Northern Indiana Public Service Company LLC

2021
Integrated Resource Plan

November 15, 2021

NIPSCO
2021 INTEGRATED RESOURCE PLAN
SUMMARY

NIPSCO
A NiSource Company

NIPSCO.com

479,000 NORTHERN INDIANA HOMES AND BUSINESSES IN 20 COUNTIES DEPEND ON NIPSCO EACH DAY FOR SAFE, RELIABLE AND AFFORDABLE ENERGY

BACKGROUND

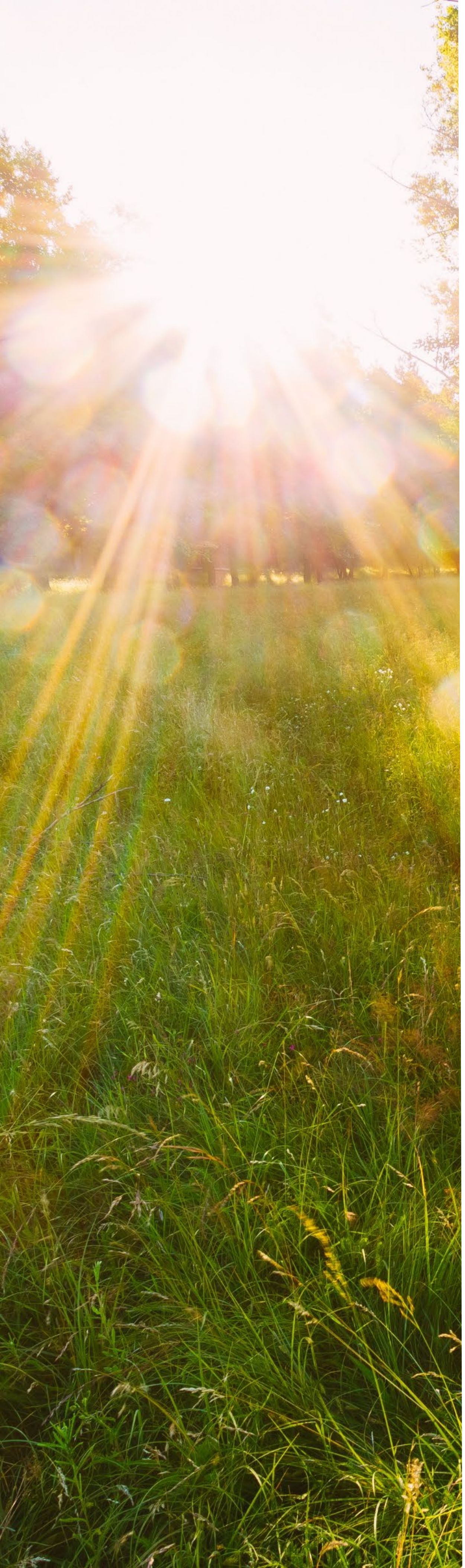
Three years after announcing our electric generation transition plan, branded “Your Energy, Your Future,” NIPSCO is proud to serve Northern Indiana families and businesses with safe and reliable energy every day. Our company’s customer-centric “Your Energy, Your Future” initiative includes the electric generation transition plan at NIPSCO, and is our balanced approach to deliver lower-cost, sustainable and reliable energy for future generations. NIPSCO presents this plan to the Indiana Utility Regulatory Commission (IURC) every three years.

Since NIPSCO introduced our plan in 2018, we debuted two operating wind farms and have begun transitioning our employees to new roles after the retirement of two coal-fired units at R.M. Schahfer Generating Station in Wheatfield, Indiana. We look forward to soon adding 12 more renewable projects that are currently in development and projected to be operational by the end of 2023.

As we evolve alongside our communities and the changing energy landscape, we use a forward-looking analysis framework to create an Integrated Resource Plan (IRP), which establishes a road map for near-term electric portfolio decisions and our long-term vision. Our process involves a comprehensive analysis of our future energy mix, informed by valuable input from numerous stakeholders including customers, regulators, and local community leaders.

NIPSCO’s industry-leading plan creates a vision for the future that keeps our customers’ best interests at the forefront. It is consistent with our goal to transition to the best cost and cleaner electric supply mix while maintaining reliability, diversity and flexibility for the technology and market changes on the horizon.

YOUR ENERGY YOUR FUTURE



ABOUT THE 2021 INTEGRATED RESOURCE PLAN

Our IRP charts a path to best meet the energy needs of our customers for the next 20 years, and it is updated every three years. The 2021 plan reflects the dynamic changes taking place in the electric industry, the changing needs and behaviors of our customers, and the subsequent evolving policy and market rules.

Our 2021 IRP captures this evolving environment and creates a highly flexible plan that achieves the following:

- Refines the window to retire all remaining coal-fired generation to between 2026 and 2028, with our largest plant retired by 2023
- Retires aging gas peaker units between 2025 and 2028
- Replaces retired generation resources with a diverse, flexible, and scalable mix of incremental resources, including short-term contracted capacity resources, expanded demand side management programs, solar, large battery energy storage, and new gas peaking resources
- Explores potential hydrogen generation pilots and emerging energy storage technologies on the path toward further decarbonization of the generation portfolio
- Continues on the trajectory of reducing carbon emissions* from generation by 90% (from a 2005 baseline) by 2030 identified in the 2018 IRP and illuminates the pathway for further emissions reductions

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* NIPSCO may sell in the future and has previously sold the Renewable Energy Credits from renewable generation to a third party.

NIPSCO IS INTEGRATED INTO THE BROADER ENERGY MARKETPLACE

NIPSCO's service territory and resources are part of the Midcontinent Independent System Operator (MISO) power market, specifically located within Local Resource Zone 6 (LRZ6), covering Indiana and parts of Kentucky. Independent System Operators (ISOs) like MISO perform the following key roles:

- Ensure the reliability of the electric system by complying with Federal Energy Regulatory Commission (FERC) Orders and North American Electric Reliability Corporation (NERC) Reliability Standards
- Oversee markets for energy, capacity, ancillary services, and transmission rights
- Direct the daily operation of the electric system, including plant dispatch

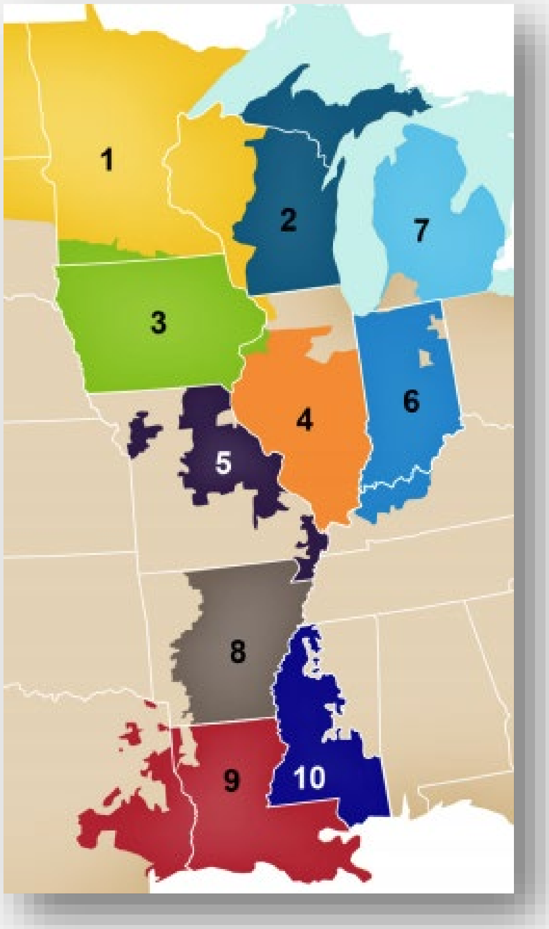
Therefore, as a member of MISO, NIPSCO is not independently responsible for system reliability and market operations. However, NIPSCO must offer its resources into the market, respond to MISO signals and instructions, and comply with a dynamic set of market rules and standards. In addition, as a Transmission Operator (TOP), NIPSCO is responsible for directly complying with a variety of NERC standards associated with reliability.

The MISO market is currently in the midst of significant change, meaning that NIPSCO must navigate its own portfolio decisions while recognizing this dynamic external environment. These MISO changes include:

- A system-wide transition away from coal and towards more intermittent renewable resources
- The emergence of new technologies with operating profiles that are very different from traditional generation resources like coal and natural gas
- The evolution of market rules to accommodate these changes, such as:
    - Evaluating the use of seasonal reserve margin targets
    - Development of new methods of calculating capacity credit for intermittent resources
    - Establishment of participation models for storage resources

Given the uncertainties associated with future MISO market changes, it is critical that NIPSCO ensure resource planning decisions are flexible enough to adapt over time.

MISO FOOTPRINT



GENERATION CAPACITY

- 184,287 MW (market)
- 198,933 MW (reliability)

TRANSMISSION LINES

- 65,800 miles

STATES/PROVINCES

- 15 U.S. States
- 1 Canadian Province

MISOENERGY.ORG

NIPSCO's 2021 INTEGRATED RESOURCE PLAN APPROACH

Resource planning is a complex undertaking, one that must address the inherent uncertainties and risks that exist in the evolving electric industry landscape. In the 2021 IRP, several key planning themes shaped the way NIPSCO approached the development of its preferred plan and the supporting analysis. These included a focus on:

- **Long-Term Planning With Intermittent Resources**, particularly associated with understanding the system reliability implications of a portfolio that will have significant intermittent resources

- **Carbon Emissions and Environmental Policy Trends**, including assessment of 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

- **Flexibility & Adaptability of the Portfolio** to meet evolving MISO rules and state and federal energy and environmental policy changes

Using in-depth data, modeling and risk-based analysis provided by internal and external subject matter experts, NIPSCO's IRP projects future energy and capacity needs and evaluates available options to meet those needs.

The 2021 IRP also introduced an enhanced evaluation of the reliability of NIPSCO's portfolio to better understand the implications of a resource mix with significant intermittent resources, particularly in light of the MISO market evolution and NIPSCO's operational responsibilities. NIPSCO's expanded analysis incorporated both economic and non-economic assessments of reliability.

NIPSCO's 2021 IRP is based on the best available information at the time this IRP is filed. Changes that affect our plan may arise, which is why it's important for us to remain flexible and adaptable as we continually evaluate current market conditions, the evolution of technology—particularly energy storage and hydrogen-based technology —and demand side resources, as well as changing laws and environmental regulations.

ENGAGING CUSTOMER AND PUBLIC STAKEHOLDERS

Indiana's energy future is everyone's concern. That's why any discussion of resource planning for the future must bring all stakeholders into the conversation. We engaged stakeholder groups and individuals in a variety of ways throughout the entirety of the planning process.

NIPSCO initiated stakeholder advisory outreach for its 2021 IRP in March when we hosted a virtual public meeting and launched a web page for interested stakeholders to follow the progress. Given the ongoing COVID-19 pandemic, public stakeholder meetings and stakeholder interactions were entirely virtual during this planning cycle. Four additional virtual public meetings followed in May, July, September and October. NIPSCO also hosted a virtual technical webinar to discuss the reliability assessments. Each of these public stakeholder meetings had over 100 registered participants and garnered a high level of stakeholder participation. Members of our executive leadership team and several of our subject matter experts attended each meeting to hear feedback and answer questions.

Throughout the IRP process, stakeholders were also invited to meet with us on a one-on-one basis to discuss key concerns and perspectives. NIPSCO met with several stakeholders in virtual one-on-one settings and exchanged written correspondence with several others. Each interaction provided a forum for discussion and feedback related to the many components of the IRP. Valuable discussions arose in several key areas, including load forecasting calculations, energy efficiency program analysis, generation portfolio modeling techniques, and reliability assessment considerations.

Stakeholder feedback gained throughout the process was used to inform and improve the final plan. A summary of the meeting materials, including presentations and stakeholder questions, is available at **NIPSCO.com/IRP**.

5
VIRTUAL PUBLIC MEETINGS

1
TECHNICAL WEBINAR

MORE THAN
100
REGISTERED PARTICIPANTS

PROCESS ENABLES
STAKEHOLDER SUPPORTED PLAN

FORECASTING FUTURE CUSTOMER DEMAND

Projecting customers' energy needs is a key component of the IRP process, and several enhancements to the development of the demand forecast were implemented in the 2021 IRP. For the first time, the IRP demand forecast incorporates an Industrial Service Structure tariff, known as Rate 831, and its subsequent impact on large industrial customer load. Approved in 2019, this new industrial service structure tariff gives certain large industrial customers the option to procure most of their energy and capacity needs on their own.

Leveraging NIPSCO's load forecasting tools, we developed monthly net energy and peak load projections to evaluate seasonal energy peak periods throughout the plan horizon. This was done through an econometric analysis of customer count, energy usage per customer, and customer class-level load factor data, along with detailed analysis of the impact of changes in customer behavior on load requirements.

New to 2021, NIPSCO forecasted the impact of customer owned distributed energy resources (DER) and Electric Vehicles (EV) on load across a range of adoption scenarios. NIPSCO's final forecasts combined the baseline econometric load projections with the DER and EV analysis across planning scenarios to capture a range of future load growth outcomes.

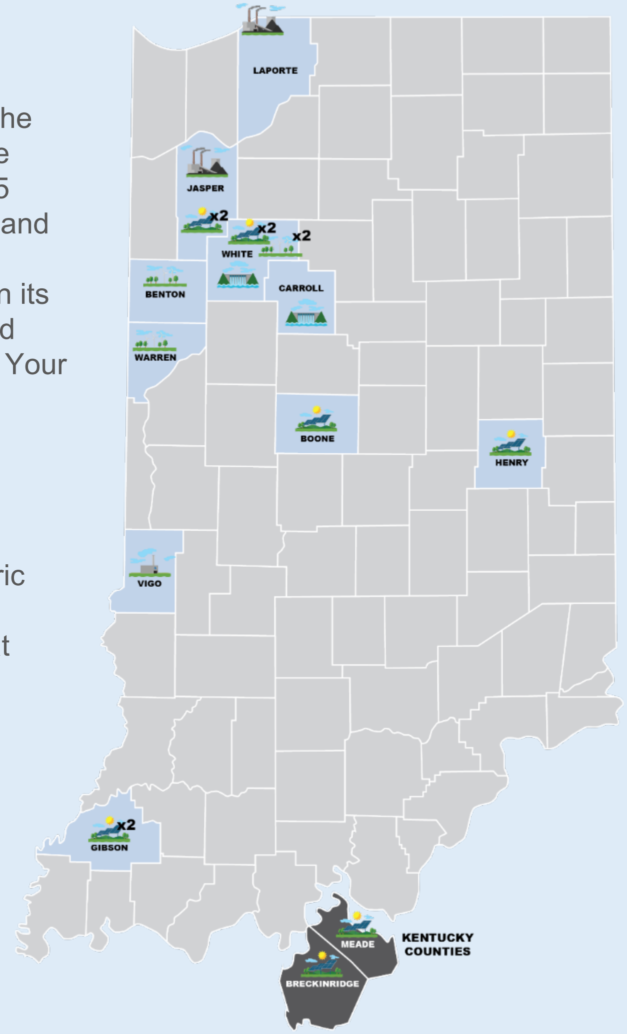
LOAD FORECAST HIGHLIGHTS

PEAK LOAD	NIPSCO's 2021 IRP load forecast expects near-term **summer peaks** to be around **2,300 MW** and **winter peaks** to be around **1,600 MW** Peak load expectations are over **600 MW lower** than those from the 2018 IRP due to a new industrial service tariff, although interruptible demand response supply resources from industrial customers are also down.
EVs	The load forecast includes a range of **electric vehicle penetration** scenarios, representing between approximately **10 to 80 MW of peak load** impact and **up to 8% of total sales** over the long-term
DERs	The load forecast scenarios suggest that **customer-owned distributed energy resources** have the potential to reduce summer peak loads between **40 to 160 MW** over the long-term.

CURRENT SUPPLY

NIPSCO's resource portfolio is in the midst of a transition. Since the 2018 IRP, NIPSCO has proceeded with retirement activities at the R.M. Schahfer Generating Station. Schahfer Coal Units 14 and 15 were retired in 2021, while the remaining Schahfer Coal Units 17 and 18 are on track to retire by the end of 2023. To replace the retired capacity at Schahfer, the company continues to make progress on its 14 approved renewable energy projects, including wind, solar, and solar plus battery storage resources, as part of our "Your Energy, Your Future" transition plan. Two of these wind projects were placed in service in 2020 and the remaining 12 projects are expected to be completed throughout 2022 and 2023.

Additionally, NIPSCO's resource portfolio is composed of its last remaining coal-fired plant (Michigan City Unit 12), two hydroelectric plants (Norway and Oakdale), a natural gas-fired combined cycle (Sugar Creek), two older vintage natural gas-fired peaking units at Schahfer (Units 16A and 16B), two older vintage wind contracts (Barton, Buffalo Ridge), and demand-side resources (DSM).



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	200 MW	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*	204 MW	WHITE	2023
ELLIOT SOLAR	200 MW	GIBSON	2023

* Projects are Power Purchase Agreements (PPAs)

PLANNED RENEWABLE RESOURCES EXPECTED TO ADD 3,330MW INSTALLED CAPACITY

ADDITIONAL $5B CAPITAL INVESTMENTS, MUCH OF WHICH STAYS IN THE INDIANA ECONOMY

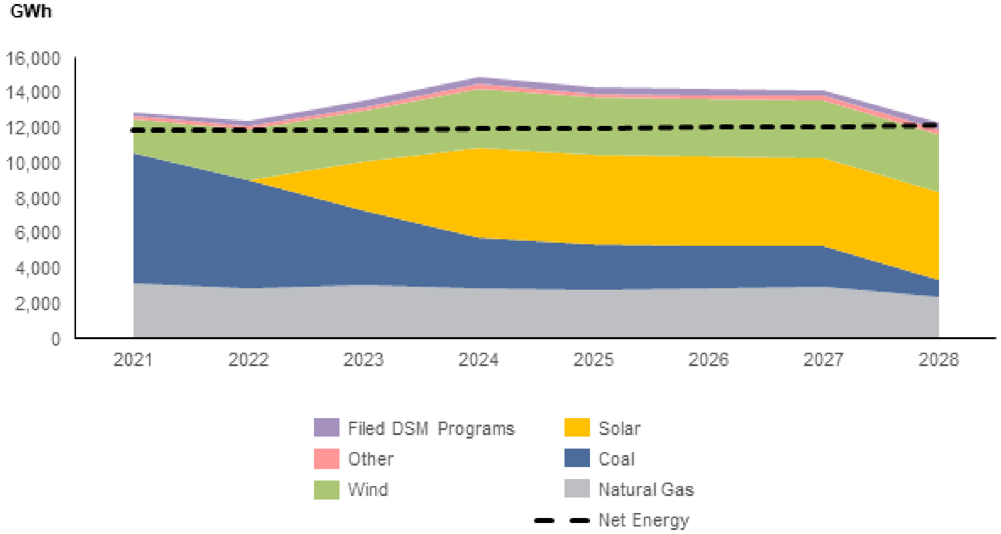
CURRENT FACILITIES

GENERATION FACILITIES	INSTALLED CAPACITY (MW)	FUEL	COUNTY
MICHIGAN CITY RETIRING 2026-2028	469MW	COAL	LAPORTE
R.M. SCHAHFER RETIRING 2021/2023	1,780MW	COAL	JASPER
R.M. SCHAHFER RETIRING 2025-2028	155MW	NATURAL GAS	JASPER
SUGAR CREEK	535MW	NATURAL GAS	VIGO
NORWAY HYDRO	7.2MW	WATER	WHITE
OAKDALE HYDRO	9.2MW	WATER	CARROLL

CURRENT SUPPLY CONT.

As NIPSCO looks beyond the implementation of its short-term action plan from the 2018 IRP, it is clear that evolving market dynamics require attention not only to annual supply and demand of capacity and energy, but also energy adequacy on an hourly basis, as illustrated below. Thus, the 2021 IRP was structured to ensure a full assessment of the type of resources needed to respond to evolving market conditions and future portfolio retirements.

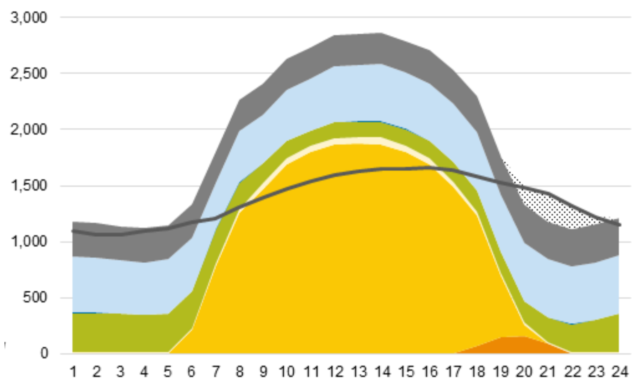
ANNUAL ENERGY



NIPSCO is well positioned to produce more energy than needed on an annual basis, driven by the energy value and dispatch advantage of wind and solar resources entering the portfolio.

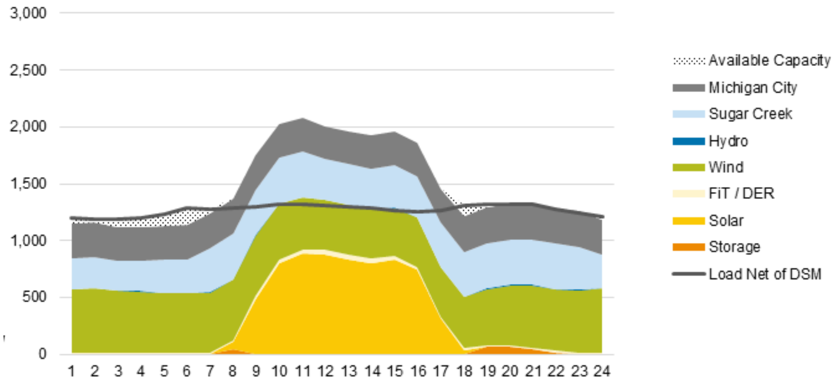
AVERAGE SUMMER DAY AFTER SCHAHFER COAL RETIREMENT

INCLUDING MICHIGAN CITY UNIT12
AND UNITS 16A AND 16B



AVERAGE WINTER DAY AFTER SCHAHFER COAL RETIREMENT

INCLUDING MICHIGAN CITY UNIT12
AND UNITS 16A AND 16B



Across a 24-hour day, there are hours where renewable resources are not available, particularly overnight for solar. As NIPSCO looks forward to the retirement of its Michigan City coal plant and vintage peakers at Schahfer, replacement resources will need to provide availability when renewable output is low to minimize market exposure.

ANALYZING FUTURE SUPPLY OPTIONS – RFP

NIPSCO conducted three separate Requests for Proposals (RFP) events covering all-sources to help inform the 2021 IRP planning process and to gain information on available, actionable projects with real costs from the marketplace. All energy technology companies were eligible to participate, and for the 2021 RFP, NIPSCO received 182 proposals— representing 78 individual projects with more than 15 gigawatts (GW) of installed capacity (ICAP). In concert with the core IRP analysis, RFP screening criteria included energy source availability, technical feasibility, commercial availability, economic attractiveness and environmental compatibility.

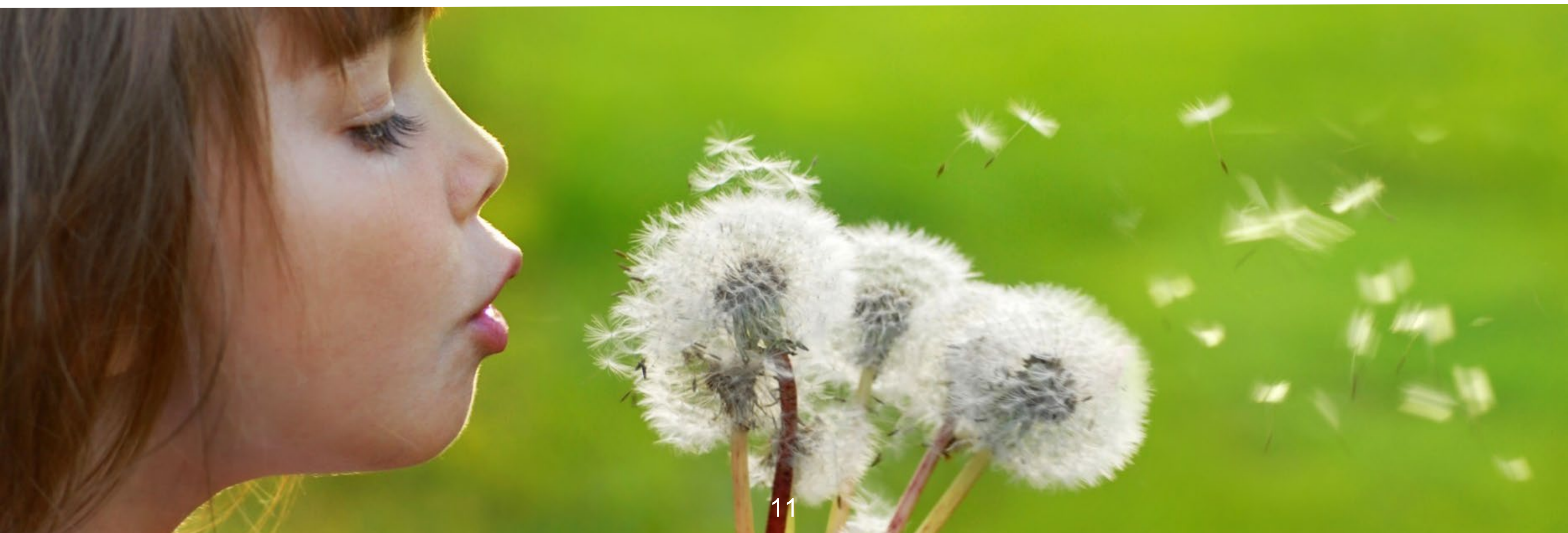
DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY

DSM programs and energy efficiency measures have been an integral part of the NIPSCO supply mix. Promoting energy efficiency is not only good for customers, but it can play an important role in helping ensure that we can meet future energy needs. Consequently, the assessment of DSM and energy efficiency programs is a core component of the IRP process. NIPSCO offers a variety of programs to help residential and business customers save energy. The programs are tailored to customers and designed to help ensure energy savings.

Since 2010, NIPSCO customers have saved more than 1.3 million megawatt hours of electricity by participating in the range of energy efficiency programs offered by NIPSCO. Technologies continue to change, and it’s important that we constantly evaluate our offerings. We regularly track and report on program performance, which helps to inform and improve future program filings and customer offerings. The 2021 IRP included a robust assessment of future DSM programs through a Market Potential Study and rigorous portfolio analysis of the various options.

ENHANCED RELIABILITY ASSESSMENT

The ongoing energy transition is requiring the considerations of system reliability impacts within the resource planning process as new resources like solar, wind and storage have different operational characteristics from traditional thermal resources like coal and natural gas. NIPSCO has incorporated several expanded elements and enhancements to the core IRP economic analysis to capture resource planning and power markets operating with more intermittent resources. NIPSCO engaged a third-party expert to perform a reliability assessment to better understand the ability of potential replacement resources to support the continued reliable operation of the system. The assessment involved series of system analyses to quantify the performance of potential replacement resources against an independently developed set of reliability criteria and measures. The results of the assessment were incorporated into the analysis to inform portfolio evaluation and the Preferred Plan.



KEY ANALYTICAL ELEMENTS OF THE 2021 IRP

NIPSCO's 2021 IRP is the result of a year-long, multi-disciplinary analytical exercise that incorporates the following major elements:

SCENARIO ANALYSIS	Scenario analysis to evaluate four integrated, but divergent future states-of-the-world for commodity prices, load growth, carbon regulation, other environmental policy drivers, and the evolution of the MISO power market
ROBUST RISK ANALYSIS	Robust risk analysis to assess uncertainty in gas and power prices and, new to the 2021 IRP, hourly wind and solar output
MULTI-PHASED PORTFOLIO ANALYSIS	A multi-phased portfolio development process that identified a wide range of future plans with different existing fleet retirement dates, various levels of carbon emissions reductions, and a range of dispatchability characteristics
ENHANCED RELIABILITY ASSESSMENT	An advanced assessment of reliability, which evaluated a range of economic and technical reliability components, including ancillary services, blackstart, and other operational considerations

PREFERRED PORTFOLIO AND NEXT STEPS

Consistent with previous analyses, NIPSCO's 2021 IRP has determined that early retirement of coal is still cost-effective for customers. Accordingly, NIPSCO has refined the retirement timing of Michigan City Generating Station Unit 12 to occur between 2026 and 2028. The precise timing of the retirement will be influenced by system reliability impacts, federal/state regulatory policy direction, MISO market rules evolution and securing the replacement resources.

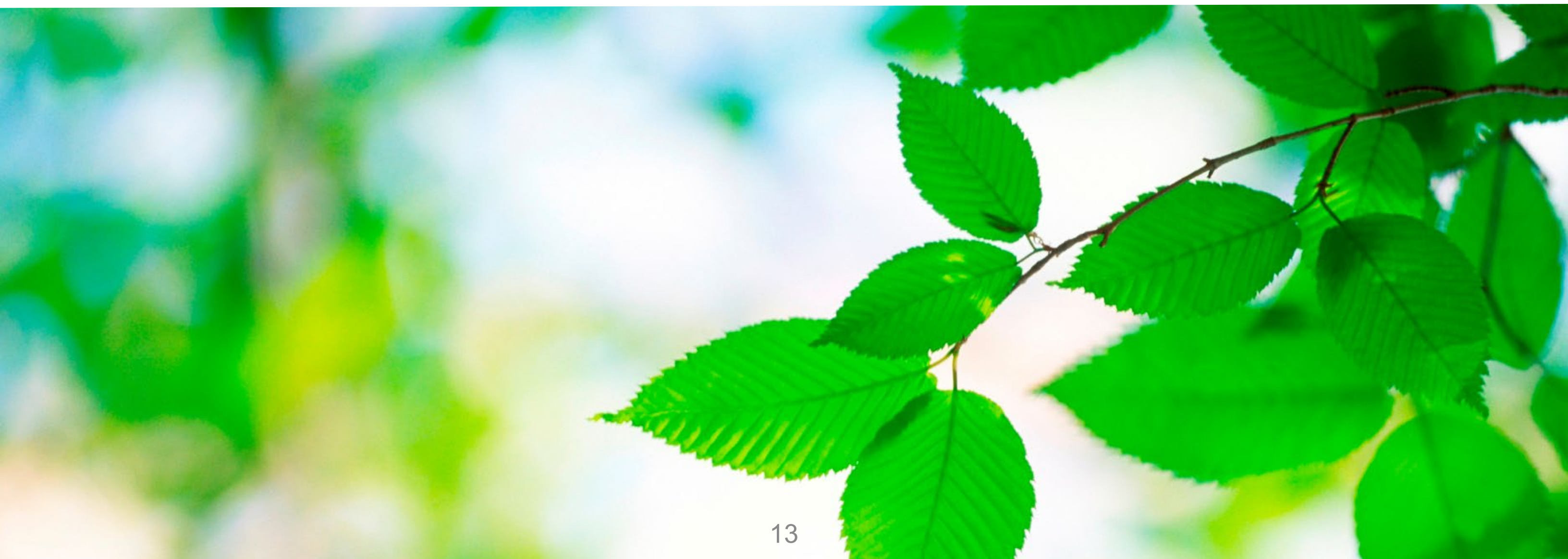
NIPSCO operates two vintage gas peaking units – Units 16A and 16B – at the Schahfer Generating Station. Given the operational condition and age of the units, the analysis pointed to retiring 16A and 16B between 2025 and 2028.

The flexibility in the retirement timing of the peaking units along with Michigan City 12 allows NIPSCO to optimize the decision. NIPSCO will pursue cost-effective resources that cover the capacity needs for both facilities, although the units do not have to retire at the same time.

To replace the retiring resources, NIPSCO has identified a preferred pathway that balances all of NIPSCO's major planning objectives, while preserving flexibility in an environment of market, technology, and policy uncertainty. In the near-term, replacement options include a diverse, flexible, and scalable mix of incremental resources, including DSM resources, distributed energy resources, solar, stand-alone energy storage, and upgrades to existing facilities at the Sugar Creek Generating Station. The plan also calls for a natural gas peaking unit to replace existing vintage gas peaking units at Schahfer and support system reliability and resiliency, as well as upgrades to the transmission system to enhance the electric generation transition.

Over the longer term, additional solar and wind capacity may be added if environmental policy makes it more economic than competing resources, and additional storage capacity may be added as further technology, policy, 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.

NIPSCO'S 2021 IRP AFFIRMS THE COMPANY'S CUSTOMER-CENTRIC "YOUR ENERGY, YOU FUTURE" ELECTRIC GENERATION TRANSITION TO LOWER-COST AND RELIABLE ENERGY FOR OUR CUSTOMERS IN THE YEARS TO COME.



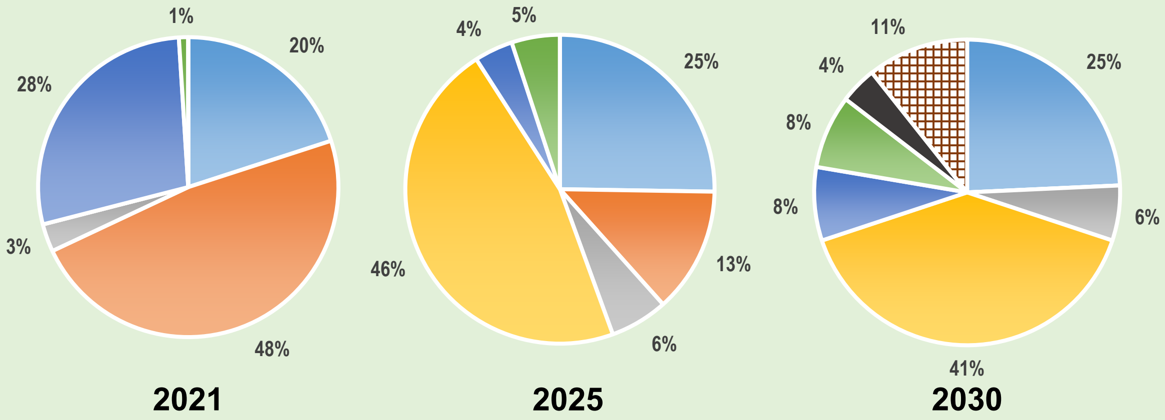
PREFERRED PORTFOLIO AND NEXT STEPS CONT.

This pathway does not alter the company's previously stated goal of a 90% reduction in carbon emissions (from a 2005 baseline) by 2030.

NIPSCO's 2021 IRP outlines refinements to the timeline of our future generation plans, and it enables flexibility to adapt to evolving technologies, policies and market rules while providing additional time for research and further refinement to our long-term energy strategy – NIPSCO will continue to update its future energy strategy in the next IRP. This 2021 IRP affirms the company's customer-centric "Your Energy, Your Future" electric generation transition to lower-cost and reliable energy for our customers in the years to come. Learn more about the "Your Energy, Your Future" plans at NIPSCO.com/future. More information about NIPSCO's electric supply strategies and the IRP process can be found at **NIPSCO.com/IRP**.

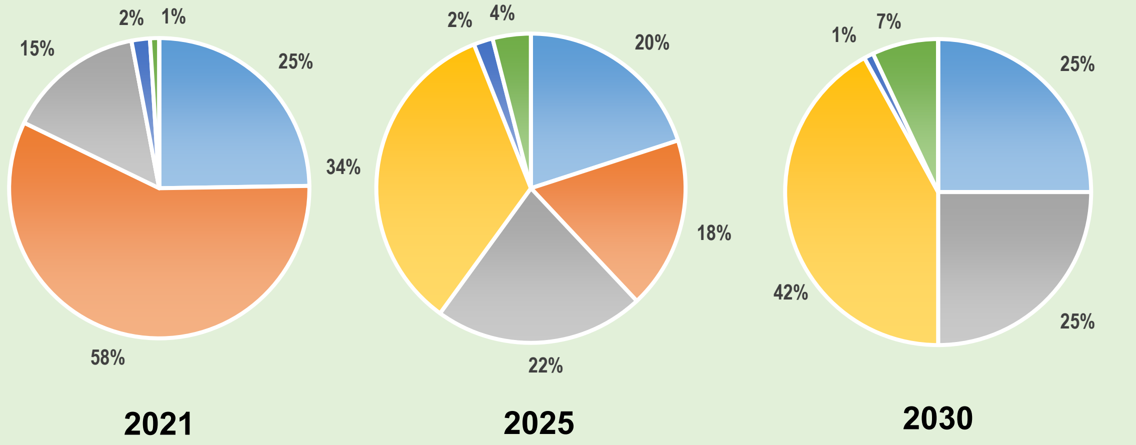
NIPSCO PROJECTED CAPACITY MIX Projected Unforced Capacity (UCAP)

NIPSCO's summer capacity mix transitions away from coal towards a more diverse mix of resources, with the flexibility to pivot to peaking gas or storage and add more solar and wind over the long term. New peaking capacity may be hydrogen-enabled as further diligence is performed.



NIPSCO ENERGY MIX

NIPSCO's energy mix transitions away from coal towards a portfolio that is predominantly renewable. Flexibility in the plan allows for even more solar and wind additions over time, depending on the balance of new gas and storage resources and evolving policy and market rules changes.



🟦 Natural Gas
🟧 Coal
⬜ Wind
🟨 Solar + Storage
🟦 Other*
🟩 DSM
⬛ New Storage
▦ New Gas or New Storage

*** Includes Hydro, DER,**
FIT and Thermal Contracts

ACTION PLAN

	NEAR TERM ACTIONS (2022-2025)	MID-TERM ACTION (2026-2028)
RETIRE	• Schahfer Units 17 and 18 (by 2023)	• Michigan City Unit 12 • Schahfer Units 16A and 16B
PREPARE	• MC12-related transmission projects • Further diligence to optimize quantities and resource types • Secure approvals for replacement projects	• Full implementation of Transmission projects • Secure approvals for replacement projects • Optimize quantities/resource types
REPLACE	• ~3,000MW of wind/solar projects approved by the IURC • Currently approved DSM plan and future approved DSM plan • NIPSCO Owned DER (up to 10MW) • Short term Capacity Contracts (150MW) • Storage (135-370MW*)	• Sugar Creek Uprate (30-53MW) • Solar (100-250MW) • Storage (135-370MW*) • Gas Peaking (up to 300MW) • Hydrogen Electrolyzer Pilot (20MW**)
	ONGOING	
MONITOR	• Actively monitor changing federal/state policy, MISO market rules and technology advancements	

* Exact Storage ICAP MW to be optimized
**Assumes Green Hydrogen; Quantities to be optimized

Table of Contents

ACRONYMS AND ABBREVIATIONS

A

AC	Air Conditioning
ACE	Affordable Clean Energy
ACP	Alternative Compliance Payment
ACS	American Community Survey 2019
AEO	Annual Energy Outlook (from EIA)
AER	Aggressive Environmental Regulation Scenario
ASHP	Air Source Heat Pumps
AMI	Advanced Metering Infrastructure
A/S	Ancillary Services
ATC	Around-the-Clock

B

BEV	Battery Electric Vehicles
BNEF	Bloomberg New Energy Finance
BPM	Business Practice Manual

C

C&I	Commercial and Industrial
CAA	Clean Air Act – EPA issued initial rules in 1970
CAGR	Compound Annual Growth Rate
CAIR	Clean Air Interstate Rule
CapEx	Capital Expenditures
CAP	Community Advisory Panel
CAPP	Central Appalachia
CATF	Clean Air Task Force
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals – EPA issued rules June 2010
CCS	Carbon Capture and Sequestration or Carbon Capture and Storage
CCUS	Carbon capture, utilization, and storage
CDD	Cooling Degree Days
CEPP	Clean Electricity Performance Program
CF	Capacity Factor
CO2	Carbon Dioxide
Company	Northern Indiana Public Service Company LLC
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity

CRA	Charles River Associates (IRP Consultant)
CT	Combustion Turbine
CWA	Clean Water Act

D

DA	Distribution Automation
DER	Distributed Energy Resource
DG	Distributed Generation
DG Statute	Indiana Code Ch. 8-1-40
DOE	U.S. Department of Energy
DR	Demand Response
DRR1	Demand Resource Type 1
DSM	Demand-Side Management
DSM Statute	Ind. Code § 8-1-8.5-10

E

EDG	Excess Distributed Generation
EDR	Emergency Demand Response
EE	Energy Efficiency
EIA	Energy Information Administration of the U.S. Department of Energy
EISA	Energy Independence and Security Act of 2009
ELCC	Effective Load Carrying Capability
ELG	National Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
ESOP	Energy Storage Operations
ESP	Electrostatic Precipitator
ESR	Electric Storage Resources
EV	Electric Vehicles
EWD	Economy-Wide Decarbonization Scenario

F

FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization

G

GDS	GDS Associates, Inc.
GDS Team	GDS and Demand Side Analytics

GHG	Green House Gas
GPCM	Gas Pipeline Competition Model
GPR	Green Power Rider

H

H2	Hydrogen
HDD	Heating Degree Days
HDV	Heavy-Duty Vehicle
Hg	Mercury
HRSG	Heat Recovery Steam Generator
HSPF	Heating Seasonal Performance Factor
HVAC	Heating, Ventilation, and Air Conditioning

I

IA	Interconnection Agreement
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated Gas Combined Cycle
ILB	Illinois Basin
IMEP	Interregional Market Efficiency Project
IQW	Income Qualified Weatherization
IRP	Integrated Resource Planning
IRP Rule	170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC/Commission	Indiana Utility Regulatory Commission

K

kWh	Kilowatt hour

J

JA	Junior Achievement
JOA	Joint Operating Agreement

L

LCOE	Levelized Cost of Electricity/Energy

LCOH	Levelized Cost of Hydrogen
LDV	Light-Duty Passenger Vehicle
LED	Light Emitting Diode
LLF	Line Loss Factors
LMR	Load Modifying Resource
LMP	Locational Marginal Pricing
LNB	Low NO_x Burner
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LRZ 6	MISO Load Resource Zone 6

M

MAP	Maximum Achievable Potential
MDV	Medium-Duty Vehicle
MFDI	Multi Family Direct Install
Michigan City	Michigan City Generating Station
Michigan City 12	Michigan City Unit 12
MISO	Midcontinent Independent System Operator, Inc.
MOSEP	CRA's Moment Simulation Energy Price
MPS	Market Potential Study
MTEP	MISO Transmission Expansion Planning
MW	Megawatt

N

NAAQS	National Ambient Air Quality Standard – EPA issued rules January 2013
NAPP	Northern Appalachian
NBV	Net Book Value
NDC	Net Demonstrated Capacity
NERC	North American Electric Reliability Corporation (formerly Council)
NETL	National Energy Technology Laboratory
NG	Natural Gas
NGF	CRA's Natural Gas Fundamentals Market Model
NIPSCO	Northern Indiana Public Service Company LLC
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value of Revenue Requirements
NSRDB	National Solar Radiation Database
NREL	National Renewable Energy Laboratory
NTG	Net To Gross
NYMEX	New York Mercantile Exchange

O

O&M	Operations and Maintenance
OFA	Over-Fire Air
OSB	Energy Efficiency Oversight Board
OUCC	Indiana Office of Utility Consumer Counselor

P

PEM	Proton Exchange Membrane
PenDER	CRA's DER Penetration Model
PEV	Plug-In Electric Vehicle
PGC	Potential Gas Committee
PHEV	Plug-In Hybrid Electric Vehicle
Pilot Program	IN-Charge Electric Vehicle Pilot Program
PJM	PJM LLC (Regional Transmission Organization)
PPA	Purchase Power Agreement
PRB	Powder River Basin
PTC	Production Tax Credit
PV	Photovoltaic

Q

Quanta Technology	Quanta Technology, LLC

R

RAN	Resource Availability and Need
RAP	Realistic Achievable Potential
RCx	Retro-Commissioning
REC	Renewable Energy Credit
Ref	Reference Case Scenario
RFP/2021 RFPs	Request for Proposals/2021 RFP Events
RIIA	Renewable Integration Impact Assessment
RIM	Rate Payer Impact Measure
RPPA	Renewable Purchase Power Agreement
RTO	Regional Transmission Organization (Independent System Operator)

S

SAIFI	System Average Interruption Frequency Index (Reliability-see also SAIDI and CAIDI)
SAM	System Advisor Model
SBDI	Small Business Direct Install
SCADA	Supervisory Control and Data Acquisition

SCED	Security-Constrained Economic Dispatch
Schahfer	R.M. Schahfer Generating Station
Schahfer 16 A/B	Schahfer Units 16A and 16B
SCUC	Security-Constrained Unit Commitment
SEER	Seasonal Energy Efficiency Ratio
SMR	Small Modular Reactors
SNCR	Selective Non-Catalytic Reduction
SO2	Sulfur Dioxide
SQE	Status Quo Extended Scenario
STEM	Science, technology, engineering, and math
Sugar Creek	Sugar Creek Generating Station

T

T&D	Transmission and Distribution
TDSIC	Transmission, Distribution, and Storage System Improvement Charge
TRC	TRC Companies, Inc.
TRM	Technical Resource Manual

U

UCAP	Unforced Capacity (the amount of Installed Capacity that is actually available)
UCT	Utility Cost Test
Urban League	Urban League of Northwest Indiana

V

VOM	Variable Operations and Maintenance Costs

W

WACC	Weighted Average Cost of Capital

Section 1. Integrated Resource Plan

1.1 Short Term Action Plan

Northern Indiana Public Service Company LLC has developed a short-term action plan in this 2021 IRP that ensures NIPSCO can confidently provide the least cost, cleanest supply portfolio available while maintaining reliability, diversity and flexibility during a time of transition within NIPSCO's own resource portfolio and dynamic change in the overall energy industry.

As previously planned, NIPSCO will complete the retirement and shutdown of Schahfer Units 17 and 18 by the end of 2023 and continue activities associated with the implementation of transmission system reliability upgrades. NIPSCO will continue to complete and place in service wind, solar, and solar plus storage replacement resources previously approved by the Commission for the scheduled 2023 retirement of all coal units at Schahfer.

Beyond the activities associated with the retirement of the Schahfer coal units, NIPSCO's short-term action plan focuses on maintaining flexibility for retirement of additional units and replacement with new resources. Consistent with previous analyses, early retirement of coal units is still cost-effective for customers, and NIPSCO has refined the retirement timing of Michigan City to occur between 2026 and 2028. Additionally, NIPSCO's two vintage gas peaking units (Schahfer 16A/B) will also retire between 2025 and 2028. Flexibility in timing allows NIPSCO to optimize the retirement dates of Michigan City and Schahfer 16A/B, pursuing cost-effective resources that fulfill emerging capacity needs.

The robust response to the 2021 RFPs (discussed in more detail in Section 4) indicates that there is a diverse set of resources and projects to meet NIPSCO supply needs over the near term. NIPSCO will select replacement projects/bids through the 2021 RFPs evaluation process, prioritizing capacity-advantaged resources that address our reliability requirements, including thermal contracts, storage, and gas peaking resources. NIPSCO will also engage with bidders on emerging technology resources, such as long-duration energy storage and hydrogen technologies, to pursue pilots and inform how such technologies can be deployed by NIPSCO to achieve further decarbonization of the generation portfolio over the long term. Additionally, NIPSCO will further study strategically-sited NIPSCO-owned DER opportunities with the potential to defer substation and other distribution system investment (discussed further in Section 4).

NIPSCO will make the necessary regulatory filings with the Commission and continue to monitor federal and state policy, MISO market trends, and emerging technologies, while staying actively engaged with project developers and asset owners to maintain flexibility and optionality. If necessary, NIPSCO may conduct future RFPs to identify preferred resources to replace Michigan City 12 and Schahfer 16A/B.

NIPSCO will continue the implementation of its current DSM plan through 2023.[1] NIPSCO will also continue to comply with existing environmental regulations and all NERC compliance standards and requirements. Lastly NIPSCO will continue to invest and modernize its electric infrastructure to maintain the safe and reliable delivery of electricity to its customers

As described in greater detail in Section 9, the action items included in NIPSCO's short-term action plan include those listed in Table 1-1.

Table 1-1: 2021 IRP Short-Term Action Plan

Complete and place in service 12 remaining renewable facilities approved by the IURC
Complete retirement and shutdown remainder of Schahfer coal units (17,18) by 2023
Refine the retirement of Michigan City 12 to be between 2026 and 2028 by making required notifications to MISO, NERC, and other organizations as appropriate
Monitor the operating condition of the Schahfer 16A/B and plan for their retirement between 2025 and 2028 by making required notifications to MISO, NERC, and other organizations as appropriate, including preserving the optionality to use existing interconnection rights at the site through the MISO generator replacement process
Implement required reliability and transmission upgrades necessitated by retirement of the Michigan City 12 and Schahfer 16A/B
Confirm Sugar Creek uprate options in more detail with the plant's turbine manufacturer and schedule the uprate in accordance with the plant's maintenance cycles
Identify candidate DER projects as part of NIPSCO's distribution planning activities and consistent with planning-level assumptions developed in the IRP; implement identified projects after additional project-specific diligence
Continue implementation of filed DSM Plan for 2022 through 2023
Select replacement projects identified from the 2021 RFPs, initially prioritizing thermal PPA and solar resources
Perform deeper diligence on gas peaker and storage projects from the 2021 RFPs, selecting projects that conform to the preferred portfolio's requirements as NIPSCO tracks MISO guidelines, Commission requirements, and system reliability needs
As needed, conduct a subsequent RFP(s) to identify additional resources that may be available with attributes that are consistent with those required to implement the preferred portfolio

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[1] On September 1, 2021, the IURC issued an Order in Cause No. 45456 approving NIPSCO's proposed Electric DSM Program for the period of 2022-2023.

Explore potential pilot projects from the RFP associated with emerging technologies, such as long duration storage and hydrogen
File CPCN(s) and other necessary approvals for selected replacement projects
Procure short-term capacity as needed from the MISO market or through short-term bilateral capacity transactions
Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape
Perform additional reliability analysis within the NIPSCO system as needed to ensure evolving portfolio meets all reliability needs and requirements
Comply with NERC, EPA, and other regulations
Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

1.2 Plan Summary

NIPSCO’s preferred portfolio pathway preserves flexibility and our ability to adapt to expected changes in environmental regulations, federal and state energy policy, and other market forces, while providing additional time for further research, refinement and confirmation of our long-term energy plans. The plan was developed to ensure that a reliable, compliant, flexible, diverse and affordable supply will continue to be available to meet future customer needs. NIPSCO carefully planned and considered the impacts to its employees, the environment and the local economy of the communities NIPSCO serves (property tax, supplier spend, employee base) as the plans were developed.

This preferred plan was developed through substantial quantitative and qualitative analyses that capture the ever evolving energy landscape to allow NIPSCO to remain flexible in a time of uncertainty. NIPSCO completed an analysis to evaluate the retirement timing of its remaining existing generating fleet relative to viable alternatives (See Section 9). NIPSCO utilized the 2021 RFP solicitations to identify the best combination of supply- and demand-side resources to meet its capacity needs.

The 2021 RFPs provided NIPSCO insight into the most relevant types of resources available to meet customer needs and their prices (*See* Section 4). NIPSCO performed both the existing fleet and replacement analyses using robust scenario and risk-based (stochastic) analyses that capture the flexibility and adaptability of the portfolio among changing market rules; carbon emissions and regulations/incentives in an uncertain policy future; and system reliability implications of a portfolio with significant intermittent resources. NIPSCO also performed an enhanced reliability assessment to understand the reliability implications of potential resource additions to the NIPSCO portfolio and incorporated the results into the final scoring to create the optimal plan.

It is important to note that the IRP is a snapshot in time, and while it establishes a direction for NIPSCO, it is subject to change as the energy landscape continues to evolve. NIPSCO will continue to engage its stakeholders and be transparent in its decisions following submission of this 2021 IRP.

NIPSCO's supply strategy for the next 20 years is expected to:

- Phase out 100% of its coal emissions by the 2026-2028 time period based on the ultimate retirement timing date for Michigan City;
- Replace retired generation resources with a diverse, flexible, and scalable mix of incremental resources, including short-term capacity contracts, solar, large energy storage, and gas peaking resources;
- Seek to advance NIPSCO's knowledge and understanding of future hydrogen pilots and other emerging storage technologies identified as potential pathways toward further decarbonization of the generation portfolio in the long term;
- Remain on the CO2 emission reduction pathway identified in the 2018 IRP, with the opportunity to further reduce emissions based on technology advances; and
- Continue the Company's commitment to energy efficiency and demand response by executing DSM plans.

1.3 Emerging Issues

NIPSCO's preferred plan follows a diverse and flexible supply strategy, with a mix of market purchases and different low variable cost generation resources, to provide the best balanced mitigation against marker rules, policy, and technology uncertainty.

1.3.1 Market Rules Uncertainty

At the outset of its 2021 IRP process, NIPSCO identified several regulatory developments at the MISO level that could impact portfolio performance. While MISO has advanced policy development and proposed tariff revisions in many areas over the last year, several areas of uncertainty remain, requiring NIPSCO to ensure portfolio decisions are flexible enough to adapt to the changing market rules environment. These include:

- Ongoing activities associated with RAN framework and the pending implementation of a seasonal capacity construct;
- MISO's transition to an ELCC methodology to assess capacity credit for wind and solar resources over time and by season;

- MISO’s ongoing RIIA study, which may highlight new emerging reliability issues and potential market design responses;
- MISO’s implementation of market rules associated with FERC Order 841, which requires ISOs and RTOs to establish a participation model for storage resources in energy, capacity, and ancillary services markets.

1.3.2 Policy Uncertainty

As of the time of the development of NIPSCO’s 2021 IRP preferred portfolio, federal policymakers were debating significant changes to energy and environmental policy, and debates on such policy topics will continue at the federal and state level. Major policy uncertainties that could impact the ultimate direction of NIPSCO’s preferred plan include:

- The potential implementation of a stand-alone storage ITC;
- The potential implementation of a hydrogen PTC or other federal incentives for hydrogen development;
- The potential implementation of a carbon tax, clean energy standard or CEPP that could impact the relative economics of different generating resource types.

1.3.3 Technology Uncertainty

As the power sector continues to navigate a period of significant change, NIPSCO expects that technology evolution will be rapid, requiring regular review of the supply-side resource marketplace and flexibility in the preferred portfolio. Going forward, NIPSCO expects power sector technology evolution to continue to impact both short-term procurement activities and long-term resource decisions. In particular, NIPSCO will continue to monitor the following:

- Stand-alone storage resource costs, efficiencies, and operational parameters, such as cycle limits, depth of discharge specifications, and ongoing expenses;
- Grid-forming inverter technology that could provide reliability benefits, such as blackstart, fast frequency response, and inertial response, to NIPSCO’s system as it becomes more inverter-based;
- Hydrogen production developments, particularly associated with electrolysis of water with clean electricity sources (“green hydrogen”) and the costs and capabilities of turbines and other thermal resources to burn hydrogen or blend hydrogen with natural gas;
- CCUS costs and sequestration opportunities, particularly associated with the Sugar Creek facility;

- Long-duration storage technologies, including gravity storage, and their associated costs, efficiencies, and other value drivers; and

- Other technologies that may emerge over the long term, including small modular reactors and other nuclear technology.

Section 2. Planning for the Future

2.1 IRP Public Advisory Process

NIPSCO's 2021 IRP stakeholder process focused on continuing to increase transparency around its planning process and enhance public involvement through extensive stakeholder interactions. At each stakeholder meeting, NIPSCO provided information on the processes and assumptions involved in the development of the IRP and solicited relevant input for consideration. Furthermore, to facilitate stakeholder outreach and ongoing communications, NIPSCO maintained a web page on its website with current information about the IRP. NIPSCO posted all meeting agendas, presentations, meeting notes and other relevant documents to the web page.

As part of the IRP process NIPSCO conducted an RFP solicitation to identify the most viable capacity resources currently available in the market place to best meet customer needs. NIPSCO sought input from stakeholders regarding the approach and design of the All-Source RFP to ensure a robust and transparent process that yielded the desired results.

Stakeholders were invited to meet with NIPSCO throughout the IRP process to discuss key issues, concerns and perspectives. NIPSCO extended an invitation to participate in the stakeholder process to the Commissioners and Commission staff, the OUCC and stakeholders that participated in previous IRP public advisory processes. NIPSCO's executive leadership and its subject matter experts attended each public advisory meeting. In the section that follows, NIPSCO provides an overview of its stakeholder process. A more comprehensive accounting of stakeholder meetings, presentations and meeting notes is included in Appendix A.

As part of the 2021 IRP process, NIPSCO hosted five virtual public advisory meetings plus one virtual technical webinar, which was focused on the additional reliability analysis that NIPSCO introduced in this IRP. For all meetings, NIPSCO posted an open invitation on its website for any party wishing to register.

In addition to the public advisory meetings, NIPSCO participated in a number of one-on-one meetings with individual stakeholders to address specific concerns and issues that were raised as a result of information presented and discussed at the public advisory meetings. NIPSCO also corresponded with individual stakeholders on a variety of issues throughout the process.

2.1.1 Stakeholder Meeting 1

NIPSCO's first stakeholder meeting was held virtually on March 19, 2021. In this first meeting, NIPSCO set the stage for the 2021 IRP. An update on the progress of the 2018 Short Term Action Plan and the ongoing generation transition plan was discussed. NIPSCO then outlined the fundamental pillars of NIPSCO's long-term resource planning strategy, which includes producing a plan that is reliable, compliant, flexible, diverse, and affordable. Process improvements from the 2018 IRP were then discussed in detail, including the approach to reliability. NIPSCO then walked through the resource planning approach for 2021, which is structurally similar to the 2018 process with changes and enhancements.

NIPSCO provided an in depth discussion on key assumptions used in the 2021 IRP, including commodity prices and the load forecast, which included impacts from EVs and DERs. NIPSCO then walked through the treatment of uncertainty and introduced scenario concepts. Finally, NIPSCO concluded with the stakeholder advisory meeting road map and indicated a RFP would be conducted in conjunction with the 2021 IRP. The meeting presentation (including the agenda), notes (including questions/responses), and registered participants for Meeting 1 are included in Appendix A.

2.1.2 Stakeholder Meeting 2

NIPSCO's second stakeholder meeting was held virtually on May 20, 2021. In this second meeting, NIPSCO provided an overview of the resource planning process and provided an update on NIPSCO's response to stakeholder feedback received since the first meeting. NIPSCO then provided an overview of the major considerations that are taken into account while performing a long-term planning exercise with intermittent resources. NIPSCO outlined the MISO functions and various roles, then introduced major regulatory changes related to MISO market operations since the 2018 IRP. NIPSCO then provided an overview of NIPSCO's environmental impact targets, outlined the environmental controls present on NIPSCO's generation fleet, and summarized how the 2018 IRP's preferred portfolio addressed specific environmental compliance requirements.

NIPSCO then provided an overview of how the 2021 IRP will perform both scenario and stochastic analysis. The four planning scenarios were re-introduced and each of the key variables drivers within each scenario was expanded on in depth. NIPSCO then provided a summary of the major stochastic variable inputs, including a detailed discussion on how renewable generation uncertainty would be incorporated in the 2021 IRP.

NIPSCO also provided an overview of NIPSCO's RFP, including specifics of each bid event, the range of capacity being requested, duration expectations, and other details. The evaluation criteria, logistics, and timing were also discussed. The meeting presentation (including the agenda), stakeholder presentations, notes (including questions / responses), and registered participants for Meeting 2 are included in Appendix A.

2.1.3 Stakeholder Meeting 3

NIPSCO's third stakeholder meeting was held virtually on July 13, 2021. In this third stakeholder meeting, NIPSCO provided an overview of the resource planning process and progress since the second stakeholder meeting. NIPSCO then shared an in-depth overview of DSM resource modeling, methodology, and how these resources are considered in the IRP. NIPSCO also introduced supply-side DER options being considered in the IRP. NIPSCO then provided an overview of the 2021 RFP Results. NIPSCO and the RFP manager, CRA, provided an overview of the proposals received and a summary of the pricing. NIPSCO also explained how the RFP results would be integrated into the IRP analysis and important next steps for both the IRP and RFP processes. The presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 3 are included in Appendix A.

2.1.4 Stakeholder Meeting 4

NIPSCO's fourth stakeholder meeting was held virtually on September 21, 2021. In this fourth meeting, NIPSCO reviewed the overall IRP process and reminded stakeholders of the various inputs and assumptions discussed during previous meetings, including key planning themes, NIPSCO's integrated scorecard, scenario and stochastic inputs, and supply and demand resource options. NIPSCO then provided an overview of its supply-demand balance and its portfolio energy position on an annual and hourly basis, followed by a detailed review of the preliminary findings from the portfolio modeling.

NIPSCO explained the rationale for conducting a two-stage portfolio analysis and reviewed detailed results for the existing fleet and replacement analyses. These results included portfolio optimization outcomes, revenue requirement projections, scenario cost ranges, stochastic analysis results, and other major metrics on NIPSCO's integrated scorecard associated with environmental sustainability, reliability, and social and economic impacts. NIPSCO also reviewed preliminary findings from its sub-hourly ancillary services analysis and outlined the key elements of the ongoing technical reliability assessment. The presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 4 are included in Appendix A.

2.1.5 Technical Webinar

NIPSCO held a technical webinar on October 12, 2021. The technical webinar focused on the enhanced reliability considerations in the 2021 IRP, providing a forum for stakeholder questions. NIPSCO reviewed its approach to reliability in this IRP, which considers both the economic and non-economic aspects of reliability. During the meeting, NIPSCO and CRA presented the economic analysis of sub-hourly energy and ancillary services value, and Quanta Technology reviewed the non-economic reliability assessment performed for all replacement portfolios. NIPSCO, CRA, and Quanta Technology responded to stakeholder questions. The presentation (including the agenda), notes (including questions / responses), and registered participants for the Technical Webinar are included in Appendix A.

2.1.6 Stakeholder Meeting 5

NIPSCO's fifth stakeholder meeting was held virtually on October 21, 2021. In this fifth meeting, NIPSCO reviewed the public advisory process, resource planning activities, existing fleet and replacement analyses, and the reliability assessment presented in the October 12th Technical Webinar. NIPSCO also responded to stakeholder feedback related to DSM topics and alternative customer cost summaries. NIPSCO then reviewed its preferred resource plan and preliminary action plan and responded to stakeholder questions and feedback. The meeting presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 5 are included in Appendix A.

2.1.7 One-on-one Stakeholder Meetings

NIPSCO held a number of one-on-one meetings with its stakeholders throughout the public advisory process. Generally, the meetings related to either (1) clarifications, (2) additional information regarding the RFP solicitation, or (3) providing additional data. Information relating to the stakeholder requests can be found in the presentation included in Appendix A (Slides 48 through 52) and Appendix A(Slides 11 through 23).

NIPSCO's 2021 IRP is the result of analysis performed by NIPSCO that includes consideration of stakeholder input. NIPSCO has made a good-faith effort to be open and transparent regarding input assumptions and modeling results. NIPSCO appreciates the participation of its stakeholders, including the Commission staff, the OUCC, NIPSCO's largest industrial customers and community action groups, all of which participated extensively throughout the IRP development process. NIPSCO's stakeholders and Commission staff provided valuable feedback throughout the process, which has been considered and incorporated as applicable. The written feedback NIPSCO received, as well as the Company's responses, is included in Appendix A. Despite best efforts to address and resolve all input from stakeholders, there were instances wherein NIPSCO still incorporated, for example, methodologies that were not supported by all stakeholders.

2.2 IRP Planning Process

NIPSCO's 2021 IRP is in compliance with the Commission's IRP Rule. A matrix showing NIPSCO's compliance with each section of the IRP Rule (providing a reference to the appropriate Section(s) of the IRP) is included in Section 11: Compliance with Proposed Rule.

Long term resource planning requires addressing risks and uncertainties and for NIPSCO, the first step in this process is to identify objectives and metrics. Next NIPSCO develops market perspectives for key variables such as customer demand and commodity prices. This involves the creation of distinct thematic "states-of-the-world" that represent potential future operating environments for NIPSCO. Then NIPSCO constructs integrated resource portfolio strategies and performs detailed modeling and analysis to evaluate the performance of various resource portfolios across a range of potential futures as well as a distribution of key stochastic variables. NIPSCO's goal is to develop a resource plan that is reliable, compliant with all regulations, diverse, flexible and affordable for customers with careful consideration of all stakeholder viewpoints.

The long-term strategic plan identifies expected energy and demand needs over a 20-year horizon and recommends a potential resource portfolio to meet those needs. The short-term strategic plan identifies the steps NIPSCO will take over the next three years to implement the long-term strategic plan.

NIPSCO recognizes future economic and environmental changes are difficult to accurately predict. While the 2021 IRP addresses a wide range of plausible market conditions and portfolio strategies, new information is evaluated and incorporated as it becomes available as part of NIPSCO's commitment to continuous planning.

NIPSCO's IRP team included experts from key areas of NIPSCO and its affiliate NiSource Corporate Services Company. The following energy consultants also provided input:

GDS 1850 Parkway Place, Suite800 Marietta, GA 30067	Developed DSM measures inputs for a long-term DSM forecast
CRA 200 Clarendon Street Boston, MA 02116	Provided fundamental long term commodity price forecasts and performed portfolio modeling and analysis. A separate division of CRA provided assistance in administering the All-Source RFP and evaluating the responses.
Demand Side Analytics 691 John Wesley Dobbs Ave NE Suite V3 Atlanta, GA 30312	Provided assistance with analyzing demand response measures and opportunities
Quanta Technology 4020 Westchase Blvd., Suite 300 Raleigh, NC 27607	Provided technical reliability assessment of replacement portfolio options

2.2.1 Contemporary Issues

NIPSCO also participated in the Commission's IRP Contemporary Issues Technical Conferences that occurred since NIPSCO completed its last IRP. Dates and topics discussed included:

Date	Topics
April 15, 2019	• Load shapes and planning • Utilizing data bases • Long-term planning and procurement • Integration of DERs • NIPSCO's IRP/RFP and preliminary lessons learned • Life cycle analysis of GHG emissions and resource planning
August 25, 2020	• Benefits of RTOs • Resource adequacy • Implications of changing resource mix • Transmission planning • DERs
September 24, 2020	• Renewable integration models • All-source competitive solicitation • Grid-interactive efficient buildings

	- Time and locational value of EE
June 8, 2021	- EE and load forecasting
July 15, 2021	- Development and use of MPSs - EE Oversight Boards
August 19, 2021	- Development of EE bundles selected in the IRP optimization process and into utility program offerings

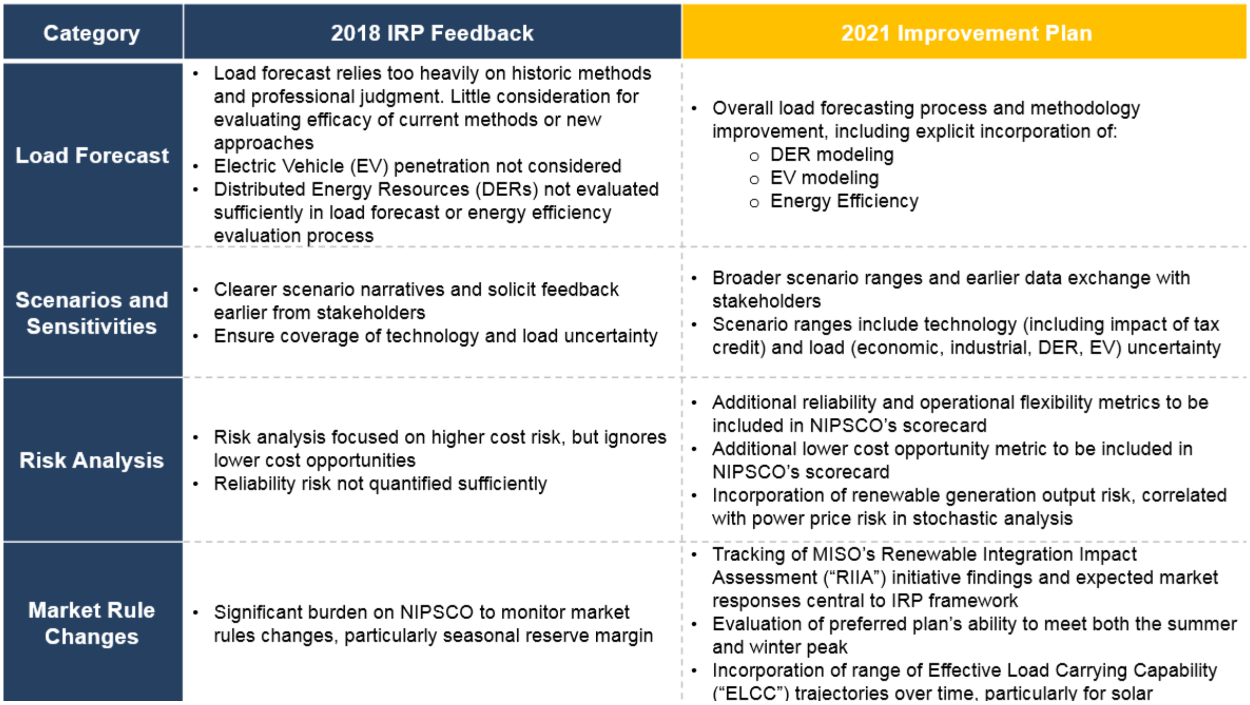
To the extent the information applicable and appropriate, NIPSCO included the items discussed during the technical conference in its analysis.

2.2.2 2018 IRP Feedback and 2021 Process Improvement Efforts

NIPSCO strives to continuously improve all aspects of its resource planning process and, for the 2021 IRP, NIPSCO reviewed the major feedback it received throughout the 2018 IRP process and implemented key improvements. The process improvements in the 2021 IRP were designed to enhance the robustness of the load forecast, improve upon established advanced risk modeling techniques, and remain flexible to MISO market rule changes.

Table 2-1 summarizes the major areas of feedback received on NIPSCO's 2018 IRP and the improvements that were included in the 2021 IRP process.

Table 2-1: Process Improvement



Category	2018 IRP Feedback	2021 Improvement Plan
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
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
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
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

2.2.3 Equitable Transition

As the resource mix and generation technologies in the industry continue to transition, the topic of equity or "just transition" to ensure all customers and communities are included has surfaced as a core issue to address. The vision of an equitable transition is one that improves universal access to energy to customers and communities, ensures inclusion of all stakeholders in strategy/decision-making, and ensures a fair division of costs and benefits.

NIPSCO recognizes the importance of equity and a "just transition" for NIPSCO's customers and communities as the generation portfolio evolves. In 2018, as part of the selection of projects to replace the retiring Schahfer coal units, NIPSCO indicated a strong preference for projects that were located in the communities the Company serves, and if that was not possible, within the State of Indiana. Thirteen of the 14 projects we selected are within the State of Indiana, and the construction and ongoing operations of the plants will deliver enduring economic benefits to those communities and the state. Of note, the Dunn's Bridge I and II projects will be located in Jasper County where the Schahfer plant is located and will contribute significantly to the property tax base for that community for years to come. Furthermore, as part of the 2019 and 2021 RFP solicitations, NIPSCO incorporated proposal-specific benefit and risk factors outlined in the evaluation criteria, which included, but were not limited to, impacts on local communities that NIPSCO serves, minority- or women-owned business enterprises, and the enterprise's supplier diversity spending. Incorporating these factors into the bidding process was another step forward for integrating equity considerations into the IRP.

In the 2021 IRP Stakeholder process, the topic of equity considerations was discussed, including a recommendation that NIPSCO consider the addition of an equity metric as part of its scorecard. NIPSCO welcomed this discussion and is always interested in engaging broadly with stakeholders on this important topic. NIPSCO recognizes that measuring equity in the energy transition is a complex process and is taking steps to further expand its knowledge and understanding of different ways and approaches to evaluate this issue. NIPSCO and NiSource employees are participating in the Equity in a Clean Energy Economy Collaborative, which brings together diverse stakeholders to create new approaches and tools to ensure equity in a clean energy economy for at-risk customers and communities. NIPSCO looks forward to engaging in a state-wide dialogue with the Commission, other utilities, and interested stakeholders on the topic of equity in future IRP Contemporary Issues Technical Conferences and other forums. NIPSCO will continue to examine future resource decisions within the context of broader issues like equity and where possible will seek to develop metrics and measures to better assess the impact of those decisions.

2.3 Resource Planning Approach

Consistent with the principles set out in Section 1.1, the 2021 IRP identifies a preferred portfolio plan for NIPSCO over a 20-30 year[2] planning horizon that seeks to deliver reliable,

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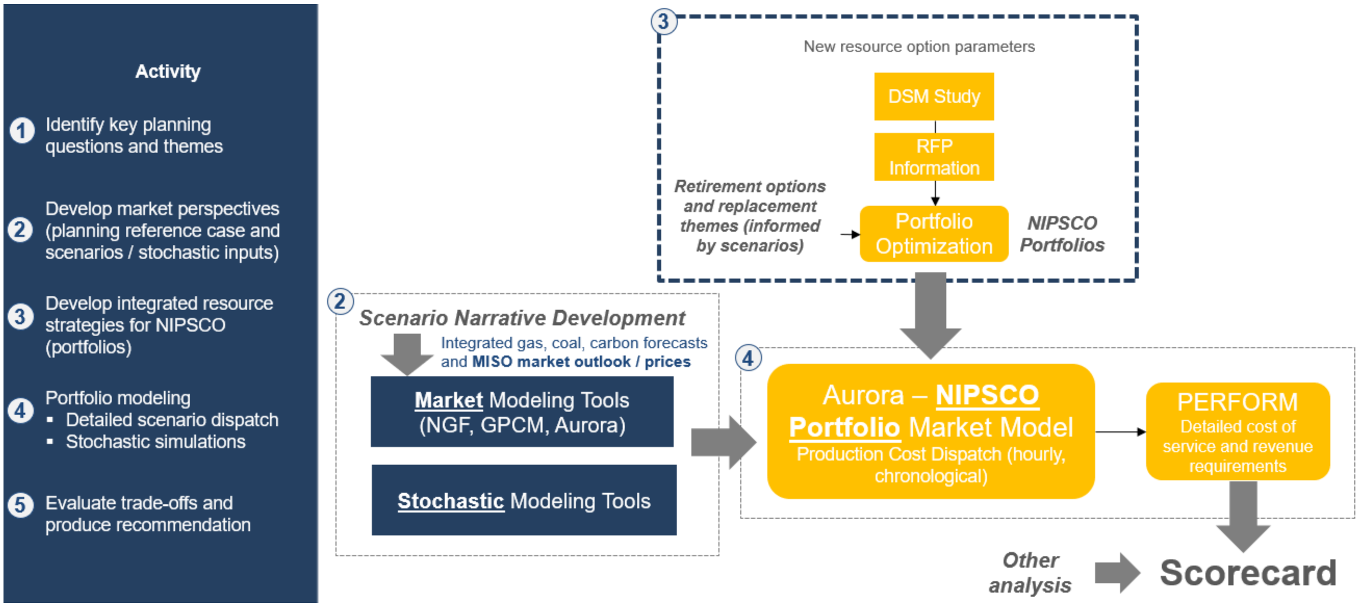
[2] Note that fundamental market modeling and portfolio dispatch is performed over a 20-year period, and NIPSCO performs a 10-year end effects analysis in the financial modeling framework to arrive at 30-year NPVRR estimates. The end effects analysis grows variable costs at the rate of inflation, but specifically accounts for full rate base accounting and incorporates the impacts of contract expirations during the end effects period.

compliant, flexible, diverse and affordable electric service to its customers. NIPSCO's 2021 IRP was performed according to the detailed planning approach process that is outlined in Figure 2-1 and described in more detail below. While structurally similar to the 2018 IRP process, the 2021 approach has incorporated new approaches and process enhancements in order to respond to feedback that was received, as noted above.

Figure 2-1: Overall Integrated Resource Planning Approach



Step 1: Identify Key Planning Questions and Themes

The first step in NIPSCO's planning approach was to identify key planning questions and themes to guide the overall analysis framework. These key questions and themes influence all other elements of the IRP process, including the structuring of market perspectives, the identification of potential resource strategies, and the definition of objectives and metrics against which to evaluate future portfolios in NIPSCO's integrated scorecard framework. The major themes of the 2021 IRP are described in more detail below.

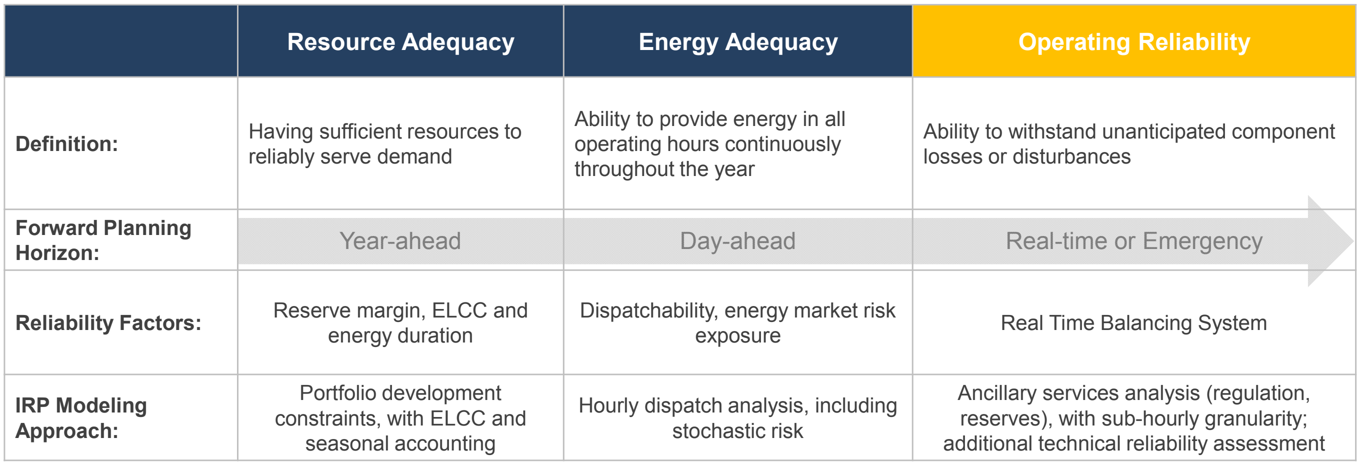
Retirement Timing for Existing Gas and Coal Units

NIPSCO's 2016 and 2018 IRPs explicitly evaluated the retirement timing of NIPSCO's coal fleet, with detailed evaluations of different retirement date permutations across all units. With all Schahfer coal units now planned for retirement by 2023, NIPSCO's 2021 IRP has been structured to evaluate various retirement pathways for the remaining thermal assets in the portfolio: the coal-fired Michigan City Unit 12, the natural gas-fired Schahfer 16A/B peaking units, and the natural gas-fired Sugar Creek combined cycle. As in past IRPs, NIPSCO's analysis framework has been structured to fully evaluate different retirement dates along with the corresponding impacts associated with ongoing costs and new replacement options. This provides a transparent means of assessing key portfolio evolution strategies over both the short-term and the long-term.

Reliability

The ongoing energy transition is transforming the way that resource planners need to think about the role of reliability in an IRP process, and a power market with more intermittent resources requires 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. MISO has been studying the impacts of growing intermittent generation penetration in the market for the last several years through the RIIA[3] initiative, which lays out the key emerging elements of reliability and serves as a useful framework for resource planning. The RIIA report defined three major focus areas for reliability, which are summarized along with other factors in Figure 2-2.

Figure 2-2: Reliability Elements from MISO's Renewable Integration Impact Assessment



	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; additional technical reliability assessment

Consistent with the reliability elements identified by MISO, NIPSCO's 2021 IRP has incorporated the following elements and enhancements:

- An expanded view of resource adequacy to assess seasonal (summer and winter) planning reserve margins and to evaluate changing ELCC credit for resources over time;

- A broadened stochastic uncertainty analyses to incorporate hourly renewable generation uncertainty and its expected relationship with hourly MISO power prices;

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[3] MISO published a summary report in February, 2021, which can be accessed here: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

- A sub-hourly ancillary services analysis to assess the potential value for fast response resources such as CTs and energy storage and solar plus storage in the energy, regulation, and reserves markets over time;

- An additional technical reliability assessment to evaluate resources and portfolios against key reliability standards and metrics that are unable to be quantified in the IRP's core economic analysis; and

- Incorporation of new scorecard metrics that develop reliability scores and assess broader perspectives of tail risk.

Flexibility and Adaptability of the Portfolio

A key element of NIPSCO's 2018 IRP was *flexibility*. The preferred plan specifically incorporated expectations that NIPSCO would regularly evaluate new resource options, track technology change, and adapt to market rules and policy evolution. And NIPSCO's implementation of its short-term action plan did exactly that by; (i) conducting an additional set of RFPs to secure additional projects beyond those selected in 2018; (ii) adjusting NIPSCO's procurement strategy to integrate storage into certain solar projects; and (iii) evolving the analytical tools used in IRP studies to incorporate broader risks and market considerations in the 2020 portfolio analysis and now in this 2021 IRP.

The 2021 IRP has been structured around these same principles in the following ways:

- NIPSCO identified key regulatory developments early in the planning process to ensure market scenarios and portfolios were constructed to be flexible to imminent changes. These included:
    - MISO's RAN framework and the pending implementation of a seasonal capacity construct;
    - In 2021, the Indiana General Assembly passed House Enrolled Act 1520, a three-year Forward Looking Resource Adequacy Requirement
    - MISO's transition to an ELCC methodology to assess capacity credit for wind and solar resources over time and by season;
    - FERC Order 2222, which enables DERs to participate fully in wholesale markets; and
    - FERC Order 841, which requires ISOs such as MISO to establish a participation model for electric storage resources in energy, capacity, and ancillary services markets.

- NIPSCO conducted RFP events to solicit actionable resource offers of all types and duration and specifically requested information on emerging technologies to understand likely technology trends in the coming decade;

- NIPSCO deployed a portfolio construction process that did not rely solely on least cost optimization, but assessed a wide range of strategies to understand tradeoffs and identify the attractiveness of different pathways under different states-of-the-world for commodity prices, environmental policy, and MISO market evolution.

Carbon Emissions and Environmental Policy

NIPSCO's 2018 IRP laid out a plan to significantly reduce carbon emissions by 2030 through the retirement of its coal fleet and replacement with predominantly renewable resources. Meanwhile, federal energy and environmental policy proposals have outlined several means of achieving ambitious carbon emission reductions from the power sector through a number of mechanisms, including extension of tax credits, a clean energy standard, and programs to provide grants or impose penalties on utilities based on their future clean energy expansion plans. Given NIPSCO's desire to use the 2021 IRP to assess a range of environmental policy futures and a range of potential portfolio strategies, the following considerations have been made:

- Expansion of NIPSCO's IRP planning scenarios to incorporate a range of environmental policy outcomes, including two distinct net-zero emission constructs: one based on the implementation of a carbon tax or cap-and-trade mechanism and one based on the implementation of a series of policy incentives and clean energy standard mechanisms.

- Development of net-zero portfolio concepts for NIPSCO that incorporate long-term options to retire or retrofit all fossil resources in the portfolio.

Scorecard Definition

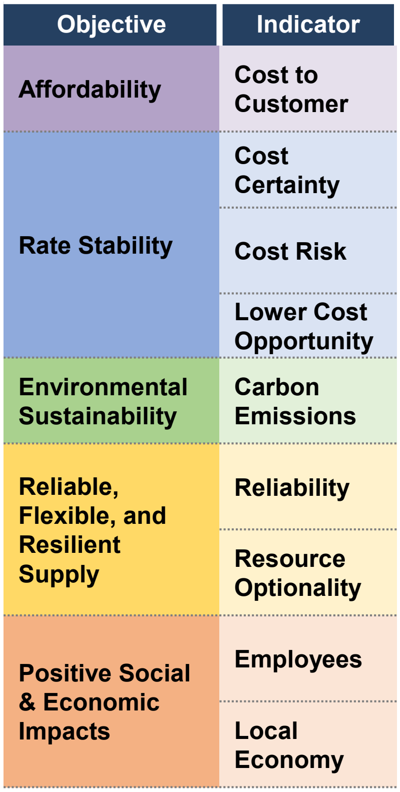
With these key planning questions and themes identified, NIPSCO worked to define a series of scorecard objectives and indicators against which to measure portfolio options. The scorecard is a means of reporting key metrics for different portfolio options to transparently review tradeoffs and relative performance. It does <u>not</u> produce a single score or ranking of portfolios, but serves as a tool to facilitate decision-making

For its 2021 IRP scorecard, NIPSCO identified five major planning objectives and multiple metrics within nine key indicator categories, as summarized in Figure 2-3. The objectives include Affordability; Rate Stability; Environmental Sustainability; Reliable, Flexible, and Resilient Supply; and Positive Social and Economic Impacts. These are similar to those used in the 2018 IRP, with the following key modifications:

- Based on stakeholder feedback, the Rate Stability objective was expanded to assess different measures of cost risk and a new measure for lower cost opportunity.

- The reliability-focused objective was refined to incorporate new measures of technical reliability and an additional review of economic opportunities in the sub-hourly ancillary services markets.

Figure 2-3: Key Scorecard Objectives and Indicators



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

Step 2: Develop Market Perspectives

Prior to performing any portfolio-specific analysis, NIPSCO developed perspectives on key *external* market drivers and other major planning assumptions. This involved the use of several market models and forecasting approaches in order to arrive at a Reference Case set of inputs and a set of scenarios against which to evaluate resource options. The elements involved in this step are described in more detail below.

Key Market Forecast Inputs

Market and commodity price forecasts are important drivers for NIPSCO's IRP, since they influence the variable costs of operation for many resources, the dispatch of certain power plants, and NIPSCO's interaction with the MISO market. CRA produced commodity price forecasts for major inputs, including natural gas prices, coal prices, emission allowance prices, and power prices (energy and capacity) for the Reference Case and three alternative integrated market scenarios. For certain inputs, CRA relied on support from NIPSCO's subject matter experts for details or assumptions that are specific to NIPSCO's current operating fleet. For example, for coal pricing, delivered coal contract details and expected coal transportation rates were provided by NIPSCO's Fuel Supply group in order to conform to near-term price expectations for the existing fleet of plants. Long-term fundamental forecasts were blended in over time. Figure 2-4 presents a summary of the source and reference information for each of the major market inputs.

Figure 2-4: Major Market Input Sources

Major Input	Source	Section Reference for More Detail
Natural Gas Prices	CRA forecasts and NIPSCO operations team	8 (fundamental forecasts, including scenarios and stochastic inputs) 4 (current gas procurement strategies)
Coal Prices	CRA forecasts and NIPSCO fuel supply group	8 4 (coal procurement and current contracts/ transportation arrangements)
Emission Prices and Environmental Regulation	CRA forecasts and NIPSCO environmental group	8
MISO Power Prices	CRA forecasts	8
MISO Capacity Prices	CRA forecasts	8

CRA relied on the following models to perform this work:

- CRA's NGF model, which provides a bottom-up forecast of North American gas production and prices with a focus on shale gas supply and other unconventional resources. Key NGF outputs include a long-term price forecast for domestic natural gas, as well as breakeven costs and production data for major gas basins across the United States. NGF is a national model, useful for macroeconomic scenarios. CRA also licenses the GPCM for regional basis analysis.

- The Aurora model, which CRA licenses, performs regional long-term capacity expansion analysis and produces hourly MISO market prices at a zonal level based on a fundamental dispatch of the market. Market inputs for the Aurora model include fuel prices, emission prices, regional load forecasts, existing resource parameters and announced regional capacity additions and retirements, and costs and operational parameters for new technology resource options. CRA also deploys a capacity market model, which produces an internally consistent capacity price outlook based on MISO market rules.

- Gas and power price stochastic inputs were developed with CRA's MOSEP mode. The tool's Monte Carlo engine simulates price deviations around expected paths based on historical volatility and gas-power correlation to yield hundreds of iterations of daily and hourly price paths. CRA also integrated hourly renewable output uncertainty into the process, based on historical weather data. The details of the stochastic development process are discussed in more detail in Section 8.

Environmental Planning Inputs

For the 2021 IRP, the joint NIPSCO-CRA team developed a range of potential environmental policy input assumptions across market scenarios, given significant uncertainty regarding the outcome of ongoing policy debates at the federal level. These environmental planning inputs included a range of tax credit extension, CO2 pricing, and clean energy target assumptions. NIPSCO's environmental group provided perspective on the policy ranges and the likely impacts for NIPSCO's fleet. A comprehensive review of key environmental planning drivers is provided in Section 7.

Energy and Demand Forecast

For the 2021 IRP, CRA developed an independent load forecast for NIPSCO's energy sales and expected future summer and winter peaks. Although independent, CRA coordinated with NIPSCO's load forecast experts to review data and discuss modeling approaches. The 2021 IRP explicitly included a robust accounting of the impacts of historical DSM, as well as quantitative scenario-based projections of EV and customer-owned DER penetration and their impacts on NIPSCO's load growth outlook. Scenario variables also included economic growth, industrial load uncertainty, and broader market-wide electrification. All methods, assumptions and detailed forecast results are provided in Section 3.

Existing NIPSCO Portfolio Parameters

NIPSCO's IRP models incorporate all elements of the existing portfolio. NIPSCO's generation operations and planning groups provided the following characteristics for the existing set of resources: capacity, heat rates, emission rates, other operational characteristics of fossil-fired resources, variable O&M costs, fixed O&M costs, forced outage rates, maintenance schedules, must run schedules for coal units, energy and capacity contracts, feed-in-tariff contracts, existing DSM data, and renewable shapes. Certain details regarding the existing fleet are provided in Section 4.

New Resource Parameters

NIPSCO relied on multiple sources for major input assumptions associated with new resource options. DSM resource options and costs were developed by GDS, as described in Section 5. Supply-side resource options were developed according to the 2021 RFPs. The 2021 RFPs provided real-world cost information and resource operational characteristics, including capacities, heat rates, and expected capacity factors for renewable resources. Section 4 describes this process in more detail, along with a review of emerging technologies that may be viable over the long-term for NIPSCO and across the broader MISO market. In addition, for the first time in 2021, NIPSCO also introduced DER resource options, inclusive of potential cost savings associated with distribution system investment deferrals. Details of this process are also described in Section 4.

Planning Reserve Margin Target

NIPSCO operates in the MISO market and must demonstrate a sufficient planning reserve margin to ensure reliability and resource adequacy. The MISO UCAP planning protocol was used to determine the planning reserve margin target to use in the 2021 IRP update, and NIPSCO set its target to 9.4%, as per current MISO standards. This target is based on NIPSCO's coincident peak in MISO. For winter planning reserve margin purposes, NIPSCO also assumed a 9.4% target, although formal rules and seasonal reserve margin standards have yet to be defined for MISO's forthcoming seasonal resource adequacy construct.

Financial Assumptions

Several financial assumptions are relevant to projecting annual revenue requirements, such as the expected return on equity and debt, tax rates, and the discount rate used when calculating the NPV. A summary of the major financial assumptions used in the 2021 IRP is provided in Figure 2-5.

Figure 2-5: Major Financial Assumptions

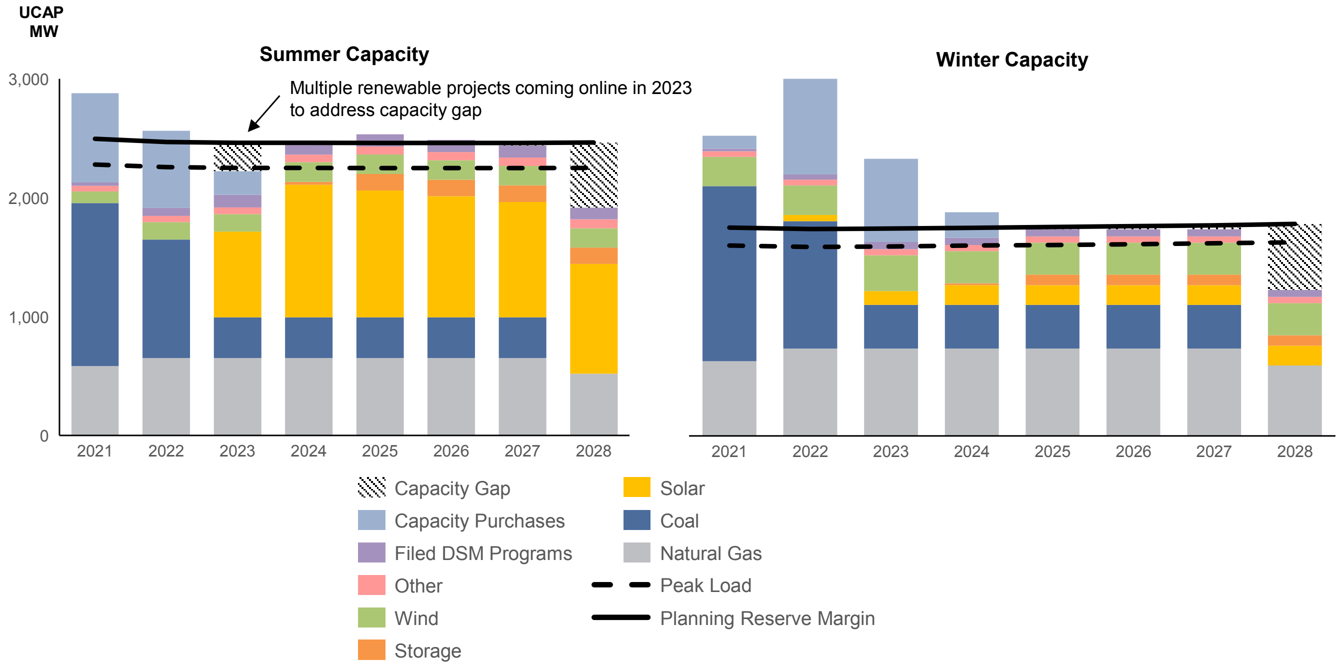
Financial Assumption	Value
Cost of Equity	9.90%
Cost of Debt	4.97%
Equity %	57.11%
Debt %	42.89%
After-Tax Weighted Average Cost of Capital	7.26%
Federal Income Tax Rate	21.00%
State Income Tax Rate	4.90%
Blended Income Tax Rate	24.87%
Property Tax Rate	2.16%
Discount Rate	7.26%
Allowance for Funds Used During Construction%	7.44%
Blended Depreciation Rate for Existing Assets	3.88%

Step 3: Develop Integrated Resource Strategies

The third major step in the 2021 IRP process was to develop resource strategies or portfolios for further evaluation. Foundational to this step was establishing NIPSCO's starting supply-demand position and energy balance, inclusive of the actions taken since the 2018 IRP. NIPSCO is currently in the midst of retiring its coal-fired Schahfer units and replacing them primarily with wind, solar, and storage resources.[4] As shown in Figure 2-6, these new resources will support NIPSCO in maintaining sufficient capacity reserves to meet peak load obligations plus the assumed MISO 9.4% planning reserve margin, until additional resource retirements are made.[5]

While winter loads are considerably lower than summer demand, the lower capacity credit for solar resources in the winter results in comparable reserve margin positions across seasons. While NIPSCO currently expects to meet reserve margin requirements from a planning perspective, it is important to note that uncertainty in load growth, planning reserve margin targets, and seasonal capacity accreditation for renewable resources requires flexibility in future resource procurement.

