NIPSCO

RECEIVED
November 1, 2016
INDIANA UTILITY
REGULATORY COMMISSION

2016 Integrated Resource Plan

Stakeholder Meeting #1 – Thursday, May 5, 2016

Time: *9 am – 3:30 pm CT (10 am – 4:30 pm ET)*

Location: *Radisson Hotel at the Star Plaza*
800 E. 81st Avenue
Merrillville, IN 46410

Background
NIPSCO is due to submit an Integrated Resource Plan (IRP) to the Indiana Utility Regulatory Commission (IURC) on November 1, 2016. The IRP is our plan for meeting the future energy needs of our customers over the next 20 years with cost-effective, reliable, and sustainable supplies of electricity while addressing the inherent uncertainties and risks that exist in the electric utility industry.

Agenda: **All times are in CT*

Time (CT)	Topic
9:00 am	Welcome & Introductions Overview of Public Advisory Process Overview of NIPSCO Load Forecasting
10:30 am	*Break*
10:45 am	DSM Environmental Considerations
11:45 am	*Lunch*
12:30 pm	IRP Development
2:30 pm	Next Steps Closing

2016 IRP Public Advisory Meeting

May 5, 2016

NIPSCO

Agenda

Schedule	Agenda Item
9:00–9:15	Welcome and Introductions
9:15–9:30	Overview of Integrated Resource Plan (IRP) Process
9:30–10:00	Overview of NIPSCO
10:00–10:30	Customer Load Forecasting
10:30–10:45	Break
10:45–11:15	Demand Side Management (DSM)
11:15–11:45	Environmental Considerations
11:45–12:30	Lunch
12:30–2:30	IRP Development and Discussion
2:30–3:30	Public Advisory Feedback and Next Steps

Welcome and Introductions

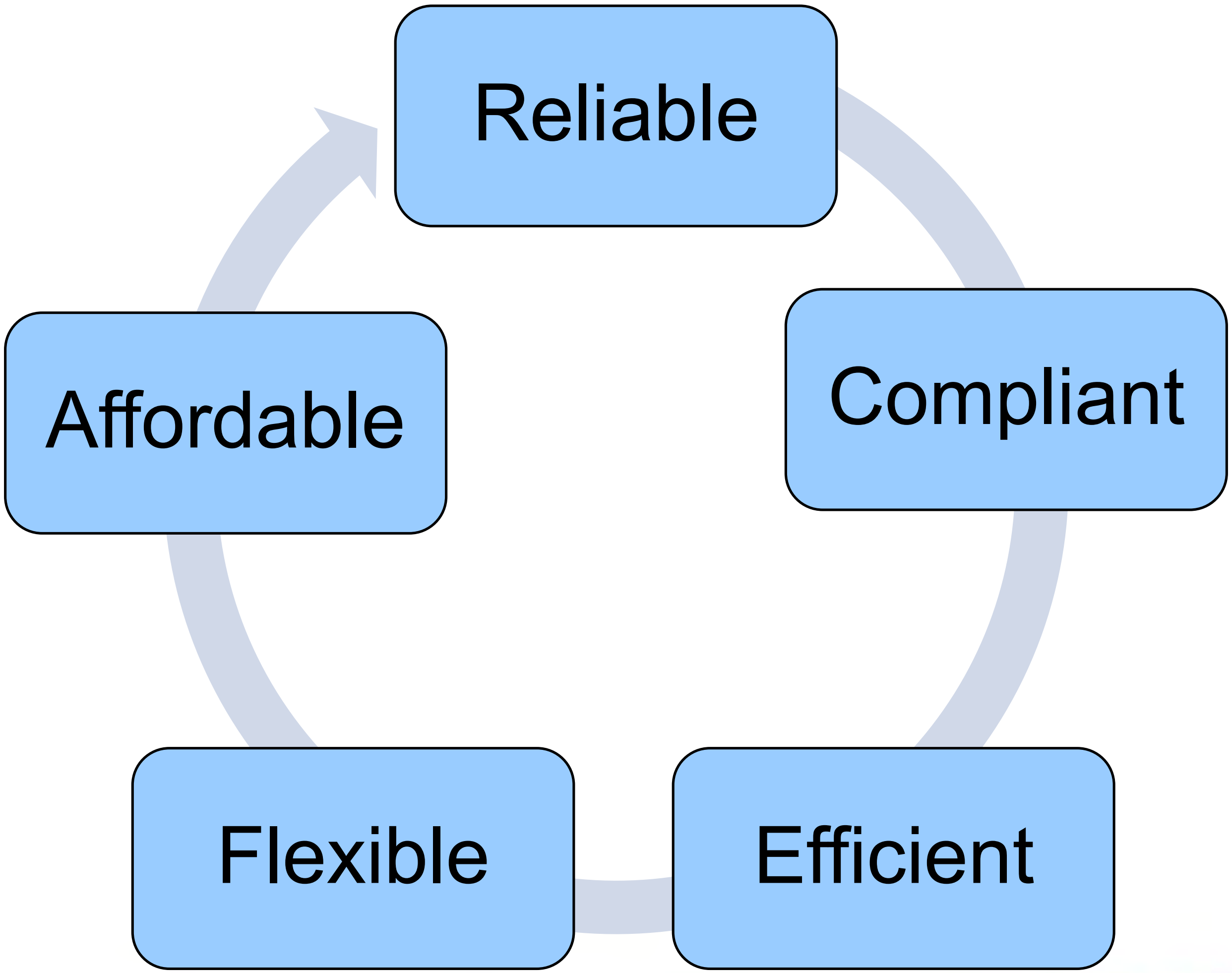
Presented by

Violet Sistovaris

Executive Vice President

Safety Message

Integrated Resource Plan Guiding Principles



Overview of the Public Advisory Process

Presented by

Dr. Marty Rozelle

The Rozelle Group Ltd

Overview Of Public Advisory Process

Objectives

- Enhance public involvement through multiple public advisory meetings
- Solicit relevant input for consideration in the development of the 2016 IRP
- Facilitate discussion on NIPSCO's IRP process

Timeline

Date	Activity	Location
May 5, 2016	- Public Advisory Meeting #1	Radisson Hotel – Star Plaza, Merrillville, IN
Jul 12, 2016	- Public Advisory Meeting #2	Radisson Hotel – Star Plaza, Merrillville, IN
Aug 2016	- Public Advisory Meeting #3	TBD
TBD	- Public Advisory Meeting #4	TBD
Aug–Oct 2016	- Develop IRP Report and Document Process - Monitor Business Conditions and Finalize the Plan	N/A
Oct 2016	- Submit IRP Document to the Indiana Utility Regulatory Commission (IURC)	N/A

NIPSCO Electric Business Overview

Presented by

Daniel Douglas

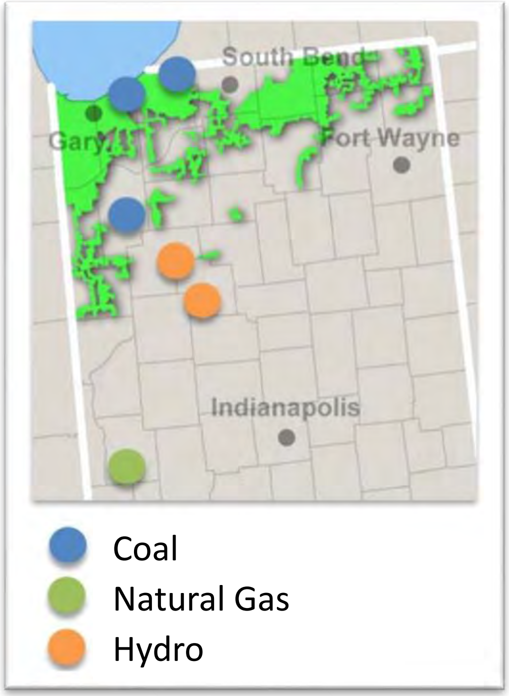
Executive Director, Corporate Strategy & Development

NIPSCO Electric Business

NIPSCO Electric Business

Electric Customer Count	~460,000
Major Industrial Customers	ArcelorMittal, Praxair, BP, US Steel, NLMK
Generation Capacity (MW)	3,405
2015 Internal Peak Load (MW)	3,050
Transmission System (miles)	2,800
Distribution System (miles)	10,000
Industrial Interruptible (MW)	530 (per Cause No. 44688)
2015 Residential Demand Savings (MW)	44
2015 Commercial & Industrial Demand Savings (MW)	20
Wind Feed-in-Tariff (MW)	1
Solar FIT (MW)	19
Biomass FIT (MW)	14

NIPSCO Electric Service Territory & Generation Assets



NIPSCO Generation Assets

Unit	Michigan City 12	Bailly 7	Bailly 8	Bailly 10	Schahfer 14	Schahfer 15	Schahfer 16A	Schahfer 16B	Schahfer 17	Schahfer 18	Norway	Oakdale	Sugar Creek CT 1A	Sugar Creek CT 1B	Sugar Creek SCST	Barton (PPA)	Buffalo Ridge (PPA)
Fuel	Coal	Coal	Coal	Natural Gas	Coal	Coal	Natural Gas	Natural Gas	Coal	Coal	Water	Water	Natural Gas	Natural Gas	Natural Gas	Wind	Wind
Capacity (MW)	469	160	320	31	431	472	78	77	361	361	4	6	152	154	229	50	50

Notes: Map excludes Peaker Capacity

2014 IRP Lessons Learned & Continuous Improvement Action Plan

2014 IRP Feedback	Continuous Improvement Action Plan
Enhance Stakeholder Process	- Participated in joint educational session with Indiana utility peers to develop foundational reference materials - Engaging stakeholders to obtain feedback on IRP analysis and future world alternatives
Improve Load Forecasting Process	- Clarify the detailed narrative and load forecast enhancements
Clarify DSM Modeling	- Provide DSM development and modeling methodology detail
Expand Scenarios and Sensitivities	- Develop a robust set of scenarios and sensitivities to capture a wider range of potential risks/uncertainties - Increase emphasis on environmental rules and regulations
Address Customer-owned and Distributed Generation	- Evaluate distributed generation and Combined Heat & Power
Provide Confidential Data Proxies	- Reduce use of confidential data and use public/representative proxy data as substitute for proprietary data

NIPSCO

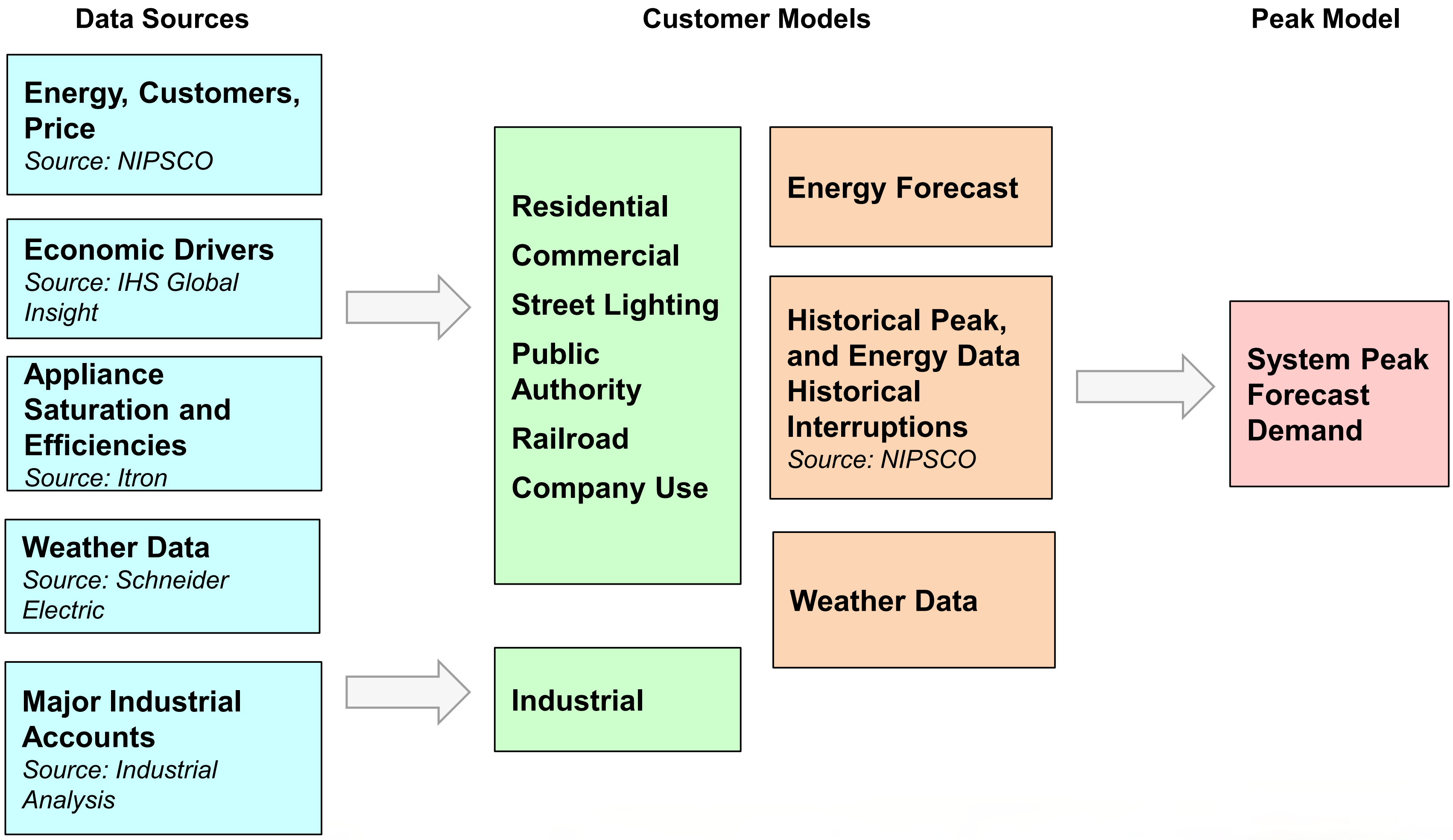
Long-Term Energy and Demand Forecast

Presented by

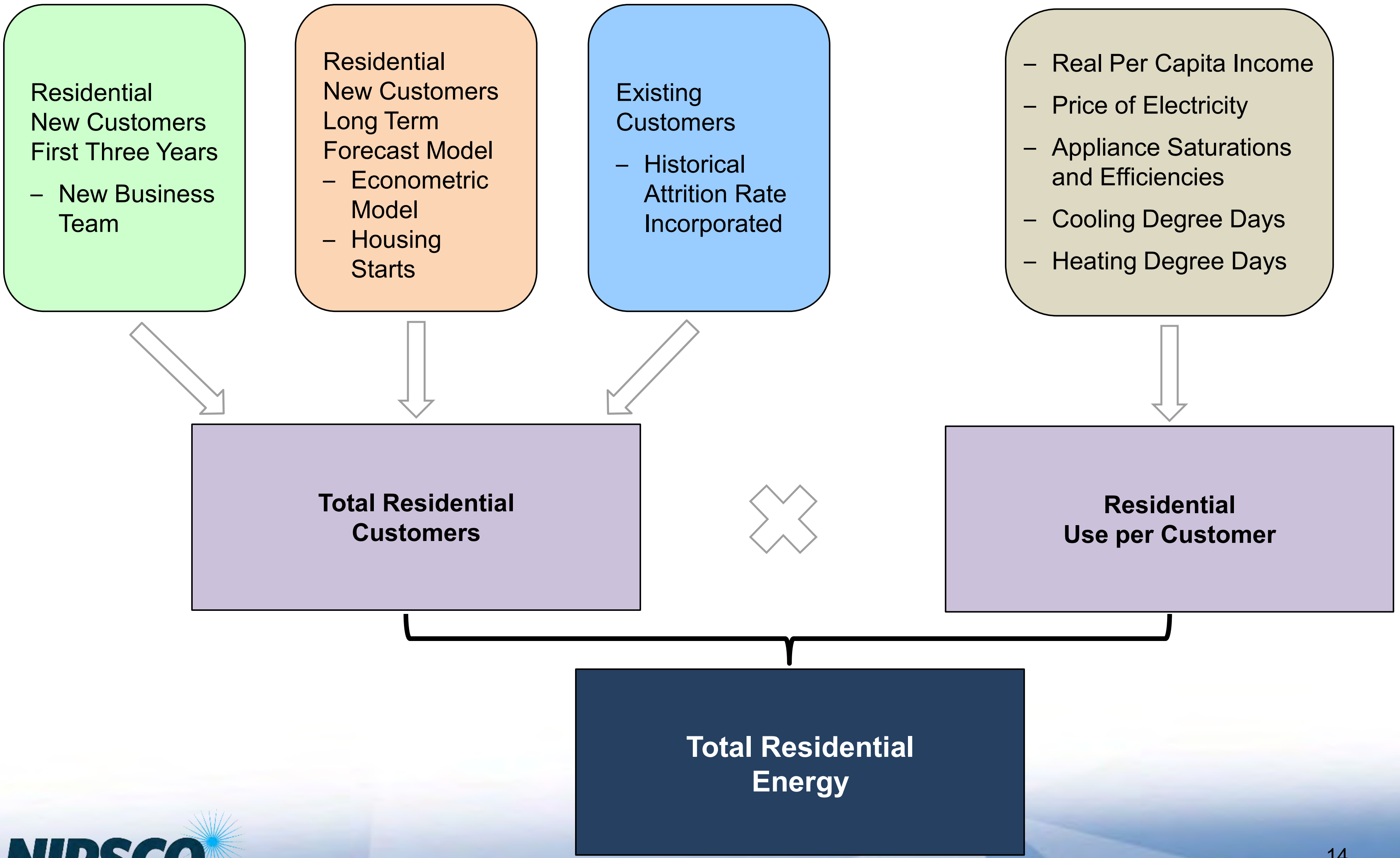
Amy Efland

Lead Forecasting Analyst

Load Forecasting Process

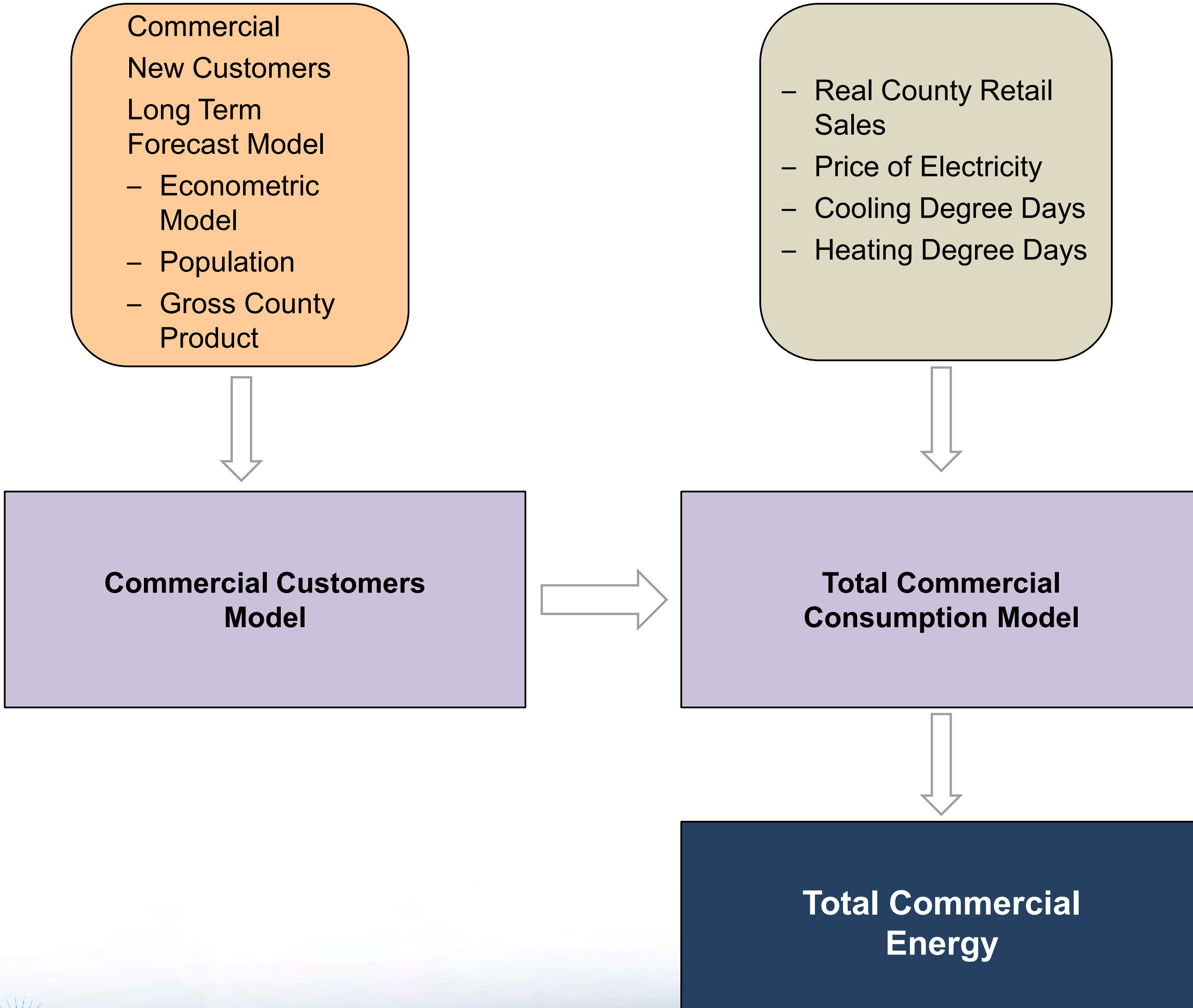


Residential Energy Forecast



NIPSCO

Commercial Energy Forecast



Industrial Energy Forecast

- Individual Discussions with the Largest Industrial Customers
- Represents Approximately 80% of the Industrial Load

- Recent Historical Industrial Sales Trends
- Regional and Global Trends for Specific Industries
- Represents the Remaining 20% of the Industrial Load

Total Industrial Energy

"Other" Energy Forecast

- Recent Historical Data
- Anticipated Future Trends

Public Authority
Railroad
Company Use

- Econometric Approach
- Number of Hours of Dark
- Anticipated Future Trends

Street Lighting

Total "Other" Energy

Peak Forecast

- Cooling Degree Hour
- Heating Degree Hour
- Relative Humidity at the Time of Peak
- Load Factor
- Residential, Commercial, and Industrial Energy Use

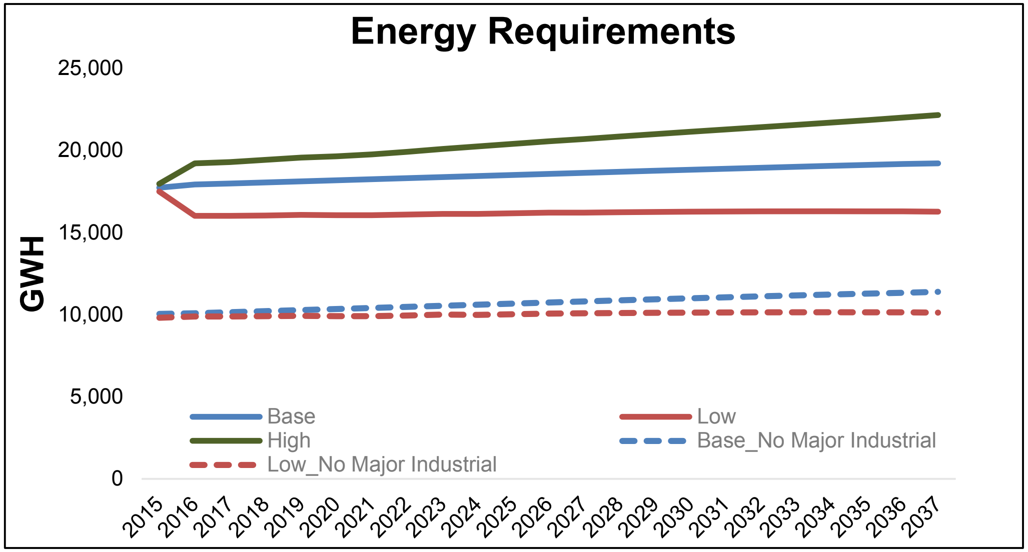
↓

Total Peak Forecast

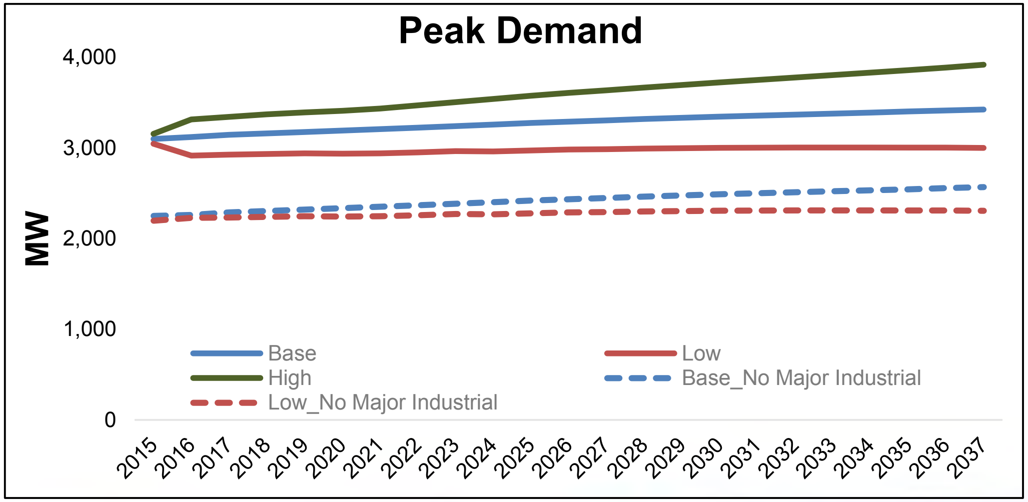
NIPSCO peak model is a function of the weather at peak hour and the composition and level of load for:

- Residential class
- Commercial class
- Industrial class

Load Forecasts



Energy Requirement Projections	2016-2037 CAGR
Base	0.33%
Low	0.08%
High	0.68%
Base-No Major Industrial	0.58%
Low-No Major Industrial	0.12%



Peak Demand Projections	2016-2037 CAGR
Base	0.45%
Low	0.14%
High	0.80%
Base-No Major Industrial	0.60%
Low-No Major Industrial	0.16%

Notes: Compound Annual Growth Rate (CAGR)

Demand Side Resources

Presented by

Alison Becker

Manager Regulatory Policy

Demand Side Management Process

1 Potential ☑
- Study
- Customers
- Savings
- Costs
- Groupings

2 Benefit ☑
- *DSMore*
- Standard Tests
- Cost-Effective

3 Supply & Demand ☑
- IRP
- NIPSCO Resource Portfolio
- Cost-Effective Portfolio

4 Implementation ☑
- Request For Proposal
- Programs
- Vendors
- EM&V

Existing Demand Side Resources

Residential

- Heating Ventilation and Air Conditioning (HVAC) Rebates
- Residential Lighting Program
- Home Energy Analysis (HEA)
- Appliance Recycling
- Low Income Appliance Replacement
- School Education
- Behavioral
- Income Qualified Weatherization

Commercial & Industrial

- Prescriptive Program
- Custom Program
- New Construction Program
- Small Business Direct Install Program
- Retro-Commissioning Program

Demand Response

- Industrial Interruptible

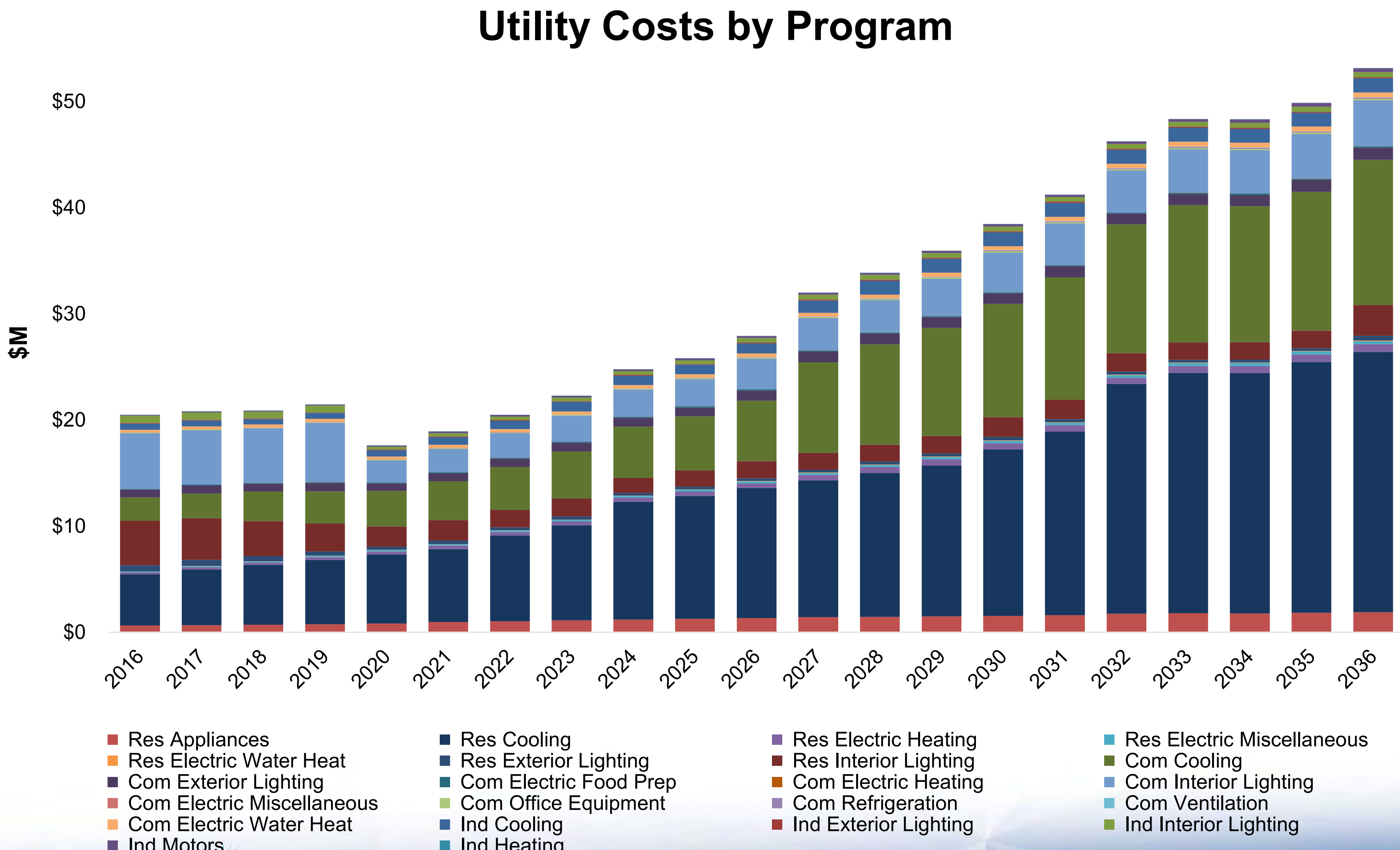
Selectable Future Groupings

Energy Efficiency (EE)		
Residential Program Groupings	**Commercial Program Groupings**	**Industrial Program Groupings**
Appliances	Cooling	Cooling
Cooling	Exterior Lighting	Exterior Lighting
Heating	Food Preparation	Interior Lighting
Miscellaneous	Heating	Motors
Exterior Lighting	Interior Lighting	Ventilation
Interior Lighting	Miscellaneous	
Water Heating	Refrigeration	
	Ventilation	
	Water Heating	
	Office Equipment	

Demand Response (DR)	
Residential DR Program	**Commercial DR Program**
Water Heating	Water Heating
Air Conditioning	Air Conditioning

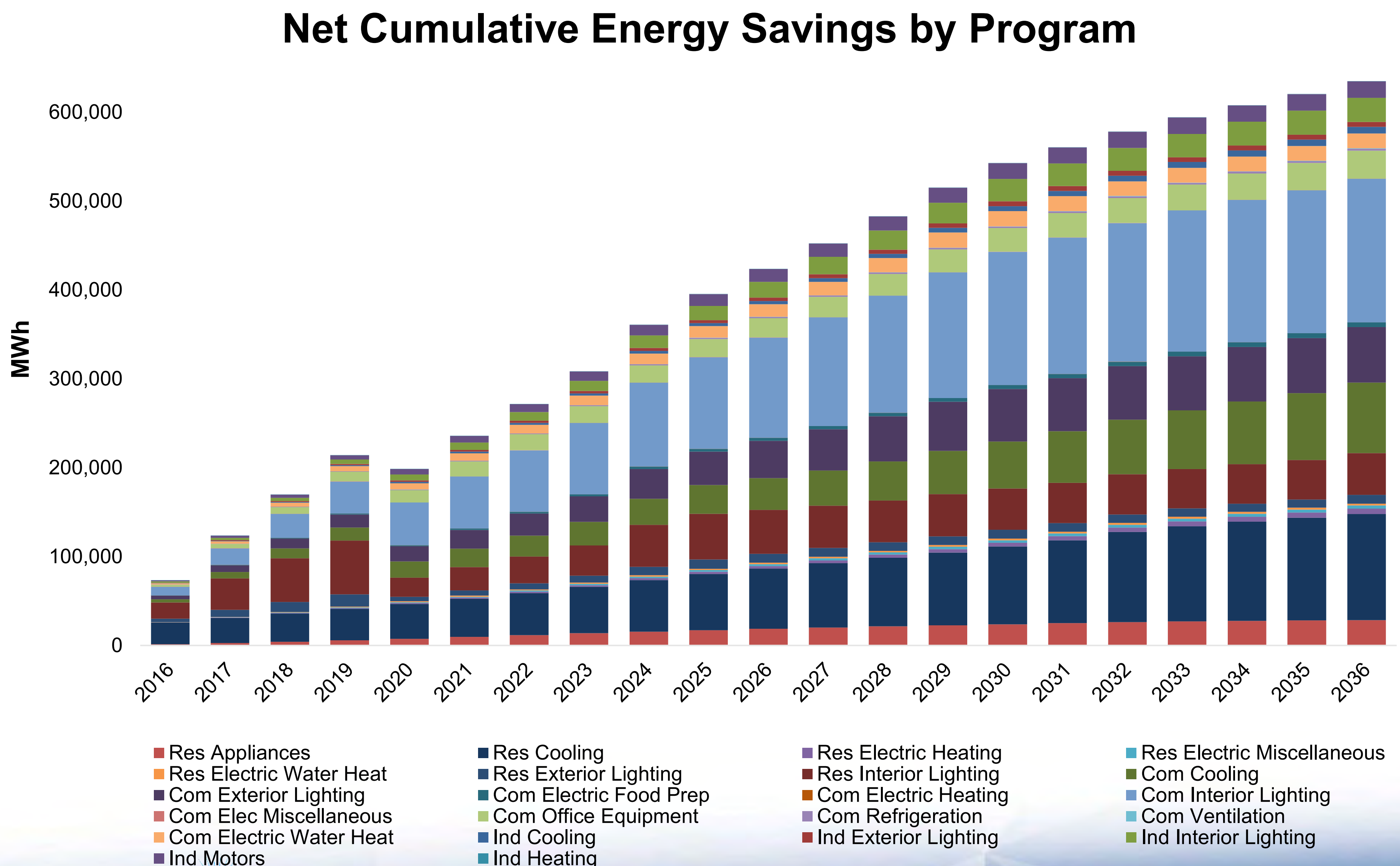
NIPSCO

Utility Program Costs

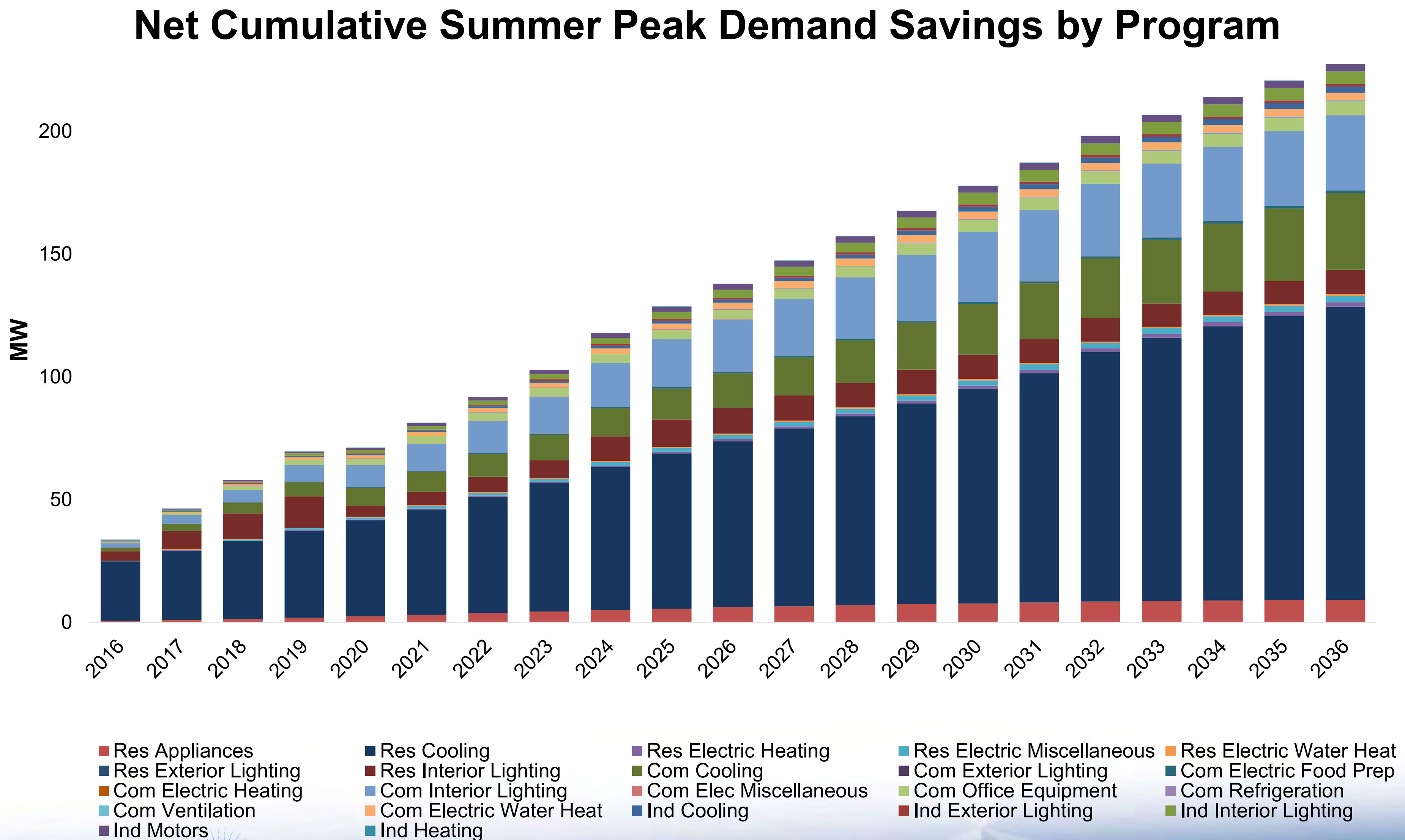


Note: Costs are not present value costs

Energy Savings



Demand Savings



Environmental Considerations

Presented by

Kelly Carmichael

Vice President Environmental

Environmental Considerations

- **Clean Water Act 316(b) Cooling Water Intake Structures**
  - Requires all large existing steam electric generating stations with cooling water intake structures to deploy the best technology available to minimize adverse environmental impacts to fish and shellfish
- **Electric Steam Power Effluent Limitation Guidelines (ELG)**
  - Regulates wastewater stream processes and byproducts associated with steam electric power generation including ash handling water and flue gas desulfurization (FGD) wastewater

Environmental Considerations (Cont.)

- **Coal Combustion Residuals (CCR)**
  - Rule criteria that may require storage, treatment and disposal units to modify or cease CCR receipt based on:
    - Structural integrity requirements
    - Impact to groundwater
    - Locational requirements
- **National Ambient Air Quality Standards (Ozone NAAQS)**
  - The ozone standard has been lowered from 75 parts per billion to 70 parts per billion
  - Further lowering of standard is possible

NIPSCO

Environmental Considerations (Cont.)

- **Cross State Air Pollution Rule (CSAPR)**
  - Reduces overall emissions of sulfur dioxide (SO_2) and Nitrogen Oxides (NOx) by setting state-wide caps on power plant emissions
  - Allowance allocations may continue to be updated as standards are lowered
  - Draft revisions to CSAPR currently proposed by EPA
- **Clean Power Plan (CPP)**
  - Regulates carbon dioxide (CO_2) emissions from existing fossil-fuel fired electric generating units under the Clean Air Act
  - CPP establishes national CO_2 emission standards that are applied to each state's mix of affected electric generating units likely in the form of state-specific emission rate or mass emission limits

NIPSCO

Environmental Considerations (Cont.)

	CCR	ELG
Effective	October 17, 2015	January 4, 2016
Purpose	Establishes storage and disposal requirements for CCRs	Establishes discharge and disposal limits for wastewaters
Regulated	CCRs from bottom ash, boiler slag, fly ash and certain FGD solids	Wastewater streams associated with bottom ash, boiler slag, FGD, fly ash, flue gas mercury control waste, landfill leachate, and non-chemical metal cleaning waste
Compliance Timing	Multiple rule requirements each with its own compliance date; Earliest unit cease receipt of CCRs October 2018 or 2023 if unit is retired	Between November 1, 2018 and December 31, 2023
Enforcement	Self Implementing	Indiana Department of Environmental Management - National Pollutant Discharge Elimination System

NIPSCO

Environmental Compliance Cost Estimates ($M)

	ELG	CCR	316(b)	Ozone	Total Compliance Costs
Bailly (2023 Retirement)	$ 0	$5 - 7	$ 0	$ 0	$5 - 7
Bailly (No Retirement)	$189 - 265	$53 - 74	$32-40	$ 0	$274 - 379
Michigan City	$1 - 2	$40 - 55	$ 0	$ 0	$41 - 57
Schahfer	$224 - 313	$85 - 120	$ 0	$0 - 325	$309 - 758
Total (Bailly Retirement)	**$225 - 315**	**$130 - 182**	**$ 0**	**$0 - 325**	**$355 - 822**
Total (No Retirement)	**$414 - 580**	**$178 - 249**	**$32 - 40**	**$0 - 325**	**$624 - 1,195**

Mass-Based Allocation Based On CPP Federal Implementation Plan

INDIANA

Compliance Periods	Indiana Mass Emissions Cap	Renewable Energy Set Aside	Output-Based Set Aside	Clean Energy Incentive Program Set Aside	Total Allowances Distributed to Utilities
Interim Step 1 Period 2022-2024	92,010,787	4,600,539	0	5,754,076	**81,656,172**
Interim Step 2 Period 2025-2027	83,700,336	4,185,017	1,106,150	0	**78,409,169**
Interim Step 3 Period 2028-2029	78,901,574	3,945,079	1,106,150	0	**73,850,345**
Finial Period 2030-2031, 32-33, etc.	76,113,835	3,805,692	1,106,150	0	**71,201,993**

NIPSCO

Compliance Periods	Bailly Allowances	Michigan City Allowances	Schahfer Allowances	Sugar Creek Allowances	Total NIPSCO Allowances*
Interim Step 1 Period 2022-2024	1,481,933	1,771,796	5,390,361	1,620,081	**10,264,170**
Interim Step 2 Period 2025-2027	1,423,005	1,701,342	5,176,017	1,555,659	**9,856,023**
Interim Step 3 Period 2028-2029	1,340,269	1,602,423	4,875,076	1,465,211	**9,282,979**
Finial Period 2030-2031, 32-33, etc.	1,292,206	1,544,959	4,700,251	1,412,667	**8,950,081**

NIPSCO

Notes: All units are in annual average short tons of CO_2
* Additional allowances available from renewable, output based and clean energy set-asides

Lunch

IRP Development

Presented by

Edward Achaab

Manager Resource Planning

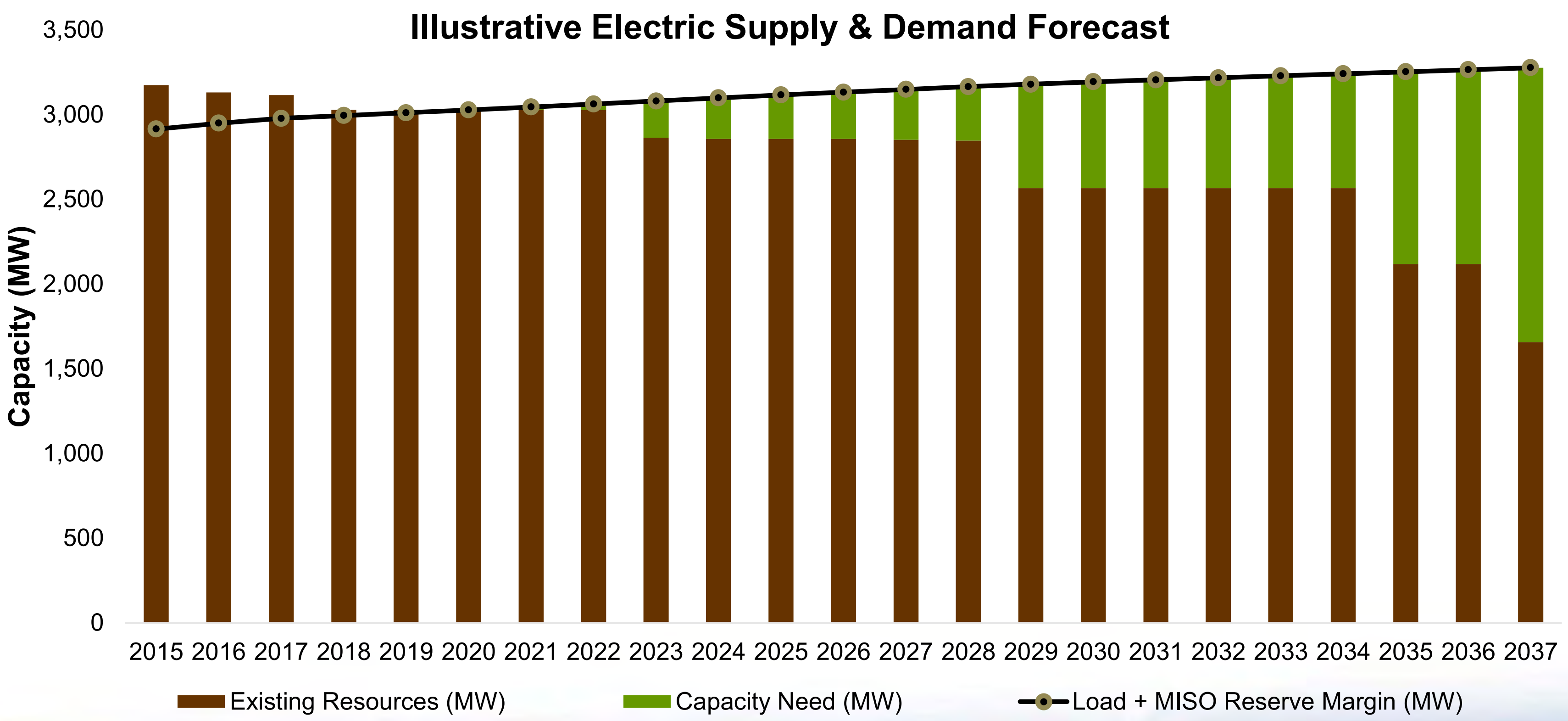
IRP Is About "Matching Supply And Demand"

Step1
Gather data, develop input assumptions, screen technologies, and create scenarios

Step 2
Develop portfolios, deploy planning strategies to assess various options

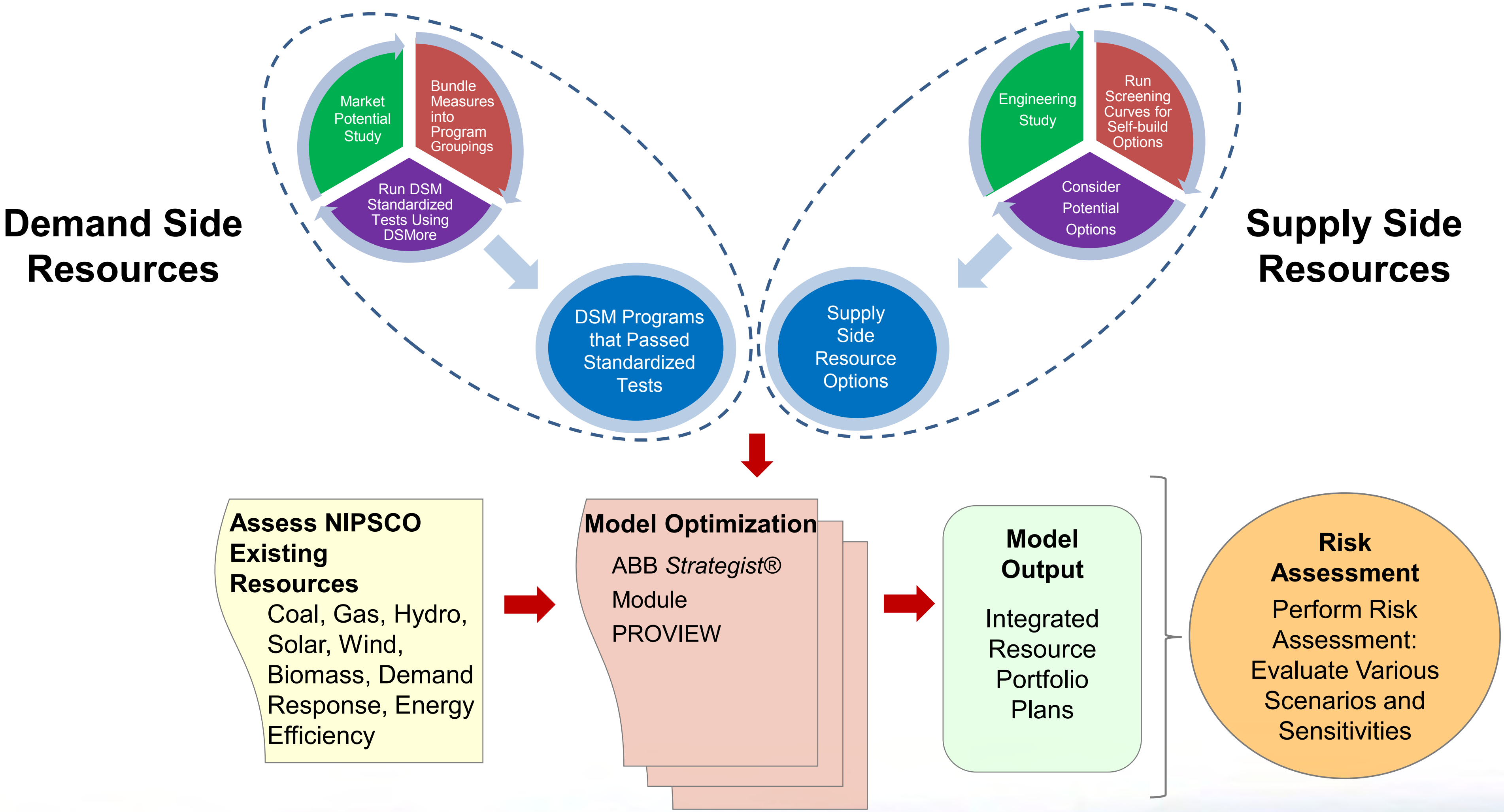
Step 3
Analyze portfolios, assess risks, and select the preferred plan

Step 4
Develop IRP report and submit report by November 1, 2016



NIPSCO

Resource Modeling Optimization



Future Resource Options

Options	Sources
• Conventional Technology • Renewable Technology • Distributed Generation (DG) Technology	Engineering Study by Sargent & Lundy (S&L)
• Demand Side Energy Efficiency • Demand Response	Market Potential Study by Applied Energy Group (AEG)

Screening Criteria For Future Supply Side Options

- Energy Source Availability
- Technical Feasibility
- Commercial Availability
- Economically Attractive
- Environmental Compatibility

Future Supply Side Resources

Conventional Resources

Coal
- Integrated Gasification Combined Cycle
- Circulating Fluidized Bed
- Supercritical Pulverized Coal

Gas
- Combustion Turbine
- Combined Cycle Combustion Turbine (CCGT)
- Coal to Gas Conversion

Nuclear
- Small Module Reactor
- Advanced Pressurized Water Reactor

Renewable & Emerging Resources

Wind
- Onshore – Utility Scale
- Offshore – Utility Scale
- Onshore – DG

Solar
- Photovoltaic – Utility Scale
- Photovoltaic – DG

Other
- Combined Heat & Power
- Battery Storage
- Microturbines
- Biomass
- Reciprocating Engine

New Resource Costs

Illustrative

Technology	Size (MW)	Variable O&M ($/MWh)	Fixed O&M ($/kW/yr)	Total Overnight Cost in 2014[1] ($/kW)
Scrubbed Coal New	1,300	4.47	31.16	2,917
Coal-Gasification Integrated Combined Cycle (IGCC)	1,200	7.22	51.37	3,727
Advanced Gas/Oil Combined Cycle (CC)	400	3.27	15.36	1,017
Advanced Combustion Turbine	210	10.37	7.04	671
Advanced Nuclear	2,234	2.14	93.23	5,366
Distributed Generation-Base	2	7.75	17.44	1,477
Distributed Generation - Peak	1	7.75	17.44	1,774
Biomass	50	5.26	105.58	3,659
Wind	100	0	39.53	1,980
Wind Offshore	400	0	73.96	6,154
Photovoltaic[2,3]	150	0	24.68	3,279

Sources and notes: EIA Annual Energy Outlook 2015; All costs in 2013 $; [1]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded; These represent costs of new projects initiated in 2014; [2]Capital costs are shown before investment tax credits are applied; [3]Costs and capacities are expressed in terms of net AC power available to the grid for the installed capacity

Scenario Vs. Sensitivity

A **scenario** is a simulation of a future world described in terms of a technical, regulatory, and load environment, as well as fuel costs, capital costs, economic drivers, customer-owned resources

A **sensitivity** is a case run against a specific scenario varying one element, such as fuel prices

NIPSCO

Sources and notes: Definitions adapted from *Electricity Director's Final Report 2014-2015 Integrated Resources Plans*, IURC, p. 9; Varying one "element" of a scenario to create a sensitivity may require changes to multiple variables to ensure that input data are properly correlated; For example, a low gas price sensitivity also requires correlated (lower) electricity prices

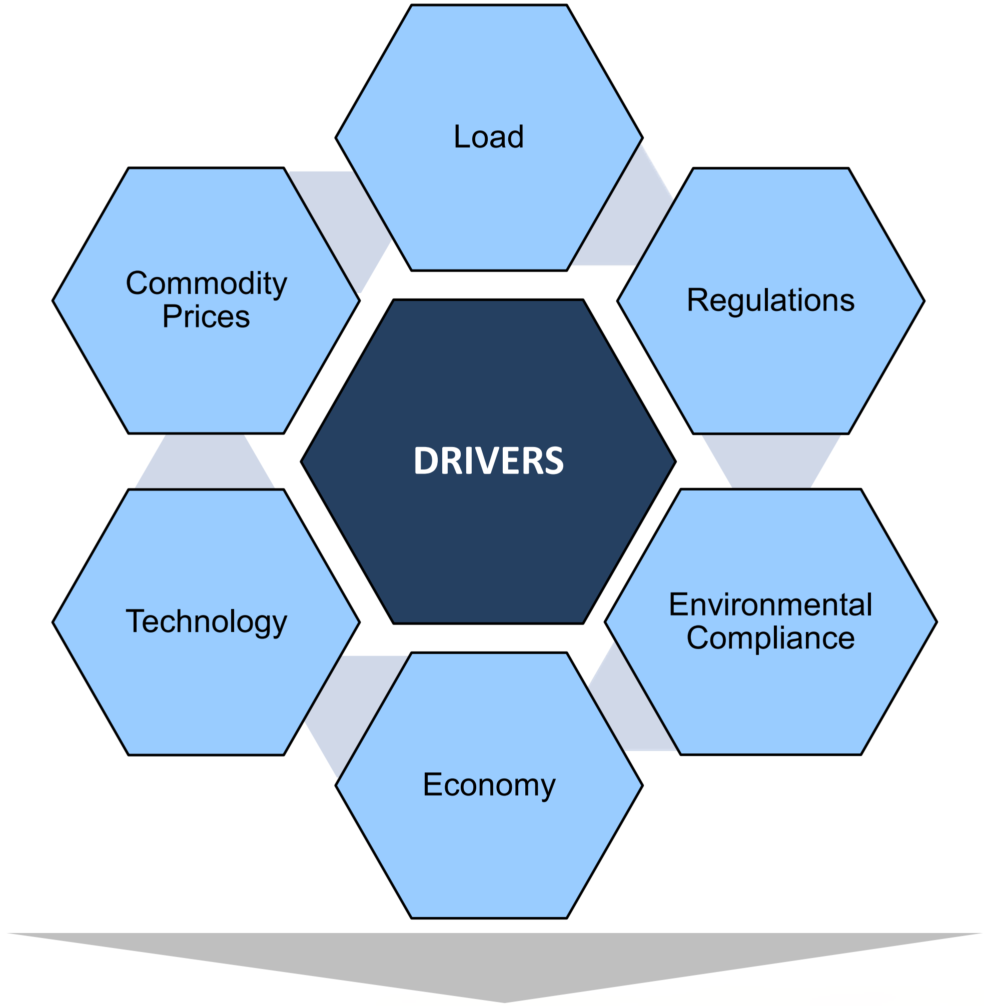
NIPSCO's Scenarios Building Process

1. Identify highest impact risks/uncertainties
2. Imagine possible futures
3. Design scenarios
4. Analyze the diversity and robustness of scenarios

- Scenario-building is an iterative process of creating and consolidating different possibilities
- NIPSCO identifies risks/uncertainties that could potentially affect its business environment
- The list of uncertainties becomes a set of building blocks that guides NIPSCO in thinking about possible futures
- NIPSCO develops narratives to describe the possible futures
- The list of possible futures is grouped by common "theme" or scenario
- Candidate scenarios are assessed for diversity and robustness

NIPSCO's Goal Is To Utilize A Well Designed And Robust Set Of Scenarios

Risks And Uncertainties



These Drivers Form The Foundation Of NIPSCO's Scenarios

Scenarios And Sensitivities

Scenarios	**Base**	**Challenged Economy**	**Aggressive Environmental Regulation**	**Booming Economy**
Sensitivities	No CO_2 Price	No CO_2 Price	High Renewables & Increasing Load	No CO_2 Price
	Low Load	No Major Industrial Load	High Renewables & Decreasing Load	No Major Industrial Load
	High Gas Price			
	No Major Industrial Load			

Sources and Notes: Definitions adapted from *Electricity Director's Final Report 2014-2015 Integrated Resources Plans*, IURC, p. 9; Varying one "element" of a scenario to create a sensitivity may require changes to multiple variables to ensure that input data are properly correlated; For example, a low gas price sensitivity also requires correlated (lower) electricity prices

NIPSCO

Base Scenario And Sensitivities

Base

Base Scenario

- The scenario NIPSCO considers most likely to occur
- Economy (national, regional, and local) continues to recover
- Load growth slowly increases
- National Carbon Policy effective 2023
- Natural gas supplies from Appalachia remain strong
- Non-carbon environmental compliance costs reflect only current and proposed regulations, including CSAPR, ELG, CCR, and 316(b)

Sensitivities	Descriptions
No CO_2 Price	- National Carbon Policy is not effected and no carbon price is modeled - Natural gas and power prices reflect a broader energy market not subject to carbon policy
Low Load	- Load is lower over the study period
High Gas Price	- Natural gas and on-peak power prices are higher - Environmental compliance costs are higher
No Major Industrial Load	- Load is significantly lower due to the loss of major industrial load

Challenged Economy Scenario And Sensitivities

Challenged Economy

Challenged Economy Scenario

- Economic downturn with growth stalling
- Customer load growth stagnates, but no major industrial customer loss
- National Carbon Policy effective 2023
- Reduced demand for natural gas and coal
- Non-carbon environmental compliance costs reflect only current and proposed regulations

Sensitivities	Descriptions
No CO_2 Price	- National Carbon Policy is not effected and no carbon price is modeled - Natural gas and power prices reflect a broader energy market not subject to carbon policy
No Major Industrial Load	- Load is significantly lower over the study period due to the loss of major industrial load

NIPSCO

Aggressive Environmental Regulation Scenario And Sensitivities

Aggressive Environmental Regulation

Aggressive Environmental Regulation Scenario

- Environmental regulations are more stringent than currently anticipated for both power generation and natural gas production (hydraulic fracturing)
- Non-carbon environmental compliance costs are higher than the Base Scenario
- Stricter National Carbon Policy effective 2023
- More stringent regulations placed on coal production

Sensitivities	Descriptions
High Renewables and Increasing Load	- Indiana's voluntary renewable portfolio standard (RPS) becomes mandatory - Natural gas and power prices reflect the mandatory RPS and higher CO_2 price - Load is greater over the study period
High Renewables and Decreasing Load	- Indiana's voluntary renewable portfolio standard (RPS) becomes mandatory - Natural gas and power prices reflect the mandatory RPS and higher CO_2 price - Load is lower over the study period

NIPSCO

Booming Economy Scenario And Sensitivities

Booming Economy

Booming Economy Scenario

- Economic growth is greater than expected
- State and national regulators introduce more stringent environmental regulations with reduced risk of negatively impacting economic growth, but compliance costs increase
- More aggressive regulatory environment leads to higher natural gas and coal production costs
- National Carbon Policy effective 2023
- Non-carbon environmental compliance costs are higher than the Base scenario

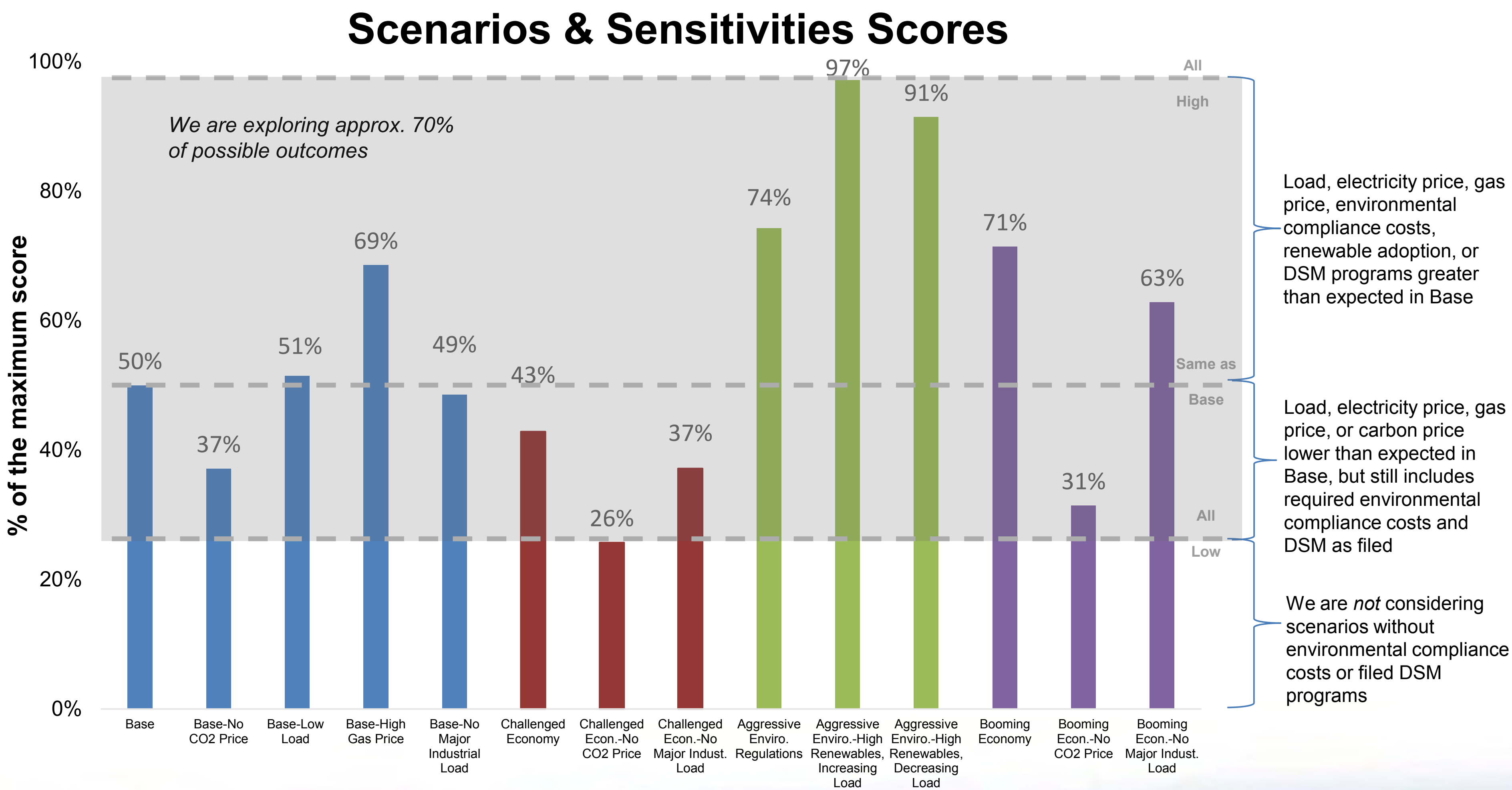
Sensitivities	Descriptions
No CO_2 Price	- The National Carbon Policy is not effected and non-carbon regulations are same as Base case - Natural gas and power prices reflect a broader energy market not subject to the carbon legislation
No Major Industrial Load	- Load is significantly lower due to loss of major load over the study period

NIPSCO

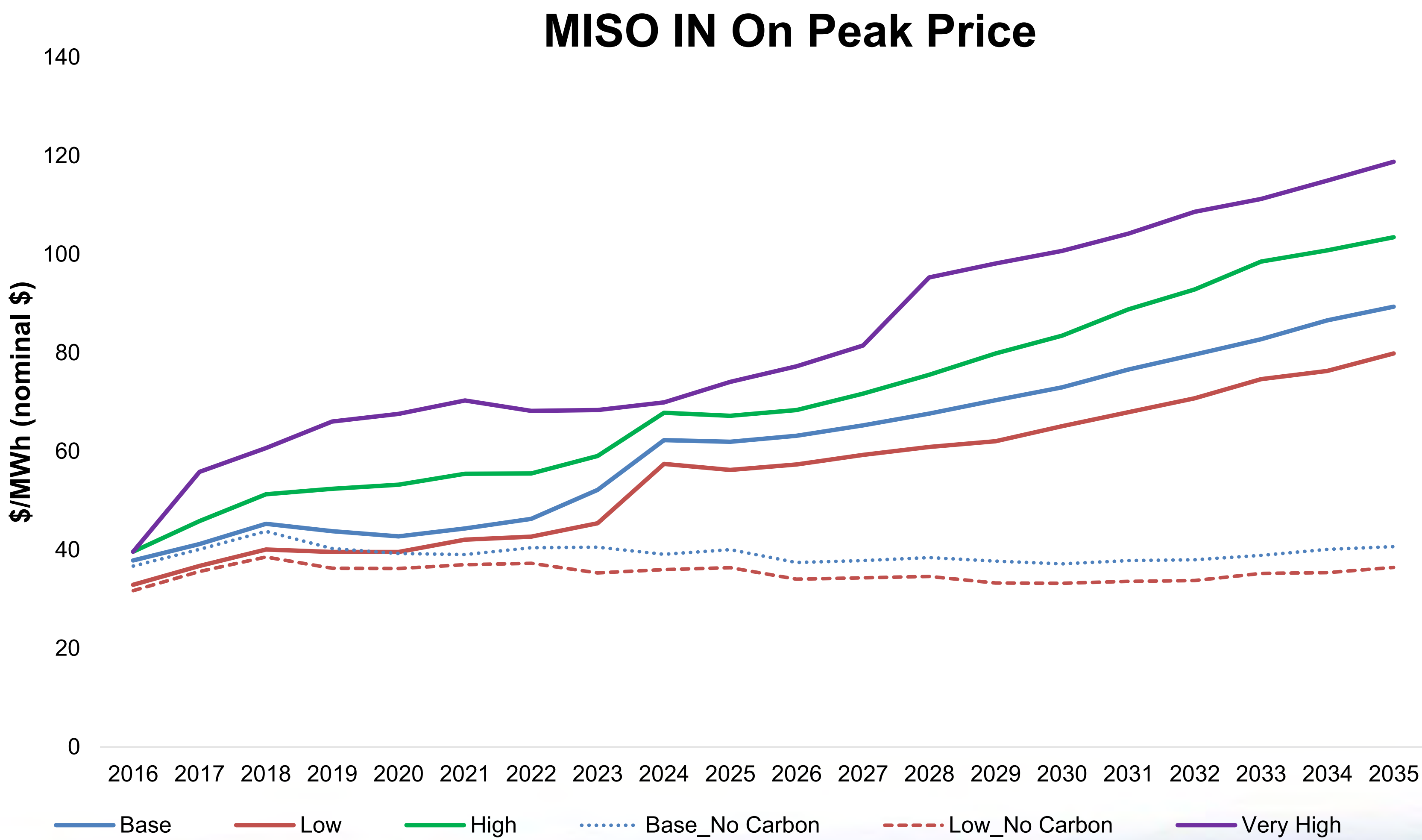
Scenarios And Sensitivities Variables Descriptions

Scenarios & Sensitivities	NIPSCO Load	CO_2 Price	Natural Gas Price	Power Price	DSM	RPS	Enviro. Compliance Costs
Base	**Base Load**	**Y**	**Base**	**Base**	**Base**	**N**	**Base**
No CO_2 Price	Base Load	N	Base No CO_2	Base No CO_2	Low	N	Base
Low Load	Low Load	Y	Base	Base	Base	N	Base
High Gas Price	Base Load	Y	High	High	High	N	High
No Major Industrial Load	Base, No Major Indust.	Y	Base	Base	Base	N	Base
Challenged Economy	**Low Load**	**Y**	**Low**	**Low**	**Low**	**N**	**Base**
No CO_2 Price	Low Load	N	Low No CO_2	Low No CO_2	Very Low	N	Base
No Major Industrial Load	Low, No Major Indust.	Y	Low	Low	Low	N	Base
Aggressive Environmental Regulation	**Base Load**	**Y**	**High**	**High**	**High**	**N**	**High**
High Renewables & Increasing Load	High Load	Y	Very High	Very High	Very High	Y	High
High Renewables & Decreasing Load	Low Load	Y	Very High	Very High	Very High	Y	High
Booming Economy	**High Load**	**Y**	**High**	**High**	**High**	**N**	**High**
No CO_2 Price	High Load	N	Low no CO_2	Low no CO_2	Very Low	N	Base
No Major Industrial Load	Base, No Major Indust.	Y	High	High	High	N	High

Scenario Variable Diversity Analysis

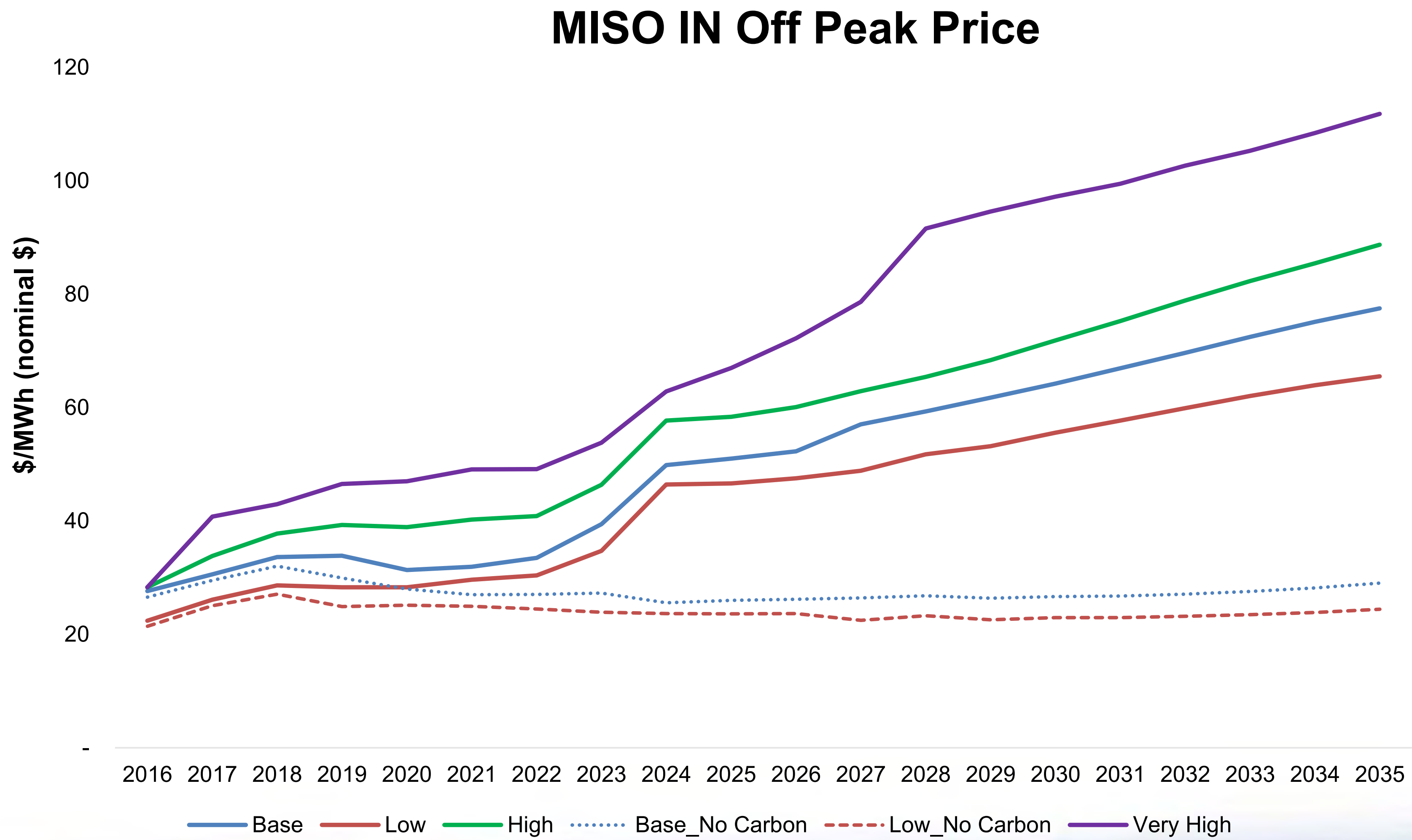


On-Peak Electricity Price Forecast



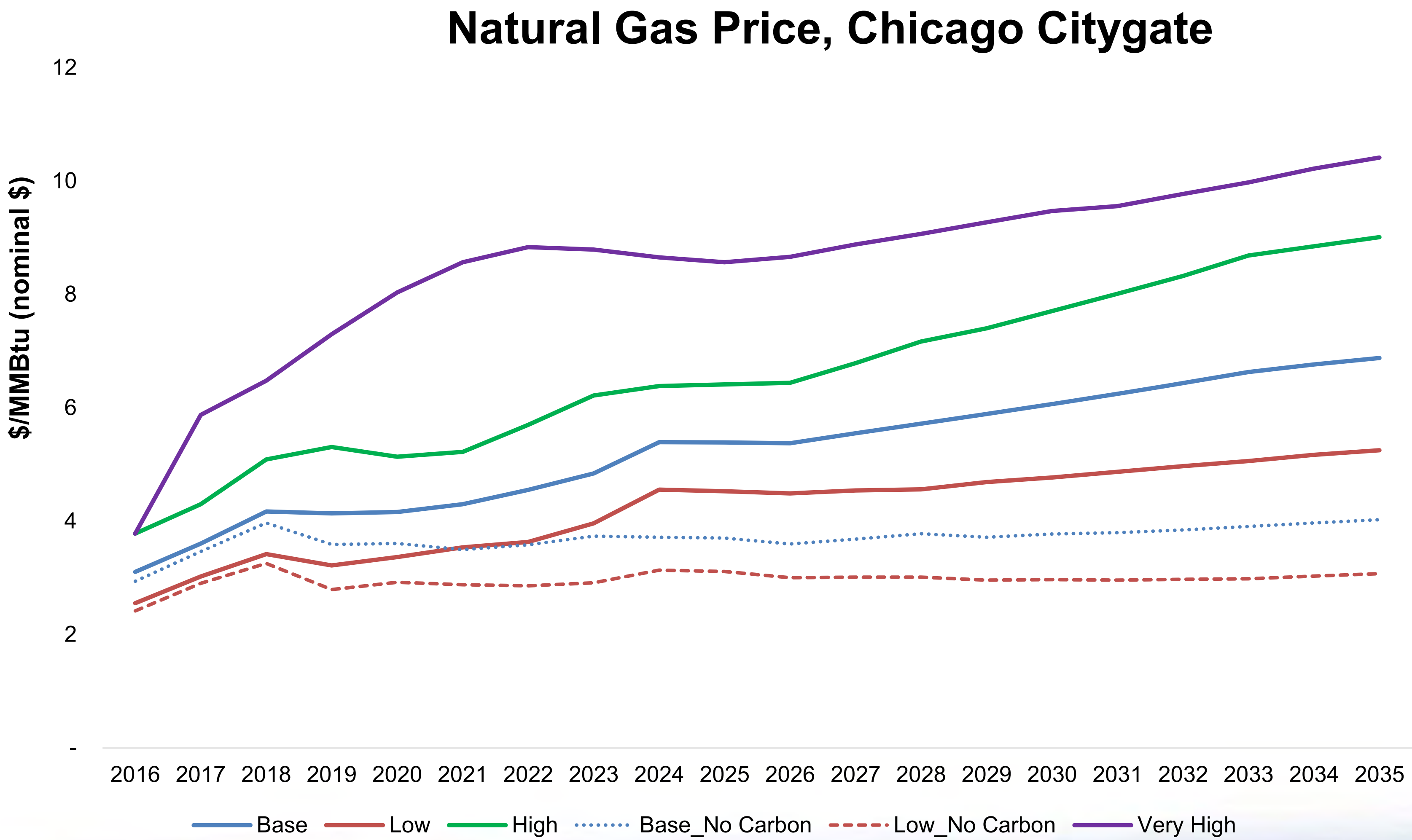
Source: PIRA Energy Group, NiSource Requested Scenarios 2016

Off-Peak Electricity Price Forecast



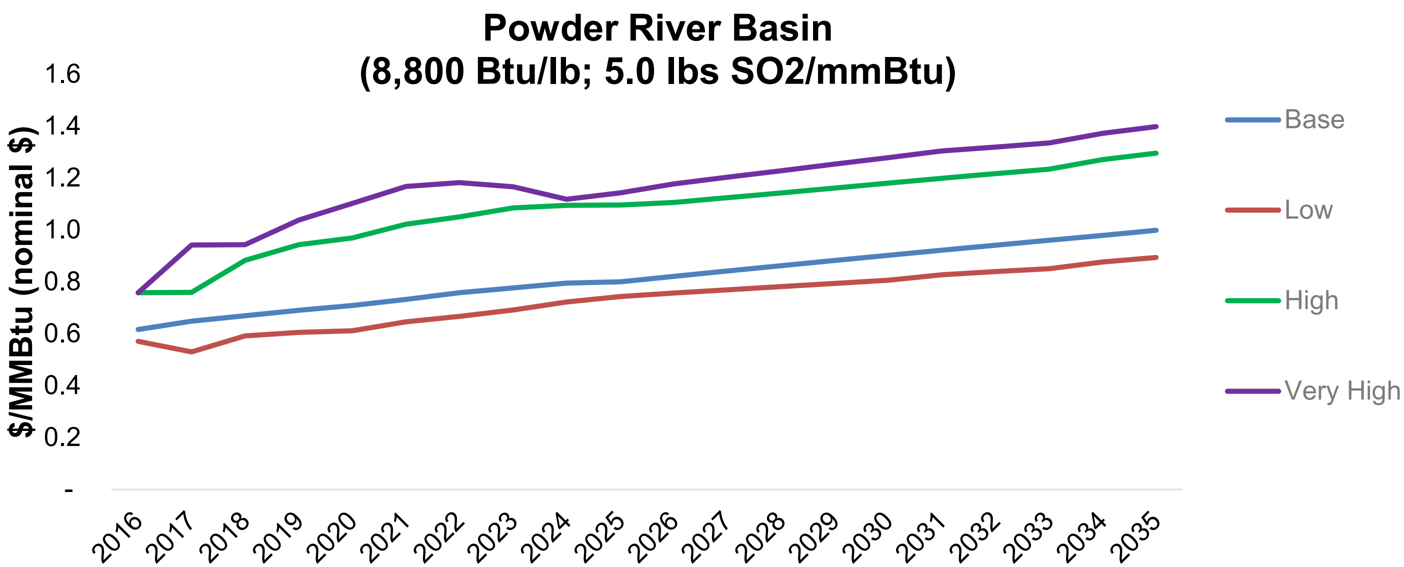
Source: PIRA Energy Group, NiSource Requested Scenarios 2016

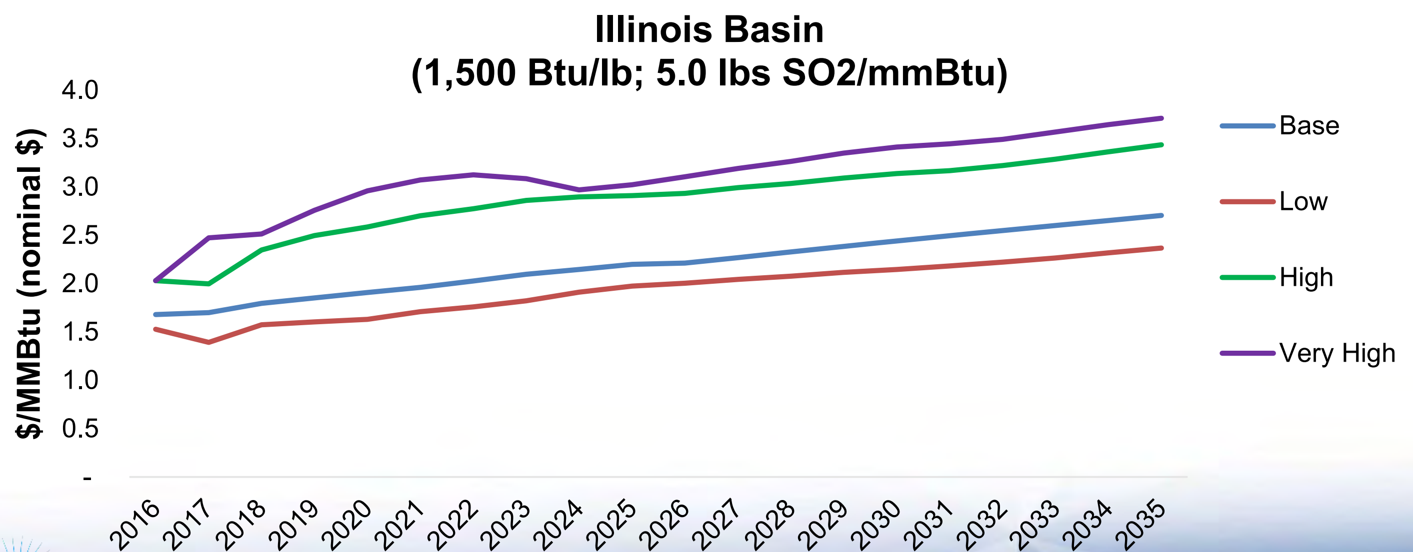
Natural Gas Price Forecast



Source: PIRA Energy Group, NiSource Requested Scenarios 2016

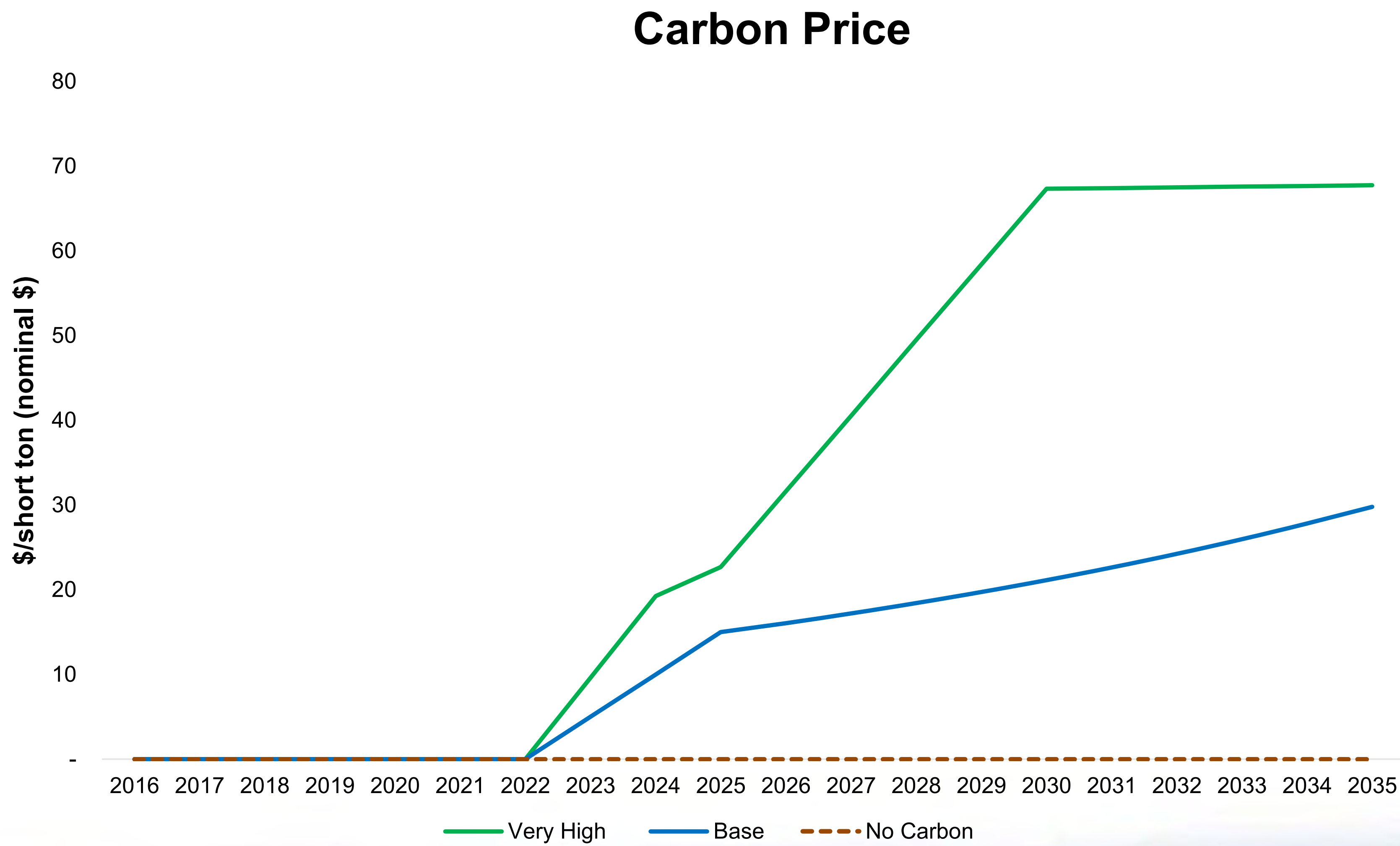
Coal Price Forecast





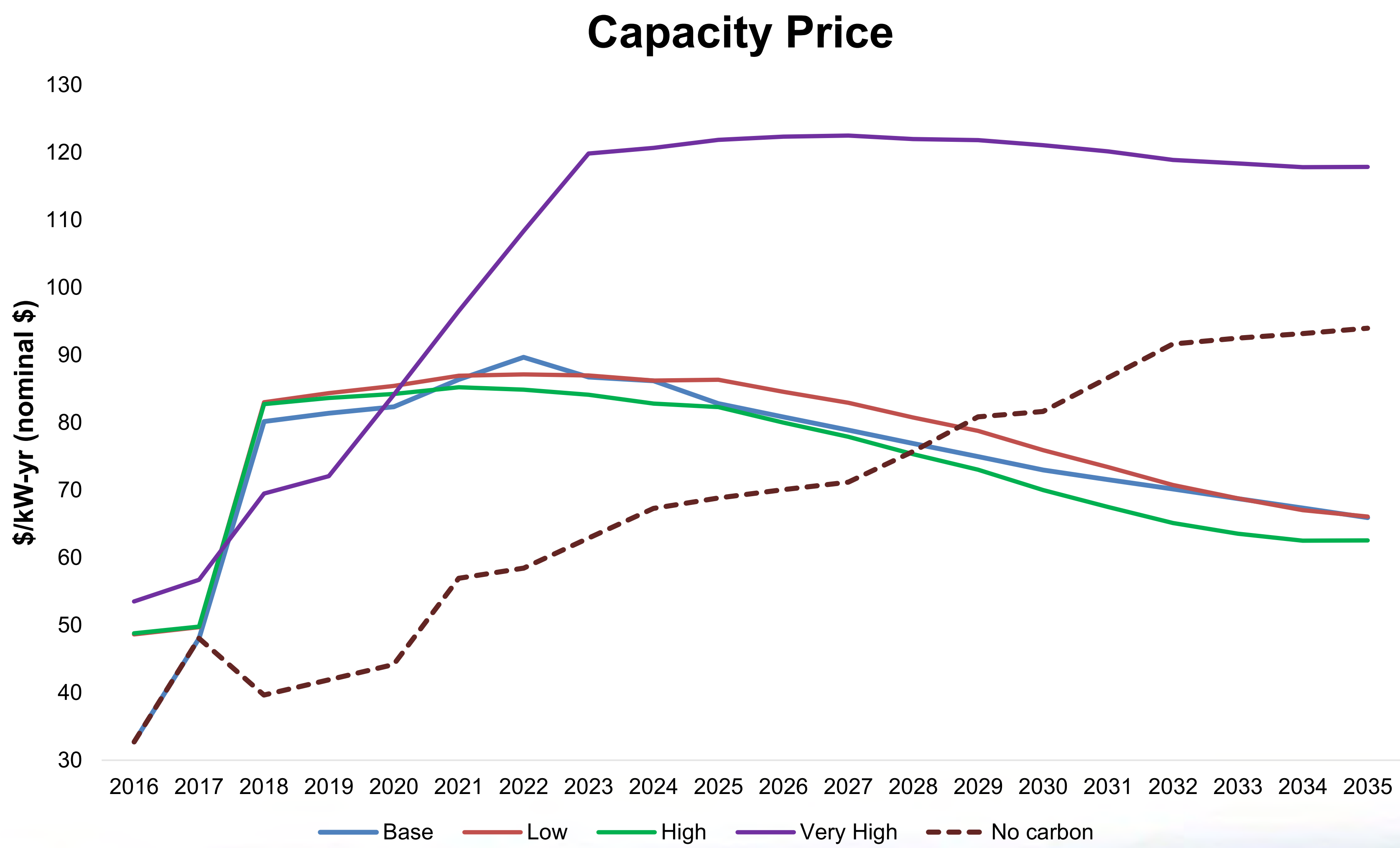
Source: PIRA Energy Group, NiSource Requested Scenarios 2016

CO_2 Price Forecast



Source: PIRA Energy Group, NiSource Requested Scenarios 2016

Capacity Price Forecast (MISO IN)



Source: PIRA Energy Group, NiSource Requested Scenarios 2016

Next Steps

Presented by

Dr. Marty Rozelle

The Rozelle Group Ltd

Next Steps

- Participant speakers
- Future meeting timeline
- Meeting summary *(Available May 12th, 2016)*
- NIPSCO website *(www.nipsco.com/irp)*
- NIPSCO IRP email *(NIPSCO_IRP@nisource.com)*

Q&A

Northern Indiana Public Service Company
2016 Integrated Resource Planning
Stakeholder Meeting #1
SUMMARY

May 5, 2016

Welcome and Introductions

Dr. Marty Rozelle introduced herself as facilitator, and provided logistical information including the location of the restrooms, the materials that have been distributed, and the process of the meeting today. She asked all participants to introduce themselves. She checked with those on the phone to make sure they could hear and see the slides, and explained that they may type their questions into the online meeting system. She described the logistics of speakers and discussions, and outlined the meeting ground rules.

Dr. Rozelle explained that NIPSCO's is seeking to enhance public involvement through a series of four stakeholder meetings to solicit input on the 2016 Integrated Resource Plan (IRP). She outlined the future meetings, with the next meeting scheduled for July12 to provide an in-depth review of NIPSCO's existing generating resources. In August, with the date to be determined, the preliminary results of the modeling will be discussed. At the final meeting in the fall, NIPSCO will describe the proposed IRP, which will be submitted to the Indiana Utility Regulatory Commission (IURC or Commission) in October.

She checked with participants to see if anyone would like to provide a presentation in the afternoon, asking them to let her know by the break this morning so the allotted times of each presentation could be determined.

Overview of Public Advisory Process
Violet Sistovaris, Executive Vice President, NIPSCO
(slides 3-6)

Ms. Sistovaris began with a safety message on good driving practices. She reminded participants to make sure that their vehicles are in good operating condition and to do a quick 'walk around' before road trips, since several people had driven here from Indianapolis. She also noted that it is very important to eliminate distractions while in the vehicle.

She thanked participants for being here today, saying how important stakeholder input is to the planning process. She outlined the guiding principles for the IRP, which are reliability, affordability, flexibility, efficiency, and compliance. NIPSCO's goal is to minimize cost impact on customers while meeting needs for electricity. She noted that NIPSCO's customer base is heavily industrialized, with approximately 40% of the load represented by five industrial customers. Environmental issues will always be critical to the company and are always changing. For the IRP, the portfolio that best meets future needs will address all of these principles with both supply side and demand side resources, and will include the ideas from stakeholders. She assured participants that their time and input is highly valued by NIPSCO and will support the scenario development and modeling efforts. She encouraged participants to ask any questions they like as we proceed through the meeting today and noted that there are many people from NIPSCO in the audience who are happy to talk during breaks about specific questions.

NIPSCO Electric Business Overview
Dan Douglas, Executive Director Corporate Strategy and Development
(slides 9-11)

Dan Douglas thanked participants for attending. He said that transparency and depth of analysis are key issues for NIPSCO while developing the IRP, as is clarity in writing the report to be submitted to the IURC.

He provided an overview of the company, saying that NIPSCO is a combination gas and electric utility with about 460,000 customers. Of these, five industrial customers make up about 40% of the total load, which is an unusually high percentage among utilities. NIPSCO has about 3,400 megawatts (MW) of nameplate capacity, a peak load of about 3 gigawatts, and has about 13,000 miles of transmission and distribution lines.

About 530 MW of interruptible power are available for industrial customers and NIPSCO has historically offered a program for residential customers. In the Feed-In Tariff ("FIT") program, there are about 35 MW of wind, solar, and biomass. NIPSCO's overall resource mix in 2015 was about 70% coal-based capacity, including generation, demand response, and feed-in tariffs. He explained that discussions are ongoing regarding the question of the Bailly plant retirement or continued operation. This issue will continue to be explored as part of the IRP process.

Mr. Douglas described the lessons NIPSCO learned from the 2014 IRP process. There were six main areas of comments received from the IURC and stakeholders. First, it was recommended that NIPSCO enhance the stakeholder process. Previously, NIPSCO held many one-on-one meetings with customers and stakeholders, which NIPSCO is committed to offering again if there is interest. Mr. Douglas noted that this year there was a joint IRP educational session, and the number of NIPSCO stakeholder meeting will be increased to four sessions supplemented by additional one-on-one meetings, which he offered to all participants.

Second, the load forecasting process has been modified and will be explained in more detail at this meeting. The process will also be better described in this year's report. Additionally, the modeling for demand-side management (DSM) will be clarified and streamlined, by selecting each of 24 program groupings[1] on its own merit.

The number of scenarios developed will be expanded this year, and additional sensitivities will be evaluated. These will be discussed in detail this afternoon. He emphasized that some scenarios will be more plausible than others. For example, an unlikely "black swan," or highly implausible, but very impactful, scenario will be included. NIPSCO will focus on the plausible ones, but will provide the variety in order to fully inform stakeholders.

NIPSCO will address distributed generation ("DG") and combined heat and power ("CHP") in more detail for this IRP. He noted that industrial customer DG is an especially difficult situation to evaluate. The DG technologies to be evaluated will include wind, solar, and microgrids, with all having an equal probability of being chosen in the modeling.

Finally, there were comments regarding the issue of confidential information during the previous sessions. This year, more public and proxy data will be used so that it may be shared with stakeholders and the use of confidential data will be reduced, in an effort to be more transparent. He asked stakeholders to let NIPSCO know if this approach is clear.

Participants had the following questions, with answers provided after:

- How much of annual energy produced are coal, gas, and renewables? Please use 2015 percentages.
    - Tony Sayers, General Manager of Generation answered that, without having numbers in front of him, gas production was approximately 35-40% of total generation, the coal production was at about 38%, and the remainder came from hydro, wind, and market purchases.
- Are FIT numbers shown on slide 10 installed or projected? If installed, how many more are projected under FIT 2.0?
    - The FIT numbers are installed, with FIT 2.0 equaling 15 MW and FIT 1.0 equaling 20 MW.
- Are the generators bid into the MISO (Midcontinent Independent System Operator) market?
    - Yes.
- When will the annual report for FIT 2.0 be filed? Will this provide information on resources committed under contract and still available?
    - This information is anticipated to be included in the report, which is to be filed in July.

[1] During the meeting, Mr. Douglas said there were 24 groupings. There are actually 22 energy efficiency groupings and 4 demand response groupings included in the analysis.

Load Forecasting
Amy Efland, Lead Forecasting Analyst
(slides 12-19)

Amy Efland is an analyst with NiSource. She explained that the forecasting process is conducted once per year. To describe the process, she used an analogy of a house: the foundation and floors include the basic building blocks of input data and customer modeling, leading to the roof, or the peak system demand forecast.

The data sources used in creating the load forecast include energy, customer, and price data generated by NIPSCO, economic drivers, appliance saturation and efficiencies, weather data, and industrial customer information. Models are developed for residential users, commercial users, industrial users, as well as for all other types of customers including street lighting, public authorities, railroads, and company use.

The residential customer forecast is developed in three parts. Data is gathered to produce an estimate of the total number of residential customers. Additional data are used to develop a profile of residential use per customer, yielding total residential energy demand. The forecasting team receives the initial three years of the forecast from the New Business team and then utilizes a regression model to forecast the fourth year and beyond. Residential energy consumption represents about 20% of NIPSCO's load.

The commercial customer model is based primarily on population and gross county product. The major drivers of the commercial energy model are customers, price, real county retail sales, and weather. Econometric models are utilized to estimate total commercial energy consumption, which represents about 23% of NIPSCO's load.

The industrial model is quite different from the residential and commercial models. It is largely based on discussions with NIPSCO's 20 largest individual customers who constitute about 80% of NIPSCO's industrial load. NIPSCO's industrial load is about 50% of its overall load.

The last energy group model is called "other," which includes public authorities, railroads, and company use (collectively representing less than 1% NIPSCO's load), as well as street lighting consumption.

Finally, a peak forecast is developed that includes assessments of the weather at the peak hour as well as the predicted loads for residential, commercial, and industrial customer classes.

Ms. Efland showed graphics illustrating the base, high, and low forecasts as well as the forecasts for when large industrial customers are removed, both for energy requirements and peak demand. She discussed these projections in terms of expected growth in load in terms of compound annual growth rates (CAGR). These projections show that the base energy forecast is .33% compound annual growth rate for the period of the IRP, 2016 to 2037, while the peak demand for the base case is .45%.

Demand Side Management
Alison Becker, Manager Regulatory Policy
(slides 20-26)

Alison Becker introduced NIPSCO's demand side management ("DSM") programs and the process by which it will be included in the IRP model. She noted that a list of acronyms used in these presentations has been provided to participants today, thanking Indianapolis Power and Light (IPL) for its preparation.

She described how NIPSCO will model demand side resources in the IRP, which is different from the 2014 IRP. She explained changes in policies related to demand side management that have impacted the modeling process since the last IRP. In 2014, Senate Enrolled Act ("SEA") 340 allowed large industrial customers to opt out of energy conservation programs, and since industrial customers are a large part of NIPSCO's load, this changed the way NIPSCO models, designs, and delivers the energy efficiency programs. Another outcome of SEA 340 was the repeal of the Commission's previous goal of a 2% reduction in sales by the year 2019 through energy efficiency programs The removal of the state-wide 2% goal and the ability for large industrial customers to opt out of participation in utility-sponsored energy efficiency programs has changed the way many utilities, including NIPSCO, model DSM in the IRP.

Last year with the passage of SEA 412, additional clarification was provided requiring 3-year DSM plans to be filed by 2017. NIPSCO plans to take the direction from SEA 412 and recent Commission orders from other utilities when building its next 3-year DSM plan. Ms. Becker said that one of the most helpful aspects of DSM planning is coordination with its Oversight Board, which meets on a monthly basis. This board is comprised of representatives from the Citizens Action Coalition ("CAC"), Office of Utility Consumer Counsel ("OUCC"), and the Industrial Group; all of whom are represented at the meeting today. This group provides an opportunity for ongoing dialogue and continuous improvement in the provision of energy efficiency programs in NIPSCO's service territory.

Ms. Becker explained that the DSM development process follows a traditional model. NIPSCO assesses the market potential for energy efficiency in its service territory with Oversight Board input. NIPSCO also considers its customer profiles (including removal of customers who have opted out of participation), estimates of the amount of achievable savings, and the costs of administering the programs. From the Market Potential Study (MPS), NIPSCO developed 22 groupings of DSM programs to be used in the IRP modeling. NIPSCO plans to take whatever groupings the model selects and use that to develop its next three year DSM plan for approval by the IURC.

The benefits of DSM are estimated using the *DSMore* model, as well as the standard tests for cost effectiveness – Total Resource Cost Test (TRC), Utility Cost Test (UCT), Participant Cost Test (PCT), and the Ratepayer Impact Measurement (RIM). The tests determine if the benefits exceed the costs of the programs. Some programs do not pass the tests and, therefore, are not offered. However, there are other programs, such as low income programs, that do not pass the test, but are offered because of other benefits provided. Low income programs are generally not cost-effective, but are in the best interest of customers. Ms. Becker explained that NIPSCO also carries out Evaluation, Measurement, and Verification ("EM&V") every year on each of its programs. The Oversight Board is responsible for selecting the EM&V vendor to evaluate the programs. This approach for modeling was developed to address comments from stakeholders and the IURC on the 2014 IRP.

For NIPSCO's current DSM programs, GoodCents provides the Residential program portfolio, which includes a Low Income Refrigerator Replacement partnered with an Appliance Recycling program. Lockheed Martin provides the Commercial and Industrial program portfolio, which is efficient as they are also working in Indiana Michigan Power's (I&M) service territory. This allows Lockheed Martin to foster economies of scale, particularly since much of NIPSCO's gas service territory overlaps with I&M's electric territory. As an example of a commercial and industrial program, Lockheed Martin is offering a Retro-commissioning program, which allows customers to analyze their building envelope and look to improve building processes. She said that Lockheed Martin is focusing on reaching out to smaller commercial and small business customers, as larger industrial customers have opted out of the programs. The benefit of this approach is that NIPSCO has a program focused on customers that do not have sophisticated energy managers on staff.

She showed the list of selectable program groupings for residential and commercial and industrial customers that will be included in the IRP modeling. These were divided into energy efficiency and demand response programs, since the SEA 412 does not consider demand response to be DSM, but it is a DSM program for purposes of IRP modeling.

Ms. Becker showed a chart estimating utility costs per program over the 20-year planning horizon. Costs include program administration and customer incentives. The highest-cost programs tend to include residential cooling and commercial cooling. Conversely, she presented a profile of net cumulative energy savings by program, showing that the greatest cumulative energy savings from the suite of programs comes from interior and exterior commercial lighting as well as residential air conditioning. During peak periods, residential cooling has the greatest savings potential. She noted that NIPSCO will be considering a new air conditioning cycling program as part of its planning process.

Ms. Becker reiterated that the Oversight Board will continue to provide advice throughout the planning process. Ms. Becker also suggested hosting a DSM-specific meeting to review the DSM Plan development process.

Environmental Considerations
Kelly Carmichael, Vice President Environmental
(slides 27-33)

Kelly Carmichael observed that the impact of the environmental field on the energy sector is growing and changing. He focused on environmental compliance, noting that NIPSCO is dedicated to serving its customers in a more sustainable way and has a strong commitment to the environment.

Mr. Carmichael told the group that the U.S. Environmental Protection Agency ("EPA") has released more than 10,000 pages of new regulations for utilities in the last year, and NIPSCO will endeavor to translate these new regulations into aspects of the IRP. He provided an overview of the six main regulations that affect the energy industry.

Major regulations include the Clean Water Act 316(b), which seeks to regulate cooling water intake structures. It requires the use of best available technology to better protect aquatic species. This regulation mainly affects the Bailly Plant. Second, the Electric Steam Power Effluent Limitation Guidelines (ELG) focuses on improving the quality of wastewater streams at power plants from ash water and flue gas desulfurization ("FGD") systems. This affects Bailly, Michigan City and Schahfer generating units. These rules start to phase in late 2018 and will be enforced by the Indiana Department of Environmental Management ("IDEM") under the National Pollutant Discharge Elimination System ("NPDES") authority.

Last October, EPA released a final rule around coal combustion residuals ("CCR") that may require modification of coal ash handling processes and impoundments. More data collection on existing facilities is needed to inform compliance with these regulations. Mr. Carmichael provided more detail on this rule, saying that as early as October 2018 coal ash units, such as impoundments, may need to cease receiving coal ash residuals.

EPA continues to look at lowering the National Ambient Air Quality Standards ("NAAQS") compliance limits, with the ozone standard already lowered from 75 parts per billion ("ppb") to 70 ppb. Nitrogen oxide (NO_x) is an ozone precursor, so this may translate into tighter standards for NO_x for the utility industry. The Cross State Air Pollution Rule is a 'cap and trade' program. A lower cap could tighten the NO_x allocation for NIPSCO. The extent of the requirements and potential lowering of the NIPSCO cap is not known at this time and would potentially come in the form of future rulemaking. As a result NIPSCO provided a cost range from no cost to an estimated cost associated with installing NO_x controls on Schahfer Units 17 and 18 – the only NIPSCO units without back-end NO_x controls. Regarding sulfur dioxide (SO_2), all NIPSCO facilities are fully scrubbed, so not much additional work needs to be done; therefore there are no IRP costs projected for this.

Mr. Carmichael showed a data table estimating compliance costs for these regulations at each NIPSCO coal-fired plant, showing a range of total costs from $355 million base case retiring the Bailly plant in or before 2023 to $1.2 billion with continued Bailly operation.

The federal Clean Power Plan ("CPP") regulates CO_2 emissions from existing power plants. There is much work that still needs to be done at both the state and federal levels to evaluate and comply with these rules.

He explained that, in a carbon-constrained future, the IRP will model various scenarios including base, high, and low carbon costs. This will ultimately help to estimate carbon compliance costs. He showed charts estimating carbon allocations (in annual average short tons of CO_2) for Indiana and consequent projections for NIPSCO, assuming a Clean Power Plan federal implementation plan. This is a multi-phased approach, and carbon allowances were shown for each successive phase. He cautioned that these are gross estimates based on a set of assumptions and not final carbon allowances.

Participants had the following questions and comments:

- With just 35% of coal generated electricity last year (and coal = 70% of your capacity), is it fair to say your coal plants were often not competitive on the MISO market and it was less expensive to purchase energy from MISO or run your natural gas plants at higher capacity?
    - No, because the market reflects market coal costs. The 35% capacity is what the market is demanding from coal. NIPSCO is not forcing coal into the market uneconomically.
- Can you explain why Schahfer only operated at 37.74% capacity last year?
    - Again, that's what the market demanded.
- Regarding slide 32 (environmental compliance costs), can you provide the precise technologies included in each of these costs?
    - For ELGs, these reflect a zero-liquid-discharge approach. The alternative technology is bio-reactors and NIPSCO has very little to no confidence that they will operate in a compliant manner in northern climates, but the Company continues to evaluate this. For CCR, for the purposes of the IRP, the assumption is that the current coal ash impoundments would need some level of modification to be in compliance.
- I am also curious about the Bailly retirement scenario in 2023, are you assuming it will meet the locational and structural requirements for that site? Will this information be available in the IRP?
    - NIPSCO does not know yet, but these estimated costs reflect the work that may need to be done to continue to operate the plants. If Bailly were to operate beyond 2023, more work and analysis would need to be completed. If Bailly does not meet the requirements, it is more about the clean-up and remediation of the site. NIPSCO plans to have a more clear

indication by the time the IRP is finalized of the potential costs as a result of collecting data over the summer.

- Is it possible then that we might see that information by the IRP filing period associated with the locational/structural components?
  - NIPSCO should have more data by the filing date, but not sure about having all of the information. However, the Company should have a better indication of where things will head.
- What are NIPSCO's emissions now?
  - In 2015, total emissions were about 14-15 million tons.
- What precise carbon price would trigger retirement of each unit?
  - In 2014, we ran break-point carbon pricing analysis and the plan is to refresh that for this IRP. There have been a lot of changes in commodity prices and environmental compliance that affect costs since 2014.
- Why are Michigan City allowances remaining higher, as they have historically? These communities are bearing an undue burden from this plant.
  - Michigan City costs reflect the installation of a $250 million FGD system, which employs a baghouse technology that significantly reduces the particulate and emissions from that unit. The FGD came online last year and the community will see the associated air quality improvements starting this year.
- Why is it disproportionately higher? We want equity in reduction of pollution.
  - The emissions aren't disproportionately higher now that new emissions technology has been installed, and moving forward this plant should be on par or in some cases better than the coal fleet across the U.S. The CO_2 allocations shown on slide 33 are based on the historic runtimes of the facilities and Michigan City has historically operated more than the other plants. This does not mean that these are the final allocations.
- We want equity in reduction in co-pollutions and carbon pollution as these decisions are being made, thus they need to have more reductions.

IRP Development
Edward Achaab, Manager Resource Planning
(slides 35-57)

Edward Achaab told the group that his team is responsible for doing the modeling for the IRP. He described how the entire process works and how the components are brought together. The IRP is about supply and demand. NIPSCO conducts four basic steps. This is the main topic of today's meeting.

The first step includes data gathering, development of assumptions, screening of technologies, and the creation of scenarios. In step two, the modeling is conducted to develop and evaluate portfolios to address various options. Step three analyzes the portfolios, assesses risks, and selects the preferred portfolio. Creating the IRP report is the final step.

Mr. Achaab described resource modeling optimization, which incorporates demand side resources and supply side resources. The ABB *Strategist Model PROVIEW* is used to optimize NIPSCO's existing resources and produce alternative IRP portfolio plans.

He explained that future supply-side resource options included conventional technologies, renewable technologies, and distributed generation. Future demand-side resource options included energy efficiency programs and demand response programs. Data for these was gathered from an engineering study conducted by Sargent & Lundy and the MPS DSM conducted by Applied Energy Group, or AEG.

The screening criteria for alternative portfolios include energy source availability, technical feasibility, commercial availability, economic attractiveness, and environmental compatibility. Possible resources include conventional coal, natural gas technologies, nuclear, wind (utility scale and distributed generation), solar (photovoltaic and DG), and other resources such as combined heat and power ("CHP"), battery storage, microturbines, biomass, and reciprocating engines.

He showed a table illustrating comparative estimated costs of new generating resources in dollars per kilowatt, for a range of coal, gas, nuclear, and renewable generation technologies.

Participant questions and comments included the following:

- Can NIPSCO provide the analysis that shows that modular nuclear is commercially available?
    - Yes.
- Can NIPSCO provide the data that helped them come to the conclusion that new integrated gasification combined cycle (IGCC), new coal, and new nuclear were economically attractive?
    - Yes.
- Are the energy sources you look at within NIPSCO's service territory? Why?
    - Yes. Particularly with solar, solar power is a function of solar insolation. This kind of information is utilized when determining how much of that resource is available in or near our service territory.
- Would you consider building in other parts of Indiana?
    - The IRP only looks at resource type, not location. This can be determined later at implementation stages. Locating a technology is not a limiting factor – NIPSCO has a combined cycle generation turbine (CCGT) at Sugar Creek, which is not located in our service territory.
- A participant said she's surprised to see conventional scrubbed coal on the list. She felt that some of these are not viable, and that no other utilities are considering new coal plants, especially with carbon costs in the future. She also stated that new nuclear plants are not being considered due to high costs. Please explain.
    - NIPSCO does not want to pre-judge technologies that may be "good" or "bad", which is why all commercially available resources are included in the

model. NIPSCO recognizes that it would be unlikely that the model would select either conventional coal or nuclear.

- A participant stated that NIPSCO noted it was not pre-screening supply-side resources, but that the IRP was going to pre-screen demand-side resources and asked NIPSCO to explain that.
  - NIPSCO noted that it is necessary to group some of the demand-side resources together so that they can all be included in the model.
  - Please see below for comments made by the Commission staff after lunch regarding the selection of resources.
  - If NIPSCO would be permitted to earn a rate of return on a utility solar PV purchase power agreement as is currently being considered in California, would this change how you would model utility-scale solar in the IRP?
    - The IRP is not a rate model, although NIPSCO does include existing regulations such as the production tax credit. Otherwise, rates are not specifically considered.
  - Would NIPSCO consider more utility-scale solar if the state of Indiana provided financial incentives for solar PV ground mounted on brownfield and/or Superfund sites?
    - The model does not consider such items in the selection of resources.
  - Would you consider joint ventures with municipalities to develop such utility-scale solar projects on these numerous Brownfield sites as a special economic development tariff? The participant noted that a special economic tariff is available, although she recognizes that it would need approval from the IURC.
    - The approach for deploying solar like that is outside of the IRP process.
  - Are there, or could there be, plans for PV on public schools and Section 8 apartments, thus passing the energy efficiency savings to the most vulnerable and most impacted by increasing energy rates and hosting the polluting sites?
    - Technologies come to us through third parties, and we look at what is available. Again, the model does not consider such policy decisions.

LUNCH

Prior to beginning the afternoon portion of the discussion, Bob Venick and Bob Pauley of IURC discussed NIPSCO's inclusion of various resources in its planning process and referred to slide 40. They clarified that the Commission is asking utilities to be as inclusive with planning process as they can be, and have asked all utilities to be more expansive in their analysis of risk. This means that utilities should not be pre-selecting resources either on the demand- or supply- side. This does not mean that any of these particular resources will be selected, but they provide 'bookends' in order to make sure that the utility has a good representation of the risks. NIPSCO characterized it correctly by looking at "black swan events." This is very much what NIPSCO has assessed here in the technologies of the IRP. The IURC would like, however, to see how the utilities are planning to handle the black swan events. And noted that they did not get enough information when NIPSCO referenced the black swan scenario earlier in the meeting.

IRP Development, Continued

Developing scenarios and sensitivities are NIPSCO's way of making sure a wide range of possible future world situations based on a set of 'drivers' are considered. Scenarios look at all the main drivers – in this case, load, commodity prices, technology, economy, regulations and environmental compliance. Sensitivities vary only one element, such as gas price, within a scenario.

Mr. Achaab described the scenario building process that includes identifying risks and uncertainties, imagining possible futures, designing alternative scenarios, and analyzing the diversity and robustness of scenarios.

The proposed scenarios to be developed for the 2016 IRP include:

- ✓ Base Case
- ✓ Challenged Economy
- ✓ Aggressive Environmental Regulation
- ✓ Booming Economy

The Base Case is what NIPSCO considers the most likely to occur, with a slow load growth, a recovering economy, and a carbon policy coming into effect in 2023. The sensitivities to be run for this scenario are: no CO_2 price, low load, high gas price, and no major industrial load.

Questions from participants included:

- Do any of these scenarios assume that a national carbon policy will become more stringent after 2030? This should be considered.
    - Yes, one scenario looks at a much higher CO_2 price as a result of increased environmental regulation.
- For the Base Case, a participant suggested modeling a higher CO_2 price after 2030.
    - Mr. Achaab explained that this is assumed in the third sensitivity, which assumes a high gas price.
- What's the assumption about CO_2 limits after 2030 in the Base Case?
    - Referring to slide 56, prices start at around $5 increasing to nearly $70 in 2035.

The second scenario is termed Challenged Economy, considering an economic downturn with growth stalling, a stagnant customer load, a carbon policy starting in 2023, reduced demand for natural gas and coal, and limited new environmental regulation. Sensitivities are: no CO2 price, and no major industrial load due to the loss of industry.

- Why wouldn't the loss of industry be included in the scenario, rather than just as a sensitivity?

- The loss of some industry is already included in the low load growth forecast used as input for the scenario. The sensitivity looks at losing all industrial load.

The next scenario is termed Aggressive Environmental Regulation. Here, environmental regulations are assumed to be more stringent for power generation, gas production, and coal production and compliance costs are higher overall. Sensitivities include: high use of renewables and increasing load, and high renewables with decreasing load.

The last scenario assumes a Booming Economy, where economic growth is higher than expected, environmental regulations and compliance costs increase leading to higher gas and coal prices, and a national carbon policy comes into effect in 2023. Sensitivities are: no CO_2 price, and no major industrial load.

- In the Booming Economy scenario, what is the economic growth factor, i.e. the percent?
  - We don't have that information here today but will provide an answer following the meeting.

Mr. Achaab showed a chart summarizing these elements of all the scenarios and sensitivities. This outlined assumptions about the NIPSCO loads, CO_2 prices, natural gas prices, power price, DSM adoption, availability of renewable portfolio standards, and environmental compliance costs. A participant felt that these descriptions of the scenarios were too general and lacked sufficient detail.

A graphic was presented that illustrated the variability of the scenarios, indicating how they divert from the Base Case. This shows that a relatively wide range of assumptions is being evaluated. Mr. Achaab made the point that all cases include some form of DSM and some form of environmental regulation.

To describe costs to be used in the modeling, he showed a series of charts estimating MISO prices for electricity, natural gas, and coal, as well as carbon and capacity prices for the various scenarios over the planning timeframe.

Participant questions and comments included the following:

- Do any scenarios or sensitivities assume a national carbon policy will become more stringent after 2030 (the end point for the Clean Power Plan?
  - Yes. The Aggressive Environmental Regulation scenarios and sensitivities assume a stricter national carbon policy. Edward Achaab referenced slide 56 for the carbon price.
- One participant asked how Mr. Achaab scored the chart demonstrated on slide 51?
  - The risks that were identified by NIPSCO and formed the foundations of the scenarios were scored on a scale of 1 to 5. The 1, 2, 3, 4, 5 scores represent *Very Low, Low, Medium, High, and Very High*, respectively.

Referencing slide 50, each score for the various risks (Load, CO_2 price, Gas price, Power price, etc.) within the scenarios and sensitivities were summed. The total score for the various scenarios and sensitivities were expressed as percentages of the maximum score as indicated on slide 51.

Stakeholder Presentations

Several stakeholders chose to wait until they could attend in person to provide presentations. NIPSCO emphasized that all participants are invited to make presentations at each of the stakeholder meetings, so anyone who wishes to speak at the July 12 meeting will be able to indicate that when registering. The company also invited participants to request a one-on-one meeting should they like to do this.

Next Steps

Dr. Rozelle outlined the schedule for follow-up from this meeting, and the tentative schedule for the remainder of the workshops. Any additional comments or questions can be sent to: NIPSCO_IRP@nisource.com

Citizens Action Coalition said they would like to see more detail about demand side resources at the next meeting, as a compliment to more information on generation resources. Ms. Becker re-iterated NIPSCO's offer to host a DSM-specific stakeholder meeting. Dan Douglas clarified that both supply side and demand side options will be examined in more detail in the August workshop. Alison Becker also offered individual meetings with stakeholders before the July meeting if desired.

Dr. Rozelle thanked everyone for coming, and reminded them to drive safely, as Ms. Sistovaris had said.

NIPSCO

2016 Integrated Resource Plan

Stakeholder Meeting #2 – Tuesday, July 12, 2016

Time: *9:00 am – 2:30 pm CT (10:00 am – 3:30 pm ET)*

Location: *Radisson Hotel at the Star Plaza*
800 E. 81st Avenue
Merrillville, IN 46410

Background
NIPSCO is due to submit an Integrated Resource Plan (IRP) to the Indiana Utility Regulatory Commission (IURC) on November 1, 2016. The IRP is our plan for meeting the future energy needs of our customers over the next 20 years with cost-effective, reliable, and sustainable supplies of electricity while addressing the inherent uncertainties and risks that exist in the electric utility industry.

