NIPSCO Integrated Resource Plan 2018 Update

Public Advisory Meeting One

March 23, 2018
Welcome and Introductions

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

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

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

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

*Webinar*
Overview of Public Advisory Process

• 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
NIPSCO 2016 IRP Preferred Plan Creates Capacity Need

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

- **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
## 2016 IRP Directors Report Feedback And Improvement Plan

<table>
<thead>
<tr>
<th>Subject</th>
<th>2016 IRP Feedback</th>
<th>2018 Improvement Plan</th>
</tr>
</thead>
</table>
| **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
# 2016 IRP Directors Report Feedback And Improvement Plan

<table>
<thead>
<tr>
<th>Subject</th>
<th>2016 IRP Feedback</th>
<th>2018 Improvement Plan</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost Assumptions</td>
<td>• Capital cost estimates for new capacity resources were based on proprietary consultant information  &lt;br&gt; • “…No scenario or sensitivity covered uncertainties of resource technology cost”</td>
<td>• Leveraging 3rd party and publicly available datasets to develop a range of current and future capital cost estimates for new capacity resources  &lt;br&gt; • Conducting an “all-source” Request for Proposal solicitation for replacement capacity resources</td>
</tr>
<tr>
<td>DSM Modeling</td>
<td>• DSM groupings are not getting quite the same treatment as the supply side resources</td>
<td>• Utilizing new modeling capabilities will enable DSM to be treated equally with other supply side resources</td>
</tr>
<tr>
<td>Preferred Plan and Scorecard</td>
<td>• “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”  &lt;br&gt; • “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”</td>
<td>• Providing detailed analysis on selection of the Preferred Plan driven by need for it to be actionable  &lt;br&gt; • Developing enhanced scorecard methodology to include more quantifiable metrics that better evaluate tradeoffs  &lt;br&gt; • Incorporating rate impact analysis as part of preferred plan metrics</td>
</tr>
</tbody>
</table>

Source: Final DIRECTOR’S REPORT for the 2016 Integrated Resource Plans, November 2, 2017
Break
Modeling Approach

Jim McMahon & Pat Augustine
Charles River Associates (CRA)
Key Areas Where CRA Is Supporting NIPSCO With The 2018 IRP

- 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

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

Fundamental Commodity Price Forecasting

Integrated Resource Planning
Overview Of Resource Planning Approach

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

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

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

Overview of Resource Planning Approach:

- Load forecasts
- Emission prices
- Fuel forecasts
- Technology costs
- Expert judgment
- Historical Data
- Econometric Analysis
- DSM Screening
- Monte Carlo Engine (Chronological, hourly dispatch model)
- PERFORM (Detailed cost of service)
Models And Tools To Be Used In The 2018 IRP

Environmental, Power Market and Financial Models

NEEM Model
- Effect of environmental constraints on power sector
- Emission prices and ERC prices
- “Optimal” regional supply mix

NGF Model and GPCM
- Fundamental supply and demand for natural gas
- Regional basis

PERFORM
- Retail rates and earnings impacts based on dispatch of utility portfolio
- Cash flow analysis
- Integration with other utility costs (T&D)

Monte Carlo Engine
- Stochastic analysis to measure portfolio risk

AURORAxmp
- Chronological dispatch
- Power prices & capacity factors
- Detailed portfolio modeling

Portfolio Analysis – Costs and Risks

Market Input and Portfolio Development
NGF Model – Natural Gas Price Forecasting

- 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 unproved
- 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.
NEEM: Macro-level Market Analysis

1. Simulates economic dispatch based on array of macro-level model inputs

2. Provides key outputs to be used in more detailed resource planning work

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
Aurora: Regional Power Market *And* Portfolio Analysis Tool

**CRA Power Market Modeling Process**

**Major Inputs**
- Existing Resources
- Fuel Prices
- Emission Prices
- Demand
- Transmission Interconnections

**Modeling System**
- NIPSCO Portfolios
  - Scenarios or Stochastics
  - AURORAxmp
    - Hourly Chronological Dispatch
    - Detailed Market Representation
    - Utility portfolio specification
  - New Builds & Retirements

**Major Outputs**
- Portfolio Costs
- Energy Prices by Zone
- Plant Dispatch, Revenues, and Cost Profiles
- Capacity Prices

To PERFORM
PERFORM: Cost Of Service And NPVRR Calculations

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
Modeling Of Uncertainty

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 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

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

*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.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Base</th>
<th>Aggressive Environmental Regulation</th>
<th>Challenged Economy</th>
<th>Booming Economy &amp; Abundant Natural Gas</th>
</tr>
</thead>
</table>
|          | - Reference case commodity price outlook, with 2026 carbon price | - High carbon price  
- Feedbacks to gas, coal, and power prices  
- Non-carbon environmental compliance costs are stricter  
- Tech. breakthrough for renewable/storage costs | - Low load, including loss of industrial load  
- No carbon price  
- Feedbacks to gas, coal, and power prices | - 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**

- **More renewables, storage, and DSM; more coal retirements**
- **Fewer renewables and DSM; better coal economics; fewer self-builds and more reliance on market**
- **More gas CCGT, fewer renewables and DSM**
Scenario Descriptions

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

<table>
<thead>
<tr>
<th>Scenario Theme</th>
<th>NIPSCO Load</th>
<th>CO₂ Price</th>
<th>Natural Gas Price</th>
<th>Coal Price</th>
<th>Power Price</th>
<th>Capital Costs</th>
<th>Other Enviro. Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
</tr>
<tr>
<td>Aggressive Environmental Regulation</td>
<td>Base</td>
<td>High</td>
<td>High</td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Challenged Economy</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>Base</td>
<td>Base</td>
</tr>
<tr>
<td>Booming Economy &amp; Abundant Natural Gas</td>
<td>High</td>
<td>Base</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>Base</td>
<td>Base</td>
</tr>
</tbody>
</table>
Process For Using Scenarios And Stochastics In The Analysis

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**

Captures broader range, with more monthly and daily volatility.