Figure 2-6: Starting Supply-Demand Balance by Season



From an energy perspective, the portfolio is expected to be in balance in the near-term on an annual basis, with a growing net long position anticipated into the middle of the next decade,

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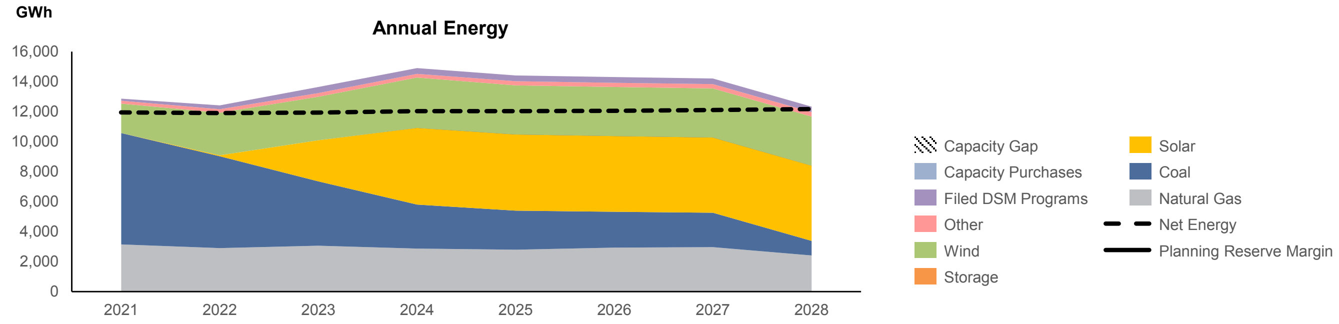
[4] Note that capacity credit for new resources may not be accounted for until the calendar year after they enter operation due to seasonal accreditation rules. In addition, the capacity credit for some storage resources is not reflected until 2025 (after a full year of operations) due to pairing configuration with solar resources.

[5] Note that the graphic shows planned retirements of the Michigan City 12 coal unit and the Schahfer 16AB natural gas-fired units in 2028. This 2021 IRP evaluated these retirement decisions in further detail, as discussed in Section 9.

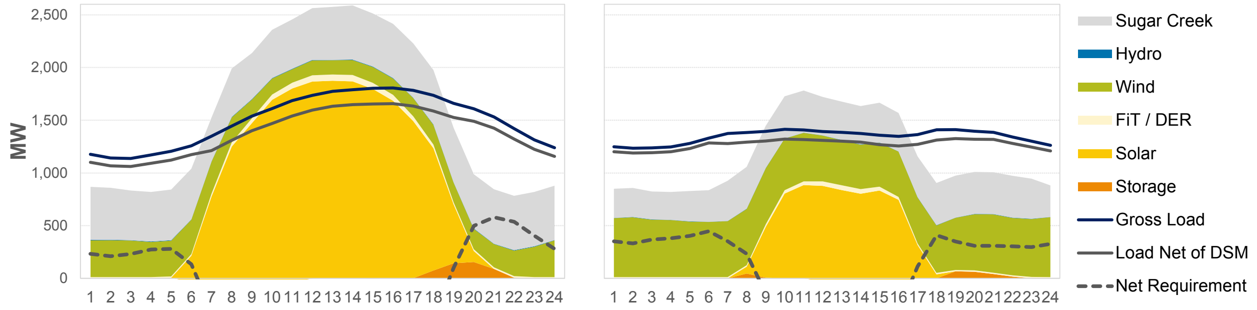
driven by the energy value and dispatch advantage of the wind and solar resources entering the portfolio. This is illustrated in Figure 2-7. However, the tight capacity position may create hourly gaps, particularly in the winter mornings and evenings when solar resources ramp down.

Figure 2-7: Starting Annual Net Energy Balance



These hourly energy gaps are shown for an average future summer day and an average future winter day *after the retirement of Michigan City 12 and Schahfer 16A/B* in Figure 2-8. As illustrated in these graphics, there are hours of the day where renewable resources are not available, notably overnight for solar resources. Furthermore, solar resources may experience steep production declines in the evening hours. Currently, NIPSCO's Sugar Creek, Schahfer 16A/B, and Michigan City 12 units are available during all hours of the day when called upon, and when economic, NIPSCO can purchase from the MISO market. However, as Michigan City 12 and Schahfer 16A/B retire, the portfolio will require new resources to be available to mitigate against specific hourly energy exposure, even as the portfolio has enough total energy to meet requirements on an annual basis.

Figure 2-8: Hourly Projected Energy Balance – Average Summer and Winter Day



With this foundational starting point, the 2021 IRP's portfolio development process relied on multiple inputs and approaches, which are described in more detail in Section 4 (Supply Side Resource Options), Section 5 (Demand Side Resource Options), and Section 9 (Portfolio

Analysis). In the context of the major themes identified in step one and the starting supply-demand balance noted above, NIPSCO believes that the dynamic planning environment requires an advanced two-stage portfolio development approach to first assess the existing fleet and to then evaluate replacement options, rather than a traditional approach that relies solely on the deployment of single least cost optimization runs. While portfolio optimization analysis for both supply side and demand side resources with the Aurora model's portfolio optimization tool was a critical part of the portfolio development process, NIPSCO's approach to portfolio construction does not rely solely on this one framework. This is due to three major considerations:

- Retirement analyses are difficult to perform in standard least cost optimization planning models, since capital and maintenance budgets vary based on expected end-of-life date. Most optimization frameworks are not set up to dynamically adjust current and future budgets in a single optimization pass, so NIPSCO evaluates the economic implications of various retirement concepts independently, with least cost optimization techniques used to identify replacement resource options for each existing fleet pathways.

- Least cost is not the only metric in NIPSCO's integrated scorecard, so determining portfolios solely through least cost optimization runs could fail to evaluate portfolios that are lower risk or provide other valuable attributes for customers (including environmental sustainability, reliability, or positive social and economic impacts). For example, in the 2021 IRP, NIPSCO has explicitly evaluated the costs of net zero carbon emission concepts and has assessed a range of different replacement themes with different reliability attributes. Such portfolios would not be feasibly identified or evaluated through single-round optimization runs.

- The approach supports transparency of results. If NIPSCO were to rely solely on optimized portfolios, it would be difficult to evaluate how much higher cost other options might be, leaving stakeholders a limited set of outputs to review, particularly if unable to perform optimization simulations on their own. Overall, NIPSCO's approach in this 2021 IRP has allowed for the evaluation of 17 different portfolio concepts to transparently present the landscape of future options.

<u>Step 4: Portfolio Modeling</u>

After detailed portfolios were constructed, each of them was evaluated in CRA's suite of resource planning tools, namely Aurora and a utility financial model known as PERFORM. The Aurora model performs an hourly, chronological dispatch of NIPSCO's portfolio within the MISO power market, accounting for all variable costs of operation, all contracts or PPAs, and all economic purchases and sales with the surrounding market. Aurora produces projections of asset-level dispatch and the total variable costs associated with serving load. It also produces estimates for other key metrics, such as carbon dioxide emissions over time and capacity and generation by fuel type. CRA also deployed its ESOP model to evaluate sub-hourly energy and ancillary services value, as described in more detail in Section 8.

The Aurora output is then used by CRA's PERFORM model to build a full annual revenue requirement, inclusive of capital investments, fixed operating and maintenance costs, and financial accounting of depreciation, taxes, and utility return on investment. The PERFORM model produces annual and net present value estimates of revenue requirements. The full set of portfolio modeling is undertaken for all portfolio options for the Reference Case, each individual integrated market scenario, and a full stochastic distribution of potential outcomes associated with select commodity prices and hourly renewable generation.

Step 5: Evaluate Tradeoffs and Produce Recommendations

The final step in NIPSCO's IRP process is to evaluate the various portfolios with an integrated scorecard and produce recommendations for a preferred plan. As discussed in Step 1, NIPSCO identified several planning objectives for its scorecard. In this step, metrics were recorded against all key planning criteria, and tradeoffs were evaluated. Ultimately, NIPSCO management is responsible for selecting the preferred portfolio based on an assessment of all options and scorecard metrics. This process and the preferred portfolio selection is described in Section 9.

Section 3. Energy and Demand Forecast

3.1 Introduction and Major Highlights of the Forecast

This section provides an overview of NIPSCO's load forecast. For the 2021 IRP, NIPSCO expanded its relationship with CRA to produce a load forecast by customer class, including residential, commercial, small industrial and large industrial customers.[6] This entailed an econometric core load forecast, plus projections for EV and DER penetration throughout the service territory. Major highlights of the forecast include:

- NIPSCO's energy sales are projected to grow at a CAGR of approximately 0.2% over the next 20 years. Summer peak load is projected to *decline* at a CAGR of 0.2%, while winter peak load is projected to *increase* at a CAGR of 0.2%.

- Residential and commercial customer counts are projected to grow at CAGRs of 0.5% and 0.8%, respectively, with the small industrial customer count projected to grow at a rate of 0.3% per year. Residential and commercial sales are projected to grow at slower rates than customer counts, while small industrial and large firm industrial sales are projected to decline.

- EV growth has the potential to add between approximately 150 to 1,000 GWh to the sales forecast and between 10 and 80 MW to peak load.

- Customer-owned DERs have the potential to reduce the sales forecast by approximately 125 to 450 GWh, while reducing summer peak load by between approximately 40 and 160 MW and winter peak load by up to 100 MW.

- NIPSCO's scenario analysis provides a broad range of potential load growth outcomes based on uncertainty regarding future economic growth, EV and DER penetration, other electrification, and potential industrial load migration.

3.2 Forecasting Methodology Overview

For the 2021 IRP, NIPSCO has made several enhancements to its load forecasting methodology, which are discussed in detail in this section. The overall load forecasting methodology includes five key steps, which are illustrated in Figure 3-1 and described as follows:

- **Data Gathering**: Compilation of historical data, including historical energy consumption and number of customers by class, historical demand side management program impacts, Moody's macroeconomic variables (such as state-level data on number of households, employment, and personal income), and

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[6] Additionally, railroad, street lighting, public authority and company use energy forecasts are incorporated in the total energy forecast. However, the load forecast for these customer classes has been projected using a simple moving average assumption based on historical data, rather than a regression estimation method.

weather variables (heating and cooling degree days based on historical temperature and humidity).

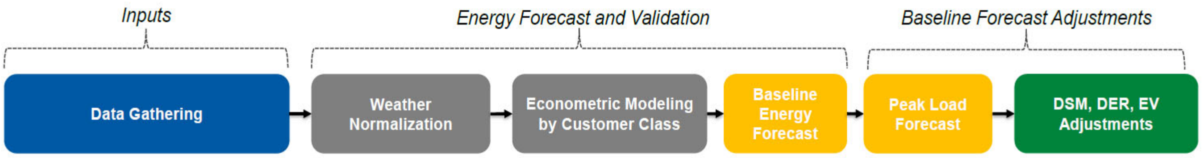
- **Weather Normalization:** Development of weather-normalized energy sales by class (kWh/customer) for the historical period, *excluding* historical DSM program impacts.

- **Econometric Modeling by Customer Class:** Testing of all economic and demographic "driver" variables in a dynamic regression system, and performance of post-estimation tests on econometric models' specification and forecasting performance (for example, Systemic Mean Absolute Percentage Errors).

- **Baseline Energy and Peak Load Forecast Development:** Development of baseline customer count and energy forecasts for each NIPSCO customer rate class, *excluding* historical DSM, and development of accompanying peak load forecasts using the energy forecast and load factors by customer rate class.

- **Adjustments:** Adjustments to the load forecast to incorporate existing and planned *known* DSM programs, projections for electric vehicle and distributed energy resource penetration ranges, as well as additional factors in the scenario analysis, including other electrification and industrial load loss.

Figure 3-1: Summary of NIPSCO Load Forecasting Methodology



3.3 Base Customer Count, Electric Energy, and Peak Demand Forecast

3.3.1 Data Gathering, Weather Normalization, and Econometric Modeling

NIPSCO developed *baseline* forecasts for customer count and energy usage per customer separately, employing an econometric analysis of monthly historical customer class data. First, NIPSCO collected historical data by customer class on the number of customers and energy consumption at a monthly level from 2010 through 2020,[7] macroeconomic and demographic

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[7] It is important to note that NIPSCO's baseline load forecast takes out all historical DSM and EE savings from historical electric energy consumption prior to the econometric analysis.

indicators for the region from Moody's Analytics,[8] weather data (heating and cooling degree days based on historical temperature and humidity) from the National Oceanic and Atmospheric Administration, and information regarding NIPSCO's historical DSM and EE program savings.

After constructing datasets for each customer class, NIPSCO developed econometric regression models for forecasting the number of customers for each customer class, controlling for key drivers. These key variables are regional economic and demographic factors, including household counts (for residential and commercial) and employment in the manufacturing sector (for industrial) and dummy variables that control for seasonal and annual impacts. Specifically, the following variables were used in the development of the customer count model:

- The number of households is the key variable used to forecast residential and commercial customer count.[9]
- For the small industrial sector forecast, regional historical employment in the manufacturing sector is used as the key variable.[10]
- Finally, dummy variables control for factors that cannot be controlled with any other variable in regression equations that is not associated with regional economic or demographic factors, such as monthly seasonality.

A representation of the estimated regression model for the customer count forecast is presented in Equation 3-1.

Equation 3-1: Regression Equation for Customer Count Forecast

$$C_{\mathrm{it}} = \mathrm{b_o} + \mathrm{b_1 X_{it}} + \mathrm{b_{jt}\theta_t} + \pi_{\mathrm{it}}$$

Where

i=customer class (residential, commercial and small industrial)

t= month

b_o= constant term

C_{it} = number of customers in a given customer class i in month t

X_{it}= Macroeconomic variable (e.g., number of households for residential and commercial classes in a given month i)

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[8] Note that the final IRP load forecast was based on economic data from Moody's as of April, 2021. NIPSCO presented preliminary load forecasts based on earlier vintage Moody's data in its first public stakeholder meeting in March, 2021. Therefore, very minor differences in customer count and load growth rates are present in the final numbers relative to the preliminary data that was initially reviewed in the first stakeholder meeting.

[9] The expected coefficient on the number of households variable is positive for both residential and commercial customer classes suggesting that an increase in the number of households is associated with an increase in the number of residential and commercial customers in NIPSCO territory.

[10] The expected coefficient on the manufacturing employment variable is positive for the small industrial customer class, suggesting that an increase in employment in manufacturing is associated with an increase in the number of small industrial customer count in NIPSCO territory.

$b_1, b_2, .. b_j$ = Estimated coefficients (slopes) for each variable included in the regression model.
$b_{jt}\theta_t$= time dummies
π_{it} = random error term

Similarly, NIPSCO developed econometric regression models for predicting energy sales[11] for each customer class that would control for key drivers for energy consumption including weather and regional economic and demographic drivers. Specifically, key variables for the residential, commercial and small industrial class regression equations included the average class-specific monthly retail rate, heating and cooling degree days, real personal income (for residential), employment in the manufacturing sector (for commercial and small industrial), and dummy variables that control for seasonal impacts on energy consumption. The following variables were used in the development of the electric energy sales per customer model:

- The average retail rate controls for the impact of the cost of electric energy on the amount of electricity consumption in each customer class.[12]
- Heating and cooling degree day variables control for the impact of weather on electricity consumption. Particularly, residential and commercial sectors are responsive to outside temperature because a significant portion of electricity consumption is used for air conditioning, and to a lesser extent space heating, for these two customer classes.[13]
- Demographic variables (i.e., real personal income and employment in the manufacturing sector) control for the impact of regional economic factors on electricity consumption.[14]
- Dummy variables control for factors that cannot be controlled with any other variable in regression equations such as monthly seasonality that is not associated with weather.

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[11] The electric energy forecast is predicted for energy consumption per customer, which is the ratio of total energy consumption by total number of customers in a specific customer class in a given month (i.e., residential energy use per customer (MWh/customer) is calculated as total residential energy consumption (MWh) in a given month divided by the total number of residential customers in that month).

[12] The expected coefficient on the average monthly retail rate variable is negative, suggesting that an increase in average retail rate is associated with a lower amount of electricity consumption.

[13] The expected coefficients on heating degree days and cooling degree days suggest that (i) an increase in the number of heating degree days is associated with higher electricity consumption, specifically due to space heating; and (ii) an increase in the number of cooling degree days is associated with higher electricity consumption, specifically due to space cooling.

[14] The expected coefficient on real personal income and employment in the manufacturing class is positive, suggesting that (i) an increase in regional real personal income is associated with higher electric energy consumption due to an increase in wealth (e.g., larger homes, increase in number of home appliances); and (ii) an increase in employment is associated with higher electric energy consumption due to an increase in commercial and industrial economic activity.

A representation of the estimated regression model for the usage per customer forecast is presented in Equation 3-2.

Equation 3-2: Regression Equation for Usage per Customer Forecast

$$\mathrm{D_{it}} = \mathrm{a_o} + \mathrm{a_1 P^e_{it}} + \mathrm{a_2 X_{it}} + \mathrm{a_3 Weather_{it}} + \mathrm{a_{jt}}\theta_t + \varepsilon_{it}$$

Where

i=customer class (residential, commercial and small industrial)

t= month

a_o= constant term

D_{it}= electric energy usage per customer in a given customer class i in a given month

P^e_{it}= average retail electricity rate in a given customer class i in a given month

X_{it}= Macroeconomic variable (e.g., real personal income for residential class in a given month)

$Weather_t$= variables included to control for weather such as heating and cooling degree days

$a_{jt}\theta_t$= time dummies that control for seasonality in demand.

ε_{it}= random error term

$a_1, a_2, a_3, \, ..a_j$ = Estimated coefficients (slopes) for each variable included in the regression model.

Figure 3-2 summarizes the key variables included in both the energy per customer and customer count load forecast equations for residential, commercial and small industrial customer classes.

Figure 3-2: Econometric Model Parameters for Core Load Forecast

	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

After estimating regression equations for each customer class, a number of statistical tests were performed to validate the regression equations specifications and forecast errors. CRA selected the presented model based on R-squared, adjusted R-squared, Root Mean Squared Error and Mean Absolute Percentage Error. Stata software was then used to construct the load forecast data for each customer class.

3.3.2 New Industrial Service Structure

The 2021 IRP incorporates NIPSCO's new industrial service tariff, known as Rate 831, and its subsequent impact on industrial load. This new industrial service tariff was included in the settlement agreement in Cause No. 45159, approved by the Commission in 2019 and it gives certain large industrial customers the option to secure their own energy and capacity needs. For IRP planning purposes, NIPSCO's load forecast for the large industrial customer class includes Rate 832, Rate 833, and Rate 831 (Tier 1 energy only) customers.[15]

3.3.3 Customer Count Forecast

Historical customer count data indicates that approximately 87% of NIPSCO customers are residential class with a historical CAGR of 0.4% between 2010 and 2019. The commercial class makes up about 12% of NIPSCO customers, and the small industrial class makes up about 0.4% of NIPSCO customers. The CAGR between 2010 and 2019 for commercial and small industrial is 0.6% and *minus* 1.4%, respectively.

Figure 3-3 presents NIPSCO's projected customer count for the Residential class, and Figure 3-4 presents NIPSCO's projected customer count for the Commercial and Small Industrial customer classes (green line for commercial and blue line for small industrial).

The CAGR is also calculated for each customer class projection between 2021 and 2040 in order to provide an understanding on the future growth trends for NIPSCO's customer count growth trends. NIPSCO's forecast projects residential and commercial CAGRs of 0.5% and 0.8%, respectively. The small industrial customer class growth rate is projected to be slower, at 0.3% through 2040.

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[15] Note that hourly historical meter data for each individual industrial customer is analyzed when developing the load forecast for the large industrial customer class that NIPSCO services. The energy consumption of industrial customers under Tiers 2 and 3 on Rate 831 is excluded from the load forecast because this load is not served by NIPSCO.

Figure 3-3: NIPSCO Residential Customer Count Forecast

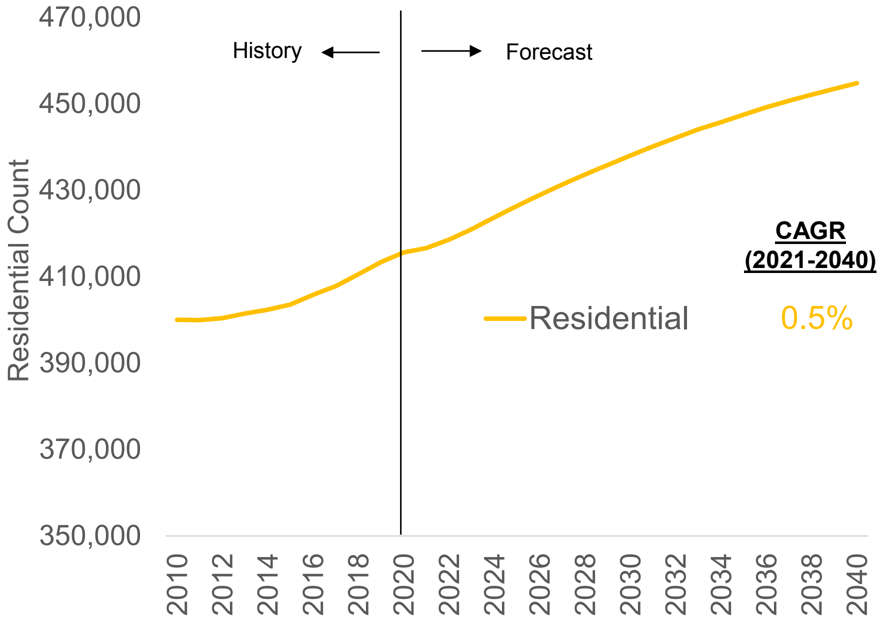
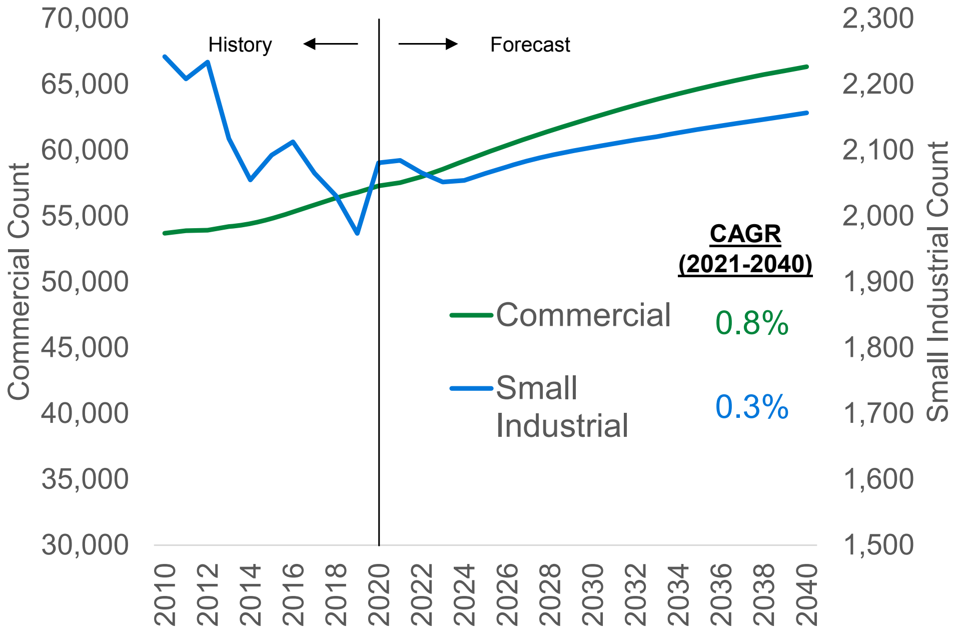


Figure 3-4: NIPSCO Commercial and Small Industrial Customer Count Forecast

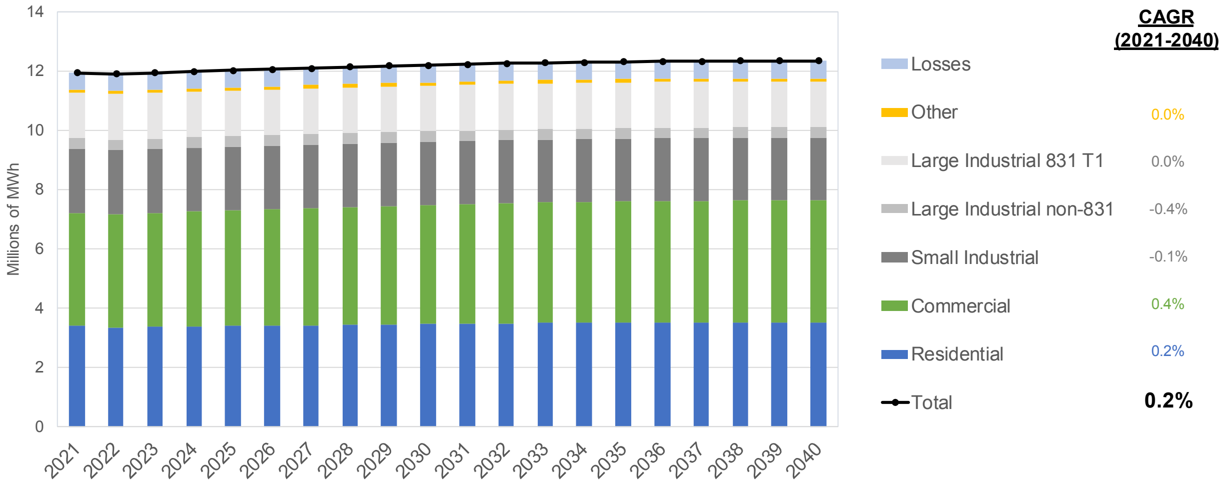


3.3.4 Sales per Customer and Total Electric Sales Forecast

To obtain the total monthly energy sales forecast for each class between 2021 and 2040, the energy sales per customer forecast is multiplied by the customer count forecast. The residential and commercial sectors make up almost half of total NIPSCO electric energy sales, followed by the Small Industrial customer class. Historical energy sales data shows that approximately 22% of NIPSCO electric energy sales are from the residential class. The commercial class makes up about 25% of NIPSCO electric energy sales, and the small industrial class makes up about 14% of NIPSCO electric energy sales. Note that electric energy sales for the Large Industrial customer class only include customers under the new tariff structure that are served by NIPSCO.

Figure 3-5 presents NIPSCO's projected electric energy sales forecast by customer class and total NIPSCO energy sales through 2040.[16] The CAGR for residential customers is projected to be 0.2%, and the CAGR for commercial energy sales is projected to be 0.4%, while the CAGR for the small industrial class is projected to be -0.1% between 2021 and 2041.

Figure 3-5: NIPSCO Electric Sales Forecast by Customer Class



3.3.5 Peak Load Forecast Development

After developing the baseline energy forecasts, NIPSCO developed peak load forecasts on a monthly basis. Applying monthly peak load factors and developing specific monthly peak load projections are improvements for the 2021 IRP, enabling NIPSCO to compare seasonal peak load differences, particularly the summer and winter peaks.

NIPSCO's historical sample meter data was used to develop the monthly peak load factors for the residential, commercial and small industrial customer classes, as presented in Figure 3-6. Based on the sample data, peak load factors are lowest during summer months including June, July

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[16] Note that "Other" includes Railroad, Street Lighting, Public Authority, and Company Use. Note that losses are calculated monthly to arrive at net energy for load that must be served by generation. Losses are approximately 5% on an annual basis.

and August and higher during winter months including January, February and December. The formula used to develop load factors is summarized in Equation 3-3.

Equation 3-3: Load Factor Calculation

$$Load\ Factor = \left(\frac{Usage\ (kWh)}{\left(Demand\ kW\ *\ 24\frac{hr}{day} * X\frac{days}{mo}\right)}\right)$$

Figure 3-6: Calculated Peak Load Factors by Customer Class

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%

Note that in summarizing the annual system peak, NIPSCO calculated the highest sum of monthly peaks, not the sum of the highest monthlies for each class (i.e., a coincident peak), allowing for the development of summer and winter peak load forecasts by customer class, which are presented in Figure 3-7. While summer peak load is projected to stay stable through 2040, the winter peak is projected to grow at 0.3%.[17] This is consistent with historical trends that indicate that peak load in the winter months has been growing faster than summer months historically.

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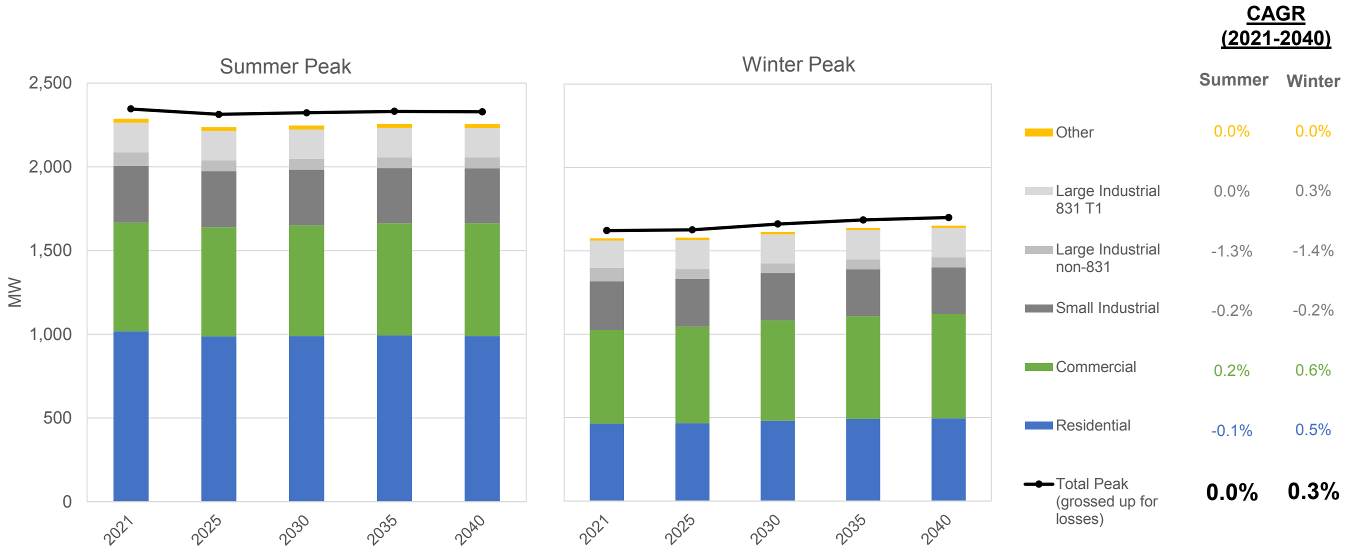
[17] Note that these growth rates refer to the baseline econometric analysis and do not reflect NIPSCO's final load forecast, which includes additional adjustments discussed in more detail below.

Figure 3-7: NIPSCO Peak Load Forecast by Customer Class



3.4 Electric Vehicles

3.4.1 Methodology Overview

NIPSCO developed a range of potential EV penetration rates based on existing data regarding EV counts in NIPSCO counties and a top-down forward outlook based on third-party projections. NIPSCO-specific and external information about electricity charging usage and hourly charging patterns was then used to estimate the impact on NIPSCO sales and peak load requirements for each of the four market scenarios.

The EV fleet was broken down into four classes of vehicle fleets, which were independently forecasted:

- LDVs
- Transit vehicles, such as buses and shuttle vans
- MDVs
- HDVs

3.4.2 Core Data Source Inputs

3.4.2.1 Starting Vehicle Count Estimates

NIPSCO developed estimates of the starting values for vehicle counts within the four major categories from the following major sources:

- LDVs: NIPSCO EV customer database

- Transit/MDV/HDV: National Transit Database, with estimates for the total vehicle counts in NIPSCO's territory

3.4.2.2 Vehicle Count Growth Rate Projections

To develop future projections for EV growth, NIPSCO largely relied on the EV forecasts for MISO LRZ 6 from the 2021 MTEP process. NIPSCO deduced EV sales CAGR from the three MTEP Futures scenarios and mapped them to Low, Medium, and High scenarios. These assumptions are provided in Table 3-1. NIPSCO also used public information from Bloomberg New Energy Finance for the heavy-duty vehicle sector.

Table 3-1: Electric Vehicle Sales CAGR by Scenario

	2020-2024	2025-2029	2030-2034	2035-2040
Low	33%	15%	11%	11%
Med	49%	21%	16%	15%
High	59%	30%	21%	15%

To determine the energy impact of the EV fleet, NIPSCO relied on a range of sources by vehicle class as documented in Table 3-2:

- For LDVs, the electricity demand per mile was determined from the 2019 EPA Automotive Trends Report for common vehicle model types: 0.28 kWh/mi for BEV and 0.075 kWh/mi for PHEV (assuming around one-third of the time PHEVs charge from the electric grid).

- For transit vehicles, MDVs, and HDVs, NREL, DOE, and specific vehicle data sources were used to estimate electricity demand per mile over time.

- Efficiency improvements over time were assumed, driven by a variety of factors, such as vehicle light-weighting, improvements in passenger driving behavior to maximize fuel economy, and others. A generic long-term improvement rate in kWh/mi efficiency was assumed at 0.5% per year, with faster near-term efficiency improvement in the Medium and High scenarios.[18]

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[18] Electric Power Research Institute. Environmental Assessment of a Full Electric Transportation Portfolio Volume 1 Background, Methodology, and Best Practices. September 2015. 3002006875. https://www.eenews.net/assets/2015/09/18/document_cw_01.pdf. Based on U.S. Energy Information Administration Annual Energy Outlook, 2013

Table 3-2: Electric Vehicle Energy Usage Assumptions Summary

		LDVs	Transit Vehicles	MDVs	HDVs
Avg. Miles per Day		40	77[2]	66[4]	250[4]
Retirement Age		15 years	8 years[3]	8 years[3]	15 years[3]
BEV % of Total EVs	**Low**	42% -> 75%	42% -> 75%	42% -> 75%	-
	Med	42% -> 75%	42% -> 75%	42% -> 75%	-
	High	42% -> 90%	42% -> 100%	42% -> 90%	20% -> 40%
Fuel Economy (2021 vintage)	**BEV**	0.28 kWh/mi[1]	2.18 kWh/mi[2]	0.51 kWh/mi[5]	2.00 kWh/mi[4]
	PHEV	0.075 kWh/mi[1]	1.17 kWh/mi[2]	0.33 kWh/mi[5]	0.83 kWh/mi[4]

(1) EPA (2019) Automotive Trends Report 2019.

(2) NREL (2016). "NREL Evaluates Performance of Fast-Charge Electric Buses." https://www.nrel.gov/docs/fy16osti/67057.pdf

(3) National Transit Database 2019 Vehicles.

(4) DOE (2019). "Medium- and Heavy-Duty Vehicle Electrification: An Assessment of Technology and Knowledge Gaps."

(5) Based on Rivian 1-T and N-Gen Workhorse models.

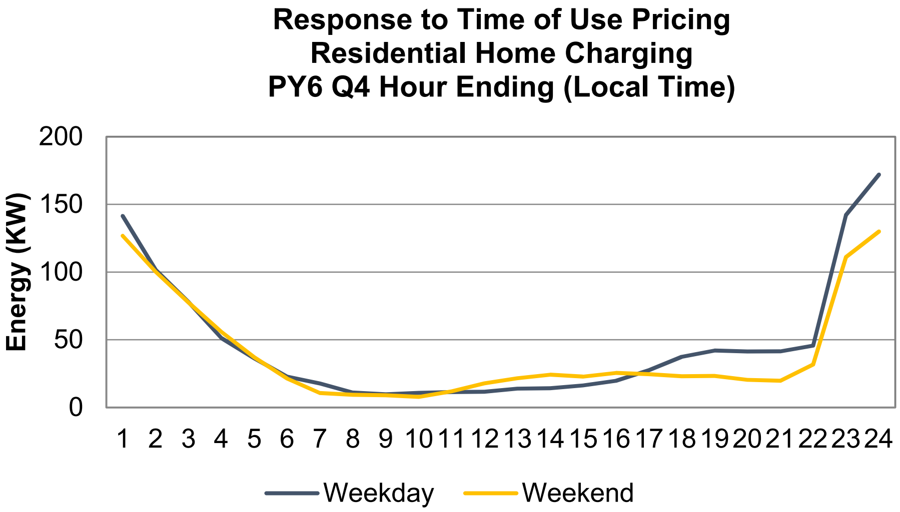
3.4.3 Light Duty Vehicles

3.4.3.1 Historical Service Territory Data: NIPSCO's IN-Charge Program

On February 1, 2012, the Commission issued a Final Order in Cause No. 44016 approving NIPSCO's Pilot Program through January 31, 2015 on February 1, 2012. On October 29, the Commission approved NIPSCO's 30-day filing to extend its EV program an additional two years through January 31, 2017. On January 11, 2017, the Commission issued a Final Order in Cause No. 44828 approving NIPSCO's request for modification of its EV Program to provide that participants of record as of January 31, 2017 would be subject to an energy charge of $0.070894 per kilowatt hour for all kilowatt hours used per month in the PEV Off-Peak Hours, plus all applicable Riders for a period of 23 months.

As of 2019, NIPSCO received 382 customer enrollments in the Pilot Program. From customer enrollment data, the typical customer drove 40 miles per day, with the time of use charging shape depicted below. The typical BEV model was a Tesla Model S, and typical PHEV models were Chevy Volt and Nissan Leaf. The data on customer charging patterns, usage, and fuel economy informed the inputs for the light-duty vehicles modeling. NIPSCO found that the discounted energy during off-peak times of 10 p.m. to 6 a.m. (local time) had a significant impact on charging behavior, as shown in Figure 3-8.

Figure 3-8: NIPSCO Time of Use Residential Home Charging Shape



3.4.3.2 Fleet Growth Forecast

As per the Indiana Bureau of Motor Vehicles, there were 1,262 electric vehicles registered in NIPSCO counties in 2018, of which 693 were PHEV, 499 BEVs, and the remainder various other vehicle types (i.e. motorcycles, utility EV). LDV numbers by County are provided in Table 3-3.

Using this starting number of EV registrations in NIPSCO counties, the annual sales of light duty vehicles were forecasted to grow according to the MTEP Futures-informed CAGRs shown in Table 3-1. To reflect increasing acceptance of BEV models, the mix of BEV-to-PHEV is trended over time to 75% BEVs of total EVs in the Low and Medium scenarios and 90% in the High scenario.

The replacement of older, less efficient vehicles is assumed to naturally occur as vehicles age and owners adopt new vehicle models. To reflect this process of stock turnover, an average car lifetime of 15 years was assumed. The combination of new BEV and PHEV sales per year, as well as the retirement of the existing stock, resulted in fleet-wide projections for BEVs and PHEVs.

Table 3-3: Light Duty Vehicles in NIPSCO Counties (LDV Registrations)

County	2014	2015	2016	2017	2018
BENTON	1	1	1	3	2
DEKALB	1	4	18	18	37
ELKHART	33	45	63	78	134
FULTON	4	5	5	4	9
JASPER	4	7	11	18	22
KOSCIUSKO	12	17	22	32	57
LAKE	116	154	185	250	344
LAPORTE	17	30	40	62	79
MARSHALL	7	8	9	14	40
NEWTON	2	2	2	7	11
PORTER	68	84	107	140	226
PULASKI		1	2	4	6
SAINT JOSEPH	50	71	87	148	229
STARKE	1	3	3	5	22
STEUBEN	3	6	10	18	32
WHITE	2	5	5	7	12
Total	321	443	570	808	1262

3.4.3.3 Peak Demand Impact

NIPSCO applied two EV charging shapes to the forecast scenarios to capture a variety of potential influences on charging behavior, such as rate design, public charging infrastructure availability and incentives, technology improvements in fast-charging, and smart charging infrastructure. The Low EV Penetration scenario charging shape, shown in Figure 3-9 was based on time-of-use data from NIPSCO's IN-Charge program, although shifted a few hours to exhibit price responsiveness consistent with the Aurora forecasted power prices.[19] NIPSCO found that the discounted energy during off-peak times of 10 p.m. to 6 a.m. (local time) had a significant impact on charging behavior.

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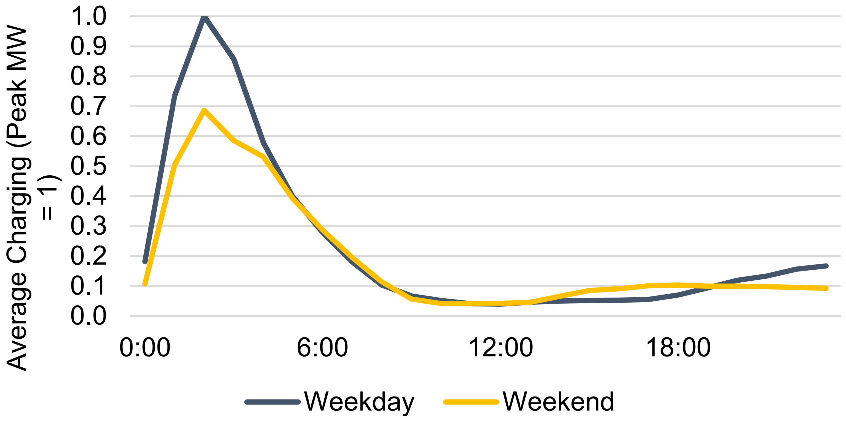
[19] NIPSCO made this change in response to stakeholder feedback arising from the First Stakeholder Meeting on March 19, 2021, as described in the May 20, 2021 Stakeholder Meeting materials.

Figure 3-9: Low EV Penetration Charging Shape



The High EV Penetration scenario charging shape, shown in Figure 3-10, was based on data from the DOE's EV Project,[20] which utilized data from over 10,000 charging systems in 18 regions across the US. The time-of-day charging demand for all EV Project regions was reviewed from this report, including a variety of residential Level 2, public Level 2, and DC fast-charging stations.

Figure 3-10 High EV Penetration Charging Shape

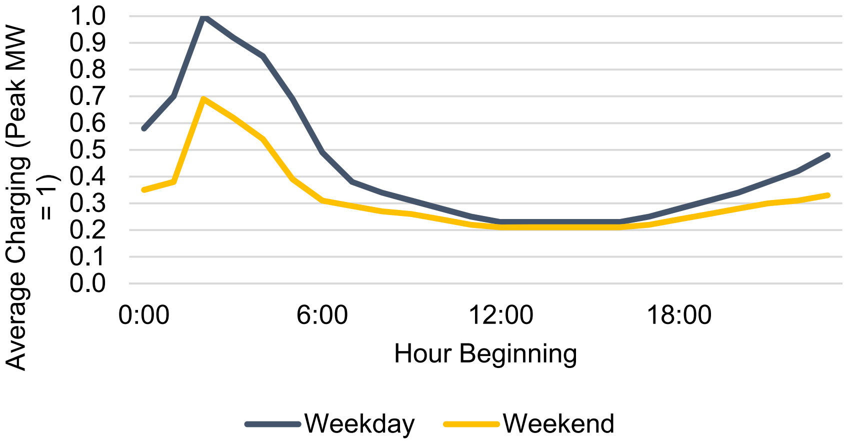


Figure 3-11 provides a view of the charging profiles versus expected hourly price shapes, displaying how charging behavior was assumed largely during the overnight periods.

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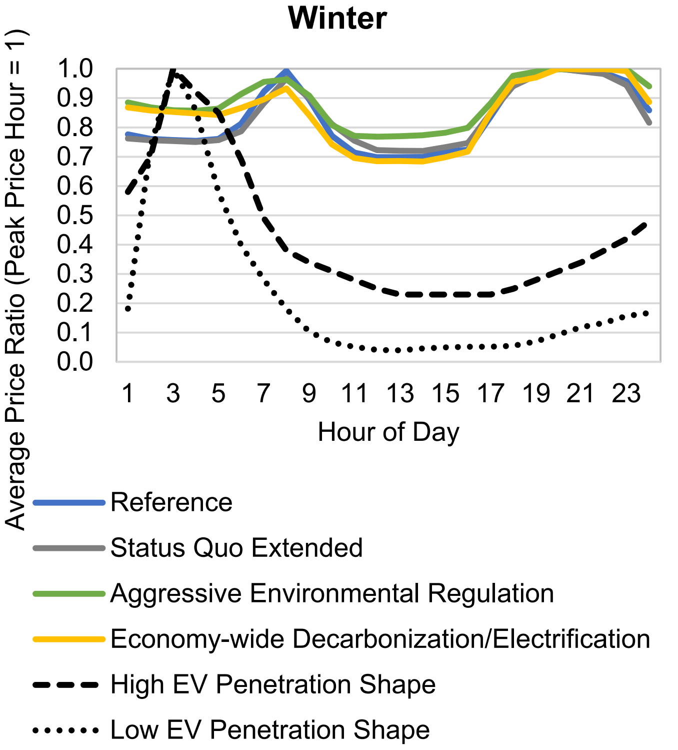
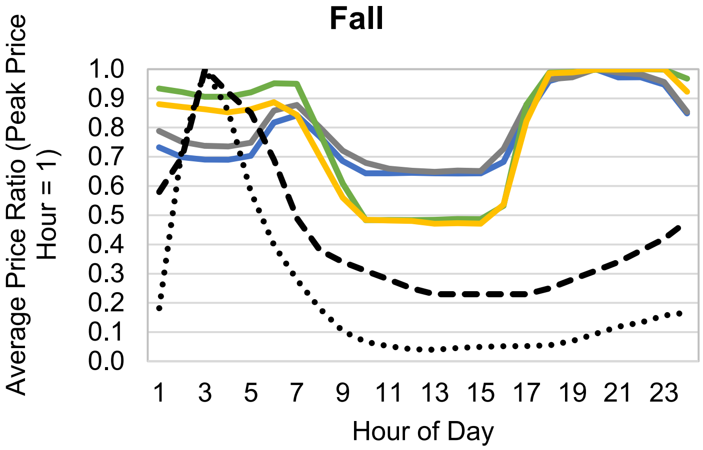
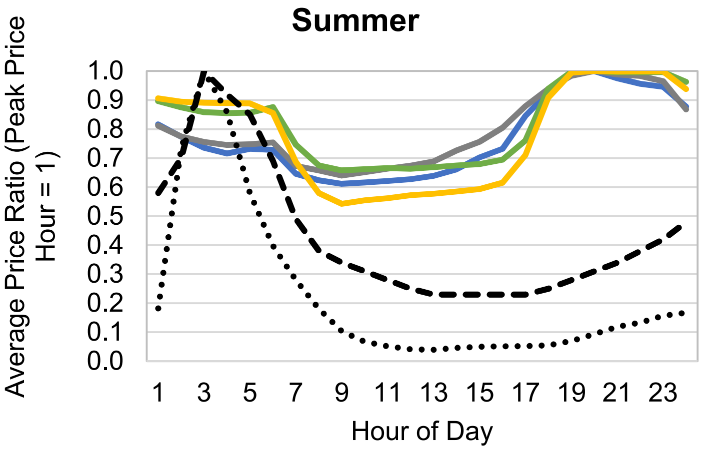
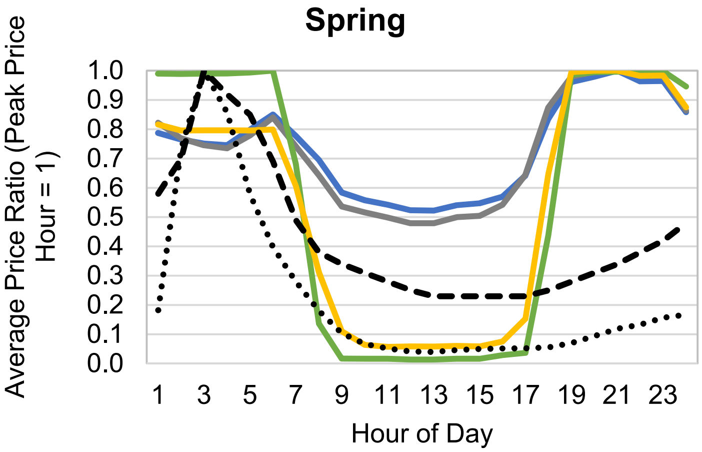
[20] Schey, S., Scoffield, D., Smart, J. (2014) "A First Look at the Impact of Electric Vehicle Charging on the Electric Grid in The EV Project." *EVS26 International Battery, Hybrid and Fuel Cell Electric Vehicle Symposium.* https://www.energy.gov/sites/prod/files/2014/02/f8/evs26_charging_demand_manuscript.pdf

Figure 3-11: EV Charging Shapes vs. Normalized Hourly Power Prices by NIPSCO Scenario









3.4.4 Transit Vehicles

The same approach to estimating fleet wide vehicle numbers, energy and peak demand impacts was applied to the transit vehicle sector, which includes buses, cutaway vans, and shuttles. However, unlike with the light-duty vehicle category, limited data is available on the adoption of electric transit vehicles within NIPSCO's service territory. To estimate the total number of transit vehicles in NIPSCO counties, data was developed from the 2019 National Transit Database, the Federal Transit Administration's repository of data on financial, operating, and asset conditions of American transit systems. Filtering on those metropolitan areas in NIPSCO counties, there were approximately 263 transit vehicles registered in NIPSCO counties. Assuming a number of these vehicles are electric in proportion to the light-duty vehicle fleet (~0.2% of light-duty vehicles were some form of BEV/PHEV), a forecast of electric transit vehicles was developed using the MTEP Futures'-implied CAGRs. For the High scenario, the assumption of a 100% electric transit fleet is assumed, given the nature of several municipalities' stated goals.

The operating assumptions for transit vehicles are provided in Table 3-3. From the National Transit Database, an average lifetime of eight years was determined. This data point is consistent with the idea that higher utilization leads to shorter lifetimes, when compared to the 15-year lifespan of passenger light-duty vehicles. The number of miles driven per year and electric usage in kWh/mi were taken from an NREL study on Fast-Charge Electric Buses.[21]

Assuming passenger transportation patterns are identical between using a car versus public transport, the same EV charging patterns as shown in Figure 3-9 and Figure 3-10 were applied for the transit vehicle category.

3.4.5 Medium Duty Vehicles

Medium-duty vehicles include city delivery vans, walk-in vans, and other large commercial vehicles within the Class 2-6 classification by the Federal Highway Administration. Given there is limited data on electrified MDVs, available data on the Indiana fleet of MDV/HDV Registrations was used to determine the total number of MDVs in NIPSCO counties. Around 19,600 MDVs were calculated, from which a proportion (0.23% electric, based on the LDV Registrations dataset) led to approximate starting numbers for the electric MDV forecast.

According to NIPSCO NIPSCO's New Business department, a large order of several hundred delivery vans for a large fleet operator is expected to come online in the territory in early-through-mid 2020s. Therefore, this delivery fleet of 700 vehicles was assumed in the MDV forecast, with online dates of 2022-2030. As a result, the near-term growth rates in MDVs appears higher than the MTEP Futures-inspired CAGRs, as shown in Table 3-4 versus Table 3-1. Other relevant forecasting assumptions are outlined in Table 3-2.

Table 3-4: MDV and HDV Electric Vehicle Sales' CAGR by Scenario

	2020-2024	**2025-2029**	**2030-2034**	**2035-2040**
Low – MDV	50%	23%	15%	11%
Med – MDV	72%	30%	16%	15%
High – MDV	79%	30%	21%	15%
High – HDV	5%	33%	20%	20%

Commercial vehicles might be expected to charge more frequently than LDVs, given their higher energy density requirements and potential for optimization of their logistics. The charging shape for MDVs and HDVs (discussed in the next section) is taken from the charging pattern from an NREL field study conducted in 2016 and illustrated in Figure 3-12.[22]

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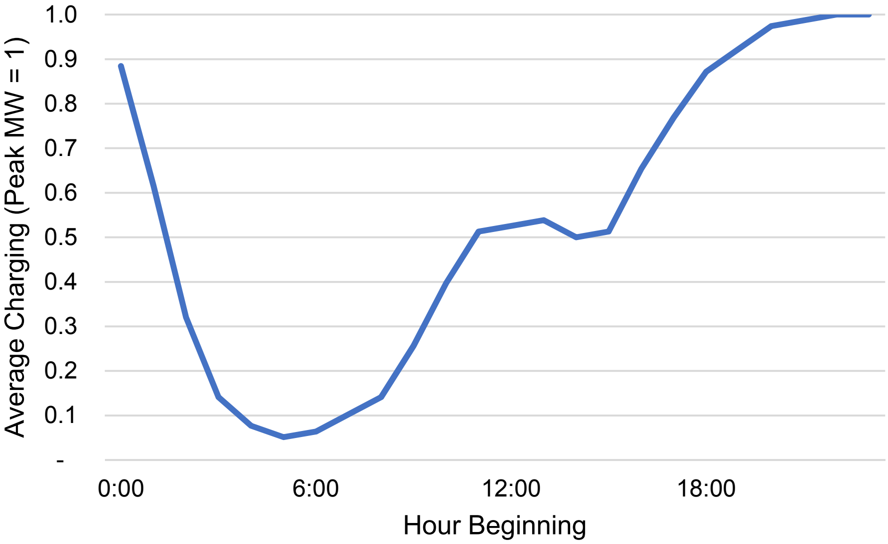
[21] NREL (2016). "NREL Evaluates Performance of Fast-Charge Electric Buses." https://www.nrel.gov/docs/fy16osti/67057.pdf

[22] NREL (2016). "Field Evaluation of Medium-Duty Plug-In Electric Delivery Trucks." https://www.nrel.gov/docs/fy17osti/66382.pdft

Figure 3-12: MDV/HDV Charging Pattern



3.4.6 Heavy Duty Vehicles

Heavy-duty vehicles, classified by the Federal Highway Administration as Class 7-8 vehicles, include semi-trucks utilized in the industrial sector, highway trucks for ground freight, and other large vehicles. Given the significant energy density required to haul heavy cargo and batteries' relatively lower energy density than liquid fuels, electric trucking is unlikely without significant technology improvement. For this reason, a forecast was developed only for the High scenario.

As with the MDV forecast, starting numbers of total HDVs in NIPSCO's territory were taken from the database of medium- and heavy-duty vehicles in NIPSCO counties. To reflect relatively slower advancement of the enabling technology, near-term growth in HDVs is minimal, whereas stronger annual sales growth rates are projected in the 2025+ time frame.

The charging profile as illustrated in Figure 3-12 is similarly applied to the HDV sector in order to estimate peak demand impact. Other relevant forecasting assumptions are outlined in Table 3-2.

3.4.7 Electric Vehicle Forecast Results

3.4.7.1 Vehicle Count Projections

Figure 3-13 presents the LDV vehicle count forecast. Across scenarios, assuming that customers replace their cars on average after a 15-year life, and assuming that the average car ownership is 1.5 vehicles per household[23], EVs represent 10%, 39%, and 97% of new vehicle sales by 2040 for the Low, Medium, and High scenarios. Considering the retirement and replacement of older vehicles, EVs represent 7%, 19%, and 48% of total vehicle stock by 2040 for the Low, Medium, and High scenarios.

Figure 3-13: LDV Vehicle Count Forecast

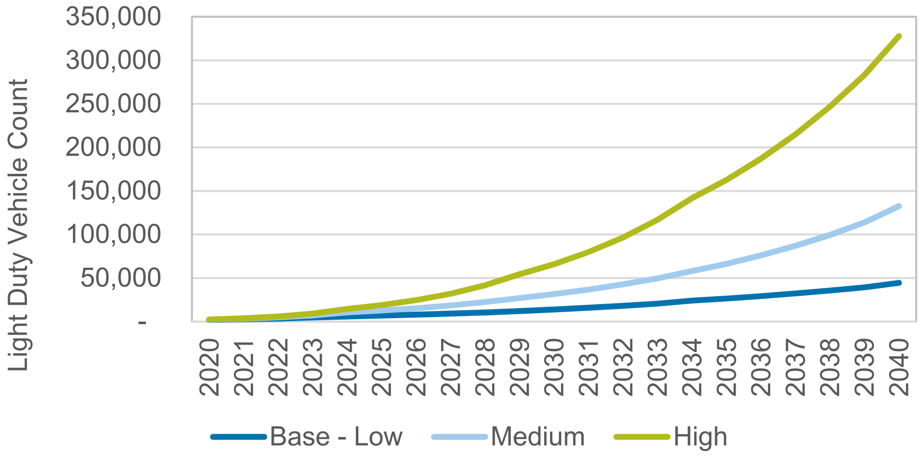


Figure 3-14 presents the MDV vehicle count forecast. Assuming that commercial vehicles are replaced after an 8-year life, and total commercial vehicles grow proportionally to the commercial customer class, EVs represent 12%, 49%, and 77% of new vehicle sales by 2040 for the Low, Medium, and High scenarios respectively. Considering the retirement and replacement of older vehicles, EVs represent 15%, 46%, and 72% of total vehicle stock by 2040 for the Low, Medium, and High scenarios.[24]

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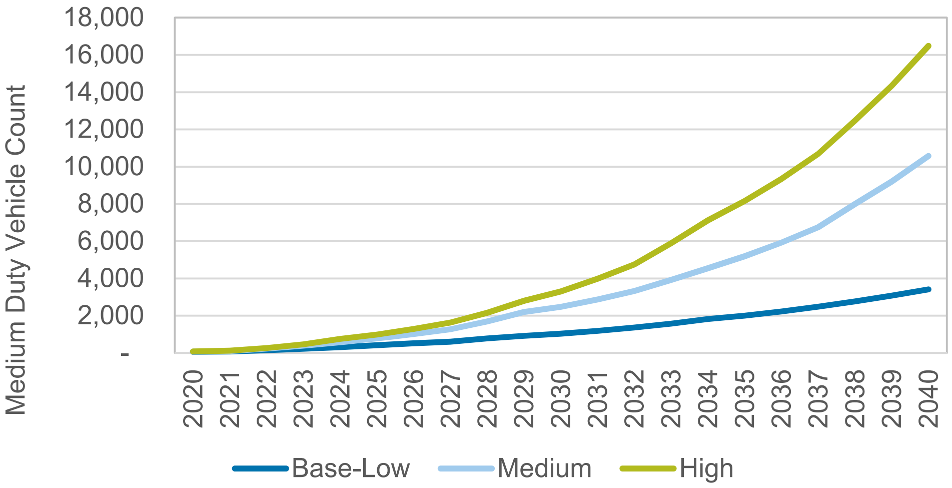
[23] Representative of sampling of cities throughout Indiana from the U.S. Census Bureau's American Community Survey: Compiled and accessed through Governing.com.

[24] Note that the total stock % is higher than new sales % in the Low case, due to the annual growth trajectory and relatively short assumed lifespan of vehicles.

Figure 3-14: MDV Vehicle Count Forecast



3.4.7.2 Sales and Peak Load Impact Projections

The overall impact of electric vehicle growth on NIPSCO's sales and summer and winter peak load forecasts across scenarios is summarized in Figure 3-15.[25] The LDV forecast is the primary driver of the overall forecast levels and range, contributing over 120 GWh in the low scenario and over 800 GWh in the high scenario by 2040. The MDV contribution is expected to range from approximately 25 to 120 GWh. Transit electrification is projected to be far less impactful than LDV and MDV growth. Transit vehicles represent an additional 1.8 GWh in the Low scenario; 2 GWh in the Medium scenario and 10 GWh in the High scenario by 2040. The HDV forecast for the High scenario represents an additional 74 GWh of energy impact and 10 MW of peak demand in 2040. Nonetheless, this represents around 18% of total HDV sales and 8% of the total HDV stock, assuming a 15-year life. This finding is aligned with industry sources that suggest a minor penetration of electrified HDVs.

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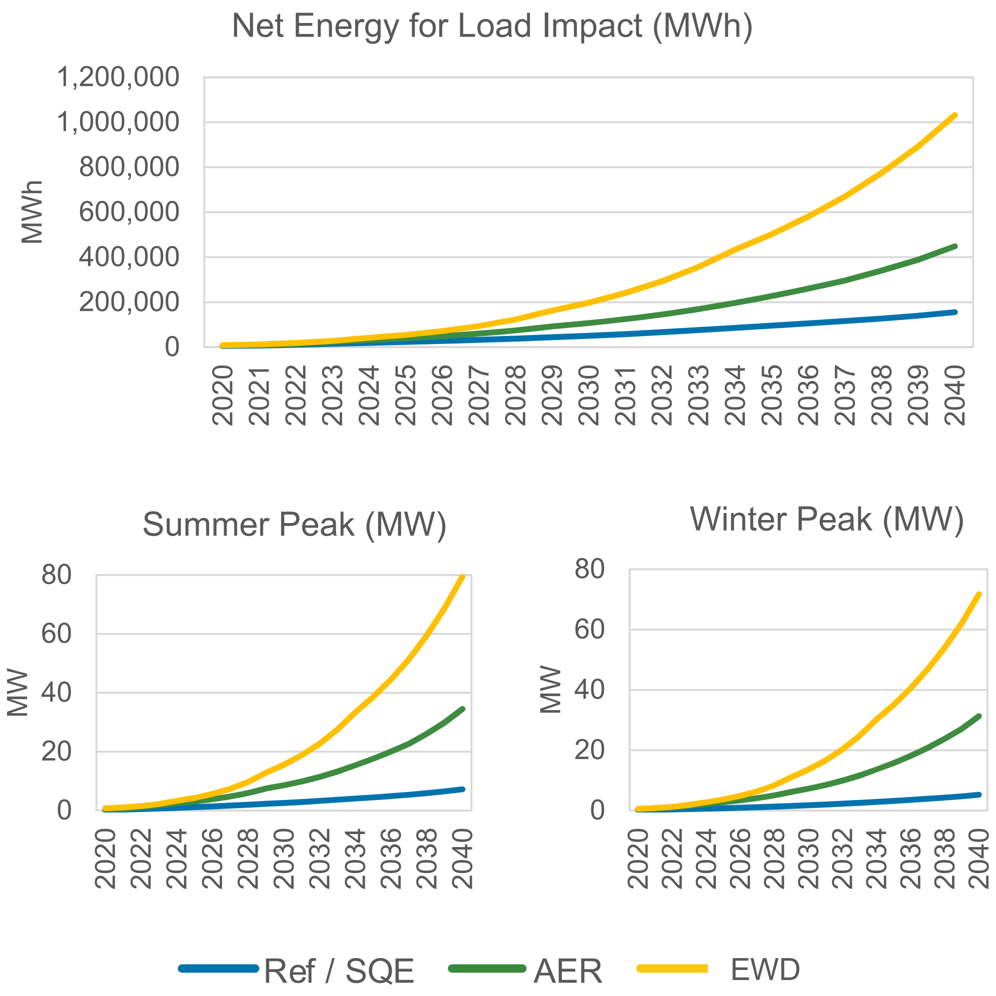
[25] Note that the net energy for load and peak load impacts include a 5% gross-up for losses. Ref = Reference; SQE = Status Quo Extended; AER = Aggressive Environmental Regulation; EWD = Economy-Wide Decarbonization

Figure 3-15: Total EV Energy and Peak Load Impacts by Scenario



3.5 Distributed Energy Resources

Customer-owned DERs are expected to grow throughout NIPSCO's territory, and this can potentially have a significant impact NIPSCO's net sales and peak demand requirements. To estimate a range of impacts for DER penetration in the 2021 IRP, NIPSCO deployed CRA's agent-based PenDER model, customized and calibrated to NIPSCO's existing database of DER customers. As solar PV resources (with or without storage) are expected to be the most widespread DER resource type, NIPSCO's DER study focused exclusively on solar and storage technologies, excluding wind, biomass, and other resources. In addition, the study focused on two main customer groups likely to adopt DER: residential and commercial.

3.5.1 PenDER Model Description

PenDER is an agent-based model developed by CRA that simulates the adoption decisions and interactions via social networks of thousands of autonomous agents to provide granular forecasting of DER adoption. Techno-economic variables and demographic characteristics of the simulated agents contribute to an individual agent's probability to adopt DER based on an economic review of retail rate expectations, the costs of installing DER, and potential financial incentives.

The techno-economic variables deployed in the PenDER modeling for NIPSCO's 2021 IRP include:

- The capital cost of a solar PV system, inclusive of expected ITC benefits
- Solar capacity factor and solar system lifetime expectations
- Retail rates (for net metering) and wholesale rates projections
- Assumptions for customer discount rate
- Demographic data from the ACS for NIPSCO counties to estimate agents' household incomes

The combination of the techno-economic variables and agent income levels are then used to develop a calculation of payback period and household budget in order to assess the probability of DER adoption through a calibrated logit probability function.

While economics plays an important role in the decision to install DER, the personal propensity and communal influences to adopt new technology also play a role, as described through the Bass diffusion model of technology forecasting.[26] Therefore, the simulated agents are randomly assigned a "Bass innovation index," representing their personal propensity on a scale of early adopters to laggards of new technology. Relationships between agents are modeled through "social networks," with an average size of 13 agents belonging to one network. As more agents in one's network adopt DER, the more likely a given agent will also adopt.

Ultimately, an agent's decision to adopt DER is influenced by the combination of techno-economic factors (through payback period and household budget) as well as personal and communal influences (through personal preferences and network effects).

3.5.2 Key Input Assumptions

The techno-economic input assumptions for PenDER used in NIPSCO's 2021 IRP are summarized in Table 3-5 and Table 3-6 and as follows:

- **Solar System Characteristics**: Data from the Net Metering program enrollment provided information regarding the average size of DER solar systems currently installed on NIPSCO's system, which was approximately 8 kW for residential

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[26] See Bass, F (1969). "A New Product Growth for Model Consumer Durables." *Management Science*. 15 (5): 215-227

customers and 100 kW for commercial customers. NIPSCO approximated CFs for the DER systems based on NREL data and assumed a 25-year life for solar projects.

- **Capital Cost and Tax Credit Inputs:** Assumptions regarding capital cost projections, capacity factor, and lifetime for solar PV were taken from NREL's Annual Technology Baseline for the Advanced, Moderate, and Conservative cases for both residential and commercial solar PV technologies.[27] Assumptions regarding extensions to the federal ITC were consistent with those defined across NIPSCO's four core planning scenarios.

- **Retail Rate Growth**: Retail rate growth is uncertain and dependent on NIPSCO's generation plan, commodity prices, regulatory policy, transmission and distribution system cost drivers, and several other factors. NIPSCO developed a range of real retail rate growth rates with broad alignment to NIPSCO's four core planning scenarios.

- **Net Metering / Excess Distributed Generation:** NIPSCO's Net Metering and Excess Distributed Generation programs are governed by Indiana Code Ch. 8-1-40 and the Commission's Rules and General Administrative Orders. The DG Statute establishes the methodology under which NIPSCO procures electricity supplied by customers with qualifying distributed generation resources and offsets the cost of the electricity supplied to such customers. The DG Statute requires that an electricity supplier's net metering tariff remain available until the earlier of the following: "(1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier [or] (2) July 1, 2022." As of January 1, 2021, the aggregate amount of net metering facility nameplate capacity under NIPSCO's net metering tariff exceeded 1.5% of its most recent summer peak load (the statutory threshold) and NIPSCO filed Cause No. 45505 to gain Commission approval for an Excess Distributed Generation Rider which is still pending approval. The total net metering capacity (based off 2020 summer peak) is around 45 MW. Since the NIPSCO proposed Excess Distributed Generation Rider filing is still pending approval, PenDER simulated various future scenarios under various energy metering incentive programs. In two scenarios – SQE and Ref – the statuary net metering cap was enforced, after which DER is compensated at wholesale power prices times a 1.25 multiplier. In the AER and EWD scenarios, net metering is extended through 2040. These policy scenarios were designed to assess a broad range of potential DER penetration outcomes.

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[27] NREL (National Renewable Energy Laboratory). 2020. 2020 Annual Technology Baseline. Golden, CO.

Table 3-5: DER Capital Cost, ITC, and Incentives by Scenario

	Status Quo Extended	Reference Case	Aggressive Environmental Regulation	Economy-Wide Decarbonization
	SQE	**Ref**	**AER**	**EWD**
Capital Cost	High	Med	Low	Low
ITC	Current Policy	Two-year extension	Five-year extension	Ten-year extension
Retail Rates Real Growth Rate	-0.25%	0.00%	1.0%	-0.04%
Energy Metering Incentive Programs	Net Metering Cap, then wholesale	Net Metering Cap, then wholesale	Net Metering Extended through 2040	Net Metering Extended through 2040

- **Solar System Characteristics:** Data from the Net Metering program enrollment provided information regarding the average size of DER solar systems currently installed on NIPSCO's system, which was approximately 8 kW for residential customers and 100 kW for commercial customers. NIPSCO approximated CF for the DER systems based on NREL data and assumed a 25-year life for solar projects.

- **Financial Inputs**: Assumptions regarding the financing of PV systems, namely the WACC, were developed based on the rationale that the WACC for residential and commercial customers would be at a premium to the financing costs for utility-scale solar. NIPSCO also has assumed that small customers (i.e. residential) have higher financing costs than larger-scale customers with better access to capital.

Table 3-6: Residential and Commercial Project Parameter Assumptions

	Residential	Commercial
Average PV Size	8 kW	100 kW
Solar CF	15-16%	15-16%
Solar Lifetime	25 years	25 years
Inflation	2%	2%
Real After-Tax WACC	7.70%	6.00%

- **Household Income**: The household income distributions were determined from the ACS for NIPSCO counties. The ACS is a nationwide survey that collects and produces information on demographic, housing, economic, and social characteristics of the nation's population every year. Household income is defined as the "pretax cash income of the householder and all other people 15 years and older in the household, whether or not they are related to the householder."[28] Agents in the PenDER model were assigned a household income level to preserve consistency with the distribution of income levels in NIPSCO's service territory from the ACS.

- **Storage Integration**: Initial DER modeling did not account for behavioral change that might maximize DER resource capacity credit. However, after receiving stakeholder comments, NIPSCO incorporated an assumed integration of DER storage resources over time. By storing solar energy during the day and discharging energy during peak hours, distributed storage could reduce peak demands and increase the net effective capacity contribution for such resources. For modeling purposes, NIPSCO assumed that by 2040, solar output would be supported by storage in the following manner: 5% of total installed solar capacity would be matched by storage in the Reference scenario, 25% in the Aggressive Environmental Regulation scenario, and 33% in the EWD scenario.

- **Bass Innovation Index Parameters:** By using NIPSCO's customer adoption numbers from 2012 through 2019 from the Net Metering program, PenDER's bass innovation index parameters were calibrated to match historical adoption decisions (using historic retail rates and solar PV capital costs).

3.5.3 DER Forecast Results

Using all of the input assumptions outlined above, NIPSCO deployed the PenDER model to estimate a range of DER penetration levels across the four major planning scenarios. Projections for cumulative customer-owned DER installations and associated storage additions are shown in Figure 3-16, with the resulting cumulative energy impacts summarized in Figure 3-17.[29] (AER), and 40% (EWD and Electrification). The cumulative peak summer impact from DER is shown in Figure 3-18.

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[28] Guzman, G. (September 2020). "Household Income: 2019". *American Community Survey*. https://www.census.gov/content/dam/Census/library/publications/2020/acs/acsbr20-03.pdf

[29] Note that this graphic displays energy projections at the customer meter. For purposes of inclusion in the IRP load forecast modeling, NIPSCO grossed up the energy impact by 5% to incorporate line losses.

Figure 3-16: Projected Cumulative Customer-Owned DER Installations

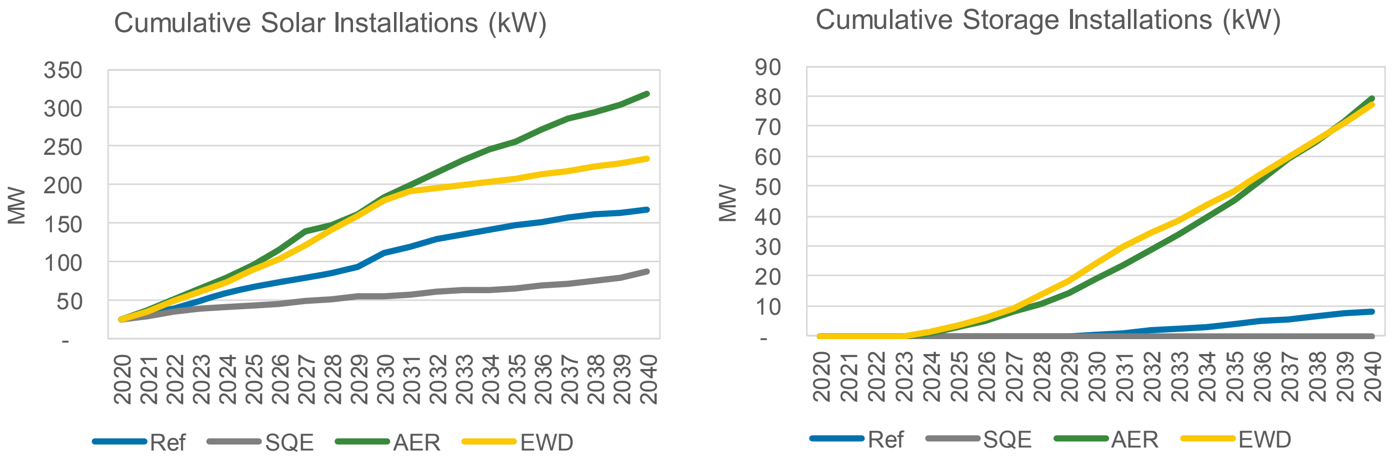
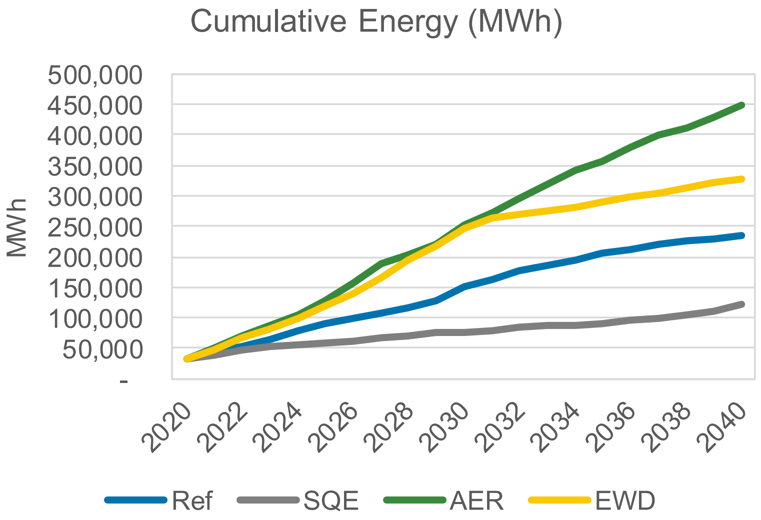


Figure 3-17: Projected Cumulative Customer-Owned DER Energy Impact



For peak accounting, NIPSCO evaluated expected contributions for solar and storage resources based on MISO's RIIA studies[30] and the fundamental expectations for market evolution across the four planning scenarios. The resulting contributions to both summer and winter peak periods are shown in Figure 3-18.

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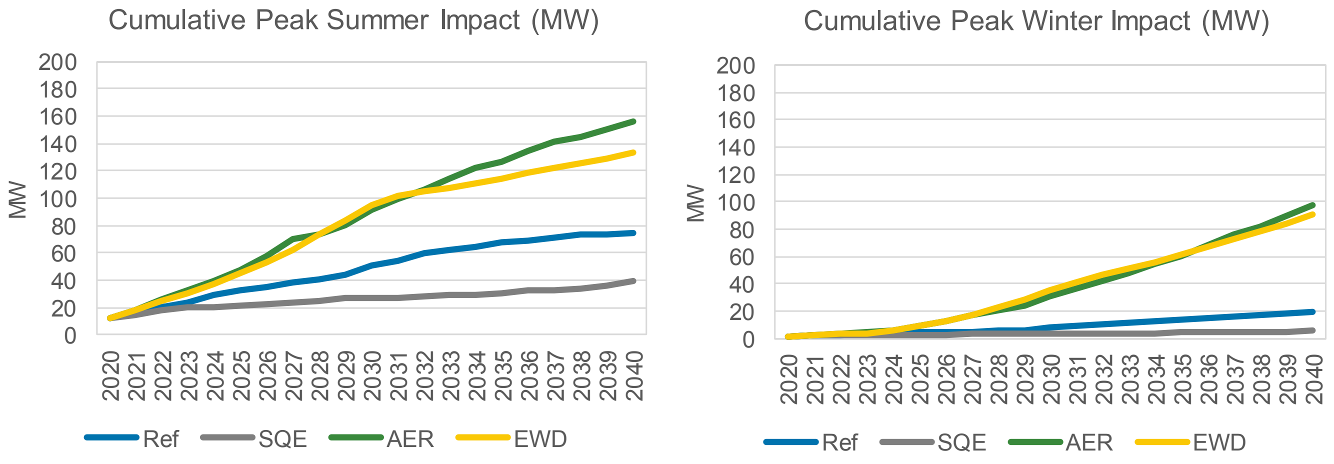
[30] See in particular, Figure RA-18 for Distributed PV in the MISO RIIA Summary Report, https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

Figure 3-18: Customer DER Cumulative Peak Summer and Winter Impact



3.6 Scenario Analysis

NIPSCO combined the base econometric modeling analysis with the EV and DER analysis across all four planning scenarios to develop a range of future load growth outcomes, as outlined in Table 3-7. The remainder of this section outlines the key drivers of scenario uncertainty and provides a summary of the forecasts.

Table 3-7: Scenario Drivers Summary

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*	

3.6.1 Economic Variables

NIPSCO relied on Moody's macroeconomic data for forecasts of the econometric variables described in Section 3.3.1. NIPSCO used the Moody's Baseline forecast for the Reference Case as of April 2021, and deployed the 10th percentile upside scenario for the high case (mapped to the EWD scenario) and the 90th percentile downside scenario for the low case (mapped to the SQE scenario).

As per Moody's documentation,[31] "by definition the probability that the economy will perform better than this projection is equal to 50%, the same as the probability that it will perform worse" under the Baseline forecast. The economic variables are then flexed up and down in the alternative scenarios. Under the 10th percentile upside scenario, Moody's assumes:

- Effective vaccine implementation allows businesses to reopen sooner, driving consumer and business confidence higher than the baseline;
- Fiscal stimulus boosts the economy more than expected, consumers return to higher levels of spending, and unemployment falls; and
- Although inflation and long-term interest rates rise more than in the baseline, the stock market continues to rise.

Under the 90th percentile downside scenario, Moody's assumes:

- COVID-19 incidences rise and concerns build regarding whether enough people will agree to be vaccinated, causing businesses to reopen more slowly than expected;
- Consumer confidence erodes, reducing spending and causing the economy to fall back into recession; and
- Unemployment rises and the stock market falls significantly.

3.6.2 Electric Vehicles

NIPSCO developed a range of EV penetration scenarios with resulting impacts on the load forecast, as described in Section 3.4 and mapped to the scenarios as summarized in Table 3-7.

3.6.3 Distributed Energy Resources

NIPSCO developed a range of DER penetration scenarios with resulting impacts on the load forecast, as described in Section 3.5 and mapped to the scenarios as summarized in Table 3-7.

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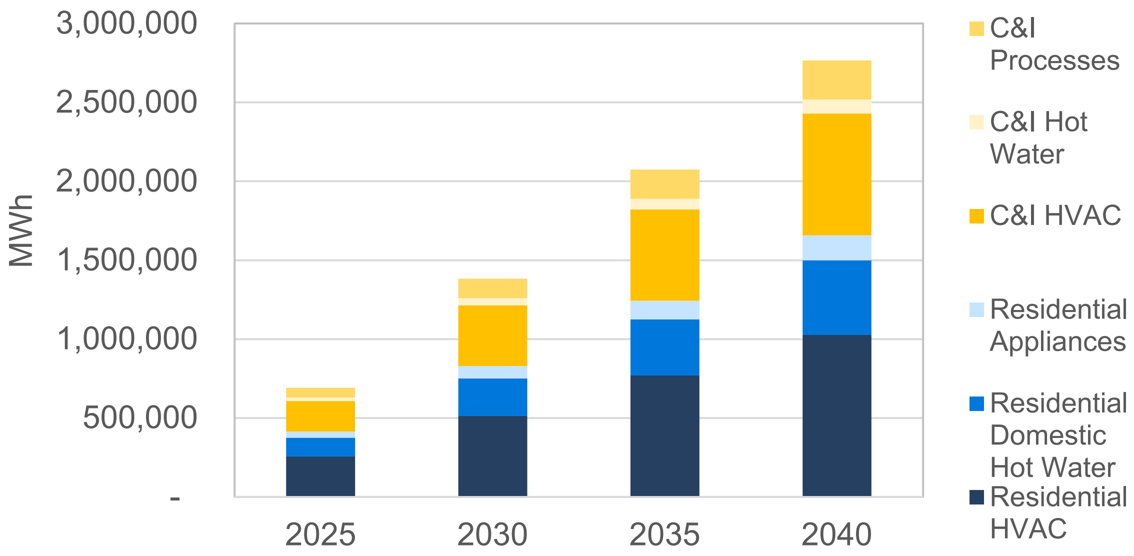
[31] All scenario narrative documentation is adopted from Moody's Analytics' U.S. Macroeconomic Outlook Baseline and Alternative Scenarios: April, 2021.

3.6.4 Other Electrification

For the EWD scenario, NIPSCO incorporated additional electrification impacts according to the electrification study developed by AEG for MISO's MTEP 2021 process. This study incorporated potential electrification of residential and commercial/industrial heating, hot water, appliances, and processes. NIPSCO adopted the projections for LRZ 6 to its service territory and added loads as summarized in Figure 3-19. As many of the electrification impacts have larger demand impacts in the winter than summer, the peak profile was also impacted.

Figure 3-19: Electrification Impact on NIPSCO Energy Sales



3.6.5 Industrial Load Risk

For the Status Quo Extended scenario, NIPSCO incorporated the potential for additional industrial load migration to the new industrial rate service structure. The scenario incorporated a reduction of firm industrial load in Rate 831 down to 70 MW.

3.6.6 Scenario Results

Figure 3-20 presents a summary of the total net energy for load forecast across the four planning scenarios. The Reference Case and AER scenarios expect net sales to grow on a CAGR of just below 0.2% per year. They both rely on the same underlying economic forecast and EV (increase in net load) and DER (decrease in net load) growth tend to offset each other. The high EV and other electrification impacts drive the CAGR in the EWD scenario above 1.4% over the study period, while lower economic growth and industrial load loss assumptions result in negative growth in the SQE scenario.

Figure 3-20: Total Net Energy for Load Forecast across Scenarios

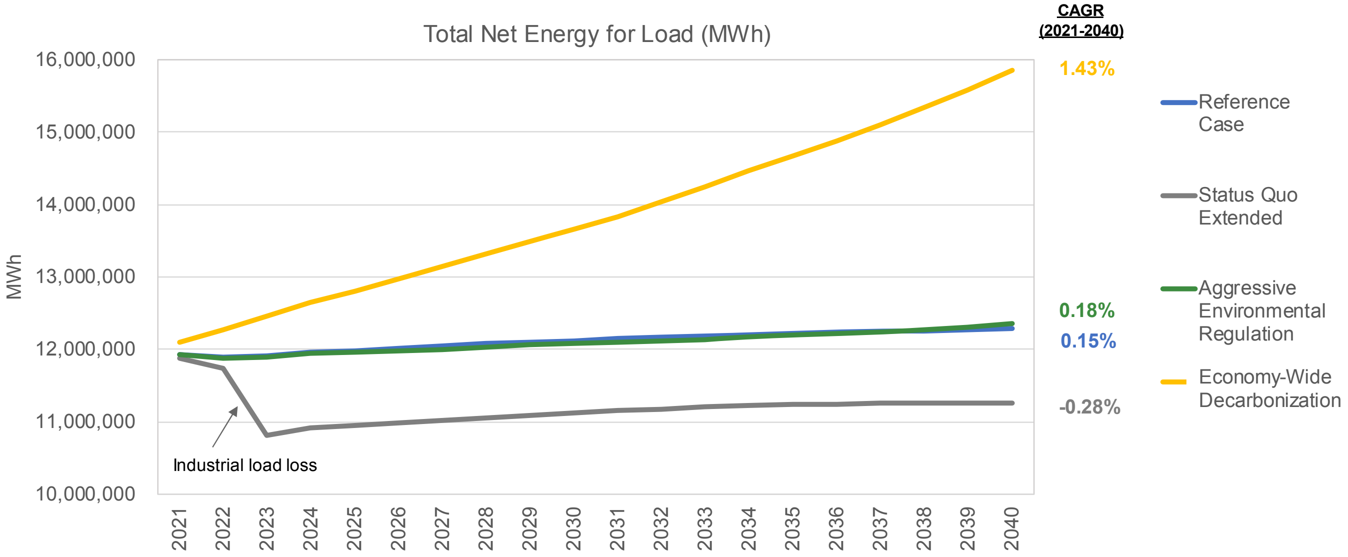
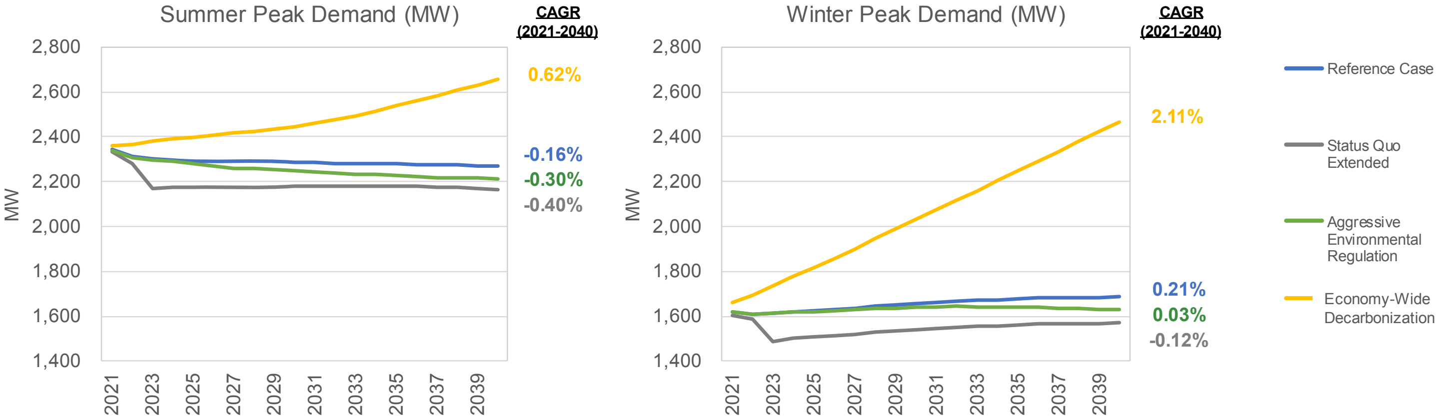


Figure 3-21 summarizes the all-in peak load forecasts for both the summer and winter seasons across scenarios. Peak load is generally expected to grow at a slower rate than sales, particularly in the summer time period, with three out of the four cases exhibiting negative CAGRs. In the winter, the expected peak growth rates are projected to be higher, with a CAGR above 2% in the EWD scenario as a result of electrification impacts that are concentrated in the heating season.

Figure 3-21: Summer and Winter Peak Load Forecasts across Scenarios



3.7 Detailed Forecast Results

The remainder of this section provides detailed annual sales and peak demand forecasts by customer class for the Reference Case and by category across all four scenarios.

Table 3-8: Customer Count Forecast by Major Customer Segment – Reference Case

Year	Residential	Commercial	Small Industrial
2021	416,604	57,530	2,028
2022	418,557	57,981	2,006
2023	420,987	58,542	2,005
2024	423,685	59,165	2,013
2025	426,348	59,781	2,027
2026	428,891	60,368	2,040
2027	431,304	60,925	2,050
2028	433,590	61,453	2,059
2029	435,819	61,968	2,067
2030	438,007	62,474	2,075
2031	440,110	62,959	2,082
2032	442,122	63,424	2,088
2033	444,036	63,866	2,094
2034	445,767	64,266	2,100
2035	447,491	64,664	2,105
2036	449,164	65,051	2,111
2037	450,689	65,403	2,116
2038	452,086	65,726	2,121
2039	453,429	66,036	2,125
2040	454,746	66,340	2,130
2021-2040 CAGR	**0.5%**	**0.8%**	**0.3%**

Table 3-9: Electric Sales Forecast (Inclusive of Historical Energy Efficiency Programs Only) – Reference Case

Year	Residential	Commercial	Small Industrial	Large Industrial non-831	Large Industrial 831 T1	Other*	Losses	Total MWh
2021	3,395,795	3,800,474	2,159,154	381,929	1,527,600	110,200	564,935	11,940,087
2022	3,358,783	3,820,236	2,154,978	352,212	1,541,760	110,393	564,051	11,902,413
2023	3,370,774	3,845,252	2,152,399	352,227	1,541,760	110,323	565,493	11,938,227
2024	3,388,242	3,873,709	2,150,579	353,194	1,542,000	110,346	567,560	11,985,631
2025	3,398,391	3,900,840	2,149,084	352,245	1,541,760	110,346	569,150	12,021,815
2026	3,409,746	3,926,110	2,147,191	352,250	1,541,760	110,356	570,761	12,058,173
2027	3,423,005	3,949,461	2,144,979	352,255	1,541,760	110,364	572,369	12,094,192
2028	3,438,589	3,970,855	2,142,568	353,217	1,542,000	110,373	574,046	12,131,648
2029	3,453,761	3,991,285	2,140,029	352,265	1,541,760	110,382	575,566	12,165,047
2030	3,467,788	4,010,980	2,137,384	352,269	1,541,760	110,391	577,041	12,197,613
2031	3,480,116	4,029,325	2,134,661	352,274	1,541,760	110,399	578,368	12,226,902
2032	3,490,838	4,046,170	2,131,872	353,237	1,542,000	110,406	579,589	12,254,112
2033	3,499,537	4,061,487	2,129,048	352,284	1,541,760	110,413	580,548	12,275,076
2034	3,506,036	4,073,853	2,126,171	352,287	1,541,760	110,419	581,300	12,291,826
2035	3,511,925	4,086,001	2,123,240	352,289	1,541,760	110,425	582,012	12,307,652
2036	3,516,488	4,097,337	2,120,292	353,247	1,542,000	110,430	582,667	12,322,461
2037	3,519,122	4,106,322	2,117,313	352,291	1,541,760	110,435	583,021	12,330,264
2038	3,519,797	4,113,349	2,114,328	352,290	1,541,760	110,439	583,232	12,335,196
2039	3,519,584	4,119,474	2,111,314	352,289	1,541,760	110,443	583,355	12,338,219
2040	3,519,047	4,125,105	2,108,251	353,239	1,542,000	110,447	583,483	12,341,572
2021-2040 CAGR	**0.2%**	**0.4%**	**-0.1%**	**-0.4%**	**0.0%**	**0.0%**	**0.2%**	**0.2%**

*Other includes Railroad, Street Lighting, Public Authority, and Company Use

Table 3-10: Peak Load Forecast (Inclusive of Historical Energy Efficiency Programs Only) – Reference Case

Year	Residential	Commercial	Small Industrial	Large Industrial non-831	Large Industrial 831 T1	Other*	Total MW	System Wide Peak (Grossed Up for Losses)
2021	1,017	649	340	82	176	24	2,287	2,346
2022	997	648	337	64	176	24	2,245	2,321
2023	992	649	336	64	176	24	2,240	2,316
2024	991	650	335	64	176	24	2,240	2,315
2025	987	652	335	64	176	24	2,238	2,313
2026	986	654	334	64	176	24	2,238	2,313
2027	985	656	333	64	176	24	2,239	2,314
2028	986	658	333	64	176	24	2,241	2,317
2029	988	660	332	64	176	24	2,244	2,319
2030	989	662	332	64	176	24	2,247	2,322
2031	990	664	332	64	176	24	2,249	2,325
2032	991	666	331	64	176	24	2,252	2,328
2033	992	667	331	64	176	24	2,254	2,329
2034	992	669	330	64	176	24	2,255	2,330
2035	992	670	330	64	176	24	2,256	2,331
2036	992	672	329	64	176	24	2,257	2,332
2037	992	673	329	64	176	24	2,257	2,332
2038	991	673	328	64	176	24	2,257	2,331
2039	990	674	328	64	176	24	2,256	2,330
2040	989	675	327	64	176	24	2,255	2,329
2021-2040 CAGR	**-0.1%**	**0.2%**	**-0.2%**	**-1.3%**	**0.0%**	**0.0%**	**-0.1%**	**0.0%**

*Other includes Railroad, Street Lighting, Public Authority, and Company Use

Table 3-11: Reference Case Electric Sales Forecast with Adjustments

	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	(138,4790	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%**

*DERs are reductions to the load served by NIPSCO.

