Northern Indiana Public Service Company

2016
Integrated Resource Plan

November 1, 2016

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List of Acronyms

AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
CAIDI	Customer Avg Interruption Duration Index
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CO_2	Carbon dioxide
DSM	Demand-side Management
DLC	Direct Load Control
ECR	Environmental Cost Recovery
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
FAC	Fuel Adjustment Clause
GWh	Gigawatt Hour
ICAP	Installed Capacity (MW)
IRP	Integrated Resource Plan
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt hour
MW	Megawatt
MWh	Megawatt hour
MISO	Midcontinent ISO
NO_x	Nitrogen oxide
NVPRR	Net Present Value Revenue Requirements
O&M	Operation and Maintenance expense
RTO	Regional Transmission Organization
SAIDI	System Avg Interruption Duration Index
SAIFI	System Avg Interruption Frequency Index
SO_2	Sulfur dioxide
TDSIC	Transmission, Distribution, and Storage System Improvement Charge
UCAP	Unforced Capacity (MW)

Definitions

2017 Filing	Request for approval in 2017 of an energy efficiency plan for implementation in 2019
316(b)	Section 316(b) Cooling Water Intake Structure rule of the Clean Water Act
AEG	Applied Energy Group
AMR	Automated Meter Reading
AP-1000	Advanced Pressure Water Reactor
ARC	Aggregator of Retail Customers
ARCA	Appliance Recycling Centers of America
Bailly	Bailly Generating Station
BFB	Bubbling Fluidized Bed
BPJ	Best Professional Judgement
BTA	Best Technology Available
C&I	Commercial and Industrial
CAA	Clean Air Act
CAPs	Community Advisory Panels
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Days
CFB	Circulating Fluidized Bed
CIP	Critical Infrastructure Protection
Commission	Indiana Utility Regulatory Commission
CPP	Clean Power Plan
CSAPR	Cross State Air Pollution Rule
DA	Distribution Automation
DRR1	Demand Response Resource Type 1
EDR	Emergency Demand Response Resource
EDR	Economic Development Rider
EE	Energy Efficiency
EGUs	Electric Generating Units
EIA	United States Energy Information Agency
ELG	Effluent Limitation Guidelines
ELG	Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FIT	Renewable Feed-in Tariff
GHG	Greenhouse Gases
GPR	Green Power Rider
HDD	Heating Degree Days

HVAC	Heating, Ventilation and Air Conditioning
IA	Interconnection Agreement
IDEM	Indiana Department of Environmental Management
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin
IQW	Income Qualified Weatherization
LMR	Load Modifying Resource
MAE	Mean Absolute Erro
Michigan City	Michigan City Generating Station
MISO	Midcontinent Independent Operator System, Inc.
MMP	Morgan Marketing Partners
MP	Market Participant
MPS	Market Potential Study
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Projects
NAAQS	National Ambient Air Quality Standards
NAPP	Northern Appalachian
NERC	North American Electric Reliability Corporation
NIPSCO	Northern Indiana Public Service Company
NOAA	National Oceanic and Atmospheric Administration
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
OSB	Oversight Board
OUCC	Indiana Office of Utility Consumer Counselor
PC	Pulverized Coal
PJM	PJM Interconnection LLC
PM	Particulate Matter
PRA	MISO Planning Resource Auction
PRB	Powder River Basin
Proposed Rule	Proposed Rule to modify 170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans
Rate Case Order	Commission Order dated July 18, 2016 in Cause No. 44688
RCx	Retro-Commissioning
RECs	Renewable Energy Certificates
RPA	Renewable Portfolio Standards
RPPA	Renewable Power Purchase Agreement
SBDI	Small Business Direct Install
Schahfer	R.M. Schahfer Generating Station
Section 10	Ind. Code § 8-1-8.5-10
SMR	Small Modular Reactors
TOU	Time of Use
TRC	Total Resource Cost
VSR	Variable Shunt Reactors

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IRP

2016 Integrated Resource Plan Executive Summary

The electric industry is in the midst of unprecedented change. Customer needs and the way energy is consumed continues to evolve. Technologies are rapidly changing and expanding. Environmental compliance requirements are expanding. And, infrastructure is aging. The electric generation landscape is shifting dramatically, not just for NIPSCO but for the country as a whole.

In the midst of this dynamic world, maintaining affordability while providing reliable, flexible, cleaner sources of power remains a top priority for energy providers.

From modernizing our energy infrastructure to managing a diverse and cost-effective supply of electricity, NIPSCO is focused on the future. We are planning today to meet the needs of the residential, commercial and industrial customers of tomorrow.

About the 2016 Integrated Resource Plan

To help ensure we continue to meet the needs of our customers, we must have a roadmap to prepare for future energy needs. Our 2016 Integrated Resource Plan (IRP) charts a path on how best to meet those needs over the next 20 years (through 2037). NIPSCO presents this plan to the Indiana Utility Regulatory Commission (IURC).

About NIPSCO

More than 460,000 northern Indiana homes and businesses depend on NIPSCO each day for safe, reliable and affordable energy.

Northern Indiana is fortunate to be home to some of the top production facilities in the United States. This has a unique impact on NIPSCO's energy demand profile. Five of our largest industrial customers, primarily in steel and oil refining, account for about 40% of NIPSCO's energy demand.

As a member of the regional transmission organization Midcontinent Independent System Operator (MISO), NIPSCO is able to supplement its own energy resources through other participating utilities in MISO's 15-state area. This relationship helps ensure reliability and cost effective operations.

Resource planning is a complex undertaking, one that requires addressing the inherent uncertainties and risks that exist in the electric industry. Key factors referred to in the IRP include market conditions, fuel prices, environmental regulations, economic conditions and technology advancements.

Using in-depth data, modeling and analysis provided by internal and external subject matter experts, we project future energy needs and evaluate available options to meet those needs.

The projections included in our plan are based on the best available information at this point in time. Changes that affect our plan may arise, which is why it's important for us to remain flexible and continually evaluate current market conditions, use of renewable generation, energy efficiency advancements, as well as laws and environmental regulations, such as the U.S. Environmental Protection Agency's (EPA) Clean Power Plan. It's important to note that due to this inherent uncertainty, our course of action is subject to change as new information becomes available.

Commodities
Assumptions
Resources
Variables
Regulatory
Legislative Economy
Environment

Stakeholder Engagement

Because resource planning requires considering a number of viewpoints, external stakeholder involvement is a critical component throughout the development of the IRP. We approached outreach in a number of ways, and are appreciative of the engagement from a number of groups and individuals.

NIPSCO first initiated stakeholder advisory efforts for its 2016 IRP in May, hosting a public meeting and launching a webpage for interested stakeholders to follow the progress. Four additional public meetings followed in July, August, September and October. In addition to posting public invitations on our IRP webpage, we sent an invitation to past IRP stakeholder participants. Members of our executive leadership team and several of our subject matter experts attended each meeting to hear feedback and answer questions.

Throughout the IRP process, stakeholders were also invited to meet with us on a one-on-one basis to discuss key concerns and perspectives. Each interaction provided a forum for discussion and feedback related to the many components of the IRP.

Valuable discussions arose in several key areas, including environmental regulations, fuel costs, load forecasting calculations, energy efficiency program analysis and renewable energy development.

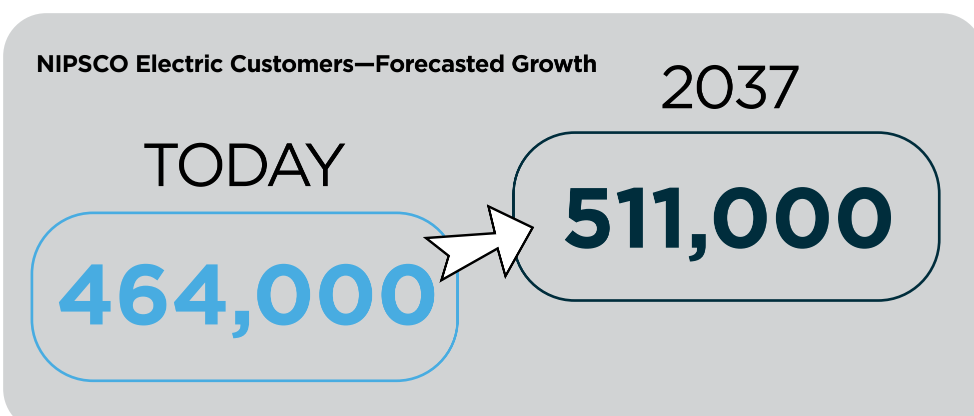
The feedback gathered during the stakeholder process raised valuable questions, helped us better evaluate our options and improved the final plan. A summary of the meeting materials including presentations and stakeholder questions is available at NIPSCO.com/IRP.

Forecasting Future Customer Demand

Projecting customers' energy needs is another key component of the IRP process. Looking 20 years into the future does not come without challenges, so we rely on data-driven models to help develop our best estimates. Specific models are developed for residential users, commercial users and industrial users, as well as for all other types of customers including street lighting, public authorities, railroads and company use.

Data sources used in creating the forecast include energy, customer and price data, economic drivers, weather data and appliance saturation. Given the unique makeup of NIPSCO's customer base, industrial operations are another significant variable. In order to best model their load requirements, we rely on discussions with our 20 largest industrial customers.

With this data, we developed base, high and low forecasts, both for energy requirements and peak demand. Our forecasts project an increase in overall customer energy usage of 0.33% compound annual growth rate (CAGR) for the period of the IRP (2017 to 2037), while the peak demand for the base case is 0.45%. The total number of NIPSCO electric customers is projected to increase from approximately 464,000 today to about 511,000 by 2037.



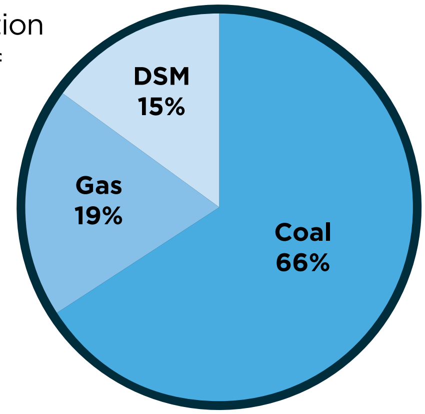
Current Supply

NIPSCO's current resource portfolio is made up of hydroelectric, wind, demand side resources and natural gas fired sources in addition to the company's coal-fired plants. Coal remains the largest part of NIPSCO's fleet, accounting for 66% of total capacity. Roughly 20% of the resource portfolio is powered by natural gas.

Another important element of our supply mix is our Industrial Interruptible Program, which offers incentives to our largest-consuming customers for reducing their usage. The program accounts for about 530 MW, or 15%, of our resource mix.

NIPSCO also offers a Net Metering and Feed-in Tariff Program, which allows commercial and residential customers to generate their own power from green resources. In the Feed-In Tariff (FIT) program, there are about 35 MW of wind, solar and biomass.

NIPSCO Supply Mix (2015)



*DSM= Demand-Side Management prior to Evaluation, Measurement and Verification. Also includes Industrial Interruptible Program.

Analyzing Future Supply Options

Evaluating each source of electric generation for its total cost, environmental benefits, reliability, impact on the electric system and risks is an important step in the IRP. We conducted a thorough review of options, including:

- Coal
- Nuclear
- Natural Gas
- Energy Efficiency
- Renewable (wind, solar, biomass)
- Demand Response
- Hydroelectric
- Customer (Distributed) Generation

Specific screening criteria include energy source availability, technical feasibility, commercial availability, economic attractiveness and environmental compatibility.

Renewable energy has evolved a great deal in recent years. However, today's sources such as wind and solar lack the same level of reliability offered by natural gas or coal-fired generation. It is important to find the right balance of renewable energy within our overall portfolio. In the short term, we expect it will serve as a supplemental supply of power with future potential to grow into a more significant source.

Analyzing Supply Options

Technology	Size (MW)	Total Overnight Cost in 2014[1] ($/kW)
Scrubbed Coal New	1,300	2,197
Coal-Gasification Integrated Combined Cycle (IGCC)	1,200	3,727
Advanced Gas-Oil Combined Cycle (CC)	400	1,017
Advanced Combustion Turbine	210	671
Advanced Nuclear	2,234	5,366
Distributed Generation-Base	2	1,477
Dstributed Generation-Peak	1	1,774
Biomass	50	3,659
Wind	100	1,980
Wind Offshore	400	6,154
Photovoltaic[2,3]	150	3,279

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

Energy Efficiency

Promoting energy efficiency is not only good for customers, it can play an important role in helping ensure we can meet future energy needs. For many years, NIPSCO has offered programs to help residential and business customers save energy. The programs are tailored to customers and designed to help ensure energy savings.

Because technologies continue to change, it's important that we constantly evaluate our offerings. We regularly track and report on program performance, which helps to inform and improve future program filings. A market potential study was conducted to help deepen our understanding of how much can be saved over a 20-year period as a result of energy efficiency initiatives. In our most recent analysis, achievable energy-savings potential equated to 3.5% by 2021.

Our upcoming energy efficiency program portfolio will be filed in 2017. To help ensure we can meet changing needs such as evolving technologies and updates to building codes and product standards, we plan to seek vendors who will put together programs that are flexible as well as cost effective.

Environmental Considerations

Improving air and water quality is important, and NIPSCO has made substantial progress in recent years. First, we have gradually expanded our supply mix to include alternative forms of electric generation besides coal. We have also implemented environmental improvements throughout our fleet. In total, we have invested more than $800 million in new technologies at coal-fired units to improve air quality in compliance with federal regulations.

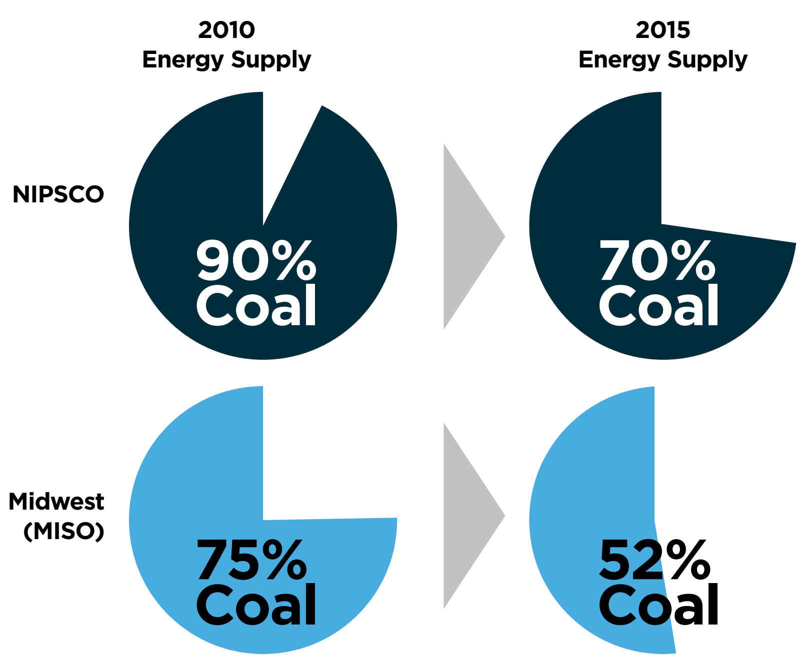
To further support renewable energy, we give customers the power to choose green energy not only through the Net Metering and Feed-in Tariff Programs, but also through the Green Power Program, in which we buy renewable energy credits on customers' behalf.

Environmental improvement efforts and associated requirements are projected to continue to be at the forefront of electric generation. The U.S. EPA continues to present new regulations to improve air and water quality, coal ash management and more.

In our IRP evaluation process, we factored in rules, based on what we know today. We are closely following EPA developments and will continue to evaluate paths to reduce emissions while maintaining reliability and controlling costs to customers.

Shifting Away from Coal

Due to regulatory and economic factors, including low natural gas prices, NIPSCO's energy supply has already been shifting to include less coal-fired generation. We see the same trend among utilities here in the Midwest and nationally.



*Pre-Entergy Integration

Environmental regulations also contribute to decreased reliance on coal, as does the age and condition of generating plants. At this point, we estimate both the environmental upgrades and maintenance capital costs to be up to $1 billion in order to continue running these plants into the future.

	Unit	Capacity (MW)	Year in Service
Bailly	7	160	1962
	8	320	1968
	10	31	1968
Michigan City	12	469	1974
Schahfer	14	431	1976
	15	472	1979
	17	361	1983
	18	361	1986

Findings & Next Steps

Throughout the IRP analysis, we are striving to balance the needs of our customers, employees and other community stakeholder interests. Our goal as we look forward is to transition to the best cost, cleanest electric supply mix available while keeping options open for the future as technologies and markets change.

We have reached an important decision point as a result of our analysis—whether to invest in compliance upgrades at our existing plants or retire units. The main factors in helping to make these decisions are reliability, compliance, flexibility, diversity and affordability.

The results point to the retirement of four of NIPSCO's seven coal-fired electric generating units at two different power plants over the next seven years—roughly 50 percent of the existing coal fleet.

Specifically, we plan to retire our Bailly Generating Station coal-fired units (7 and 8) as soon as mid-2018 and two of our coal-fired units (17 and 18) at R.M. Schahfer Generating Station by 2023.

Portfolio

✓ **Affordable**
✓ **Reliable**
✓ **Compliant**
✓ **Diverse**
✓ **Flexible**

We are proactively managing any workforce impacts, and our goal is to offer continued employment opportunities for all existing NIPSCO employees whose jobs may be affected by the eventual retirement of these coal-fired generating units.

We will maintain our Sugar Creek combined cycle gas units, Michigan City Unit 12, Schahfer Units 14, 15, 16 A & B and Bailly Unit 10. In order to meet our environmental commitments, we will proceed with filing our environmental compliance plan for Michigan City Unit 12 and Schahfer Units 14 and 15. Furthermore, we plan to continue offering the Interruptible Program to our large industrial customers and maintain current wind Purchase Power Agreements (PPAs). Our upcoming energy efficiency portfolio filing will also contribute to balancing supply and demand.

Short-Term Plans for Generation Replacement

As always, NIPSCO is focused on ensuring we are prepared to meet our customers' energy needs. In the short term (through 2019), we will rely primarily on our existing resources.

There may be a window of time when we will have to purchase short-term capacity to fill any gaps during the transition. If additional capacity is needed, we will procure from the MISO market and/or PPAs.

Long-Term Plans for Generation Replacement

While we continue to assess, the plan for long-term replacement generation will be further revisited and refined in our next IRP.

In the meantime, we will begin work to identify lowest cost replacement options. Based on what we know now, we expect combined cycle gas turbine (CCGT) to be a likely avenue, but that is subject to change based on key market, compliance and technology developments. Between now and our next IRP filing, we will continue to monitor those developments. As always, transparency is important, and we intend to remain engaged with interested stakeholders.

For more information on NIPSCO's IRP, please visit NIPSCO.com/IRP.

Section 1. Integrated Resource Plan

1.1 Plan Summary

Northern Indiana Public Service Company's ("NIPSCO") preferred portfolio plan was developed to ensure that a reliable, compliant, flexible, diverse and affordable supply was available to meet future customer needs. NIPSCO carefully planned and considered the impacts to its employees, the environment and the local economy (property tax, supplier spend, employee base) as the plans were developed.

This plan was developed through substantial quantitative and qualitative analysis. NIPSCO completed a thoughtful analysis to evaluate NIPSCO's generation units relative to viable alternatives. *See* Section 8.4: Retirement Analysis. NIPSCO also evaluated resource options to determine the combinations of supply-side, demand-side, self-build and market resources to meet its capacity needs. *See* Section 8.5: Resource Optimization Modeling. NIPSCO performed both the retirement and optimization analysis using a robust scenario and sensitivity analyses for different economic, environmental, cost, risk and regulatory uncertainty to inform the optimal plan.

It is important to note that the integrated resource plan is a snapshot in time and while it establishes a direction for NIPSCO, it is subject to change as the operating environment changes. NIPSCO will continue to engage its stakeholders and be transparent in its decisions commensurate with and following submission of this 2016 IRP.

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

- Lead to a lower cost, cleaner, diverse and compliant portfolio by retiring 50% of NIPSCO's coal capacity by the end of 2023;
- Continue the Company's commitment to energy efficiency and demand response by including programs that are economically viable for all customers;
- Continue to comply with environmental regulations, specifically the Effluent Limitation Guidelines ("ELG") and Coal Combustion Residuals ("CCR") for the retained coal generation;
- Maintain an appropriate level of interruptible service for the Company's major industrial customers;
- Reduce customer and Company exposure to customer load, market and technology risks by intentionally allocating a portion of the portfolio to shorter duration supply;
- Strongly consider cost to customers, while considering all technologies and fuels as viable to provide shorter duration supply;

- Add combined cycle gas turbine ("CCGT") capacity to meet supply needs that are not covered by shorter duration supply options;

- Continue to evaluate additional supply retirements in light of changing market conditions and policy requirements;

- Continue to invest in infrastructure modernization to maintain safe and reliable delivery of energy services; and

- Continue to comply with North American Electric Reliability Corporation ("NERC") Critical Infrastructure Protection ("CIP") cyber security standards.

1.2 Short Term Action Plan

NIPSCO's short term action plan consists of the actions NIPSCO will take for the period 2017 through 2019. The objective of the plan is to ensure that a reliable, compliant, flexible, diverse and affordable electric supply will be available to NIPSCO's customers during this 3-year period.

NIPSCO's short term action plan will focus on the implementation of retirements and identification of replacement capacity. Assuming approval from the Midcontinent Independent System Operator, Inc. ("MISO"), NIPSCO plans to retire Bailly Generating Station ("Bailly") Units 7 and 8 by May 2018. The replacement capacity necessary to meet the customer demand during the short term action plan period will range from approximately 150 MWs to 200 MWs and this capacity need will be addressed with either short term purchase power agreements and/or market capacity purchases, whichever provides the best alignment of costs and mitigation of risks for customers.

NIPSCO will continue to provide economically viable demand side management for customers during the short term action plan period. *See*, Table 8-20: DSM Groupings Selection. NIPSCO will also pursue approval to invest in and associated recovery of environmental capital relating to ELG and CCR for Michigan City Generating Station ("Michigan City") Unit 12 and R.M. Schahfer Generating Station ("Schahfer") Units 14 and 15. While preliminary analysis shows that compliance with ELG and CCR is not preferred, NIPSCO will evaluate the value of developing a compliance option at Schahfer Units 17 and 18.

Finally, prior to the end of the first quarter of 2019, NIPSCO expects to complete a request for proposals to build a CCGT to meet supply needs beginning in 2023. This evaluation will create a baseline for comparison of other technology and supply options.

As described in greater detail in Section 8.5.7: Short-Term Action Plan, the action items included in NIPSCO's short term action plan.