Agenda: **All times are in CT*

Time (CT)	Topic
9:00 am	Welcome & Introductions Public Advisory Process & Review of 1st Meeting NIPSCO 2015 Market Potential Study
10:00 – 11:00 am	NIPSCO DSM Program Potential
11:00 – 11:15 am	*Break*
11:15 – 12 pm	IRP Modeling of DSM
12 pm	*Lunch*
12:45 – 1:45 pm	IRP Output and DSM Program Filing DSM Measure Example
1:45 – 2:15 pm	External Stakeholder Presentations
2:15 – 2:30 pm	Next Steps Closing

NIPSCO 2016 IRP
Public Advisory Meeting 2

July 12, 2016

NIPSCO

Meeting Outline

Schedule	Agenda Item
9:00–9:20	Welcome and Introductions
9:20–9:40	Public Advisory Process and Review of 1st Meeting
9:40 –10:00	NIPSCO 2015 Market Potential Study
10:00–11:00	NIPSCO Demand Side Management (DSM) Program Potential
11:00–11:15	*Break*
11:15–12:00	IRP Modeling of DSM
12:00–12:45	*Lunch*
12:45–1:15	IRP Output and DSM Program Filing
1:15–1:45	DSM Measure Example
1:45–2:15	External Stakeholder Presentations
2:15–2:30	Next Step and Closing

Welcome and Introductions

Presented by

Violet Sistovaris

Executive Vice President

Safety Message

The Public Advisory Process

Presented by

Dr. Marty Rozelle

The Rozelle Group Ltd

Overview of Public Advisory Process

Objectives

- Enhance public involvement through multiple public advisory meetings
- Solicit relevant input for consideration in the development of the 2016 IRP
- Promote discussion on NIPSCO's IRP process

Stakeholder Interactions

- Since the 1st Public Advisory Meeting on May 5th, NIPSCO has met with stakeholder groups.

- 1st Stakeholder Meeting Materials
  - Presentation materials and summary meeting notes are posted on NIPSCO's IRP webpage: www.NIPSCO.com/irp.

NIPSCO

IRP Stakeholder Process & Timeline

Presented by

Daniel Douglas

Vice President, Corporate Strategy & Development

IRP Public Stakeholder Process and Timeline

Proposed

	May 5th	July 12th	August 23rd	TBD (Mid September)
Key Questions	-What process will NIPSCO use for its IRP? -What are the key assumptions driving the scenarios and sensitivities?	-How will NIPSCO incorporate Demand Side Management Resources in the IRP?	-Deep dive into NIPSCO's existing generation -What are the optimal replacement options to fill the supply gap?	-What is NIPSCO's preferred plan?
Agenda/ Content	-Overview of process -NIPSCO overview -Load forecasting -Demand side management -Environmental considerations -IRP development -Public advisory process	-Review Market Potential Study -Describe and Review Demand Side Management measure groupings -Introduce Demand Side Management Modeling Methodology	-Overview of existing generation by unit (costs, environmental, etc.) -Retirement analysis -Outline preferred retirement direction and describe resulting capacity gap through time -Replacement options (supply-side and demand-side)	-Address input from July 12th and August 23rd -Describe Preferred Path and logic -Explain NIPSCO retirement and replacement timeline (File IRP, RFP, CPCN, etc) -Process for replacement (Need->RFP->CPCN)
Key Deliverable	-Key assumptions -Overview of scenarios and sensitivities	-Common understanding of the grouping of DSM measures -Clear picture of NIPSCO's DSM modeling methodology	-Stakeholder feedback and shared understanding of generation alternatives	-Communicate NIPSCO's IRP responsibility -NIPSCO's preferred plan
Meeting Format	-6 hour in person session	-5.5 hours in person session	-6 hours in person session	-2 hour TBD

Screening of Supply-side Resources

- Sargent and Lundy reviewed the supply-side resource options and screened the resources following five criteria
- Reviewed 32 different resource options and screened out 11

Energy Source Availability

Technical Feasibility

Commercial Availability

Economic Attractiveness

Environmental Compatibility

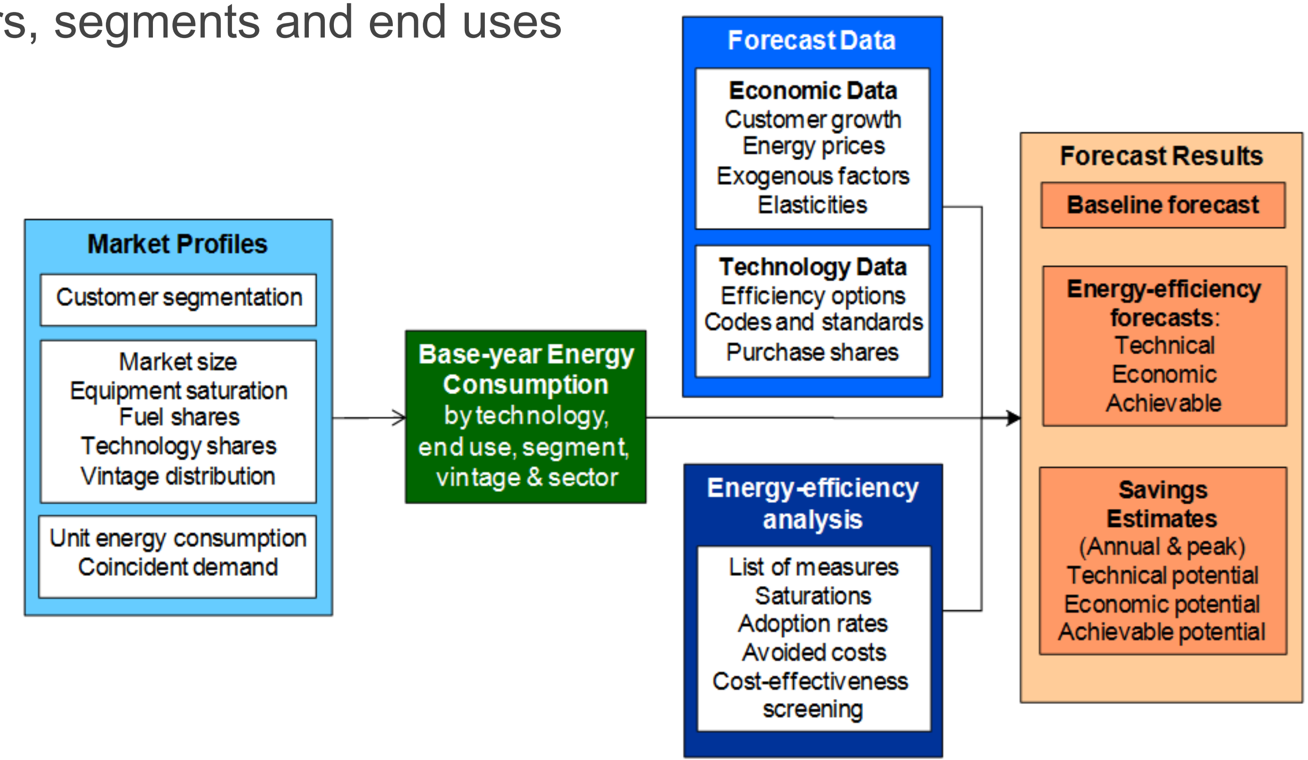
AEG
Applied Energy Group

2015 Market Potential Study

Presented by
David Costenaro – Director
Bridget Kester – Senior Project Manager

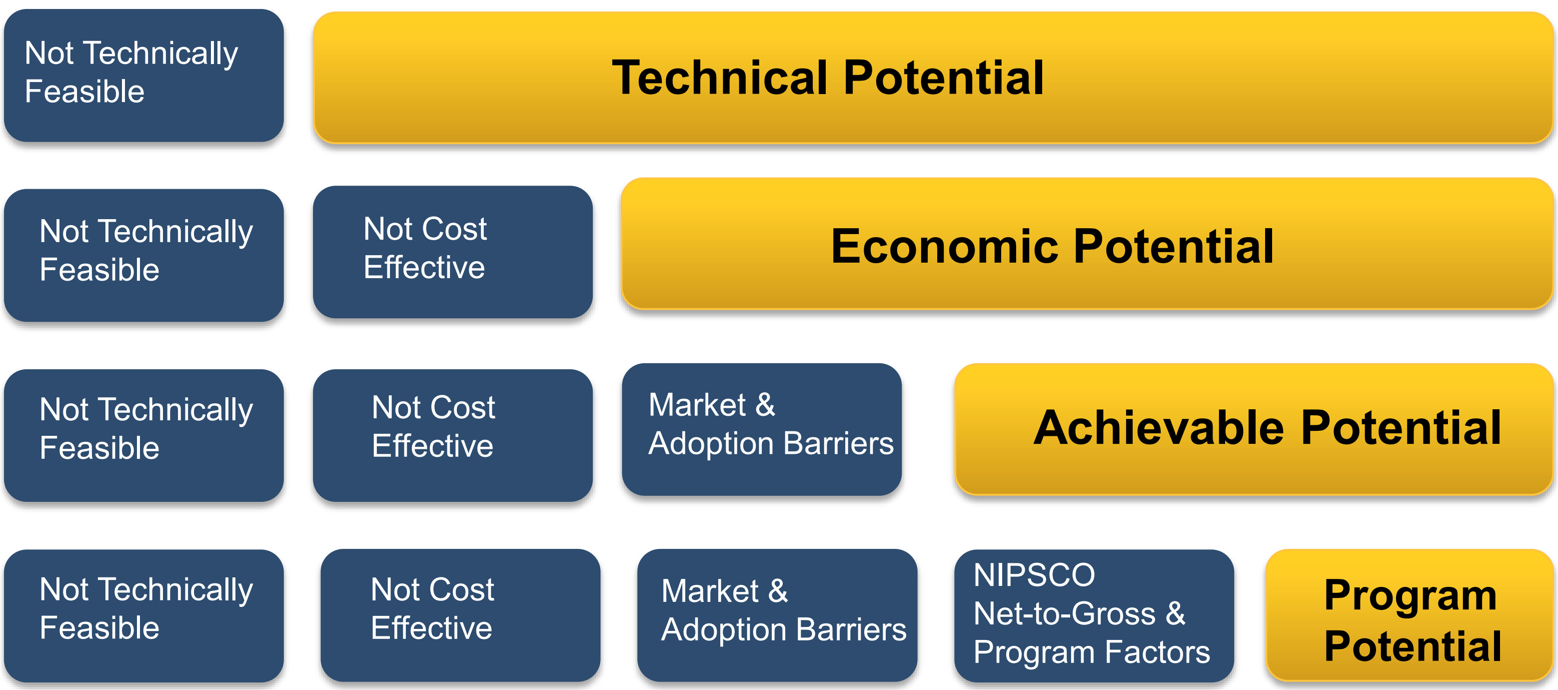
2015 Market Potential Study

- Provides estimates of the potential reductions in annual electricity use and summer peak demand for electricity customers in NIPSCO's service territory for 2016-2036
- AEG developed a baseline projection of how customers are likely to use electricity in the absence of future programs. The baseline provides the metric against which future program savings are measured.
- Defined and characterized several hundred DSM measures to be applied to all sectors, segments and end uses



AEG Applied Energy Group

Definitions of DSM Potential



*For more complete definitions, see National Action Plan for Energy Efficiency, 2007a, and XENERGY, 2002

AEG Applied Energy Group

Measure-Level Potential

AEG utilizes a bottom-up approach for the measure level analysis

LoadMAP™

Achievable potential

Establish Customer Acceptance

Historic Experience
Other studies

Technical and Economic potential

Screen EE Measures

Measure descriptions
Emerging technologies
Indiana TRM 2.2
Avoided costs
AEG's DEEM

End-use projection by segment

Project the Baseline

Prototypes and energy analysis (***AEG's BEST***)
Forecast data
Customer surveys
Secondary data
Codes and Standards

Base-year energy use by segment

Characterize the Market

NIPSCO customer data
Customer surveys (KEMA 2010)
Secondary data
AEG's Energy Market Profiles

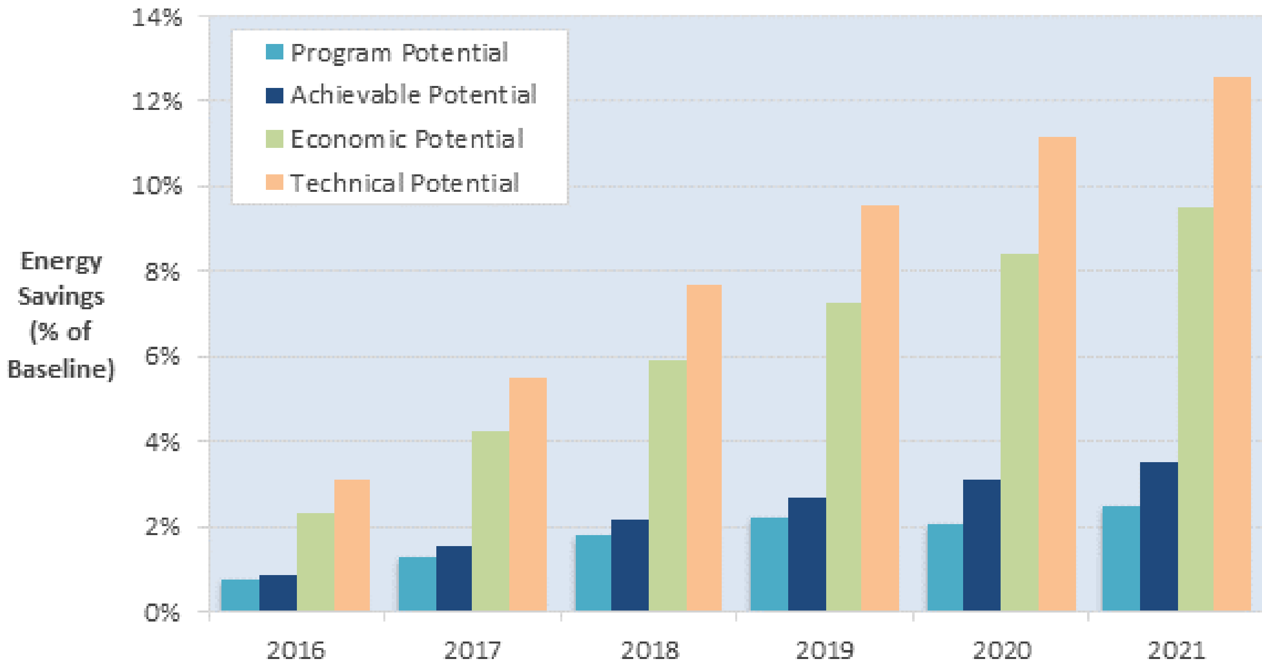
Establish objectives

AEG Applied Energy Group

Summary of Measure Level DSM Potential (Annual Energy, GWh)

	2016	2017	2018	2019	2020	2021
Baseline projection (GWh)	9,235	9,281	9,310	9,329	9,318	9,307
Cumulative Savings (GWh)						
Technical Potential	284	510	716	891	1,038	1,171
Economic Potential	214	391	548	678	784	881
Achievable Potential	81	144	199	249	289	328
Program Potential	71	120	165	208	193	230
Cumulative Savings as a % of Baseline						
Technical Potential	3.1%	5.5%	7.7%	9.5%	11.1%	12.6%
Economic Potential	2.3%	4.2%	5.9%	7.3%	8.4%	9.5%
Achievable Potential	0.9%	1.5%	2.1%	2.7%	3.1%	3.5%
Program Potential	0.8%	1.3%	1.8%	2.2%	2.1%	2.5%

Summary of DSM Potential as % of Baseline Projection (Annual Energy)



AEG Applied Energy Group

Flow of DSM Measures

DSM Market Potential Study
Applied Energy Group

1. MPS Technical Potential

716 GWh Savings in 2018 from
100% of Measure Savings at
100% of Applicable Customers

MPS Economic Screen
Eliminates 33% of Measures with
TRC<1.0

2. MPS Economic Screen:

548 GWh Savings in 2018 from
77% of Measure Savings at
100% of Applicable Customers

MPS Achievable/Adoption Factor
Eliminates 64% of Customers that
will not participate

3. MPS Achievable Potential:

199 GWh Savings in 2018 from
77% of Measure Savings at
36% of Applicable Customers

Program Potential & IRP Inputs
Morgan Marketing Partners

Program Potential removes an
additional 11% of Measure Savings
through implementation factors and
more sophisticated Economic Screen

4. DSMore Economic Screen
170 GWh Savings in 2018 from
66% of Measure Savings at
36% of Applicable Customers

Integrated Resource Plan
NIPSCO

IRP Final Modeling Result Defines DSM to be Procured with RFPs

IRP (hypothetically) removes an
additional 4% of Measures in resource
selection process

5. IRP Economic Selections
NOT YET KNOWN - HYPOTHETICAL:

160 GWh Savings in 2018 from
62% of Measure Savings at
36% of Applicable Customers

AEG Applied Energy Group

Also a Possible Flow…

DSM Market Potential Study
Applied Energy Group

1. MPS Technical Potential:

716 GWh Savings in 2018 from
100% of Measure Savings at
100% of Applicable Customers

MPS Achievable/Adoption Factor Eliminates 64% of Customers that will not participate

3. MPS Customer Adoption:

Estimated 258 GWh Savings in 2018 from
100% of Measure Savings at
36% of Applicable Customers

- Could possibly eliminate steps 2 and 4, which perform economic screening and pre-condition the data for input into the IRP
- Still always apply customer adoption factor since DSM is voluntary.
- This is done by some utilities in the Pacific Northwest
    - (although there is still substantive work in Step 4 to prepare the DSM inputs in 8,760-hour format, bundle them for IRP software, etc)
- Would arrive at essentially the same answer.
- IRP would have many more measure inputs without steps 2 and 4, increasing runtime and complexity.

IRP (hypothetically) removes the same Measures as non-economic through resource selection process, but requires more data and more runtime

Integrated Resource Plan
NIPSCO

IRP Final Modeling Result Defines DSM to be Procured with RFPs

5. IRP Economic Selections

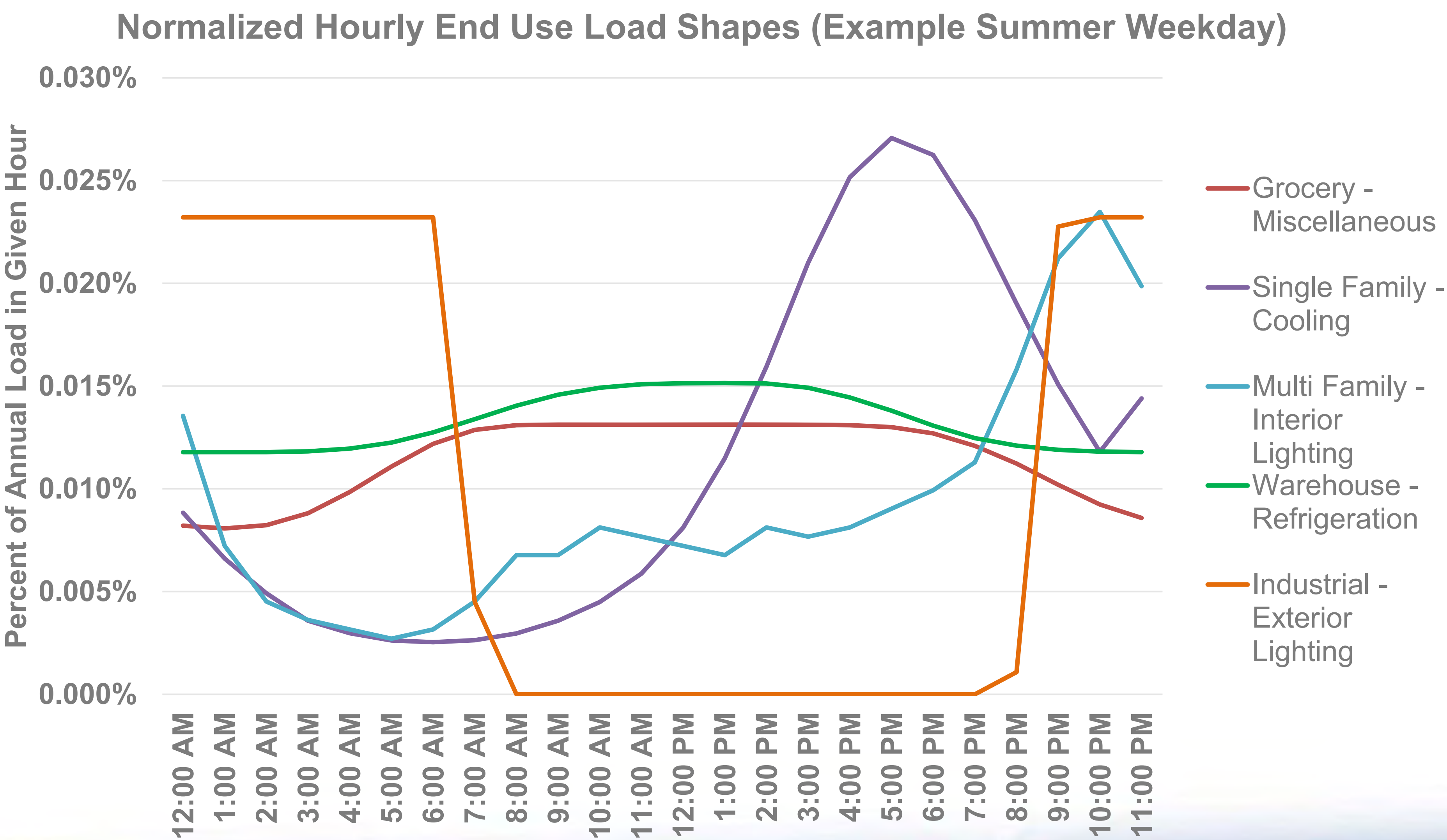
NOT YET KNOWN - HYPOTHETICAL:
160 GWh Savings in 2018 from
62% of Measure Savings at
36% of Applicable Customers

AEG Applied Energy Group

Measure Grouping Indicators

- Each measure is labelled with a ‘grouping indicator’ that assigns it to a specific DSM Grouping.
- Model constraints limit the number of alternatives that can be optimized.
- Iterative process that resulted from discussions with AEG, NIPSCO and Morgan Marketing Partners.
  - Each measure was associated with a Grouping during the Market Potential Study development.
  - Including hundreds of individual DSM measures in the IRP would cripple the computational speed of the model.
  - Grouping of measures by similar load shape (ex: lighting, heating) and customer segment allows the model to analyze large groups of measures more efficiently.

End Use Load Shapes



NIPSCO DSM Program Potential

Presented by

Rick Morgan

Morgan Marketing Partners

DSM Program Potential Step

- Following the Achievable Potential Step, AEG sends all of the measures from the Market Potential Study to Morgan Marketing Partners for further analysis and review.
- The Program Potential Step compares the DSM measures' savings and costs from the MPS to NIPSCO's actual program results to see if the MPS findings are aligned with NIPSCO's program history.
  - Utilizes EM&V reports from past program years to review the data and to help with any adjustments.
- Default decision is to keep a measure unless problems or not cost effective.
- Some measures that were not cost effective were kept for specific markets (Low Income) and other reasons.

*EM&V = Evaluation, Measurement and Verification

DSMore Cost Benefit Analysis

- The analysis determines if each measure (not Grouping) is cost-effective from a Total Resource Cost Test perspective utilizing the cost-effectiveness model DSMore.
- Unlike the Economic Potential step in the MPS, DSMore takes hourly prices and hourly energy savings from the measures and then correlates both to weather.
- Measures are screened out if they are not cost-effective or could not be implemented in NIPSCO's service territory over the time period the MPS projected.
- 27 measures were screened out at this step.
- The final DSM Program Potential results represent the subset of measures that can be realistically implemented in NIPSCO's service territory considering budget and market constraints.

*DSMore = Modeling software that is nationally recognized and used in many states to determine cost-effectiveness.

NIPSCO

Screening of Residential Measures

- **Residential Removed**
  - 13 Measures Removed – did not pass TRC
  - Represents 2.9% reduction for 2016-2019 period

Water Heater less than 55 gal
Residential Linear Fluorescent
Clothes Dryer
Personal Computers
Monitor
Laptops
TVs
Printer Fax Copier
Pool Pump
Hot Tub Spa
Furnace Fan
Water Heater - Drainwater Heat Recovery
Water Heater - Tank Wrap

- **Residential Retained**
  - 11 Measures Retained – did not pass TRC
  - Represents 8.5% of 2016-2019 Period – includes Low Income

Central AC - almost passes UCT
Air-Source Heat Pump - 2/3 for Low Income
Geothermal Heat Pump - starts 2020 less than 500 units 20 years
Room AC - Only MF
Specialty Interior Lighting - Almost passes, costs expected to drop
Refrigerator - passes UCT just misses TRC
Central AC - Maintenance and Tune-Up - participation starts 2027
Central Heat Pump - Maintenance - TRC .97
Home Energy Management System - New single family only, total 52 units and starts 2034
Whole-House Fan - Installation - Low Income, MF and Mobile Home only
Roofs - High Reflectivity - MF only

*MF = Multi-Family

Screening of Commercial Measures

- **Commercial Removed**
  - 10 Measures Removed did not pass TRC
  - Represents 3.7% reduction for 2016-2019 Period
  - Can vary based on building type

Small Com_Existing Ventilation_Electric
Small Com_New_Ventilation_Electric
Small Com_Existing_Cooling_Elec_Insulation Wall Cavity
Small Com_Existing_Cooling_Elec_Economizer
Small Com_Existing_Ventilation_Elec_Variable Speed Control
Small Com_Existing_Grocery - ECMs for Display Cases
Small Com_New_Cooling_Chiller - VSD on Fans
Small Com_New_Elec_ Drainwater Heat Recovery
Small Com_New_Grocery - ECMs for Display Cases
Small Com_New_Cooling_ Occupancy Sensors

- **Commercial Retained**
  - 14 measures retained
  - Represents 2.1% of 2016-2019 Savings

Air Source Heat Pump
Geothermal Heat Pump
Exterior Linear Fluorescent
Chilled Water Reset
Desuperheater
Interior Fluorescent De-lamp
Anti-Sweat Heater
Grocery Display Case LED Lighting
Grocery Display Case Motion Sensor
Pre-Rinse Splay Valves
New Wall Cavity Insulation
New Ecomomizer
New Ventilation Variable Speed Control
New Cooling Commissioning

Screening of Industrial Measures

- **Industrial Removed**
  - 4 Measures Removed – did not pass TRC
  - Represents 5.9% Reduction for 2016-2019 Period

Small Industrial Ventilation
Interior Linear Fluorescent
Exterior Linear Fluorescent
Small Industrial Chiller – Variable Speed Drive on Fans

- **Industrial Retained**
  - 6 Measures Retained
  - Represents 2.5% of 2016-2019 Period

Small IN Air Cooled Chiller
Small IN Geothermal Heat Pump
Small IN Chilled Water Reset
Small IN Roof Top Unit
Small IN Motor Commissioning
Small IN Cooling Ceiling Insulation

*IN= Industrial

Definition of Avoided Cost

In the context of DSM activities

AVOIDED COST:
The monetary value of reducing peak energy and demand consumption on the customer side of the meter…

…as quantified by the system costs that would otherwise be incurred to procure the required energy, capacity, T&D, and other resources.

Application of Avoided Costs

- **Used in Cost Effectiveness Tests**
  - Energy and Capacity – DSMore uses Hourly Market Prices based on historic values.
  - Prices are adjusted based on weather using a 33-year weighted average weather value.
  - Transmission and Distribution – provided this value from NIPSCO that is consistent with their other planning efforts.

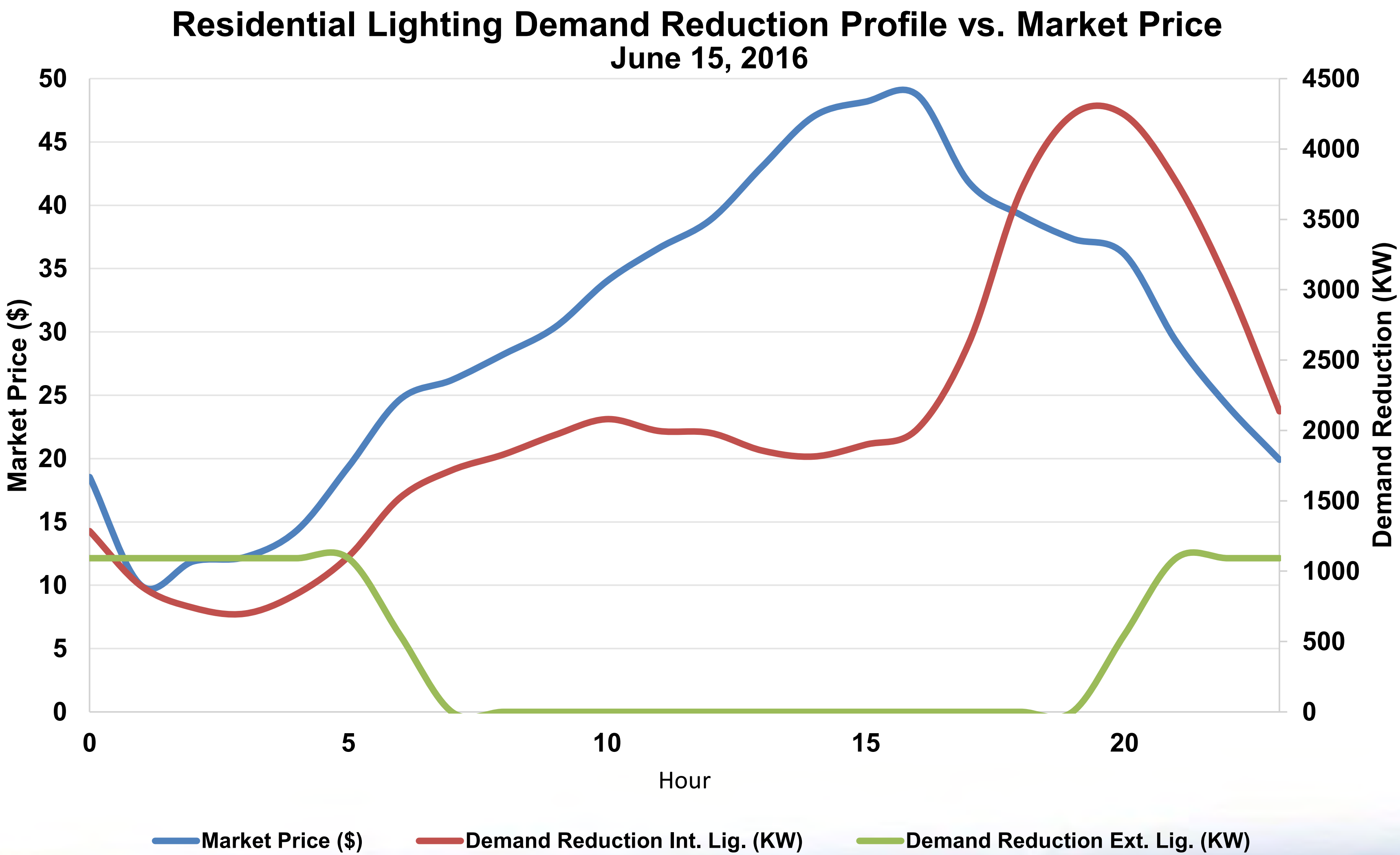
- Avoided Cost Benefits ($) are calculated for each measure individually by the hour that savings occur. These are added together to get the grouping value by hour.

- **Benefit Cost Ratio: Avoided Cost "Benefits"/"Costs"**

Costs (denominator) vary depending on the test being calculated while benefits stay the same for two primary tests.

- TRC "Costs" = Program Implementation Costs <u>plus</u> Customer's Incremental Costs
- UCT "Costs" = Program Implementation Costs <u>plus</u> Program Incentives to Customers

DSM Savings Profile and Market Price



DSM Measure Aggregation

- After measures are adjusted for NIPSCO-specific markets (Program Potential) and screened through DSMore, the individual measures are aggregated into the DSM Groupings by the grouping indicator and are provided to NIPSCO for analysis within the IRP.

- Results from the Program Potential step are provided as inputs to NIPSCO's IRP.

- **Programs vs. Groupings:**
  - "Programs" are not used in the IRP analysis because the IRP is a long-term analysis and programs will and should change over time.
  - Programs are focused on delivery methods to overcome market barriers, which are constantly changing.
  - Groupings represent a higher level of measure bundling and allow NIPSCO to be more flexible with its inclusion of DSM in the IRP.

Portfolio of Energy Efficiency DSM Groupings

Residential EE Groupings	Commercial EE Groupings	Industrial EE Groupings
Res Appliances	Com Cooling	Industrial Cooling
Res Cooling	Com Exterior Lighting	Industrial Exterior Lighting
Res Electric Heating	Com Electric Food Prep	Industrial Interior Lighting
Res Electric Miscellaneous	Com Electric Heating	Industrial Motors
Res Electric Water Heat	Com Interior Lighting	Industrial Heating
Res Exterior Lighting	Com Elec Miscellaneous	
Res Interior Lighting	Com Office Equipment	
	Com Refrigeration	
	Com Ventilation	
	Com Electric Water Heat	

*EE = Energy Efficiency

AEG Applied Energy Group

Portfolio of DSM Demand Response Groupings

Residential DR Groupings	Commercial DR Groupings
Res Cooling Direct Load Control	Small Com Cooling Direct Load Control
Residential Water Heating Direct Load Control	Med Com Cooling Direct Load Control
	Small Com Water Heating Direct Load Control
	Med Com Water Heating Direct Load Control

Four of the Commercial Demand Response Groupings were combined into two Groupings. The small and medium Commercial groupings have the same load shape and, therefore, were combined into the same Grouping.

Residential DR Groupings	Commercial DR Groupings
Res Cooling Direct Load Control	Commercial Cooling Direct Load Control
Residential Water Heating Direct Load Control	Commercial Water Heating Direct Load Control

*The portfolio also included 2 Industrial DR Groupings, which will be discussed in another section.

*DR = Demand Response

AEG Applied Energy Group

DSM Groupings Construction

IRP Achievable Potential Measures (IRP grouping indicator)

↓

Program Potential – adjustments are made based on NIPSCO experience and markets

↓

DSMore Inputs by Measure (IRP grouping indicator included) – Cost Effectiveness Results by measure

↓

Aggregation of individual measure results based on IRP Grouping at hourly level

↓

IRP Input of Hourly Data by IRP Grouping of measures

NIPSCO

IRP Modeling of DSM

Presented by

Edward Achaab

Manager Resource Planning

Industrial Demand Response Groupings

Similar to the Commercial DR Groupings, the Market Potential Study provided four Industrial DR Groupings broken out by Large and Extra Large, which were then combined into 2 Industrial DR Groupings.

Industrial Demand Response Groupings
Industrial DR Interruptible Load Tariffs
Industrial DR Curtailment Agreements

	2016 MW
Rider 675 (Interruptible Service)	
Current (subscribed and credited with MISO)	**377.1**
Proposed	530
Available Above Proposed If No Cap	29.5
TOTAL	**559.5**

MISO DRR Rider 681	**56**

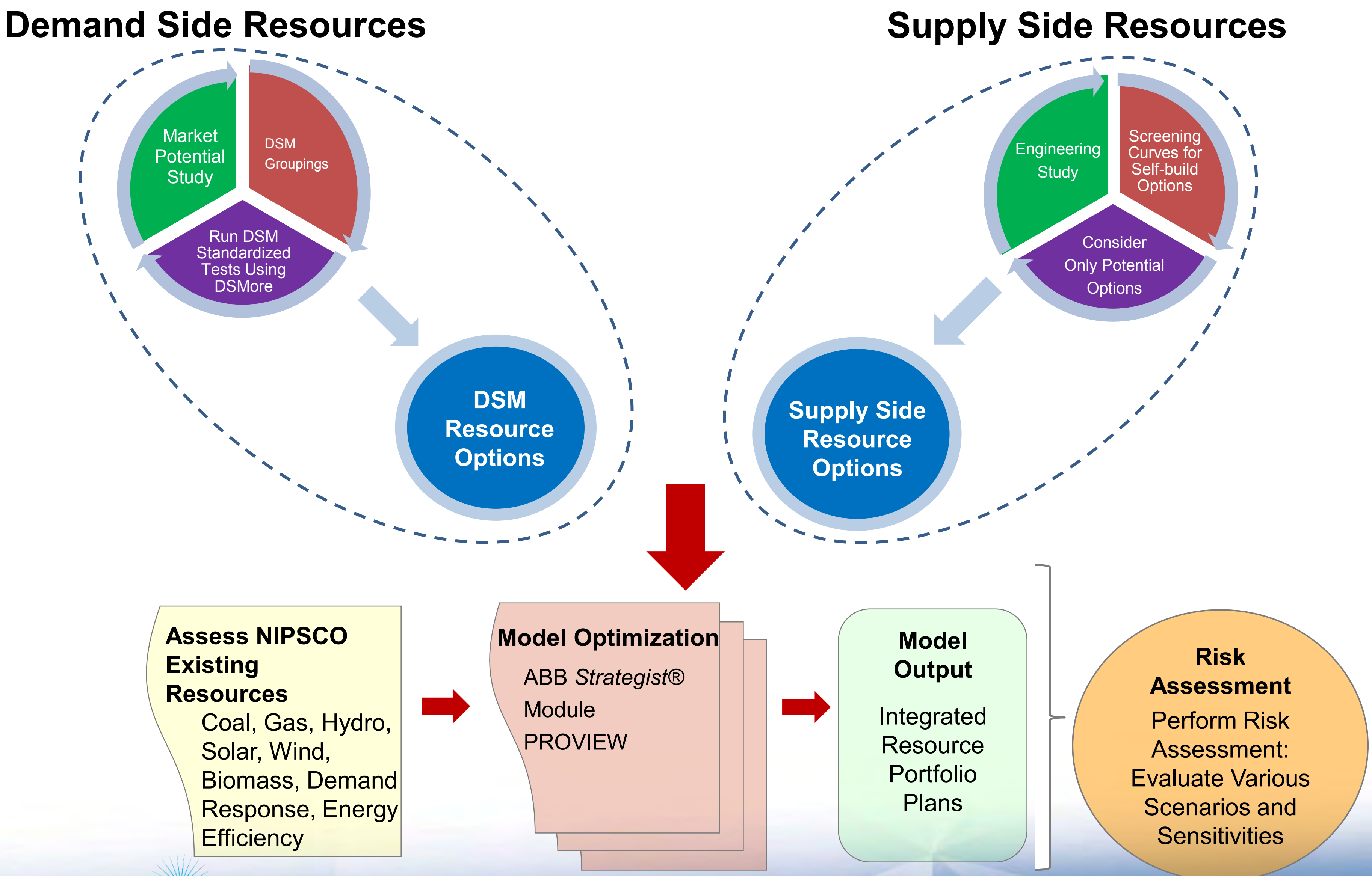
The MISO Demand Response Resources ("DRR") Rider 681 is an energy product and is not curtailable.

IRP Model Analysis

DSM Inputs into the model:

- NIPSCO uses the Program Potential amount of savings as inputs into the model.
- Energy, Capacity, Costs, Savings Load Shape
- Load Shape – DSMore outputs are provided in 8760 hourly data.
- The NIPSCO IRP team runs the 8760 hourly data through an Excel-macro model that converts the 8760 hourly data into typical-week format for *Strategist*®.
- The same steps are also taken for other parameters such as power prices.

Resource Modeling Optimization



DSM Groupings in *Strategist®*

- Each grouping is individually and fully selectable within *Strategist®*.
- The DSM Groupings compete against a variety of supply-side resources including coal, gas, nuclear, solar, wind, etc.
- Each grouping has an individual cost per year along with a savings profile in terms of capacity and energy.
- The DSM Groupings will be optimized in each scenario to better understand their value across different futures.

NIPSCO

Scenario Selections

Demand-side Resources

- NIPSCO analyzes which DSM Groupings fare better across a wide selection of future worlds/scenarios.
- There may be consistent selections of DSM Groupings across all of the scenarios.
  - For example, the same ten DSM groupings may be selected in every scenario.
  - Groupings selected in every scenario represent the most cost-effective options and the best opportunity for energy efficiency in NIPSCO's service territory.
- Alternatively, some DSM groupings may be selected by the model in one scenario, but not in other scenarios.

Supply-side Resources

- The supply-side resources are analyzed across all of the scenarios.
- Represent larger resource selections within the model. *Strategist*® also takes into account the cost to build each facility.
- Different supply-side resources may be selected by the model in specific scenarios and not in others

Preferred Portfolio Analysis

- NIPSCO's goal is to look beyond simply utilizing economics as a the only guiding principle for selection of its Preferred Portfolio, and this includes DSM.
- When working to select the preferred portfolio, NIPSCO plans to take several principles into account: cost, environmental impacts, diversity of resources, costs/benefits to different customer classes, etc.
  - NIPSCO's goal is to balance these principles in order to better select a holistic and flexible portfolio for the future.
- This review process will include qualitative principles in addition to quantitative metrics to help determine which portfolio is not only cost-effective, but one that follows other principles that may guide NIPSCO when analyzing possible future worlds.

IRP DSM Output

- *Strategist*® may select different combinations of DSM Groupings for each scenario.
- NIPSCO will review the common selections of DSM groupings across all scenarios and also review the DSM grouping selections in individual scenarios.
- If additional DSM groupings are added to the Preferred Portfolio than were selected in a specific scenario, NIPSCO will run the final selection of DSM groupings through the model to review how the additional groupings affect the total cost of the portfolio.

IRP DSM Results and Plan Timeline

Presented by

Alison Becker

Manager Regulatory Policy

2016 IRP Results Discussion

How will NIPSCO utilize the results of the 2016 IRP to create a DSM Plan that is consistent with SEA 412?

- NIPSCO plans to utilize the DSM Groupings from its Preferred Portfolio to serve as the foundation for its next DSM program plan filing.

How are NIPSCO Request for Proposals ("RFPs") for DSM programming incorporated into this process?

- Responses are dependent on vendor experience and the amount of energy efficiency they consider to be achievable in NIPSCO's market.
- Vendors propose different programs that may combine measures from several DSM Groupings also based upon experience.
- Proposed programs are influenced by deliverability and flexibility and these implementation factors are necessary components of a RFP process so that NIPSCO will be better able to meet the needs of a constantly changing market.
- Market changes include updates to codes and standards, new technologies, new vendors.
- NIPSCO needs to retain some flexibility to respond to these market changes.

IRP and DSM Plan Timeline

- This is a unique timeline for implementation due to the long lead time between the completion of the market potential study and the actual implementation of a program.
- Depending on the proposed RFPs, NIPSCO may include some measures in their final program designs that were not selected by the IRP or leave out some measures that were selected by the IRP.
- Working with their Oversight Board ("OSB"), NIPSCO may also make changes to programs during the program cycles in order to ensure that the savings goals are achieved at the portfolio level.
- Income Qualified is not a specific DSM Grouping, but NIPSCO is committed to offering Income Qualified programs in the future.
- NIPSCO wants to ensure that it remains committed to offering a consistent amount of DSM programs to all of its customers and working with its OSB.

IRP Process Measure Example

Presented by

Alison Becker

Manager Regulatory Policy

NIPSCO

IRP Process Measure Example: LED Light Bulb

- MPS Analysis
- Program Potential Review
- Aggregation of measure into DSM Grouping
- IRP analysis
- DSM Grouping selection
- Program creation
- Customer contact with measure
- Evaluation, Measurement, and Verification

LED Light Bulb Assumptions

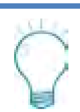
In this **hypothetical** example:

- TRC B/C ratio = 1.6
- Annual kWh savings = 35
- Measure cost = $8 (40% rebate, 60% customer portion)
- Program cost = 20% of Measure cost
- Lifetime = 12 years

NIPSCO

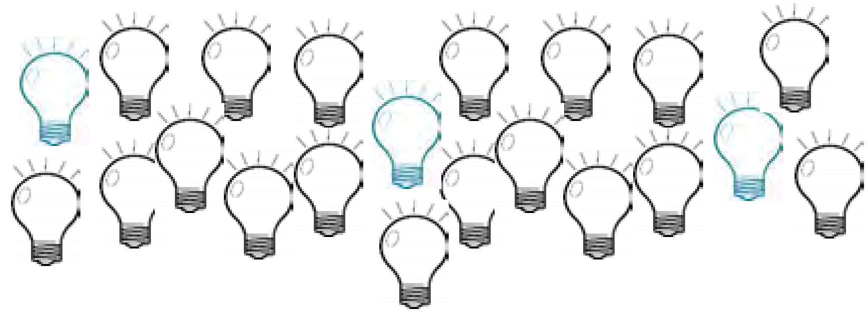
Step 1 – MPS Analysis: Technical Potential

- AEG utilizes LoadMAP Model to develop estimates of DSM potential and includes appliance/equipment models customized by end use.
- LoadMAP will provide forecasts of total energy use and energy efficiency savings associated with energy saving lighting measures.
- The Technical Potential assumes that all energy saving lighting measures will be put in all of the available sockets.
- No cost is applied to the light bulb.



LED Light Bulb

Measure:



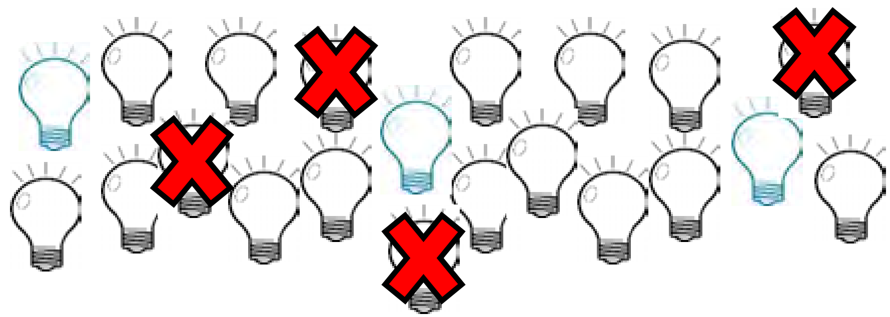
Application:

NIPSCO

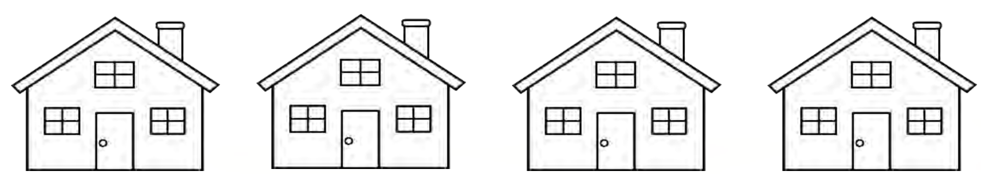
Step 2 – MPS Analysis: Economic Potential

- The Economic Potential assumes that all of the <u>cost-effective</u> lighting measures will be put in all of the sockets.
- Assuming LED light bulb could be installed in all applications.
- Economic Potential is looking at the cost of the light bulb outside of a utility program.

Measure:

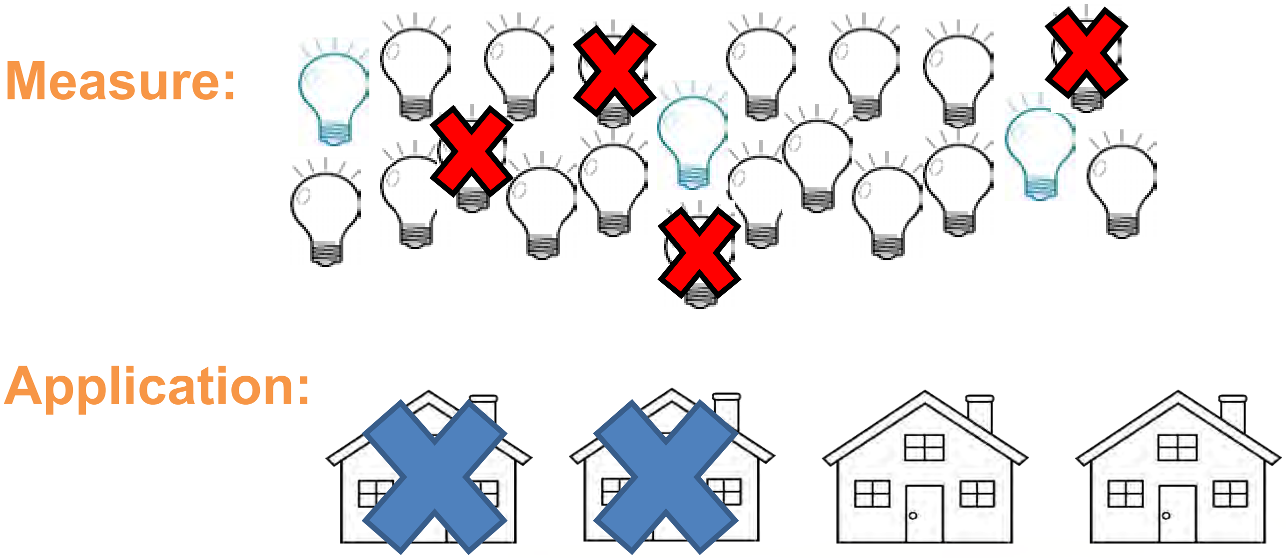


Application:



Step 3 – MPS Analysis: Achievable Potential

- The Achievable Potential takes adoption rates into account and assumes that some of the light bulbs will be put in some of the cost-effective sockets.
- A proxy program cost is applied to the light bulb. 50% incentive cost and 20% utility cost.

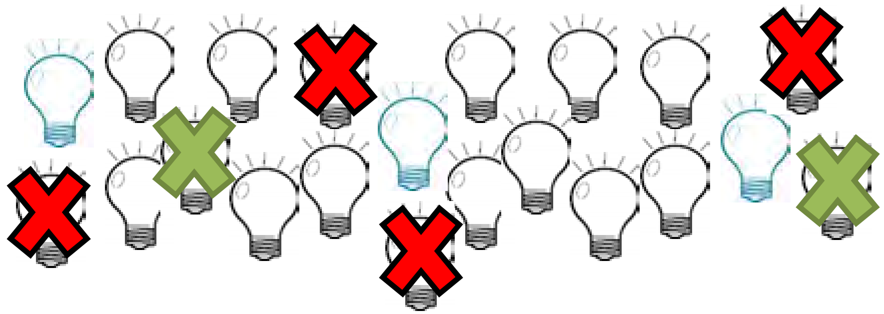


NIPSCO

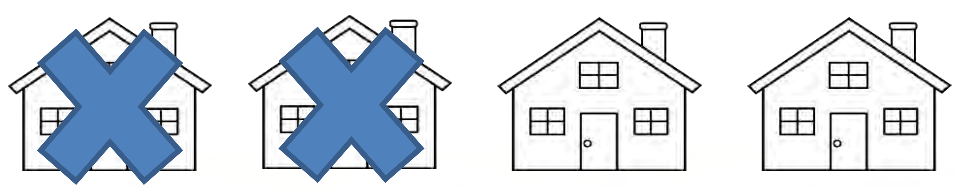
Step 4 – Program Potential

- The Program Potential incorporates installation rates and free ridership from NIPSCO EM&V reports.
- DSMore measures cost-effectiveness at the hourly rate using the TRC test.
- A comparable program cost (to NIPSCO's current programs) is applied to the LED light bulb.

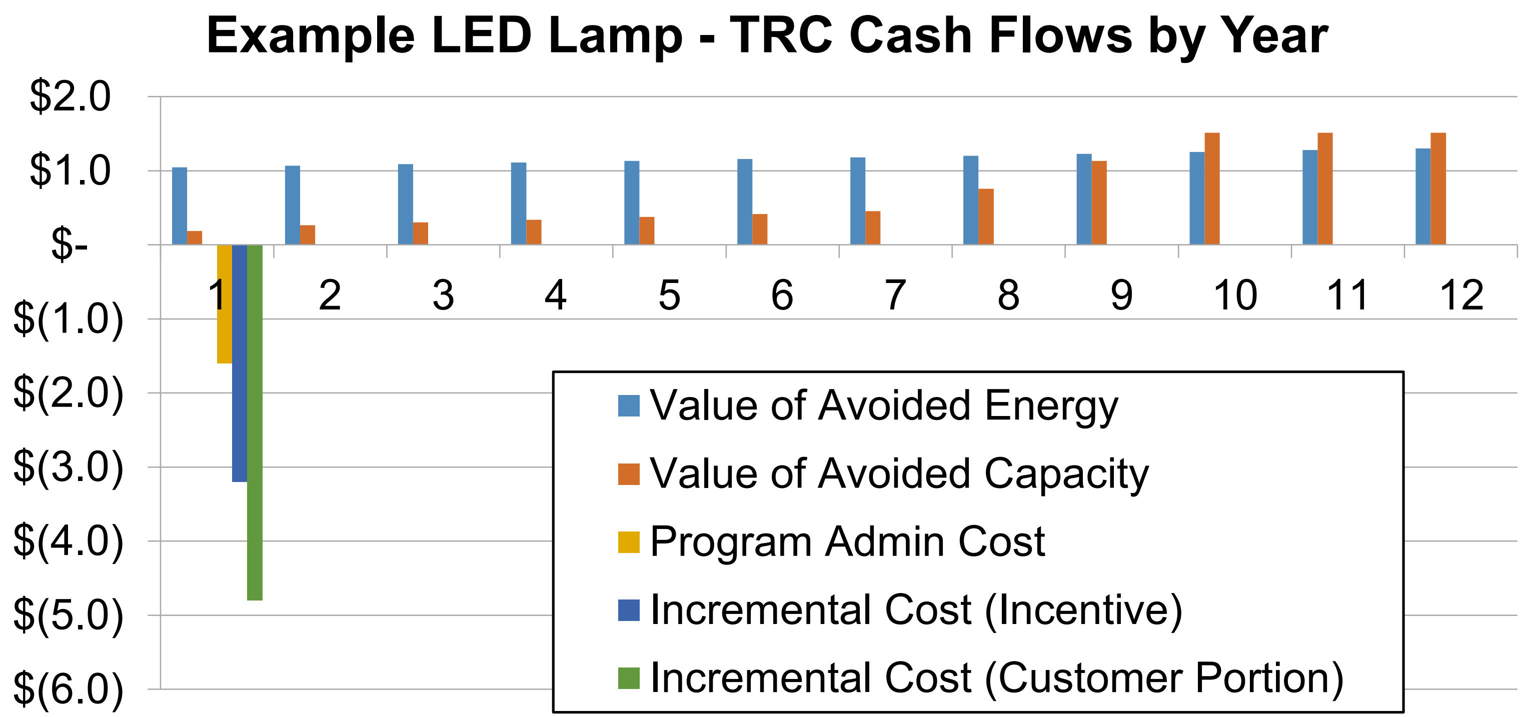
Measure:



Application:



Example of TRC Cost Benefit Analysis



In this **hypothetical** example:

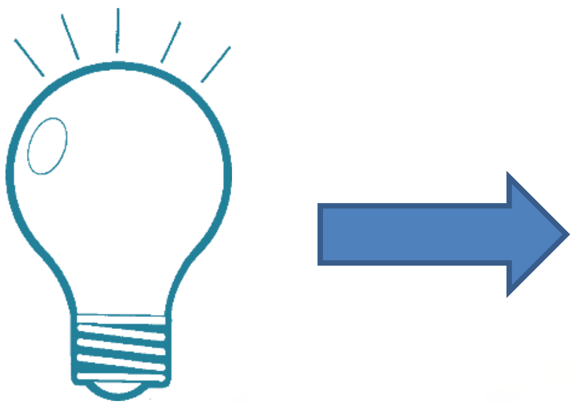
- TRC B/C ratio = 1.6
- Annual kWh savings = 35
- Measure cost = $8 (40% rebate, 60% customer portion)
- Program cost = 20% of Measure cost
- Lifetime = 12 years

NIPSCO

Step 5 – DSM Grouping Aggregation

What kind of load shape grouping would a LED light bulb measure best fit within? *Residential Lighting*

- The LED light bulb has a specific load shape and it is grouped with other measures that have similar load shapes.
- Other measures include Residential specialty lighting.
- The measures are also grouped by customer segment: Residential, Commercial and Industrial.

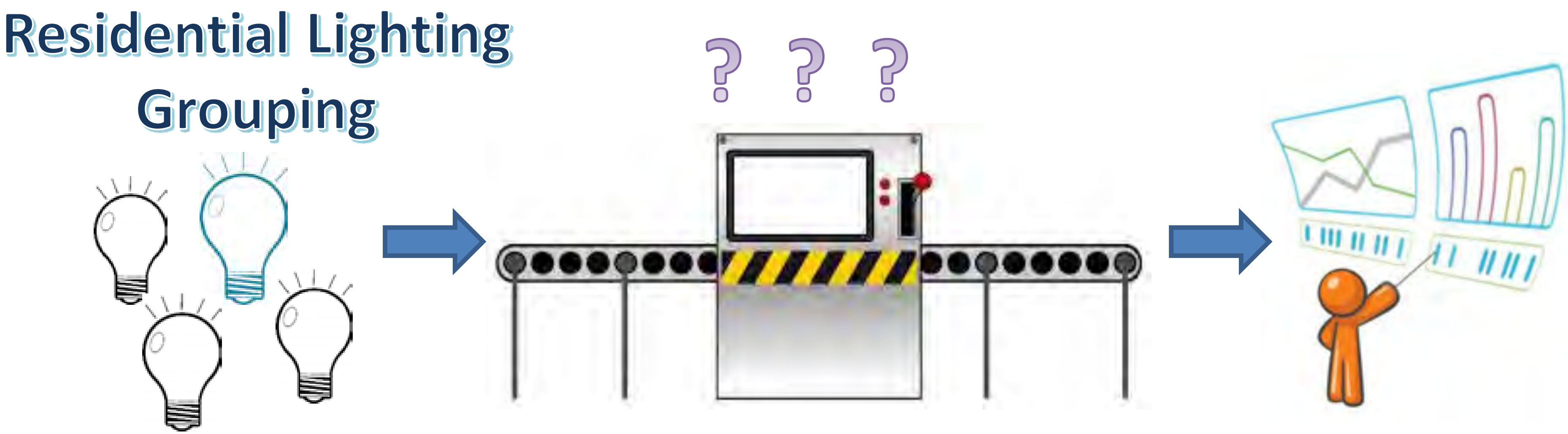


Residential Lighting Grouping

NIPSCO

Step 5 – IRP Analysis

- *Strategist*® looks for the most cost-effective resource option.
- *Strategist*® would analyze the savings opportunity for Residential Lighting and either select it for a specific scenario or not.



DSM Groupings (Input)

***Strategist*® Model (Analysis)**

Model Results (Output)

Step 6 – DSM Groupings Selection

- *Strategist*® will analyze the 26 DSM groupings – cost, savings, demand.
- The model will select the most cost-effective groupings, which could include Residential Lighting.
- Output from the model includes different DSM Grouping selections by scenario.
- Therefore, Residential Lighting may be selected by some of the four scenarios or 10 of the sensitivities.

Step 7 – NIPSCO Program Creation

- NIPSCO sends out a Request for Proposal (“RFP”) for energy efficiency implementation vendors to respond with program offerings.
- For the 2016-2018 DSM Plan, NIPSCO provided the groupings selected by the IRP and asked responders to propose programs that would fit within the savings profiles of each of the IRP groupings.
- This provides vendors with flexibility in proposing programs they have experience providing while also fulfilling the requirement of offering the DSM resources selected by the IRP.
- NIPSCO is still determining how it will build its next program filing following the 2016 IRP.

Step 8 – Customer Interaction

- NIPSCO's Residential Lighting program offers the incentives at the retail level…customers only see the reduced cost.
- Compare their different energy efficient light bulb options at the point of sale
- The customer purchases the LED light bulb at a lower cost.
- Installs the LED light bulb at home = savings

NIPSCO

Step 9 – Evaluation, Measurement & Verification

- Demonstrates the value of energy efficiency programs by analyzing the energy savings and the cost benefits of the programs
- The EM&V provider, contracted by NIPSCO, is selected by its Oversight Board ("OSB").
- NIPSCO's EM&V provider completes analysis on NIPSCO's Residential Lighting program and determines the amount of savings the customer achieved by installing the LED light bulb.
- The EM&V provider also looks at how well NIPSCO's program is designed and implemented.
- Such evaluation efforts are critical to understanding and improving program performance for the future. These results are used in NIPSCO's planning processes and is incorporated in future IRPs and program design.

Stakeholder Presentations

Integrate Electric Energy Equity
Our Power Plan

Presented by Denise Abdul-Rahman, MBA, HCM, HIS
NAACP Indiana,
Environmental Climate Justice Chair

Northern Indiana Public Service Company, Integrated Resource Plan

July 12th 2016

WE APPLAUD NIPSCO FOR

- Societal Cost Test
- Weatherization partnerships
- FIT, Net Metering, and Green Power

INDICATORS FOR MEANINGFUL ENERGY EFFICIENCY PROGRAMS

- Communities of color want to contribute to reversing climate change by using energy more efficiently.

- Data shows that households of color pay 30% more in energy costs compared to White households – mostly in electricity and space heating costs

.

- One reason for this is that people of color, relegated to areas of historical disinvestment and lacking the accumulated wealth to relocate, often live in older homes where new insulation and electrical appliances could help cut such costs.

LIFTING THE HIGH ENERGY BURDEN IN AMERICA'S LARGEST CITIES: HOW ENERGY EFFICIENCY CAN IMPROVE LOW INCOME AND UNDERSERVED COMMUNITIES

A recent report issued by the American Council for an Energy-Efficient Economy (ACEEE) and the Energy Efficiency for All (EEFA) coalition, with participation from the **National Association for the Advancement of Colored People (NAACP)**

Key findings from the report include the following:

- On average, low-income households pay 7.2% of household income on utilities – more than three times the amount that higher income households pay (2.3%).
- If low-income housing stock were brought up to the efficiency level of the average U.S. home, this would eliminate 35% of the average low-income energy burden of low-income households. For African-American and Latino households, 42% and 68% of the excess energy burden, respectively, would be eliminated.

Other key findings include the following:

- The Southeast and Midwest regions had the highest average energy burdens across all groups.
- Overall, low-income households experienced the highest median energy burden (7.2%), followed by African-American households (5.4%), low-income households living in multifamily buildings (5.0%), Latino households (4.1%), and renting households (4.0%).
- In 17 cities — which is more than one-third of the cities studied — a quarter of low-income households experienced an energy burden greater than 14%, substantially higher than the 3.5% median for all households.
- On average, African-American and white households paid similar utility bills, but African-American households experienced a median energy burden 64% greater than white households (5.4% and 3.3%, respectively). Latino households paid lower utility bills, on average, than African-American and white households did, yet they experienced a median energy burden 24% greater than white households (4.1% and 3.3%, respectively).

Air, Poverty, Unemployment and Energy Sector

- **71%** of African American **live** in counties in **violation** of **air** quality standards
- African American **child** is two to three times more likely than a white child to die of an **asthma attack**
- African Americans **unemployment** rate is twice that of white
- The energy sector obtains approximately **$41 Billion** from African Americans every year, African Americans only hold **1.1%** of energy jobs and gain less than **.1%** of the revenue from the energy sector

RETIRE

Retire Michigan City Generating Plant by 2018

Deaths: 28 ($200,00)
Heart Attacks 44 ($4,800)
Asthma Attacks: 470 ($24)
Hospital Admissions: 20 ($470)
Chronic Bronchitis: 17 ($7500)
Asthma ER Visits: 29 ($11)

Clean Air Taskforce 2012, Annual mortality living near Michigan City Power Plant

Equity, Energy, Economic Opportunity

1) Absolute CO2 Emissions Reductions in overly burdened communities
2) Equity analyses
3) Prioritization of energy conservation, energy efficiency, wind, solar and energy storage opportunities, removing incentives for the combustion of waste, Hydro,biomass or any other fuels for energy generation; and,
4) Workforce training and economic development funding mechanisms in place to support workers and communities to transition towards a clean energy economy

Our Preferred Scenario Encompasses Distribution of Equity within the Integrated Resource Planning Process

- An EQUITY METRIC
- Benchmark the reduction of CO_2 in non-attainment areas,
- Benchmark the distribution of clean energy to overly burdened communities as defined in the ACEEE report
- Benchmark Energy Efficiency program outreach, access and outcomes
- Benchmark economically blighted and vulnerable communities overburdened by energy cost or by power plant pollution access to jobs, programs, cleaner air and resistance to climate change
- Benchmark Meaningful, as related to the Clean Power Plan and relevant stakeholders

NIPSCO can make an immediate stark Economic and Sustainable difference in Michigan City, Gary, etc. and enhance the quality of the lives in the communities you serve and reside.

THANK YOU

American Council for an Energy-Efficient Economy (ACEEE), Energy Affordability, *Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities* NAACP Indiana External reviewer, January 2016

http://energyefficiencyforall.org/sites/default/files/Lifting%20the%20High%20Energy%20Burden_0.pdf

Clean Air Taskforce, http://www.catf.us/fossil/problems/power_plants/, 2012

Energy Democracy, Community Led Solutions

http://www.centerforsocialinclusion.org/wp-content/uploads/2013/10/Energy-Democracy-Community-Led-Solutions.pdf

NAACP, Just Energy: Reducing Pollution and Creating jobs Indiana Report
http://naacp.3cdn.net/5502c09b47ddedffb9_wrim6j5v0.pdf

Next Steps

Presented by

Dr. Marty Rozelle

The Rozelle Group Ltd

Next Steps

- **Future meeting timeline:**
  - 3rd Meeting scheduled for August 23, 2016
  - 4th Meeting scheduled for mid-September, date TBD
- **Meeting summary:** Available July 26, 2016
- **NIPSCO website:** *www.NIPSCO.com/irp*
- **NIPSCO IRP email:** *NIPSCO_IRP@nisource.com*

QUESTIONS

Demand Side Management/Energy Efficiency Terms

Term	Definition	Source (if applicable)
Achievable Potential	Refines economic potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of DSM measures.	Market Potential Study ("MPS")
Avoided Cost	The incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from a qualifying facility or facilities, the utility would generate or maintain itself or purchase from another source.	170 IAC 4-4.1
Economic Potential	Represents the adoption of all ***cost-effective*** DSM measures. In this analysis, the cost-effectiveness is measured by the total resource cost (TRC) test, which compares lifetime energy and capacity benefits to the costs of the delivering the measure through a utility program, with incentives not included since they are a transfer payment. If the benefits outweigh the costs (that is, if the TRC ratio is greater than 1.0), a given measure is included in the economic potential. Customers are then assumed to purchase the most efficient cost-effective option applicable to them at any decision juncture.	MPS
Energy Efficiency Goals	All energy efficiency produced by cost effective plans that are: 1) reasonably achievable; 2) consistent with an electricity supplier's integrated resource plan; and 3) designed to achieve an optimal balance in an electricity supplier's service territory.	IC 8-1-8.5-10 (c)
Grouping	A bundling of measures with similar load shapes and end uses.	
Measure	Any capital investment that reduces energy costs in an amount sufficient to recover the total cost of purchasing and installing such measure over an appropriate period of time and maintains or reduces non-renewable energy consumption.	United States Department of Energy
Plan	Goals, programs, program budgets, program costs and procedures submitted by an electricity supplier to the Indiana Utility Regulatory Commission.	IC 8-1-8.5-10 (f)

Program	A method of delivering measures to or seeking behavioral change by customers in the most efficient and cost-effective manner, with the ultimate goal of producing customer energy and demand savings.	
Program Costs	1) Direct and indirect costs of energy efficiency programs; 2) costs associated with the evaluation, measurement and verification of program results; and 3) other recoveries or incentives approved by the Indiana Utility Regulatory Commission.	IC 8-1-8.5-10 (g)
Program Potential	Creates utility programs from the measure-level, achievable potential results. This includes the subset of measures that can realistically be implemented considering alignment with near-term implementation accomplishments and budgetary constraints, as well as long-term strategic goals and planning constraints.	MPS
Technical Potential	Theoretical upper limit of DSM potential. It assumes that customers adopt all feasible measures regardless of their cost. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option. Technical potential also assumes the adoption of every other available measure, where applicable. For example, it includes installation of high-efficiency windows in all new construction opportunities and air conditioner maintenance in all existing buildings with central and room air conditioning. These retrofit measures are phased in over a number of years to align with the stock turnover of related equipment units, rather than modeled as immediately available all at once.	MPS
Program Potential	Creates utility programs from the measure-level, achievable potential results. This includes the subset of measures that can realistically be implemented considering alignment with near-term implementation accomplishments and budgetary constraints, as well as long-term strategic goals and planning constraints.	MPS

Applicable Statutes and Rules

IC 8-1-8.5-3(e) provides:

(e) In addition to such reports as public utilities may be required by statute or rule of the commission to file with the commission, a utility:

> (1) may submit to the commission a current or updated integrated resource plan as part of a utility specific proposal as to the future needs for electricity to serve the people of the state or the area served by the utility; and
> (2) shall submit to the commission an integrated resource plan that assesses a variety of demand side management and supply side resources to meet future customer electricity service needs in a cost effective and reliable manner.

The commission shall adopt rules under IC 4-22-2 concerning the submission of an integrated resource Hoplan under subdivision (2).

The current IRP rules provide at 170 IAC 4-7-6(a)(7) and 170 IAC 4-7-7(b) that the IRP must include:

(7) A discussion of demand-side programs, including existing company-sponsored and government-sponsored or mandated energy conservation or load management programs available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy.

> (b) An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements.
> The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers. For a utility-sponsored program identified as a potential demand side resource, the utility's plan shall, at a minimum, include the following:
>
> > (1) A description of the demand-side program considered.
> > (2) A detailed account of utility strategies designed to capture lost opportunities.
> > (3) 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 resources under consideration such as project life and seasonal operation.
> > (4) The customer class or end-use, or both, affected by the program.
> > (5) A participant bill reduction projection and participation incentive to be provided in the program.
> > (6) A projection of the program cost to be borne by the participant.
> > (7) Estimated energy (kWh) and demand (kW) savings per participant for each program.
> > (8) The estimated program penetration rate and the basis of the estimate.
> > (9) The estimated impact of a program on the utility's load, generating capacity, and transmission and distribution requirements.

The proposed IRP rule as of 7-5-16:
SECTION 13. 170 IAC 4-7-7 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-7 Selection of resources
Authority: IC 8-1-1-3
Affected: IC 8-1-8.5; IC 8-1.5

Sec. 7. (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.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-7; filed Aug 31,1995, 9:00 a.m.: 19 IR 23; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)

Northern Indiana Public Service Company
2016 Integrated Resource Planning
Stakeholder Workshop #2
SUMMARY

July 12, 2016

Welcome and Introductions

Dr. Marty Rozelle, the facilitator, welcomed participants and said that the agenda was very full so she would be strict with time. She outlined the objectives for the meeting and the agenda. She said the consultants would provide the information on the data used in demand side management ("DSM") modeling. NIPSCO would then discuss how DSM is incorporated into the Integrated Resource Plan ("IRP") process. Finally, there would be stakeholder presentations later in the afternoon.

She asked participants to write down their questions during the presentations, and told those on the phone they could submit questions through the chat feature on the online webinar. She provided the internet connection password.

Dr. Rozelle reported that NIPSCO met with several stakeholder groups since the first workshop in May. Materials from the first workshop are posted on NIPSCO's website at www.NIPSCO.com/irp. She announced that there would be another stakeholder meeting on August 23 that would feature NIPSCO's generating resources, and a final stakeholder meeting would be held in September to discuss the preferred plan for NIPSCO's IRP filing.

Participants were asked to introduce themselves. Alison Becker of NIPSCO listed participants who attended via webinar and phone. Dr. Rozelle introduced NIPSCO President Kathleen O'Leary to open the meeting.

Overview of Public Advisory Process
Kathleen O'Leary, President, NIPSCO
(Slides 3-7)

Ms. O'Leary welcomed everyone to the second stakeholder meeting for the 2016 IRP, saying she was speaking for Violet Sistovaris who was not able to attend the meeting. She noted that the main topic of the meeting would focus on DSM, which can play an important role in the energy future of NIPSCO. She thanked stakeholders for taking the time to attend.

For the safety moment, Ms. O'Leary told the group that the Company has recently made a decision that employees will soon be unable to use the telephone while driving, noting that many companies that put safety first have adopted this policy. She said that although it may be difficult for people who spend a lot of time in the car, it's a decision that makes everyone more aware of road safety. She urged participants to minimize distractions while driving.

Review of IRP Meeting 1 and Timeline
Daniel Douglas, Vice President Corporate Strategy and Development
(Slides 8-10)

Dan Douglas provided an overview of the stakeholder process and provided a summary of the May stakeholder meeting. He noted that based on feedback received during individual stakeholder meetings, the meeting would focus on DSM rather than a deep-dive into NIPSCO's existing generation fleet as originally planned. Mr. Douglas gave an overview of how the meeting would flow with (1) Dave Costenaro of Applied Energy Group ("AEG") talking about the types of DSM savings potential as well as the available energy measures, (2) Rick Morgan of Morgan Marketing Partners discussing how the measures are grouped together as inputs to the IRP, (3) Ed Achaab of NIPSCO describing how the DSM model inputs are used in the IRP model, and (4) Alison Becker of NIPSCO summarizing how NIPSCO will use the model results to develop NIPSCO's DSM plan as well as walking through how a DSM measure moves through the entire IRP process.

Mr. Douglas noted that NIPSCO would talk about the development and management of NIPSCO's generation resources, as well as retirement options, and the optimization plans being developed for the IRP during the August 23 stakeholder meeting and NIPSCO will discuss the preferred IRP portfolio during the September stakeholder meeting. He offered to hold individual meetings with stakeholders, if interested, prior to the August 23 stakeholder meeting.

Mr. Douglas noted the five factors used to screen supply-side resources: (1) energy source availability, (2) technical feasibility, (3) commercial availability, (4) economic attractiveness, and (5) environmental compatibility. He said NIPSCO used 21 of the 32 supply-side resource options that came out the Sargent & Lundy Study, which is necessary from an efficiency standpoint for the model.

A participant asked whether there could be more specificity on the various screens, noting that the Ratepayer Impact Measure ("RIM") test provides different results than the Utility Cost Test ("UCT") and Total Resource Cost ("TRC"). More specifically, she wondered how these screens compare to each other. Mr. Douglas answered that a more in depth discussion of the various screens would be included later in the presentation.

NIPSCO 2015 Market Potential Study
David Costenaro, Director, AEG
Bridget Kester, Senior Project Manager, AEG
(Slides 11-19)

Dave Costenaro provided an overview of the five major steps in developing an IRP. He noted Bridget Kester would discuss Steps 1, 2 and 3 – the Market Potential Study ("MPS"), Rick Morgan would discuss Step 4 – the DSM program potential and IRP inputs, and Ed Achaab would discuss Step 5 – the IRP model selections.

AEG, working with Rick Morgan of Morgan Marketing Partners, developed the MPS for NIPSCO. Ms. Kester described how AEG conducted the MPS for both electricity and natural gas. AEG considered how much can be saved using DSM over a 20 year period. A market profile for the base year was the first step, showing how energy was used in 2014. Using information from NIPSCO, AEG broke the total market into sectors (Residential, Commercial, and Industrial) looking at market size, new versus existing construction, energy end-uses, and other factors. AEG compiled all of the information to create a baseline projection. It is the baseline projection against which AEG assesses the different levels of DSM savings potential. In essence, AEG asked the question "if there were no energy efficiency programs, what would energy usage look like?" AEG then develops 20-year projections for each potential analysis scenario with different assumptions about the energy efficiency measures that are applied to the baseline projection. These forecasts look at technical, economic, and achievable levels of savings potential and predict annual energy and peak demand savings.

AEG explained that The National Action Plan for Energy Efficiency describes the framework of the Market Potential Study. The MPS addresses: (1) **technical potential**, which assumes that the most efficient option is always selected upon the replacement of an old measure; (2) **economic potential**, which identifies the subset of measures within the technical potential that are cost-effective according to the total resource cost test ("TRC"), which includes the avoided costs provided by NIPSCO; (3) **achievable potential**, which takes into account the market and adoption barriers that might exist, recognizing that not all customers will adopt all available and cost-effective measures. Ms. Kester explained how these steps are performed using AEG's *LoadMap* model. She stated that Rick Morgan would talk more about **program potential**, which is NIPSCO-specific and was considered downstream of the MPS.

The results of the MPS were shown for 2016 to 2021. Cumulative achievable potential starts around 1% in the first year and increases to 3.5% by 2021.

Participant questions and comments included the following:

- How do you take into account technological advances that might occur in the future?
  - AEG responded that the analysis does not include or imagine new technologies that do not exist or have supporting reliable data or projections, but it does include those that are known at this time, including those that may not be cost effective.
- Is it right that opt-out customers (41.8% of load) are not included in this study? The participant pointed out that this approach may not be accurate since opt-out customers can rejoin the program.
  - AEG noted that it did remove the opt-out customers from the study and did the analysis on the remaining NIPSCO customers. Ms. Becker clarified that NIPSCO will talk more about this policy decision later in the meeting and explained that the goal for the morning session was for the consultants to discuss the process and then NIPSCO would discuss how it made various policy decisions in the afternoon session.
- In regard to utilizing historic information [to build the baseline projection] and estimates of customer participation levels, there has been a lot of turmoil and variability in the DSM process since 2009, so how do you account for that wide variation?
  - AEG considers the previous year's performance, benchmark to other regional utilities, and looks at other planning studies that AEG and other consultants have done to provide a general view of customer adoption in the marketplace. In a voluntary program, it would be unreasonable to expect anything close to 100% customer participation. Based on this information, AEG makes assumptions about how adoption may increase given various scenarios.
- What are the most subjective inputs in the model and how do you determine future customer acceptance rather than just past?
  - AEG stated that it would not characterize any of the modeling as subjective, stating that it is data-driven. The achievable potential does deal with people, who are difficult to predict and must be dealt with statistically and in averages, so that may be considered less objective than other inputs. Future customer acceptance is estimated by researching locations that have had DSM programs for longer periods of time to look at market trends. Benchmarking also helps address this issue.

Mr. Costenaro summarized the end-to-end flow of data from the MPS through the end of the IRP using five steps, showing that the potential energy savings are sequentially reduced through application of the required potential analysis steps. Referring to slide 16, he said the numeric data on the chart are from the market potential modeling and the *DSMore* economic screen. Step 1, the technical screen, considered 100% of measure savings and 100% of customers. The MPS economic screen in the economic potential step eliminated 33% of measures considered in this process with a TRC ratio of less than 1, but does not affect the number of customers. The achievable potential step applied customer adoption rates and eliminated 64% of customers who would not participate, but did not affect the number of measures. The program potential step, which Rick Morgan described (see below), removed an additional 11% of measure savings before the data is ready for input to the IRP.

Mr. Costenaro also described an alternative approach that could have been undertaken with fewer steps (in response to Citizens Action Coalition questions). In this approach, steps 2 and 4 are skipped such that a less-processed dataset is presented as inputs to the IRP. It is important to note that this process would require significantly more modeling time and effort by the IRP staff and software, but the results would be roughly the same as the 5-step process actually implemented in the MPS.

He then discussed the process that was used to determine what measures would be included in the IRP, based on end-use load shapes. Measures with similar end-use load shapes are grouped together.

Participant questions and comments included:

- How and why did you choose the TRC for the cost/benefit analysis?
  - The current Indiana rule states to look at 5 tests, but traditionally more weight has been placed on the TRC analysis. This may change in future.
- Why not use the UCT instead?
  - NIPSCO responded that there is always a judgment call about which test to use and in what form. The UCT is a little more lenient because it does not consider the cost that consumers pay. From NIPSCO's point of view, the UCT will be cheaper, but it will not necessarily be cost-effective for the customer. These program design options have been discussed with Citizens Action Coalition and other stakeholders. NIPSCO indicated it is committed to continue to look at this; the IRP is not the end of the DSM evaluation process. But the MPS is finished, due to time constraints and it will not be revised based on other assumptions for this current version.
- Regarding load shapes, there was a question about residential cooling peak. Did you consider showing commercial and industrial cooling that are peaking at the same time?
  - The load shapes pictured on the slide are only illustrative examples, and many others from the analysis are not shown. AEG included commercial cooling load shapes and many others in the model to provide the appropriate characterization of each measure and load considered.
- Are the measures also grouped or distinguished by cost levels when bundled and prepared for the IRP?
  - No, they were just compiled by end-use load shape for the groupings to be input to the IRP.
- How are you making sure that a large portion of the 36% of customers targeted for adoption are the most energy-burdened of your customers?
  - Ms. Becker pointed out that this is a policy question; the model does not make these choices or specify locations and customer populations. It simply looks at averages and available measures.

NIPSCO DSM Program Potential
Rick Morgan, Morgan Marketing Partners ("MMP")
(Slides 20-32)

Rick Morgan apologized for not being at the meeting in person. His objective in this presentation was to explain the program potential step of the modeling process.

He explained that the program potential step is about refinement and localization to NIPSCO's service territory. Evaluation information is applied based on NIPSCO history and on past budgets allotted to programs. As a default, measures are kept in for additional analysis unless hourly data shows that the measure is not cost effective in NIPSCO's service territory. However, some measures that are not cost effective have continued to be analyzed to serve specific customers or objectives.

The model used for the DSM program analysis is *DSMore*, which analyzes the hundreds of measures emerging from the market potential models. This model evaluates on an hourly basis, allowing it to be correlated to weather and hourly market prices rather than annual averages. Weather data from 33 years are used, as well as multiple years of power market data, resulting in a weather-weighted price. A small portion of measures (about 27) were screened out through this process. The default position was to keep measures in the analysis unless they were not cost-effective or otherwise not suited for NIPSCO's particular service territory or program framework.

Mr. Morgan demonstrated the results of the residential measures screening (Slide 22) describing some measures that were removed or retained based on the TRC test. Many non-cost-effective measures were also retained in the analysis for reasons other than the TRC criteria. Similar examples were presented for commercial and industrial measure screening.

He described the concept of avoided cost, which is the value of reducing peak energy and demand on the customer side of the meter. Avoided costs can include energy costs, transmission and distribution costs, and other resource costs and are used in the cost-effectiveness tests. Cost and benefits are calculated for each measure individually and are added together in the DSM groupings when prepared for input to the IRP. Avoided cost benefits are the same for the TRC and UCT tests, although the costs from each test are slightly different. The TRC includes all costs, while the UCT includes only the utility costs and neglects the customer share of the measure cost. Benefits derived from the measure impacts also vary based on the hour. Mr. Morgan explained the details using a chart representing the market price that changes over time versus the examples of residential interior and exterior lighting impacts that align better and worse respectively with the time periods of high market value.

The individual measures are aggregated into groupings (for example, residential lighting) to be provided as inputs into the IRP. In explaining programs versus groupings, Mr. Morgan said that programs are about delivery methods and should be changeable, and not tied specifically to measures and technologies. Programs are developed to overcome market barriers, which change and evolve over time. Using the DSM load-shape groupings and leaving the program design flexible over the 20-year IRP analysis period allows NIPSCO to deliver programs effectively and flexibly to customers to meet evolving needs.

The portfolio of energy efficiency (DSM groupings) was shown for residential, commercial and industrial sectors (Slide 30) as well as demand response ("DR") groupings.

In summary, Mr. Morgan reviewed the process of building the DSM groupings that are used in the IRP. He noted that the benefit/cost tests are produced during the modeling process and include both TRC and UCT in addition to PCT, RIM and the Societal Cost Test. They are all based on the California Standard Practice Manual calculations.

Questions and comments included the following:

- What is the total number of measures screened out between technical potential and program potential?
    - Mr. Morgan noted that the number of measures screened is not a good indicator of how much savings were removed. Some measures can represent a very small savings and others a large amount of savings. Mr. Morgan stated he could remove 100 measures, but the measures would only represent 1% of savings potential. The number of measures does not directly represent the amount of savings available. Specifically, 27 measures were removed from the Achievable to Program potential step. While AEG could provide the other data, the better indicator is the amount of energy savings that is reduced or added during the step.
- Is MMP's work on DSM program potential the same as preparing an Action Plan?
    - Mr. Morgan explained that the *DSMore* analysis is the same, but the timeframes are different. Action Plans are for programs and are not as technology driven. He explained that for the IRP, the goal is to look longer term and try to not restrict what is offered. Program potential is projected over 20 years based on average costs to operate programs because the IRP requires NIPSCO to represent the cost for 20 years (kilowatt hours saved) as input to the IRP.
- A participant noted that program potential is typically evaluated for a small segment of time, not 20 years.
- How are avoided costs for transmission and distribution calculated since transmission and distribution may be location specific?
    - Mr. Morgan responded that this data is provided by NIPSCO based on averages across the system. There are ways to get very specific distribution costs in isolated areas, but in putting together the analysis the goal is to represent what happened on the system.
- What's the difference between AEG and MMP's application of avoided cost in the MPS versus the detailed analysis? Will they be different when NIPSCO files a plan?

    - AEG uses gross annual averages due to the comprehensive, high level nature of the MPS. MMP uses a more granular economic analysis with long term weather data and market prices correlated on an hourly basis. It is also worth noting that avoided cost projections are updated by NIPSCO annually and may result in different values in the analysis steps depending on the schedule.
- What is the difference between AEG's application of program results for customer take rates versus NIPSCO's program history?
    - AEG's analysis considers averages and generic costs, which are taken at a very high level because the study considers the entire universe of possible measures. With the processed subset of data that MMP received in the Achievable Potential, it applied localized details and NIPSCO's evaluation results, including NIPSCO-specific net-to-gross ("NTG") numbers to produce the Program Potential. MMP started with the gross numbers that are created based on AEG's MPS and refines them with NIPSCO's NTG numbers.
- How is the TRC analysis in this process different than industry-defined TRC?
    - They are not different; just the terms are different. Formulas for the tests are from the California Standard Practice Manual.
- Are avoided capital costs included?
    - Yes if MMP knows what they are. MISO data is embedded in some of these.
- Is the urban heat island factored into projected energy use by air conditioning that will be used by energy-burdened customers?
    - The analysis used the savings based on the Technical Resource Manual ("TRM") in Indiana, which considers a variety of weather zones to take the various service territories into account. Loads and measure impacts were derived using local weather zones.
- Are the groupings done by end-use cost buckets?
    - No, they are not explicitly categorized or sub-divided by cost. The groupings each have a unique size and cost that emerges after completing the AEG and MMP analysis process. The avoided cost benefits are the same assumptions applied across all groupings.
- Will NIPSCO be providing levelized costs by grouping? Are you able to put them in smaller buckets instead of the larger buckets? This participant's concern is how energy efficiency will be picked when it is such a large group within in the IRP model.
    - Mr. Achaab said that as of today NIPSCO is not providing levelized costs by grouping. He noted that the Tennessee Valley Authority ("TVA") has started to break out the DSM costs into tiers. NIPSCO is starting with DSM Groupings, which is very complicated and challenging in itself and NIPSCO will look into doing the tiered model in the future, but not for the 2016 IRP.
- Does the avoided cost capture the full cost of new generation for the period?
    - DSMore is not a comparison of a wind mill versus energy efficiency. The analysis represents the market value of avoided purchases, but is not a

comparison of efficiencies of various generation technologies – that is what the IRP provides.

- Does avoided cost change over the future?
    - Yes, avoided cost changes going forward. MMP used a historical value in correlation with weather and prices. MMP is expecting avoided costs to change in the future. Data on this is obtained from NIPSCO, among other sources. MMP represents NIPSCO's future cost in a consistent way.

IRP Modeling of DSM
Edward Achaab, Manager Resource Planning, NIPSCO
(Slides 33-40)

Mr. Achaab summarized that the input to NIPSCO's model includes 22 energy efficiency groupings and 4 demand response groupings that resulted from the process described by previous presenters. The 2 Industrial demand response groupings were not incorporated into the model. Instead, NIPSCO is planning to model around 527 megawatts ("MW") of interruptible service in the 2016 IRP. The 527 MW was a result of NIPSCO's rate case settlement. If NIPSCO assumed there was not a cap on the amount of Interruptible demand response, NIPSCO could have included an additional 29.5 MW. The 56 MW Demand Response Rider 681 is not incorporated into the model as it represents energy and not capacity.

Mr. Achaab reviewed the DSM inputs into the model, which include energy savings, capacity savings, program costs, and savings load shapes. As noted by Mr. Morgan, the *DSMore* load shape data are provided in 8,760 hourly data (the number of hours in one year). NIPSCO runs the annual hourly data in an Excel macro-model that converts it into a typical week format for input into the *Strategist* IRP model.

Mr. Achaab reviewed the overall IRP modeling process. He showed a slide illustrating how demand side resources (as explained by the previous presenters) and supply side resources (from the Sargent & Lundy study and existing NIPSCO resource data) are initially screened prior to being included as inputs to the IRP analysis. The screening of potential future resources helps narrow down the number of viable options for the model; NIPSCO needs to be able to provide a number of options that are sizeable enough to allow the model ample enough time for the model to solve without crashing.

Mr. Achaab noted that the *Strategist* model uses dynamic programming, in which the model produces exponential options; this is why it is very important to screen the number of options before inputting them into the model. The 26 DSM groupings are included in the model along with all other supply side resources including coal, gas, renewables, etc. and all of the resources compete with each other on equal footing. The DSM groupings will be optimized in each scenario to better understand their value across different futures represented by the four scenarios and 10 sensitivities that were identified at the first stakeholder workshop. Mr. Achaab noted that NIPSCO would be adding an additional scenario that will be reviewed at the next meeting. The objective of the optimization process is to determine which resource options fare best across the scenarios. A consistent selection of DSM groupings across all of the scenarios represents the best opportunities for energy efficiency within NIPSCO's service territory. He explained that the same process is used in modeling supply side resources.

Several factors are used to evaluate the preferred portfolio. Economics is the primary factor but, as Violet Sistovaris outlined at the first meeting, NIPSCO also considers cost effectiveness, reliability, compliance, flexibility, and efficiency. Some of these factors can be costed out (quantitative) and others represent values to the company (qualitative). Mr. Achaab observed that because the cost of traditional generation will likely increase over time depending on the scenario, DSM may look more attractive in a particular scenario. He cited the aggressive environmental scenario as an example of a scenario in which the cost of traditional generation will likely increase due to increasing commodity prices and environmental compliance costs. In such a scenario, the value of DSM is attractive due to the increased costs of operating the alternative traditional generation.

The *Strategist* model selects the optimal plan, but also provides sub-optimal plans. The least-cost plan will be identified, as will others that meet different objectives like environmental compliance. Additional DSM groupings may be added to the preferred portfolio for reasons other than cost, and these will be re-run through the model as appropriate to compare costs.

Questions and comments included the following:

- Indiana Utility Regulatory Commission (IURC) staff asked several technical questions about the models used and how they process the 8,760 hourly shapes. Mr. Achaab explained how they are done and also said there may be adjustments in the future through a transition to another model that does not need to convert the 8,760 hourly shape to a typical week format.
- The CAC asked what NIPSCO meant by re-running the additional DSM groupings through the model.
    - Mr. Achaab clarified by saying if NIPSCO selects the Base Case scenario plan and 13 DSM groupings were selected in that plan, NIPSCO may decide to add 3 additional DSM groupings that were selected in other scenarios. In that case, NIPSCO will take the 16 DSM groupings and re-run them through the model to see what the cost variance is from adding the 3 additional DSM groupings to the Base Case scenario to show the difference between the new proposed plan and the original scenarios.

IRP Results and DSM Program Filing
Alison Becker, Manager, Regulatory Policy
(Slides 35-57)

Before beginning her presentation, Ms. Becker addressed several earlier stakeholder questions. In response to the question of why NIPSCO did not consider the opt-out customers in its MPS, she explained that the General Assembly requires utilities to allow large customers to opt out of participation in the DSM programs. Not including those customers in the study was a judgment call, but the Company decided to focus on what it knows is occurring now in its service territory. She stated that NIPSCO will be inviting these customers to opt back in to participate in the program, and if this happens those customers will be added back into future studies and other analyses. In response to the question relating to relying on the TRC test as an economic screen, she stated that while recognizing that people have different views on this and that other cost benefit approaches are available, as a matter of policy, NIPSCO has chosen to continue using the TRC test. In response to the NAACP question of how the cost of energy affects lower income customers, Ms. Becker noted that the MPS does not provide information about specific customer classes such as low income. She stated while there are a variety of ways that assisting NIPSCO's low income customers comes into play, it is not a part of the modeling. The low income services are built into the programs after NIPSCO receives the modeling results. She noted these type of questions are handled through policy in developing an overall business plan, and NIPSCO will evaluate these issue in putting together a DSM plan and planning new facilities such as redevelopment of brownfields sites.

Ms. Becker provided an overview of her presentation. She said that the next step after the IRP is to prepare a 3-year energy efficiency plan using the results of the IRP. Based on the results of the IRP, requests for proposals ("RFP") are issued to vendors to implement the selected DSM groupings. Different approaches have been used in the past to do this. This year it was based on achievable results from the Market Potential Forecast, which were included in the RFPs. For the next energy efficiency plan, the IRP results will be used in the RFPs to vendors.

The contracts used with vendors are pay-for-performance, so contractors need to demonstrate actual kilowatt-hour savings. This approach results in savings and accurate reporting and provides for a process for continual feedback and improvement. GoodCents and Lockheed Martin are the two current vendors for NIPSCO's DSM programs. NIPSCO asks the vendors what is possible to achieve in NIPSCO's service territory based on the MPS, evaluation, measurement and verification ("EM&V") results, and the vendor's experience. It is important to note that the MPS is prepared from an academic view, but then the implementers are looking at what can actually be achieved in NIPSCO's service territory. Vendors do not necessarily find their programs to fit neatly into the DSM groupings. NIPSCO plans to work with its Oversight Board to put together an RFP to seek vendors who will put together programs that meet deliverability and flexibility objectives to allow the vendors to better meet changing market needs (such as updates to codes and standards, new technologies, and different programs).

She gave an example of how NIPSCO was the first utility in the State to pilot smart Nest thermostats to its customers.

A draft RFP is prepared and reviewed with NIPSCO's Oversight Board, which includes the OUCC, CAC, and the Industrial Group. When finalized, it is sent out to vendors to respond. This process needs to be completed by the end of 2017 to coincide with the filing of an energy efficiency plan. The filing can be made either before or after issuance of the RFPs, and this has not been decided for the upcoming plan. While income-qualified programs are not specific DSM offerings for the IRP, NIPSCO will continue to offer a low income program in future energy efficiency plans.

Ms. Becker asked participants what NIPSCO should do if the model selects less DSM than is currently being offered. Suggestions included to make sure as many programs as possible are included in the bundles for selection, and that the IRP should include the energy efficiency potential amount from the economic or technical potential step instead of screening out measures.

Questions and comments from participants included the following:

- Will the RFPs be required to meet the energy efficiency goals that come out of the IRP? Or will it be different?
    - We don't know for sure yet. It depends on the modeling results and input from the Oversight Board. The intention is to make sure the RFP and the energy efficiency plan are consistent with the IRP and that the plan has a good balance of resources available.
- How does this relate to the amount of gas savings, since NIPSCO provides both gas and electric programs?
    - For its DSM programs, NIPSCO tries to run joint programs for both gas and electric as often as possible. The gas program tends to follow the structure of the electric program, so NIPSCO will look to maintain about the same amount of spending for gas as in the past. NIPSCO looks to offer combined programs when possible to provide better savings and higher customer satisfaction.
- With the latest draft of the IRP rules, the cost/benefit test requirement was removed, so NIPSCO is only using program potential. Will NIPSCO reconsider using program potential in the future?
    - As the Commission's IRP Rule continues to be finalized, NIPSCO will determine how to best proceed.
- How do you incorporate industrial customer opts-out that are doing energy efficiency now into the IRP process?
    - NIPSCO has seen the amount of energy purchased by those decline, so it is accounted for in other ways than the energy efficiency programs. Also, a number of customers still participate in demand response programs, which are not considered energy efficiency, and these are still considered in the IRP.
- Are measures also grouped by cost?
    - No.

- What do you do when the response to the RFP doesn't produce the savings that the IRP expects?
    - Fortunately, this has not happened yet. If it does happen, perhaps the Oversight Board can assist in suggesting new ideas. Then a determination needs to be made about whether to go forward, and whether it needs to be reviewed with the IURC.

DSM Measure Example
Alison Becker, Manager, Regulatory Policy, NIPSCO

Ms. Becker presented an example of how an LED light bulb moves through the IRP process. She reviewed the assumptions made about the costs and savings of the example LED light bulb, and showed a series of graphics illustrating the implementation steps involving the technical, economic, achievable, and program potential steps of the IRP process involving the LED light bulb.

Step 1 is to determine the technical potential of the measure, which does not consider economic or customer adoption rates. No cost is applied to the light bulb and every available application of the measure is installed. Step 2 is to evaluate economic potential in the absence of any incentive programs. This step is looking at the cost-effective lighting measures and assumes every economic application of the measure is still available. Step 3 looks at the achievable potential, which is where customers come into play. In this step incentive programs are considered to estimate what percentage of customers might adopt the program if given an incentive to do so. In step 4, the program potential, or predicted installation rate, is assessed. This step looks at the installation rates and the free-ridership estimates for NIPSCO's residential lighting programs.

All of this information is input to the *DSMore* model to determine cost effectiveness. Ms. Becker presented an example of the TRC cost/benefit analysis. This approach produces a front-end-loaded cost. Avoided energy and avoided capacity costs continue throughout the measure's life cycle operation. The end result, applied to the light bulb, is TRC benefit/cost ratio of 1.6, based on annual kWh savings of 35, a measure cost of $8 with a 40% customer rebate, a program cost of 20% of the measure cost, and a 12-year program life.

Step 5 is the DSM grouping aggregation, where the load shape of this measure is matched with similar options, e.g. 'residential lighting.' The DSM groupings are provided to NIPSCO as inputs into the IRP model. For the IRP analysis, the *Strategist* model looks for the most cost-effective option among both supply-side and demand-side resources by analyzing impacts and costs and either selects or omits a given DSM grouping for a particular scenario. Step 6 is selection of DSM groupings.

Step 7 is to create a DSM program and prepare an RFP. The question of whether to send out the groupings has not yet been decided because this proved to be a confusing issue in previous vendor responses. The main objective is to allow vendors to achieve the target savings and allow them the flexibility to do so. Ms. Becker asked the IURC for support on this approach.

Step 8 is customer interaction. For example, LED light bulbs may be marketed and offered through specific stores with an incentive for customers. The customer will purchase the reduced-priced LED light bulb in a store participating in the program in NIPSCO's service territory. Step 9 is EM&V of the program and the specific measure, the LED light bulb. An independent evaluator is selected for this task by the Oversight Board. In-store intercept surveys may be included in this process for programs like residential lighting. Ms. Becker noted that while she would like to hire more Indiana-based companies to do this, the companies that do it have data from all over the country. The results are used to improve future IRPs and DSM programs.

Questions and comments included:

- Looking at the graph, what we're not seeing is that the technology isn't 100% reliable. Some of the bulbs will fail early, is the cost of replacing bulbs as needed included in this analysis?
    - Yes, it's included in the development of the TRM in calculating the average life of the measure.
- Wouldn't there be administrative and marketing costs that go beyond the first year?
    - Not in this example. For most programs that have measures installed, you walk away after that first installation, but there could be in other measures or programs.
- When are lost revenues factored into the cost/benefit analysis? Don't avoided energy costs change over time, and how would that be accounted for?
    - Lost revenues are factored in depending on the test. The RIM and PCT tests are two cost benefit tests that include lost revenues in the analysis.
- Using the example of someone who stores these DSM measures instead of installing them, when the vendor looks at how many bulbs are purchased do they account for how many have actually been installed to calculate their associated savings?
    - Yes, the evaluators extrapolate the results from the participant surveys and any other information that is provided.
- The CAC offered feedback on NIPSCO's energy efficiency bundles, as follows:
    - Use the technical potential in the IRP
    - Group energy efficiency bundles by end use cost bins in addition to accounting for load shapes
    - Include industrial opt-out customers in the analysis

Stakeholder Presentations

NAACP Indiana – Integrate Electric Energy Integrity
Denise Abdul-Rahman, Environmental Justice Chair

Denise Abdul-Rahman introduced herself, and said that NAACP has a unique stake in the energy planning process. They feel that they are the experts when it comes to their communities, and they recognize how important these plans are to the federal Clean Power Plan and other state and federal regulations. She thanked NIPSCO for making space for them in this process. The NAACP applauded NIPSCO for including a societal cost test in the 2014 IRP and including weatherization partnerships and other programs like net metering, the feed-in tariff, and the Green Power Program.

She would like NIPSCO to consider indicators for meaningful energy efficiency.
- Communities of color want to contribute to reversing climate change by using energy more efficiently.
- Households of color pay 30% more in energy costs compared to white households.
- For various reasons people of color often live in older homes that are not energy efficient.

The NAACP recently contributed to a research study with the American Council for an Energy-Efficient Economy ("ACEEE") and the Energy Efficiency for All ("EEFA") coalition that show that, on average, low income households pay 7.2% of income on utilities, more than 3 times that of higher income households, which spend 2.3%. If low-income housing stock were brought up to the efficiency level of average U.S. homes it would eliminate about 35% to 68% of the low-income and minority excess energy burden.

The Southwest and Midwest regions have the highest average energy burdens across all groups. People living in major cities have higher energy costs than others including Indianapolis in the statistic of cities with greater than 14% energy burden for low-income families. People of color in these areas have higher energy burdens than whites.

Don't discount the fact that low income communities bear a disproportionate burden of costs and health effects from poor air quality. Ms. Abdul-Rahman asked that NIPSCO retire the Michigan City coal plant by 2018, and showed data describing mortality rates in the region from the Clean Air Task Force 2012. In interviewing people who lived near this plant, they reported high incidences of health problems among the community, which has high proportions of African Americans and low income residents.

Ms. Abdul-Rahman also requested that utilities do a CO_2 reduction analysis in overly burdened communities, perform equity analyses when evaluating IRPs, promote clean energy, and create workforce training and economic development to transition to a clean energy economy. She encouraged NIPSCO to include an equity metric in its preferred scenario, and outlined the components that the NAACP would like to see considered in a preferred scenario.

Praxair Energy
Rick Nelson, Energy Manager

Rick Nelson stated that Praxair is the largest industrial gas supplier in North America and had worldwide sales of $8.3 billion in 2013, in many types of gases. Praxair has 26,000 employees with over 2,500 customers and procures electricity in 26 states and provinces, which provides Praxair with a broad view of electricity prices and energy practices and policies.

It is a very energy-intensive industry and electricity is at its highest cost at approximately $400 million/year. Because of this, Praxair is well aligned with and supportive of energy efficiency. Praxair has long-established energy efficiency goals (Key Performance Indicators, or KPIs), which they are meeting. They upgrade and replace equipment as needed to increase energy efficiency, and have completed more than 175 projects, saving $250 million since 2009. In Indiana, Praxair has many customers including steel mills and chemical industries. Praxair has merchant air separation, gas pipelines, and corporate offices in Indianapolis, and it has 30 stores in Indiana employing over 1,000 people for $80 million in payroll.

Between 2010 and 2013, Praxair completed 30 projects in Northwest Indiana, which cost $12 million and provided energy efficiency savings of 200 million kilowatt hours. Most of these programs did not receive any energy incentives. Mr. Nelson pointed out that large industries have incentives to increase energy efficiency, and they will continue to implement their own energy efficiency programs using their expertise and experience. The type of energy efficiency projects implemented by Praxair do not lend themselves to one-size-fits-all utility-sponsored DSM programs. The collection of lost margins and performance incentives are a disincentive to participate, which led Praxair to opt out of the programs. Praxair has little-to-no interest in opting back in, so such an assumption should not be included in NIPSCO’s IRP planning.

- In response to this discussion, the Citizens Action Coalition noted that they may file a written response to some of these comments. Representatives noted that they appreciate what industry has done, but that the 1-megawatt threshold for opting out is very low in general. There was discussion about this and it was agreed that such opt-in efforts may be better geared toward smaller companies closer to the 1 MW threshold.

ArcelorMittal USA
Paul Ciesielski

Paul Cielsielski said that high electricity costs are the greatest incentives to reduce energy use for high-energy-exposed companies, which strive to make their plants cost effective to stay competitive in the marketplace. ArcelorMittal is an Energy Star partner, and has designated energy champions at each plant. In the last 4 years, projects resulted in 25 MW of reduction in consumption. Utility projects constitute a very small percentage of total load and are not that effective, which is why industrial opt-out is appropriate because it allows businesses to re-channel funds to help the bottom line. In a regulated power market state, utilities have no competition and there are no lost margins from remarketing energy savings. There is a tipping point for industries to shift to alternative sources of energy, which results in cost-shifting and becomes punitive for every customer class.

- A participant asked why all customers shouldn't contribute to energy efficiency programs since the benefits accrue to all.
    - Mr. Cielsielski said ArcelorMittal is trying to achieve a reduction in load and doing it without utility assistance. His question is why one steel company should subsidize its competition? It is not a cost of service based approach to rate setting – cost of service is the appropriate way for rates to be established, including rates related to DSM and energy efficiency programs.

Conclusion and Next Steps

Marty Rozelle outlined the schedule for follow-up from the meeting, and the tentative schedule for the remainder of the workshops. The third meeting will be held on August 23. She said that notes from this meeting would be posted on the website (www.nipsco.com/irp) by July 26. Any additional comments or questions can be sent to: NIPSCO_IRP@nisource.com. She thanked the participants in advance for filling out the feedback form.

Ms. Becker thanked everyone for participating. She offered individual meetings as a follow up if any stakeholders so desire. She also commended NIPSCO's Meredith Hurley for all of her work on the IRP, as she told the group the Meredith would be moving to Chicago and leaving NIPSCO. In conclusion, Ms. Becker reminded everyone to drive home safely.

NIPSCO

2016 Integrated Resource Plan

Stakeholder Meeting #3 – Tuesday, August 23, 2016

Time: *9:00 am – 3:00 pm CT (10:00 am – 4:00 pm ET)*

Location: *Radisson Hotel at the Star Plaza*
800 E. 81st Avenue
Merrillville, IN 46410

Background
NIPSCO is due to submit an Integrated Resource Plan (IRP) to the Indiana Utility Regulatory Commission (IURC) on November 1, 2016. The IRP is our plan for meeting the future energy needs of our customers over the next 20 years with cost-effective, reliable, and sustainable supplies of electricity while addressing the inherent uncertainties and risks that exist in the electric utility industry.

Agenda: **All times are in CT*

Time (CT)	Topic
9:00 – 9:15 am	Welcome & Introductions
9:15 – 9:30 am	Public Advisory Process & Review of 1st & 2nd Meetings
9:30 – 10:00 am	Overview of Existing Generation
10:00 – 10:15 am	*Break*
10:15 – 11:30 am	Generation Planning Methodology & Retirement Analysis
11:30 am – 12:15 pm	*Lunch*
12:15 – 12:45 pm	Review of Risks and Uncertainties
12:45 – 1:45 pm	Resource Optimization Modeling
1:45 – 2:00 pm	*Break*
2:00 – 2:30 pm	Stakeholder Presentations
2:30 – 3:00 pm	Public Advisory Feedback & Next Steps

2016 IRP Public Advisory Meeting

August 23, 2016

UPDATED

NIPSCO

Agenda

Schedule	Agenda Item
9:00 – 9:15	Welcome and Introductions
9:15 – 9:30	Public Advisory Process and Review of 1st & 2nd Meetings
9:30 – 10:00	Overview of Existing Generation
10:00 –10:15	Break
10:15 –11:30	Generation Planning Methodology and Retirement Analysis
11:30 –12:15	Lunch
12:15 –12:45	Review of Risks and Uncertainties
12:45 –1:45	Resource Optimization Modeling
1:45 – 2:00	Break
2:00–2:30	Stakeholder Presentations
2:30–3:00	Public Advisory Feedback and Next Steps

NIPSCO

Welcome and Introductions

Presented by

Violet Sistovaris

Executive Vice President

IRP Stakeholder Process & Timeline

Presented by

Daniel Douglas

Vice President, Corporate Strategy & Development

Stakeholder Interactions

- Since the 1st & 2nd Public Advisory Meetings on May 5th & July 12th, respectively, NIPSCO has met with stakeholder groups

- 1st & 2nd Stakeholder Meetings Materials
  - Presentation materials and summary meeting notes are posted on NIPSCO's IRP webpage: www.NIPSCO.com/irp

IRP Public Stakeholder Process and Timeline

Proposed

	May 5th	July 12th	August 23rd	September 12th	October 3rd
Key Questions	- What process will NIPSCO use for its IRP? - What are the key assumptions driving the scenarios and sensitivities?	- How will NIPSCO incorporate Demand Side Management Resources in the IRP?	- Deep dive into NIPSCO's existing generation - What are the optimal replacement options to fill the supply gap?	- Where are the stakeholders focused? - What is NIPSCO's preferred retirement plan?	- What is NIPSCO's Preferred Plan?
Agenda/ Content	- Overview of process - NIPSCO overview - Load forecasting - Demand side management - Environmental considerations - IRP development - Public advisory process	- Review Market Potential Study - Describe and Review Demand Side Management measure groupings - Introduce Demand Side Management Modeling Methodology	- Overview of existing generation by unit (costs, environmental, etc.) - Retirement analysis - Outline preferred retirement direction and describe resulting capacity gap through time - Replacement options (supply-side and demand-side)	- Discuss retirement paths and address related stakeholder feedback - Address input from prior stakeholder and subsequent 1:1 meetings - Share any initial analysis from 1:1 stakeholder meetings	- Share any results from 1:1 stakeholder analytical requests (these will also be shared in 1:1 meetings between 9/12 and 10/3) - Describe Preferred Replacement Path and logic relative to alternatives - Explain NIPSCO short term action plan
Key Deliverables	- Key assumptions - Overview of scenarios and sensitivities	- Common understanding of the grouping of DSM measures - Clear picture of NIPSCO's DSM modeling methodology	- Stakeholder feedback and shared understanding of generation alternatives	- NIPSCO's preferred retirement plan - Overview of stakeholder analysis requests	- Review of Stakeholder feedback - NIPSCO's Preferred Plan
Meeting Format	- 6 hour in person session	- 5.5 hours in person session	- 6 hours in person session	- 2 hour Touch point/ Webinar	- 4 hour in person session

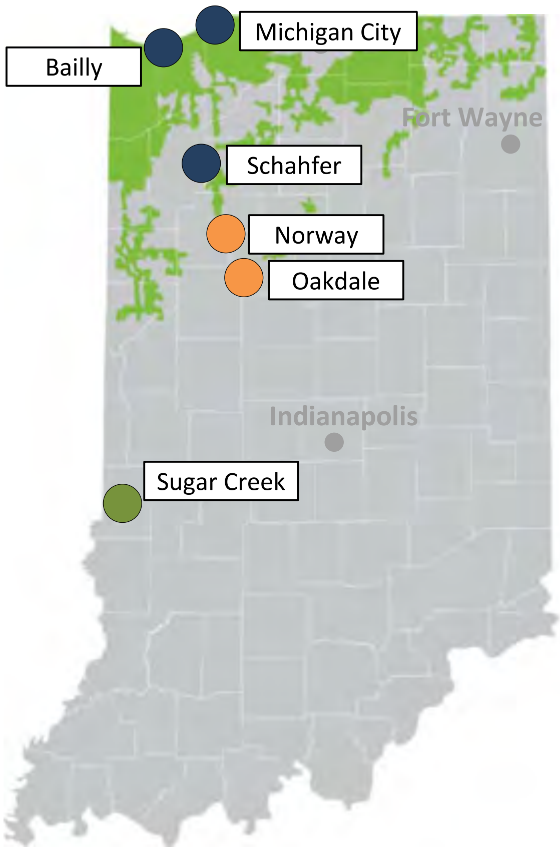
Overview of Existing Generation

Presented by

Daniel Douglas

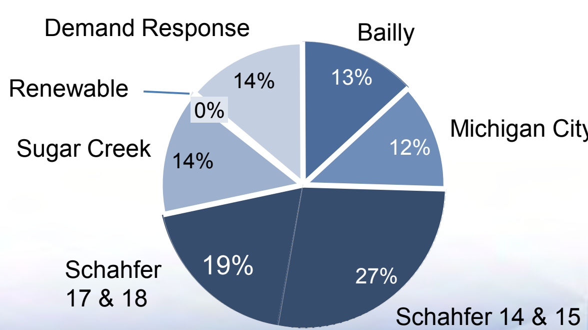
Vice President, Corporate Strategy & Development

NIPSCO Supply Resource Overview

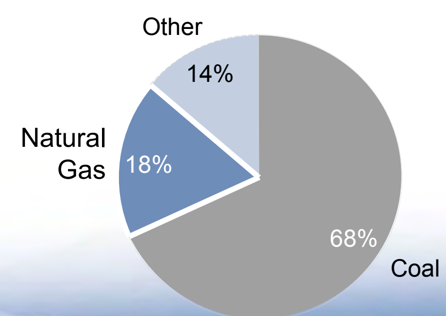


Resource	Unit	Fuel	Capacity NDC (MW)	Year in Service	Employees
Bailly	7	Coal	160	1962	
	8	Coal	320	1968	
	10	NG	31	1968	
		Total	511		110
Michigan City	12	Coal	469	1974	108
Schahfer	14	Coal	431	1976	
	15	Coal	472	1979	
	16A	NG	78	1979	
	16B	NG	77	1979	
	17	Coal	361	1983	
	18	Coal	361	1986	
		Total	1,780		315
Sugar Creek		NG	535	2002	19
Hydro	Norway	Water	4	1923	
	Oakdale	Water	6	1925	
		Total	10		8
Wind		Wind	16	2009	
Demand Response		Interr.	527	2016	
NIPSCO			3,848		560

NIPSCO Generation (% of Capacity)



NIPSCO Fuel Mix (% of Capacity)



NDC: Net Demonstrated Capacity

Changes In Electric Generation Supply

Fuel Shifts Are An Industry-Wide Trend

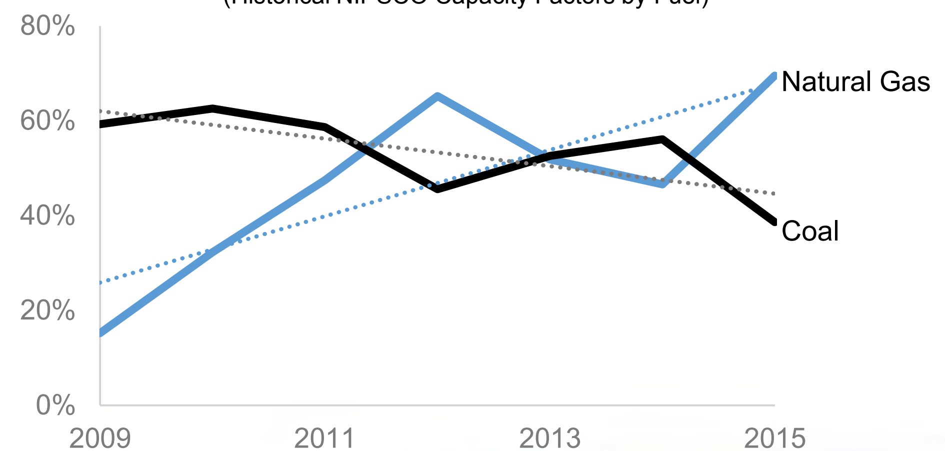
	2010 Energy Supply	2015 Energy Supply
NIPSCO	90% Coal	72% Coal
MISO (Midwest)	75% Coal*	52% Coal

** Pre-Entergy Integration*

What's Driving The Change?

