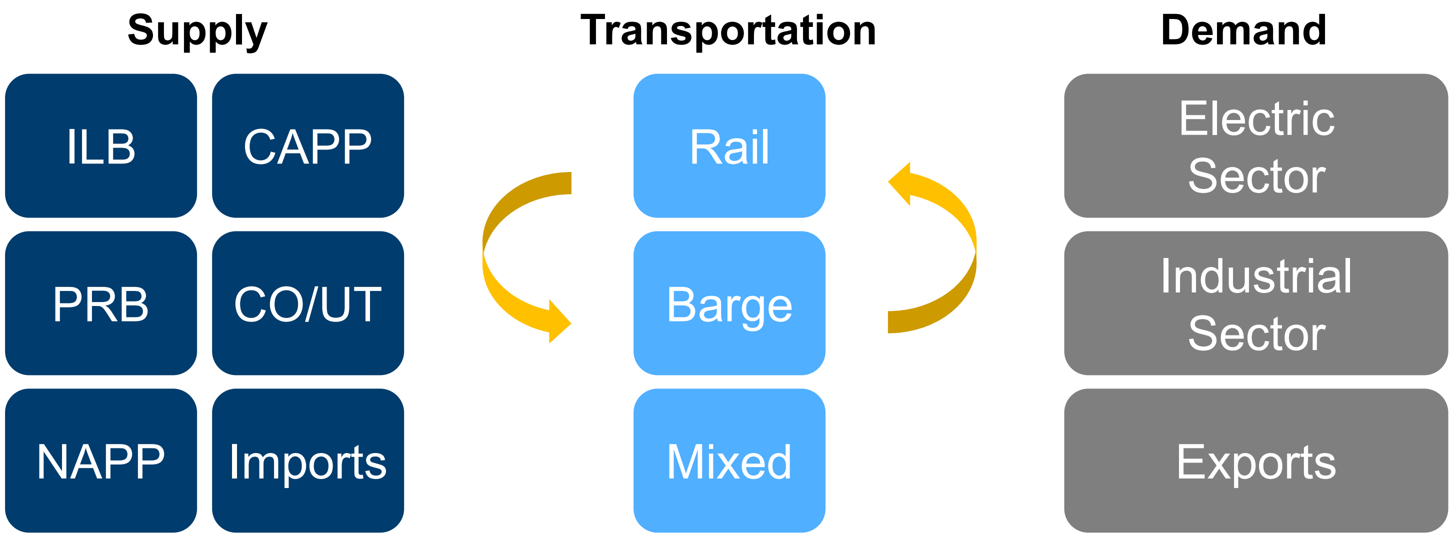


- The downward price pressure driven by improvements in drilling and O&M costs is moderated by lower domestic oil prices and associated gas volumes
- CRA observed limited productivity improvements in 2020 relative to prior years, and these seem to be primarily driven by crowding into prime regions, not 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

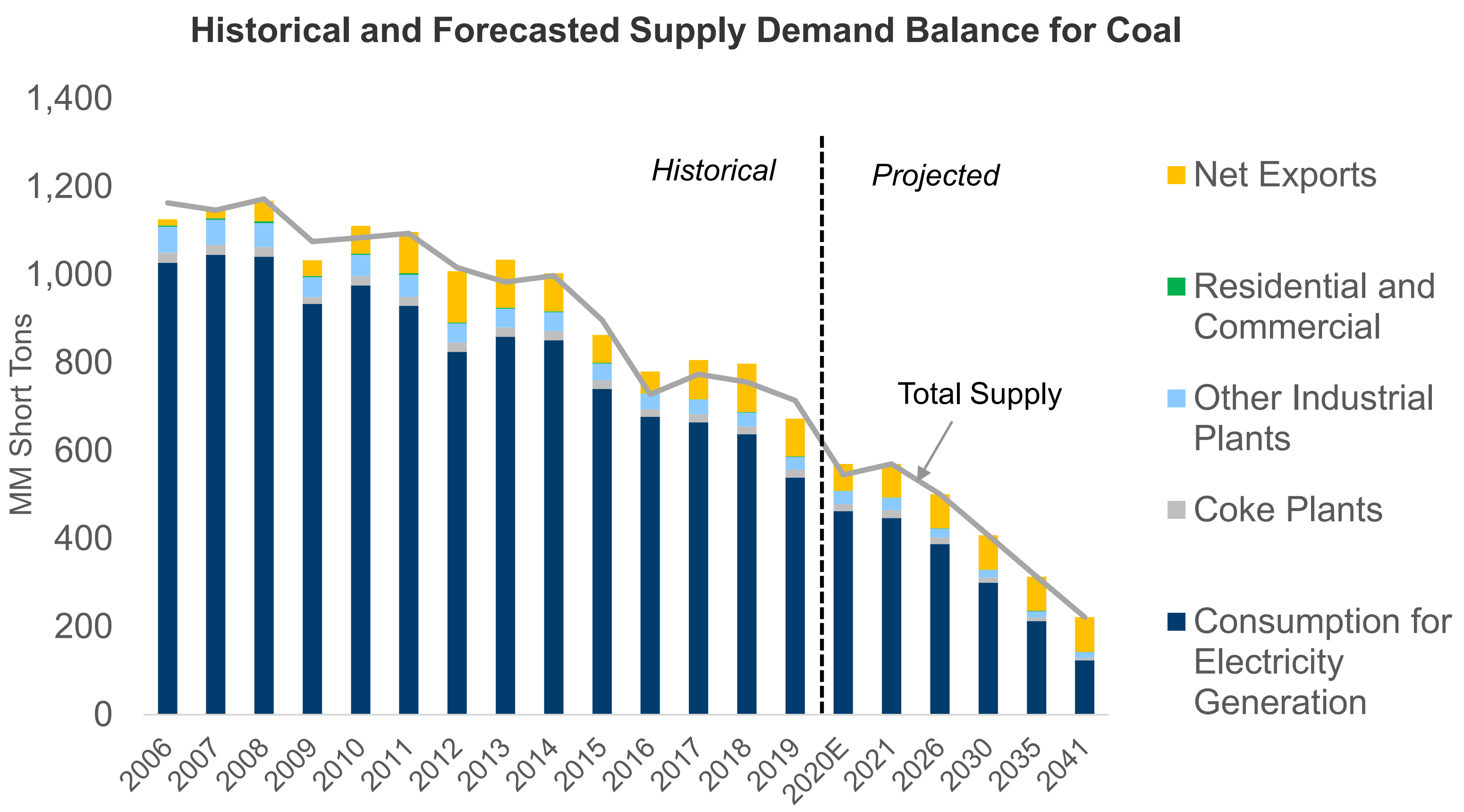
CRA forecasts coal prices based on an analysis of coal supply and demand dynamics

- 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

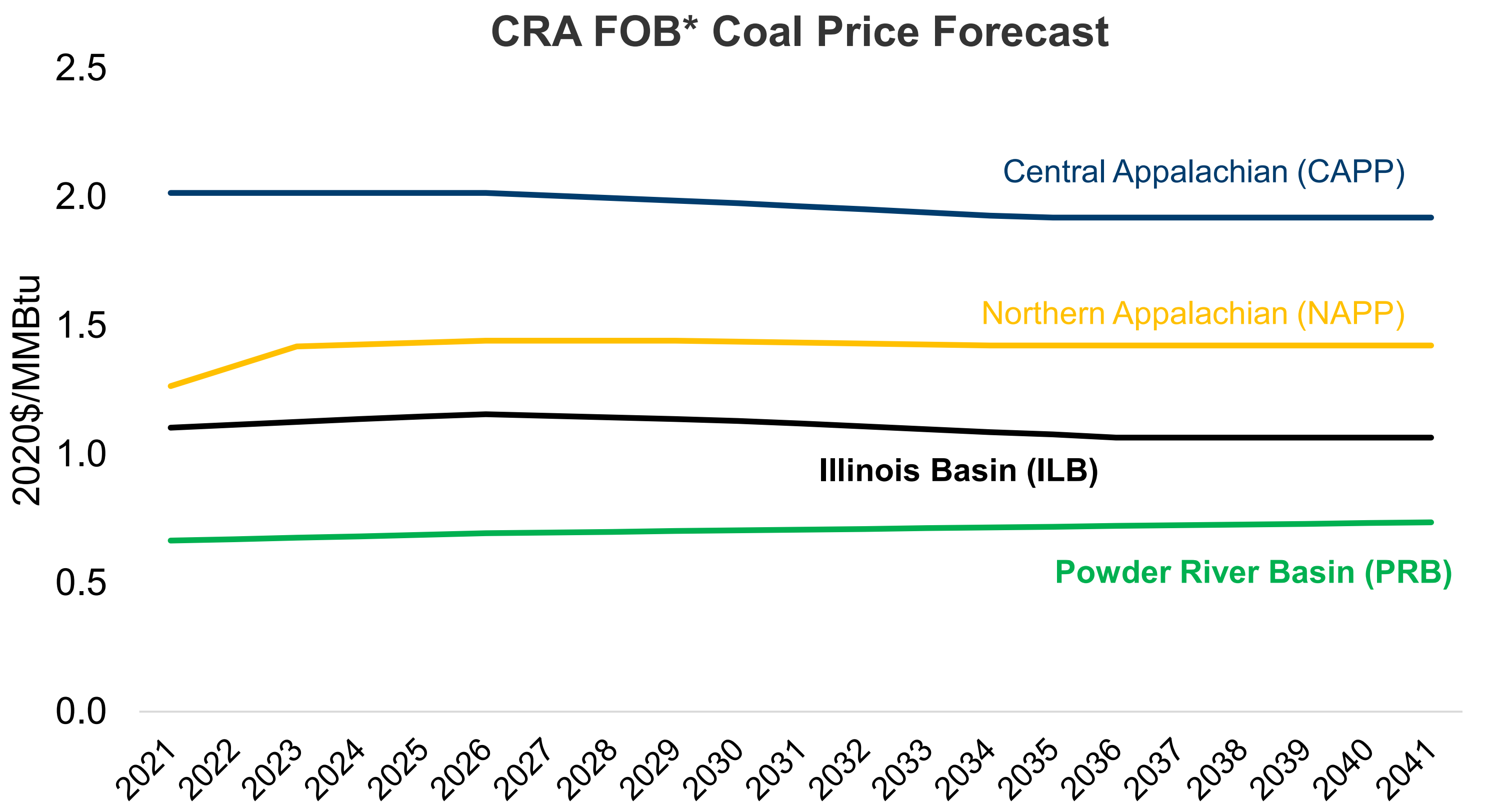


Historical: 2006-2019 data from EIA and MSHA
Forecast: CRA Analysis

- 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

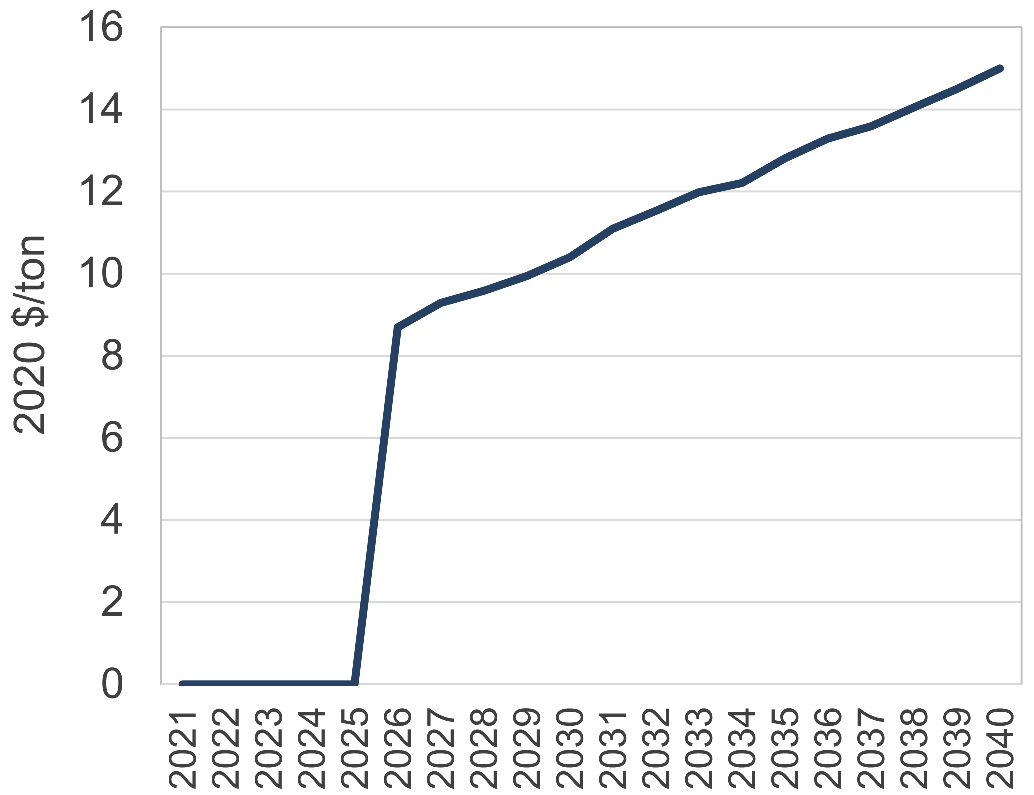
***Reference Case** with a modest carbon price in 2026 and beyond is reasonable and reflective of several pathways for regulation (legislation or executive action via EPA or FERC)*