Table 1-1: 2016 IRP Short-Term Action Plan

Retire Bailly Units 7 and 8 by May 2018
Meet capacity needs with shorter duration purchase power agreements or market purchases
Offer service options for customers, including demand-side management
Utilize available interruptible resources, as needed, to meet requirements
Evaluate building a CCGT to meet supply needs beginning in 2023
Invest in infrastructure modernization to maintain safe and reliable delivery of energy services
Comply with NERC CIP cyber security standards
Comply with regulations, including Environmental Protection Agency regulations

1.3 Comparison of 2014 and 2016 IRPs

NIPSCO's 2016 IRP accelerates the retirement of approximately 50% of its coal generation versus the 2014 IRP where the timing of coal generation retirements were age-based. An additional 150.7 MW of demand response (interruptible service) has been added in accordance with the Indiana Utility Regulatory Commission's ("Commission") Order dated July 18, 2016 in Cause No. 44688 (the "Rate Case Order"). The 2016 IRP process included an expanded set of scenarios and sensitivities to capture a wider range of potential risks and uncertainties; improved load forecasting process; and enhanced public advisory process that included more meetings and increased participation by various stakeholder groups.

1.4 Emerging Issues

NIPSCO's preferred plan follows a diverse and flexible supply strategy, with a mix of market purchases and different low fixed-cost generation types, to provide the best balanced mitigation against customer, technology and market risks.

1.4.1 Customer Risk

NIPSCO's five largest industrial customers (ArcelorMittal, US Steel, NLMK, BP and Praxair) account for approximately 40% of NIPSCO's energy demand and approximately 1,200 MW of peak load plus reserves when viewed on a non-coincident, individual customer basis. Most of these customers are closely tied to global steel industry cycles. This concentration of customers tied to a single industry poses significant customer risk. Loss of one or more of these customers, for whatever reason, would result in a significant decline in billing revenues.

Residential and commercial customers comprise most of the remaining demand, and while diversified and not likely to move, would likely see impacts from a loss of industrial customers who are major employers in NIPSCO's service territory.

1.4.2 Technology Risk

Technology risk can be thought of as two separate risks from the perspective of a regulated utility. Technology risks play a role in inducing market volatility, and it also has the potential to erode the value of existing assets. Technology changes drive a portion (but by no means all) of the volatility in market prices, both for capacity and energy. To the extent that a utility or its customers are exposed to market risk in general, they are exposed to this aspect of technology risk. Separately, technological and regulatory changes can render specific generation technologies obsolete and can force their premature retirement such as is currently happening to coal generation.

It is difficult to avoid exposure to one or the other type of technology risk when supplying demand using a traditional regulated utility approach. Fully avoiding technological obsolescence risk requires avoiding investing in generation, which exposes the utility and its customers to market risk. Investing in generation mitigates or eliminates market risk but exposes the utility and its customers to some amount of technological obsolescence risk.

Balancing these two risks in light of the technology choices available is key to mitigating overall supply portfolio risk. Currently available new build generation technologies, such as CCGT and renewables, have very low fixed operating costs, so the likelihood of forced shutdown in the foreseeable future is likely lower than it has been for coal and nuclear which have very high fixed costs.

1.4.3 Market Risk

Historically, the MISO North region, of which Indiana is a part, has had excess capacity above and beyond the regional reliability requirement. This oversupply in the MISO Planning Resource Auction (“PRA”), has resulted in historically low prices in the region prior to the 2015/2016 planning year.

However, due to net retirement of both merchant and regulated generation across the MISO North region, MISO’s excess capacity has been declining. As a result, the PRA clearing price for Indiana’s Local Resource Zone 4 rose to $72/MWD in 2016/2017 from the prior year’s $3.48/MWD. Also, MISO is projected to move into a capacity shortfall position in 2018/2019 across the entire footprint which is likely to contribute to higher capacity prices.

Some states that have restructured their retail regulation to move away from the vertically-integrated model have had growing concerns over the ability of the existing PRA to incent new merchant generation to bring capacity to market. In MISO, this would include both Illinois and 10% of Michigan. For these two states, the existing MISO capacity market structure appears to be unsustainable.

So much so that MISO is attempting to resolve this issue with a proposal for a 3-year forward auction for these states. However, as of the time of this writing, the Independent Market Monitor is not in agreement with MISO’s proposed approach. Michigan appears to be preempting the forward auction proposal by developing a separate state capacity program along with MISO for its retail choice participants, which will require separate Federal Energy Regulatory

Commission ("FERC") approval to implement. Given the lack of enthusiasm in the stakeholder process (and some outright opposition) and the Independent Market Monitor's opposition to MISO's forward auction proposal, FERC will need to make the final determination on Illinois' capacity market design in what is likely to be a contested proceeding.

Taking all of these elements under consideration, capacity prices in MISO's PRA and bilateral market are likely to continue to increase in the MISO North region in the next five years. Thus, any strategy which relies heavily on market purchases in the near term should be approached with caution and with a self-build backup in hand, at least until market structure and the related capacity price uncertainty is resolved at FERC.

Section 2. Planning for the Future

2.1 IRP Public Advisory Process

NIPSCO's 2016 IRP stakeholder process focused on increasing transparency around its planning process and enhancing public involvement through more extensive stakeholder meetings. At each stakeholder meeting, NIPSCO provided information on the process and development of the IRP and solicited relevant input for consideration in its development. Additionally, to facilitate stakeholder outreach and ongoing communications, NIPSCO maintained a web page on its website with current information about the IRP. NIPSCO posted all meeting agendas, presentations, meeting notes and other relevant documents to the web page. Stakeholders were invited to meet with NIPSCO throughout the IRP process to discuss key issues, concerns and perspectives. NIPSCO extended an invitation to participate in the stakeholder process to the Commission Staff, the Indiana Office of Utility Consumer Counselor ("OUCC") and stakeholders that participated in previous IRP public advisory processes. NIPSCO's executive leadership and its subject matter experts attended each public advisory meeting. In the section that follows, NIPSCO provides an overview of its stakeholder process. A more comprehensive accounting of stakeholder meetings, presentations and questions/answers is included in Appendix A.

On February 3, 2016 the Indiana Energy Association facilitated an educational meeting to provide an overview of the IRP process and provided a high level discussion of the key components of the complex process. The meeting included a discussion of the following: (1) IURC Director's Report Development Process presented by Dr. Bob Pauley, (2) Public Advisory Process Overview presented by the OUCC, (3) IRP Building Blocks & Development presented by IPL, (4) Load Forecasting presented by Vectren, (5) Resources presented by Duke, (6) Scenarios and Sensitivities presented by IPL, (7) Regional Transmission Organizations presented by NIPSCO, and (8) Resource Modeling presented by I&M and IPL.

As part of the 2016 IRP process, NIPSCO had originally planned to hold a total of four stakeholder meetings. In an effort to enhance stakeholder involvement, and to further address stakeholder concerns, two additional meetings were added. NIPSCO hosted four in-person public advisory meetings and two webinars. NIPSCO also posted an open invitation on its website for any party wishing to register.

In addition to the public advisory meetings, NIPSCO participated in a number of one-on-one meetings with individual stakeholders to address specific concerns and issues that were raised as a result of information presented and discussed at the public advisory meetings. Based on feedback received from its previous stakeholder efforts during the 2014 IRP process, NIPSCO strived to provide further transparency regarding inputs and assumptions that were included in its 2016 IRP.

2.1.1 Stakeholder Meeting 1

NIPSCO's first stakeholder meeting was held in Merrillville, Indiana on May 5, 2016. For those unable to join in person, a webinar format was also made available. In this first meeting, NIPSCO provided an overview of the (1) public advisory process, (2) existing and future resource options, (3) customer load forecasting methodology, (4)environmental considerations and other data assumptions that were used in the modeling, and (5) a general overview of NIPSCO's initial scenarios and sensitivities. Stakeholders requested clarification regarding (1) data points used in the IRP (e.g., percentage of renewables, technologies utilized, emissions, etc.), (2) assumptions regarding carbon pricing, (3) selection of supply-side and demand-side resources, and (4) how solar was included in the modeling. The meeting agenda, presentation, and summary (including questions / responses) for Meeting 1 are included in Appendix A, Exhibit 1.

2.1.2 Stakeholder Meeting 2

NIPSCO's second stakeholder meeting was held in Merrillville, Indiana on July 12, 2016. For those unable to join in person, a webinar format was also made available. Although NIPSCO originally intended to discuss generation resources at this meeting, based on stakeholder feedback, the focus was changed to an in-depth discussion of DSM. It was apparent from stakeholder feedback that a deep dive into how DSM is incorporated into the IRP was going to be worthwhile. At this meeting, NIPSCO reviewed (1) how DSM was incorporated into its IRP process, (2) how the Market Potential Study was created, (3) how NIPSCO-specific levels of savings and groupings were prepared for the IRP, (4) the model optimization process, and (5) the IRP in relation to the DSM plan timeline. Additionally, to provide stakeholders who were not familiar with the DSM process a clearer understanding, NIPSCO walked through an example of one DSM measure and what happens to that measure at each step of the market potential study and IRP process. NIPSCO consultants Applied Energy Group and Morgan Marketing Partners also shared portions of the presentations to help describe their processes and related involvement in advancing the DSM analysis for this IRP. Stakeholders requested clarification regarding (1) the benefit cost tests, (2) avoided costs, (3) program potential, and (4) industrial opt outs. Three stakeholders, NAACP Indiana, Praxair Energy and Arcelor Mittal, USA, made presentations at the meeting. The meeting agenda, presentation, stakeholder presentations, terminology sheet, and summary (including questions / responses) for Meeting 2 are included in Appendix A, Exhibit 2.

2.1.3 Stakeholder Meeting 3

NIPSCO's third stakeholder meeting was held in Merrillville, Indiana on August 23, 2016. For those unable to join in person, a webinar format was also made available. At this meeting, NIPSCO provided an overview of its existing generation resources and generation planning methodology. NIPSCO presented its retirement analysis and its most viable option for retirement of generation units. The Company also discussed the resulting capacity gap through time. NIPSCO's goal for this meeting was to obtain stakeholder feedback on its preferred retirement plan and gain a shared understanding of generation alternatives. Key issues for stakeholders included clarification relating to (1) environmental considerations, (2) load forecasts used in Strategist®, (3) DSM inputs, and (4) model constraints/boundaries. Two stakeholders, U.S. DOE Midwest Combined Heat and Power Technical Assistance Partnership and an attorney with the law firm of Lewis & Kappes (counsel for NIPSCO Industrial Group, an ad hoc group of industrial users located in the electric service territory of NIPSCO) made presentations. The meeting agenda, presentation, stakeholder presentations and summary (including questions / responses) for Meeting 3 are included in Appendix A, Exhibit 3.

2.1.4 Stakeholder Meeting 4

NIPSCO hosted its fourth stakeholder meeting as an on-line webinar held on September 12, 2016. The webinar focused on assuring that stakeholder questions and concerns to date had been resolved. Matrices of all stakeholder questions received from the first three stakeholder meetings, as well as the corresponding answers, were distributed to participants. Participants were once again given an opportunity to ask questions and request additional input on their concerns. NIPSCO also provided a status update on the one-on-one meetings that had been held with various stakeholders including the OUCC, Citizens Action Coalition, NIPSCO Industrial Group, Sierra Club and Commission Staff. The one-on-one meetings provided NIPSCO an opportunity to address the individual concerns and modeling requests of it stakeholders. The meeting agenda, presentation, summary (including questions / responses), and the matrices of all stakeholder questions received from the first three stakeholder meetings (inclusive of post-meeting responses) for Meeting 4 are included in Appendix A, Exhibit 4.

2.1.5 Stakeholder Meeting 5

NIPSCO's hosted its fifth stakeholder meeting as an on-line webinar held on September 26, 2016. Some of the stakeholders expressed an interest in seeing the data prepared by PIRA relating to its preparation of environmental assumptions for NO_x, SO_2 and CO_2 and correlated long-term commodity assumptions. After extensive discussions with PIRA, PIRA indicated its concern about the proprietary nature of its data and was not willing to provide the data to the stakeholders. Nonetheless, PIRA did indicate that it was willing to provide the stakeholders with an opportunity to view the proprietary data. The webinar was held for that sole purpose. NIPSCO understands the stakeholders' consternation regarding access to the proprietary data and intends to utilize data that will be accessible to stakeholders in its next IRP. The list of attendees for Meeting 5 are included in Appendix A, Exhibit 5.

2.1.6 Stakeholder Meeting 6

NIPSCO's sixth and final stakeholder meeting was held in Merrillville, Indiana on October 3, 2016. For those unable to join in person, a webinar format was also made available. At this meeting, NIPSCO provided an overview of its public advisory process and prior meetings. NIPSCO shared the model runs prepared at the request of the Sierra Club, Clean Line, the OUCC and NIPSCO Industrial Group. NIPSCO also presented its optimization results and walked through its preferred resource plan and short term action plan. One stakeholder, Indiana Distributed Energy Alliance made a presentation. Key issues for stakeholders included clarification relating to (1) the amount of DSM and renewables in the preferred plan (2) the retirement of Schahfer Units 17 and 18, and (3) discount rates and reserve margins used in the modeling. The meeting presentation (including agenda), the stakeholder presentation, and summary (including questions / responses) and for Meeting 6 are included in Appendix A, Exhibit 6.

2.1.7 One-on-one Stakeholder Meetings

NIPSCO held a number of one-on-one meetings with its stakeholders throughout the public advisory process. Generally, the meetings related to either (1) clarifications, (2) identification of issues in and presentation of issues in the report, or (3) running requested scenarios. Information relating to running requested scenarios can be found in the presentation included in Appendix A, Exhibit 6 (Slides 8 through 29). Information relating to clarifications and presentation of issues can be found in the presentation included in Appendix A, Exhibit 4 (Slides 7 through 10).

NIPSCO's 2016 IRP is the result of analysis performed by NIPSCO that includes consideration of stakeholder input. NIPSCO has made a good-faith effort to be open and transparent regarding input assumptions and modeling results. NIPSCO appreciates the participation of its stakeholders, including the Commission staff, the OUCC, NIPSCO's largest industrial customers and community action groups, all of which participated extensively throughout the IRP development process. NIPSCO's stakeholders and Commission staff provided useful feedback throughout the process, which has been considered and incorporated as applicable.

Despite best efforts to address and resolve all input from stakeholders, there were instances wherein NIPSCO still incorporated, for example, methodologies that were not supported by all stakeholders. For example, the Citizens Action Coalition would prefer that for purposes of evaluating industrial energy efficiency programs NIPSCO assume that all applicable industrial load or energy as part of the analysis regardless of whether the customer(s) had elected its statutory right to opt-out of such programs. In this IRP, NIPSCO has elected to observe that industrial customer right and election by not including such load in its DSM or energy efficiency analysis, even though the Citizens Action Coalition would prefer otherwise. NIPSCO expects to continue a dialogue with the Citizens Action Coalition regarding this point leading up to and through its next program filing in 2017 at the Commission.

2.2 IRP Planning Process

NIPSCO's 2016 IRP is in compliance with the Commission's Proposed Rule to modify 170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans ("Proposed Rule"). A matrix showing NIPSCO's compliance with each section of the Proposed Rule (providing a reference to the appropriate Section(s) and Page(s) of the IRP) is included in Section 10: Compliance with Proposed Rule.

NIPSCO used a combined planning process and a portfolio optimization model to develop its 2016 IRP. The model develops resource portfolio plans by selecting various demand- and supply-side options to balance supply with projected customer electric load with a goal to develop a long-term strategic plan ensuring NIPSCO will continue to provide reliable, reasonable-cost service to customers.

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

The 2016 IRP involved iterative supply- and demand-side optimizations using correlated data assumptions. Internal and external resources were used to accomplish the tasks to complete the process. They include:

- Collecting data for the planning process including operating parameters, customer demand forecast, economic conditions and energy commodity markets forecasts.
- Identifying demand- and supply-side resource options (market-based, self-build and renewable resources).
- Considering environmental externalities and potential future changes in cost.

NIPSCO recognizes planning for future economic and environmental changes are difficult to accurately predict. The 2016 IRP addresses the most likely contingencies based on uncertainty analyses. New information in NIPSCO's planning process is analyzed and incorporated as it becomes available.

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

Applied Energy Group, Inc. 500 Ygnacio Valley Road, Suite 450 Walnut Creek, California 94596	Developed DSM measures inputs for a long-term DSM forecast
IHS Global Insight 24 Hartwell Avenue Lexington, Massachusetts 02421	Provided forecasts of independent variables for load forecasting process
Itron, Inc. 2111 North Molter Road Liberty Lake, Washington 99019	Provided historical and forecasted end use data
Morgan Marketing Partners 6205 Davenport Drive, Madison, Wisconsin 53711	Provided assistance with modeling DSM programs in DSMore™
PIRA Energy Group 3 Park Avenue, 26th Floor New York, New York 10016	Provided environmental assumptions for NO_x, SO_2 and CO_2 and correlated long-term commodity assumptions

Sargent & Lundy 55 East Monroe Street Chicago, Illinois 60603	Performed engineering study
Telvent DTN, Inc. 9110 West Dodge Road Omaha, Nebraska 68114	Provided hourly weather data for three Indiana weather stations

2.2.1 Contemporary Issues

NIPSCO also participated in the Commission's IRP Contemporary Issues Technical Conference held March 22, 2016. One of the topics discussed during the conference was the integration of energy efficiency into the IRP. NIPSCO incorporated into the 2016 IRP process the integration of energy efficiency during the optimization modeling to ensure that all programs were given equal opportunity to be selected by the model. This included demand response (interruptible) and energy efficiency programs separated by class – residential, commercial and industrial. These programs had different load shapes and different costs. See Section 8.5.1 for more details on the process used. DSM was also integrated in the load forecast process. The forecast included in the 2016 IRP reflects NIPSCO's existing or past DSM programs. When appropriate, new DSM program impacts are subtracted from the forecast to account for new anticipated impacts or levels not accounted for in historical data. The forecast included in the 2016 IRP reflects historical DSM impacts and trends through December 2014.

2.2.2 Process Improvement Efforts

NIPSCO has developed a robust set of scenarios and sensitivities to capture uncertainty. While this effort helps mitigate risk, a more dynamic effort would involve the inclusion of a stochastic process in the IRP modeling. Strategist® was the primary tool utilized in the IRP modeling process and is unfortunately incapable of directly utilizing statistical tools within its engine. An overview of the Strategist Optimization Model is included in Appendix C.

Table 2-1 shows feedback received on NIPSCO's 2014 IRP and the improvements that were included in its 2016 IRP process.

Table 2-1: Process Improvement

2014 IRP Feedback	Improvements Included in the 2016 Process
Enhance Stakeholder Process	- Participated in joint educational session with Indiana utility peers to develop foundational reference materials - Engaged stakeholders to obtain feedback on IRP analysis and future world alternatives - Expanded to 6 stakeholder meetings from 4 in 2014 - Maintained focus on one on one stakeholder meetings
Improve Load Forecasting Process	- Clarified the detailed narrative to better articulate load forecasting methodology - Implemented multiple enhancements to load forecasting process
Clarify DSM Modeling	- Provided DSM development and modeling methodology detail in narrative - Dedicated one of the stakeholder meetings to clarify DSM modeling process and results
Expand Scenarios and Sensitivities	- Developed a robust set of scenarios and sensitivities to capture a wider range of potential risks/uncertainties - Increased the number of scenarios from 3 to 2014 to 5 in 2016 - Increase emphasis on environmental rules and regulations
Address Customer-owned and Distributed Generation	- Evaluated distributed generation and Combined Heat & Power
Provide Confidential Data Proxies	- Reduced use of confidential data and use public/representative proxy data as substitute for proprietary data

In future IRPs, NIPSCO will evaluate new software that can incorporate statistical uncertainty directly in the modeling process. This will allow for the addition of tools such as error bands that can help provide detail currently missing in this IRP. NIPSCO also will consider software that utilizes sub-hourly dispatch and carbon constrained dispatch as these features are necessary to capture the evolution of the electric system. As software continues to evolve and develop, NIPSCO will evaluate opportunities to directly incorporate aspects of the transmission and distribution systems into its modeling process as this will likely be necessary to capture the impacts of future distributed generation.

2.3 Expansion Plan Criteria

Consistent with the principles set out in Section 1.1, the 2016 IRP identifies changes and additions needed over a 20 year planning horizon for NIPSCO to deliver reliable, compliant, flexible, diverse and affordable electric service to its customers. Mathematical constraints placed upon the optimization included NIPSCO's Internal Load, the MISO Planning Reserve Margin, and construction lead time as associated with capacity expansion options. The following constraints and criteria were utilized in the optimization process that produced an array of economically ranked resource portfolios:

- Planning Reserve Margin: The Planning Reserve Margin ensures a minimum level of resource adequacy. The MISO UCAP planning protocol was used as the Planning Reserve Margin. The Company constrained the IRP optimization so that no resource mix would be accepted that achieved a Planning Reserve Margin of less than 7.60% for years 2016 to 2037. Based upon NIPSCO's generation fleet reliability, MISO's targeted UCAP planning reserve margin of 7.60% is roughly equivalent to a traditional Planning Reserve Margin of 15.2% using the ICAP planning protocol. Care was taken to ensure that in all cases large scale resources could be selected but excessive overbuild did not occur.

- Economically Ranking Competing Plans: A minimization of NPVRR criterion was used in the Strategist® model for economically ranking competing plans from the optimization.

- Siting Issues and Related Constraints: NIPSCO evaluated both a brownfield and greenfield development.

The planning criteria also involved a technology assessment of supply-side generating resources. A key criteria was whether the supply-side resource had technological adaptive characteristics. NIPSCO also sought to ensure that selected technology is commercially available in order to maximize reliability and price certainty. NIPSCO preferred resources that promote fuel diversification from both a supply and transportation perspective to encourage a balanced range of fuel options while maintaining economic flexibility. NIPSCO also considered operational requirements, such as black start capability. *See* the Sargent & Lundy Engineering Study Technical Assessment in Confidential Appendix I.

The planning criteria included several financial goals to promote a thorough resource evaluation and selection process. The process minimizes the Net Present Value of NIPSCO's generation-related revenue requirement over three build strategies including least cost, low emissions, and renewable focused from 2016 to 2037. Price certainty is promoted by considering an array of supply and demand side options including but not limited to energy efficiency, renewables, and traditional fossil fuel generation. Finally, the 2016 IRP minimizes risk by looking for opportunities to reduce fuel and energy market volatility.