- Low Cost Natural Gas Supply
- Environmental Regulations
- Age and Condition of Plants
- Shifts in Market Power Prices

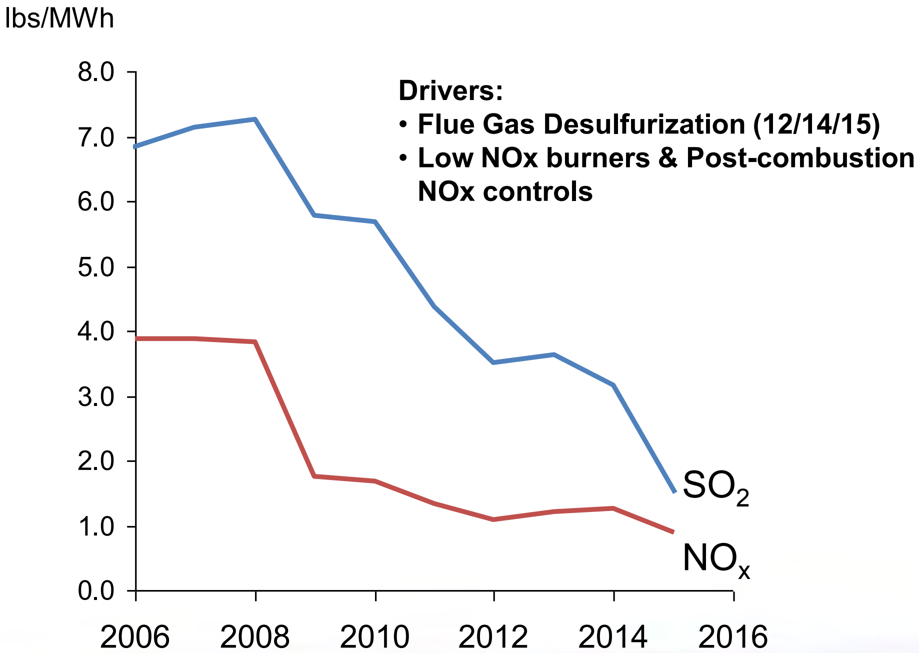
NIPSCO's Coal Units Are Being Dispatched Less
(Historical NIPSCO Capacity Factors by Fuel)

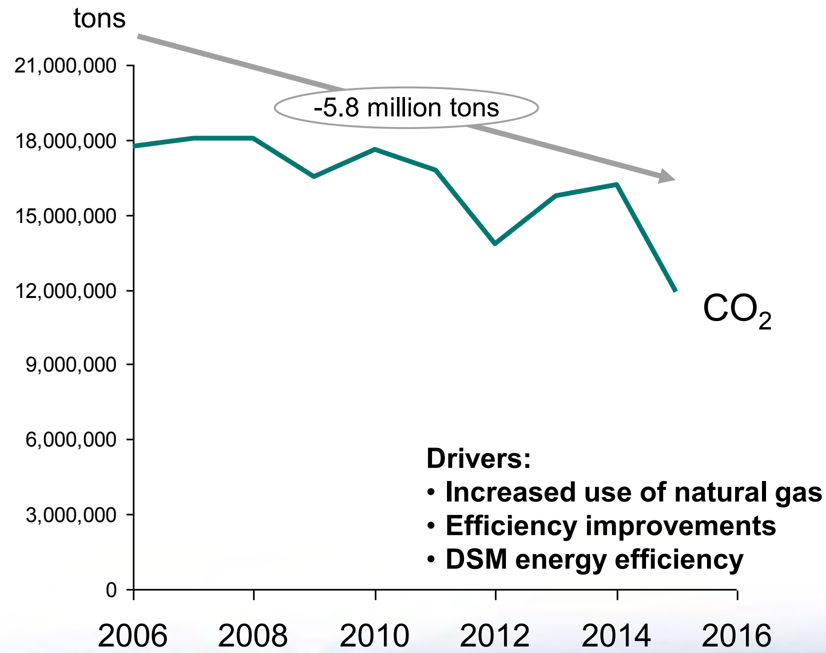


NIPSCO Emissions Have Decreased

- Investments in environmental controls have significantly reduced NOx and SO_2 rates from the generation fleet
- A changing fuel mix with increasing reliance on natural gas is driving carbon dioxide emissions reductions

Historical NIPSCO Emissions



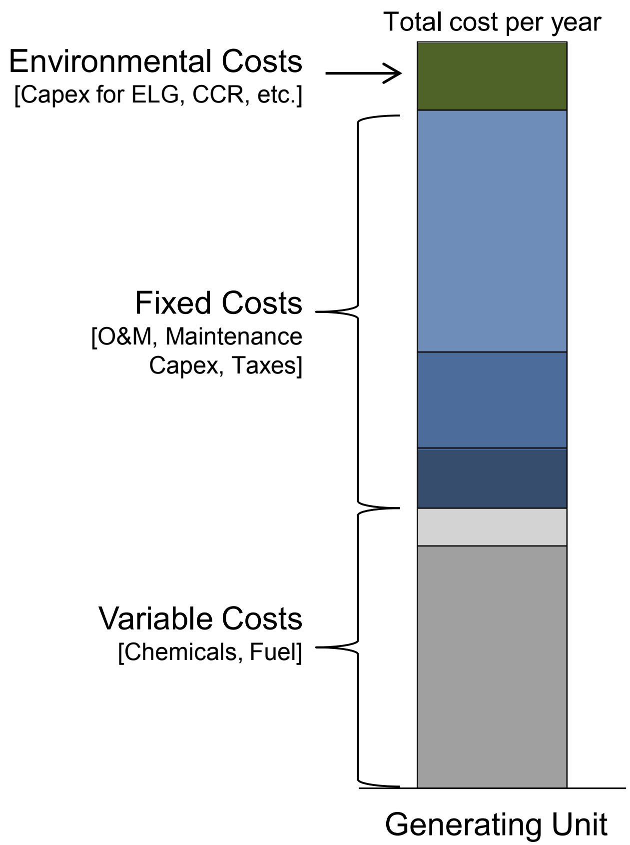


Source: U.S. Environmental Protection Agency Air Markets Program Database. Accessed August 10, 2016

Generation Costs

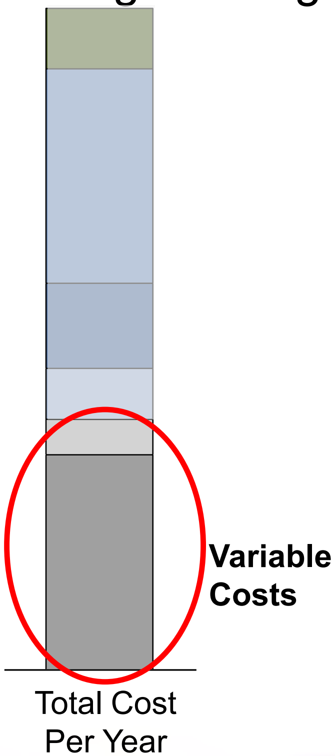
Illustrative

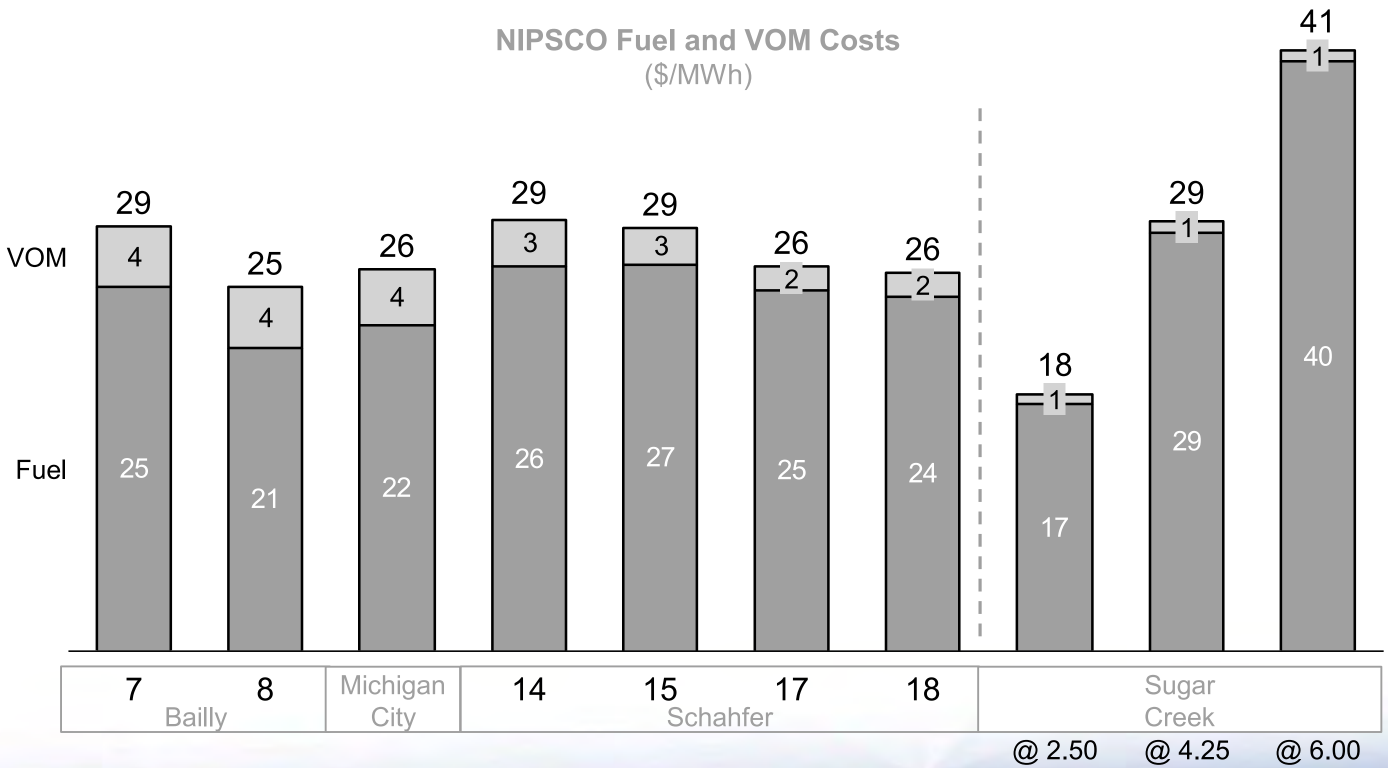
- **Generation costs vary for each NIPSCO unit**
- **Key cost components are:**
  - Environmental costs for controls required to be compliant with future regulations like effluent limitations guidelines (ELG) and coal combustion residuals (CCR)
  - Fixed costs including O&M, labor, capital recover, allowed return and any necessary maintenance capital expenses
  - Variable costs including fuel and environmental chemicals
- **The sum of these costs over time and is expressed as net present value of revenue requirement (NPVRR)**



Variable Costs

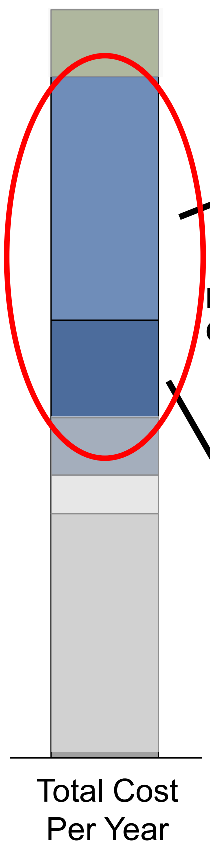
- Fuel is the largest variable cost; natural gas generation can be below or above coal-fired generation with a breakeven price around $4.25/MMBtu
- Variable Operation & Maintenance (VOM) costs include chemicals for environmental controls and are generally higher for coal versus natural gas fuel generators



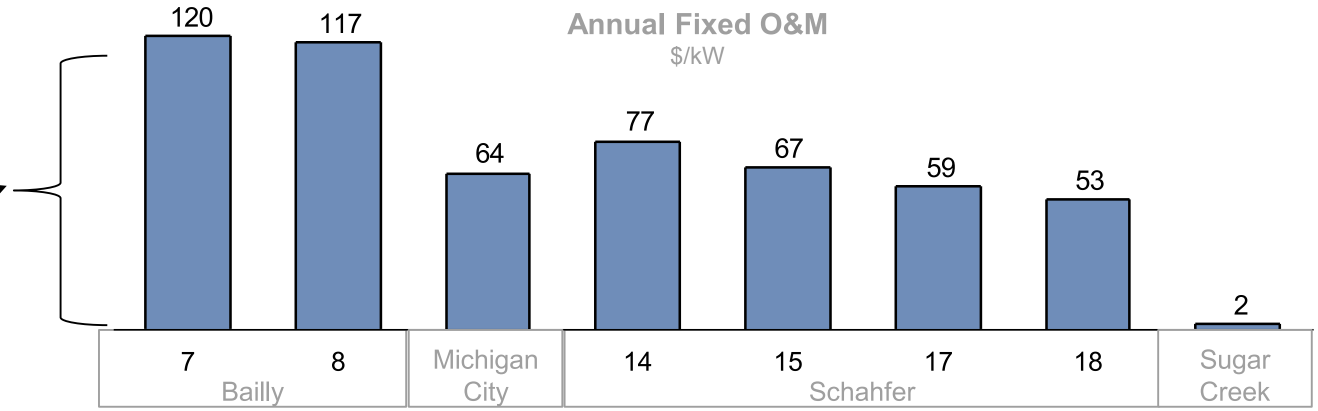


Notes: Variable costs vary based on market conditions; costs shown here are forecast 2017 average annual heat rates, coal contract and variable operating costs; a range of natural gas prices from $2.50 -- $6/MMBtu are shown for illustrative purposes

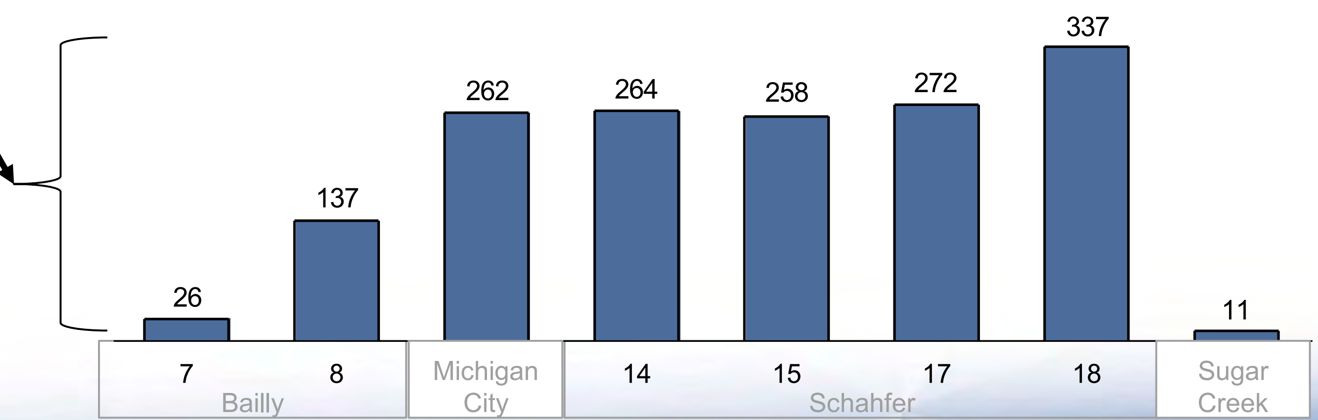
Maintenance Capital and O&M



- **NIPSCO coal assets have higher fixed costs than alternatives**



- **And require significant ongoing maintenance capital**



NIPSCO

Notes: Maintenance O&M and Maintenance Capital are averages of 6-year forecasts and 10-year forecasts, respectively, divided by installed capacity

Environmental Rules Require Compliance Capital For NIPSCO Units

Rule	Rule Focus	Rule Criteria	Affected Stations	Compliance Options	Est. NIPSCO Capital Cost
Effluent Limitation Guidelines	• Lowers constituent limits for specific wastewater streams	• Impacts Bottom Ash / Boiler Slag Transport Water and FGD Wastewater • Federally mandated, state implemented through water discharge permits • Compliance required by end of 2023	• Bailly • Michigan City • Schahfer	• Bottom Ash and FGD water treatment • Zero Liquid Discharge • Retirement	\$410M–\$580M
Coal Combustion Residuals	• Storage and disposal of CCR units	• Rule criteria that may trigger units to cease CCR receipt: – Structural integrity: Apr. 2017 – Impact to Groundwater: Oct. 2018 – Fail locational requirements: Apr. 2019	• Bailly • Michigan City • Schahfer	• Ground water monitoring • Remote ash conveying • Retirement	\$180M–\$250M
Clean Water Act 316(b)	• Intake water	• Requires stations with cooling water intake structures to deploy the best technology available to minimize adverse impacts to fish and shellfish	• Bailly	• Porous dike • Retirement	\$32M–\$40M
Ozone	• NOx emissions	• Standard lowered from 75ppb to 70ppb • Further lowering is possible	• NIPSCO Fleet	• Re-dispatch • NOx control (U17/18) • Retirement	\$0–\$325M
Clean Power Plan	• Carbon dioxide emissions	• Establishes national CO_2 emission standards likely in the form of state-specific emission rate or mass emission limits	• NIPSCO Fleet	• Heat rate improvements • Increased natural gas dispatch • Renewables • Energy efficiency • Retirement	unknown

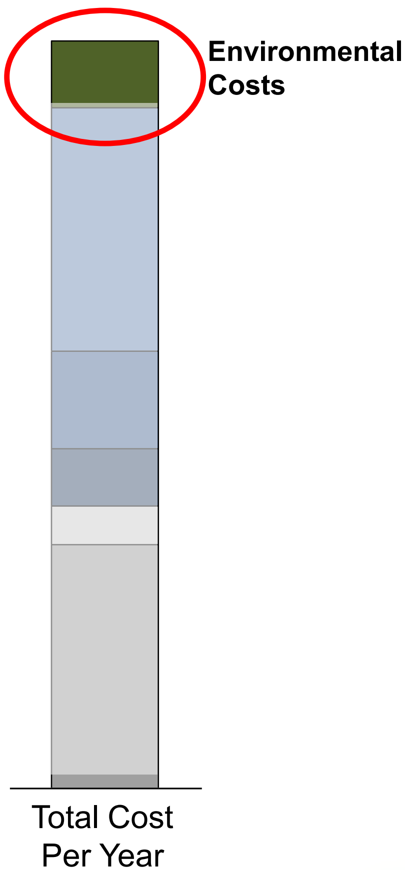
Total: \$625M–\$1.2B

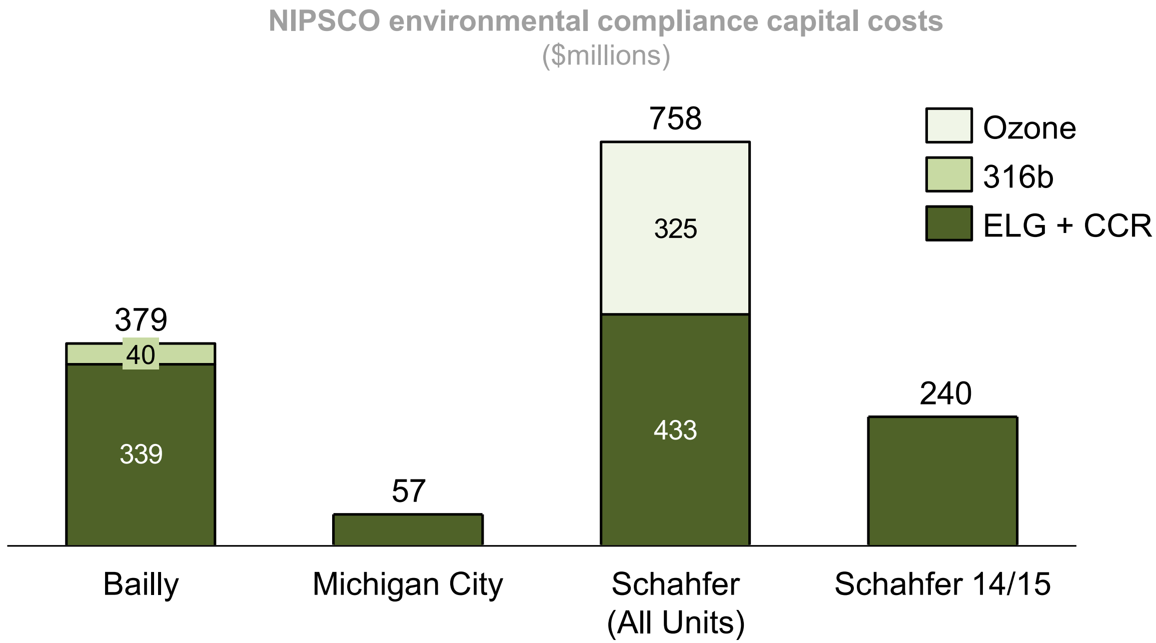
CCR and ELG rules create a near-term comply/retire decision for coal units: make the required capital investments or retire by the end of 2018 & 2023

NIPSCO

Environmental Capital Requirements Are Significant For Some NIPSCO Coal Units

- Environmental compliance needs vary by unit





Notes: Cost estimates for compliance assuming no retirement; retirement as a compliance option would lower compliance cost; estimates shown in direct dollars with no escalation and reflect upper range of estimation accuracy

Break

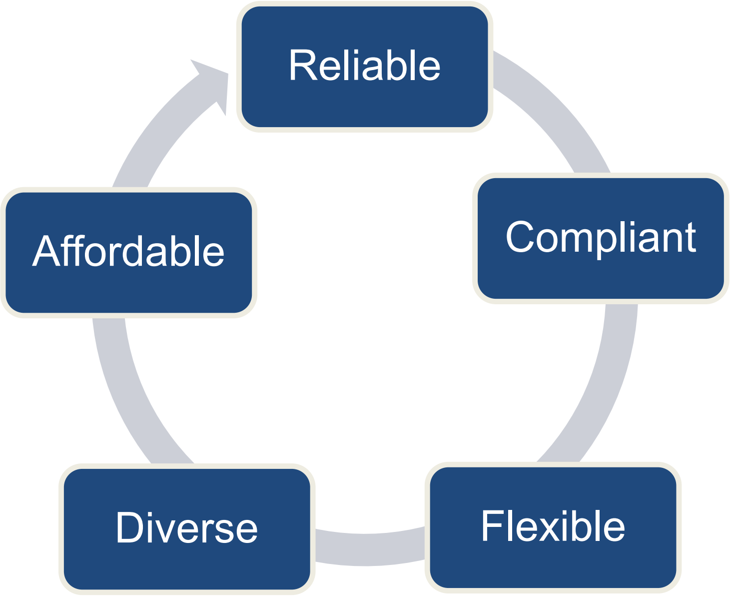
Generation Planning Methodology And Retirement Analysis

Presented by

Daniel Douglas

Vice President, Corporate Strategy & Development

How Does NIPSCO Plan For The Future?



Requires Careful Planning and Consideration for:

- Our employees
- Impact on the environment
- Changes in the local economy (property tax, supplier spend, employee base)

Evaluate Existing NIPSCO Generation

- Previously, IRP retirements were focused on age-based criteria
- As many of NIPSCO plants approach age based retirement dates, further analysis is necessary to refine retirement dates

Is the ongoing cost of operating an existing NIPSCO unit, including all required environmental compliance controls, greater than the cost of retiring the unit and replacing with an alternative?

Cost to Keep

- Ongoing variable costs
- Ongoing fixed costs
- Future environmental controls costs

<
(Maintain Unit)

>
(Consider Retirement)

Cost of Alternative

- Ongoing variable costs
- Ongoing fixed costs
- Future environmental controls costs
- Cost to retire existing unit
  (T&D upgrades, remaining net book value, property & income taxes)

<u>Note</u>: In all comparison studies, the costs of the replacement unit are scaled on a megawatt basis to the same generating capacity as the existing unit.

A Combined Cycle Gas Turbine Is Used In The Retirement Analysis As A Proxy For Viable Alternative

Retirement Analysis

- CCGT

Step 1

Generation Alternatives Analysis

- Complete analysis and evaluation of all Supply-side and Demand-side Resources

Step 2

Cost of Alternative

- Ongoing variable costs
- Ongoing fixed costs
- Future environmental controls costs
- Cost to retire existing unit (T&D upgrades, remaining net book value, property & income taxes)

- **CCGT is for retirement analysis only and is not our selection**; we will optimize for other supply- and demand-side resources
- CCGT is a good proxy because: favorable levelized cost of electricity (LCOE), reliable, dispatchable, straightforward to plan, permit and build
- Retirement methodology is consistent with others in the industry

Various Retirement Portfolios Were Constructed

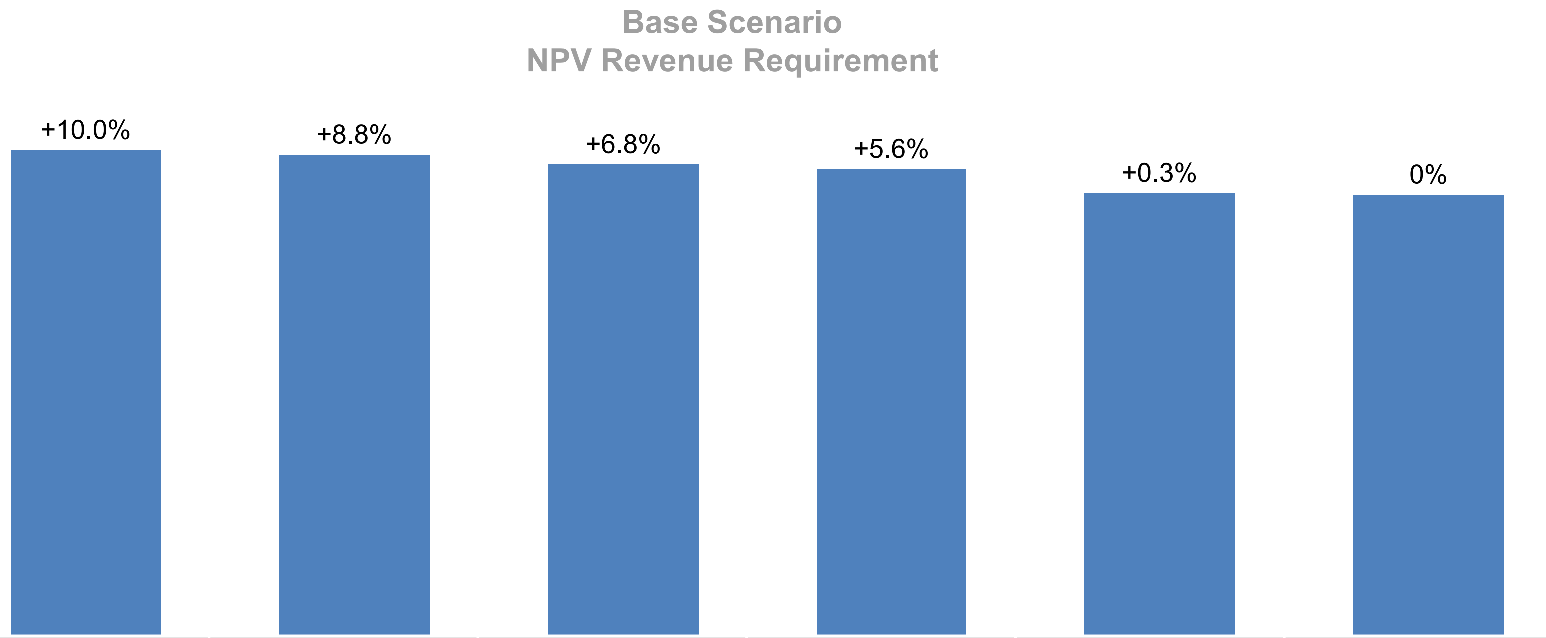
		Age Based	Retire 20% Coal (2023)	Retire 20% Coal (2018)	Retire 50% Coal	Retire 80% Coal	Retire 100% Coal
Retire:		Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 Schahfer: 17,18	Bailly: 7,8 Schahfer: 14,15,17,18	Bailly: 7,8 Michigan City: 12 Schahfer: 14,15,17,18
Comply/Keep:		Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None
Bailly	7	Retire 2023	Retire 2023	**Retire 2018**	Retire 2018	Retire 2018	Retire 2018
	8	Retire 2028	**Retire 2023**	**Retire 2018**	Retire 2018	Retire 2018	Retire 2018
Michigan City	12	Comply (2034)	Comply (2034)	Comply (2034)	Comply (2034)	Comply (2034)	**Retire 2023**
Schahfer	14	Comply (2037)	Comply (2037)	Comply (2037)	Comply (2037)	**Retire 2023**	Retire 2023
	15	Comply (2039)	Comply (2039)	Comply (2039)	Comply (2039)	**Retire 2023**	Retire 2023
	17	Comply (2043)	Comply (2043)	Comply (2043)	**Retire 2023**	Retire 2023	Retire 2023
	18	Comply (2046)	Comply (2046)	Comply (2046)	**Retire 2023**	Retire 2023	Retire 2023

Notes: The dates in parenthesis are age-based

NIPSCO

Cost To Customer Impacts Of Each Portfolio Was Analyzed

Preliminary



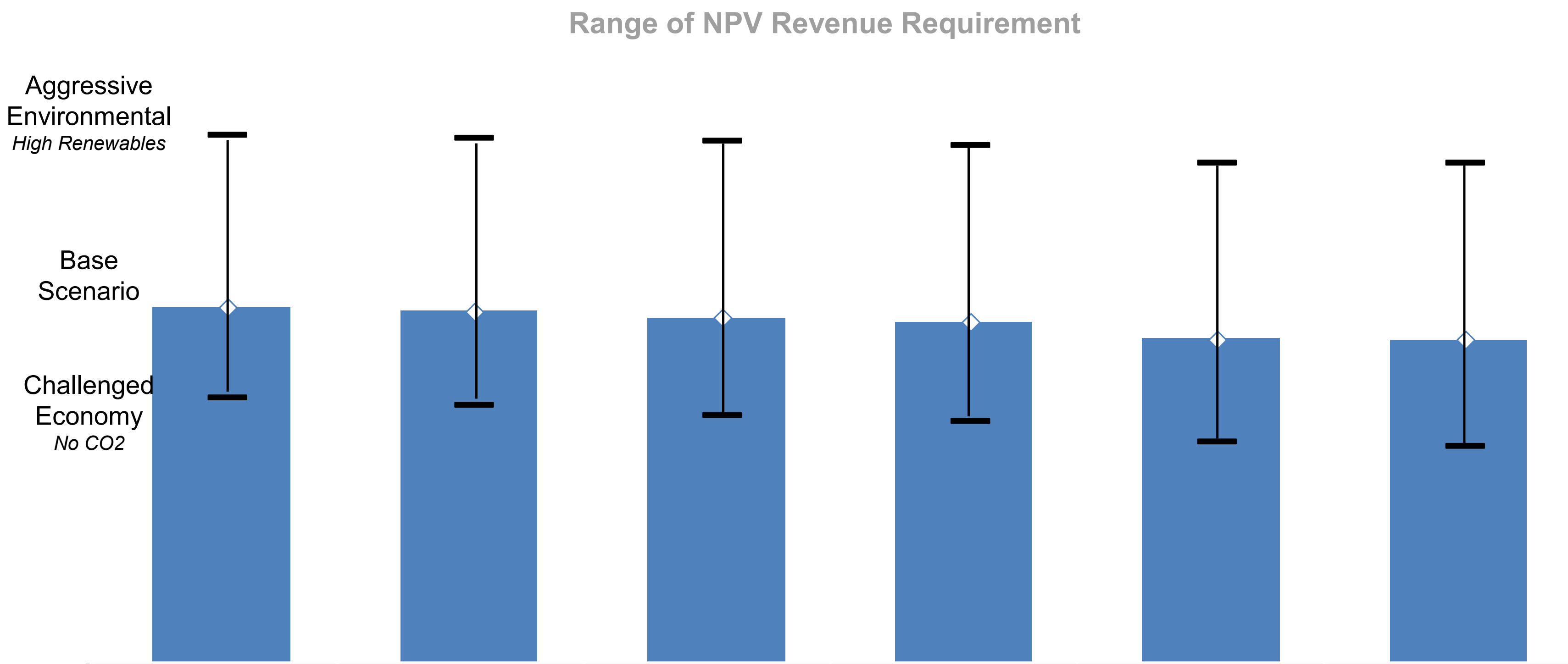
	Age Based	Retire 20% Coal (2023)	Retire 20% Coal (2018)	Retire 50% Coal	Retire 80% Coal	Retire 100% Coal
Retire:	Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 Schahfer: 17,18	Bailly: 7,8 Schahfer: 14,15,17,18	Bailly: 7,8 Michigan City: 12 Schahfer: 14,15,17,18
Keep:	Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None

Notes: Present Value of Revenue Requirement; NOT a bill impact analysis

NIPSCO

Cost To Customer Rankings For Retirement Portfolios Remained Consistent Across A Wide Range Of Scenarios

Preliminary

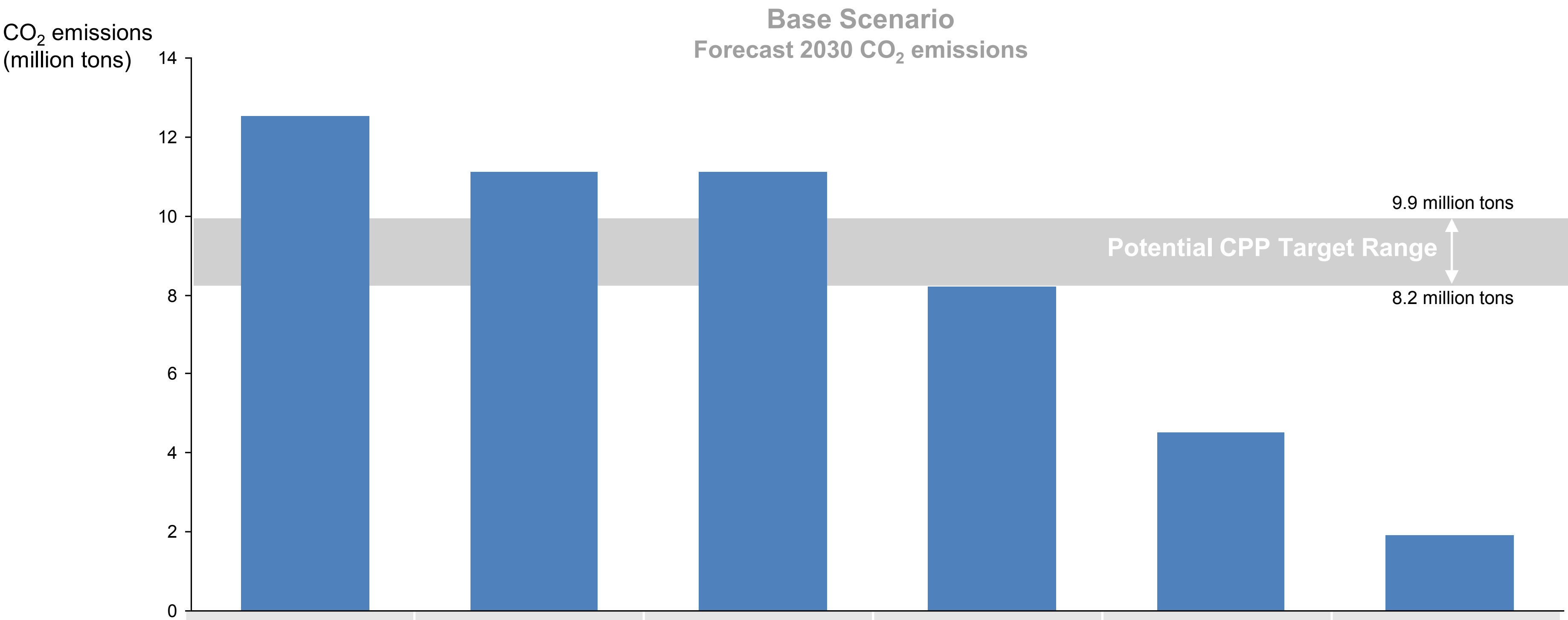


	Age Based	Retire 20% Coal (2023)	Retire 20% Coal (2018)	Retire 50% Coal	Retire 80% Coal	Retire 100% Coal
Retire:	Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 Schahfer: 17,18	Bailly: 7,8 Schahfer: 14,15,17,18	Bailly: 7,8 Michigan City: 12 Schahfer: 14,15,17,18
Keep:	Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None

NIPSCO

Potential To Meet Clean Power Plan (CPP) Compliance Targets

Preliminary



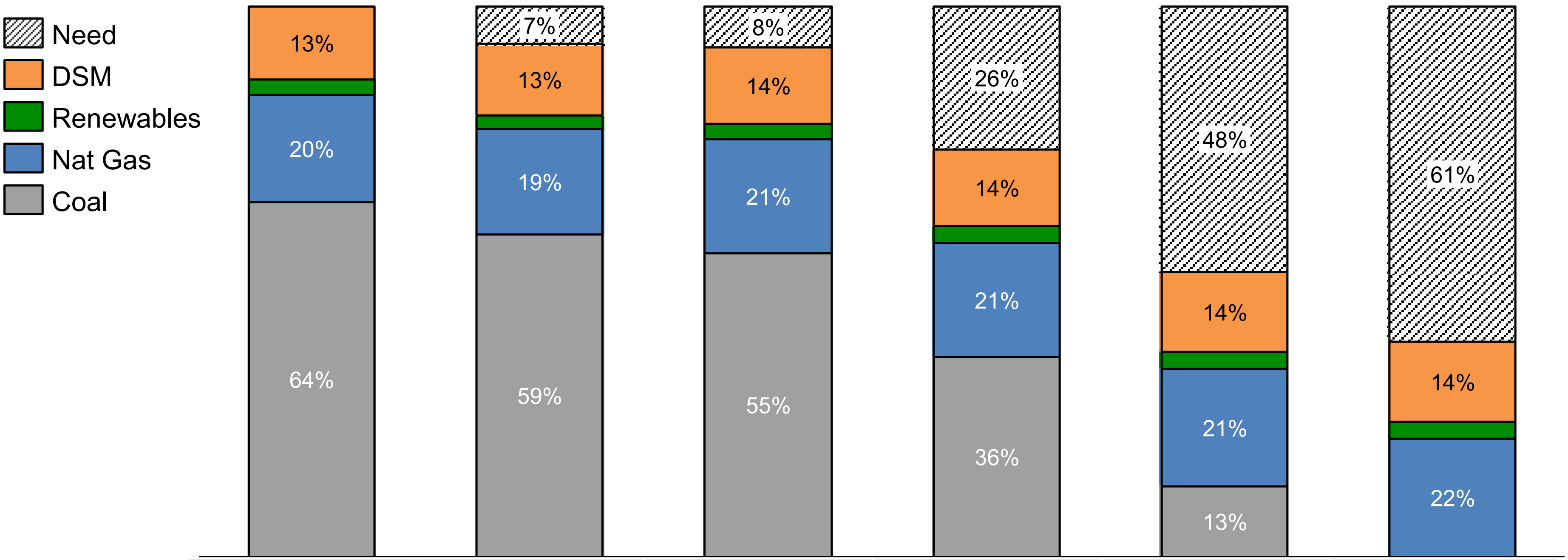
	Age Based	Retire 20% Coal (2023)	Retire 20% Coal (2018)	Retire 50% Coal	Retire 80% Coal	Retire 100% Coal
Retire:	Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 Schahfer: 17,18	Bailly: 7,8 Schahfer: 14,15,17,18	Bailly: 7,8 Michigan City: 12 Schahfer: 14,15,17,18
Keep:	Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None

NIPSCO

Notes: CPP target range reflects estimates of potential 2030 NIPSCO targets based from EPA 111(d) rule; under the proposed federal plan any replacement emissions from either a power purchase agreement or new CCGT would not count against compliance; emissions estimated from typical annual capacity factors applied to unit-level emission factors for each retirement portfolio

Portfolio Diversity of Each Retirement Portfolio

Preliminary



	Age Based	Retire 20% Coal (2023)	Retire 20% Coal (2018)	Retire 50% Coal	Retire 80% Coal	Retire 100% Coal
Retire:	Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 Schahfer: 17,18	Bailly: 7,8 Schahfer: 14,15,17,18	Bailly: 7,8 Michigan City: 12 Schahfer: 14,15,17,18
Keep:	Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None

Notes: Portfolio diversity shown as a percentage of forecast installed capacity in 2025; DSM includes Industrial Interruptibles

Retirement Scenarios

Preliminary

Multiple Scenarios Being Analyzed

	Age Based	Retire 20% Coal (2023)	Retire 20% Coal (2018)	Retire 50% Coal	Retire 80% Coal	Retire 100% Coal
Retire:	Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 (2018) Schahfer: 17,18 (2023)	Bailly: 7,8 Schahfer: 14,15,17,18	Bailly: 7,8 Michigan City: 12 Schahfer: 14,15,17,18
Keep:	Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None
Cost to Customer	🔴	🔴	🟡	🟡	🟢	🟢
Portfolio Diversity	🔴	🟡	🟡	🟢	🟡	🔴
Employees	🟢	🟡	🟡	🟡	🔴	🔴
Environmental Compliance	🔴	🔴	🔴	🟢	🟢	🟢
Communities & Local Economy	🟢	🟡	🟡	🟡	🔴	🔴

Key
- 🔴 Worse
- 🟡 Better
- 🟢 Best

Expected Outcome

- A final retirement decision has not been made; alternatives are being evaluated with stakeholders
- Initial analysis indicates the most viable option is that Bailly Units 7 and 8 will retire as soon as 2018 and Schahfer Units 17 and 18 will retire by 2023, subject to MISO and other considerations
- NIPSCO's preferred plan will be finalized in its November IRP submission

NIPSCO

Lunch

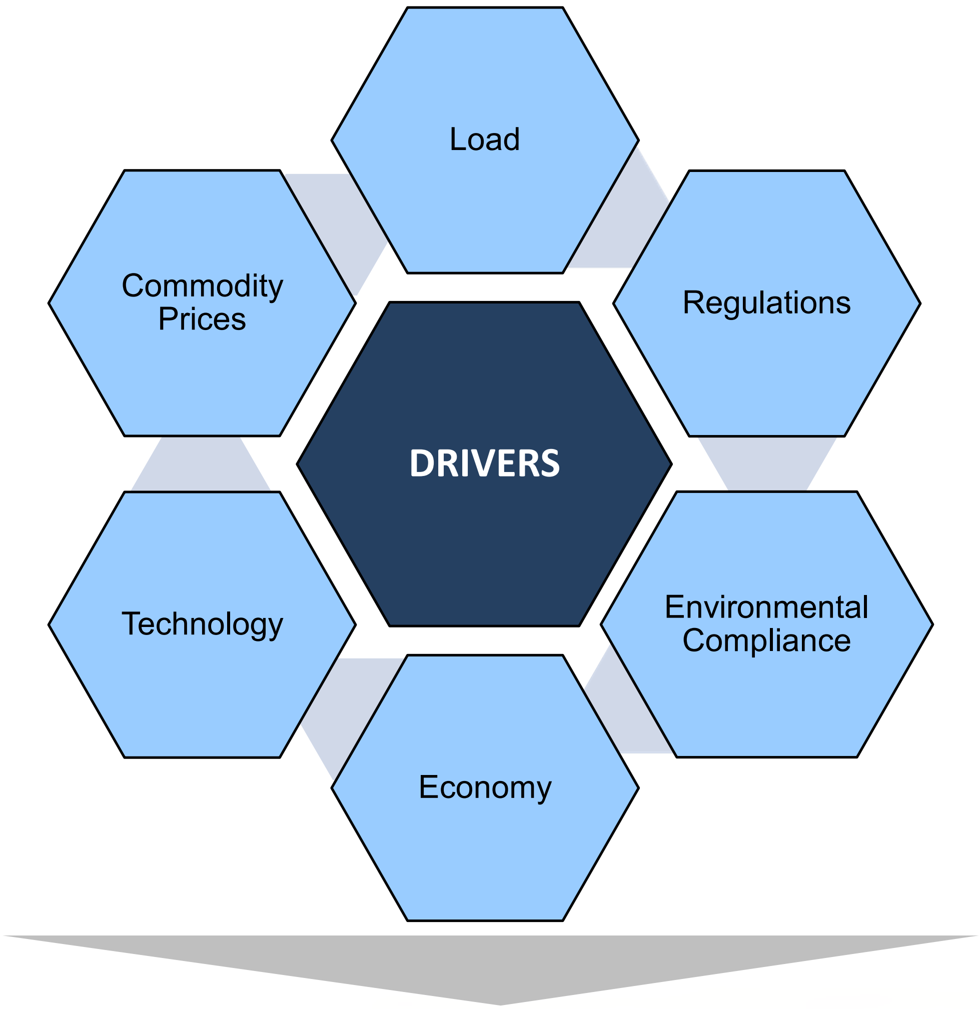
Review of Risks and Uncertainties

Presented by

Edward Achaab

Manager Resource Planning

Risks And Uncertainties



These Drivers Form The Foundation Of NIPSCO's Scenarios

Scenarios And Sensitivities

Scenarios

Base	Challenged Economy	Aggressive Environmental Regulation	Booming Economy	Base Delayed Carbon

Sensitivities

Base	Challenged Economy	Aggressive Environmental Regulation	Booming Economy
No CO_2 Price	No CO_2 Price	High Renewables & Increasing Load	No CO_2 Price
Low Load	Loss of Major Industrial Load	High Renewables & Decreasing Load	Loss of Major Industrial Load
High Gas Price			
Loss of Major Industrial Load			

Sources and Notes: Definitions adapted from *Electricity Director's Final Report 2014-2015 Integrated Resources Plans*, IURC, p. 9; Varying one "element" of a scenario to create a sensitivity may require changes to multiple variables to ensure that input data are properly correlated; For example, a low gas price sensitivity also requires correlated (lower) electricity prices

Scenarios And Sensitivities Variables Descriptions

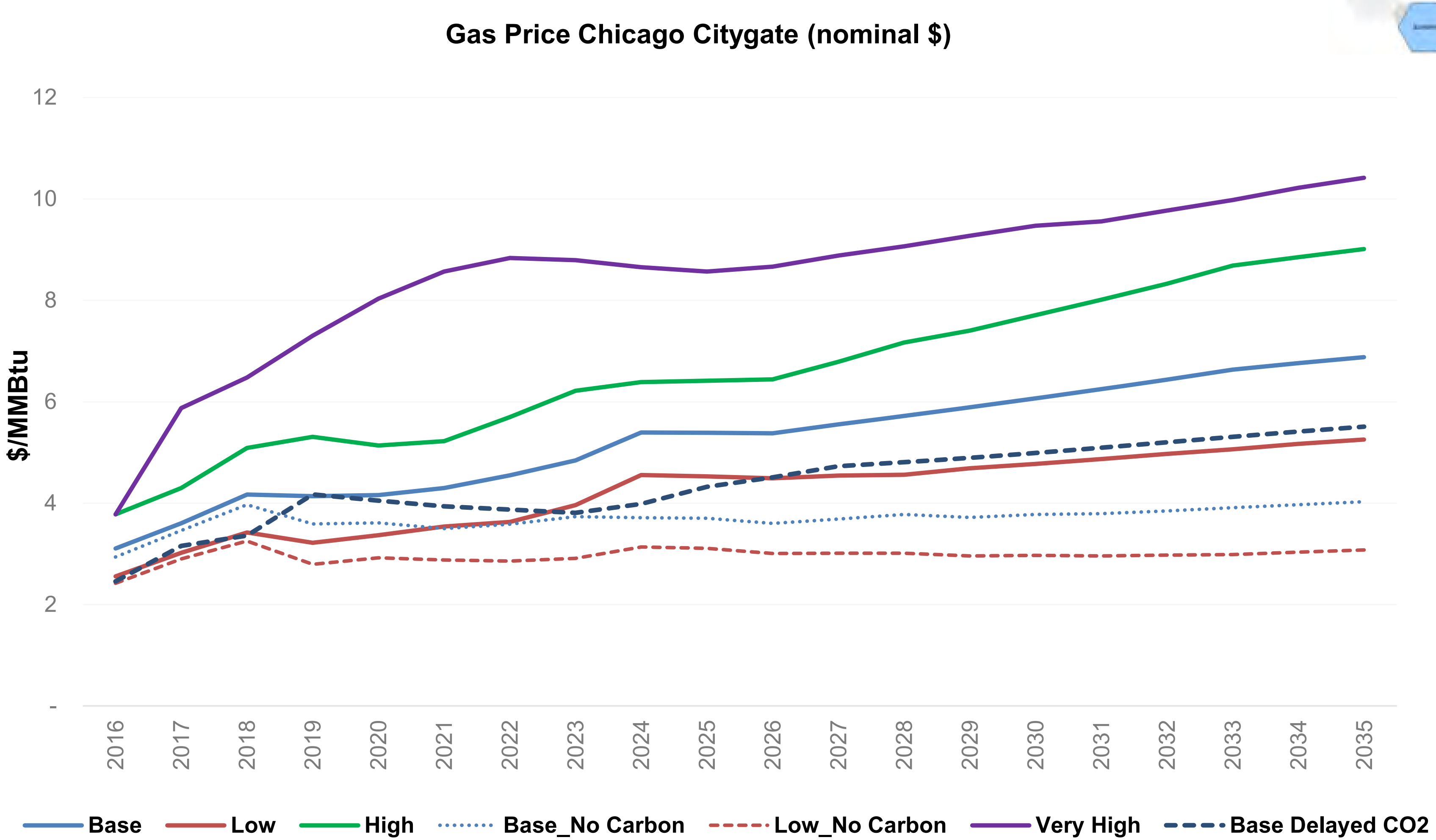
Scenarios & Sensitivities	NIPSCO Load	CO_2 Price	Natural Gas Price	Power Price	RPS
Base (B)	**Base Load**	**Base**	**Base**	**Base**	**No**
No CO_2 Price (Bs1)	Base Load	No	Base No CO_2	Base No CO_2	No
Low Load (Bs2)	Low Load	Base	Base	Base	No
High Gas Price (Bs3)	Base Load	Base	High	High	No
Loss of Major Industrial Load (Bs4)	Base, Loss Major Industrial	Base	Base	Base	No
Challenged Economy (CE)	**Low Load**	**Base**	**Low**	**Low**	**No**
No CO_2 Price (CEs1)	Low Load	No	Low No CO_2	Low No CO_2	No
Loss of Major Industrial Load (CEs2)	Low, Loss Major Industrial	Base	Low	Low	No
Aggressive Environmental Regulation (AE)	**Base Load**	**High**	**High**	**High**	**No**
High Renewables & Increasing Load (AEs1)	High Load	High	Very High	Very High	Yes
High Renewables & Decreasing Load (AEs2)	Low Load	High	Very High	Very High	Yes
Booming Economy (BE)	**High Load**	**Base**	**High**	**High**	**No**
No CO_2 Price (BEs1)	High Load	No	Base no CO_2	Base no CO_2	No
Major Industrial Load (BEs2)	Base, Loss Major Industrial	Base	High	High	No
Base Delayed Carbon (BDC)	**Base Load**	**Base BDC**	**Base BDC**	**Base BDC**	**No**

Fundamental Commodity Price Forecasts

- **PIRA Energy Consultants provided the following Commodity Price Forecasts:**
  - Natural Gas Chicago City Gate Pricing
  - Coal (Powder River Basin-PRB & Illinois Basin-ILB) Pricing
  - CO_2 Pricing
  - MISO Indiana Electricity Power Pricing (On-Peak & Off-Peak)
  - MISO Indiana Capacity Pricing

- **The 2016 IRP uses seven commodity pricing scenarios:**
  - Base Case
  - Base Delayed Carbon
  - Base No Carbon
  - Low
  - Low No Carbon
  - High
  - Very High

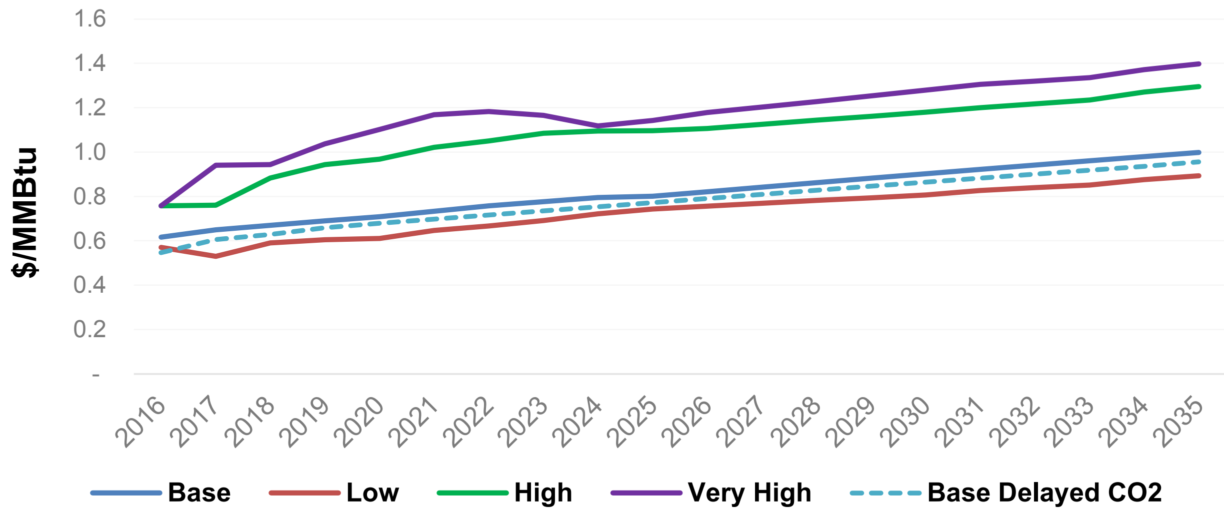
Natural Gas Price Forecast



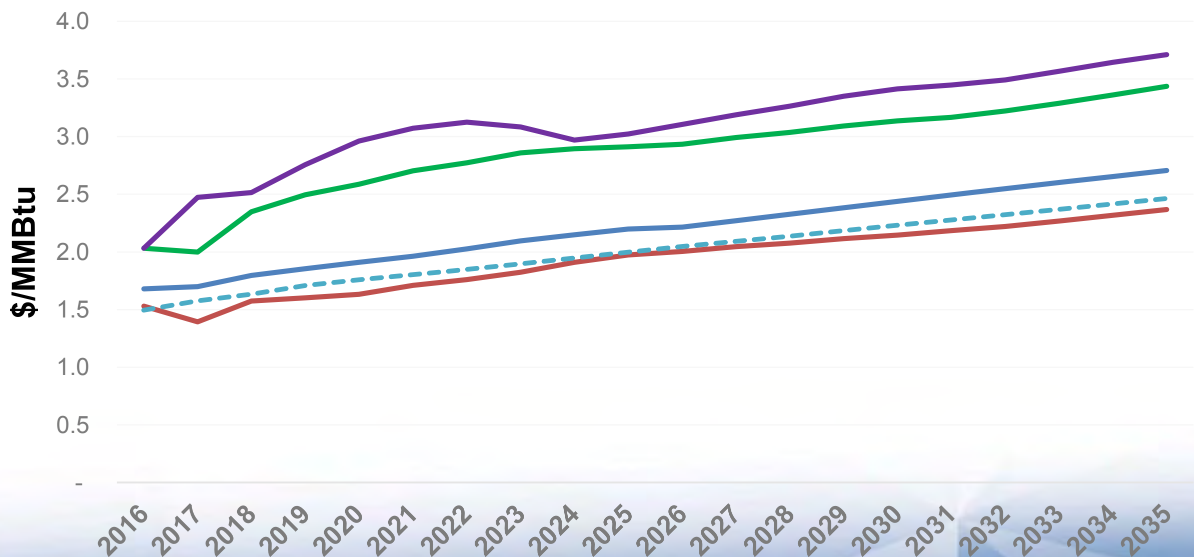
Source: PIRA Energy Group, NiSource Requested Scenarios 2016

Coal Price Forecast

PRB (nominal$ 8,800 Btu/lb; 5.0 lbs SO_2/MMBtu)



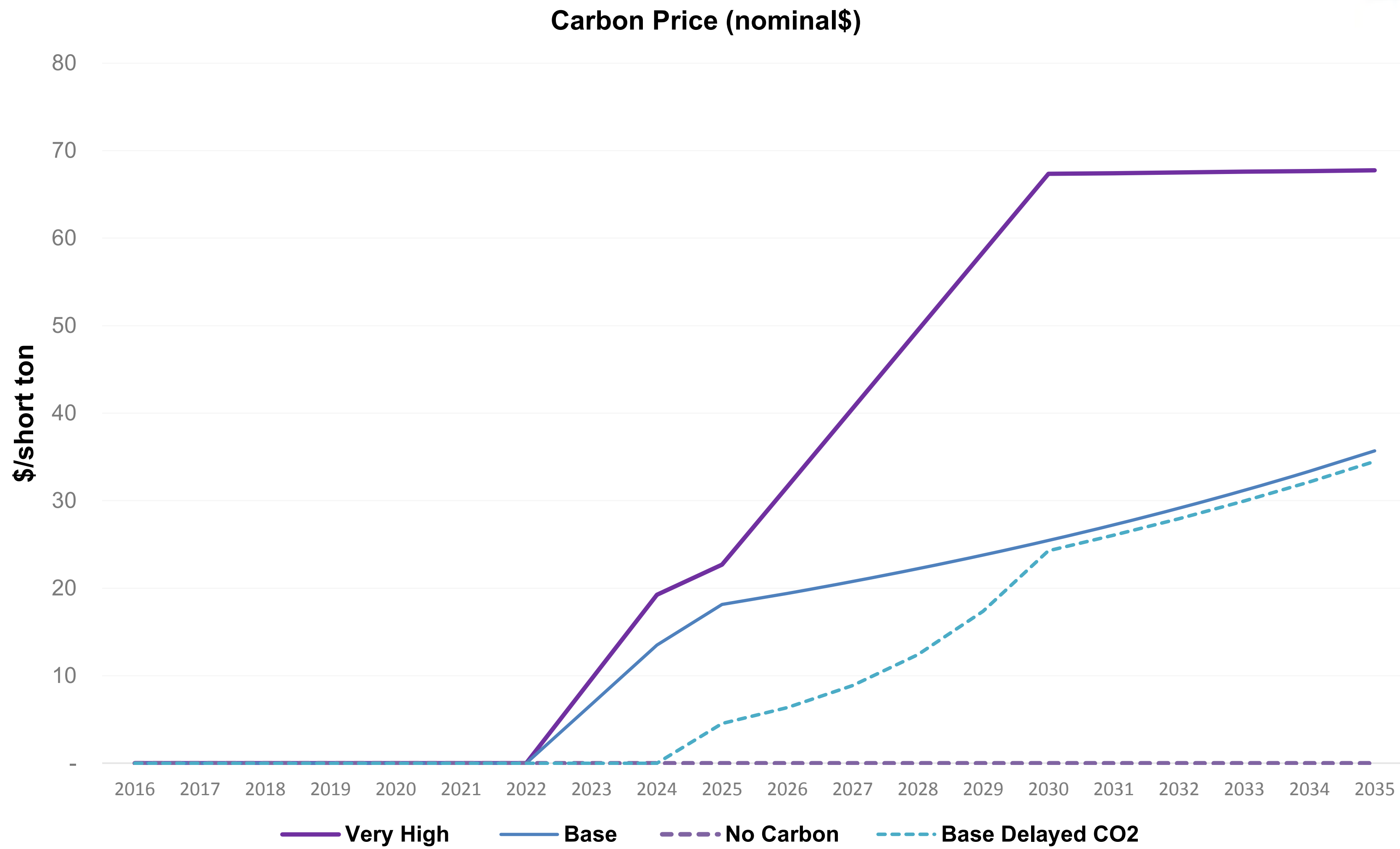
ILB (nominal$ 1,500 Btu/lb; 5.0 lbs SO_2/MMBtu)



Source: PIRA Energy Group, NiSource Requested Scenarios 2016

NIPSCO

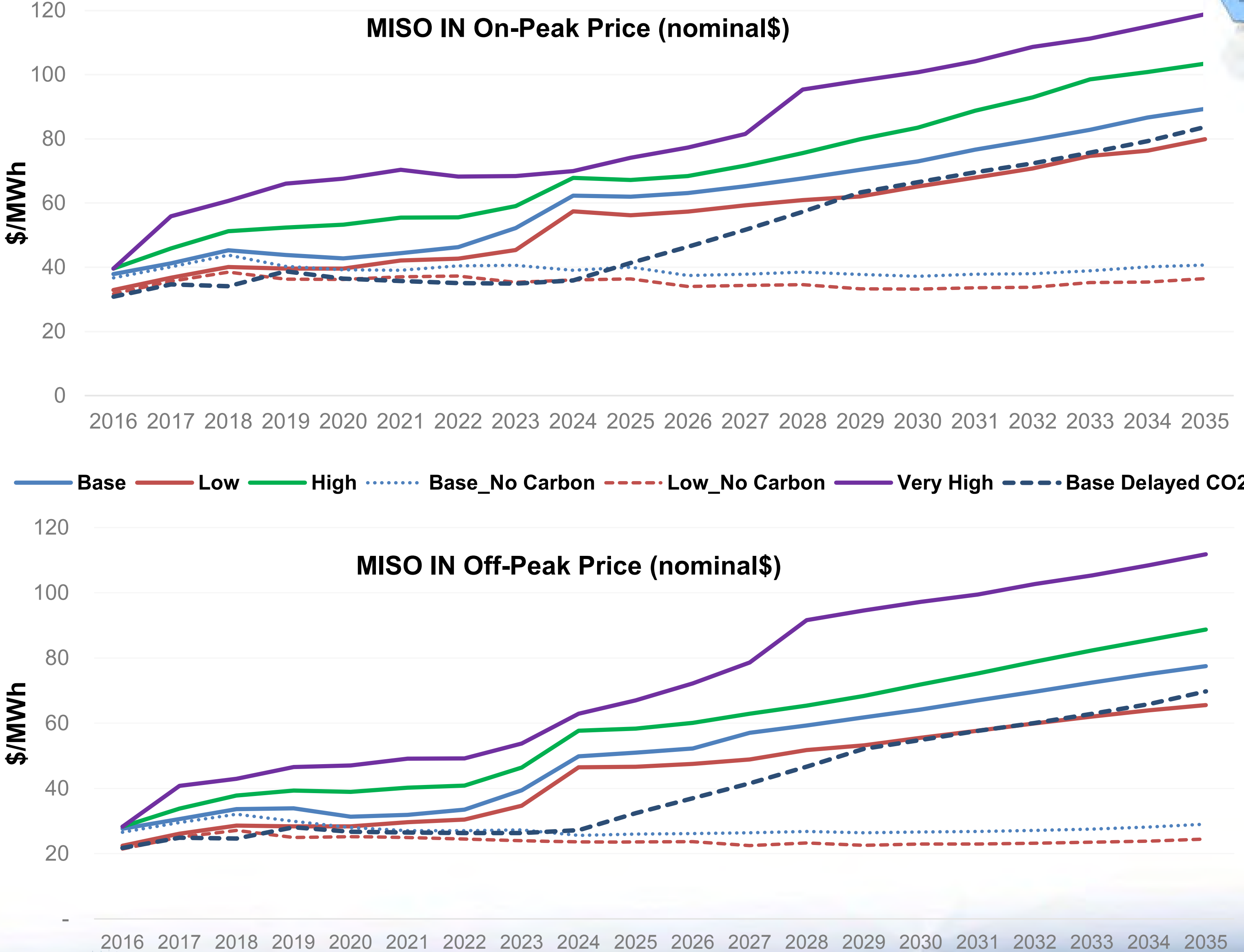
CO_2 Price Forecast



Source: PIRA Energy Group, NiSource Requested Scenarios 2016

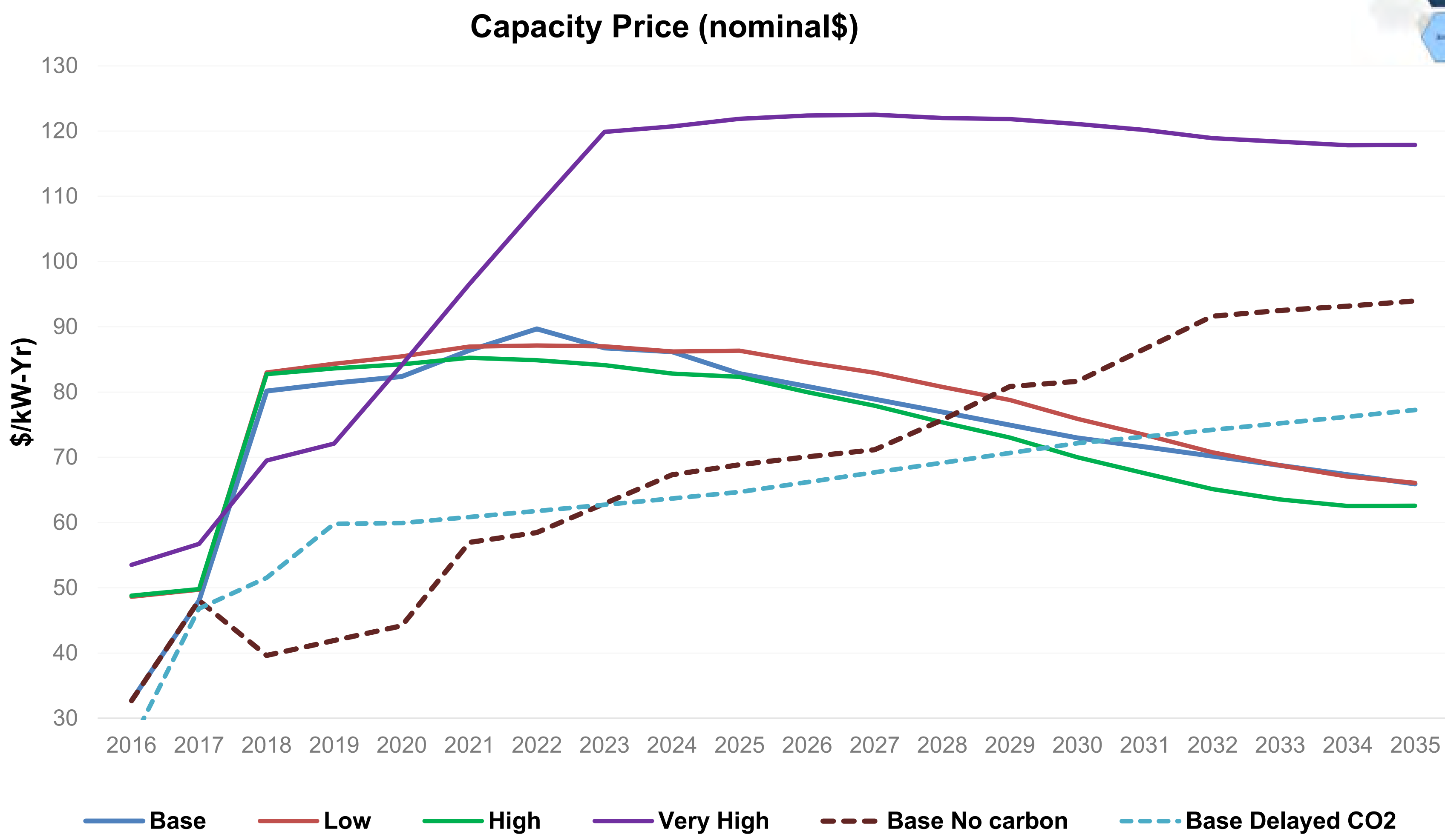
NIPSCO

MISO Indiana Power Price Forecast



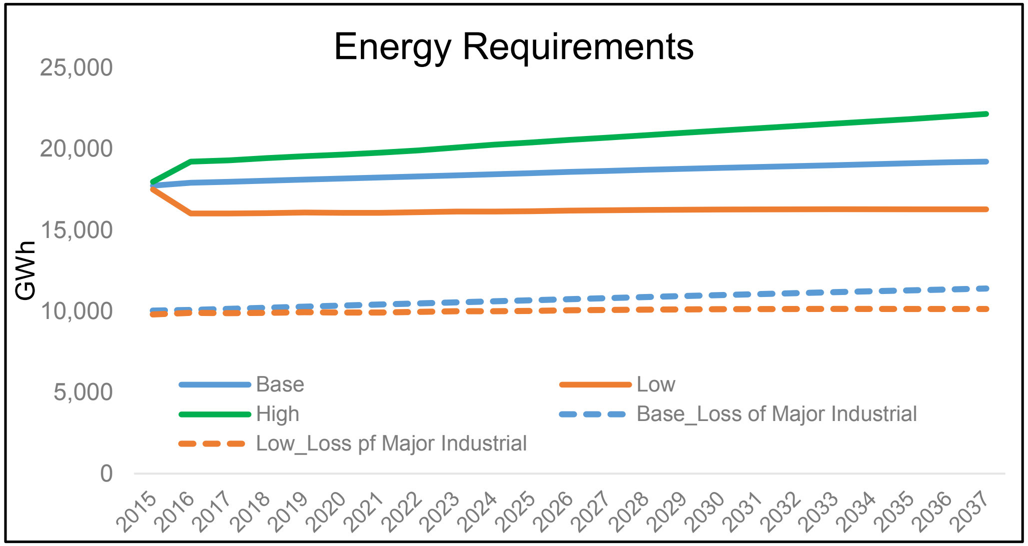
Source: PIRA Energy Group, NiSource Requested Scenarios 2016

Capacity Price Forecast (MISO IN)

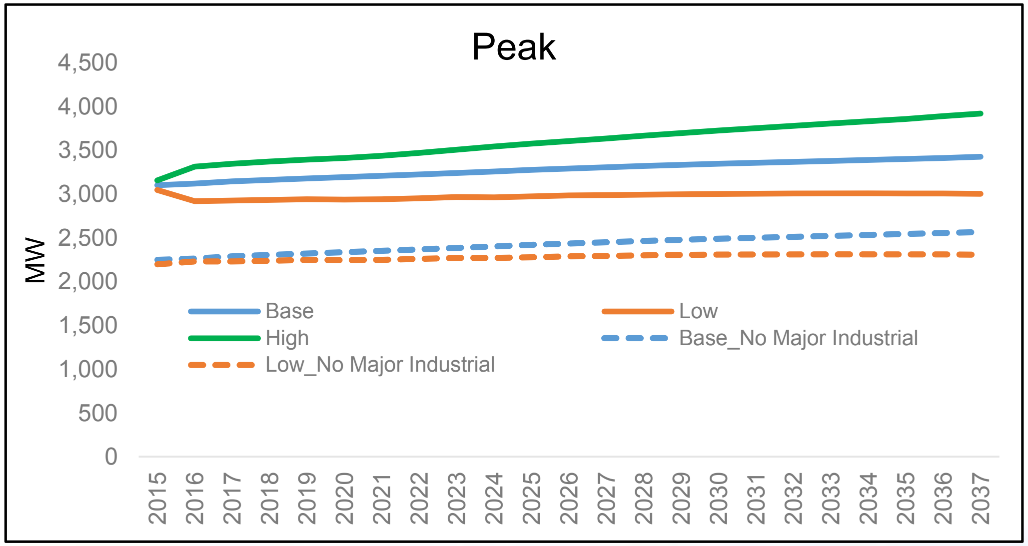


Source: PIRA Energy Group, NiSource Requested Scenarios 2016

Load Forecasts



Energy Requirement Projections	2016-2037 CAGR
Base	0.33%
Low	0.08%
High	0.68%
Base-Loss of Major Industrial	0.58%
Low-Loss of Major Industrial	0.12%



Peak Demand Projections	2016-2037 CAGR
Base	0.45%
Low	0.14%
High	0.80%
Base-Loss of Major Industrial	0.60%
Low-Loss of Major Industrial	0.16%

Notes: Compound Annual Growth Rate (CAGR)

Selectable Future Resource Options

- **Demand-side Resources:**
  - 22 Energy Efficiency Programs
  - 4 Demand Response Programs

- **Supply-side Resources:**
  - Conventional Resources (Coal, Gas, Nuclear)
  - Renewable and Emerging Resources
    - Wind
    - Solar
    - Other (CHP, Battery Storage, Microturbine, Biomass, & Reciprocating Engine)

Portfolio of DSM Groupings

Energy Efficiency (EE)

Residential Program Groupings	Commercial Program Groupings	Industrial Program Groupings
Appliances	Cooling	Cooling
Cooling	Exterior Lighting	Exterior Lighting
Heating	Food Preparation	Interior Lighting
Miscellaneous	Heating	Motors
Exterior Lighting	Interior Lighting	Heating
Interior Lighting	Miscellaneous	
Water Heating	Refrigeration	
	Ventilation	
	Water Heating	
	Office Equipment	

Demand Response (DR)

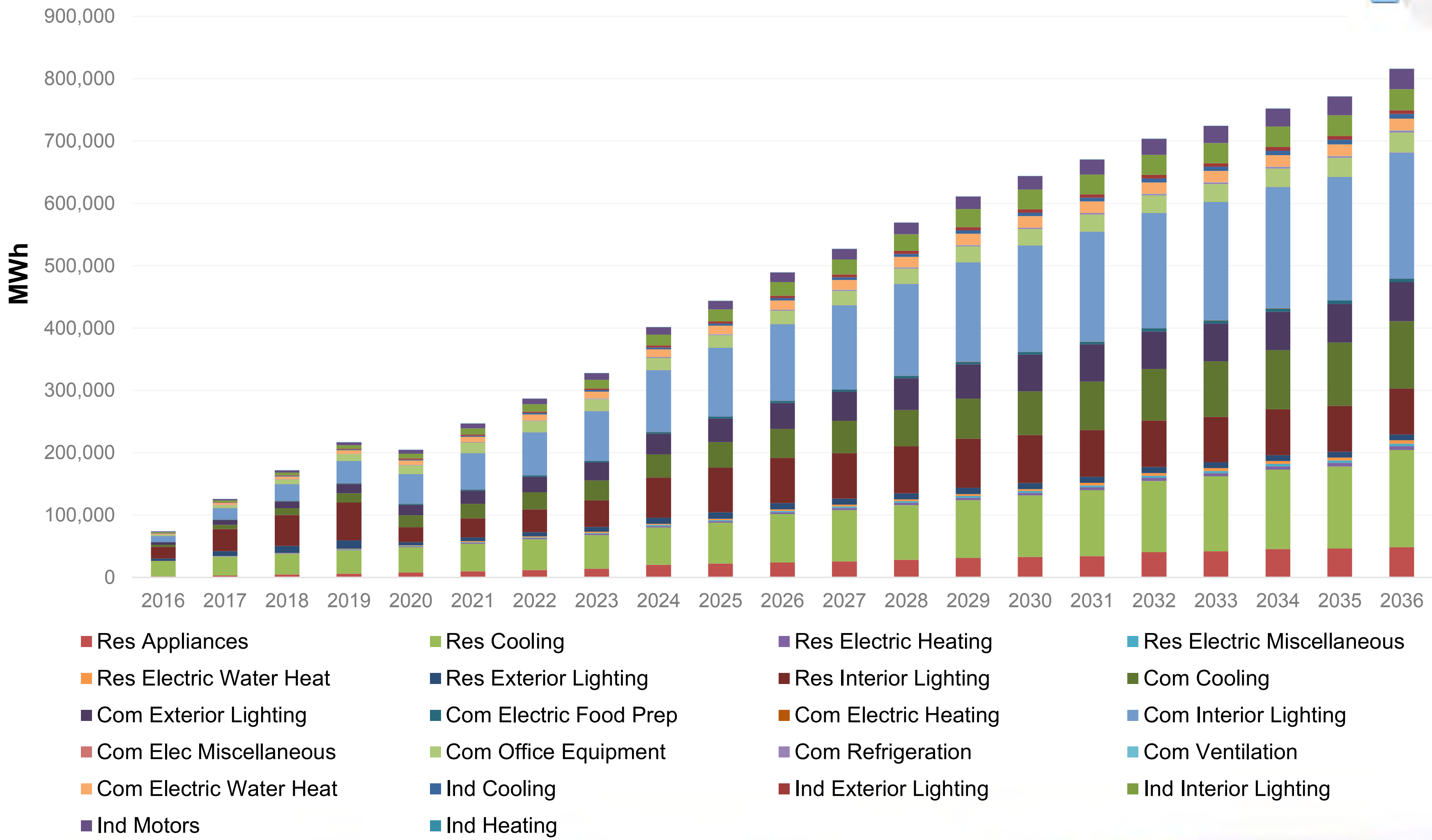
Residential DR Program	Commercial DR Program
Water Heating Direct Load Control	Water Heating Direct Load Control
Cooling Direct Load Control	Cooling Direct Load Control

Industrial Demand Response (DR)

Rider 675 Industrial Interruptible Service

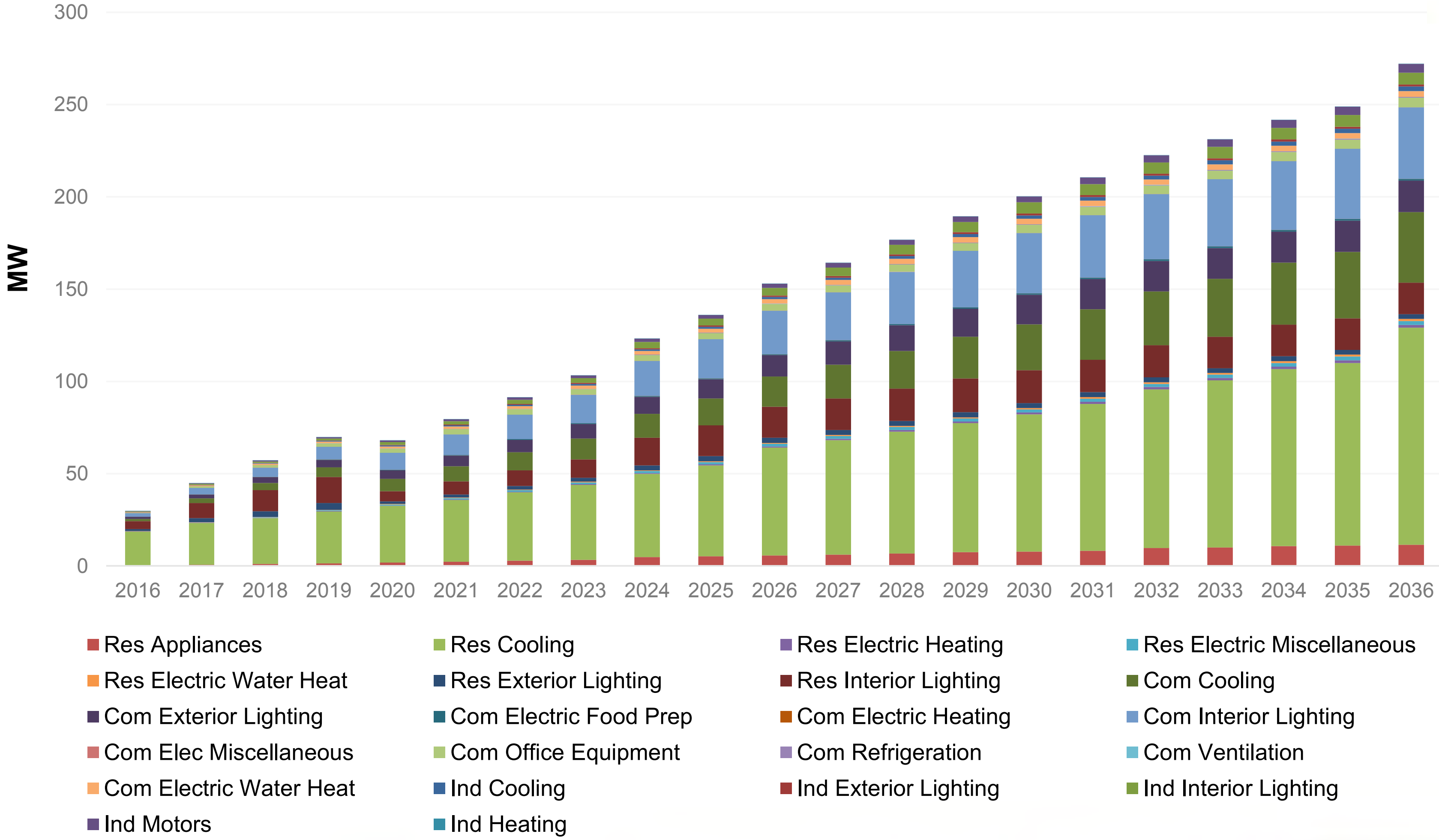
NIPSCO

Selectable: Net Cumulative Energy Savings by Grouping



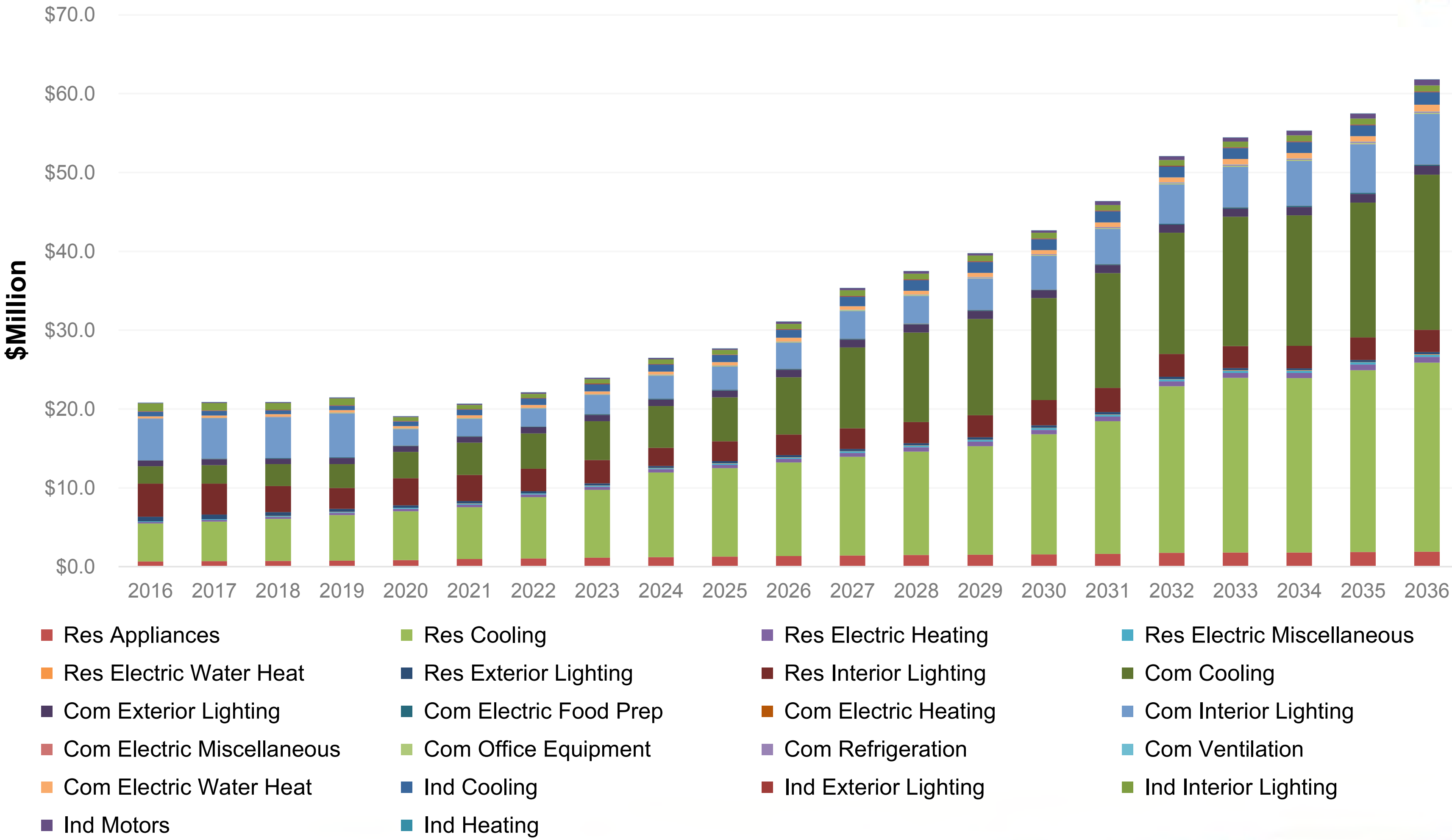
Sources: Applied Energy Group Market Potential Study and Morgan Marketing Partners

Selectable: Net Cumulative Summer Peak Demand Savings



Sources: Applied Energy Group Market Potential Study and Morgan Marketing Partners

Selectable: Utility Program Costs by Grouping

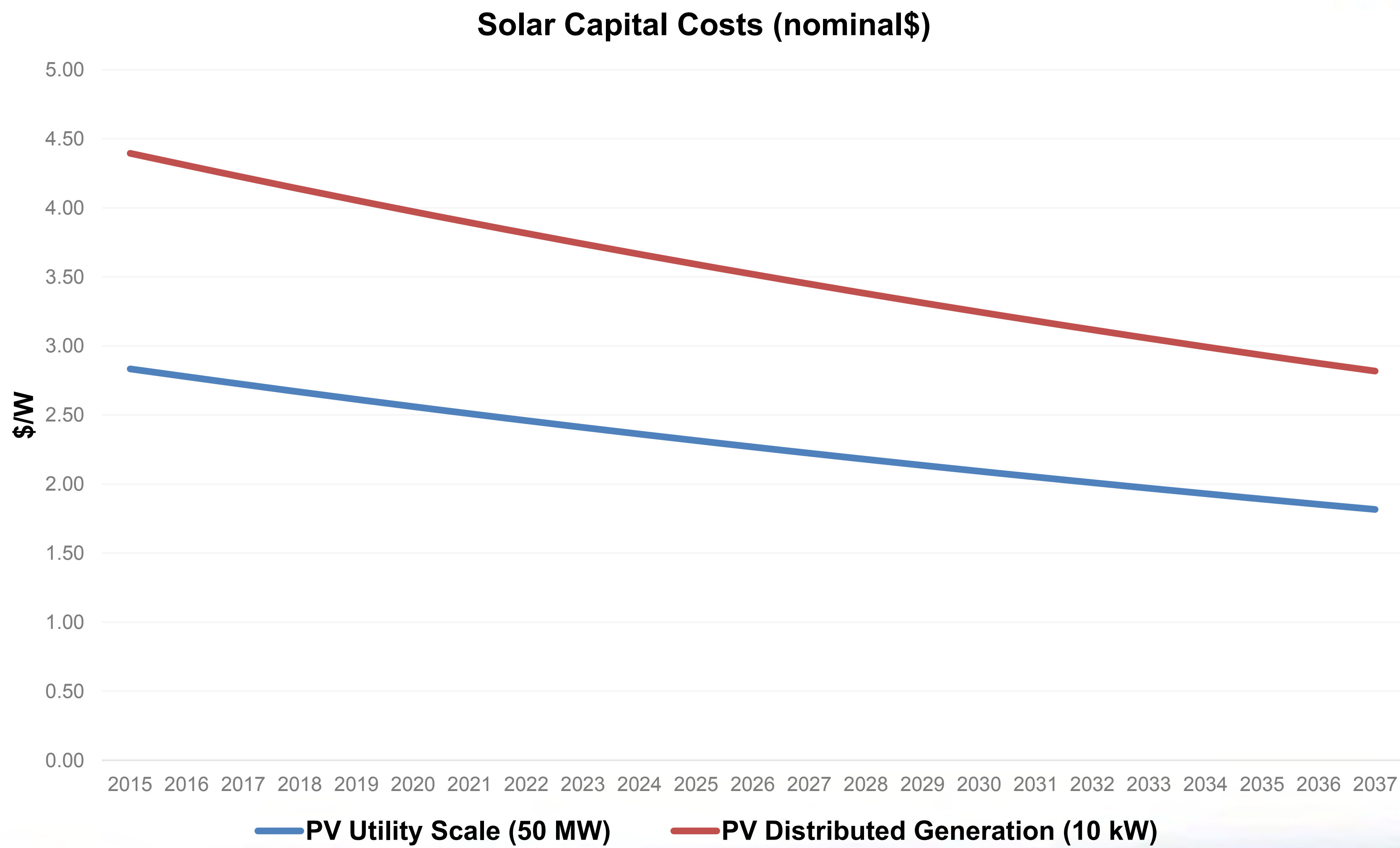


Sources and Notes: Applied Energy Group Market Potential Study and Morgan Marketing Partners; Costs are not present value costs

Costs of Future Supply-Side Options

Renewable & Emerging Technologies

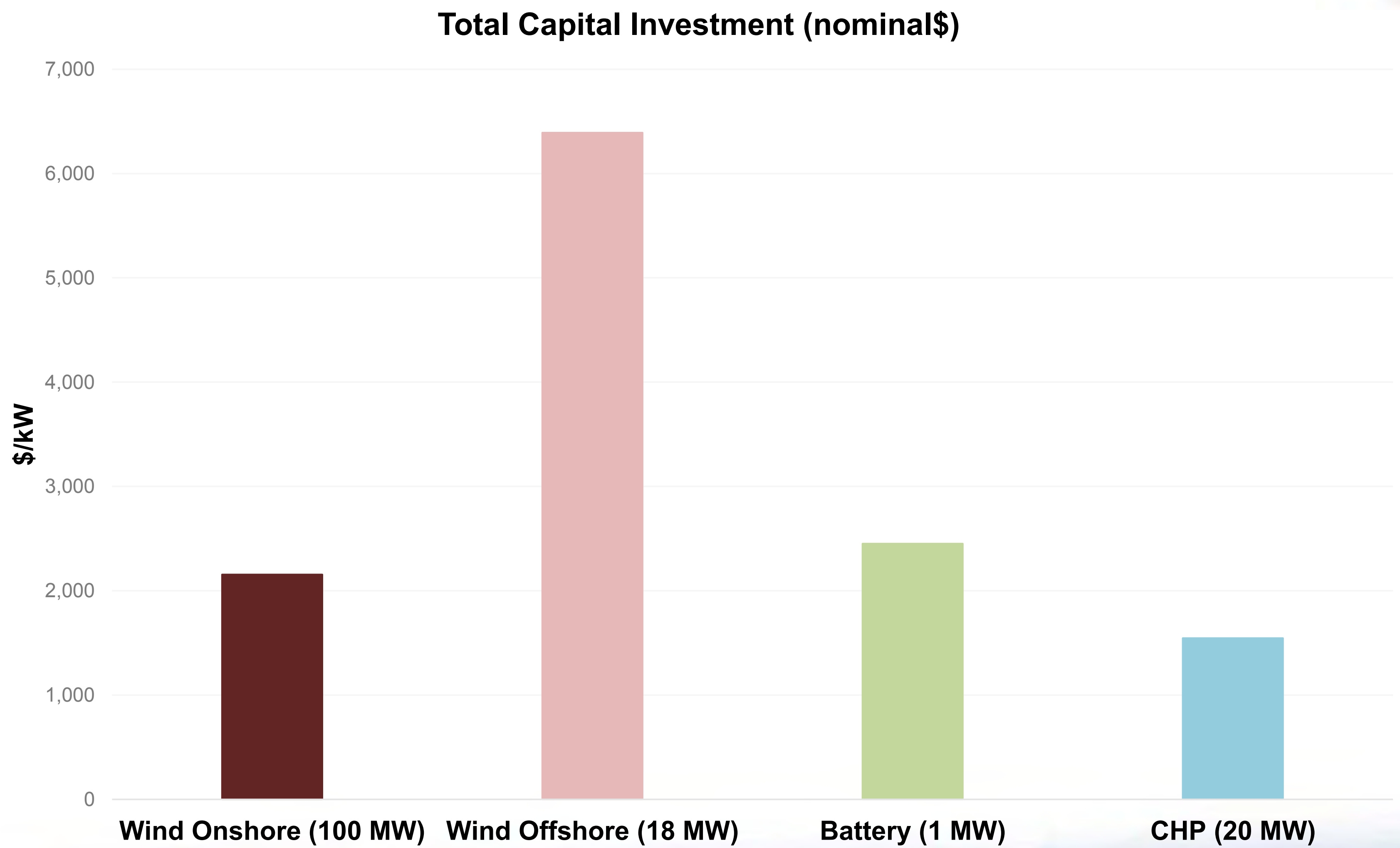
Solar Capital Costs



NIPSCO

Note: NiSource Analysis, Sargent & Lundy

Other Technologies' Capital Costs

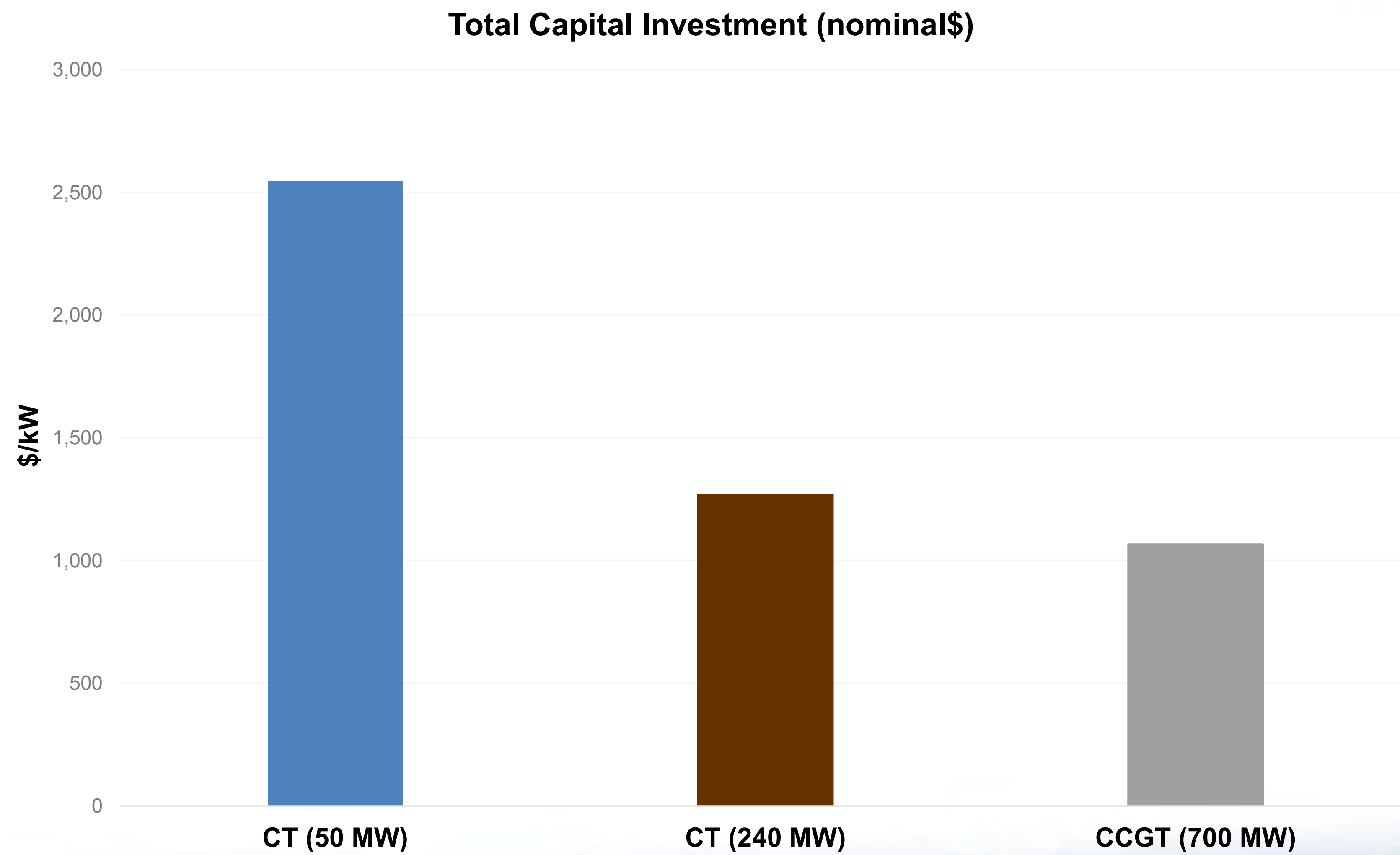


Note: Sargent & Lundy

Costs of Future Supply-Side Options

Conventional Technologies

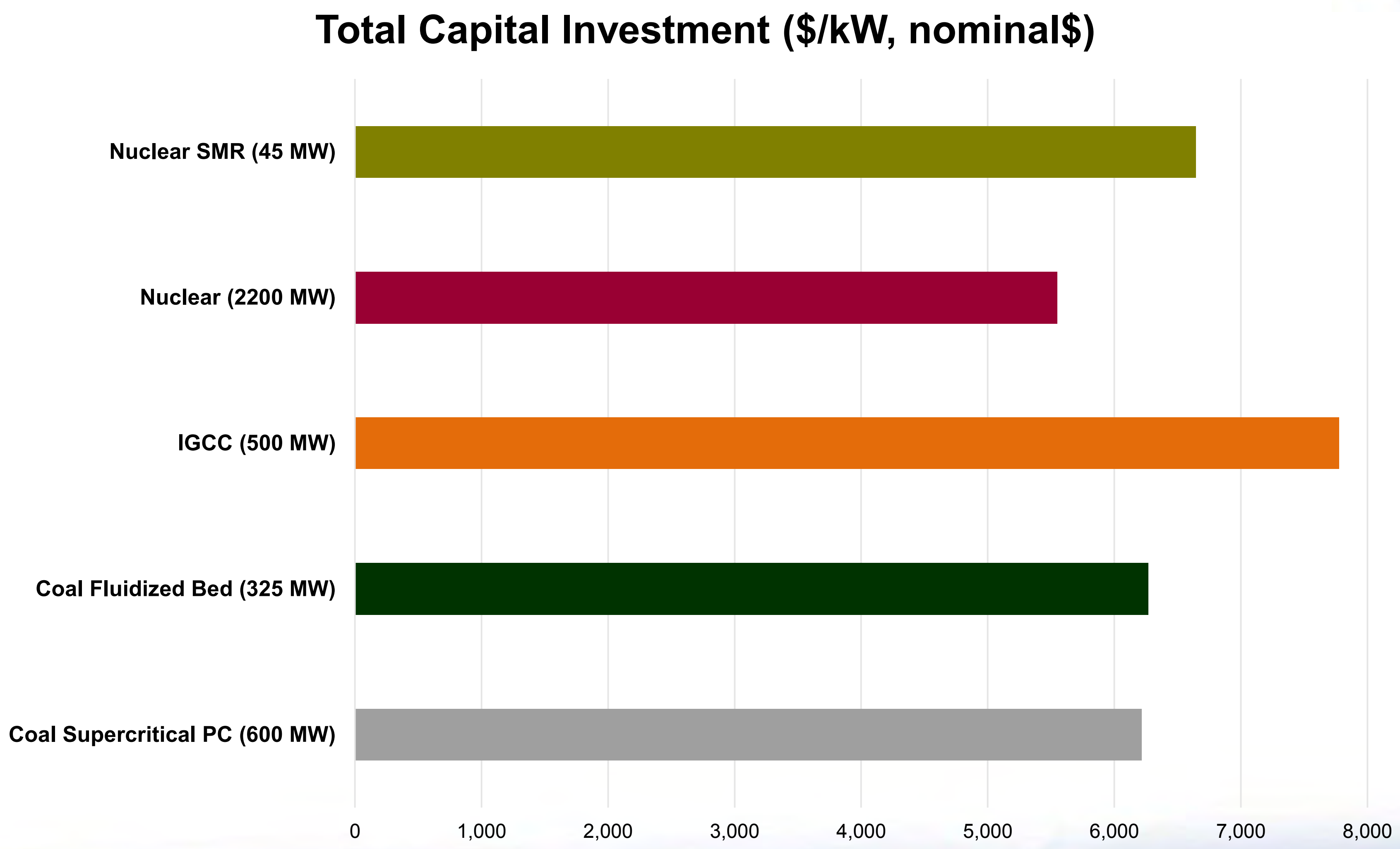
Natural Gas Technologies



Note: Sargent & Lundy

Other Conventional Technologies

UPDATED



Note: Sargent & Lundy

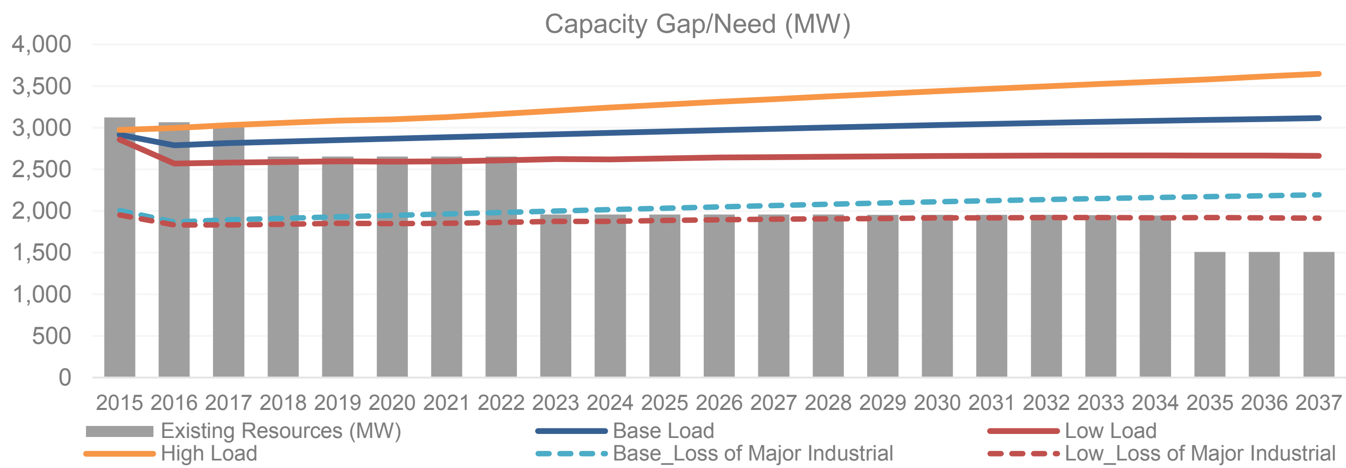
Resource Optimization Modeling

Presented by
Edward Achaab
Manager Resource Planning
&
Andrew Kramer, Ph.D.
Lead Resource Planning Analyst

Retirement Scenarios Drive Future Resource Needs

	Age Based	Retire 20% Coal (2023)	Retire 20% Coal (2018)	Retire 50% Coal	Retire 80% Coal	Retire 100% Coal
Retire:	Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 (2018) Schahfer: 17,18 (2023)	Bailly: 7,8 Schahfer: 14,15,17,18	Bailly: 7,8 Michigan City: 12 Schahfer: 14,15,17,18
Keep:	Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None
Cost to Customer	🔴	🔴	🟡	🟡	🟢	🟢
Portfolio Diversity	🔴	🟡	🟡	🟢	🟡	🔴
Employees	🟢	🟡	🟡	🟡	🔴	🔴
Environmental Compliance	🔴	🔴	🔴	🟢	🟢	🟢
Communities & Local Economy	🟢	🟡	🟡	🟡	🔴	🔴

Key
🔴 Worse
🟡 Better
🟢 Best



NIPSCO has not made a final retirement decision and is evaluating alternatives with stakeholders …NIPSCO's preferred plan will be finalized in its November Integrated Resource Plan submission

Example *Strategist*® Resource Expansion Plan

Illustrative

	Plan Rank	1	2	3	4	5	6	7	….	2,500
	2016	DSM1	DSM1	DSM1	DSM1	DSM1	DSM1	DSM1		DSM1
	2018	DSM2	DSM2	DSM2	DSM2	DSM2	DSM2	DSM2		DSM2
	2020	ST PPA	ST PPA	ST PPA	ST PPA	ST PPA	ST PPA	ST PPA		ST PPA
	2022	ST PPA	ST PPA	ST PPA	ST PPA	ST PPA	ST PPA	ST PPA		ST PPA
	2024	Retire Unit X	Retire Unit X	Retire Unit X	Retire Unit X	Retire Unit X	Retire Unit X	Retire Unit X		Retire Unit X
	2026	Gas CC	Gas CC	Gas CC	Gas CT	Gas CC	Gas CC	Gas CC		Gas CC
	2028	CHP	CHP	CHP	Solar	Solar	Solar	Solar		CHP
	2030			CHP		Solar	Wind	Battery		Coal
	2032	Wind	Wind	Wind	Wind	Wind	Wind	Wind		Wind
	2034		CHP		Wind			Wind		
	2036	Retire Unit Y	Retire Unit Y	Retire Unit Y	Retire Unit Y	Retire Unit Y	Retire Unit Y	Retire Unit Y		Retire Unit Y
	2038	Gas CT	Gas CT	Gas CT	Gas CT	Gas CT	Gas CT	Gas CT		Nuclear
A	**NPVRR (000$)**	**$12,000,000**	$12,600,000	$13,860,000	$15,523,200	$17,851,680	$21,064,982	$26,331,228	….	$47,396,210
B	**Renewable Focus (%)**	5%	5%	5%	7%	8%	10%	**20%**	….	6%
C	**CO_2 Emissions (tons)**	10,000,000	9,500,000	9,550,000	**7,500,000**	8,500,000	9,000,000	8,000,000	….	10,000,000

A: Least Cost Plan	Traditional least cost optimization
B: Renewable Focus	Cost effective combination of renewables and emerging technologies
C: Low Emission	Cost effective resources to create lower emitting portfolio

Scenarios Analysis

	Base	Challenged Economy	Aggressive Environmental Regulation	Booming Economy	Base Delayed Carbon
Sensitivities	No CO_2 Price	No CO_2 Price	High Renewables & Increasing Load	No CO_2 Price	
	Low Load	Loss of Major Industrial Load	High Renewables & Decreasing Load	Loss of Major Industrial Load	
	High Gas Price				
	Loss of Major Industrial Load				

Sources and Notes: Definitions adapted from *Electricity Director's Final Report 2014-2015 Integrated Resources Plans*, IURC, p. 9; Varying one "element" of a scenario to create a sensitivity may require changes to multiple variables to ensure that input data are properly correlated; For example, a low gas price sensitivity also requires correlated (lower) electricity prices

Base Scenario And Sensitivities

Base

Base Scenario

- The scenario NIPSCO considers most likely to occur
- Economy (national, regional, and local) continues to recover
- Load growth slowly increases
- National Carbon Policy effective 2023
- Natural gas supplies from Appalachia remain strong
- Non-carbon environmental compliance costs reflect only current and proposed regulations, including CSAPR, ELG, CCR, and 316(b)

Sensitivities	Descriptions
No CO_2 Price	- National Carbon Policy is not effected and no carbon price is modeled - Natural gas and power prices reflect a broader energy market not subject to carbon policy
Low Load	- Load is lower over the study period
High Gas Price	- Natural gas and on-peak power prices are higher - Environmental compliance costs are higher
Loss of Major Industrial Load	- Load is significantly lower due to the loss of major industrial load

Base Scenario Portfolios

Base

Preliminary

Least Cost Portfolio			
Expansion Plan (MW)			
Year	Gas	DSM	Purch
2016	-	533	-
2017	-	16	-
2018	-	24	154
2019	-	32	162
2020	-	34	177
2021	-	42	185
2022	-	46	199
2023	1,258	50	-
2024	-	55	-
2025	-	59	-
2026	-	61	-
2027	-	64	-
2028	-	67	-
2029	-	70	-
2030	-	72	-
2031	-	73	-
2032	-	74	-
2033	-	75	-
2034	-	76	-
2035	629	74	-
2036	-	75	-
2037	-	61	-

Renewable Focus Portfolio						
Expansion Plan (MW)						
Year	Gas	Wind	Solar	CHP	DSM	Purch
2016	-	-	-	-	533	-
2017	-	-	-	-	16	-
2018	-	-	-	-	24	154
2019	-	-	-	-	32	162
2020	-	-	-	-	34	177
2021	-	-	-	-	42	185
2022	-	-	-	-	46	199
2023	822	-	77	19	50	-
2024	-	-	13	-	55	-
2025	-	-	13	-	59	-
2026	-	-	13	-	61	-
2027	-	-	13	-	64	-
2028	-	8	-	-	67	-
2029	-	16	-	-	70	-
2030	-	16	-	-	72	-
2031	-	8	-	-	73	-
2032	-	8	-	-	74	-
2033	-	16	-	-	75	-
2034	-	16	-	-	76	-
2035	-	71	383	-	74	-
2036	-	8	-	-	75	-
2037	-	32	-	-	61	-

Low Emission Portfolio									
Expansion Plan (MW)									
Year	Gas	Nuke	Bio	Recip	Wind	Solar	Batt	DSM	Purch
2016	-	-	-	-	-	-	-	533	-
2017	-	-	-	-	-	-	-	16	-
2018	-	-	-	-	-	-	-	24	154
2019	-	-	-	-	-	-	-	32	162
2020	-	-	-	-	-	-	-	34	177
2021	-	-	-	-	-	-	-	42	185
2022	-	-	-	-	-	-	-	46	199
2023	822	-	43	-	-	51	-	50	-
2024	-	-	-	-	-	13	-	55	-
2025	-	-	-	-	-	13	-	59	-
2026	-	-	-	-	-	13	-	61	-
2027	-	-	-	-	-	13	-	64	-
2028	-	-	-	-	-	13	-	67	-
2029	-	-	-	-	-	13	-	70	-
2030	-	-	-	1	8	-	1	72	-
2031	-	-	-	-	16	-	-	73	-
2032	-	-	-	-	8	-	-	74	-
2033	-	-	-	-	16	-	-	75	-
2034	-	-	-	-	16	-	-	76	-
2035	-	488	-	-	-	-	-	74	-
2036	-	-	-	-	-	-	-	75	-
2037	-	-	-	-	-	-	-	61	-

Base Scenario Portfolios

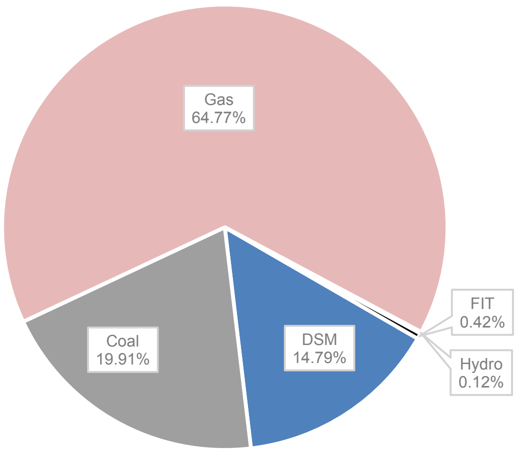
UPDATED

Preliminary

Base

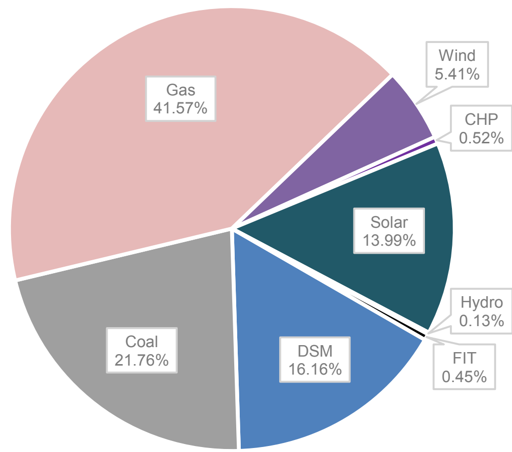
Resource Mix (Percent of Capacity)

2037 Least Cost



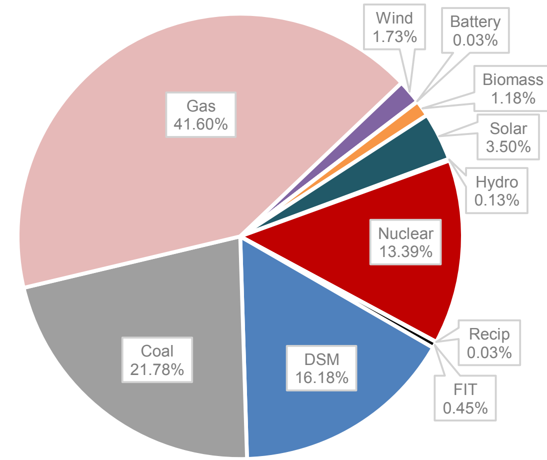
Total CO_2 (tons) =224,613,890

2037 Renewable Focus



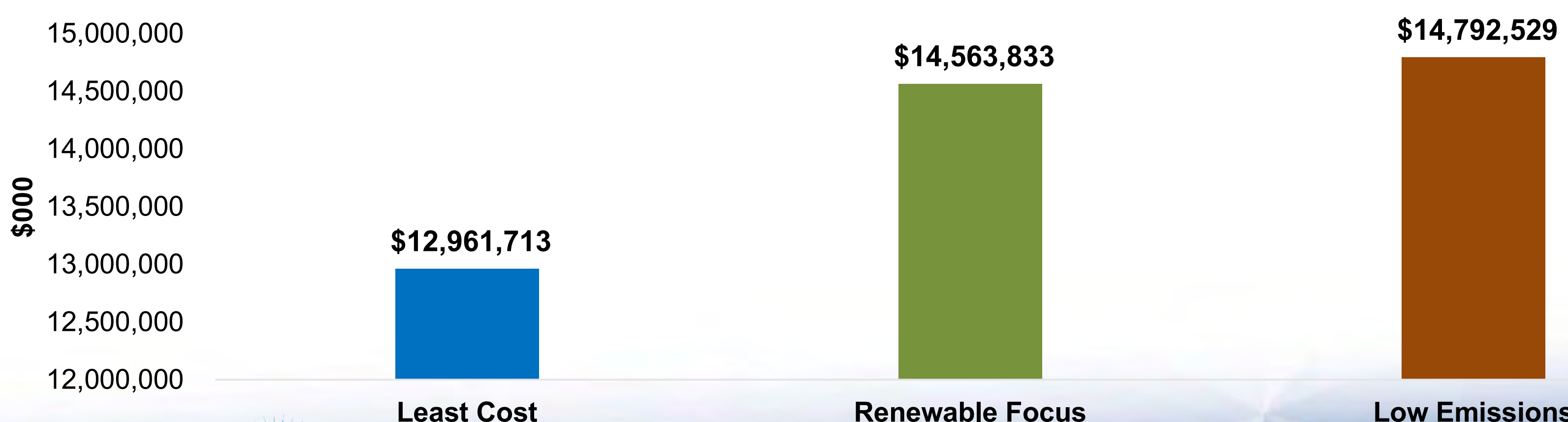
Total CO_2 (tons) =197,692,036

2037 Low Emissions



Total CO_2 (tons) =196,723,883

Portfolio NPVRR



NIPSCO

Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Challenged Economy

Challenged Economy Scenario And Sensitivities

Challenged Economy Scenario

- Economic downturn with growth stalling
- Customer load growth stagnates, but no major industrial customer loss
- National Carbon Policy effective 2023
- Reduced demand for natural gas and coal
- Non-carbon environmental compliance costs reflect only current and proposed regulations

Sensitivities	Descriptions
No CO_2 Price	- National Carbon Policy is not effected and no carbon price is modeled - Natural gas and power prices reflect a broader energy market not subject to carbon policy
Loss of Major Industrial Load	- Load is significantly lower over the study period due to the loss of major industrial load

NIPSCO

Challenged Economy Scenario Portfolios

Challenged Economy

Preliminary

Least Cost Portfolio			
Expansion Plan (MW)			
Year	Gas	CHP	DSM
2016	-	-	531
2017	-	-	7
2018	-	-	11
2019	-	-	15
2020	-	-	17
2021	-	-	21
2022	-	-	24
2023	629	19	28
2024	-	-	32
2025	-	-	34
2026	-	-	37
2027	-	-	40
2028	-	-	42
2029	-	19	45
2030	-	-	47
2031	-	-	48
2032	-	-	50
2033	-	-	51
2034	-	-	51
2035	629	-	49
2036	-	-	50
2037	-	-	47

Renewable Focus Portfolio				
Expansion Plan (MW)				
Year	Gas	Solar	CHP	DSM
2016	-	-	-	531
2017	-	-	-	7
2018	-	-	-	11
2019	-	-	-	15
2020	-	-	-	17
2021	-	-	-	21
2022	-	-	-	24
2023	629	-	19	28
2024	-	-	-	32
2025	-	-	-	34
2026	-	-	-	37
2027	-	-	-	40
2028	-	-	-	42
2029	-	13	-	45
2030	-	-	-	47
2031	-	-	-	48
2032	-	-	-	50
2033	-	13	-	51
2034	-	-	-	51
2035	193	242	-	49
2036	-	-	-	50
2037	-	-	-	47

Low Emission Portfolio				
Expansion Plan (MW)				
Year	Gas	Nuke	Solar	DSM
2016	-	-	-	531
2017	-	-	-	7
2018	-	-	-	11
2019	-	-	-	15
2020	-	-	-	17
2021	-	-	-	21
2022	-	-	-	24
2023	629	-	13	28
2024	-	-	-	32
2025	-	-	-	34
2026	-	-	13	37
2027	-	-	-	40
2028	-	-	-	42
2029	-	-	-	45
2030	-	-	13	47
2031	-	-	-	48
2032	-	-	-	50
2033	-	-	-	51
2034	-	-	-	51
2035	-	488	-	49
2036	-	-	-	50
2037	-	-	-	47

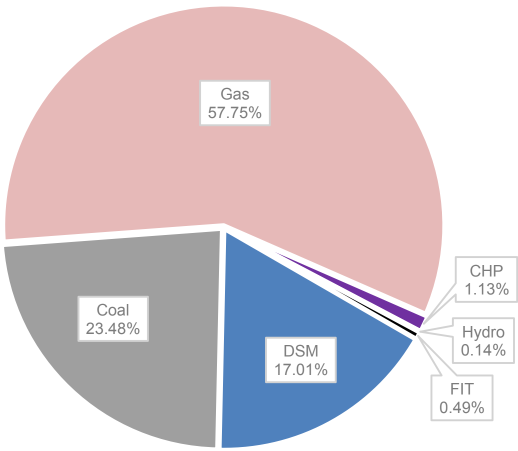
Challenged Economy Scenario Portfolios

Preliminary

Challenged Economy

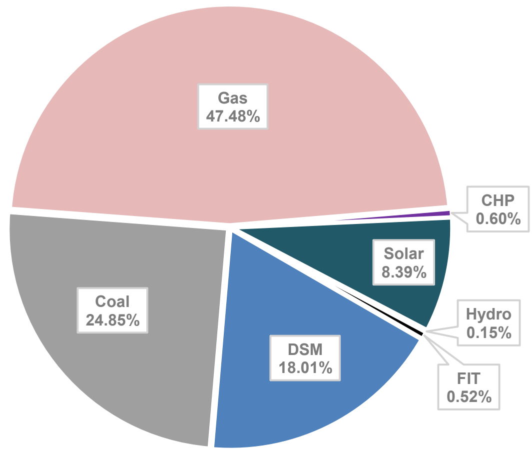
Resource Mix (Percent of Capacity)

2037 Least Cost



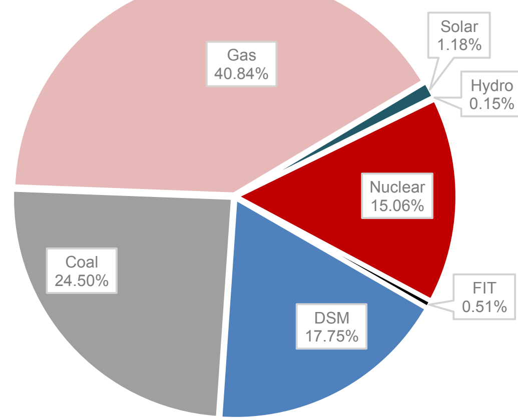
Total CO_2 (tons) =175,891,763

2037 Renewable Focus



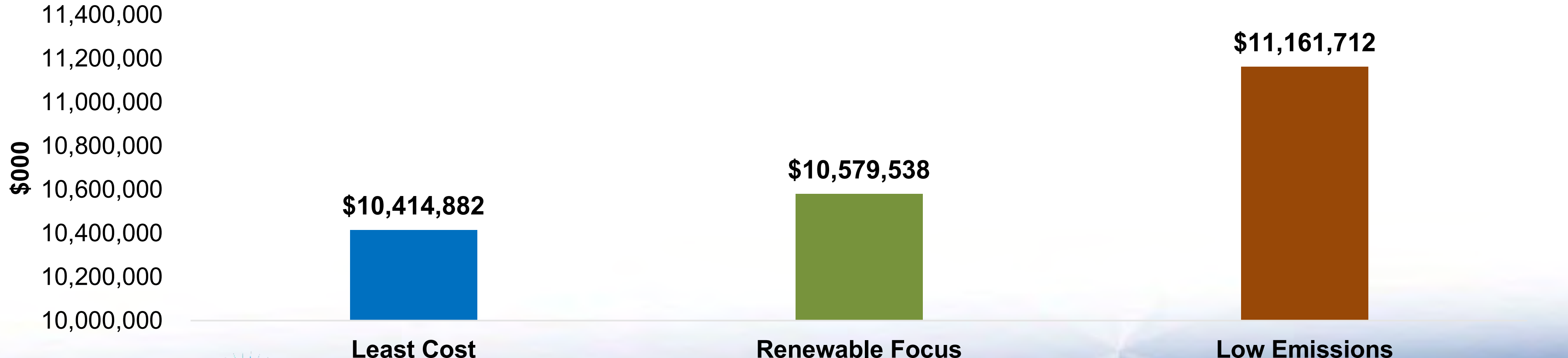
Total CO_2 (tons) =170,772,647

2037 Low Emissions



Total CO_2 (tons) =168,860,176

Portfolio NPVRR



Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Aggressive Environmental Regulation

Aggressive Environmental Regulation Scenario And Sensitivities

Aggressive Environmental Regulation Scenario

- Environmental regulations are more stringent than currently anticipated for both power generation and natural gas production (hydraulic fracturing)
- Stricter National Carbon Policy effective 2023
- More stringent regulations placed on coal production
- Non-carbon environmental compliance costs reflect only current and proposed regulations

Sensitivities	Descriptions
High Renewables and Increasing Load	- Indiana's voluntary renewable portfolio standard (RPS) becomes mandatory - Natural gas and power prices reflect the mandatory RPS and higher CO_2 price - Load is greater over the study period
High Renewables and Decreasing Load	- Indiana's voluntary renewable portfolio standard (RPS) becomes mandatory - Natural gas and power prices reflect the mandatory RPS and higher CO_2 price - Load is lower over the study period

NIPSCO

Aggressive Environmental Regulation

Aggressive Environmental Regulation Scenario Portfolios

Preliminary

Least Cost Portfolio

Expansion Plan (MW)

Year	Gas	DSM	Purch
2016	-	534	-
2017	-	14	-
2018	-	20	158
2019	-	27	168
2020	-	27	185
2021	-	33	195
2022	-	37	208
2023	1,258	41	-
2024	-	47	-
2025	-	51	-
2026	-	54	-
2027	-	57	-
2028	-	60	-
2029	-	63	-
2030	-	65	-
2031	-	67	-
2032	-	68	-
2033	-	69	-
2034	-	70	-
2035	629	68	-
2036	-	69	-
2037	-	67	-

Renewable Focus Portfolio

Expansion Plan (MW)

Year	Gas	Wind	Solar	Batt	CHP	DSM	Purch
2016	-	-	-	-	-	534	-
2017	-	-	-	-	-	14	-
2018	-	-	-	-	-	20	158
2019	-	-	-	-	-	27	168
2020	-	-	-	-	-	27	185
2021	-	-	-	-	-	33	195
2022	-	-	-	-	-	37	208
2023	822	-	77	-	19	41	-
2024	-	-	13	-	-	47	-
2025	-	-	13	1	-	51	-
2026	-	-	13	-	-	54	-
2027	-	-	13	-	-	57	-
2028	-	16	-	-	-	60	-
2029	-	16	-	-	-	63	-
2030	-	8	-	-	-	65	-
2031	-	16	-	-	-	67	-
2032	-	8	-	-	-	68	-
2033	-	16	-	-	-	69	-
2034	-	16	-	-	-	70	-
2035	-	71	383	-	-	68	-
2036	-	8	-	-	-	69	-
2037	-	16	-	-	-	67	-

Low Emission Portfolio

Expansion Plan (MW)

Year	Gas	Nuke	Bio	Recip	Wind	Solar	Batt	MT	DSM	Purch
2016	-	-	-	-	-	-	-	-	534	-
2017	-	-	-	-	-	-	-	-	14	-
2018	-	-	-	-	-	-	-	-	20	158
2019	-	-	-	-	-	-	-	-	27	168
2020	-	-	-	-	-	-	-	-	27	185
2021	-	-	-	-	-	-	-	-	33	195
2022	-	-	-	-	-	-	-	-	37	208
2023	822	-	43	-	-	51	-	-	41	-
2024	-	-	-	-	-	13	1	-	47	-
2025	-	-	-	-	-	26	-	-	51	-
2026	-	-	-	1	-	-	-	-	54	-
2027	-	-	-	-	-	13	-	-	57	-
2028	-	-	-	-	-	13	-	-	60	-
2029	-	-	-	-	16	-	-	-	63	-
2030	-	-	-	-	-	13	-	-	65	-
2031	-	-	-	-	8	-	-	0.3	67	-
2032	-	-	-	-	16	-	-	-	68	-
2033	-	-	-	-	16	-	-	-	69	-
2034	-	-	-	-	8	-	-	-	70	-
2035	-	488	-	-	-	-	-	-	68	-
2036	-	-	-	-	-	-	-	-	69	-
2037	-	-	-	-	-	-	-	-	67	-