**Capital Cost Inputs**

**Portfolio Cost Outputs**

Deterministic forecast

Simple "low" sensitivity

Simple "high" sensitivity

Probability of unacceptable outcomes not captured by sensitivity

ILLUSTRATIVE
Using Stochastics In The Analysis

Scenario development exercise and historical data analysis support input development

Monte Carlo Engine

Sampling 100s or 1000s of iterations

Expert judgment

Plant (portfolio) parameters

Econometric Analysis

Historical Data

P1

P2

P3

P4

PERFORM Financial Module

Cost Distributions

Portfolio Costs
Distributions Of Outcomes Can Be Developed

Portfolio 1 is more likely to have a low cost outcome, but...

...90th percentile of portfolio 2 is lower
Portfolios Can Be Compared On Cost And Risk Basis

ILLUSTRATIVE

- Portfolio 1
- Portfolio 2
- Portfolio 3
- Portfolio 4
- Portfolio 5

Increasing Cost

Low Mean of NPVRR ($Million) High

SD NPVRR ($ Million)

Low Increasing Risk High

Portfolio Options

- Portfolio 1
- Portfolio 2
- Portfolio 3
- Portfolio 4
- Portfolio 5

Mean

95%

5%
Key Assumptions in the Integrated Resource Plan-Part 1
Long-Term Energy and Demand Forecast

Mahamadou Bikienga
Lead Forecasting Analyst
Agenda

• 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
Load Forecasting 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**
Load Forecasting 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

Energy Forecast

Historical Peak, and Energy Data.
Historical Interruptions
Source: NIPSCO

System Peak Forecast Demand

Use of Internal Data

Weathen Data
Source: Schneider Electric
Load Forecasting 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

Energy Forecast

Historical Peak, and Energy Data. Historical Interruptions
Source: NIPSCO

Weather Data
Source: Schneider Electric

System Peak Forecast Demand

Use of External Data
Load Forecasting Process

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

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

Energy Forecast

Historical Peak, and Energy Data.
Historical Interruptions
Source: NIPSCO

Weather Data
Source: Schneider Electric

System Peak Forecast Demand
Residential Customer And Energy Forecast Process

- Total Residential Customers Forecast
- Residential Use per Customers Forecast
- Total Residential Energy Forecast
Residential Customer And Energy Forecast Process

- Residential New Customers For First Five Years - New Business Team
- Long Term New Residential Customers $f(\text{Local Housing Starts})$
- Existing Customers Historical attrition rate incorporated

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

Total Residential Customers Forecast

\[ \times \]

Total Residential Energy Forecast

Residential Use per Customers Forecast
Residential Customer And Energy Forecast Process

- **Residential New Customers For First Five Years**
  - New Business Team

- **Long Term New Residential Customers** $f(\text{Local Housing Starts})$

- **Existing Customers** Historical attrition rate incorporated

- **Residential kWh per Customer** $f(\text{Residential Electric Price, Real Per Capita Income, efficiency, weather})$

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

- **Total Residential Customers Forecast**

- **Total Residential Energy Forecast**

- **Residential Use per Customers Forecast**
Commercial Customer And Energy Forecast Process

\[ f(\text{Population, Real Gross County Product}) \]

Commercial Customers

Total Commercial Customers Forecast
Commercial Customer And Energy Forecast Process

- **Commercial Customers**
  \[ f(\text{Population, Real Gross County Product}) \]

- **Total Commercial Customers Forecast**

- **Commercial Total Use**
  \[ f(\text{Commercial Customers, Real County Retail Sales, Commercial Electric Price, weather}) \]

- **Total Commercial Energy Forecast**
Industrial Energy Forecast Process

- Major Accounts Energy Forecast
- Other Industrial Energy Forecast
- Total Industrial Energy Forecast
Industrial Energy Forecast Process

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

- Individual Customer Interviews
- Regional and Global Trends for Specific Industries
- Recent Historical Industrial Sales Trends

Individual forecast for major accounts

- Major Accounts Energy Forecast
- Other Industrial Energy Forecast

Total Industrial Energy Forecast
Other Energy Forecast Process

- Public Authority – Government facilities
- Public Authority Railroad Company Use
- Street Lighting
- Street Lighting accounts for new LED lights program
- Total Other Energy Forecast
Other Energy Forecast Process

Public Authority – Government facilities

Recent historical data

Anticipated future trends

Public Authority Railroad Company Use

Street Lighting

Street Lighting accounts for new LED lights program

Total Other Energy Forecast
Other Energy Forecast Process

Recent historical data

Anticipated future trends

Public Authority – Government facilities

Public Authority Railroad Company Use

Street Lighting

F(Number of hours of dark, Anticipated future trends)

Street Lighting accounts for new LED lights program

Total Other Energy Forecast
Peak Demand Forecast Process

- 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
Peak Demand Forecast Process