Table 3-12: Reference Case Peak Demand Forecast with Adjustments

	Summer Peak (MW)				Winter Peak (MW)			
	Base Load	EV Load	DERs*	All-In	Base Load	EV Load	DERs*	All-In
2021	2,346	0	(5)	2,341	1,622	0	(1)	1,621
2022	2,321	0	(8)	2,313	1,611	0	(1)	1,610
2023	2,316	1	(13)	2,304	1,614	0	(2)	1,612
2024	2,315	1	(18)	2,298	1,622	1	(2)	1,620
2025	2,313	1	(22)	2,292	1,626	1	(3)	1,624
2026	2,313	1	(25)	2,290	1,633	1	(3)	1,630
2027	2,314	2	(27)	2,289	1,640	1	(4)	1,637
2028	2,317	2	(30)	2,289	1,650	1	(4)	1,647
2029	2,319	2	(33)	2,289	1,654	1	(5)	1,651
2030	2,322	3	(41)	2,284	1,661	2	(6)	1,656
2031	2,325	3	(45)	2,283	1,667	2	(8)	1,662
2032	2,328	3	(50)	2,281	1,676	2	(9)	1,669
2033	2,329	4	(53)	2,281	1,678	2	(10)	1,670
2034	2,330	4	(55)	2,279	1,682	3	(11)	1,673
2035	2,331	4	(58)	2,278	1,686	3	(13)	1,676
2036	2,332	5	(60)	2,277	1,692	4	(14)	1,682
2037	2,332	5	(62)	2,275	1,692	4	(15)	1,681
2038	2,331	6	(64)	2,273	1,694	4	(16)	1,682
2039	2,330	6	(65)	2,272	1,695	5	(17)	1,683
2040	2,329	7	(66)	2,270	1,699	5	(18)	1,686
2021-2040 CAGR	**0.0%**	**18.6%**	**14.8%**	**-0.2%**	**0.2%**	**17.3%**	**19.4%**	**0.2%**

*DERs are reductions to the load served by NIPSCO.

Table 3-13: SQE Electric Sales Forecast with Adjustments

	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%**

*DERs are reductions to the load served by NIPSCO.

Table 3-14: SQE Peak Demand Forecast with Adjustments

	Summer Peak (MW)				Winter Peak (MW)			
	Base Load	EV Load	DERs*	All-In	Base Load	EV Load	DERs*	All-In
2021	2,338	0	(3)	2,335	1,606	0	(0)	1,606
2022	2,284	0	(6)	2,279	1,588	0	(1)	1,588
2023	2,174	1	(8)	2,167	1,490	0	(1)	1,489
2024	2,182	1	(9)	2,174	1,503	1	(1)	1,502
2025	2,182	1	(10)	2,173	1,507	1	(1)	1,506
2026	2,184	1	(11)	2,174	1,514	1	(1)	1,513
2027	2,185	2	(12)	2,174	1,520	1	(2)	1,520
2028	2,187	2	(14)	2,175	1,529	1	(2)	1,529
2029	2,189	2	(15)	2,176	1,533	1	(2)	1,533
2030	2,191	3	(16)	2,178	1,539	2	(2)	1,539
2031	2,193	3	(16)	2,180	1,545	2	(2)	1,544
2032	2,195	3	(17)	2,180	1,552	2	(3)	1,552
2033	2,195	4	(18)	2,181	1,554	2	(3)	1,554
2034	2,195	4	(19)	2,180	1,557	3	(3)	1,557
2035	2,194	4	(19)	2,180	1,560	3	(3)	1,560
2036	2,194	5	(21)	2,178	1,565	4	(3)	1,565
2037	2,193	5	(22)	2,176	1,564	4	(3)	1,564
2038	2,191	6	(23)	2,174	1,565	4	(3)	1,566
2039	2,188	6	(25)	2,170	1,565	5	(4)	1,566
2040	2,186	7	(29)	2,164	1,568	5	(4)	1,569
2021-2040 CAGR	**-0.4%**	**18.6%**	**12.6%**	**-0.4%**	**-0.1%**	**17.3%**	**13.5%**	**-0.1%**

*DERs are reductions to the load served by NIPSCO.

Table 3-15: AER Electric Sales Forecast with Adjustments

	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%**

*DERs are reductions to the load served by NIPSCO.

Table 3-16: AER Peak Demand Forecast with Adjustments

	Summer Peak (MW)				Winter Peak (MW)			
	Base Load	EV Load	DERs*	All-In	Base Load	EV Load	DERs*	All-In
2021	2,346	1	(7)	2,340	1,622	1	(1)	1,621
2022	2,321	1	(14)	2,308	1,611	1	(2)	1,610
2023	2,316	2	(21)	2,296	1,614	2	(3)	1,612
2024	2,315	2	(29)	2,289	1,622	2	(5)	1,619
2025	2,313	3	(37)	2,280	1,626	3	(8)	1,621
2026	2,313	4	(47)	2,269	1,633	3	(11)	1,625
2027	2,314	5	(60)	2,258	1,640	4	(16)	1,628
2028	2,317	6	(65)	2,258	1,650	5	(20)	1,635
2029	2,319	7	(71)	2,255	1,654	6	(24)	1,637
2030	2,322	9	(83)	2,248	1,661	7	(30)	1,638
2031	2,325	10	(91)	2,244	1,667	8	(36)	1,640
2032	2,328	11	(100)	2,239	1,676	10	(42)	1,643
2033	2,329	13	(108)	2,235	1,678	12	(49)	1,640
2034	2,330	15	(115)	2,230	1,682	14	(56)	1,640
2035	2,331	18	(120)	2,229	1,686	16	(62)	1,639
2036	2,332	20	(129)	2,223	1,692	18	(70)	1,640
2037	2,332	23	(136)	2,219	1,692	21	(78)	1,634
2038	2,331	26	(140)	2,218	1,694	24	(85)	1,633
2039	2,330	30	(145)	2,215	1,695	27	(93)	1,630
2040	2,329	34	(152)	2,212	1,699	31	(101)	1,629
2021-2040 CAGR	**0.0%**	**23.5%**	**17.8%**	**-0.3%**	**0.2%**	**22.5%**	**28.3%**	**0.0%**

*DERs are reductions to the load served by NIPSCO.

Table 3-17: EWD Electric Sales Forecast with Adjustments

	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%**	**17.1%**	**16.6%**	**1.4%**

*DERs are reductions to the load served by NIPSCO.

Table 3-18: EWD Peak Demand Forecast with Adjustments

	Summer Peak (MW)					**Winter Peak (MW)**				
	Base Load	EV Load	Other Electrification	DERs*	All-In	Base Load	EV Load	Other Electrification	DERs*	All-In
2021	2,349	1	17	(6)	2,361	1,626	1	34	(1)	1,660
2022	2,344	1	34	(14)	2,367	1,626	1	68	(2)	1,693
2023	2,345	2	51	(20)	2,379	1,633	2	102	(3)	1,734
2024	2,344	3	69	(26)	2,390	1,641	3	137	(5)	1,776
2025	2,342	4	86	(35)	2,397	1,611	4	206	(8)	1,813
2026	2,342	6	103	(43)	2,407	1,617	5	247	(12)	1,857
2027	2,342	7	120	(53)	2,417	1,623	6	288	(16)	1,902
2028	2,342	10	137	(65)	2,425	1,629	8	330	(22)	1,945
2029	2,343	13	154	(75)	2,435	1,635	11	371	(28)	1,988
2030	2,344	15	172	(87)	2,444	1,640	14	412	(36)	2,030
2031	2,345	19	189	(95)	2,458	1,645	17	453	(42)	2,073
2032	2,345	23	206	(98)	2,475	1,649	20	494	(47)	2,116
2033	2,345	28	223	(101)	2,494	1,653	25	536	(52)	2,161
2034	2,280	33	305	(104)	2,515	1,656	30	577	(57)	2,206
2035	2,279	39	327	(108)	2,537	1,659	35	618	(62)	2,249
2036	2,278	45	349	(112)	2,560	1,661	41	659	(68)	2,292
2037	2,277	51	371	(116)	2,583	1,663	47	700	(74)	2,336
2038	2,275	59	393	(120)	2,607	1,664	54	741	(80)	2,379
2039	2,272	69	415	(123)	2,632	1,665	62	783	(87)	2,423
2040	2,269	79	436	(128)	2,658	1,665	72	824	(93)	2,467
2021-2040 CAGR	**-0.2%**	**26.0%**	**18.6%**	**17.3%**	**0.6%**	**0.1%**	**27.0%**	**18.2%**	**28.3%**	**2.1%**

*DERs are reductions to the load served by NIPSCO.

Section 4. Supply-Side Resources

NIPSCO's generation fleet is in the midst of a transition as with much of the electric industry. NIPSCO is committed to make every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest cost reasonably possible. Consistent with this objective and as set forth in the 2018 IRP, NIPSCO continues to execute on the generation plan to retire coal generation and replace it with a mix of renewable resources. NIPSCO's supply-side resources are comprised of the existing coal and natural gas units, renewable generation currently in-service and planned to be in-service, and a mix of future resource options.

4.1 Existing Resources

NIPSCO has a variety of generation resources to meet its customers' forecast capacity and energy needs. Not only do these resources need to meet the principles set out in Section 1, they must operate within MISO, the Regional Transmission Organization, and subject to NERC standards. NIPSCO has registered with NERC as a Distribution Provider, Generator Owner, Generator Operator, Load Serving Entity, Purchasing-Selling Entity, Resource Planner and Transmission Planner. NIPSCO is registered as a Balancing Authority, Transmission Operator and Transmission Owner in MISO. Each Registered Entity is subject to compliance with applicable NERC and Regional Reliability Organization Reliability standards approved by FERC. In NIPSCO's case, its Regional Reliability Organization is ReliabilityFirst.

NIPSCO-owned generating resources consist of coal, natural gas and hydro units. Additionally NIPSCO meets it customer needs with 4 wind purchase power agreements. The total NDC of the existing resources is 2,491 MW across multiple generation sites, including Schahfer (Units 16A, 16B, 17 and 18), Michigan City (Unit 12), Sugar Creek and two hydroelectric generating sites near Monticello, Indiana (Norway Hydro and Oakdale Hydro). Of the total capacity, 48% is from coal-fired units, 28% is from natural gas-fired units and 24% is from wind and hydroelectric generation units. Table 4-1 provides a summary of the current generating facilities operated by NIPSCO.

Table 4-1: Net Demonstrated Capacity

Resource	Unit	Fuel	Capacity NDC (MW)
Michigan City	12	Coal	469
Schahfer	16A	NG	78
	16B	NG	77
	17	Coal	361
	18	Coal	361
		Subtotal	877
Sugar Creek		NG	535
Hydro	Norway	Water	4
	Oakdale	Water	6
		Subtotal	10
Wind		Wind	600
NIPSCO			2,491

NG=Natural Gas

4.1.1 Michigan City

Michigan City is located on a 134-acre site on the shore of Lake Michigan in Michigan City, Indiana. It has one base-load unit, Unit 12 and is equipped with SCR and OFA systems to reduce NO_x emissions. A new FGD system was placed in service in 2015. The individual unit characteristics of Michigan City are provided in Table 4-2.

Table 4-2 Michigan City Generating Station

	Unit 12
NET Output	
Min (MW)	315
Max (MW)	469
Boiler	Babcock & Wilcox
Burners	10 Cyclone
Main Fuel	Coal
Turbine	General Electric
Frame	G2
In-Service	1974
Environmental Controls	FGD, SCR, OFA

4.1.2 Schahfer

Schahfer is located on approximately a 3,150-acre site two miles south of the Kankakee River in Jasper County, near Wheatfield, Indiana. It is the largest of NIPSCO's generating stations. There are two coal-fired base-load units and two gas-fired simple cycle peaking units that came on-line over an 11-year period ending in 1986. The Schahfer units are equipped with significant environmental control technologies, including FGD to reduce SO2 emissions and SCR, SNCR, LNB, and OFA systems to reduce NO_x emissions. As part of the Company's CAIR Compliance Phase I Strategy, FGD system upgrades to improve SO_2 removal efficiency were completed for Units 17 and 18 in 2010 and 2009, respectively. The individual unit characteristics of Schahfer are provided in Table 4-3.[32]

Table 4-3 : Schahfer

	Unit 17	Unit 18	Unit 16A	Unit 16B
Net Output				
Min (MW)	125	125	------	------
Max (MW)	361	361	78	77
Boiler	Combustion Engineering	Combustion Engineering	-----	-----
Burners	6 Pulverizers	6 Pulverizers	-----	-----
Main Fuel	Coal	Coal	Gas	Gas
Turbine	Westinghouse	Westinghouse	Westinghouse	Westinghouse
Frame	BB243	BB243	D501	D501
In-Service	1983	1986	1979	1979
Environmental Controls	FGD, LNB, OFA	FGD, LNB, OFA	-----	-----

4.1.3 Sugar Creek

Sugar Creek is located on a 281-acre rural site near the west bank of the Wabash River in Vigo County, Indiana. The gas-fired CTs and CCGTs were available for commercial operation in 2002 and 2003, respectively. Sugar Creek was purchased by NIPSCO in July 2008, and is its newest thermal electric generating facility. Sugar Creek has been registered as a MISO resource since December 1, 2008. Two generators and one steam turbine generator are operated in the CCGT mode and environmental control technologies include SCR to reduce NO_x, and dry low NO_x combustion systems. The individual unit characteristics of Sugar Creek are provided in Table 4-4.

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[32] Units 14 and 15 were retired effective October 1, 2021.

Table 4-4: Sugar Creek

	CT 1A	CT 1B	SCST
NET Output			
Min (MW)	120	120	120
Max (MW)	156	157	222
Heat Recovery Steam Generator	Vogt Power	Vogt Power	---
Main Fuel	Gas	Gas	Steam
Turbine	GE	GE	GE
Frame	7FA	7FA	D11
In-Service	2002	2002	2003
Environmental Controls	SCR, DLN	SCR, DLN	---

4.1.4 Norway Hydro and Oakdale Hydro (NIPSCO-Owned Supply Resources)

Norway Hydro is located near Monticello, Indiana on the Tippecanoe River. The dam creates Lake Shafer, a body of water approximately 10 miles long with a maximum depth of 30 feet, which functions as its reservoir. Norway Hydro has four generating units capable of producing up to 7.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 4 MW. The individual unit characteristics of the Norway Hydro are provided in Table 4-5.

Table 4-5: Norway Hydro

	Unit 1	Unit 2	Unit 3	Unit 4
NET Output				
Min (MW)	---	---	---	---
Max (MW)	2	2	2	1.2
In-Service	1923	1923	1923	1923
Main Fuel	Water	Water	Water	Water

Oakdale Hydro is located near Monticello, Indiana along the Tippecanoe River. The dam creates Lake Freeman, a body of water approximately 12 miles long with a maximum depth of 45 feet, which functions as its reservoir. Oakdale Hydro has three generating units capable of producing up to 9.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 6 MW. The individual unit characteristics of the Oakdale Hydro are provided in Table 4-6.

Table 4-6: Oakdale Hydro

	Unit 1	Unit 2	Unit 3
NET Output			
Min (MW)	---	---	---
Max (MW)	4.4	3.4	1.4
In-Service	1925	1925	1925
Main Fuel	Water	Water	Water

4.1.5 NIPSCO Wind Purchase Power Agreements and Joint Venture

NIPSCO is currently engaged in a 20-year PPA with Iberdrola, in which NIPSCO will purchase generation from Barton. Barton, located in Worth County, Iowa, went into commercial operation on April 10, 2009. The individual unit characteristics of Barton are provided in Table 4-7.

Table 4-7: Barton Wind PPA

	Barton PPA
NET Output	
Per Unit (MW)	2
Number of Units	25
Total Output (MW)	50
In-Service	2009
Main Fuel	Wind

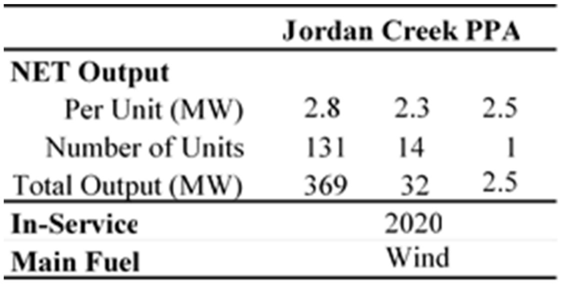
NIPSCO is also engaged in a 15-year PPA with Iberdrola, in which NIPSCO will purchase generation from Buffalo Ridge. Buffalo Ridge, located in Brookings County, South Dakota, went into commercial operation on April 15, 2009. The individual unit characteristics of Buffalo Ridge are provided in Table 4-8.

Table 4-8: Buffalo Ridge Wind PPA

	Buffalo Ridge PPA
NET Output	
Per Unit (MW)	2
Number of Units	24
Total Output (MW)	50
In-Service	2009
Main Fuel	Wind

NIPSCO is also engaged in a 15-year PPA with NextEra Energy Resources, LLC, in which NIPSCO will purchase the power directly from Jordan Creek, which will operate and maintain the facilities. Jordan Creek, located in Benton and Warren counties, Indiana, near Williamsport, Indiana, went into commercial operation in December 2020. The individual unit characteristics of Jordan Creek are provided in Table 4-9.

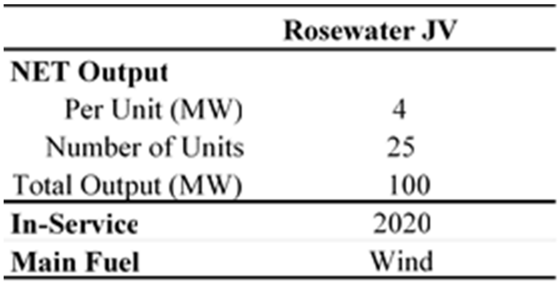
Table 4-9: Jordan Creek Wind PPA



	Jordan Creek PPA		
NET Output			
Per Unit (MW)	2.8	2.3	2.5
Number of Units	131	14	1
Total Output (MW)	369	32	2.5
In-Service	2020		
Main Fuel	Wind		

The Rosewater wind project, developed and constructed by EDP Renewables North America LLC, is located in White County, Indiana and went into commercial operation in December 2020. EDP Renewables and NIPSCO entered into a joint venture and ownership agreement for the Rosewater project. The individual unit characteristics of Rosewater are provided in Table 4-10.

Table 4-10: Rosewater Wind JV



	Rosewater JV
NET Output	
Per Unit (MW)	4
Number of Units	25
Total Output (MW)	100
In-Service	2020
Main Fuel	Wind

4.1.6 Total Resource Summary

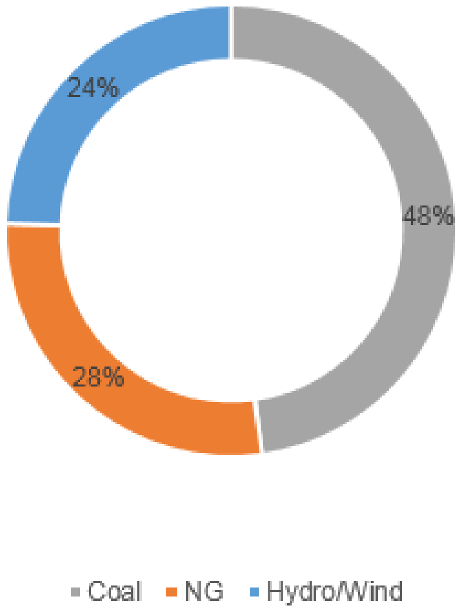
Table 4-11 illustrates various characteristics of NIPSCO's owned and contracted generating units. Figure 4-1 illustrates NIPSCO's existing resources by fuel type.

Table 4-11: Existing Generating Units

Resource	Unit	Fuel	Capacity NDC (MW)	Year In Service
Michigan City	12	Coal	469	1974
Schahfer	16A	NG	78	1979
	16B	NG	77	1979
	17	Coal	361	1983
	18	Coal	361	1986
		Subtotal	877	
Sugar Creek		NG	535	2002
Hydro	Norway	Water	4	1923
	Oakdale	Water	6	1925
		Subtotal	10	
Wind	Barton	Wind	50	2009
	Buffalo Ridge		50	2009
	Rosewater		100	2020
	Jordan Creek		400	2020
		Subtotal	600	
NIPSCO			2,491	

NG=Natural Gas

Figure 4-1: Existing Resources Net Demonstrated Capacity



4.2 Fuel, Energy, and Capacity Procurement Strategy for Existing Resources[33]

As NIPSCO operates as a public utility providing electric service to customers, the procurement of fuel, energy, and capacity at the lowest reasonably possible cost is the foundation of NIPSCO's strategy. NIPSCO's Fuel Supply team ensures all fuel, energy, and capacity supply meets Indiana Code § 8-1-2-42(d).

4.2.1 Coal Procurement and Inventory Management Practices

4.2.1.1 Coal Supply Strategy

NIPSCO employs a multifaceted strategy to guide coal procurement activities associated with the fuel supply requirements for its coal-fired units. The goal of this strategy is to maximize reliability while maintaining customer affordability. Key elements include: (1) procuring coal supply from sources that minimize the delivered cost of coal, O&M costs, environmental costs, inventory costs and other financial impacts ("total cost of ownership"); (2) hedging customers' price exposure with forward purchases to protect against price volatility; (3) supporting environmental compliance; (4) maintaining reliable inventory levels; (5) ensuring reliability of coal supply and delivery; and (6) maximizing operational flexibility and reliability by procuring coal types that can be used in more than one unit whenever possible.

4.2.1.2 Coal Procurement

NIPSCO maintains a five-year baseline coal forecast that is used to create a strategy that drives its fuel procurement plan. The forecast is used to estimate coal and related coal transportation procurement requirements needed to maintain reliable and economic coal inventory levels. The strategy and fuel procurement plan are highly dynamic and are updated on a periodic basis in response to energy market conditions. Over the past several years, environmental regulations, a significant influx of highly variable renewable generation (e.g. wind and solar), low natural gas prices, and energy efficiency and other demand side initiatives have made coal-fired generation the marginal supply source. Consequently, this has created an environment with highly variable and nearly unpredictable coal purchase requirements. Therefore, NIPSCO's fuel procurement plans must remain as flexible as possible while still maintaining supply reliability. Obtaining volume flexibility can be challenging since coal suppliers and transportation providers typically require firm volume commitments.

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[33] Due to the timing of the IRP, this section was written during the summer of 2021 and the forecast is based on the market at that time. During the latter part of the third quarter, and into the fourth quarter, the coal and natural gas markets have become volatile and prices have increased. The IRP is an imperfect snapshot in time and the changes in these markets are indicative of that. At the time of submission of the IRP, it is unknown how long current trends will continue or if the markets will return to previous levels. As always, NIPSCO will continue to monitor the markets and make adjustments as necessary.

4.2.1.3 Coal Pricing Outlook

Coal competes for a share of the energy market against other fuels (natural gas, nuclear, and oil), renewable energy sources (biomass, hydro, wind, and solar) and energy efficiency programs. Specifically, energy market supply and demand generally set the market price of these competing sources. Also, coal prices are influenced by the supply and demand balance in domestic, international, and metallurgical coal markets, coal production costs, transport costs, and environmental compliance considerations. Over the last decade, energy market dynamics have been heavily influenced by the increased exploration and production of North American shale oil and gas resources and have fundamentally altered the price spread between coal and natural gas. Lower production costs and highly efficient natural gas extraction processes (horizontal drilling and fracking) have kept natural gas a competitive fuel when used in high efficiency, CCGT units. In addition, increases in wet gas production to gather petroleum liquids further increase natural gas supply when oil prices rise. These market dynamics displaced a significant amount of coal-fired electric generation and have kept coal prices relatively low. Decreased coal demand and higher mining costs driven by government regulations have adversely impacted coal producers' margins and profits causing a number of producer bankruptcies over the last few years. The restructuring of coal companies' debt and other costs through the bankruptcy process has allowed some of these coal companies to continue coal production in this competitive environment. Class I railroads have also realized that their rates must be rationalized to allow coal to compete in this environment. Supply has been reduced and any significant increase in demand could result in coal price volatility. However, several factors may limit the upside for coal prices. The first factor is the cost to produce electricity from coal has increased significantly due to stringent environmental regulations placed on coal-fired electric generation. A second factor is the continuation of coal-fired generation retirements which will continue to reduce coal demand in the long run. Lastly, the increased competitiveness of natural gas generation and renewables will also limit demand for coal if coal prices spike in the long run.

The competitive energy market has also driven a shift in coal supply regions. Specifically, the relatively high cost to produce coal in the Central Appalachian regions and low coal prices have resulted in declining coal production and this has increased market share of the lower cost ILB region. Even with its higher sulfur content, ILB coal has become an export resource, and its use has increased domestically as utilities have installed FGDs to meet tighter SO2 limits and other emission standards. Some utilities in the southeast are now using ILB coal that replaced higher cost Columbian and Central Appalachia coal.

The PRB in Wyoming and Montana is the largest coal producing basin in the United States. PRB coal has a lower heat content than coals mined in other basins; however, some utilities have units designed to efficiently utilize lower cost PRB coal and over the last 20 years, a number of utilities retrofitted older coal units to use PRB coal in a blend with either Central Appalachian, ILB, or NAPP coals to reduce their overall fuel costs and lower SO2 emissions. Asian demand for PRB coal has also grown as Japan and China have built new, high efficiency coal units and new coal plants are being built in Korea and Taiwan as well as they prepare to meet their future electricity demand.

In general, most export tonnage originates from Central Appalachian and NAPP coal regions for metallurgical and steam coal markets abroad. Coal suppliers rely on international markets to offset losses in domestic markets; however, the pressure to reduce coal use worldwide will likely reduce international demand in the long run as well.

Overall, these fundamentals are bearish for long-term coal demand. Notwithstanding, NIPSCO will continue to monitor market dynamics and coal prices and incorporate in its procurement strategies.

4.2.1.4 NIPSCO Coal Pricing Outlook

NIPSCO currently procures coal from three geographic regions in the United States: the PRB, the ILB, and the NAPP region. Domestic demand for coal has continued to trend lower over the last several years; therefore, prices have remained relatively low and stable. NAPP coal and ILB coal market pricing over the last several years has been relatively flat. Pricing for PRB coal has remained low over the last several years and is close to the marginal cost of production.

Domestic and international coal prices have increased during 2021 as the economic recovery from the 2020 pandemic has caused a surge in demand. Export dynamics can drive pricing modestly higher for some coal types (e.g. NAPP and ILB) when global demand increases as well; however, the long-term trends for both demand and pricing are bearish.

4.2.1.5 Coal and Issues of Environmental Compliance

Depending on the manner and extent of current and future environmental regulations, NIPSCO's coal purchasing strategy will continue to evolve in a manner that meets current and future environmental requirements.

4.2.1.6 Maintenance of Coal Inventory Levels

NIPSCO has an ongoing strategy to maintain stable coal inventories and reviews inventory targets levels annually. NIPSCO may make adjustments in anticipation of changes in supply availability relative to demand, transportation constraints, and unit consumption. NIPSCO may modify target inventory levels on a unit-by-unit basis depending on the unit consumption, delivery rates, reliability of coal supply, and station coal handling operations. Adequate inventories are essential to maintaining generation reliability. Uncertainty in consumption rates and variability in delivery performance generally require higher levels of inventory to insure reasonably adequate reliability.

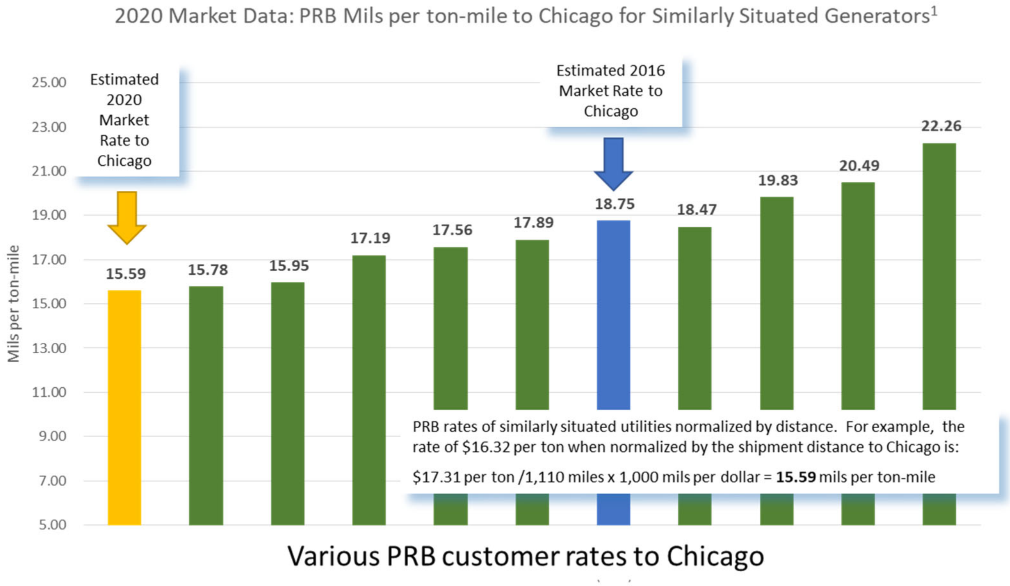
4.2.1.7 Forecast of Coal Delivery and Transportation Pricing

To ensure the delivery of fuel in a timely and cost-effective manner, NIPSCO negotiates and executes transportation contracts that consider current and future coal supply commitments. All fuel procurement options are compared on a delivered cost basis, which includes a complete evaluation of all potential logistical issues.

Coal deliveries, excluding exceptional weather conditions, have been somewhat stable from the various supply regions. Railroads typically make investment in infrastructure and equipment to support anticipated shipment rates. The cyclical nature of the railroad business can create short term transportation constraints and can impact NIPSCO's coal deliveries. These cycles have been shorter in duration and more volatile over the past several years. The decline in coal demand has made it difficult for railroads to invest in coal infrastructure and this may lead to transportation constraints if there is a significant increase in overall coal demand.

Transportation rates have declined over the last four years given the competition in the energy markets. Railroads have been willing to rationalize rail rates, as shown in the market assessment plots below, in order to remain competitive in the energy market. Figure 4-2 highlights the estimated reduction in PRB coal transportation rates since 2016. This pricing trend has improved the competitiveness of NIPSCO's coal-fired generation to a certain extent.

Figure 4-2: PRB Customer Rates



2020 Market Data: PRB Mils per ton-mile to Chicago for Similarly Situated Generators[1]

Estimated 2020 Market Rate to Chicago

Estimated 2016 Market Rate to Chicago

PRB rates of similarly situated utilities normalized by distance. For example, the rate of \$16.32 per ton when normalized by the shipment distance to Chicago is:

\$17.31 per ton /1,110 miles x 1,000 mils per dollar = **15.59** mils per ton-mile

1. Source: 2020 EIA data

4.2.1.8 NIPSCO Transportation Pricing Outlook

NIPSCO has limited rail options from various supply regions for most of its coal transportation moves, and is further disadvantaged due to its geographical location. Not only are rail transportation options limited, other transport modes (trucking, barging and lake vessels) are not economically or logistically feasible alternatives. NIPSCO's largest generating station, Schahfer, is served by only one Class I railroad. All coal deliveries by this railroad to Schahfer have been transported under agreements with escalating transportation rates plus a fuel surcharge indexed to oil prices. Beginning in 2017, NIPSCO and this railroad worked to develop a creative, market-based indexed agreement that lowered rates to improve the station's competitiveness in the market. A second indexed rate agreement has also been recently adopted with another railroad. As stated above, energy markets have forced a rationalization of coal pricing and associated transportation costs. NIPSCO expects this dynamic to continue for the foreseeable future.

As a result of these changes in the energy markets and agreement structures, NIPSCO's PRB and ILB coal transportation rates though 2020 have reduced by nearly 25%-50% since 2017. Fuel surcharges continue to fluctuate with the changes in oil prices. Transportation pricing is expected to remain soft as long as energy prices stay low and relatively flat over the next five years. Increases in fuel charges could lead to modest transportation cost increases if oil prices trend higher.

4.2.1.9 Coal Contractual Flexibility, Deliverability and Procurement

Contract terms for coal and coal transportation agreements range between one to five years in duration. Spot coal purchases are made on an as-needed basis to manage inventory fluctuations. Fuel blending strategies can be adjusted to conserve a particular type of coal if supply problems are experienced. In addition, coal suppliers and railroads have been more amenable to providing some volume flexibility including lower minimum volume obligations or elimination of minimum volume obligations entirely. This flexibility has supported NIPSCO's inventory management efforts.

4.2.2 Natural Gas Procurement and Management

NIPSCO currently procures natural gas for its CCGT generating station using a natural gas supply contract with an energy manager that delivers to the interstate pipeline interconnect at the station, or other locations along the interstate pipeline upon request of NIPSCO for balancing purposes. NIPSCO currently holds firm capacity on Midwestern Gas Transmission Company interstate pipeline and releases the capacity to the energy manager. The contract has provisions to purchase next day and intraday firm gas supplies to serve the daily needs of the facility. NIPSCO nominates and balances the gas supply needs of the CCGT generating station. A portion of the gas supply for Sugar Creek is financially hedged with the intention of smoothing out market price swings over a specific time period. The volatility mitigation plan consists of purchasing monthly NYMEX Henry Hub natural gas contracts that settle at expiration.

The coal units and CTs at NIPSCO are located within the NIPSCO natural gas local distribution company service territory. NIPSCO maintains a separate contract for firm delivered natural gas supply and energy management for these units. The contract has provisions to nominate next-day usage based on the expected usage of each generating station. The actual usage is balanced daily and balancing is the responsibility of the energy manager.

4.2.3 Electric Generation Gas Supply Request for Proposal Process

NIPSCO conducts two separate RFPs for the electric generation firm natural gas supply, one for the Sugar Creek facility and a separate one for the coal units and CTs. The RFP process may be done on a seasonal or annual basis depending on the current contract length and supplier agreement. The process includes qualifying potential suppliers, customizing the RFP based on near-term system needs, and gas supply trends. Suppliers are chosen based on the overall value of the package and ability to serve the needs of the facility. To date, NIPSCO has entered into electric generation gas supply agreements that extend no longer than one year, but is always evaluating the value and benefits of longer term agreements.

4.3 Planned Resource Summary

In addition to its existing resource portfolio, NIPSCO has a number of planned renewable resource projects with expected in-service dates through 2023. The planned projects have been filed with the Commission and are in various stages of development. The projects are summarized in Table 4-12.

Table 4-12: Planned Renewable Projects

Project	Technology	Expected ICAP (MW)	Battery Capacity (MW)	Expected In-Service
Indiana Crossroads	Wind	300	-	2021
Indiana Crossroads II	Wind	200	-	2023
Greensboro	Solar + Storage	100	30	2022
Brickyard	Solar	200	-	2022
Green River	Solar	200	-	2023
Gibson	Solar	280	-	2023
Cavalry	Solar + Storage	200	60	2023
Dunns Bridge I	Solar	265	-	2022
Dunns Bridge II	Solar + Storage	435	75	2023
Indiana Crossroads	Solar	200	-	2022
Elliott	Solar	200	-	2023
Fairbanks	Solar	250	-	2023
Total		**2,830**	**165**	

4.3.1 Planned Wind Resources

NIPSCO is in the process of developing two wind projects that are expected to be in service by 2023. The first, Indiana Crossroads, developed and constructed by EDP Renewables North America, LLC, is located in White County, Indiana and is expected to go into commercial operation by December 2021. The planned unit characteristics of Indiana Crossroads are provided in Table 4-13.

Table 4-13: Indiana Crossroads Wind JV

	Indiana Crossroads Wind JV
Net Output	
Per Unit (MW)	4.2
Number of Units	72
Total Output (MW)	302.4
In-Sevice	2021
Main Fuel	Wind

NIPSCO has entered into a 15-year PPA starting in 2023 with EDP Renewables North America, LLC, in which NIPSCO will purchase the power directly from Indiana Crossroads II Wind, who will operate and maintain the facility. Indiana Crossroads II Wind, located in White County, Indiana, is expected to go into commercial operation by December 2023. The planned unit characteristics of Indiana Crossroads II Wind are provided in Table 4-14.

Table 4-14: Indiana Crossroads II Wind PPA

	Indiana Crossroads II Wind PPA	
Net Output		
Per Unit (MW)	4.2	5.6
Number of Units	6	32
Total Output (MW)	25.2	179.2
In-Sevice	2023	
Main Fuel	Wind	

4.3.2 Planned Solar and Solar + Storage Resources

NIPSCO has 10 planned solar projects, three of which include additional battery storage, that are expected to be in service by 2023.

NIPSCO has entered into a 20-year PPA starting in 2022 with NextEra Energy Resources, LLC, in which NIPSCO will purchase the power directly from Greensboro, who will operate and maintain the facility. Greensboro, located in Henry County, Indiana, is expected to go into commercial operation by December 2022. The planned unit characteristics of Greensboro are provided in Table 4-15.

Table 4-15: Greensboro Solar + Storage PPA

	Greensboro PPA
Solar Output	
Total Output (MW)	100
Storage Output	
Total Output (MW)	30
Output Period (Hrs.)	3
Discharge Limits (Cycles/Yr.)	100
In-Service	**2022**
Main Fuel	**Solar + Storage**

NIPSCO has entered into a 20-year PPA starting in 2022 with NextEra Energy Resources, LLC, in which NIPSCO will purchase the power directly from Brickyard, who will operate and maintain the facility. Brickyard, located in Boone County, Indiana, is expected to go into commercial operation by December 2022. The planned unit characteristics of Brickyard are provided in Table 4-16.

Table 4-16: Brickyard Solar PPA

	Brickyard PPA
Solar Output	
Total Output (MW)	200
In-Service	**2022**
Main Fuel	**Solar**

NIPSCO has entered into a 20-year PPA starting in 2023 with NextEra Energy Resources, LLC, in which NIPSCO will purchase the power directly from Green River, who will operate and maintain the facility. Green River, located in Breckenridge and Meade Counties, Kentucky, is expected to go into commercial operation by June 2023. The planned unit characteristics of Green River are provided in Table 4-17.

Table 4-17: Green River Solar PPA

	Green River PPA
Solar Output	
Total Output (MW)	200
In-Service	**2023**
Main Fuel	**Solar**

NIPSCO has entered into a 22-year PPA starting in 2023 with Arevon Energy, in which NIPSCO will purchase the power directly from Gibson, who will operate and maintain the facility.

Gibson, located in Gibson County, Indiana, is expected to go into commercial operation by June 2023. The planned unit characteristics of Gibson are provided in Table 4-18.

Table 4-18: Gibson Solar PPA

	Gibson PPA
Solar Output	
Total Output (MW)	280
In-Service	**2023**
Main Fuel	**Solar**

The Calvary Solar + Storage project, developed and constructed by NextEra Energy Resources, LLC, is located in White County, Indiana and is expected to go into commercial operation by December 2023. NIPSCO will enter into a joint venture and ownership agreement for the Cavalry project. The planned unit characteristics of Cavalry are provided in Table 4-19.

Table 4-19: Cavalry Solar + Storage JV

	Cavalry JV
Solar Output	
Total Output (MW)	200
Storage Output	
Total Output (MW)	60
Output Period (Hrs.)	3
Discharge Limits (Cycles/Yr.)	100
In-Service	**2023**
Main Fuel	**Solar + Storage**

The Dunns Bridge I Solar project, developed and constructed by NextEra Energy Resources, LLC, is located in Jasper County, Indiana and is expected to go into commercial operation by December 2022. NIPSCO will enter into a joint venture and ownership agreement for the Dunns Bridge I project. The planned unit characteristics of Dunns Bridge I are provided in Table 4-20.

Table 4-20: Dunns Bridge I Solar JV

	Dunns Bridge I JV
Solar Output	
Total Output (MW)	265
In-Service	**2022**
Main Fuel	**Solar**

The Dunns Bridge II Solar + Storage project, developed and constructed by NextEra Energy Resources, LLC, is located in Jasper County, Indiana and is expected to go into commercial operation by December 2023. NIPSCO will enter into a joint venture and ownership agreement for the Dunns Bridge II project. The planned unit characteristics of Dunns Bridge II are provided in Table 4-21.

Table 4-21: Dunns Bridge II Solar + Storage JV

	Dunns Bridge II JV
Solar Output	
Total Output (MW)	435
Storage Output	
Total Output (MW)	75
Output Period (Hrs.)	3
Discharge Limits (Cycles/Yr.)	100
In-Service	**2023**
Main Fuel	**Solar + Storage**

The Indiana Crossroads Solar project, developed and constructed by EDP Renewables North America, LLC, is located in White County, Indiana and is expected to go into commercial operation by December 2022. NIPSCO will enter into a joint venture and ownership agreement for the Indiana Crossroads Solar project. The planned unit characteristics of Indiana Crossroads Solar are provided in Table 4-22.

Table 4-22: Indiana Crossroads Solar JV

	Indiana Crossroads Solar JV
Solar Output	
Total Output (MW)	200
In-Service	**2022**
Main Fuel	**Solar**

The Elliott Solar project, developed and constructed by Arevon Energy, is located in Gibson County, Indiana and is expected to go into commercial operation by June 2023. NIPSCO will enter into a joint venture and ownership agreement for the Elliott project. The planned unit characteristics of Elliott are provided in Table 4-23.

Table 4-23: Elliott Solar JV

	Elliott JV
Solar Output	
Total Output (MW)	200
In-Service	**2023**
Main Fuel	**Solar**

The Fairbanks Solar project, developed and constructed by Invenergy Renewables Global, LLC, is located in Sullivan County, Indiana and is expected to go into commercial operation by December 2023. NIPSCO will enter into a joint venture and ownership agreement for the Fairbanks project. The planned unit characteristics of Fairbanks are provided in Table 4-24.

Table 4-24: Fairbanks Solar JV

	Fairbanks JV
Solar Output	
Total Output (MW)	250
In-Service	**2023**
Main Fuel	**Solar**

4.4 MISO Wholesale Electricity Market

MISO supplies an important element to NIPSCO's long term plans. MISO provides an enduring, relatively efficient market for marginal purchases and sales of electricity. In 2021, MISO has members from 15 states and one Canadian province with a generation capacity of 184,000 MW and 65,800 miles of high-voltage transmission. MISO manages one of the world's largest energy and operating markets that includes a Day-Ahead Market, Real-Time Market and Financial Transmission Rights Market.

4.4.1 Operations Management and Dispatch Implications

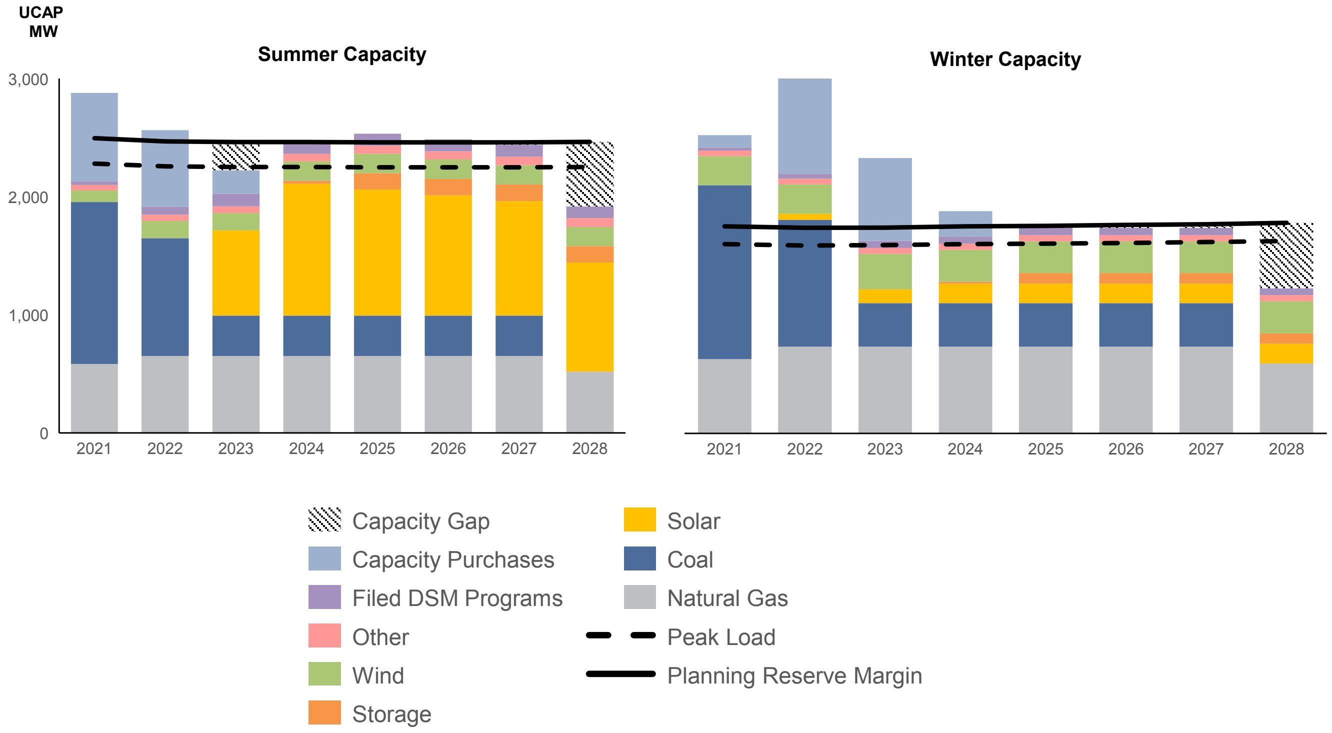
The future dispatch of NIPSCO's electric generation fleet will be a function of the cost to market price (or locational marginal price). Many factors will contribute to the dispatch of local units within NIPSCO's service territory. The delivered cost of coal and natural gas, transmission congestion, environmental considerations, and the overall generation mix within MISO may affect the level of future dispatch.

4.5 Resource Adequacy and Current Supply-Demand Balance

Consistent with the principles set out in Section 1, NIPSCO is committed to meet the energy needs of its customers with reliable, compliant, flexible, diverse, and affordable supply. As part of the Resource Adequacy planning process, NIPSCO utilizes the peak demand forecast coincident with the MISO peak demand to determine its capacity requirements. The MISO coincident peak is where NIPSCO demand is projected to be at the time the entire MISO system peaks, which is typically in the summer. The methodology for calculating the coincident peak demand is described in detail in Section 3.

In addition, as MISO market rules evolve, NIPSCO will need to track resource adequacy compliance in different ways. First, as MISO moves towards a seasonal capacity construct, winter reserve margin tracking will be required. Second, as renewable resources become a greater share of NIPSCO's portfolio, the seasonal capacity credit or ELCC will likely change over time and will need to be monitored. NIPSCO's assessment of its existing and planned resources against the future needs of its customers for both the summer and winter seasons is shown in Figure 4-3.

Figure 4-3: Resource Adequacy Assessment



4.6 Future Resource Options

As demonstrated in the 2018 IRP, the cost and operational estimates for future resource options modeled in the IRP should reflect the best available market data. In 2021, NIPSCO developed inputs for portfolio modeling based on real bid data that was received in three separate RFP events covering all sources.

4.6.1 Request for Proposal

NIPSCO worked with CRA's Auctions and Competitive Bidding practice during the spring and early summer of 2021 to conduct three separate RFP events covering all-sources. NIPSCO provided the RFP design summary to stakeholders in April 2021 and solicited feedback. During NIPSCO's second Public Advisory meeting, an overview of the RFP design, feedback received during the comment period, and timeline were presented to stakeholders. After incorporating stakeholder feedback, NIPSCO and CRA formally launched the RFP events on May 20, 2021 and closed the window for proposals on June 30, 2021.

The RFPs provided several guidelines to bidders, which are summarized below:

- Technology: The RFPs requested all solutions regardless of technology. Event 1: wind and wind paired with storage, Event 2: solar and solar paired with storage, and Event 3: thermal, stand-alone storage, emerging technologies, and other capacity resources.

- Size: The RFPs defined an overall size range of 400 - 650 MW for the portfolio, but placed no size restrictions on the potential bidders. The RFPs explicitly allowed for resources below 400 MW to offer their solution as a piece of a potential total need. The RFPs also encouraged larger resources to offer their solution for consideration.

- Ownership Arrangements: The RFPs were open to asset purchases (new or existing) and PPAs. However, they required that resources qualify as MISO internal generation (i.e., not pseudo-tied into MISO).

- Duration: The RFPs requested delivery beginning in 2024, 2025, and 2026, but indicated that alternative deliveries would be evaluated. The minimum contractual term and/or estimated useful life was requested to be five years.

- Deliverability: The RFPs required that bidders have physical deliverability utilizing Network Resource Integration Service to MISO LRZ6.

- Participants and Pre-Qualification: The RFPs required counterparties be credit-worthy to ensure an ability to fulfill future resource obligations.

Overall, the RFPs generated a large amount of bidder interest, with 182 total proposals received across a range of deal structures. Within those 182 proposals, NIPSCO received bids for 78 individual projects across five states with over 15 GW of ICAP represented.[34] Many of the proposals offered variations on pricing structure and term length, and the majority of the projects were in various stages of development. A summary of the total number of proposals received by technology type is shown in Figure 4-4.

Figure 4-4: Summary of Number of Proposals Received by Technology Type

Proposal Count by Technology and Transaction Structure

	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**
States Represented	**IL, IN, KY**	**IL, IN, KY, WI**	**IN, WI**	**IL, IN, KY**	**IL, IN, MO**	**IN**	**MISO**	

On a total MW basis, the 15 GW of ICAP offered represented just under 10 GW of UCAP, providing a sufficiently large set of candidate options for NIPSCO to evaluate for any capacity

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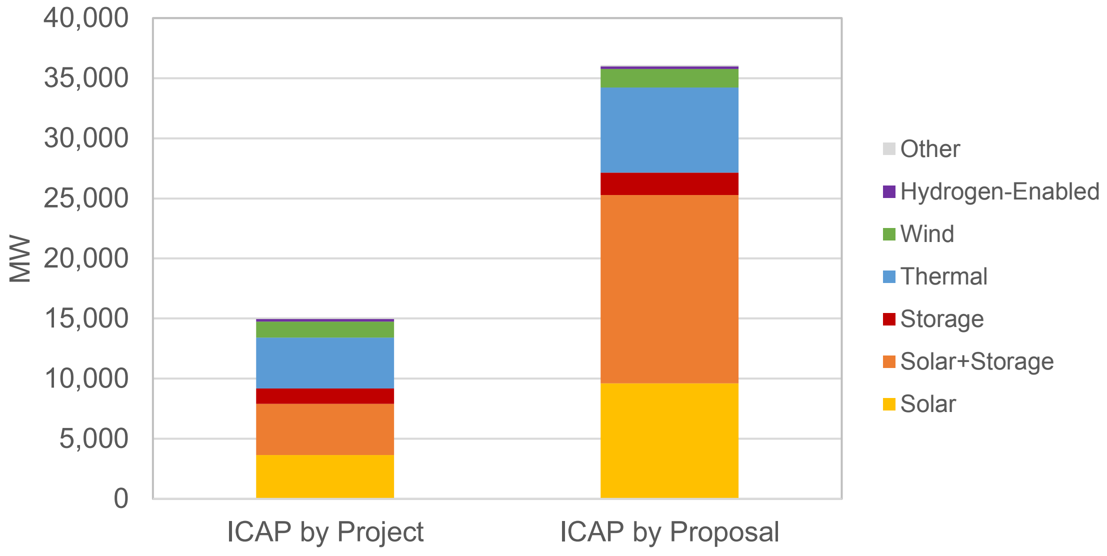
[34] CRA received a bid package from one bidder following the formal bid deadline. This bid included 3 proposals for 2 separate storage facility options.

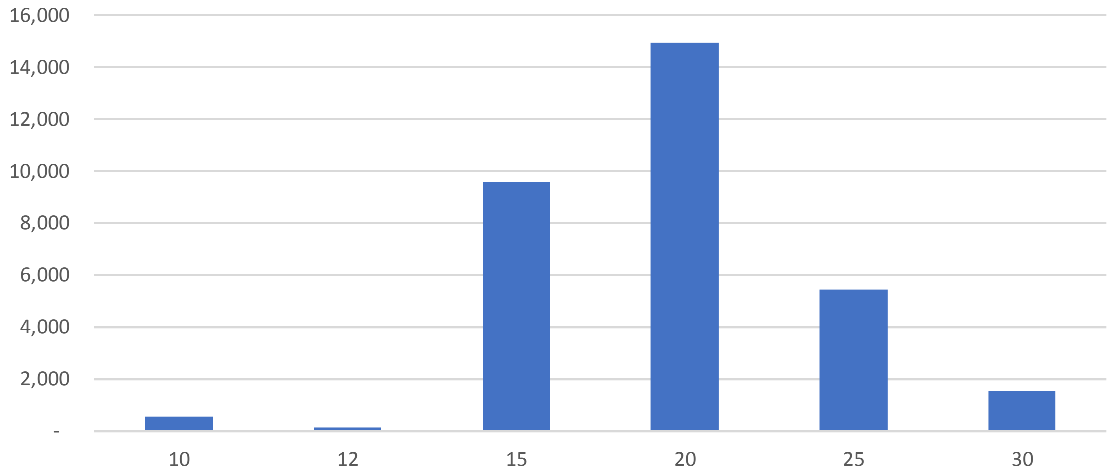
need during the RFP delivery window. Approximately 25% of UCAP was in the form of solar or solar paired with storage. Another 26% were natural gas-fired projects. However, a significant amount of wind and storage resources were also offered. Figure 4-5 shows a summary of total MW offered in response to the RFPs by type.

Figure 4-5: Total MW of Proposals Received by Technology



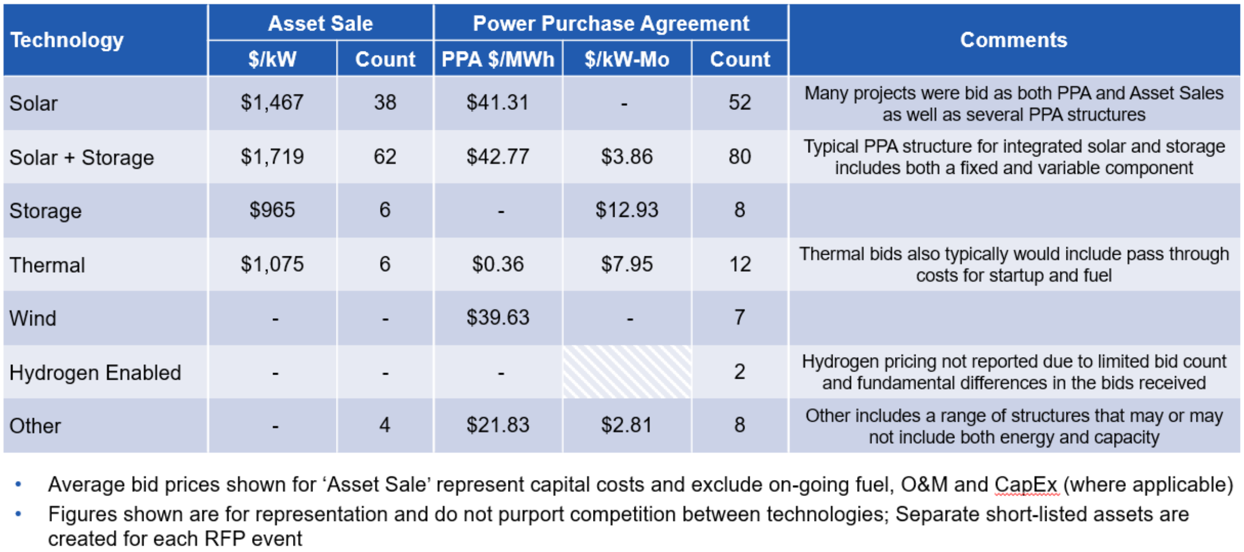
Most PPA offers were relatively long in duration, with the majority of proposals offering contracts for 15 year terms or longer. Several bidders offered shorter-term options, including a number that provided NIPSCO with options to select from multiple duration possibilities. Figure 4-6 provides a summary of the total ICAP MW offered by duration.

Figure 4-6: Summary of Proposals Received by PPA Duration (ICAP MW)



Most importantly, the responses to the RFPs provided transactable cost and price information to be incorporated in the IRP analysis. Overall, much of the cost information was relatively consistent with past NIPSCO RFP subject to market adjustments. This indicated that technology change and developer activity in a competitive process are dynamic forces that influence the costs of resource options for NIPSCO in the future. A summary of the various proposals by type and by price is provided in Figure 4-7. Note that due to confidentiality considerations, individual project prices cannot be disclosed.

Figure 4-7: Summary of Proposals by Price



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

4.6.2 Incorporation of the RFP Results into the IRP

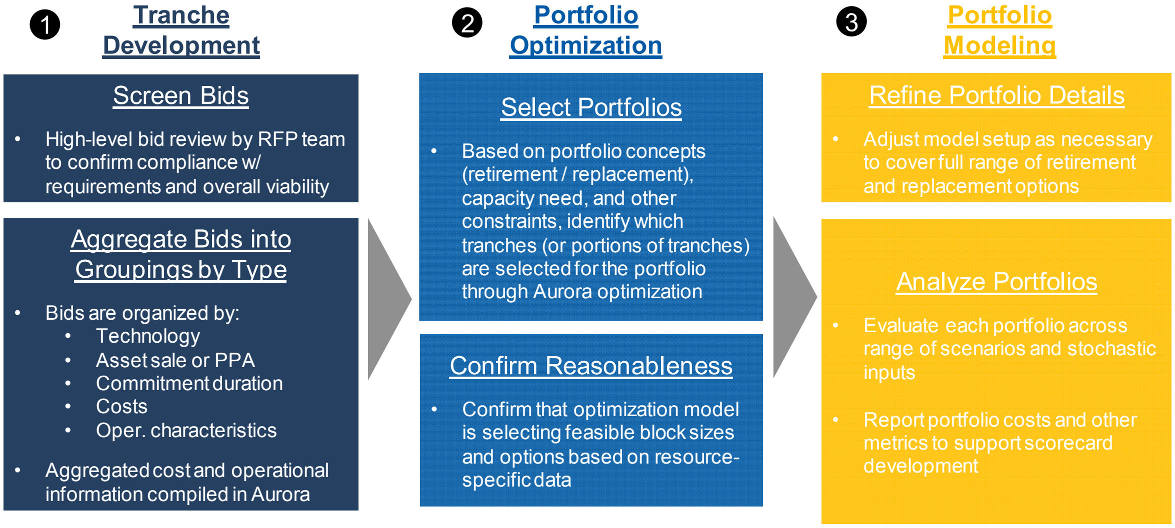
After gathering the bidder data from the RFP, the next step in the process was to organize the information and incorporate the results into the IRP analysis. NIPSCO and CRA developed a three-step process for RFP-IRP integration, which is outlined in Figure 4-8:

(1) Tranche Development: Screen bids for viability and organize the various bids into groupings or tranches according to technology, whether the bid offered a PPA or an asset acquisition, the bid’s commitment duration, and the bid’s costs and operational characteristics.

(2) Portfolio Optimization: Perform portfolio optimization analysis based on NIPSCO’s potential capacity need and other portfolio design constraints, confirming option viability based on feasible block sizes of tranche data from the RFPs.

(3) Portfolio Modeling: Develop and refine comprehensive portfolios with selected tranches from the portfolio optimization step and analyze them across the full set of scenarios and stochastic inputs.

Figure 4-8: Tranche Development and Assessment Process



❶ 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

❷ 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

4.6.3 Tranche Development

It was determined that a tranche approach would be most effective in aggregating the numerous data points from the RFPs into useable IRP information for three main reasons:

- The IRP is intended to select the best resource mix and future portfolio concept rather than select specific assets or projects. While the IRP analysis can now be highly informed by actionable data from the RFPs, it is only meant to develop a planning-level recommended resource strategy. NIPSCO determined that asset-specific selection would require an additional level of diligence, including assessment of development risk, evaluation of locational advantages or disadvantages for specific projects, and review of transmission system impacts, to be conducted outside of the standard IRP process.

- The IRP is a highly transparent and public process that requires sharing of major inputs with stakeholders and the public. 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 would improve the efficiency of setup and runtime.

When developing tranches, the CRA RFP team first organized resources by technology and then sorted them into categories according to whether they were offered as asset sales or PPAs. Projects were screened by the RFP team to determine conformity with bid requirements, and any non-conforming bids were eliminated. Duplicate projects that were offered multiple times under different structures were consolidated into the lowest-cost option to avoid double-counting.

Beyond the initial organization and screening, the bids were then arranged by commitment duration and finally costs and operational characteristics.

Ultimately, the tranche development process resulted in the production of 19 total tranches. These are summarized by resource type, size, term, and costs for PPA options in Figure 4-9 and for asset sale options in Figure 4-10. As a naming convention, tranches with a "P" represent PPA offers, while those with an "A" represent asset sale offers.

Figure 4-9: Summary of PPA RFP Tranches Used in Modeling

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.

Figure 4-10: Summary of Asset Sale RFP Tranches Used in Modeling

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.

4.6.4 Renewable Resource Tax Incentives and Tax Equity Partnership

Federal tax incentives are currently in place for renewable and paired renewable/storage resources. Resources are eligible for a PTC or an investment tax credit ITC. The PTC provides a credit of $25/ MWh[35] for all generation produced by the facility, and the ITC provides a credit as a portion of the total cost of the facility. It is generally advantageous for wind resources to take the PTC, due to their high capacity factors, and solar resources to take the ITC.

The tax incentives are currently in the midst of a phase-out, with the implications on IRP modeling assumptions of current law summarized in Figure 4-11. However, NIPSCO's scenario analysis incorporates different assumptions for extensions over time (see details in Section 8). In order to qualify for the credits, projects need to begin construction by a certain date and be put into service by a certain date. The start of construction deadline can be met as long as certain equipment purchases and development costs have been "safe harbored" by federal tax authorities.[36] The safe harbor for beginning of construction is investment of at least 5% of the total project cost on or before the specified date.

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[35] This value is indexed to inflation.

[36] Note that in May 2020 the Internal Revenue Service issued guidance to extend PTC and ITC deadlines in light of potential construction delays and supply chain disruptions associated with the COVID-19 pandemic. In-service date deadlines for 2020 and 2021 PTC projects have been extended by one year, while certain ITC spend schedules were extended by several months. Thus, a wind project safe harbored in 2017 with 80% of the total PTC could potentially still enter into service in 2022. However, given that all RFP wind bids were PPAs, NIPSCO assumes that all tax credit eligibility assumptions are embedded in PPA prices.

Figure 4-11: Current PTC (Wind) and ITC (Solar) Phase-Out Schedule

PTC - Wind

Last Year Project Can Be Placed in Service to Qualify for Continuity Safe Harbor	Credit Percentage
2022	60%
2023	60%
2024	60%
2025	60%
2026+	0%

ITC – Solar and Paired Solar + Storage

Last Year Project Can Be Placed in Service to Maximize ITC	ITC Percentage
2022	30%
2023	30%
2024	26%
2025	26%
2026+	10%

Given the importance of these tax incentives, NIPSCO performed a review of their impact on RFP bids prior to developing final costs for the portfolio modeling. The impact of the tax incentives needed to be treated differently for the different types of RFP bids:

- For PPAs, no adjustments were needed, since tax incentives flow to the developer and are theoretically reflected in PPA pricing; and
- For asset ownership, tax benefits flow to the utility and ultimately to the customer in rates, so adjustments needed to be made.

Without proper structuring, the Internal Revenue Code normalization rules stretch the flow of tax benefits to the customers over the regulatory life of the asset, but an alternative tax equity ownership structure can adjust the flow of benefits. In this arrangement, NIPSCO and a tax equity investor would form a partnership to develop a renewable energy project. The tax equity investor would invest to obtain a specified internal rate of return through the receipt of tax benefits in the form of depreciation, tax credits, and cash for a specified timeframe. NIPSCO would place its portion of the investment, which would be a fraction of the total cost, in rate base.

In order to properly account for the rate base reduction impact of partnering with a tax equity investor, CRA worked with NIPSCO's tax team to develop relevant financial models consistent with the analysis performed to support prior solar project applications to estimate the breakdown of capital expenditures. Assuming 26% ITC eligibility, the tax equity contribution is estimated to be around 31% of total capital costs once additional tax advantages like accelerated tax depreciation are taken into account, meaning NIPSCO would cover the remaining 69%. This level would decline with a lower ITC percentage.

In the scenarios where NIPSCO assumes the presence of a new storage ITC, similar tax equity capital cost contributions were modeled. Although specific tax equity partnership structures may vary for stand-alone storage resources relative to solar projects as a result of their lack of net energy production, similar reductions in cost would be expected, particularly under a future refundable or direct pay ITC structure in which NIPSCO would be able to directly assume the tax benefit. The expectations of tax equity partner contributions for renewable resources are summarized in Figure 4-12.

Figure 4-12: Capital Cost Adjustments due to Tax Equity Partnership

Resource Type	Tax Equity Capital Cost Contribution
Solar, Solar + Storage, or Stand-alone Storage with 26% ITC	31%
Solar, Solar + Storage, or Stand-alone Storage with 10% ITC	15%

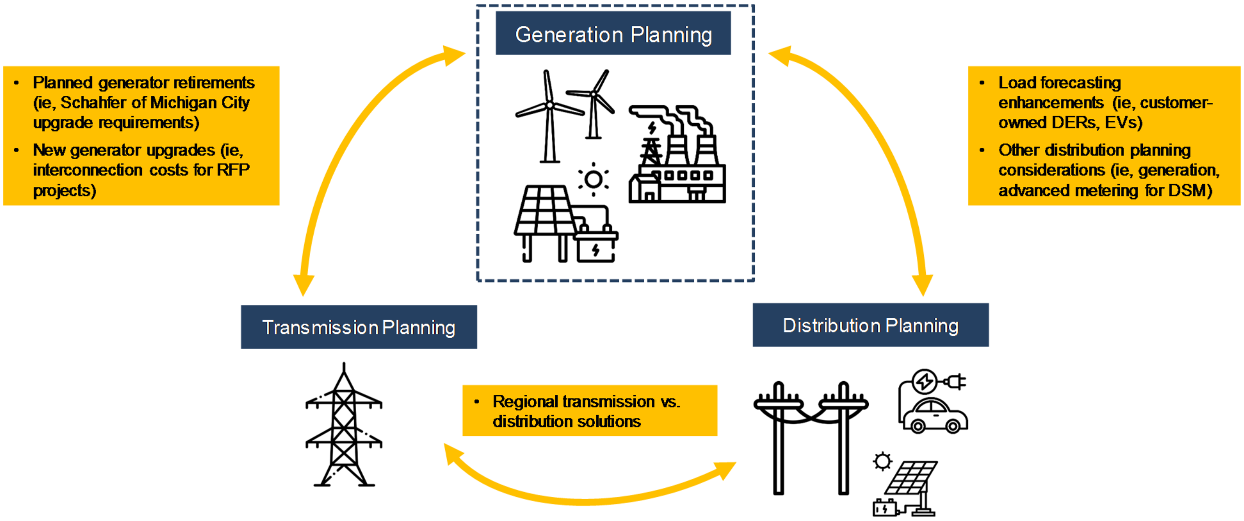
4.6.5 Sugar Creek Uprate Opportunity

NIPSCO operations identified a capital investment opportunity to increase the megawatt range available at the Sugar Creek generating station. The potential project would be an Advanced Gas Path program, which utilizes hot gas path technology to incorporate cooling and sealing enhancements and technology. The program would allow for higher firing temperatures resulting in additional gas turbine output and reduced gas turbine heat rate. The capital project has the potential to increase the MW range of Sugar Creek by 30-53MW for a capital investment range between $13M and $23M (Class 5 estimate). The timing of the project regardless of the level of MW increase would align with a planned outage in the fall of 2026 with the MW available starting in 2027. The 2021 IRP modeled the higher end of the MW range (53MW at an estimated capital investment of $23M). Further engineering due diligence and evaluation will be required prior to implementing such an uprate opportunity at Sugar Creek.

4.6.6 Distributed Energy Resources

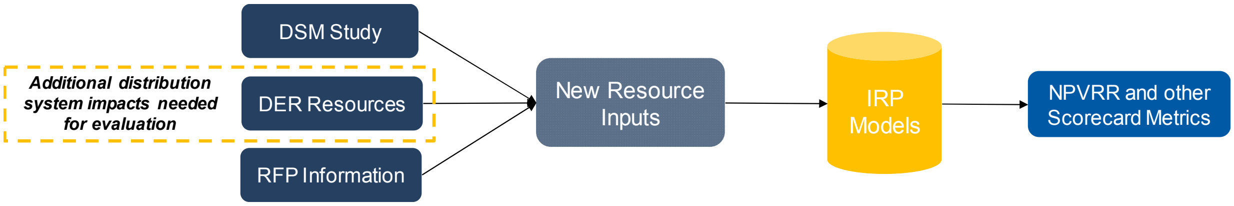
While NIPSCO's IRP has historically been centered on core generation planning questions, the interaction between generation and transmission and distribution planning has been an important consideration. For example, planned generation retirements include estimates of transmission system upgrade requirements, and the economic analysis of new generation additions includes transmission interconnection costs. In addition, NIPSCO's load forecasting process now includes more detail associated with customer-owned DER and electric vehicle penetration, and the DSM study incorporates DR programs reliant on advanced metering infrastructure. These interconnections across generation, transmission, and distribution planning are illustrated in Figure 4-13.

Figure 4-13: Integrated Planning Framework Illustration



In the 2021 IRP, market changes have motivated NIPSCO to explicitly assess DERs as supply-side candidate options. These changes include significant declines in technology costs for solar and storage, making distributed options cost-competitive, and regulatory developments like FERC Order 2222,[37] which will establish new market structures for DER integration. Therefore, in addition to the evaluation of DERs in NIPSCO's load forecast (*See* Section 3), the 2021 IRP is evaluating additional *supply-side* DER options, inclusive of distribution system impacts, against other resource options, as illustrated in Figure 4-14.

Figure 4-14: Process Illustration for DER Integration as a Supply-Side Resource



In order to fully evaluate DER resources, the IRP analysis must incorporate several distinctions between traditional utility-scale options and those sited at the distribution level. There are differences associated with resource costs, impacts on the T&D system, likely storage

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[37] 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 has ordered that "regional grid operators must revise their tariffs to establish DERs as a category of market participant." Although compliance filings were originally due in July 2021, MISO has requested a nine-month extension and has established a cross-functional task force to study the issue.

operational parameters, peak credit accounting, and ancillary services eligibility, as illustrated in Figure 4-15.

Figure 4-15: Distinctions between Utility-Scale and DER Resource Options

	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

Specific to the potential to defer distribution system investments, NIPSCO's distribution planning team 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. As part of this process, the team identified 21 locations on the system that will require capacity improvement investments in the next five years and assessed the following for each location, ultimately identifying eight locations with generation addition opportunities[38]:

- Estimated distribution upgrade project cost at various locations on the system;
- Potential battery storage and paired solar plus storage additions that could defer the distribution upgrade, with consideration given for the availability of nearby land to site capacity; and
- 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 additions, and estimated investment deferral, a NPV of deferred investment on a $/kW basis was developed for each location. NIPSCO and CRA then categorized the projects identified by the distribution planning team into High, Medium, and Low bundles of deferred distribution investment costs to allow for resource selection and economic portfolio analysis, as illustrated in Figure 4-16.

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

Figure 4-16: DER Bundle Characteristics for IRP Modeling

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**

From a portfolio modeling perspective, each of these resource options was made available for selection and analysis in the portfolio assessment phase.[39] Given uncertainty in future opportunities on the distribution system and in the regulatory landscape, only near-term opportunities were evaluated. Within the core IRP modeling, a cost premium relative to larger-scale projects from the RFP was assumed,[40] and the NPV of the deferred distribution investment was subtracted from the capital cost of the resource options.

4.6.7 Emerging Technologies

4.6.7.1 Green Hydrogen

The 2021 IRP contemplates multiple deep decarbonization scenarios (*See* Section 8), and NIPSCO recognizes that new, emerging technologies will be needed to achieve emission reduction levels that aim towards a net zero target. One such emerging technology is hydrogen, which may be well-positioned to help decarbonize certain sectors of the economy, including the electricity sector, over the long-term.

The concept of using hydrogen as a source of clean fuel or as a long-duration storage solution has been present in the energy industry for some time. When burned for fuel or consumed in a fuel cell, pure hydrogen emits zero greenhouse gas emissions. In addition, once produced, hydrogen may be stored in existing natural gas infrastructure until it is ready to be burned for fuel in a gas turbine, distributed for residential and commercial heating, or sold to an industrial customer. Due to these characteristics, hydrogen has the potential to be a dispatchable, versatile, zero-emitting alternative to fossil fuels or intermittent resources.

Many obstacles exist to achieving cost-effective, widespread production and consumption of hydrogen in the near term (including cost, lack of availability of transportation and distribution infrastructure, and regulatory uncertainty). However, with sufficiently high carbon emissions prices or natural gas commodity prices, as well as potential technological advancement and federal subsidies for hydrogen, it may become an attractive and versatile fuel option in the long term.

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[39] It should be emphasized that the IRP is used 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.

[40] A cost premium of 20% to utility-scale resource options was incorporated in NIPSCO's analysis, reflective of public sources, such as NREL's Annual Technology Baseline: https://atb.nrel.gov/electricity/2021/data

For the 2021 IRP, NIPSCO considered hydrogen as a possible resource option and developed cost inputs based on RFP responses (through which multiple bidders offered solutions that contemplated the production or use of hydrogen fuel) and independent research and analysis. The research developed a quantitative framework and set of cost assumptions to estimate potential LCOH trajectories to proxy for the expected future market price of hydrogen. NIPSCO then modeled the resulting hydrogen production costs in Aurora as a fuel option for hydrogen-enabled gas turbines and analyzed its dispatch and cost performance in the broader market.

The remainder of this section provides additional context around hydrogen production, a detailed discussion of NIPSCO's LCOH framework and input assumptions, and an analysis of NIPSCO's hydrogen production cost results.

Background on Hydrogen

Hydrogen Production Technology

Hydrogen has the potential to store and deliver zero-emitting energy. However, hydrogen does not typically exist in an isolated form in nature and must be produced from compounds containing it. Today, hydrogen is most commonly produced from thermal processes such as SMR of natural gas, producing what is referred to as "grey" hydrogen (or "blue" hydrogen, if a carbon capture and storage facility is further used to capture and store the carbon emissions from the SMR process). As electrolyzer and renewable prices become more competitive, however, and as existing or expected environmental regulations and targets continue to decrease the use of fossil fuels, renewable energy may instead be used to power the process of water electrolysis to produce "green" or renewable hydrogen. Green hydrogen is made by using zero-emissions electricity to power an electrolyzer, which splits water into hydrogen and oxygen through the electrolysis process, while producing no greenhouse gas emissions.

Green hydrogen is currently more expensive than grey or blue hydrogen, primarily due to low economies of scale, and it is not produced commercially. However, the potential for federal tax incentives for hydrogen production, expectations for significant improvements in system cost components, and continued market evolution toward increased renewable penetration and carbon regulation may make green hydrogen production more attractive in the long term. NIPSCO received multiple bids associated with hydrogen pilot projects or hydrogen enablement in its 2021 RFP, demonstrating that developers are currently actively exploring hydrogen opportunities and validating NIPSCO's effort to assess long-term hydrogen economics within this IRP.

Hydrogen Production Constructs

While green hydrogen is not currently produced at a commercial scale, a "hydrogen economy" could one day develop in one of many forms, each of which would suggest a different modeling approach within a utility resource plan. While these frameworks are speculative, they are useful in helping to define a quantitative approach for analyzing the long-term viability of green hydrogen in the 2021 IRP. NIPSCO considered several hypothetical hydrogen deployment models, as summarized in Figure 4-17.

Figure 4-17 Possible Hydrogen Production Configurations

Business Model	Electrolyzer Ownership	Electricity Ownership	Gas Plant Ownership
"Islanded" NIPSCO Ownership Model	**NIPSCO** *Capex + fixed costs for electrolyzer, water, storage*	**NIPSCO** *Capex + fixed costs or PPA for renewable electricity*	**NIPSCO** *Gas plant retrofit costs*
		NIPSCO + Market	
		Market *Grid electricity prices*	
"Economy" Purchase H2 for a NIPSCO-owned H2-enabled gas plant	**Third Party** *Modeled as a PPA cost for green H2 (inclusive of all production costs)*	**Third Party**	
"Economy" Purchase green H2-fueled energy through a PPA			**Third Party**

In the near term, the most likely hydrogen "business model" is one in which the utility owns or contracts with all components of the hydrogen production process, including the electrolyzer and electricity sources to produce hydrogen, then consumes the produced hydrogen at its own hydrogen-enabled gas plants to produce electricity during optimal hours. This approach, sometimes referred to as an "islanded" or "closed-system" approach, would be the most appropriate framework in the absence of a functional, widespread hydrogen economy and is consistent with the type of bids offered in response to NIPSCO's RFP. The hydrogen production cost from the "islanded" approach would include the amortized fixed costs to install and operate the electrolyzer, hydrogen storage facilities, and specific renewable projects used to power the electrolysis process, as well as the variable costs for any grid-sourced electricity and water. Additional costs to transport the hydrogen to the gas plant and to retrofit and operate the plant would also be separate, post-production costs to the utility.

Alternatively, if a functional hydrogen economy is assumed to develop over time, one could extend the "islanded" approach to assume that the utility producer of hydrogen can also optimally sell hydrogen to customers in a broader hydrogen market. For modeling purposes, one could easily imagine the opposite situation, in which the utility simply purchases hydrogen from the market or contracts with third-party green hydrogen producers at a negotiated commodity price to fuel a gas plant. This approach assumes that a suitable transmission and distribution infrastructure builds out over the long term in the hydrogen economy and aims to capture the economics within the assumed hydrogen market as a whole, rather than just the utility-specific power generation assets that would "feed" the electrolyzer. The assumed market commodity price of hydrogen would be an all-in cost, including the fixed and variable costs of production. NIPSCO used the latter framework as the basis for its long-term economic analysis.

Hydrogen Modeling Input Assumptions Development

Hydrogen Production Cost Components

To transparently build up a long-term price trajectory for green hydrogen production, NIPSCO developed a set of input assumptions for each of the cost components. Production costs were assumed to include electrolyzer capital and fixed O&M costs, electricity, and water. All data was drawn from public sources and was adjusted for MISO LRZ 6-specific hydrogen production costs based on local renewable capacity factors and power prices.

Electrolyzer CapEx

Electrolyzer costs are expected to drop significantly over the next twenty years, primarily due to economies of scale and competition from global manufacturers. It is projected that economies of scale will play a noticeable role in lowering overall balance of plant costs, where cost savings between 15-45% can be achieved through increasing annual electrolyzer production. Furthermore, larger electrolyzer systems tend to cost less than smaller systems on a $/kW basis. This $/kW cost difference can range from 33-56%, dependent on future production levels.[41] To develop long-term cost assumptions for electrolyzer capital costs, CRA and NIPSCO conducted a literature review of historical and forecast electrolyzer CapEx estimates. Most data were pulled from a database published by Glenk et al. (2019),[42] which included only original sources of data found in journal articles, industry data, publicly available reports, and interviews with industry sources, and excluded literature that did not provide clear cost estimates or methodologies for producing cost estimates. CRA then developed a potential trajectory for electrolyzer capital costs that achieved long-term estimates recently published by the IEA,[43] BNEF,[44] and Bank of America-Merrill Lynch. The cost estimates for the PEM electrolyzer technology are summarized in Figure 4-18.[45]

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[41] Ahmad Mayyas et. al, "Manufacturing Cost Analysis for Proton Exchange Membrane Water Electrolyzers" *National Renewable Energy Laboratory* 2019. https://www.nrel.gov/docs/fy19osti/72740.pdf

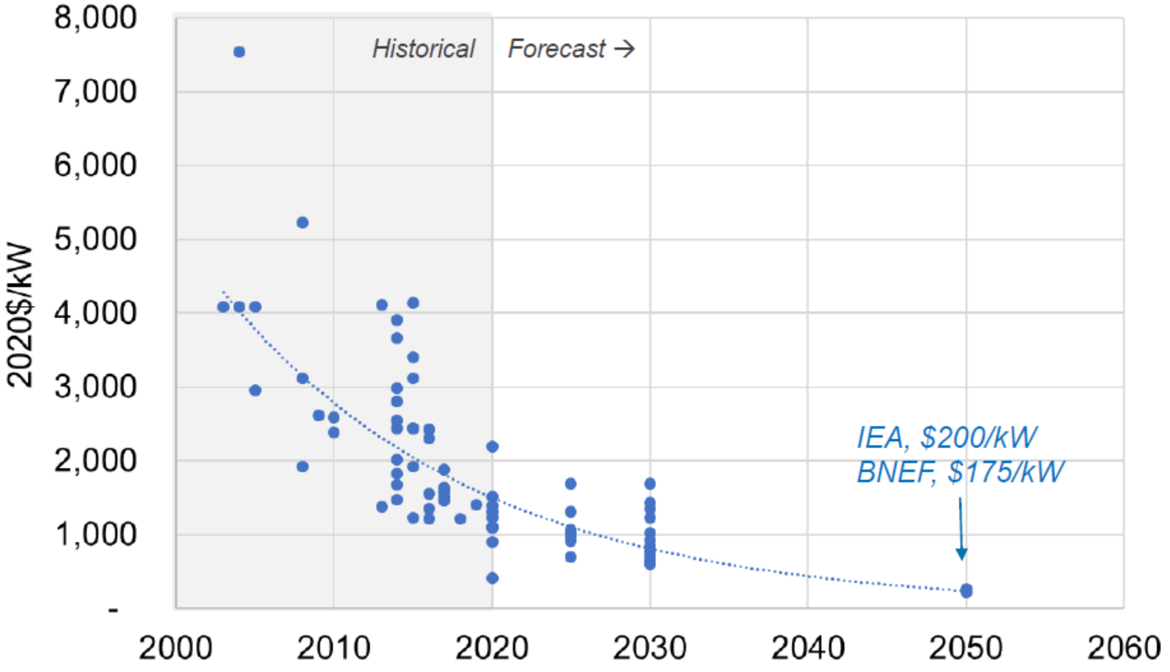
[42] Gunther Glenk and Stefan Reichelstein. "Economics of converting renewable power to hydrogen." In: Nature Energy 4.3 (2019), pp.216-222.

[43] IEA. The Future of Hydrogen. 2019. https://www.iea.org/reports/the-future-of-hydrogen

[44] BNEF. Hydrogen: The Economics of Production from Renewables. 2019.

[45] PEM systems are capable of operating at high pressures, obviating the need for compression.

Figure 4-18 Extrapolated Electrolyzer CapEx Trajectory



As the figure shows, PEM electrolyzer CapEx costs have declined significantly over the last decade. Over the next several decades, cost improvements may be driven by economies of scale of individual electrolyzers, technology advancements, and growth and competition in global electrolyzer manufacturing to achieve capital costs in the $175-200/kW range.

Electrolyzer Fixed O&M

Based on industry research, electrolyzer fixed O&M costs have been typically assumed at 1.5% to 3% of the original electrolyzer CapEx. Electrolyzer fixed O&M was assumed to be 2% of the original capex for NIPSCO's 2021 IRP analysis.

Variable Cost of Water

Based on industry research, NIPSCO assumed variable water costs at $0.08/kg of hydrogen in 2020$.

Electrolyzer Conversion Efficiency

A 100% efficient electrolyzer would be able to produce 0.03 kg hydrogen per kWh. This "ideal" efficiency is scaled down by a conversion efficiency parameter, which varies by electrolyzer type. For this analysis, conversion efficiencies were based on IEA estimates for modest improvements over time from 60% in 2020 to 74% in 2050 for a PEM electrolyzer.[46]

Storage

The small size and density of hydrogen result in challenges associated with storing the fuel when compared to natural gas. In the gaseous state, hydrogen can be stored in pressurized containers in small volumes.[47] Geological formations such as rock caverns, depleted gas fields, and salt caverns have also been utilized in the United States to store gaseous hydrogen.[48] NIPSCO's service territory has multiple gas storage sites that could be utilized for gaseous hydrogen storage.[49] However, the use of these fields for gaseous hydrogen storage would need to be assessed on a case-by-case basis due to the varying nature of such geological formations.

Liquid hydrogen is another option for hydrogen storage. However, the cost of liquification is often more expensive than the cost of hydrogen itself, ranging from \$2.75 to \$4.57/kg.[50,51] Conversion and storage of hydrogen as ammonia is also feasible, but currently only makes sense if the ultimate end-product is ammonia.[52]

Given the variable nature of storage prices based upon volume, geological availability, and different sector demands, and the potential for hydrogen storage costs to be covered by existing infrastructure within NIPSCO's service territory, storage pricing has been omitted from the IRP cost estimates.

Variable Cost of Electricity

As explained previously, green hydrogen production requires a source of renewable electricity to power the electrolysis process. The cost of electricity is likely to be the most significant driver of hydrogen production costs, but can be minimized by co-locating renewables with hydrogen production facilities, by using renewable energy that might otherwise be curtailed, and by using an optimal mix of solar, wind, storage, and/or market purchases and sales to achieve higher electrolyzer utilization and achieve the best possible economics for the system.

NIPSCO focused on market power prices, renewable capital cost trajectories, and expected federal tax credits developed for the EWD and AER scenarios (*See* Section 8), which are the two most likely scenarios that might enable economic hydrogen dispatch. For renewable and storage technology CapEx estimates, NIPSCO used capital cost data from NIPSCO's recent RFPs in the near term and data from the NREL Annual Technology Baseline 2020 over the long term, with adjustments for expected technology advancements and federal tax credits that aligned with the

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[46] IEA. The Future of Hydrogen. 2019. https://www.iea.org/reports/the-future-of-hydrogen

[47] BNEF. Hydrogen Economy Outlook. 2020.

[48] IEA. The Future of Hydrogen. 2019. https://www.iea.org/reports/the-future-of-hydrogen

[49] "PDMS Oil and Gas Map." Indiana Geological Survery. Indiana University Bloomington. Accessed August 31, 2021. https://igws.indiana.edu/PDMS/Map/.

[50] Elizabeth Connelly et. al. "Current Status of Hydrogen Liquefaction Costs" *U.S. Department of Energy* 2019.

[51] BNEF. Hydrogen Economy Outlook. 2020.

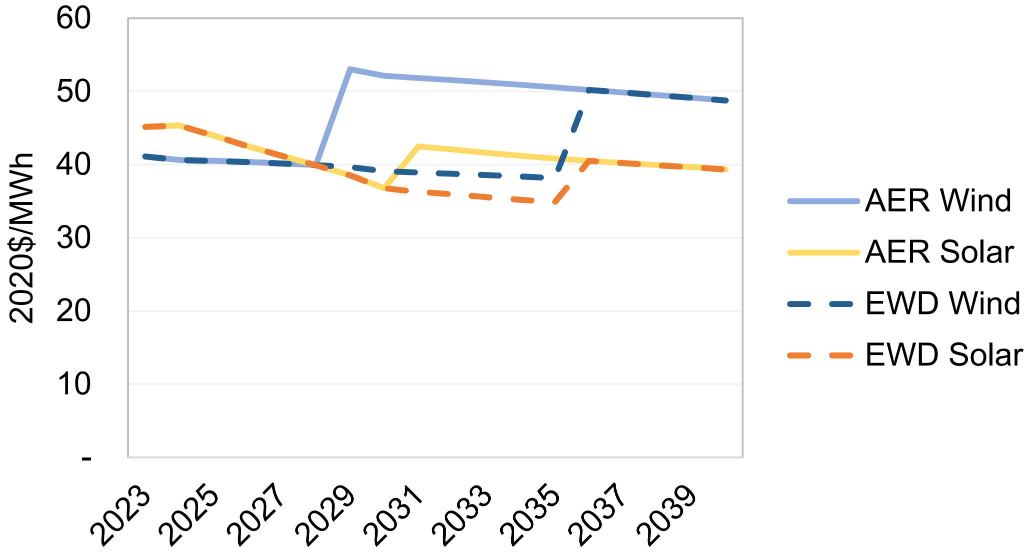
[52] IEA. The Future of Hydrogen. 2019. https://www.iea.org/reports/the-future-of-hydrogen

IRP scenario narratives (*See* Section 8). For wholesale market power prices, NIPSCO used the EWD and AER scenario power price trajectories developed for the 2021 IRP scenario analysis.[53]

To develop long-term cost of electricity assumptions, NIPSCO determined the LCOE of various configurations of renewable generation, including standalone solar; standalone wind; market electricity purchases; and optimized hybrid combinations of solar, wind, 4-hour battery storage, and market purchases and/or sales.

For the standalone renewable configurations, NIPSCO determined the LCOE of the renewables including amortized capital and fixed operating costs and congestion cost estimates. These estimates are shown in Figure 4-19: S

Figure 4-19: Standalone Wind and Solar LCOE by IRP Scenario



In addition to standalone renewable LCOEs, NIPSCO also considered hybrid configurations to address the possibility that better economics and higher electrolyzer utilization targets could be achieved by combining the hourly production profiles of wind and solar, incorporating battery storage, and/or optimally purchasing electricity from the wholesale power market during the lowest-priced hours.[54] To analyze the economics of such a configuration, NIPSCO developed an optimization tool to determine the least-cost capacity mix of solar, wind, battery storage, and hourly market purchases and sales when assuming a fixed "target" electrolyzer

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[53] Section 8 of this report summarizes NIPSCO's MISO market scenario assumptions and modeling outcomes. As noted in that section, new technologies such as hydrogen are likely needed to achieve deep decarbonization. However, the two scenarios have very different power price outcomes based on different assumptions regarding carbon emission regulation.

[54] Without hybrid configurations, devoted standalone solar or standalone wind resources would need to be significantly "overbuilt" above the size of the electrolyzer. Standalone wind would need to be overbuilt to approximately 3 times the size of the electrolyzer to achieve a utilization of 80 percent. The maximum achievable electrolyzer utilization with standalone solar is only 55 percent due to zero nighttime energy from solar plants, and would require overbuilding solar to at least 800 times the size of the electrolyzer. Hourly solar and wind capacity factor data for this analysis was based on data from NIPSCO's planned standalone solar and wind resources.

utilization of 80 percent. The optimization model took as inputs hourly solar and wind generation, hourly battery storage dispatch, capital and fixed costs of the renewables, and hourly wholesale market prices. The optimization model then aimed to minimize capital and fixed costs of the wind, solar, and battery components plus the costs of any market purchases while achieving at least an 80 percent electrolyzer utilization.[55]

Based on the optimization analysis, NIPSCO determined that the least-cost source of electricity to power the electrolyzer and achieve an 80 percent utilization in the EWD case was to purchase all power from the market during optimal hours. In the AER case, the least-cost source of electricity was a mix of optimal hourly market power purchases and solar generation.

For the resulting optimized hybrid renewable configurations, NIPSCO then determined a final hybrid LCOE that included the LCOE of the preferred renewable portfolio and any cost of purchasing wholesale power during optimal hours.

4.6.7.2 Developing Hydrogen Costs for the 2021 IRP

Several bidders in the 2021 RFP discussed the topic of hydrogen production and consumption in electric generating resources, and multiple bidders offered projects associated with either electrolysis-based hydrogen production (in the form of a small-scale pilot program) or enablement of natural gas turbines to burn the fuel. Such bidder interest confirmed the viability of the technology and prompted NIPSCO to develop hydrogen cost projections over time for use in the IRP portfolio modeling. In order to develop cost projections, NIPSCO (i) used bidder-provided information for near-term cost benchmarking associated with *both* hydrogen production and the additional costs required to enable the fuel to be consumed in natural gas turbines and (ii) developed long-term LCOH trajectories based on the information and inputs described above.

Levelized Cost of Hydrogen over Time

NIPSCO's LCOH projections were based on assumptions for the levelized cost of an electrolyzer, the variable costs associated with water, and the LCOE of renewables (potentially combined with optimal hourly net market purchases as discussed above). For IRP portfolio modeling purposes, the hydrogen cost was then included as the fuel component of the dispatch cost for a hydrogen-enabled gas plant, allowing the resource type to compete with other options, including as a fuel alternative (with different fuel and emissions costs) versus natural gas.

Given significant uncertainty regarding the future costs of electrolysis and electricity, support for hydrogen production in the form of a federal subsidy program might be required to achieve cost-competitiveness and achieve significant decarbonization, particularly in the AER and EWD market scenarios. Although at the time of the development of major input assumptions for this IRP no hydrogen subsidy legislation had passed the U.S. Congress, several proposals were under consideration, and NIPSCO has incorporated an assumed $0.50/kg subsidy sensitivity in the AER and EWD scenarios for IRP portfolio modeling.