NIPSCO

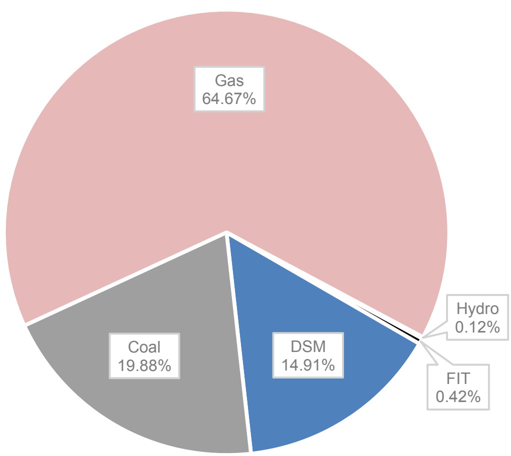
Aggressive Environmental Regulation Scenario Portfolios

Preliminary

Aggressive Environmental Regulation

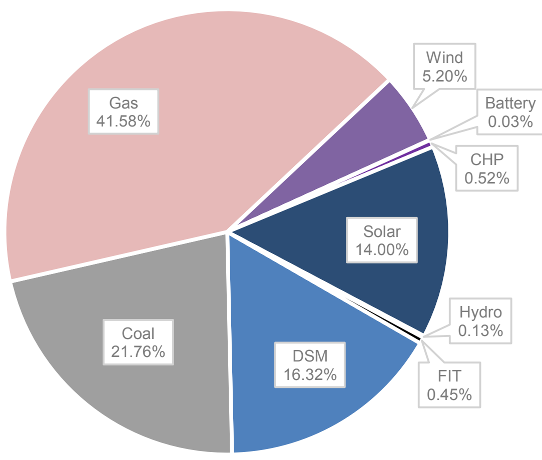
Resource Mix (Percent of Capacity)

2037 Least Cost



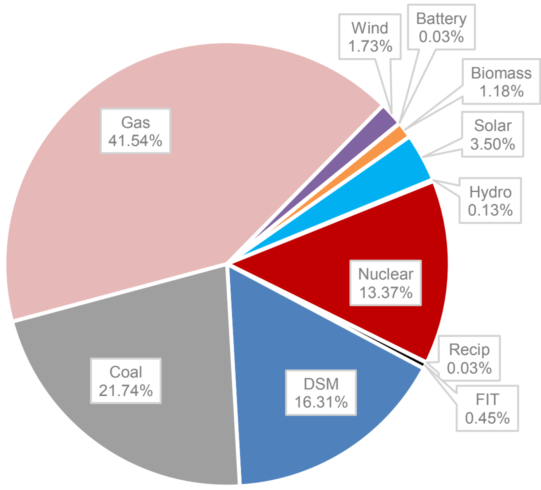
Total CO_2 (tons) =168,973,370

2037 Renewable Focus



Total CO_2 (tons) =153,862,710

2037 Low Emissions



Total CO_2 (tons) =152,787,795

Portfolio NPVRRs

Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Booming Economy Scenario And Sensitivities

Booming Economy

Booming Economy Scenario

- Economic growth is greater than expected
- State and national regulators introduce more stringent environmental regulations with reduced risk of negatively impacting economic growth, but compliance costs increase
- More aggressive regulatory environment leads to higher natural gas and coal production costs
- Higher cost National Carbon Policy effective 2023
- Non-carbon environmental compliance costs reflect only current and proposed regulations

Sensitivities	Descriptions
No CO_2 Price	- The National Carbon Policy is not effected and non-carbon regulations are same as Base case - Natural gas and power prices reflect a broader energy market not subject to the carbon legislation
Loss of Major Industrial Load	- Load is significantly lower due to loss of major load over the study period

NIPSCO

Booming Economy Scenario Portfolios

UPDATED

Booming Economy

Preliminary

Least Cost Portfolio				
Expansion Plan (MW)				
Year	Gas	CHP	DSM	Purch
2016	-	-	531	-
2017	-	-	9	1
2018	-	-	14	391
2019	-	-	18	410
2020	-	-	16	430
2021	-	-	19	455
2022	-	-	21	489
2023	1,258	-	23	-
2024	-	19	25	-
2025	-	19	27	-
2026	629	-	28	-
2027	-	-	28	-
2028	-	-	29	-
2029	-	-	30	-
2030	-	-	31	-
2031	-	-	31	-
2032	-	-	32	-
2033	-	-	32	-
2034	-	-	33	-
2035	629	-	31	-
2036	-	-	31	-
2037	-	-	28	-

Renewable Focus Portfolio						
Expansion Plan (MW)						
Year	Gas	Wind	Solar	CHP	DSM	Purch
2016	-	-	-	-	531	-
2017	-	-	-	-	9	1
2018	-	-	-	-	14	391
2019	-	-	-	-	18	410
2020	-	-	-	-	16	430
2021	-	-	-	-	19	455
2022	-	-	-	-	21	489
2023	1,015	63	128	19	23	-
2024	-	-	38	-	25	-
2025	-	-	38	-	27	-
2026	-	-	26	-	28	-
2027	-	-	38	-	28	-
2028	-	-	26	-	29	-
2029	-	-	38	-	30	-
2030	-	-	26	-	31	-
2031	-	-	26	-	31	-
2032	-	-	38	-	32	-
2033	-	-	26	-	32	-
2034	-	-	38	-	33	-
2035	629	-	-	-	31	-
2036	-	-	-	-	31	-
2037	-	-	-	-	28	-

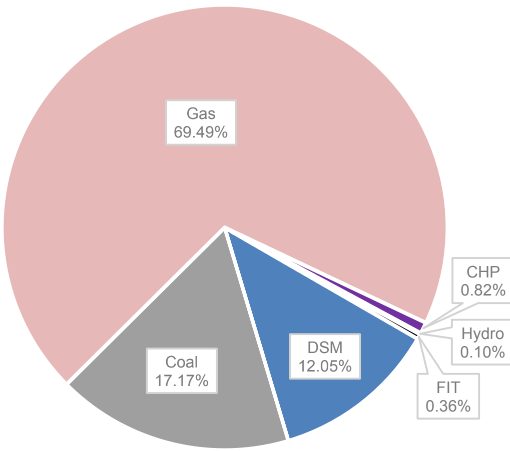
Low Emission Portfolio									
Expansion Plan (MW)									
Year	Gas	Nuke	Bio	Recip	Wind	Solar	Batt	DSM	Purch
2016	-	-	-	-	-	-	-	531	-
2017	-	-	-	-	-	-	-	9	1
2018	-	-	-	-	-	-	-	14	391
2019	-	-	-	-	-	-	-	18	410
2020	-	-	-	-	-	-	-	16	430
2021	-	-	-	-	-	-	-	19	455
2022	-	-	-	-	-	-	-	21	489
2023	1,015	-	43	-	47	115	1	23	-
2024	-	-	-	1	24	13	-	25	-
2025	-	488	-	-	-	-	-	27	-
2026	-	-	-	-	-	-	-	28	-
2027	-	-	-	-	-	-	-	28	-
2028	-	-	-	-	-	-	-	29	-
2029	-	-	-	-	-	-	-	30	-
2030	-	-	-	-	-	-	-	31	-
2031	-	-	-	-	-	-	-	31	-
2032	-	-	-	-	-	-	-	32	-
2033	-	-	-	-	-	-	-	32	-
2034	-	-	-	-	-	-	-	33	-
2035	-	1,987	-	-	-	-	-	31	-
2036	-	-	-	-	-	-	-	31	-
2037	-	-	-	-	-	-	-	28	-

Booming Economy Scenario Portfolios UPDATED ~~Preliminary~~

Booming Economy

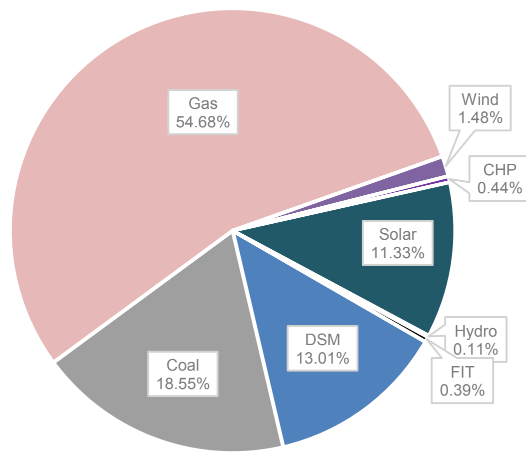
Resource Mix (Percent of Capacity)

2037 Least Cost



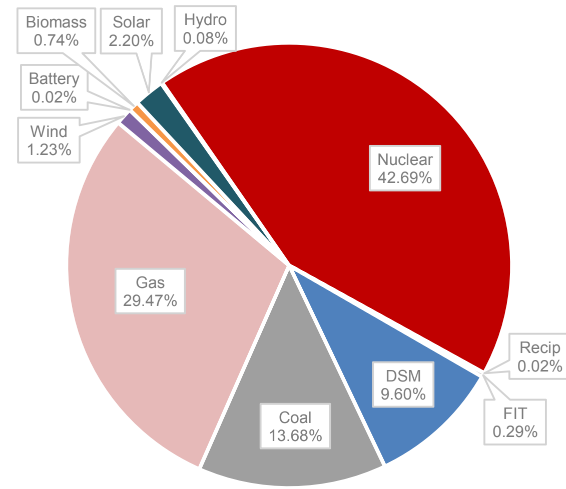
Total CO_2 (tons) =246,060,539

2037 Renewable Focus



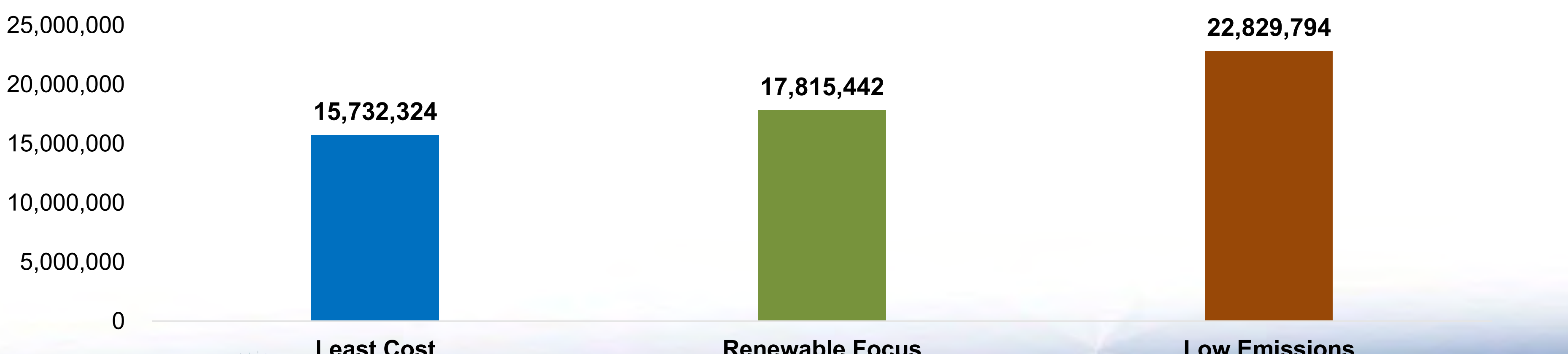
Total CO_2 (tons) =215,580,665

2037 Low Emissions



Total CO_2 (tons) =212,365,034

Portfolio NPVRRs ($K)



NIPSCO

Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Base Case Delayed Carbon Scenario

Base Case Delayed Carbon

Base Case Delayed Carbon Scenario

- The scenario represents revised assumptions to the Base Scenario
- Economy (national, regional, and local) continues to recover
- Load growth slowly increases
- National Carbon Policy effective 2025
- Lower input fuel prices due to increased supply growth and weakness in demand from the power sector
- Lower technology cost and tax credits drive renewable growth
- Non-carbon environmental compliance costs reflect only current and proposed regulations, including CSAPR, ELG, CCR, and 316(b)

NIPSCO

Base Case Delayed Carbon Scenario Portfolios

Base Case Delayed Carbon

Preliminary

Least Cost Portfolio			
Expansion Plan (MW)			
Year	Gas	DSM	Purch
2016	-	531	-
2017	-	6	-
2018	-	9	170
2019	-	12	184
2020	-	15	198
2021	-	19	210
2022	-	22	225
2023	1,258	25	-
2024	-	30	-
2025	-	33	-
2026	-	37	-
2027	-	40	-
2028	-	44	-
2029	-	47	-
2030	-	50	-
2031	-	52	-
2032	-	54	-
2033	-	56	-
2034	-	57	-
2035	629	58	-
2036	-	60	-
2037	-	61	-

Renewable Focus Portfolio						
Expansion Plan (MW)						
Year	Gas	Wind	Solar	CHP	DSM	Purch
2016	-	-	-	-	531	-
2017	-	-	-	-	6	-
2018	-	-	-	-	9	170
2019	-	-	-	-	12	184
2020	-	-	-	-	15	198
2021	-	-	-	-	19	210
2022	-	-	-	-	22	225
2023	822	-	102	19	25	-
2024	-	-	13	-	30	-
2025	-	-	13	-	33	-
2026	-	-	13	-	37	-
2027	-	8	-	-	40	-
2028	-	16	-	-	44	-
2029	-	16	-	-	47	-
2030	-	8	-	-	50	-
2031	-	8	-	-	52	-
2032	-	8	-	-	54	-
2033	-	16	-	-	56	-
2034	-	16	-	-	57	-
2035	-	79	370	-	58	-
2036	-	8	-	-	60	-
2037	-	16	-	-	61	-

Low Emission Porfolio									
Expansion Plan (MW)									
Year	Gas	Nuke	Bio	Recip	Wind	Solar	Batt	DSM	Purch
2016	-	-	-	-	-	-	-	531	-
2017	-	-	-	-	-	-	-	6	-
2018	-	-	-	-	-	-	-	9	170
2019	-	-	-	-	-	-	-	12	184
2020	-	-	-	-	-	-	-	15	198
2021	-	-	-	-	-	-	-	19	210
2022	-	-	-	-	-	-	-	22	225
2023	822	-	43	-	-	77	-	25	-
2024	-	-	-	-	-	13	-	30	-
2025	-	-	-	-	-	13	-	33	-
2026	-	-	-	-	-	13	-	37	-
2027	-	-	-	-	-	13	-	40	-
2028	-	-	-	-	8	-	-	44	-
2029	-	-	-	-	16	-	-	47	-
2030	-	-	-	-	8	-	1	50	-
2031	-	-	-	1	8	-	-	52	-
2032	-	-	-	-	16	-	-	54	-
2033	-	-	-	-	16	-	-	56	-
2034	-	-	-	-	8	-	-	57	-
2035	-	488	-	-	-	-	-	58	-
2036	-	-	-	-	-	-	-	60	-
2037	-	-	-	-	-	-	-	61	-

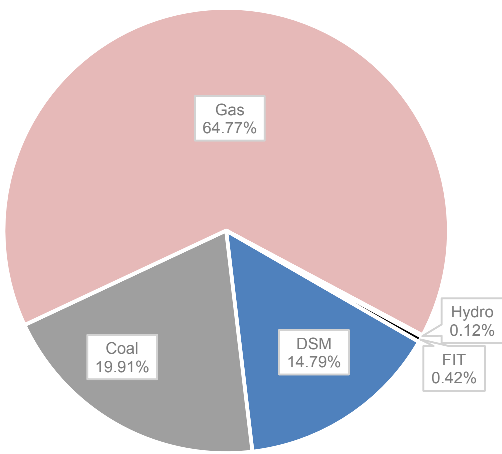
Base Delayed Carbon Scenario Portfolios UPDATED

~~Preliminary~~

Base Case Delayed Carbon

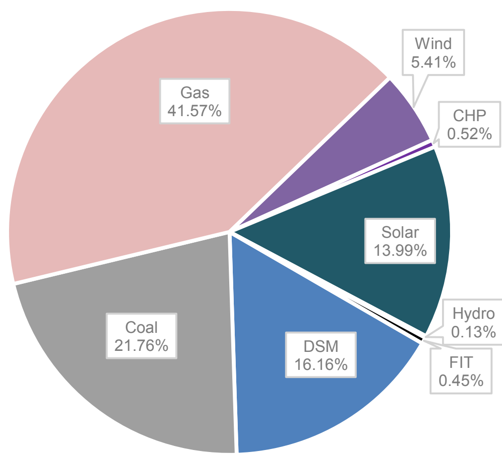
Resource Mix (Percent of Capacity)

2037 Least Cost



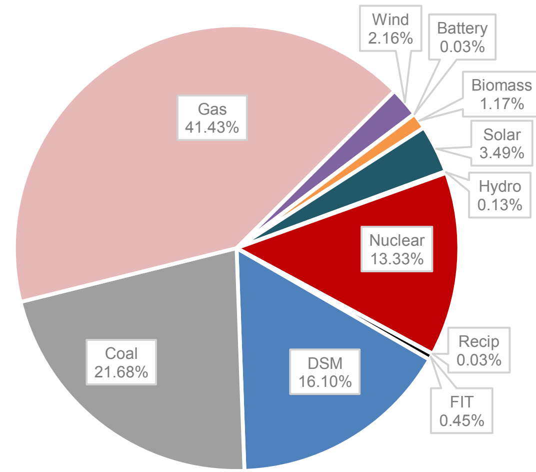
Total CO_2 (tons) =175,813,976

2037 Renewable Focus



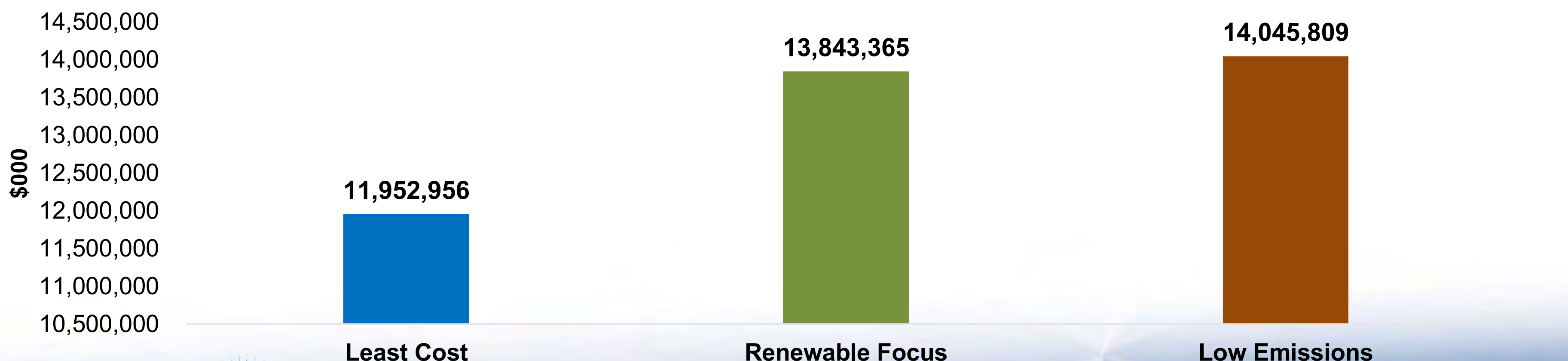
Total CO_2 (tons) =148,515,033

2037 Low Emissions



Total CO_2 (tons) =146,769,599

Portfolio NPVRR



Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

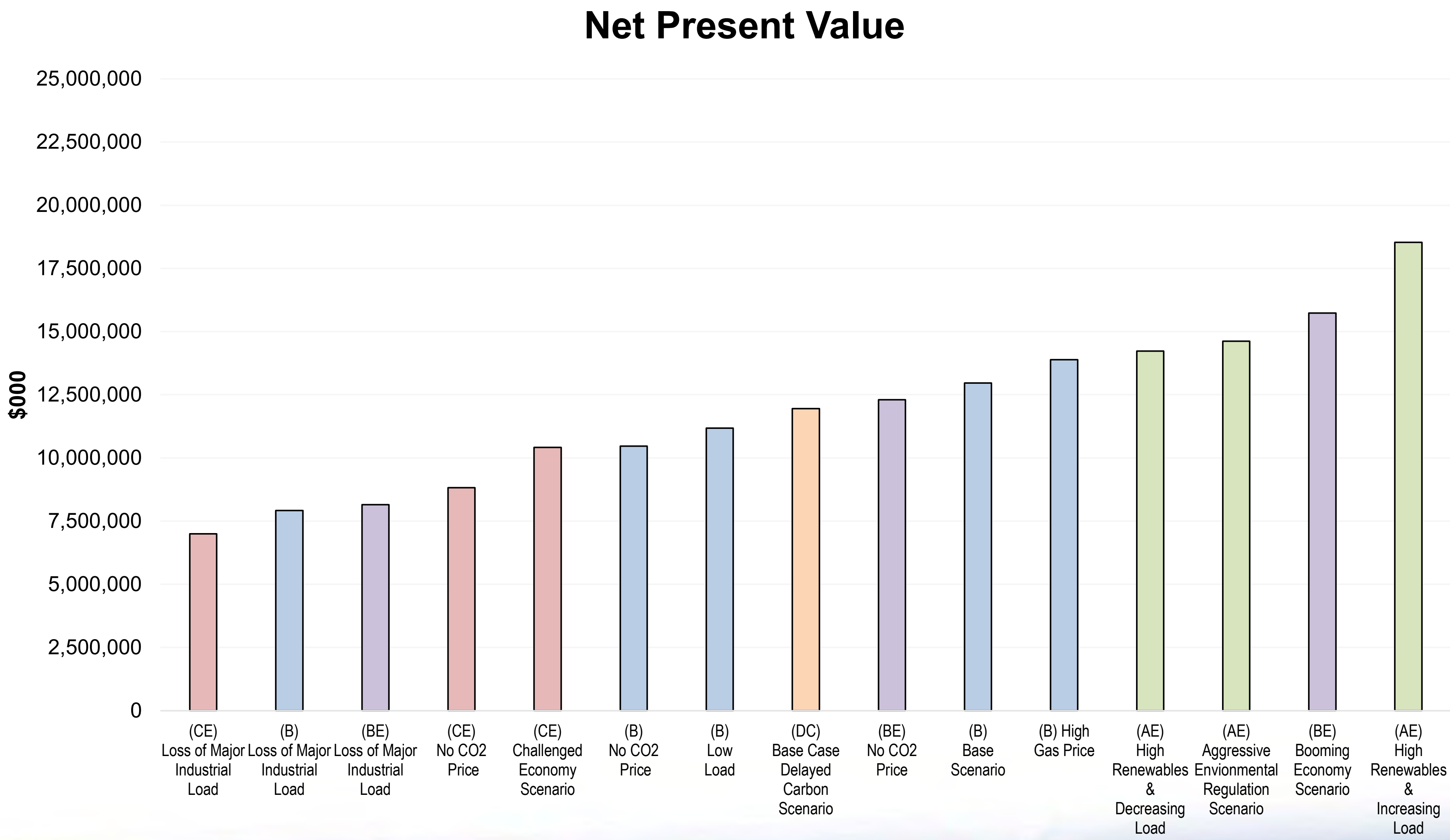
Sensitivities Analysis

Scenarios	Base	Challenged Economy	Aggressive Environmental Regulation	Booming Economy	Base Delayed Carbon
Sensitivities	No CO_2 Price	No CO_2 Price	High Renewables & Increasing Load	No CO_2 Price	
	Low Load	Loss of Major Industrial Load	High Renewables & Decreasing Load	Loss of Major Industrial Load	
	High Gas Price				
	Loss of Major Industrial Load				

Sources and Notes: Definitions adapted from *Electricity Director's Final Report 2014-2015 Integrated Resources Plans*, IURC, p. 9; Varying one "element" of a scenario to create a sensitivity may require changes to multiple variables to ensure that input data are properly correlated; For example, a low gas price sensitivity also requires correlated (lower) electricity prices

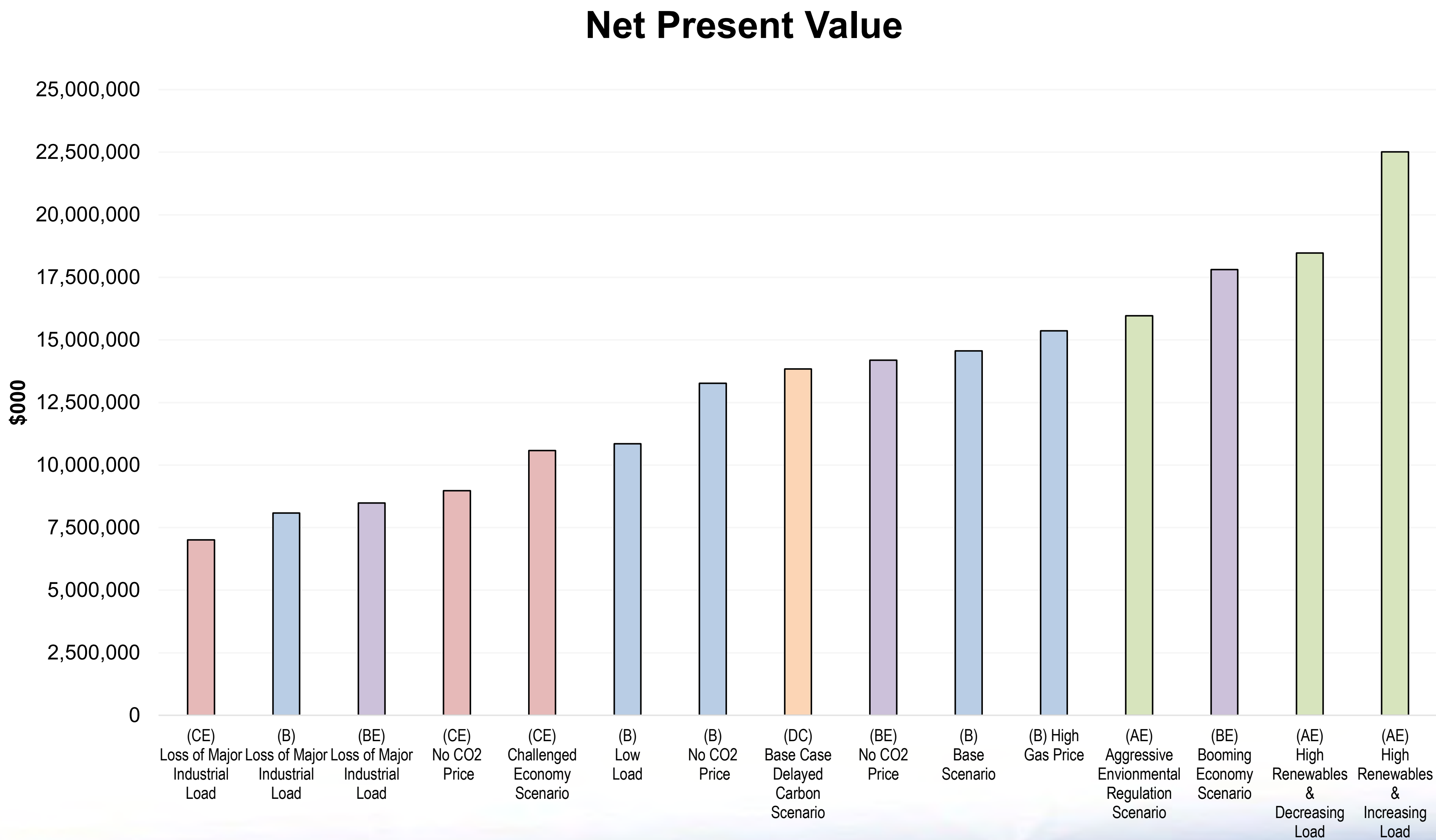
Scenarios And Sensitivities Summary:
Least Cost Strategy

Preliminary



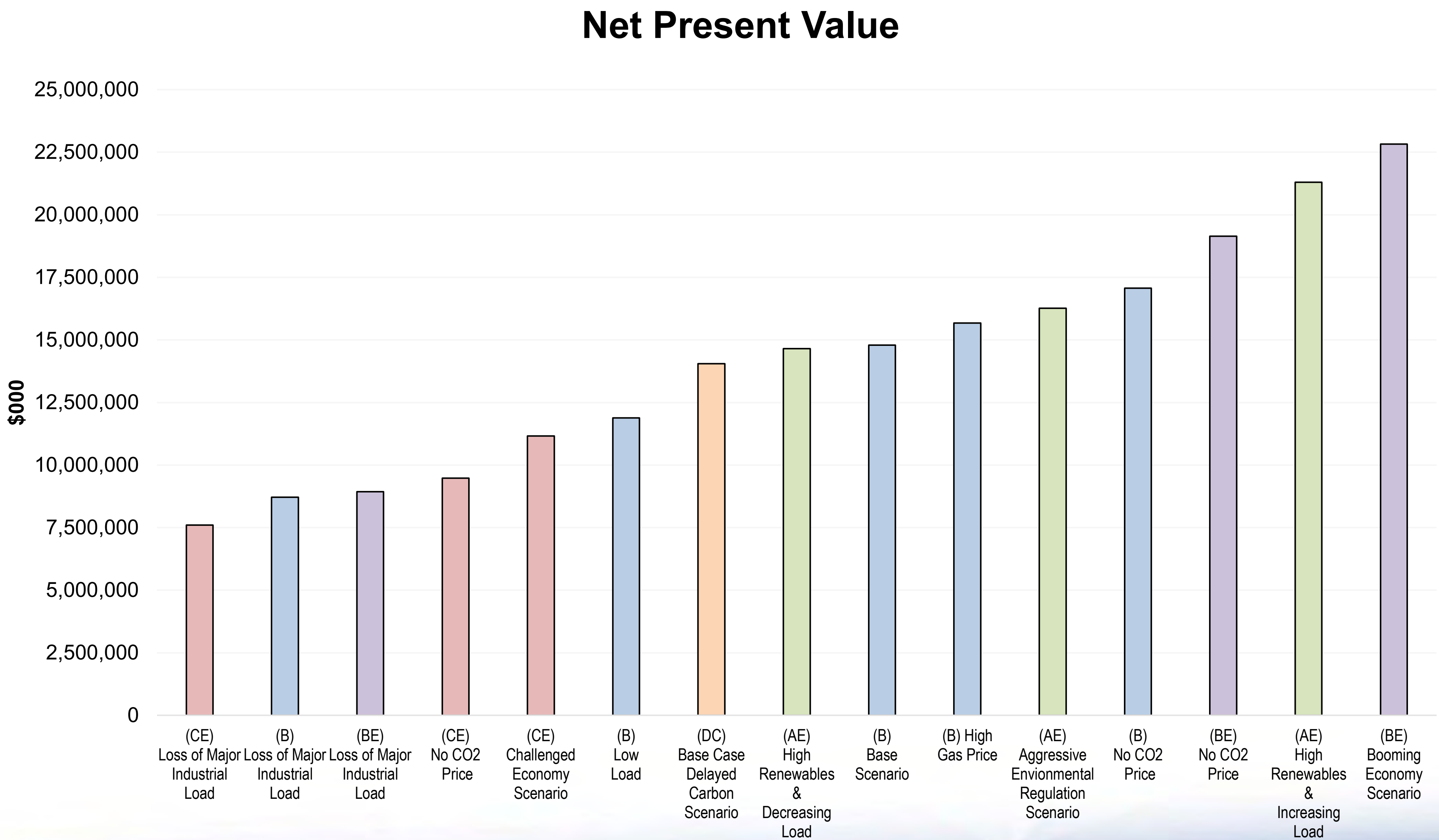
Scenarios And Sensitivities Summary: Renewable Focus Strategy

Preliminary

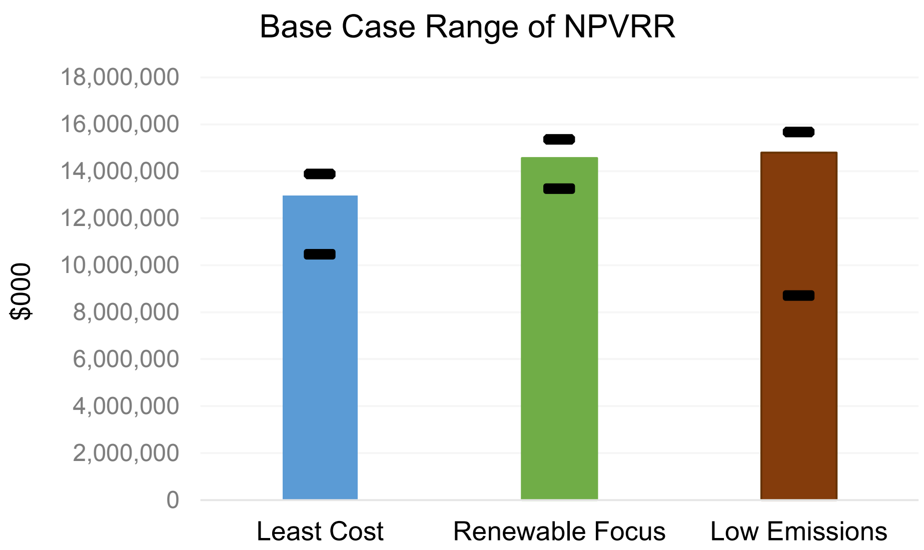


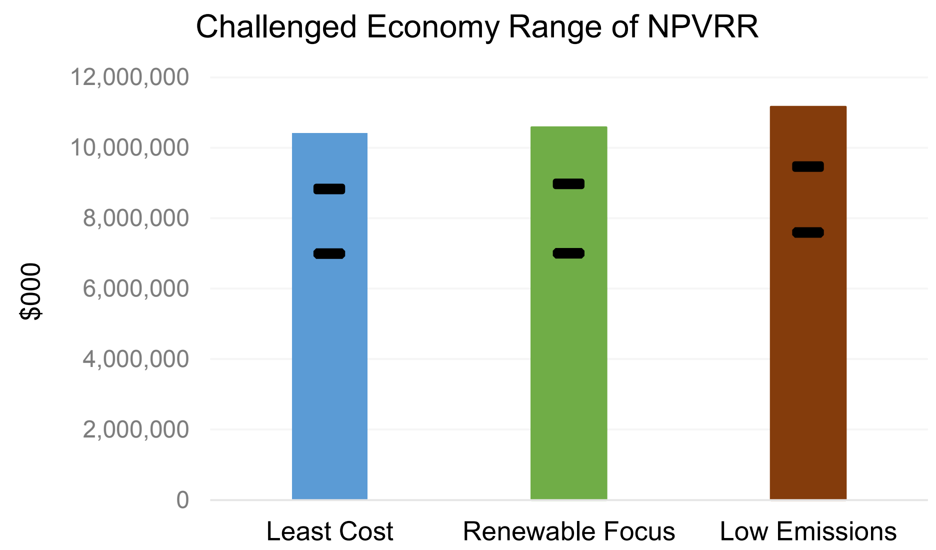
Scenarios And Sensitivities Summary:
Low Emissions Strategy

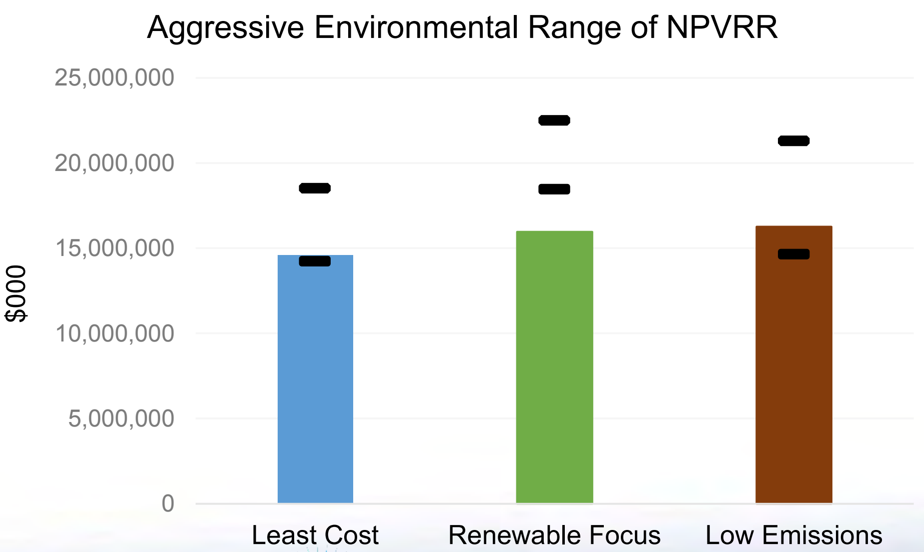
Preliminary

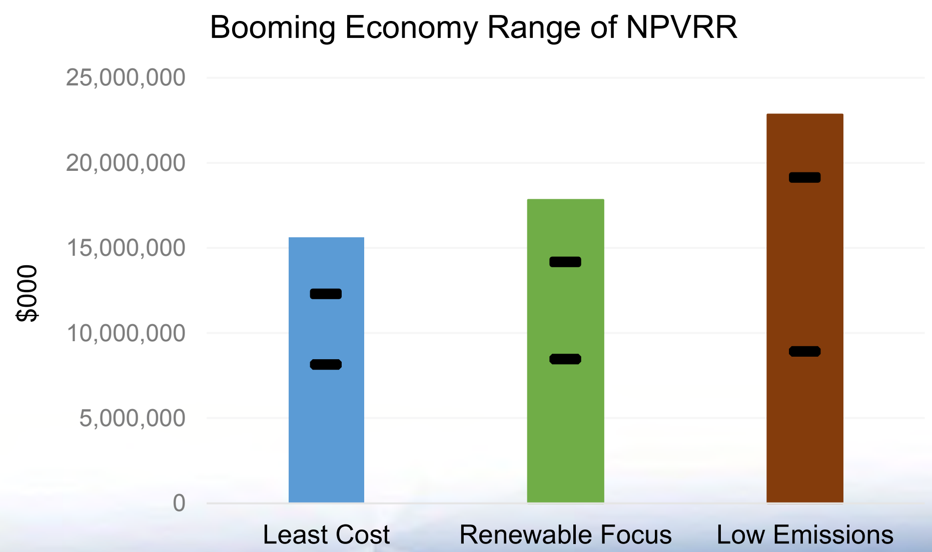


Preliminary Commodity Sensitivities Across Cases

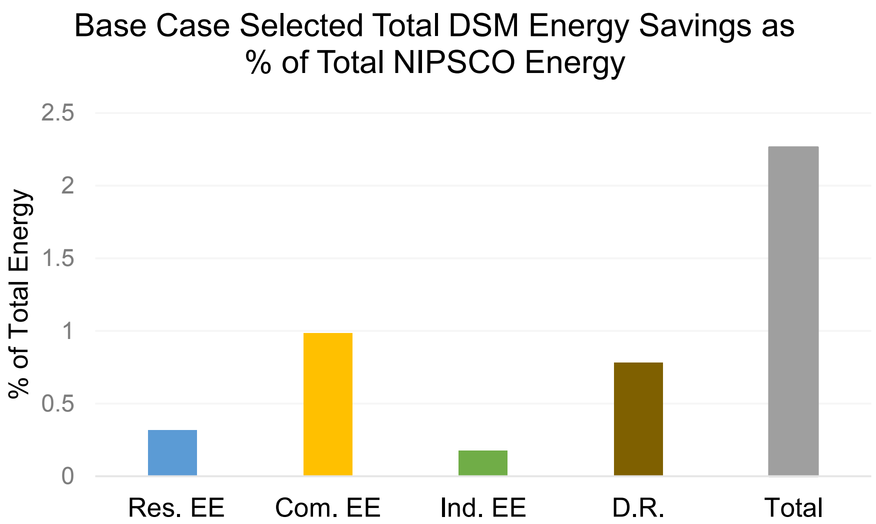


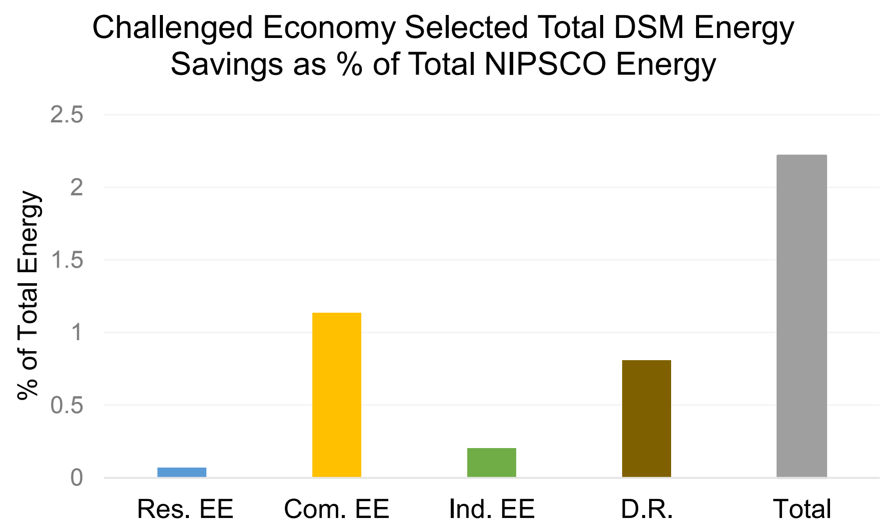


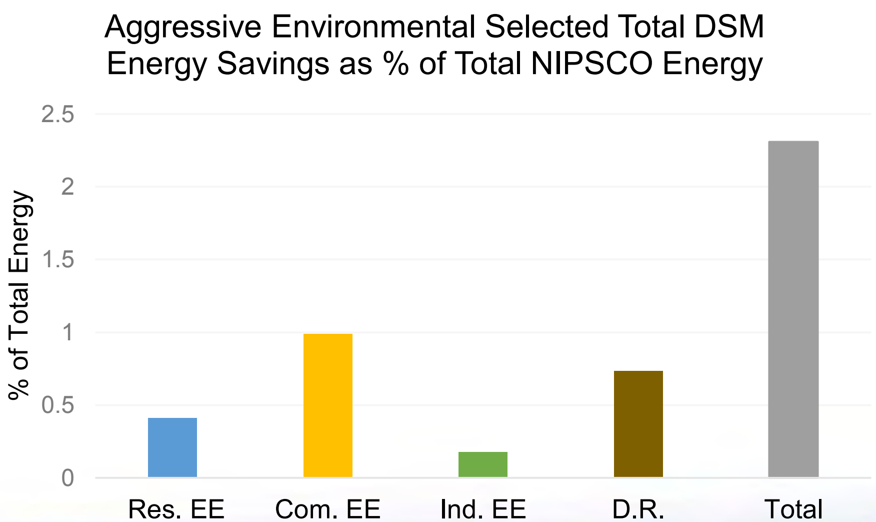


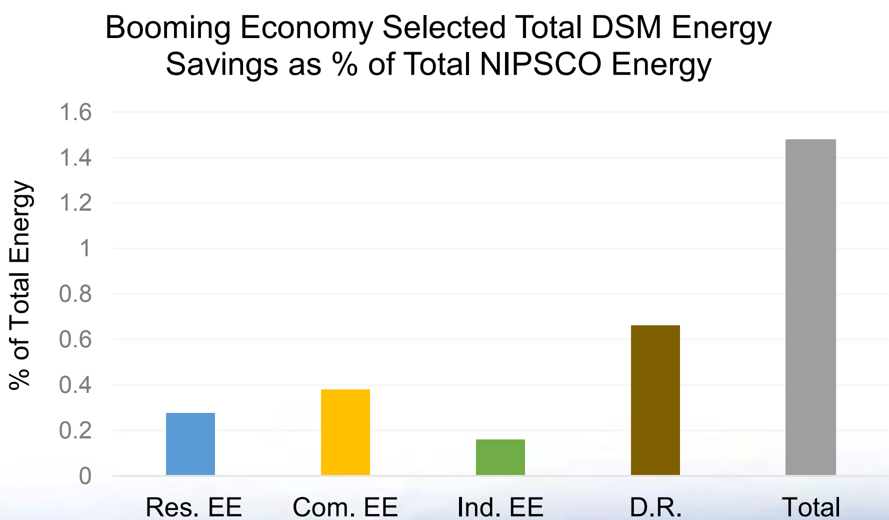


Preliminary DSM Selection Across Scenarios

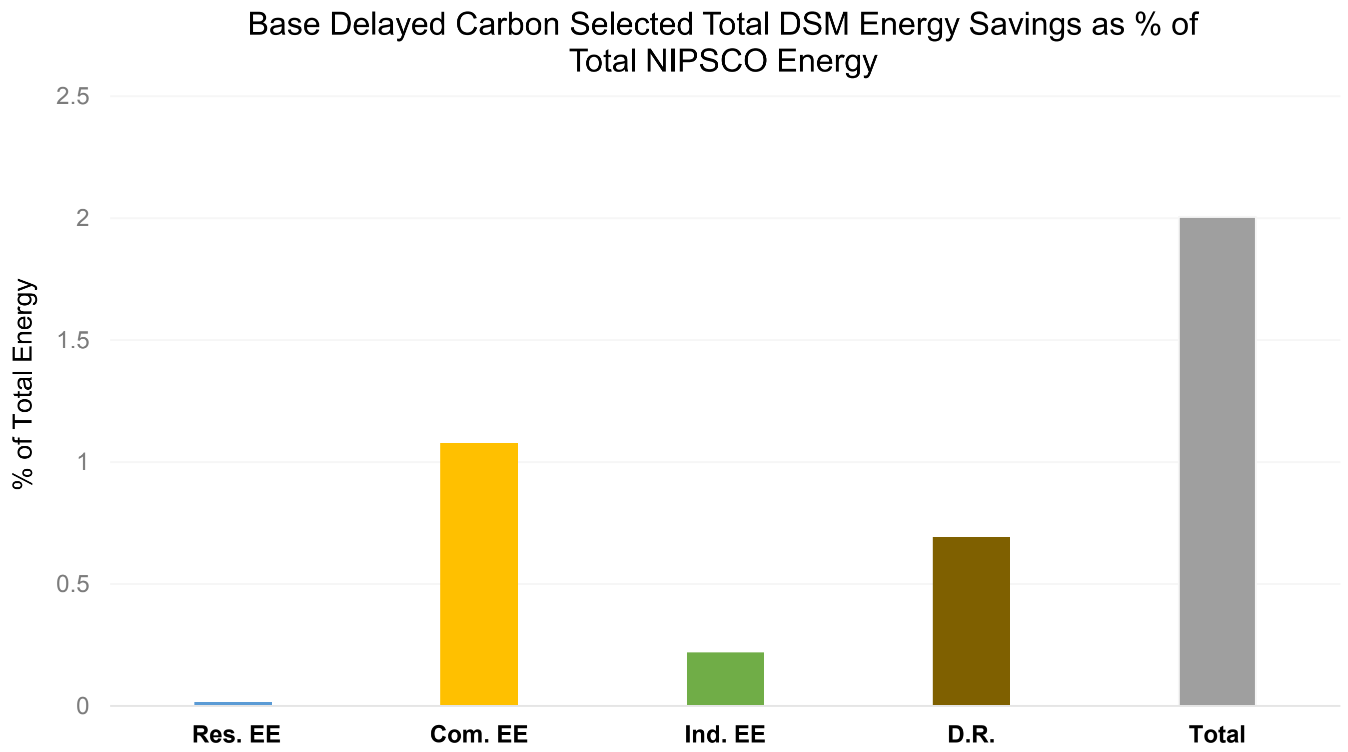




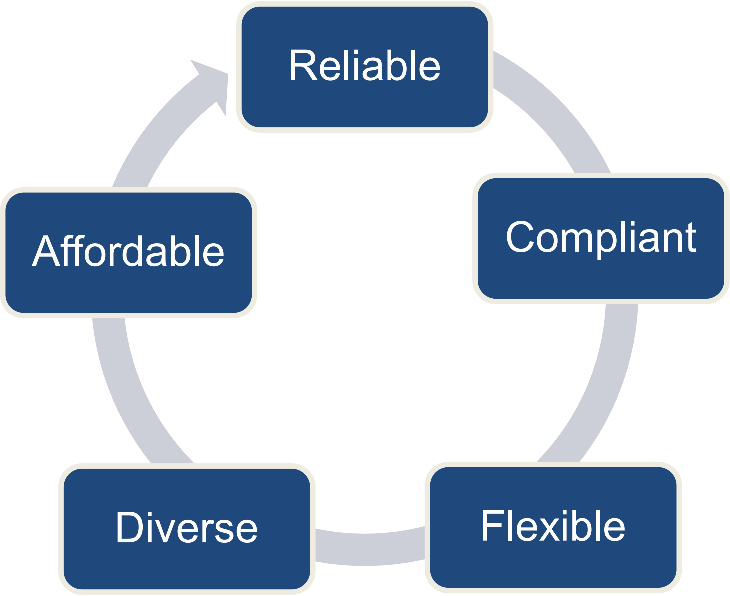




Preliminary DSM Selection For Base Delayed Carbon



How Does NIPSCO Plan For The Future?



Requires Careful Planning And Consideration For:

- Our employees
- Impact on the environment
- Changes in the local economy (property tax, supplier spend, employee base)

Stakeholder Presentations

Next Steps

Presented by

Dr. Marty Rozelle

The Rozelle Group Ltd

IRP Public Stakeholder Process and Timeline

Proposed

	May 5th	July 12th	August 23rd	September 12th	October 3rd
Key Questions	- What process will NIPSCO use for its IRP? - What are the key assumptions driving the scenarios and sensitivities?	- How will NIPSCO incorporate Demand Side Management Resources in the IRP?	- Deep dive into NIPSCO's existing generation - What are the optimal replacement options to fill the supply gap?	- Where are the stakeholders focused? - What is NIPSCO's preferred retirement plan?	- What is NIPSCO's Preferred Plan?
Agenda/ Content	- Overview of process - NIPSCO overview - Load forecasting - Demand side management - Environmental considerations - IRP development - Public advisory process	- Review Market Potential Study - Describe and Review Demand Side Management measure groupings - Introduce Demand Side Management Modeling Methodology	- Overview of existing generation by unit (costs, environmental, etc.) - Retirement analysis - Outline preferred retirement direction and describe resulting capacity gap through time - Replacement options (supply-side and demand-side)	- Discuss retirement paths and address related stakeholder feedback - Address input from stakeholder and 1:1 meetings - Share initial analysis from 1:1 stakeholder meetings	- Share any results from 1:1 stakeholder analytical requests (these will also be shared in 1:1 meetings between 9/12 and 10/3) - Describe Preferred Replacement Path and logic relative to alternatives - Explain NIPSCO retirement and replacement timeline (File IRP, RFP, CPCN, etc)
Key Deliverables	- Key assumptions - Overview of scenarios and sensitivities	- Common understanding of the grouping of DSM measures - Clear picture of NIPSCO's DSM modeling methodology	- Stakeholder feedback and shared understanding of generation alternatives	- NIPSCO's preferred retirement plan - Overview of stakeholder analysis requests	- Review of Stakeholder feedback - NIPSCO's Preferred Plan
Meeting Format	- 6 hour in person session	- 5.5 hours in person session	- 6 hours in person session	- 2 hour Touch point	- 4 hour in person session

Next Steps

- **Future meeting timeline:**
  - 4th Meeting scheduled for September 12th
  - 5th Meeting scheduled for October 3rd
- **Meeting summary:** Available September 6, 2016
- **NIPSCO website:** *www.NIPSCO.com/irp*
- **NIPSCO IRP email:** *NIPSCO_IRP@nisource.com*

NIPSCO IRP Process
Opportunities for Combined Heat and Power (CHP)

August 23, 2016

David Baker

US DOE Midwest CHP TAP

U.S. Department of Energy
CHP Technical Assistance Partnerships
MIDWEST

Presentation Outline

- DOE CHP TAPs
- What is CHP? Benefits/Market Opportunities
- CHP in Indiana – Current and Potential
- CHP in Integrated Resource Plans
- Benefits and Examples of Utility-owned CHP
- Utility CHP Incentive Programs in the Midwest
- CHP TAP Technical Assistance

DOE CHP TAPs

U.S. DOE CHP Deployment Program

- **Market Analysis and Tracking** – Supporting analyses of CHP market opportunities in diverse markets including industrial, federal, institutional, and commercial sectors.

- **Technical Assistance through DOE's CHP Technical Assistance Partnerships (CHP TAPs)** – Promote and assist in transforming the market for CHP, waste heat to power, and district energy with CHP throughout the United States

- **Just Launched Combined Heat and Power (CHP) for Resiliency Accelerator -**

  Collaborating with Partners to support consideration of CHP and other distributed generation solutions for critical infrastructure resiliency planning at the state, local, and utility levels

- **Packaged CHP System Challenge (under development) -**

  Increase CHP deployment in underdeveloped markets with standardized, pre-approved and warrantied packaged CHP systems driven by strong end-user engagement via Market Mover Partners, such as cities, states, and utilities

www.energy.gov/chp

U.S. Department of Energy
CHP Technical Assistance Partnerships
Midwest

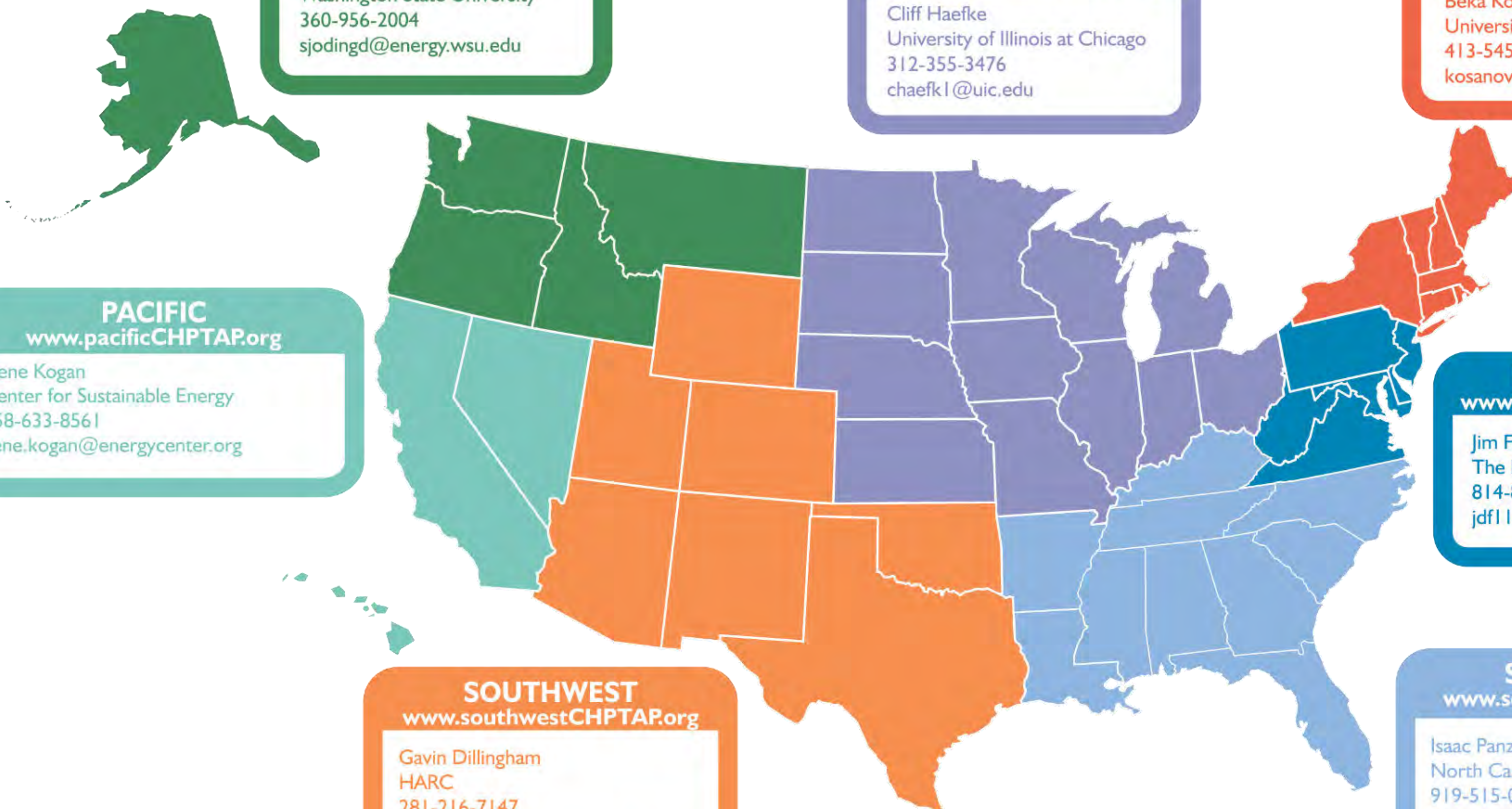
DOE CHP Technical Assistance Partnerships (CHP TAPs) Key Activities

DOE's CHP TAPs promote and assist in transforming the market for CHP, waste heat to power, and district energy or microgrid with CHP throughout the United States. Key services include:

- **Market Opportunity Analysis**
  Supporting analyses of CHP market opportunities in diverse markets including industrial, federal, institutional, and commercial sectors
- **Education and Outreach**
  Providing information on the energy and non-energy benefits and applications of CHP to state and local policy makers, regulators, end users, trade associations, and others.
- **Technical Assistance**
  Providing technical assistance to end-users and stakeholders to help them consider CHP, waste heat to power, and/or district energy or microgrid with CHP in their facility and to help them through the development process from initial CHP screening to installation.

www.energy.gov/chp

DOE CHP Technical Assistance Partnerships (CHP TAPs)



NORTHWEST
www.northwestCHPTAP.org

Dave Sjoding
Washington State University
360-956-2004
sjodingd@energy.wsu.edu

MIDWEST
www.midwestCHPTAP.org

Cliff Haefke
University of Illinois at Chicago
312-355-3476
chaefk1@uic.edu

NORTHEAST
www.northeastCHPTAP.org

Tom Bourgeois
Pace University
914-422-4013
tbourgeois@law.pace.edu

Beka Kosanovic
University of Massachusetts Amherst
413-545-0684
kosanovi@ecs.umass.edu

PACIFIC
www.pacificCHPTAP.org

Gene Kogan
Center for Sustainable Energy
858-633-8561
gene.kogan@energycenter.org

MID-ATLANTIC
www.midatlanticCHPTAP.org

Jim Freihaut
The Pennsylvania State University
814-863-0083
jdf11@psu.edu

SOUTHWEST
www.southwestCHPTAP.org

Gavin Dillingham
HARC
281-216-7147
gdillingham@harcresearch.org

SOUTHEAST
www.southeastCHPTAP.org

Isaac Panzarella
North Carolina State University
919-515-0354
ipanzarella@ncsu.edu

DOE CHP Technical Assistance Partnerships (CHP TAPs): Program Contacts

chp@ee.doe.gov

Claudia Tighe
CHP Deployment Program Manager
Office of Energy Efficiency and Renewable Energy (EERE)
U.S. Department of Energy
E-mail: claudia.tighe@ee.doe.gov

Jamey Evans
Project Officer, Golden Field Office
EERE
U.S. Department of Energy
E-mail: jamey.evans@go.doe.gov

Patti Welesko Garland
Enterprise Account POC
CHP Deployment Program
EERE, U.S. Department of Energy
E-mail: Patricia.Garland@ee.doe.gov

Ted Bronson
DOE CHP TAP Coordinator
Power Equipment Associates
Supporting EERE
U.S. Department of Energy
E-mail: tbronson@peaonline.com

CHP TAP Project Development Technical Assistance

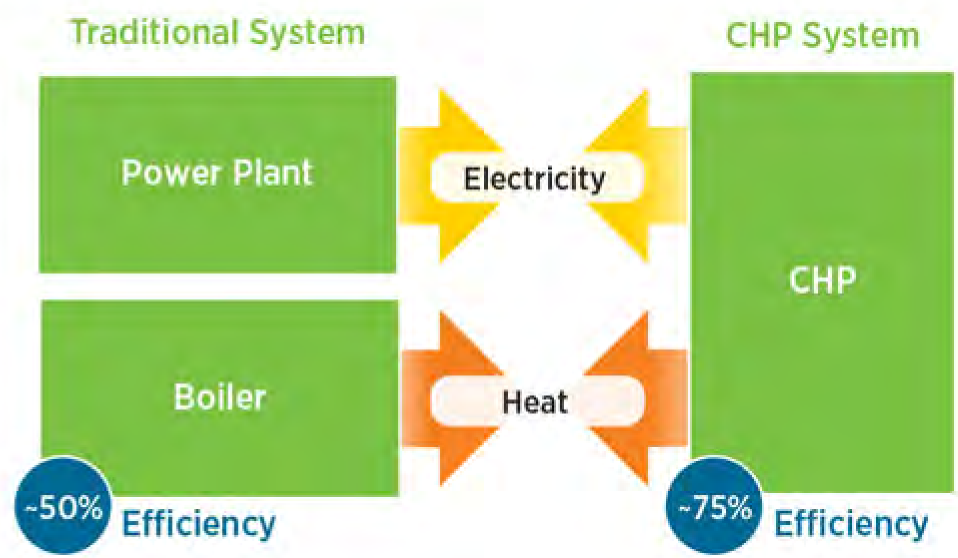
Screening and Preliminary Analysis → **Feasibility Analysis** → **Investment Grade Analysis** → **Procurement, Operations, Maintenance, Commissioning**

US DOE CHP TAP Services:

- **Screening and Preliminary Analysis:** Quick screening questions with spreadsheet payback calculator.
- **Feasibility Analysis:** Uses available site information. Estimate: savings, Installation costs, simple paybacks, equipment sizing and type.
- **Investment Grade Analysis:** 3rd Party review of Engineering Analysis. Review equipment sizing and selection.
- **Procurement, Operations, Maintenance, Commissioning:** Review specifications and bids. Limited operational analysis

What is Combined Heat & Power (CHP)?

- Form of Distributed Generation (DG)
- An integrated system
- Located at or near a building / facility
- Provides at least a portion of the electrical load and
- Uses thermal energy for:
  - Space Heating / Cooling
  - Process Heating / Cooling
  - Dehumidification

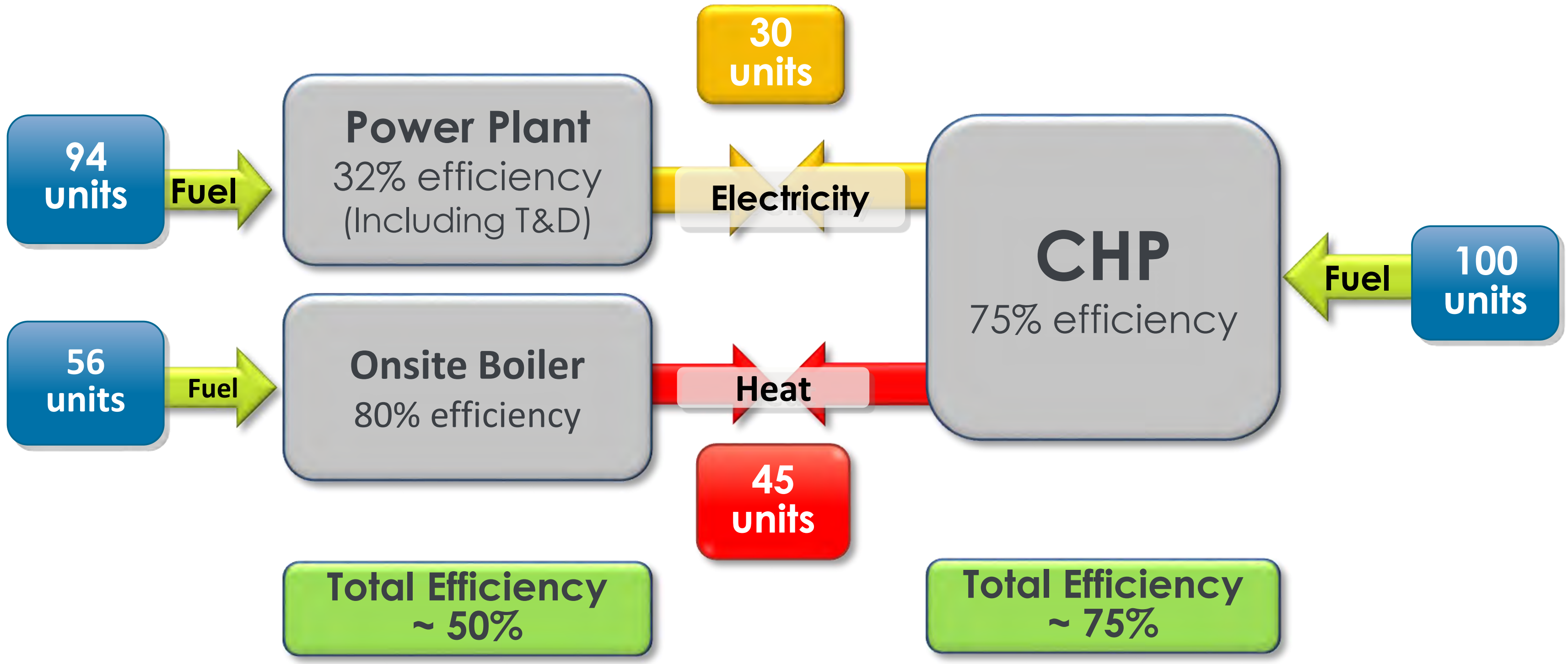


CHP provides efficient, clean, reliable, affordable energy – today and for the future.

Source: *http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_clean_energy_solution.pdf*

U.S. Department of Energy
CHP Technical Assistance Partnerships
Midwest

CHP Recaptures Heat of Generation, Increasing Energy Efficiency, and Reducing GHGs



30 to 55% less greenhouse gas emissions

What Are the Benefits of CHP?

- CHP is *more efficient* than separate generation of electricity and heat
- Higher efficiency translates to *lower operating cost,* (but requires capital investment)
- Higher efficiency *reduces emissions of all pollutants*
- CHP can also *increase energy reliability and enhance power quality*
- On-site electric generation *reduces grid congestion and avoids distribution costs*

Critical Infrastructure and Resiliency Benefits of CHP

"Critical infrastructure" refers to those assets, systems, and networks that, if incapacitated, would have a substantial negative impact on national security, national economic security, or national public health and safety."

Patriot Act of 2001 Section 1016 (e)

Applications:

- Hospitals and healthcare centers
- Water / wastewater treatment plants
- Police, fire, and public safety
- Centers of refuge (often schools or universities)
- Military/National Security
- Food distribution facilities
- Telecom and data centers

CHP (if properly configured):

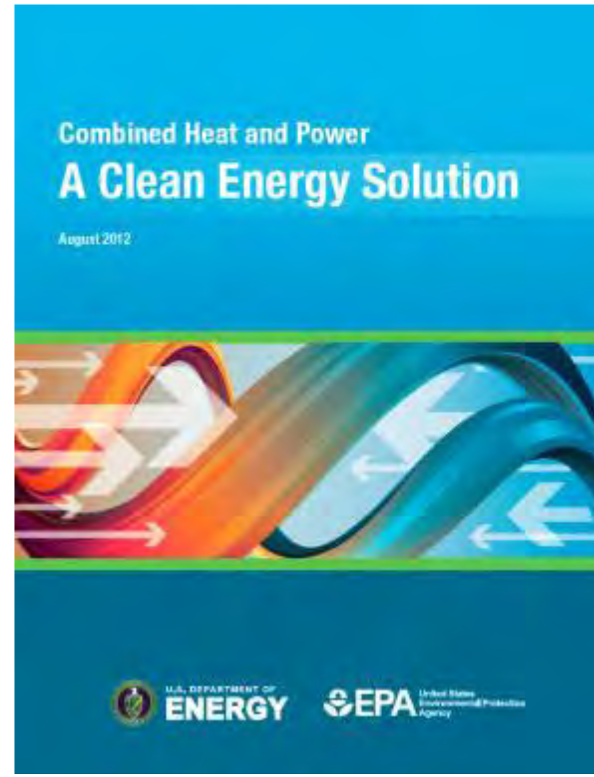
- Offers the opportunity to improve Critical Infrastructure (CI) resiliency
- Can continue to operate, providing uninterrupted supply of electricity and heating/cooling to the host facility

U.S. Department of Energy
CHP Technical Assistance Partnerships
Midwest

Emerging Drivers for CHP

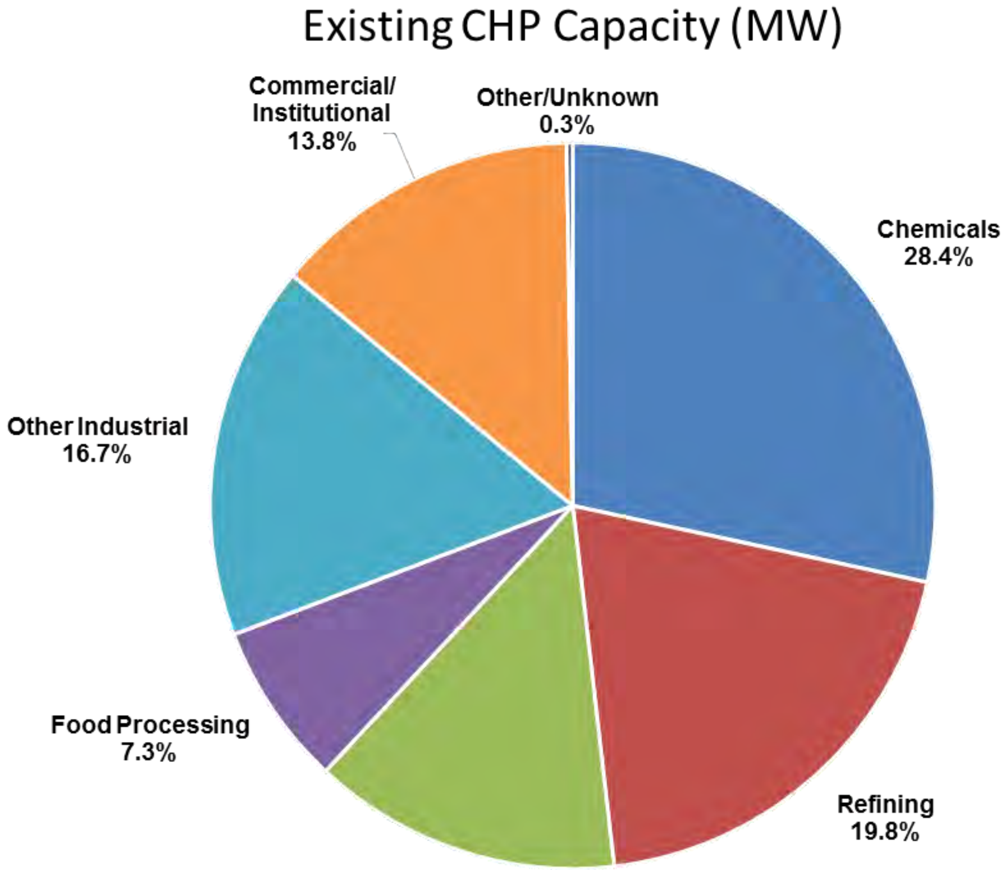
- Benefits of CHP recognized by state and federal policymakers
- Favorable outlook for natural gas supply and price in North America
- Opportunities created by environmental drivers
- Utilities finding economic value
- Energy resiliency and critical infrastructure

DOE / EPA CHP Report (8/2012)



Report:
http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_clean_energy_solution.pdf

CHP Today in the United States



Source: DOE CHP Installation Database (U.S. installations as of Dec. 31, 2015)

- **81 GW** of installed CHP at over 4,300 industrial and commercial facilities
- 8% of U.S. Electric Generating Capacity; 14% of Manufacturing Capacity
- Avoids more than **1.8 quadrillion Btus** of fuel consumption annually
- Avoids **241 million metric tons of CO_2** compared to separate production

U.S. Department of Energy
CHP Technical Assistance Partnerships
Midwest

What markets are attractive for CHP?

Industrial
- Chemical manufacturing
- Ethanol
- Food processing
- Natural gas pipelines
- Petrochemicals
- Pharmaceuticals
- Pulp and paper
- Refining
- Rubber and plastics

Commercial
- Data centers
- Hotels and casinos
- Multi-family housing
- Laundries
- Apartments
- Office buildings
- Refrigerated warehouses
- Restaurants
- Supermarkets
- Green buildings

Institutional
- Hospitals
- Schools (K – 12)
- Universities & colleges
- Wastewater treatment
- Residential confinement

Agricultural
- Concentrated animal feeding operations
- Dairies
- Wood waste (biomass)

Indiana – Current CHP Installations and Technical Potential

Indiana Existing CHP Installation Summary

38 CHP Sites = 2,262.6 MW Generating Capacity

Table: Industrial Sector

Market	Sites	MW
Primary Metals	9	1,446.8
Petroleum Refining	1	660.6
Food & Beverage	4	26.6
Transportation Equip.	1	15.5
Agriculture/Dairy	5	7.6
Chemicals	1	4.9
Machinery/Computer Equip.	1	3.5
Miscel. Manufacturing	1	0.1

Table: Commercial/Institutional Sector

Market	Sites	MW
Colleges/Universities	4	80.3
Landfill/Solid Waste	2	6.6
Hospitals	2	3.5
District Energy	1	3.4
Schools	2	2.8
Health Clubs	2	0.3
Wastewater	1	0.1
Restaurants	1	0.1

Table: Fuel Type

Fuel Type	Sites	MW
Biomass	10	24.6
Coal	6	834.1
Natural Gas	14	765.2
Oil	1	3.5
Waste	7	635.2

Table: Prime Mover Technology

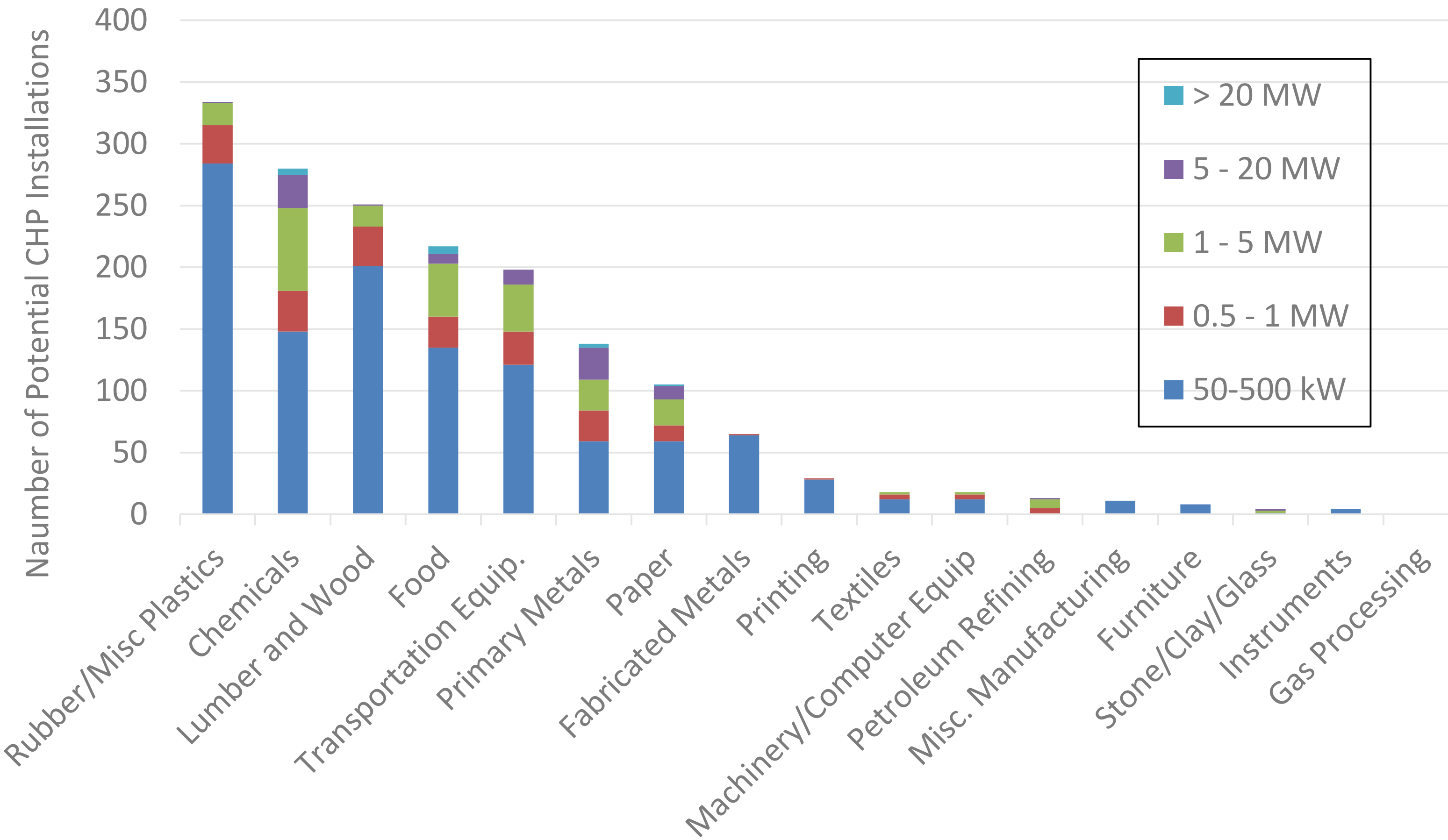
Technology	Sites	MW
Boiler/Steam Turbine	13	1305.2
Combined Cycle	3	726.3
Combustion Turbine	2	29.5
Microturbine	7	0.7
Reciprocating Engine	11	15.8
Waste Heat to Power	2	185.0

Source: www.energy.gov/chp-installs

U.S. Department of Energy
CHP Technical Assistance Partnerships
Midwest

Indiana CHP Technical Potential in the Industrial Sector (no. of sites)

1,693 Sites

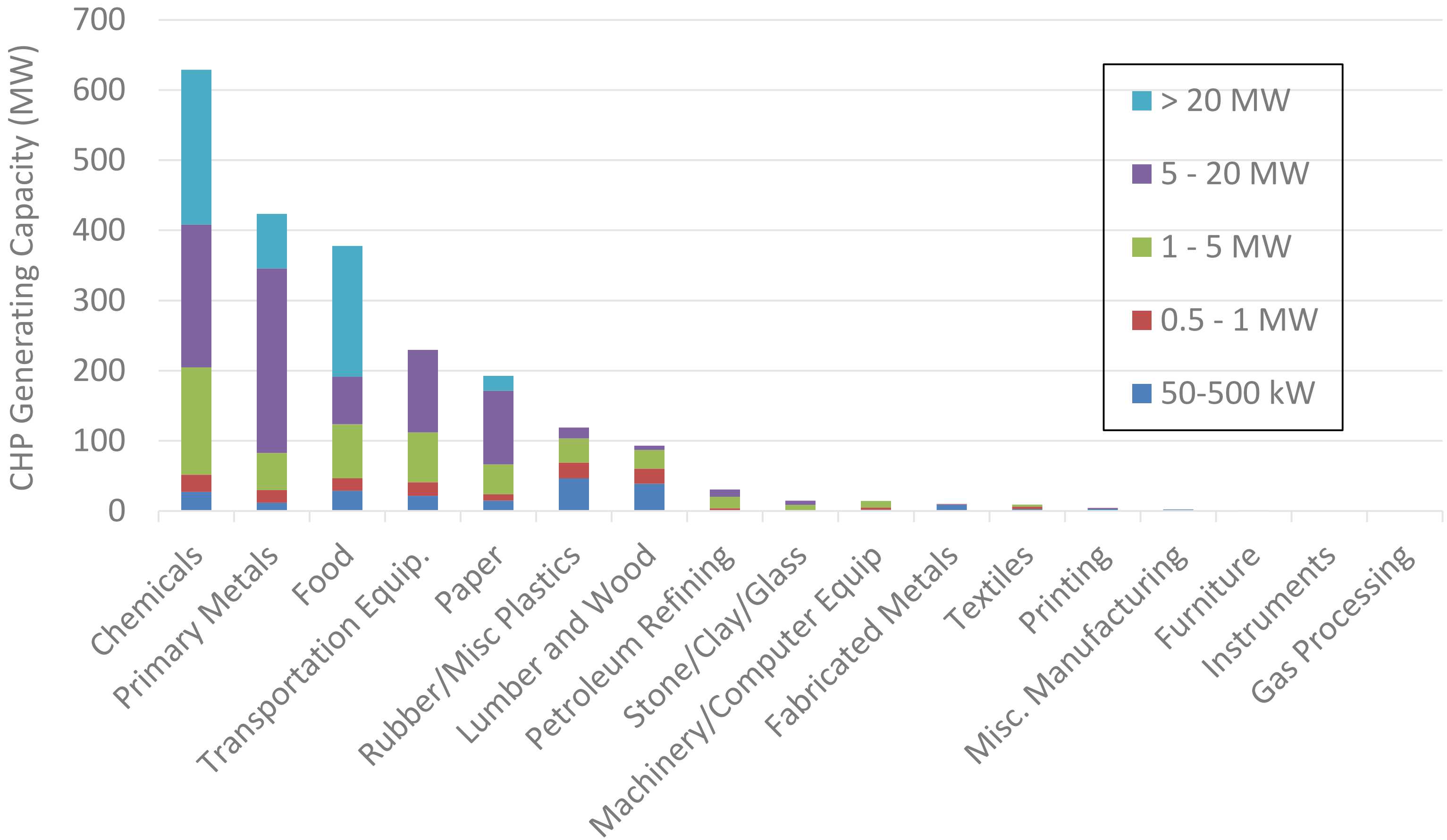


Source: energy.gov/chp-potential

U.S. Department of Energy CHP Technical Assistance Partnerships Midwest

Indiana CHP Technical Potential in the Industrial Sector (MW)

2,151 MW

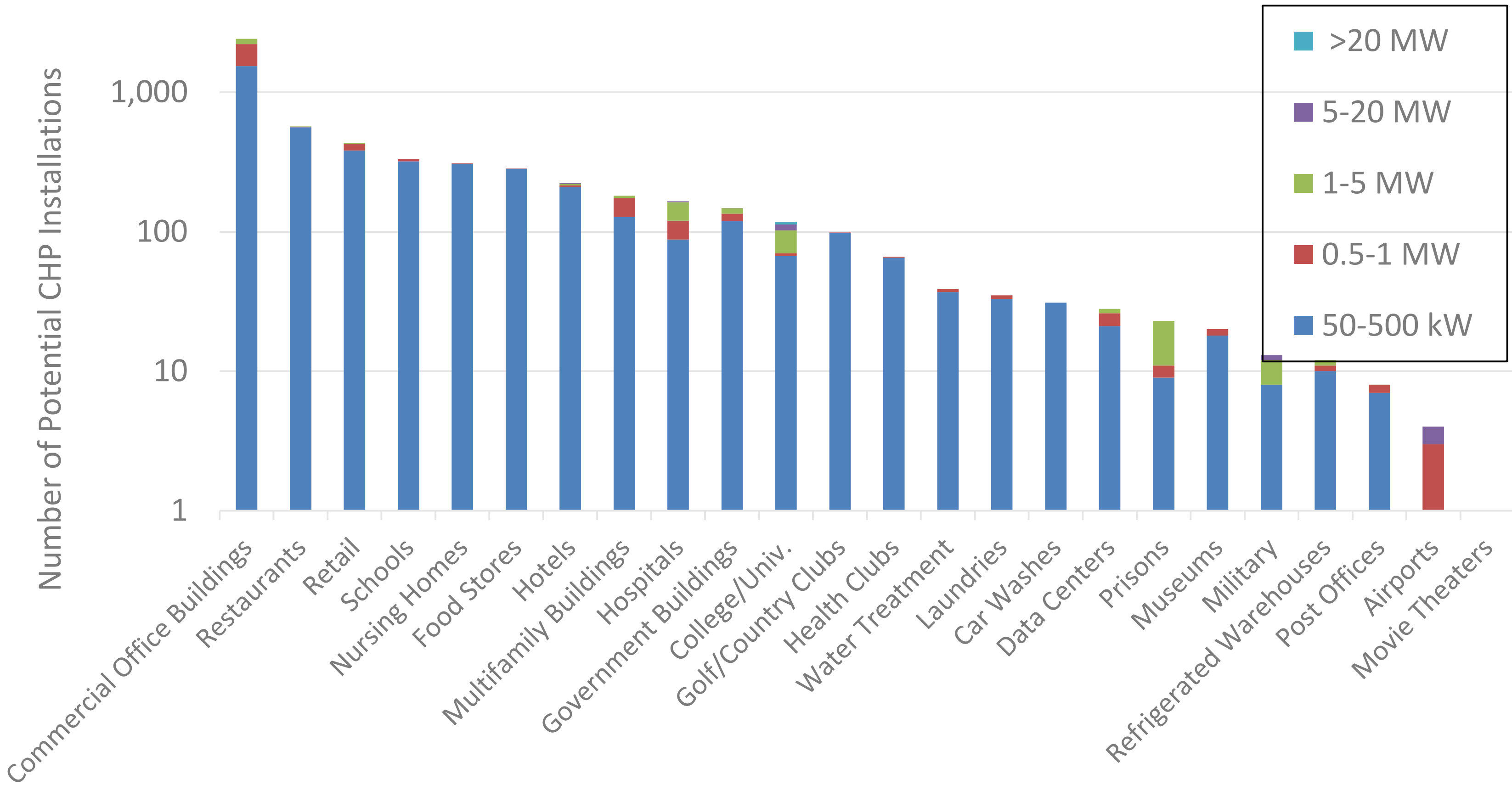


Source: energy.gov/chp-potential

U.S. Department of Energy
CHP Technical Assistance Partnerships
Midwest

Indiana CHP Technical Potential in the Commercial Sector (no. of sites)

5,552 Sites

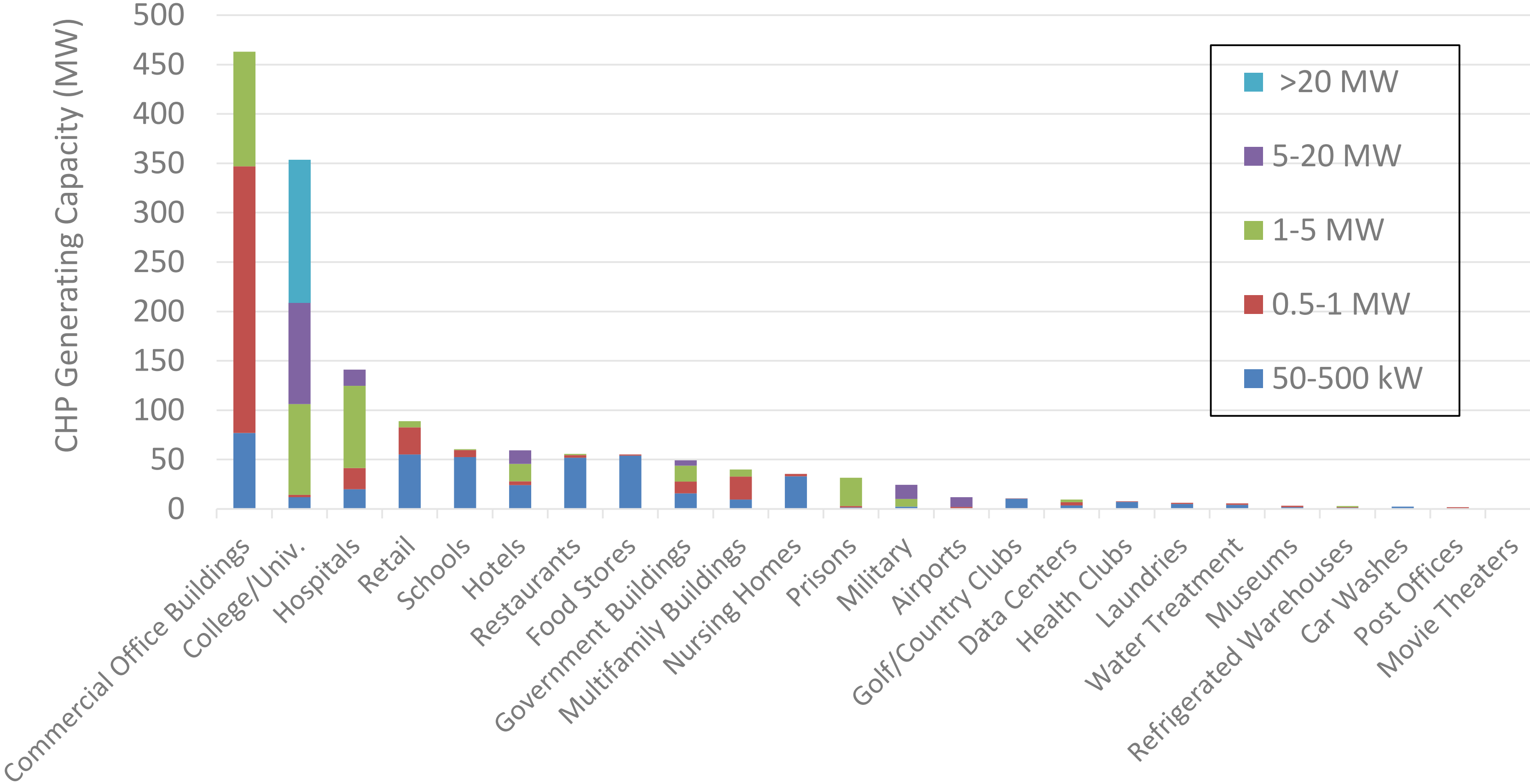


Source: energy.gov/chp-potential

U.S. Department of Energy
CHP Technical Assistance Partnerships
Midwest

Indiana CHP Technical Potential in the Commercial Sector (MW)

1,521 MW

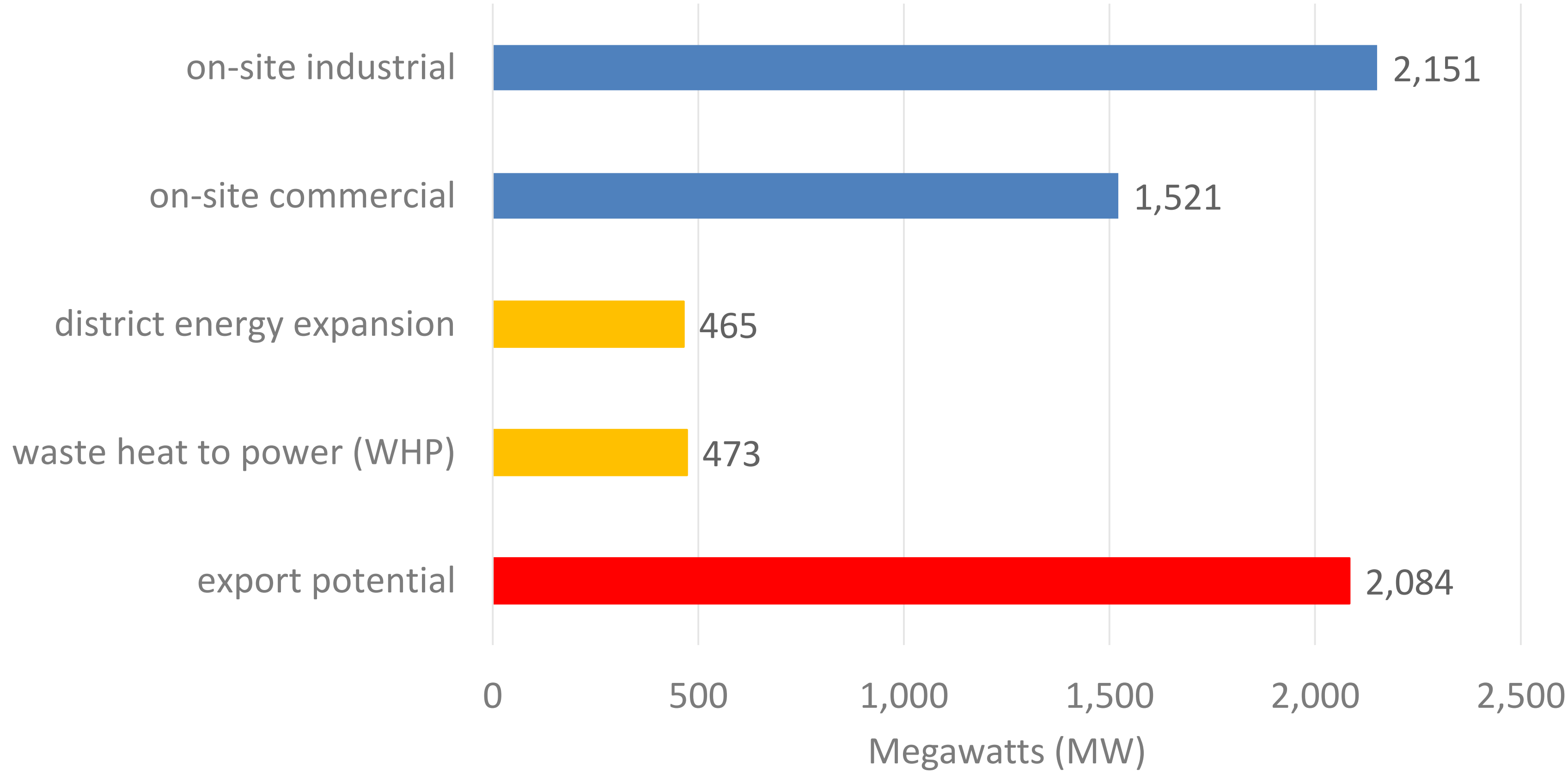


Source: energy.gov/chp-potential

U.S. Department of Energy
CHP Technical Assistance Partnerships
Midwest

Indiana Technical Potential for CHP

(all types)



Source: energy.gov/chp-potential

U.S. Department of Energy
CHP Technical Assistance Partnerships
Midwest

CHP in Integrated Resource Plans

CHP and IRPs

- DOE, US EPA, RAP, ACEEE, NASEO, and Pew Charitable Trust – all highlight the important role that IRPs can play in evaluating and promoting CHP as an option for efficiently and cost-effectively meeting electric demand.
- 13 states require or "call out" CHP as an option to be considered in utility IRPs: Connecticut, Georgia, Iowa, Indiana, Kentucky, Nebraska, Nevada, New Mexico, Oregon, Massachusetts, Minnesota, Utah, and Washington.
- "Integrated resource planning helps monetize the benefits of CHP that do not currently have a market value, such as reduced emissions and increased resiliency and efficiency, enabling planners to account for all of the technology's advantages." *(Pew Charitable Trust)*

Sources: epa.gov/statelocalclimate/resources/action-guide.html;
synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf
aceee.org/policy-brief/utility-initiatives-integrated-resource-planning
pewtrusts.org/en/research-and-analysis/fact-sheets/2015/03/10-reasons-states-should-include-chp-in-clean-power-plans
naseo.org/data/sites/1/documents/publications/CHP-for-State-Energy-Officials.pdf

Utility IRP Examples

- Indiana utilities – Duke Energy Indiana's IRP recommends 15 MW of CHP, while Indiana and Michigan Power's preferred scenario includes 27 MW
- In its report on best practices in integrated resource planning, Regulatory Assistance Project (RAP) cites IRP processes conducted by Arizona and Colorado utilities and by PacificCorp, a utility that provides power across six Western states, as conducting detailed analyses of CHP and other distributed generation
- Duke Energy – recently announced plans for a utility-owned and operated 21 MW CHP system at Duke University and its Duke Energy Carolinas and Duke Energy Progress IRPs propose three more similar projects to be developed by 2021
- Alabama Power – its system includes >500 MW of company-owned and 1,500 MW of customer-owned CHP generation. Its most recent IRP makes clear the company continues to try to identify "CHP projects that are expected to bring benefits to all customers" and attributes its success in developing CHP resources to "a good working arrangement between all parties" and "an adaptive regulatory process".

Sources: in.gov/iurc/files/2015_Duke_IRP_Report_Volumn_1_Public_Version.pdf
indianamichiganpower.com/global/utilities/lib/docs/info/projects/IntegratedResourcePlan/2015
synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf
energy.sc.gov/files/view/2015DECIRP.pdf
alabamapower.com/about-us/regulation/pdf/IRP.pdf

Benefits and Examples of Utility-Owned CHP

Benefits of Utility Ownership of CHP *ACEEE*

- Can bring benefits to the utility, the facility where it is located, and to ratepayers
- Utilities can size a system to meet a customer's full thermal load (which maximizes its efficiency) and export excess power to the grid
- The value of the steam sales are credited back to the revenue requirement, thus reducing the cost of this generation resource
- Strategically-sited CHP can avoid or defer T&D system investments and reduce maintenance costs
- Siting the CHP resource close to the load avoids transmission losses and costs (an average of 7%, greater in peak periods)
- CHP can offer a cost-effective way to meet efficiency goals
- CHP is a fast and flexible asset that increases reliability and resiliency and reduces emissions
- CHP has fuel flexibility, including the ability to take advantage of local biomass or biogas resources

Source: aceee.org/files/pdf/white-paper/chp-and-electric-utilities.pdf

Project Snapshot:

Utility/University Partnership

DUKE ENERGY

Duke Energy / Duke University Campus

Durham, NC

Application/Industry: University/Healthcare
Capacity: 21 MW
Prime Mover: Combustion Turbine
Fuel Type: Natural Gas
Thermal Use: Space Heating, Hot Water, Cleaning/Sterilization
Installation Year: 2018 projected
Project Costs: $55 million

Testimonial: "This partnership will provide value for Duke University and will accelerate our progress towards climate neutrality," said Duke University's executive vice president Tallman Trask III. "By combining steam and electricity generation systems, we can increase efficiency and reduce our overall consumption by millions of units of energy each year, and have a positive effect on the community at large."

"In the future, the project could also be used to isolate the critical loads on the campus, providing a method to increase reliability to hospitals and clinics as additional grid back up."

Source: https://news.duke-energy.com/releases/duke-energy-duke-university-partner-on-innovative-power-project

U.S. Department of Energy
CHP Technical Assistance Partnerships
Midwest

Utility CHP Incentive Programs in the Midwest

Illinois - Public Sector CHP Pilot Program

Type	Incentive Value	Issue Date
Design Incentive	\$75/kW capacity	Completion of the design phase
Construction Incentive	\$175/kW capacity	Successful commissioning of the system
Production Incentive (Conventional CHP)	\$0.08/kWh ($\eta \geq 70\%$ HHV) OR \$0.06/kWh ($60\% \leq \eta < 70\%$ HHV) of "useful electric energy" produced	After 12 months of operation based on meeting the measured operating requirements of the system
Production Incentive (WHP)	\$0.08/kWh of "useful electric energy produced" – assumes no additional fossil fuel utilized	After 12 months of operation

- Eligible projects: local governments, public schools/universities, state/federal facilities, water treatment plants, public hospitals
- Existing CHP/WHP systems requiring significant upgrades to bring back online are eligible
- Total Incentive (Design+Construction+Production) capped at lesser of \$2M or 50% of cost
- Design incentive is capped at \$195,000 or 50% of design cost
- Construction total capped at 50% of construction cost

U.S. Department of Energy
CHP Technical Assistance Partnerships
Midwest

Illinois - ComEd Smart Ideas CHP Pilot

- Incentives are available for both topping* and bottoming cycle systems, including waste-heat-to-power
  - *Topping cycle systems must obtain at least 60% HHV efficiency and utilize 20% of the useful thermal output to be eligible for incentives
- Potential installation incentives through Custom program:
  - Interconnection fees: 50% of associated costs up to $25,000
  - $0.07/kWh for eligible kWh following the Illinois Technical Resource Manual (TRM)
    - Paid after a 12-month M&V period once the CHP is commissioned
    - Project must have net zero output to the grid on an annual basis
- Also available to customers with a demand of 1 MW or greater:
  - Feasibility study incentive: covers 50% of study cost up to $25,000

For more information: https://www.comed.com/SiteCollectionDocuments/WaysToSave/Business/PY9_CHP_flyer_v03.pdf

Ohio - Dayton Power & Light CHP Program

- Qualified projects will receive a rebate based on kWh generated during the first year the project is commissioned, and rated design capacity
  - $0.08 per kWh Generated and $100 per kW Capacity
- Incentives are limited to 50% of the total design and construction project cost and capped at $500,000
- Generation will be paid in two installments at 6 and 12 months; capacity will be paid at project completion
- Reimbursement are determined on a sliding efficiency scale
  - 60-70% LHV efficiency = 80% of calculated payment
  - 70-80% LHV efficiency = 90% of calculated payment
  - 80% LHV efficiency or higher = 100% of calculated payment
- Eligible equipment must have a payback based on electricity cost savings of under 7 years

For more information: https://www.dpandl.com/save-money/business-government/custom-rebates/chp-rebates/

Ohio – AEP CHP Program

- Proposing a program to provide $9.5 million in incentives from 2017-2019
- To develop up to 18 CHP projects (2 large projects, 6 medium size projects, and 9 small projects)
- Estimates 45 MW of new CHP capacity
- The minimum total system efficiency required is 60% with a minimum 20% useful thermal energy.
- Incentives:
  - Up to $0.01/kWh for five years
  - limited to the lower of 25% of the cost of the project or $250,000
  - made annually, beginning twelve months after full commissioning
- Incentive for high efficiency:
  - CHP Efficiency (LHV) = 80% or more: 100% of the calculated payment
  - CHP Efficiency (LHV) = 70% up to 80%: 75% of the calculated payment
  - CHP Efficiency (LHV) = 60% up to 70%: 50% of the calculated payment

Source: http://aceee.org/files/pdf/aep-ohio-2015-2017-ee-pdr-plan.pdf

Availability of Technical Assistance

CHP TAP Project Development Technical Assistance

Screening and Preliminary Analysis	Feasibility Analysis	Investment Grade Analysis	Procurement, Operations, Maintenance, Commissioning
Quick screening questions with spreadsheet payback calculator.	Uses available site information. Estimate: savings, Installation costs, simple paybacks, equipment sizing and type.	3rd Party review of Engineering Analysis. Review equipment sizing and selection.	Review specifications and bids. Limited operational analysis

US DOE CHP TAP Services:

Summary

- CHP provides energy savings, reduced carbon footprint, and resiliency benefits
- DOE estimates 4.6 GW of CHP technical potential at Indiana industrial and commercial facilities (plus an additional 2.1 GW in exports)
- The IRP process provides an opportunity for evaluating CHP as an option (e.g. utility ownership and/or utility incentives)
- Please contact the U.S. DOE Midwest CHP TAP for technical assistance

Thank You

Cliff Haefke
Director
(312) 355-3476
chaefk1@uic.edu

David Baker
Senior Research Specialist
(312) 996-2615
dsbaker@uic.edu

Energy Resources Center
University of Illinois at Chicago

U.S. Department of Energy
CHP Technical Assistance Partnerships
MIDWEST

www.MidwestCHPTAP.org

Northern Indiana Public Service Company
2016 Integrated Resource Plan
Public Advisory Meeting #3
SUMMARY

August 23, 2016

Meeting Overview & Introductions
Dr. Marty Rozelle, The Rozelle Group Ltd.

Marty Rozelle provided an overview of the meeting and asked participants in the room and on the phone to introduce themselves. She said that the agenda is quite full so she would be strict with time. She asked people to hold questions until the end of presentations if possible, and to use the comment cards to write questions. She reminded webinar participants that they need to dial in on the phone to be heard, and asked everyone to please stay on topic and respect different points of view. NIPSCO will be hosting two more stakeholder meetings for the 2016 Integrated Resource Plan (IRP): a webinar on September 12 and an in-person meeting on October 3. Dr. Rozelle introduced Violet Sistovaris of NIPSCO to open the meeting.

Welcome
Violet Sistovaris, Executive Vice President, NIPSCO
(slide 3)

Ms. Sistovaris thanked everyone for coming to the third stakeholder meeting, and emphasized that the ideas and suggestions from stakeholders are very valuable to the company in conducting long-range resource planning. For her safety message she reminded participants that children are now going back to school, so take care while driving, look around carefully, and slow down. She noted that most accidents with children occur in school zones. She said she will be here for much of the workshop today and looks forward to hearing the presentations and discussions.

IRP Stakeholder Process & Timeline
Daniel Douglas, Vice President Corporate Strategy & Development, NIPSCO
(slides 4-6)

Dan Douglas thanked everyone for coming. He said he was glad to see some new participants in the audience. He noted that this is the third meeting conducted in connection with NIPSCO's 2016 IRP, and that several one-on-one meetings with individual stakeholders have also been held since the July Public Advisory Meeting. He reminded participants that meeting materials from previous meetings are posted on NIPSCO's IRP web page at www/NIPSCO.com/irp. He then went into a review of the May 5th and July 12th meetings before providing an overview of the expectations for the third Public Advisory Meeting, which would focus on existing generation, NIPSCO's retirement analysis, and the optimal replacement options to fill in the potential retirement plan. He emphasized that none of the outcomes to be discussed are final, and feedback is welcome.

Mr. Douglas noted that the September 12 meeting will be a 2-hour webinar in which NIPSCO will address input from prior meetings, both Public Advisory and 1:1 and share any initial analysis from those meetings. In addition, NIPSCO plans to provide information related to NIPSCO's preferred retirement plan and an overview of stakeholder analysis requests. A fourth in-person meeting will be held on October 3 to discuss the preferred IRP plan. This will allow more time for stakeholders to have more input to the planning and modeling.

Overview of Existing Generation
Daniel Douglas
Kelly Carmichael, Vice President Environmental, NIPSCO
(slides 7-15)

Mr. Douglas showed a map of NIPSCO's six generating stations along with a table of power plant specifics. Coal generation is spread across three facilities: Bailly, Michigan City, and Schahfer. There are about 560 employees who support NIPSCO's power plants, with 530 working at coal plants.

Mr. Douglas explained there are changes in generation at NIPSCO and across the country, in that the percentage of coal generation is declining. At NIPSCO, coal generation dropped from 90% in 2010 to 72% in 2015. This is also the case across the Midcontinent Independent System Operator (MISO) footprint. The capacity factor for natural gas was about 15% in 2009 but is now 75%. Conversely, the coal capacity factor has gone down. Changes that drive this are low natural gas prices and reliable supply, with low prices (below $4) also forecast for the next 10 years. Environmental regulations also contribute to decreased reliance on coal, as does the age and condition of generating plants, and shifts in market power prices.

Mr. Douglas went on to explain that emissions from power plants have also decreased over the past 10 years, much driven by the change from coal to natural gas as well as efficiency improvements in coal plants, demand side management (DSM), and energy efficiency (EE). He showed a graph illustrating the significant reductions in sulfur dioxide (SO_2) and nitrous oxide (NO_x) emissions over the past decade. He noted that capital expenditures on environmental controls on units 12, 14, 15 (Michigan City and Bailly) have totaled more than $800 million over the past five years.

Mr. Douglas talked about generation costs, which include the key components of environmental costs, fixed costs including operations and maintenance (O&M) and labor, and variable costs such as fuel. He clarified that the net present value revenue requirement (NPVRR) cost is the sum of these annual costs over time; in the case of the IRP this timeframe is 20 years.

According to Mr. Douglas, Fuel represents the largest portion of variable costs. Natural gas generation can be below or above coal, with a breakeven price of $4.25/MMBTU to be equivalent to coal costs. If gas price is forecast at about $2.50/MMBTU, this would equate to a generation cost of about $17 per megawatt hour (MWh).

Mr. Douglas explained that fixed costs include annual O&M costs. Bailly costs about $55 to $100 million per year to maintain. Michigan City is about $30 million, Schahfer is $100 million, and Sugar Creek is $4 to 5 million. Mr. Douglas estimated costs per year for each plant, saying that the total cost is about $600 million for all plants over the next 10 years.

Kelly Carmichael reviewed environmental regulations at present and as predicted for the future. The five having the most impact on NIPSCO operations and decisions include Effluent Limitation Guidelines (ELG), Coal Combustion Residuals (CCR) rules, Clean Water Act 316(b), lower ozone emission standards that are reflected in the Cross State Air Pollution rule, and the Clean Power Plan (CPP). These regulate wastewater streams, storage and disposal of fly ash, cooling water intake, NO_x and CO_2 emissions. Mr. Carmichael discussed details of compliance for each station for each regulation, outlining compliance options and estimated capital costs for compliance. NIPSCO estimates the total compliance cost for the fleet to be between $625 million and $1.2 billion, the vast majority of which is at coal-fired plants. This will cause NIPSCO to make a decision about whether to invest in compliance upgrades or to retire the units in 2018 and 2023.

Mr. Carmichael reported that the CPP is currently stayed by the courts. It will be heard by lower courts this September, but will probably go back to the Supreme Court. According to Mr. Carmichael, in any case the federal election may affect the ultimate disposition of this rule. He stated that carbon constraints will likely become a reality in future.

Participants had the following questions and comments:

- Please verify that the ELG has been rolled into National Pollutant Discharge Elimination (NPDES) permits.
  - Correct. This affects Schahfer in 2020 and Michigan City in 2025.
- These estimates don't include compliance with the CPP, right?
  - Correct.
- Does NIPSCO think it will meet the structural integrity requirements of the ELG? Does this mean that work needs to be done on impoundments?
  - We are assuming we'll need to work on the impoundments. Closed cycle transport of water systems is included in the IRP assumptions, as is converting to dry systems.

- Are the costs shown here indicative of all combined cycle turbines (CCTs)?
  - Yes

Generation Planning Methodology and Retirement Analysis
Daniel Douglas
(slides 17-26)

Mr. Douglas explained that NIPSCO needs to decide on the most viable retirement path, but noted that NIPSCO is still having conversations about this. According to him, the main factors considered in making these decisions include reliability, compliance, flexibility, diversity, and affordability. For example, 70% reliance on coal or any fuel is not very diverse. The duration of assets is also a consideration and NIPSCO needs to include the right mix of facility lifetimes. The economics of the generation are also an important factor and any decision must carefully plan for and consider NIPSCO employees. Finally, according to Mr. Douglas, the impacts on the environment and changes in the local economy are also critical.

Mr. Douglas noted that previous IRPs mainly considered age-based criteria for retirements. Many of the current plants are approaching their age-based retirement dates, so NIPSCO is evaluating whether these previously estimated dates still make sense. The main question is whether the cost of continuing to operate the plants is greater than the cost of retiring it and replacing it with another alternative. All the other previously-mentioned factors need to be considered as well.

Mr. Douglas explained that the retirement plan outlined in the presentation is what is being included in the IRP models, but other options may be considered after stakeholder consultation. It is also important to note that, for this analysis, a combined cycle gas turbine was used as the proxy for a replacement asset, but this is not necessarily the alternative that would be installed.

Mr. Douglas then showed a chart of the six different retirement combinations that were developed for this analysis, including age-based retirement and various percentages of coal retirement from 20% to 100%. For example, compliance with ELG by end of 2034 at Michigan City suggested that retirement should occur in 2023. Impacts to customer rates of each of these portfolios was estimated, showing that the “Retire 100% Coal” option is the least expensive in terms of NPVRR, whereas the age-based construct is the most expensive.

The retirement portfolios were run through the IRP scenarios. One output of this was the potential to meet CPP compliance targets. In the Base Case scenario, for example, options that would retire 50% or more coal are expected to meet or exceed these targets of 8.2-9.9 million tons reduction in emissions.

Mr. Douglas showed that diversity was considered for each retirement portfolio, evaluating the percentages of DSM, renewables, natural gas, and coal included in each.

The various coal retirement options would result in a fleet ranging from zero to 64% coal generation, with natural gas representing 19-22% in all cases.

He showed a color-coded chart of the 6 retirement portfolios indicating “worse”, better, and “best” for the criteria of cost to customer, portfolio diversity, number of employees affected, effects on communities and local economies, and environmental compliance. He stressed again that NIPSCO has not made a retirement decision, and this is just the first release of this information that has been communicated to employees today. Under the retire 100% coal option, 530 employees would be negatively affected. In the 80% retirement option 420 employees would be affected in 80%, and the 50% coal retirement option would affect 240 employees. Further, Schahfer is the largest taxpayer in Jasper County today, so loss of this plant would affect that local economy the most.

In summary, Mr. Douglas told the group that NIPSCO has decided its preferred retirement direction at this time is the **Retire 50% Coal** option. This plan includes:

- √ Retire Schahfer units 17 & 18 in 2023, not spending any further funds on environmental compliance.
- √ Retire Bailly units 7 & 8 in 2018.

He offered to meet individually with stakeholders to discuss this issue, since the information presented here is new to everyone today. A press release will be issued this afternoon. NIPSCO welcomes key stakeholder and MISO input to this discussion.

Participants had a number of questions and observations, as follows:

- With respect to the cost analysis, you’re taking into account the fixed costs. What are you using to estimate these costs as well as the rate of return? What ranges were you using for return on equity, etc. on investments as part of fixed costs?
    - Cost to keep is estimated at a high level, making assumptions about fuel and chemical costs, maintenance, and environmental compliance. We used the same assumptions as included in our current rate case.
- Have you ever looked back at prior IRP efforts – pointing to Michigan City 12 and Schafer 14 and 15 – you spent like $800 Million and now you’re starting to talk about retiring them –this is a good illustration of how difficult this process is.
    - You’re exactly right. These are challenges we face as we look at the future – you’re making in some cases 40 and 60 year decisions based on 5-year information. That’s why you’re going to find us looking at buy and build options – but also purchase – for shorter term duration opportunities as well.
- I downloaded the slides this morning – but that page is different than the hand out – at what point will the hand out be posted? Could you mark any new versions with a date or time? Also, there are some slides that are marked preliminary. I’m trying to understand the notations.
    - There are several new slides that were withheld until after we had discussions with NIPSCO employees – which occurred this morning. We wanted to walk through it in a way that we didn’t have the information out

there before we talked to our employees. The hand out was posted to the website this morning at 8:30. This is the final version. The preliminary stamp is there because we are still running the numbers internally. We are getting tighter, but we do expect stakeholders will provide feedback and we have estimates of CCR and ELG. We didn't want to give the impression that these are final numbers. The deck out there is what you should review.

- Did you look at stranded costs that will result from closing plants?
    - Yes. Mr. Douglas explained what these costs for each unit were. These are mainly costs of flue gas desulphurization (FGD) units that were constructed.
- How do these retirement options perform compared to the CPP compliance targets?
    - To get below the compliance targets NIPSCO would need to retire at least 50% of coal resources.
- A participant noted that these estimates don't cover total NIPSCO emissions but just those covered by EPA rule 111(d). So total fleet emissions may not meet the targets.
- Just to qualify the methodology – you made an assumption that NIPSCO will recover those stranded costs and customers will pay for those – is that correct?
    - Yes.
- What is the timeframe of the retirement analysis?
    - It is a 20-year run – 2016-2037.
- Having read the footnote, I would just point out that these numbers don't equal NIPSCO total emissions.
    - Just the ones covered by the ELG Rule. If replaced by something other than renewables – there would there be CO_2 reduction.
- Did you do any sort of review of scenarios on impact on customer rates?
    - NIPSCO didn't analyze individual customer rates beyond the revenue requirement calculation. We didn't break down to individual rate analysis NPVRR is the cost to the customers over the 20 year period..
- So what coal and natural gas cases are we looking at – high cost or differentiated – customer rates start to mean something when you have coal in your fleet.
    - :It is not in the deck – runs it across – you see the rough ordering of these scenarios. It is similar if not exactly the same across all of the scenarios. You might see a switch between 50% and 80% - but you will find retiring more coal makes sense in most if not all cases going forward. We are happy to share those either in a 1-on-1 meeting or at the September meeting.
- Did you say that the potential CPP target date was for 2023 or 2030?
    - The range is our expected range for 2030. The model has steps to get down to this range by 2030. We picked the lowest piece of potential range by 2023 and said we would be compliant. It steps down from 2035, 2025 – it's hard to show the step down, so we used the end date.

- In your modeling of CPP and the possibility of getting rid of 100% by 2023, in modeling have you run the infrastructure? My understanding is that we don't have the piping volume to handle the gas without coal.
    - This is the end perspective. On a national level that is a real and apparent risk. NIPSCO happens to be in an advantageous position. There are 7 major pipelines coming through our territory. So from gas supply – we think there is an opportunity there. We are not necessarily recommending to go with a CCGT. We will look at it and evaluate. We might not choose that going forward. NIPSCO is an interesting anomaly for that national story. I do caution assuming that we are going to move into a CCGT. We are evaluating a number of options.
- Please clarify the CPP targets. Can you take credits for retiring a coal unit against replacing it with an existing CCT unit? The entity operating the emissions source gets credit for it.
    - : The policy is not settled yet – as NIPSCO sees it – the way EPA is approaching – 111(d) for existing sources and 111(b) for new sources. So in this analysis, you're getting the benefit of the retirement under 111(d). If you build, it would need to meet the New Source Performance Standards. They are regulated differently – not helpful with the cap.
- So if you retire a coal plant – enter into a PPA with existing CGCT – can you take the benefit of the treatment against the cap?
    - If PPA – the other part would be getting the benefit. We would not from a carbon perspective. NIPSCO would not need to comply, just the emission source.
- If the retirement plan performs below the CPP limits, have you assumed any carbon trading within the system?
    - No.
- What percent of renewables is assumed?
    - It is single digits. There is 130 megawatts of wind contracts existing today - wind contracts with 100 MW of nameplate and then there is the 30+ MW of feed in tariff. The pie chart shows 0%. The math would show 3%. Only about 15% of wind counts toward MISO capacity.
- The Sierra Club representative said that she appreciates that the analysis was done in this way. This organization would like to encourage utilities to let the market fill unmet needs rather than dictating any specific technology when preparing request for proposals (RFPs). This might encourage clean energy, given the rapid changes in technology today.
    - I would echo those thoughts. We view the market is changing. First, we have a unique customer base. Second, we see technology changing rapidly. Natural gas is changing – market prices are changing as well. Market customer and technology. We are taking into account when filling those needs.
- Please clarify that these scenarios include an assumption that CCGT is the replacement technology.
    - Yes that is a fair clarification. These scenarios do assume CCGT as a proxy that assumes the MW we need would be filled with a CCGT. If we

only need 2 MW – we wouldn't go and build a CCGT to fill that. While we looked at and used a CCGT, we are absolutely not tied to CCGT or natural gas going forward – we want to have an honest and wholesome look at what those options are going forward.

- Is it correct that the cost to customers is based on the CCGT proxy assumption?
  - Yes. We are not using something more or less expensive. Just using the CCGT. If there is a wind farm, CCGT that costs less than a new CCGT – there are opportunities for those scenarios to be lower than what it is there.
- This analysis seems to imply that only coal creates jobs and investment in communities.
  - From an employee standpoint –it takes 110 employees to run a 500 MW mostly coal-based facility. That is about 10 times the number of employees needed to operate a gas plant. (see Bailly with 110 employees compared to Sugar Creek with 19 employees.) Solar and wind facilities only have a very small maintenance staff. This analysis doesn't look at technologies, per se, but at NIPSCO employees. So transition to a different technology or purchase through a PPA – impacts NIPSCO employees – it is a NIPSCO retention story. We are looking out for our employees. We fairly firmly believe that whatever generation replaces coal going forward – there will likely be fewer employees. As to community economic impacts, – the amount of property tax from NIPSCO in Jasper County is significant. We didn't make any assumptions going forward – just the removal of the property tax in that county – without getting into where new generation would be located. All it is recognizing is the impact of the facilities. It may be different based on replacement strategy.
- The cost is basically the cost of retirement – not replacement, right?
  - The cost of replacement is built into this – the cost of a CCGT.
- For environmental compliance, are you suggesting that there's an environmental compliance quality difference between the scenarios, rather than that you won't be compliant?
  - We will be compliant in any case. The lower coal retirement scenarios are not as viable in future. There are a number of forces – costs, portfolio, employees, environmental, communities – we have not made a retirement decision. We want more conversations – this is the start of that conversation. As you can imagine, when you start putting scenarios out like this it raises questions. We need to be careful to how we have rolled it out. We met with employees this morning. You will see – this is not final - stakeholder conversations – could be adjusted going forward. We need to set up a plan – need to move forward. We believe we should retire Bailly 7 and 8 in May of 2018 and Schafer 17 and 18 by 2023. Really it gets back to not spending compliance dollars going forward. Subject to MISO – Attachment Y process – and feedback from stakeholders. We will not finalize until submission of the IRP. It currently sits at the retire 50% coal scenario. Pressures can push either way. We believe this is a good

balance. This afternoon we will review that plan only and identify the replacement options. We want to meet 1-on-1. It is hard to get feedback when you're just meeting for the first time. There have been significant changes from 2014 – bright lines with different opinions – we want to hear and gain that perspective. While this is not out yet, given the impact on employees and communities – we are releasing a press release outlining the retirement of 50% coal with many caveats. This is not final. You'll find the wording is for our employees and communities. We view this as the most viable solution – subject to change based on stakeholder, MISO and other considerations.