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

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

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

MISO Coincident Peak Forecast
Load Forecasts

Energy Requirement Projections

<table>
<thead>
<tr>
<th></th>
<th>2018-2039 CAGR</th>
</tr>
</thead>
<tbody>
<tr>
<td>NIPSCO Total Energy</td>
<td>0.33%</td>
</tr>
<tr>
<td>NIPSCO System Peak</td>
<td>0.41%</td>
</tr>
<tr>
<td>MISO Coincident Peak</td>
<td>0.44%</td>
</tr>
</tbody>
</table>

Note: CAGR = Compound Annual Growth Rate

\[
\frac{\text{MISO Coincident Peak}}{\text{NIPSCO System Peak}} = \sim 95\%
\]
Capital Cost Assumptions for Future Resources

Fred Gomos
Manager Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)
### Approach For Capital Cost Assumptions In 2018 IRP

<table>
<thead>
<tr>
<th>Step 1</th>
<th>Develop initial NIPSCO portfolios</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• Review technologies based on costs, feasibility, and regulatory constraints</td>
</tr>
<tr>
<td></td>
<td>• Obtain current and future capital cost estimates from multiple 3rd party data sources</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Step 2</th>
<th>Evaluate portfolios across Scenarios and Stochastics (including capital costs)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• Assess relative costs and risks of portfolio options</td>
</tr>
<tr>
<td></td>
<td>• Perform preliminary assessment of portfolio costs, risks, and other metrics (pre-RFP)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Step 3</th>
<th>Integrate RFP results</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• Based on RFP process, incorporate specific capacity offers that align with preliminary assessment of portfolio performance</td>
</tr>
<tr>
<td></td>
<td>• Evaluate portfolios using more certain capital cost information from RFP bids</td>
</tr>
</tbody>
</table>
### 3rd Party Data Sources

<table>
<thead>
<tr>
<th>Data Source</th>
<th>Description</th>
<th>Link</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sargent &amp; Lundy</td>
<td>NIPSCO Integrated Resource Plan Engineering Study Technical Assessment (2015)</td>
<td>N/A</td>
</tr>
<tr>
<td>Energy Information Administration (EIA)</td>
<td>Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (2018 AEO)</td>
<td>EIA Capital Cost Estimates</td>
</tr>
<tr>
<td>Utility Integrated Resource Plans</td>
<td>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)</td>
<td>Empire District Avista Puget Sound Energy Idaho Power</td>
</tr>
<tr>
<td>Lazard</td>
<td>Levelized Cost of Energy Analysis Version 11.0 (2017)</td>
<td>Lazard LCOE V. 11.0</td>
</tr>
<tr>
<td></td>
<td>Lazard Levelized Cost of Storage Version 3.0 (2017)</td>
<td>Lazard LCOS V.3.0</td>
</tr>
<tr>
<td>IHSMarkit</td>
<td>US Solar PV Capital Cost and Required Price Outlook</td>
<td>IHSMarkit</td>
</tr>
<tr>
<td></td>
<td>US Wind Capital Cost and Required Price Outlook</td>
<td>Bloomberg New Energy Finance</td>
</tr>
<tr>
<td></td>
<td>US Battery Storage: Costs, Drivers, and Market Outlook (2017)</td>
<td>(subscription required)</td>
</tr>
<tr>
<td>Bloomberg New Energy Finance</td>
<td>Historical and forecast U.S. PV Capex Stack by Segment and Region</td>
<td>Bloomberg New Energy Finance</td>
</tr>
<tr>
<td></td>
<td>Key cost input in LCOE Scenarios, 1H 2017</td>
<td>(subscription required)</td>
</tr>
<tr>
<td>National Renewable Energy Technology Laboratory</td>
<td>NREL Annual Technology Baseline 2017</td>
<td>NREL ATB 2017</td>
</tr>
</tbody>
</table>
## Current Capital Cost Estimates ($/kW) – Gas, Coal, Nuclear Technologies

### 2017 $/kW

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

Not Exhaustive

<table>
<thead>
<tr>
<th>Sources</th>
<th>CCGT</th>
<th>CT</th>
<th>Coal to Gas Conversion</th>
<th>Gas Recip</th>
<th>Coal IGCC</th>
<th>Coal CFB</th>
<th>Supercritical Coal</th>
<th>Nuclear APWR</th>
<th>Nuclear SMR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lazard</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EIA</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NREL</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>BNEF</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>S&amp;L Report</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Empire</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PSE IRP</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Avista IRP</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Idaho Power IRP</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IHS</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Berkeley Lab</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
# Current Capital Cost Estimates ($/kW) – Renewables, Storage, And Other

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

Not Exhaustive
Capital Cost Projections, Including Uncertainty

• 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).
Wind Cost Projections

Current Observed Data Range

Forecast Range with Stochastics

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)
Solar PV Cost Projections

Current Observed Data Range

Forecast Range with Stochastics

2017 $/kW

- 5th Percentile
- 25th Percentile
- 50th Percentile
- 75th Percentile
- 95th Percentile

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)
Storage (Li-Ion 4-hr) 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).
Lunch
Key Assumptions in the Integrated Resource Plan-Part 2
Outline

• Natural Gas Price Outlook
• Coal Price Outlook
• Carbon Price Outlook
• MISO Power Market Outlook
• Appendix Information
  – 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