REFERENCE CASE CARBON PRICE DEVELOPMENT

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

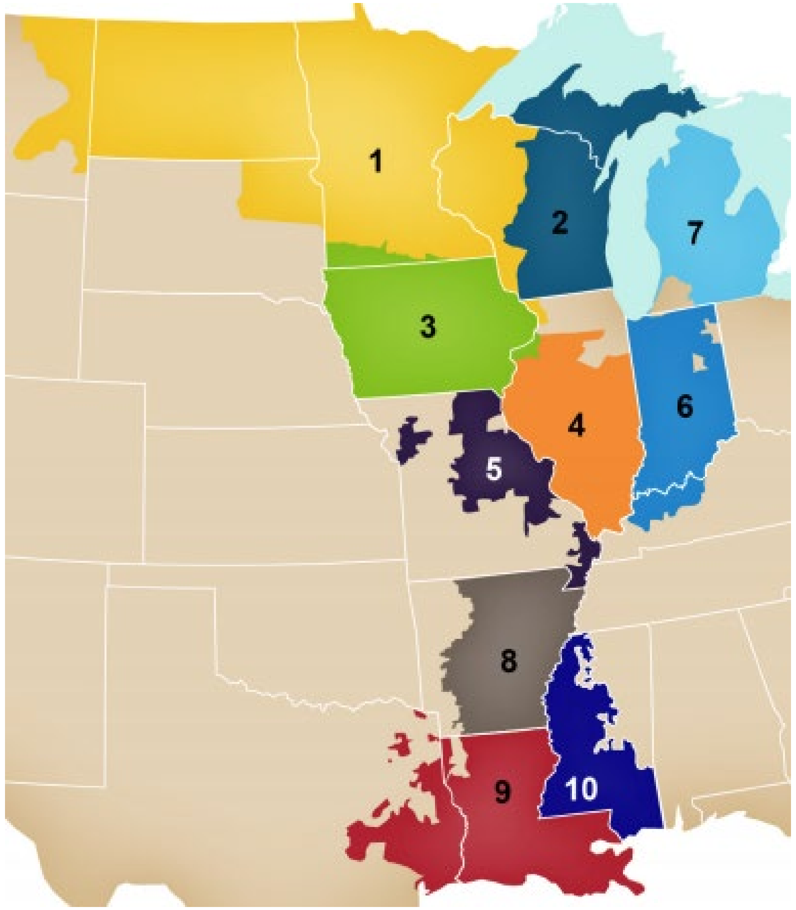
<u>Reference Case</u> (similar to 2018 IRP)

- 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, <u>*with a current or recent historical baseline year*</u>
- 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



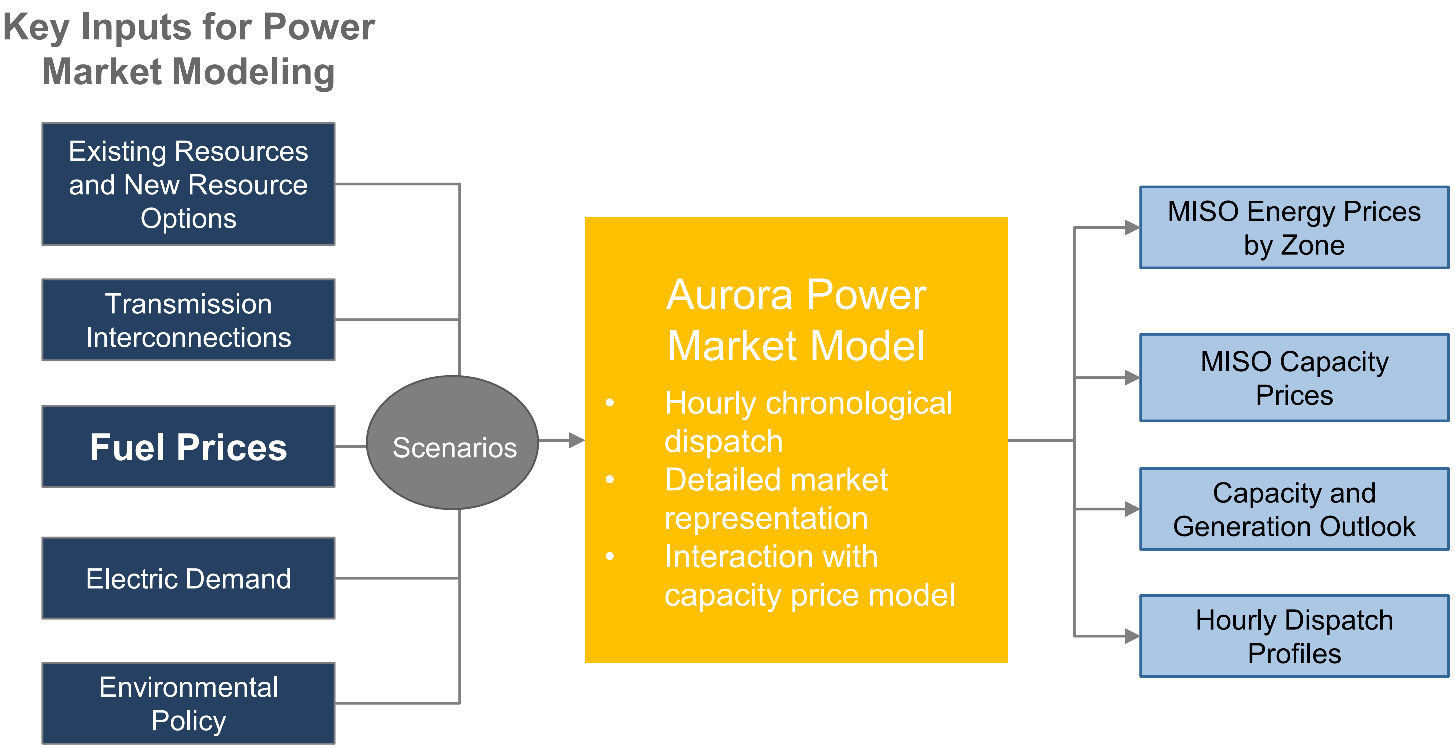
MISO OVERVIEW

- 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



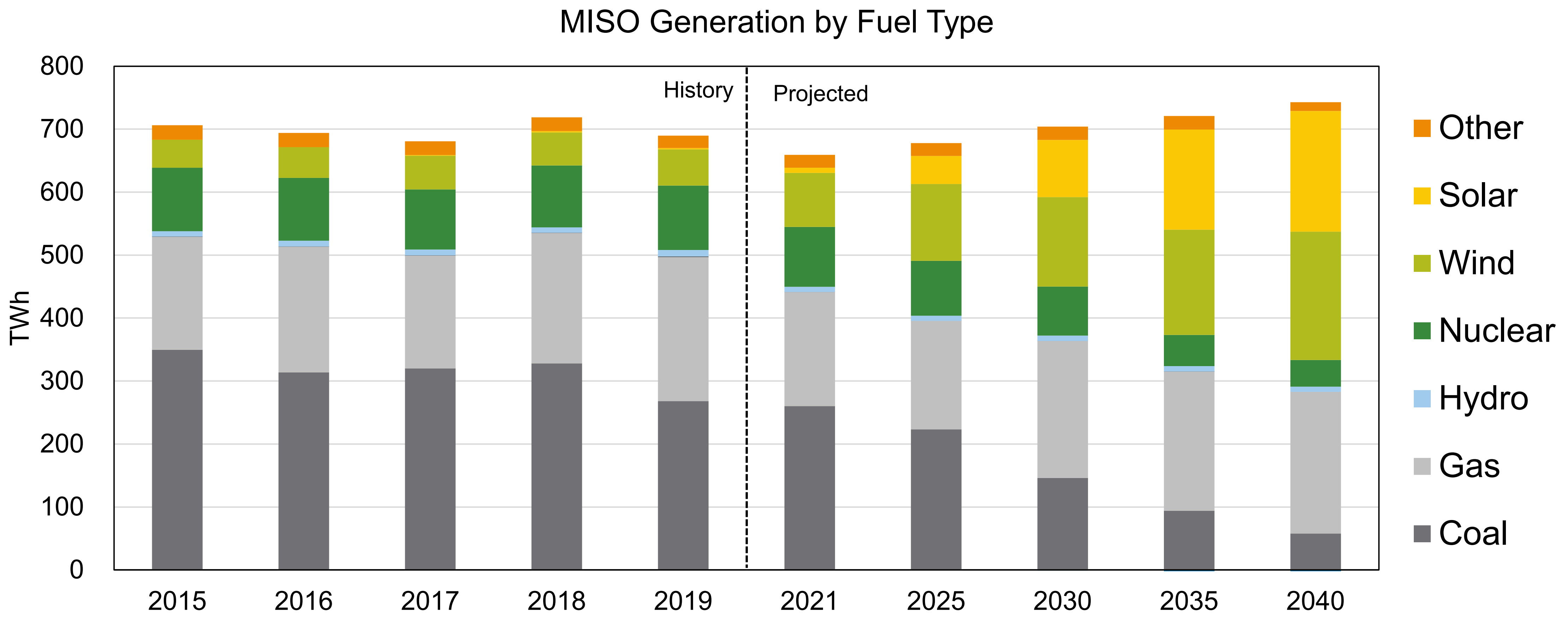
SUMMARY OF KEY MISO MARKET INPUTS FOR REFERENCE CASE

- **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

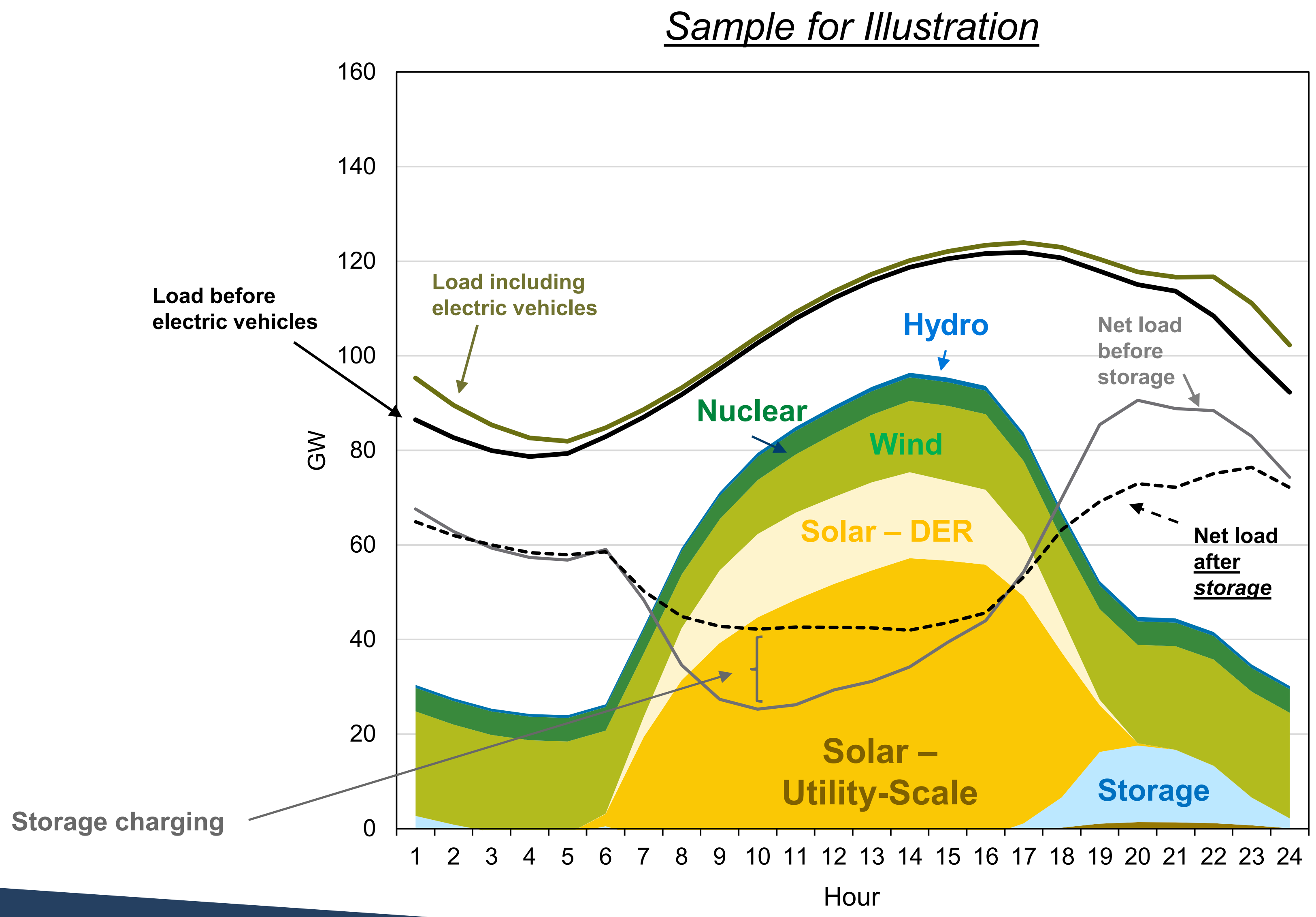


MISO ENERGY PROJECTED TO SHIFT TOWARDS RENEWABLES

- 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 =

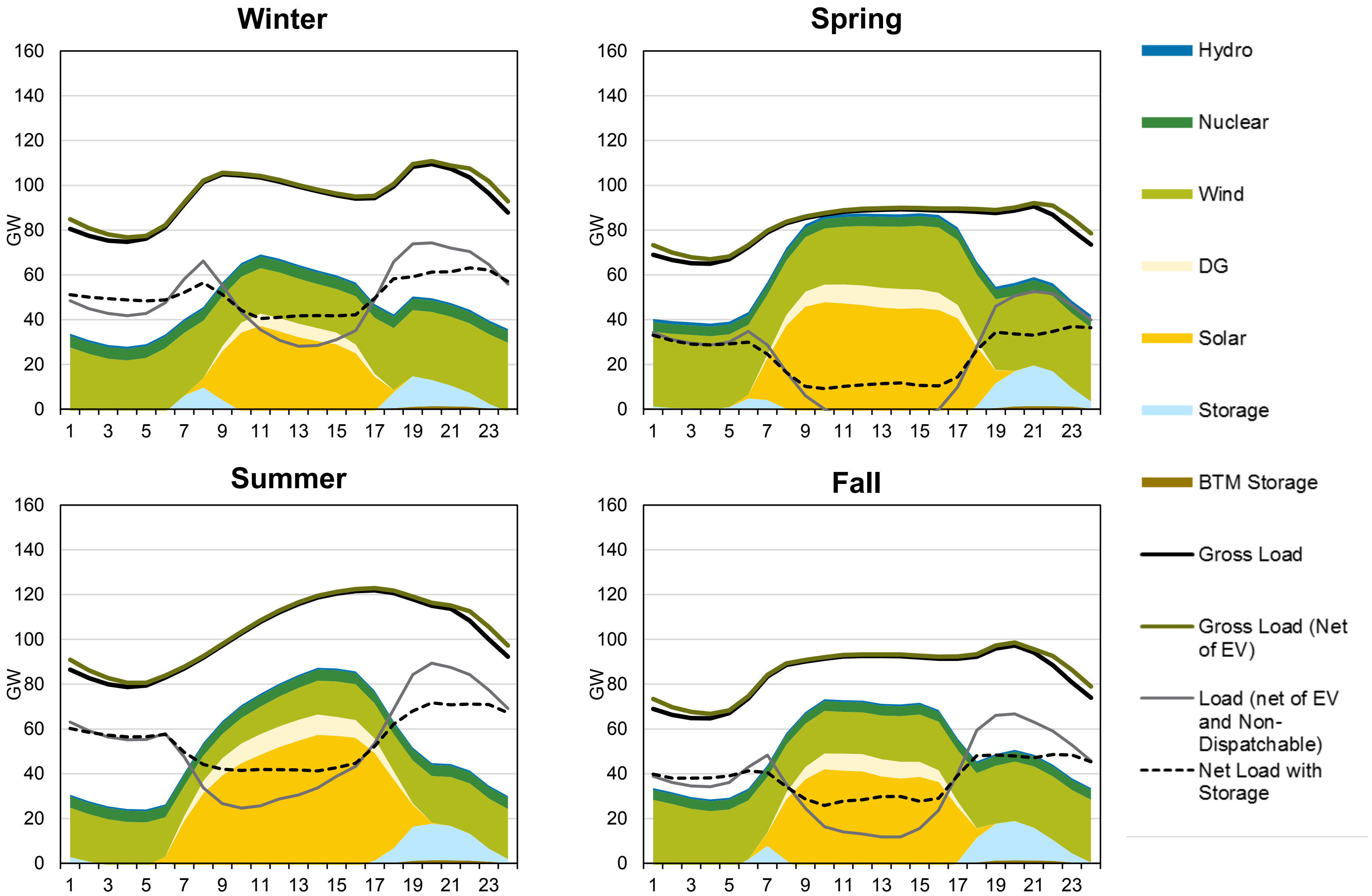
Load (including EVs)

