Appendix A

Exhibit 1

NIPSCO Integrated Resource Plan 2018 Update

Public Advisory Meeting One

March 23, 2018

NIPSCO®

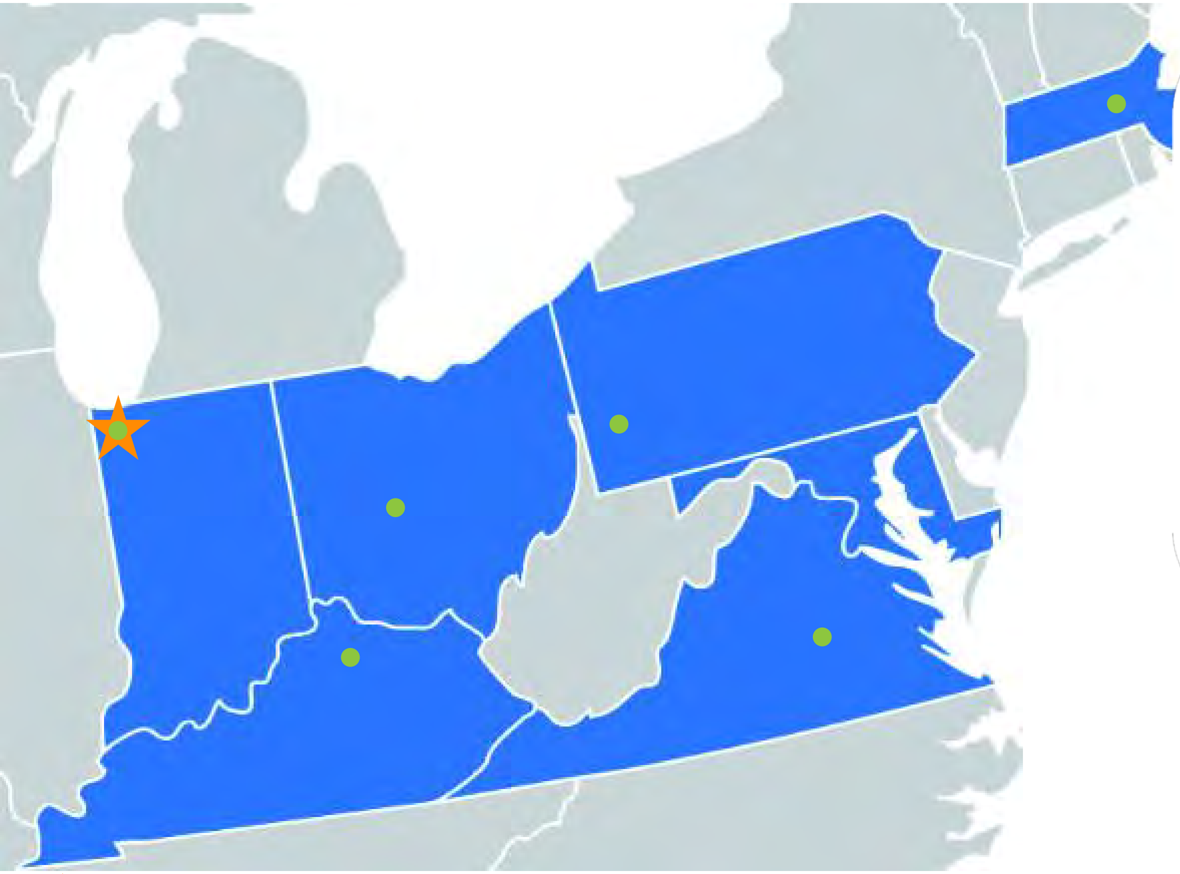
NiSource®

- **Welcome**
- **Introductions**
- **Safety Moment**
- **Purpose of Today**
  - Why is NIPSCO doing an update to its Integrated Resource Plan?
  - How has the process improved since 2016?
  - Provide key drivers, data
  - Provide information regarding a request for proposal for new capacity
  - Discuss the Public Advisory Process and start to get your input and feedback

Agenda

Time	Topic
9:00-9:30	Welcome and Introductions
9:30-10:15	Why a 2018 IRP Update/Improvements from 2016 Plan
10:15-10:30	Break
10:30-11:15	Modeling Approach for 2018 IRP
11:15-12:00	Key Assumptions in the 2018 IRP-Part 1
12:00-12:45	Lunch
12:45-1:15	Key Assumptions in the 2018 IRP-Part 2
1:15-1:30	Demand Side Management and the 2018 IRP
1:30-1:45	Break
1:45-2:00	Request for Proposal for Capacity
2:00-2:20	Stakeholder Presentations
2:20-2:25	2018 Public Advisory Process
2:25-2:30	Wrap Up

One of the Nation's Largest Natural Gas Distribution Companies



- 7-state footprint
- ~7,500 employees
- ~3.5M natural gas utility customers
- ~500K electric utility customers

Columbia Gas

NIPSCO

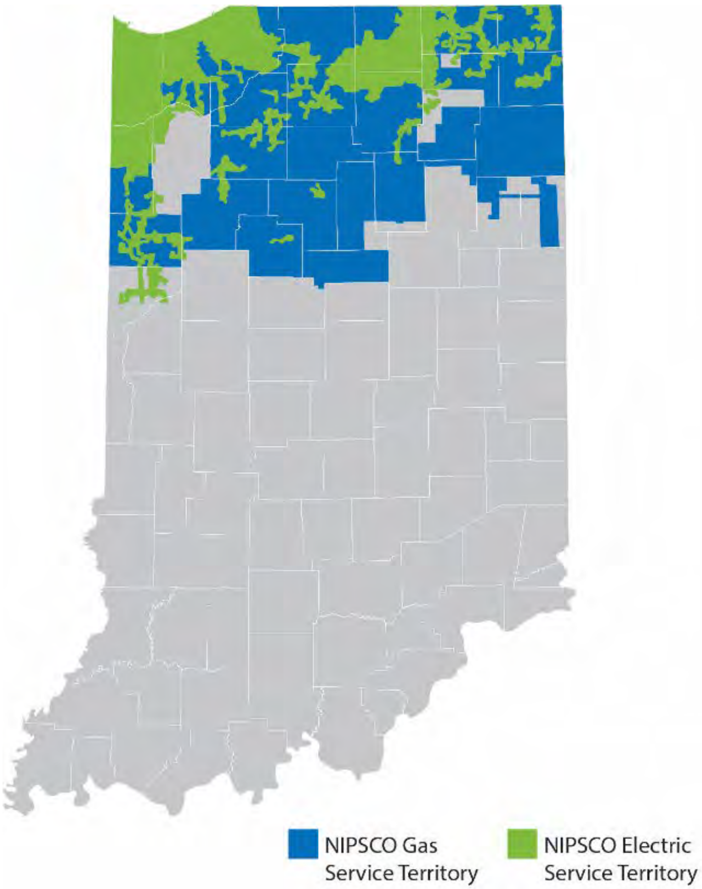
★ Corporate Headquarters ● State Utility Headquarters

Electric

- 468,000 electric customers in 20 counties
- ~3,400 MW generating capacity*
  - Operates 6 electric generating facilities (3 coal, 1 natural gas, 2 hydro)
  - Additional 100 MW of wind purchased power
- 12,800 miles of transmission and distribution
  - Interconnect with 5 major utilities (3 MISO; 2 PJM)
  - Serves 2 network customers and other independent power producers

Gas

- 819,000 natural gas customers in 32 counties
- 17,000 miles of transmission and distribution lines
- Interconnections with 7 major interstate pipelines
- 2 on-system storage facilities



2,900
Employees

Merrillville, Ind.
Headquarters

*Post Bailly retirements in May 2018, NIPSCO will have ~2900 MW of generating capacity and two coal generating facilities

	Meeting 1 (March 23)	Meeting 2 (May 11)	Meeting 3* (July 24th)	Meeting 4 (September 19)	Meeting 5 (October 18)
Key Questions	-Why has NIPSCO decided to file an IRP update in 2018? -What has changed from the 2016 IRP? -What are the key assumptions driving the 2018 IRP update? -How is the 2018 IRP process different from 2016?	-What is NIPSCO existing generation portfolio and what are the future supply needs? -Are there any new developments on retirements? -What are the key environmental considerations for the IRP? -How are DSM resources considered in the IRP?	-What are the preliminary results from the all source RFP Solicitation?	-What are the preliminary findings from the modeling?	-What is NIPSCO's preferred plan? -What is the short term action plan?
Meeting Goals	-Communicate and explain the rationale and decision to file in 2018 -Articulate the key assumptions that will be used in the IRP -Explain the major changes from the 2016 IRP -Communicate the 2018 process, timing and input sought from stakeholders	-Common understanding of DSM resources as a component of the IRP -Common understanding of DSM modeling methodology -Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap -Key environmental issues in the IRP	-Communicate the preliminary results of the RFP and next steps	-Stakeholder feedback and shared understanding of the modeling and preliminary results -Review stakeholder modeling and analysis requests	-Communicate NIPSCO's preferred resource plan and short term action plan -Obtain feedback from stakeholders on preferred plan

*Webinar

- **Your input is critical to the process**
- **Today's meeting is the first of five meetings**
- **The Public Advisory Process provides NIPSCO with feedback on its assumptions and sources of data and helps inform the modeling process**
  - It also serves as a "check" on the modeling process as results are received
- **This improves the Integrated Resource Plan and its results**
- **Your candid and on-going feedback is key**
  - Please ask questions and make comments!
  - Ability to make presentations as part of each Public Advisory Meeting
    - If you wish to make a presentation today and have not already indicated so, please see Alison Becker during break or at lunch
- **Please provide feedback on the process itself as NIPSCO wants to continue to make this valuable for you as well as the Company**

Dan Douglas

Vice President Corporate Strategy & Development

2016 NIPSCO IRP Preferred Plan

2018 NIPSCO IRP Update

Current Resources

Retire

- Bailly Unit 7 and 8 by May 2018
- Schahfer Units 17 and 18 by 2023

Comply

- Invest in environmental compliance (CCR and ELG) for Schahfer Units 14,15 and Michigan City 12

Maintain

- All gas fired units; Sugar Creek CCGT, Schahfer Units 16A&B and Bailly 10 Combustion Turbines
- Industrial interruptibles program
- Wind Power Purchase Agreements

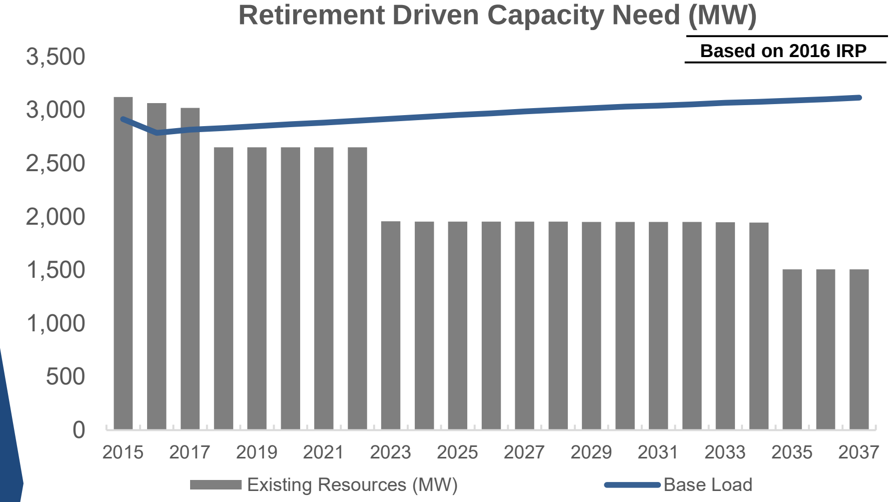
Future Resource Need

Short-Term (2018-2022)

- Rely on existing resources
- File DSM/EE program action plans
- Fill capacity gaps with MISO procurement and or PPA

Long-Term (2023+)

- Combined Cycle Gas Turbine (CCGT) as a long term generation solution in 2023 and 2035
- Monitor MISO market fundamentals, capacity pricing and contract resource pricing



Driver and Rationale for 2018 Update

- Preserve NIPSCO's ability to fully consider all resource options to address the capacity need
- Examine the remaining coal units (Schahfer 14,15,17,18 and Michigan City 12) in light of upcoming ELG compliance expenditures

Subject	2016 IRP Feedback	2018 Improvement Plan
Commodity Price Forecasts	• "NIPSCO's assumption doesn't capture the nuanced and dynamic relationships between oil and natural gas markets or whether the historic correlations between natural gas and coal markets are changing" • "Given the importance of fuel forecasts in retirement decisions that are a focal point of this IRP, it is surprising that NIPSCO only relied on one projection for fuel prices" • No transparency and availability of underlying assumptions for fuel forecasts	• Utilizing independently generated commodity price forecasts using an integrated market model • Providing transparent assumptions related to key inputs and outputs • Benchmarking against publicly available forecasts
Scenarios and Sensitivities	• "NIPSCO's construction of scenarios and sensitivities in the 2016-2017 IRP is a significant advancement over the 2014 IRP. The clarity of the narratives was commendable and transparency was exceptional"	• Building upon the progress made in the 2016 IRP with the same scenarios or thematic "states of the world" to develop portfolios and inform risk analysis
Risk Modeling	• "NIPSCO's planning model is not capable of stochastic analyses so it relied on scenario analyses and sensitivity analyses in preparing its IRP"	• Implementing efficient risk informed (stochastics) analysis with the ability to flex key variables

Source: Final DIRECTOR'S REPORT for the 2016 Integrated Resource Plans, November 2, 2017

Subject	2016 IRP Feedback	2018 Improvement Plan
Capital Cost Assumptions	• Capital cost estimates for new capacity resources were based on proprietary consultant information • "…No scenario or sensitivity covered uncertainties of resource technology cost"	• Leveraging 3rd party and publicly available datasets to develop a range of current and future capital cost estimates for new capacity resources • Conducting an "all-source" Request for Proposal solicitation for replacement capacity resources
DSM Modeling	• DSM groupings are not getting quite the same treatment as the supply side resources	• Utilizing new modeling capabilities will enable DSM to be treated equally with other supply side resources
Preferred Plan and Scorecard	• "The lack of basic information about the Preferred Plan, combined with the poor discussion relating the Preferred Plan to the IRP's analyses and metrics, makes any evaluation of the Preferred Portfolio problematic at best" • "The score card would benefit from a more detailed narrative to detail those metrics that can be quantified as well as those metrics that do not lend themselves to quantification"	• Providing detailed analysis on selection of the Preferred Plan driven by need for it to be actionable • Developing enhanced scorecard methodology to include more quantifiable metrics that better evaluate tradeoffs • Incorporating rate impact analysis as part of preferred plan metrics

Source: Final DIRECTOR'S REPORT for the 2016 Integrated Resource Plans, November 2, 2017

Jim McMahon & Pat Augustine
Charles River Associates (CRA)

Fundamental Commodity Price Forecasting

- Fundamentally driven, transparent long-term price forecasts
- Forecasts for the following products:
  - Power & fuels: natural gas and coal, including fuel basis and transport
  - MISO energy and capacity prices

Integrated Resource Planning

- Scorecard development
- Portfolio development
- Risk informed portfolio analysis (stochastics)
- Retail rate forecasting
- Tradeoff analysis
- Stakeholder engagement

Overview Of Resource Planning Approach

1 Identify key objectives and metrics

2 Develop market perspectives (planning reference case and scenarios)

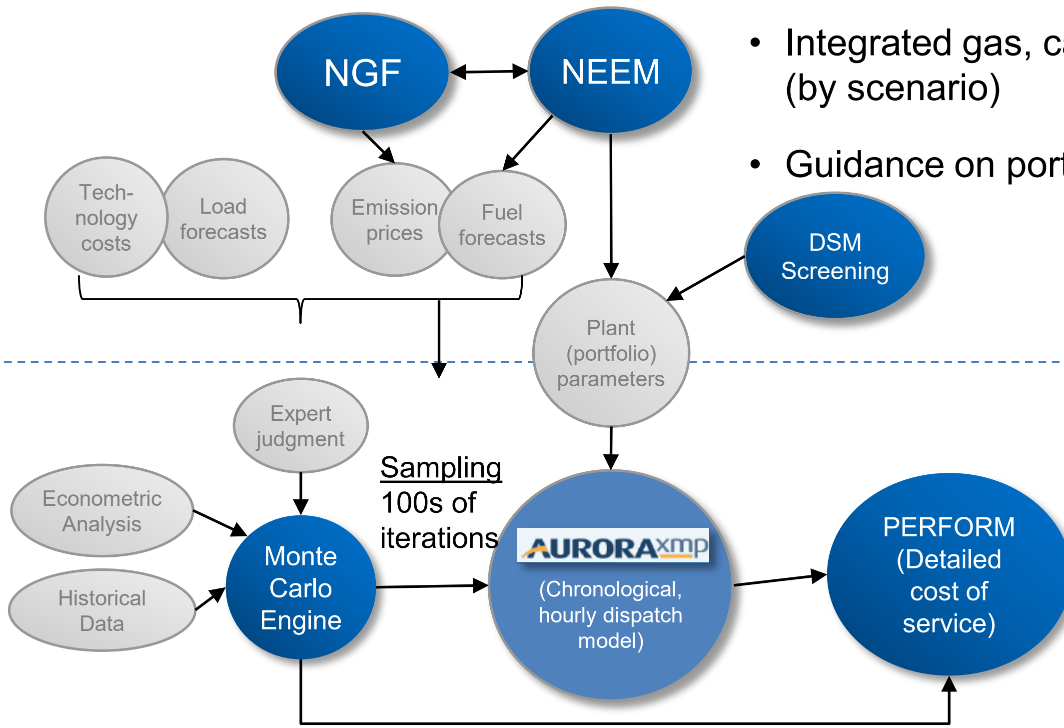
3 Develop integrated resource strategies for NIPSCO (portfolios)

4 Portfolio modeling
- Detailed scenario dispatch
- Stochastic simulations

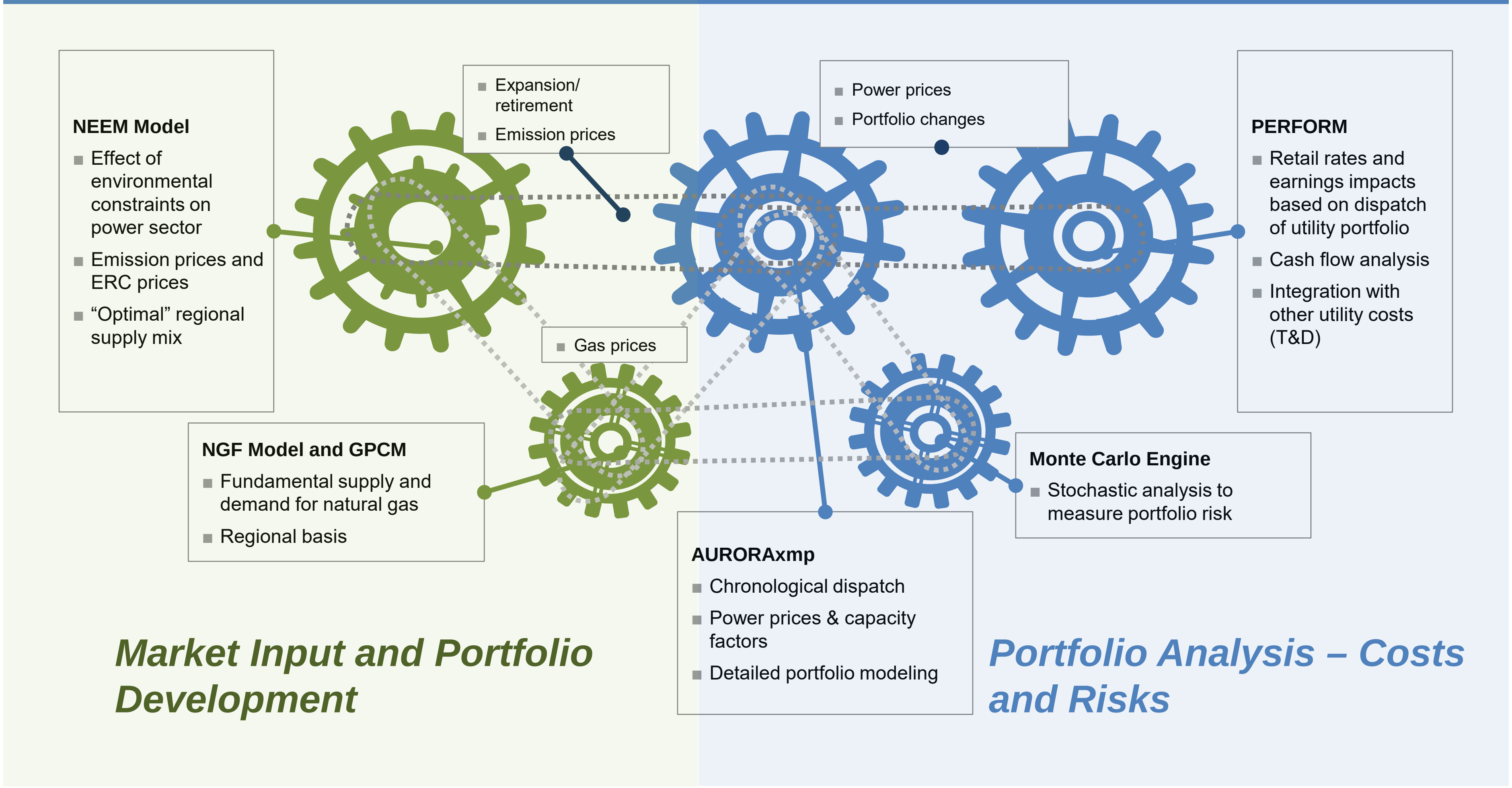
5 Evaluate tradeoffs and produce recommendation

This year's process will be structurally similar to NIPSCO's 2016 IRP process, but with changes and enhancements to respond to stakeholder feedback.

- Integrated gas, carbon forecasts (by scenario)
- Guidance on portfolio options



Environmental, Power Market and Financial Models



- **NGF optimizes production at natural gas basins throughout the US, providing the lowest cost solution based on the costs and performance characteristics of shale and other production basins, for meeting future gas demand**
- **NGF is integrated with NEEM, which provides electric and non-electric sector gas demand for a given price**

Gas Supply

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

Well Performance

- Drilling & completion costs
- Environmental compliance costs
- Royalties & taxes
- First year initial production rate
- Changing drilling and production efficiencies
- Productivity decline curve
- Well lifetime
- Distribution of performance

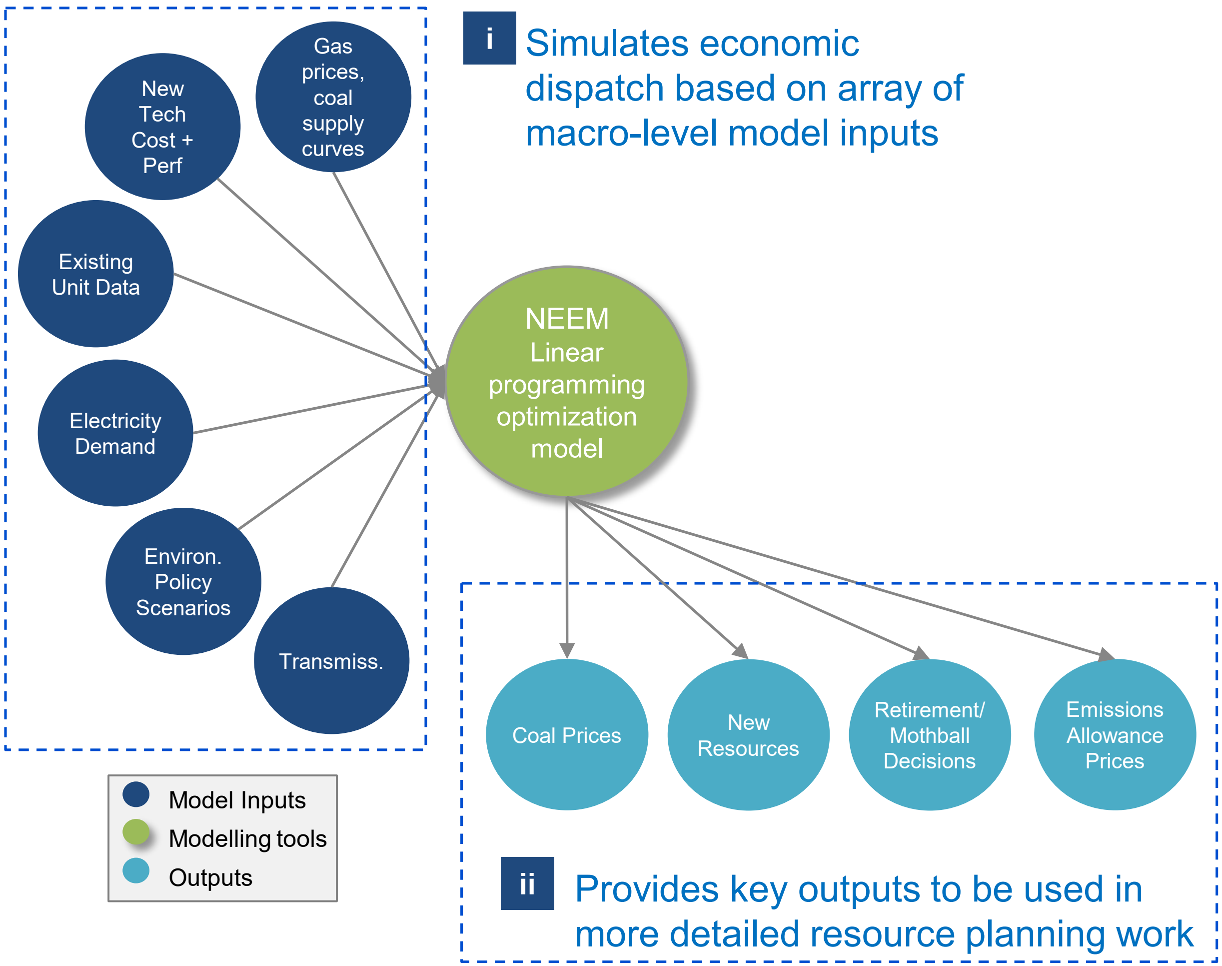
Gas Demand

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

Other Market Drivers

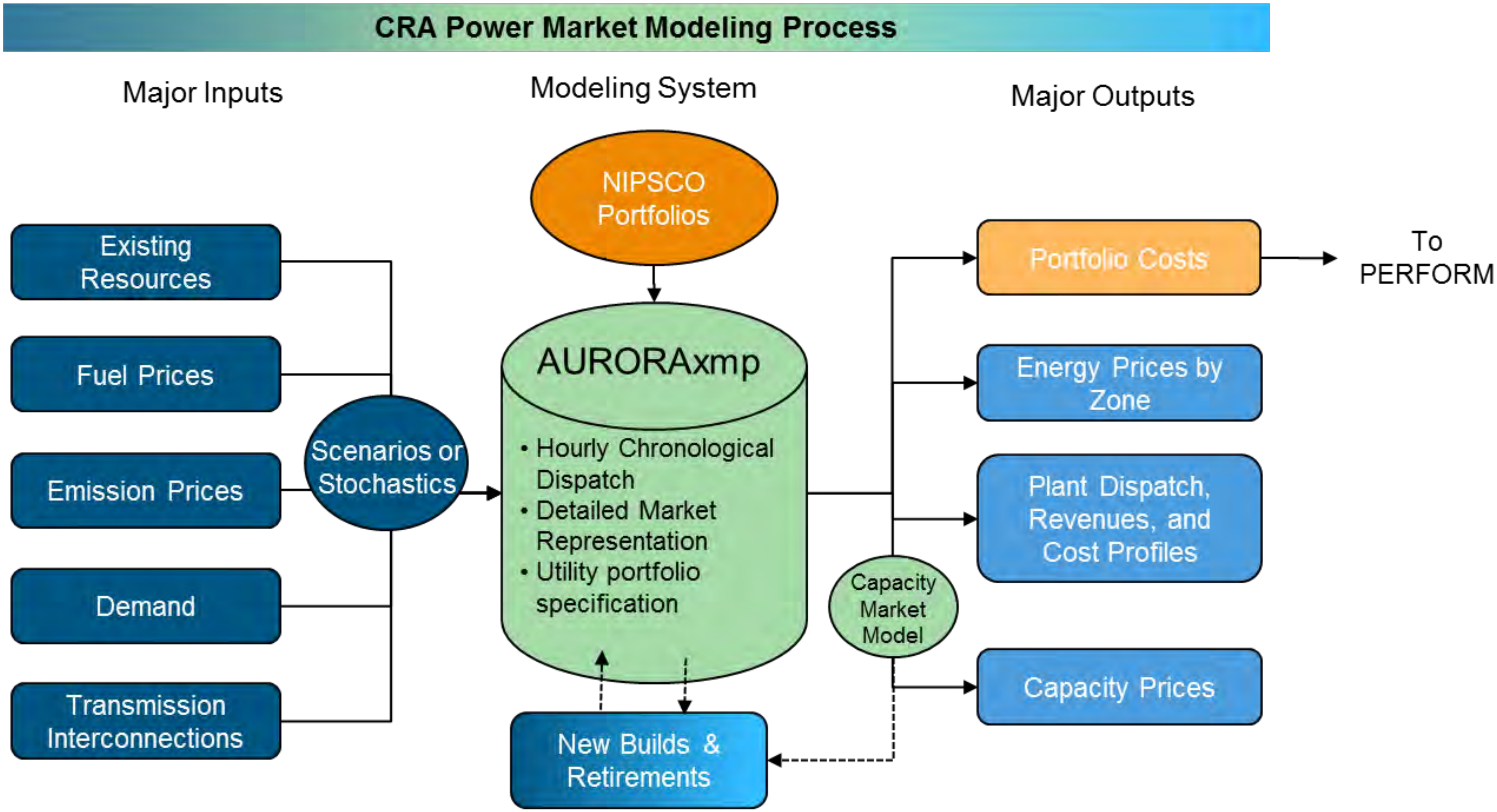
- Value of NGL / condensates
- Natural gas storage

CRA continuously enhances NGF to reflect changes in key gas market drivers



CRA's NEEM Market Model:

- Minimizes the present value of incremental costs to the electric sector, while meeting demand and complying with environmental limits
- Its inputs include:
  - Technology cost assumptions
  - Operational parameters
  - Fuel prices
  - Electricity demand
  - Emission caps
  - Renewable portfolio standards
- Provides output such as coal prices by basin, new electric resource build pattern, retirement and mothball decisions, emissions and allowance prices


CRA Power Market Modeling Process
Major Inputs
Modeling System
Major Outputs
NIPSCO Portfolios
Existing Resources
Fuel Prices
Emission Prices
Demand
Transmission Interconnections
Scenarios or Stochastics
AURORAxmp
• Hourly Chronological Dispatch
• Detailed Market Representation
• Utility portfolio specification
New Builds & Retirements
Capacity Market Model
Portfolio Costs
To PERFORM
Energy Prices by Zone
Plant Dispatch, Revenues, and Cost Profiles
Capacity Prices

Data Collection

Portfolio Fixed Costs
- New additions / retirements (by portfolio)
- Technology costs
- Capital forecasts
- OpEx forecasts
- Load growth forecasts
- Specific investments
- Financial assumptions (WACC)

Portfolio Variable Costs
- Portfolio dispatch and associated power supply costs from Aurora analysis

Scenario/ Stochastic Analysis
- Flexibility to run scenarios/stochastics on capital, fuel, power, dispatch, etc.
- Rapid analysis of multiple portfolio options

PERFORM Model

Financial Module
- Cost of service calculation
- Detailed treatment of tax depreciation
- Asset-specific summaries

Outputs

NPVRR
- Summaries of net present value of revenue requirements
- NPV summaries by component

Retail Rate Forecast
- Forecast of generation rate (average) is possible
- Rate forecast based on perfect ratemaking assumptions (not intended to forecast specific rates by year or class)

Risk Analysis
- Scenarios or stochastic illustrate potential risk around retail rate forecast or NPVRR

Scenario and stochastic approaches often address different questions, but can be used together to perform a robust assessment of risk

Scenarios
Single, Integrated Set of Assumptions

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

Stochastics:
Statistical Distributions of Inputs

- **Can evaluate "tail risk" impacts**
  - Short-term price volatility impacts portfolio performance
    - Value of certain portfolio assets is dependent on market price volatility
    - Commodity price exposure risk is broader than single scenario ranges
- **Develops a rich dataset of potential outcomes based on observable data, with the recognition that the real world has randomness**
  - Large datasets can allow for evaluation of key drivers and broader representation of distribution of outcomes
  - Can robustly calculate statistical metrics to evaluate 95^{th} percentile outcomes

- **As in the 2016 IRP* process, the first step is to identify major drivers of potential uncertainty which could influence IRP outcomes**
- **Then, develop future perspectives regarding major drivers**
- **Next, assess whether scenario or stochastic (or both) treatment is appropriate**

Uncertainty Driver	Stochastics	Scenarios	Comments
Fuel Prices	✓	✓	Robust sets of historical data can support statistical analysis on top of fundamental forecasts
Carbon Prices	✓	✓	Discrete scenarios can be probability-weighted and integrated with fuel/power forecasts
Power Prices	✓	✓	Robust sets of historical data can support statistical analysis on top of fundamental forecasts
Capital Costs	✓	✓	Broad uncertainty around technology change and future cost drivers can be parameterized through review of source data and expert opinion
Load		✓	Large risks relate to loss of major industrial load, which is a discrete event
Other Environ. Policy		✓	Policy shifts (ie, with ELG compliance) are best evaluated in discrete scenario fashion

***2016 IRP Drivers*: Load, Regulations, Environmental Compliance, Economy, Technology, Commodity Prices**

2018 Scenario Theme Development

As in the 2016 IRP, the 2018 IRP is using the same "scenarios" or thematic "states-of-the-world" under which to develop portfolios and to inform stochastic distributions

Base

- Reference case commodity price outlook, with 2026 carbon price
- Reference case capital cost projections
- Non-carbon environ. costs reflect only current and proposed regulations (ELG, CCR)

Aggressive Environmental Regulation

- High carbon price
- Feedbacks to gas, coal, and power prices
- Non-carbon environmental compliance costs are stricter
- Tech. breakthrough for renewable /storage costs

Challenged Economy

- Low load, including loss of industrial load
- No carbon price
- Feedbacks to gas, coal, and power prices

Booming Economy & Abundant Natural Gas

- Low natural gas prices as a result of larger resource base
- Feedbacks to coal and power prices
- Cheap energy costs drive stronger economic growth and higher load

Likely implications for NIPSCO Portfolios

- Aggressive Environmental Regulation: ***More renewables, storage, and DSM; more coal retirements***
- Challenged Economy: ***Fewer renewables and DSM; better coal economics; fewer self-builds and more reliance on market***
- Booming Economy & Abundant Natural Gas: ***More gas CCGT, fewer renewables and DSM***

Each scenario will have a unique combination of key input variables and a fully integrated set of commodity market price forecasts

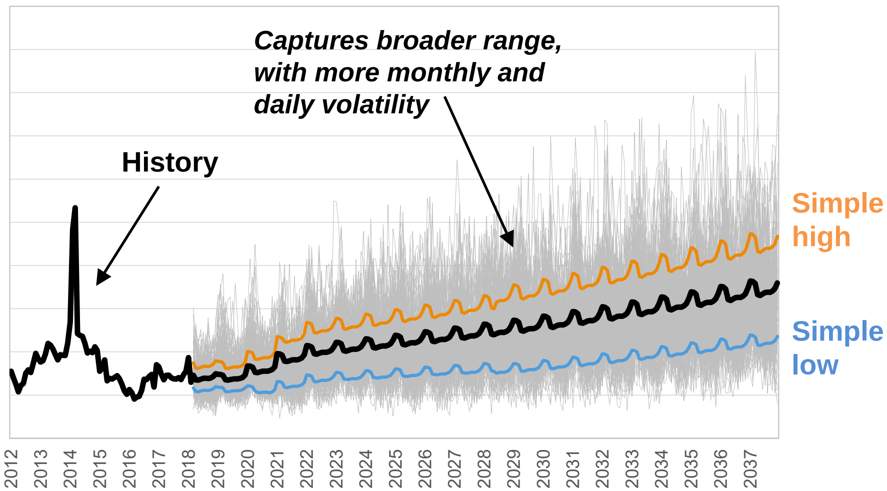
Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs	Other Enviro. Costs
Base	Base	Base	Base	Base	Base	Base	Base
Aggressive Environmental Regulation	Base	**High**	**High**	**Low**	**High**	**Low** renew./ sto.	**High**
Challenged Economy	**Low**	**Low**	**Low**	**High**	**Low**	Base	Base
Booming Economy & Abundant Natural Gas	**High**	Base	**Low**	**Low**	**Low**	Base	Base

Develop All Scenario Details	• Specify key input parameters • Run models to develop integrated set of commodity price inputs and other major variables
Evaluate Favorable NIPSCO Portfolio Concepts for Each Scenario	• Run portfolio models to assess potential preferred plans under each scenario • Use expert judgment, where necessary, to establish reasonable portfolio strategies within the identified theme
Develop Stochastic Distributions	• Use scenario ranges to complement the statistically-based stochastic input development process (for example, to cover full range of fuel and power outcomes across carbon regimes)
Run All Portfolios across All Scenarios and Stochastics	• Evaluate *each* portfolio against all scenarios *and* against stochastic distributions for a rigorous review of risk profile

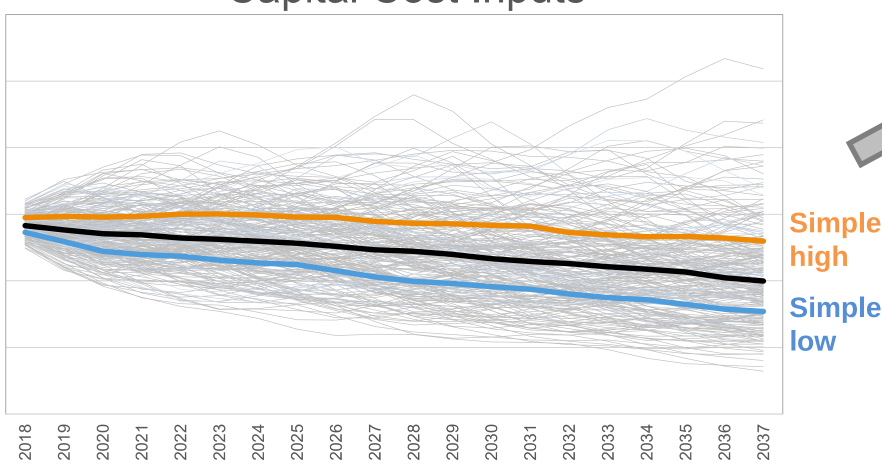
Stochastic Analysis Provides Improved Coverage Of Uncertainty

Stochastic distributions based on historical volatility, underlying correlations between inputs, and expert assessment of future ranges

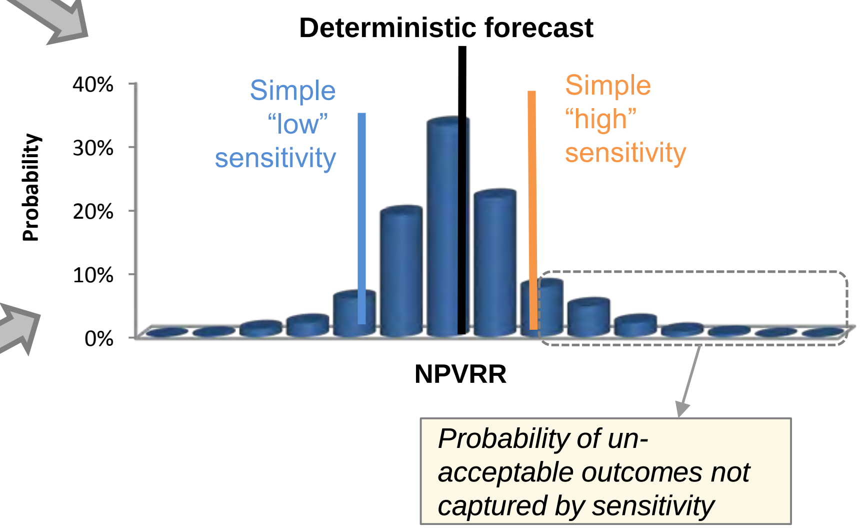
Gas Price Inputs



Capital Cost Inputs

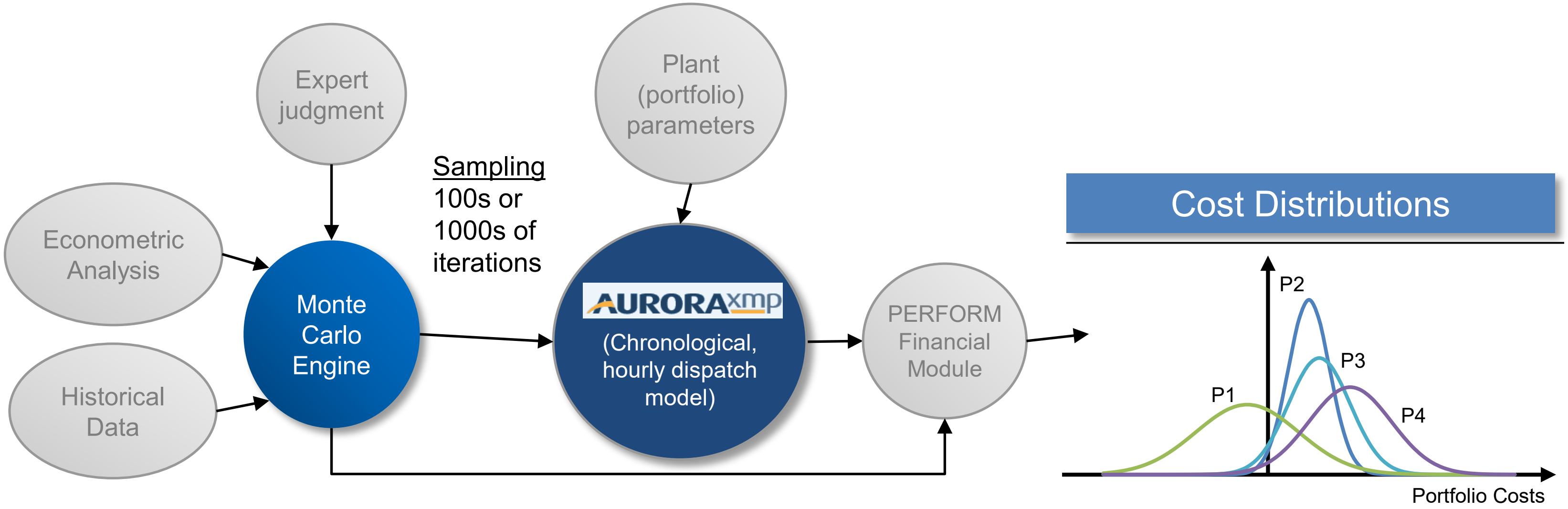


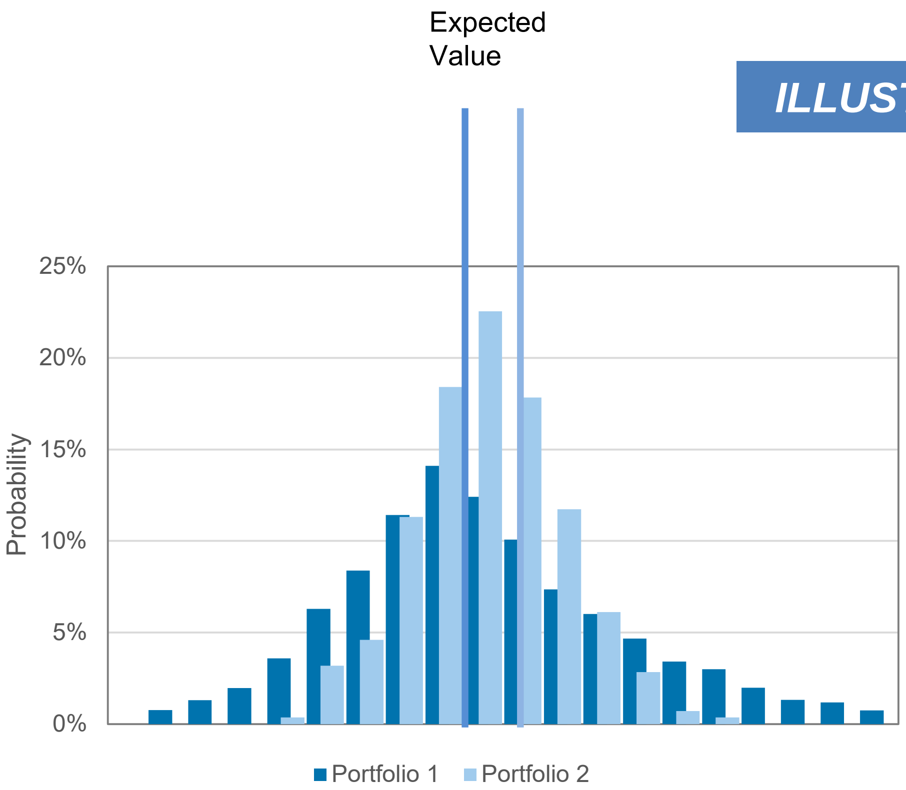
Portfolio Cost Outputs



ILLUSTRATIVE

Scenario development exercise and historical data analysis support input development





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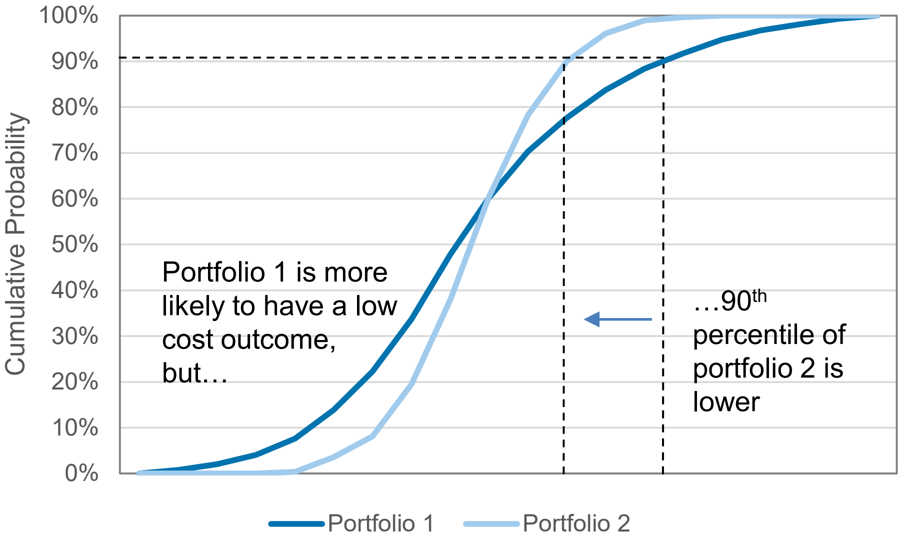

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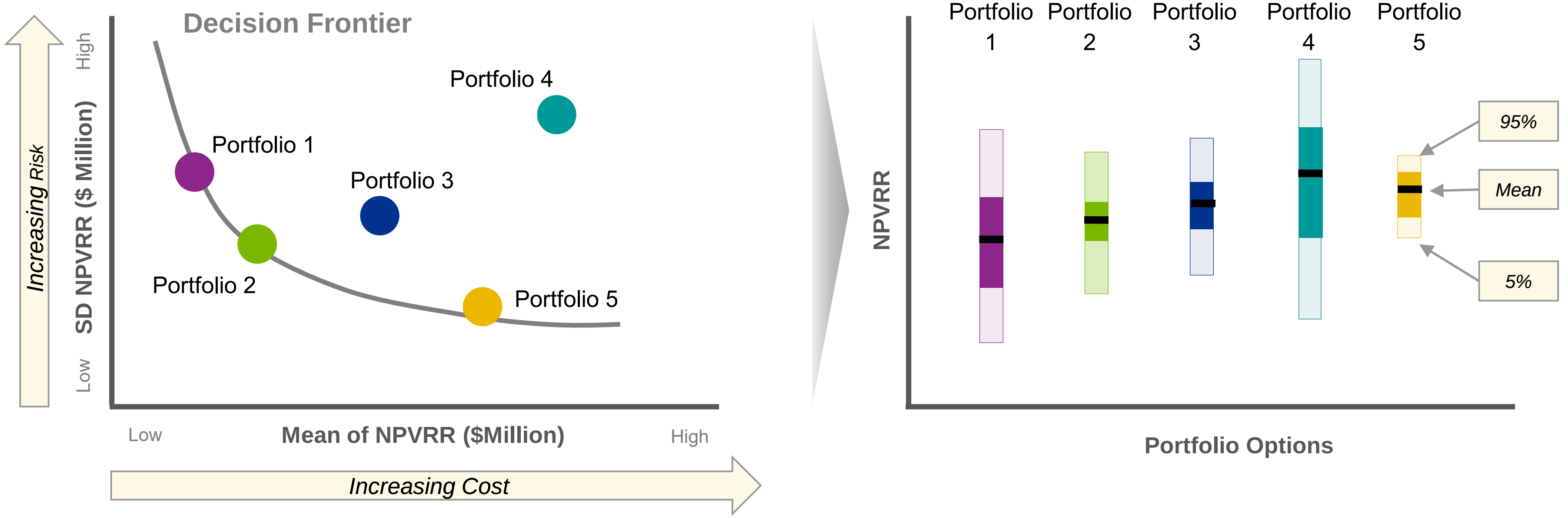
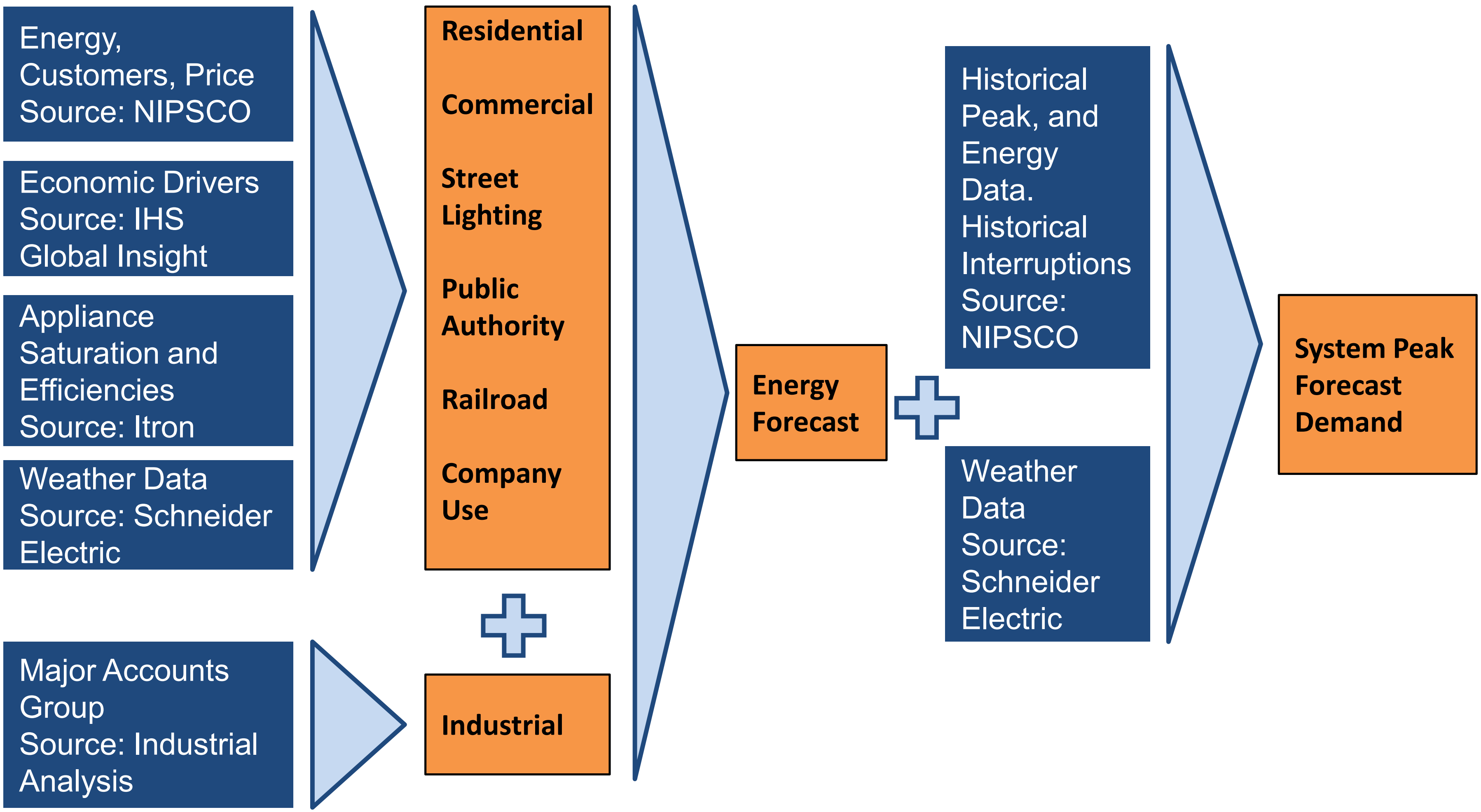


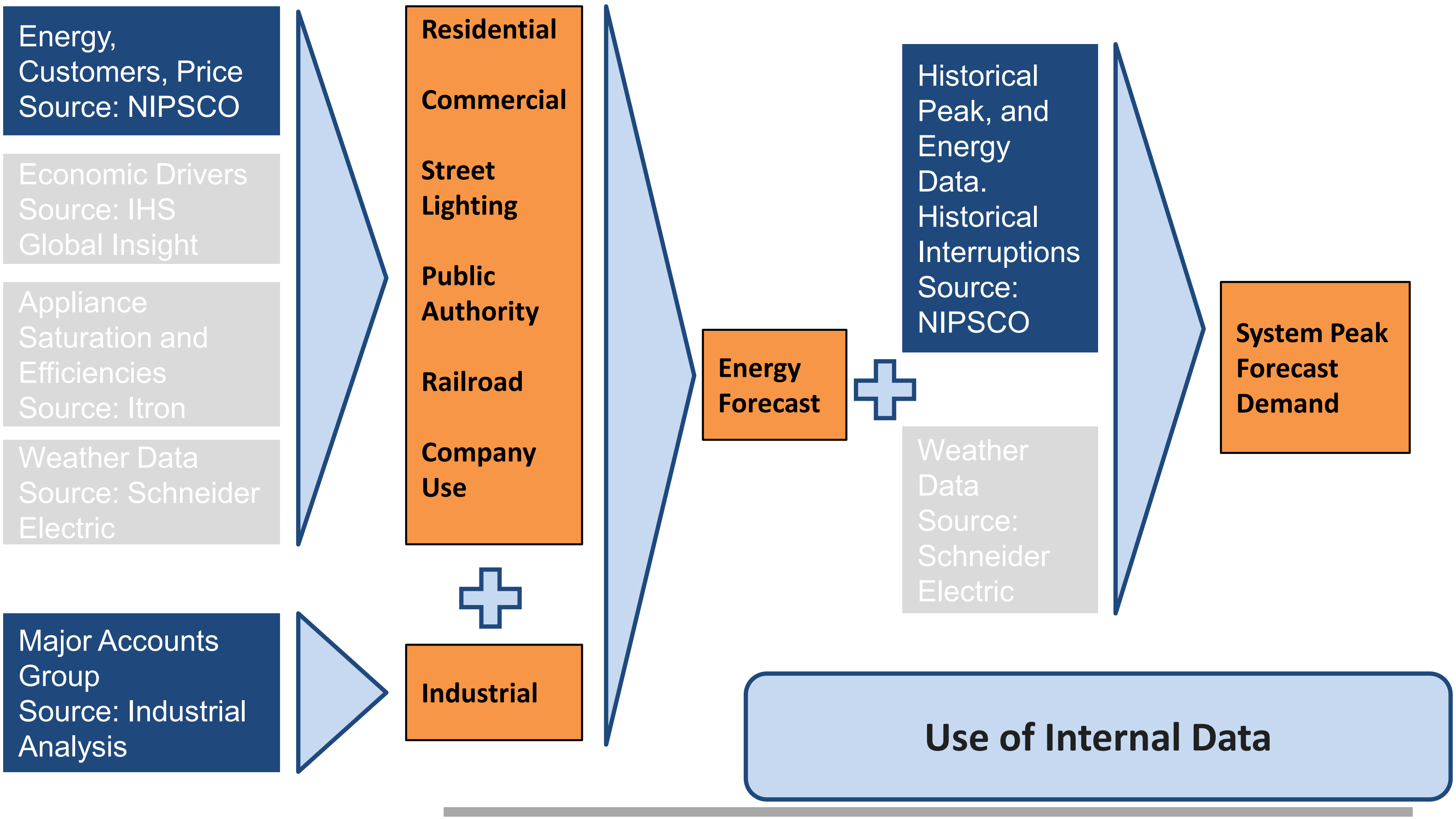
Long-Term Energy and Demand Forecast

Mahamadou Bikienga
Lead Forecasting Analyst

- **Load Forecasting Process**
- **Residential Customer and Energy Forecast**
- **Commercial Customer and Energy Forecast**
- **Industrial Energy Forecast**
- **Other Energy Forecast**
- **Peak Forecast**
- **Load Forecast Outlook**

2018 IRP Load Forecast Process
=
2016 IRP Load Forecast Process


Energy, Customers, Price Source: NIPSCO
Economic Drivers Source: IHS Global Insight
Appliance Saturation and Efficiencies Source: Itron
Weather Data Source: Schneider Electric
Major Accounts Group Source: Industrial Analysis
Residential
Commercial
Street Lighting
Public Authority
Railroad
Company Use
Industrial
Energy Forecast
Historical Peak, and Energy Data. Historical Interruptions Source: NIPSCO
Weather Data Source: Schneider Electric
System Peak Forecast Demand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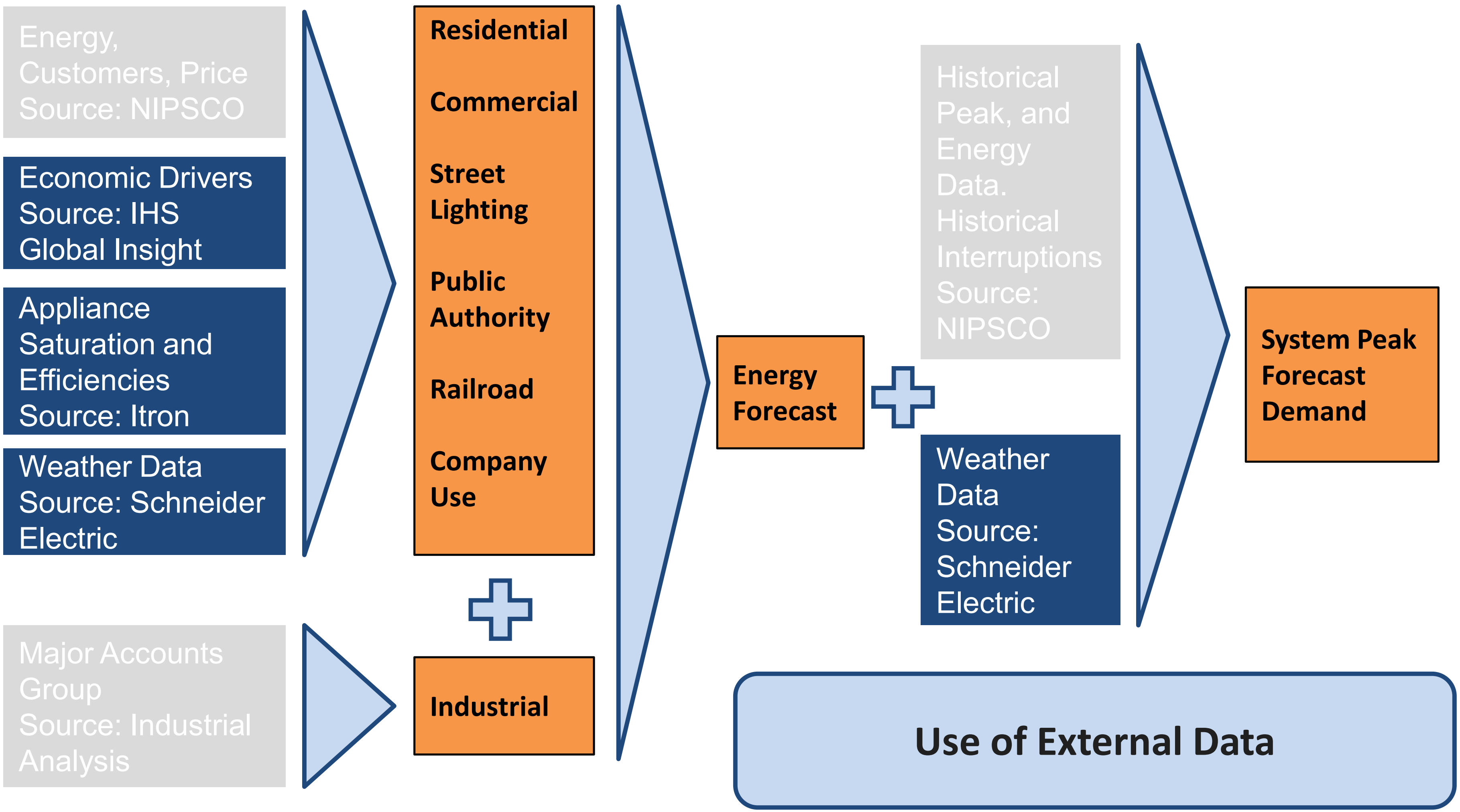
System Peak Forecast Demand
Use of Internal Data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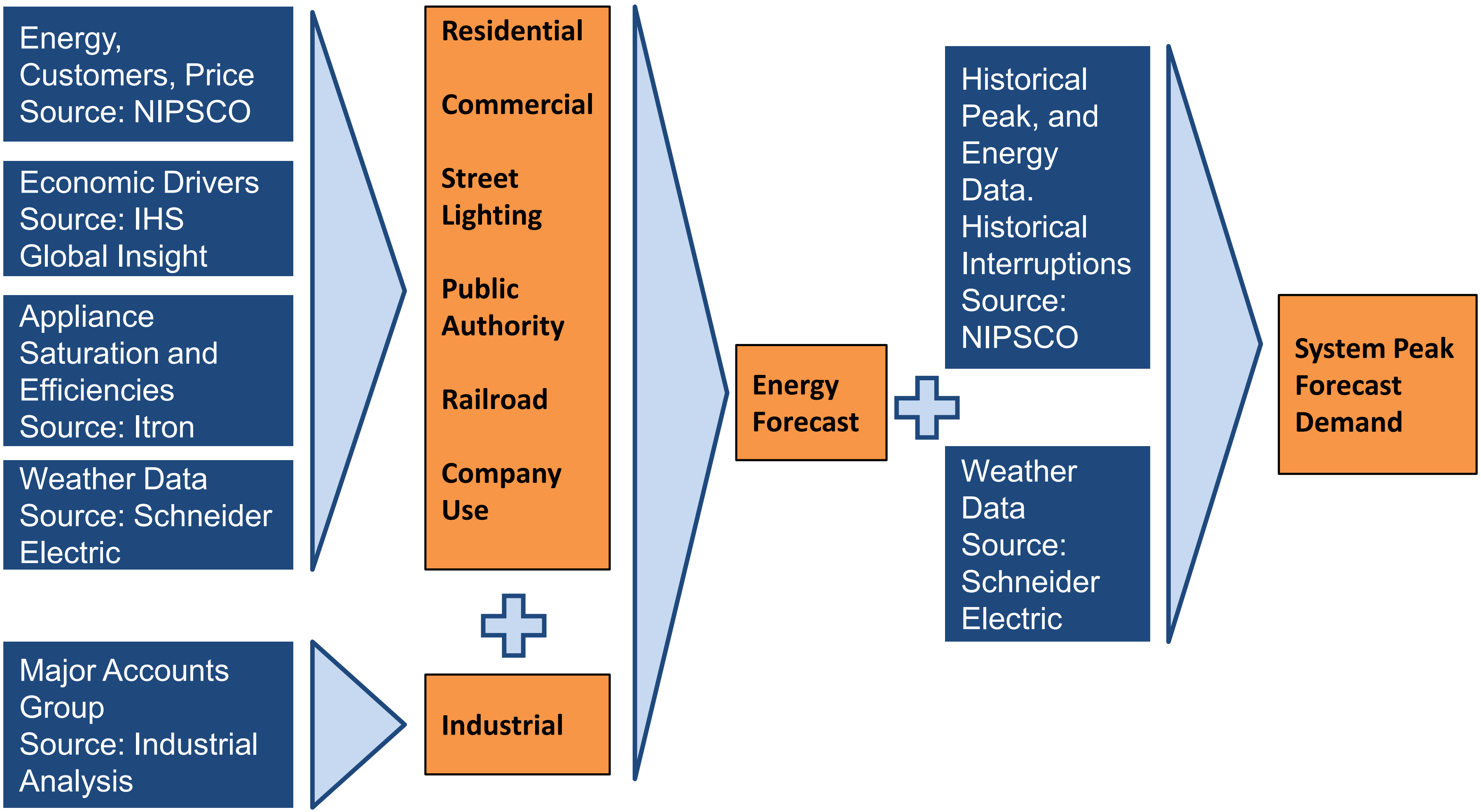
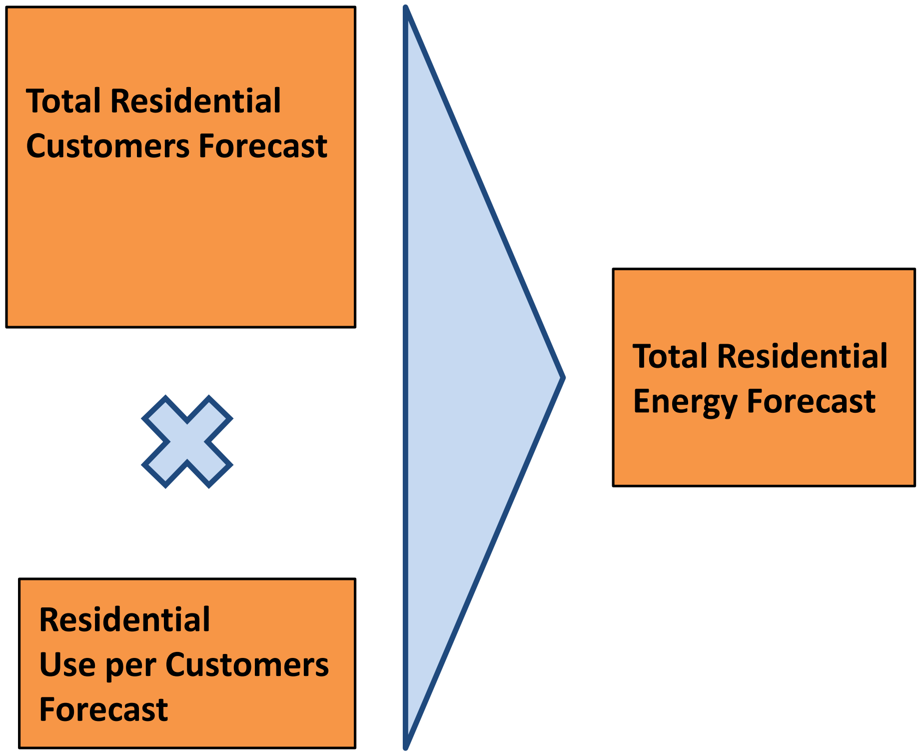
Energy Forecast
Historical Peak, and Energy Data. Historical Interruptions Source: NIPSCO
Weather Data Source: Schneider Electric
System Peak Forecast Demand
Use of External Data

Updated annually, models adjusted annually and as needed, 23 years outlook




Total Residential Customers Forecast
Residential Use per Customers Forecast
Total Residential Energy Forecast

New Business uses a grassroots approach to forecast for first 5 years

Residential New Customers For First Five Years
- New Business Team

Long Term New Residential Customers *f(Local Housing Starts)*

Existing Customers
Historical attrition rate incorporated

Total Residential Customers Forecast

×

Residential Use per Customers Forecast

Total Residential Energy Forecast

New Business uses a grassroots approach to forecast for first 5 years

Residential New Customers For First Five Years
- New Business Team

Long Term New Residential Customers *f(Local Housing Starts)*

Existing Customers
Historical attrition rate incorporated

Total Residential Customers Forecast

Residential kWh per Customer
f(Residential Electric Price, Real Per Capita Income, efficiency, weather)

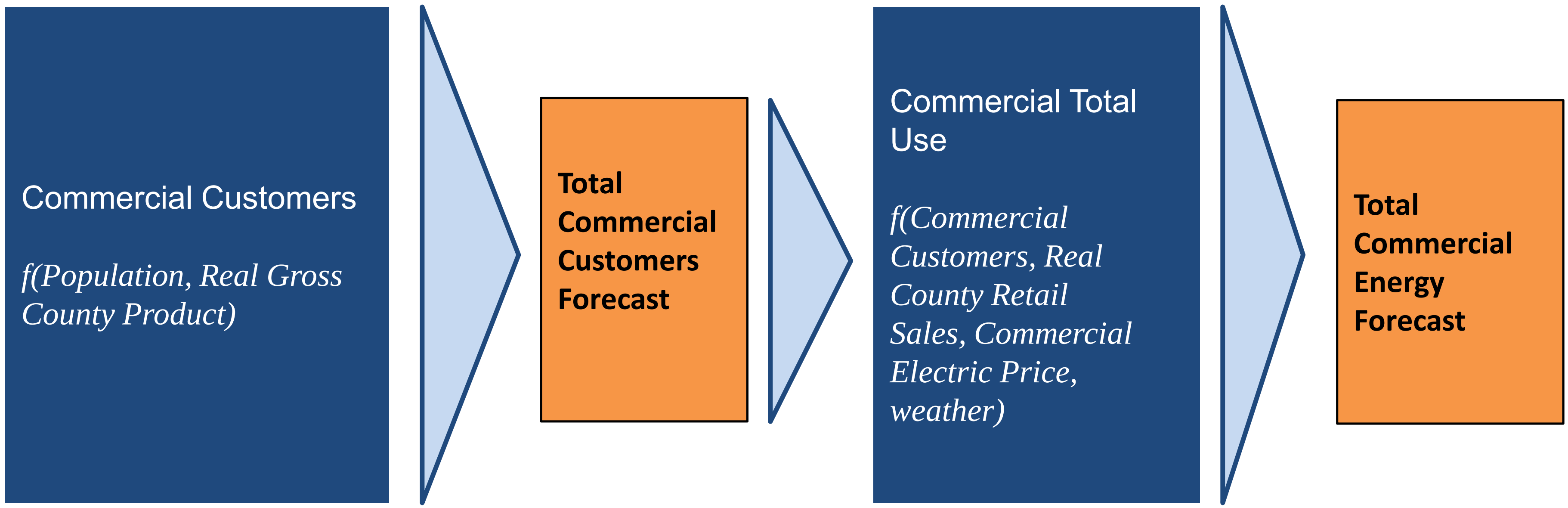
Residential Use per Customers Forecast

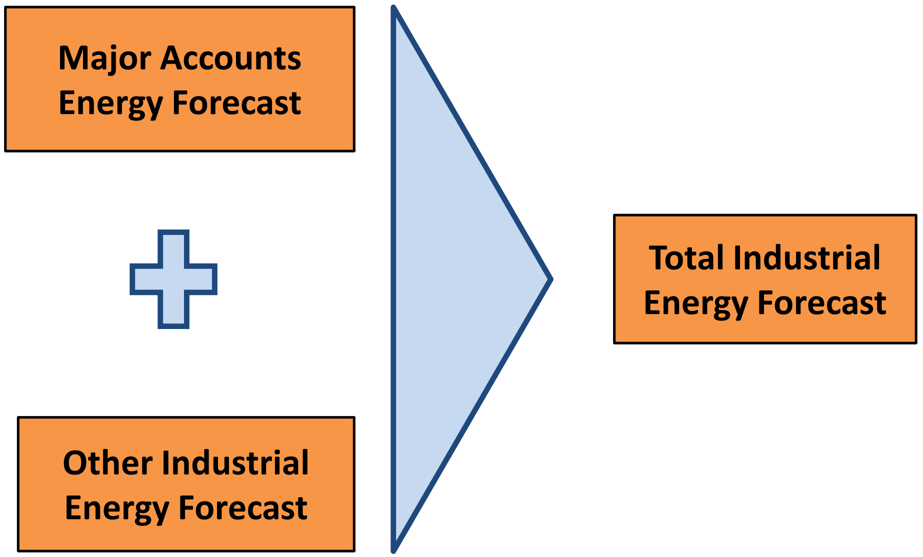
Total Residential Energy Forecast

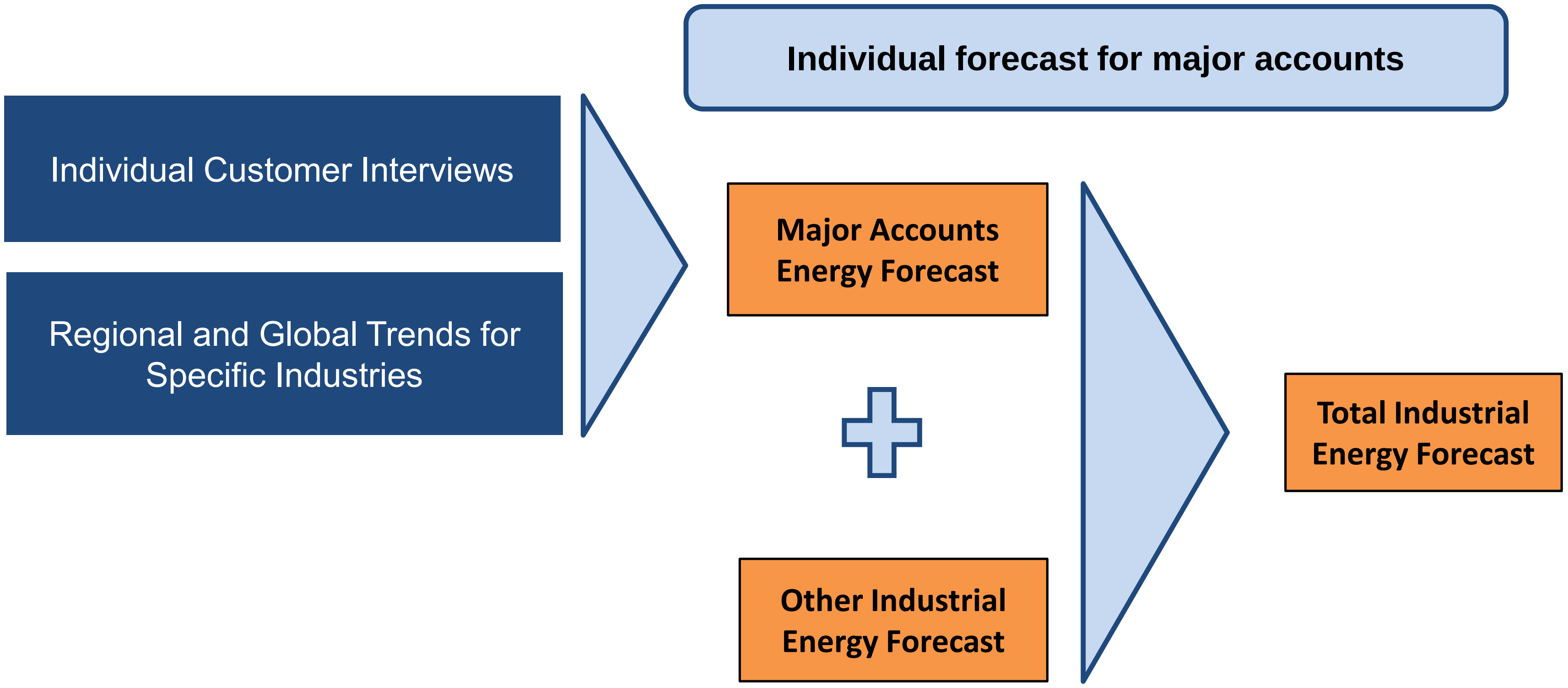
Commercial Customers

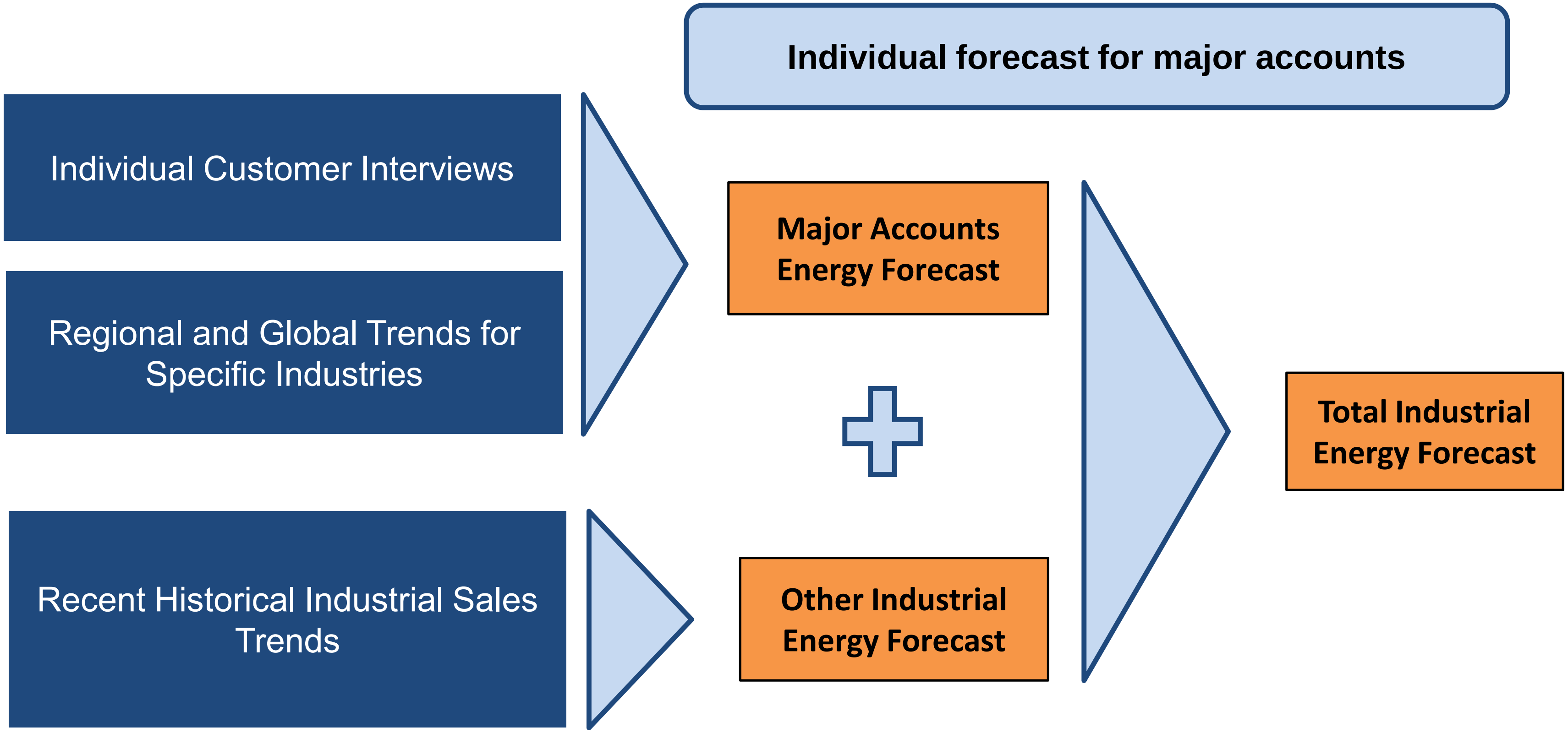
f(Population, Real Gross County Product)

Total Commercial Customers Forecast

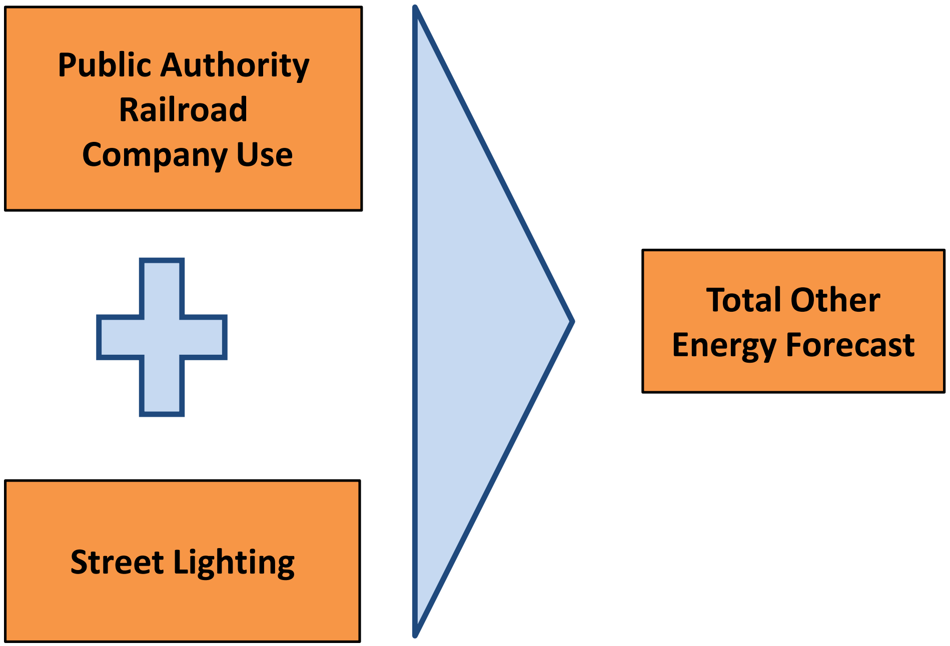

Commercial Customers
f(Population, Real Gross County Product)
Total Commercial Customers Forecast
Commercial Total Use
f(Commercial Customers, Real County Retail Sales, Commercial Electric Price, weather)
Total Commercial Energy Forecast


Major Accounts Energy Forecast
Other Industrial Energy Forecast
Total Industrial Energy Forecast

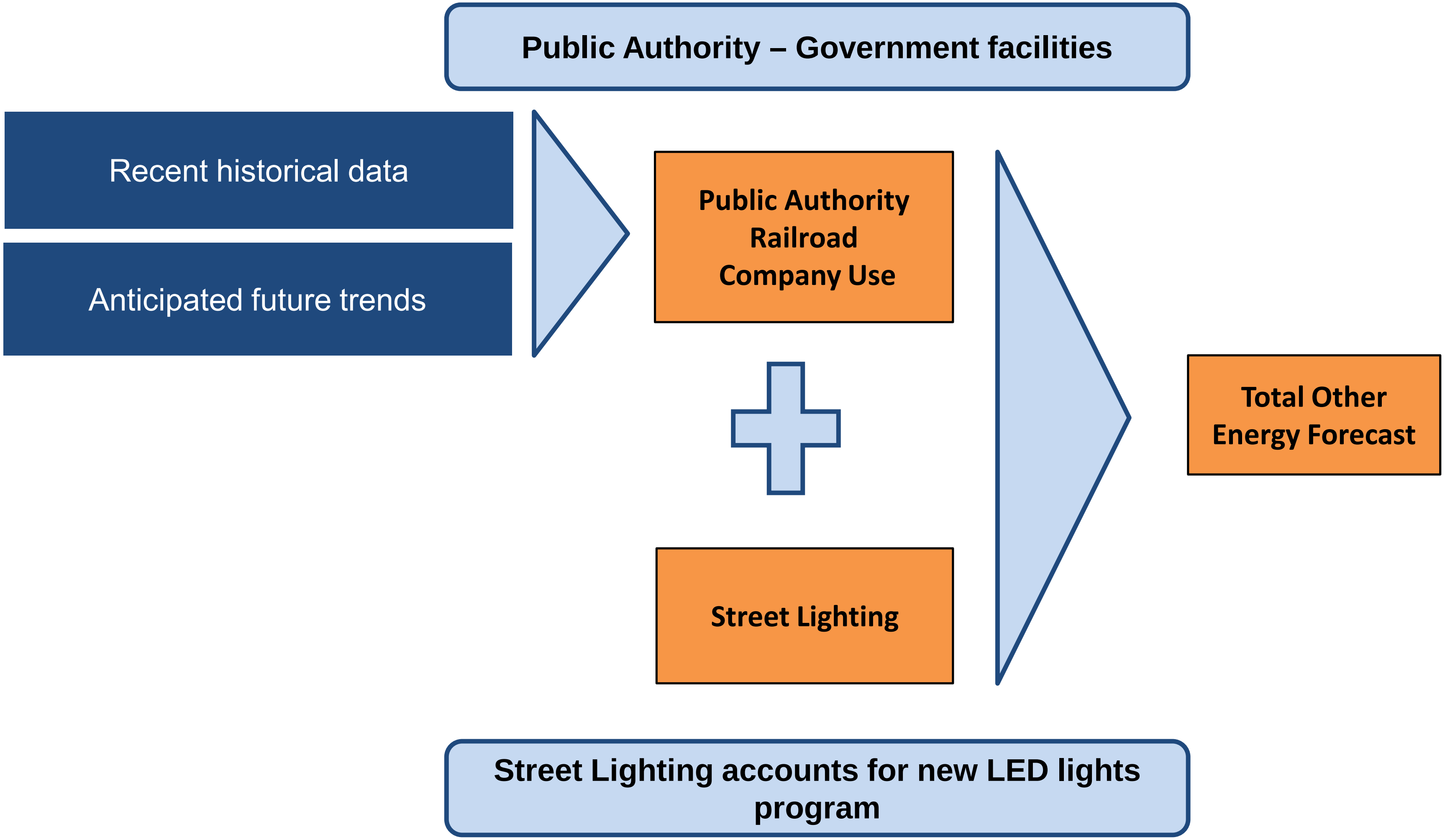

Individual forecast for major accounts
Individual Customer Interviews
Regional and Global Trends for Specific Industries
Major Accounts Energy Forecast
Other Industrial Energy Forecast
Total Industrial Energy Forecast

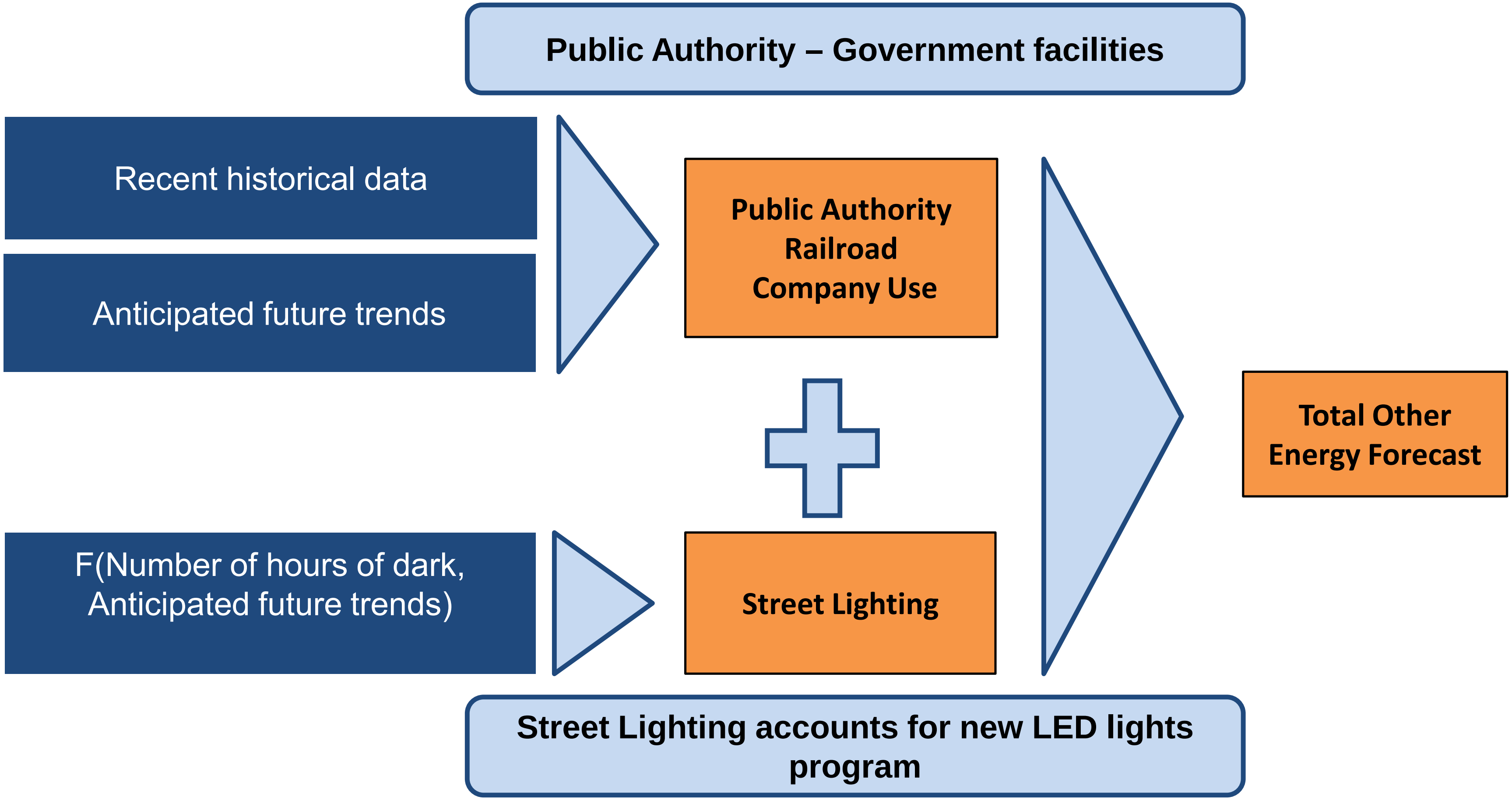

Individual forecast for major accounts
Individual Customer Interviews
Regional and Global Trends for Specific Industries
Recent Historical Industrial Sales Trends
Major Accounts Energy Forecast
Other Industrial Energy Forecast
Total Industrial Energy Forecast

Public Authority – Government facilities



Street Lighting accounts for new LED lights program


Public Authority – Government facilities
Recent historical data
Anticipated future trends
Public Authority
Railroad
Company Use
Street Lighting
Total Other
Energy Forecast
Street Lighting accounts for new LED lights program


Public Authority – Government facilities
Recent historical data
Anticipated future trends
Public Authority
Railroad
Company Use
Total Other
Energy Forecast
F(Number of hours of dark,
Anticipated future trends)
Street Lighting
Street Lighting accounts for new LED lights
program

Residential, Commercial, and Small Industrial Energy Use

Cooling Degree Hour (Summer)

Heating Degree Hours (Winter)

Relative humidity at the time of peak

Load Factor

NIPSCO’s system peak

Total Peak Demand Forecast

NIPSCO's system peak

- Residential, Commercial, and Small Industrial Energy Use
- Cooling Degree Hour (Summer)
- Heating Degree Hours (Winter)
- Relative humidity at the time of peak
- Load Factor

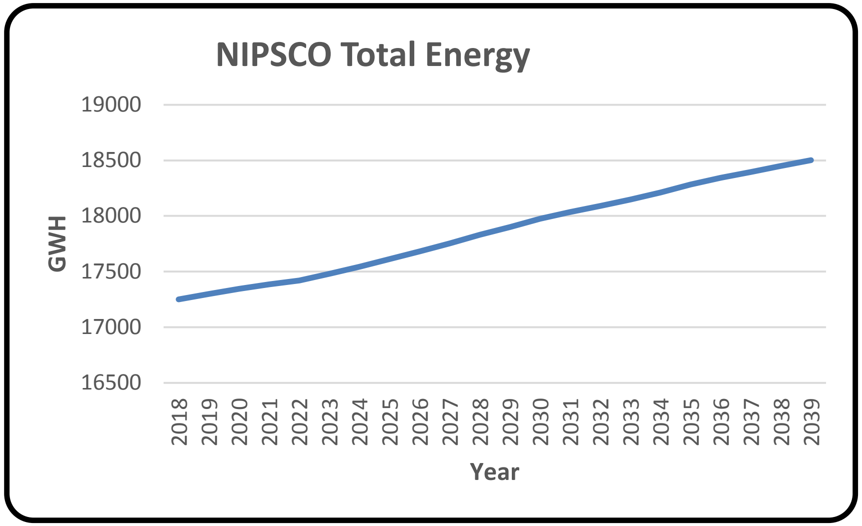
Total Peak Demand Forecast

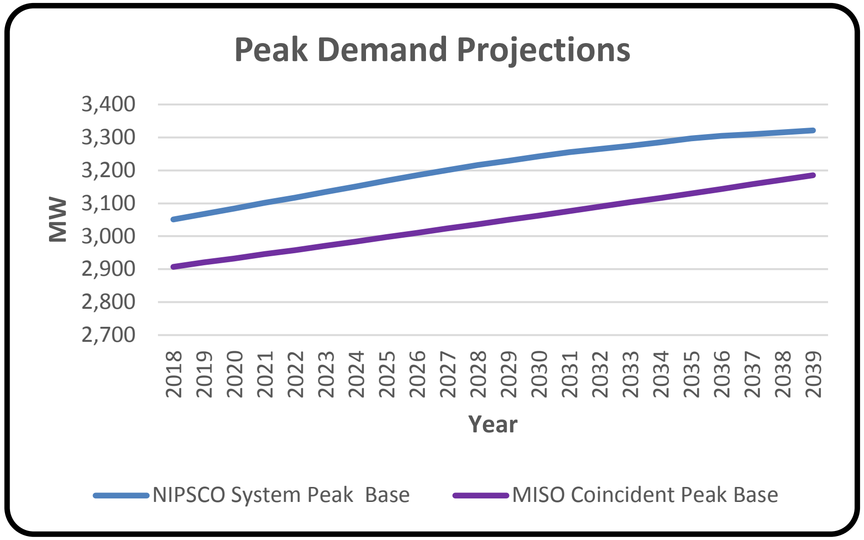
MISO Coincident Peak – NIPSCO's system peak at time of MISO's system peak

- NIPSCO monthly peak
- NIPSCO Cooling Degree Hours at the time of the MISO system peak

MISO Coincident Peak Forecast

Load Forecasts





Energy Requirement Projections	2018-2039 CAGR
NIPSCO Total Energy	0.33%
NIPSCO System Peak	0.41%
MISO Coincident Peak	0.44%

$$\frac{\textbf{\textit{MISO Coincident Peak}}}{\textbf{\textit{NIPSCO System Peak}}} = \sim 95\%$$

Fred Gomos
Manager Corporate Strategy & Development

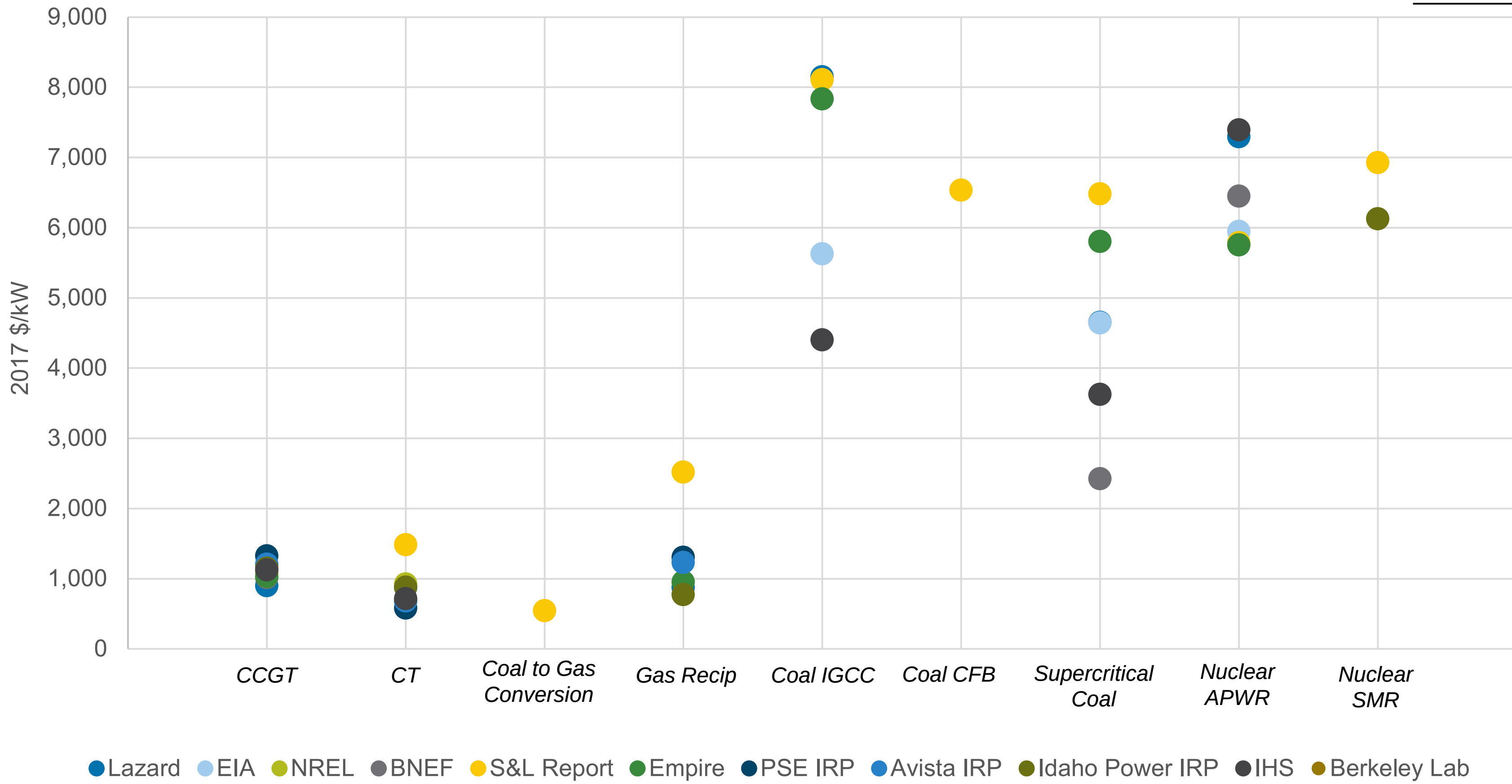
Pat Augustine
Charles River Associates (CRA)

Step 1	Develop initial NIPSCO portfolios	• Review technologies based on costs, feasibility, and regulatory constraints • Obtain current and future capital cost estimates from multiple 3rd party data sources
Step 2	Evaluate portfolios across Scenarios and Stochastics (including capital costs)	• Assess relative costs and risks of portfolio options • Perform preliminary assessment of portfolio costs, risks, and other metrics (pre-RFP)
Step 3	Integrate RFP results	• Based on RFP process, incorporate specific capacity offers that align with preliminary assessment of portfolio performance • Evaluate portfolios using more certain capital cost information from RFP bids

3rd Party Data Sources

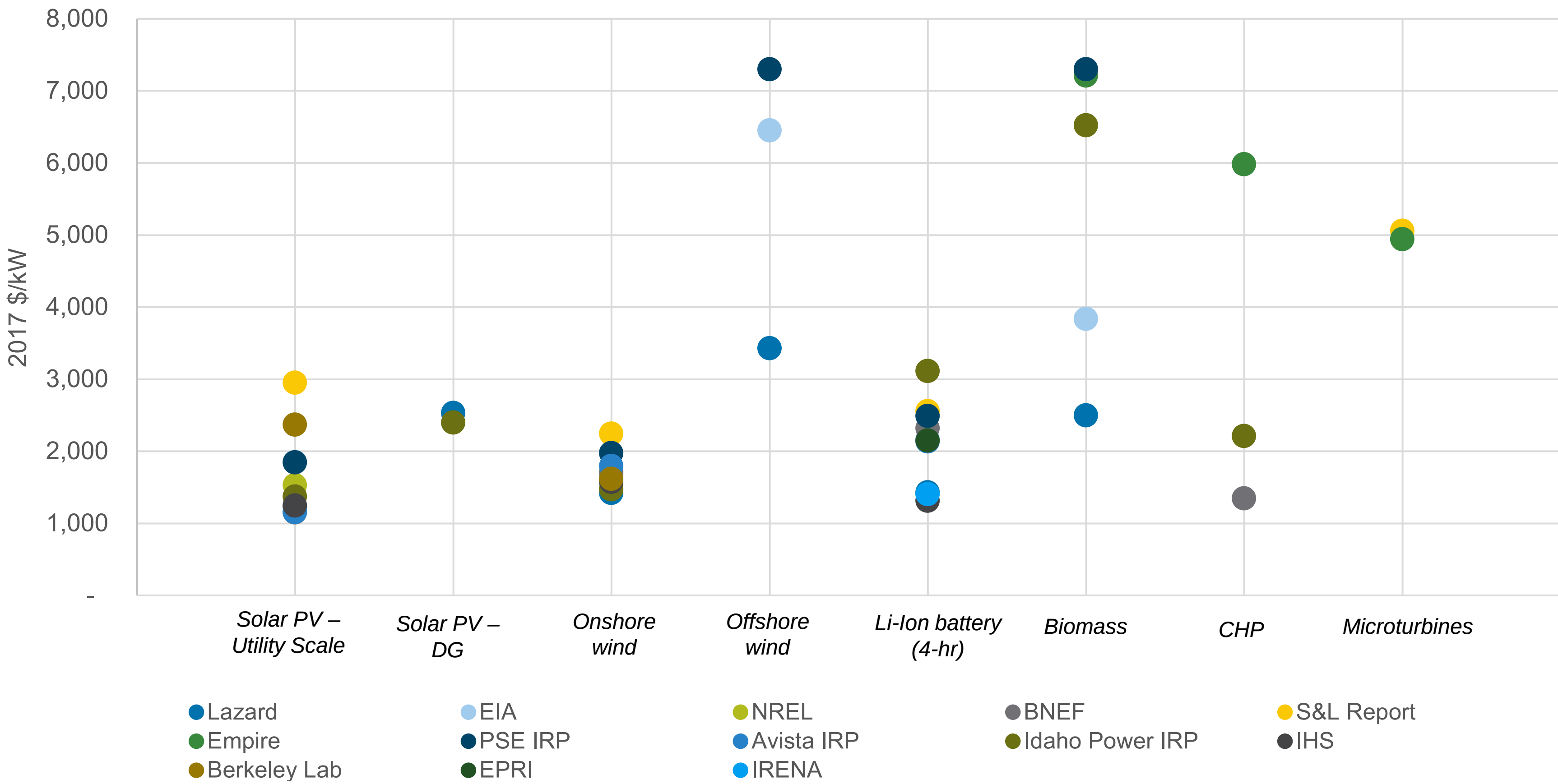
Data Source	Description	Link
Sargent & Lundy	NIPSCO Integrated Resource Plan Engineering Study Technical Assessment (2015)	N/A
Energy Information Administration (EIA)	Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (2018 AEO)	EIA Capital Cost Estimates
Utility Integrated Resource Plans	Empire District Electric Company, Puget Sound Energy, Avista Utilities and Idaho Power (screened for filings with transparent data within the last 6 months to year)	Empire District Avista Puget Sound Energy Idaho Power
Lazard	Levelized Cost of Energy Analysis Version 11.0 (2017)	Lazard LCOE V. 11.0
	Lazard Levelized Cost of Storage Version 3.0 (2017)	Lazard LCOS V.3.0
IHSMarkit	US Solar PV Capital Cost and Required Price Outlook	IHSMarkit (subscription required)
	US Wind Capital Cost and Required Price Outlook	
	US Battery Storage: Costs, Drivers, and Market Outlook (2017)	
	North American Power Market Fundamentals: Rivalry, October 2017 – New Capacity Characteristics & Costs	
Bloomberg New Energy Finance	Historical and forecast U.S. PV Capex Stack by Segment and Region	Bloomberg New Energy Finance (subscription required)
	Key cost input in LCOE Scenarios, 1H 2017	
	Benchmark Capital Costs for a Fully-Installed Energy Storage System (2017)	
National Renewable Energy Technology Laboratory	NREL Annual Technology Baseline 2017	NREL ATB 2017

Not Exhaustive



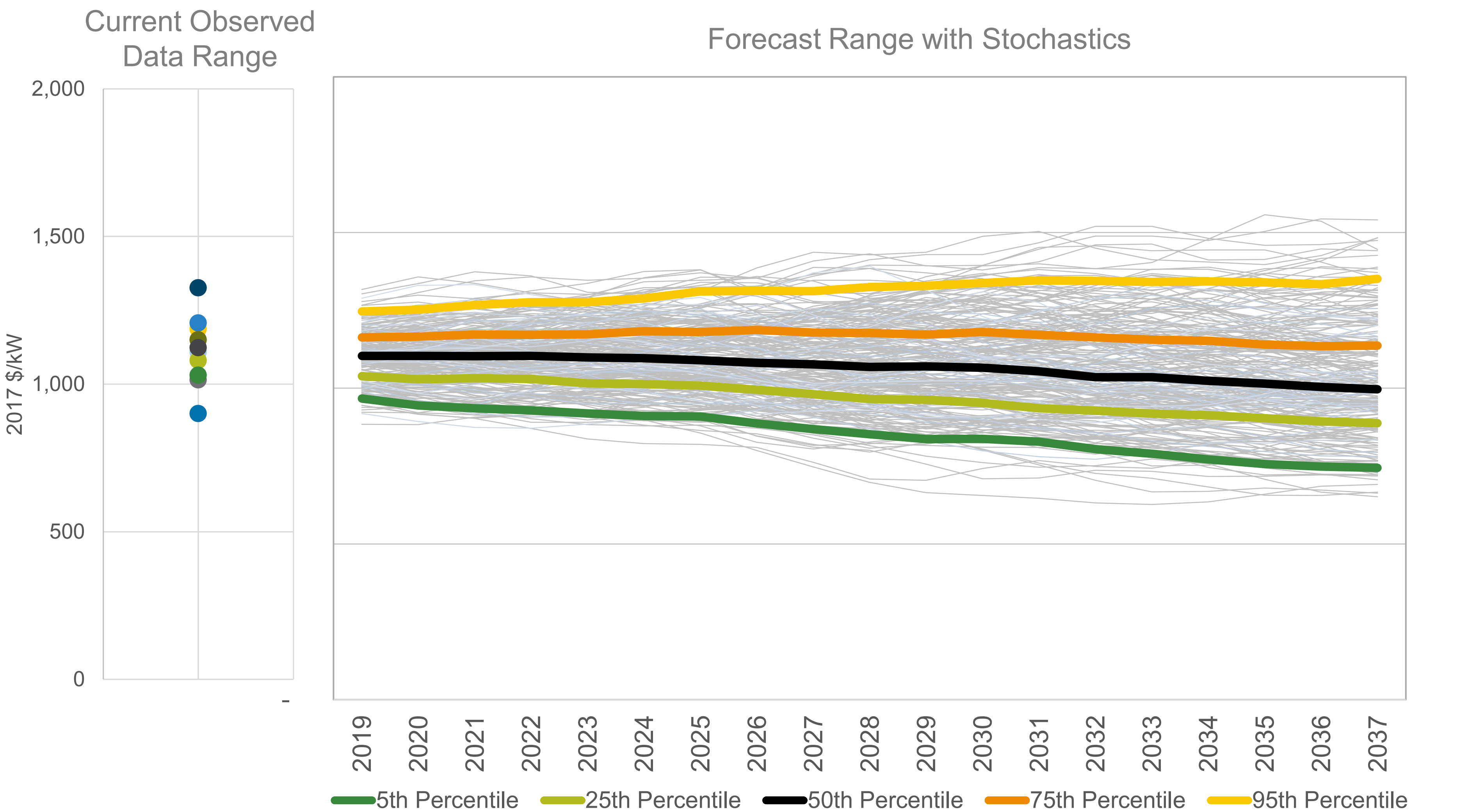
2017 $/kW	CCGT	CT	Coal to Gas Conversion	Gas Recip	Coal IGCC	Coal CFB	Supercritical Coal	Nuclear APWR	Nuclear SMR
Average	1,113	834	543	1,276	6,824	6,536	4,605	6,437	6,527
Median	1,116	715	543	1,092	7,835	6,536	4,646	6,198	6,527
Min	900	583	543	775	4,401	6,536	2,425	5,752	6,126
Max	1,326	1,485	543	2,519	8,150	6,536	6,482	7,392	6,927

Not Exhaustive



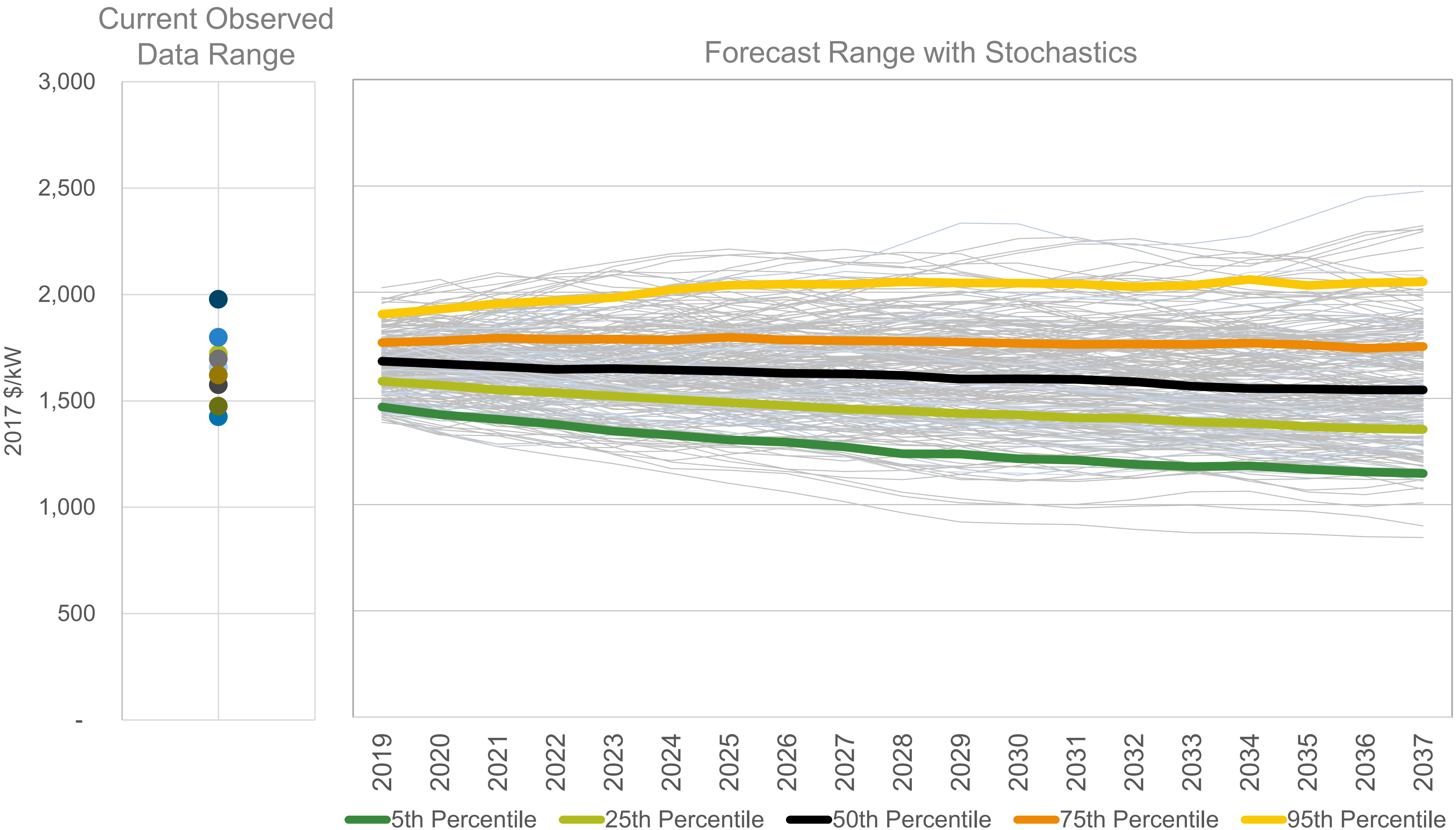
2017 $/kW	Solar PV – Utility Scale	Solar PV – DG	Onshore Wind	Offshore wind	Li-Ion battery (4-hr)	Biomass	CHP	Microturbines
Average	1,673	2,466	1,719	5,728	2,110	5,475	3,182	5,001
Median	1,453	2,466	1,677	6,454	2,160	6,522	2,213	5,001
Min	1,155	2,400	1,425	3,430	1,317	2,500	1,350	4,943
Max	2,370	2,532	1,977	7,300	3,114	7,300	5,984	5,059

- **The team used the range of data sources to develop forecasts for capital costs over time that include uncertainty bands**
- **Methodology for developing forecasts for a given technology consisted of several steps:**
  - Identify expected range of capital costs over time from data sources (starting point ranges and long-term forecasts, where they exist)
  - Using an interactive expert opinion approach based on the source data, elicit distributions for capital costs in three time periods (near-term, mid-term, and long-term)
  - Simulate 500 paths for capital costs based on random sampling from distributions



How to interpret the probability distributions and diagnostic statistics:

- 50th percentile is the middle value – half the observations are above this value and half are below
- Generally, percentiles represent thresholds below which a given percentage of observations is expected to fall (i.e., the 95th percentile indicates that 95% of the cost observations in that year are at or below this level)



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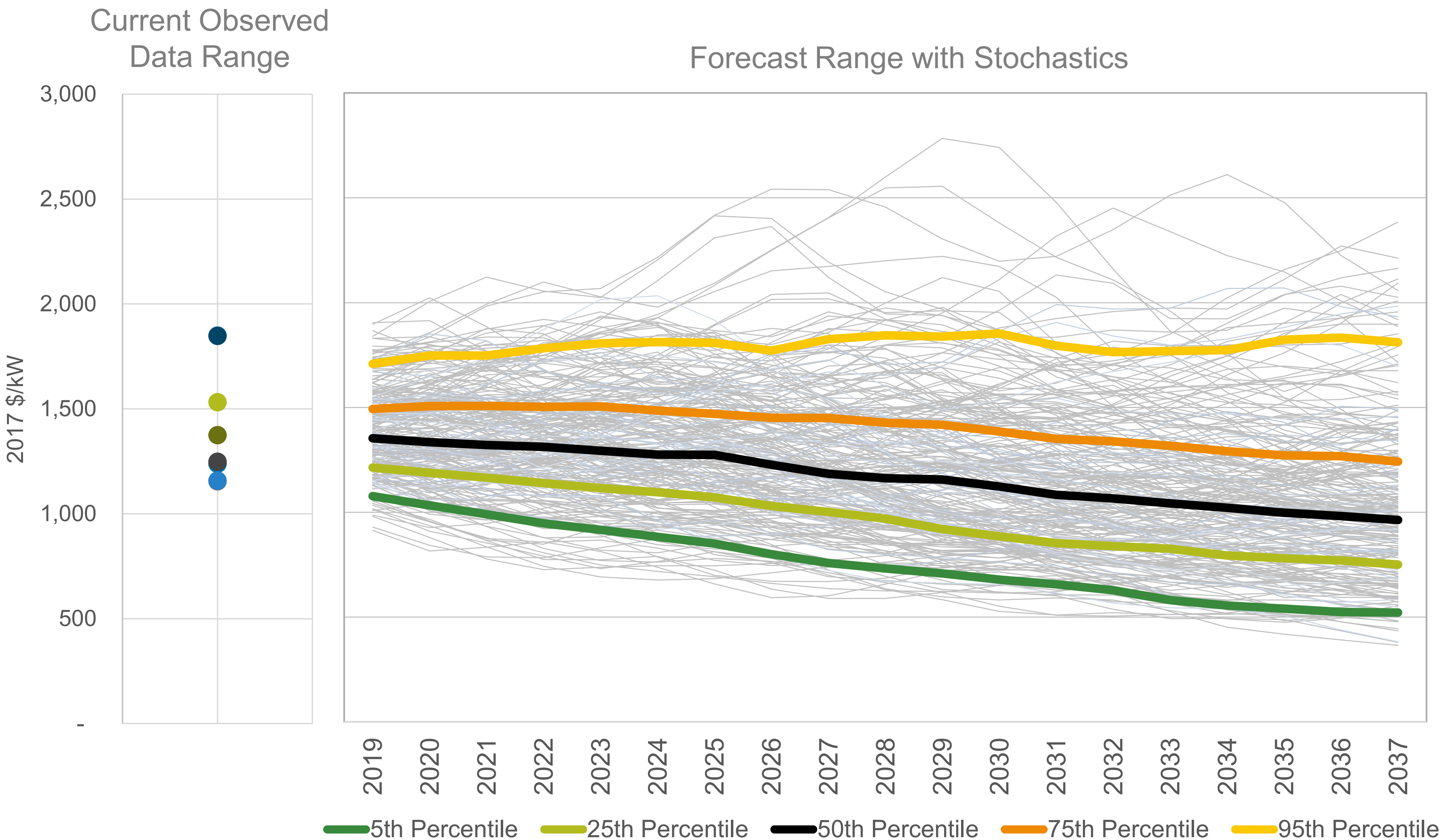

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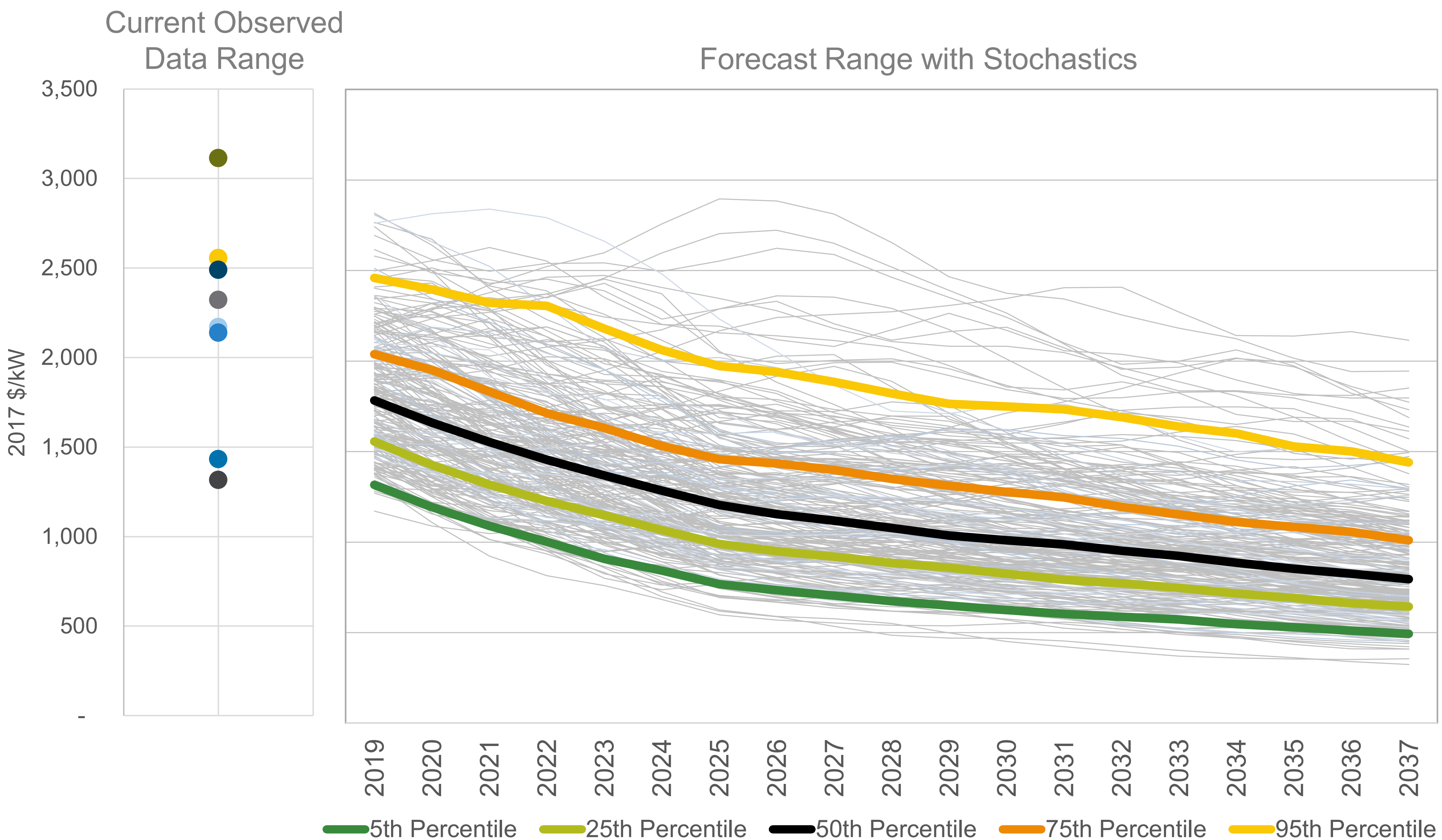

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2018 COMMODITY PRICE FORECASTING

NIPSCO IRP Stakeholder Meeting

Robert Kaineg & Pat Augustine

March 23, 2018

Charles River Associates

Outline

- Natural Gas
- Coal
- Power

CRA Natural Gas Outlook

Natural Gas Market Overview

- The industry has undergone a considerable transformation over the last decade
- Low cost shale gas has reduced domestic prices, and the Mid-Atlantic has transformed from a gas importer into a major production region, bottlenecked by existing midstream infrastructure

Trailing Trends

Regional Gas Supply Growth

Changing Pipeline Flows

- Northeast and Mid-Atlantic transformed from a major importer to a net supplier despite significant demand growth driven by coal switching
- Sizable gas infrastructure investments made in midstream to address flow issues
- Changing supply dynamics due to generation, industrial, and Mexico exports are starting to reverse flows of the major US gas transport backbone

Leading Trends

Supply & Pricing Dynamics

- Low cost North American supply still has significant growth upside (improved drilling economics and a large resource base)
- A sustained low gas price environment starting to incent additional power generation demand for gas (new capacity + further coal and nuke to gas substitution)
- Techniques developed in the Marcellus moving back into traditional regions (e.g. Haynesville) likely to improve productivity of these regions

Demand Growth Potential

- The electric sector increasingly relies on gas generation to meet energy needs, IRPs tend to rely on new gas and renewables meet growing load
- Short term LNG outlook firming ~10bcf/d of firm projects coming online in the next 2-4 years, another 8-10 bcf/d of potential in the following decade
- Sustained low gas prices driving interest in petrochemical investments

NGF Model – Natural Gas Price Forecasting

Gas Supply

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

Well Performance

- Drilling & completion costs
- Environmental compliance costs
- Royalties & taxes
- First year initial production rate
- Changing drilling and production efficiencies
- Productivity decline curve
- Well lifetime
- Distribution of performance

Gas Demand

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

Other Market Drivers

- Value of NGL / condensates
- Natural gas storage

CRA continuously enhances NGF to reflect changes in key gas market drivers

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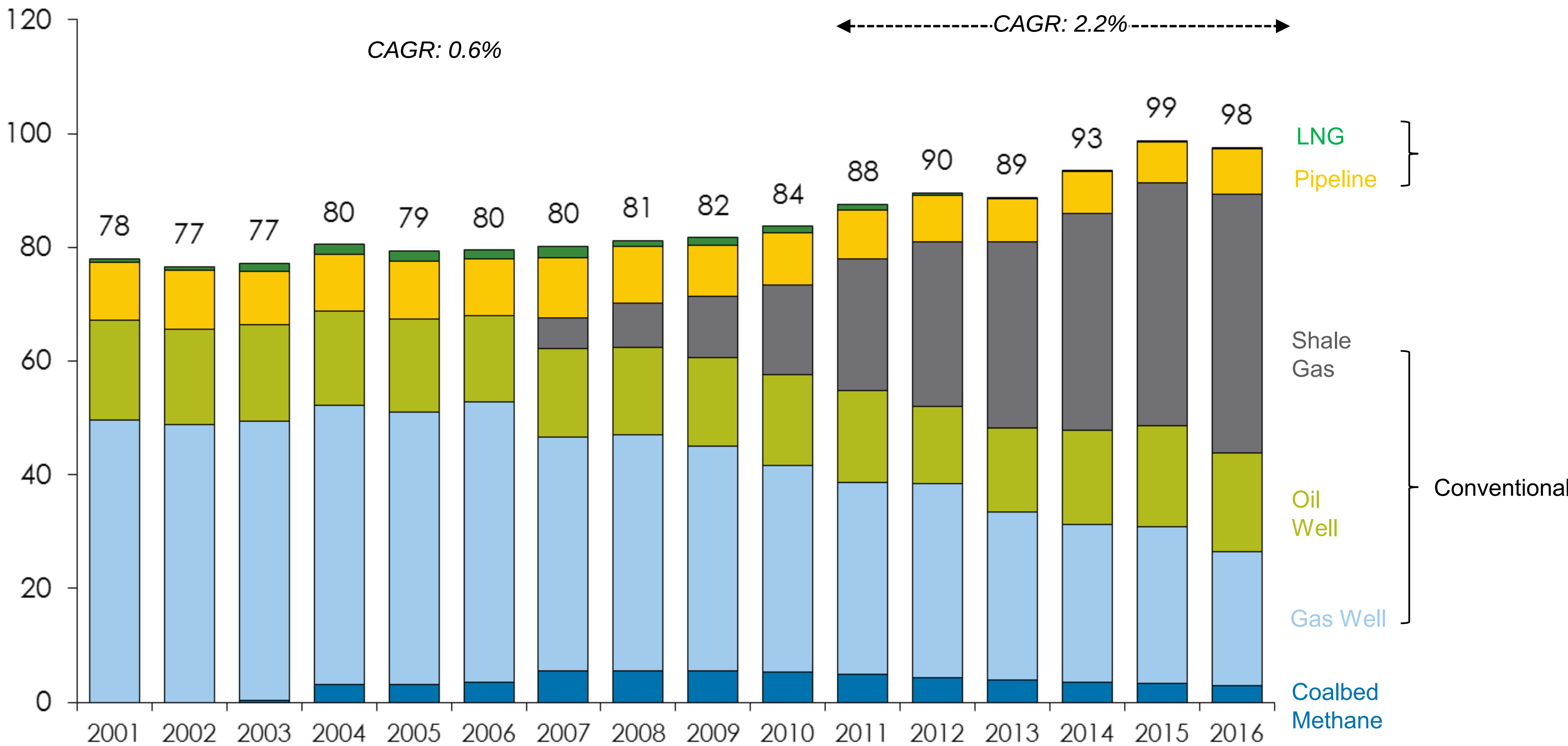
Key Modeling Inputs and Drivers of CRA's Gas Price Forecast

Driver	CRA Approach	Explanation
Resource Size	• Rely on Potential Gas Committee (PGC) 2016 "Most-Likely" unproven estimates	CRA assumes a starting point of PGC 2016 "Minimum" resource, and grows the resource base to achieved PGC 2016 "Most Likely" volumes by 2050
Well Productivity	• IP rates based on historic data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	CRA based individual well productivity on historic data for initial mode year, IP rates improve annually in line with EIA assumptions The "Poor Heavy" resource base is conservative, and reflects the fact that sampled data reflects only geology expected to be productive
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	CRA based individual well productivity on available historic data, adopted EIA assumptions for cost improvements over time
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2017 Reference Case (with CPP)	The AURORA case assumes "base case" carbon pressure and AEO 2017 Reference assumes CPP, meaning demand estimates are consistent
LNG Exports	• Under-construction projects completed, ~9 bcf/d exports assumed by 2019, volumes grow another ~5 bcf/d from 2021 to 2031	Current advanced-stage projects expected to come online and be highly utilized driving 2019 view Low domestic prices drive further international interest for US gas, but no other projects able to complete before 2021
Pipeline Exports	• Mexican export increase to ~8bcf/d by 2021, 10.5bcf/d by 2030	CRA expects pipeline export capacity to meet growing gas demand in Mexico will be ~60% utilized by 2021, and 75% utilized by 2031
NGL & Condensate Value	• Liquids valued at 70% of AEO 2017 Reference Oil Price	AEO17 for long-term oil price forecast; 70% value for NGLs is consistent with last 5 years of price history

Key Natural Gas Market Trends – Shale Gas

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

Gas Withdrawals and Imports



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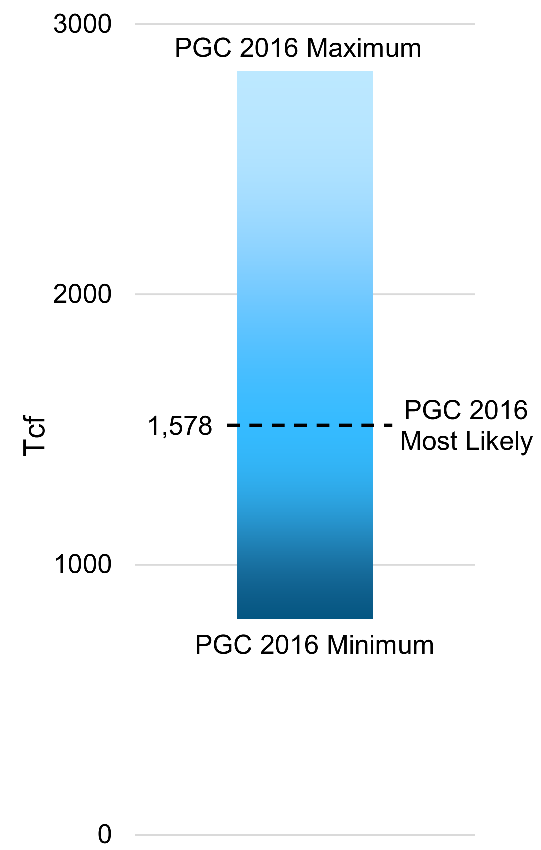
CRA relies on the PGC 2016 "Minimum" value as the starting value for recoverable shale reserves, resource grows at a steady rate until the PGC "Most Likely" value is reached in 2050

- **Probable** – gas associated with known fields
- **Possible** – gas outside of known fields, but within a productive formation in a productive province
- **Speculative** – gas in formations and provinces not yet proven productive

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

Uncertainty Range for Shale Resource in PGC 2016



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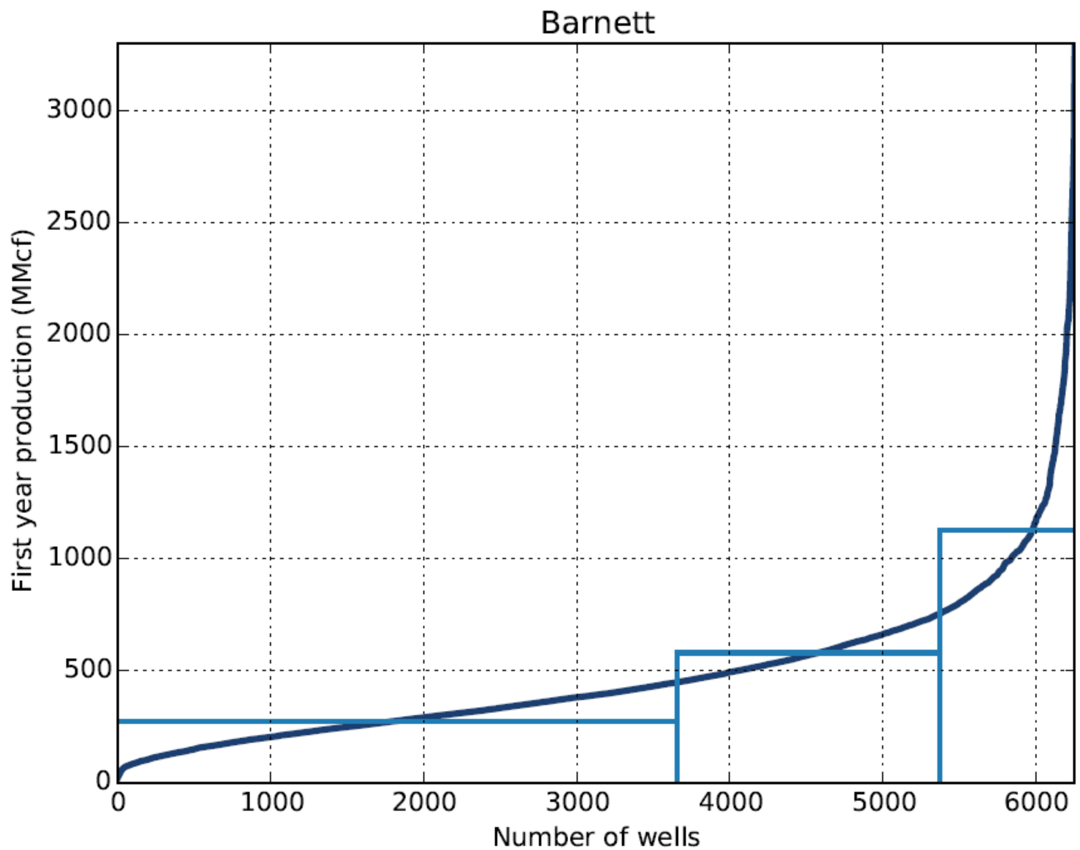
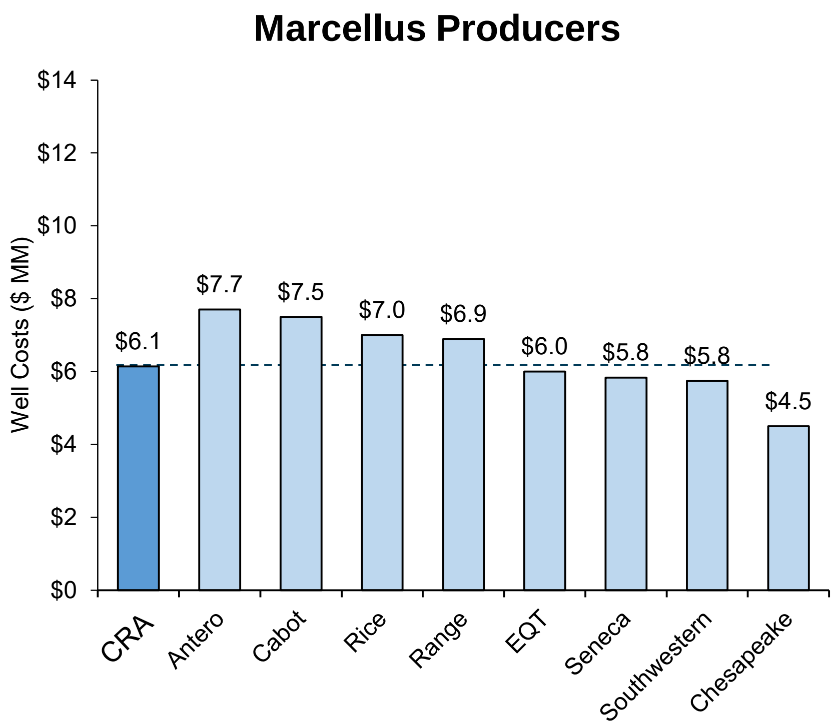
CRA assumed “Poor Heavy” productivity distribution (50% poor, 20% prime, 30% average) for future undiscovered resource

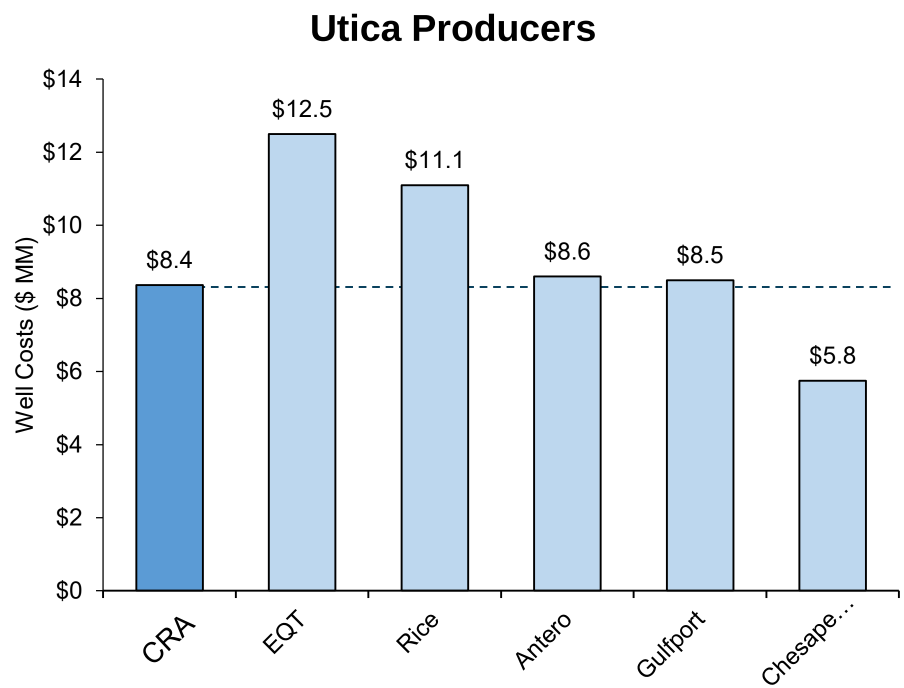


This productivity analysis was performed for all basins in CRA's model with sufficient recent drilling data

Gas Price Drivers – Drilling Costs

- CRA develops drilling cost assumptions by evaluating reported costs from major producers within a supply region





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Well productivity & cost structure improves in CRA's base case consistent with EIA Tier 1 rate of EUR growth

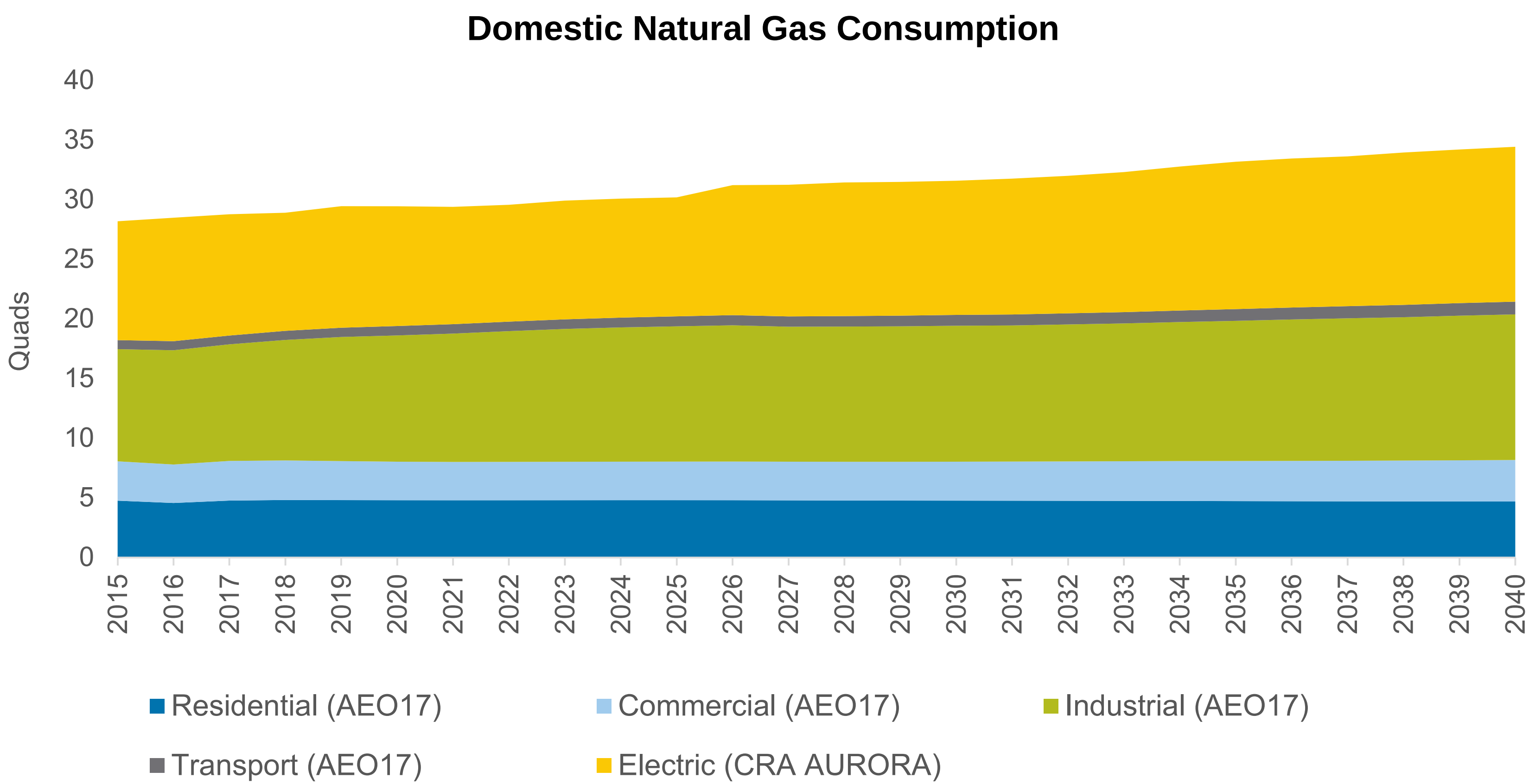
Table 9.6. Onshore lower 48 technology assumptions