2.4 Planning with Risk and Uncertainty

NIPSCO has envisioned a range of potential futures. To quantify risk associated with these possible outcomes, five scenarios were created. This modeling decision has avoided excess risk by considering all likely worlds while utilizing historical volatility to inform uncertainty analysis. These scenarios provide a framework to evaluate future investments, strategies and business decisions. For the 2016 IRP, NIPSCO developed five scenarios:

(1) Base

(2) Challenged Economy

(3) Aggressive Environmental Regulation

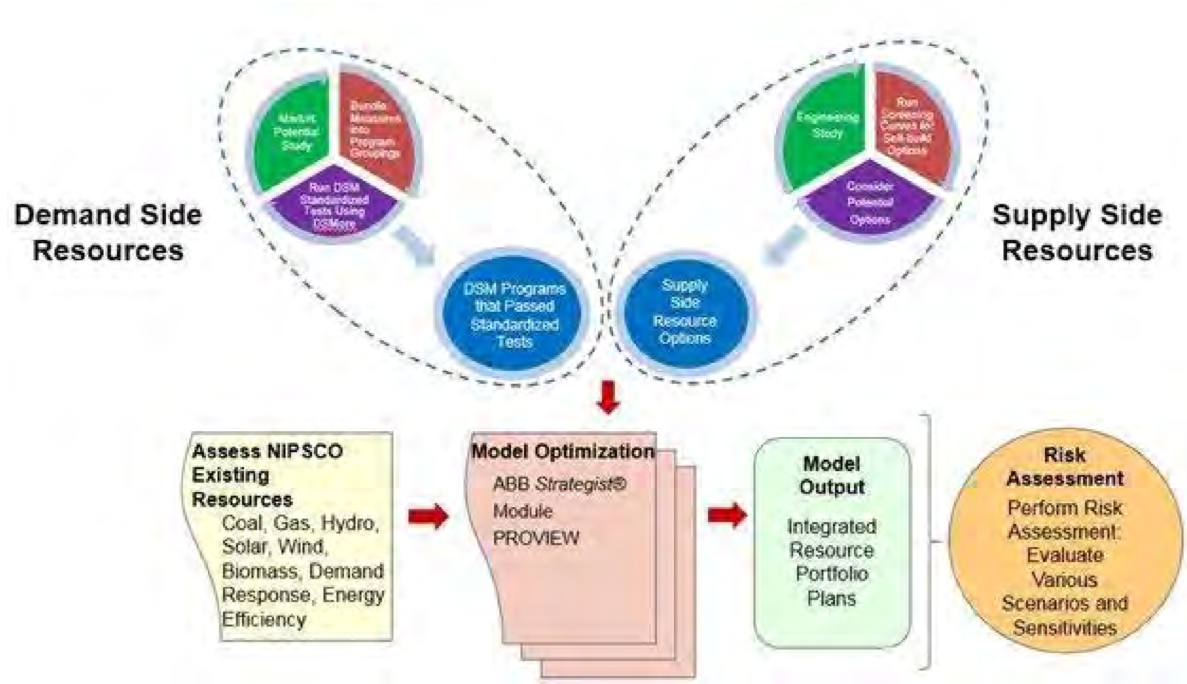
(4) Booming Economy

(5) Base Delayed Carbon

NIPSCO's scenarios utilized a broad base of inputs and assumptions from both external and internal subject matter experts while focusing on a range of outcomes for the most significant and uncertain market drivers including customer load, market pricing, fuel cost, and environmental regulations.

While the most significant drivers established the direction of the scenario, the range of each scenario was further expanded and explored through sensitivity analysis. A sensitivity changes one variable, and the applicable correlated variables, in a scenario. NIPSCO looked at ten sensitivities where load growth, commodity prices and carbon were changed. More discussion relating to the scenarios and sensitivities is included in Section 8.

2.5 Resource Optimization Process



For modeling purposes, assumptions were required in regards to quantities such as NIPSCO's Internal Load, the MISO market and fuel pricing. The resource optimization analysis consistently employed a number of key assumptions within the modeling process which included:

- Economic: Economic assumptions regarding the inflation rate were provided by IHS Global Insight. NIPSCO's capital structure, long-term debt rate and allowed rate of return on equity were taken from NIPSCO's ECRM filing in Cause No. 42150-ECR-27 and used to define the after-tax weighted cost of capital, otherwise known as the discount rate.

- Planning Reserves: Based on the MISO capacity planning protocol that tracks the reliability of generators by shifting the obligation of system wide reserves to the individual generators, the planning reserves were targeted at 7.60% throughout the IRP period. Each generator's ICAP is derated to UCAP. Based on NIPSCO's generation fleet reliability, MISO's targeted UCAP planning reserve margin of 7.60% is equivalent to using an ICAP planning reserve margin of 15.2%. The projected forced outage metrics for each of NIPSCO's existing assets were provided by its Operations Departments and are consistent with NIPSCO's financial plan. Projected forced outage metrics for the self-build supply-side resources were provided by Sargent and Lundy in its assessment of forced outage metrics for generic units.

- Energy and Demand Forecast: The optimization process uses the Energy and Demand Forecast. *See* Section 3: Energy and Demand Forecast.

- Fuel Commodity and Transportation: The options analysis utilized the correlated fuel commodity forecast for coal and natural gas. Natural gas pricing was assumed at Henry Hub and adjusted for the basis to the Chicago City Gate, plus transportation to burnertip. In order to obtain transportation rates, the pipeline tariff rates, along with storage and balancing rates, were escalated for transportation over time. For coal pricing, coal site specific costs were assumed at the mine mouth, and incorporated transportation costs to account for benefits or detriments associated with location, i.e., rail or barge. *See* Figures 8-3 through 8-5 for the fuel assumptions.

- Environmental: The emissions price assumptions for NO_x, SO_2 and CO_2 were provided by PIRA Energy Group. *See* Figure 8-6 for the CO_2 prices. NIPSCO developed estimates for investments to comply with the EPA's Final Regulations for Cooling Water Intake Structures at Existing Facilities under Section 316(b) of the Clean Water Act, and to comply with EPA regulations pertaining to coal ash under subtitle D of Resource Conservation and Recovery Act, and with an amendment to existing ELG. A carbon cost has been assumed to be implemented in 2023 and 2025 in the Base and Base Case Delayed Carbon scenarios, respectively, to reflect reduced carbon emissions from fossil-fuel generation. In all other scenarios and sensitivities, carbon cost has been assumed to be implemented in 2023 except for the "no carbon" cases in which no carbon cost is assumed across the planning horizon. Further environmental discussion is included in Section 7: Environmental Considerations.

- Energy Market: The energy market forecast from NIPSCO's Energy Supply and Optimization organization is based on a fully integrated and modeled scenario, taking into account reasoned market trends and public policy decisions regarding climate change and power generation fuel choice. This case represents NIPSCO's official forecast available to all internal stakeholders. NIPSCO's forecast is zonal in nature and represents the day-ahead energy prices for the Indiana Hub provided by PIRA Energy Group, adjusted by basis to the NIPSCO load hub. *See* Figures 8-7 and 8-8 for further information relating to the energy market forecast.

- Market Capacity Price: NIPSCO used information as provided by PIRA Energy Group for long-term forecast of capacity prices at the Indiana Hub.

- Operating and Capital Costs: The alternatives analysis incorporates operating and capital costs associated with each facility type. Operating constraints for wind and solar renewable alternatives considered a typical day operations shape that defined the hourly output of the resource. NIPSCO relied upon historical wind and sunshine data to derive a typical day shape. Those shapes were used for all future years in the planning horizon.

- Off-System Market: The off-system market is modeled in accordance with MISO's operational model. All generation is sold into the MISO market at the generator hub and all load requirements are purchased from the market at the NIPSCO load hub.

- Regulations: The alternatives analysis incorporated a balanced set of existing and proposed regulations, laws, practices and policies.

The primary assumptions that served as the basis of this IRP are shown in Table 2-2.

Table 2-2: Underlying Assumptions Base Case

Forecast Item	% Compound Annual Growth Rate
60-Minute MW Peak Demand Before DSM Effects	
5 year, 2016-2020	0.58%
10 year, 2016-2025	0.54%
20 year, 2016-2035	0.46%
Total MWh Energy Before DSM Effects	
5 year, 2016-2020	0.36%
10 year, 2016-2025	0.36%
20 year, 2016-2035	0.34%
Natural Gas Prices, 2016-2035	4.33%
PRB Coal, 2016-2035	2.58%
Illinois Basin Coal Prices for New Units, 2013-2035	2.54%
General Inflation Rate Measured by the CPI over, 2016-2035	1.90%
Miscellaneous	**Value**
After-Tax Weighted Cost of Capital	7.49%
Accumulated Funds Used during Construction	8.20%
Effective Income Tax Rate	39.14%
Minimum Reserve Margin	
2016 through 2035	7.60%
Planning Period (Base Year 2013)	2016-2037
Assumed Availability of Existing Coal-fired Units (years)	60
Assumed Availability of Existing Gas-fired Units (years)	40
Assumed Existing Units Unavailable (calendar year)	
Unit 7	2018
Unit 8	2018
Unit 10	2023
Unit 12	2035
Unit 17	2023
Unit 18	2023

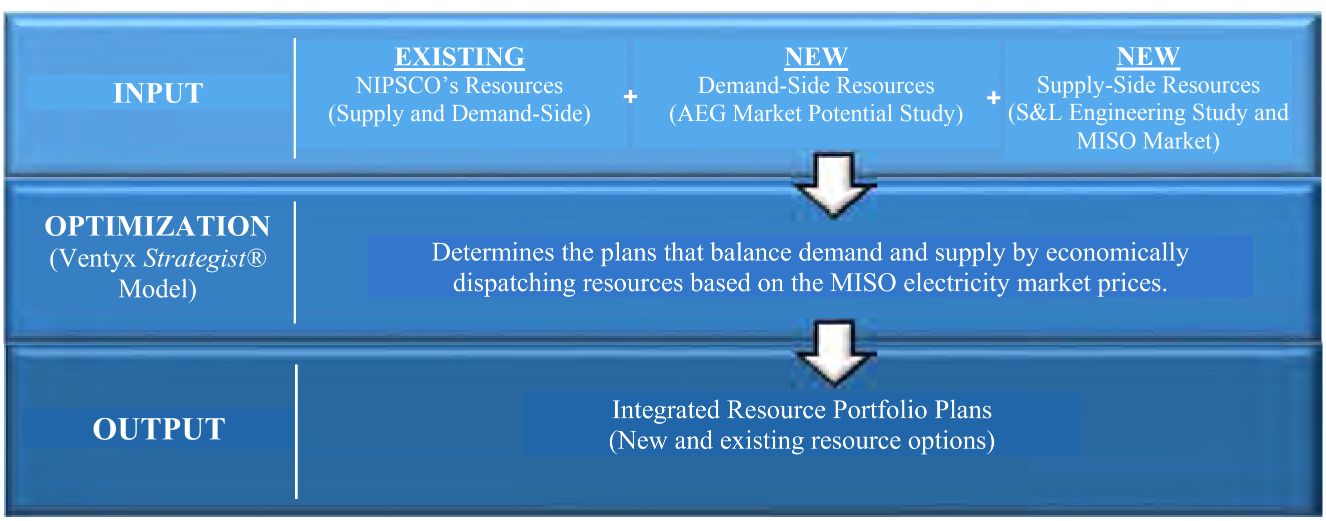
The resource optimization process considers the utilization of resources to balance supply and demand. The customer demand forecast is assimilated with existing resources, including registered demand-side resources, NIPSCO-owned supply-side generation, new demand-side resources options identified in the Market Potential Study conducted by AEG included in Appendix B and new supply-side resource options as identified in the Sargent & Lundy Engineering Study Technical Assessment in Confidential Appendix I. The studies evaluated potential new resource options for NIPSCO's long-range planning and developed their costs and operating assumptions. A list of the resource options considered are summarized in Table 2-3.

Table 2-3: New Resource Options Considered

Technology	Considered as Resource Option
Natural Gas	✓
Coal	✓
Nuclear	✓
Renewable	✓
Energy Storage	✓
Distributed Generation	✓
Combined Heat & Power	✓
Biomass	✓
Microturbines	✓
Reciprocating Engine	✓
DSM Residential Programs	✓
DSM Commercial Programs	✓
DSM Industrial Programs	✓

The inputs detailed in this section were included in the ABB Strategist® resource optimization model. In a given portfolio, the model dispatched available resources and subsequently calculated the revenue requirement over the planning horizon. It is not uncommon for thousands of different resource portfolios to be constructed by the model. The modeling results also included a ranking of the resource portfolios from lowest to highest cost to customers. NIPSCO has applied judgment to ensure that resource portfolios selected for further consideration represent the lowest reasonable risk adjusted cost to customers. This analysis was performed for all scenarios and sensitivities. Figure 2-1 shows a graphical look of the resource optimization process.

Figure 2-1: Resource Optimization



NIPSCO explored and evaluated the various combinations of available demand-side and supply-side options to meet its short- and long-term future resource requirements. The scenario and sensitivity analysis was used to test the robustness of resource combinations. More discussion relating to the scenarios and sensitivities is included in Section 8: Managing Risk and Uncertainty.

Section 3. Energy and Demand Forecast

3.1 Major Highlights / High Level Summary / Discussion of Load

Some of the major highlights include:

- NIPSCO's jurisdictional energy sales are projected to grow 0.3% per year over the next 20 years.

- The residential and commercial compound annual growth rates are projected to be 0.8% and 0.7%, respectively, during the period 2016-2037. The industrial class growth rate is projected to be flat at 0.0% during this same period.

- Peak demand is expected to grow from 3,118 MW in 2016 to 3,424 MW by 2037 representing an annual growth rate of 0.4% during the period 2016-2037.

NIPSCO's long term forecast incorporates historical customer usage and its relationship to economic, demographic, end use and weather data. The load forecast reflects historical impacts of past conservation and DSM programs. Regional saturation and efficiency trends are provided by Itron, Inc., a national utility consulting firm. Economic and demographic data utilized in the forecast is from IHS Global Insight. Historical annual load shapes and seasonal load shapes can be found in Appendices D and E.

3.2 Development of the Forecast – Method and Data Sources

NIPSCO's energy and peak forecast process reflects a system of dynamic models that are continually evaluated, updated and selected based on their ability to provide accurate projections of future energy needs of customers. Current modeling trends, statistical properties, data utilized in the forecast process and current peer utility approaches to forecasting are all considered during the forecast development. NIPSCO utilizes individual forecast models for residential, commercial, industrial, street lighting, public authority, railroad and company use. The forecast also relies upon a 60-minute electric peak demand model. Each of the individual forecast models utilizes methods that account for the unique characteristics of each class. The residential and commercial energy and total peak demand forecast models use an econometric approach to forecast long-term electric energy sales and peak hour demands.

The industrial energy forecast model is developed in two parts. The first part uses a grassroots approach by developing forecasts for the largest individual industrial customers. The second part of the industrial outlook represents all other customers included in the industrial class. To generate the total industrial class forecast, the individual customer forecasts are combined with the portion of the forecast representing the balance of the industrial class load. The street lighting, public authority and railroad class models rely on current usage levels and recent patterns. Projections for Company use and losses also rely on recent usage trends and levels. Historical DSM impacts and trends are reflected in the residential and commercial forecast. The residential and commercial outlook incorporate existing or past NIPSCO DSM programs by utilizing historical data in the modeling process. Past DSM impacts and trends are captured though the model structure and used in the calculation of the forecast. After the completion of the forecast process, NIPSCO completes regular internal forecast performance assessments for the residential, commercial and industrial models to ensure the accuracy and reasonableness of the projections.

NIPSCO evaluates the forecast process on an ongoing basis looking to incorporate improvements that result in a more robust process. Currently, some of the improvements under consideration include updates to the street lighting model, the data frequency used in the forecast model, alternative efficiency variables and estimation techniques to capture changing usage trends.

3.2.1 Data Sources - Internal

Class energy sales, number of customers by class, internal peak demand, historical interruptions and electric prices are all collected internally by NIPSCO. This information is used to develop the long term sales and demand forecast. NIPSCO uses NAICS coding for its non-residential customers.

3.2.2 Data Sources - External

Schneider Electric

NIPSCO uses two weather measures in the forecast, specifically cooling degree days ("CDD") and heating degree days ("HDD") as defined by the National Oceanic and Atmospheric Administration ("NOAA"). The Company purchases weather data for three NOAA stations: Valparaiso, South Bend and Fort Wayne. For modeling purposes, the weather from these three stations is represented as a weighted average with the weights based on the geographical distribution of NIPSCO's weather-sensitive load. For the forecast period, the Company assumes the weather data to be equal to the 1976-2010 average for both CDD and HDD. The weighted weather concepts for the peak hour model are cooling degree hours, heating degree hours and relative humidity.

IHS Global Insight

NIPSCO purchases national, state and county economic and demographic data from IHS Global Insight. Economic data used in the production of the forecast represents the most current information from the vendor at the time the forecast is developed.

Itron, Inc.

Historical and forecasted saturation and efficiency data is obtained from Itron, Inc., a national utility consulting firm. Itron, Inc. produces an annual statistically-adjusted end use model by census region reflecting historical and future saturation and efficiency trends. Itron, Inc. works closely with the United States Energy Information Agency ("EIA") to embed EIA's latest equipment saturation and efficiency trend forecasts into its annual models. NIPSCO utilizes this information reflecting the East North Central census region in the long-term residential forecast model.

3.3 Residential

The Residential Energy Forecast Model is calculated in conjunction with NIPSCO's New Business team, using a residential customer model and an average residential use per customer model. Average residential use per customer projections are multiplied by the total residential customer count forecast to generate the total residential energy forecast. The residential use per customer model is a function of the residential price of electricity, appliance saturations, and efficiencies as defined in an end use variable supplied by Itron, Inc. and real per capita income.

NIPSCO does not incorporate the price of natural gas into the residential forecast model due to the low population of NIPSCO customers who utilize electric space heating. Customers with electric space heating account for only 5% of NIPSCO's residential customers. Other forecast considerations integrated into the residential forecast model include residential customer counts, CDDs and HDDs.

The residential customer count is a function of a three-year outlook for new construction provided by NIPSCO's New Business team and is developed using a grassroots approach. This approach includes conducting interviews with real estate developers and builders; thus, assuring that short-term housing market intelligence and recent trends are included in the forecast. The longer term customer outlook is modeled as a function of housing starts. Both short term and long term forecasts are adjusted for customer attrition applied at an average historic rate. Total residential customers are calculated by incorporating the new customer outlook, existing customers and the historic attrition rate.

Econometric models are utilized to estimate the residential new customer and usage per customer models. Seventeen years of data was employed in the residential new customer model. The model produces an R-Square of 0.9866 in addition to strong T-Stats for each variable and directionally confirms the relationships expected between the independent and dependent variables. Nineteen years of historical data is used in the development of the residential use per customer long-term outlook. The model yielded an R-Square of 0.9784 and confirms statistically strong relationships between the independent and dependent variables.

- Residential New Customer Equation

  New Residential Customers = f(Local Housing Starts)

- Residential Usage Per Customer Equation

  Residential kWh per Customer = f(Residential Electric Price, Itron Index, Real Per Capita Income, Heating Degree Days (HDD), Cooling Degree Days (CDD))

Table 3-1: NIPSCO Residential Customers

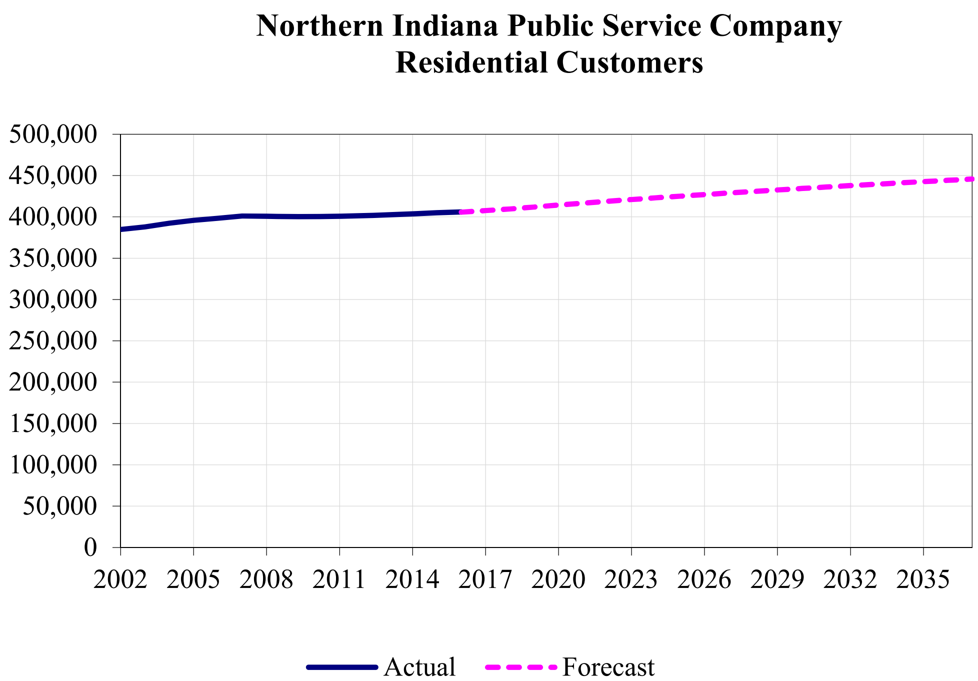
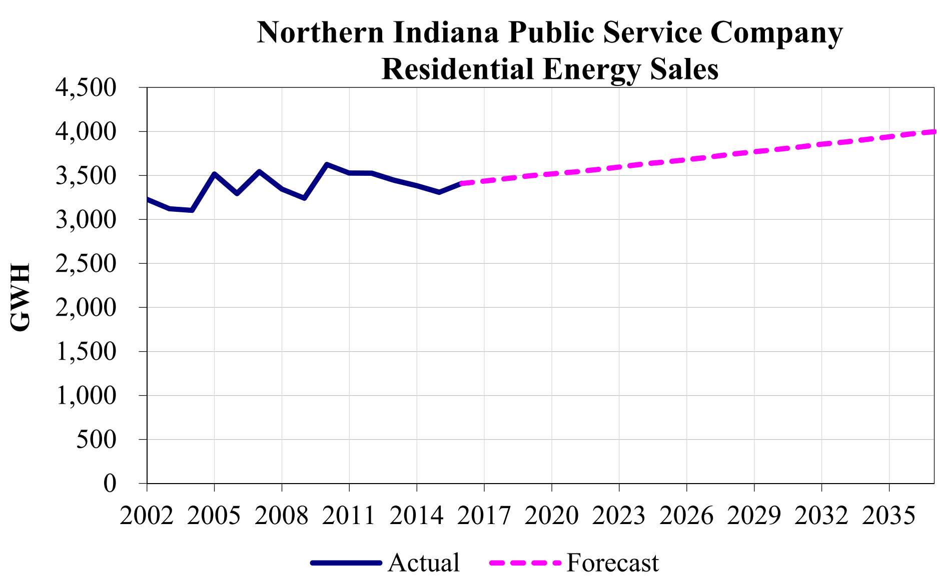


Table 3-2: NIPSCO Residential Energy Sales



3.4 Commercial

The Commercial Energy Forecast Model has been estimated using a total commercial energy consumption model. Commercial energy consumption is a function of the commercial customer count, real county retail sales, commercial electric price and CDD. When included in the model, HDD showed no significance and was removed from the final model specification. As with residential, the initial three-year outlook for commercial customers is provided by NIPSCO's New Business team. The longer term view is modeled as a function of local population and real gross county product. The commercial customer count forecast also reflects a historical attrition rate.