<table>
<thead>
<tr>
<th>Trailing Trends</th>
<th>Leading Trends</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Regional Gas Supply Growth</strong></td>
<td><strong>Supply &amp; Pricing Dynamics</strong></td>
</tr>
<tr>
<td>▪ Vast shale gas resource base continues to expand driven by improving technology (hydraulic fracturing / horizontal &amp; multi-pad drilling)</td>
<td>▪ Low cost North American supply still has significant growth upside (improved drilling economics and a large resource base)</td>
</tr>
<tr>
<td>▪ Large recent gas production growth in Marcellus/Utica due to significant resource advantages (high IP rates / low decline rates)</td>
<td>▪ A sustained low gas price environment starting to incent additional power generation demand for gas (new capacity + further coal and nuke to gas substitution)</td>
</tr>
<tr>
<td>▪ Environmental groups now opposing all pipeline expansion projects under a “keep it in the ground” mentality</td>
<td>▪ Techniques developed in the Marcellus moving back into traditional regions (e.g. Haynesville) likely to improve productivity of these regions</td>
</tr>
<tr>
<td><strong>Changing Pipeline Flows</strong></td>
<td><strong>Demand Growth Potential</strong></td>
</tr>
<tr>
<td>▪ Northeast and Mid-Atlantic transformed from a major importer to a net supplier despite significant demand growth driven by coal switching</td>
<td>▪ The electric sector increasingly relies on gas generation to meet energy needs, IRPs tend to rely on new gas and renewables meet growing load</td>
</tr>
<tr>
<td>▪ Sizable gas infrastructure investments made in midstream to address flow issues</td>
<td>▪ 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</td>
</tr>
<tr>
<td>▪ Changing supply dynamics due to generation, industrial, and Mexico exports are starting to reverse flows of the major US gas transport backbone</td>
<td>▪ Sustained low gas prices driving interest in petrochemical investments</td>
</tr>
</tbody>
</table>
NGF Model – Natural Gas Price Forecasting

- 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.
## Key Modeling Inputs and Drivers of CRA’s Gas Price Forecast

<table>
<thead>
<tr>
<th>Driver</th>
<th>CRA Approach</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource Size</td>
<td>• Rely on Potential Gas Committee (PGC) 2016 “Most-Likely” unproven estimates</td>
<td>CRA assumes a starting point of PGC 2016 “Minimum” resource, and grows the resource base to achieved PGC 2016 “Most Likely” volumes by 2050</td>
</tr>
<tr>
<td>Well Productivity</td>
<td>• IP rates based on historic data</td>
<td>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</td>
</tr>
<tr>
<td></td>
<td>• IP improves as per EIA Tier 1 assumptions</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Resource base is “Poor Heavy”</td>
<td></td>
</tr>
<tr>
<td>Fixed &amp; Variable</td>
<td>• Fixed and variable costs based on reported data</td>
<td>CRA based individual well productivity on available historic data, adopted EIA assumptions for cost improvements over time</td>
</tr>
<tr>
<td>Well Costs</td>
<td>• Costs improve as per EIA assumptions</td>
<td></td>
</tr>
<tr>
<td>Domestic Demand</td>
<td>• Electric demand taken from AURORA base case, RCI demand based on AEO 2017 Reference Case (with CPP)</td>
<td>The AURORA case assumes “base case” carbon pressure and AEO 2017 Reference assumes CPP, meaning demand estimates are consistent</td>
</tr>
<tr>
<td>LNG Exports</td>
<td>• Under-construction projects completed, ~9 bcf/d exports assumed by 2019, volumes grow another ~5 bcf/d from 2021 to 2031</td>
<td>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</td>
</tr>
<tr>
<td>Pipeline Exports</td>
<td>• Mexican export increase to ~8bcf/d by 2021, 10.5bcf/d by 2030</td>
<td>CRA expects pipeline export capacity to meet growing gas demand in Mexico will be ~60% utilized by 2021, and 75% utilized by 2031</td>
</tr>
<tr>
<td>NGL &amp; Condensate Value</td>
<td>• Liquids valued at 70% of AEO 2017 Reference Oil Price</td>
<td>AEO17 for long-term oil price forecast; 70% value for NGLs is consistent with last 5 years of price history</td>
</tr>
</tbody>
</table>
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

- CAGR: 0.6%
- CAGR: 2.2%
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.

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

- **PGC assigns resource to three probability categories:**
  - **Minimum** – 100% probability that state resource is recoverable
  - **Most Likely** – what is most likely to be recovered, with reasonable assumptions about source rock, yield factor, and reservoir conditions
  - **Maximum** – the quantity of gas that might exist under the most favorable conditions, close to 0% probability that this amount of gas is present
CRA assumed “Poor Heavy” productivity distribution (50% poor, 20% prime, 30% average) for future undiscovered resource

- The bulk of gas resource is unproven, meaning the geology of that resource is currently unknown

- CRA generated productivity distributions for each production basing based on 2010-2016 drilling data

- These average rates are based off of drilling data in regions that producers expected to have favorable geology

- CRA believes it is prudent to assume that other sites within productive formations were not chosen due to expectations of poor geology

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.

- These charts illustrate 2016-2017 reported costs in the Marcellus and Utica basins across major producers.