minus

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

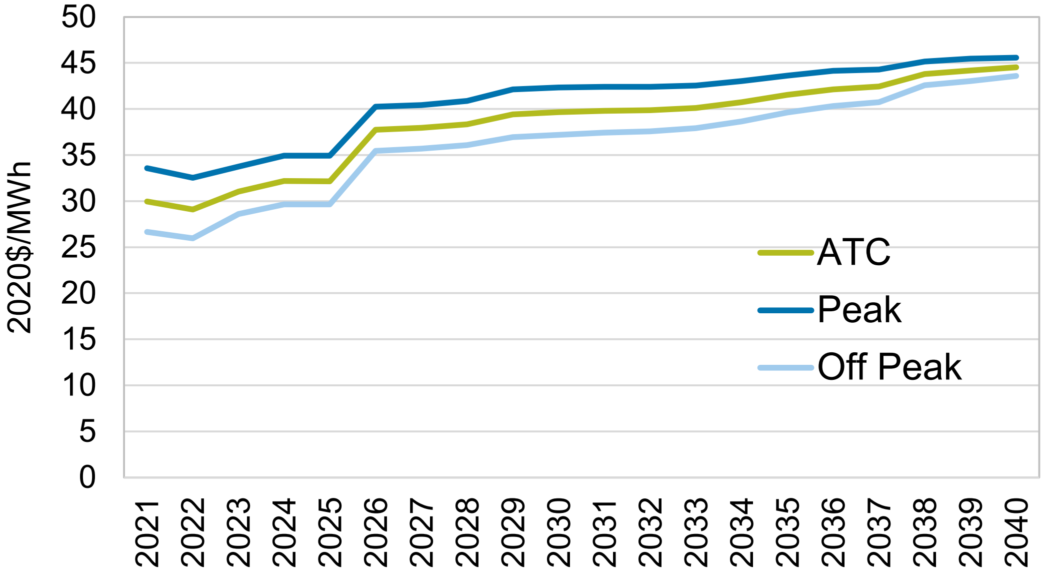
HOURLY ENERGY PROFILE – MISO 2040

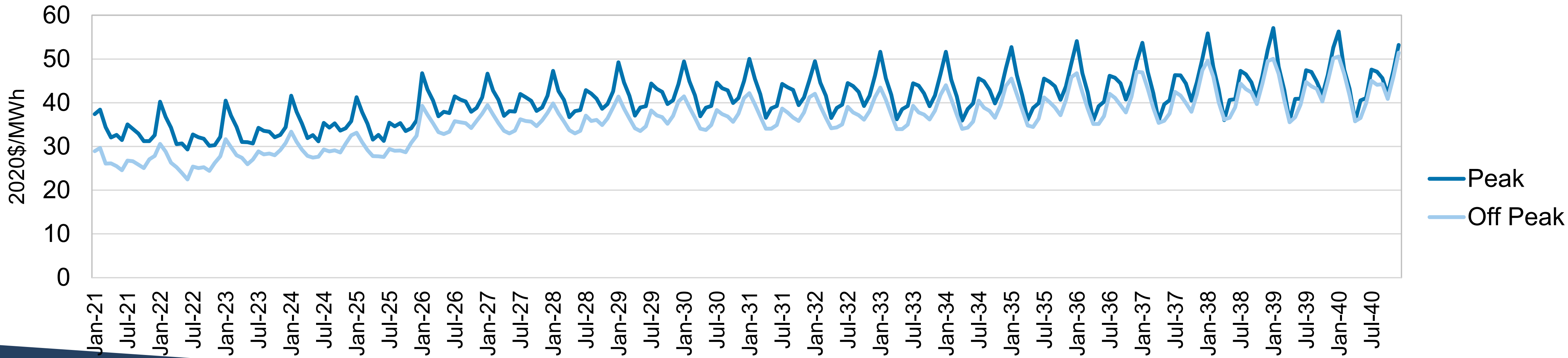
- Renewable penetration will impact resource dispatch and MISO hourly prices over time, with differences by season:
  - Mid-day hours in the spring may have sufficient generation output to meet demand
  - Summer evening peaks will require ramping support



REFERENCE CASE POWER PRICE FORECAST – MISO ZONE 6

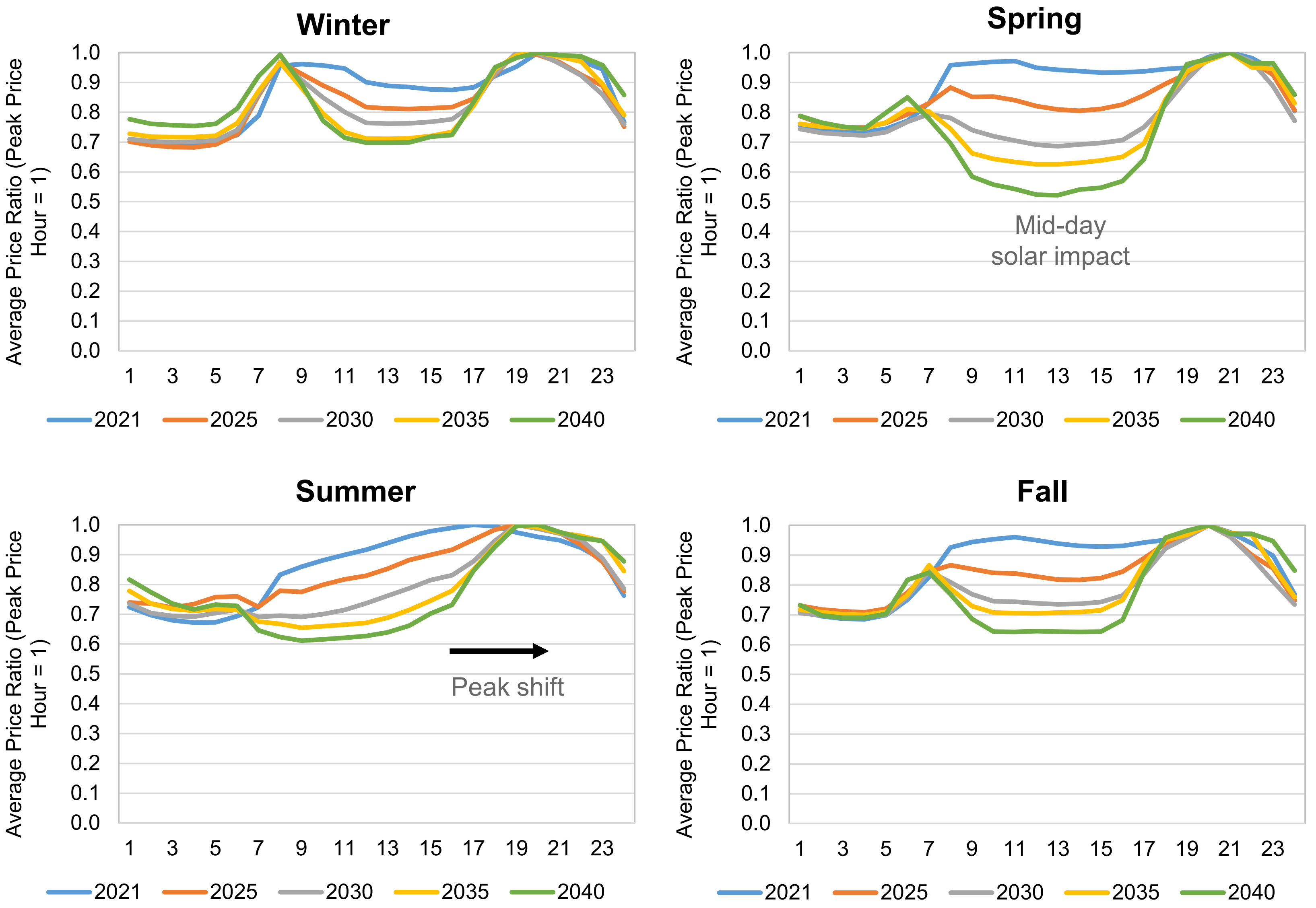
- Power prices are expected to stay relatively flat in the near-term, due to flat gas and coal prices
- Some upward pressure expected into the 2020s as a result of higher natural gas prices, although growing renewables lower the market heat rate over time
- National carbon price, starting in 2026, drives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





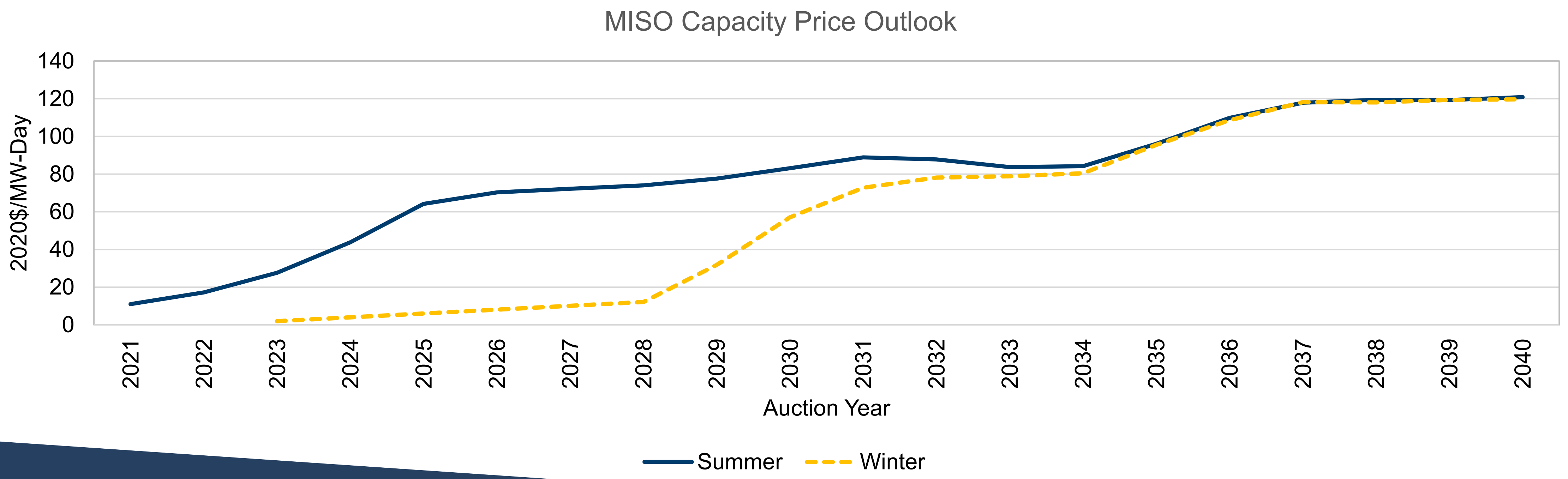
HOURLY PRICE SHAPES EXPECTED TO EVOLVE OVER TIME

- 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

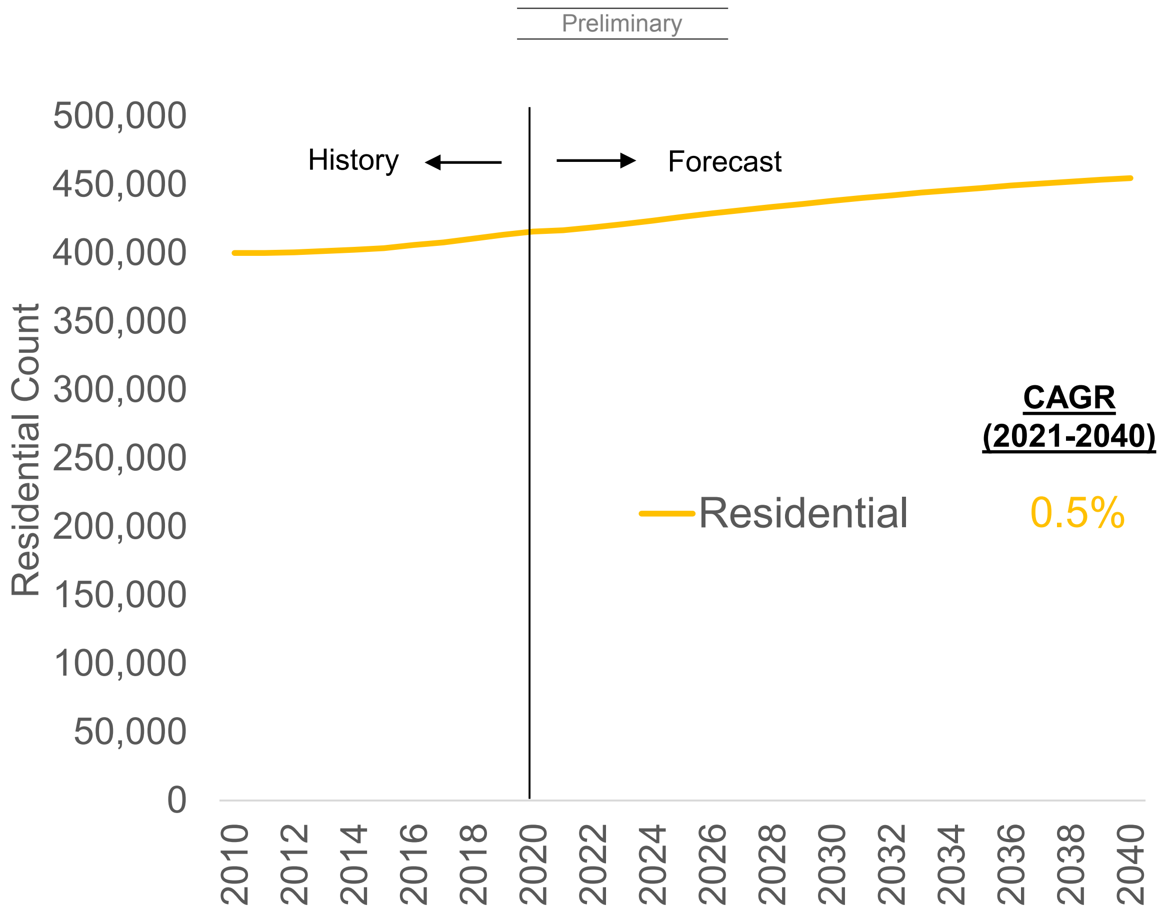
- Baseline customer count and sales per customer energy forecasts by class are projected with best fitting regional macroeconomic variables, heating and cooling degree days, seasonality factors, and expected retail rate growth trends
- CRA tested various macroeconomic variables using Moody's historical 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)