Crude Oil and Natural Gas Resource Type	Drilling Cost	Lease Equipment & Operating Cost	EUR-Tier 1	EUR-Tier 2
Tight oil	-1.00%	-0.50%	1.00%	3.00%
Tight gas	-1.00%	-0.50%	1.00%	3.00%
Shale gas	-1.00%	-0.50%	1.00%	3.00%
All other	-0.25%	-0.25%	0.25%	0.25%

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

– Based values for IP rates and well costs are based on producer-reported values

CRA modeled electric gas demand in AURORA under base case CO2 assumptions, Residential, Commercial, Industrial and Transportation sector demand taken from AEO2017



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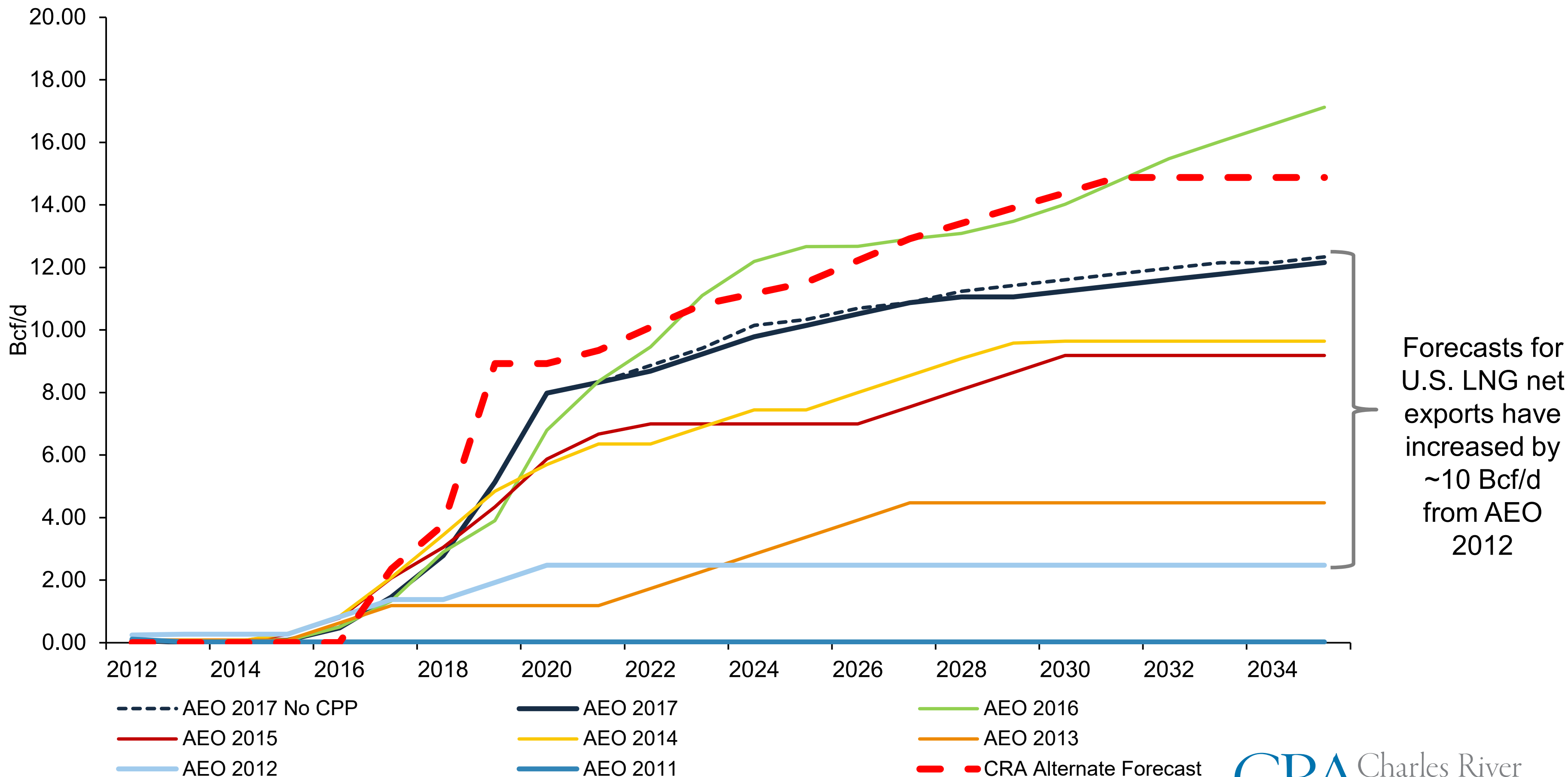
Gas Price Drivers – LNG

- Forecast of LNG Exports: AEO 2017 Reference Case LNG exports are between 25%-35% higher than AEO 2015, but lower than AEO 2016
- BP forecasts higher LNG exports than AEO, with ~15 Bcf/d of exports by 2030 and ~22 Bcf/d by 2035
- LNG exports could potentially be higher than AEO 2017 projects, given current planned builds



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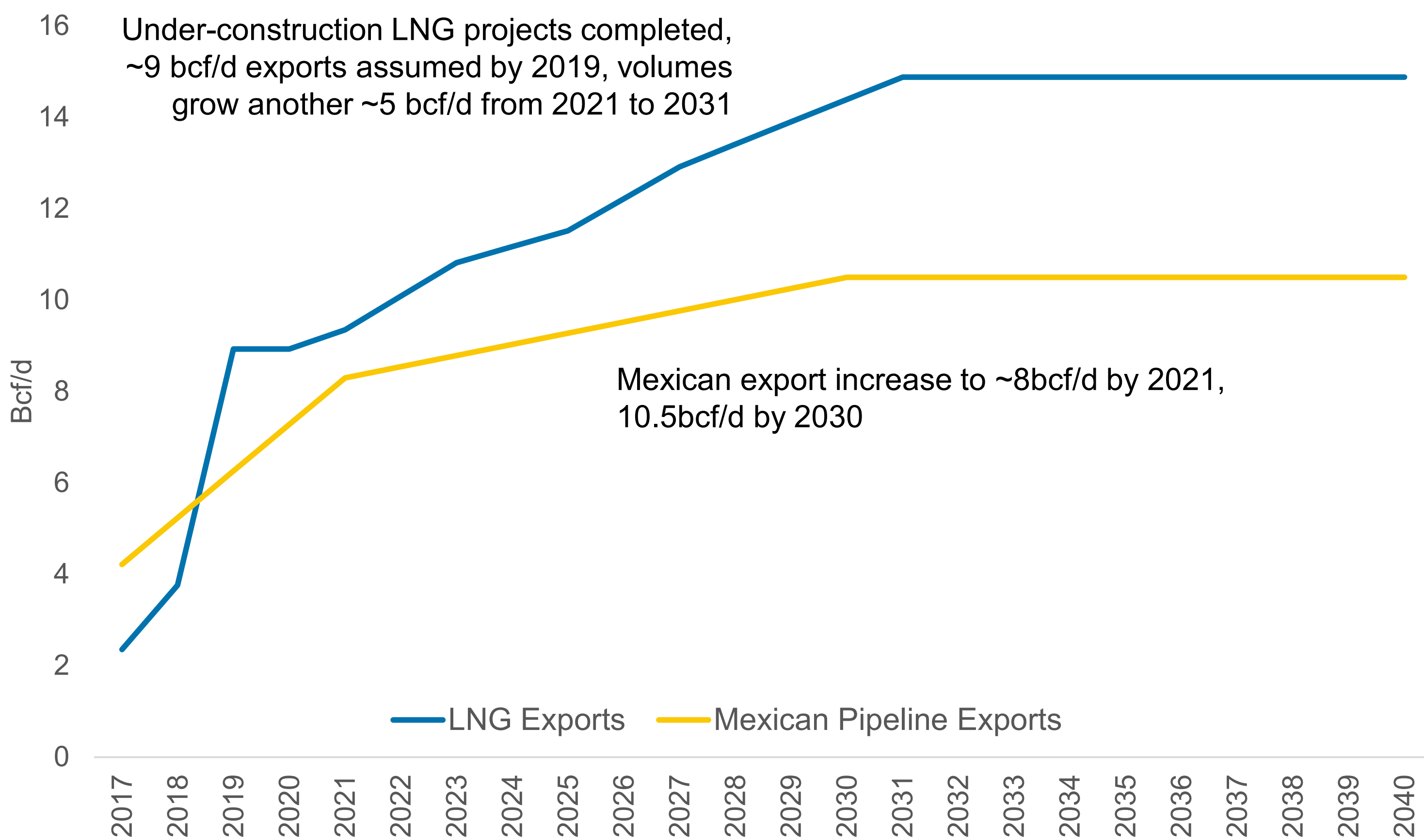
CRA assumes that LNG & Mexican gas exports grow through the 2030s



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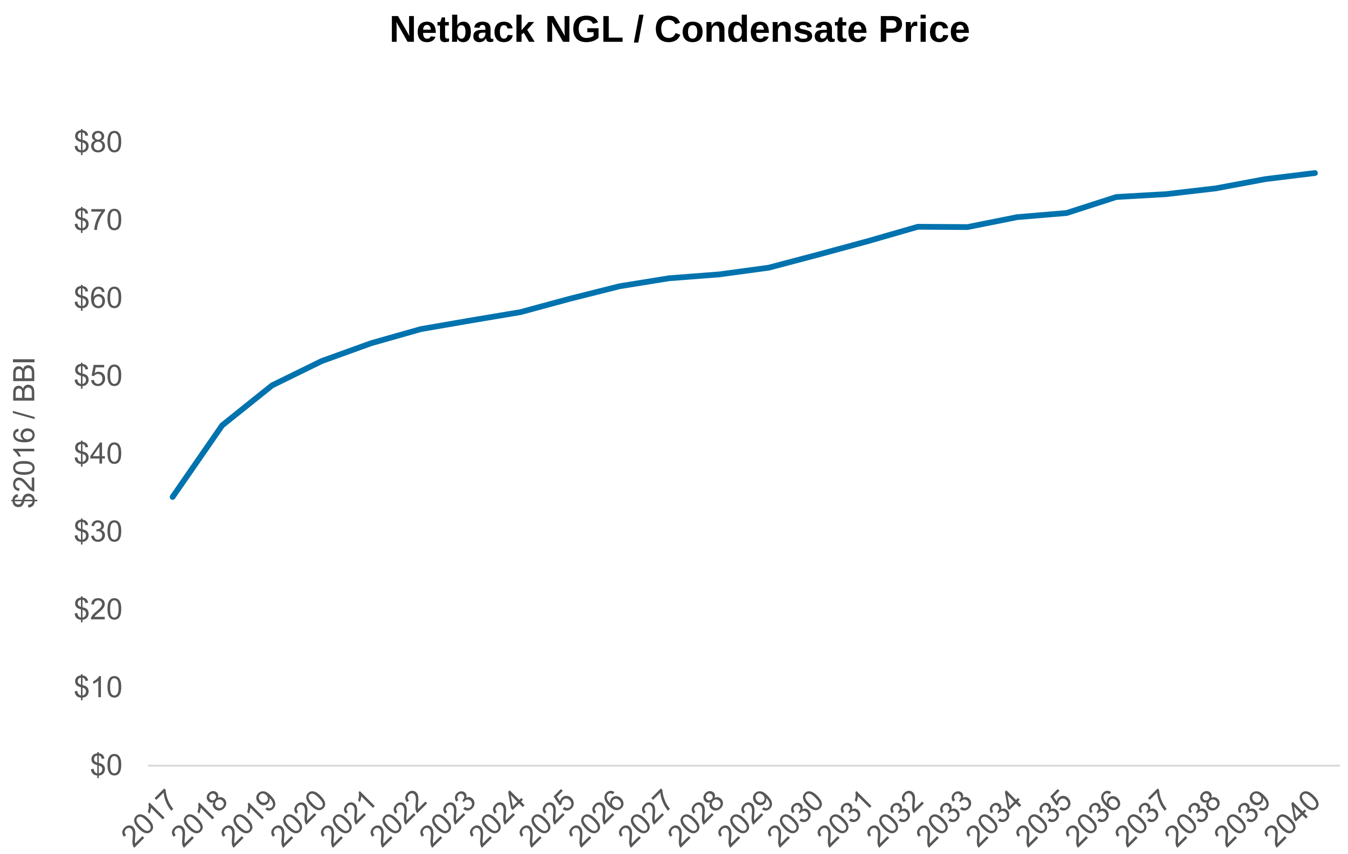
CRA assumes NGL & condensates valued at 70% of AEO reference case oil price forecast



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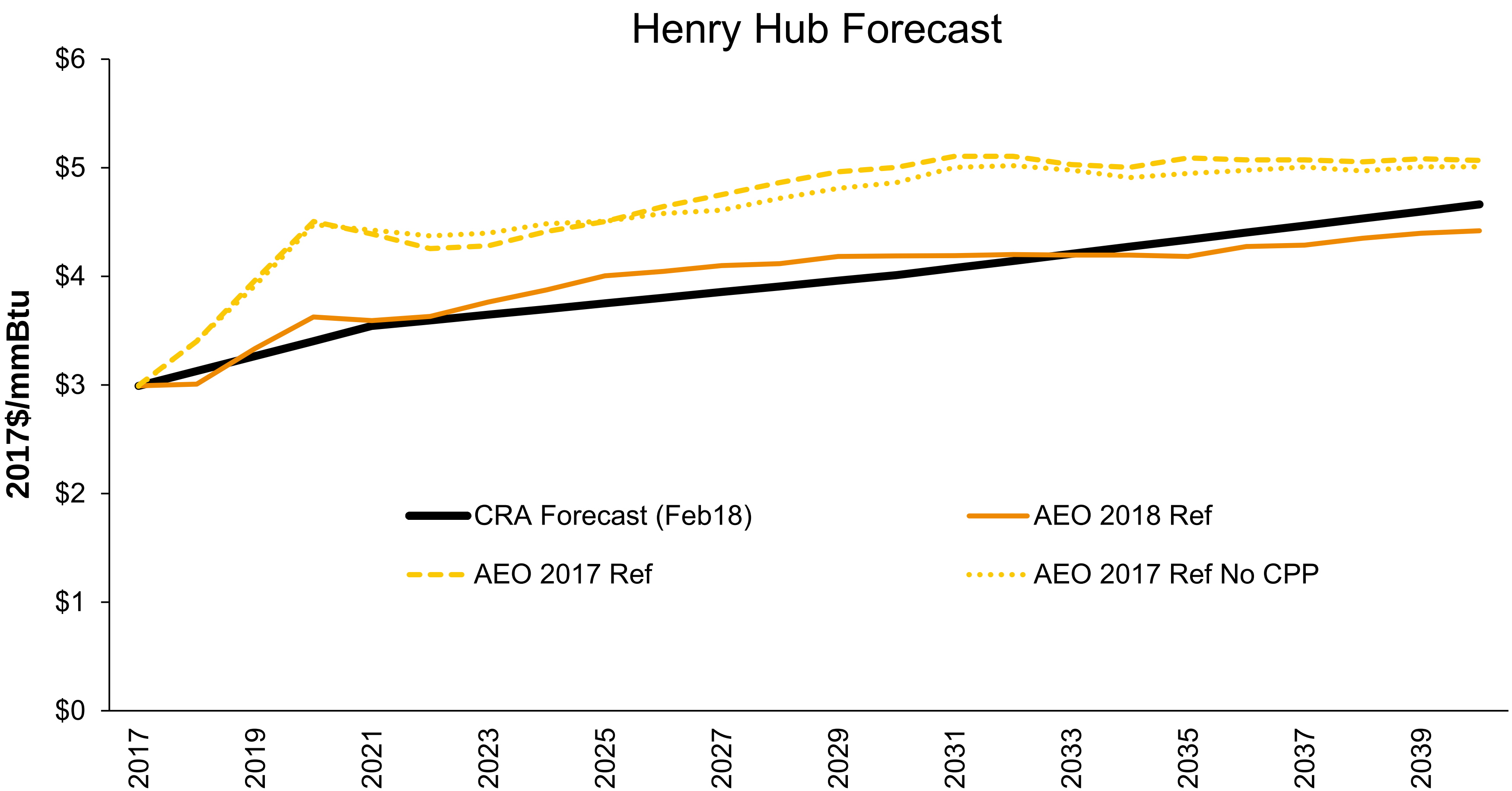
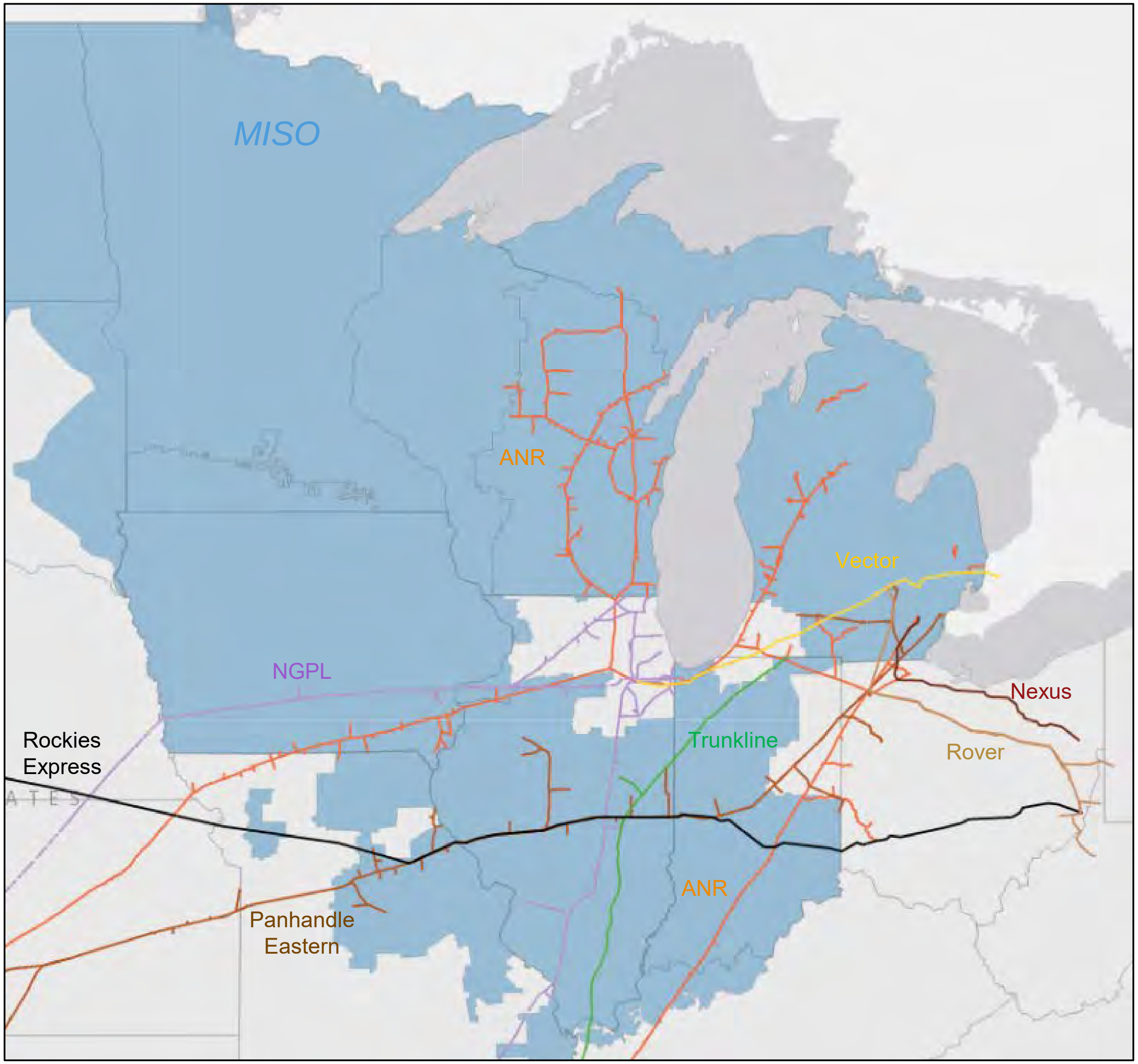
CRA Natural Gas Price View



Local Gas Dynamics in MISO



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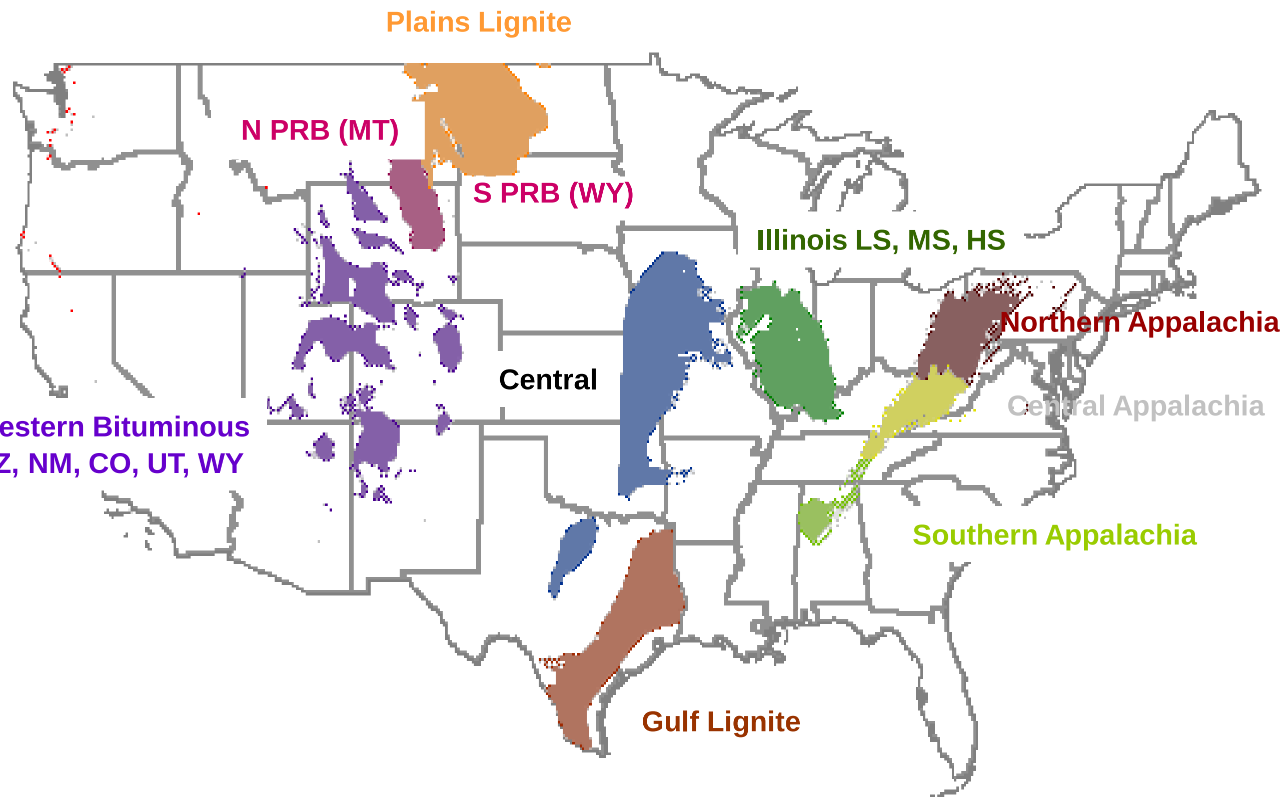
Coal Market Outlook

- Coal forecasting process assesses future supply/demand balance for the U.S. coal market:
  - Macroeconomic drivers, including domestic and international demand
  - Microeconomic drivers, including trends in mining costs and production trends
- The CRA NEEM model has coal supply curves, which are calibrated to reflect market analysis
- NEEM and AURORA are run in iterative fashion under various market views to develop coal price forecast



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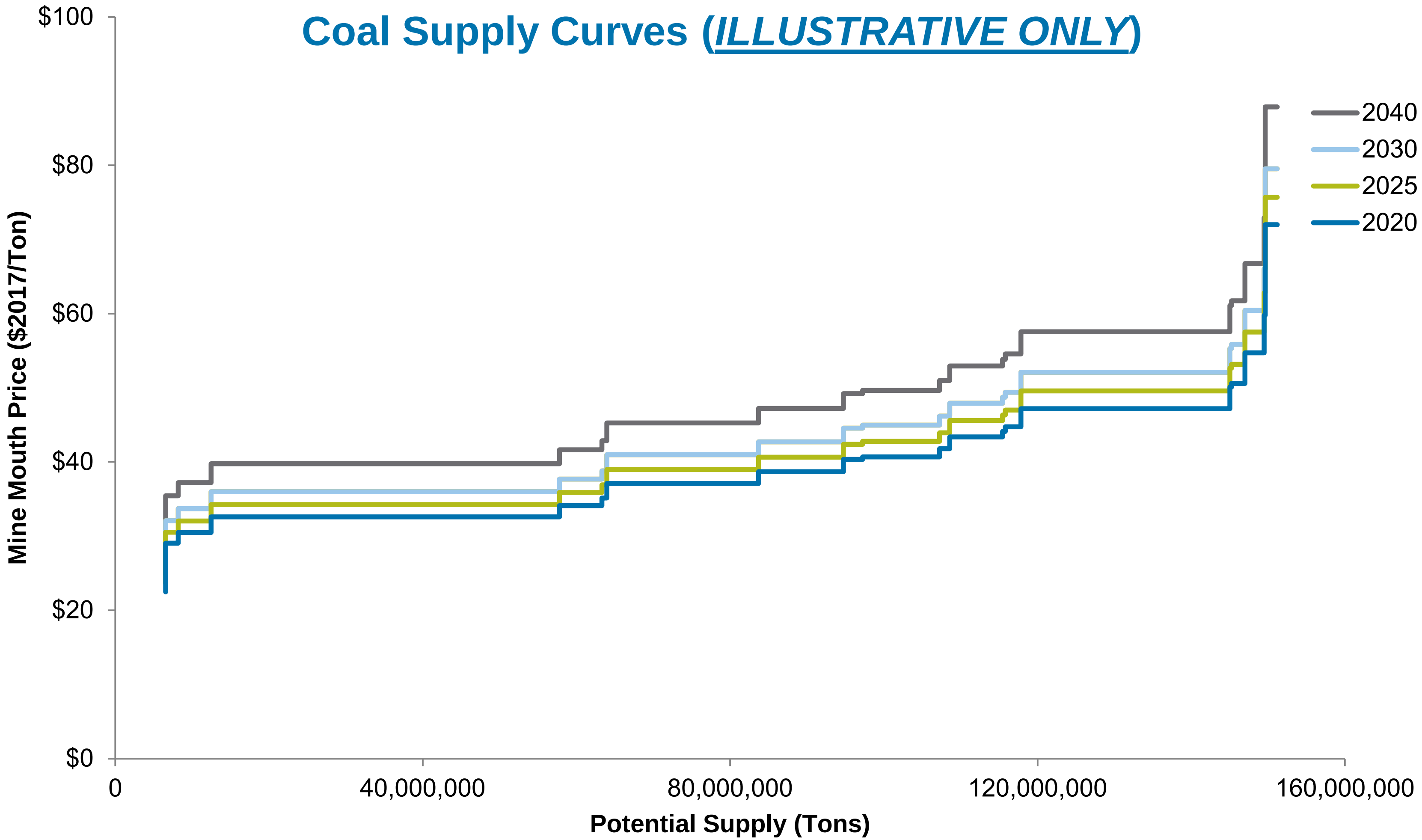
Each basin in NEEM is represented by a set of annual supply curves, which change over time to reflect cost developments & depletion (if applicable)



U.S. Coal Prices expected to be mostly flat over the study period

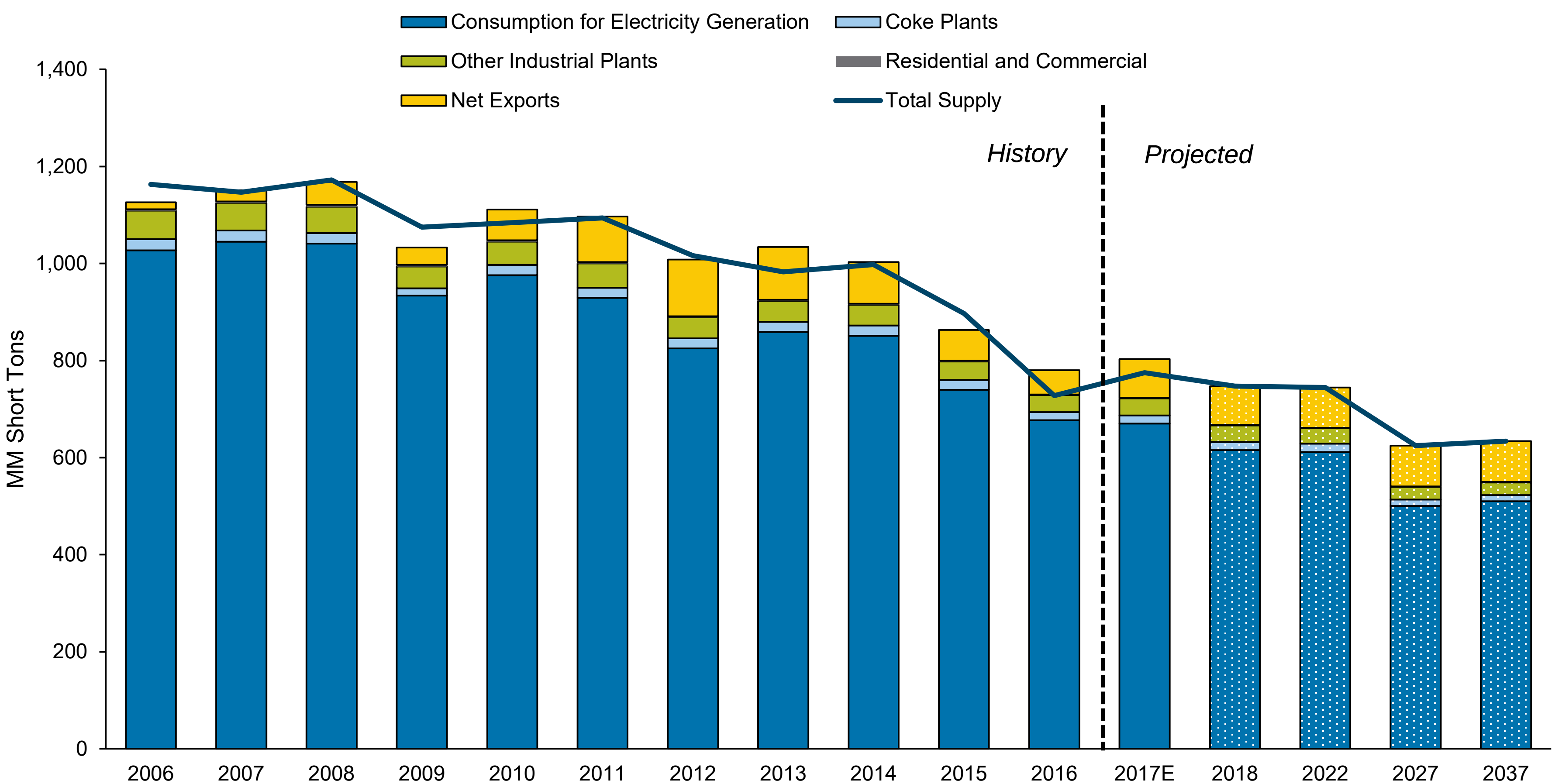
– This indicates that many market participants expect relatively weak coal demand during 2018-2021, with little appreciation or decline in real dollar pricing from current levels

– Initial results show a net decline in coal-fired demand over the study period

– CRA expects U.S. steam coal demand to fall significantly (~25%) over the next decade

– Increased renewable generation and the retirement of about 33 GW of coal-fired capacity is expected in the first 5 years of the forecast

Supply Demand Balance for U.S. Coal - 2006-2037



Trends in Regional U.S. Coal Production

Coal Type	Current to 2027 Production Forecast (% decline)	Comments
CAPP	-21%	High cost drives decline in electric sector demand; met coal demand sustained
NAPP	-13%	Increased int'l demand and some replacement of CAPP demand
ILB	-9%	Increased int'l demand and some replacement of CAPP demand
PRB	-22%	Domestic steam coal demand declines, especially after CO_2 pressure

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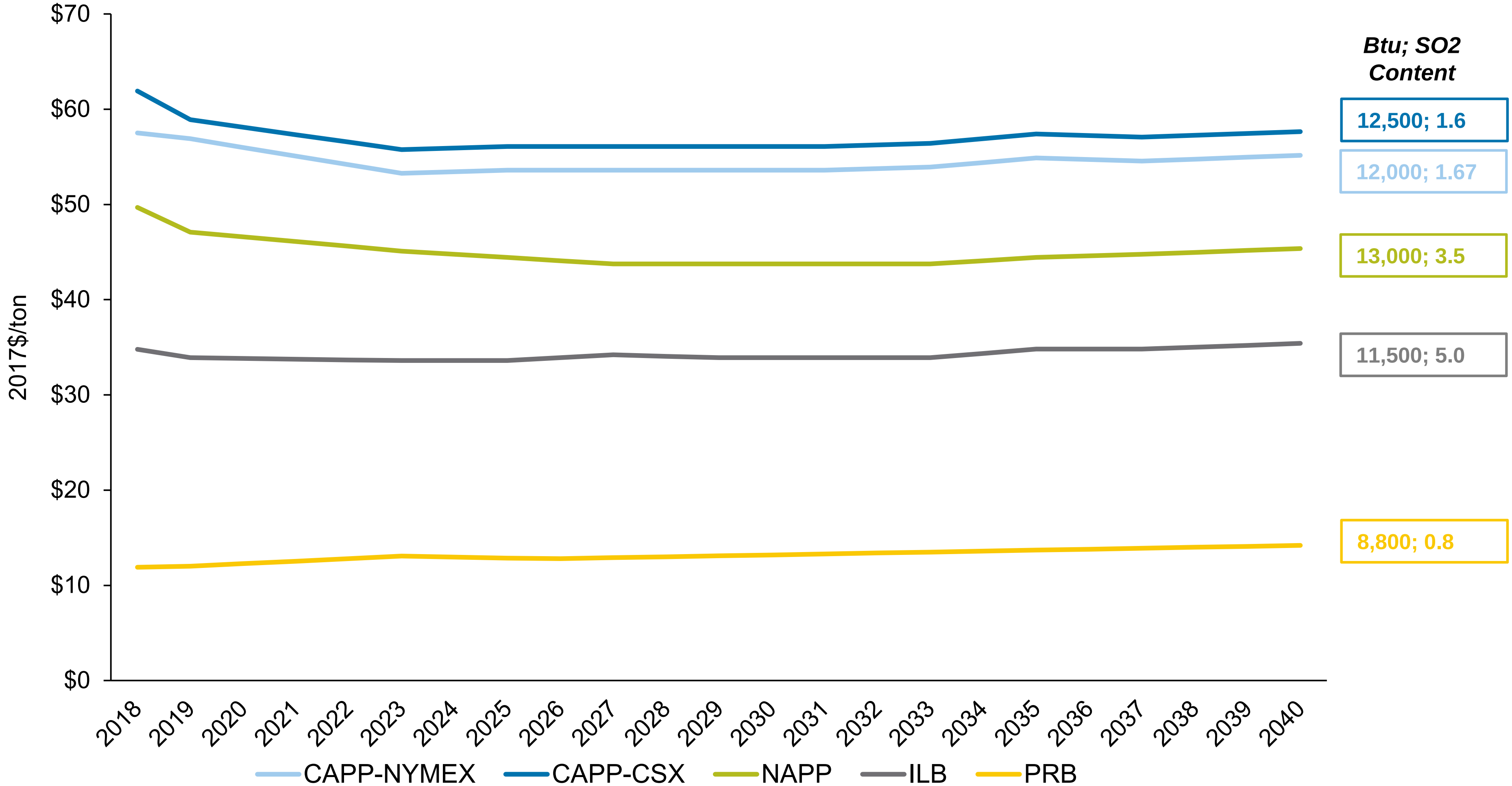
Summary of Price Trends by Coal

Coal	Market Trend
CAPP	• Lower demand is expected to drive a price decline (in real dollars per ton) for Appalachian coal through the early-to-mid-2020s • Thereafter, reserve depletion expected to drive modest increase in real coal price for Appalachian coals
NAPP	• NAPP prices trend with CAPP, but reflect the lower production costs in Northern Appalachia • NAPP's lower cost profile, due to larger longwall mines, allows highly efficient mining of large-block coal reserves
ILB	• Abundant reserves of ILB coal and low production cost (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth
PRB	• PRB prices increase modestly (in real dollars per ton) at an average rate of 0.8%/year through the forecast period • Price growth over time driven by higher production costs due to downward-sloping coal seams/reserve depletion.

Forecast of Commodity Prices for Key U.S. Coal Types

Over the long-term, coal price projections are generally flat in real terms



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Carbon Price Outlook

Carbon Policy and Emission Pricing

- Assumes a new federal rule or legislative action coming into force by the mid-2020s. Analysis suggests a ~20% reduction in U.S. coal demand post-2026 vs. a $0 carbon price scenario.
- Rationale
  - Timing: New administration post-2020 would need to re-develop rule through EPA or pursue a legislative fix with a newly constructed Congress. Earliest likely implementation around 2026.
  - Stringency: In line with CPP-type stringency (ie, 30-40% reductions in emissions vs. historical baseline)

- Assumes a modified EPA plan to control carbon, with focus on “Building Block 1” coal plant heat rate efficiency improvements. No specific tax or emission cap requirement would be present under such regulations.
- Rationale
  - Trump Administration has withdrawn CPP with a focus on modest replacement to meet requirements of the endangerment finding. Thus, the base case would follow current rule revision expectations, with long-term potential of a continued divided Congress/Executive Branch and/or prolonged legal challenges for any future EPA regulation.

- Assumes a stricter new federal rule or legislative action coming into force by the mid-2020s. Price levels are generally consistent with a 50-60% reduction in electric sector CO_2 emissions relative to 2005 by the 2030s.
- Rationale
  - Timing: Same as Base Case
  - Stringency: Would represent an initial pathway towards aggressive carbon reduction goals (ie, 80% by 2050 target under the “2 degree” scenario). *Note that economy-wide reduction scenario has not been evaluated to date.*

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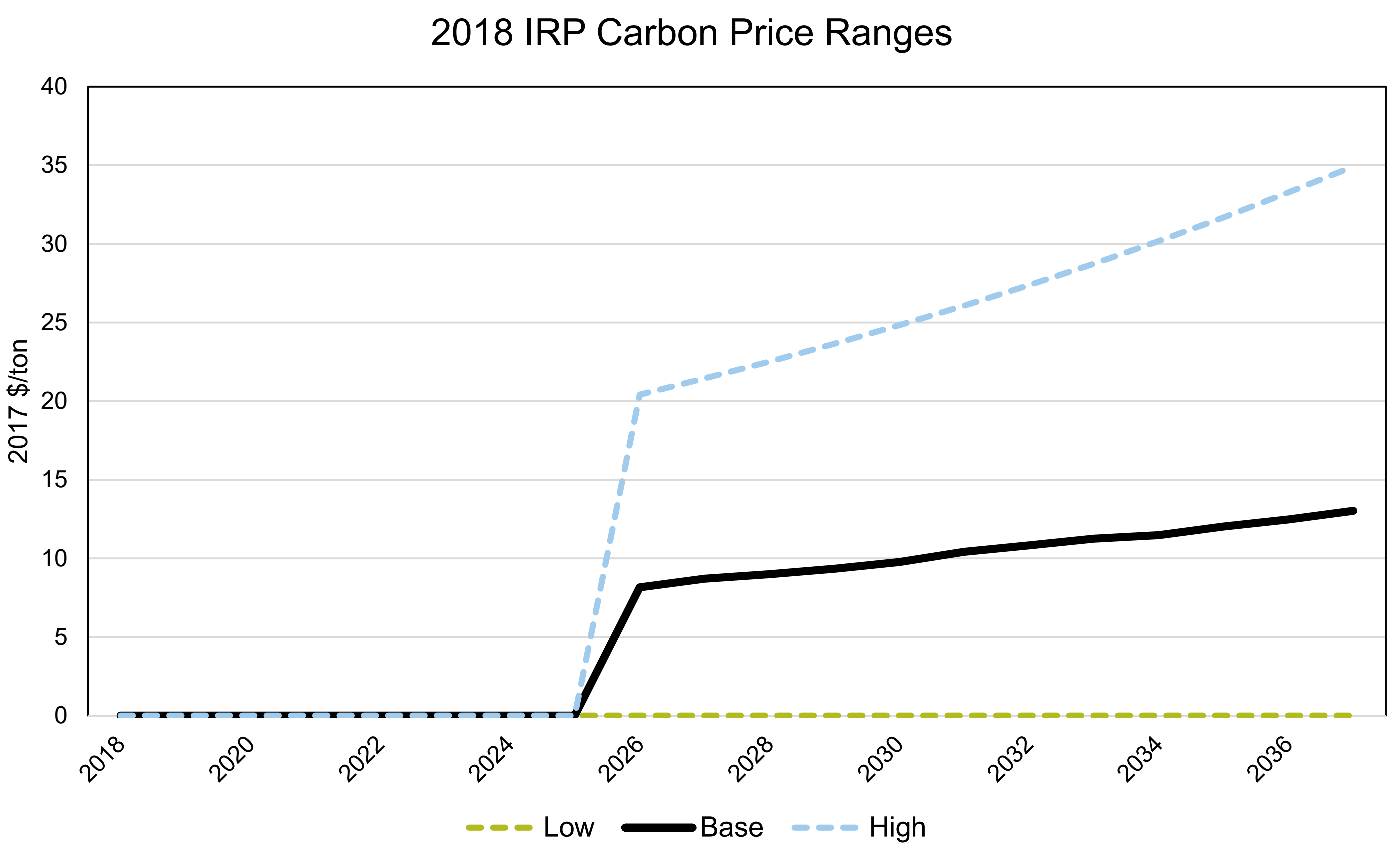
Carbon Policy and Emission Pricing



**Note that high case represents a potential initial pathway for an 80% power sector CO2 emission reduction by 2050. An additional scenario with broader economic impacts may be assessed at a later time as a separate scenario.*

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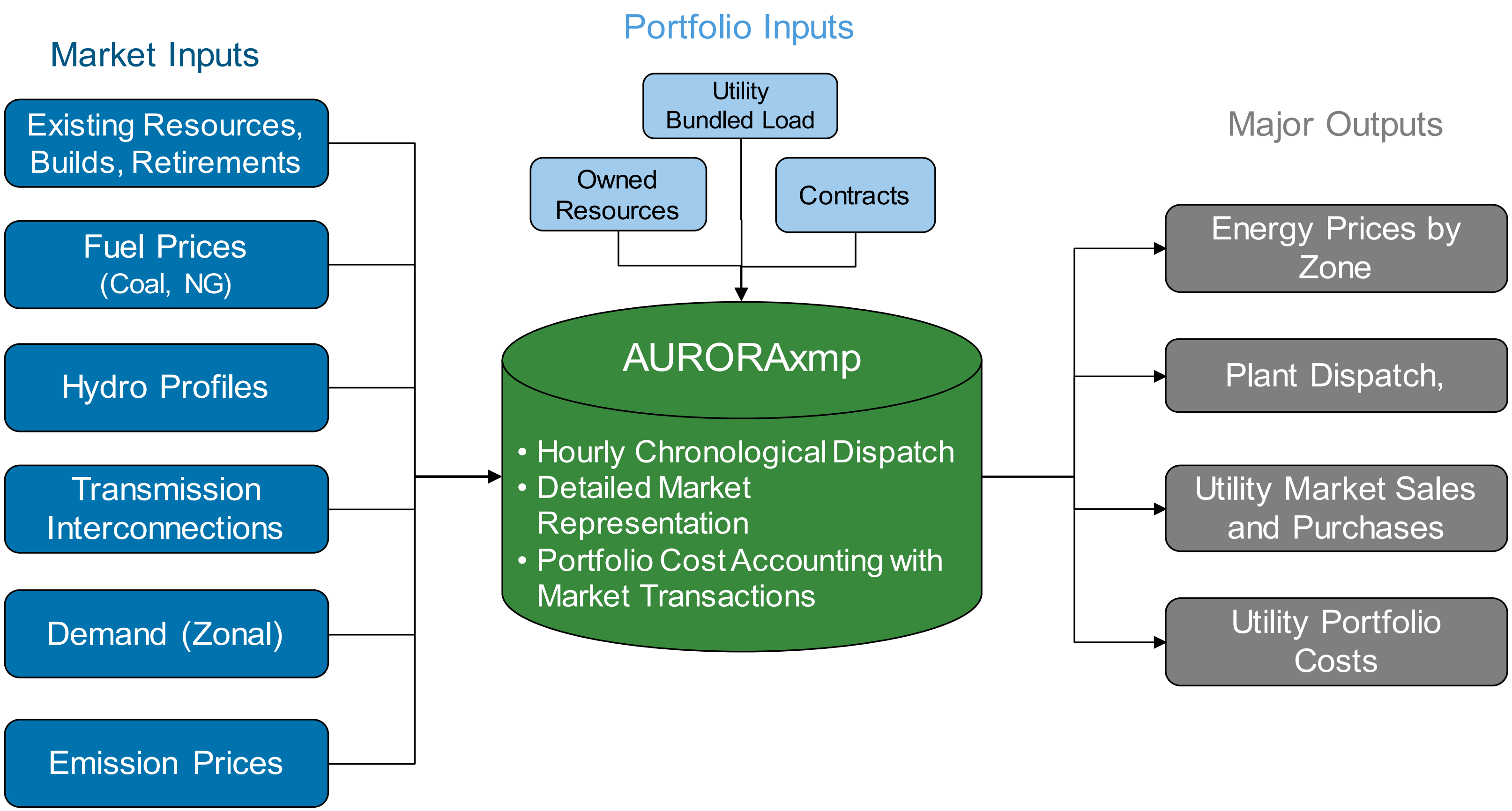
MISO Power Market Outlook

AURORA – Power Price Forecasting



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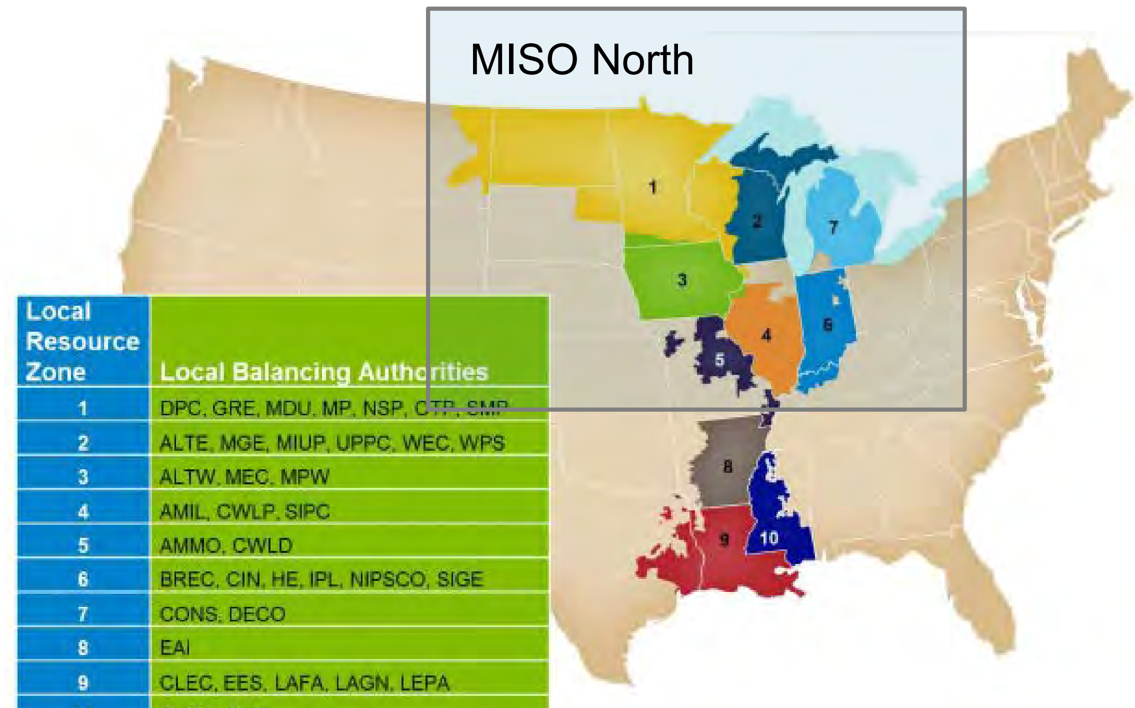
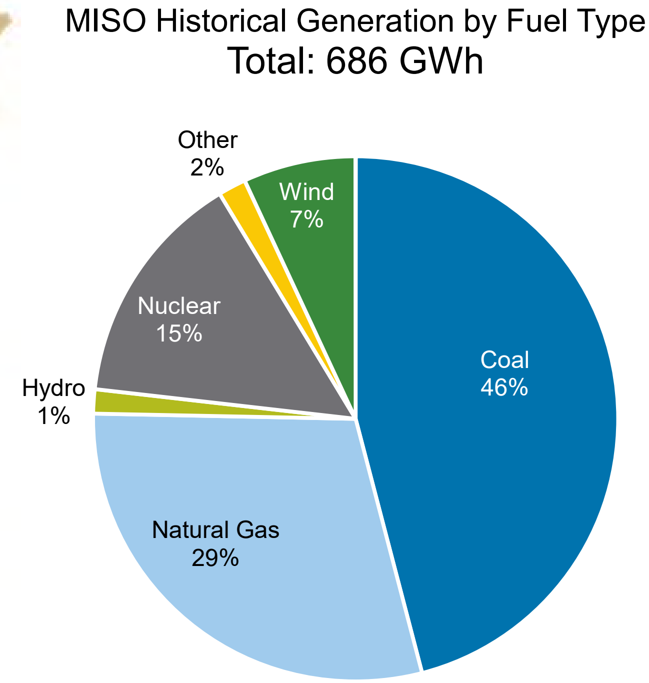
MISO – Overview



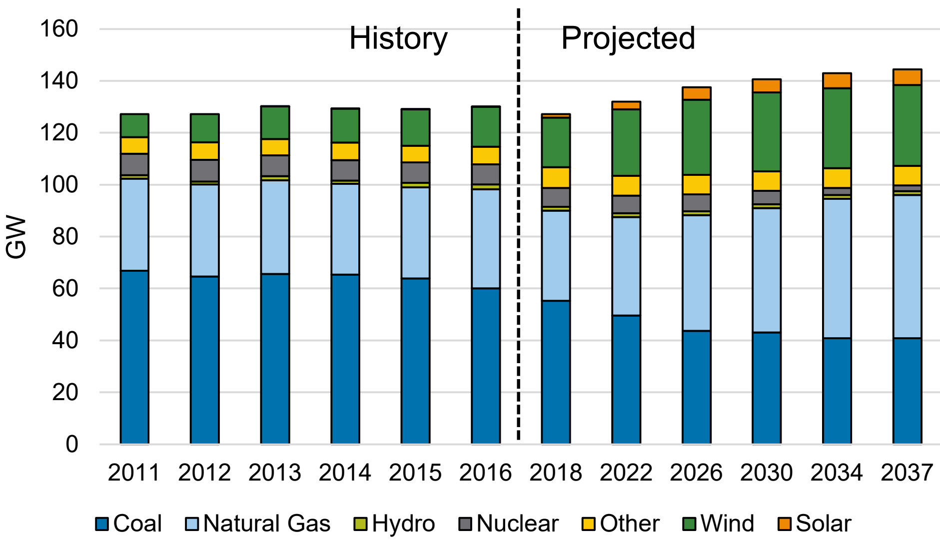
Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME



Expected continued shift from coal to gas and renewables in MISO

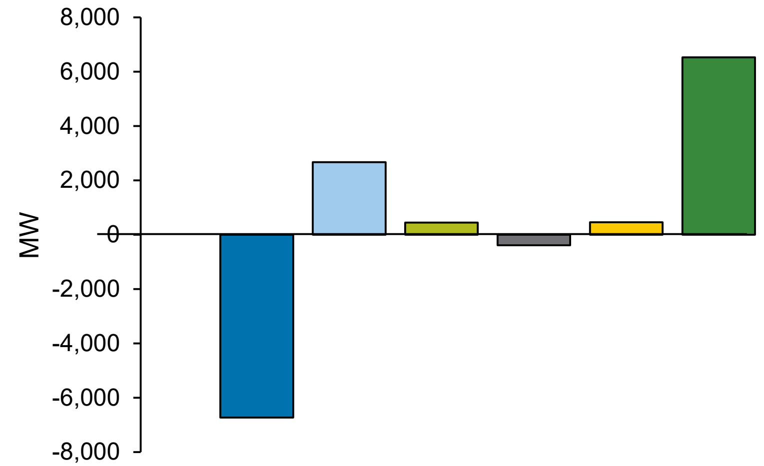
- 6.3 GW decline in net coal capacity; no new coal plants since 2013
- Indiana Zone: Bailly 7 and 8, Schahfer 17 and 18, and Vectren AB Brown plant

MISO North* Net Winter Capacity by Fuel Type



*MISO North includes LRZ 1-7

Net Change in Capacity, 2011-2016



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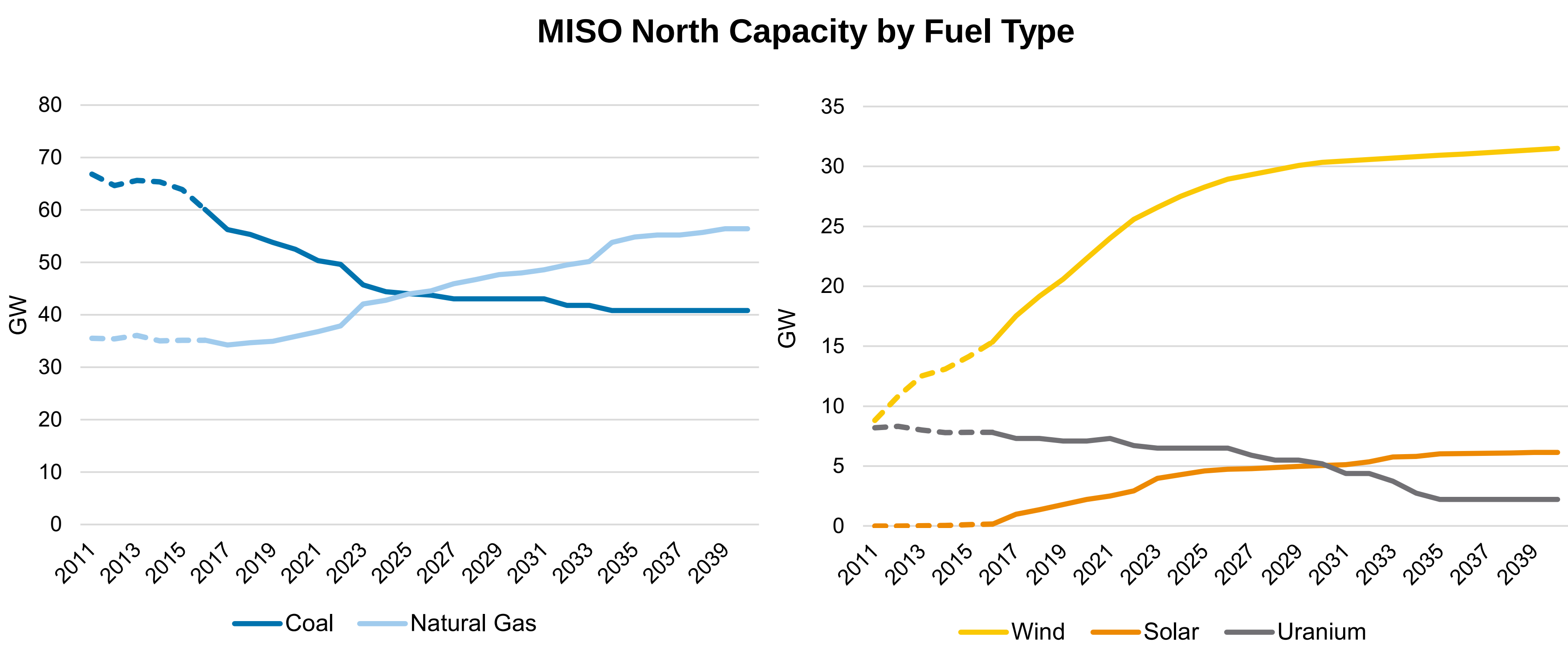
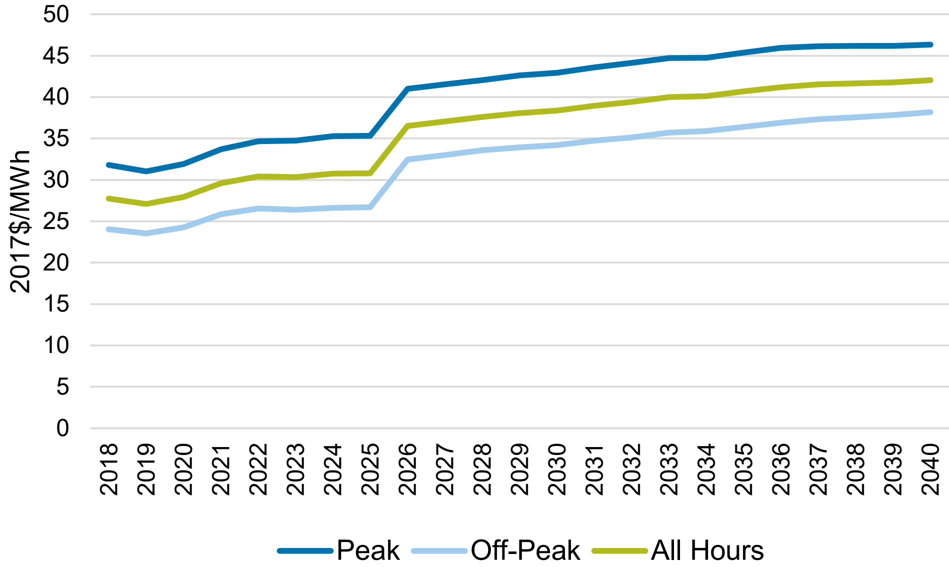
CRA expects broad trends to continue across MISO

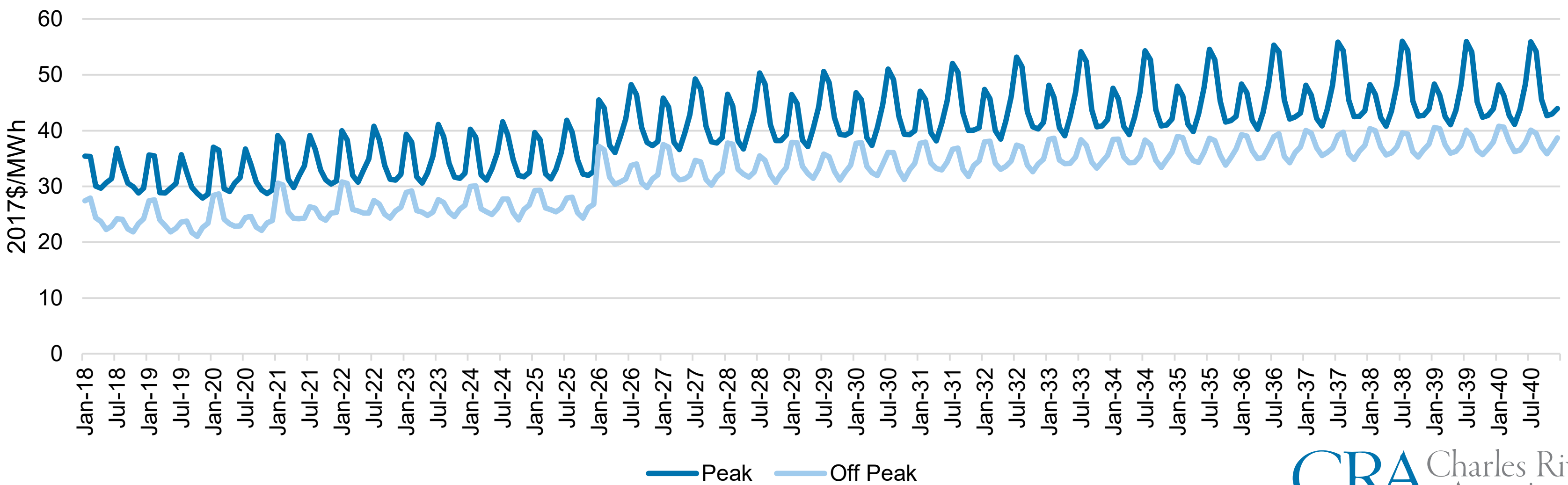
- Coal comprised 46% of total energy produced in MISO-North in 2016, compared with 61% of energy in 2011
- Retiring coal and nuclear capacity is expected to be replaced by a mix of gas and renewables



CRA Power Price Forecast – MISO Zone 6

- Power prices are relatively flat in the near-term, due to flat gas and coal prices and relatively modest load growth
- Some upward pressure expected into the 2020s as a result of higher natural gas prices, although growing renewables lower the market heat rate over time
- National carbon price, starting in 2026, drives price increase





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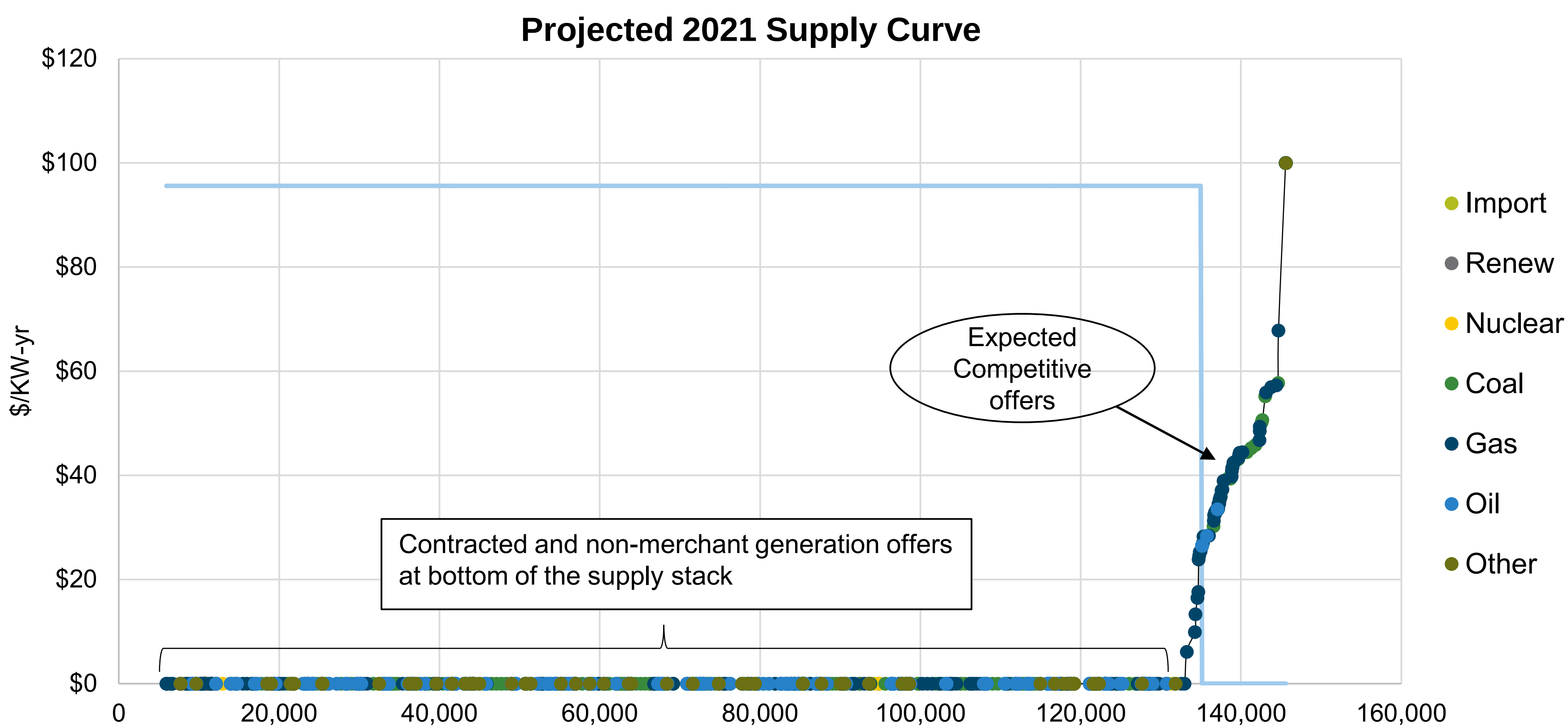
Capacity prices are influenced by market design



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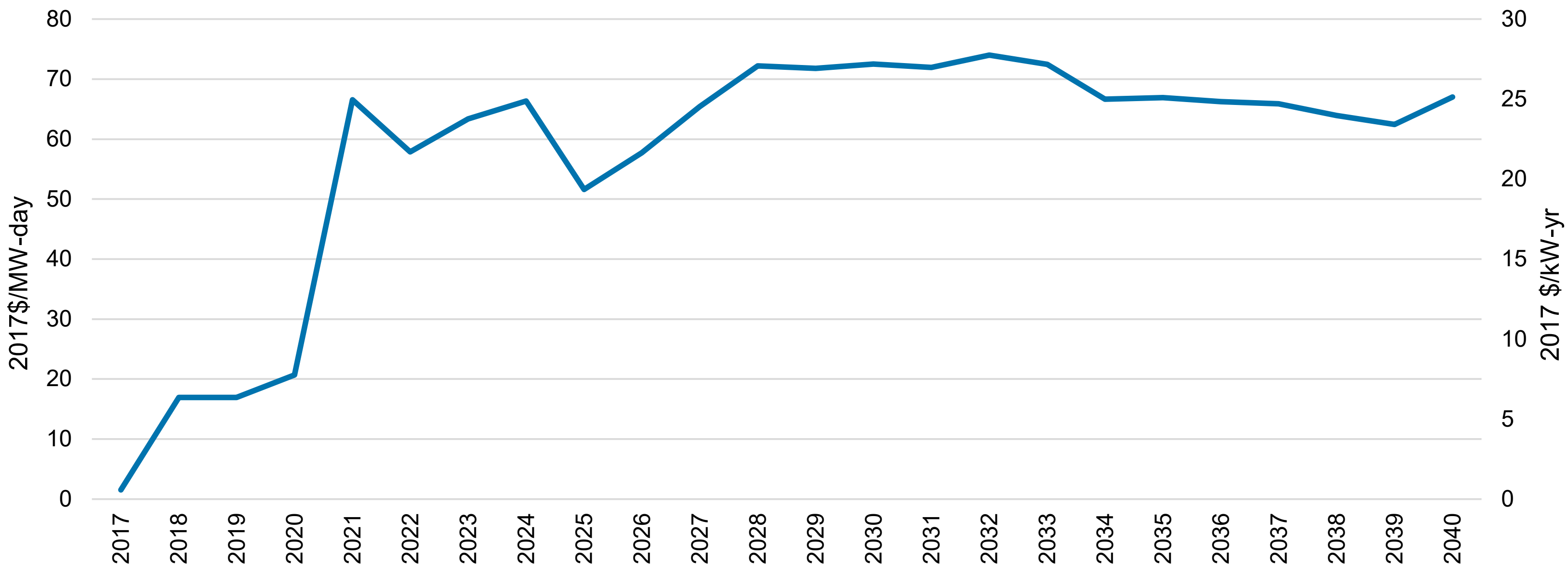
CRA MISO Capacity Price Forecast

- Flat load and increases in renewable, behind-the-meter, and DR/EE supply
- Tariff revisions impacted offer thresholds on the low end
- Import constraints between North and South relaxed



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Demand Side Management Update

Alison Becker
Manager Regulatory Policy

Richard Spellman
GDS Associates (GDS)

2018 Electric DSM Savings Update

- The Electric DSM Savings Update report will focus on a 20-year time horizon (2019-2038).
- For years 2019-2021, data will be gathered from NIPSCO's recent filing in Cause No. 45011 pending before the Indiana Utility Regulatory Commission ("IURC").
- GDS will update measure costs, kWh and kW savings, useful lives, saturation data, etc.

2018 Electric DSM Savings update (continued)

- The savings update will consider new sources of secondary data that are now available.
- The final Electric DSM Savings Update report will be completed by June 1, 2018
  - GDS will present draft results to the Oversight Board during the April meeting

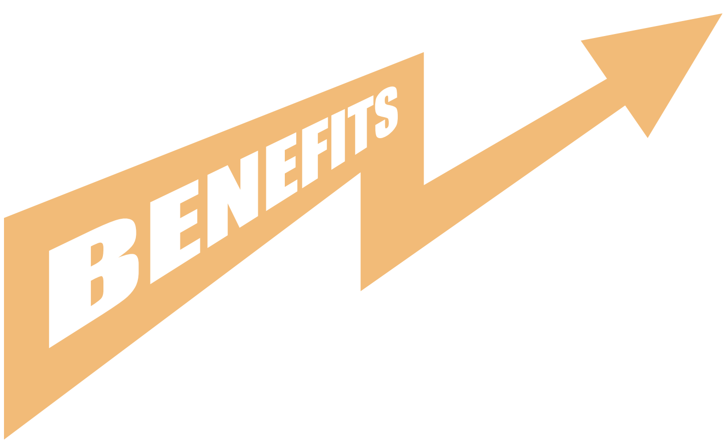
2018 Electric DSM Savings Update Report Contents

- Recommended cost-effective DSM savings measures and programs.
- Information on innovative programs and technologies.
- Budgets for each program.
- A cost-effectiveness ranking for all technologies (measures) reviewed.
- Cost-effectiveness evaluations for each proposed program.
- GDS will calculate the Total Resource Cost (“TRC”) test, the Utility Cost test, the Participant test and the Rate Impact Measure (“RIM”) test.
- The TRC test will be used to determine measure, program and portfolio cost effectiveness.

Technical Approach for Electric Baseline Development

FOUR-STEP PROCESS TO COMPLETING BASELINE DEVELOPMENT

1) Review Existing Market Data
2) Conduct Additional Primary Market Research
3) Market Characterization/Segmentation
4) Energy Usage (8760) Modeling / Forecast Calibration



BENEFITS OF APPROACH

~ Identify Data Gaps

~ Collection of Updated Market Data

~ Development of Updated and Detailed Market Segmentation

~ Alignment of Baseline End Use / Technology Consumption Estimates with Overall Energy Consumption Forecasts

Development of DSM Assumptions

- GDS will develop appropriate base case and energy efficient case assumptions at the measure level to inform the measure characterization.
- Updates will include:
  - Measure costs
  - Measure kWh and kW savings
  - Measure lives
  - Measure and equipment saturation data

Technical Approach-Measure Assumptions

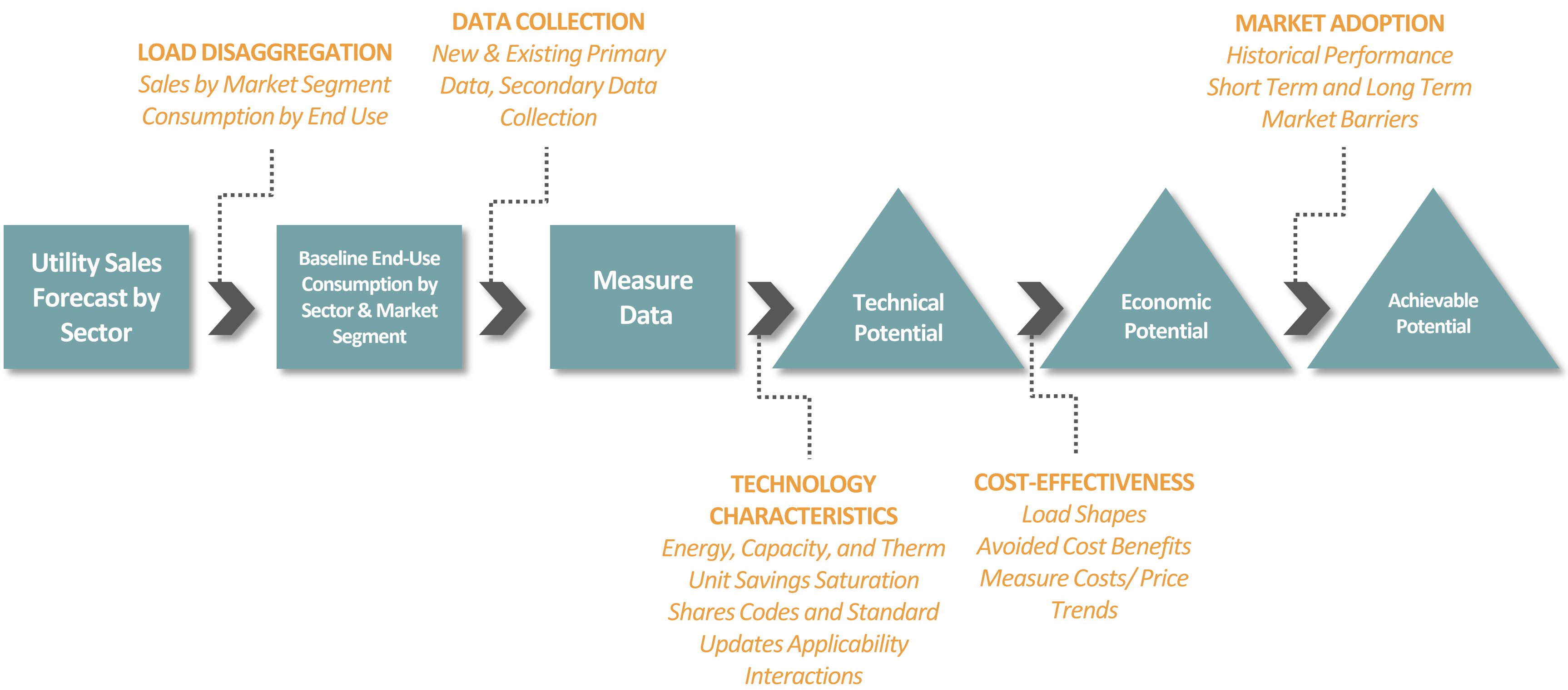
ASSUMPTION DEVELOPMENT

- **Develop measure database with detailed sourcing**
- **Account for codes and standards**
- **Coordinate with NIPSCO/OSB on critical methodological decisions**
  - Future potential of currently installed efficient technologies
  - Applicable replacement strategies (e.g. Replace on burnout, retrofit, early replacement)
  - Achievable potential scenario development
- **Develop appropriate funding levels and market adoption rates**
- **Quality control of model inputs/outputs**

METHODS & SOURCES

- **Review of existing market data (Subtask 1.1)**
- **Primary market research (Subtask 1.2); surveys, interviews, on-site inspections**
- **Indiana Technical Resource Manual version 2.2 for measure data**
- **NIPSCO program planning and evaluation data, other industry sources**
- **Energy modeling software**

Assessment of Potential Savings



Development of Funding Levels

GDS will recommend the appropriate and necessary funding levels that will support achieving specific levels of program penetration and delivery over various time periods.

Paul Kelly
Director of Federal Regulatory Policy

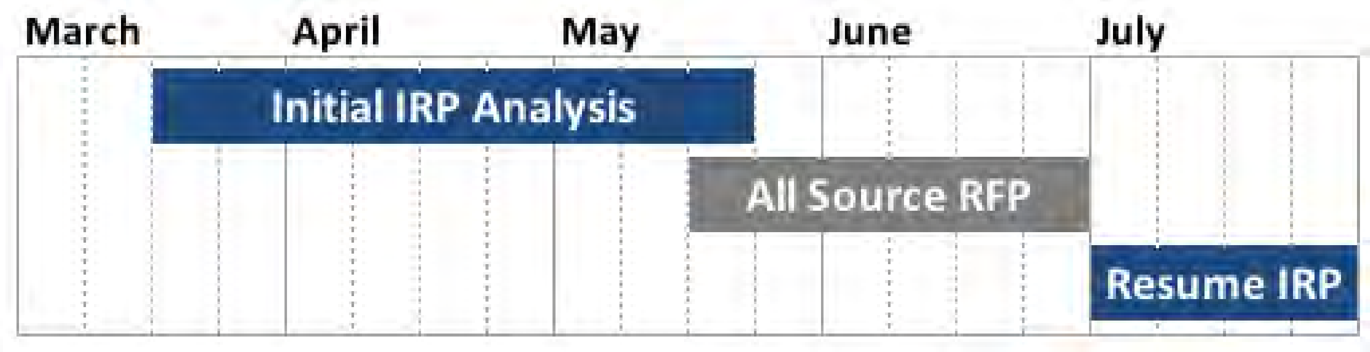
Goal **Identify every viable resource in the market that can best meet our customers' needs**

- **Expert Assistance**
  - Retained Charles River Associates (CRA) to develop and administer RFP
  - Utilizing a separate division within CRA to ensure independence from the IRP process
- **Stakeholder Input**
  - Seeking feedback on approach/design to ensure a robust, transparent process and result
- **Resource Evaluation Criteria**

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

- **Technology**
  - Requesting all solutions regardless of technology, including demand-side options and storage
- **Size**
  - Defining a minimum total need of 600 MW for the portfolio but without a cap
  - Allows smaller resources <600 MW to offer their solution as a piece of the total need
  - Also encourages larger resources >600 MW to offer their solution for consideration
- **Acceptable Arrangements**
  - Seeking bids for asset purchases and purchase power agreements for new and existing resources
- **Duration**
  - First year of need begins June 1, 2023
  - Minimum contractual term and/or estimated useful life of 5 years
- **Deliverability**
  - Solutions must have firm transmission delivery to MISO Local Resource Zone 6
- **Participants & Pre-Qualification**
  - Intending to leverage CRA's network of contacts and recommendations from stakeholders
  - Requiring utility-grade counterparties to ensure credit quality and ability to fulfill resource obligation

Timeline for the RFP



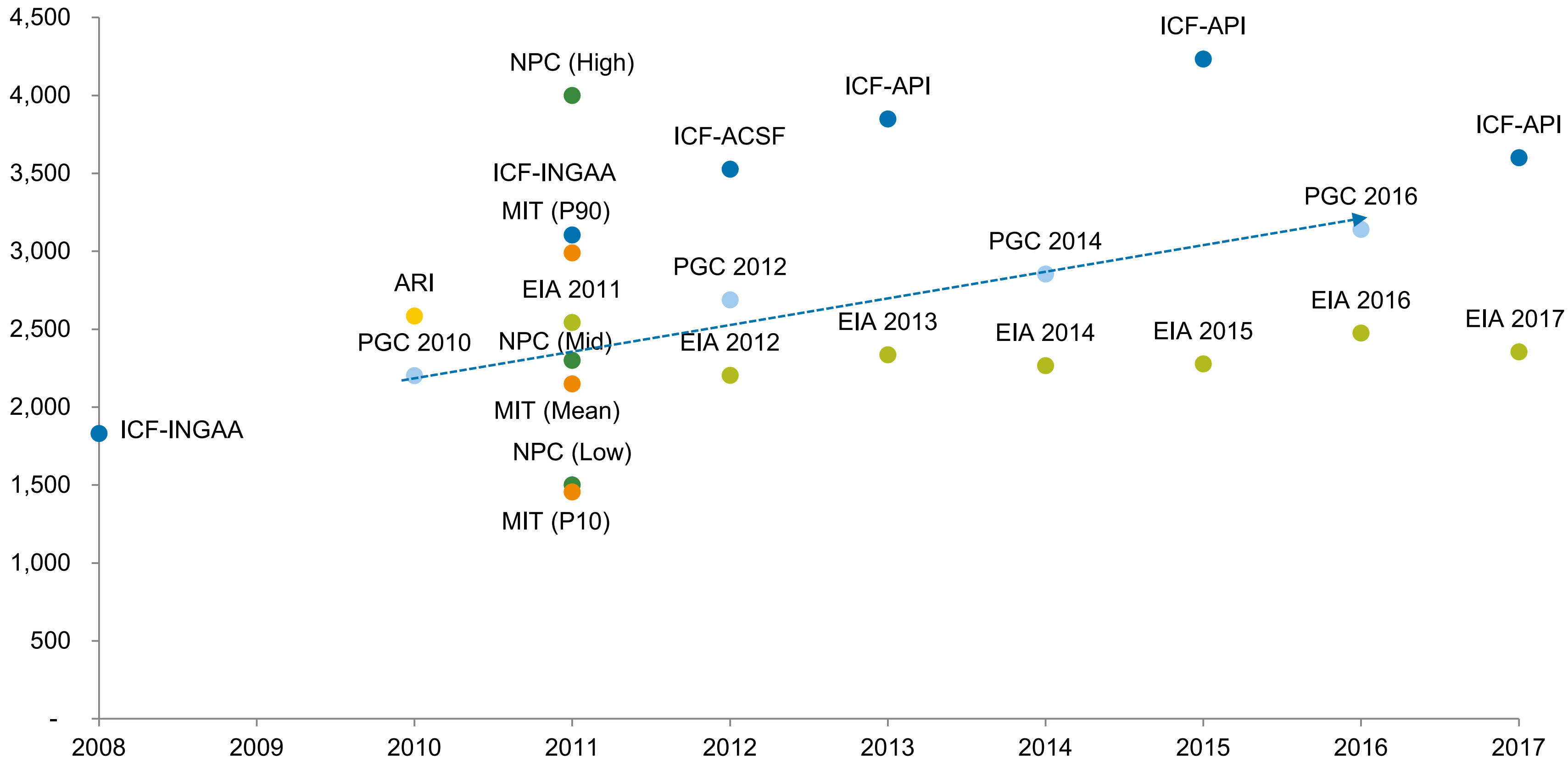
Date	Event
March 23rd	Overview RFP design with stakeholders
April 6th	RFP Design Summary document shared with stakeholders to request feedback
April 20th	Stakeholder feedback on Design Summary due back to NIPSCO
May 14th	**RFP initiated**
May 28th	Notice of Intent and Pre-qualifications due from potential bidders
June 29th	**RFP closes**
July 24th	Summary of RFP bids presented at Public Advisory Meeting webinar; IRP resumes analysis incorporating results of RFP

Similar to the 2016 IRP, NIPSCO plans to conduct a robust stakeholder engagement process for the 2018 IRP, including five formal stakeholder engagement meetings and one on one meetings with interested parties

	Meeting 1 – March 23- Avalon Manor	Meeting 2 – May 11 Avalon Manor	Meeting 3 – July 24 Webinar, SouthLake	Meeting 4 – September 19 Fair Oaks Farms	Meeting 5 – October 18 Fair Oaks Farms
Key Questions	- Why has NIPSCO decided to file an IRP update in 2018? - What has changed from the 2016 IRP? - What are the key assumptions driving the 2018 IRP update? - How is the 2018 IRP process different from 2016?	- What is NIPSCO existing generation portfolio and what are the future supply needs? - Are there any new developments on retirements? - What are the key environmental considerations for the IRP? - How are DSM resources considered in the IRP?	- What are the preliminary results from the all source RFP Solicitation?	- What are the preliminary findings from the modeling ?	- What is NIPSCO's preferred plan? - What is the short term action plan?
Meeting Goals	- Communicate and explain the rationale and decision to file in 2018 - Articulate the key assumptions that will be used in the IRP - Explain the major changes from the 2016 IRP - Communicate the 2018 process, timing and input sought from stakeholders	- Common understanding of DSM resources as a component of the IRP - Common understanding of DSM modeling methodology - Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap - Key environmental issues in the IRP	- Communicate the preliminary results of the RFP and next steps	- Stakeholder feedback and shared understanding of the modeling and preliminary results - Review stakeholder modeling and analysis requests	- Communicate NIPSCO's preferred resource plan and short term action plan - Obtain feedback from stakeholders on preferred plan

Gas Price Drivers – Resource Size

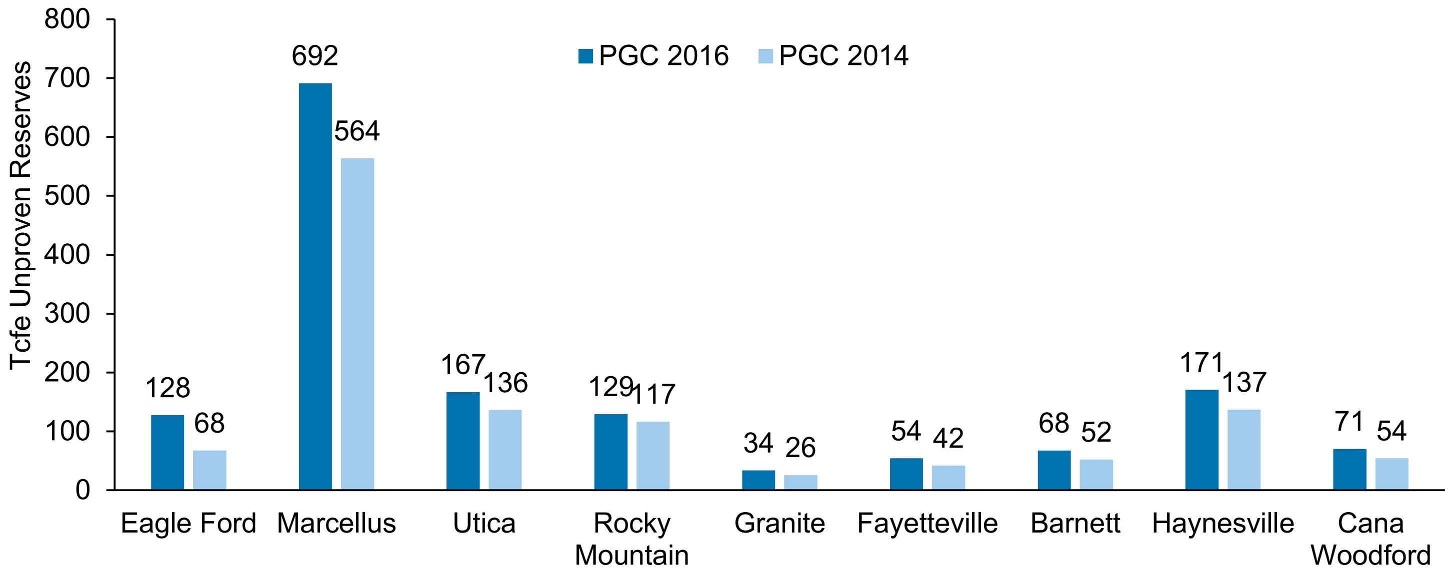
Estimates of resource in place have grown steadily as additional gas and oil continue to be discovered and extraction technology improves



* Note that CRA relies on the Potential Gas Committee (PGC) biennial report as the basis for our NGF resource estimate

Gas Price Drivers – Resource Size

- Shale resource drives the increase in total U.S. gas resource estimates in the PGC 2016 Natural Gas Supply Study
  - PGC 2016, released in July of 2017, estimates a "Traditional" unproved gas resource of 2,658 Tcf, a 12% increase from PGC 2014
  - The increase in total resource growth is driven primarily by shale gas resource, PGC 2016 estimates a total of 1,578 Tcf of shale resource, up from 1,253 Tcf in PGC 2014
- This is PGC's fifth consecutive publication showing an increase in resource estimates



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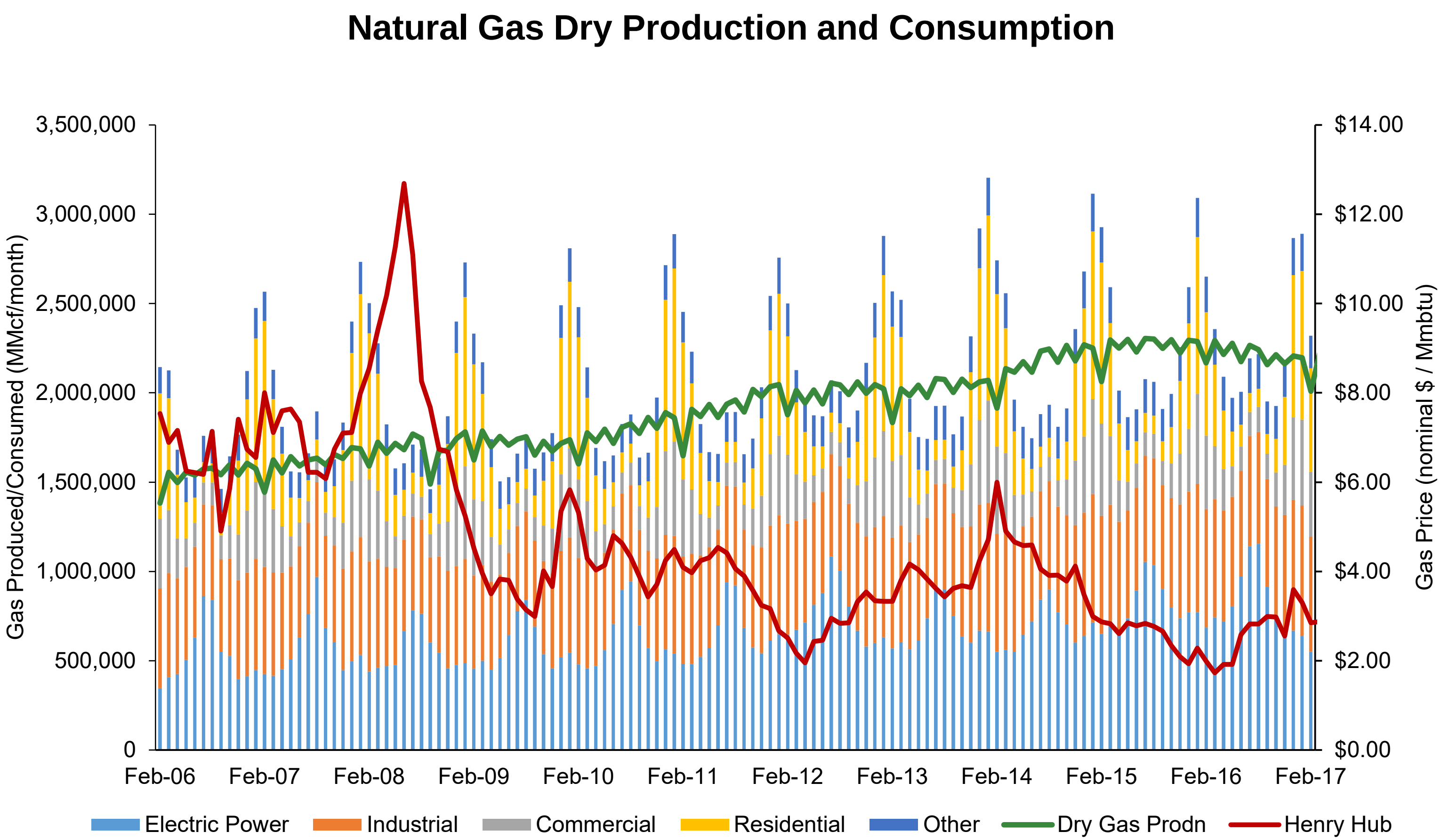
Gas Price Drivers – Well Productivity



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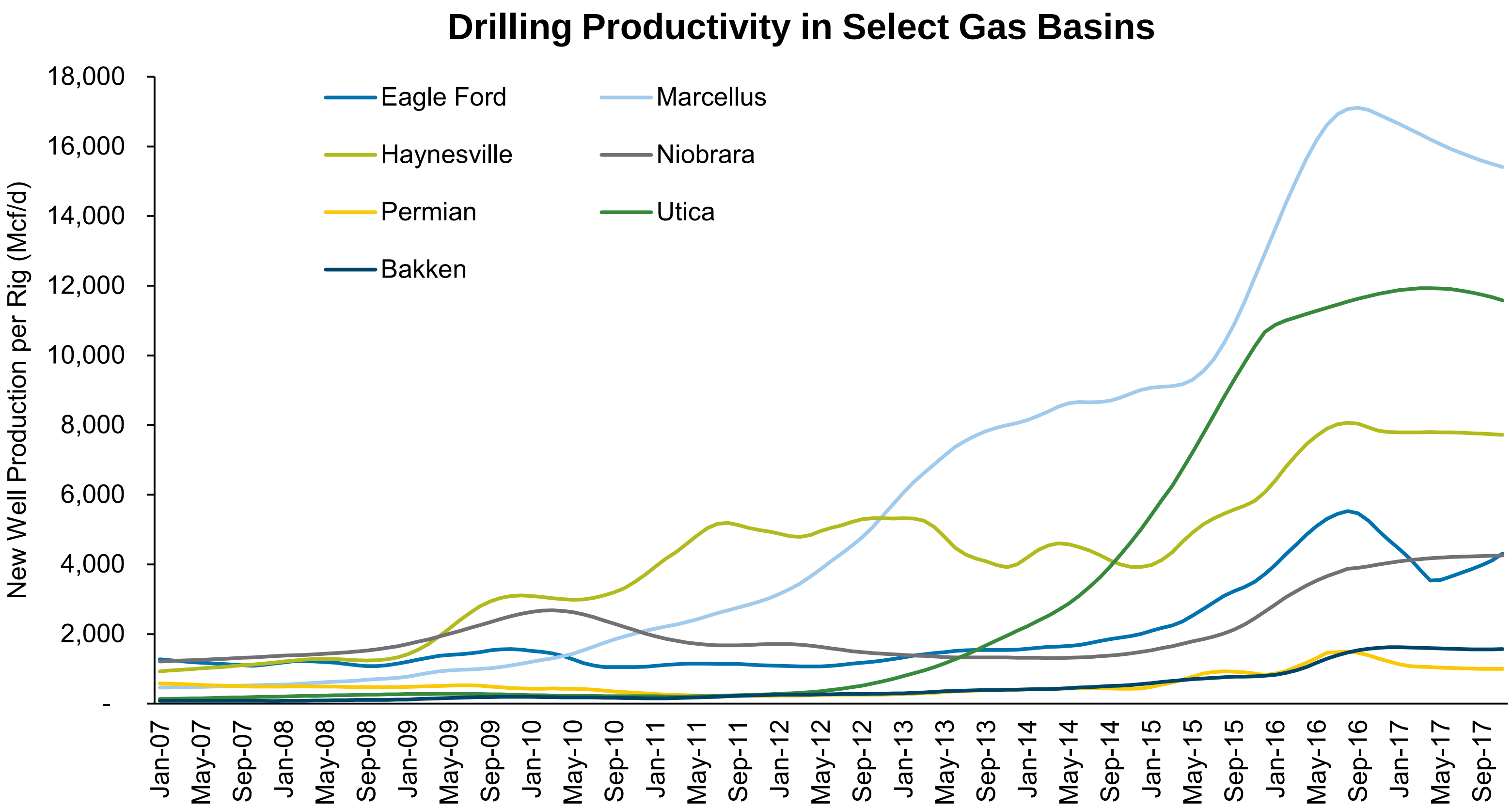
Gas Price Drivers – Productivity Trends



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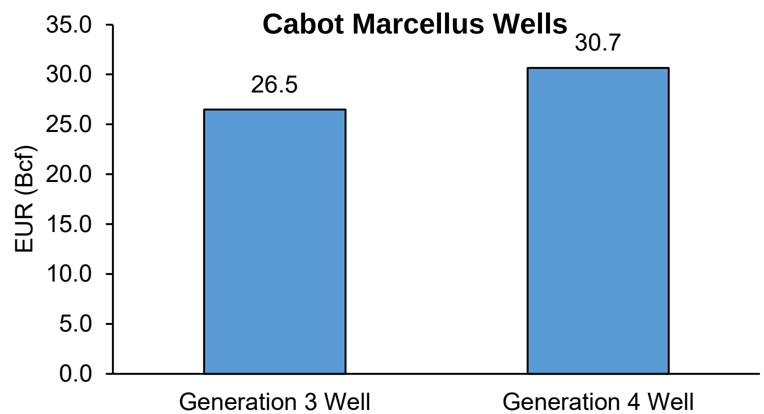
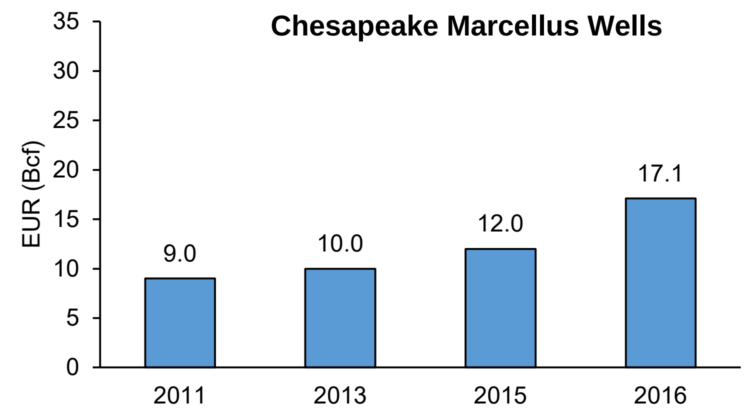
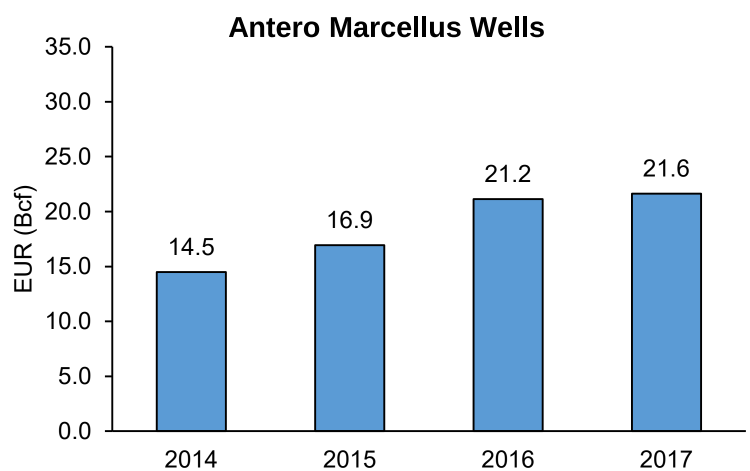
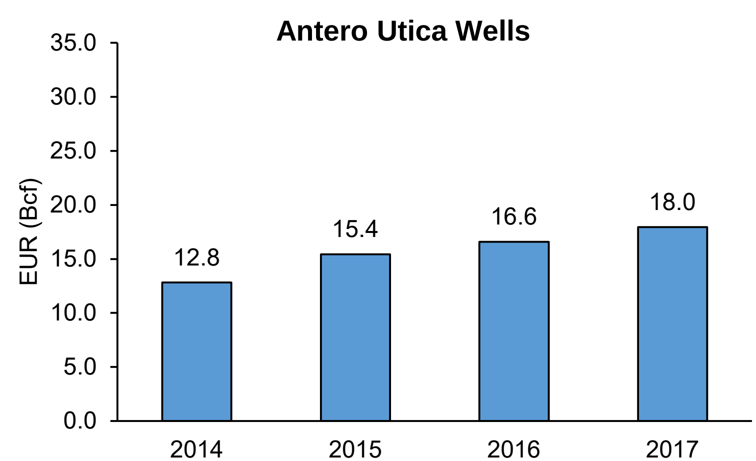
Appendix – Natural Gas - Productivity

Well productivity on a per well basis has been consistently improving, even as longer laterals and multi pad drilling improve per rig performance

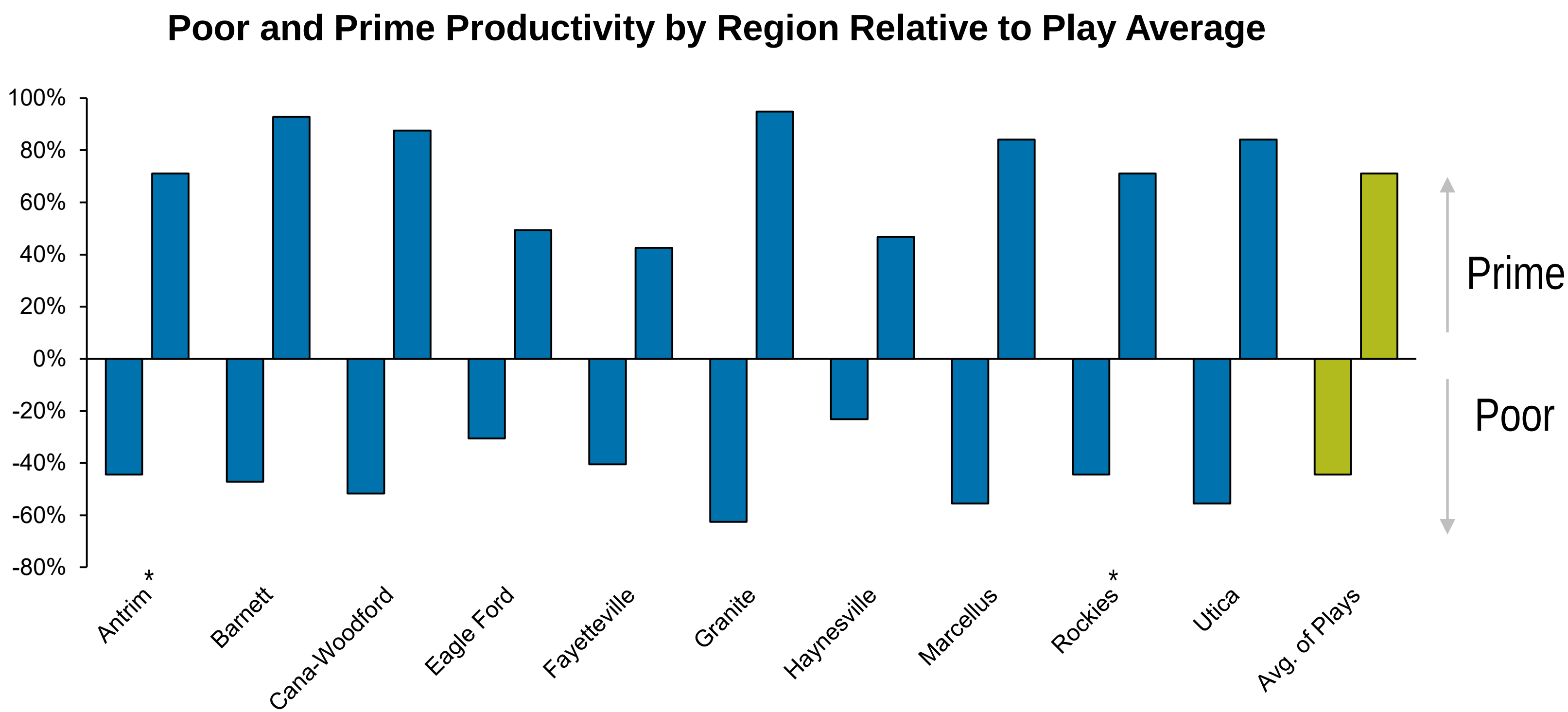








Productivity Distribution by Major Shale Basin



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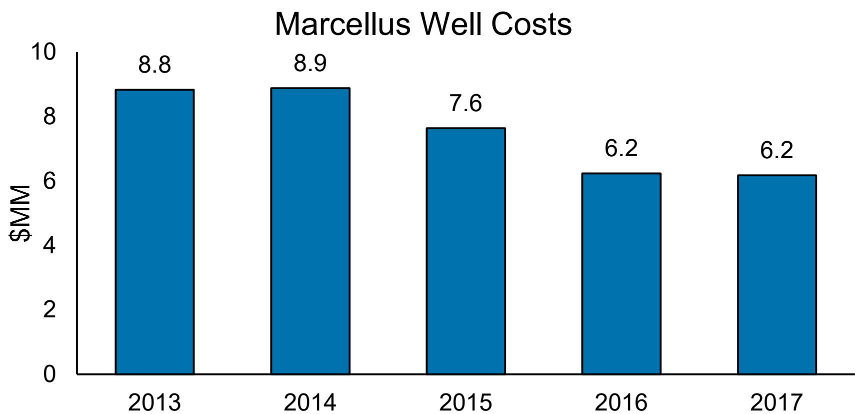
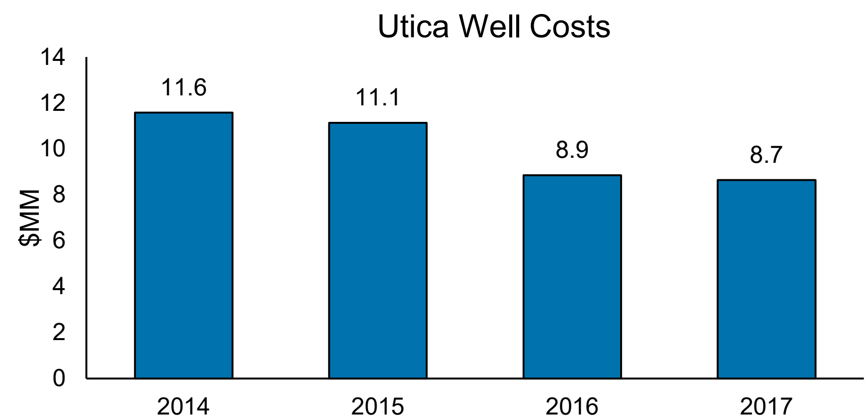
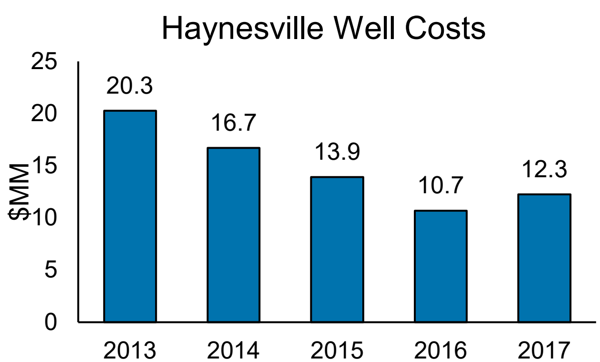
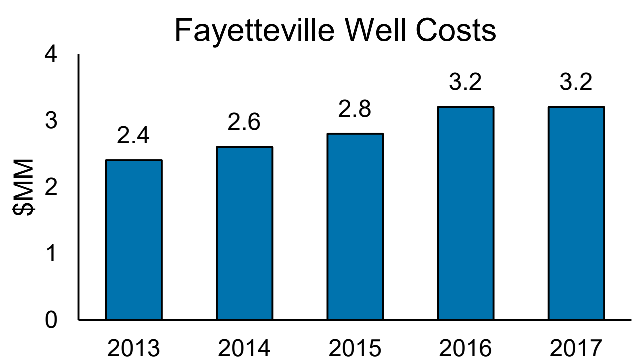
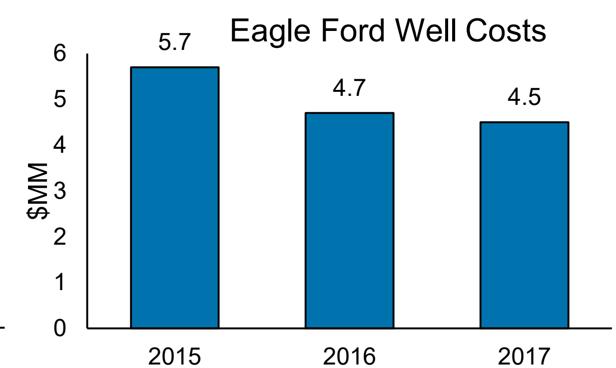
Gas Price Drivers – Drilling Costs











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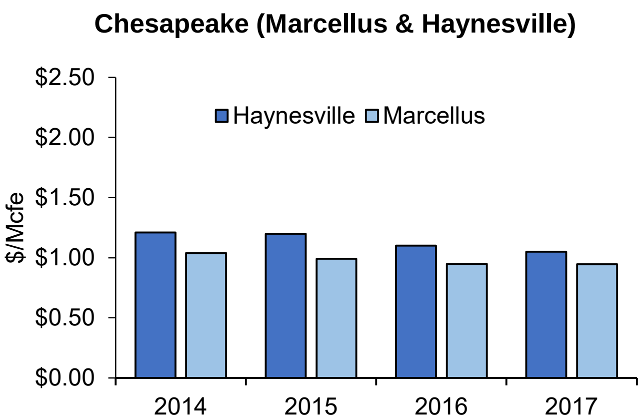
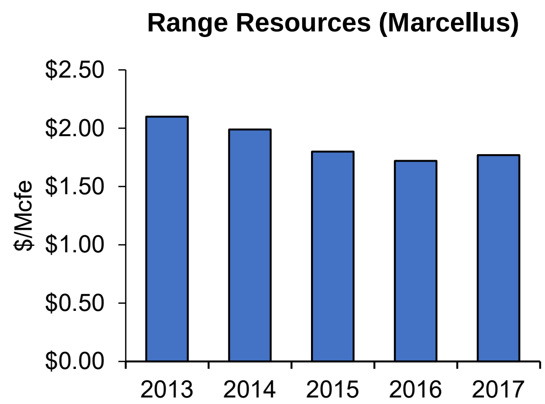
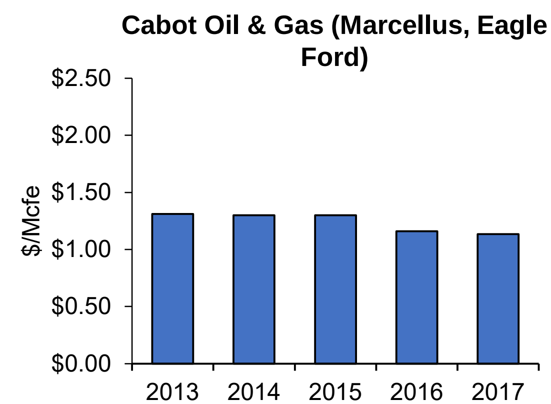
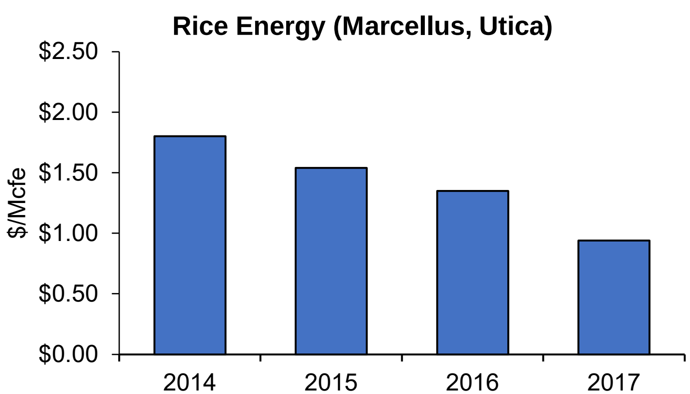
Gas Price Drivers – O&M Costs

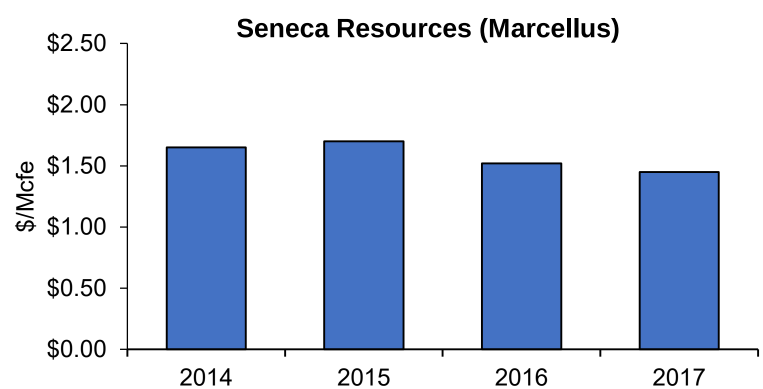
O&M Cost by Producer







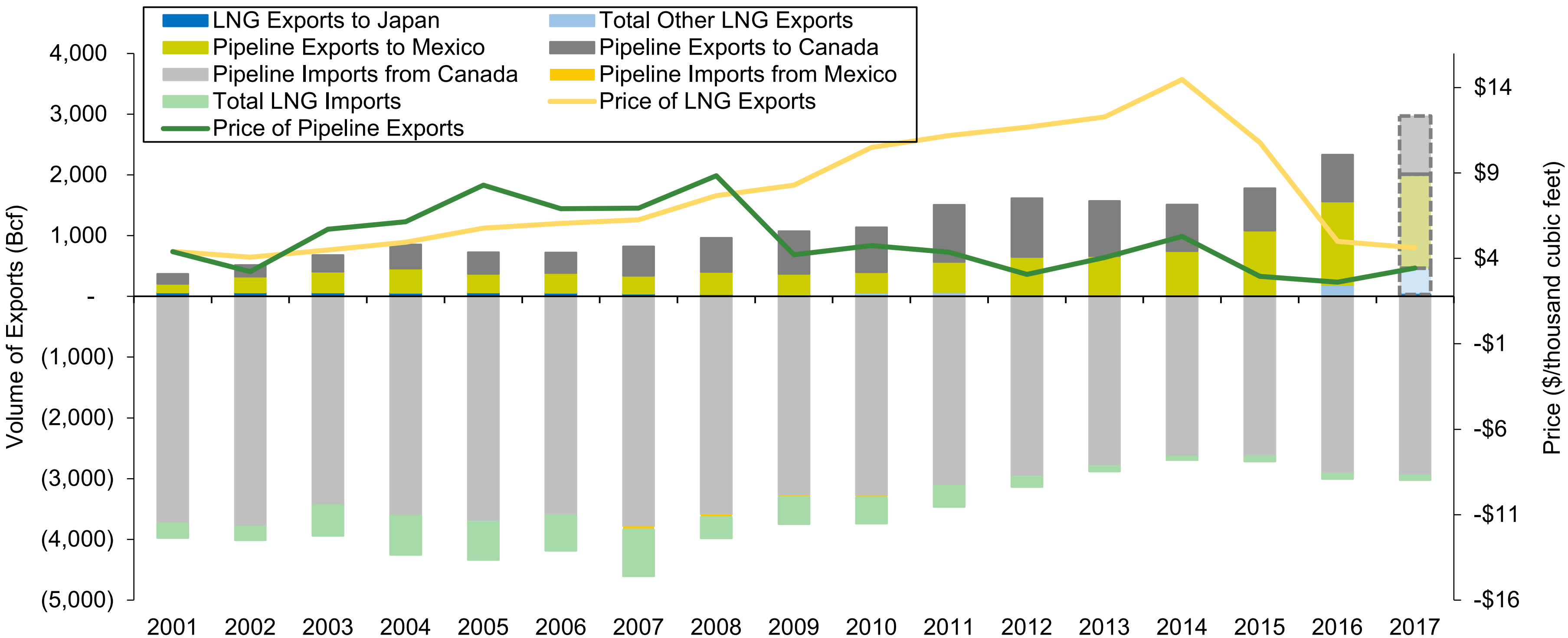




Gas Price Drivers – LNG

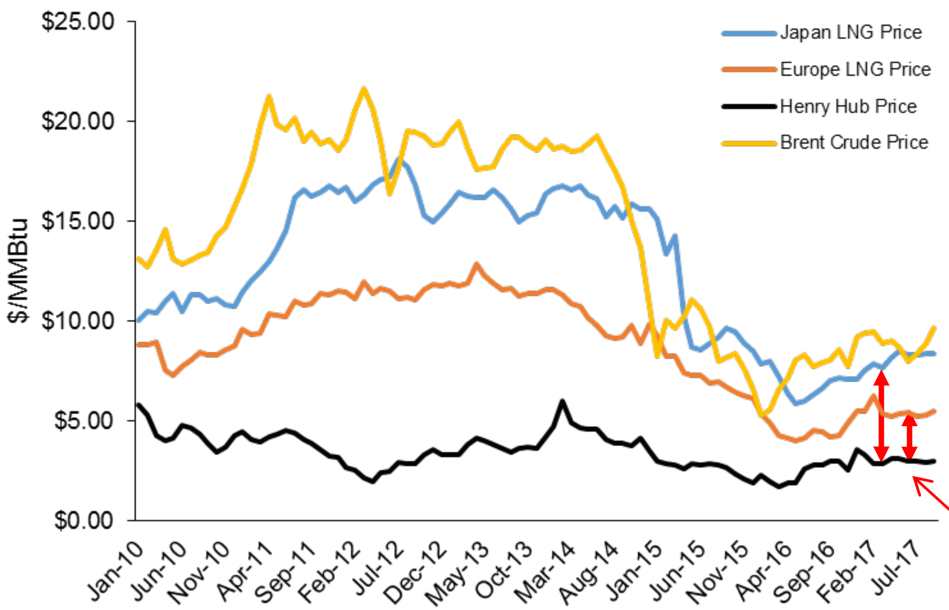
- US gas exports continue to grow, driven by export capacity additions and stabilized international market prices

U.S. Exports (LNG and Pipeline: 2001-2017 (Projected))

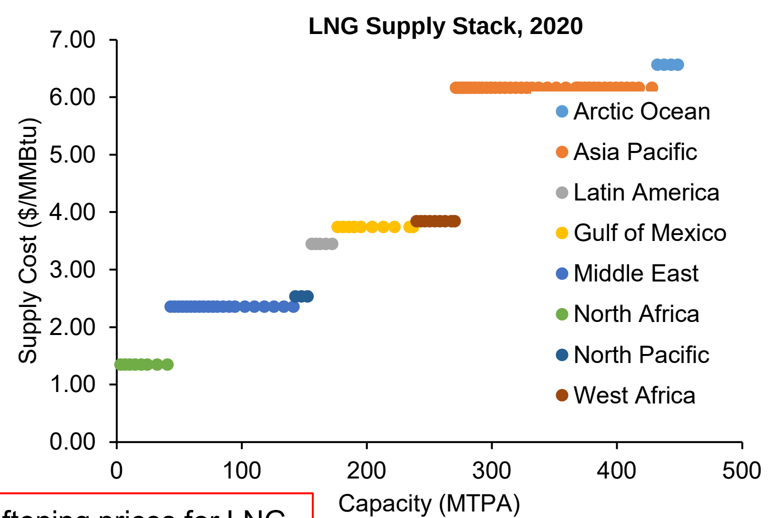


* 2017 data includes monthly average pricing data up to September 2017 and annualized projected volumes based on daily averages up to September

Gas Price Drivers – LNG



Softening prices for LNG exports threatens many potential projects



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Gas Price Drivers – LNG

US LNG terminal forecast largely unchanged in the past year, approximately 10 Bcf/d is now under construction or already completed

	Project	Status	FTA / Non FTA	Expected In Service	Capacity (Bcf/d)
In Service / Under Construction	Sabine (T1-T3)	Operating	Non-FTA		1.8 Bcf/d
	Sabine (T4)	Commissioning	Non-FTA	2018	0.6 Bcf/d
	Cove Point (Full Terminal)	Commissioning	Non-FTA	2017	0.82 Bcf/d
	Sempra Cameron (T1-T3)	Under Const.	Non-FTA	2019	1.8 Bcf/d
	Elba/Southern LNG (T1-T5)	Under Const.	Non-FTA	2018	0.36 Bcf/d
	Freeport (T1-T3)	Under Const.	Non-FTA	2018-19	1.8 Bcf/d
	Sabine (T5)	Under Const.	Non-FTA	2018	0.6 Bcf/d
	Corpus Christi (T1-T2)	Under Const.	Non-FTA	2018-19	2.14 Bcf/d
	Sub-total				**9.92 Bcf/d**
Awaiting FID	Sabine (T6)	Approved	Non-FTA	2021 +	0.6 Bcf/d
	Lake Charles (T1-T3)	Approved	Non-FTA	2021 +	2.1 Bcf/d
	Magnolia (T1-T4)	Approved	FTA	2021 +	1.0 Bcf/d
	Golden Pass	Approved	Non-FTA	2021 +	2.0 Bcf/d
	Sempra-Cameron (T4-T5)	Approved	Non-FTA	2021 +	1.4 Bcf/d
	Corpus Christi (T3)	Approved	Non-FTA	2021 +	1.4 Bcf/d
	Sub-total				**8.5 Bcf/d**
	Terminals (Proposed)				**19 Bcf/d**
	Terminals (Pre-Filing)				**4.75 Bcf/d**
	Grand Total				**42.17 Bcf/d**

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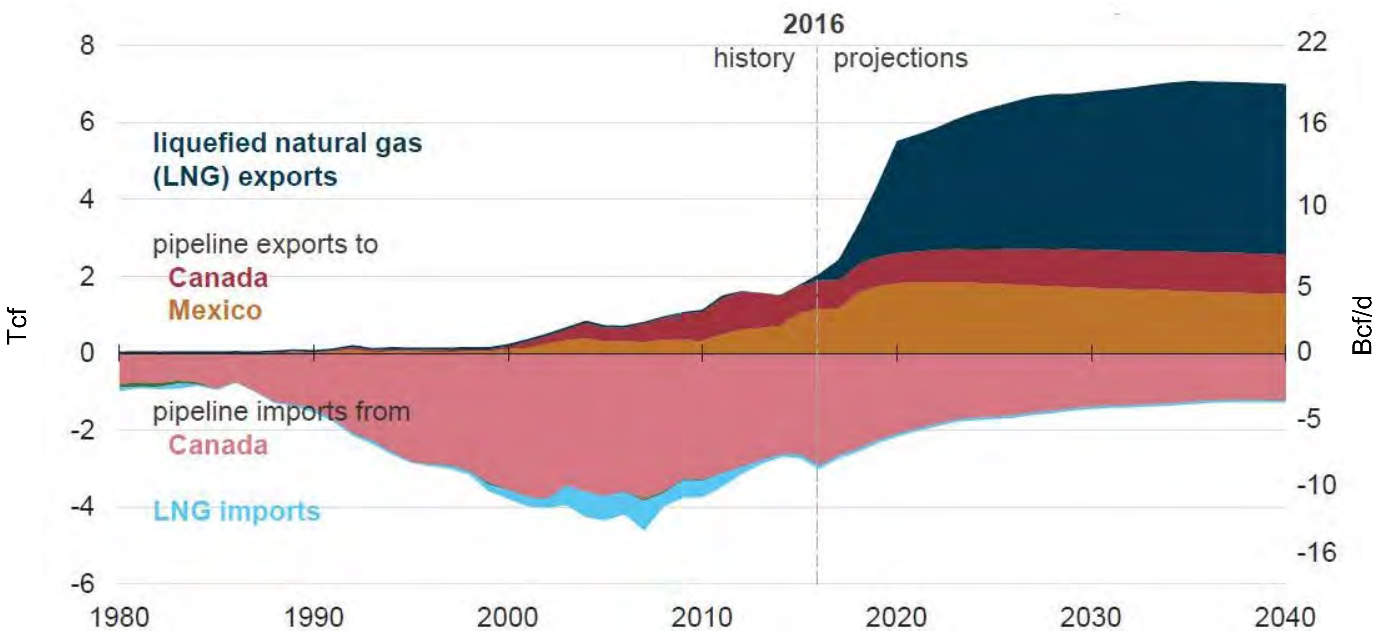
Gas Price Drivers – Net Pipeline Exports

- EIA projects that US transitions to net exporter of natural gas by 2020

Net Exports from USA (AEO 2017)



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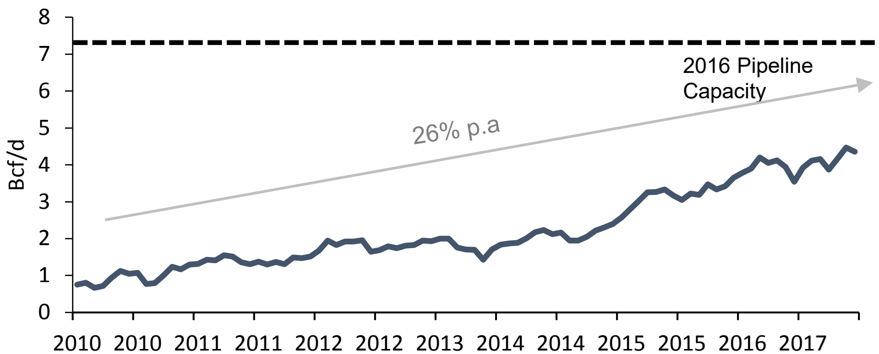
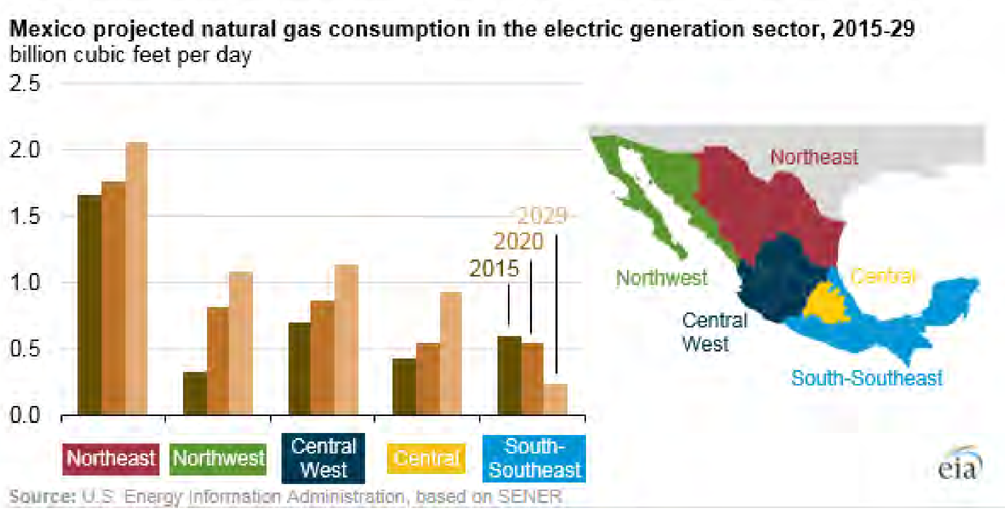
Gas Price Drivers – Net Pipeline Exports

Mexican exports have steadily risen over the last five years, and are expected to rise as electric sector demand grows while domestic production remains flat/declines

Net Exports to Mexico (2009 – 2017)





Pipeline	Online Year	Capacity (Bcf/d)
Tula - Villa de Reyes	2017	0.6
Sur de Texas - Tuxpan	2018	2.6
Tuxpan - Tula	2017	0.7
San Isidros - Samalayuca	2017	1.13
Comanche Trail Pipeline	2017	1.1
Trans-Pecos Pipeline	2017	1.3
Samalayuca - Sásabe	2018	0.5
La Laguna – Aguascalientes	2018	1.1
Nueces – Brownsville	2018	2.6

- Mexico's 2015-2019 gas development plan includes 12 new gas infrastructure projects, totaling over 3,200 miles of pipeline and 9 Bcf/d – as of July, 7 of the 12 projects have been awarded contracts
- Pipeline export capacity to Mexico is expected to double from current levels, to 14 Bcf/d, by 2018

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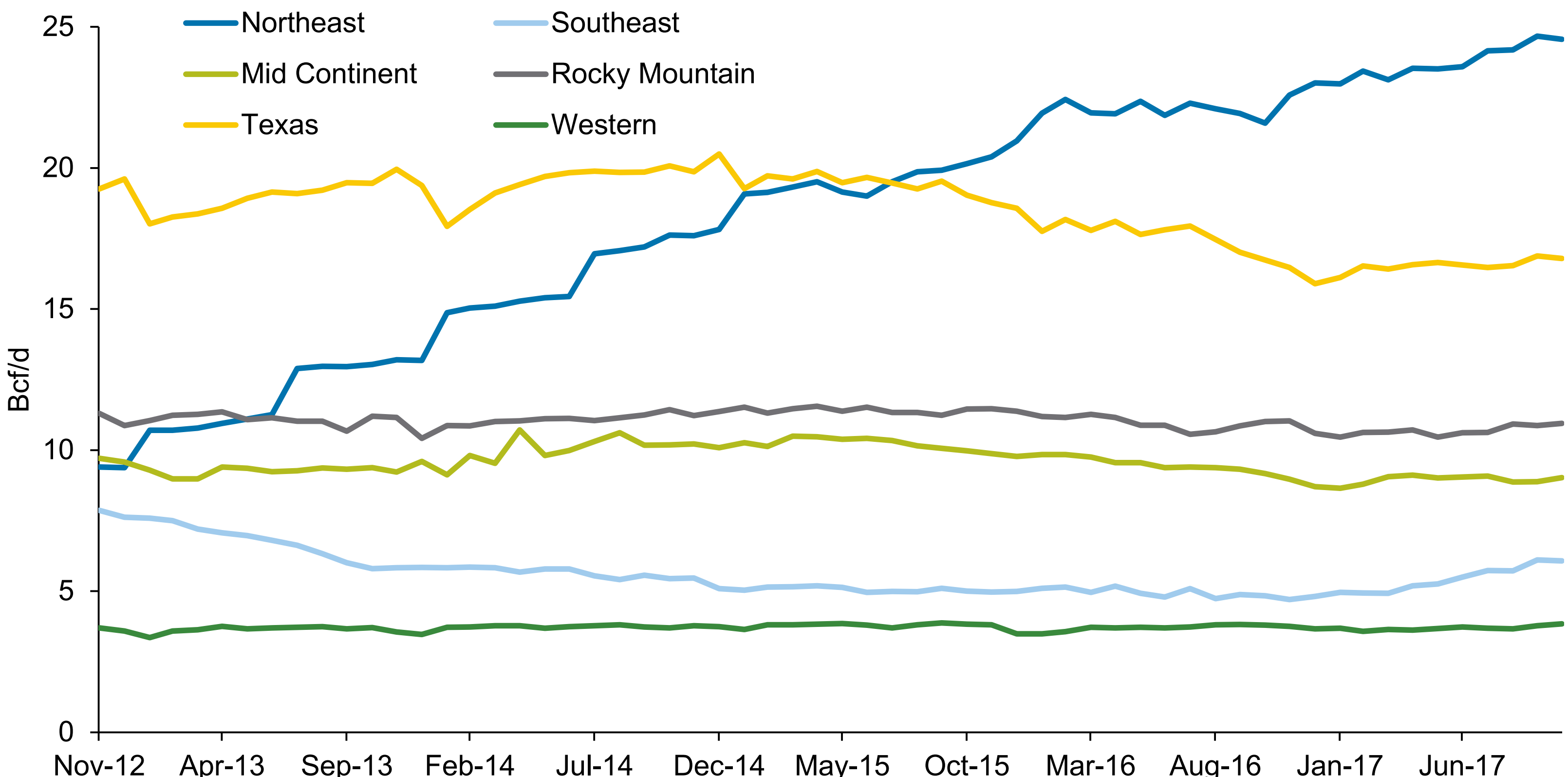
Key Natural Gas Market Trends – Changes in Flows

- The Northeast region has shifted from a net importer to a net exporter of natural gas, impacting regional prices and direction of gas flow across major pipelines
- These trends should continue as new large pipeline projects (Rover, Nexus, MVP and ACP) will provide long term export capacity for Marcellus/Utica production



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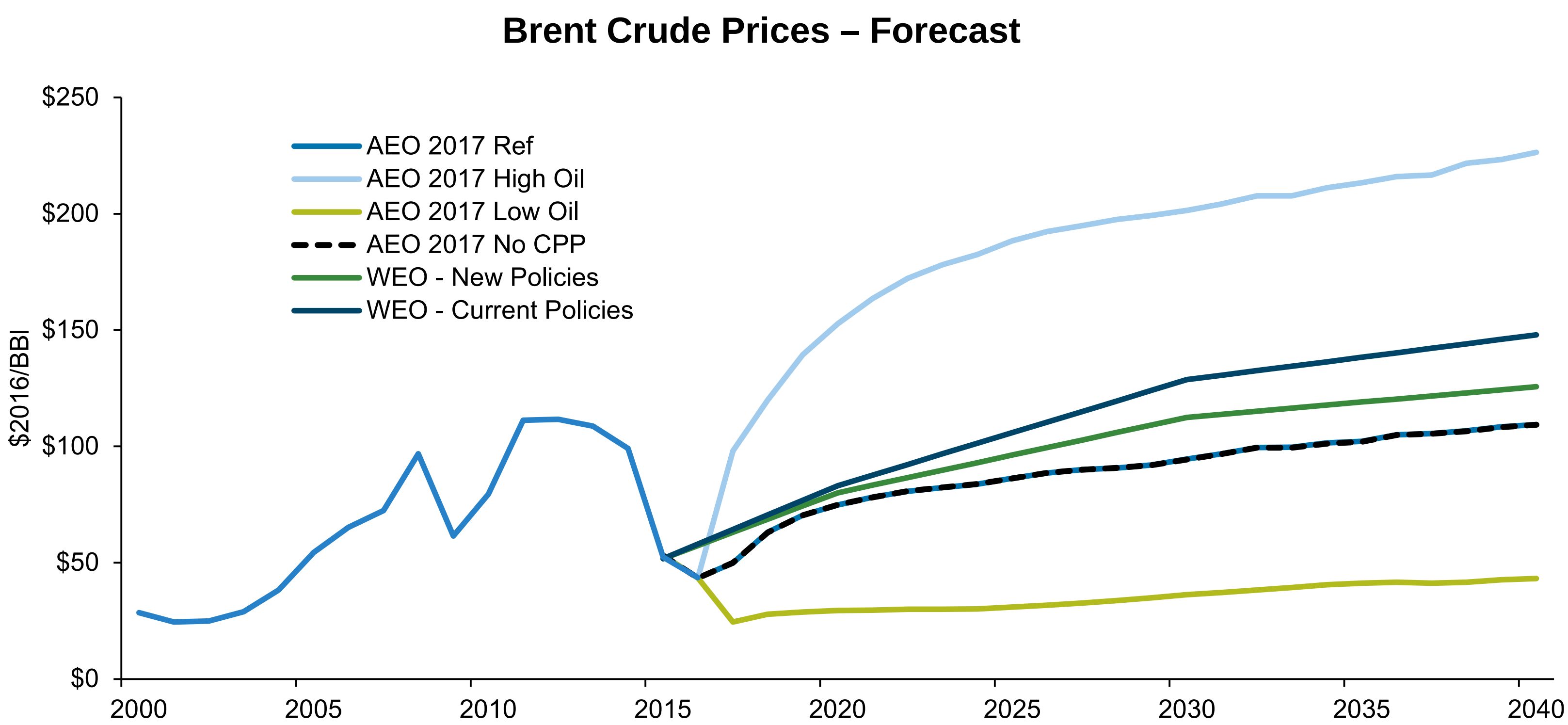
Gas Price Drivers – Oil / NGL Prices



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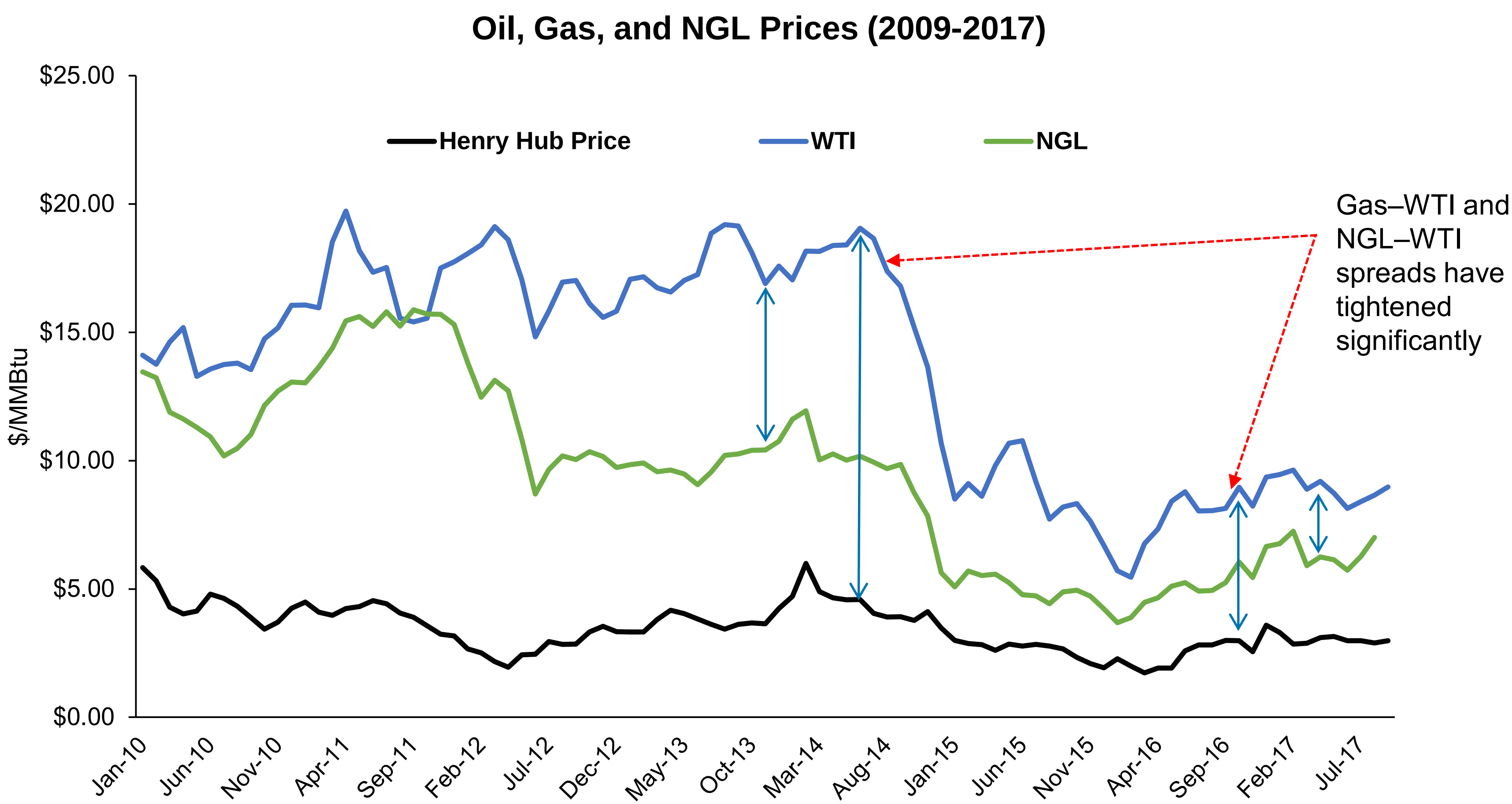
Gas Price Drivers – Oil / NGL Prices



Note: NGL Composite price encompasses NGL spot prices at Mont Belvieu with monthly volumes used to calculate weight.