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[55] An alternative approach to the one described here could be to instead optimize the size of the electrolyzer to achieve a sufficiently high utilization to achieve the best possible economics.

NIPSCO's long-term LCOH trajectories, assuming significant continued improvements in electrolyzer capital costs and optimized electricity costs from a hybrid combination of renewable resources and market purchases, are shown in Figure 4-20 for the EWD case and Figure 4-21 for the AER Case. The graphics show costs with and without an assumed $0.50/kg subsidy, which could be in the form of a specific federal policy or other grant or outside investment.

Figure 4-20: Levelized Cost of Hydrogen (2020$/kg) (EWD)

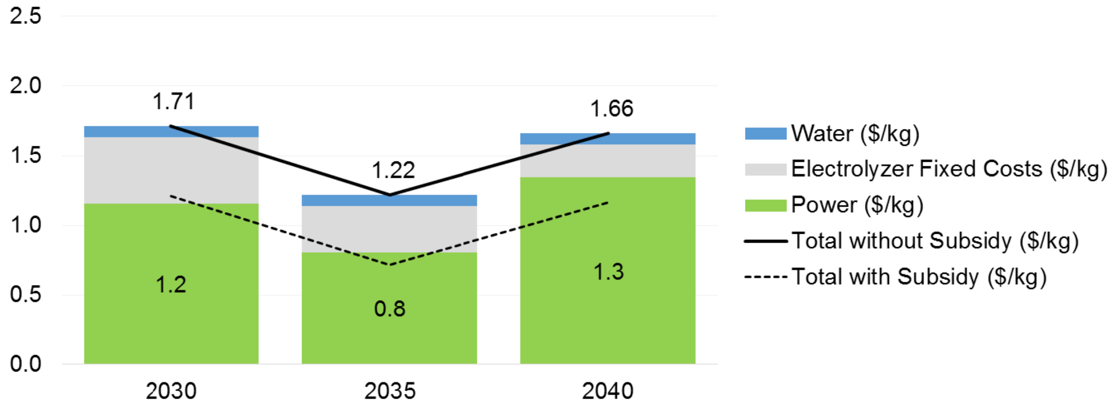
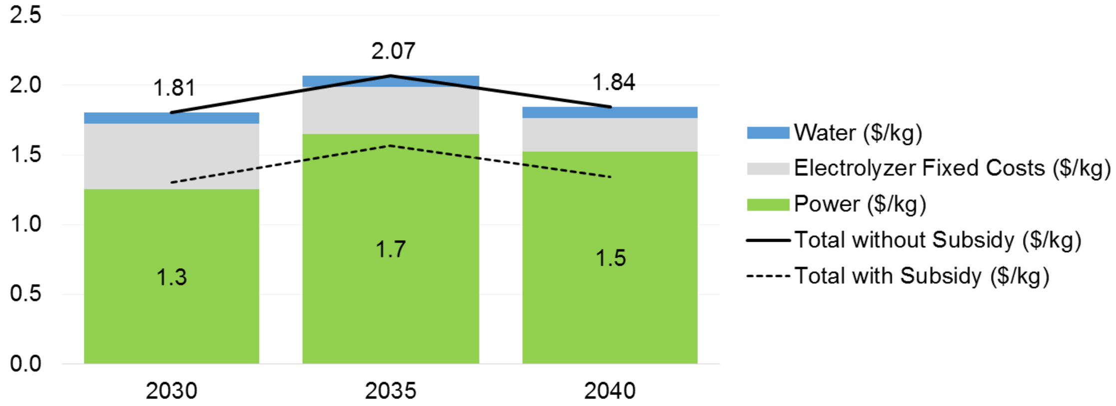


Figure 4-21: Levelized Cost of Hydrogen (2020$/kg) (AER)



As seen in these graphics, electricity costs are expected to make up the majority of long-term hydrogen production costs. EWD electricity costs were projected to be lower through 2035 due to the 10-year investment tax credit and production tax credit extension assumption (*See* Section 8), then to jump up by 2040 when the tax credits were assumed to phase out. AER electricity costs were projected to decline modestly from 2035 to 2040, as the optimized portfolio of renewables/storage was assumed to buy and sell in the MISO power market at times and take advantage of large price swings (selling at high prices and buying at low prices), while maintaining an 80% CF for the electrolyzer. Although the assumed electricity costs are based on fundamental forward scenario modeling, they are reasonably grounded in assumptions around market evolution and technology advancements associated with decarbonizing futures and produce indicative hydrogen commodity prices for the long term.

A summary of the final near-term RFP and long-term hydrogen costs that were included in the IRP analysis are summarized in Figure 4-22.

Figure 4-22: Summary of Near-Term and Long-Term Hydrogen Costs for 2021 IRP

	Hydrogen P1 H2-Enabled Peaker		Hydrogen P2 + Sugar Creek	
	Near-term	Long-term	Near-term	Long-term
COD Year	2025 (5% H2-Enabled)	2032 (100% H2-Enabled)	2025 (5% H2-Enabled)	2032 (100% H2-Enabled)
Electrolyzer Fixed Costs (2020$/kg)	$1.78 (CRA Trajectory)	$0.47 (CRA Trajectory)	$2.30 (RFP)	$0.47 (CRA Trajectory)
Power (2020$/kg)	Grid Only (Low-Priced Hours)	Optimal Hybrid	Grid Only (Low-Priced Hours)	Optimal Hybrid
Water (2020$/kg)	$0.08			
Possible Subsidy (2020$/kg)	-$0.50			
Additional Portfolio Costs	-	Plant Retrofit Cost (30% CT Capital and FOM)	-	Plant Retrofit Cost (30% of CC Capital and FOM)

Hydrogen Blending in Gas Turbines

To consume hydrogen fuel in natural gas turbines, certain modifications need to be made to the turbines themselves, as well as other infrastructure such as pipelines and emission controls. Multiple bidders to NIPSCO's 2021 RFP either outlined such modifications or proposed specific costs to allow small amounts of hydrogen to be burned in generating facilities. The magnitude of the cost impact is dependent on the amount of hydrogen being consumed in the facility relative to the amount of natural gas (i.e. the blending percentage). While only relatively low hydrogen blends (5-20%) have been used in gas turbine technologies today, a plant can be upgraded to accommodate higher hydrogen blend concentrations as emissions restrictions become more stringent and/or as the hydrogen industry expands. Key operational considerations include:

- Combustor configuration
- Safety and flammability controls
- NO_x controls
- Pipeline upgrades
- On-site hydrogen storage
- Maintenance changes

For purposes of the IRP modeling, NIPSCO used bidder data to develop near-term cost impacts for hydrogen blending at low levels (5%) and public sources and manufacturer data to project the costs required to achieve very high levels of blending (including up to 100% hydrogen consumption) over the long-term. Based on bidder data, a CCGT or combustion turbine CT dispatching on a blend of 5% hydrogen are estimated to have between a zero and 10 percent cost premium for capital and fixed operating costs over a fully natural gas-fired combustion turbine.[56] In the longer-term, thermal plants retrofitted to accommodate pure (100%) hydrogen were assumed to require an additional 30 percent of the original plant capex and operating costs.

Value Stacking Hydrogen Electrolysis

Beyond the value of producing hydrogen fuel for use in thermal generating resources, the use of electrolyzer load as a potential ancillary service in the real time markets is an avenue of research that is currently being explored. Currently, electrolyzers as a grid management tool have been proven on a kW scale to have response times similar to battery systems.[57] While feasibility will still need to be tested on a MW-scale, there may be potential for a fleet of electrolyzers to serve as ancillary load in real time to be ramped up and down in order to provide regulation service and maintain grid frequency.

4.6.7.3 Long-Term Uncertainties with Hydrogen

As an emerging technology, NIPSCO recognizes that the landscape for hydrogen use in the power sector is subject to significant change over the long-term, particularly associated with technology change, federal policy initiatives, and investment in the sector from developers and public authorities. NIPSCO is committed to maintaining flexibility in its future resource decisions and expects to continue tracking the following uncertainties associated with hydrogen deployment:

- Technology advancement associated with electrolyzer capital and operating costs;
- Federal incentives that may develop, including direct subsidies or hydrogen production tax credits that vary based on the source of the electricity used in production;
- Developments in hydrogen transmission, distribution, and storage infrastructure and how they interact with current natural gas infrastructure;
- MISO market dynamics, including the potential for hydrogen production opportunities to develop due to renewable curtailment risk (which could otherwise be diverted to hydrogen production) or local congestion that drives electricity prices very low near certain renewable projects;

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[56] While certain RFP bidders indicated that no modifications to existing generating resources would be required to burn low hydrogen percentage blends, others suggested a small cost would be required to address certain on-site infrastructure requirements.

[57] J. Eichman et. al. “Novel Electrolyzer Applications: Providing More Than Just Hydrogen” *NREL* 2014

- Broader carbon emission reduction policies, which could put a price on carbon or incentivize the use of clean energy sources such as hydrogen; and

- The price of natural gas, which remains a competing fuel for hydrogen.

4.6.8 Carbon Capture, Utilization, and Storage

Another emerging technology that may be positioned to support the decarbonization of the electricity sector is CCUS. Broadly, this technology refers to processes that (i) capture and separate CO2 directly from a fossil fuel (such as from coal in an IGCC process) or the flue gas of an electric power plant post-combustion or other point-source emission stream of CO2; (ii) purify, compress, and transport the CO2; and (iii) utilize (such as in an EOR process) or sequester the CO2 underground in saline reservoirs or unused coal seams.

NIPSCO's RFP did not generate any bids related to CCUS, so specific portfolio modeling has not been performed for this technology. However, the MISO market scenario analysis incorporated CCUS technology as a plausible generation resource option under scenarios with significant carbon reduction trajectories (*See* Section 8), and it remains a potentially feasible option for the Sugar Creek combined cycle over the long-term. As a result, NIPSCO plans to continue to assess CCUS technology in the future, particularly as a long-term means of achieving a net zero emission profile. The remainder of this section provides an overview of the technology, potential cost ranges, and federal policy support considerations.

4.6.8.1 CCUS Technology Overview

CCUS is an emissions reduction technology that can be applied to electricity generation processes, such as fossil fuel combustion or gasification. To minimize the costs of transportation and sequestration, a relatively pure stream of CO2 must first be separated from a mixture of gases, such as flue gas or synthetic gas or "syngas" (in the case of an IGCC process). There are multiple technologies available to capture CO2, although the most common application involves chemical absorption via ionic liquid solvent, such as compounds of ethanolamines.[58] In this example, CO2 would be absorbed by the solvent and regenerated as a relatively pure stream at a higher temperature. As a result, a heat source is required and may be provided from redirecting steam from electric generating turbines or by burning natural gas.

The CO2 is then compressed to a high-pressure stream and transported for sequestration. CO2 can be stored underground as a supercritical fluid at temperatures in excess of 88 degrees Fahrenheit and pressures in excess of 1,057 pounds per square inch.[59] The most suitable storage locations include saline formations and oil and gas reservoirs. Retrofitting a power plant for CO2 removal through chemical absorption may include, but not limited to, the installation of absorber-stripper columns, heat exchanger, compression and drying system, and piping.[60] The energy

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[58] IEA 2021, "About CCUS: Principal Technologies." https://www.iea.org/reports/about-ccus

[59] This temperature and pressure define CO2's critical point. NETL Carbon Capture Storage FAQs. https://netl.doe.gov/coal/carbon-storage/faqs/carbon-storage-faqs

[60] National Energy Technology Laboratory 2013, *Cost and Performance of Retrofitting NGCC Units for Carbon Capture*. DOE/NETL-2018/1896. https://netl.doe.gov/projects/files/CostPerformanceRetrofittingNGCCforCarbonCapture_040119.pdf

penalty associated with the heat source and auxiliary loads (including energy to compress CO2) are typically quoted with CCUS technology parameters.

4.6.8.2 CCUS Cost Estimates

Since the 2021 RFP did not yield any CCUS projects, NIPSCO-specific portfolio analysis of the technology was not performed. However, in order to develop perspective on long-run CCUS costs to be used in the MISO market scenario analysis (*See* Section 8) and to approximate the potential cost and operational impacts of a CCUS retrofit to the existing Sugar Creek combined cycle, CRA and NIPSCO performed a review of third-party estimates. Overall, costs for CCUS projects fall within the following three categories:

- Capturing CO2 at the source of emission and compressing or liquifying it for transport[61];
- Transporting the CO2 via pipeline, ship, or truck, as appropriate; and
- Sequestering the CO2 underground, including costs associated with injection, monitoring, and verification.

To develop planning-level cost estimates for use in the MISO market modeling and to approximate cost ranges for NIPSCO, a range of sources were reviewed, including the EIA Annual AEO, the Global CCS Institute, the NETL, and the CATF.[62] From a high-level perspective, CRA's MISO market analysis suggests that under a scenario with high carbon prices or a significant clean energy standard that aims to achieve deep decarbonization, CCUS can be competitive with other technologies like hydrogen, or new nuclear in 2035 and beyond, depending on plant-specific cost and locational considerations, and transportation infrastructure.

Across scenarios, the economics tended to favor coal CCS in the AER scenario (high gas prices, high carbon price), with more gas CCS projects likely to be economic in the EWD scenario (with lower gas prices and a clean energy standard with accompanying clean energy credit prices).[63] The referenced studies and CRA's MISO market analysis suggest that CCUS is likely to be cost-effective at CO2 prices between $50-150/ton, depending on future costs of fuel, technology advancement, and transportation requirements.

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[61] Capital expenditures are largely associated with an absorption tower, energy consumption requirements that are often represented through reductions in power output of the host facility, and compression costs.

[62] Specific sources include the 2021 AEO (https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf), the Global CCS Institute's *Global Costs of Carbon Capture and Storage* study (https://www.globalccsinstitute.com/archive/hub/publications/201688/global-ccs-cost-updatev4.pdf), NETL's *Economics of CCUS* presentation by Tim Fout from November 2020, and CATF's "Estimate of CO2 Capture Performance and Cost Parameters for Gulf Coast Power Fleet Modeling," (https://www.catf.us/wp-content/uploads/2018/12/Estimate_of_CO2_Capture_Performance_and_Cost_Parameters.pdf)

[63] See Section 8 of this report for more detail.

For NIPSCO in particular, the saline aquifer geological features around NIPSCO's natural gas-fired Sugar Creek combined cycle plant may be appropriate for CCUS siting,[64] so CRA and NIPSCO developed planning-level cost and operational estimates associated with a potential future conversion. These include new capital and operating costs that would be associated with a CCUS facility, as well as changes in net plant output and efficiency and are summarized in Figure 4-23. Right now, NIPSCO is aware of four natural gas combined cycle CCUS demonstration projects that are currently under study, with cost estimates expected towards the end of 2021 and into 2022.[65] As these engineering studies are completed and more information is developed, NIPSCO will likely refine the potential cost and operational implications of CCUS deployment at Sugar Creek in future IRPs.

Figure 4-23: Indicative Sugar Creek CCUS Costs and Operational Parameters

Characteristic	Units	Before Retrofit	After Retrofit	*See* Note
Net Capacity to Grid (Winter)	ICAP MW	545	473	1
Net Capacity to Grid (Summer)	ICAP MW	530	460	1
Heat Rate (Winter)	Btu/kWh	6,903	8,091	2
Heat Rate (Summer)	Btu/kWh	6,912	8,103	2
Incremental Installed CapEx	2021$/kW	0	976	3
VOM Costs	2021$/MWh	1.15	1.32	4
Incremental VOM Costs applied to post-retrofit capacity	2021$/MWh	0	1.22	3
Fixed Operations and Maintenance Costs	2021$/kW-yr	23.33	26.86	4
Incremental FOM applied to post-retrofit capacity	2021$/kW-yr	0	22.72	3
CO2 Emission Rate	lbs/MMBtu	118.86	13.7	4,5

Notes:
1: Assumes a 13.16% energy penalty / parasitic load being met by a portion of Sugar Creek to operate CCUS equipment.
2: Assumes a 17.22% heat rate penalty due to carbon capture; gas for compression, and other factors.
3: Based on Global CCS Institute, CATF, and NETL
4: Increased by a factor of 1.15 (i.e., 545 / 473 MW) after retrofit to account for grid MW being lower although capacity still used to power capture equipment.
5: Assumes 90% carbon capture

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[64] See the DOE's *Carbon Storage Atlas:* https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf and Great Plains Institute's report titled, "Transport Infrastructure for Carbon Capture and Storage, Whitepaper on Regional Infrastructure for Midcentury Decarbonization. https://www.betterenergy.org/wp-content/uploads/2020/06/GPI_RegionalCO2Whitepaper.pdf. In addition, Wabash Valley Resources' proposed CCUS project is in close proximity. For more information, see: https://www.wvresc.com/

[65] These projects include Panda Sherman and Golden Spread Mustang in Texas, Mississippi Power's Daniel plant, and Alabama Power's Barry plant, as summarized in a Working Draft of the *2021 Status of Carbon Capture Utilization and Sequestration for Application to Natural Gas-Fired Combined Cycle and Coal-Fired Power Generation* technical discussion paper prepared for the Indiana Electric Association and other parties.

4.6.8.3 CCUS Policy Support Considerations

The U.S. tax code currently offers a performance-based tax credit for eligible carbon capture and sequestration projects that securely store CO2 in geological formations or use CO2 for enhanced oil recovery. These incentives, known as the 45Q credits, award between $35-50 per sequestered ton of CO2 and are available for 12 years after the project enters into service. As of the time of the production of this report, Congress is also considering additional policy support for CCUS projects that could include increases to the 45Q credit value, direct payment of subsidies, longer construction windows to preserve credit eligibility, and other grants or direct support for demonstration or transportation projects. NIPSCO will continue to track CCUS policy activity along with broader federal environmental policy initiatives as it evaluates long-term decarbonization options in future IRPs.

4.6.8.4 Long Duration Storage

Although a large majority of storage bidders in the RFP offered four-hour duration lithium-ion battery storage technologies, longer duration storage technologies may become more viable over the long-term in order to balance diurnal variations in renewable energy resources as well as variations in demand from weekends (low demand) to weekdays (high demand). The technology can also provide needed capacity during longer duration weather events, such as snowstorms, extended cloud cover, or wind droughts that could last for several days.

The value of long-duration storage is likely to increase as intermittent renewable generation increases within the MISO footprint. In addition to energy arbitrage, some long-duration technologies may also be able to effectively offer additional ancillary services value, such as spinning reserve and regulation to the portfolio (*See* Section 9 for more detail on NIPSCO's evaluation of ancillary services value in this IRP).

4.6.8.5 Long-Duration Storage in the RFP

While long-duration storage RFP bids were either non-competitive or unpriced (due to technology immaturity), multiple bidders offered information and perspectives on potential long-duration storage technologies. Technologies included:

- **Gravity storage**, where large objects are lifted to charge and released to discharge. Such solutions are generally scalable, highly efficient, and have few limits on cycle frequency of depth of discharge, providing certain advantages over lithium-ion technology. One bidder proposed a gravity storage solution to use locally sourced material for the storage system objects, such as coal combustion residuals or other items that might otherwise be landfilled.

- **Flow batteries**, which store energy in electrolyte reservoirs, transferring electrons back and forth between oxidation states causing charge and discharge. Electrolytes are dissolved in water and stored in two tanks connected by an iron selective membrane. These batteries can cycle frequently without degradation (contrary to lithium-ion), although their round-trip efficiency is usually lower.

- **Compressed or liquefied air**, where air or gas is compressed or liquefied during charging and expanded or evaporated during discharging. The component parts of these technologies are generally well understood, and it may be possible to use existing infrastructure, such as abandoned natural gas storage facilities, in a compressed air application. However, siting challenges may exist, and round-trip efficiencies are generally lower than other technologies.

Given the expectation that energy storage will be a part of NIPSCO's long-term portfolio (*See* Section 9 for more information on the key outcomes of the portfolio analysis), NIPSCO will continuously evaluate the landscape of storage options, as technology advances and market conditions evolve. Although four-hour lithium-ion battery storage may comprise early additions to the portfolio, longer-duration options are likely to be considered in more detail in future IRPs.

4.6.9 Small Modular Reactors

SMRs are a new generation of nuclear fission technology utilizing smaller reactor designs, modular factory fabrication, and passive safety features. SMR can potentially provide a zero-carbon alternative for providing base-load electricity without CO2 emissions, and its siting flexibility and improved safety features potentially allow the technology to be sited closer to demand centers, reducing transmission investments. Key features of an SMR include:

- Small physical footprints;
- Limited on-site preparation, leading to faster construction time and scalability;
- Siting flexibility including sites previously occupied by coal-fired plants; and
- Passive safety features, allowing the reactor to safely shutdown in an emergency without requiring human interventions.

SMR is still in the early stages of development, and NIPSCO did not receive any bids related to this technology in the RFP, even in an unpriced informational fashion, as it did with other emerging technologies. In addition, there remain uncertainties regarding the cost, performance, and availability of the technology. As a result, NIPSCO has not evaluated SMR technology as a realistic resource option associated with the implementation of its preferred portfolio over the next several years. However, as the technology evolves and as potential demonstration projects are pursued in the coming years, NIPSCO will continue to monitor progress on SMRs. Depending on technology evolution, future IRPs may assess the resource in more detail, particularly as a long-term option to achieve decarbonization objectives well into the 2030s.

Section 5. Demand-Side Resources

5.1 Existing Resources

5.1.1 Existing Energy Efficiency Resources

NIPSCO actively promotes energy conservation and efficiency to customers and works with its contractors to offer cost-effective energy efficiency programs. On September 1, 2021, the Commission issued a Final Order in Cause No. 45456 approving a Settlement Agreement among NIPSCO, the Indiana Utility Consumer Counselor, and the Citizens Action Coalition of Indiana, Inc. which included NIPSCO's proposed EE programs for the period of January 1, 2022 through December 31, 2023 (the "2022-2023 Plan"). To support the continuation of its program offerings for the period 2022 through 2023, NIPSCO recommended, and its OSB approved, TRC as the vendor to continue implementing both its residential and C&I programs. The OSB also agreed that ILLUME Advising would continue as the EM&V vendor for both program years.

2022-2023 Residential Programs

Home Rebates

The Home Rebates program is designed to provide incentives to residential customers to replace inefficient HVAC equipment with energy-efficient alternatives. These measures will be paid per-unit installed, reimbursing customers for a portion of their cost. The program's intent is to help remove the financial barrier associated with the initial cost of these energy-efficient alternatives. The program will promote premium efficiency air conditioners, air conditioner tune-ups, smart thermostats, ENERGY STAR® air purifiers, ENERGY STAR dehumidifiers, ENERGY STAR clothes dryers, ductless mini-split heat pumps, ENERGY STAR pool pumps, heat pumps and heat pump water heaters.

Lighting Products

The Lighting Products program is designed to increase the purchase and use of energy-efficient lighting products among NIPSCO's residential electric customers. The program provides instant discounts by using upstream wholesale incentives to buy down the incremental costs on lighting products that meet the energy efficiency standards set by the DOE's ENERGY STAR Program. ENERGY STAR specifications are an important external factor to certify the quality and efficiency of program measures. As the ENERGY STAR specifications change, program offerings are adjusted accordingly. These adjustments ensure that the program offers incentives for lighting products that meet the latest standards and highest quality of efficiency. General service lamps will not be included in this program. Other specialty, reflector and retrofit kits will be included in this program. As part of the Settlement Agreement approved in Cause No. 45456, if the EISA standards go into effect, adjustments will be made to the program through the EM&V process.

Home Energy Analysis

The Home Energy Analysis program is designed to help eligible customers improve the efficiency and comfort of their homes, as well as deliver an immediate reduction in electricity (kWh) consumption and promote additional efficiency work. This program will provide homeowners with the direct installation of low-cost, energy-efficient measures followed by the delivery of a Comprehensive Home Assessment report to the customer. This program is unique in that it provides a whole home assessment leading to easy to achieve kWh savings opportunities.

Appliance Recycling

The Appliance Recycling program is designed to provide an incentive to residential customers who choose to recycle a qualifying primary or secondary working refrigerator and/or freezer, room air conditioner and dehumidifier. TRC will utilize a qualified subcontractor for the implementation of this program.

School Education

The School Education program is designed to produce electric savings by influencing fifth grade students and their families to focus on the efficient use of electricity. It will provide classroom instruction, posters, and activities aligned with national and state learning standards and energy education kits filled with energy-saving products and advice. Students will participate in an energy education presentation at school, learning about basic energy concepts through class lessons and activities. Students will also receive an energy education kit of quality, high-efficiency products and are instructed to install the energy-efficient products at home with their families as well as complete a worksheet. The experience at home will complete the learning cycle started at school.

Multi-Family Direct Install

The MFDI program is designed to provide a "one-stop shop" to multifamily building owners, managers, and tenants of multifamily units containing three or more residences receiving service from NIPSCO. With flexible and affordable options, the program will generate immediate energy savings and improvements in two distinct program phases. Phase I is a walkthrough assessment of each property, which is conducted to determine eligibility for direct installation services provided by the MFDI program, along with complementary incentive offers available through other NIPSCO programs. Property managers will be presented with an Energy Improvement Plan that prioritizes recommendations along with a proposal to provide the direct installation services outlined in Phase II. Phase II is an in-unit direct installation of energy-efficient devices at no-cost or low-cost to the tenant or landlord, such as LED light bulbs, low-flow showerheads, faucet aerators, pipe wrap, and programmable thermostats. Educational materials about home operation, maintenance, and behavior factors that may reduce energy consumption, will be provided to tenants in each living unit. TRC will utilize a qualified subcontractor for the implementation of this program.

Home Energy Report

The Home Energy Report program (also known as the Behavioral program) is designed to encourage energy savings through behavioral modification. The program will provide customers with home energy reports that contain personalized information about their energy use and provide ongoing recommendations to make their homes more efficient. Customers will be randomly chosen to participate in the program and may opt-out if they do not wish to participate. The reports engage customers and drive them to take action to bring their energy usage in line with similar homes and encourage participation in other complimentary residential programs. The program will empower customers to understand their energy usage better and uses competition through neighbor comparisons to influence customers to act on this knowledge, resulting in changed behavior.

Residential New Construction

The Residential New Construction program is designed to increase awareness and understanding by home builders of the benefits of energy-efficient building practices, with a focus on capturing energy efficiency opportunities during the design and construction of single family homes. This program is designed to produce long-term, cost-effective savings as a result of the training they have received to achieve the various Home Energy Rating System tiers, along with strategies for incorporating the Silver, Gold, and Platinum designations into their marketing efforts to attract home buyers.

HomeLife EE Calculator

The HomeLife EE Calculator program is designed to offer NIPSCO's residential customers an online "do-it-yourself" audit and an energy savings kit for carrying out this audit, at no cost to the customer. The audit tool will effectively: (1) identify low-cost/no-cost measures that a NIPSCO residential customer can easily implement to manage electric consumption; (2) allow eligible customers to request a free home energy kit; (3) educate customers about the variety of programs available to them through the residential energy efficiency portfolio; and (4) assist customers in finding qualified and experienced contractors through a network of trade allies.

Income Qualified Weatherization

The IQW program is designed to provide energy efficiency services to qualifying low-income households. For a household to be eligible to participate in the IQW program, the customer must be a NIPSCO residential customer with active service that receives Low-Income Home Energy Assistance, Temporary Assistance for Needy Families, Supplemental Security Income, or Supplemental Security Disability Income and has not received weatherization services in the past 10 years from the date of application. Qualifying participants receive the direct installation of no-cost EE measures and a Comprehensive Home Assessment to identify areas of the home where additional energy savings can be achieved to make the home more comfortable and reduce energy costs.

Residential Online Marketplace

The Residential Online Marketplace program provides an online store for NIPSCO electric customers to purchase and install EE measures with an instant incentive applied at the time of purchase. The Residential Online Marketplace ensures only NIPSCO customers are eligible to purchase and limits are set on the quantities purchased to ensure timely installation.

Table 5-1 shows the projected energy savings (MWh) by year for each of the Residential programs[66].

Table 5-1: 2022-2023 Projected Residential Energy Savings (MWh)

Residential Programs	2022	2023	2022-2023
Home Rebates	1,905	1,905	3,810
Lighting Products	11,500	11,500	23,000
Home Energy Analysis	384	384	768
Appliance Recycling	2,900	2,945	5,845
School Education	2,167	2,167	4,334
Multifamily Direct Install	1,502	1,502	3,004
Home Energy Report	23,120	23,444	46,564
Residential New Construction	886	886	1,772
Home Life EE Calculator	185	185	370
Income Qualified Weatherization	1,060	1,060	2,120
Residential Online Marketplace	630	909	1,539
Total Residential Programs	**46,239**	**46,887**	**93,126**

Table 5-2 shows the annual total program budget for each of the Residential programs. Program budget includes implementation costs, NIPSCO administration costs, NIPSCO marketing costs, and EM&V costs.[67]

Table 5-2: 2022-2023 Residential Program Budget

Residential Programs	2022	2023	Total
Home Rebates	$ 698,494	$ 704,281	$ 1,402,775
Lighting Products	$ 2,941,831	$ 2,976,763	$ 5,918,594

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[66] Table 5-1 represents incremental, gross savings at the meter from the plan approved by the Commission in Cause No. 45456. On a net basis, inclusive of measure life considerations, the annual, cumulative impacts modeled for IRP purposes are slightly different. In addition, at the time of the development of the DSM inputs for the IRP, slightly different adjustments were applied to the near-term DSM savings expectations, resulting in slightly different numbers used for IRP modeling purposes. However, given that these savings are part of the plan approved by the Commission, they were universally applied across all portfolios and do not impact comparisons across portfolio options.

[67] In its Final Order, the Commission approved that NIPSCO (with OSB approval) is authorized to increase any individual program funding by up to 20% of the total program budget, even if this exceeds the overall 2022-2023 DSM Plan budget approved by the Commission. These budgets do not reflect the potential adjustment.

Home Energy Analysis	$ 232,562	$ 233,729	$ 466,291
Appliance Recycling	$ 446,068	$ 461,920	$ 907,988
School Education	$ 1,012,988	$ 1,019,570	$ 2,032,558
MFDI	$ 648,845	$ 653,404	$ 1,302,249
Home Energy Report	$ 2,405,925	$ 2,510,799	$ 4,916,724
Residential New Construction	$ 261,262	$ 263,951	$ 525,213
HomeLife EE Calculator	$ 83,195	$ 83,757	$ 166,952
IQW	$ 872,791	$ 876,012	$ 1,748,803
Residential Online Marketplace	$ 115,475	$ 167,834	$ 283,309
Total Residential Programs	**$ 9,719,436**	**$ 9,952,020**	**$ 19,671,456**

2022-2023 C&I Programs

Prescriptive

The Prescriptive program is designed to provide incentives for a set list of energy efficient measures and will be paid based on per unit installed, reimbursing the customer for a portion of the cost. The Prescriptive program will offer incentives to NIPSCO's C&I customers that are making electric EE improvements in existing buildings.

Custom

The Custom program will be available to C&I customers for installing new energy-saving equipment. Custom incentives are designed for more complicated projects, RCx projects), or those that incorporate alternative technologies. Project pre-approval will be required for all Custom incentives to ensure that only cost-effective projects are approved. Qualifying measures will be required to have a Total Resource Cost test score greater than 1.0, have a simple payback greater than 12 months (less than 12 months for RCx measures), and not be included as an EE measures in the Prescriptive Program. RCx projects examine energy consuming systems for cost-effective savings opportunities. The RCx process identifies operational inefficiencies that can be removed or reduced to yield energy savings.

C&I New Construction

The C&I New Construction program is designed to encourage construction of energy efficient C&I facilities within the NIPSCO service territory. This program will offer financial incentives to encourage building owners, designers and architects to exceed standard building practices and achieve efficiency, above and beyond the 2010 Indiana Energy Conservation Code. The goal of the New Construction program is to produce newly constructed and expanded buildings that are efficient from the start. New construction projects that may be eligible for incentives under the New Construction program may include any of the following: (1) new building projects wherein no structure or site footprint presently exists; (2) addition to or expansion of an existing building or site footprint; and (3) a total "gut" rehabilitation for a change of purpose requiring replacement of all electrical and mechanical systems/equipment.

Small Business Direct Install

The SBDI program is designed to facilitate participation in the NIPSCO business EE program of small C&I customers that do not possess the in-house expertise or capital budget to develop and implement an energy efficiency plan. The SBDI program will offer a variety of ways for small businesses, with billing demands not exceeding 200 kW, to improve the efficiency of their existing facilities. Measures will be paid out on a per unit basis, much the same way as the Prescriptive program, but with slightly higher incentive rates in an effort to encourage energy efficient investment from these smaller commercial customers. Incentive payments to the approved trade allies will occur following measure implementation and submission of all required paperwork. If additional incentives are available through other programs, customers will be directed to the appropriate application.

C&I Online Marketplace

The C&I Online Marketplace program will provide an online store for NIPSCO electric customers to purchase and install EE measures with instant incentive applied at the time of purchase. The C&I Online Marketplace program will ensure only NIPSCO customers are eligible to purchase and limits are set on the quantities purchased to ensure timely installation.

Smart Energy Engagement

The Smart Energy Engagement program will provide NIPSCO customers with a tailored self-service platform when they opt-in to the program. The Smart Energy Engagement platform will provide customers with the knowledge and insights to make meaningful and energy efficient choices in their facilities. Through personalized energy efficiency suggestions, the program will provide uplift to other C&I programs while providing behavioral savings based upon the changes made at the facility outside of other commercial and industrial programs.

Table 5-3 shows the projected energy savings (MWh) by year for each of the C&I programs.[68]

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[68] Table 5-3 represents incremental, gross savings at the meter from the Final Order in Cause No. 45456. At the time of the IRP, slightly different adjustments were used for modeling but were universally applied.

Table 5-3: 2019-2021 Projected C&I Energy Savings (MWh)

C&I Programs	2022	2023	Total
Prescriptive	42,388	43,130	85,518
Custom	37,591	37,481	75,072
C&I New Construction	4,607	4,688	9,295
SBDI	2,764	2,813	5,577
C&I Online Marketplace	4,252	4,344	8,596
Smart Energy Engagement	544	1,305	1,849
Total C&I Programs	**92,146**	**93,761**	**185,907**

Table 5-4 shows the total annual program budget for each of the C&I programs. Program budget includes implementation costs, NIPSCO administration costs, NIPSCO marketing costs, and EM&V costs.

Table 5-4: 2022-2023 C&I Program Budget

C&I Programs	2022	2023	Total
Prescriptive	$ 6,300,411	$ 6,652,393	$ 12,952,804
Custom	$ 6,216,345	$ 6,478,063	$ 12,694,408
C&I New Construction	$ 743,239	$ 790,337	$ 1,533,576
SBDI	$ 378,354	$ 401,330	$ 779,684
C&I Online Marketplace	$ 555,857	$ 603,107	$ 1,158,964
Smart Energy Engagement	$ 21,652	$ 53,524	$ 75,176
Total C&I Programs	**$ 14,215,858**	**$ 14,978,754**	**$ 29,194,612**

Table 5-5shows the projected energy savings (MWh) by year for all Residential and C&I programs included in the 2022-2023 Plan.

Table 5-5: 2022-2023 Projected Combined Energy Savings (MWh)

	2022	2023	Total
Total Residential Programs	46,239	46,887	93,126
Total C&I Programs	92,146	93,761	185,907
Total 2022-2023 Plan	**138,385**	**140,648**	**279,033**

Table 5-6 shows the annual total program budget for all Residential and C&I programs included in the 2022-2023 Plan.

Table 5-6: 2022-2023 Combined Program Budget

	2022	2023	Total
Total Residential Programs	$9,719,436	$9,952,020	$19,671,456
Total C&I Programs	$14,215,858	$14,978,754	$29,194,612
Total 2022-2023 Plan Budget	**$23,935,294**	**$24,930,774**	**$48,866,068**

Table 5-7 shows the eligible customer classes and rate schedules for each of the Residential and C&I programs included in the 2022-2023 Plan.

Table 5-7: Eligible Customers

Program	Customer Class	Electric Rate Schedule
Home Rebates	Residential	811
Lighting Products	Residential	811
Home Energy Analysis	Residential	811
Appliance Recycling	Residential	811
School Education	Residential	811
MFDI	Residential	811
Home Energy Report	Residential	811
Residential New Construction	Residential	811
HomeLife EE Calculator	Residential	811
IQW	Residential	811
Residential Online Marketplace	Residential	811
Prescriptive	C&I	820, 821, 822, 823, 824, 825, 826, 831, 832, 833, 841, or 844
Custom	C&I	820, 821, 822, 823, 824, 825, 826, 831, 832, 833, 841, or 844
C&I New Construction	C&I	820, 821, 822, 823, 824, 825, 826, 831, 832, 833, 841, or 844
SBDI	C&I	820, 821, 822, or 823 who have not had a billing demand of 200 kW or greater in any month during

Program	Customer Class	Electric Rate Schedule
		the previous 12 months
C&I Online Marketplace	C&I	820, 821, 822, 823, 824, 825, 826, 831, 832, 833, 841, or 844
Smart Energy Engagement	C&I	820, 821, 822, or 823 who have not had a billing demand of 200 kW or greater in any month during the previous 12 months

5.1.2 Existing Demand Response Resources

5.1.2.1 Capacity Resources

On December 4, 2019, the Commission issued a Final Order in Cause No. 45159, NIPSCO's most recent rate case which revised its industrial service structure by removing Rider 775 and Rate 734 and added Rate 831. The new industrial service structure requires NIPSCO's largest industrial customers on Rate 831 to designate their firm service with the remainder of their service requirements being registered as a MISO LMR which is by definition curtailable. NIPSCO experienced an increase in registered LMRs as a result of this new industrial power service for large customers structure, unless those Rate 831 customers utilize other options within the rate to acquire capacity from the MISO annual Planning Resource Auction or through a bilateral agreement between NIPSCO and a third party entered on their behalf. In addition, the large industrial customers will continue to be eligible to participate in MISO's DR Resource program discussed below.

5.1.2.2 Energy-Only Resources

NIPSCO offers DRR1 and EDR through Riders 781 and 782, respectively. These Riders are available to a customer on Rates 823, 824, 825, 826, 831, 832, and 833 that has a sustainable ability to reduce energy requirements through indirect participation in the MISO wholesale energy market by managing electric usage as dispatched by MISO. Through these Riders, the Customer or Aggregator of Retail Customer curtails a portion of its electric load through participation with the Company acting as the Market Participant with MISO. These Riders are available to any load that is participating in the Company's other interruptible or curtailment Riders, unless MISO rules change and do not permit load used by the Company as a LMR to also participate as a DRR1 or EDR. Although the DRR1 and EDR offered under Riders 881 and 882, respectively, do not qualify as a Capacity Resource, they do offer a means for Customers to offer into the MISO market and to be paid for the portion of their electric load curtailed. This provides economic benefit to the customers participating in these Riders and for other NIPSCO customers through an overall lower electric system demand, which can avoid purchased power or the need for higher cost generation resources to be committed through the MISO market. Currently, NIPSCO has one customer participating in Rider 881 as DRR1. No customers are participating in Rider 882 as EDR.

5.2 DSM MPS

5.2.1 DSM MPS – Purpose and Key Objectives

To support the IRP and DSM planning for NIPSCO, NIPSCO contracted with the GDS Team to conduct a DSM MPS (a copy of which is included in Appendix B). The DSM MPS provides an update of DSM program costs and savings for a 20-year time horizon (2024-2043).[69] The study included primary market research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities in order to develop estimates of technical, economic, and achievable potential. Separate estimates of energy efficiency and demand response potential were developed. The effort was highly collaborative, as the GDS Team worked closely with the NIPSCO OSB to produce reliable estimates of future savings potential, using the best available information and best practices for developing market potential savings estimates.

5.2.2 Impact of Opt-out Customers

The GDS Team reviewed the latest information available from NIPSCO related to energy efficiency program participation, measure and program savings data, results of NIPSCO's 2016 MPS, NIPSCO's electric load and customer forecasts, NIPSCO load research data, electric avoided costs, program evaluation reports, and NIPSCO's 2022-2023 Plan. NIPSCO requested that GDS prepare its base case DSM market potential assuming that C&I electric customers, who had opted out of NIPSCO's energy efficiency programs prior to January 1, 2017, would be excluded from the DSM MPS. In Indiana, commercial or industrial customers with a peak load greater than 1 MW are eligible to opt out of utility-based electric energy efficiency programs. In the NIPSCO service area, approximately 16% of commercial kWh sales have opted out of utility-based electric energy efficiency programs, while roughly 80% of industrial kWh sales have opted out.

5.2.3 Modeling Framework

The GDS Team used its energy efficiency and DR planning models to prepare the DSM MPS. These models allow the user to develop forecasts of measure and program costs, participants, kWh and kW savings, savings of other fuels, and benefit/cost ratios over the planning horizon. These models are transparent and all formulas, model inputs and model outputs can be viewed by the model user.

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[69] Near term (2022-2023) savings in the IRP are informed by NIPSCO's currently approved DSM Plan. Based on discussions with the NIPSCO OSB it was agreed that the DSM MPS would be used to inform the remaining years of the IRP.

5.2.4 Key Assumptions That Impact Energy Efficiency Potential

The GDS Team updated several input assumptions during the process of preparing the DSM MPS. The changes made for a few of these input assumptions are discussed below.

5.2.4.1 Updated NIPSCO Load Forecast, Avoided Cost Forecast and General Planning Assumptions

NIPSCO provided the GDS Team with its latest electric load forecast for 2020 through 2040. Following discussions with NIPSCO, CRA, and the NIPSCO OSB, it was agreed that the original NIPSCO forecast included implied assumptions about future EE based on historical DSM performance. GDS coordinated with NIPSCO to add these historical impacts back into the MPS forecast to avoid any potential over-counting of future energy efficiency potential in the NIPSCO service area.[70] The GDS Team then extended the NIPSCO load forecast through the year 2043. GDS used this new load forecast to calculate the percent of electric MWH sales and peak demand saved each year by DSM programs. NIPSCO's new load forecast projects that total MWH sales to ultimate customers will only increase 0.3% per year, on average, through the year 2048.

NIPSCO also provided GDS with updated planning assumptions for the general inflation rate, escalation rates for NIPSCO electric rates, the utility discount rate, line losses by class of service, and the planning reserve margin.[71] GDS used these assumptions to develop the 2021 MPS.

5.2.4.2 NIPSCO DSM Assumptions for Measure Costs, Savings, Useful Lives, and Market/Equipment Characteristics

GDS reviewed the assumptions for measure costs, savings, and useful lives included in prior NIPSCO DSM plans, as well as the 2019 DSM Savings, and updated these assumptions where appropriate. GDS utilized data specific to NIPSCO when it was available and current. GDS used the most recent NIPSCO evaluation report findings (as well as NIPSCO program planning documents), the 2015 Indiana TRM, the Illinois TRM, and the Michigan Energy Measures Database to inform a large portion of the data requirements. Evaluation report findings, NIPSCO program planning assumptions, and the Indiana TRM were leveraged to the extent feasible. Additional data sources were only used if these sources either did not address a certain measure or contained outdated information. Building energy simulation modeling results formed the basis for most heating and cooling end use measure savings, primarily in the residential sector. The NREL Energy Measures Database also served as a key data source in developing measure cost estimates.

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[70] NIPSCO and the GDS Team also coordinated with CRA to confirm that the modified sales forecast used in the MPS closely aligned with the NIPSCO sales forecast used in the 2022 IRP, and that both made adjustments to remove any embedded assumptions about future DSM program impacts.

[71] NIPSCO provided the GDS Team with both average and peak line loss factors. The GDS Team used the peak LLFs to adjust savings at the meter to the generator-level. NIPSCO has not conducted a marginal versus average line loss study, but the use of the peak LLF for DSM impacts is used as a proxy for the marginal LLF. The peak residential line loss used in the analysis was 4.11%. The peak commercial and industrial LLF were 3.76% and 2.41% respectively.

Additional source documents included American Council for an Energy-Efficient Economy research reports, covering topics like emerging technologies.

In addition to measure assumption development, the GDS Team engaged in primary market research to collect updated equipment penetration, saturation, and efficiency characteristics, as well as customer willingness to participate in program offerings data, across select end-uses/technologies. GDS conducted a combination of online/mail surveys, as well as a limited amount of on-site follow up site visits, to conduct the research. The resulting data was used to develop updated estimates of baseline and efficient equipment saturation estimates in the market potential study and to develop expected long-term adoption rates for energy efficiency over the study horizon.

5.2.4.3 Federal Appliance and Equipment Efficiency Standards

The DOE develops and implements federal appliance and equipment standards to improve energy efficiency, saving consumers energy and money. This DOE program was initially authorized to develop, revise, and implement minimum energy efficiency standards by the federal Energy Policy and Conservation Act in 1975. Several subsequent legislative amendments have required regular updates to these standards and have expanded the list of products covered by the standards. The DOE is currently required to periodically review standards and test procedures for more than 60 products, representing about 90% of home energy use, 60% of commercial building energy use, and 30% of industrial energy use.

By law, the DOE is expected to review each national appliance standard every six years and publish either a proposed rule to update the standard or determine that no change to the existing standard is needed. As of March 2021, DOE has missed legal deadlines for twenty-eight product standards since 2016.[72] Given these delays in future standard updates, the initial start year of 2024 for this analysis, and that the analysis is not intended to predict how or when energy codes and standards will change over time, there are only limited known improvements to federal codes and standards to reasonably account for in this analysis.

The primary adjustment in this analysis impacts residential screw-based lighting. Although DOE did issue a final rule stating that the EISA backstop has not been triggered and adopted a narrow definition of general service lighting, based on discussion with NIPSCO program administrators and the NIPSCO OSB, the base case analysis for the 2021 MPS severely limited the future potential for residential lighting throughout the analysis timeframe. The base case assumes only a limited number of direct-install screw-based lighting opportunities for standard, specialty, and reflector bulbs over the analysis period.

Although not exhaustive, other key adjustments include:

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[72] Missed Deadlines for Appliance Standards. Prepared by the Appliance Standards Awareness Project. Updated March 2021.

- The baseline efficiency for ASHP is anticipated to improve to 15 SEER/8.8 HSPF in 2023. As the new standards allow for a sell-through period, the baseline efficiency is assumed to be the new federal standard beginning in 2024.

- The baseline efficiency for split system central AC systems is anticipated to improve to 14 SEER in 2023. As the new standards allow for a sell-through period, the baseline efficiency is assumed to be the new federal standard, beginning in 2024.

- DOE established the first national standards for pool pumps in 2017, becoming effective in 2021. The new standards cut energy use for in-ground pool pumps by approximately 70% and can be met by switching from single-speed to variable-speed pool pumps.

- In 2019, the DOE made new standards effective for residential, portable and whole-home dehumidifiers. The new standards are based on a new metric, the integrated energy factor, and improve the test procedure to better reflect the actual energy consumption of dehumidifiers in the home. The new standards range from 1.30 L/kWh for small dehumidifiers up to 2.8 L/kWh for larger capacity dehumidifiers.

- In July 2019, the DOE made new standards effective for more efficient furnace fan/motors. The standards are expected to improve efficiency by approximately 45% over the current baselines. To date, many furnaces are equipped with standard induction motors, which operate at about 60-65% efficiency. The new standard creates a shift to electronically commutated motors.

- DOE established new standards for pre-rinse spray valves, setting maximum flow rates between 1.0 and 1.28 gallons per minute. The new standards took effect in early 2019 and were reflected in the analysis

5.2.5 Energy Efficiency Measures & Potential

5.2.5.1 Measures Considered

For the residential sector, there were 182 unique electric energy efficiency measures included in the energy efficiency potential analysis. Table 5-8 provides a summary of the types of measures included for each end use in the residential sector. The measure list was developed based on a review of current NIPSCO programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. The residential measures were then further broken out to include permutations across housing type (single-family vs. multifamily) and income type (income-qualified vs. market rate).

Table 5-8: Types of Electric Energy Efficiency Measures included in the Residential Sector Analysis

End Use	Measure Types Included
Electronic Equipment	ENERGY STAR Desktop and Laptop Computers, Monitors, and Printer/Fax/Copier/Scanner ENERGY STAR Smart Power Strips and Smart Plugs ENERGY STAR Televisions
Appliances	ENERGY STAR and Smart Refrigerators ENERGY STAR Freezers ENERGY STAR Washing Machines ENERGY STAR and Smart Clothes Dryers Heat Pump Dryers ENERGY STAR Dehumidifier Refrigerator Pick-up and Recycling Freezer Pick-up and Recycling Refrigerator Replacement in Low Income Homes
Envelope	Building Insulation Improvements (Attic, Wall, Floor, Etc.) Air sealing (Weatherization) Radiant Barriers High Efficiency Windows and Smart Window Film Covering Cool Roofing
HVAC (Heating & Cooling) Equipment	High Efficiency Air Conditioning High Efficiency Air Source Heat Pump (ASHP) Ductless Minisplit Heat Pumps Geothermal Heat Pumps AC/ASHP Tune-Up HVAC Filter Whistle Heating & Cooling Duct Sealing and Repair High Efficiency Natural Gas Furnace High Efficiency Natural Gas Boiler Wi-Fi Smart Thermostat Smart Vents/Sensors
Lighting	Interior LED Bulbs and Fixtures Exterior LED Bulbs and Fixtures LED Nightlights Occupancy Sensors Smart Light Switch Exterior Lighting Controls
Pools	Pool Pump Controls High Efficiency Pool Pumps High Efficiency Pool Pump Heaters
Water Heating	Heat Pump Water Heater Smart Water Heater – Tank Controls and Sensors Faucet Aerators & Low Flow Showerheads Thermostatic Restriction Valve and Shower Timers Hot Water Pipe and Tank Insulation Solar Water Heating System
Other	Home Energy Reports and Other Types of Behavioral Programs Energy Efficiency Education Kits for Employees of NIPSCO’s Customers High Efficiency Well Pump High Efficiency Hot Tub Dryer Vent Cleaning

End Use	Measure Types Included
	Refrigerator Coil Cleaning

For the C&I sector, there were 272 unique electric energy efficiency measures included in the energy efficiency potential analysis. Table 5-9 provides a summary of the types of measures included for each end use in the C&I sector. Measures are assumed to be included as part of NIPSCO's current portfolio of offerings, either under their current Prescriptive or Small Business Direct Install programs, or under the Custom program offering.

Table 5-9: Types of Electric Energy Efficiency Measures included in the C&I Sector Analysis

End Use	Measure Types Included
Cooking	Efficienct Steamers Efficient Griddles Efficient Fryers Efficient Overs Efficient Holding Cabinets
Envelope	Building Insulation Improvements High Efficiency Windows Reflective Film
HVAC Controls	Smart Thermostats Custom Energy Management System Installation/Optimization Occupancy Control System Retro-Commissioning
Lighting	Fixture Retrofits High Bay LED Equipment LED Bulbs and Fixtures Lighting Occupancy Sensors Custom Interior and Exterior Lighting Advanced Lighting Controls Lighting Power Density Reduction Retro-Commissioning
Office Equipment	POS Terminals Printer/Copier/Fax Machines Desktop and Laptop PCs and Monitors Computer Room Economizers Computer Room Hot Aisle Cold Aisle Configuration High Efficiency Computer Room Air Conditioning Units Efficient Servers Office Equipment / Plug Load Controls
Refrigeration	Strip Curtains and Auto Door Closers Efficient Refrigerators/Freezers/Ice Machines High Efficiency/Variable Speed Compressors Electronically Commutated Motors Cooler Motors Door Heater Controls Efficient Compressors and Controls Floating Head Pressure Controls

End Use	Measure Types Included
	Display Case Lighting and Controls Custom Refrigeration Retro–Commissioning
Space Cooling	Efficient Cooling Equipment Evaporative Pre-Cooler Economizer Air Source Heat Pump Geothermal Heat Pump Chiller/HVAC Maintenance Chilled Water Reset Room AC Custom HVAC/Chillers Retro-Commissioning
Ventilation	Variable Speed Drive Duct Repair and Sealing
Water Heating	Energy Star Dishwashers Energy Star Clotheswashers Heat Pump Water Heaters Faucet Aerator/Low Flow Nozzles Pre-Rinse Spray Valves Custom Water Heating
Other	Compressed Air – Engineered Nozzle Compressed Air Audit and Leak Repair Efficient Transformers Custom Motors and Drives Custom Process Whole Building Energy Monitoring Building Operator Certification Behavior Based Efficiency Retro-Commissioning
Industrial - Agriculture	Engine Block Heater Timer Energy Efficient/Energy Free Livestock Waterer High Volume Low Speed Fans High Efficiency Exhaust Fans Dairy Refrigeration Tune-up
Industrial – Machine Drive	High Efficiency Compressed Air Equipment and Controls Synchronous belt drives Motors – Efficient Rewind Motors and Drives Fan System Optimization Pumping System Optimization Energy Information Systems Advanced Lubricants Sensors & Controls Retro-Commissioning
Industrial – Process and Other	Strategic Energy Management High Efficiency Welders High Speed Turbo Blower for Wastewater Hybrid Injection Molding Fiber Laser Replacing CO2 laser High Efficiency Battery Charger Pellet Dryer Insulation

End Use	Measure Types Included
	Lab Fume Hood Ventilation Reduction and Control Industrial Air Curtain Process Compressor Optimization Process Controls / EMS

5.2.5.2 Achievable Electric Energy Efficiency Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial constraints, customer awareness and willingness-to-participate in programs, technical constraints, and other barriers that the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- MAP estimates achievable potential with NIPSCO paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- RAP estimates achievable potential with NIPSCO paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

Residential Sector Achievable Potential

Table 5-10 shows the cumulative annual achievable residential sector energy efficiency potential for the years 2024 to 2043 and estimates of the annual NIPSCO energy efficiency budgets for the residential sector.[73] Cumulative annual residential MWh savings represent 27% and 15% of residential sales in the maximum achievable and realistic achievable potential scenarios, respectively.

Table 5-10: Achievable Residential Sector Incremental Annual Energy Efficiency Potential and Annual Utility Budgets (Maximum and Realistic Achievable)

	Maximum Achievable			Realistic Achievable		
	Cumulative Annual			Cumulative Annual		
Year	MWh	MW	Budget	MWh	MW	Budget
2024	50,366	9.4	$17,245,434	45,035	8.5	$9,363,102
2025	85,608	18.5	$23,957,484	72,106	15.5	$11,020,579

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[73] All achievable potential savings are gross and do not include any adjustments for expected free-ridership and/or spillover.

	Maximum Achievable			Realistic Achievable		
	Cumulative Annual			Cumulative Annual		
Year	MWh	MW	Budget	MWh	MW	Budget
2026	127,468	30.3	$32,227,373	101,220	23.2	$12,786,099
2027	176,830	45.1	$41,806,956	132,398	31.6	$14,626,688
2028	228,929	62.5	$52,211,328	161,081	40.4	$16,533,275
2029	285,999	82.4	$62,431,679	190,284	49.1	$18,396,048
2030	346,854	104.2	$71,793,701	220,.76	58.0	$20,275,471
2031	410,763	127.5	$80,060,363	250,886	67.3	$22,192,009
2032	479,875	151.4	$86,300,126	279,387	76.4	$23,871,191
2033	539,072	174.2	$90,583,304	305,906	85.3	$24,972,401
2034	592,381	195.9	$93,761,064	330,027	94.0	$26,369,185
2035	643,187	216.5	$95,859,792	353,525	102.6	$27,508,982
2036	690,687	235.7	$97,153,498	376,161	110.7	$28,521,946
2037	735,238	253.7	$97,863,520	398,479	118.6	$29,352,722
2038	776,413	70.1	$98,118,519	419,720	126.0	$30,061,955
2039	816,633	285.5	$101,632,810	440,993	132.8	$32,681,985
2040	853,399	299.6	$102,154,997	461,177	139.4	$33,312,211
2041	886,611	312.5	$102,238,857	480,345	145.6	$33,879,207
2042	916,354	323.9	$102,829,779	498,286	151.5	$34,619,673
2043	943,612	334.1	$103,112,316	515,223	157.0	$35,112,002

Table 5-11 below provides the UCT benefit/cost ratios for the period 2024 to 2043 for the residential sector maximum and achievable potential[74]. The overall UCT benefit/cost ratio for the residential portfolio of energy efficiency programs is 1.71 in the realistic achievable potential scenario. In the maximum achievable potential scenario, the overall UCT drops below 1.0 to 0.86.[75]

Table 5-11: Utility Cost Test Benefit/Cost Ratios for Residential Programs (2019 to 2048 Period)

Achievable Potential Type – C&I	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio

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[74] NIPSCO utilized the UCT as the test for screening measures for inclusion.

[75] Economic screening for cost-effectiveness was performed assuming incentive levels consistent with historical levels. The GDS Team did not rescreen measure cost-effectiveness in the MAP scenario assuming 100% incentives. As a result, the MAP scenario includes measures that are not cost-effectiveness under the UCT at 100% incentives and the overall MAP UCT falls below a 1.0.

MAP	$841,694,153	$958,024,364	($116,330,211)	0.88
RAP	$470,746,985	$273,081,219	$197,665,766	1.72

C&I Achievable Electric Energy Efficiency Savings

Table 5-12 shows the cumulative annual achievable energy efficiency savings for the years 2024 – 2043 and estimates of the annual energy efficiency budgets. Cumulative annual savings by 2043 for the MAP and RAP scenarios represents 20% and 16% of C&I sales respectively.[76]

Table 5-12: Achievable C&I Sector Energy Efficiency Potential and Annual Budgets

	Maximum Achievable			Realistic Achievable		
	Cumulative Annual			Cumulative Annual		
Year	MWh	MW	Budget	MWh	MW	Budget
2024	88,301	16.5	$49,047,767	80,368	14.1	$13,133,235
2025	174,181	32.0	$48,535,990	155,758	27.0	$12,721,890
2026	259,712	47.0	$48,368,022	227,913	39.0	$12,355,219
2027	343,634	61.5	$48,376,420	296,288	50.2	$12,023,457
2028	425,512	75.5	$48,360,068	359,462	60.7	$11,721,374
2029	493,640	87.2	$47,927,154	408,819	68.6	$11,307,472
2030	564,392	99.5	$51,544,572	459,678	76.9	$12,245,644
2031	638,296	12.5	$54,621,761	513,537	85.8	$13,173,990
2032	708,997	124.9	$57,082,250	565,934	94.3	$14,058,857
2033	779,631	137.4	$58,939,912	619,913	103.2	$14,883,277
2034	838,585	148.1	$60,288,922	664,530	110.4	$15,632,102
2035	886,664	158.7	$61,151,215	701,379	116.1	$16,302,651
2036	914,019	161.9	$61,771,723	721,384	119.1	$16,887,147
2037	941,500	167.2	$62,216,028	743,405	122.5	$17,376,241
2038	965,836	171.9	$62,544,201	764,165	125.7	$17,793,928
2039	975,022	172.2	$62,722,386	773,346	125.9	$18,149,958
2040	986,901	172.9	$62,904,305	786,104	126.8	$18,431,551
2041	1,001,908	174.3	$63,090,045	802,193	128.4	$18,673,789
2042	1,014,321	175.3	$63,279,685	815,329	129.9	$18,891,199
2043	1,026,889	176.5	$63,473,307	828,760	131.5	$19,085,795

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[76] C&I savings and sales exclude current opt-out customers. All achievable potential savings are gross and do not include any adjustments for expected free-ridership and/or spillover.

Table 5-13 shows the NPV of benefits, NPV of costs, net benefits, and the benefit-cost ratio for the C&I sector as a whole, under both the maximum and achievable potential scenarios.

Table 5-13: Benefit Cost Analysis Results – UCT

Achievable Potential Type – C&I	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
MAP	$1,044,498,910	$647,750,938	$396,747,972	1.6
RAP	$821,153,048	$170,179,466	$650,973,582	4.8

5.2.6 DR Potential

Prior to NIPSCO's rate case in 2018, NIPSCO's demand response portfolio was comprised of load curtailment agreements from a small number of large industrial customers. NIPSCO was responsible for procuring capacity to meet the full peak loads of these customers, but also offered a substantial portion of these loads to MISO as LMRs to help satisfy capacity requirements. With the 2018 rate case, NIPSCO must now only procure enough resources for a portion of these customers' loads (known as "firm" loads, approximately 170 MW in total). However, NIPSCO can no longer claim the remaining "non-firm" portion of these customers' loads – nearly 700 MW – as demand response. See above for a description of Rate 831.

Thus, while NIPSCO now has a lower total load obligation than before the 2018 rate case, it also cannot claim any demand response from Rate 831 customers. The change to NIPSCO's demand response portfolio is important to keep in mind when making comparisons to NIPSCO's historical demand response offerings and prior potential studies. For the 2021 MPS and the 2022 IRP, the "non-firm" load associated with Rate 831 customers was neither included in the demand response potential assessment nor in NIPSCO's future capacity requirements.

In addition to the removal of Rate 831 interruptible loads from the NIPSCO DR portfolio, residential AC cycling via direct load control switches was suspended in 2015. NIPSCO does not currently have any other DR offerings. As a result, the DR portion of the MPS considered the following DR program types: residential smart (Wi-Fi enabled) thermostats, residential water heater DR, residential and small C&I dynamics rates[77], and medium and large C&I load curtailment.

Similar to the energy efficiency portion of the MPS, for the DR portion of the MPS cost-effectiveness is screened using the UCT and includes two achievable potential scenarios. For each demand response program, the maximum achievable potential represents aggressive assumptions around incentives and program design, which in turn drives higher participation. In the MAP

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[77] Represented by an event-based critical peak pricing program. Enabling AMI is assumed to be in place by 2030, at which time demand response potential savings begin to accrue. AMI costs are not included in demand response program costs.

scenario, incentives are maximized so that the overall UCT is at or near a 1.0. The realistic achievable potential represents more "middle-ground" assumptions around program incentives and design. Thus, the RAP scenarios have lower total demand response potential, but are more cost-effective than the MAP scenarios. Each program is also assumed to have a ramp rate, reaching full program capacity after two or three years, which reflects time required to market to and enroll customers in each program.

The MAP and RAP demand response by program over the 2024-2043 Market Potential Study horizon are shown in Figure 5-1 and Figure 5-2 respectively.

Figure 5-1: Maximum Achievable DR Potential by Program

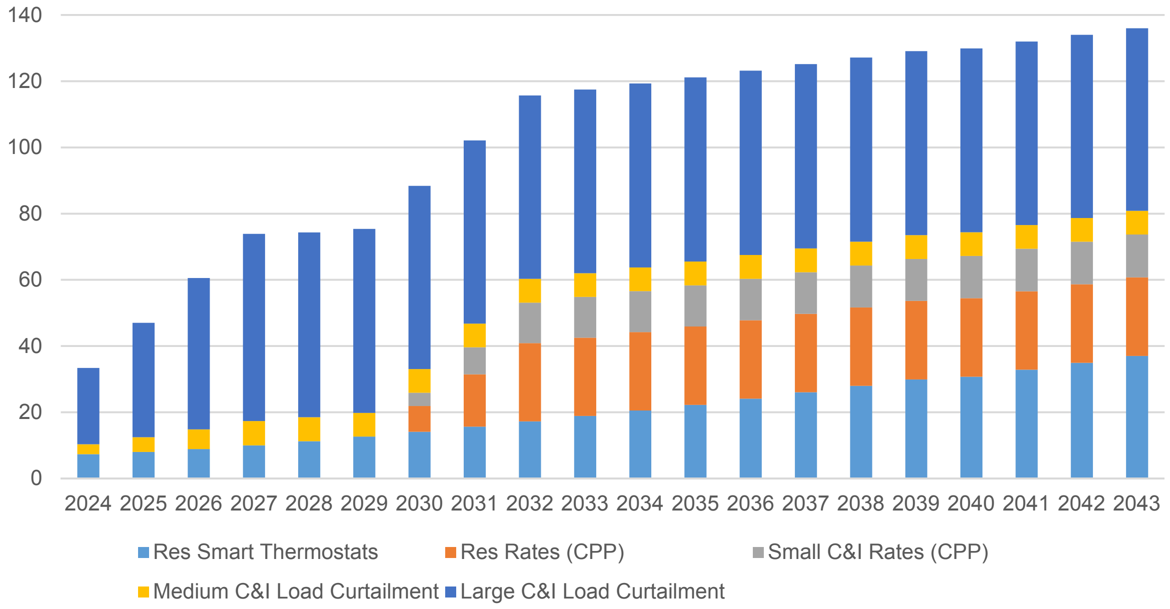
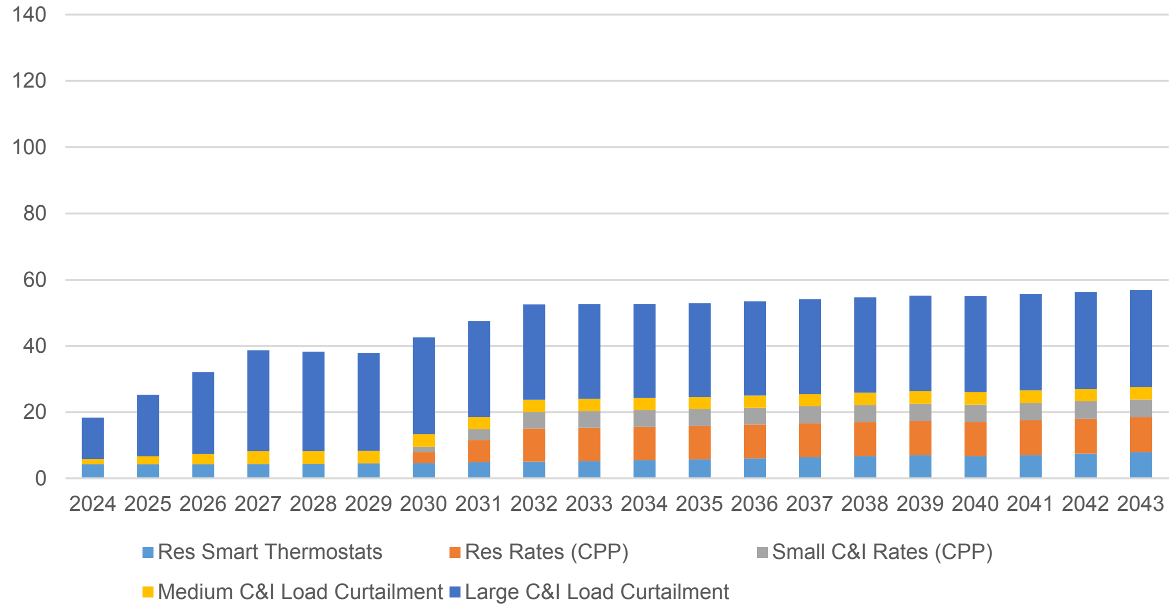


Figure 5-2: Realistic Achievable DR Potential by Program



5.3 Future Resource Options

5.3.1 Energy Efficiency Bundles

For the DSM base case of the IRP analysis, NIPSCO used the realistic achievable potential identified in the MPS as the starting point for developing energy efficiency bundles to be modeled in Aurora.[78] Based on coordination between NIPSCO and the NIPSCO OSB, the GDS Team initially provided energy efficiency inputs at the aggregate sector level in order to minimize the chances that the IRP would only select the lowest cost measures and limit NIPSCO's ability to offer broad programs. Following a review of these initial cost and savings inputs, the GDS Team further segmented the residential sector savings into high-cost measures (Tier 2) and low/mid cost measures (Tier 1). The GDS Team provided the energy efficiency IRP inputs across three different vintage bundles: 2024-2029, 2030-2035, and 2036-2041 to better optimize the value of energy efficiency to the system over different time periods.

In addition, four adjustments to the MPS's realistic achievable energy efficiency potential were necessary, prior to inclusion in the IRP. The first adjustment converted the energy efficiency potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts to remove MWh and MW impacts that would have occurred in the absence of NIPSCO's programs. Net savings were calculated by applying NIPSCO's most current (2019) program evaluation results and NTG ratios to the MPS estimates of gross realistic achievable savings.

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[78] The realistic achievable potential was selected as the 'base case' for purposes of IRP modeling based on the overall cost-effectiveness relative to the maximum achievable potential. The maximum achievable potential was also provided to NIPSCO for additional scenario modeling. These inputs can be found in an appendix to this document.

The second adjustment aligned the level of income-qualified potential, identified in the realistic achievable potential, with levels achieved historically by NIPSCO. The MPS assumes NIPSCO pays near full cost for all possible income-qualified potential savings, regardless of cost-effectiveness. However, this produces an income-qualified budget that significantly outpaces historical spending for the income-qualified sector and would create cross-subsidization concerns across customer segments. As a result of aligning the income-qualified sector spending in the IRP with recent historical levels, income-qualified achievable savings were also scaled accordingly.

The third adjustment was to provide the achievable potential savings at the generator level. The MPS savings are reported at the meter-level. Sector savings were adjusted based on the LLFs noted above, to convert savings from the meter level up to the generator level.

The fourth adjustment was to re-screen the cost-effectiveness of measures under an alternative cost of avoided generation. The MPS's avoided cost of generation was based on a CCGT unit. However, NIPSCO does not expect for that type of unit to be the marginal capacity addition for future capacity needs in the portfolio based on the 2018 IRP's key findings, a conclusion confirmed in this IRP's portfolio analysis.[79] As a result, the overall cost-effectiveness of measures was re-screened using a lower avoided cost of generation associated with a combustion turbine, or "peaking" unit.

Due to annual differences in the mix of energy efficiency measures included in the realistic achievable scenario and associated NTG ratios, as well as alignment of income-qualified savings with historical levels, the energy efficiency impacts modeled in the IRP ranged from 92% of the gross realistic achievable potential identified in the MPS in 2024 to 87% in 2041. The fourth adjustment, the alternative avoided cost of generation, had a negligible impact (0.1% reduction) on the modeled inputs.[80]

The energy efficiency impacts provided to NIPSCO for IRP modeling, by vintage block, are shown in Table 5-14 through Table 5-16 below.[81] The EE MWh and MW impacts for each vintage block provide the cumulative annual lifetime savings. Conversely, because EE program costs are only incurred during the year of measure installation, budgets are only reflected during the identified years in each vintage block.

In addition to the annual impacts shown in these tables, hourly (or 8,760) shapes that reflect the various measures and end-uses reflected in the achievable potential were provided to NIPSCO to permit the IRP model to assess the value of energy savings on an hourly basis. The 8,760 shapes are unique for each EE sector and vintage bundle.

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[79] See Section 9 for more detail on NIPSCO's portfolio modeling process and results.

[80] The avoided cost of energy is the primary driver in overall cost-effectiveness for energy efficiency measures. The alternate avoided cost of generation had a more sizable influence on the demand response IRP inputs.

[81] MW represents the summer impact.

Table 5-14: 2024-2029 Energy Efficiency Base Case Bundles

	Residential Tier 1			Residential Tier 2			IQW			C&I			Total		
	Cumulative			Cumulative			Cumulative								
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2024	42,020	6.8	$5,672,439	608	0.6	$766,210	780	0.3	$712,070	72,236	12.6	$10,061,654	115,644	20.3	$17,212,373
2025	64,645	11.7	$6,518,628	1,343	1.4	$963,319	1,597	0.5	$754,496	140,139	24.1	$9,837,750	207,723	37.8	$18,074,194
2026	88,707	17.0	$7,371,826	2,236	2.4	$1,185,332	2,406	0.8	$800,200	205,301	34.9	$9,661,507	298,650	55.0	$19,018,865
2027	114,128	22.6	$8,214,631	3,292	3.5	$1,426,181	3,275	1.0	$850,409	267,221	45.0	$9,525,882	387,917	72.1	$20,017,104
2028	136,284	28.1	$9,061,965	4,369	4.7	$1,678,014	4,210	1.3	$905,505	324,590	54.5	$9,423,873	469,453	88.6	$21,069,358
2029	158,502	33.7	$9,842,780	5,387	5.8	$1,932,244	5,211	1.6	$966,344	369,219	61.6	$9,233,829	538,318	102.7	$21,975,197
2030	107,022	27.6		4,843	5.2		5,080	1.6		350,417	58.9		467,363	93.3	
2031	98,966	26.5		4,286	4.6		4,967	1.6		333,787	56.9		442,005	89.6	
2032	88,666	25.0		3,642	3.9		4,936	1.5		312,003	54.2		409,246	84.6	
2033	77,105	23.3		2,917	3.1		4,674	1.5		291,283	51.4		375,980	79.3	
2034	71,350	22.3		2,511	2.3		4,323	1.4		262,510	46.8		340,693	72.8	
2035	65,378	21.2		2,485	2.2		3,945	1.4		238,977	42.5		310,785	67.4	
2036	58,601	20.0		2,460	2.2		3,537	1.3		202,094	36.0		266,692	59.5	
2037	51,577	18.7		2,434	2.2		3,097	1.2		167,155	29.9		224,262	52.0	
2038	45,685	17.2		2,409	2.2		2,616	1.2		136,257	24.5		186,967	45.0	
2039	36,884	14.8		2,377	2.2		2,339	1.1		96,404	16.5		138,005	34.6	
2040	31,194	12.7		2,342	2.1		2,208	1.0		76,862	12.3		112,606	28.2	
2041	25,119	10.4		2,301	2.1		2,074	1.0		62,075	9.0		91,568	22.5	
2042	19,186	8.1		2,255	2.1		1,917	0.9		48,474	6.1		71,832	17.2	
2043	12,863	5.7		2,200	2.1		1,754	0.8		37,030	3.6		53,846	12.1	
2044	6,784	3.5		2,099	2.0		1,585	0.8		22,918	1.0		33,386	7.2	
2045	5,535	2.6		2,032	1.9		1,537	0.7		17,431	0.7		26,534	5.9	
2046	4,477	1.6		1,950	1.8		1,487	0.7		12,108	0.5		20,021	4.6	
2047	3,269	0.5		1,853	1.6		1,434	0.7		6,987	0.3		13,542	3.1	
2048	2,896	0.5		1,741	1.5		1,407	0.7		3,593	0.2		9,637	2.8	
2049	2,292	0.4		1,464	1.2		1,202	0.6		253	0.0		5,211	2.1	
2050	1,900	0.3		1,271	1.0		1,006	0.5		240	0.0		4,418	1.8	
2051	1,442	0.2		1,032	0.8		790	0.4		225	0.0		3,490	1.5	
2052	1,047	0.2		743	0.6		552	0.3		206	0.0		2,549	1.1	
2053	569	0.1		399	0.3		289	0.1		186	0.0		1,443	0.6	
2054	0	0.0		0	0.0		0	0.0		140	0.0		140	0.0	
2055	0	0.0		0	0.0		0	0.0		117	0.0		117	0.0	
2056	0	0.0		0	0.0		0	0.0		91	0.0		91	0.0	
2057	0	0.0		0	0.0		0	0.0		63	0.0		63	0.0	

	Residential Tier 1			Residential Tier 2			IQW			C&I			Total		
	Cumulative			Cumulative			Cumulative								
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2058	0	0.0		0	0.0		0	0.0		32	0.0		32	0.0	

Table 5-15: 2030-2035 Energy Efficiency Base Case Bundles

	Residential Tier 1			Residential Tier 2			IQW			C&I			Total		
	Cumulative			Cumulative			Cumulative								
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2030	73,637	11.8	$10,645,345	1,626	1.6	$2,180,718	1,210	0.3	$1,033,695	64,790	10.2	$9,990,166	141,264	24.0	$23,849,925
2031	104,181	18.9	$11,497,378	3,309	3.3	$2,416,098	2,487	0.7	$1,108,192	130,178	20.1	$10,731,919	240,155	43.0	$25,753,588
2032	135,041	26.1	$12,211,052	5,103	5.1	$2,632,386	3,772	1.0	$1,190,305	199,379	30.6	$11,431,164	343,295	62.8	$27,464,907
2033	165,824	33.3	$12,483,614	6,987	7.0	$2,825,041	5,149	1.4	$1,280,730	268,994	41.3	$12,074,547	446,955	83.0	$28,663,932
2034	188,222	39.6	$13,104,763	8,553	8.9	$2,991,165	6,631	1.8	$1,380,296	338,157	52.4	$12,648,607	541,563	102.8	$30,124,832
2035	210,094	45.9	$13,585,116	9,731	10.0	$3,129,427	8,215	2.2	$1,488,355	395,206	61.8	$13,154,113	623,246	119.9	$31,357,011
2036	145,775	38.2		8,645	8.8		8,045	2.2		364,850	58.0		527,315	107.2	
2037	133,917	36.5		7,662	7.8		7,894	2.2		337,666	55.0		487,139	101.4	
2038	120,712	34.5		6,652	6.7		7,845	2.1		304,060	51.0		439,270	94.3	
2039	106,595	32.5		5,632	5.6		7,463	2.1		274,678	47.0		394,368	87.2	
2040	99,287	31.2		5,104	4.5		6,894	2.0		231,375	40.0		342,660	77.7	
2041	91,702	30.0		5,066	4.5		6,284	1.9		205,377	35.5		308,429	71.8	
2042	83,051	28.4		5,030	4.4		5,628	1.8		177,979	30.7		271,688	65.3	
2043	74,132	26.8		4,994	4.4		4,921	1.7		148,882	25.6		232,929	58.5	
2044	66,227	25.1		4,994	4.4		4,166	1.6		124,544	21.3		199,931	52.3	
2045	53,493	21.9		4,934	4.4		3,675	1.5		90,730	14.4		152,831	42.2	
2046	45,481	19.3		4,859	4.4		3,510	1.4		78,183	11.6		132,033	36.7	
2047	37,152	16.5		4,767	4.4		3,330	1.4		65,211	8.8		110,460	31.0	
2048	29,401	13.0		4,659	4.3		3,106	1.3		52,968	6.4		90,134	25.0	
2049	21,378	9.4		4,534	4.3		2,862	1.2		40,810	3.8		69,585	18.8	
2050	13,644	6.1		4,256	4.1		2,608	1.2		25,069	1.2		45,577	12.6	
2051	11,276	4.5		4,108	3.9		2,548	1.1		19,691	1.0		37,623	10.5	
2052	9,225	2.9		3,952	3.7		2,484	1.1		14,183	0.8		29,844	8.4	
2053	7,024	1.2		3,790	3.4		2,417	1.1		8,549	0.6		21,781	6.2	
2054	6,344	1.1		3,622	3.2		2,384	1.1		4,532	0.3		16,883	5.6	
2055	4,958	0.9		2,996	2.5		2,033	0.9		396	0.1		10,383	4.4	
2056	4,054	0.7		2,487	2.1		1,687	0.8		367	0.1		8,595	3.7	
2057	3,057	0.5		1,927	1.7		1,311	0.6		336	0.1		6,632	2.8	
2058	2,116	0.4		1,323	1.1		906	0.4		304	0.1		4,648	2.0	
2059	1,094	0.2		678	0.6		469	0.2		271	0.1		2,512	1.0	

	Residential Tier 1			Residential Tier 2			IQW			C&I			Total		
	Cumulative			Cumulative			Cumulative								
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2060	0	0.0		0	0.0		0	0.0		203	0.1		203	0.1	
2061	0	0.0		0	0.0		0	0.0		166	0.0		166	0.0	
2062	0	0.0		0	0.0		0	0.0		127	0.0		127	0.0	
2063	0	0.0		0	0.0		0	0.0		86	0.0		86	0.0	
2064	0	0.0		0	0.0		0	0.0		44	0.0		44	0.0	

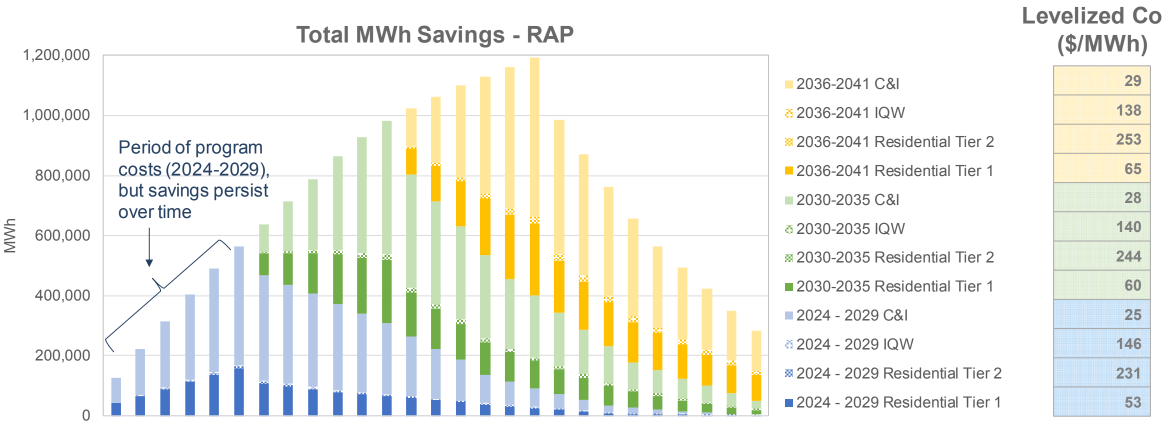
Table 5-16: 2036-2041 Energy Efficiency Base Case Bundles

	Residential Tier 1			Residential Tier 2			IQW			C&I			Total		
	Cumulative			Cumulative			Cumulative								
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2036	86,182	13.8	$14,037,844	2,252	2.1	$3,241,120	1,865	0.5	$1,605,310	85,505	13.1	$13,586,204	175,804	29.5	$32,470,479
2037	119,901	21.6	$14,414,673	4,379	4.2	$3,320,083	3,824	1.0	$1,731,492	167,657	25.3	$13,935,305	295,761	52.0	$33,401,554
2038	152,893	29.3	$14,760,648	6,507	6.3	$3,369,455	5,800	1.5	$1,868,904	251,076	37.6	$14,224,827	416,276	74.6	$34,223,833
2039	189,011	37.4	$16,816,359	8,639	8.3	$3,405,708	7,907	2.0	$2,015,673	329,395	49.8	$14,462,555	534,952	97.5	$36,700,295
2040	214,485	44.3	$17,211,164	10,257	10.3	$3,430,339	10,151	2.6	$2,173,736	404,355	62.0	$14,637,419	639,248	119.2	$37,452,657
2041	239,990	51.1	$17,522,638	11,365	11.2	$3,442,526	12,524	3.2	$2,345,291	460,125	71.3	$14,779,493	724,003	136.9	$38,089,948
2042	172,854	43.1		10,143	10.0		12,302	3.1		422,317	66.7		617,616	122.9	
2043	160,371	41.3		9,087	8.9		12,108	3.1		389,312	63.0		570,878	116.3	
2044	146,955	39.6		8,080	7.8		12,105	3.1		349,898	58.5		517,037	108.9	
2045	132,747	37.7		7,072	6.7		11,640	3.0		317,153	54.2		468,612	101.6	
2046	123,841	36.4		6,580	5.6		10,767	2.9		265,562	45.6		406,750	90.5	
2047	114,784	35.1		6,580	5.6		9,825	2.8		233,322	39.9		364,511	83.5	
2048	104,518	33.5		6,579	5.6		8,812	2.7		200,059	34.0		319,969	75.8	
2049	94,088	31.8		6,579	5.6		7,721	2.5		166,046	28.1		274,435	68.1	
2050	84,783	29.9		6,579	5.6		6,512	2.3		138,177	23.0		236,051	60.8	
2051	70,447	26.3		6,423	5.6		5,653	2.2		99,698	15.3		182,222	49.5	
2052	62,046	23.4		6,255	5.6		5,377	2.1		85,253	12.4		158,930	43.5	
2053	53,596	20.5		6,076	5.6		5,078	2.0		70,707	9.5		135,457	37.5	
2054	41,744	15.9		5,889	5.5		4,719	1.9		57,348	6.9		109,700	30.3	
2055	29,763	11.3		5,696	5.5		4,332	1.8		44,312	4.4		84,104	22.9	
2056	17,946	7.1		5,324	5.2		3,949	1.7		27,224	1.6		54,443	15.6	
2057	14,826	5.2		5,148	5.0		3,868	1.7		21,249	1.3		45,090	13.2	
2058	12,174	3.4		4,972	4.7		3,770	1.6		15,237	1.0		36,154	10.7	
2059	9,482	1.6		4,796	4.4		3,679	1.6		9,190	0.7		27,146	8.3	
2060	8,627	1.5		4,620	4.2		3,633	1.6		4,845	0.4		21,725	7.6	
2061	6,604	1.2		3,739	3.3		3,082	1.3		458	0.1		13,883	5.9	

	Residential Tier 1			Residential Tier 2			IQW			C&I			Total		
	Cumulative			Cumulative			Cumulative								
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2062	5,253	0.9		3,012	2.7		2,544	1.1		422	0.1		11,231	4.8	
2063	3,866	0.7		2,272	2.0		1,969	0.9		386	0.1		8,493	3.6	
2064	2,596	0.5		1,522	1.3		1,353	0.6		351	0.1		5,822	2.5	
2065	1,305	0.2		764	0.7		695	0.3		316	0.1		3,081	1.3	
2066	0	0.0		0	0.0		0	0.0		237	0.1		237	0.1	
2067	0	0.0		0	0.0		0	0.0		191	0.1		191	0.1	
2068	0	0.0		0	0.0		0	0.0		144	0.0		144	0.0	
2069	0	0.0		0	0.0		0	0.0		96	0.0		96	0.0	
2070	0	0.0		0	0.0		0	0.0		48	0.0		48	0.0	

The DSM bundles were incorporated into the IRP as eligible resources in the portfolio optimization analysis and through additional portfolio evaluation discussed later in this report. The DSM bundling approach allows for a representation of potential program duration over time, with differentiation across customer type and costs. Figure 5-3 provides an illustration of the annual expected MWh savings for each energy efficiency bundle under RAP assumptions, along with a summary of the levelized costs. Figure 5-4 provides an illustration of the peak demand savings for each bundle. As shown, the expected savings during the summer peak period for the energy efficiency bundles are considerably greater than those during the winter.

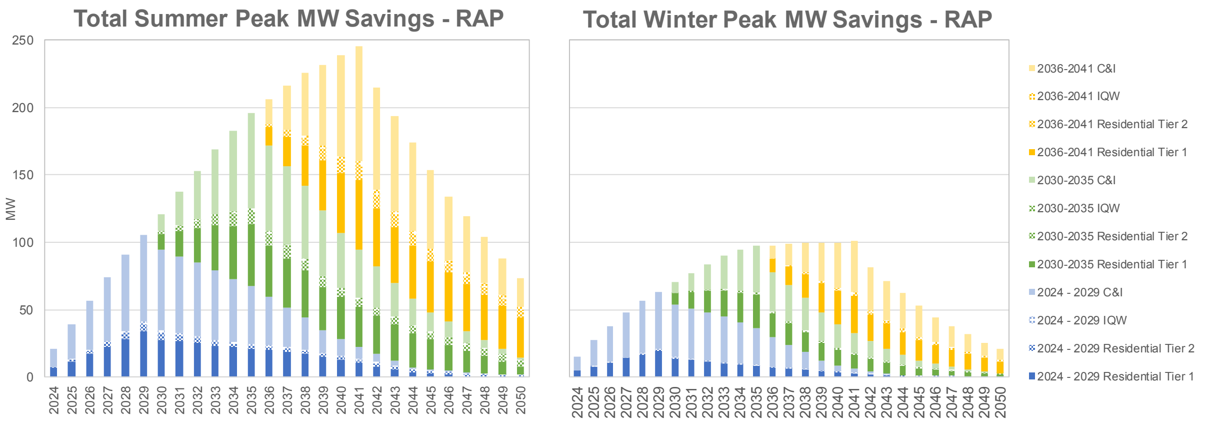
Figure 5-3: Energy Efficiency MWh Savings Bundle Illustration - RAP



	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

Figure 5-4: Energy Efficiency Peak MW Savings Bundle Illustration - RAP



IQW = Income Qualified Weatherization

5.3.2 DR Bundles

In IRP modeling, NIPSCO considered DR alongside other supply resources to supply capacity and energy needs. To facilitate this effort, the GDS Team provided NIPSCO with annual program potential and costs for the RAP and MAP scenarios for three program sub-segments. The first sub-segment was the Residential segment, which includes only the residential smart thermostat results, because the water heater direct load control program was not found to be cost effective in any scenario. The second sub-segment was the C&I segment, which consists of the Medium and Large C&I load curtailment programs. The third and final sub-segment was the Dynamic Rates sub-segment, which includes both the Residential and Small C&I critical peak pricing dynamic rates programs.

Consistent with the EE IRP inputs, the GDS Team rescreened the demand response program cost-effectiveness under an alternate avoided cost scenario, which assumed a lower cost for avoided generation than used in the MPS. This alternate case is meant to reflect the cost of a CT as the proxy unit, instead of a CCGT unit as in the base case. This change had no impact on residential water heater direct load control, residential rates, and small C&I rates. For the remaining programs (residential smart thermostats and Medium C&I Load Curtailment) the incentive levels, and therefore the enrollment rates, were reduced to ensure the programs remained cost-effective. The result is a reduction in the total demand response potential as well as overall program costs per kW of capacity. The alternative case MAP potential is 41 MW, compared to 57 MW in the base case used in the MPS. The alternate avoided cost MAP potential is 100 MW, compared to 136 MW in the MPS. This corresponds to a 26% and 28% reduction in potential for the RAP and MAP scenarios, respectively.

Table 5-17 provides the DR inputs used in the IRP modeling based on the RAP scenario.[82]

Table 5-17: DR Base Case Bundles

	Rate DR		Residential DR		C&I DR	
Year	**MW**	**$/kW-yr**	**MW**	**$/kW-yr**	**MW**	**$/kW-yr**
2024	0.00		2.15	$53.97	8.53	$84.12
2025	0.00		2.13	$39.24	12.89	$68.95
2026	0.00		2.13	$40.17	17.21	$61.96
2027	0.00		2.16	$40.91	21.48	$58.20
2028	0.00		2.21	$41.61	21.36	$59.70
2029	0.00		2.27	$42.27	21.25	$50.11
2030	4.90	$221.28	2.34	$42.91	21.17	$51.33
2031	10.00	$103.60	2.43	$43.56	21.14	$52.55
2032	15.00	$63.26	2.53	$44.19	21.16	$53.74
2033	15.08	$21.02	2.64	$44.81	21.19	$54.93
2034	15.16	$21.28	2.75	$45.41	21.22	$56.12
2035	15.24	$21.53	2.88	$46.00	21.24	$57.30

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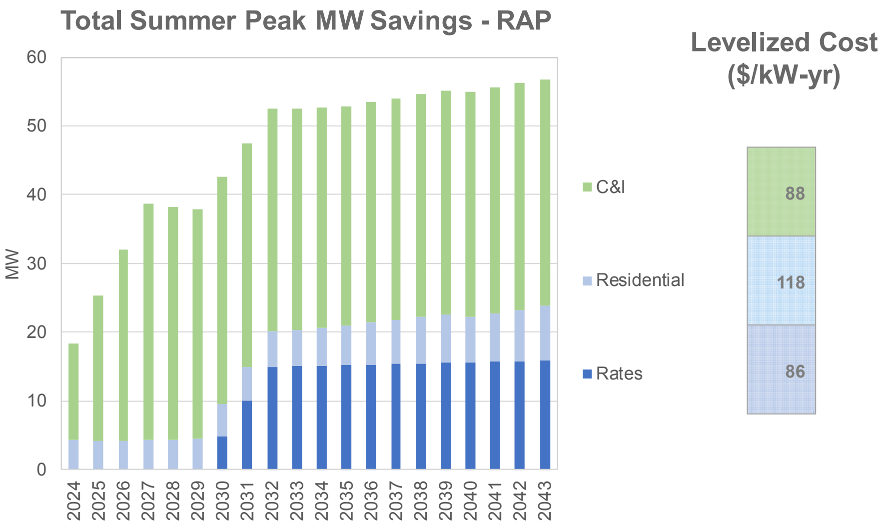
[82] The RAP was selected as the 'base case' for purposes of IRP modeling based on the overall cost-effectiveness relative to the MAP. The MAP was also provided to NIPSCO for additional scenario modeling. These inputs can be found in Appendix B to this document. As with the EE inputs, the costs have been adjusted to represent program costs less the avoided transmission and distribution benefit from the programs.

	Rate DR		Residential DR		C&I DR	
Year	**MW**	**$/kW-yr**	**MW**	**$/kW-yr**	**MW**	**$/kW-yr**
2036	15.32	$21.79	3.03	$46.56	21.24	$58.50
2037	15.40	$22.03	3.19	$47.10	21.24	$59.70
2038	15.48	$22.27	3.35	$47.66	21.23	$60.91
2039	15.56	$22.52	3.51	$48.42	21.20	$62.12
2040	15.64	$22.77	3.32	$48.65	21.17	$63.34
2041	15.73	$23.00	3.53	$49.13	21.13	$64.56
2042	15.81	$23.23	3.75	$49.67	21.07	$65.79
2043	15.89	$23.46	3.96	$50.27	21.01	$67.03

DR bundles were similarly incorporated in to the IRP analysis under three total bundles for Dynamic Rates, Residential, and C&I customers. DR programs provide summer peak savings as summarized in Figure 5-5, but minimal winter peak and energy value to the portfolio.