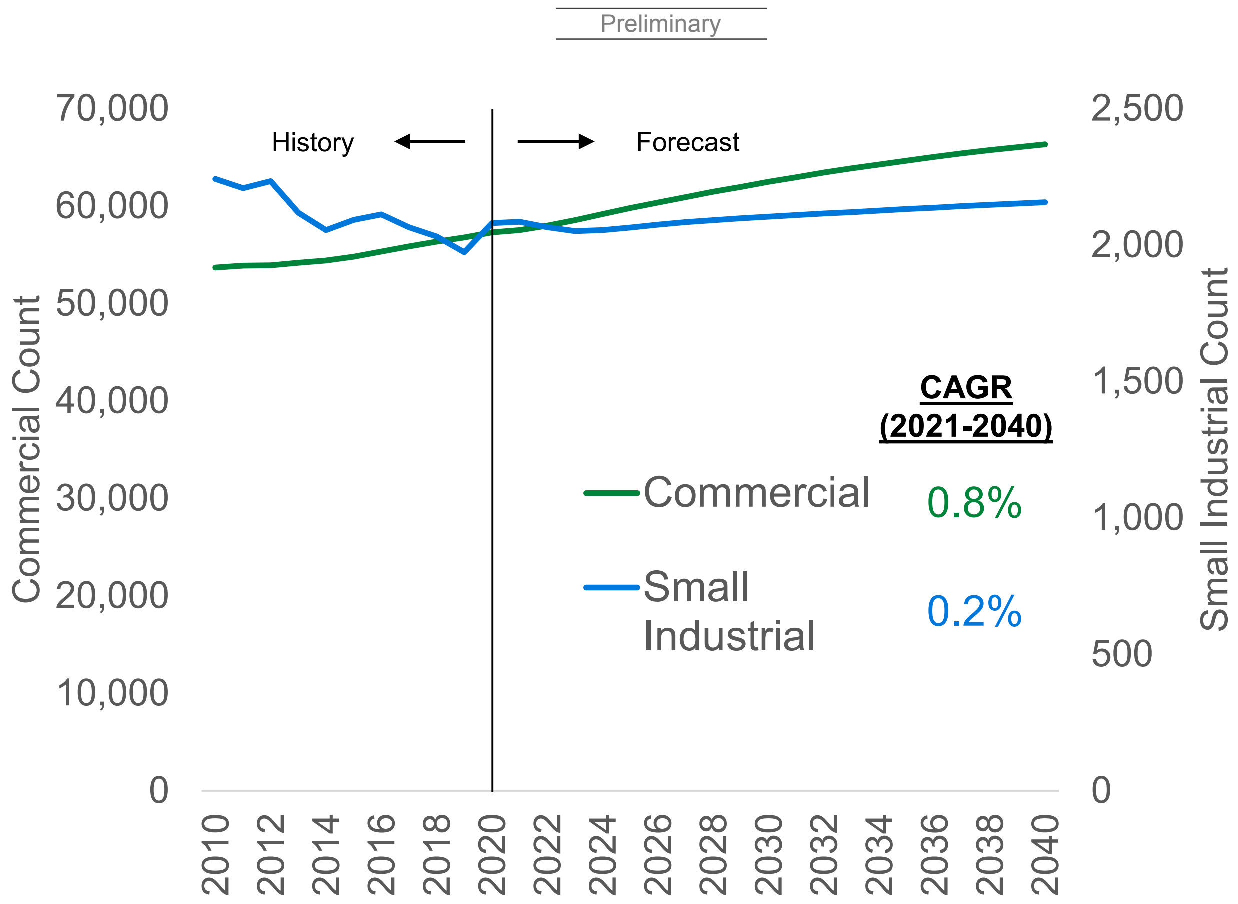
	Residential	Commercial	Small Industrial
Customer Count Forecast	*Number of households*, seasonal and annual dummies	*Number of households*, seasonal and annual dummies	*Manufacturing employment*, seasonal and annual dummies
Baseline Sales per Customer Forecast	*Real personal income*, average retail rate,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

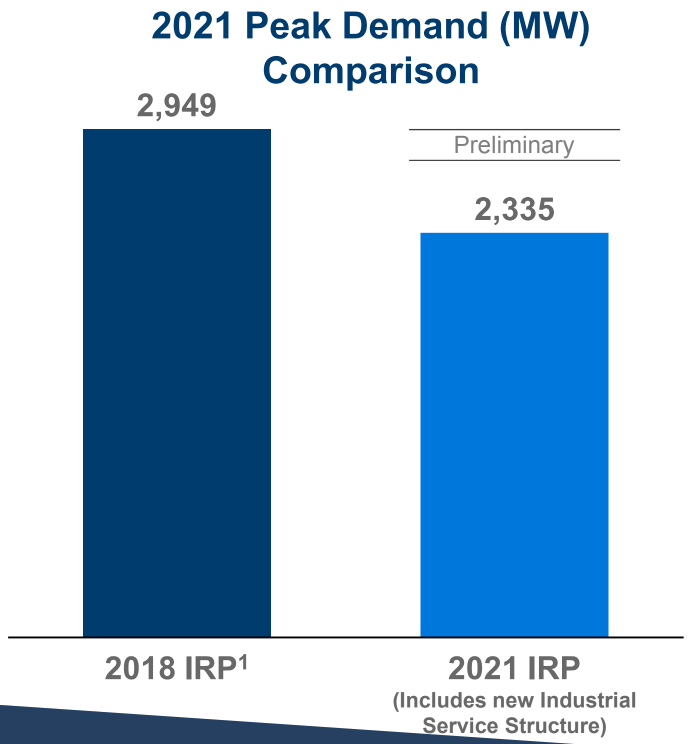
Customer count expectations are largely driven by number of households (R and C) and manufacturing employment expectations (Small I)

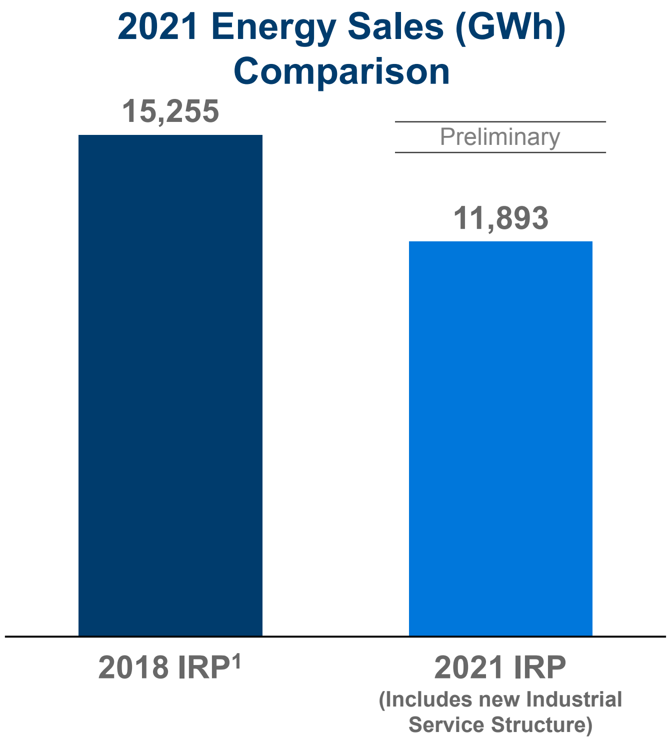




NEW INDUSTRIAL SERVICE STRUCTURE

- 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

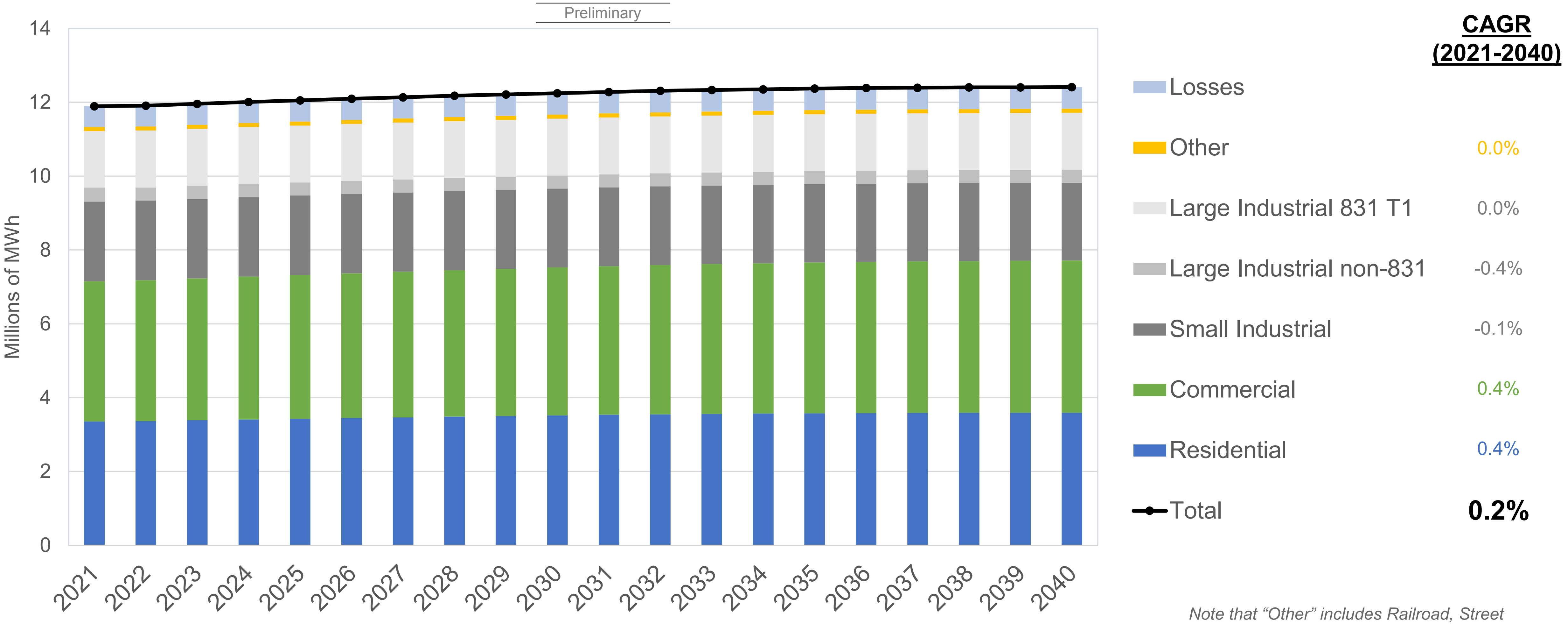




[1]Source: 2018 IRP p. 29 (Table 3-10)