- How does this retirement plan compare to what was discussed in the 44688 rate case with respect to these plants and the depreciation schedules?
  - I don't know the rate case number. That rate case included the Retire 20% coal option, and the depreciation study was based on that. The settlement did not accelerate the depreciation on Unit 8.

Review of Risks and Uncertainties
Edward Achaab, Manager Resource Planning, NIPSCO
(slides 28-43)

Ed Achaab said he would talk about the input assumptions used in modeling. He discussed how assumptions about the drivers of load, commodity prices, technology, economy, environmental compliance, and regulations affect scenario development. He reminded the group that the scenarios developed from these risks and uncertainties include Base Case, Challenged Economy, Aggressive Environmental Regulation, and Booming Economy. A suite of sensitivities was developed within the scenarios to capture factors such as carbon regulation, load changes, and commodity prices. He showed a chart summarizing the input assumptions to each scenario and sensitivity.

Based on conversations with stakeholders, an additional scenario was developed and added. This is called Base Delayed Carbon scenario and reflects the delayed implementation of carbon dioxide reduction regulations and possible prices. Currently, these regulations are proposed to begin in 2025.

Regarding commodity prices, NIPSCO uses a third-party consultant, PIRA Energy Consultants. The 2016 IRP will use seven commodity pricing assumptions. Mr. Achaab illustrated forecast gas prices at the Chicago Citygate, rising from about $4 per MMBtu in 2016 to up to about $11 for various scenarios, considering environmental impacts of gas development, penetration of renewables, changes in load for MISO Indiana, and other market factors. In the coal market, prices are quite flat as a factor of the above variables.

Forecasted CO_2 emission pricing was also illustrated, showing increases over time for various scenarios. Power prices closely follow natural gas prices, according to MISO Indiana forecasts. Supply and demand in the region affects the projected capacity prices. In response to a stakeholder comment, Mr. Achaab noted that MISO only uses one year forward pricing and tends to be very spotty, so its capacity prices are not shown as a comparison in these charts. Mr. Achaab then reviewed the load forecast data used in modeling, as previously presented at the first stakeholder workshop in May.

Next Mr. Achaab summarized selectable future resource options that are available. He noted that DSM resources include 22 energy efficiency programs and 4 demand response programs. He showed charts detailing the components of the various DSM “bundles” and indicating energy and capacity savings for these various groupings.

He described the available supply side resources including conventional coal, gas, and nuclear, and renewable and emerging resources such as wind, solar, combined heat and power, battery storage, microturbines, biomass, and reciprocating engines. Solar capital costs are expected to come down, both at the photovoltaic (PV) utility scale (50 MW or more) and the distributed generation component (10 kW). NIPSCO has assumed 50% credit for solar from MISO, but in the model a solar shape needs to be added to the capacity credit to account for the seasonality of the resource and when the solar resource hits NIPSCO’s system peak. He also talked about including the federal tax credit for solar (investment tax credit) in the model.

Mr. Achaab then illustrated the costs of future supply side resources, noting that solar capital costs are expected to come down. Similar to solar, he pointed out that NIPSCO applies a capacity credit per MISO as well as a historical wind shape in NIPSCO’s service territory. He then talked about the production tax credit for wind generation. He noted that for the combined head and power (CHP) cost, NIPSCO used a typical 20 MW unit based on discussions with industry.

Questions and comments from participants included the following:

- How was the long term Indiana Hub MISO Wholesale Electric Energy price forecasts developed and did they include any assumptions regarding the CPP such as enforcing the Mass Cap and re-dispatching the system to meet compliance?
    - NIPSCO works with PIRA, who use proprietary models; they did not include caps but used a CO_2 proxy price.
- The capacity price forecast chart appears to be counterintuitive. Can you explain?
    - These are results from the proprietary models. For example, in a high pricing environment – in the future – there is incentive for more capacity additions, which will consequently lead to the market being adequately supplied and hence cause capacity prices to plateau or even decline. We can follow up 1-on-1.
- Did NIPSCO update its method to develop the typical week loads used in the Strategist model? The typical week loads presented in the Appendix (pages 23-36) to the 2014 IRP had each month’s peak demand equal to the annual system coincident peak and a resulting annual energy in the neighborhood of 22 million

MWh when scaled back to 8760 hours per year from the typical weeks. On its face this seems to be erroneous and so if this is intentional, I would like to understand this better if the same methods are being used in the current IRP. If the method has changed, can you explain what the new assumptions are?
    - Load forecast input is converted to the typical week format for the model; therefore, commodity prices need to be done in the same way so there is an "apples to apples" comparison. He offered to provide more information outside of this meeting. Reminded participants that details regarding the typical week conversion for the model was provided in the third meeting and will also be in the IRP.
- Did NIPSCO benchmark the PIRA forecasts through other sources?
    - Yes, on the load side, NIPSCO performs historical variance analysis to assess the forecast. For gas prices, these fluctuate greatly from week to week, so the approach is to use a range that incorporates most reasonable possibilities. PIRA has a good reputation in the industry.
- Has NIPSCO altered any of the EE bundles and DSM groupings since the last meeting? The concern is that these bundles may be too large and tend to compete against each other. Some stakeholders have been suggesting making smaller bundles, similar to what Indianapolis Power and Light is doing based on costs of programs.
    - No, these are the same as those described at the last meeting. We will look to put that in a future MPS.
- Regarding the screens (benefit cost tests) that were described at the last meeting, is NIPSCO continuing to use the program screen?
    - Yes, because you either screen components out during the analysis, or they will get screened out during the DSM analysis. This way NIPSCO can keep the DSM plan consistent with the IRP.
- For the solar photovoltaic data shown on this chart on Slide 45, does this mean a maximum of 10 kW can be built? This seems to be a very large gap between 50 MW of utility scale solar and 10 kW for residential, and this doesn't seem reasonable.
    - No, each "bucket" would be 10 kW, but there can be many buckets selected by the model. If stakeholders have data on costs for other size units, NIPSCO can look at those.
- So then why only looking at one option for distributed solar – 10 KW is a blip – DG is anything up to certainly 1 MW is the cap for net metering. I think there is an awful lot of gap between utility scale of 50 MW and 10 KW is very small.
    - These are fairly typical residential installation packages system – California – those are the type of packages you can go and buy.
- In NIPSCO service territory there are a lot of bigger ones.
    - Give us useful information that you want us to look at.
- There is no reference to time in the illustrations of technology capital costs. Did NIPSCO assume costs would go up or down during the planning period?
    - One of the feedback from previous IRP was the need for more information in the public report. We tried to find a nice balance to provide in a public version. We are more than happy to share the confidential analyses that

    - were performed for us – on a high level. We used the engineering study. The dollars are nominal as of today and are escalated for all of these technologies (Slide 46). We assume all are going up. This information can be provided to those who have signed a non-disclosure agreement.
- The integrated gasification combined cycle (IGCC) capital investment cost of $1,100/kW is not even close to the actual cost of units built. Where did these costs come from?
    - They were based on Sargent & Lundy studies. They went through the process and provided the data. These data were checked during the meeting and found to be in error. The correct cost should be approximately $7,800/kW. PLEASE NOTE: Slide 49 has been updated to reflect correct costs for total capital investment.
- What years are these?
    - These are nominal dollars.
- With the IGCC and some of these coal costs – are you including the price of CO2 capture – with any rules that are on the books now – are they considered – to build any new – would need to meet what is today. This isn't based on any other costs seen around the nation?
    - No. They were provided by Sargent & Lundy.
- Laura Arnold informed the group that she has tweeted the slide 45 showing solar capital costs. A response said that solar can be built at $1.25 per watt, rather than the $2.50 indicated in these data.

Resource Optimization Modeling
Edward Achaab
Andrew Kramer, PhD, Lead Resource Planning Analyst, NIPSCO
(slides 50-76)

Mr. Achaab noted that the retirement scenarios drive future resource needs. He showed a graph illustrating capacity gaps with different load variables under a 50% retirement option.

He explained that the *Strategist* model uses dynamic programming. He showed an example of the range of resource expansion plans output from the model. The first (#1) plan will always be the least cost option, taking the optimal resources to fill a capacity gap. In addition to cost, NIPSCO will also use two other strategies: renewable focus and low emissions in the 2016 IRP. There can be up to 2,500 options created by this model per each run, and NIPSCO has not decided on any particular plan yet. For each scenario discussed in this presentation, there will be three portfolios included in the range of expansion plans: least cost, renewable focus, and low emissions.

Andrew Kramer told the group that he is one of the people who runs the *Strategist* model. He said he would talk about the scenario analysis for the five scenarios with sensitivities, and offered individual meetings with stakeholders in future to discuss the large amount of data included here.

The Base Case Scenario is the most likely, according to NIPSCO. Dr. Kramer reviewed the assumptions included in this scenario as well as the sensitivities run in this scenario, noting that these sensitivities can make a notable difference in the output. He showed a table indicating the least-cost, renewable, and low emissions portfolios for the Base Case. These outline expansion plans for all years between 2016 and 2037. He said that in the renewable focus portfolio there is not as much gas included, and wind and solar are added in most years. The low emissions portfolio also includes other resources such as biomass and nuclear. He showed graphs summarizing the resource mix, as percentages of the plan, for each portfolio in 2037, as well as cost estimates in NPVRR for each portfolio.

Similar data were presented for each scenario modeled. In discussing the Challenged Economy scenario, Dr. Kramer reviewed the input assumptions. Data on expansion plans for the least cost, renewable, and low emissions portfolios were presented and the resource mixes were illustrated on pie charts. Dr. Kramer then reviewed the Aggressive Environmental Regulation scenario assumptions, which are quite different from the previous scenarios. Finally, according to Dr. Kramer, the Booming Economy scenario reflects increased commodity and environmental compliance costs. These expansion plans include quite a bit of gas and DSM as well as some CHP and addition of nuclear capacity in the low emissions portfolio. He explained the additional scenario, Base Case Delayed Carbon, includes the revised assumptions of the base case scenario with steady economic growth with load growth slowly increasing, and the National Carbon Policy becoming effective in 2025. In addition, the scenario includes lower technology and tax credits are assumed as well.

Mr. Achaab summarized the analysis of the scenarios and sensitivities. He illustrated the net present value costs of the portfolios for each sensitivity included in each scenario, under the three strategies of least cost, renewable energy focus, and low emissions. He talked about the range of NPVRR (in $ billions) for preliminary commodity sensitivities across the scenarios. He also presented details of DSM selection for the various scenarios in terms of total energy sales.

Mr. Achaab reiterated that NIPSCO is planning for the future must meet the criteria for affordability, reliability, diversity, flexibility, and compliance, and requires careful consideration of employees, environmental impacts, and local economic effects.

Participant questions and comments included the following:

- So just to make sure, if the Strategist loads were developed the same way as they were in the 2014 IRP which seemed to overstate NIPSCO's Annual Energy requirement by 4 Million MWh, and this was carried through into the 2016 IRP which as stated earlier, might be the case, this would then in turn overestimate projected operational savings from replacing say coal units with CCGT proxys when the variance costs are of the proxy is cheaper than the retired coal.
    - The 5 load curves – high low, base and much lower – we are actually looking at different load requirements – go to low case energy requirement

– and match to tell what is going. We would be happy to discuss as a 1-on-1.

- Does the low emissions case use total CO_2 from all plants?
  - Yes, emissions are cumulative for the entire portfolio.
- What's the difference between the renewable focus and low emissions strategies? They seem to be similar.
  - Yes, they can be similar but the low emissions category could include other technologies such as nuclear, which are not renewables.
- Can more than one resource expansion element be selected in the same year?
  - Yes.
- Looking at Slide 52 – under Column 1 2016 – DSM1 – Could multiple resources be selected – could it be DSM1 and wind?
  - Yes.
- Assuming that the referenced 533 MW of DSM is the industrial tariff from n the rate case – why is that shown under DSM?
  - DSM includes demand response as well – so does include tariff.
- So you're saying these figures are not just their tariff but also the DSM – EE plans – incremental that would hit in 2016
  - Yes.
- Please clarify if these numbers for purchases are cumulative from year to year.
  - No, each year is specific and they do not accumulate.
- Did you limit the market capacity purchase in a given year used to meet the peak demand plus planning reserve margin?
  - No. Capacity purchases were limited to 500 mw – for all intents and purposes, it was unlimited.
- Why are those numbers not changing in the different portfolios?
  - The DSM optimization was decided prior to – we did groupings of 3, 4 and then 5 for industrials – overall methodology – resources for DSM competed between a mixture of gas and renewables – done prior to resource optimization – allowed it to select against allowable gas and wind – that would have been more similar.
- So the DSM optimization was handled prior to the development of these portfolios?
  - In conjunction – then after DSM was optimized, because DSM can reduce the need for capacity. So it was done first. So you will see this in the next portfolio as well.
- So for DSM – you have 533 – that doesn't carry forward?
  - It hits in that year and carries forward. The DSM is different – within Strategist it has the programs – it has measures being added and dropping off – the DSM if you look at the profile – you still have a gradual increasing trend.
- Where is the additional capacity savings for the EE measures in 2016?
  - You would need to subtract it out of the 533 MW. In 2016 maximum interruptible is 527.75 MW – the remainder is 2016 DSM. To clarify – with these 3 options this is still a base scenario – wouldn't expect to change under these options because as you go through the other scenarios – the

    - DSM amounts are changing. For each of the scenarios they will be similar across the strategies.
- On slide 56 – 2037 – least cost – DSM 14.79 – 2037 renewable focus – DSM 16.91 MW and low 19.27 MW – doesn't really match that higher slide.
    - It relates to the overall amount of resources that are available. The numerator didn't change but the denominator did change.
- Slides 56, 59, 62 each show total emissions well in excess of the CPP target range presented on Slide 24. Can you comment on this?
    - Strategist was not set up to cap the total amount of CO2 emissions. It can do a cap on it. (Ed) That is the total CO2 associated with the portfolio. The one shown earlier on the retirement discussion was just what comes in every year from our existing generation – the 150 – 160,000 is the total cumulative of the entire portfolio – existing generation as they are run – 2015 – 2037 and is cumulative. It is not apples to apples.
- How is there only 1% solar in the 2037 renewable focus portfolio?
    - The model is selecting on pricing alone in this scenario – deemed least cost – in this case solar was fully selectable – a lot brought in incrementally here – in the case of looking for massive increase of renewables – when the scenarios come in – when it has no choice but to bring in more.
- A participant noted that the Clean Energy Incentive Program is planned to incentivize investments in the 2020-21 timeframe. Did you include these in the model?
    - No, we haven't included it but are happy to learn more from you and incorporate it if appropriate.
- .5 MW of Solar seems bizarre.
    - If we use the nameplate capacity then that percentage would be much higher – assuming 50% capacity credit from MISO – only capacity from peak level – previous slide shows peak level – can get you that information – percentage toward peak in the model. If you express the percentages on a nameplate basis it would be higher.
- I missed the footnote. But could you also expand on Adam's statement that the mass cap wasn't enforced . . . were the outputs checked to ensure compliance based on pricing penalty in the dispatch.
    - So these are preliminary. We haven't gone back to see what the CO_2 – see how far away we are from CPP compliance.
- The ability to purchase from the market is limited to purchases until 2022; why is that? Is this a NIPSCO-imposed policy constraint and not a model constraint?
    - Yes, that's correct. We are treating purchases as a proxy, and NIPSCO decided not to do market purchases in the long term. We think it doesn't make sense to buy more than 150 MW, so we assume that something would be built instead. However, we may not build new facilities ourselves but could purchase that capacity from others who build these facilities. Dan Douglas said that we can take that constraint off and allow the model to continue making market purchases; he thinks the results may be similar, however.

- I don't see anything that NIPSCO incorporated the incentives for clean energy for years 2020 and 2021 into what the model would select. Are you aware? Would you look into that?
  - No we didn't look into that – if we can get some guidance we would look at that.
- Why was the ability to purchase only limited up through 2022? So maybe you knew that you were going to build in 2023, is that why?
  - Because of the MISO capacity construct – we treated the purchases more as a proxy. NIPSCO decided we would probably not be able to purchase in the long term so decided not to do past 2022. The least cost option – it looks like if you allow it to purchase – it will purchase if you leave it unconstrained. So we decided to use through 2022. It is a little bit of modeling nuance. To try to build a CCGT or some other technology, they come in big chunky sizes. Then past 2023 you can go and you've got large gap. Just because it shows that we put something in – doesn't mean we would build or own – could be a PPA to purchase that capacity going forward. However, no decisions have been made at this point how that capacity will actually be filled .
- On Slide 55 – showing 2022 – we only need 200 MW from purchase from the market but we're going to build 2 CTs?
  - What is happening is that Schafer 17 and 18 are being retired – you would stop doing purchases – you would add something – not necessarily build or own. What I think the model is selecting on an economic basis to build in 2023 – it is a constraint but not causing us to do uneconomic things. It is a technology choice not sort of a contractual ownership choice. The model is telling us either through purchase or contract – combined cycles appear to be the cheapest selection in 2022 - not really directing.
- The extent then is driven by economics – or did you impose it as a boundary condition?
  - We needed to steer the model because the model would choose to build. What we did was allow it to do market purchases– so that it would not build to fill a small gap – once the gap was big enough – we removed that boundary condition. They can run the scenario that way – but that's not impacting it.
- I would be interested in seeing an all market scenario as a point of comparison.
  - Thank you for that suggestion. Yes we can do that.
- Please clarify that all these model runs include the 50% coal retirement assumption, and there is no provision for retiring more than 50% coal.
  - Correct, but we are open to other options based on conversations with stakeholders. It is clear that we are putting constraints on the model – not costs – because lowest costs would choose 100% retirement.
- Is that billions or millions.
  - Yes these are billions – cumulative.
- You aren't modeling industrial EE in these models, correct? Industry initiatives for energy efficiency still are occurring by companies. I don't see how this is reflected in the models here. How are you reflecting it in the load forecast?

- Industrial EE load that has opted out of participated in the programs is not included in the analysis. This would include any initiatives taken on by the customer on its own. While the savings are not specifically included in DSM, they are reflected in decreased sales from NIPSCO. Reference Amy Efland's presentation on load forecasting from the first stakeholder workshop.

Stakeholder Presentations

David Baker, U.S. Dept. of Energy Midwest CHP Technical Assistance Partnership (DOE CHP TAP)
Opportunities for Combined Heat and Power (CHP)

Mr. Baker explained that this group within the Department of Energy is located at the University of Illinois Energy Resources Center in Chicago, one of seven such centers providing technical assistance. Services include market analysis, end user technical assistance, and education and outreach. He described CHP as an integrated system at a site that uses electricity and uses waste heat for processes, which increases efficiency to 75% or more. This results in lower operating costs, higher efficiency and reduced grid congestion. Target industries are those with large loads, commercial facilities, healthcare, and others. There are 38 CHP sites in Indiana with 2,300 MW of capacity, as well as facilities at universities. A study of the technical potential across states found that there is a potential for installation of an addition 2,100 MW industrial, 1,500 MW commercial, and 500 MW each for smaller sites. About 2,000 MW could be exported to the grid.

Both governmental agencies and private trusts say that CHP can be an important component in IRP development. Examples include Duke Energy and Indiana-Michigan Power. Duke in the Carolinas recommends 80 MW of new CHP, and Alabama Power includes about 500 company-owned and 1,500 MW private-owned CHP generation. He provided an example of a project at Duke University for a 21 MW plant.

The ACEEE recently prepared a white paper showing that CHP can bring benefits to both the utility and the user by reducing the cost of the generating resource, avoiding transmission costs, having fuel flexibility, and meeting energy efficiency goals. Several Midwest utilities have programs that encourage CHP. The DOE CHP TAP program provides free technical assistance such as site screening and recommendations about CHP feasibility as well as help with Requests for Proposals. (RFP).

CHP provides energy savings, reduced carbon footprint and resiliency benefits. DOE estimates 4.6 gigawatts (GW) of CHP technical potential at Indiana industrial and commercial sites. Please contact them for assistance.

Joseph Rompala, Lewis & Kappas

Mr. Rompalla is here on behalf of a coalition of NIPSCO industrial customers. He wants to share concerns of these clients. In many ways the IRP process is helpful in presenting a view of what the future may hold. To that end, he thanked NIPSCO for its openness and willingness to share information, and for including stakeholders in the process. There are limitations on the IRP process, however. For example, not specifying decisions about future generation is frustrating.

The real issue to his clients is the effect of future plans and new generation assets on customer rates, because these rates impact private industry decision-making processes as well. Financing mechanisms and return on investments, balance between debt and equity, and level of cost escalation all make a difference to ratepayers. The IRP is not the ultimate arbiter of these decisions. The Indiana Utility Regulatory Commission's Certificate of Public Convenience and Necessity (CPCN) process is designed to shift risk from the utility to the customer, and must be balanced. Industry is catalyst for economic growth and ensuring NIPSCO's load. Competitive procurement and the CPCN process are important to industrial customers. Any decisions being made are opportunities for them to take a more comprehensive and collaborative approach.

Next Steps

Dr. Marty Rozelle reminded the group that the next meeting will be on September 12. This will be a webinar, from 9:00 to 11:00 Central time. October 3 will be an in-person meeting here in Merrillville.

Violet Sistovaris thanked participants for coming and spending their day. She said that adding the October date is good because it gives stakeholders more time to digest this information and provide more feedback. She said she agrees with Joe Rompala that the CPCN process is an important component in decision making, but that the IRP provides a framework for those decisions. She encouraged everyone to work to understand each other's points of view and respect differing perspectives. She committed NIPSCO to continuing to work on this.

She said that copies of the press release are available at the door and that NIPSCO looks forward to speaking with everyone next month.

NIPSCO

Draft as of September 6

2016 Integrated Resource Plan

Stakeholder Meeting #4 (Webinar) – Monday, September 12, 2016

Time: *9:00 am –11:00 am CT (10:00 am – noon pm ET)*

Location: *Webinar / Conference Call*
[information shared with registrants prior to call]

Background
NIPSCO is due to submit an Integrated Resource Plan (IRP) to the Indiana Utility Regulatory Commission (IURC) on November 1, 2016. The IRP is our plan for meeting the future energy needs of our customers over the next 20 years with cost-effective, reliable, and sustainable supplies of electricity while addressing the inherent uncertainties and risks that exist in the electric utility industry.

Agenda: **All times are in CT*

Time (CT)	Topic
9:00 – 9:10 am	Welcome & Introductions
9:10 – 9:20 am	Public Advisory Process Update
9:20 – 10:00 am	Status Update of One-on-one Meetings & Requests
10:00 – 10:30 am	Review of First Three Meetings' Questions & Answers
10:30 – 10:45 am	Stakeholder Questions / Comments
10:45 – 11:00 am	Next Steps

2016 IRP Public Advisory Webinar

September 12, 2016

NIPSCO

Agenda

Schedule (ET)	Agenda Item
10:00 – 10:10	Welcome and Logistics for Webinar
10:10 – 10:20	Public Advisory Process Update
10:20 – 11:00	Status Update of One-on-one Meetings & Requests
11:00 – 11:30	Review of First Three Meetings' Questions & Answers
11:30 – 11:45	Stakeholder Questions / Comments
11:45 – 12:00	Next Steps

- **Objectives for today's Webinar:**
  - Discuss retirement paths from August 23 meeting and address related stakeholder feedback
  - Address input from prior stakeholder and subsequent 1:1 meetings
  - Share any initial analysis from 1:1 stakeholder meetings

NIPSCO

Logistics for Webinar

Presented by

Alison M. Becker

NIPSCO

Public Advisory Process Update

Presented by

Timothy R. Caister

Public Advisory Process update

- 1st, 2nd & 3rd Stakeholder Meeting Materials
  - Presentation materials and summary meeting notes are posted on NIPSCO's IRP webpage: www.NIPSCO.com/irp

IRP Public Stakeholder Process and Timeline

Proposed

	May 5th	July 12th	August 23rd	September 12th	October 3rd
Key Questions	- What process will NIPSCO use for its IRP? - What are the key assumptions driving the scenarios and sensitivities?	- How will NIPSCO incorporate Demand Side Management Resources in the IRP?	- Deep dive into NIPSCO's existing generation - What are the optimal replacement options to fill the supply gap?	- Where are the stakeholders focused? - What is NIPSCO's preferred retirement plan?	- What is NIPSCO's Preferred Plan?
Agenda/ Content	- Overview of process - NIPSCO overview - Load forecasting - Demand side management - Environmental considerations - IRP development - Public advisory process	- Review Market Potential Study - Describe and Review Demand Side Management measure groupings - Introduce Demand Side Management Modeling Methodology	- Overview of existing generation by unit (costs, environmental, etc.) - Retirement analysis - Outline preferred retirement direction and describe resulting capacity gap through time - Replacement options (supply-side and demand-side)	- Discuss retirement paths and address related stakeholder feedback - Address input from prior stakeholder and subsequent 1:1 meetings - Share any initial analysis from 1:1 stakeholder meetings	- Share any results from 1:1 stakeholder analytical requests (these will also be shared in 1:1 meetings between 9/12 and 10/3) - Describe Preferred Replacement Path and logic relative to alternatives - Explain NIPSCO short term action plan
Key Deliverables	- Key assumptions - Overview of scenarios and sensitivities	- Common understanding of the grouping of DSM measures - Clear picture of NIPSCO's DSM modeling methodology	- Stakeholder feedback and shared understanding of generation alternatives	- NIPSCO's preferred retirement plan - Overview of stakeholder analysis requests	- Review of Stakeholder feedback - NIPSCO's Preferred Plan
Meeting Format	- 6 hour in person session	- 5.5 hours in person session	- 6 hours in person session	- 2 hour Touch point/ Webinar	- 4 hour in person session

Status Update of One-on-one Meetings & Requests

Presented by

Daniel Douglas

Summary of 1:1 Meetings

Stakeholder	Subject Area of Discussion / Requests	Status Update
OUCC	PIRA input data tables	In process
	Additional sensitivity for return on for remaining net book value of retiring assets included in retirement portfolios	In process
	Exact dollar amounts of remaining net book value of retiring assets included in retirement portfolios	In process
	Cost estimates for Ozone compliance	In process
CAC	DSM/Energy Efficiency bundles	Discussed that the methodology included in July 12 presentation is the methodology utilized

NIPSCO

Summary of 1:1 Meetings (cont.)

Stakeholder	Subject Area of Discussion / Requests	Status Update
NIPSCO Industrial Group	By retirement portfolio, provide the annual increase to the revenue requirement (cash flow view)	In process
	Interest in seeing the data tables behind a number of the curves assumed in the model	Awaiting further specific requests from Industrial Group
	What is the amortization period for the remaining net book value of retiring assets included in retirement portfolios?	In process
	Unconstrained model through 2023	In process
	Further clarity and details regarding the CCR/ELG timelines, risks and options for compliance	In process

Summary of 1:1 Meetings (cont.)

Stakeholder	Subject Area of Discussion / Requests	Status Update
NIPSCO Industrial Group (cont.)	Review the presented retirement portfolios across higher gas costs and avoid a regrets scenario	In process
Brubaker	Discussion of typical week load assumptions from 2014 IRP and any impact to this IRP submission	Resolved
	Various retirement analysis questions, including avoided O&M and environmental cost estimates	No further action items at this time
Sierra Club	Various topics including, net book values, solar and wind cost assumptions.	No further action items at this time
IURC Staff	Discussion of scenarios / sensitivities, including portfolio outputs by scenarios and DSM assumptions and results. Further discussion of suggestions for the report.	Incorporating suggestions into the IRP report

Review of First Three Meetings' Questions & Answers

Presented by

Timothy R. Caister

Meeting One: Key Issues from Stakeholders

- General clarification of data points used in the IRP
  - Percentage of renewables, technologies utilized, emissions etc.

- Carbon pricing
  - Correlated with numerous model inputs including gas pricing, coal pricing etc., so there may be more than a single retirement breakpoint as a function of carbon pricing.
  - Proprietary PIRA data utilized

- Inclusion of supply side and demand side resources
  - Model allows all potential resources, including new coal, nuclear, integrated gasification combined cycle (IGCC), that are deemed “viable” to be selected

- Inclusion of solar
  - Option for generic solar distributed generation
  - Pricing reflects subsidies for renewables as are currently available

Meeting Two: Key Issues from Stakeholders

- Benefit Cost Tests
  - Use of the Total Resource Cost Test (TRC)
  - Applicability of other cost tests
- Avoided Costs
  - What is included?
- Program Potential
  - Relationship to savings
  - Development of an Action Plan
  - DSM Program Groupings
- Industrial Opt-Outs
  - Excluded from Market Potential Study and load available for DSM

NIPSCO

Meeting Three: Key Issues from Stakeholders

- Clarifications on Environmental Considerations
  - ELG, CCR, CPP
  - Renewables
  - Incorporation of emissions

- Clarification of Load Forecasts used in Strategist
  - PIRA models

- Clarification of DSM Inputs
  - DSM Optimization

- Model Constraints/Boundaries
  - Economic considerations

- *Discussions continue following August 23*

Stakeholder Questions / Comments

Next Steps

Presented by

Daniel Douglas

IRP Public Stakeholder Process and Timeline

Proposed

	May 5th	July 12th	August 23rd	September 12th	October 3rd
Key Questions	- What process will NIPSCO use for its IRP? - What are the key assumptions driving the scenarios and sensitivities?	- How will NIPSCO incorporate Demand Side Management Resources in the IRP?	- Deep dive into NIPSCO's existing generation - What are the optimal replacement options to fill the supply gap?	- Where are the stakeholders focused? - What is NIPSCO's preferred retirement plan?	- What is NIPSCO's Preferred Plan?
Agenda/ Content	- Overview of process - NIPSCO overview - Load forecasting - Demand side management - Environmental considerations - IRP development - Public advisory process	- Review Market Potential Study - Describe and Review Demand Side Management measure groupings - Introduce Demand Side Management Modeling Methodology	- Overview of existing generation by unit (costs, environmental, etc.) - Retirement analysis - Outline preferred retirement direction and describe resulting capacity gap through time - Replacement options (supply-side and demand-side)	- Discuss retirement paths and address related stakeholder feedback - Address input from prior stakeholder and subsequent 1:1 meetings - Share any initial analysis from 1:1 stakeholder meetings	- Share any results from 1:1 stakeholder analytical requests (these will also be shared in 1:1 meetings between 9/12 and 10/3) - Describe Preferred Replacement Path and logic relative to alternatives - Explain NIPSCO short term action plan
Key Deliverables	- Key assumptions - Overview of scenarios and sensitivities	- Common understanding of the grouping of DSM measures - Clear picture of NIPSCO's DSM modeling methodology	- Stakeholder feedback and shared understanding of generation alternatives	- NIPSCO's preferred retirement plan - Overview of stakeholder analysis requests	- Review of Stakeholder feedback - NIPSCO's Preferred Plan
Meeting Format	- 6 hour in person session	- 5.5 hours in person session	- 6 hours in person session	- 2 hour Touch point/ Webinar	- 6 hour in person session

Next Steps

- **Future meeting timeline:**
  - 5th Meeting scheduled for October 3rd
- **Meeting summary:** Available September 26, 2016
- **NIPSCO website:** www.NIPSCO.com/irp
- **NIPSCO IRP email:** *NIPSCO_IRP@nisource.com*

NIPSCO

Supplemental Slides

Appendix

Brubaker Requested Information

Customer Load Requirements (GWh)

- This is the energy forecast we receive from the load forecasting team which is directly input to Strategist

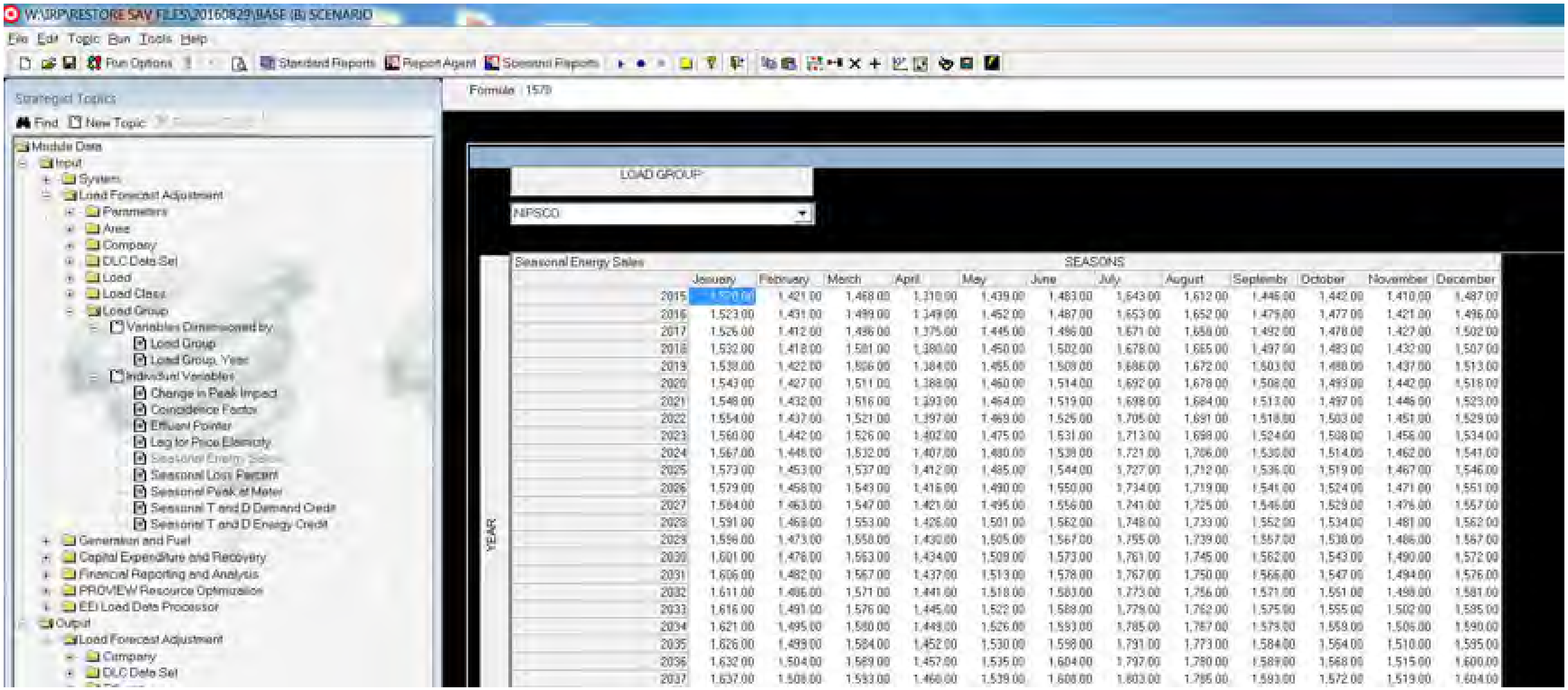
	ENERGY JANUARY	ENERGY FEBRUARY	ENERGY MARCH	ENERGY APRIL	ENERGY MAY	ENERGY JUNE	ENERGY JULY	ENERGY AUGUST	ENERGY SEPTEMBER	ENERGY OCTOBER	ENERGY NOVEMBER	ENERGY DECEMBER	Total
2015	1,570	1,421	1,468	1,310	1,439	1,483	1,643	1,612	1,446	1,442	1,410	1,487	**17,731**
2016	1,523	1,431	1,499	1,349	1,452	1,487	1,653	1,652	1,479	1,477	1,421	1,496	**17,917**
2017	1,526	1,412	1,496	1,375	1,445	1,496	1,671	1,658	1,492	1,478	1,427	1,502	**17,977**
2018	1,532	1,418	1,501	1,380	1,450	1,502	1,678	1,665	1,497	1,483	1,432	1,507	**18,045**
2019	1,538	1,422	1,506	1,384	1,455	1,508	1,686	1,672	1,503	1,488	1,437	1,513	**18,113**
2020	1,543	1,427	1,511	1,388	1,460	1,514	1,692	1,678	1,508	1,493	1,442	1,518	**18,174**
2021	1,548	1,432	1,516	1,393	1,464	1,519	1,698	1,684	1,513	1,497	1,446	1,523	**18,234**
2022	1,554	1,437	1,521	1,397	1,469	1,525	1,705	1,691	1,518	1,503	1,451	1,529	**18,300**
2023	1,560	1,442	1,526	1,402	1,475	1,531	1,713	1,698	1,524	1,508	1,456	1,534	**18,370**
2024	1,567	1,448	1,532	1,407	1,480	1,538	1,721	1,706	1,530	1,514	1,462	1,541	**18,446**
2025	1,573	1,453	1,537	1,412	1,485	1,544	1,727	1,712	1,536	1,519	1,467	1,546	**18,511**
2026	1,579	1,458	1,543	1,416	1,490	1,550	1,734	1,719	1,541	1,524	1,471	1,551	**18,575**
2027	1,584	1,463	1,547	1,421	1,495	1,556	1,741	1,725	1,546	1,529	1,476	1,557	**18,640**
2028	1,591	1,469	1,553	1,426	1,501	1,562	1,748	1,733	1,552	1,534	1,481	1,562	**18,711**
2029	1,596	1,473	1,558	1,430	1,505	1,567	1,755	1,739	1,557	1,538	1,486	1,567	**18,770**
2030	1,601	1,478	1,563	1,434	1,509	1,573	1,761	1,745	1,562	1,543	1,490	1,572	**18,831**
2031	1,606	1,482	1,567	1,437	1,513	1,578	1,767	1,750	1,566	1,547	1,494	1,576	**18,883**
2032	1,611	1,486	1,571	1,441	1,518	1,583	1,773	1,756	1,571	1,551	1,498	1,581	**18,942**
2033	1,616	1,491	1,576	1,445	1,522	1,588	1,779	1,762	1,575	1,555	1,502	1,585	**18,995**
2034	1,621	1,495	1,580	1,449	1,526	1,593	1,785	1,767	1,579	1,559	1,506	1,590	**19,051**
2035	1,626	1,499	1,584	1,452	1,530	1,598	1,791	1,773	1,584	1,564	1,510	1,595	**19,107**
2036	1,632	1,504	1,589	1,457	1,535	1,604	1,797	1,780	1,589	1,568	1,515	1,600	**19,168**
2037	1,637	1,508	1,593	1,460	1,539	1,608	1,803	1,785	1,593	1,572	1,519	1,604	**19,220**

Internal Peak Load (MW)

- This is the internal peak load we receive from the load forecasting team which is directly input to Strategist

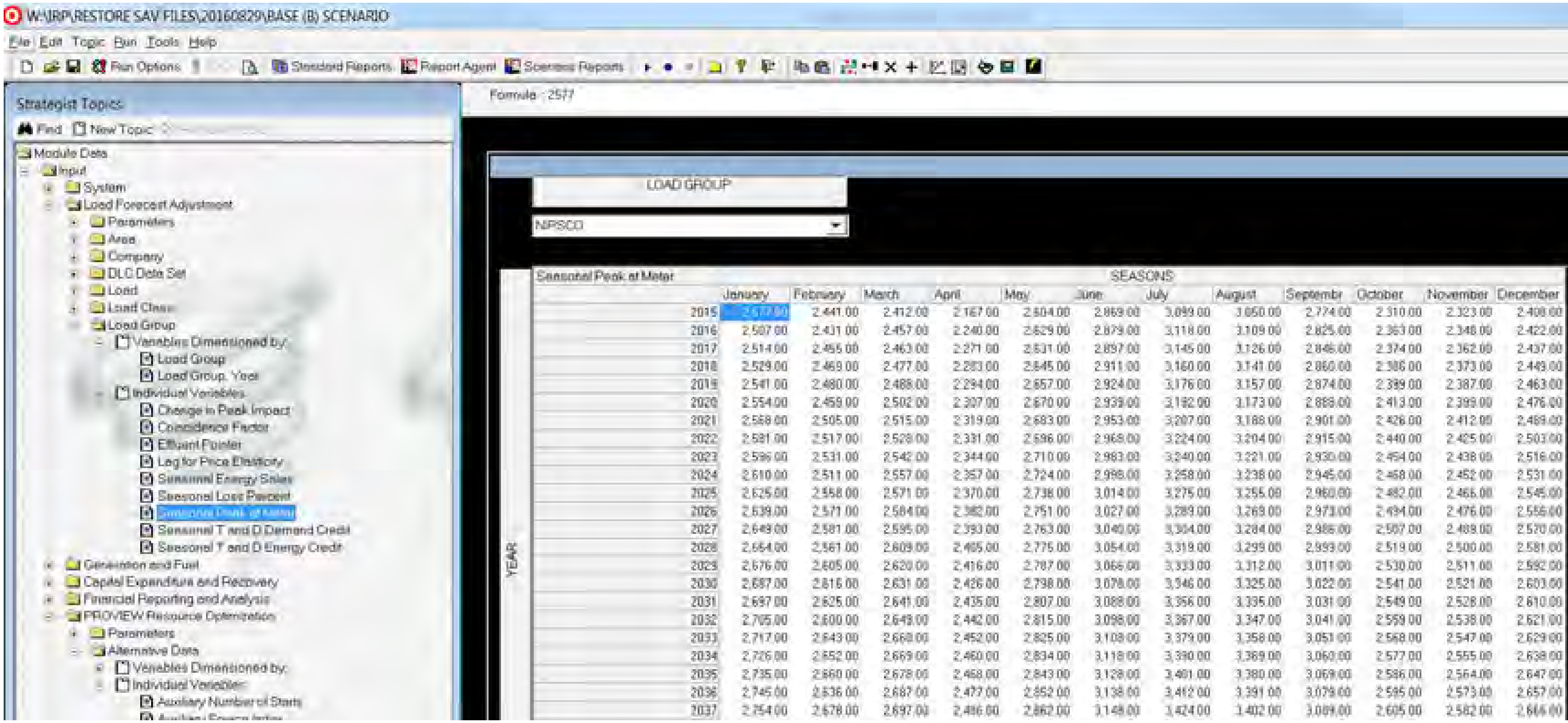
	PEAK JANUARY	PEAK FEBRUARY	PEAK MARCH	PEAK APRIL	PEAK MAY	PEAK JUNE	PEAK JULY	PEAK AUGUST	PEAK SEPTEMBER	PEAK OCTOBER	PEAK NOVEMBER	PEAK DECEMBER
2015	2,577	2,441	2,412	2,167	2,604	2,869	3,099	3,050	2,774	2,310	2,323	2,408
2016	2,507	2,431	2,457	2,240	2,629	2,879	3,118	3,109	2,825	2,363	2,348	2,422
2017	2,514	2,455	2,463	2,271	2,631	2,897	3,145	3,126	2,846	2,374	2,362	2,437
2018	2,529	2,469	2,477	2,283	2,645	2,911	3,160	3,141	2,860	2,386	2,373	2,449
2019	2,541	2,480	2,488	2,294	2,657	2,924	3,176	3,157	2,874	2,399	2,387	2,463
2020	2,554	2,459	2,502	2,307	2,670	2,939	3,192	3,173	2,888	2,413	2,399	2,476
2021	2,568	2,505	2,515	2,319	2,683	2,953	3,207	3,188	2,901	2,426	2,412	2,489
2022	2,581	2,517	2,528	2,331	2,696	2,968	3,224	3,204	2,915	2,440	2,425	2,503
2023	2,596	2,531	2,542	2,344	2,710	2,983	3,240	3,221	2,930	2,454	2,438	2,516
2024	2,610	2,511	2,557	2,357	2,724	2,998	3,258	3,238	2,945	2,468	2,452	2,531
2025	2,625	2,558	2,571	2,370	2,738	3,014	3,275	3,255	2,960	2,482	2,466	2,545
2026	2,639	2,571	2,584	2,382	2,751	3,027	3,289	3,269	2,973	2,494	2,476	2,556
2027	2,649	2,581	2,595	2,393	2,763	3,040	3,304	3,284	2,986	2,507	2,489	2,570
2028	2,664	2,561	2,609	2,405	2,775	3,054	3,319	3,299	2,999	2,519	2,500	2,581
2029	2,676	2,605	2,620	2,416	2,787	3,066	3,333	3,312	3,011	2,530	2,511	2,592
2030	2,687	2,616	2,631	2,426	2,798	3,078	3,346	3,325	3,022	2,541	2,521	2,603
2031	2,697	2,625	2,641	2,435	2,807	3,088	3,356	3,335	3,031	2,549	2,528	2,610
2032	2,705	2,600	2,649	2,442	2,815	3,098	3,367	3,347	3,041	2,559	2,538	2,621
2033	2,717	2,643	2,660	2,452	2,825	3,108	3,379	3,358	3,051	2,568	2,547	2,629
2034	2,726	2,652	2,669	2,460	2,834	3,118	3,390	3,369	3,060	2,577	2,555	2,638
2035	2,735	2,660	2,678	2,468	2,843	3,128	3,401	3,380	3,069	2,586	2,564	2,647
2036	2,745	2,636	2,687	2,477	2,852	3,138	3,412	3,391	3,079	2,595	2,573	2,657
2037	2,754	2,678	2,697	2,486	2,862	3,148	3,424	3,402	3,089	2,605	2,582	2,666

Customer Energy Requirements in Strategist: INPUT



YEAR	January	February	March	April	May	June	July	August	Septembr	October	November	December
2015	[illegible]	1,421.00	1,468.00	1,310.00	1,439.00	1,483.00	1,643.00	1,612.00	1,446.00	1,442.00	1,410.00	1,487.00
2016	1,523.00	1,431.00	1,499.00	1,349.00	1,452.00	1,487.00	1,653.00	1,652.00	1,479.00	1,477.00	1,421.00	1,496.00
2017	1,526.00	1,412.00	1,496.00	1,375.00	1,445.00	1,496.00	1,671.00	1,658.00	1,492.00	1,478.00	1,427.00	1,502.00
2018	1,532.00	1,418.00	1,501.00	1,380.00	1,450.00	1,502.00	1,678.00	1,665.00	1,497.00	1,483.00	1,432.00	1,507.00
2019	1,538.00	1,422.00	1,506.00	1,384.00	1,455.00	1,509.00	1,686.00	1,672.00	1,503.00	1,488.00	1,437.00	1,513.00
2020	1,543.00	1,427.00	1,511.00	1,388.00	1,460.00	1,514.00	1,692.00	1,678.00	1,508.00	1,493.00	1,442.00	1,518.00
2021	1,548.00	1,432.00	1,516.00	1,393.00	1,464.00	1,519.00	1,698.00	1,684.00	1,513.00	1,497.00	1,446.00	1,523.00
2022	1,554.00	1,437.00	1,521.00	1,397.00	1,469.00	1,525.00	1,705.00	1,691.00	1,518.00	1,503.00	1,451.00	1,529.00
2023	1,560.00	1,442.00	1,526.00	1,402.00	1,475.00	1,531.00	1,713.00	1,698.00	1,524.00	1,508.00	1,456.00	1,534.00
2024	1,567.00	1,448.00	1,532.00	1,407.00	1,480.00	1,538.00	1,721.00	1,706.00	1,530.00	1,514.00	1,462.00	1,541.00
2025	1,573.00	1,453.00	1,537.00	1,412.00	1,485.00	1,544.00	1,727.00	1,712.00	1,536.00	1,519.00	1,467.00	1,546.00
2026	1,579.00	1,458.00	1,543.00	1,416.00	1,490.00	1,550.00	1,734.00	1,719.00	1,541.00	1,524.00	1,471.00	1,551.00
2027	1,584.00	1,463.00	1,547.00	1,421.00	1,495.00	1,556.00	1,741.00	1,725.00	1,546.00	1,529.00	1,476.00	1,557.00
2028	1,591.00	1,468.00	1,553.00	1,426.00	1,501.00	1,562.00	1,748.00	1,733.00	1,552.00	1,534.00	1,481.00	1,562.00
2029	1,596.00	1,473.00	1,558.00	1,430.00	1,505.00	1,567.00	1,755.00	1,739.00	1,557.00	1,538.00	1,486.00	1,567.00
2030	1,601.00	1,476.00	1,563.00	1,434.00	1,509.00	1,573.00	1,761.00	1,745.00	1,562.00	1,543.00	1,490.00	1,572.00
2031	1,606.00	1,482.00	1,567.00	1,437.00	1,513.00	1,578.00	1,767.00	1,750.00	1,566.00	1,547.00	1,494.00	1,576.00
2032	1,611.00	1,486.00	1,571.00	1,441.00	1,518.00	1,583.00	1,773.00	1,756.00	1,571.00	1,551.00	1,498.00	1,581.00
2033	1,616.00	1,491.00	1,576.00	1,445.00	1,522.00	1,589.00	1,779.00	1,762.00	1,575.00	1,555.00	1,502.00	1,585.00
2034	1,621.00	1,495.00	1,580.00	1,449.00	1,526.00	1,593.00	1,785.00	1,767.00	1,579.00	1,559.00	1,506.00	1,590.00
2035	1,626.00	1,499.00	1,584.00	1,452.00	1,530.00	1,598.00	1,791.00	1,773.00	1,584.00	1,564.00	1,510.00	1,595.00
2036	1,632.00	1,504.00	1,589.00	1,457.00	1,535.00	1,604.00	1,797.00	1,780.00	1,589.00	1,568.00	1,515.00	1,600.00
2037	1,637.00	1,508.00	1,593.00	1,460.00	1,539.00	1,608.00	1,803.00	1,785.00	1,593.00	1,572.00	1,519.00	1,604.00

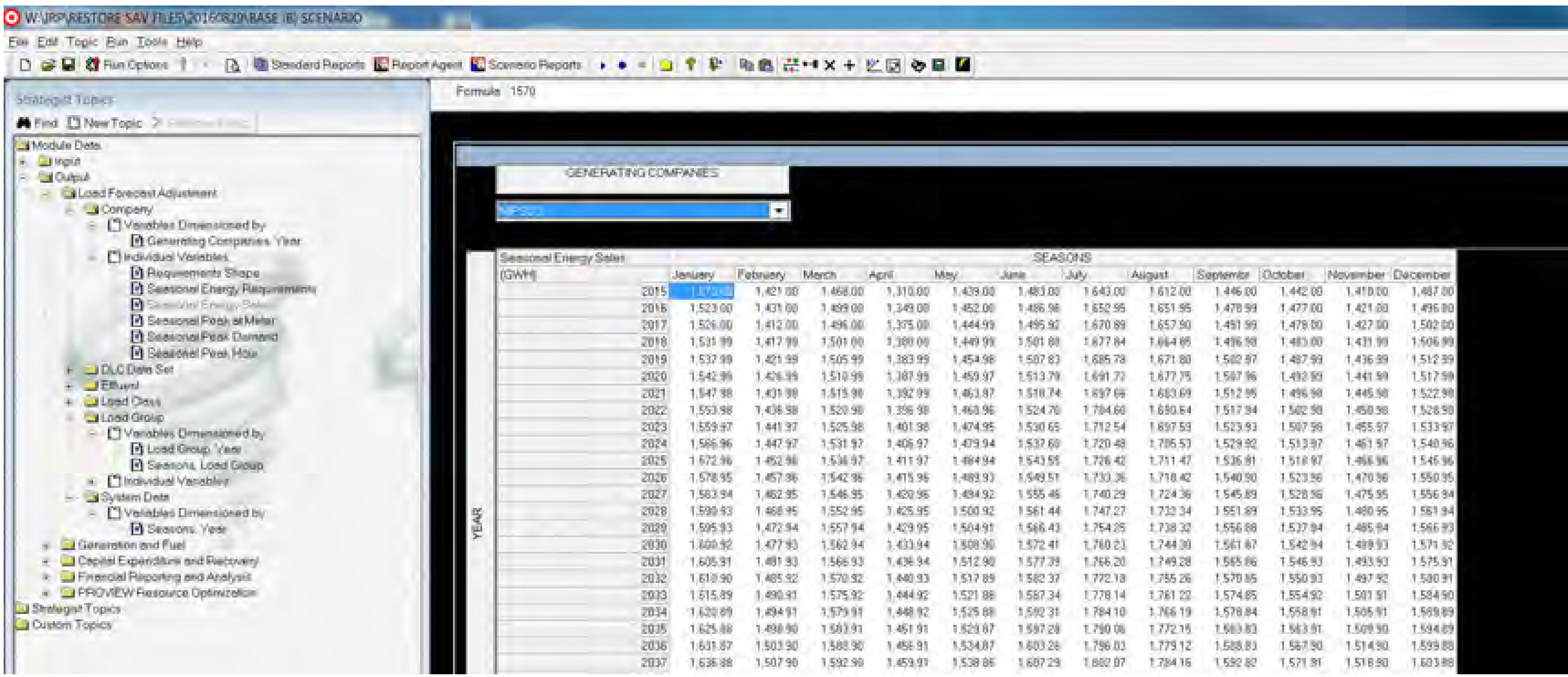
Internal Peak Load in Strategist: INPUT



Seasonal Peak at Meter — SEASONS

YEAR	January	February	March	April	May	June	July	August	Septembr	October	November	December
2015	2,577.00	2,441.00	2,412.00	2,167.00	2,604.00	2,869.00	3,099.00	3,050.00	2,774.00	2,310.00	2,323.00	2,408.00
2016	2,507.00	2,431.00	2,457.00	2,240.00	2,629.00	2,879.00	3,118.00	3,109.00	2,825.00	2,363.00	2,348.00	2,422.00
2017	2,514.00	2,455.00	2,463.00	2,271.00	2,631.00	2,897.00	3,145.00	3,126.00	2,846.00	2,374.00	2,362.00	2,437.00
2018	2,529.00	2,469.00	2,477.00	2,283.00	2,645.00	2,911.00	3,160.00	3,141.00	2,860.00	2,386.00	2,373.00	2,449.00
2019	2,541.00	2,480.00	2,488.00	2,294.00	2,657.00	2,924.00	3,176.00	3,157.00	2,874.00	2,399.00	2,387.00	2,463.00
2020	2,554.00	2,459.00	2,502.00	2,307.00	2,670.00	2,939.00	3,192.00	3,173.00	2,888.00	2,413.00	2,399.00	2,476.00
2021	2,568.00	2,505.00	2,515.00	2,319.00	2,683.00	2,953.00	3,207.00	3,188.00	2,901.00	2,426.00	2,412.00	2,489.00
2022	2,581.00	2,517.00	2,528.00	2,331.00	2,696.00	2,968.00	3,224.00	3,204.00	2,915.00	2,440.00	2,425.00	2,503.00
2023	2,596.00	2,531.00	2,542.00	2,344.00	2,710.00	2,983.00	3,240.00	3,221.00	2,930.00	2,454.00	2,438.00	2,516.00
2024	2,610.00	2,511.00	2,557.00	2,357.00	2,724.00	2,998.00	3,258.00	3,238.00	2,945.00	2,468.00	2,452.00	2,531.00
2025	2,625.00	2,558.00	2,571.00	2,370.00	2,738.00	3,014.00	3,275.00	3,255.00	2,960.00	2,482.00	2,466.00	2,545.00
2026	2,639.00	2,571.00	2,584.00	2,382.00	2,751.00	3,027.00	3,289.00	3,269.00	2,973.00	2,494.00	2,476.00	2,556.00
2027	2,649.00	2,581.00	2,595.00	2,393.00	2,763.00	3,040.00	3,304.00	3,284.00	2,986.00	2,507.00	2,489.00	2,570.00
2028	2,664.00	2,561.00	2,609.00	2,405.00	2,775.00	3,054.00	3,319.00	3,299.00	2,999.00	2,519.00	2,500.00	2,581.00
2029	2,676.00	2,605.00	2,620.00	2,416.00	2,787.00	3,066.00	3,333.00	3,312.00	3,011.00	2,530.00	2,511.00	2,592.00
2030	2,687.00	2,616.00	2,631.00	2,426.00	2,798.00	3,078.00	3,346.00	3,325.00	3,022.00	2,541.00	2,521.00	2,603.00
2031	2,697.00	2,625.00	2,641.00	2,435.00	2,807.00	3,088.00	3,356.00	3,335.00	3,031.00	2,549.00	2,528.00	2,610.00
2032	2,705.00	2,600.00	2,649.00	2,442.00	2,815.00	3,098.00	3,367.00	3,347.00	3,041.00	2,559.00	2,538.00	2,621.00
2033	2,717.00	2,643.00	2,660.00	2,452.00	2,825.00	3,108.00	3,379.00	3,358.00	3,051.00	2,568.00	2,547.00	2,629.00
2034	2,726.00	2,652.00	2,669.00	2,460.00	2,834.00	3,118.00	3,390.00	3,369.00	3,060.00	2,577.00	2,555.00	2,638.00
2035	2,735.00	2,660.00	2,678.00	2,468.00	2,843.00	3,128.00	3,401.00	3,380.00	3,069.00	2,586.00	2,564.00	2,647.00
2036	2,745.00	2,636.00	2,687.00	2,477.00	2,852.00	3,138.00	3,412.00	3,391.00	3,079.00	2,595.00	2,573.00	2,657.00
2037	2,754.00	2,678.00	2,697.00	2,486.00	2,862.00	3,148.00	3,424.00	3,402.00	3,089.00	2,605.00	2,582.00	2,666.00

Customer Energy Requirements in Strategist _ OUTPUT

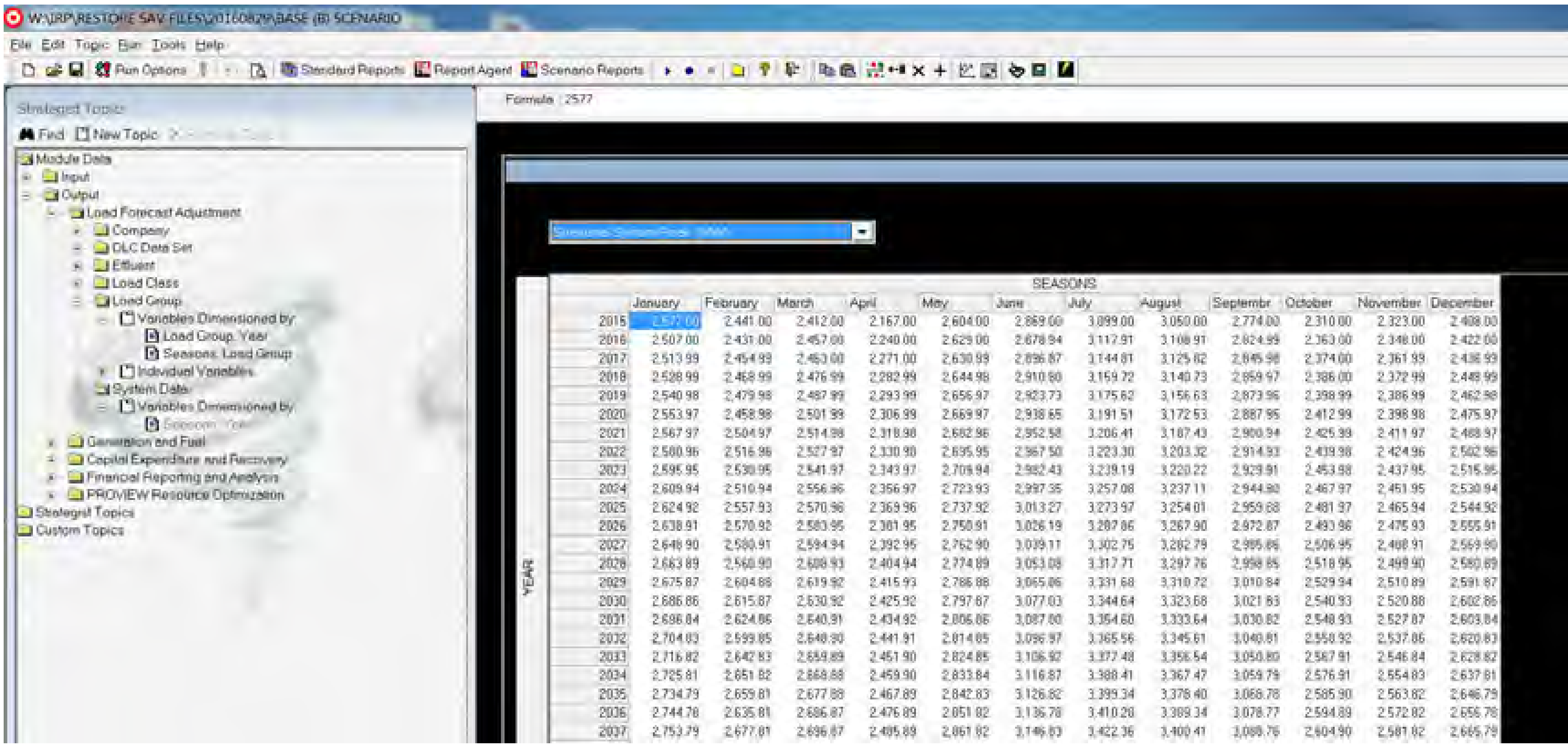


Seasonal Energy Sales (GWH) — SEASONS

	January	February	March	April	May	June	July	August	September	October	November	December
2015	[illegible]	1,421.00	1,468.00	1,310.00	1,439.00	1,483.00	1,643.00	1,612.00	1,446.00	1,442.00	1,410.00	1,487.00
2016	1,523.00	1,431.00	1,499.00	1,349.00	1,452.00	1,486.98	1,652.95	1,651.95	1,478.99	1,477.00	1,421.00	1,496.80
2017	1,526.00	1,412.00	1,496.00	1,375.00	1,444.99	1,495.92	1,670.89	1,657.90	1,491.99	1,479.00	1,427.00	1,502.00
2018	1,531.99	1,417.99	1,501.00	1,389.00	1,449.99	1,501.88	1,677.84	1,664.85	1,496.98	1,483.00	1,431.99	1,506.99
2019	1,537.99	1,421.99	1,505.99	1,383.99	1,454.98	1,507.83	1,685.78	1,671.80	1,502.97	1,487.99	1,436.99	1,512.99
2020	1,542.99	1,426.99	1,510.99	1,387.99	1,459.97	1,513.79	1,691.72	1,677.75	1,507.96	1,492.99	1,441.99	1,517.99
2021	1,547.98	1,431.98	1,515.98	1,392.99	1,463.87	1,518.74	1,697.66	1,683.69	1,512.95	1,496.98	1,445.98	1,522.98
2022	1,553.98	1,436.98	1,520.98	1,396.98	1,468.96	1,524.70	1,704.60	1,690.64	1,517.94	1,502.98	1,450.98	1,528.98
2023	1,559.97	1,441.97	1,525.98	1,401.98	1,474.95	1,530.65	1,712.54	1,697.53	1,523.93	1,507.98	1,455.97	1,533.97
2024	1,566.96	1,447.97	1,531.97	1,406.97	1,479.94	1,537.60	1,720.48	1,705.53	1,529.92	1,513.97	1,461.97	1,540.96
2025	1,572.96	1,452.96	1,536.97	1,411.97	1,484.94	1,543.55	1,726.42	1,711.47	1,536.91	1,518.97	1,466.96	1,545.96
2026	1,578.95	1,457.96	1,542.96	1,415.96	1,489.93	1,549.51	1,733.36	1,718.42	1,540.90	1,523.96	1,470.96	1,550.95
2027	1,583.94	1,462.95	1,546.95	1,420.96	1,494.92	1,555.46	1,740.29	1,724.36	1,545.89	1,528.96	1,475.95	1,556.94
2028	1,590.93	1,468.95	1,552.95	1,425.95	1,500.92	1,561.44	1,747.27	1,732.34	1,551.89	1,533.95	1,480.95	1,561.94
2029	1,595.93	1,472.94	1,557.94	1,429.95	1,504.91	1,566.43	1,754.25	1,738.32	1,556.88	1,537.94	1,485.94	1,566.93
2030	1,600.92	1,477.93	1,562.94	1,433.94	1,508.96	1,572.41	1,760.23	1,744.30	1,561.87	1,542.94	1,489.93	1,571.92
2031	1,605.91	1,481.93	1,566.93	1,436.94	1,512.90	1,577.39	1,766.20	1,749.28	1,565.86	1,546.93	1,493.93	1,575.91
2032	1,610.90	1,485.92	1,570.92	1,440.93	1,517.89	1,582.37	1,772.18	1,755.26	1,570.85	1,550.93	1,497.92	1,580.91
2033	1,615.89	1,490.91	1,575.92	1,444.92	1,521.88	1,587.34	1,778.14	1,761.22	1,574.85	1,554.92	1,501.91	1,584.90
2034	1,620.89	1,494.91	1,579.91	1,448.92	1,525.88	1,592.31	1,784.10	1,766.19	1,578.84	1,558.91	1,505.91	1,589.89
2035	1,625.88	1,498.90	1,583.91	1,451.91	1,529.87	1,597.28	1,790.06	1,772.15	1,583.83	1,563.91	1,509.90	1,594.89
2036	1,631.87	1,503.90	1,588.90	1,456.91	1,534.87	1,603.26	1,796.03	1,779.12	1,588.83	1,567.90	1,514.90	1,599.88
2037	1,636.88	1,507.90	1,592.90	1,459.91	1,538.86	1,607.29	1,802.07	1,784.16	1,592.82	1,571.91	1,518.90	1,603.88

NIPSCO

Internal Peak Load in Strategist: OUTPUT



YEAR	January	February	March	April	May	June	July	August	Septembr	October	November	December
2015	2,577.00	2,441.00	2,412.00	2,167.00	2,604.00	2,869.00	3,099.00	3,050.00	2,774.00	2,310.00	2,323.00	2,408.00
2016	2,507.00	2,431.00	2,457.00	2,240.00	2,629.00	2,678.94	3,117.91	3,108.91	2,824.99	2,363.00	2,348.00	2,422.00
2017	2,513.99	2,454.99	2,463.00	2,271.00	2,630.99	2,896.87	3,144.81	3,125.82	2,845.98	2,374.00	2,361.99	2,436.93
2018	2,528.99	2,468.99	2,476.99	2,282.99	2,644.98	2,910.80	3,159.72	3,140.73	2,859.97	2,386.00	2,372.99	2,449.99
2019	2,540.98	2,479.98	2,487.99	2,293.99	2,656.97	2,923.73	3,175.62	3,156.63	2,873.96	2,398.99	2,386.99	2,462.98
2020	2,553.97	2,458.98	2,501.99	2,306.99	2,669.97	2,938.65	3,191.51	3,172.53	2,887.95	2,412.99	2,398.98	2,475.97
2021	2,567.97	2,504.97	2,514.98	2,318.98	2,682.96	2,952.58	3,206.41	3,187.43	2,900.94	2,425.99	2,411.97	2,488.97
2022	2,580.96	2,516.96	2,527.97	2,330.98	2,695.95	2,967.50	3,223.30	3,203.32	2,914.93	2,439.98	2,424.96	2,502.96
2023	2,595.95	2,530.95	2,541.97	2,343.97	2,709.94	2,982.43	3,239.19	3,220.22	2,929.91	2,453.98	2,437.95	2,515.95
2024	2,609.94	2,510.94	2,556.96	2,356.97	2,723.93	2,997.35	3,257.08	3,237.11	2,944.90	2,467.97	2,451.95	2,530.94
2025	2,624.92	2,557.93	2,570.96	2,369.96	2,737.92	3,013.27	3,273.97	3,254.01	2,959.68	2,481.97	2,465.94	2,544.92
2026	2,638.91	2,570.92	2,583.95	2,381.95	2,750.91	3,026.19	3,287.86	3,267.90	2,972.87	2,493.96	2,475.93	2,555.91
2027	2,648.90	2,580.91	2,594.94	2,392.95	2,762.90	3,039.11	3,302.75	3,282.79	2,985.86	2,506.95	2,488.91	2,569.90
2028	2,663.89	2,560.90	2,608.93	2,404.94	2,774.89	3,053.08	3,317.71	3,297.76	2,998.85	2,518.95	2,499.90	2,580.89
2029	2,675.87	2,604.88	2,619.92	2,415.93	2,786.88	3,065.86	3,331.68	3,310.72	3,010.84	2,529.94	2,510.89	2,591.87
2030	2,686.86	2,615.87	2,630.92	2,425.92	2,797.87	3,077.03	3,344.64	3,323.68	3,021.83	2,540.93	2,520.88	2,602.86
2031	2,696.84	2,624.86	2,640.91	2,434.92	2,806.86	3,087.00	3,354.60	3,333.64	3,030.82	2,548.93	2,527.87	2,603.84
2032	2,704.83	2,599.85	2,648.90	2,441.91	2,814.85	3,096.97	3,365.56	3,345.61	3,040.81	2,558.92	2,537.86	2,620.83
2033	2,716.82	2,642.83	2,659.89	2,451.90	2,824.85	3,106.92	3,377.48	3,356.54	3,050.80	2,567.91	2,546.84	2,628.82
2034	2,725.81	2,651.82	2,668.88	2,459.90	2,833.84	3,116.87	3,388.41	3,367.47	3,059.79	2,576.91	2,554.83	2,637.81
2035	2,734.79	2,659.81	2,677.88	2,467.89	2,842.83	3,126.82	3,399.34	3,378.40	3,068.78	2,585.90	2,563.82	2,646.79
2036	2,744.78	2,635.81	2,686.87	2,476.89	2,851.82	3,136.78	3,410.28	3,389.34	3,078.77	2,594.89	2,572.82	2,656.78
2037	2,753.79	2,677.81	2,696.87	2,485.89	2,861.82	3,146.83	3,422.36	3,400.41	3,088.76	2,604.90	2,581.82	2,665.79

Seasonal Summary Report

TEMP - Notepad

File Edit Format View Help

09/02/16 11:23:48 V04.0 R04.2

NIPSCO 2016 IRP
BASE CASE
12/08/2015

NIPSCO 2016 IRP
GENERATION AND FUEL MODULE
SEASONAL SUMMARY REPORT

NIPSCO

------ 2015 SYSTEM ------		SEASON 1 January	SEASON 2 February	SEASON 3 March	SEASON 4 April	SEASON 5 May	SEASON 6 June	SEASON 7 July	SEASON 8 August	SEASON 9 Septembr	SEASON 10 October	SEASON 11 November	SEASON 12 December	ANNUAL
ENERGY REQUIRED	GWH	1570.	1421.	1468.	1310.	1439.	1483.	1643.	1612.	1446.	1442.	1410.	1487.	17731.
PEAK LOAD	MW	2577.	2441.	2412.	2167.	2604.	2341.	2571.	2522.	2246.	2310.	2323.	2408.	2571.
LOAD FACTOR	PCT	81.89	86.63	81.80	83.96	74.28	87.98	85.89	85.90	89.41	83.90	84.30	83.00	78.72

NIPSCO 2016 IRP
BASE CASE
12/08/2015

NIPSCO 2016 IRP
GENERATION AND FUEL MODULE
SEASONAL SUMMARY REPORT

NIPSCO

------ 2016 SYSTEM ------		SEASON 1 January	SEASON 2 February	SEASON 3 March	SEASON 4 April	SEASON 5 May	SEASON 6 June	SEASON 7 July	SEASON 8 August	SEASON 9 Septembr	SEASON 10 October	SEASON 11 November	SEASON 12 December	ANNUAL
ENERGY REQUIRED	GWH	1523.	1431.	1499.	1349.	1452.	1487.	1653.	1652.	1479.	1477.	1421.	1496.	17919.
PEAK LOAD	MW	2507.	2431.	2457.	2240.	2629.	2351.	2590.	2581.	2297.	2363.	2348.	2422.	2590.
LOAD FACTOR	PCT	81.65	84.58	82.00	83.64	74.23	87.84	85.78	86.02	89.42	84.01	84.06	83.02	78.76

NIPSCO 2016 IRP
BASE CASE
12/08/2015

NIPSCO 2016 IRP
GENERATION AND FUEL MODULE
SEASONAL SUMMARY REPORT

NIPSCO

------ 2017 SYSTEM ------		SEASON 1 January	SEASON 2 February	SEASON 3 March	SEASON 4 April	SEASON 5 May	SEASON 6 June	SEASON 7 July	SEASON 8 August	SEASON 9 Septembr	SEASON 10 October	SEASON 11 November	SEASON 12 December	ANNUAL
ENERGY REQUIRED	GWH	1526.	1412.	1496.	1375.	1445.	1496.	1671.	1658.	1492.	1478.	1427.	1502.	17978.
PEAK LOAD	MW	2514.	2455.	2463.	2271.	2631.	2369.	2617.	2598.	2318.	2374.	2362.	2437.	2617.
LOAD FACTOR	PCT	81.59	85.59	81.64	84.09	73.82	87.70	85.82	85.77	89.39	83.68	83.91	82.84	78.42

Northern Indiana Public Service Company
2016 Integrated Resource Plan
Public Advisory Webinar
SUMMARY

September 12, 2016

Meeting Overview & Introductions
Timothy Caister, NIPSCO

Timothy Caister opened the meeting by providing an overview of the agenda. He discussed the objectives of the webinar, which were to: 1) discuss retirement paths from the August 23 meeting and address related stakeholder feedback; 2) address input from prior stakeholder and subsequent 1:1 meetings; and 3) share any initial analysis from 1:1 stakeholder meetings. Alison Becker provided an overview of the logistics of the meeting which included introductions of those participating in the meeting and the fact that the “chat” feature on the webinar would be used to ask questions.

Public Advisory Process Update
Timothy Caister, NIPSCO

Mr. Caister provided an update on the Public Advisory Process to date. He noted there have been three previous stakeholder meetings and the presentation materials and summary notes are posted on NIPSCO’s IRP webpage at www.NIPSCO.com/irp.

IRP Stakeholder Process & Timeline
Daniel Douglas, NIPSCO

Daniel Douglas provided an overview of the September 12 webinar as well as the final stakeholder meeting scheduled for October 3, 2016. The October 3 meeting is scheduled to focus on “what is NIPSCO’s preferred plan?” The agenda will focus on sharing any results from the 1:1 stakeholder analytical requests, describing the preferred replacement path and the logic relative to the alternatives and explaining NIPSCO’s short term action plan. In addition, the meeting will provide a review of stakeholder feedback and an overview of NIPSCO’s preferred plan. He noted it is expected to be a 4 hour in person session.

Status Update of One-on-One Meetings and Requests

Daniel Douglas

Mr. Douglas provided a summary of the 1:1 meetings held to date, focusing on the outstanding issues from each meeting and if those issues had been resolved. He noted that the OUCC had asked for the PIRA input data tables and stated that NIPSCO was still working on getting that information. The OUCC had also asked for additional sensitivity for return on for remaining net book value of retiring assets included in retirement portfolios and Mr. Douglas reported that is in process, along with the exact dollar amounts of remaining net book values of retiring assets included in retirement portfolios. Kelly Carmichael discussed the OUCC's request for the cost estimates for ozone compliance and noted that NIPSCO needed to provide additional follow up information.

Ms. Becker explained that in its 1:1, the Citizens Action Coalition (CAC) had asked if NIPSCO could or would break down energy efficiency groupings into smaller "bundles" based on cost per kilowatt hour (kWh) as has been done by some other utilities. Ms. Becker explained that a discussion had been held with the CAC that the process was too far along in this IRP and NIPSCO's software was unable to handle the number of groupings that would be created under such an analysis. Therefore, the methodology discussed in the July 12 presentation would be used for the 2016 IRP, with the cents/kWh likely to be used in subsequent IRPs.

Question
You had 26 different combinations of supply- or demand-side resources? Demand-side.

Mr. Douglas then reviewed the discussion with the Industrial Group. He noted they asked for the annual increase to the revenue requirement by retirement portfolio, as well as what is the amortization period for the remaining net book value of retirement assets included in the retirement portfolios. He explained these two items are still in process. In addition, the Industrial Group's request for an "unconstrained" model through 2023 is being run. Mr. Carmichael provided an update on the Industrial Group's request for further clarity and details regarding the Coal Combustion Residuals and Effluent Limitations Guidelines rules. However, NIPSCO still owes the Industrial Group additional information, including risks and options for compliance. Finally, Mr. Douglas noted that NIPSCO is working on the Industrial Group's request to review the presented retirement portfolios across higher gas costs to avoid a "regrets" scenario. There was one open item from the Industrial Group related to the data tables behind a number of the curves in the model, but NIPSCO was awaiting specific requests from the Industrial Group on this issue.

Question
Another clarification question, so the remaining net book value is the cost of retiring assets (or at least the primary cost of retirement? So to be specific the net book value of the retiring asset is really the gross cost of capital that we paid initially to build that

plant, less the accumulated depreciation. For Bailly and Schafer 17 and 18 – laid out a most viable scenario – retiring all 3 early. Ultimately that would mean the net book value would be less. There are costs of removal baked in there as well –environmental management, costs associated with the shutdown of the facility

NIPSCO then provided an update on its discussions with Brubaker and Associates. During its 1:1 meeting with NIPSCO, it requested a discussion of typical week load assumptions from the 2014 IRP and any impact those assumptions would have on this IRP and well as asking various retirement analysis questions, including questions about avoided operations and maintenance costs and environmental costs estimates. Mr. Douglas reported there are no further action items at this time.

A 1:1 meeting was also held with the Sierra Club, where questions were asked on various topics, including net book values and solar and wind cost assumptions. Mr. Douglas reported there were no outstanding action items at the time of the webinar.

Mr. Douglas then reported on the 1:1 meeting with the Indiana Utility Regulatory Commission (Commission), which focused on a discussion of the scenarios and sensitivities, including the portfolio outputs by scenarios and demand side management assumption and results. Mr. Douglas noted that, while the Commission did not have any outstanding issues for NIPSCO to address, it did have a number of suggestions for NIPSCO to incorporate while drafting the report and NIPSCO will be utilizing those suggestions as it finalizes its IRP.

Questions
What is the “drop dead” deadline for running additional sensitivities and model runs? Ideally we were hoping to get most of those scenarios by last Friday. Obviously if there are additional scenarios that are helpful we would like to get them in as soon as possible. So while there is no strong drop dead deadline we are hopeful that we can get any new scenarios this week.

When does NIPSCO assume Schahfer Units 17 and 18 would need to install SCRs? A little unclear because the SCRs would be driven by a rule not yet released. It would be a further ratcheting down. So what they did in the rule – there is a new standard that will need a rulemaking. We’re projecting that would further drop the cap lower. Schafer 17 and 18 do not have back end control for IRP – back end control would be needed for those 2 units. I believe it is out in the early 2020s – but we will get that answer to you. If we maintain the 2023 retirement dates for Schafer 17 and 18 – it is unlikely that money for SCRs would need to be spent, subject to EPA rule.

Review of the First Three Meetings Questions and Answers
Timothy Caister

Mr. Caister provided a review of the main themes of the questions from the first three meetings. He noted in meeting one the main themes centered around gaining general clarification of the data points utilized in the IRP. Also, there were questions about carbon pricing. Attendees were interested in knowing the data utilized and how it was correlated the various other model inputs. There were also questions about the inclusion of supply- and demand-side resources in the model and how solar was included in the model.

He then provided a review of the key issues discussed in meeting two, which focused on demand-side resources. He noted that the benefit cost tests were a key topic of the second meeting, as well as what was included in avoided costs. There was also a great deal of discussion regarding program potential and the relationship to savings, the development of an action plan and development groupings to go into the model. Finally, there was a great deal of discussion around whether or not customers who opted out of participation in DSM programs should be included in the Market Potential Study.

As for the third meeting, Mr. Caister noted that there were a number of clarifications on a variety of environmental considerations. In addition, there were questions and clarifications on the load forecasts used in Strategists as well as the way DSM was optimized and used as an input. Finally, there were questions around the model constraints and boundaries. Ms. Becker then showed the group the matrix of all of the questions asked during each of the three previous meetings and the post-meeting responses, which allowed NIPSCO to go back and check any facts and talk to any addition subject matter experts and provide a more complete answer than may have been possible the day of the meeting. The answers provided the day of each of the meetings are provided in the notes from the meeting, but the post-meeting responses provide a more complete answer based on additional time to review. She noted that both documents will be included in the IRP appendices. Mr. Caister encouraged all stakeholders to review the responses and to let NIPSCO know if there are any questions or concerns.

Questions
Strategist allows the expert of inputs/outputs into a text format (.rtf) When you file your IRP will you provide those inputs and outputs to those stakeholders that have signed an NDA? Yes – so typically in addition to the public version – we include a confidential version and those are contained in the CD that is provided under a signed NDA.

Have you had discussions with MISO regarding retirements or will you have those prior to finalizing the IRP? We have not had those discussions to date. The process is to file with MISO for an Attachment Y – anytime you retire a facility. When appropriate we will be filing that with MISO – sooner rather than later. Ultimately it is a confidential filing but I think will file prior to IRP submission in November.

Next Steps
Timothy Caister
Daniel Douglas

Mr. Caister asked if there were any additional questions from the meeting. Mr. Douglas then reminded everyone that the next meeting will be October 3, in person, at the Radisson Hotel. Mr. Caister stated that the meeting summary from this meeting will be available October 3. Mr. Caister thanked everyone for attending the webinar.

Organization	Question	Response	How addressed in IRP
Sierra Club	How much of the annual energy produced is coal, natural gas and renewables (in percentages)?	NIPSCO's current fuel mix, as a percentage of capacity, is 68% coal, 18% natural gas and 14% other, with "other" being comprised of interruptiles at approximately 13.7% and renewables comprising the remainder.	N/A
	What is the installed numbers between FIT 1.0 and 2.0?	The installed numbers for FIT 1.0 is 20 MW and 2.0 is 16 MW.	N/A
IURC	Please clarify what is the market?	Market hydros and wind refer to these generation resources being bid into the MISO market.	N/A
IndianaDG	When will the FIT annual report be filed? Will the upcoming report include what has been committed, what is under contract and what is still available?	The FIT annual report was filed in July and the information was included in the report.	N/A
Sierra Club	With just 35% of coal generated electricity last year and coal representing 70% of actual coal, is it fair to say that your coal plants were often not competitive on the MISO markets and it made more sense to buy off the market?	The 35% of the referred to is the capacity on the market, which is the same as saying what the market is demanding from coal. NIPSCO does not force its coal generation into the market uneconomically.	N/A
Sierra Club	Hasn't Schafer operated at 37% capacity?	Yes, Schahfer operated at 37% because this is what the market demanded.	N/A

Organization	Question	Response	How addressed in IRP
OUCC	What precise technologies are you assuming for each environmental cost?	The costs for ELG reflect a zero liquid discharge approach. NIPSCO has very little to no confidence that the alternative technology, bio-reactors, will operate in a compliant way in northern climates. NIPSCO continues to evaluate CCR wth the current costs reflecting that coal ash impoundments will need some level of modification to be compliant.	NIPSCO continues to utilize zero liquid discharge (ZLD) technology to achieve compliance with the ELG rule. NIPSCO has narrowed CCR compliance technology to remote ash conveying or under the boiler ash conveying and has modified these costs accordingly in its IRP modeling.
OUCC	On Slide 32, curious about the Bailly retirement scenario in 2023. Are you assuming it will meet the locational and structural requirements for that site?	Althought it is unknown at that time if Bailly will meet the locational and structural requirements for the site, the costs included at the time of the first meeting reflect the work that may need to be done to continue to operate the plant. If requirements are not met, clean-up and remediation will make up the costs.	The final IRP will be updated based on the retirement strategies as discussed during the third stakeholder meeting. Although no decisions had been made as of the date of that meeting, a 50% coal retirement scenario was considered, which included Bailly 7&8 being retired in 2018, which means NIPSCO would include clean up and remidation of the site in the IRP.
OUCC	Is it possible that we might see that information by the IRP filing period associated with the locational/structural components?	Although NIPSCO will not have all of the information by the time the IRP is filed, it is hoped that additional information will be available to be included.	This information will not be available by the November 1, 2016 IRP filing date, but NIPSCO will share with stakeholders as it becomes available.

Organization	Question	Response	How addressed in IRP
OUCC	Slide 33: About where do your CO2 emissions fall now?	Per slide 10 in the August 23rd third public advisory meeting slide deck posted to the NIPSCO IRP website, which includes a full historial view of CO_2, the historical NIPSCO CO_2, SO_2 and NO_x emissions, emissions for 2015 were approximately 12 million tons.	N/A
OUCC	It would be helpful if you could give us some idea of what precise carbon price would trigger a retirement of each unit? That would be very helpful.	In 2014, NIPSCO completed a break-point analysis on carbon pricing. Carbon pricing is correlated with numerous model inputs including gas pricing, coal pricing, etc. These quantities all feed into retirement optimization. Due to the complex nature of these linked variables, there may be more than a single retirement breakpoint as a function of carbon pricing. To determine these breakpoints, the linkage between carbon and the previously mentioned pricing is needed. This information is supplied by third party vendor, PIRA, and is proprietary to their internal models. NIPSCO does not have access to these needed assumptions nor access to an optimization model that can accomodate them. Varying the single parameter of carbon pricing without consideration of these other key modeling variables would produce technically invalid model results.	N/A
Sierra Club	Do any scenarios or sensitivities assume national carbon policy will become more stringent after 2030 (the end point for the Clean Power Plan)?	The scenarios and sensitivities vary the carbon pricing based upon the setup. In some of these, there is very aggressive pricing when carbon pricing kicks in, but 2030 is not significant . In two of the scenarios NIPSCO assumes a mandatory renewable portfolio standard starting in 2025.	N/A

Organization	Question	Response	How addressed in IRP
NAACP	Why are Michigan City allowances remaining higher? These communities are bearing an on-going burden.	NIPSCO recently completed the dry flue gas desulferization (FGD) on the Michigan City station and employed a bag-house technology that significantly reduces the particulates and emissions from that unit, which came online late last year. The community will see the associated air quality improvements.	N/A
NAACP	Why are emissions dis-proportionately higher in Michigan City?	The emissions are not disproportionately higher now that the new emissions technology has been installed. The emissions will be better moving forward, and historic data will not be reflective of what happens in the future. On Slide 33, the CO_2 allowances are driven from the historic run-times of facilities. Michigan City has historically run more. These are not solidified into what will actually be allocated.	N/A
CAC	Can NIPSCO provide the data that came to the conclusion that new IGCC (integrated gasification combined cycle), new coal and new nuclear were "economically attractive?"	NIPSCO has made the policy decision to consider all viable options, as determed by an independent engineering analysis. That does not mean any particular option would be selected. Please note, although included in the analysis, NIPSCO is not finidng the options of a new IGCC, new coal and new nuclear as prefered in terms of least cost modeling .	These will continue to be options in the IRP, but policy considerations will also be considered before final decisions are made.
OUCC	You look at what is in NIPSCO's service territory?	NIPSCO does consider what is in its service territory, particularly when it comes to distributed generation. For example, solar power included in the model is a function of the solar installed in the service terrtory and model considers how much of that resource is available in or near NIPSCO's service territory.	N/A
OUCC	For an IGCC, would NIPSCO consider building this in its service territory?	For these types of technologies, NIPSCO does not select a location; the model selects the technology. Locational issues are more about solar and wind. As an example, NIPSCO has a CCGT at Sugar Creek, which is not in its service territory. The location of a resource would be considered in a request for proposal (RFP).	N/A

Organization	Question	Response	How addressed in IRP
Sierra Club	I am surprised to see conventional coal plants on the list, especially with carbon emissions? Also nuclear is very expensive?	These technologies are included because NIPSCO does not want to make a pre-judgement. All the known technologies that are available to NIPSCO are in the model. No other utilities are considering those technologies.	N/A
CAC	You are not pre-screening supply-side resources, but you are going to screen demand-side resources?	Both demand- and supply-side resources are pre-screened, albeit in different ways. The demand-side resources are grouped together so they can be included in the model in a way that does not overwhelm the model. NIPSCO's goal is to broaden the resource selection capabilities within the model in future IRPs.	N/A
IndianaDG	If NIPSCO would be permitted to earn a rate of return on PPAs (purchase power agreements) for solar, would that change how you would model utility-scale solar in the IRP?	The IRP is not a rate model, NIPSCO does include existing regulations and tax credits including the investment tax credit (ITC) for solar and production tax credit (PTC) for wind. However, the IRP modeling process does not include rates as part of the process.	N/A
IndianaDG	Would NIPSCO consider more utility scale sources if Indiana subsidizes?	NIPSCO pricing reflects subsidies for renewables as is currently available (such as PTC for wind and ITC for solar). Additional subsidies can be input into the model; however, these numbers would have to be provided to NIPSCO with supporting documentation to provide justification for their inclusion. IRP modeling is a time consuming process and only defensible inputs should be used due to model validation and time constraints.	N/A

Organization	Question	Response	How addressed in IRP
IndianaDG	Would NIPSCO consider joint ventures with municipalities to develop solars as a special economic development tariff?	The approach for deploying solar in that manner is outside the IRP process.	N/A
NAACP	Are there plans for PV(photovoteic) on schools and Section 8 apartments considered in the IRP?	The model has a selection option for a generic solar distributed generation (DG) unit; it makes no difference if this is for schools, residential, commercial, etc.	N/A

Organization	Question	Response	How addressed in IRP
CAC	Were the opt out customers not included in the MPS? I don't understand the rationale for removing the opt out customers especially since they can opt back into the programs.	Customers who have elected to opt out from participation in NIPSCO's demand side management programs were not included in the Market Potential Study because they were not considered part of the "market" from which there could be potential. NIPSCO recognizes that such customers could opt back into participation. The fact that the IRP is currently done every two years means that a customer that opted back into participation in DSM programs could be included in an update to NIPSCO's MPS and future IRP. However, for the current IRP, NIPSCO wanted to look at the market as it stands as far as available load. Similarly, NIPSCO did not consider any new load that might enter the service territory during the short-term or long-term planning horizon, nor any companies that might exit NIPSCO's service territory. The MPS only considers load that is available for participation at this time.	This load is not included in the load available for energy efficiency demand side management, but could be included in interruptible demand side management, as that is not part of the opt out program
CAC	In terms of incorporating historic program information, I am curious about this because there has been a lot of turmoil in the past with all the vendors and changing companies, how is that taken into account?	Vendor performance is one component of information used in the MPS. However, it is not the only one. When AEG starts at the beginning of a study, it uses the previous year's program performance, which provides one source of information regarding NIPSCO's service territory and a current or most recent program's potential/performance. Another step is to benchmark with other peer utilities and to review benchmarking studies. The key is that historic program information does not come from one source; it comes from a variety of sources. This provides a means to incorporate various experiences with programs to determine the most likely potential for NIPSCO's service territory.	N/A

Organization	Question	Response	How addressed in IRP
Sierra Club	What are the most subjective inputs in your model? How do you determine future customer acceptance rather than just past? How do you factor?	The "take rates," or the number of customers who will adopt a particular measure, are somewhat subjective. However, AEG is are able to benchmark take rates in order to look for trends, which removes a great deal of the subjectivity and AEG uses that information to build trends into the future.	N/A
Sierra Club	How and why did you choose TRC for cost-benefit? Did you consider and calculate other measures for comparative purposes?	Both NIPSCO as well as its vendors utilize all of the benefit cost tests as part of the analysis as to whether or not to offer a program. These include the Participant (PAC), Total Resource Cost (TRC), Ratepayer Impact Measure (RIM) and Utility Cost (UCT) tests. Traditionally, in Indiana, more weight has been placed on the TRC test, which is why NIPSCO continues to use it as its litmus test as to whether or not to offer a program or include a measure. Furthermore, while the draft IRP rule removes the requirement that benefit cost tests be included in the IRP, the draft DSM rule maintains them as a consideration. As such, NIPSCO must balance leaving something in for consideration in the IRP when it will only be found not cost effective as part of DSM. Given the linkage that the DSM offering must be consistent with IRP, NIPSCO looks to keep the analysis consistent throughout as well. Ultimately, as both rules are finalized, NIPSCO made the policy decision to continue reviewing all results of the benefit costs test, but utilizing the results of the TRC as the threshold test for the MPS analysis.	N/A

Organization	Question	Response	How addressed in IRP
CAC	What about using UCT test (rather than TRC test)? Isn't UCT more likely used in IRP economic screen? Typically Program Potential only determined for a small segment of time (not for 20 years). How do you account for that?	There is always a judgment call about which test to use and in what form. There are certainly benefits and detriments to each test. For example, the UCT measures the ratio of the net benefits of the program to the program cost incurred by the utility for the programs. On the other hand, the TRC takes into account the incremental cost borne by the participant. It is important as part of the analysis to consider the cost to the customer, as that is part of the economic analysis.	N/A
CAC	It seems to me that Step 5 would utilize the UCT test that's what prompted my question?	As discussed above, the UCT does not consider the cost to the customer, therefore, more programs and measures will pass. However, Indiana Code requires the Commission to consider the cost to the customer. Because of this, NIPSCO utilized the TRC, which is a common metric in the Midwest and the rest of the United States because it considers the cost to the customer.	N/A
Sierra Club	Will they calculate others [cost benefit tests]?	All of the benefit cost tests were calculated by Morgan Marketing Partners as part of determining program potential (Step 4). In addition, once the final programs are selected each of the benefit cost tests are once again calculated. If NIPSCO seeks approval of its DSM program prior to issuing a request for proposal and selecting a vendor for its next DSM plan, an interim benefit cost test calculation will be run based on the programs/measures selected by the model.	N/A

Organization	Question	Response	How addressed in IRP
CAC	Are there groupings by end-use costs? e.g. 0 – 3 cents lighting, 3 – 6 cents lighting, etc.	NIPSCO did not elect to further refine its grouping by costs. Rather it allowed the model to select by end-use only. They were not grouped by cost, just by end-use load shape. There are a variety of ways to model DSM and other Indiana utilities have done it differently than NIPSCO. NIPSCO will continue to look for feedback from the Commission as well as stakeholders and will likely modify its modeling in its next IRP unless clear direction is given from the Commission to maintain the current practice. It is important to note that, preliminarily, the model has selected, with a combination of energy efficiency and demand response, over 2% of the total energy coming from DSM options. Of that, approximately 1.5% is from energy efficiency measures.	N/A
NAACP	How are you making sure that a large portion of the 36% of applicable customers are the most energy burdened of your customers?	During this part of the process, specific populations are not targeted. Probabilities are used in the development of the MPS, but there is not a great deal of insight into what customers will actually adopt what measures. The data is then put into the IRP model and the information comes our regarding the groupings the model selects for demand side resources. Ultimately, NIPSCO puts programs together to achieve various policy goals and providing assistance to its low income customers is one of those policy goals. The General Assembly has encouraged NIPSCO and other utilities to offer such programs by not making those programs subject to benefit cost tests.	Not part of the IRP, but low income/energy burdened customers are considered when putting together the portfolio of programs.

Organization	Question	Response	How addressed in IRP
CAC	What about Industrial Opt Outs that are doing EE? How is that taken into account by NIPSCO? Concern about NIPSCO overbuilding/having excess generation/capacity without this industrial opt out information.	There are ways to measure industrial load other than the MPS. Most specifically, this is done through the industrial load forecast. When planning for demand side resources, NIPSCO wanted to plan for the resources it had available through its own programs. This meant studying the customers that are participating in the programs.	The load forecasting function will assist with limiting excess generation/capacity issues in the IRP.
CAC	What is total number of measures screened out between technical potential and program potential? I see percentages on Slide 16 for Technical to Economic to Achievable, but not the number of measures.	A total of 27 measures were removed moving from the Achievable to Program potential step. However, as a word of caution, one of the problems with numbers of measures is that it is not related to the amount of savings. Some measures can represent a large amount of savings and others a very small amount of savings. One hundred measures could be removed, but those measures would only represent 1% of savings potential. Providing the number of measures removed does not provide a good indicator of how much savings is totally removed from the potential.	N/A
CAC	Is your work on doing DSM Program Potential the same as preparing an Action Plan?	The DSMore analysis is the same, but the difference is the length of time analyzed. Action Plans are for programs and are not as technology driven. The Program Potential in the MPS is a longer-term look for the IRP does not restrict what is offered based on a specific set of programs chosen by NIPSCO. Ultimately, an Action Plan is developed once the DSM Groupings are selected by the IRP model and better defined for a smaller period of time.	NIPSCO plans to develop an Action Plan prior to filing its Section 10 filing based on the DSM Groupings selected by the IRP model. This will serve as a refresh of the MPS as well as providing more specify around how the goals established by the IRP will be achieved.

Organization	Question	Response	How addressed in IRP
CAC	So, typically Program Potential is determined for a small segment of time and not over 20 years?	No, Program Potential is projected for 20 years based on these measures and average costs for operating the program. The cost needs to be represented over the 20 year period. However the Action Plan is then developed for a shorted time period. Frequently a MPS and Action Plan are done at the same time, with the Action Plan taking a small subset of the available Program Potential. NIPSCO will use the Program Potential to feed into the IRP model and then use the results of the IRP model to formulate its Action Plan.	N/A
IURC	How are "Avoided Costs" for T&D calculated?	The Avoided Costs for Transmission and Distribution is determined by NIPSCO based on what it sees on average across the system as a whole.	N/A
CAC	What is the difference of AEG's application of NIPSCO's program results in figuring out "take-rate" in achievable potential step versus your application of NIPSCO's program history?	AEG uses averages and generic costs and takes a very high-level, broad brush approach. In considering information for NIPSCO more specifically, Morgan Marketing Partners applies localized details and NIPSCO results, including the evaluation results, which provide take rates and other net-to-gross ("NTG") results, which are applied to the information from AEG. The gross numbers that are created based on AEG's adoption rates and refined with NIPSCO's NTG results.	N/A
CAC	What is the difference between AEG's application of avoided cost versus Morgan's application of avoided cost? Are they different? Will they be different than avoided costs used once NIPSCO files for DSM plan? Are avoided capital costs included?	AEG uses annual averages. NIPSCO updates the avoided cost numbers annually. Morgan Marketing Partner uses the model to estimate a probability of high or low prices occurring, rather than the avoided cost actuals. These are the probability scores. The benefit cost scores do not go into the model directly.	N/A

Organization	Question	Response	How addressed in IRP
CAC	Slide 26 – How is this different from industry defined TRC (not TRC cost benefit) that nets out benefits from total costs? I think it's technically called TRC net levelized costs which are all costs minus all benefits regardless of which sponsor incurs costs or benefits.	They are not different; the terms are interchangeable. The tests from the California Standard Practice Manual are used. The avoided capital costs are included when possible. It is embedded in the total avoided cost number and not defined separately.	N/A
NAACP	Urban heat island factored into the projected energy used by an air conditioning, that will be used by energy burdened and others?	The Indiana Technical Resource Manual was used, which considered a variety of different environments in Indiana. To the extent urban heat islands were included in the Indiana Technical Resource Manual, they were included in the Market Potential Study. This is another example of how policy drives energy efficiency programs outside of the market potential study/IRP.	N/A
CAC	Are there groupings by end-use costs? e.g. 0 – 3 cents lighting, 3 – 6 cents lighting, etc. Are you going to provide levelized costs per grouping? Are you able to put them in smaller buckets instead of the larger buckets?	Although not grouped by cost, the buckets do vary in size. The size of the buckets vary by implementation costs, but the avoided costs will not be different because of those groupings. It is simply the cost for the measure or the program to acquire the savings. To NIPSCO, this made the most sense for a) modeling in the IRP and b) developing the Section 10 Plan based on the IRP. It provides a mechanism to determine what programs to offer and to put together a request for proposal to vendors to offer to those programs. NIPSCO will continue to monitor Commission recommendations on this issue for future IRP development.	NIPSCO elected to not do tiered modeling because of the number of groupings it would create and the difficulty that would cause in running the model. NIPSCO will consider this in the development of future IRPs.

Organization	Question	Response	How addressed in IRP
Sierra Club	In your professional view, does the avoided cost capture the true full cost of new generation for the period?	Avoided cost represents the market value of avoided capacity and energy purchases, but it is not a comparison of efficiencies of various generation technologies. That is the purpose of the IRP.	N/A
Sierra Club	Oh and doesn't avoided cost change over future?	Avoided cost does change going forward. To compensate for this, a historical value is used in correlation with weather and prices. All of the financials and forecasted changes are put into DSMore. This allows NIPSCO's future avoided cost to be represented in a consistent way.	N/A
CAC	With the latest draft of the IRP rules, cost-benefit test requirement was removed. NIPSCO is only using Program Potential – 2 steps down from Economic Potential (which is step with cost-benefit test). Will NIPSCO reconsider input of Program Potential?	NIPSCO has considered this and will continue to do so as the Commission's IRP Rule continues to be finalized. However, the demand side management rule still considers the benefit cost test results before programs may be approved. As such, in order to assure that a Section 10 plan is consistent with the IRP, it is important to screen out measures that are not cost effective as part of the development of the MPS. NIPSCO is concerned about having the IRP select measures that are later found to be not cost effective and then have a Section 10 Plan denied for not being consistent with the IRP. Again, NIPSCO will continue to seek direction from the Commission on this issue for inclusion in subsequent market potential studies, IRPs and Section 10 filings. At this time, this seems to be the most conservative approach.	N/A

Organization	Question	Response	How addressed in IRP
CAC	What do you mean by re-running any additional DSM Groupings that may be selected?	If NIPSCO selects the Base Case Scenario and in that scenario, 13 DSM Groupings were selected, NIPSCO may decide to add three additional DSM Groupings that were selected in other scenarios. NIPSCO would then include the 16 DSM Groupings and re-run them as a set in the model. This will show what the cost variance is of adding those three DSM Groupings to the original selection. This could provide an additional option for NIPSCO to select when putting together its Section 10 Plan.	N/A
IURC	Does DSMore analysis produce hourly loads in EEI format? If yes, does strategist use hourly load data in EEI format? If so, what does the Excel-macro model do?	Morgan Marketing Partners provides NIPSCO with the data in Excel, which is converted in the same manner as EEI format to weekly data. The Excel macro-model converts the 8760 hourly data into weekly data. Because others have indicated that using the 8760 hourly data is valuable, NIPSCO is working to update to a model in future IRPs that will have the capability to do that.	N/A for this IRP, but NIPSCO hopes to have that capacity in its next IRP filing.
CAC	Why didn't NIPSCO consider the opt out customers when it was preparing the MPS?	The General Assembly required utilities to allow large customers to opt out of participation in DSM programs and a number of NIPSCO's customers did opt out of its programs. For the 20 year planning horizon, NIPSCO wanted to look at what we know is happening right now for customers who are still participating in the programs. As discussed above, when planning for demand side resources, NIPSCO wanted to plan for the resources it had available through its own programs. This meant studying the customers that are participating in the programs.	N/A

Organization	Question	Response	How addressed in IRP
	Why did NIPSCO use the TRC test as a screen?	Both NIPSCO as well as its vendors utilize all of the benefit cost tests as part of the analysis as to whether or not to offer a program. These include the Participant (PAC), Total Resource Cost (TRC), Ratepayer Impact Measure (RIM) and Utility Cost (UCT) tests. Traditionally, in Indiana, more weight has been placed on the TRC test, which is why NIPSCO continues to use it as its litmus test as to whether or not to offer a program or include a measure.	N/A
CAC	With the RFPs, are they going to be required to meet what the EE goals are that come out of the IRP? The language in the statute contemplates reasonably achievable in addition to being consistent with the IRP? How is that going to mesh up?	NIPSCO has an Oversight Board ("OSB") made up of the Office of Utility Consumer Counselor, Citizens Action Coalition of Indiana and Industrial Group. NIPSCO will work with the OSB to determine the next steps related to the Section 10 filing, including what requests for proposals to offer and when. The language in the statute of "reasonably achievable" does add another layer to the discussion and is something that NIPSCO and the OSB will need to consider when putting together the RFPs and filing. Our intention is to make sure that it is consistent with our IRP and provide a good balance of resources.	N/A
CAC	How do you see the DSM plan coordinating with the amount of gas savings?	NIPSCO always works to provide joint programs as much as possible. Generally, the electric plan is established first and then the gas program follows. With gas prices where they are right now, it makes it difficult to offer cost-effective programs, but NIPSCO is committed to offering some level of gas energy efficiency programs, typically around the same level year-over-year.	N/A
OUCC	What does NIPSCO do when the response from the RFP process does not produce the savings amount selected by the IRP?	While that has not been an issue, if it were to occur, the OSB would need to discuss it.	N/A

Organization	Question	Response	How addressed in IRP
IURC	Since T&D may be location specific and, to the extent DSM affects on T&D may be used to reduce congestion, how does the model calculate the value of DSM?	While there are ways to get very specific distribution costs in isolated areas, NIPSCO is looking to represent what is happening to the system as a whole. As such, the data is collected and used in the modeling for the MPS based on averages across the system.	N/A
Sierra Club	When do lost revenues factor in to cost-benefit analysis? Don't avoided energy costs change over time and how would that be accounted for?	Lost revenues are factored in depending on the test (both the RIM and PCT include lost revenues as an input).	N/A
Sierra Club	Why shouldn't all customers contribute to energy efficiency programs since benefits accrue to all?	Customers who have opted out of such programs would likely argued that they are already spending money on energy efficiency without an incentive from the utility and there is no reason why they should subsidize the competition. State law has provided customers with the opportunity for eligible customers to opt out of participation in programs and NIPSCO will continue to provide that opportunity.	N/A

Organization	Question	Response	How addressed in IRP
Sierra	The Effluent Limitation Guidelines (ELG) would be rolling into National Pollutant Discharge Elimination System (NPDES) permits when they expire? Bailly expires in 2017 – what are the other 2?	Yes, that is correct. Bailly is the first and the other two are Schahfer in 2020 and Michigan City.	Considered already.
	The estimate (for compliance with environmental rules) does not include any estimates for Clean Power Plan costs. Those would be in addition to the estimates?	That is correct. NIPSCO did assume power price and optimization of the supply portfolio.	N/A
OUCC	Would you meet the structural integrity requirements of the ELG?	For purposes of the IRP, assuming NIPSCO will need to do some work on the impoundments, the requirements would be met. The assumption is that NIPSCO will close the cycle transport of water systems, but that can change. At this point, the Company is being conservative by assuming we will need to go to dry systems.	N/A
Mittal	On the slide for Sugar Creek maintenance, do you consider that to be indicative of all combined cycle turbines (CCTs)?	Yes, the Sugar Creek maintenance number is indicative of the cost for maintenance of other CCTs.	N/A

Organization	Question	Response	How addressed in IRP
SUFG	Are the environmental costs (slide 15) above the capital costs (slide 13)?	Yes, the environmental costs are incremental to the capital costs.	N/A
IG	With respect to the cost analysis that you are doing, you're taking into account the alternative fixed costs – capital and projected rate of return. Can you go a little more into what you are using for the estimation of those capital costs and rate of return – the cost of the alternative? What ranges was NIPSCO using on its return on investment, cost of capital, as part of fixed costs. What are you using as projected rate of return, what do you envision for capital structure, cost of debt?	The cost to keep is estimated at a high level. This included making assumptions about ongoing fixed costs, variable costs such as fuel and chemical costs and costs associated with environmental compliance.	N/A

Organization	Question	Response	How addressed in IRP
Praxair	Have you ever looked back at prior IRP efforts – pointing to Michigan City 12 and Schafer 14 and 15 – you spent like $800 Million and now you're starting to talk about retiring them –this is a good illustration of how difficult this process is.	It is exactly right that the process is very difficult. The Company is making, in some cases, 40 and 60 year decisions based on today's forecasts. To compensate for this, NIPSCO is considering buy, build and purchase (for shorter-term opportunities) options.	N/A
Indiana DG	I'm getting confused, I downloaded the slides this morning – but that page is different than the hand out – at what point will the hand out be posted? Could you mark any new versions with a date or time? Also, there are some slides that are marked preliminary. I'm trying to understand the notations.	NIPSCO elected to withhold several slides until after discussions were held with NIPSCO employees on the potential retirements. Those discussions were held the morning of the meeting (August 23, 2016). An updated presentation was subsequently posted to www.nipsco.com/irp. Some slides still contain the preliminary stamp because NIPSCO is still running the numbers internally. Although the analysis is getting closer to being finalized, the Company expects to make adjustments based on stakeholder feedback and there will also be updated estimated related to Coal Combustion Residuals (CCR) and ELG. Because these are not final numbers, the deck is marked as such.	N/A

Organization	Question	Response	How addressed in IRP
Praxair	Did you look at stranded costs that will result from closing plants?	Yes, the potential for stranded costs for closing plants was considered as part of the process. The stranded costs would include the costs of the flue gas desulphurization (FGD) units.	N/A
BP	Just to qualify the methodology-you made an assumption that NIPSCO will recover those stranded costs and customers will pay for those-is that correct?	Yes, the recovery of the stranded costs from customers for closing plants was considered as part of the process.	N/A
SUFG	What is the timeframe of the retirement analysis?	As with the rest of the IRP, NIPSCO used a 20 year time period, 2016-2037.	N/A
Sierra	On slide 24, having read the footnote, I would just point out that these numbers don't equal NIPSCO's total emissions.	That is correct. This slide is used to show the emissions covered by the ELG rule and the impact retirements could have on meeting the compliance targets. The slide is meant to demonstrate that replacement emissions from any source other than renewables (i.e. a new CCGT or a purchase power agreement) would not count toward NIPSCO's compliance. It is not meant to demonstrate NIPSCO's total current or future emissions based on potential retirements.	N/A
Praxair	On slide 23, did you do any sort of review of scenarios on the impact on customer rates?	Given how the model is run, NIPSCO did not do anything beyond the revenue requirement calculation. The net present value revenue requirement (NPVRR) provides the cost to customers over the 20 year period, but NIPSCO did not break the costs down to the individual rate analysis at this time.	N/A

Organization	Question	Response	How addressed in IRP
Praxair	What coal and natural gas cases are we looking at? High costs or differentiated-customer rates start to mean something when you have coal in your fleet.	While it is not in the deck, you do start to see the rough ordering of the scenarios. The answer comes out similar, if not exactly the same, across each of the scenarios. That answer is that retiring more coal makes sense in most if not all cases going forward, but you might see a switch between some of the retirement combinations. NIPSCO is happy to address this more fully either in a 1:1 meeting or at the September 12 webinar.	N/A
OUCC	Did you say what the potential CPP target was for 2023 or 2030?	The range provided is NIPSCO's expected range for 2030. NIPSCO's model has steps to get to this range by 2030. To get to this range, NIPSCO selected the lowest potential range by 2023 in order to be compliant. While there are intermediate step-downs, they are difficult to illustrate on this chart without complicating the picture~~s~~, that is why the end date of 2030 was selected.	N/A
NIPSCO Union Rep.	In your modeling of CPP and the possibility of getting rid of 100% by 2023, in modeling have you run the infrastructure? My understanding is that we don't have the piping volume to handle the gas without coal.	While this is a real and apparent risk on the national level, NIPSCO happens to be in an advantageous position. There are 7 major pipelines coming through its service territory. So from gas supply, there is an opportunity there. However, that does not mean NIPSCO is recommending to go with a CCGT. The Company will look at all available options and evaluate.	N/A

Organization	Question	Response	How addressed in IRP
BP	Please clarify the CPP targets. Can you take credits for retiring a coal unit against replacing it with an existing CCT unit? The entity operating the emissions source gets credit for it.	The policy is not settled yet. NIPSCO views the EPA as approaching 111(d) for existing sources and 111(b) for new sources. So in this analysis, the retirements provides benefits under 111(d). Any construction would need to meet the New Source Performance Standards, which are regulated differently and are not helpful with meeting the cap. As NIPSCO finalizes its strategy, it will continue to monitor federal rules and regulations to ensure continued compliance.	N/A
BP	So if you retire a coal plant – enter into a PPA (purchase power agreement) with existing CCGT – can you take the benefit of the treatment against the cap?	No, as the CCGT is still an emissions source. Under the PPA, the other party, rather than NIPSCO as the purchaser, would accrue any benefit from a carbon perspective. On the other hand, it would be the seller, rather than NIPSCO, who would need to comply with the 111(d) regulations.	N/A
Sierra	If the retirement plan performs below the CPP limits, have you assumed any carbon trading within the system?	NIPSCO has not assumed any carbon trading at this time.	N/A
Indiana DG	What percentage of renewables is represented?	At this point, it is single digits. The pie chart on slide 8 shows 0%. NIPSCO has wind contracts for 100 MW today. In addition, participants in the Feed-In Tariff provide another 30+ MW of renewable energy currently. Only about 15% of wind counts toward MISO capacity. NIPSCO also has to two hydroelectric facilities with 10 MW of net demonstrated capacity.	N/A

Organization	Question	Response	How addressed in IRP
Sierra	I appreciates that the analysis was done in this way. This organization (Sierra Club) would like to encourage utilities to let the market fill unmet needs rather than dictating any specific technology when preparing request for proposals (RFPs). This might encourage clean energy, given the rapid changes in technology today.	NIPSCO appreciates the compliment. The Company views the market as changing and approached this IRP through that lens. Given NIPSCO's unique customer base and the rapid changes in technology, regulations and market prices for natural gas, it was important to take a step back and assess the entire fleet.	N/A
Praxair	Just to clarify – these scenarios include an assumption that CCGT is the replacement technology.	Yes that is a fair clarification. However, it is important to note that these scenarios assume CCGT as a proxy that assumes the MW needed would be filled with a CCGT. If NIPSCO only needed 2 MW, the Company would not build a CCGT to fill that. However, the model used a CCGT for ease of comparison only. NIPSCO is absolutely not tied to CCGT or natural gas going forward. The plan is to have a complete look at the various options once the needs are known.	N/A
Praxair	Is it correct that the cost to customers is based on the CCGT proxy assumption?	That is correct. At this time, and for ease of comparison, NIPSCO used the cost of a CCGT. Again, that does not mean NIPSCO would only use a CCGT for any needed capacity; only that it was what was used for the modeling.	N/A

Organization	Question	Response	How addressed in IRP
CAC	This analysis seems to imply that only coal creates jobs and investment in communities.	That was not the intended implication. However, there are certain realities that come from a coal plan. For example, from an employee standpoint, it takes 530 employees to run NIPSCO's three coal-based facilities. For comparison, Bailly is a 511 MW facility with 110 employees and Sugar Creek is a 535 MW facility with 19 employees. Similarly, solar and wind facilities only have a very small maintenance staff. This analysis is not looking at the construction of new facilities, but at the long-term employment of NIPSCO employees. Transitioning to a different technology or purchasing capacity through a PPA impacts NIPSCO employees, which was the purpose of this particular analysis. Whatever generation replaces coal going forward, there will likely be fewer employees. In addition to the impact on NIPSCO's employees, which impacts their communities as well, there are other economic impacts, particularly related to property taxes. For example, the amount of property tax from NIPSCO in Jasper County is significant. NIPSCO did not make any assumptions going forward related to where any new generation would be located. The model simply removed the property taxes from Jasper County.	N/A
Mittal	The cost is basically the cost of retirement – not replacement, right?	It is a cost of a replacement and the replacement is the cost of a CCGT.	N/A

Organization	Question	Response	How addressed in IRP
Praxair	For environmental compliance, are you suggesting that there's an environmental compliance quality difference between the scenarios, rather than that you won't be compliant?	First, it is important to know that NIPSCO will be compliant in any case. The lower coal retirement scenarios are not as viable in future. There are number of forces: costs, portfolio, employees, environmental, communities to be considered in this decision. As such, a decision has not been made regarding the retirements. NIPSCO wants to have additional conversations around these scenarios and the questions raised by them. At this point, the analysis shows NIPSCO should retire Bailly 7 and 8 in May of 2018 and Schafer 17 and 18 by 2023. This is because it gets back to not spending money to comply with environmental regulations going forward. However, the process is subject to additional feedback from stakeholders and the MISO Attachment Y process. The decision will not be finalized until the submission of the IRP. As mentioned several times, NIPSCO looks to have 1:1 meetings with stakeholders for further discussions.	N/A
IG	How does this retirement plan compare to what was discussed in the 44688 Rate Case with respect to these plants and the depreciation schedules?	The Settlement Agreement as approved by the Commission in Cause No. 44688 did not accelerate the depreciation on Unit 8 at Bailly. The rate case included the retire 20% coal and the deprecation study was based on that.	N/A

Organization	Question	Response	How addressed in IRP
IG	How was the long term Indiana Hub MISO Wholesale Electric Energy price forecasts developed and did they include any assumptions regarding the CPP such as enforcing the Mass Cap and re-dispatching the system to meet compliance?	NIPSCO works with PIRA, which uses proprietary models; they did not include caps but used a CO_2 proxy price.	N/A
Mittal	The capacity price forecast chart appears to be counter-intuitive. Can you explain?	In a high pricing environment (in the future), there is incentive for more capacity additions, which will consequently lead to the market being adequately supplied and hence cause capacity prices to plateau or even decline. Please note: these results are from proprietary models. NIPSCO can follow up 1-on-1.	N/A

Organization	Question	Response	How addressed in IRP
IG	Did NIPSCO update its method to develop the typical week loads used in the Strategist model? The typical week loads presented in the Appendix (pages 23-36) to the 2014 IRP had each month's peak demand equal to the annual system coincident peak and a resulting annual energy in the neighborhood of 22 million MWh when scaled back to 8760 hours per year from the typical weeks. On its face this seems to be erroneous and so if this is intentional, I would like to understand this better if the same methods are being used in the current IRP. If the method has changed, can you explain what the new assumptions are?	The load forecast input is converted to the typical week format for the model; therefore, commodity prices need to be done in the same way so there is an appropriate comparison. NIPSCO can provide more information outside of the meeting. Details regarding the typical week conversion for the model was provided here and will also be provided in future meetings and in the IRP.	N/A
CAC	Did NIPSCO benchmark the PIRA forecasts through other sources?	Yes, on the load side, NIPSCO performs historical variance analysis to assess the forecast. For gas prices, these fluctuate greatly from week to week, so the approach is to use a range that incorporates most reasonable possibilities. PIRA has a good reputation in the industry.	N/A

Organization	Question	Response	How addressed in IRP
CAC	Has NIPSCO altered any of the DSM groupings and EE bundles since the last meeting? The concern is that these bundles may be too large and tend to compete against each other. Some stakeholders have been suggesting making smaller bundles, similar to what Indianapolis Power and Light is doing based on costs of programs.	Although not grouped by cost, the buckets do vary in size. The size of the buckets vary by implementation costs, but the avoided costs will not be different because of those groupings. It is simply the cost for the measure or the program to acquire the savings. To NIPSCO, this made the most sense for a) modeling in the IRP and b) developing the Section 10 Plan based on the IRP. It provides a mechanism to determine what programs to offer and to put together a request for proposal to vendors to offer to those programs. NIPSCO will continue to monitor Commission recommendations on this issue for future IRP development. NIPSCO may elect to break down by costs for future market potential studies/IRPs.	N/A
CAC	Regarding the screens (benefit cost tests) that were described at the last meeting, is NIPSCO continuing to use the program screen?	Yes, because you either screen components out during the analysis, or they will get screened out during the DSM analysis. This way NIPSCO can keep the DSM plan consistent with the IRP.	N/A
Indiana DG	For the solar photovoltaic data shown on this chart on Slide 45, does this mean a maximum of 10 kW can be built? This seems to be a very large gap between 50 MW of utility scale solar and 10 kW for residential, and this doesn't seem reasonable?	No, each "bucket" would be 10 kW, but there can be many buckets selected by the model. If stakeholders have data on costs for other size units, NIPSCO can look at those.	N/A

Organization	Question	Response	How addressed in IRP
	So then why only looking at one option for distributed solar – 10 KW is a blip – DG is anything up to certainly 1 MW is the cap for net metering. I think there is an awful lot of gap between utility scale of 50 MW and 10 KW is very small.	These are fairly typical residential installation packages. NIPSCO elected to use the typical system rather than the top of the range. If there is additional information regarding the typical system, NIPSCO would gladly consider it.	N/A
Sierra	So the previous slide – solar over time – wind – a single cost – no reference to time – Did you assume these costs would go up or down in planning period.	The dollars are nominal as of today and are escalated for all of these technologies (Slide 46). We assume all are going up. One of the feedback from previous IRP was the need for more information in the public report. As an aside, NIPSCO received feedback in its previous report that too much of its data was marked confidential. As such, the Company attempted to find a balance a public version of data. For this slide, we used an engineering study. NIPSCO is more than happy to share the confidential analyses that were performed on a high level with those who have a non-disclosure agreement.	N/A
Sierra	The integrated gasification combined cycle (IGCC) capital investment cost of $1,100/kW is not even close to the actual cost of units built. Where did these costs come from?	These data were checked during the meeting and found to be in error. The correct cost should be approximately $7,800/kW. PLEASE NOTE: Slide 49 has been updated to reflect correct costs for total capital investment. These are nominal dollars.	N/A

Organization	Question	Response	How addressed in IRP
OUCC	With the IGCC and some of these coal costs – are you including the price of CO2 capture – with any rules that are on the books now – are they considered – to build any new – would need to meet what is today. This isn't based on any other costs seen around the nation?	The costs were provided by Sargent & Lundy, so would likely be based on costs throughout the country.	N/A
IG	So just to make sure, if the Strategist loads were developed the same way as they were in the 2014 IRP which seemed to overstate NIPSCO's Annual Energy requirement by 4 Million MWh, and this was carried through into the 2016 IRP which as stated earlier, might be the case, this would then in turn overestimate projected operational savings from replacing say coal units with CCGT proxys when the variance costs are of the proxy is cheaper than the retired coal.	The 5 load curves: base, low, high, base with no major industrial and low with no major industrial. This allows NIPSCO to model various load requirements and forecast the energy requirements and the peak load for the various load forecasts.	N/A
Sierra	Does the low emissions case use total CO_2 from all plants?	Yes, the emissions are cumulative for the entire portfolio.	N/A

Organization	Question	Response	How addressed in IRP
	What is the difference between renewable and low emission? They seem to be similar.	Yes, they can be similar but the low emissions category could include other technologies such as nuclear, which are not renewables.	N/A
	Can more than one resource expansion element be selected in the same year?	Yes.	N/A
CAC	Looking at Slide 52 – under Column 1 2016 – DSM1 – Could multiple resources be selected – could it be DSM1 and wind?	Yes.	N/A
CAC	Assuming that the referenced 533 MW of DSM is the industrial tariff from the rate case – why is that shown under DSM?	For purposes of the IRP, demand side management includes all demand side resources, not just energy efficiency. Therefore, demand response is included.	N/A
	So you're saying these figures are not just their tariff but also the DSM – EE plans – incremental that would hit in 2016?	Yes.	N/A
BP	Please clarify if these numbers for purchases are cumulative from year to year?	No, each year is specific and they do not accumulate.	N/A
IG	Did you limit the market capacity purchase in a given year used to meet the peak demand plus planning reserve margin?	Capacity purchases were limited to 500 MW, which for all intents and purposes makes it unlimited.	N/A

Organization	Question	Response	How addressed in IRP
CAC	Why are the DSM numbers not changing in the different portfolios?	The DSM optimization was decided through the market potential study with seven residential groupings, 10 commercial groupings and five industrial groupings for energy efficiency and two groupings each for residential and commercial for demand response. In addition, NIPSCO considered all of the Rider 975 Industrial Interruptible services as demand response for the demand side resources. The demand-side resources then competed with a mixture of gas and renewables. This is why you see a similar selection in the various scenarios.	N/A
	So the DSM optimization was handled prior to the development of these portfolios?	First DSM was optimized because DSM can reduce the need for capacity. Then the remainder of the portfolio is filled out.	N/A
	So for DSM you have 533 MW in 2016. That doesn't carry forward?	Yes, it does carry forward. The way Strategist models the programs, it has measures being added and dropping off based on the life of the measure. Therefore you have a gradual increasing trend.	N/A
	Where is the additional capacity savings for the EE measures in 2016?	You would need to subtract it out of the 533 MW. In 2016, the maximum interruptible is 527.75 MW. The additional 5.25 MW in 2016 is the additional DSM savings for the year. It is important to note that with these options, this is still a base scenario, but you would not expect DSM to change as you go through the other scenarios. For each of the scenarios they will be similar across the strategies.	N/A
CAC	On slide 56 – 2037 – least cost – DSM 14.79 – 2037 renewable focus – DSM 16.91 and low 19.27 – doesn't really match that higher slide.	It relates to the overall amount of resources that are available. The numerator did not change but the denominator did change.	N/A

Organization	Question	Response	How addressed in IRP
IG	Slides 56, 59, 62 each show total emissions well in excess of the CPP target range presented on Slide 24. Can you comment on this?	Strategist was not set up to cap the total amount of CO2 emissions. However, it can put a cap on it, which is the total CO_2 associated with the portfolio. Slide 24 is used to show the emissions covered by the ELG rule and the impact retirements could have on meeting the compliance targets. The graphs on slides 56, 59 and 62 (and 65 and 68) provide the total CO_2 (in tons) over the 20 years for three portfolios under each of the five scenarios. These slides are meant to show carbon in two different ways.	N/A
Indiana DG	How is there only 1% solar in the 2037 renewable focus portfolio?	The model is selecting on pricing alone in this scenario. NIPSCO makes each of the demand- and supply-side resources available for the model to select at the cost of those resources and the model does that. In this case, the model selected 0.5% solar.	N/A
	(The model selecting) .5% CHP (combined heat and power) seems bizarre.	Much of that is based on the capacity factor assigned to CHP by MISO. If nameplate capacity were used, the amount would be higher, but that would not be an accurate number to use within the model.	N/A
IG	I missed the footnote. But could you also expand on Adam’s statement that the mass cap wasn’t enforced . . . were the outputs checked to ensure compliance based on pricing penalty in the dispatch.	These are preliminary. We haven’t gone back to see what the CO2 – see how far away we are from CPP compliance.	N/A

Organization	Question	Response	How addressed in IRP
David Baker	The ability to purchase from the market is limited to purchases until 2022; why is that? Is this a NIPSCO-imposed policy constraint and not a model constraint?	Yes, the constraint is imposed by NIPSCO because the Company is treating purchases as a proxy, and NIPSCO decided not to do market purchases in the long term. It does not make sense to buy more than 150 MW, so we assume that something would be built instead of purchased at that level. However, NIPSCO may not build new facilities itself but could purchase that capacity from another company that builds the facilities. The constraint could be removed and the model could be allowed to continue making market purchases, but the results are likely to be similar.	N/A
Sierra	I don't see anything that NIPSCO incorporated the incentives for clean energy for 2020 and 2021 into what the model would select. Are you aware? Would you look into that?	While NIPSCO did not look into that, the Company would be happy to with additional guidance.	N/A
BP	Why was the ability to purchase only limited up through 2022? So maybe you knew that you were going to build in 2023, is that why?	This limitation through 2022 was due to the MISO capacity construct. NIPSCO treated the purchases more as a proxy. NIPSCO decided it would probably not be able to purchase in the long term so decided not to do so past 2022. The least cost option looks like it will purchase if you leave it unconstrained. Building something such as a CCGT or another technology is going to be in big, chunky sizes. Past 2023 NIPSCO has a larger gap to fill and building something makes more sense. However, again, it is important to note that just because NIPSCO used building a CCGT in the model, a decision has not been made at the final outcome.	N/A

Organization	Question	Response	How addressed in IRP
	On Slide 55 - showing 2022 – we only need 200 from purchase from the market but we're going to build 2 CTs?	With Schafer 17 and 18 being retired NIPSCO would stop doing purchases and would need to build something, although not something that NIPSCO would necessarily build or own itself. On an economic basis, the model is selecting to build in 2023. Ultimately, the model is assisting with technology choices, but not whether it is a contractual or ownership choice. The model is telling us either through purchase or contract, CCGTs appear to be the cheapest selection in 2022, but not really directing if NIPSCO builds or contracts for that capacity.	N/A
	The extent that is driven by economics – or did we impose it as a boundary condition?	NIPSCO needed to steer the model because the model would choose to build rather than make market purchases. What the Company did was to allow it to do market purchases– so that it would not build to fill a small gap. However, once the gap was large enough, the boundary condition was removed, which allowed the model to select build.	N/A
IG	I would be interested in seeing an all market scenario as a point of comparison.	NIPSCO can provide such a scenario.	N/A
Sierra	Please clarify that all these model runs include the 50% coal retirement assumption, and there is no provision for retiring more than 50% coal.	NIPSCO used the 50% coal retirement assumption for its model runs, but is open to other options based on conversations with stakeholders. Constraints are clearly being placed on the model because, if not, the lowest costs would always select the 100% retirement option.	N/A

Organization	Question	Response	How addressed in IRP
	You aren't modeling industrial EE in these models, correct? Industry initiatives for energy efficiency still are occurring by companies. I don't see how this is reflected in the models here. How are you reflecting it in the load forecast?	That is correct. Demand-side resources only include Company-sponsored programs and customers who participate in those programs. Industrial EE initiatives completed by customers without incentives from NIPSCO are not specifically included but are reflected in decreased sales from NIPSCO. Reference Amy Efland's presentation on load forecasting from the first stakeholder meeting.	N/A

Meeting 5 Participants

Marathon Petroleum Company LP

NIPSCO Industrial Group

Citizens Action Coalition of Indiana, Inc.