Figure 5-5: DR Summer Peak MW Savings Bundle Illustration - RAP



5.4 Consistency between IRP and Energy Efficiency Plans

The DSM Statute, which became law on May 6, 2015, requires, among other things, that a utility's EE goals are (1) reasonably achievable; (2) consistent with the utility's IRP, and (3) designed to achieve an optimal balance of energy resources in the utility's service territory. A utility was required to petition the Commission for approval of an energy efficiency plan under the DSM Statute beginning not later than calendar year 2017, and not less than once every three years thereafter.

To remain consistent with the requirements of DSM Statute, NIPSCO carried out a lengthy analysis of the DSM resources included in its IRP process. As noted above, NIPSCO completed a Market Potential Study in 2021 to determine the achievable amount of savings. *See* Appendix B. NIPSCO, through the MPS process discussed above, conducted an in-depth review of the amount of savings that would be achievable in its service territory with its current customer base. Following that in-depth review process and as outlined above, NIPSCO incorporated energy efficiency and demand response bundles into the model for selection as resources. NIPSCO allowed the EE and DR, broadly referred to as DSM resources, to be selected across all portfolio concepts that were evaluated in the Existing Fleet and Replacement analysis phases (*See* Section 9).

In accordance with the DSM Statute, NIPSCO intends to request approval in 2022 of an EE plan for implementation in 2024 that includes:

- EE goals that are: (1) reasonably achievable; (2) consistent with NIPSCO's 2021 IRP; and (3) designed to achieve an optimal balance of energy resources in its service territory;
- EE programs that are: (1) sponsored by an electricity supplier; and (2) designed to implement EE improvements;
- program budgets;
- program costs that include: (1) direct and indirect costs of energy efficiency programs; (2) costs associated with the EM&V of program results; (3) recovery of lost revenues and performance incentives;[83] and
- EM&V procedures that involve an independent EM&V.

NIPSCO intends to develop a DSM Action Plan prior to its filing in 2022 based on the EE selected by the IRP model. This may be updated if another MPS has been completed. The DSM Action Plan will take into account the results of the IRP for implementation and evaluation of the EE plan.

The benefit of a DSM Action Plan is that it uses various forms of information, including the IRP, to develop the best strategy for an energy efficiency plan. The DSM Action Plan will then be used to develop the DSM RFPs. The results of the winning bids will be utilized to develop the filing, with support from the MPS, IRP and DSM Action Plan. This is the most effective way to ensure NIPSCO has an EE plan that is based on real-world, achievable results from vendors who are committed to those results. Bidders' responses to the savings identified in NIPSCO's DSM RFP will vary based on the individual bidder's perception of NIPSCO's customer base and their previous experiences within other service territories, etc. This unique process for development of the DSM RFPs and creation of the EE plan allows NIPSCO to compensate for the

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[83] For purposes of this filing, the "direct costs" are those associated with implementing the programs, including any costs associated with program start up, while "indirect costs" are the NIPSCO administrative costs;

long lead time between the completion of a market potential study and the actual implementation of a program.

It is important to note that the final program design is determined by the bidder(s) selected by NIPSCO, with consideration of input from its OSB. The selected bidder's(s') predictions of the market into the program design as they determine what may or may not work in the NIPSCO's service territory is important for designing an EE program. That means that the programs included in the MPS typically change. NIPSCO uses the MPS as a feed into the IRP to develop the Action Plan. This Action Plan allows NIPSCO to take into account not just the results of the IRP, but also the experience of NIPSCO and its vendors with a particular program or measure. For example, electric hot water heating has a great deal of potential, but NIPSCO has not found there to be much interest from customers in the program. Knowing this means that NIPSCO will either (a) not structure a large amount of savings around a measure which has historically shown little participation or (b) need to increase the incentive to increase participation, which may impact the cost effectiveness of the program.

That does not mean that the EE plan will be without change. Until the programs are administered to the customer base and the first-hand experiences with energy efficiency occur, informed judgments must be used to establish the initial estimates of program impacts in NIPSCO's service territory. That is the benefit of utilizing an OSB. It provides an on-going mechanism to adjust to changing market conditions, including codes and standards and new technologies, and to ensure NIPSCO is capturing as much energy efficiency savings as possible for the amount of funding available.

Section 6. Transmission and Distribution System

Consistent with the principles set out in Section 1, NIPSCO continues to invest in its existing T&D resources to ensure reliable, compliant, flexible, diverse and affordable service to its customers. NIPSCO continually assesses the current physical T&D system resources for necessary improvements and upgrades to meet future customer demand or other changing conditions. As part of this effort, NIPSCO participates in the planning processes at the state, regional, and federal levels to ensure that its customers' interests are fully represented and to coordinate its planning efforts with others. The goals of the planning process include:

- Adequately serve native customer load and maintain continuity of service to customers under various system contingencies.
- Proactively maintain and increase availability and reliability of the electric delivery system.
- Manage costs while being consistent with the above guidelines

6.1 Transmission System Planning

6.1.1 Transmission System Planning Criteria and Guidelines

NIPSCO Transmission System Planning Criteria requires performance analysis of the transmission system for the outage of various system components including but not limited to generators, lines, transformers, substation bus sections, substation breakers, and double-circuit tower lines. Adequacy of transmission system performance is measured in terms of NIPSCO planning voltage criteria, facility thermal ratings, fault interrupting capability, voltage stability, and generator rotor angle stability as documented in the NIPSCO 2021 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (Confidential Appendix C). When a violation of one or more of these requirements is identified, Transmission Planning develops mitigations that may consist of operating measures and/or system improvements.

6.1.2 North American Electric Reliability Corporation

NIPSCO is subject to the NERC, which is certified by the FERC to establish and enforce reliability standards for the bulk-electric system and whose mission is to ensure the reliability of the North American bulk electric system. NIPSCO is registered with NERC as a Balancing Authority, Distribution Provider, Generator Owner, Generator Operator, Resource Planner, Transmission Owner, Transmission Operator, and Transmission Planner. Together with MISO, in a Coordinated Functional Registration, NIPSCO is registered as a Balancing Authority, Transmission Owner, and Transmission Operator. Each Registered Entity is subject to compliance with applicable NERC standards, and ReliabilityFirst Regional Reliability Organization standards approved by FERC. Non-compliance with these standards can result in potential fines or penalties.

6.1.3 Midcontinent Independent System Operator, Inc.

NIPSCO participates in the larger regional transmission reliability planning process through its membership in the MISO, which annually performs a planning analysis of the larger regional transmission system through the MTEP. The MTEP process identifies reliability adequacy on a larger regional basis and ensures that the transmission plans of each member company are compatible with those of other companies. It should be noted that any transmission project driven by local factors that NIPSCO needs to build must be submitted to MISO for its planning review to ensure that there is no harm to other systems in the region. Under extenuating circumstances, NIPSCO can request expedited review of these projects.

Requests by generation owners to connect new generators to the NIPSCO transmission system, to change the capacity of existing generators connected to the NIPSCO transmission system, or otherwise modify existing generators connected to the NIPSCO transmission system are handled through the MISO Generation Interconnection Process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests. Requests by generation owners connecting to the PJM transmission system are to be coordinated with NIPSCO by PJM through MISO per the process defined by the MISO-PJM JOA.

Requests by generation owners in the MISO footprint to retire existing generators are handled through the MISO Attachment Y process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify either operating procedures or improvements and upgrades necessary to accommodate these requests. Requests by generation owners in the PJM footprint to retire existing generators may be reviewed by MISO for impacts on the NIPSCO transmission system per the process defined by the MISO-PJM JOA, but the generation owners in the PJM footprint are under no obligation to mitigate any resulting constraints on the NIPSCO transmission system.

Requests by generation owners to secure transmission service are handled through the MISO Transmission Service Request process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests.

Because NIPSCO is situated on a very significant boundary (seam) between MISO and PJM, NIPSCO participates in the coordination of transmission planning efforts between MISO and PJM as defined in the MISO-PJM JOA. In addition, MISO may propose transmission system projects or other upgrades that are not reliability based, but are economically based targeted at gains in market efficiency including the lowering of delivered energy costs to the end use customer. These projects must pass the criteria specified in MISO's tariff (including a minimum benefit to cost ratio) before approval.

NIPSCO is also an active participant in MISO and PJM's IMEP planning processes as defined in the MISO-PJM JOA. The IMEP processes focus on evaluating potential transmission projects to lower the overall production cost and lower delivered energy costs to the end use customer for both of the MISO and PJM footprints. These projects must pass the criteria specified in MISO-PJM JOA (including a minimum joint benefit to cost ratio) before approval.

6.1.4 Market Participants

MISO has a process through which market participants can request voluntary upgrades on the NIPSCO transmission system to better accommodate generation outlet capacity, reduce congestion, or other market driven needs. If a market participant wishes to pursue these types of upgrades, they must submit their proposal to MISO and NIPSCO for evaluation in the process defined by the MISO tariff and corresponding Business Practice Manuals. The costs to perform these types of upgrades are negotiated between the market participant and NIPSCO.

6.1.5 Customer Driven Development Projects

NIPSCO may be contacted to undertake transmission upgrades by individual customers based on the customer's plans for economic development or expansion. In coordination with the customer, NIPSCO Major Accounts and NIPSCO Economic Development will determine if identified transmission upgrades are necessary to meet the customer's development or expansion plans. Any transmission upgrades identified via this route, that are applicable under the MISO planning processes, are evaluated by MISO to ensure there is "no harm" to any other system in the region as a result of these upgrades.

6.1.6 NIPSCO Transmission System Capital Projects

NIPSCO's current capital project plan for future years as driven by NIPSCO's planning processes and any projects designated and approved through the MISO MTEP planning effort includes:

- Dune Acres 138kV breaker upgrades
- MISO MTEP20 IMEP Project: Rebuild of the Michigan City to Trail Creek to Bosserman 138kV circuits.
- Maple to LNG 138kV circuit rebuild
- LNG to Stillwell 138kV circuit rebuild
- Maple to New Carlisle 138kV circuit rebuild
- New Hiple to Northport 138kV Circuit
- New 138/69kV substation, Menges Ditch, in Elkhart County

In addition to current portfolio, NIPSCO completed the following transmission system projects, including:

- Multi-Value Project 11: Sugar Creek Substation upgrades to accommodate the new 345 kV circuit from Ameren's Kansas West substation to the NIPSCO/Duke Energy Indiana jointly-owned Sugar Creek substation
- Circuit 13812 Maple Substation upgrade
- Circuit 13854 Aetna Substation line drop upgrade
- LaGrange Substation 138kV Ring bus conversion
- Hiple 138kV relay upgrades for added redundancy
- Kosciusko circuit 13881 switch upgrades
- Bosserman to New Carlisle Circuit rebuild
- MISO Market Efficiency Project: Reynolds Circuit 138109 switch upgrades.
- MISO Market Efficiency Project: Circuit 13835, Roxana to Praxair, line upgrade
- MISO Market Efficiency Project: Circuit 13813, Michigan City to Bosserman, line upgrade
- MISO Market Efficiency Project: Circuit 34504, Munster to Burnham, line upgrade

6.1.7 Electric Infrastructure Modernization Plan

The TDSIC plan is an initiative to modernize infrastructure through upgrades to the NIPSCO electric and natural gas delivery systems. The Commission issued its Order in Cause No. 44733 on July 12, 2016 approving NIPSCO's 7-Year Electric TDSIC Plan (2016-2022). NIPSCO terminated this 7-Year Electric Plan effective May 31, 2021, and filed a new Electric Plan on June 1, 2021 in Cause No. 45557.[84] NIPSCO's Electric TDSIC Plan, which runs from 2021 through 2026, is focused on transmission and distribution investments made for safety, reliability, and system modernization. The Plan also makes provision for appropriate economic development projects in the future, although none are proposed at this time.

NIPSCO's Electric TDSIC Plan includes necessary investments that enable NIPSCO to continue providing safe, reliable electric service to its customers into the future. The Plan is comprised of three main segments: (1) investments that target replacement of aging assets (Aging Infrastructure); (2) investments intended to maintain the reliability of NIPSCO's electric system to deliver power to customers when they need it (System Deliverability); and (3) investments to modernize NIPSCO's communications and AMI technologies (Grid Modernization).

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[84] As of the submission of this 2021 IRP, NIPSCO's proposed TDSIC Plan was pending before the Commission.

6.2 Distribution System Planning

NIPSCO's distribution system is reviewed for local circuit, substation and source feed adequacy. Normal operating status as well as single element or contingency failure loading and voltage operating characteristics are evaluated along with circuit and system wide reliability metrics (i.e., CAIDI, SAIDI, SAIFI).[85] Distribution operating and design criteria rely on NIPSCO design thresholds in accordance with Company Standards, Distribution Systems Planning Criteria, and equipment manufacturer ratings. Voltage operating criteria are based on American National Standards Institute (ANSI) C84.1 and Indiana Administrative Code 170 IAC 4-1-20.

System improvement plans are developed and applied based upon mitigation of identified deficiencies associated with service capacity, service voltage, reliability levels, and load growth patterns. Specific and trending distribution component failures are mitigated through capital and infrastructure improvement processes. Infrastructure upgrade and replacement activities consider system characteristics including severity of operating deficiencies, likelihood of failure, potential customer impact, current substation and line topology, and equipment age and condition. Available new technologies are integrated into improvement and replacement activities where appropriate.

Net metering is an electricity policy for consumers who own renewable (solar, wind, biomass) energy facilities. Its application provides an incentive for customers to install renewable energy systems and generate electricity to offset their individual usage each month. If a participant produces more electricity than they use on a monthly basis, the customer can receive energy credits worth their utility retail rate for their excess generation that can be applied to future usage. The Net Metering program is ending for new customer applications for non-residential customers as of October 1, 2021 and for residential customers as of July 1, 2022. As new customers seek to interconnect after the Net Metering end dates the EDG, currently pending with the Commission in Cause No. 45505, will be made available to customers interested in interconnecting if approved by the Commission.

The renewable feed-in tariff (renewable energy payments) is another policy mechanism designed to encourage the adoption of renewable energy sources and helped accelerate the move toward renewable energy sources. The tariff provides power developers with a predictable purchase price for self-generation under a long-term power purchase arrangement, which helps support financing opportunities for these types of projects. The micro solar, micro wind, intermediate wind, and biomass capacity are not fully subscribed and applications are still being accepted. The intermediate solar category is closed and no longer accepting applications.

NIPSCO implemented its renewable feed-in tariff in July 2011 along with its existing net metering program. These programs helped introduce customer-owned renewable resource based generation onto NIPSCO's electric distribution system. The feed-in tariff program began to attract

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[85] CAIDI is the Customer Average Interruption Duration Index and represents the average time of an outage during the year. SAIFI is the System Average Interruption Frequency Index and represents the average number of times that a system customer experiences an outage during the year. SAIDI is the System Average Interruption Duration Index and represents the number of minutes a utility's average customer did not have power during the year.

a significant amount of renewable generation projects which began coming "on line" in 2012 and has continued to grow. NIPSCO's net metering, feed-in tariff, and pending EDG tariff generation interconnection programs provide, or will provide, an incentive and path for customers to integrate their own distributed generation resources into NIPSCO's electric distribution systems. Solar, wind, and biomass fueled generation resources have been deployed by customers in varying amounts across the service territory.

By the end of 2020, renewable generation data identified 30.4 MWs associated with the net metering program and 36.1 MWs of generation associated with the feed-in tariff program. An aggregate breakdown by renewable fuel type is provided below. These values represent generation resources that include landfill gas combustion engines, animal waste gas combustion engines, photovoltaic solar array farms, small roof mounted and ground mounted residential solar arrays, intermediate sized commercial wind turbines, and small commercial and residential wind turbines.

Net Metering Generation:

- 28.2 MWs - Solar Generation
- 1.9 MWs - Wind Generation
- 0.3 MWs - Solar/Wind Combination Generation

Feed-In Tariff Generation:

- 21.6 MWs - Solar Generation
- 0.2 MWs - Wind Generation
- 14.3 MWs - Biomass Generation

The above biomass related generation value excludes 13.6 MWs of existing landfill based generation interconnected to NIPSCO's distribution system. Although these renewable generation sources feed into NIPSCO's network, the power deliveries are associated with customer PPAs with parties other than NIPSCO. These customers do not participate in NIPSCO's net metering or feed-in tariff programs. In total, approximately 80 MWs of generation is interconnected to NIPSCO's distribution system.

Long term system performance evaluations associated with customer generation continue to evolve as generation penetration levels increase. Performance concerns continue to be associated with adequate control of voltage on distribution primary systems. As larger customer owned generation is added or multiples of mid to large unit are introduced on common circuits, control of voltage levels at remote locations becomes more challenging under normal operating conditions, much less under abnormal operating conditions. Overall, impacts on system operations has yet to be fully determined and will depend upon the demonstrated long term performance and reliability of various installed generating resources including solar, wind, and biomass based generation fueled resources. Differences in operational characteristics, generation penetration, power delivery timing, and location all affect the relative impact on local distribution system operations at any given time.

The diverse types of customer-owned generation also have varying effects on the electric system. NIPSCO has observed that local generation most often varies substantially depending upon individual customer equipment, generation size, and generation input resources. Fuel resource type affects power delivery in various ways depending upon owner controlled resources as is the case of landfill and animal by-product gas inputs, or external environmental conditions such as wind velocity and solar irradiance. Highly variable outputs have been observed to occur on both solar and wind turbine installations. For instance, rapid changes in solar generation have exhibited swings of 85% of full rated output, within seconds. These conditions represent sizable down-up-down shifts in system operating characteristic on local circuits associated with some of the larger half MW or greater rated customer owned solar fields. These swings can present challenges to maintaining appropriate service voltage stability on distribution circuits. In addition to these more rapid changes relating to industry recognized “cloud affect,”

NIPSCO has also observed that more widespread weather patterns such as seasonal rain or snow storms also dramatically influence individual daily peak PV generation outputs on a longer term scale. Longer duration output reductions of 75% to 95% of rated equipment output have been observed during seasonal inclement weather conditions. Significantly reduced output levels can extend over several or more days, especially during winter season months. Wind powered generation was also observed to be as much, if not more, unpredictable and variable in power delivered to the distribution system. However, this has had less impact on NIPSCO distribution systems in recent years because little activity has occurred associated with small scale wind generation. On the other hand, large biomass fueled combustion turbines continue to be less volatile in generated outputs in comparison to solar and wind associated generation. Landfill based biomass generation facilities tend to be the most predictable followed by animal waste gas associated generation. However, even though biomass fueled resources exhibit a steadier dispatch of power, random events still occur where large customer generation drops off completely. The impact of lost generation becomes more significant with larger individual generators since local distribution systems need to adjust to compensate for fast changes in power resources. NIPSCO has also observed a trend with older large biomass (landfill) generation resources where output decreases with age of the landfill itself and associated generation equipment. 25% to 50% reductions in output have been observed at several sites.

Based upon past distribution system operating history associated with installed renewable generation resources, these technologies present a recognized energy resource that can be utilized to successfully supplement customer electric energy needs. However, their impact on local electric distribution infrastructure has not demonstrated to be sufficiently available to be considered an adequate substitute for NIPSCO’s local electric resources in reliably meeting electric capacity and service needs for its customers. Considering that distributed generation resources have no obligation for power deliverability, operate in a “take it as you make it” mode, and can cease operations at any time for whatever reason, all lead to the lower confidence level regarding availability of power supply, especially during periods of system stress or problems. Consequently, continued traditional capital investment into local distribution infrastructure is necessary to insure that the utility can meet all service obligations to its customers.

6.2.1 Evolving Technologies and System Capabilities

NIPSCO continues the expansion of its distribution SCADA systems, improve its DA systems, and apply other new technologies.

NIPSCO's application of SCADA on distribution substations has undergone expansion, resulting in an increase in coverage from 25% to its current level of 43% of all associated stations. Distribution circuit coverage stands at approximately 48% of all circuits. As part of its ongoing infrastructure improvement programs, new, as well as rebuilt distribution substations, and their associated circuits, are assessed for the application of SCADA and DA in their scope and construction. New station projects, as well as full or partial station rebuild projects are currently being implemented at a rate of approximately five or more per year. Based on continuation of these activities, further expansion of NIPSCO's substation SCADA and DA systems are anticipated to continue.

NIPSCO initiated a new program for technology upgrades on existing control schemes and systems associated with its legacy DA systems. The original DA systems at NIPSCO date back to as early as the 1990's. Older system control schemes and equipment are scheduled to be upgraded to new SEL distribution network automation control systems. These new systems feature automatic network reconfiguration and self-healing actions using algorithms that provide more flexibility and higher levels of reliability. They allow much greater levels of customization of settings and flexibility to fit specific operating conditions. The newer DA automated systems will further enhance how the system determines the best path forward when recognizing faults and restoring customer services. Application of these newer DA control schemes are anticipated to further reduce the amount of permanent outages seen by customers, resulting in improvements in SAIDI and SAIFI metrics. In addition to the above operational improvements, the new systems also provide an opportunity for scaling (expansion) of DA systems that did not exist prior due to previous limitations on the older technologies.

In 2020, NIPSCO initiated the roll out of it new "trip saver" program for the application of more advanced types of local distribution line protection. This program applies new state of the art automated line reclosers. These newer devices are being applied throughout NIPSCO's territory to better handle temporary line faults. This equipment is applied and mounted in place of typical line fuses, and combines the best aspects of fuse-saving and fuse-blowing strategies to improve overall system reliability and prevent temporary faults from becoming sustained outages. Application of these devices will reduce the amount of permanent outages seen by customers resulting in improvements in SAIDI and SAIFI metrics. New equipment is being applied to replace older technologies such as "triple-shot" fuse installations and older traditional hydraulic reclosers.

NIPSCO continues to evaluate the benefits of emerging smart grid, DA, and other applicable technologies and to assess their deployment based upon corporate investment strategies in infrastructure as part of its long term approach.

Section 7. Environmental Considerations

7.1 Environmental Sustainability

NIPSCO is committed to delivering energy safely, reliably, and in an environmentally responsible and sustainable way. Since 2005, NIPSCO's impact to the environment has been reduced, and NIPSCO remains committed and on-track to achieve aggressive GHG and other environmental impact targets. Progress and targets for electric generation are summarized in Table 7-1.

Table 7-1: Environmental Sustainability Targets

	Progress Through 2020 % Reductions from 2005	Target 2025 % Reductions from 2005	Target 2030 % Reductions from 2005
Carbon Dioxide (Electric Generation)	66%	50%	90%
NOx	89%	90%	99%
SO2	98%	90%	99%
Mercury	96%	90%	99%
Water Withdrawal	91%	90%	99%
Water Discharge	95%	90%	99%
Coal Ash Generated	71%	90%	100%

NIPSCO has also invested in environmental controls across its coal fleet which allow for compliance with environmental requirements and environmental improvements while NIPSCO transitions to a more sustainable generation portfolio. See Table 7-2.

Table 7-2: Environmental Controls

Unit	Year In Service	Fuel Source	Particulate Matter (PM) Control	Sulfur Dioxide (SO2) Control	Nitrogen Oxide (NO_x) Control	Mercury (Hg) Control	Coal Ash	*Planned Retirement
MCGS U12	1974	Coal	Baghouse	Dry FGD	OFA & SCR	ACI & FA	SFC	2028
RMS U14	1976	Coal	ESP	Wet FGD	OFA & SCR	ACI & FA	SFC	2021
RMS U15	1979	Coal	ESP	Wet FGD	LNB w/ OFA, SNCR	ACI & FA	SFC	2021
RMS U16A	1979	Natural Gas	--	--	--	--	--	--
RMS U16B	1979	Natural Gas	--	--	--	--	--	--
RMS U17	1983	Coal	ESP	Wet FGD	Advanced LNB w/ OFA	--	--	2023
RMS U18	1986	Coal	ESP	Wet FGD	Advanced LNB w/ OFA	--	--	2023
Sugar Creek	2002	Natural Gas	--	--	SCR	--	--	--
Norway	1923	Water	--	--	--	--	--	--
Oakdale	1925	Water	--	--	--	--	--	--

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

7.2 Environmental Compliance Plan Development

NIPSCO operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste, and solid waste that protect health and the environment. NIPSCO is committed to complying with all regulatory requirements. This commitment is embodied in the NiSource Environmental, Health & Safety, and Climate Change Policies and is implemented through a comprehensive environmental management system. Compliance plans are developed, reviewed, and evaluated for implementation to meet new and changing legislative and regulatory developments.

7.3 Environmental Regulations

7.3.1 Solid Waste Management

The EPA finalized a rule regulating the management and disposal of the CCR which became effective on October 19, 2015. The CCR rule regulates CCRs under the RCRA Subtitle D as nonhazardous. The CCR rule is implemented in phases establishing requirements related to groundwater monitoring, CCR management and disposal, reporting, recordkeeping, and document management.[86] The rule allows NIPSCO to continue its byproduct beneficial use program, significantly reducing CCR that must be disposed.

To comply with the rule, NIPSCO completed capital expenditures in 2019 to modify its infrastructure and manage CCRs. NIPSCO continues to assess and monitor groundwater quality at its generating stations to comply with CCR rule requirements and to determine if historic CCR management and disposal practices will require corrective measures.

7.3.2 Clean Water Act

The CWA establishes water quality standards for surface waters as well as a permit program for regulating discharges into the waters of the United States. Under the CWA, EPA created a program to establish wastewater discharge standards for industry, including electric utilities. In addition, the CWA made it unlawful to discharge from a point source into navigable waters without a permit. The NPDES permit program implements the CWA's provisions.

7.3.3 Effluent Limitations Guidelines

EPA first promulgated the ELG Rule in 1974, and has amended the regulation many times, with the latest revision effective date of December 14, 2020. The ELG Rule regulates wastewater discharges from power plants operating as utilities. The implementing requirements are incorporated into NPDES permits. Significant capital expenditure is not required for NIPSCO to comply with the ELG Rule given the expected retirement dates of the coal units at Schahfer, and the dry FGD and CCR-related investments at Michigan City.

7.3.4 Clean Air Act

NIPSCO emissions of nitrogen oxides of NO_x, SO2, and mercury have been reduced by nearly 90% since 2005. All Northern Indiana counties are in attainment of the NAAQS with the exception of the ozone standards in Lake and Porter Counties, which are included in Chicago metropolitan area nonattainment.

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[86] https://www.nipsco.com/about-us/ccr-rule-compliance-data-information

In April 2021, the EPA published the Revised CSAPR Update for the 2008 NAAQS. Starting with the 2021 ozone season (i.e., May through September), the rule requires additional NOx reductions from power plants in 12 states, including NIPSCO generation stations. NIPSCO plans to comply with this rule through the continuous operation of emissions controls, retirement of coal generation, allowance allocations from the EPA, and allowance transactions (as appropriate). Emission allowance inventories under the EPA CSAPR and Acid Rain programs are provided in the tables below.

Retaining Schahfer Units 17 and 18 beyond 2023 would likely require expenditures to further reduce NOx emissions. Although both Schahfer Units 17 and 18 are already equipped with low-NO_x burners and OFA systems for NO_x reduction, SCR or SNCR could be installed for post-combustion NO_x control for compliance with anticipated regulation.

In July 2019, under the authority of the Clean Air Act, the EPA published the final ACE Rule, which establishes emission guidelines for states to use when developing plans to limit carbon dioxide at coal-fired electric generating units based on heat rate improvement measures. The U.S. Court of Appeals for the D.C. Circuit vacated and remanded the rule in January 2021. NIPSCO will continue to monitor this matter. Potential requirements under the ACE Rule were not included in the IRP modeling because they are unlikely to be implemented.

7.3.5 Emission Allowance Inventory and Procurement

7.3.5.1 CSAPR Emission Allowance Inventory

Under CSAPR, the EPA allocates annual SO2, annual NO_x, and ozone season NO_x allowances to NIPSCO, which are summarized in Table 7-3.

Table 7-3: CSAPR Allowance Inventory

CSAPR Allowance Inventory*

Year	Annual SO2	Annual NO_x	Ozone Season NO_x
Bank**	149,348	11,973	203
2021 – 2023 Annual Allocation	28,998	13,026	***
2024 Annual Allocation	21,725	12,178	N/A
Total	**258,067**	**63,229**	**4,006**

** Allowance inventory available as of August 2021*

*** Reflects emission allowances from 2020 and earlier*

****2,192 allowances were allocated for 2021 and 1,611 allowances were allocated for 2022*

7.3.5.2 Title IV Acid Rain - SO2 Emission Allowance Inventory

In conjunction with CSAPR, the Title IV Acid Rain Program will continue to regulate SO2 emissions. Table 7-4 lists the actual number of SO2 Acid Rain Program emission allowances held in inventory by NIPSCO as of July 2021 for the period 2021 through 2051. Based on current projections of future emissions, NIPSCO does not need to procure additional allowances to comply with the Acid Rain Program.

Table 7-4: SO2 Acid Rain Program Emission Allowances

Acid Rain Program
SO2 Allowance Inventory*

Year	Allowances
Bank**	315,086
2021-2051 Annual Allocation	50,706
Total	**1,886,972**

* Allowance inventory available as of August 2021
** Reflects emission allowances from 2020 and earlier

7.4 Climate-Related Considerations

As of 2021, NIPSCO has reduced carbon dioxide emissions from electric generation by 66% since 2005, and has targeted a 90% reduction by 2030 through the anticipated retirement of all NIPSCO-owned coal generation.

Although several legislative and executive actions related to GHG emissions have been attempted over the last decade, there is currently no federal price on carbon and no binding power sector GHG emission limits at the federal level. However, given multi-faceted efforts through the Biden Administration and Congress to reduce GHG emissions, NIPSCO's IRP modeling includes several climate-related scenarios, including net-zero, clean energy standard, and carbon price scenarios. Refer to Section 8 for further discussion of carbon policy and prices.

This report also describes the resilience of NIPSCO's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario, which aligns with recommendations from the Task Force for Climate-Related Financial Disclosures.

Section 8. Managing Risk and Uncertainty

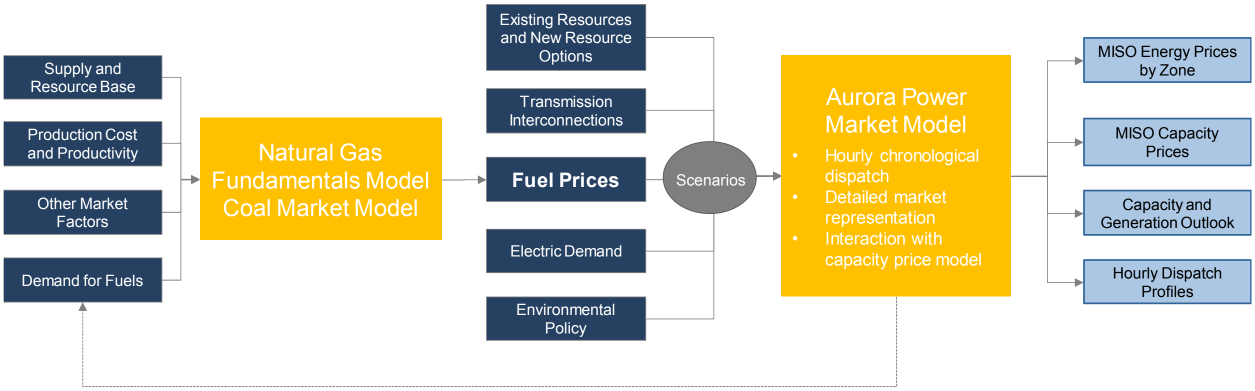
8.1 Introduction & Process Overview

In the 2021 IRP, NIPSCO deployed an approach to evaluating risk and uncertainty that involved the development of a fundamentals-based set of key Reference Case market drivers and the deployment of both scenarios and stochastic analysis to assess variance around this Reference Case.[87] NIPSCO developed the major inputs and associated uncertainty ranges for the 2021 IRP through the following process:

- Development of the Reference Case set of assumptions through fundamental energy sector, commodity price, and load forecasting models;
- Identification of the key drivers of uncertainty and appropriate assignment to scenario or stochastic analysis frameworks;
- Development of distinct scenario themes with accompanying model-based forecast assumptions; and
- Development of stochastic distributions for relevant variables.

The major market assumptions for the Reference Case and the scenarios were developed using a set of fundamental market models deployed by CRA and summarized in Figure 8-1. These models include the NGF model for natural gas price projections and the Aurora model for long-term MISO-wide capacity expansion, production cost analysis, and granular power price forecasting. Section 2 has additional detail on the models used in the IRP.

Figure 8-1: Fundamental Market Modeling Structure



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[87] Since the development of the Reference Case assumptions in Spring 2021, market forwards for key fuel and power prices have increased. Although near-term market prices are higher than the Reference Case forecast as of the time of the submission of this report, NIPSCO's IRP assumptions remain valid for portfolio analysis because (i) as discussed in Section 8.5, NIPSCO's stochastic analysis was designed to capture price volatility consistent with current market behavior and covers recent price movements; (ii) market forwards suggest a decline in fuel and power prices by 2023 towards levels consistent with the Reference Case forecast; and (iii) the scenario ranges cover a widening envelope of price outcomes over time to reflect potential fundamental drivers of long-term higher or lower price trajectories.

The next section provides an overview of the fundamental drivers that underpin the NIPSCO Reference Case for gas prices, coal prices, carbon prices, and power market prices, while the remainder of the chapter discusses the scenarios and associated assumptions and the stochastic distributions that were developed to support the 2021 IRP process.

8.2 Reference Case Market Drivers and Assumptions

8.2.1 Natural Gas Prices

Figure 8-2 provides an overview of the key inputs that drive CRA's fundamental forecast in the NGF model. NIPSCO's 2021 Reference Case natural gas price forecast is driven by several key market assumptions regarding the major supply and demand dynamics in the North American natural gas market. Figure 8-3 summarizes the major supply side drivers, along with CRA's approach and assumptions for each driver, as well as supporting explanations. Figure 8-4 summarizes the same information for the major demand side drivers. The remainder of this section then provides additional detail related to each driver.

Figure 8-2: Overview of CRA's NGF Model Inputs

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

Figure 8-3: Supply Side Natural Gas Price Drivers – Reference Case

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

*IP = Initial Production

Figure 8-4: Demand Side Natural Gas Price Drivers – Reference Case

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

Resource Size

In developing long-term estimates for natural gas resource size, CRA relied on the PCG 2018[88] "minimum" value as the starting value for recoverable shale reserves, with the resource base growing over time at a steady rate until the PGC "most likely" value is reached in 2050. The assumed values and ranges are shown in Figure 8-5.

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[88] Note that the PGC 2018 view was released in October 2019, with PGC 2020 not available at the time of the development of NIPSCO's 2021 IRP assumptions. Scenario development (discussed further below) incorporates a range of views on the future resource base, anticipating potential ranges of resource base in the PGC 2020 report.

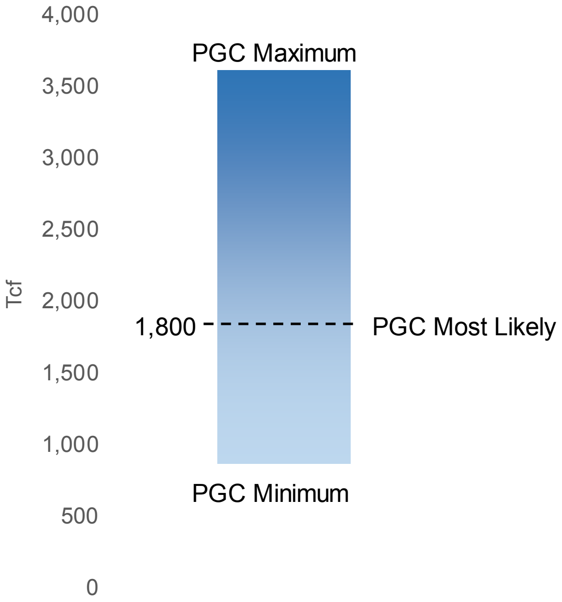
PGC evaluates three categories of potential resource:

- Probable – gas associated with known fields;
- Possible – gas outside of known fields, but within a productive formation in a productive province; and
- Speculative – gas in formations and provinces not yet proven productive.

PGC assigns resource to three probability categories:

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

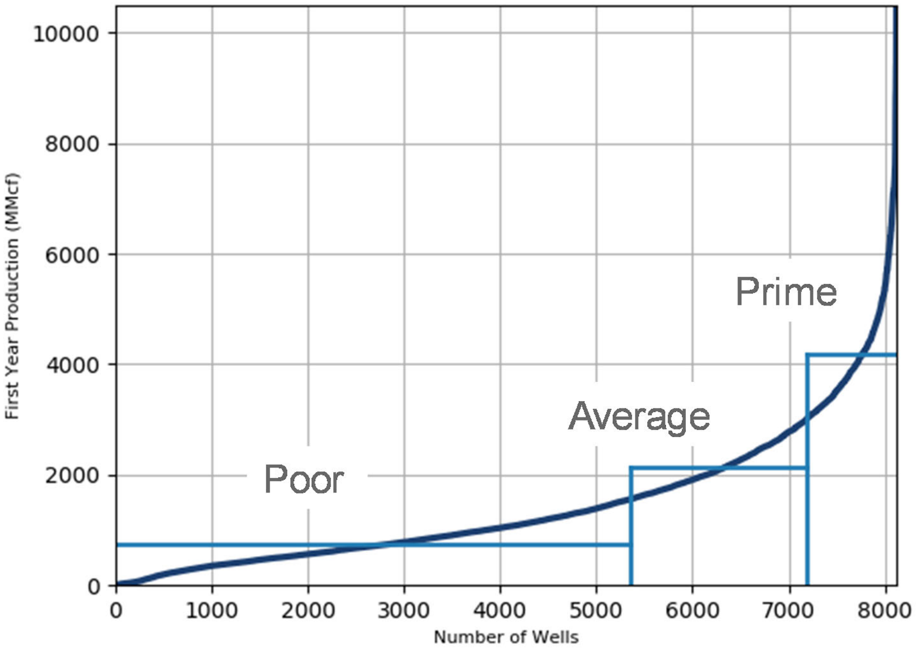
Figure 8-5: Uncertainty Range for Shale Resources in PGC 2018



Well Productivity

Natural gas well productivity assumptions are important drivers of ultimate production efficiency, especially since the bulk of the natural gas resource is currently unproven, meaning that the geology of that resource is currently unknown. In developing assumptions for this variable, CRA generated productivity distributions for each production basin based on drilling data in regions that producers expected to have favorable geology. CRA's view is that historical data has a bias towards higher producing sub-regions, since the wells that are completed and ultimately produce gas do not reflect a random sampling of the underlying geology in each basin. Therefore, to reflect the expectation that the remaining resource is more likely to be lower quality over time as the premium acreage is depleted, CRA assumes a "Poor Heavy" productivity distribution for future undiscovered resource in the Reference Case. An example of this distribution for the Appalachian region is shown in Figure 8-6, with the number of wells shown on the x-axis and the level of first-year production shown on the y-axis.[89]

Figure 8-6: Well Productivity Distribution Illustration for Appalachia



Well Costs

CRA develops drilling cost assumptions by evaluating reported costs from major producers within a supply region. Producers reported improvements in drilling and O&M costs across most, but not all, shale basins in 2020, and CRA broadly assumes that these improvements will continue over time. Figure 8-7 summarizes current drilling costs in the major production regions, while Figure 8-8 summarizes current O&M costs in the same basins.

For going forward costs, CRA relies on the EIA's AEO projections for improvements in drilling and O&M costs. EIA's approach incorporates annual improvements to key well inputs that account for ongoing innovation in upstream technologies and reflects the average annual growth rate in natural gas and crude oil resources from historical time periods. Drilling costs are expected to decline by 1% per year for tight oil and shale gas formations and decline by 0.25% per

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[89] Distribution is based on CRA analysis of the Lasserdata drilling database. This proprietary database is produced by Lasser, Inc. and includes historical monthly oil and gas production data.

year for all other basins. Equipment and operating costs are expected to decline by 0.5% per year for tight oil and shale gas formations and decline by 0.25% per year for all other basins.

Figure 8-7: Shale Gas Drilling Costs

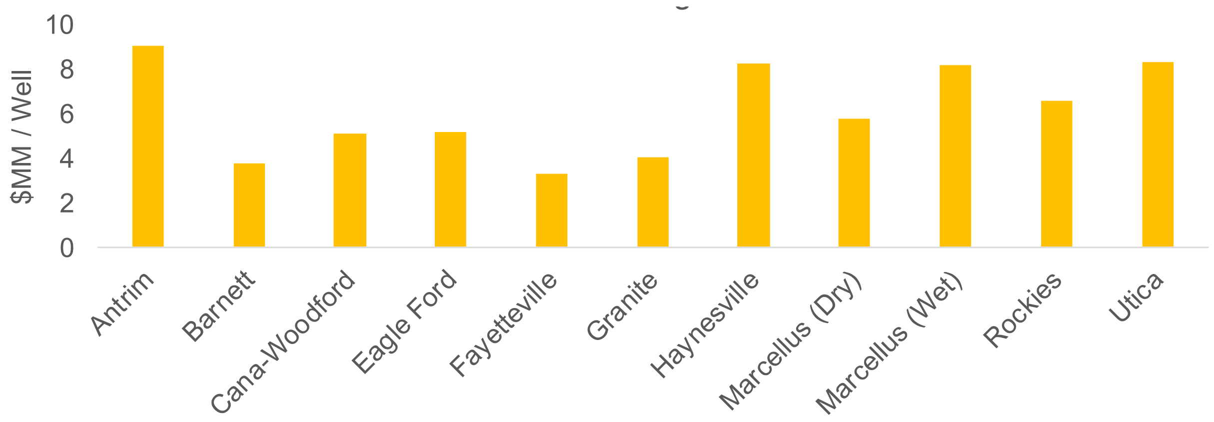
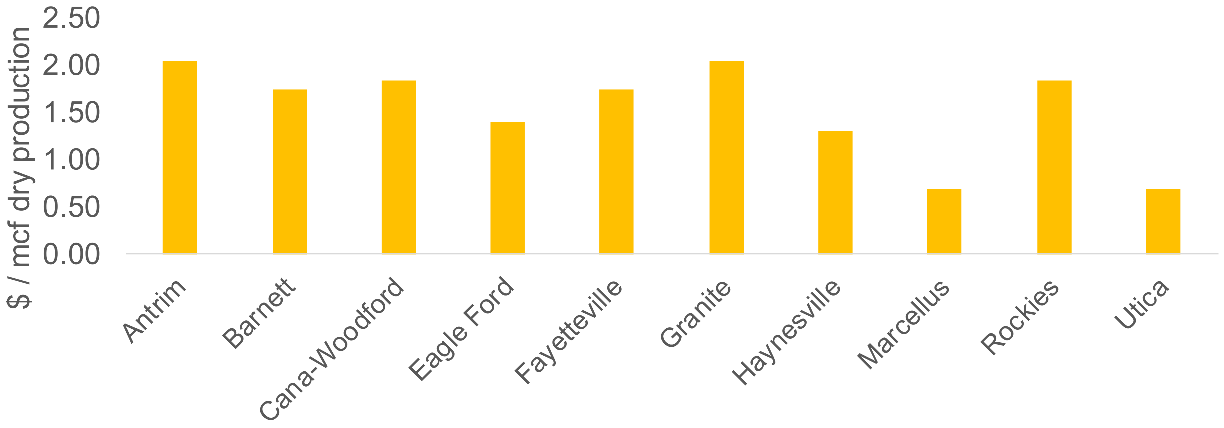


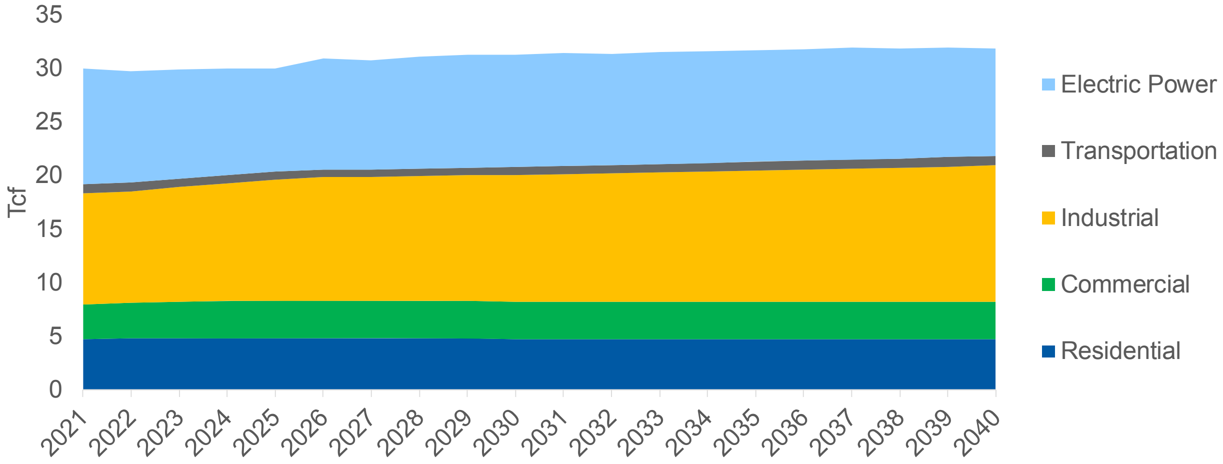
Figure 8-8: Shale Gas O&M Costs



Domestic Demand

In projecting domestic natural gas demand growth, CRA relies on the AEO's projections for residential, commercial, industrial, and transport demand and develops an independent electric sector demand forecast using its hourly Aurora dispatch model of the entire United States. Figure 8-9 presents historical and forecast domestic demand assumptions through 2040 from these sources. Electric sector demand is expected to be relatively flat throughout the forecast horizon. The AEO's growth expectations for other sectors are also relatively flat, with some growth expected in the industrial sector over time.

Figure 8-9: Domestic Natural Gas Demand Assumptions – Reference Case

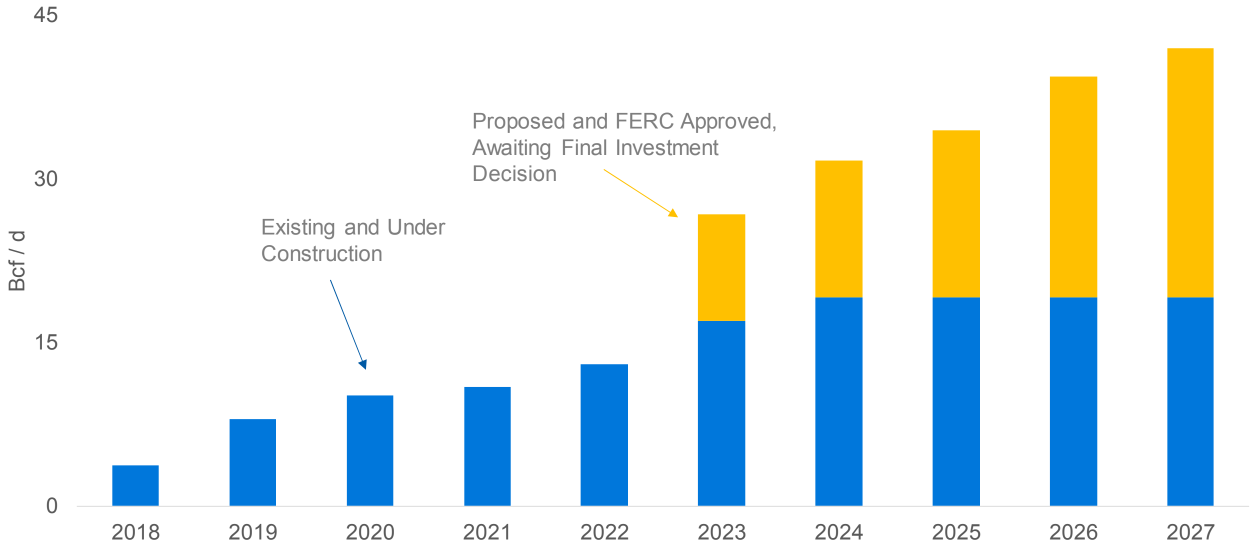


Exports – LNG and to Mexico

CRA develops projections for natural gas exports to Mexico via pipeline and to other international markets through LNG by reviewing estimates published by sources like the AEO and conducting analysis of specific export projects under development.

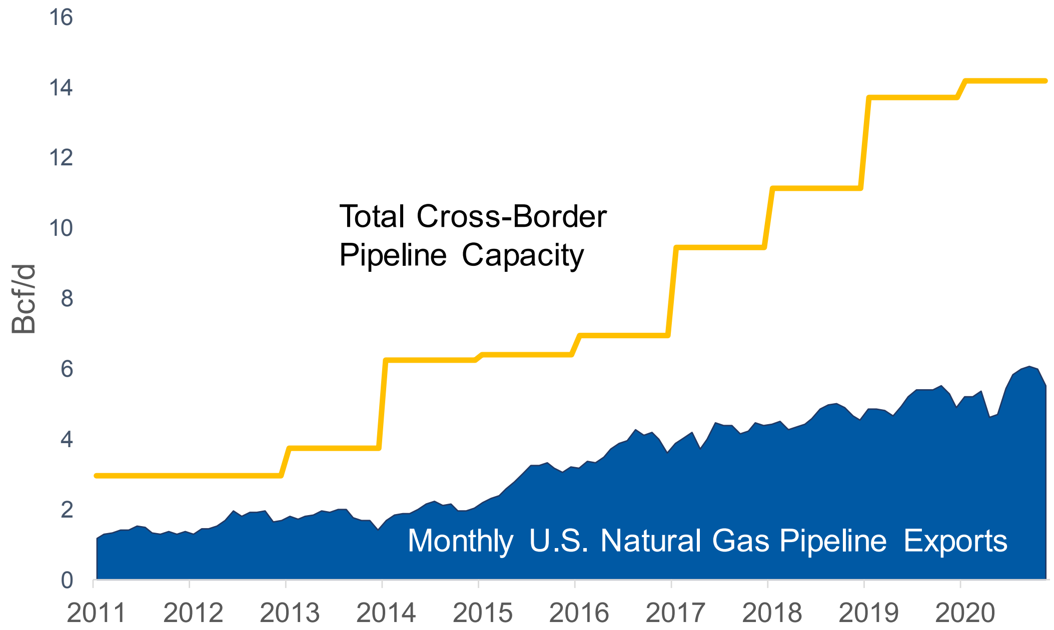
While several LNG export projects are now online or under construction, due to softening prices and increased competition, CRA expects that few, if any, currently proposed projects will be completed after Calcasieu Pass and Golden Pass come online in 2023 and 2024. CRA's Reference Case projection for LNG exports is shown in Figure 8-10 in the blue bars, growing to just under 20 bcf/day by 2024. The incremental proposed projects shown in yellow are not included in the Reference Case view.

Figure 8-10: LNG Export Volume Projections by Year and Approval Status



While CRA expects that exports to Mexico will also increase over time, actual exports to Mexico are not keeping pace with the expansion of cross-border export capacity, as illustrated in Figure 8-11. Numerous pipeline projects within Mexico have faced construction delays, and completed projects are operating well below capacity. For example, the 1.1 Bcf/d Comanche Trail pipeline has been utilized only 10% on average since completion in June 2017, and the 1.4 Bcf/d Trans-Pecos pipeline completed in 2017 currently has operated at 10-15% of total capacity since completion. Therefore, in the Reference Case, CRA projects modest additional growth in export volume, but expects that pipeline capacity will continue to be underutilized.

Figure 8-11: Net Exports to Mexico by Pipeline

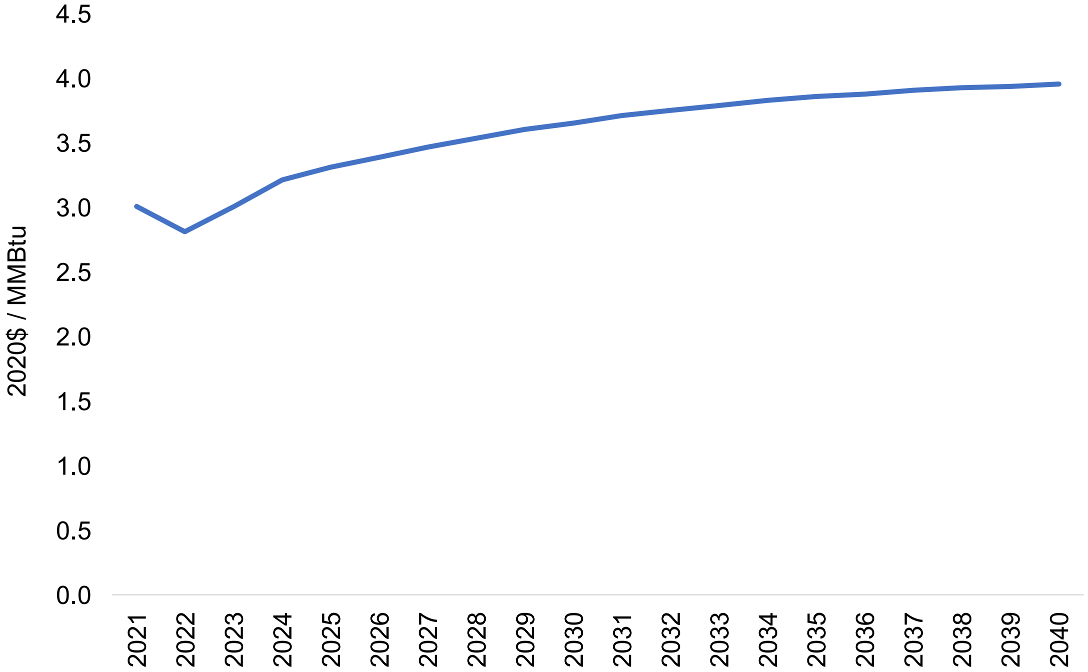


Reference Case Price Forecast

CRA's Reference Case price forecast was developed based on each of the supply-demand inputs discussed above and is shown in Figure 8-12. Although prices at Henry Hub have remained below $3/MMBtu in recent years, the Reference Case still expects price rises towards $4/MMBtu (real) over the long-term. A brief summary of the key drivers of the expectation for increasing prices follows:

- 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;
- Expectations for downward price pressure driven by improvements in drilling and O&M costs are likely to be moderated by lower domestic oil prices and associated gas volumes; and
- CRA has 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.

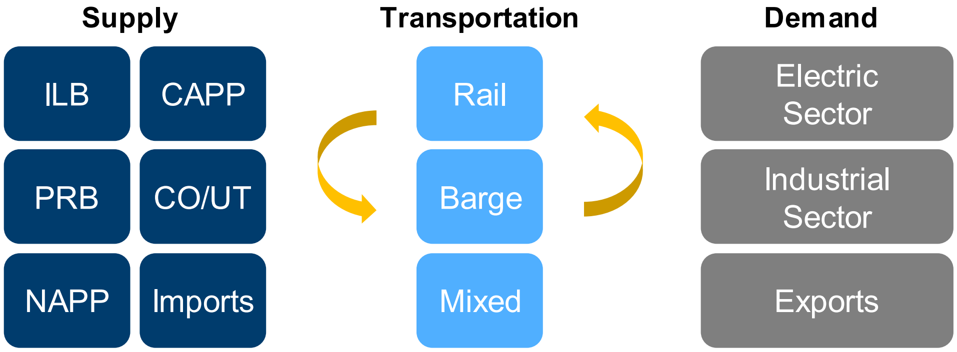
Figure 8-12: Reference Case Gas Price Forecast



8.2.2 Coal Prices

NIPSCO's 2021 Reference Case coal price forecast was driven by a fundamental view of the major supply and demand dynamics for each of the four major coal basins in the United States, integrated with other Reference Case assumptions for natural gas prices (discussed above), carbon prices (discussed below), and the expected evolution of the power sector over time. The core forecasting process incorporates perspectives on coal supply, demand, and transportation to deliver fuel to plants throughout the U.S, as illustrated in Figure 8-13. CRA's process assesses the future supply/demand balance for the U.S. coal market based on macroeconomic drivers, including domestic and international demand, and microeconomic drivers, including trends in mining costs and production.

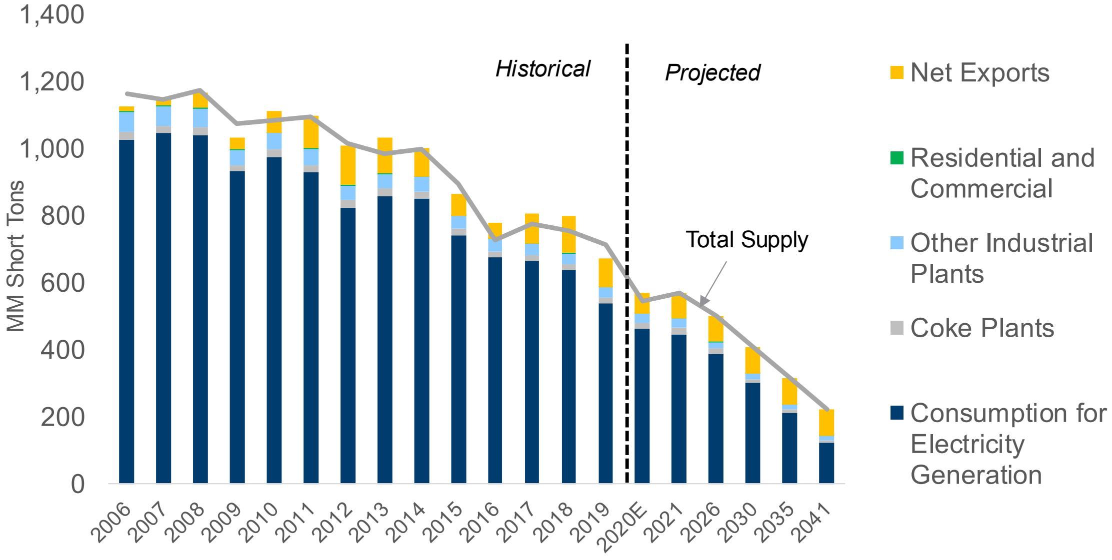
Figure 8-13: Coal Forecasting Process Overview



Coal Supply and Demand Trends

Figure 8-14 summarizes historical and projected supply and demand for U.S. coal over the period from 2006 through 2041, which shows that coal demand has generally been in decline over the last fifteen years. A total of 20 GW of coal generating capacity retired in the U.S. in 2019 and 2020, and low natural gas prices have continued to dampen demand, such that total demand for U.S. coal declined by about 228 million tons/year (or 29%) between 2018 and 2020, with domestic demand declining by about 178 million tons/year (or 26%), and total U.S. coal exports declining by about 50 million tons/year (or 43%). Furthermore, 2019 coal demand was about half of where it was in 2010. Modest additional declines are expected in the next five years, with more substantial declines expected after 2026, particularly if carbon regulation is implemented, as is projected in the Reference Case.

Figure 8-14: Supply-Demand Balance for U.S. Coal – 2006-2041[90]



Reference Case Price Forecast

CRA's Reference Case price forecast is driven by both the regional production outlook and an assessment of production costs at various demand levels. Figure 8-15 presents the Base Case price outlook by coal supply region, with additional basin-level commentary provided below:

- CAPP: Demand for CAPP steam coal has declined steeply, due to the high production cost of this coal, and the diversion of most remaining Central Appalachian coal supplies to the metallurgical coal market.
- NAPP and ILB: The current prices for NAPP and ILB coals appear to be below the levels needed to sustain the current levels of coal production in these regions.

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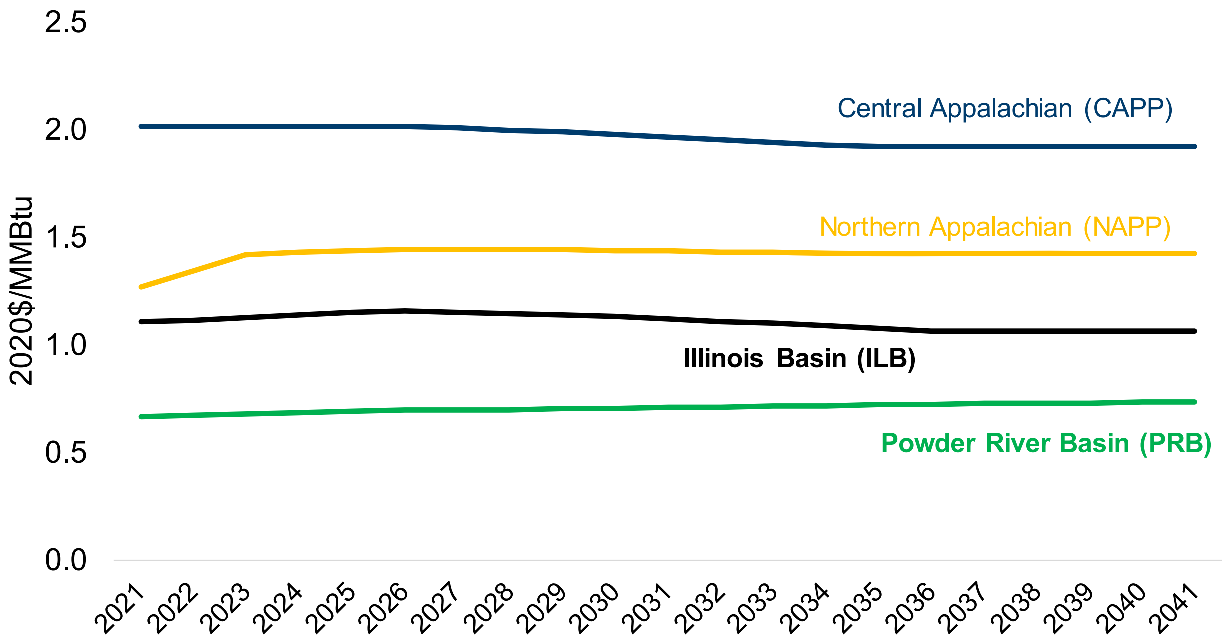
[90] 2006-2019 data is from EIA and the Mine Safety and Health Administration.

Therefore, some upward movement in these prices is expected during 2021-2026. After 2026, real declines in prices are expected to resume as coal demand falls.

- PRB: Prices for PRB coal are expected to increase slightly in real terms (by an average of about 0.5%/year) over the forecast period. This reflects the unique geology of the PRB region, in which the coal seams slope downward at a gradual but constant rate, so that any amount of incremental coal production is likely to result in gradually increasing mining costs over time.

Figure 8-15: Reference Case Coal Price Forecast



8.2.3 Carbon Policy and Prices

Although several legislative and executive actions related to carbon emissions have been attempted over the last decade, there is currently no price on carbon and no binding emission limits at the federal level. As of the time of the development of NIPSCO's 2021 IRP assumptions, the Biden Administration has begun to take executive actions related to carbon emission reductions and has introduced several climate-related legislative proposals as part of its overall infrastructure package. Recent and potential executive actions include:

- Re-joining the international Paris accords and re-engagement in international agreements related to greenhouse gas emission reductions;

- Limiting access to fossil fuel production on federal lands and directing the EPA to impose stricter standards on production;

- Directing the EPA to re-interpret Clean Air Act authority to regulate CO2 emissions from power plants;

- Appointing FERC commissioners who could encourage or institute carbon pricing in wholesale markets; and

- Mandating the reduction of greenhouse gas emissions for federal fleets, buildings, and other operations.

Legislative proposals being debated in 2021 include:

- Extensions of the investment and production tax credits for renewable and other clean energy resources such as nuclear and carbon capture and storage, and expansions of similar tax credits for resources like storage and new transmission;

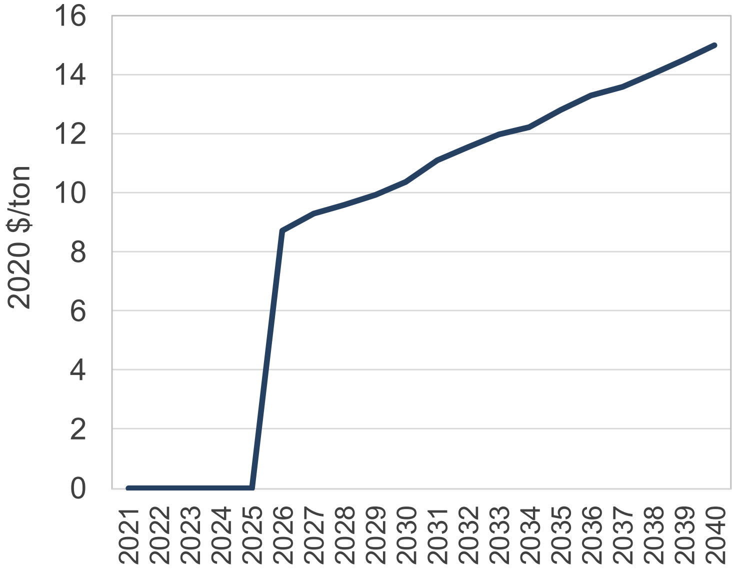
- A goal of a 100% carbon-free power sector by 2035, potentially through a clean energy standard;

- Direct subsidies and incentives for electric vehicles and energy efficiency measures; and

- New research and development initiatives, including investment in infrastructure resiliency and new technology such as hydrogen.

Given such efforts to regulate carbon emissions, NIPSCO's Reference Case incorporates price on carbon emissions starting in 2026, which is reflective of several different potential pathways for legislative action or executive regulation. Similar to NIPSCO's 2018 IRP, CRA's analysis suggests that pricing between $9-15/ton (in real 2020$) between 2026 and 2040 would achieve 30-40% reductions in CO2 emissions from the U.S. power sector relative to a recent historical year baseline. Such a carbon price would likely result in significant additional coal-to-gas switching nationwide and pressure approximately 80% of the existing coal fleet across the country to retire by 2040. The price would also improve the economics of renewable and other clean energy generation, resulting in total clean energy accounting for over 50% of total U.S. electricity production. The pricing outlook incorporated in the Reference Case is shown in Figure 8-16 in real dollars per short ton.

Figure 8-16: Base Case Carbon Price Forecast



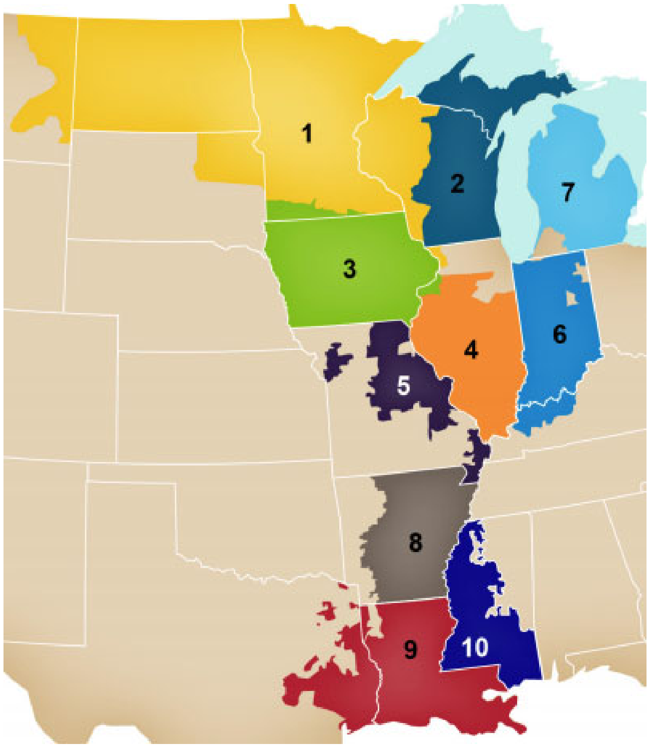
8.2.4 MISO Energy and Capacity Prices

NIPSCO operates within the MISO region, which includes parts of fifteen states throughout the Midwest and South. The traditional MISO North footprint covers parts of Indiana, Michigan, Illinois, Missouri, Kentucky, Iowa, Wisconsin, Minnesota, North Dakota, South Dakota, and Montana, as illustrated in Figure 8-17. Overall, MISO provides the following services to members and participants:

- 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; and
- 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

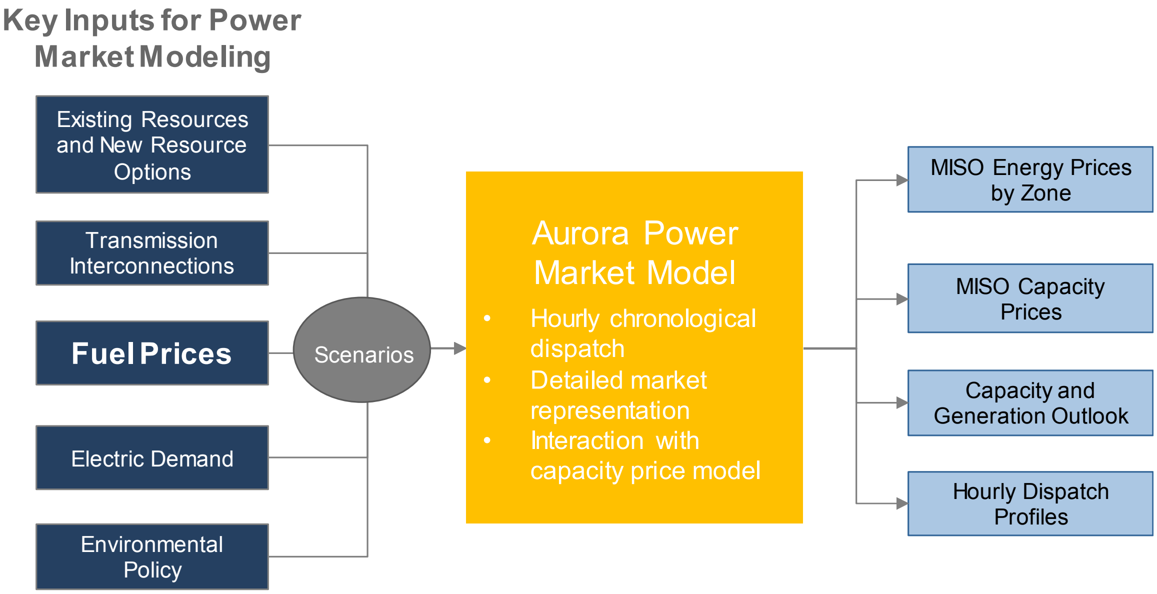
NIPSCO territory and resources fall within LRZ 6, covering Indiana and parts of Kentucky. In developing the Reference Case market price forecasts for energy and capacity, CRA deployed its Aurora market model to represent the entire MISO footprint and produce fundamental, hourly price projections that are internally consistent with the fundamental outlook for natural gas prices, carbon prices, and the future capacity mix in the region.

Figure 8-17: MISO Footprint



Based on the market inputs for fuel and carbon prices, along with other inputs associated with existing and new resource expectations throughout MISO, regional transmission interconnections, and regional electric demand, CRA developed Reference Case expectations for the MISO market, including energy capacity prices according to the process shown in Figure 8-18.

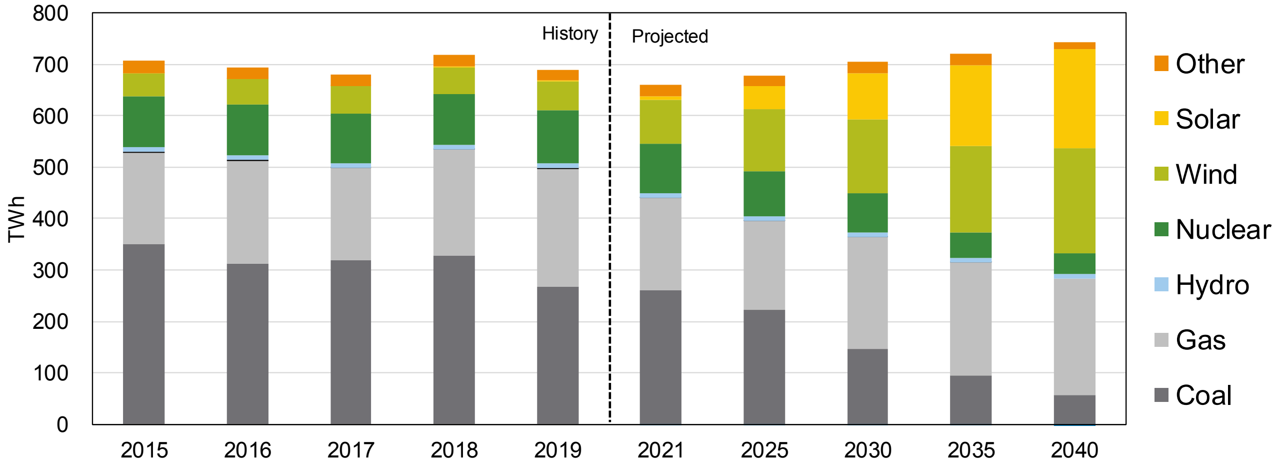
Figure 8-18: Power Market Modeling Process



MISO Capacity Mix

CRA's Reference Case analysis expects a continued shift from coal capacity and energy production toward renewables, and to a lesser extent natural gas, over the next two decades. Since 2015, coal generation has declined from approximately 50% of the total MISO mix to less than 40%, and the Reference Case forecast projects that it will reach 20% by 2030 and less than 10% by 2040. Meanwhile, the Reference Case expects significant growth in renewable energy from wind and solar, such that by 2040 over half of energy generation throughout the region is expected to be from renewable resources. CRA's Reference Case projection of the evolution of the MISO energy mix is presented in Figure 8-19.

Figure 8-19: MISO Generation by Fuel Type – History and Reference Case Projections



Reference Case Energy Price Forecast

CRA's Reference Case MISO energy market forecast is presented in Figure 8-20 on an annual basis and in Figure 8-21 on a monthly basis. The Reference Case expects that power prices will stay relatively flat in the near-term, due to flat gas and coal prices, although upward pressure on prices is expected into the 2020s as a result of higher projected natural gas prices. The expected national carbon price in 2026 drives a projected increase in power prices in that year, although growing renewable penetration over the long-term mitigates future price growth expectations. In fact, convergence in peak and off-peak prices is projected over time in the Reference Case due to growing solar energy output, which tends to reduce peak pricing.

Figure 8-20: LRZ6 (Indiana) Reference Case Annual Price Projections

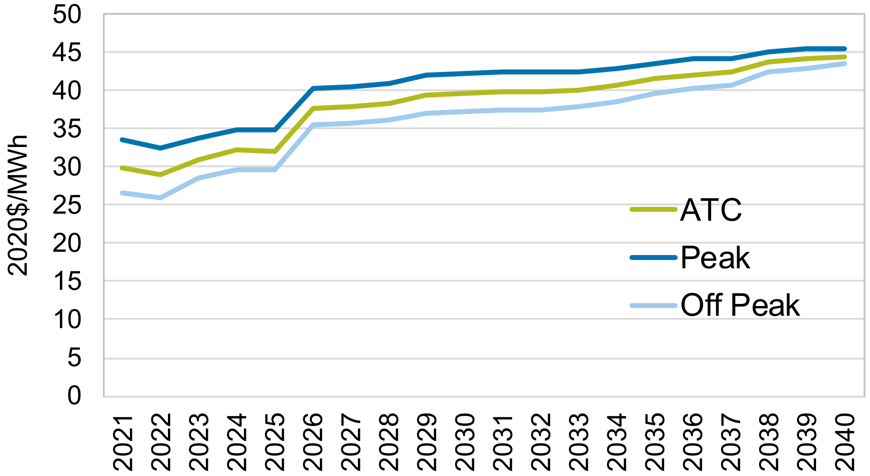
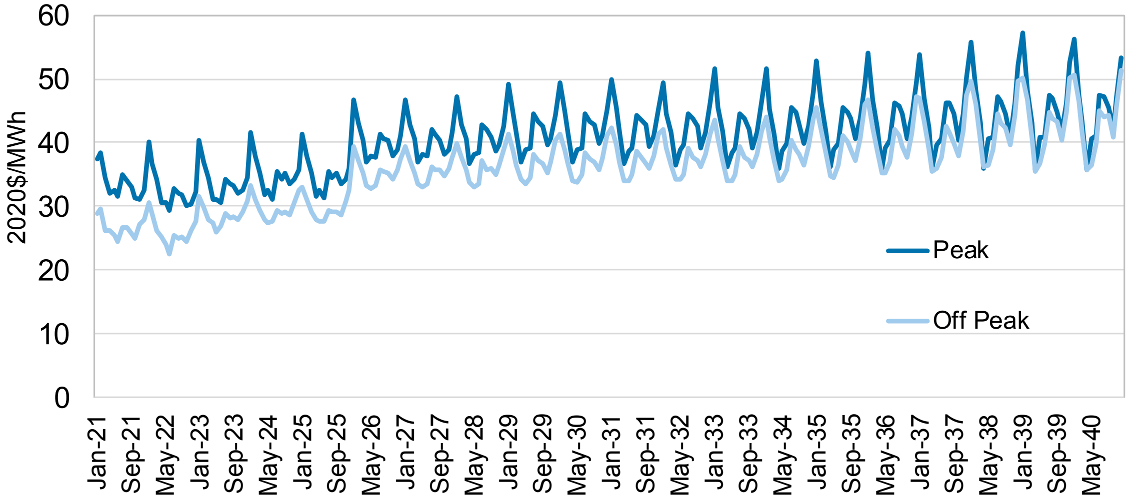
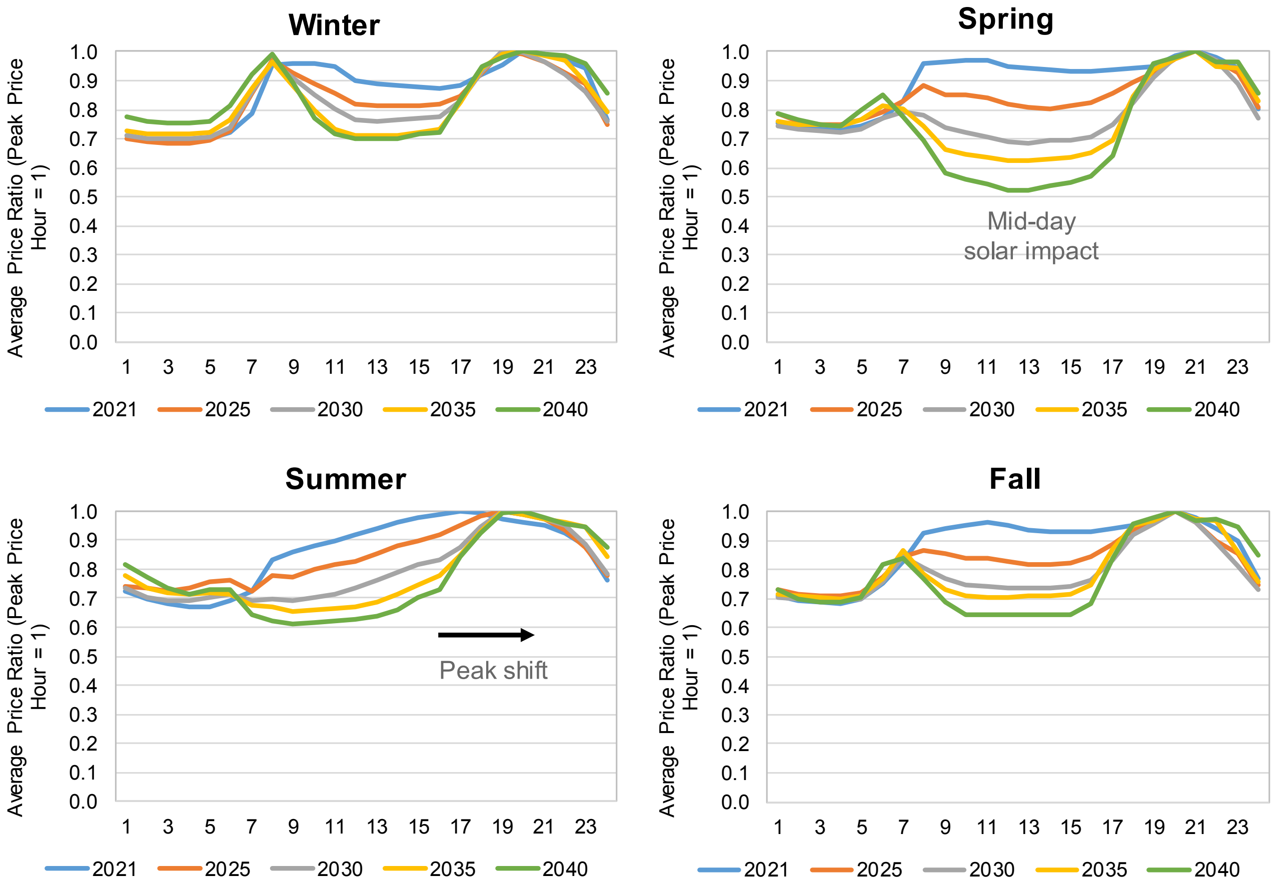


Figure 8-21: LRZ6 (Indiana) Reference Case Monthly Price Projections



Given the expectation for a growing share of intermittent renewable resources in the MISO market over time, hourly price profiles are likely to shift, and CRA's analysis incorporates this phenomenon over time. For example, mid-day prices are expected to decline as a result of solar output, particularly in the spring months when solar output is high, but electric demand is generally low. In addition, the peak price periods during the summer months are expected to shift from mid-afternoon to early evening, in line with solar generation patterns. This is illustrated in Figure 8-22.

Figure 8-22: MISO Hourly Energy Price Shape Projections Over Time

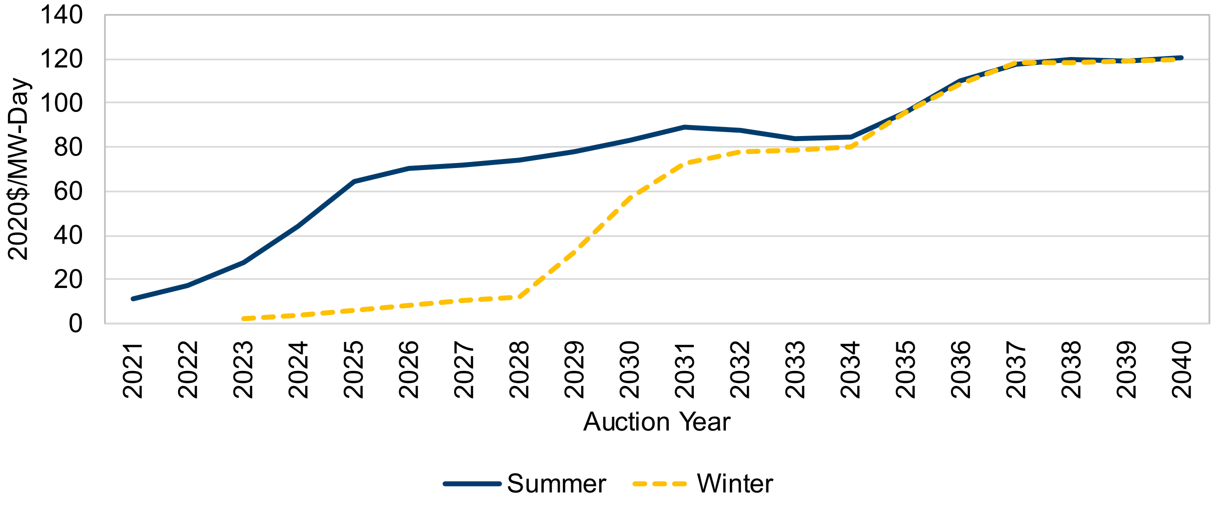


Reference Case Capacity Price Forecast

In addition to the energy market, MISO also operates a capacity market which procures capacity in an annual auction. The capacity market is based on an administratively-set demand requirement and supply offers from market participants that are willing to sell capacity. Recent market prices have been relatively low even as coal capacity retires as a result of flat load and as the market has witnessed increases in renewable capacity and behind-the-meter, demand response, and energy efficiency supply.

Going forward, 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 reserve margin throughout the system. Over the longer-term, CRA's price forecast is based on existing unit going-forward costs in a utility-dominant market, although there may be periods of volatility between the CONE and $0 (for example, LRZ 7 cleared at CONE in 2020). Given the expectation for MISO to institute a seasonal capacity construct in 2021, the capacity price outlook also includes expectations for pricing in the winter months. In the near-term, winter reserve margins are higher than summer reserve margins, 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 expected summer and winter prices. Figure 8-23 presents the Reference Case capacity price projections over time.

Figure 8-23: Reference Case MISO Capacity Price Projections



8.3 Defining Risk and Uncertainty Drivers and Scenario and Stochastic Treatment

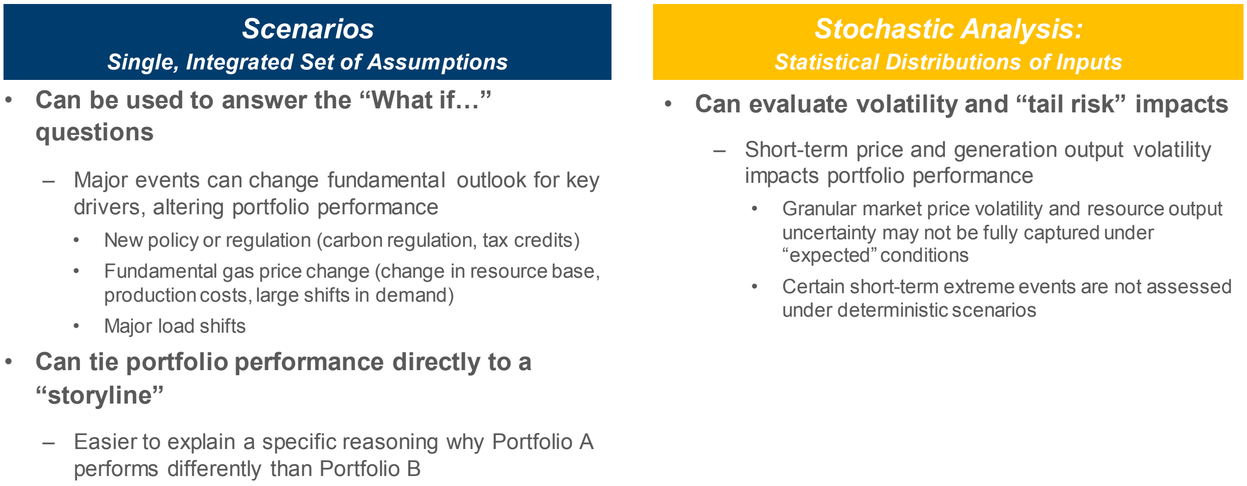
After defining the Reference Case market drivers and conditions, NIPSCO worked to identify the key uncertainties and drivers that could impact future portfolio performance over the long-term. These were grouped into four major categories, including:

- Commodity prices, especially for natural gas and power;
- Environmental policy, particularly regarding carbon pricing, other greenhouse gas emission reduction policies, and federal subsidies and tax credits for specific technologies;
- NIPSCO load growth, including uncertainty associated with economic growth, EV penetration, DER penetration, electrification, and industrial load; and
- The future value of intermittent resources associated with capacity credit and hourly generation output.

After identifying the major drivers of uncertainty, NIPSCO then assessed whether each would be best addressed through scenario or stochastic analysis. In the 2021 IRP, NIPSCO has structured its risk and uncertainty analysis to analyze portfolio decisions across *both* scenario risk and stochastic risk, since the two complementary approaches can be used to answer different questions and quantify risk in different fashions. Scenarios were structured to assess major changes to specific market driver assumptions, along with related feedbacks, while stochastic analysis was performed to evaluate more granular volatility and tail risk, largely based on historical data observations. Figure 8-24 provides a summary of the primary purposes and benefits of deploying each approach. In the 2021 IRP, NIPSCO evaluated uncertainty variables in the following fashion:

- Scenario variables:
  - Annual and monthly natural gas prices;
  - Federal carbon policy regulation, including through carbon prices or a clean energy standard;
  - Federal technology incentives, including extensions and expansions of the production and investment tax credits;
  - Hourly MISO power market prices
  - NIPSCO and MISO regional load growth, driven by economic factors, EV and DER penetration, electrification initiatives, and industrial load risk; and
  - Capacity credit for solar resources over time.
- Stochastic variables:
  - Daily natural gas prices;
  - Hourly MISO power market prices; and
  - Hourly renewable generation output for wind and solar resources;

Figure 8-24: Scenario and Stochastic Uncertainty Approaches



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

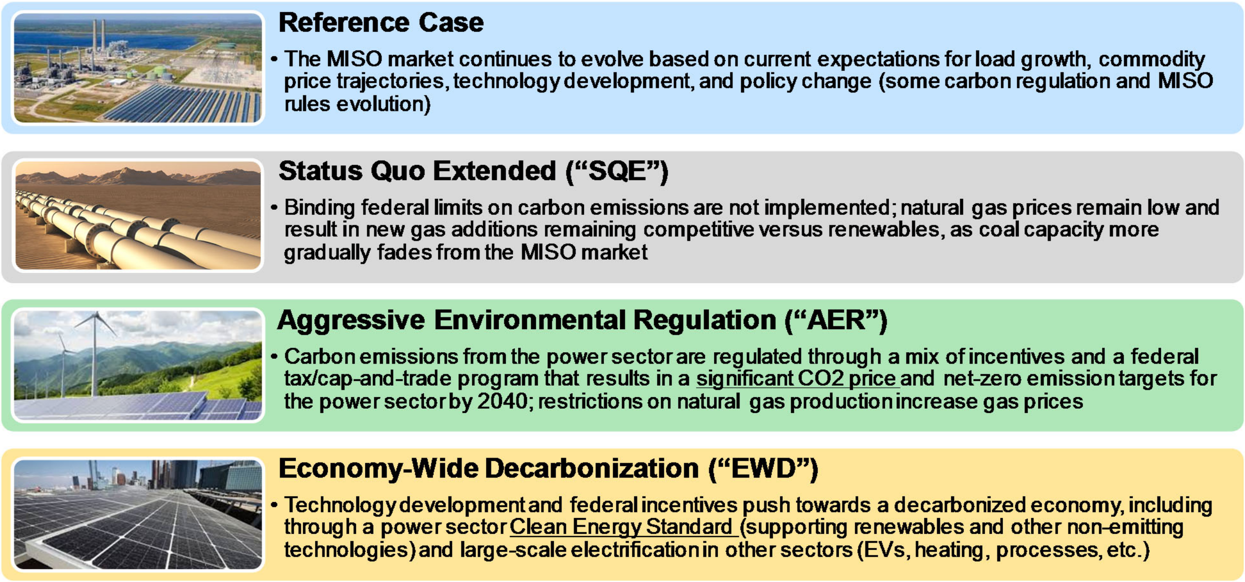
- **Can evaluate volatility and "tail risk" impacts**
  - Short-term price and generation output volatility impacts portfolio performance
    - Granular market price volatility and resource output uncertainty may not be fully captured under "expected" conditions
    - Certain short-term extreme events are not assessed under deterministic scenarios

8.4 IRP Scenarios

8.4.1 Scenario Overview

In the scenario development process, NIPSCO developed narratives to describe possible futures, which were organized around "themes" or "states-of-the-world." The first step in developing the scenario themes was to construct assumptions for key macro drivers, which would ultimately translate into changes for the more detailed drivers impacting NIPSCO's portfolio costs. Ultimately, NIPSCO developed three scenarios to supplement the Reference Case, relying on the foundation that was built in its 2016 and 2018 IRP processes, but incorporating recent market and regulatory trends and specific risks related to the 2021 IRP Reference Case assumptions. A summary of the scenario themes is shown in Figure 8-25.

Figure 8-25: Scenario Theme 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.)

NIPSCO then assessed the themes for diversity and robustness and translated the scenario themes into specific assumptions for the key inputs of gas price, carbon policy, federal technology incentives, load growth, and solar capacity credit. Figure 8-26 summarizes the directional movement of the key input assumptions relative to the Reference Case, while the subsequent sections of this chapter outline the detailed inputs that were developed for each scenario.[91]

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[91] Note that CRA's fundamental MISO market modeling process develops unique MISO market outcomes for each scenario based on the fundamental inputs outlined in the table. Therefore, MISO power market prices are not explicitly noted as input assumptions.

Figure 8-26: Summary of 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%

8.4.2 Status Quo Extended Scenario

Summary Description

The SQE scenario represents a future with persistently low natural gas prices, limited federal regulation of carbon emissions from the power sector, and lower near-term economic growth. The scenario addresses the combined risks of low commodity prices for natural gas and power, no carbon price, and very low load growth for NIPSCO. Given the large amount of uncertainty related to federal action to control carbon emissions, the scenario specifically develops a future where carbon emissions are not restricted while conventional fuel prices remain low, testing the robustness of portfolios against this important risk.

Natural Gas Prices

CRA used its fundamental natural gas market modeling framework (as discussed above) to develop drivers for the SQE scenario's price trajectory. Overall, lower prices are realized through the following assumptions:

- Larger resource size: PGC and other forecasts have consistently shown growth in resource from year to year. In the SQE scenario, the starting unproven resource anticipates a growth in resources expected in the upcoming PGC 2020. The assumed 15% increase is well within the range of uncertainty from the 2018 unproven PGC estimates.

- Higher well productivity: Improvements in well productivity are assumed to be realized more quickly in this scenario, but stall in the 2040s after achieving long-term targets from the Reference Case.

- Lower fixed and variable well costs: Improvements in drilling technology are assumed to occur more quickly, but stall in the 2040s after achieving long-term targets from the Reference Case. In addition, environmental costs are assumed to decrease to reflect lower CO2 pressure relative to the Reference Case (as discussed in more detail below).

- Lower export demand: Under construction LNG projects are assumed to be delayed in this scenario due to low prices and lack of demand. In addition, LNG capacity factors are assumed to stay around 60% due to low prices and demand. Capacity factors for pipeline exports are assumed to be 50% in this scenario, down from a 70% expectation in the Reference Case.

Figure 8-27 summarizes the major natural gas price drivers for the SQE scenario relative to those in the Reference Case.