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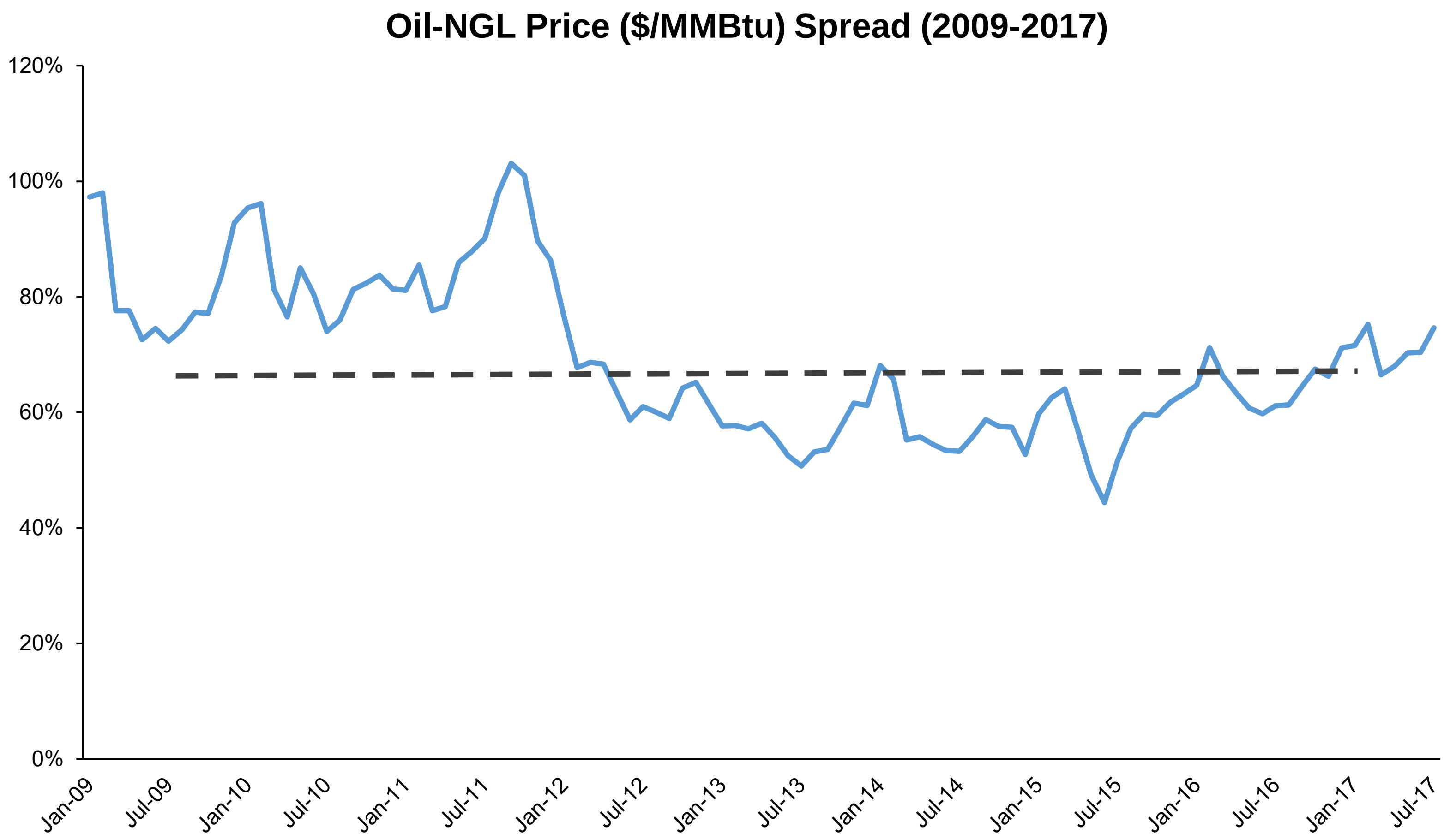
Gas Price Drivers – Oil / NGL Prices



Source: EIA

Methodology for Forecasting U.S. Steam Coal Prices

- Macroeconomic drivers:
  - U.S. market: Electric demand growth expected to be met through natural gas generation under expected gas prices and environmental requirements
  - International market: International demand for exports of steam and metallurgical coals from the U.S. grow modestly
- Microeconomic drivers:
  - Trends in coal mining costs for key supply regions
  - Production trends for key coal supply regions, incl. mine expansions and closures

Coal units in the model see a delivered coal price that incorporates commodity and transport costs

Delivered Unit Fuel Cost ($/ton) = Transportation Cost ($/ton) + Solved Mine Mouth Price ($/ton)

- CRA calibrates these inputs to reflect market developments that affect coal supply and transport costs

Coal Outlook Overview

- The price downturn from 2011-2016 reflects the 27% decline in U.S. coal production from 2014-2016

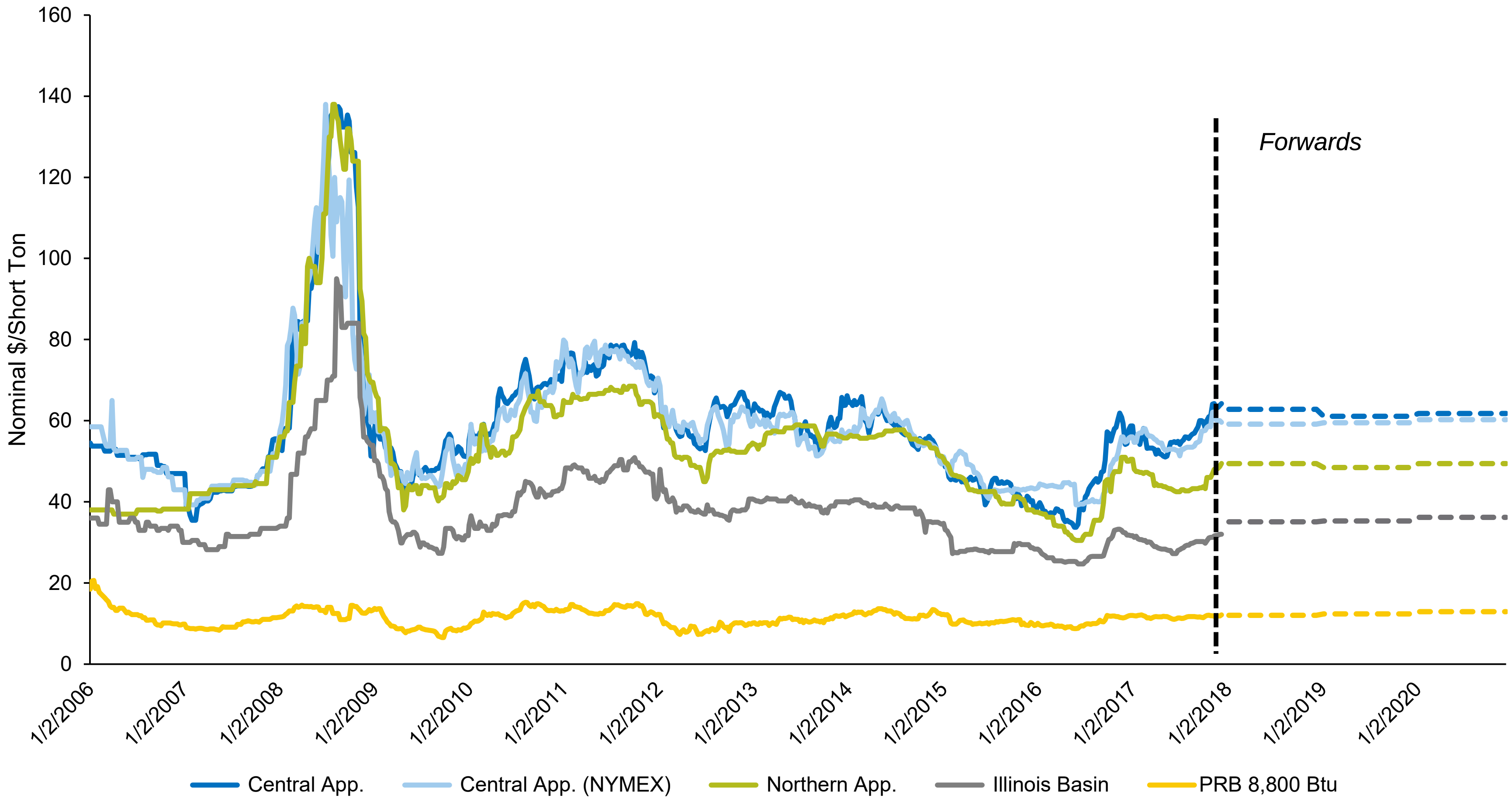
- Price increase caused by increased demand for U.S. coals exports, and a reduction in U.S. coal stockpiles

- 8-10% decline from 2017 levels by 2022, and a 25% decline by 2027, driven by CO_2 pricing from 2026

- In real terms, CRA projects prices to generally remain near current levels over the 2020-2040 period

- Due to high mining costs, Central Appalachian coal production is primarily targeted at the metallurgical coal market, and less than 30 million tons/year of this coal is currently used for electric generation within the U.S.

Historical Coal Prices vs. Forwards



Source: Coaldesk LLC broker sheet, 12/8/2017. Price for NAPP 3.5# coal is estimated based on published Coaldesk data.

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The U.S. electric sector makes up the bulk of domestic demand, and is expected to decrease its reliance on coal over the forecast period

- Coal's share of 2017 U.S. electric generation was about 32%
- Carbon pressure and sustained low gas prices are likely to drive a decline in coal's market share
- CRA's base case shows that coal generation accounts for approximately 24% of total generation from 2027-2035

- Low gas prices and growing renewable generation are expected to drive 30+ GW of coal-fired retirements over the 2018-2022 period
- After 2022, tightening environmental targets and new, highly efficient NGCC entry continue this trend; CRA expects 23-24% of electric demand to be met by coal-fired units by the late 2030s

International demand for U.S. coal expected to grow modestly, driven by emerging Asian economies and decommissioning of EU nuclear units

- CRA projects 52 million tons of metallurgical coal and 40 million tons of steam coal in 2017

- Europe is the primary market for U.S. exports of both metallurgical and steam coal. However, Asia is an important secondary market, especially for metallurgical coal.
- The global scarcity of metallurgical coal reserves may allow the U.S. to maintain its 2017-2018 production levels for these coals, despite being a relatively high-cost producer.

- Several coal terminals have been proposed in the Pacific Northwest, Millennium Bulk Terminal (MBT), the last currently active project of this type, was denied its water quality certification in September 2017
- CRA's preliminary case assumes that the MBT is not completed

U.S. Mining Costs by Coal Supply Region, 2015-2017

– Smaller average size of the coal mines and greater reserve depletion in CAPP leads to an increase in expected production costs, relative to other major U.S. coal supply regions

Cash Operating Costs Per Ton of Coal

(averages for 1Q-3Q of each year unless otherwise noted)

	YTD 2015	YTD 2016	YTD 2017	Nominal % Change 2015-2017
Central App				
Arch Coal (CAPP)	$54.25	$51.30	$61.11	**NM²**
Contura Energy (East)¹	$66.45	N/A	$72.35	**NM²**
Northern App				
Consol Coal Resources	$34.47	$30.03	$29.57	**-14.2%**
Illinois Basin				
Alliance Resource Partners (ILB EBITDA expense)	$31.67	$30.03	$25.67	**-18.9%**
Peabody Energy (Midwestern U.S.)	$33.46	$30.96	$32.23	**-3.7%**
Powder River Basin ("PRB")				
Arch Coal (PRB)	$10.69	$10.95	$10.45	**-2.2%**
Cloud Peak Energy	$9.81	$10.07	$9.68	**-1.3%**
Contura Energy (PRB)¹	$10.38	N/A	$10.02	**-3.5%**
Peabody Energy (PRB)	$9.97	$9.80	$9.57	**-4.0%**

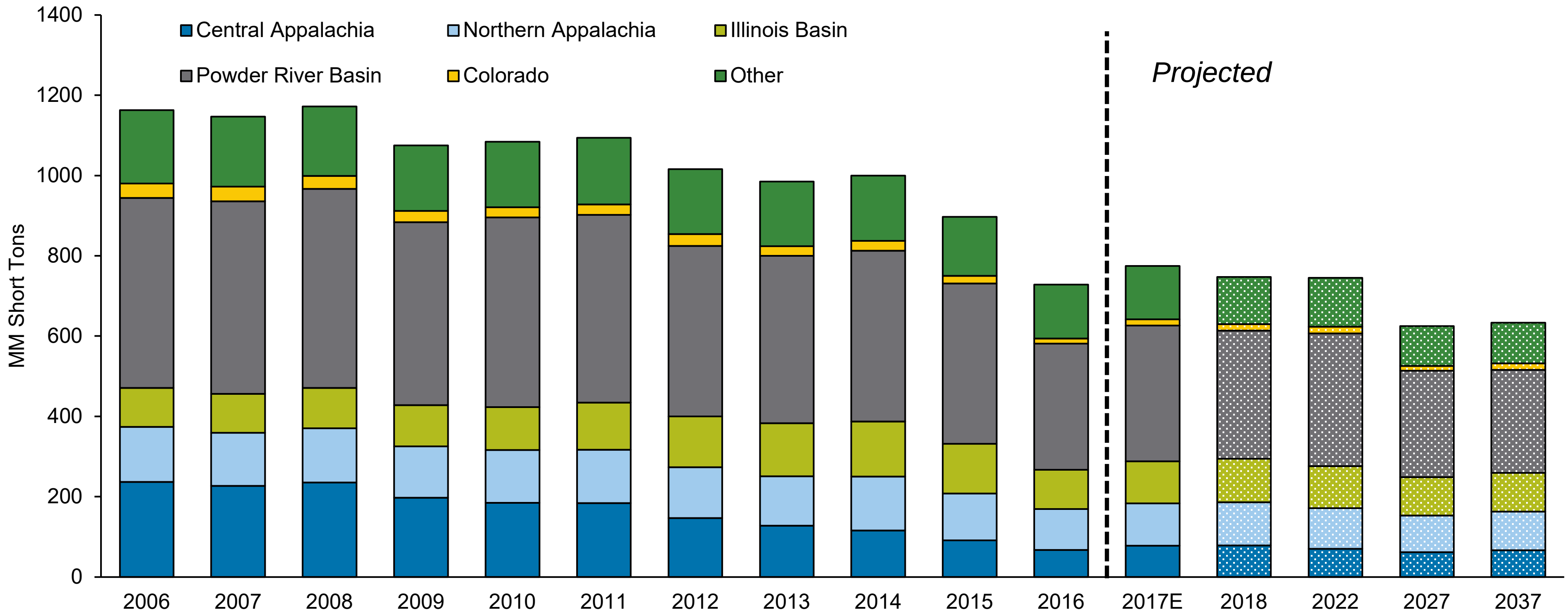
Source: Company financial reports.

Notes:

1. 2015 data is 1Q2015 only.

2. 2015-2017 mining cost comparisons for Central Appalachia are not meaningful due to increasing concentration on metallurgical coal production during this period.

U.S. Coal Production by Supply Region - 2006-2037

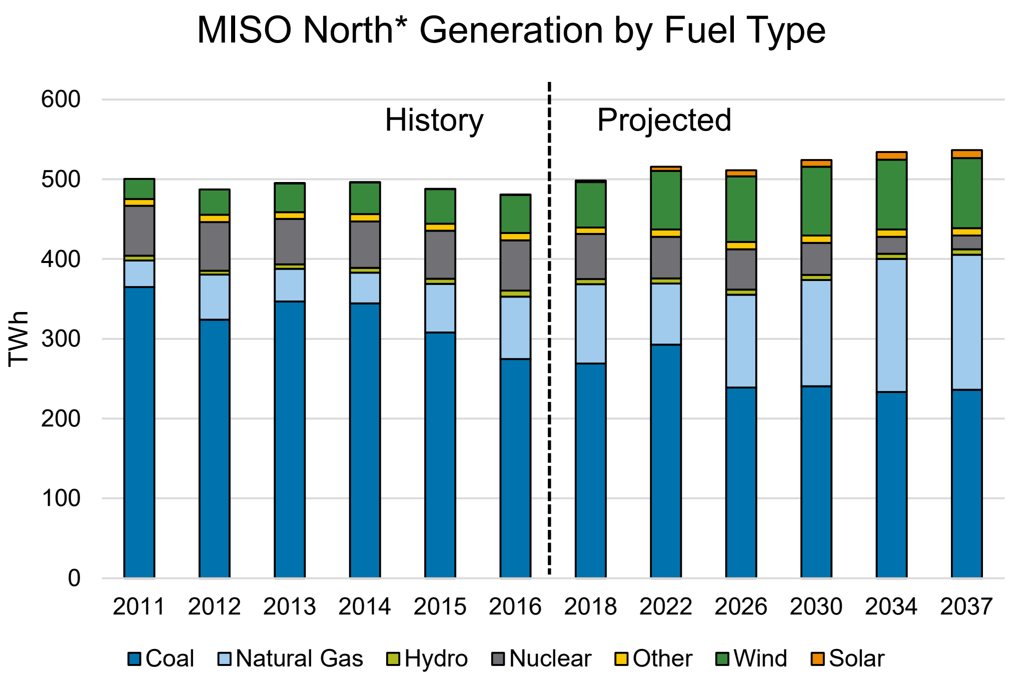


Net Change in Coal Production (MM Tons)	2006-2017	2017-2022	2022-2037
Central Appalachia	(159)	(8)	(3)
Northern Appalachia	(32)	(4)	(5)
Illinois Basin	8	0	(9)
Powder River Basin	(135)	(8)	(73)
Colorado	(20)	1	(1)
Other	(50)	(11)	(20)
Total	**(388)**	**(30)**	**(112)**

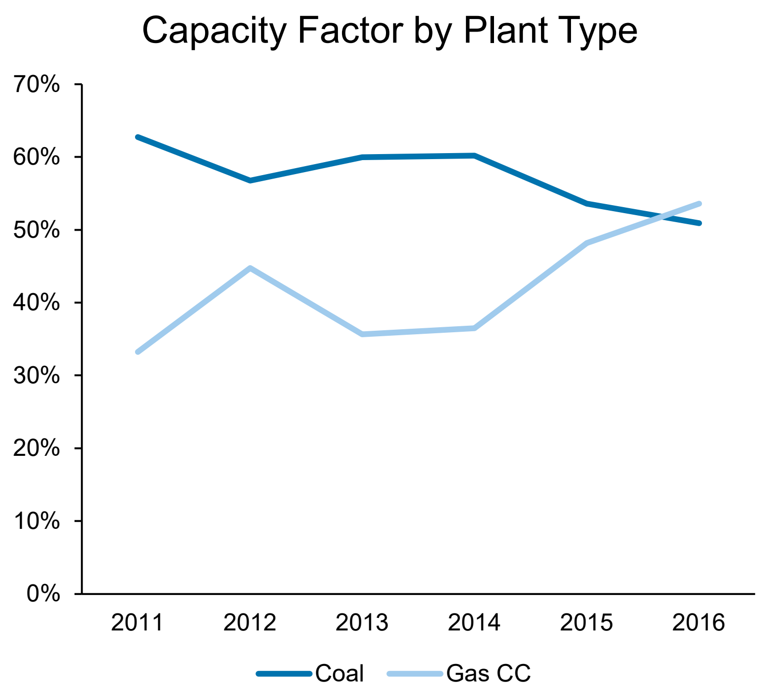
Sources: 2006-2016 data from U.S. Mine Safety and Health Administration (MSHA) and Energy Information Administration (EIA). 2017 and later data is estimated.

CRA Charles River Associates

Generation has shifted from coal to gas and wind in recent years



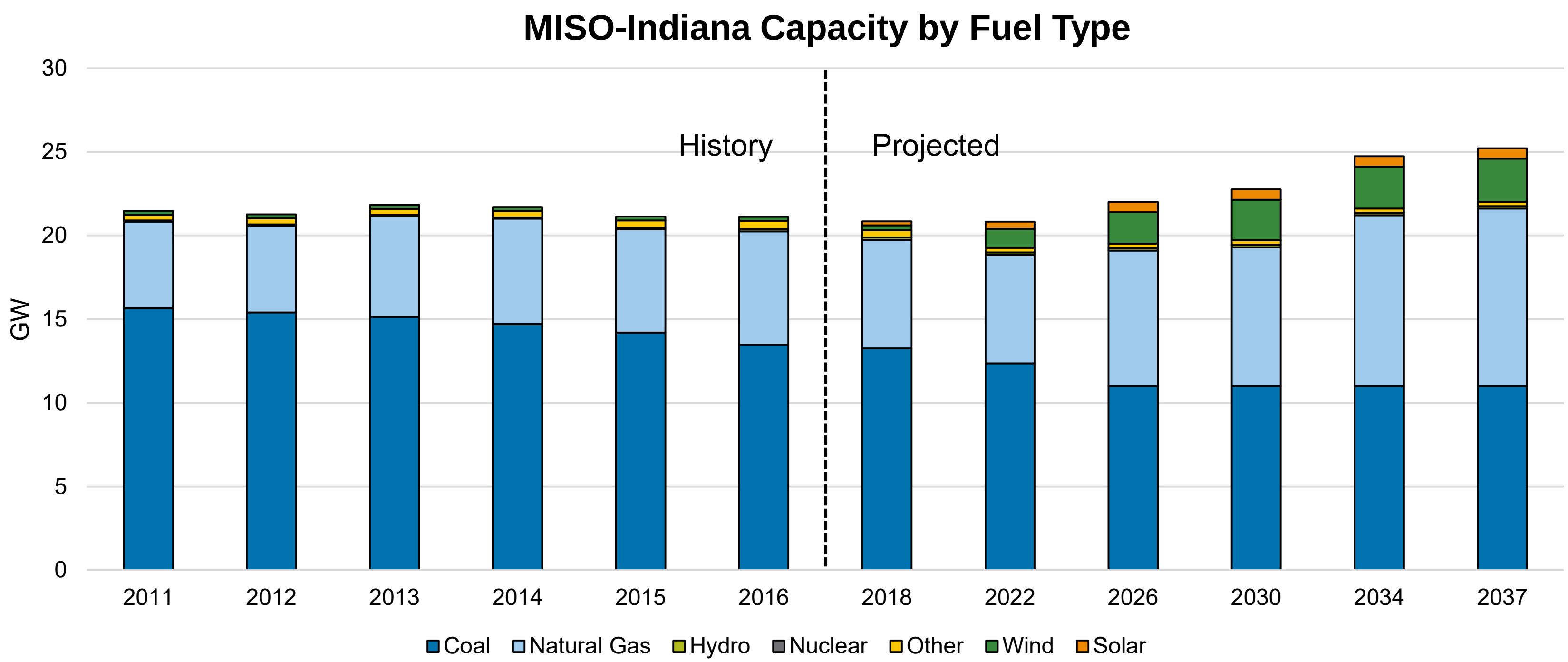
*MISO North includes LRZ 1-7



CRA Charles River Associates

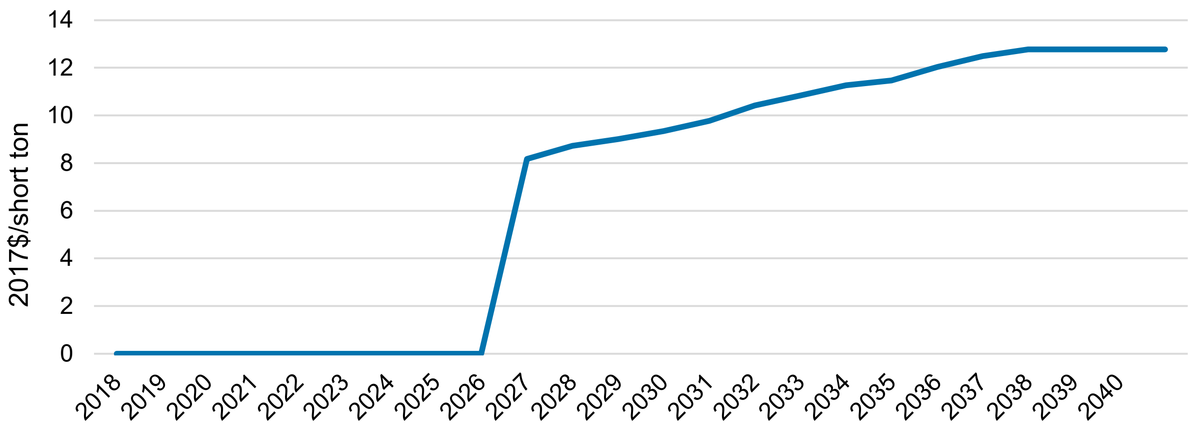
MISO-Indiana Zone

– For example: IPL Eagle Valley gas CC expected online in June 2018



Charles River Associates

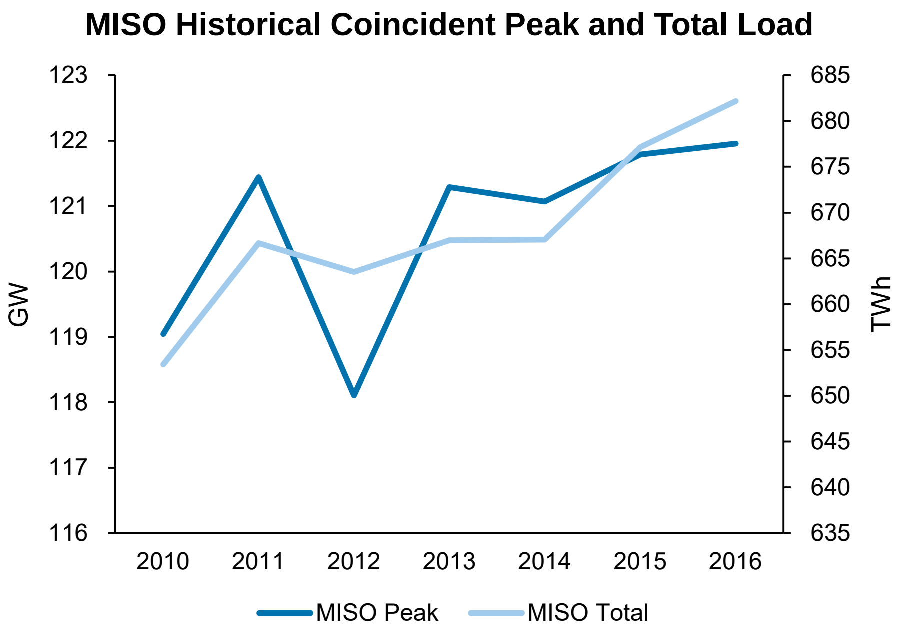
Environmental policy drivers influence shift in generation mix and power price forecast

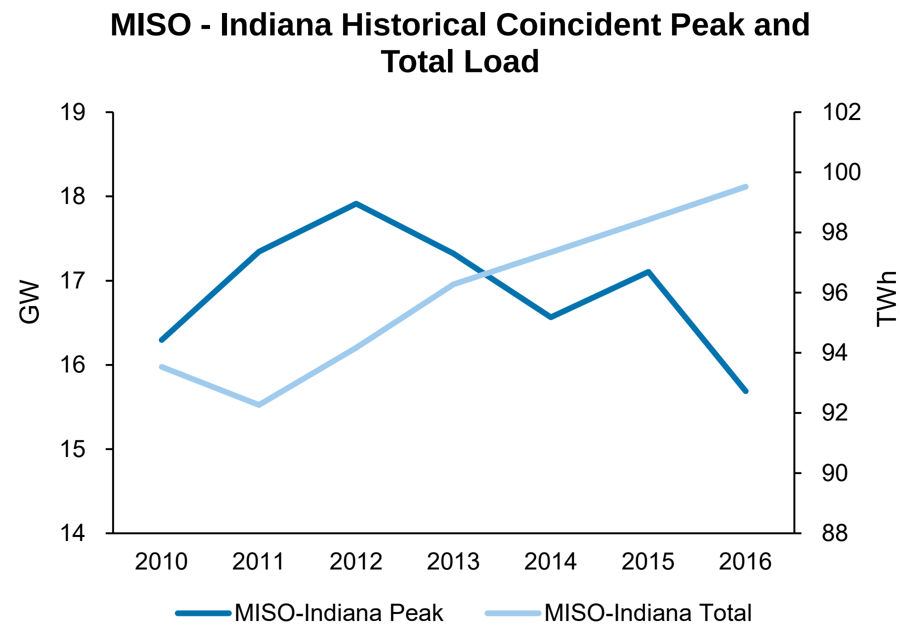


MISO RPS Targets

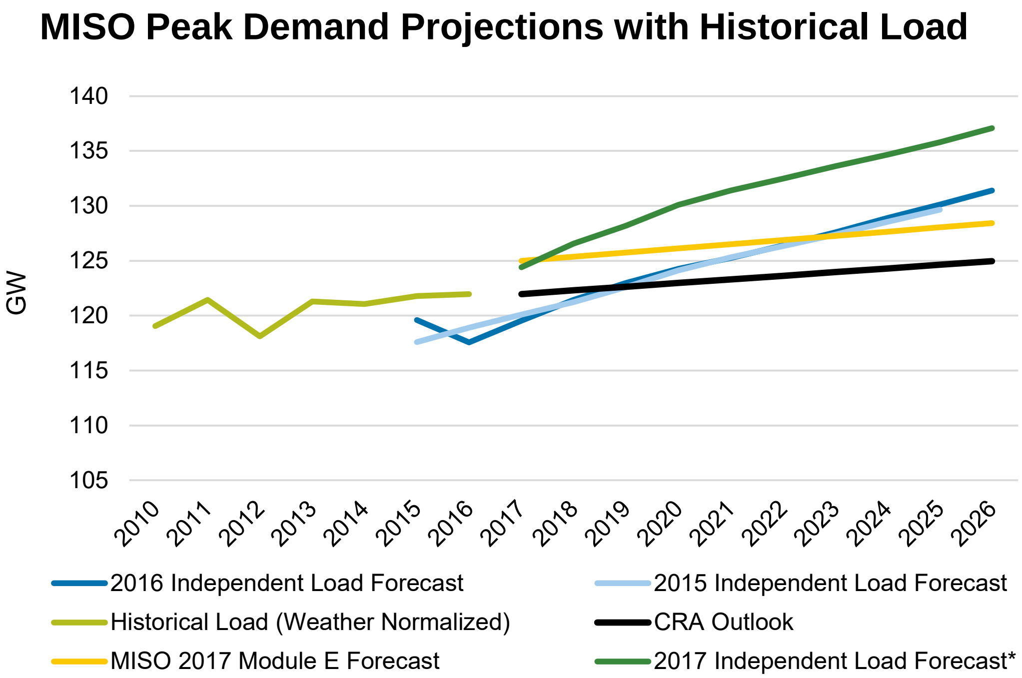
25% (IL, MN), 15% (MI, MO), 10% (IN, ND, WI), *None* (AR, MS, LA, IA)

Electricity demand growth in MISO has been relatively modest





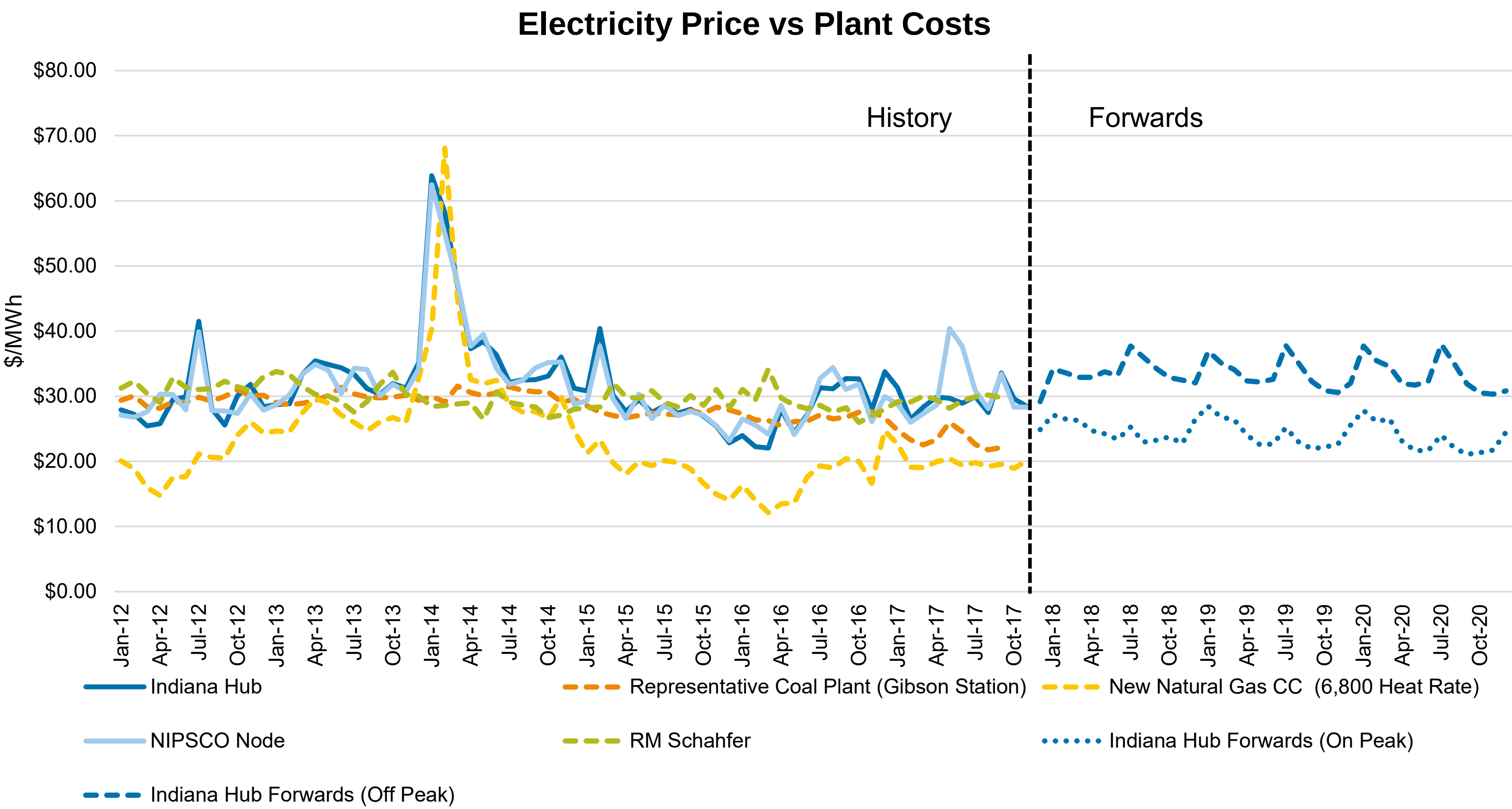
CRA expects modest growth in annual, peak demand



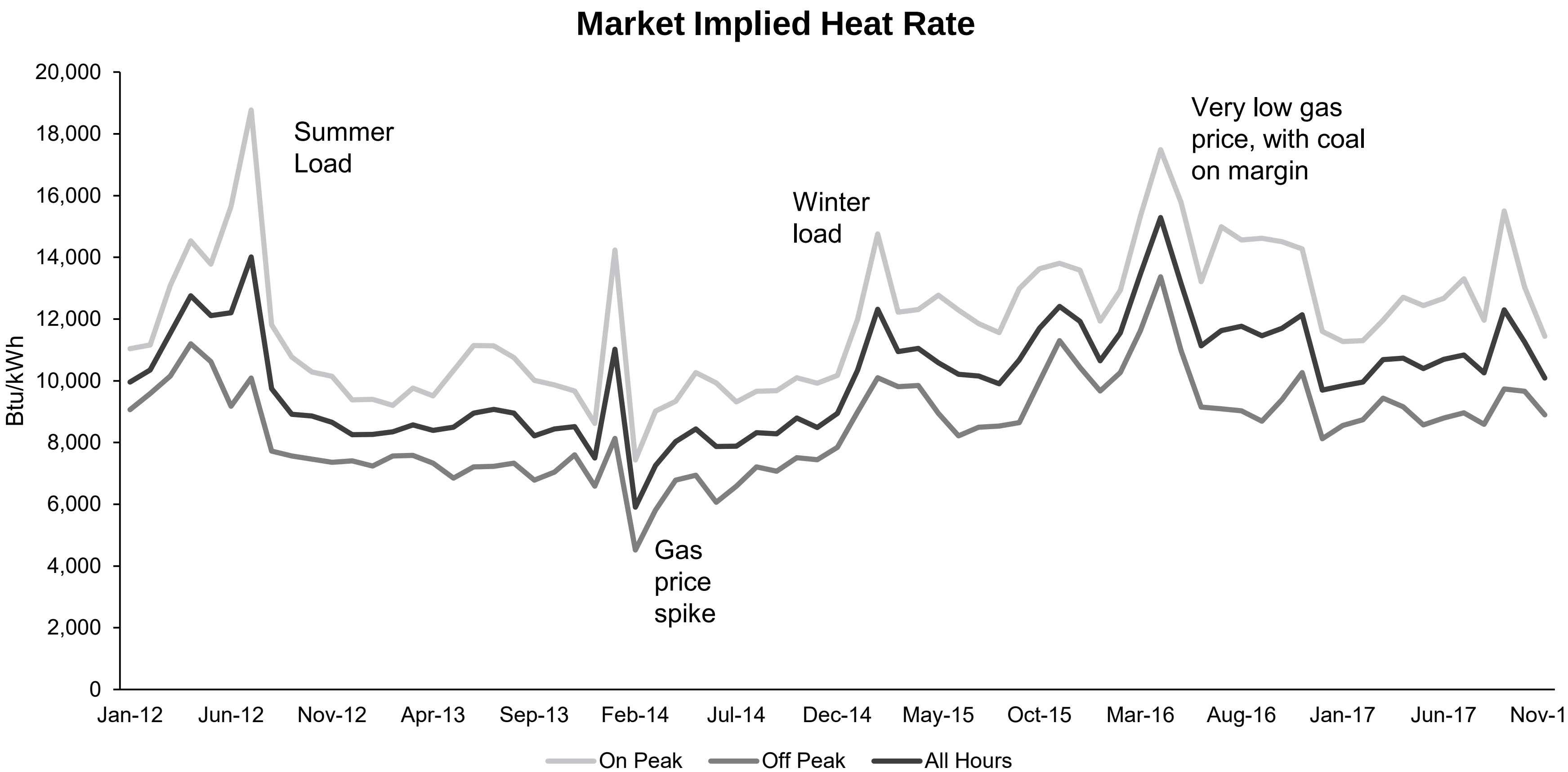
Peak Load Forecast	10-Year Summer Peak CAGR
2010-2016 Weather-Normalized	*0.40%*
2015 Independent Load Forecast	0.98%
2016 Independent Load Forecast	1.12%
2017 MISO Module E	0.27%
CRA Outlook	**0.24%**

*Note 2017 ILF Forecast does not include impact of DR and DG

MISO Energy Market Dynamics



Market heat rate is seasonal, with increases in recent years

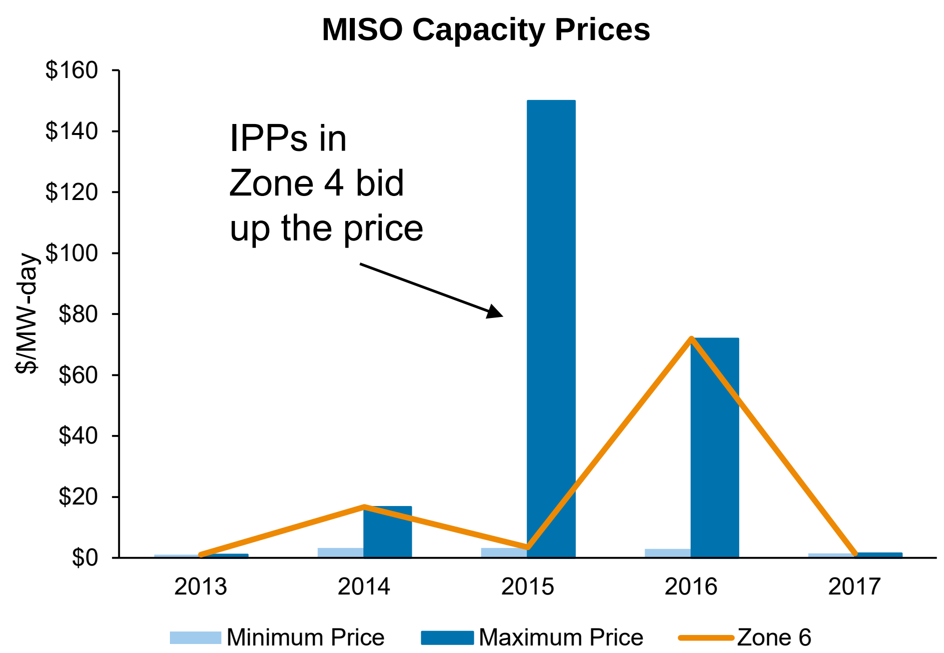


*Using Indiana Hub and RexEast Gas Price Index

CRA Charles River Associates

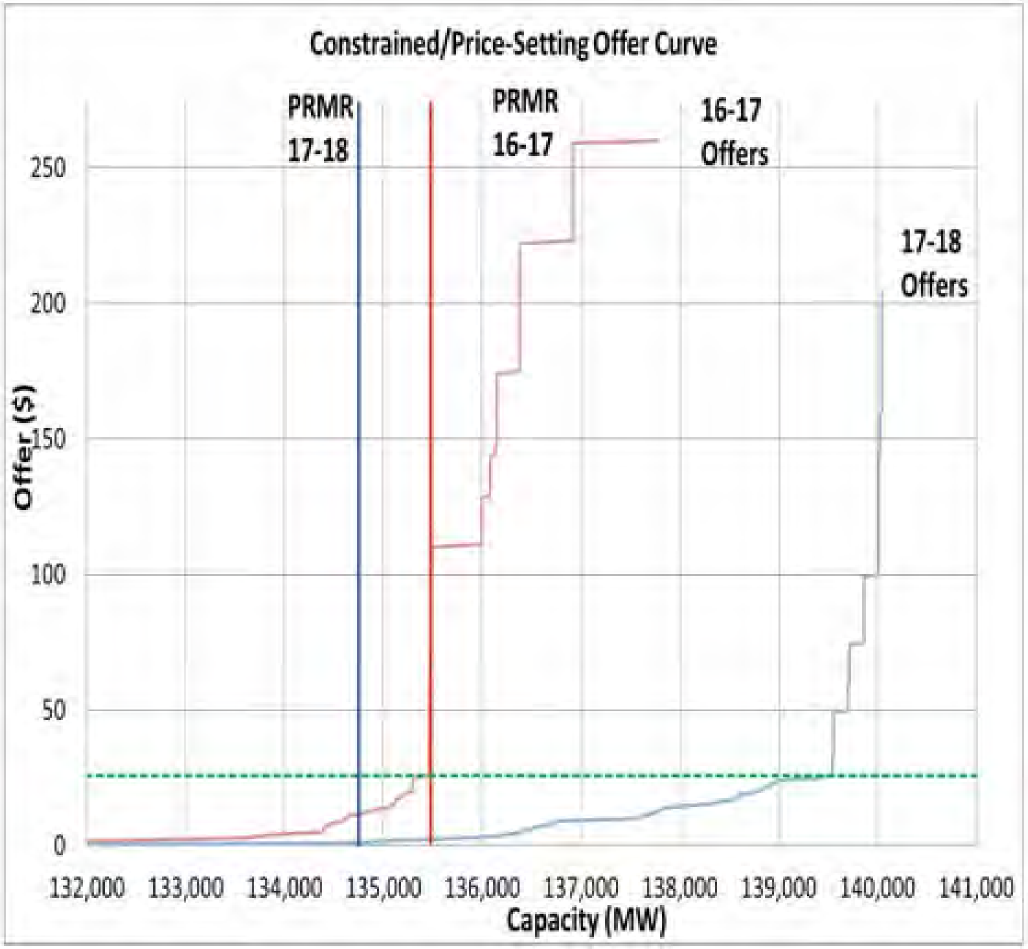
MISO Resource Adequacy and Capacity Market

- Vertical demand curve
- Prompt, rather than forward, market



Explaining the downward trend between 2016/17 and 2017/18 auctions

- More renewables
- More behind-the-meter
- More DR/EE



Source: MISO

CRA Charles River Associates

Acronym	Definition
CRA	Charles River Associates (IRP Consultant)
NEEM	North American Electricity and Environment Model
NGF	Natural gas sector market model
ELG	Effluent Limitation Guidelines
CCR	Coal Combustion Residuals
NPVRR	Net Present Value of Revenue Requirement
LNG	Liquefied Natural Gas
MISO	Midcontinent Independent System Operator
CONE	Cost of New Entry
EIA	Energy Information Administration
AEO	Annual Energy Outlook (from EIA)

INTEGRATED RESOURCE PLANNING

ACRONYMS

ACRONYMS

A

AC	Alternating Current
ACEEE	American Council for an Energy Efficient Economy
ACESA	American Clean Energy and Security Act of 2009
ACI	Activated Carbon Injection
ACLM	Air Conditioning Load Management
	Annual Energy Outlook (from EIA)
AFUDC	Allowance for Funds used During Construction
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ARRA	American Recovery and Reinvestment Act of 2009
ASM	Ancillary Services Market
ATC	Available Transfer Capability or Capacity

B

BA	Balancing Authority or Balancing Area
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BESS	Battery Energy Storage System

C

C&I	Commercial and Industrial
CAA	Clean Air Act – EPA issued initial rules in 1970
CAAA	Clean Air Act Amendments – 1990
CAGR	Compound Annual Growth Rate
CAIR	Clean Air Interstate Rule
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals – EPA issued rules June 2010
CCS	Carbon Capture and Sequestration or Carbon Capture and Storage
CCT	Clean Coal Technology
CDD	Cooling Degree Days
CFL	Compact Fluorescent Lighting
CHP	Combined Heat & Power
CIP	Critical Infrastructure Protection
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity

CPP	Clean Power Plan
CPW	Cumulative Present Worth
CRA	Charles River Associates (IRP Consultant)
CVR	Conservation Voltage Reduction
CSPAR	Cross State Air Pollution Rule – EPA issued rules July 2011
CT	Combustion Turbine

D

DA	Distribution Automation, or Day Ahead Scheduling
DG	Distributed Generation
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand-Side Management

E

ECS	Energy Control System
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EFORd	Equivalent Forced Outage Rate demand
EIA	Energy Information Administration of the U.S. Department of Energy
ELG	National Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
EV	Electric Vehicles

F

FAC	Fuel Adjustment Clause
FEED	Front End Engineering Design
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization

G

GDP	Gross Domestic Product
GHG	Green House Gas

H

HAP	Hazardous Air Pollutant
HDD	Heating Degree Days

Hg	Mercury
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning

I

ICAP	Installed Capacity
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated Gas Combined Cycle
IMM	Independent Market Monitor
IRP	Integrated Resource Planning
ISO	Independent System Operator
IURC	Indiana Utility Regulatory Commission

K

kWh	Kilowatt hour

J

JCSP	Joint Coordinated System Planning

L

LAER	Lowest Achievable Emission Rate
LMR	Load Modifying Resource
LMP	Locational Marginal Pricing
LNB	Low NO_x Burner
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LSE	Load Serving Entity

M

MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MFDI	Multi Family Direct Install
MISO	Midcontinent Independent System Operator
MPS	Market Potential Study
MSA	Metropolitan Statistical Area
MTEP	Midcontinent ISO Transmission Expansion Planning
MVA	Mega Volt Ampere, Mega Volt Amplifier, or Multivariate Analysis
MVP	Multi-Value Projects (transmission for both reliability and economic benefits)

MW	Megawatt

N

NAAQS	National Ambient Air Quality Standard – EPA issued rules January 2013
NEEM	North American Electricity and Environmental Model
NERC	North American Electric Reliability Corporation (formerly Council)
NG	Natural Gas
NGF	Natural Gas Sector Market Model
NID	Net Internal Demand
NIST	National Institute of Standards and Technology
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value of Revenue Requirements
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange

O

O&M	Operations and Maintenance

P

PC	Pulverized Coal
PCT	Participant Cost Test (see EM&V)
PHEV	Plug-In Hybrid Electric Vehicle
PJM	PJM LLC (Regional Transmission Organization)
$PM_{2.5}$	Particulate Matter that is 2.5 micrometers in diameter or smaller
PPA	Purchase Power Agreement
PRMucap	Planning Reserve Margin on UCAP (Unforced Capacity)
PV	Photovoltaic
PVRR	Present Value Revenue Requirement

R

RCRA	Resource Conservation and Recovery Act (coal ash disposal regulations)
REC	Renewable Energy Credit
REP	Renewable Energy Production
RES	Renewable Energy Standards
RFC	Reliability First Corporation
RFP	Request for Proposals
RIM	Rate Payer Impact Measure (see EM&V)

RRaR	Revenue Requirement at Risk
RTO	Regional Transmission Organization (Independent System Operator)

S

SAIFI	System Average Interruption Frequency Index (Reliability-see also SAIDI and CAIDI)
SCADA	Supervisory Control and Data Acquisition
SCPC	Super Critical Pulverized Coal
SCR	Selective Catalytic Reduction (pollution control)
SIP	State Implementation Plan (environmental)
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SREC	Solar Renewable Energy Credit

T

TBEL	Technology Based Effluent Limits
TOU	Time of Use
TRC	Total Resource Cost Test (see EM&V)
TW	Terawatt

U

UCAP	Unforced Capacity (the amount of Installed Capacity that is actually available)
UCT	Utility Cost Test (see EM&V)
Ultra SCPC	Ultra Super Critical Pulverized Coal

V

VAR	Volt Ampere Reactive, Variance, or Value at Risk

W

WQBEL	Water Quality Based Effluent Limits

Northern Indiana Public Service Company
2018 Integrated Resource Planning
Public Advisory Meeting #1
SUMMARY

March 23, 2018

Welcome and Introductions

Alison Becker opened the meeting by asking participants in the room and on the telephone to introduce themselves. She then introduced Violet Sistovaris.

Overview of Public Advisory Process
Violet Sistovaris, Executive Vice President, NiSource and President, NIPSCO

Ms. Sistovaris began by welcoming participants and explaining NIPSCO's decision to update its Integrated Resource Plan ("IRP") and the importance of stakeholders to that process. She continued with a safety message about severe weather preparedness and discussed the purposes of the meeting and reviewed the agenda. Ms. Sistovaris then provided an overview of NiSource and NIPSCO and a roadmap for the Stakeholder Engagement process and an overview of the public advisory process. She noted that NIPSCO will have a total of five public advisory meetings, with four of them being in person and the fifth as a webinar.

Why a 2018 IRP Update and Improvements from 2016
Dan Douglas, Vice President, Corporate Strategy and Development

Mr. Douglas thanked participants for attending. He explained the need for an update to NIPSCO's 2016 IRP, noting that the 2016 IRP Preferred Plan created a need for additional capacity. He provided an overview of the 2016 Preferred Plan and discussed the drivers and rationale for the 2018 update. Specifically, NIPSCO is doing the update now to preserve its ability to fully consider all resource options to address the capacity need. For example, a combined cycle gas turbine ("CCGT") takes several years to build. In order to have it online by the time the capacity is required in 2023, NIPSCO needs to make decisions this year. The IRP update is crucial to that process.

After providing information on why the 2018 update is required, Mr. Douglas reviewed the lessons learned from the 2016 IRP process. He provided information on NIPSCO's improvement plan in several areas, including commodity price forecasts, scenarios and sensitivities, risk modeling, capital costs assumptions, demand side management ("DSM") modeling and the Preferred Plan and scorecard.

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

- What do you think of recent tariffs that will affect solar equipment coming from other countries?
  - Solar costs have been volatile and are difficult to plan for. We have tried to take into account all known factors including tax incentives, expert cost forecasts and supply and demand forecasts.
- There are a number of concerns related to the resource(s) that may be selected as well as the short notice related to this update. It will be important to have access to the modeling early in the process. Generally, there is a concern with the timing of the update.
  - NIPSCO recognizes the extra work the update creates for stakeholders and apologizes for that. However, the Company finds it to be the right thing for the customers. Mr. Douglas also noted that it was encouraging to see so many stakeholders in attendance and that NIPSCO is pleased with the level of engagement in the process. Finally, he noted that NIPSCO has started the Public Advisory process earlier than in 2016 and will continue to look for ways to engage stakeholders.
- There was discussion about the request for proposal ("RFP") process that will be upcoming related to the additional capacity. There was a question about if the process would be opened up for stakeholder input. In addition, there was a question about the formal process related to the IRP. When will NIPSCO submit, when will comments be due, etc.?
  - The intention is to facilitate the processes for stakeholder input, both formal and informal. There was discussion on how this process would fit with a filing related to a certificate of public convenience and necessity ("CPCN") if a CCGT were selected and Mr. Douglas noted that a CCGT is an example of a technology that has the longest lead time. There is no bias for any specific technology and the data in the IRP (and received from the RFP) will be the driver of the decision making.
- Expression of appreciation for five meetings, but request for other ways to solicit feedback. This could include online comments, etc.
  - NIPSCO is happy to discuss alternative ways of soliciting feedback.
- The evaluation will be on a unit-by-unit basis?
  - Yes. NIPSCO is grouping Units 14 and 15 and Units 17 and 18 together.
- Sounds as though NIPSCO is committing to reevaluating the retirement of Units 17 and 18?
  - Yes.
- How will the metrics gathered be used and weighted? If they are not weighted, are they not all treated as equal?
  - It will be important to have a discussion around metrics, but it is difficult to make those determinations without the data. It is important to look at environmental attributes, costs to customers, etc. Ultimately, NIPSCO

    - owns the Preferred Plan decision and will base that decision on stakeholder feedback and the scorecard criteria, not a formulaic answer given by weightings of the criteria. Once the decision has been made, NIPSCO understands the need to discuss it with stakeholders.
- At a high level, the IRP should inform the RFP, which should then inform a CPCN. It would be good to understand this process.
    - NIPSCO recognizes this process is unique, but given the need for capacity, NIPSCO's IRP will be enhanced by the real data that comes from an RFP. The decision was made to go through an RFP as quickly as possible and use those cost results to inform the IRP. Once again, although the timing is built on the long lead-time for a CCGT, no decisions have been made.
- The Xcel Energy RFP was renewable focused. Need to have sufficient time to discuss the RFP.
    - Today's discussion is meant to introduce the RFP and NIPSCO's planned process. However, there will be additional time for input as part of that process. The goal of the RFP is to make sure it is broad enough to capture a variety of resources without being overly complex. NIPSCO is open to ideas for how to make sure it is an "all source" RFP.

Modeling Approach
Jim McMahon and Pat Augustine, Charles River Associates ("CRA")

Messrs. McMahon and Augustine provided information related to NIPSCO's modeling approach for the IRP. The discussion started by reviewing the key areas where CRA is providing support for the 2018 IRP Update: fundamental commodity price forecasting and integrated resource planning. Mr. McMahon then reviewed the resource planning approach and models and tools to be used in the 2018 IRP Update. Regarding forecasting, CRA noted it has a Natural Gas Price Fundamentals Model ("NGF Model") and provided an overview of that as well as a discussion related to macro-level market analysis using CRA's North American Electricity and Environment Market ("NEEM") Model. There was also discussion around the use of Aurora to provide regional power market and portfolio analysis and how the PERFORM model will be utilized to perform net present value revenue requirement ("NPVRR") calculations. Charles River Associates discussed the modeling of uncertainty and also how it identifies risks and uncertainties.

NIPSCO is using the same "scenarios" for the 2018 IRP Update: Base, Aggressive Environmental Regulation, Challenged Economy, and Booming Economy & Abundant Natural Gas. In addition to discussing the scenario framework, CRA provided a table detailing the key input variables for each of the scenarios. As the next step, CRA explained how stochastics will be used in the analysis and how the use of stochastics provides improved coverage of uncertainty. Mr. Augustine finished with a discussion on the distribution of outcomes and how portfolios can be compared on a cost and risk basis.

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

- DSM is included on Slide 15, but not on Slide 16. What will be the basis of the DSM screening?
    - The basic information will come from GDS Associates, the company selected by NIPSCO to perform the update to the projected DSM savings. Slide 16 shows how CRA will incorporate that projected savings, as DSM is an input to the Aurora model.
- The extraction of natural gas produces more greenhouse gas. Does the model capture that?
    - The model does not explicitly capture greenhouse gas emissions from natural gas extraction. A final greenhouse gas emission number associated with gas consumption can be determined through reverse engineering, but it is not an input into the IRP modeling.
- Does the model incorporate the idea of an option value in terms of uncertain technologies?
    - Yes, it is represented explicitly in the modeling and that will become clearer when the results are released.
- Do you have a technique to determine historical accuracy?
    - There are ways. CRA did a validation process against the 2016 IRP, but it is not truly back-casting. There is a regular exercise in the Aurora model for back-casting capacity factors, market prices, and generation by fuel type, which is based on history. Stochastics also assist with incorporating the randomness inherent in the market.
- Will stakeholders be able to suggest scenarios?
    - Yes, it is encouraged. Stakeholder scenarios will help NIPSCO fine tune its analysis.
- Extraction emissions will not be included, correct?
    - That is correct. It may be something NIPSCO and CRA could have together by the September meeting. Right now, NIPSCO only looks at things as the United States Environmental Protection Agency does. In other words, emissions on the customer-side are included, but nothing is accounted for prior to its use by NIPSCO.
- Who determines the base case?
    - NIPSCO noted there would be additional discussion in the afternoon and that NIPSCO is looking at CRA for input as well as from the stakeholders. However, the ultimate decision is NIPSCO's.
- Is NIPSCO continuing to assume an effluent limitation guidelines ("ELG") requirement?
    - Yes, one of the scenarios will consider a less stringent ELG requirement, but the Base Case will be with the ELG requirement as it stands today.
- There does not appear to be a Base Case run with different fuel price scenarios?
    - This is an example of how the use of stochastics provides a wide range of information. NIPSCO is willing to discuss scenarios more in-depth to ensure thoughts are being captured.

- The point is that scenarios are a set of integrated and interrelated assumptions. How do you tease out and get at low and high gas prices? Can you get at that through the stochastic modeling process?
  - o Scenarios establish potential states-of-the-world for high and low gas prices based on fundamental factors. In addition, stochastic modeling incorporates a broader range of potential outcomes, but it is still difficult to tease out the underlying reasons for specific price movements in certain variables such as gas prices. The scenario process is looking to capture themes NIPSCO finds to be reasonable, while the stochastics add a broader range of uncertainty.
- Regarding Base Case question in carbon pricing, there is a concern of the definition of the scenario. Want to have a discussion before locked in.
  - o NIPSCO welcomes the feedback.
- One of your options is purchasing capacity for a period of time. Will you get into the level of detail of considering what you see with other Midwest generating units?
  - o Yes. (It was noted NIPSCO hoped to address that more in depth in the afternoon session.)

Long-Term Energy and Demand Forecast
Mahamadou Bikienga, Lead Forecasting Analyst

Mr. Bikienga provided an overview of the load forecasting process noting that it was much the same as the 2016 process. The forecast is updated annually and the models are updated annually, or as needed. The forecast provides a 23 year outlook. There is a residential, commercial, and industrial process. In addition, for “other energy” (public authority, railroad, company use and street lighting), NIPSCO has a specific process. Mr. Bikienga outlined the peak demand forecast process and then provided NIPSCO’s Total Energy and Peak Demand projections for the period of 2018-2039. The compound annual growth rate (“CAGR”) for the period is 0.33% for NIPSCO total energy; 0.41% for NIPSCO System Peak; and 0.44% for Midcontinent Independent System Operator (“MISO”) Coincident Peak.

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

- What is the relationship between income and the customer forecast? Is the assumption that the higher the income, the higher the usage?
  - o A higher income level may mean more appliances, more usage in the household, and less sensitivity to the thermostat setting. The core assumption is higher income, higher usage.
- Total energy use per customer is declining, but the charts indicate load growth is increasing?
  - o Overall, it is a very small difference. There is slow growth, with rates similar to the last IRP. Industrial growth is actually projected to be flat. This data is available, and, with the appropriate non-disclosure agreement in place, this information can be shared.

- Should there be scenarios for the load forecast? How can electric vehicles be incorporated into the forecast?
    - o NIPSCO has considered electric vehicles in the past, but they have very little impact. To the extent the IRP team needs additional information for scenarios, Load Forecasting can supply that.
- Do the models take into account the increase in solar usage? For example, Arcelor might go to all solar. Do you have contractual agreements with companies to make sure they will do what they say they will do?
    - o When forecasting for industrial usage, information is provided by the largest customers and that assists with the forecasting process.
    - o NIPSCO considers the loss of industrial load as part of the IRP process. The Company is taking into account scenarios of high and low industrial energy usages in forecasting the industrial energy volumes.

Capital Costs Assumptions for Future Resources
Fred Gomos, Manager, Corporate Strategy and Pat Augustine, CRA

Mr. Gomos provided an overview of NIPSCO's approach for capital costs assumptions in the 2018 IRP. He cited 3 important aspects of developing capital costs in the 2018 IRP, namely, moving away from proprietary, single point estimates, and utilizing publicly available data sources and using data from the RFP to collapse the uncertainty in developing capital cost estimates. Mr. Gomos noted that step one is the development of initial portfolios; step two is the evaluation of those portfolios across scenarios and stochastics; and the final step is integrating the portfolios into the IRP. He then provided an update on the data sources to be used in the 2018 update, which are based on more publicly available data than in previous IRP processes. The current capital costs estimates for gas, coal, and nuclear technologies and for renewables, storage, and other technologies were reviewed, with a note that these would continue to be refined.

The capital cost projections for CCGT, wind, solar photovoltaics, and storage (lithium-ion 4 hour) were reviewed, with the forecast range with stochastics discussed. It was noted that the team used a range of data sources to develop the forecasts and went through several steps: identifying the range of capital costs over time, using interactive expert opinion approach based on the source data, and simulating 500 paths for capital costs based on random sampling from distributions.

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

- Are you considering retrofits of any of the existing plants?
    - o A range of compliance cost options are included, including ELG compliance costs.
- When there is only one input, how does that impact the modeling?
    - o There will be an initial process to evaluate the expected costs and then, from that, a shorter list of feasible technologies will be developed. For the

feasible technologies, NIPSCO will have more data to allow for a full range of options to be considered.

- Regarding the solar and battery graphs, it seems the common understanding is that battery costs are going down. But, based on the graph, surprised at the high band in a short amount of time when prices are expected to go down.
    - There is a great deal of uncertainty where the price really is. NIPSCO expects the RFP to give better price information. However, the current slide is based on existing data, which incorporates a wide band of uncertainty, but a generally declining cost trajectory over time.
- Will the Xcel Energy information from its latest RFP be utilized among the data sources?
    - No, as they did not publish capital costs.
- Looking at the solar and storage information, do you combine it?
    - For purposes of the capital cost assumptions, no. That will be considered as part of another process.
- How do you anticipate including other third party studies for solar, wind and storage?
    - Slide 56 refers to the various studies that have been utilized.
- Will NIPSCO consider other forecasts, and, if so, what is the timeframe for providing that information?
    - NIPSCO will ultimately place more emphasis on the information contained in the responses to the RFP, but is interested in other forecasts as well, which are hopefully within the bands of the current projections. The goal is to get data from third party developers, as that is the best idea of what is executable in the market.
- How will the RFP data be integrated?
    - The data on the slides in this section will be updated with information from the RFP. NIPSCO will continue to discuss how best to do this.

2018 Commodity Price Forecasting
Robert Kaineg and Pat Augustine, CRA

Charles River Associates provided information regarding how commodity prices would be forecasted as part of the 2018 IRP. Robert Kaineg started by providing CRA's natural gas outlook, which included an overview of the market, price forecasting, key modeling inputs, market trends, and price drivers. He then provided information regarding the local gas dynamics in MISO. Next, he provided the same type of overview for the coal market, including a discussion of trends in regional coal production in the United States and a summary of the price trends by coal. Pat Augustine provided information on carbon dioxide ("CO_2") pricing, with information on the base case, low case and high case. He then gave an update on the MISO market outlook. He started by providing an overview of how AURORA does power price forecasting and provided information regarding the MISO footprint. Mr. Augustine noted that it is expected that there will be a continued shift from coal to gas and renewables and provided CRA's Power Price Forecast for MISO Zone 6. He then provided information regarding capacity prices and how they are influenced by market design and ended by providing CRA's MISO capacity forecast.

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

- Is the price reflective of the cost of capacity (what capacity in the market is going to cost)? The prices look low.
    - o The model is not anchored to the cost of new entry. Instead, given the structure of the MISO capacity market, there will be entities that will build to native load, meaning that the existing units are going to set prices closer to the cost to stay in the market. In the Base Case, the assumptions will not necessarily reflect new cost because of the design and participation of the region.
- Would appreciate the ability to have as much information regarding what you have come up with so far in advance of the May meeting.
    - o NIPSCO will work to provide that.

Demand Side Management Update
Alison Becker, Manager, Regulatory Policy
Richard Spellman, GDS Associates, Inc.

Ms. Becker provided a brief overview regarding how NIPSCO is updating its DSM forecast for the 2018 IRP. She explained that while NIPSCO is working with its Oversight Board ("OSB") on a full market potential study ("MPS"), the timing of the 2018 IRP update did not make completing that practical in order to have the data in time for the modeling in the IRP. Therefore, NIPSCO has elected to do a 2018 Electric DSM Savings Update, with a full MPS being completed after that process is complete. She then introduced Mr. Spellman, who is the president of GDS Associates, the firm selected by NIPSCO and the OSB to perform this work, to provide an overview of the Savings Update process. Mr. Spellman explained the types of information that will be included in the Savings Update and noted that it will cover the same years included in the IRP Update (2019 to 2038). He noted this will be completed by June 1, 2018 and that GDS will work with NIPSCO and the OSB on finalizing the data.

Mr. Spellman reviewed the report contents and stated that, while the intention was to use the Total Resource Cost test as the main screening of cost effectiveness, stakeholders had requested NIPSCO to use the Utility Cost Test and that was being considered by NIPSCO. He explained that for the DSM Savings Update Report due on June 1, GDS will update assumptions relating to measure costs, kilowatt hour ("kWh") and kilowatt savings and useful lives. Mr. Spellman then reviewed the technical approach for baseline development that will be completed for the development of the full energy efficiency potential study to be completed in 2019. Finally, he went through the process related to the assessment of potential savings for the full potential study to be completed in 2019 and discussed how GDS will recommend appropriate funding levels based on the projected savings.

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

- Assuming the load forecast essentially incorporates the continuation of DSM programs as they have been in the past, how does this analysis impact that? Can past levels be accommodated or increased in the future?
    - A NIPSCO representative explained that the impacts of NIPSCO's existing DSM programs are captured in the consumption piece of load forecasting. .GDS will work closely with NIPSCO to remove the impacts of NIPSCO's existing energy efficiency programs from the NIPSCO load forecast. Typically, a calculation is performed to determine the percentage of forecast annual kWh sales that are expected to be saved in the future with energy efficiency programs, which is based on the impacts of DSM programs being removed from NIPSCO's load forecast.

RFP for Capacity
Paul Kelly, Director of Federal Regulatory Policy

Mr. Kelly provided an overview of NIPSCO's "all-source" RFP, which was still in the development at the time of the meeting. He noted that a different division of CRA had been retained to assist in the development and administration of the RFP process and that NIPSCO would be seeking stakeholder feedback on the approach/design to ensure a robust, transparent process and result. He also provided an outline of the resource evaluation criteria being considered. Mr. Kelly gave detail around the key design elements of the all-source RFP, noting that all solutions, regardless of technology would be considered. NIPSCO is open to asset purchases and purchase power agreements for new and existing resources. He then explained the timeline for the IRP, indicating a Design Summary would be shared with stakeholders on April 6 to request feedback. Ultimately, the RFP is scheduled to be initiated May 14, with a close date of June 29. At the July 24 IRP Public Advisory Meeting, a summary of the results will be presented.

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

- The schedule only allows 14 days for feedback, which is overly ambitious. Would request the opportunity to sign a non-disclosure agreement to have an opportunity to view the entire RFP.
    - That is something NIPSCO is happy to work through.
- Demand response is not typically contracted for more than one year. That should be considered in the design elements.
    - Great example of helpful feedback. This is something NIPSCO will take into account.
- How much of the IRP will already be completed when the proposals are received? How do you take the information from the RFP and weave it into the IRP?
    - The intent is to summarize by technology, size, range, etc. and put information into IRP for those technologies. The portfolio design can then be run on those numbers and replace the forecast information that was used.
- What are you looking for with the RFP? Actually contracting with vendors?

    - NIPSCO wants to understand the price of a resource instead of relying on a forecast. It is important to know what is real and available within the MISO footprint and deliverable to NIPSCO's customer load. The RFP will be binding and, once the Preferred Plan is in place, the Company can begin the process of contracting with individual bidders based on the solutions selected within the Preferred Plan.
- Glad all resources are included. There are parties interested in participating and hope the RFP will allow for those bidders.
    - That is something NIPSCO wants as well.
- Will you piece together resources to get to the 600 MW or must it all be in one proposal?
    - The intent is to get whatever size resources bidders want to propose and then NIPSCO can solve for meeting the 600 MW needed by combining bidder(s) as needed.
- Is there flexibility on the length of the contract? Must it only be for five years?
    - Five years is defined as the minimum term.
- The capacity need not be within NIPSCO's service territory, just within the MISO footprint?
    - Correct. NIPSCO is required to meet its planning reserve obligation in MISO with Zonal Resource Credits for its Local Resource Zone 6. Therefore, all resources considered will need to have firm delivery to Zone 6 in order to qualify for the required capacity accreditation.
- Is the MISO region the same as the Zone?
    - No. MISO covers 15 states and a portion of Canada. While transmission from the far western part of MISO could be expensive, it is possible that a resource that is electrically distant from NIPSCO's load could bid into this RFP if it can establish the firm transmission delivery to Zone 6.
- How is the local community impact being considered? Are you considering the health and environmental impacts (for example, Michigan City with 28% of the population below the poverty level)?
    - NIPSCO plans to evaluate environmental impact as an evaluation criteria in the RFP in a way that is similar to the IRP's coal retirement analysis The Company is open to considering additional ideas and perspectives from its stakeholders on how to further assess environmental/emissions impact as well as the local community impact.
- Does NIPSCO intend to have a carbon price as part of the RFP?
    - NIPSCO is simply requesting a price for the capacity, not something specifically for carbon. The Company expects it will be an integrated price to evaluate on the cost component. Would be interested in perspectives from stakeholders on how to consider carbon in the evaluation.
- Will NIPSCO be considering self-build options in the RFP?
    - No, NIPSCO is not evaluating a self-bid option in the RFP. While NIPSCO has continued to evaluate the CCGT solution that was identified at the time of the 2016 IRP, the focus of this RFP is looking more broadly at all viable solutions to address its needs.
- When do you expect to see the execution of contracts?

  - NIPSCO does not look to transact any earlier than the close of the IRP process. Once NIPSCO is through the stakeholder process and has developed its Preferred Plan, the Company will consider negotiating definitive agreement(s) in the fourth quarter of 2018.

Stakeholder Presentations

David Repp from Jet provided a presentation "Technology Introduction and Adaptability to Indiana Power Facilities," which provided information on an alternative to existing desulfurization technology. He walked through an overview of the technology, the technical features, and the benefits that could be provided.

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

- The Indiana Coal Council favors this technology. With what type of coal can this technology be utilized?
  - Can adapt on a wide range of low and high sulfur coals. You need to look at the economics-the higher the sulfur, the more economical the process is. That is the type of coal in Indiana.
- Is this a replacement of a scrubber?
  - That is a site-specific answer. The absorber is similar to what you would expect for a limestone absorber. You can retrofit a limestone scrubber into this technology and it will not cost much in capital.
- Have you qualified for any Department of Energy funding for this?
  - In discussions. The concept is ammonia based and not new. The Department of Energy has paid for new absorbers with this technology and a cost-share to retrofit, both were successful. In total, 300 units have been installed.

2018 Public Advisory Process and Closing

Ms. Becker outlined the remainder of the Public Advisory Process, with the following meetings scheduled:

Date	Location	Main Topic(s)
May 11, 2018	Avalon Manor, Merrillville, IN	• Existing Generation • Environmental Considerations • Retirements Update • DSM in the IRP
July 24, 2018	Webinar	• Preliminary Results from the RFP
September 19, 2018	Fair Oaks Farms, Fair Oaks, IN	• Preliminary Findings from the Modeling
October 18, 2018	Fair Oaks Farms, Fair Oaks, IN	• NIPSCO's Preferred Plan • Short Term Action Plan

Timothy Caister, Vice President, Regulatory Policy closed the meeting by thanking the attendees for their attendance and active participation.

Jiangnan Environmental Technology

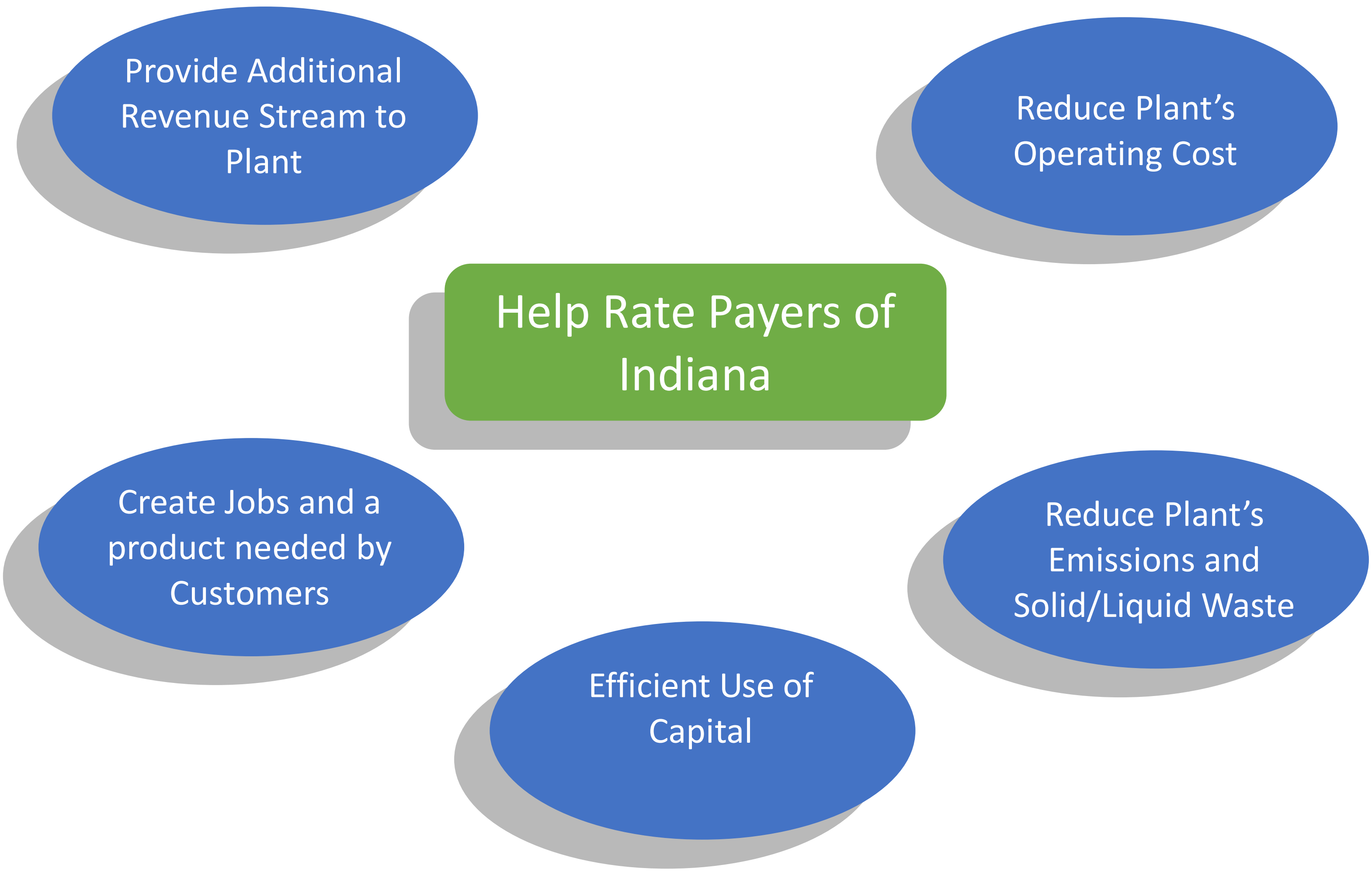
Technology Introduction and Adaptability to Indiana Power Facilities

Prepared Personally For:

NIPSCO

March 23rd, 2018

An Alternative to Existing Desulfurization Technology



Help Keep Plants Viable

About JET

JET provides customized solutions in Engineering, Construction and Operations Services for Power Plant Desulfurization. In 1998 JET established the first ammonia desulfurization technology research institute in China, and launched the first recovery type ammonia desulfurization unit in 2004. With a global vision, and a strong organizational culture heavily focused on R&D, JET is dedicated towards providing cost effective solutions towards eliminating air pollution, improving living conditions, and helping our customers meet increasingly stringent emission standards.

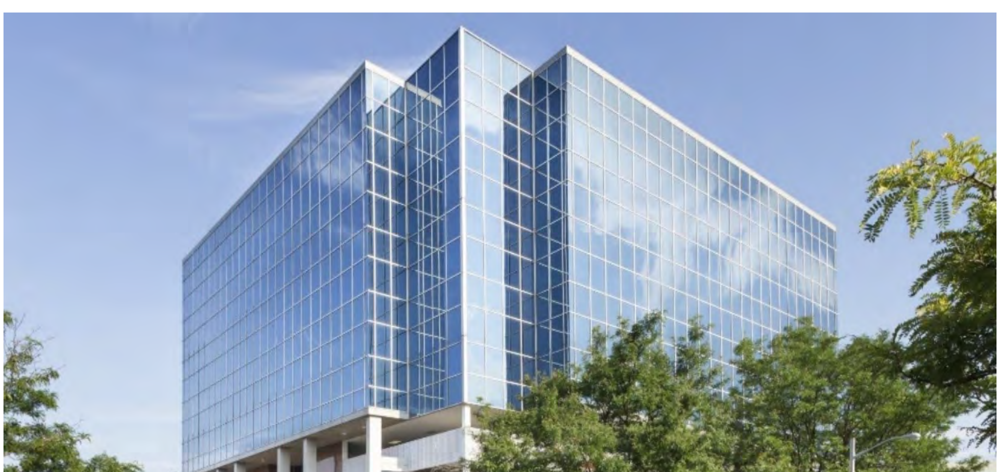
Global leader with 80% market share in Ammonia-Based Desulfurization

65 patents and patent applications

150+ projects with more than 300 installed units

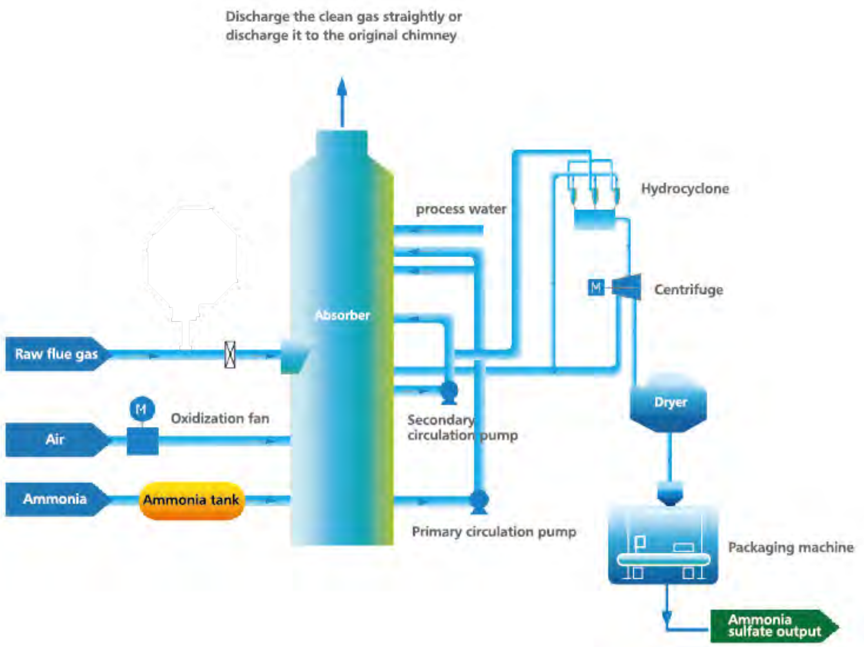
20+ installations with capacity bigger than 700,000 SCFM

JNEP (China Office)



JET Global Headquarters (Ridgefield Park, NJ)

Technology



	Year	Features	NH_3 recovery	SO_2 emission ppm	Total dust lb/MMSCF	Performance
1st Gen	1998	Basic NH_3 based deSOx	not controlled	~ 70		Meets SO_2 emission limit
2nd Gen	2010	NH_3 based deSOx with NH_3 recovery control	≥ 97%	< 35		Meets HG2001-2010 standard
3rd Gen	2013	Fine PM control	≥ 98%	< 17.5	≤ 4.72	Meets GB13223-2011 special emission limit
4th Gen	**2015**	**Ultrasound-enhanced deSOx and PM-removal integration**	**≥ 99%**	**< 12**	**≤ 1.18**	**Meets ultra-low emission limit***

Performance:
- SO_2 emission ≤ 12 ppm
- Particulate Matter Emissions ≤ 1.18 lb/MMSCF
- Ammonia Slip ≤ 3 ppm
- Ammonia Recovery Rate ≥ 99%

Technical Features

Advantages of EADS compared to Limestone Process

	EADS	LIMESTONE
Process	Turn waste (SO_2) to high value fertilizer	Consume 1.6 ton limestone & generate 0.7 ton CO_2 per ton SO_2 removed
Capital Cost	0.8 Base	Base
Operating Cost	<100% Base or even make profit	Base
SO_2 Removal Efficiency	>99.5%	<97%
SO_2 Emission	12 PPM	35 to 70 PPM
Waste Water Generation	No	Yes
Solid Waste Generation	No	Yes
Synergy with Carbon Capture System	Yes	No

1

Low Operating Cost

The liquid-to-gas ratio of the ammonia process is only 1/6 to 1/3 of the limestone-gypsum process. Therefore, the power consumption of the ammonia-based process is about 50% less than that of the limestone-gypsum process.

The byproduct of the ammonia-based process is ammonium sulfate, which can be sold as fertilizer. The sales revenue from ammonium sulfate can offset the total cost of ammonia, and lower the overall operating cost.

2

No Secondary Pollution and High-value Byproduct

The EADS technology is environmentally friendly. Unlike other FGD processes such as limestone-gypsum process, it recovers SO_2 efficiently without generating any waste water, solid waste, or CO_2.

The byproduct of the ammonia-based process is saleable fertilizer, whereas the by-product of the limestone-gypsum process is gypsum and its sales value is significantly lower than that of ammonium sulfate. In some cases, the gypsum need to be disposed of as solid waste

3

High SO2 Removal Efficiency

Ammonia is a substance with much higher alkalinity and reactivity with SO_2, making it a more efficient absorbent than limestone. Therefore, the absorption of ammonia-based absorbent is faster than the limestone slurry. As a result, SO_2 removal up to 99% and SO_2 emission as low as 12 ppmv can be achieved by the ammonia-based process.

4

Excellent Adaptability and System Reliability

EADS technology can be applied to coal with sulfur content from 0.2% to 8% and flue gas with SO_2 content from 100 to 10,000 ppmv or higher.

5

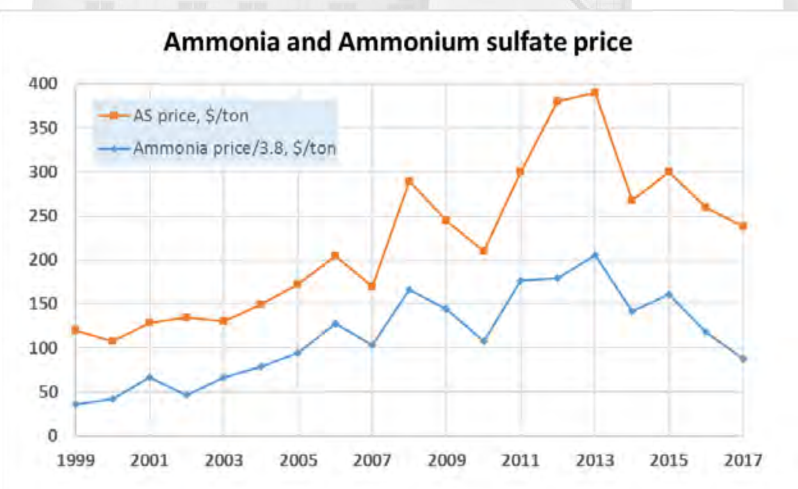
Proven Technology

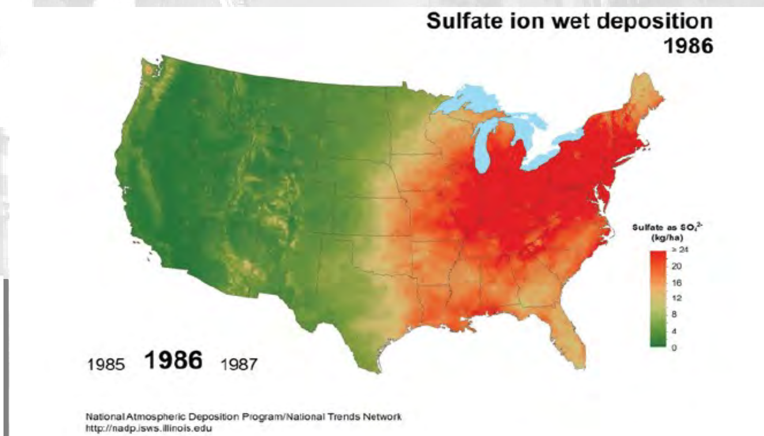
The technology proposed in this proposal is reliable and commercially proven. To date, more than 150 EADS projects have been put into operation or under construction.

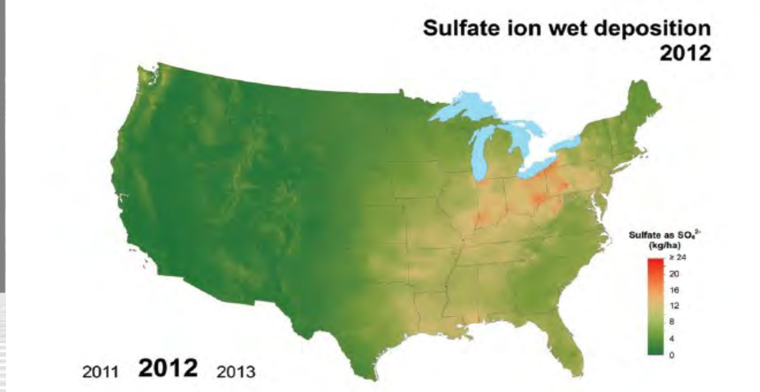
Ammonia/Ammonium Sulfate

The EADS technology uses “ammonia” as the desulfurization absorbent, and anhydrous ammonia, aqueous ammonia, or gaseous ammonia can be used as the desulfurization agent. We are currently in talks with the following ammonia suppliers. Ammonia can also be synthesized from coal or natural gas.

Ammonium sulfate product will be sold to fertilizer produces as a feedstock for producing compound fertilizers or directly sold to fertilizer retailers. Ammonium sulfate is widely used in the US and Latin America, where about 70% of the fertilizers is imported. **Nitrogen based Fertilizer is a growing market with a 2016 demand of 121 Million Tons!**







Comments from our Clients

"The newly-built ammonia-based FGD project, Tower #5, has been successfully completed and no malfunction occurs since the operation. We want to thank you for the remarkable contribution to our project…" -------- Wanhua Chemical Group Co.,Ltd

"The retrofit project for our Boiler #1 within 3 months meets the emission regulations as planned, while the cost and power consumption are much lower. We much appreciate your efforts in overcoming difficulties during the retrofit, such as the limited space of the site..." -------- Sinopec Qilu Petrochemical Company

"We sincerely thank JET's efforts and contributions in our coal-to-olefin retrofit project. The project is a highly difficult and challenging project, where the sites are small and the construction and operation run at the same time. Despite the difficulties, JET has successfully completed the construction, and the flue gas is much cleaner than before when the Limestone-gypsum process was applied…" -------- Shenhua Ningxia Coal Industry Group Co., Ltd.

Flexible Business Models – Low/No capital investment required from plant

- EPC
- BOT (Build – Operate – Transfer)
- BOO (Build – Operate – Own)

Thank you for your interests in our technologies

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JET
Jiangnan Environmental Technology

All Source Request for Proposals – Interim Summary

Introduction and Request for Proposal Overview

Northern Indiana Public Service Company ("NIPSCO") does business in the State of Indiana as a regulated public utility. NIPSCO generates, transmits and distributes electricity for sale in Indiana and the broader Midcontinent Independent System Operator, Inc. ("MISO") regional electricity market.

NIPSCO is committed to meeting the energy needs of its customers today and in the future. Through the Integrated Resource Planning ("IRP") process, NIPSCO identifies its long term capacity needs and charts a path on how best to meet those needs. The IRP process seeks to identify preferred resource portfolios that are reliable, compliant, flexible, diverse and affordable, all of which are guiding principles of NIPSCO. Long term resource planning requires addressing risks and uncertainties created by a number of factors including the costs associated with new resources.

In its 2016 IRP, NIPSCO identified a minimum capacity need of 600 megawatts ("MW") by 2023. To address that projected resource need, NIPSCO has concluded that it is in the best interest of its customers to seek to acquire, construct or contract for additional generating capacity located within the MISO market. NIPSCO is releasing an "all source" Request for Proposals ("RFP") for supply and demand side capacity ("DSM") resources. An RFP solicitation is the best opportunity to mitigate the uncertainty associated with the cost of new resources. The purpose of the RFP is to identify the most viable resource(s) available to NIPSCO in the marketplace to meet the needs of its customers. NIPSCO is currently in the initial phases of the RFP process designed to both inform the IRP and identify specific assets, resources, projects or contractual options that best meet the Company's resource requirements.

A key aspect of NIPSCO's proposed process is the integration of the IRP and RFP processes which will be conducted in parallel. The parallel design is intended to ensure that the resource requirements identified through the IRP process were informed by the most current and accurate market information and that the RFP asset selection is consistent with the NIPSCO IRP. NIPSCO will first identify its preferred resource portfolio by aggregating data from the RFP responses and inputting such data into its IRP modeling. The RFP bid evaluation and selection process will be based upon the specific resource needs identified through this IRP modeling as well as the bid evaluation criteria.

NIPSCO is committed to a collaborative process considering the needs of all stakeholders throughout the design of the RFP. **The following memorandum represents a current outline of the proposed process and is seeking stakeholder feedback and comments by Friday, April 20th, 2018 to *nipsco_irp@nisource.com.*** NIPSCO will take stakeholder comments under advisement and reserves the right to update the process documents, timeline, bidding requirements or evaluation criteria prior to the official launch of the RFP.

The NIPSCO RFP is being designed to consider all sources of capacity and the company has no stated or unstated preference for the fuel source or deal structure related to the potential resource options available through the market. Consistent with that, the RFP will be issued as an all source procurement process that will consider a range of existing and in-development fossil and non-fossil fuel sources, purchase power agreements (including capacity-purchase agreements) ("PPA"), and DSM proposals in order to identify the mix of resources that best serves customer needs.

NIPSCO has retained Charles River Associates ("CRA") to support the IRP, RFP and stakeholder processes. CRA has a long track record of executing structured procurement processes on behalf of its utility clients and will support NIPSCO throughout the RFP design and execution.

Requesting Stakeholder Feedback – Design Subject to Change

NIPSCO is providing this interim summary of the All Source RFP to stakeholders to request their feedback on the proposed design. As such, it is currently in a "draft" state and will not be finalized until NIPSCO has considered all feedback received from our stakeholders and completed additional internal review.

Information and Schedule

The RFP is scheduled to launch on May 14th, 2018. At or before the 14th of May, CRA will initiate a marketing process in association with the launch. The marketing process will include the release of a public Information Website; one or more bidder information sessions; advertising in trade publications and direct outreach to potential process participants. The goal of the marketing process is to create bidder interest in the process and to educate potential bidders about the objectives of the integrated IRP and RFP work streams. Tentative key dates for the RFP include the following:

- May 14, 2018: RFP Issued
- May 16, 2018: Bidder Information Session
- May 28, 2018: Bidder Notice of Intent and Prequalification Due
- June 4, 2018: Prequalification Notices Sent to Approved Bidders
- June 29, 2018: Bidder Proposals Due
- July 2, 2018: Start of Bid Evaluation Period
- September 15, 2018: Bid Evaluation Completed
- Quarter 4 2018: Definitive Agreements Signed with Winning Bidders

It is anticipated that any asset purchase agreements, DSM agreements or PPA that may arise as a result of the RFP process would go into effect at or around 2023. However, the timing of any individual agreement may be an element of the proposal details submitted in response to the RFP. As such, NIPSCO is willing to entertain proposals with delivery prior to 2023 in the event such agreement is advantageous for NIPSCO's customers.

Certain information will be made available to bidders in advance of the proposal due date. The public Information Website will be the central source of information for the process. All bidders will have equal access to information to ensure a fair, equitable and non-discriminatory RFP.

Capacity Assets Considered in the RFP

As noted above, NIPSCO intends to issue an all-source RFP and will consider a wide range of options to meet customer needs. NIPSCO is anticipating the receipt of bids from any of the following categories of capacity assets:

- Asset purchases for new or existing resources including dispatchable, intermittent / renewables, stand-alone storage or resources paired with storage (semi-dispatchable)
- PPA
- DSM options

While the draft RFP makes specific reference to the above categories, NIPSCO will consider bids from non-traditional resource options outside the above set to the extent that they meet the basic bid requirements for the RFP. Additionally, there is no minimum offer or offer cap associated with this RFP. NIPSCO will consider bids from resources smaller or larger than the 600 MW need identified.

Key Qualification Requirements

NIPSCO is considering all sources to meet their resource requirements, however, there will be certain minimum qualification requirements associated with participation in the RFP process and certain threshold requirements on assets supporting the bids evaluated. These requirements fall into four general categories:

1. **Counterparty credit requirements**: NIPSCO will require that PPA counterparties and developers meet certain minimum credit and financial standing requirements. Potential counterparties that do not meet the minimum requirements may need to post additional performance collateral or be supported by parental guarantees.

2. **Asset reliability and deliverability requirements**: NIPSCO requires operational control of any physical asset bid into the RFP. Physical assets must also be interconnected at the transmission voltage (under MISO's functional control). Physical assets bid or that support a PPA bid into the RFP must have firm delivery capability into MISO Load Resource Zone 6 ("LRZ6"). In addition, bidders must demonstrate that resources currently meet MISO's (n-1) contingency criteria and either demonstrate that they meet (n-1-1) transmission criteria or provide cost estimates for the upgrades required to do so.

3. **Key development milestones:** New or planned generation facilities or PPA supported by new or planned generation facilities that have a development timeline greater than {*X*} months must have executed a pro-forma MISO Interconnection Service Agreement, Interconnection Construction Services Agreement and completed a MISO System Impact Study for the project for the proposed delivery point. New or planned generation facilities or PPA supported by new or planned generation facilities that have a development timeline less than or equal to {*X*} months must provide a timeline showing ability to complete key development milestone prior to June 1, 2023 including the above referenced items for the MISO generator interconnection queue.

4. **Remaining useful life:** Assets bid into the RFP must have an expected remaining useful life of at least five (5) years. NIPSCO will also not consider PPA with contract terms of less than five (5) years unless for DSM which NIPSCO will allow a minimum term of one (1) year.

Proposals supported by assets that do not meet the threshold criteria will not be evaluated further and will not be selected as a winning bidder through this process. Facilities not meeting the threshold criteria could be considered outside this process on a case by case basis or as NIPSCO needs dictate.

Proposal Content Requirements

As part of this RFP, NIPSCO will request information from bidders in order to inform the IRP process and to evaluate the bids received. Certain required information is commercially sensitive and proprietary. As a result, access to information will be restricted consistent with the terms and conditions of the non-disclosure agreement associated with the RFP. The information requested from bidders in association with the RFP process include the following:

- Counterparty corporate and financial information
- Experience of the facility operator or the project developer
- Facility name, location, interconnection points and commercial operating node
- Facility capacity availability and deliverability information
- Generation technology including dispatch and emissions characteristics
- Facility revenues and operating costs
- Generation facility operating data
- Generation facility operating and maintenance plan including information on long term service agreements (“LTSA”)
- Detailed fuel supply information including fuel supply contract information
- Emissions and waste disposal compliance information
- Water supply and permitting information
- Capital expenditure plan including the cost of compliance with certain pending or proposed environmental restrictions or action
- Pending legal action or material contingencies
- Development milestones, interconnection and permitting information
- Offer price including any transferred liabilities
- Asset purchase agreement (“APA”) and/or PPA markups

Because NIPSCO is conducting this RFP as part of its IRP public advisory process, NIPSCO will summarize bids by size and technology for presentation to stakeholders unless fewer than 3 bids are received for any given category. Bidder names will also be shared in the form of an aggregate list. The individual bids will be considered highly confidential.

Modeling Scenarios and Key Assumptions

NIPSCO’s IRP team is tasked with analyzing near and long-term power market performance under a range of commodity, demand and environmental scenarios. Modeling conducted in support of the IRP includes a Base Case set of parameters reflecting NIPSCO’s outlook for key drivers of power market performance and operations. The IRP process will also perform scenario analysis on certain parameters including natural gas prices, coal prices, carbon prices, power prices, NIPSCO load and costs of new resources.

In association with the 2018 IRP, NIPSCO is also developing a stochastic analysis to analyze the cost and risk-related tradeoffs between different resource and retirement combinations for the NIPSCO portfolio. The preliminary stochastic analysis relies on replacement cost estimates of different types of generating capacity. These estimates will be updated consistent with information derived from the all source RFP.

IRP modeling will be used to generate an optimal acquisition portfolio for NIPSCO reflecting the Base Case, scenarios, the stochastic analysis and supported by the updated resource costs generated through the RFP process. The optimal portfolio will be used in the RFP process to determine the amount of capacity from each resource category to select as winning bidders.

RFP Evaluation Criteria

The RFP team will begin the evaluation of RFP bids concurrent with the IRP scenario modeling and stochastic analysis.

Certain bids may be disqualified from consideration to the extent that they do not meet the threshold requirements for the RFP or if the bids are otherwise non-conforming.

Bids that survive the initial screening will be subject to further analysis and ranking. RFP bids will be grouped consistent with the asset categories used for the IRP and will be reviewed using a multi-dimensional evaluation framework. The framework considers reliability and deliverability, cost, asset-specific environmental considerations, development risk and asset specific risk factors. NIPSCO intends to weight evaluation criteria as part of the framework.

1. **Facility Reliability and Deliverability**: Bidders will be requested to provide power flow analyses under the MISO (*n-1*) reliability guidelines. Bidders will also be required to provide power flow analysis under NIPSCO's (*n-1-1*) reliability criteria or the cost to mitigate the difference between (*n-1*) and (*n-1-1*). Bidders will also be required to provide operating history and projected facility loadings over recent and near-term planning years. Assets that can demonstrate they currently meet NIPSCO reliability guidelines will receive full credit under the reliability category.

2. **Facility Cost**: NIPSCO will perform an evaluation of the cash cost of each bid. The cost analysis will examine the asset bid price, asset specific estimates of fixed and operating costs, capital expenditures, taxes, congestion costs and other cash considerations. Results will be adjusted for offsetting market revenues and presented on a net $/MW-day basis.

3. **Environmental Considerations:** NIPSCO will consider the specific environmental profile of individual assets. The evaluation will consider both criteria pollutants and asset carbon intensity in order to evaluate the asset specific exposure to scenarios or regulations not explicitly considered in the IRP modeling and to differentiate among the bids for assets within a given category.

4. **Development Risk:** Existing resources will receive full credit under this evaluation category. Plants in development will be awarded points based on the developer experience in MISO and development milestones achieved. Proposals will receive points based on the

demonstrated ability of the bidder to meet the key milestones in the development timeline as measured by the MW placed into service in MISO to date by the developer. Points will also be awarded in pro-rata fashion based on the development progress of the proposed project itself. In all cases, development projects must provide development collateral in support of meeting the target commercial operation date.

5. **Asset Specific Risk Factors:** Considerations may include, but not be limited to, fuel supply security and reliability, pending litigation or material contingencies associated with the facility or operator, and uncertainty related to transmission infrastructure or upgrades that may affect the facility operations. Proposals with no additional risks, or with risks for which the Respondent has described full mitigation measures, will receive the full credit.

Post RFP Timeline

Bidder proposals are due to NIPSCO by 5:00 PM EDT Central Prevailing Time on June 29th, 2018. The bid evaluation process will begin immediately upon receipt of the bids. It is expected that the bid evaluation will be completed by mid-September 2018 and a list of finalists will be submitted to NIPSCO by CRA for modeling within the IRP. Once the Preferred Plan is determined, it is expected that NIPSCO will enter into final negotiation with selected finalists and work towards definitive agreement(s) to be executed during the fourth quarter of 2018.

During the final negotiation period, NIPSCO will conduct site visits, if applicable, and execute a detailed engineering review of each asset in consideration of a definitive agreement. In addition, NIPSCO may perform additional dispatch modeling of each finalist as part of a broader due diligence effort designed to ensure that all stakeholder interests are protected and the selected asset(s) meet(s) NIPSCO's reliability and deliverability requirements.

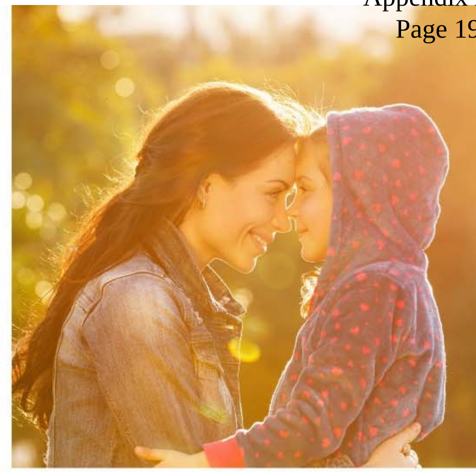
All definitive agreement(s) would be subject to the granting of a Certificate of Public Convenience and Necessity ("CPCN") by the Indiana Utility Regulatory Commission. Agreements may require approval in other jurisdictions or at the Federal Energy Regulatory Commission, depending on the nature of the agreement or the asset(s) selected. Any regulatory filing(s) would begin after the conclusion of NIPSCO's due diligence and the execution of definitive agreements. As such, any definitive agreements are subject to regulatory approval.

NIPSCO Public Advisory Meeting 1 Registered Participants		
First Name:	**Last Name:**	**Company:**
Lauren	Aguilar	OUCC
Linda	Anguiano	Progressive Democrats of America - Calumet Region
Laura	Arnold	Indiana Distributed Energy Alliance (IndianaDG)
Russ	Atkins	NIPSCO
Pat	Augustine	Charles River Associates
Greg	Baacke	NIPSCO
Lisa	Beck	
Vernon	Beck	NIPSCO
Alison	Becker	NIPSCO
Anne	Becker	Lewis Kappes
Mahamadou	Bikienga	NiSource
Marc	Blanchard	BP
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	IURC
Wendy	Bredhold	Sierra Club
Tim	Caister	NIPSCO
Andy	Campbell	NIPSCO
Kelly	Carmichael	NiSource
Mary	Chambers	NIPSCO
Daniel	Douglas	NIPSCO
Jeffery	Earl	Indiana Coal Council
Claudia	Earls	NiSource
Amy	Efland	NiSource/NIPSCO
Greg	Ehrendreich	MEEA
Steve	Francis	Sierra Club - Hoosier Chapter
Thomas	Frank	Commuity Strategy Group
Fred	Gomos	NiSource
Doug	Gotham	State Utility Forecasting Group
Robert	Greskowiak	Invenergy LLC
Corey	Hagelberg	Beyond Coal
Barry	Halgrimson	Retired
John	Halstead	350 IN-Calumet
Rina	Harris	Vectren
John	Henderson	Stoll Keenon Ogden PLLC
David	Hicks	Indeck Energy Services, Inc.
Stephen	Holcomb	NIPSCO
Shelby	Houston	IPL/AES
Jim	Huston	Indiana Utility Regulatory Commission
Robert	Kaineg	Charles River Associates
Pauline	Katsouros	NIPSCO
Paul	Kelly	NIPSCO
Bryan	Little	NIPSCO
Jonathan	Mack	NIPSCO
Debi	McCall	NIPSCO
Jim	McMahon	CRA

NIPSCO Public Advisory Meeting 1 Registered Participants		
First Name:	**Last Name:**	**Company:**
Emily	Medine	EVA
Tony	Mendoza	Sierra Club
Nancy	Moldenhauer	none
Richard	Nelson	Praxair, Inc.
Adam	Newcomer	NIPSCO
Elizabeth	Palacio	Ms.
April	Paronish	Indiana Office of Utility Consumer Counselor
Bob	Pauley	IURC
Jodi	Perras	Sierra Club
Carmen	Pippenger	IURC
Thom	Rainwater	Development Partners Group
Jeff	Reed	OUCC
David	Repp	JET Inc
Matt	Rice	Vectren
Joe	Rompala	Lewis Kappes
Edward	Rutter	Indiana Office of Consumer Counselor
Anthony	Salcedo	Sal-tec Service
Cliff	Scott	NIPSCO
Brent	Selvidge	IPL
Robert	Seren	NIPSCO
Frank	Shambo	NIPSCO
Violet	Sistovaris	NIPSCO
Matt	Smith	Carmeuse Lime and Stone
Joan	Soller	MISO
Dick	Spellman	GDS Associates, Inc.
Jennifer	Staciwa	NIPSCO
Karl	Stanley	NiSource
Bruce	Stevens	Indiana Coal Council
George	Stevens	I U R C
Kathleen	Szot	NIPSCO
Maureen	Turman	NiSource
Bob	Veneck	Indiana Utility Regulatory Commission
Victoria	Vrab	NIPSCO
Jennifer	Washburn	CAC
Michael	Whitmore	NIPSCO
Ashley	Williams	Sierra Club
Fang	Wu	SUFG
James	Zucal	NIPSCO

Appendix A

Exhibit 2



NIPSCO Integrated Resource Plan 2018 Update

Public Advisory Meeting Two

May 11, 2018

Agenda

Time	Topic
9:00-9:15	Welcome and Introductions • Safety Moment
9:15-9:30	How Does NIPSCO Plan For The Future? • Public Advisory Process
9:30-10:15	Modeling Uncertainty: Scenarios and Stochastics for 2018 Integrated Resource Plan
10:15-10:30	Break
10:30-11:00	DSM Modeling Methodology
11:00-11:45	NIPSCO Generation Overview • Operating Costs • Environmental Considerations
11:45-12:30	Lunch
12:30-12:45	2018 Scorecard
12:45 -1:15	Retirement Analysis
1:15 -1:30	Break
1:30-2:00	Replacement Analysis
2:00-2:15	Request for Proposals Update
2:15-2:45	Stakeholder Presentations
2:45-3:00	Next Steps and Wrap Up

Welcome and Introductions

- Introductions
- Welcome from Violet Sistovaris, President, NIPSCO and Executive Vice President, NiSource

Wi-Fi Password: guest1234

Safety Moment: May is National Electric Safety Month

- An estimated annual average of 70 electrocution fatalities are associated with consumer products
- There are reported cases of electric shock drowning that occur at marinas or in swimming pools each year
- National and State Electric Codes seek to reduce fatalities, injuries and fires
- The Electrical Safety Foundation International has additional resources available at www.esfi.org

NIPSCO's Planning and the Public Advisory Process

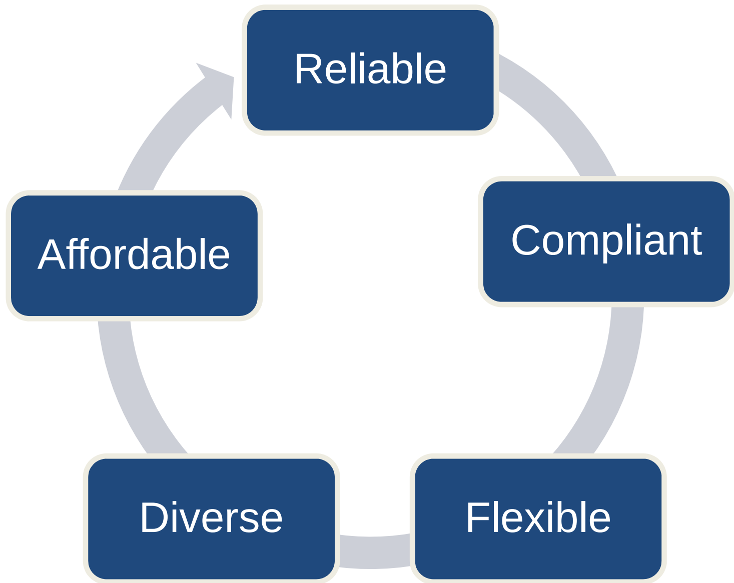
Dan Douglas
Vice President, Corporate Strategy & Development

How Does NIPSCO Plan for the Future?

Charting The Long-Term Course for Electric Generation

About the IRP Process

- Every three years, NIPSCO outlines its long-term plan to supply electricity to customers over the next 20 years
- This study – known as an Integrated Resource Plan (IRP) – is required of all electric utilities in Indiana
- IRP process includes extensive analysis of a range of generation scenarios, with criteria such as reliable, affordable, compliant, diverse and flexible



Requires Careful Planning and Consideration for:

- NIPSCO's employees
- Environmental regulations
- Changes in the local economy (property tax, supplier spend, employee base)

Overview of the Public Advisory Process

- **Today's meeting is the second of five meetings**
  - Four in person meetings and one webinar
- **Your participation and candid feedback is key to the process**
  - Please ask questions and provide comments on the material being presented and the process itself to ensure this is a valuable exercise for you and NIPSCO
- **The Public Advisory process provides NIPSCO with feedback on its assumptions and sources of data. This helps inform the modeling process and the overall IRP results**
  - It also serves as a "check" on the modeling process as results are received
- **Ability to make presentations as part of each Public Advisory meeting**
  - If you wish to make a presentation today and have not already indicated so, please see Alison Becker during break or at lunch
- **Public Advisory Meeting Materials**
  - Presentation materials and summary meeting notes are posted on NIPSCO's IRP webpage: www.nipsco.com/irp

Stakeholder Engagement Roadmap

	Meeting 1 (March 23)	Meeting 2 (May 11)	Meeting 3* (July 24th)	Meeting 4 (September 19)	Meeting 5 (October 18)
Key Questions	- Why has NIPSCO decided to file an IRP update in 2018? - What has changed from the 2016 IRP? - What are the key assumptions driving the 2018 IRP update? - How is the 2018 IRP process different from 2016?	- What is NIPSCO existing generation portfolio and what are the future supply needs? - Are there any new developments on retirements? - What are the key environmental considerations for the IRP? - How are DSM resources considered in the IRP?	- What are the preliminary results from the all source RFP Solicitation?	- What are the preliminary findings from the modeling?	- What is NIPSCO's preferred plan? - What is the short term action plan?
Meeting Goals	- Communicate and explain the rationale and decision to file in 2018 - Articulate the key assumptions that will be used in the IRP - Explain the major changes from the 2016 IRP - Communicate the 2018 process, timing and input sought from stakeholders	- Common understanding of DSM resources as a component of the IRP and the methodology that will be used to model DSM - Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap - Key environmental issues in the IRP	- Communicate the preliminary results of the RFP and next steps	- Stakeholder feedback and shared understanding of the modeling and preliminary results - Review stakeholder modeling and analysis requests	- Communicate NIPSCO's preferred resource plan and short term action plan - Obtain feedback from stakeholders on preferred plan

**Webinar*

Stakeholder Interactions

- **Since the March 23rd Public Advisory meeting, NIPSCO has met with stakeholder groups**

Stakeholder	Subject Area/Discussion Topic
Sierra Club	All-Source Request for Proposals (RFP) and integration with IRP
OUCC	All-Source RFP and integration with IRP

Modeling of Uncertainty

Jim McMahon & Pat Augustine
Charles River Associates (CRA)

Modeling of Uncertainty

- **Generation decisions are generally capital intensive and long-lived, understanding and incorporating future risk and uncertainty is important**
- **NIPSCO analysis uses both scenarios and stochastics to assess risk**

Scenarios
Integrated Set of Assumptions

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

Stochastics:
Statistical Distributions of Inputs

- **Can evaluate volatility and "tail risk"**
  – Short-term price volatility impacts portfolio performance
    - Value of certain portfolio assets is dependent on market price volatility
    - Commodity price exposure risk is broader than single scenario ranges
- **Develops a dataset of potential outcomes based on observable data, with the recognition that the real world has randomness**
  – Large datasets can allow for evaluation of key drivers and broader representation of distribution of outcomes
  – Can calculate statistical metrics to evaluate 95th percentile outcomes

Identifying Risks and Uncertainties

- **As in the 2016 IRP process, the first step is to identify major drivers of potential uncertainty which could influence IRP outcomes**
  – Then develop future perspectives regarding major drivers
  – Next assess whether scenario or stochastic (or both) treatment is appropriate

	2018 IRP		
2016 IRP Drivers	**IRP Drivers**	**Scenarios**	**Stochastics**
Load	Load	✓	
Regulation	Policy *(Inc. Environmental)*	✓	
Environmental Compliance			
Economy	Economy	✓	
Technology	Technology	✓	✓
Commodity Prices	Commodity Prices	✓	✓

Integrated Scenarios

- **Represent Distinct Thematic Views of the future operating environments for NIPSCO**
- **The 2018 IRP will use "scenarios" or thematic "states-of-the-world" under which to develop portfolios and to inform stochastic distributions**
- **The scenarios are used to establish reasonable ranges of key variables, which guide portfolio development and stochastic development**

Theme	Drivers			
	Load	**Policy**	**Economy**	**Technology**
Base Case	Base load forecast	National carbon price expected in 2026 with new federal policy; current regulations on CCR/ELG	Long-term growth trends in line with historical averages	Expected continued declines in solar/storage costs; base case nat. gas production costs
Aggressive Environmental Regulation	Base load forecast	**Policy forces drive stricter carbon controls and stronger renewable targets**	Reference case macroeconomic factors persist	**Renewable (wind and solar) and storage costs decline significantly, supported by policy push**
Challenged Economy	**Loss of industrial load; remaining customer load growth stagnates**	No national carbon policy	**Economic downturn with growth stalling**	Base technology assumptions
Booming Economy & Abundant Natural Gas	**Greater load growth, maintenance of industrial customers**	Base environmental policy; strong support for gas extraction	**Low-cost energy paradigm prevails and economic growth greater than expected**	**Continued efficiency gains in NG extraction drive lower operations costs and focus on most productive plays**

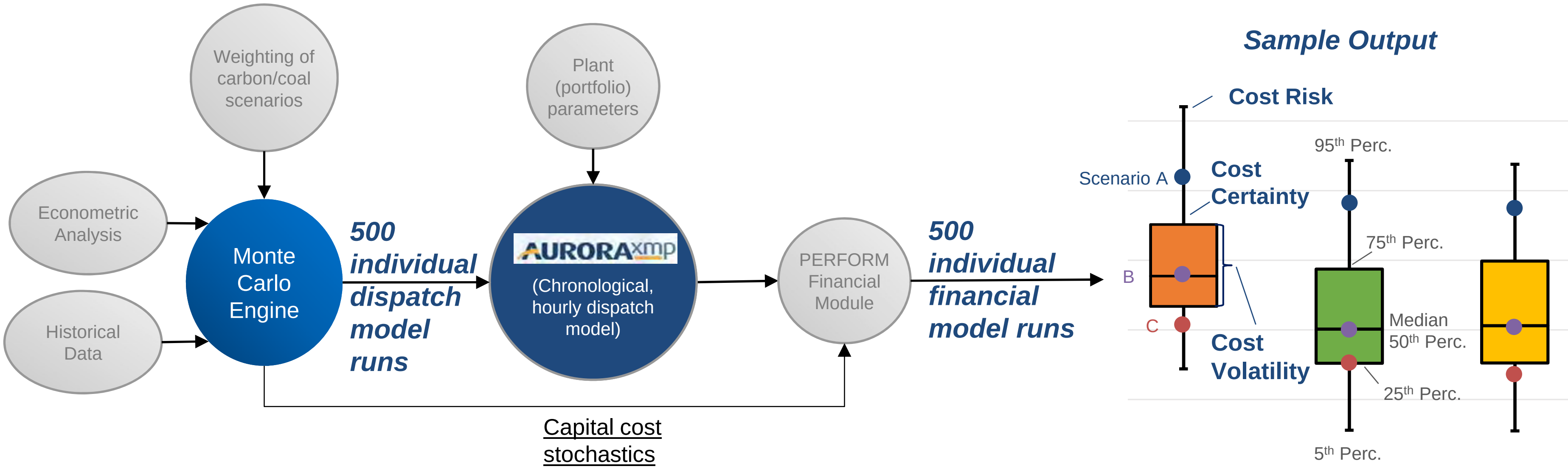
Scenario Considerations Inform Combinations of Input Variables

- **Based on technology, policy, consumer and economic considerations, each scenario has a unique combination of key input variables and a fully integrated set of commodity market price forecasts**

Scenario Theme	NIPSCO Load*	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs
Base	Base	Base	Base	Base	Base	Base
Aggressive Environmental Regulation	Base	**High**	**High (CO_2)**	**Low (CO_2)**	**High (CO_2)**	**Low** renew./ sto.
Challenged Economy	Low	**Low**	**Low (No CO_2)**	**High (No CO_2)**	**Low (No CO_2)**	Base
Booming Economy & Abundant Natural Gas	High	Base	**Low**	**Low (Low Gas)**	**Low (Low Gas)**	Base

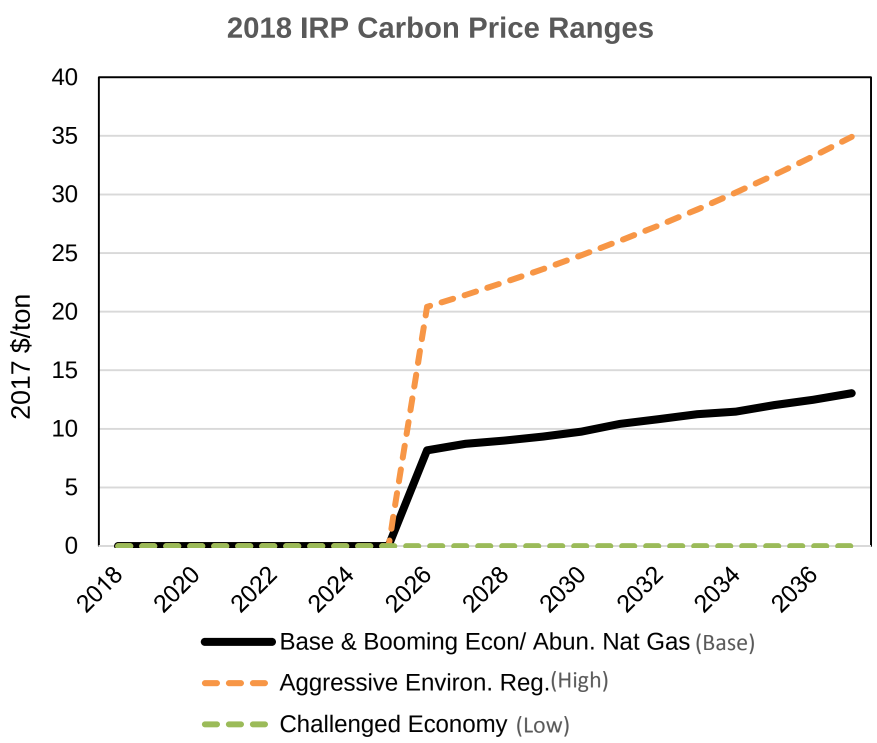
**Currently all scenarios assume NIPSCO Base load forecasts shown in March 23rd meeting, final modeling will integrate high and low load forecasts*

Stochastic Analysis Process and Benefits



- **Stochastic analysis provides a complementary, but extensive assessment of relative portfolio performance, as compared to scenarios:**
  - Captures random outcomes that are unanticipated in scenarios. For example:
    - Power price spikes that are driven by weather and outages rather than fuel prices
    - Market conditions where expected fuel and power correlations break down
    - Combinations of outcomes for key variables (capital costs, commodity costs, carbon prices) that wouldn't be contemplated through scenario construction
  - Ability to quantify costs at the 75th and 95th percentiles and measure cost volatility and risk
    - Captures tail risk outcomes not picked up in scenario trajectories
    - Measures risk over a broad range of outcomes, rather than being limited to the range of scenarios developed

Scenario Ranges of Discrete Variables – Carbon Price



25% weighting: High Case

- Assumes a stricter new federal rule or legislative action coming into force by the mid-2020s. Price levels are generally consistent with a 50-60% reduction in electric sector carbon dioxide (CO_2) emissions relative to 2005 by the 2030s

50% weighting: Base Case

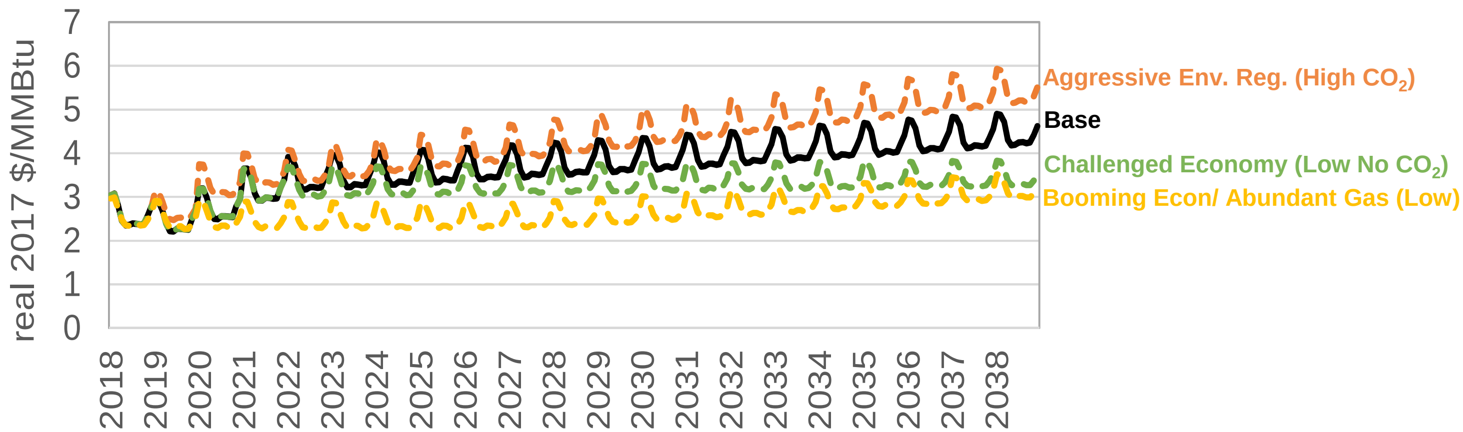
- Assumes a new federal rule or legislative action coming into force by the mid-2020s. Analysis suggests a ~20% reduction in U.S. coal demand post-2026 vs. a $0 carbon price scenario

25% weighting: Low Case

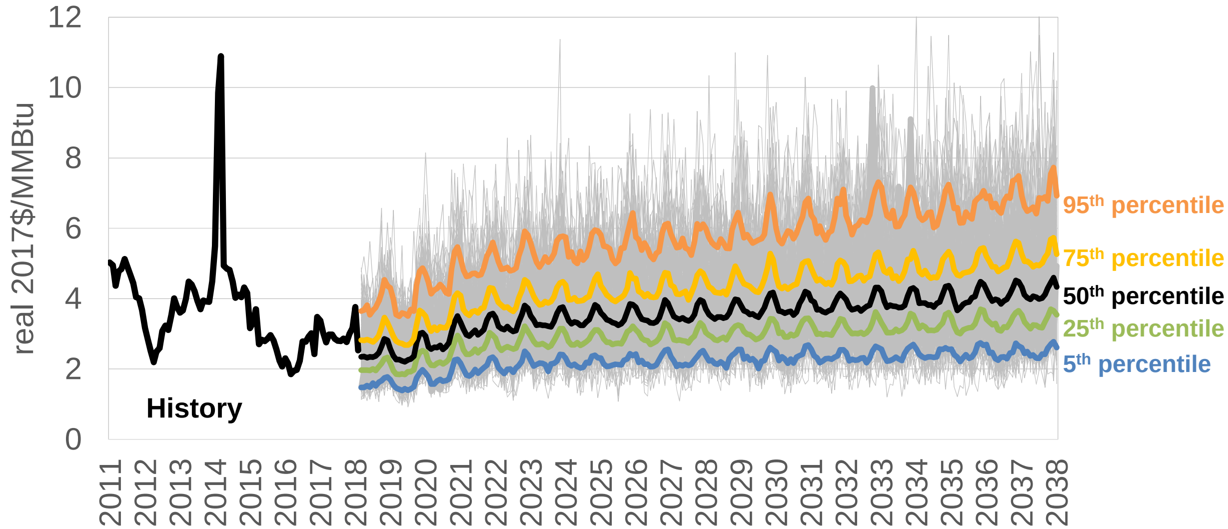
- Assumes a modified Environmental Protection Agency plan to control carbon, with focus on "Building Block 1" coal plant heat rate efficiency improvements. No specific tax or emission cap requirement would be present under such regulations

Scenario and Stochastic Ranges of Key Variables – Natural Gas

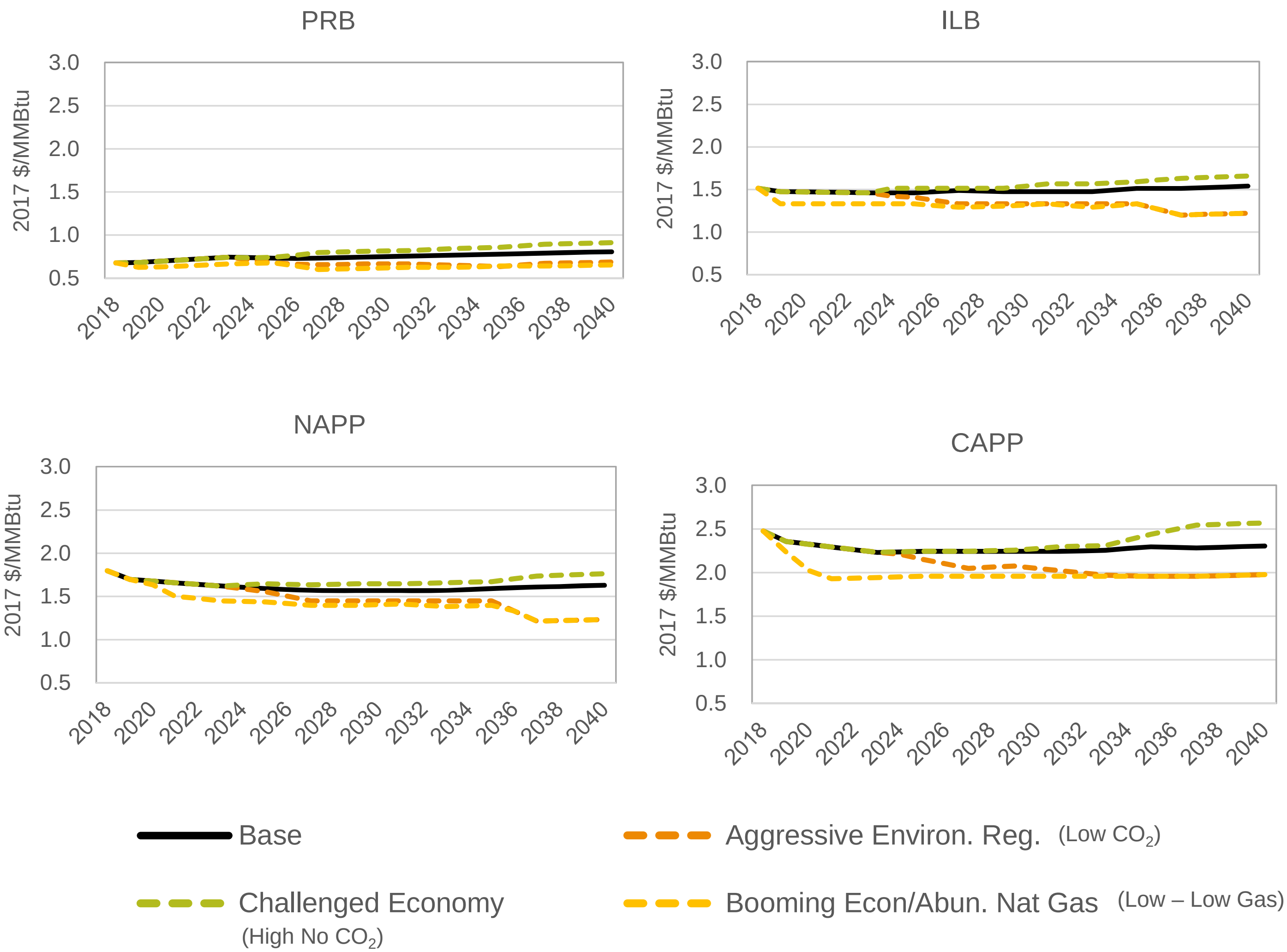
Scenario Range
(Chicago City gates)



Stochastic Distribution



Scenario Ranges of Discrete Variables - Coal



25% weighting: Challenged Economy (High Coal Price)

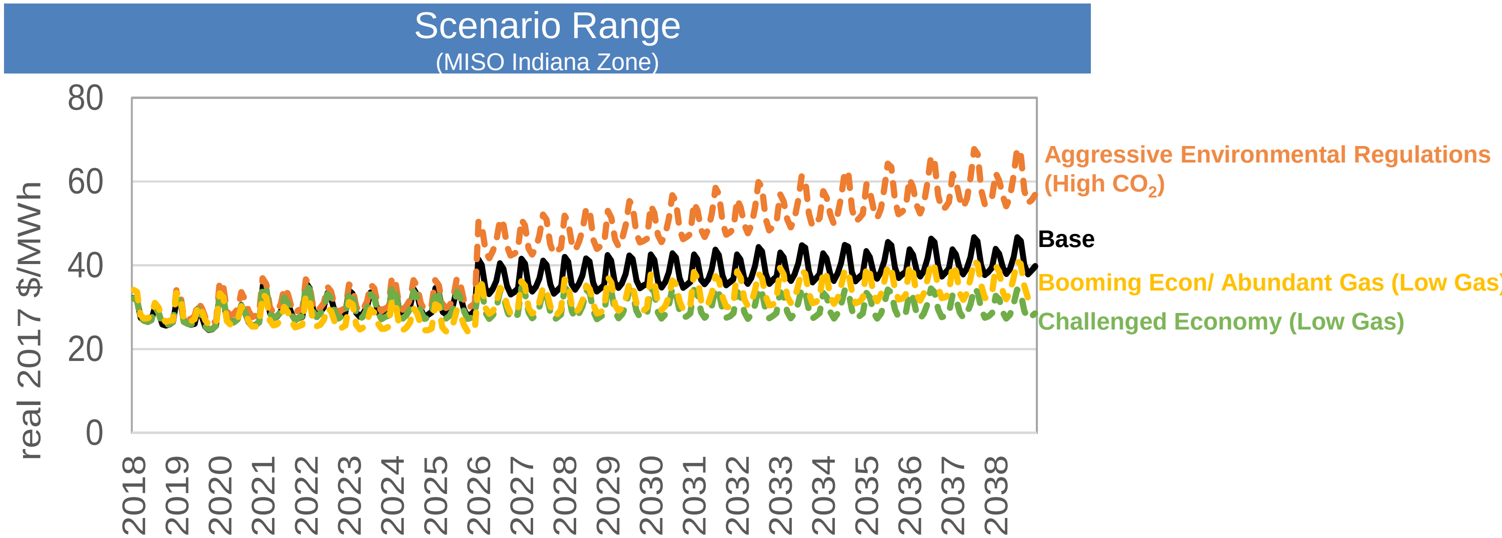
- Long-term demand generally up 10-35% without a carbon price, depending on coal basin

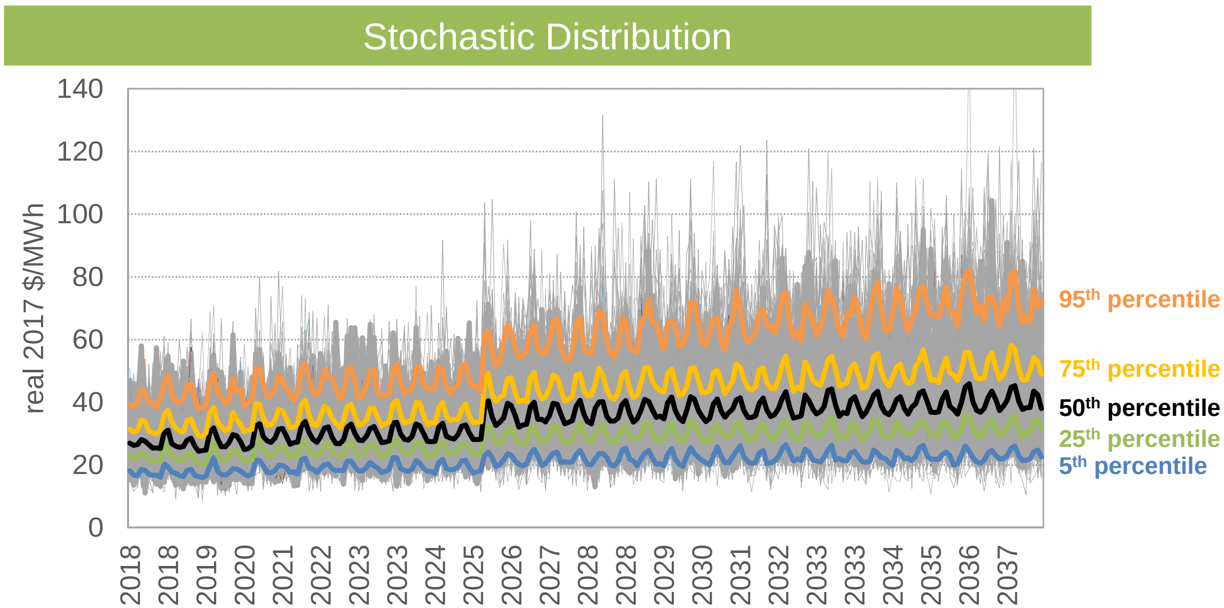
50% weighting: Base Case

25% weighting: Aggressive Environ. Reg. & Booming Econ/Abundant Natural Gas (Low Coal Price)

- Long-term demand down 10-50% with both high carbon and persistently low natural gas prices, depending on coal basin
- Short-term demand eroded under Abundant Natural Gas scenario

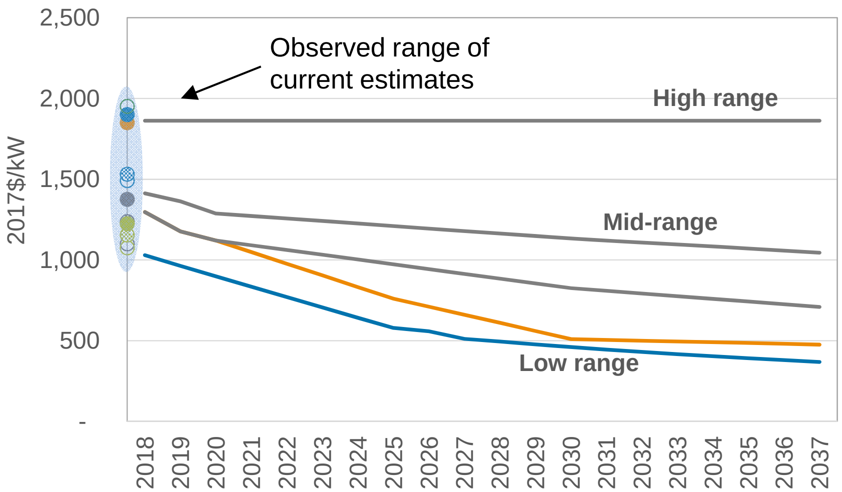
Scenario and Stochastic Ranges of Key Variables – Power Prices

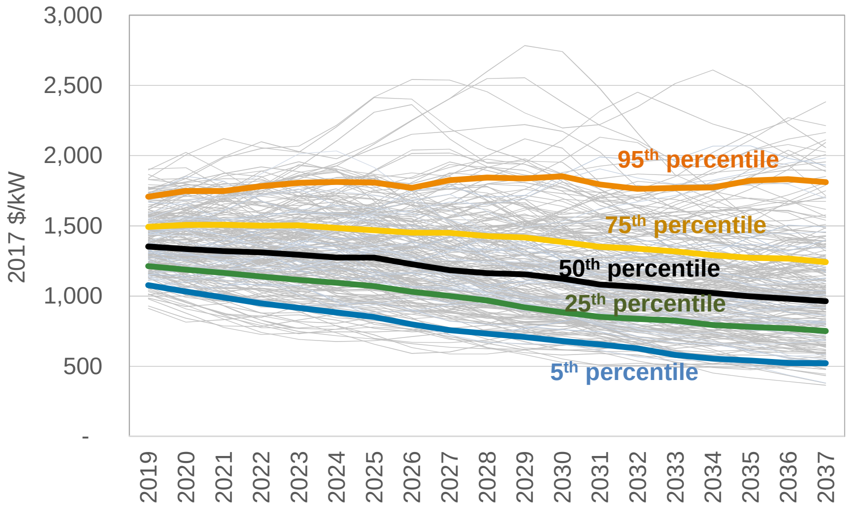




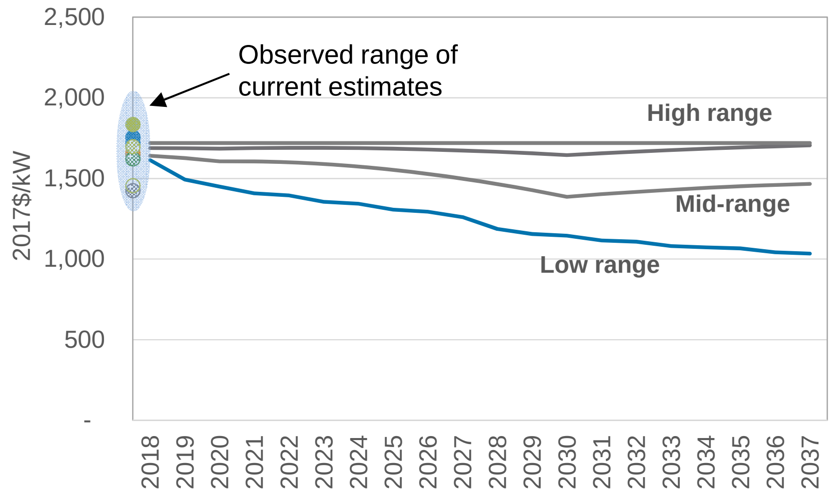
Scenario and Stochastic Ranges of Key Variables – Capital Costs

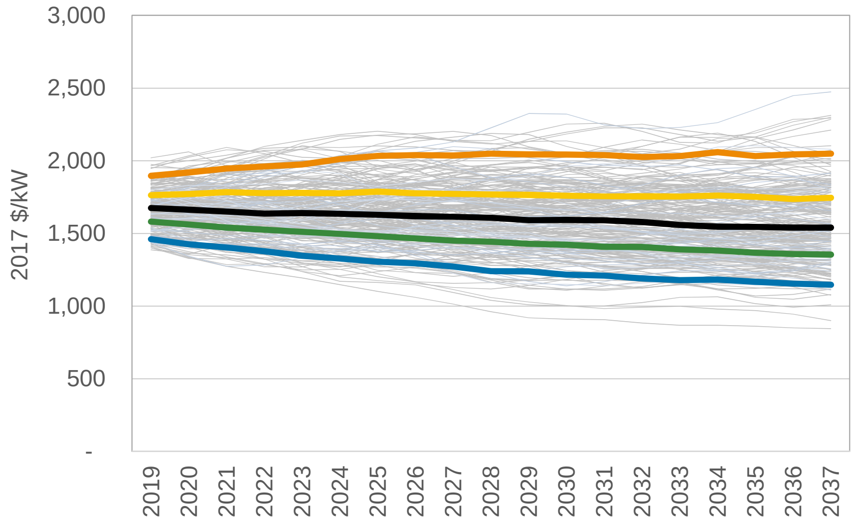
Solar Capital Costs





Wind Capital Costs





Break

DSM Modeling Methodology

Dick Spellman
GDS Associates, Inc.