- Some producers (Antero, Seneca, Chesapeake) report cost reductions up to 35-37% since 2014.
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

<table>
<thead>
<tr>
<th>Crude Oil and Natural Gas Resource Type</th>
<th>Drilling Cost</th>
<th>Operating Cost</th>
<th>EUR-Tier 1</th>
<th>EUR-Tier 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tight oil</td>
<td>-1.00%</td>
<td>-0.50%</td>
<td>1.00%</td>
<td>3.00%</td>
</tr>
<tr>
<td>Tight gas</td>
<td>-1.00%</td>
<td>-0.50%</td>
<td>1.00%</td>
<td>3.00%</td>
</tr>
<tr>
<td>Shale gas</td>
<td>-1.00%</td>
<td>-0.50%</td>
<td>1.00%</td>
<td>3.00%</td>
</tr>
<tr>
<td>All other</td>
<td>-0.25%</td>
<td>-0.25%</td>
<td>0.25%</td>
<td>0.25%</td>
</tr>
</tbody>
</table>


- EIA’s approach incorporates annual improvements to key well inputs that account for ongoing innovation in upstream technologies and reflects the average annual growth rate in natural gas and crude oil resources plus cumulative production from 1990 between AEO2000 and AEO2015.

- CRA has adopted EIA improvement assumptions in our base case for productivity improvements, fixed costs, and O&M costs.
  - Based values for IP rates and well costs are based on producer-reported values
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
CRA assumes that LNG & Mexican gas exports grow through the 2030s

CRA Net Exports (LNG & Mexican Pipeline)

Under-construction LNG projects completed, ~9 bcf/d exports assumed by 2019, volumes grow another ~5 bcf/d from 2021 to 2031

Mexican export increase to ~8 bcf/d by 2021, 10.5 bcf/d by 2030
CRA assumes NGL & condensates valued at 70% of AEO reference case oil price forecast
CRA Natural Gas Price View

- CRA’s natural gas price forecast moves from $3/MMBtu to ~$4.50/MMBtu (real $) by 2040
- EIA released the 2018 AEO in February 2018, revising down their reference case Henry Hub price forecast by an average of 14%, moving much closer to the CRA outlook
Completion of the Rover and Nexus Pipeline projects will bring significant new pipeline capacity to the eastern MISO region.

Eastern MISO expected to see price declines relative to HH in the near term.

Costs and/or constraints on the existing pipeline grid will result in a price gradient from east to west with prices in Chicago being approximately $0.10/MDt higher than MI.

Regional pipeline enhancements will result in some price convergence in the next decade.
Coal Market Outlook
Coal price forecast is based on fundamental analysis

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

Coal Supply Curves (ILLUSTRATIVE ONLY)
U.S. Coal Prices expected to be mostly flat over the study period

• Near-term forward price curves for 2018-2021 deliveries are generally either flat or slightly backwardated as a result of the recent rally in prices for U.S. steam coals
  – 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

• The forwards curve is consistent with CRA’s outlook for near-term coal demand
  – 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
Coal

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

Trends in Regional U.S. Coal Production

- Total coal production in the U.S. declined from 897 million tons to about 728 million tons (or 19%) between 2015 and 2016 and then increased 6.5% (to about 775 million tons) in 2017
- Modest additional declines are expected in the next five years, with more substantial declines expected by 2027 if carbon pressure is implemented

<table>
<thead>
<tr>
<th>Coal Type</th>
<th>Current to 2027 Production Forecast (% decline)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAPP</td>
<td>-21%</td>
<td>High cost drives decline in electric sector demand; met coal demand sustained</td>
</tr>
<tr>
<td>NAPP</td>
<td>-13%</td>
<td>Increased int’l demand and some replacement of CAPP demand</td>
</tr>
<tr>
<td>ILB</td>
<td>-9%</td>
<td>Increased int’l demand and some replacement of CAPP demand</td>
</tr>
<tr>
<td>PRB</td>
<td>-22%</td>
<td>Domestic steam coal demand declines, especially after CO₂ pressure</td>
</tr>
</tbody>
</table>
### Summary of Price Trends by Coal

<table>
<thead>
<tr>
<th>Coal</th>
<th>Market Trend</th>
</tr>
</thead>
</table>
| 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. |
Over the long-term, coal price projections are generally flat in real terms.

- **CAPP-NYMEX**: $12,500; 1.6
- **CAPP-CSX**: $12,000; 1.67
- **NAPP**: $13,000; 3.5
- **ILB**: $11,500; 5.0
- **PRB**: $8,800; 0.8
Carbon Price Outlook
Carbon Policy and Emission Pricing

• 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.
  – 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)

• Low Case
  – 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.

• 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 CO₂ 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.*
*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.
MISO Power Market Outlook
AURORA – Power Price Forecasting

CRA uses the Aurora model for regional price formation analysis and detailed NIPSCO portfolio modeling.
MISO – Overview

- NIPSCO territory and resources fall within the Midcontinent Independent System Operator (MISO) region and are located within Local Resource Zone 6 (LRZ6), covering Indiana and northern Kentucky
- MISO has a diverse fuel mix with substantial coal and natural gas generation capacity

MISO Historical Generation by Fuel Type
Total: 686 GWh

**Coal** 46%
**Natural Gas** 29%
**Nuclear** 15%
**Wind** 7%
**Other** 2%
**Hydro** 1%
Expected continued shift from coal to gas and renewables in MISO

- 7.5 GW of coal capacity has retired in MISO-North between 2011 and 2016
  - 6.3 GW decline in net coal capacity; no new coal plants since 2013
- An additional 10.5 GW of MISO North coal capacity is expected to retire by 2023
  - Indiana Zone: Bailly 7 and 8, Schahfer 17 and 18, and Vectren AB Brown plant
- As of June 2017, 52% of 2017 MISO coal fleet is at least sixty years old, with 88% older than fifty years