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

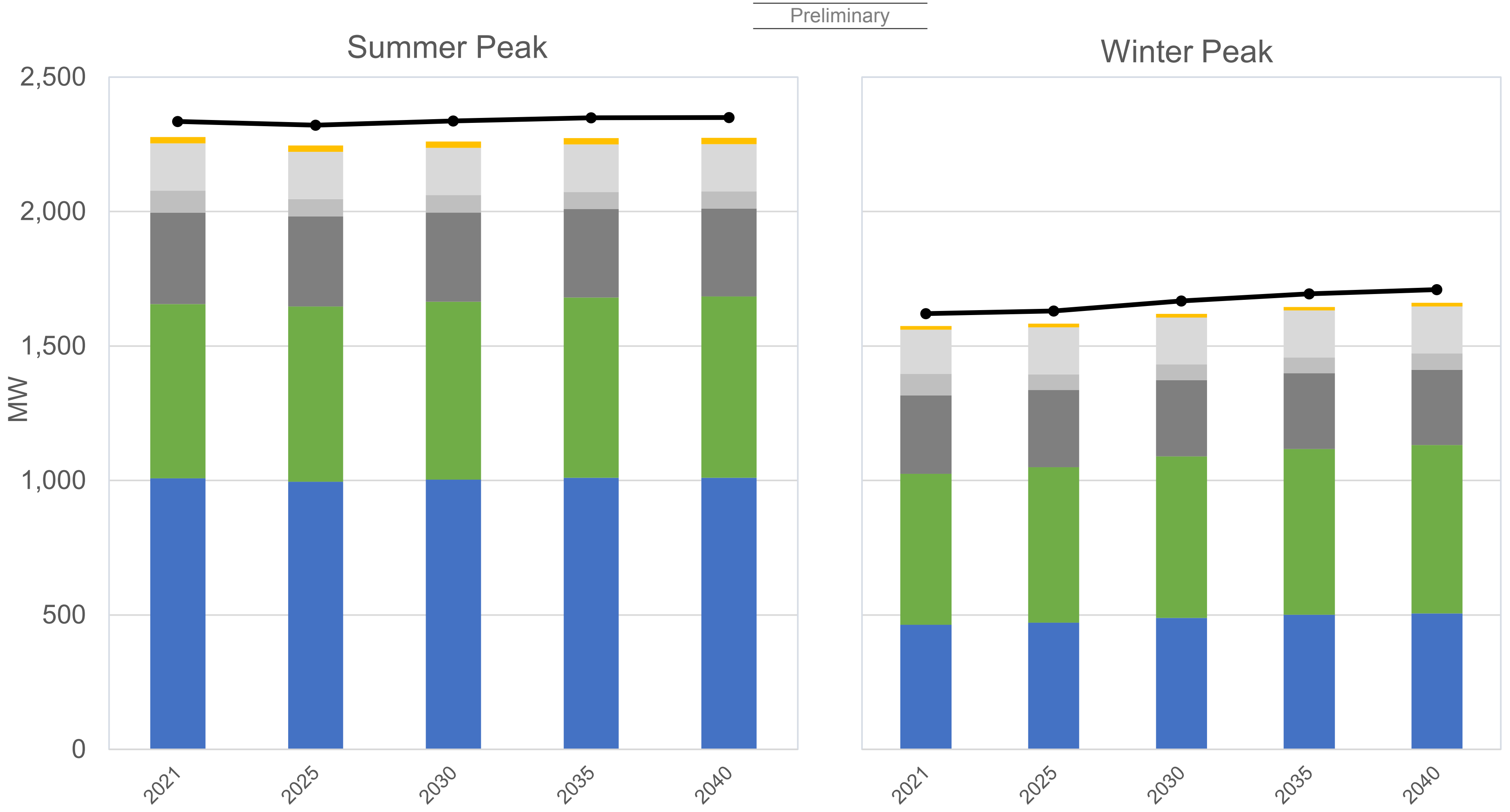
Monthly Load Factor

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



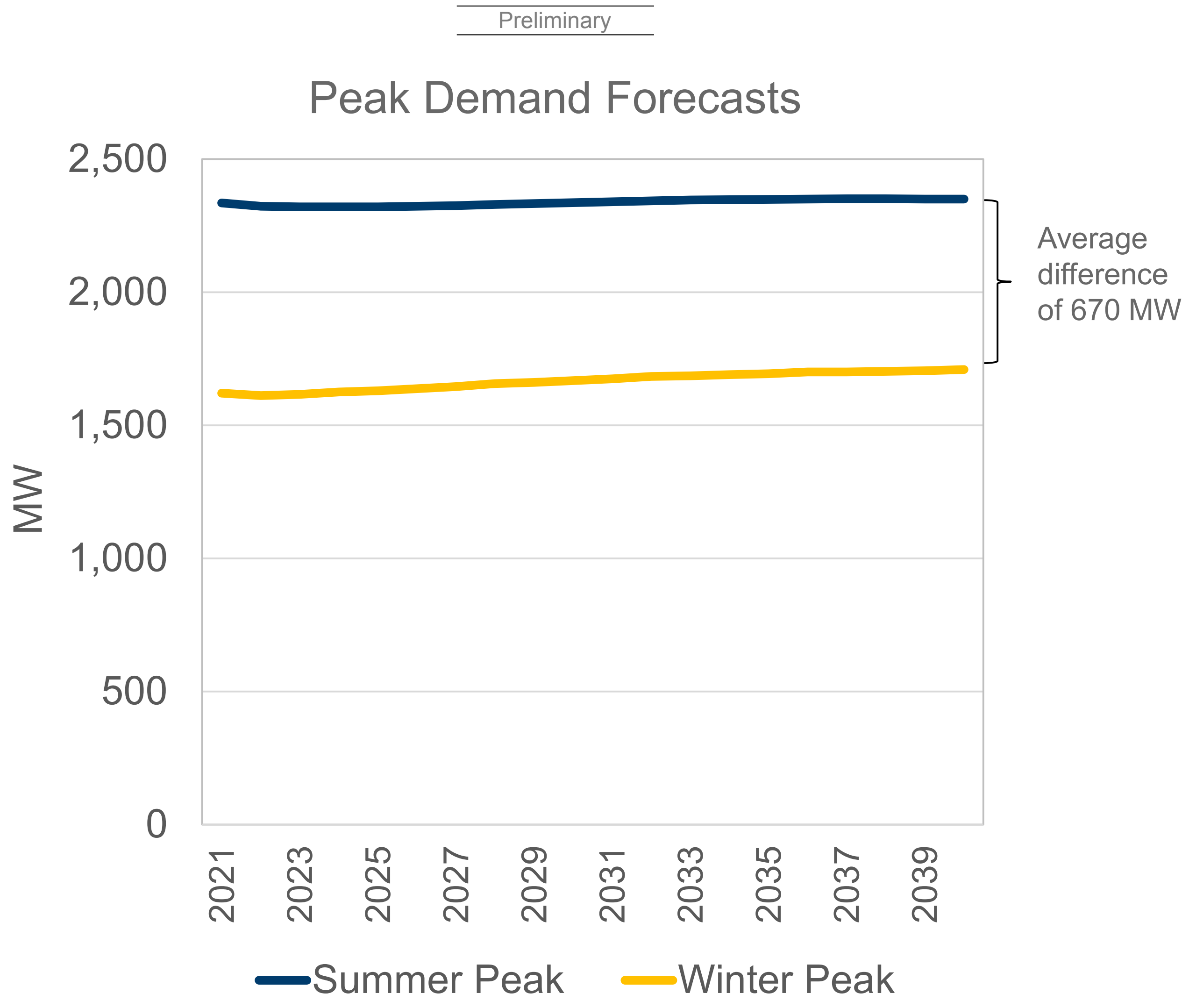
CAGR (2021-2040)

	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

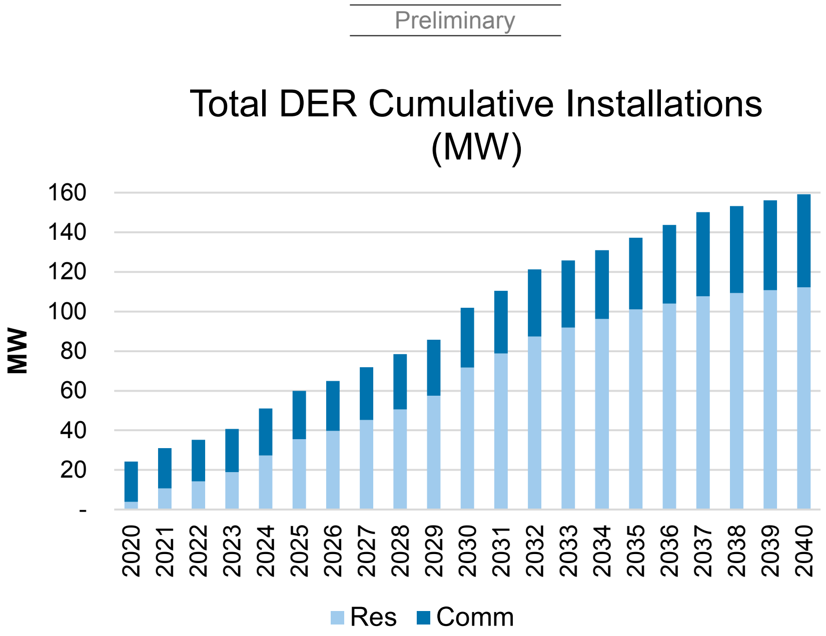
- "Agents" are modeled as representative of NIPSCO's customers, and each agent is randomly assigned a household income level based on the American Community Survey 2019 income distribution across NIPSCO counties
- Each agent is assigned a propensity to adopt new technology (bass innovation index)
- Relationships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

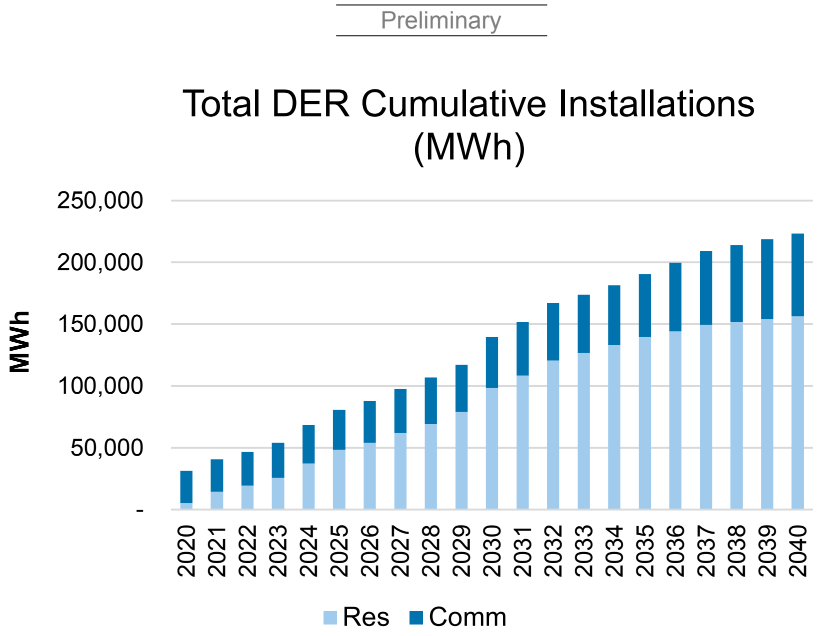
An agent will adopt DER if:

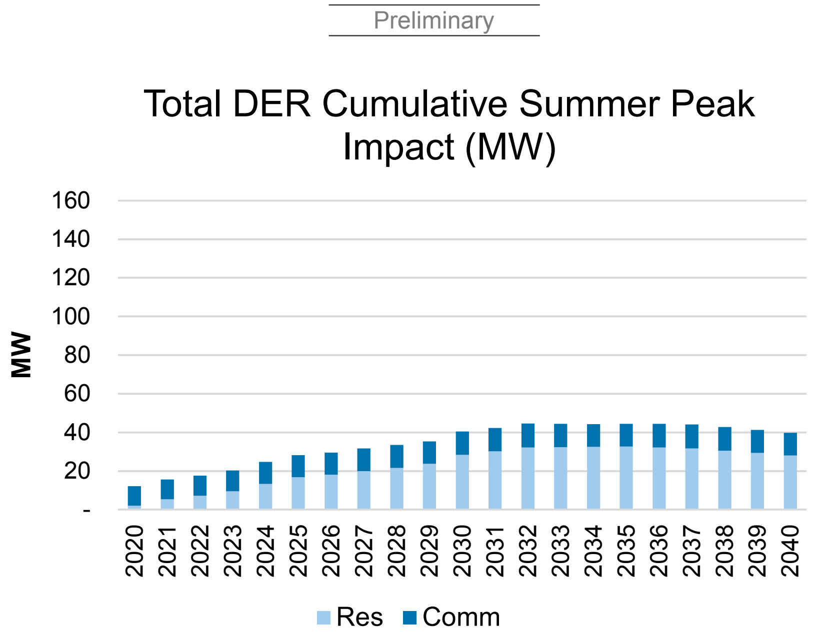
- the agent's probability of adoption is sufficiently high *(according to the economics and probability assessment from the previous slide)*
- the agent is an innovator type (bass innovation level within some threshold level) or a significant portion of the agent's network has adopted the technology

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)







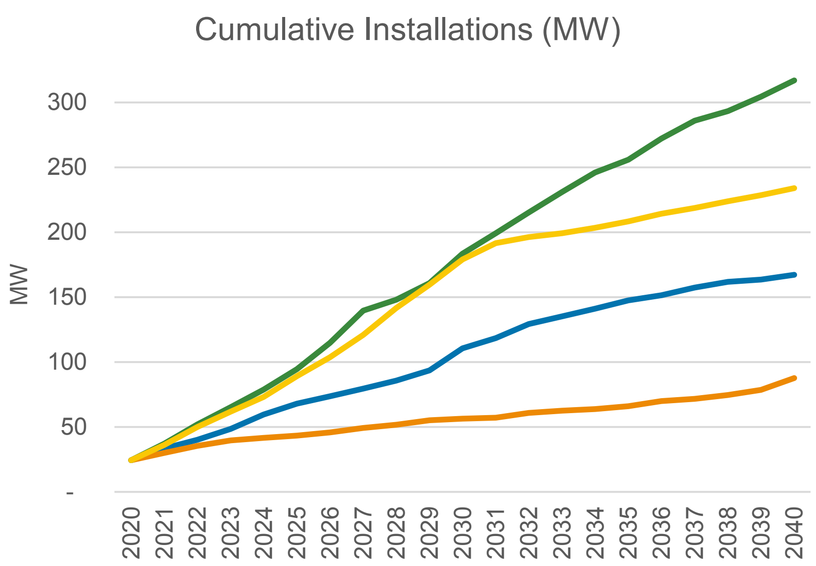
SCENARIO CONSIDERATIONS

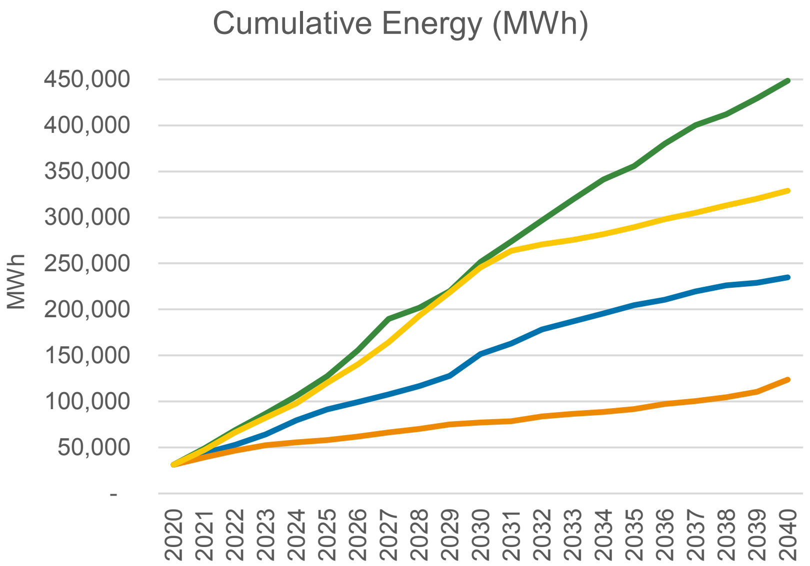
Several uncertainties are likely to drive customer payback economics over time:

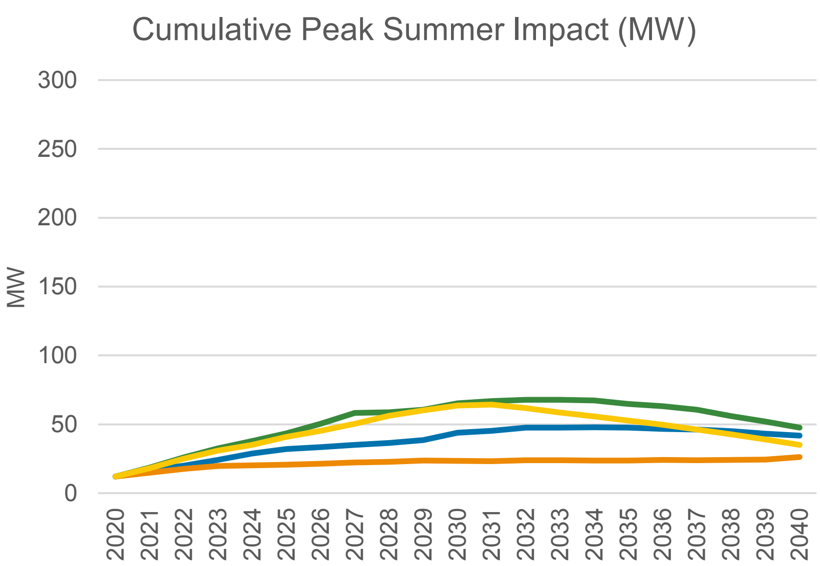
- **Capital Costs for Solar**
- **Investment Tax Credit Incentives**
- **Other Incentive Structures**
- **Retail Rate Growth Trends**