Econometric models are utilized to estimate the commercial customer and total usage models. Twelve years of data was employed in the commercial customer model. The model produces an R-Square of 0.9950 in addition to strong T-Stats for each variable and directionally confirms the relationships expected between the independent and dependent variables. Twenty one years of data was used in the development of the commercial energy long-term outlook. The model yielded an R-Square of 0.9950 and confirms statistically strong relationships between the independent and dependent variables.

- Commercial Customer Equation

  Commercial Customers = f(Population, Real Gross County Product)

- Commercial Usage Equation

  Commercial Total Use = f(Commercial Customers, Real County Retail Sales, Commercial Electric Price, Cooling Degree Days (CDD))

Table 3-3: NIPSCO Commercial Customers

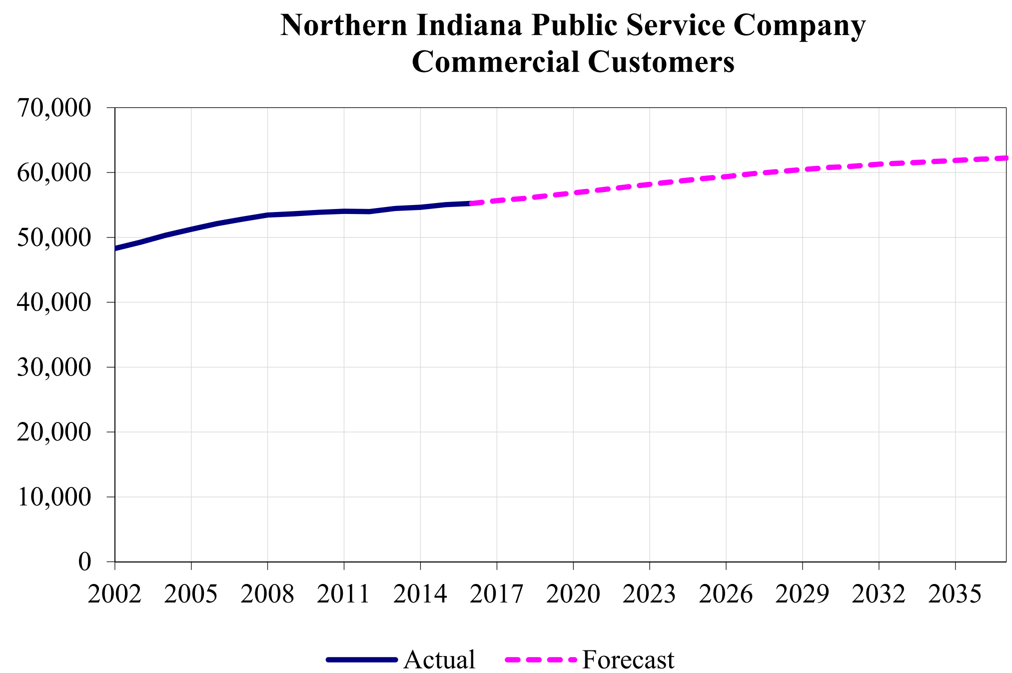
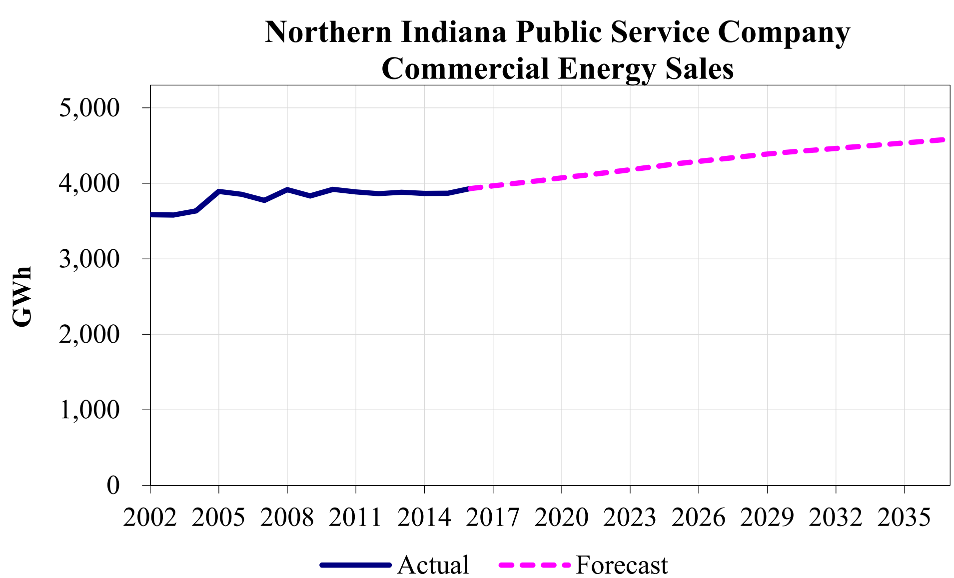


Table 3-4: NIPSCO Commercial Energy Sales



3.5 Industrial

The Industrial Energy Forecast Model projects the expected level of industrial energy sales in NIPSCO's service territory based on individual discussions with its largest industrial customers, recent historical industrial sales trends, and regional and global trends for specific industries. Accordingly, the industrial energy forecast model contains individual forecasts for the major industrial account customers.

Information specific to the creation of the industrial sales forecast is obtained by outreach by the NIPSCO Major Accounts Department to each of its 25 individually forecasted industrial customer accounts. NIPSCO discusses individual business, economic and strategic objectives with each of its individually forecasted industrial accounts. As a part of these discussions, the projected effect of the customer's energy efficiency programs are already taken into account with the forecast provided to NIPSCO. The goals, plans, and concerns outlined in these one-on-one discussions form the basis of a recommendation for each customer's forecast. Other items considered in the development of the forecast include historical consumption, industry trade publications, global market news, business outlook conferences, and routine customer interaction. The resulting forecast incorporates the outlook for steel producers, refiners, industrial gases and a variety of other industrial manufacturing companies in NIPSCO's service territory. Notably, for the development of NIPSCO's industrial energy forecast for the 2016 IRP, this forecast integrates the economic and business projections of these customers and their consumption related to each of their major industrial production sites in NIPSCO's service territory.

The industrial sales forecast model also integrates a sales forecast for the remaining industrial accounts (identified as Other Industrial). This portion of the NIPSCO electric forecast is based primarily on historical data (billed volume) from the past six years with greater consideration given to use for the most recent year. Annual and monthly volumes were analyzed - min, max, and averages were calculated. Historical trends, if any, were identified and are reflected in the forecast.

Table 3-5: Industrial Energy Sales

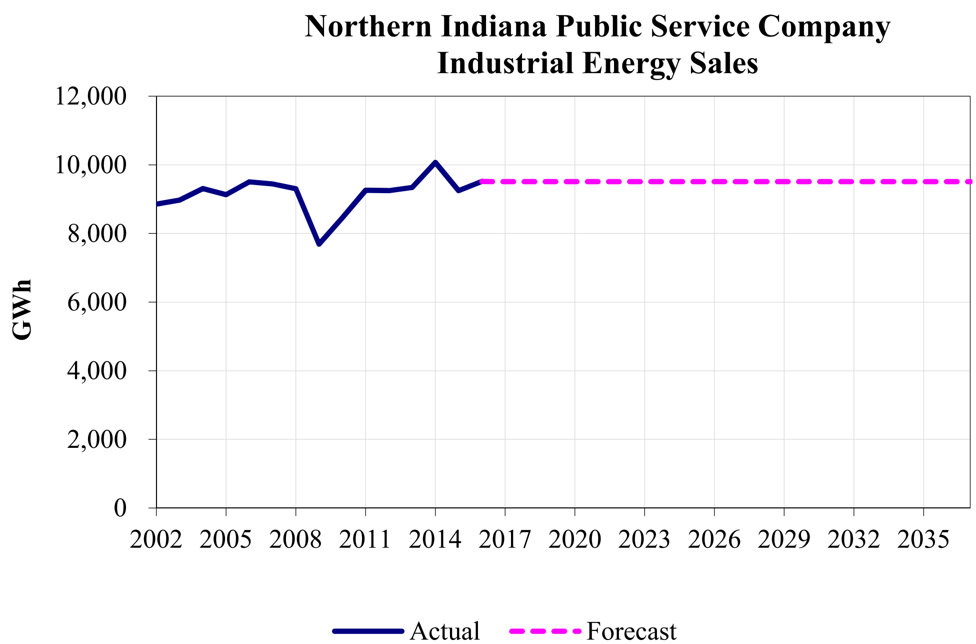


Table 3-6: Total Customers

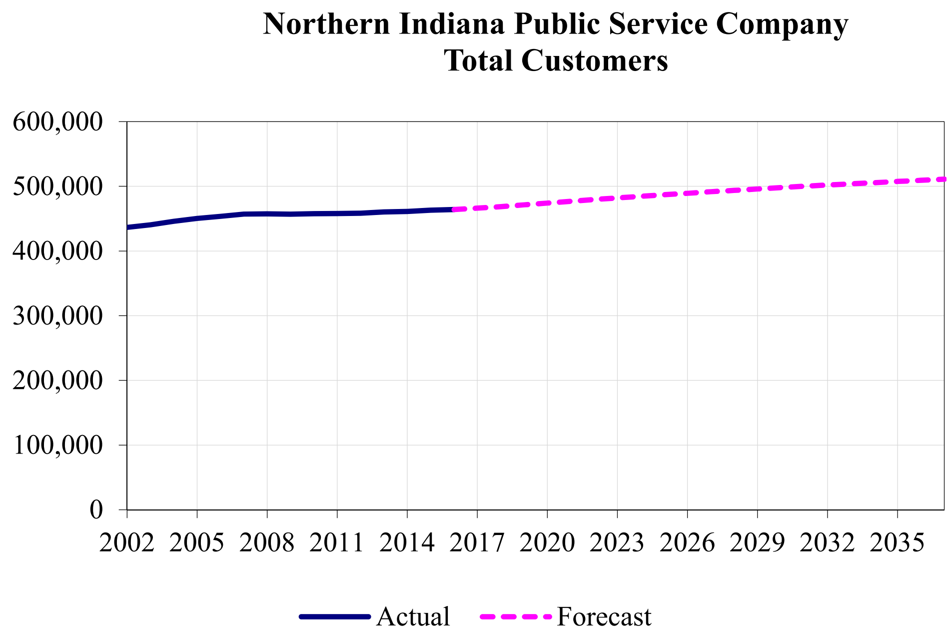
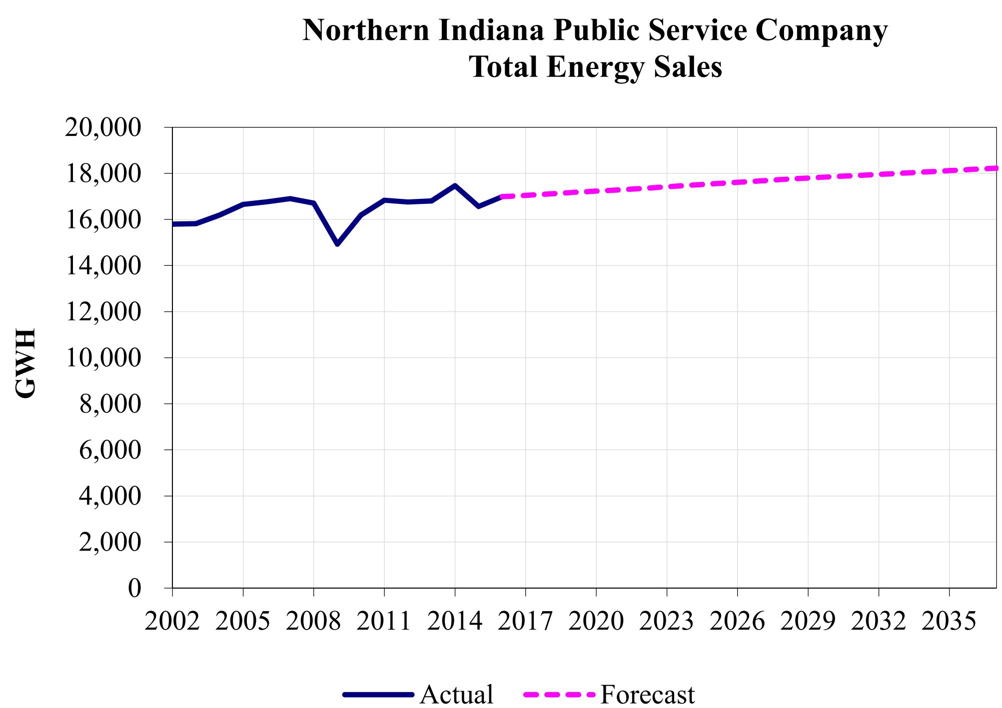


Table 3-7: Total Energy Sales



3.6 Street Lighting, Public Authority, Railroads, Company Use, Losses

The street lighting, public authority, railroads, Company use and losses forecasts are based on both current usage levels and anticipated future trends. However, updates to the street light modeling process are being made and will be reflected in future IRPs. The future street lighting model will utilize an econometric model and will reflect anticipated levels of impacts related to NIPSCO's street lighting replacement program.

3.7 Peak

NIPSCO uses an econometric model to project future peak demand on its system. The model incorporates residential, commercial, and industrial energy levels, cooling degrees (summer) and heating degrees (winter) at peak hour, and the level of relative humidity at peak hour. The model also accounts for recent historical load factor levels and patterns associated with NIPSCO's large industrial customers. Using thirty years of data, the peak forecast is derived with a two-step approach accounting for the large influence of the industrial class and the contribution of smaller customers.

The first step of the peak model accounts for the impact of residential, commercial, and small industrial energy levels and patterns. The model also takes into account the influence of weather at the time of the peak. Utilizing thirty years of historical data, the model yielded an R-Square of 0.9427 and confirms a statistically strong relationships between the independent and dependent variables

The second step of the peak model accounts for the contribution of NIPSCO's large industrial customers to the NIPSCO peak. The model estimates the load factor associated with large customers and utilizes this to project peak. The load factor is estimated using a polynomial model that employs recent monthly load factory data to identify a monthly pattern. Once the load factor is estimated, it is combined with the large customer energy forecast to calculate this portion of the peak forecast. The large customer peak is then added to the initial peak generated from the first step to yield the total company peak outlook.

Peak Model

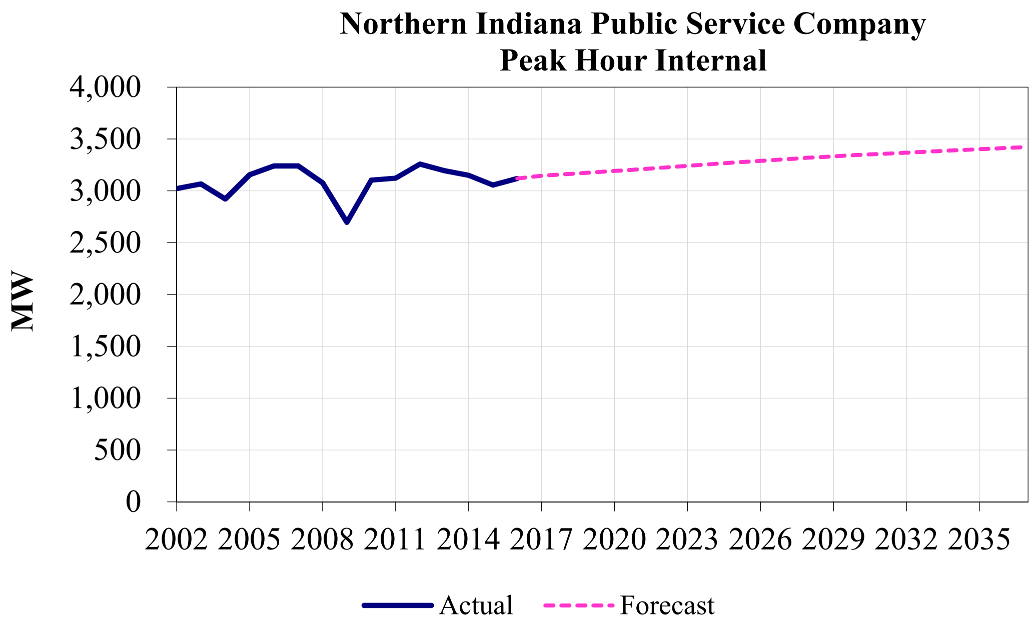
Peak_Step1 = f(Residential Energy, Commercial Energy, Small Industrial Energy, Cooling Degree Hour(Summer), Heating Degree Hours(Winter), Summer Humidity, Winter Humidity)

Large Company Load Factor = f(Time, Time^2)

Peak_Step2 = f(Large Company Load Factor, Large Company Energy, Monthly Hours)

NIPSCO Peak=Peak_Step1 + Peak_Step2

Table 3-8: Peak Hour



3.8 Customer Self-Generation

Customer Self-Generation assumes that most of NIPSCO's large electric customers with self-generation utilize the generation as a by-product of process steam production needs. This type of generation is difficult to predict by NIPSCO, and, therefore, challenging to dispatch by NIPSCO without significant coordination between the customer and utility. Although it is difficult to dispatch or coordinate, NIPSCO does have a currently-effective tariff rider available to such customers that enables the purchase from qualifying cogeneration facilities in the situation where the customer's generation exceeds load. Any such purchases are made pursuant to Rider 778 - Purchases from Cogeneration Facilities and Small Power Production Facilities - and this Rider allows for the purchases pursuant to a contract between NIPSCO and the customer. To the extent qualified and provided, Rider 778 also provides the ability to purchase capacity from such qualifying facilities.

3.9 Weather Normalization

NIPSCO produces estimates of weather-normalized energy for prior annual periods. Because industrial class energy consumption varies little with weather, NIPSCO weather-normalizes kWh sales for the residential and commercial classes only. The normalization procedure uses coefficients obtained from regressions using ten years of monthly data of kWh/customer/day on CDD/day and HDD/day with additional terms for some month's CDD and a trend variable as appropriate.

The general normalization equation is specified on a monthly per day basis and then scaled to a monthly concept by multiplying by days:

*Normal kWh/Customer = Actual kWh/Customer + ((CDD coefficient) * (Normal CDD – Actual CDD)) + (HDD coefficient * (Normal HDD – Actual HDD))*

Where

*Monthly Normal kWh = (Normal kWh/Customer * Customers) and*

Annual Normal kWh is the sum of the monthly normal kWh.

The actual and normal energy sales for residential and commercial customers are shown in Figure 3-1 and Figure 3-2, respectively.

Figure 3-1: NIPSCO Residential GWh

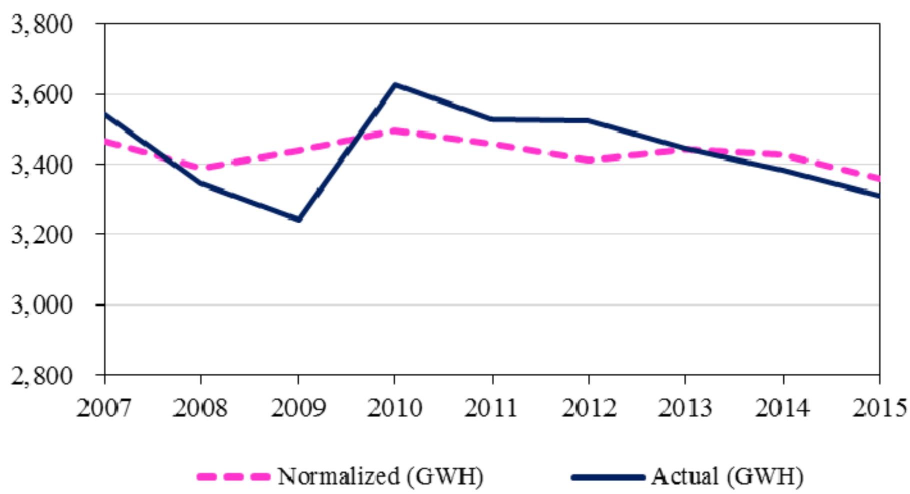
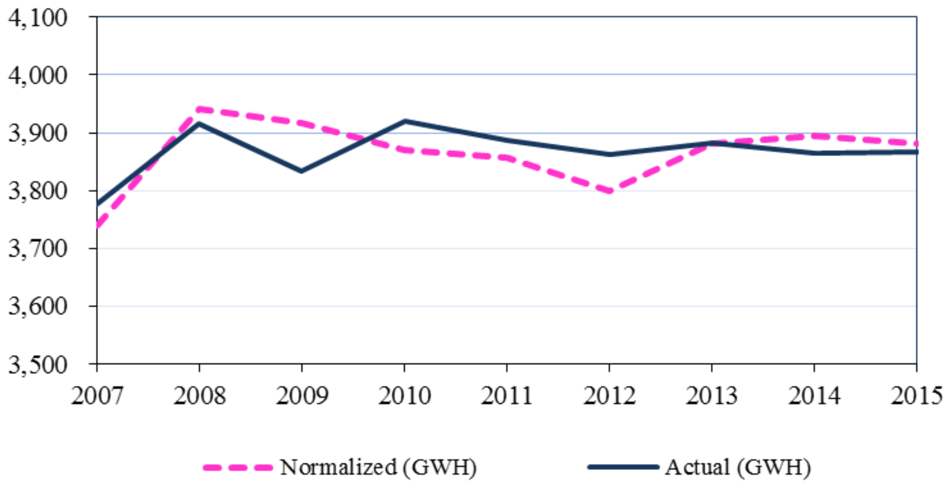


Figure 3-2: NIPSCO Commercial GWh



3.10 Forecast Results – Base Case

Over the forecast period, total energy and peak hour demand are projected to grow at 0.3% and 0.4%, respectively. NIPSCO expects overall customer growth to increase about 0.5% annually. Table 3-9 illustrates NIPSCO's electric energy and demand forecast.