MISO North* Net Winter Capacity by Fuel Type

Net Change in Capacity, 2011-2016

*MISO North includes LRZ 1-7
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
Capacity prices are influenced by market design

- CRA builds up the MISO supply curve, allowing merchant generators in MISO to offer into the capacity market at their calculated “missing money”
- Contracted and self-supplied capacity is expected to offer into the market at $0 or opt out

**Projected 2021 Supply Curve**

- Expected Competitive offers
- Contracted and non-merchant generation offers at bottom of the supply stack
CRA MISO Capacity Price Forecast

• Reserve margin declines were broadly evident in MISO in 2016, but the market crashed again in 2017 as a result of:
  – 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

• CRA expects low market prices to persist through 2021, when coal and nuclear retirements may drive prices up towards the going-forward costs of existing units

• CONE pricing is not expected in the reference case, since it is likely that utility builds, under cost-of-service ratemaking, will enter the market and keep reserve margins in the 17-19% range
Demand Side Management Update

Alison Becker
Manager Regulatory Policy

Richard Spellman
GDS Associates (GDS)
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

**LOAD DISAGGREGATION**
Sales by Market Segment
Consumption by End Use

**DATA COLLECTION**
New & Existing Primary Data, Secondary Data Collection

**UTILITY SALES FORECAST BY SECTOR**

**BASELINE END-USE CONSUMPTION BY SECTOR & MARKET SEGMENT**

**MEASURE DATA**

**TECHNICAL POTENTIAL**

**MARKET ADOPTION**
Historical Performance
Short Term and Long Term Market Barriers

**ECONOMIC POTENTIAL**

**ACHIEVABLE POTENTIAL**

**TECHNOLOGY CHARACTERISTICS**
Energy, Capacity, and Therm Unit Savings Saturation Shares Codes and Standard Updates Applicability Interactions

**COST-EFFECTIVENESS**
Load Shapes
Avoided Cost Benefits
Measure Costs/Price Trends
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.
Break
Request for Proposal ("RFP") for Capacity

Paul Kelly
Director of Federal Regulatory Policy
Overview of NIPSCO’s All-Source RFP

**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
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

• **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

<table>
<thead>
<tr>
<th>Date</th>
<th>Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>March 23rd</td>
<td>Overview RFP design with stakeholders</td>
</tr>
<tr>
<td>April 6th</td>
<td>RFP Design Summary document shared with stakeholders to request feedback</td>
</tr>
<tr>
<td>April 20th</td>
<td>Stakeholder feedback on Design Summary due back to NIPSCO</td>
</tr>
<tr>
<td>May 14th</td>
<td>RFP initiated</td>
</tr>
<tr>
<td>May 28th</td>
<td>Notice of Intent and Pre-qualifications due from potential bidders</td>
</tr>
<tr>
<td>June 29th</td>
<td>RFP closes</td>
</tr>
<tr>
<td>July 24th</td>
<td>Summary of RFP bids presented at Public Advisory Meeting webinar; IRP resumes analysis incorporating results of RFP</td>
</tr>
</tbody>
</table>
Stakeholder Presentations/Comments
2018 Public Advisory Process
# 2018 IRP Stakeholder Engagement Meetings

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.

<table>
<thead>
<tr>
<th>Meeting 1 – March 23</th>
<th>Meeting 2 – May 11</th>
<th>Meeting 3 – July 24</th>
<th>Meeting 4 – September</th>
<th>Meeting 5 – October 18</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avalon Manor</td>
<td>Avalon Manor</td>
<td>Webinar, SouthLake</td>
<td>Fair Oaks Farms</td>
<td>Fair Oaks Farms</td>
</tr>
</tbody>
</table>

### 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
Wrap Up
Appendix
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

Change in PGC Resource Estimate by CRA Shale Basin

![Graph showing the change in PGC resource estimate by CRA Shale Basin](image)
Gas Price Drivers – Well Productivity

Natural gas production declined in response to low market prices in 2016, but remains near record highs despite low price levels.

### Natural Gas Dry Production and Consumption

![Graph showing natural gas dry production and consumption from February 2006 to February 2017. The x-axis represents months from February 2006 to February 2017, while the y-axis shows gas produced/consumed in MMcf/month. The graph includes data for various categories such as Electric Power, Industrial, Commercial, Residential, Other, Dry Gas Prodn, and Henry Hub.](image-url)
Increased productivity per rig over the last 5-8 years has driven much of the cost improvements that allow for higher production at lower prices, though initial 2017 data shows that this improvement may be flattening.
Gas Price Drivers – Productivity Trends

Well productivity on a per well basis has been consistently improving, even as longer laterals and multi pad drilling improve per rig performance.
CRA’s analysis of well production data shows a wide distribution between the average productivity of a region and its best and worst performing regions.