Pat Augustine
Charles River Associates (CRA)

DSM Modeling Steps

Step 1	Step 2	Step 3
DSM Analysis	Identify DSM "bundles" or decrements	Analyze *each* "bundle" across *all* scenarios and full stochastic range
• Evaluate detailed program-level opportunities in service territory (DSM Savings Update) • Identify program impacts and associated costs	• Aggregate detailed DSM measures into "bundles" of measures that reflect energy savings potential at varying levels of measure costs per lifetime kWh saved • Produce bundles with detailed energy savings characteristics and costs	• Run each DSM "bundle" or decrement in IRP models against other resource options • Record savings, risks, environmental metrics • Assess vs. costs to identify the preferred DSM plan to be integrated into portfolio

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

NIPSCO Electric DSM Savings Update
Presentation to IRP Public Advisory Meeting

May 11, 2018

NIPSCO DSM SAVINGS UPDATE –STATUS REPORT

DSM Modeling Step 1

- NIPSCO's 2019 to 2021 DSM Goals
- Screening Uses Utility Cost Test
- Energy Efficiency MWH and MW Savings
  - 2019 to 2038
- Analysis of Demand Response

DSM SAVINGS UPDATE METHODOLOGY – ALL SECTORS

DSM Modeling Step 1

- DSM potential and costs (2019 -2021) match NIPSCO Program Plan filed with the Indiana Utility Regulatory Commission in Cause No. 45011
  - 2019 to 2021 projections developed by NIPSCO and Lockheed Martin
- Program participation for 2022+ based on participation trends from NIPSCO's August 2016 potential study (except residential lighting)
- For years after 2021, GDS added new measures from the NIPSCO 2016 potential study but not explicitly listed in the 2019 -2021 DSM plan
  - Measure incentive levels after 2021 are based on NIPSCO paying a percentage of measure incremental costs
- Program non-incentive costs include NIPSCO and vendor administration; evaluation, measurement and verification; and NIPSCO marketing
  - 2019 to 2021 non-incentive costs obtained from NIPSCO
- Program non-incentive costs per first-year kWh saved from program plan year 2021 escalated at half the rate of inflation

NIPSCO DSM BUDGETS – 2019 TO 2021

DSM Modeling Step 1

NIPSCO 2019 TO 2021 ENERGY EFFICIENCY PROGRAM BUDGETS				
Sector	2019	2020	2021	Total
Residential	$9,817,510	$9,815,352	$9,809,956	$29,442,818
Commercial/Industrial	$9,047,189	$10,052,433	$11,057,674	$30,157,296
Total	$18,864,699	$19,867,785	$20,867,630	$59,600,114
INCREMENTAL ANNUAL MWH SAVINGS	122,974	130,947	138,918	392,839
$ Per First Year kWh Saved	$0.153	$0.152	$0.150	$0.152

2018 ELECTRIC DSM SAVINGS UPDATE – METHODOLOGY

DSM Modeling Step 1

- The Electric DSM Savings Update covers a 30-year time horizon (2019-2048).
- DSM savings update "base case" excludes savings for commercial and industrial ("C&I") customers who opted out of NIPSCO programs prior to 2017.
  - Final Update report will include potential savings for opted out customers.
- Impacts of Energy Independence and Security Act ("EISA") standards for efficacy of lighting measures reflected in the Update.
  - New standards will reduce lighting savings potential.
- NIPSCO's latest electric and natural gas avoided costs used in calculations of the Utility Cost Test.
  - This test is used to determine measure, program and portfolio cost effectiveness

NIPSCO RESIDENTIAL PROGRAMS 2019 -2021

DSM Modeling Step 1

- Heating, Ventilation and Air Conditioning Energy Efficient Equipment Rebates
- Residential Lighting
- Home Energy Assessment
- Appliance Recycling
- School Education
- Multifamily Direct Install
- Home Energy Report
- Multifamily Direct Install
- Home Energy Report
- Residential New Construction
- HomeLife Energy Efficiency Calculator
- Employee Education
- Income Qualified Weatherization

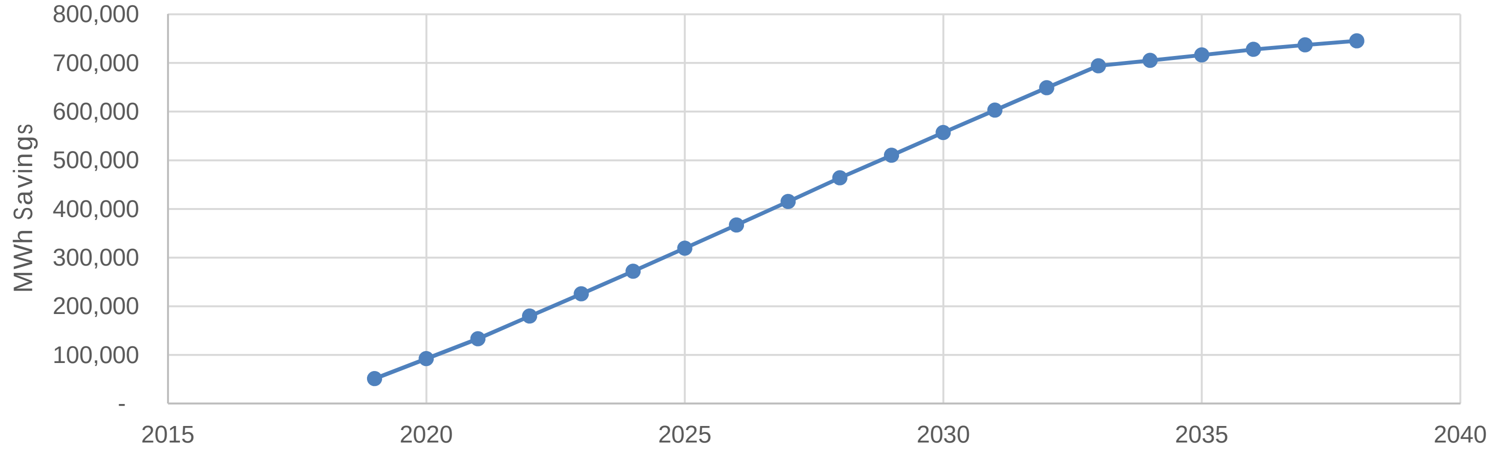
RESIDENTIAL MEASURES ADDED BY GDS AFTER 2021

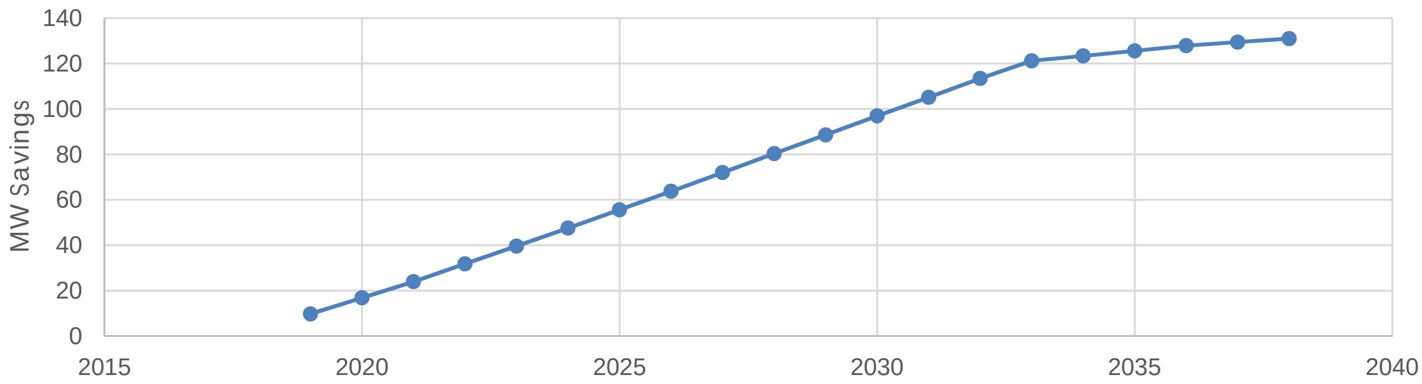
DSM Modeling Step 1

- Low Income Whole- House Program
- Dryer Vent Cleaning
- Refrigerator Coil Cleaning
- High Efficiency Clothes Washer
- High Efficiency Refrigerator
- High Efficiency Freezer
- High Efficiency Dehumidifier
- High Efficiency TV
- Energy Star ® PCs
- Energy Star Printer/Fax/Copier
- Energy Star Monitor
- High Efficiency Well Pump
- High Efficiency Clothes Dryer
- High Efficiency Hot Tub/Spa

RESIDENTIAL CUMULATIVE ANNUAL MWH AND MW SAVINGS

DSM Modeling Step 1





These are preliminary results.

C&I PROGRAMS 2019 -2021

DSM Modeling Step 1

- Prescriptive
- Custom
- C&I New Construction
- Small Business Direct Install
- Retro Commissioning

C&I MEASURES ADDED AFTER 2021

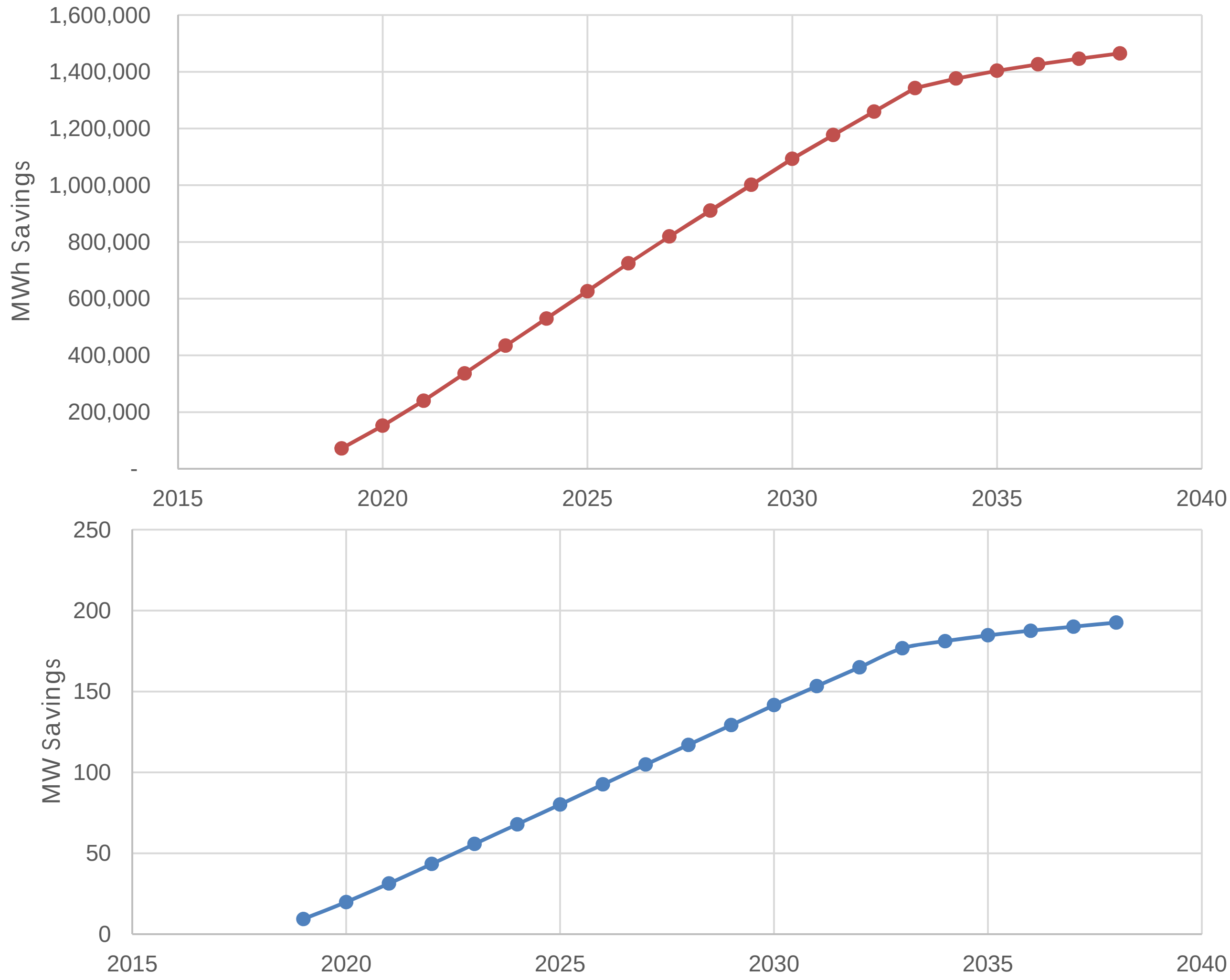
DSM Modeling Step 1

- Chiller, Rooftop Unit ("RTU"), Compressed Air, Fan System, Pumping System Maintenance
- Energy Star Office Equipment/Point-of-Sale Terminal
- HVAC Duct Repair and Sealing, Economizer
- Building Shell – Increased Insulation (R-value)
- Pool Pump Timer
- Pre-Rinse Spray Valve
- High Efficiency/Variable Speed Refrigeration Compressor, Floating Head Pressure Controls
- Room Air Conditioner
- RTU – Evaporative Precooler
- Water Heating – Desuperheater, Drainwater Heat Recovery, Faucet Aerator, Pipe Insulation, Solar
- Chilled Water Reset
- Geothermal Heat Pump
- Compressed Air Variable Frequency Drives
- Efficient Motor Rewind
- High Efficiency Transformers
- Agricultural Energy Efficiency Measures

NOTE: These measures may currently be available through the Custom program, but were added as specific measures for analysis and energy efficiency potential modeling purposes.

C&I CUMULATIVE ANNUAL MWH AND MW SAVINGS

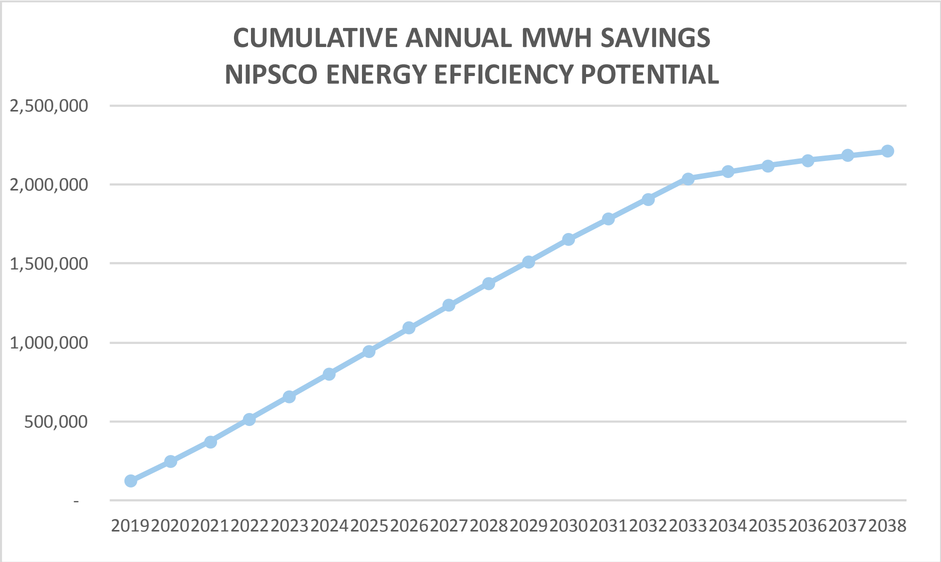
DSM Modeling Step 1

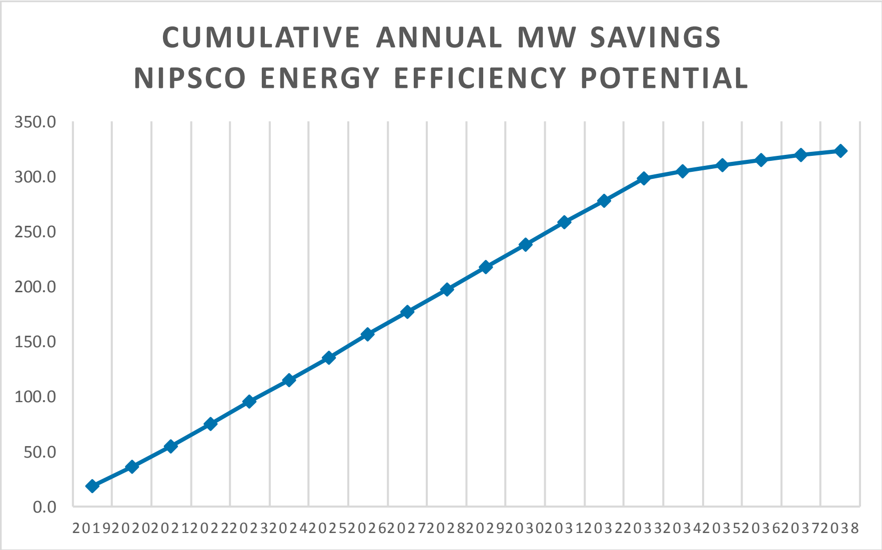


These are preliminary results.

TOTAL (ALL SECTORS) ANNUAL MWH AND MW SAVINGS

DSM Modeling Step 1

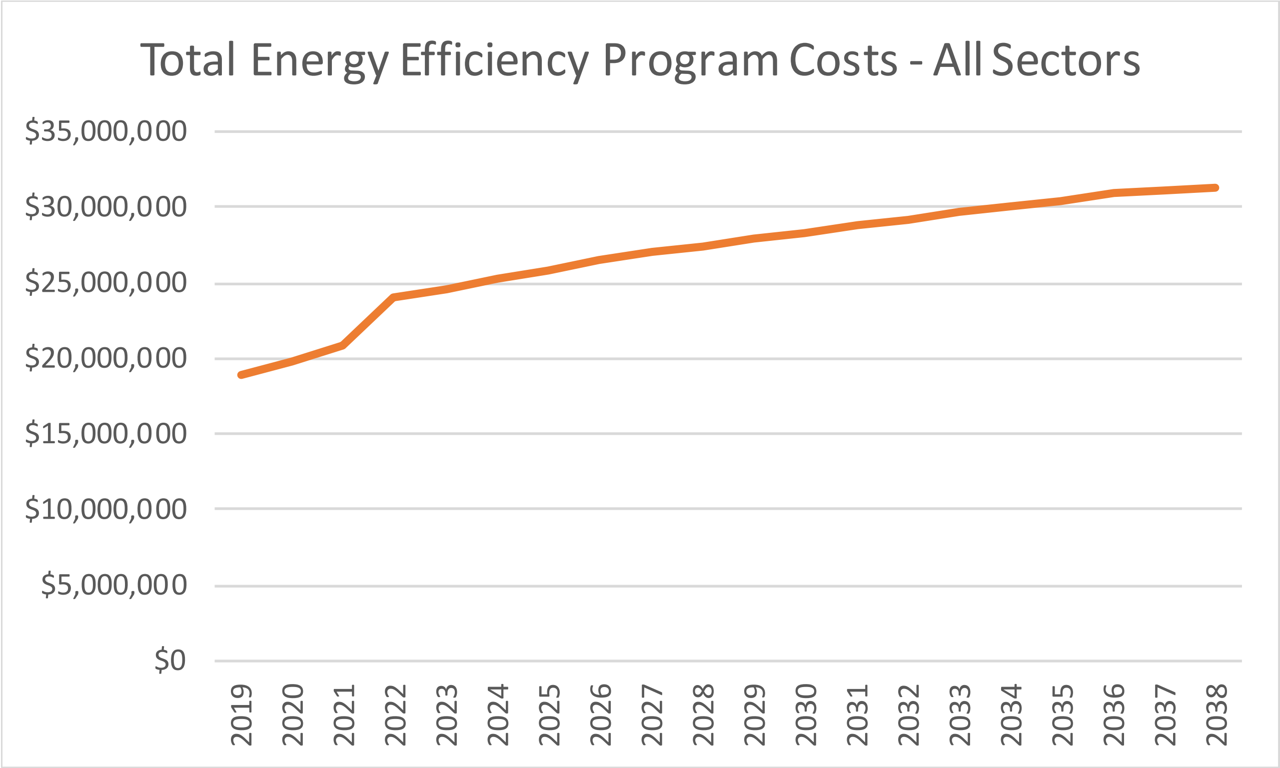




These are preliminary results.

TOTAL ENERGY EFFICIENCY PROGRAM COSTS

DSM Modeling Step 1



These are preliminary results.

DEMAND RESPONSE MEASURES FOR THE DSM SAVINGS UPDATE (RESIDENTIAL AND C&I)

- Direct load control – Central Air Conditioning
- Direct load control – Electric Water Heating
- Interruptible load tariffs
- Third Party Aggregator

NEXT STEPS FOR DSM UPDATE REPORT

DSM Modeling Step 1

- DSM Electric Savings Update report and achievable potential data inputs for the IRP are due June 1, 2018.
- In May will develop “low,” “medium,” and “high” DSM scenarios for input into IRP models and refine estimates of program costs and savings.

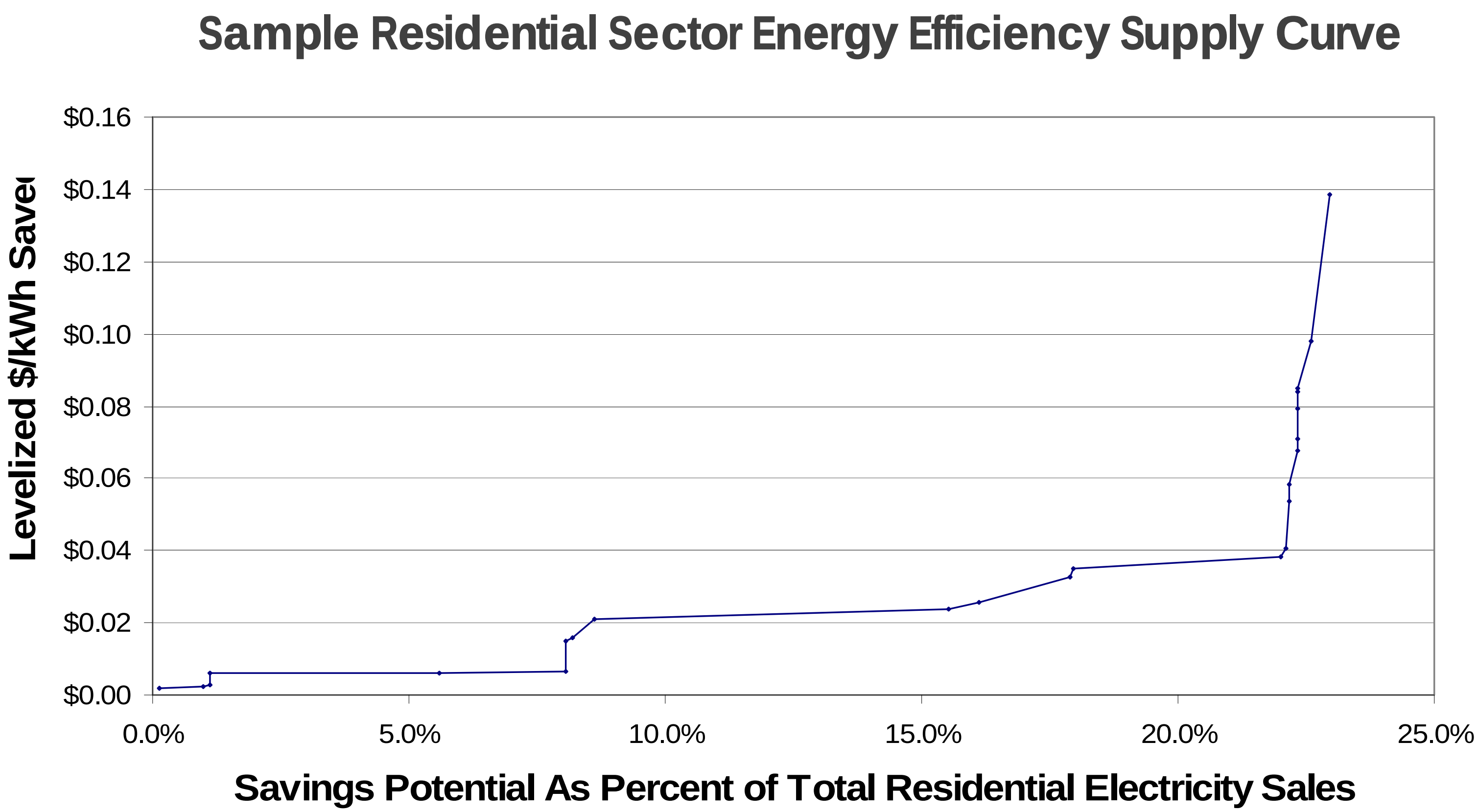
IDENTIFY DSM "BUNDLES"

DSM Modeling Step 2

- For the "low", "medium" and "high" DSM scenarios, GDS sorted energy efficiency measures into categories based on the measure cost per lifetime kWh saved.
- For example, all energy efficiency measures costing less than $.01 per lifetime kWh saved were included in bundle #1.
- Measures costing from $.01 to $.02 were included in bundle #2, and so forth.
- This creates an energy efficiency supply curve.

EXAMPLE ENERGY EFFICIENCY SUPPLY CURVE

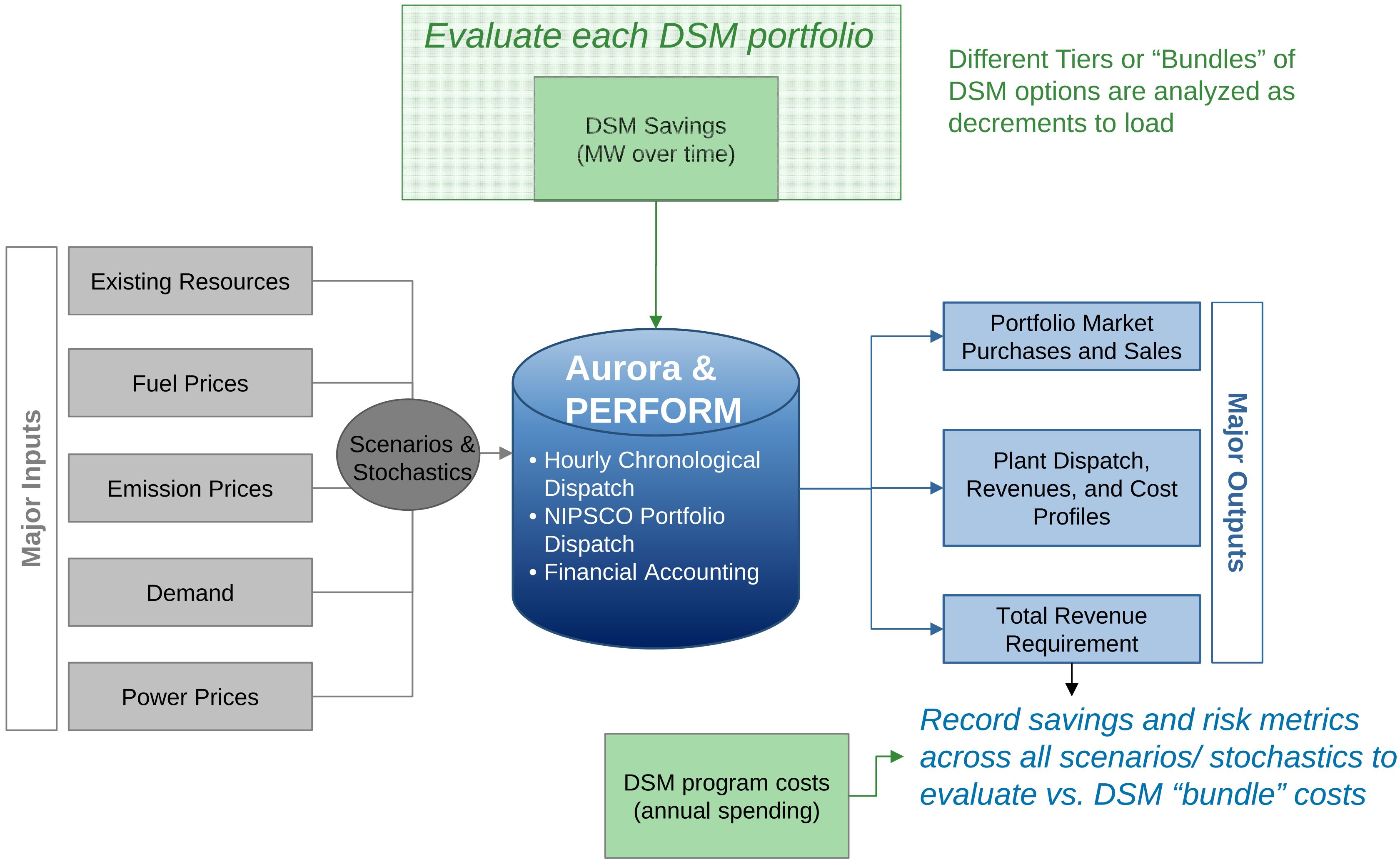
DSM Modeling Step 2



DSM Modeling Steps

Step 1	Step 2	Step 3
DSM Analysis	Identify DSM "bundles" or decrements	Analyze *each* "bundle" across *all* scenarios and full stochastic range
• Evaluate detailed program-level opportunities in service territory (DSM Savings Update) • Identify program impacts and associated costs	• Aggregate detailed DSM measures into "bundles" of measures that reflect energy savings potential at varying levels of measure costs per lifetime kWh saved • Produce bundles with detailed energy savings characteristics and costs	• Run each DSM "bundle" or decrement in IRP models against other resource options • Record savings, risks, environmental metrics • Assess vs. costs to identify the preferred DSM plan to be integrated into portfolio

DSM Modeling in IRP

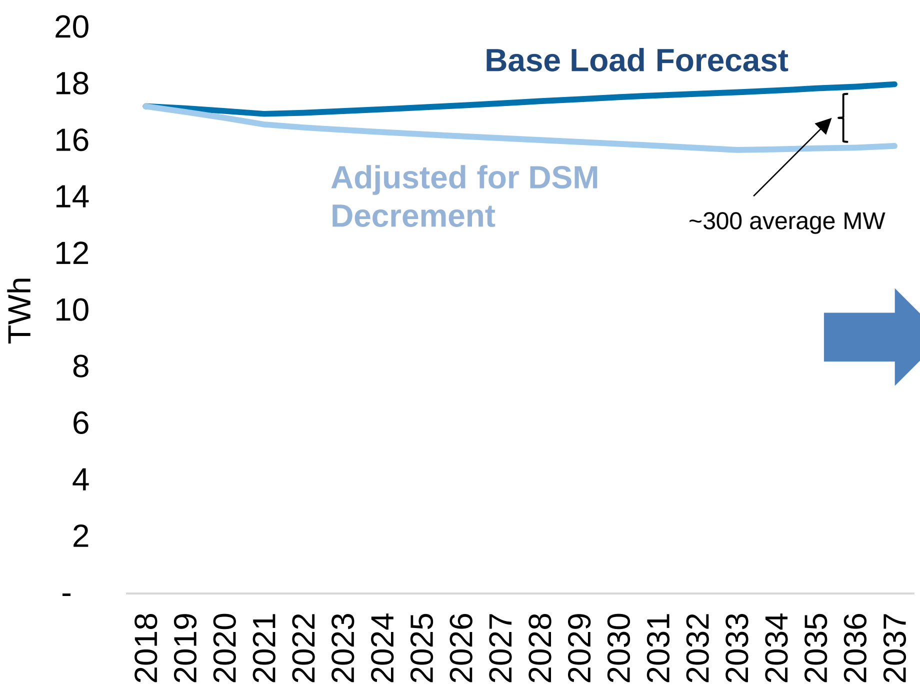


DSM Modeling in IRP

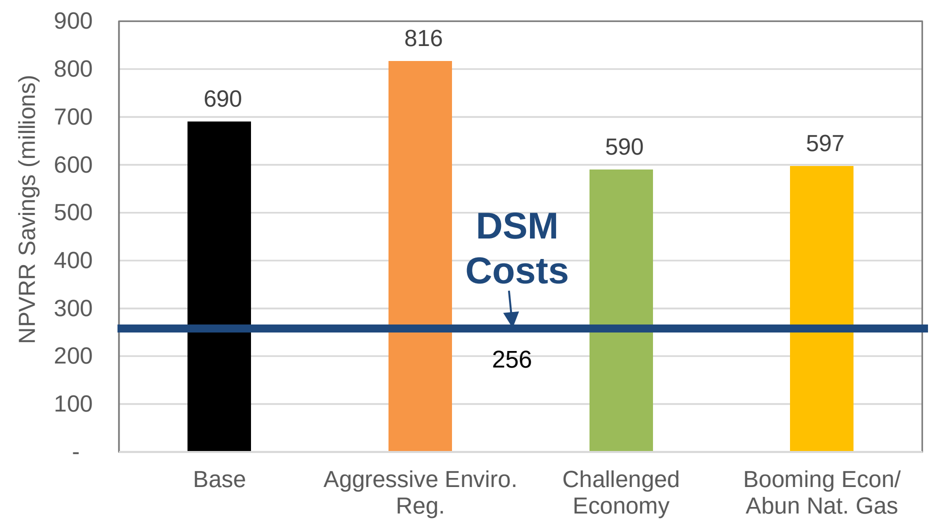
- **Once DSM decrements are identified, they will be run through IRP models to evaluate savings under scenarios and stochastics, accounting for all major uncertainties**
  – Uncertainties will include DSM costs and DSM savings volumes over time

Illustrative

Load Impact



Savings Summary



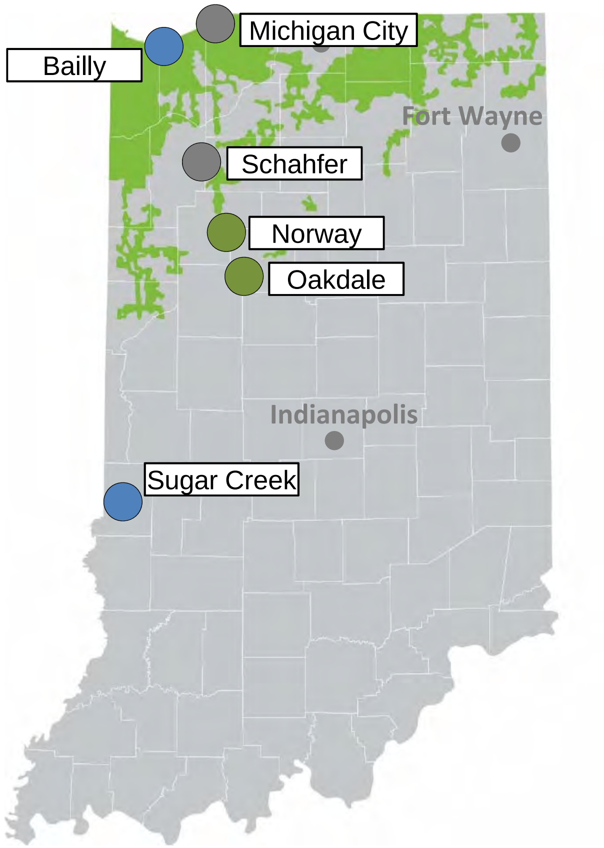
Analysis to be performed for each bundle to evaluate preferred DSM plan

*Note: Indicative analysis has been performed for "mid-case" DSM bundle under initial cost and savings estimates. As the IRP proceeds, more detailed analysis for all bundles, inclusive of hourly savings profiles, for all scenarios and stochastics will be performed.

Generation Overview

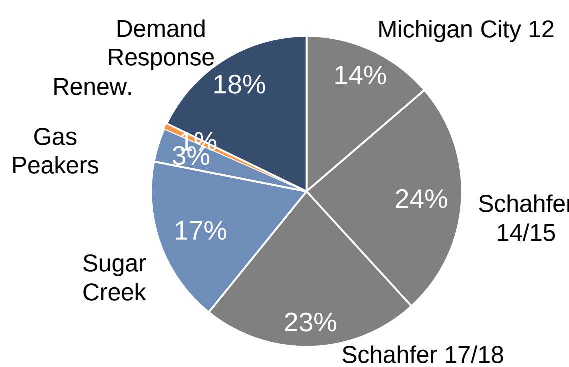
Fred Gomos
Manager, Corporate Strategy & Development

NIPSCO 2018 Supply Resource Overview

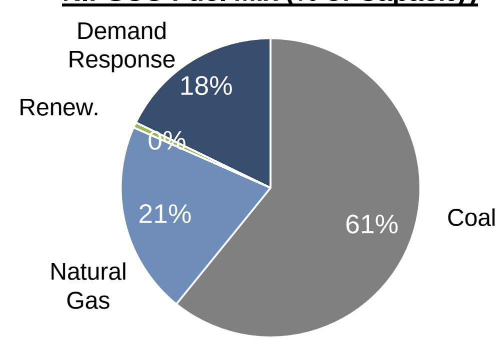


Resource	Unit	Fuel	Capacity NDC (MW)	Capacity UCAP (MW)	% of Capacity (UCAP)
Michigan City	12	Coal	469	418	14%
Schahfer	14	Coal	431	320	10%
	15	Coal	472	428	14%
	16A	NG	78	64	2%
	16B	NG	77	25	1%
	17	Coal	361	344	11%
	18	Coal	361	346	11%
		Subtotal	1,780	1,527	50%
Sugar Creek		NG	535	526	17%
Bailly	10	NG	31	18	1%
Hydro	Norway	Water	4	2	0%
	Oakdale	Water	6	2	0%
		Subtotal	10	3	0%
Wind		Wind	100	14	0%
Demand Response		DSM / Interrupt.	559	559	18%
NIPSCO			3,484	**3,066**	100%

NIPSCO Generation (% of Capacity)



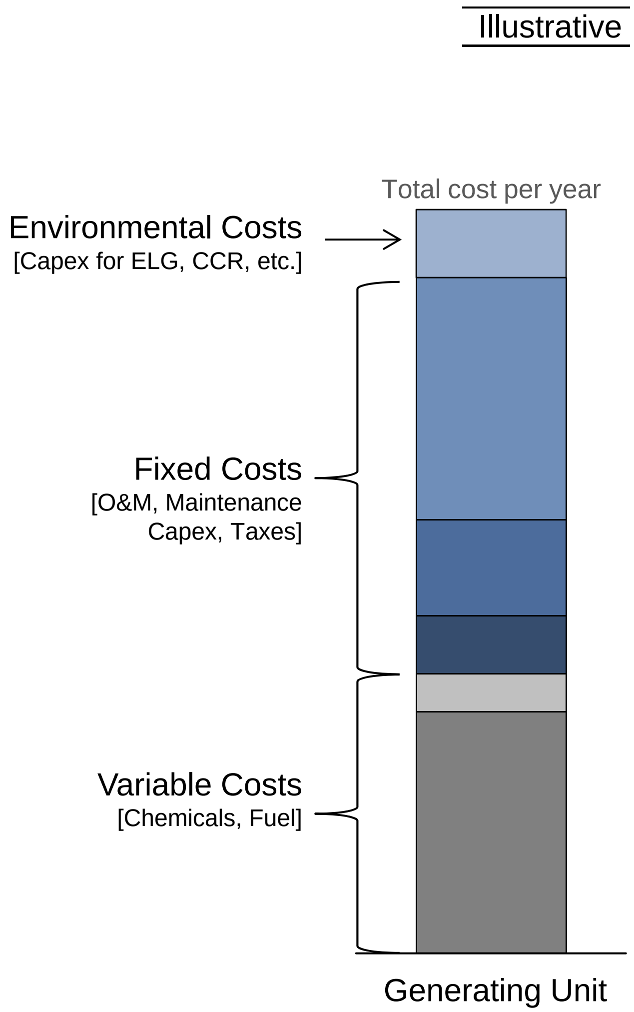
NIPSCO Fuel Mix (% of Capacity)



NDC: Net Demonstrated Capacity

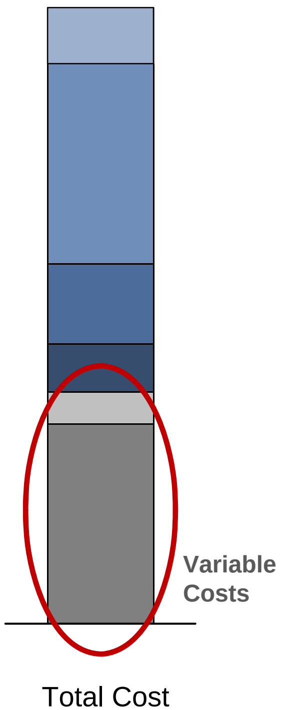
Generation Costs

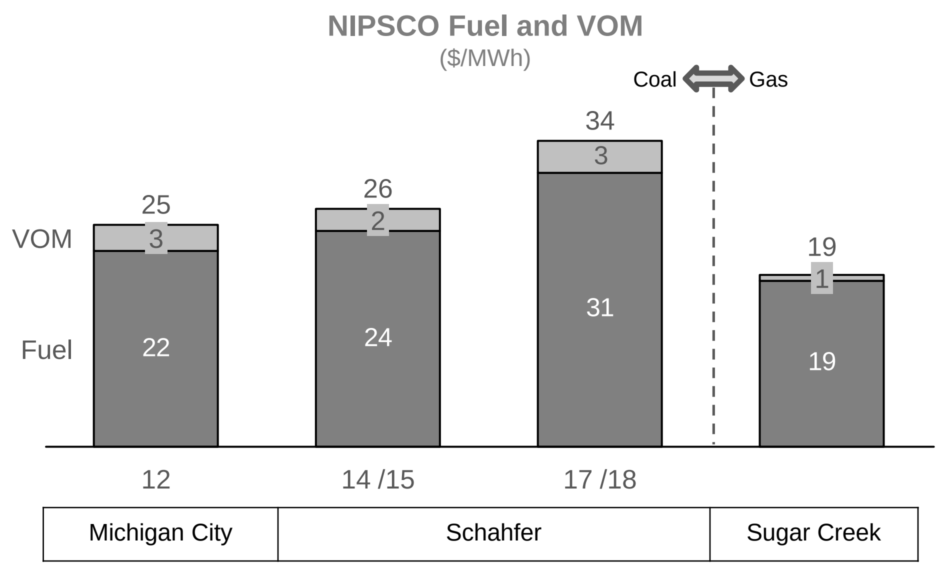
- **Generation costs vary for each NIPSCO unit**
- **Key cost components are:**
  - Environmental costs for controls required to be compliant with future regulations like effluent limitations guidelines (ELG) and coal combustion residuals (CCR)
  - Fixed costs including operations and maintenance (O&M), labor, capital recovery, allowed return, any necessary maintenance capital expenses (Maintenance Capex), and taxes
  - 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 (coal or natural gas) is the largest variable cost for NIPSCO units
- Variable Operation and Maintenance (VOM) costs include chemicals for environmental controls and are generally higher for coal versus natural gas fuel generators

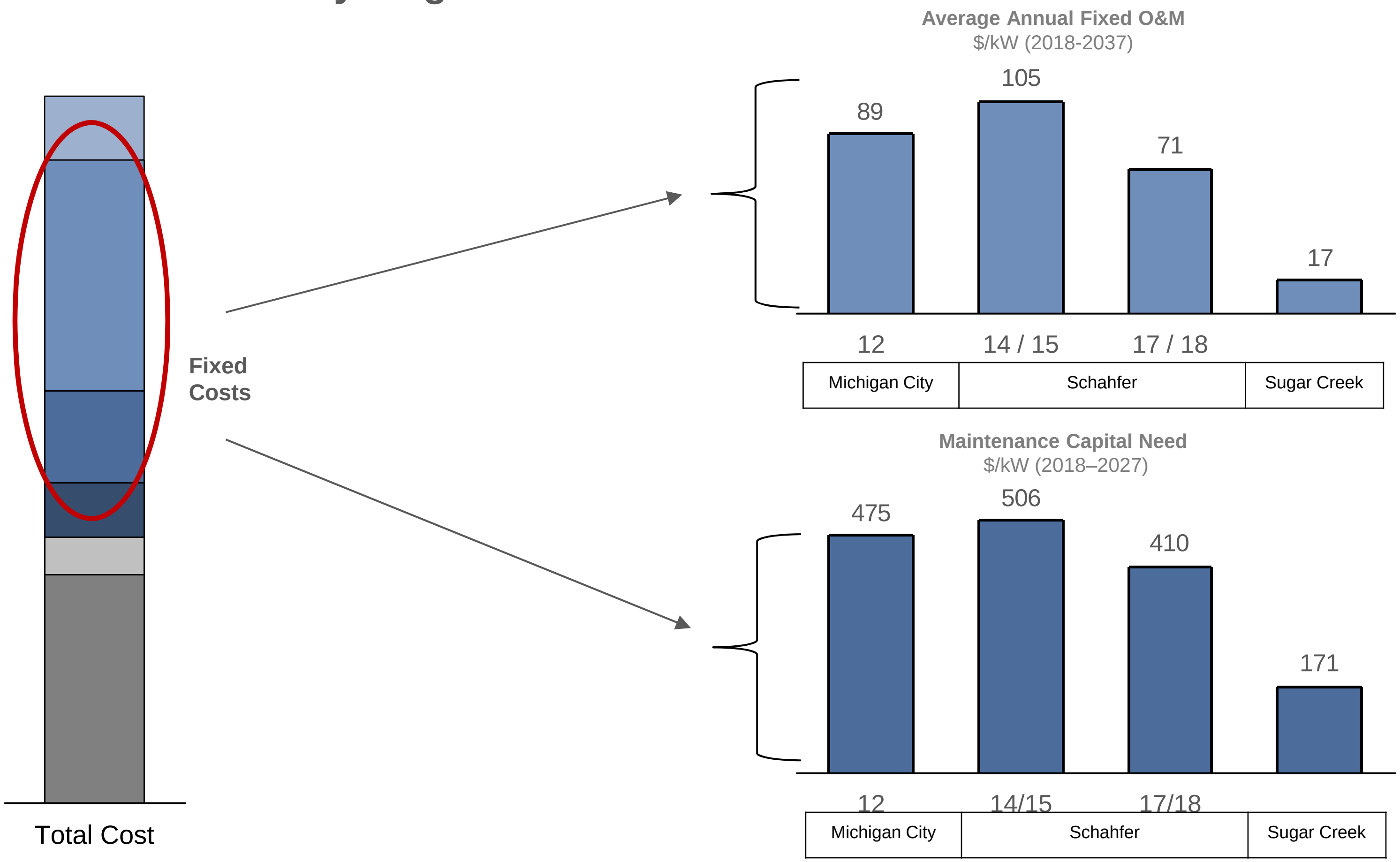




Notes: Cost shown here represent 2018 forecasts based on average annual heat rates, NIPSCO coal and natural gas prices based on 2018 contract prices; coal range from $2.06 - $2.54 $/MMBtu, Natural gas $2.61 $/MMBtu all in real 2017 $. Variable costs can vary based on market conditions.

Operating and Maintenance Costs for NIPSCO Units

- **Coal units have sizeable ongoing maintenance capital needs to relative to alternatives**
- **NIPSCO coal units have ~4 to 5x higher fixed operating and maintenance costs than combined cycle gas turbines**



Notes: Fixed O&M is based on 20 year average assuming units are retained until age based retirement date. Maintenance capital is based on a 10 year forecast divided by unit UCAP

Environmental Considerations

Kelly Carmichael
Vice President Environmental

Stakeholder Request: NiSource Environmental Targets Announced In 2017 – On Track

Reduction by 2025

Air Emissions Nitrogen Oxides Sulfur Dioxide Mercury	90%
Water Withdrawal	90%
Wastewater Discharge	90%
Coal Ash Generated	60%
Greenhouse Gas (Electric Generation & Methane)	50%

*** Reductions from 2005 Levels**

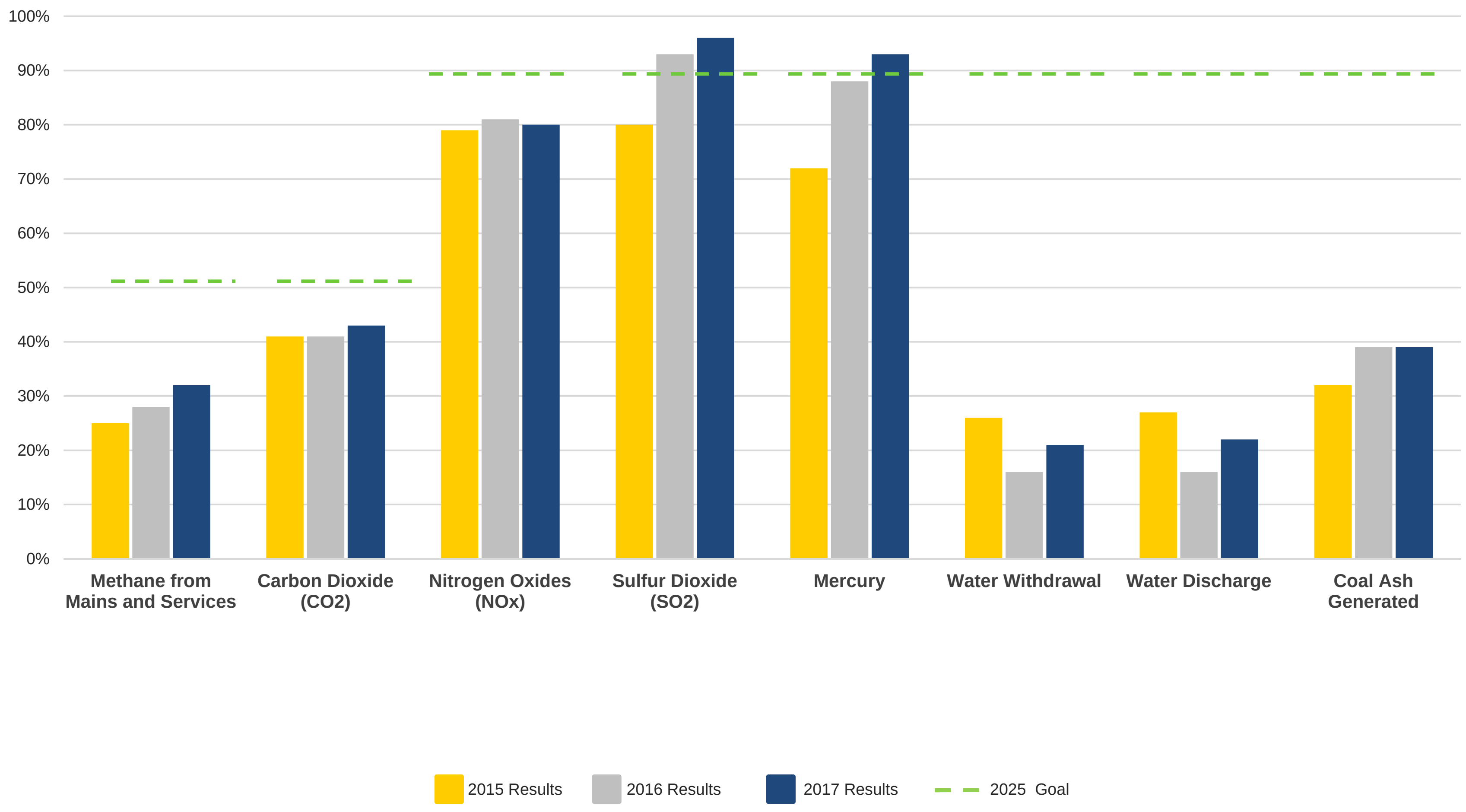
Greenhouse Gas Targets

Paris Accord U.S. Target
26-28% by 2025 from 2005 Levels

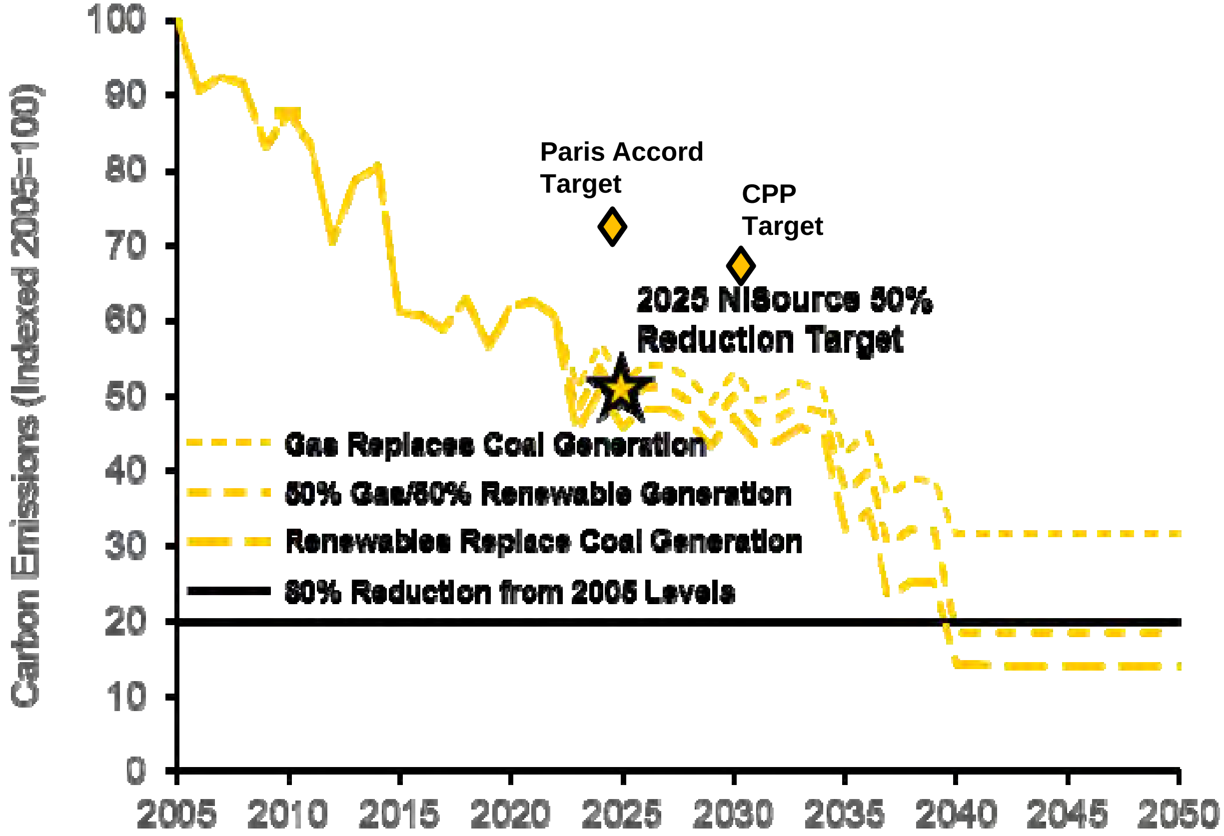
Clean Power Plan (CPP) Target
32% by 2030 from 2005 Levels

NiSource Target
50% by 2025 from 2005 Levels
(Paris and CPP Achieved 10+ Years Early)

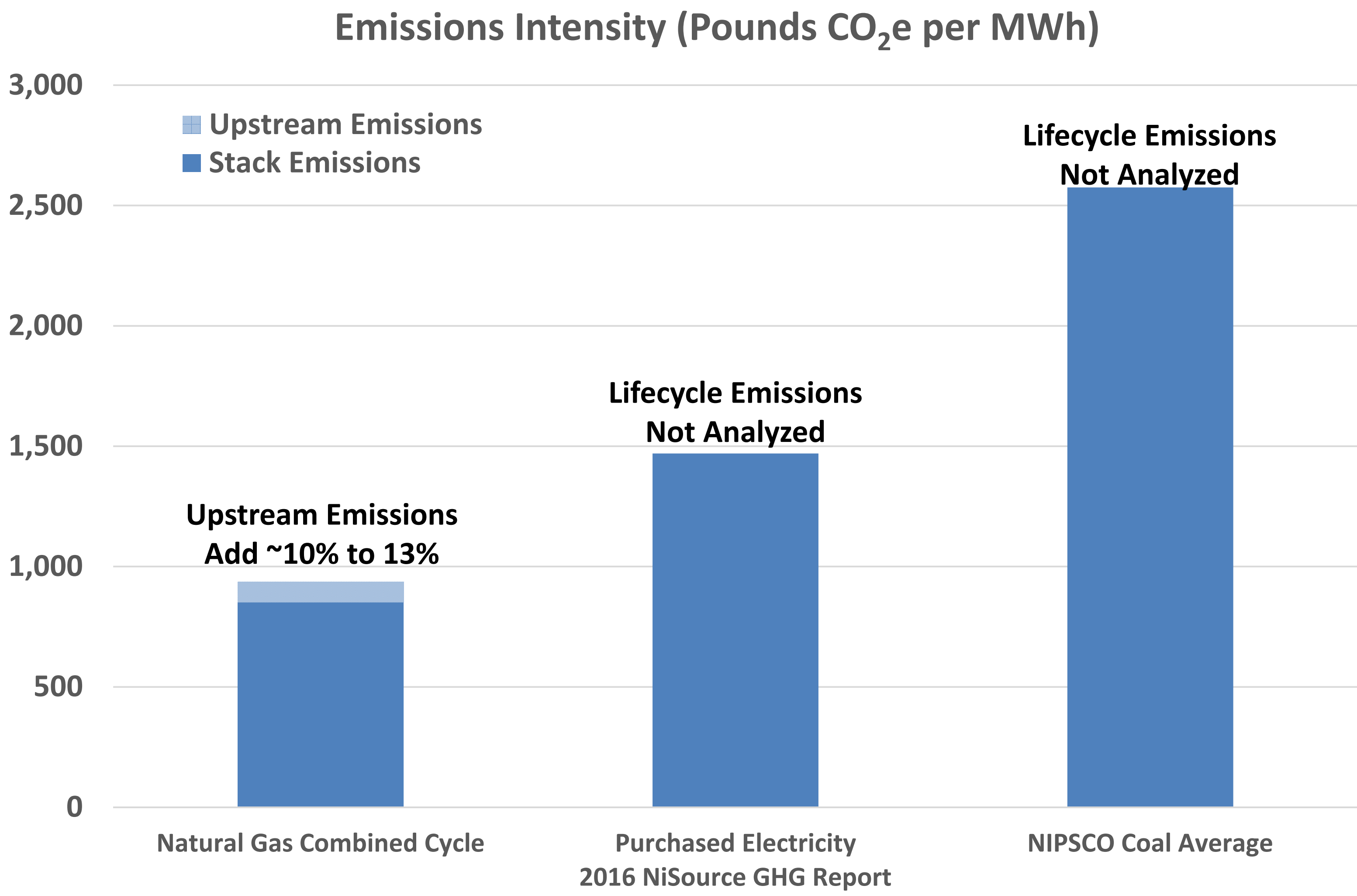
Stakeholder Request: NiSource Environmental Targets Announced In 2017 – On Track



Stakeholder Request: NiSource Carbon Emissions Trajectories



Stakeholder Request: Carbon Emissions Comparison



Natural Gas Combined Cycle lifecycle data derived from EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2016 and 1.2% methane leakage as found in https://www.epa.gov/sites/production/files/2017-08/documents/lacey_aga_-_ghgi_webinar_comments_on_uncertainty_analysis_aug_24_2017.pdf

Stakeholder Request: Northwest Indiana Achieves Environment Protection Agency (EPA) Health-Based Air Quality Standards

	# of IDEM* Monitors	NW Indiana** Data
Ozone	6	Achieves Standard***
Particulate Matter	12	Achieves Standard
Nitrogen Oxides (NOx)	1	Achieves Standard
Sulfur Dioxide (SO_2)	2	Achieves Standard
Carbon Monoxide	1	Achieves Standard
Lead	4	Achieves Standard

** Indiana Department of Environmental Management*
** Lake, Porter, LaPorte, Newton, & Jasper Counties*
****** Lake & Porter Counties are nonattainment for ozone due to their inclusion in the Chicago metropolitan statistical area (MSA). One monitor near the IL-WI border exceeded the standard.*

Key Environmental Rules Create Near Term Compliance Requirement

ELG and CCR Rule Summary

Coal Combustion Residuals (CCR)

- Regulates New and Existing Coal Ash Landfills and Surface Impoundments
- Phased Compliance 2015 - 2053
  - Phase I: Separate Ponds from Generation
  - Phase II: Close CCR Ponds
  - Phase III: Implement Groundwater Remedy and Monitoring
- EPA Reconsidering Portions of Rule
  - EPA Proposals in 2018; Final in 2019
  - May Add Flexibility into Compliance Plans
  - Overall Do Not Anticipate Significant Changes to NIPSCO Compliance Plan

Effluent Limitation Guidelines (ELG)

- National Standards for Treatment of Wastewater Streams
- Rule 'Finalized' in 2015
- Compliance Plan 2018 - 2023
  - Zero Liquid Discharge
    - Michigan City Unit 12
    - RM Schahfer Units 14 & 15
  - Retirements
    - Bailly Units 7 & 8
    - RM Schahfer Units 17 & 18
- EPA Reconsidering Portions of Rule
  - EPA Proposal in 2019; Final in 2020
  - Initial Compliance May Be Postponed
  - Revisiting Treatment Requirements
  - $170M Capital Recovery Filing Paused

Coal Combustion Residual (CCR) Compliance

- **Order granted by the Indiana Utility Regulatory Commission in December 2017 for CCR compliance on Units 12,14,15**
- **CCR compliance work is underway and largely complete; 90% of CCR spending expected by the end of 2018**
  - Because capital is largely spent, unit retirement analysis does not include any CCR savings when contemplating early retirement for units 12, 14 and 15
- **CCR compliance capital for Units 17/18 was not included in petition**
- **Cost for maintaining the option to retain Units 17/18 has increased**
  - Joint Units 14/15/17/18 CCR compliance solution is no longer available
  - CCR compliance on Units 17/18 would require a stand-alone project with cost estimate of ~$85M (direct costs only, does not include indirect costs or allowance for funds used during construction)
    - Approximately equivalent to the Units 14/15 remote ash conveying cost since units are similar

CCR costs are no longer incremental for Units 12/14/15 and have increased for Units 17/18

Effluent Limitation Guidelines Compliance

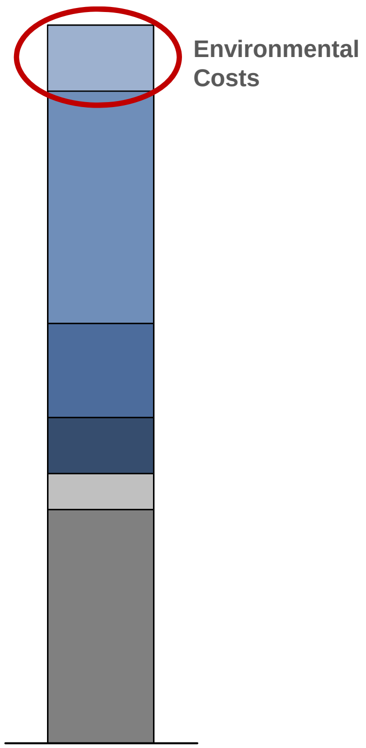
Compliance Path	Description	Cost Estimate		
Zero Liquid Discharge (ZLD)	• Most stringent; no wastewater • Units 14/15 <150gpm required treatment • Units 17/18 800gpm requires treatment; more volume equals higher cost • Unit 12: dry FGD requires no capital for ELG compliance	Units 14/15 17/18 12	Capital Cost $170M $375M $0M	O&M cost $3M/y $7M/y $0M/y
Non-ZLD Option	• Less expensive; treatment of heavy metals • Units 14/15 <150gpm required treatment • Units 17/18 800gpm requires treatment • Unit 12: dry FGD requires no capital for ELG compliance	Units 14/15 17/18 12	Capital Cost $134M $310M $0M	O&M cost $0.8M/y $3.9M/y $0M/y
Retirement	• Retirement by rule ELG implementation date (assumed to be 2023) is a compliance pathway	• No cost		
Extended Compliance Date	• EPA may provide an extended compliance date beyond 2023	• TBD based on EPA rulemaking		

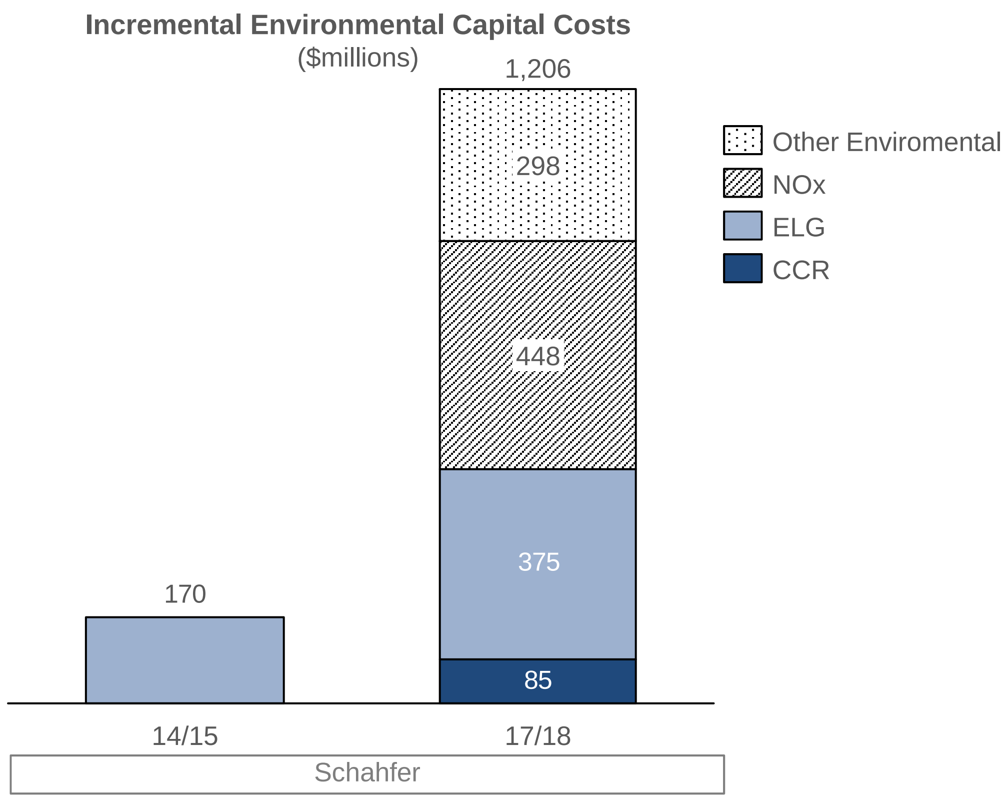
ELG compliance path not contemplated in 2016 IRP

Currently not part of the ELG Rule

Incremental Environmental Compliance Capital Costs By Unit

- NIPSCO coal units have varying levels of capital needs in order to comply with environmental rules
- Retaining Schahfer Units 17/18 beyond 2023 requires additional capital investment beyond ELG and CCR compliance





Sources and Notes: CCR costs not considered incremental for units 12,14,15; ELG cost based on ZLD compliance option assuming no retirement, retirement as a compliance option would lower compliance costs. NOx cost based on a 2024 in service date and assumes more stringent compliance standards by 2025. Other environmental include absorber vessels, dewatering system and stack lining replacement. NOx and Other Environmental costs reflect upper range of accuracy and includes directs, indirects and escalation

Lunch

2018 IRP Scorecard

Dan Douglas
Vice President Corporate Strategy & Development

The Proposed 2018 Scorecard Will Inform the NIPSCO Preferred Plan

2016 Scorecard
Cost to Customer
Portfolio Diversity
Environmental Compliance
Employees
Communities and Local Economy

2018 Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30 year net present value (NPV) of revenue requirement
Cost Certainty	• Certainty that revenue requirement within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: 95th percentile of cost to customer
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas
Environmental	• Reaching 80% Carbon reduction by 2050 • Metric: Total annual carbon emissions
Short Term Optionality	• Ability to adjust the portfolio to react to changes in Large Industrial load • Metric: Quantity of Industrial coincident demand matched to flexible resources
Long Term Optionality	• Flexibility resulting from combinations of ownership, duration, and diversity • Metric: Duration of generation commitments
Employees	• Net impact on NiSource jobs • Metric: Number of permanent NiSource jobs created / retained
Local Economy	• Affect on the local economy from property taxes and jobs • Metric: Charles River Associates developed economic multiplier

Retirement Analysis

Fred Gomos
Manager, Corporate Strategy & Development

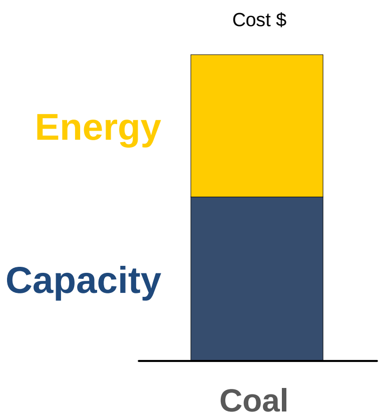
Pat Augustine
Charles River Associates (CRA)

The Retirement Analysis

- Framework evaluates the cost to keep a Unit versus the cost of retirement and replacement with an alternative
- 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

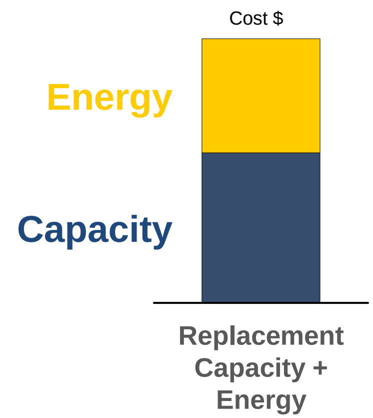


<
(Maintain Unit)

>
(Consider Retirement)

Cost of Alternative

- Ongoing variable costs
- Ongoing fixed costs
- Future environmental controls costs
- Cost to retire existing unit (transmission and distribution upgrades, remaining asset value)



Replacement assumed capacity priced at the highest possible capacity price (MISO cost of new entry, CONE) plus energy priced at market

A Projection of MISO's Cost of New Entry (CONE) Plus Energy is Used in the Retirement Analysis as a Proxy for Viable Alternative

Retirement Analysis

- MISO CONE + Market Energy

Step 1

Replacement Analysis

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

Step 2

Cost of Alternative

- Ongoing variable costs
- Ongoing fixed costs
- Future environmental controls costs
- Cost to retire existing unit (T&D upgrades, remaining asset value)

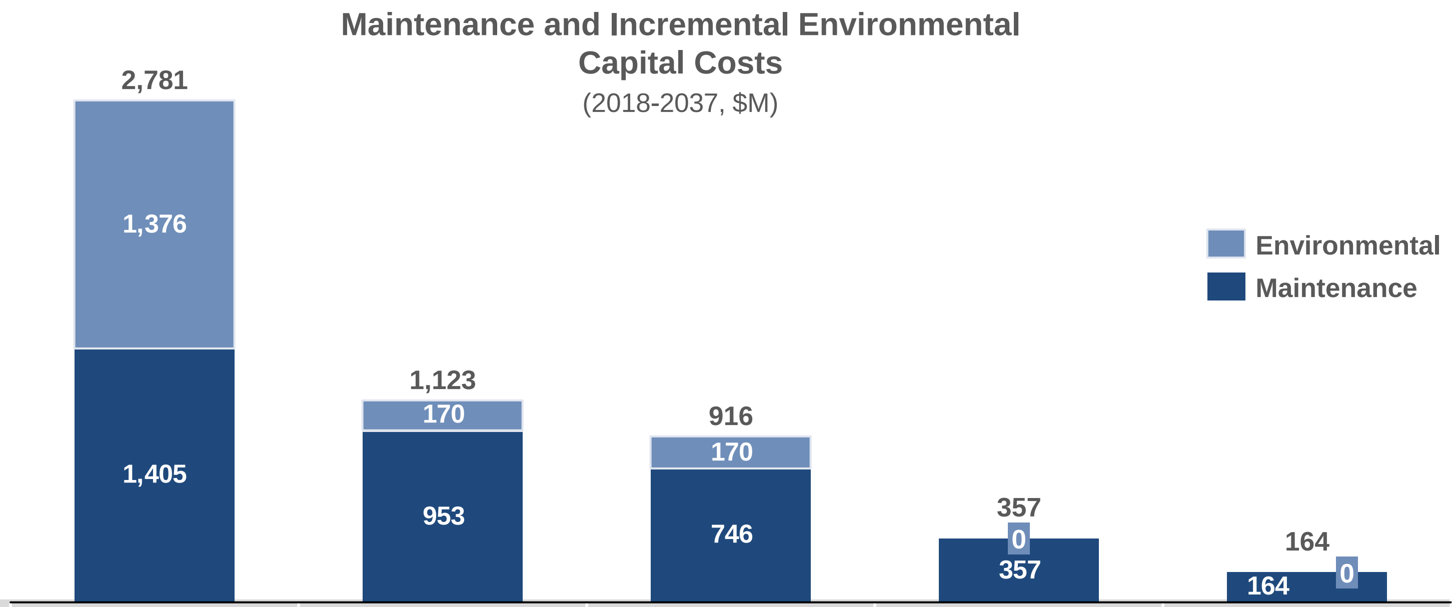
- **MISO's CONE + Energy is for retirement analysis only and is not NIPSCO's selection**
  - NIPSCO will optimize for other supply- and demand-side resources
- **MISO's CONE is a reasonable, conservative proxy because it represents the cost of new entry for MISO capacity**
  - The replacement analysis, supported by the RFP, will provide viable market alternatives
- **Retirement methodology is consistent NIPSCO's 2016 IRP analysis and with others in the industry**

Various Retirement Combinations Were Constructed

	1a	2a	3a	4	5
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal in 2030 w/ ELG**	**15% Coal in 2023**	**0% Coal in 2023**
Retire:	None	Schahfer:17,18 (2023)	Schahfer:17,18 (2023) Schahfer:14,15 (2030)	Schahfer:17,18 (2023) Schahfer:14,15 (2023)	Michigan City:12 (2023) Schahfer:17,18 (2023) Schahfer:14,15 (2023)
Retain:	Michigan City: 12 Schahfer:14,15,17,18	Michigan City: 12 Schahfer:14,15	Michigan City: 12 Schahfer:14,15	Michigan City: 12	None
Env. Compliance	CCR ELG: ZLD	CCR ELG: ZLD	CCR ELG: ZLD	CCR ELG: Retirement	CCR ELG: Retirement
Michigan City 12	**Retain** CCR ELG: N/A	→	→	→	**Retire 2023** CCR ELG: N/A
Schahfer 14	**Retain** CCR ELG: ZLD	→	**Retire 2030** CCR ELG: ZLD	**Retire 2023** CCR ELG: Retirement	→
Schahfer 15	**Retain** CCR ELG: ZLD	→	**Retire 2030** CCR ELG: ZLD	**Retire 2023** CCR ELG: Retirement	→
Schahfer 17	**Retain** CCR ELG: ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→
Schahfer 18	**Retain** CCR ELG: ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→

Capital Cost By Retirement Combination

- **Although there are some environmental cost savings, cost reduction from earlier retirement of coal units is primarily from avoided maintenance costs**

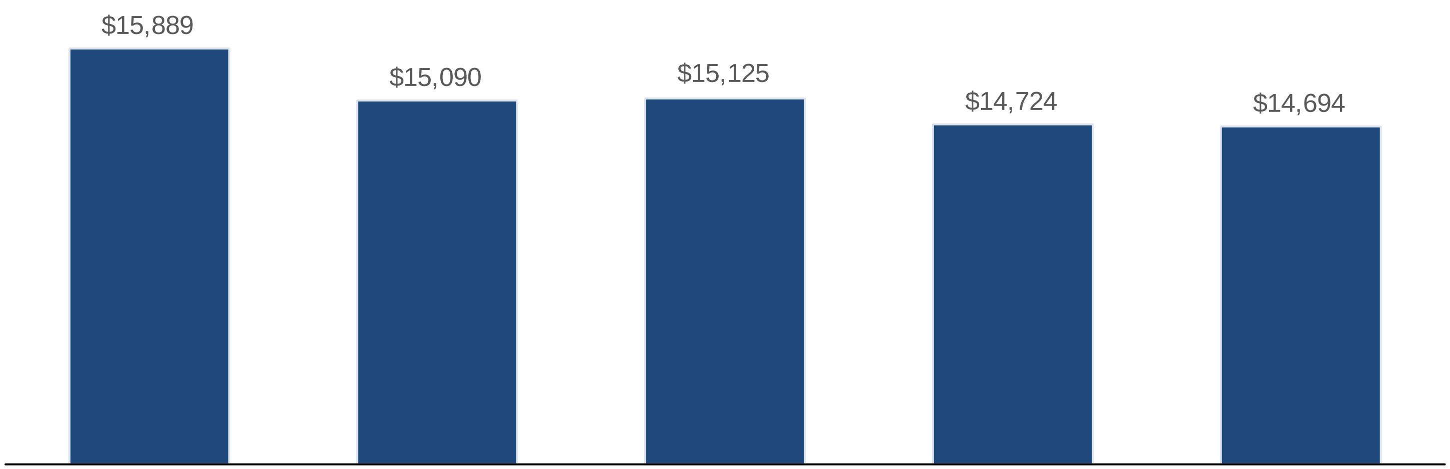


Portfolio Transition Target:	65% Coal through 2035 (1a)	40% Coal in 2023 (2a)	15% Coal in 2030 (3a)	15% Coal in 2023 (4)	0% Coal in 2023 (5)
Retire:	None	Schahfer:17,18 (2023)	Schahfer:17,18 (2023) Schahfer:14,15 (2030)	Schahfer:17,18 (2023) Schahfer:14,15 (2023)	Michigan City:12 (2023) Schahfer:17,18 (2023) Schahfer:14,15 (2023)
Retain:	Michigan City: 12 Schahfer:14,15,17,18	Michigan City: 12 Schahfer:14,15	Michigan City: 12 Schahfer:14,15	Michigan City: 12	None

Notes: CCR costs not considered incremental for units 12,14,15

Results: Deterministic Cost to Customers

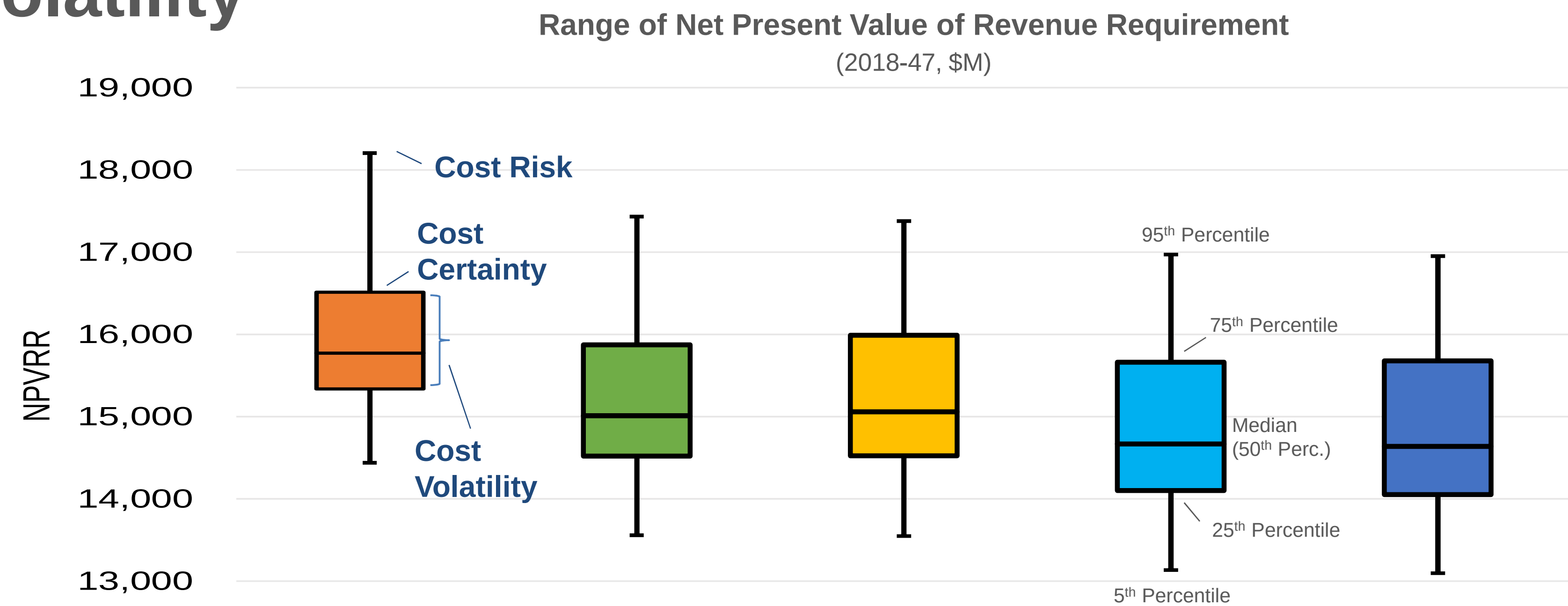
Net Present Value of Revenue Requirement
(2018-47, $M)



Portfolio Transition Target:	**65% Coal through 2035** 1a	**40% Coal in 2023** 2a	**15% Coal in 2030** 3a	**15% Coal in 2023** 4	**0% Coal in 2023** 5
Retire:	None	Schahfer:17,18 (2023)	Schahfer:17,18 (2023) Schahfer:14,15 (2030)	Schahfer:17,18 (2023) Schahfer:14,15 (2023)	Michigan City:12 (2023) Schahfer:17,18 (2023) Schahfer:14,15 (2023)
Retain:	Michigan City: 12 Schahfer:14,15,17,18	Michigan City: 12 Schahfer:14,15	Michigan City: 12 Schahfer:14,15	Michigan City: 12	None
Delta from Least Cost	$1,195M 8.1%	$397M 2.7%	$431M 2.9%	$30M 0.2%	--

Note: ZLD results shown here, Non-ZLD results are not materially different and are in the appendix.

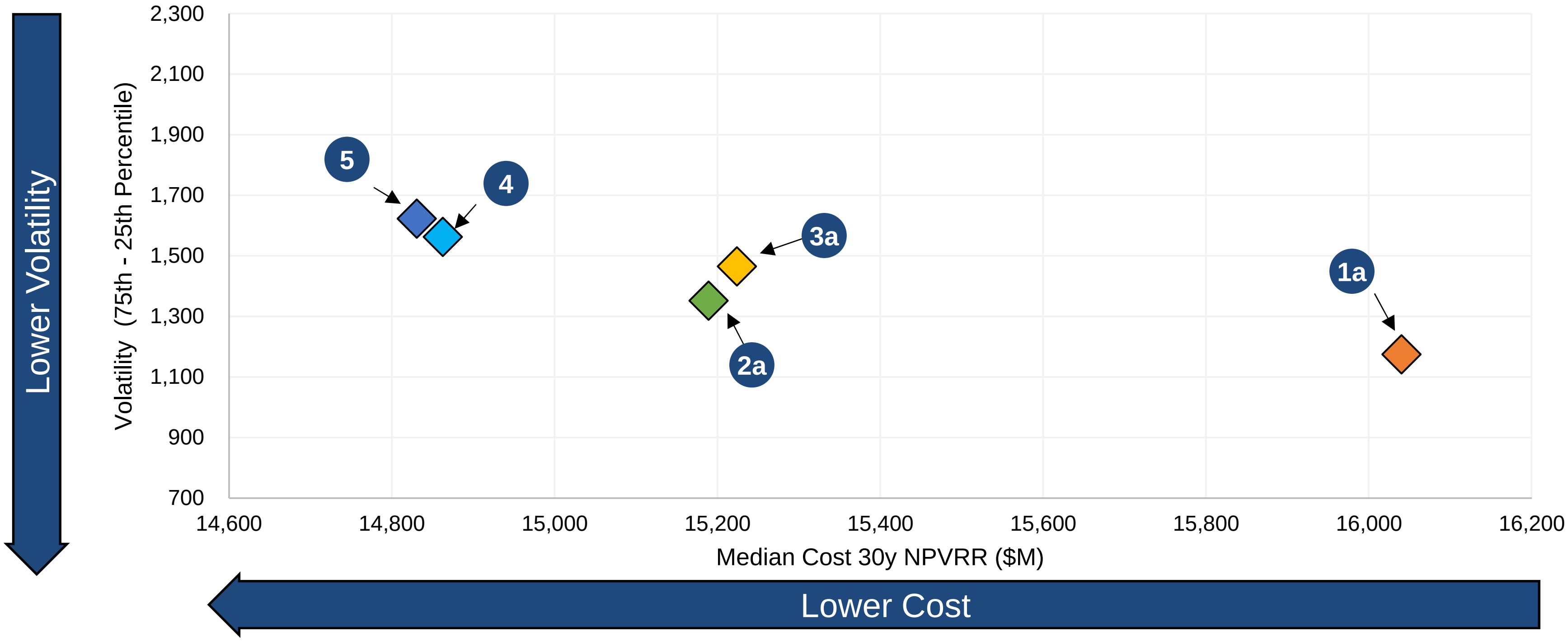
Results: Stochastic Cost Certainty, Risk, and Volatility



Portfolio Transition Target:	65% Coal through 2035 1a	40% Coal in 2023 2a	15% Coal in 2030 3a	15% Coal in 2023 4	0% Coal in 2023 5
Retire:	None	Schahfer:17,18 (2023)	Schahfer:17,18 (2023) Schahfer:14,15 (2030)	Schahfer:17,18 (2023) Schahfer:14,15 (2023)	Michigan City:12 (2023) Schahfer:17,18 (2023) Schahfer:14,15 (2023)
Retain:	Michigan City: 12 Schahfer:14,15,17,18	Michigan City: 12 Schahfer:14,15	Michigan City: 12 Schahfer:14,15	Michigan City: 12	None
Delta from Lowest Cost Certain (75th%)	+$849M 5.4%	+$211M 1.3%	+$326M 2.1%	+$0M 0%	+$14M 0.1%
Delta from Least Risk (95th%)	+$1,254M 7.4%	+$481M 2.8%	+$427M 2.5%	+$21M 0.1%	+$0M 0%

Note: ZLD results shown here, Non-ZLD results are not materially different and are in the appendix.

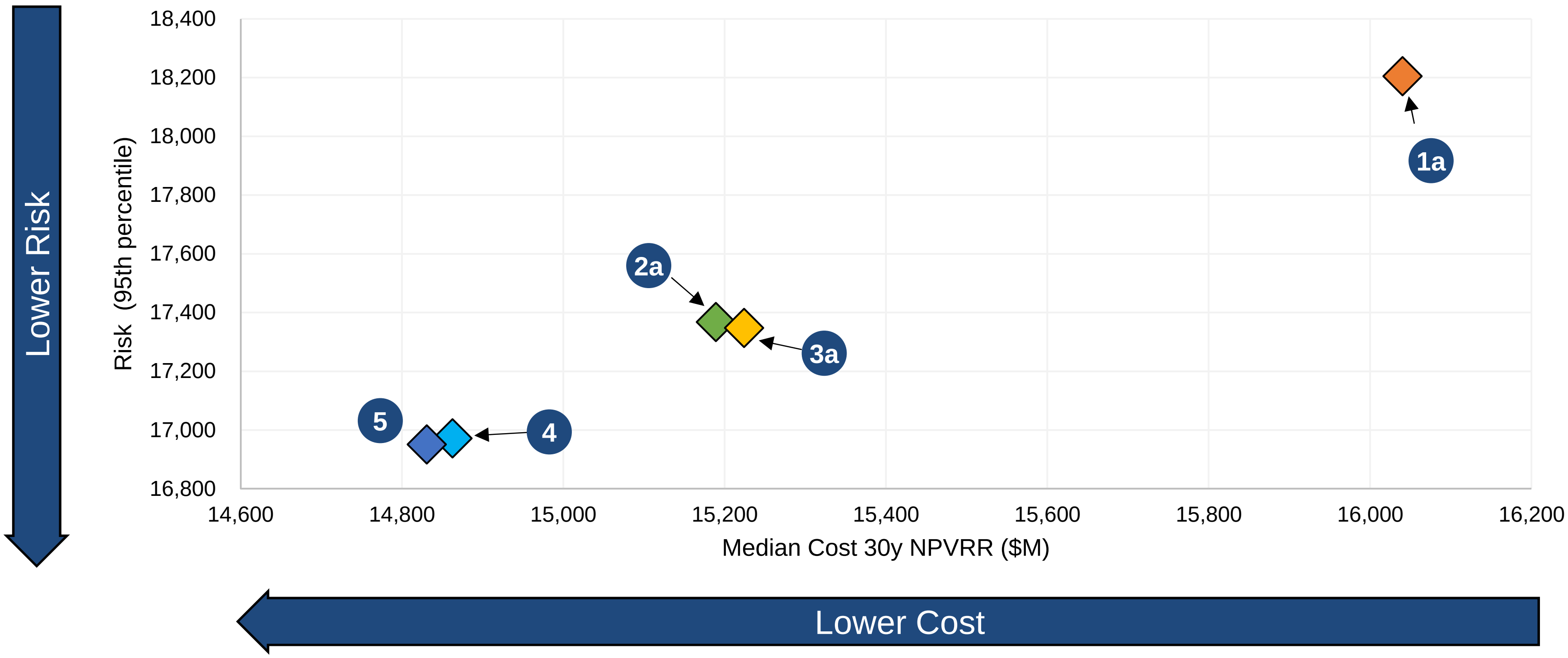
Results: Stochastic Cost Volatility



Portfolio Transition Target:	65% Coal through 2035 1a	40% Coal in 2023 2a	15% Coal in 2030 3a	15% Coal in 2023 4	0% Coal in 2023 5
Retire:	None	Schahfer:17,18 (2023)	Schahfer:17,18 (2023) Schahfer:14,15 (2030)	Schahfer:17,18 (2023) Schahfer:14,15 (2023)	Michigan City:12 (2023) Schahfer:17,18 (2023) Schahfer:14,15 (2023)
Retain:	Michigan City: 12 Schahfer:14,15,17,18	Michigan City: 12 Schahfer:14,15	Michigan City: 12 Schahfer:14,15	Michigan City: 12	None
Incremental Volatility ($M)	0	177	291	388	448
Incremental Cost ($M)	1,210	359	394	32	0

Note: ZLD results shown here, Non-ZLD results are not materially different and are in the appendix.

Results: Stochastic Cost Risk



Portfolio Transition Target:	65% Coal through 2035 1a	40% Coal in 2023 2a	15% Coal in 2030 3a	15% Coal in 2023 4	0% Coal in 2023 5
Retire:	None	Schahfer:17,18 (2023)	Schahfer:17,18 (2023) Schahfer:14,15 (2030)	Schahfer:17,18 (2023) Schahfer:14,15 (2023)	Michigan City:12 (2023) Schahfer:17,18 (2023) Schahfer:14,15 (2023)
Retain:	Michigan City: 12 Schahfer:14,15,17,18	Michigan City: 12 Schahfer:14,15	Michigan City: 12 Schahfer:14,15	Michigan City: 12	None
Cost + Risk	18,205	17,432	17,378	16,972	16,951
Rank (1=lowest)	5	4	3	2	1

Note: ZLD results shown here, Non-ZLD results are not materially different and are in the appendix.

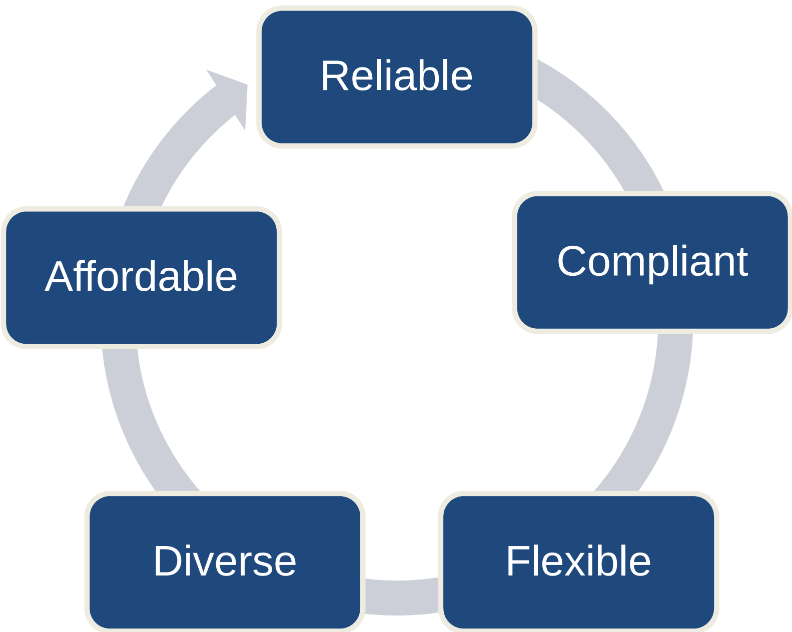
Replacement Analysis

Dan Douglas
Vice President Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

How Does NIPSCO Plan for the Future?

Charting The Long-Term Course For Electric Generation

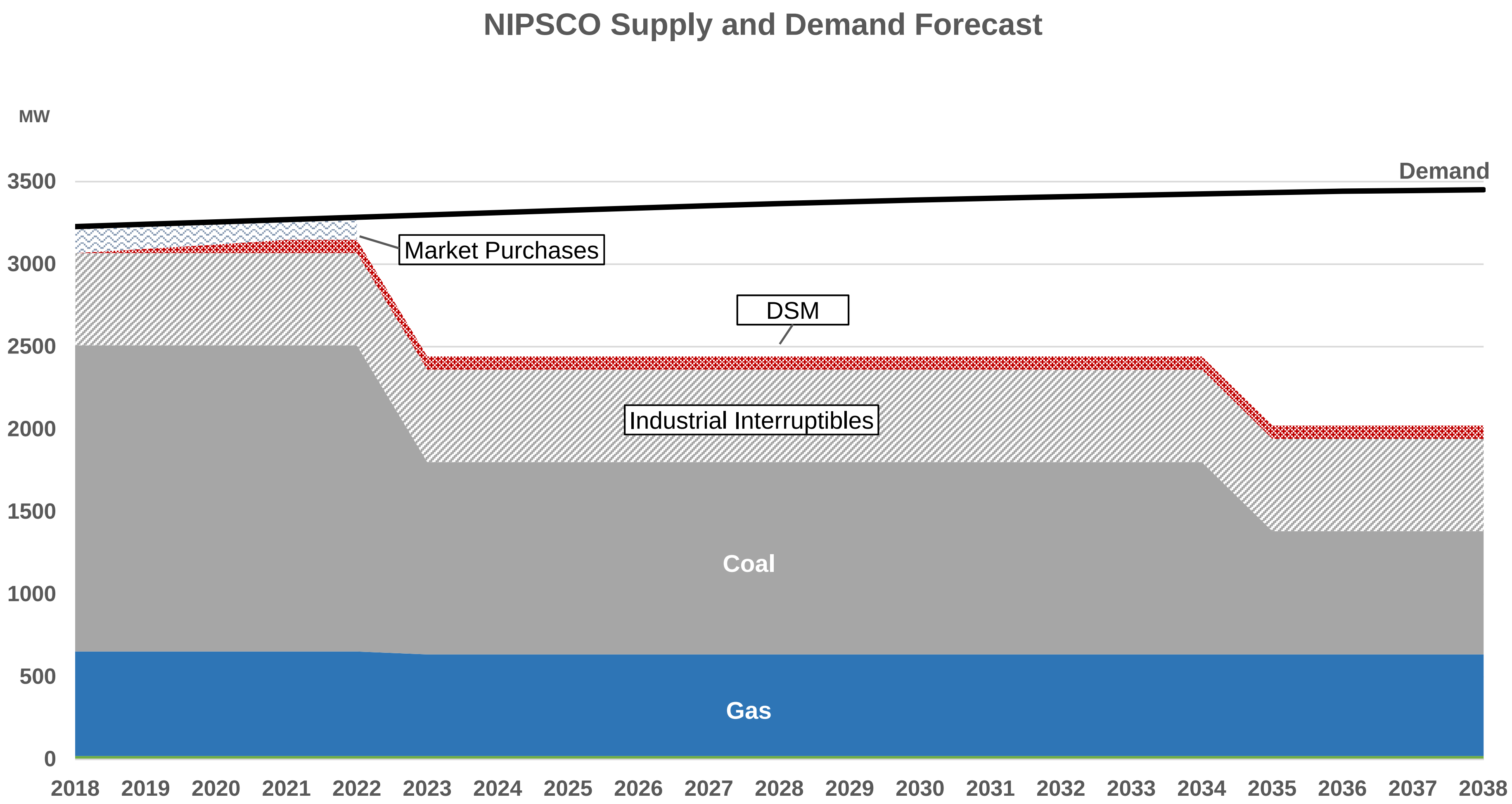


Requires Careful Planning and Consideration for:

- Our employees
- Environmental regulations
- Changes in the local economy (property tax, supplier spending, employee base)

Retiring Schahfer 17/18 Will Create a Need for New Resources

Based on 2018 Initial IRP Modeling



Replacement Resource Combinations Will Consider Ownership, Duration and Diversity

1 / 2 Ownership / Duration

- Generation can be owned by buying or building a facility, or can be secured through a financial contract
- Duration is the length of time commitment to a specific resource; shorter duration can partially mitigate industrial risk
- Ownership and duration are correlated: financial contracts are best suited for shorter duration and facility/asset ownership is best suited for longer duration resources

Considerations

- What is the right level of duration risk for the customer & NIPSCO?
- What ownership structures are best suited for each resource opportunity?

Ownership

Financial/ Contract — **Asset/ Facility**

Duration

Industrial	Short Term	Long Term
≤ 1 yr	1–10 yrs	10+ yrs

3 Diversity

- Diversity is the mix of fossil, renewable and efficiency resources in the entire NiSource portfolio
- Diversity is measured by carbon dioxide emission rate intensity (carbon dioxide emissions per megawatt hour)

- What is the right mix of supply resources that aligns with NiSource environmental targets and satisfies customer and stakeholder interests?
- How does the updated NiSource generation portfolio compare to industry peers?

Diversity

Higher CO_2 Emissions per MWh — **Lower CO_2 Emissions per MWh**

4^{th} Quartile — **1^{st} Quartile**

Fewer Renewables — More Renewables

Sources & Notes: Represents average quartile CO_2 lbs/MWh; Benchmarking Air Emissions of the 100 Largest Electric Power Producers *https://www.nrdc.org/sites/default/files/benchmarking-air-emissions-2016.pdf*

Resource Combinations

Nine combinations are constructed exploring the full range of ownership, duration, and diversity possibilities

Ownership / Duration:

- All portfolios will include ≤1 year purchases
- Three options:
  - Short duration
  - Mix of Short and Long durations
  - Long duration

Short Duration	Mix of Short and Long	Long Duration
25%: ≤1yr 75%: 1-10yr	25%: ≤1yr 37.5%: 1-10yr 37.5%: 10+yrs	25%: ≤1yr 75%: 10+yrs

Diversity:

- Three options:
  - Higher carbon emissions
  - Average carbon emissions
  - Average-Low carbon emissions

Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
4th Quartile avg. rate 1,999	3rd Quartile avg. rate 1,515	2nd Quartile avg. rate 1,013

Diversity

Ownership / Duration	Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
Short Duration	A 1-yr Market Capacity: 216 MW Purchase Power Agreement (PPA) (gas): 1,100 MW	B 1-yr Market Capacity: 216 MW PPA (gas): 600 MW PPA (renew): 1,500 MW	C 1-yr Market Capacity: 216 MW PPA (renew): 3,200 MW
Mix of Short and Long	D 1-yr Market Capacity: 216 MW PPA (gas): 550 MW CCGT: 550 MW	E 1-yr Market Capacity: 216 MW PPA (gas): 300 MW PPA (renew): 750 MW CCGT: 300 MW Renewables: 750 MW	F 1-yr Market Capacity: 216 MW PPA (renew): 1,600 MW Renewables: 1,600 MW
Long Duration	G 1-yr Market Capacity: 216 MW CCGT: 1,100 MW	H 1-yr Market Capacity: 216 MW CCGT: 600 MW Renewables: 1,500 MW	I 1-yr Market Capacity: 216 MW Renewables: 3,200 MW

Notes: nameplate capacity values are shown in the table; emission rates shown in CO_2 lbs/MWh

Replacement Resource Framework

- **Leveraging 3rd party and publicly available datasets to develop a range of current and future capital cost estimates for new capacity resources**

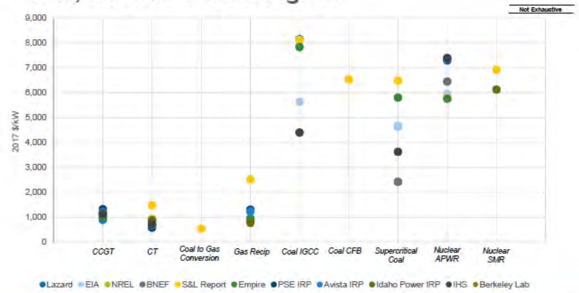
1) Use multiple data sources

3rd Party Data Sources

Data Source	Description	Link
Sargent & Lundy	NIPSCO Integrated Resource Plan Engineering Study Technical Assessment (2015)	N/A
Energy Information Administration (EIA)	Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (2018 AEO)	EIA Capital Cost Estimates
Utility Integrated Resource Plans	Empire District Electric Company, Puget Sound Energy, Avista Utilities and Idaho Power (screened for filings with transparent data within the last 6 months to year)	Empire District Avista Puget Sound Energy Idaho Power
Lazard	Levelized Cost of Energy Analysis Version 11.0 (2017)	Lazard LCOE V. 11.0
	Lazard Levelized Cost of Storage Version 3.0 (2017)	Lazard LCOS V.3.0
IHSMarkit	US Solar PV Capital Cost and Required Price Outlook	IHSMarkit (subscription required)
	US Wind Capital Cost and Required Price Outlook	
	US Battery Storage: Costs, Drivers, and Market Outlook (2017)	
	North American Power Market Fundamentals: Rivalry, October 2017 – New Capacity Characteristics & Costs	
Bloomberg New Energy Finance	Historical and forecast U.S. PV Capex Stack by Segment and Region	Bloomberg New Energy Finance (subscription required)
	Key cost input in LCOE Scenarios, 1H 2017	
	Benchmark Capital Costs for a Fully-Installed Energy Storage System (2017)	
National Renewable Energy Technology Laboratory	NREL Annual Technology Baseline 2017	NREL ATB 2017

2) Compile current costs

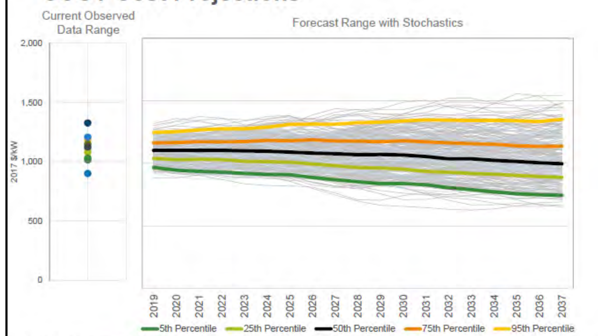
Current Capital Cost Estimates ($/kW) – Gas, Coal, Nuclear Technologies



2017 $/kW	CCGT	CT	Coal to Gas Conversion	Gas Recip	Coal IGCC	Coal CFB	Supercritical Coal	Nuclear APWR	Nuclear SMR
Average	1,113	834	543	1,278	6,824	6,536	4,605	6,437	6,527
Median	1,116	715	543	1,092	7,835	6,536	4,646	6,198	6,527
Min	900	583	543	775	4,401	6,536	2,425	5,752	6,126
Max	1,326	1,485	543	2,519	8,150	6,536	6,482	7,392	6,927

3) Project future costs & capture uncertainty with stochastics

CCGT Cost Projections



How to interpret the probability distributions and diagnostic statistics:
- 50th percentile is the middle value – half the observations are above this value and half are below
- Generally, percentiles represent thresholds below which a given percentage of observations is expected to fall (i.e., the 95th percentile indicates that 95% of the cost observations in that year are at or below this level)

- **Conducting an all-source request for proposal (RFP) solicitation for replacement capacity resources**
  - RFP results collapse uncertainty for 2023 costs
  - Insert 2023 projects from RFP into the analysis and re-run

Results: Deterministic Cost to Customer

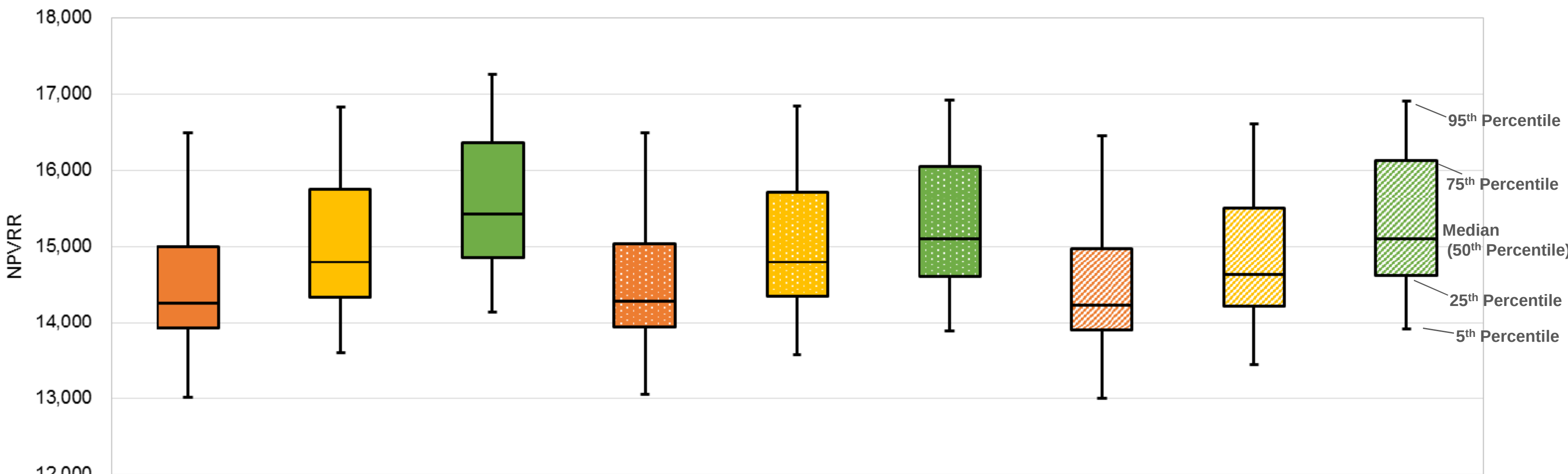
Diversity

Ownership / Duration

	Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
Short Duration	A Δ from Least Cost: +$140M / 1.0%	B Δ from Least Cost: +$553M / 3.8%	C Δ from Least Cost: +$1,081M / 7.5%
Mix of Short and Long	D Δ from Least Cost: +$86M / 0.6%	E Δ from Least Cost: +$449M / 3.1%	F Δ from Least Cost: +$915M / 6.3%
Long Duration	G Δ from Least Cost: +$0 / 0%	H Δ from Least Cost: +$318M / 2.2%	I Δ from Least Cost: +$721M / 5.0%

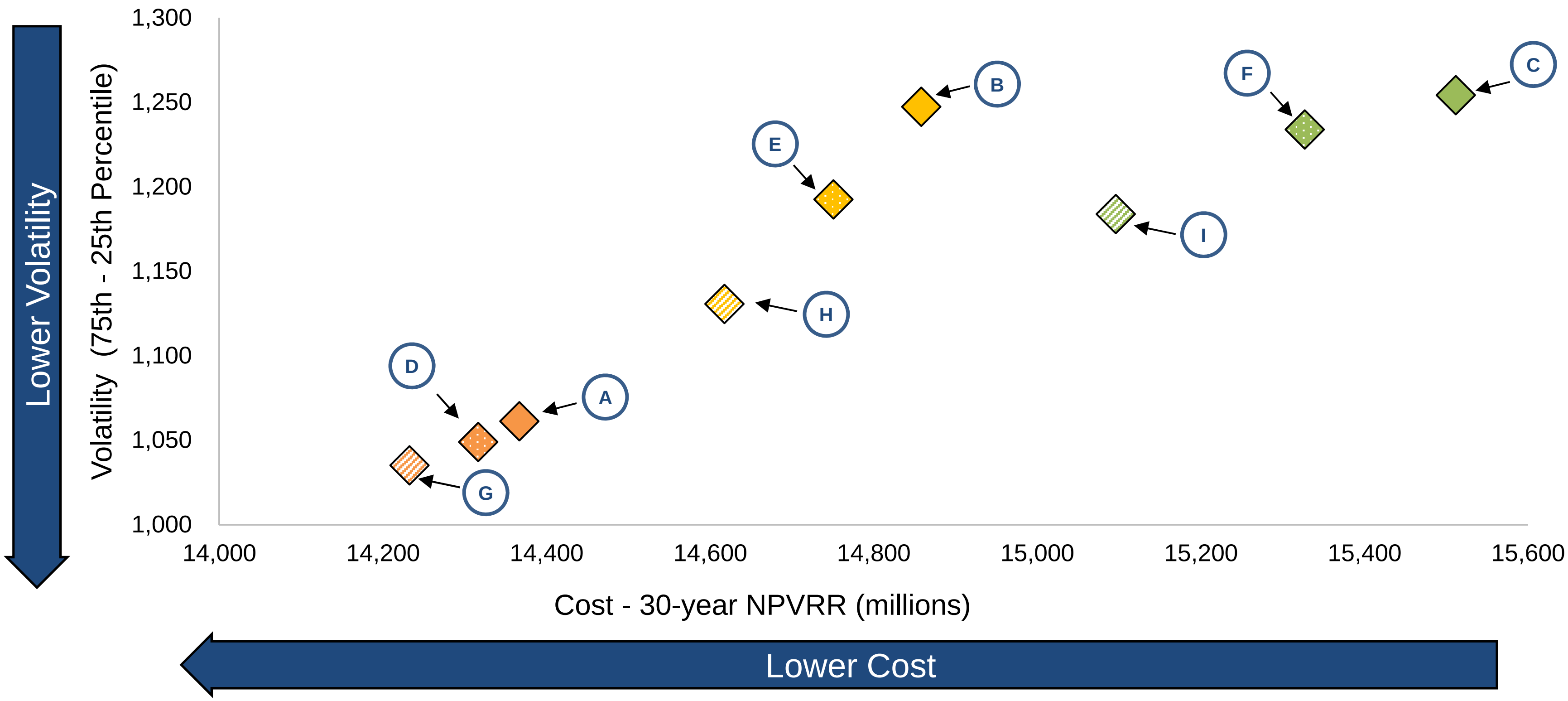
Results: Stochastic Cost Certainty, Risk, and Volatility

Range of Net Present Value of Revenue Requirement
(2018-47, $M)



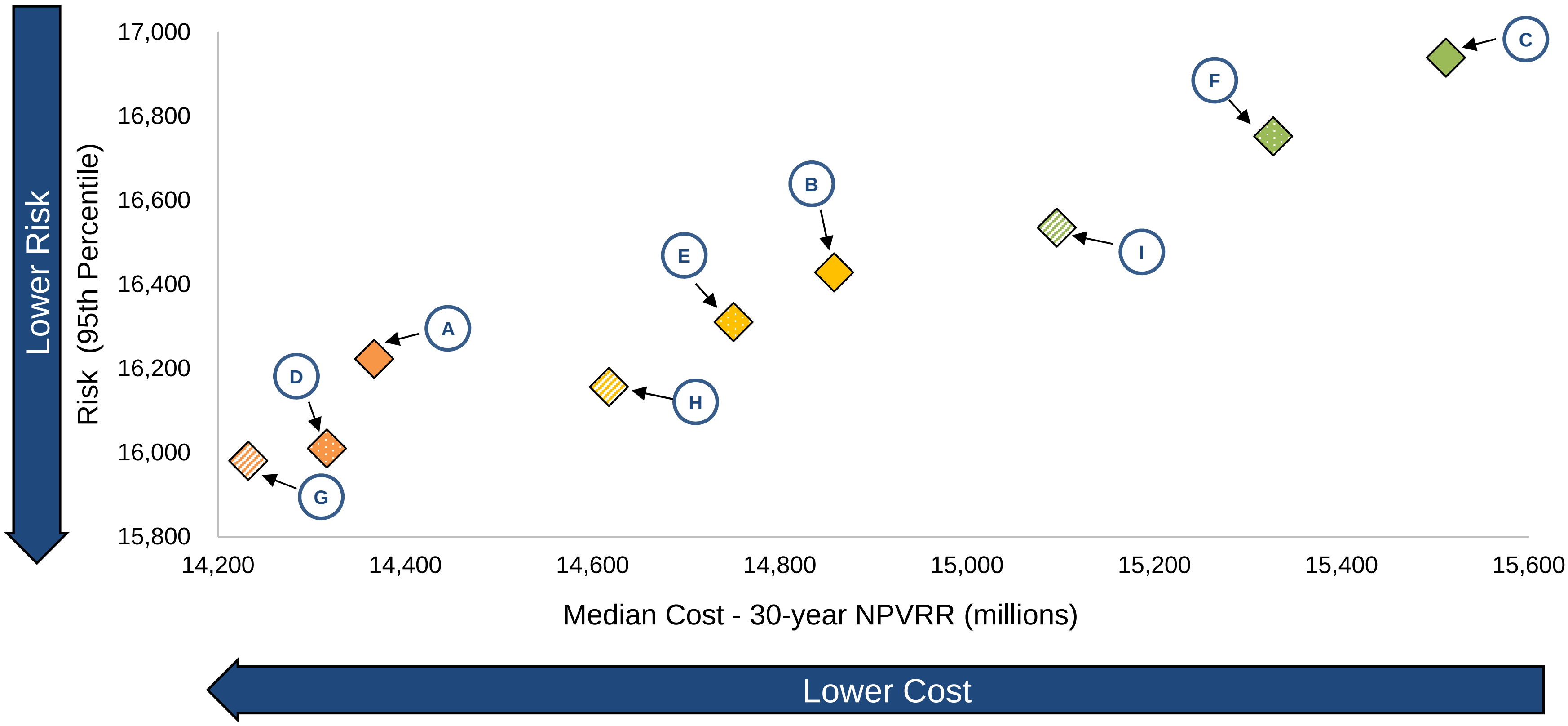
	Short Duration, Higher Carbon Emissions (A)	Short Duration, Avg. Carbon Emissions (B)	Short Duration, Avg.-Low Carbon Emissions (C)	Short & Long Duration, Higher Carbon Emissions (D)	Short & Long Duration, Avg. Carbon Emissions (E)	Short & Long Duration, Avg.-Low Carbon Emissions (F)	Long Duration, Higher Carbon Emissions (G)	Long Duration, Avg. Carbon Emissions (H)	Long Duration, Avg.-Low Carbon Emissions (I)
Delta from Lowest Cost Certain (75th%)	+$157M 1.1%	+$848M 5.7%	+$1,383M 9.3%	+$95M 0.6%	+$701M 4.7%	+$1,211M 8.2%	+$0M 0%	+$525M 3.5%	+$982M 6.6%
Delta from Least Risk (95th%)	+$243M 1.5%	+$448M 2.8%	+$959M 6.0%	+$29M 0.2%	+330M 2.1%	+$772M 4.8%	+$0M 0%	+$176M 1.1%	+$555M 3.5%

Results: Stochastic Cost Volatility



	Short Duration, Higher Carbon Emissions (A)	Short Duration, Avg. Carbon Emissions (B)	Short Duration, Avg.-Low Carbon Emissions (C)	Short & Long Duration, Higher Carbon Emissions (D)	Short & Long Duration, Avg. Carbon Emissions (E)	Short & Long Duration, Avg.-Low Carbon Emissions (F)	Long Duration, Higher Carbon Emissions (G)	Long Duration, Avg. Carbon Emissions (H)	Long Duration, Avg.-Low Carbon Emissions (I)
75th Percentile (Cost + Upside Volatility)	15,015	15,705	16,240	14,953	15,558	16,068	14,857	15,383	15,839

Results: Stochastic Cost Risk



	Short Duration, Higher Carbon Emissions (A)	Short Duration, Avg. Carbon Emissions (B)	Short Duration, Avg.-Low Carbon Emissions (C)	Short & Long Duration, Higher Carbon Emissions (D)	Short & Long Duration, Avg. Carbon Emissions (E)	Short & Long Duration, Avg.-Low Carbon Emissions (F)	Long Duration, Higher Carbon Emissions (G)	Long Duration, Avg. Carbon Emissions (H)	Long Duration, Avg.-Low Carbon Emissions (I)
Cost + Risk	16,223	16,429	16,940	16,010	16,311	16,753	15,981	16,157	16,535

RFP for Capacity

Paul Kelly
Director of Federal Regulatory Policy

Bob Lee
Charles River & Associates

Stakeholders Providing Feedback on the RFP

		Letter to NIPSCO	Interim Design Summary	Draft RFP Document (with non-disclosure agreement)
	Indiana Coal Council	✓	✓	
	Sierra Club		✓	
	Indiana Distributed Energy Alliance		✓	
	Citizens Action Coalition of Indiana, Inc.			✓
	Indiana Office of Utility Consumer Counselor			✓
Developers	Martin Banks		✓	
Developers	Jiagnan Environmental Technology (JET)		✓	
Developers	First Solar		✓	
Developers	Orion Renewable Energy Group LLC		✓	

Summary of Feedback Received and Incorporated

Stated Goal

Identify viable resources that can best meet our customers' needs

- Ensure RFP is truly all-source
- Clarify bidder qualifications, evaluation criteria and weightings
- Ensure transparency by sharing RFP results as much as possible
- Clarify scope of non-disclosure agreement and confidential information
- Allow demand response (DR) contracts with a term of 1 year and clarify DR rules
- Clarify need is based on 2016 IRP conclusion of Units 17/U18 retirements
- Market RFP to bidder audience including potential Units 17/U18 buyers
- Note no obligation to contract as a result of the RFP
- Clarify timeline to show completion of IRP and expectations as to when the review process will be completed
- Include bid requirements to filter out high risk, speculative projects; recognize MISO has specific development milestones in the queue
- Consider other recent RFPs across the United States (Xcel, AEP, Denton,TX, etc.)
- Added May 16, 2018 webinar for potential bidders to introduce RFP and answer questions at front end of timeline
- Lower credit and pre-qualification requirements

Summary of Feedback Received but Not Incorporated

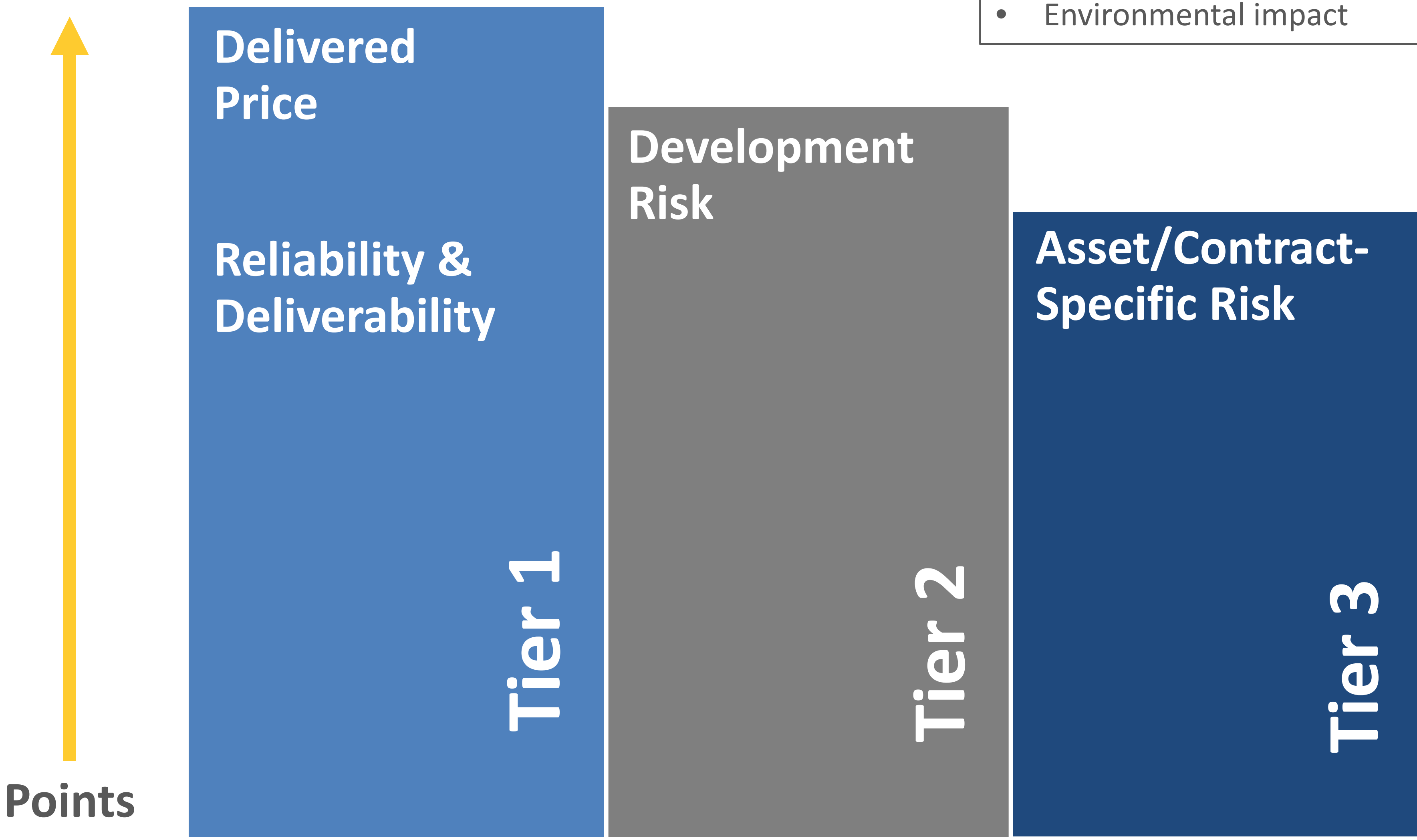
- Provide more than 45 days and/or adjust pre-bid conference timing
- Share individual bid responses
- Retain consultant to develop Units 17/U18 bid package
- Do not negotiate until IRP is submitted and accepted by Indiana Utility Regulatory Commission
- Include flexibility (frequency, time and size of irreversible decision) as an evaluation criteria
- Include full life cycle assessments (LCA) and annual carbon intensity
- Require assets to demonstrate advanced dispatch capabilities
- Require bidder and their suppliers to prove financial performance
- Require solar PV resources to meet certain industry standards
- Eliminate potential for fossil resources
- Remove MISO Zone 6 firm delivery requirement or allow financial solution
- Allow under/over-delivery for renewable energy

* NIPSCO received comments relating to scope and process of the IRP not reflected here; also multiple questions about the RFP were received that will be answered in the RFP release

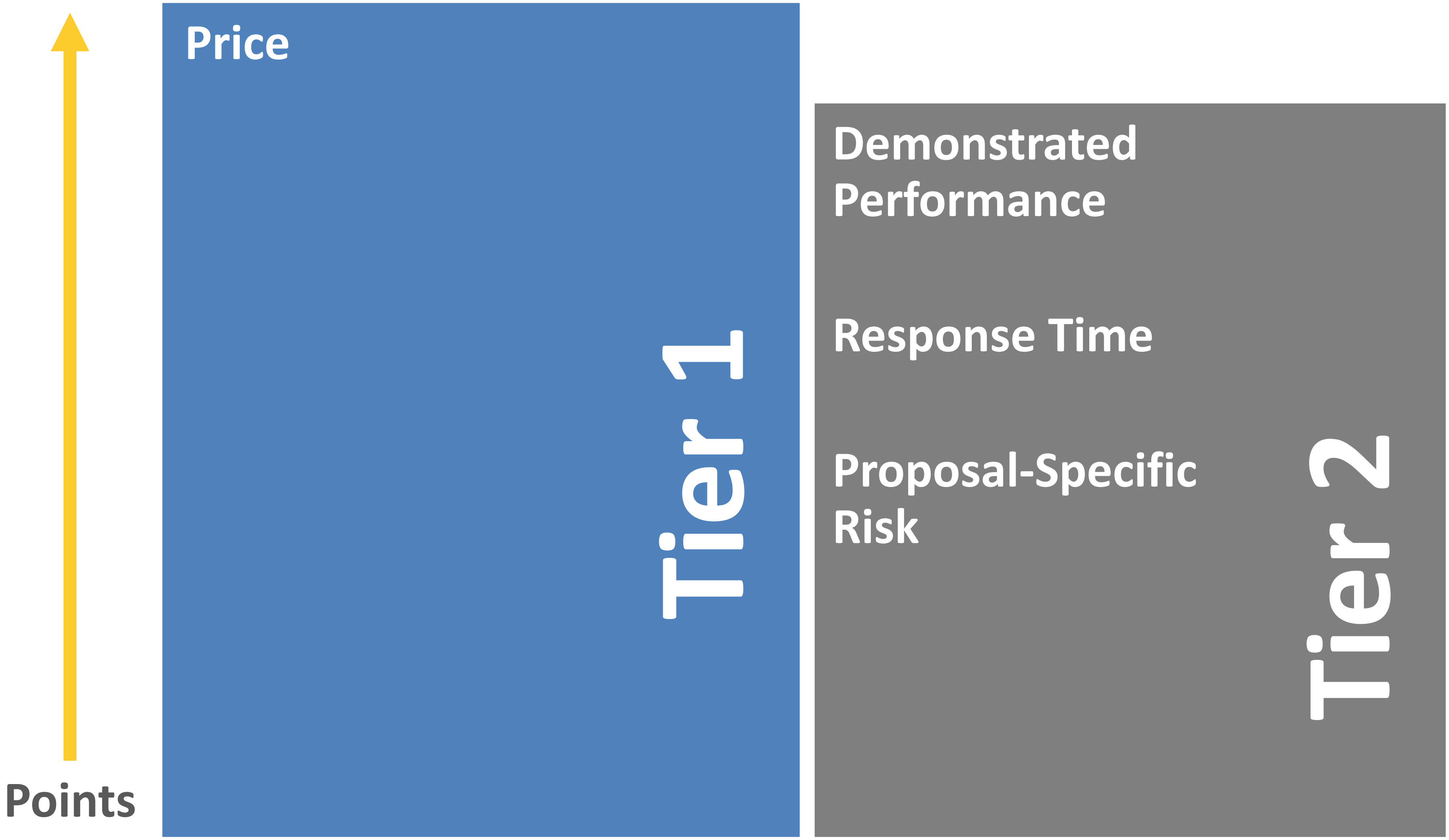
Final Evaluation Criteria (non-DR)

Other 3/23 Criteria not included:

- Portfolio diversity
- Employee impact
- Community impact
- Environmental impact



Final Evaluation Criteria (DR)



Key Design Elements of the All-Source RFP

- **Technology**
  - Requesting all solutions regardless of technology, including demand-side options and storage
- **Size**
  - Defining a minimum total need of 600 MW for the portfolio but without a cap
  - Allows smaller resources <600 MW to offer their solution as a piece of the total need
  - Also encourages larger resources >600 MW to offer their solution for consideration
- **Ownership Arrangements**
  - Seeking bids for asset purchases (new or existing) and purchase power agreements
  - Resource must qualify as MISO internal generation (not pseudo-tied) or load (DR)
- **Duration**
  - Requesting delivery beginning 6/1/2023 but will evaluate deliveries as early as 6/1/2020
  - Minimum contractual term and/or estimated useful life of 5 years (except for DR, which is 1 year)
- **Deliverability**
  - Must have firm transmission delivery to MISO Zone 6
  - Must meet N-1-1 reliability criteria or show cost estimate to achieve that quality
- **Participants & Pre-Qualification**
  - Marketing RFP to broad bidder audience which began last month to provide plenty of notice
  - Requiring credit-worthy counterparties to ensure ability to fulfill resource obligation

Revised Timeline for the RFP

Date	Event
March 23rd	Overview RFP design with stakeholders
April 6th	RFP Design Summary document shared with stakeholders to request feedback
April 20th	Stakeholder feedback on Design Summary due back to NIPSCO
May 14th	**RFP initiated**
May 16th	**RFP Webinar for bidders (includes Q&A session)**
May 28th	Notice of Intent and pre-qualifications due from potential bidders
June 29th	**RFP closes**
July 24th	Summary of RFP bids presented at Public Advisory webinar; IRP analysis incorporates results of RFP

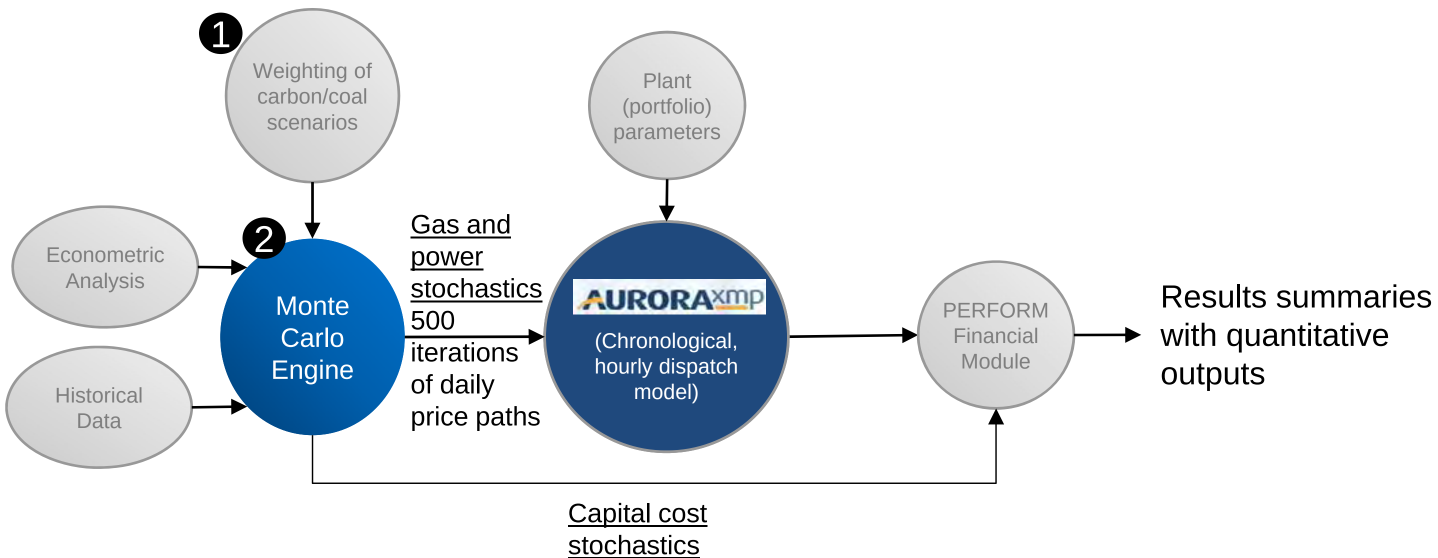
Stakeholder Presentations/Comments

Wrap Up

Appendix

Developing Stochastic Inputs

- **Scenario development supports stochastic development process**
  1. **Scenarios are probability-weighted for discrete variables (carbon/coal)**
  2. **Monte Carlo Engine is run for natural gas and power prices for each weighted scenario, based on historical data analysis, which incorporates:**
     - Daily price spikes for gas
     - Power price volatility on a daily and hourly level, implicitly based on observations like market load shocks, fuel price changes, and plant outages



Stochastics Development Details

1. **Historical Data Analysis**
   - Analyze historical commodity prices to find a stochastic (econometric) model that best captures the observed behavior of prices in the modeled region.
   - Key parameters, which define the stochastic price processes, include:
     - volatility levels (randomness),
     - mean-reversion rate (convergence to long-term price trends and forecasts)
     - correlation between with power and gas prices in the regions
2. **Parameter Estimation**
   - Fit historical data to an econometric model by running regressions and estimating stochastic process parameters
3. **Monte Carlo Simulations**
   - Simulate future spot prices using a Monte Carlo simulation model based on the estimated stochastic price processes (for gas and power prices)
   - Run 10,000 paths per commodity using antithetic draw techniques to ensure fast convergence and a balanced and risk-adjusted coverage of the full spectra of positive and negative price jumps in simulated price time series
4. **Cost Probability Distributions for Each Scenario**
   - CRA performed Monte Carlo simulations for each fundamental market scenario and probability-weighted them to develop the full set of stochastics
   - 500 draws were sampled for the full Aurora-PERFORM runs

Base Scenario

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs	Other Enviro. Costs
Base	Base	Base	Base	Base	Base	Base	Base

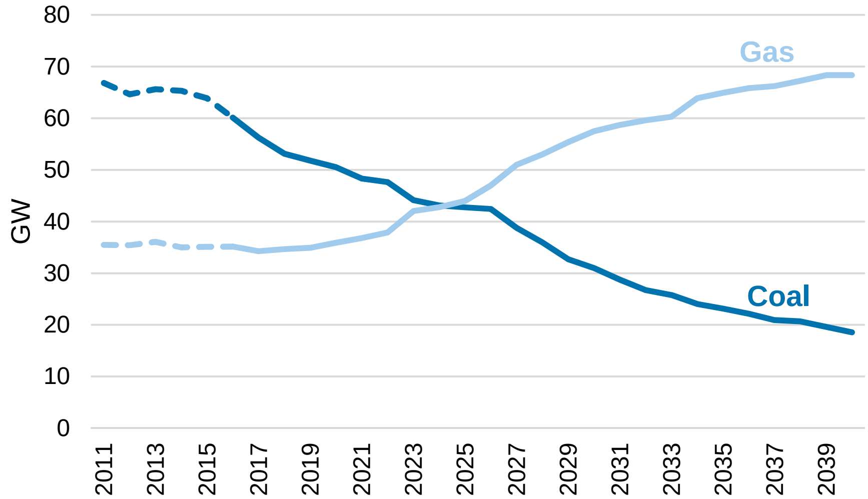
- **The scenario NIPSCO considers most likely to occur**
- **Detailed assumptions were provided during March 23 stakeholder meeting**
  - NIPSCO total energy growing at 0.33% per year and peak at 0.41% per year
  - Carbon price starting at $8/ton (real) in 2026, escalating to $13/ton (real) by 2037
  - Natural gas prices trending from current levels to $4/MMBtu (real) by 2030 and $4.50/MMBtu (real) by 2037
  - Coal prices generally flat to declining in most basins; real growth expected in PRB prices
  - Power prices correlated to gas and carbon prices; shift in MISO supply mix from coal to gas and renewables
  - Capital cost declines expected for solar and battery storage
  - Non-carbon environmental compliance costs reflect current regulations, including CSAPR, ELG, CCR, and 316(b)

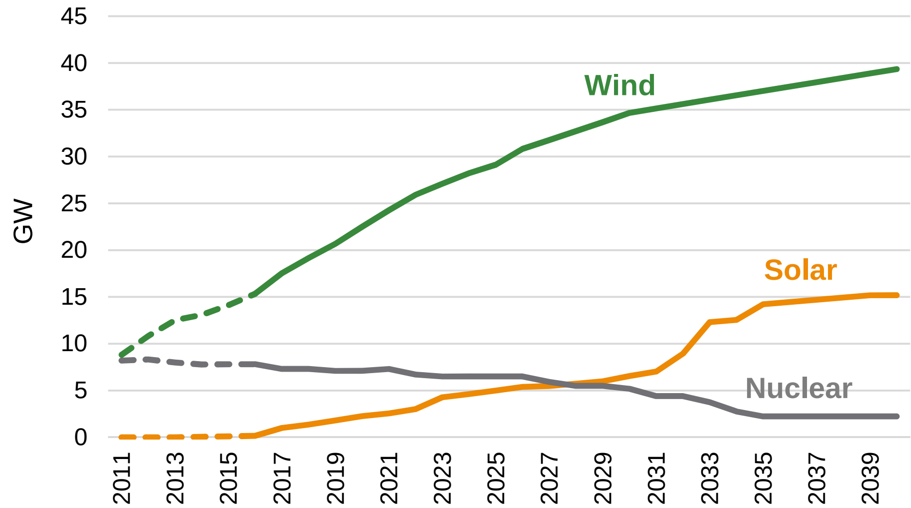
Aggressive Environmental Regulation Scenario

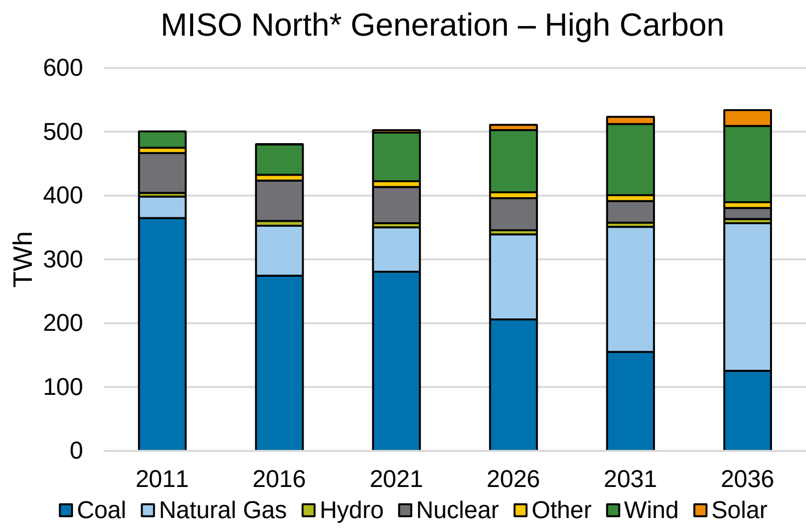
Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs	Other Enviro. Costs
Aggressive Environmental Regulation	Base	**High**	**High (CO_2)**	**Low (CO_2)**	**High (CO_2)**	**Low** renew./ sto.	Base

- Carbon price starting at ~$20/ton (real) in 2026, escalating to ~$13/ton (real) by 2037
- Natural gas prices trend up towards $5.50/MMBtu (real) over time
- Coal prices decline vs. base case as a result of declining demand
- Power prices correlated to gas and carbon prices and rise significantly higher than base case; faster shift in MISO supply mix from coal to gas and renewables
- More significant cost declines for solar and battery storage

MISO Market Changes: Aggressive Environmental Regulation







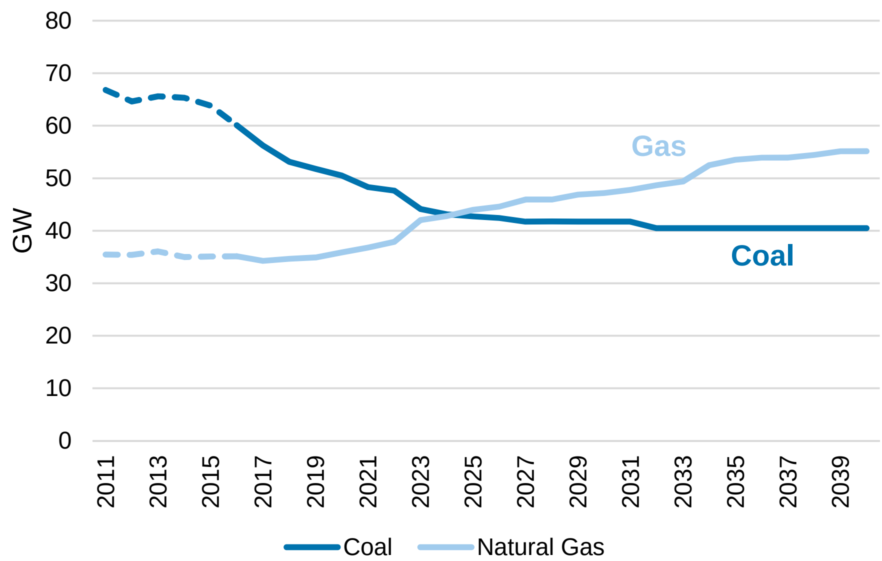
**MISO North includes LRZ 1-7*

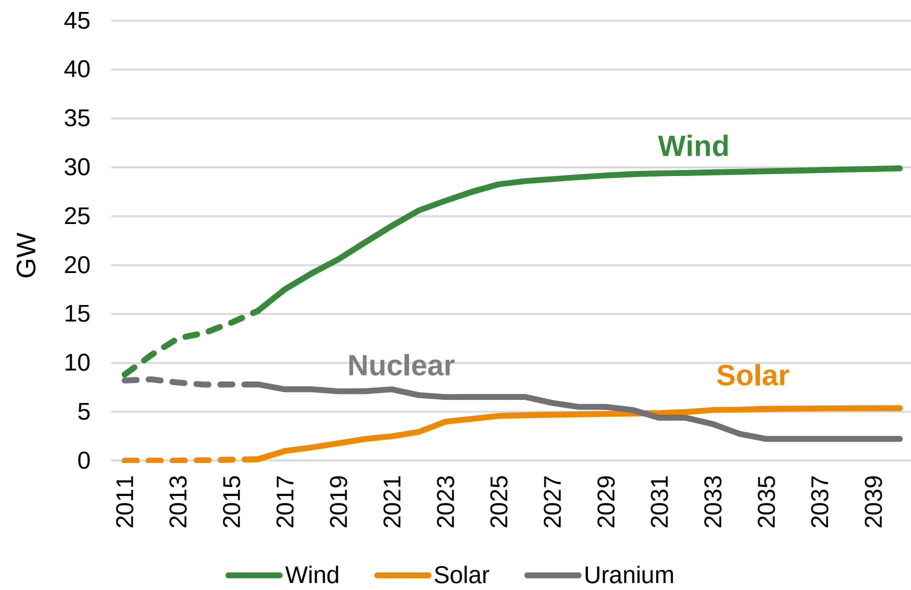
Challenged Economy Scenario

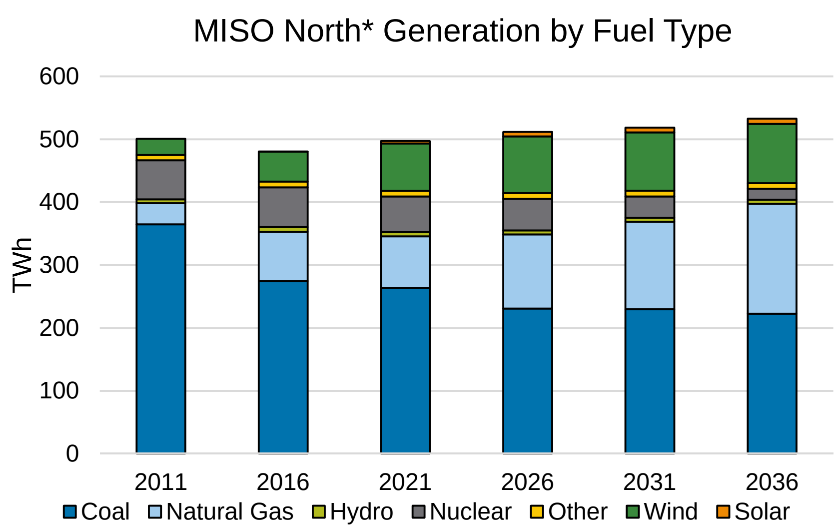
Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs	Other Enviro. Costs
Challenged Economy	**Low**	**Low**	**Low (No CO_2)**	**High (No CO_2)**	**Low (No CO_2)**	Base	**Low**

- **No price on carbon**
- **Natural gas prices stabilize around $3.50/MMBtu (real) over the long-term**
- **Coal prices modestly increase vs. base case as a result of increase long-term demand**
- **Power prices correlated to gas and carbon prices and remain relatively flat in real terms over time; slightly fewer renewables and coal retirements in MISO supply mix**
- **Lower NIPSCO load as a result of a loss in industrial demand**

MISO Market Changes: Challenged Economy







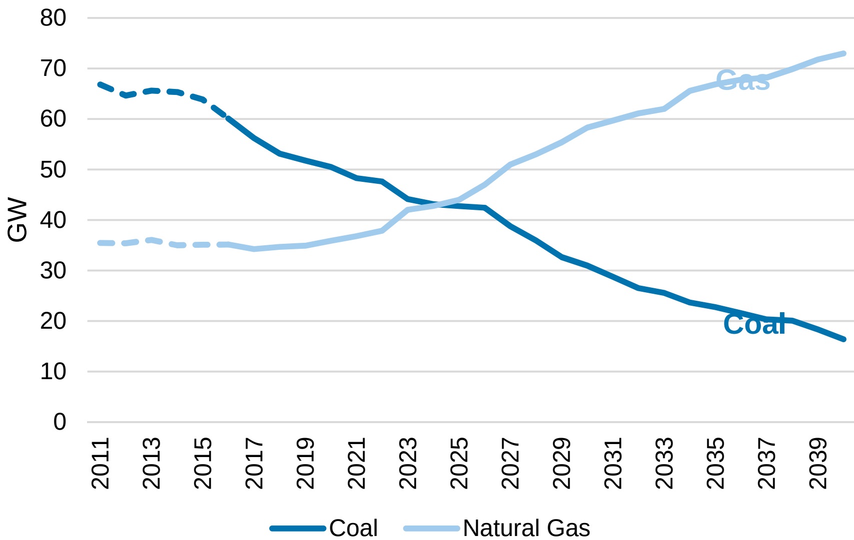
MISO North includes LRZ 1-7

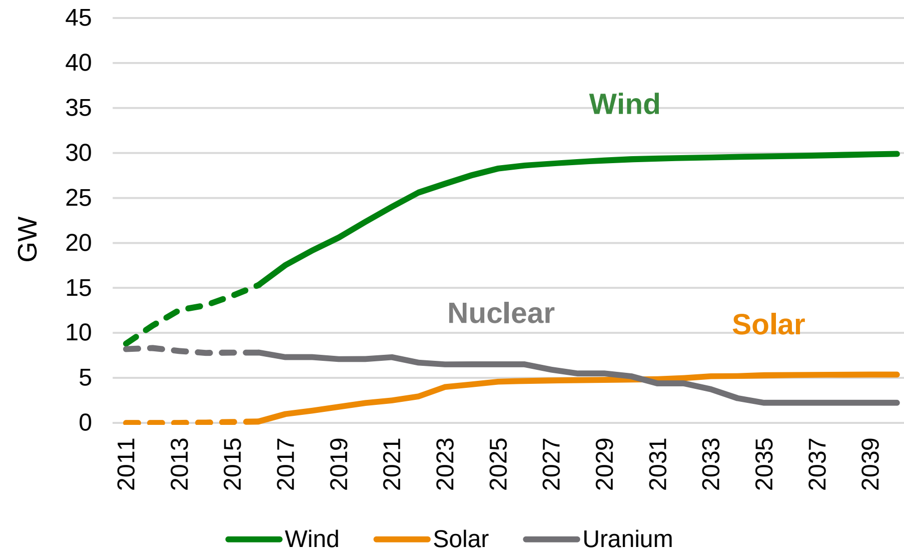
Booming Economy and Abundant Natural Gas Scenario

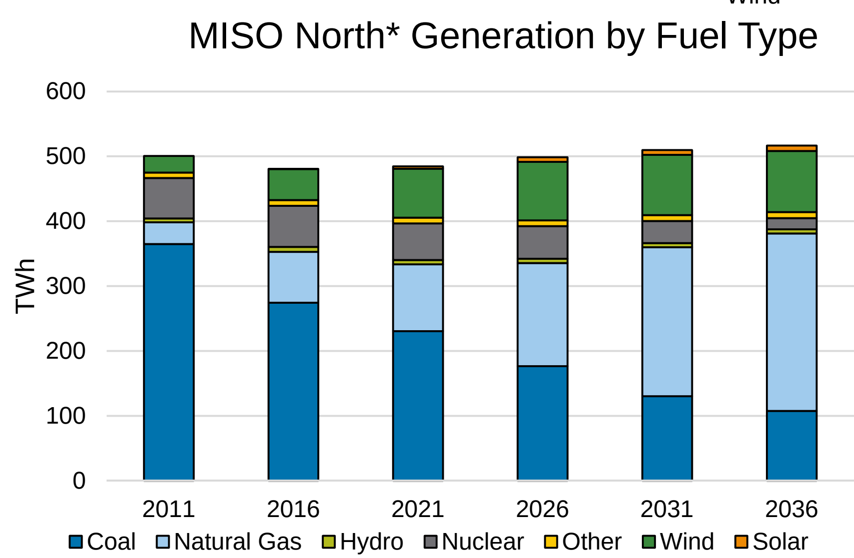
Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs	Other Enviro. Costs
Booming Economy & Abundant Natural Gas	**High**	Base	**Low**	**Low (Low Gas)**	**Low (Low Gas)**	Base	**High**

- **Natural gas prices are expected to stay lower for longer, primarily as a result of lower production costs**
- **Coal demand is likely to erode with sustained low gas prices, driving coal prices down**
- **Power prices correlated to gas and carbon prices and remain relatively flatter for longer in real terms, although a spike still occurs in 2026 with the carbon price; fewer renewables and significantly more coal retirements in MISO supply mix as a result of very cheap gas over the next ten years**

MISO Market Changes: Booming Economy and Abundant Natural Gas







*MISO North includes LRZ 1-7

Northern Indiana Public Service Company
2018 Integrated Resource Planning ("IRP")
Public Advisory Meeting #2
SUMMARY

May 11, 2018

Welcome and Introductions

Alison Becker opened the meeting by asking participants in the room and on the telephone to introduce themselves and reviewing the agenda for the day. She then introduced Violet Sistovaris. Violet Sistovaris, Executive Vice President, NiSource and President, NIPSCO provided an introduction and thanked participants for being there. She expressed NIPSCO's commitment to the process and to obtaining stakeholder input. Ms. Becker then presented a safety moment.