Carmeuse Lime, Inc.

Indiana Distributed Energy Alliance

United States Steel Corporation

Primary Energy Recycling Corporation

Vectren Corp.

Energy Ventures Analysis, Inc.

Indiana Utility Regulatory Commission

Indiana Office of Utility Consumer Counselor

2016 IRP Public Advisory Meeting

October 03, 2016

NIPSCO

Agenda

Schedule	Agenda Item
9:00 – 9:15	Welcome and Introductions
9:15 – 9:30	Public Advisory Process and Review of Prior Meetings
9:30 – 10:30	Stakeholder Model Runs
10:30 –10:45	Break
10:45 –noon	Optimization Results
noon –12:45	Lunch
12:45 –1:45	Preferred Resource Plan & Short Term Action Plan
1:45–2:15	Stakeholder Presentations
2:15–2:30	Public Advisory Feedback and Next Steps

NIPSCO

Welcome and Introductions

Presented by

Frank Shambo

Senior Vice President, Regulatory and Legislative Affairs

NIPSCO

IRP Stakeholder Process & Timeline

Presented by
Timothy Caister
Vice President, Regulatory Policy

NIPSCO

Stakeholder Interactions

- Since the 1st , 2nd , 3rd & 4th Public Advisory Meetings on May 5th , July 12th, August 23rd, & September 12th, respectively, NIPSCO has met with stakeholder groups

- 1st , 2nd , 3rd & 4th Stakeholder Meetings Materials
  - Presentation materials and summary meeting notes are posted on NIPSCO's IRP webpage: www.NIPSCO.com/irp

IRP Public Stakeholder Process and Timeline

	May 5th	July 12th	August 23rd	September 12th	October 3rd
Key Questions	- What process will NIPSCO use for its IRP? - What are the key assumptions driving the scenarios and sensitivities?	- How will NIPSCO incorporate Demand Side Management Resources in the IRP?	- Deep dive into NIPSCO's existing generation - What are the optimal replacement options to fill the supply gap?	- Where are the stakeholders focused? - What is NIPSCO's preferred retirement plan?	- What is NIPSCO's Preferred Plan?
Agenda/ Content	- Overview of process - NIPSCO overview - Load forecasting - Demand side management - Environmental considerations - IRP development - Public advisory process	- Review Market Potential Study - Describe and Review Demand Side Management measure groupings - Introduce Demand Side Management Modeling Methodology	- Overview of existing generation by unit (costs, environmental, etc.) - Retirement analysis - Outline preferred retirement direction and describe resulting capacity gap through time - Replacement options (supply-side and demand-side)	- Discuss retirement paths and address related stakeholder feedback - Address input from prior stakeholder and subsequent 1:1 meetings - Share any initial analysis from 1:1 stakeholder meetings	- Share results from 1:1 stakeholder analytical requests - Overview of Optimization results - Describe Preferred Replacement Path and logic relative to alternatives - Explain NIPSCO short term action plan
Key Deliverables	- Key assumptions - Overview of scenarios and sensitivities	- Common understanding of the grouping of DSM measures - Clear picture of NIPSCO's DSM modeling methodology	- Stakeholder feedback and shared understanding of generation alternatives	- NIPSCO's preferred retirement plan - Overview of stakeholder analysis requests	- Review of Stakeholder feedback - NIPSCO's Preferred Plan
Meeting Format	- 6 hour in person session	- 5.5 hours in person session	- 6 hours in person session	- 2 hour Touch point/ Webinar	- 6 hour in person session

NIPSCO

Stakeholder Run Requests

Presented by

Edward Achaab

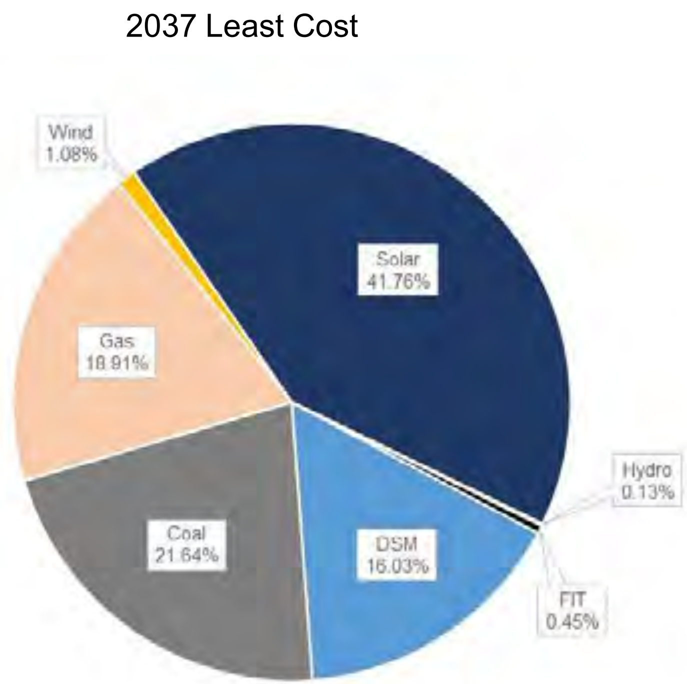
Manager Resource Planning

Sierra Club
All Renewable Case

Base Scenario Portfolio with all Renewables

Base

Resource Mix (Percent of Capacity)



Total CO_2 (tons)= 164,540,864

Total NPVRR($000)= 18,602,160

All Renewable Portfolio				
Expansion Plan (MW)				
Year	Wind	Solar	DSM	Purch
2016	-	-	533	-
2017	-	-	11	-
2018	-	-	15	142
2019	-	-	20	155
2020	-	-	18	174
2021	-	-	21	186
2022	-	-	25	201
2023	-	1,020	29	-
2024	-	-	34	-
2025	-	-	37	-
2026	-	-	40	-
2027	-	-	42	-
2028	-	-	45	-
2029	-	-	48	-
2030	-	128	50	-
2031	-	-	50	-
2032	-	-	52	-
2033	-	-	53	-
2034	-	-	53	-
2035	-	383	51	-
2036	39	-	52	-
2037	-	-	60	-

NIPSCO

Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Sierra Club

100 Percent Coal Retirement Case

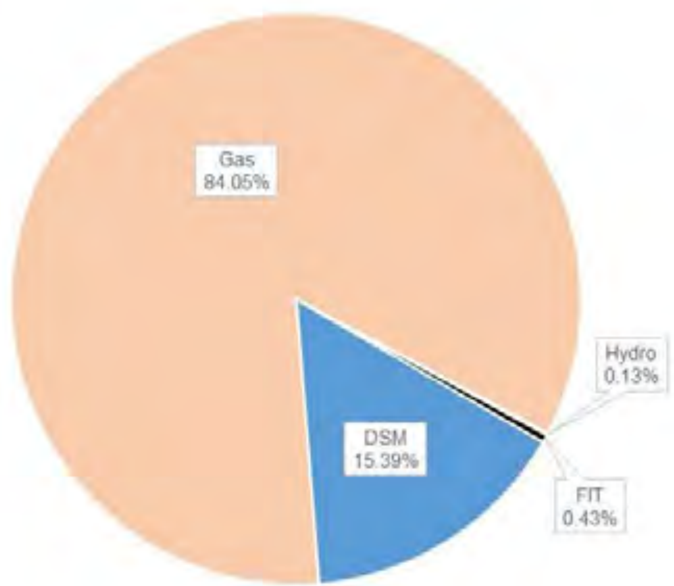
NIPSCO

Base Scenario Portfolio

Base

Resource Mix (Percent of Capacity)

2037 Base Case



Total CO_2 (tons) = 219,044,417

NPVRR($000) = 12,811,594

Least Cost Portfolio			
Expansion Plan (MW)			
Year	Gas	DSM	Purchases
2016	-	533	-
2017	-	11	-
2018	-	15	142
2019	-	20	155
2020	-	18	174
2021	-	21	186
2022	-	25	201
2023	2,516	29	-
2024	-	34	-
2025	-	37	-
2026	-	40	-
2027	-	42	-
2028	-	45	-
2029	-	48	-
2030	-	50	-
2031	-	50	-
2032	-	52	-
2033	-	53	-
2034	-	53	-
2035	-	51	-
2036	-	52	-
2037	-	60	-

NIPSCO

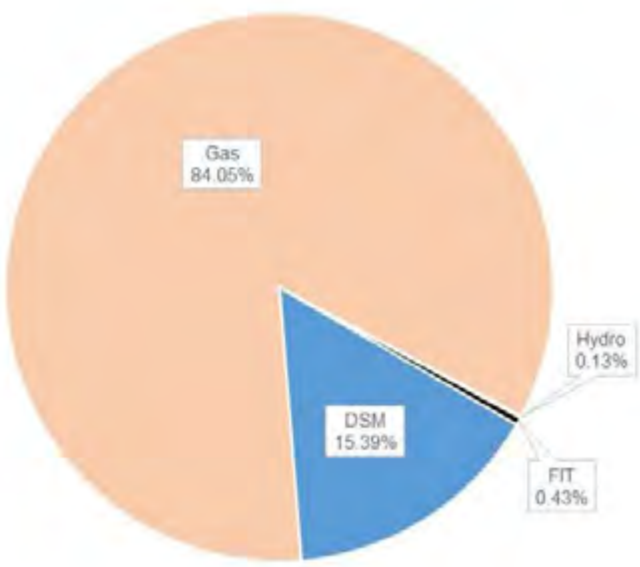
Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Base No CO_2 Scenario Portfolio

Base

Resource Mix (Percent of Capacity)

2037 Base No Carbon



Total CO_2 (tons) = 157,936,253

NPVRR ($000) = 10,605,722

Least Cost Portfolio			
Expansion Plan (MW)			
Year	Gas	DSM	Purchases
2016	-	529	-
2017	-	2	-
2018	-	3	155
2019	-	4	171
2020	-	6	187
2021	-	7	202
2022	-	8	219
2023	2,516	9	-
2024	-	10	-
2025	-	11	-
2026	-	12	-
2027	-	13	-
2028	-	14	-
2029	-	14	-
2030	-	15	-
2031	-	15	-
2032	-	16	-
2033	-	16	-
2034	-	16	-
2035	-	16	-
2036	-	17	-
2037	-	15	-

NIPSCO

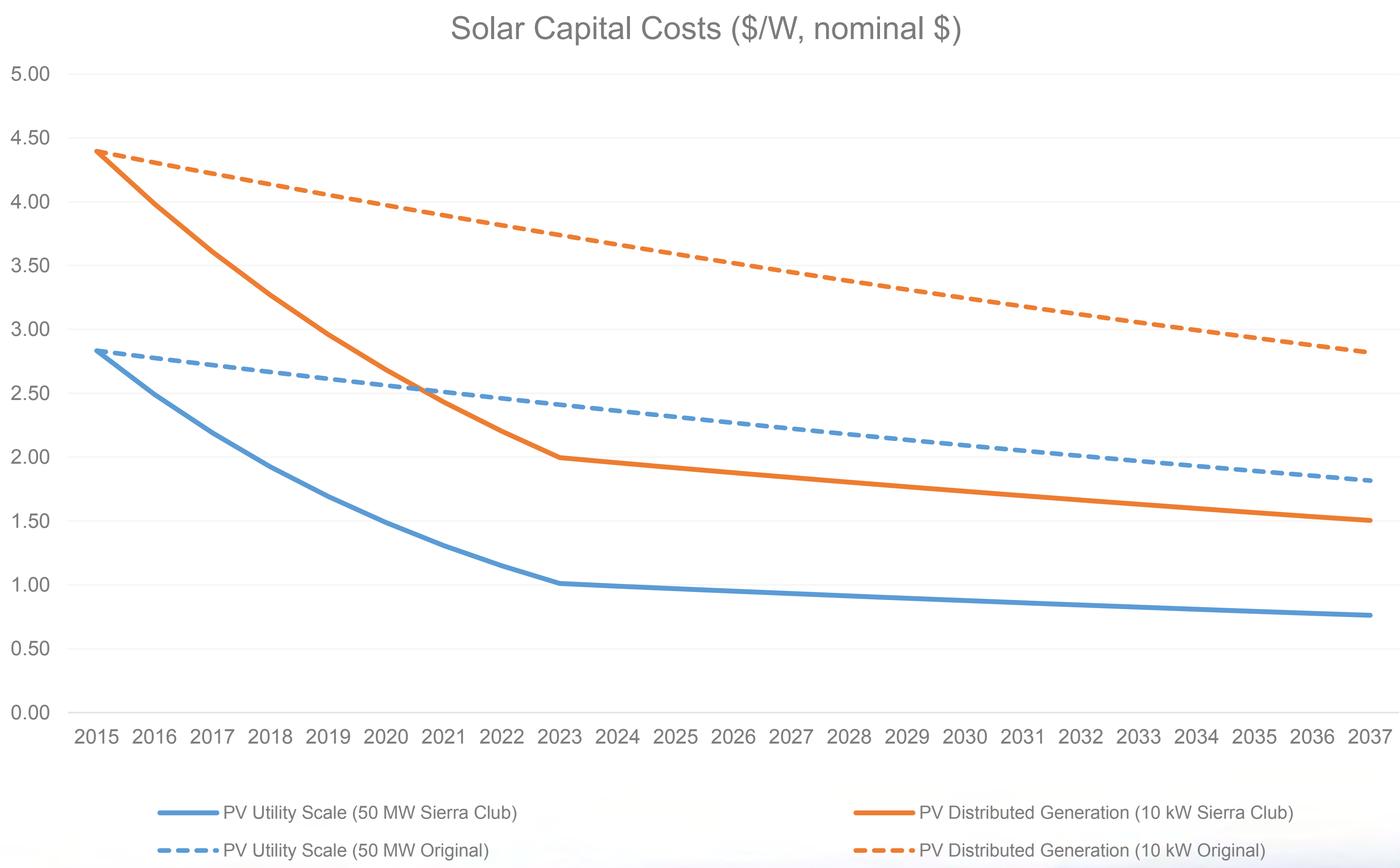
Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Sierra Club

Much Lower Solar Costs

- Utility Scale Solar at $1.00/Watt by 2023
- DG Solar at $2.00/Watt by 2023

Lower Cost Solar Sensitivity



Base Scenario Portfolios with Lower Solar Costs

Base

Least Cost Portfolio			
Expansion Plan (MW)			
Year	Gas	DSM	Purch
2016	-	543	-
2017	-	21	-
2018	-	25	142
2019	-	30	155
2020	-	28	174
2021	-	31	186
2022	-	35	201
2023	1,258	39	-
2024	-	44	-
2025	-	47	-
2026	-	50	-
2027	-	52	-
2028	-	55	-
2029	-	58	-
2030	-	60	-
2031	-	60	-
2032	-	62	-
2033	-	63	-
2034	-	63	-
2035	629	61	-
2036	-	62	-
2037	-	70	-

Renewable Focus Portfolio							
Expansion Plan (MW)							
Year	Gas	Wind	Solar	Batt	CHP	DSM	Purch
2016	-	-	-	-	-	543	-
2017	-	-	-	-	-	21	-
2018	-	-	-	-	-	25	142
2019	-	-	-	-	-	30	155
2020	-	-	-	-	-	28	174
2021	-	-	-	-	-	31	186
2022	-	-	-	-	-	35	201
2023	822	-	89	-	19	39	-
2024	-	-	13	1	-	44	-
2025	-	-	26	-	-	47	-
2026	-	8	-	-	-	50	-
2027	-	8	-	-	-	52	-
2028	-	16	-	-	-	55	-
2029	-	16	-	-	-	58	-
2030	-	16	-	-	-	60	-
2031	-	8	-	-	-	60	-
2032	-	8	-	-	-	62	-
2033	-	16	-	-	-	63	-
2034	-	16	-	-	-	63	-
2035	-	71	383	-	-	61	-
2036	-	8	-	-	-	62	-
2037	-	8	-	-	-	70	-

Low Emission Portfolio									
Expansion Plan (MW)									
Year	Gas	Nuke	Bio	Recip	Wind	Solar	Batt	DSM	Purch
2016	-	-	-	-	-	-	-	543	-
2017	-	-	-	-	-	-	-	21	-
2018	-	-	-	-	-	-	-	25	142
2019	-	-	-	-	-	-	-	30	155
2020	-	-	-	-	-	-	-	28	174
2021	-	-	-	-	-	-	-	31	186
2022	-	-	-	-	-	-	-	35	201
2023	822	-	43	-	-	64	-	39	-
2024	-	-	-	-	-	26	-	44	-
2025	-	-	-	-	-	13	-	47	-
2026	-	-	-	-	-	13	-	50	-
2027	-	-	-	-	-	13	-	52	-
2028	-	-	-	-	8	-	-	55	-
2029	-	-	-	-	16	-	-	58	-
2030	-	-	-	1	8	-	1	60	-
2031	-	-	-	-	16	-	-	60	-
2032	-	-	-	-	8	-	-	62	-
2033	-	-	-	-	16	-	-	63	-
2034	-	488	-	-	-	-	-	63	-
2035	-	-	-	-	-	-	-	61	-
2036	-	-	-	-	-	-	-	62	-
2037	-	-	-	-	-	-	-	70	-

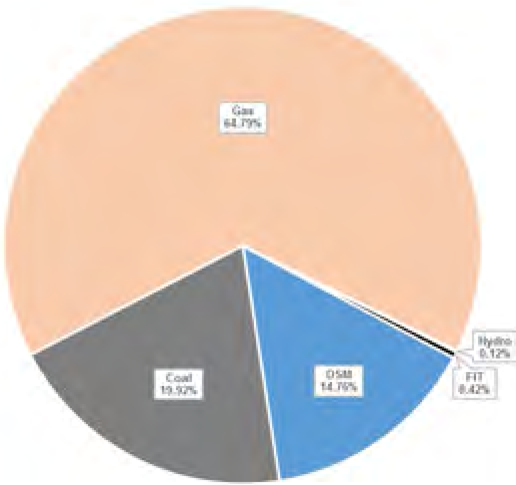
NIPSCO

Base Scenario Portfolios with Lower Solar Cost

Base

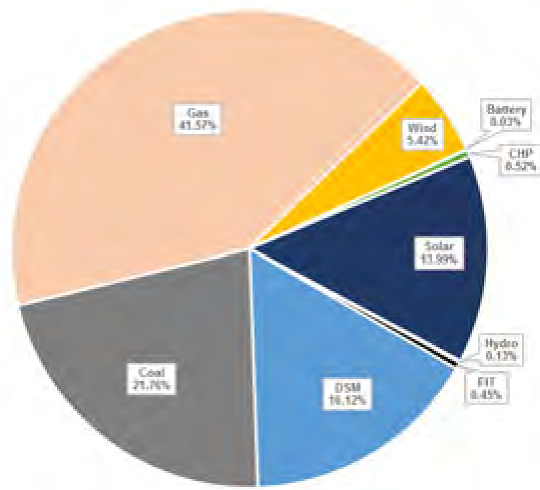
Resource Mix (Percent of Capacity)

2037 Least Cost



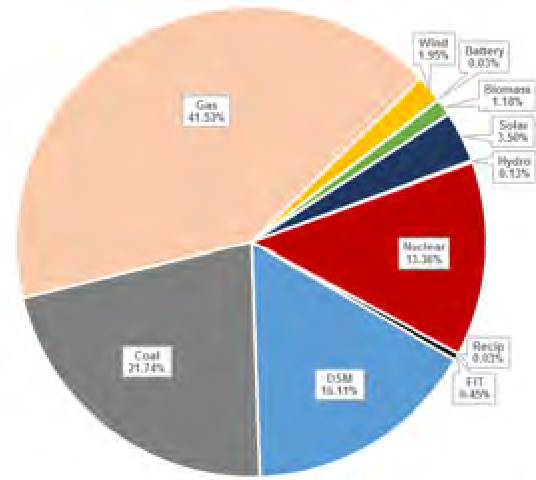
Total CO2 (tons) =224,948,625

2037 Renewable Focus



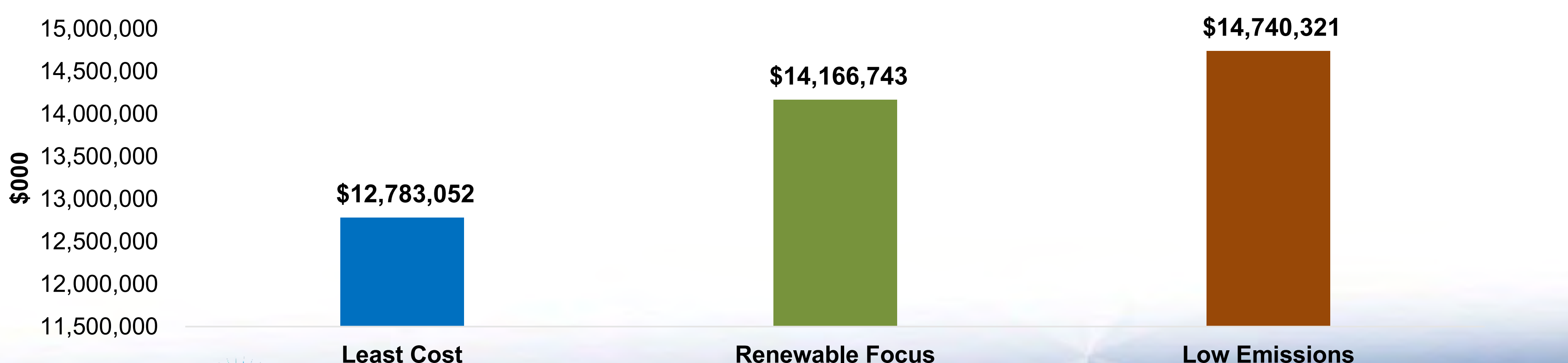
Total CO2 (tons) =197,031,618

2037 Low Emissions



Total CO2 (tons) =197,736,355

Portfolio NPVRR



NIPSCO

Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Clean Line
Lower Cost Wind
– $1700/kW

Base Scenario Portfolios with $1700/kW Wind

Base

Least Cost Portfolio

Expansion Plan (MW)

Year	Gas	DSM	Purch
2016	-	533	-
2017	-	11	-
2018	-	15	142
2019	-	20	155
2020	-	18	174
2021	-	21	186
2022	-	25	201
2023	1,258	29	-
2024	-	34	-
2025	-	37	-
2026	-	40	-
2027	-	42	-
2028	-	45	-
2029	-	48	-
2030	-	50	-
2031	-	50	-
2032	-	52	-
2033	-	53	-
2034	-	53	-
2035	629	51	-
2036	-	52	-
2037	-	60	-

Renewable Focus Portfolio

Expansion Plan (MW)

Year	Gas	Wind	Solar	Batt	CHP	DSM	Purch
2016	-	-	-	-	-	533	-
2017	-	-	-	-	-	11	-
2018	-	-	-	-	-	15	142
2019	-	-	-	-	-	20	155
2020	-	-	-	-	-	18	174
2021	-	-	-	-	-	21	186
2022	-	-	-	-	-	25	201
2023	822	-	89	-	19	29	-
2024	-	-	13	1	-	34	-
2025	-	16	-	-	-	37	-
2026	-	-	13	-	-	40	-
2027	-	-	13	-	-	42	-
2028	-	16	-	-	-	45	-
2029	-	16	-	-	-	48	-
2030	-	16	-	-	-	50	-
2031	-	8	-	-	-	50	-
2032	-	8	-	-	-	52	-
2033	-	16	-	-	-	53	-
2034	-	16	-	-	-	53	-
2035	-	71	383	-	-	51	-
2036	-	8	-	-	-	52	-
2037	-	8	-	-	-	60	-

Low Emission Portfolio

Expansion Plan (MW)

Year	Gas	Nuke	Bio	Recip	Wind	Solar	Batt	DSM	Purch
2016	-	-	-	-	-	-	-	533	-
2017	-	-	-	-	-	-	-	11	-
2018	-	-	-	-	-	-	-	15	142
2019	-	-	-	-	-	-	-	20	155
2020	-	-	-	-	-	-	-	18	174
2021	-	-	-	-	-	-	-	21	186
2022	-	-	-	-	-	-	-	25	201
2023	822	-	43	-	-	64	-	29	-
2024	-	-	-	-	16	-	-	34	-
2025	-	-	-	1	-	13	1	37	-
2026	-	-	-	-	-	13	-	40	-
2027	-	-	-	-	-	13	-	42	-
2028	-	-	-	-	16	-	-	45	-
2029	-	-	-	-	16	-	-	48	-
2030	-	-	-	-	-	13	-	50	-
2031	-	-	-	-	8	-	-	50	-
2032	-	-	-	-	-	13	-	52	-
2033	-	-	-	-	16	-	-	53	-
2034	-	488	-	-	-	-	-	53	-
2035	-	-	-	-	-	-	-	51	-
2036	-	-	-	-	-	-	-	52	-
2037	-	-	-	-	-	-	-	60	-

Base Scenario Portfolios with $1700/kW Wind

Preliminary

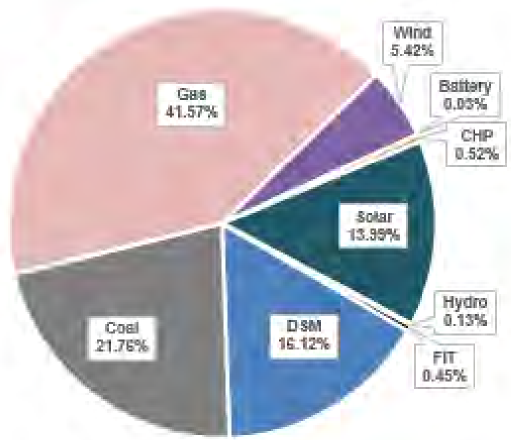
Base

Resource Mix (Percent of Capacity)

2037 Least Cost

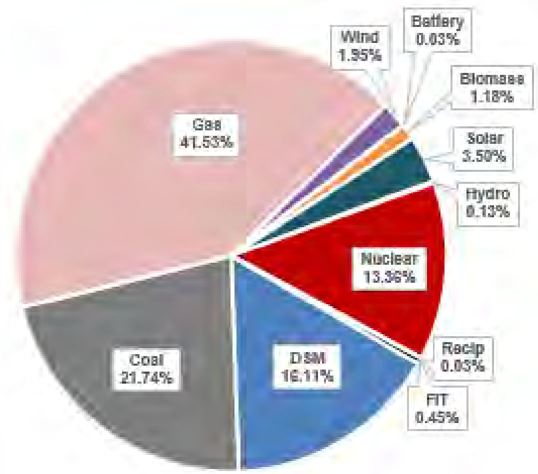
Total CO_2 (tons) =224,948,625

2037 Renewable Focus



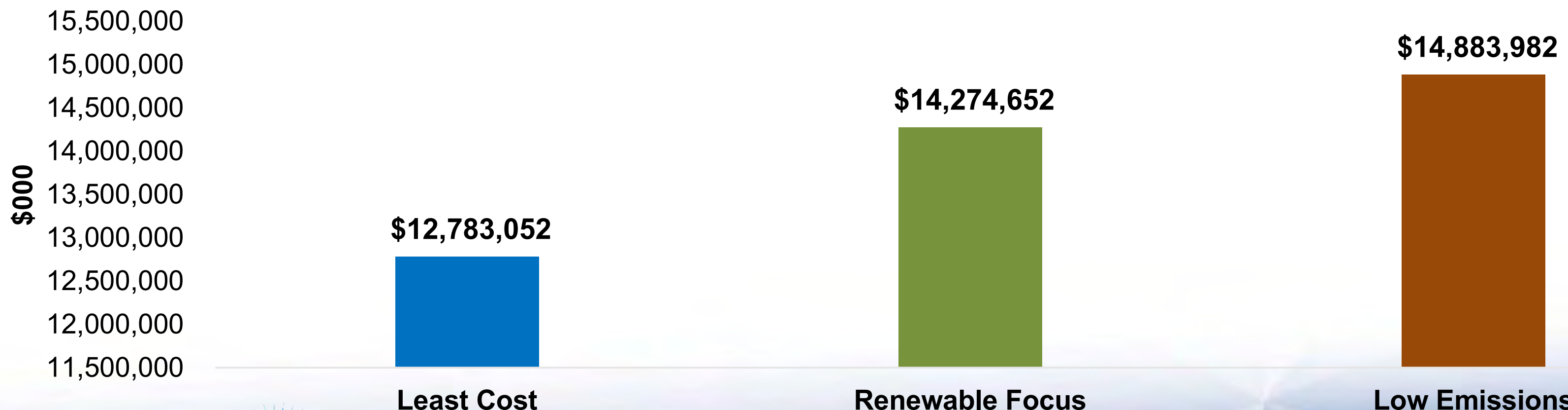
Total CO_2 (tons) =197,737,001

2037 Low Emissions



Total CO_2 (tons) =197,053,034

Portfolio NPVRR



NIPSCO

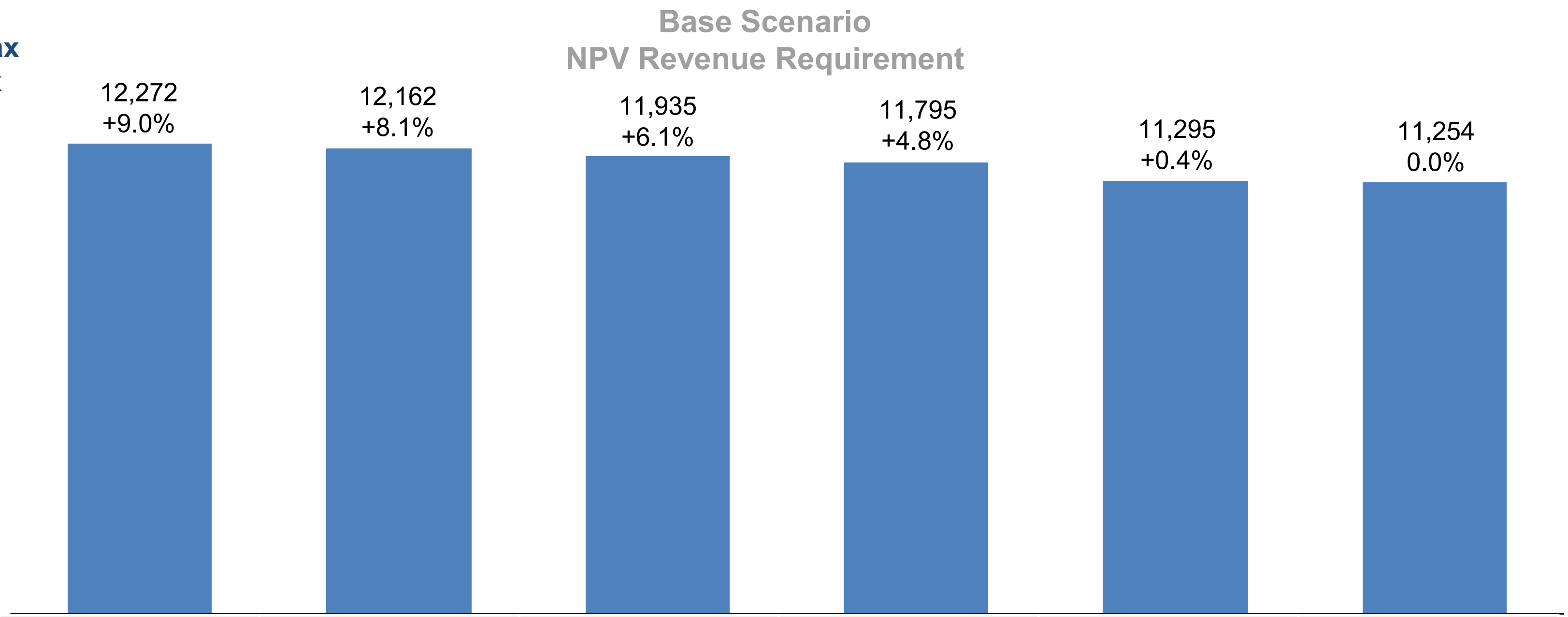
Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

OUCC

Cost To Customer Impacts Of Retirement Portfolios

Post Strategist Adjustments:

- **Property Tax**
- **Income Tax**
- **Return On**



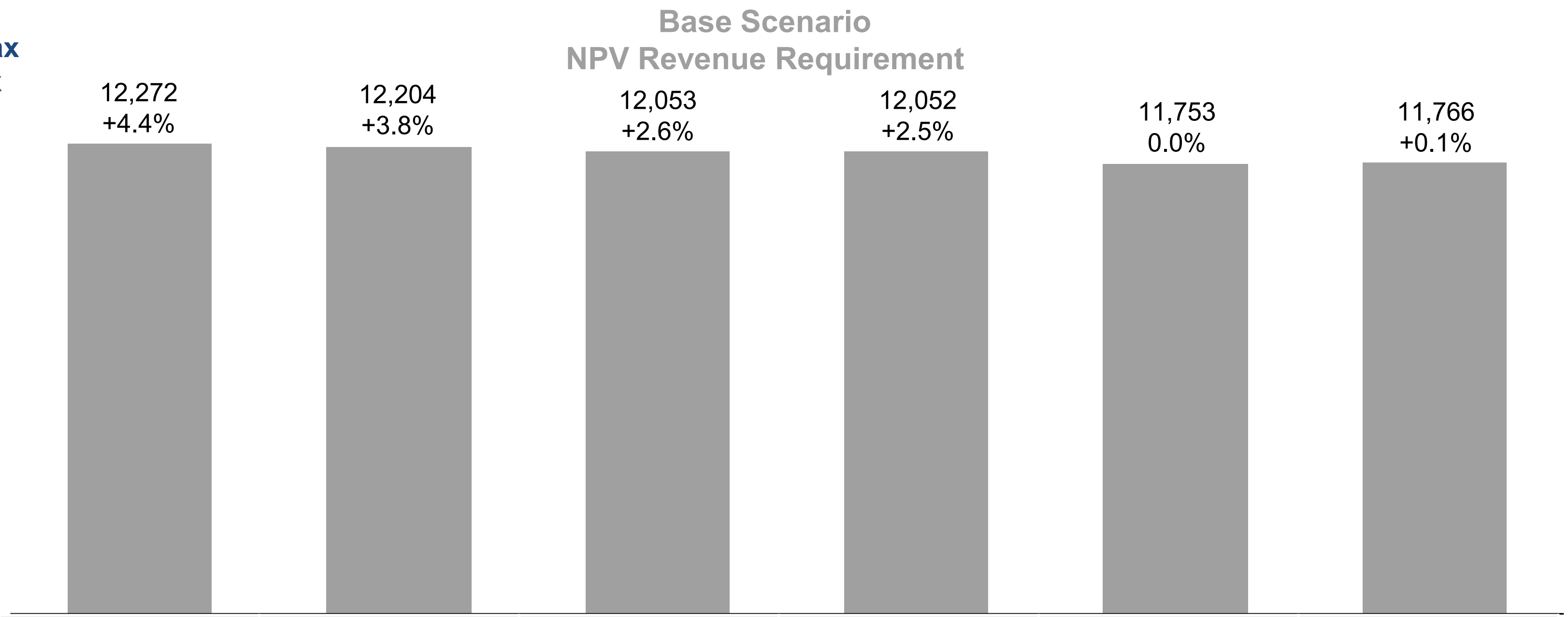
	Age Based	Retire 20% Coal (2023)	Retire 20% Coal (2018)	Retire 50% Coal	Retire 80% Coal	Retire 100% Coal
Retire:	Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 Schahfer: 17,18	Bailly: 7,8 Schahfer: 14,15,17,18	Bailly: 7,8 Michigan City: 12 Schahfer: 14,15,17,18
Keep:	Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None

Notes: Present Value of Revenue Requirement; NOT a bill impact analysis; model adjustments stop collection of property tax, income tax and "return on" when a unit is retired

NIPSCO

Cost To Customer Impacts Of Retirement Portfolios

Post Strategist Adjustments:
- **Property Tax**
- **Income Tax**



	Age Based	Retire 20% Coal (2023)	Retire 20% Coal (2018)	Retire 50% Coal	Retire 80% Coal	Retire 100% Coal
Retire:	Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 Schahfer: 17,18	Bailly: 7,8 Schahfer: 14,15,17,18	Bailly: 7,8 Michigan City: 12 Schahfer: 14,15,17,18
Keep:	Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None

Notes: Present Value of Revenue Requirement; NOT a bill impact analysis; model adjustments stop collection of property tax and income tax when a unit is retired

Remaining Net Book Value at Retirement Date ($M)

	1	2	3	4	5	6
Retire	None	BGS: 7,8 in 2022	BGS: 7,8 in 2018	BGS: 7,8 in 2018 RMSGS: 17,18	BGS: 7,8 in 2018 RMSGS: 14,15,17,18	BGS: 7,8 in 2018 RMSGS: 14,15,17,18 MC: 12
Keep/Comply	BGS: 7,8 RMSGS: 14,15,17,18 MC: 12	RMSGS: 14,15,17,18 MC: 12	RMSGS: 14,15,17,18 MC: 12	RMSGS: 14,15 MC: 12	RMSGS: 14,15 MC: 12	None
Bailly	$0	$168	$290	$290	$290	$290
Schahfer	$0	$0	$0	$263	$1173	$1173
Michigan City	$0	$0	$0	$0	$0	$415
Total	**$0**	**$168**	**$290**	**$553**	**$1,463**	**$1,878**

Notes: Includes costs of removal

NIPSCO

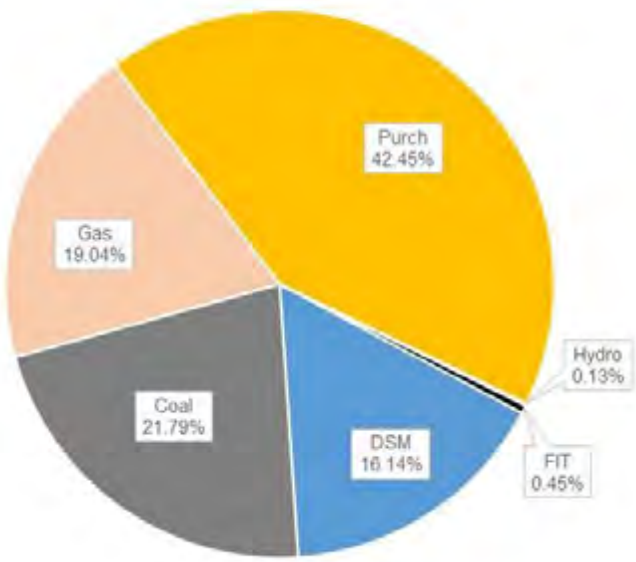
Industrial Group Request

Base Scenario Portfolio: Unconstrained Purchases Case

Base

Resource Mix (Percent of Capacity)

2037 Base with only Purchases



Total CO_2 (tons) = 164,472,081

NPVRR($000) = 12,429,940

Least Cost Portfolio		
Expansion Plan (MW)		
Year	DSM	Purchases
2016	533	-
2017	11	-
2018	15	142
2019	20	155
2020	18	174
2021	21	186
2022	25	201
2023	29	929
2024	34	944
2025	37	959
2026	40	972
2027	42	985
2028	45	998
2029	48	1,014
2030	50	1,026
2031	50	1,036
2032	52	1,046
2033	53	1,063
2034	53	1,077
2035	51	1,529
2036	52	1,540
2037	60	1,545

NIPSCO

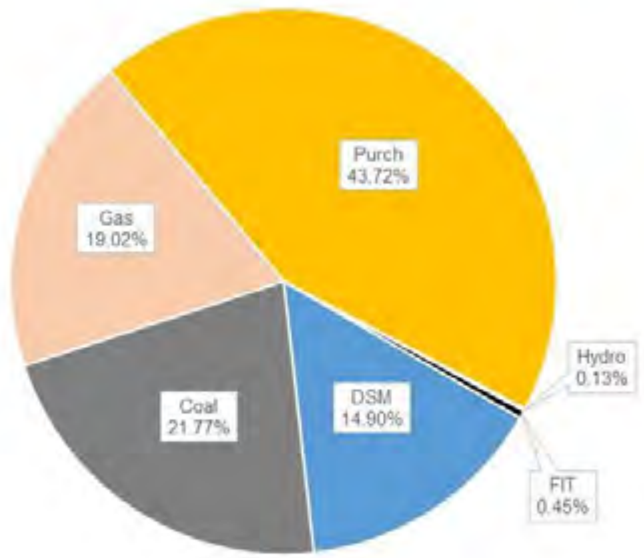
Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Base No CO_2 Scenario Portfolio: Unconstrained Purchases Case

Base

Resource Mix (Percent of Capacity)

2037 Base No Carbon with only Purchases



Total CO_2 (tons) = 125,742,998

NPVRR ($000) = 9,481,731

Least Cost Portfolio		
Expansion Plan (MW)		
Year	DSM	Purchases
2016	529	-
2017	2	-
2018	3	155
2019	4	171
2020	6	187
2021	7	202
2022	8	219
2023	9	950
2024	10	970
2025	11	988
2026	12	1,002
2027	13	1,017
2028	14	1,032
2029	14	1,050
2030	15	1,063
2031	15	1,074
2032	16	1,085
2033	16	1,103
2034	16	1,116
2035	16	1,567
2036	17	1,578
2037	15	1,593

NIPSCO

Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Schahfer Units 17&18 Timing

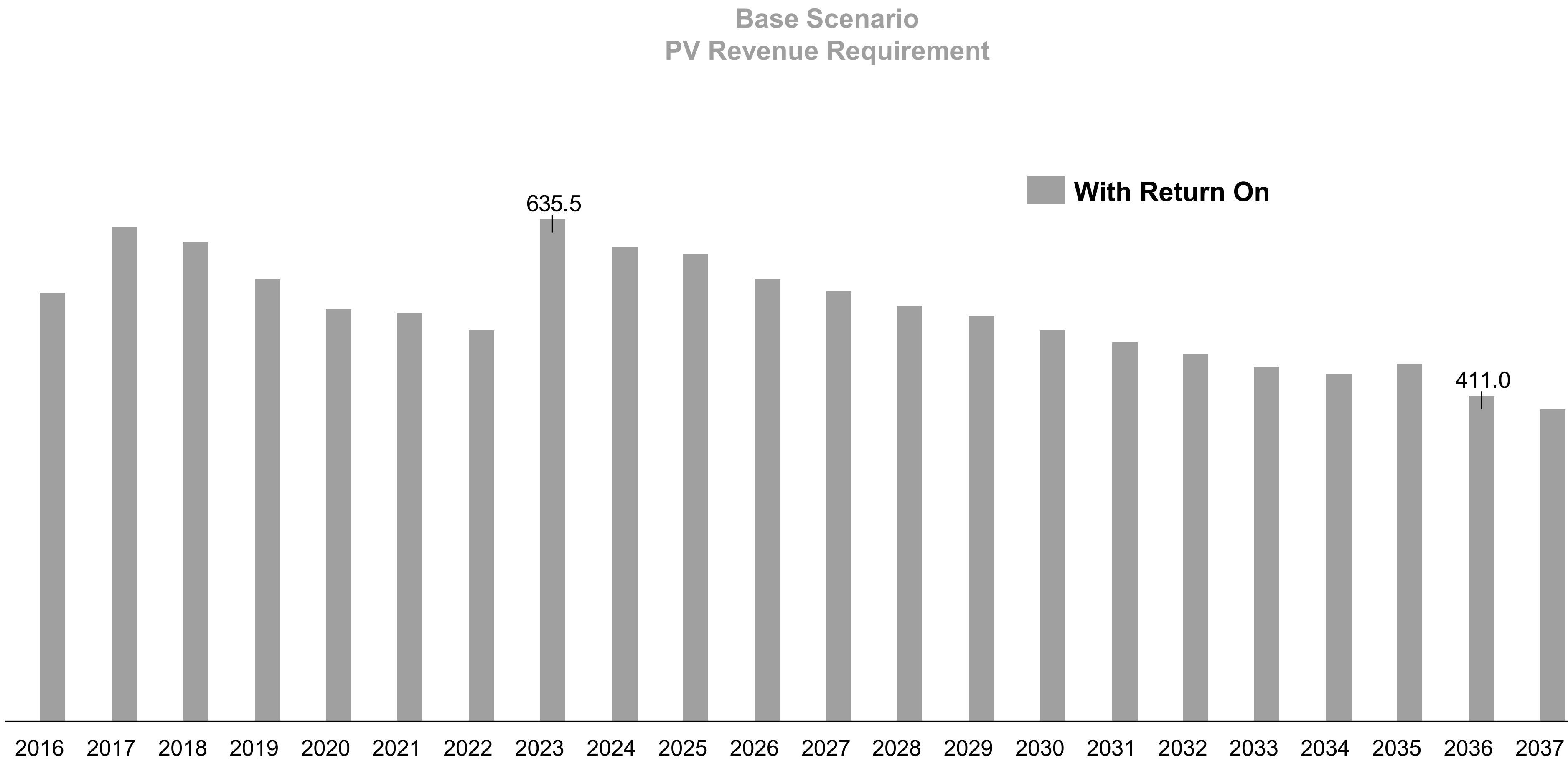
Compliance Timelines

CCR	Continue to Run	2018
	Retire	2023 (Ponds Must Be Closed)
ELG	Zero Liquid Discharge	2023
	Other Technology	2020 – 2023

Event	Key Dates	Issues if Operation Continues Beyond 2023	
CCR Compliance Plan and Recovery Filing	4Q16 or 1Q17	Would need to include Units 17/18 investments to achieve the requirements by 2018.	CCR Rule provides for extensions in limited circumstances. Would need to qualify for extensions.
ELG Compliance Plan and Recovery Filing	2017	Units 17/18 investment not planned on being included.	ELG compliance likely not until 2023. Could file/amend (2019) and likely still meet requirements.
CCR Declaration with EPA/IDEM -retirement as method of compliance	By October 2018	Investments not in place by October 2018 if operated beyond 2023.	Need to qualify for extensions if decision is made to run U17/18 indefinitely after October 2018.
ELG Technology Build Out	2020 – 2023	If work not started ~2020 difficult to impossible to achieve investment by 2023.	Compress build-out schedule if after 2020. However, 2023 is a firm deadline for ELG.
ELG Compliance	December 2023 (latest)	Operation after December 2023 without ELG investment.	Limited or none.
Cease Operation of Units	2023	Once a Unit ceases operation it is virtually impossible to restart.	Limited or none.

NIPSCO

Annual Revenue Requirement View of Preferred Retirement Plan



	Retire 50% Coal
Retire:	Bailly: 7,8 (2018) Schahfer: 17,18 (2023)
Keep:	Michigan City: 12 Schahfer: 14,15

NIPSCO

Other Requests

- IURC Staff
- Brubaker
- CAC

Break

Optimization Results

(as of 10/03/2016)

Presented by

Edward Achaab

Manager Resource Planning

NIPSCO

Scenarios Analysis

Scenarios

Base	Challenged Economy	Aggressive Environmental Regulation	Booming Economy	Base Delayed Carbon

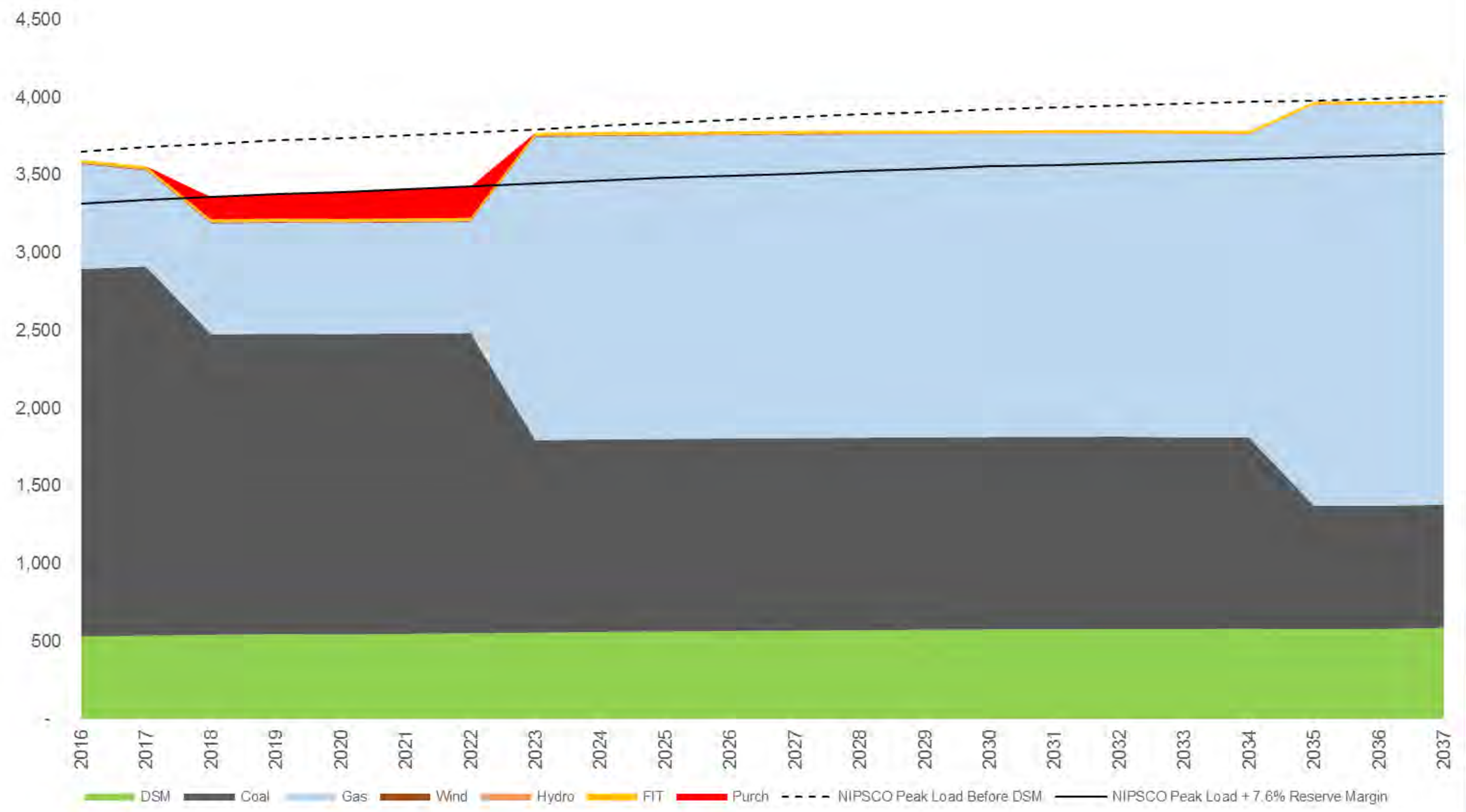
Sensitivities

Base	Challenged Economy	Aggressive Environmental Regulation	Booming Economy	Base Delayed Carbon
No CO_2 Price	No CO_2 Price	High Renewables & Increasing Load	No CO_2 Price	
Low Load	Loss of Major Industrial Load	High Renewables & Decreasing Load	Loss of Major Industrial Load	
High Gas Price				
Loss of Major Industrial Load				

Sources and Notes: Definitions adapted from *Electricity Director's Final Report 2014-2015 Integrated Resources Plans*, IURC, p. 9; Varying one "element" of a scenario to create a sensitivity may require changes to multiple variables to ensure that input data are properly correlated; For example, a low gas price sensitivity also requires correlated (lower) electricity prices

Base Scenario Capacity Expansion Least Cost Portfolio

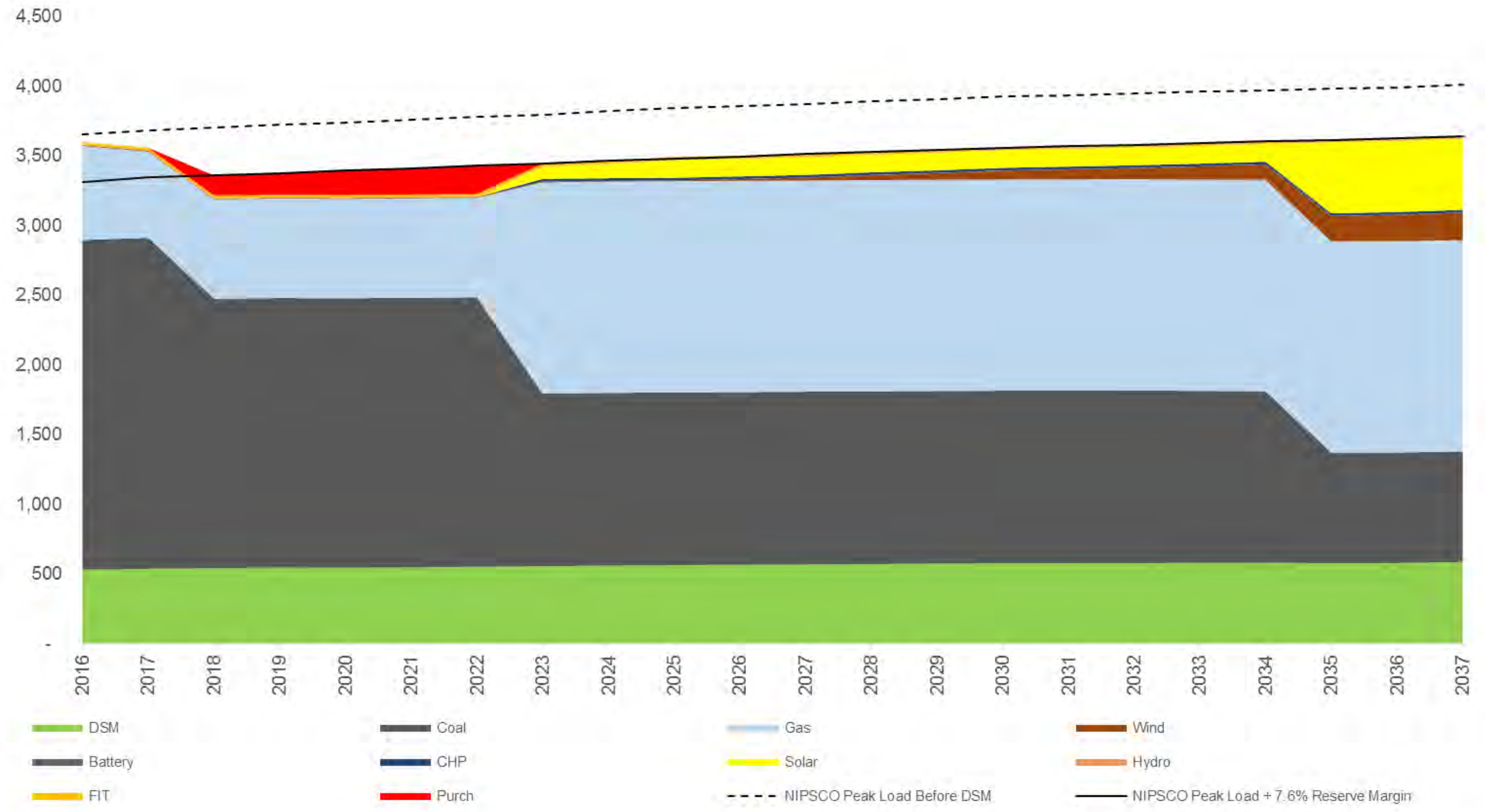
Base



NIPSCO

Base Scenario Capacity Expansion
Renewable Focus Portfolio

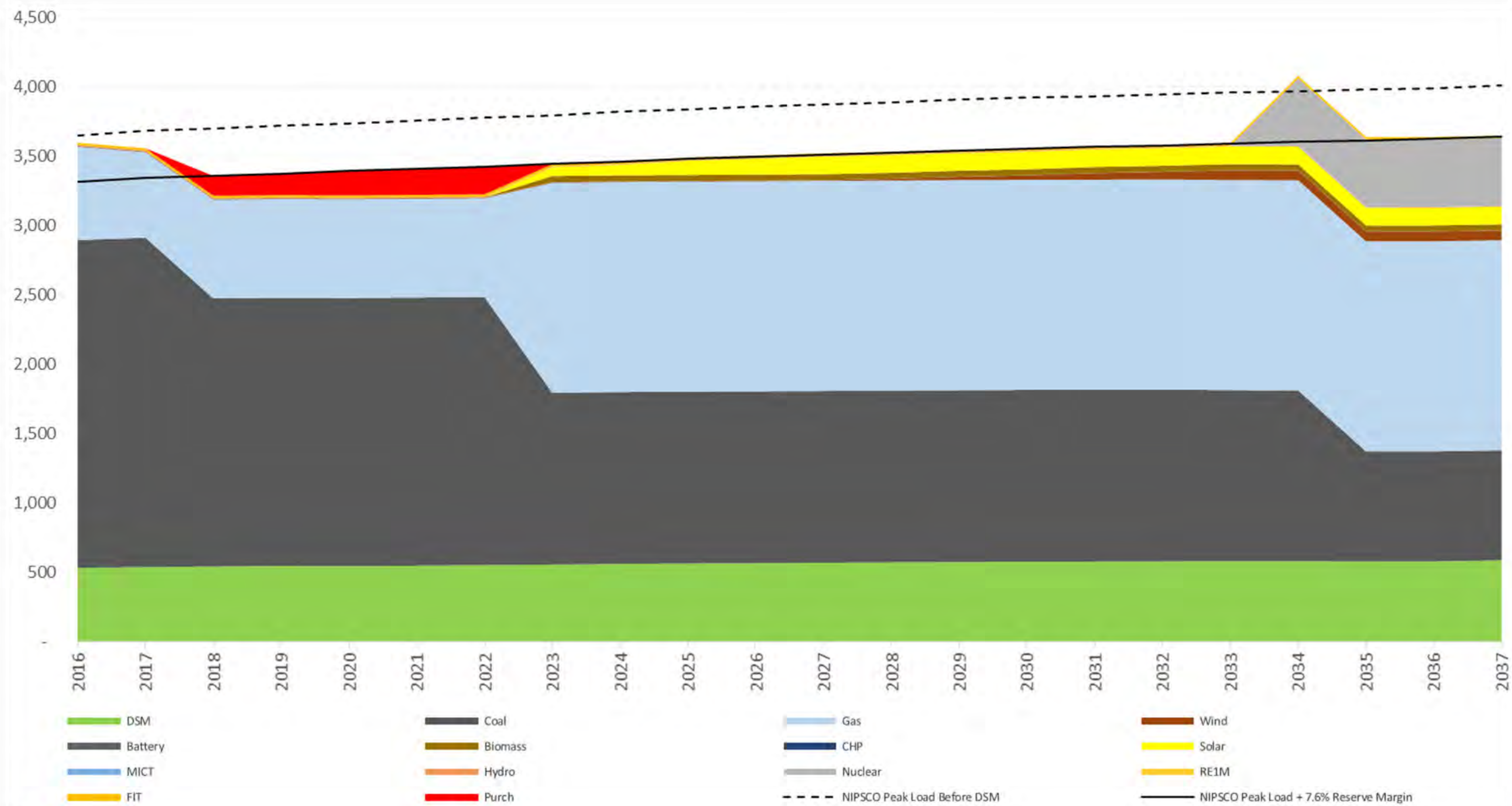
Base



NIPSCO

Base Scenario Capacity Expansion
Low Emission Portfolio

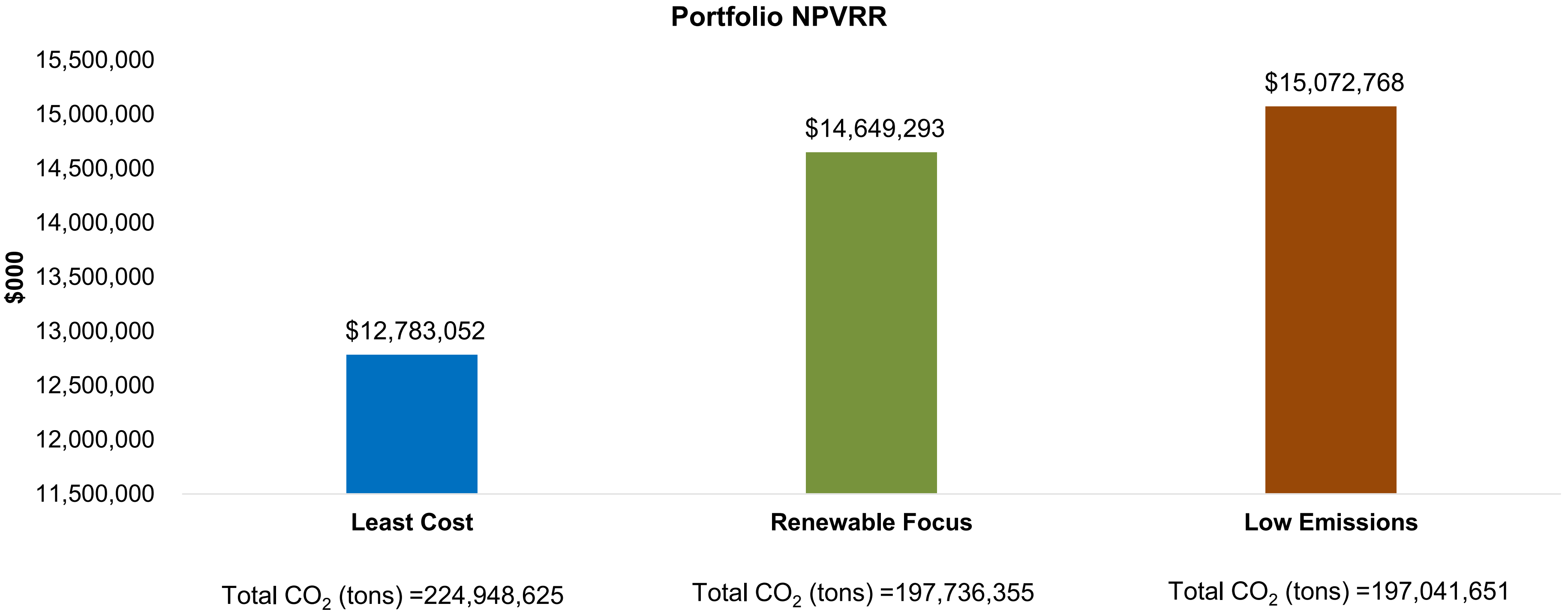
Base



NIPSCO

Base

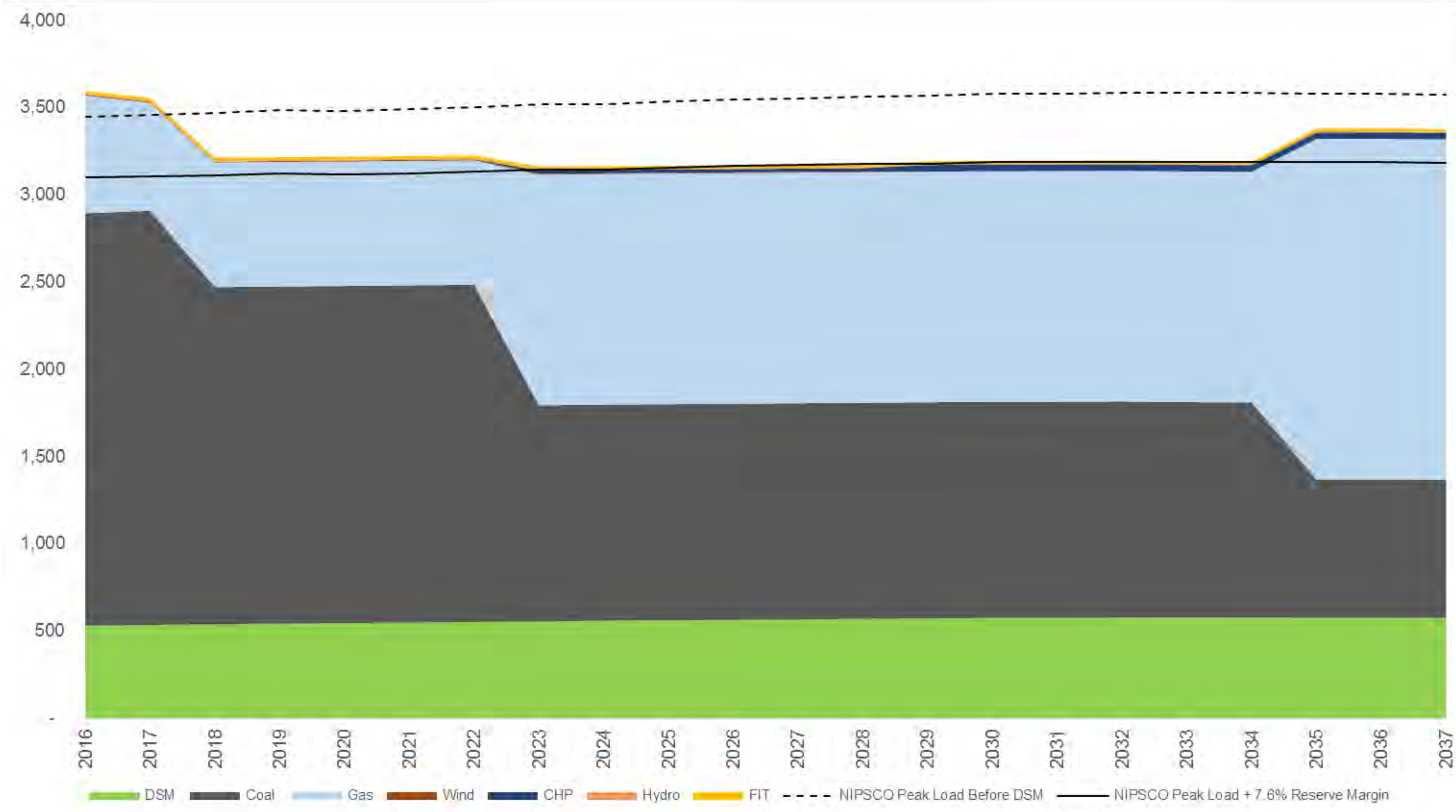
Comparison Of Base Scenario Portfolios



Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Challenged Economy Scenario Capacity Expansion Least Cost Portfolio

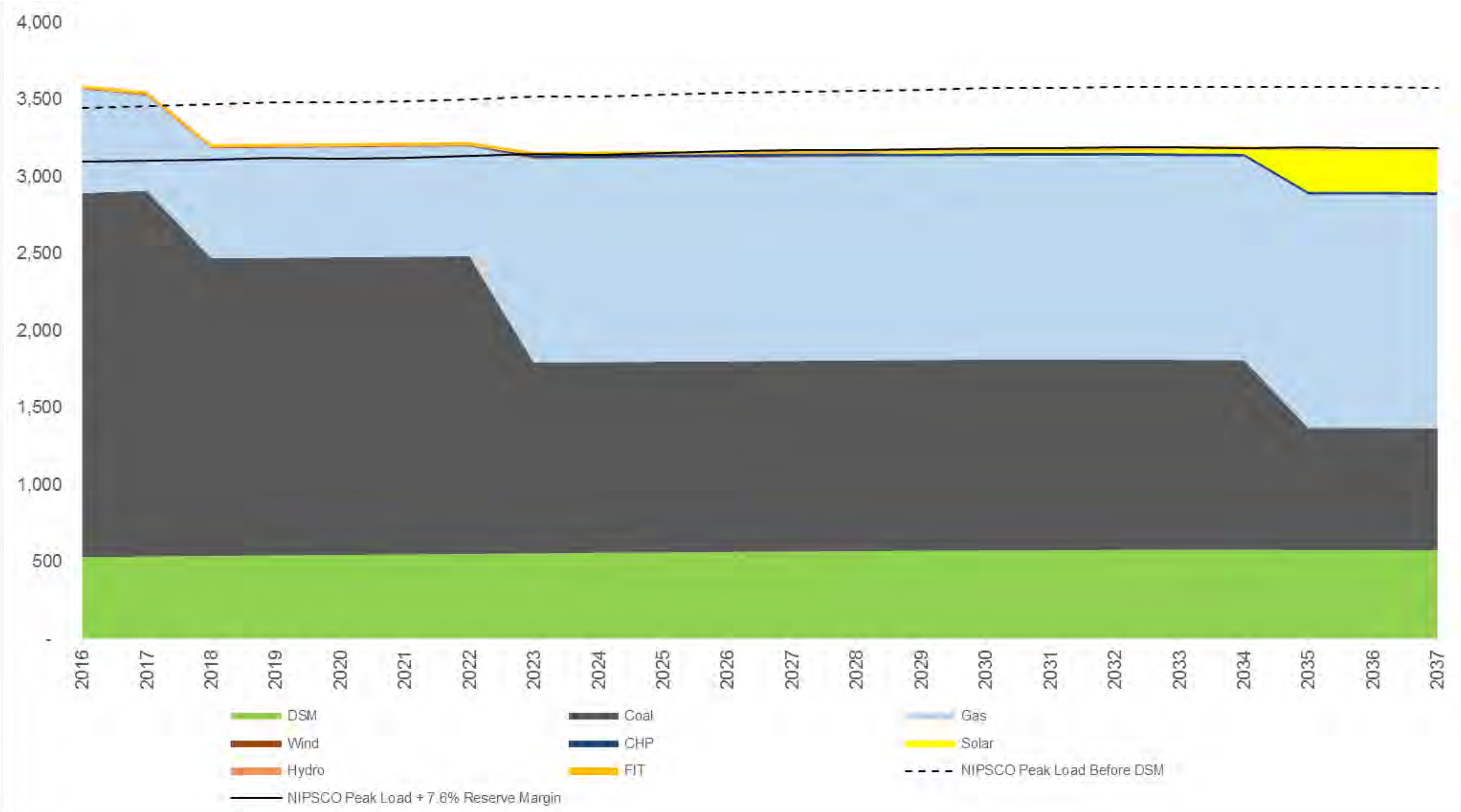
Challenged Economy



NIPSCO

Challenged Economy Scenario Capacity Expansion Renewable Focus Portfolio

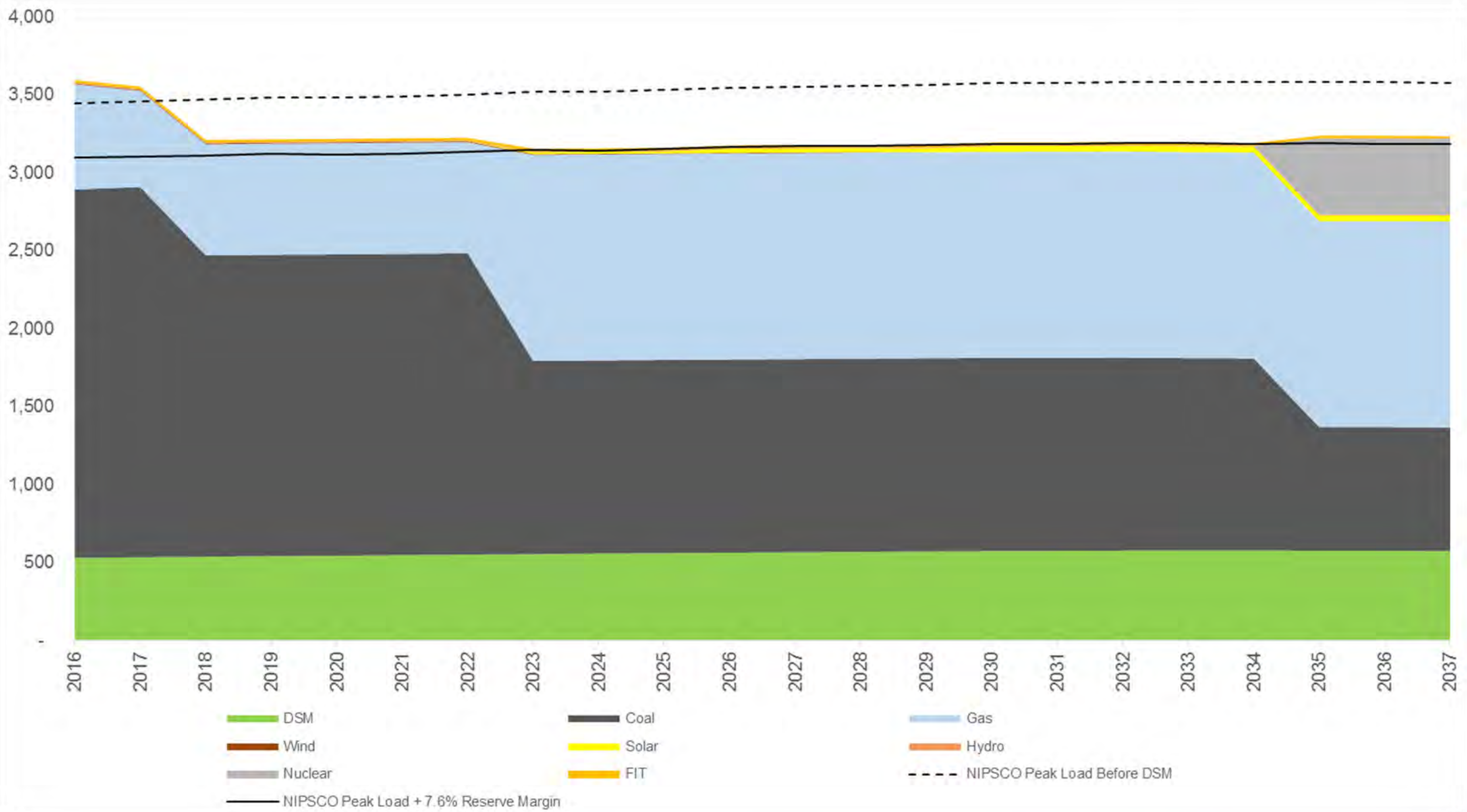
Challenged Economy



NIPSCO

Challenged Economy Scenario Capacity Expansion Low Emission Portfolio

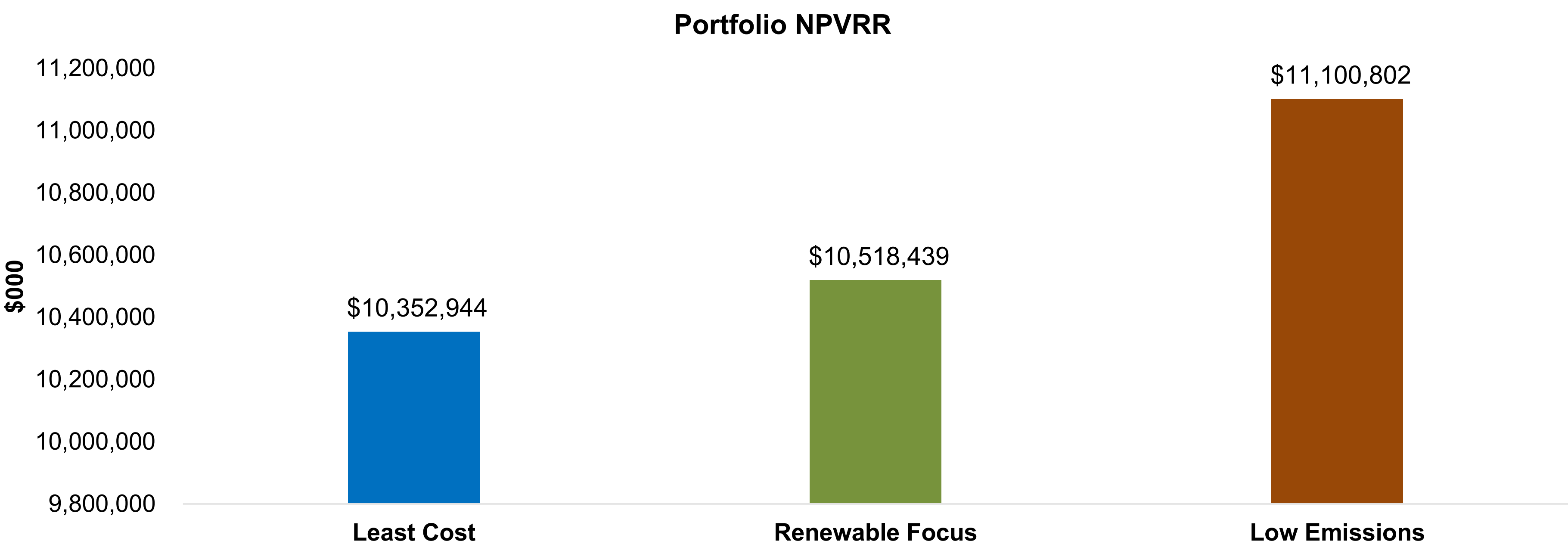
Challenged Economy



NIPSCO

Comparison Of Challenged Economy Portfolios

Challenged Economy



Total CO_2 (tons) =176,009,766

Total CO_2 (tons) =170,848,058

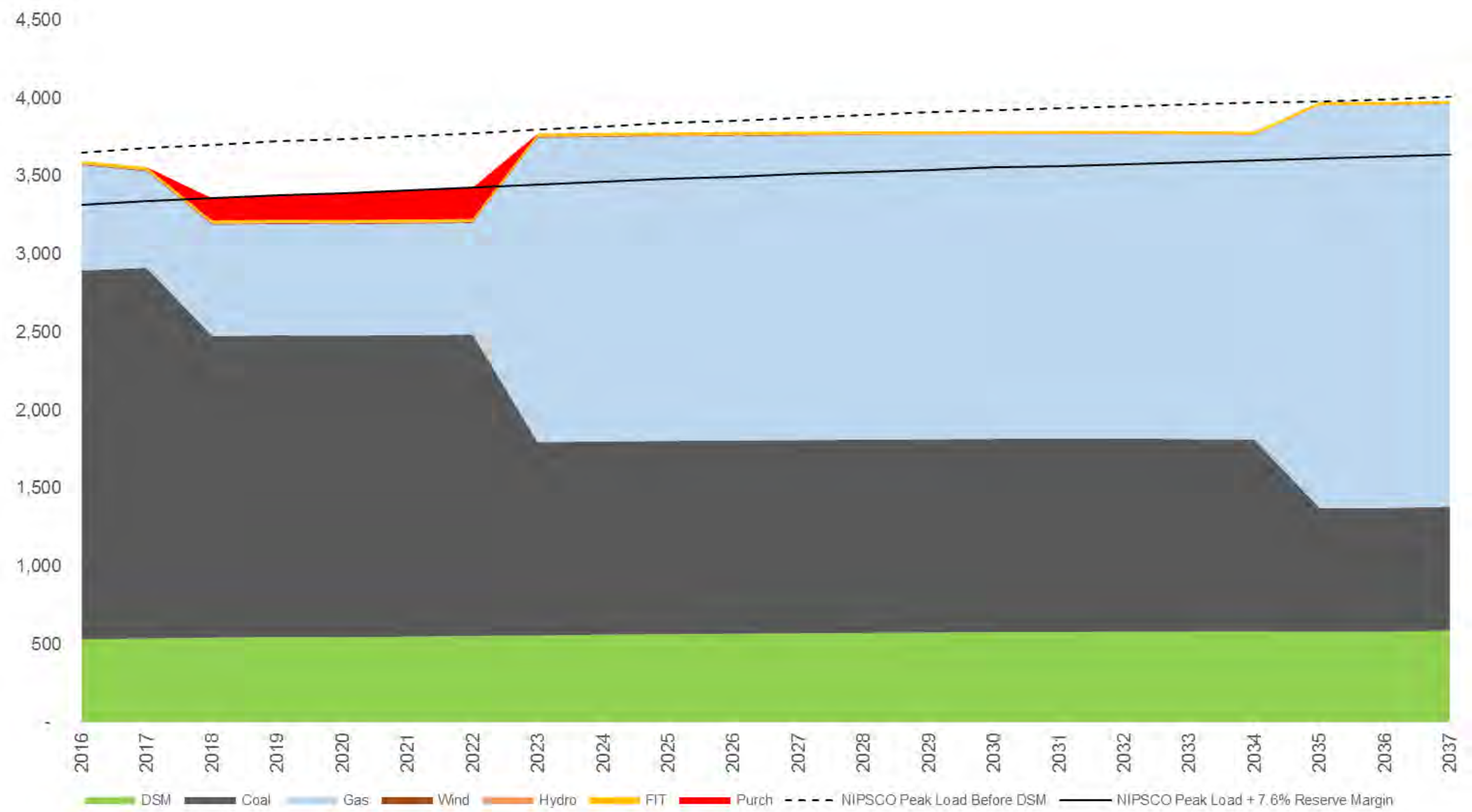
Total CO_2 (tons) =168,909,617

NIPSCO

Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Aggressive Enviro. Scenario Capacity Expansion Least Cost Portfolio

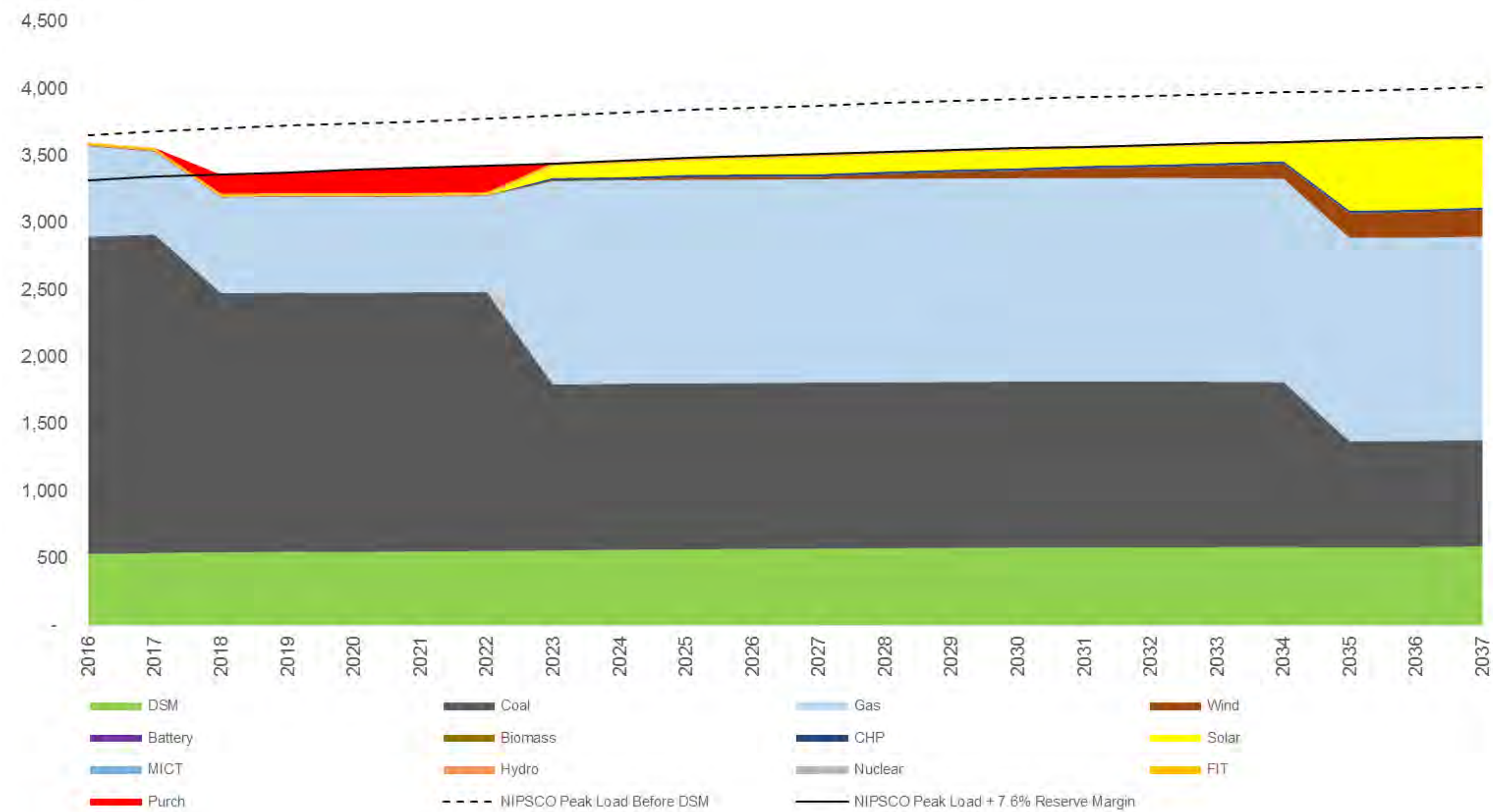
Aggressive Environmental Regulation



NIPSCO

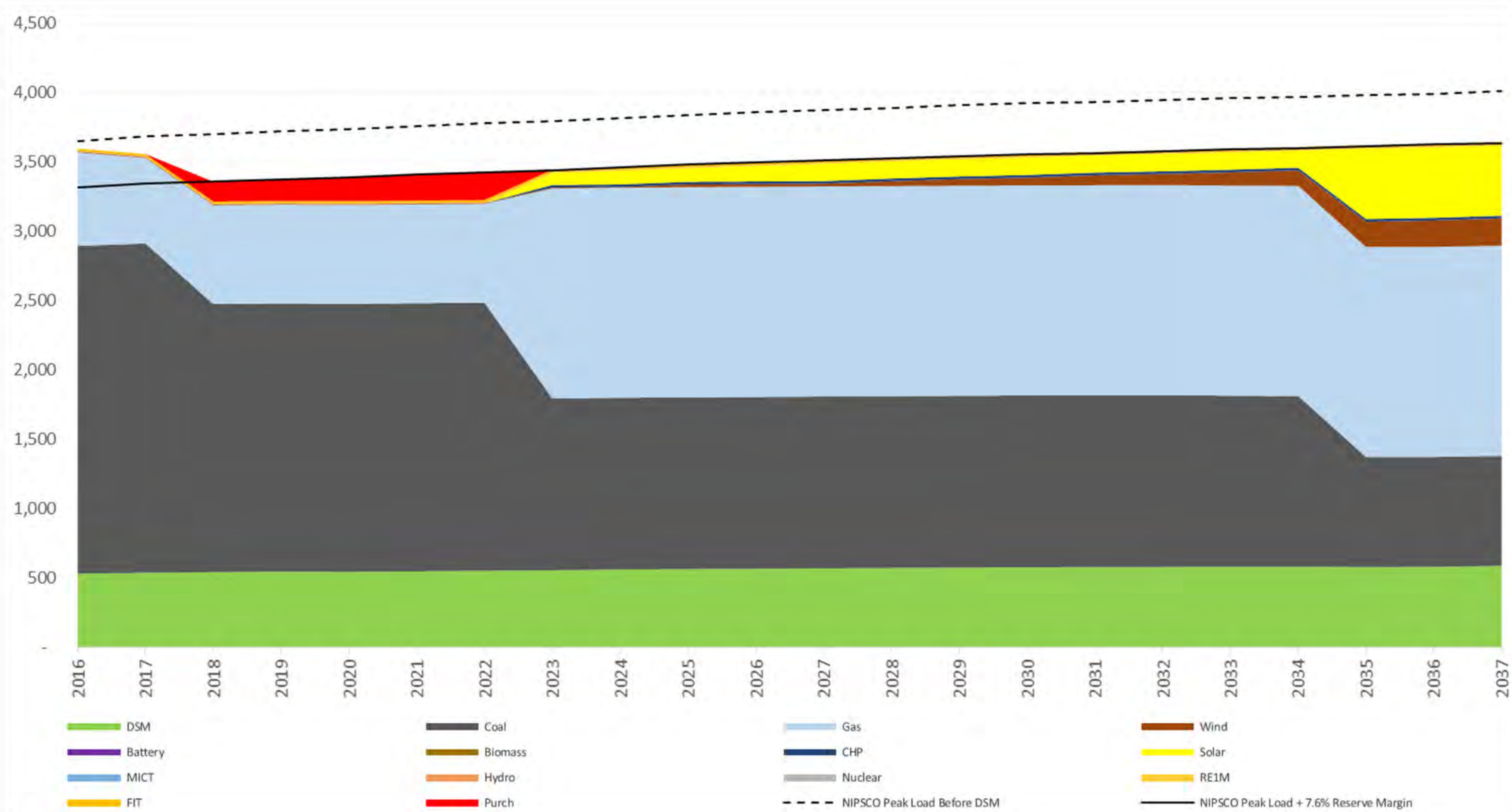
Aggressive Enviro. Scenario Capacity Expansion Renewable Focus Portfolio

Aggressive Environmental Regulation



Aggressive Enviro. Scenario Capacity Expansion Low Emission Portfolio

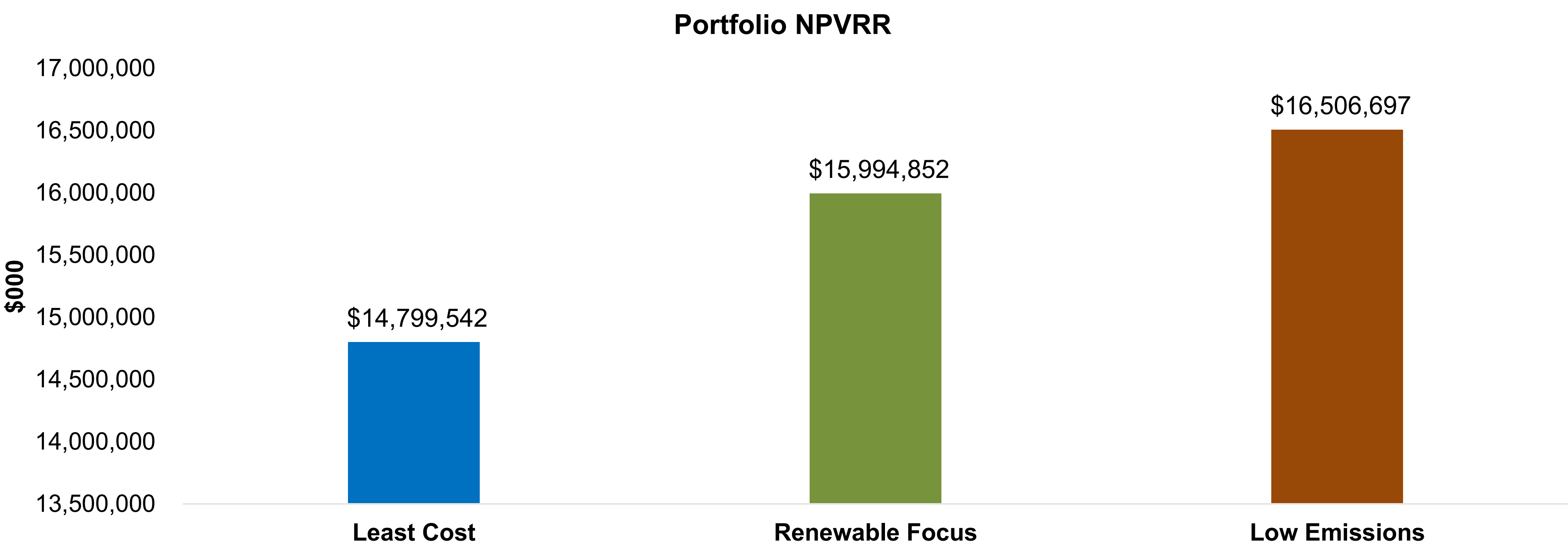
Aggressive Environmental Regulation



NIPSCO

Aggressive Environmental Regulation

Comparison Of Aggressive Enviro. Portfolios



Total CO_2 (tons) =169,058,005

Total CO_2 (tons) =153,772,958

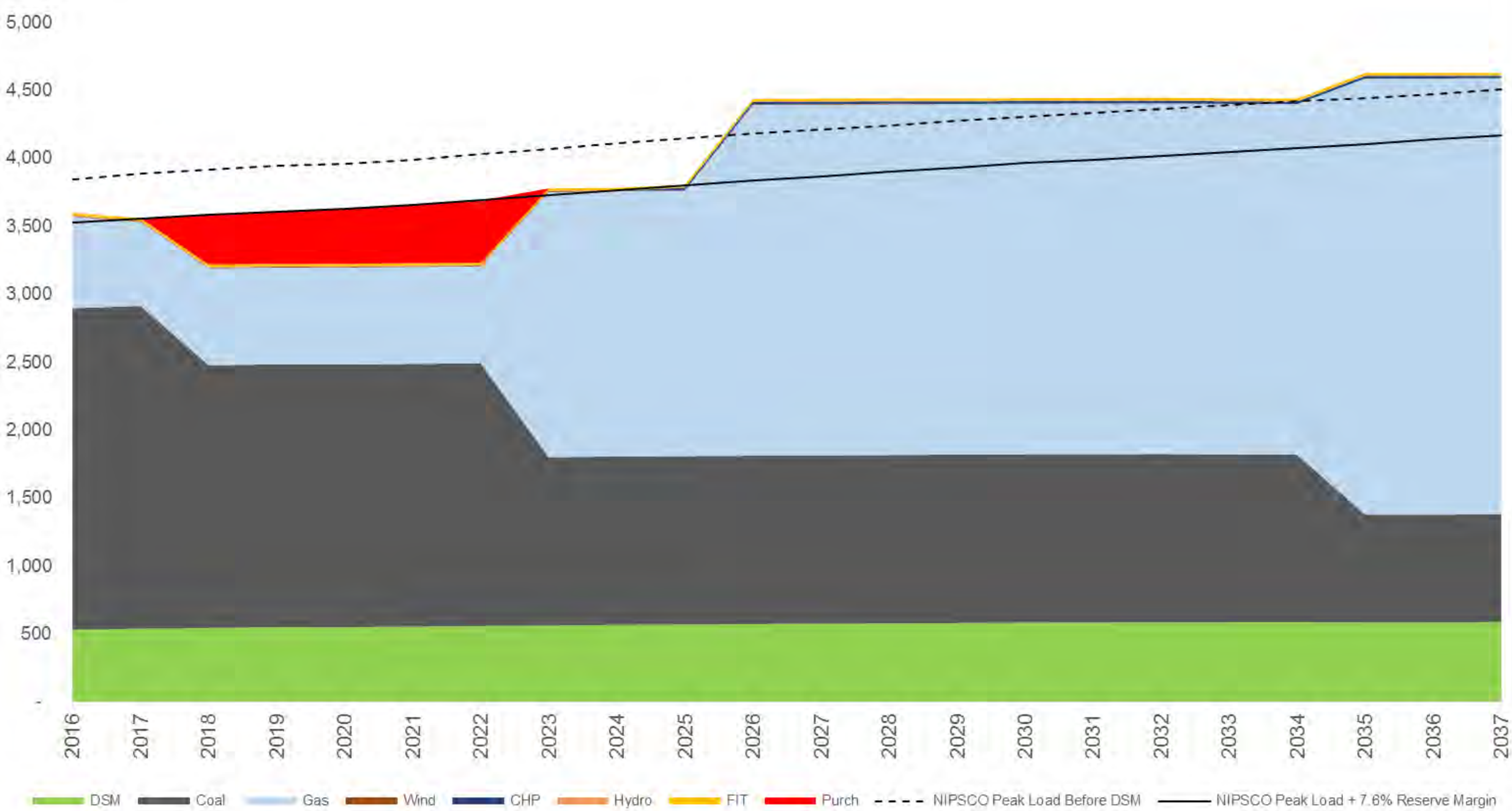
Total CO_2 (tons) =152,510,713

NIPSCO

Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Booming Economy Scenario Capacity Expansion Least Cost Portfolio

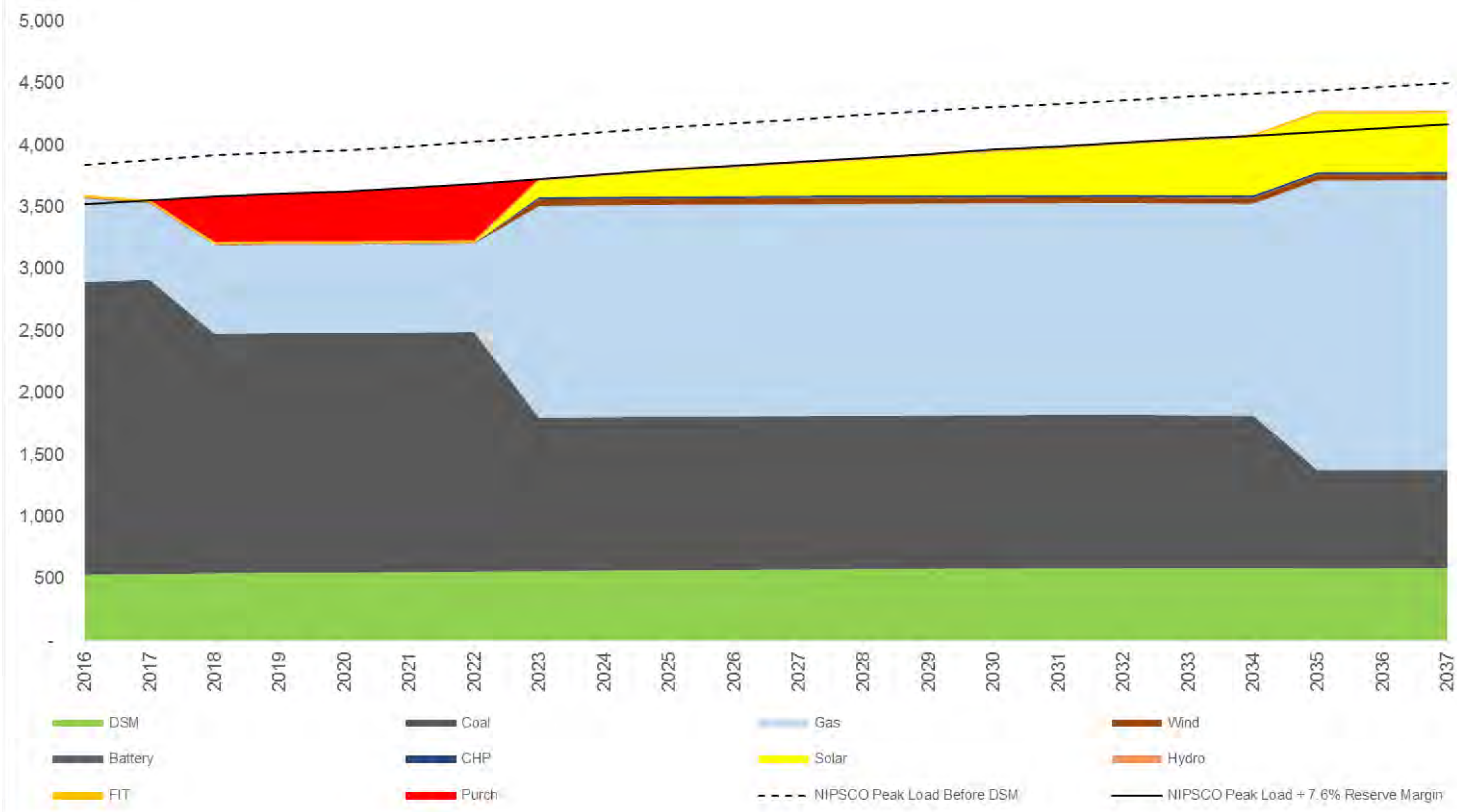
Booming Economy



NIPSCO

Booming Economy Scenario Capacity Expansion Renewable Focus Portfolio

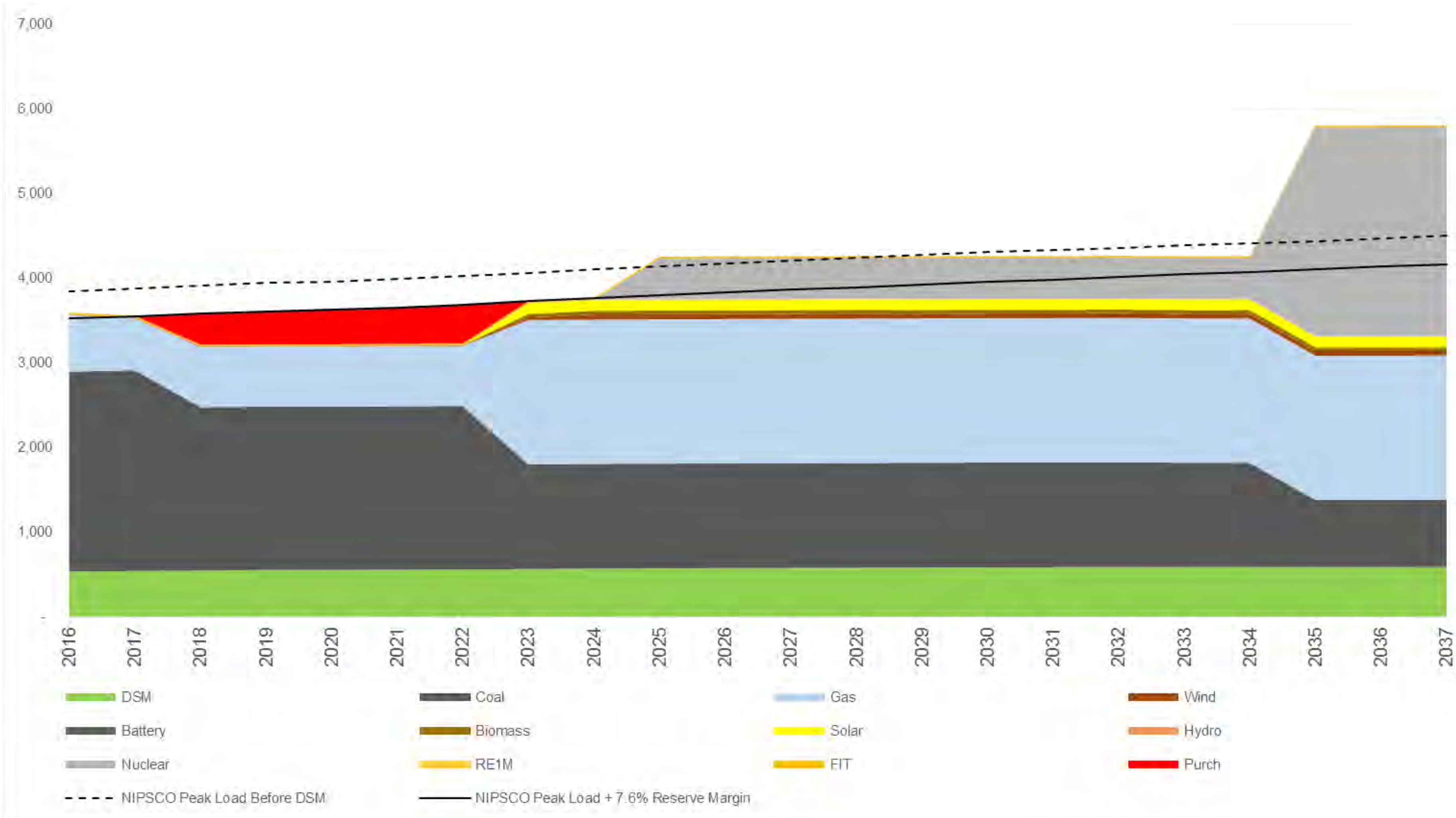
Booming Economy



NIPSCO

Booming Economy Scenario Capacity Expansion Low Emission Portfolio

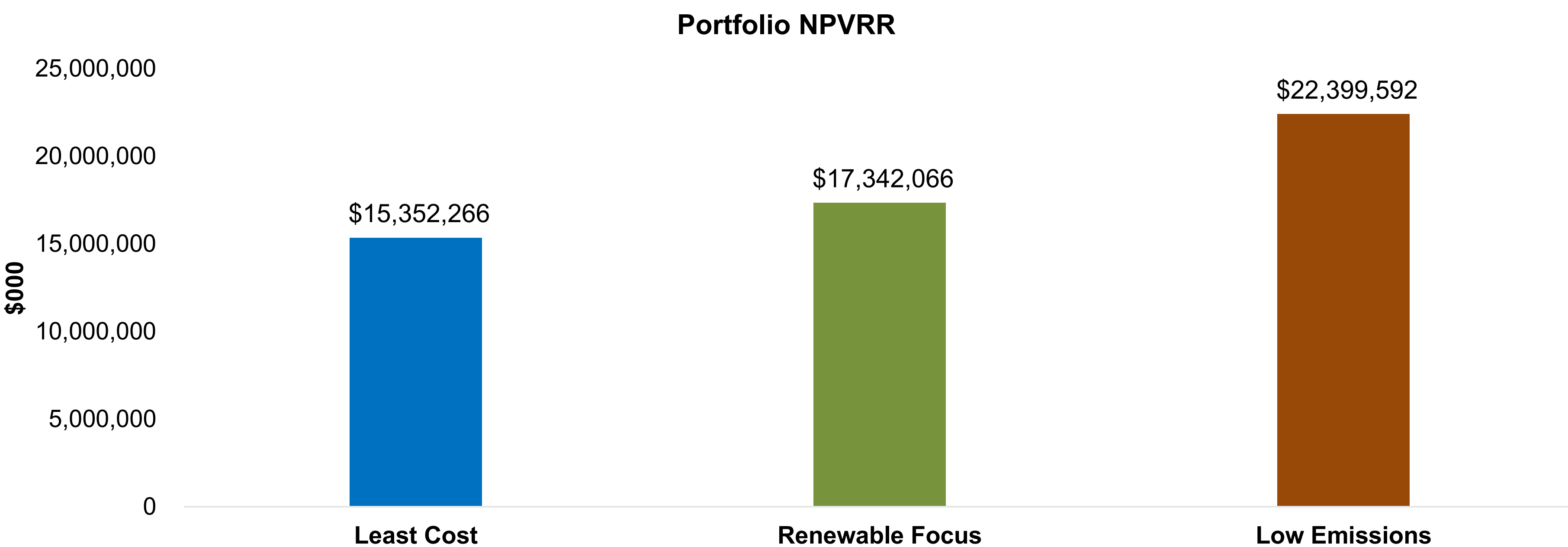
Booming Economy



NIPSCO

Comparison Of Booming Economy Portfolios

Booming Economy



Total CO_2 (tons) =246,326,145

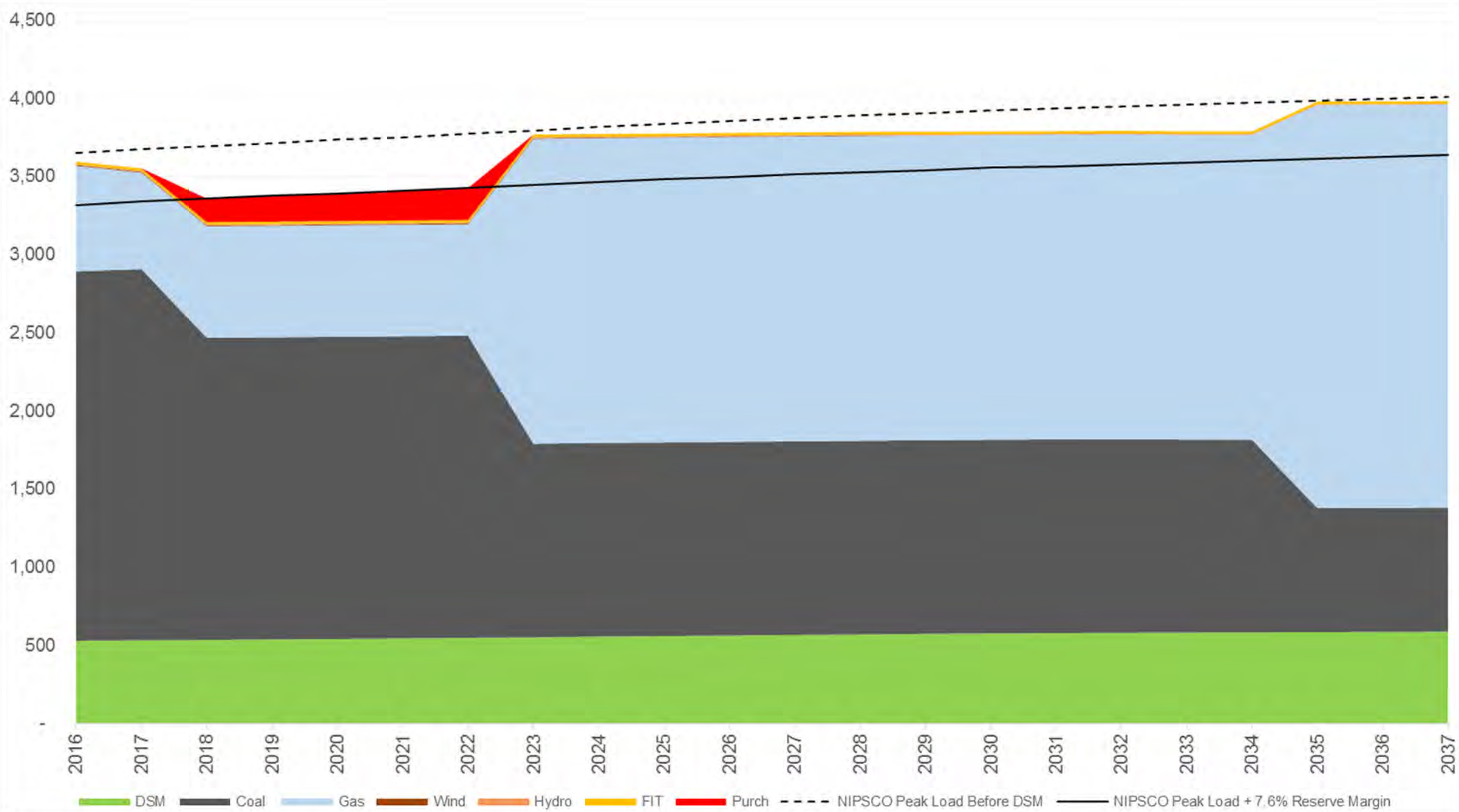
Total CO_2 (tons) =215,810,843

Total CO_2 (tons) =212,512,266

Notes: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Base Delayed Carbon Scenario Capacity Expansion Least Portfolio

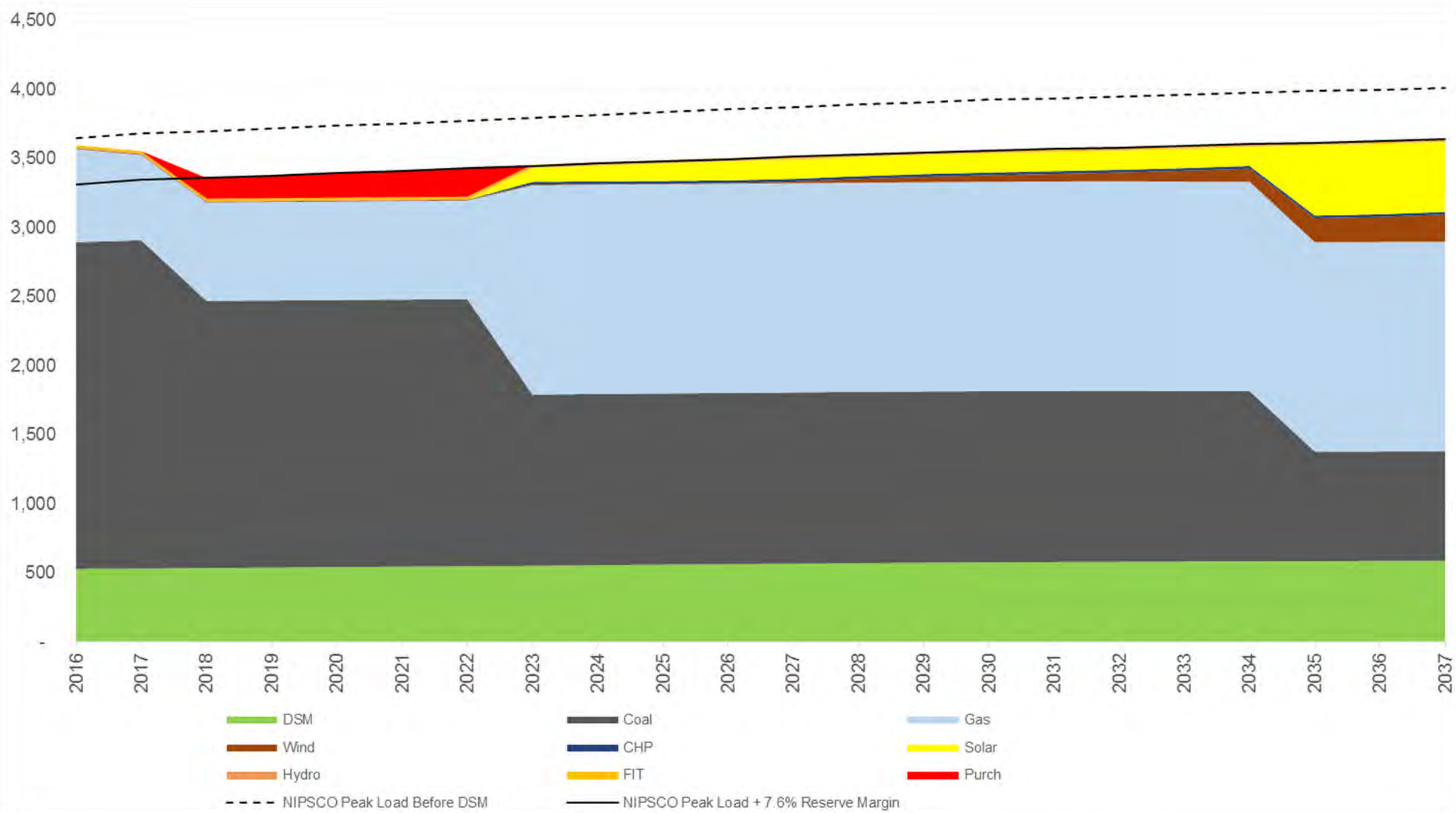
Base Case Delayed Carbon



NIPSCO

Base Delayed Carbon Scenario Capacity Expansion Renewable Focus Portfolio

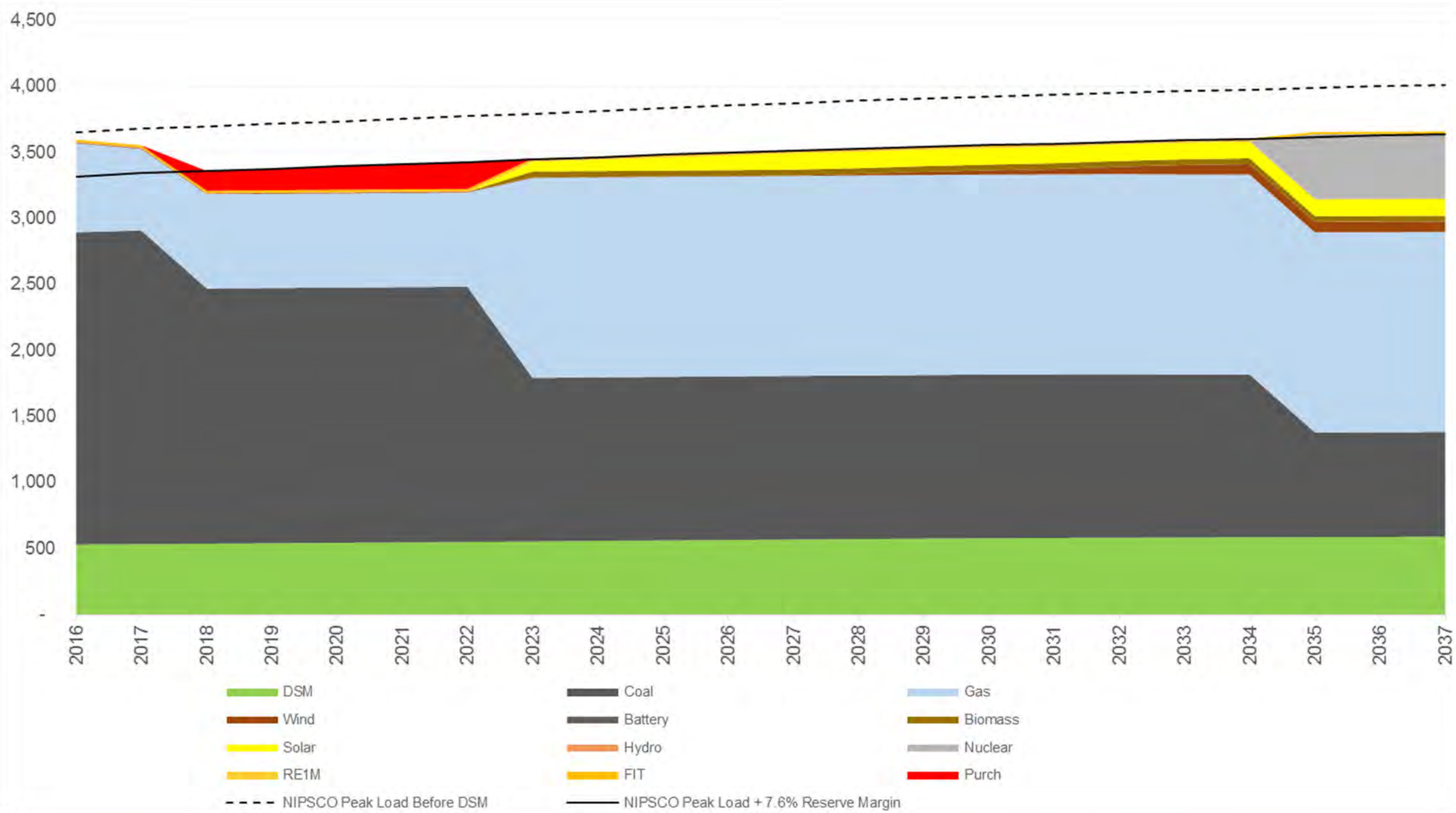
Base Case Delayed Carbon



NIPSCO

Base Delayed Carbon Scenario Capacity Expansion Low Emission Portfolio

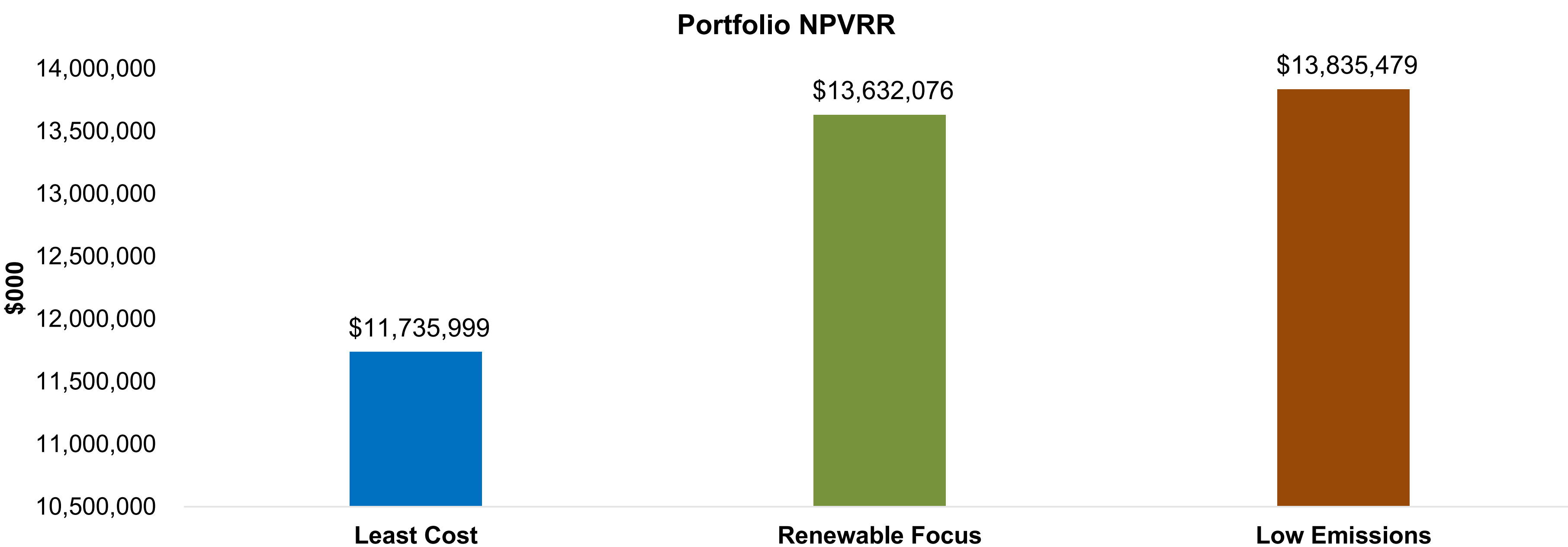
Base Case Delayed Carbon



NIPSCO

Base Delayed Carbon Scenario Net Present Value Revenue Requirements

Base Case Delayed Carbon



Total CO_2 (tons) =185,239,925

Total CO_2 (tons) =158,029,243

Total CO_2 (tons) =156,262,113

<u>Notes</u>: Total CO_2 amount is from 2015 – 2037. Includes both existing and new resources in the portfolio

Cumulative 2015-2037 Energy Mix

Least Cost Portfolio								
Scenario	**Coal**	**Gas**	**Wind**	**CHP**	**Hydro**	**FIT**	**DSM**	**Net Purchases***
Base	25.2%	56.2%	0.9%	-	0.3%	0.8%	2.8%	13.8%
Challenged Economy	24.0%	45.3%	1.1%	0.6%	0.3%	0.9%	2.9%	24.9%
Aggressive Environmental	22.2%	33.3%	0.9%	-	0.3%	0.8%	2.8%	39.7%
Booming Economy	26.0%	52.8%	0.9%	0.3%	0.2%	0.7%	2.5%	16.5%
Base Delayed Carbon	18.6%	52.3%	0.9%	-	0.3%	0.8%	2.6%	24.5%

NIPSCO

Notes: * Negative Net Purchases represent a "Long" energy position, where by NIPSCO is selling to the market and positive Net Purchases represent a "short" position, whereby NIPSCO is buying from the market. Over the planning horizon, NIPSCO is long and short throughout the year at different times.