Note that recent drilling data for the Antrim and Rockies basins was insufficient to estimate distributions, and the average of the U.S. is used to parameterize these plays.
Gas Price Drivers – Drilling Costs

- Producers have been reporting declining well costs in multiple plays, especially in the Marcellus and Utica.
- Haynesville and Eagle Ford have also seen significant well cost improvements, while Fayetteville costs have been constant/rising.
Gas Price Drivers – O&M Costs

O&M Costs continue trend of improvement across regions and producers

O&M Cost by Producer

Chesapeake (Marcellus & Haynesville)

Range Resources (Marcellus)

Cabot Oil & Gas (Marcellus, Eagle Ford)

Rice Energy (Marcellus, Utica)

Seneca Resources (Marcellus)
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))

- Lower demand from Asia affecting LNG market prices, but export volumes continue to grow

* 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

Trends in LNG Pricing

• Landed prices for U.S. LNG vary greatly: Henry Hub has been steady above $2.50/MMBtu, in Europe the spot market for gas settles around $5.00/MMBtu, and in Japan just above $7.00/MMBtu

• Prices support projects currently under construction but lower import-market prices may cause proposed export terminals not already under construction not to break ground

• LNG demand is expected to balance U.S. production, opening US gas prices to global gas market fundamentals

• U.S LNG costs are projected to be in the middle of the future supply “stack”, becoming cheaper than W. Africa by 2020, but lower cost competitors may not be able to ramp up supply as quickly

Softening prices for LNG exports threatens many potential projects
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

### Actual/Proposed Projects at Existing U.S. Import / Export Terminals

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

- EIA expects pipeline imports from Canada to continue their historic decline, while US exports to Canada grow modestly
- EIA expects exports to Mexico grow to 5-6 bcf/d, despite projecting much greater increase in pipeline capacity, with more than 10 bcf/d of existing and under construction expected online by 2018
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)**

- Net exports currently are ~4 Bcf/d, over 4 times more than exports in 2010.
- Recently announced export projects:
  - 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.

### Pipeline Online

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

Mexico projected natural gas consumption in the electric generation sector, 2015-29 billion cubic feet per day.

Source: U.S. Energy Information Administration, based on SENER.
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.

Gas Production by Region

- Northeast
- Southeast
- Mid Continent
- Rocky Mountain
- Texas
- Western
• NGLs are an important value stream for many of the most productive shale regions
• NGL are prices typically driven by changes to oil prices, which are subject to a high degree of uncertainty over the forecast period, as seen above
Gas Price Drivers – Oil / NGL Prices

NGL prices have dropped considerably in the past 5 years and are trending between Henry Hub and WTI – recent price trends indicate possible strengthening.

**Note:** NGL Composite price encompasses NGL spot prices at Mont Belvieu with monthly volumes used to calculate weight.
NGL prices have recovered to around 70% of WTI prices since mid 2012.

Source: EIA
Methodology for Forecasting U.S. Steam Coal Prices

• Evaluate historical trends and forward curves for U.S. steam coal prices

• Analyze expected future supply/demand balance for the U.S. coal market, taking into account key market drivers:
  – 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

• Calibrate NEEM supply curves to reflect market analysis

• Run NEEM-AURORA under various market views to develop coal price forecast
Coal units in the model see a delivered coal price that incorporates commodity and transport costs

<table>
<thead>
<tr>
<th>Delivered Unit Fuel Cost ($/ton)</th>
<th>Transportation Cost ($/ton)</th>
<th>Solved Mine Mouth Price ($/ton)</th>
</tr>
</thead>
</table>

- CRA’s NEEM Model represents supply curves for 22 different coal basins in North America as well as imported coal

- Every coal-burning unit has an individual transport cost assumption for each coal that it is able to burn

- Coal supply curves and transportation costs, for US coals, are based on the latest EPA NEEDS database
  - CRA calibrates these inputs to reflect market developments that affect coal supply and transport costs

- Coals are differentiated by heat content, sulfur content, mercury content, and carbon content
Coal Outlook Overview

• Steam coal has experienced several “boom and bust” cycles over the past decade
  – The price downturn from 2011-2016 reflects the 27% decline in U.S. coal production from 2014-2016

• Currently, an 18-month rally in steam coal prices has brought spot prices back closer to long-run equilibrium levels.
  – Price increase caused by increased demand for U.S. coals exports, and a reduction in U.S. coal stockpiles

• CRA expects U.S. demand for coal-fired generation to continue to fall over the IRP study period
  – 8-10% decline from 2017 levels by 2022, and a 25% decline by 2027, driven by CO₂ pricing from 2026

• Decline in expected long-term demand counteracts increases in production costs and depletion
  – In real terms, CRA projects prices to generally remain near current levels over the 2020-2040 period

• Mines in Central Appalachia and Northern Appalachia can produce both steam and metallurgical coal; for these mines the outlook for met coal has a significant impact on the steam coal market
  – 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.
Source: Coaldesk LLC broker sheet, 12/8/2017. Price for NAPP 3.5# coal is estimated based on published Coaldesk data.
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

• U.S. electric generation is expected to increase modestly from 2018-2037, but coal’s market share is expected to decline over this same 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

• U.S. coal-fired capacity is expected to decline significantly over the next two decades
  – 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

- 2017 U.S. coal exports expected to total about 92 million tons, up about 50% from 2016 levels, reflecting strengthening international demand for U.S. coals
  - CRA projects 52 million tons of metallurgical coal and 40 million tons of steam coal in 2017

- Market fundamentals suggest that the U.S. is likely to maintain exports around 2017-2018 levels over the forecast period
  - 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.