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**

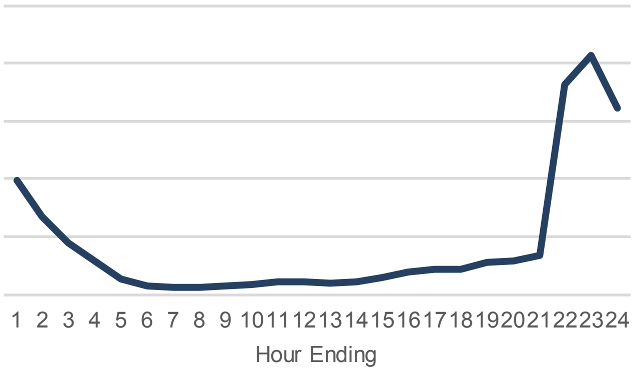
Efficiency Improvements

- **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**

Representative* Charging Shape

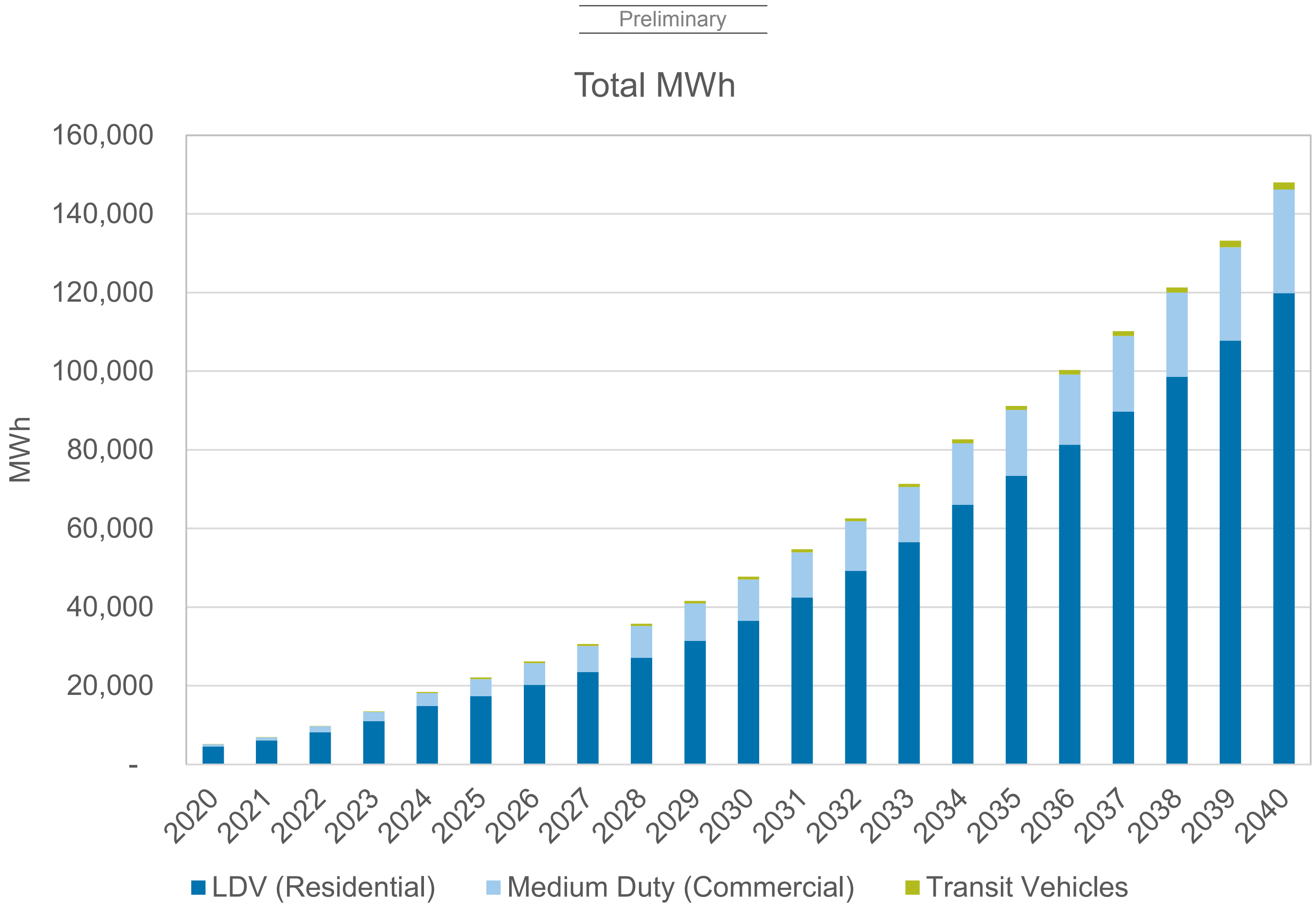


Sample shape used for LDVs/Transit in Base Case

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

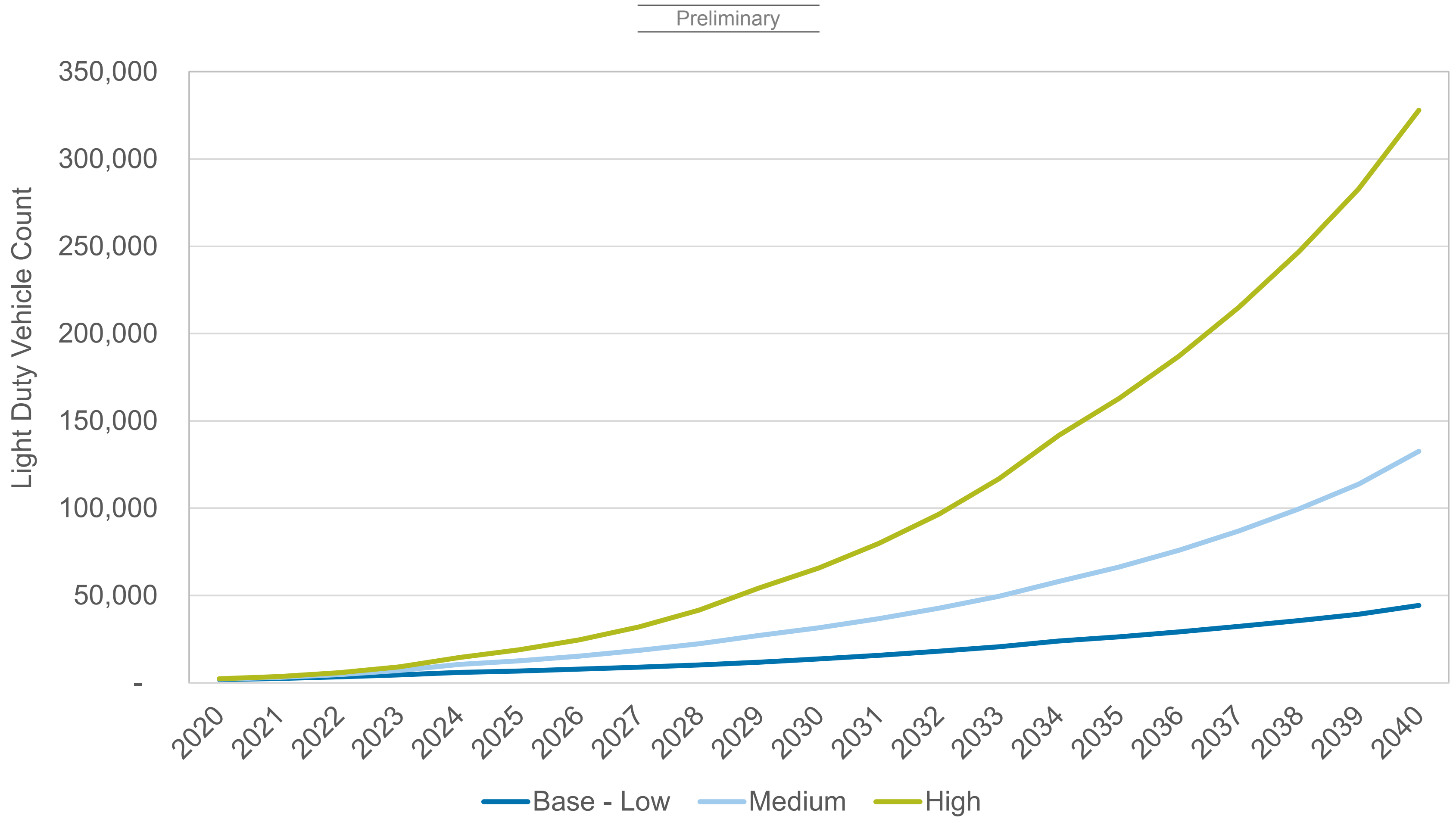
Medium & Heavy Duty Vehicles

- 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

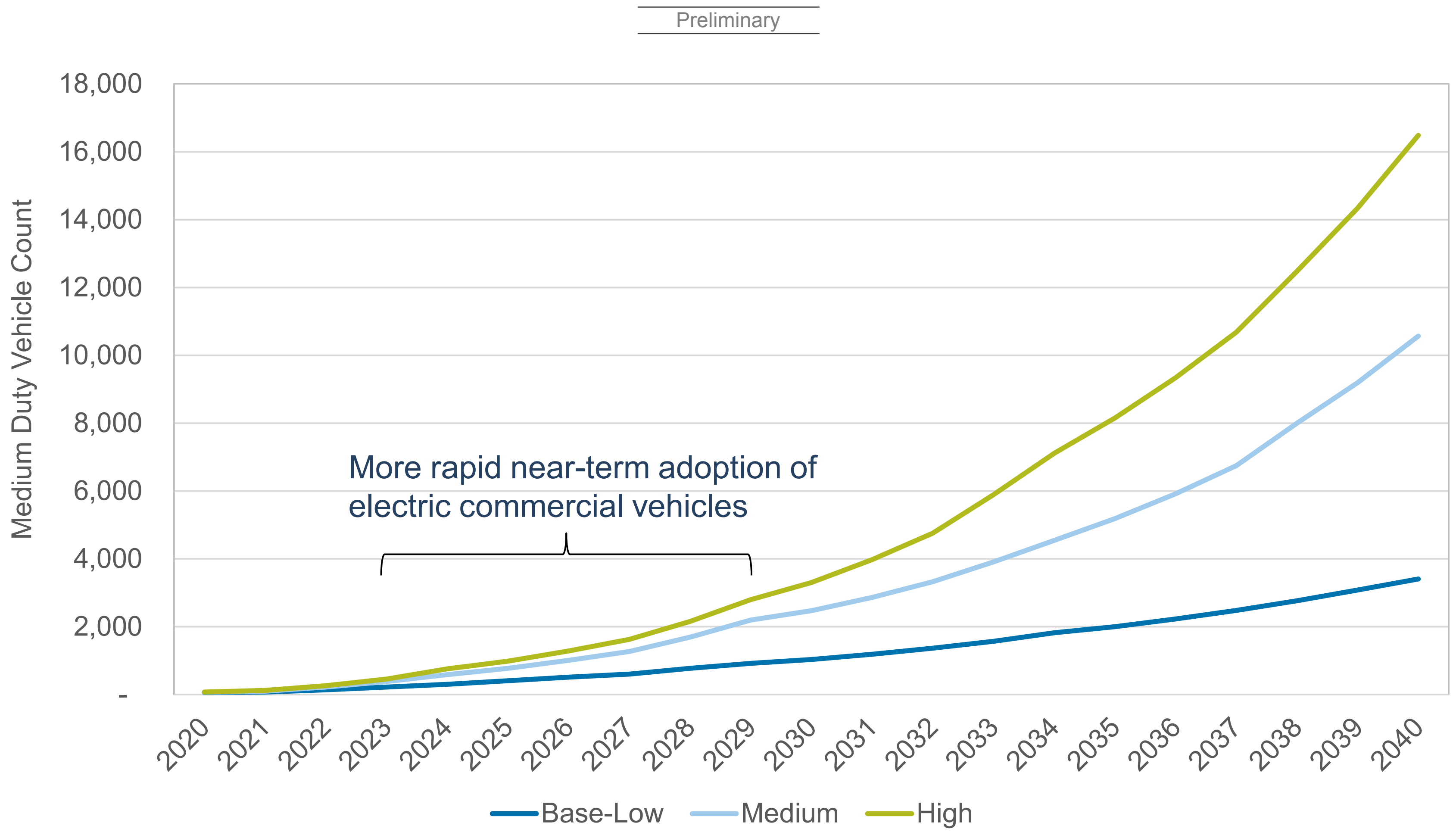
- Local transit vehicles, such as buses and shuttle buses, are expected to electrify in proportion to LDVs.
- 100% electric-only fleet expected in the High scenario