Table 3-9: Electric Energy and Demand Forecast

FP0715

Year	Energies (GWh) Total Retail *	% Change	Losses	Total Output	% Change	Load Factor	Internal Peak Hour MW	Internal Peak Hour % Change
2006	16,767		733	17,500		61.7%	3,238	
2007	16,904	0.8%	751	17,655	0.9%	62.2%	3,239	0.0%
2008	16,705	-1.2%	897	17,602	-0.3%	65.3%	3,076	-5.0%
2009	14,925	-10.7%	858	15,783	-10.3%	66.8%	2,696	-12.4%
2010	16,191	8.5%	915	17,106	8.4%	62.9%	3,103	15.1%
2011	16,836	4.0%	892	17,728	3.6%	64.8%	3,122	0.6%
2012	16,756	-0.5%	925	17,681	-0.3%	62.0%	3,257	4.3%
2013	16,798	0.2%	839	17,638	-0.2%	63.0%	3,194	-1.9%
2014	17,467	4.0%	940	18,407	4.4%	66.7%	3,149	-1.4%
2015	16,563	-5.2%	886	17,449	-5.2%	65.2%	3,055	-3.0%
2016	16,989	2.6%	928	17,917	2.7%	65.6%	3,118	2.1%
2017	17,046	0.3%	931	17,977	0.3%	65.3%	3,145	0.9%
2018	17,110	0.4%	935	18,045	0.4%	65.2%	3,160	0.5%
2019	17,175	0.4%	938	18,113	0.4%	65.1%	3,176	0.5%
2020	17,233	0.3%	941	18,174	0.3%	65.0%	3,192	0.5%
2021	17,289	0.3%	944	18,234	0.3%	64.9%	3,207	0.5%
2022	17,353	0.4%	948	18,300	0.4%	64.8%	3,224	0.5%
2023	17,419	0.4%	951	18,370	0.4%	64.7%	3,240	0.5%
2024	17,491	0.4%	955	18,446	0.4%	64.6%	3,258	0.5%
2025	17,552	0.4%	959	18,511	0.4%	64.5%	3,275	0.5%
2026	17,613	0.3%	962	18,575	0.3%	64.5%	3,289	0.4%
2027	17,674	0.3%	965	18,640	0.3%	64.4%	3,304	0.4%
2028	17,742	0.4%	969	18,711	0.4%	64.4%	3,319	0.5%
2029	17,798	0.3%	972	18,770	0.3%	64.3%	3,333	0.4%
2030	17,855	0.3%	975	18,831	0.3%	64.2%	3,346	0.4%
2031	17,905	0.3%	978	18,883	0.3%	64.2%	3,356	0.3%
2032	17,961	0.3%	981	18,942	0.3%	64.2%	3,367	0.3%
2033	18,011	0.3%	984	18,995	0.3%	64.2%	3,379	0.3%
2034	18,064	0.3%	987	19,051	0.3%	64.2%	3,390	0.3%
2035	18,117	0.3%	990	19,107	0.3%	64.1%	3,401	0.3%
2036	18,176	0.3%	993	19,168	0.3%	64.1%	3,412	0.3%
2037	18,225	0.3%	995	19,220	0.3%	64.1%	3,424	0.3%
Compound Average Growth Rate 2016-2037								
	0.3%			**0.3%**			**0.4%**	

** Retail does not include bulk sales*

Table 3-10 illustrates NIPSCO's electric energy by customer class.

Table 3-10: Energies by Customer Class

FP0715						
Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Other (GWh)	Total* (GWh)	Percent Change
2006	3,294	3,856	9,503	114	17,500	
2007	3,544	3,775	9,444	142	17,655	0.9%
2008	3,346	3,916	9,305	138	17,602	-0.3%
2009	3,241	3,834	7,691	159	15,783	-10.3%
2010	3,626	3,920	8,459	186	17,106	8.4%
2011	3,527	3,886	9,257	166	17,728	3.6%
2012	3,524	3,863	9,250	119	17,681	-0.3%
2013	3,445	3,882	9,340	132	17,638	-0.2%
2014	3,384	3,864	10,071	148	18,407	4.4%
2015	3,310	3,867	9,249	138	17,449	-5.2%
2016	3,411	3,931	9,518	129	17,917	2.7%
2017	3,437	3,968	9,512	129	17,977	0.3%
2018	3,467	4,003	9,512	129	18,045	0.4%
2019	3,497	4,037	9,512	129	18,113	0.4%
2020	3,519	4,073	9,512	129	18,174	0.3%
2021	3,540	4,109	9,512	129	18,234	0.3%
2022	3,567	4,145	9,512	129	18,300	0.4%
2023	3,596	4,182	9,512	129	18,370	0.4%
2024	3,630	4,221	9,512	129	18,446	0.4%
2025	3,653	4,259	9,512	129	18,511	0.4%
2026	3,681	4,292	9,512	129	18,575	0.3%
2027	3,709	4,325	9,512	129	18,640	0.3%
2028	3,744	4,358	9,512	129	18,711	0.4%
2029	3,769	4,388	9,512	129	18,770	0.3%
2030	3,798	4,417	9,512	129	18,831	0.3%
2031	3,824	4,440	9,512	129	18,883	0.3%
2032	3,857	4,464	9,512	129	18,942	0.3%
2033	3,881	4,490	9,512	129	18,995	0.3%
2034	3,911	4,513	9,512	129	19,051	0.3%
2035	3,941	4,536	9,512	129	19,107	0.3%
2036	3,975	4,560	9,512	129	19,168	0.3%
2037	3,999	4,585	9,512	129	19,220	0.3%
Compound Average Growth Rate 2016-2037						
	0.8%	**0.7%**	**0.0%**	**0.0%**	**0.3%**	

**Includes Total Retail and Losses*

Table 3-11 displays the NIPSCO forecast by customer counts by class.

Table 3-11: Customer Counts by Class

FP0715					
Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Total Customers
2006	398,349	52,106	2,509	759	453,723
2007	400,991	52,815	2,509	755	457,070
2008	400,640	53,438	2,484	754	457,316
2009	400,016	53,617	2,441	746	456,820
2010	400,522	53,877	2,432	740	457,571
2011	400,567	54,029	2,405	737	457,738
2012	401,177	53,969	2,445	758	458,349
2013	402,638	54,452	2,374	799	460,263
2014	403,272	54,635	2,338	751	460,996
2015	404,889	55,053	2,327	743	463,012
2016	405,859	55,235	2,201	751	464,046
2017	407,634	55,685	2,201	751	466,271
2018	409,695	56,003	2,201	751	468,650
2019	412,043	56,442	2,201	751	471,437
2020	414,405	56,878	2,201	751	474,235
2021	416,674	57,315	2,201	751	476,941
2022	418,896	57,750	2,201	751	479,598
2023	421,069	58,186	2,201	751	482,206
2024	423,140	58,625	2,201	751	484,717
2025	425,118	59,068	2,201	751	487,137
2026	427,056	59,384	2,201	751	489,392
2027	428,965	59,832	2,201	751	491,749
2028	430,798	60,150	2,201	751	493,900
2029	432,610	60,466	2,201	751	496,028
2030	434,436	60,786	2,201	751	498,174
2031	436,224	60,973	2,201	751	500,149
2032	437,899	61,294	2,201	751	502,146
2033	439,545	61,485	2,201	751	503,982
2034	441,169	61,676	2,201	751	505,797
2035	442,754	61,868	2,201	751	507,574
2036	444,308	62,060	2,201	751	509,320
2037	445,849	62,252	2,201	751	511,053
Compound Average Growth Rate 2016-2037					
	0.4%	**0.6%**	**0.0%**	**0.0%**	**0.5%**

3.11 Discussion of Forecast and Alternative Cases

3.11.1 High/Low Growth Cases

The high and low load growth cases were constructed from the base case forecast models and employed optimistic and pessimistic economic and demographic data from IHS Global Insight. The forecast models are estimated at the 95% confidence level and reflect the high and low model bands. The industrial scenarios are constructed individually for each forecasted customer. The high load growth scenario is created by looking at the customer's previous five years of history and using their peak usage and demand, as well as taking into account current business practices and any other potential growth. The low load growth scenario takes each individual customer's "worst case" scenario, whereas customer's minimum operating levels with major loads are idled, and using Rate limitations and other business protocols as guiding factors. Table 3-12 reflects NIPSCO's base, high and low load forecast scenarios for selected years.

Table 3-12: NIPSCO IRP Scenarios – Selected Year

	Energy Sales – GWh			Internal Demand - MW		
Year	Base GWh	High GWh	Low GWh	Base MW	High MW	Low MW
2016	17,917	19,205	16,018	3,118	3,313	2,917
2021	18,234	19,758	16,059	3,207	3,435	2,940
2026	18,575	20,550	16,203	3,289	3,606	2,983
2031	18,883	21,267	16,282	3,356	3,749	3,004
2036	19,168	22,001	16,286	3,412	3,887	3,004
		v Base			v Base	
		High GWh	Low GWh		High MW	Low MW
2016	-	7.19%	10.60%	-	6.2%	-6.5%
2021	-	8.36%	11.93%	-	7.1%	-8.3%
2026	-	10.63%	12.77%	-	9.6%	-9.3%
2031	-	12.62%	13.78%	-	11.7%	-10.5%
2036	-	14.78%	15.04%	-	13.9%	-12.0%

Gigawatt hours ("GWh")

3.11.2 Alternative Cases/Removal of Major Industrial Load

In addition to the high and low load growth cases, two additional scenarios have been constructed. These scenarios remove major industrial customer load from the base and low cases. Table 3-13 reflects these scenarios and displays NIPSCO's base forecast, the base forecast reflecting no major industrial load and the low forecast scenario without major industrial load.

Table 3-13: NIPSCO IRP Scenarios – Selected Year

	Energy Sales - GWh			Internal Demand - MW		
Year	Base GWh	Base - Loss of Major Industrial GWh	Low - Loss of Major Industrial GWh	Base MW	Base - Loss of Major Industrial MW	Low - Loss of Major Industrial MW
2016	17,917	10,083	9,891	3,118	2,262	2,229
2021	18,234	10,404	9,918	3,207	2,351	2,247
2026	18,575	10,746	10,063	3,289	2,433	2,289
2031	18,883	11,053	10,141	3,356	2,500	2,310
2036	19,168	11,339	10,145	3,412	2,556	2,310
		v Base			v Base	
		Base - Loss of Major Industrial GWh	Low - Loss of Major Industrial GWh		Base - Loss of Major Industrial MW	Low - Loss of Major Industrial MW
2016	-	-43.72%	-44.80%	-	-27.5%	-28.5%
2021	-	-42.94%	-45.60%	-	-26.7%	-29.9%
2026	-	-42.15%	-45.83%	-	-26.0%	-30.4%
2031	-	-41.46%	-46.29%	-	-25.5%	-31.2%
2036	-	-40.85%	-47.07%	-	-25.1%	-32.3%

3.12 Evaluation of Model Performance and Accuracy

NIPSCO tracks its forecast in terms of mean absolute error ("MAE"). Data for 2004-2015 show that the MAE of the one-year-ahead peak hour demand forecast is 3.7%; the two-year-ahead forecast has a 4.2% MAE; and the MAE for the five-year-ahead forecast is 4.4%. These represent total forecast error including the effect of abnormal weather at peak. The comparable MAE for GWh sales is 3.3% for the one-year-ahead forecast; 4.0% for the two-year-ahead forecast; and 3.4% for the five-year-ahead forecast. Class comparisons to weather-normalized actual data show variances with residential and commercial of 1.7% and 2.6% MAE for the one-and two-year ahead forecasts. Industrial GWh are not weather normalized because historically they have not fluctuated with weather and show 3.1% and 7.7% MAE for the one-year-ahead and the two-year-ahead forecast. NIPSCO does not have any firm wholesale power sales.

Table 3-174 shows data for 2004-2015 for total GWh sales and peak hour MW and compare forecasts to actual data not normalized for weather. GWh sales by class are compared to actual data normalized for weather.

Table 3-14: Internal Peak Hour Demand (MW)

Internal Peak Hour Demand - MW
Absolute % Variance of Forecast v Actual

		1-Year Ahead		2-Year Ahead		5-Year Ahead	
Year	Actual *	Forecast	% Var.	Forecast	% Var.	Forecast	% Var.
2004	2,921	3,052	4.5%	3,030	3.7%	2,951	1.0%
2005	3,154	3,046	3.4%	3,091	2.0%	3,104	1.6%
2006	3,238	3,099	4.3%	3,077	5.0%	3,064	5.4%
2007	3,239	3,154	2.6%	3,134	3.2%	3,146	2.9%
2008	3,076	3,224	4.8%	3,188	3.6%	3,201	4.1%
2009	2,696	3,024	12.2%	3,248	20.5%	3,170	17.6%
2010	3,103	2,965	4.5%	3,088	0.5%	3,232	4.2%
2011	3,122	3,134	0.4%	3,093	0.9%	3,282	5.1%
2012	3,257	3,183	2.3%	3,195	1.9%	3,323	2.0%
2013	3,194	3,172	0.7%	3,306	3.5%	3,233	1.2%
2014	3,149	3,209	1.9%	3,243	3.0%	3,287	4.4%
2015	3,055	3,173	3.9%	3,259	6.7%	3,300	8.0%
Average			**3.8%**		**4.5%**		**4.8%**

**Actual peak not adjusted for weather. Forecasted peaks assume normal weather; therefore, variance includes weather effect.*

Table 3-15: Total GWh including Losses

Total GWh including Losses
Absolute % Variance of Forecast v Actual

		1-Year Ahead		2-Year Ahead		5-Year Ahead	
Year	Actual *	Forecast	% Var.	Forecast	% Var.	Forecast	% Var.
2004	16,911	17,224	1.9%	17,078	1.0%	18,018	6.5%
2005	17,396	17,031	2.1%	17,531	0.8%	17,544	0.9%
2006	17,500	16,750	4.3%	17,235	1.5%	17,544	0.3%
2007	17,655	17,725	0.4%	16,916	4.2%	17,928	1.5%
2008	17,602	18,355	4.3%	17,938	1.9%	18,374	4.4%
2009	15,783	16,898	7.1%	18,446	16.9%	17,716	12.2%
2010	17,106	15,910	7.0%	17,340	1.4%	17,373	1.6%
2011	17,728	16,715	5.7%	16,931	4.5%	18,389	3.7%
2012	17,681	17,754	0.4%	17,220	2.6%	18,804	6.3%
2013	17,638	17,591	0.3%	18,622	5.6%	18,258	3.5%
2014	18,407	18,275	0.7%	17,786	3.4%	18,367	0.2%
2015	17,449	18,417	5.5%	18,611	6.7%	17,747	1.7%
Average			**3.3%**		**4.2%**		**3.6%**

** Actual GWh not adjusted for weather. Forecasted GWh assumes normal weather, therefore, variance includes weather effect.*

Table 3-16: Residential and Commercial GWh

Residential and Commercial GWh Absolute % Variance of Forecast v Actual		1-Year Ahead		2-Year Ahead	
	Normal *	Forecast	% Var.	Forecast	% Var.
2006	7,273	7,290	0.2%	7,151	1.7%
2007	7,207	7,477	3.8%	7,423	3.0%
2008	7,328	7,641	4.3%	7,600	3.7%
2009	7,357	7,534	2.4%	7,757	5.4%
2010	7,366	7,431	0.9%	7,659	4.0%
2011	7,313	7,428	1.6%	7,474	2.2%
2012	7,213	7,382	2.3%	7,492	3.9%
2013	7,323	7,414	1.2%	7,427	1.4%
2014	7,320	7,398	1.1%	7,466	2.0%
2015	7,241	7,409	2.3%	7,461	3.0%
Average			**2.0%**		**3.0%**

** Adjusted for weather*

Table 3-17: Industrial GWh

Industrial GWh Absolute % Variance of Forecast v Actual		1-Year Ahead		2-Year Ahead	
	Actual *	Forecast	% Var.	Forecast	% Var.
2006	9,503	8,722	8.2%	9,320	1.9%
2007	9,444	9,441	0.0%	8,749	7.4%
2008	9,305	9,861	6.0%	9,523	2.3%
2009	7,691	8,579	11.6%	9,833	27.8%
2010	8,459	7,692	9.1%	8,879	5.0%
2011	9,257	8,220	11.2%	8,629	6.8%
2012	9,250	9,243	0.1%	8,632	6.7%
2013	9,340	9,111	2.4%	10,020	7.3%
2014	10,071	9,799	2.7%	9,245	8.2%
2015	9,249	9,923	7.3%	10,055	8.7%
Average			**5.9%**		**8.2%**

** No weather effect measured for industrial load*

Section 4. Supply-Side Resources

4.1 Fuel Procurement Strategy

4.1.1 Coal Procurement and Inventory Management Practices

4.1.1.1 Coal Supply Strategy

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

4.1.1.2 Coal Procurement

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

4.1.1.3 Coal Pricing Outlook

Coal competes for a share of the energy market against other fuels (natural gas, nuclear, and oil), renewable energy sources (biomass, hydro, wind, and solar) and energy efficiency programs. Specifically, energy market supply and demand generally set the market price of these competing sources. Also, coal prices are influenced by the supply and demand balance of coal in domestic, international, and metallurgical coal markets, coal production costs, transport costs, and environmental compliance considerations. Recent energy market dynamics have been heavily influenced by the increased exploration and production of North American shale oil and gas resources and have fundamentally altered the price spread between coal and natural gas. Lower cost and highly efficient natural gas extraction processes (horizontal drilling and fracking) have caused an oversupply resulting in a reduction in natural gas prices. An increase in wet gas production to gather petroleum liquids over the past few years have further increased natural gas supply. These dynamics are expected to keep natural gas pricing low in the near term. Longer term natural gas prices are expected to recover somewhat with the addition of new combined cycle natural gas generation and increased liquefied natural gas export capacity. This should allow coal pricing to move off of current levels in the long run.

Natural gas is currently displacing a significant amount of coal fired electric generation, driving lower coal prices. Decreased coal demand and higher mining costs driven by stringent government regulations have adversely impacted coal producers' margins and profits causing a number of producer bankruptcies. The restructuring of coal companies' debts and other costs should allow them to produce coal in this low energy price environment for a period of time. Supply will likely be rationalized and any significant increase in demand could result in coal price volatility. However, the cost to produce electricity from coal has increased significantly due to stringent environmental regulations placed on coal fired electric generation. This dynamic may limit coal demand upside and pricing.

In general, rising coal production costs and low coal prices have resulted in declining Appalachia coal production – a dynamic that has increased market share of the lower cost Illinois Basin ("ILB") region, which includes locations in Indiana and generally produces a higher sulfur coal than coal mined in other regions. Several new mines have opened up in the ILB, particularly in Illinois. With its higher sulfur content, ILB coal is viewed as being a potential export resource, but also available for domestic use in generating stations that have installed flue gas desulfurization systems which nearly eliminate sulfur dioxide emissions. Southeast utilities are targeting ILB coal on a long-term basis as replacement for Columbian and Central Appalachia coal.

Powder River Basin ("PRB") coal from Wyoming and Montana has a lower heat content per pound of coal than coal mined in other regions. Domestic utilities that have not traditionally burned PRB coal are now blending or are evaluating blending PRB coal with Central Appalachian, ILB, or Northern Appalachian ("NAPP") coals to reduce their overall fuel costs. Prior to a softening in Asian economies (China in particular), Asian demand for PRB coal grew as Japan and China were building new, high efficiency coal units, and new coal plants are being built in Korea and Taiwan as well as they prepare to meet their future electricity demand. Historically, Central Appalachian and NAPP coal have been exported into metallurgical coal and some steam coal markets abroad; however, the lack coal demand and the strong dollar have also nearly eliminated this market option for domestic coal producers.

Lastly, low energy prices and current and future environmental regulations will continue to put pressure on coal supply and coal demand. Notwithstanding, NIPSCO will continue to monitor market dynamics and coal prices in subsequent planning activities.

4.1.1.4 NIPSCO Coal Pricing Outlook

NIPSCO currently procures coal from three geographic regions in the United States: the PRB, the ILB, and the NAPP region. Market demand for all coal, including ILB coal has decreased for reasons stated above; therefore, prices have steadily fallen. NAPP coal used by NIPSCO as a blend fuel in two of its cyclone units was historically heavily exported; however, the international demand for metallurgical and steam coal has been drastically reduced. Although NAPP coal has had a robust market overseas, lethargic international demand and the stronger US dollar have caused export prices to collapse. NAPP producers have brought that supply back to the domestic market which helped drive prices lower. Pricing for PRB coal has also fallen and is close to the marginal cost of production. All coal pricing is expected to remain soft as long as energy prices stay low and the overhang of natural gas over supply will likely keep energy prices low, which will keep coal prices low for the balance of 2016 into 2017.

4.1.1.5 Coal and Issues of Environmental Compliance

Depending on the manner and extent of current and future environmental regulations, NIPSCO's coal purchasing strategy will continue to be to meet these environmental requirements.

4.1.1.6 Maintenance of Coal Inventory Levels

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

4.1.1.7 Forecast of Coal Delivery and Transportation Pricing

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

Coal deliveries, excluding exceptional weather conditions, have become more fluid in all geographic regions, particularly shipments originating in the PRB region due to infrastructure improvements. Railroads will need to continue making major investments in infrastructure and capital equipment to ensure timely deliveries and ease railroad congestion. The cyclical nature of the railroads' customers' businesses can create short term transportation constraints which have had a significant impact on NIPSCO's coal deliveries. These cycles have been shorter in duration and more volatile over the past several years.

Transportation rates continue trending upward given the leverage that the large Class I railroads have (limited competition). The railroads have shifted additional cost risk onto customers by passing on their fuel costs through fuel surcharges. However, the current environment has put downward pressure on the rail rates and also low oil prices have reduced the fuel surcharge revenues.

4.1.1.8 NIPSCO Transportation Pricing Outlook

NIPSCO has limited rail options at the origin and destination for most of its coal transportation moves, and is further disadvantaged due to its geographical location. Not only are rail transportation options limited, other transport modes (trucking, barging and lake vessels) are not economically and logistically feasible alternatives. NIPSCO's largest generating station, Schahfer, is served by only one railroad. All coal deliveries by this railroad to Schahfer are transported under escalated transportation rates and onerous fuel surcharges. Increased rail competition, particularly at Schahfer, would likely mitigate these costs. A north/south Indiana railroad providing direct access to Schahfer, and potential access to other industry in northern Indiana, and the Port of Indiana, would allow Schahfer direct access to burn Indiana coal, and also be a possible economic stimulus for the northern region. Currently, the interchange for Indiana coal transported to Schahfer is near Chicago, adding miles to the transport route, increasing the delivered cost of Indiana coal to the station. NIPSCO continues to look for alternatives for Schahfer and evaluate the feasibility of these alternatives.

PRB and ILB coal transportation rates have remained relatively stable and are expected to remain so in the near term. Fuel surcharges continue to fluctuate with the changing West Texas Intermediate Crude pricing.

4.1.1.9 Coal Contractual Flexibility, Deliverability and Procurement

Contract terms for coal and coal transportation agreements are typically one to five years in duration. Spot purchases are made on an as-needed basis to manage inventory fluctuations. In an effort to minimize variations in inventory levels and accommodate unit maintenance outages, most coal types under contract can be used in more than one unit. The fuel blending strategy can also be adjusted to conserve a particular type of coal if supply problems are experienced. Both coal and rail transportation contracts have force majeure clauses that cover events beyond the reasonable control of the party affected that prevent the mining, processing, or loading of coal at the mines, receiving, transporting, or delivering of coal by the rail carriers, or accepting, unloading, or burning of coal at the generating stations.

4.1.2 Bio-Fuels

NIPSCO is exploring the possibility of utilizing bio-fuels in a co-firing process with coal as one possibility to reduce CO_2 emission to comply with the Clean Power Plan. However, the EPA stance on the benefit and use of bio-fuels as one of the tools used to mitigate CO_2 under the CPP is still unclear. In addition, further uncertainty around CO_2 reduction rules has been created with the recent Supreme Court stay of the CPP. NIPSCO is continuing to evaluate potential CO_2 reduction strategies through the use of various renewable energy sources including bio-fuels.