Figure 8-27: Summary of Natural Gas Price Drivers for SQE Scenario

Driver	Reference Case	Low (SQE)	
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• 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"	• Accelerated improvement in well productivity	↑
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	• Accelerated improvements in drilling technology • Lower environmental costs	↓
NGL & Condensate Value	• Liquids valued at 70% of Annual Energy Outlook (AEO) 2021 Reference Oil Price	• Base view	▬
Associated Gas Volumes	• Natural gas from shale and tight oil plays enters the market as a price taker	• Base view	▬
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	• 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	• 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	• Lower usage rates on pipelines	↓

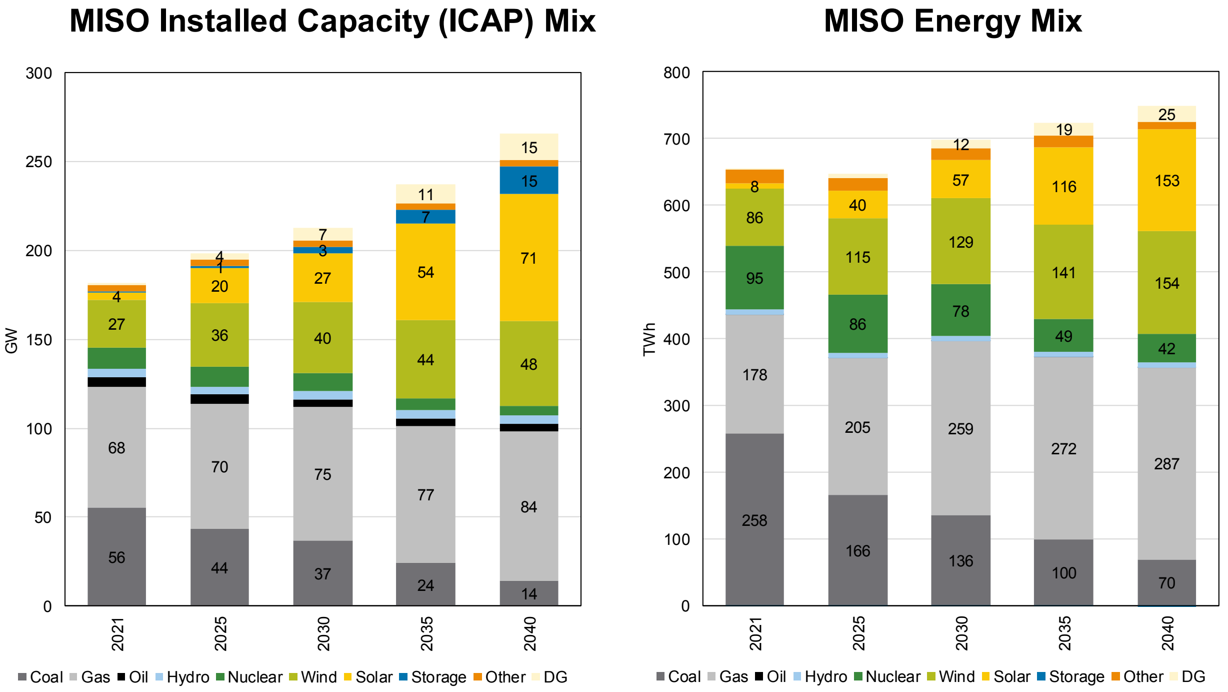
Carbon Regulation

The SQE scenario includes no price on carbon based on an expectation for less stringent environmental regulation at the federal level. The scenario assumes that continued hurdles in Congress stymie proposed environmental legislation, and federal courts limit the scope of any executive actions. While states continue to advance environmental goals under this scenario, no meaningful carbon emission limits are assumed to be implemented at the federal level.

MISO Power Market Dynamics

In the SQE scenario, the MISO market is expected to transition more slowly away from fossil-fired resources and more gradually towards renewables as a result of lower natural gas prices and no price on carbon. While the Reference Case expects over half of all energy in MISO to come from renewable resources by 2040, the SQE scenario expects close to 40% renewable energy by the same period. The lower expectations for solar generation in this scenario relative to the Reference Case result in ELCC or capacity credit for solar only declining to 30% (as opposed to 25%) by 2040. Meanwhile, natural gas and coal generation are projected to retain an energy share close to 50% by 2040, with most fossil-fired energy produced by natural gas. This is illustrated in Figure 8-28.

Figure 8-28: MISO Power Market Evolution for SQE Scenario



NIPSCO Load Growth

Section 3 of this report on NIPSCO's Energy and Demand Forecast outlines the load impacts associated with the SQE scenario in significant detail, but the low load trajectory is broadly premised on the following drivers:

- Lower economic growth: The Moody's 90th percentile downside is used for key economic growth factors, reflecting a scenario where the impacts of COVID-19 linger, consumer spending lags government stimulus levels, and unemployment grows again.

- Lower electric vehicle and distributed energy resource penetration, as economic conditions and market prices reduce adoption rates.
- Lower industrial load: Additional industrial load loss is assumed to reduce the firm large industrial class requirement down to 70 MW.

8.4.3 Aggressive Environmental Regulation Scenario

Summary Description

The AER scenario represents a future in which environmental regulations are more stringent than anticipated in the Reference Case. More specifically, the scenario contemplates a federal carbon tax or cap-and-trade framework that drives towards a net-zero emissions power sector and results in a significant price on carbon. In addition, the scenario includes the assumption that environmental policy restricts natural gas production and drives higher production costs for natural gas, resulting in a higher natural gas price outlook. Overall, the scenario addresses the risk of earlier and higher carbon prices and the risk of higher prices for natural gas and power.

Natural Gas Prices

As in the SQE scenario, CRA used its fundamental natural gas market modeling framework (as discussed above) to develop drivers for the AER scenario's price trajectory. Overall, higher prices are realized primarily through changes in the supply side dynamics for natural gas, including the following assumptions:

- Smaller resource size: Instead of assuming that available gas supply grows over time, the AER scenario assumes that future exploration is limited by policy actions (for example, drilling bans).
- Slower improvements in well productivity: Improvements in technology are assumed to slow over time in the AER scenario, as interest rotates into clean energy sectors due to changing policy incentives.
- Higher fixed and variable well costs: Improvements in technology are assumed to slow, as interest rotates into clean energy sectors due to changing policy incentives. In addition, environmental costs are assumed to increase in the AER scenario to reflect additional regulation of emissions from fossil fuel producing sectors, include natural gas drilling and extraction.
- Lower natural gas liquids and condensate value and lower associated gas volumes: The expected transition from internal combustion engine vehicles to electric vehicles in the AER scenario lowers petroleum demand and results in an assumption for lower oil and associated liquids prices.

Figure 8-29 summarizes the major natural gas price drivers for the SQE scenario relative to those in the Reference Case.

Figure 8-29: Summary of Natural Gas Price Drivers for AER Scenario

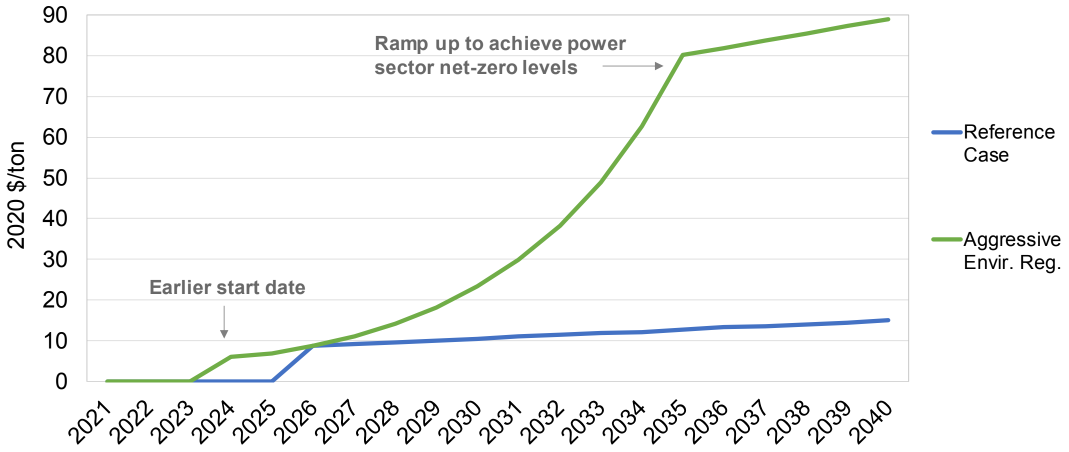
Driver	Reference Case	High (AER)
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• Remove resource growth resulting from policy changes (eg. drilling bans) ↓
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	• Slow improvement as policy drives investment into clean energy sectors ↓
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 ↑
NGL & Condensate Value	• Liquids valued at 70% of Annual Energy Outlook (AEO) 2021 Reference Oil Price	• Lower oil prices, given lower demand ↓
Associated Gas Volumes	• Natural gas from shale and tight oil plays enters the market as a price taker	• Lower, given lower oil demand ↓
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 ↓
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 ▬
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 ▬

Carbon Regulation

The AER scenario assumes a significant price on carbon, based on the premise that the Biden Administration and Congress lay the groundwork for a carbon emission reduction program via a tax or cap-and-trade regime, with future governments implementing stricter CO2 policy to establish net zero power sector targets by 2040. Under such assumptions, a price on carbon emissions would be instituted by 2024, with a ramp up in stringency over time to achieve net zero levels for the power sector. Based on CRA's analysis, in the AER scenario, a carbon price increase to the $80-90/ton range (in real 2020$) could make certain alternative technologies required to achieve net zero emissions by the 2035-2040 time period (such as hydrogen, CCS, and nuclear) economically feasible. Figure 8-30 summarizes the carbon price projection in the AER scenario relative to the Reference Case. CRA's MISO market analysis (discussed in additional detail below) projects that such a price would achieve clean energy generation percentages in the MISO region of approximately 90-95% by 2040.

In addition to the carbon pricing drivers, the AER scenario also assumes a five-year extension to the federal ITC at the 26% level and a three-year extension to the federal PTC at the 60% level. In addition, the scenario assumes that the ITC is extended to stand-alone storage facilities over the extension period. As of the time of the development of the 2021 IRP assumptions, only storage units paired with renewable energy resources can qualify for the ITC.

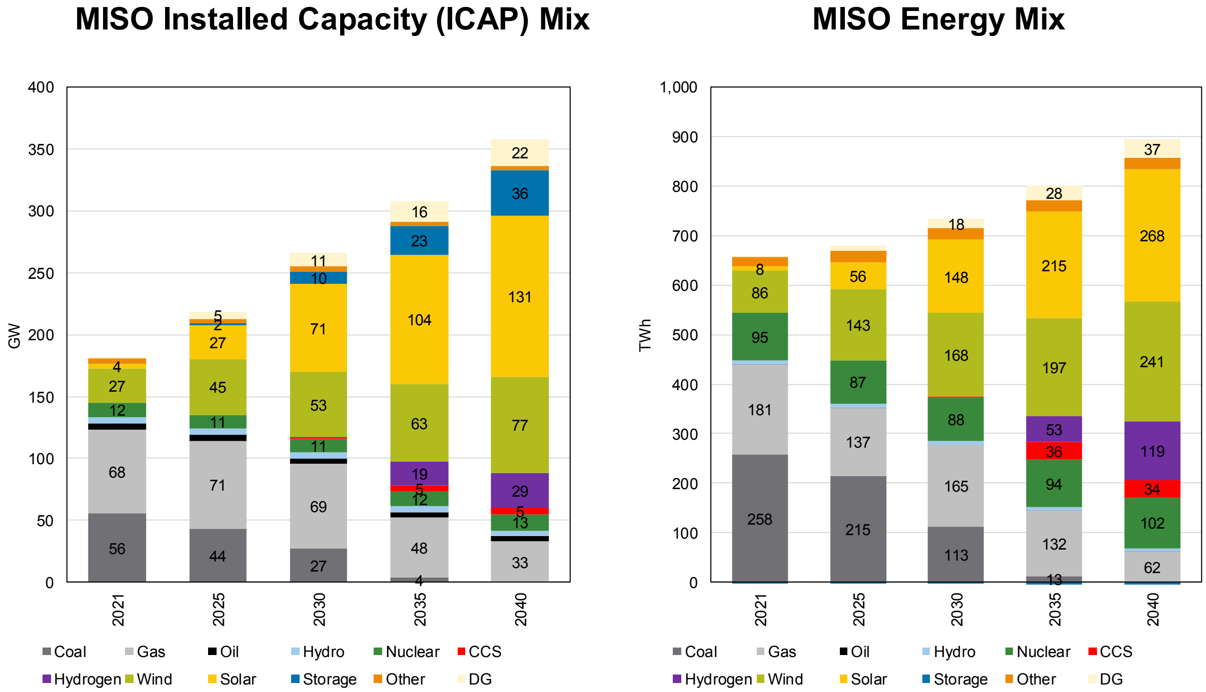
Figure 8-30: Carbon Price Projection in AER Scenario



MISO Power Market Dynamics

In the AER scenario, higher carbon prices and higher natural gas prices are expected to both accelerate the transition away from fossil-fired resources and towards clean technologies across the MISO market. All coal capacity is projected to either retire or retrofit to CCS by 2040. In addition, new nuclear capacity is projected, and hydrogen fuel is projected to be economic in new or existing gas turbine and combined cycle capacity. Overall, the MISO market is projected to generate over 90% of its energy from clean, non-CO2 emitting resources by 2040. The significant penetration of solar results in ELCC credit for solar declining to 15% (as opposed to 25%) by 2040. This is illustrated in Figure 8-31.

Figure 8-31: MISO Power Market Evolution for AER Scenario



MISO Installed Capacity (ICAP) Mix

MISO Energy Mix

NIPSCO Load Growth

Section 3 of this report on NIPSCO's Energy and Demand Forecast outlines the load impacts associated with the AER scenario in significant detail, but the load trajectory is broadly premised on the following drivers:

- Reference Case economic growth.
- Higher electric vehicle penetration due to economic factors associated with carbon taxes on gasoline fuel.
- Higher distributed energy resource penetration as a result of expected increases in retail electric rates and decreases in solar and storage technology costs.

8.4.4 Economy-Wide Decarbonization Scenario

Summary Description

The EWD scenario represents a future in which federal environmental regulations drive significant emission reductions throughout the economy *without* imposing a price on carbon. Instead, CO2 emission reductions are assumed to be the result of a power sector clean energy standard, extended and expanded federal tax credits for clean energy technologies, and measures that incentivize electrification of other parts of the economy, such as transportation and other residential, commercial, and industrial end uses. Electrification measures are projected to significantly increase power demand, particularly during the winter months. Overall, the scenario addresses the risk of strict environmental regulation without the consequent increase in power prices that would be expected with a carbon price, as well as the risk of higher-than-expected NIPSCO load.

Natural Gas Prices

By design, the natural gas price assumption for the EWD scenario is identical to the Reference Case. While certain environmental regulations in this scenario might decrease demand for natural gas, others might increase production costs. Thus, the long-term outlook from the Reference Case (see above) was preserved.

Carbon Regulation

The EWD scenario assumes several federal policy initiatives that drive towards economy-wide decarbonization. As described in more detail in Chapter 7 (Environmental Considerations), the scenario assumptions broadly adopt several elements of the climate policy objectives outlined in President Biden's infrastructure plan framework. These include the following:

- A ten-year extension for both the ITC at the 26% level and the PTC at the 60% level. In addition, the scenario assumes that the ITC is extended to stand-alone storage resources over the ten-year extension period. Furthermore, tax credit extensions or expansions to other advanced technology, such as hydrogen, CCS, and nuclear are assumed.

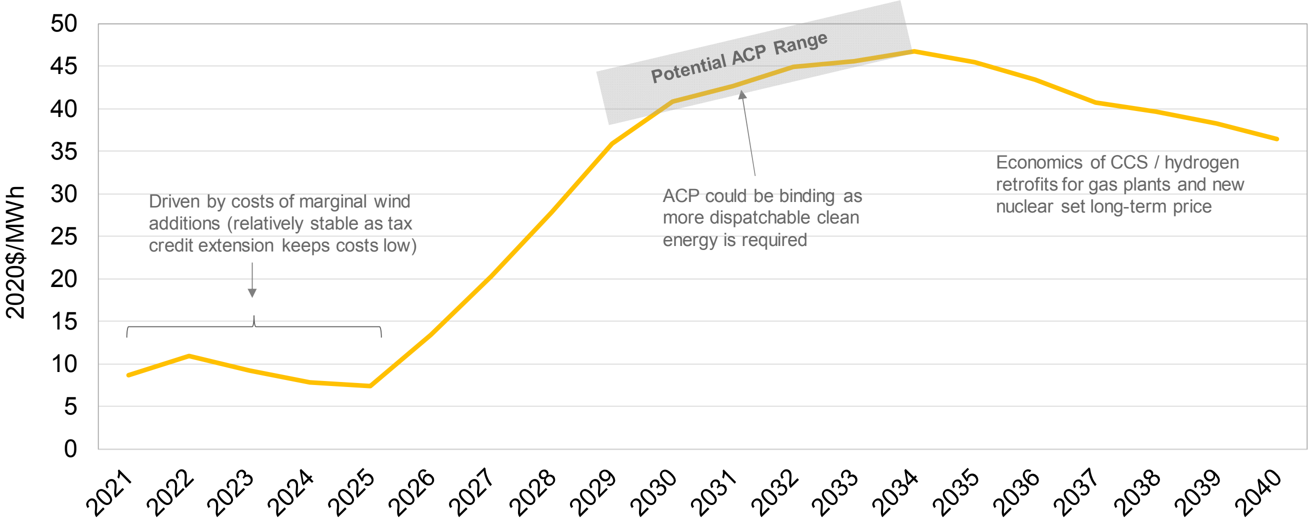
- New federal investment and incentives to promote energy efficiency and electrification, including electric vehicles and other heating/industrial processes.

- A national clean energy standard aiming to achieve net-zero carbon emissions from the power sector (inclusive of assumed non-power sector offsets) by 2040. This is broadly consistent with the Biden Administration's stated goal of net-zero emissions for the power sector in 2035, but recognizes the potential for delays in full achievement given required technology advancement.

Overall, based on these scenario design considerations, no carbon *pricing* materializes, but the binding clean energy standard would be expected to drive a market for Clean Energy Credits or Zero Emission Electricity Credits. Under this construct, load serving entities like NIPSCO would be required to demonstrate compliance with the clean energy standard and be able to do so through their own resources or through the purchase Clean Energy Credits from other suppliers. If NIPSCO were to generate more clean energy than the target, excess credits could be sold. This construct is similar to the existing markets for Renewable Energy Credits.

CRA's projection of Clean Energy Credit pricing under the EWD scenario is summarized in Figure 8-32. In the early years of the forecast horizon, the costs of marginal wind (and solar) additions would likely drive the market, keeping prices at or below $10/MWh. Over time, however, as the clean energy standard ramps up, higher cost resource additions would be required in the market, and a likely ACP would set a ceiling on the Clean Energy Credit price in the early 2030s.[92] By the late 2030s, CRA's analysis suggests that the economics of hydrogen or CCS retrofits for gas plants and new nuclear capacity would improve sufficiently to keep the Clean Energy Credit price in the $35-40/MWh range (real 2020$).

Figure 8-32: Projected Clean Energy Credit Pricing Under EWD Scenario



MISO Power Market Dynamics

In the EWD scenario, assumed tax credit extensions/expansions and the clean energy standard both contribute to the acceleration of clean technology expansion across the MISO market. All coal capacity is projected to either retire or retrofit to CCS by 2040, and some natural gas capacity is expected to retrofit to CCS as well. Unlike the AER scenario, where all CCS conversions were associated with coal-fired plants, the lower gas prices in EWD drive additional gas CCS conversions. In addition, new nuclear capacity is projected, and hydrogen fuel is projected to be economic in new or existing gas turbine and combined cycle capacity, given the value associated with expected Clean Energy Credit pricing, as discussed above. Overall, the MISO market is projected to generate over 90% of its energy from clean, non-CO2 emitting resources by 2040. The significant penetration of solar results in ELCC credit for solar declining to 15% (as opposed to 25%) by 2040.

In addition, due to the electrification growth assumptions in the EWD scenario, overall demand requirements across the MISO footprint are significantly higher than in the other scenarios, resulting in the highest capacity buildout overall. The projected MISO-wide capacity and energy mixes over time for the EWD scenario are presented in Figure 8-33.

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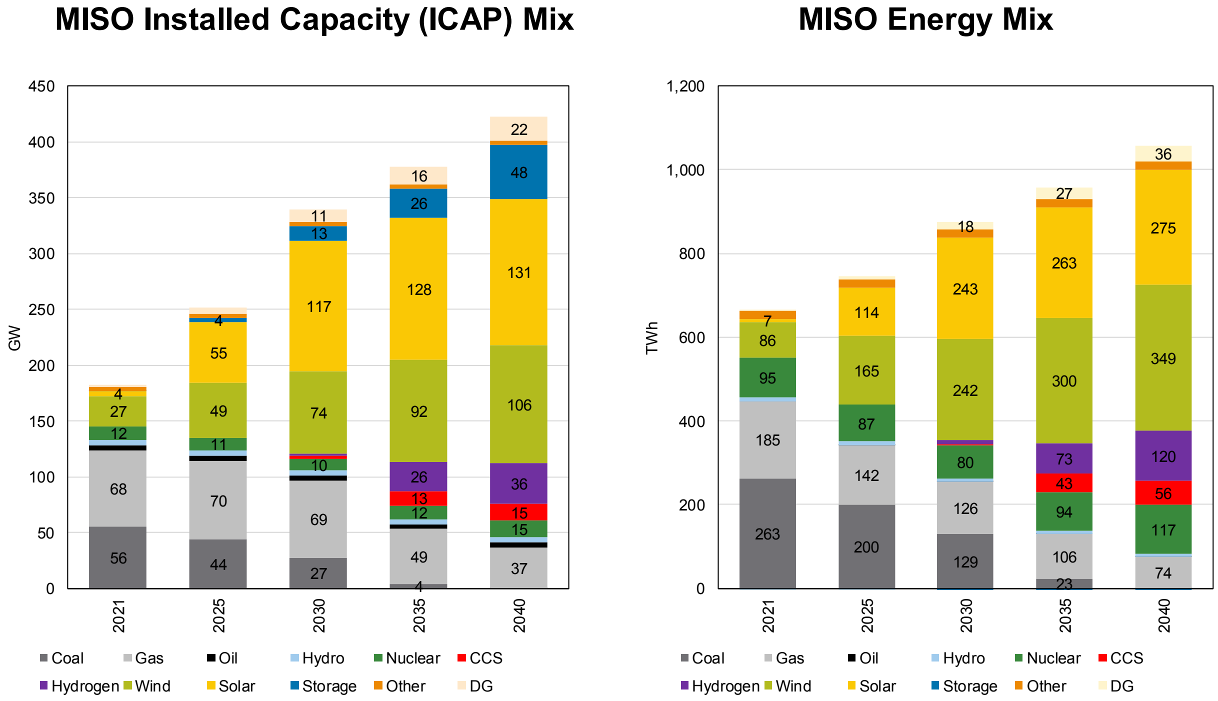
[92] Note that the ACP backstop price range used in this analysis is based loosely on provisions in the proposed CLEAN Future Act. Such provisions suggest an ACP in the $40-50/MWh (real 2020$) range by the early 2030s.

Figure 8-33: MISO Power Market Evolution for EWD Scenario


MISO Installed Capacity (ICAP) Mix

MISO Energy Mix

NIPSCO Load Growth

Section 3 of this report on NIPSCO's Energy and Demand Forecast outlines the load impacts associated with the EWD scenario in significant detail, but the load trajectory is broadly premised on the following drivers:

- Higher economic growth: The Moody's 10th percentile upside is used for key economic growth factors, reflecting a scenario where post-COVID-19 re-openings and fiscal stimulus boost economic growth more than expected.
- Higher electric vehicle and distributed energy resource penetration, as a result of policy incentives (extended ITC, EV subsidies, etc.), technology advancement, and behavioral change.
- Higher electrification in other sectors of the economy, including residential and commercial/industrial heating, hot water, appliances, and processes, based on information from MISO's MTEP Futures process.

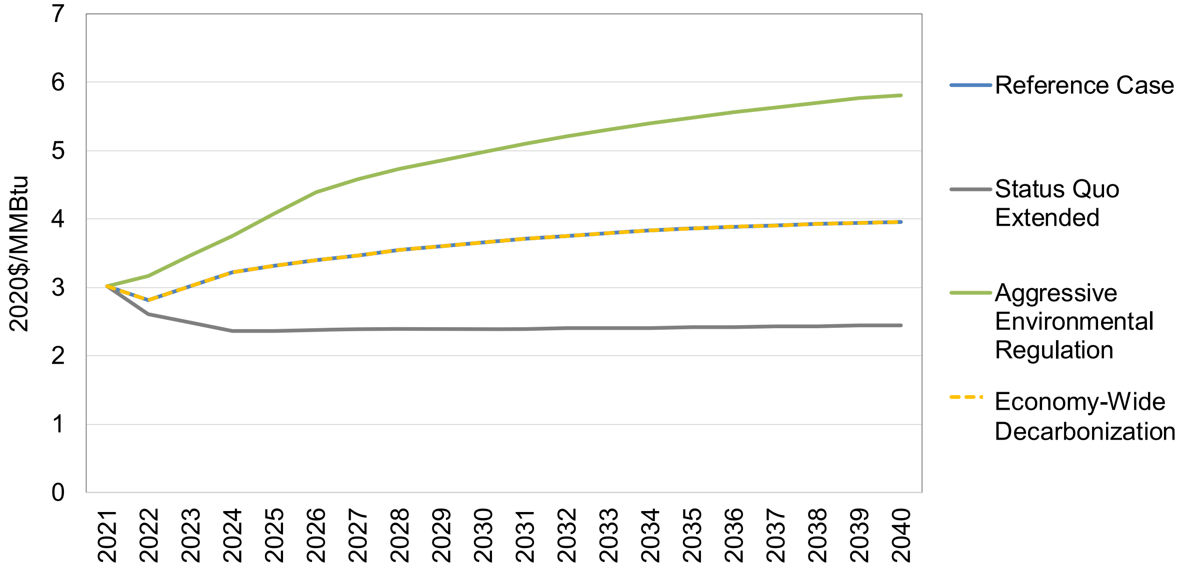
8.4.5 Scenario Comparisons

The following section provides a series of summary comparisons across all four planning scenarios to illustrate the ranges of outcomes NIPSCO has evaluated for key metrics including natural gas prices, carbon regulation, MISO power market dynamics, and NIPSCO load growth.

Natural Gas Prices

Figure 8-34 summarizes natural gas price projections for the Henry Hub across all four scenarios. As discussed above, the supply and demand impacts for the SQE scenario result in gas prices staying at or below $2.50/MMBtu (in real 2020$) over the entire fundamental forecast period. On the other hand, expectations for lower supply, higher production costs, and lower associated liquids prices result in an increase in natural gas prices in the AER scenario over time. In that scenario, gas prices climb to nearly $6/MMBtu (in real 2020$) by 2040.

Figure 8-34: Natural Gas Price Range across Scenarios



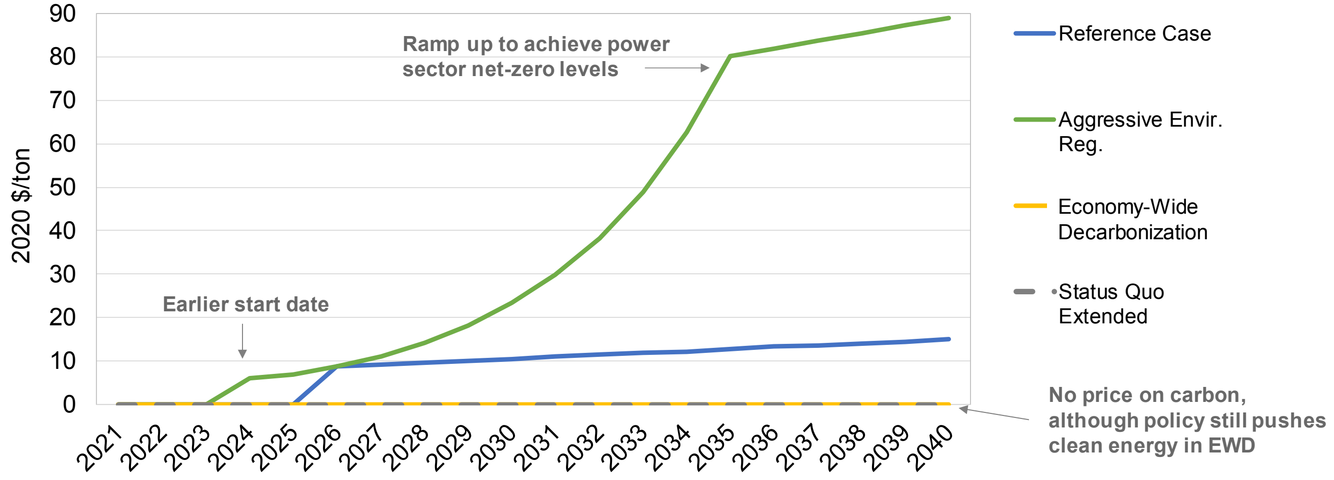
Carbon Regulation

As noted earlier, NIPSCO's scenarios incorporate a wide range of potential carbon regulation outcomes, including the possibility that carbon emissions are not regulated at the federal level over the study horizon as well as two different means of achieving deep power sector decarbonization (through a carbon price or a clean energy standard with extended federal subsidies). The rationale and potential outcome for NIPSCO's carbon policy scenarios relative to the Reference Case are summarized in Figure 8-35, with a comparison of carbon prices illustrated in Figure 8-36. This approach allows NIPSCO's 2021 IRP to assess a broad range of price outcomes, while also recognizing the significant uncertainty associated with policy design and ultimate implementation.

Figure 8-35: Carbon Policy Scenario Comparisons

	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

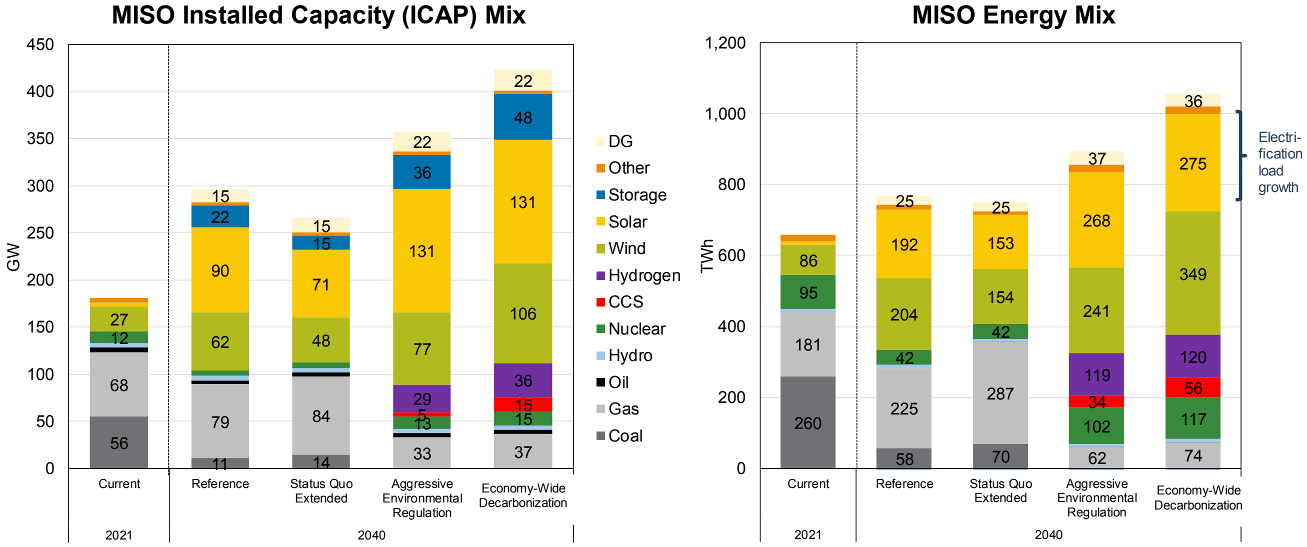
Figure 8-36: Carbon Price Range across Scenarios



MISO Power Market Dynamics

The MISO power market is projected to evolve very differently across NIPSCO's four planning scenarios. As discussed earlier, the Reference Case projects a steady transition away from coal capacity and energy towards renewables and, to a lesser extent, natural gas. The SQE scenario projects a stronger role for fossil capacity and energy over time, while the AER and EWD scenarios project significant shifts towards renewables and new clean energy technologies, including nuclear, CCS, and hydrogen. In addition, incremental load from electrification activities is included in the scenarios that achieve high levels of decarbonization, particularly EWD. These dynamics are illustrated in Figure 8-37, which summarizes the current MISO capacity and energy mix and the projections in 2040 across all four scenarios.

Figure 8-37: MISO Capacity and Energy Mix Outlook across Scenarios



Given the growing penetration of intermittent energy resources across all scenarios, the hourly generation profiles at the MISO market level are also projected to be significantly different across scenarios over time. This impacts expected dispatch of various resource types and market prices at the hourly level. Figure 8-38, Figure 8-39, and Figure 8-40 all display projected hourly generation projections by resource type at the MISO level for a sample summer, winter, and spring shoulder month, respectively for 2040. The figures display expected hourly output for non-dispatchable renewable and nuclear resources, along with gross and net load projections. Major seasonal observations include:

- In the summer, large ramping requirements are likely to develop in the evenings, especially in the AER and EWD scenarios.
- In the winter, higher overnight loads need to be met when solar is unavailable, particularly in the EWD case, with high electrification-driven winter loads.
- In the spring shoulder months, mid-day energy output from renewables could be as high as system loads, resulting in low prices and potential curtailment if not stored.

Figure 8-38: MISO Hourly Generation Projections – Summer, 2040

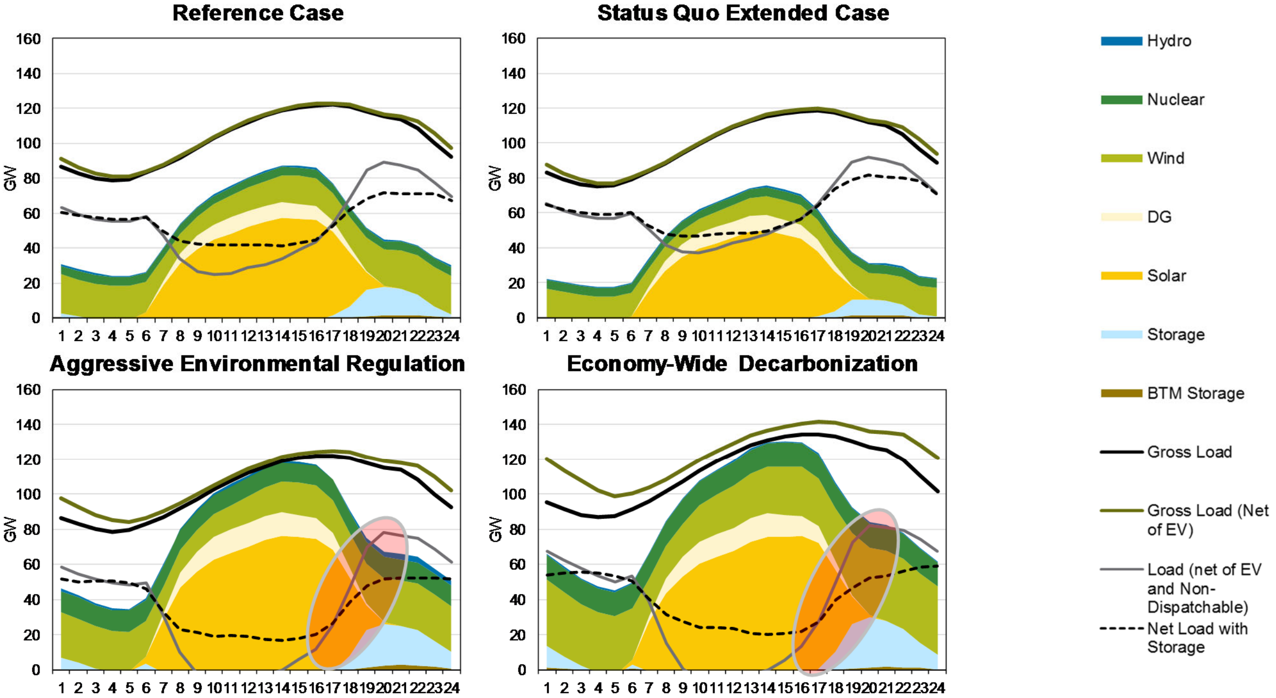


Figure 8-39: MISO Hourly Generation Projections – Winter, 2040

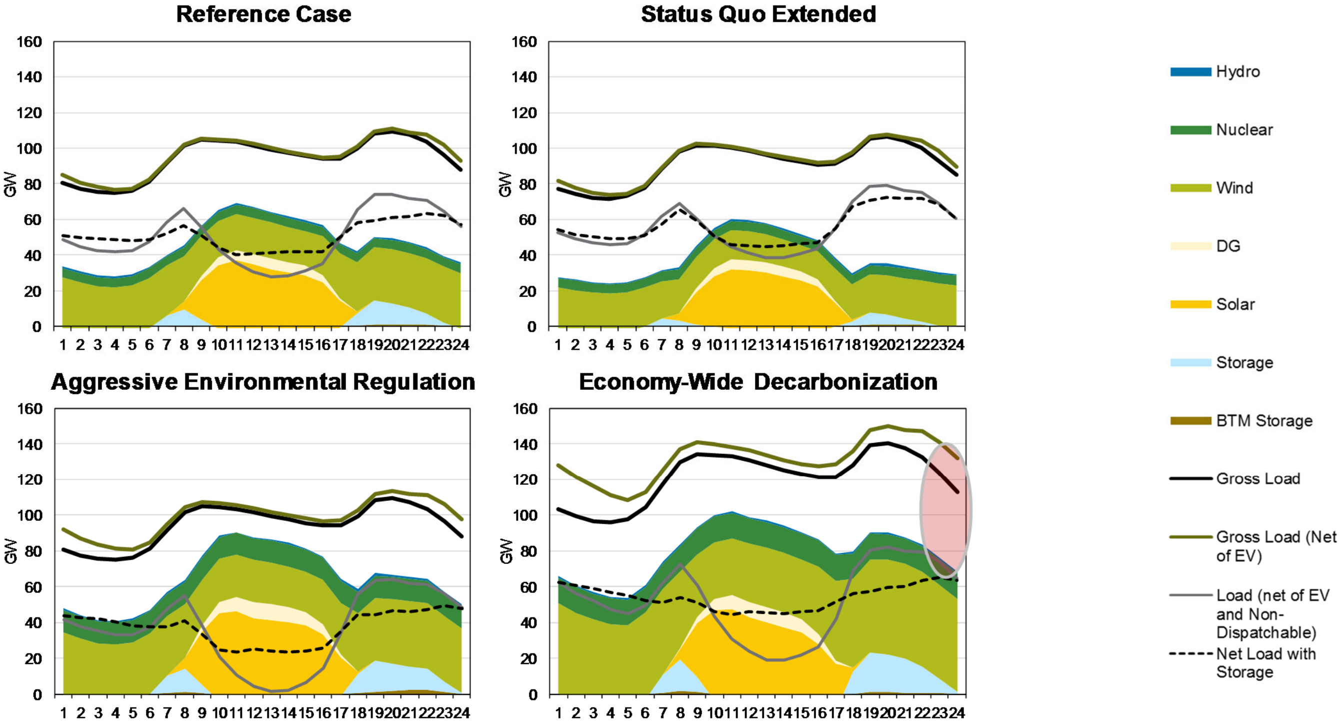
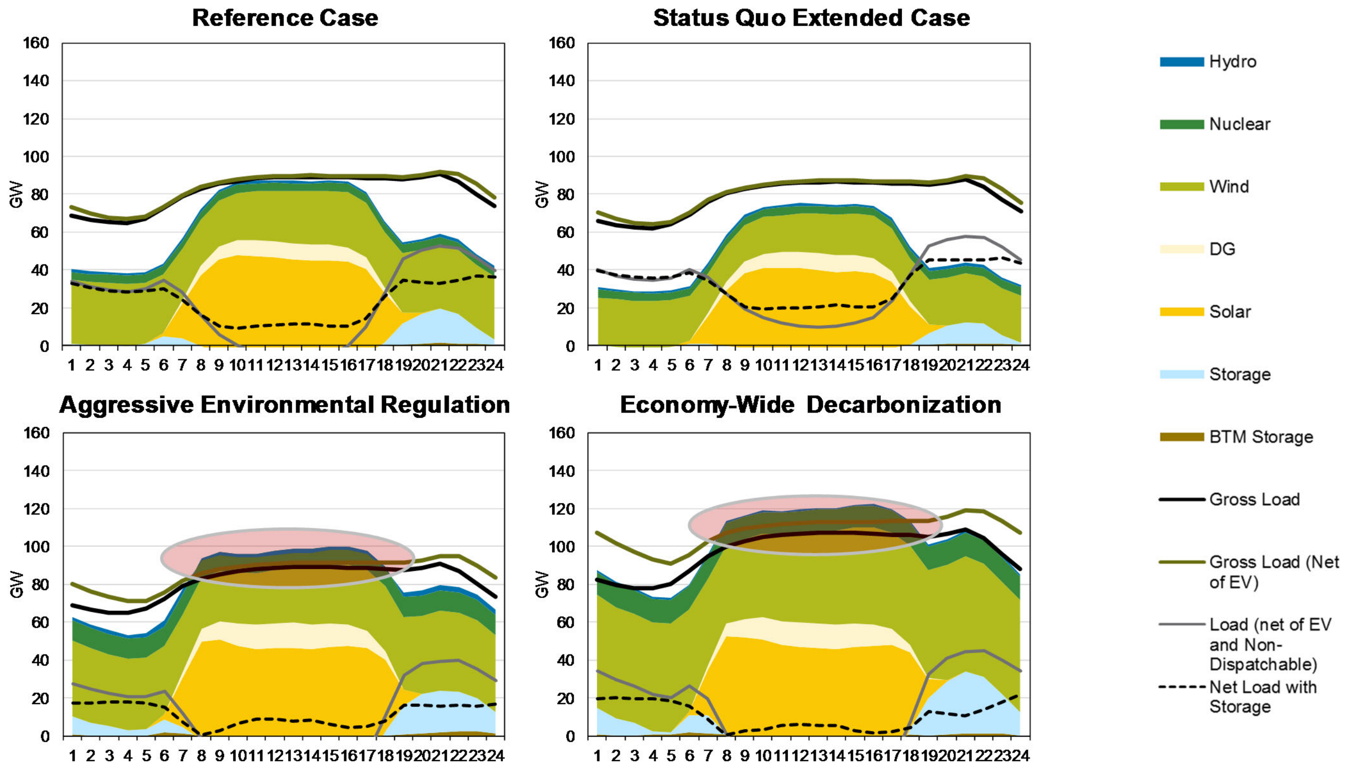


Figure 8-40: MISO Hourly Generation Projections – Spring Shoulder Month, 2040



The different energy market projections contribute to a range of outcomes for MISO-wide clean energy penetration, MISO-wide CO2 emissions, energy prices at various levels of granularity, and capacity prices.

While MISO's generation mix is currently composed of approximately 30% clean energy resources (wind, solar, hydro, other renewables, and nuclear), the four scenarios project this level to grow to between 40% to 70% by 2030 and between 50% to 90% by 2040. Note that to achieve 100% clean energy and net zero emission power sector outcomes in the AER and EWD scenarios, additional offsets outside the power sector are assumed to be acquired by market participations. Figure 8-41 summarizes the projected clean energy percentages over time across scenarios.[93] Similarly, a range of carbon emission reductions across MISO are projected across the four scenarios. The MISO market has already achieved an approximate 30% reduction in CO2

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[93] Note that the clean energy 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.

emissions relative to a 2005 baseline, with an expected reduction of between 50% and 63% by 2030 and 63% to 92% by 2040. This is illustrated in Figure 8-42.[94]

Figure 8-41: MISO Clean Energy Percentage Projections across Scenarios

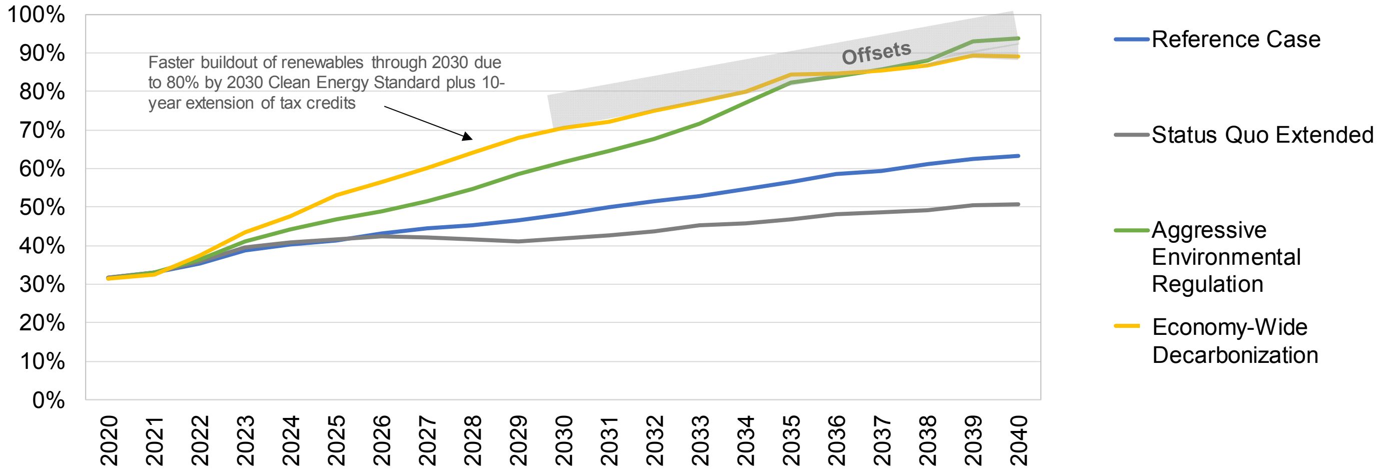
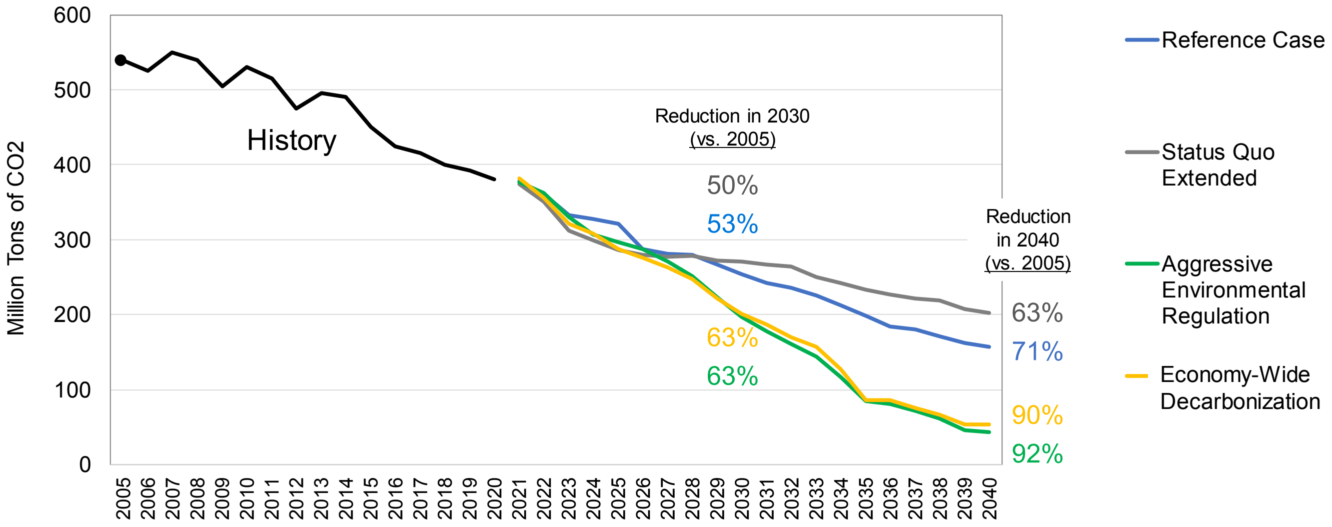


Figure 8-42: MISO CO2 Emission Reduction Projections across Scenarios



MISO energy prices are projected to vary considerably across scenarios as well. On an "all-hours" or ATC basis, the Reference Case projects prices to increase to approximately

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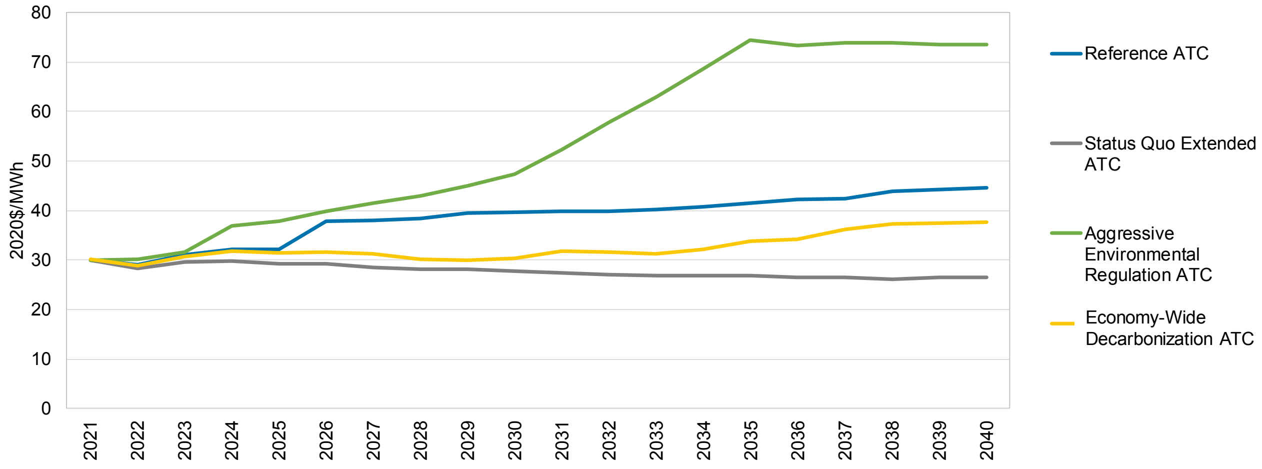
[94] Historical data from 2005-2019 is taken from MISO Futures documentation from 2020 and 2021. CRA interpolated data from 2018 to first model year of 2021.

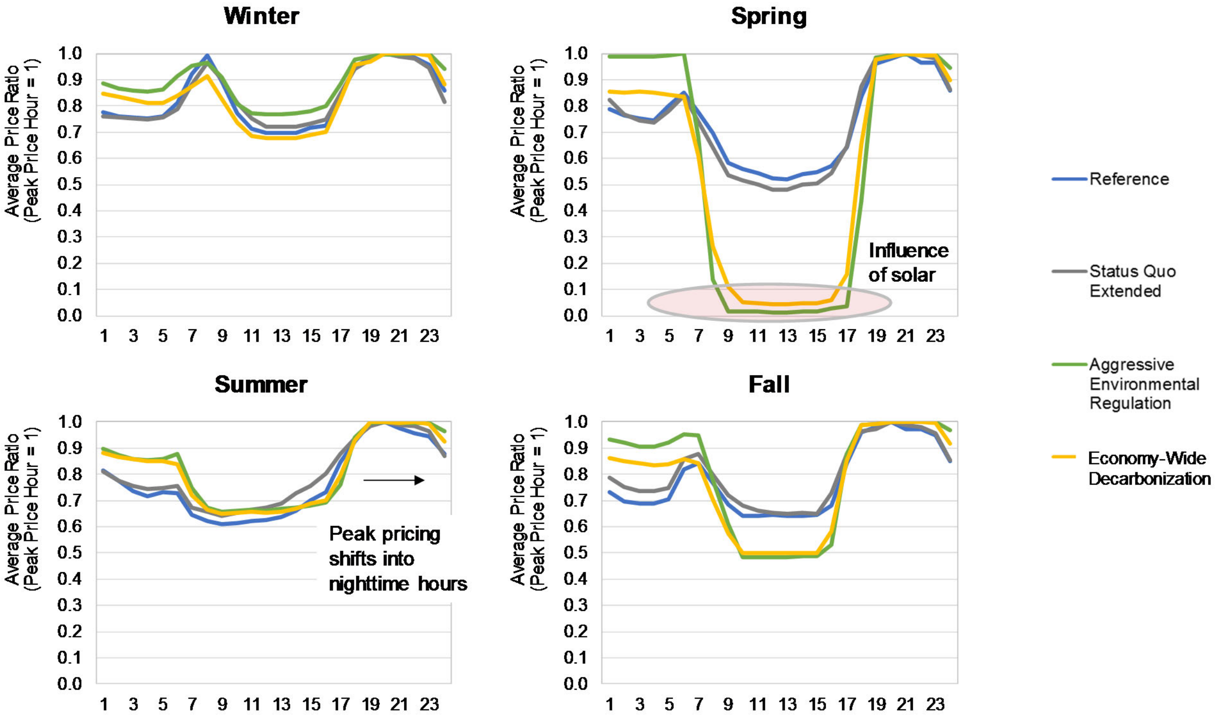
$45/MWh (real 2020$) by 2040, while the scenarios include prices that range between below $30/MWh to above $70/MWh by the same time. Rising natural gas and carbon prices drive the AER scenario's prices highest, while the SQE and EWD scenarios have flatter pricing in real terms due to lower gas price expectations, the lack of a carbon price, and expectations for growing renewable penetration. The ATC price projections across scenarios are summarized in Figure 8-43.

Figure 8-43: MISO Zone 6 ATC Power Prices across Scenarios



On an hourly basis, the shape of power prices is also likely to evolve very differently over time, particularly as growing levels of renewable energy enter the market. By 2040, all scenarios are expected to have peak hours shift later into the evening during summer months, while mid-day prices during the shoulder months (spring and fall) are expected to decline significantly as a result of solar energy penetration, particularly in the AER and EWD scenarios. This dynamic is shown in Figure 8-44, which illustrates the wide range of hourly market price risk that NIPSCO is evaluating across its scenarios.

Figure 8-44: MISO Zone 6 Hourly Price Shapes by Season (2040) across Scenarios



While capacity prices are also expected to vary across scenarios, CRA expects them to remain relatively low in the near-term, although continued coal retirements over the 2020-2024 period are expected to tighten the system. Over time, NIPSCO's analysis incorporates the likelihood of MISO moving to a multi-seasonal capacity construct with different prices across seasons. In the summer months, under the AER scenario, coal retirements and replacement with resources including hydrogen-enabled gas turbines and long-duration storage are projected to push prices higher. This is illustrated in Figure 8-45. In the winter months, 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. The winter capacity price projections across scenarios are illustrated in Figure 8-46.

Figure 8-45: MISO Summer Season Capacity Price Projections across Scenarios

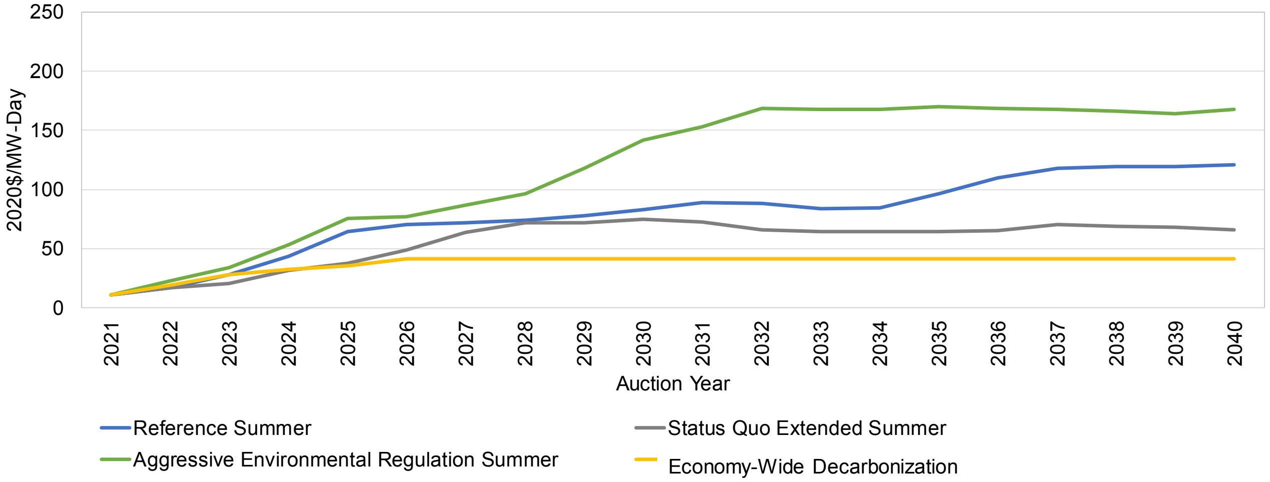
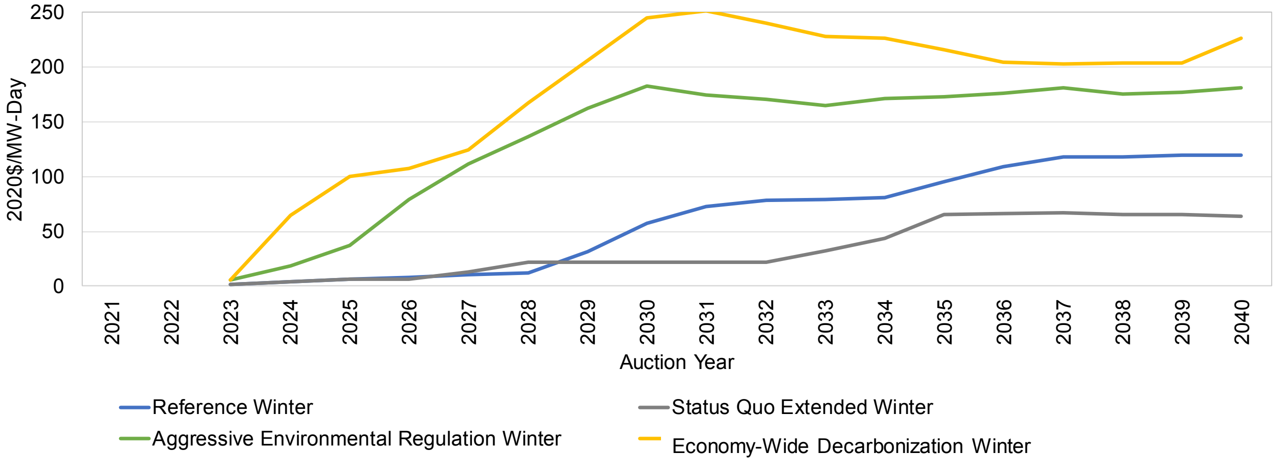


Figure 8-46: MISO Winter Season Capacity Price Projections across Scenarios



NIPSCO Load Growth

Section 3 of this report on NIPSCO's Energy and Demand Forecast provides significant detail regarding the range of load uncertainties evaluated across each of the scenarios. As described in that chapter, NIPSCO's load scenarios vary economic growth assumptions, electric vehicle and distributed energy resource penetration, other electrification, and industrial load loss risk. Overall, this approach results in a significant range of potential energy sales and peak load outcomes for NIPSCO across scenarios. The ranges are summarized in Figure 8-47 and Figure 8-48, with additional supporting detail documented in Section 3.

Figure 8-47: Total NIPSCO Net Energy for Load Forecast across Scenarios

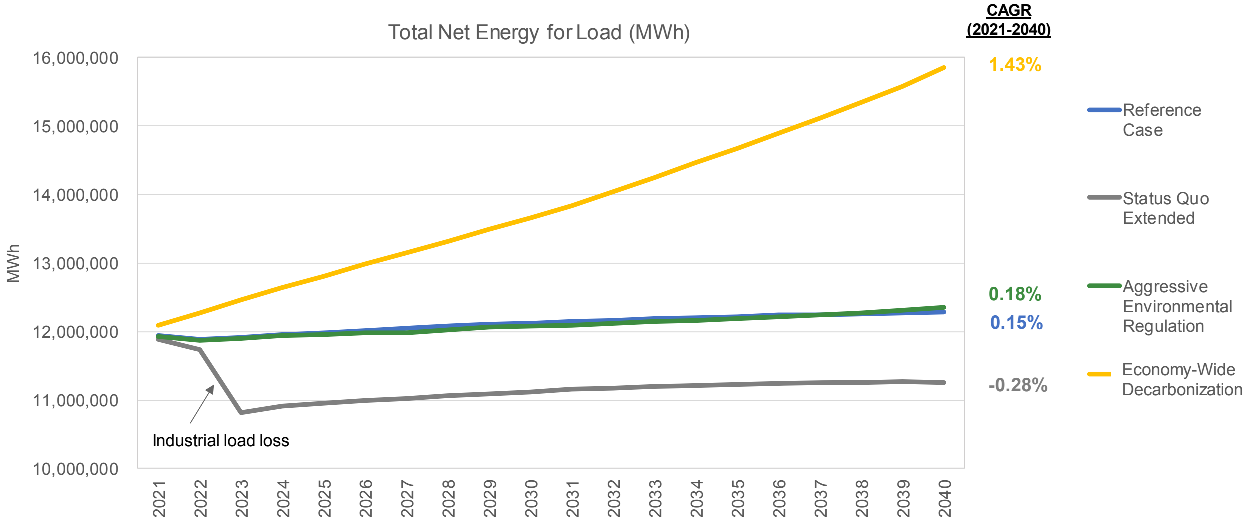
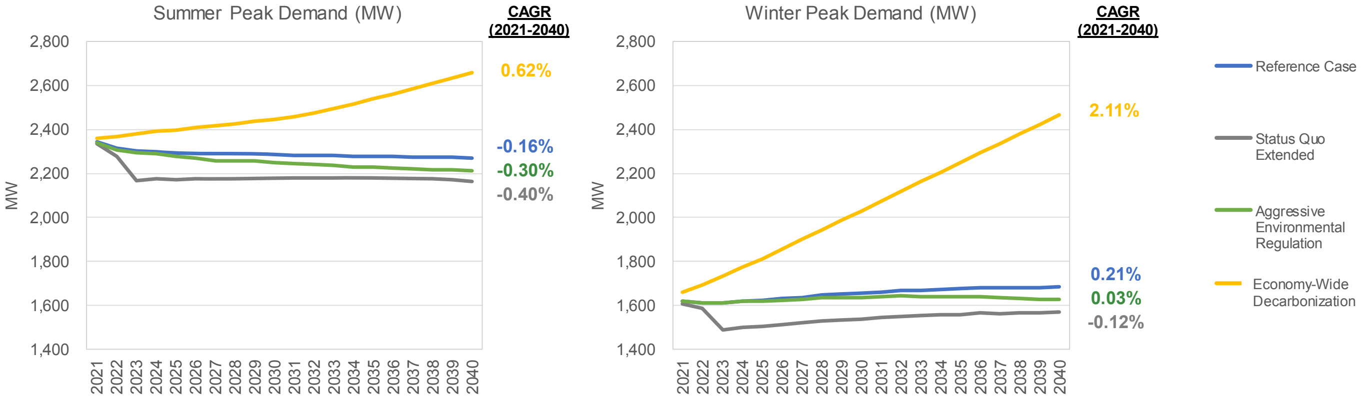


Figure 8-48: NIPSCO Summer and Winter Peak Load Forecasts across Scenarios



8.5 Stochastic Input Development

As discussed above, NIPSCO identified commodity prices and renewable generation output as stochastic variables to be analyzed in the 2021 IRP. The stochastic analysis approach broadly encompassed the following four steps:

1. **Input data development**, including development of fundamental forecasts (as described above), and review of historical price and weather data;

2. **Statistical and fundamental analysis**, including commodity price simulation and analysis to evaluate the impact of renewable energy output on power prices over time;

3. **Final stochastic input development**, including a description of how simulated commodity prices are combined with renewable shapes; and

4. **Portfolio analysis** with the stochastic inputs to evaluate key metrics for NIPSCO's integrated scorecard.

The remainder of this section provides an overview of the first three steps in the overall process, outlining the data development and analysis that contributes to stochastic input development, while the next chapter in this report covers the portfolio analysis.

8.5.1 Input Data Development

Fundamental Forecasts

The commodity price stochastic inputs were developed around the Reference Case natural gas and power price forecasts outlined earlier in this chapter. NIPSCO's stochastic analysis for the 2021 IRP is centered on the Reference Case fundamental forecasts for natural gas and MISO power prices as described above in Section 8.2.

Historical Commodity Price Data

Historical daily average gas and power price data were gathered to observe key price characteristics and calibrate simulation model parameters to reflect realistic market price behavior. These characteristics include, but are not limited to, standard deviation, range of prices around a seasonal median price, magnitude and frequency of sudden price spikes, market heat rate, and correlation between gas and power. Historical prices from the period January 1, 2016 through December 31, 2020 were used to summarize relevant market price behavior and constrain the dataset to include only the most recent market dynamics. This limits the dataset, but has the benefit of excluding data from periods of time with different natural gas fundamentals and with a MISO market generation mix that was very different than today's. The daily gas spot index from Chicago Citygates and the day-ahead ATC price strip from the NIPSCO zone within MISO were the specific pricing points used in this analysis.[95]

Historical Weather and Solar / Wind Availability Data

To determine the expected impact of renewable availability on hourly power prices, historical weather data from NREL was used to proxy historical wind and solar availability using NREL's SAM. To ensure that the weather data collected aligned with expected renewable

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[95] Data was retrieved from S&P Global Market Intelligence: Commodity Charting Tool.

availability over the planning horizon, a representative location within NIPSCO's service territory was selected in White County, Indiana.

Using SAM, the historical weather data for this location was downloaded at an hourly granularity from the NREL NSRDB[96] and the NREL Wind Integration Datasets.[97] Data was downloaded for as many historical weather years as were available (2007-2013 for the wind dataset and 2007-2019 for the solar dataset). Both datasets provide historical meteorological data and are managed by NREL. The data includes key meteorological descriptors including diffuse horizonal irradiance, direct normal irradiance, albedo, wind velocity (meters per second), temperature, snow depth, elevation above sea level, atmospheric pressure, and wind direction, among others.

Next, the collected weather data was used in conjunction with SAM's built-in resource performance models to simulate historical hourly solar and wind availability. SAM's performance models take as inputs data elements from the weather files to represent the renewable resource and ambient weather conditions that affect the system's performance. To further ensure that the resulting resource performance data was as representative as possible of the specific wind and solar resources in NIPSCO's portfolio, CRA defined in SAM the solar panel and wind turbine specifications associated with NIPSCO's planned renewable projects.

The process outlined above resulted in seven historical hourly trajectories for wind availability (representing historical weather years 2007 through 2013) and thirteen historical hourly trajectories for solar availability (representing historical weather years 2007 through 2019). The NREL simulations produced reasonable annual average capacity factors for wind and for solar in the selected location (the upper 30% range for a representative wind resource and mid 20% range for a representative solar resource).

8.5.2 Statistical and Fundamental Analysis

Commodity Price Uncertainty using MOSEP

To develop stochastic price paths for natural gas and power prices, CRA simulated daily natural gas and power price volatility using its MOSEP model. MOSEP is a regime-switching, mean-reverting model[98] that takes as input expected paths for electricity and gas prices developed through the fundamental forecasting analysis. The tool's Monte Carlo engine simulates price deviations around the expected paths based on historical volatility and gas-power correlation to yield "actual" or "realized" price paths. The model parameters are calibrated to historical gas market and MISO power market price behavior as mentioned above. A sample illustration of two

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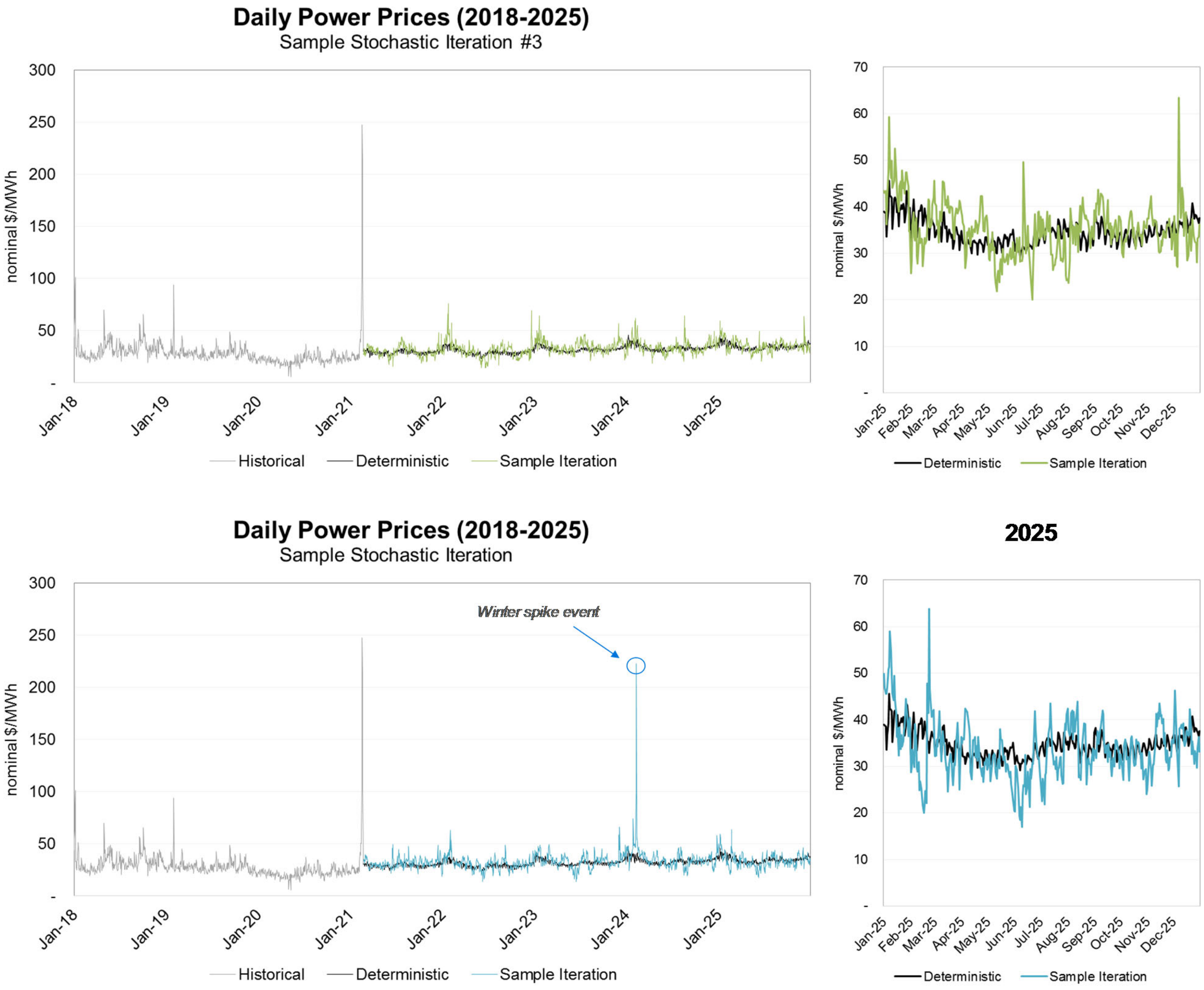
[96] NREL NSRDB, https://nsrdb.nrel.gov/

[97] NREL Wind Integration Datasets, https://www.nrel.gov/grid/wind-integration-data.html

[98] Commodity prices have been found to exhibit a mean-reverting behavior. The regime-switching feature of the model allows for simulation of price spikes by modeling different price regimes (e.g., normal price regime, spike price regime). The simulated switching between regimes is facilitated by a transition matrix. Given the current regime, the transition matrix specifies the probabilities of staying in the current regime or moving to a different regime. The probabilities are estimated based on historical data. For references, see the following paper, on which MOSEP is based - Higgs, H. & Worthington, A. "Stochastic price modelling of high volatility, mean-reverting, spike-prone commodities: The Australian wholesale electricity market." Energy Economics, 2008.

daily power price paths produced by MOSEP is shown in Figure 8-49. As illustrated, the stochastic price paths exhibit more daily volatility than the deterministic Reference Case price projections, and this is consistent with historical price behavior.

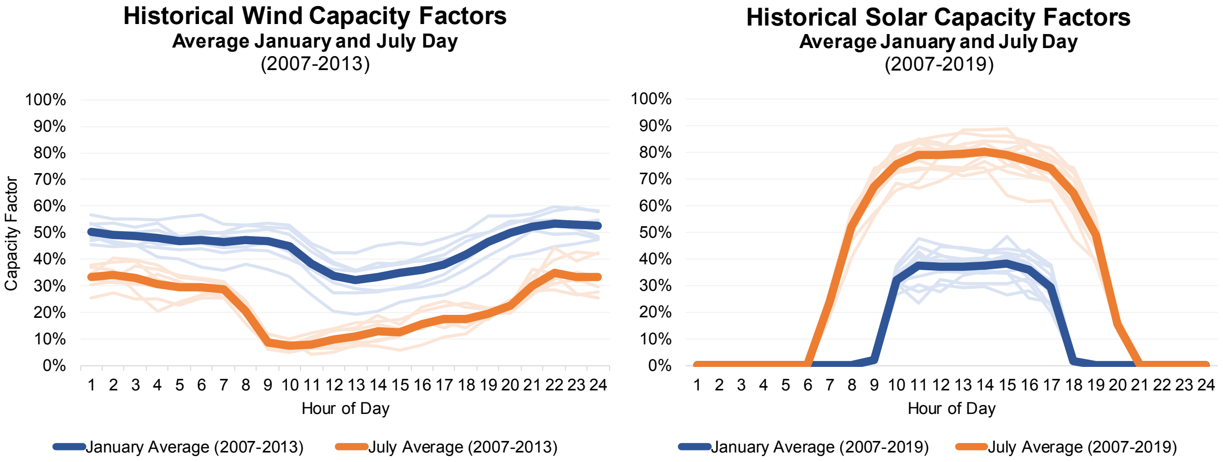
Figure 8-49: Sample Power Price Iterations



Integrating Renewable Output Uncertainty

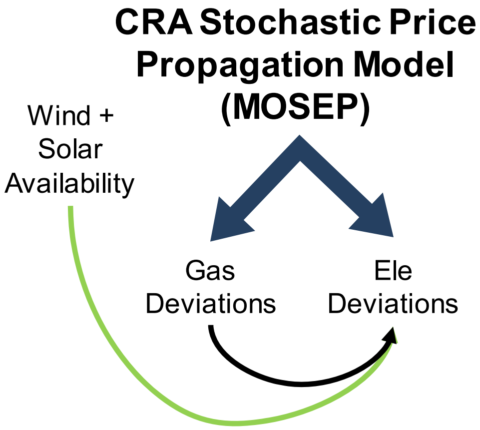
The integration of renewable output uncertainty into NIPSCO's stochastic analysis process was an enhancement for the 2021 IRP. Given the significant growth in intermittent renewable capacity within NIPSCO's portfolio (and the broader MISO market), incorporating the risk of renewable output uncertainty allowed NIPSCO to assess a broader range of risks associated with energy market exposure as market dynamics evolve. A sample illustration of monthly average wind and solar output profiles is shown in Figure 8-50, highlighting the fact that a range of capacity factors is to be expected for intermittent renewable resources over any long-term planning horizon.

Figure 8-50: Sample Renewable Output Iterations



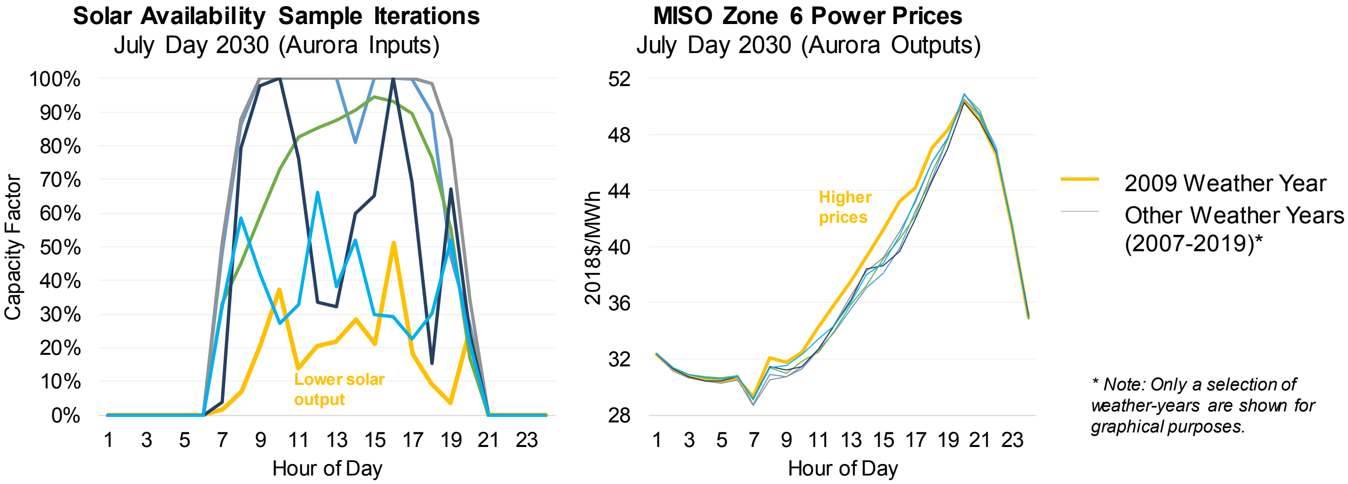
Furthermore, assuming that power prices and renewable output evolve independently of each other potentially underestimates the risk of growing levels of intermittent generation in NIPSCO's portfolio. This is because higher levels of intermittent generation output are generally expected to depress price levels. However, the magnitude of this effect is uncertain, particularly due to lack of relevant actual historical data. Therefore, for NIPSCO's stochastic analysis, the magnitude 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. This process is shown in illustrative form in Figure 8-51.

Figure 8-51: Illustration of Renewable Availability Integration in Stochastic Process



To evaluate the impact of different wind and solar output levels on MISO market prices, CRA performed fundamental power market analysis across a variety of inputs for wind and solar output based on a sample of historical weather years. Furthermore, since the negative impact of renewable availabilities on electricity prices is expected to become larger as renewable penetration increases, CRA performed the analysis assuming a number of forward test years and, thus, varying levels of renewable penetration. Figure 8-52 illustrates a small sample of solar output availabilities for a sample July day and their impacts on hourly MISO LRZ 6 power prices for the same day. As is shown, when solar output is lower, market prices would be expected to be higher, illustrating the likely correlation between these two variables.

Figure 8-52: Sample Solar Output and Power Price Iterations – Reference Case



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

CRA analyzed the relationship between hourly renewable availabilities and hourly power prices through a regression analysis. CRA ultimately specified a regression model that estimates the impact on power prices of hourly solar and wind availabilities. Seasonal variables (fall, summer, spring, or winter) and an hour of day indicator (nighttime vs. daytime) in combination with renewable availabilities were also found to be significant in explaining the variations in power price.[99] Two major conclusions were made from this analysis:

1. **Renewable availability has a significant negative impact on power prices, all else equal**: As shown in Figure 8-53, CRA's regression analysis found that an increase in renewable capacity factor had a significant impact on power prices at the hourly level, with solar output changes being most impactful during the spring and summer months and wind output changes being most impactful during nighttime hours.

2. **The impact of renewable availability on power prices increases with level of renewable penetration**: As shown in Figure 8-54, CRA's regression analysis found that the impact of renewable capacity factors on power prices grows over time, as the share of renewable generation in the market grows. The impact of solar output changes increased by over a factor of three between 2025 and 2040, and the impact of wind output changes increased by over a factor of four between 2025 and 2040 in CRA's simulations.

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[99] Interactions between solar and wind availability with seasonal dummy variables were included in the regression because it is expected that the season of the year will change the impact of solar availability and of wind availability on power prices. Hour of day dummy variables were included because it is expected that nighttime will change the impact of wind availability on power prices.

Figure 8-53: Negative Impact on Hourly Power Price per 1% Increase in Renewable Resource Capacity Factor – by Season

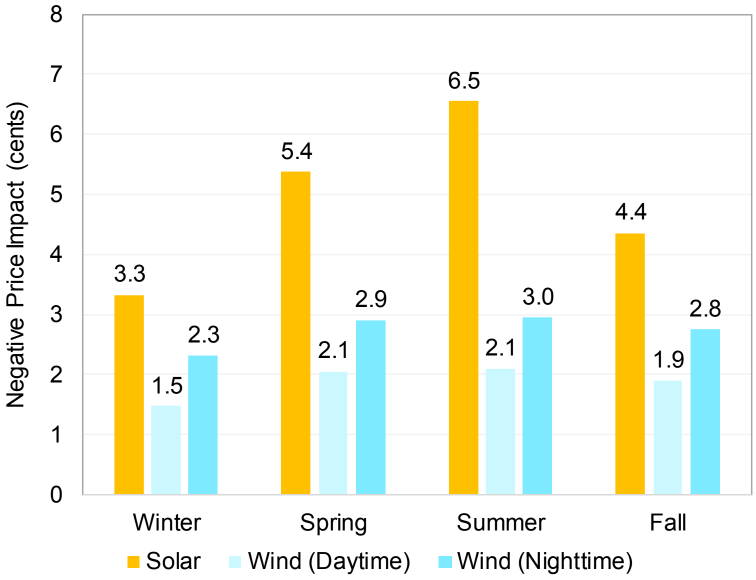
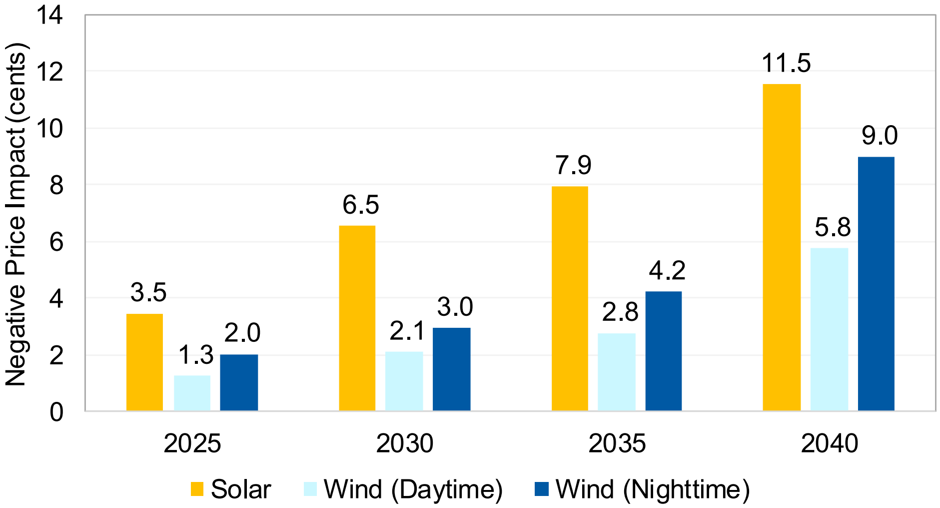


Figure 8-54: Negative Impact on Hourly Power Price per 1% Increase in Renewable Resource Capacity Factor – Summer Season over Time



8.5.1 Final Stochastic Input Development

After analyzing the likely impact of renewable output on future power prices, CRA combined the historical renewable output profiles with the power and gas stochastic price paths developed in the MOSEP tool to create the final stochastic inputs used for NIPSCO's portfolio analysis. Hourly renewable availabilities were randomly drawn from history and paired with power and gas price paths, with the regression-based impact added to the power prices to arrive at the final sets of stochastic inputs.

The stochastic input development process results in 500 daily or hourly price paths for gas and power, respectively. The paths can be plotted along with estimated prediction intervals. Time series for the twenty-year forecast period for natural gas prices and power prices, including historical price data, are illustrated in Figure 8-55 and Figure 8-56, respectively. These graphics show, on a monthly level, the broad range of the individual price paths (in light gray) along with representations of the monthly 5th, 50th, and 95th percentile values.

The values associated with a given percentile do not represent specific price trajectories, but instead indicate the price levels which exceed the associated proportion of the 500 prices at any given point in time. For example, the top blue line in Figure 8-55 represents the monthly 95th percentile for natural gas prices, which means that 95% of the simulated values are below this price level at any given point in time. In other words, 5% of the price realizations in any given month across the full range of simulated values would be expected to be above this level. These values can come from different price paths over time, since each path is likely to be relatively volatile, moving up and down. In fact, it is highly unlikely that a single path would be at the 95th percentile for a sustained period of time. Overall, the stochastic inputs allow for evaluation of portfolio performance against extreme price outcomes on the high side and on the downside, including at the daily and hourly price levels, which are not shown in these graphics.

Figure 8-55: Stochastic Distribution for Natural Gas Prices

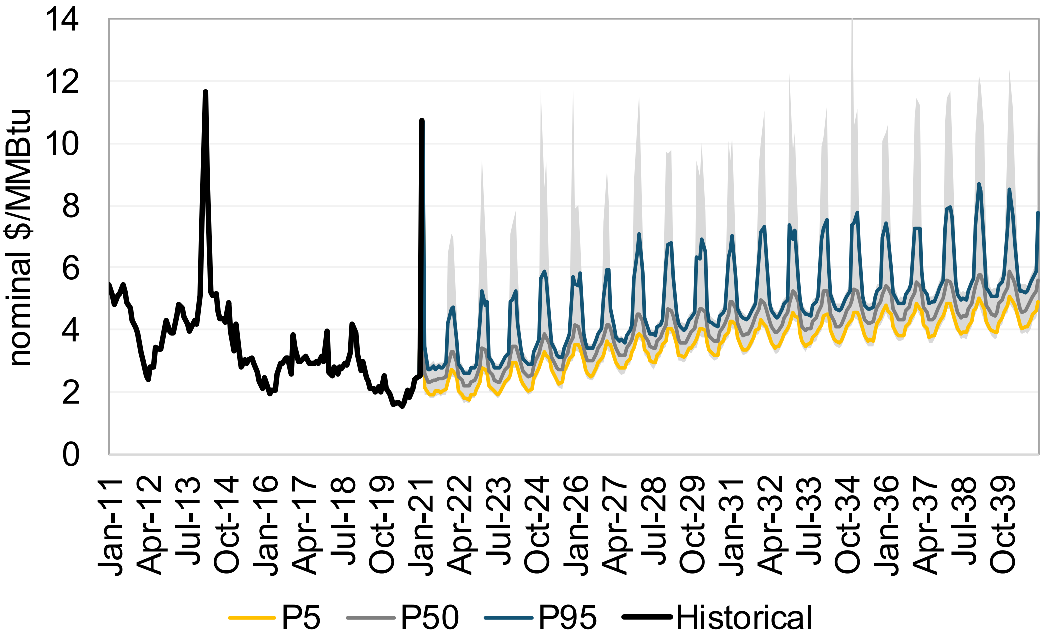
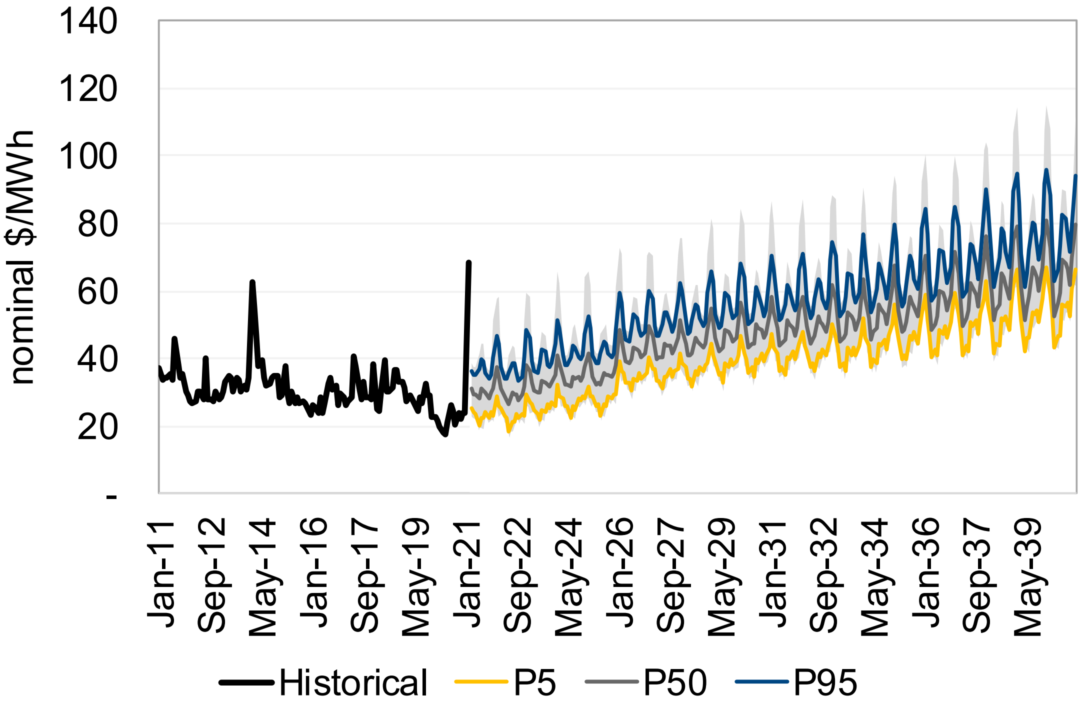


Figure 8-56: Stochastic Distribution for Power Prices



Section 9. Portfolio Analysis

9.1 Existing Fleet Analysis

9.1.1 Process Overview

NIPSCO's 2018 IRP established a roadmap to retire all coal capacity by 2028 and developed a short-term action plan focused on a portfolio of renewable resource additions to replace retiring capacity at the Schahfer plant through 2023 (*See* Section 4 for more detail on the new renewable resources). After the implementation of that short-term action plan, approximately 65% of NIPSCO's generation fleet will be set for the next several years, with the 2021 IRP analysis evaluating potential retirement pathways for the remainder of NIPSCO's existing fleet. As discussed in more detail in Section 2, NIPSCO determined that it was most efficient and effective to evaluate retirement decisions for the existing fleet on a stand-alone basis, while performing an additional replacement analysis to assess a wide range of replacement resource strategies. Although performed in two steps, the existing fleet and replacement analyses are both based on the same major inputs and assumptions, which are described in parts of Section 8 and below.

NIPSCO believes that performing an existing fleet analysis requires careful planning and consideration of several factors. To that end, NIPSCO has used an integrated scorecard methodology to evaluate existing fleet portfolios, as described in Section 2. In addition to the net present value of revenue requirements in the Reference Case, NIPSCO has also considered multiple rate stability metrics, carbon emissions, and the effect of unit retirements on NIPSCO's employees and the local economies of the communities it serves.

9.1.2 Existing Fleet Analysis Methodology

The existing fleet analysis has been conducted according to the following steps:

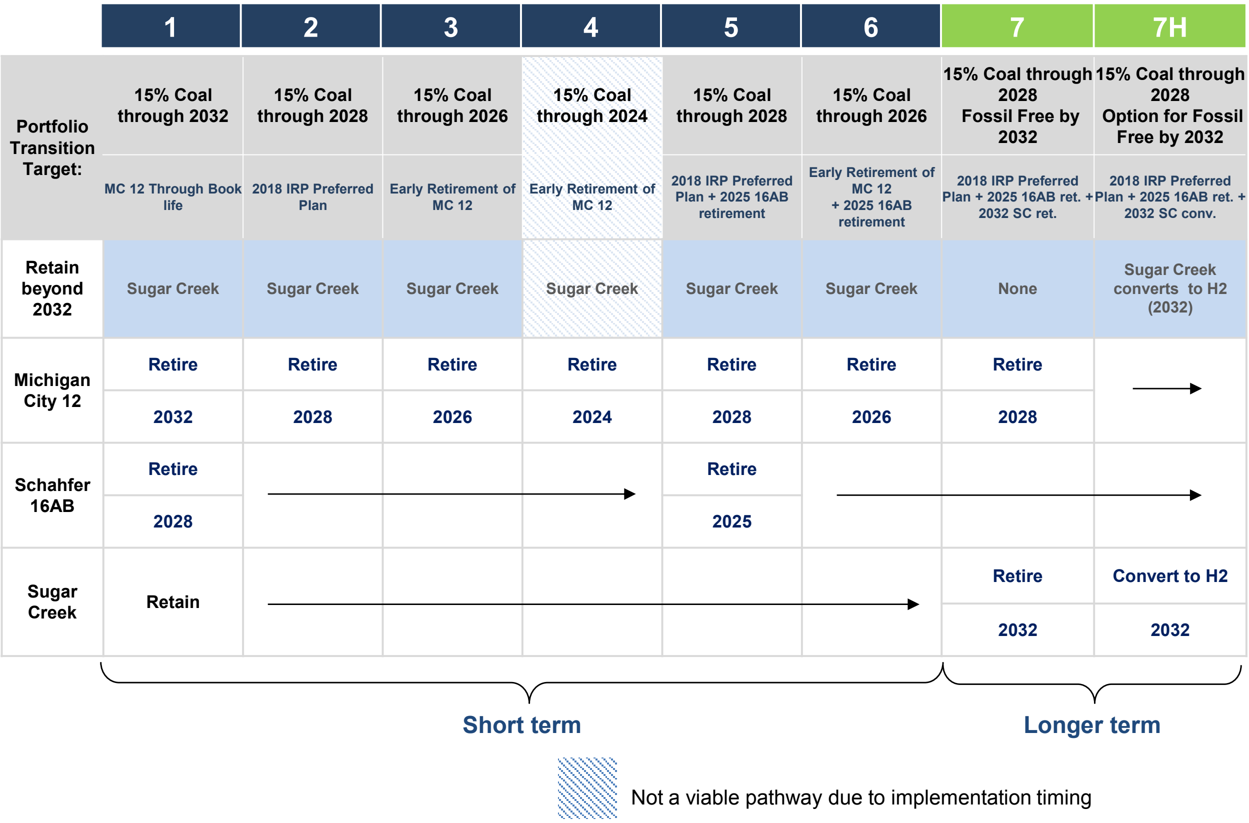
- Identify plausible retirement and retention plans for the existing fleet and specify individual retirement/retention combinations or "portfolios."
- Identify the least-cost replacement capacity to fill the resulting capacity gap for each retirement portfolio based on the results from the RFP conducted by NIPSCO and other available supply-side and demand side resources (*See* Sections 4 and 5 for more detail on these resource options).
- Evaluate each portfolio, including its associated least-cost capacity replacement, in the IRP tools for each scenario (as defined in Section 8). The evaluation includes a full accounting of the ongoing operations of each existing plant and the costs of alternatives.
- Record costs, risks, and other metrics in the integrated scorecard to identify the preferred existing fleet strategy.