NIPSCO's Planning and the Public Advisory Process
Dan Douglas, Vice President, Corporate Strategy and Development

Mr. Douglas thanked participants for attending. He explained how NIPSCO plans for the future and provided an overview of the public advisory process, including reviewing the current point in the stakeholder engagement process. Mr. Douglas also provided an update on stakeholder interactions to date.

Modeling of Uncertainty
Pat Augustine, Charles River Associates ("CRA")

Mr. Augustine provided information related to NIPSCO's modeling of uncertainty in the IRP. He noted that NIPSCO's process will utilize both scenarios and stochastics to assess risk. The 2018 IRP will employ the same scenario-development process as the 2016 IRP, which is to identify drivers of potential uncertainty which could influence IRP outcomes. As an additional step in the 2018 IRP, the process will also assess whether scenario or stochastic treatment (or both) for the underlying drivers is appropriate. Mr. Augustine then discussed the details of the scenario concepts, which drive the development of integrated combinations of input variables and inform the stochastic ranges. Because NIPSCO is utilizing stochastics for the first time, Mr. Augustine provided an overview of the process and the benefits of stochastic analysis. He also provided the scenario ranges of discrete variables for carbon price and coal price and stochastic ranges for natural gas prices, power prices, and capital costs.

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

- Is NIPSCO also doing some teasing out of some of the drivers in relation to risk? For example booming economy and natural gas prices don't necessarily go together. Would NIPSCO be willing to do some teasing out with the drivers within each of the scenarios?
    - Yes, NIPSCO is open to incorporating stakeholder input on the combinations of key drivers and how they are related. Under the Booming Economy scenario, natural gas prices are low due to high-levels of low-cost natural gas production, which supports strong economic growth. However, one could envision an alternative state-of-the-world where high load growth drives higher gas prices. Overall, the scenario development process intends to develop an initial range of plausible outcomes, while the full stochastics will capture a wider range of combinations of factors not contemplated in any one specific scenario. If you have a specific set of assumptions, the team would be willing to talk through that.
- In looking at key drivers for environmental and seeing carbon controls, is NIPSCO also considering any other stricter policies for wastewater treatment, etc.? That issue can be and has been an issue with plant closures.
    - Kelly Carmichael will discuss environmental policy further. However, if there is something you think is missing, NIPSCO can address that if appropriate. All of the environmental policy expected to affect the NIPSCO fleet is being considered.
- Regarding the drivers on the technology side, is there anything on the horizon where NIPSCO can keep some of its generators that are retiring or is the Company looking at some technology developments to keep some of the generators?
    - That is the purpose of the process. The IRP will consider the environmental costs and impacts and what it means for potential retirements. Kelly will discuss environmental control options further, and ifIf there are uncertainties, the retirements can be considered again.
- There is a discussion of a correlation between booming economy and low gas prices, but it is not clear if there is a correlation. The bigger issue is that there are not more scenarios.
    - It is probably possible to come up with dozens of scenarios that evaluate different potential outcomes in the market. The scenarios being discussed are the starting point, with the stochastics providing a fuller treatment of uncertainty around a broader range of combinations. If there are specific scenarios that stakeholders believe are missing, NIPSCO is happy to talk through the issue and decide whether additional modeling would be useful.
- There is a concern with how Aurora works. The impression is, when you do portfolio optimization, given the way the portfolio outputs occur, it seems there is no way to operate without stochastics.
    - While the comment generally characterizes one capability of Aurora modeling correctly, the description of how Aurora works and how it is being used in the

process is not complete. In Aurora you can optimize portfolios under a base case and across different scenarios, but you can also pre-define a portfolio and evaluate it across scenarios and stochastics. It is important to note that the process does not restrict Aurora to be only an optimizer model. While we plan to evaluate portfolio optimization, the entire scenario and stochastic risk analysis is based on using the model not to optimize, but as a comprehensive dispatch tool. In this way, the user can input different portfolios and then run through all scenarios and stochastics along with a full scorecard assessment.

- Aurora evaluates portfolios in a rigorous framework through stochastics. NIPSCO is asking stakeholders for input but there is not a lot of transparency for stakeholders in terms of what types of resources would make up costs of the portfolio. There is not really a good way for us to understand the resource needs. It is hard to say we want NIPSCO to run a specific portfolio.
    - All of the inputs will be made available, including gas prices, coal prices, power prices, etc. for the scenarios and stochastics. These are available in spreadsheet format, so Aurora is not needed to see what is going in to the modeling process. In addition, NIPSCO will provide portfolio output details and if different portfolios are desired, within reason, those can be run.
- There is also a concern related to correlations.
    - NIPSCO will continue to review this and is open to more specific stakeholder input on input scenarios.
- Why have the load forecasts on slide 14 not been developed yet? How does this fit into the schedule for the request for proposals for capacity ("RFP")?
    - The team continues to work on the scenarios and they are expected to be finished in the next month, so that they are ready prior to RFP results being received.. The IRP process includes some initial modeling to identify preliminary themes and results, some of which will be shared today, and then have final model results with all scenario and stochastics details for presentation in September.
- Very concerned about the use of stochastics rather than a binary consideration, particularly as it relates to carbon. There needs to be a base case without carbon and coal and gas pricing and stochastics do not provide that.
    - It is important to note that stochastics are not replacing scenarios. The four individual scenarios are still being run, including the one with no carbon price. If there are other scenarios that are needed, NIPSCO will evaluate them. Ultimately, NIPSCO is keeping the scenario framework to complement to stochastics.
- How are capital cost stochastics being treated with the RFP?
    - Thus far, NIPSCO is using a range of capital costs to obtain insight on portfolio performance. As the RFP results are received, NIPSCO will refine all capital cost (or PPA price) estimates with better data.
- On slide 17, there is a spike in natural gas prices in 2014, what is that? How is that spike included in the forecast going forward?
    - The spike was from the very cold "polar vortex" weather event in January and February of that year. That behavior and other randomness is picked up to

some extent going forward. The volatility metric is captured in the prices going forward.

- On slide 16, is the dashed line the highest carbon prices?
    - o The orange dashed line is the high carbon price scenario. Carbon prices are not a stochastic variable, but are treated as three discrete scenarios with probability weighting. 25% of the iterations will be at high level, 50% at the middle level, and 25% at the bottom level. Fuller natural gas and power price stochastics are built around the corresponding carbon price trajectories in the three scenarios.
- Where are these stochastics being used?
    - o They are being used in the analysis of the portfolio options. So when portfolio economics are considered, all stochastics are utilized to evaluate the portfolios across hundreds of potential market outcomes.
- Will NIPSCO provide supporting data on the gas and coal forecast?
    - o Yes.
- Regarding the power pricing distributions, are they results or forecasts?
    - o Looking at slide 19, this shows the price forecasts from the Aurora model output for each individual scenario and the full stochastic distribution that is developed based on these price forecasts and the historical data analysis.
- Following up on the spike in 2014, does the forecast incorporate the likelihood of increasing extreme weather?
    - o No. The data relies on the historical data as it is.
- How far back in history does NIPSCO consider? The graphs go back to 2011.
    - o Yes, that is the approximate eight-year period of historical data that is used as representative of current and expected market conditions when developing the stochastic distributions.
- Will NIPSCO use fixed operations and maintenance (“O&M”) costs?
    - o Yes, those are evaluated as plant-level costs in the portfolio analysis.
- Assume there is a similar chart for battery costs. Does NIPSCO’s modeling incorporate the improvements in solar/wind capacity value? Is that captured?
    - o To the extent a battery option is being evaluated, it is included. To date, the initial portfolios have just looked at stand-alone solar and wind options, but batteries paired with intermittent resources would improve their capacity value. We expect such offers may be provided in the RFP.
- Regarding the notion of option value, there is uncertainty in variables, costs, load, technology, etc. To what extent does NIPSCO’s model capture this?
    - o It depends on the portfolio construction, but the modeling and scorecard development is intended to try to capture this. For example, a contract with a shorter duration can be evaluated, and it will have a different market exposure and potentially show a benefit of waiting until a lower-cost resource is available in the future. Furthermore, portfolio optionality is a separate scoring metric in the scorecard process.
- Will the model be used to select resources? Can Aurora do that?
    - o Yes, it can optimize for the lowest cost resource. However, this is not the only way that we will be using the model. The full stochastic analysis will evaluate a series of portfolios with different risk and cost metrics.

- Does any scenario explore electric vehicles?
    - o Not explicitly to date. NIPSCO continues to evaluate if there is sufficient demand to include this is the forecast, but, to date, there has not been enough demand from electric vehicles to include them in the forecast. It is, however, reviewed on an annual basis.
- The capital costs are based totally on renewables. Why they are not compared to coal and gas?
    - o Slide 20 shows just two examples. There are a whole list of technologies included in the modeling, including fossil options. This was shared in the March Stakeholder meeting
- Is there anywhere that summarizes what is included in load, such as residential community solar or rooftop solar, used to decrease demand or the projections of the ramp up of those projects?
    - o There is nothing specific included for distributed solar at this time.

Demand Side Management ("DSM") SM Modeling Methodology
Alison Becker, Manager, Regulatory Policy, Dick Spellman, GDS Associates, Inc., and Pat Augustine, CRA

Ms. Becker provided an overview of the DSM modeling steps. Mr. Spellman then provided an overview of GDS Associates' work on the DSM Savings Update Report including the methodology being utilized to conduct the update. He discussed how the NIPSCO 2019-2021 program request is the basis for the first three years of the Update Report and then provided information on measures to be added after 2021. Mr. Spellman provided preliminary projections for cumulative annual megawatt ("MWh") and megawatt ("MW") savings for both the residential and the commercial and industrial ("C&I") sectors, as well as the associated projected budgets. He also provided the combined total MWh and MW savings and costs. Mr. Spellman provided information on the demand response measures to be included in the Update Report and information regarding the next steps. This included a discussion of how the DSM "bundles" will be identified (through three scenarios and based on a $/kilowatt hour ("kWh") saved and finished by showing an example of an energy efficiency supply curve.

Mr. Augustine then reviewed Step 3 of the process, which is modeling the DSM bundles across all scenarios and the full stochastic range. He showed how this will be completed in steps with Aurora and PERFORM and how the uncertainties will be accounted for.

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

- On slide 34, are the numbers cumulative? Would 2015 results be added to 2020?
    - o No. The cumulative results only include 2019 through 2038. It excludes installations before 2019.
- Each data point stands on its own?

  - Yes. For example, if a pump has a useful life of 20 years and one pump is installed each year, at the end of 20 years, the incremental annual number of pumps installed would be one pump per year, and the cumulative annual number of pumps installed after 20 years would be 20 pumps.
- Does the cost per kWh saves in the first year include NIPSCO administrative costs and evaluation, measurement and verification?
  - Yes.
- Does it include the costs to the customer?
  - NIPSCO elected, at the behest of the stakeholders, to use the Utility Cost Test for cost effectiveness screening of measures and programs. The Utility Cost test does not include costs incurred by customers.. However, the DSM Savings Update analysis and report will also include the Participant Cost Test, which does include the cost to the participant.
- If a customer has to pay incentives or lost revenues, that should be considered.
  - Lost revenues are included in the Ratepayer Impact Measure ("RIM") test, which will also be included in the analysis. But, again, in determining which measures to include in the IRP, the stakeholders requested NIPSCO to utilize the Utility Cost Test and NIPSCO agreed to that request.
- Slide 43, regarding the blue line for DSM costs, is the present value of DSM costs being captured in each bar?
  - The blue line is the present value of DSM costs. Each bar shows the present value of portfolio savings under the different scenarios.
- Slide 43, the bars are not revenue requirements?
  - Correct, they represent savings estimates.
- How is NIPSCO determining available savings if the plan is to not allow Aurora to do the optimization?
  - Aurora can be run with the existing portfolio and load forecast to arrive at a net present value of revenue requirements. Another model simulation can then be run with lower load requirements as a result of DSM savings. In the second simulation, the costs to serve the system will go down. Savings are associated with lower energy and capacity costs.
- Not allowing Aurora to make the election means it is only considering dispatch. Not understanding whether DSM is being considered to delay capacity additions.
  - It is accurate to say that Aurora only considers dispatch costs, but the full Aurora-PERFORM model incorporates savings associated with delaying capacity additions. So when a DSM bundle is evaluated, lower capacity costs will also be included. This is accounted for in the illustrative example shown on Slide 43.
- This process seems to underestimate the amount of DSM available.
  - There will be a base, high and low case for DSM. The base case is about 1% and GDS is working with NIPSCO and stakeholders on the low and high cases. Will gladly provide details.
- Has NIPSCO accounted for how catastrophic storms may impact the grid or how more people generating their own power may impact DSM?

  - o Not for these purposes. For these purposes, NIPSCO only considered opportunities to reduce load. NIPSCO does not consider distributed generation in its DSM analysis.

Generation Overview
Fred Gomos, Manager, Corporate Strategy

Mr. Gomos provided an overview of NIPSCO's supply resources as of 2018. Bailly is no longer part of the supply mix as the unit is retired. He also discussed generation costs and how they vary for each unit. He then provided information related to variable costs as well as O&M costs for NIPSCO units.

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

- Regarding Schahfer Unit 14, why is unforced capacity ("UCAP") so low in comparison to nameplate capacity?
  - o It is related to the operational profile. Those units have a lower UCAP because of performance issues, but should improve over time.

UCAP is assigned by MISO based on the units historical Equivalent Forced Outage Rate ("EFORd" therefore if a unit has had performance or operation issues in the past it will get a lower UCAP rating relative to its nameplate capacity until it can demonstrate it can consistently perform at a level close to its nameplate rating

Environmental Considerations
Kelly Carmichael, Vice President, Environmental

Mr. Carmichael provided answers to various stakeholder requests from the first meeting, including NiSource environmental targets announced in 2017 (the Company is on track), NiSource's carbon emissions trajectories, a carbon emissions comparison, and health-based air quality standards in Northwest Indiana (the region has achieved Environment Protection Agency ("EPA") standards). He then provided an overview of key environmental rules and near term compliance requirements and discussed the costs of such compliance by generation unit for coal combustion residual ("CCR") and effluent limitation guidelines ("ELG") compliance.

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

- Regarding the presentation by JET at the last Public Advisory meeting, has NIPSCO considered that?
  - o The presentation was around ammonia based scrubbing and it was considered a few years ago. Must balance that NIPSCO is not a large utility and not in a position to develop technologies. Based on research at the time, it was determined NIPSCO should go with proven technologies. With ELG where they are now, NIPSCO is open to new technologies.
- Will NIPSCO be considering other technologies such as those that can be obtained on a contracted basis to reach ELG compliance?
  - o Once a rule is issued, NIPSCO will evaluate the various options.
- Nothing will be done as part of the IRP process?

  - NIPSCO has already received a request to consider ELG at zero cost and that will be examined. From a policy perspective, it is important to note that environmental rules are constantly evolving and the currently-proposed environmental control regulations may be revised.
- Do you know the percentage reduction for a 1.5 limit as opposed to 2 as it relates to the climate targets?
  - This is unknown. NIPSCO is guided based on the Ceres 2 Degree framework for the electric sector, and a number of groups are also considering the broader 80%.
- Regarding ELG, what is the best guess on when the process will begin after the rule is finalized?
  - The process has already begun with pilot studies for other technologies that would reduce costs and meet the standards. However, the process will begin in earnest as soon as the revised draft rule is received.
- Was there an increase from the last IRP?
  - Slide 57 reflects current understanding of the costs. NIPSCO will go back and review the previous costs.
- Has NIPSCO considered algae treatment for wastewater in Michigan City for example?
  - When NIPSCO has completed its CCR compliance, both the flue gas desulfurization (“FGD”) and CCR wastewater streams will be eliminated, and NIPSCO will be at zero discharge. However, it has been considered for carbon, but it is still an emerging technology.
- The Paris Climate Accord is inadequate and the less we do now, the more urgent it becomes. Have you considered that burning fossil fuels increases client negligence?
  - Must balance with reliability and costs to customers. We are working to get replacement generation online and are being transparent about our targets and are on a trajectory to outpace the Paris Accord.
- We strongly reject the move to natural gas.
- With high levels in ground water, what is being done so it is not migrating?
  - NIPSCO is in compliance with CCR and deploying capital that will allow closure of all the ponds. In addition, NIPSCO has deployed a network to monitor and sample wells. At this point, there is no indication that there are or will be off-site groundwater impacts. However, NIPSCO will deploy more wells, close coal ash ponds and consider groundwater remediation based on sampling data that is publicly available.
- Regarding slides 51 and 52: On slide 51, the percentage reduction is based on a baseline of 2005. On slide 52, looking at that alternative, it would be phased in.
  - It is difficult to look that far in the future. The graph on slide 52 assumes all coal would be replaced.
- Regarding the air quality, although the slide indicates Northwest Indiana met all EPA standards, is that an aggregate of all of the various counties in the NIPSCO footprint? If American Lung Association data is considered the results are different.

  - These are monitors deployed by the State of Indiana, which is compared to the EPA National Ambient Air Standards. All of the monitors meet the EPA standards, it is not aggregate data.
- How does NIPSCO feel about exceeding the EPA standards?
  - For clarity "achieve" means that the standards are not being exceeded. Ten years ago, regional air quality measures did not achieve the standards. Today all the measures achieve the air quality standards.
- Perhaps NIPSCO could look at a different model that looks at EPA as well as other organizations such as the American Lung Association so there isn't such a big change.
  - It is highly likely that the American Lung Association is an active participant in determining the EPA standards.
- Investing in gas and fossil fuels: why is NIPSCO continuing to invest in fossil fuels? Would it not be better to go to other sources of energy?
  - That is part of the process in the IRP as well as the RFP.
- Is there a consideration of running a model without natural gas? A model with all renewable energy and recouping losses later?
  - Yes, there are many factors being considered.
- It is clear that it is not just a carbon issue, so would like to sit down and discuss how the modeling could be adjusted. For example, the ELG requirements will likely be revisited. There is also potential for water contamination due to CCR ponds, which could lead to another cost.
  - NIPSCO is happy to meet to talk about issues and how to address environmental modeling and other items with the IRP. On the technical side, for ELG, NIPSCO is showing Zero Liquid Discharge ("ZLD") because it is clear EPA is going to revisit the rule and will likely get more stringent. Utilizing ZLD eliminates those risks. As stated before, we continue to close ponds and assess groundwater.
- Regarding the air quality standards, how close to your plants are the three monitors located? The Indiana Department of Environmental Management is not as protective of the environment as it could be. Does NIPSCO do its own monitoring in neighborhoods around the plants?
  - Some of the monitors are actually inside the plants. NIPSCO has turned its monitors over to the State for an unbiased assessment of air quality and the network is specifically designed to be representative of the air quality near NIPSCO's plants and other industrial facilities in Northwest Indiana.

2018 Scorecard
Daniel Douglas, VP, Corporate Strategy and Development

Mr. Douglas reviewed the proposed scorecard and noted that it will inform the NIPSCO Preferred Plan. He reviewed the various criteria from the 2016 scorecard and noted how it has been expanded for the 2018 version. He then reviewed each of the criteria and provided an overview of the descriptions and metrics.

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

- Was there explicit weighting of the last IRP?
    - No, and NIPSCO does not intend to in this IRP, either. The Company does not want it to be formulaic.
- Can you talk more about the cost certainty and cost risk area?
    - This gets back to the stochastic work. Back on slide 15, the right side shows how NIPSCO tries to illustrate the cost certainty and cost risk metrics. On the orange bar, Point B is the median, which is the expected cost to customers. The 75th percentile is the cost certainty and the 95th percentile is the cost risk.
- What is NIPSCO using as the metric?
    - The cost certainty is the 75th percentile. The cost risk metric is the 95th percentile. The result is a revenue requirement which allows comparing of the retirement combinations at the 95th percentile for each one.
- Has NIPSCO considered the correlation between those measures and the overall scoring?
    - They will be somewhat correlated as NIPSCO goes through the process if cost certainty is viewed as the more likely high end. However, NIPSCO will take the correlation into account as the criteria are scored.
- How will the results be presented? Color coded?
    - The intention is to be quantitative as the process moves forward. NIPSCO will clearly outline the scoring metrics and the underlying metric and scoring will be available.
- How is NIPSCO going to put them all together? How will the information be shown on the scorecard? Only by color?
    - The plan is to not show a final combined score for each one of the combinations, but will share the rationale for selecting Preferred Plan.
- Regarding environmental, is NIPSCO open to other measurements as well?
    - Yes.

Retirement Analysis
Fred Gomos, Manager, Corporate Strategy and Pat Augustine, CRA

Mr. Gomos provided an overview of how the retirement analysis is being conducted, including how the framework evaluates the all the cost to keep an existing NIPSCO nit versus the cost of retirement and replacement with an alternative. He then discussed how NIPSCO is utilizing the Midcontinent Independent System Operator (“MISO”) Cost of New Entry (“CONE”) plus energy is used in the analysis as a proxy for a viable alternative. He then reviewed the various retirement combinations that were constructed and the capital costs by retirement combination. Mr. Augustine then reviewed the results of the deterministic cost to customers; stochastic costs certainty, risk, and volatility; stochastic cost volatility; and stochastic cost risk.

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

- Although I understand using MISCO CONE, it might make sense to look at as a range. NIPSCO is using the highest end, which raises the cost of new generation.
  - Using CONE is a good proxy because it is the worst possible case. At this point, NIPSCO does not know if it is going into the market, building or buying something. Since combined cycle gas turbine, wind and solar costs are likely close to or lower than MISO's CONE estimate on an all-in basis, CONE provides a good proxy and is conservative for analysis.
- Slide 65 seems to break out the decision into a separate retirement methodology. It is unclear why NIPSCO needs this as opposed to running the model with and without the units. It appears that NIPSCO is missing how each unit is dispatched.
  - In 2016, NIPSCO did not have the modelling tools to do it through the model so we ran them as separate analyses. While we have the modelling tools today, the Company is still maintaining the same format for the 2018 update. If the issues are considered together, the focus on retirements is lost. NIPSCO needs a process to look at retirements decisions separately from the replacement decision.
- Slide 65, how does NIPSCO propose to accommodate if the 2023 date for ELG is not relevant? These numbers are based on what rules are today, and those rules may change. Would it be better to consider when the rule changes?
  - NIPSCO does not know how the rule might be updated, it is necessary to use the current versions of the rules as we understand them today
- Slide 66, is this only coal, not the entire system?
  - Correct, these costs are only for the coal fleet.
- Slide 67, is that the entire system?
  - Yes, this is a different presentation than slide 66. Slide 67 summarizes the full cost of service.
- Is it possible that Scenario 1a would look different if carbon costs were not included?
  - Yes, this slide only considers the Base Case assumptions.
- Slide 69, the lower left corner is where NIPSCO wants to be, correct?
  - Yes.
- Based on this, other factors are overwhelming the costs and risks. Is NIPSCO not weighting?
  - There are no conclusions being made at this point. NIPSCO could select portfolios based on a combination of criteria. The ultimate goal is to serve the customers in a safe, reliable and cost effective way. Stochastics help in providing new ways to do that and the scorecard will assist in showing the tradeoffs in the decision that NIPSCO is trying to make.
- It will be key to understand the scorecard.

- Encouraged to see Portfolio 5 as far to the lower left as any other option. If NIPSCO had included the risks posed by burning fossil fuels, such as a destabilized climate, would it move Portfolio 5 even more to the lower left corner?
    - In this part of the analysis, NIPSCO is quantifying the cost to serve load within the MISO market, along with an associated risk metric that is quantified through analysis of the stochastic variables discussed this morning. Other environmental considerations might be included in other elements of the scorecard.

Replacement Analysis
Dan Douglas, VP, Corporate Strategy and Development and Pat Augustine, CRA

Mr. Douglas discussed how NIPSCO plans for the future and noted that retiring Schahfer Units 17/18 will create a need for new resources. He stated that as replacements are considered, replacement resource combinations will take into account ownership, duration and diversity and he reviewed the considerations as part of this process. Mr. Augustine then provided an overview of the results of the resource combinations, including a discussion of the replacement resource framework. The results presented included the deterministic cost to customer; stochastic cost certainty, risk, and volatility; stochastic cost volatility; and stochastic cost risk.

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

- A short-term power purchase agreement ("PPA") versus company owned asset is missing from the scorecard How does NIPSCO view a PPA vs a Company owned asset NIPSCO is about the customer first and the decision will be made on that basis. The goal is to do what is best for customers, even if it means forgoing an opportunity for asset ownership. When NIPSCO calculates carbon emissions, are they only direct from power generation, or do they include transportation, mining and waste?
    - The calculation only includes direct emissions.
- What are renewables for NIPSCO? Does the Company have plans to use anything other than solar and wind?
    - NIPSCO currently has renewables that are not solar and wind including biomass projects. Other renewable resources will be evaluated if offered in the RFP.
- Slide 75 is unclear how it will be used. On diversity, it is not clear which of those is cost diverse. Is the middle or right column more diverse? Is "diversity" a code word for carbon emissions? The farther to the right, the lower the emissions are.
    - Thank you for the suggestion to change the title. Diversity is related to portfolio diversity, specifically around carbon emission intensity.
- Slide 75, if trying to map out, how does a PPA including coal fit into the boundary?

    - It could fit in the top left hand side, which is the reason to go through the RFP process. Although NIPSCO is unaware of any coal PPAs, if they exist, it will become apparent through the RFP process.
- Slide 80, was this done in spreadsheet or the model?
    - It was done through a full run of the Aurora-PERFORM stochastic modeling
- If NIPSCO ran the model with industry estimates, will the Company rerun the existing model with RFP results?
    - Yes. This current process was intended to show some of the potential tradeoffs. There will be a few phases of the analysis, with an update that incorporates RFP results.

Request for Proposals ("RFP") for Capacity
Paul Kelly, Director, Federal Regulatory Policy and Bob Lee, CRA

Mr. Kelly reviewed the stakeholders who had provided feedback on the RFP, though a letter to NIPSCO, comments on the Interim Design Study or by commenting on the draft RFP document after completing a non-disclosure agreement ("NDA"). He provided a summary of the feedback received and noted what had been incorporated and what had not been incorporated. Mr. Lee then reviewed the final evaluation criteria for non-demand response resources and demand response resources and reviewed the key design elements of the RFP. He finished by presenting the revised timeline for the RFP.

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

- Slide 84, the second bullet, it is contradictory to slide 83. Entities have been able to access through NDAs.
    - That was the RFP document prior to issuing. The results will be shared in the aggregate to parties. With certain limitations, parties who have executed an NDA will be able to view the bids.
- Please clarify if in the RFP NIPSCO is considering each technology in and of itself? NIPSCO is not comparing between technologies.
    - That is correct. The information will be provided to the IRP team, which will conduct the modeling as discussed and come back with the optimum portfolio.
- NIPSCO should consider expanding cost to customer to include cost to customer health, etc.
- Will NIPSCO be bidding?
    - No.
- Is NIPSCO eliminating a self-build option?
    - It does not mean that.
- Please clarify the results of the bidding. NIPSCO will not release the individual bids, but distribution and information on the costs without specific bidder information will be made available?
    - Correct. NIPSCO will release the average price.

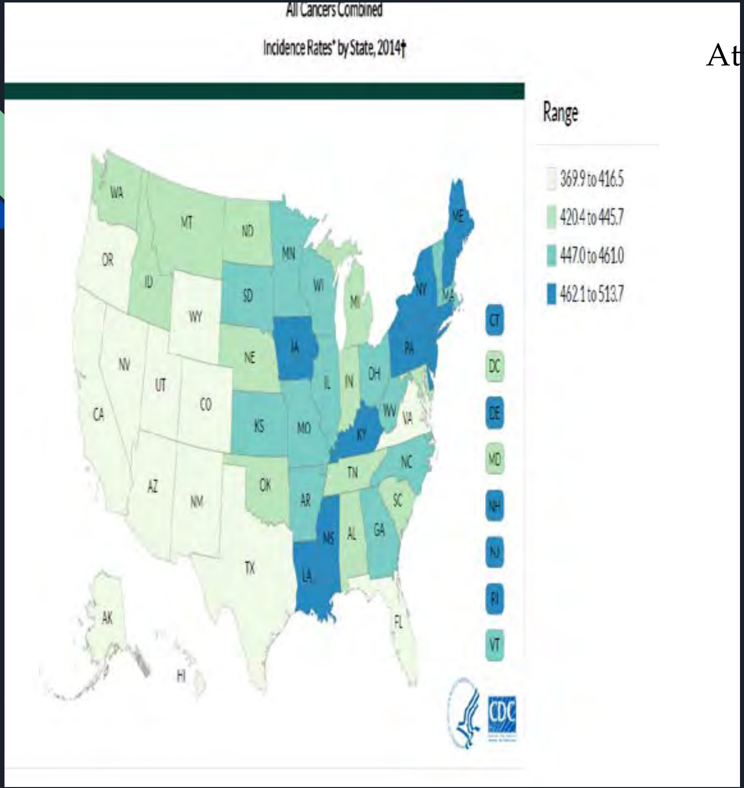
Stakeholder Presentations

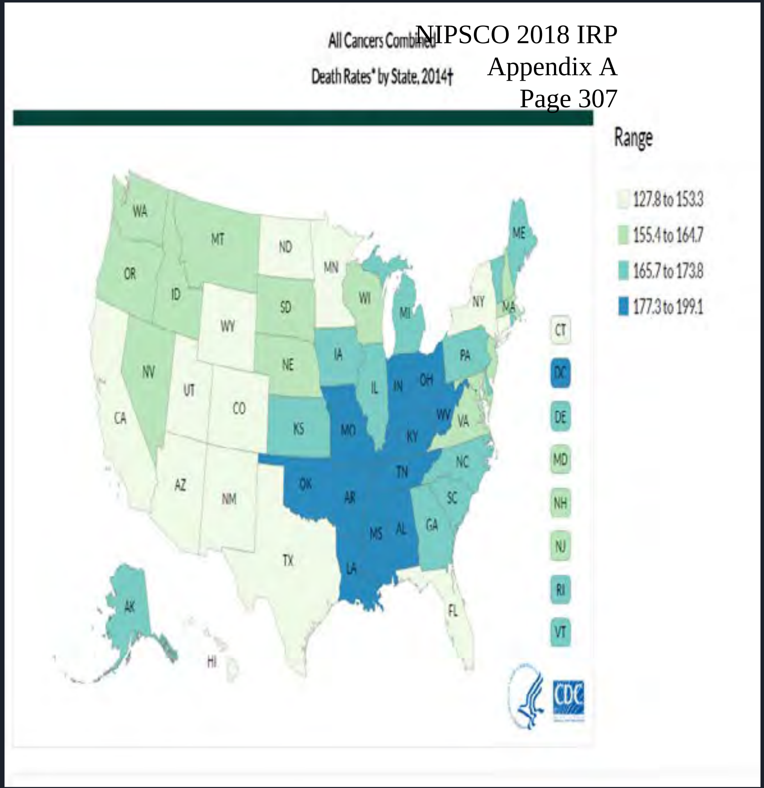
Dany Brooks; David Chiesa of S&C Electric Company; and Scott Houldieson (United Auto Workers), Barry Halgrimson, and Sam Henderson (Hoosier Environmental Council) provided stakeholder presentations.

Ms. Becker closed the meeting by thanking the attendees for their attendance and active participation.

The Health Ramifications of Coal in Indiana

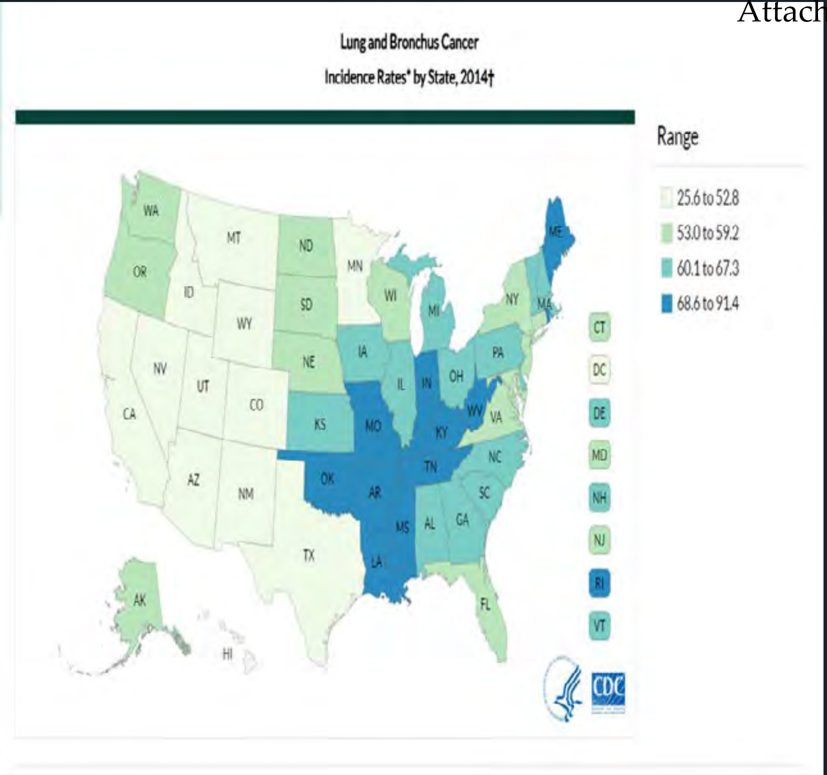
By Dany Brooks
With Supervision of PhD Candidate
Jamie Hough

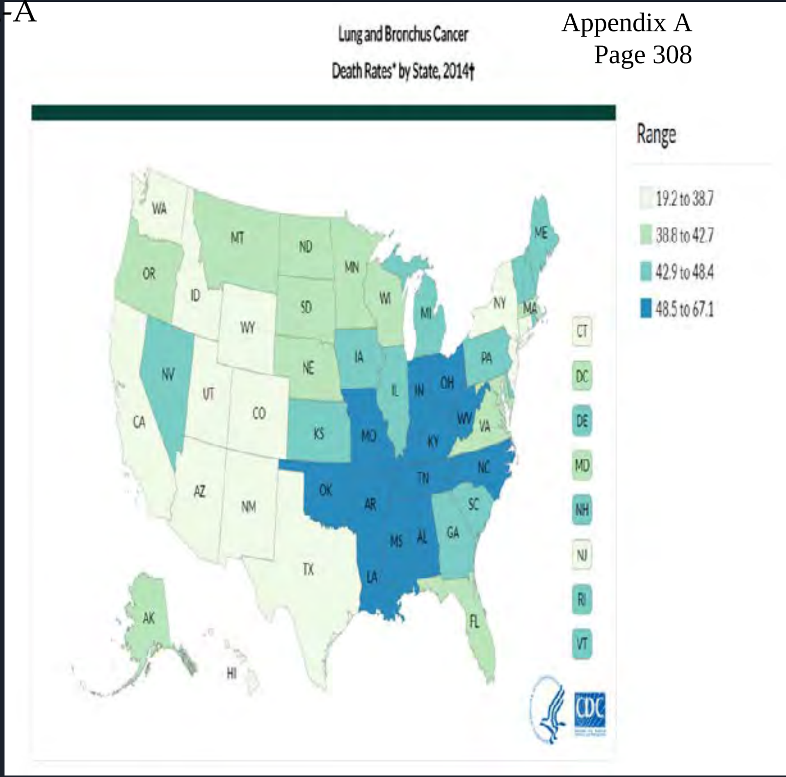




Combined Cancers Rate Maps from CDC. https://www.cdc.gov/cancer/dcpc/data/state.htm

Attachment 2-A

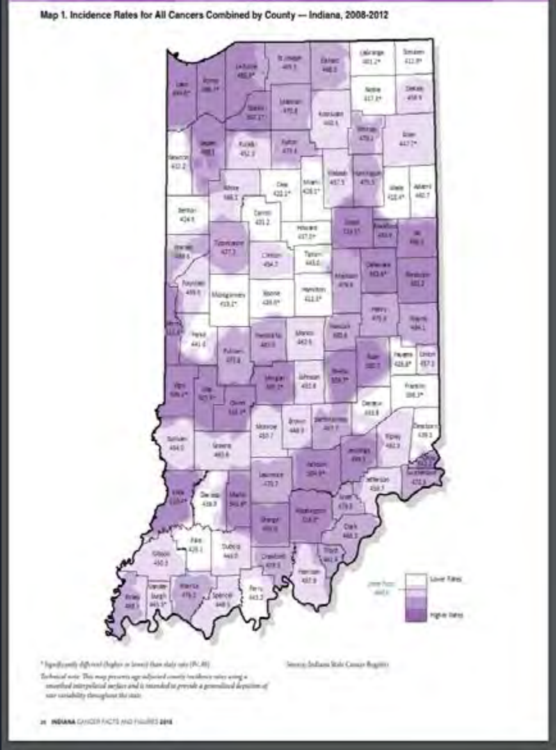




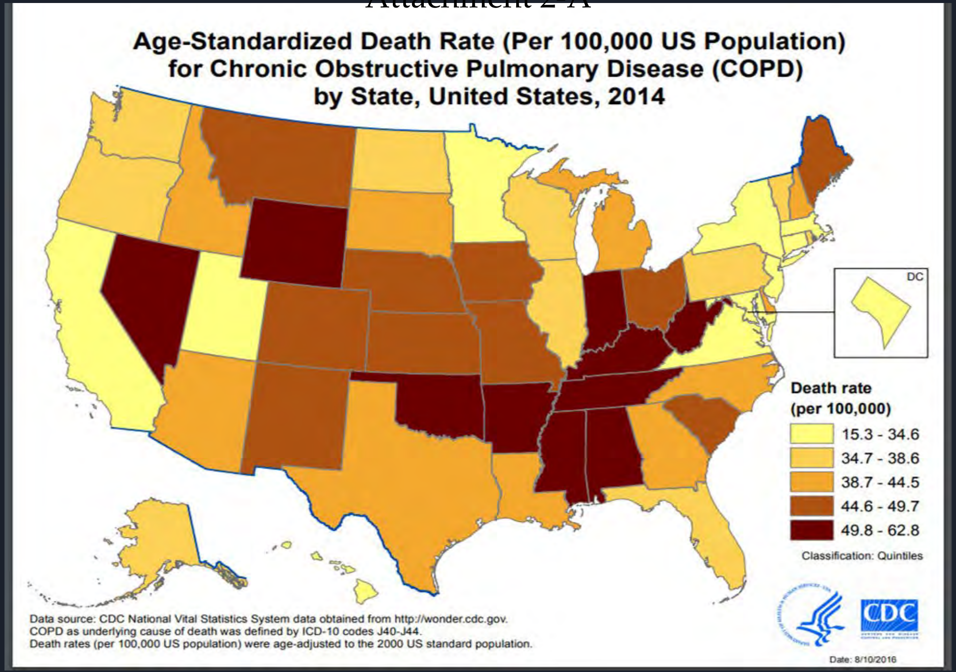
Lung Cancer Rate Maps from CDC.

https://www.cdc.gov/cancer/lung/statistics/state.htm

Attachment 2-A



All Cancers Combined by County Map by IN Gov.

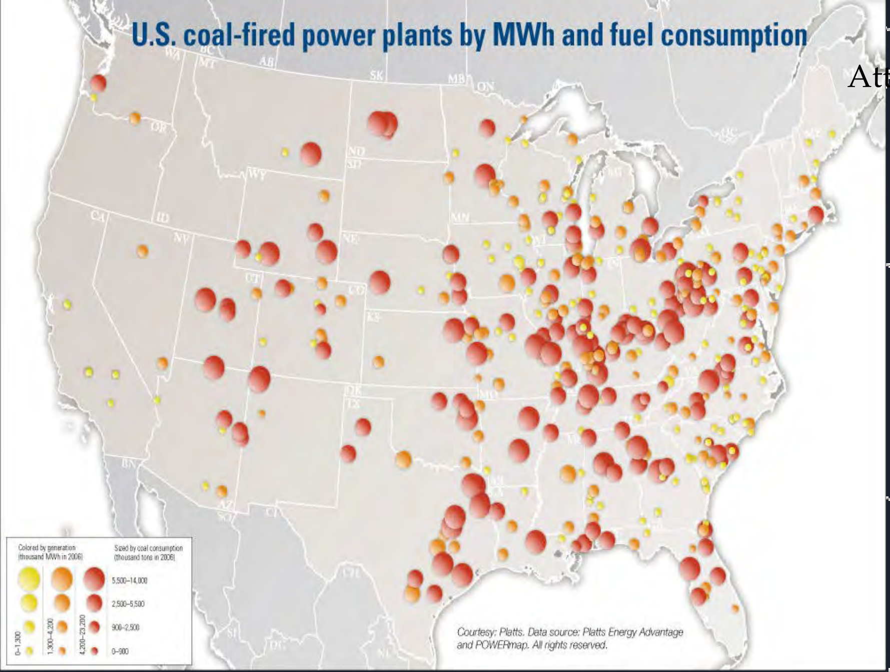


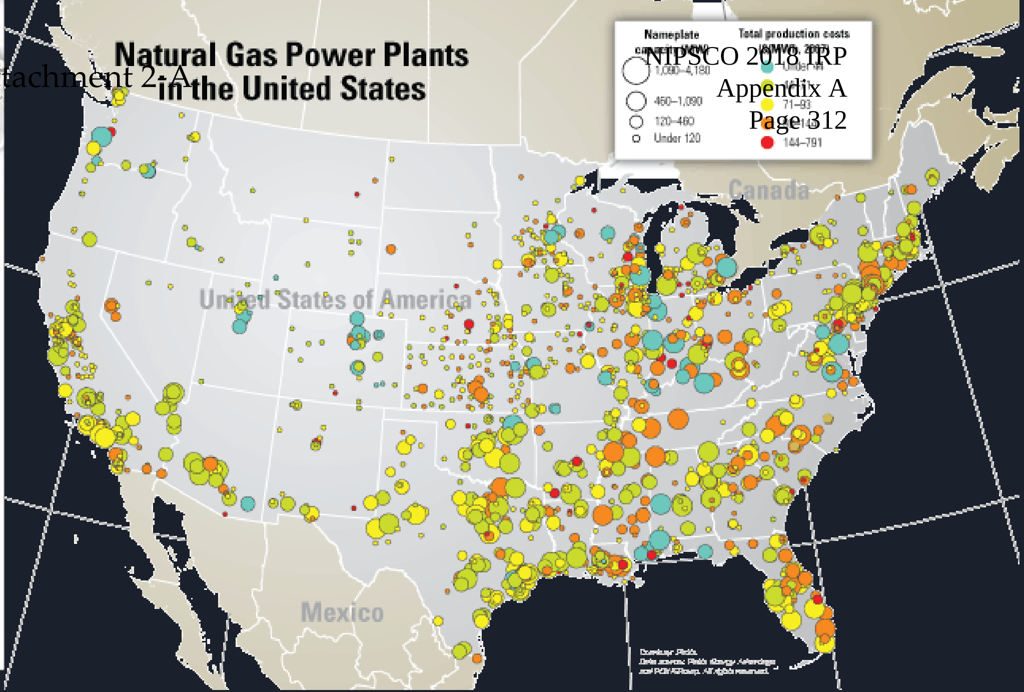
COPD Death Rate Map from CDC.

https://www.cdc.gov/copd/data.html

Confounding Health Data

- With this health data, there are many questions which must be answered
- Health problems never can be simplified to a single factors ***yet the weight of any of these contributing factors cannot be dismissed on the premise that there are other serious causes.***
- Proximity to coal fired power plants is one of the greatest of these factors





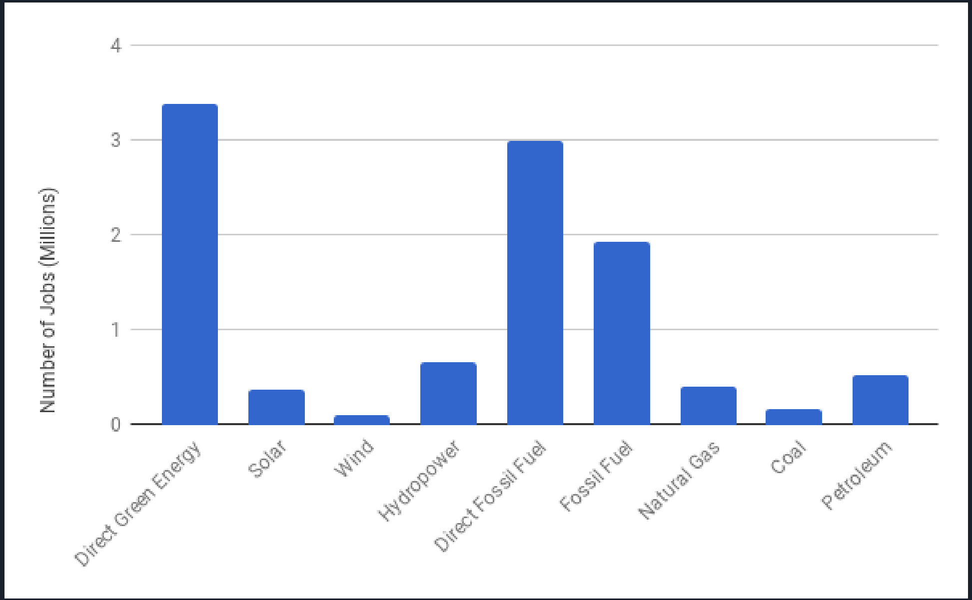
Natural Gas and Coal Power Plant Location

Map by Power Magazine.

Without fossil fuels, Where do We go?

- Green energy acts restorative and regenerative for economy, health and the climate, it has become the perfect solution
- T.H. Chan School of Public Health at Harvard estimates through various studies monetary benefits of **$33 billion** dollars surpassing initial costs of **$17 billion.**
- Estimates in the same study sub-benefits of **$29 billion** in health care effects and **$21 billion** in climate benefits.
- Estimates also with investments into wind turbines with a capacity of **3000 MW** benefits of **$690 million**

A Green Future



Data from Environmental and energy Study Institute. http://www.eesi.org/papers/view/fact-sheet-jobs-in-renewable-energy-and-energy-efficiency-2017

Green Myths

- Duke energy estimates construction cost of 600 MW coal power plant at $2 Billion therefore has an estimated $3.3 million per MW
- Green energy provides cheap alternatives
  - Solar estimated $1 million per MW
  - Wind estimated $1-$2 million per MW
  - Hydro estimated $3 million per MW

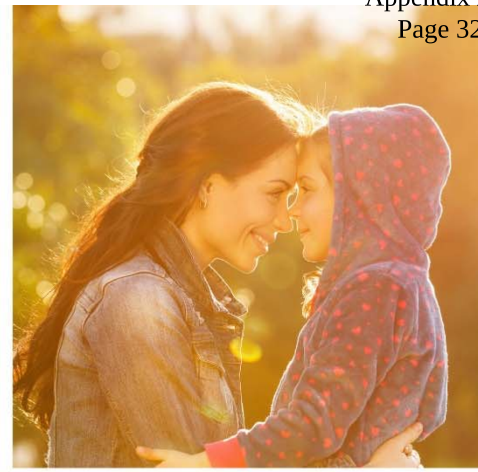
Invest in Our Future

NIPSCO Public Advisory Meeting 2 Registered Participants		
First Name:	Last Name:	Company:
Denise	Abdul-Rahman	Indiana State Conference of the NAACP
Lauren	Aguilar	OUCC
Jake	Allen	IPL
Linda	Anguiano	Progressive Democrats of America - Calumet Region
Russ	Atkins	NIPSCO
Pat	Augustine	Charles River Associates
Alison	Becker	NIPSCO
Anne	Becker	Lewis Kappes
Mahamadou	Bikienga	NiSource
Michael	Blank	Peabody
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	IURC
Dany	Brooks	Purdue University
Wade	Cameron	Wade Cameron
Andrew	Campbell	NIPSCO
Becky	Campbell	First Solar
Kelly	Carmichael	NiSource
Michael	Cella	Toyota Tsusho
Gilles	Charriere	Sierra Club/ NIPSCO customer
David	Chiesa	S&C Electric Company
Thomas	Cmar	Earthjustice
Jeffrey	Corder	St. Joseph Phase II, LLC
Elena	DeLaunay	Rockland Capital, LLC
Dan	Douglas	NIPSCO
Jeffery	Earl	Indiana Coal Council
Claudia	Earls	NiSource
Amy	Efland	NiSource/NIPSCO
Steve	Francis	Sierra Club - Hoosier Chapter
Julia	Friedman	Oracle
Fred	Gomos	NiSource
Isabelle	Gordon	Office of Utility Consumer Counselor
Doug	Gotham	State Utility Forecasting Group
Robert	Greskowiak	Invenergy LLC
Corey	Hagelberg	Beyond Coal
Barry	Halgrimson	Retired
Rina	Harris	Vectren
Samuel	Henderson	Hoosier Environmental Council
Stephen	Holcomb	NIPSCO
Allison	Holly	GE
Scott	Houldieson	UAW
Shelby	Houston	IPL/AES
Robert	Kaineg	Charles River Associates
Pauline	Katsouros	NIPSCO
Sam	Kliewer	Cypress Creek Renewables
Tim	Lasocki	Orion Renewable Energy Group LLC

NIPSCO Public Advisory Meeting 2 Registered Participants		
First Name:	Last Name:	Company:
Jonathan	Mack	NIPSCO
Cyril	Martinand	ArcelorMittal
Debi	McCall	NIPSCO
Karen	McCoy	Nipsco
Jim	McMahon	CRA
Emily	Medine	EVA
Nick	Meyer	NIPSCO
Kevin	Moore	MIDWEST WIND & SOLAR LLC
Adam	Newcomer	NIPSCO
Kerwin	Olson	Citizens Action Coalition of IN
Elizabeth	Palacio-Vargas	Ms.
April	Paronish	Indiana Office of Utility Consumer Counselor
Bob	Pauley	IURC
Rom	Poplawski	U.S. Global Energy LLC
Dennis	Rackers	Energy & Environmental Prosperity Works!
Dennis	Rackers	NIPSCO
Thom	Rainwater	Development Partners Group
David	Repp	JET Inc
Matt	Rice	Vectren
Edward	Rutter	Indiana Office of Consumer Counselor
Carter	Scott	Ranger Power LLC
Cliff	Scott	NIPSCO
Brent	Selvidge	IPL
Frank	Shambo	NIPSCO
Violet	Sistovaris	NIPSCO
Matt	Smith	Carmeuse Lime and Stone
Anna	Sommer	Sommer Energy, LLC
Dick	Spellman	GDS Associates, Inc.
Jennifer	Staciwa	NIPSCO
Karl	Stanley	NiSource
Liz	Stanton	Applied Economics Clinic
Bruce	Stevens	Indiana Coal Council
George	Stevens	I U R C
Alice	Tharenos	peabody
Michael	Therrian	midwest wind and solar
Will	Vance	Indianapolis Power & Light
Victoria	Vrab	NIPSCO
Jennifer	Washburn	CAC
Ashley	Williams	Sierra Club
John	Williams	Arcelor Mittal
Victoria	Wittig	Save the Dunes
David	Woronecki-Ellis	Sierra Club Dunelands Group
Jen	Woronecki-Ellis	Sierra Club Dunelands Group
Fang	Wu	SUFG

Appendix A

Exhibit 3



NIPSCO Integrated Resource Plan 2018 Update

Public Advisory Meeting Three

July 24, 2018

Welcome and Introductions

Process for Today's Webinar

- In order to best facilitate today's discussion, we are asking that you use the "chat" feature on the webinar to ask questions.
- Please type your question at any point and it will be read to the audience by the facilitator.
- When entering your question, please include your name and organization you are representing (if applicable).
- If time permits, we will have an open discussion after the material has been presented.
- You may also email questions to nipsco_irp@nisource.com and those questions will be answered as they are received.
- We look forward to your thoughts and questions!

Agenda

Time	Topic
12:30 – 12:45	Welcome, Introductions, and Safety Moment
12:45 – 1:00	Update on the Integrated Resource Plan (“IRP”) Process
1:00 – 1:30	All-Source Request for Proposals (“RFP”) Results Overview
1:30 – 1:45	Incorporating the RFP Results
1:45 – 2:25	Stakeholder Presentations / Contingency
2:25 – 2:30	Next Meeting / Wrap Up

Safety Moment:

- **Slips, trips, and falls are the most common form of injury to office workers, and is also a common injury among non-office workers.**
- **Across all of private industry, there were 229,240 injuries involving days away from work in 2016 due to slips, trips, and falls.**
- **Several practices can help reduce or avoid slips, trips, and falls:**
  - Stay Clutter Free: Look for boxes or other impediments in walkways.
  - Step on Up: Standing on office chairs is a common source of falls. Be especially careful of office chairs with casters or rollers. Use a specifically designed step-stool or ladder instead.
  - Maintain a Clear Line of Vision: workers can run into each other around blind corners.
  - Slippery Flooring: Skid resistant flooring or carpeting can help prevent slips, trips, and falls. Be especially careful of liquid spills or runoff from rain and snow on flooring.

NIPSCO's Planning and the Public Advisory Process

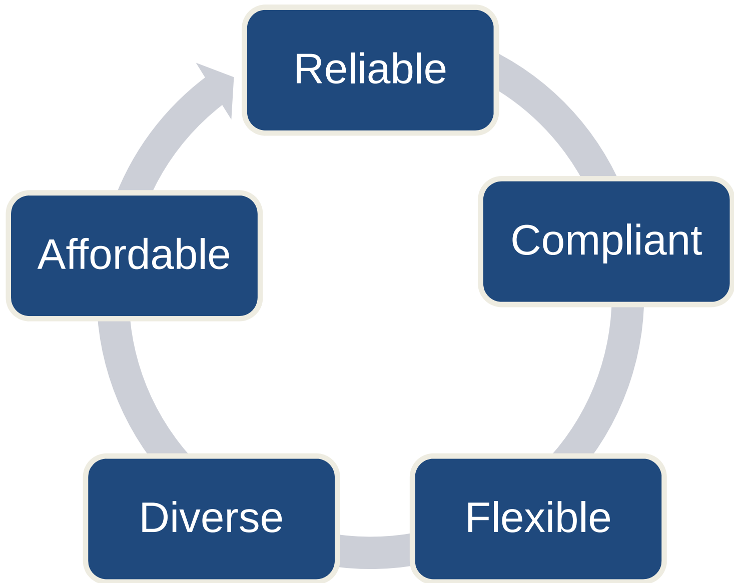
Dan Douglas
Vice President, Corporate Strategy & Development

How Does NIPSCO Plan for the Future?

Charting The Long-Term Course for Electric Generation

About the IRP Process

- Every three years, NIPSCO outlines its long-term plan to supply electricity to customers over the next 20 years
- This study – known as an Integrated Resource Plan (IRP) – is required of all electric utilities in Indiana
- IRP process includes extensive analysis of a range of generation scenarios, with criteria such as reliable, affordable, compliant, diverse and flexible



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

Stakeholder Engagement Roadmap

	Meeting 1 (March 23)	Meeting 2 (May 11)	Meeting 3* (July 24th)	Meeting 4 (September 19)	Meeting 5 (October 18)
Key Questions	- Why has NIPSCO decided to file an IRP update in 2018? - What has changed from the 2016 IRP? - What are the key assumptions driving the 2018 IRP update? - How is the 2018 IRP process different from 2016?	- What is NIPSCO existing generation portfolio and what are the future supply needs? - Are there any new developments on retirements? - What are the key environmental considerations for the IRP? - How are DSM resources considered in the IRP?	- What are the preliminary results from the all source RFP Solicitation?	- What are the preliminary findings from the modeling?	- What is NIPSCO's preferred plan? - What is the short term action plan?
Meeting Goals	- Communicate and explain the rationale and decision to file in 2018 - Articulate the key assumptions that will be used in the IRP - Explain the major changes from the 2016 IRP - Communicate the 2018 process, timing and input sought from stakeholders	- Common understanding of DSM resources as a component of the IRP and the methodology that will be used to model DSM - Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap - Key environmental issues in the IRP	- Communicate the preliminary results of the RFP and next steps	- Stakeholder feedback and shared understanding of the modeling and preliminary results - Review stakeholder modeling and analysis requests	- Communicate NIPSCO's preferred resource plan and short term action plan - Obtain feedback from stakeholders on preferred plan

**Webinar*

Stakeholder Interactions

- **Since the May 11 Public Advisory meeting, NIPSCO has met with stakeholder groups**

Stakeholder	Subject Area/Discussion Topic
Sierra Club	IRP Modelling and Scenarios
OUCC	All-Source RFP, IRP Modelling and Scenarios, Load Forecasting
CAC	IRP Modelling and Demand Side Management (DSM)
IURC	All-Source RFP and IRP Modelling

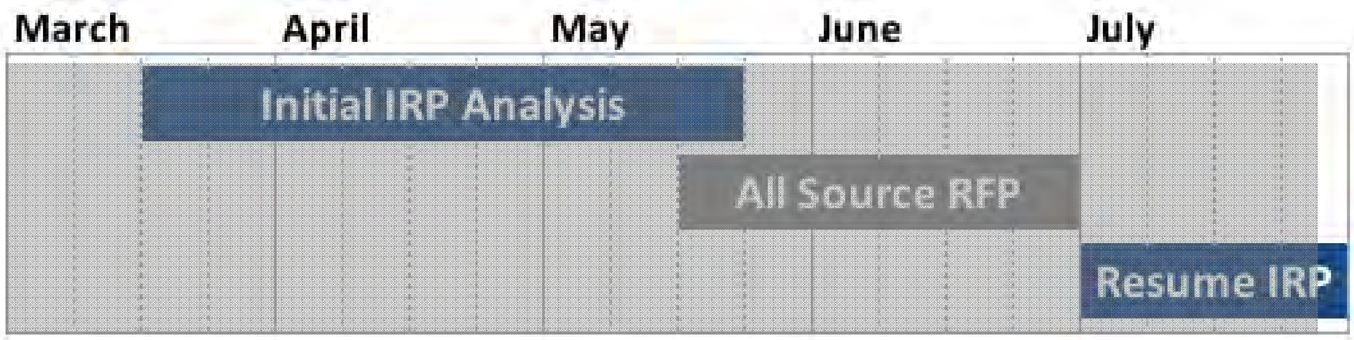
All-Source RFP Results Summary

Paul Kelly
Director, Federal Regulatory Policy

Andy Campbell
Director, Regulatory Support and Planning

Bob Lee
Charles River Associates

Timeline for the RFP



Date	Event
March 23rd	Overview RFP design with stakeholders
April 6th	RFP Design Summary document shared with stakeholders to request feedback
April 20th	Stakeholder feedback on Design Summary due back to NIPSCO
May 14th	RFP initiated
May 28th	Notice of Intent and Pre-qualifications due from potential bidders
June 29th	RFP closes
July 24th	Summary of RFP bids presented at Public Advisory Meeting webinar; IRP resumes analysis incorporating results of RFP

Key Design Elements of the All-Source RFP

- **Technology - All solutions regardless of technology**
- **Size**
  - Minimum total need of 600 megawatts (“MW”) for the portfolio but without a cap
  - Allows smaller resources to offer their solution as a piece of the total need
  - Also encourages larger resources to offer their solution for consideration
- **Ownership Arrangements**
  - Seeking bids for asset purchases (new or existing) and purchase power agreements
  - Resource must qualify as Midcontinent Independent System Operator (“MISO”) internal generation (not pseudo-tied) or load (demand response or “DR”)
- **Duration**
  - Requesting delivery beginning June 1, 2023 but will evaluate deliveries before 2023
  - Minimum contractual term and/or estimated useful life of 5 years (except for DR, which is 1 year)
- **Deliverability**
  - Must have firm transmission delivery to MISO Zone 6
  - Must meet N-1-1 reliability criteria or show cost estimate to achieve that quality
- **Participants & Pre-Qualification**
  - Marketed RFP to broad bidder audience and Bidder Conference
    - Platts Megawatt Daily, North American Energy Marketers Association (NAEMA), NIPSCO Press Release
  - Required credit-worthy counterparties to ensure ability to fulfill resource obligation

Participating Bidders – Thank you!

Innovateus Solar
Development Partners
APEX Clean Energy
edp renováveis
Big Rivers Electric Corporation
Cypress Creek Renewables
EDF renewables
enel Green Power
NextEra Energy
ALLETE clean energy
e.on
Calpine Energy Solutions
EmberClear – An Innovative Project Development Company
ibV energy partners
Invenergy
Hecate Energy
J. Ranck Electric, Inc.
juwi
Rockland Capital
Origis Energy – Powering the Solar Revolution
res
Ranger Power
bp
Southern Current
Jet JNG US
voltus – Less Energy • More Cash
ARES
PSG Energy Group
Tenaska
EDF Energy
Glide Path

Overview of Proposals Received

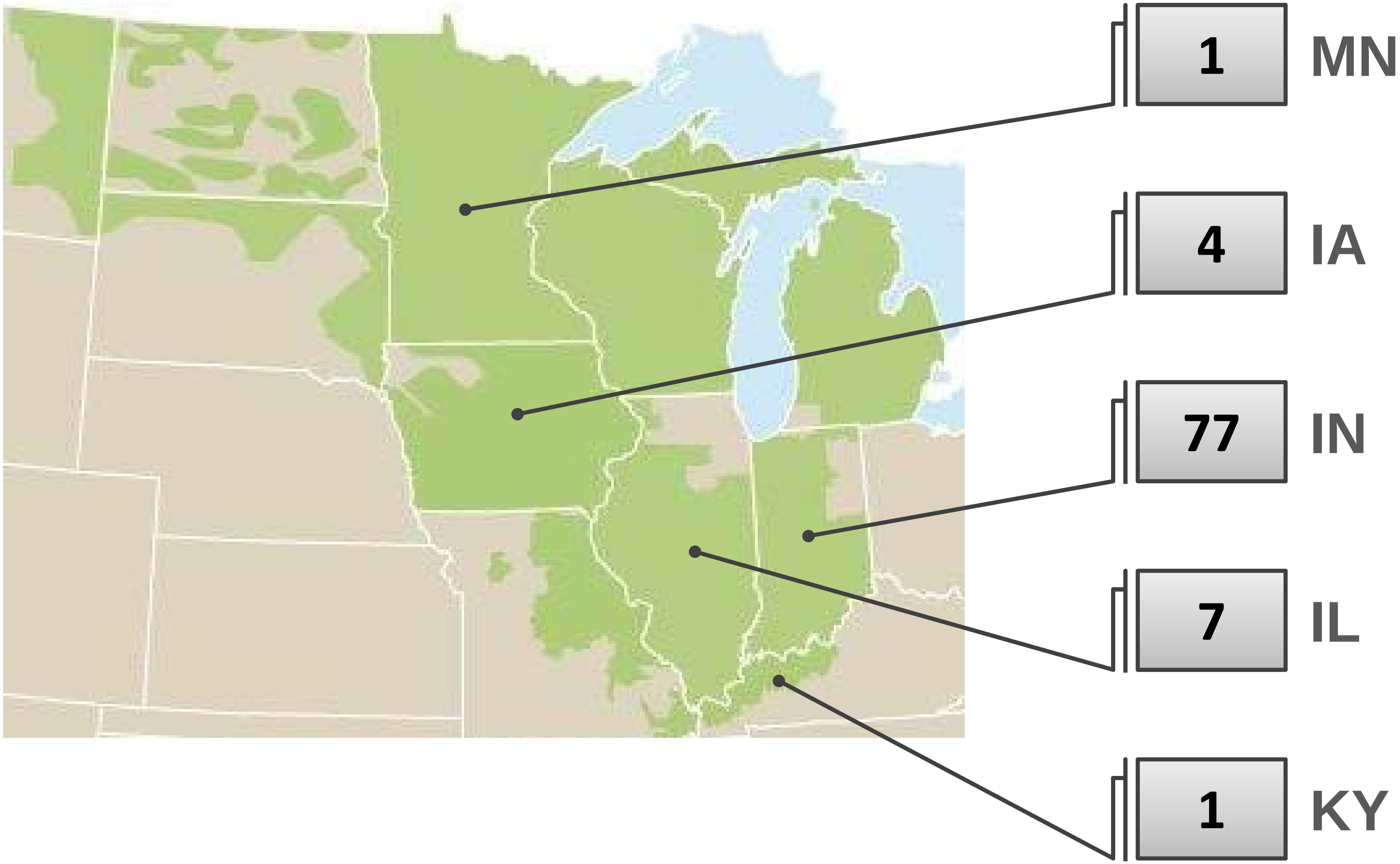
Count of Proposals

Technology	CCGT*	CT**	Other Fossil	Wind	Wind + Solar + Storage	Solar	Solar + Storage	Storage	Demand Response	Total
Asset Sale	4	-	-	1	-	1	-	-	-	6
PPA* **	8	-	3	6	-	26	7	8	1	59
Option	3	1	-	7	1	8	4	1	-	25
Total	15	1	3	14	1	35	11	9	1	90
Locations	IN, IL	IN	IN, KY	IA, IN, IL, MN	IN	IL, IN, IA	IN	IN	IN	

- **The RFP generated a tremendous amount of bidder interest**
- **90 total proposals were received across a range of deal structures**
  - ❖ **59 individual projects across five states with ~13.3 gigawatts ("GW") (installed capacity or "ICAP") represented**
  - ❖ Many of the proposals offering variations on pricing structure and term length
  - ❖ Several instances of renewables paired with storage
  - ❖ Majority of the projects are in various stages of development

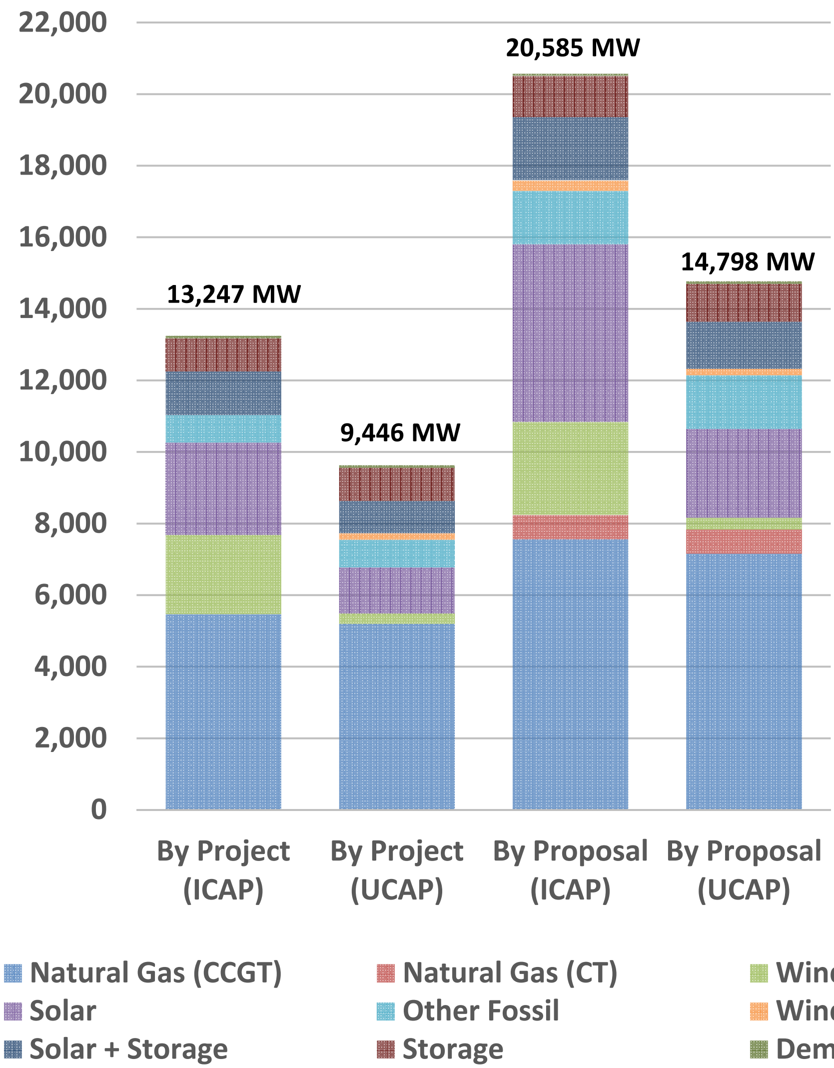
*Combined Cycle Gas Turbine **Combustion Turbine ***Purchase Power Agreement

Distribution of Proposals Received



Proposals Received by Technology (MW)

Note: Unforced capacity ("UCAP") MW are estimated using MISO class averages by technology



	ICAP by Project		ICAP by Proposal	
	(MW)	%	(MW)	%
Natural Gas (CCGT)	5,470	40%	7,561	37%
Natural Gas (CT)	-	0%	685	3%
Wind	2,209	16%	2,594	13%
Solar	2,580	19%	4,965	24%
Other Fossil / Coal	772	6%	1,494	7%
Wind + Solar + Storage	-	0%	300	1%
Solar + Storage	1,220	9%	1,760	9%
Storage	925	7%	1,155	6%
Demand Response	70	1%	70	0.3%

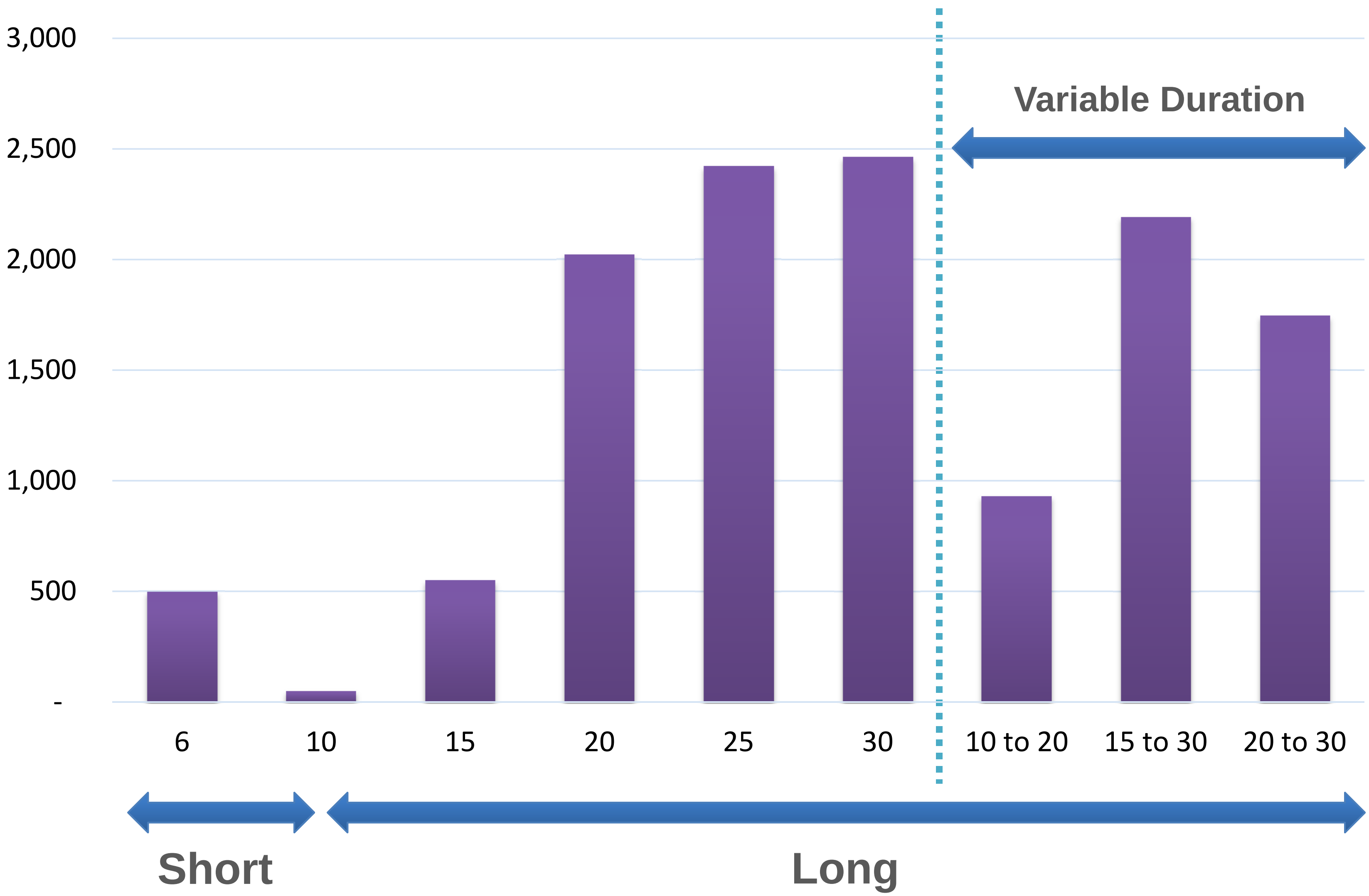
	UCAP by Project		UCAP by Proposal	
	(MW)	%	(MW)	%
Natural Gas (CCGT)	5,199	55%	7,157	48%
Natural Gas (CT)	-	0%	678	5%
Wind	287	3%	329	2%
Solar	1,291	14%	2,483	17%
Other Fossil / Coal	772	8%	1,494	10%
Wind + Solar + Storage	-	0%	110	1%
Solar + Storage	902	10%	1,322	9%
Storage	925	10%	1,155	8%
Demand Response	70	1%	70	0.5%

Proposals Received by Technology (MW) "UCAP"

Note: UCAP MW are estimated using MISO class averages by technology

Technology	CCGT	CT	Other Fossil	Wind	Wind + Solar + Storage	Solar	Solar + Storage	Storage	Demand Response	Total
Asset Sale	2,020	-	-	30	-	25	-	-	-	2,075
PPA	2,574	-	1,494	119	-	1,796	810	1,055	70	7,917
Option	2,563	678	-	180	110	662	513	100	-	4,806
Total	7,157	678	1,494	329	110	2,483	1,322	1,155	70	14,798
Locations	IN, IL	IN	IN, KY	IA, IN, IL, MN	IN	IL, IN, IA	IN	IN	IN	

PPA Range of Durations (MW) "UCAP"



Overall Summary and Pricing Received

	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage	4	705	3	465	$1,182.79	$/kW	
	Wind + Solar + Storage	1						
	Storage	1						
Purchase Power Agreement	Combine Cycle Gas (CCGT)	8	2,715	6	2,415	$7.86	$/kW-Mo	+ fuel and variable O&M
	Solar + Storage	7	1,055	5	755	$5.90	$/kW-Mo	+ $35/MWh (Average)
	Storage	8	1,055	5	925	$11.24	$/kW-Mo	
	Solar	26	3,591	16	1,911	$35.67	$/MWh	
	Wind	6	788	4	603	$26.97	$/MWh	
	Fossil	3	1,494	2	772	N/A		Structure not amenable to price comparison
	Demand Response	1						
	Total	**90**	**20,585**	**59**	**13,247**			

Preliminary – Subject to Due Diligence

RFP Evaluation Process

Determining a list of finalists by technology

- **Representative cost and performance characteristics by technology were developed based on RFP bids and provided to the IRP team for portfolio optimization modeling**
  - ❖ IRP to determine the preferred portfolio for execution
- **Bid evaluation considered both cost and non-cost factors (non-DR)**
  - ❖ Tier 1 factors – Asset Cost and Facility Reliability & Deliverability
  - ❖ Tier 2 factors – Development Risk
  - ❖ Tier 3 factors – Asset Specific Risk
- **List of finalists by technology for possible definitive agreement(s)**

Incorporating the RFP Results into the IRP

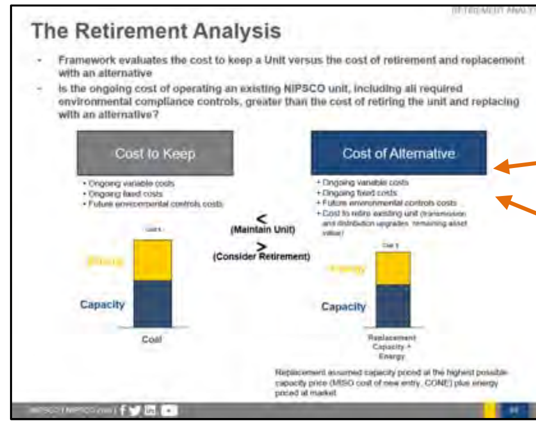
Dan Douglas
Vice President, Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

How Will The RFP Feed Into The IRP?

The results of the RFP will feed back into the IRP to inform both the retirement analysis and the replacement analysis

- ## Retirement Analysis
  - MISO Cost of New Entry ("CONE") plus market energy was used in the initial IRP analysis as a proxy for replacement costs
  - RFP results provide known and visible replacement costs and volumes
  - Representative project groups will be constructed from RFP results, assembled by technology and ownership, for use in the updated IRP analysis
  - Retirement analysis will be re-run using the representative RFP projects as selected by the optimization model



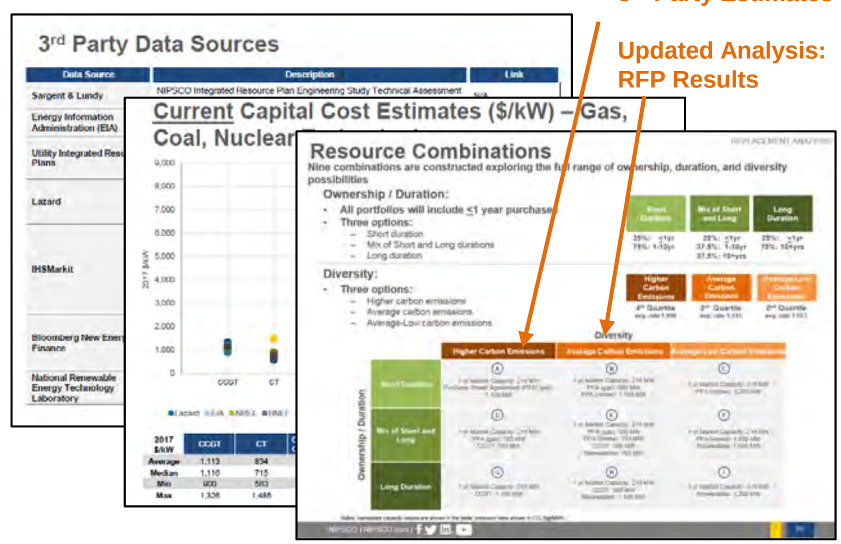
Initial Analysis: CONE + modeled market energy

Updated Analysis: RFP Results + modeled market energy

- ## Replacement Analysis
  - Initial IRP replacement costs used estimates from multiple third-party data sources; no visibility into actual replacement costs for projects available to NIPSCO
  - RFP results provide visibility into executable alternatives for NIPSCO
  - Replacement analysis will be run using somewhat simplified and anonymized RFP results

Initial Analysis: 3rd Party Estimates

Updated Analysis: RFP Results



How Will The RFP Feed Into The IRP?

- The RFP responses provide key input data for supply-side portfolio costs
- A three-step process to update and run the IRP models will be carried out over the next two months

1

Develop Model Inputs

- Specify input assumptions by resource type "tranche" based on RFP results
- Develop specific resource options (supply and demand) in Aurora model format

2

Run Aurora Portfolio Optimization

- Evaluate least-cost portfolios for retirement and replacement analyses
  - Portfolios to fill each potential retirement capacity gap
  - Replacement portfolios for various levels of diversity and ownership (renewables vs. fossil, owned vs. PPA)

3

Run Full IRP Analysis

- Evaluate each portfolio against all scenarios *and* stochastics in Aurora and PERFORM models
- Complete scorecard with metrics across all objectives

Stakeholder Presentations/Comments

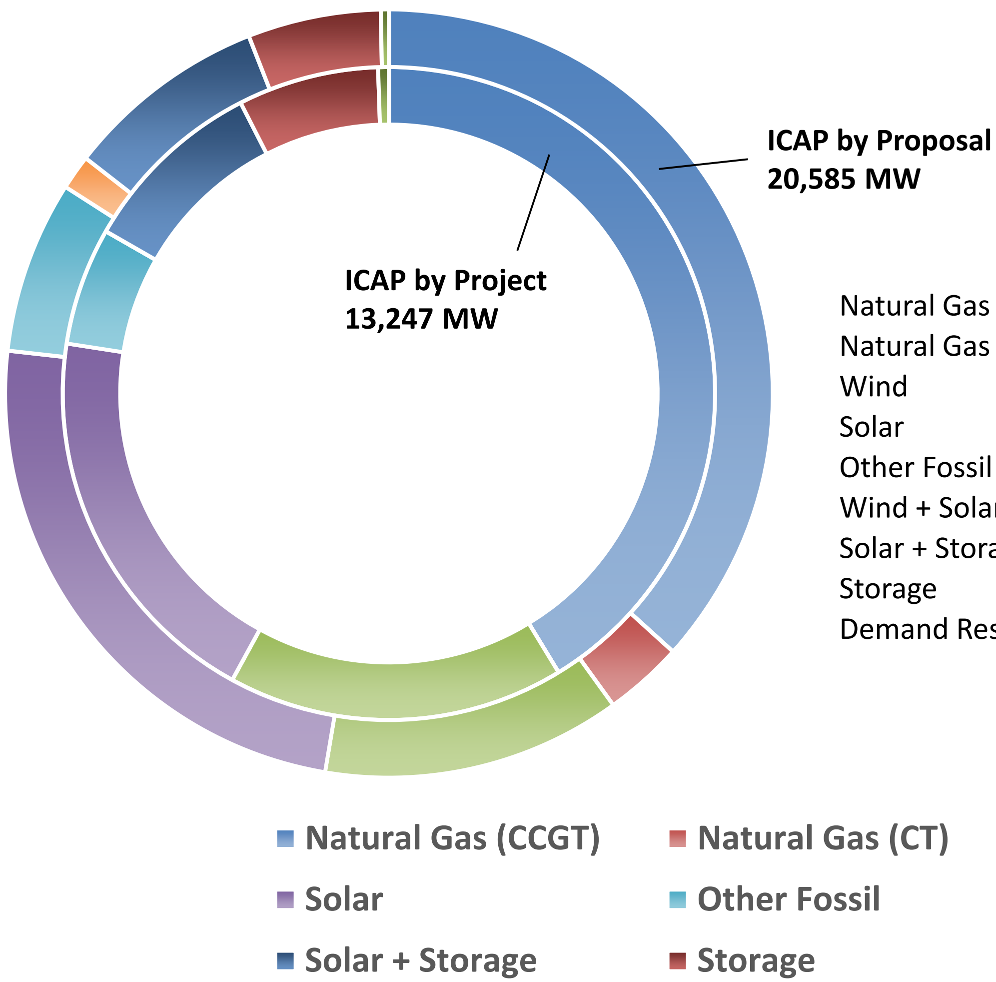
Next Steps / Wrap Up

Next Steps for RFP and IRP

RFP	IRP
• Continue to vet and evaluate the proposals received in accordance with the evaluation criteria • Determine a list of finalists by technology for possible definitive agreements once the preferred replacement path is determined	• Integrate results from the RFP into the IRP for the retirement and replacement analysis to be presented at the September 19th meeting • Setup and run stakeholder requested scenarios

Appendix

Proposals Received by Technology (MW) “ICAP”



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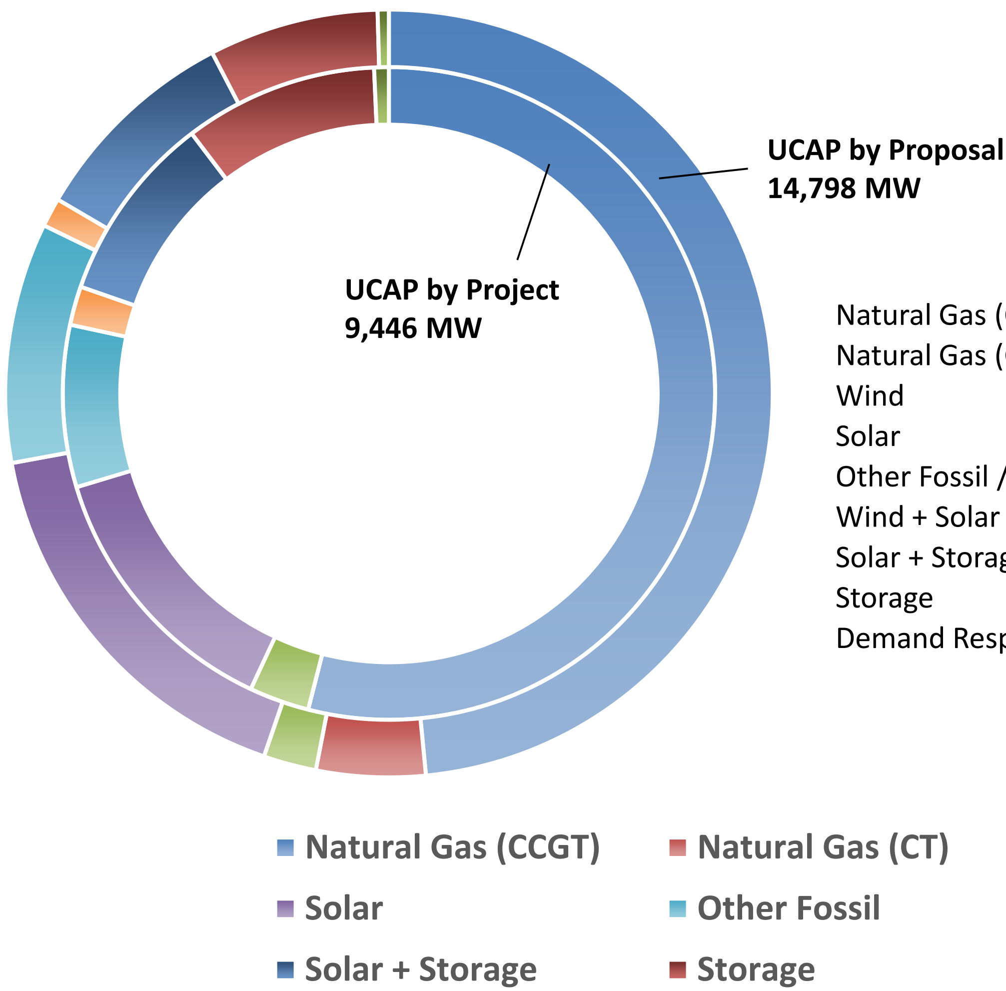

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Northern Indiana Public Service Company
2018 Integrated Resource Planning (“IRP”)
Public Advisory Meeting #3 (Webinar)
SUMMARY

July 24, 2018

Welcome and Introductions
Alison Becker, Manager, Regulatory Policy

Alison Becker opened the meeting by explaining the process for the webinar and introducing those who would be speaking. She then reviewed the agenda and did a safety moment.

NIPSCO’s Planning and the Public Advisory Process
Dan Douglas, Vice President, Corporate Strategy and Development

Mr. Douglas thanked participants for attending. He explained how NIPSCO plans for the future and provided an overview of the public advisory process, including reviewing the current point in the stakeholder engagement process. Mr. Douglas also provided an update on stakeholder interactions to date. He noted that the NAACP of Indiana had provided documents to NIPSCO regarding on-bill financing for energy efficiency and indicated NIPSCO would post the documents on the IRP website (nipsco.com/irp)

All-Source Request for Proposals (“RFP”) Results Summary
Paul Kelly, Director, Federal Regulatory Policy, Andy Campbell, Director, Regulatory Support and Planning and Bob Lee, Charles River Associates (“CRA”)

Paul Kelly provided an overview of where NIPSCO is in the RFP process, and Andy Campbell provided an overview of the key design elements of the RFP. He then presented a slide with the participating bidders. Bob Lee with CRA provided more in-depth information regarding the bids received. He provided an overview of the proposals received, which totaled 90 across a range of deal structures. He noted that most of the proposals were in Indiana, but there were bids received from throughout the Midwest. He then provided an overview of the proposals received by technology breaking them down by unforced capacity (“UCAP”) and installed capacity (“ICAP”). The greatest amount of megawatts was for combined cycle gas turbines (“CCGTs”), but there were proposals for a variety of renewables, including storage, as well as demand response. For purchase power agreements ("PPAs"), he provided an analysis of the range of durations by UCAP. Mr. Lee then provided an overall summary and the pricing received. He noted that for any technology where there was only one bid, for confidentiality reasons, the pricing was not provided. For asset sales, the range was a low of $959.61 for a CCGT to a high of $1,457.07 per kilowatt for those technologies where an average could be provided. For PPAs, the pricing units were different, so a range was unable to be provided. It is important to note that this information is all preliminary and subject to further due diligence.

The RFP evaluation process was reviewed, which will determine the list of finalist by technology. It was noted that the representative cost and performance characteristics by technology were developed based on the bids and provided to the IRP team for portfolio optimization and modeling. The IRP will determine the preferred portfolio for execution. The bid evaluation is made up of three tiers: a) asset cost and facility reliability and deliverability; b) development risk; and c) asset specific risk. The list of finalist by technology will be determined for possible definitive agreement(s).

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

- The slides indicate NIPSCO received 90 bids but only 31 participating bidders are listed on Slide 13. Can NIPSCO provide more information and clarification on now many bids each participant submitted?
  - This was addressed as the presentation progressed.
- Will all 90 bids summated on slide 14 be passed through to cost-effectiveness analysis (i.e., they've passed pre-screening qualifications, etc.)?
  - At this point, not every bid has been reviewed to determine whether it is a conforming bid. There has been no bid analysis for conformance or elimination at this point. Each bid is being reviewed, and qualifying bids will be incorporated in the IRP modeling process, which will use summarized bid data.
- What is "other fossil"?
  - It includes a few different bids. Some of the bids relate to the Schaefer units and another is a system power bid not tied to any other fossil bid.
- Will this presentation be sent to participants?
  - Yes, it is available at www.nipsco.com/irp
- Can you provide low-high range?
  - NIPSCO does not want to provide any individual bidder information at this point and using a range beyond what is on the slide may inadvertently disclose that information
  - NOTE: A graph with the range of the proposals in megawatts and by technology is being provided with the notes of this meeting for additional information.
- For energy storage, is there any variable operations and maintenance payment or just a capacity payment?

    - For the most part it is a straight capacity payment, but there may be certain instances where there is a variable payment included in the proposal.
- Will the bidders get to see how their bids are characterized in the IRP modeling?
    - Most of the bids are straight forward, but CRA will work with any bidder where additional information is needed. It is important to note that the IRP is not necessarily modeling individual facilities but rather technologies
- Can you indicate any more information on the size of the projects bid? For example, what was the proposed size of the solar and wind projects? When will you reveal a list of finalists?
    - NIPSCO and CRA cannot provide a specific answer on size at this point. Some were as low as 5 megawatts for an individual project and others upwards of several hundred megawatts. CRA's recommendations to NIPSCO are due mid-September, but there is no date certain for public disclosure at this point.
- How will you determine UCAP?
    - For facilities currently in development, the Midcontinent Independent System Operator ("MISO") rules were generally utilized. In some cases, the bidders provided information about the UCAP.
- Can you clarify what is being modeled by the IRP team? If not individual bids, then what?
    - The individual bid data were aggregated into representative tranches. Each tranche represents a number of similar facilities of the same technology type with similar costs and operational profiles. NIPSCO is not modeling each individual project that was bid into the IRP. Rather, the process will model various technologies because NIPSCO does not want the model to select the winning proposals, but rather to use the information to improve the estimates of retirement economics and to develop thematic replacement resource options for the IRP. The RFP team will then perform detailed analysis to select specific projects based on the project portfolio themes selected through the IRP process.
- Are any of the bids from minority business enterprises, then women business enterprises and can you disclose how many are accepted?
    - This was not included in the RFP criteria, but NIPSCO will take it as an action item to ask the bidders and report in a future meeting.

Incorporating the RFP Results into the IRP
Dan Douglas, and Pat Augustine, CRA

Mr. Douglas provided an overview of how the RFP will feed into the IRP. He noted that the RFP will inform both the retirement analysis and the replacement analysis and provided additional details on both. For the initial retirement analysis, the MISO cost of new entry ("CONE") was used as a proxy for replacement costs and now, the RFP results will provide known replacement costs and volumes. Once the RFP projects are selected through an optimization model analysis, the retirement analysis will be re-run using those projects. He then explained that, for the replacement analysis, the initial

IRP replacement costs used estimates from multiple third-party sources. The RFP results will be utilized and will provide visibility into executable alternatives for NIPSCO. He noted that, ultimately, the replacement analysis will be run using somewhat simplified and anonymized RFP results.

Pat Augustine then reviewed the process for feeding the results into the IRP. He stated that step one is to develop the model inputs, which includes specifying inputs by resource type "tranche" based on the RFP results. This results in the development of specific resource options for the Aurora model. He then said that step two is to run the Aurora Portfolio optimization to evaluate the least-cost portfolios for retirement and replacement analysis. Finally, Mr. Augustine noted that a full IRP analysis will be run which will evaluate each portfolio against all scenarios and stochastics in the models and complete the scorecard with metrics across all objectives.

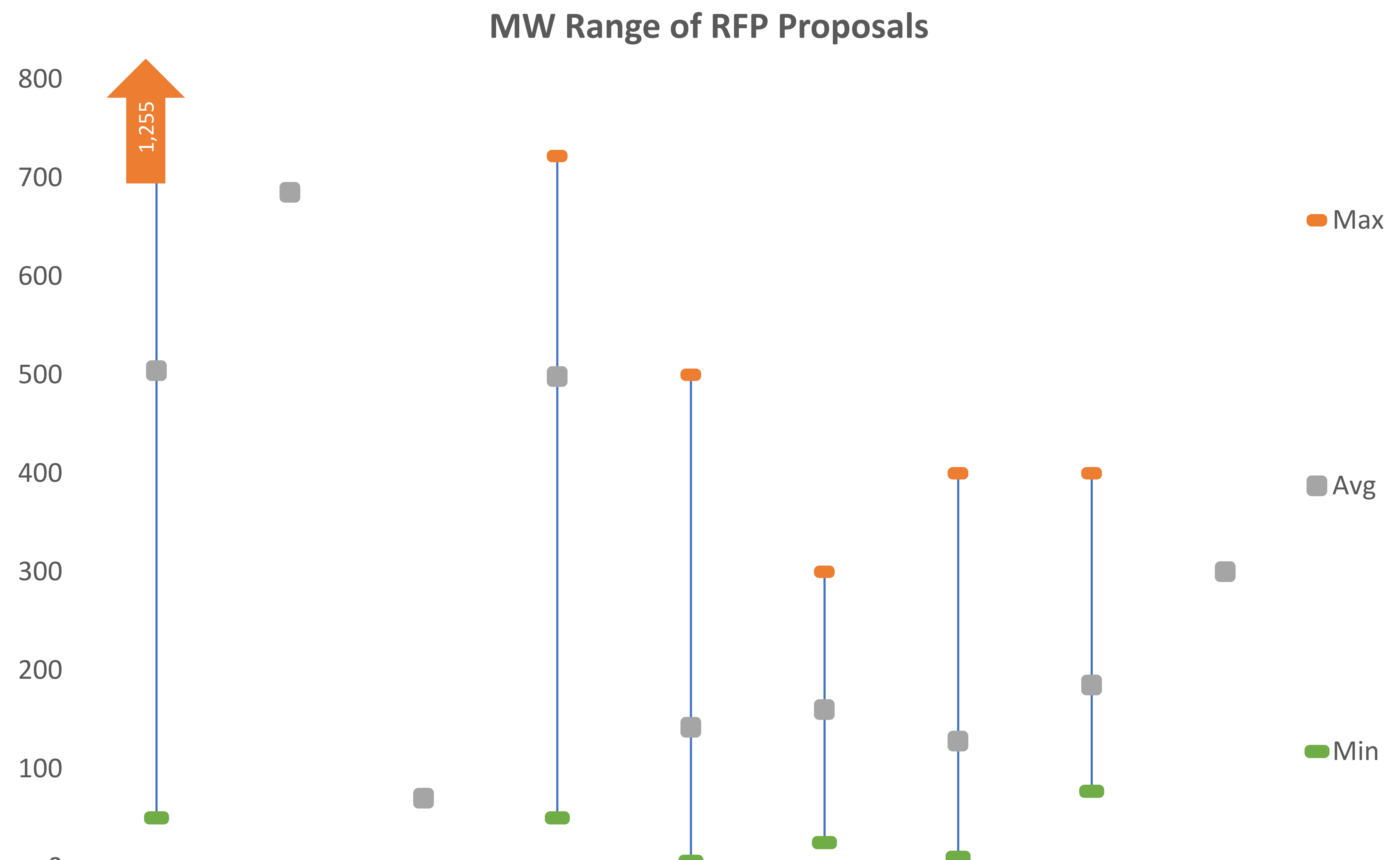
Participants had the following questions and comments, with answers provided after:

- To follow up on a previous question, there are 5 bids of 1,055 MW for energy storage. Are all 5 projects similar size, or is there a wide range in sizes for these units?
  - NIPSCO will need to review the data and follow up.
- Will all of the individual bids will be modeled in Aurora and allowed to be selected on an economic basis?
  - Each individual bid is not going to be evaluated as an individual option. Rather, multiple bids with similar characteristics will be combined into tranches. Thus, the IRP modeling will be done with average cost and operational parameter estimates, while still preserving sufficient detail from the RFP bids.
- Will there be sensitivity analysis that includes the range of bid prices instead of just average cost?
  - Multiple tranches will exist, which will implicitly include a range of bid prices. The averages presented today are only a high-level summary, while the tranches will effectively incorporate lower and higher cost levels. NIPSCO understands that there is a desire to have individual bid-based modeling as we go through the IRP. However, the goal is to not pick asset-specific winners and losers as part of the IRP analysis. There may be some confusion regarding the tranche process and NIPSCO is happy to walk through that a little more (NOTE: as a follow up to the meeting, a "technical webinar" has been scheduled for August 28 from 2:00-4:00 ET/1:00-3:00 CT. Additional information will be available at www.nipsco.com/irp).
- Will the UCAP determinations and calculations be disclosed?
  - UCAP has been disclosed in summary level across the portfolio of projects that have come back. There is no intention of sharing UCAP by proposal given the sensitives of the proposals.

Stakeholder Presentations

There were no stakeholder presentations.

Mr. Kelly and Ms. Becker closed the meeting by thanking the attendees for their attendance and active participation.



	CCGT	CT	DR	Other Fossil	Solar	Solar + Storage	Storage	Wind	Wind + Solar + Storage
Max	1255			722	500	300	400	400	
Avg	504	685	70	498	142	160	128	185	300
Min	50			50	6	25	10	77	

March 2017

LIGHTS OUT IN THE COLD

Reforming Utility Shut-Off Policies as If Human Rights Matter

Environmental and Climate Justice Program, NAACP

LIGHTS OUT IN THE COLD: Reforming Utility Shut-Off Policies as If Human Rights Matter

March 2017

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The National Consumer Law Center

The Michigan Welfare Rights Organization

The Committee to End Utility Shut Offs

Public Utility Law Center

EXECUTIVE SUMMARY

As a part of a broader consumer protection arrangement, the adoption of utility disconnection policies acknowledges the problems faced by customers who are vulnerable to having their utilities disconnected. Unfortunately, the interests of these customers often compete with the interests of utility companies, regulators, and other utility customers. This poses an obstacle to the design of appropriate disconnection policies that recognize the necessity of utility services and the rights of utility customers. A "disconnection policy" describes the justifications, procedures, and consumer protections with which a utility must comply before terminating service to a customer. Although a utility typically maintains the right to disconnect a customer for a variety of reasons, there are more problematic issues with disconnection because of nonpayment.[1]

Aftermath of a space heater fire in Prince George's County, MD
Source: http://patch.com/maryland/bowie/space-heaters-cause-bedroom-fires-twice-week-0

This report provides a comprehensive overview of common disconnection protections and policies employed by utilities nationwide, explores critical issues that should be considered in the development of disconnection policies, and calls for concrete action toward establishing policies that protect the well-being of all utility customers and the eventual **ELIMINATION OF UTILITY DISCONNECTIONS**. The need to incorporate human rights into the utility business model is a key component of the larger reform of the extractive energy economy and movement toward energy justice. The energy justice movement upholds that all individuals have the right to: safe, sustainable energy production; resilient and updated energy infrastructure; affordable energy; and uninterrupted energy service.[2]

This report discusses common disconnection protections across all types of utilities, but focuses on those set for Investor-Owned Utilities (IOU's). Issues with existing disconnection practices and state level model policies are explored. Recommendations for the establishment of a right to utility service are put forward to ensure the future protection of utility customers.

EXISTING STATE POLICIES

PROCEDURAL PROTECTIONS AND CONSIDERATIONS:

- All states require utility companies to provide a written, phone, or personally delivered notice before a disconnection.

- There is a wide range of disconnection limitations. Some states will not disconnect during certain hours of days of the week, while other states will not disconnect before or during a holiday.
- Fifteen states do not specify policies for utility reconnection fees.

SEASONAL PROTECTIONS:

- Date-based protections take place during the colder months, usually between the months of November and March or April. Temperature protections are based on various ranges of hot and cold temperatures that could place residents in danger. Most of the states will not disconnect when temperatures are below 32°F or above 95°F, but the offering of this protection varies by state.
- Nine states do not provide any state regulated seasonal protections for utility customers. These states include: Alaska, California, Colorado, Connecticut, Florida, North Dakota, Oregon, Tennessee, and Virginia.

PAYMENT ASSISTANCE

- Most states offer a payment plan option to avoid disconnections and charge a fee to reconnect to utility services.

PROTECTIONS FOR SOCIALLY VULNERABLE GROUPS

- Medical protections are generally offered for disabled or elderly customers. Generally, a medical certificate is required to postpone a disconnection for various amounts of time.
- Eight states do not have regulations establishing standard protections for socially vulnerable groups. Among these states are: Alaska, Arkansas, Colorado, Florida, Kentucky, North Carolina, North Dakota, and Rhode Island.

THE RIGHT TO UNINTERUPTED ENERGY SERVICE

The establishment of a universal **right to uninterrupted energy service** would ensure that provisions are in place to prevent utility disconnection due to non-payment and arrearages.[3] Toward establishing such a right, we call for all utility companies to advocate for and incorporate the following foundational principles into their models, operations, and policies:

1. Secure **ACCESS** to utility services for all households;
2. Ensure **INCLUSION** of all customers in the development of utility policies and regulations;
3. Create full **TRANSPARENCY** of the information and actions of utility companies, regulating bodies, legislatures, and utility affiliated organizations;
4. Guarantee the **PROTECTION** of the human and civil rights of all customers; and
5. Advance programs that help **ELIMINATE POVERTY**, so that all customers can pay utility bills.

While the end goal is clear—**to prioritize utility policies that place a moratorium on utility service disconnections**—these principles can be furthered through the following practices:

PROCEDURAL PROTECTIONS

1. Require multiple attempts at both written and telephonic or in-person contact before disconnection;
2. Secure notification of disconnection by mail;
3. Require a post-disconnection notice to all customers;
4. Provide additional notice provisions for customers who can be disconnected remotely;
5. Restrict disconnections to times between 8:00am-2:00pm on days when the utility has employees available to reconnect utility services;
6. Provide notice and utility disconnection policies in multiple languages;
7. Remove all policies allowing utilities to charge disconnection and reconnection fees;
8. Cease the collection of deposits for utility service activation and/or reconnection;

SEASONAL PROTECTIONS

9. Include seasonal protections with both temperature and date-based solutions;
10. Set disconnection arrearage minimums for customers who use utility services as the primary source of heating or cooling during periods of seasonal protection;
11. Provide utility services during extreme weather events that fall outside of seasonal protection periods;

PAYMENT ASSISTANCE

12. Allow budget payment plans to distribute utility costs throughout the year;
13. Allow partial payment plans to customers to prevent disconnections;
14. Provide connections to social services and case management resources for households with arrearages;

PROTECTIONS FOR THE SOCIALLY VULNERABLE

15. Establish simple procedures for socially vulnerable groups to apply and be registered for protection from disconnection;
16. Implement customer surveys in advance of extreme weather seasons to screen for socially vulnerable individuals;
17. Ensure active outreach to socially vulnerable customers and households for inclusion in protection programs; and
18. Registration into these programs should be complimented with a notification to local and/or state emergency relief agencies and safety responders.

The policies and protections detailed in this report represent stop-gap measures to lessen harms on utility customer wellbeing. In advancing energy justice, all individuals have the right to: safe, sustainable energy production; resilient and updated energy infrastructure; affordable energy; and uninterrupted energy service.[4] The NAACP calls for the development of policies and utility structures that improve energy efficiency throughout the energy continuum, advance clean and renewable energy production, encourage and enable the development of distributed generation, and protect human life and wellbeing. These aspects are components of the larger utility system change that we must build.

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FOREWORD: A CALL TO MORALITY—*BY JACQUELINE PATTERSON, NAACP ENVIRONMENTAL AND CLIMATE JUSTICE PROGRAM DIRECTOR*

I will never forget the sound of fear in my father's voice on the phone or the look of desperation in his eyes when I walked through the door. I was home to take care of my Dad in what turned out to be his last days on earth. I had gone out to get some items that he needed. My cell phone rang and it was him on the other end saying that the power had gone out and he didn't know how long his respirator would run without it. I raced home and as I opened the door, my Dad was just standing in the middle of the living room, attached to his respirator, looking desperate. It turned out to just be that I needed to flip the switch on the circuit breaker. But it brings home the reliance that so many have on electricity to sustain life.

As many of us were enjoying turkey, ham, or tofurkey with loved ones, exchanging presents, and engaging in holiday festivities, for some of us, all was not merry and bright. Too many are shivering in the deep freeze that had assailed a large swath of the nation, huddled around space heaters or open oven doors in homes lit by candles or kerosene lamps, because they could not pay their electricity/heating bills and were thus without this vital resource. The stories over the years are too many to list, but each one alone represents a moral imperative for systems reform of the utility business model because no life should be lost for lack of the basic human right to safe shelter, in a land of plenty:

- A Maryland man in dire straits after having his electricity disconnected, resorted to using a generator to power the home where he was raising his seven children.[5] Carbon monoxide released by the generator killed the entire family as they slept.[6] Also in MD, a fire swept through a row house killing 10 people, including 7 children aged 7 months, 5 , 7 , 11 and 12 years, and two 3 year olds, as well as 3 adults, after the termination of the electricity caused residents to begin using candles and a kerosene lamp for electricity.[7]
- In Michigan, John Skelley, a 69-year-old man, passed away in his home from hypothermia and other causes, several days after his gas service was disconnected.[8] Also in Michigan, a fire sparked by a space heater being used to heat the home after utilities had been shut off took the lives of three people.[9]
- In New York, three young boys, ages 4 months, 2 years, and 5 years died in a fire caused by a candle used for light after the utility company disconnected service for non-payment.[10]In another New York incident, a child died in a fire started by a candle, in a home where service was scheduled to be reconnected 24 hours after the desperate measures took his life.[11]
- In California, five children, ages 4, 1 and two 2 year olds, lost their lives when their electricity had been disconnected and their mothers, who were sisters living together, used candlelight to light their home, resulting in a fire. [12]

Too often these tragedies are chalked up to the inevitable consequences of poverty and implicitly relegated to being sad, but acceptable losses, with an unspoken notion that “We can’t save them all!” However, every one of these losses was preventable and we cannot, in good conscience, stand by and watch more when we have the means to ensure access for all.

The cost of extreme poverty should not be a death sentence.

Whether it is extremes in heat, extremes in cold, or the need for electricity to power life saving devices like respirators or medicines requiring refrigeration not to mention just providing light, electricity/heating/cooling is essential, not just for quality of life, but also for maintenance of life!

We've shared a small sampling of illustrative stories of the consequences of inaction on utility shut-offs that have spanned decades. Yet, with relative inaction, in terms of system reform, so many more are in harm's way now, with the potential for dire circumstances resulting in desperate and possibly deadly actions. As of December 15, 2015, in Pennsylvania alone, at least 9,169 households had no central heating and 414 households were using potentially unsafe heating sources.[13] In Michigan, ravaged by the post-industrial economic downturn, from January to September 2013, DTE Energy--a utility company formerly known as Detroit Edison--reported 169,407 shut-offs, while another utility company, Consumers Energy (CMS), reported 118,203 shutoffs. Disconnections in Michigan have increased dramatically since the crash of 2008, with DTE completing two and half times as many shutoffs in 2011 than in 2007.[14] This trend is observable on a national scale.

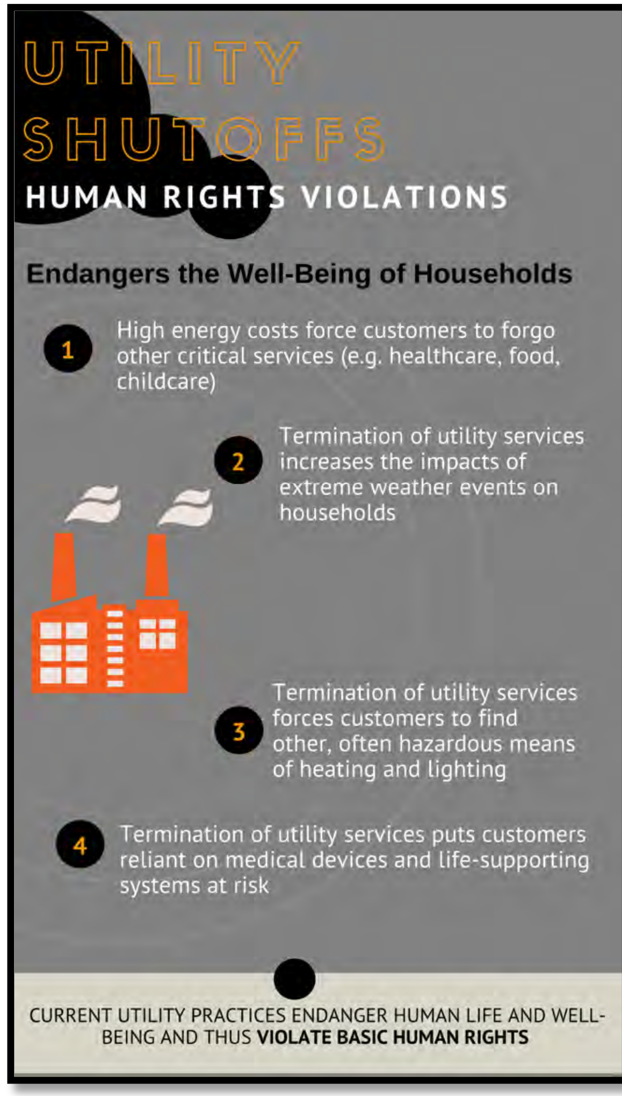
The headlines today heralding the "winter weather blast" with 99 million people in the US under a winter weather advisory[15] highlight the proven fatal cocktail being mixed with the ingredients being harsh weather and lack of protection for thousands of vulnerable households who are struggling with making ends meet, placing them in a vice that can result in resorting to hazardous means of lighting and heating.

Science has spoken and so has Mother Nature as she continues respond to our abuse in the form of the polluting ways we employ to generate energy. Climate change is already resulting in weather extremes from extreme heat to extreme cold to extreme storms.[16] As such, we are seeing more days where air conditioning or at least a fan is required and days of extreme cold requiring heat, and greater amounts of snow to such an extent that even if someone wanted to leave an unheated home in search of warmth elsewhere, this may not be an option. Besides which, the ongoing crisis of homelessness finds the most vulnerable communities without available shelter space, or any alternatives if their homes are unsafe.[17]

Nationwide, annual temperatures have been rising over the past 50 years.[18] The hottest parts of the country, including Texas, the Southwest, and Florida have already experienced large increases in extreme heat days, including days over 90°F, 95°F, and 100°F. Extreme heat when paired with rising humidity levels, make blistering hot days more dangerous. Cities in these states are facing the greatest projected increases in dangerous heat over the next several decades.[19] With more than 80 percent of Americans living in cities, urban heat islands, combined with greenhouse gas heat trapping, can have serious health effects for hundreds of millions of people during the hottest months of the year. Heat is already the number one weather-related killer in the U.S., triggering asthma attacks, heart attacks, and other serious health impacts.[20] The National Center for Disaster Preparedness of Columbia University in New York, projects that about 3,000 people in the U.S. could die each year from heat waves under current climate warming patterns. This estimate is a combination of various factors, including exposure to the higher greenhouse gas emissions, higher urban-based populations, and impeded climate adaptation and mitigation efforts.[21]

Winter storms have also increased in frequency and intensity since the 1950s, and their tracks have shifted and power intensified in the U.S. Other trends in severe storms, including the intensity and frequency of tornadoes, hail, and damaging thunderstorm winds, are being studied intensively for their relationship to climate change.[22] Loss of internal temperature control, due to extreme heat and cold, can result in a variety of illnesses, including heat cramps, heat exhaustion, heatstroke, and hyperthermia when exposed to extreme heat, and hypothermia and frostbite when exposed to extreme cold. Exposure to temperature extremes can worsen chronic health conditions.[23]

There are utilities, such as the Roanoke Rural Electric Co-Op in North Carolina, that are being intentional about designing a business model that is human rights based, protective of the environment, yet financially sound. At the same time, other utilities are driving our continued slide towards catastrophic climate change by denying science, and in some cases, intentionally obscuring science as well as by their refusal to aggressively pursue energy efficiency, embrace the transition to clean energy, and/or allow/facilitate distributed generation of clean energy.[24] [25] [26] And some of the most aggressive utilities are the ones behind the highest numbers of shutoffs where there is record keeping. These utilities obstinately defend the practices of fossil fuel based energy production, disproportionately polluting the very same communities, with the highest rates of shut-offs, to produce the very electricity to which they do not have access.



> *In Dayton Texas, Sam Houston Electric Cooperative has disconnected the utilities of vulnerable households in areas impacted by the Cedar Power Project, which operated three trash burning incinerators until 2008.*[27] *The air pollution produced by incinerators is known to contribute to the development of chronic diseases like chronic obstructive pulmonary disease (COPD) as well as many other serious health problems.*[28]

Given that low-income communities, communities of color, and vulnerable persons, including people who are elderly, pay the highest proportion of their incomes to energy and they are most vulnerable to shut off and most likely to suffer from the pollution from energy production, this is a prime example of the deep injustices in the extractive economy.

As detailed in this report, there are utilities that have managed to reform in such a way that provides protections for low-income customers. Yet too many companies and their trade associations use their influence on the Public Utilities Commissions and Public Service Commissions[29] to push back on the protections communities need.[30] We must put pressure on utility companies that have refused to innovate despite the models being out there for operating utilities in a humane way that maintains operations and uphold human rights. Not only do we need pro-people policies to reform utility company practices in the short term, but in the long term we need a people led movement to seize the reins of our utilities sector, including water, another essential resource that befalls a similar fate of being withheld from those suffering from extreme poverty.

The NAACP is a part of building the new economy that puts power in the hands of the people, literally and figuratively. However, in the meantime, we have developed this study that chronicles the best and worst of utility policies and practices with the aim of uplifting examples of the most humane policies, and providing a blueprint for reform for those who continue to sacrifice the lives of vulnerable communities for profit. We are issuing a call to legislators, regulators, utility companies, researchers, and advocates for us all to step up our efforts in reforming what we have now, even while we as people's advocates push for total-systems change. Until we have transformed to the new, people led, economy, we must all take responsibility for pushing for the reforms that protect the lives of those who are most vulnerable. We particularly issue a call to conscience to the legislators, regulators, and the companies that have used the profits from the electricity and heating bills that we pay every day, to suppress human rights through anti-customer protection, anti-regulatory, anti-clean energy, anti-energy efficiency, anti-distributed generation lobbying while staunchly maintaining practices that have taken lives.

While we build a new economy with foundational principles of human rights, community ownership and control, participatory democracy, and shared wealth and wellness, through this effort, the NAACP, its units, and its partners and allies will work to ensure that utilities, regulators, and legislators are held accountable to executing policies and practices that ensure that right to the commons, resources essential for life, are upheld for all!

LIGHTS OUT IN THE COLD:

REFORMING UTILITY SHUT-OFF POLICIES AS IF HUMAN RIGHTS MATTER

INTRODUCTION

Disconnection policies consist of the justifications, procedures, and consumer protections with which a utility must comply before terminating service to a customer. Unfortunately, the interests of these customers often compete with the interests of other stakeholders. This poses an obstacle for the design of appropriate disconnection policies that recognize the necessity of utility services and the rights of vulnerable customers. The need to incorporate human rights into the utility business model is apparent.

Disconnection policies are implemented by legislatures and regulators, and vary widely from state to state. Some policies are protective of consumers, while others lack safeguards. The right to uninterrupted energy service must be established and upheld for the protection of human life. In the long term, the termination of households from utility services must be eliminated, in the interim, it is critical to ensure the absolute highest level of protections for vulnerable households facing disconnection.

This report discusses common disconnection protections across all types of utilities, but focuses on those set for Investor-Owned Utilities (IOU's). Issues with existing disconnection practices and state level model policies are also explored. Financial options are presented as a short-term solution to reduce a household's risk of disconnection, however, the report sets forth broad principles and specific recommendations for stakeholders as we move towards a shared vision of an energy democracy. While the report highlights disconnection practices mandated by state legislatures and authorized regulatory bodies, the issues and impacts outlined can, and have, applied to Publicly-Owned Utilities (POU's) as well.

TYPES OF UTILITY COMPANIES

Investor Owned Utilities (IOUs)

Investor-owned utilities are privately-owned, for-profit electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return. Traditionally, the investor-owned utilities own generation, transmission, and distribution assets. These utilities are regulated by state legislatures and the regulatory bodies to which they delegate authority. Customer rates are set and regulated by the Public Utility Commission through public process that includes some customer participation.

Publicly Owned Utilities (POUs)/Consumer owned utilities (COUs)

Publicly owned utilities are under public control and regulation. These utilities are organized in various forms, such as municipal owned, rural cooperatives, public utility districts. COUs have varied regulatory structures. Customer rates are set by each utility's governing body-board or city council in a public forum.

Municipally owned: A municipally or city-owned utility is a non-profit electricity provider that is owned and operated by the municipality it serves. Municipals may or may not have their own generation facilities. For municipals without their own generation often develop a contract with another company to generate electricity. Since the customers are local, the municipals do not need to transmit electricity over high-voltage power lines. Generally, municipal-owned utilities are controlled by the City Council or a special board or committee.

Rural Electric Co-ops: Rural Electric Cooperatives are operated by and for the people of the community. The Electric Co-ops were formed to bring electricity to rural households that investor-owned utilities do not serve. They are divided into distribution cooperatives or generation and transmission cooperatives. Distribution co-ops provide end-users with electricity. Generation and transmission co-ops are usually owned and managed by several distribution co-ops to sell wholesale power to distribution co-ops. The consumers of the utility elect a board to manage and make decisions for the Cooperative.

Public Utility Districts (PUDs): Public Utility Districts are utility-only government agencies that provide things like electricity, natural gas, sewage treatment, waste collection/management, telecommunications, or water. The utility districts are created by the local government bodies. PUDs are regulated by a board or commission that is elected by the voters of that district.

No longer should the narrative be, poor people making bad choices and paying the consequences for their bad choices. The principles and actions promoted by this report apply to all utilities. It is time that utility companies are held accountable for the lives and families that they endanger, and that we all transition to the mindset that access to energy and utility services is a human right. The right to uninterrupted energy service must be established and upheld for the protection of human life. In the long term, the termination of households from utility services must be eliminated, in the interim, it is critical to ensure the absolute highest level of protections for vulnerable households facing disconnection.

THE HUMAN COST OF UTILITY DISCONNECTION

"These companies are getting rich while we freeze to death."

-Bernard, resident of Detroit, MI

The following is a collection of true stories about real people whose lives were cut short, or nearly cut short, by utility companies who were willing to pull the plug to protect profits.

THE PEOPLE OF DETROIT, MICHIGAN

"DTE [Energy] changes my rates practically every month. They're constantly trying to squeeze every penny out of us. I keep my gas nearly at zero and they are still charging me an arm and a leg."

-Daryl, resident of Detroit, MI

In 2010, utility shutoffs by DTE Energy resulted in several deadly house fires in Detroit that caused several deaths, including the deaths of two wheelchair-using brothers on Dexter Avenue and three children on Bangor Street. In response, DTE tried to preserve a favorable image by misdirecting attention away from its responsibility for the tragedies, making an outcry to bring "energy thieves" to justice—unidentified people who the company accused of illegally connecting houses to DTE power lines. With the support of the Michigan state government, DTE called for the arrest of "energy thieves" and launched a spying campaign against Detroit residents, which included the use of invasive aerial infrared photography to determine which households still had heat after having their power disconnected for nonpayment.

Meanwhile, DTE also launched a publicity campaign to promote its charity, the Heat and Warmth Fund (THAW), as well as its Winter Protection Plan (WPP) program. Not only do these programs protect only seniors from utility shutoffs during the winter, but they also place families into payment plans that essentially keep them in a state of permanent debt to the company. In many cases, families cannot afford to stay on track with the payment plans that are offered and end up having their power disconnected anyway.

After visiting a DTE office to make a payment, a Detroit resident named Bernard commented, "I came in here to pay $236. That was the minimum amount they said would stop them from shutting off our utilities. They wanted me to pay $560, but I just don't have the money. People on my block are using whatever they have—space heaters, stovetops, anything they can think of. Finding an alternative way to keep warm has become necessary to survive. And you know the company is making good money. These companies are getting rich while we freeze to death."

At the same DTE office, a Detroit resident and mother of three named Tametria said, "They set me up on a payment plan, where I was supposed to pay $300 every month. I kept up with most of the payments, but when I lost my job, they still shut us off. I have three kids, and now we've had to move in with a friend. I came in today and they said I have to pay $2,600 to get my house turned back on. It's unbelievable. We can't move back into our house because we can't afford those thousands of dollars."[31]

ROBERT ROBERTS – OVERLAND PARK, KANSAS

In 2016, a senior living in Overland Park, KS had his electricity shut off by his utility company even though he needed a nebulizer and oxygen to breathe. Robert A. Roberts, Sr. was already struggling to pay medical bills that piled up because of his health problems, including multiple sclerosis and chronic obstructive pulmonary disease (COPD).

A concerned neighbor, Randen Smith, decided to help Mr. Roberts by powering his medical equipment with an extension cord that was connected to Mr. Smith's home. Kansas City Power & Light (KCP&L) said it was "unsafe" to provide electricity to Mr. Roberts through the extension cord and ordered Mr. Smith to pull the plug, threatening to also shut off his power if he refused. Mr. Smith refused to stop helping Mr. Roberts. "I don't want someone dying on my hands," Smith said. "Maybe KCP&L doesn't mind, but it bothers me that someone needs help and electricity and oxygen to live, so I'm going to help."

Mr. Roberts had been living with his son and grandchildren in Overland Park since 1989.[32] The family lives less than one mile away from an incinerator used to burn medical waste, which has been operated by Shawnee Mission Medical Center since 2008.[33] The air pollution produced by incinerators is known to contribute to the development of chronic diseases like COPD, as well as many other serious health problems.

MARVIN SCHUR – BAY CITY, MICHIGAN

In 2009, a 93-year-old man named Marvin Schur froze to death in his home after his utility company restricted his electricity because of an unpaid bill. The official cause of his death was hypothermia, which was determined by a medical examiner who called it "a slow, painful death." Mr. Schur owed more than $1,000 and, as a penalty, the utility company installed a "limiter" to restrict his use of electricity, resulting in his death.

A utility bill was found on Mr. Schur's kitchen table with a large amount of money attached to it—a sign that he was trying to save up to pay his bill. The utility company was owned by Bay City, Michigan. Bay City manager Robert Bellerman stated that he did not believe the company did anything wrong.[34]

JESSE WYANT – EUDORA, KANSAS

"That's premeditated murder—if you know a person is on life-sustaining oxygen, and you pull the plug and you kill them."*-Ms. Wyant, resident of Eudora, KS*

In Eudora, KS in 2011, Beverly and Jesse Wyant were notified by the city that their electricity would be shut off if they did not pay their bill, even though Jesse, age 86, was terminally ill and needed an oxygen concentrator to survive. The couple was having difficulty making ends meet after a fire destroyed much of their home. Since then, they struggled to pay for refurbishments and other expenses so they could cope with the damage. The city refused to wait a mere five days for Beverly's state pension payment to come in; instead, they set up a turnoff time. Luckily, their daughter could pay the bill for them to keep the electricity on, but many families are not fortunate enough to have the resources to do this.[35]

LESTER BERRY – DAYTON, TEXAS

Although Lester Berry, a 70-year-old resident of Liberty County, TX, was only $129.62 behind on his electricity bill, his utility company cut off his power, resulting in his death. Mr. Berry had congestive heart failure and COPD, which meant that he needed constant power to his oxygen concentrator to survive. When Sam Houston Electric Cooperative disconnected his electricity, Mr. Berry very painfully suffocated to death.

Mr. Berry was found with his hand inches away from his phone, which needed electricity to work, leading his son to believe that he tried to call for help just before he died. Mr. Berry's family said the electric power provider was well informed about his need for electricity to power his life-sustaining medical equipment, so they had no reason to assume his power would be disconnected for nonpayment of a mere $129.62.[36]

Dayton, TX, where Lester Berry died, was home to the Cedar Power Project, which operated three trash burning incinerators until 2008.[37] The air pollution produced by incinerators is known to contribute to the development of chronic diseases like COPD, as well as many other serious health problems.

The instances of customer endangerment illustrated in the above stories highlight the need for change. With the myriad of protections, programs, and policies that exist for utility customers at risk of disconnection due to nonpayment there is no reason for undue suffering. In the interest of protecting the rights of utility customers, it is necessary to understand how utilities protect against disconnections due to nonpayment, and where there is opportunity for improvement.

DISCONNECTION POLICIES AND THEIR REGULATION

WHAT IS A DISCONNECTION POLICY?

A "disconnection policy" describes the justifications, procedures, and consumer protections with which a utility must comply before terminating service to a customer. Although a utility typically maintains the right to disconnect a customer for a variety of reasons, there are particular considerations with disconnection as a result of nonpayment.[38] Disconnection policies may be found in whole or in part in state statutes, regulations, public utility commission orders, and utility tariffs, but are most frequently established in regulations.[39] Regulators and other policymakers determine which elements to include or omit in disconnection polices, leading some disconnection policies to be more protective of consumers than others.[40] Some components that are commonly found in disconnection policies include:

1. Required notice to the customer that the utility intends to disconnect service;
2. Limitations on disconnections during certain times of year or in extreme weather;
3. Limitations on the day or time of day when a disconnection may occur;
4. Protections for customers who have disabilities, are elderly, or seriously ill; and
5. The availability of payment plans for customers who have trouble affording their bills.[41]

A disconnection notice
Source: Benefits Learning Network

HOW ARE DISCONNECTION POLICIES REGULATED?

Unlike other businesses, public utilities are bound by the public's interest because they are "of public consequence, and affect the community at large."[42] Many public utilities are even granted monopolies in exchange for what is supposed to be tight regulation in the public's interest. It is within the powers of legislatures to both regulate public utilities and define what it means for that utility to act in the public interest.[43] Traditionally, this has meant the protection of the health, safety, and general welfare of the public.[44]

Legislatures delegate their authority to directly oversee public utilities to officials who serve in public utility commissions or other regulatory agencies.[45] Despite this delegation of regulatory authority, the legislatures retain the right and the duty to define the "public interest" which utilities must adhere to and which utility regulators must protect.[46] Legislatures and regulators exercise broad power over public utilities, but the role of regulators is limited by the legislature's definition of the public interest.