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

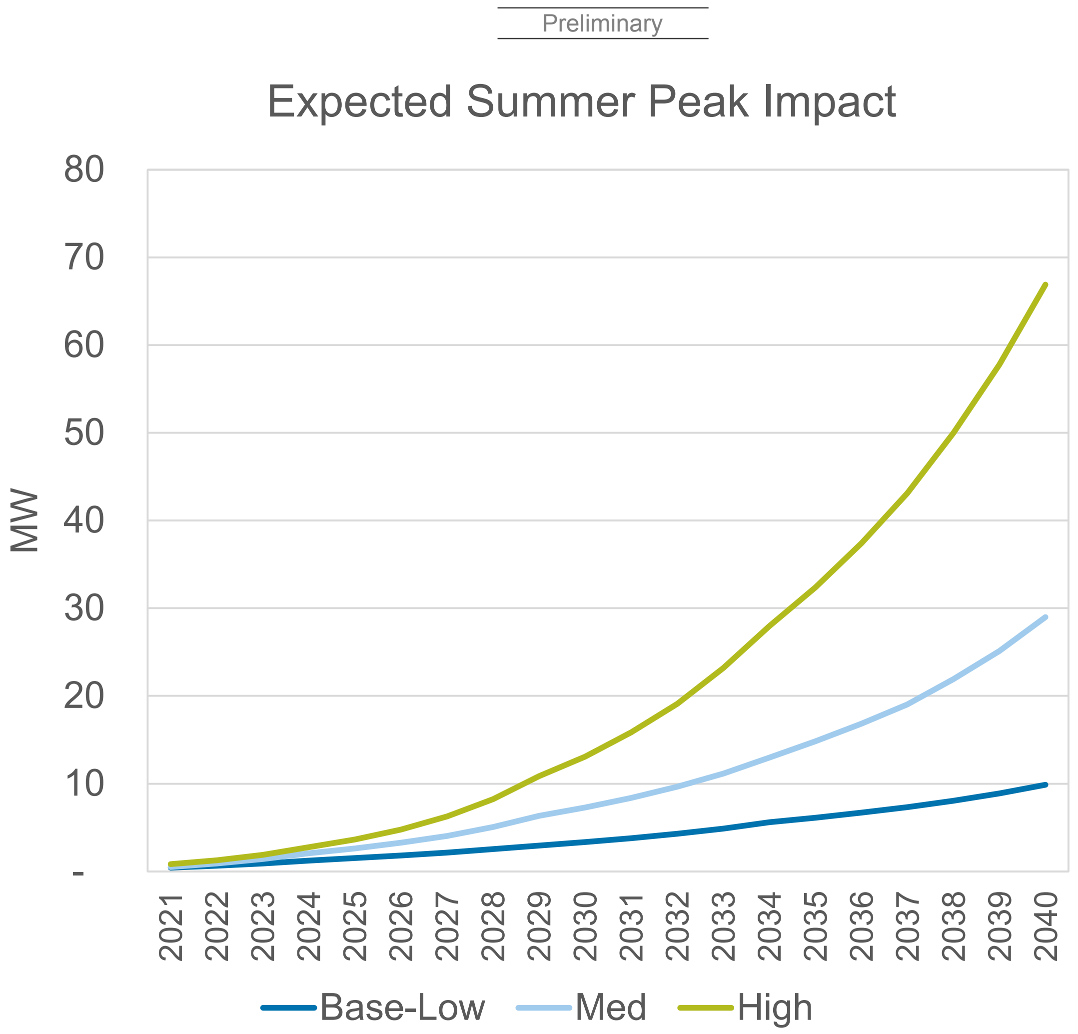
2040 estimates

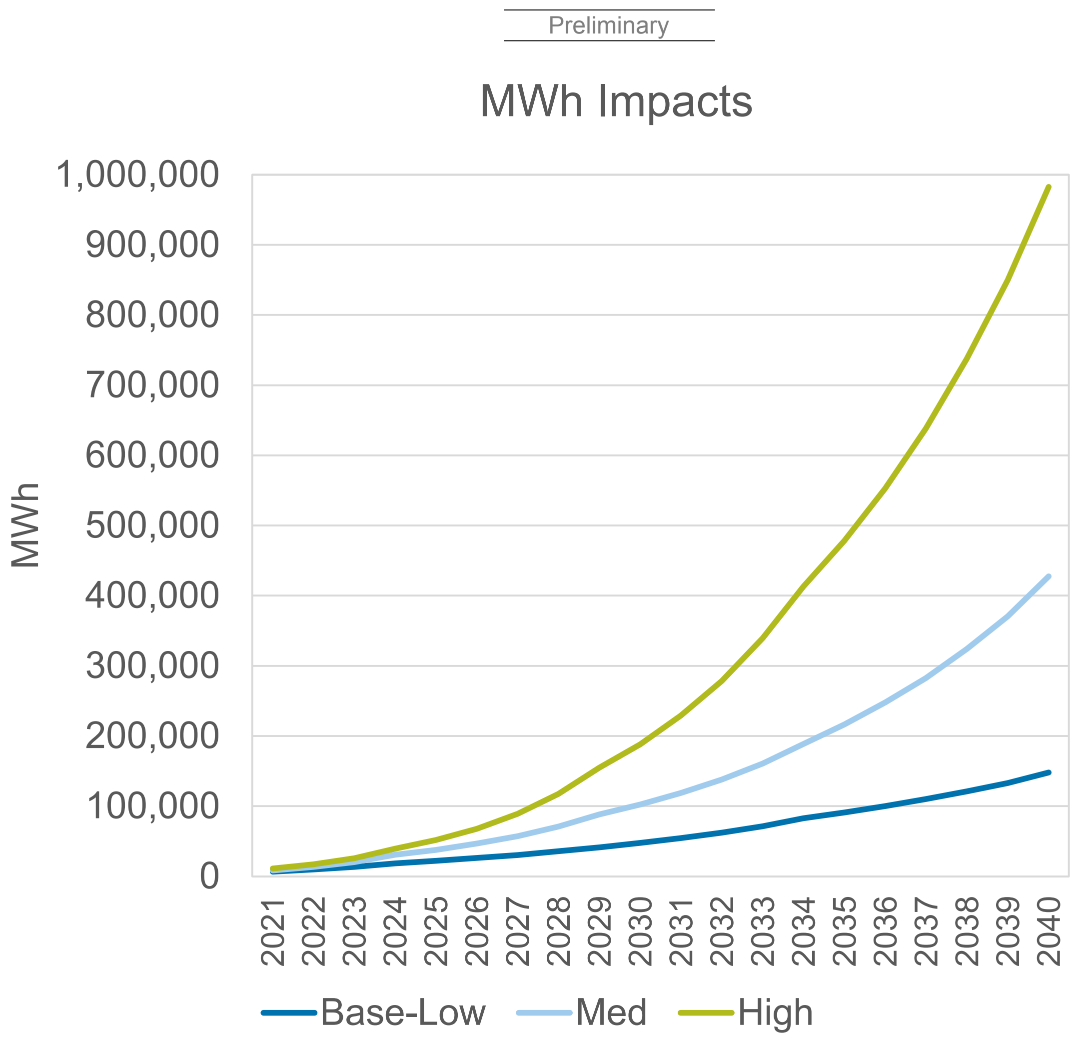
High: 10 GWh energy, 0.5 MW peak demand

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

- 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

Preliminary

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%**

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

Preliminary

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 <u>significant CO_2 price</u> 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 <u>Clean Energy Standard</u> (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 *See next slide for details*	Solar Capacity (ELCC) Credit *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%

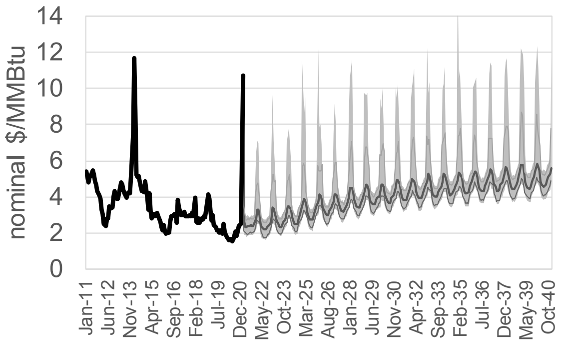
SCENARIO IMPACTS TO LOAD

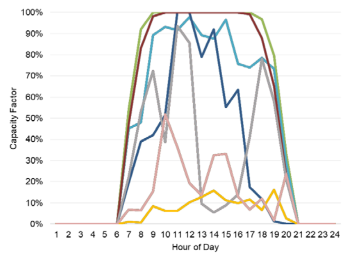
Scenario Name	Economic Growth	EV Penetration	DER Penetration	Other Electrification	NIPSCO Industrial Load
Reference Case	**Base** *Moody's Baseline forecast*	**Low** *Current trends persist (MTEP Future I)*	**Base** *Baseline expectations for continued growth, which is exponential in areas*		
Status 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

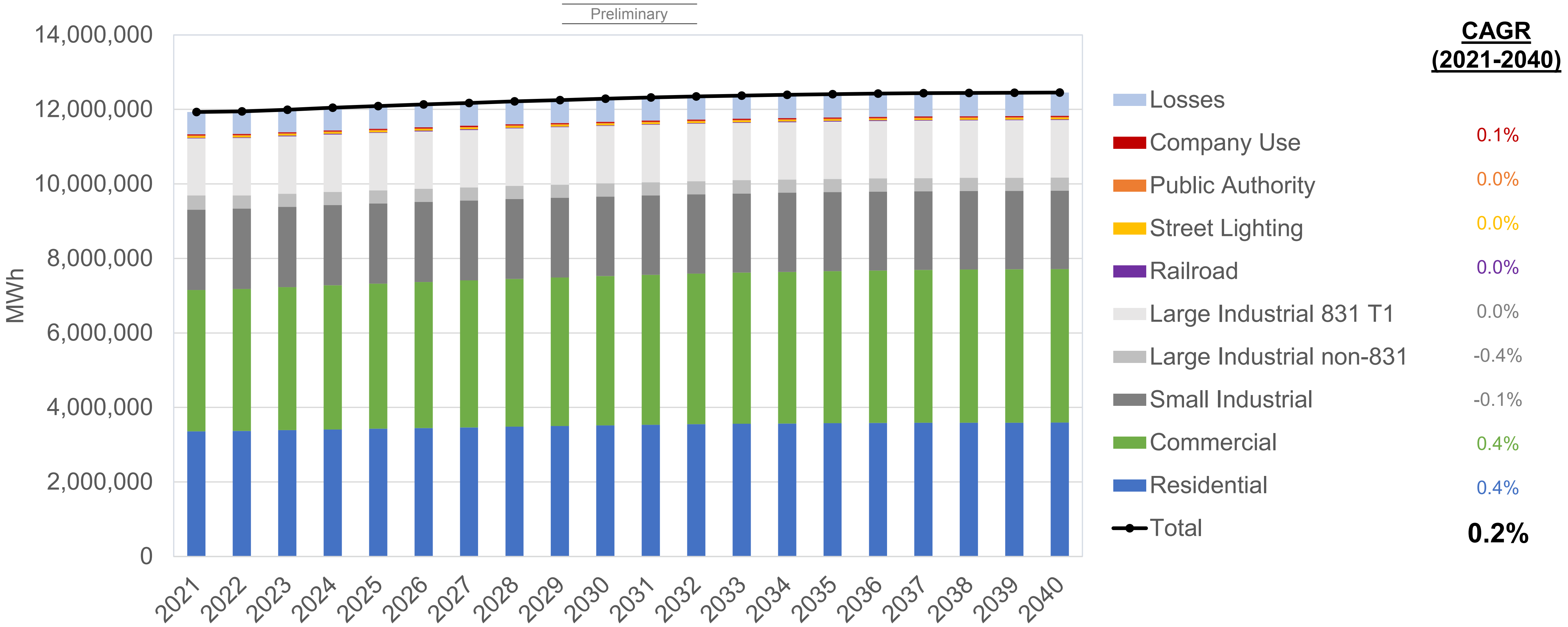
- Complimentary to the IRP portfolio analysis:
  - Cost to our customers
  - Reliability
  - Deliverability
  - Duration
  - Environmental impact
  - Employee and operational impact
  - Local community impact