Cumulative 2015-2037 Energy Mix

Renewable Focus Portfolio

Scenario	Coal	Gas	Wind	Battery	CHP	Solar	Hydro	FIT	DSM	Net Purchases*
Base (B)	25.5%	39.1%	12.1%	0.01%	0.5%	4.7%	0.3%	0.8%	2.8%	14.3%
Challenged Economy (CE)	23.9%	42.4%	1.1%	-	0.4%	1.6%	0.3%	0.9%	2.9%	26.6%
Aggressive Environmental (AE)	22.1%	24.2%	12.2%	0.003%	0.3%	4.7%	0.3%	0.8%	2.8%	32.7%
Booming Economy (BE)	26.9%	33.8%	7.4%	0.003%	0.4%	7.2%	0.2%	0.7%	2.5%	20.8%
Base Delayed Carbon (BDC)	18.4%	36.4%	10.8%	-	0.3%	5.0%	0.3%	0.8%	2.6%	25.4%

Notes: * Negative Net Purchases represent a "Long" energy position, where by NIPSCO is selling to the market and positive Net Purchases represent a "short" position, where by NIPSCO is buying from the market. Over the planning horizon, NIPSCO is long and short throughout the year at different times.

Cumulative 2015-2037 Energy Mix

Low Emissions Portfolio

Scenario	Coal	Gas	Wind	Battery	Biomass	Solar	MICT	Hydro	Nuclear	Recip	FIT	DSM	Net Purchases*
Base	25.4%	39.0%	6.3%	0.006%	0.1%	2.8%	0.0009 %	0.3%	0.9%	0.002%	0.8%	2.8%	21.7%
Challenged Economy	23.8%	41.8%	1.1%	-	-	0.8%	-	0.3%	1.4%	-	0.9%	2.9%	27.0%
Aggressive Environmental	22.0%	24.1%	5.8%	0.006%	0.0%	2.6%	0.0002 %	0.3%	0.9%	0.001%	0.8%	2.8%	39.7%
Booming Economy	27.1%	31.4%	8.2%	0.005%	0.1%	2.7%	-	0.2%	5.4%	0.002%	0.7%	2.5%	21.5%
Base Delayed Carbon	18.2%	36.3%	6.5%	0.003%	0.1%	2.8%	-	0.3%	1.4%	0.001%	0.8%	2.6%	31.1%

NIPSCO

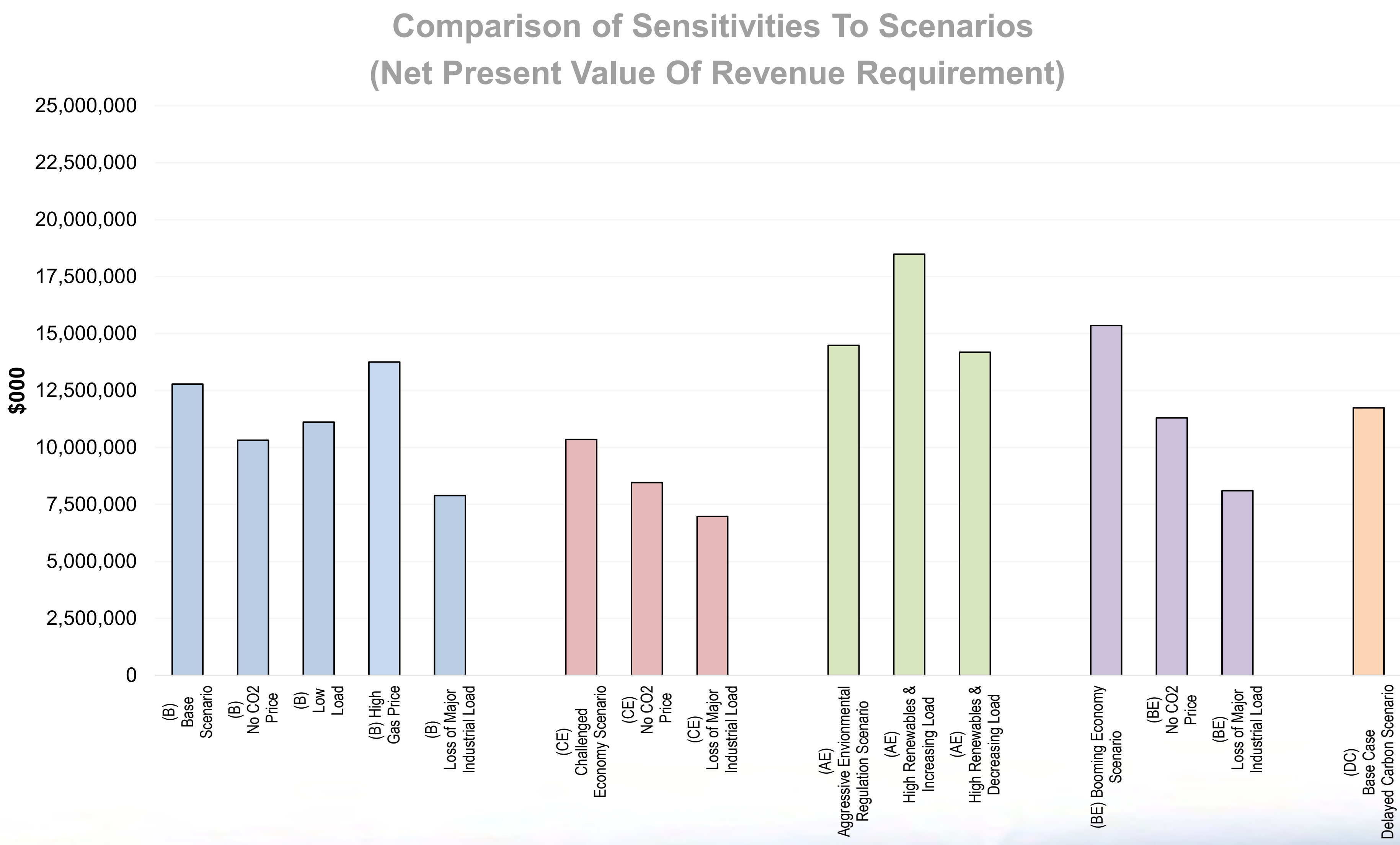
Notes: * Negative Net Purchases represent a "Long" energy position, where by NIPSCO is selling to the market and positive Net Purchases represent a "short" position, where by NIPSCO is buying from the market. Over the planning horizon, NIPSCO is long and short throughout the year at different times.

Sensitivities Analysis

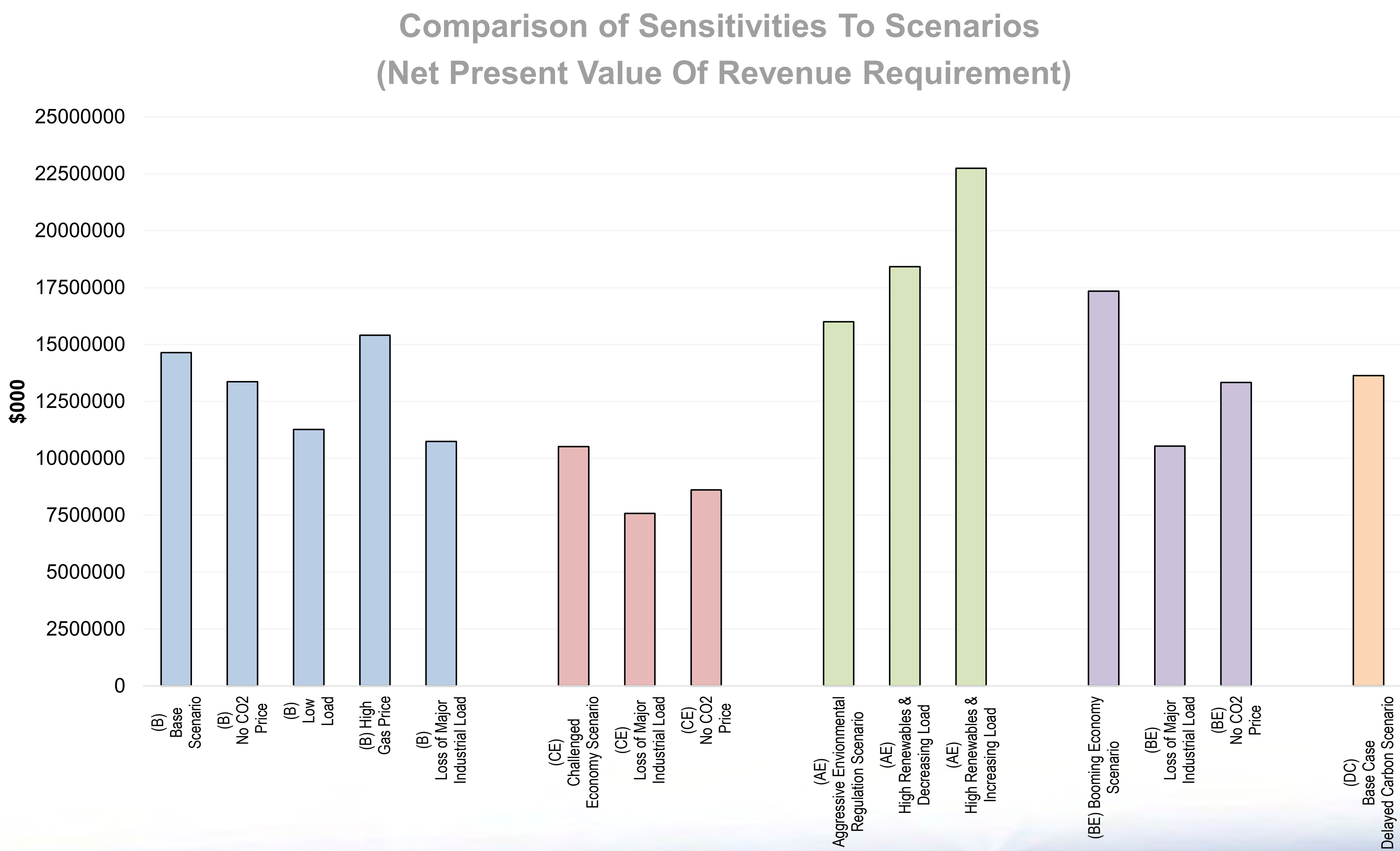
Scenarios	Base	Challenged Economy	Aggressive Environmental Regulation	Booming Economy	Base Delayed Carbon
Sensitivities	No CO_2 Price	No CO_2 Price	High Renewables & Increasing Load	No CO_2 Price	
	Low Load	Loss of Major Industrial Load	High Renewables & Decreasing Load	Loss of Major Industrial Load	
	High Gas Price				
	Loss of Major Industrial Load				

Sources and Notes: Definitions adapted from *Electricity Director's Final Report 2014-2015 Integrated Resources Plans*, IURC, p. 9; Varying one "element" of a scenario to create a sensitivity may require changes to multiple variables to ensure that input data are properly correlated; For example, a low gas price sensitivity also requires correlated (lower) electricity prices

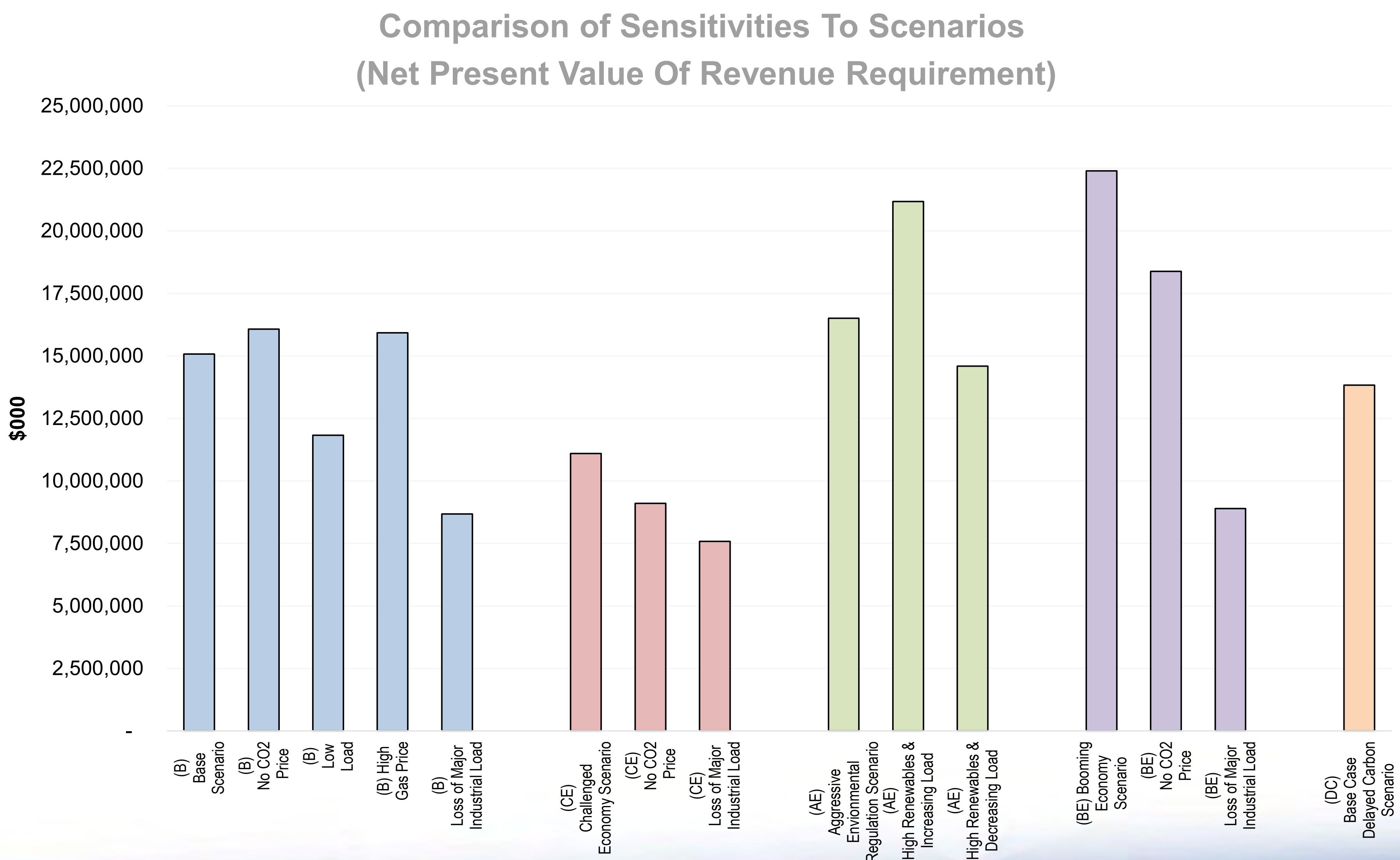
Least Cost Portfolio



Renewable Focus Portfolio



Low Emission Portfolio



Cumulative 2015-2037 Energy Mix

Least Cost Portfolio

Sensitivity	Coal	Gas	Wind	CHP	Solar	Hydro	FIT	DSM	Net Purchases*
Base No CO2	18.6%	37.7%	0.9%	-	-	0.3%	0.8%	1.9%	39.8%
Base Low Load	28.5%	46.6%	1.1%	0.8%	-	0.3%	0.9%	3.2%	18.7%
Base High Gas	28.6%	48.1%	0.9%	-	-	0.3%	0.8%	2.8%	18.5%
Base Loss of Major Ind. Load	43.8%	71.3%	1.7%	3.6%	-	0.5%	1.4%	2.6%	-24.8%
Challenged Economy No CO_2	17.2%	36.0%	1.1%	0.1%	-	0.3%	0.9%	2.7%	41.6%
Challenged Economy Loss of Major Ind. Load	39.4%	73.6%	1.8%	-	-	0.5%	1.5%	2.4%	-19.2%
Aggressive Environmental High Renewables & Increasing Load	25.5%	33.7%	18.0%	0.6%	-	0.2%	0.7%	2.6%	18.7%
Aggressive Environmental High Renewables & Decreasing Load	32.1%	29.4%	13.0%	-	-	0.3%	0.9%	3.3%	21.0%
Booming Economy No CO_2	16.6%	34.8%	0.9%	0.3%	-	0.2%	0.7%	2.4%	44.1%
Booming Economy Loss of Major Ind. Load	49.9%	61.7%	51.3%	-	2.6%	0.5%	1.4%	2.6%	-69.9%

NIPSCO

Notes: * Negative Net Purchases represent a "Long" energy position, where by NIPSCO is selling to the market and positive Net Purchases represent a "short" position, where by NIPSCO is buying from the market. Over the planning horizon, NIPSCO is long and short throughout the year at different times.

Cumulative 2015-2037 Energy Mix

Renewable Focus Portfolio

Sensitivity	Coal	Gas	Wind	Battery	CHP	Solar	Hydro	Nuclear	FIT	DSM	Net Purchases*
Base No CO_2	18.6%	27.9%	15.8%	-	0.2%	5.0%	0.3%	-	0.8%	1.9%	29.4%
Base Low Load	28.4%	43.5%	1.1%	-	0.5%	1.6%	0.3%	-	0.9%	3.2%	20.5%
Base High Gas	29.2%	33.7%	12.3%	0.006%	0.4%	4.7%	0.3%	-	0.8%	2.8%	15.8%
Base Loss of Major Industrial Load	43.7%	71.4%	51.3%	-	-	2.6%	0.5%	-	1.4%	2.6%	-73.5%
Challenged Economy No CO_2	17.1%	34.1%	1.1%	-	0.1%	1.4%	0.3%	-	0.9%	2.7%	42.2%
Challenged Economy Loss of Majr Ind. Load	39.1%	68.4%	1.8%	-	-	-	0.5%	2.2%	1.5%	2.4%	-15.8%
Aggressive Environmental High Renewables & Increasing Load	25.5%	22.0%	92.1%	0.002%	0.3%	0.5%	0.2%	-	0.7%	2.6%	-44.1%
Aggressive Environmental High Renewables & Decreasing Load	31.9%	15.4%	84.3%	0.004%	-	7.6%	0.3%	-	0.9%	3.3%	-43.7%
Booming Economy No CO_2	16.9%	27.7%	1.9%	-	0.2%	7.2%	0.2%	-	0.7%	2.4%	42.7%
Booming Economy Loss of Mjr Ind. Load	49.9%	61.7%	51.3%	-	-	2.6%	0.5%	-	1.4%	2.6%	-69.9%

NIPSCO

Notes: * Negative Net Purchases represent a "Long" energy position, where by NIPSCO is selling to the market and positive Net Purchases represent a "short" position, whereby NIPSCO is buying from the market. Over the planning horizon, NIPSCO is long and short throughout the year at different times.

Cumulative 2015-2037 Energy Mix

Low Emissions Portfolio

Scenario	Coal	Gas	Wind	Battery	Biomass	Solar	MICT	Hydro	Nuclear	Recip	FIT	DSM	Net Purchases*
Base No CO_2	18.9%	27.6%	8.6%	0.005%	0.1%	2.9%	-	0.3%	1.9%	0.001%	0.8%	1.9%	36.9%
Base Low Load	28.5%	43.1%	1.1%	0.006%	-	0.6%	-	0.3%	0.8%	-	0.9%	3.2%	21.5%
Base High Gas	29.3%	33.7%	6.6%	0.003%	0.1%	2.7%	-	0.3%	0.5%	0.002%	0.8%	2.8%	23.2%
Base Loss of Major Industrial Load	44.5%	68.0%	1.7%	-	-	-	-	0.5%	1.2%	-	1.4%	2.6%	-19.8%
Challenged Economy No CO_2	17.2%	33.7%	1.1%	0.005%	-	0.3%	-	0.3%	0.5%	0.001%	0.9%	2.7%	43.3%
Challenged Economy Loss of Majr Ind. Load	39.1%	68.4%	1.8%	-	-	-	-	0.5%	2.2%	-	1.5%	2.4%	-15.8%
Aggressive Environmental High Renewables & Increasing Load	25.6%	21.9%	31.2%	-	-	10.4%	-	0.2%	-	-	0.7%	2.6%	7.4%
Aggressive Environmental High Renewables & Decreasing Load	32.0%	27.0%	19.9%	-	-	-	-	0.3%	-	-	0.9%	3.3%	16.6%
Booming Economy No CO_2	17.3%	25.9%	2.9%	0.005%	0.1%	2.7%	0.001%	0.2%	2.1%	0.001%	0.7%	2.4%	45.7%
Booming Economy Loss of Mjr Ind. Load	51.2%	58.6%	1.7%	-	-	-	-	0.5%	0.7%	-	1.4%	2.6%	-16.7%

NIPSCO

Notes: * Negative Net Purchases represent a "Long" energy position, where by NIPSCO is selling to the market and positive Net Purchases represent a "short" position, where by NIPSCO is buying from the market. Over the planning horizon, NIPSCO is long and short throughout the year at different times.

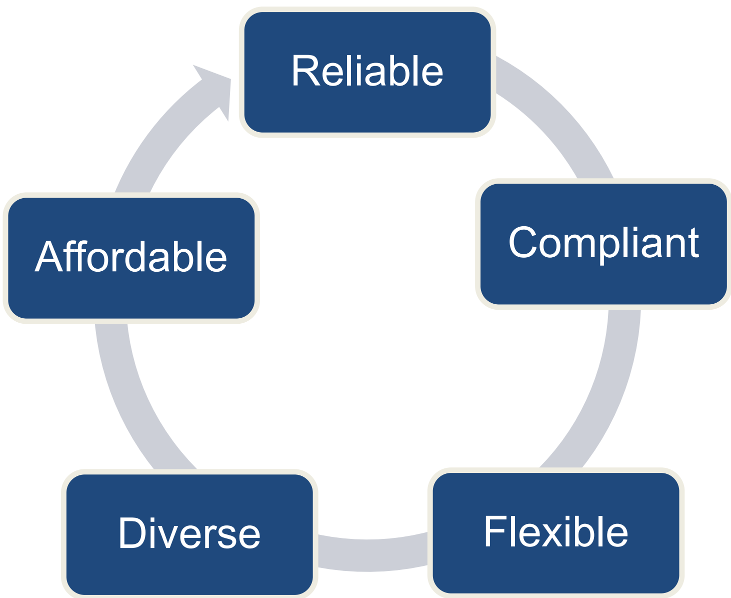
Lunch

Preferred Plan & Short Term Action Plan

Presented by
Dan Douglas
Vice President, Corporate Strategy & Development

NIPSCO

Preferred Supply Portfolio Criteria



Requires Careful Planning And Consideration For:

- Our employees
- Impact on the environment
- Changes in the local economy (property tax, supplier spend, employee base)

The IRP, while informative is simply a submission to the IURC; NIPSCO intends to remain engaged with interested stakeholders

Action Plan For NIPSCO's Current Generation

- **Retire 50% of NIPSCO's coal capacity by the end of 2023**
  - Pursue the most viable option, Bailly Units 7 and 8 will retire as soon as 2018 and Schahfer Units 17 and 18 will retire by the end of 2023, subject to MISO and other considerations
  - Will continue to monitor key market, compliance and technology developments
- **Maintain current gas fueled generation**
  - Sugar Creek CCGT, Schahfer 16A&B CTs, Bailly 10 CT
- **Continue the interruptibles program**
- **Maintain current wind Purchase Power Agreements (PPAs)**
- **File DSM/EE Program Filings in 2017**
- **Proceed with CCR/ELG compliance plan filing(s) for Michigan City 12 and Schahfer 14&15**

A Diverse Supply Portfolio That Includes Shorter Duration, Flexible Supply In the Portfolio Can Reduce Risk

Reliable
Affordable
Compliant
Diverse
Flexible

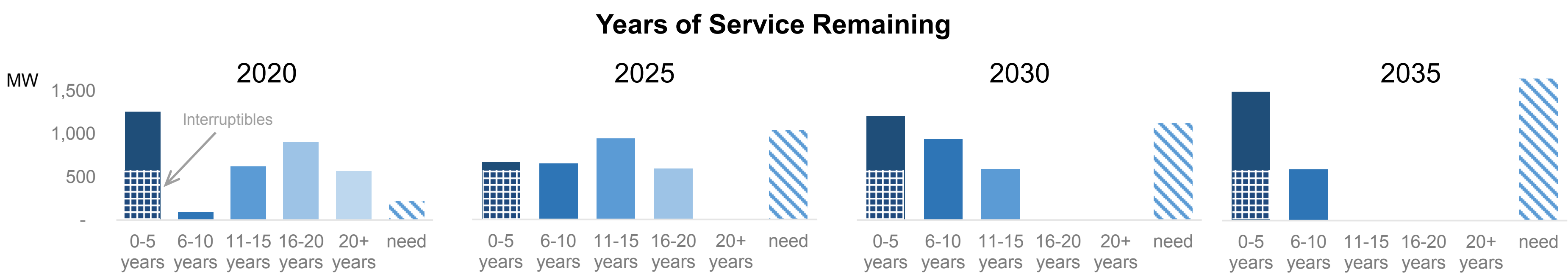
- **Customer risk**
  - The five large industrials account for about ~40% NIPSCO's energy demand, and ~1,200 MW of peak load plus reserve; these customers are largely tied to steel industry cycles
  - Residential and Commercials customers comprise most of the remaining demand and while diversified and unlikely to move remarkably would likely see some impacts from loss industrials who are major employers

- **Technology risk**
  - Technology changes drive a portion (but by no means all) of the volatility in market prices, both for capacity and energy
  - Technological (and regulatory) changes can render specific generation technologies obsolete, and can force their premature retirement

- **Market risk**
  - Historically MISO North (i.e. excluding the Entergy region) has had excess capacity above and beyond the regional reliability requirement
  - However, due to retirement of both merchant and regulated generation, and a market model that does not support merchant new entry, MISO's excess capacity has been declining

In addition to Interruptibles, NIPSCO intends to have a portion of the portfolio allocated to short duration supply in the form of PPAs and/or market purchases

Duration Of Current Portfolio Averages 12 Years



(% of installed capacity)	2020	2025	2030	2035
0-5 years	34%	17%	31%	40%
6-10 years	3%	17%	24%	16%
11-15 years	17%	24%	15%	0%
16-20 years	25%	15%	0%	0%
20+ years	16%	0%	0%	0%
need	6%	27%	29%	44%
Average Duration	**10 years**	**7 years**	**4 years**	**2 years**

There is no less than 17% of the generation portfolio that is flexible (<5yr tenor) over the next 20 years

NIPSCO

Note: average duration is MW-weighted and includes generation strategy retirements and age-based retirement dates

NIPSCO Supply Resource Plan and Timing

Expected

Base

	Near-Term	Mid-Term	Long-Term
Timing	2016 – 2018	2019 – 2023	2024 – 2037
NIPSCO Activity Description	• Implement retirements with a focus on interests of customers, employees and local communities • Identify and secure lowest cost near-term replacement capacity	• Monitor market developments and pricing • Establish long-term replacement capacity optionality	• Monitor market and industry development and refine future IRPs
Retirements	• Bailly 7/8 (accelerated)	• Schahfer 17/18 (accelerated) • Bailly 10	• Michigan City 12 (age-based)
Expected Capacity Need	0 – 150MW	150 – 950MW	950 – 1,600MW
NIPSCO's Preferred Replacement Plan	• Demand Side Management • PPA / Market purchases	• CCGT • PPA / Market purchases	• CCGT • PPA / Market purchases
Expected Regulatory Filings	• CPCN for CCR/ELG • DSM	• CPCN for replacement capacity	• CPCN for replacement capacity

NIPSCO

How Will NIPSCO Pursue PPAs/Market Purchases?

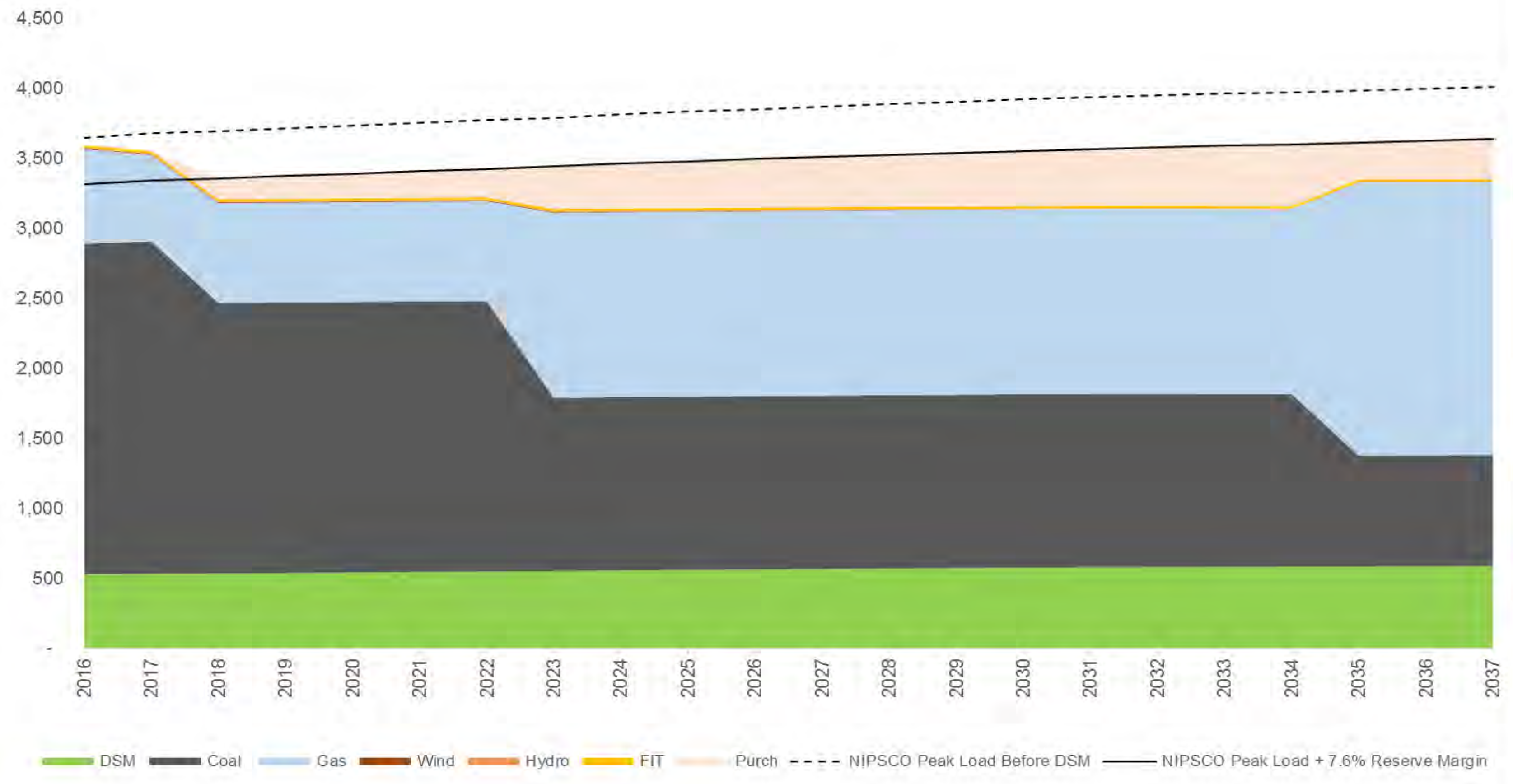
Reliable
Affordable
Compliant
Diverse
Flexible

- **Caution on market purchases**
  - MISO capacity market has historically been oversupplied, but is projected to tighten in the coming years due to retirement of both merchant and regulated generation resulting in higher Planning Reserve Auction prices
  - MISO is attempting to fix this issue, but considerable obstacles remain and market design risk and potential for increased capacity prices is likely to be high in the next several years
  - Thus, any strategy which relies on market purchases should be approached with caution with alternatives options available

- **How will NIPSCO execute shorter term duration supply?**
  - Evaluate MISO capacity and PPA market (exact RFP timing to be finalized)
  - Consider all technologies as viable; assume that renewables will be advantaged given tax incentives
  - Pick the lowest cost option for customers

Preferred Plan Capacity Expansion

Base

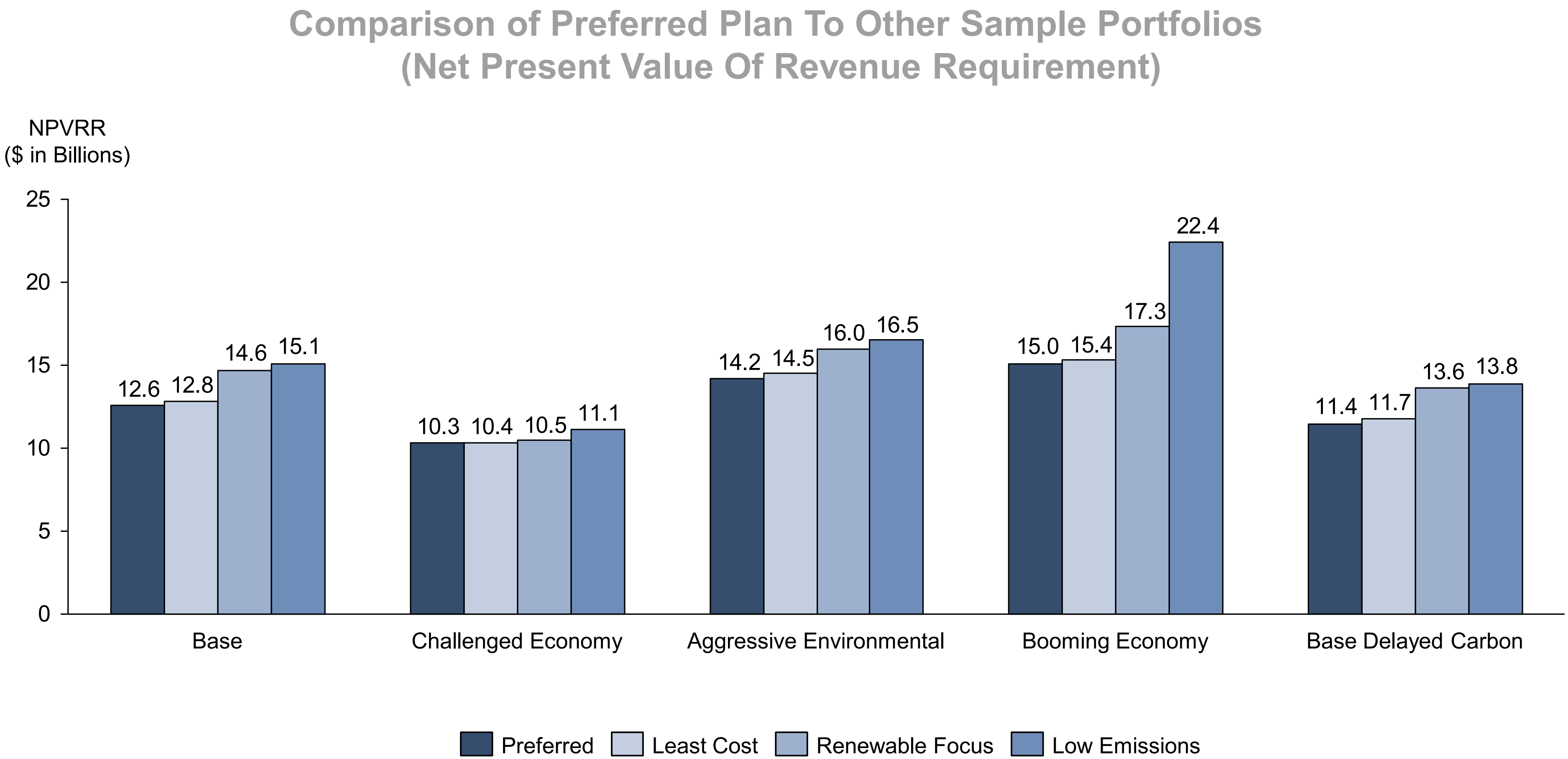


	Coal	Gas	Wind	Hydro	FIT	DSM	Net Purchases
Cumulative 2015-2037 Energy Mix	24.90%	40.90%	0.90%	0.30%	0.80%	2.80%	29.50%

NIPSCO

Notes: These results may differ from what will be presented in the 2016 IRP document due to a change operating characteristics which will be reflected in the final optimization runs performed for the document.

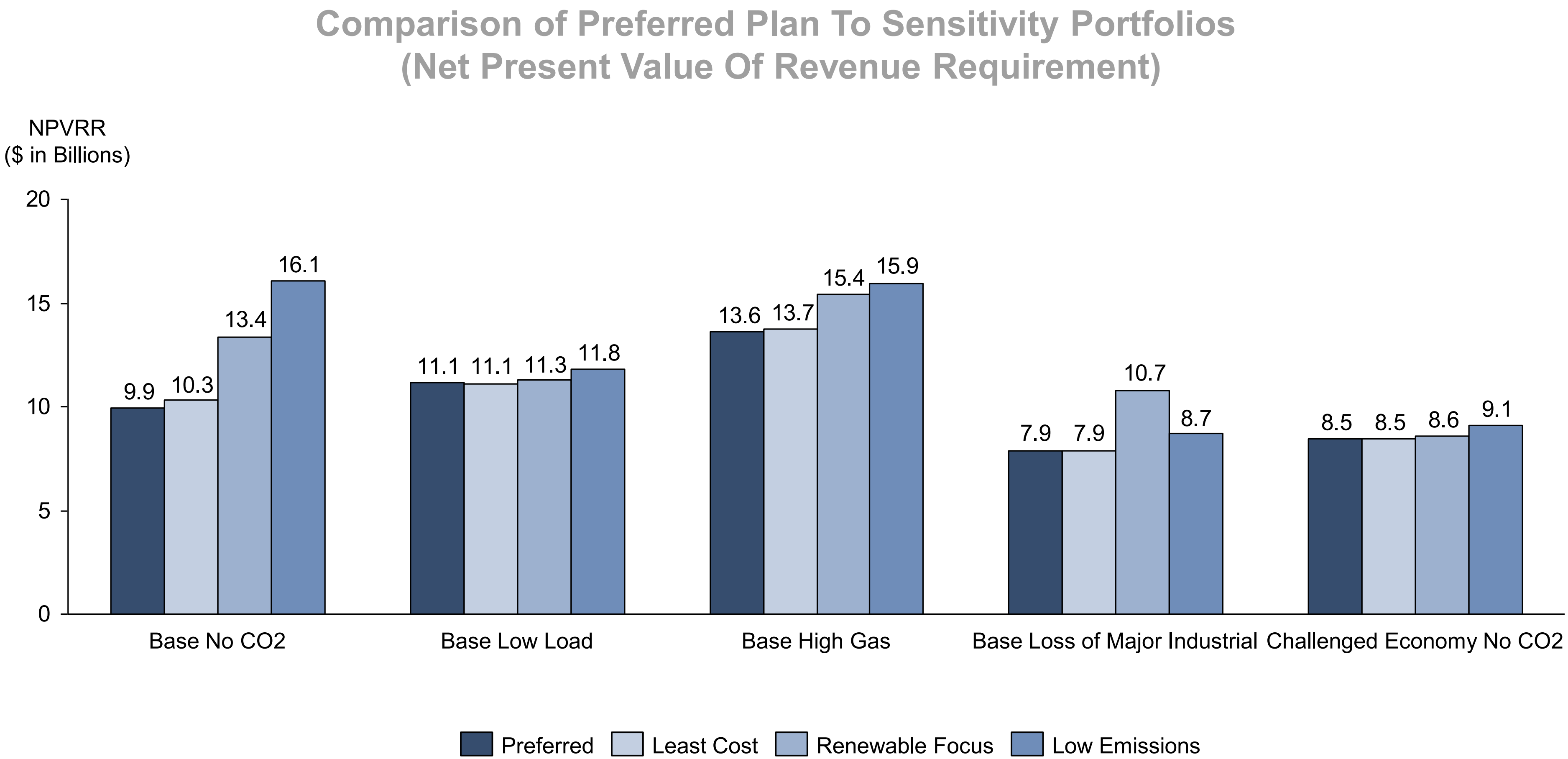
Comparison Of Preferred Plan To Optimization: Scenarios



NIPSCO's Preferred Plan Compares Well to Other Portfolios Across All Scenarios

NIPSCO

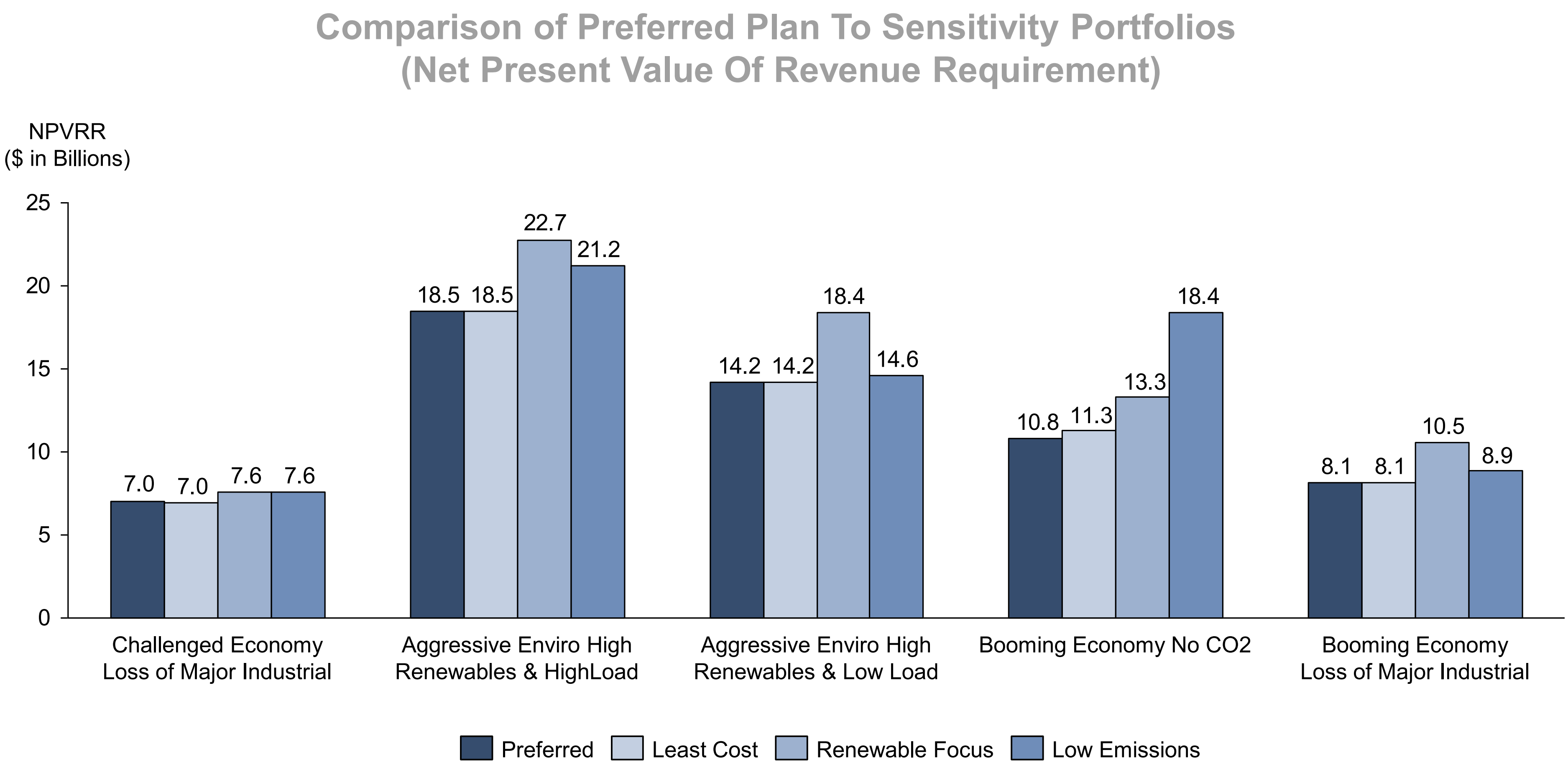
Comparison Of Preferred Plan To Optimization: Sensitivities



NIPSCO's Preferred Plan Compares Well to Other Portfolios Across All Scenarios

NIPSCO

Comparison Of Preferred Plan To Optimization: Sensitivities



NIPSCO's Preferred Plan Compares Well to Other Portfolios Across All Scenarios

Demand Side Management

Selected Program Groupings	Groupings That Will Receive Further Consideration	Program Groupings Not Selected
These programs were selected in the majority of the IRP optimization runs	*These programs were occasionally selected in several of the optimization runs*	*These programs were not selected by the IRP optimization runs*
13 Program Groupings	9 Program Groupings	4 Program Groupings
– Res Electric Water Heat	– Res Appliances	– Res Cooling
– Res Exterior Lighting	– Res Electric Miscellaneous	– Res Electric Heating
– Res Interior Lighting	– Com Electric Heating	– Com Cooling
– Com Exterior Lighting	– Com Ventilation	– Industrial Heating
– Com Electric Food Prep	– Industrial Cooling	
– Com Electric Water Heat	– Res Cooling Direct Load Control (DLC)	
– Com Interior Lighting	– Res Water Heating DLC	
– Com Elec Miscellaneous	– Com Cooling DLC	
– Com Office Equipment	– Com Water Heating DLC	
– Com Refrigeration		
– Industrial Exterior Lighting		
– Industrial Interior Lighting		
– Industrial Motors		

NIPSCO will file its DSM plan in 2017

NIPSCO's Preferred Resource Plan

2018-2022	2023+
Short Term (take action in near-term)	**Long Term** (IRP placeholder, begin planning)
• Maintain Interruptibles • Procure necessary capacity from the MISO market and/or PPA • File for environmental compliance capital on Michigan City 12 and Schahfer 14&15 • Preserve option to build a CCGT for future long-term generation	• Identify CCGT as a portion of likely long-term generation solution • Market purchases and/or PPA to fill remaining capacity needs

- **Short-term action plan for November 1 IRP filing**
  - Maintain an appropriate amount of Interruptibles
  - Market PPA / purchases to meet required capacity obligations; renewables will be considered
  - ELG/CCR filing and CPCN for Michigan City 12 and Schahfer 14&15 environmental compliance
- **Long-term generation plan**
  - Include a CCGT in 2023 and 2035
    - Preserve options to build; a decision can be made as late as 2019
  - Monitor MISO market fundamentals and capacity pricing as well as PPA pricing

Stakeholder Presentations

Next Steps

Presented by

Dr. Marty Rozelle

The Rozelle Group Ltd

Next Steps

- **Submit IRP by November 1st :**
- **Meeting summary:** Available October 17, 2016
- **NIPSCO website:** *www.NIPSCO.com/irp*
- **NIPSCO IRP email:** *NIPSCO_IRP@nisource.com*

NIPSCO

Supplemental Slides

2014 IRP Lessons Learned & Continuous Improvement Action Plan

2014 IRP Feedback	Continuous Improvement Action Plan
Enhance Stakeholder Process	- Participated in joint educational session with Indiana utility peers to develop foundational reference materials - Engaging stakeholders to obtain feedback on IRP analysis and future world alternatives
Improve Load Forecasting Process	- Clarify the detailed narrative and load forecast enhancements
Clarify DSM Modeling	- Provide DSM development and modeling methodology detail
Expand Scenarios and Sensitivities	- Develop a robust set of scenarios and sensitivities to capture a wider range of potential risks/uncertainties - Increase emphasis on environmental rules and regulations
Address Customer-owned and Distributed Generation	- Evaluate distributed generation and Combined Heat & Power
Provide Confidential Data Proxies	- Reduce use of confidential data and use public/representative proxy data as substitute for proprietary data

NIPSCO

DSM Selection Across All Cases

		Residential							Commercial										Industrial					Demand Response				
Scenario	**Sensitivity**	REAP	RECG	REHG	REMS	REWH	REEL	REIL	COCG	COEL	COFP	COHG	COIL	COMS	COOE	CORF	COVE	COWH	INCG	INEL	INIL	INMT	INHG	DRRA	DRCA	DRRH	DRCH	**Total**
Base						1	1	1		1	1		1	1	1	1		1		1	1	1						**13**
	Bs1					1				1	1			1	1			1		1	1	1						**9**
	Bs2					1	1	1		1	1		1	1	1	1		1		1	1	1					1	**14**
	Bs3					1	1	1		1	1		1	1	1	1		1		1	1	1						**13**
	Bs4					1	1	1		1	1		1	1	1	1		1		1	1	1						**13**
CE						1	1			1	1		1	1	1	1		1		1	1	1					1	**13**
	CEs1					1					1		1	1	1			1		1	1	1			1	1	1	**12**
	CEs2					1	1			1	1		1	1	1	1		1		1	1	1						**12**
AE					1	1	1	1		1	1		1	1	1	1		1		1	1	1						**14**
	AEs1	1			1	1	1	1		1			1	1	1	1	1	1		1	1	1			1			**16**
	AEs2	1				1	1	1		1	1		1	1	1	1	1	1		1	1	1						**15**
BE						1	1	1		1	1	1	1	1	1	1		1		1	1	1			1			**15**
	BEs1					1				1	1		1	1	1			1	1	1	1	1		1	1	1		**14**
	BEs2					1	1	1		1	1		1	1	1	1		1		1	1	1						**13**
BDC						1				1	1		1	1	1	1		1		1	1	1						**11**
Scenario	Mode (5)	0	0	0	1	5	4	3	0	5	5	1	5	5	5	5	0	5	0	5	5	5	0	0	1	0	1	
All	Mode (15)	2	0	0	2	15	11	9	0	14	14	1	14	15	15	12	2	15	1	15	15	15	0	1	4	2	3	

	All	Scenarios
Tier 1	10	11
Tier 2	3	2
Tier 3	9	4
Not Selected	4	9
	26	26

NIPSCO

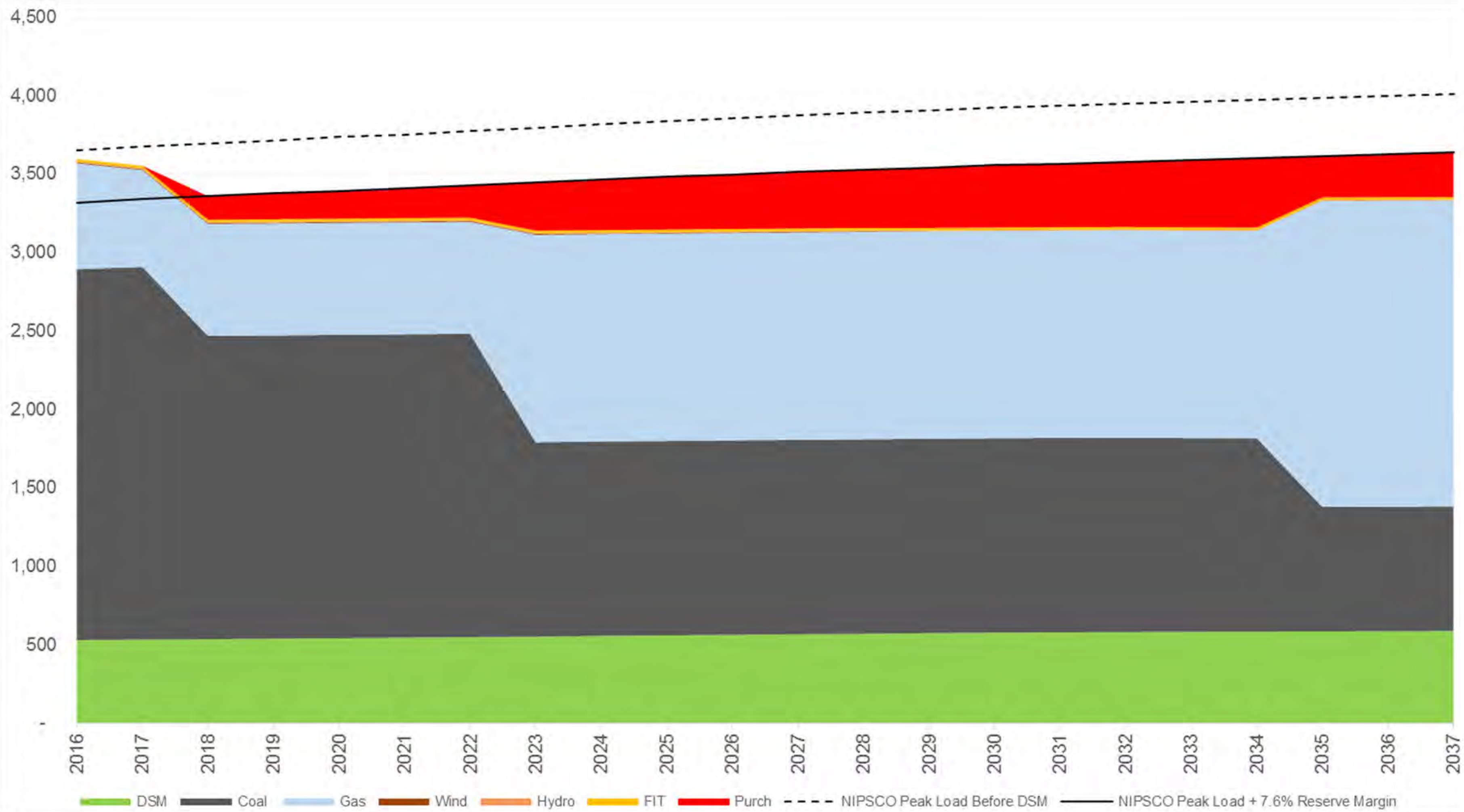
2016 IRP Public Advisory Meeting Appendix

October 03, 2016

NIPSCO

Base Scenario Capacity Expansion Preferred Portfolio

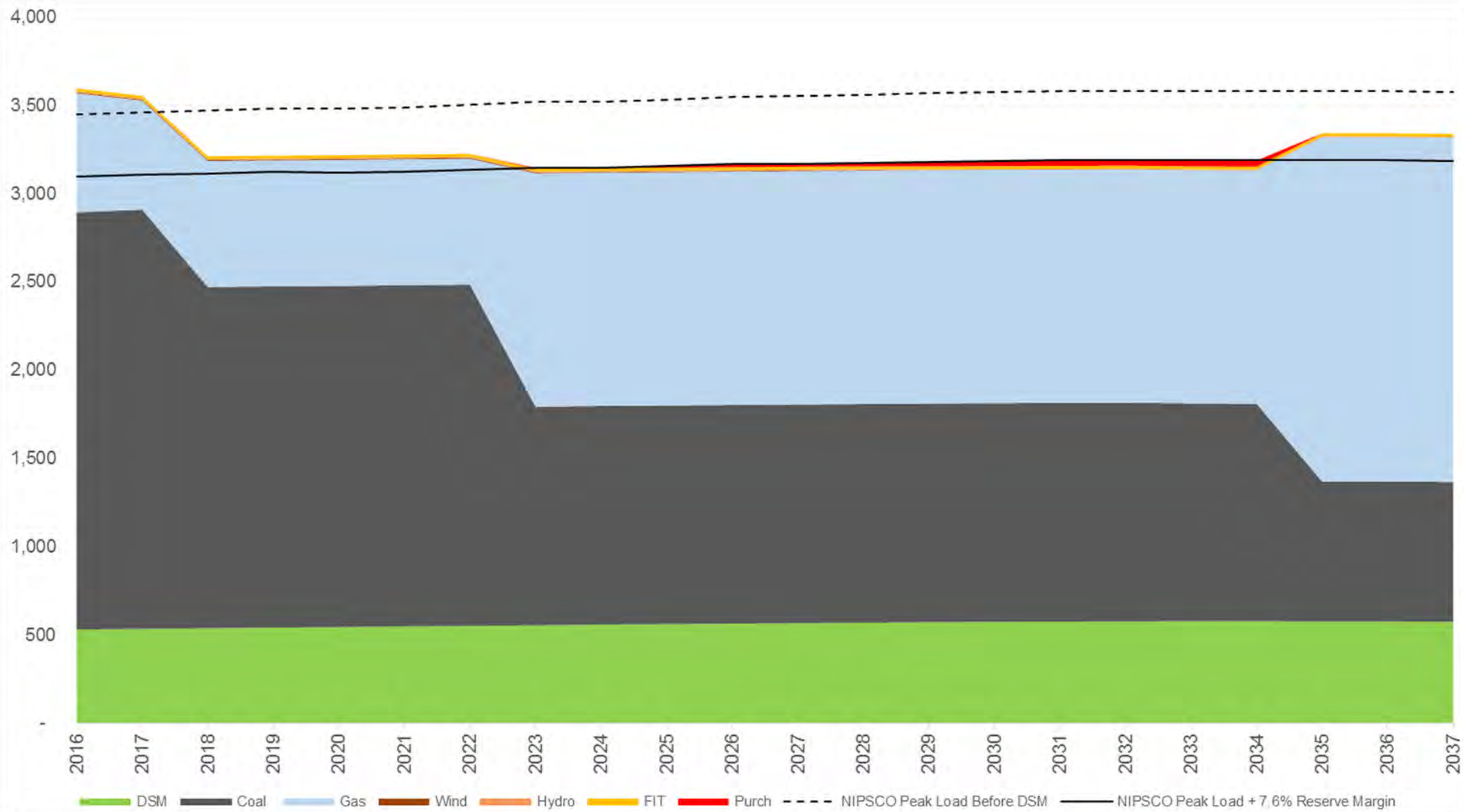
Base



NIPSCO

Challenged Economy Capacity Expansion Preferred Portfolio

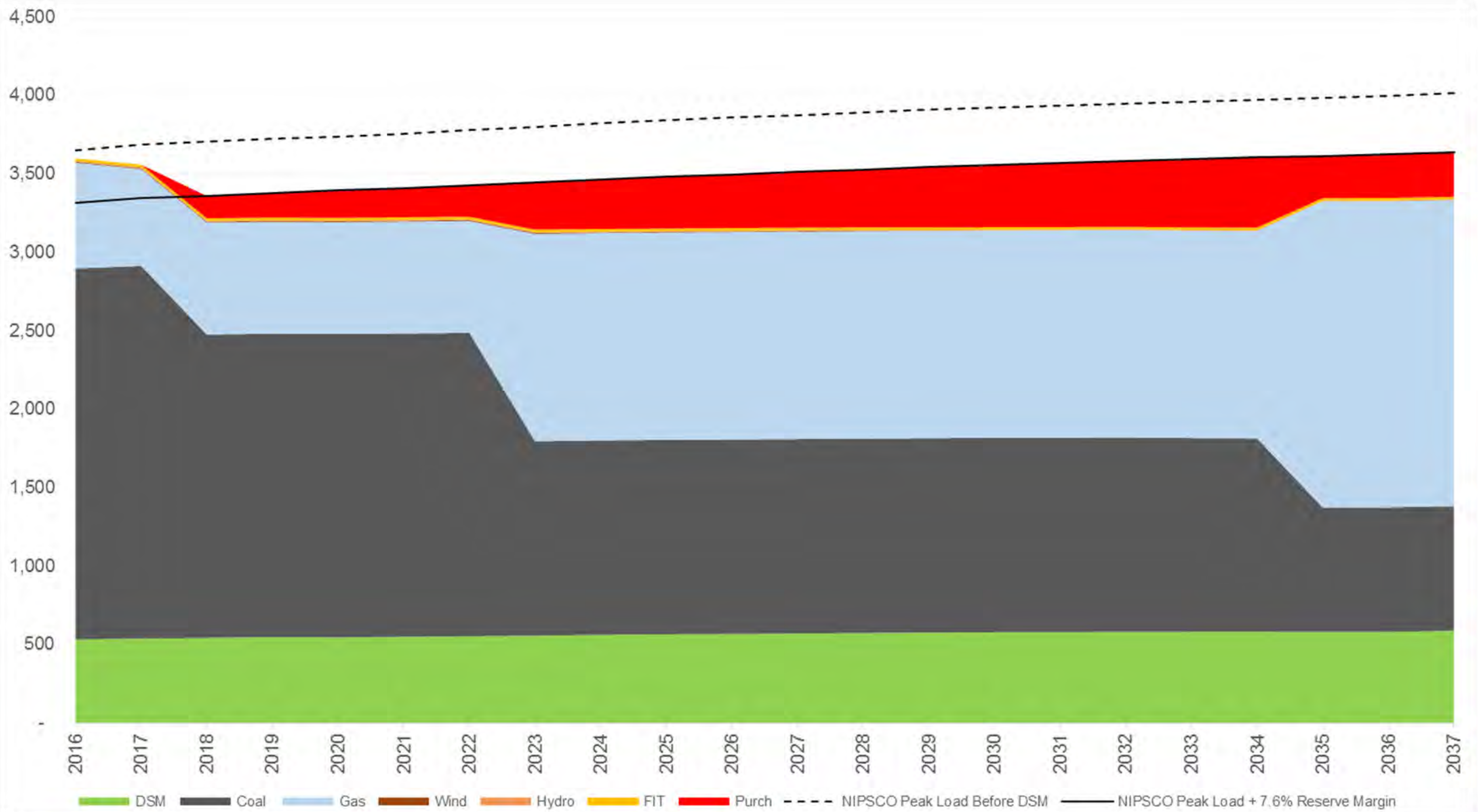
Base



NIPSCO

Aggressive Environmental Capacity Expansion Preferred Portfolio

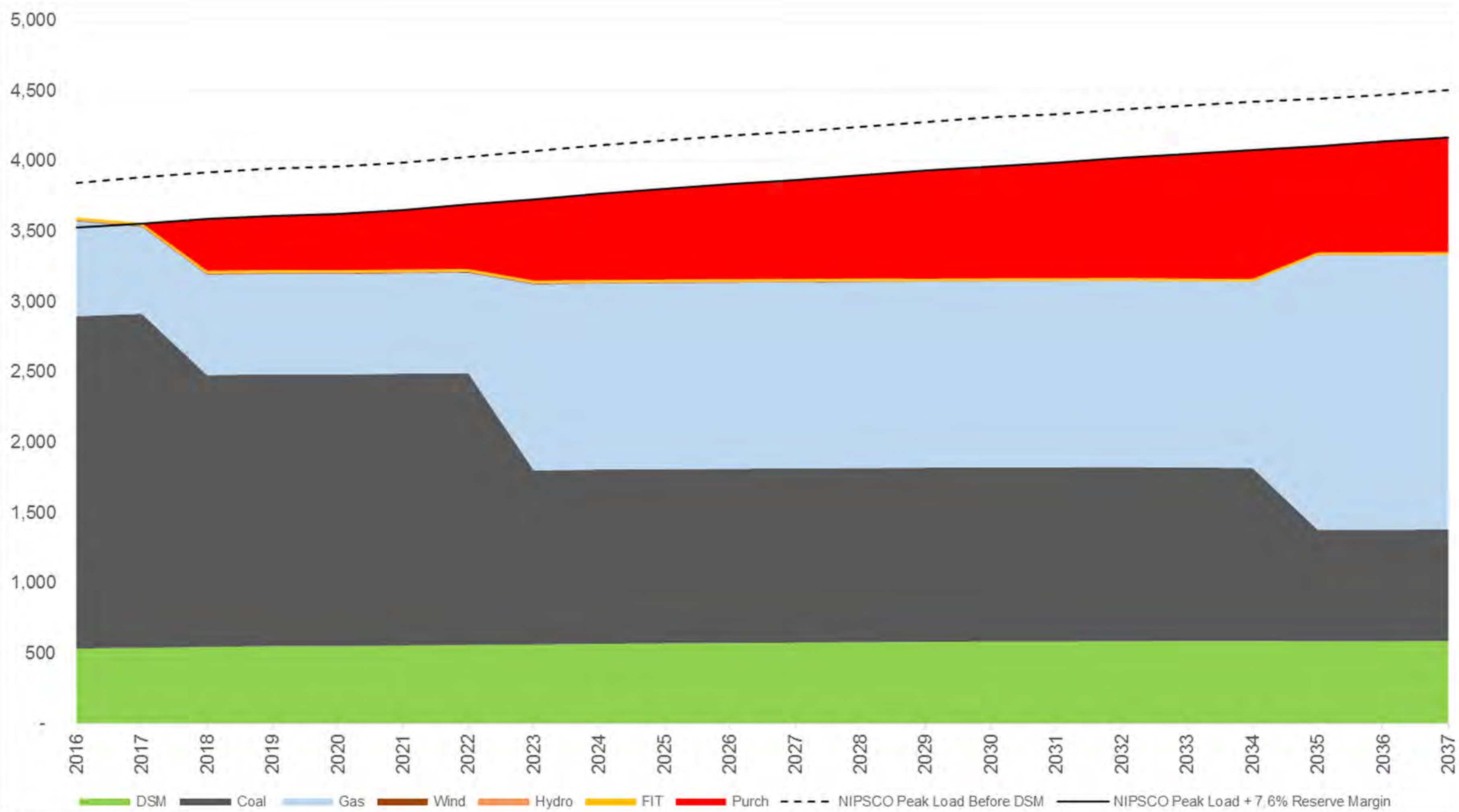
Base



NIPSCO

Booming Economy Capacity Expansion Preferred Portfolio

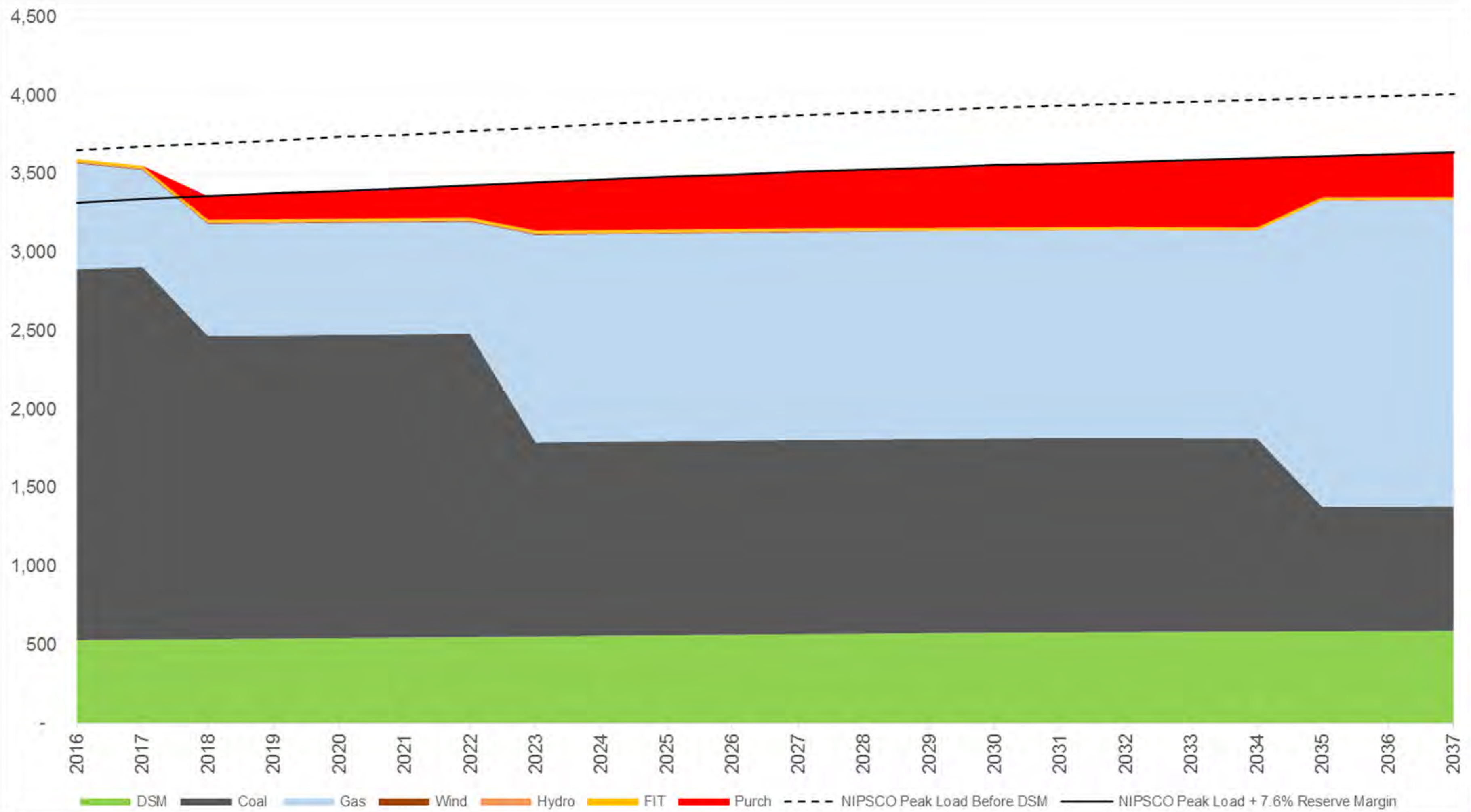
Base



NIPSCO

Base Delayed Carbon Capacity Expansion Preferred Portfolio

Base



NIPSCO

Preferred Plan Cumulative 2015-2037 Energy Mix

Preferred Plan							
Scenario	**DSM**	**Net Purchases***	**Coal**	**Gas**	**Wind**	**Hydro**	**FIT**
Base	2.8%	29.5%	24.9%	40.9%	0.9%	0.3%	0.8%
Challenged Economy	2.9%	25.8%	24.0%	45.0%	1.1%	0.3%	0.9%
Aggressive Environmental	2.8%	48.2%	22.1%	24.9%	0.9%	0.3%	0.8%
Booming Economy	2.5%	38.1%	25.6%	31.9%	0.9%	0.2%	0.7%
Base Delayed Carbon	2.6%	39.0%	18.4%	38.0%	0.9%	0.3%	0.8%

Notes: * Negative Net Purchases represent a "Long" energy position, where by NIPSCO is selling to the market and positive Net Purchases represent a "short" position, where by NIPSCO is buying from the market. Over the planning horizon, NIPSCO is long and short throughout the year at different times.

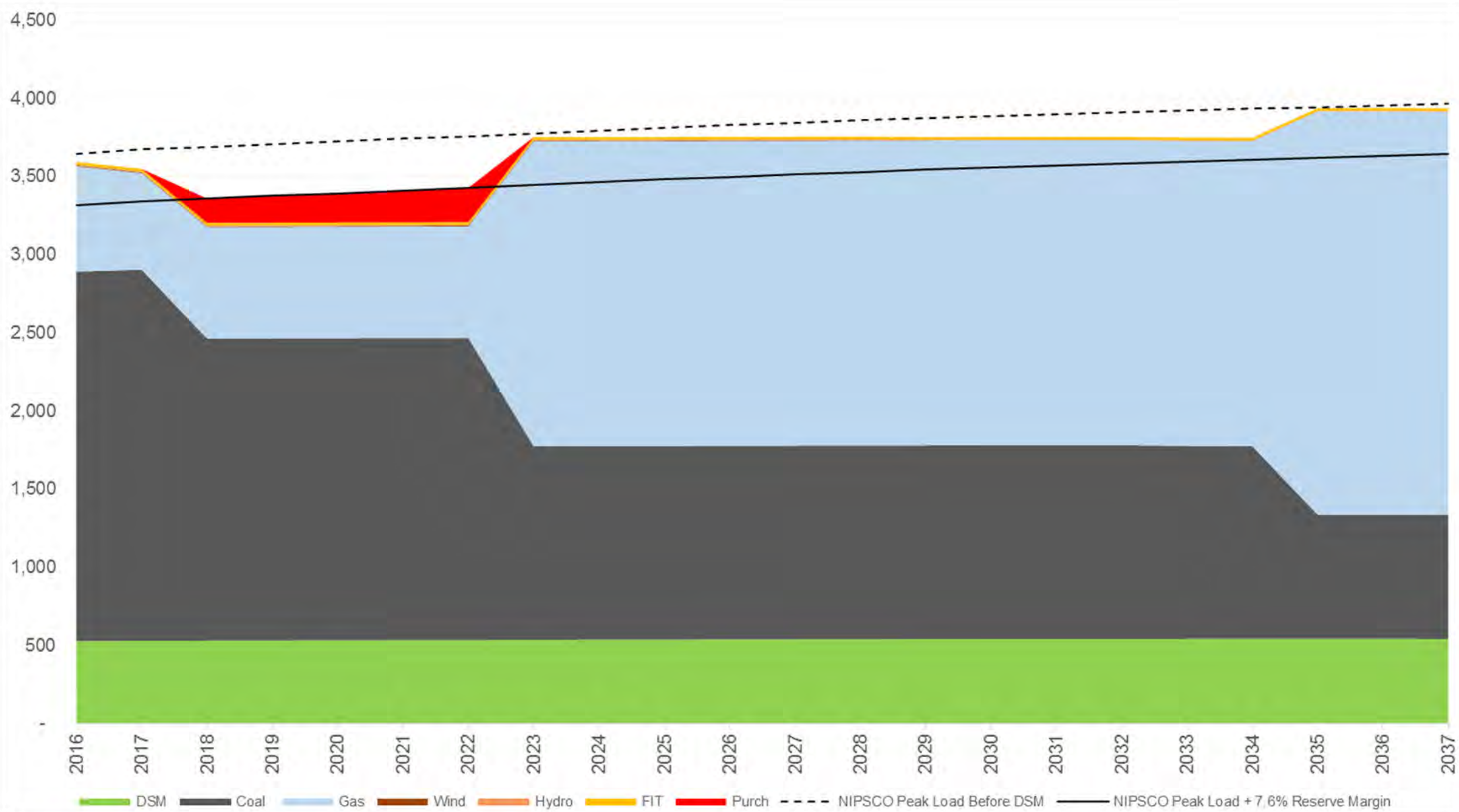
NIPSCO

Sensitivities Analysis

Scenarios	Base	Challenged Economy	Aggressive Environmental Regulation	Booming Economy	Base Delayed Carbon
Sensitivities	No CO_2 Price	No CO_2 Price	High Renewables & Increasing Load	No CO_2 Price	
	Low Load	Loss of Major Industrial Load	High Renewables & Decreasing Load	Loss of Major Industrial Load	
	High Gas Price				
	Loss of Major Industrial Load				

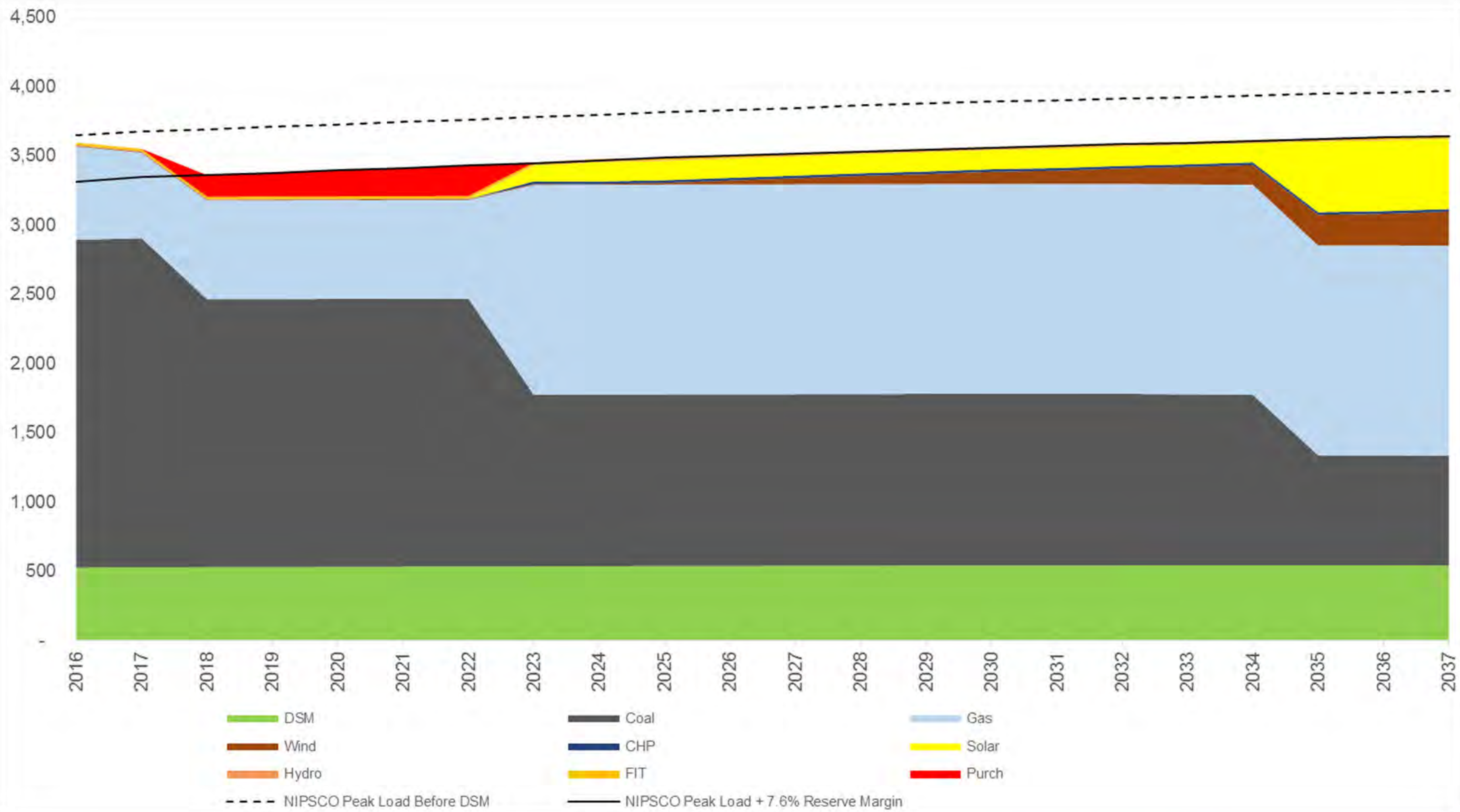
Sources and Notes: Definitions adapted from *Electricity Director's Final Report 2014-2015 Integrated Resources Plans*, IURC, p. 9; Varying one "element" of a scenario to create a sensitivity may require changes to multiple variables to ensure that input data are properly correlated; For example, a low gas price sensitivity also requires correlated (lower) electricity prices

Base No CO2 Scenario Capacity Expansion (Least Cost)



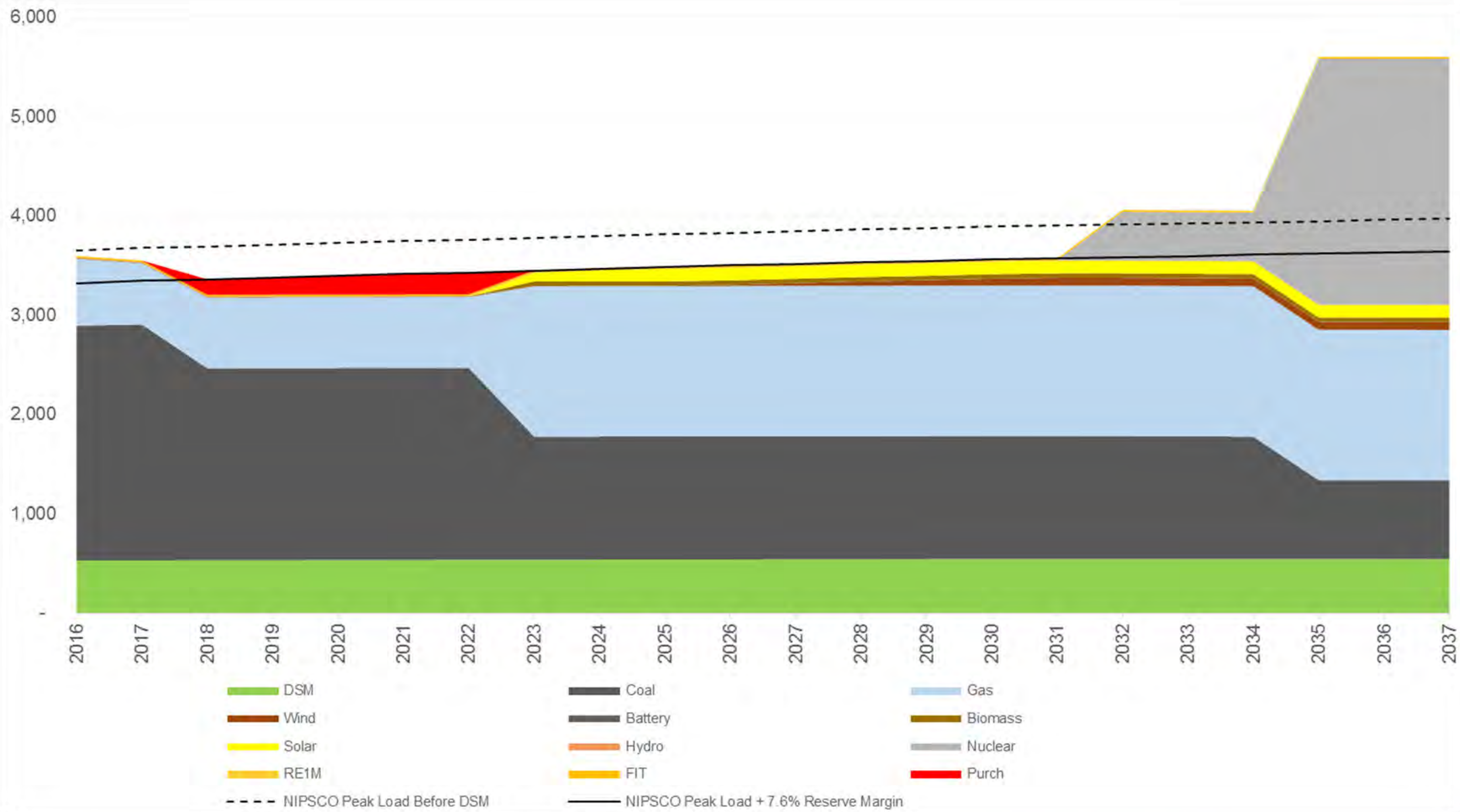
NIPSCO

Base No CO2 Scenario Capacity Expansion (Renewable)



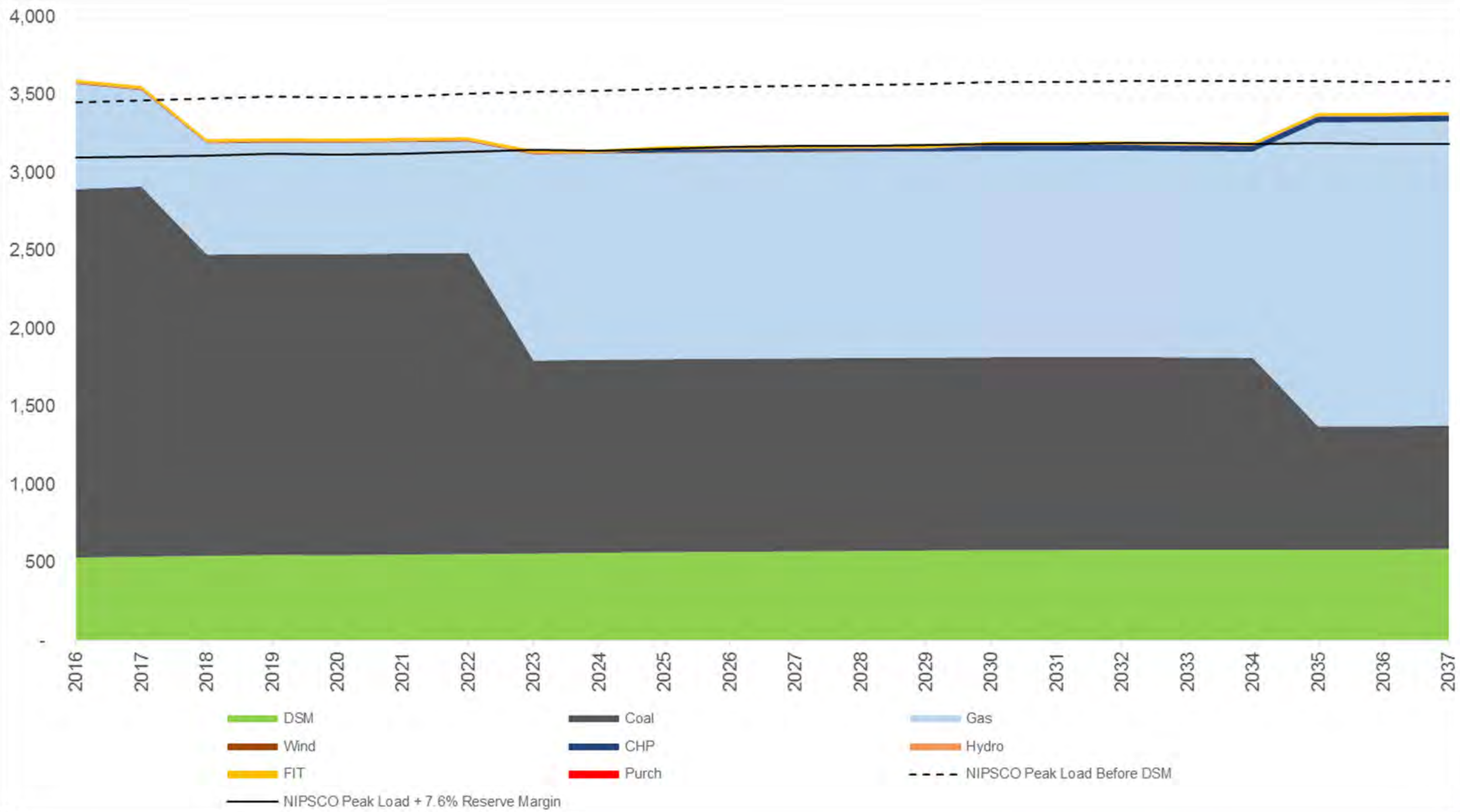
NIPSCO

Base No CO2 Scenario Capacity Expansion (Low Emission)

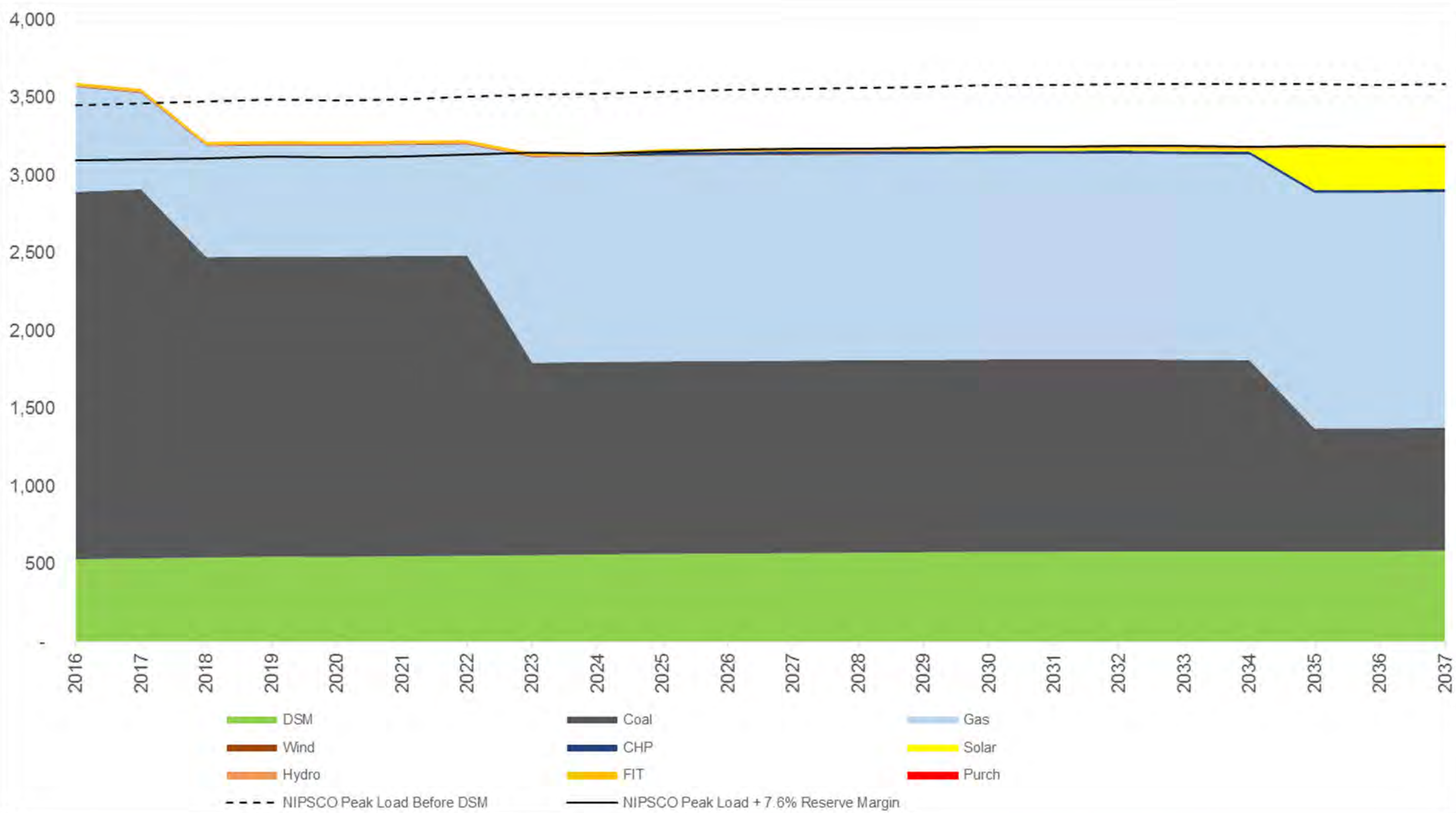


NIPSCO

Base Low Load Scenario Capacity Expansion (Least Cost)

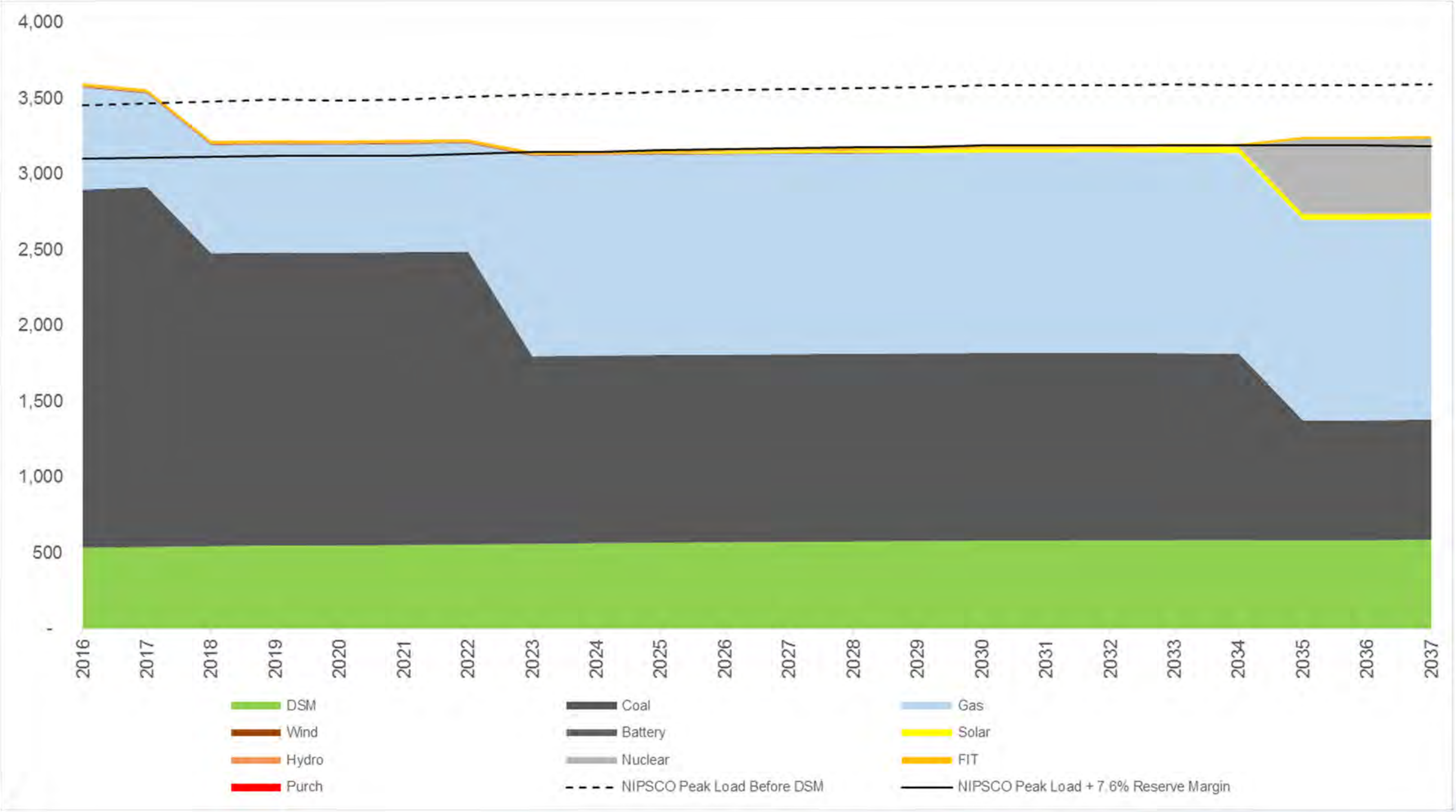


Base Low Load Scenario Capacity Expansion (Renewable)



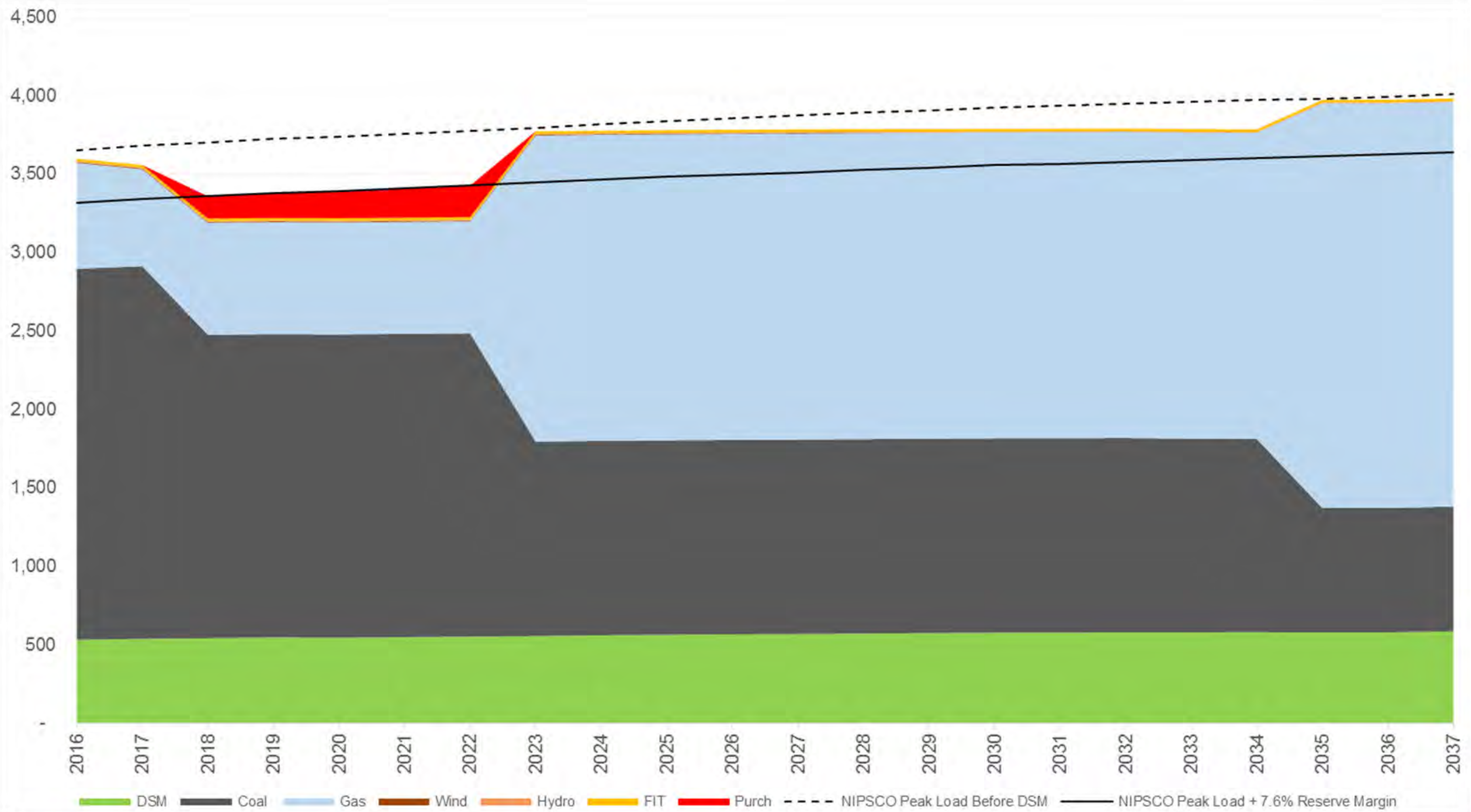
NIPSCO

Base Low Load Scenario Capacity Expansion (Low Emission)



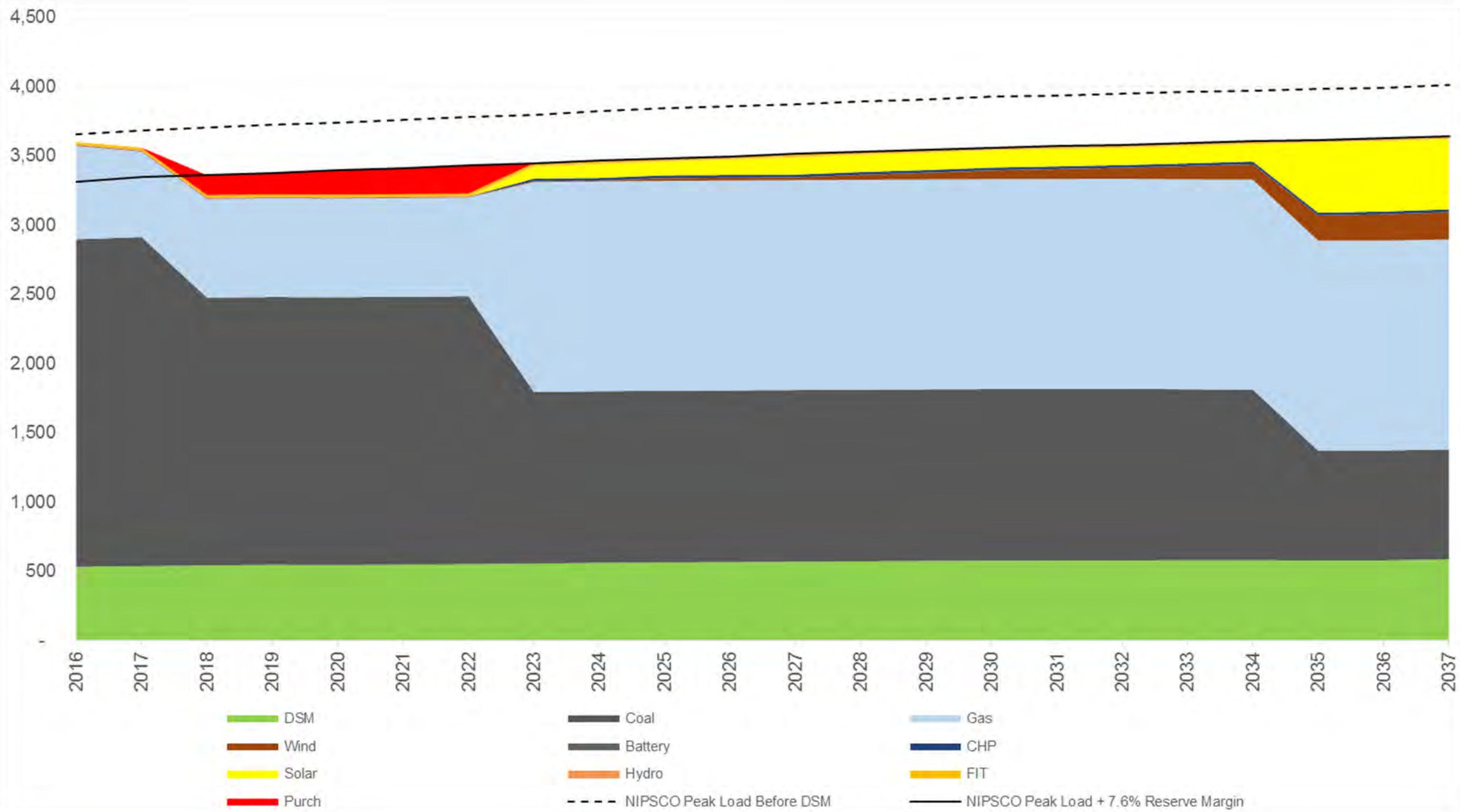
NIPSCO

Base High Gas Price Scenario Capacity Expansion (Least Cost)



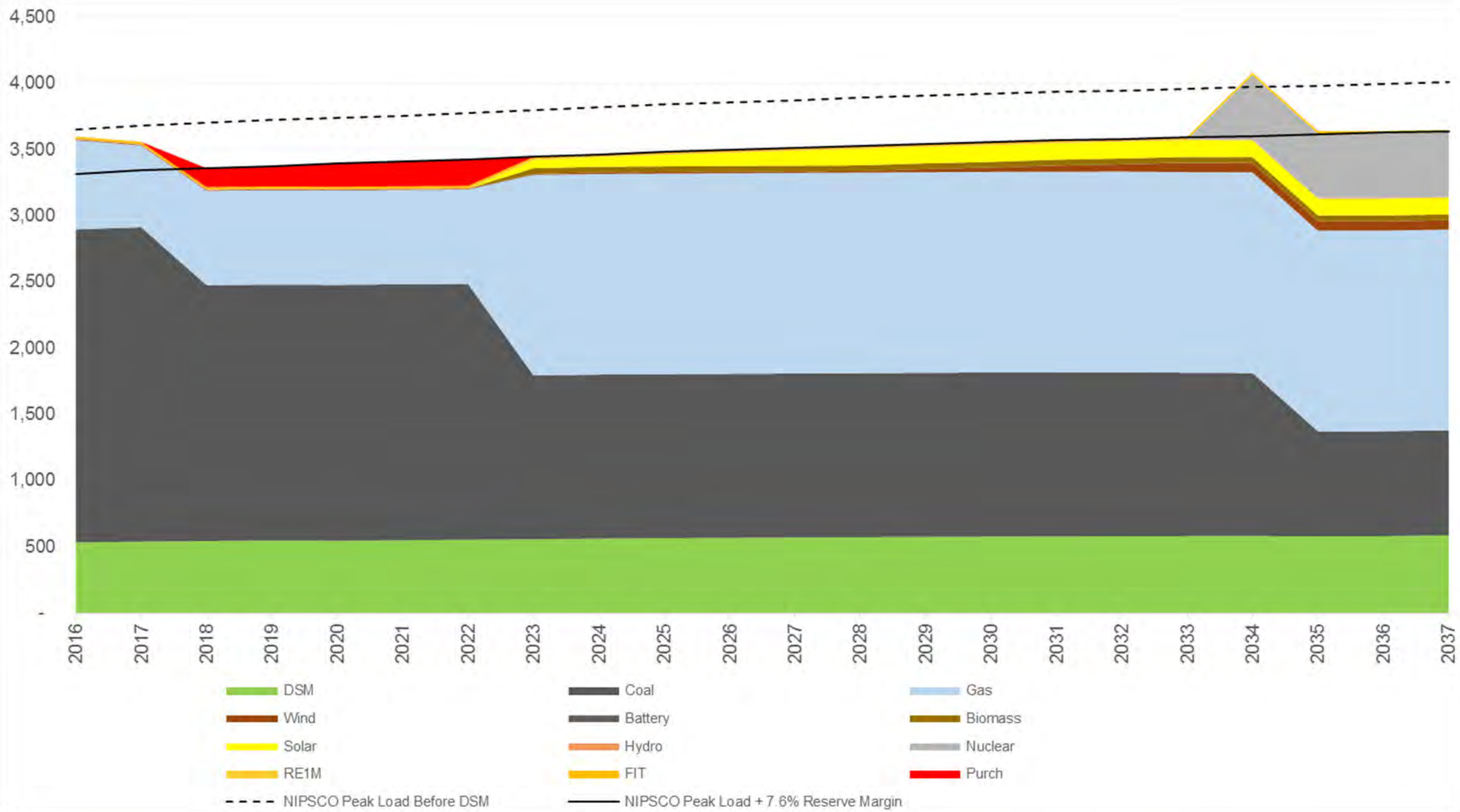
NIPSCO

Base High Gas Price Scenario Capacity Expansion (Renewable)

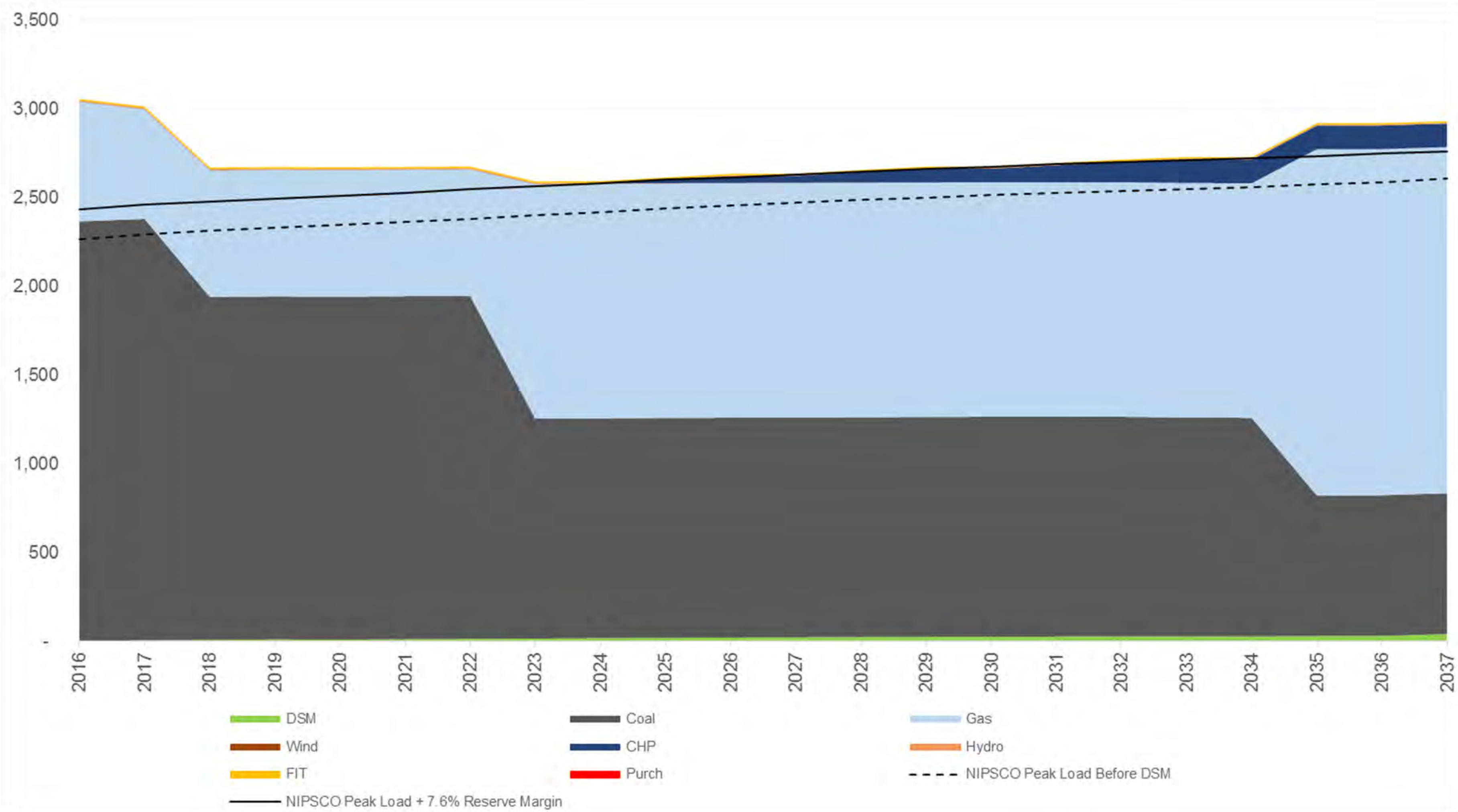


NIPSCO

Base High Gas Price Scenario Capacity Expansion (Low Emission)

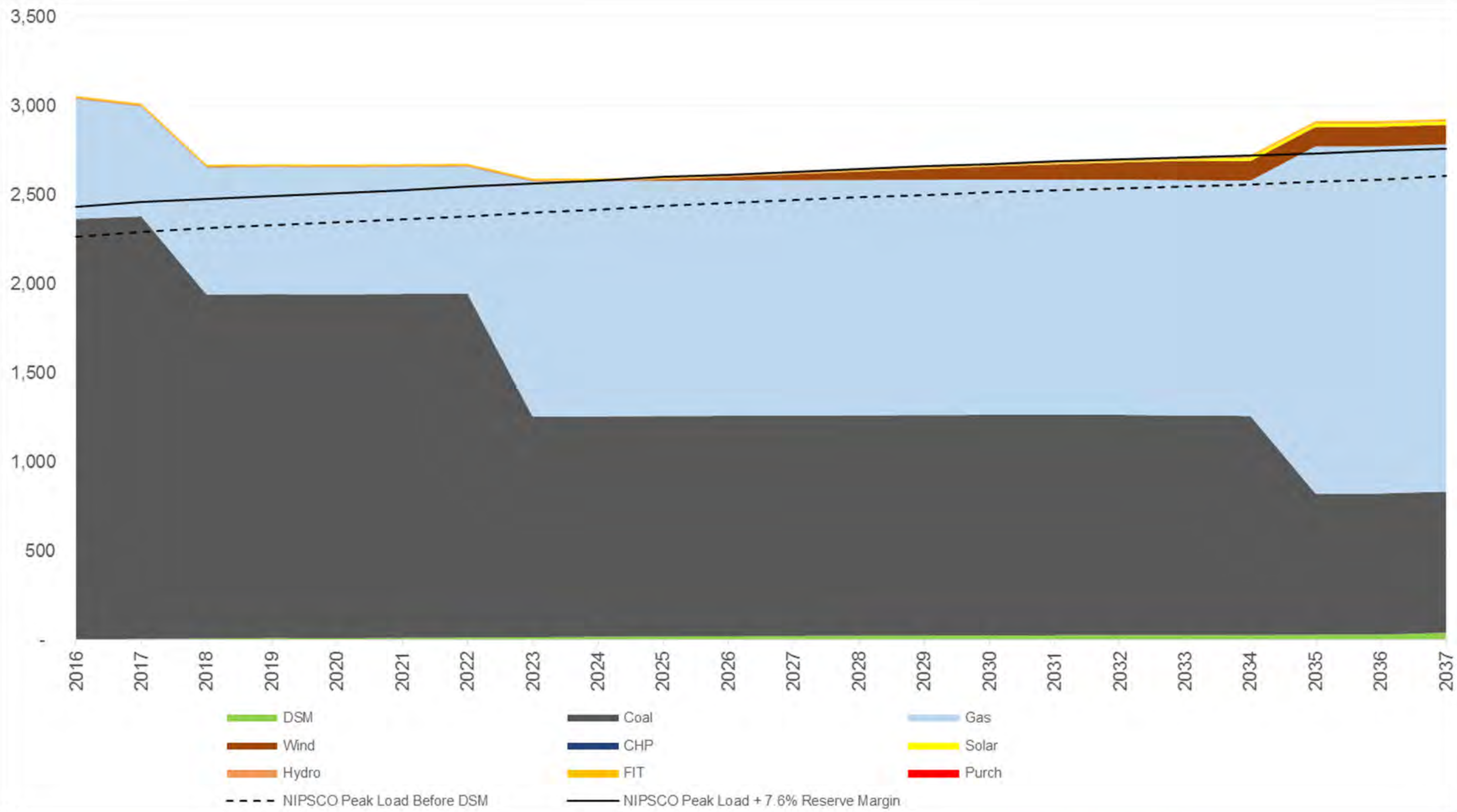


Base No Major Ind Load Scenario Capacity Expansion (Least Cost)