9.1.3 Identification of Existing Fleet Portfolios

NIPSCO's remaining fossil-fueled generation plants were evaluated for potential retirement throughout the IRP's planning horizon. This includes Michigan City Unit 12 (coal), Schahfer Units 16A and 16B (natural gas steam), and Sugar Creek (natural gas CCGT). NIPSCO identified eight existing fleet portfolios for analysis based on different combinations of unit retirements at different points in time, as summarized in Figure 9-1:

- The first four portfolios examine the retirement timing of Michigan City Unit 12, including bookend concepts that evaluate retention of the plant beyond its announced retirement date to the end of its book life in 2032 and an early retirement by 2024, a portfolio concept that is not viable from an implementation perspective.
- Portfolios 5 and 6 vary the retirement timing of Schahfer Units 16A/B between 2025 and the expected end of the units' useful operational life in 2028.
- Portfolios 7 and 7H evaluate long-term concepts for potential Sugar Creek retirement and hydrogen conversion, respectively. These portfolios were developed to provide a long-term view towards net-zero decarbonization pathways, although key implementation actions would be made more than a decade into the future.

Figure 9-1: Overview of Existing Fleet Portfolios



	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

Longer term

▨ Not a viable pathway due to implementation timing

9.1.4 Existing Fleet Cost Assumptions

The evaluation of each existing fleet portfolio was performed through a full portfolio analysis that included dispatch in Aurora and financial accounting in PERFORM (*See* Section 2 for more detail on the overall modeling process). Market assumptions were consistent with those outlined earlier in Section 8 for the Reference Case and the three alternative scenarios. In addition to the major market inputs and the costs of replacement resources (see next section below), several relevant assumptions were made regarding the ongoing costs of the existing coal fleet.

Ongoing costs include fuel, fixed O&M costs, and maintenance capital, as well as the recovery of remaining book value associated with each plant as of April 2021. This recovery includes return of (depreciation), return on, and income and property taxes associated with the remaining net book value of NIPSCO's existing fleet.

Fixed O&M costs included all labor, materials, engineering and support services, and overhead costs necessary to operate the plant. For all units, projections of fixed O&M costs were obtained for each year within 2021-2040. These costs were then escalated at 2.1% per year[100] for the 2041-2050 end effects modeling period. Additional detail is provided in Confidential Appendix

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[100] The EIA's AEO assumes a 2.1% rate of inflation for "All Commodities," which is used as a long-term proxy of general cost inflation for the end effects extrapolation.

D. As an existing unit's projected retirement date moves up, the relative fixed O&M spend tended to decrease during the years leading up to retirement.

Maintenance capital costs included the projected capital expenditures necessary to keep the units running through the analysis period at the projected level of operations. For all units, projections of maintenance capital costs were obtained for each year within 2021-2040. These costs were then escalated at 2.1% per year 2041-2050 end effects modeling period. Additional detail is provided in Confidential Appendix D. Similar to fixed O&M costs, as an existing unit's projected retirement date moves up, the relative capital spend tended to decrease during the years leading up to retirement.

NIPSCO also included estimated transmission upgrade costs associated with Schahfer and Michigan City's retirements. An additional $6.7 million of capital expenditures was incorporated for transmission upgrades at the time Schahfer 16A/B retires in any existing fleet portfolio. An additional $82.9 million of capital expenditures was incorporated for transmission upgrades at the time Michigan City retires in any existing fleet portfolio.

Recovery of depreciation expenses on existing capital by 2033 has also been incorporated in the existing fleet analysis. NIPSCO assumes that each unit continues to depreciate at the same rate of 3.88% until 2033, regardless of whether the unit has been retired or not. This means that each retirement portfolio has the same depreciation schedule for existing capital. At 2033, the sum of all coal plants' NBV on existing capital is equal to the negative "cost of removal" for all the coal plants. The negative NBV on existing capital in 2033 lowers rate base in perpetuity. The cost of removal was estimated by John J. Spanos, an expert witness supporting NIPSCO's 2019 Electric Rate Case[101] In addition to the "return of" (depreciation) the net book value, NIPSCO continues to earn a "return on" the net book value equal to NIPSCO's assumed weighted average cost of capital. NIPSCO assumes that property and income tax will *not* be collected on the remaining NBV of the plant if it is retired.

9.1.5 Identification of Least-Cost Replacement Capacity

As in the 2018 IRP, NIPSCO's All-Source RFP provided insight into the supply and pricing of resource alternatives available to NIPSCO (*See* Section 4 for details on the process and the costs and operational parameters of the individual tranches used for evaluation). In addition, NIPSCO identified other resource options, including DERs (*See* Section 4), an uprate at the existing Sugar Creek facility (*See* Section 4), and bundles of DSM resource options over time (*See* Section 5).

With these resource options, a portfolio optimization was performed within Aurora's portfolio optimization tool under each of the eight retirement portfolio concepts to identify least-cost sets of replacement resources under Reference Case market conditions. The portfolio optimization modeling was performed for both the winter and summer peak seasons and was

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[101] See Cause No. 45159.

designed to minimize the net present value of revenue requirements, with certain constraints for reserve margins, maximum off-system energy sales, and resource eligibility.[102]

Overall, the economic optimization model selected a diverse set of resources. 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 tends to favor resources that offer greater levels of firm capacity relative to their energy contributions. When available for selection, the resources universally selected through 2027 included (all values in ICAP) included the following:

- Approximately 10 MW of NIPSCO-owned DERs with the largest distribution cost deferrals;
- The uprate to the existing Sugar Creek CCGT at the modeled level of 53 MW;
- Approximately 68 MW (summer peak credit)[103] of DSM resources by 2027, which includes the cumulative impact of both Tier 1 Residential and Commercial programs by 2027, with Commercial programs being most cost effective;[104]
- Thermal capacity contracts from the 2021 RFP up to 150 MW;

In addition, several different resource types were consistently selected at various sizes and timings based on retirement dates and resource eligibility. These included:

- A natural gas peaker up to 300 MW (hydrogen-enabled in Portfolio 7H);
- Various levels of stand-alone storage between 135 MW and 570 MW;
- Solar capacity up to 250 MW;
- Wind capacity up to 200 MW;
- A 20 MW electrolyzer pilot at Sugar Creek in Portfolio 7H.

Figure 9-2 provides a summary of the capacity resources that were selected under Portfolios 1-6, and Figure 9-3 provides a summary of the capacity resources that were selected under Portfolios 7 and 7H. Note that these portfolios do not represent NIPSCO's preferred replacement strategy, but only least-cost optimization outcomes that are used to evaluate retirement implications associated with the existing fleet.

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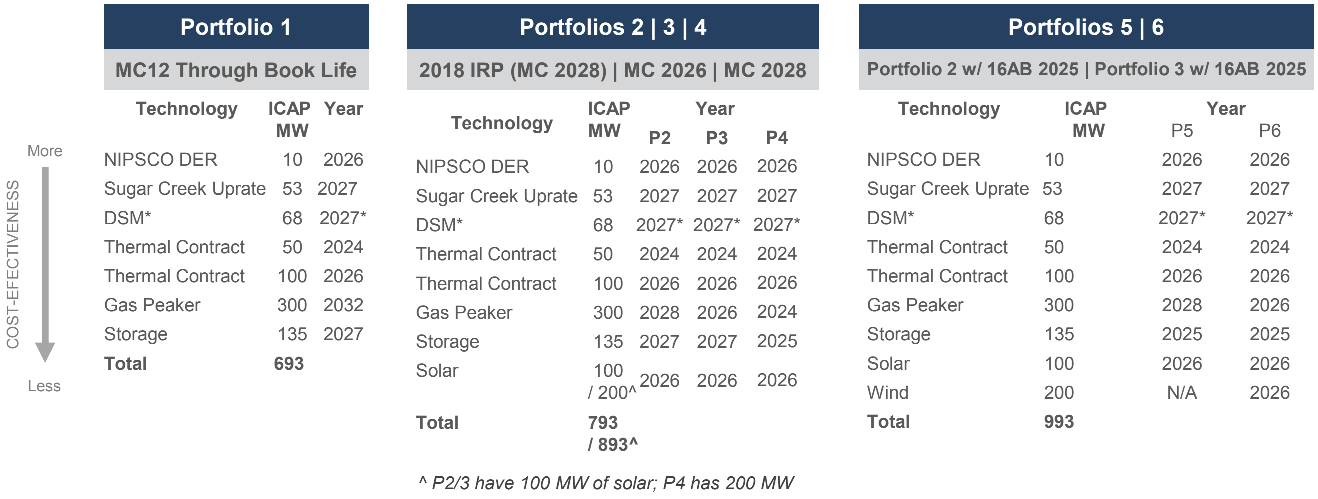
[102] Portfolios were optimized against winter reserve margin constraints (9.4%), followed by summer to ensure compliance with both. A maximum net energy sales limit of 30% during the fleet transition (2023-2026), falling to 25% in 2030+, was enforced. Portfolios 7 and 7H are designed to achieve net zero emissions over the study horizon, so eligible resources were restricted. Portfolio 7 did not allow for new fossil resources, and Portfolio 7H "forced in" hydrogen-enabled resources

[103] Note that the winter peak impact of the selected DSM resources is approximately 46MW.

[104] Note that the Tier 1 Residential and Commercial DSM bundles were selected across all time horizons in the fundamental modeling period. Additional detail on bundle costs and savings is provided in Section 5.

Figure 9-2: Summary of Least-Cost Replacement Capacity: Portfolios 1-6



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	**P3**	**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^**			

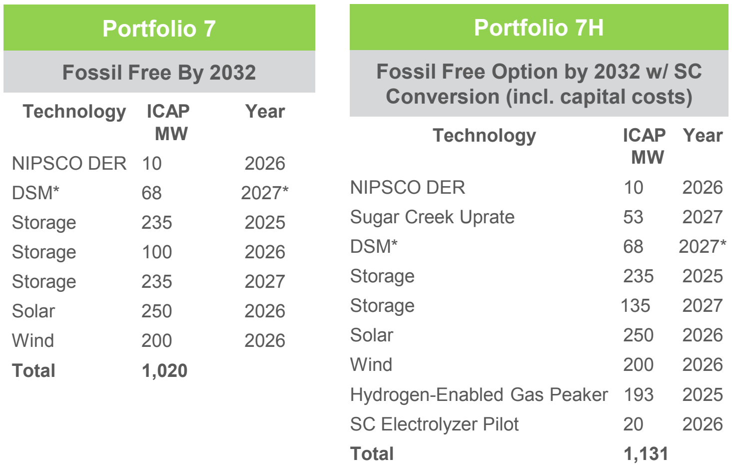
^ P2/3 have 100 MW of solar; P4 has 200 MW

Portfolios 5 | 6

Portfolio 2 w/ 16AB 2025 | Portfolio 3 w/ 16AB 2025

Technology	ICAP MW	Year	
		P5	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**		

Figure 9-3: Summary of Least-Cost Replacement Capacity: Portfolios 7 & 7H



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**	

9.1.6 Evaluation of Each Existing Fleet Portfolio – Scorecard Metrics

NIPSCO developed a set of decision criteria objectives and metrics against which to evaluate the full set of existing fleet portfolios. The analysis was then conducted to quantify the performance of each portfolio against each scorecard metric. The following section describes each of the key objectives and metrics in more detail:

- Cost to Customer is measured by the overall NPVRR under Reference Case Conditions.

- Cost Certainty measures the certainty that the net present value of revenue requirements falls within the range of the scenario outcomes and is quantified by the range in NPVRR across scenarios.

- Cost Risk measures the risk of unacceptable, high-cost outcomes and is quantified by the highest scenario NPVRR.

- Lower Cost Opportunity measures the potential for lower cost outcomes and is quantified by the lowest scenario NPVRR.[105]

- Carbon Emissions measures the carbon intensity of the portfolio and is quantified by the cumulative short tons of CO2 emitted from the generation portfolio from 2024 through 2040.[106]

- Employees and Local Economy measures the positive social and economic impacts of NIPSCO's existing generation fleet and are measured by the net impact on permanent jobs associated with the current generation fleet and the net present value of property taxes associated with the current fleet relative to the 2018 IRP's conclusions, respectively.

A summary of the decision criteria metrics for the existing fleet analysis is provided in Figure 9-4, noting that reliability metrics are addressed more fully in the replacement analysis that seeks to evaluate the tradeoffs of different replacement resources more comprehensively.

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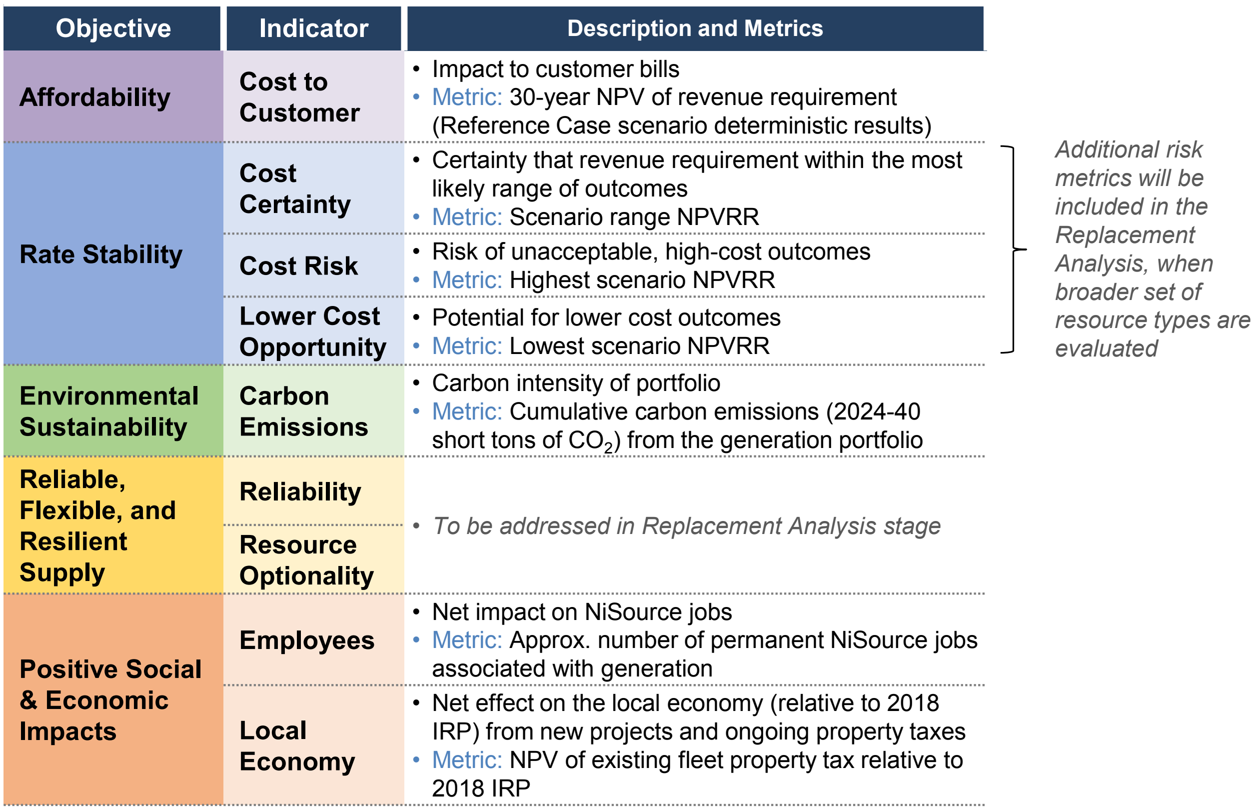
[105] Note that additional rate stability and risk metrics are included in the Replacement Analysis phase, including those associated with the stochastic analysis.

[106] These years represent the fundamental modeling horizon after the retirement of the Schahfer coal units, which is common to all portfolios.

Figure 9-4: Scorecard Metrics for Existing Fleet Analysis



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

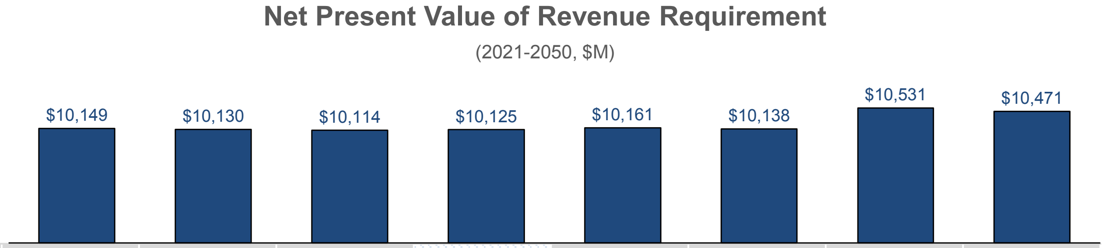
9.1.7 Evaluation of Each Existing Fleet Portfolio – Results

Reference Case Cost Results

The eight existing fleet portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail) to estimate revenue requirements for each over time. The assessment was first performed across the Reference Case set of market assumptions and inputs to calculate baseline projections of the NPVRR over the thirty-year planning horizon, which are summarized in Figure 9-5.

Under the Reference Case market conditions, 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, with Portfolio 3 (retirement of Michigan City 12 in 2026) having the lowest cost overall. However, 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. In addition, the analysis suggests that 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.

Figure 9-5: Cost to Customer Impacts – Existing Fleet Portfolios


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

Scenario Cost Results

In addition to the analysis under Reference Case conditions, NIPSCO also evaluated each existing fleet portfolio against each scenario described earlier in Section 8. The NPVRR for each retirement portfolio across each scenario is summarized in Figure 9-6, with additional details regarding the scenario results described below.

Under the SQE scenario, all portfolio costs are projected to decline due to no carbon price and lower gas and power prices. Given that the lower natural gas price outlook harms near-term coal plant performance, earlier retirement of Michigan City 12 is slightly lower cost than retaining the unit longer, although Portfolios 2-4 are all within $20 million on an NPVRR basis. The cost premium associated with moving towards a net zero strategy (Portfolios 7 and 7H) is highest under this scenario.

Under the AER scenario, higher carbon prices and higher gas prices drive higher portfolio costs, particularly for Portfolio 1, which retains Michigan City 12 until 2032. However, Portfolios 2 and 3 are lower cost than Portfolio 4, as the higher gas prices benefit Michigan City's performance for a few years until replacement resources can enter as the carbon price increases over time. Under this scenario, Portfolio 7 has the lowest NPVRR.

Under the EWD scenario, portfolio costs are the highest, given the highest load growth expectations and growing clean energy requirements. The relative ordering of Portfolios 1-4 is the same as in the Reference Case, but Portfolio 6 has the lowest NPVRR of the first six due to the benefit realized by higher levels of renewable energy additions taking advantage of the clean energy standard construct. In addition, Portfolios 7 and 7H are the lowest cost under this scenario, with the value of hydrogen energy providing 7H a significant cost benefit.

Figure 9-6: Cost to Customer across All Scenarios – Existing Fleet Portfolios (30-year NPVRR – millions of $)

	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

Overall, across scenarios, the following key observations were made:

- Retirement of Michigan City 12 in 2026 has a slightly lower NPVRR (less than $20 million) relative to retirement in 2028 across all scenarios.
- Retirement of Michigan City 12 in 2032 is always higher cost than earlier retirement, with the largest difference in the AER scenario.
- Portfolio 2 (retirement of Schahfer 16AB in 2028) is slightly lower cost than Portfolio 5 (retirement of Schahfer 16AB in 2025), although additional renewable additions with early 16AB retirement (Portfolio 6) results in a lower NPVRR under the two 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.

CO2 Emissions

The retirement timing for Michigan City 12 is the major driver of CO2 emission differences across the eight portfolios, with Sugar Creek remaining the largest source of emissions into the 2030s. Therefore, earlier retirement of either unit results in lower overall CO2 emissions for the portfolio. Figure 9-7 illustrates the projected CO2 emissions by portfolio over time for the Reference Case, while Figure 9-8 presents the cumulative emissions over the 2024-2040 period for each scenario, along with a reporting of the scenario average. Emissions vary across scenarios based on different dispatch projections for the fossil units and the potential for hydrogen blending at Sugar Creek in the AER and EWD scenarios in Portfolio 7H.

Figure 9-7: Annual CO2 Emissions for Existing Fleet Portfolios – Reference Case

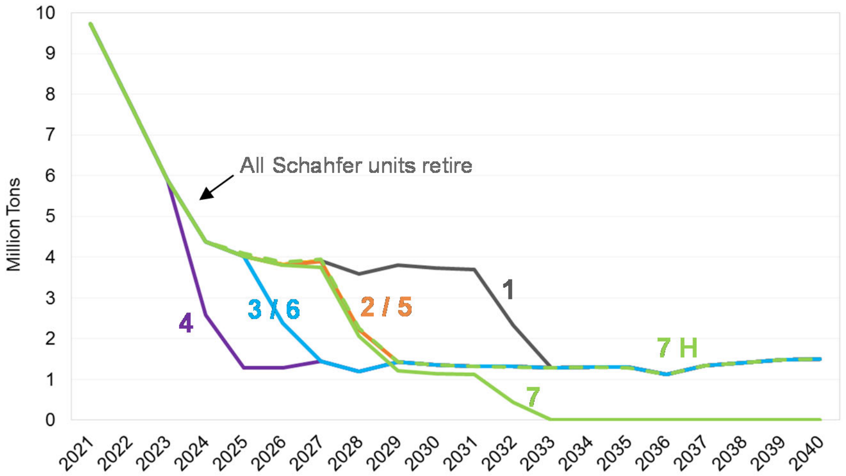
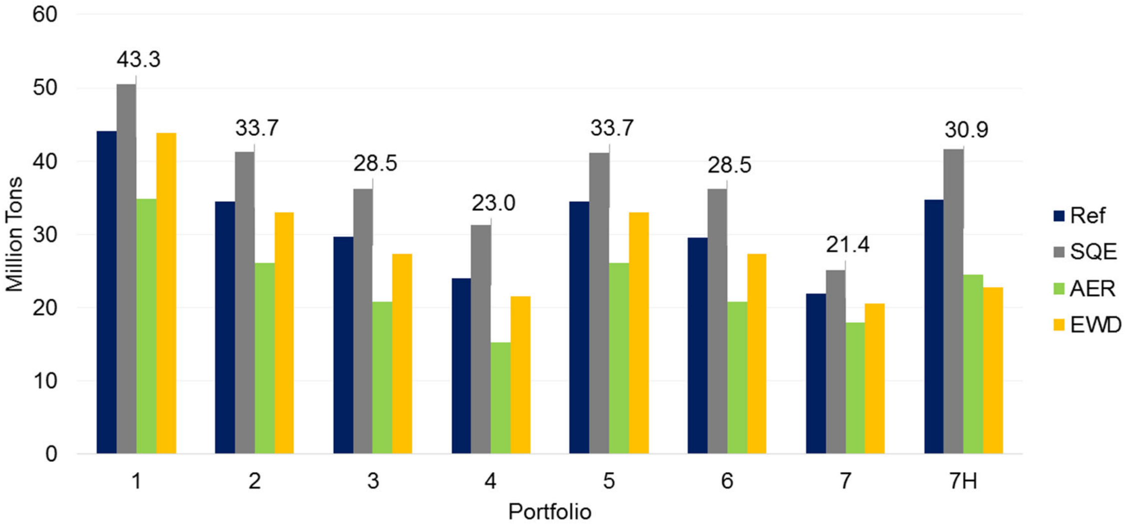


Figure 9-8: 2024-2040 Cumulative Tons of CO2 Emissions for Existing Fleet Analysis – All Scenarios with Average



9.1.8 Existing Fleet Analysis Scorecard Summary

Figure 9-9 presents a summary of all scorecard metrics for each of the eight existing fleet portfolios. This includes the cost metrics associated with the Reference Case NPVRR, the risk metrics associated with the scenario analysis, carbon emissions, NIPSCO employees, and the local economy, as described above.

Figure 9-9: Retirement Portfolio 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

The following key observations were made:

- 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 CO2 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 jobs for NIPSCO employees 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 CO2 emissions (Portfolio 7H), provides a hedge against significant environmental regulations that would otherwise raise portfolio costs.

9.1.9 Preferred Existing Fleet Portfolio

NIPSCO's preferred existing fleet portfolio strategy is to retire Michigan City 12 between 2026 and 2028 , to optimize the retirement timing of Schahfer 16A/B between 2025 and 2028, and to keep open the option of retiring or retrofitting the Sugar Creek plant in the 2030s based on environmental policy evolution and technology advancement.

Overall, Portfolio 2 (2028 Michigan City 12 retirement) and Portfolio 3 (2026 Michigan City 12 retirement) were the lowest cost, viable existing fleet portfolio options, and preserving optionality for the Michigan City 12 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.

In addition, although Schahfer 16A/B may provide relatively low-cost capacity through 2028, NIPSCO will retain flexibility with retirement timing based on the ultimate Michigan City 12 retirement timing and associated replacement opportunities, Schahfer 16A/B's operational performance, and policy and technology developments.

Finally, while Portfolios 7 and 7H are higher cost under currently expected conditions, 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 policy implementation. Therefore, NIPSCO's preferred existing fleet portfolio strategy explicitly keeps such long-term options open regardless of the retirement dates for Michigan City and Schahfer 16A/B. As a result, the replacement analysis (described in more detail below) continued to evaluate such strategies in more detail.

It is anticipated that NIPSCO's 2021 IRP preferred retirement strategy will require certain upgrades to the transmission system in order to maintain system reliability and remain compliant with NERC transmission planning standards, NIPSCO Planning criteria, and MISO requirements. As noted above, nearly $90 million in costs was assessed with the retirement of Michigan City 12 and the Schahfer 16 A/B units in the IRP analysis. This assumption will be validated once NIPSCO proceeds with filing the required forms with MISO (Attachment Y).

With its preferred existing fleet portfolio strategy, NIPSCO has balanced customer cost and cost risk, with portfolio flexibility and the ability to successfully and reliability transform its supply resources to meet its customers' needs. This option also balances other non-economic considerations such as environmental sustainability, portfolio flexibility, employee considerations, and property tax impacts.

Under such a portfolio, a capacity gap of up to 547 MW in the summer and up to 515 MW in the winter will open up by 2028,[107] as shown in Figure 9-10, which summarizes current and expected capacity resources against NIPSCO's Reference Case load forecast, inclusive of planning reserve margin requirements, and assuming the *earliest potential resource retirements* studied in the existing fleet analysis (Schahfer 16A/B in 2025 and Michigan City 12 in 2026). Uncertainty in the future capacity gap will be driven by load growth, MISO planning reserve margin targets, and realized renewable resource capacity credit over time. This capacity gap is the subject of the replacement analysis that is described next.

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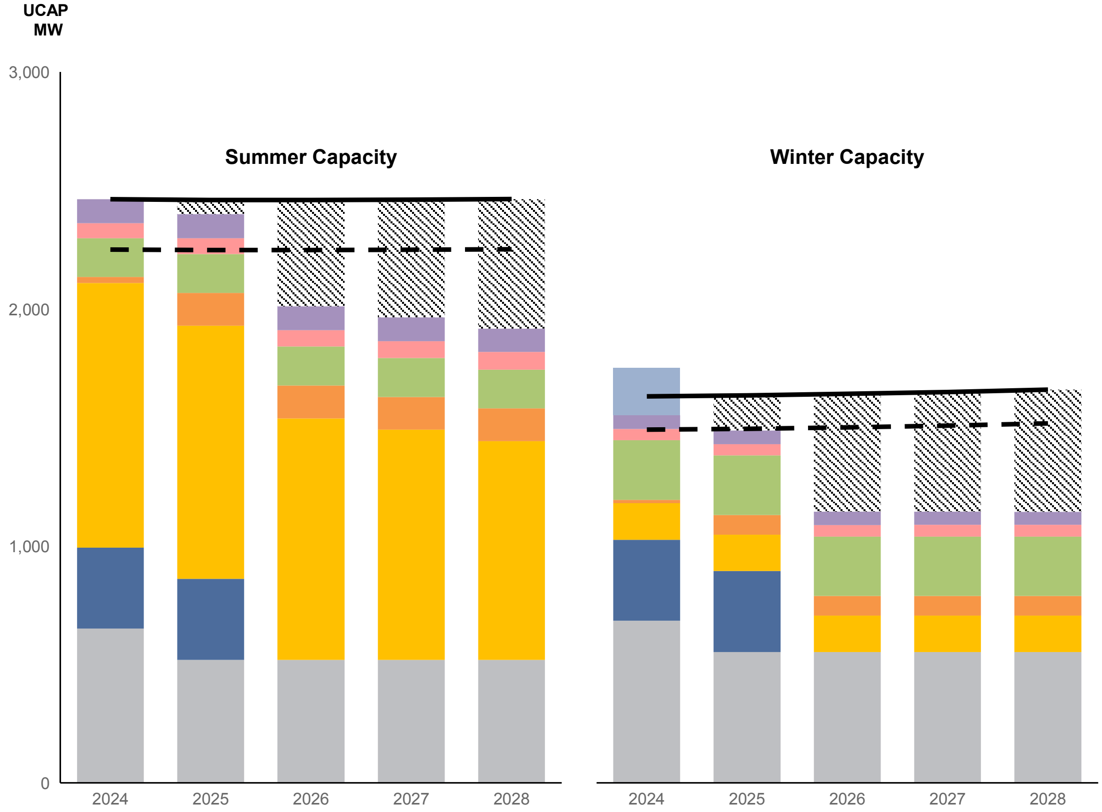
[107] The capacity gap would be slightly smaller in 2025 or 2026 if the Michigan City 12 and Schahfer 16AB units are retired at points in time prior to 2028. However, this represents the resulting gap by 2028 of any retirement strategy, as illustrated in Figure 9-10.

Figure 9-10: Earliest Future Capacity Need Based on Unit Retirements



9.2 Replacement Analysis

9.2.1 Process Overview

NIPSCO evaluated a range of potential resource replacement options to fill the capacity gap that would develop as the Michigan City 12 and Schahfer 16A/B units retire. For the replacement analysis, Portfolio 3 from the existing fleet analysis was used to assess portfolio selection under the earliest possible retirement of Michigan City 12, noting that Portfolio 2 (Michigan City 12 retirement in 2028) would have similar results, with small changes in resource addition timing.[108]

NIPSCO's replacement analysis was performed in a similar manner to the existing fleet analysis, with the following major steps:

- Identify replacement resource concepts for NIPSCO, primarily around considerations for CO2 emission intensity and resource dispatchability.

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[108] This approach does not imply that NIPSCO has determined a specific Michigan City12 retirement date, but is useful for replacement resource selection, given that 2026 was deemed to be the earliest viable retirement date.

- Develop specific replacement portfolios within each concept using IRP optimization tools, bids from the RFPs, and expert judgment.

- Evaluate each replacement portfolio in the IRP tools for each scenario and across the full stochastic distribution of major market inputs (as discussed in detail in Section 8).

- Record costs, risks, and other metrics in the integrated scorecard to arrive at a preferred replacement portfolio strategy.

9.2.2 Identification of Replacement Resource Concepts

NIPSCO developed a matrix of replacement resource concepts based on two key planning considerations. The first consideration was structured around the "dispatchability" of the resource options. Broadly speaking, dispatchability refers to the ability of resources within the portfolio to provide energy "on demand," meaning that resources not reliant on external weather conditions and factors and resources with longer energy duration capabilities are considered more dispatchable. Across the dispatchability consideration, three categories were broadly defined:

- Portfolios that meet only the existing summer reserve margin requirements over time and tend to contain more solar capacity than other dispatchable resource types;[109]

- Portfolios that meet both winter and summer reserve margin requirements over time and tend to contain additional thermal or storage capacity;

- "Enhanced" reserve margin portfolios that more fully rely on local resources with longer energy duration capabilities, especially thermal resources. Such a portfolio category recognizes the need for local resources during emergency conditions and anticipates future MISO market policy developments that may reduce the capacity credit for resources with limited energy durations, such as four-hour batteries.

The second consideration was structured around the CO2 emission intensity of each potential portfolio option. While no specific emission intensities were defined, portfolios with more fossil-fired resource capacity were considered to have higher emission intensities, while portfolios with more renewable and storage capacity were considered to have lower emission intensities. In addition, specific net-zero emission concepts based on retirement or conversion to hydrogen of all fossil resources in the portfolio were developed.

Overall, nine different concepts were identified for more detailed portfolio development, as shown in Figure 9-11. These portfolios are referred to as Portfolios A-I throughout the rest of this Section.

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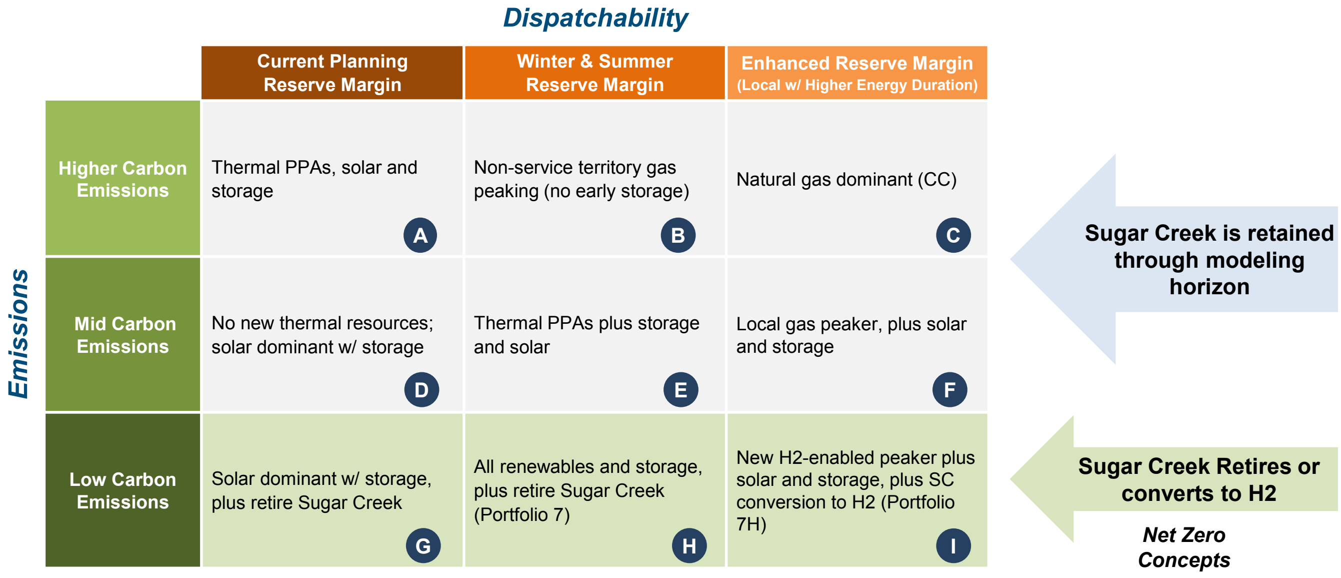
[109] Given expectations for MISO market rules changes, these portfolio concepts are not viable, but were evaluated to assess their costs across scenarios along with other tradeoffs. Certain stakeholders also expressed an interest in evaluating this theme.

Figure 9-11: Replacement Consideration Matrix



	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

9.2.3 Development of Specific Replacement Portfolios

Based on the nine replacement concepts, NIPSCO then developed specific portfolios to fit each theme. This was done through a combination of the Aurora model's portfolio optimization capability and expert judgment to adjust portfolio concepts based on optimization analysis and available RFP bids.

DSM and DER Selection

Across all portfolio themes, the following DSM bundles were incorporated based on the economic optimization analysis: (i) Tier 1 residential EE for 2024-2029, 2030-2035, and 2036-2041; (ii) commercial and industrial EE for 2024-2029, 2030-2035, and 2036-2041; and (iii) the residential DR rates programs after 2030. (*See* Section 5 for additional detail on the specific energy and peak savings contributions of each bundle). In addition, 10 MW of NIPSCO DER was incorporated in all portfolio themes, reflecting the DER opportunities with the largest investment deferral benefit (*See* Section 4 for additional detail).

All-Source RFP Resource Selection

Beyond DSM and DER additions, NIPSCO used the following approach to select RFP project additions for each of the portfolio themes, which are summarized in Figure 9-12 with incremental ICAP additions and in Figure 9-13 with new resource UCAP contributions shown in the context of the remaining portfolio and expected seasonal reserve margin requirements for 2027:

- Portfolios B, E, and F were based on the optimized portfolio themes from the existing fleet analysis, with specific RFP tranches to identify local versus remote gas peaking options (in Portfolios B and F) and to adjust the amount of gas peaking, storage, and solar capacity to fit the themes and meet reserve margin requirements.

- The net energy sales constraint enforced in the existing fleer analysis phase was relaxed to allow for fossil resources with higher energy contributions for Portfolio C, allowing for the inclusion of a combined cycle.

- Optimization testing was evaluated across Reference and high environmental regulation scenarios under summer reserve margin targets only to develop Portfolios A, D, and G with higher levels of solar and solar plus storage.

- Portfolios H and I were mapped to Portfolios 7 and 7H, respectively from the existing fleet analysis to capture the net zero concepts with Michigan City retirement in 2026.

Beyond the RFP selection period, NIPSCO relied upon the optimization analysis results from the existing fleet analysis phase, which suggested that generic solar and storage resources were most cost-effective additions over time to meet capacity needs and energy requirements associated with expectations for declining capacity factors for the Sugar Creek unit, expiring wind contracts, and solar degradation over time. Solar and storage addition amounts were adjusted to ensure reserve margin targets were met across each of the portfolio themes.[110] A summary of the total capacity additions through 2040 for all nine portfolios is shown in Figure 9-14, with a 2040 supply-demand balance on a UCAP basis summarized in Figure 9-15.

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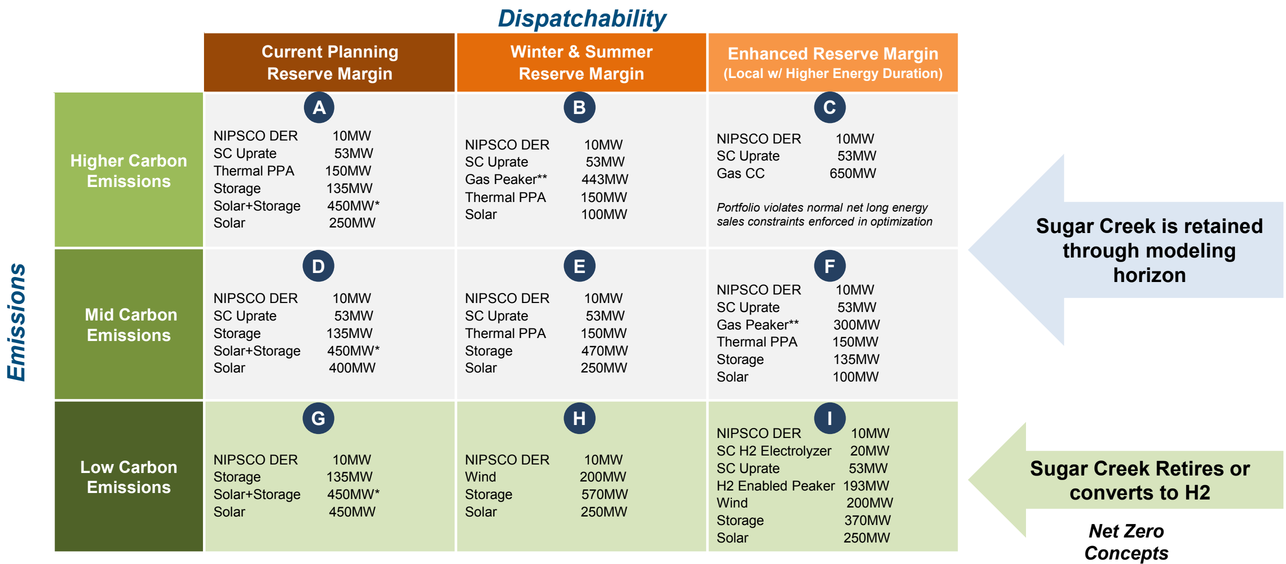
[110] Note that for portfolio development purposes, a mix of PPA and owned resources was assumed over the long-term, as opposed to a generic PPA least cost solution that was identified by the optimizer. This is consistent with NIPSCO's 2018 IRP preferred portfolio and does not necessarily represent NIPSCO's preferred procurement strategy for projects into the 2030s. Future IRPs will assess ongoing needs on a regular basis.

Figure 9-12: Replacement Portfolio Resource Additions through 2027 (ICAP MW)



	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 100MW	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

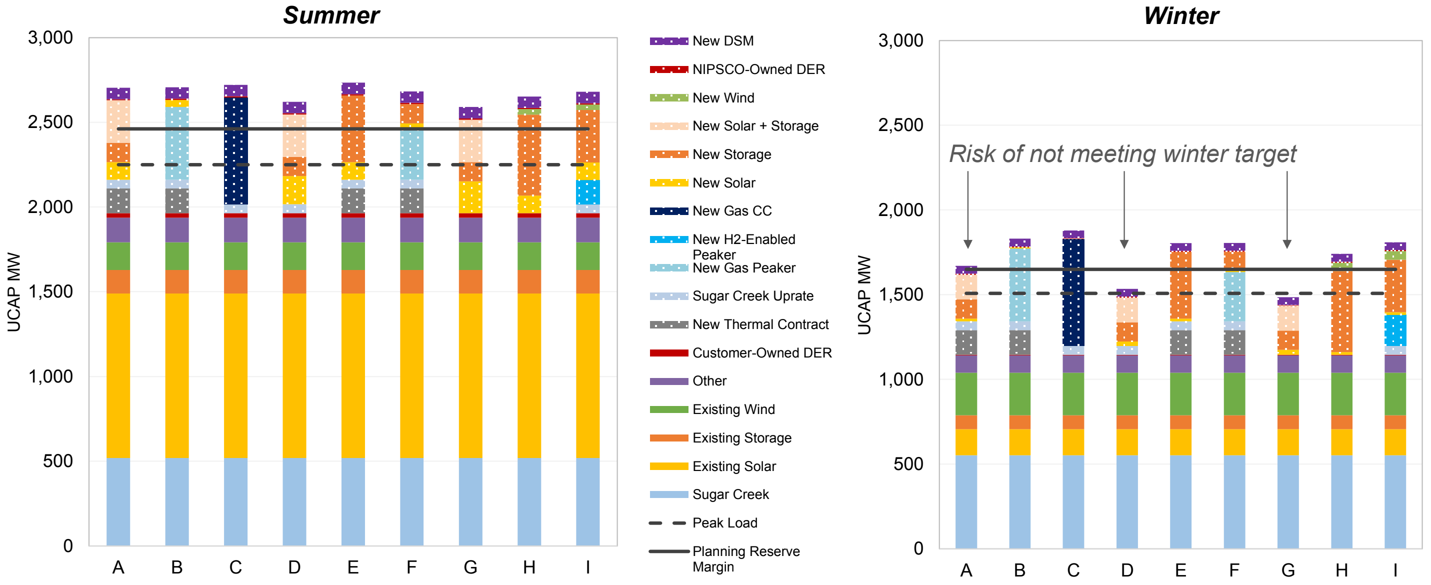
Sugar Creek is retained through modeling horizon

Sugar Creek Retires or converts to H2

Net Zero Concepts

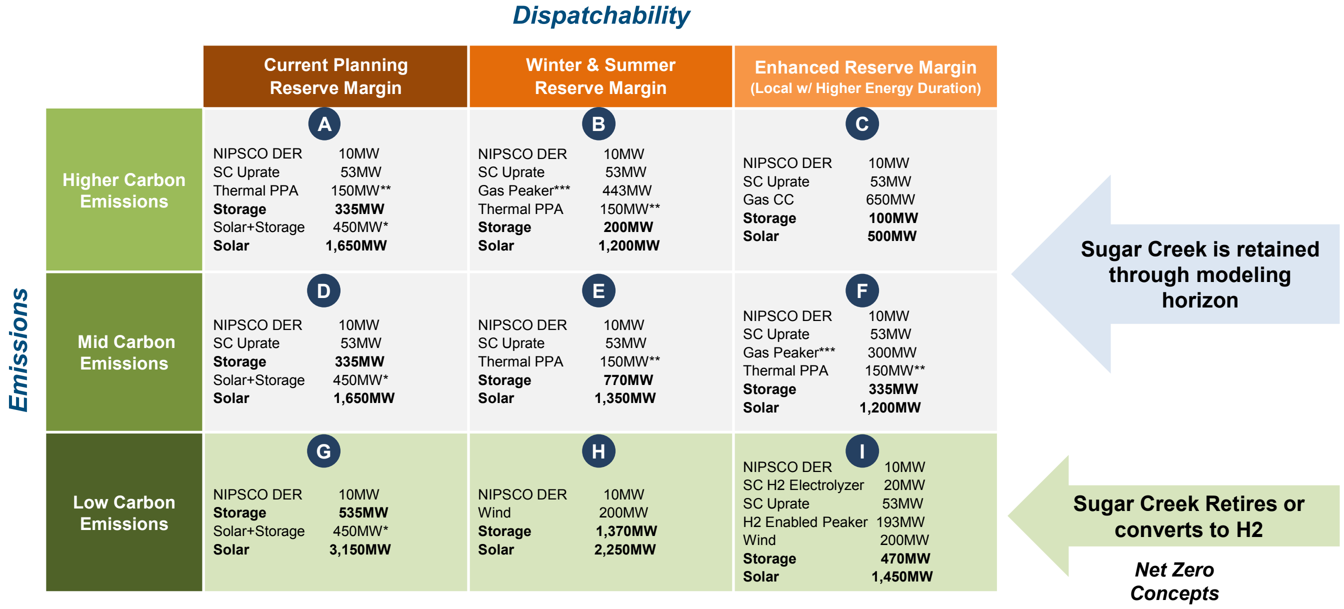
Note: Residential/Commercial DSM universally selected across portfolios
**Represents 300 MW of solar and 150 MW of storage*
***Gas peaker in Portfolio B represents an out-of-service territory PPA; Gas peaker in Portfolio F represents asset sale proposal*

Figure 9-13: 2027 Supply Mix by Replacement Portfolio (UCAP MW) – without Michigan City 12 and Schahfer 16AB



Risk of not meeting winter target

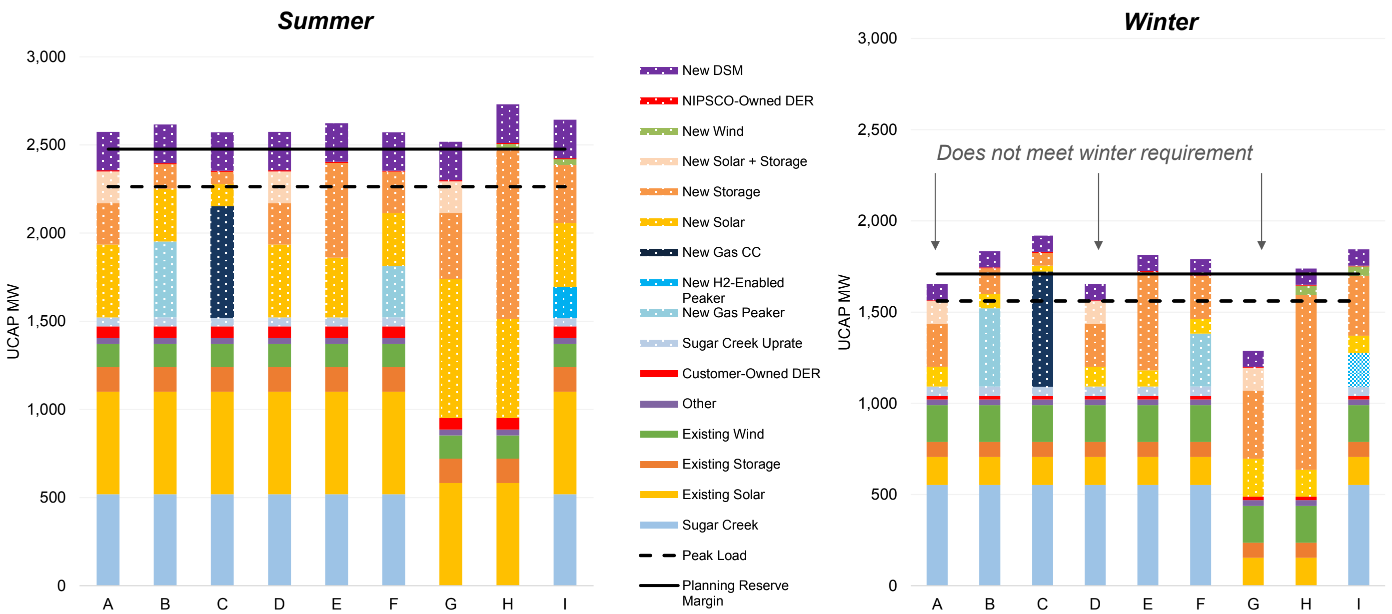
Figure 9-14: Replacement Portfolio Resource Additions through 2040 (ICAP MW)



	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**

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*

Figure 9-15: 2040 Supply Mix by Replacement Portfolio (UCAP MW)



9.2.4 Evaluation of Each Replacement Portfolio – Scorecard Metrics

Similar to the scorecard developed for the existing fleet analysis, NIPSCO developed a scorecard of objectives, indicators, and key metrics associated with the replacement analysis (*See* Figure 9-16). While major objectives remained consistent across stages of the analysis, some changes were made for the replacement scorecard relative to the existing fleet scorecard:

- Risk metrics associated with the stochastic analysis were added, which included several measurements of points on the stochastic distribution of revenue requirement outcomes relative to the median: (i) cost certainty was measured at the 75th percentile; (ii) cost risk was measured with the 95th percentile conditional value at risk, or the average of all outcomes above the 95th percentile; and (iii) lower cost opportunity was measured at the 5th percentile.

- Reliability was measured in an economic fashion through the potential value upside in the ancillary services markets and through the Reliability Assessment scoring (see additional detail later in this section).

- Resource optionality was measured through the MW-weighted commitment duration of generation commitments in the year 2027.

- Employee count was not recorded, given uncertainty with future project details.

Figure 9-16: Scorecard Metrics for Replacement Analysis

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 Reliability Assessment scoring
	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

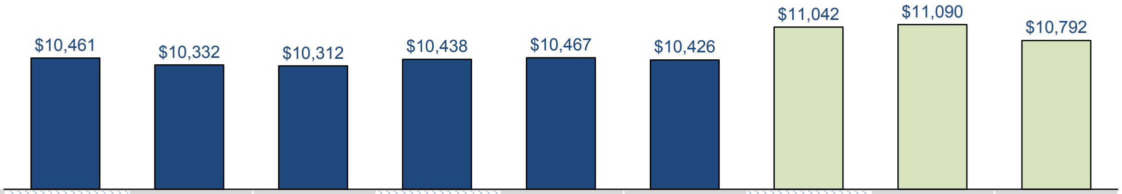
9.2.5 Evaluation of Replacement Portfolios – Core Analysis Results

Reference Case Cost Results

The nine replacement portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail) to estimate revenue requirements for each over time. The assessment was first performed across the Reference Case set of market assumptions and inputs to calculate baseline projections of the NPVRR over the thirty-year planning horizon, which are summarized in Figure 9-17.

Under the Reference Case market conditions, Portfolios A through F are all within ~$150 million of each other on an NVPRR basis, with Portfolios B, C, and F (portfolios with natural gas capacity additions) having the lowest costs. Portfolio C has the lowest NPVRR, but develops a very net long position, with excess energy sales offsetting portfolio costs.[111] 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.

Figure 9-17: Reference Case Cost to Customer Impacts – Replacement Portfolios (30-year NPVRR – millions of $)



Replacement Theme	▨ **Thermal PPAs, solar and storage** A	**Non-service territory gas peaking (no early storage)** B	**Natural gas dominant (CC)** C	▨ **No new thermal resources; solar dominant w/ storage** D	**Thermal PPAs plus storage and solar** E	**Local gas peaker, plus solar and storage** F	▨ **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
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

Scenario Cost Results

In addition to the analysis under Reference Case conditions, NIPSCO also evaluated each replacement portfolio against each scenario described earlier in Section 8. The NPVRR for each replacement portfolio across each scenario is summarized in Figure 9-18, with additional details regarding the scenario results described below.

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[111] This portfolio is also higher than several alternatives over a 20-year period, indicating that the long-term merchant energy margins contribute to the overall lower costs.

Figure 9-18: Cost to Customer across All Scenarios – Replacement Portfolios (30-year NPVRR – millions of $)

Replacement Portfolio	Reference Case	Status Quo Extended	Aggressive Environmental Regulation	Economy-Wide Decarbonization
A	10,461	9,657	11,356	12,015
B	10,332	9,400	11,444	12,182
C	10,312	9,309	11,637	12,518
D	10,438	9,644	11,338	11,965
E	10,467	9,588	11,373	12,126
F	10,426	9,495	11,489	12,243
G	11,042	10,485	11,573	11,809
H	11,090	10,458	11,482	12,011
I	10,792	9,933	11,550	11,848

*Note that Portfolio I was assessed with a hydrogen subsidy of $0.50/kg in the AER and EWD scenarios.

Under the SQE Scenario, with no carbon regulation and low natural gas prices, portfolios with more gas generation (particularly Portfolio C) are lower in cost. In addition, under this scenario, the cost of pursuing a net zero strategy increases, with the spread from the lowest to highest cost portfolios widening to over $1 billion in NPVRR

On the other hand, under a scenario with rising gas prices and strict environmental regulation (through a carbon price in the AER scenario), portfolios with more gas generation (particularly Portfolio C) are higher cost. Among viable options that meet expected summer and winter reserve margin requirements, Portfolio E (storage and solar, with no new gas capacity additions) is lowest cost

Finally, under the EWD scenario, similar trends as those observed in the AER scenario are also evident. However, clean energy resources have more value in this scenario, given the Clean Energy Standard construct and long-term extensions in federal tax credits, resulting in Portfolio I (assuming a future hydrogen subsidy)[112] having lowest costs among viable portfolios.

Overall, across scenarios, the following key observations were made:

- 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 than alternatives in other scenarios and are not viable options, given expected market rule changes.

- Adding new combined cycle capacity (Portfolio C) results in the lowest costs under the Reference and SQE scenarios, but is highest cost in the AER and EWD

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[112] As noted in Section 8, environmental regulation, particularly in the EWD scenario, could include subsidies for emerging technologies such as hydrogen. Section 4.6.4.1 discusses the development of green hydrogen costs for the 2021, including the $0.50/kg subsidy sensitivity evaluated here.

scenarios, illustrating how adding significant amounts of additional natural gas-fired energy to the portfolio contributes to higher levels of scenario risk.

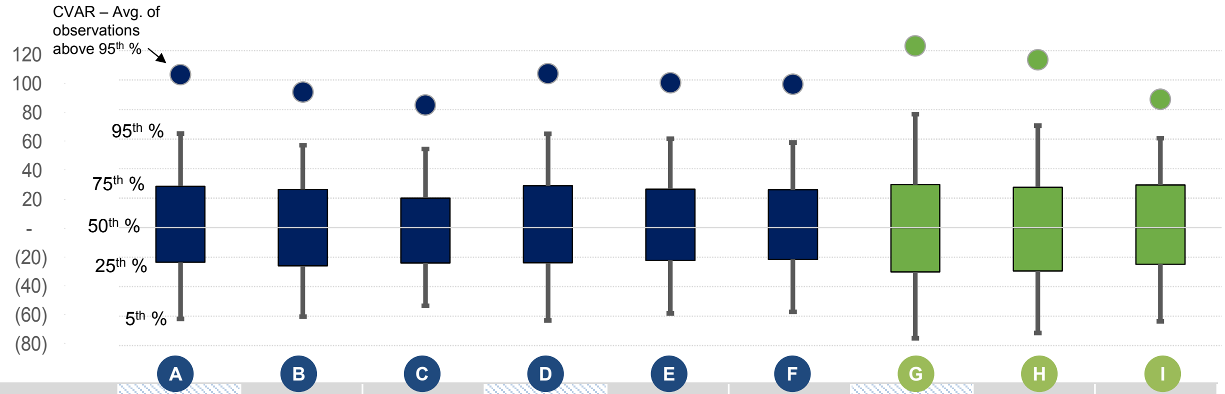
- While a portfolio approach that retires all thermal resources by 2032 and relies solely on renewables and storage (Portfolio H) provides a high level of scenario cost certainty, it is highest cost under Reference Case conditions.

Stochastic Analysis Results

In addition to assessing each replacement portfolio against each market scenario, NIPSCO has also evaluated the replacement options against the full stochastic distribution of potential outcomes for commodity prices and renewable output, as described in more detail in Section 8. The stochastic assessment is used to further evaluate the risk of each of the portfolios against a framework that is focused on short-term price and renewable output volatility as opposed to the long-term movement in macroeconomic or policy trends that are assessed across scenarios.

Figure 9-19 presents a summary of the stochastic results for each of the replacement portfolios, with the graphics highlighting the spread in NPVRR relative to the median (50th percentile) cost for each portfolio. The 25th to 75th percentile range is shown in the shaded box are, while the 5th and 95th percentiles are marked by the tails or "whiskers" shown below and above the box, respectively. The CVAR or average of the observations above the 95th percentile is indicated with a dot. The key risk metrics associated with NIPSCO's integrated scorecard framework are shown in the table below the graphic.

Figure 9-19: Summary of Stochastic Results – Replacement Portfolios (30-year NPVRR – millions of $)



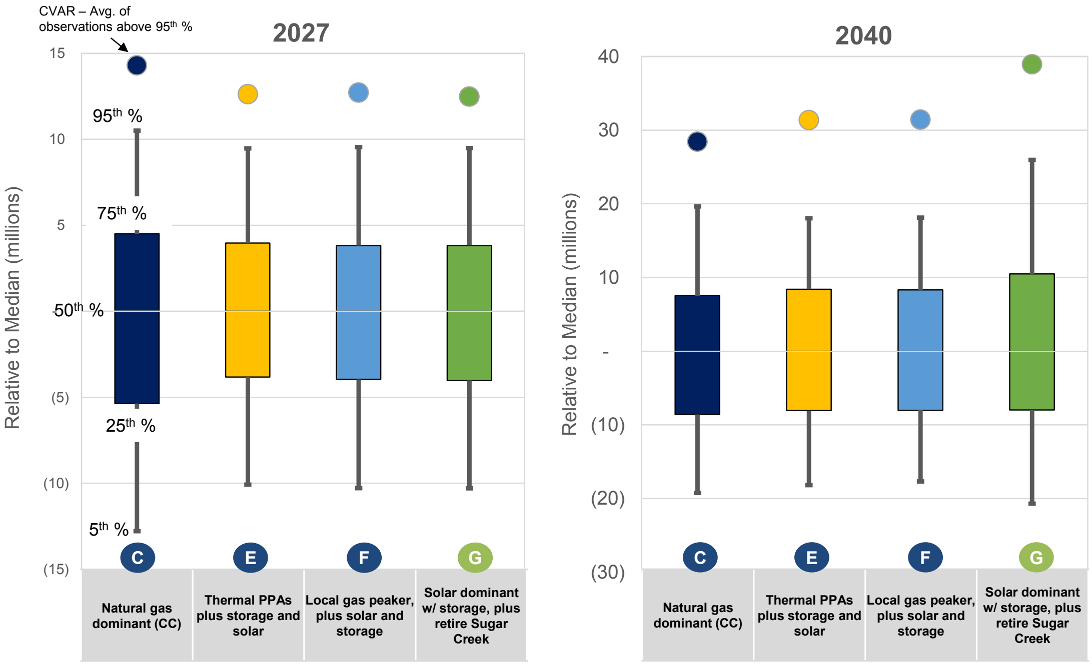
Replacement Theme	Thermal PPAs, solar and storage	Non-service territory gas peaking (no early storage)	Natural gas dominant (CC)	No new thermal resources; solar dominant w/ storage	Thermal PPAs plus storage and solar	Local gas peaker, plus solar and storage	Solar dominant w/ storage, plus retire Sugar 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

Overall, the 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. However, the stochastic analysis results do indicate that over the 30-year time horizon, dispatchability serves to mitigate tail risk, as portfolios that retain Sugar Creek or add natural gas, including with hydrogen enablement, or storage capacity (Portfolios B, C, E, F, and I) perform best at minimizing upside cost risk by resulting in the lowest difference in the 95th CVAR relative to the median. Meanwhile, the lowest downside range is observed in renewable-dominant portfolios, showcasing that such portfolio strategies (illustrated through Portfolios A, D, G, and H) have the broadest range of outcomes.

The stochastic analysis also illustrates the changing risks likely to be faced by NIPSCO's portfolio over time. Under current market conditions, portfolios with larger amounts of natural gas energy are likely to be highly exposed to market price and dispatch risk. As a result, over the next several years, Portfolio C is likely to have a broader range of cost outcomes and higher tail risk. However, over time, as the market becomes more dominated by intermittent resources, renewable output uncertainty becomes more correlated to power prices, and NIPSCO portfolio strategies that rely most on intermittent renewable resources (Portfolio G, for example) have the greatest tail risk. This is because they expose the portfolio to high costs associated with low renewable output/high market price events.

This phenomenon is illustrated in Figure 9-20, which show the range of stochastic cost outcomes for a selection of four portfolios in the years 2027 and 2040. While Portfolio C has the greatest risk exposure in 2027 and Portfolio G has the greatest risk exposure in 2040, 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.

Figure 9-20: Risk Profile Evolution for a Sample of Replacement Portfolios



This conclusion can also be illustrated by evaluating a sample of daily outcomes from the stochastic analysis across seasons. As shown in Figure 9-21, during summer days, power prices are likely to be negatively correlated to solar output, with price dips during mid-day hours (when solar output is high) and price spikes in the evenings and overnight (when solar output is low). As a result, a portfolio dominated by solar capacity will have excess energy during low-priced hours and could be exposed to market purchases during high-priced hours. Portfolios that integrate storage or other dispatchable resources could mitigate this risk, which may be even more pronounced on days with low solar output (right graphic).

Figure 9-22 provides additional examples during the winter season, a time of year when solar output will be lower and potentially more volatile. As a result, during days with low solar output, significant market exposure is possible for portfolios without sufficient dispatchable capacity, particularly during the morning and evening peak load periods.

Figure 9-21: Sample Stochastic Iterations for Summer Day Solar and Storage Output

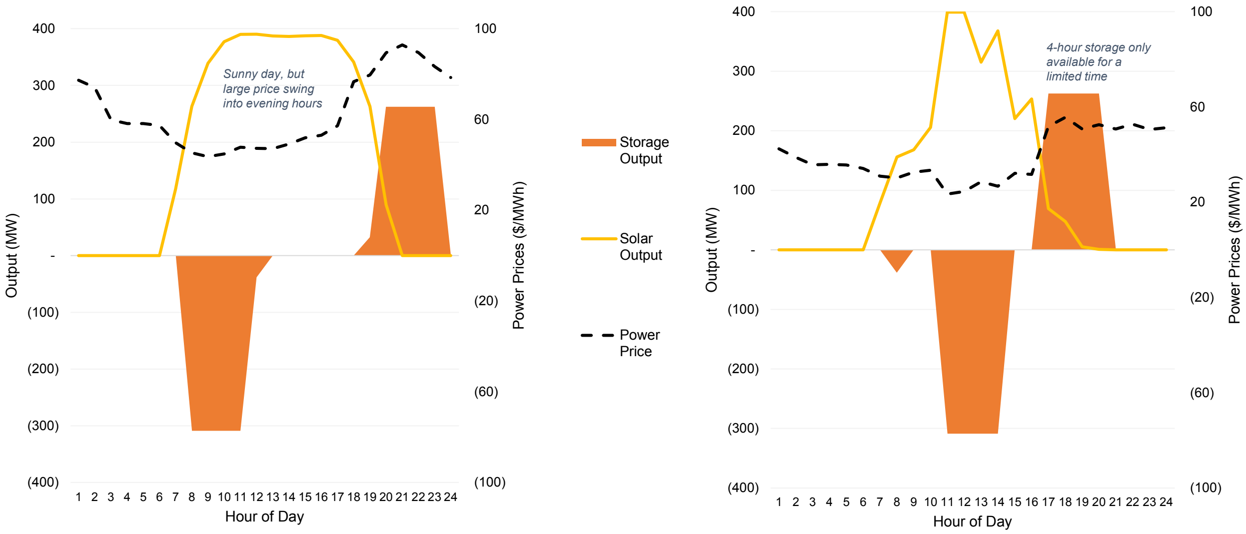
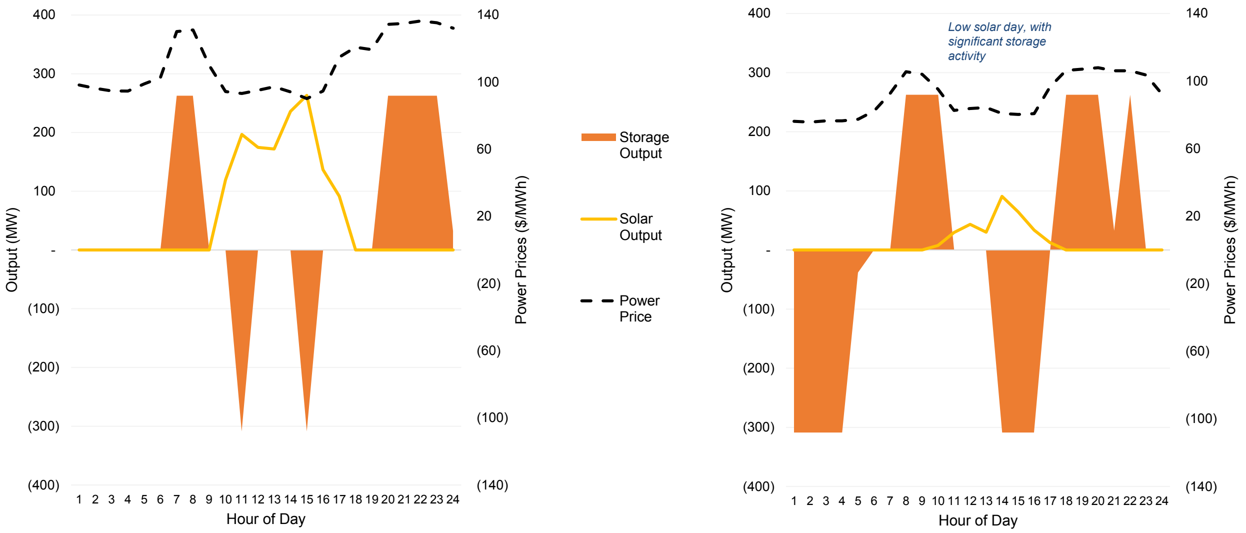


Figure 9-22: Sample Stochastic Iterations for Winter Day Solar and Storage Output



CO2 Emissions

Across replacement portfolios, the biggest drivers of future CO2 emissions are whether the portfolio adds a significant new source of CO2 emissions in the form of a combined cycle (Portfolio C) and how Sugar Creek operates into the 2030s.[113] Therefore, Portfolio C has the highest emission profile over time, and Portfolios G and H (and Portfolio I if Sugar Creek converts to hydrogen) have the lowest emission profile. Figure 9-23 illustrates the projected CO2 emissions by portfolio over time for the Reference Case, while Figure 9-24 presents the cumulative emissions over the 2024-2040 period for each scenario, along with a reporting of the scenario average. As

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[113] Note that the replacement portfolios were all evaluated under the assumption of a 2026 retirement date for Michigan City 12, which is not necessarily NIPSCO's preferred portfolio. See Figure 9-7 for the impact of retirement in 2026 versus 2028 on CO_2 emissions.

in the existing fleet analysis, emissions vary across scenarios based on different dispatch projections for the fossil units and the potential for hydrogen blending at Sugar Creek in the AER and EWD scenarios in Portfolio I.

Figure 9-23: Annual CO2 Emissions for Existing Fleet Portfolios – Reference Case

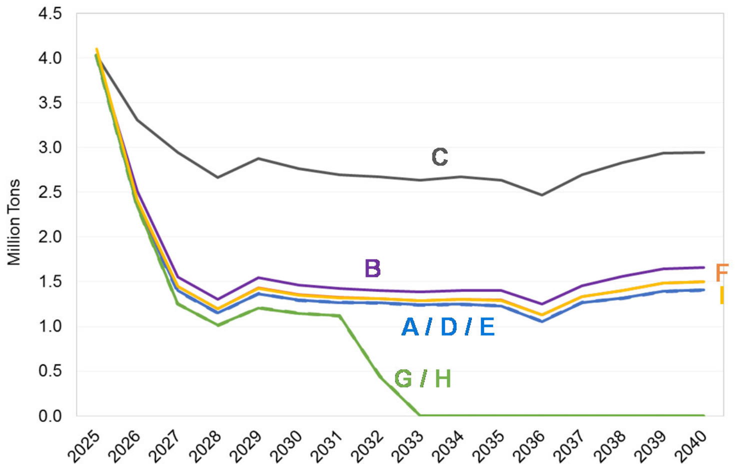
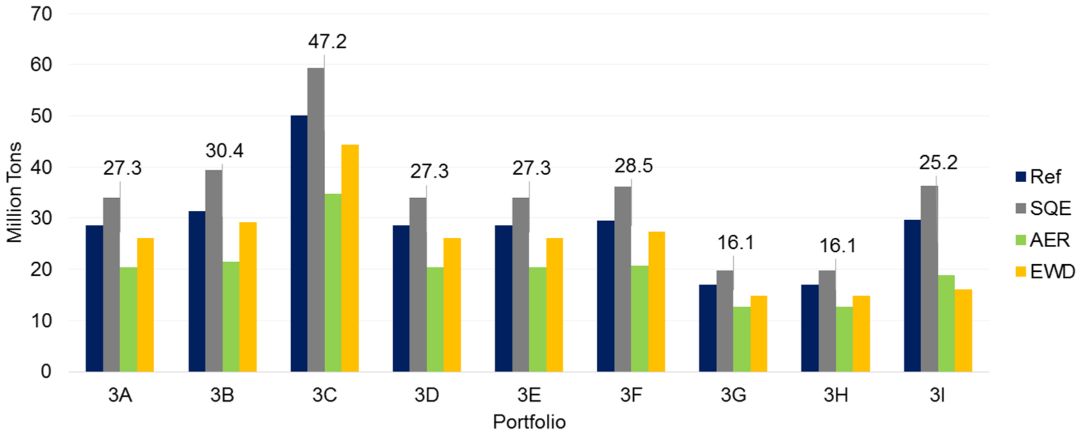


Figure 9-24: 2024-2040 Cumulative Tons of CO2 Emissions for Existing Fleet Analysis – All Scenarios with Average



Additional DSM Analysis

As noted earlier, all of NIPSCO's replacement portfolios contain several DSM measures that were found to be cost-effective in the optimization analysis. These included: (i) Tier 1 residential EE for 2024-2029, 2030-2035, and 2036-2041; (ii) commercial and industrial energy efficiency for 2024-2029, 2030-2035, and 2036-2041; and (iii) the residential DR rates programs after 2030. As discussed in Section 5, the core portfolio analysis was performed for RAP levels of DSM, although NIPSCO also evaluated the impact of using MAP levels, which includes additional savings available at higher costs, as summarized in Figure 9-25 and Figure 9-26,[114] respectively.

Figure 9-25: MAP vs. RAP Annual GWh Savings – Residential Tier 1 and Commercial and Industrial Programs

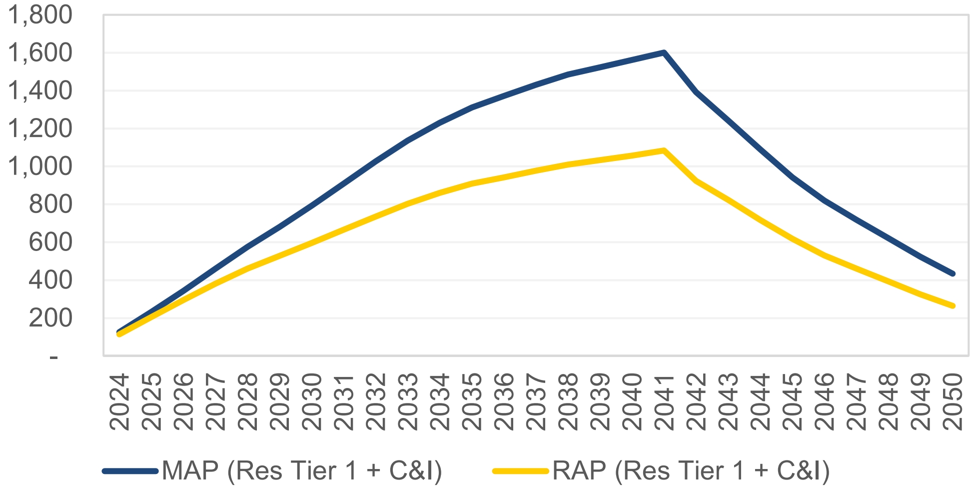


Figure 9-26 : Levelized Costs ($/MWh) by DSM Bundle – RAP vs. MAP

		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

Using these inputs, NIPSCO evaluated the impact of moving to the MAP DSM bundles for a selection of replacement portfolios. This was done by effectively "forcing in" the same residential and commercial/industrial energy efficiency programs identified in the original optimization analysis, but at the MAP level instead of at the RAP level. This has the impact of both reducing energy requirements and mitigating the need for some long-term capacity additions. The impact of reduced energy requirements was evaluated through a re-dispatch of the portfolios in the Aurora portfolio model, while 100 MW of future storage additions in the 2030s were removed to reflect the reduced capacity obligation.

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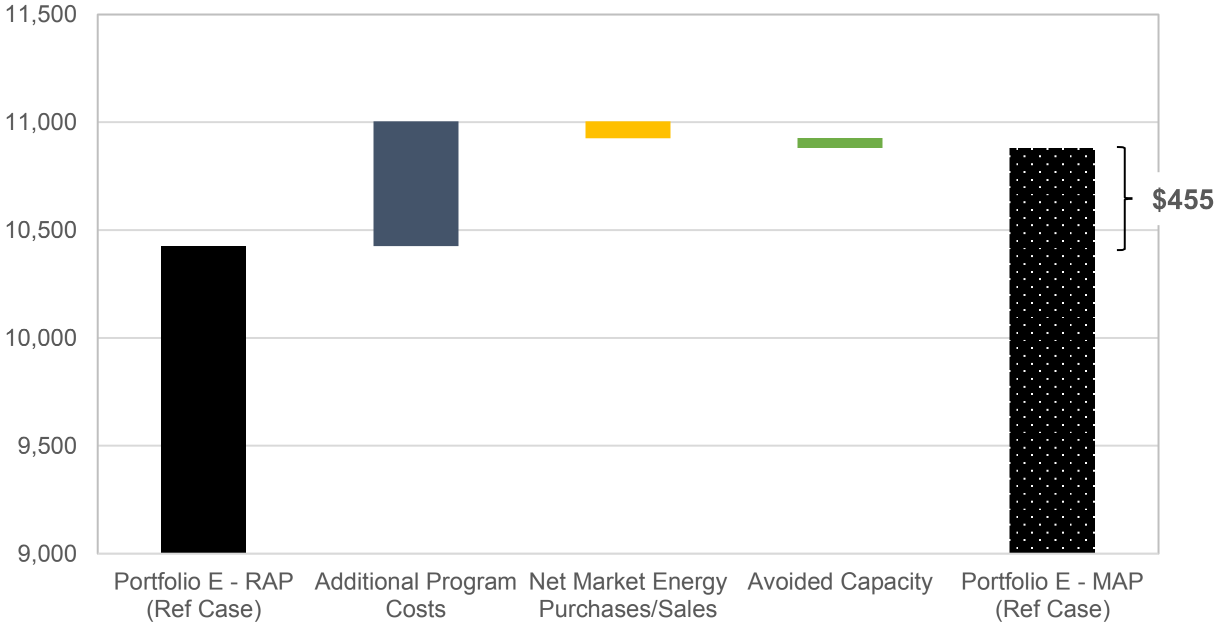
[114] Note that levelized costs are presented prior to cost adjustments for avoided T&D investment.

Under Reference Case conditions, NIPSCO's analysis found that moving from the RAP to the MAP DSM bundles would increase the 30-year NPVRR by $455 million for Portfolio F.[115] As illustrated in Figure 9-27, the additional program costs represent $578 million in NPVRR, while the value of saved energy associated with fewer net market purchases represented $78 million in NPVRR and the savings associated with avoided storage capacity additions represented $45 million in NPVRR. Alternative scenarios with higher costs of energy (especially the AER scenario) would increase the savings associated with net market energy purchases/sales, but still would not offset additional program costs. This analysis confirmed that the DSM programs contained in NIPSCO's preferred portfolio will be based on the RAP assumptions.

Figure 9-27: 30-year NPVRR Impact of Shifting from RAP to MAP – Portfolio F Example



9.2.6 Sub-Hourly Modeling with Ancillary Services

9.2.6.1 Background

Although the IRP's core economic analysis captures most portfolio cost elements, NIPSCO has broadened the scope of the 2021 IRP to assess additional elements of reliability, including Operating Reliability, as defined in MISO's RIIA report and summarized in Figure 9-28. Although all Operating Reliability elements cannot be evaluated in an economic fashion, MISO does operate markets for ancillary services which aim to enhance reliability at a very granular level and in real time.

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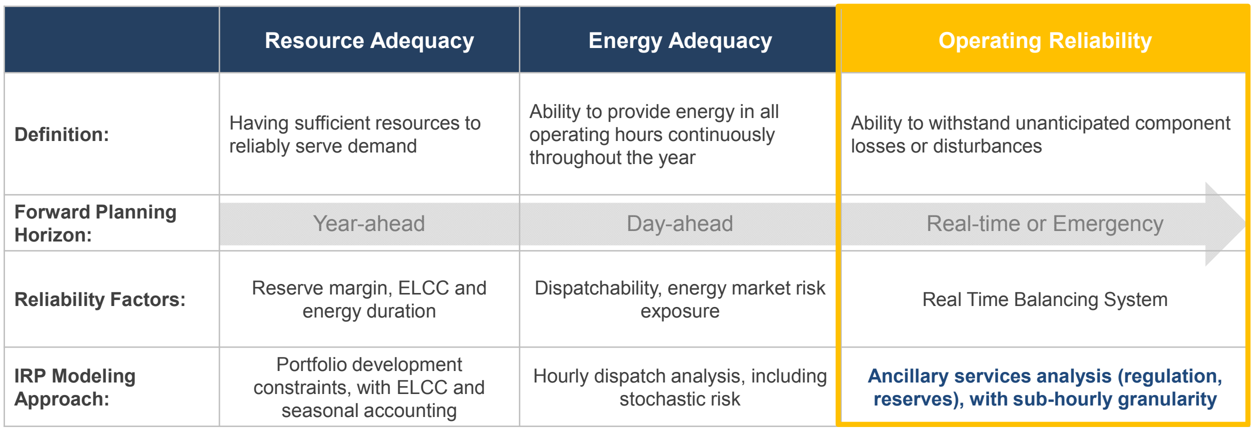
[115] NIPSCO also tested the impact on Portfolio E and found that moving from the RAP to the MAP DSM bundles would increase the 30-year NPVRR by $429 million.

Figure 9-28: Overview of Different Elements of Reliability and IRP Modeling Approach



	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**

MISO Ancillary Services Market Overview

MISO operates two energy and operating reserve markets: day-ahead and real-time. The day-ahead clears every hour, on the eve of the day of operations, on a co-optimized basis using SCUC, SCED, and SCED-pricing computer programs. On the day of operations, the real-time clears every 5-minutes on a co-optimized basis using SCED. The operating reserve market is composed of regulating reserves and contingency reserves. Resources are permitted to switch between markets, and there is no minimum threshold for continuous provision into a single market.[116] Currently, storage resources are only permitted to participate in the regulation market, but MISO is underway with tariff filings to allow them to participate in energy and other ancillary services markets.[117]

Resources participating in the day-ahead and real-time markets have the ability to specify, along other offer parameters, a commitment status which describes the ability or inability to dispatch. The five statuses are: economic, must-run (self-commit), outage, emergency, and not participating. “Economic” designates a resource available for commitment by the operator. “Must-run” designates a resource committed per market participant request and available for dispatch by MISO. “Outage” designates a resource not available in the energy or operating reserve markets because it is undergoing a planned or forced outage. “Emergency” designates a resource available for only emergency situations. “Not participating” designates a resource which will not participate in day-ahead or real-time energy market but is available.

Frequency regulation is used to address small mismatches between supply and demand. Regulating generators cleared in the day-ahead or real-time market must be fully deployable in regulation-up and regulation-down directions within a specified time period. Unlike some other

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[116] MISO BPM 002 – p. 142

[117] BPM002 – p. 132, 170

RTOs that have separate markets for regulation-up and regulation-down, MISO has a single regulation market.

Contingency reserves are used to address unforeseen events such as a large generator tripping offline. Contingency reserves are composed of spinning and supplemental reserves. Spinning reserves are provided by units that are synchronized to grid, not generating at their maximum output, and able to ramp up their generation. Supplemental reserves are also provided by units that are not synchronized to the grid but are able to come online quickly if needed.

FERC Order 841 Implications for Storage Market Participation

The role of storage in the energy and ancillary services markets is likely to continue to evolve as the electricity markets comprise more intermittent resources. As a result, FERC issued Order No. 841 to boost competition in the storage sector and ensure that markets like MISO provide just and reasonable rates. Order No. 841 requires each RTO and ISO to revise its tariff to establish a participation model for electric storage resources consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, will help facilitate their participation in the RTO/ISO markets.

MISO is responsible for implementing this order and has been granted an extension for compliance through 2022. Some key elements of MISO's market design changes are likely to include the following:

- A proposal to establish a unique offer structure for ESR in both the Day-Ahead Market and the Real-Time Market and to provide flexibility to ESR owners by establishing a Commitment Status to communicate how the resource will be available to the markets.

- Enablement of ESR to provide energy and ancillary services, blackstart service, and reactive supply and voltage control.

- Allowance of ESR to qualify as Use Limited Resources to accommodate resources that may need or desire their commitment to be limited to four hours per day in order to reliably provide a service.

- Allowance for ESR to both receive and inject electric energy in a way that recognizes physical and operational characteristics and optimizes benefits to MISO and prevents conflicting dispatch instructions through a single offer curve made up of both discharge segments (i.e., price/MW pairs for positive values or injections) and charge segments (i.e., price/MW pairs for negative values or withdrawals). Resources will be paid or pay the LMP at the pricing node for, respectively, injections to discharge and withdrawals to charge. Efficiency losses will not be considered load or station power but will be included in energy schedules.

- Ability of ESR to participate and set prices in the Planning Reserve Auction, submit wholesale bids to buy energy though the Day-Ahead and Real-Time Energy Offer

Curves, participate in MISO's markets as price takers, self-schedule, and manage their State of Charge.

9.2.6.2 Energy Storage Resource Operations Model Overview

Since the core Aurora market and portfolio model is fundamentally based on a day-ahead simulation, NIPSCO has performed additional analysis to estimate the incremental value streams that flexible resources can achieve by participating in markets beyond day-ahead energy. To do this, CRA employed its proprietary ESOP model,[118] an optimization model that computes revenues through participation in energy and A/S markets with five-minute granularity. Given simulated energy and ancillary services pricing information, ESOP solves for optimal dispatch decisions unique to a price-taking resource's technological characteristics and a regional market's participation rules. A comparison of the Aurora portfolio tool and the ESOP model is summarized in Figure 9-29.

Figure 9-29: Comparison of Aurora Portfolio Tool and ESOP

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 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 value for specific asset type

For the 2021 IRP, the MISO five-minute real-time markets for energy, frequency regulation,[119] and spinning reserves were evaluated, with a focus on the performance of storage, paired solar plus storage, and natural gas peaking resources in order to evaluate specific tradeoffs of these capacity-advantaged resource options in NIPSCO's portfolio.

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[118] Note that while the ESOP model was originally designed for storage evaluation, modified versions simulate the operations of other fast response resources such as natural gas peakers.

[119] MISO has a single market for regulation up and regulation down services. When providing regulation services, a unit will follow a signal from the system operator. Since it is impossible to know whether the regulation signal will dispatch a unit up or down and by how much ahead of time, ESOP assumes that a unit will be dispatched in both directions while participating in the regulation market. For battery storage, regulation down services can be provided when backing down from a discharge cycle or charging. Since the analysis has assumed that paired solar plus storage resources receive the investment tax credit, in order to participate in the regulation market, it was assumed that a battery resource must have sufficient ability to either back down from a discharge cycle or charge from the paired solar resource. Although such behavior is only required for the first five years of resource operation, for modeling simplicity, this assumption was maintained throughout the analysis.

9.2.6.3 Development of Sub-Hourly Prices for Energy and Ancillary Services

ESOP is run with five-minute price streams for real-time energy, regulation, and spinning reserves prices. As Aurora's long-term capacity expansion tool is used to generate hourly price trajectories representative of the day-ahead energy market, CRA developed a methodology to estimate real-time price trajectories based on historical relationships between day-ahead energy and real-time energy and ancillary services prices, applied to the day-ahead energy prices forecasts developed for each of the four planning scenarios (*See* Section 8 for more detail on the MISO market scenario development process). As part of this process, the following historical data was gathered, based on the period June 1, 2018 to May 31, 2019:

- NIPS.AZ day-ahead hourly LMP[120]
- NIPS.AZ real-time five-minute LMP[121]
- MISO real-time hourly regulation and spinning reserve prices[122]
- Real-time five-minute LMP from NIPSCO node[123]

The relationship between historical hourly day-ahead LMP and five-minute real-time LMP was used to shape the MISO-scenario driven price forecasts to real-time five-minute LMP inputs for ESOP. Because historical regulation and spinning reserve prices services were unavailable at a five-minute granularity, a proxy for a five-minute price shape was taken from the neighboring PJM interface for the same historical period. Similarly, a relationship between hourly day-ahead LMP and sub-hourly ancillary service prices was taken to determine real-time inputs into ESOP.

ESOP was run for the following test years using five-minute real-time price inputs:

- June 1, 2025 to May 31, 2026
- June 1, 2030 to May 31, 2031
- June 1, 2035 to May 31, 2036
- June 1, 2040 to May 31, 2041

9.2.6.4 Operational Parameters for Technology Options

While Section 4 of this report provides a summary of all key cost and operational inputs associated with the RFP bid resource tranches and used in the core economic portfolio analysis,

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[120] ABB Energy Velocity Suite. ABB

[121] ABB Energy Velocity Suite. ABB

[122] MISO has one clearing price for regulation up and down. Prices gathered from ABB Energy Velocity Suite. Only hourly ancillary service clearing prices were available.

[123] PJM. PJM Data Miner 2 Tool. Five-minute RT LMP, NIPSCO node. http://dataminer2.pjm.com/feed/rt_fivemin_hrl_lmps.

evaluation in ESOP requires more granular operational input assumption development to assess sub-hourly ramp rates and other constraints. Therefore, CRA and NIPSCO reviewed individual bids to assess bidder expectations for key storage and gas peaker parameters and to develop assumptions for ESOP modeling, which are summarized in Figure 9-30.

Figure 9-30: Resource Operational Parameter Input Assumptions for ESOP Analysis

Lithium-Ion	Units	Value
Duration (Energy/Power Ratio)	hours	4
Roundtrip Efficiency	%	87%
Cycles per Year	#	365
Parasitic Load	%/hr	0.50%
Ramp Rate	%/min	100%
State of Charge Lower Bound[124]	%	0%
State of Charge Upper Bound	%	100%
VOM	$/MWh	0

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	Hrs/yr	3,000
Min Downtime	Hrs	4
Min Runtime	Hrs	2
Emission Rate	lb CO2/MMBtu	119
Start Costs	$/MW/start	18
VOM	$/MWh	2

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[124] Note that multiple bidders indicated no limits to state of charge boundaries, although other sources suggest that lower and upper bounds of between 10-20% and 80-90%, respectively might be expected for lithium-ion battery technology. As a result, multiple assumptions were tested in the ESOP modeling, and it was determined that this parameter is not a significant driver of results.

9.2.6.5 Key Findings from ESOP Analysis

Based on the resource types that comprise NIPSCO's portfolio options (see discussion of portfolio composition and definition in the earlier sub-sections of this Section) and the types of resources likely to have opportunities for additional value in the sub-hourly energy and ancillary services markets beyond what is accounted for in the core portfolio analysis, CRA evaluated three distinct technology options in ESOP:

- Lithium-ion four-hour duration battery storage;
- Paired solar plus storage (lithium-ion four-hour duration) at a 2:1 ratio;[125] and
- Natural gas-fired combustion turbine peaker

As noted above, the three resource types were assessed over four sample future years in order to estimate the incremental value that might be available in the sub-hourly energy and ancillary services markets above what is captured in the Aurora model's day ahead hourly assessment. The analysis found that the most significant upside is for battery technology, particularly in the regulation market, as illustrated in the Reference Case margin projections summarized in Figure 9-31. Key findings by technology included:

- **Lithium-Ion battery**: As the most highly flexible resource option, the battery can respond rapidly in real time to changing price signals at five-minute granularity. Most notably, the resource can participate regularly in the regulation market, providing up and down service given its unique ability to charge or discharge. An illustration of simulated charging and discharging behavior along with energy and regulation price behavior is shown for a sample summer day in Figure 9-32. This shows how the battery can adjust its state of charge very rapidly to respond to 5-minute price signals, while also participating in the regulation market.
- **Paired solar plus storage**: As in the hourly Aurora modeling, the solar component provides significant energy value, while the upside from the ESOP analysis is primarily limited to participation in the regulation market. It is important to note that current ITC rules limit the battery's flexibility and ability to take advantage of the regulation market, given that the battery resource must charge predominantly from the solar component.
- **Natural gas-fired combustion turbine**: The gas peaking resource is able to monetize real-time sub-hourly volatility, providing value upside compared to the Aurora day ahead hourly modeling. However, regulation opportunities are only available when the unit is already operating for energy, limiting the upside when compared to the battery storage projections. Spinning reserve revenues are also likely to be available, but these are less valuable than regulation.

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[125] Note that the most attractive RFP tranches, including those selected in the portfolio development phase, were at ratios of approximately 2:1 (solar:storage), so this configuration was analyzed in the ESOP analysis.