The most economic use of bio-fuels would be to co-fire agricultural waste (corn stover) with coal at NIPSCO's existing generating stations. The required capital and operation and maintenance costs would likely be minimal at a 10% to 20% co-firing rate. Corn stover and other agricultural waste products would likely need to be processed and pelletized to be utilized economically in NIPSCO's existing generating facilities. A study performed by Sargent and

Lundy for NIPSCO estimated that there would likely be the equivalent of 20-40 MW of crop residues in northern Indiana.[1]

Given the relatively low cost of using bio-fuels when compared to other renewable sources and ease of deployment, NIPSCO is currently working with a potential supplier of pelletized crop residues to evaluate the potential CO_2 reductions and how these could be used to help achieve CO_2 reductions if the CPP is adopted or a similar CO_2 reduction rule issued by the EPA in the future.

4.1.3 Natural Gas Procurement and Management

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

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

4.2 Electric Generation Gas Supply RFP Process

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

[1] The Sargent and Lundy study estimated the total MW for crop residues used in a stoker application. The amount of energy is assumed to be similar for NIPSCOs cyclone and pulverized boilers after crop residues are pelletized.

4.3 Existing Resources

NIPSCO has a variety of generation resources to meet its customers' forecast capacity and energy needs. Not only do these resources need to meet the principles set out in Section 1.1, they must operate within MISO, the Regional Transmission Organization, and subject to North American Electric Reliability Corporation standards. NIPSCO has registered with NERC as a Distribution Provider, Generator Owner, Generator Operator, Load Serving Entity, Purchasing-Selling Entity, Resource Planner and Transmission Planner. NIPSCO is registered as a Balancing Authority, Transmission Operator and Transmission Owner in MISO. Each Registered Entity is subject to compliance with applicable NERC and Regional Reliability Organization, ReliabilityFirst*,* standards approved by the Federal Energy Regulatory Commission.

4.4 Generation Portfolio

The NIPSCO generating facilities have a total installed capacity of 3,305 MW and consisting of six separate generation sites, including the R.M. Schahfer Generating Station (Units 14, 15, 16A, 16B, 17 and 18), Michigan City Generating Station (Unit 12), Bailly Generating Station (Units 7, 8 and 10), Sugar Creek Generating Station and two hydroelectric generating sites near Monticello, Indiana (Norway Hydro and Oakdale Hydro). Of the total capacity, 77.9% is from coal-fired units, 21.8% is from natural gas-fired units and 0.3% is from hydroelectric units. NIPSCO also has two purchase power agreements for wind generation (Buffalo Ridge and Barton).

provides a summary of the generating facilities operated by NIPSCO.

Table 4-1: Net Demonstrated Capacity (NDC)

Resources	Fuel	ICAP (MW)
Michigan City 12	Coal	469
Bailly 7	Coal	160
Bailly 8	Coal	320
Bailly 10	Natural Gas CT	31
Schahfer 14	Coal	431
Schahfer 15	Coal	472
Schahfer 17	Coal	361
Schahfer 18	Coal	361
Schahfer 16A	Natural Gas CT	78
Schahfer 16B	Natural Gas CT	77
Norway	Hydro	4
Oakdale	Hydro	6
Sugar Creek	Natural Gas CCGT	535
Total		**3,305**

4.4.1 Bailly Generating Station

Bailly is located on a 100-acre site on the shore of Lake Michigan in Porter County, Indiana. There are two base-load units and one peaking unit that came on-line over a six-year period ending in 1968. The units are equipped with various environmental control technologies, including FGD to reduce SO_2, SCR and Over-Fire Air (OFA) systems to reduce NO_x emissions. The individual characteristics of the Bailly units are provided in Table 4-2.

Table 4-2: Bailly Generating Station

	Unit 7	Unit 8	Unit 10
NET Output			
Min (MW)	100	190	----
Max (MW)	160	320	31
Boiler	Babcock & Wilcox	Babcock & Wilcox	----
Burners	4 Cyclone	8 Cyclone	----
Main Fuel	Coal	Coal	Gas
Turbine	General Electric	General Electric	Westinghouse
Frame	D6	G2	W301G
In-Service	1962	1968	1968
Environmental Controls	FGD, SCR, OFA	FGD, SCR, OFA	----

4.4.2 Michigan City Generating Station

Michigan City is located on a 134-acre site on the shore of Lake Michigan in Michigan City, Indiana. It has one base-load unit, Unit 12 and is equipped with SCR and OFA systems to reduce NO_x emissions. A new FGD system was placed in service in 2015. The individual unit characteristics of Michigan City are provided in Table 4-3.

Table 4-3: Michigan City Generating Station

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

4.4.3 R.M. Schahfer Generating Station

Schahfer is located on approximately a 3,150-acre site two miles south of the Kankakee River in Jasper County, near Wheatfield, Indiana. It is the largest of NIPSCO's generating stations. There are four coal-fired base-load units and two gas-fired simple cycle peaking units that came on-line over an 11-year period ending in 1986. The Schahfer units are equipped with significant environmental control technologies, including FGD to reduce SO_2 emissions and SCR, Low NO_x Burners (LNB), and OFA systems to reduce NO_x emissions. Unit 14 burns low and medium sulfur coal blends and Unit 15 burns low-sulfur coals to minimize SO_2 emissions. As part of the Company's Clean Air Interstate Rule (CAIR) Compliance Phase I Strategy, FGD system upgrades to improve SO_2 removal efficiency were completed for Units 17 and 18 in 2010 and 2009, respectively. Installation of a new LNB with OFA system was completed on Unit 15 in 2009. A new FGD plant on Unit 14 was placed in service in 2013. FGD installation on Unit 15 was completed in 2014. The individual unit characteristics of Schahfer are provided in Table 4-4.

Table 4-4: R.M. Schahfer Generating Station

	Unit 14	Unit 15	Unit 17	Unit 18	Unit 16A	Unit 16B
NET Output						
Min (MW)	290	250	125	125	----	----
Max (MW)	431	472	361	361	78	77
Boiler	Babcock & Wilcox	Foster Wheeler	Combustion Engineering	Combustion Engineering	----	----
Burners	10 Cyclone	6 Pulverizers	6 Pulverizers	6 Pulverizers	----	----
Main Fuel	Coal	Coal	Coal	Coal	Gas	Gas
Turbine	Westinghouse	General Electric	Westinghouse	Westinghouse	Westinghouse	Westinghouse
Frame	BB44R	G2	BB243	BB243	D501	D501
In-Service	1976	1979	1983	1986	1979	1979
Environmental Controls	FGD, SCR, OFA	FGD, LNB, OFA	FGD, LNB, OFA	FGD, LNB, OFA	----	----

4.4.4 Sugar Creek Generating Station

Sugar Creek is located on a 281-acre rural site near the west bank of the Wabash River in Vigo County, Indiana. The gas-fired combustion turbines (CTs) and combined cycle gas turbine (CCGT) were available for commercial operation in 2002 and 2003, respectively. Sugar Creek was purchased by NIPSCO in July 2008, and is its newest electric generating facility. Sugar Creek has been registered as a MISO resource since December 1, 2008. Two generators and one steam turbine generator are operated in the CCGT mode and environmental control technologies include SCR to reduce NO_x, and dry low NO_x (DLN) combustion systems. The individual unit characteristics of Sugar Creek are provided in Table 4-5.

Table 4-5: Sugar Creek Generating Station

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

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

Norway Hydro is located near Monticello, Indiana on the Tippecanoe River. The dam creates Lake Shafer, a body of water approximately 10 miles long with a maximum depth of 30 feet, which functions as its reservoir. Norway Hydro has four generating units capable of producing up to 7.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 4 MW. The individual unit characteristics of the Norway Hydro are provided in Table 4-6.

Table 4-6: Norway Hydro

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

Oakdale Hydro is located near Monticello, Indiana along the Tippecanoe River. The dam creates Lake Freeman, a body of water approximately 12 miles long with a maximum depth of 45 feet, which functions as its reservoir. Oakdale Hydro has three generating units capable of producing up to 9.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 6 MW. The individual unit characteristics of the Oakdale Hydro are provided in Table 4-7.

Table 4-7: Oakdale Hydro

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

4.4.6 Barton and Buffalo Ridge Wind (NIPSCO PPAs)

NIPSCO is currently engaged in a 20-year PPA with Iberdrola, in which NIPSCO will purchase generation from Barton. Barton, located in Worth County, Iowa, went into commercial operation on April 10, 2009. The individual unit characteristics of Barton are provided in Table 4-8.

Table 4-8: Barton Wind PPA

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

NIPSCO is also engaged in a 15-year PPA with Iberdrola, in which NIPSCO will purchase generation from Buffalo Ridge. Buffalo Ridge, located in Brookings County, South Dakota, went into commercial operation on April 15, 2009. The individual unit characteristics of Buffalo Ridge are provided in Table 4-9.

Table 4-9: Buffalo Ridge Wind PPA

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

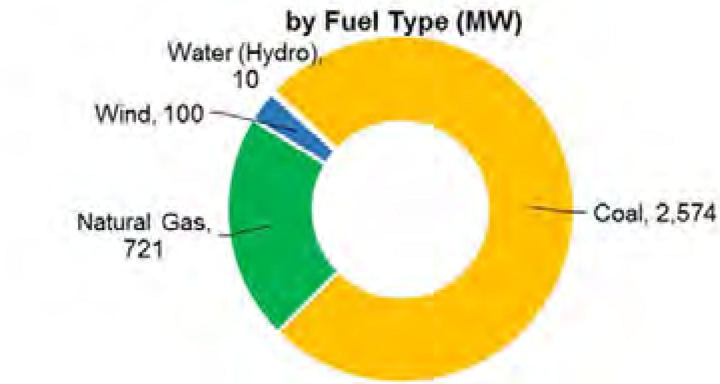
4.5 Total Resource Summary

Table 4-10 illustrates various characteristics of NIPSCO's owned and contracted generating units. Figure 4-1 illustrates NIPSCO's existing resources by fuel type.

Table 4-10: Existing Generating Units

Unit	NDC (MW)	Type	Typical Fuel	In-Service Date
Michigan City 12	469	Steam	Coal	May 31, 1974
Bailly 7	160	Steam	Coal	November 30, 1962
Bailly 8	320	Steam	Coal	July 31, 1968
Bailly 10	31	Combustion Turbine	Natural Gas	November 30, 1968
Schahfer 14	431	Steam	Coal	December 31, 1976
Schahfer 15	472	Steam	Coal	October 31, 1979
Schahfer 16A	78	Combustion Turbine	Natural Gas	December 31, 1979
Schahfer 16B	77	Combustion Turbine	Natural Gas	December 31, 1979
Schahfer 17	361	Steam	Coal	April 28, 1983
Schahfer 18	361	Steam	Coal	February 14, 1986
Norway	4	Hydro	Water	June 8, 1923
Oakdale	6	Hydro	Water	November 11, 1925
Sugar Creek CT 1A	156	Combustion Turbine	Natural Gas	June 15, 2002
Sugar Creek CT 1B	157	Combustion Turbine	Natural Gas	June 15, 2002
Sugar Creek SCST	222	Steam	Natural Gas	June 15, 2003
Barton(PPA)	50	Wind	Wind	April 10, 2009
Buffalo Ridge(PPA)	50	Wind	Wind	April 15, 2009
Total System	**3,405**			

Figure 4-1: Existing Resources Net Demonstrated Capacity

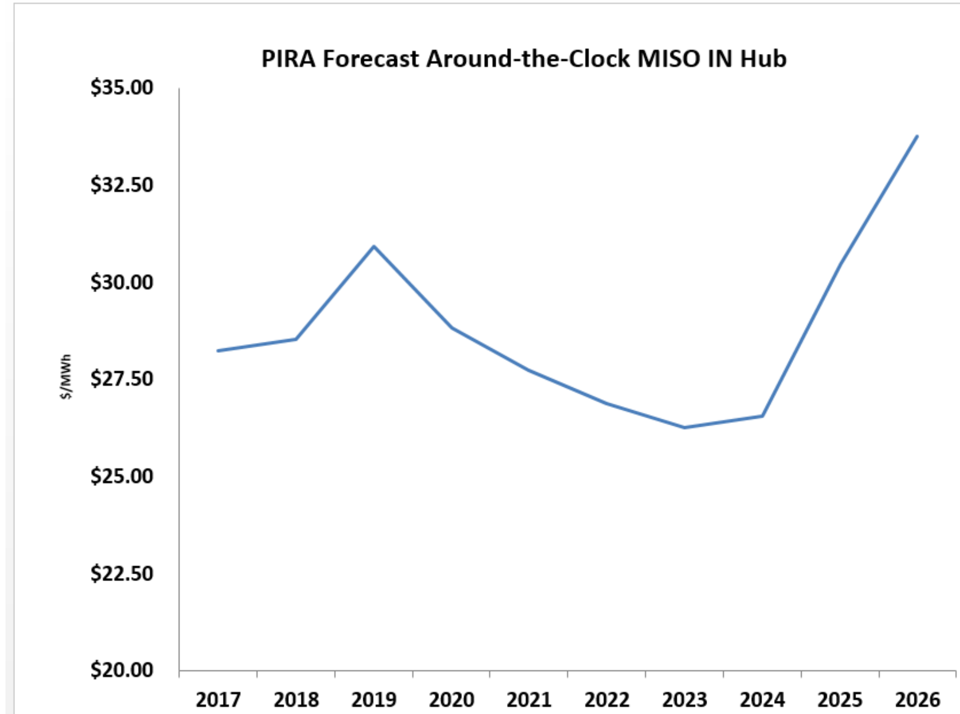


4.6 Operations Management and Dispatch Implications

As previously noted, NIPSCO entered into a Consent Decree with the EPA requiring NIPSCO to reduce emissions over a defined period of years through primarily capital improvements on existing generation resources. An EPA mandated MACT rule required NIPSCO to design and obtain approval to meet new air emission standards. In order to meet the terms of the Consent Decree and the MACT requirements, NIPSCO utilizes predictive tools to forecast effluent emission levels based on unit operations, as well as determine levels of output for the individual generators that can help reduce the overall emissions. Based on output from the predictive tools and current operations statistics, NIPSCO also has the ability to modify unit operations and unit offers for dispatch into MISO as needed in order to remain environmentally compliant.

Additionally, the future dispatch of NIPSCO's electric generation fleet will be a function of the cost to market price (or LMP). As shown in Figure 4-3, the latest 24-hour, Indiana hub, PIRA forecast would indicate that marginal coal units should increase in dispatch over the next 2-3 years as prices continue to increase. While unit dispatch should increase given the price forecast, as is today, many factors will contribute to the dispatch of local units within NIPSCO's service territory. The delivered cost of coal and natural gas, transmission congestion, environmental considerations and the overall generation mix within MISO may affect the level of future dispatch.

Figure 4-2: Around-the-Clock MISO IN Hub



4.7 MISO Wholesale Electricity Market

MISO supplies an important element to NIPSCO's long term plans – ongoing liquidity. MISO provides an enduring, relatively efficient market for marginal purchases and sales of electricity. In 2016, MISO has members from 15 states and 1 Canadian province with a generation capacity of 175,600 MW and 65,800 miles of transmission.

4.8 Resource Adequacy

Consistent with the principles set out in Section 1.1, NIPSCO is committed to meet the energy needs of its customers with reliable, compliant, flexible, diverse and affordable supply. NIPSCO's assessment of its existing resources against the future needs of its customers is shown in Table 4-11.

Table 4-11: Assessment of Existing Resources v. Demand Forecast (Base)

	(a)	(b)	(c)	(d)	(e)	(f)
Year	Existing Resources Unforced Capacity - UCAP (MW)	Internal Peak From Demand Forecast (MW)	Demand Response (MW)	Internal Peak Minus Demand Response (MW)	Internal Peak Minus Demand Response Plus Reserve Margin (MW)	Capacity Position Long/(Short) (MW)
				(b)-(c)	(d) + (d) x Reserve Margin	(a)-(e)
2016	3,065	2,788	528	2,591	2,788	277
2017	3,020	2,816	528	2,617	2,816	204
2018	2,649	2,833	528	2,633	2,833	(184)
2019	2,649	2,849	528	2,648	2,849	(200)
2020	2,649	2,867	528	2,664	2,867	(218)
2021	2,649	2,883	528	2,680	2,883	(234)
2022	2,649	2,901	528	2,696	2,901	(252)
2023	1,934	2,919	528	2,713	2,919	(985)
2024	1,932	2,937	528	2,730	2,937	(1,005)
2025	1,932	2,956	528	2,747	2,956	(1,024)
2026	1,932	2,971	528	2,761	2,971	(1,039)
2027	1,932	2,987	528	2,776	2,987	(1,055)
2028	1,932	3,003	528	2,791	3,003	(1,071)
2029	1,928	3,018	528	2,805	3,018	(1,090)
2030	1,928	3,032	528	2,818	3,032	(1,104)
2031	1,928	3,043	528	2,828	3,043	(1,115)
2032	1,928	3,056	528	2,840	3,056	(1,128)
2033	1,924	3,068	528	2,851	3,068	(1,144)
2034	1,921	3,080	528	2,862	3,080	(1,159)
2035	1,482	3,091	528	2,873	3,091	(1,609)
2036	1,482	3,104	528	2,884	3,104	(1,622)
2037	1,482	3,116	528	2,896	3,116	(1,634)

NOTES:

1. UCAP is a NIPSCO estimated value

2. UCAP reflects units retiring after the peak season in the years - ***2017, 2022, and 2034***

3. Reserve Margin for 2016-2037 is ***7.6%.***

4. Existing Resources UCAP includes Feed-In Tariffs

NIPSCO's existing resources Net Demonstrated Cap and Unforced Capacity are shown in Table 4-12.

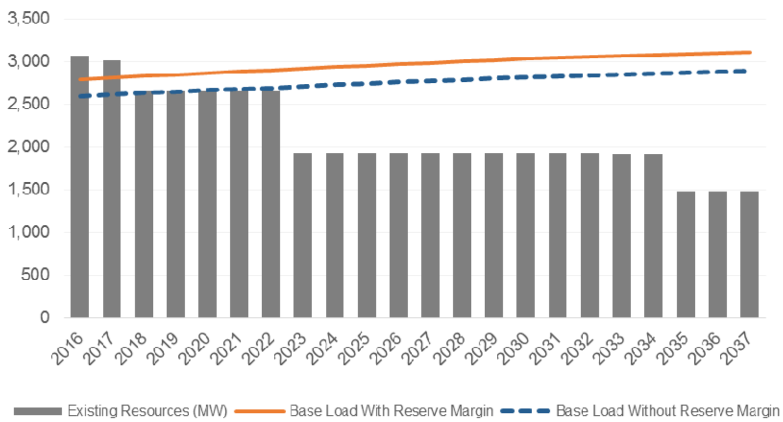
Table 4-12: NIPSCO's Existing Resources NDC and 2016 UCAP

Existing Unit	NDC (MW)	Unforced Capacity (MW)
Bailly 7	160	151
Bailly 8	320	276
Bailly 10	31	21
Michigan City 12	469	427
Schahfer 14	431	375
Schahfer 15	472	435
Schahfer 16A	78	71
Schahfer 16B	77	58
Schahfer 17	361	351
Schahfer 18	361	351
Sugar Creek	535	525
Norway Hydro	4	2
Oakdale Hydro	6	3
Barton Wind PPA	50	4
Buffalo Ridge Wind PPA	50	2
Total	**3,405**	**3,049**

When calculating the total UCAP of existing resources, a unit retirement is subtracted in the year the unit is no longer available. The proposed retirement for the existing units during the study period is shown in Section 8.4.2.2: Preferred Retirement Option.

Another way to view the assessment is by looking at Figure 4-3: Resource Adequacy Assessment (MW), showing column (a) NIPSCO's existing resources in UCAP and column (e) NIPSCO's future customers' needs with and without the MISO reserve margin.

Figure 4-3: Resource Adequacy Assessment (MW)



In order to bridge any capacity and energy gaps, NIPSCO has evaluated future resources that can meet that gap.

4.9 Future Resource Options

Future resource options may be used to meet the future electricity requirements of NIPSCO's customers. NIPSCO commissioned an engineering study from Sargent & Lundy to provide information and analysis on future supply-side resource options for NIPSCO. *See* Confidential Appendix I for the Sargent & Lundy Engineering Study Technical Assessment. A discussion of future demand-side resource options is included in Section 5: Demand-Side Resources.

4.9.1 Future Supply-Side Resource Options Screening Criteria

Sargent & Lundy conducted a preliminary screening for new utility scale self-build central and distributed generation supply-side resource options. The resource options that passed a set of criteria established for screening were input into the Strategist® model and were part of the resource optimization. The criteria established for preliminary evaluation is defined below in Table 4-13.

Table 4-13: Supply-Side Screening Criteria

Criteria	Description
Energy Source Availability	The extent to which a viable source of energy (or fuel) is readily available in or near the NIPSCO territory for the specific technology.
Technical Feasibility	The extent to which the specific technology is technically viable from an engineering, design, and construction standpoint
Commercial Availability	The extent to which the specific technology is commercially available in the marketplace, taking into account the maturity of the technology and its supply chain.
Economically Attractive	The extent to which the specific technology is competitively priced at wholesale or resale prices relative to other technologies, renewable or non-renewable, with the current incentives in place taken into account
Environmental Compatibility	The ability of the developer to obtain permits and permissions to operate from local, state, or federal regulators, including an assessment of water usage and availability, protection and conservation of biodiversity, and other miscellaneous environmental and social impacts, as appropriate.

Sargent & Lundy evaluated each technology against the criteria and rated them. If the technology was deemed viable, cost and performance analyses were performed. If the technology rating was poor and was deemed impractical, no further analyses were conducted.

4.9.2 Future Natural Gas Resource Options

The following supply-side natural gas resource options were reviewed for the 2016 IRP:

- Combustion Turbines:
    - a simple cycle aeroderivative combustion turbine: small simple-cycle plant representing a GE LM6000 PD SPRINT (LM6000) of 50 MW capacity
    - a simple cycle frame combustion turbine: large simple cycle plant representing Siemens SGT6-5000F combustion turbine of 240 MW capacity
- Combined Cycle: a single plant configuration of 2 x 1 (i.e. two CTs/HRSGs and one ST) representing the Siemens SGT6-5000F Frame turbine with air-cooled generator with a total of 700 MW capacity.

All natural gas assumptions including costs, schedules and performance assumptions were provided in the Sargent & Lundy Engineering Study Technical Assessment in Confidential Appendix I. The natural gas resource options are listed in Table 4-14.