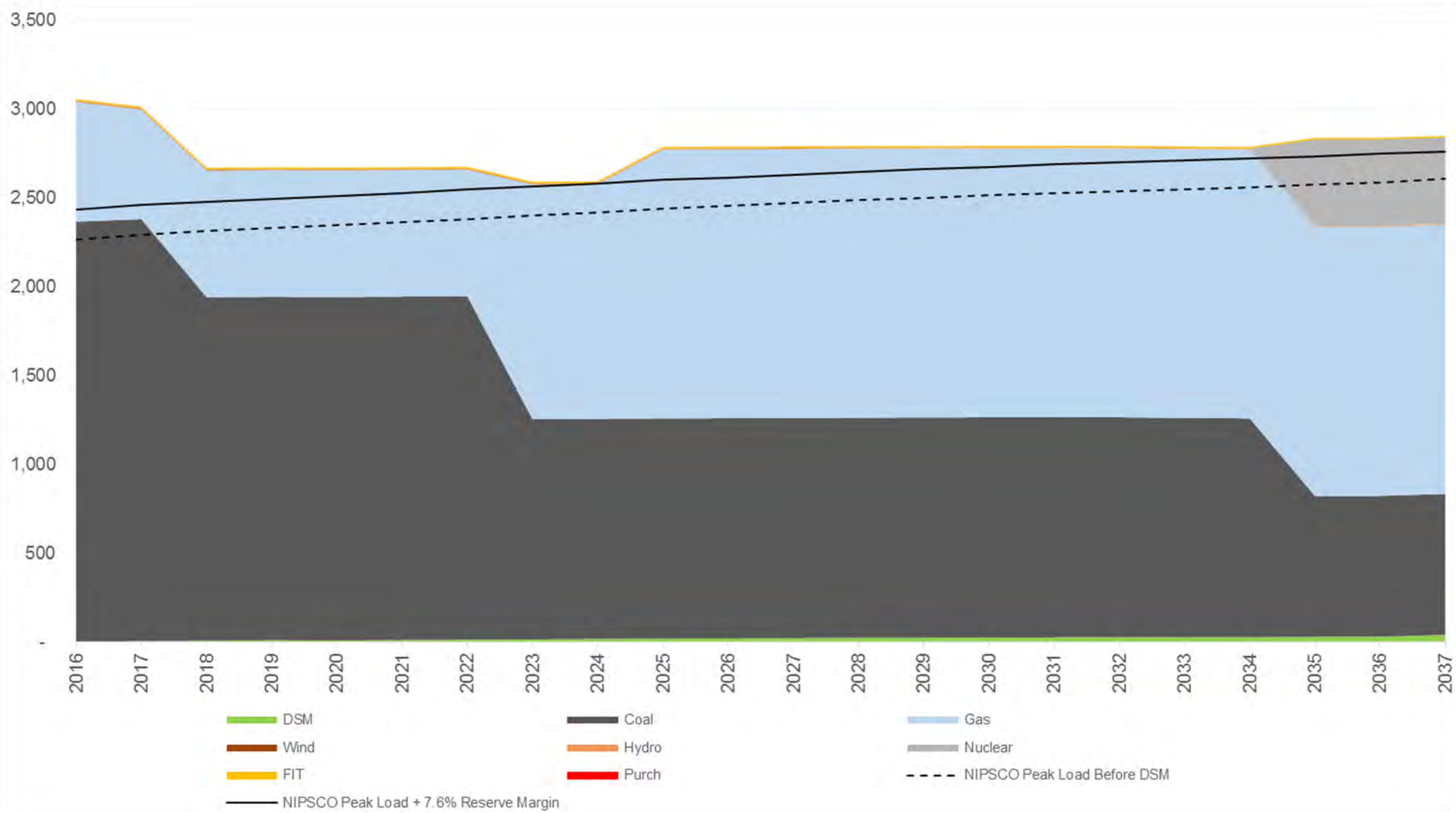


NIPSCO

Base No Major Ind Load Scenario Capacity Expansion (Renewable)

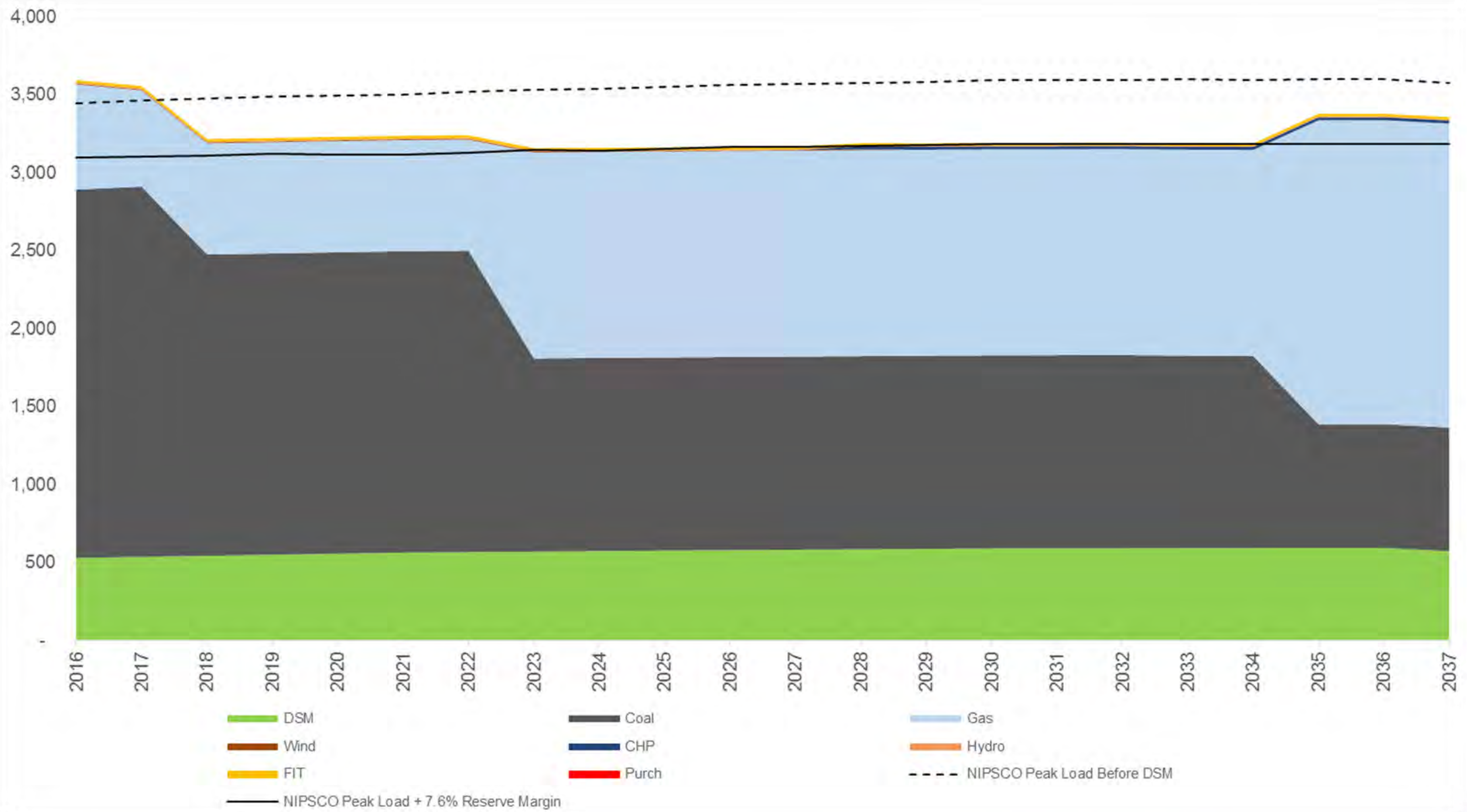


Base No Major Ind Load Scenario Capacity Expansion (Low Emission)



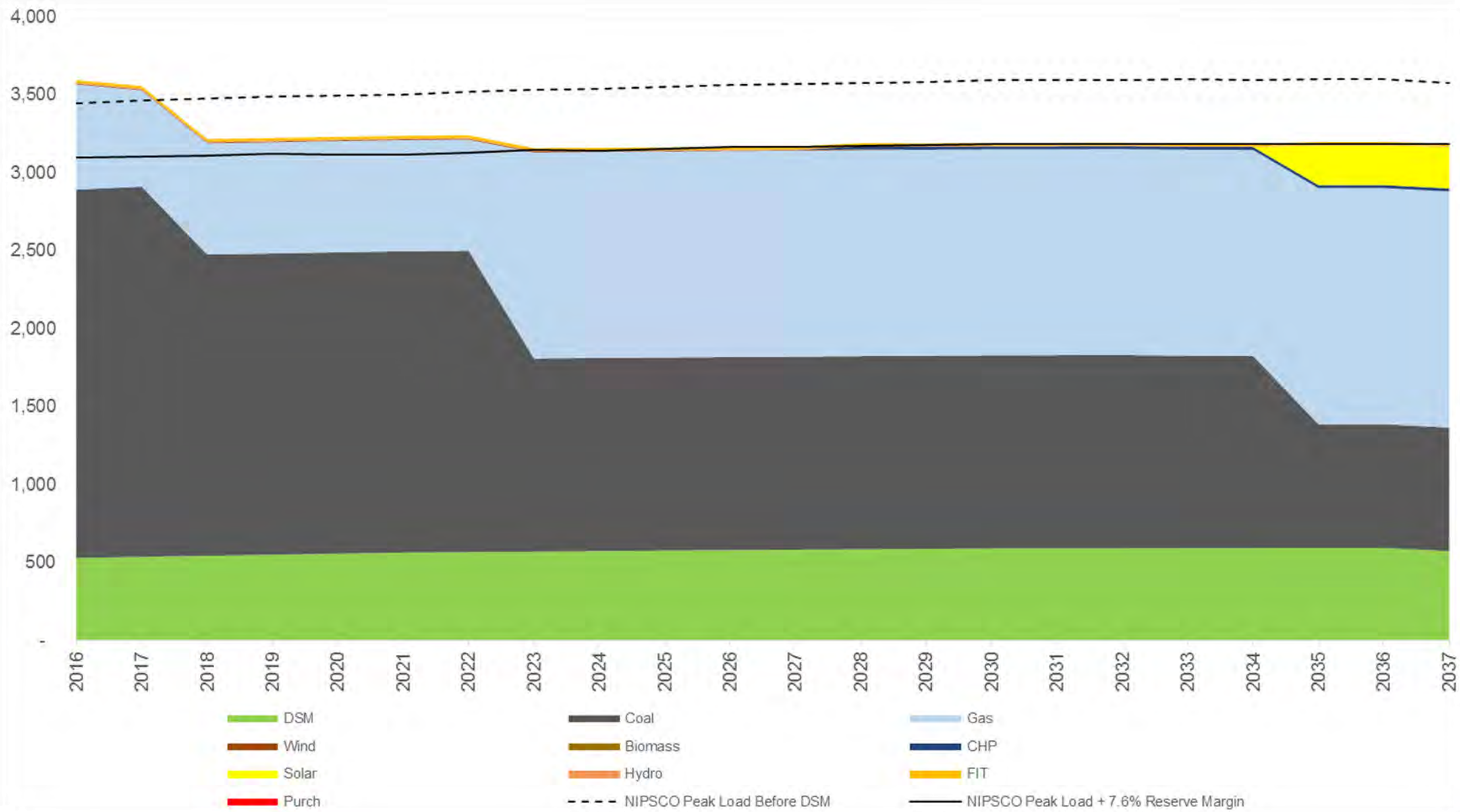
NIPSCO

Challenged Economy No CO2 Scenario Capacity Expansion (Least Cost)



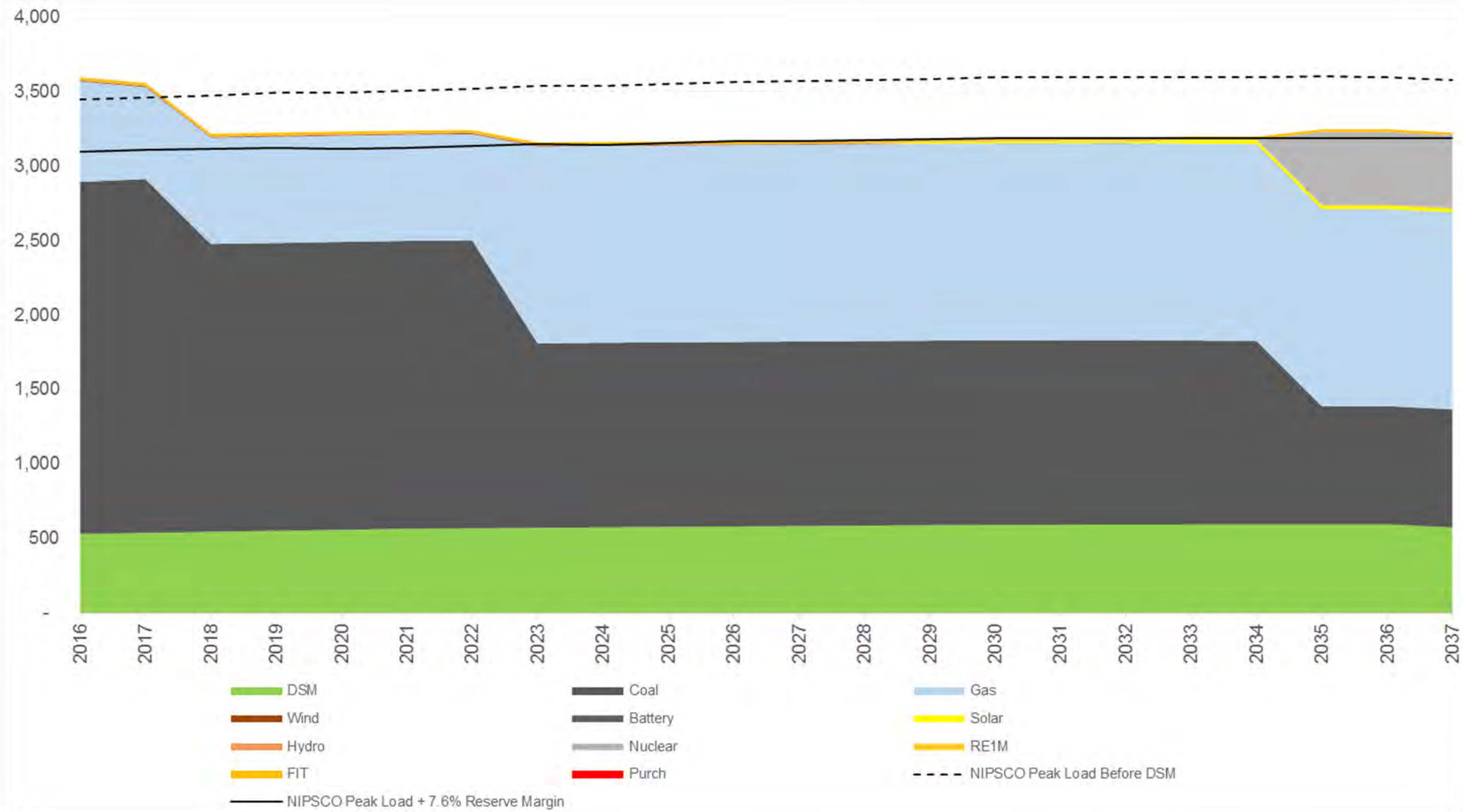
NIPSCO

Challenged Economy No CO2 Scenario Capacity Expansion (Renewable)



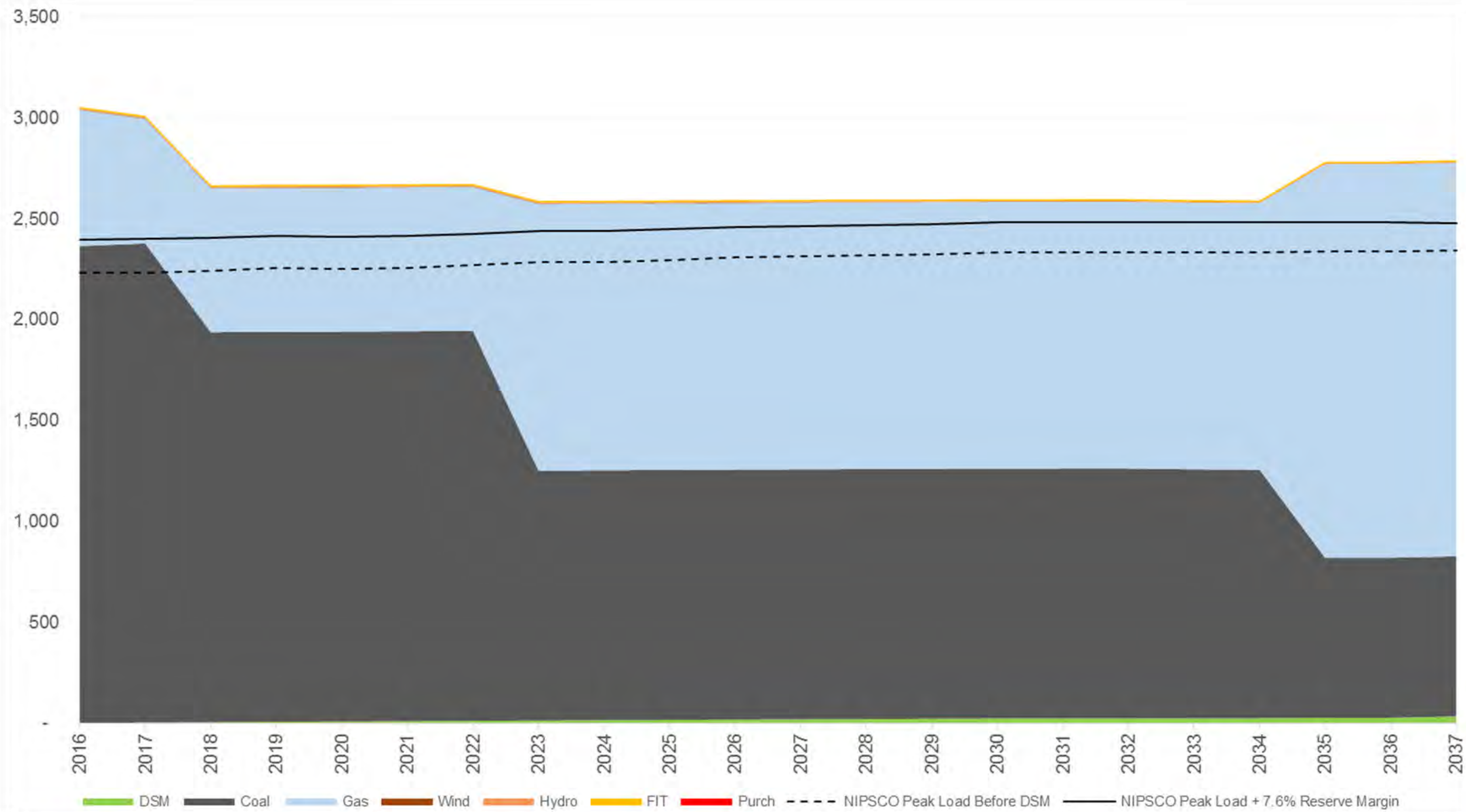
NIPSCO

Challenged Economy No CO2 Scenario Capacity Expansion (Low Emission)



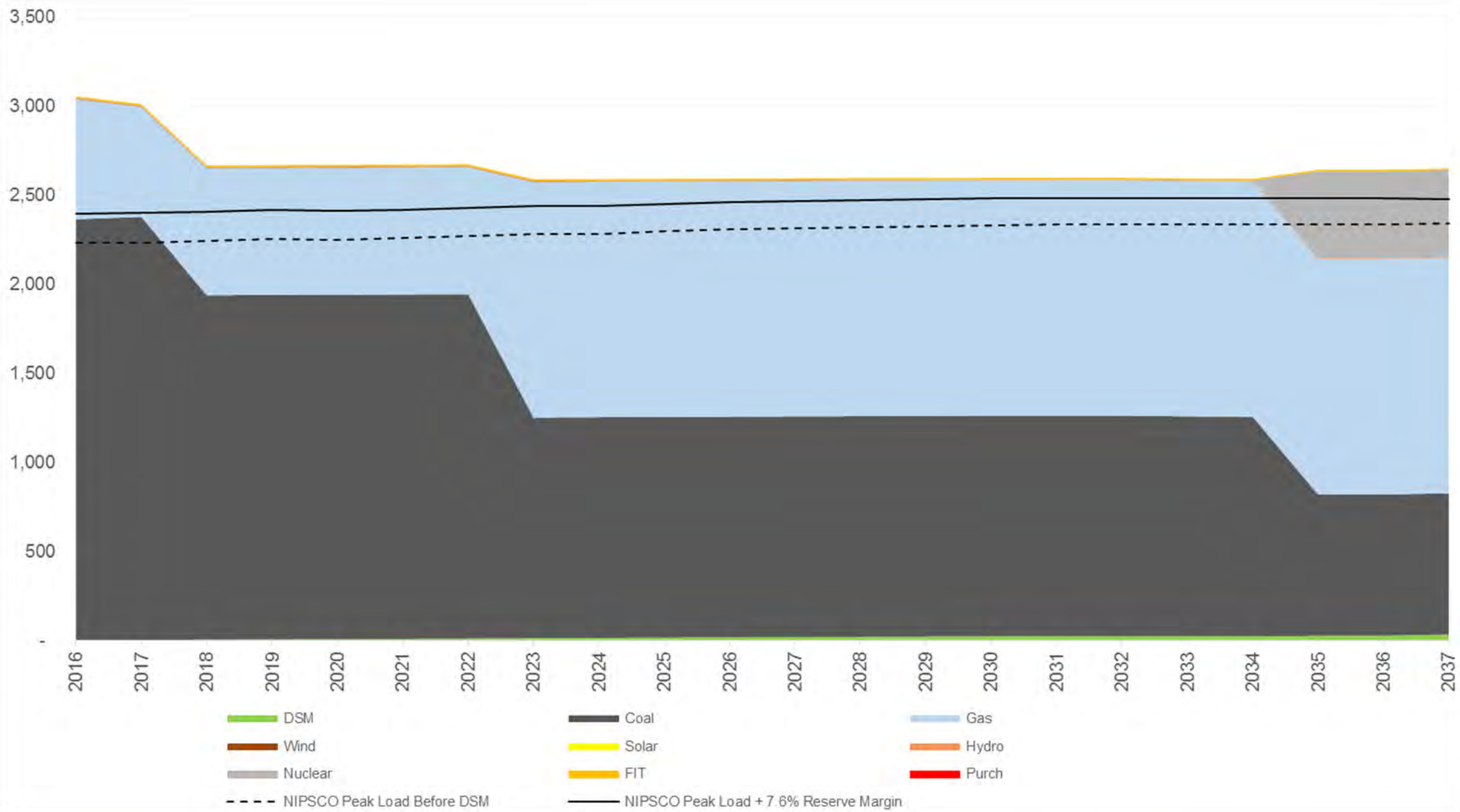
NIPSCO

Challenged Economy No Major Ind Load Scenario Capacity Expansion (Least Cost)



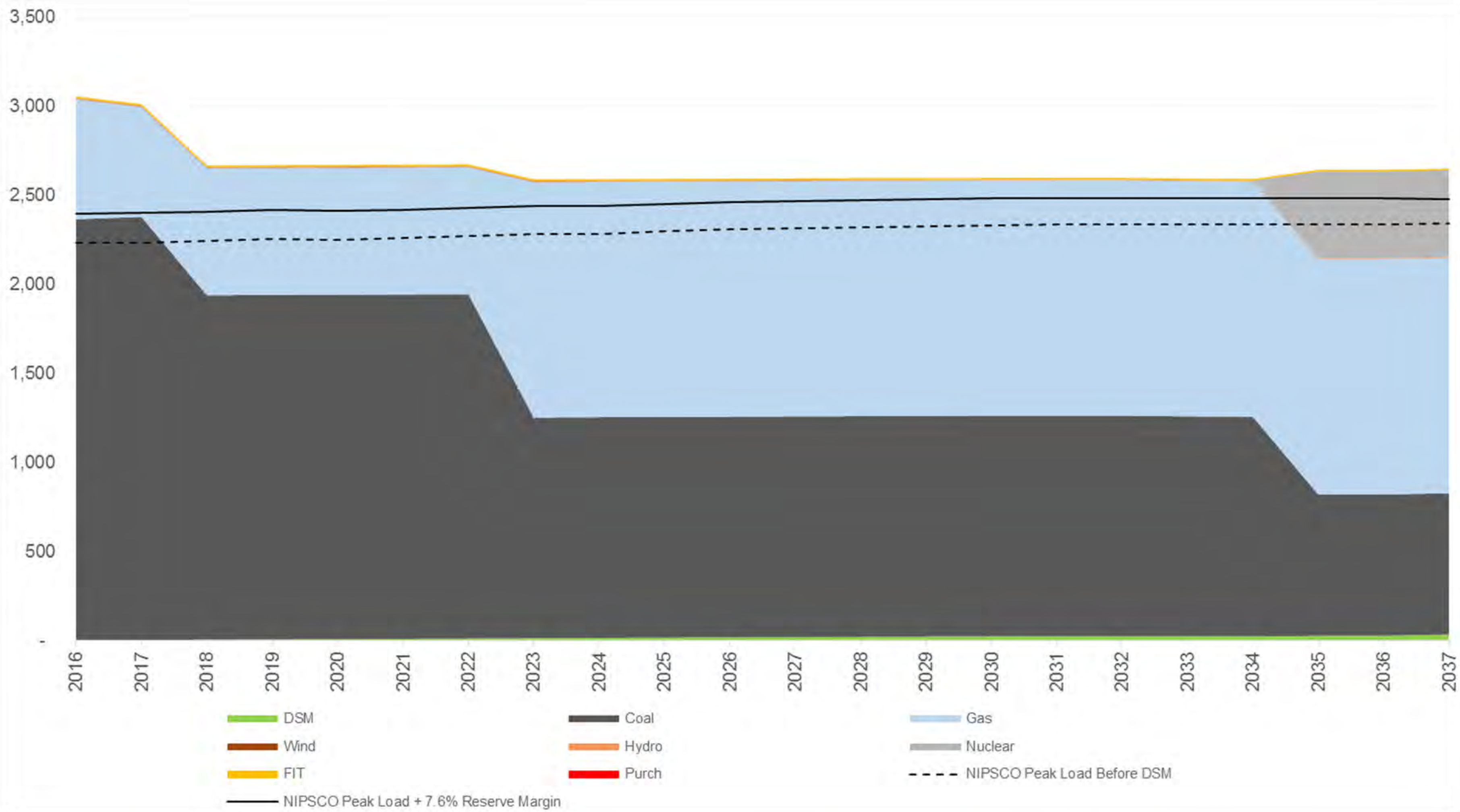
NIPSCO

Challenged Economy No Major Ind Load Scenario Capacity Expansion (Renewable)



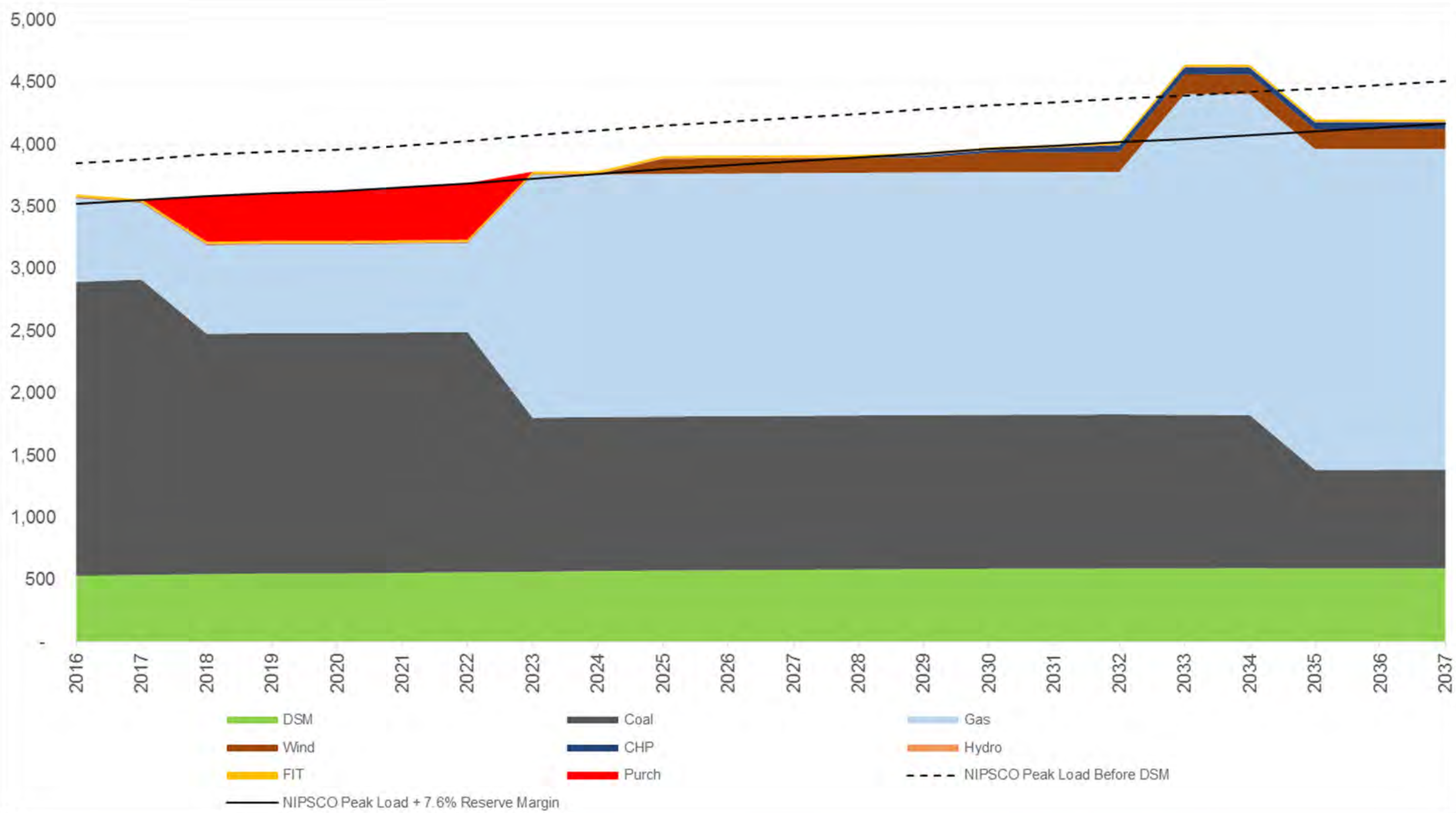
NIPSCO

Challenged Economy No Major Ind Load Scenario Capacity Expansion (Low Emission)



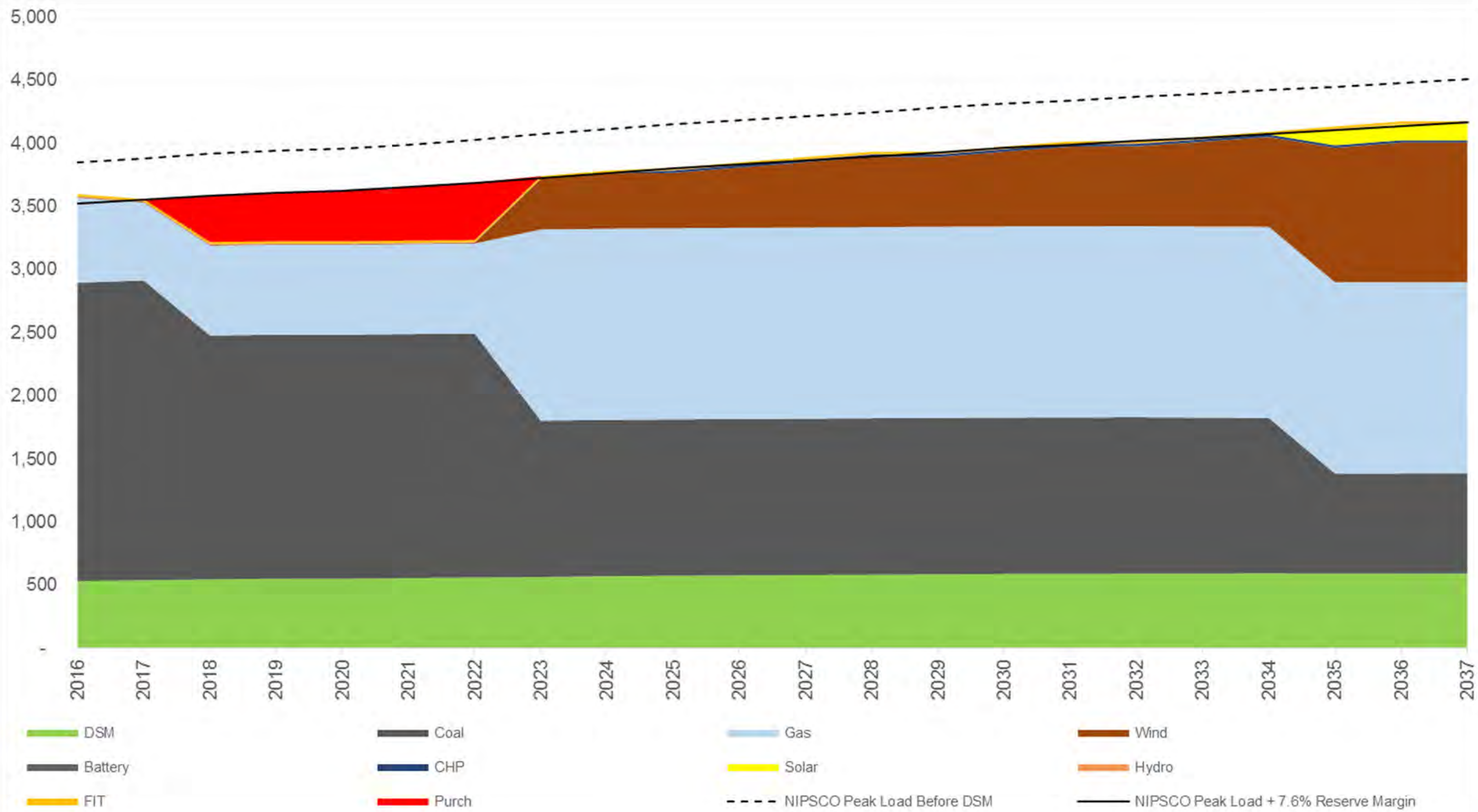
NIPSCO

Aggressive Environmental High Renewables & Incr Load Scenario Capacity Expansion (Least Cost)



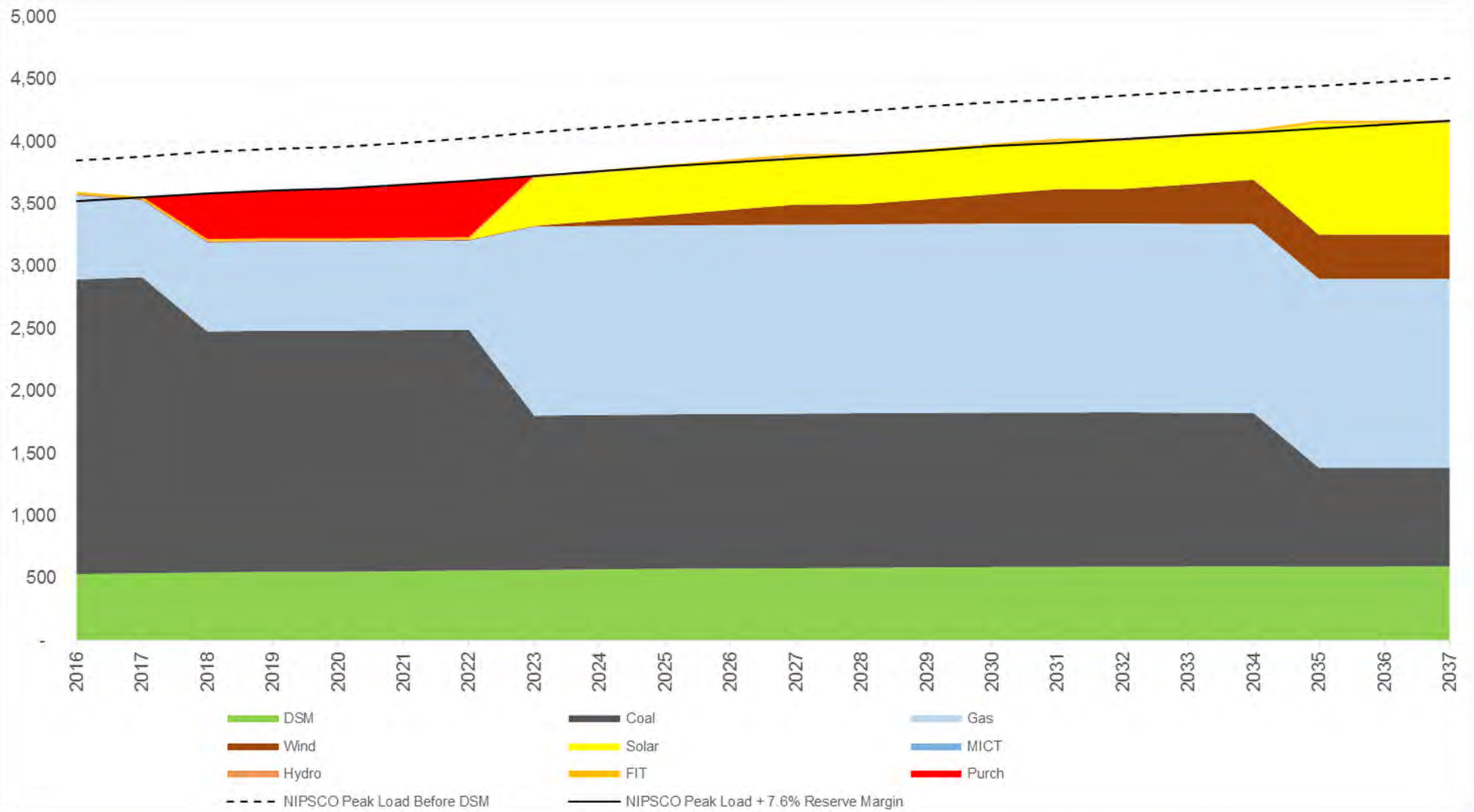
NIPSCO

Aggressive Environmental High Renewables & Incr Load Scenario Capacity Expansion (Renewable)



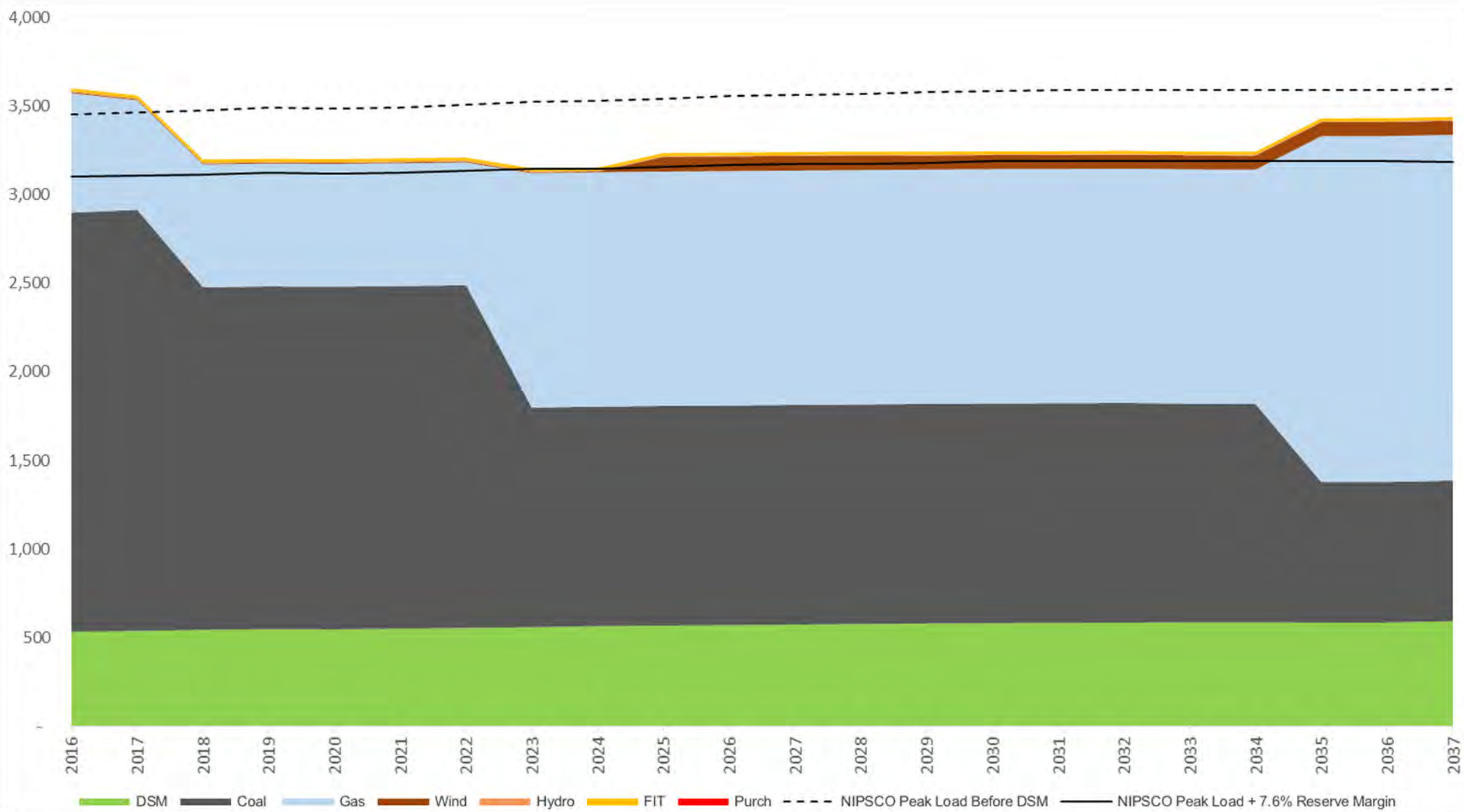
NIPSCO

Aggressive Environmental High Renewables & Incr Load Scenario Capacity Expansion (Low Emission)

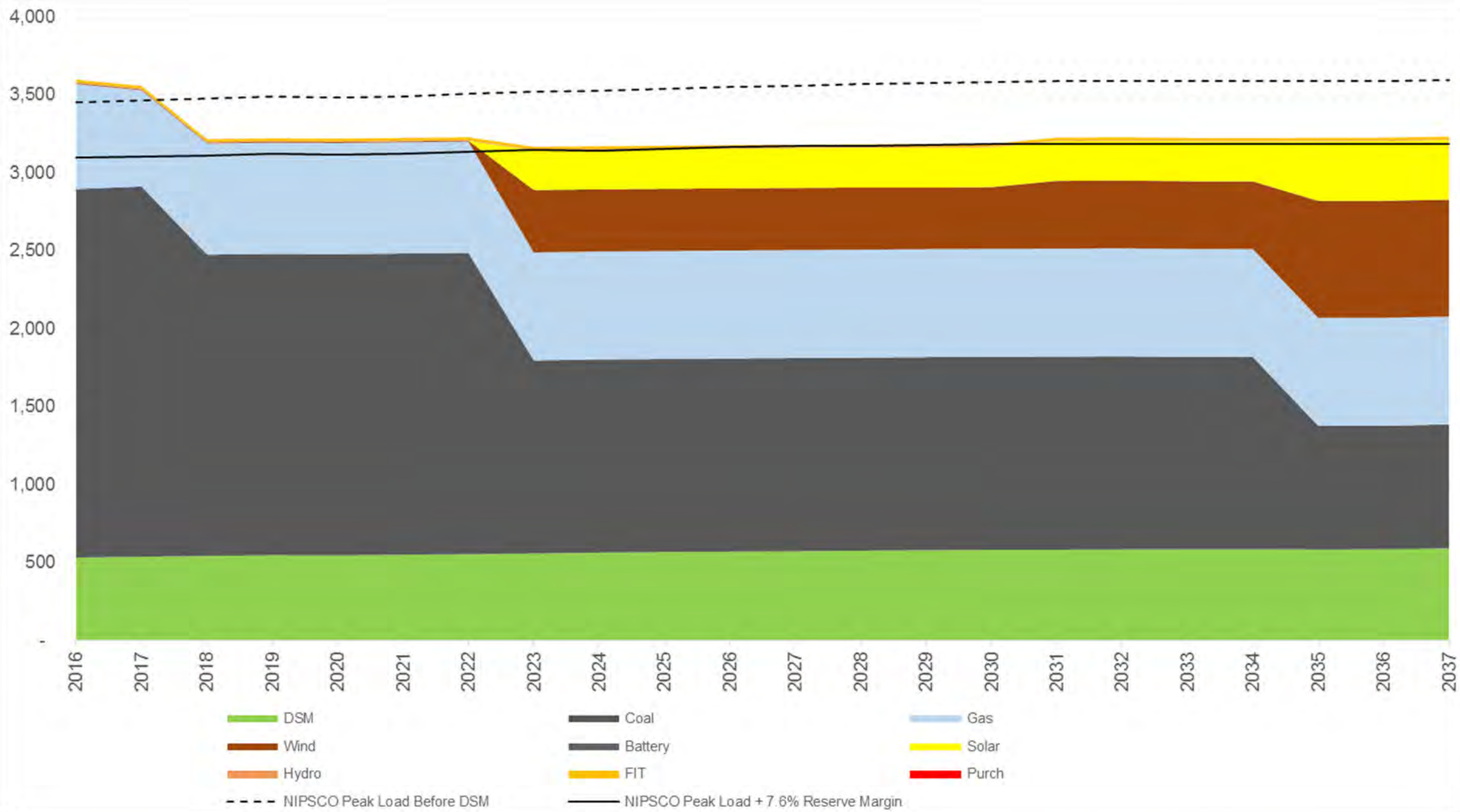


NIPSCO

Aggressive Environmental High Renewables & Decr Load Scenario Capacity Expansion (Least Cost)

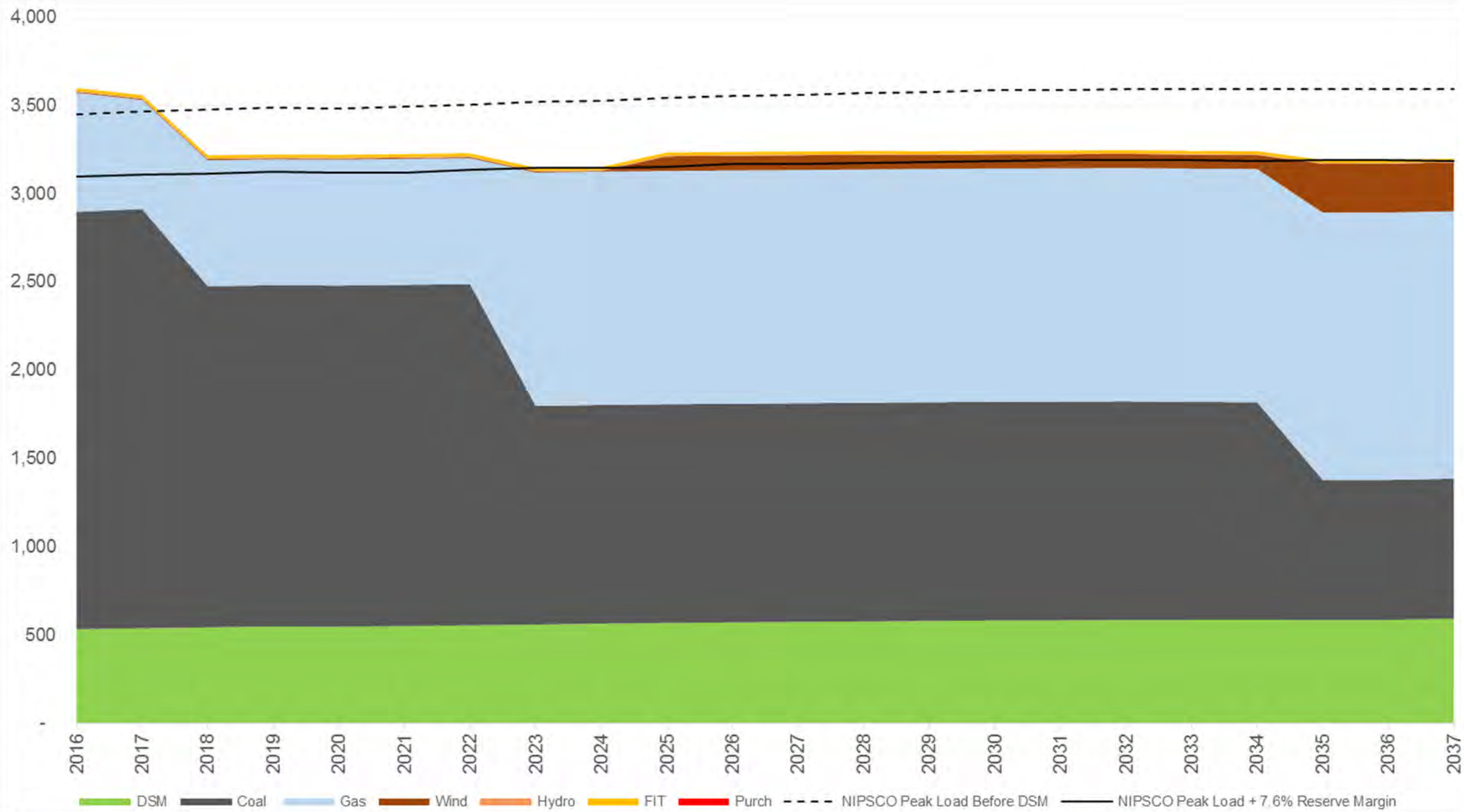


Aggressive Environmental High Renewables & Decr Load Scenario Capacity Expansion (Renewable)

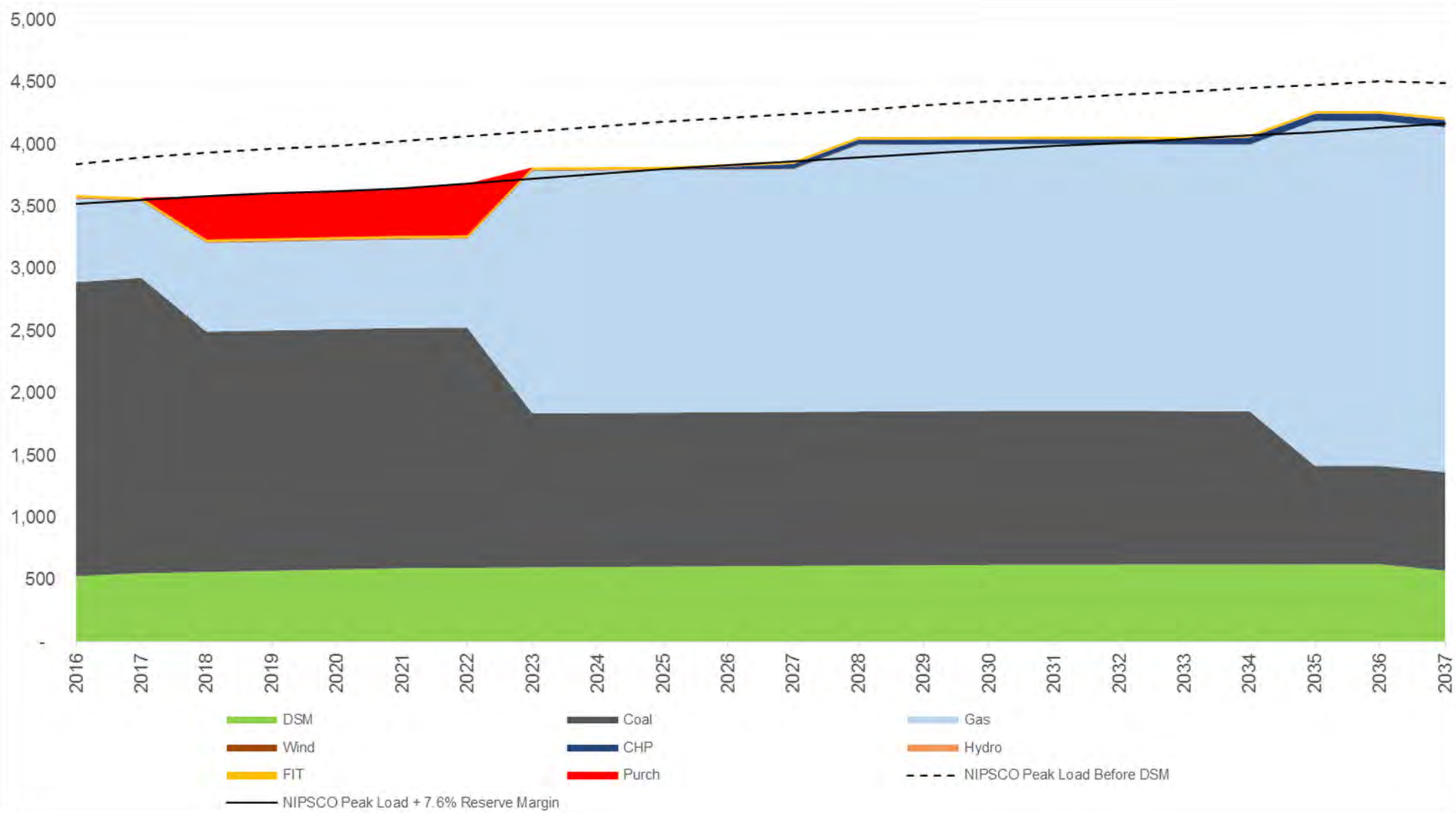


NIPSCO

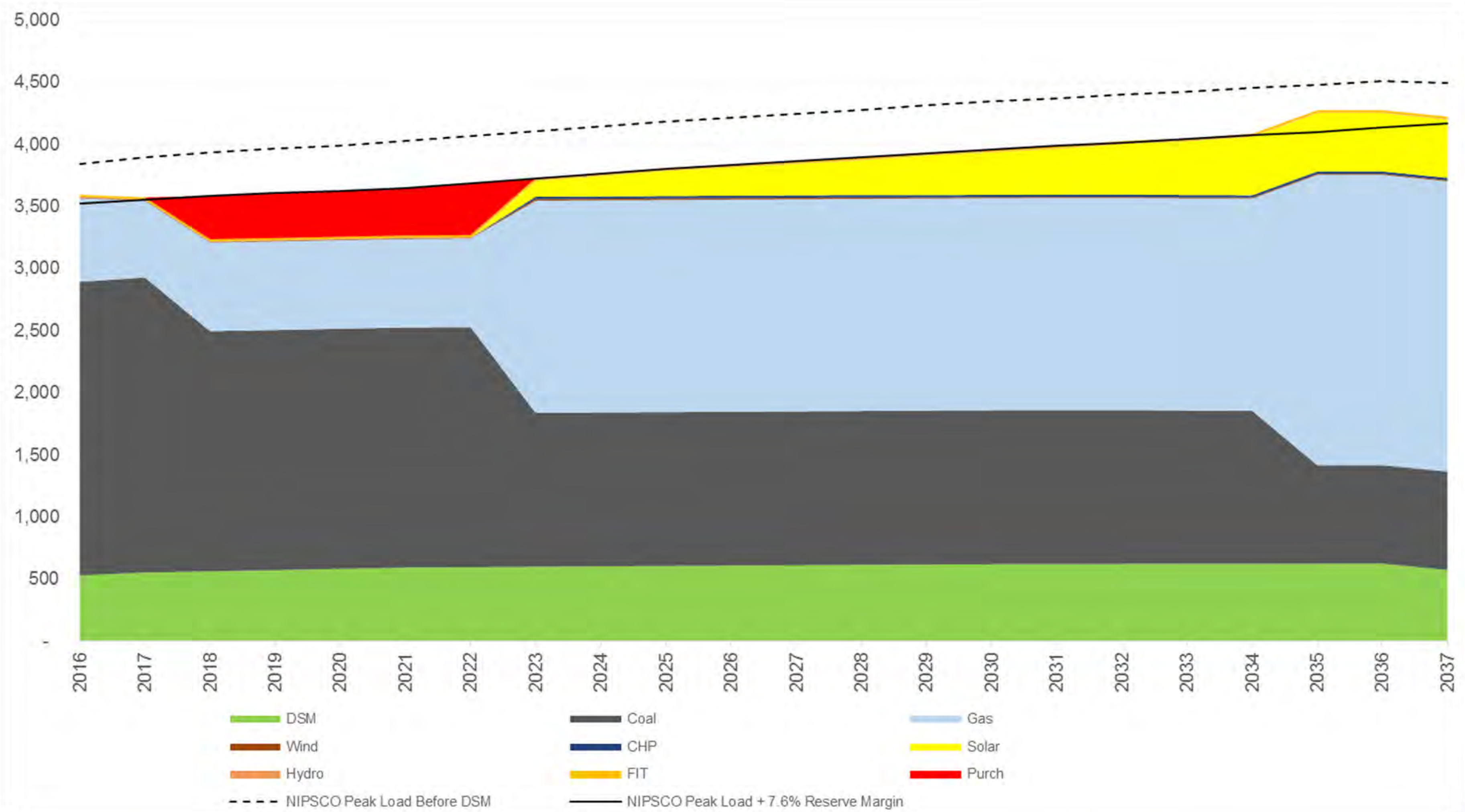
Aggressive Environmental High Renewables & Decr Load Scenario Capacity Expansion (Low Emission)



Booming Economy No CO2 Scenario Capacity Expansion (Least Cost)

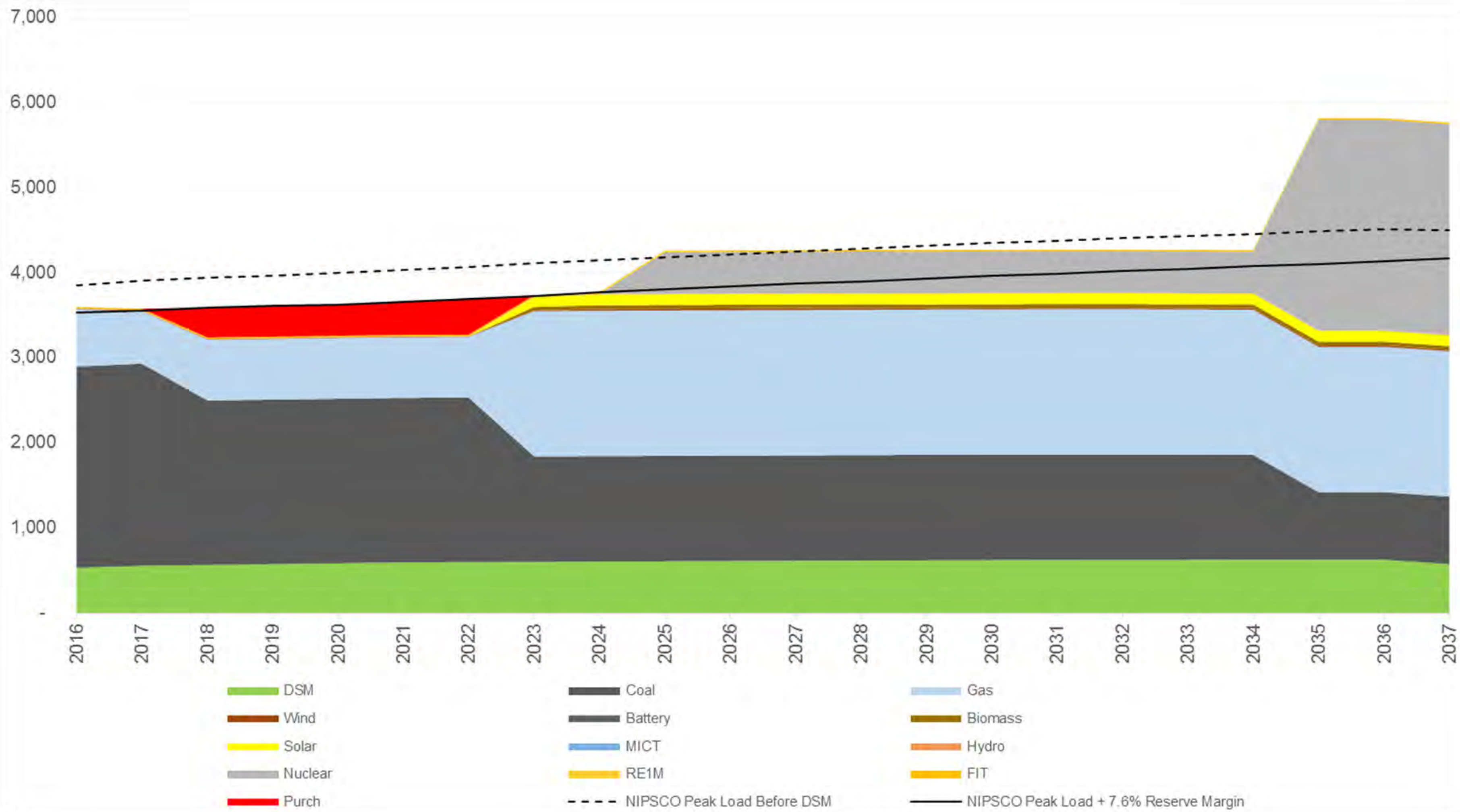


Booming Economy No CO2 Scenario Capacity Expansion (Renewable)



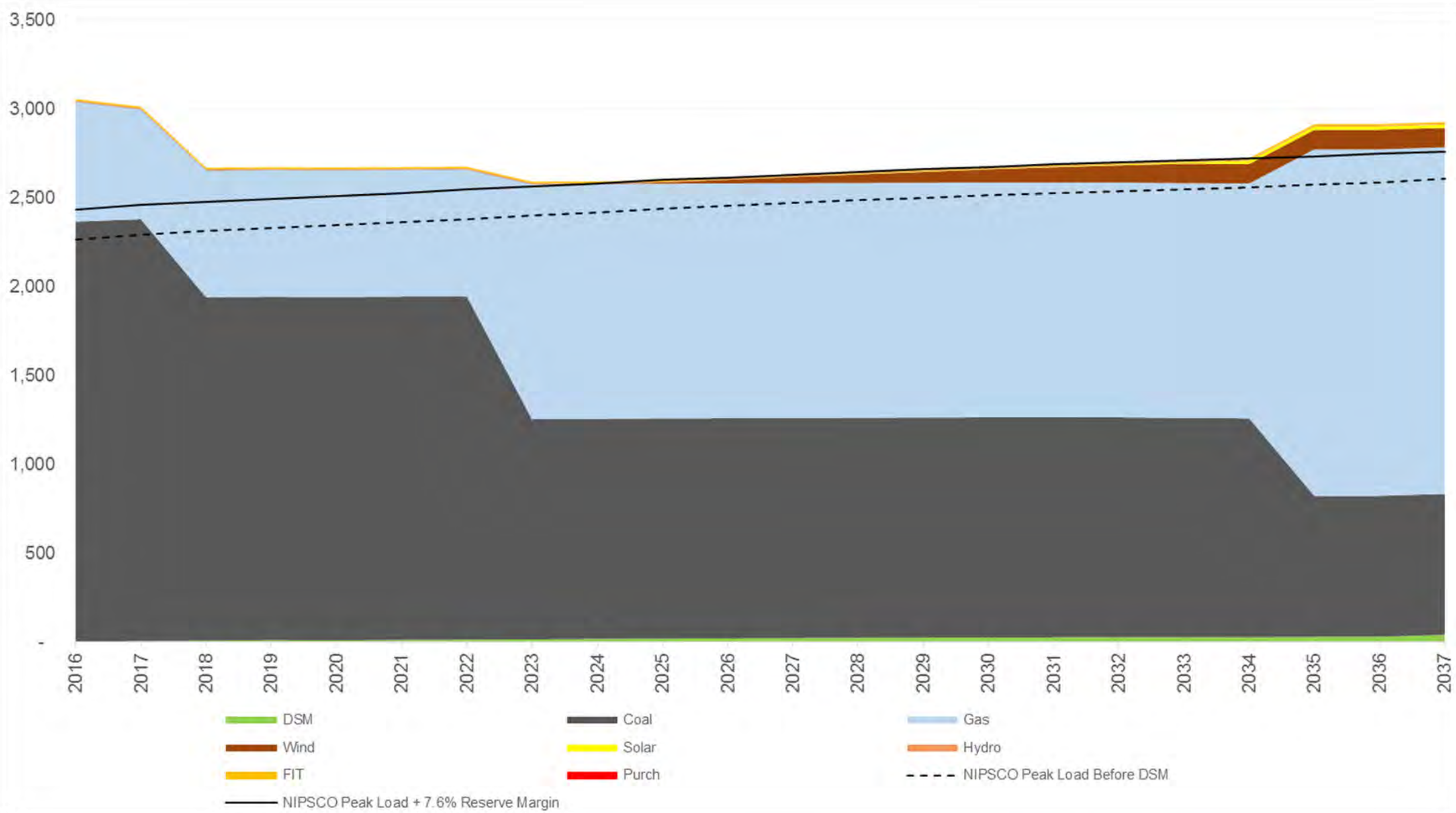
NIPSCO

Booming Economy No CO2 Scenario Capacity Expansion (Low Emission)



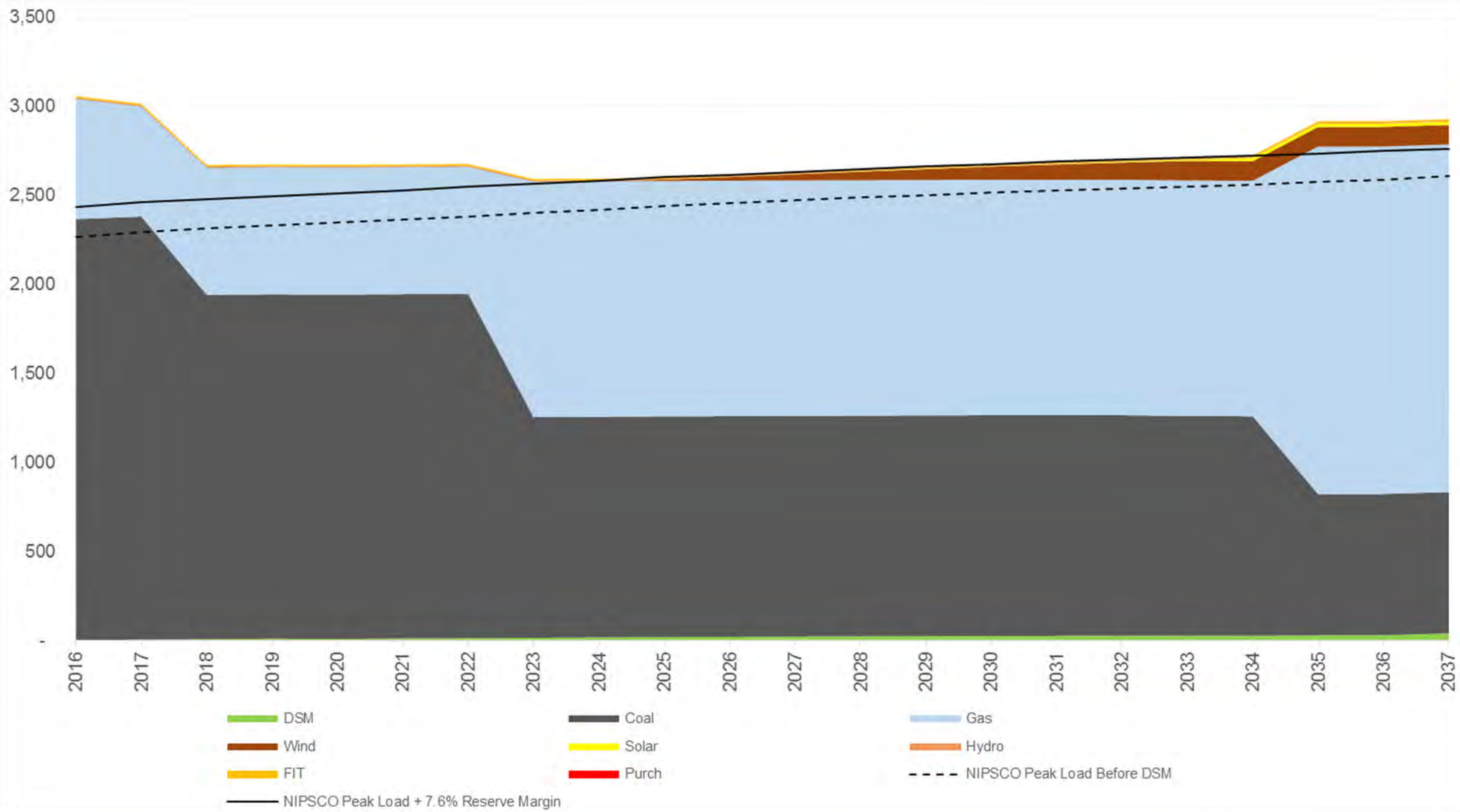
NIPSCO

Booming Economy No Major Ind Load Scenario Capacity Expansion (Least Cost)



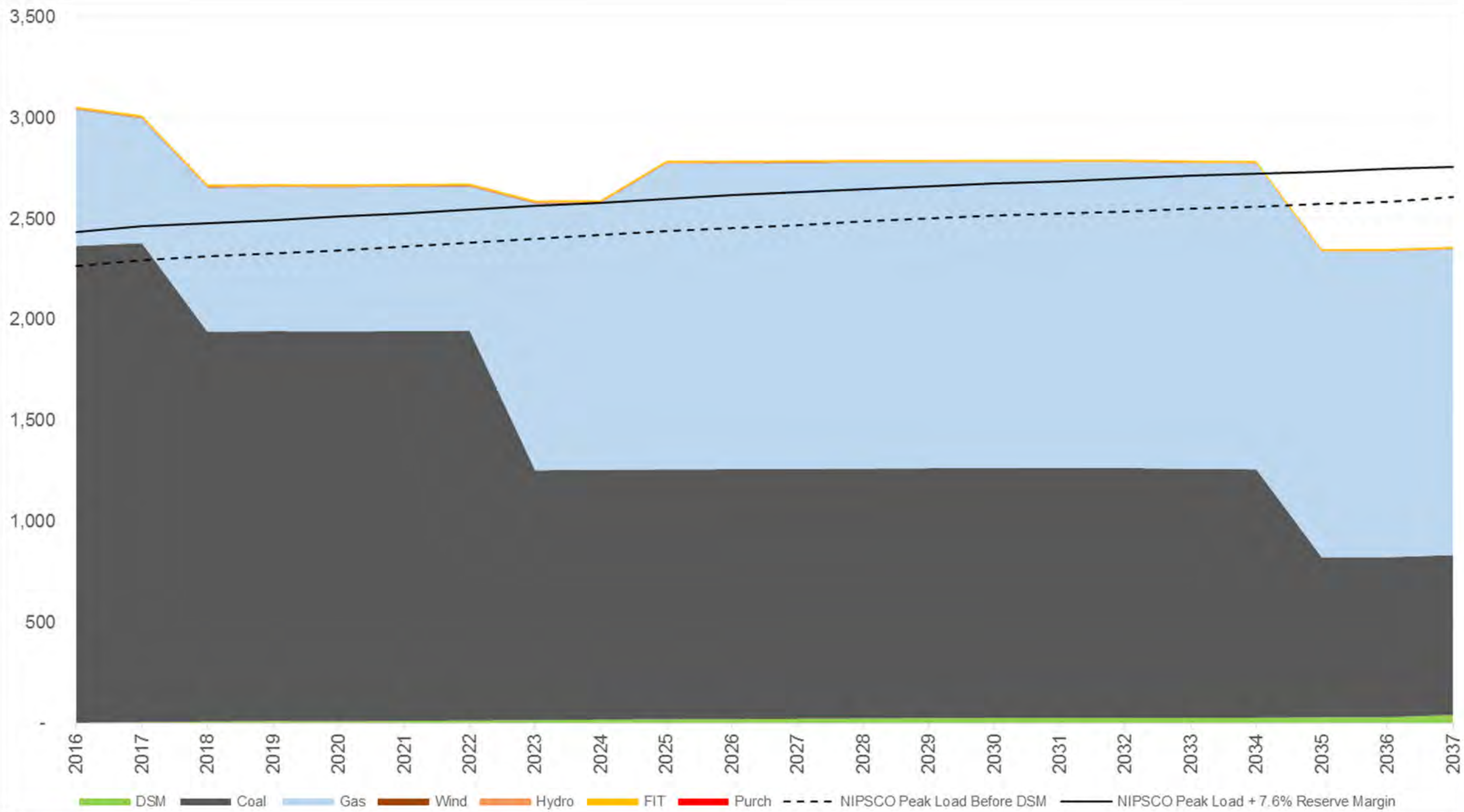
NIPSCO

Booming Economy No Major Ind Load Scenario Capacity Expansion (Renewable)



NIPSCO

Booming Economy No Major Ind Load Scenario Capacity Expansion (Low Emission)



NIPSCO

Energy Mix (Preferred Plan)

Scenario	DSM	Net Purchases	Coal	Gas	Wind	Hydro	FIT
Base No CO2 (BS1)	1.9%	49.0%	18.5%	28.5%	0.9%	0.3%	0.8%
Base Low Load (BS2)	3.2%	19.4%	28.5%	46.6%	1.1%	0.3%	0.9%
Base High Gas (BS3)	2.8%	31.5%	28.4%	35.3%	0.9%	0.3%	0.8%
Base No Mjr Ind Load (BS4)	2.6%	-21.2%	43.7%	71.4%	1.7%	0.5%	1.4%
Challenged Economy No CO2 (CE1)	2.7%	41.8%	17.3%	36.0%	1.1%	0.3%	0.9%
Challenged Economy No Mjr Ind Load (CE2)	2.4%	-19.2%	39.4%	73.6%	1.8%	0.5%	1.5%
Aggressive Environmental High Renewables & Incr Load (AE1)	2.6%	29.7%	25.4%	23.3%	18.0%	0.2%	0.7%
Aggressive Environmental High Renewables & Decr Load (AE2)	3.3%	21.0%	32.0%	29.5%	13.0%	0.3%	0.9%
Booming Economy No CO2 (BE1)	2.4%	53.3%	16.8%	25.7%	0.9%	0.2%	0.7%
Booming Economy No Mhr Ind Load (BE2)	2.6%	-17.7%	49.9%	61.7%	1.7%	0.5%	1.4%

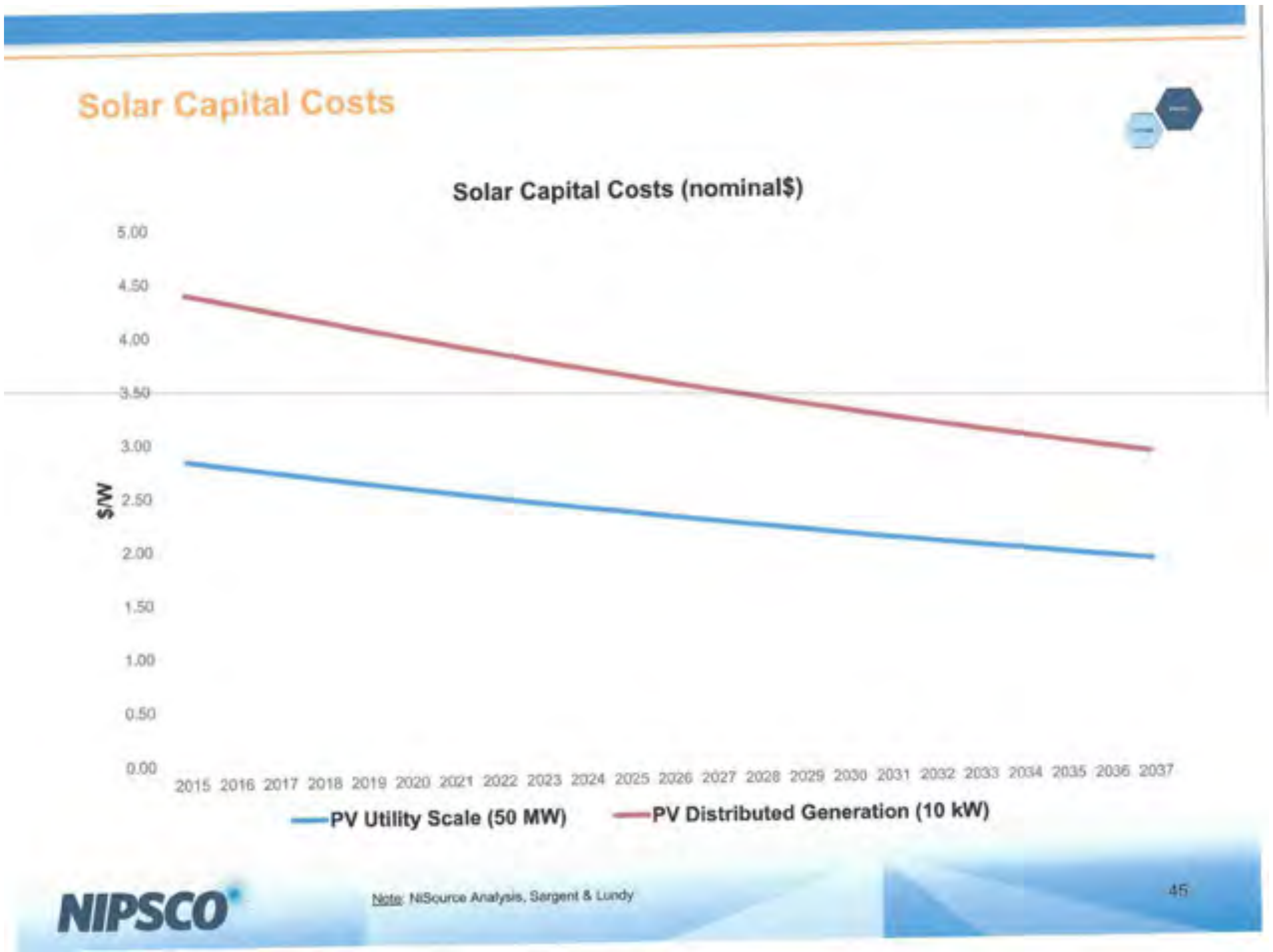
NIPSCO IRP 1:1 meeting

September 30, 2016

Cost of PV Solar

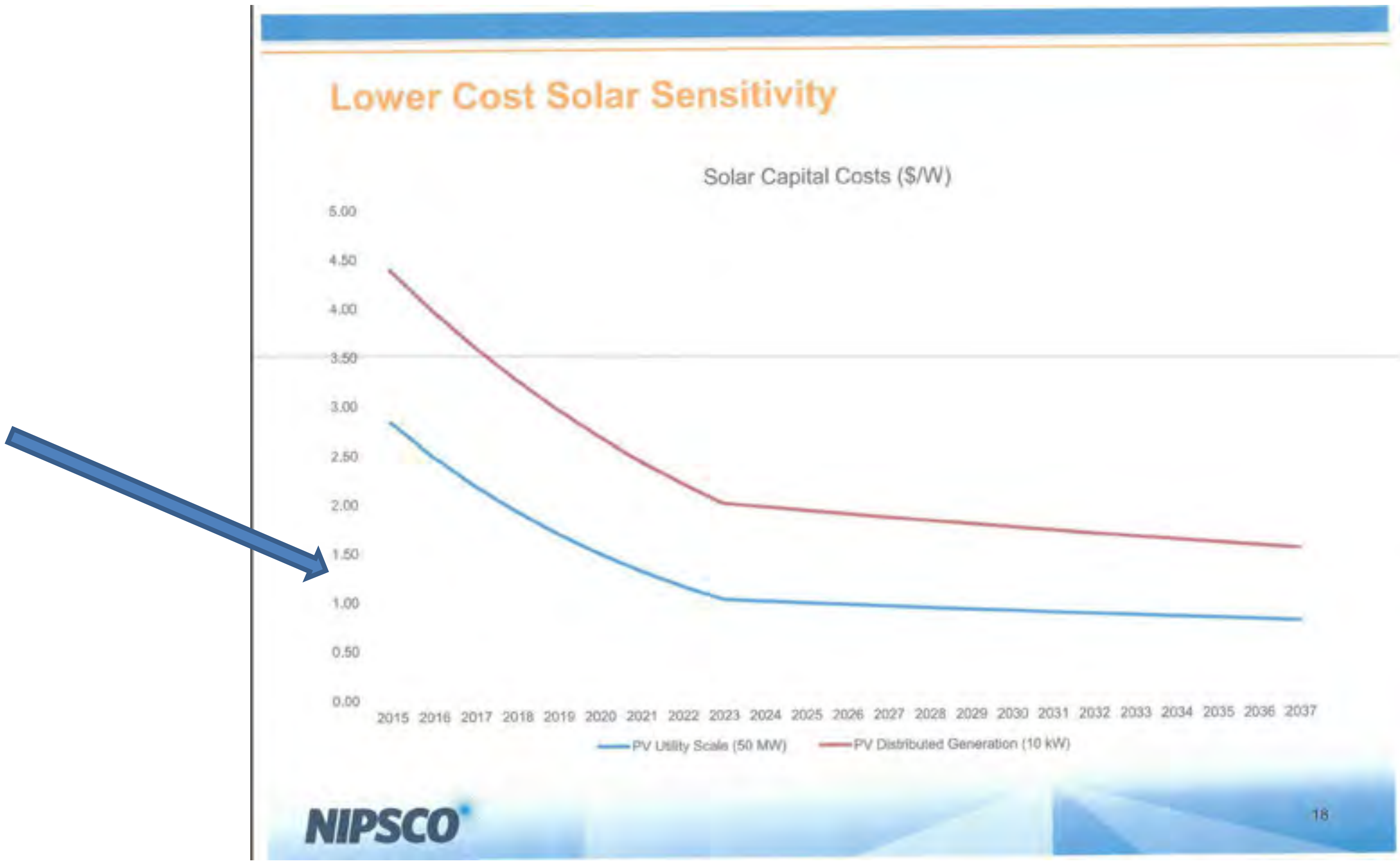
- Solar Capital Costs slide significantly overstates Utility Scale Cost – current market
- Panel prices at historic lows
- Equipment and BOS costs continue to drop
- Advantages of scale manifesting itself in installation efficiencies
- Development volumes for utility scale PV increasing exponentially

NIPSCO 3rd Stakeholder deck

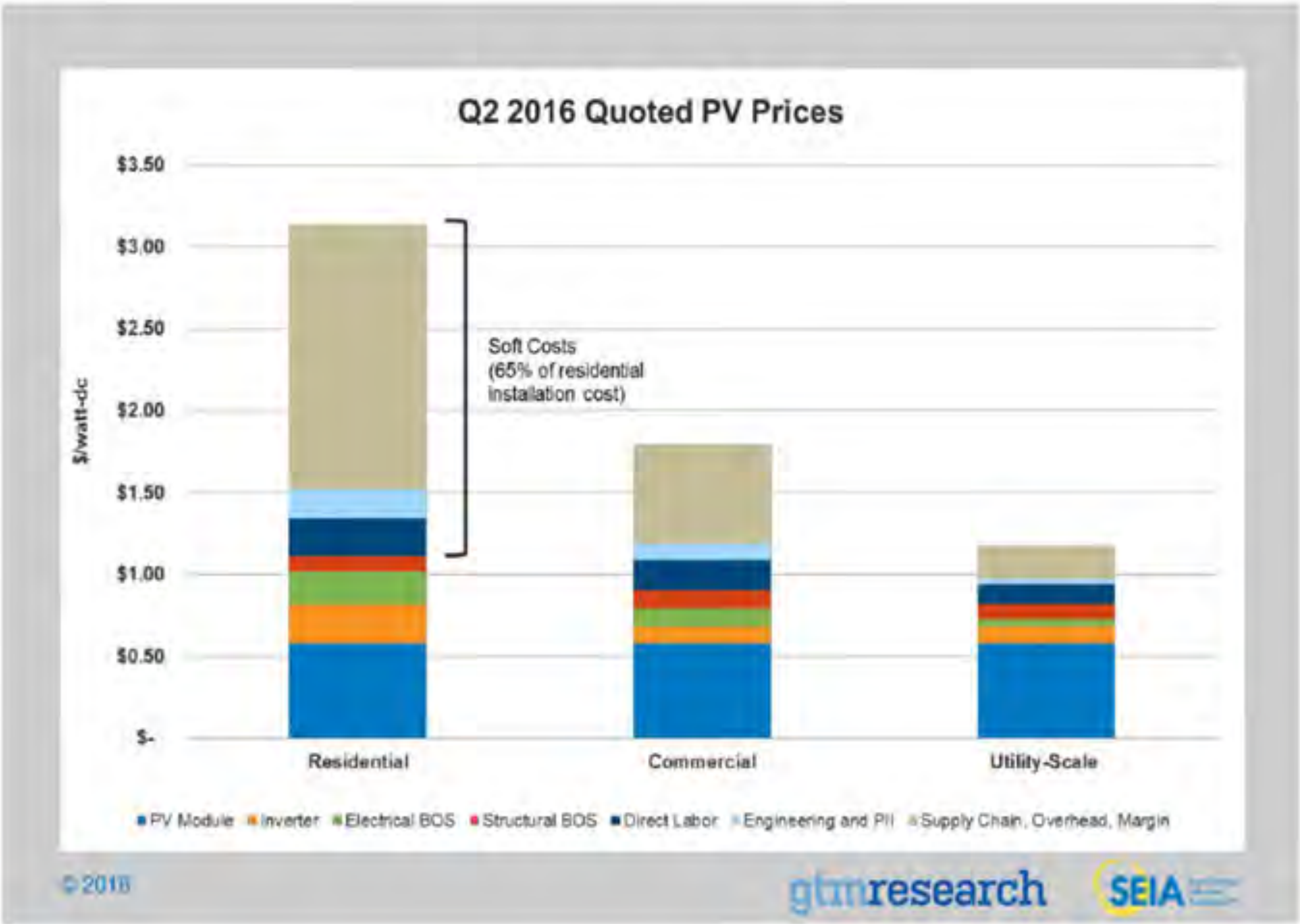


NIPSCO 5th Stakeholder deck

(Sierra Club)



GTM / SEIA research
(quoted project prices)



Driven in part by Module prices

(Tier 1 modules selling for $0.49/w)

gtm:
A Wood Mackenzie Business

SOLAR

GRID EDGE

ETC.

Videos

The Energy Gang

Webinars

White Papers

Source: GTM Research ***PV Pulse, March 2016***

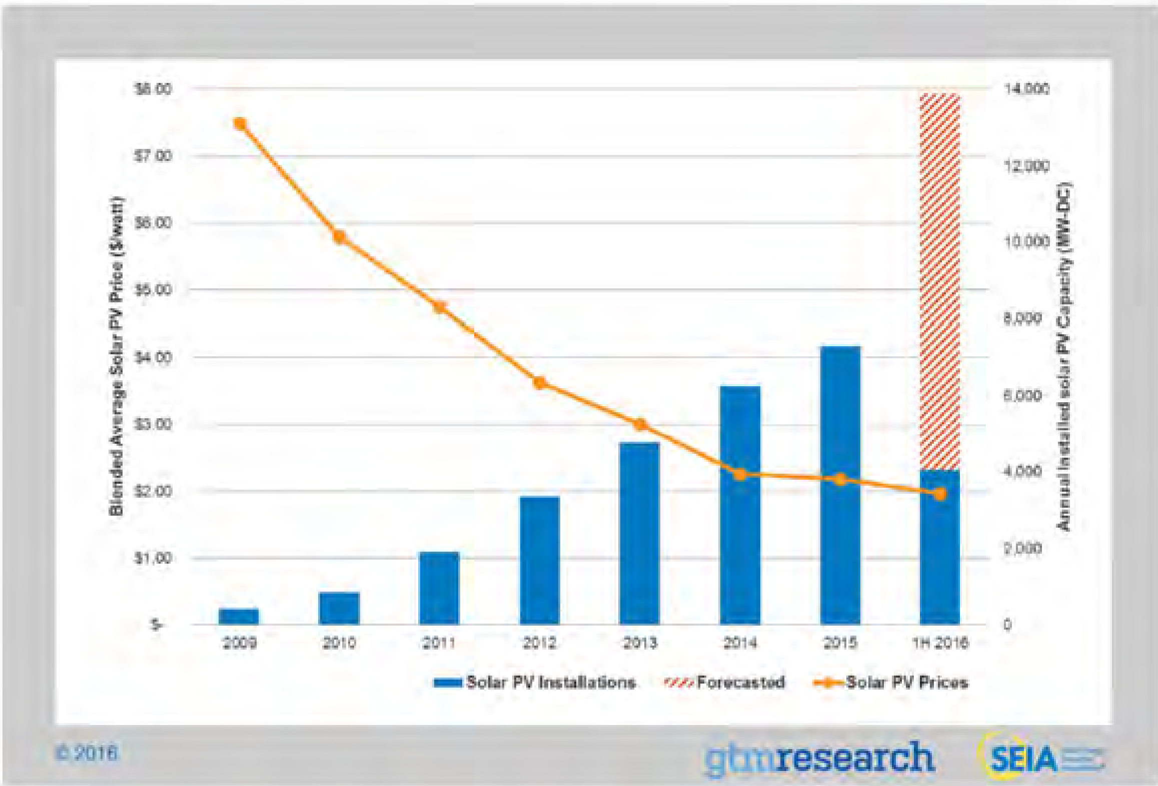
Assuming a stable supply-demand landscape, GTM Research anticipates that global blended prices will steadily fall at an annualized rate of 5 percent and reach 44 cents per watt by 2020.

Source: GTM Research ***PV Pulse, March 2016***

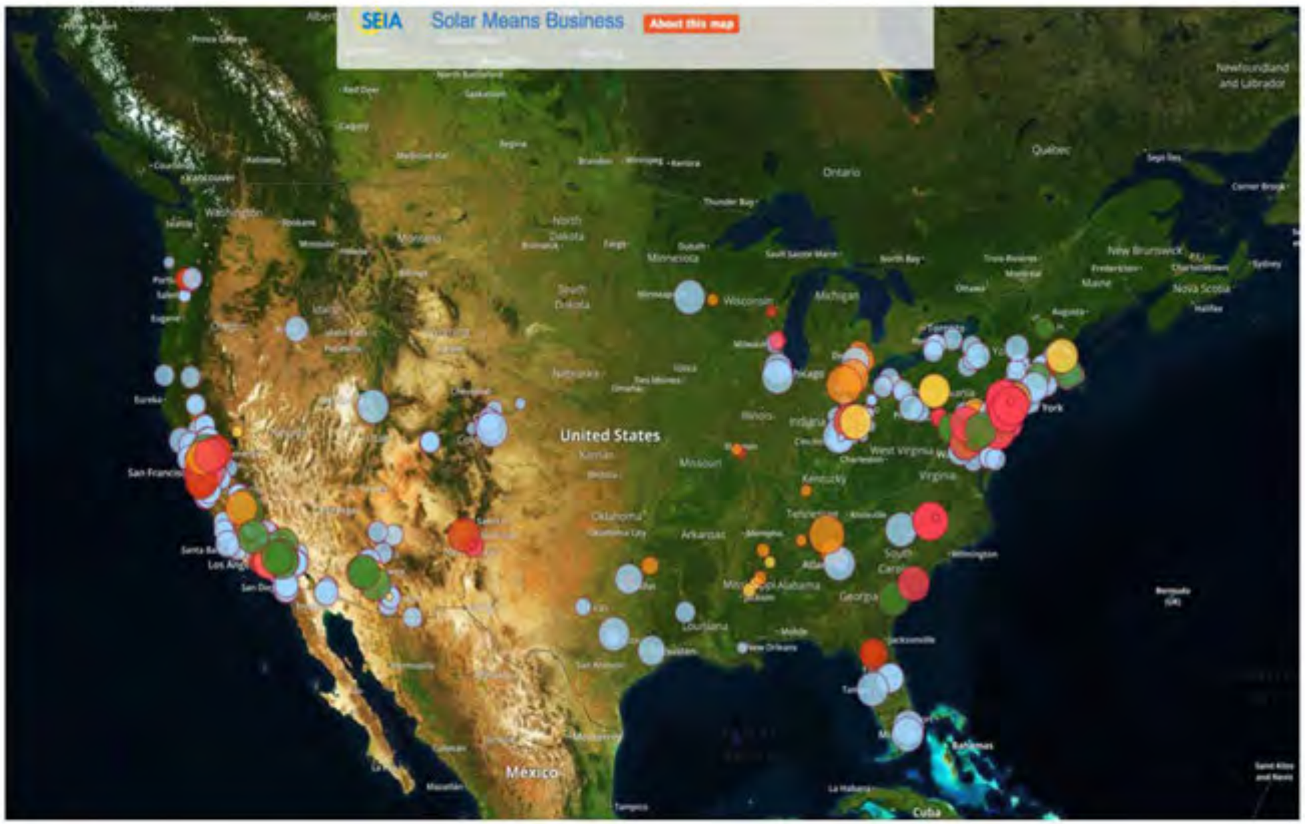
Driving Industry Growth Rate
(60% Avg YoY growth since 2011)

Growth in Solar is led by Falling Prices

The cost to install solar has dropped by more than 70% over the last 10 years, leading the industry to expand into new markets and deploy thousands of systems nationwide.

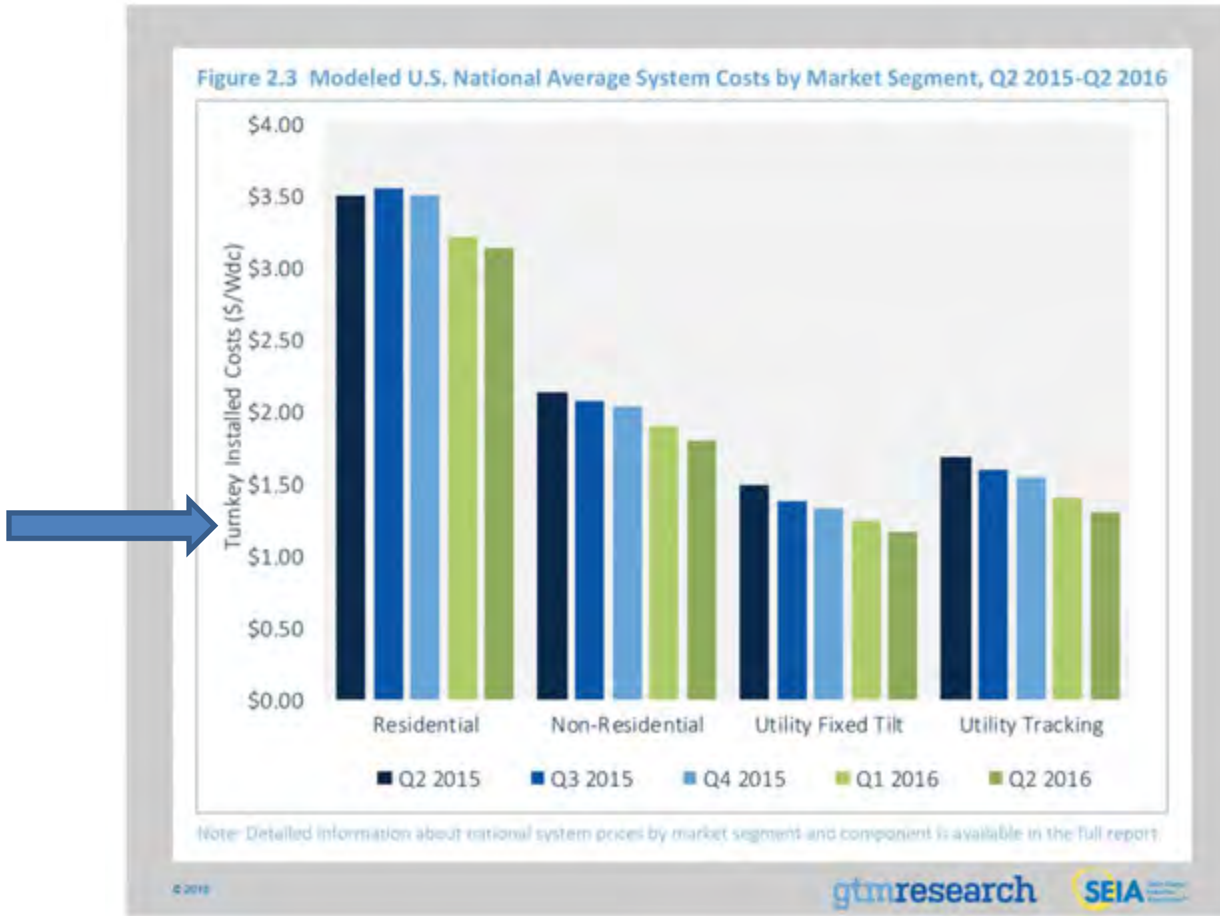


Development not just on the Coasts

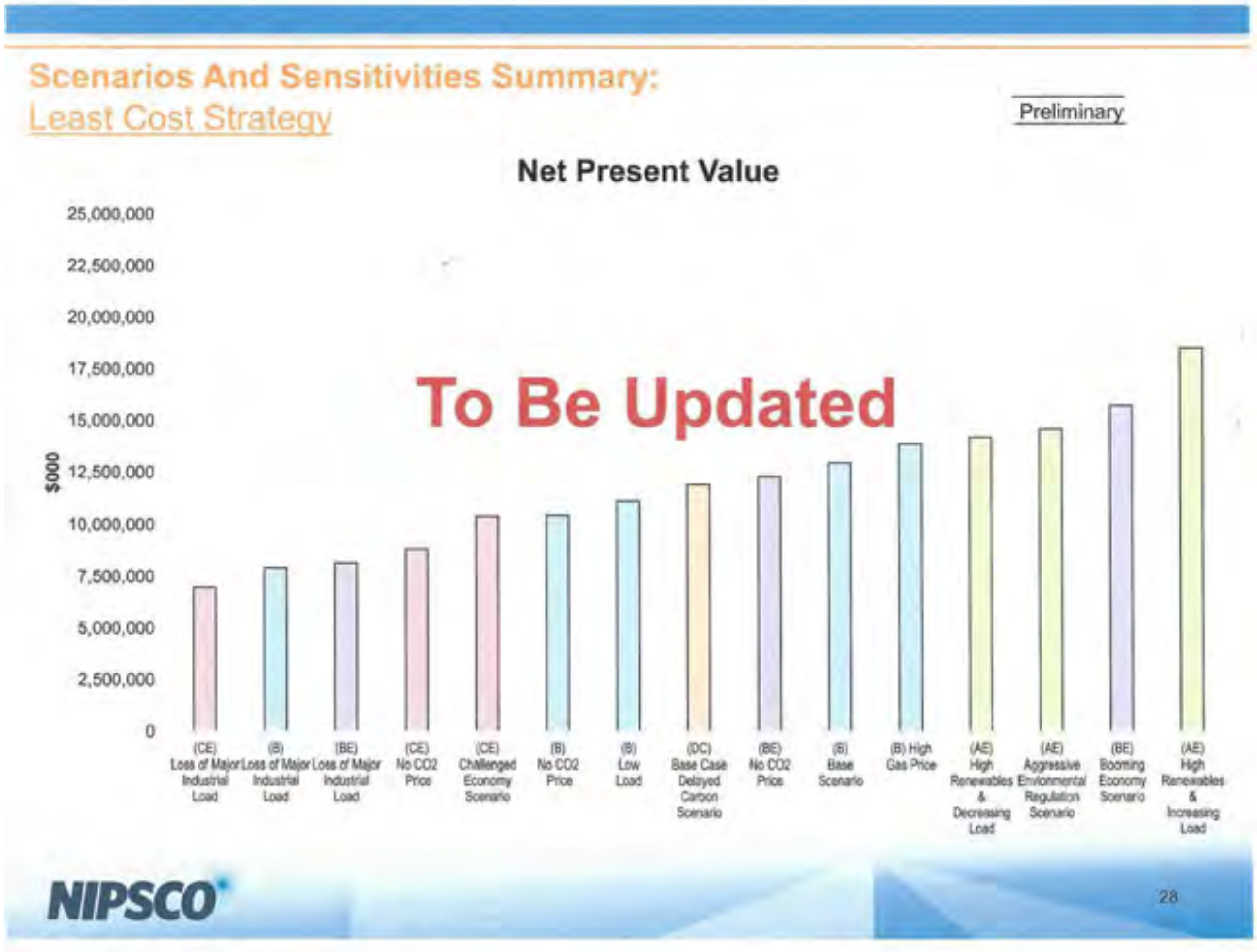


Single Axis Trackers have come of age

(enhanced yield without the cost or O&M)



NPV Cost for Solar?



Northern Indiana Public Service Company
2016 Integrated Resource Planning
Stakeholder Meeting #5
SUMMARY

October 3, 2016

Introductions
Dr. Marty Rozelle, The Rozelle Group Ltd.

Dr. Marty Rozelle, the facilitator, welcomed participants observing that NIPCSO has likely had more stakeholder meetings than any other utility for the Integrated Resource Plan (IRP) processes.

She checked that those on the phone could hear the proceedings, outlined the objectives for the meeting and gave an overview of the agenda and meeting timing, planning to finish by 2:30. She asked participants to introduce themselves, and Alison Becker of NIPSCO named those on the phone. Dr. Rozelle introduced Frank Shambo, NIPSCO's Vice President for Regulatory and Legislative Affairs, to open the meeting.

Welcome
Frank Shambo, NIPSCO Senior Vice President Regulatory and Legislative Affairs

Mr. Shambo said that it was wonderful to see everybody at the meeting, observing that this will be the last formal meeting in the 2016 IRP process. He thanked participants for their committed engagement both in these workshops and in individual meetings with NIPSCO staff. For his safety moment, he reminded participants that it is important to watch out for deer on the highways, particularly in the evenings and mornings when deer are moving to water sources. Collisions cause great damage to all involved.

Public Advisory Process & Review of Prior Meetings
Tim Caister, Vice President, Regulatory Policy
(slides 4-6)

Mr. Caister reviewed the topics covered in group and individual meetings that NIPSCO has held since May 2016, and thanked everyone who participated. He reminded attendees that all materials would be available on the website www.nipsco.com/irp. He introduced the topics that would be covered during the meeting.

Stakeholder Model Runs
Edward Achaab, Manager, Resource Planning
Daniel Douglas, Vice President, Corporate Strategy & Development
(slides 7-29)

Dr. Rozelle asked participants to hold questions on each model run until the results from each stakeholder group are finished.

Ed Achaab said that NIPSCO modeled several scenarios suggested by stakeholders. These include *All Renewables*, *100% Coal Retirement*, and *Much Lower Solar Cost* cases proposed by Sierra Club, a *Lower Cost Wind* variable proposed by Clean Line, a deeper analysis of *customer costs* requested by the Office of Utility Consumer Counsel (OUCC), and an Industrial Group proposal to evaluate *unconstrained market purchases*. These are described below, with participant comments following.

Sierra Club Requests:

The *All Renewables* portfolio contains about 42% solar, 16% demand side management (DSM), 1% wind and the remainder is generated by gas and coal. This was modeled in the *NIPSCO Base Case* scenario; the cost is $5.8 billion higher but carbon dioxide (CO_2) emissions went down by 60 million tons. In the case of the *100% Coal Retirement* option, CO_2 emissions decreased by 50 million tons. This portfolio relies almost entirely on gas and DSM. Sierra Club also requested an evaluation using much lower solar costs at $1 per watt by 2023 for utility-scale solar, coupling battery storage with renewable generation, and a cost of $2 per watt for distributed generation (DG). NIPSCO was unable to include the battery storage element due to uncertainties about technologies and costs. Mr. Achaab showed the model results for these. The cost of renewable generation went down significantly and CO_2 decreased a bit.

- A participant asked for further explanation of the huge drop in DSM between 2016 and 2017.
    - NIPSCO responded that this was because industrial interruptible was modeled as available in 2017, resulting in a decrease of 522 additional megawatts (MW).
- A participant questioned why NIPSCO would need to couple solar and wind with backup when the Midcontinent Independent System Operator (MISO) system effectively serves as a backup? She explained why she thought this is true.
    - NIPSCO responded that this was an individual request by Sierra Club. NIPSCO understands that there research is ongoing. Although each system has different peaks, and there is some volatility with traditional resources, with wind and solar weather is also a factor. Although batteries are a potential solution to store excess generation, they are not available today. Regarding MISO, NIPSCO would need to put assets into MISO and then buy them back.

Regarding Type 4 turbines, NIPSCO did not have a specific source or data to rely on for this analysis.

- What is the source of Sierra Club cost data? Indiana Distributed Energy Alliance feels these costs for solar might be high compared to recent available data.
    - NIPSCO responded that Sierra Club did not provide a specific source.

Clean Line Request:

Clean Line requested an analysis using a cost of wind of $1,700 per kilowatt (about $500 less than the NIPSCO estimate). In this case the cost of the portfolio decreased due to reduced costs of wind.

OUCC Request:

Dan Douglas presented these results. He reviewed a chart summarizing the 6 retirement scenarios discussed at the June stakeholder workshop. The 100% retirement portfolio is the lowest cost, and age-based retirements are the highest cost. The OUCC asked what would happen if NIPSCO continued to collect a return on these investments. These data were presented. The 80% coal retirement now becomes the baseline, but it is only .1% lower than the 100% retirement option. He then showed remaining net book value for each facility at the retirement date, with age-based retirements being zero, and others having some additional cost. Of the scenarios modeled, the preferred one is Scenario 4 in this case, with a cost of $553 million.

- What year does Schahfer retire?
    - NIPSCO responded that Schahfer 17 and 18 would retire in 2023
- When will NIPSCO collect stranded costs?
    - NIPSCO responded that it would collect stranded costs over the period represented by the age-based retirement date. NIPSCO also considered a scenario that brought all of these costs forward to the present, but the costs remain about the same.

Industrial Group Request:

The Industrial Group (IG) noted that in NIPSCO scenarios, most purchases end in 2022. It asked for an evaluation that does not constrain this option. The answer is that CO_2 emissions go down.

It also wondered what would happen if Schahfer Units 17 & 18 had a later retirement date rather than the planned retirement in 2023. NIPSCO reported that this is a complicated analysis in trying to work backward in the decision. The main issues revolve around the types and levels of environmental compliance needed. The Coal Combustion Residual rule (CCR) is a driver here. Compliance with Emissions Limitation Guidelines (ELG) is also a major cost. A summary of this analysis was presented.

The IG also asked for an estimate of the annual net present value of the preferred retirement plan (50% coal retirement). A chart was shown with this information by year. The spike in cost in 2023 is due to installation of a new combined cycle gas turbine (CCGT). Costs trend down after the remainder of the planning period.

- What is the cost of going ahead with CCR compliance measures to keep Schahfer open?
    - NIPSCO did not have the exact figure available at this meeting, but said it would be in the hundreds of millions (perhaps $220 million).
- What rate of return are you assuming?
    - 9.75%, as in the last case. This is expected to average about 6% over time.
- What discount rate are you using, and is this consistent with the rate case?
    - 7.49%, which is consistent with the rate case.

Mr. Achaab explained that several other requests for specific requests were made by stakeholders, including suggestions for the report from the Indiana Utility Regulatory Commission (IURC) staff, requests for information from Brubaker, and requests from the Citizens Action Coalition (CAC).

- Are you going to run different discount rates as suggested by IURC staff?
    - NIPSCO responded that the goal of the IRP is to provide a comparison across scenarios, so as long as we use consistent data the results should be comparable. However, NIPSCO will look at different rates prior to the IRP filing.
- The CAC expressed its disappointment that its specific recommendations on how to model DSM differently were not addressed.
    - NIPSCO responded that they were not able to do this because it would have required redoing the Market Potential Study, which used different methods. The Company committed to continue discussions on how to model DSM in future IRPs, market potential analyses and in its three year Plan filing that it will make with the IURC in 2017.

Optimization Results
Edward Achaab
(slides 31-62)

Mr. Achaab reminded participants of the 5 scenarios that were evaluated:
- *Base Case*
- *Challenged Economy*
- *Aggressive Environmental Regulation*
- *Booming Economy*
- *Base Case – Delayed Carbon Implementation*

He then presented the results of optimization modeling that produced capacity expansion plans for 3 sensitivities of each scenario, including a *Least Cost* portfolio, a *Renewable Focus* portfolio, and a *Low Emissions* portfolio.

Using the *Base Case* as an example, he explained to participants how to interpret the graphics presented. The dotted line is NIPSCO's predicted load without DSM, and solid black line is the load with 7.4% reserve margin. He pointed out that the grey portion is the coal generation and there is a decline in all scenarios; this modeling assumes 50% coal retirement. The green portion represents the 13 DSM programs that were selected. Mr. Achaab explained that in some cases NIPSCO is "long" on generation and in some cases "short", meaning that the Company is generating more than it needs in the first instance or generating less than in requires in the second, and, therefore, buying capacity from MISO. Mr. Achaab summarized the costs and CO_2 emissions of each of the Base Case variations. Across the board, the *Low Emissions* portfolios were the highest cost.

Results of the *Challenged Economy* scenario modeling were presented, for *Least Cost*, *Renewable Focus*, and *Low Emissions* portfolios. Nuclear was added at the end of the planning period for the Low Emissions portfolio. Costs and CO_2 emissions were summarized.

In the *Aggressive Environmental* scenario portfolios *Combined Heat and Power (CHP)*, *Wind, Solar, Battery, Biomass, Nuclear*, and *CCGTs* were all added at various points.

For the *Booming Economy* scenario there is *CCTG*, *Wind*, *Solar*, *Battery*, *Biomass*, *Reciprocating Engine*, and *Nuclear* in the various portfolios.

The *Base Delayed Carbon* scenario added significant solar.

Stakeholder comments and questions included the following:

- There were questions about the way data were graphically presented.
  - Mr. Achaab explained that a few of the slides presented today have been updated and are different from the ones previously included in the website slides. NIPSCO said it will update the slides posted on nipso.com/irp.
- Why is NIPSCO building gas when your capacity is so high?
  - NIPSCO explained that it used 7.6% reserve margin, which is the minimum. In addition, units come in set sizes, so sometimes the model ends up with more capacity than is needed by using these (i.e. the unit size may not exactly conform to the reserve margin needs). In addition, since the load changes from year to year, NIPSCO considers it good practice to not include a maximum reserve.
- Why are you using 7.6% reserve margin? Unless NIPSCO is exactly coincident with MISO, it should be lower.
  - NIPSCO responded that although there have been years when NIPSCO has matched the MISO reserve margin exactly, because the model is looking 20 years out, the more conservative approach was to assume the MISO reserve margin requirements.
- Is industrial interruptible included in the 500 MW of DSM in all scenarios?
  - Yes

Mr. Achaab then showed summary charts of the cumulative energy mixes inherent in the *Least Cost*, *Renewable Focus*, and *Low Emissions* portfolios for the 5 scenarios for the 2015-37 period. These charts indicated percentages the resources used to meet loads including coal, gas (Sugar Creek plus additional installations), wind, CHP, hydro, feed-in tariff (FIT), DSM, and net purchases from the market or sales to the market. Solar and battery storage are added in the *Renewable Focus* and *Low Emissions* portfolios. In the least cost option for the Base Case, about 25% coal generation is included. He pointed out that percentages may be a bit misleading since each scenario has a different total energy requirement.

Mr. Achaab presented results of the sensitivity analyses (risks) (slide 56) conducted for each scenario and portfolio. Sensitivities included:
- *No CO2 Price*
- *Low Load*
- *High Gas Price*
- *Loss of Major Industrial Load*
- *High Renewables & Increasing Load*
- *High Renewables & Decreasing Load*

In the summary of results of this analysis Mr. Achaab showed only the metric of present value of revenue requirement (PVRR), as he said that the total analysis was very complicated and will be presented in an appendix to the IRP. He also presented charts detailing the cumulative energy mix for 2015-37 for the various sensitivities in each portfolio.

Questions from participants included the following:

- Why would there be purchases if there is excess capacity, as in several cases presented here?
  - NIPSCO responded that the Company estimates whether the cost to run an asset in a particular environment is favorable or not, considering fuel, operating and other costs. If not, NIPSCO would purchase from the market.
- As shown on these slides, have the definitions of least cost, renewable focus, and low emissions changed from previous meetings?
  - The data results are as of today, and operating characteristics change frequently. But in the main, assumptions and data are the same as discussed at previous meetings.
- A stakeholder said that his group would like to compare the different portfolios under these sensitivities, so suggested a different way of visually presenting the data.
  - NIPSCO responded that it can show these data in other ways and asked for stakeholders to share suggestions for how they would like to see the data.
- Where net purchases are negative, does this mean it’s more cost effective to buy than to generate?
  - Yes, in some cases.

Stakeholder Presentations

Laura Arnold, Indiana Distributed Energy Alliance

Ms. Arnold said that most of the information she will present is extracted from Green Tech Media (GTM Research) and the solar energy industry. For those interested, these can be downloaded from SEIA (http://www.seia.org/).

Regarding the cost of utility-scale solar photovoltaics (PV), NIPSCO's presentation significantly overestimates costs. Costs continue to drop, and more residential and utility PV market segments continue to be added. More than 51% of all new electric generating capacity came from solar in the first quarter of 2015. For community solar, more than 1/3 of that total has come on line since 2014. Since the first quarter of 2016, 2,051 MW were added in the U.S., an increase of more than 43% over 2015. According to this source, solar PV can be provided as low as just over $1 per watt. It's driven in part by solar PV module prices, which can now be purchased for $.49 per watt for utility-scale developments. Solar installations are not limited to the east and west coasts but occur throughout the country. There is more interest in single axis tracker mechanisms. Additionally, solar PV does not need to be brought online at 600 MW increments but can be added at much lower levels to fill specific needs. In conclusion, Indiana DG believes that the overall cost of solar installation is far lower than NIPSCO's estimates.

Ms. Arnold observed that some of her constituents still cannot relate to the IRP process and what it means to them. She offered to discuss how technology costs can really work to reduce costs to customers.

Questions and comments were as follows:

- A stakeholder requested that NIPSCO to look back at previous IRPs to see how assumptions and estimates played out in real life. Specifically, it would be interesting to see if costs of renewables were overestimated.
    - Mr. Achaab pointed out that the IRP looks at total installed costs, including interconnection and other costs, therefore an absolute comparison would be difficult.
- On the charts presented there is a significant drop in solar PV costs between 2009 and 2014, but then it flattens out. Why is this happening?
    - Ms. Arnold couldn't answer this because she hasn't seen the full report. She suggested checking with Green Tech Media.
- Do these prices take into account any available tax incentives?
    - It varies. In some cases, federal incentives are included. There are state by state analyses, but one must purchase these data. There is a list of rankings of states' utility-scale solar installations; California is #1, North Carolina is #2, and Indiana is #16.

Preferred Plan & Short Term Action Plan
Dan Douglas
(slides 64-76)

Dan Douglas reviewed the main criteria for decision making: reliability, environmental compliance, technology and fuel diversity to enhance flexibility, and affordability for customers. These decisions require consideration of employees, the environment, and local economies.

He emphasized that, while this is the last stakeholder meeting for this IRP cycle, NIPSCO intends to remain engaged with stakeholders. He noted that, in some ways the IRP is the beginning of the planning process.

The short-term action plan to address NIPSCO's current generation includes:

- Retire 50% of NIPSCO's coal capacity by the end of 2023.
    - Including Bailly Units 7 and 8 starting in 2018 and Schahfer Units 17 and 18 in 2023
- Maintain current gas fueled generation.
    - Including Sugar Creek CCGT, Schahfer Units 16A and 16B CTs, Bailly Unit 10 CT
- Continue the interruptibles program.
- Maintain the current wind Purchase Power Agreements (PPAs).
- Complete DSM/EE Program filing in 2017 and beyond..
- Proceed with CCR/ELG compliance plan filings for Michigan City Unit 12 and Schahfer Units 14 and 15.

Mr. Douglas discussed the rationale for the preferred plan selection. Primary considerations include customer risk, technology risk, and market risk. Therefore, plans that include shorter-duration and flexible supply in the portfolio are preferable.

He stated that about 40% of NIPSCO's energy demand is from five large industrial customers, so changes could affect them significantly, as well as affecting residential and commercial customers. Technology changes drive some portion of the volatility in market prices, and changes can render specific technologies obsolete. Therefore, the preferred portfolio will be comprised of about 20% of shorter term assets including interruptibles. He noted that NIPSCO will also look at PPAs that are shorter in duration, e.g. 5 years. Mr. Douglas showed a summary of the NIPSCO current portfolio, which averages about 12 years' duration. He said that by the end of this IRP planning period, the average portfolio duration will be significantly reduced.

Mr. Douglas provided an overview of the actions and timing included in the preferred plan. He noted that actions proposed in the near term (2016-2018) are more certain than those farther out in time. In the short term, retirements will be implemented with a focus on customer, employee and local economy interests, and identifying the lowest-cost replacements. Mr. Douglas noted there is a short-term need for up to 150 MW of additional generation, which will preferably be met through DSM, PPAs and market purchases. Mr. Douglas noted that along with the DSM Plan filing, regulatory filings will include a Certificate of Public Convenience and Necessity (CPCN) for CCR/ELG.

Regarding market purchases, he noted some cautions including potentially higher prices due to regional retirements that may result in higher planning reserve auction prices. He said that NIPSCO assumes that renewables will be advantaged due to tax incentives, and all technologies will be considered.

He showed a graphic of the preferred plan capacity expansion mix of coal, gas, wind, hydro, FIT, DSM and market purchases. He then showed a comparison of the preferred plan to the other scenarios relative to PVRR, showing that the preferred plan is the least cost option in all cases. He provided details of the DSM program groupings that have been selected by the model runs to date. Other groupings may be considered further, and others were not viable and not selected.

A summary was provided of how NIPSCO's preferred resource plan would be broken into the shorter term of 2018 to 2022 and longer term beyond 2023. Short-term actions include maintaining interruptibles, making market purchases including PPAs, and regulatory compliance actions for the Michigan City and Schahfer plants. Longer-term actions include potential additions of CCGTs (or similar) in 2023 and 2035, and strategic monitoring of the MISO market.

Participants had the following questions and comments:

- To replace Bailly, short term market purchases are planned. When does NIPSCO need to make the decision on replacement of Schahfer?
    - NIPSCO responded that it will stay engaged with stakeholders over the next couple of years as this process continues. The Company needs to figure out specific costs of replacements so it can develop accurate options. There is a 4- to 5-year build cycle, so it is expected that there may be Requests for Proposals (RFPs) and a CPCN filing in late 2018 or early 2019. NIPSCO is not set on CCTGs but will also look at other options such as wind, solar, nuclear, etc.
- Please evaluate the extension of permits for Schahfer Units 17 and 18 so we can make a comparison of stranded costs.
    - NIPSCO responded that it will look at this, but that it is important to remember that there are costs associated with any approach.
- Is there a fuel availability risk as well as a fuel price risk, e.g. as a result of fracking?
    - NIPSCO responded that there is and the Company has attempted to account for this in the modeling of different scenarios and sensitivities.
- When is the next IRP? How does this fit in with a CPCN filing in 2019?
- NIPSCO's next IRP is to be filed in 2019. However, the Company will evaluate this as planning continues and will communicate with interested parties about the actual timing of the next IRP

- There is no new solar in the preferred plan, correct?
  - Correct
- If you're concerned about local government tax base, building solar in the local markets would help these communities, rather than purchasing from other locations.
  - NIPSCO thanked the Sierra Club for that observation and stated that while the Company cannot guarantee that new facilities will be built in the same territories as those decommissioned, it will do whatever is possible to minimize impacts on these communities.

Stakeholder Presentations, Cont'd

Sierra Club Comments

Steve Francis of the Hoosier Chapter thanked NIPSCO for explaining the process quite well and reaching out to a range of stakeholders. He likes the idea of breaking the planning period into three phases to account for uncertainty. But even if the IRP cycle were to be moved up from 2019 it would still not accommodate near-term decisions about Schahfer and other units. He asked that NIPSCO consider pilot projects in the near term, such as *Brownfields to Brightfields*, *Solar for Schools*, and other creative programs.

He said that Sierra Club is disappointed in the results of the IRP decisions. While they understand that NIPSCO is looking for the "extreme lowest cost", they note that other utilities have included other considerations like the impact of the Clean Power Plan. Sierra Club agrees there is uncertainty on market prices, but thinks this should stimulate an increasing reliance on renewable resources. Mr. Francis said that Sierra Club would like to be involved in near-term decisions as well as long-range planning.

Conclusion and Next Steps

Tim Caister thanked everyone for coming today, and noted that the meeting is finishing well ahead of schedule. He also thanked all the NIPSCO resource planning staff who have worked so hard on developing the IRP, the specialized technical staff, and those who have provided logistical support.

NIPSCO will submit a final IRP report on November 1, 2016. Mr. Caister encouraged everyone to continue to reach out to them, saying that NIPSCO is happy to have follow-up discussions. He referred participants to the website NIPSCO.com/IRP for ongoing information and invited additional comments by email at NIPSCO_IRP@nisource.com. The summary of this meeting will be posted by October 17, 2016.