- Development of terminals on the Pacific coast may better position the U.S. to export steam coal to Asia, currently the EU is the primary market
  - 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

- NAPP, ILB, and PRB mines saw significant declines in coal production between 2015-2017
- As a result, 2017 production is concentrated at the most efficient mines, leading to nominal declines in the per-ton cost of coal production
- CAPP producers have shifted to metallurgical coal production, driving an increase in average prices from that region
  - 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)

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

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

<table>
<thead>
<tr>
<th>Region</th>
<th>Net Change in Coal Production (MM Tons)</th>
<th>2006-2017</th>
<th>2017-2022</th>
<th>2022-2037</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Appalachia</td>
<td>(159)</td>
<td>(8)</td>
<td>(3)</td>
<td></td>
</tr>
<tr>
<td>Northern Appalachia</td>
<td>(32)</td>
<td>(4)</td>
<td>(5)</td>
<td></td>
</tr>
<tr>
<td>Illinois Basin</td>
<td>8</td>
<td>0</td>
<td>(9)</td>
<td></td>
</tr>
<tr>
<td>Powder River Basin</td>
<td>(135)</td>
<td>(8)</td>
<td>(73)</td>
<td></td>
</tr>
<tr>
<td>Colorado</td>
<td>(20)</td>
<td>1</td>
<td>(1)</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>(50)</td>
<td>(11)</td>
<td>(20)</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>(388)</strong></td>
<td><strong>(30)</strong></td>
<td><strong>(112)</strong></td>
<td></td>
</tr>
</tbody>
</table>

Sources: 2006-2016 data from U.S. Mine Safety and Health Administration (MSHA) and Energy Information Administration (EIA). 2017 and later data is estimated.
Generation has shifted from coal to gas and wind in recent years

- Coal comprised 46% of total energy produced in MISO-North in 2016, compared with 61% of energy in 2011
- Coal generation has been replaced by natural gas and wind in the North

*MISO North includes LRZ 1-7
MISO-Indiana Zone

- Compared to rest of MISO, supply in the Indiana Zone consists of a greater amount of coal and gas and comparatively little wind (and no nuclear)
- Lower wind and solar presence is due to weaker renewable resources and low RPS goals in Indiana
- Retiring coal capacity expected to be replaced by mix of gas CCs and renewables
  - For example: IPL Eagle Valley gas CC expected online in June 2018

MISO-Indiana Capacity by Fuel Type

- History
- Projected

![MISO-Indiana Capacity by Fuel Type Chart]
Environmental policy drivers influence shift in generation mix and power price forecast

National Carbon Price
- Power price forecast includes a national carbon price starting in 2026

Tax reform legislation in Congress
- Current package generally harms renewable and other alternative forms of energy that rely on tax equity markets

Regional RPS Requirements
- Indiana: 10% by 2025, surrounding states have higher targets

Solar Tariff Case
- In January 2018, the Trump administration imposed a 30% tariff on solar cell and module imports in the first year, stepping down 5% each year to 15% in the fourth year. Likely impact is ~$100/kW increase in solar costs in the near term
Electricity demand growth in MISO has been relatively modest

- From 2010 to 2016, the CAGR for MISO total load was 0.40%, with total load growth in the MISO Indiana zone slightly higher, at 1.04%
- Peak loads have been flat-to-declining, with substantial year-over-year variation due to weather conditions
- **MISO Planning Reserve Margin for 2018-2019 is 8.4%, increased from 7.6% in 2016 and 7.8% in 2017, applied to NIPSCO coincident peak**
CRA expects modest growth in annual, peak demand

- Long-term drivers of electricity demand include weather, economic activity, population, and the level of energy efficiency and distributed resources
- MISO Independent Load Forecast tends to grow faster than utility expectations

### MISO Peak Demand Projections with Historical Load

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Load Forecast</th>
<th>10-Year Summer Peak CAGR</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010-2016</td>
<td>Weather-Normalized</td>
<td>0.40%</td>
</tr>
<tr>
<td>2015 ILF</td>
<td>Independent Load</td>
<td>0.98%</td>
</tr>
<tr>
<td>2016 ILF</td>
<td>Independent Load</td>
<td>1.12%</td>
</tr>
<tr>
<td>2017 MISO</td>
<td>Module E</td>
<td>0.27%</td>
</tr>
<tr>
<td>CRA Outlook</td>
<td></td>
<td>0.24%</td>
</tr>
</tbody>
</table>

*Note 2017 ILF Forecast does not include impact of DR and DG
Coal plants have tended to be higher cost than efficient gas plants in recent years and quite marginal vs. the market price.
Market heat rate is seasonal, with increases in recent years

Market heat rate has risen recently due to very low gas price and coal units setting the power price at times

---

**Market Implied Heat Rate**

- **Summer Load**
- **Winter load**
- **Gas price spike**
- **Very low gas price, with coal on margin**

*Using Indiana Hub and RexEast Gas Price Index*
MISO Resource Adequacy and Capacity Market

- MISO capacity market is optional for load-serving entities, which may also meet resource adequacy requirements through self-supply or bilateral contracts.

- MISO capacity market design:
  - Vertical demand curve
  - Prompt, rather than forward, market

- The option for self-supply and the presence of state-regulated, vertically integrated utilities result in capacity prices that are generally well below net CONE.

- Vertical demand curve contributes to high price volatility.

![MISO Capacity Prices](chart.png)

IPP in Zone 4 bid up the price.
Explaining the downward trend between 2016/17 and 2017/18 auctions

Reserve margin declines were broadly evident in MISO in 2016, but the market crashed again in 2017:

- Demand down
- More supply
  - More renewables
  - More behind-the-meter
  - More DR/EE
- Tariff revisions impacted offer thresholds on the low end
- Import constraints between North and South relaxed

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