Public utility commissions and legislatures are able to control market entry for new utility providers, set rates, set standards for the quality and safety of service, and prevent the utility from taking undue financial risks.[47] While public utility commissions are free to regulate utilities in accordance to the public interest, they may be limited in their ability to confront new challenges that fall outside of the scope of the traditional public interest goals.[48] Among these challenges include climate change, rising energy costs, air pollution, new technologies, and racial discrimination.[49]

Absent a clear public interest basis to tackle these challenges, commissions may enact regulations that go against the interests of customers.[50] Alternatively, this lack of clarity could cause commissions to be leery of taking action, or leave them unwilling to take on challenges, even if they would be permitted to do so.[51] Thus, it is important for legislatures to provide utility commissions with a clear public interest mandate to authorize and encourage the commission to regulate on emergent challenges or topics. This lack of clarity allows for continued violations of customers' rights by public utilities.

How Utility Companies are Regulated

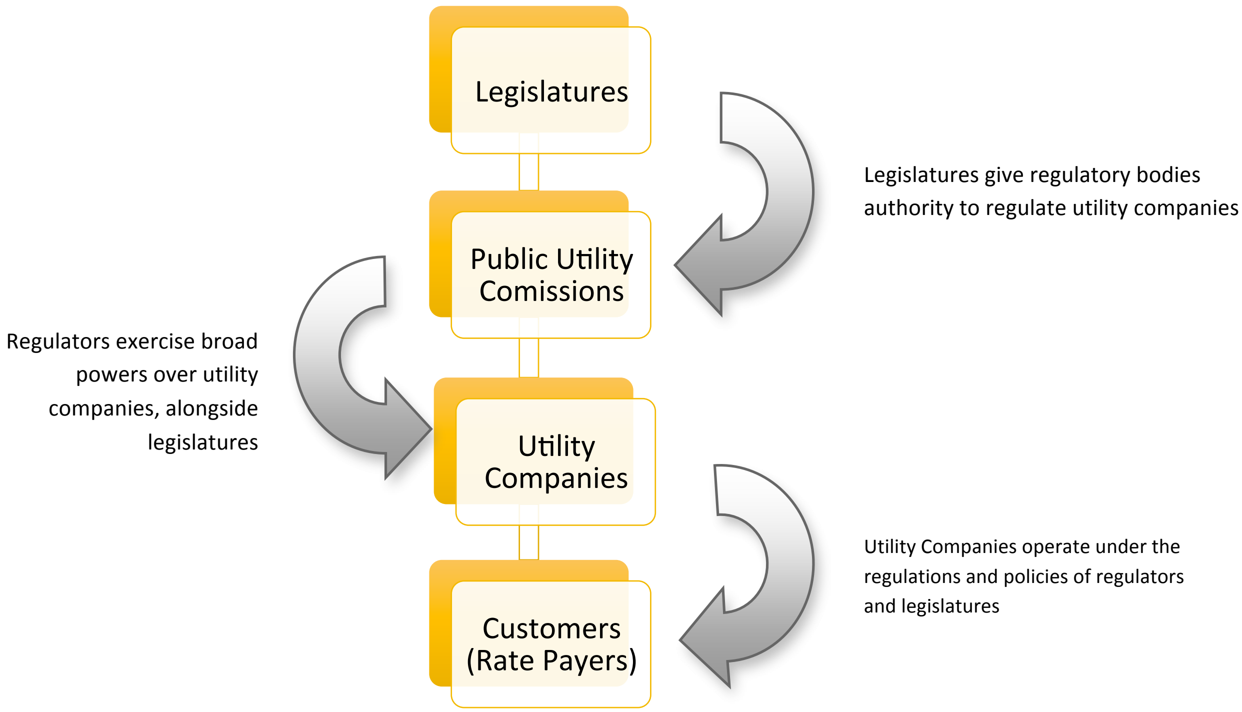


Figure 1. How Utility Models are Regulated: The Traditional Model

COMPETING INTERESTS

There are multiple stakeholders who may have competing interests regarding disconnection policies that must be considered when endeavoring to reform the utility system to solve the problems faced by those who experience utility disconnections. Figure 2 depicts some of the stakeholders who may have an interest in disconnection policies.[52] The interest of the following groups typically come into play: utility customers, those at risk and not at risk of disconnection; utility companies; and legislators and regulators. Within each of these groups are individuals that are directly and indirectly impacted by utility disconnections and other actions.

CUSTOMERS

Consumers who are at risk of being disconnected have an interest in maintaining their service under protective disconnection policies. In contrast, consumers who are not at risk of being disconnected may be asked to subsidize those customers who are unable to pay; therefore, they may want less protective policies to keep their own rates lower. This additional burden on customers in-good-standing is a form of cost shifting—when a utility charge higher rates or other fees for services to one group than another less reliable group. Such cost shifting practices undermine the ability of more customers to pay their utility bills. Too often cost shifting is practiced in instances where a utility has the ability and capacity to absorb the costs of customers at risk of nonpayment.[53]

All utility customers have an interest in disconnection policies, as disconnection from utility services for any reason directly impacts customer wellbeing and security. Often families are put at risk when utility services are denied. In most states, lack of proper and safe heating and lighting sources can be a catalyst for social service and child protective services investigations. Lack of proper heating and lighting can be designated as housing safety and physical environment hazards for children.[54] This potential of the separation of families due to utility service disconnections is not only traumatic, but frequently hinders households from seeking help when in already vulnerable positions.[55]

UTILITIES

Utilities have an interest in earning a profit, so they may prefer a less protective disconnection policy that allows them to disconnect customers more quickly once an account becomes delinquent;[56] however, utilities likely also wish to avoid putting their customers at risk, out of humanitarian concern, or, in some cases, if only to save themselves from negative press and public perception.[57]

Stakeholders in Public Utility Disconnections

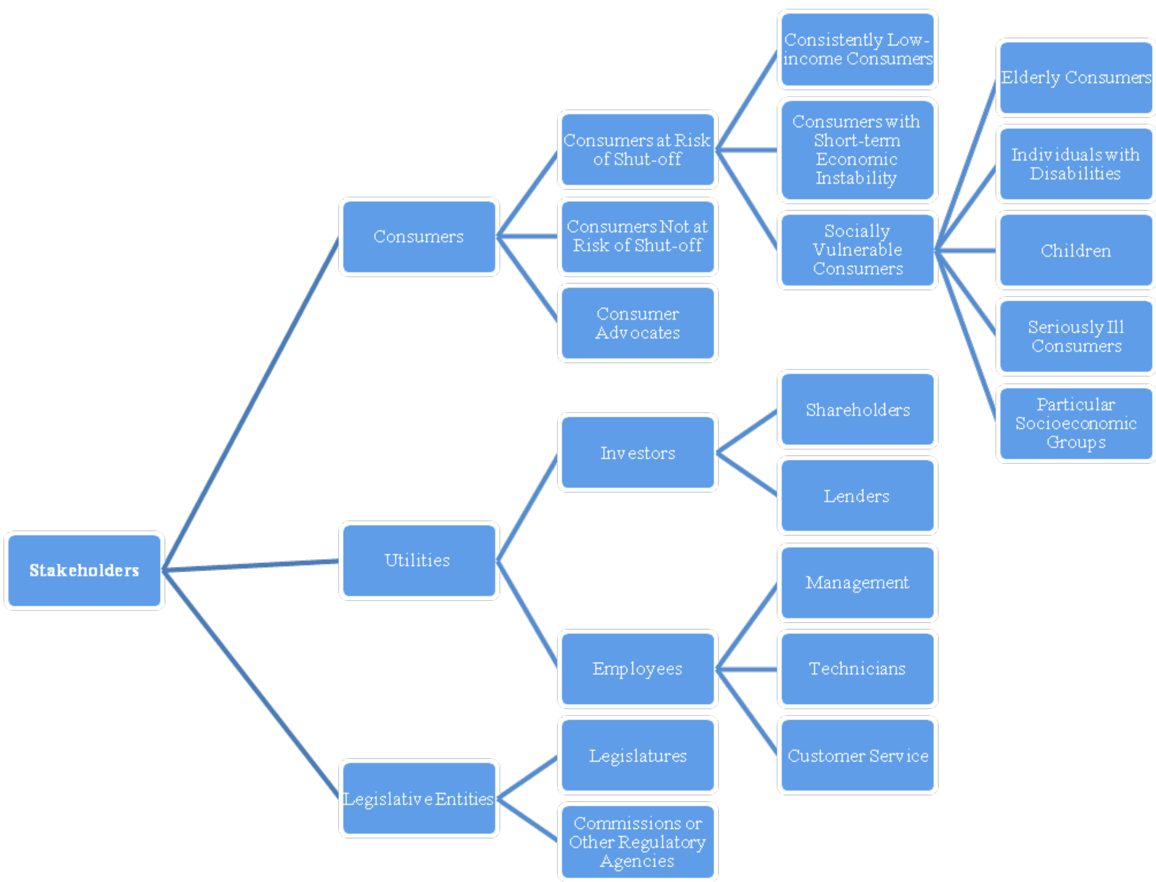


Figure 2. Stakeholders in utility disconnections

LEGISLATORS AND REGULATORS

Legislators and regulators share in the interests of both the utilities and the consumers, and they may have their own political or professional interests, but they ultimately must select a disconnection policy that will work best for the people in their state or jurisdiction.[58] In the face of these potentially competing interests, it is critical that regulators are engaged in determining how they can align the views of different stakeholders to create effective and socially-conscious disconnection policy.

DISPROPORTIONATE ENERGY BURDENS

"Something like electricity, that's really just an essential of living a normal life."

-Rudy Sylvan[59]

There are many issues with the way utilities construct and apply disconnection policies in the United States. Utility disconnections can have a discriminatory impact on low income people, people of color, elderly people, people with special health needs, and other socially vulnerable utility customers who disproportionately face potential violations of human rights. Utility companies, regulators, and legislatures have developed suites of protections, which if implemented appropriately can remediate several critical concerns for vulnerable populations. These concerns include:

1. Customers with limited income bear a disproportionate burden of energy bills;
2. Disconnections have a disparate impact on low income communities and communities of color;
3. Customers may be reliant on utility services for medical devices and life-supporting systems; and
4. Vulnerable customers' use of hazardous heating, cooling, and lighting measures can have harmful and even fatal results.

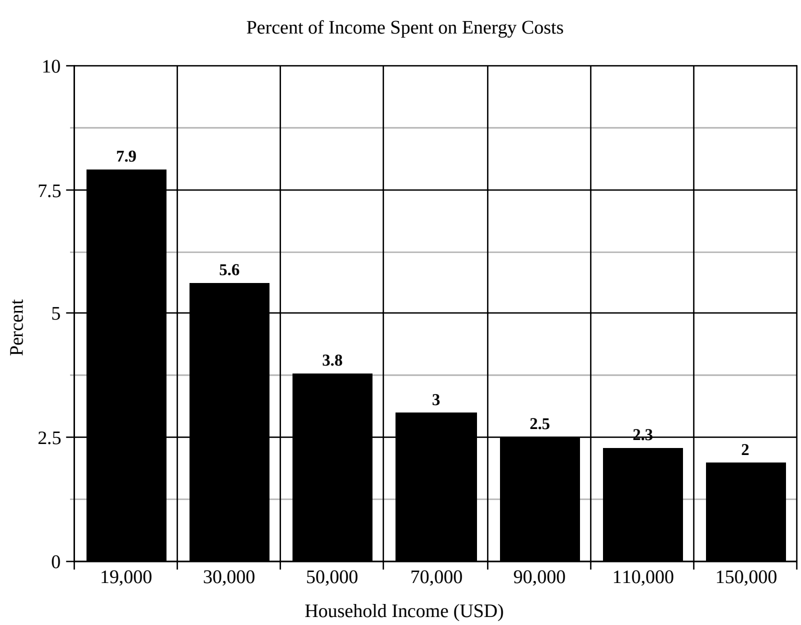


Figure3. Household Energy Burdens by household income

ENERGY BURDEN ON LOW-INCOME HOUSEHOLDS

About 48% of American families (approximately 59 million households) have pre-tax annual incomes of $50,000 or less, with an average after-tax income among these households of $22,732—less than $1,900 per month. Since families of color and seniors have comparatively lower median incomes, these groups are among the people who are most vulnerable to rising energy costs. "Median income" can be considered the midpoint, where one-half of households have incomes above this amount, and one-half have incomes below it. In 2015, the U.S. median household income was about $51,939. Table1 provides a summary of the median incomes of especially vulnerable households compared to the U.S median.[60]

Utility customers with limited income are at a higher risk of having their utilities disconnected due to nonpayment. This is due, in part, to the nature of utility payments. Utility costs often make up a larger portion of expenses for households with limited extra income (Figure 3,[61] and these costs can change throughout the year as increased heating or cooling is needed.[62] Energy costs are consuming as much of the incomes of America's lower- and middle-income families as the cost of other basic needs, such as housing, food and health care. Additionally, households with limited extra income may live in older homes that are less energy efficient, and they may not have the financial ability to pay for efficiency upgrades.[63] Customers having trouble affording electric service may also be struggling to maintain cell phone or internet service. Many existing policies around disconnection procedures ignore this and provide notice solely through electronic means.

Table 1. Mean Income for Vulnerable Groups in the United States vs. the National Median Income

Household Type	Percentage of U.S. Households	Median Income	Amount Lower than U.S. Median Income
African-American	13%	$45,186.93	-$6,752.07
Latino/Hispanic	13%	$45,186.93	-$6,752.07
Age 65+	23%	$39,993.03	-$11,945.97

Table 2. Utility disconnections in Cleveland, OH 2014-2015

Total Service Disconnections for Nonpayment Jun 2014 – May 2015	
Cleveland Electric Illuminating Company	14,594
Columbia Gas of Ohio	92,313
Dominion East Ohio	62,398
Orwell Natural Gas	$216
Total	**169,521**

Table 3. Unpaid bills for disconnections in Cleveland, OH 2014-2015

Total Number of Unpaid Bills for Disconnections Jun 2014 – May 2015	
Cleveland Electric Illuminating Company	12,306,545
Columbia Gas of Ohio	62,593,567
Dominion East Ohio	63,585,403
Orwell Natural Gas	86,447
Total	**138,571,962**

The cost of energy is not dramatically different for households that have significantly different incomes, which increases the likelihood that customers with little extra income will fall behind on utility payments and risk disconnection due to nonpayment. Utility cost remain significantly unchanged over all income groups is because:[64]

1. Electricity and other utility services are a basic human need, not a luxury, making it relatively inelastic to income compared to consumer goods;

2. Even if low-income families do use less electricity, there is an energy efficiency gap, in terms of housing and access to the proper technology; and
3. A significant portion of electricity bills are paid via fixed costs, which means it doesn't matter how much electricity you use or don't.

In 2009, households with incomes of less than $20,000 spent an average of $1,571 on utilities while households with incomes of $100,000–$119,999 spent an average of $2,572.[65] While these customers' relative incomes increased by more than 500%, the price they pay for utilities increases by only 163.7%. The reasons listed above have contributed to this pattern.

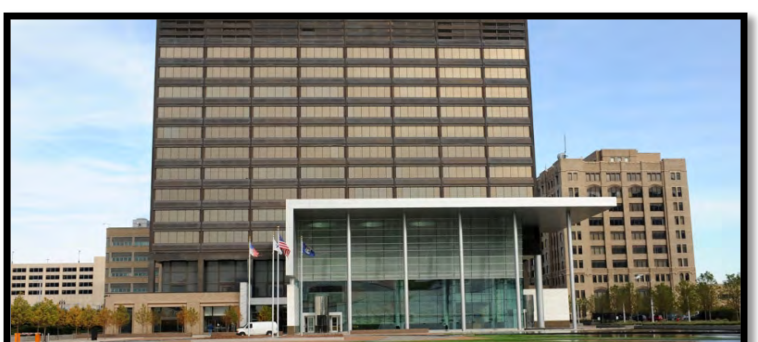
Disconnections due to nonpayment occur in significant amounts, and are on the rise in some areas.[66] In Ohio, four gas and electric companies serving the Cleveland area reported 169,521 service disconnections due to nonpayment during the twelve months between June of 2014 and May of 2015 (Table 2).[67] These disconnections equate to approximately $138,571,962 in unpaid utility bills, which averages to just over $800 per disconnection (Table 3).[68]

"The cost benefit analysis of how the utility business model is structured around utility shut offs in the face of such wealth building focus means a choice of life and death for some and the choice between a Porsche and an Audi for others.''

-Jacqueline Patterson, Director, NAACP Environmental and Climate Justice Program

PROFITEERING OF UTILITY COMPANIES

When considering that utility company executives make millions of dollars in bonuses and pay increases, annually, that exceed the amount of revenue lost to nonpayment is a further sign of injustice. First Energy, the parent company of Cleveland Electric Illuminating Company, made over $16 million *in performance bonuses alone* at the end of 2016, more than enough to cover the debt of disconnected customers from the previous year (Table 4). Disparities such as this are common, and even more drastic in other regions of the U.S. As shown in Appendix A, Ohio, as well as many other states, have electric affordability indexes above the national average (2.5%). Tennessee, South Carolina, Mississippi, Alabama, and Hawaii all have energy affordability indexes equal to or more than 3.5%. In these states, the average customer faces a higher energy burden. A burden that is deeply felt by low income and socially vulnerable populations. The stark contrast between the amount of money utility companies spend on executive bonuses and unnecessary infrastructure, illuminates the larger issue of profiteering within the energy industry.



DTE Headquarters in Detroit, MI
Source: U.S. Department of Energy

Detroit, MI Residences in the DTE Service Territory
Source: Fireplace Chats

Table 4. First Energy Executive Compensation FY 2015-2016

Cleveland Electric Illuminating Company (First Energy) 2015-2016			
Executive	Base Salary	Total Compensation	Pay Increase
1	$ 1,118,558.00	$ 4,238,701.00	$ 3,120,143.00
2	$ 636,154.00	$ 2,339,431.00	$ 1,703,277.00
3	$ 510,231.00	$ 7,054,125.00	$ 6,543,894.00
4	$ 752,789.00	$ 3,004,793.00	$ 2,252,004.00
5	$ 599,176.00	$ 2,135,552.00	$ 1,536,376.00
6	$ 552,404.00	$ 2,017,272.00	$ 1,464,868.00
Total	$ 4,169,312.00	$ 20,789,874.00	$ 16,620,562.00

DISPARATE IMPACT ON LOW INCOME COMMUNITIES AND COMMUNITIES OF COLOR

African Americans spend a significantly higher amount of their total incomes on energy—including electricity, heating, fuel, and the energy used to produce, package, transport and sell goods—than the general U.S. population, except in higher income groups. The American Association of Blacks in Energy argues that this occurs for two reasons:[69]

1. African Americans are more than twice as likely to live in poverty as non-African Americans. Low income households pay similar amounts for electricity and heating as high income households; and
2. African Americans spend a significantly higher fraction of their household income on electricity and heating than non-African Americans who spend more on energy used in the production and consumption of goods.

In general, low income populations spend a significantly higher fraction of expenditures on energy purchases than the middle-class and the wealthy: 13% of expenditures in the lowest income groups as opposed to just 5% of household income in the highest income groups.[70] The higher percentage of low income African Americans exacerbates the vulnerability of African Americans to high energy prices and in turn utility disconnections. This helps explain why increases in energy prices are likely to negatively impact African Americans more significantly than the general population.[71] In addition to the economic burden of high prices, to the extent that low income customers, low income African Americans customers in particular, choose to forgo or trade-off energy use with other necessities such as food and health care, high energy prices can represent a significant health hazard.[72] The choice between utility services and other necessities is not an easy choice. In a 2011 survey, lower-income households reported the following reactions to high energy bills:

- 24% went without food for at least one day;
- 37% went without medical or dental care;
- 34% did not fill a prescription or took less than the full dose; and.
- 19% had someone become sick because their home was too cold.[73]

While having limited extra income puts individuals at higher risk for being disconnected due to nonpayment, a customer's race may also influence how likely an individual is to be disconnected from utility service. Data from the 2009 United States Energy Information Administration's Residential Energy Consumption Survey indicates that even among financially similar customers, African Americans experienced disconnections more frequently.[74] Among all households at or below 150% of the federal poverty level, 11.3% of African American headed households were shut off in contrast to 5.5% of Caucasian headed households.[75] While every region of the United States reflected this disparity, it was most prominent in the southern region, where 16% of African American headed households at or below 150% of the poverty level were disconnected compared to approximately 6% of Caucasian headed households.[76] In this case, intentional discrimination can be difficult to prove without concrete data and research of the differences between groups in the prioritization of energy bills over other expenses. These disparities may be the result of institutional racism; uneven levels of consumer education; differences in savings, available income, or outside assistance; and geographic density of customers based on race.[77]

> **"Regardless of whether it's shut off or simply that bills are so high that people voluntarily limit usage, several things happen. People use space heaters, kerosene heaters, that increase risk of fire and carbon monoxide poisoning. And people limit use of electricity. They light the home with candles, which are often too close to something combustible."**
>
> *-David Fox of the National Low-Income Energy Consortium (NLIEC)*

USE OF HAZARDOUS HEATING METHODS

Despite the significant costs of utilities on customers with limited extra income, the use of utility services remains necessary. Heating and cooling homes accounts for 47.7% of all residential energy consumption, with 41.5% of all residential consumption going solely to heating.[78] Customers use more energy in months when heating is necessary, and customers with little extra income may be especially vulnerable to disconnection during these more costly months.[79] For customers who live in colder climates, or who experience unusually extreme weather, the consequences of being disconnected throughout the winter months are potentially severe.

A family sits and waits as emergency respondents extinguish the flames
Source: Denver Post

Customers take risks when they turn to alternative heating or light sources, such as space heaters, candles or generators, which can cause fires or emit toxic carbon monoxide.[80] As noted, there have been publicized deaths that resulted from the disconnection of a heat-utility during the winter months. ***According to the National Fire Protection Association, while only 32 percent of home heating fires involve space heaters, heaters are involved in 79 percent of home heating fire deaths.***[81] Customers face additional health hazards throughout the year particularly when they are left without air conditioning in extreme heat, and when electricity is disconnected from customers who rely on the service to power their medical devices.[82]

TYPES OF DISCONNECTION POLICIES

The policies and protections outlined in this section are common among all types of utility companies. But these are particularly measures outlined by state legislatures and authorized regulatory bodies (i.e. Public Utility Commissions, Public Service Commissions, and other bodies) for the regulation of IOUs. Many of these protections are also used by Publically-Owned Utilities (POUS) and Customer Owned Utilities (COUs).

Louisville, KY November 15, 2016: House Fire caused using space heater
Source: WLKY, Kentucky

PROCEDURAL PROTECTIONS AND CONSIDERATIONS

Procedural protections that are commonly included in disconnection policies include adequate notice prior to disconnection of the utility service and limitations on when disconnections may occur. An additional procedural option often used by states is the imposition of fees for disconnecting or reconnecting a utility service to a customer. Utility services can be disconnected and reconnected in person and remotely, depending on the type of meter or infrastructure onsite. Producers for in person or automated disconnection and reconnections have varying policies in several states. This includes differences in notice and associated fees.

Notice: Is a constitutionally assured procedural right that must be given to all customers before termination of utility service.[83] In addition to being constitutionally required, providing a robust notice to customers ensures that customers are aware that they are delinquent in their payments. This not only protects the customer from being disconnected, but it alerts customers of their duty to pay for the utility service. Though a minimum level of notice is required before any utility may be disconnected for nonpayment, the length of notice and notice procedures vary widely in different states. Typically, notice is given by mail, by posting of the notice at the customer's home, by delivery to the customer, by phone, or, in limited states, by email.[84] Some states require that notice be provided in multiple languages.[85]

Limitations on Disconnection: Many states choose to limit the days and times when utilities may disconnect a customer from service. Enacting these limitations often protects customers from being disconnected at a time when they would be unable to quickly remedy the disconnection. Most states will, at minimum, limit disconnections to business hours on days when the utility is open and available to receive a customer's payment.[86] Some states offer more customer protection by allowing disconnection only during limited hours of the business day. If a state requires personal notice before a disconnection, the state may be more lenient with the hours and days on which a disconnection may take place.

Disconnection and Reconnection Fees: Almost every state explicitly authorizes reconnection fees.[87] Reconnection fees are authorized to allow a utility to collect additional payment for the acts of disconnection and reconnection, and the provision of other customer service interactions with the customer prior to the disconnection. Reconnection fees are often adopted as a deterrent for customer to reach disconnected status.[88] Other states are more protective of certain customers, such as the elderly or low-income customers for whom a fee would prevent reconnection.[89] Some states also authorize the collection of a fee for disconnection.[90] The fee amounts and procedures for disconnection and reconnection vary among states. The Public Utility Commission, of Ohio provides a Winter Reconnect Order for residential customers under the threat of disconnection or who have been disconnected to file for have their service reconnected or maintained for the winter months. Customers filing an order must pay a $175 fee to retain service and an additional reconnection fee of $36 to reconnect service.[91] Some states, including Arkansas, do not charge disconnection fees, but may still allow for utilities to charge reconnection fees.[92]

House fires can start from even a lit candle when used for heating and light in a home

In most cases disconnection and reconnection fees are still applied for remote disconnections and reconnections—remote connections can be made simply by flipping a switch. Disconnection and reconnection fees are another obstacle for customers at risk of disconnection, as well as those who have already been disconnected. Utility companies that offer these fees as disincentives for customers do not recognize that disconnections themselves are disincentives for most customers. These administrative polices do not help any customer, but further endanger customer well-being.

Deposits and Guarantees: In some states, new utility customers or customers with poor payment history, utility companies can require payment of a deposit or the submission of a letter of guarantee from a third party able to pay in lieu of the customer. Many PCU's and other utility regulatory bodies set minimums and maximums on deposit amounts and prescribe payment installment programs for paying deposits more than a set amount.[93] Deposits are often required on top of reconnection fees and arrears.[94] Deposit amounts vary from state to state and have been reported in excess of $150.[95]

SEASONAL PROTECTIONS

Seasonal protections are included in the disconnection policies of many states. Seasonal protections are generally date-based, temperature-based, or include a combination of both protections. Most seasonal protection policies apply to winter months or cold temperatures, but some also apply to summer months and extreme heat. Seasonal protections are usually implemented to protect customers from the health risks associated with having a utility disconnected during periods that could be especially dangerous to health.

Resident reveals the duct taped windows in her Claremont Houses apartment in the Bronx, NY.
Source: David Wexler, New York Daily News

Date-Based Protections: These protections set specific dates of when customers cannot, without due diligence, be disconnected from a utility service. Dates typically span the late fall to early spring months, when temperatures are at their lowest. Though less common, some states implement date-based protection periods for the summer months as well.[96]

Temperature-Based Protections: Many states have a temperature-based protection plan to protect customers from extreme cold weather. These protections acknowledge the dangers that customers face when they are disconnected from a utility that may be providing them with heat during periods of cold weather.

PAYMENT ASSISTANCE

> **"[S]ome energy companies will offer the bare minimum in assistance. Many application assistance locations are inaccessible to disadvantaged populations... [P]rogram applications require multiple sources of documents and are so lengthy, complex and intrusive that needy applicants are discouraged from completing them. The process of applying for energy bill payment assistance should not cause added humiliation."**
>
> *-Katherine Egland, Member, National NAACP Board of Directors*

Many states require utilities to offer payment plans that may allow a customer to avoid disconnection or to more easily afford their bills throughout the course of the year. These plans can take many forms. One common option allows for all customers to enter a "budget billing" or "leveled plan." These plans are typically available to any eligible customer, and it allows a customer to divide a yearly bill evenly over twelve months.[97]A second common option is offered only to customers who are at risk of having their utility disconnected. These customers are given a chance to pay the amount due in portions rather than all at once, which allows a customer to expedite reconnection to the utility service.[98] Payment plans are also frequently required to avoid disconnection during seasonal protective periods.[99]

PROTECTIONS FOR SOCIALLY VULNERABLE GROUPS

Most states offer protection for groups that may be considered especially vulnerable to the risks and hazards associated with utility disconnections. Traditionally, this category includes protection for people who are elderly, people with special health conditions, and individuals with disabilities. Most states only require utilities to offer protections to socially vulnerable customers who register with the utility; however, for some of these groups, registration may be a barrier that prevents them from being protected under the applicable laws.

STATE DISCONNECTION PROTECTION POLICIES

Disconnection protections vary significantly by state. The combination of protections provided by utilities is ideally fit to the context of that state and its definition of public interest, however, these considerations do not result in adequate protections in all cases. To truly uphold human rights, in the public interest, the ultimate aim is to eliminate disconnections altogether and, pending broader system reform, ensure the absolute highest level of protection for vulnerable households facing disconnection. Table 5 illustrates how different protection policies and prescriptions are state by state.

Table 6 indicates the general utility disconnection policies for each state. Most states require utility companies to provide a written, phone, or personally delivered notice before a disconnection. Date based protections take place during the colder months, usually between the months of November and March or April. Temperature protections are based on various ranges of hot and cold temperatures that could place residents in danger. Most of the states will not disconnect when temperatures below 32°F or above 95°F, but the offering of this protection varies by state. Most the states offer a payment plan option to avoid disconnections and charge a fee to reconnect to utility services. Medical protections are generally offered for disabled or elderly customers. Generally, a medical certificate is required to postpone a disconnection for various amounts of time. There is a wide range of disconnection limitations. Some states will not disconnect during certain hours of days of the week, while other states will not disconnect before or during a holiday. A detailed compilation of utility disconnection protections can be found in Appendix B.

MODEL STATE POLICIES

The following polices are key examples of what utilities can do to provide more protective disconnection polices. These policies represent a step toward a more human rights based utility structure.

NOTICE

- In Oregon, a utility must provide a written notice by mail or delivery at least fifteen days before the scheduled disconnection.[100] A second notice must then be mailed or delivered five days before the scheduled disconnection.[101] The utility must attempt to make personal contact with the customer immediately before the disconnection, and if this attempt is unsuccessful, the utility must post a notice at the customer's residence.[102] Additionally, Oregon requires special notice protections following a disconnection when a utility is able to disconnect a customer remotely without making personal contact.[103]
- Some states require that notice be provided in multiple languages, as in Colorado where a utility must provide notice in English and "languages other than English where the utility's service territory contains a population of at least ten percent who speak a specific language other than English as their primary language as determined by the latest U.S. Census information."[104]

LIMITATIONS ON DISCONNECTION

- In Iowa, a customer may only be disconnected between the hours of 6:00am and 2:00pm, which ensures that a customer has an opportunity to be reconnected the same day that the disconnection takes place.[105]
- Most states provide avenues for renters to address situations where landlords fail to pay utility bills. In these instances, if a landlord fails to provide a utility, they can be held in violation of state and local housing codes and penalized. Many states have provisions which provide tenants with remedies against utility disconnections including: transferring of rental properties to tenant control; paying utility bills in place of landlords and deducting the amount from rent payments; and/or avenues for legal action and court involvement. [106]

DISCONNECTION AND RECONNECTION FEES

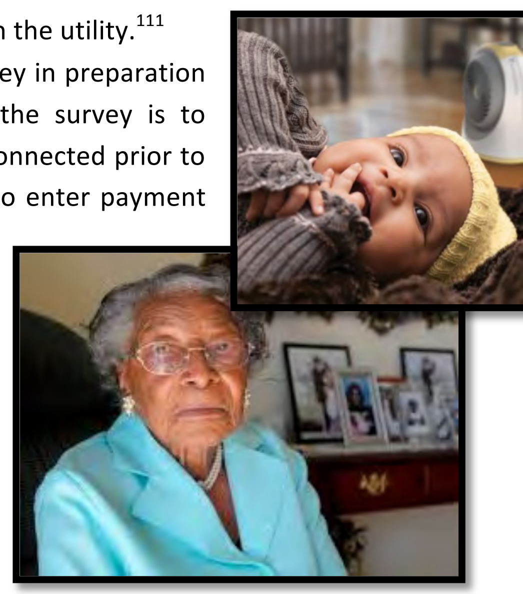
- Arkansas does not charge disconnection fees for water, gas, or electric utilities.[107]

SEASONAL PROTECTIONS

- Rhode Island has one of the most protective date-based winter seasonal protection plans. The regulation was recently passed, and became effective on November 2, 2016.[108] During the period from November 1–April 15, utilities are severely restricted in their ability to disconnect a customer for nonpayment. Customers who use a utility for their primary heating service may not be terminated unless they have arrearages greater than $500.[109] While customers who have delinquencies greater than this amount may be disconnected, the utility must first file an affidavit with the state's Division of Public Utilities and Carriers at least forty-eight hours before the scheduled disconnection.[110] Additionally, there are no disconnections allowed for any customer who has a protected status with the utility.[111]
- In Pennsylvania, utilities are required to distribute a survey in preparation for the winter protection period.[112] The purpose of the survey is to connect utilities with the customers who have been disconnected prior to the winter protection period. Utilities are encouraged to enter payment agreements with these customers so that they may be reconnected before the winter period begins.[113]

PAYMENT ASSISTANCE

- Rhode Island's Henry Shelton Act of 2011 (amended in 2016) establishes an arrearage forgiveness program for customers eligible for Low Income Home Energy Assistance Program (LIHEAP) who have had their utility services disconnected for non-payment or who have been scheduled for disconnection. Participating customers have one-twelfth of their arrearage forgiven for every month of successful payment, for up to $1,500 of forgiveness in a year.[114] This system is based



Small children, the elderly, and those with medical conditions and disabilities are particularly vulnerable to exposure to extreme weather
(Child) Source: [Olkbridge Family]
(Woman) Source: [Persimmon Hollow]

on a similar model in Massachusetts.[115]

PROTECTIONS FOR SOCIALLY VULNERABLE GROUPS

- Massachusetts offers expansive protection for individuals who are seriously ill, elderly, and have disabilities, but the state also requires that utilities take steps to protect young children.[116] No disconnections are allowed for households with children under twelve-months, or for households where the only residents are aged sixty-five or older and minor children.[117]
- To combat barriers to registration for protection programs, North Dakota implemented a utility survey that must be distributed to all new customers and all current customers on an annual basis. This survey questions all customers about any members of the household who qualify for protection due to age, illness, or disability.[118]

Table 5. Survey of State utility customer disconnection protections

State	Procedural Protections	Seasonal Protections	Payment Assistance	Protections for Vulnerable Groups
Alabama	Provide customers with a written notice five days before scheduled disconnection Requires a reconnection charge	When the temperature is forecasted to be 32°F or below for that calendar day, the utility cannot be disconnected	The utility does not have a payment plan option and	Special consideration based on age, disability, medical conditions or other circumstances is granted, but not required
Alaska	Customers receive an initial notice fifteen days before scheduled disconnection, and a second notice is provided in person, by telephone or by posting three days before a disconnection Disconnections can occur Monday-Thursday between 8:00am-5:00pm	Does not require seasonal protections	Deferred payment agreement with the utility to pay their outstanding balance in installments over a period not to exceed 12 months	A customer, who is elderly, ill, dependent on life support systems, or disabled, can have their disconnection postponed for fifteen days
Arkansas	Initial notice to be mailed eight days or delivered five days before the disconnection, Disconnections can only occur during normal business hours No reconnection charges	Disconnections are not permitted between November 1-March 31 Gas utilities may not disconnect for low-income customers When the temperature is 95°f or above, disconnections are not allowed for elderly or disabled customers	Offer payment plans for customers, who qualify as low-income, during winter protection period	Customers, who are elderly or have disabilities, must have two notice attempts at least 72 hours before shut off
Kansas	Written notice to be sent ten days before scheduled disconnection and the utility must call two times at least two days before disconnection	Disconnections are not permitted between November 1-March 31 If temperature drops below 35°F in the following 48-hour period, disconnections are not permitted	Customers must enter into negotiated payment plan, pay 1/12 of arrearage, 1/12 of current bill and disconnection, reconnection and deposit if applicable and apply for energy assistance funds to avoid disconnection	Customers with a medical certification must also provide proof of inability to pay the bill in full
Tennessee	Requires only a reasonable notice to be provided Does not specify a period for disconnections	Does not offer date based or temperature based protection	Offers payment plans for customers	A thirty day disconnect delay can be granted if physician, public health official or social service official certifies that a household member's health would be adversely affected

Table 6. Disconnection Protection Polices in the United States

State	Notice	Date Based Protection	Temp. Based Protection	Payment Plans	Reconnection Fee	Medical Protections	Disconnection Limitations
Alabama	X		X		X	X	
Alaska	X			X	X		X
Arizona	X		X		X		
Arkansas	X	X	X	X			X
California	X					X	
Colorado	X						
Connecticut	X			X	X	X	
Delaware	X	X	X	X		X	X
D.C.	X		X		X	X	X
Florida	X				X		X
Georgia	X	X	X	X	X	X	X
Hawaii	X					X	X
Idaho	X	X		X		X	X
Illinois	X	X	X	X		X	X
Indiana	X	X		X	X	X	
Iowa	X	X		X	X	X	X
Kansas	X	X	X	X	X	X	
Kentucky	X	X		X			X
Louisiana	X	X	X	X	X	X	X
Maine	X	X		X	X	X	X
Maryland	X	X	X	X		X	X
Massachusetts	X	X		X		X	X
Michigan	X	X		X	X	X	X
Minnesota	X	X	X	X	X	X	X
Mississippi	X	X	X	X	X	X	
Missouri	X	X	X	X	X	X	
Montana	X	X	X	X		X	X
Nebraska	X	X		X	X	X	X
Nevada	X		X	X	X	X	X
New Hampshire	X	X		X	X	X	X
New Jersey	X	X	X	X		X	
New Mexico	X	X		X	X	X	X
New York	X	X		X		X	X
North Carolina	X	X		X	X		X
North Dakota	X			X	X		X
Ohio	X	X		X	X	X	X
Oklahoma	X	X	X	X	X	X	X
Oregon	X			X	X	X	
Pennsylvania	X	X		X	X	X	X
Rhode Island	X	X	X	X	X		X
South Carolina	X	X		X	X	X	X
South Dakota	X	X		X		X	X
Tennessee	X			X		X	
Texas	X		X	X	X	X	X
Utah	X	X		X	X	X	X
Vermont	X	X	X	X	X	X	X
Virginia	X				X	X	X
Washington	X	X		X	X	X	X
West Virginia	X	X		X	X	X	X
Wisconsin	X	X	X	X	X	X	X
Wyoming	X	X	X	X	X	X	X

FINANCING TO REDUCE AND ELIMINATE DISCONNECTIONS

There are financing models that can help reduce the burden of utility costs on at-risk customers. These options are only steps toward a broader vision. It bares emphasis that the injustices of many utility practices are fundamental wrongdoings that contribute to the creation and continuation of poverty. The big picture is economic justice and equity, virtues that are thwarted by current utility business models regardless of strategies to reduce household energy burdens. Bill assistance programs, energy efficiency and weatherization programs, and inclusive financing models are resources that can and should be used in the short term to prevent and reduce the risk of utility disconnection. These approaches are band-aids applied to the symptoms of deep systemic roots of poverty. While they are positive and useful models and resources, they are merely a step toward the ideal.

BILL ASSISTANCE PROGRAMS

Bill assistance programs provide financial assistance for households to pay their immediate home energy bills. There are many federally funded bill assistance programs, the main programs include the: Low Income Home Energy Assistance Program (LIHEAP), the primary federal bill assistance program; Emergency Food and Shelter Program (EFSP), funded by the Federal Emergency Management Agency; and Residential Assistance for Families in Transition (RAFT), provided by the U.S. Department of Housing and Community Development. Federal Bill assistance programs, as well as those operated by non-profits, often have social service and case management resources for households.

Bill assistance programs are often the first solution at risk customers use to avoid utility disconnections
Source: La Casa De Don Pedro

LIHEAP provides funding to states, which is then distributed to qualified households. The funds dispersed by states can be direct bill assistance (the majority of funds), crisis assistance, support for weatherization programs, or other forms of aid to reduce household energy needs. Across most states, household eligibility is established between 150% and 110% of the federal poverty line, or 60% of the state median income.[119] The program also provides direct payments to tenants, who meet income eligibility requirement for fuel assistance, whose heat is included in the rent.[120]

EFSP grants are allocated at the county and regional levels. EFSP tends to pays for only one month’s utility bill and requires that the household has received a shut-off notice. In many states, the same agency that processes LIHEAP applications also administers EFSP funds. The Department of Housing and Community Development's RAFT program provides substantial help with utility and heating bills. Unlike other federal bill assistance programs, RAFT's requirements and regulations tend to change with each fiscal year. Often to qualify for RAFT assistance, households must have at least one dependent child under the age of 21 and at risk of homelessness. Utility bill payments will be made only as part of family re-housing or stabilization plans. RAFT funds are administered by regional non-profit agencies.[121]

Although many bill assistance programs exist, there is still limited federal funding available in most states for low-income residents, and some funding is available from utilities in some states. Many state programs also have trouble reaching their target populations. Even in states with more successful bill assistance programs (e.g. California, New York, Illinois, etc.), only about 1% of the eligible population are reached annually.[122] Although many households receive assistance and can avoid disconnection through bill assistance programs, they are not an effective long term solution.

WEATHERIZATION AND ENERGY EFFICIENCY PROGRAMS

Through upgrading the efficiency of homes, households can reduce the burden of their energy bills. Programs that focus on weatherization and energy efficiency fund longer term solutions to household energy burdens by cutting wasted energy, improving comfort, and lowering costs.[123] Weatherization and energy efficiency retrofits are multi-benefit approaches to alleviating many consequences of living in poverty. When done holistically, the infrastructure and ventilation improvements and use energy efficient appliances that characterize these programs can save a household from undue energy burdens and environmental health hazards.[124] Low income households, the same that are most at risk of utility disconnections, are more often living in sick buildings, homes, and communities with poor environmental health conditions.[125]

Weatherization programs install energy efficiency upgrades aimed at improving the physical space between the interior and exterior of a building, such as weather-stripping doors and windows, air sealing (as seen in the picture above), and installing insulation. Weatherization programs also fund upgrades or repairs to heating and cooling systems.[126] The most effective weatherization and energy efficiency programs address the largest household energy uses with the longest sustained savings (e.g. heating and cooling), which often have the greatest impact on reducing energy burdens.[127]


Weatherization of homes is easy and effective way to reduce energy use
Source: [Habitat for Humanity, Prince William County, VA]

Unlike bill assistance and most weatherization programs, utility energy efficiency programs can include a variety of program strategies. Some utility energy efficiency programs operate in tandem with local or statewide weatherization efforts, using similar channels to reach customers. The most common low-income energy efficiency approaches are whole-building weatherization, and the installation of low-cost energy efficiency measures (e.g., efficient lighting, high-efficiency showerheads and faucet aerators, and air infiltration reductions). Some utilities operate direct-install programs targeting multifamily rental buildings as part of their low-income program offerings.[128] Building upgrades through weatherization and energy efficiency programs are the primary way of reducing the likelihood of non-payment that most households can employ.

Reductions in energy bills often equal reductions in the risk of disconnection. Even still, investment in energy efficiency and weatherization programs is an underutilized strategy.[129]

INCLUSIVE FINANCING MODELS

Programs that help utility customers pursue home improvements can reduce monthly utility bills. With energy efficiency measures alone, customers are predicted to save $2 trillion by 2030. Inclusive financing programs use a utility tariff rather than a loan to finance cost effective energy upgrades, and they break down the barriers to access so that these savings can be realized. [130] These models are providing an avenue for access for utility customers who may not qualify for direct install programs for low-income customers yet still struggle to make ends meet and keep the lights on.

Utilities that offer inclusive financing can remove major barriers to energy efficiency and renewable energy development by allowing customers to opt into a tariff that authorizes the utility (1) to make site-specific investments in cost effective energy upgrades and (2) to recover its costs with a charge on the bill that is significantly less than the estimated savings. Where inclusive financing programs exists, they are open to all utility customers regardless of their income, credit score, or renter status.[131] Figures 4 and 5, from the Institute for Local Self-Reliance's Energy Democracy Initiative, illustrates the how inclusive financing works in the utility space. Utilities provide contractors with the upfront funding for onsite energy efficiency, weatherization, and renewable energy projects. The resulting savings from those projects is more than the costs added to the utility bill as payment for the project installation and infrastructure. The result is lower monthly utility bills. No utility offering inclusive financing based on the Pays As You Save®(PAYS®) system has reported a single disconnection for non-payment among program participants.

Many utility cooperatives have seen inclusive financing models work. At Roanoke Electric, a utility cooperative in a persistent poverty area of North Carolina, the Upgrade to $ave program has invested in upgrades at more than 300 homes. The estimated average monthly net savings for participating customers

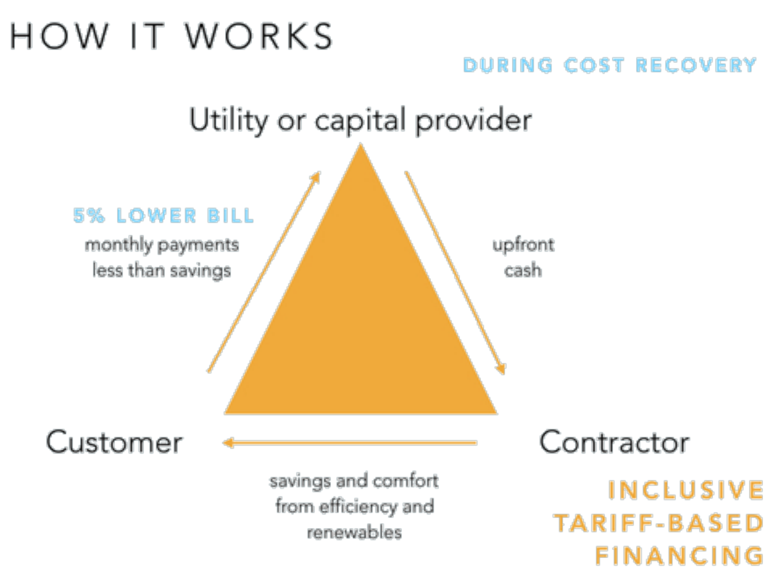


Figure4. Inclusive Financing Model, Source: Local Self-Resilience Energy Democracy Initiative

is around $50, as they pay the monthly program service charge that is capped at 75% of the estimated savings - so the customer net savings from the beginning. [132] With these savings, inclusive financing models have the express potential to reduce and eliminate utility disconnections and provide critical services to vulnerable populations.

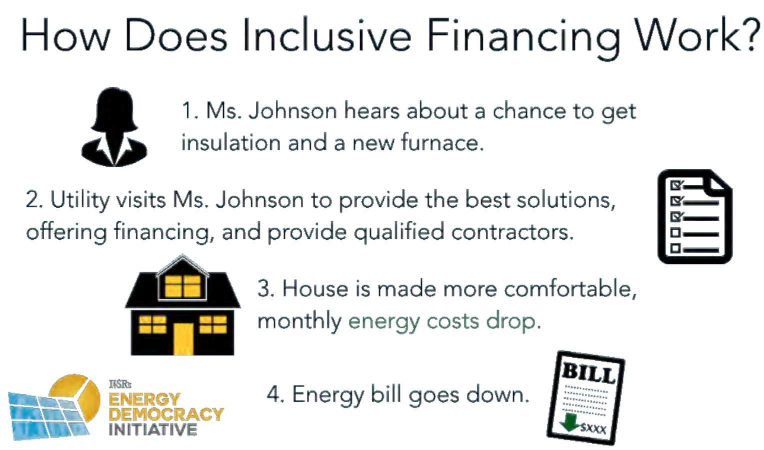


Figure 5. Simple overview of how inclusive financing works

THE NEED FOR UNINTERRUPTED SERVICE

"What kind of world do we live in where children can die a fiery death and there is no massive outcry?...We call on everyone opposed to this constant inhumanity against poor people to join us...and demand an immediate moratorium on gas and light shutoffs,"

-Maureen Taylor, State Chairperson, Michigan Welfare Rights Organization

The establishment of a universal **right to uninterrupted energy service** would ensure that provisions are in place to prevent utility disconnection due to non-payment and arrearages.[133] Toward establishing such a right, we call for all utility companies to advocate for and incorporate the following foundational principles into their models, operations, and policies:

1. Secure **ACCESS** to utility services for all households;
2. **INCLUSION** of all customers in the development of utility policies and regulations;
3. **TRANSPARENCY** of the actions of and information held by utility companies, regulating bodies, legislatures, and utility affiliated organizations;
4. **PROTECTION** of the human and civil rights of all customers; and
5. Advance programs that help **ELIMINATE POVERTY**, so that all customers can pay utility bills.

Maureen Taylor of the Michigan Welfare Right Organization
Source: Wiley Price

The policies and protections detailed in this report represent stop-gap measures to lessen harms wrought by a system that is predicated on amassing profits without regard to the impacts on people. In advancing energy justice, all individuals have the right to: safe, sustainable energy production; the resilient and updated energy infrastructure; affordable energy; and uninterrupted energy service.[134] The NAACP calls for the development of policies and utility structures that improve energy efficiency throughout the energy continuum, advance clean and renewable energy production, encourage and enable the development of distributed generation, and protect human life and wellbeing. We further call for a system that puts power in the hands of the people, literally and figuratively. These aspects are components of the larger utility system change that we must build.

Source: [People over Profit, twitter.com]

There are proven pathways for change. As demonstrated, improved energy efficiency would lower energy bills and make it less likely for utility customers to fall into arrears.[135] The same is true of distributed generation, particularly when paired with Pay As You Save (PAYS) models that would allow households to pay very little for electricity.[136] With greater energy independence and reliance on renewable sources, the entire energy system would be less vulnerable to market fluctuations, which would stabilize costs.[137] Through reducing emissions from fossil fuel based energy production, climate change mitigation goals would also benefit from these shifts. Therefore, the tremendous expense of disaster related outages, which are increasing and have real impacts on utilities' budgets,[138] would be reduced—protecting customers from yet another hazardous outage that is outside of their control.

Utility customers who are disconnected due to non-payment should not face the potential of death and suffering when viable solutions exist. Much action is needed to cease this needless endangerment. Now is the time to expand the research and evidence surrounding the impacts and issues of utility disconnections, as well as reform how we manage and operate the entities that supply these critical services.

IMPROVED DATA COLLECTION, RESEARCH, AND TRANSPARENCY

"For some customers, there is "a permanent level of unaffordability built into the rates.''

-William Yates, Senior Financial Analyst, Public Utility Law Project of New York.

There is a need for more extensive and transparent data and research concerning utility disconnections, nationwide. Until this information is more readily documented, shared, and analyzed our message will be more easily ignored. Where this information does exist, it needs to be made publicly available, especially to customers of utilities.

RECCOMENDATIONS FOR UTILITY COMMISSIONS, REGULATORS, AND UTILITIES

It is the responsibility of utility companies and those who regulate them to ensure that records and data of disconnections are documented and made publicly available, at minimum, to its customer base. In accordance with the rights, principles, and actions previously discussed, we advise public utility commissions, regulators, and utility companies to:

1. Set strict record keeping standards of the entire disconnection/ termination of service process;
2. Conduct studies on the financial and human costs of utility disconnections;
3. Make records of disconnection publicly available on commission, utility, or government websites; and
4. Use this information to evaluate and improve disconnection protection policies and safeguards.

Members of the Committee Against Utility Shutoffs (CAUS) speaking at a community event
Source: CAUS

RECCOMENDATIONS FOR GOVERNMENT AGENCIES AND ORGANIZATIONS

Several federal and state agencies and organizations collect, analyze, and release data and reports regarding the U.S. energy industry at multiple scales (e.g. U.S. Energy Information Administration). To the extent that utility disconnections are a part of these analyses is currently unknown, however, moving forward, it is imperative that this information be included and made publicly available. In accordance with the rights, principles and actions previously discussed, we advise these government agencies and organizations to:

1. Maintain extensive and up to date databases containing disconnection data provided by utility companies and regulatory sources;
2. Obtain, analyze, and make transparent aggregate utility disconnection data in U.S. energy sector reports; and
3. Hold public utility commissions, regulators, and utility companies accountable for providing complete datasets for assessment and dissemination.

RECCOMENDATIONS FOR UNIVERSITY AND NON-PROFIT RESEARCHERS

As a society, we rely on academic and professional research for input into policy development. Thus, researchers from universities and organizations with research capacity (e.g. National Consumer Law Center and the Consumer Federation of America) must also be aware of these issues and conduct studies that foster better understanding of the connections between utility disconnections, their impacts on households, and other industries and sectors. We are asking researchers from colleges, universities, and capable non-profit organizations, particularly those with strong environmental and energy justice programs, to:

1. Expand research on socially conscious utility and energy models;

2. Advance research that impacts all parts of society, particularly vulnerable populations;
3. Partner with communities in and promote community participatory research models; and
4. Use expanded data in accordance with the principles and rights outlined.

UPHOLDING HUMAN RIGHTS IN THE SHORT TERM

"Utilities are a social right. People have a right not to freeze to death! They have the right not to live on the bare edge of survival. To realize this right, however, we must fight for it. And this demonstration is an initial stage in this fight."

-Lawrence Porter, CAUS chairman and SEP Assistant National Secretary[139]

While the end goal is clear—**to prioritize utility policies that place a moratorium on utility service disconnections**— these principles can be furthered through the following practices:

PROCEDURAL PROTECTIONS

1. Require multiple attempts by phone, in writing, and, in person contact before disconnection;
2. Secure notification of disconnection by mail;
3. Require a post-disconnection notice to all customers;
4. Provide additional notice provisions for customers who can be disconnected remotely;
5. Restrict disconnections between 8:00am-2:00pm (or during hours of operations, and not later than 2 hours before close of business) on days when utilities have employees available for reconnections;
6. Provide notice and utility disconnection policies in multiple languages;
7. End policies surrounding disconnection and reconnection fees;
8. Cease the collection of deposits for utility service activation and/or reconnection;
9. Ensure that renters retain access to energy services when nonpayment is the fault of the landlord or other third party;

SEASONAL PROTECTIONS

10. Include seasonal protections with both temperature and date-based solutions;
11. Set disconnection arrearage minimums for customers who use utility services as the primary source of heating or cooling during periods of seasonal protection;
12. Provide utility services during extreme weather events that fall outside of seasonal protection periods;

Committee Against Utility Shutoffs (CAUS) Utility Shut-off Demonstration in Detroit, MI
Source: CAUS

PAYMENT ASSISTANCE

13. Allow budget payment plans to distribute utility costs throughout the year;

14. Allow partial payment plans to customers to prevent disconnections;
15. Provide connections to social services and case management resources for households with delinquent bills (i.e. budgeting, food assistance, and other social services);

PROTECTIONS FOR HOUSEHOLDS THAT ARE SOCIALLY VULNERABLE

16. Establish simple procedures for socially vulnerable groups to apply and be registered for protection from disconnection;
17. Implement customer surveys in advance of extreme weather seasons to screen for socially vulnerable individuals;
18. Ensure active outreach to socially vulnerable customers and households for inclusion in protection programs; and
19. Registration into these programs should be complimented with a notification to local and/or state emergency relief agencies and safety responders.

RECCOMENDATIONS FOR UTILITY COMPANIES

With the intent to incorporate human rights into existing utility business models, we advise Utility Companies and affiliate organizations to:

1. Operate according to the principles and practices of human rights; and
2. Cease investments and lobbying practices that undermine the right to uninterrupted utility services.

RECCOMENDATIONS FORPUBLIC UTILITY COMMISSIONS AND REGULATORS

With the intent to incorporate human rights into existing utility business models, we advise Public Utility Commissions, and regulators to:

1. Enforce and adhere to the principles and practices of a human rights based utility model;
2. Hold public hearings to investigate the extent and nature of disconnections in services areas;
3. Mandate exploration and implementation of energy efficiency, clean energy, and distributed generation programs and technologies;
4. Ensure that regulatory processes, meetings, and proceedings are accessible to all customers; and
5. Hold themselves and utility companies accountable to the concerns of customers.

INVESTOR-OWNED UTILITY ENGAGEMENT

While every state has different regulation rules, it is a common practice to contact the utility as the first step to engagement. Investor-owned utilities are regulated by the Public Service Commission (PSC)/Public Utility Commission (PUC). Generally, PSC/PUC deal with problems or issues that the consumer feels were not solved by the utility, such as,

- Service installation and line extensions
- High bills
- Quality of service
- Meter tests
- Reasonable payment arrangements
- Outages
- Incorrect rates or tariffs
- Unauthorized switching of utility service from one

RECCOMENDATIONS FOR LEGISLATURES

With the intent to incorporate human rights into existing utility business models, it is critical that legislatures:

1. Amend legal definitions of "public interest" to incorporate additional aspects of human rights;
2. Establish policies mandating the principles and practices of the right to uninterrupted utility service;
3. Pass legislation that enables the advancement of energy efficiency and clean energy programs and technology;
4. Pass legislation that enables the advancement of energy independence;
5. Provide utility commissions with a clear public interest mandate to authorize and encourage commissions to regulate on new challenges and topics including climate change, rising energy costs, air pollution, new technologies, and racial discrimination.

Traditional and innovative public interests related to disconnection policies could include: the health, safety, and welfare of the public; consumer protection from monopoly market power; protection of low-income members of society; protection of socially vulnerable groups; protection of socioeconomic group who are disproportionately impacted by utility disconnections; enabling consumers to pay for utilities.

RECCOMENDATIONS FOR UTILITY CUSTOMERS AND CONSUMER ADVOCATES

As customers and advocates, our goal in the short term is to stop the suffering of vulnerable communities and those who face utility disconnection now. We as advocates who seek to secure disconnection policies that fall outside of traditional regulations and protect the right to uninterrupted utility services must:

1. Directly engage state and local legislatures before a commission will pass regulations;
2. Demand legislatures pass specific authorizations for these regulations;
3. Petition utilities and public utility commissions to adopt these principles;
4. Hold utilities accountable for supporting the human rights of customers by documenting and building the evidence of how human and civil rights are violated;
5. Partner with research institutions to conduct community participatory research;
6. Demand improved access to Public Utility Commission and regulatory meetings and proceedings;
7. Demand increased transparency of the operations of utility companies and their affiliates; and
8. Enforce the demand for policies and practices that protect human life through grassroots advocacy (e.g. consumer education, direct negotiations, lobbying, direct action, media campaigns, and litigation where necessary, etc.)

By recognizing energy as a basic need and human right, households would ideally be protected by moratoriums whereby energy services would remain available indefinitely, particularly for vulnerable households and customers. However, right now the goal is to end the current suffering of households that are energy insecure by adopting these principles. In advancing more humane disconnection practices, we must recognize that protections do not curb utility debt accumulation or provide indefinite protections from suffering. Households who experience chronic energy insecurity are not only subjected to shut-offs, but also face increased financial liabilities, exposure to additional health risks, and residential and economic instability.[140] The policies and strategies outlined here represent a movement toward a more humanistic utility model, however, we must exemplify the change we want to see. We must develop community solar gardens and engage in community aggregated choice, while advocating for policies that move communities toward energy sovereignty (e.g. energy efficiency, clean energy, distributed generation, local hire provisions, disadvantaged business enterprise, etc.).

Advocates of the George Wiley Center, RI
Source: George Wiley Center

BUILDING ON THE LEGACY OF CHANGE

In solidarity with organizations and initiatives nationwide, we seek to advance the conversation and action around the creation of utility models that work for consumers and the environment. We stand with those who have worked for decades before us to remove the ills of utility disconnections, including TURN: The Utility Reform Network in California, the George Wiley Center in Rhode Island, the Utility Reform Project in Oregon, New York's Utility Project in New York, the Committee Against Utility Shutoffs (CAUS) and Michigan Welfare Rights Organization (MWRO) in Michigan, and national organizations like the National Consumer Law Center, and the Consumer Federation of America, among others. The work of these and other organizations have saved lives and secured the safety of so many in the states and regions in which they advocate and beyond.

Members of the George Wiley Center have successfully secured the strongest child protection in the country. In Rhode Island, there are guaranteed utility service protections for households in financial hardship with children under two years old. The Center has also challenged the State's Division of Public directly through collective community action to institute Emergency Restoration of utility service to medically vulnerable

LEADING DISCONNECTION PROTECTION WORK NATIONWIDE

TURN-: The Utility Reform Network [CA]advocates for customers and assists them with understanding their bills and utility practices. The group holds utility corporations accountable by demanding fair rates, cleaner energy and strong consumer protections.

http://www.turn.org/

George Wiley Center [RI] organizes people from low-income communities to advocate for systematic change. One of the major campaigns is based on utility justice. The "Know Your Utility Rights" clinics educate consumers on their rights and how to challenge the Division of Public Utilities.

http://www.georgewileycenter.org/utilities

Utility Reform Project [OR]is asking for a reform of the entire utility system. The group wants the control of electric utilities to be in the hands of customers and their elected officials. They want just utility rates and fair billing practices.

http://utilityreform.org/index.htm

New York Utility Project [NY] is advocating for universal service, affordability, and customer protection for New York State utility consumers.

http://utilityproject.org/

Committee Against Utility Shutoffs (CAUS) [MI] is asking for the stop to utility shut offs and for DTE Energy's top executives and government regulators to be held accountable for utility related fires.

https://www.facebook.com/stopshutoffs/

households. These are protections all states should have in place.

In December 2015, New York's Utility Project filed an amicus brief in the United States Supreme Court in Hughes v. PPL EnergyPlus, LLC. The organization sought answers to the following:

> *Whether, when a seller offers to build generation and sell wholesale power on a fixed-rate contract basis, the Federal Power Act field-preempts a state order directing retail utilities to enter into the contract; and whether the Federal Energy Regulatory Commission's (FERC's) acceptance of an annual regional capacity auction preempts states from requiring retail utilities to contract at fixed rates with sellers who are willing to commit to sell into the auction on a long-term basis.*[141]

The Utility Project frequently engages in such legal action to ensure that utility action is in accordance with customer interests and rights.

The NAACP stands with these organizations in the pursuit of the elimination of the practice of utility service disconnection. While establishing and expanding protections is pressing, advocates must remember that the goal is much larger. Utility companies and their associates must be held accountable and be leaders in the transformation of the energy sector. Equity will not be achieved overnight. It will only be achieved through hard work on the part of us all.

LONG TERM VISION

It is crucial to remember that the reforms we are calling for and the tactics we use to achieve them are in the short term to address the emergency circumstances in which all too many households find themselves. In the long term, we must continue to push for systems change, including distributed generation and people owned, human rights centered utilities. It is time to not only eliminate the harmful utility practices, but to correct the extractive economy that we currently face.

Each of the deaths and suffering detailed in this report is an indictment against the companies who wielded power and ignored the cries for mercy in the heartless pursuit of profits, and against the legislators and regulators who failed to provide adequate leadership. In the short term, we can push for the reforms as detailed above. But they've had their chance and it's time for a total system revolution.

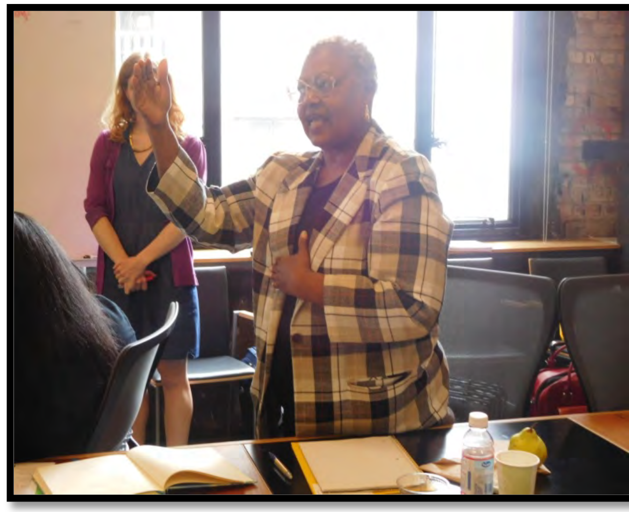
The fight against the extractive economy is not about making things better for people who are poor; it is about eliminating poverty, racism, and other social and structural inequities that render households vulnerable. In 2015, the U.S. energy sector made $178 billion from residential energy use alone. As we focus on eliminating poverty while ensuring energy security, one way of doing this is to reform the energy sector, a $6 trillion sector, by transitioning power to the people and anchoring the change in increased energy efficiency distributed generation of clean energy.

There is an opportunity to reinvent this sector, to create a shared economy and keep this money in the hands of citizens. Some individuals, households, and communities have begun to move toward energy sovereignty. Stories such as Amy Mays, (see story on Page 33, *From Persecuted by My Utility to Powered and Empowered by the SUN!)*, provide an example of what can be. It is time for a Just Transition to localized economies, grounded in ecological stewardship, community wellbeing, democratic decision-making, and locally control resources (Figure 6). [142]

Figure 6. A Just Transition, Source: Our Power Campaign, Climate Justice Alliance

VISION IN ACTION

FROM PERSECUTED BY MY UTILITY TO POWERED AND EMPOWERED BY THE SUN! - AMY MAYS, ARIZONA



Amy Mays telling her story at an NAACP Energy Justice Training in 2016

My story began in 1994 when I opened a beauty shop for my daughter. After we had been in business for four years, my troubles began with the local utility company, Salt River Project (SRP), when they required that I pay an additional deposit to continue to receive electricity services. I fought, but eventually ended up paying the additional deposit. Then, in June 2003, the utility company demanded a further deposit, even though I was current on all payments.

I contacted the Arizona State NAACP office and they convinced the utility company to reconnect the electricity if I paid a portion of the deposit. However, in August 2003, SRP again disconnected the electricity requesting the remainder of the deposit. We did not have the money so they turned off the electricity, which resulted in the closing of our nearly ten-year old business. Even though our service was terminated, with all payments up to date, the utility company inexplicably continued to demand payment for this completely illegitimate “bill.”

Since that bill from my closed business went “unpaid,” to add insult to injury, the utility company disconnected the electrical power to my home on April 8, 2004.From 2004 to 2006 I suffered without electricity, living out of my ice chest.

When I first heard about solar panels in 2006 I began reading everything I could about them. I searched online until I located a solar system designed for off-grid cabins. I ordered my first solar system for $5,000. As a trained electrician, I had the skills to install the panels myself. I purchased additional solar panels one or two panels at a time, and the necessary equipment for installation, until I had accumulated enough for an additional system, which I also installed myself. As I’ve gotten older, I’ve trained another electrician to help maintain my solar panel system.

Ten years later, now in 2016, my home is still not connected to the utility-operated grid. I haven’t paid an electricity bill since 2004, and the savings I have experienced as a result have been tremendous. Without an electricity bill to pay every month, my solar panels paid for themselves and I’ve been saving money ever since. I will never go back to the utility connection. Through my own rooftop solar panels, I have been liberated from the high rates the utility companies demand and the control they held over me!

With life threatening, high heat temperatures in Arizona, solar has literally saved my life!

I share my story with everyone I meet. In fact, my doctor was so inspired by my story that he recently had solar panels installed on his home. He, too, has been thrilled with his experience going solar and told me that last month his electricity bill has gone down to a mere $30.

It feels good to control my own power and not have to rely on the utility company for anything. I want people to know that if I can find independence through solar, then other people can do the same. The power from the sun is already there and always will be. Now people just need to find ways to use it!


NATIONAL ASSOCIATION FOR THE ADVANCEMENT OF COLORED PEOPLE
NAACP
FOUNDED
1909

Boosting Energy Efficiency through On-Bill Financing

The Environmental and Energy Study Institute's (EESI) on-bill financing initiative is a nationwide effort to help implement programs that cost-effectively cut energy use and expand clean energy access to more home homes and businesses. EESI has assembled a team that will assist utilities to design, implement, and evaluate residential meter-based on-bill financing programs. EESI will also assist rural utilities with applications to two U.S. Department of Agriculture loan programs – the Energy Efficiency Conservation Loan Program (EECLP), and the Rural Energy Savings Program (RESP) – to capitalize their projects.

EESI provides assistance to utilities looking to implement on-bill financing (OBF) projects. EESI's project team is available to:

- Share firsthand experience and lessons learned from developing utility OBF programs
- Conduct a needs assessment to determine if OBF is a good fit for the utility and its member-customers
- Identify resources and coordinate with stakeholders to overcome barriers to implementation
- Help utilities design a project and access capital for financing
- Help utilities navigate the EECLP and RESP application processes
- Assist utilities to implement and troubleshoot their projects

On-bill financing programs can vary wildly in their design. EESI's model for a successful on-bill financing program incorporates flexibility to meet local needs while maintaining the following design principles:

- Loan rates need to be set at or below five percent, with extended payback times, in order to increase the likelihood that the loans will be cash-flow positive participants
- Participants should not be required to make upfront payments for home improvements
- Programs need strong quality assurance plans that keep contractors accountable
- Programs should finance "whole house" sets of energy efficiency improvement measures to maximize cost-effective savings, with a utility advisor or other 3rd party providing guidance to participants on the package that best fits their needs
- In order to be better accessible to low-income households, programs have to offer alternative methods of loan underwriting (i.e., good bill payment history in lieu of a credit check)
- Loans should be affixed to the meter, not the individual

EESI is a nonprofit that currently has grant funding to provide technical assistance to utilities to design innovative and inclusive on-bill financing programs for their customers. EESI has helped more than 15 utilities to develop or improve their customized on-bill programs. Learn more at www.eesi.org/OBF or contact us directly.

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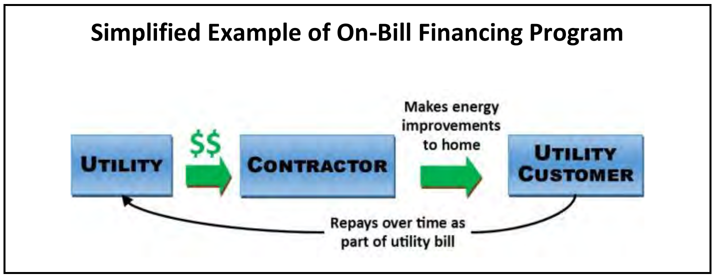
What is On-Bill Financing?



"On-bill financing" programs, in which utilities issue loans for energy improvements that are repaid as part of the utility bill, are an exciting opportunity to expand residential energy efficiency efforts around the country. Successful pilot models have shown that utilities of all types can use on-bill financing programs to significantly reduce peak demand, carbon emissions and fossil fuel use. By driving down the need for additional power generation, these programs can be a winning business strategy for utilities. On-bill financing programs can help alleviate poverty by reducing families' energy bills, while creating community-based jobs and economic growth by keeping energy dollars local and building demand for energy efficient products.

***Help My House* Pilot Program**

The "Help My House" pilot, implemented in 2011 and early 2012, produced very encouraging results among its 125 participating homes. Participants' energy bills were cut by 34 percent, saving an average of $288 per home per year after loan payments. "Help My House" was designed to address the special challenges and opportunities facing rural communities to save energy, cut household utility bills, and reduce greenhouse gas emissions, all while supporting high-skilled jobs and keeping more dollars in the local economy.

The pilot's innovative approach provided low-cost financing to co-op members for "whole house" efficiency upgrades, without upfront costs or traditional credit checks. Loans are attached to the meter and repaid over 10 years through charges on each participant's monthly bill. In most cases, monthly energy savings exceed the cost of loan payments. This improves participants' quality of life by increasing discretionary income and improving home comfort.

The comprehensive "whole house" approach, in which all of the energy efficiency measures were evaluated as part of the same system. Participating homes received a combination of air sealing, duct repair, HVAC upgrades, and insulation improvements. More than 95 percent of participants reported that they were more satisfied with their co-op after participating in the pilot.

Average "Help My House" Pilot Results	
Project Costs	$7,684
Annual kWh Savings	10,809 kWh
kWh % Savings	34%
Annual $ Savings	$1,157
Annual Loan Repayment	$869
Annual Net $ Savings	$288
Project Simple Payback	6.6 years
kWh Savings over 15 years	162,135 kWh
Net $ Savings over 15 years	$8,665

Loan capital for the pilot came primarily from a U.S. Department of Agriculture loan, supplemented by South Carolina co-op funds. Thanks in part to the success of the pilot, federal programs have been created to help co-ops around the country to develop similar programs. EESI assisted with the design and implementation of the pilot project, working in cooperation with The Electric Cooperatives of South Carolina (ECSC), the association representing the state's 20 distribution co-ops; and Central Electric Power Cooperative, the state's generation and transmission co-op. EESI participated in the "Help My House" pilot program in part to help develop a model that could be replicated by co-ops and other utilities across the country.

The value of lost energy sales to the electricity supplier and power provider depends on a number of factors. If the load shape improves and load factor increases, this could help offset the financial impact of reduced revenue on the co-op. The timing of new generation is another factor. Central's power providers are currently projected to have surplus generation capacity for the next 15 years, an unforeseen result of the drop in electricity demand growth that has occurred as a result of the economic downturn of the last several years. Unless there are significant rate, regulatory or other changes, reducing energy sales will not have the effect of deferring new generation resources for many years.

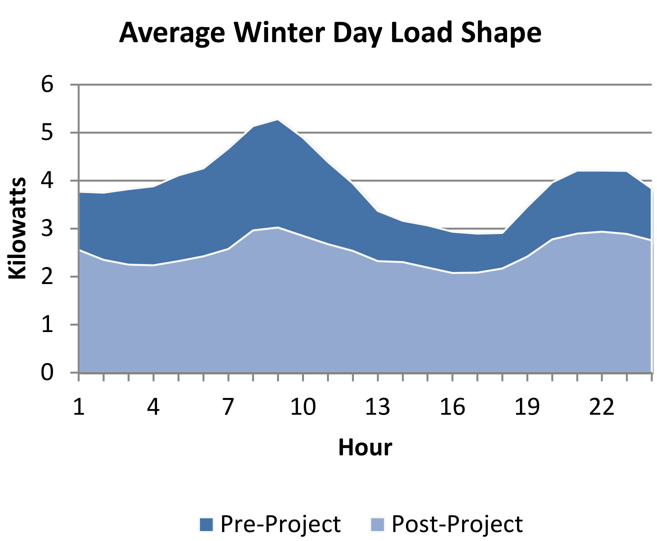
Demand Savings

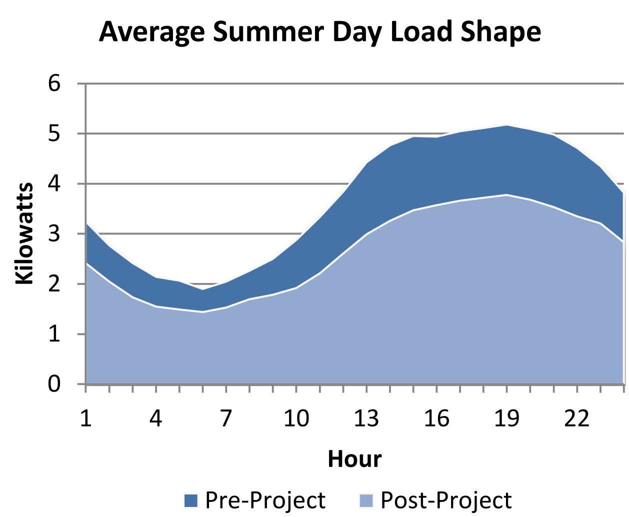
Residential users typically pay the same price per kWh regardless of when it is consumed, but the wholesale power that Central Electric purchases for its member co-ops consists of two components: an essentially flat energy charge across all hours and significant demand charges on monthly and annual peaks. The HMH pilot was designed, in part, to determine the effect of energy efficiency retrofits on peak consumption.

In the last several years, many of the homes served by co-ops in South Carolina have been equipped with advanced metering systems, which collect energy use data in hourly increments or even more frequently. Integral Analytics conducted an hourly billing data analysis on 48 of the 125 homes for which hourly use data was available in order to determine hourly savings during periods when the system was at peak demand.

The analysis models hourly use with hourly weather data, which enabled Integral Analytics to determine how the retrofits reduced energy use on the warmest summer days and the coldest winter days when the system was at peak demand. This model predicts how the retrofitted homes would perform during a typical meteorological day. The graphs below show the average hourly demand for each peak season. The difference between the pre-project line and the post-project line is the average hourly demand savings per home. The difference between the two lines over the entire year is the annual energy saved.

Figure 6 - Average Daily Load Shape by Season (kW)





The load shapes illustrate a substantial reduction in average use during peak hours. The reduced summer and winter loads make more efficient use of the distribution system, but the financial impact on the co-ops and the Central Electric system is determined by the load factor. Calculating load factor is a matter of dividing average energy by peak hourly demand. A higher load factor is desirable because it means the load is more constant. A more constant load is less expensive to serve because less money is needed to build or buy peak generation, transmission and distribution resources.

Integral Analytics conducted a billing data analysis on the homes with hourly data to calculate pre-project use during system peaks in a TMY. The table below shows what this model estimates the load factor to be before and after a HMH retrofit.

Table 9 - TMY Average Participant Load Factor Change (System Peak)

	Pre-Project (TMY weather normalized)			Post-project (TMY weather normalized)			Change in Load Fct
Month	**Avg kW**	**Peak kW**	**Load Fct**	**Avg kW**	**Peak kW**	**Load Fct**	
January	5.53	7.22	0.77	3.16	3.92	0.81	5%
February	4.74	6.74	0.70	2.82	3.75	0.75	7%
March	2.93	3.13	0.94	1.89	2.13	0.88	-5%
April	2.95	3.19	0.92	1.99	2.06	0.97	4%
May	2.87	3.99	0.72	2.01	3.04	0.66	-9%
June	3.52	5.08	0.69	2.48	3.70	0.67	-3%
July	3.76	5.03	0.75	2.69	3.66	0.73	-2%
August	3.52	4.54	0.78	2.48	3.12	0.79	2%
September	3.22	4.75	0.68	2.23	3.42	0.65	-4%
October	2.78	3.61	0.77	2.25	2.99	0.75	-2%
November	2.80	3.40	0.82	2.29	2.79	0.82	-1%
December	5.22	5.85	0.89	3.02	3.30	0.91	3%
Total			**0.78**			**0.78**	**0%**

Table 9 shows a reduction in average kW and peak kW occurring in all 12 months. Load factor, however, is a function of the relationship between average use and use during system peak. Use drops every month during the coincident peak, but the load factor increases in some months and decreases in other months. The net impact on load factor over the year is 0 percent. According to this analysis, homes that have undergone HMH retrofits would have no effect on system load factor.

The HMH pilot did not include any load management measures because doing so would have introduced additional variables into the analysis and weakened the co-ops' ability to draw conclusions on cost-effectiveness of the efficiency measures. The South Carolina co-ops have an existing demand reduction program which includes the installation of over 120,000 water heater switches and air conditioner control devices. To bring more value to the cooperatives and their members, demand reduction devices could be installed on homes receiving energy efficiency retrofits. A water heater switch reduces demand by 0.7kW in the winter time and 0.3kW in the summer. An air conditioner switch reduces the summer time peak an additional 1.0kW. Any combination of load reduction devices brings additional value to an efficiency retrofit program.

Value of Demand Savings

The residential member does not benefit directly from demand savings because the residential kWh rate is the same no matter when the electricity is used, and there is no demand charge. Several co-ops have time-of-use rates in the residential rate class, but they are rarely used by co-op members.

The distribution co-op, however, can benefit from demand savings. The value of demand savings to the co-ops is driven by wholesale power contracts that have significant demand components and can be as much as $15/kW per month. The price is higher for the power purchased during system peaks because Central pays more to suppliers during system peaks. Central buys most of its power from two generators: Santee Cooper and Duke Energy. The power they purchase consists of both monthly and annual demand charges on peak hours.

The analysis by Integral Analytics looked at demand during system peak hours each month and calculated a load factor, which is simply the average demand divided by peak demand. For a home to have a 100 percent load factor, it would use the same amount of energy for each hour of the year. The load factor for all South Carolina co-ops is 45 percent, which is below average compared to systems around the country.

For the distribution utility, reducing demand during coincident peak hours reduces expenditures for power purchase, and one to two kW per month in load management switches provide a counterbalance for some of the lost revenue that is caused by energy efficiency.

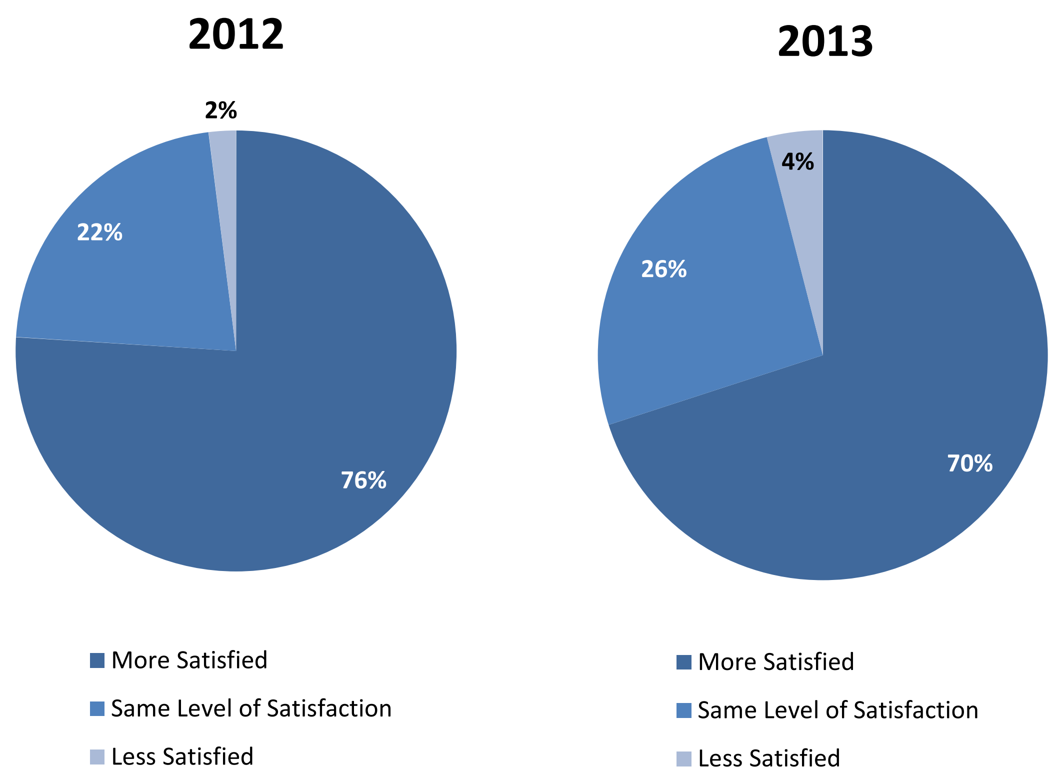
Member Satisfaction with the Pilot

Carton Donofrio Partners conducted two surveys after the HMH retrofits were complete. The first survey was conducted in early 2012, shortly after energy efficiency measures were installed but before participants had a good sense of how their homes were performing. This survey included participants as well as co-op members who knew of the pilot but did not participate. The second survey was conducted in March and April of 2013, a full year after the HMH homes had been retrofitted, and included only those consumers who participated in and completed the program.

The first survey provides a view into the opinions of both the participants and those who had been contacted about the pilot but did not participate. The vast majority (92 percent) of co-op members contacted about the pilot had the same or higher satisfaction with their co-op as a result of being contacted. Seventy-four percent of non-participants felt the same or higher satisfaction as a result of the program. This number is surprisingly high considering the fact that many of the members contacted about the program were on a high bill complaint list. The few non-participants who were less satisfied were disappointed that their homes did not qualify for the pilot despite high energy bills.

Both surveys asked participants about the level of satisfaction with the co-op compared to one year prior. Ninety-eight percent of the participants surveyed in 2012 had the same or higher level of satisfaction with the co-op compared to the previous year. In the 2013 survey, this number dropped slightly to 96 percent.

Figure 7 - HMH Participants Overall Co-op Satisfaction Compared to Year Before



Nearly all participants (96 percent) in the 2012 survey were satisfied with the installation of the efficiency measures. The same percentage of participants (96 percent) responded that they felt their homes were more comfortable after the improvements. The second survey reaffirmed the findings of a year earlier. In fact, 70 percent of program participants showed they are even more satisfied one year later.

Comfort is likely an important reason for this high level of satisfaction. After living in their newly efficient homes for a full year, 76 percent of program participants say their homes are a lot more comfortable, while an additional 13 percent say their homes are somewhat more comfortable.

In addition, participants are generally happy about their energy bills. Specifically, 89 percent of participants are either somewhat satisfied or very satisfied with post-retrofit electricity bills.

NIPSCO Public Advisory Meeting 3 Registered Participants		
First Name:	Last Name:	Company:
Denise	Abdul-Rahman	Indiana State Conference of the NAACP
Robert	Adams	AES-IPL
Lauren	Aguilar	OUCC
Anthony	Alvarez	OUCC
Mark	Anderson	Anderson & Anderson, PC
Laura	Arnold	Indiana Distributed Energy Alliance (IndianaDG)
Heidi	Aschbacher	Invenergy
Pat	Augustine	Charles River Associates
Kim	Ballard	IURC
Mike	Banas	NiSource
Alison	Becker	NIPSCO
Anne	Becker	Lewis Kappes
Richard	Benedict	Self
Mahamadou	Bikienga	NiSource
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	IURC
Wendy	Bredhold	Sierra Club
Jeffrey	Brooks-Gillies	Freelance reporter
Kelly	Carmichael	NiSource
Kathleen	Castilloux	Beckwith Electric Co, Inc
Peter	Cavan	Centrica
Michael	Cella	Toyota Tsusho
Richard	Ciciarelli	Guggenheim
Paul	Ciesielski	ArcelorMittal USA LLC
Jeffrey	Corder	St. Joseph Phase II, LLC
Nicklaus	Corder	EnFocus Development
Bette	Dodd	Lewis Kappes
Jeffery	Earl	Indiana Coal Council
Claudia	Earls	NiSource
Amy	Efland	NiSource/NIPSCO
Gregory	Ehrendreich	MEEA
Andrew	Fay	First Solar
Steve	Francis	Sierra Club - Hoosier Chapter
Doug	Gotham	State Utility Forecasting Group
Robert	Greskowiak	Invenergy LLC
Barry	Halgrimson	Retired
Allison	Holly	GE
Shelby	Houston	IPL/AES
James	Huston	Indiana Utility Regulatory Commission
Ben	Inskeep	EQ Research
Francisco	Itriago	IPL
Lynn	Jensen	Marathon Petroleum Company LP
Alex	Jorck	Whole Sun Designs Inc
Sam	Kliewer	Cypress Creek Renewables
Corey	Kupersmith	Sun2O Partners

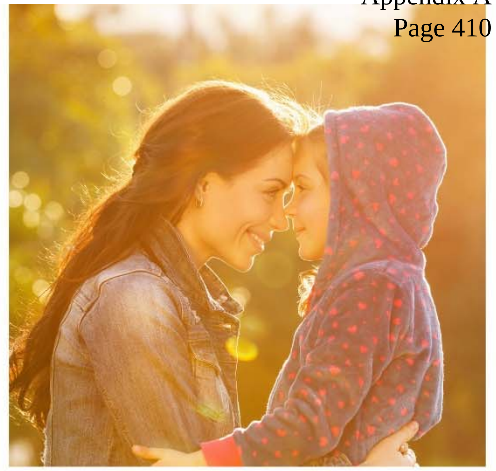
Attachment 2-A

NIPSCO Public Advisory Meeting 3 Registered Participants		
First Name:	Last Name:	Company:
Willard	Ladd	Development Partners
Tim	Lasocki	Orion Renewable Energy Group LLC
Joe	Lesches	Stone Capital
Jonathan	Mack	NIPSCO
Patrick	Maguire	Indianapolis Power and Light
James	Mangrum	Arcelor Mittal
Cyril	Martinand	ArcelorMittal
Christian	Martinez	First Solar
Karen	McCoy	Nipsco
Cassandra	McCrae	Earthjustice
Jim	McMahon	CRA
Emily	Medine	EVA
Zachary	Melda	NextEra Energy Resources
Nick	Meyer	NIPSCO
Ana	Mileva	Blue Marble Analytics
Troy	Miller	GE Power
Kevin	Moore	MIDWEST WIND & SOLAR LLC
David	Nderitu	State Utility Forecasting Group
Adam	Newcomer	NIPSCO
Mark	Noll	Charles River Associates
April	Paronish	Indiana Office of Utility Consumer Counselor
Bob	Pauley	IURC
Pamela	Paultre	NextEra Energy Resources
Jodi	Perras	Sierra Club
Carmen	Pippenger	IURC
Geof	Potter	None
Mark	Pruitt	The Power Bureau
Dennis	Rackers	Energy & Environmental Prosperity Works!
Thom	Rainwater	Development Partners Group
Jeff	Reed	OUCC
Emily	Rhodes	Delta Institute
Matt	Rice	Vectren
Adam	Rickel	NextEra Energy Resources LLC
Tonya	Rine	Vectren Corporation
Woody	Saylor	St Joseph Energy Center
Carter	Scott	Ranger Power LLC
Cliff	Scott	NIPSCO
Rob	Seren	NIPSCO
Julie	Shea	NiSource
Regiana	Sistevaris	Indiana Michigan Power Company
Violet	Sistovaris	NIPSCO
Anna	Sommer	Sommer Energy, LLC
Dick	Spellman	GDS Associates, Inc.
Jennifer	Staciwa	NIPSCO
Karl	Stanley	NiSource

NIPSCO Public Advisory Meeting 3 Registered Participants		
First Name:	Last Name:	Company:
Liz	Stanton	Applied Economics Clinic
Brian	Steinkamp	PSG Energy Group
Bruce	Stevens	Indiana Coal Council
George	Stevens	I U R C
Alice	Thare	peabody
Dale	Thomas	IURC
Bob	Veneck	Indiana Utility Regulatory Commission
Victoria	Vrab	NIPSCO
Victoria	Vrab	NIPSCO
John	Wagner	NIPSCO
Jennifer	Washburn	CAC
Keith	Weber	NiSource
Tyler	Welsh	PSG ENERGY GROUP, LLC
Ashley	Williams	Sierra Club
Bryndis	Woods	Applied Economics Clinic
Fang	Wu	SUFG
Rex	Young	Cooperative Solar LLC

Appendix A

Exhibit 4



NIPSCO Integrated Resource Plan 2018 Update

Technical Webinar

August 28, 2018

NIPSCO

NiSource

Welcome and Introductions

Process for Today’s Webinar

- In order to best facilitate today’s discussion, we are asking that you use the “chat” feature on the webinar to ask questions.
- Please type your question at any point and it will be read to the audience by the facilitator.
- When entering your question, please include your name and organization you are representing (if applicable).
- After the material has been presented, we will allow for additional discussion as time permits.
- You may also email questions to nipsco_irp@nisource.com and those questions will be answered as they are received.
- We look forward to your thoughts and questions!

Agenda

Time (CENTRAL TIME)	Topic
1:00 – 1:15	Welcome, Introductions, and Safety Moment
1:15 – 2:15	Incorporating the RFP Results into the IRP
2:15 – 2:30	Next Meeting / Wrap Up

Incorporating the RFP Results into the IRP

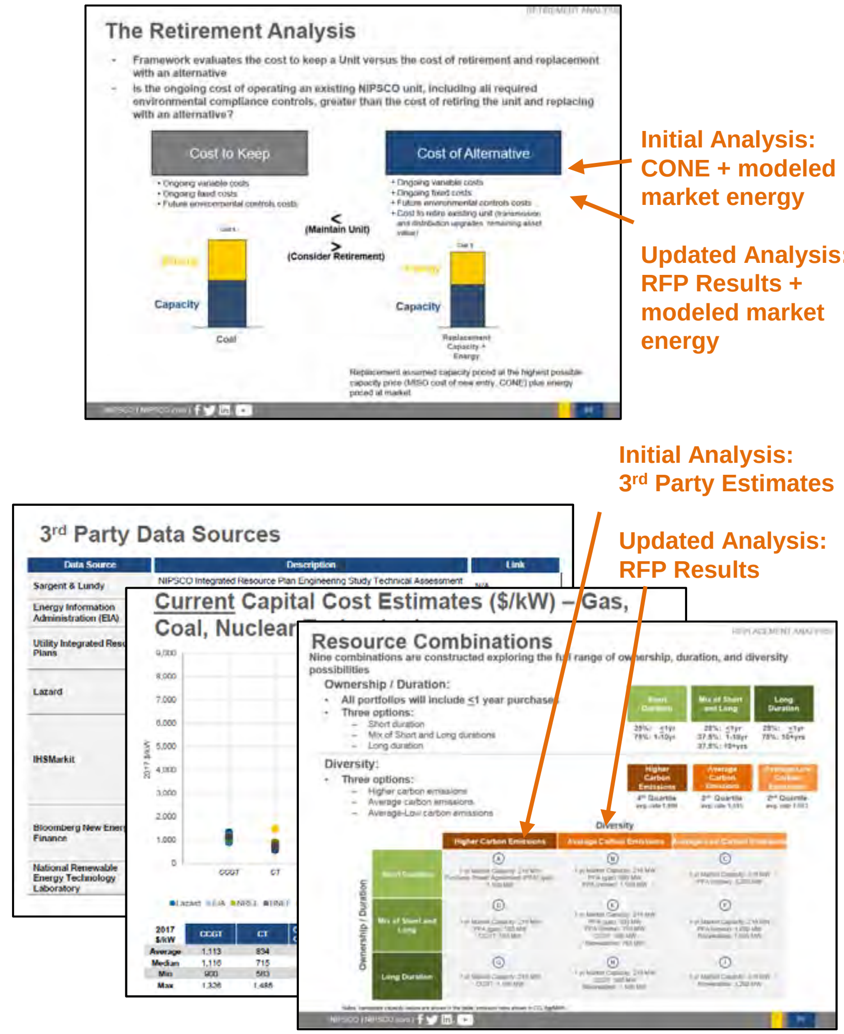
Pat Augustine
Charles River Associates (CRA)

Recap: How Will The RFP Feed Into The IRP?

The results of the RFP will feed back into the IRP to inform both the retirement analysis and the replacement analysis

- **Retirement Analysis**
  - MISO Cost of New Entry ("CONE") plus market energy was used in the initial IRP analysis as a proxy for replacement costs
  - RFP results provide known and visible replacement costs and volumes
  - Representative project groups will be constructed from RFP results, assembled by technology and ownership, for use in the updated IRP analysis
  - Retirement analysis will be re-run using the representative RFP projects as selected by the optimization model

- **Replacement Analysis**
  - Initial IRP replacement costs used estimates from multiple third-party data sources; no visibility into actual replacement costs for projects available to NIPSCO
  - RFP results provide visibility into executable alternatives for NIPSCO
  - Replacement analysis will be run using somewhat simplified and anonymized RFP results



Why Organize Bids into Representative Groups or Tranches?

- **The IRP is intended to evaluate and select the best <u>resource mix (technology)</u> and future <u>portfolio constructs</u>, and *not* to select specific assets or projects**
  - While now highly informed by current and actionable RFP data, the IRP is meant to develop a planning-level recommended resource strategy (Preferred Plan)
  - Asset-specific selection requires an additional level of diligence (assessment of development risk, locational advantages or disadvantages, transmission system impacts, etc.)
- **The IRP is a highly transparent and public process that requires sharing of major inputs with all stakeholders**
  - Evaluating asset specific options from the RFP raises confidentiality concerns as that could reveal bid specific cost and technology data which bidders typical consider as proprietary and confidential information
- **The IRP modeling is complex, and resource grouping improves the efficiency of the process**
  - Resource evaluation requires organizing large amounts of operational and cost data into IRP models, so a smaller aggregate data set improves the efficiency of setup and run time

IRP Analysis: Tranche Development and Assessment

- A three-step process to update and run the IRP models is currently in process

1 Tranche Development

Aggregate Bids into Groupings by Type

- Bids are organized by:
  - Technology
  - Asset sale or PPA
  - Commitment duration
  - Costs
  - Operational characteristics
- Aggregated cost and operational information is entered into Aurora model to be considered in optimization step

2 Portfolio Optimization

Select Portfolios

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

Confirm Viability

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

3 Portfolio Creation and Modeling

Create & Analyze Portfolios Based on Optimization

- Tranches are chosen for retirement and replacement analysis based on % selected by optimization model when confirmed as viable
- Portfolios are then run across full set of scenarios and stochastics

❶ Tranche Development

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

Representative and Illustrative

PPA Solar Tranche Example

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)		Online Year	PPA Term (years)	Price*	Capacity Factor
Bid 1	Solar	-	-	•••	2023	20	$27.xx	-
Bid 9	Solar	275	138		2023	20	$32.00	24%
Bid 10	Solar	100	50		2023	20	$34.00	24%
Bid 11	Solar	75	38		2023	20	$34.00	23%
Bid 12	Solar	25	13	•••	2023	20	$35.00	24%
Bid 13	Solar	500	250		2023	25	$35.00	25%
Bid 26	Solar	-	-		2023	20	$73.xx	-

Tranche Name	Tranche Type	# of Resources	ICAP (MW)	UCAP (MW)	Online Year	PPA Term (weighted average years)	Price (weighted average)	Capacity Factor (weighted average)
Indiana Solar #3	Solar	5	975	488	2023	23	$33.93	24.2%

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

❶ Tranche Development

- Some technology types have multiple bids with the same project, requiring tranches to be developed for PPA and asset sale options and for different durations, as necessary

Representative and Illustrative

CCGT Tranche Example

PPA

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)*	Online Year	PPA Term (years)
PPA Bid 1	CCGT	250	250	2023	6
PPA Bid 2	CCGT	625	575	2023	30
PPA Bid 3	CCGT	625	625	2023	30
PPA Bid 4	CCGT	725	700	2023	20
PPA Bid 5	CCGT	600	600	2023	30

Tranche Name	# Of Resources	ICAP (MW)	UCAP (MW)	Online Year	PPA Term (years)	Cost range** ($/kW-mo)
PPA CCGT #1	1	250	250	2023	6	
PPA CCGT #2	4	2,575	2,500	2023	27	

Sale

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)*	Online Year
Sale Bid 1	CCGT	625	625	2023
Sale Bid 2	CCGT	625	625	2023
Sale Bid 3	CCGT	1,025	925	2023
Sale Bid 4	CCGT	725	700	2023

Tranche Name	# Of Resources	ICAP (MW)	UCAP (MW)	Online Year	Price Range** ($/kW)
Sale CCGT #1	2	1,250	1,250	2023	
Sale CCGT #2	2	1,750	1,750	2023	

*Capacity is rounded to the nearest 25 MW.
**Given the small number of projects within each CCGT tranche, PPA costs and asset sale prices are not being shown to preserve confidentiality. Note that PPAs were structured as tolling arrangements with fixed cost capacity payments (in $/kW-mo) plus certain variable charges (in $/MWh).

❷ Portfolio Optimization and Selection

- **Optimization modeling allows for portions of tranches containing multiple resources to be selected**
  - After the optimization step, CRA confirms that resource selection is reasonable given available resources in tranche

Representative and Illustrative

Sample Optimization Model Output (Percentage Selected)				
Tranche Name	Illustrative 2023 Retirement Portfolio			
	No Retirements	Schahfer 17/18 Retires	All Schahfer Retires	All Schahfer + Michigan City Retire
Indiana Solar + Storage #2 (PPA)		100%	100%	100%
Indiana Solar + Storage #3 (PPA)			100%	100%
Indiana Solar #2 (PPA)		96%	100%	100%
Indiana Solar #3 (PPA)			100%	100%
Indiana Solar #4 (PPA)			8%	70%
Indiana Wind #1 (PPA)		83%	83%	83%
Indiana Wind #2 (PPA)		57%	57%	57%

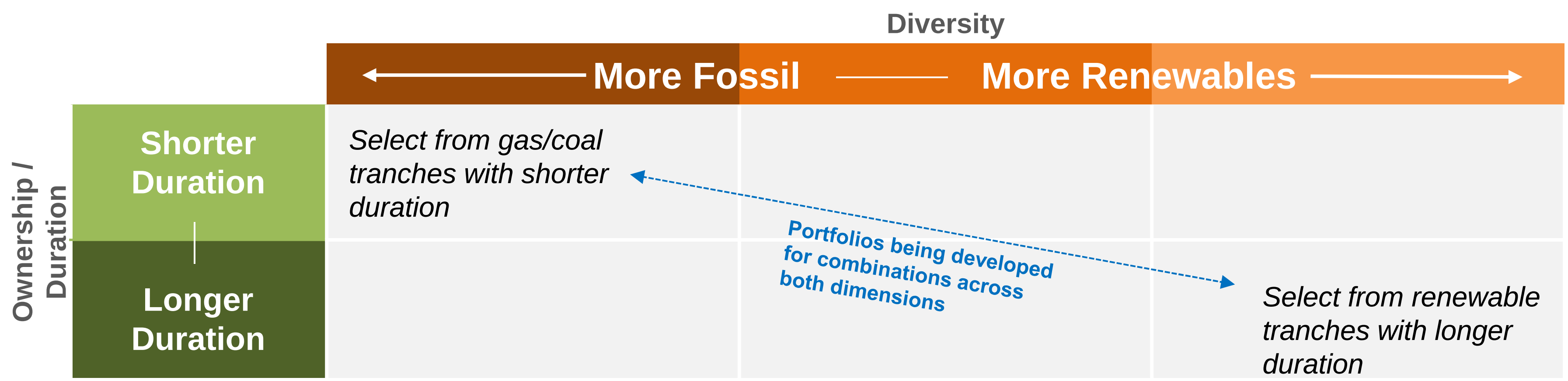
Confirm viability based on resources in tranche when portions are selected*

- Indiana Solar #4:
  - 8% of Indiana Solar #4 tranche is ~100 MW of nameplate solar, a reasonable block size for this technology and tranche based on the bids within it
- Indiana Wind #1:
  - 5 unique resources in tranche, 4 least expensive bids make up 89% of tranche, close to optimization model selection of 83%

*The optimization model may select only portions of a tranche, due to capacity need, reserve margin constraints, and other economic factors.

❸ Detailed Portfolio Creation

- **Portfolio optimization, using the tranches as resource options, is now being performed for both the retirement and replacement analyses to:**
  - Fill retirement gaps (MW) across different retirement portfolios (as shown in the illustrative example in the previous slide)
  - Build out replacement options across duration and diversity (emissions) matrix to test full range of portfolio alternatives, as shown below)



- **IRP will evaluate performance of each portfolio across *all* scorecard metrics**
- **Further narrowing down and modeling of bid-specific costs and parameters at the asset-level to be completed <u>in later RFP selection process</u>**

How UCAP Was Determined From RFP Bid Data

MISO UCAP Determination By Resource Type

- **UCAP is based on historical unit availability**
  - This accounts for forced outages and derates on most resource types
  - Renewables and other types of intermittent resources are awarded UCAP based on historical average output during the summer for hours ending 15, 16, and 17 EST
  - New resources are awarded UCAP based on class averages by resource type until historical information is available

UCAP Calculation Methodology For IRP

- **For projects with operating history, actual UCAP data was used if provided**
- **For new projects, CRA and NIPSCO have used MISO rules based on unit type:**
  - Fossil units are de-rated based on a forced outage rate provided
  - Intermittent renewables are applied class-specific de-rates for generic technologies
  - Storage resources are assumed to provide full capacity credit if they can meet 4-hour peak

MISO Planning Year 2018-2019
Pooled EFORd Class

Resource Type	Average UCAP (%)
Combined Cycle (CCGT)	95
Combustion Turbine	71 - 94
Nuclear	91
Pumped Storage	91
Steam - Coal	92
Steam - Gas	88
Steam - Oil	91
Steam - Waste Heat	91
Steam - Wood	91
Hydro	91
Wind	15
Solar	50 - ?

<table>
<tr><th colspan="6">Illustrative Example For New Projects</th></tr>
<tr><th>Resource Type</th><th colspan="3">Capacity Offered (ICAP)</th><th>Calculation Example</th><th>Resulting UCAP</th></tr>
<tr><td>CCGT</td><td colspan="3">100 MW</td><td>100 * (1 – .05)</td><td>95 MW</td></tr>
<tr><td>Wind</td><td colspan="3">100 MW</td><td>100 * (0.15)</td><td>15 MW</td></tr>
<tr><td>Solar</td><td colspan="3">100 MW</td><td>100 * (0.5)</td><td>50 MW</td></tr>
<tr><td>Solar + Storage</td><td colspan="2">100 MW solar</td><td>30 MW storage</td><td>100 * (0.5) + 30</td><td>80 MW</td></tr>
<tr><td>Wind + Storage</td><td colspan="2">100 MW wind</td><td>30 MW storage</td><td>100 * (0.15) + 30</td><td>45 MW</td></tr>
<tr><td>Wind + Solar + Storage</td><td>100 wind</td><td>100 solar</td><td>30 MW storage</td><td>100 * (0.15) + 100 * (0.5) + 30</td><td>95 MW</td></tr>
</table>

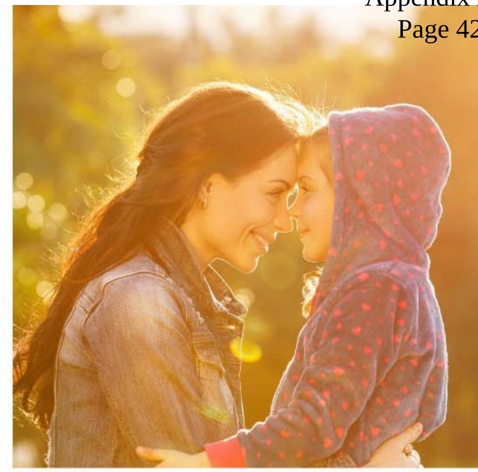
Next Steps / Wrap Up

NIPSCO Public Advisory Technical Webinar Registered Participants		
First Name:	Last Name:	Company:
Denise	Abdul-Rahman	Indiana State Conference of the NAACP
Robert	Adams	AES-IPL
Anthony	Alvarez	OUCC
Laura	Arnold	Indiana Distributed Energy Alliance (IndianaDG)
Heidi	Aschbacher	Invenergy
Kim	Ballard	IURC
Anne	Becker	Lewis Kappes
Michaela	Bell	PSG ENERGY GROUP, LLC
Mahamadou	Bikienga	NiSource
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	IURC
Wendy	Bredhold	Sierra Club
Kelly	Carmichael	NiSource
Michael	Cella	Toyota Tsusho
Jeffrey	Corder	St. Joseph Phase II, LLC
Nicklaus	Corder	EnFocus Development
Jeffery	Earl	Indiana Coal Council
Amy	Efland	NiSource/NIPSCO
Steve	Francis	Sierra Club - Hoosier Chapter
Richard	Gillingham	Hoosier Energy
Doug	Gotham	State Utility Forecasting Group
Robert	Greskowiak	Invenergy LLC
Barry	Halgrimson	Retired
Jeffrey	Hammmons	Environmental Law & Policy Center
Rina	Harris	Vectren
John	Haselden	OUCC
Shelby	Houston	IPL/AES
Jim	Huston	Indiana Utility Regulatory Commission
Ben	Inskeep	EQ Research
Dave	Johnston	Indiana Utility Regulatory Commission
Alex	Jorck	Whole Sun Designs Inc
Will	Kenworthy	Vote Solar
Mark	Kornhaus	NextEra Energy
Stefanie	Krevda	Indiana Utility Regulatory Commission
Tim	Lasocki	Orion Renewable Energy Group LLC
Tracy	Leslie	EPRI
Patrick	Maguire	Indianapolis Power and Light
Christian	Martinez	First Solar
Emily	Medine	EVA
Zachary	Melda	NextEra Energy Resources
Adam	Newcomer	NIPSCO
April	Paronish	Indiana Office of Utility Consumer Counselor
Bob	Pauley	IURC
Timothy	Powers	Inovateus Solar LLC
Dennis	Rackers	Energy & Environmental Prosperity Works!

NIPSCO Public Advisory Technical Webinar Registered Participants		
First Name:	Last Name:	Company:
Thom	Rainwater	Development Partners Group
Jeff	Reed	OUCC
Tonya	Rine	Vectren Corporation
Woody	Saylor	St Joseph Energy Center
Zachary	Scott	PSG Energy Group
Julie	Shea	NiSource
Isabella	Solari	PSG Energy Group
Jennifer	Staciwa	NIPSCO
Brian	Steinkamp	PSG Energy Group
Bruce	Stevens	Indiana Coal Council
Alice	Tharenos	peabody
William	Vance	Indianapolis Power & Light
Nathan	Vogel	Inovateus Solar
Jennifer	Washburn	CAC
Tyler	Welsh	PSG ENERGY GROUP, LLC
Rex	Young	Cooperative Solar LLC
Jim	Zucal	NIPSCO

Appendix A

Exhibit 5



NIPSCO Integrated Resource Plan - 2018 Update

Public Advisory Meeting Four

September 19, 2018

NISource

NIPSCO

Welcome and Introductions

- Introductions
- Welcome from Violet Sistovaris, President, NIPSCO and Executive Vice President, NiSource

Process for Participating Via Webinar

- In order to best facilitate today's discussion, we are asking that you use the "chat" feature on the webinar to ask questions
- Please type your question at any point and it will be read to the audience by the facilitator
- When entering your question, please include your name and organization you are representing (if applicable)
- You may also email questions to nipsco_irp@nisource.com and those questions will be answered as they are received
- We look forward to your thoughts and questions

Agenda

Time	Topics
9:30-9:45	Welcome and Introductions • Safety Moment
9:45-10:15	How Does NIPSCO Plan For The Future? • Public Advisory Process
10:15-10:30	Energy and Demand Forecast Update
10:30-10:45	Break
10:45-11:45	Modeling Uncertainty: 2018 Integrated Resource Plan Scenarios and Risk Analysis (Stochastics)
11:45- 12:30	Lunch
12:30-1:15	Retirement Analysis • Retirement Framework • Scenario Results • Risk Analysis (Stochastics) Results • Retirement Scorecard
1:15-2:00	Replacement Analysis • Incorporating Demand-Side Management • Incorporating the Results from the Request for Proposals (“RFP”) • Scenario Results • Risk Analysis (Stochastics) Results • Replacement Scorecard
2:00-2:15	Break
2:15-2:30	Stakeholder Requested Scenario Results
2:30-3:00	Stakeholder Presentations and Wrap Up

Safety Moment

Safe Driving

- **Each year there are more than 40,000 deaths nationwide related to motor vehicle crashes**

- **Top three causes of motor vehicle accidents**
  - Distracted or inattentive driving
  - Speeding
  - Impairment (drugs or alcohol)

- **Other Rules to Follow**
  - Pull through or back into parking spaces
  - Perform a 360 walk-around
  - Adjust your driving based on weather conditions

NIPSCO's Planning and the Public Advisory Process

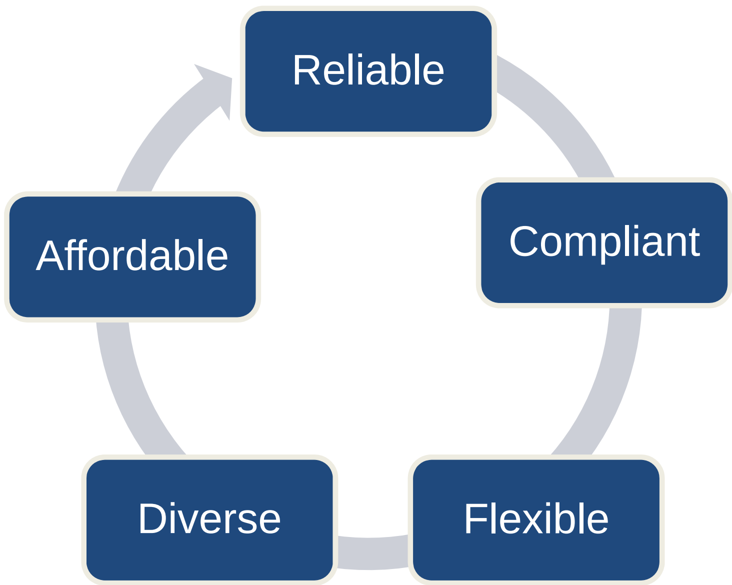
Dan Douglas
Vice President, Corporate Strategy & Development

How Does NIPSCO Plan for the Future?

Charting The Long-Term Course for Electric Generation

About the IRP Process

- Every three years, NIPSCO outlines its long-term plan to supply electricity to customers over the next 20 years
- This study – known as an Integrated Resource Plan ("IRP") – is required of all electric utilities in Indiana
- IRP process includes extensive analysis of a range of generation scenarios, with criteria such as reliable, affordable, compliant, diverse and flexible



Requires careful planning and consideration for all of NIPSCO's stakeholders including the communities we serve and our employees

Overview of the Public Advisory Process

- **Today's meeting is the fourth out of five meetings**
  - Two in-person meetings and one webinar so far
  - Additional technical webinar added at stakeholder request
  - Presentation materials and summary meeting notes are posted on NIPSCO's IRP webpage: www.nipsco.com/irp
- **The Public Advisory process provides NIPSCO with feedback on our process, assumptions and conclusions. This helps inform the modeling and the overall IRP results**
- **Your participation and candid feedback is key to the process**
  - Please ask questions and provide comments on the material being presented and the process itself to ensure this is a valuable exercise for NIPSCO and its customers
- **Ability to make presentations as part of each Public Advisory meeting**
  - If you wish to make a presentation today and have not already indicated so, please see Alison Becker during break or at lunch

Stakeholder Engagement Roadmap

	Meeting 1 (March 23)	Meeting 2 (May 11)	Meeting 3 (July 24)	Technical Webinar (August 28)	Meeting 4 (September 19)	Meeting 5 (October 18)
Key Questions	- Why has NIPSCO decided to file an IRP update in 2018? - What has changed from the 2016 IRP? - What are the key assumptions driving the 2018 IRP update? - How is the 2018 IRP process different from 2016?	- What is NIPSCO existing generation portfolio and what are the future supply needs? - Are there any new developments on retirements? - What are the key environmental considerations for the IRP? - How are DSM resources considered in the IRP?	- What are the preliminary results from the all source RFP Solicitation?	- How are the RFP results integrated into the IRP modeling?	- What are the preliminary results from the modeling and how do they inform the retirement and replacement decisions? - What is the “most viable” retirement and replacement path? - What is NIPSCO’s forecasted customer demand? - How is NIPSCO modeling risk and uncertainty in the IRP?	- What is NIPSCO’s preferred plan? - What is the short term action plan?
Meeting Goals	- Communicate and explain the rationale and decision to file in 2018 - Articulate the key assumptions that will be used in the IRP - Explain the major changes from the 2016 IRP - Communicate the 2018 process, timing and input sought from stakeholders	- Common understanding of DSM resources as a component of the IRP and the methodology that will be used to model DSM - Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap - Key environmental issues in the IRP	- Communicate the preliminary results of the RFP and next steps	- Explain the process for integrating the results from the RFP into the IRP modeling for both the retirement and replacement analysis?	- Share with stakeholders most viable retirement path and most viable replacement portfolios - Explain how NIPSCO is modeling risk and uncertainty in the IRP - Communicate NIPSCO forecasts for customer demand	- Communicate NIPSCO’s preferred resource plan and short term action plan - Obtain feedback from stakeholders on preferred plan

Stakeholder Interactions

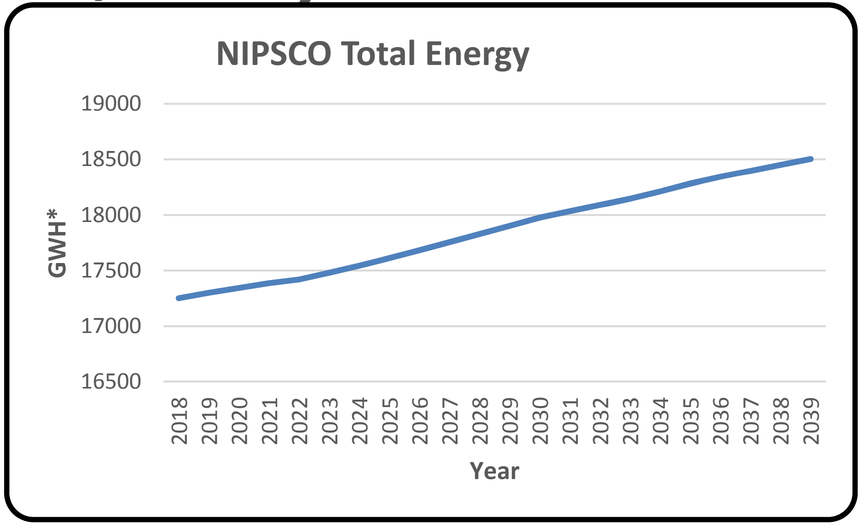
- So far during the IRP process, NIPSCO has met with and responded to requests from stakeholder groups

Stakeholder	Subject Area/Discussion Topic
Sierra Club	IRP Modeling and Scenarios
Office of Utility Consumer Counselor (“OUCC”)	All-Source RFP, IRP Modeling and Scenarios, Load Forecasting
Citizens Action Coalition of Indiana, Inc. (“CAC”)	IRP Modeling and Demand Side Management (“DSM”)
Indiana Utility Regulatory Commission (“IURC”)	All-Source RFP and IRP Modeling
NIPSCO Industrial Group	All-Source RFP and IRP Modeling
Indiana Coal Council	Scenario/Portfolio Requests
NAACP of Indiana	DSM and On-Bill financing

Energy and Demand Forecast Update

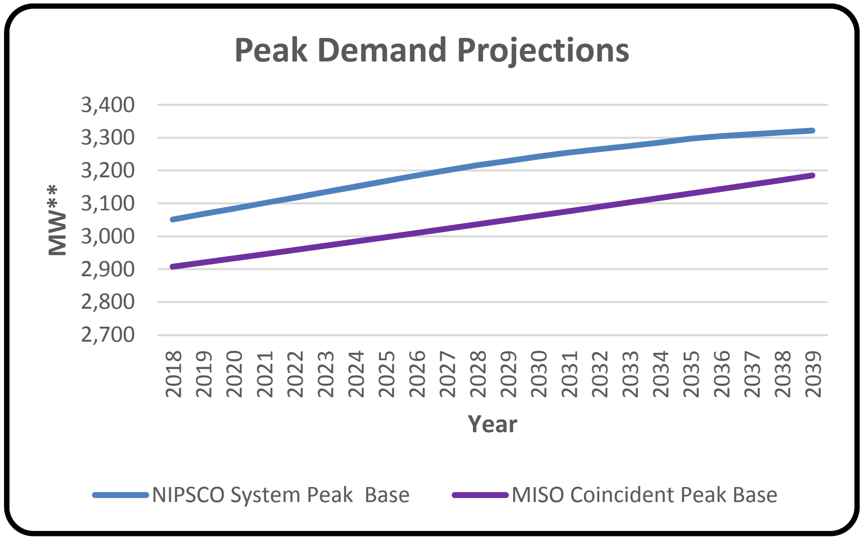
Amy Efland
Manager, Demand Forecasting

Load Forecasts (Originally Presented March 23, 2018)



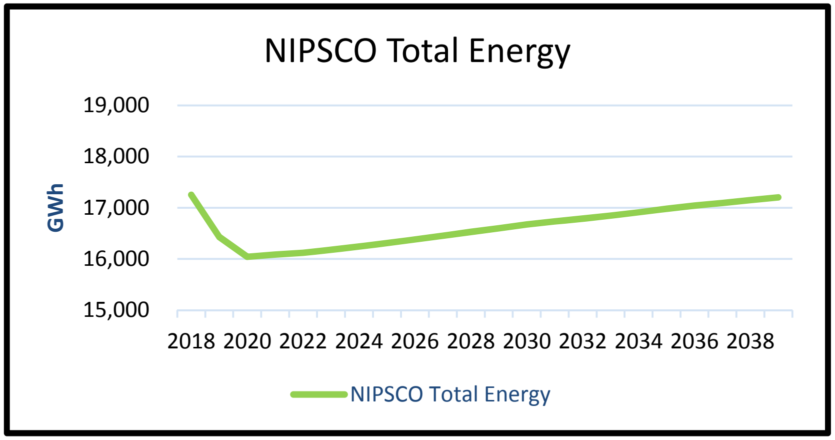
Energy Requirement Projections	2018-2039 CAGR***
NIPSCO Total Energy	0.33%
NIPSCO System Peak	0.41%
MISO Coincident Peak	0.44%

*GWH:	Gigawatt hour
**MW:	Megawatt
***GAGR:	Compound Annual Growth Rate

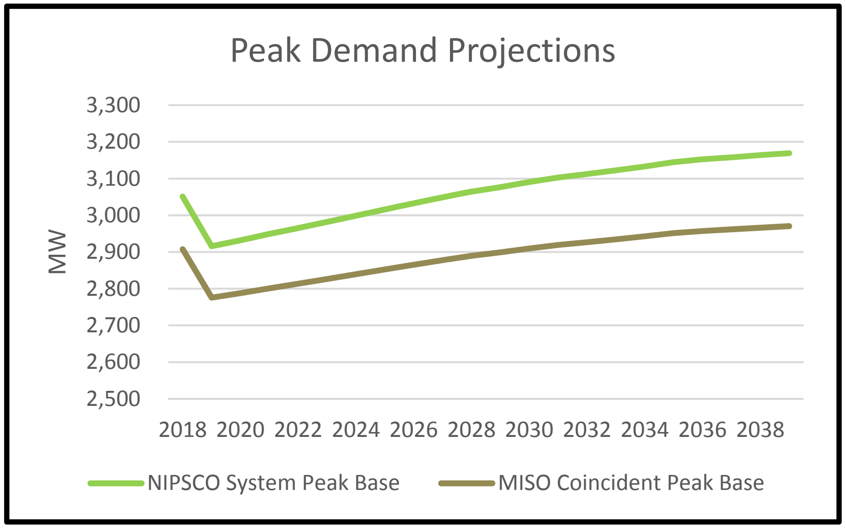


$$\frac{\textit{MISO Coincident Peak}}{\textit{NIPSCO System Peak}} = \sim 95\%$$

Base Case Update: Change In Large Industrial Customer Demand



Energy Requirement Projections	2018-2039 CAGR*
NIPSCO Total Energy	0%
NIPSCO System Peak	0.2%
MISO Coincident Peak	0.1%

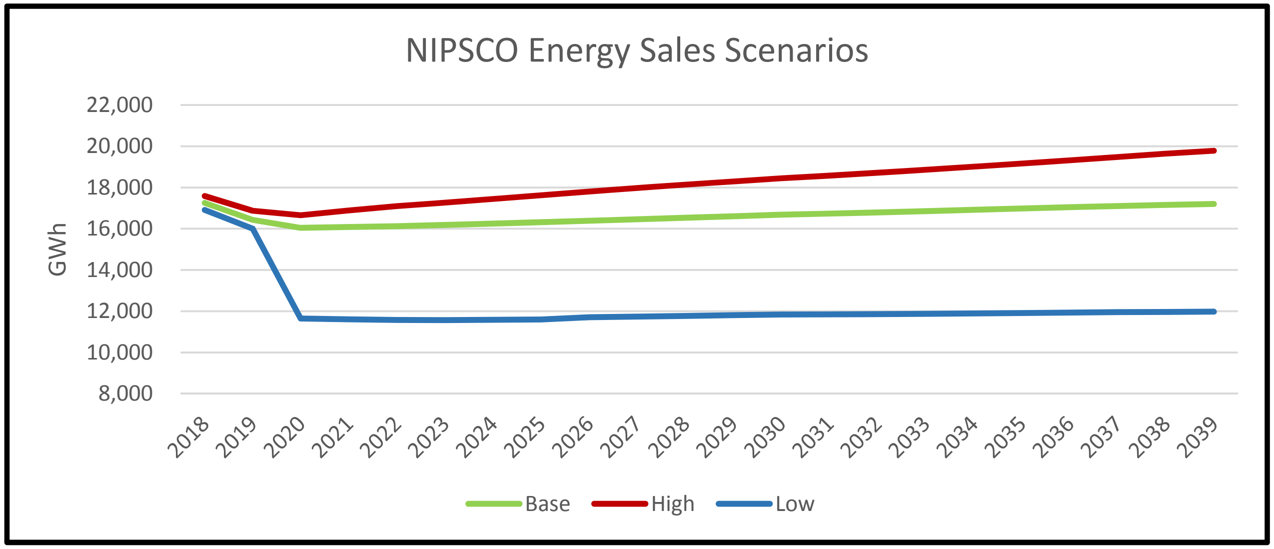


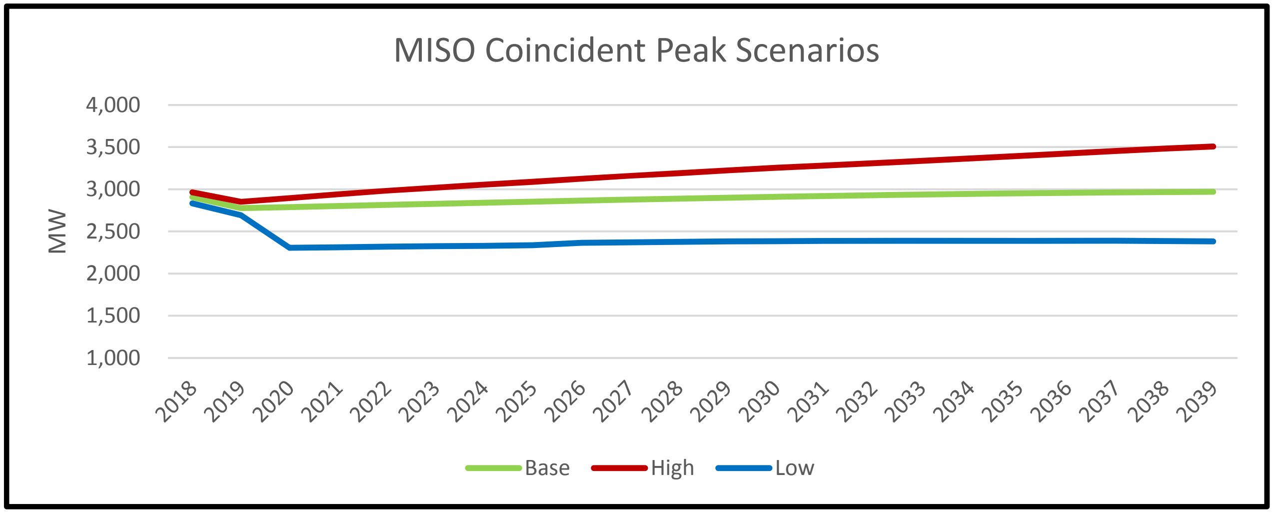
$$\frac{\textbf{\textit{MISO Coincident Peak}}}{\textbf{\textit{NIPSCO System Peak}}} = \sim 95\%$$

Energy And Load Scenarios

- High and low scenarios are constructed from the base case forecast models.
- Optimistic and Pessimistic economic and demographic data are from IHS Global Insight.
- The Industrial scenario forecasts are constructed using recent historical levels and trends for each large customer.
- The Industrial high load growth scenario is created by looking at the customer's previous five years of history giving consideration to peak usage and demand. Current business practices and other potential growth are also considered.
- The low load growth scenario accounts for the "worst case" scenario for each large customer and assumes the customer's minimum operating levels.