Table 4-14: Natural Gas Resource Options

Natural Gas Options	Size (MW)	Fuel Type
Combustion Turbine (CT) - Greenfield	50	Natural Gas
Combustion Turbine (CT) - Brownfield	50	Natural Gas
Combustion Turbine (CT) - Greenfield	240	Natural Gas
Combustion Turbine (CT) - Brownfield	240	Natural Gas
Combined Cycle (CC) - Greenfield	700	Natural Gas
Combined Cycle (CC) - Brownfield	700	Natural Gas

4.9.3 Future Coal Resource Options

The following coal resource options were reviewed for the 2016 IRP:

- Pulverized Coal ("PC"): an ultra-supercritical pulverized coal facility with a single 750 MW (gross) steam-electric generating unit;
- Circulating Fluidized Bed ("CFB"): an advanced circulating fluidized bed coal facility with a single 400 MW (gross) steam-electric generating; and
- Integrated Gasification Combined Cycle ("IGCC"): two gasification and cleanup trains supplying syngas to fuel two GE 7F-SYNGAS combustion turbine generators to turn supply waste heat to two steam generators and create steam for one steam turbine generator.

All coal assumptions including costs, schedules and performance assumptions were provided in the Sargent & Lundy Engineering Study Technical Assessment in Confidential Appendix I. The coal resource options are listed in Table 4-15.

Table 4-15: Coal Resource Options

Coal Options	Size (MW)	Fuel Type
Pulverized Coal (PC)	600	Coal
Circulating Fluidized Bed (CFB)	325	Coal
Integrated Gasification Combined Cycle (IGCC)	500	Coal

4.9.4 Future Nuclear Resource Options

The following nuclear resource options were reviewed for the 2016 IRP:

- Advanced Pressured Water Reactor ("AP-1000"): large-scale conventional reactor consisting of a Westinghouse dual-unit AP1000 design with a plant capacity of 2,200 MW; and

- Small Modular Reactors ("SMR"): smaller version of the AP1000 with a 45 MW capacity.

The nuclear assumptions including costs, schedules and performance assumptions were provided in the Sargent & Lundy Engineering Study Technical Assessment in Confidential Appendix I. The nuclear resource options are listed in Table 4-16.

Table 4-16: Nuclear Resource Options

Nuclear Options	Size (MW)	Fuel Type
Advanced Pressured Water Reactor (AP-1000)	2,200	Nuclear
Small Modular Reactors (SMR)	45	Nuclear

4.9.5 Future Renewable and Distributed Generation Resource Options

A complete list of all supply-side utility and distributed generation resource options that were considered as part of the Sargent & Lundy Engineering Study Technical Assessment in Confidential Appendix I are shown in Table 4-17.

Table 4-17: Supply Side Utility and Distributed Generation Resource Options

Resource Option
Utility Scale
Battery Storage - Advanced Lead Acid
Battery Storage - Flow (Vanadium Redox)
Battery Storage - Flow (Zn-BR)
Battery Storage - Lithium-ion
Battery Storage - Sodium Sulphur
Battery Storage - Valve Regulated Lead Acid (VRLA)
Battery Storage (Emerging Technologies - advanced lithium-ion, lithium-air)
Biomass - BFB Boiler
Combined Heat & Power (Site specific)
Compressed Air Energy Storage (CAES)
Concentrated Solar Power (CSP)
Fuel Cells
Geothermal
Liquefied Air Energy Storage (LAES)
MicroGrids (Site specific)
Pumped Storage
Solar Photovoltaic
Wind - Onshore
Wind -Offshore
Distributed Generation
Battery Storage - Advanced Lead Acid
Battery Storage - Flow (Vanadium Redox)
Battery Storage - Flow (Zn-BR)
Battery Storage - Lithium-ion
Battery Storage - Sodium Sulphur
Battery Storage - Valve Regulated Lead Acid (VRLA)
Battery Storage (Emerging Technologies - advanced lithium-ion, lithium-air)
Distributed Solar Photovoltaic (PV)
Distributed Wind - Onshore
Fuel Cells
Liquefied Air Energy Storage (LAES)
Microturbine
Reciprocating Engine

Screening Criteria: Energy Source Available, Technically Feasible, Commercially Available, Economically Attractive, and Environmentally Compatible

The following renewable and distributed generation resource options passed the initial screening performed by Sargent & Lundy and were included as part of the IRP resource optimization:

- Battery Storage: mature technology using lithium-ion battery configuration totaling 1 MW
- Biomass: single steam-electric generating facility utilizing a bubbling fluidized bed ("BFB") boiler with a gross capacity of 50 MW
- Solar Photovoltaic: utility scale solar facility of 50 MW
- Wind – Onshore: utility scale wind project with 59 1.7 MW turbines totaling 100 MW
- Wind – Off-shore: utility scale wind project with 5 3.6 MW turbines totaling 18 MW
- Distributed Solar Photovoltaic: small-scale on-site modular design and generation of 10 kW
- Distributed Wind - Onshore: distributed generation wind turbine of 1.7 MW
- Microturbine: small gas turbine connected to high-speed generator with a capacity of 400 kW
- Reciprocating Engine: stand-alone machine using biogas or methane with a capacity of 1 MW

4.9.6 NIPSCO's Existing Unit Conversion Options

Converting a coal unit to gas or combustion turbines into a combined cycle were options that NIPSCO considered as part of the 2016 IRP. Coal and combustion turbines units from the Bailly and Schahfer generating stations were considered for conversions. All conversion assumptions including costs and performance were provided in the Sargent & Lundy Engineering Study Technical Assessment in Confidential Appendix I. Table 4-18 lists the conversion options considered but not explicitly modeled due to the uncertainty around the construction lead time after the unit is brought down for the retrofit process. Also upon further analysis following the completion of the engineering study, NIPSCO determined that additional information was needed to effectively model these options. However, as more data becomes available, NIPSCO will evaluate these options in subsequent IRPs.

Table 4-18: NIPSCO's Existing Units Conversion Options

Conversion Unit (s)	Type of Conversion	Size (MW)
Bailly 7	Coal plant-to-combined-cycle gas plant	633
Schahfer Unit 14	Unit coal-to-gas	411
Schahfer Unit 15	Unit coal-to-gas	461
Schahfer Unit 17	Unit coal-to-gas	359
Schahfer Unit 18	Unit coal-to-gas	359
Schahfer Station14, 15, 17 and 18	Station coal-to-gas	1,590
Schahfer Units 16A & 16B	Combustion turbines-to-combined cycle plant	306

4.9.7 Summary of Future Resource Options Included in Resource Optimization

The listing of new supply-side and unit conversions that were included in the resource optimization, along with future demand-side resource options and demand response options, in order to meet customer demand requirements for the next 20 years are shown in Table 4-19. Future demand-side resources included in the resource optimization are described in Section 5: Demand-Side Resources.

Table 4-19: Supply-Side Resources Included in Resource Optimization

Supply-Side Resources	Size (MW)
Conventional Technologies	
Combustion Turbine - Small	50
Combustion Turbine - Large	240
Combined Cycle Combustion Turbine (CCGT)	700
Pulverized Coal (PC)	600
Circulating Fluidized Bed (CFB)	325
Integrated Gasification Combined Cycle (IGCC)	500
Advanced Pressured Water Reactor (AP-1000)	2,200
Small Modular Reactors (SMR)	45
Utility Scale	
Battery Storage - Lithium-ion	1
Biomass - BFB Boiler	50
Solar Photovoltaic	50
Wind - Onshore	100
Wind -Offshore	18
Distributed Generation	
Distributed Solar Photovoltaic (PV)	0.01
Distributed Wind - Onshore	1.7
Microturbine	0.4
Reciprocating Engine	1
Conversions	
Bailly 7	633
Schahfer Unit 14	411
Schahfer Unit 15	461
Schahfer Unit 17	359
Schahfer Unit 18	359
Schahfer Station 14, 15, 17 and 18	1,590
Schahfer Units 16A and 16B	306

Section 5. Demand-Side Resources

5.1 Existing Resources

5.1.1 Existing Energy Efficiency Resources

NIPSCO actively promotes and implements energy conservation and efficiency to both its employees and customers and works with its third party vendors to offer cost-effective Energy Efficiency programs for its customers. To support the continuance of its program offerings for the period 2016 through 2018, NIPSCO worked with its Oversight Board ("OSB") to develop two requests for proposals – one for residential programs and one for commercial and industrial ("C&I") programs. Upon review of the bids and materials presented by the invited bidders, NIPSCO recommended and its OSB approved, the selection of GoodCents as the vendor to implement the residential programs and Lockheed Martin as the vendor to implement the C&I programs. NIPSCO continues to work with both its OSB and its implementers to address program performance throughout the calendar year. In addition to these two vendors, the OSB issued an RFP for an evaluation, measurement and verification ("EM&V") vendor and selected a vendor to provide an evaluation of both the residential and C&I vendors for all three program years. A brief description of NIPSCO's current energy efficiency programs effective for the period January 1, 2016 through December 31, 2018 are as follows:

2016-2018 Residential Programs

HVAC Program

The Heating, Ventilation and Air Conditioning ("HVAC") Program is marketed as the Energy Efficiency Rebate Program offering incentives to NIPSCO customers wanting to install qualified energy efficient upgrades. The program offers a variety of rebates for both gas and electric equipment to incentivize participation in order to achieve the most savings. The primary marketing driver for this program is the construction of a strong and active network of trade allies who are capable of directly promoting the program to NIPSCO customers.

Residential Lighting Program

The Residential Lighting Program is marketed as the Lighting Discounts Program encouraging residential customers to purchase high-efficiency ENERGY STAR® qualified lighting. The program uses wholesale incentives to buy or mark down the incremental cost of energy efficient products through manufacturer and retailer partnerships. GoodCents is utilizing the services of Ecova to assist in the implementation of this program.

Home Energy Analysis Program

The Home Energy Analysis Program is marketed as the Home Energy Assessment Program producing long-term, cost-effective savings in the residential market sector. The program helps customers analyze and understand their energy usage, recommends appropriate weatherization measures, and facilitates the direct installation of specific low-cost energy-saving measures. GoodCents performs this work through the use of its own field technicians.

Appliance Recycling Program

The Appliance Recycling Program provides a $50 incentive to residential customers who recycle a working refrigerator and/or freezer. GoodCents utilizes the services of Appliance Recycling Centers of America ("ARCA") to assist in the implementation of this program.

Low Income Appliance Replacement Program

The Low Income Appliance Replacement Program is marketed as the Income Qualified Refrigerator Replacement Program providing income qualified residential customers using older, inefficient refrigerators with a new ENERGY STAR refrigerator at no cost to the customer. GoodCents utilizes the services of ARCA to provide support for this program.

School Education Program

The School Education Program is marketed as the Energy Efficiency Education Program producing cost-effective savings by influencing students and their families to focus on conservation and the efficient use of electricity and natural gas. This program is available to fifth grade students attending schools within NIPSCO's combination gas and electric service territory. GoodCents utilizes the services of AM Conservation Group and the National Energy Foundation to assist in the implementation of this program.

Behavioral Program

The Behavioral Program is marketed as the My Energy Scorecard Program utilizing both Opower and Accelerated Innovations to provide print and electronic reports to customers. The program seeks to assist customers in modifying their energy usage behaviors through print reports and online offerings.

Income Qualified Weatherization Program

The Income Qualified Weatherization ("IQW") Program produces long-term, cost-effective electric and natural gas savings, helping low-income families decrease home energy costs. The program helps qualified customers analyze and understand their energy usage, recommends appropriate weatherization measures, and facilitates the direct installation of specific energy-saving measures. GoodCents collaborates with Holistic Community Coalition to recruit participants and Urban Efficiency for the completion of the in-home assessments.

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

Table 5-1: 2016-2018 Projected Residential Energy Savings (MWh)

Residential Programs	2016	2017	2018	Total
HVAC	2,435	2,529	2,778	7,741
Residential Lighting	12,232	11,140	10,523	33,895
Home Energy Analysis	4,039	4,039	4,039	12,116
Appliance Recycling	3,592	3,592	3,592	10,776
Low Income Appliance Replacement	781	781	781	2,342
School Education	3,529	3,529	3,529	10,588
Behavioral	12,636	19,656	26,676	58,968
Income Qualified Weatherization	189	189	189	567
Total Residential Programs	**39,433**	**45,455**	**52,106**	**136,994**

Table 5-2 shows the program budget dollars by year for each of the Residential programs. Program budget includes start-up costs, incentive costs and performance costs. Start-up costs are incurred in Year 1 (2016) only. Not all Residential programs incur incentive costs.

Table 5-2: Residential Program Budget

Residential Programs	2016	2017	2018	Total
HVAC	$920,905	$935,369	$1,022,204	$2,878,478
Residential Lighting	$924,281	$887,200	$955,260	$2,766,741
Home Energy Analysis	$1,198,974	$1,205,266	$1,233,912	$3,638,152
Appliance Recycling	$992,659	$958,273	$961,751	$2,912,684
Low Income Appliance Replacement	$ 552,315	$549,591	$576,643	$1,678,548
School Education	$423,644	$411,404	$412,284	$1,247,332
Behavioral	$598,650	$634,655	$734,387	$1,967,692
Income Qualified Weatherization	$249,870	$249,870	$249,870	$749,610
Total Residential Programs	**$5,861,298**	**$5,831,628**	**$6,146,311**	**$17,839,236**

2016 C&I Programs

Prescriptive Program

The Prescriptive Program offers a menu of incentives to commercial and industrial customers for installing energy efficient measures by reimbursing a portion of the cost of those pre-selected measures. The incentives help remove customer concerns relating to the initial cost associated with implementing larger energy efficiency upgrades.

Custom Program

The Custom Program is designed for more complicated, non-prescriptive efficiency measure projects, or those that incorporate alternative technologies where incentives are based on calculated energy savings. Each project is specifically designed by the customer and thoroughly reviewed by Lockheed Martin. This program provides customers with additional ways to save energy outside of the traditional rebates program.

New Construction Program

The New Construction Program encourages energy efficient new construction of commercial and industrial facilities within NIPSCO's service territory. The program offers financial incentives to encourage building owners, designers and architects to exceed standard building practices and achieve efficiency, above and beyond the current statewide building code requirements. This program produces newly constructed and expanded buildings that are among the most efficient in the nation.

Small Business Direct Install Program

The Small Business Direct Install ("SBDI") Program delivers, through a network of pre-approved trade allies, no-cost/low-cost energy efficiency measures to save energy and reduce peak demand for small and medium commercial customers throughout NIPSCO's service territory. In addition, information about these installed measures is provided to these customers explaining the energy efficiency benefits and proper operation and maintenance practices to ensure the measure's sustained performance.

Retro-Commissioning Program

The Retro-Commissioning ("RCx") Program helps NIPSCO commercial and industrial customers determine the energy performance of their facilities and identifies energy savings opportunities by optimizing their existing systems. RCx projects holistically examine energy consuming systems for cost-effective savings opportunities. The process identifies operational inefficiencies that can be removed or reduced to yield energy savings. To maintain program cost-effectiveness and maximize savings opportunities, the RCx Program focuses on office buildings, large hotels, hospitals, large retail stores, industrial plants and refrigerated warehouses.

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

Table 5-3: 2016-2018 Projected C&I Energy Savings (MWh)

C&I Programs	2016	2017	2018	Total
Prescriptive	20,672	20,582	21,911	63,164
Custom	34,453	34,303	36,518	105,273
New Construction	4,823	4,802	5,112	14,738
Small Business Direct Install	4,134	4,116	4,382	12,633
Retro-Commissioning	4,823	4,802	5,112	14,738
Total C&I Programs	**68,905**	**68,605**	**73,035**	**210,545**

Table 5-4 shows the program budget dollars by year for each of the C&I programs. Program budget includes start-up costs, fixed costs, incentive costs and performance costs. Start-up costs are incurred in Year 1 (2016) only.

Table 5-4: C&I Program Budget

C&I Programs	2016	2017	2018	Total
Prescriptive	$2,422,549	$2,347,418	$2,499,931	$7,269,898
Custom	$4,089,844	$3,964,399	$4,221,946	$12,276,190
New Construction	$319,352	$302,892	$322,669	$944,914
Small Business Direct Install	$600,592	$585,060	$623,026	$1,808,678
Retro-Commissioning	$352,639	$336,035	$357,950	$1,046,623
Total C&I Programs	**$7,784,976**	**$7,535,804**	**$8,025,522**	**$23,346,302**

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

Table 5-5: 2016-2018 Projected Combined Energy Savings (MWh)

	2016	2017	2018	Total
Total Residential Programs	39,433	45,455	52,106	136,994
Total C&I Programs	68,905	68,605	73,035	210,545
Total 2016-2018 Electric DSM Program	**108,338**	**114,060**	**125,141**	**347,539**

Table 5-6 outlines the annual budget dollars for all Residential and C&I programs for all three years.

Table 5-6: Combined Program Budget

	2016	2017	2018	Total
Total Residential Programs	$5,861,298	$5,831,628	$6,146,311	$17,839,236
Total C&I Programs	$7,784,976	$7,535,804	$8,025,522	$23,346,302
Total 2016-2018 Electric DSM Program	**$13,646,274**	**$13,367,432**	**$14,171,833**	**$41,185,538**

Table 5-7 shows the eligible customer classes and rates for each of the Residential and C&I programs.

Table 5-7: Customers

Program	Customer Class	Electric Rates
HVAC	Residential	711
Residential Lighting Program	Residential	711
Home Energy Analysis	Residential	711
Appliance Recycling	Residential	711
Low Income Appliance Replacement	Residential	711
School Education	Residential	711
Behavioral	Residential	711
Income Qualified Weatherization	Residential	711
Prescriptive	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744
Custom	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744
New Construction	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744
Small Business Direct Install	C&I	720, 721, 722, or 723 who have not had a billing demand of 200 kW or greater in any month during the previous 12 months
Retro-Commissioning	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744

5.1.2 Existing Demand Response Resources

5.1.2.1 Capacity Resources

The Commission approved Rider 775 – Interruptible Industrial Service Rider in its Rate Case Order. Rider 775 is available to customers taking service under Rates 732, 733 or 734. Rider 775 balances the needs of all customer groups by securing the ability and willingness of participating customers to curtail or interrupt service upon demand. NIPSCO's largest and participating industrial customers provide a benefit to all customers, and are accordingly compensated through demand credits that are funded by all other customers. Rider 775 continues to provide the stable foundation from the similar and previously effective Rider 675. The interruptible credits are provided for two reasons, reliability and economic, each of which provides short- and long-term value to all customers.

In its Rate Case Order, the Commission approved revisions to Rider 775 that were a key settlement component that was based upon the inputs and compromise from all the parties who had many different viewpoints on valuation of various interruptible options, even as all parties agreed to the general concept that it clearly does add value. Specifically, the Rate Case Order approved:

- An increase of the MWs available to 530 (an increase of the MW cap by 30 MW) and an increase of the dollar cap to $57 million.

- Incorporation of new Option E that provides 400 hours of interruption capability, which is greater than any previously-effective option.

- Option C was revised to provide for two hours' notice for interruptions or curtailments and receive a demand charge credit of $9.00/kW-month.

- Customers having existing interruptible capacity under Rider 675 were entitled to re-enroll that same capacity in the same or other options under the new Rider 775 consistent with MISO requirements.

- Incremental subscribed interruptible capacity (which is estimated to be 150 MW of the new interruptible capacity) was allocated first to customers showing a demonstrated economic need, but no more than 85% of that capacity was allocated to one customer.

- The rider provides greater flexibility for customers operating commonly owned facilities to re-allocate interruptible capacity among those facilities and to permit interruptible capacity to migrate among available options consistent with MISO requirements.

The Interruptible Contract Demand is the demand that the customer makes available for interruptions and/or curtailments from one or more of the customers' premises taking service under Rates 732, 733 or 734. Customers taking service under Rider 775 specify a Firm Contract Demand that they intend to exclude from interruptions or curtailments. Customers who contract for this service are required to interrupt or curtail at the stated notice by NIPSCO and the provisions of service under the Rider. Customers are also required to meet the applicable Load Modifying Resource requirements pursuant to MISO Tariff Module E, or its successor. NIPSCO will register all subscribed 527.776 MW of Rider 775 capacity with MISO. The Load Modifying Resource value is grossed-up by the Planning Reserve Margin and the Transmission Losses, since such resources have neither transmission losses, nor forced outages. As such, the 527.776 MW of Load Modifying Resources becomes 577.567 MW of Capacity Resources that NIPSCO can utilize to meet its MISO resource adequacy requirements.

In addition to NIPSCO's Rider 775 – Interruptible Industrial Service Rider, Rate 734 – Industrial Power Service for Air Separation & Hydrogen Production Market Customers, makes available interruptions and/or curtailments of electric demands greater than 276 MW to customers taking service under this Rate. Provisions for interruptions and/or curtailments are similar to that of Rider 775 and thus qualify as a Load Modifying Resource. As such, NIPSCO has registered 15.000 MW of Load Modifying Resources under Rate 734. The Capacity Resource realized from the registration is 16.414 MW that NIPSCO can utilize to meet its MISO resource adequacy requirements.

5.1.2.2 Energy-Only Resources

NIPSCO offers Demand Response Resource Type 1 ("DRR1") and Emergency Demand Response Resource ("EDR") through Riders 781 and 782, respectively. These Riders are available to a Customer on Rates 723, 724, 725, 726, 732, 733 and 734 who has a sustainable ability to reduce energy requirements through indirect participation in the MISO wholesale energy market by managing electric usage as dispatched by MISO. Through these Riders, the Customer or Aggregator of Retail Customer ("ARC") curtails a portion of its electric load through participation with the Company acting as the Market Participant ("MP") with MISO. These Riders are available to any load that is participating in the Company's other interruptible or curtailment Riders, unless MISO rules change and do not permit load used by the Company as a Load Modifying Resource ("LMR") to also participate as a DRR1 or EDR. Although the DRR1 and EDR offered under Riders 781 and 782, respectively, do not qualify as a Capacity Resource, they do offer a means for Customers to offer into the MISO market and to be paid for the portion of their electric load curtailed. This provides economic benefit to the Customers participating in these Riders and for other NIPSCO Customers through an overall lower electric system demand, which can avoid purchased power or the need for higher cost generation resources to be committed through the MISO market. Currently, NIPSCO has two Customers participating in Rider 781 as DRR1 and no Customers are participating in Rider 782 as EDR.

5.2 DSM Resource Potential

5.2.1 Market Potential Studies – Purpose and Key Objectives

To determine the electric DSM resource potential for the 2016 IRP, NIPSCO retained Applied Energy Group ("AEG") in October 2015 to conduct a Demand Side Management Market Potential Study ("MPS"), a copy of which is included in Appendix B. NIPSCO also retained

Morgan Marketing Partners ("MMP") to develop the DSM Program Potential based on the MPS and to complete the overall benefit cost results based on the program potential as determined by the MPS. Both AEG and MMP participated in Stakeholder Meeting 2 and provided details of their interaction / engagement with the MPS and DSM. *See* Appendix A, Exhibit 2 (Presentation). The MPS excluded NIPSCO's large industrial customers who had opted out from participating in NIPSCO's electric energy efficiency programs as of January 1, 2016 as allowed by Indiana Code 8-1-8.5-9.

NIPSCO recognizes that some stakeholders recommended that the industrial opt out customers should remain in the MPS analysis, however given the current statutory construct permitting such opt-outs, NIPSCO elected to exclude industrial opt out customers from the study. NIPSCO wanted a study that would provide it with what was achievable under the current environment for which it has control within its service territory. To have included load for industrial customers that had opted out of participating in NIPSCO's programs would have provided an inapplicable amount of load that was available to participate in NIPSCO's energy efficiency efforts.