CLOSING

APPENDIX

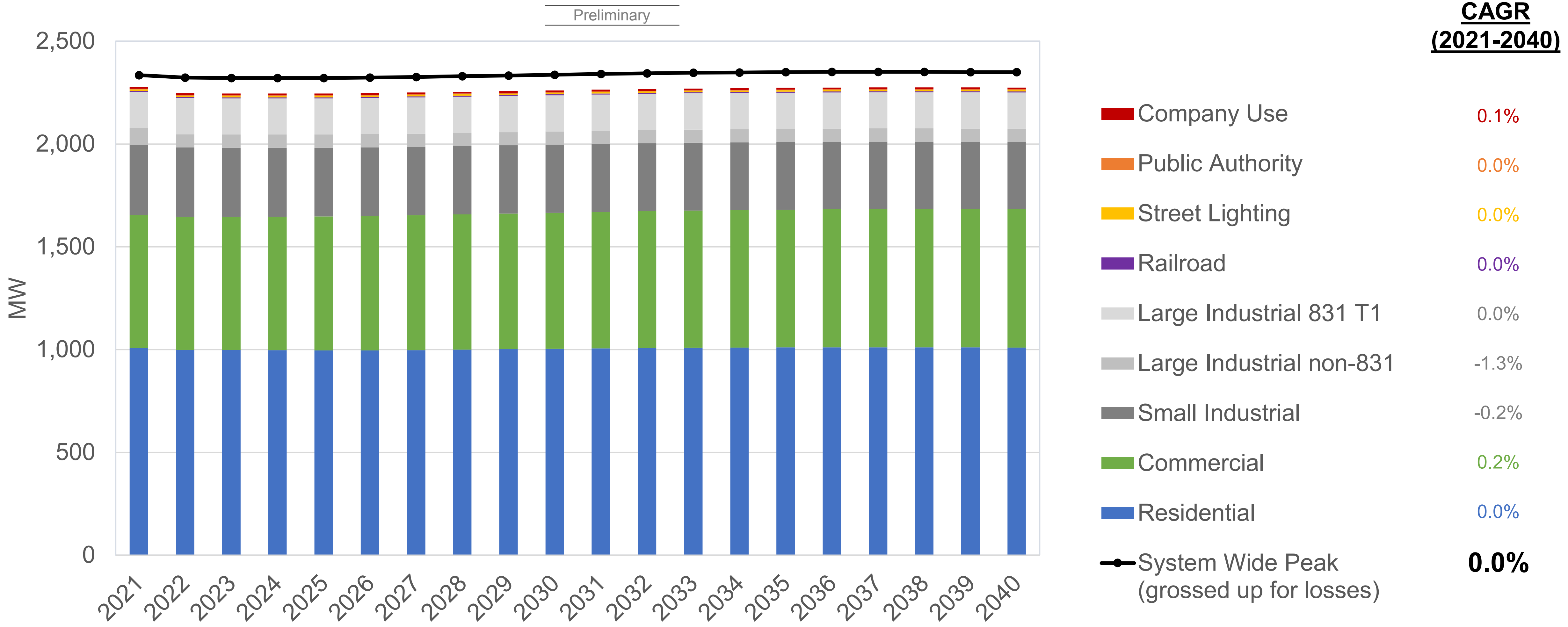
SALES FORECAST

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*



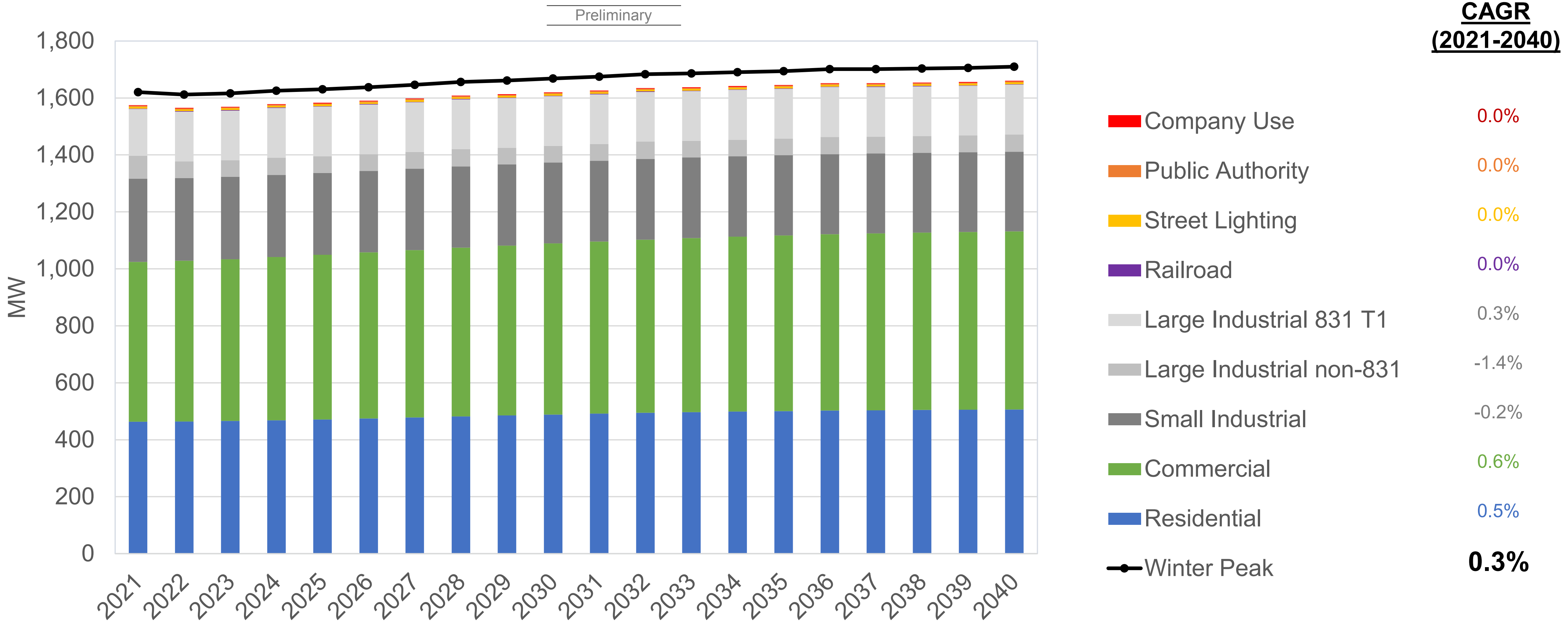
PEAK LOAD FORECAST - SUMMER

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



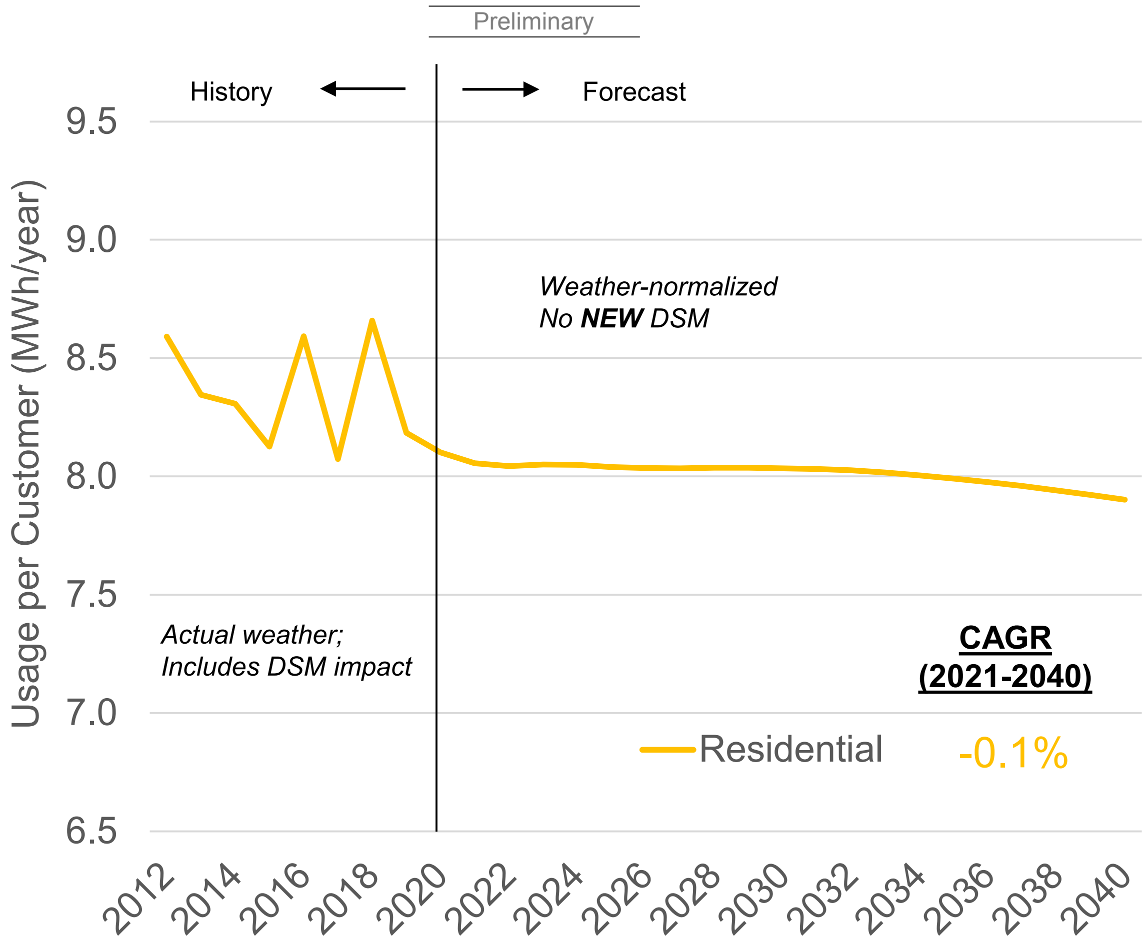
PEAK LOAD FORECAST - WINTER

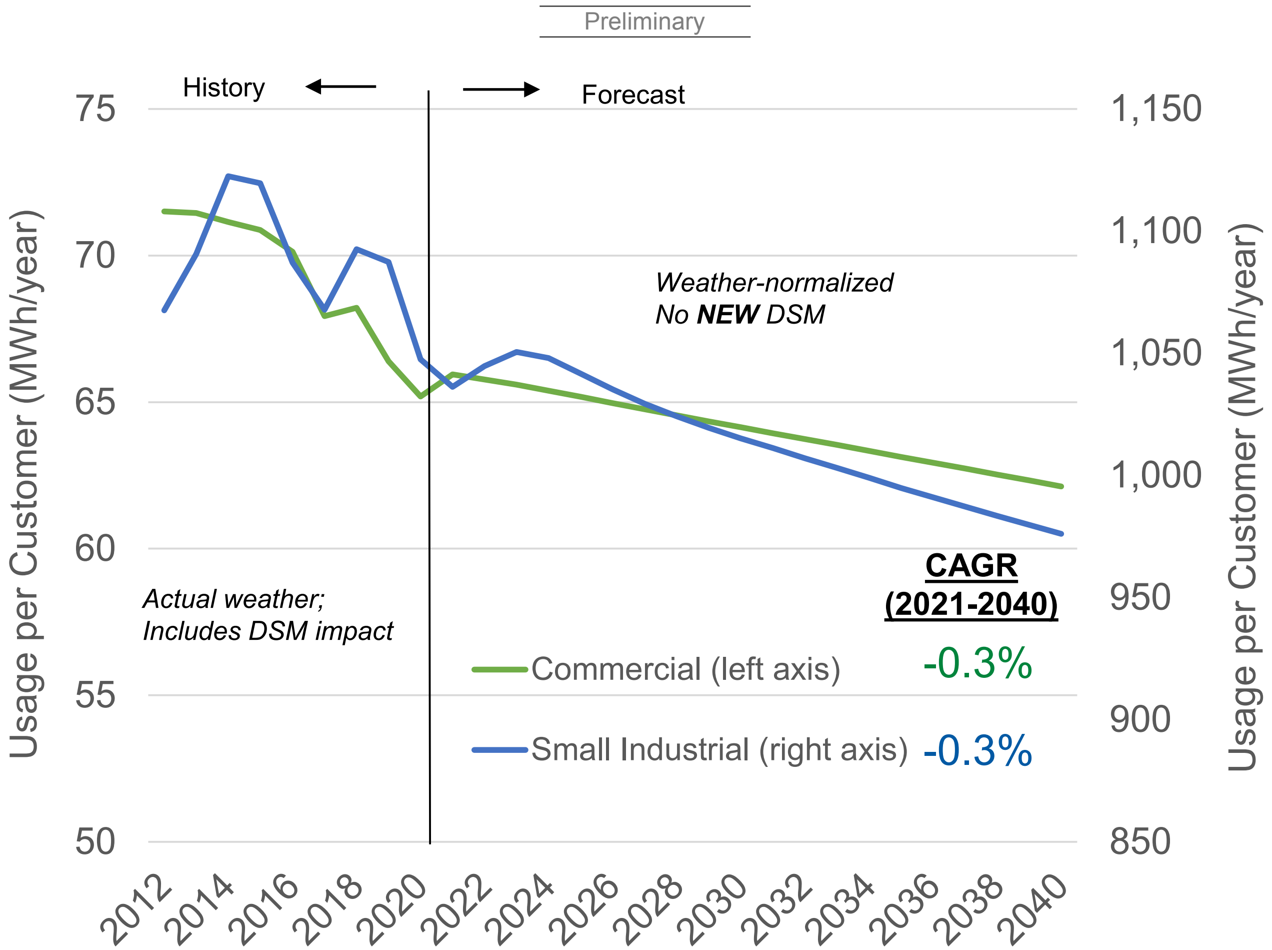
Peak load forecast is developed at a monthly level by customer class



LOAD FORECAST: USAGE PER CUSTOMER FORECASTS

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





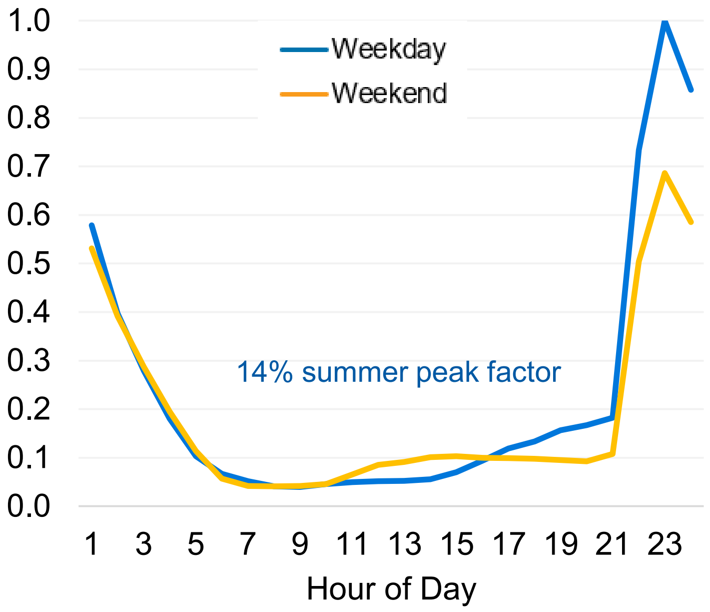
LOAD FORECAST: ACCOUNTING FOR LOSSES

- 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

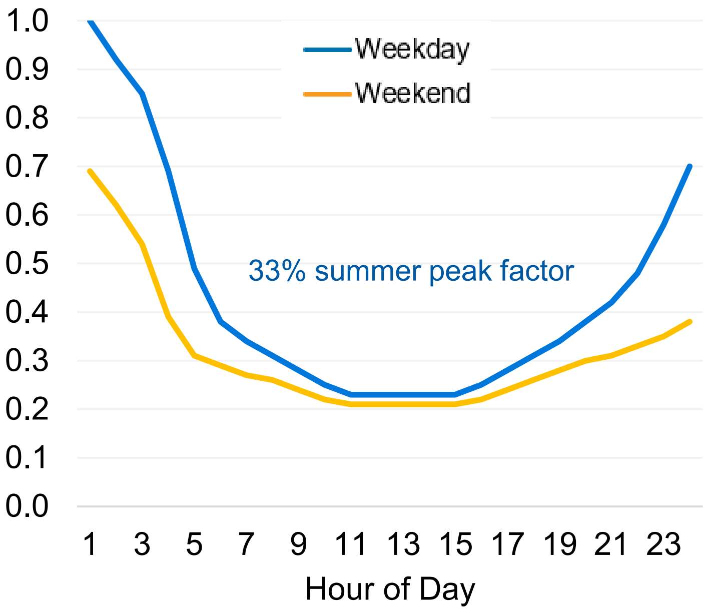
Different hourly EV charging profiles may be used according to scenario and EV class

Residential EV Charging Profile – Low Penetration[1]



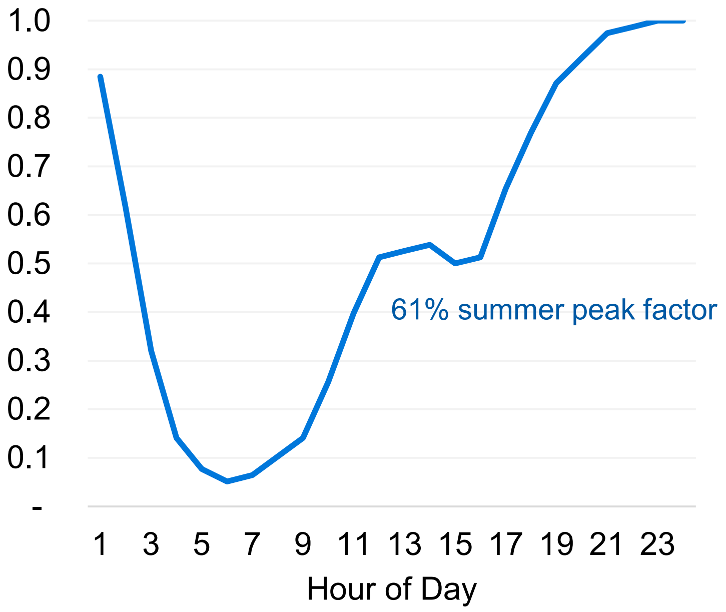
- NIPSCO's 2018 EV pilot program
- Significant off-peak demand

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