Energy And Load Scenarios (Continued)





Modeling of Uncertainty

Pat Augustine
Charles River Associates (CRA)

Modeling of Uncertainty

- **Generation decisions are generally capital intensive and long-lived, understanding and incorporating future risk and uncertainty is important**
- **NIPSCO analysis uses both scenarios and stochastics to assess risk**

Scenarios
Integrated Set of Assumptions

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

Stochastics:
Statistical Distributions of Inputs

- **Can evaluate volatility and "tail risk"**
    - Short-term price volatility impacts portfolio performance
        - Value of certain portfolio assets is dependent on market price volatility
        - Commodity price exposure risk is broader than single scenario ranges
- **Develops a dataset of potential outcomes based on observable data, with the recognition that the real world has randomness**
    - Large datasets can allow for evaluation of key drivers and broader representation of distribution of outcomes
    - Can calculate statistical metrics to evaluate 95th percentile outcomes

Scenario Considerations Inform Combinations of Input Variables

- Based on technology, policy, consumer and economic considerations, each scenario has a unique combination of key input variables and a fully integrated set of commodity market price forecasts

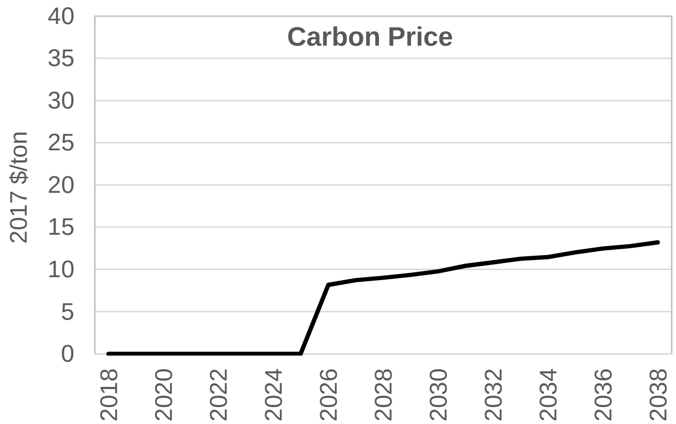
Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Base	Base	Base	Base	Base	Base
Aggressive Environmental Regulation	Base	**High**	**High (CO_2*)**	**Low (CO_2)**	**High (CO_2)**
Challenged Economy	**Low**	**Low**	**Low (No CO_2)**	**High (No CO_2)**	**Low (No CO_2)**
Booming Economy & Abundant Natural Gas	**High**	Base	**Low**	**Low (Low Gas)**	**Low (Low Gas)**

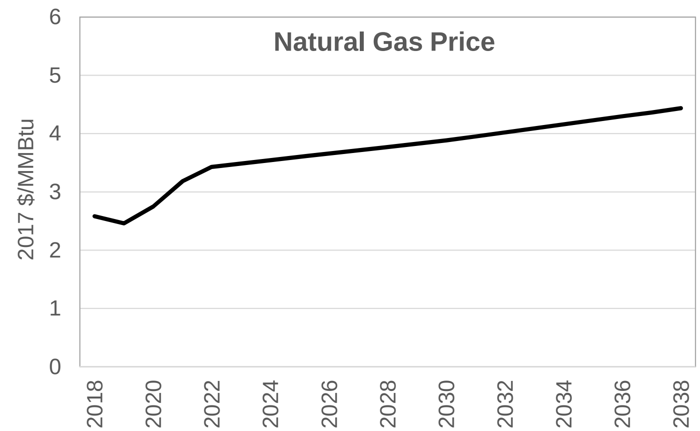
*Carbon dioxide

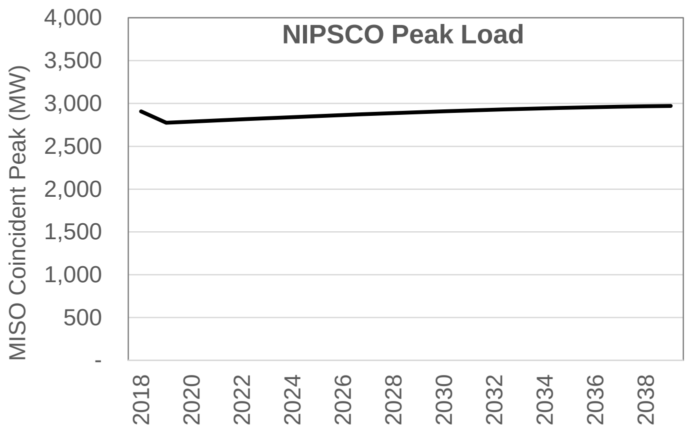
Base Case

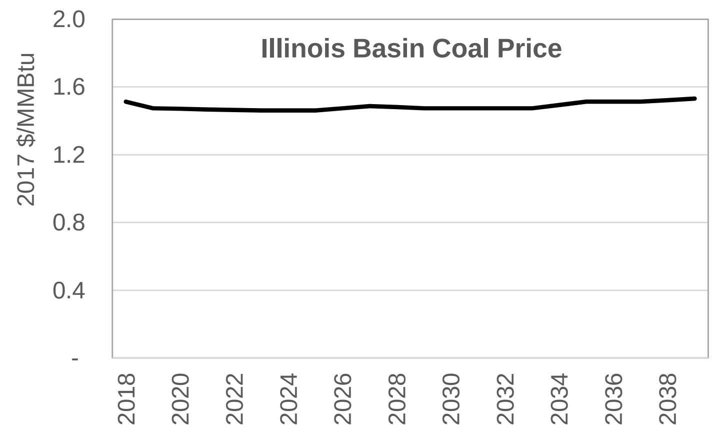
Description

- Fundamentals-based assessment of key drivers that influence NIPSCO’s portfolio costs
- CO_2 price in 2026, based on a new potential federal rule or legislative action initiated after 2020
- Natural gas resource base is in line with “most-likely” expectations, but demand pressures push natural gas prices up over time
- Coal demand is expected to erode over time, especially after 2026, keeping coal prices generally flat in real terms
- NIPSCO load forecast includes near-term loss of industrial load, but modest long-term growth



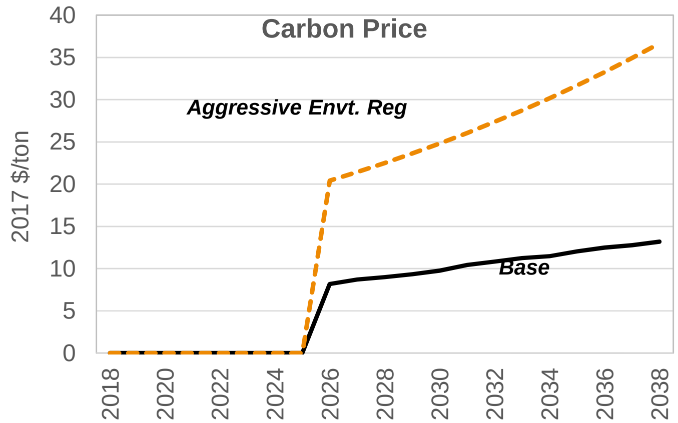


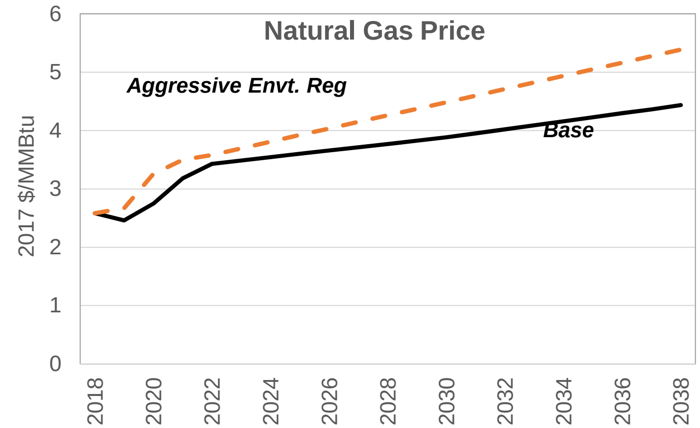


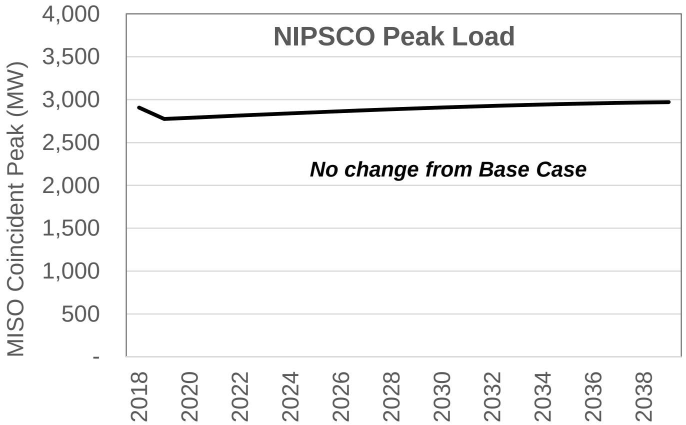


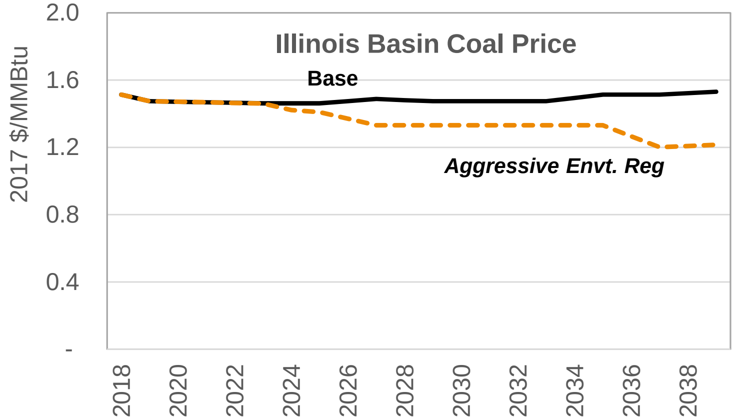
Aggressive Environmental Regulation Scenario Theme

Description	Risks Addressed
• A future in which power sector CO_2 regulations will be more stringent than currently anticipated • Higher CO_2 prices, with feedbacks driving higher gas prices and lower coal prices • Higher power prices and a faster shift in the Midcontinent Independent System Operator ("MISO") supply mix from coal to natural gas and renewables	• The risk that carbon regulations will be more stringent than expected • The risk of higher prices for natural gas and power, which are correlated



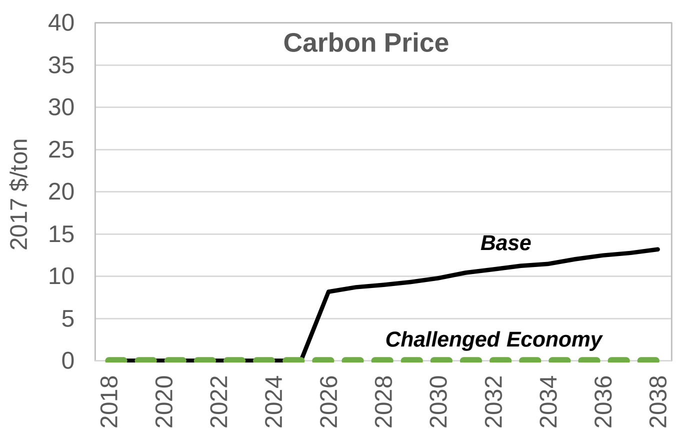


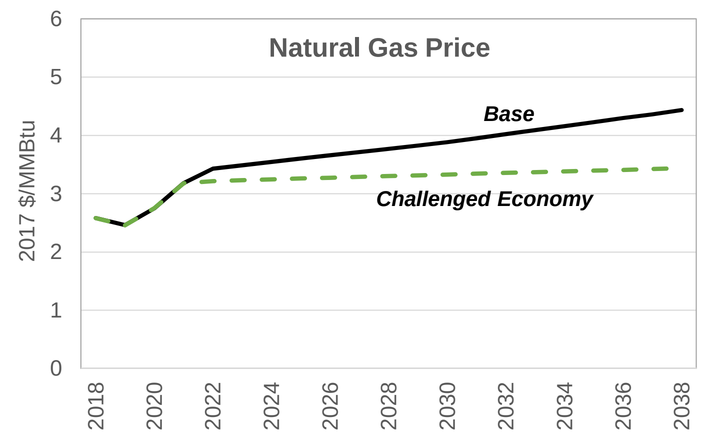


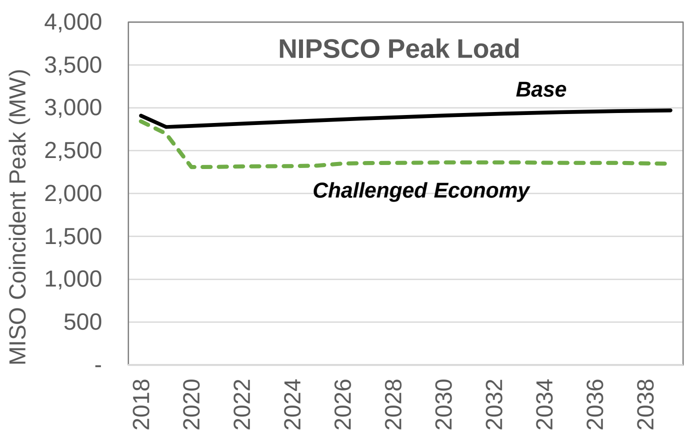


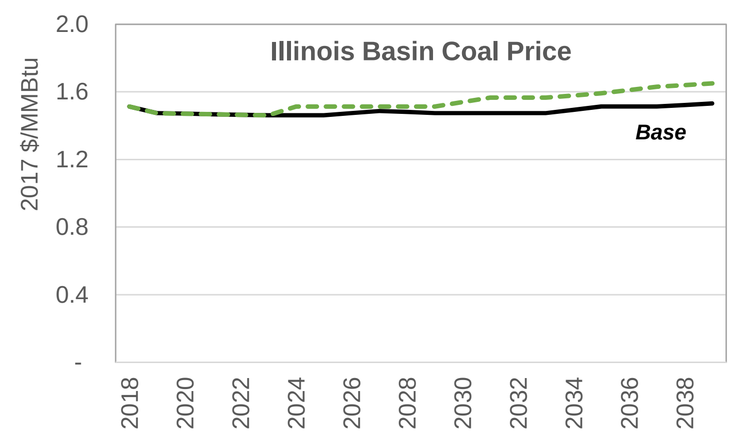
Challenged Economy Scenario Theme

Description	Risks Addressed
• A future where economic growth is stagnant and environmental regulation is limited, with no price on CO_2. • Demand feedbacks drive gas and power prices lower and coal prices higher • Load declines including the loss of large industrial load	• The risk of an economic downturn that could negatively impact NIPSCO load • The risk of no price on carbon over the forecast horizon and its expected influence on other commodity prices • The loss of large industrial customer load



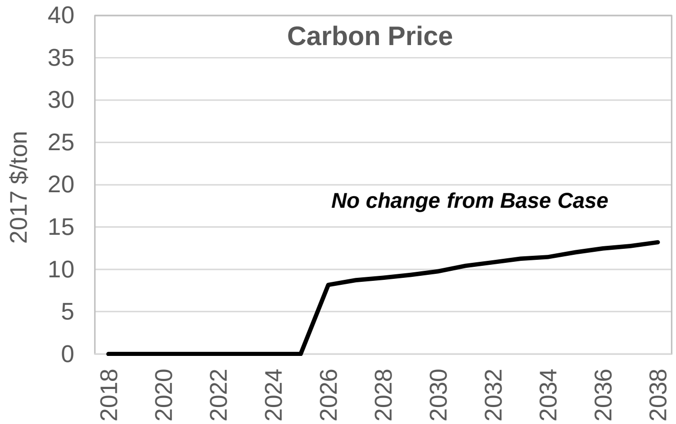


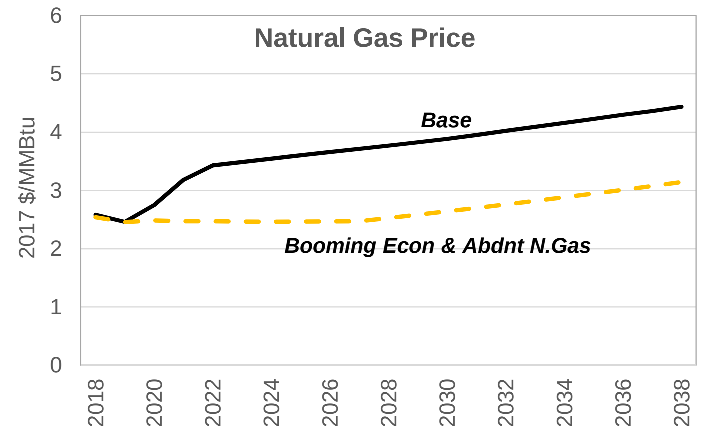


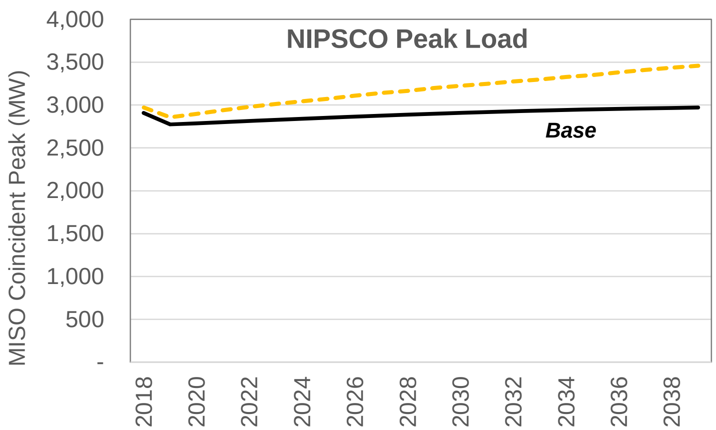


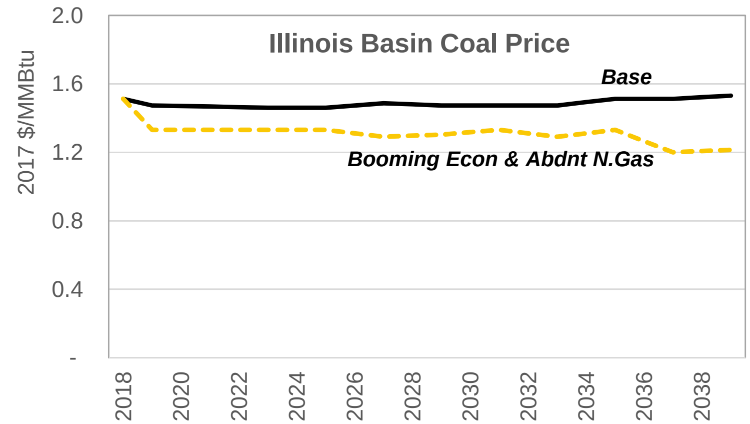
Booming Economy And Abundant Natural Gas Scenario Theme

Description	Risks Addressed
• A future where natural gas production costs remain low and the resource base remains highly productive, keeping natural gas prices low and flat in real terms over the next decade. • Feedbacks driving coal and power prices lower • Lower energy prices drive economic growth and increases to NIPSCO load	• The risk of persistently low natural gas prices • The risk of higher load growth for NIPSCO, which could result in higher exposure to the MISO market

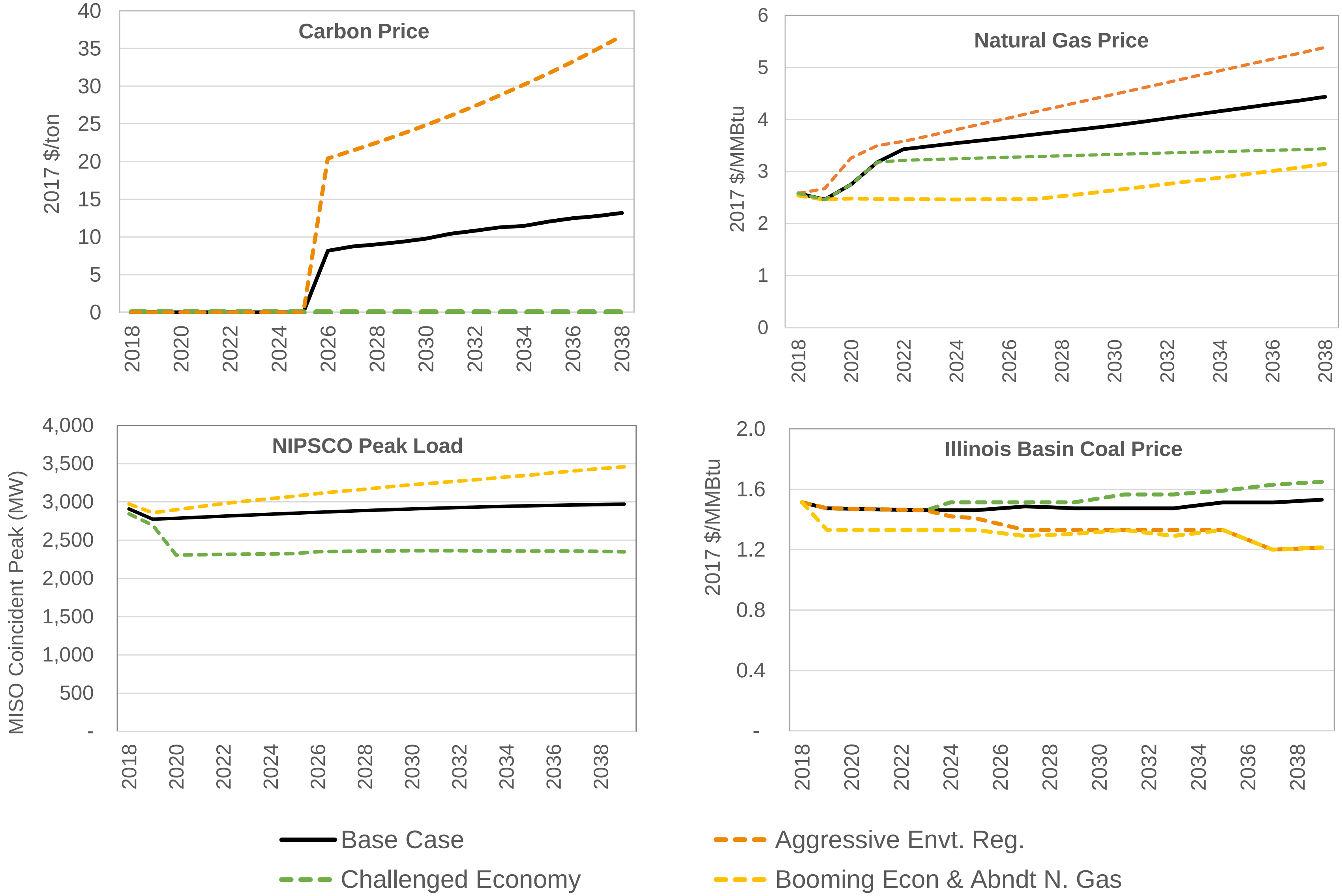








Scenario Summary

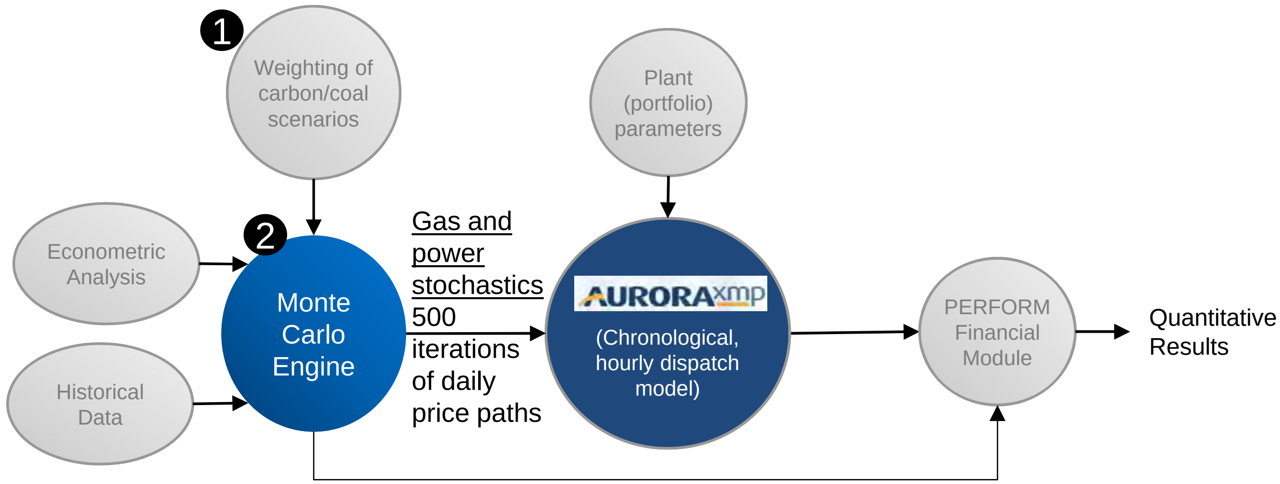


Stochastics Development

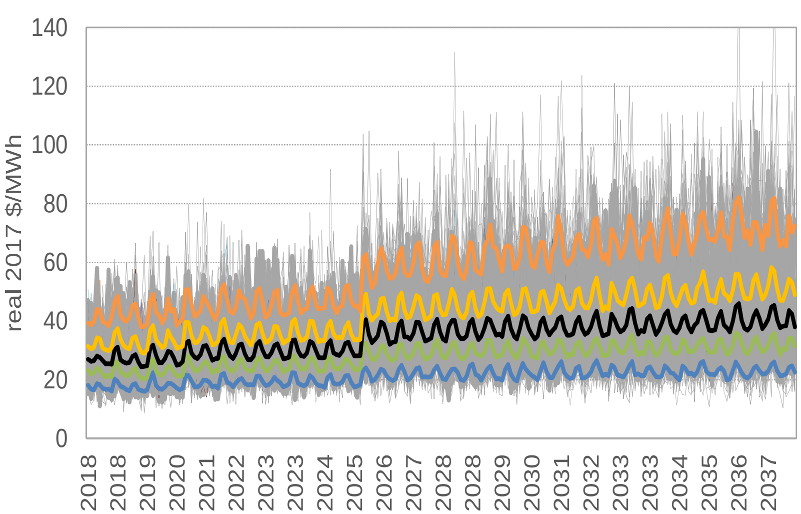
Scenario development is one component of stochastic development process

1. Scenarios are probability-weighted for discrete variables (carbon/coal)

2. Monte Carlo Engine is run for natural gas and power prices for each weighted scenario, based on historical data analysis, which incorporates daily and hourly volatility



Power Price Stochastic Distribution



Natural Gas Price Stochastic Distribution

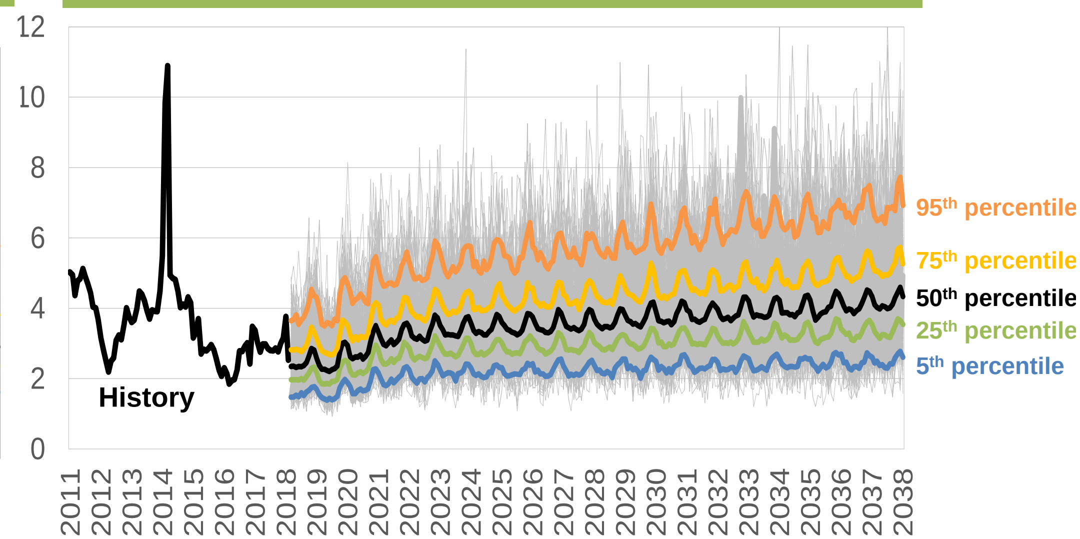
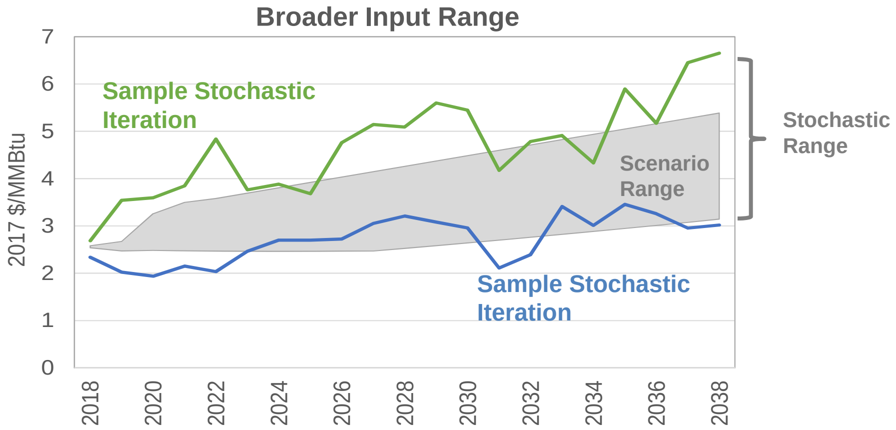
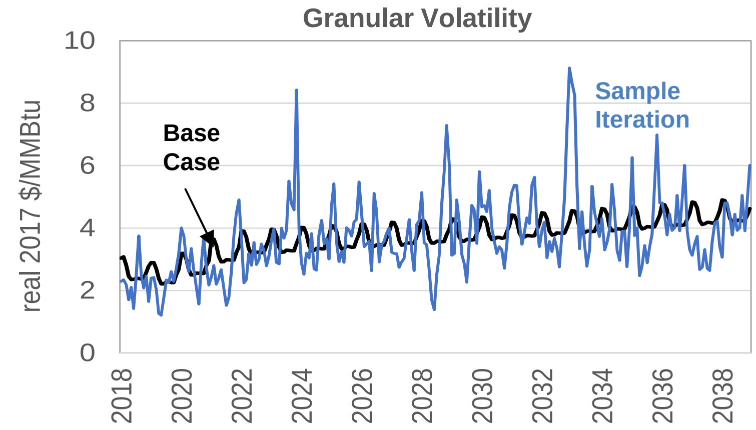
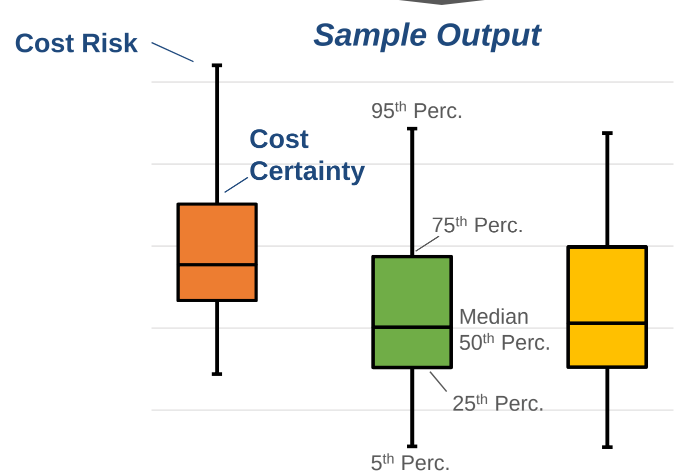


Illustration Of Stochastic Details

- **The use of stochastic inputs for commodity prices broadens the range of inputs evaluated and allows for the assessment of the impact of volatility (daily, hourly, monthly over time**







Outputs can be quantified across a probability distribution rather than discrete outcomes

Retirement Analysis

Dan Douglas
Vice President, Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

Retirement Analysis Framework

- The responses to the all-source RFP provided insight into the supply and pricing of alternatives available to NIPSCO and were fed into the retirement and replacement analysis
- Representative project groups were constructed from RFP results, assembled by technology and ownership structure, for use in the updated retirement analysis

	Retirement Analysis	Replacement Analysis
Core question	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?*	*What are the replacement resource portfolios?*
Initial analysis	MISO Cost of New Entry ("CONE") + market energy	3rd party cost and performance estimates
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

Retirement analysis uses representative RFP projects *as selected by the optimization model* – selection driven by economics

Various Retirement Combinations Were Constructed

	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City in 2035)	**15% Coal in 2023** (Mich. City in 2028)	**15% Coal by 2023** (Schfr. 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035) Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR[1] ELG[2]: non-ZLD[3]	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Michigan City 12	**Retain** CCR ELG: N/A	→	→	→	→	**Retire 2028** CCR ELG: N/A	→	**Retire 2023** CCR ELG: N/A
Schahfer 14	**Retain** CCR ELG: non-ZLD	→	**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement	→	→	**Retire 2023** CCR ELG: Retirement
Schahfer 15	**Retain** CCR ELG: non-ZLD	→	**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement	→	→	**Retire 2023** CCR ELG: Retirement
Schahfer 17	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→	→	**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement
Schahfer 18	**Retain** CCR ELG: non-ZLD NOx[4]: SCR[5]	**Retire 2023** CCR/ELG: Retirement	→	→	→	→	**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement

(hatched) Currently NOT a viable path for ELG compliance

Note: Retirement Combination 4, 15% Coal in 2028 without ELG, is not currently a viable from an ELG compliance standpoint and is shown for discussion purposes..

[1]CCR: Coal Combustion Residuals
[2]ELG: Effluent Limitation Guidelines
[3]ZLD: Zero-Liquid discharge
[4]NOx: Nitrogen oxides
[5]SCR: Selective Catalytic Reduction

What Technology Is the Model Selecting From RFP Results?

- **Economic optimization model is selecting DSM and renewables as the replacement resources in all retirement cases**
- **While the model selected resources were used for the retirement analysis, a separate replacement analysis will be performed**

Cost-effectiveness: Higher → Lower

2 3 4 **Schahfer 17/18 Retirement** ~600MW UCAP need		5 6 7 **Schahfer 14/15/17/18 Retirement** ~1,350MW UCAP need		8 **All Coal Retirement** ~1,750MW UCAP Need	
TECHNOLOGY	MW	TECHNOLOGY	MW	TECHNOLOGY	MW
MISO Market Purchase	50	MISO Market Purchase	50	MISO Market Purchase	50
DSM	125	DSM	125	DSM	125
Wind	150	Wind	150	Wind	150
Solar, Solar + Storage	390	Solar, Solar + Storage	1,070	Solar, Solar + Storage	1,500
	715		**1,395**		**1,825**

This is *not* NIPSCO's replacement resource selection or plan

Retirement Results – Base Case

- **Retaining more coal in the NIPSCO portfolio results in higher costs to customers**

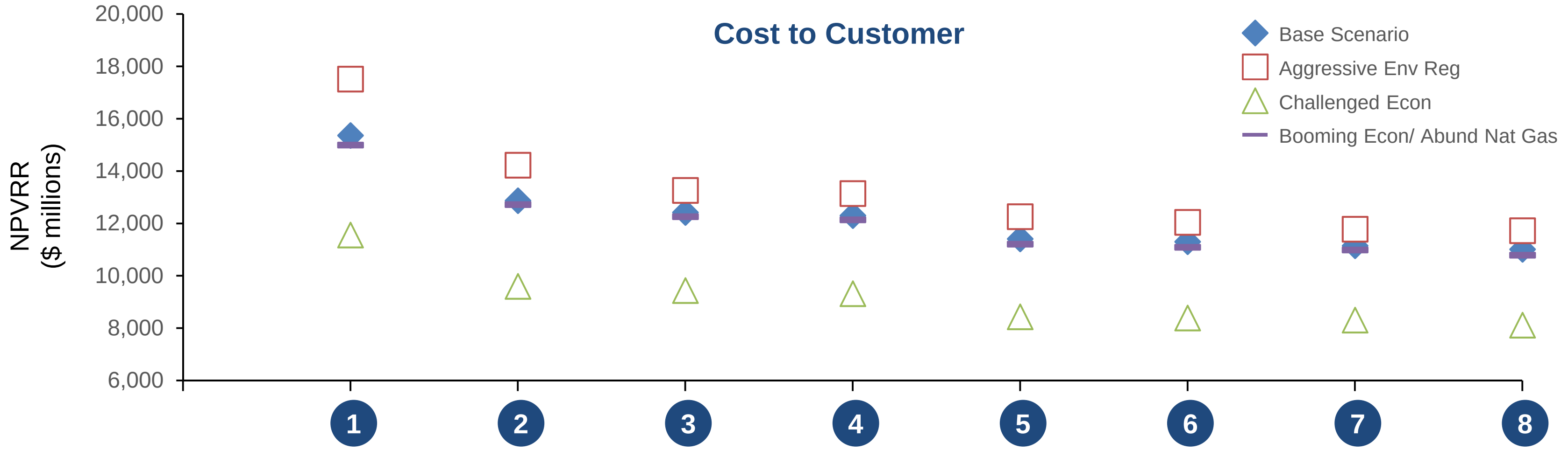
Preliminary, Subject to Change

Cost to Customer

Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal in 2028 w/ ELG**	**15% Coal in 2028 w/o ELG**	**15% Coal in 2023** (MC 2035)	**15% Coal in 2023** (MC 2028)	**15% Coal in 2023** (17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035) Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Delta from Least Cost:	$4,347M 39%	$1,856M 17%	$1,405M 13%	$1,285M 12%	$401M 4%	$292M 3%	$137M 1%	$0M

Retirement Analysis: Scenarios

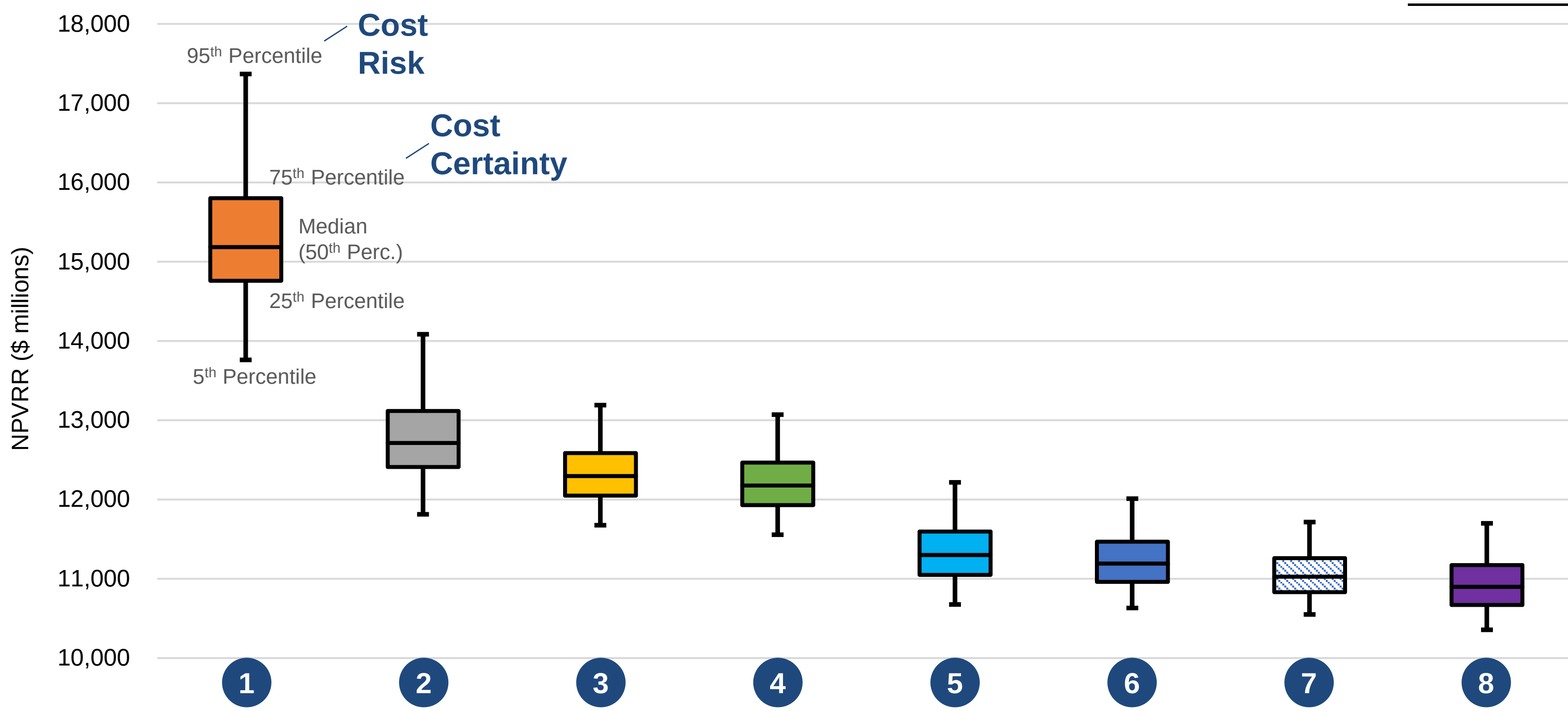
Preliminary, Subject to Change



		1	2	3	4	5	6	7	8
	Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal in 2028 w/ ELG**	**15% Coal in 2028 w/o ELG**	**15% Coal in 2023** (MC 2035)	**15% Coal in 2023** (MC 2028)	**15% Coal in 2023** (17/18 2021)	**0% Coal in 2023**
	Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
	Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Base Scenario	**Delta from Lowest Cost to Customer**	$4,347M 39.5%	$1,856M 16.9%	$1,405M 12.8%	$1,285M 11.7%	$401M 3.6%	$292M 2.7%	$137M 1.2%	$0M 0.0%
Aggressive Env Reg	**Delta from Lowest Cost to Customer**	$5,790M 49.4%	$2,502M 21.3%	$1,539M 13.1%	$1,419M 12.1%	$532M 4.5%	$320M 2.7%	$56M 0.5%	$0M 0.0%
Challenged Econ	**Delta from Lowest Cost to Customer**	$3,440M 42.4%	$1,482M 18.3%	$1,324M 16.3%	$1,204M 14.8%	$316M 3.9%	$272M 3.4%	$196M 2.4%	$0M 0.0%
Booming Econ/ Abund Nat Gas	**Delta from Lowest Cost to Customer**	$4,206M 39.0%	$1,931M 17.9%	$1,470M 13.6%	$1,350M 12.5%	$421M 3.9%	$303M 2.8%	$202M 1.9%	$0M 0.0%

Retirement Analysis: Risk (Stochastics)

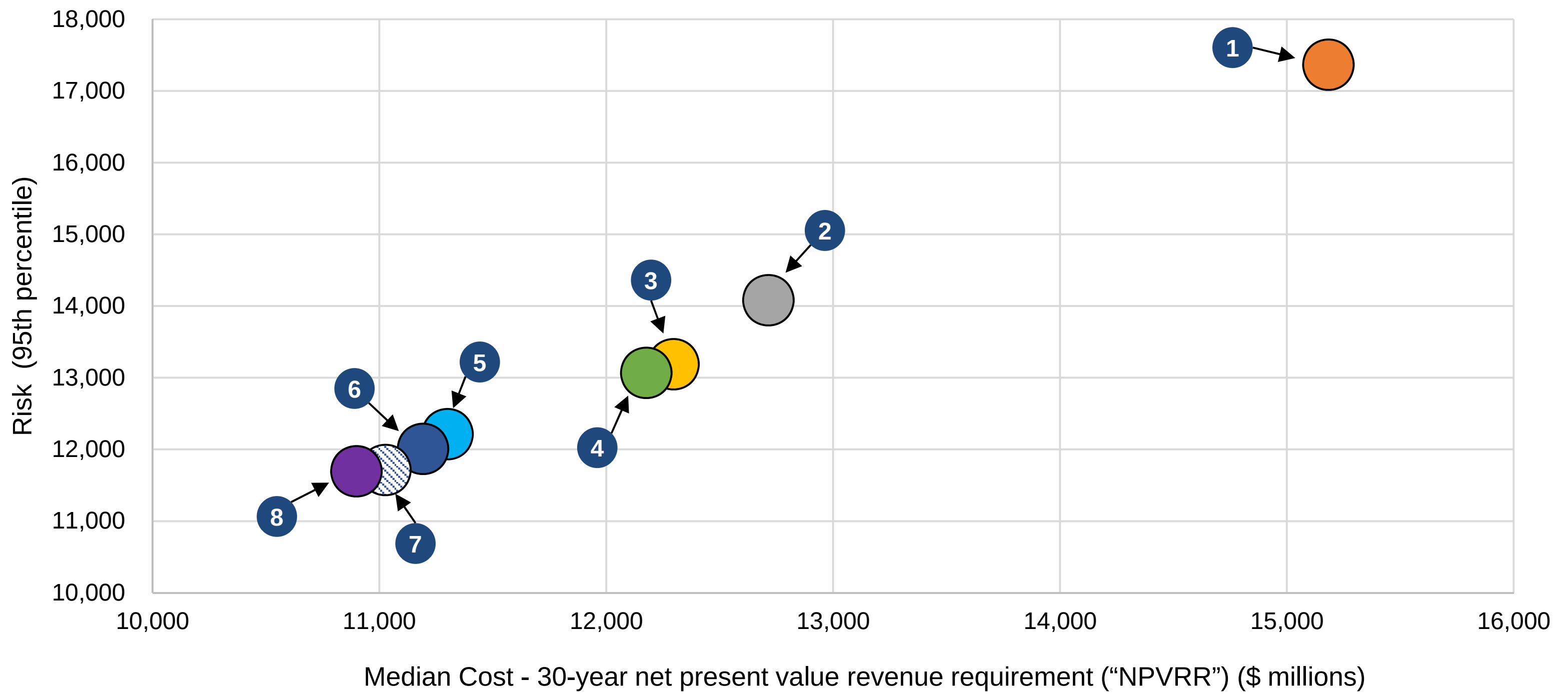
Preliminary, Subject to Change



Portfolio Transition Target:	65% Coal through 2035	40% Coal in 2023	15% Coal in 2028 w/ ELG	15% Coal in 2028 w/o ELG	15% Coal in 2023 (MC 2035)	15% Coal in 2023 (MC 2028)	15% Coal in 2023 (17/18 2021)	0% Coal in 2023
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Delta from Lowest Cost Certainty	+$4,629 41.4%	+$1,944 17.4%	+$1,414 12.7%	+$1,294 11.6%	+$424 3.8%	+$295 2.6%	+$87 0.8%	- $ - %
Delta from Lowest Cost Risk	+$5,671 48.5%	+$2,386 20.4%	+$1,492 12.8%	+$1,372 11.7%	+$517 4.4%	+$313 2.7%	+$17 0.1%	- $ - %

Retirement Analysis: Cost Risk

Preliminary, Subject to Change



	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City 2035)	**15% Coal in 2023** (Mich. City 2028)	**15% Coal by 2023** (Schfr 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement

Retirement Scorecard

2018 Retirement Scorecard	
Criteria	**Description**
Cost to Customer	• Impact to customer bills • Metric: 30-year net present value ("NPV") of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO's 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

Retirement Scorecard

Preliminary, Subject to Change

- **Analysis indicates that most viable option is the full retirement of Schahfer coal units by 2023 and Michigan city by 2028**
- **A final retirement decision has not been made; alternatives are still being evaluated with stakeholders. Finalized plan will be communicated in October**

	1	2	3	4	5	6 (Most Viable)	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City 2035)	**15% Coal in 2023** (Mich. City 2028)	**15% Coal by 2023** (Schfr 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Cost To Customer	$15,362 +$4,347 39.5%	$12,871 +$1,856 16.9%	$12,420 +$1,405 12.8%	$12,300 +$1,285 11.7%	$11,416 +$401 3.6%	$11,307 +$292 2.7%	$11,151 +$137 1.2%	$11,015 - $ - %
Cost Certainty	$15,801 +$4,629 41.4%	$13,117 +$1,944 17.4%	$12,586 +$1,414 12.7%	$12,466 +$1,294 11.6%	$11,597 +$424 3.8%	$11,468 +$295 2.6%	$11,260 +$87 0.8%	$11,173 - $ - %
Cost Risk	$17,368 +$5,671 48.5%	$14,082 +$2,386 20.4%	$13,189 +$1,492 12.8%	$13,069 +$1,372 11.7%	$12,214 +$517 4.4%	$12,009 +$313 2.7%	$11,714 +$17 0.1%	$11,697 - $ - %
Reliability Risk	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Unacceptable	Unacceptable
Employees	0	125	125	125	276	276	276	426
Local Economy	+$118M +51%	$0M -%	($19M) (8%)	($27M) (12%)	($60M) (26%)	($66M) (29%)	($65M) (28%)	($85M) (37%)

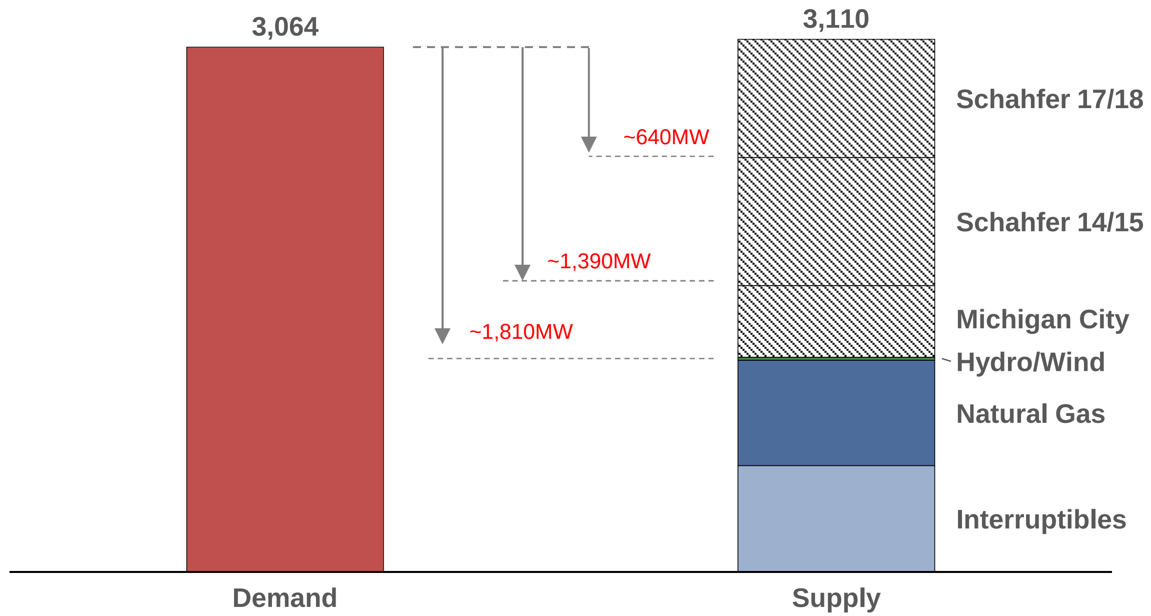
Replacement Analysis

Dan Douglas
Vice President, Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

Retirements Will Create A Need For New Resources

2023 Forecasted Demand and Supply



2023 Estimated Capacity Excess/(Need) in MWs

As-Is	50
Retire Schahfer 17/18	(640)
Retire Schahfer 14/15/17/18	(1,390)
Retire Schahfer and Michigan City	(1,810)

Notes: Demand reflects loss of BP load

Replacement Analysis Framework

- **The responses to the all-source RFP provided insight into the supply and pricing of alternatives available to NIPSCO and fed into the retirement and replacement analysis**
- **These RFP projects are used to construct resource combinations that explore the range of Ownership / Duration and Diversity possibilities**

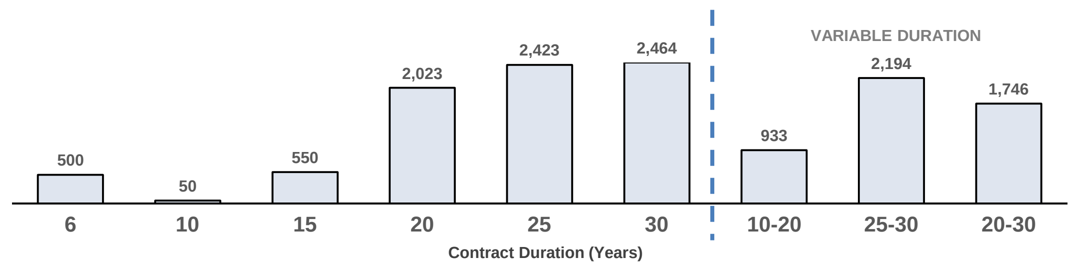
	Retirement Analysis	Replacement Analysis
Core question	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?*	*What are the replacement resource portfolios?*
Initial analysis	MISO CONE + market energy	3rd party cost and performance estimates
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

RFP Generated Significant Amount Of Responses

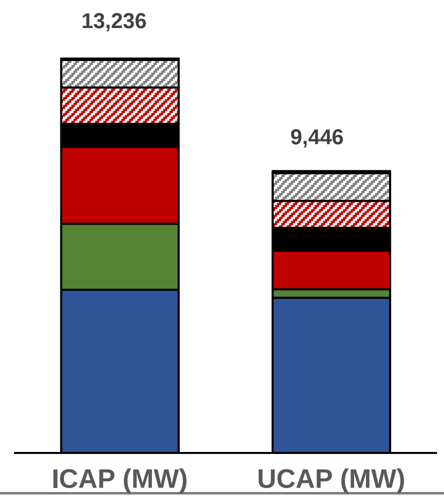
Technology & Ownership
(Overview Of Proposals)

Technology	CCGT*	CT**	Coal	Wind	Wind + Solar + Storage	Solar	Solar + Storage	Storage	Demand Resp.	Total Bids
Asset Sale	4	-	-	1	-	1	-	-	-	6
PPA	8	-	3	6	-	26	7	8	1	59
Option	3	1	-	7	1	8	4	1	-	25
Total	15	1	3	14	1	35	11	9	1	90
Locations	IN, IL	IN	IN, KY	IA, IN, IL, MN	IN	IL, IN, IA	IN	IN	IN	

Duration
(UCAP MW by duration)



Quantity & Technology & Ownership
(RFP Projects By Technology)



	ICAP*** (MW)	UCAP (est. MW)
Demand Response	70	70
Storage	925	925
Solar + Storage	1,220	902
Wind + Solar + Storage	0	0
Coal	772	772
Solar	2,580	1,291
Wind	2,209	287
Natural Gas (CT)	0	0
Natural Gas (CCGT)	5,470	5,199
	13,236	9,446

Note that totals are on a project basis, which eliminates double counting of multiple proposals for the same facility.

- Nearly 10,000 MW of MISO-recognized capacity (UCAP) was offered into the RFP
- A broad set of technologies and fuels, both fossil and renewable, are available
- Ownership and PPA options are available
- Most contract durations skew to 20+ years; several bidders did offer shorter 10-year and 15-year options
- NIPSCO has begun outreach to respondents and will not be releasing a shortlist of RFP finalists

*Combined cycle gas turbine
**Combustion turbine
***Installed Capacity

There are more than enough capacity resources bid in to RFP to meet NIPSCO's needs

Incorporating DSM In IRP Modeling

- DSM summary analysis was presented during the May public advisory meeting and the analysis approach has been refined in consultation with stakeholders
- DSM programs were evaluated and aggregated into three bundles that are available to be selected by optimization model

DSM Analysis
- Evaluate detailed program-level opportunities in service territory
- Identify program impacts and associated costs

Identify DSM "bundles" or decrements
- Aggregate detailed DSM options into "bundles" of programs to reflect varying levels of energy savings and associated costs
- Produce bundles with detailed energy savings characteristics and costs

Analyze *each* "bundle" for portfolio selection on equal footing with other resources
- Use Aurora portfolio optimization with DSM costs and hourly savings profiles
- Assess mix of bundles to be integrated into portfolio

DSM Bundle	Weighted Avg. Cost ($/MWh*)	MW Selected by 2023 (Peak / Average)	MW Selected by 2038 (Peak / Average)
1	16.98	91 / 48	310 / 174
2	23.27	34 / 20	60 / 29
3	159	0 / 0	0 / 0

Bundles #1 & #2 were selected by optimization model

*Megawatt hour

Recap from Aug. 28 Technical Webinar: Tranche Development and Assessment

1 Tranche Development

Aggregate Bids into Groupings by Type

- Bids are organized by:
  - Technology
  - Asset sale or PPA
  - Commitment duration
  - Costs
  - Operational characteristics
- Aggregated cost and operational information is entered into Aurora model to be considered in optimization step

2 Portfolio Optimization

Select Portfolios

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

Confirm Viability

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

3 Portfolio Creation and Modeling

Create & Analyze Portfolios Based on Optimization

- Tranches are chosen for retirement and replacement analysis based on % selected by optimization model when confirmed as viable
- Portfolios are then run across full set of scenarios and stochastics

Replacement Analysis: Resource Combinations Were Created That Explore The Range Of Ownership / Duration And Diversity Possibilities

- **RFP projects provide good coverage to construct resource combinations that cover the spectrum of Ownership / Duration and Diversity**

Preliminary, Subject to Change

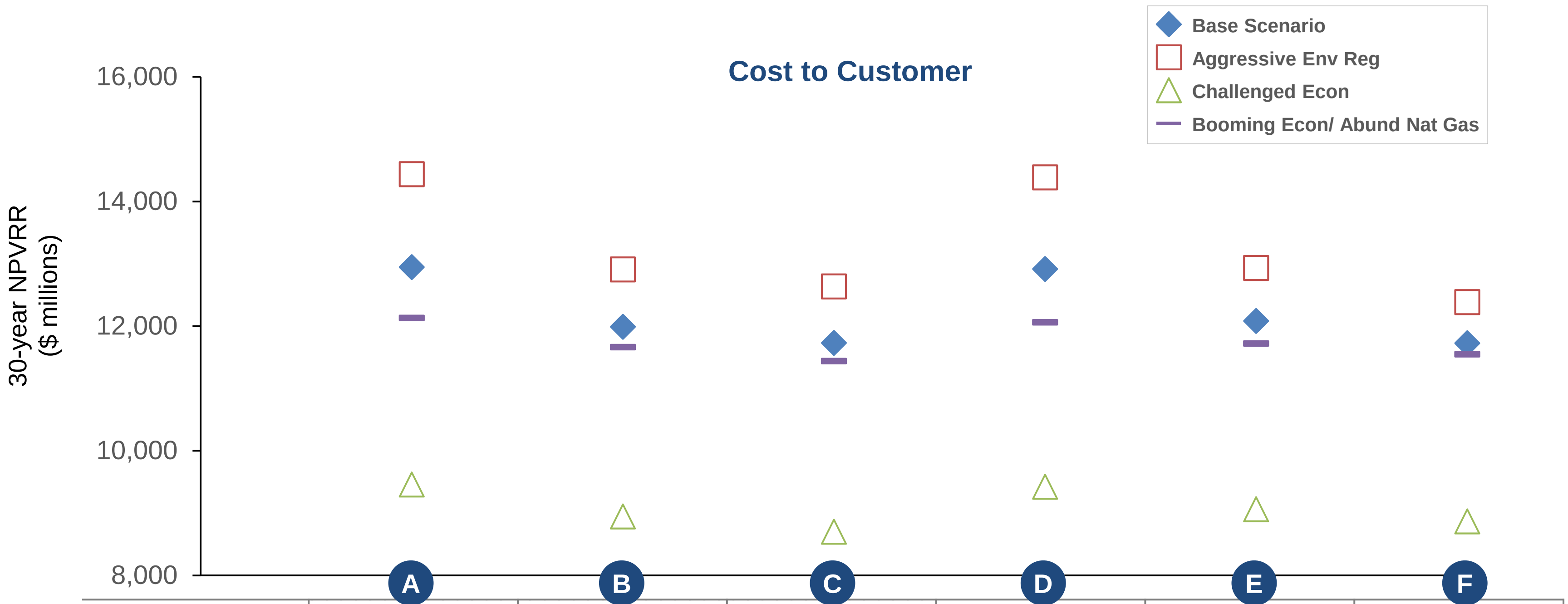
Diversity

Ownership / Duration	Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
Short Duration	**A** MISO Capacity Purchase 400MW CCGT PPA 950MW	**B** MISO Capacity Purchase 400MW CCGT PPA 250MW Renewable PPA 690MW	**C** MISO Capacity Purchase 400MW Renewable PPA 950MW
Long Duration	**D** MISO Capacity Purchase 50MW CCGT 1,300MW	**E** MISO Capacity Purchase 50MW CCGT 620MW Renewables 670MW	**F** MISO Capacity Purchase 50MW Renewables 1,300MW

Notes: Values above reflect 2023 additions shown in UCAP; additional generic solar additions are included in all portfolios starting in 2028.
All portfolios include a total of 125 MW (peak) DSM by 2023 and 370 MW (peak) DSM by 2038.

Replacement Analysis: Scenarios

Preliminary, Subject to Change



		A	B	C	D	E	F
	Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
	Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Base Scenario	Delta from Lowest Cost to Customer	\$1,222 10.4%	\$265 2.3%	\$6 0.1%	\$1,192 10.2%	\$357 3.0%	**\$0 0.0%**
Aggressive Env Reg	Delta from Lowest Cost to Customer	\$2,052 16.6%	\$524 4.2%	\$250 2.0%	\$2,002 16.2%	\$546 4.4%	**\$0 0.0%**
Challenged Econ	Delta from Lowest Cost to Customer	\$756 8.7%	\$244 2.8%	**\$0 0.0%**	\$722 8.3%	\$361 4.2%	\$165 1.9%
Booming Econ/ Abund Nat Gas	Delta from Lowest Cost to Customer	\$692 6.0%	\$224 2.0%	**\$0 0.0%**	\$622 5.4%	\$281 2.5%	\$109 1.0%

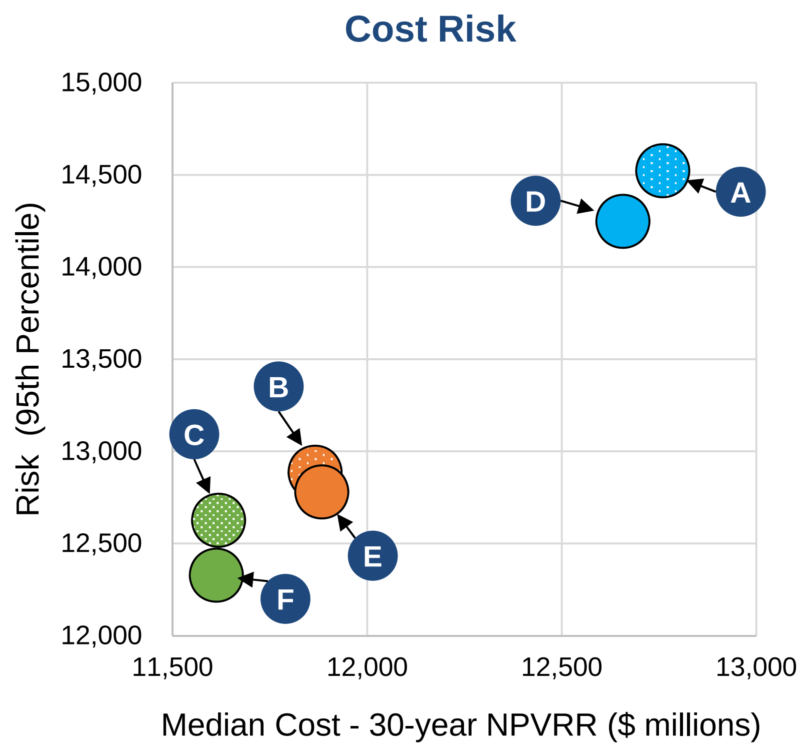
Replacement Analysis: Stochastics

Preliminary, Subject to Change

Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Delta from Lowest Median Cost	$1,147 9.9%	$254 2.2%	$6 0.1%	$1,044 9.0%	$271 2.3%	**$0 0.0%**
Delta from Lowest **Cost Certainty**	$1,477 12.5%	$371 3.1%	$124 1.0%	$1,403 11.8%	$362 3.1%	**$0 0.0%**
Delta from Lowest **Cost Risk**	$2,194 17.8%	$558 4.5%	$297 2.4%	$1,920 15.6%	$452 3.7%	**$0 0.0%**

Replacement Analysis: Stochastics

Preliminary, Subject to Change



Diversity

Ownership / Duration	Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
Short Duration	A	B	C
Long Duration	D	E	F

Replacement Scorecard

2018 Replacement Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75^{th} percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95^{th} percentile of cost to customer
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 ICAP MW sourced from non-gas resources)
Environmental	• Annual carbon emissions from the generation portfolio • Metric: Total annual carbon emissions (2030 metric tons of CO_2) from the generation portfolio
Employees	• Net impact on NiSource jobs • Metric: Approximate number of permanent NiSource jobs added
Local Economy	• Property tax amount from entire portfolio • Metric: 30-year NPV of estimated modeled property taxes from the entire portfolio

Replacement Scorecard

Preliminary, Subject to Change

Most Viable

	A	B	C	D	E	F
Ownership / Duration	**Short Duration**	**Short Duration**	**Short Duration**	**Long Duration**	**Long Duration**	**Long Duration**
Diversity:	**Higher Carbon**	**Average Carbon**	**Average-Low Carbon**	**Higher Carbon**	**Average Carbon**	**Average-Low Carbon**
Cost to Customer delta from least	$12,949 $1,222 10.4%	$11,992 $265 2.3%	$11,733 $6 0.1%	$12,920 $1,192 10.2%	$12,085 $357 3.0%	$11,727 $0 0.0%
Cost Certainty delta from least	$13,325 $1,477 12.5%	$12,218 $371 3.1%	$11,971 $124 1.0%	$13,250 $1,403 11.8%	$12,209 $362 3.1%	$11,847 $0 0.0%
Cost Risk delta from least	$14,522 $2,194 17.8%	$12,886 $558 4.5%	$12,625 $297 2.4%	$14,248 $1,920 15.6%	$12,780 $452 3.7%	$12,328 $0 0.0%
Fuel Security % non-gas capacity	45%	79%	86%	40%	72%	87%
Environmental 2030 CO_2 emissions 2005 baseline = 18.2M	2.18M	0.97M	0.97M	3.13M	2.03M	0.97M
Employees	0	0	0	<30	<30	<30
Local Economy	←		Under evaluation			→

Stakeholder Requested Scenarios

Fred Gomos
Manager, Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

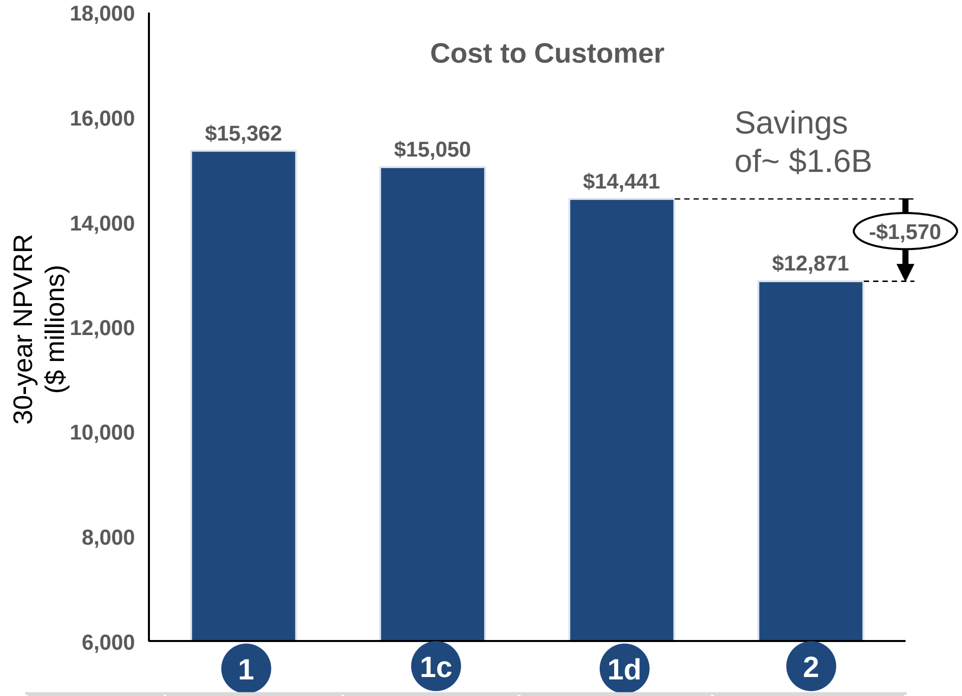
Stakeholder Request – Indiana Coal Council Portfolios for Schahfer Units 17/18

- **Indiana Coal Council requested we look at retirement combinations with less costly ELG-related compliance for Schahfer 17/18 and an alternative market case**

	1	1c	1d	2
Portfolio Transition Target:	**65% Coal through 2035**	**65% Coal through 2035**	**65% Coal through 2035**	**40% Coal in 2023**
Retire:	None	None	None	Schfr:17,18 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15
Environmental Compliance	CCR ELG: non-ZLD	CCR ELG: NONE	No Environmental Capital	CCR ELG: non-ZLD
Michigan City 12	**Retain** CCR ELG: N/A →	→	→	→
Schahfer 14	**Retain** CCR ELG: non-ZLD →	→	→	→
Schahfer 15	**Retain** CCR ELG: non-ZLD →	→	→	→
Schahfer 17	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retain** CCR **ELG: None** NOx: SCR	**Retain** CCR **ELG: None** **NOx: None**	**Retire 2023** CCR/ELG: Retirement
Schahfer 18	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retain** CCR **ELG: None** NOx: SCR	**Retain** CCR **ELG: None** **NOx: None**	**Retire 2023** CCR/ELG: Retirement

Stakeholder Request - Coal Council Scenarios

Base Case



Portfolio Transition Target:	65% Coal through 2035	65% Coal through 2035	65% Coal through 2035	40% Coal in 2023
Retire:	None	None	None	Schfr:17,18 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: NONE	No Environmental Capital	CCR ELG: non-ZLD

Alternative Case – Coal Council

- No carbon price
- High natural gas price
- $45/ton flat real delivered coal price for 17/18

	1	1c	1d	2
Portfolio Transition Target	65% Coal through 2035	65% Coal through 2035	65% Coal through 2035	40% Coal in 2023
Retire	None	None	None	Schfr:17,18 (2023)
Retain beyond 2023	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: NONE	No Environmental Capital	CCR ELG: non-ZLD

Stakeholder Request – Evaluate Coal to Gas Conversion for Schahfer Units 17/18

- **OUCC requested that NIPSCO further evaluate a coal to gas conversion for Schahfer 17/18 as a potential replacement alternative on 2023**

	6	6b
Portfolio Transition Target:	**15% Coal in 2023** (MC 2028)	**15% Coal in 2023** (MC 2028) (17/18 Conv.)
Retire:	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 (2028)	Mich. City: 12 (2028) CONVERT Schfr: 17,18 (2023)
Env. Compliance	CCR ELG: Retirement	CCR ELG: Retirement
Michigan City 12	**Retire 2028** CCR ELG: N/A	→
Schahfer 14	**Retire 2023** CCR ELG: Retirement	→
Schahfer 15	**Retire 2023** CCR ELG: Retirement	→
Schahfer 17	**Retire 2023** CCR/ELG: Retirement	**Convert to Gas 2023**
Schahfer 18	**Retire 2023** CCR/ELG: Retirement	**Convert to Gas 2023**

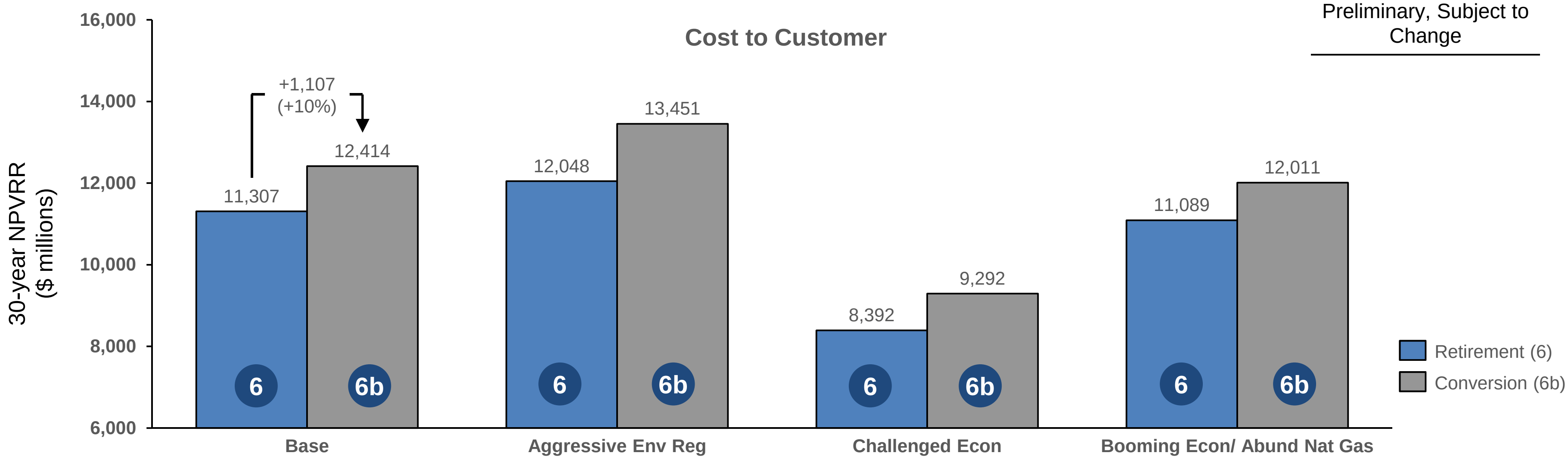
Key Assumptions

	Category	Estimated Cost	Cost Notes
Conversion Investment Costs	**Conversion**	$87M	• Equipment, materials and construction labor, contingency, owners and indirect costs • Based on S&L Study cost estimates of $121/kW
	Gas Interconnection	$68M	• Incremental cost for 30” gas pipeline interconnection
	Environmental Compliance	TBD	
Maintenance Capital	**Maintenance Capital (Total 2023-2037)**	$438M	• Assumes same maintenance capital needs as current coal operations from 2023 through 2037
Ongoing Costs	**Fixed O&M Costs ($KW-yr)**	$39	• Based on S&L Study cost estimates for expected O&M post conversion

Stakeholder Request – Evaluate Coal to Gas Conversion for Schahfer 17/18

- **Conversion is an expensive replacement alternative across all scenarios as compared to the retirement of Schahfer 17/18 and replacing with alternative selections from the RFP results**

Preliminary, Subject to Change



Portfolio Transition Target:	15% Coal in 2023	15% Coal in 2023 (17/18 gas)	15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)	15% Coal in 2023	15% Coal in 2023 (Schfr. 17/18 gas)	15% Coal in 2023	15% Coal in 2023 (Schfr. 17/18 gas)
Retire:	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:14,15 (2023)						
Retain beyond 2023:	Mich. City: 12 (2028)	Schfr:17,18 (gas) Mich. City: 12 (2028)						

Michigan City 12	Retire 2028	Retire 2028
Schahfer 14	Retire 2023	Retire 2023
Schahfer 15	Retire 2023	Retire 2023
Schahfer 17	Retire 2023	Convert to Gas 2023
Schahfer 18	Retire 2023	Convert to Gas 2023

Conversion economics are improved when gas prices are low, but is still uncompetitive with RFP alternatives

Stakeholder Presentations

Wrap Up

Northern Indiana Public Service Company
2018 Integrated Resource Planning ("IRP")

Public Advisory Meeting #4
SUMMARY

September 19, 2018

Welcome and Introductions

Alison Becker opened the meeting by having those in the room introduce themselves. She then introduced Violet Sistovaris, President, NIPSCO and Executive Vice President, NiSource. Ms. Sistovaris welcomed the participants and discussed NIPSCO's planning process and the balance the Company strives to achieve related to meeting customer needs through generation. She thanked the stakeholders for their participation in the process and encouraged on-going dialog. Ms. Becker then reviewed the process for those participating by telephone and the agenda for the day and did a safety moment.

NIPSCO's Planning and the Public Advisory Process

Dan Douglas, Vice President, Corporate Strategy and Development

Mr. Douglas thanked participants for attending. He explained how NIPSCO plans for the future and provided an overview of the public advisory process, including reviewing the current point in the stakeholder engagement process. He apologized to participants that the full presentation was not made available prior to the meeting, but noted that what NIPSCO was presenting from both a retirement and replacement perspective was substantially different than what has been shown in the past, and, therefore, the details needed to be communicated in an orderly manner. He reiterated that the decisions are not final and that feedback is appreciated in both the meeting and the weeks to come. Mr. Douglas noted that NIPSCO has a deep commitment to its employees and that the Company wants to ensure those employees are notified of possible outcomes in a thoughtful way. He then reviewed where NIPSCO is in the Public Advisory process and noted this meeting was the fourth Public Advisory meeting, with the addition of a technical webinar, for a total of five stakeholder participation opportunities. He then reviewed the stakeholder interactions that have taken place outside of the Public Advisory process, noting that seven groups have met with NIPSCO one-on-one and he encouraged stakeholders to continue to engage NIPSCO one-on-one as desired.

Energy and Demand Forecast Update
Amy Efland, Manager, Demand Forecasting

Amy Efland provided an update on the energy and demand forecasts that had previously been presented during the March Public Advisory meeting. She provided information regarding the NIPSCO energy and peak demand projections and provided an updated energy requirements projections. Ms. Efland then discussed an update to the base case related to a change in large industrial customer demand. She noted that Industrial scenario forecasts are constructed using recent historical levels and trends for each large customer. She also reviewed how the Industrial high load growth and low load growth scenarios are developed. Finally, she provided updated energy sales and coincident peak curves for the base, high and low scenarios.

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

- On Slide 13, it looks like it is showing significant drop in peak demand projections but on Slide 15 you only see that drop in the lowest scenario rather than base scenario?
    - This view has more to do with scale of the chart. Each scenario has a pretty significant drop. Looking at Slide 13, this is the base forecast and this magnifies it. You can see the same pattern.
- Given that difference in scale, there appears to be a much larger drop in load forecast. What is that getting at?
    - The Industrial portion is driving that. More equal distance for Residential and more of a downswing in the Industrial piece. The pessimistic scenario for industrial is much greater than optimistic.
- The drop in Slide 13 is significant and is reflected in Slide 15. The only difference is the scale in the chart. There is a very large drop in the low case. Please provide more discussion on that.
    - On the pessimistic side, for NIPSCO Industrial load is about 50% of total load, and the Industrial forecast through 2019 drops a half from that, which is a significant dip. The optimistic side stays consistent with the base case, which is only being driven by Residential and Commercial which is only 50% of NIPSCO's total load.
- Slide 15 is presenting Midcontinent Independent System Operator ("MISO") coincident peak scenario, not NIPSCO's?
    - The relationship and patterns are very similar. It is 95% relationship with NIPSCO base.
- Is the MISO coincident peak what you need to plan for?
    - Yes. Both are presented in the IRP, but NIPSCO plans for the MISO coincident peak.
- Is the expected baseline drop in Industrial load based on known changes from industrial customers?
    - It is based on an expected drop based on economic information and conversations with Industrial customers.

- Why showing a return to growth?
    - This is based on the number of customers and potential patterns the Company sees occurring in the future.

Modeling of Uncertainty
Pat Augustine, Charles River Associates

Pat Augustine began by discussing how generation decisions are generally capital intensive and long-lived, so it is important to understand and incorporate future risk and uncertainty. He reviewed the process for using scenarios and stochastics to assess risk. First, he explained that scenarios are used to answer "what if. . .." scenarios He then explained that stochastics evaluate more granular volatility as well as "tail risk." After providing this background, Mr. Augustine reviewed the scenarios and combinations of input variables that go into the scenarios. He noted that each scenario had a unique combination of key input variables and a fully integrated set of commodity market price forecasts. Mr. Augustine then reviewed each of the scenarios and provided a brief description. For each scenario, he reviewed the curves related to carbon, natural gas and Illinois Basin coal prices for each scenario, as well as the NIPSCO peak load. After providing each individually, he showed a slide with the scenario summary.

After presenting the various scenarios, Mr. Augustine reviewed the development of stochastics, showing power price and natural gas price stochastic distributions as two examples. He finished by noting that the use of stochastic inputs for commodity prices broadens the range of inputs evaluated and allows for the assessment of the impacts of volatility (daily, hourly, and monthly over time).

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

- Are all figures being shown in nominal dollars?
    - No. All figures are in 2017 real dollars.
- Trying to understand market based approach and want to confirm that in fact NIPSCO is looking to sell carbon dioxide ("CO_2") on the market whereas this approach would not prioritize people on the front line, especially people of color, who would be impacted by pollution elsewhere. There is a summary report out of Germany saying that carbon pricing actually does not reduce the emissions because of the profitability – entities are making profit from selling CO_2. Can you clarify-is air being sold as a commodity?
    - Broadly speaking, it is difficult to predict what a future regulation on carbon emissions will look like. However, for modeling purposes, a price on carbon is incorporated to reflect the potential costs associated with emitting CO_2 that NIPSCO would absorb. NIPSCO is not modeling any situation where NIPSCO would profit through the sale of CO_2 allowances. All prices on carbon add costs for any ton of CO_2 that is emitted. While

the Company is not modeling any policies that would directly force retirements, NIPSCO is applying costs to CO_2 emissions to assess how different portfolios perform.

- Explain in more layman's terms – is the CO_2 being traded across the market for a profit to NIPSCO or another utility to MISO?
    - No. The CO_2 price here is a cost. Any ton of CO_2 emitted by NIPSCO would be associated with a cost which is absorbed in the portfolio calculations. There is no assumption that there would be a profit from selling a potential future CO_2 allowance.
- There is an incentive to reduce, but there is a market right? Indiana could continue to host more CO_2 that would be emitted?
    - Currently there is no operating market in Indiana. The analysis assumes a future potential tax or carbon market to increase the costs associated with emitting CO_2. Structurally, a cap-and-trade regime would be designed to bring CO_2 emissions down. There is currently none in place for Indiana. The intent of a future potential policy, however, would be to drive emissions down, not establish something that NIPSCO would profit from.
- In the challenged economy, slow economic growth is paired with lack of carbon price. However, those are not really related. It would not be dynamic on its own but a combination?
    - The comments are fair. There are plenty of variations for the different variables that could theoretically be developed. However, in this case, the reason for pairing low load and no carbon price was to stress a low portfolio cost outcome. This is certainly not the only way a no carbon scenario could play out, but it was a plausible outcome that helps bracket the range of future states-of-the-world.
- These look like delivered natural gas prices. Could not some of this variability be controlled by having firm transportation at NIPSCO, and thus just looking at commodity price variability?
    - This graphic is actually only showing the underlying commodity price and is not representing the delivered price to a certain plant. The right side graphic is showing the most proximate hub point, Chicago Citygate, for natural gas. Thus, NIPSCO is only evaluating the liquid market benchmark when the Company is assessing market shocks and uncertainties in the stochastic process.

Retirement Analysis
Pat Augustine and Dan Douglas

Mr. Augustine reviewed the retirement analysis framework, noting that the responses to NIPSCO's all-source request for proposals ("RFP") were fundamental to indicating the actual projects available to NIPSCO. He noted that the key decision was what units to retire and when. He then reviewed the various retirement combinations that were constructed and went through each of the eight options. After providing the overview, he revealed the technologies being selected by the model based on the RFP results for the various retirement combinations and reviewed the results for the base case, which included an analysis of the preliminary expected cost to customer over the next 30 years. He then reviewed the preliminary results of the cost to customers over the next 30 years for each retirement combination and each of the scenarios. Then he provided a preliminary review of the stochastics for each of the retirement combinations. Finally, Mr. Augustine provided information related to the cost risk for each of the retirement combinations.

Mr. Douglas then provided an overview of the Retirement Scorecard. He explained that NIPSCO is using a scorecard to navigate the “most viable” retirement and replacement paths, noting that NIPSCO elected to remove the “red-yellow-green” color-coding in an effort to be more quantitative in the scoring. He then reviewed the Reliability Risk, Employees and Local Economy portions of the scorecard, noting that Mr. Augustine had already covered the Cost to Customer, Cost Certainty and Cost Risk components. For Reliability Risk, he noted that activities, timelines and risk of the MISO retirement process, transmission system upgrades, remaining unit dependencies, fuel and maintenance contracts, future resource procurement and the percentage of the system turning over at once were factors that were considered, but did not rise to the level of driving risk acceptability.

Regarding the impact on NIPSCO employees, he noted that there are over 400 employees at coal units that are focused on reliably and safely generating electricity for NIPSCO’s customers. This was an important consideration in the retirement analysis, with the criteria utilized being the number of employees that are impacted by retirement plans prior to 2023. His final criterion was the local economy, specifically the property tax payments made by the generation facilities to local communities. This was quantified by estimating the present value of future property taxes relative to the 2016 IRP. Mr. Douglas finished by noting these criteria are important to be considered in concert with the financial metrics to provide a comprehensive perspective on retirement considerations.

Mr. Douglas explained to participants that a number of slides were marked “preliminary, subject to change.” He further explained that this is not because NIPSCO expects the underlying analysis to change, but that the Company continues to review and ensure there are no refinements needed, including any stakeholder feedback received. He then reviewed the Retirement Scorecard, noting that the criteria discussed are along the left side. He then explained that retiring coal earlier is the most cost effective option as well as the highest cost certainty and lowest cost risk. He noted that Combination 8, which is 0% coal in 2023 has the lowest net present value requirement (“NPVRR”), with Combination 1, which is 65% coal through 2035 having the highest cost.

Mr. Douglas then noted that Combinations 1-6 are acceptable from a Reliability Risk perspective, but 7 and 8 are unacceptable. He explained that Combination 7, 15% coal by 2023 is not executable in the time allotted due to required transmission upgrades to maintain system reliability. These upgrades require coordination with MISO as well as having environmental wetland management issues, meaning they will not be complete until 2022 under the best case scenario. Combination 8 would require NIPSCO to retire and replace 1,800 megawatts ("MW") at one time. And, while the RFP indicated sufficient capacity, that much transition at one time could create reliability and execution risk for customers that the Company is not willing to accept. Furthermore, he noted, there are benefits to staggering the transition to allow for better views of technology.

After reviewing the impact to employees and the local economy (which is measured relative to the 2016 IRP retirement plan), he noted that, as indicated by the red dashed box, NIPSCO selected Combination 6, 15% coal in 2023 as the "most viable" retirement path. This Combination was selected at a high level because it is the lowest cost option that held acceptable reliability risk for customers and the system. He then provided additional details about Combination 6, including that it is preliminarily projected to save customers $1.5 billion relative to NIPSCO's 2016 preferred plan, it provides enough time to complete the necessary transmission upgrades, replacement resources can be reasonably secured by 2023, and it allows NIPSCO to continue to assess customer, technology and market changes over the next decade. Mr. Douglas also noted that Michigan City Unit 12 will be maintained through 2028 and there are no plans to retire the combined cycle gas turbine ("CCGT") at Sugar Creek at this time. He then reiterated that these decisions are not final.

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

- Slide 27: So the retirement analysis compares the cost of keeping a unit to replacing it with the most economic resource. It seems like that optimization does not actually take place in that retirement analysis, only replacement analysis?
    - It is taking place here, as the Company develops the least-cost optimized alternative set of resources for each retirement portfolio. In the full replacement analysis NIPSCO also incorporates environmental and risk metrics, so there are more considerations against which to develop replacement portfolio. Here the Company is putting all RFP results into the optimization model to find a least cost benchmark vs. coal retirements. The extra layer for replacements will be added later.
- So the retirement analysis is pitting existing resources against the most economically optimal resources from the RFP?
    - Yes.
- Regarding the treatment of stranded costs of existing resources, could you address that directly and specifically for the scenario in which the existing resources are retained? You have a set of cash flows – and then in scenarios where replaced, do you continue to reflect the ongoing capital costs of those resources after retirement?
    - All existing resource capital is recovered over time with the same depreciation rates used across all portfolios. There are some small credit backs after a unit is retired – property taxes, for example. However, in terms of current invested capital, all costs are assumed to be recovered over time, regardless of whether a plant is retired or not. Depreciation is assumed to occur through 2030.
- Through 2030? What is that date?

  - This is an assumption that the Company is using to be consistent with NIPSCO's internal depreciation rate. The coal plants were scheduled to generally operate through the 2030s. Based on the initial retirement analysis results, the Company tried to move to a depreciation assumption that accelerates recovery slightly, but does not put all of the costs immediately back on customers.
- Does that mean that you take full amount of stranded costs and those costs get recovered through 2030, meaning the depreciation rate would increase?
  - Yes – the remaining net book value of the facility is recovered, including a return on the investment, through 2030. The depreciation rate has been adjusted accordingly.
- By doing that, you are essentially burdening the replacement assets with an additional amount of depreciation in those years?
  - Yes, the Company is putting an additional cost into the portfolios with replacement assets that would not have otherwise been there. The best way to think about is that NIPSCO tried to build in what it believes can be recovered going forward. The assumption is that the Company is going to be able to recover the deprecation going forward to a certain date. It is not viable to go out past 2030, which would drag recovery way past the date of retirement.
- For the record, the last IRP update in 2016 – the Plan called for the retirement of Michigan City in 2018. There are many people with asthma. Questions: 1. ELG – is that natural gas plant and once that coal retires you are not going to replace with natural gas? 2. Have you calculated the resistance to natural gas plants that is progressively growing with people who are opposed to fossil fuels?
  - 1. "ELG" stands for effluent limitation guidelines. This has nothing to do with natural gas, but rather a capital expenditure associated with environmental compliance at the coal plants. 2. The Company will get to the replacement options, including natural gas and renewables later. Those will be presented in a similar scorecard.
- Demand Side Management ("DSM") referred on Slide 29 – is that peak load and energy efficiency?
  - Yes, it is a combination and based on the program bundles developed from the study conducted by GDS Associates. That study aggregated programs and not a single peak demand response options. The peak impact is shown here.
- Slide 29 – scenario 8 – so the all coal replacement shows 715, 1395, 1825 MW but the RFP was only for 600 MW. How do you reconcile that? Will NIPSCO need to do a new RFP?
  - The RFP asked for an approximate 600 MW but around 10,000 MW of resources were offered. The capacity shown here is all from the RFP.
- If you have an aggressive energy regulatory environment – the savings of going to scenario would be $5.8 billion, right?
  - Yes, that number is the net present value ("NPV") over the 30-year period.
- Retirement scenario 7 – how much ELG compliance is required? What needs to be done if you followed scenario 7?

- The short answer is that the Company would not need to do anything from an ELG compliance position under retirement portfolio 7.
- Just to be clear, on Slide 32, this assumes the resource plans shown on Slide 29?
  - Yes, the numberings are the same. The portfolio number labels refer back to slide 28, which is the overall legend for the 8 plans. However, please note that none of these represent a final resource plan at this point.
- Where you have portfolio transmission targets what are those? We (the NAACP) have also called for a reduction of CO_2 based on location, is that reflected somewhere?
  - In terms of location, there is no separate location metric.
- Only based on retirement? No additional efforts or ability to reduce CO_2 even if not retired?
  - Yes, all results are based on the various portfolios established in this retirement analysis.
- On the scorecard – when looking at local economic impact of retiring – where would you put in analysis any potential property tax revenue to for example Jasper County – from the renewables? Solar, wind, it looks like only looking at negative but not taking into account future property tax revenues from those?
  - NIPSCO is considering and thinking about the economic impact of replacement resources. This scorecard feels a bit like negative impacts are shown. There are positives on the Replacement Scorecard.
- On the employee side – we (the NAACP) do a lot of narrative regarding the just transition and preparing folks for the clean renewable energy sector. For example, the organization is a big proponent of an apprenticeship program – NIPSCO have anywhere envision that?
  - NIPSCO is absolutely open to that. The Company is engaged with Ivy Tech now on that type of program today to prepare employees. NIPSCO is more than willing to broaden in future – some ongoing dialogue or thoughts are welcome. There will be a need for that. There will be a switch for NIPSCO's employees and fewer employees will be required.
- The present value is basically the amount of money you have now?
  - Yes, it discounts future value back to today
- What time period are you looking at for the property tax metric?
  - Schahfer 14, 15, 17, and 18 and Michigan City unit 12 all have different lives associated with them. Generally coal plants are scheduled to retire at an age of about 60 years. Schahfer would be scheduled to operate until almost 2040 and Michigan City until 2035. So if a unit is now scheduled to retire in 2023, the loss of property tax income would be calculated over the time between the new retirement date and the original end-of-life assumption.
- Reliability risk is the only one not quantified. Is there any other Quantitative assessment?
  - The Company tried to assess all activities associated with a potential retirement. This includes transmission upgrades. For example, the plan requires three lines to rebuild or build stronger. The MISO retirement

process, remaining unit dependencies at Schahfer, and future resource procurement are also factors. For example, on future resource procurement, NIPSCO will need to execute on multiple bids from the RFP and this does not happen overnight. Also, the analysis considered the percentage of NIPSCO's system turning over at once. When you think about retirement portfolios 6, 7 and 8, you are in the neighborhood of 60%-75% of the system changing at same time.

- Please confirm that the analysis includes some of the spending that currently goes from NiSource through the plants rather than employee spend. Does this include contractor, indirect employment and impact both locally and broader scale, including that given to suppliers? Is this a comparison between current spending and that going forward?
  - Yes. This looks pretty narrowly at the property tax portion. There are obviously economic multiplier effects, but the Company has not taken all of that into account at this time. NIPSCO is cognizant of the impact on communities and is in discussions with them. On the upside, there is potential to build and own resources in some of these communities. That could offset some of the number.
- The geographic distribution of the renewable resources and how you look at that for location – and how meshes up with existing transmission distribution network
  - The Company has been looking at specific sites, but do not currently have a map to share. However, all are within MISO Zone 6, which means that the majority are in Indiana, and there are a good amount that are in the service territory today. That is a positive sign. The Company is working through the specific economics, but right now the alternatives are primarily Indiana-based.
- Remind me have you presented data as to the capital expenditures for maintenance and replacement of existing projects related to your existing fleet – or are those expenditures just embedded?
  - All of those estimates are embedded in the model. NIPSCO's Major Projects group estimates the costs to maintain the units into the future, as well as the costs to potentially wind down the operations at each facility. Those estimated costs are built into this analysis.
- If presented, where is it?
  - The numbers can be shared. The high level numbers were shown during a previous meeting and were directional and aggregated.
- What impact for Terre Haute facility?
  - The Company intends to continue to operate Sugar Creek, which is a 550 MW natural gas CCGT. The plant is economic and has a high capacity factor today.
- Can you talk about how the solar tax credit expiration affects this and the end of the wind production tax credit ("PTC")?
  - Ultimately it is assumed that the projects would take advantage of both. The PTC for wind begins to sunset in 2020. The investment tax credit for solar goes until 2023. The plan is to take advantage of both.

- Has NIPSCO analyzed a retirement scenario that starts in 2021 and then staggers the retirements over the next few years?
    - o Yes, Retirement Portfolio 7 does exactly that. As part of reviewing the potential plan, it was discovered that it requires fairly significant transmission line upgrades, which would require environmental permitting associated with wetlands and rights-of-way. Secondly, that portfolio requires MISO coordination, and it would be into 2022 for all of that to occur. It was better to package the retirements together in 2023 to allow for some contingency in the schedule for potential environment and permitting issues.
- NIPSCO's IRP is off schedule. When will the next one be submitted? In 2021 or sooner?
    - o The Indiana Energy Association submitted comments to the proposed rule suggesting an addition to allow for a utility to take its IRP out of the normal schedule. NIPSCO will work with the Indiana Utility Regulatory Commission ("IURC") on the date for the next submission.
- Can you quickly summarize the key stakeholders? Also, who makes final decision – the chief executive officer, the board of directors, who?
    - o Related to stakeholders – they are vast – customers, and most of the groups represented in this room. NIPSCO takes seriously the involvement of people from this room. NiSource owns the ultimate decision. A management team and a steering team has met on a bi-weekly basis to walk through options. Given the potential significance of changes, the NiSource board of directors is aware, but does not approve formally. However, since the replacement plan will likely require large capital expenditures, board level approval will be required going forward.
- What do you anticipate as the challenges of the MISO process through the retirements? Do you anticipate any significant challenges?
    - o The Company has run its own analysis to evaluate transmission upgrades that are needed from reliability standpoint. A similar analysis was completed for the Bailly retirement in May. MISO said NIPSCO needed to only do synchronous upgrades, which were completed.
- The reduction in employees – scenarios 7 and 8 – is it calculated as the dollar amount of operations or by personnel? Is that calculated in there as part of the savings to the company, or the bottom line cost to customers?
    - o The analysis assumes that fixed operations and maintenance costs, which include labor, would no longer need to be expended after a retirement. Does that mean the employees will not still be with the Company? Not necessarily, since just like with Bailly, NIPSCO could keep employees in other areas of the company. However, expenses associated with those employees are going away in relation to retired facilities.
- Concerned about those jobs in the "clean energy economy." In looking at scenarios 6 and 8, what would ramp you up to 0% coal and 2023? What is the $20 million included on the scorecard?
    - o That would be the local economy number.

- Regarding the cost to customers ($11,151 million for scenario 7 $11,307 million for scenario 8). How do you get the costs for scenario 8 – seems negligible?
    - o The difference between scenarios 6 and 8 is the retirement of Michigan City. However, the early retirement would shift 75% of NIPSCO's physical generation assets at one time, so keeping some capacity for a slightly longer period is the Company's most viable plan right now. The management team views the difference as a negligible cost as well, but the reliability that the plan gives us is valuable.
- Is it not true that if the Company wishes to recover its undepreciated capital in the coal plants, it will require IURC approval?
    - o Yes, that is correct.
- Babcock and Wilcox – is that study available?
    - o That is only used as an example of an engineering firm. There is no study produced by that firm

Replacement Analysis
Pat Augustine and Dan Douglas

Mr. Douglas started the review of the section by reminding participants that NIPSCO has forecasted a 2023 peak demand of just over 3,000 MWs. He stated that retiring the units at Schahfer and Michigan City will lead to a combined 1,820 MWs required. Based on this, NIPSCO completed its replacement analysis, which, like the Retirement Analysis, is still preliminary. He reviewed the replacement analysis framework, noting that the RFP was a main source of information for determining replacement options. Mr. Douglas noted that nearly 10,000 MWs of unforced capacity ("UCAP") was offered through 90 different proposals covering a broad range of technologies. These included both power purchase agreements ("PPA") and ownership options. He told the stakeholders that NIPSCO will not be releasing a short list of finalists; rather that information will be part of any certificate of public convenience and necessity process. He also informed the group that NIPSCO has begun to reach out to several bidders and is working through the list. That process is being facilitated be a separate department within Charles River Associates.

Mr. Augustine reviewed how DSM would be incorporated into the IRP modeling process. Specifically, three bundles were determined and run through the optimization model, with the model selecting bundles 1 and 2. He then provided a recap of the August 28 Technical Webinar with a reminder on tranche development and assessment. He then provided an overview of the replacement analysis, explaining that different replacement combinations were created to explore the range of ownership/duration and diversity possibilities. This created six replacement portfolios, which were categorized as high, average, and average-low carbon emissions and then short- or long-term duration. Mr. Augustine then went through the replacement analysis for the various scenarios and then the stochastics. Finally, based on the stochastics, he showed the cost risk for each of the replacement scenarios being considered and noted this was all still preliminary.

Mr. Douglas then reviewed the Replacement Scorecard. As with the Retirement Scorecard, the Replacement Scorecard is being used to help navigate the various paths and NIPSCO has done away with the “red-yellow-green” color coding in favor of more quantitative scoring. He noted that there are some nuances from the Retirement Scorecard. As with the Retirement Scorecard, Mr. Douglas explained how fuel security, environmental, employees and local economy were considered in the Replacement Scorecard. Regarding fuel security, he noted that the criterion assesses NIPSCO’s ability to reduce exposure to short-term fuel supply and/or deliverability issues, which is expressed as a percentage of capacity sourced from resources other than natural gas in 2025. Mr. Douglas explained that the environmental criterion considered the annual carbon emissions from the resource portfolio in 2030 by metric tons of CO_2. For employees, he explained that the number of NIPSCO jobs added for the resource portfolio was considered. And, finally, for the local economy, NIPSCO considered the property taxes for the portfolio, without making a determination of where the facilities would be, only considering assets that would pay property taxes.

After providing this background into the scorecard, Mr. Douglas provided the preliminary results of the analysis. He noted that NIPSCO does not expect the results to change directionally, but the analysis will continue to be reviewed, including taking stakeholder feedback into account. Mr. Douglas stated that the left side includes the criteria included in the scorecard and the various scenarios are laid out across the top. He said that including renewables is the least cost option as well as the highest cost certainty and lowest cost risk. He noted that, by comparison, portfolios with natural gas technologies have a cost over 10% higher than renewable—only portfolios. Portfolio F, which is long duration and average-low carbon pricing, which is predominately long-term renewable PPA, DSM, and a small amount of market purchases, is the lowest cost option and the strongest portfolio from a fuel security standpoint. In addition, he said, it provides the lowest emissions for customers.

Mr. Douglas pointed out that, in order to be competitive, a natural gas turbine would need to be $300/kilowatt (“kw”). However, new plants are roughly $1,000/kw and that no CCGT was included in a response to the RFP at that price. He once again stressed that the decision is not final and that the Company is open to feedback over the coming weeks to adjust this direction.

In summarizing this section, Mr. Douglas stated that NIPSCO believes the retirement and replacement path will provide reliable power, enable lower costs and provide significant environmental benefit. He noted that the scorecards demonstrate that retiring coal and replacing with renewables will create significant savings. Finally, from a reliability perspective, he committed the Company to making sure the plan keeps the lights on for its customers. He stated that transitioning from coal to renewables is a significant move and NIPSCO is approaching the shift with an appropriate level of caution and analysis.

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

- What is the MW of interruptibles on Slide 37?
  - About 600 MW
- Slide 38: Regarding hydro. Please explain the hydro-where is it located, is it water, what will be impacted?
  - The hydro plants are powered by water. They are fairly small – less than 20 MW of nameplate capacity. Ultimately NIPSCO only gets capacity value of 5 to 7 MW.
- Confirm that all projects considered are in the MISO queue on slide 39.
  - They are at various stages in the MISO queue, and some are not formally in the queue yet. Currently NIPSCO is looking for 2023 assets, so this is not surprising.
- What are the locations for the technology ownership? I am struggling with carbon markets and trading. Is this where the wind turbines are located or where the PPA is coming from? If located in other states, is this where the Company will get credit for purchasing clean energy?
  - The RFP asked that all assets be deliverable into MISO Zone 6. Environmental credits would flow to the owner of the facility. It is important to note that there is no carbon market, so with respect to CO_2 credits, the input assumptions introduce costs associated with operating plants that emit carbon.
- Regarding "cap and trade," some states will still pollute with coal fired power plant and then be able to purchase clean energy from another states and that considered acceptable with federal guidelines with cap and trade system. Did NIPSCO consider this?
  - It is hard to speculate now because there is no-cap-and trade program in place. The latest Affordable Clean Energy rule from the U.S. Environmental Protection Agency ('EPA") does not create a tradable commodity. Again, any CO_2 costs in the assumptions are costs only.
- Why would NIPSCO purchase clean energy out of state as opposed to producing in Indiana and phase out coal retirements – why would build in another state?
  - It would be based on economics. For example, Oklahoma has great wind resources, although you have to pay for the transmission path. For example, NIPSCO may be able to produce at $25/MWh here in Indiana but it could be more cost effective to get from Oklahoma if it can be obtained for $20/MWh, including transmission. If the resources are cost neutral, the Company certainly would have a bias in terms of service territory, but again, NIPSCO is letting economics lead. The vast majority of RFP responses are in Indiana, so it is unlikely that we will pursue significant out-of-state resources.
- The "installed capacity" – does that mean there are already facilities?
  - Installed Capacity ("ICAP") is the total capacity that a plant could output at any given time. UCAP is the capacity available when the MISO market is at its peak. For example, solar output is fairly well aligned when load

peaks in the mid-to-late afternoon, so MISO discounts the UCAP to 50%. Wind, however, is much lower – around 15%. This is because the wind does not typically blow in the summer afternoons when you have the MISO peak.

- For DSM that was the achievable level from the MPS?
  - Yes, bundled together by cost.
- Was there an amount higher than that bundled in?
  - There was a high case, but only the achievable base case went in.
- To clarify, NIPSCO chose not to use the decrement model sent by the Citizens Action Coalition of Indiana, Inc. ("CAC")?
  - Correct, the decrements have not been isolated individually. The analysis would likely find a similar set of results if the decrements were used since it is just a different way of organizing the data. The goal here was to put DSM on equal footing with the supply side options.
- Is NIPSCO willing to sit down with the CAC to see how using the decrement model would impact the analysis?
  - Yes.
- Is a "MISO Capacity Purchase" different from a PPA? How?
  - Yes, the decision was made to carve out 400 MW of MISO short-term market purchases in the short-duration portfolio concepts. This is separate from any PPAs offered in the RFP.
- What is the cutoff (in years) between short and long term duration PPAs?
  - Short term is generally defined as 15 years or less. In concepts A & B, a 6-year CCGT option was included. In concepts B & C, the shortest renewable PPA was 15 years.
- Overview of all the responses tabulated, if technology gave you an option, how is that being categorized? As PPA, long term duration, etc.?
  - An initial level of screening was performed to see whether an asset sale or PPA was more economic and then kept it in one tranche to avoid double counting. Overall, PPA and asset sale costs for the same asset were similar. Project-level pricing analysis is being done on the RFP team and not as part of this IRP.
- Is this analysis neutral on whether the asset would be secured by PPA or through NIPSCO self-build?
  - Yes. NIPSCO has completed a self-build CCGT analysis and compared it to the RFP results. The internal build cost is higher than what can be obtained from the market, and the Company is no longer evaluating or considering a self-build CCGT option.
- Why do bundles A through F add up to 1,720 MW when earlier it was noted that 1,810MW was needed?
  - Note that DSM is not shown in each individual box, but is included for each portfolio.
- Point of Clarity, when doing the calculation we included DSM in the 1,720 number.
  - The number that is being targeted for 2023 is 1,400MW, which would allow for all of the Schahfer capacity to be replaced. The question might

be referring to the additional capacity associated with the Michigan City retirement in 2028. You should note that the replacement capacity here is only showing RFP capacity that is selected in the 2023 time period. Beyond that, there are generic solar additions that fill future gaps associated with Michigan City.

- Is the cost to customer based upon on the levelized cost of entry (LCOE)? If yes, has there been any analysis of the impact of the scenarios on year-by-year rates?
  - The cost is based on a full build-up of an all-in revenue requirement, baking in all costs associated with new resource options and annual spend associated with maintenance, capital, fuel, and other costs associated with the current fleet.
- The question is actually whether the costs are levelized?
  - All inputs are annual numbers reflecting when the various costs would be faced over time. The results summaries are presented as an NPV, but there are year-by-year results which can be provided.
- And does the "Cost to Customer" include recovery of the undepreciated capital of the retired plants?
  - Yes.
- Slide 44- visually if I am looking at the lowest point on portfolio C, it appears to be lower cost than portfolio F, is there a measure between the delta?
  - No there is not a metric for that, since the analysis focused on upside cost risk. You are making a good point, since there are outcomes where C is lower cost than F. This tends to occur when there is no carbon price and power market prices are low. However, on the flipside, the opposite is true. If the market is higher, having that exposure in portfolio C will bring the cost up on the high end.
- For short duration project, what you assume comes after is that you are choosing generic projects for the remaining 30 years?
  - The Company is assuming that a generic set of resources, which tend to be solar, are included after the expiry of short-duration projects
- Just to be clear, portfolio F is in UCAP. So the ICAP value is going to be closer to 2,600MW in round numbers, correct (assuming that it is mostly solar)?
  - That is generally fair, yes. Portfolio F has around 150-200 MW of wind UCAP, which translates to around 1,000 MW of ICAP. The remainder is solar or solar plus storage, so it is fair to say that the total ICAP of the renewables would be in that range.
- Regarding the environmental metric, can you clarify what is meant by "inside the fence line" and is this in line with what you are developing/retiring to this metric? Also, discussion on measuring out co-pollutants on CO_2.
  - Yes, co-pollutants are being discussed with the Environmental team. “Inside the fence” means owned by NIPSCO, although not necessarily physically in its service territory. Assets such as Sugar Creek are outside of the territory, but owned by the Company. The policy is to record emissions only for units owned by the Company.
- Do the PPA agreements presume NIPSCO liability for CO_2 emissions?

  - For reporting purposes, NIPSCO is following EPA rules - if it is accounted for it but if another entity owns it, the owner will count it too, so that double counts.
- Is it appropriate to assume all portfolios A-F meet all criteria in reliability scorecard?
  - Yes.
- Just to clarify, how is the carbon price applied to PPAs?
  - The carbon price is added to the variable cost component of gas-based PPA bids. Bidders did not explicitly assume a cost for carbon, so it was assumed that NIPSCO would pay for any future carbon costs as a pass-through in the same way as the cost of natural gas. The CCGT PPAs tend to be structured around a fixed capacity price plus variable costs, and carbon would be included in variable.
- The CO_2 emissions should be reflected in scorecard.
  - NIPSCO Understands the concern and a one-on-one follow up is welcomed.
- What is the sense of solar or wind or some other unknown resource?
  - If NIPSCO had to make an assessment from a UCAP perspective it would be solar because wind UCAP ratings are lower. But ICAP may be larger for solar as well.
- Are you talking about familiar fields of solar panels?
  - The IRP team has not looked at RFP responses, but these projects are large scale wind and solar photovoltaics.
- Are you trying to normalize this to NIPSCO customers, what will this do to my bill and how are you going to communicate that?
  - Hard to answer. Cost savings will be realized from the retirement/replacement plan. The analysis indicates this path would be lower than if the Company continued with coal assets. Does that mean, lower bills? That cannot be answered at this time, but it is clear bills will be lower than the alternative.
- Are you assuming solar plus storage or bids for both?
  - The Company did receive bids for solar plus storage.

Stakeholder Requested Scenarios
Pat Augustine

Mr. Augustine provided an overview of scenarios requested by the Indiana Coal Council and the Office of Utility Consumer Counselor ("OUCC"). He said that the Indiana Coal Council requested NIPSCO look at retirement combinations with less costly environmental compliance for Schahfer Units 17/18 and an alternative market case. He then provided the results of that scenario. Mr. Augustine then reviewed the OUCC's request that NIPSCO consider converting Schahfer Units 17/18 from coal to gas and provided the results of that request.

- Why would you need to kick water out to convert?
    - After discussions with OUCC, it was determined NIPSCO should update the environmental compliance assumptions. Some of the original cost assumptions included would not be needed on a coal-to-gas conversion. Under this scenario, some stack to re-work would be required, but not the de-watering.
- Confirm, if converted to gas, would or would not need water?
    - Would not need water.
- Why not compare the lower environmental capital expenditures to scenario 6?
    - Those results are available. However, the point here is to provide an apples-to-apples comparison of keeping Units 17/18 vs. the RFP alternative. Thus, the intent of showing retirement portfolio 2 is to isolate the impact of the Unit 17/18 economics, without also incorporating all of the other impacts of retiring 14/15 and Michigan City. The results for other portfolios are available for those who have interest.
- Slide 51, the $438 million assumes same capital needs as current coal needs - would like to understand why that assumption is reasonable?
    - Because of other communication commitments, no operations staff were available. However, the costs are boiler costs, so they would be the same, whether the unit(s) is/are fired by coal or gas. NIPSCO is committed to working with the OUCC on this issue.
- Is it fair to put “TBD” on the environmental compliance number?
    - That is fair since there may be updates to be made. NIPSCO will work with OUCC to refine the analysis.
- OUCC would agree but would want best numbers possible and sure that scenario is still best, but would like actual numbers. OUCC not coming across that they prefer the conversion but just want to see numbers, not advocating for that.

Stakeholder Presentations

The Sierra Club/Beyond Coal Campaign provided a presentation that consisted of a speech, a video including interviews of NIPSCO customers and a PowerPoint presentation showing the results of a mural made by children in NIPSCO’s service territory.

Ms. Becker closed the meeting by thanking the attendees for their attendance and active participation and noted the next meeting is scheduled for October 18, 2018.

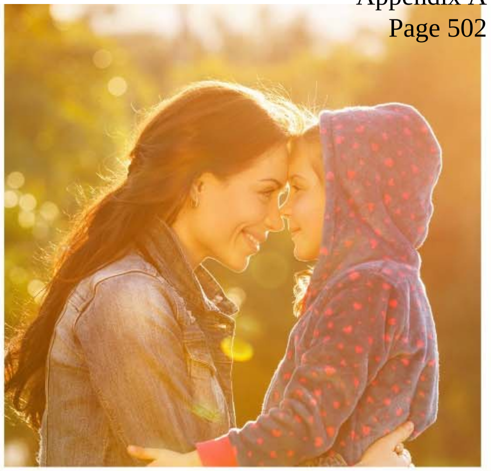
NIPSCO Public Advisory Meeting 4 Registered Participants		
First Name:	Last Name:	Company:
Denise	Abdul-Rahman	Indiana State Conference of the NAACP
Robert	Adams	AES-IPL
Lauren	Aguilar	OUCC
Jake	Allen	IPL
Anthony	Alvarez	OUCC
Laura	Arnold	Indiana Distributed Energy Alliance (IndianaDG)
Pat	Augustine	Charles River Associates
Kim	Ballard	IURC
Richard	Benedict	Self
Anne	BEcker	Lewis Kappes
Mahamadou	Bikienga	NiSource
Marc	Blanchard	BP
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	IURC
Wendy	Bredhold	Sierra Club
Andy	Campbell	NIPSCO
Kelly	Carmichael	NiSource
Joseph	Conn	NWI Beyond Coal Campaign
Jeffrey	Corder	St. Joseph Phase II, LLC
Nick	Corder	EnFocus Development
Dan	Douglas	NIPSCO
Jeffery	Earl	Indiana Coal Council
Michael	Eckert	Office of Utility Consumer Counselor
Amy	Efland	NiSource/NIPSCO
Gregory	Ehrendreich	MEEA
Clare	Everts	Charles River Associates
Steve	Francis	Sierra Club - Hoosier Chapter
John	Garvey	CRA
Fred	Gomos	NiSource
Doug	Gotham	State Utility Forecasting Group
Abby	Gray	OUCC
Stacie	Gruca	OUCC
Corey	Hagelberg	Beyond Coal
Jeffrey	Hammons	Environmental Law & Policy Center
John	Haselden	OUCC
Shelby	Houston	IPL/AES
Paul	Kelly	NIPSCO
Will	Kenworthy	Vote Solar
Sam	Kliewer	Cypress Creek Renewables
Mark	Kornhaus	NextEra Energy
Kim	Krupsaw	Vectren Corp
Tim	Lasocki	Orion Renewable Energy Group LLC
Jonathan	Mack	NIPSCO
Patrick	Maguire	Indianapolis Power and Light
Finnian	McCabe	Ground Star Energy llc

NIPSCO Public Advisory Meeting 4 Registered Participants		
First Name:	Last Name:	Company:
Debi	McCall	NIPSCO
Cassandra	McCrae	Earthjustice
James	McMahon	CRA
Emily	Medine	EVA
Zachary	Melda	NextEra Energy Resources
Nick	Meyer	NIPSCO
Ana	Mileva	Blue Marble Analytics
Adam	Newcomer	NIPSCO
David	Ober	Indiana Utility Regulatory Commission
Kerwin	Olson	Citizens Action Coalition of IN
April	Paronish	Indiana Office of Utility Consumer Counselor
Bob	Pauley	IURC
Jodi	Perras	Sierra Club
Timothy	Powers	Inovateus Solar LLC
Mark	Pruitt	The Power Bureau
Dennis	Rackers	Energy & Environmental Prosperity Works!
Thom	Rainwater	Development Partners Group
Jeff	Reed	OUCC
David	Repp	JET Inc
Adam	Rickel	NextEra Energy Resources LLC
Chad	Ritchie	Lockheed Martin
Edward	Rutter	Indiana Office of Consumer Counselor
Carter	Scott	Ranger Power LLC
Cliff	Scott	NIPSCO
Zachary	Scott	PSG Energy Group
Rob	Seren	NIPSCO
Frank	Shambo	NIPSCO
Regiana	Sistevaris	Indiana Michigan Power Company
Violet	Sistovaris	NIPSCO
Barbara	Smith	OUCC
Jennifer	Staciwa	NIPSCO
Bruce	Stevens	Indiana Coal Council
George	Stevens	I U R C
Emily	Straka	Ranger Power
Alice	Tharenos	peabody
Dale	Thomas	IURC
Maureen	Turman	NiSource
William	Vance	Indianapolis Power & Light
Bob	Veneck	Indiana Utility Regulatory Commission
Nathan	Vogel	Inovateus Solar
Victoria	Vrab	NIPSCO
John	Wagner	NIPSCO
Jennifer	Washburn	CAC
Adam	Watson	NiSource Inc.
Rev. Curtis	Whittaker, Sr.	Progressive Community Church

NIPSCO Public Advisory Meeting 4 Registered Participants		
First Name:	Last Name:	Company:
Ryan	Wilhelmus	Vectren
Ashley	Williams	Sierra Club
Bryndis	Woods	Applied Economics Clinic
David	Woronecki-Ellis	Sierra Club Dunelands Group
Jen	Woronecki-Ellis	Sierra Club Dunelands Group
Fang	Wu	SUFG
Jim	Zucal	NIPSCO

Appendix A

Exhibit 6



NIPSCO Integrated Resource Plan - 2018 Update

Public Advisory Meeting Five

October 18, 2018

NIPSCO®

Welcome and Introductions

Process for Participating Via Webinar

- In order to best facilitate today's discussion, we are asking that you use the "chat" feature on the webinar to ask questions
- Please type your question at any point and it will be read to the audience by the facilitator
- When entering your question, please include your name and organization you are representing (if applicable)
- You may also email questions to nipsco_irp@nisource.com and those questions will be answered as they are received
- We look forward to your thoughts and questions

Agenda

Time (Central Time)	Topics
9:30-9:45	Welcome and Introductions • Safety Moment
9:45-10:30	Public Advisory Process, Review of Prior Meetings and Update on Stakeholder One-on-One Meetings
10:30-10:45	Break
10:45-11:15	Stakeholder Requested Analysis
11:15-11:45	Updated Retirement and Replacement Analysis
11:45- 12:30	Lunch
12:30-1:30	Preferred Resource Plan and Short Term Action Plan
1:30-1:45	Break
1:45-2:15	Stakeholder Presentations
2:15-2:30	Public Advisory Feedback/Next Steps/Wrap Up

Safety Moment:

Fire Extinguisher Use and Limitations

- **Fire Extinguishers are used to prevent small fires from becoming larger.**
  - Do not use them to combat large or rapidly moving fires.
  - Always be aware of your safety and always call the appropriate authorities to combat the fire.
- **P.A.S.S. Method to using a fire extinguisher.**
  - **P- Pull.** Pull the pin. Hold the extinguisher away and release the locking mechanism.
  - **A- Aim.** Aim the stream towards the base of the fire.
  - **S- Squeeze.** Squeeze the lever slowly and evenly
  - **S- Sweep.** Sweep the nozzle side to side to combat the fire.
- **Limitations**
  - A dry chemical fire extinguisher such as the common red “ABC” extinguishers will reach a distance of 5 to 20 feet.
  - A 10lb to 20lb dry chemical fire extinguisher will most likely last only 10 to 25 seconds.
  - Fire extinguishers are to fight small fires only – a good rule of thumb is to use one only if the fire is the size of a small trash can or smaller.
  - Must be inspected to maintain operating order.

NIPSCO's Planning and the Public Advisory Process

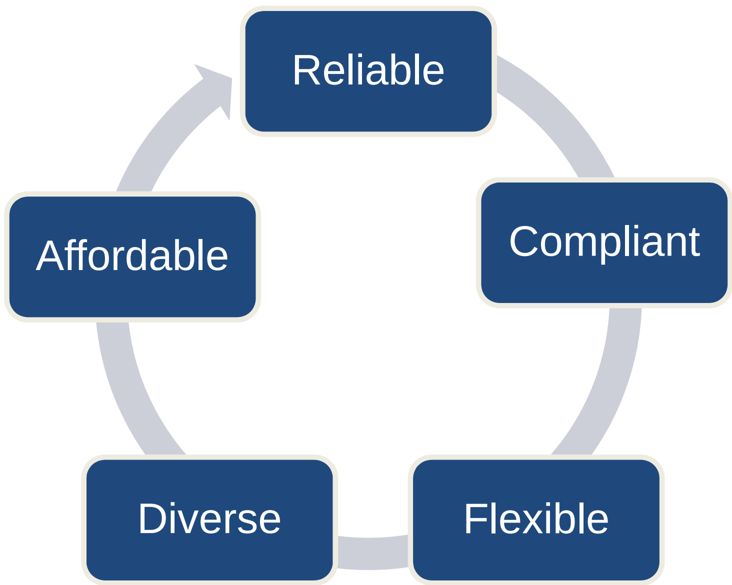
Dan Douglas
Vice President, Corporate Strategy & Development

How Does NIPSCO Plan for the Future?

Charting The Long-Term Course for Electric Generation

About the IRP Process

- Every three years, NIPSCO outlines its long-term plan to supply electricity to customers over the next 20 years
- This study – known as an Integrated Resource Plan ("IRP") – is required of all electric utilities in Indiana
- IRP process includes extensive analysis of a range of generation scenarios, with criteria such as reliable, affordable, compliant, diverse and flexible



Requires careful planning and consideration for all of NIPSCO's stakeholders including the communities we serve and our employees

Overview of the Public Advisory Process

- **Today's meeting is the fifth out of five meetings**
  - Three in-person meetings and one webinar so far
  - Additional technical webinar added at stakeholder request
  - Presentation materials and summary meeting notes are posted on NIPSCO's IRP webpage: www.nipsco.com/irp
- **The Public Advisory process provides NIPSCO with feedback on our process, assumptions and conclusions. This helps inform the modeling and the overall IRP results**
- **Your participation and candid feedback is key to the process**
  - Please ask questions and provide comments on the material being presented and the process itself to ensure this is a valuable exercise for NIPSCO and its customers
- **Ability to make presentations as part of each Public Advisory meeting**
  - If you wish to make a presentation today and have not already indicated so, please see Alison Becker during break or at lunch

Stakeholder Engagement Roadmap

	Meeting 1 (March 23)	Meeting 2 (May 11)	Meeting 3 (July 24)	Technical Webinar (August 28)	Meeting 4 (September 19)	Meeting 5 (October 18)
Key Questions	- Why has NIPSCO decided to file an IRP update in 2018? - What has changed from the 2016 IRP? - What are the key assumptions driving the 2018 IRP update? - How is the 2018 IRP process different from 2016?	- What is NIPSCO existing generation portfolio and what are the future supply needs? - Are there any new developments on retirements? - What are the key environmental considerations for the IRP? - How are DSM resources considered in the IRP?	- What are the preliminary results from the all source request for proposals ("RFP") Solicitation?	- How are the RFP results integrated into the IRP modeling?	- What are the preliminary results from the modeling and how do they inform the retirement and replacement decisions? - What is the "most viable" retirement and replacement path? - What is NIPSCO's forecasted customer demand? - How is NIPSCO modeling risk and uncertainty in the IRP?	- What is NIPSCO's preferred plan? - What is the short term action plan?
Meeting Goals	- Communicate and explain the rationale and decision to file in 2018 - Articulate the key assumptions that will be used in the IRP - Explain the major changes from the 2016 IRP - Communicate the 2018 process, timing and input sought from stakeholders	- Common understanding of DSM resources as a component of the IRP and the methodology that will be used to model DSM - Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap - Key environmental issues in the IRP	- Communicate the preliminary results of the RFP and next steps	- Explain the process for integrating the results from the RFP into the IRP modeling for both the retirement and replacement analysis	- Share with stakeholders most viable retirement path and most viable replacement portfolios - Explain how NIPSCO is modeling risk and uncertainty in the IRP - Communicate NIPSCO forecasts for customer demand	- Communicate NIPSCO's preferred resource plan and short term action plan - Obtain feedback from stakeholders on preferred plan

Stakeholder Interactions

- During the IRP process, NIPSCO has met with and responded to requests from stakeholder groups
- Also received written comments from stakeholders

Stakeholder	Subject Area/Discussion Topic
Sierra Club	IRP Modeling and Scenarios
Office of Utility Consumer Counselor ("OUCC")	All-Source RFP, IRP Modeling and Scenarios, Load Forecasting
Citizens Action Coalition of Indiana, Inc. ("CAC")	IRP Modeling and Demand Side Management ("DSM"), DSM Decrement Approach
Indiana Utility Regulatory Commission ("IURC")	All-Source RFP and IRP Modeling
NIPSCO Industrial Group	All-Source RFP and IRP Modeling
Indiana Coal Council	Scenario/Portfolio Requests
NAACP of Indiana	DSM, On-Bill financing, Retirement Dates
St. Joseph Energy Center	All-Source RFP and IRP Modeling

Stakeholder Requested Analysis Results

Pat Augustine
Charles River Associates

Stakeholder Requested Analysis

- **As part of the 2018 IRP Public Advisory Process, Stakeholders have requested that NIPSCO run the following analyses:**

		Requested Analysis
Stakeholder	OUCC	Evaluate the conversion of Schahfer Units 17 and 18 to burn natural gas
	CAC	Decrements Approach for Energy Efficiency and DSM Modeling
	Indiana Coal Council	Lower Cost ELG Compliance Scenarios Alternative Market Scenario • No carbon price • High natural gas price • $45/ton flat real delivered coal price for 17/18

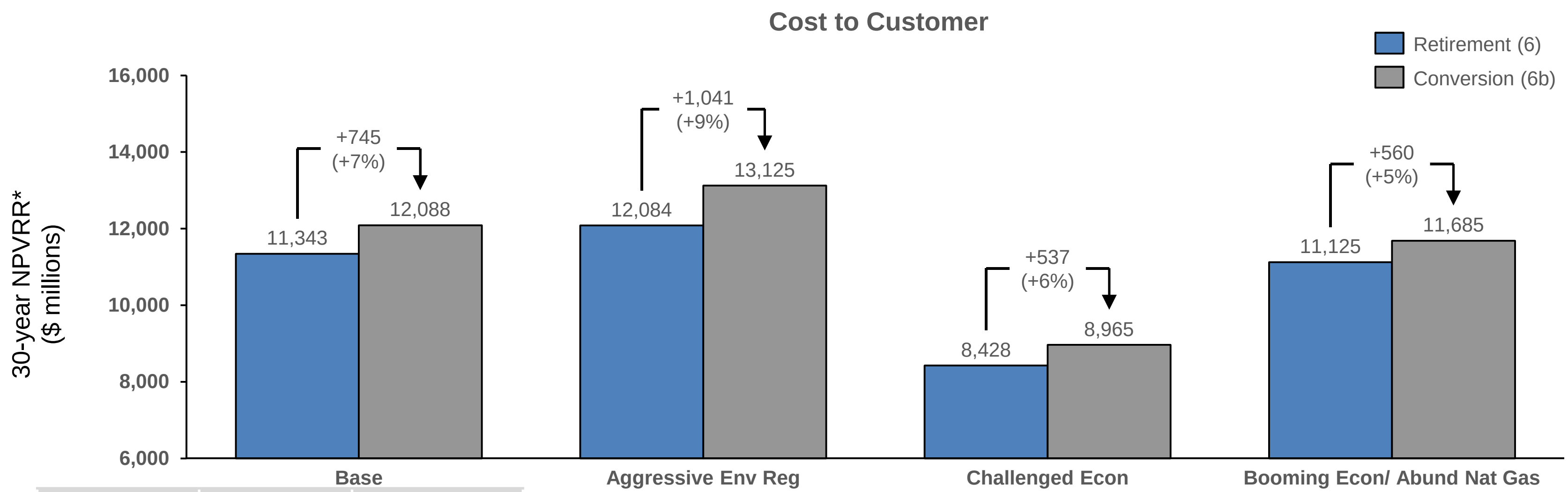
Coal to Gas Conversion Analysis Assumptions (Converting Either 17/18 or Unit 17 only)

	Category	NIPSCO Assumption	Notes
Operating Parameters	Conversion Capacity(megawatts, or “MW”) per unit	302	15% de-rate from current unforced capacity rating (“UCAP”) of 355 MW
	Heat Rate (Btu/kWh)	11,106	
	Forced Outage Rate	10%	

	Category	Estimated Cost	Notes
Conversion Investment Costs	Conversion (2015$)	$43M for 17 $87M for 17/18	• Equipment, materials and construction labor, contingency, owners and indirect costs from Sargent and Lundy (“S&L”) November 2015 Engineering Study Technical Assessment for the 2016 NIPSCO IRP. Estimated cost of $121/kW
	Gas Interconnection	$0M	• Based on the data from the S&L November 2015 Engineering Study Technical Assessment for the 2016 NIPSCO Integrated Resource Plan and a preliminary review with NIPSCO Gas Systems Engineering, it would be possible to convert Unit 17 or Unit 18 to natural gas without installing an additional pipeline as long as both Units 14 and 15 are retired. Leaving Units 14 and 15 in operation would likely create operational limitations related to when the units would be available to start up. Conversion of Units 17 and 18 to run simultaneously would require an additional pipeline. The size of the additional line could be smaller than the 30” referenced it the S&L study but further detailed engineering analysis would be required to determine the appropriate size. Assumed zero cost in analysis
	Environmental Compliance	$0M	• The revised analysis assumes no environmental compliance capital costs if the units are converted to natural gas
Maintenance Capital	Maintenance Capital (Total 2024-2038) Nominal $	$122M for U17 $298M for 17/18	• Assumes maintenance capital needs will be 25% lower than current coal operations. Derived from review of last 3 years of capital expenditures for 17/18 that showed 25% of maintenance capital expenditures was for coal specific components
Ongoing Costs	Fixed Operations and Maintenance (“O&M”) Costs (2015$/kW-yr)	$39	• Based on S&L Study cost estimates for expected O&M post conversion

Coal to Gas Conversion Results (Units 17 and 18): Cost To Customer

- **Across all scenarios, converting both Unit 17 and 18 would cost NIPSCO customers between $540M to $1.04B more than retirement and replacement with economically optimized resource selections from the RFP results**



Portfolio Transition Target:	15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)
Retire:	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 (2028)	Schfr:17,18 (gas) Mich. City: 12 (2028)

Aggressive Env Reg	
15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

Challenged Econ	
15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

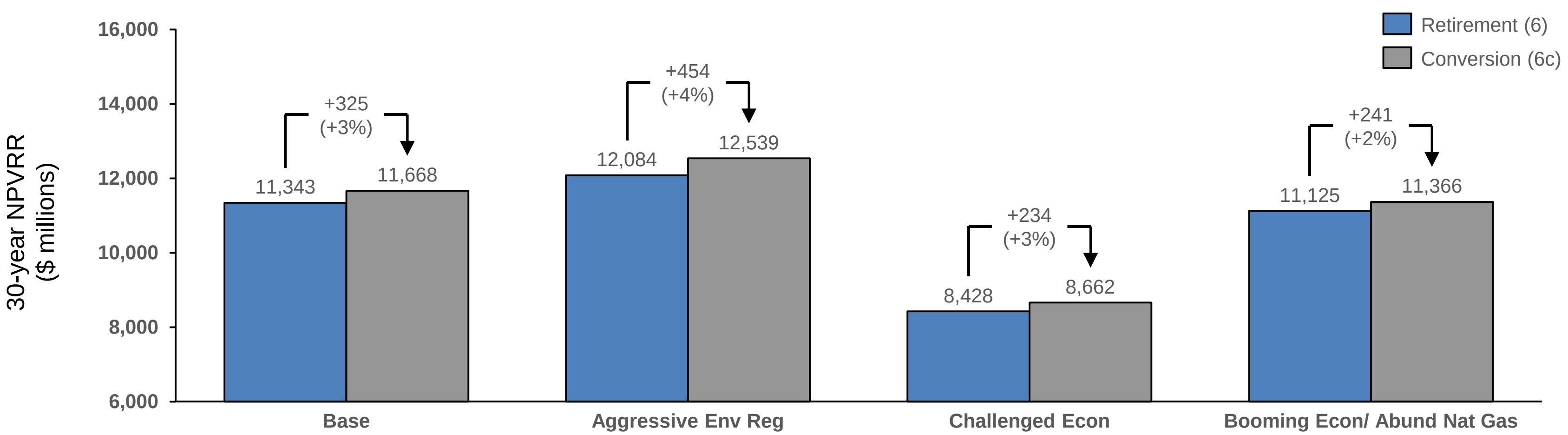
Booming Econ/ Abund Nat Gas	
15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

Michigan City 12	Retire 2028	Retire 2028
Schahfer 14	Retire 2023	Retire 2023
Schahfer 15	Retire 2023	Retire 2023
Schahfer 17	Retire 2023	Convert to Gas 2023
Schahfer 18	Retire 2023	Convert to Gas 2023

*NPVRR: Net present value of revenue requirements

Coal to Gas Conversion Results (Unit 17 Only): Cost To Customer

- Across all scenarios, converting a single Unit (17) would cost NIPSCO customers between $230M and $450M more than retirement and replacement with economically optimized resource selections from the RFP results



Portfolio Transition Target:	15% Coal in 2023	15% Coal in 2023 (Schfr. 17 gas)
Retire:	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 (2028)	Schfr:17(gas) Mich. City: 12 (2028)

15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

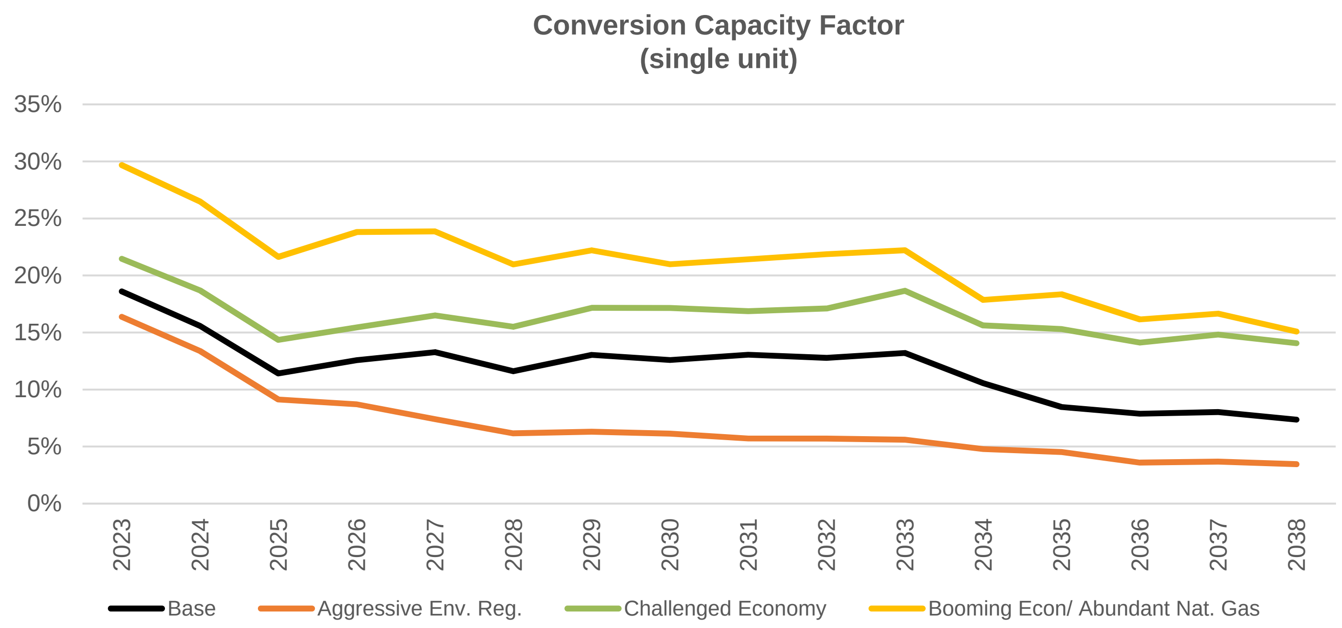
15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

Michigan City 12	Retire 2028	Retire 2028
Schahfer 14	Retire 2023	Retire 2023
Schahfer 15	Retire 2023	Retire 2023
Schahfer 17	Retire 2023	Convert to Gas 2023
Schahfer 18	Retire 2023	Retire 2023

Coal to Gas Conversion Results: Capacity Factors

- **The Base Case capacity factors are in the 7-16% range, while the full range across all scenarios is about 3-25%**
- **Capacity Factors tend to fall over time, as gas prices generally increase and as the Midcontinent Independent System Operator ("MISO") market evolves towards having more lower variable cost capacity.**
- **Under all scenarios, conversion leads to higher MISO market purchases, potentially increasing NIPSCO customer's exposure to market risk**



Notes: 2023 is a partial year, since the converted unit is assumed to begin operating in June. The 2023 annual capacity factor is thus slightly weighted towards the higher summer months.

Decrements Approach for Energy Efficiency and DSM Modeling

- **CAC proposed that NIPSCO consider evaluating energy efficiency and DSM programs with an avoided cost decrements approach.**
- **As per CAC guidance, this approach should do the following:**

When modeled as "decrements," energy efficiency savings are assumed to be fixed in any given modeling run. That is, they are embedded as reductions to the load forecast and are not selectable resources.

- ***The blocks are modeled without any assumption as to their cost.***
- ***The supply-side plan is allowed to simultaneously change with each decrement of efficiency, meaning that it is possible that future supply-side additions could be avoided as levels of energy efficiency increase.***

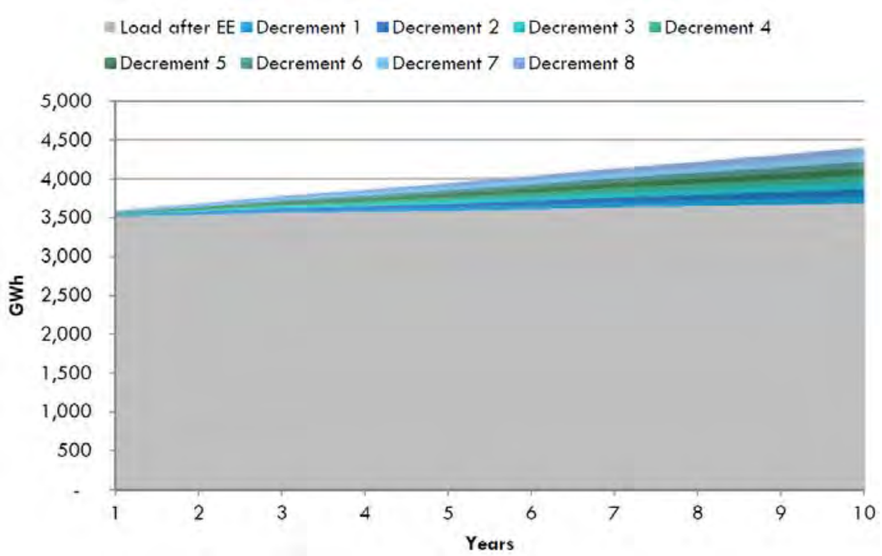
- ***The key output is the net present value ("NPV") of each scenario, which represents the total capacity and energy costs over the study period, discounted to the present year's dollars.***

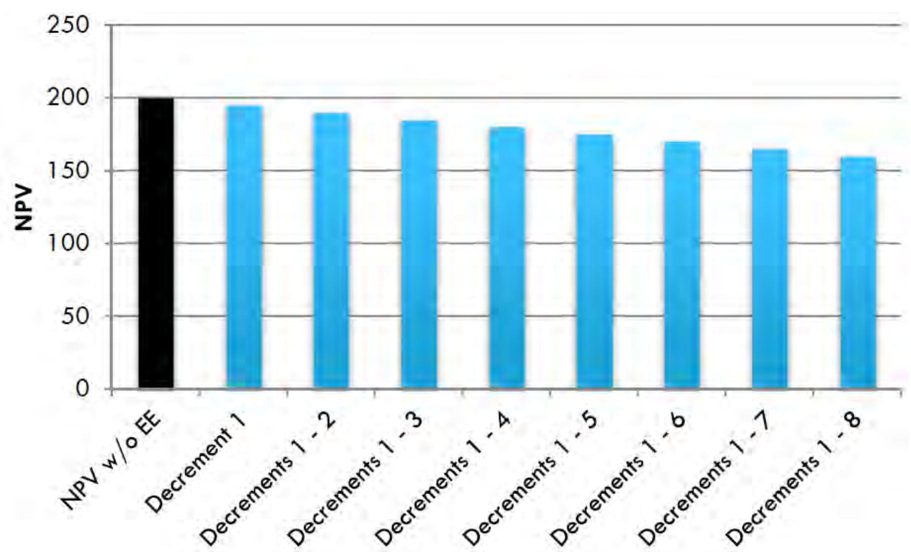
Source: Sommer, Anna, "An Avoided Cost Decrement Approach to Energy Efficiency in IRPs," April 10, 2018

Decrements Approach

- The approach is designed to identify potential decrements (or savings) from the load forecast and evaluate the impacts of such savings on portfolio NPV, without accounting for any costs

Illustrative Load after 8 Decrements → **Illustrative NPV for 8 Decrements**





Source: Sommer, Anna, "An Avoided Cost Decrement Approach to Energy Efficiency in IRPs," April 10, 2018

Comparison to NIPSCO IRP Approach

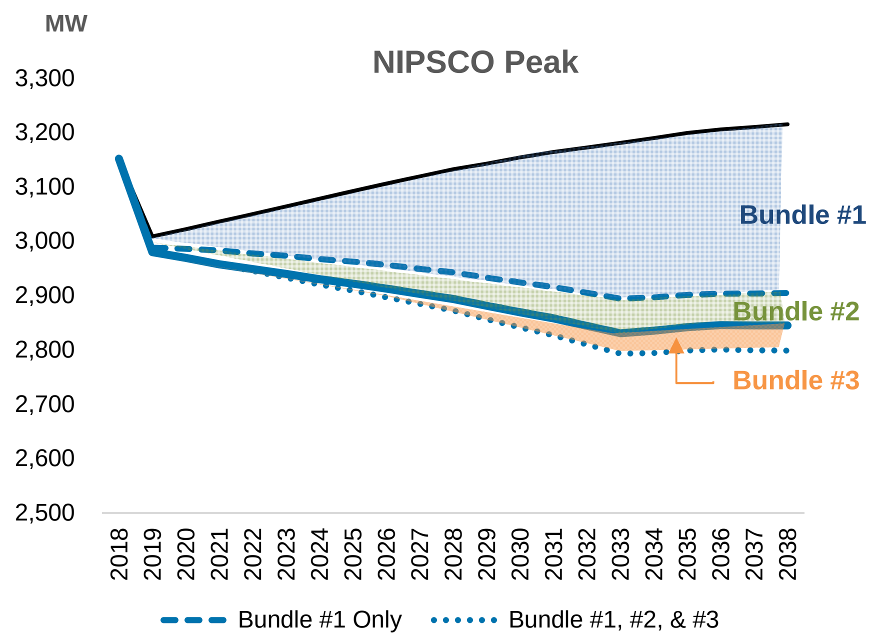
	NIPSCO 2018 IRP	Decrements Approach
EE/DSM input development – energy savings	GDS Associates, Inc. ("GDS") study identified 3 bundles based on a bottom-up program review, organized by cost	Could use decrements of any size (but NIPSCO preserved 3 bundles for hourly shape integrity in its decrements evaluation)
EE/DSM input development – cost	GDS study produced cost estimates for each bundle by residential or commercial and industrial sector	No cost estimates are required, but savings can be compared to costs, as available
Resource selection process	Aurora portfolio optimization evaluates energy efficiency /DSM bundles on equal footing with other supply-side resources (as determined by the request for proposal responses)	No "selection" of resources, as decrements are all "hard-coded" to record savings
Evaluation criteria	Net present value revenue requirement ("NPVRR") within IRP structure	NPVRR of savings, with potential to move cost-effectiveness questions into more detailed DSM study phase

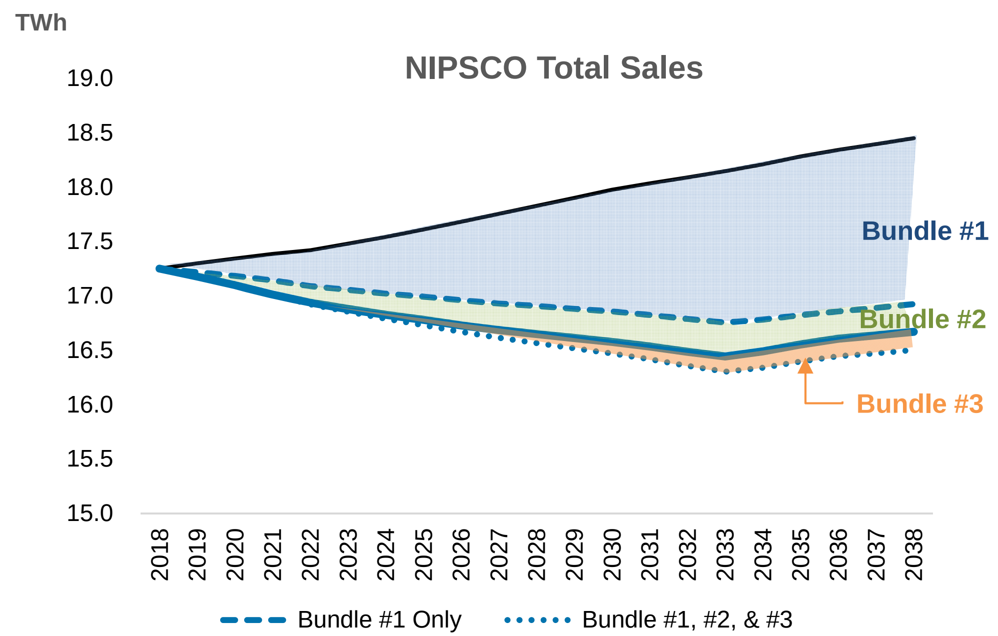
Decrement Definition for NIPSCO IRP

- **In performing a decrements analysis, NIPSCO utilized the same bundles that were established by GDS in its Energy Efficiency Savings Update.**

DSM Bundle #	Weighted Avg. Cost ($/MWh)
1	16.98
2	23.27
3	159.00

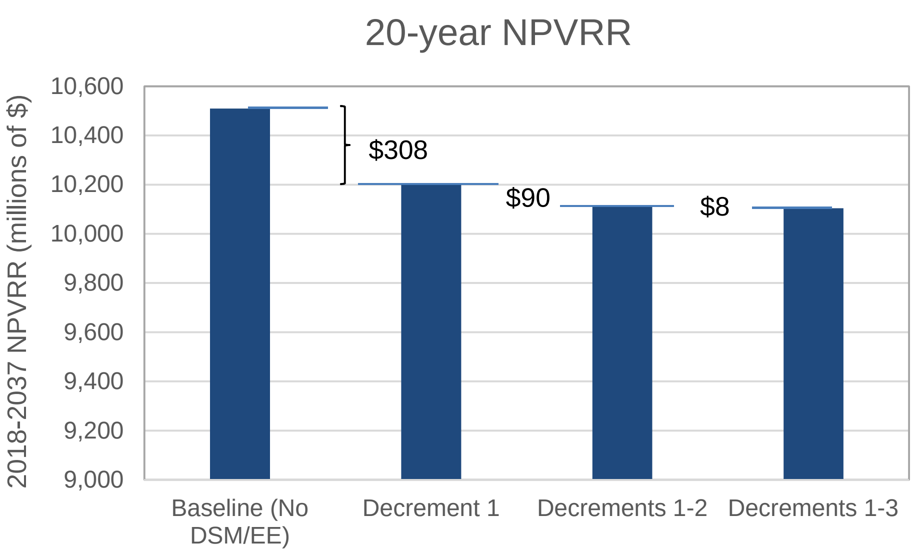
Impact of Selected DSM on NIPSCO Peak and Average Load





Decrement Portfolio Results

- **Decrement portfolio runs result in lower portfolio costs due to <u>less energy to serve,</u> which results in fewer fuel and energy market purchases, and <u>avoided solar capacity additions,</u> either from RFP resources or generic builds**
  - Bundle #1 avoids 298 MW, Bundle #2 avoids 60 MW, and Bundle #3 avoids 43 MW of **UCAP** additions over the forecast horizon



Summary of NPV of Savings and Costs

	NPV of Savings	NPV of Costs	Net Benefit
Bundle #1	307,639,744	131,461,432	176,178,312
Bundle #2	89,685,940	51,063,023	38,622,917
Bundle #3	7,804,359	108,310,129	(100,505,770)

- **Bundles 1 and 2 are cost-effective in this approach, while Bundle 3 is not**
- **This is consistent with the analysis performed in the IRP**

Stakeholder Request – Indiana Coal Council Portfolios for Schahfer Units 17/18

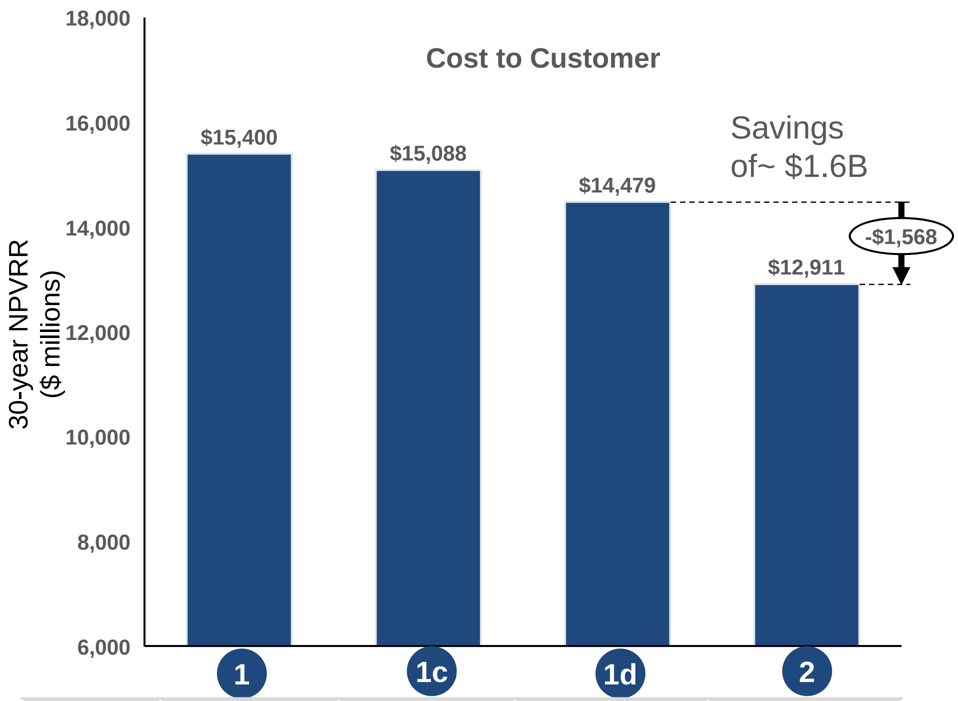
- Indiana Coal Council requested NIPSCO evaluate retirement combinations with less costly ELG-related compliance for Schahfer 17/18 and an alternative market case

	1	1c	1d	2
Portfolio Transition Target:	**65% Coal through 2035**	**65% Coal through 2035**	**65% Coal through 2035**	**40% Coal in 2023**
Retire:	None	None	None	Schfr:17,18 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15
Environmental Compliance	CCR[1] ELG[2]: non-ZLD[3]	CCR ELG: NONE	No Environmental Capital	CCR ELG: non-ZLD
Michigan City 12	**Retain** CCR ELG: N/A	→	→	→
Schahfer 14	**Retain** CCR ELG: non-ZLD	→	→	→
Schahfer 15	**Retain** CCR ELG: non-ZLD	→	→	→
Schahfer 17	**Retain** CCR ELG: non-ZLD NOx[4]: SCR[5]	**Retain** CCR **ELG: None** NOx: SCR	**Retain** CCR **ELG: None** **NOx: None**	**Retire 2023** CCR/ELG: Retirement
Schahfer 18	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retain** CCR **ELG: None** NOx: SCR	**Retain** CCR **ELG: None** **NOx: None**	**Retire 2023** CCR/ELG: Retirement

[1]Coal Combustion Residuals
[2]Effluent Limitation Guidelines
[3]Zero Liquid Discharge
[4]Nitrogen Oxides
[5]Selective Catalytic Reduction System

Stakeholder Request – Indiana Coal Council Scenarios

Base Case



Portfolio Transition Target:	65% Coal through 2035	65% Coal through 2035	65% Coal through 2035	40% Coal in 2023
Retire:	None	None	None	Schfr:17,18 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: NONE	No Environmental Capital	CCR ELG: non-ZLD

Alternative Case – Coal Council

- No carbon price
- High natural gas price
- $45/ton flat real delivered coal price for 17/18

65% Coal through 2035	**65% Coal through 2035**	**65% Coal through 2035**	**40% Coal in 2023**
None	None	None	Schfr:17,18 (2023)
Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15
CCR ELG: non-ZLD	CCR ELG: NONE	No Environmental Capital	CCR ELG: non-ZLD

Retirement Analysis

Dan Douglas
Vice President, Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

Recap: Retirement Analysis Framework

- **The responses to the all-source RFP provided insight into the supply and pricing of alternatives available to NIPSCO and were fed into the retirement and replacement analysis**

- **Representative project groups were constructed from RFP results, assembled by technology and ownership structure, for use in the updated retirement analysis**

	Retirement Analysis	Replacement Analysis
Core question	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?*	*What are the replacement resource portfolios?*
Initial analysis	MISO Cost of New Entry (“CONE”) + market energy	3rd party cost and performance estimates
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers’ needs?