Figure 9-31: Reference Case Annual Margin Comparison by Technology: Aurora Day Ahead Energy vs. ESOP Sub-Hourly Energy Plus Ancillary Services

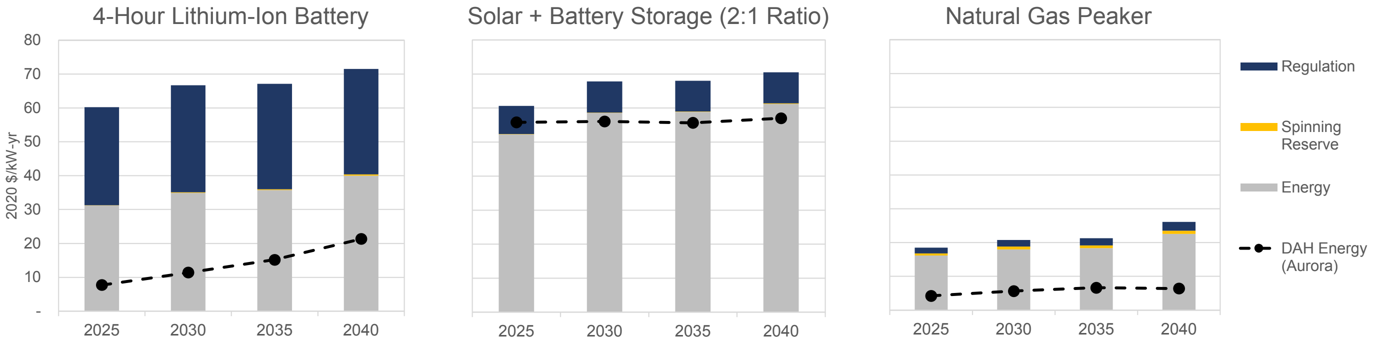
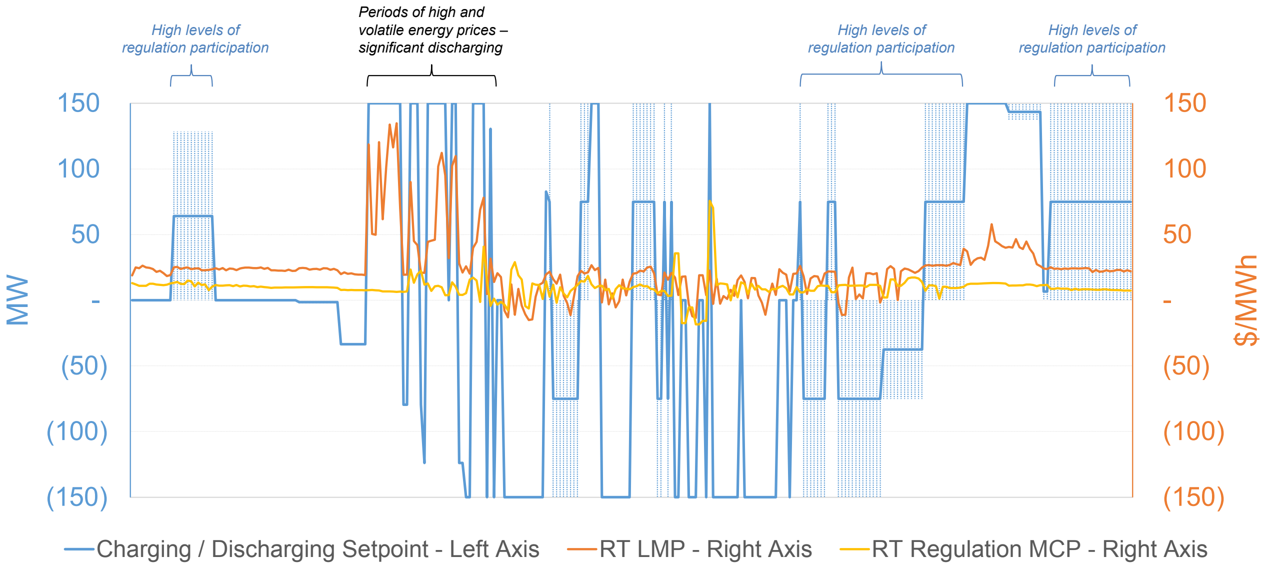
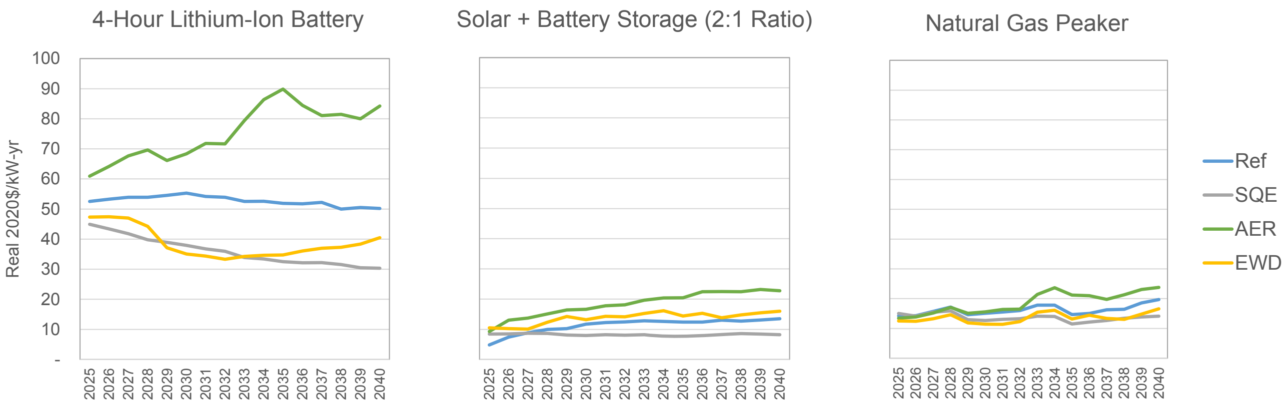


Figure 9-32: Sample Summer Day of Battery Dispatch



In addition to the Reference Case analysis, CRA evaluated the performance of the three resource options across the three alternative market scenarios (see Section 8 for more detail). Across all scenarios, the incremental value associated with the sub-hourly energy and ancillary services markets was projected to be greatest for the battery. This was especially the case in the AER, with high energy prices due to high carbon and natural gas prices, and high levels of renewable penetration driving larger price spreads across hours. A summary of the simulated incremental value by technology and scenario is shown in Figure 9-33.[126]

Figure 9-33: Incremental Sub-Hourly Energy and Ancillary Services Value by Technology across Scenarios



9.2.6.6 Portfolio Cost Implications

After performing the core ESOP analysis at the resource level, CRA and NIPSCO built up portfolio-level impacts according to the amounts of lithium-ion battery storage, paired solar plus storage, and natural gas peaking capacity in each of the nine replacement portfolios. This was accomplished by attributing the annual $/kW-yr incremental value shown in Figure 9-33 to each MW of storage, solar plus storage, or gas peaker in the portfolios to arrive at an aggregate total net present value impact. This is summarized by portfolio and across all scenarios in Figure 9-34 Overall, the analysis reached the following conclusions:

- Portfolios with the largest amounts of storage (Portfolios E and H) have the greatest potential to lower the 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 and lower prices and lower price spreads in the SQE scenario driving lower estimates.

- While these estimates provide perspective on the relative performance of various portfolio strategies, significant uncertainty exists and the realization of such benefits is dependent on market rules evolution, MISO generation mix changes, and market participant behavior.

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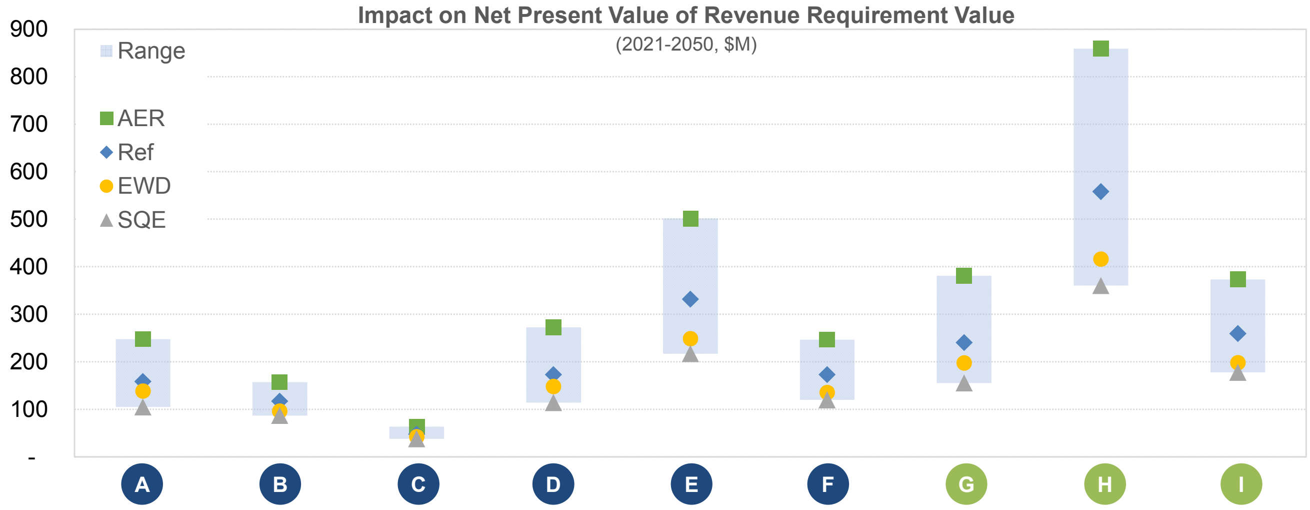
[126] Note that since the ESOP analysis was only performed for five sample years, estimates for the other model years were made through interpolation.

Figure 9-34: Range of Additional Value Opportunity by Replacement Portfolio



9.2.7 Non-Economic Reliability Assessment

Economic analysis alone does not capture the full suite of reliability attributes offered by various resources. As outlined in Section 6, NIPSCO participates in MISO in a variety of roles with various compliance standards and responsibilities, and any future resource decisions (retirement or replacement) will need to consider the non-economic implications for NIPSCO's ability to comply with both NERC and MISO standards and procedures now and into future.

Under normal system operating conditions, NIPSCO is tied to MISO and PJM's systems for dispatch of its resources and the balancing of energy. However, under emergency or blackout conditions ("islanded operation"), NIPSCO's resources should have the capability to reliably serve the critical demand of its customers.

With the goal of understanding the relative ability of replacement portfolios to support the reliable operation of the system, NIPSCO engaged Quanta Technology, a third-party technical expert, to perform a planning-level reliability assessment of all replacement generation resources under consideration. The Quanta Technology Reliability Assessment Final Report is attached as Confidential Appendix E. In this assessment, Quanta Technology identified reliability criteria and metrics that individually and collectively serve to enhance the reliability attributes of a given portfolio, developed a scoring methodology for individual technologies, and scored and ranked portfolios across these metrics. The results of the assessment were then incorporated into the Replacement scorecard to support overall portfolio evaluation.

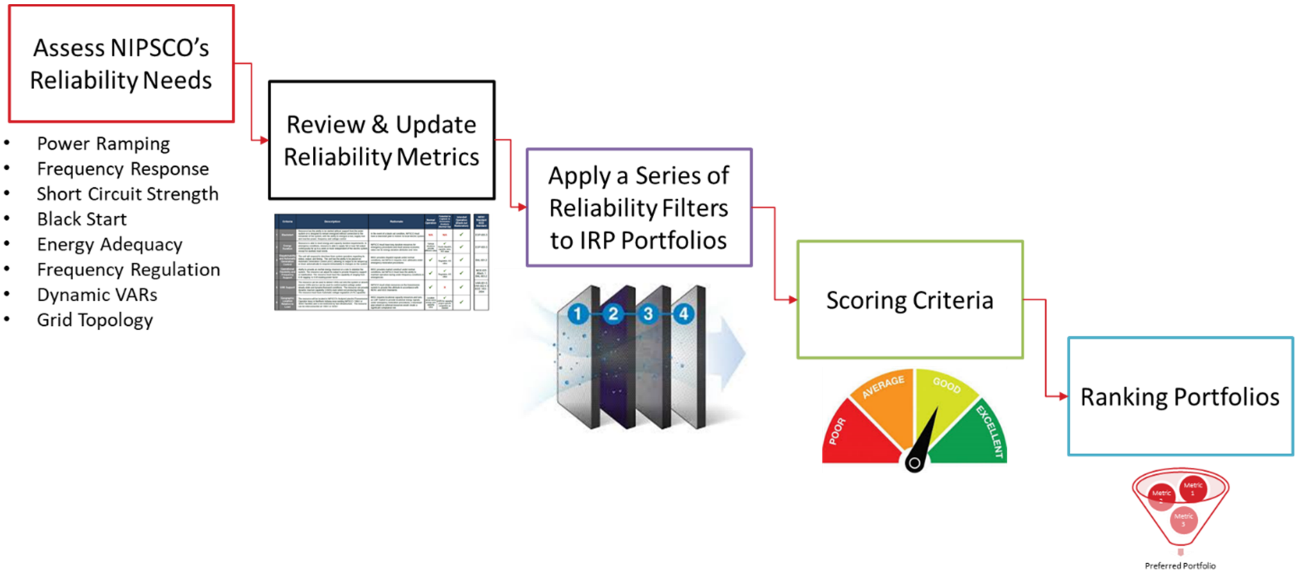
9.2.7.1 Study Methodology

The reliability assessment study was performed according to the steps outlined in Figure 9-35. The first two steps assessed NIPSCO's reliability needs and then reviewed, refined, and augmented the initial set of reliability metrics identified by NIPSCO.

The study then proceeded to conduct a series of system analyses, each quantifying the performance of each of the nine replacement portfolios against each measure, and where appropriate, determining the required mitigations to address any performance gaps. The nature of the study is akin to a series of analysis filters that ultimately help identify reliability concerns that would need mitigation.

Finally, a scoring matrix was developed with acceptable performance thresholds to provide a quantifiable score for each reliability measure. These scores were aggregated for each metric, and eventually for each portfolio. Portfolios were then ranked according to their reliability attributes with the highest scores to those with the least reliability concerns.

Figure 9-35: Reliability Study Methodology



9.2.7.2 Reliability Criteria and Metrics

NIPSCO developed an initial set of reliability criteria that are important to the continued reliable operation of the grid and that enable NIPSCO to fulfill its obligations under NERC and MISO standards. Quanta Technology performed a critical assessment of these metrics, resulting in a final list of reliability and resilience criteria summarized in Figure 9-36.

Figure 9-36: 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 Adequacy	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	Resources 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	Resources are able 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	Resources can deliver VARs out onto the system or absorb excess VARs to control system voltage under steady-state and dynamic/transient conditions. Resources can provide dynamic reactive capability (VARs) even when not producing energy and have Automatic voltage regulation (AVR) capability ranging from 0.85 lagging (producing) to 0.95 leading (absorbing) 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	Resources are located in NIPSCO's footprint (electric Transmission Operator Area) in Northern Indiana near existing NIPSCO 138kV or 345kV facilities and are not restricted by fuel infrastructure. Preferred locations are ones that have multiple power evacuation/deliverability paths and are close to major load centers.	Although MISO runs markets that value location, 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 (DAH) hourly market and in the real-time (RT) 5-minute market. Deviations from these schedules have financial consequences, and the ability to accurately forecast the output of a resource up to 38 hours ahead of time for DAH and 30 minutes for RT is advantageous.
8	Short Circuit Strength Requirement	Resources help 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's footprint and across MISO and replacements with increasing levels of IBRs will lower the short circuit strength of the system. Resources that provide higher short circuit current provide a better future proofing without the need for expensive mitigation measures.

After establishing the criteria, a set of quantified metrics were developed to measure the technical ability of resources to enhance a given criterion, as summarized in Figure 9-37. Quanta Technology performed detailed analysis at the resource level to evaluate each metric.

Figure 9-37: Reliability Metrics

	Metric	Measure
1	Blackstart	Qualitative Assessment of Risk of not Starting
2	Energy Adequacy	Energy not Served during market emergencies (% of load consumption increase)
		Energy Not Served when Islanded (Worst 1-week) %
3	Dispatchability and Automatic Generation Control	Dispatchable (%CAP, unavoidable VER Penetration)
		Increased Freq Regulation Requirements (MW)
		1-min Ramp Capability (MW)
		10-min Ramp Capability (MW)
4	Operational Flexibility and Frequency Support	Inertia MVA-s
		Inertial Gap FFR MW (islanded operation)
		Primary Gap PFR MW (islanded operation)
5	VAR Support	Dynamic VAR to load Center Capability (MVAr)
6	Location	Average Number of Evacuation Paths
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) MW
8	Short Circuit Strength	Required Additional Synchronous Condensers MVA

9.2.7.3 Reliability Assessment Details

Based on the criteria and metrics summarized above, the study evaluated all nine replacement portfolios for the year 2030 across a variety of assessments summarized in Figure 9-38. Given the dynamic and uncertain nature of renewable energy developments associated with technology mix, sites, and sizes, as well as the future state of the transmission grid that will be required to enable the integration of these resources, this study attempted to provide an envelope of outcomes (and in many cases, best or optimistic outcomes) under a regime of well-coordinated or guided project development processes.

Figure 9-38: Metrics and Measures Results – Raw Scores

System Condition	Reliability Assessment
Normal	• deliverability of dynamic reactive power to load centers • short circuit strength • predictability of portfolio output • increased need for regulation reserves • geographic location and ability to evacuate the power
Emergency – Max Gen	• energy adequacy – Need for market purchases
Isolated	• black start and restoration • short circuit strength • ability to control frequency (inertial and primary frequency response) • power ramping capability • energy adequacy to serve the critical demand of customers.

Several assumptions were made in the study. For example, operating renewable resources economically require them to generate all the time at their maximum potential power levels as allowed by solar irradiance and wind speeds. This mode of economic operation precludes these resources from providing frequency response in the upward direction, as will be required when a generator or import is suddenly lost. Reducing the power output to enable participation in frequency response in the upward direction is very expensive. However, the speed of control of the IBRs makes them perfectly suited for participating in frequency response in the downward direction (i.e., curtailment), as will be required when a large load or export is suddenly lost.

Given that this was a planning level assessment, screening-level quantitative studies were conducted for a set of reliability standards, including inertial response, primary frequency response, secondary frequency response, short circuit strength, system ramping requirements, dynamic reactive support, and energy adequacy along with a qualitative assessment of blackstart and system restoration capability. Other areas of reliability assessment are outside the scope of this study, but might include system protection, power quality, flicker, and control interactions. Detailed system studies will be required to ascertain the reliability of the system once a portfolio is selected and the location, size, and technology of all portfolio resources are available.

9.2.7.4 Summary of Results

The technical reliability assessment included a quantitative analysis of each measure, (except blackstart), using information associated with resource technology, size, location, and expected production. Blackstart was scored qualitatively by assessing the risk of successfully restoring the system based on a strategy of using standalone energy storage and synchronous generation within NIPSCO's service territory to start existing synchronous condensers and then other nearby resources of solar plus storage, solar PV, and wind technologies, in that order.

The assessment identified potential reliability gaps for each of the nine replacement portfolios and also suggested potential mitigations to these gaps. The mitigations take the form of grid-forming inverter technology, additional blackstart capability, additional fast power resources such as battery storage, super capacitors, or combustion turbines, and additional synchronous condensers. The key findings of this study included the following:

- Reliability concerns were identified for each portfolio, especially under emergency and islanded conditions, and mitigation measures were identified as follows:
    - Stand-alone energy storage should have grid-forming inverters (GFM) with additional capabilities including black start and fast frequency response (FFR). GFM inverters are not widely used today in the US market, but the technology is available and is recommended for portfolios with high penetration of IBRs.
    - Gas peakers and combined cycle units in portfolios C, F, and I should have blackstart capability.
    - Additional fast power resources may be needed in some portfolios. These have been quantified for energy storage technology. However, super capacitors or combustion turbines can also provide the same function, but the size should be determined for these technologies.
    - Specifications of short circuit ratio (SCR) of inverters should not exceed 3.
    - Provision of additional synchronous condensers should be considered to increase the grid's short circuit strength ranging from 0 to 802 MVAr.
- Many reliability areas were not covered by this study including:
    - The study assumed that any required grid upgrades will be implemented as part of MISO interconnection process.
    - Given that all IRP portfolios were designed to meet MISO's reserve margin targets, a separate portfolio-level resource adequacy study was not conducted.
    - All reliability assessments in this study applied screening-level indicative analyses. Detailed system studies are essential and should be conducted to properly assess system reliability of the preferred portfolio options.

9.2.7.5 Scoring Methodology and Performance Thresholds

Figure 9-39 summarizes the thresholds that were used in the study to score each measure, along with the rationale for setting the threshold values. Measures that exceeded the upper threshold were deemed satisfactory (Pass) and given a score of 1, while those measures below the lower threshold were deemed problematic and given a score of 0. Measures in between were considered cautionary and given a score of ½. The scores of measures within each of the eight individual metrics were averaged to yield a single score for each metric. Metric scores were then added for each portfolio and compared. The maximum score of each portfolio was eight.

Figure 9-39: Scoring Thresholds

	Year 2030		1 (Pass)	½ (Caution)	0 (Problem)	Rationale
1	Blackstart	Ability to blackstart using Storage & Synchronous Condensers	>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 during market emergencies (% of load consumption increase)	<5%	5-20%	>20%	Ability of portfolio resources to serve unanticipated growth in load consumption during MISO emergency max-gen events.
		Energy Not Served when Islanded (Worst 1-week) %	<70%	70-85%	>85%	Ability of Resources to serve critical loads 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)

9.2.7.6 Reliability Ranking of IRP Portfolios

Figure 9-40 presents the normalized resources for each replacement portfolio across each of the eight metrics, and Figure 9-41 summarizes the resulting portfolio scores and rankings.

Figure 9-40: Normalized Results

	Year 2030		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 during market emergencies (% of load consumption increase)	10%	2%	2%	21%	2%	3%	26%	3%	2%
		Energy Not Served when Islanded (Worst 1-week) %	76%	79%	32%	75%	78%	56%	74%	73%	58%
3	Dispatchability and Automatic Generation Control	Dispatchable (%CAP, unavoidable VER penetration%)	28%	18%	55%	27%	44%	45%	26%	47%	47%
			58%	45%	42%	63%	50%	45%	65%	51%	51%
		Increased Freq Regulation Requirement (% Peak Load)	2.3%	1.6%	1.5%	2.5%	1.8%	1.6%	2.6%	2.0%	2.0%
		1-min Ramp Capability (%CAP)	24.0%	22.6%	17.8%	22.8%	47.2%	29.4%	22.1%	49.3%	39.0%
		10-min Ramp Capability (%CAP)	41.7%	50.7%	52.1%	39.6%	64.4%	60.3%	37.1%	63.7%	61.5%
4	Operational Flexibility and Frequency Support	Inertia (seconds)	2.13	3.38	4.17	2.02	2.07	3.58	1.81	1.73	2.60
		Inertial Gap FFR (%CAP)	11.2%	32.1%	10.7%	11.0%	0.0%	6.1%	11.6%	0.0%	0.0%
		Primary Gap PFR (%CAP)	18.8%	44.7%	25.9%	17.9%	0.0%	19.1%	17.7%	0.0%	1.3%
5	VAR Support	Dynamic VAR to load Center Capability (%CAP)	47.8%	47.8%	35.1%	48.5%	44.7%	43.6%	49.1%	47.4%	47.1%
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)	-4.1%	-8.0%	11.4%	-5.0%	14.9%	15.8%	-5.3%	17.4%	17.1%
8	Short Circuit Strength	Required Additional Synch	25%	11%	0%	33%	15%	0%	35%	21%	11%

		Condensers (%Peak Load)									

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

Figure 9-41: Portfolio Scores and Ranking

	Year 2030		A	B	C	D	E	F	G	H	I	Weight
1	Blackstart	Qualitative Assessment of Risk of not Starting	1/2	0	1	1/2	1/2	1	1/2	1/2	1	12.5%
2	Energy Adequacy	Energy not Served during market emergencies (% of consumption increase)	1/2	1	1	0	1	1	0	1	1	6.3%
		Energy Not Served when Islanded (Worst 1-week) %	1/2	1/2	1	1/2	1/2	1	1/2	1/2	1	6.3%
3	Dispatchability and Automatic Generation Control	Dispatchable (VER Power Penetration %)	1/2	1	1	0	1/2	1	0	1/2	1/2	3.1%
		Increased Freq Regulation Requirement (% Peak Load)	1/2	1	1	1/2	1	1	1/2	1/2	1/2	3.1%
		1-min Ramp Capability (%CAP)	1	1	1	1	1	1	1	1	1	3.1%
		10-min Ramp Capability (%CAP)	0	1/2	1/2	0	1/2	1/2	0	1/2	1/2	3.1%
4	Operational Flexibility and Frequency Support	Inertia (seconds)	1/2	1	1	1/2	1/2	1	0	0	1/2	4.2%
		Inertial Gap FFR (%CAP)	0	0	0	0	1	1/2	0	1	1	4.2%
		Primary Gap PFR (%CAP)	0	0	0	0	1	0	0	1	1/2	4.2%
5	VAR Support	Dynamic VAR to load Center Capability (%CAP)	1	1	1/2	1	1	1	1	1	1	12.5%
6	Location	Average Number of Evacuation Paths	1	1/2	1	1	1	1	1	1	1	12.5%
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW)	1/2	1/2	1	1/2	1	1	1/2	1	1	12.5%
8	Short Circuit Strength	Required Additional Synch Condensers (%Peak Load)	0	1/2	1	0	1/2	1	0	1/2	1/2	12.5%
	Portfolio Scores		**52%**	**56%**	**84%**	**47%**	**79%**	**92%**	**45%**	**76%**	**85%**	

	# 0	4	3	2	6	0	1	7	1	0
	# 1/2	7	5	2	5	6	2	4	6	6
	# 1	3	6	10	3	8	11	3	7	8
	Total Measures	14	14	14	14	14	14	14	14	14

The highest ranked portfolios across the eight reliability metrics are:

1. F (Score 92%)
2. I (Score 85%)

3. C (Score 84%)
4. E (Score 79%)
5. H (Score 76%)

Replacement Analysis Scorecard Summary

Figure 9-42 presents a summary of all scorecard metrics for each of the nine replacement portfolios. This includes the cost metrics associated with the Reference Case NPVRR, the risk metrics associated with the major outcomes from the scenario and stochastic analyses, carbon emissions, reliability, resource optionality, and impacts on the local economy, as described above. The following key observations were made:

- Portfolios that have the highest solar additions and meet only the summer reserve margin target (Portfolios A, D, and G) are not viable options for NIPSCO, given expected MISO ruls changes, even though they perform best under high environmental regulation scenarios (AER and EWD).

- 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.

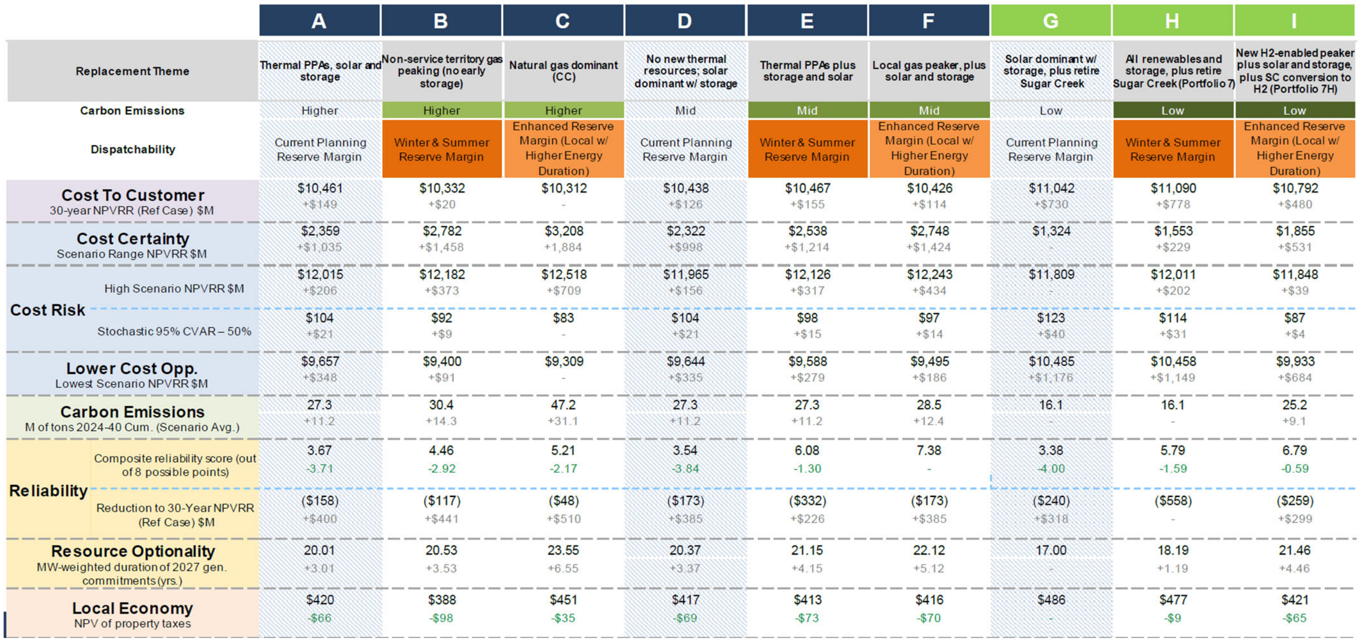
- While a portfolio approach that retires all thermal resources by 2032 and relies solely on renewables and storage (Portfolio H) provides a high level of scenario cost certainty, the lowest emission profile, significant upside value opportunity associated with ancillary service markets, and significant 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 Portfolios B, E, and F, performs better under scenarios with high environmental regulation/incentives (particularly EWD), and mitigates stochastic tail risk.

- Portfolios with local thermal peaker and storage resources (particularly Portfolios F and I and to a lesser extent Portfolio E) provide the most reliability attributes and perform best on the composite reliability score.

Figure 9-42: Replacement Portfolio Scorecard



		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
	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
	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

9.3 Preferred Replacement Portfolio

NIPSCO has identified Portfolio F as a preferred near term replacement portfolio concept, with the potential to pivot towards Portfolio I based on continued RFP bid diligence, technology evolution, and potential federal policy changes. Across each of these preferred concepts, NIPSCO has concluded that certain resources that provide near-term capacity (the Sugar Creek uprate, attractive DER opportunities, thermal capacity contracts, and demand side management programs) appear to be cost-effective additions to the portfolio and should be pursued in order to firm up the capacity position of the portfolio in the near-term and in anticipation of future retirements.

Beyond those capacity additions common to all candidate portfolios, solar, storage and natural gas peaking resources appear to be economic replacement options for Michigan City and Schahfer 16A/B.[127] Integrating dispatchable capacity into the portfolio over the long term (without materially increasing gas-fired energy exposure and CO2 emissions through a CCGT) tends to mitigate cost risk associated with intermittent resources and will help meet pending seasonal reserve margin requirements. However, the quantities and characteristics of storage and gas peaking resource additions require further study to confirm reliability can be maintained and to understand the value of each resource type given ongoing and potential market and policy changes.

Near-term capacity additions, including the Sugar Creek uprate, attractive DER, thermal capacity contracts, DSM, solar, storage, and a natural gas peaker, preserve flexibility in an environment of market, policy, and technology uncertainty. NIPSCO's preferred portfolio allows

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[127] Portfolio I also contains some wind capacity, which NIPSCO may consider depending on future federal policy developments.

the Company to monitor technology and policy trends that will inform future action and maintain a pathway to a Net Zero emissions portfolio over the long term, including with emerging technology such as hydrogen.

Figure 9-43 summarizes the elements of NIPSCO's preferred plan, including the expected ranges of capacity additions by resource type through the 2027 period. As additional diligence is performed and as more information is obtained regarding market, policy, and technology change, NIPSCO will refine the specific capacity addition numbers.

Figure 9-43: Preferred Portfolio Capacity Addition Ranges by 2027

Resource	**MW by 2027**	**Notes**
Sugar Creek Uprate	30-53 MW	Two options offered by the manufacturer; additional diligence will confirm pricing and timing
Solar + Storage DER Opportunities	~10 MW	Specific projects to be identified, with distribution deferral opportunities consistent with attractive IRP tranche assumptions
Thermal Capacity Contracts	150 MW	Likely up to 10-year term
DSM	~68 MW	Represents Tier 1 residential plus all commercial energy efficiency programs (46 MW of winter peak)
Solar	100-250 MW	Dependent on specific asset attributes and further bid diligence; Natural gas peaking capacity may be hydrogen-enabled.
Storage	135-370 MW	
Natural Gas Peaker	Up to 300 MW	

This preferred portfolio maintains NIPSCO on a trajectory that significantly shifts its generation mix from coal towards renewables and adds capacity-advantaged resources that are needed to meet future reserve margin requirements, protect against hourly energy market exposure, and preserve reliability for customers. As shown in Figure 9-44,[128] NIPSCO's preferred plan anticipates new capacity-advantaged resources entering into service by the middle of the decade, including storage, natural gas (the Sugar Creek uprate and new peaking capacity), and thermal capacity contracts. It also includes additional solar and new DSM programs.

As shown in Figure 9-45, total energy from the preferred portfolio is projected to be roughly in balance with NIPSCO's load requirements, with flexibility around the ultimate timing of the Michigan City 12 retirement. Although new storage and gas peaking resources provide limited net energy contribution on an annual basis, they support the portfolio's energy adequacy when intermittent resources are unavailable.

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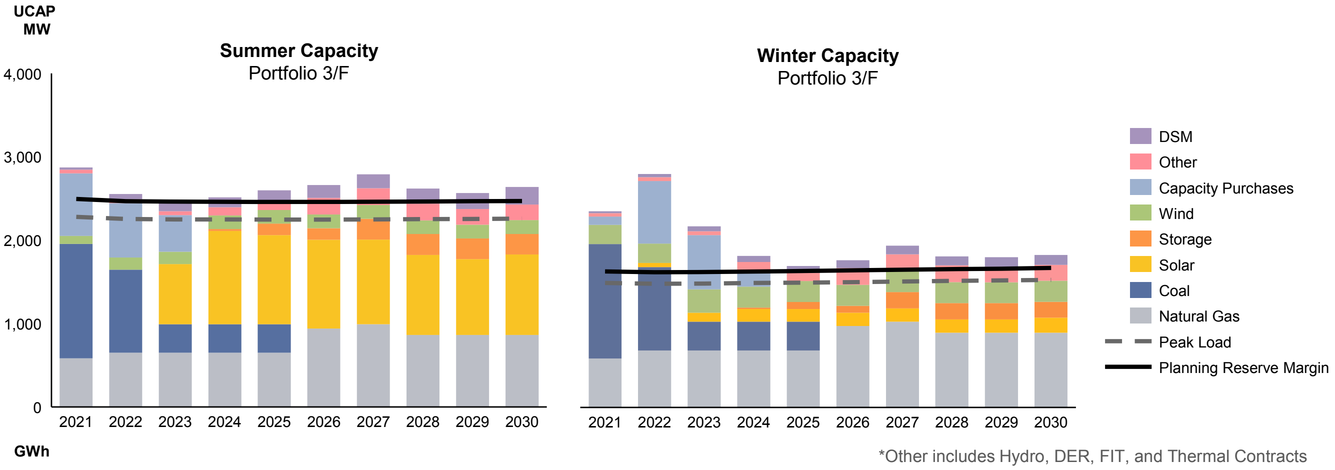
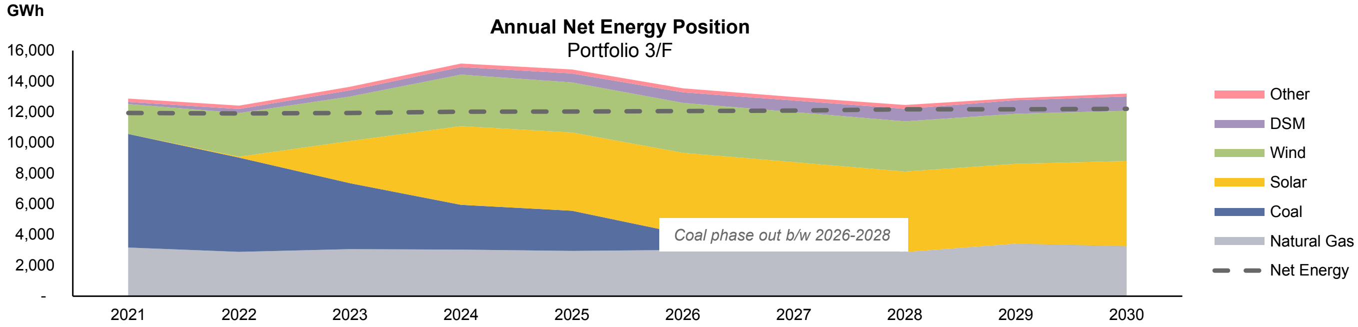
[128] For illustrative purposes, Figure 9-44 and Figure 9-45 show Replacement Portfolio F based on Portfolio 3 from the Existing Fleet analysis.

Figure 9-44: Preferred Portfolio Summer and Winter Capacity Mix



*Other includes Hydro, DER, FIT, and Thermal Contracts

Figure 9-45: Preferred Portfolio Energy Mix



*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

9.3.1 Preferred Portfolio Summary

NIPSCO's preferred portfolio was developed to ensure that a reliable, compliant, flexible, diverse and affordable set of resources is available to meet future customer needs. As part of the portfolio selection process, NIPSCO also considered the impacts to its employees, the environment, reliability, and impacts on the local economy. The major components of the NIPSCO resource strategy are expected to:

- Continue to implement NIPSCO's portfolio transition by integrating new renewable projects and taking the necessary steps to retire the Michigan City coal plant by 2028;

- Continue the Company's commitment to EE and DR by executing the current filed DSM plan and continuing to plan for significant residential and commercial DSM programs over time;
- Provide a cost-effective portfolio for customers while also balancing other objectives associated with rate stability, environmental sustainability, and positive social and economic impacts;
- Ensure that system reliability is preserved as NIPSCO and the broader MISO market increase the amount of intermittent resource capacity;
- Reduce customer and NIPSCO exposure to market, policy, and technology risks by intentionally integrating modular, highly diverse new resource alternatives over the next several years;
- Preserve flexibility in resource procurement, particularly over the long-term;
- Continue to actively monitor federal policy, technology, and MISO market trends, while staying engaged with project developers and asset owners to understand the landscape of new resource options;
- Continue to invest in infrastructure modernization to maintain safe and reliable delivery of energy services;
- Continue to comply with NERC, MISO, and EPA standards and regulations.

It is important to remember that this preferred portfolio as part of the 2021 IRP is a snapshot in time and while it establishes a direction for NIPSCO, it is subject to change as the external operating environment changes. In addition, the submission of this plan and its resulting preferred portfolio does not stop the transparency of the process or engagement with stakeholders.

9.3.2 Financial Impact

Figure 9-46 shows NIPSCO's financial impact of Replacement Portfolio F under the retirement dates from Existing Fleet Portfolio 3 over the planning period. While NIPSCO's preferred portfolio intentionally retains flexibility to incorporate elements of Portfolios 3 and 5 from the Existing Fleet analysis, as well as Portfolios F and I from the Replacement analysis, this summary is being provided as a baseline benchmark.

The 30-year NPVRR is broken down into operating and capital costs. The operating costs include the fixed and variable costs associated with both existing units and future resources, as well as contract costs and net market purchases. The capital costs include all capital related costs for existing units and costs related to the acquisition of new resources in the preferred portfolio. These costs include depreciation expenses, capital charges, and taxes. In order to present a levelized net present value rate summary, the total energy forecast for NIPSCO is also discounted over the 30-year period at the same rate.

Figure 9-46: Financial Impact Summary[129]

Financial Impact Summary	
Operating Costs ($000)	5,195,199
Capital Costs ($000)	5,231,167
Total Revenue Requirement ($000)	10,426,365
Total Energy Requirement (GWh)	146,316
Cents/kWh	7.13

Note that Total Energy Requirement is the discounted value of 30 years of energy forecasts, rather than a total sum. This is done to allow for the cents per kWh summary to be reflective of a levelized net present value calculation.

NIPSCO expects that existing cash balances, cash generated from operating activities, and funding through inter-company loan arrangements with its parent company will meet anticipated operating expenses and capital expenditures associated with NIPSCO's short-term action plan.

In the long term, future operating expenses as well as recurring and nonrecurring capital expenditures are expected to be obtained from a number of sources including: (i) existing cash balances; (ii) cash generated from operating activities; (iii) inter-company loan arrangement; (iv) additional external debt financing with unaffiliated parties; (v) new equity capital and (vi) tax equity financing. NiSource, Inc. procures external funding from the bank and capital markets (debt and equity). NiSource's long-term debt ratings are currently BBB at Fitch and Baa2 at Moody's.

9.3.3 Developments That Will Shape NIPSCO's Preferred Portfolio Implementation

As summarized in Section 2, NIPSCO identified several key themes that have influenced the development of this 2021 IRP and that will shape the ultimate implementation of NIPSCO's short-term action plan. As noted above, NIPSCO's preferred portfolio incorporates ranges of new resource additions to reflect the fact that several evolving external factors will influence final procurement decisions. These can broadly be categorized into factors associated with RFP bid negotiations and follow-up, MISO market rules changes, federal policy changes, and technology development.

RFP Bid Negotiations

Although the 2021 IRP involves smaller overall capacity changes than the 2018 IRP, in many ways the resource implementation will be more complex. This is largely due to the fact that specific diligence needs to be completed on a smaller sub-set of discrete projects, as opposed to

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[129] The information is based on Replacement Portfolio F under the retirement date assumptions from Portfolio 3 from the Existing Fleet analysis. As discussed throughout this section, to preserve flexibility, NIPSCO's ultimate preferred portfolio may incorporate elements of Portfolios 3 and 5 from the Existing Fleet analysis and Portfolios F and I from the Replacement analysis.

the greater flexibility afforded NIPSCO in 2018 associated with identifying many renewable projects to fill a relatively large capacity target.

As NIPSCO proceeds with its short-term implementation plan, the following RFP bid diligence will be required:

- Review the best-performing gas peaker bids to confirm consistency with Reliability Assessment conclusions, assess opportunities for hydrogen enablement, and evaluate overall project viability and feasibility;
- Assess characteristics of storage bids to confirm consistency with Reliability Assessment, such as a preference for grid forming inverter technology, and other operational requirements; and
- Consider additional RFPs for capacity resources if needed to re-assess the landscape and ensure consistency with all IRP preferred portfolio requirements.

MISO Market Rules Changes

At the outset of its 2021 IRP process, NIPSCO identified several regulatory developments at the MISO level that would impact portfolio performance and ultimate implementation of the preferred plan. While MISO has advanced policy development implementation in many areas over the last year, several areas of uncertainty remain, requiring NIPSCO to ensure portfolio decisions are flexible enough to adapt to the changing environment. These include:

- Ongoing activities associated with MISO's RAN framework and the pending implementation of a seasonal capacity construct: Throughout 2021, MISO engaged with stakeholders regarding the implementation of a four-season capacity construct. While still not final, NIPSCO expects a filing on this proposal with FERC to be followed by implementation over the next few years. NIPSCO's 2021 IRP has explicitly planned for this, but portfolio adjustments may be needed in the event of different reserve margin targets (for example, a higher winter standard than modeled in the IRP) and evolving capacity accreditation rules.
- MISO's transition to an ELCC methodology to assess capacity credit for wind and solar resources over time and by season: NIPSCO's 2021 IRP incorporated a range of ELCC trajectories over time by scenario (*See* Section 8 for details across scenarios and earlier parts of this section for the impacts on NIPSCO's supply-demand balance) and assumed different summer and winter capacity credit ratings for intermittent technologies. However, as MISO implements new ELCC accounting procedures and the seasonal capacity construct, and as the amount of intermittent capacity in the broader market increases, credit values may evolve differently than what NIPSCO has assumed in the IRP. Therefore, resource procurement will need to remain flexible in order to ensure planning reserve margins are maintained.

- MISO's ongoing RIIA study: Although the 2021 IRP was designed specifically to evaluate reliability across the many dimensions identified in recent RIIA reports, NIPSCO will continue to track developments and their impact on the portfolio.

- MISO's implementation of market rules associated with FERC No. Order 841, which requires ISOs and RTOs to establish a participation model for storage resources in energy, capacity, and ancillary services markets: The 2021 IRP has identified significant value opportunities for storage resources in the sub-hourly energy and ancillary services markets. However, rules for storage implementation are not fully established, with MISO requesting implementation delays until 2022. As these rules are formalized, including for capacity accreditation and energy and ancillary services participation, NIPSCO will continue to track developments and adapt its resource procurement plans (particularly around storage) accordingly.

Federal Energy and Environmental Policy Changes

As of the time of the development of NIPSCO's 2021 IRP preferred portfolio, federal policymakers were debating significant changes to energy and environmental policy. While NIPSCO's scenarios have contemplated a broad range of policy outcomes largely consistent with the state of the debate (*See* Section 8 for more detail), certain outcomes could impact portfolio implementation decisions. The most relevant include:

- The potential implementation of a stand-alone storage ITC: NIPSCO's preferred portfolio contains a wide range of potential storage additions, and NIPSCO's scenario analysis indicated that storage resources perform better in scenarios that assume the implementation of a storage ITC. Therefore, if implemented, NIPSCO's preferred portfolio retains the flexibility to pivot towards higher levels of storage additions.

- Changes to current implementation of the ITC including, potential "direct-pay" provisions and Internal Revenue Service normalization rules.

- The potential implementation of a hydrogen PTC or other federal incentives for hydrogen development: NIPSCO's portfolio analysis suggested that federal subsidies for hydrogen production would improve the performance of portfolios that integrate this resource type into the mix. Therefore, if federal legislation includes direct subsidies or other incentives associated with hydrogen production or use, NIPSCO may adapt by exploring pilot programs or other initiatives designed to test and integrate hydrogen into its generation mix.

- The potential implementation of a carbon tax, clean energy standard or CEPP: Various recent policy proposals have offered several alternative means of incentivizing clean energy additions, and certain policy outcomes may influence the amount of new renewable capacity (both solar and wind) that NIPSCO ultimately adds to its portfolio through the short-term implementation plan.

Technology Change

As the power sector continues to navigate a period of significant change, NIPSCO expects that technology evolution will be rapid, requiring regular review of the supply-side resource marketplace and flexibility in the preferred portfolio. For example, as NIPSCO implemented the short-term action plan from its 2018 IRP, additional paired solar plus storage additions were made in response to improving technology and declining costs for lithium-ion battery storage. Going forward, NIPSCO expects power sector technology evolution to continue to impact both short-term procurement activities and long-term resource decisions. In particular, NIPSCO will continue to monitor the following:

- Stand-alone storage resource costs, efficiencies, and operational parameters, such as cycle limits, depth of discharge specifications, and ongoing expenses;

- Grid-forming inverter technology that could provide reliability benefits, such as blackstart, fast frequency response, and inertial response, to NIPSCO's system as it becomes more inverter-based;

- Hydrogen production developments, particularly associated with electrolysis of water with clean electricity sources ("green hydrogen") and the costs and capabilities of turbines and other thermal resources to burn hydrogen or blend hydrogen with natural gas;

- CCS costs and sequestration opportunities, particularly associated with the Sugar Creek facility;

- Long-duration storage technologies, including gravity storage, and their associated costs, efficiencies, and other value drivers;

- Other technologies that may emerge over the long term, including small modular reactors and other nuclear technology.

Other Factors

As with the implementation of NIPSCO's 2018 IRP, NIPSCO will again continue to perform project-specific analyses for any new resources that may enter the portfolio to evaluate items such as congestion and nodal price risk, energy deliverability, and other reliability topics. This may include detailed nodal and power flow modeling and other local transmission and distribution system analyses.

9.4 Short-Term Action Plan

NIPSCO's short-term action plan covers the period 2022 to 2027 and includes several elements, as summarized in

Figure 9-47. NIPSCO will initiate the planning process for the retirement of the Michigan City 12 and Schahfer 16AB units, leaving flexibility in ultimate timing, as described in the preferred existing fleet portfolio section above. During the retirement implementation period, NIPSCO will make the required notifications to MISO, NERC and other relevant organizations of its intention to retire units, and NIPSCO will also identify and implement reliability and transmission upgrades resulting from the retirements.

NIPSCO will also select replacement resources identified through the 2021 RFP evaluation process, prioritizing resources that were common across all portfolios that influenced the preferred portfolio selection. These include short-term thermal contracts and some solar resources. NIPSCO will also take the necessary steps to proceed with uprates to the Sugar Creek CCGT facility and identify opportunities for DER projects with distribution deferral costs consistent with the attractive tranche selected in the preferred portfolio. NIPSCO will also continue to implement the filed DSM plan for 2022 to 2024 and will continue to pursue longer-term DSM implementation consistent with the bundles selected in the preferred portfolio.

In addition, NIPSCO will perform due diligence on the short-list of gas peaker and storage bids and will conduct additional targeted RFP solicitations and associated portfolio analysis if current projects do not meet all reliability and other considerations inherent in the preferred portfolio. For the projects selected, NIPSCO will pursue the required approvals from the Commission to acquire those projects. Finally, to fill any short-term capacity needs during this period, NIPSCO will rely on MISO market purchases or short-term bilateral capacity contracts.

9.5 Conclusion

The NIPSCO Integrated Resource Plan seeks to ensure reliable, cost-effective electric service for customers while maintaining a robust and diverse pool of supply-side generation and demand-side options. This 2021 IRP incorporated several emerging trends and greatly expanded the analysis of risk and reliability to identify a preferred portfolio that is highly flexible to changing external conditions. It is no longer possible to view the world in terms of choosing a simple least cost option, and NIPSCO has identified an implementation roadmap that reflects the need to minimize future environmental impacts, maximize resource diversification, and preserve optionality over the long-term.

Figure 9-47: Short-Term Action Plan Summary

Complete and place in service 12 remaining renewable facilities approved by the IURC
Complete retirement and shutdown remainder of Schahfer coal units (17,18) by 2023
Refine the retirement of Michigan City 12 to be between 2026 and 2028 by making required notifications to MISO, NERC, and other organizations as appropriate
Monitor the operating condition of the Schahfer 16A/B and plan for their retirement between 2025 and 2028 by making required notifications to MISO, NERC, and other organizations as appropriate, including preserving the optionality to use existing interconnection rights at the site through the MISO generator replacement process
Implement required reliability and transmission upgrades necessitated by retirement of the Michigan City 12 and Schahfer 16A/B
Confirm Sugar Creek uprate options in more detail with the plant's turbine manufacturer and schedule the uprate in accordance with the plant's maintenance cycles
Identify candidate DER projects as part of NIPSCO's distribution planning activities and consistent with planning-level assumptions developed in the IRP; implement identified projects after additional project-specific diligence
Continue implementation of filed DSM Plan for 2022 through 2023
Select replacement projects identified from the 2021 RFPs, initially prioritizing thermal PPA and solar resources
Perform deeper diligence on gas peaker and storage projects from the 2021 RFPs, selecting projects that conform to the preferred portfolio's requirements as NIPSCO tracks MISO guidelines, Commission requirements, and system reliability needs
As needed, conduct a subsequent RFP(s) to identify additional resources that may be available with attributes that are consistent with those required to implement the preferred portfolio
Explore potential pilot projects from the RFP associated with emerging technologies, such as long duration storage and hydrogen
File CPCN(s) and other necessary approvals for selected replacement projects
Procure short-term capacity as needed from the MISO market or through short-term bilateral capacity transactions
Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape

Perform additional reliability analysis within the NIPSCO system as needed to ensure evolving portfolio meets all reliability needs and requirements
Comply with NERC, EPA, and other regulations
Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

Section 10. Customer Engagement

10.1 Enhancing Customer Engagement

People must be at the center of a sustainable energy future. Understanding and incorporating the diverse needs and perspectives of NIPSCO's customers is important, and the Company is focused on continuously improving how it serves and engages with its customers. Whether it is transitioning to lower-cost and cleaner energy sources, helping customers understand changes and enhancements to their service, or listening to customer feedback about how they want to interact with NIPSCO, customers have been and continue to be the central focus.

10.1.1 Leveraging Customer and Stakeholder Feedback

NIPSCO relies on customer feedback to uncover service improvement opportunities. Those feedback mechanisms include the Customer Advisory Panel, J.D. Power customer satisfaction surveys, customer surveys administered by the MSR Group, online customer panels, and comments and complaints that are emailed or called in to NIPSCO's customer care center, as well as the IURC Consumer Affairs Division. NIPSCO also surveys customers to determine customer satisfaction with its customer care center and interactions with field personnel, as well as with other interactions, such as mobile, integrated voice responses and the website. The company also researches best practices that have been demonstrated by those within the utility sector as well as those outside of the industry. Customer feedback is the primary driver behind many of the changes to operations, improvements to customer communications, enhancements to services, and other offerings that have been instituted in recent years.

In 2020, NIPSCO also partnered with E Source, a company with 30+ years of industry expertise, to perform a market research study gathering voice-of-customer insights that shed a unique light on their experiences and expectations of NIPSCO, utilities, and energy. The study was designed to determine a baseline on NIPSCO customer wants and needs while identifying ways to bridge gaps between those wants and needs and NIPSCO's brand promise. The customer insights provided a fresh perspective on ways NIPSCO can best meet the expectations of today's customers, which will include updating brand messaging and validating in-flight customer experience investments and enhancements, while also potentially providing business case data for future customer-focused initiatives.

Direct customer feedback has been critical in helping NIPSCO and its parent company, NiSource, to better understand and prioritize customer needs. Based on customer feedback, the following features and capabilities have been implemented – or are currently being implemented – at NIPSCO and its five sister utilities:

- Service Request Management: Allowing customers to start, stop and transfer service digitally;
- Mobile Application: Delivering a mobile application so customers can directly conduct utility business via a native mobile application; and

- Chatbot and Live Chat: Allowing customers to receive support via a chatbot or via online chat with a live agent.

Customer feedback also allows NIPSCO to drive continuous incremental improvements across existing initiatives, including paperless enrollments and ongoing website enhancements, and helps NIPSCO better understand areas in which customers are satisfied with their interactions and areas in which the Company can continue to improve across technologies, processes and experiences.

10.1.2 Customer Education – Your Energy, Your Future

As NIPSCO transitions away from coal generation and toward lower-cost, cleaner generation options, it is important for customers to understand why and how this transition will occur so NIPSCO can maintain customer trust and confidence in the essential, reliable energy it provides.

One of the ways NIPSCO has been able to help educate customers about its "Your Energy, Your Future" generation transition plan is through a robust awareness campaign. The campaign – which included advertising and public relations efforts to communicate this message – started in 2019, was refreshed in 2020, and has continued in 2021. The goal of the NIPSCO public education efforts is to generate awareness about the generation transition by helping customers understand the customer, economic, and environmental benefits of these changes.

Part of the campaign included the creation of a dedicated website, or microsite, to house all information related to NIPSCO's Your Energy, Your Future generation transition, which can be found at NIPSCO.com/future.

New in 2020 was an "explainer" video prominently featured on the microsite that breaks down the basics of NIPSCO's generation transition in three minutes – highlighting customer cost savings, continued reliability, lower emissions, and additional economic benefits to the communities NIPSCO serves. The video was viewed by nearly 30,000 customers between NIPSCO's website and Facebook page over a 22-week period, when the advertising campaign was in flight.

Along with the microsite and video, NIPSCO utilized television, radio and print advertising, bill inserts, customer emails, and social media to reach customers and educate them about the generation transition. Press releases were also utilized to announce the latest renewable energy project news.

In 2020, NIPSCO partnered with the Center for Innovation through Visualization and Simulation through Purdue University Northwest to create a virtual simulation of a wind farm showing how wind energy is captured and delivered to customers' homes through the distribution system. The simulation will be featured on the Your Energy, Your Future microsite, along with being loaded into virtual reality goggles that NIPSCO representatives will bring to community events once COVID-19 restrictions are fully lifted.

NIPSCO's 2020 Your Energy, Your Future ad campaign's "Leaving It Better" story featuring Gary, Indiana resident and community leader LaJuan Clemons was nominated and won an Emmy award in June 2021. The Lower Lakes Chapter of the National Academy of Television Arts & Sciences awards Emmys to stations, studios, and production companies, and the LaJuan video story was entered in partnership with NIPSCO's advertising agency, Borshoff, and its production partner, Bayonet Media. The winning video featured LaJuan's inspiring story of how he helps Leave It Better in his Gary, Indiana, community. The video won in the Branded Content–Short-Form Content category.

Annually, NIPSCO garners customer feedback through a sentiment and awareness study from the Your Energy, Your Future campaign. The most recent study, conducted at the end of 2020, showed 67% of customers have a favorable view of NIPSCO's generation transition plan. Feedback showed customers associated NIPSCO's generation transition with cleaner energy, reducing emissions and improving the environment, while also demonstrating that they understand NIPSCO will continue to provide reliable energy into the future. Customer feedback on external campaigns helps NIPSCO learn which parts of its plan may need more consumer education in the future.

10.1.3 NIPSCO's Customer Workshop Series

NIPSCO has kicked off the ninth season of its Customer Workshop Series in partnership with Purdue University. Due to the COVID-19 pandemic, NIPSCO Major Accounts elected not to host the Customer Workshop Series in 2020. Other than this one-year break, hundreds of NIPSCO Transmission and C&I customers from all over northern Indiana have attended the various workshops since 2011. The series includes workshops ranging from the technical (Understanding HVAC, Fundamentals of Compressed Air, Energy Savings 101, Demand Management, Lighting, etc.) to the interpersonal (Six Sigma, Managing Time & Stress, Becoming a Leader, Managing Across Generations, etc.), and customers are able to pick which workshops are valuable to their businesses and reserve openings for themselves and/or their colleagues at no expense.

Attendees are able to interact with industry experts and representatives from the NIPSCO Major Accounts team, as well as their peers at other companies, learning best practices and voicing their current challenges and solutions in an open, classroom setting. Each season, customers complete surveys, and the feedback is used to improve the subsequent season. During the 2021 season, NIPSCO continued to host classes throughout the service territory while abiding by Centers for Disease Control and Prevention guidelines for social distancing to protect the health and well-being of customers, Purdue employees, and NIPSCO team members.

10.2 Community Partnerships

10.2.1 Community Advisory Panels

Another avenue used by NIPSCO to engage with its customers and stakeholders is the use of Community Advisory Panels (CAPs), which serve as a forum to discuss new company initiatives and programs as well as to educate and facilitate feedback regarding service and other NIPSCO-related matters in our communities. NIPSCO has five regional CAPs across the

Company's northern Indiana footprint. CAPs are composed of individual customers, as well as local government and community leaders representing a diverse, broad cross-section of NIPSCO customers. NIPSCO senior management meets with each of the regional CAPs three times a year to share the Company's strategic direction and to ask members of the CAPs for insight on emerging issues. In 2019, NIPSCO adjusted the CAP territories slightly to reflect changes made to the areas that its Public Affairs managers serve. During 2020, NIPSCO was able to conduct three annual meetings virtually to maintain the integrity of the program. CAP members received updated information on NIPSCO's Your Energy, Your Future generation transition plan, as well as background on how the MISO operates in connection with NIPSCO and other states. In addition, NIPSCO utilized the CAP relationships throughout 2020 to communicate operational updates NIPSCO initiated as a result of COVID-19.

10.2.2 Partners For Clean Air

NIPSCO is a Gold Member of the Northwest Indiana Partners for Clean Air, a coalition of businesses, industries, local governments, and community groups committed to improving overall air quality and public health through voluntary actions. NIPSCO's voluntary actions include implementing energy-efficiency programs for customers and the Your Energy, Your Future generation transition. On April 30, 2021, NIPSCO received the Business Award at the annual Partners for Clean Air virtual award ceremony. To win this award, NIPSCO partnered with South Shore Clean Cities to support the construction of 24 new, public electric vehicle charging stations by matching funds for grant projects with $500 donations for eligible participants. Level 2 electric vehicle charging stations have been installed in 18 communities across northern Indiana.

10.3 Customer Programs

10.3.1 Feed-in Tariff

NIPSCO's FIT Phase I was approved on July 13, 2011, in Cause No. 43922. Implementation began immediately as a three-year pilot program with a 30 MW capacity cap. Phase I offered a higher rate to participants selling electricity than the retail electric rate in the current approved sales tariffs and provided an incentive to encourage development of renewable generating resources. The pilot program was designed to help maximize the development of renewable energy in Indiana, which welcomed biomass, wind, hydro and solar resources. The FIT provides the customer a sell-back opportunity to NIPSCO at a predetermined price for up to 15 years through a RPPA. Participating customers receive payment from NIPSCO for the amount of electricity generated and delivered to NIPSCO through an approved interconnection and metering point.

Additional program details:

- The participating generator must be an existing NIPSCO electric customer.
- An IA and RPPA are required to reserve capacity or enter the queue.

- The customer is responsible for interconnection fees and installation costs in accordance with the Indiana Administrative Code.

- The customer is responsible for maintenance and proper operation of the generating device in a safe manner consistent with the IA.

Phase I concluded in March 2015 with a total subscription of 29.7 MW and is summarized in Table 10-1.

Table 10-1: FIT Phase I In-Service

Technology	Total FIT (kW)
Biomass	14,348
Solar (large)	14,500
Solar (small)	690
Wind (large)	150
Wind (small)	10
New Hydro	0
Total	**29,698**

NIPSCO's FIT Phase II was approved on February 4, 2015, in Cause No. 44393. NIPSCO released Phase II, Allocation I of the FIT program in March 2015 and Phase II, Allocation II in March 2017. Phase II allows for an additional 16 MW of renewable capacity, bringing the total FIT capacity cap up to 46 MW. Table 10-2shows the subscription for Phase II as of July 2020.

Table 10-2: FIT Phase II Project Totals

Technology	In-service (kW)	Queue (kW)	Total FIT (kW)
Micro Solar	229	80	309
Intermediate Solar	6,170	1,800	7,970
Micro Wind	20	0	20
Intermediate Wind	0	0	0
Biomass	0	0	0
Total	6,419	1,880	8,299

With over 36 MW of capacity currently interconnected in the FIT program, as of December 31, 2020, NIPSCO had a total metered generation from customers selling electricity of 904,806 MWh. Micro solar, micro wind, intermediate wind and biomass all have remaining capacity; however, there is an existing queue for the limited amount of remaining intermediate solar capacity. Despite continued interest in the FIT program, especially the intermediate solar technology, there are no plans to offer another FIT program in the future. Table 10-3 shows the annual production and growth by technology segment.

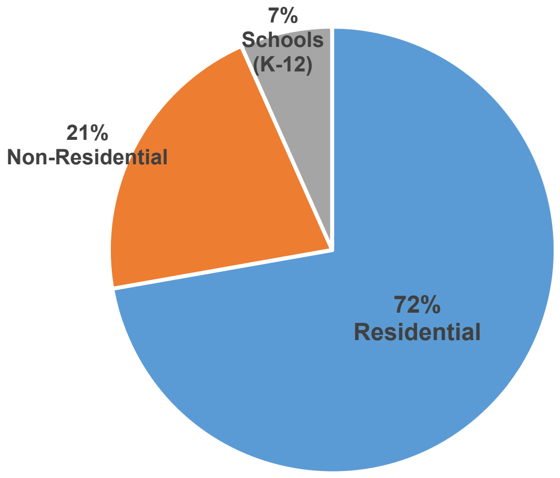
Table 10-3: Annual Production by Technology – Generation (MWh)

Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Biomass	6,220	19,152	31,603	49,917	81,370	83,552	89,486	94,942	94,552	96,144	646,938
Intermediate Solar	-	434	15,789	21,665	22,436	22,697	24,391	27,450	16,707	30,345	181,914
Micro Solar	-	119	472	719	818	825	849	849	857	899	6,407
Intermediate Wind	-	-	90	166	218	166	168	180	143	115	1,246
Micro Wind	-	4	16	12	9	8	8	8	8	8	81
Total	**6,220**	**19,709**	**47,970**	**72,479**	**104,851**	**107,248**	**114,902**	**123,429**	**112,267**	**127,511**	**836,586**

10.3.2 Net Metering

NIPSCO's Net Metering Rider allows customers to install renewable energy generation to offset all or part of their own electricity requirements. Net metering is the measurement of the difference between the electricity that is supplied by NIPSCO and the electricity that is supplied back to NIPSCO by an eligible net metering customer. Production is measured on a kWh basis. To be eligible, a customer must be in good standing and operate a solar, wind, biomass or hydro generating facility that has a nameplate capacity of less than or equal to 1 MW. NIPSCO follows the rules and guidelines set forth in the Indiana Administrative Code with respect to Net Metering and the interconnection process. Customers with a fully executed Net Metering Agreement and IA receive a credit for each kWh provided to NIPSCO above their own usage requirements. NIPSCO's Net Metering program capacity as of December 31, 2020 was 30.4 MW. The total measured generation by the Net Metering customers for 2020 was 20,483,454 kWh. The current classification of NIPSCO's 779 Net Metering customers is shown in Figure 10-1.

Figure 10-1 : Classification of Net Metering Customers



To be guaranteed to participate in the nonresidential Net Metering program, a customer interconnection application had to be submitted by October 1, 2021. Nonresidential applications approved by December 31, 2021 will also be allowed to participate. Residential and biomass interconnection applications will continue to be accepted until July 1, 2022, or until there is no remaining capacity available, as outlined in Senate Enrolled Act 309. Once the Net Metering program is no longer available for any classification of customer, a customer can elect to submit an interconnection application for the EDG Rider, if approved by the Commission.[130] In 2020, NIPSCO implemented the use of DocuSign to expedite contract execution and provide convenience for customers.

10.3.3 Green Power Rider Program

NIPSCO's GPR program was approved on December 19, 2012, in Cause No. 44198. NIPSCO's request for an extension of its GPR program, with certain modifications and as a component of NIPSCO's approved tariff on a non-pilot basis, was approved on December 30, 2014, in Cause No. 44520. The GPR Program is a voluntary program that allows customers to designate a portion or all of their monthly electric usage that they want to be renewable energy. Customers can enroll online or by calling NIPSCO.

Green power is energy generated from renewable and/or environmentally friendly sources or a combination of both, which meets the Green-e® Energy National Standard for Renewable Electricity Products in all regions of the United States. Eligible sources of green power include solar; wind; geothermal; hydropower that is certified by the Low Impact Hydropower Institute; solid, liquid, and gaseous forms of biomass; and co-firing of biomass with non-renewables. Green power includes the purchase of RECs from the sources described above. For the GPR program, NIPSCO's residential electric customers can designate 25%, 50% or 100% of their total electricity usage they would like to be renewable energy. In addition to those options, NIPSCO's nonresidential customers also have the option to designate 5% or 10% of their total electricity usage they would like to be renewable energy. As of December 31, 2020, 1,496 customers were participating in the GPR Program. Figure 10-2 shows the breakdown among residential customers as of December 31, 2020.

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[130] As of the submission of this report, NIPSCO's EDG Rider was pending before the Commission in Cause No. 45505.

Figure 10-2 GPR Program Residential Customer Count[131]

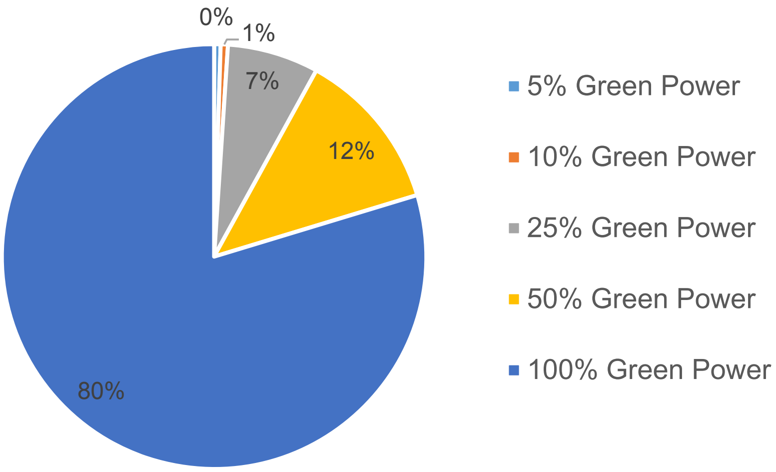
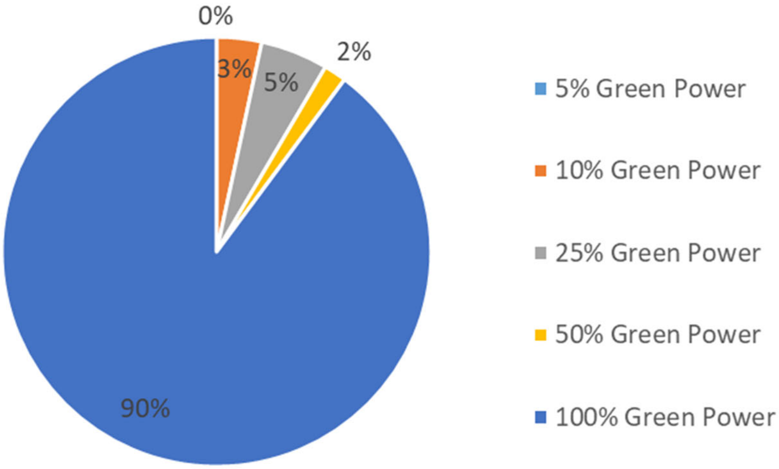


Figure 10-3 shows the breakdown of commercial and industrial customers as of December 31, 2020.

Figure 10-3: GPR Program Commercial Customer Count



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[131] Previously residential customers had the option to enroll at 5% or 10%. Customers who elected one of those options were grandfathered in when those levels were discontinued for residential customers.

NIPSCO's GPR program for the period of January 1 through December 31, 2020, accounted for 21,308,200 kWh of energy consumption designated as green power. Residential customers accounted for 11,060,703 kWh of energy consumption, and C&I customers accounted for 10,247,497 kWh of energy consumption of designated green power. For both residential and commercial customers, the majority of the GPR program enrollments designate 100% of their energy as green power. Table 10-4 shows the energy consumption designated as Green Power for participating customers, by rate type, for the period January 1 through December 31, 2020.

Table 10-4 2020 Green Power Customers by Rate Type (kWh)

Rate Type	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	Total 2020
Commercial	893,256	892,359	927,167	846,381	758,117	992,134	1,168,867	1,048,591	1,029,012	901,414	787,791	815,614	11,060,703
Residential	860,081	765,934	724,971	697,433	643,985	898,306	1,319,713	1,166,669	1,072,389	665,051	631,954	801,011	10,247,497
Total	**1,753,337**	**1,658,293**	**1,652,138**	**1,543,814**	**1,402,102**	**1,890,440**	**2,488,580**	**2,215,260**	**2,101,401**	**1,566,465**	**1,419,745**	**1,616,625**	**21,308,200**

Participating customers are billed under their current applicable rates, with a separate line item showing the premium to participate in the GPR program. This premium is calculated by multiplying the GPR rate by the kWhs the customer specifies to be subject to the GPR. Table 10-5 shows the green power premiums applicable during the period January 1, 2017, through December 31, 2020.

Table 10-5: Green Power Rates

July 2017 to June 2018	July 2018 to June 2019	July 2019 to June 2020	July 2020 to June 2021
$0.002940	$0.001805	$0.001657	$0.002860

10.3.4 Transportation Decarbonization: DC Fast charging stations & IDEM Grant

The Indiana Volkswagen Environmental Mitigation Trust Fund Committee was formed to manage the disbursement of Indiana's share of funds from the Environmental Mitigation Trust created as part of Volkswagen's settlement of Clean Air Act violations regarding diesel emissions from its vehicles. IDEM is the lead agency for the state of Indiana's participation in the Environmental Mitigation Trust. In late 2020, NIPSCO joined the Indiana Utility Group, a consortium of eight Indiana utilities, to apply for Electric Vehicle DC Fast Charging funding. In March 2021, the Indiana Utilities Group submitted a coordinated grant application for 61 DC fast-charging stations, 10 of which were for NIPSCO's service territory. Along with the IDEM grant of more than $900,000, NIPSCO is investing more than $1.4 million in constructing these charging stations. NIPSCO has a goal of having all 10 stations in operation by late 2022.

10.3.5 Advanced Metering Infrastructure

NIPSCO has proposed to implement AMI meter technology for its electric customers, and this proposal is still pending in a proceeding before the Commission.[132] AMI is central to NIPSCO's efforts to enable modern energy capabilities. These capabilities include integration of electric vehicle charging and customer-owned generation resources into the distribution grid, improved forecasting of electricity demand thus enabling better planning for the future, and access to data that helps NIPSCO to both understand impacts to and anticipate issues with the distribution system as generation technology and usage patterns evolve to maintain reliability.

10.4 Corporate Development and Community Support

10.4.1 Supporting Economic Growth

NIPSCO partners with community leaders and state, regional, and local economic development organizations to attract and support the expansion of new and existing businesses and to help create more jobs across the NIPSCO service territory. In addition to being one of the largest employers in the region, NIPSCO spends $1.1 million in economic development efforts each year, which has resulted in 85 new businesses or expansions and 8,700 local jobs in the past 10 years.

NIPSCO's Rider 877 – Economic Development Rider offers discounts on existing tariff services for qualifying projects that bring new jobs and investment from outside the NIPSCO service territory. When coupled with local and state incentives, a powerful package is created with often positive results.

NIPSCO's Your Energy, Your Future generation transition will help save Indiana's businesses and families money and also make northern Indiana more economically competitive. The generation transition positions Indiana as a more attractive location to employers, as well as residents, as NIPSCO brings a sustainable balance of cleaner, lower-cost renewable energy to its portfolio. For example, in 2019, the Digital Crossroads Data Center – a more than $50 million facility bringing jobs and revenue to the area – decided to open in Hammond, Indiana. NIPSCO's generation transition commitment was part of what attracted the business to the area, as it looked to be the most energy-efficient, lowest-latency urban data center in the United States.

10.4.2 Supplier Diversity

Cultivating a diverse pipeline of suppliers helps bring innovative ideas and processes, a competitive advantage, and other benefits to NIPSCO's communities. NIPSCO has created a supplier diversity program that strengthens and widens the playing field for qualified suppliers who are typically underutilized in the supply chain of a large corporation.

In 2020, NIPSCO's direct supplier spending in Indiana was $1.057 billion. Of that, $95.9 million was spent on diverse businesses and $19.6 million was spent on diverse subcontractors.

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[132] See Cause No. 45557, NIPSCO's TDSIC Plan further discussed in Section 6.

10.4.3 Workforce Development

NIPSCO continues to lead efforts and partnerships focused on workforce development – both for the current and future workforce generations. Some of the highlights include:

- **Ivy Tech Partnership for Energy Industry Training Program:** This program began in 2009 and provides training in electric-line, power plant technology, and gas technology areas. NIPSCO has hired more than 60 students from the program, and graduates are guaranteed an interview opportunity. Additionally, NIPSCO provides instructors for these training classes and, in 2017, provided a full-scale electric distribution system for training purposes built within the Ivy Tech Valparaiso campus energy technology lab – the only such facility in an educational setting in Indiana. NIPSCO is currently working with Ivy Tech to review the entire program and update the curriculum to meet the training needs for renewable energy generation operation and maintenance.

- **NIPSCO Energy Academy:** Started in 2014, the NIPSCO Energy Academy program is a partnership designed to prepare area students for high-demand jobs in the electronics, energy, and utility industries. It is the first initiative of its kind in Indiana, and it will serve students from Michigan City High School, LaPorte High School, New Prairie High School, South Central High School, LaCrosse High School, and Westville High School. More than 100 students that have gone through the program. NIPSCO is currently looking to add a similar Energy Academy in Lake County.

- **IN-POWER Youth Mentoring Program:** In 2010, NIPSCO introduced the IN-POWER Youth Mentoring Program – a unique mentoring program for local high school students that takes a holistic approach to developing a more highly skilled future workforce in the energy sector. The program was expanded with IN-POWER STEM PLUS, designed to give 7th and 8th grade students a firsthand experience on gas and electric safety while teaching them about the various aspects of STEM needed in the energy sector. NIPSCO employees and American Association of Blacks in Energy Indiana members serve as mentors and instructors. Participants receive college credits, unique mentoring and internships, among other opportunities.

- **NIPSCO Energy Ambassador Program:** The NIPSCO Energy Ambassador program, in partnership with the Urban League, is a college- and career- readiness program initiated in 2019. This opportunity invites 11th and 12th grade students throughout northwest Indiana to participate in virtual workshops and activities designed to educate students about NIPSCO's operations and encourage STEM learning. In this, the program's third year, NIPSCO donated $60,000 to the Urban League to support the 2021 summer internship. Other goals of the program include reducing social-emotional barriers for students, increasing students' interest in STEM careers, boosting self-esteem and supporting educations goals. Approximately 45 students participate annually and:

    - Receive informational training from NIPSCO representatives
    - Disseminate NIPSCO customer-centric information to their respective communities to provide awareness
    - Participate in career exploration experiences
    - Participate in community service outreach activities
    - Attend workshops to become college or career ready

- **JA Support:** NIPSCO provides annual support for classroom business education programs through both contributions and volunteer instructors across NIPSCO's service area. For the past several years, NIPSCO has supported a "JA Day" in a local Hammond and East Chicago school systems. In 2021, NIPSCO partnered with JA to offer a virtual platform that taught participating students about different job sectors.

- **City of Gary Summer of Opportunity Job Program:** The Summer of Opportunity places youth in meaningful work opportunities throughout Gary, with lunch-and-learn workshops featuring local professionals, with every other session focusing on financial literacy. Local youth staff six summer program sites that offer summer meals and learning. NIPSCO partners with the mayor's office, Gary Youth Services Bureau, Urban League, and the Gary Chamber of Commerce to create a set of supports that enable strong transitions from school year to school year and from high school to college and career.

- **Girl Scouts Engineering Day:** For more than five years, NIPSCO has hosted approximately 125 girls from kindergarten to 4th grade for the annual Introduce a Girl to Engineering Day. The girls come from local Girl Scout troops along with some young relatives of NIPSCO and NiSource employees. The four-hour event is part of the company's efforts to help build the next generation of female leaders, support local communities and provide opportunities for local students interested in STEM-related careers. The event is organized by the employee resource group Developing and Advancing Women (DAWN) at NiSource.

- **On My Way Pre-K:** NIPSCO was a lead sponsor of the Pilot Pre-K Program, which began in 2016, and has been shown to be a successful early education program to improve children's chances of being ready to learn when they reach kindergarten and throughout their educational experiences, a key factor in breaking the cycle of poverty.

10.4.4 Corporate Citizenship

NIPSCO believes that reinvesting in the communities where its employees live and work will enhance the quality of life for everyone. Each year, NIPSCO donates time, money, and other resources to hundreds of local philanthropic programs and organizations across its 30-county service area, focusing on:

- Safety
- Economic and workforce development
- Environmental stewardship
- STEM and energy education
- Basic needs and hardship assistance

Through these programs and partnerships, NIPSCO is working hard with its communities to build a brighter future for years to come.

In 2020, NIPSCO and the NiSource Charitable Foundation contributed approximately $1 million to local organizations throughout the NIPSCO service territory.

A highlight of that effort includes NIPSCO's annual Charity of Choice campaign, during which employees select one nonprofit organization or an area of need to support. Fundraisers, volunteerism, and other activities are planned throughout a summer-long, employee-led campaign. Recent benefactors and causes selected by employees have included autism, veterans, Boys & Girls Clubs, the American Heart Association, the American Red Cross, and organizations supporting the community through the COVID-19 pandemic. The 2021 Charity of Choice campaign supported mental health awareness and education.

10.4.5 Volunteerism

NIPSCO employees have a passion for volunteering and giving back to their local communities. Through a program called Dollars for Doers, cultivated by NIPSCO's parent company, NiSource Inc., employees translate their community service into financial support for organizations they care about most. The program contributes up to $500 per employee to an organization in return for volunteer time. In 2019, NIPSCO employees volunteered more than 2,100 hours, which resulted in more than $56,000 of contribution to local organizations. In 2020, while the COVID-19 pandemic limited how NIPSCO employees could safely volunteer time across the service area, NIPSCO employees contributed more than 1,000 volunteer hours, equating to an additional impact of $30,953 to various charities.

Additionally, NIPSCO employees volunteer their personal time and resources with more than 100 local nonprofit boards, local associations and other local community efforts each year.

Section 11. Compliance with IRP Rule

Rule	Section(s)
170 IAC 4-7-2: Integrated Resource Plan Submission	
(d) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents: (1) The integrated resource plan.	Submitted via email on November 15, 2021
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the assumptions in the IRP.	Confidential Appendix D
(3) An IRP summary that communicates core IRP concepts and results to non-technical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) the IRP public advisory process; and (vi) any additional details the commission staff may request. (B) A simplified discussion of resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	Executive Summary
(e) Contemporaneously with the submission of an IRP, a utility shall provide to the director the following: (1) The name and address of each known entity considered by the utility to be an interested party. (2) A statement that the utility has sent each known interested party, electronically or by deposit in the United States mail, First Class postage prepaid, a notice of the utility's submission of the IRP to the commission. The notice must include the following information: (A) A general description of the subject matter of the submitted IRP. (B) A statement that the commission invites interested parties to submit written comments on the utility's IRP within 90 days of the IRP submittal.	Transmittal Letter

Rule	Section(s)
An interested party includes any business, organization, or customer that participated in the utility's previous public advisory process. A utility is not required to separately notify all of its customers. (3) A statement that the utility has served a copy of the documents submitted under subsection (d) above on the office of the consumer counselor.	
170 IAC 4-7-2.6: Public Advisory Process	
(a) The following utilities are exempt from this section: (1) A municipally owned utility; (2) A cooperatively owned utility; and (3) A utility submitting an IRP under subsection 2(b) of this rule. (b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP. (c) The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by interested parties, the commission, and its staff. (d) The utility retains full responsibility for the content of its IRP.	N/A
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following: (A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable energy and non-energy benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and its rationale. (2) The utility is encouraged to hold additional meetings as appropriate. (3) The schedule for meetings shall be determined by the utility and shall:	Section 2.1 Appendix A

Rule	Section(s)
(A) be consistent with its internal IRP development schedule; and (B) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP. (4) The utility or its designee shall: (A) chair the participation process (B) schedule meetings; and (C) develop and publish to its website agendas and relevant material for those meetings at least seven calendar days prior to the meeting; and (D) develop and publish to its website minutes within fifteen calendar days following each meeting; (5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility. (6) The utility shall take reasonable steps to notify its customers; the commission; and interested parties of its public advisory process.	
170 IAC 4-7-2.7: Contemporary Issues	
(a) The commission or its staff may host an annual technical conference to facilitate: (1) identifying contemporary issues; (2) identifying best practices to manage contemporary issues; and (3) instituting a standardized IRP format. (b) The agenda of the technical conference shall be set by the commission staff. Utilities and interested parties may request commission staff include specific contemporary issues and presenters. (c) The director may designate specific contemporary issues for utilities to address in the next IRPs by providing the utilities and interested parties with the contemporary issues to be addressed. The utility shall address the designated contemporary issues in its next IRP. In addition, prior to its next IRP the utility shall provide to interested parties either a discussion of the impacts of such issues on its IRP or describe how it has taken the contemporary issues into account.	N/A
(d) A utility shall address new issues raised in a contemporary issues technical conference if the contemporary issues technical conference occurred at least one (1) year prior to the submittal date of a utility's IRP.	Section 2
170 IAC 4-7-4: Integrated Resource Plan Contents	

Rule	Section(s)
An IRP must include the following:	
(1) At least a 20 year future period for a predicted or forecasted analysis.	Used throughout
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with subsection 5(a) of this rule.	Section 3.2 Section 3.3 Section 3.4 Section 3.4 Section 3.5 Section 3.6 Section 3.7 Section 3.9 Section 3.10 Section 3.11
(3) At least three alternative forecast scenarios of peak demand and energy usage in compliance with subsection 5(b) of this rule.	Section 3.7
(4) A description of the utility's existing resources in compliance with subsection 6(a) of this rule.	Section 4.3 Section 4.4 Section 4.5 Section 5.1
(5) A description of possible alternative methods of meeting future demand for electric service in compliance with subsection 6(b) of this rule.	Section 5
(6) The resource screening analysis and resource summary table required in subsection 7(a) of this rule.	Section 4.6
(7) The information and calculation of tests required for potential resources in compliance with subsections 7(b)-7(e) of this rule.	Appendix B
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with subsection 8(a) and 8(b) of this rule.	Section 8.1 Section 9.2 Section 9.3 Confidential Appendix D
(9) A description of the utility's preferred resource portfolio and the information required in compliance with subsection 8(b) of this rule.	Section 9.2 Section 9.3
(10) A short term action plan listing plans for the next three year period to implement the utility's preferred resource portfolio and its workable strategy. The short term action plan shall comply with section 9 of this rule.	Section 1.1 Section 9.4
(11) A discussion of the inputs; methods; and definitions used by the utility in the IRP.	Section 2 Section 3.3 Section 4.4 Section 4.9

Rule	Section(s)
	Section 5.1 Section 5.2 Section 5.3 Section 7.3 Section 8.1 Section 8.2 Section 8.4 Section 9.2 Section 9.3 Appendix A Confidential Appendix D
(12) Appendices of the data sets and data sources used to establish alternative forecasts in subsection 9(b) of this rule. If the IRP references a third party data source, the IRP must include the following for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of any adjustments made to the data. The data must be submitted with the IRP in a manipulable format.	Confidential Appendix D
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by the following: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use.	Section 3 See Note 1
(14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	Section 3
(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	See Note 2

Rule	Section(s)
(16) A discussion detailing how information from Advanced Metering Infrastructure (AMI) and smart grid will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	Section 3 Section 5.2 Appendix B
(17) A discussion of distributed generation within the service territory and its potential effects on generation, transmission, and distribution planning and load forecasting.	Section 9 Section 6.2 Section 10.3.1
(18) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Appendix A
(19) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	Section 4.1
(20) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission have been taken into account and influenced the IRP development.	Section 7.3.5
(21) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Section 2.3
(22) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	Section 7.3 Section 8.2.3
(23) A discussion of how the utilities' resource planning objectives, such as cost effectiveness, rate impacts, risks and uncertainty, were balanced in selecting its preferred resource plan.	Section 9.3
(24) A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include existing federal environmental laws; existing state laws, such as renewable energy requirements and energy efficiency laws; and existing policies, such as tax incentives for renewable resources that are certain. Existing laws or policies continuing throughout at least some portion of the planning horizon with a high	Section 9.3

Rule	Section(s)
probability of expiration or repeal must be eliminated or altered when applicable. (C) Not include future resources, laws, or policies unless the utility receives stakeholder input on the inclusion and it meets the following conditions: (i) Future resources have obtained regulatory approvals. (ii) Future laws and policies have a high probability of being enacted. A base case need not align with the utility's preferred resource portfolio.	
(25) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	Section 9.3
(26) A brief description, focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies, and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. This description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) the limits of the utility's transmission use; (ii) the utility's assessment practices developed through experience and study; and (iii) operating restrictions and limitations particular to the utility.	Confidential Appendix C
(27) A list and description of the contemporary methods utilized by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and	Section 2.2 Section 3.2 Section 8.1 Section 9.3 Appendix B

Rule	Section(s)
(iv) analysis of risk and uncertainty.	
(28) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	Section 5.2 Appendix B
(29) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically in a manipulable format. For purposes of comparison, a utility must maintain three (3) years of hourly data.	Section 3.1 Confidential Appendix D
(30) A summary of the utility's most recent public advisory process, including: (A) Key issues discussed. (B) How the utility responded to the issues (C) A description of how stakeholder input was used in developing the IRP.	Section 2.1 Appendix A
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	Section 4.6 Section 5 Appendix B
170 IAC 4-7-5: Energy and Demand Forecasts	
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following: (A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	Section 3 Confidential Appendix D

Rule	Section(s)
(2) Disaggregation of historical data and forecasts by customer class, interruptible load, end-use where information permits.	Section 3
(3) Actual and weather normalized energy and demand levels.	Section 3.7
(4) A discussion of methods and processes used to weather normalize.	Section 3.3.1
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	Section 3.7
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes, rate classes, or both. (C) Firm wholesale power sales.	Section 3.7
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	Section 3.2
(8) Justification for the selected forecasting methodology.	Section 3
(9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data, such as described in subdivision 4(10) of this rule.	No Response Needed
(b) In providing at least three (3) alternative forecasts of peak demand and energy usage the utility shall include high, low, and most probable peak demand and energy use forecasts to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most likely based on alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices, including competition. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption. (10) State and federal energy policies. (11) State and federal environmental policies.	Section 3.7
(c) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, analysis as part of the on-going efforts to improve the credibility of the load forecasting process.	Section 3.2
170 IAC 4-7-6: Resource Assessment	
(a) In describing its existing electric power resources, the utility must include in its IRP the following information:	Section 4.4 Section 4.5

Rule	Section(s)
(1) The net dependable generating capacity of the system and each generating unit.	
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	Section 4.5 Section 4.6.5 Section 9.1
(3) A fuel price forecast by generating unit.	Section 8.2
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and (D) subsequent disposal; and (E) water consumption and discharge; at each existing fossil fueled generating unit.	Section 4.1
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network. (D) An assessment of the transmission component of avoided cost.	Section 5.2 Section 6.1
(6) A discussion of DSM programs and their estimated impact on the utility's historical and forecasted peak demand and energy. The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	Section 3.2 Section 5.1 Section 5.3 Appendix B
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Innovative rate design as a resource in meeting future electric service requirements.	Section 5.2
(2) Demand-side resources, including Demand response programs, and Energy efficiency programs.	Section 5.2 Section 5.4 Appendix B

Rule	Section(s)
For a demand-side resource identified in the IRP, the utility shall, include the following: (A) A description of the program considered. (B) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to programs under consideration such as project life and seasonal operation. (C) The customer class or end-use, or both, affected by the program. (D) A participant bill impact projection and participation incentive to be provided in the program. (E) A projection of the program costs to be borne by the participant. (F) Estimated annual and lifetime energy (kWh) and demand (kW) savings per participant for each program. (G) The estimated program penetration rate and the basis of the estimate. (H) The estimated impact of a DSM program on the utility's load, generating capacity, and transmission and distribution requirements. (I) whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	See Note 3
(3) For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered, including: (i) Size (MW). (ii) Utilized technology and fuel type. (iii) Additional transmission facilities necessitated by the resource. (B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Section 4.1 Section 4.5 Section 4.6
(4) transmission facilities as a resource including new projects, upgrades to transmission facilities, efficiency improvements, and smart grid technology.	Section 6.1 Section 6.2
In analyzing transmission resources, the utility shall include the following: (A) A description of the timing, types of expansion, and alternative options considered.	Section 6.1 Section 6.2

Rule	Section(s)
(B) The approximate cost of expected expansion and alteration of the transmission network.	Section 6.1.6
(C) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.	Section 6.1
(D) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	Section 6.1
170 IAC 4-7-7: Selection of Resources	
(a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	Section 4.6 Section 5.2 Section 5.3 Appendix B
(b) The following information must be provided for a resource selected for further analysis: (1) A description of significant environmental effects, including the following: (A) Air emissions. (B) Solid waste disposal. (C) Hazardous waste and subsequent disposal. (D) Water consumption and discharge. (2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan and the commission analysis to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.	Section 9.2
(c) For each DSM program analyzed under this section, the IRP must include one (1) or more of the following tests to evaluate the cost-effectiveness of the program. (1) Participant cost test. (2) Ratepayer impact measure. (3) Utility cost test. (4) Total resource cost test.	Section 5.2 Appendix B

Rule	Section(s)
(5) Other reasonable tests accepted by the commission.	
(d) A utility is not required to calculate a test result in a specific format.	N/A
(e) For each program in subsection (c), a utility must calculate the net present value of the program's impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the interest rate used in the net present value calculation.	Section 5.2 Appendix B
(f) For a test performed under subsection (c), an IRP must: (1) specify the components of the benefit and the cost for the test; and (2) identify the equation used to calculate the result.	Appendix B
(g) If a reasonable cost-effectiveness analysis for a program cannot be performed using the tests in subsection (c), because it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	N/A
(h) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	N/A
170 IAC 4-7-8: Resource Portfolios	
(a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios. In selecting the candidate resource portfolios, the utility shall consider the following: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	Section 8.4
(b) With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how each candidate resource portfolio performed across a wide range of potential futures. (2) The results of testing and rank ordering the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metric(s). (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Section 9.2 Confidential Appendix D

Rule	Section(s)
(c) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information: (1) A description of the utility's preferred resource portfolio.	Section 9.3
(2) Identification of the variables used.	Section 9.3
(3) Identification of the standards of reliability.	Section 9.3
(4) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Section 9.3
(5) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following: (A) safety; (B) reliability (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Section 9.2
(6) An analysis showing the preferred resource portfolio utilizes, to the extent practical, all economical supply-side resources and demand-side resources as sources of new supply.	Section 9.3
(7) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility including their impacts on the utility's transmission and distribution system for the first ten years of the planning period.	Section 5.3 Appendix B
(8) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	Section 9.3
(9) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance;	Section 9.3

Rule	Section(s)
(ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (x) operating costs; (v) construction costs; (vi) resource performance; (vii) load requirements; (viii) wholesale electricity and transmission prices; (ix) RTO requirements; and (x) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	
(10) A description of the utility's workable strategy allowing it to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including the following changes: (A) The demand for electric service. (B) The cost of a new supply-side resources or demand-side resources.. (C) Regulatory compliance requirements and costs. (D) Changes in wholesale market conditions. (E) Changes in fuel costs. (F) Changes in environmental compliance costs. (G) Changes in technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	Section 9.3
(11) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	Section 2.2
170 IAC 4-7-9: Short Term Action Plan	
(a) A short term action plan shall be prepared as part of the utility's IRP, and shall cover a three (3) year period beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period. (b) The short term action plan must include, but is not limited to, the following:	Section 1.1 Section 9.4

Rule	Section(s)
(1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective. (2) Identification of energy efficiency goals for implementation of energy efficiency that can be produced by reasonably achievable, cost effective plans developed in accordance with 170 IAC 4-8-1 *et seq*. and consistent with the utility's longer resource planning objectives. (3) The implementation schedule for the preferred resource portfolio. (4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts. (5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired.	

Note 1: NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumption patterns by DSM program. The savings associated with DSM programs are gauged and claimed based on various TRMs, including the Indiana TRM, and the DSM programs are evaluated by program year by a third party EM&V administrator. NIPSCO will continue to consider its options. NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumptions patterns by end use.

Note 2: As part of its DSM functions, DSM programs are evaluated by program year by a third party EM&V administrator. As part of the EM&V process, the administrator surveys a sample of customers who have and have not participated in NIPSCO's DSM program. NIPSCO conducted an MPS (see Appendix B) that includes primary data. In addition, NIPSCO has previously completed lighting and market effect studies. NIPSCO used customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns as part of its updated MPS.

Note 3: Customer bill impacts are calculated directly utilizing the customer rate and the savings of each measure/participant. Appropriate escalators and discount rates are used to determine the NPV of these savings and then Aggregated across all measures/participants. Incentives are also included in the cost benefit analysis as an input on a per participant/measure basis. Appropriate escalators and discount rates are applied and the NPV calculated.