Retirement analysis based on most recent data and representative RFP projects *as selected by the optimization model* – selection driven by economics

Recap: Various Retirement Combinations Were Constructed

Portfolio Transition Target:	1 65% Coal through 2035	2 40% Coal in 2023	3 15% Coal by 2028 w/ ELG	4 15% Coal by 2028 w/o ELG	5 15% Coal in 2023 (Mich. City in 2035)	6 15% Coal in 2023 (Mich. City in 2028)	7 15% Coal by 2023 (Schfr. 17/18 2021)	8 0% Coal in 2023
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035) Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR[1] ELG[2]: non-ZLD[3]	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Michigan City 12	**Retain** CCR ELG: N/A	→	→	→	→	**Retire 2028** CCR ELG: N/A	→	**Retire 2023** CCR ELG: N/A
Schahfer 14	**Retain** CCR ELG: non-ZLD	→	**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement	→	→	**Retire 2023** CCR ELG: Retirement
Schahfer 15	**Retain** CCR ELG: non-ZLD	→	**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement	→	→	**Retire 2023** CCR ELG: Retirement
Schahfer 17	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→	→	**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement
Schahfer 18	**Retain** CCR ELG: non-ZLD NOx[4]: SCR[5]	**Retire 2023** CCR/ELG: Retirement	→	→	→	→	**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement

Currently NOT a viable path for ELG compliance

Note: Retirement Combination 4, 15% Coal in 2028 without ELG, is not currently a viable from an ELG compliance standpoint and is shown for discussion purposes.

[1]CCR: Coal Combustion Residuals
[2]ELG: Effluent Limitation Guidelines
[3]ZLD: Zero-Liquid discharge
[4]NOx: Nitrogen oxides
[5]SCR: Selective Catalytic Reduction

Recap: What Technology Is the Model Selecting From RFP Results?

- **Economic optimization model is selecting DSM and renewables as the replacement resources in all retirement cases**
- **While the model selected resources were used for the retirement analysis, a separate replacement analysis was performed**

Cost-effectiveness: Higher → Lower

2 3 4 — Schahfer 17/18 Retirement (~600MW UCAP need)

TECHNOLOGY	MW
MISO Market Purchase	50
DSM	125
Wind	150
Solar, Solar + Storage	390
	715

5 6 7 — Schahfer 14/15/17/18 Retirement (~1,350MW UCAP need)

TECHNOLOGY	MW
MISO Market Purchase	50
DSM	125
Wind	150
Solar, Solar + Storage	1,070
	1,395

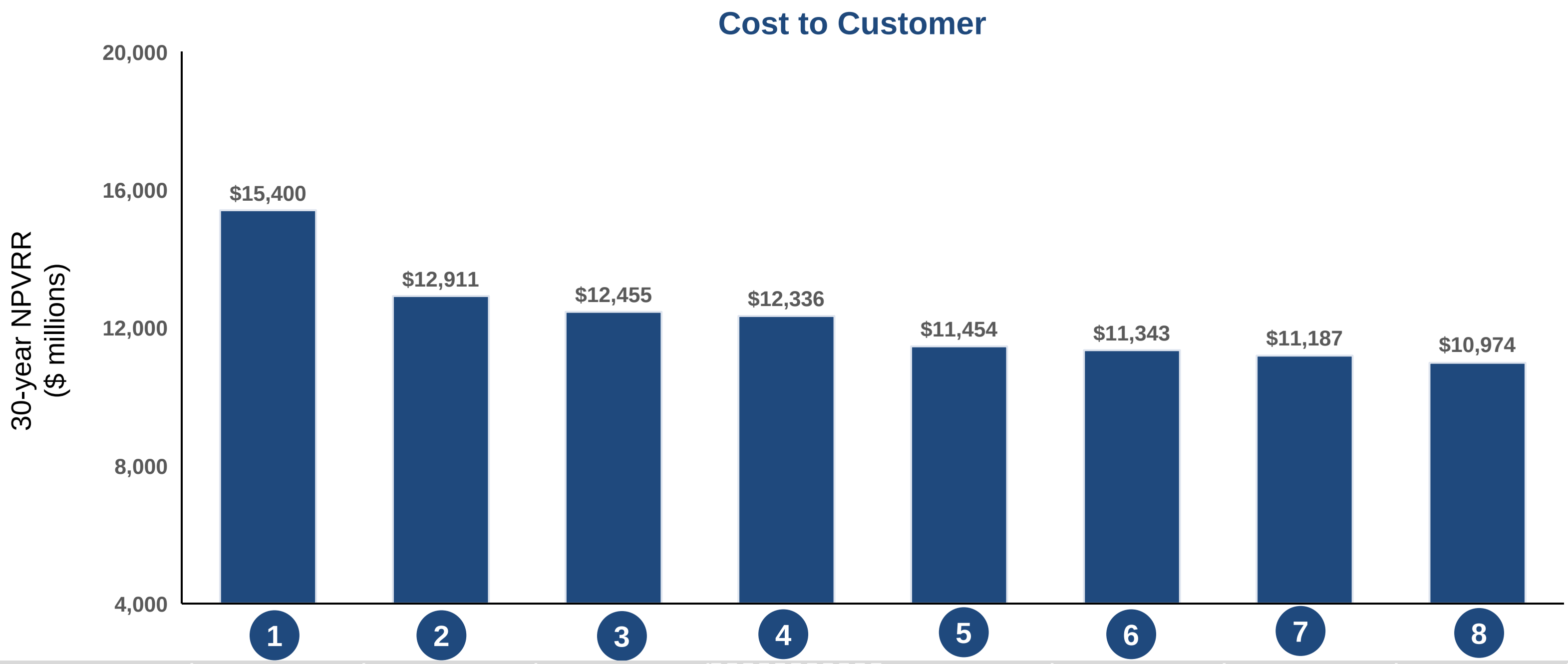
8 — All Coal Retirement (~1,750MW UCAP Need)

TECHNOLOGY	MW
MISO Market Purchase	50
DSM	125
Wind	150
Solar, Solar + Storage	1,500
	1,825

This is *not* NIPSCO's replacement resource selection or plan

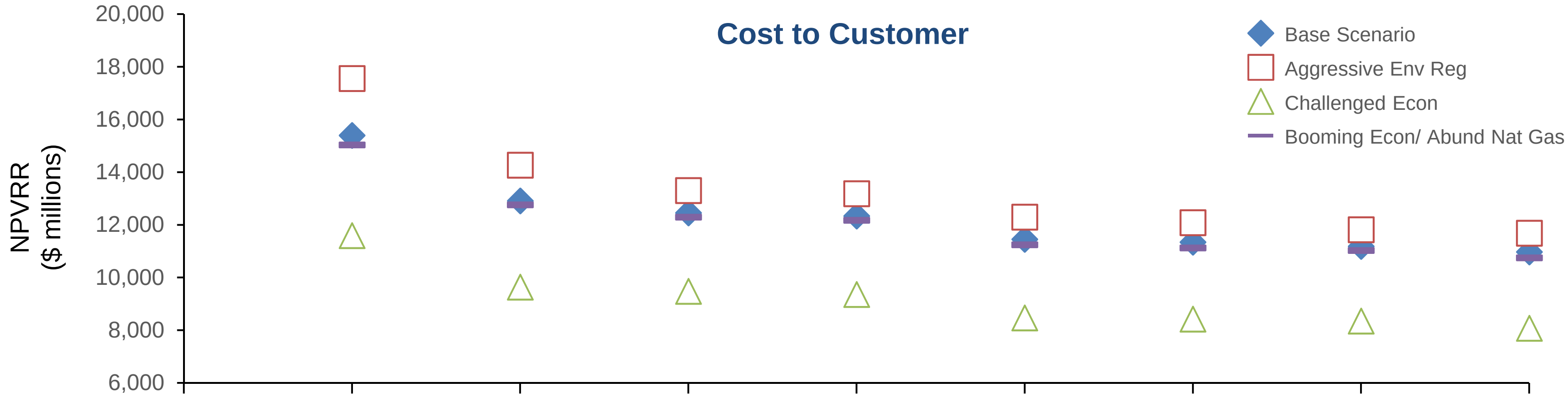
Retirement Results – Base Case

- **Retaining more coal in the NIPSCO portfolio results in higher costs to customers**



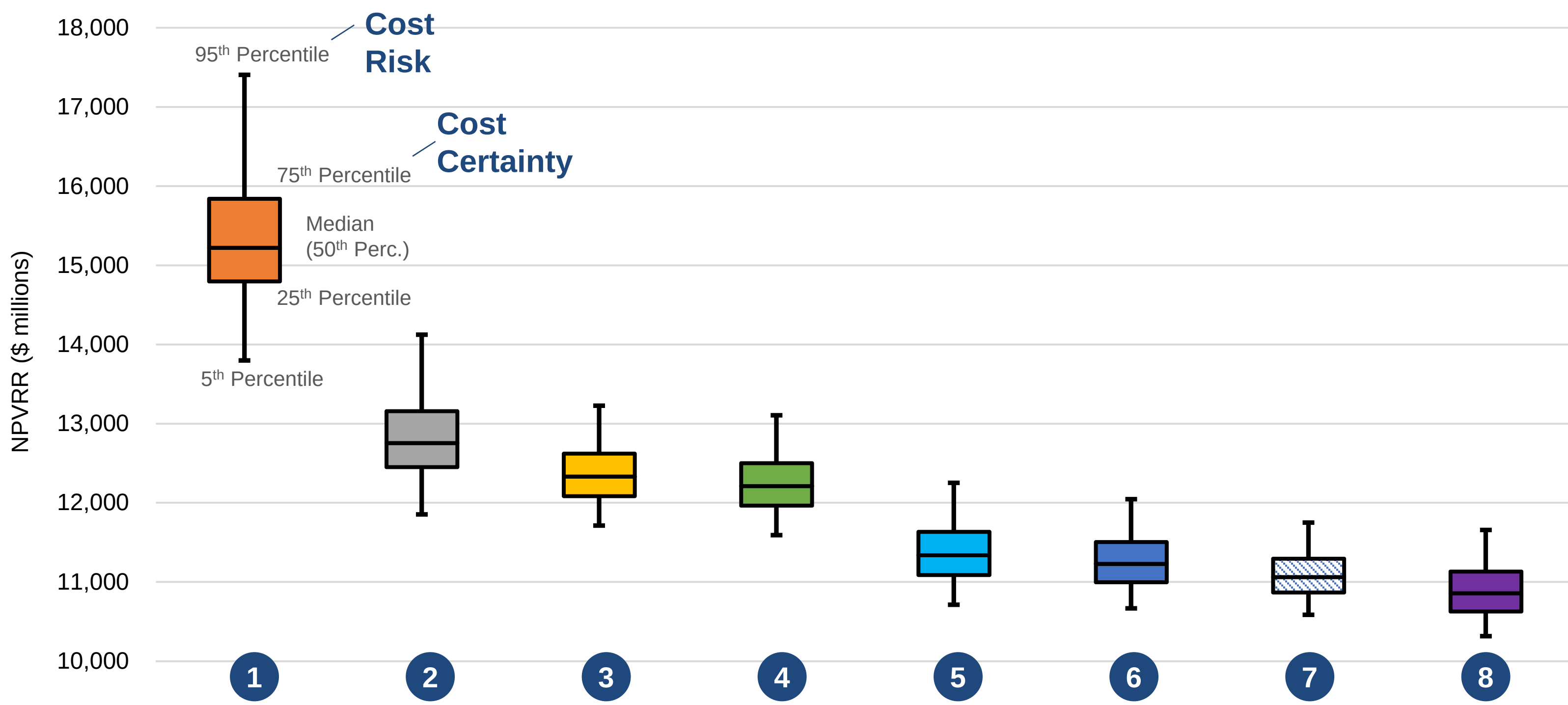
	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal in 2028 w/ ELG**	**15% Coal in 2028 w/o ELG**	**15% Coal in 2023** (MC 2035)	**15% Coal in 2023** (MC 2028)	**15% Coal in 2023** (17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035) Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Delta from Least Cost:	$4,426M 40%	$1,937M 18%	$1,481M 13%	$1,361M 12%	$479M 4%	$369M 3%	$213M 2%	$0M

Retirement Analysis: Scenarios



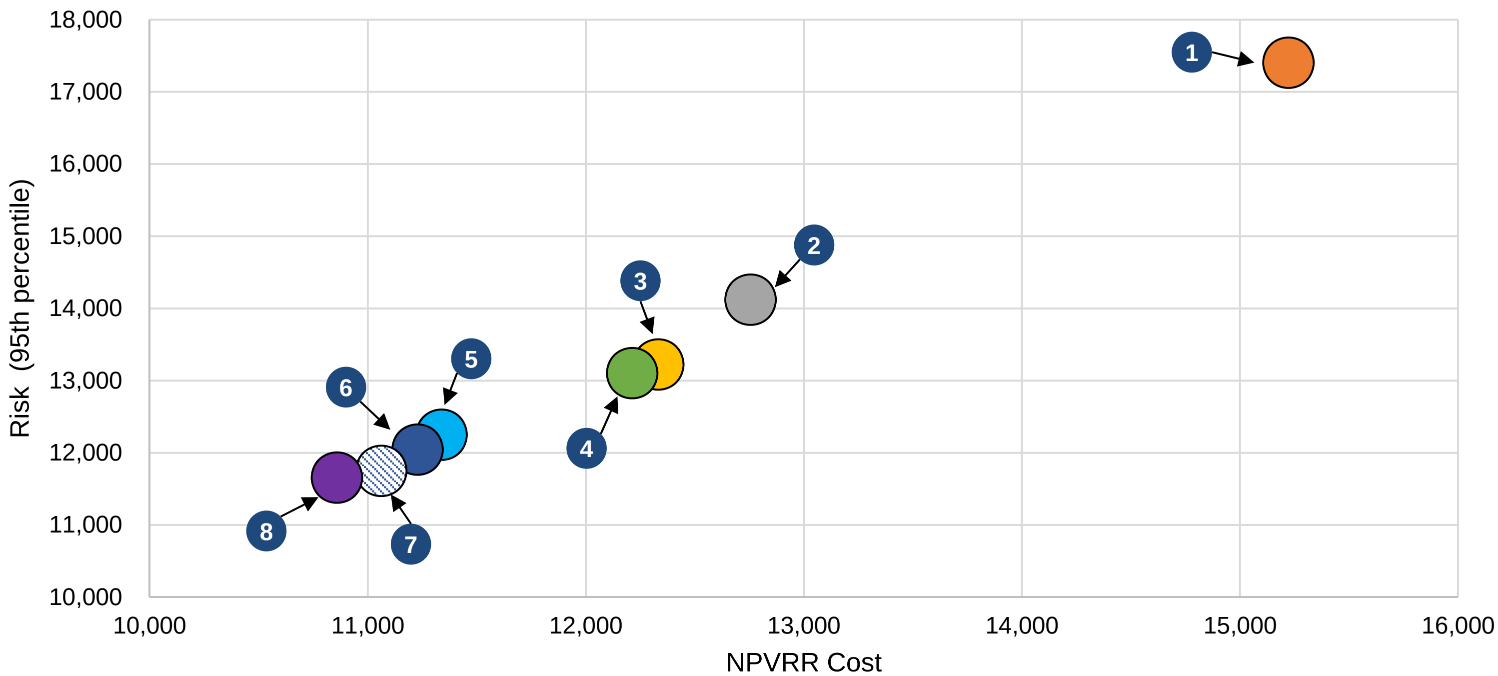
		1	2	3	4	5	6	7	8
	Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal in 2028 w/ ELG**	**15% Coal in 2028 w/o ELG**	**15% Coal in 2023** (MC 2035)	**15% Coal in 2023** (MC 2028)	**15% Coal in 2023** (17/18 2021)	**0% Coal in 2023**
	Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
	Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Base Scenario	**Delta from Lowest Cost to Customer**	$4,426M 40.3%	$1,937M 17.7%	$1,481M 13.5%	$1,361M 12.4%	$479M 4.4%	$369M 3.4%	$213M 1.9%	$0M 0.0%
Aggressive Env Reg	**Delta from Lowest Cost to Customer**	$5,869M 50.2%	$2,584M 22.1%	$1,616M 13.8%	$1,496M 12.8%	$610M 5.2%	$396M 3.4%	$132M 1.1%	$0M 0.0%
Challenged Econ	**Delta from Lowest Cost to Customer**	$3,519M 43.6%	$1,563M 19.3%	$1,400M 17.3%	$1,280M 15.8%	$395M 4.9%	$349M 4.3%	$272M 3.4%	$0M 0.0%
Booming Econ/ Abund Nat Gas	**Delta from Lowest Cost to Customer**	$4,285M 39.9%	$2,013M 18.7%	$1,546M 14.4%	$1,426M 13.3%	$499M 4.6%	$380M 3.5%	$278M 2.6%	$0M 0.0%

Retirement Analysis: Risk (Stochastics)



Portfolio Transition Target:	65% Coal through 2035	40% Coal in 2023	15% Coal in 2028 w/ ELG	15% Coal in 2028 w/o ELG	15% Coal in 2023 (MC 2035)	15% Coal in 2023 (MC 2028)	15% Coal in 2023 (17/18 2021)	0% Coal in 2023
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Delta from Lowest Cost Certainty	+$4,708 42.3%	+$2,026 18.2%	+$1,490 13.4%	+$1,370 12.3%	+$502 4.5%	+$372 3.3%	+$163 1.5%	- $ - %
Delta from Lowest Cost Risk	+$5,750 49.3%	+$2,467 21.2%	+$1,569 13.5%	+$1,449 12.4%	+$596 5.1%	+$389 3.3%	+$93 0.8%	- $ - %

Retirement Analysis: Cost Risk



	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City 2035)	**15% Coal in 2023** (Mich. City 2028)	**15% Coal by 2023** (Schfr 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement

Retirement Scorecard

2018 Retirement Scorecard	
Criteria	**Description**
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO's 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

Retirement Scorecard and Preferred Retirement Path

- **The most viable option for NIPSCO is the full retirement of Schahfer coal units by 2023 and Michigan City by 2028**
- **While retiring more coal earlier is less expensive to customers, the reliability risk of those portfolio is unacceptable to NIPSCO**

Preferred Retirement Path (portfolio 6)

	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City 2035)	**15% Coal in 2023** (Mich. City 2028)	**15% Coal by 2023** (Schfr 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Cost To Customer	$15,400 +$4,426 40.3%	$12,911 +$1,937 17.7%	$12,455 +$1,481 13.5%	$12,336 +$1,361 12.4%	$11,454 +$479 4.4%	$11,343 +$369 3.4%	$11,187 +$213 1.9%	$10,974 - $ - %
Cost Certainty	$15,840 +$4,708 42.3%	$13,158 +$2,026 18.2%	$12,622 +$1,490 13.4%	$12,502 +$1,370 12.3%	$11,634 +$502 4.5%	$11,504 +$372 3.3%	$11,295 +$163 1.5%	$11,132 - $ - %
Cost Risk	$17,406 +$5,750 49.3%	$14,123 +$2,467 21.2%	$13,225 +$1,569 13.5%	$13,105 +$1,449 12.4%	$12,252 +$596 5.1%	$12,045 +$389 3.3%	$11,750 +$93 0.8%	$11,656 - $ - %
Reliability Risk	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Unacceptable	Unacceptable
Employees	0	125	125	125	276	276	276	426
Local Economy	+$118M +47%	$0M -%	($23M) (9%)	($31M) (12%)	($65M) (26%)	($74M) (29%)	($74M) (29%)	($94M) (37%)

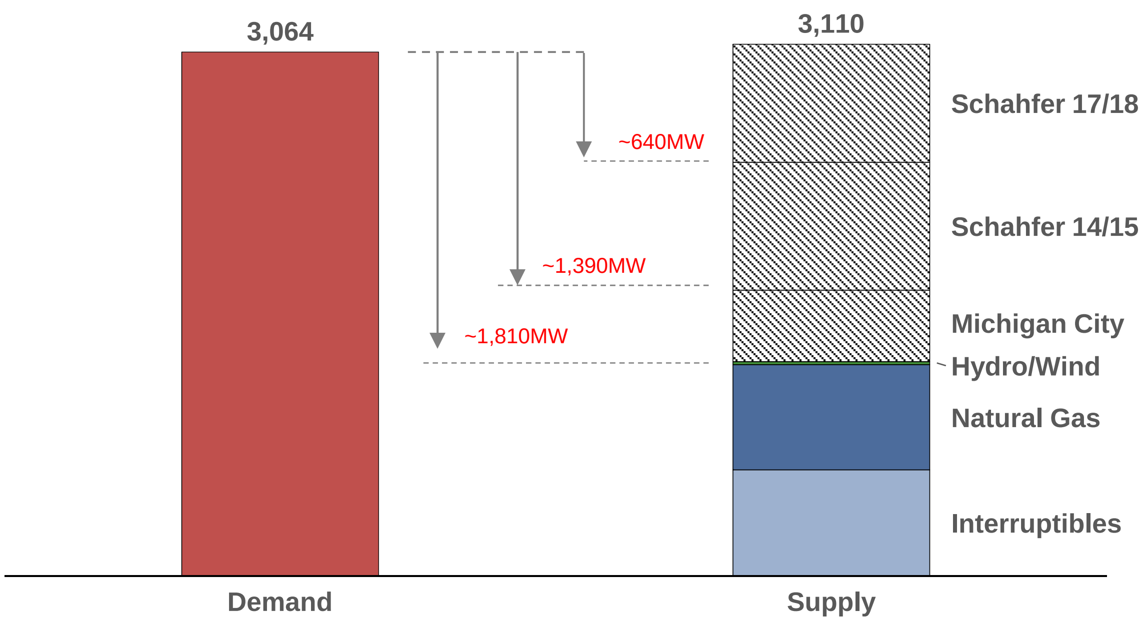
Replacement Analysis

Dan Douglas
Vice President, Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

Retirements Will Create A Need For New Resources

2023 Forecasted Demand and Supply



2023 Estimated Capacity Excess/(Need) in MWs

As-Is	**50**
Retire Schahfer Units 17/18	**(640)**
Retire Schahfer Units 14/15/17/18	**(1,390)**
Retire Schahfer and Michigan City	**(1,810)**

Notes: Demand reflects loss of BP load

Replacement Analysis Framework

- **The responses to the all-source RFP provided insight into the supply and pricing of alternatives available to NIPSCO and fed into the retirement and replacement analysis**
- **These RFP projects are used to construct resource combinations that explore the range of Ownership / Duration and Diversity possibilities**

	Retirement Analysis	Replacement Analysis
Core question	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?*	*What are the replacement resource portfolios?*
Initial analysis	MISO CONE + market energy	3rd party cost and performance estimates
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

Replacement Analysis: Resource Combinations Were Created That Explore The Range Of Ownership / Duration And Diversity Possibilities

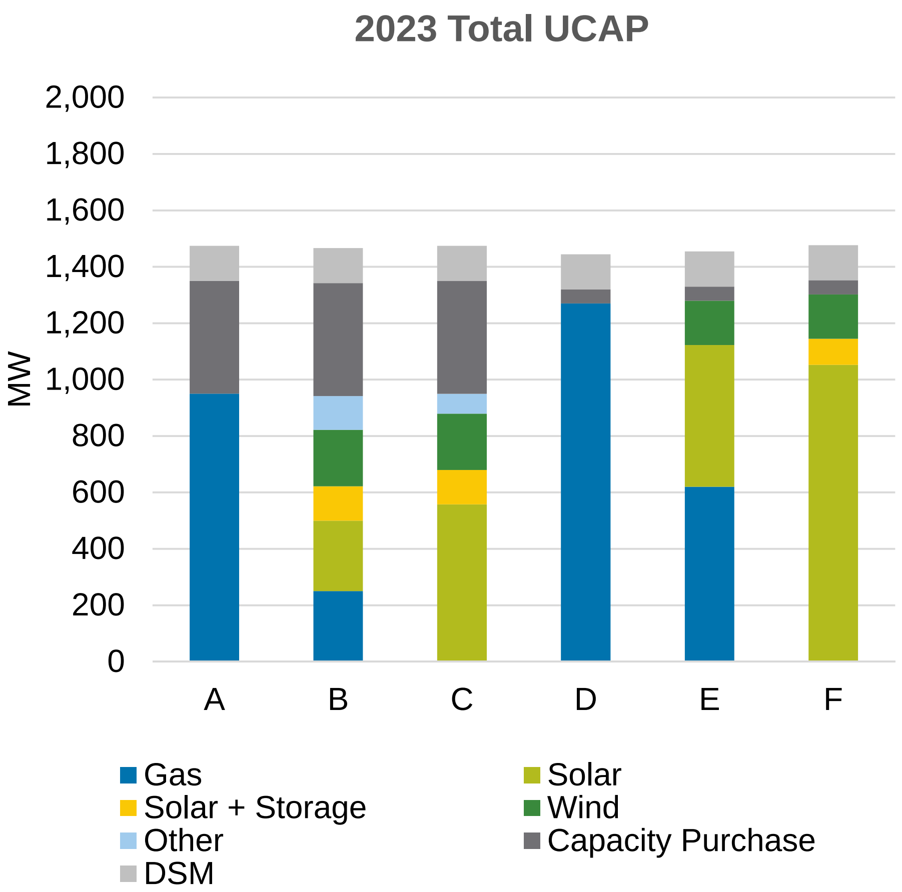
- **RFP projects provide good coverage to construct resource combinations that cover the spectrum of Ownership / Duration and Diversity**

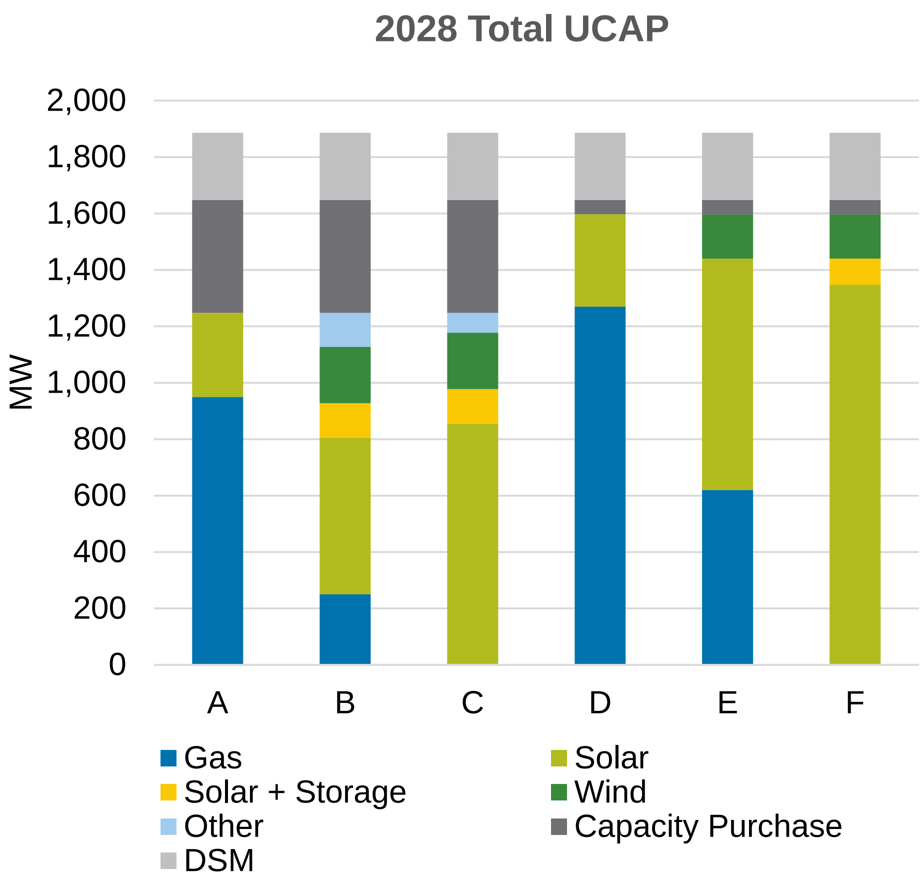
Diversity

Ownership / Duration	Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
Short Duration	**A** MISO Capacity Purchase 400MW Combined Cycle Gas Turbine ("CCGT") Purchase Power Agreement ("PPA") 950MW	**B** MISO Capacity Purchase 400MW CCGT PPA 250MW Renewable PPA 690MW	**C** MISO Capacity Purchase 400MW Renewable PPA 950MW
Long Duration	**D** MISO Capacity Purchase 50MW CCGT 1,300MW	**E** MISO Capacity Purchase 50MW CCGT 620MW Renewables 670MW	**F** MISO Capacity Purchase 50MW Renewables 1,300MW

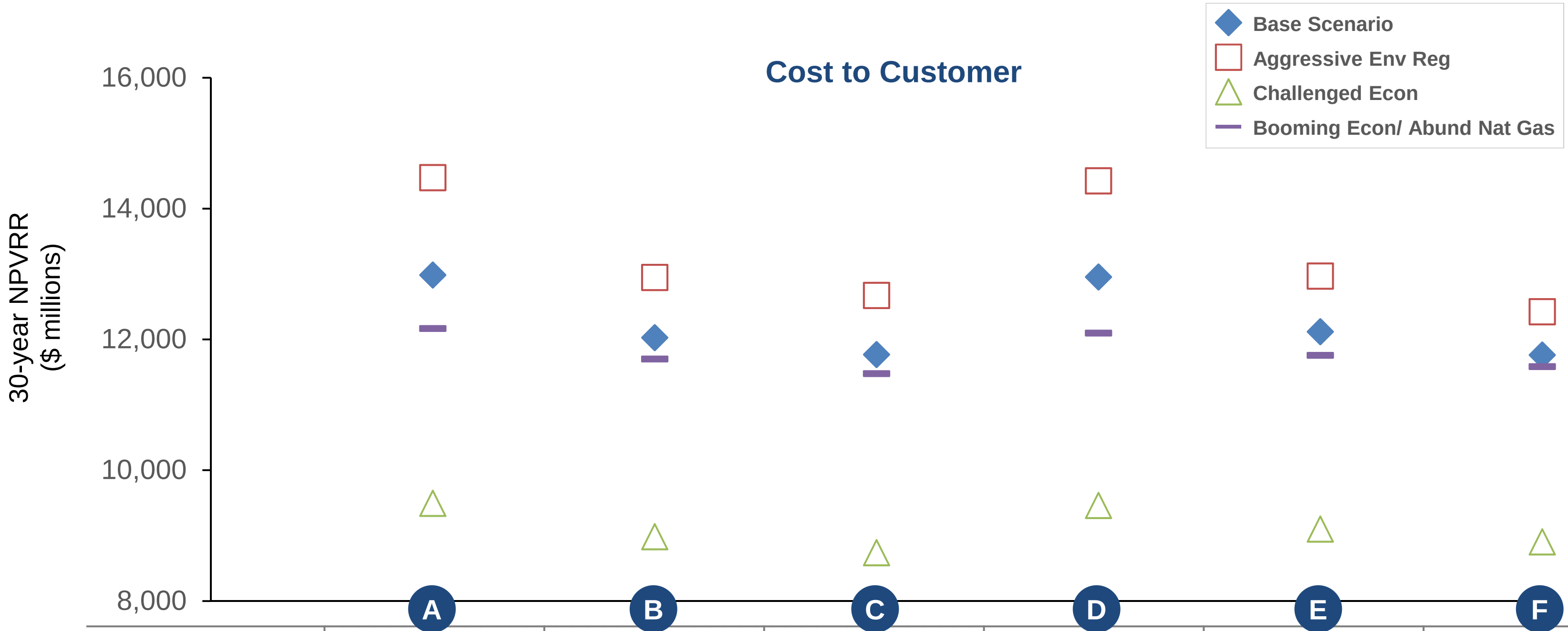
Notes: Values above reflect 2023 additions shown in UCAP; additional generic solar additions are included in all portfolios starting in 2028.
All portfolios include a total of 125 MW (peak) DSM by 2023 and 370 MW (peak) DSM by 2038.

2023 And 2028 New Resources Additions By Portfolio (UCAP MW)



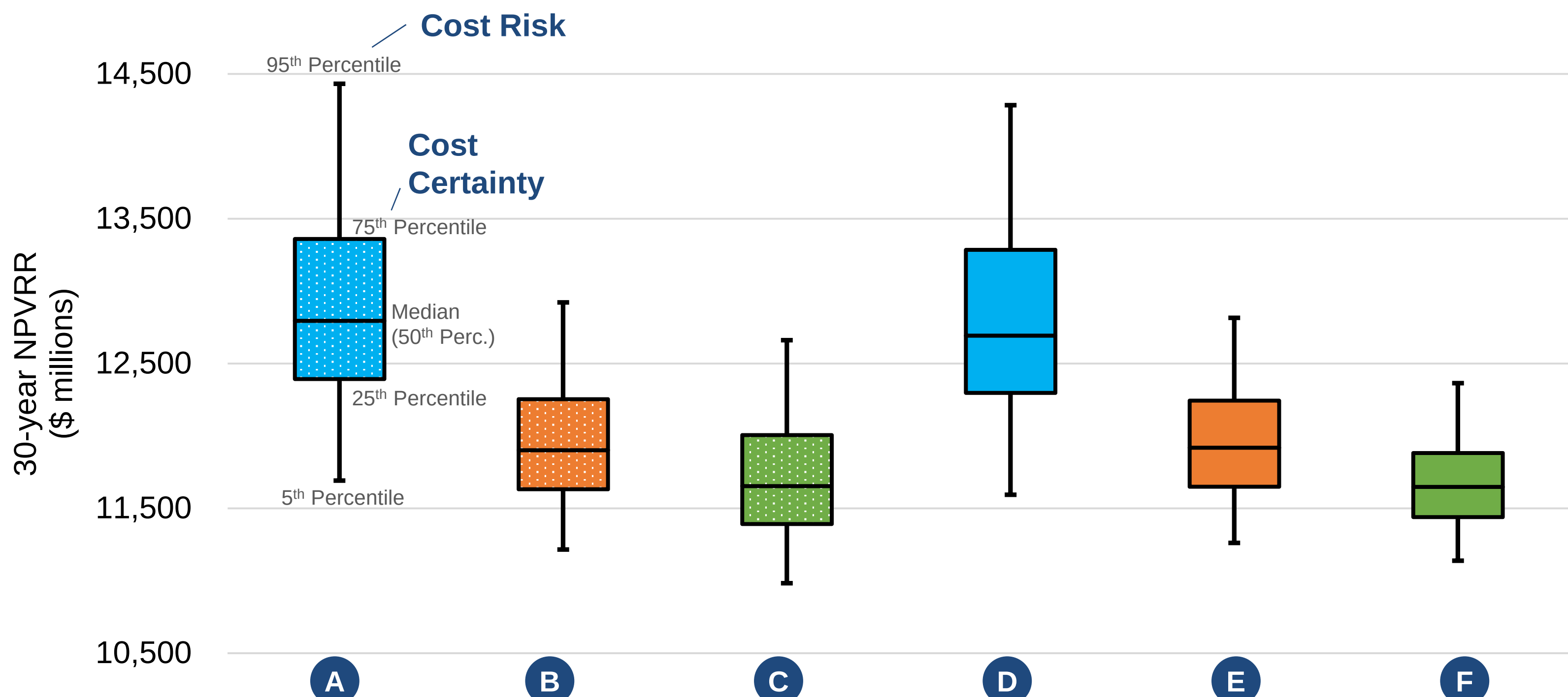


Replacement Analysis: Scenarios



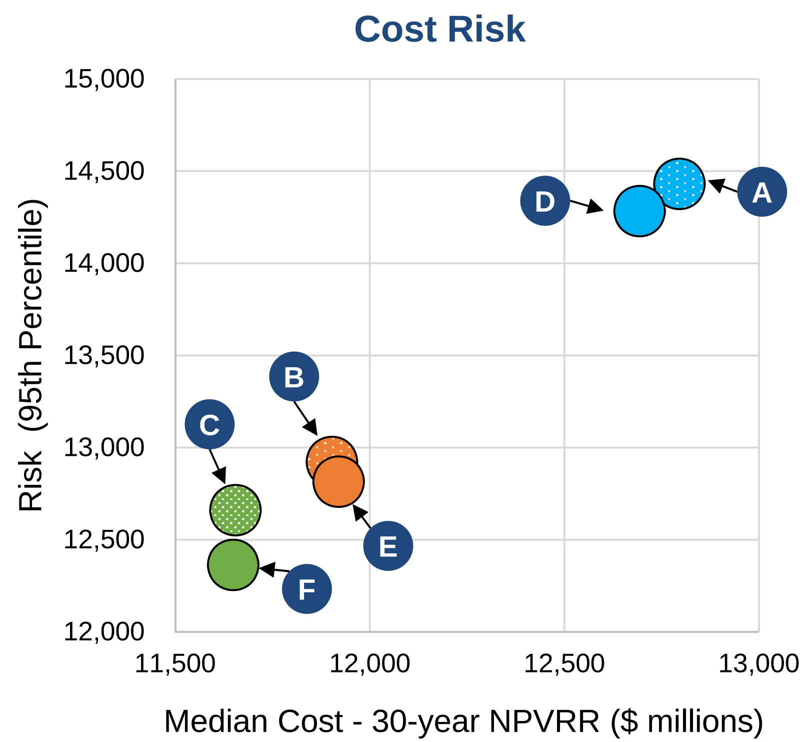
		A	B	C	D	E	F
	Ownership / Duration	**Short Duration**	**Short Duration**	**Short Duration**	**Long Duration**	**Long Duration**	**Long Duration**
	Diversity:	**Higher Carbon**	**Average Carbon**	**Average-Low Carbon**	**Higher Carbon**	**Average Carbon**	**Average-Low Carbon**
Base Scenario	**Delta from Lowest Cost to Customer**	$1,222 10.4%	$265 2.2%	$6 0.1%	$1,192 10.1%	$357 3.0%	**$0 0.0%**
Aggressive Env Reg	**Delta from Lowest Cost to Customer**	$2,052 16.5%	$524 4.2%	$250 2.0%	$2,002 16.1%	$546 4.4%	**$0 0.0%**
Challenged Econ	**Delta from Lowest Cost to Customer**	$756 8.6%	$244 2.8%	**$0 0.0%**	$722 8.3%	$361 4.1%	$165 1.9%
Booming Econ/ Abund Nat Gas	**Delta from Lowest Cost to Customer**	$692 6.0%	$224 2.0%	**$0 0.0%**	$622 5.4%	$281 2.4%	$109 1.0%

Replacement Analysis: Stochastics



	A	B	C	D	E	F
Ownership / Duration	**Short Duration**	**Short Duration**	**Short Duration**	**Long Duration**	**Long Duration**	**Long Duration**
Diversity:	**Higher Carbon**	**Average Carbon**	**Average-Low Carbon**	**Higher Carbon**	**Average Carbon**	**Average-Low Carbon**
Delta from Lowest Median Cost	$1,147 9.8%	$254 2.2%	$6 0.1%	$1,044 9.0%	$271 2.3%	**$0 0.0%**
Delta from Lowest Cost Certainty	$1,477 12.4%	$371 3.1%	$124 1.0%	$1,403 11.8%	$362 3.0%	**$0 0.0%**
Delta from Lowest Cost Risk	$2,067 16.7%	$558 4.5%	$297 2.4%	$1,920 15.5%	$452 3.7%	**$0 0.0%**

Replacement Analysis: Stochastics



Diversity

Ownership / Duration	Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
Short Duration	A	B	C
Long Duration	D	E	F

Replacement Scorecard

2018 Replacement Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 installed capacity MW sourced from non-gas resources)
Environmental	• Annual carbon emissions from the generation portfolio • Metric: Total annual carbon emissions (2030 metric tons of carbon dioxide, or “CO_2”) from the generation portfolio
Employees	• Net impact on NiSource jobs • Metric: Approximate number of permanent NiSource jobs added
Local Economy	• Property tax amount from entire portfolio • Metric: 30-year NPV of estimated modeled property taxes from the entire portfolio

Replacement Scorecard and Preferred Replacement Portfolio

- Replacement portfolios with renewables are more cost effective than portfolios without renewables
- Portfolio F is the preferred replacement portfolio for NIPSCO as it performs well across cost and risk metrics: Cost to Customer; Cost Certainty, and Cost Risk while lowering emissions and fuel security risk

Preferred Replacement Path

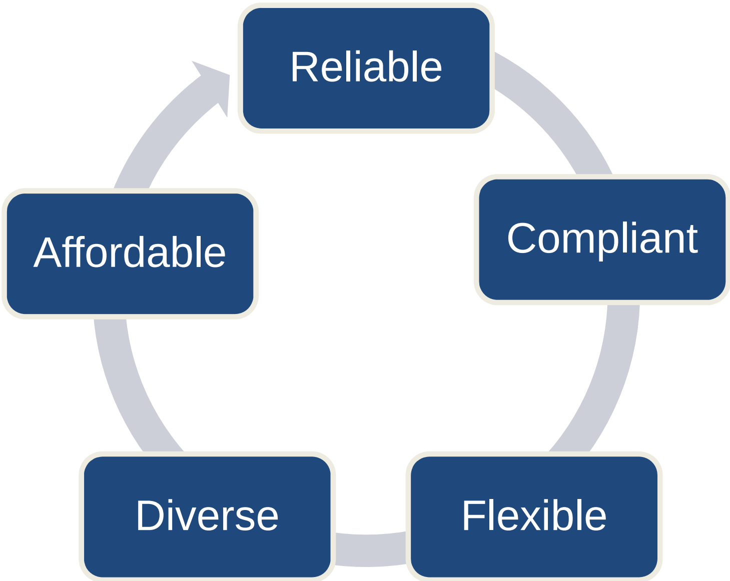
	A	B	C	D	E	F
Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Cost to Customer delta from least	$12,985 $1,222 10.4%	$12,028 $265 2.2%	$11,769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

Lunch

Preferred Resource Plan

Dan Douglas
Vice President, Corporate Strategy & Development

NIPSCO Preferred Supply Portfolio Criteria



Requires careful planning and consideration for all of NIPSCO's stakeholders including the communities we serve and our employees

The IRP is an informative submission to the IURC; NIPSCO intends to remain engaged with interested stakeholders

Action Plan For Current Supply Resources

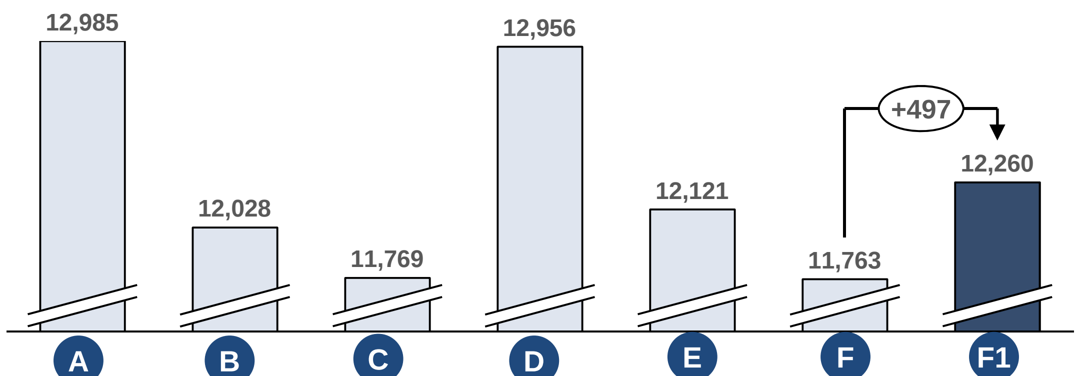
- **Retire all of NIPSCO's coal capacity by the end of 2028**
  - Pursue most viable path, consisting of the retirement of Schahfer 14,15,17,18 by the end of 2023 and Michigan City 12 by the end of 2028, subject to MISO and other considerations
- **Maintain current gas fueled generation**
- **Maintain current wind Purchase Power Agreements**
- **Implement filed 3 year Demand Side Management plan for 2019 to 2021**

NIPSCO Supply Resource Plan And Timing

Timing	Near Term 2018 – 2020	Mid Term 2021 – 2023	Long Term 2024 – 2037
NIPSCO Activity Description	• Initiate retirement process of Schahfer Units 14,15,17,18 • Identify and begin implementation of required reliability and transmission upgrades • Select initial replacement projects identified from the 2018 RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve customer savings • Actively monitor technology and market trends and evolution	• Fully implement required reliability upgrades • Actively monitor technology and market trends, and continue engagement with project developers and asset owners to understand landscape • Conduct subsequent RFP to identify preferred resources to fill the remainder of the 2023 capacity need; procure replacement resources • Implement Schahfer coal retirement with a focus on interests of customers, employees and local communities	• Monitor market and industry development and refine future IRPs
Retirements	• None	• Schahfer Units14/15/17/18 (2023)	• Michigan City Unit 12 (2028)
Expected Capacity Additions	~150-200MW (UCAP)	~1,100-1,150MW (UCAP)	~400MW (UCAP)
NIPSCO's Preferred Replacement Plan	• Demand Side Management • PPA / Market purchases • Primarily Wind	• Demand Side Management • Wind/Solar/Storage • Market Purchases	• Demand Side Management • Wind/Solar/Storage • Market Purchases
Expected Regulatory Filings	• Approvals for replacement capacity projects	• Approvals for replacement capacity projects • DSM Plan for 2022- 2025 (file in late 2020)	• Approvals for replacement capacity projects

Procuring Wind In 2020 To Realize Tax Benefits Leads To Lower Customer Cost

- **Indiana wind resources bid into the All-Source RFP are attractive replacement options that have increasing demand and are subject to near-term phase out of tax incentives**
- **NIPSCO would need to procure these wind resources in 2020 to realize Production Tax Credit benefits and lower customer cost**
- **What is the value of these wind resources (or alternatively, if we elect not to procure, what is the incremental cost)?**
  - A new “No Wind” portfolio F1 was constructed from Portfolio F with no wind and instead relying on the next set of most attractive solar tranches
  - **Excluding wind would raise the 30-year NPV by about $500 million**, resulting in a higher cost than the optimized wind/solar/CCGT option (Portfolio E)



Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon	Average-Low Carbon (No Wind)

- Portfolio F with no wind removes the lowest-cost energy resources (which tend to have an LCOE in the $25-35/MWh *nominal* range) and replaces with slightly higher cost solar resources that produce far less energy
- The impact is that the “No Wind” portfolio relies much more heavily on market purchases over the forecast horizon (up to ~35-40% in 2030 verses ~15% when wind is in the portfolio)

2019 to 2021 DSM Plan Summary

Eleven Residential and five Commercial and Industrial ("C&I") programs with a total 392,839 MWh Gross Energy Efficiency Goals over the three year period.

Residential Programs

- Heating, Ventilation and Air Conditioning Energy Efficient Equipment Rebates
- Residential Lighting
- Home Energy Assessment
- Appliance Recycling
- School Education
- Multifamily Direct Install
- Home Energy Report
- Residential New Construction
- HomeLife Energy Efficiency Calculator
- Employee Education
- Income Qualified Weatherization

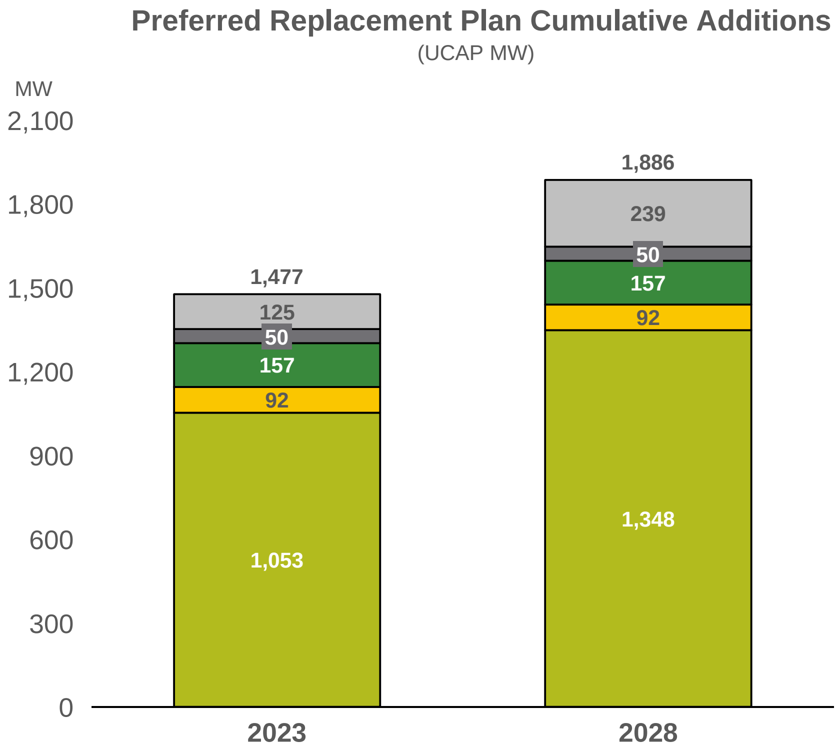
C&I Programs

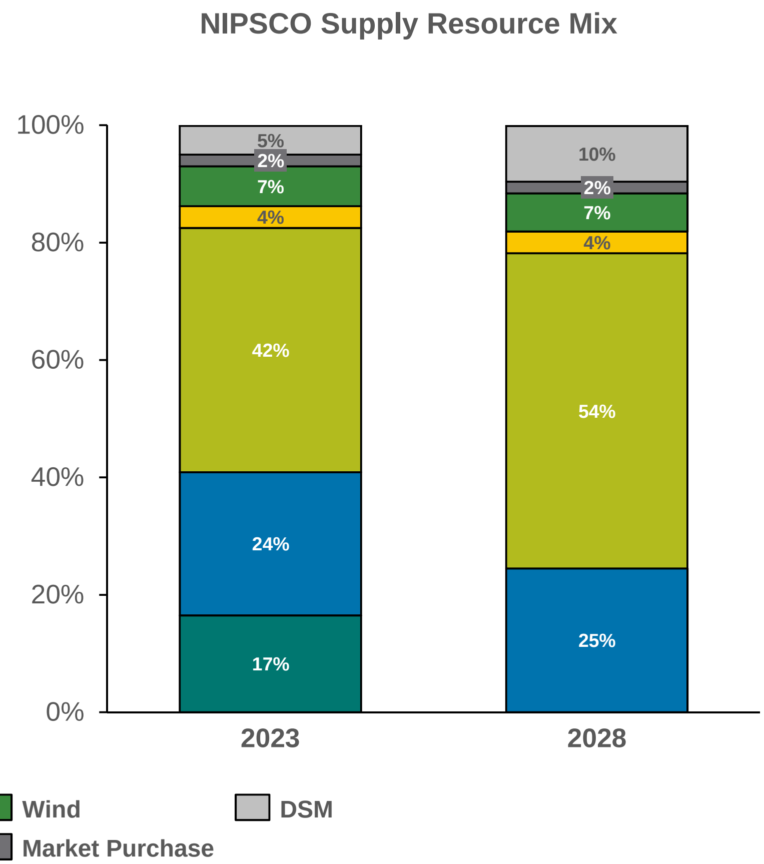
- Prescriptive
- Custom
- C&I New Construction
- Small Business Direct Install
- Retro Commissioning

2019 – 2021 NIPSCO Electric DSM Plan was approved by the IURC on September 12, 2018

NIPSCO Cumulative Replacement Resource Mix

- By 2023, the IRP preferred plan calls for adding approximately 1,150 MW of solar and solar+ storage, 160 MW of wind, 125 MW of DSM and 50 MW of market purchases to the NIPSCO supply portfolio
- In 2028, an additional 300 MW of solar and 114 MW of DSM resources is expected to be added





Preferred Resource Plan

NIPSCO Preferred Plan

Short-Term (2019-2022)	• Initiate retirement of Schahfer Units 14,15,17,18 • Identify and implement required reliability and transmission upgrades resulting from retirement of the units • Select replacement projects identified from the 2018 RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve lowest customer cost • File for Certificate(s) of Public Convenience and Necessity and other necessary approvals for selected replacement projects • Procure short-term capacity as needed from the MISO market or through short-term PPA(s) • Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape • Conduct a subsequent All-Source RFP to identify preferred resources to fill remainder of 2023 capacity need (likely renewables and storage) • Continue implementation of filed DSM Plan for 2019 to 2021 • Comply with North American Electric Reliability Corporation, U.S. Environmental Protection Agency, and other regulations • Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services
Long-Term (2023+)	• Retire Schahfer Units 14,15,17,18 by the end of 2023 and Michigan City Unit 12 by the end of 2028 • Monitor market and industry evolution and refine future IRP plans

Stakeholder Presentations

Public Advisory Feedback/ Next Steps/ Wrap Up

Next Steps

IRP	RFP
• Submit IRP by October 31st 2018 • Meeting summary available November 2, 2018 • NIPSCO IRP website: www.nipsco.com/irp • NIPSCO IRP email: nipsco_irp@nisource.com	• Counterparty outreach indicating if NIPSCO is intending to move forward with their proposal in the fourth quarter of 2018 • Begin commercial negotiations that aligns with IRP preferred plan • Future RFP event(s) – Given the number of potential transactions there will likely be a need for at least one additional RFP

Closing Remarks

Violet Sistovaris, President, NIPSCO and Executive Vice President, NiSource

Northern Indiana Public Service Company
2018 Integrated Resource Planning ("IRP")
Public Advisory Meeting #5
SUMMARY

October 18, 2018

Welcome and Introductions

Alison Becker opened the meeting by having those in the room introduce themselves. Ms. Becker then reviewed the agenda for the day and did a safety moment.

NIPSCO's Planning and the Public Advisory Process

Dan Douglas, Vice President, Corporate Strategy and Development

Dan Douglas thanked the participants for attending and noted that engagement continues to surpass prior years. He said this continued and deep involvement makes NIPSCO's process stronger, more transparent and hopefully better understood. He then provided a review of how NIPSCO plans for the future and how NIPSCO considers the perspectives of each of the stakeholders in the room as well as the communities NIPSCO serves and the employees that serve the customers. He noted that the IRP is an important part of the internal strategic process and a strong indicator of NIPSCO's future resource actions. He provided an update on the Public Advisory process and reminded the group that NIPSCO looks forward to further feedback. He stated that, for this meeting, the focus will be on two questions: what is NIPSCO's preferred plan and what is the short term action plan? He then provided an update on the one-on-ones that have taken place with stakeholders throughout the process stating that these meetings have largely focused on modeling, the all source request for proposals ("RFP") and demand side management ("DSM"), along with specific modelling runs and stated information about those runs will be provided today. He finished the section by again thanking the participants, particularly those who have taken the time to participate in individual meetings.

Stakeholder Requested Analysis

Pat Augustine, Charles River Associates

Pat Augustine began by providing an update to the stakeholder-requested analysis noting that the Office of Utility Consumer Counselor ("OUCC") asked for NIPSCO to evaluate the conversion of Schahfer Units 17 and 18 from coal to natural gas, the Citizens Action Coalition of Indiana, Inc. (“CAC”) requested NIPSCO to re-run the DSM modeling using its proposed decrements approach, and the Indiana Coal Council requested NIPSCO to use a lower cost for the effluent limitation guidelines (“ELG”) compliance and an alternative market scenario. Mr. Augustine reviewed the OUCC’s request and noted changes to the assumptions and estimated costs associated with the conversion since the last meeting. He noted that both the gas interconnection and environmental costs had now been assumed to be $0. He then provided an update on the costs to the customer to undertake the conversion. To convert both Units under the new assumptions, it would costs customers between $540 million to $1.04 billion more than retirement and replacement with economically optimized resource selections from the RFP results. He then provided the projected cost to convert only Unit 17 ($230 M to $450 M) and showed the capacity factors under the various scenarios.

Mr. Augustine then reviewed the request from the CAC, noting that it had asked for energy efficiency and demand side management programs to be evaluated as “fixed” blocks in the modeling runs. This allows the supply-side plan to simultaneously change with each decrement of efficiency, meaning that it is possible that future supply-side additions could be avoided as levels of energy efficiency increase. He stated that the approach is designed to identify potential decrements from the load forecast and evaluate the impacts of the savings on the portfolio net present value of revenue requirements (“NPVRR”) without accounting for costs. He provided an illustration of the load and NPV for eight decrements under an illustrative example. Mr. Augustine then showed a comparison to NIPSCO’s approach and reminded the group that NIPSCO had used three “bundles” based on the cost of the energy efficiency savings as provided through the DSM Savings Update report. Finally, Mr. Augustine showed the decrement portfolio results using these three bundles and noted that the results using the decrements analysis were similar to the results NIPSCO achieved in its IRP analysis.

Mr. Augustine then turned his attention to the Indiana Coal Council’s request and noted that the Indiana Coal Council requested that NIPSCO evaluate retirement combinations with less costly ELG-related compliance for Schahfer Units 17 and 18 and an alternative market case. He updated the results from the previous meeting based on new numbers and noted that the Indiana Coal Council’s assumptions included no cost for carbon compliance, a high natural gas price and a $45/ton flat real delivered coal price for Units 17 and 18.

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

- Why should any of this cost the consumer anything?
    - The consumer would pay for all costs of service to operate this potential converted facility and any other resources used to serve load.
- No matter what energy that a consumer receives is going to cost them - why would consumer have to pay for the conversion?

- The ultimate cost to operate the entire system is the basis of the cost to consumer metric in this modeling framework. The costs that NIPSCO is showing are the NPV of a projection of 30 years of future costs. In this particular portfolio, NIPSCO is showing that a conversion would be higher cost than the alternatives. At this point, this analysis just shows cost differences across different portfolio strategies. The coal-to-gas conversion was not selected in preferred plan.

- What is a decrement? Is it a slice versus a bundle or a collection of those slices?
  - The decrement in this case is the same as the bundle. We are using the term “bundle” here to be consistent with the analysis that GDS Associates (“GDS”), the DSM consultant, performed. GDS developed three distinct bundles, which are aggregates of savings based on a cost ordering of potential DSM programs. In this example, the decrement is the same thing. In general terms, a decrement could represent any slice (i.e., 0.5%, 1% savings, etc.) but here the analysis uses the bundles that were already developed.
- The CAC would like to thank NIPCSO for performing the analysis which captured what we asked the Company to do. The CAC appreciates it, but only one thing that we reflected on, and it ended up not mattering for NIPSCO that there were not smaller decrements, but in the future could use smaller decrements.
  - Thank you. Bundle 1 was a fairly large decrement. It was found to all be cost effective, but your point is well taken. There could be a more granular look in future analysis.

Retirement Analysis
Pat Augustine and Dan Douglas

Mr. Augustine provided a recap from the previous meeting regarding the retirement analysis, sharing updates where applicable. He reviewed the retirement analysis framework, noting that the responses to the RFP were fundamental to indicating the actual projects available to NIPSCO. He noted that the key decision was what units to retire and when. He then reviewed the various retirement combinations that were constructed and went through each of the eight options. After providing the overview, he revealed the technologies being selected by the model based on the RFP results for the various retirement combinations and reviewed the results for the base case, which included an analysis of the expected cost to customer over the next 30 years. He then reviewed the results of the cost to customer analysis over the next 30 years for each retirement combination under each of the scenarios. Then he provided a review of the stochastics analysis results for each of the retirement combinations. Finally, Mr. Augustine provided information related to the cost risk for each of the retirement combinations.

Mr. Douglas then provided an overview of the Retirement Scorecard. He explained that NIPSCO is using a scorecard to navigate the “most viable” retirement and replacement paths. He then reviewed the Reliability Risk, Employees and Local Economy portions of the scorecard, noting that Mr. Augustine had already covered the Cost to Customer, Cost Certainty and Cost Risk components. For Reliability Risk, he noted that activities, timelines and risk of the MISO retirement process, transmission system upgrades, remaining unit dependencies, fuel and maintenance contracts, future resource procurement and the percentage of the system turning over at once were factors that were considered. As with Mr. Augustine's remarks, much of this was a review of the previous meeting, with Mr. Douglas noting any changes that had taken place since the last discussion.

Regarding the impact on NIPSCO employees, he noted that there are over 400 employees at coal units that are focused on reliably and safely generating electricity for NIPSCO's customers. This was an important consideration in the retirement analysis, with the criteria utilized being the number of employees that are impacted by retirement plans prior to 2023. His final criterion was the local economy, specifically the property tax payments made by the generation facilities to local communities. This was quantified by estimating the present value of future property taxes relative to the 2016 IRP. Mr. Douglas finished by noting these criteria are important to be considered in concert with the financial metrics to provide a comprehensive perspective on retirement considerations.

He noted that the Company continued to review the scorecard findings to ensure there are no refinements needed based stakeholder feedback received. He then reviewed the Retirement Scorecard, noting that the criteria discussed are along the left side. He then explained that retiring coal earlier continued to be the most cost effective option as well as the highest cost certainty and lowest cost risk. He noted that Combination 8, which is 0% coal in 2023 has the lowest net present value requirement ("NPVRR"), with Combination 1, which is 65% coal through 2035 having the highest cost.

Mr. Douglas then noted that Combinations 1-6 are acceptable from a Reliability Risk perspective, but 7 and 8 are unacceptable. He reminded the group that Combination 7, 15% coal by 2023, with Units 17 and 18 retired by 2021, is not executable in the time allotted due to required transmission upgrades to maintain system reliability. These upgrades require coordination with the Midcontinent Independent System Operator, Inc. ("MISO") as well as having environmental wetland management issues, meaning they will not be complete until 2022 under the best case scenario. Combination 8 would require NIPSCO to retire and replace 1,800 megawatts ("MW") at one time. And, while the RFP indicated sufficient capacity, that much transition at one time could create reliability and execution risk for customers that the Company is not willing to accept. Furthermore, he noted, there are benefits to staggering the transition to allow for better views of technology.

After reviewing the impact to employees and the local economy (which is measured relative to the 2016 IRP retirement plan), he noted that, as indicated by the red dashed box, NIPSCO selected Combination 6, 15% coal in 2023 as the "most viable" retirement path. This Combination was selected at a high level because it is the lowest cost option that held acceptable reliability risk for customers and the system. He then provided additional details about Combination 6, indicating that it provides enough time to complete the necessary transmission upgrades, that replacement resources can be reasonably secured by 2023, and that it allows NIPSCO to continue to assess customer, technology and market changes over the next decade. Mr. Douglas also noted that Michigan City Unit 12 will be maintained through 2028 and there are no plans to retire the combined cycle gas turbine ("CCGT") at Sugar Creek at this time. He concluded by noting this will be the preferred plan in NIPSCO's IRP submission.

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

- Do the coal retirement cases include costs per the recent court ruling?
  - All the coal retirement cases do include environmental compliance costs associated with the Coal Combustion Residuals rule ("CCR"). They are included in the capital schedules that were shared with the Indiana Coal Council a few weeks back. There have been no adjustments, so CCR costs are included here.
- To be clear, the cases without coal include CCR?
  - If there is a retirement, the CCR expenditures would change slightly versus the situation where all of Schahfer were to stay online beyond 2023. However, anything currently being spent on CCR is included across the board. The CCR rule refers to coal combustion residuals capital.
- Notion of selecting resources from IRP to do a retirement analysis and yet units retire are to inform resources that are optimal, so can you address that idea?
  - The initial analysis involved doing retirement analysis against the cost of new entry ("CONE") and market purchases because there was not an optimized set of real options to compare.
- Do you really need to do those (the retirement and replacement analysis) separate? Looks like you could perform a single analysis instead of two separate analyses to inform retirement and replacement at the same time.
  - The main reason for doing a separate replacement analysis is to allow for an evaluation against the multi-dimensional scorecard framework. So while the preferred retirement portfolio does have an economically optimized set of replacement resources, the IRP is also interested in testing risk, environmental benefits, and other factors. The second phase replacement analysis dives deeper and broadens the range of portfolio concepts that will be discussed later in the presentation. For example, NIPSCO is able to build out different concepts around commitment duration and portfolio diversity. Purchase power agreement(s) ("PPA(s)") versus ownership or natural gas resources versus renewables are two examples.
- On slide 30, why is number 4 highlighted?
  - The shading simply indicates that it is not a viable path for ELG compliance at the moment.
- Also on slide 30, scenario 4 highlighted in the table, but scenario 7 is also highlighted in the graph. Why is scenario 7 highlighted?
  - This is not an intentional highlight, but a shading to differentiate from the other portfolios. The graphic simply does not have enough unique colors.

- On the local economic impact, the economic impact when a coal unit is shutdown is clear. However, what about the economic impact of the resources being added, for example, whether it is a wind farm or solar facility, those would also have potential property tax impacts to the local economy? Since NIPSCO has not provided locations of the alternative resources, the Company does not have the positive impacts yet?
  - That is correct. As far as providing for any positive economic impact, NIPSCO does not know at this point where facilities will be located. However, there could be respondents to the RFP in the exact same counties that could offset these numbers. It is important to note that NIPSCO is not far along enough down that path to make such a conclusion.
- Are we correct to understand local economy as local property taxes?
  - Correct
- On reliability risk, a complicated mix of factors was reduced to a binary measurement of acceptable/unacceptable, but it does not capture variances between scenarios. It would be good in future IRPs to discuss further and different degradations of variability.
  - There are always opportunities to get sharper on this. NIPSCO took strides forward from 2016, but the Company always has opportunities to improve the process. Ultimately the analysis was challenging regarding how to capture 6, 7, 8 different factors within a single metric. Ultimately, it was decided to call it reliability risk because there were clear markers that made it possible/not possible. However, your approach shows how NIPSCO can improve in the future.
- Would Michigan City be a good source for wind? And as a follow up, that would be a good transition of jobs in that area.
  - NIPSCO continues reviewing specific bids from the RFP now, but there is not a specific answer on location right now.
- Are property taxes going up, going down or stabilizing?
  - If the plant is retired, there would no longer be a facility there and the property taxes paid by NIPSCO would go away. The Schahfer plant is in Jasper County and is the number one property taxpayer in the county. If it retires, less taxes would be paid to the county.
- Can you unpack the component parts of reliability? Is this from MISO? Do they all have weight? There is no separate scorecard?
  - The analysis starts with MISO, the independent system operator in the region. To retire an asset, NIPSCO must go through a retirement filing with MISO, which is known as an Attachment Y filing. After a potential retirement, the Company is responsible for changes to the transmission system, primarily a set of upgrades that would be identified through the MISO process. We have 5 or 6 upgrades that need to happen with the retirement of Schahfer. Beyond that process, NIPSCO considers the remaining unit dependencies at Schahfer to evaluate the feasible timing of retirements. It is also important to understand current contracts and the costs that go into operating the units. NIPSCO also considered the

challenges associated with future resource procurement. The RFP resulted in around 30 bidders and 90 different projects. These developers may be looking at other opportunities and we require time to negotiate and consider many potential projects. Finally, the Company examined the percentage of the system turning over at once. When you talk about retiring 2/3 of the portfolio and switching to intermittent power, NIPSCO wants to have something to step through over time rather than turn everything over at one point. In summary, this category was a "catch-all" bucket with miscellaneous smaller factors that drive NIPSCO to a binary decision.

- Regarding property taxes, if Schahfer is the biggest payer of property taxes in Jasper County, what entity is the largest payer in Michigan City?
    - NIPSCO is not the largest contributor of property taxes in LaPorte County, but it is one of the top three.
- On transmission upgrades, are these built into costs?
    - Yes, they are built into the costs. NIPSCO considered different retirement scenarios and the applicable permitting issues, and captured costs associated with the pretty significant amount of work needs to be done there. The project plan goes out into 2022 or 2023 even if the required projects were started immediately.
- First, going back to cost of customer, does NIPSCO have the rates by year.
    - The Company has determined the total revenue requirement but have not broken down rates to customer class. The analysis thus far assumes perfect rate making.
- Also, with respect to cost certainty around the RFP responses, did you consider tariffs?
    - The responses came through in the June timeframe and were evaluated in July. Most of the turbines would have steel as a major component and the developers were likely aware of many of the tariffs so it is NIPSCO understanding that many were procured at a price point consistent with their RFP bids.
- Does NIPSCO feel an ethical responsibility to coal miners?
    - Absolutely, but the Company is also focused on our employees and our customers. NIPSCO hopes that lower costs for customers, including large industrial customers, will help improve the local economy.
- Between scenarios 6 and 8 can you explain how both retire Michigan City, but with a difference of five years. What happens in those 5 years?
    - The employee line shows only those jobs impacted through 2023. The remaining difference in economics is for the extra five years of Michigan City operation versus RFP alternatives.
- It seems as those there are very minute differences between scenarios 5 & 6 and the only change is the Michigan City retirement date?
    - Michigan City runs fairly economic today (i.e. it is often dispatched based on price), so changing the retirement date has a relatively small impact. Most of the environmental work has been completed at the site, and NIPSCO realizes a relatively strong dispatch with a fairly good heat rate.

There are savings associated with retirement, but not as big as with the Schahfer retirement. Costs are important, so we believe accelerating the retirement from 2035 is the right thing for our customers. Reliability risk is also significant, which is why we are focused on 2028.

- The difference in dates for the retirements at the coal plants affects the amount of maintenance required. Is that true statement?
    - Yes, that is correct. The maintenance capital schedules vary based on expected retirement date. For example, if you have a 10-year old car, if you know you will keep it another 5 years, you will get a tune up, change the tires, etc. If you know you will sell it in year, you will likely wait to do maintenance work. With the coal plants, we have similarly looked at maintenance schedules and stepped those costs down accordingly.
- Would NIPSCO change the retirement date at Michigan City if the County and customer base agreed that retirement in 2023 was fine with them?
    - Reliability risk is an important factor. NIPSCO must maintain reliability and keep the lights on going forward. The retirement plan involves making moves that are directionally different than our peers and there is a bit of a comfort level with maintaining what works. It is a rare moment when you get all stakeholders to come to agreement.
- With reliability risk, is it not possible to just “flip a switch” and rely on the MISO market? Will that not be a possible situation once NIPSCO has converted to renewables?
    - At some point, something needs to generate electricity. NIPSCO’s expectation is that, given the economics, there will be more and more transition to renewables. MISO is not in the room, but it would likely say that as there are more intermittent resources on the system, there will be more risk on MISO to preserve reliability.
- Regarding reliability risk, do you foresee keeping with this theme to retire Schahfer in 2023 and Michigan City will continue to bear burden of hosting coal and then retire or convert to natural gas in Michigan City? From an equity injustice lens, would be very burdensome (ongoing burden, ongoing inequity) if this community continues to bear the burden of environmental burden. This is particularly true for communities of color, low income, etc. The Indiana Conference of the NAACP would adamantly appeal that whenever you retire, that the community does not get the burden of methane or other environment impacts. There have been health impacts to communities that have born the burden all of these years.
    - Although the replacement plan has not be discussed yet in this presentation, as of now, NIPSCO will not transition coal to gas at Michigan City based on current economics.
- Did NIPSCO take into consideration the communities? Did the Company take into consideration the fact that the Michigan City population is minority and environmental justice and where in the matrix is that considered or exercised?
    - NIPSCO’s wants to be compliant with all United States Environmental Protection Agency (“EPA”) rules, so any plan selected by NIPSCO needs

to be compliant with those rules. NIPSCO does take that into account and the Company wants to take care of the customers in that territory.

Replacement Analysis
Pat Augustine and Dan Douglas

Mr. Augustine reviewed and updated the replacement analysis. He started the review of the section by reminding participants that NIPSCO has forecasted a 2023 peak demand of just over 3,000 MWs. He stated that retiring the units at Schahfer and Michigan City will lead to a combined 1,810 MWs required. Based on this, NIPSCO completed its replacement analysis. He reviewed the replacement analysis framework, noting that the RFP was a main source of information for determining replacement options. Mr. Augustine noted that various resource combinations were created to explore the range of ownership/duration and diversity possibilities. He then reviewed the possible resource additions based on unforced capacity ("UCAP") in 2023 and 2028. After this explanation, he showed the various replacement scenarios and the stochastics for those scenarios.

Mr. Douglas then reviewed the Replacement Scorecard. As with the Retirement Scorecard, the Replacement Scorecard is being used to help navigate the various paths and NIPSCO has done away with the "red-yellow-green" color coding in favor of more quantitative scoring. He noted that there are some nuances from the Retirement Scorecard. As with the Retirement Scorecard, Mr. Douglas explained how fuel security, environmental, employees and local economy were considered in the Replacement Scorecard. Regarding fuel security, he noted that the criterion assesses NIPSCO's ability to reduce exposure to short-term fuel supply and/or deliverability issues, which is expressed as a percentage of capacity sourced from resources other than natural gas in 2025. Mr. Douglas explained that the environmental criterion considered the annual carbon emissions from the resource portfolio in 2030 by metric tons of CO_2. For employees, he explained that the number of NIPSCO jobs added for the resource portfolio was considered. And, finally, for the local economy, NIPSCO considered the property taxes for the portfolio, without making a determination of where the facilities would be, only considering assets that would pay property taxes.

After providing this background into the scorecard, Mr. Douglas provided the results of the analysis. He said that including renewables is the least cost option as well as the lowest cost certainty and lowest cost risk. He noted that, by comparison, portfolios with natural gas technologies have a cost over 10% higher than renewable-only portfolios. Portfolio F, which is long duration and average-low carbon pricing, which is predominately long-term renewable PPA or renewable ownership, DSM, and a small amount of market purchases, is the lowest cost option and the strongest portfolio from a fuel security standpoint. In addition, he said, it provides the lowest emissions for customers.

In summarizing this section, Mr. Douglas stated that NIPSCO believes the retirement and replacement path will provide reliable power, enable lower costs and provide significant environmental benefit. He noted that the scorecards demonstrate that retiring coal and replacing with renewables will create significant savings. Finally, from a reliability perspective, he committed the Company to making sure the plan keeps the lights on for its customers. He stated that transitioning from coal to renewables is a significant move and NIPSCO is approaching the shift with an appropriate level of caution and analysis.

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

- For scenario E, how did you come up with mix of resources as opposed to 300 CCGT and 1070 renewables? How did that mix come about?
    - This was primarily due to the nature of the bids that came in. NIPSCO was broadly looking to split the renewable and natural gas capacity fairly evenly on a UCAP basis. All long-term combined cycle gas turbine ("CCGT") bids included projects in the 600-700 MW range, so that naturally fit into the portfolio concept, with the remainder being renewables.
- Are you performing life cycle analysis of carbon emissions?
    - No, we are focused on the point of emissions for generating capacity.
- On slide 38, what is included in the "other" category?
    - "Other" incorporates a system power bid and a small demand response offer. The system power bid was short-term and the demand response bid was one year in duration.
- Is any gas self-build?
    - No, a self-build was evaluated and compared to the RFP bids, but all of the portfolios analyzed were with resources from the RFP.
- Throughout the analysis, it is either 2023 or 2028 for the retirements. 2028 is unacceptable for Michigan City. And what is going to keep you from reneging on all of this? 2028 is 10 years from now and asthma, cancer, and everything else wrong with these scenarios and how can you re assure the people? Is there a way to move all this up?
    - Please look back at the retirement scorecard. NIPSCO has to provide an affordable, compliant, and diverse portfolio. This is all really complicated, but please look at the transmission that needs to be built before the Units can be retired. Your concerns are heard, but it is important to note the NIPSCO is pulling retirements earlier by 10-20 years (or more) and trying to make significant strides for better costs for customers while being environmentally friendly.
- Can you clarify what is meant by "inside the fence line"?
    - This means at the point of generation, not taking into account any emissions that may have happened during the production or transmission of natural gas. We only count emissions created at the generation site, which is aligned with EPA metrics.

- Fewer than 30 jobs are created in scenario F, where does that compute with the 276 employees lost with optimal retirement scorecard? This could be net reduction from 276 to 30?
    - o The 276 is related to those who are working at the Schahfer facility now. They may not all necessarily lose jobs but they would not be working at Schahfer. In the replacement analysis, NIPSCO is demonstrating the "steady state" number of jobs for a solar or wind facility. There would also be an influx of construction jobs to get things up and running. So overall, NIPSCO would offset some of the jobs lost at Schahfer.
- Does NIPSCO plan to report on indirect emissions in the future?
    - o In a previous meeting, there was a discussion on this. For NIPSCO and NiSource, you can go to the annual report or greenhouse gas report where greenhouse gas emissions inside the fence line are calculated as well as "scope 2" (associated with transport) and "scope 3" (vendors, etc). This is available on the website.
- What is the nameplate capacity of solar, as well as energy storage, selected in the preferred plan?
    - o The UCAP is available on Slide 38.
- Slide 38 is unclear as to what amount of energy storage is selected (conflated with solar).
    - o The solar plus storage project is about 180 MW of nameplate capacity. 175 MW of the capacity is solar, with 4.9 MW of battery storage.
- When is the next IRP?
    - o Based on the proposed rule, the IRP is required every 3 years. We were on schedule to do it in 2019, but moved it up. We will continue to work with the Indiana Utility Regulatory Commission on the next date, but it is assumed the next IRP will be submitted in 2021 (based on a 2018 date) or 2022 (based on the original 2019 date).
- I appreciate that NIPSCO is acknowledging that clean energy is the most affordable and viable option that distinguishes you from Indiana's other investor owned utilities ("IOUs"). What differentiates and allows you to acknowledge it?
    - o NIPSCO cannot speak to other utilities and their decisions. The Company is making decisions based on its customers and based on its assets. The retirement and replacement plans are the right decisions from cost, local economy, and fuel security perspectives. NIPSCO considered what is available to customers through the RFP, and the Company evaluated the tradeoffs, and feels it's the right decision for customers.
- Through preferred plan, how much weight is given to local resources? How are they ultimately the beneficiaries of this?
    - o NIPSCO required the resources to be within MISO and within Zone 6 of MISO. NIPSCO supports resources within the service territory for taxes and to benefit the local economy.
- Is NIPSCO going to limit choice to existing RFP library or will the Company consider other competitive bids once the technology has been selected?
    - o Right now NIPSCO is focused on the responses to the recent RFP.

- Was there any kind of notice taken regarding if the equipment was made in the United States versus overseas?
  - No, the Company did not consider that.
- Will there be a regulatory filing for undepreciated coal plants?
  - Yes, inside the rate case NIPSCO will be filing on October 31, 2018.
- Can you give any more definition to timing of RFP? And amount of RFP? At that point, after the replacement of Schahfer Units, right?
  - Right now, NIPSCO is focusing on projects with expiring wind production tax credits. Our intention is to take advantage of those before they phase out, although wind will provide a limited amount of firm UCAP. The Company also sees some solar projects are well priced that it can take advantage of through the recent RFP. NIPSCO is negotiating those as well. However, since the Company does not plan to fill the full retirement gap right away, another RFP will likely be required in the 2019-2021 timeframe. At this point, there are not more specifics.
- How will Schahfer retirement impact Georgia Pacific Gypsum?
  - While it is expected there will be an impact, it is not known. The facility was built with the idea that it would take gypsum from Schahfer. Georgia Pacific has known since the last IRP that a retirement was possible, so this is not truly a new issue for it.
- Thank you for your extensive work on the IRP. The NIPSCO Industrial Group appreciates it. We understand and appreciate it is a complex and very nuanced undertaking. While we are still reviewing your findings, we generally support the direction of your resource planning efforts. We look forward to working together as we move forward; specifically in the certificate of public convenience and necessity (“CPCN”) proceedings coming down the road.
  - Thank you.
- A statement in medicine, “you can't improve what you can't measure.” So did NIPSCO take into consideration the international concern with the climate crisis and how fast to move, where to move, how to move? There has been no secret that a lot of concern with climate change and damage caused by smaller increase in global temperatures. If you did, how you metricize that and if you did, where did it appear? As a follow up statement, latest report, 100% by 2030
  - On Slide 43, we have a specific line for environmental impact related to CO_2 emissions. NIPSCO is reducing emissions by 90% by 2030, so I think you'll find that we have been aggressive on that front and more aggressive than the Paris Climate Agreement. The latest report calls for a 45% reduction by 2030 under the 1.5 degree scenario. The Company will beat that by twice the magnitude and more quickly.

Preferred Resource Plan
Dan Douglas

Mr. Douglas started by reviewing NIPSCO’s preferred supply portfolio criteria, nothing that NIPSCO comes back to five key principles: reliable, compliant, flexible, diverse and affordable which are first and foremost focused on NIPSCO's customers. He noted that the Company also carefully considered the perspectives of each of the stakeholders in the room as well as the communities served and the employees that serve customers. He reminded the group that the submission of the IRP is not the end of NIPSCO's engagement in this process. As always, the Company will remain engaged with all interested stakeholders. He then provided an overview of the action plan for NIPSCO's current supply resources, noting the NIPSCO will maintain current gas generation and current wind PPAs. The recently approved DSM Plan will be implemented from 2019-2021. Mr. Douglas then walked the group through the components of the Company's preferred supply plan in the short-, medium-, and long-term. In the short term, so from now to 2020 NIPSCO's activities will center on: Initiating the retirement process for the units slated for retirement at Schahfer; identifying and implementing required reliability and transmission upgrades; selecting projects from the 2018 RFP evaluation process prioritizing resources that have expiring tax credits; and continuing to monitor market trends and how technology continues to evolve.

Mr. Douglas noted that, during this time period, NIPSCO expects to add about 150 to 200 MW of UCAP capacity, with the expected source to be primarily from wind. However, all sources in the RFP will be considered, in addition to DSM and market purchases or short term PPAs as needed. He noted that, once the projects have been selected, NIPSCO will make the necessary regulatory filings.

Regarding the midterm period from 2021, NIPSCO's activities will primarily consist of: implementing the reliability upgrades; continuing to actively monitor technology and market trends and engaging with developers and asset owners to understand the landscape for generation; conducting a subsequent RFP to identify resources to fill the remainder of the 2023 capacity gap. In addition, NIPSCO will implement the Schahfer retirement focusing on customers, employees and the impact to local communities. Mr. Douglas stated that, during this time period, NIPSCO expects to add about between 1,100 and 1,150 MW of UCAP capacity identified from the next RFP, likely solar/storage, DSM and market purchases. NIPSCO will file the next DSM plan for 2022 to 2025 in late 2020 as well as for any required regulatory approvals for replacement resources.

Finally, he discussed plans for the long term starting in 2024. NIPSCO will be focused on monitoring the market and industry developments and refining its future resource plans. In 2028 the last remaining coal Unit, Michigan City 12, will retire and NIPSCO will have a 400 MW UCAP need which will be filled with DSM, wind/solar/storage and market purchases.

Mr. Douglas then discussed the procurement of wind resources in 2020 to realize tax benefits, which lead to lower customer costs. He noted that NIPSCO's analysis shows that acquiring wind in 2020, while still eligible for the full tax credits, provides a 30-year NPV benefit of almost $500M to customers if those purchases are included in the preferred portfolio. He also provided information regarding NIPSCO's current DSM plan, noting that the plan projects savings of over 392,000 MWh over the three year period.

He then turned to a discussion of NIPSCO's cumulative replacement resource mix, noting that, by 2028, 75% of the NIPSCO supply will come from renewables and DSM resources. In summary, he provided an overview of NIPSCO's preferred plan for the 2018 IRP, noting the plan is broken out into the short-term (2019-2022) and the long-term (2023 and beyond). He concluded by saying that the actions coming out of this IRP will place NIPSCO on a course to continue providing reliable power while enabling lower costs and providing significant environmental benefit.

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

- On slide 51, can you confirm that it is in UCAP rather than nameplate capacity? It shows 1,348 MW of solar by 2028. Does that really mean 2,676 MW of nameplate capacity, since you multiply by 2 to get from solar UCAP to solar nameplate capacity?
  - Yes, can confirm the slide is denominated in UCAP.
- Can you confirm NIPSCO is planning to file a new rate case on Oct 31?
  - Yes.
- Do you intend to charge more for electricity through renewables than other resources?
  - No, renewables will be baked into the cost of the total portfolio. The plan is not for renewable resources to cost more for customers than other resources.
- Regarding the carbon market: NIPSCO is getting some form of revenue from carbon. Is that revenue passed onto customer to reduce rates, maybe? Is there a scenario around revenue and put into basket to help with solar/wind equity?
  - There is no carbon market and no revenue coming from it. If that became available, further discussions would take place.
- Are you doing it because of good corporate reason or because you're projecting to sell?
  - There is no projection of revenue from a future carbon market in this analysis. In the scenarios with a carbon tax, we assume that a carbon tax is being paid by NIPSCO, rolling through customer costs.
- Are you being incentivized to reduce carbon in those scenarios?
  - Yes
- There is a market for renewable energy credits ("RECS") from other states. In the RFP is that REC owned by the installer, and, therefore, probably baked into their bids?
  - That is correct. NIPSCO used the renewable costs, whether it is PPA or asset sales, as per the RFP bids that came through. There is no separate REC price stream that is isolated out or credited back to NIPSCO. Customers would pay for the REC attribute, so it would be in their interest if we were to sell any in the future.

- On Slide 38, please clarify, nameplate capacity of solar in the plan.
  - That slide is unclear as to what is selected. The solar plus storage project is about 180 MW of nameplate capacity. 175 MW of the capacity is solar, with 4.9 MW of battery storage.
- Once these bids are accepted, are the receivers transparent to all?
  - The process is ongoing and NIPSCO is in the middle of a negotiation and commitment process now. There will be clarity in the CPCN process, which will document the selected projects.
- Will the CPCN process show who was accepted?
  - Yes
- The RFP had asked them to commit to offering process and ability through December of 2018. Did that get changed?
  - The RFP specifically asked them to hold the price through the end of year. However, there is no mutually exclusive arrangement, so developers can also negotiate with others if they wish.
- Just to correct the record - Kelly is correct, the reduction is 45% by 2030 and 100% by 2050 and reducing from 2010 CO_2 levels. It is still if you make the targets, you will not be contributing to Armageddon, but not necessarily reducing to where we need to go long term. Still behoove you to get out as fast as possible.
  - Your point is understood.

Stakeholder Presentations

Laura Arnold of Indiana DG provided a presentation regarding net metering and where NIPSCO is in reaching 1.5% of the summer peak and the amount of net metering related to commercial customers. Denise Abdul-Rahman of the Indiana State Conference of the NAACP provided a presentation regarding the efforts the Indiana State Conference of the NAACP has undertaken related to environmental and climate justice and discussed its concerns with NIPSCO’s preferred plan.

Violet Sistovaris, President, NIPSCO and Executive Vice President, NiSource, provided participants with an update on the recent incident involving Columbia Gas of Massachusetts and NiSource’s response. She the closed the meeting by thanking the attendees for their attendance and active participation throughout the process.

Stakeholder Presentation on
Non-residential Net Metering Problem

by Laura Ann Arnold, President
Indiana Distributed Energy

October 18, 2018

Impact of non-residential net metering on NIPSCO IRP

IndianaDG Mission Statement

- To be the voice of the renewable energy (RE) and distributed generation (DG) business, educational and public sectors in Indiana to advocate public policies and to foster economic growth which fosters this business sector, creates jobs, promotes national security, provides stabilized energy resources and improves the quality of the environment.

IndianaDG Members

- Developers of renewable energy and distributed generation (RE&DG) both located in Indiana doing projects here and elsewhere across the country
- Manufacturers of RE/DG systems
- Supporting non-profits and individuals wanting to develop RE/DG projects

Problem: What happens when 1 of 3 groups of customers reaches 1.5% cap?

- NIPSCO is on the verge of reaching its 1.5% cap for 1 of the 3 groups of net metering customers.
- An 890 kW proposed project was told there was insufficient capacity for a non-residential net metering agreement.
- Customer downsized project to 500 kW.
- Most recently 84 kW left for non-residential net metering.

What does SEA 309-2017 tell us should happen now?

- Let’s look at the relevant sections of SEA 309-2017 for some guidance.
- Unfortunately, SEA 309 is somewhat ambiguous and creates uncertainty about next step.
- Some guidance from revised net metering rule.

SEA 309-2017
Chapter 40. Distributed Generation

- Sec. 10. Subject to sections 13 and 14 of this chapter, a net metering tariff of an electricity supplier must remain available to the electricity supplier's customers until the earlier of the following:

Chapter 40. Distributed Generation; Sec. 10 con't

- (1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.
- (2) July 1, 2022.

Chapter 40. Distributed Generation Sec. 10 con't

- **Before July 1, 2022, if an electricity supplier reasonably anticipates, at any point in a calendar year, that the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff will equal at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier, the electricity supplier shall, in accordance with section 16 of this chapter, petition the commission for approval of a rate for the procurement of excess distributed generation.**

Sec. 10 con't

- Sec. 12. (a) Before January 1, 2018, the commission shall amend 170 IAC 4-4.2-4, and an electricity supplier shall amend the electricity supplier's net metering tariff, to do the following:
- Increase the allowed limit on the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.

- **Modify the required reservation of capacity under the limit described in subdivision (1) to require the reservation of:**
  - **forty percent (40%) of the capacity for participation by residential customers; and**
  - **fifteen percent (15%) of the capacity for participation by customers that install a net metering facility that uses a renewable energy resource described in IC 8-1-37-4(a)(5).**

SEA 309-Section 16

- Sec. 16. Not later than March 1, 2021, an electricity supplier shall file with the commission a petition requesting a rate for the procurement of excess distributed generation by the electricity supplier. After an electricity supplier's initial rate for excess distributed generation is approved by the commission under section 17 of this chapter, the electricity supplier shall submit on an annual basis, not later than March 1 of each year, an updated rate for excess distributed generation in accordance with the methodology set forth in section 17 of this chapter.
-

Section 17

- **Sec. 17. The commission shall review a petition filed under section 16 of this chapter by an electricity supplier and, after notice and a public hearing, shall approve a rate to be credited to participating customers by the electricity supplier for excess distributed generation if the commission finds that the rate requested by the electricity supplier was accurately calculated and equals the product of:**

SEA 309; Section 17

- **(1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year;**
- **(2) multiplied by one and twenty-five hundredths (1.25).**

- ***Average marginal price = LMP or locational marginal price***

What does revised net metering rule say about this?

- Can an investor-owned electric utility exceed the 1.5% of summer peak load cap for net metering?
- The answer is YES.

170 IAC 4-4.2-4 Availability

- **170 IAC 4-4.2-4 Availability**
- Authority: IC 8-1-1-3; IC 8-1-40-12
- Affected: IC 8-1-2-34.5; IC 8-1-37-4; IC 8-1-40

- Sec. 4. (a) An investor-owned electric utility shall offer net metering to a customer that installs a net metering facility prior to the earlier of the following:

170 IAC 4-4.2-4 Availability

- (1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the investor-owned electric utility's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the investor-owned electric utility; or
- (2) July 1, 2022.

170 IAC 4-4.2-4 Availability

- (b) The investor-owned electric utility **<u>may</u>** limit the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one and one-half percent (1.5%) of the most recent summer peak load of the utility, with:

- (1) forty percent (40%) of the capacity reserved solely for participation by residential customers; and

170 IAC 4-4.2-4 Availability

- (1) forty percent (40%) of the capacity reserved solely for participation by residential customers; and
- (2) fifteen percent (15%) of the capacity reser ved solely for participation by customers that install a net metering facility that uses a renewable energy resource described in IC 8-1-37-4(a)(5).

170 IAC 4-4.2-4 Availability

- However, the investor-owned electric utility <u>**may**</u> increase the limit on the aggregate amount of net metering facility nameplate capacity at the investor-owned electric utility's sole discretion.

Duke Energy proposes to exceed net metering cap

- In Duke Energy Indiana Cause No. 45145, Andrew Ritch states: "The Company agreed that participants under Rider 26 would be eligible for net metering, but solar facilities installed pursuant to this program will be in addition to and will not count against the system net metering cap contained in the Company's net metering tariff, Standard Contract Rider No. 57. Therefore, this customer option would not be competing with other customer options for the net metering eligibility under the system-wide cap. The Company also agreed that Rider participation would initially be limited to a total of 12 MWs."

PURPA Implementation: federal & state public utility commission

- US Congress passed the Public Utility Regulatory Policies Act (PURPA) in 1978.
- QF = Qualifying Facility—Two categories:
  - Small power producers which are renewable energy such as solar, wind, biomass or geothermal
  - Cogeneration facilities which sequentially produce electricity & thermal energy; aka CHP

NIPSCO seems to believe customers should use PURPA

- Frank Shambo 10/15/18 email states: ".…all business and home owners are allowed to add renewable resources for their own benefit. There is no cap that constrains this activity. The cap solely deals with additional incentives. I would also note that NIPSCO has also offered a Standard Contract for the purchase of capacity and energy from qualifying facilities since 1985. A copy of the Standard Contract is attached. The value of energy and capacity is updated annually. This agreement would provide benefits for the energy that is pushed back onto NIPSCO's system above the volume used by the customer. "

Should NIPSCO petition IURC for new tariff?

- SEA 309-2017 appears unclear as to <u>*when*</u> NIPSCO should petition the IURC to establish the average marginal price times 1.25%.

What is the current status of net metering?

- The last formal information is contained in the 2018 Net Metering Report for the year ending 2017.
- There is a need for earlier reporting than Feb. 28, 2019 to determine if other utilities are approaching their net metering cap for any category of customers.

Table 1. Nameplate Capacity by utility and by resource type, 2017

Table 1. Nameplate Capacity by utility and by resource type, 2017

	Total (kW)	Solar (kW)	Wind (kW)[8]	Biomass (kW)
Duke Energy Indiana	17,878	15,659	2,220	0
NIPSCO	10,689	8,641	2,048	0
I&M	10,405	9,909	256	240
Vectren	7,799	7,782	16	0
IPL	2,369	2,319	50	0
Total	49,140	44,310	4,590	240

Table 3. Nameplate Capacity relative to 1.5% peak load by utility, 2017

Table 3. Nameplate Capacity relative to 1.5% peak load by utility, 2017

	2016 Summer Peak Load (kW)	2017 Net Metering Capacity (kW)	Percent of peak load	Remaining Net Metering Capacity under 1.5% cap (kW)
Vectren	1,097,700	7,799	0.71%	8,667
NIPSCO	3,142,160	10,689	0.34%	36,444
Duke Energy Indiana	5,492,000	17,878	0.33%	64,502
I&M	3,659,700	10,405	0.28%	44,491
IPL	2,716,000	2,369	0.09%	38,371
Total	16,107,560	49,140	0.31%	192,474

Table 3. Solar Nameplate Capacity Growth year over year

Table 7. Solar Nameplate Capacity growth year over year

	Capacity (kW)	% change from previous year	Absolute change from previous year (kW)
2005	23		
2006	66	188%	43
2007	121	83%	55
2008	167	38%	46
2009	307	84%	140
2010	529	72%	221
2011	1,119	112%	591
2012	1,789	60%	670
2013	2,657	49%	868
2014	4,346	64%	1,689
2015	8,123	87%	3,777
2016	15,476	91%	7,353
2017	44,310	186%	28,834

Table 8. Wind Nameplate Capacity growth year over year

Table 8. Wind Nameplate Capacity growth year over year

	Capacity (kW)	% change from previous year	Absolute change from previous year (kW)
2005	0		
2006	0		
2007	19		19
2008	65	243%	46
2009	196	202%	131
2010	255	30%	58
2011	732	187%	477
2012	3,509	379%	2,777
2013	4,431	26%	922
2014	4,446	0%	15
2015	4,620	4%	174
2016	4,476	-3%	-144
2017	4,590	3%	114

Contact information

- Laura Ann Arnold, President

Indiana Distributed Energy Alliance

545 E. Eleventh Street

Indianapolis, IN 46202

(317) 635-1701

(317) 502-5123 cell

Laura.Arnold@IndianaDG.net or

Laura.Arnold@thearnoldgroup.biz

INDIANA STATE CONFERENCE OF THE NAACP ENVIRONMENTAL AND CLIMATE JUSTICE PROGRAM

Denise Abdul-Rahman
BS, MBA, HCM, HIS
317-331-0815
darahman17@gmail.com

@denisearahman

History and Background

- Indiana State Conference of the NAACP is 58 years old
- 35 Branches across the State including Youth and College
- Our Indiana Environmental Climate Justice Program work is local (city), state, midwest, national and global advocacy
- National NAACP is 110 years old
- 2500 Branches

The Indiana State Conference of the NAACP Environmental and Climate Justice (ECJ) Program

Environmental injustices, including climate change, have a disproportionate impact on communities of color and low income communities in the US and around the world. Our work is implemented within the context of human and civil rights issue, advocating for three objectives:

Reduce Harmful Emissions Equitably Particularly Greenhouse Gases

Advance Equitable Energy Efficiency and Equitable Energy

and Strengthen Community Resistance and Livability.

Engage/Educate

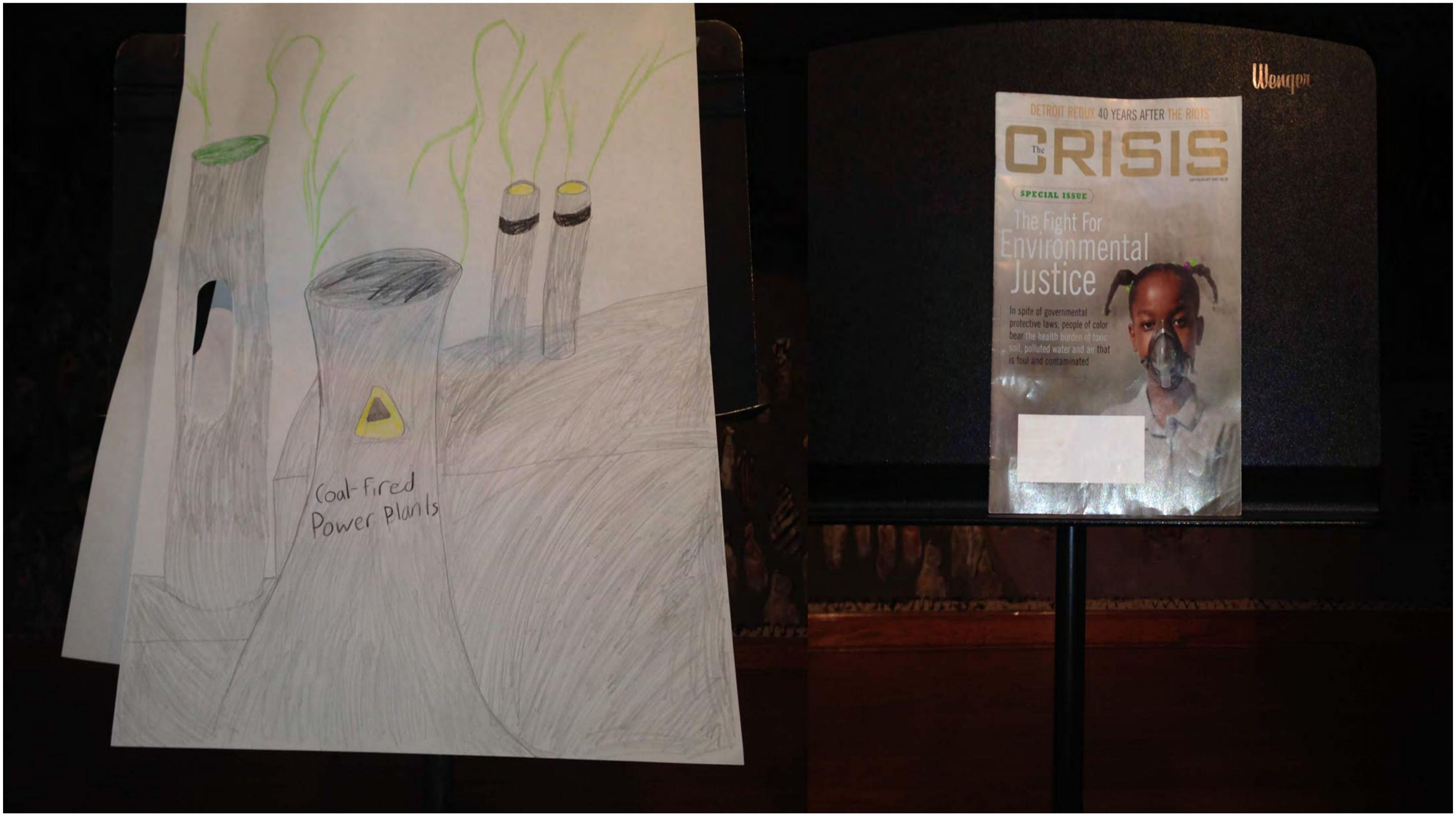
Empowerment (We support the existing power)

Advocate

*Jemez Principles

1. ***Be Inclusive, 2. Bottom up organizing, 3. Let People Speak for themselves, 4. Work Together in solidarity and mutuality, 5. Build Just Relationships among Ourselves 6. Commitment to Self Transformation***


BREAKFAST: IMAGINE WOMEN
HIP HOP TO ENERGY DEMOCRACY
HORIZON CONVENTION CENTER, Interurban Hall, Municie, IN
CONTACT: Denise Abdul-Rahman at darahman17@gmail.com
ENERGY DEMOCRACY
FREE! JOIN US OCT 26
7:30am-9:30am
Celebrating People Power,
Healthy Communities, and Make Art with
Dr. Denise Fairchild, Keynote Speaker
Janet McCabe, Special Guest Speaker
Jacqueline Patterson, Key Address
Nicole Burts, Moderator
Manon Voice, Hip Hop Artist
Stacia Moon, Trained Musician
Ess McKee, Mixed Media Creator
Denise Abdul-Rahman, Speaker, Organizer and Facilitator
CLIMATE JUSTICE ALLIANCE
COMMUNITIES UNITED FOR A JUST TRANSITION
ENERGY DEMOCRACY NATIONAL TOUR 2018


Coal-Fired
Power Plants
Wenger
DETROIT REDUX 40 YEARS AFTER THE RIOTS
The CRISIS
SPECIAL ISSUE
The Fight For
Environmental
Justice
In spite of governmental protective laws, people of color bear the health burden of toxic soil, polluted water and air that is foul and contaminated

Friday, March 28, 2014

Meeting tackles the environment

Barbara Bolling Williams (right), president of the NAACP State Conference and national board member of the NAACP, welcomes invited panelists to the "Just Energy: Reducing Pollution and Creating Jobs" town hall meeting. The NAACP is a conduit for environmental justice and primarily advocates for clean energy, climate, environment (air, water, food), stewardship and connecting the community with a green economy.

At the meeting, which was held at Mount Zion Baptist Church, Dana Reed Wise (left), chief of the bureau of environmental health for the Marion County Public Health Department, speaks on environmental climate issues as Rep. Vanessa Summers, D-Indianapolis, listen to her perspective. (Photos/Curtis Guynn)


VIETNAM VETERAN
NAACP
2016
A WIN FOR ALL
NAACP
2016
A WIN FOR ALL
VOTE YES CLEAN ENERGY
NAACP
2016
A WIN FOR ALL

OUR AIR, OUR ENERGY,OUR WATER, OUR CHILDREN & OUR ENVIRONMENT

DEMOGRAPHIC FACTS:

- ✓ 41.6% PEOPLE OF COLOR LIVE WITHIN INDIANAPOLIS- MARION COUNTY[1]
- ✓ 83% LOW INCOME LIVE WITHIN A 3 MILE RADIUS OF IPL POWER PLANT[2]
- ✓ BLACK CHILD THREE TIMES LIKELY TO BE ADMITTED INTO THE HOSPITAL, TWO TIMES LIKELY TO DIE OF AN ASTHMA ATTACK [3]

1 Brown, Amos "Blacks continue to power city's population growth, Census says" July 10, 2014

2,3 Coal Blooded: Putting Profits Before People. National Association for the Advancement of Colored People, 2013

Attend Indianapolis City County Council Meeting August 18th, 2014 at 7:00 pm VOTE TO AMEND RESOLUTION 241

NAACP
A 2016 Closure
is a
Win For All
VOTE
to
AMEND
RESOLUTION 241
OUR AIR, OUR ENERGY, OUR WATER, OUR CHILDREN & OUR ENVIRONMENT
NOW !

NAACP

THE OLDEST CIVIL RIGHTS ORGANIZATION IN THE NATION!

105 YEARS!

NAACP WANTS JUSTICE NOW! 2016 A WIN FOR ALL!

WE WANT JUSTICE FOR OUR EXISTING COMMUNITIES, EXISITING YOUTH AND EXISTING BUSINESSES RIGHT HERE AND RIGHT NOW !

IPL HARDING STREET

RETIRE UNIT #7 NOW!

---Environmental Justice Score of an F

Assure: *No Job losses and Just transition

***Provide Community Benefit Agreement**

***Renewable & Clean Energy *Along with MBE & WBE Contract Opportunities**


ENERGY
ENERGY
OVERDEVELOPMENT AND THE DELUSION OF ENDLESS GROWTH
NINJAGO


NAACP

Coal Blooded

Putting Profits Before People

NAACP Indigenous Environmental Network LVEJO

Indianapolis Power and Light

Just Energy Reducing Pollution and Creating Jobs Campaign Called for 2016 stop burning coal

Town Hall Mount Zion Baptist Church

Resolutions

City County Council

Burned coal until February 2016 and currently burning “natural” gas.

Huge polluter in 2014, 77% of the City of Indianapolis industrial air pollution according to Energy Justice Network

Michigan City Coal Burning Cooling Tower


INDIANA NAACP ENVIRONMENTAL JUSTICE
&
KHEPRW INSTITUTE
PRESENT
#JUSTENERGY FREEDOM
COMMUNITY EMPOWERMENT DISCUSSION
BLACKS & SOLAR
HOW MUCH DO YOU KNOW?
WHEN: THURSDAY, FEBRUARY 19TH, 2015
TIME: 6:00 PM
WHERE:
KHEPRW INSTITUTE

WWW.NAACP.ORG
NAACP

JUST ENERGY CHOICE

INDUSTRIAL FOSSIL FUEL POWER PLANT

- People of color disproportionately host industrial power plants
- Nearly 1600 die from asthma attack yearly
- Black child three times as likely to be rushed to emergency
- African Americans pay 41 billion a year to the energy sector and only held 1.1% of the sector jobs 2009 AABE
- Property values decline by 15%
- Homeland Security Weakness
- Climate Change and Carbon Pollution
- Fixed Rate Charges and Volumetric Charges

CLEAN AND RENEWABLE ENERGY

- Only 600 early adapters in Indiana, so opportunity is vast
- Job Growth is 418% nationwide
- MBE Solar Development & Installation opportunities
- Healthier communities
- Increase property values
- Solar price falling
- A Strength to Homeland Security
- Offers Climate Preparedness to our communities
- Energy Empowerment the ability to generate energy and obtain credit

Indiana NAACP Environmental Climate Justice
Prepared by Indiana Green Outreach IGO

Attachment 2-A

Legislation and Net Metering Symposium

HB 1320 Distributed Generation *IBLC Net Metering

SB 412 Integrated Resource Plans (requires plan submission one time every three years, no third party required to implement Energy Efficiency and evaluation,verification to be conducted by independent evaluation

SB 340 Demandside Management (allowed Industrials to opt out)

03 10 15

You are cordially invited to,

INDIANA NAACP ENVIRONMENTAL JUSTICE

& THE ALLIANCE FOR SOLAR CHOICE

Support Tax Free Net Metering

MARCH 10, 2015
5:30 PM
SKYLINE CLUB
1 AMERICAN SQUARE, 36TH FLOOR
INDIANAPOLIS, IN 46282

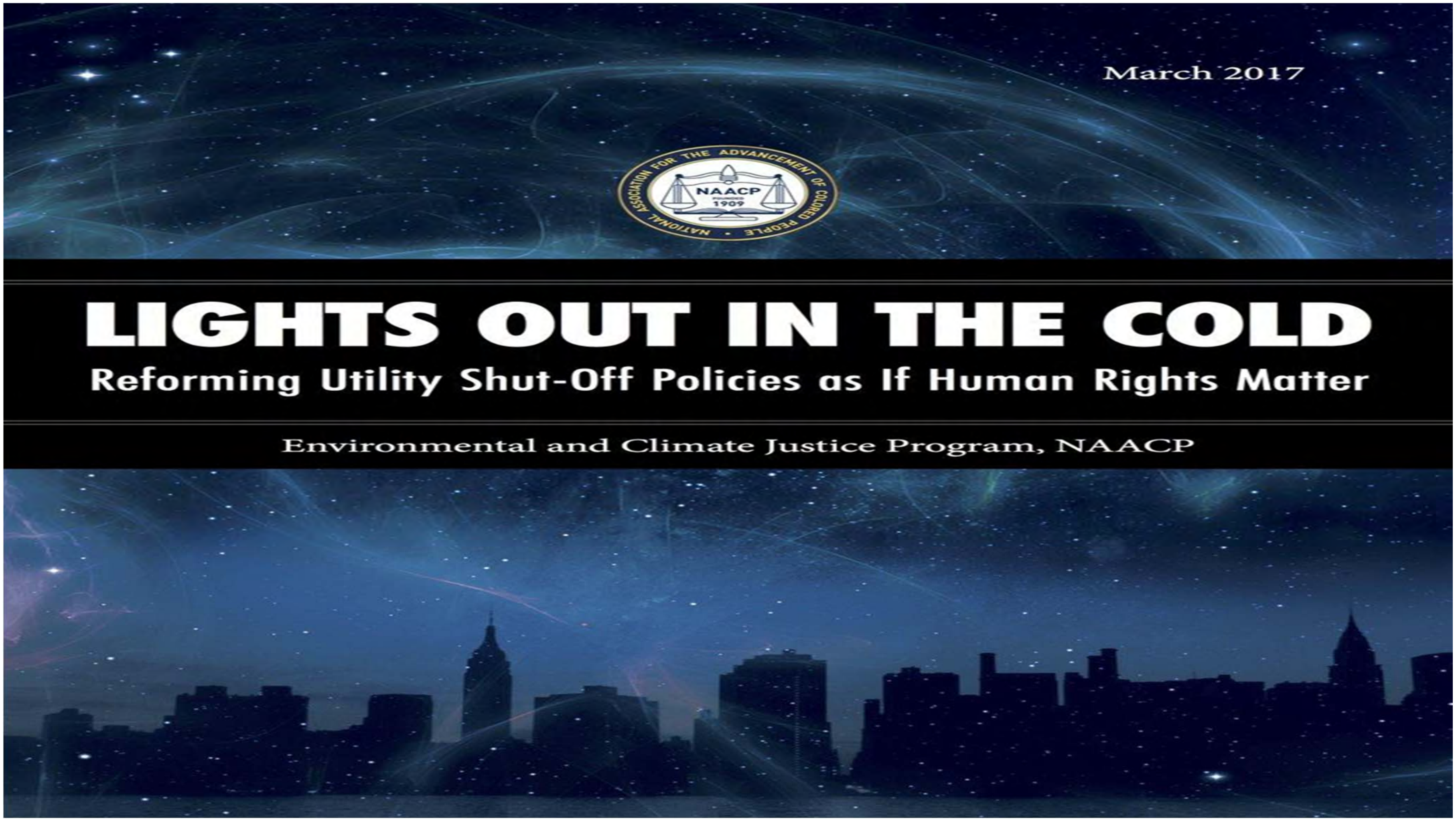
Heavy H'orderves

KINDLY RESPOND BY MARCH 5, 2015
TO DENISE AT 317-331-0815 OR
INECJNAACP@ATT.NET

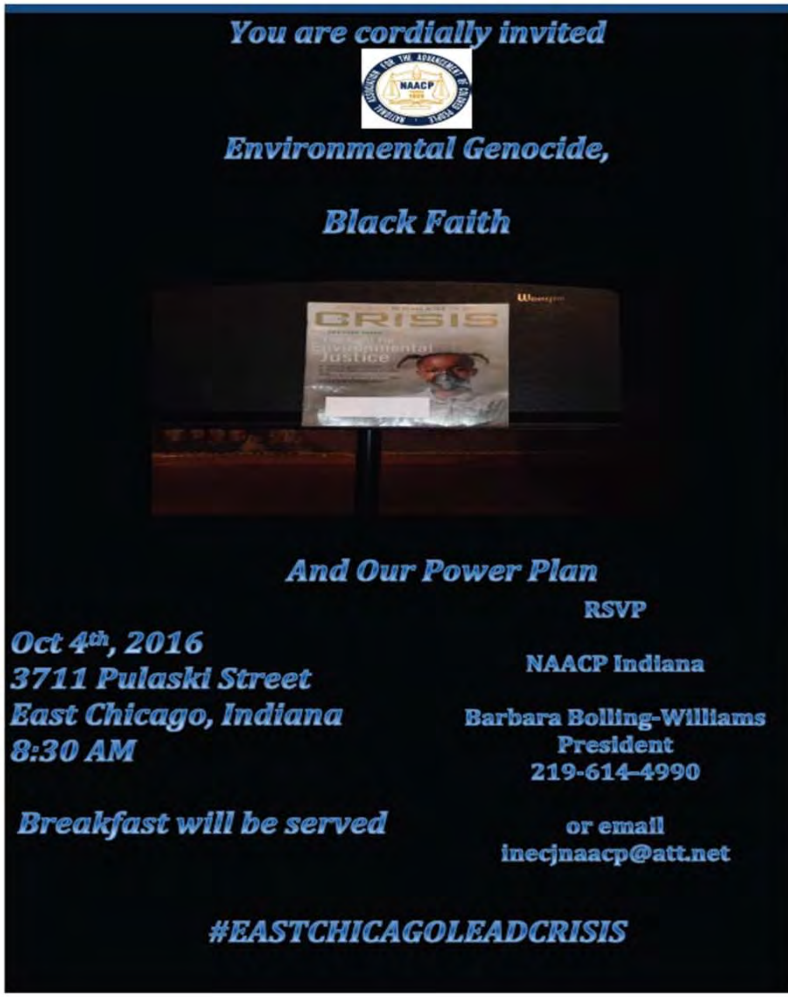

INDIANA ENERGY JUSTICE SNAPSHOT
ENERGY JUSTICE SYMPOSIUM

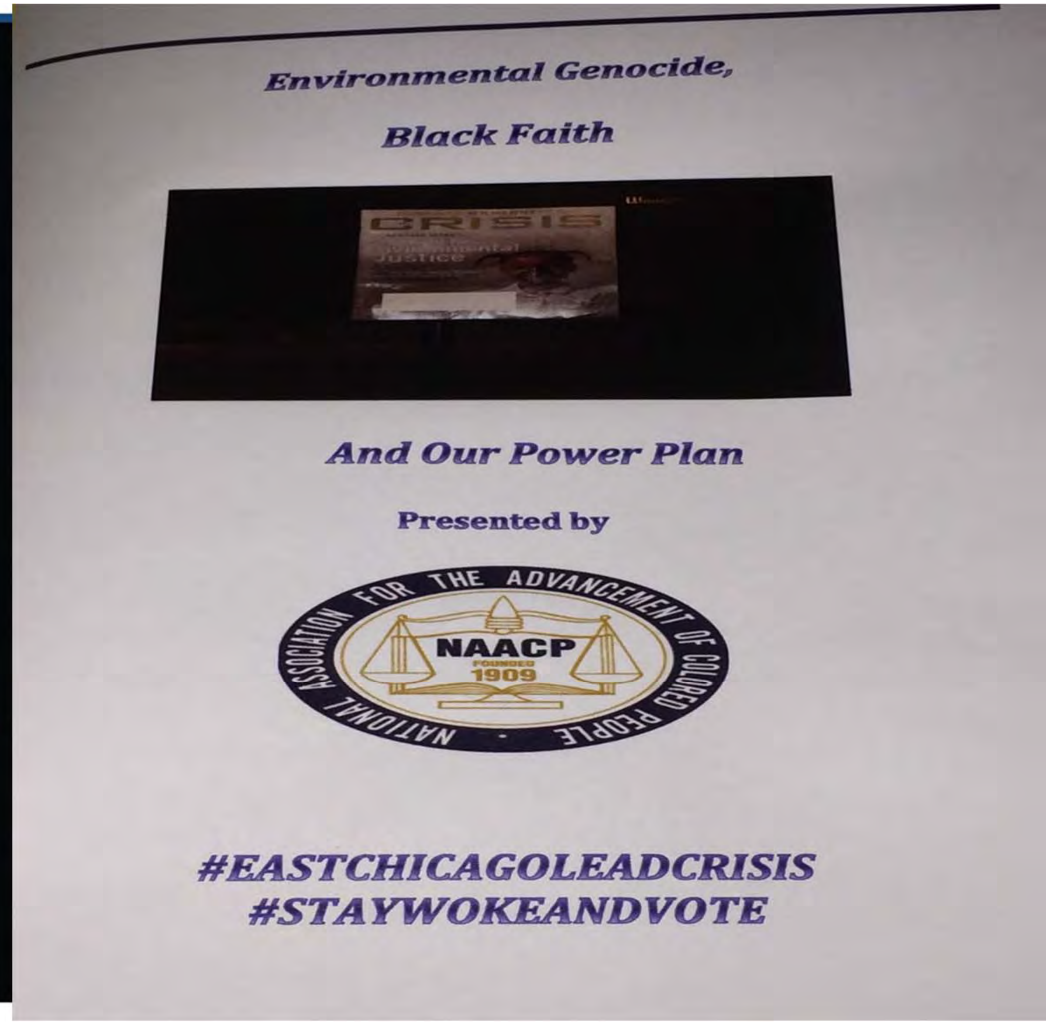
Indiana Utility Regulatory Commission/Office of Utility Consumer Counseling

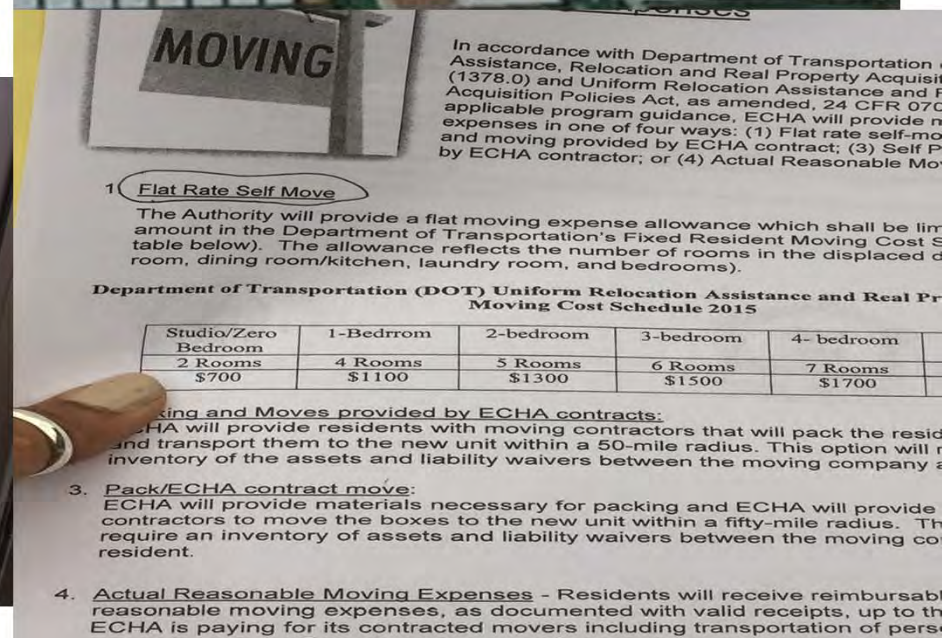
- Five Investor owned utilities
- Equity- CO 2 reductions, oppose carbon markets, better energy efficiency programs like inclusive on bill financing
- Equitable location of solar development
- Solar/Wind Apprenticeships
- MBE/WBE contracting opportunities
- Provided survey on Bill Design based on the number of high disconnects


March 2017
NATIONAL ASSOCIATION FOR THE ADVANCEMENT OF COLORED PEOPLE
NAACP
1909
LIGHTS OUT IN THE COLD
Reforming Utility Shut-Off Policies as If Human Rights Matter
Environmental and Climate Justice Program, NAACP

Clean Power Plan and the Clean Energy Incentive Plan
Our Power Plan EPA Region V, over 10 organization and 85 attendees


You are cordially invited
Environmental Genocide,
Black Faith
And Our Power Plan
RSVP
Oct 4th, 2016
3711 Pulaski Street
East Chicago, Indiana
8:30 AM
NAACP Indiana
Barbara Bolling-Williams
President
219-614-4990
Breakfast will be served
or email
inecjnaacp@att.net
#EASTCHICAGOLEADCRISIS


Environmental Genocide,
Black Faith
And Our Power Plan
Presented by
NATIONAL ASSOCIATION FOR THE ADVANCEMENT OF COLORED PEOPLE
NAACP
FOUNDED
1909
#EASTCHICAGOLEADCRISIS
#STAYWOKEANDVOTE



MOVING

In accordance with Department of Transportation
Assistance, Relocation and Real Property Acquisit
(1378.0) and Uniform Relocation Assistance and R
Acquisition Policies Act, as amended, 24 CFR 070
applicable program guidance, ECHA will provide m
expenses in one of four ways: (1) Flat rate self-mo
and moving provided by ECHA contract; (3) Self P
by ECHA contractor; or (4) Actual Reasonable Mo

1. Flat Rate Self Move

The Authority will provide a flat moving expense allowance which shall be lim
amount in the Department of Transportation's Fixed Resident Moving Cost S
table below). The allowance reflects the number of rooms in the displaced d
room, dining room/kitchen, laundry room, and bedrooms).

Department of Transportation (DOT) Uniform Relocation Assistance and Real Pr
Moving Cost Schedule 2015

Studio/Zero Bedroom	1-Bedrrom	2-bedroom	3-bedroom	4- bedroom
2 Rooms	4 Rooms	5 Rooms	6 Rooms	7 Rooms
$700	$1100	$1300	$1500	$1700

...king and Moves provided by ECHA contracts:
...HA will provide residents with moving contractors that will pack the resid
...nd transport them to the new unit within a 50-mile radius. This option will r
inventory of the assets and liability waivers between the moving company a

3. Pack/ECHA contract move:
ECHA will provide materials necessary for packing and ECHA will provide
contractors to move the boxes to the new unit within a fifty-mile radius. Th
require an inventory of assets and liability waivers between the moving co
resident.

4. Actual Reasonable Moving Expenses - Residents will receive reimbursabl
reasonable moving expenses, as documented with valid receipts, up to th
ECHA is paying for its contracted movers including transportation of pers

URGENT SUPPORT FOR RESIDENTS OF
WEST CALUMET HOUSING COMPLEX&Zone 1,2,3
DONATE FRESH FRUITS AND VEGETABLES

FIRST BAPTIST CHURCH
EAST CHICAGO

Pastor Sloss
4911 McCOOK AVENUE
EAST CHICAGO, INDIANA 46312
(219) 398-0758

Contact: NAACP Indiana
Denise Abdul-Rahman
Environmental Climate Justice Chair
inecjnaacp@att.net

Barbara Bolling Williams
President
(219) 614-4889

AND PICK UP FRESH FRUIT AND VEGETABLES
Fruits and Vegetables can absorb lead poisoning the children need it to protect their brains & bodies

DELIVERIES ACCEPTED

Wednesdays between
11:00 am - 2:00 pm

Distribution to residents:

Wednesdays between
5:30 pm - 7:00 pm

Thursdays between
11:00 am - 2:00 pm

"Until Futher Notice"

FOOD ABSORBS LEAD CAMPAIGN

FIRST BAPTIST CHURCH EAST CHICAGO

REVERAND DOUGLAS SLOSS
4911 McCOOK AVENUE
EAST CHICAGO, INDIANA 46312
(219) 398-0758

WWW.NAACP.ORG
NAACP

FRIENDSHIP MISSIONARY BAPTIST CHURCH

DEACON GORDON FLEMING
4756 MELVILLE AVENUE
EAST CHICAGO, INDIANA 46312

Donate Here for Food, Moving Expenses, Child Care, Transportation As Needed

Deliveries Accepted
1st Baptist Church
Wednesdays
11 -2 pm

Friendship Missionary Baptist Church
Anytime

Distribution to Community
1st Baptist Church
Wednesdays 5:30 -7 pm
Thursdays 11 am – 2 pm

Friendship Missionary Baptist
Saturday 11-1 pm

CONTACT FOR MORE INFORMATION
NAACP INDIANA
DENISE ABDUL-RAHMAN
Environmental Climate Justice Chair

BARBARA BOLLING WILLIAMS
President
(219) 614-4889

Attachment 2-A


EPA

East Chicago Listening Sessions, Roundtable, Food Absorbs Lead Campaign, Filtration Systems, Petitions and Letters to the Governor


ATTENTION
CALUMET


THE CRISIS TODAY
@1:00pm ET
WTHE 1520AM
Mineola, New York
(covering the NY, NJ, and CT metro area)
www.wthe1520am.com
-or-
Tunein.com
Also tune-in:
WCCG 105.4FM (Fayetteville, NC)
Saturdays @ 6am
Airs each Tuesday
ALERT: Legal commentary from Attorney Jimmie Meyerson.
................GUESTS...............
ENVIRONMENTAL JUSTICE IN INDIANA
BARBARA BOLLING- WILLIAMS
Member, NAACP Board of Directors
President, Indiana NAACP State Conference
--and--
DENISE ABDUL-RAHMAN
Environmental & Climate Justice Chair
Indiana NAACP State Conference
--followed by--
FLOYD NORMAN
Animator, Writer and Comic Book Artist
The Walt Disney Company
(first African American artist to remain at Disney studios on a long-term basis)
CALL-IN: 516-877-WTHE (9843)
EMAIL: judgeblackburneradio@aol.com
judgeblackburneradio@gmail.com
Text CRISIS to 62227

NAACP Delegation to People's Climate March 2017, East Chicago resident and Indianapolis resident deliver water to Indigenous Women Water Protectors

Site 0153

Starkly advocated for the adherence of Executive Order 12898 and recognizing that the community met the criteria of an Environmental Justice Community

Called for Due Diligence and Meaningful involvement

NATIONAL ASSOCIATION FOR THE ADVANCEMENT OF COLORED PEOPLE
NAACP
1909

OUR YOUTH SCIENTISTS

ENGAGE, EMPOWER, AND EDUCATE

Indiana State Conference
East Chicago, Indiana
October 10th-14th,2017


SCIENTISTS
Indiana State Conference
East Chicago, Indiana
October 10th-14th,2017

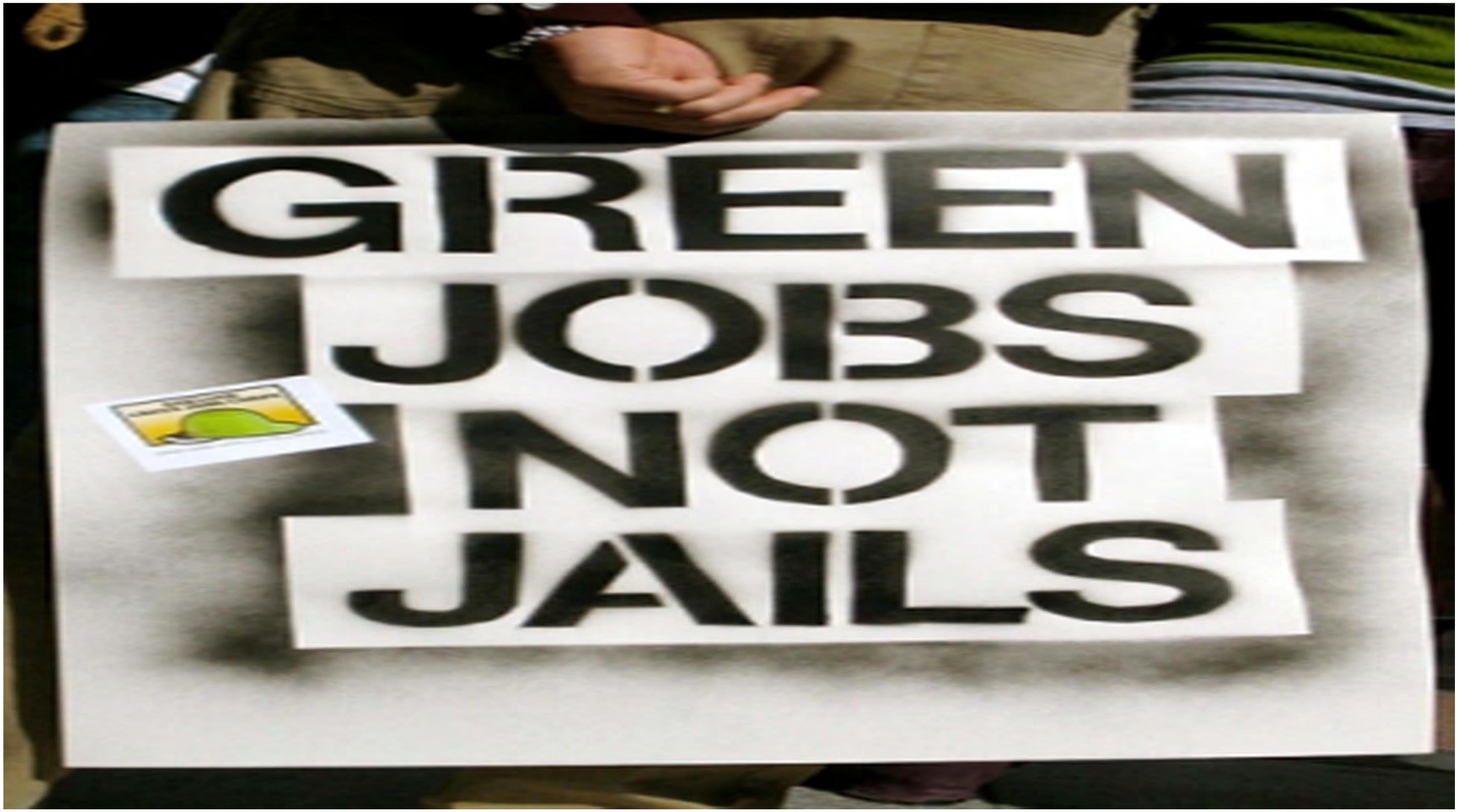

LeadCheck
INSTANT


Please
Wait
Here


School
GRATITUDE
WITH

Blight to Flight on our Just Transition from lead, climate change and Green Economics woman lead forum


INDIANA NAACP
STATE CONFERENCE
NATIONAL ASSOCIATION FOR THE ADVANCEMENT OF COLORED PEOPLE
NAACP
FOUNDED
1909
WE ARE MOVING OUR
COMMUNITIES FROM
BLIGHT TO FLIGHT
ENVIRONMENTAL AND
CLIMATE JUSTICE
IT'S ABOUT US!
JUST TRANSITION
LABOR


GREEN
JOBS
NOT
JAILS

Our Impact

- Our Methodology is for Collective Systemic Change
- Our work is Instrumental in amplifying, and starkly lifting the EJ narrative of Indiana
- Opened opportunity for the inclusion of community and MBE's relating to Resiliency planning, energy decisions, environmental hazard and more
- Creates academia opportunities for student research that does not exist in Indiana and beyond
- Protect Health
- Ramping Education Green Economic Job training Opportunity
- Location of energy development
- Youth empowerment and adult empowerment via Citizen Science
- Federal, State and Local Legislative Impact
- More within Indiana Utility Regulatory Commission, Office of Utility Consumer Counseling
- Climate, water, air, incineration, food access, brownfields, energy, housing, economics, criminal justice, schools, transportation equity, recycling equity and much more


NATIONAL ASSOCIATION FOR THE ADVANCEMENT OF COLORED PEOPLE
NAACP
1909
BREAKFAST: IMAGINE WOMEN
HIP HOP TO ENERGY DEMOCRACY
HORIZON CONVENTION CENTER, Interurban Hall, Municie, IN
CONTACT: Denise Abdul-Rahman at darahman17@gmail.com
ENERGY DEMOCRACY
FREE! JOIN US OCT 26
7:30am-9:30am
Celebrating People Power,
Healthy Communities, and Make Art with
Dr. Denise Fairchild, Keynote Speaker
Janet McCabe, Special Guest Speaker
Jacqueline Patterson, Key Address
Nicole Burts, Moderator
Manon Voice, Hip Hop Artist
Stacia Moon, Trained Musician
Ess McKee, Mixed Media Creator
Denise Abdul-Rahman, Speaker, Organizer and Facilitator
CLIMATE JUSTICE ALLIANCE
COMMUNITIES UNITED FOR A JUST TRANSITION
ENERGY DEMOCRACY NATIONAL TOUR 2018

Julian Bond once said to me, ‘If you don’t speak, Noone Can Hear You’ One aspect of my theory of change is to reimagine and utilize oratory as a pathway to movement and change

THANK YOU

QUESTIONS?

Denise Abdul-Rahman

BS, MBA, HCM, HIS

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@denisearahman

Attachment 2-A

NIPSCO Public Advisory Meeting 4 Registered Participants		
First Name:	Last Name:	Company:
Denise	Abdul-Rahman	Indiana State Conference of the NAACP
Robert	Adams	AES-IPL
Lauren	Aguilar	OUCC
Jake	Allen	IPL
Anthony	Alvarez	OUCC
Laura	Arnold	Indiana Distributed Energy Alliance (IndianaDG)
Pat	Augustine	Charles River Associates
Kim	Ballard	IURC
Richard	Benedict	Self
Anne	BEcker	Lewis Kappes
Mahamadou	Bikienga	NiSource
Marc	Blanchard	BP
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	IURC
Wendy	Bredhold	Sierra Club
Andy	Campbell	NIPSCO
Kelly	Carmichael	NiSource
Joseph	Conn	NWI Beyond Coal Campaign
Jeffrey	Corder	St. Joseph Phase II, LLC
Nick	Corder	EnFocus Development
Dan	Douglas	NIPSCO
Jeffery	Earl	Indiana Coal Council
Michael	Eckert	Office of Utility Consumer Counselor
Amy	Efland	NiSource/NIPSCO
Gregory	Ehrendreich	MEEA
Clare	Everts	Charles River Associates
Steve	Francis	Sierra Club - Hoosier Chapter
John	Garvey	CRA
Fred	Gomos	NiSource
Doug	Gotham	State Utility Forecasting Group
Abby	Gray	OUCC
Stacie	Gruca	OUCC
Corey	Hagelberg	Beyond Coal
Jeffrey	Hammons	Environmental Law & Policy Center
John	Haselden	OUCC
Shelby	Houston	IPL/AES
Paul	Kelly	NIPSCO
Will	Kenworthy	Vote Solar
Sam	Kliewer	Cypress Creek Renewables
Mark	Kornhaus	NextEra Energy
Kim	Krupsaw	Vectren Corp
Tim	Lasocki	Orion Renewable Energy Group LLC
Jonathan	Mack	NIPSCO
Patrick	Maguire	Indianapolis Power and Light
Finnian	McCabe	Ground Star Energy llc

NIPSCO Public Advisory Meeting 4 Registered Participants		
First Name:	Last Name:	Company:
Debi	McCall	NIPSCO
Cassandra	McCrae	Earthjustice
James	McMahon	CRA
Emily	Medine	EVA
Zachary	Melda	NextEra Energy Resources
Nick	Meyer	NIPSCO
Ana	Mileva	Blue Marble Analytics
Adam	Newcomer	NIPSCO
David	Ober	Indiana Utility Regulatory Commission
Kerwin	Olson	Citizens Action Coalition of IN
April	Paronish	Indiana Office of Utility Consumer Counselor
Bob	Pauley	IURC
Jodi	Perras	Sierra Club
Timothy	Powers	Inovateus Solar LLC
Mark	Pruitt	The Power Bureau
Dennis	Rackers	Energy & Environmental Prosperity Works!
Thom	Rainwater	Development Partners Group
Jeff	Reed	OUCC
David	Repp	JET Inc
Adam	Rickel	NextEra Energy Resources LLC
Chad	Ritchie	Lockheed Martin
Edward	Rutter	Indiana Office of Consumer Counselor
Carter	Scott	Ranger Power LLC
Cliff	Scott	NIPSCO
Zachary	Scott	PSG Energy Group
Rob	Seren	NIPSCO
Frank	Shambo	NIPSCO
Regiana	Sistevaris	Indiana Michigan Power Company
Violet	Sistovaris	NIPSCO
Barbara	Smith	OUCC
Jennifer	Staciwa	NIPSCO
Bruce	Stevens	Indiana Coal Council
George	Stevens	I U R C
Emily	Straka	Ranger Power
Alice	Tharenos	peabody
Dale	Thomas	IURC
Maureen	Turman	NiSource
William	Vance	Indianapolis Power & Light
Bob	Veneck	Indiana Utility Regulatory Commission
Nathan	Vogel	Inovateus Solar
Victoria	Vrab	NIPSCO
John	Wagner	NIPSCO
Jennifer	Washburn	CAC
Adam	Watson	NiSource Inc.
Rev. Curtis	Whittaker, Sr.	Progressive Community Church

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NIPSCO Public Advisory Meeting 4 Registered Participants		
First Name:	Last Name:	Company:
Ryan	Wilhelmus	Vectren
Ashley	Williams	Sierra Club
Bryndis	Woods	Applied Economics Clinic
David	Woronecki-Ellis	Sierra Club Dunelands Group
Jen	Woronecki-Ellis	Sierra Club Dunelands Group
Fang	Wu	SUFG
Jim	Zucal	NIPSCO