The MPS provided an estimate of the potential reductions in annual electricity use and summer peak demand for electric customers in NIPSCO's service territory from energy efficiency ("EE") efforts from 2016 to 2036. As further described in Appendix A, Exhibit 2 (Presentation), to produce a reliable and transparent estimate of the DSM resource potential, AEG performed the following tasks, using its Load Management Analysis and Planning (LoadMAP) tool, to meet NIPSCO's key objectives:

- Used updated information and data from NIPSCO, as well as secondary data sources, to describe how customers use energy by sector, segment, end use and technology.

- Removed the commercial and industrial customers who had already opted out or who NIPSCO forecasted to opt out of EE programs as of January 1, 2016 as allowed by Indiana Code 8-1-8.5-9.

- Developed a baseline projection of how customers are likely to use electricity in the absence of future programs. This provides the metric against which future program savings are measured and utilized updated technology data, modeling assumptions, and energy baselines that reflect both current and anticipated federal, state, and local energy efficiency legislation that will impact DSM potential.

- Defined and characterized several hundred DSM measures that were applied to all sectors and end uses. Using the Indiana TRM from 2013 and other secondary data as data sources, measure costs, savings, and lifetimes were added to LoadMAP.

- Estimated the Technical, Economic, and Achievable Potential at the measure level for energy efficiency and demand response within NIPSCO's service territory over the 2016-2036 planning horizon, including annual energy savings and summer peak demand savings.

MMP used the measure-level savings estimates to develop the program potential. The program potential includes budget and impact estimates for the subset of measures that fit these criteria. The final budgets and impacts were then run through cost-effectiveness modeling using the DSMore tool to finalize the cost-effective program savings potential. NIPSCO utilized this as the inputs into the IRP because anything that was not cost effective at this point would later be screened out as part of the subsequent DSM program filing. Therefore, NIPSCO only wanted to consider programs in the IRP that had cost-effective program savings potential as this would be critical for ultimate selection as a DSM program.

Programs are built from measures and their individual market penetration rates. To build the program groupings in the IRP, individual measure penetration estimates are made for the MPS and then grouped into "programs." Within that document, each program grouping has a penetration applied for each measure during the period of the IRP. These estimates are based on the AEG LoadMAP model. AEG assists electric and gas utilities with load forecasting approaches and models that address key issues facing specific markets and end uses. They offer a full suite of forecasting services, including its fully-integrated end-use and efficiency forecasting model (LoadMAP). NIPSCO used LoadMAP to develop the baseline projection and the estimates of DSM potential. The LoadMAP end-use forecasting framework allows utilities to develop forecasts that address appliance standards, building codes, naturally occurring efficiency, emerging technologies, customer-sited renewable energy, distributed energy and electric vehicles specifically. It also allows utilities to incorporate expected savings from future energy efficiency programs. AEG developed LoadMAP in 2007 and has enhanced it over time, using it for the EPRI National Potential Study and numerous utility-specific forecasting and potential studies since that time. Built in Excel, the LoadMAP framework is both accessible and transparent and has the following key features:

- Embodies the basic principles of rigorous end-use models (such as EPRI's REEPS and COMMEND) but in a more simplified, accessible form.

- Includes stock-accounting algorithms that treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life and appliance vintage distributions defined by the user.

- Balances the competing needs of simplicity and robustness by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data are available, and treats end uses separately to account for varying importance and availability of data resources.

- Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately.

- Uses a simple logic for appliance and equipment decisions. Other models available for this purpose embody complex decision choice algorithms or diffusion assumptions, and the model parameters tend to be difficult to estimate or observe and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP approach allows the user to drive the appliance and equipment choices year by year directly in the model. This flexible approach allows users to import the results from diffusion models or to input individual assumptions. The framework also facilitates sensitivity analysis.

- Includes appliance and equipment models customized by end use. For example, the logic for lighting is distinct from refrigerators and freezers.

- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type or income level).

- Incorporates energy-efficiency measures, demand-response options, combined heat and power (CHP) and distributed generation options and fuel switching.

Consistent with the segmentation scheme and the market profiles used in the IRP, the LoadMAP model provides forecasts of baseline energy use by sector, segment, end use, and technology for existing and new buildings. It also provides forecasts of total energy use and energy-efficiency savings associated with the various types of potential.

5.2.2 Development of Baseline Projection

AEG first had to develop base-year market profiles, which is fundamental to developing a baseline projection. This included segmenting out the customer base, as well as determining the market size, equipment saturation, fuel and technology shares, and vintage distribution. Lastly, it involved determining the unit energy consumption and coincident demand.

Table 5-8 summarizes the specific model inputs for the market profiles, in conjunction with the corresponding key data sources.

Table 5-8: Data Applied for the Market Profiles

Model Inputs	Description	Key Sources
Market size	Base-year residential dwellings, commercial floor space, and industrial employment	NIPSCO billing data NIPSCO Load Forecast AEO 2015
Annual intensity	Residential: Annual use per household Commercial: Annual use per square foot Industrial: Annual use per employee	NIPSCO billing data AEG's Energy Market Profiles AEO 2015 Other recent studies
Appliance/equipment saturations	Fraction of dwellings with an appliance/technology Percentage of C&I floor space/employment with equipment/technology	NIPSCO 2010 Residential Saturation Survey American Community Survey AEG's Energy Market Profiles NIPSCO Load Forecast
UEC/EUI for each end-use technology	UEC: Annual electricity use in homes and buildings that have the technology EUI: Annual electricity use per square foot/employee for a technology in floor space that has the technology	Recent Midwest potential studies HVAC uses: BEST simulations using prototypes developed for NIPSCO Engineering analysis
Appliance/equipment age distribution	Age distribution for each technology	Recent AEG studies, EIA Data (CBECS, RECS)
Efficiency options for each technology	List of available efficiency options and annual energy use for each technology	AEG DEEM AEO 2015 Previous studies
Peak factors	Share of technology energy use that occurs during the peak hour	NIPSCO system peak data EnergyShape database

Once the market profiles were established, a baseline projection was developed for the annual electricity use and summer peak demand for 2016 through 2036 by customer segment and end use, without the addition of new utility programs. The end-use projection includes the relatively certain impacts of known and adopted legislation, as well as codes and standards that will unfold over the study timeframe. All such legislation and mandates that were defined as of June 2015 are included in the baseline. It should be noted that the status of the Clean Power Plan was still in flux at the time of this analysis, and therefore, was not specifically considered.

The baseline projection is the foundation for the analysis of savings from future energy efficiency efforts as well as the metric against which potential savings are measured. The baseline projection allows AEG to see how customers would use energy outside of a structured utility-sponsored energy efficiency program. Inputs to the baseline projection include:

- Current economic growth forecasts (i.e., customer growth, income growth)
- Electricity price forecasts
- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards
- Known and adopted legislation
- Naturally occurring efficiency improvements, which include purchases of high-efficiency equipment options by early adopters.

AEG also developed a baseline projection for summer and winter peak by applying the peak factors from the energy market profiles to the annual energy forecast in each year.

Table 5-9 summarizes the LoadMAP model inputs required for the baseline projection. These inputs are required for each segment within each sector, as well as for new construction and existing dwellings/buildings.

Table 5-9: Data Needs for Baseline Projection and Potentials Estimation in LoadMAP

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential and C&I sectors	NIPSCO load forecast AEO 2015 economic growth forecast
Equipment purchase shares for baseline projection	For each equipment/technology, purchase shares for each efficiency level; specified separately for existing equipment replacement and new construction	Shipments data from AEO AEO 2015 regional forecast assumptions[2] Appliance/efficiency standards analysis NIPSCO program results and evaluation reports
Electricity prices	Forecast of average energy and capacity avoided costs and retail prices	NIPSCO forecast
Utilization model parameters	Price elasticities, elasticities for other variables (income, weather)	EPRI's REEPS and COMMEND models AEO 2015

2 AEG developed baseline purchase decisions using the Energy Information Agency's *Annual Energy Outlook* report (2015), which utilizes the National Energy Modeling System (NEMS) to produce a self-consistent supply and demand economic model. AEG calibrated equipment purchase options to match manufacturer shipment data for recent years and then held values constant for the study period. This removes any effects of future increases in naturally occurring conservation or effects of future DSM programs that may be embedded in the AEO forecasts.

Additional assumptions by customer class regarding codes and standards, measure equipment, efficiency levels by year, and future equipment standards is included in the MPS (Appendix B, Pages 15-17).

5.2.3 Determining Measure Potential

Once the Market Characterization and the Baseline Projection inputs are established, the energy efficiency measures are screened for Technical and Economic Potential. Following that, they are screened for Achievable Potential, and finally, Program potential.

Figure 5-1: Definitions of DSM Potential

AEG's analysis provides information for the first three levels of savings potential – Technical Potential, Economic Potential, and Achievable Potential. MMP's analysis provides information for the final level of savings potential – Program Potential. The steps below provide more information regarding each savings potential level:

Step 1: **Technical Potential** is defined as the theoretical upper limit of DSM potential. It assumes that customers adopt all feasible measures regardless of their cost. At the time of existing equipment failure, it assumes that customers replace their equipment with the most efficient option available. In new construction, it assumes that customers and developers also choose the most efficient equipment option. Technical Potential also assumes the adoption of every other available measure, where applicable. For example, it includes installation of high-efficiency windows in all new construction opportunities and air conditioner maintenance in all existing buildings with central and room air conditioning. These retrofit measures are phased in over a number of years to align with the stock turnover of related equipment units, rather than modeled as immediately available all at once.

Step 2: **Economic Potential** represents the adoption of all cost-effective DSM measures. In this analysis, the cost-effectiveness is measured by the industry-standard total resource cost ("TRC") test, which compares lifetime energy and capacity benefits to the costs of delivering the measure through a utility program, with incentives not included since they are a transfer payment. If the benefits outweigh the costs (that is, if the TRC ratio is greater than 1.0), a given measure is included in the Economic Potential. Customers are then assumed to purchase the most efficient cost-effective option applicable to them at any decision juncture. For example, in interior lighting, CFLs and LED lamps are cost-effective, but Economic Potential assumes that 100% of the lightbulbs that turn over will be the more-efficient LED lamps.

Step 3: **Achievable Potential** refines the Economic Potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of DSM measures. Determining Achievable Potential is important because it takes into account human psychology and acknowledges that not all customers will participate in an energy efficiency program even if it makes sense from an economic perspective.

Step 4: **Program Potential** analyzes energy efficiency from the measure-level within NIPSCO's service territory utilizing the Achievable Potential results.

AEG provided the results of its analysis from Steps 1 through 3, the measure-level Achievable Potential data, to MMP for additional review and refinement. The Program Potential step incorporates the information from NIPSCO's historic EM&V reports from past program years and applies that information to the Achievable Potential savings amount. The Program Potential is focused on localizing the energy efficiency potential to NIPSCO's service territory and NIPSCO customers.

5.3 Screening Criteria

5.3.1 DSM Program Potential

MMP used the measure-level savings estimates from AEG to develop the Program Potential savings estimates for NIPSCO. To assure the measures were cost effective given the specifics of NIPSCO's service territory, MMP utilized the DSMore economic analysis tool to perform the final screening. DSMore utilized NIPSCO-provided (1) utility rates, (2) escalation rates, (3) discount rates for the utility, society and the participant, (4) avoided costs, and (5) previous EM&V levels for NIPSCO's past programs.

To assess the effectiveness of program design and implementation, an evaluation of all programs was conducted by a third-party EM&V vendor. MMP utilized the evaluation results from NIPSCO's 2014 program year to develop NIPSCO's program potential savings estimates. *See* 2014 Demand-Side Management Programs Evaluation Report – FINAL dated June 2015 prepared by The Cadmus Group, Inc., filed October 28, 2015 in Cause No. 43912 (the "2014 EM&V Report"). In its 2014 EM&V Report, Cadmus quantified each program's impacts on energy use and assessed each program's influence on encouraging future energy efficiency projects and market transformation effects in the energy marketplace.

The process evaluation included:

- Program Design Assessment - Review of program mission, logic, and design structure; suggest strength, improvement opportunities, modification to programs, etc.

- Program Implementation Assessment - Review of quality control, operation practice, program targeting, marketing outreach efforts, program timing, etc.

- Program Administration Assessment - Review of program oversight, staffing, management and staff training, program information and reporting, the effectiveness of the technology and systems used, etc.

- Program Participant Response Assessment - Participant interactions, satisfaction, as well as trade allies' interaction and satisfaction, etc.

While the evaluation efforts can be slightly different for each program, the overall work involves the following:

- Reviewing program materials and methods of operation

- Conducting interviews with program managers, implementers, trade allies and partners

- Conducting surveys with participants and non-participants

- Analyzing process evaluation data

- Developing process evaluation reports outlining program strengths, improvement opportunities, and program modifications

MMP utilized past evaluation reports for NIPSCO programs to review the DSM measures within the Program Potential step. The net-to-gross ratios from previous evaluations were applied to the Achievable Potential savings to provide NIPSCO with a better estimate of what is achievable in its service territory.

Table 5-10 demonstrates the amount of savings potential at each step of the process:

Table 5-10: Summary of DSM Potential

	2016	2017	2018	2019	2020	2021
Baseline projection (GWh)	**9,235**	**9,281**	**9,310**	**9,329**	**9,318**	**9,307**
Cumulative Savings (GWh)						
Technical Potential	284	510	716	891	1,038	1,171
Economic Potential	214	391	548	678	784	881
Achievable Potential	81	144	199	249	289	328
Program Potential	73	126	172	217	204	247
Cumulative Savings as a % of Baseline						
Technical Potential	3.1%	5.5%	7.7%	9.5%	11.1%	12.6%
Economic Potential	2.3%	4.2%	5.9%	7.3%	8.4%	9.5%
Achievable Potential	0.9%	1.6%	2.1%	2.7%	3.1%	3.5%
Program Potential	0.8%	1.4%	1.8%	2.3%	2.2%	2.7%

5.3.2 Measure Grouping Indicators

After the savings potential estimation process, the measures were bundled into DSM Groupings. Each measure that was not screened out in the MPS was labeled with a grouping indicator that assigned it to a specific DSM Grouping. A Grouping is defined as a bundling of measures with similar load shapes and end uses. Grouping measures by similar load shape and customer segment allows the IRP model to analyze large groups of measures more efficiently. The model is not capable of computing smaller Groupings of DSM savings potential because including hundreds of DSM measures in the IRP would cripple the computational speed of the model. Grouping the measures together allowed NIPSCO to incorporate DSM in a manner that is consistent with supply-side resources and allowed the model to efficiently analyze all resource options on an equal footing. The screening process for supply-side resources can be found in Section 1.

It is important to note that NIPSCO did not assign the measures into specific program offerings, but instead grouped the measures by end use. This enables NIPSCO to be more flexible when creating programs specific to its service territory and encourages vendors to propose programs that are deliverable and in direct response to market demands. Since the IRP is looking for resource options over a 20-year period, it is integral that NIPSCO provide the model with flexibility when selecting DSM. The DSM Groupings by end-use application and load shape provide this flexibility. In its IRP, NIPSCO elected not to further define its Groupings by costs per kWh. Rather, NIPSCO placed the measures into end-use groups only. There are a variety of ways to model DSM and NIPSCO elected to model its measures by end-use.

5.3.3 Energy Efficiency Groupings

Table 5-11 provides a description of the energy efficiency DSM Groupings.

Table 5-11: DSM Groupings

Grouping Name	Description
Residential Appliances	This grouping allows for the removal of inefficient refrigerators and freezers, to be replaced with more efficient units for single-family, mobile home, multi-family and low income households
Residential Cooling	This grouping includes cooling measures such as Central AC units, insulation, thermostats, and electric behavioral programs for single-family, mobile home, multi-family and low income households
Residential Exterior Lighting	This grouping only includes one exterior lighting measure (screw-in-R0086) for single-family, mobile home, multi-family and low income households
Residential Heating	This grouping includes two measures of heat pumps (air-source and geothermal) for single-family, mobile home, multi-family and low income households
Residential Interior Lighting	Screw-in and specialty interior lighting measures are included in this grouping for single-family, mobile home, multi-family and low income households
Residential Miscellaneous	The three measures included in this grouping are dehumidifiers, pool pumps and well pumps for single-family, mobile home, multi-family and low income households
Residential Water Heating	This grouping includes measures such as faucet aerators, low flow showerheads and pipe insulation for single-family, mobile home, multi-family and low income households (electric-only or combo-fuel customers with an electric water heater)
Commercial Cooling	This grouping allows for new cooling equipment or replacement of old equipment of chillers, heat pumps, insulation and other AC measures for small commercial customers
Commercial Exterior Lighting	This grouping allows for new exterior lighting or replacement of old lighting with the three measures of HID, linear fluorescent and screw-in bulbs for small and large commercial customers
Commercial Food Preparation	Dishwashers, fryers, ovens and other food prep measures are included in this grouping as new measures or replacement equipment for small commercial customers

Grouping Name	Description
Commercial Heating	This grouping includes two measures of heat pumps (air-source and geothermal) as a new measure or to replace an existing unit for small commercial customers
Commercial Interior Lighting	This grouping allows for new interior lighting or replacement of old lighting measures including high bay and linear fixtures, screw-in bulbs, and daylighting controls for small and large commercial customers
Commercial Miscellaneous	This grouping includes two measures of pool heater and pool pump as a new measure or to replace an existing unit for small commercial customers
Commercial Office Equipment	As a new measure or a replacement for old equipment, this grouping includes energy efficient desktop computers and laptops, monitors, servers and other office equipment for small commercial customers
Commercial Refrigeration	This grouping allows for new measures or replacement of inefficient measures including grocery store display cases and motion sensor lighting, refrigerator measures, vending machines and icemakers for small commercial customers
Commercial Ventilation	This grouping only includes one ventilation measure (Variable Speed Control) for small commercial customers
Commercial Water Heating	As a new measure or a replacement for old equipment, this grouping includes pre-rinse spray valves, faucet aerators and other water heater measures for small commercial customers (electric-only or combo-fuel customers with an electric water heater)
Industrial Cooling	This grouping allows for new cooling equipment or replacement of old equipment of chillers, geothermal heat pumps, insulation and other AC measures for small industrial customers
Industrial Exterior Lighting	This grouping allows for new exterior lighting or replacement of old lighting with HID and screw-in measures for small and large industrial customers
Industrial Heating	This grouping only includes one heating measure (geothermal heat pump) for small industrial customers
Industrial Interior Lighting	This grouping allows for new interior lighting or replacement of old lighting measures including high bay fixtures, screw-in bulbs, and LED exit lighting for small and large industrial customers
Industrial Motors	This grouping allows for new measures or replacement of old units including compressed air measures, fan and pumping systems optimization and other retro-commissioning efforts for small and large industrial customers

5.3.4 Application of Avoided Costs

Avoided Cost is defined as the monetary value of reducing peak energy and demand consumption on the customer side of the meter and quantified by the system costs that would otherwise be incurred to procure the required energy, capacity, transmission & distribution, and other resources. The annual avoided cost calculation includes:

- The cost-based proxy for electric generation capacity (annualized $/kW) multiplied by the expected annual demand savings attributed to each measure adjusted by the applicable future year escalation factor;
- Estimated transmission capacity cost ($/kW) multiplied by the expected annual demand savings attributed to each measure adjusted by the applicable future year escalation factor;
- Estimated distribution capacity cost ($/kW) multiplied by the expected annual demand savings attributed to each measure adjusted by the applicable future year escalation factor;
- Estimated annual average energy cost ($/kWh) multiplied by the expected annual energy savings attributed to each measure adjusted by the applicable future year escalation factor; and
- Estimated MISO Ancillary Charges ($/kWh) multiplied by the expected annual energy savings attributed to each measure adjusted by the applicable future year escalation factor.

In the cost effectiveness models, avoided cost was calculated on an hourly basis based on the energy saved at that time plus its relationship to the peak hour. For avoided energy and capacity, the DSMore model used hourly market prices based on MISO historic values in relation to weather. Those prices were calculated using a 33-year weighted average weather value for each hour. Transmission and distribution avoided costs were also calculated using a value developed by NIPSCO that is consistent with its other planning models.

Avoided Cost Benefit dollars were calculated for each measure individually by the hour that savings occur. These individual measure values were added together to get the grouping value by hour.

Tables 5-12 through 5-15 show the avoided cost assumptions, interest rates used for the analysis, charges for avoided cost calculations and future year escalation factors.

Table 5-12: Avoided Cost Assumptions

Discount Rates	
Electric Utility Discount Rate (%)	6.53%
Real Discount Rate (%)	2.43%
Participant Discount Rate (%)	15.00%
Participant Income/Sales Tax Rate (%)	7.00%
System Losses	
Residential Electric Losses (%)	2.97%
Residential Peak Electric Losses (%)	4.11%
Commercial Average (Primary & Secondary) Electric Losses (%)	2.65%
Industrial Electric Losses (%)	1.65%
Industrial Peak Electric Losses (%)	2.41%
Electric Generation Avoided Capacity Cost – Summer	
Cost-Based Proxy for Avoided Electric Generation Capacity (Annualized $/kW)	$122.92
Coincident Month (1-12)	7
Coincident Hour (1-24)	14
Supplemental Reserve Margin (%)/MISO Planning Reserve Margin before EFOR	7.30%
Avoided Transmission & Distribution Capacity Cost – Electric ($/kW)	
Avoided Distribution	$46.32
Avoided Transmission	$ 2.42
Total Avoided T&D	$48.75
Avoided Energy Cost – Electric ($/kWh)	
Annual Average ($/kWh)	$0.0350
Annual MISO Peak Hours (%)	47.6%
Annual MISO Off-Peak Hours (%)	52.4%

Table 5-13: Interest Rates Used for the Analysis

Discount Rates as of May, 2015		
Electric Utility Discount Rate (%)	6.53%	Dependent on what is allowed by the most recent Electric Rate Order; it's a weighted average of long term debt, common equity, post 1970 ITC, and customer deposits
Real Discount Rate (%)	2.43%	Represents the interest based on NIPSCO's credit score/rating
Participant Discount Rate (%)	15.00%	Represents the interest to fund using credit card
Participant Income/Sales Tax Rate (%)	7.00%	Set by the State of Indiana

Table 5-14: MISO Ancillary Charges for Avoided Cost Calculations

	Avoided MISO Ancillary Charges ($/kWh)
Jan	$0.00301256
Feb	$0.00326895
Mar	$0.00343791
Apr	$0.00418363
May	$0.00361793
Jun	$0.00294769
Jul	$0.00229824
Aug	$0.00227363
Sep	$0.00280726
Oct	$0.00377392
Nov	$0.00264818
Dec	$0.00248225

Table 5-15: Applicable Future Year Escalation Factor for Avoided Cost Calculations

	Electric Base Rates	Electric Fuel Cost Factor	Electric Avoided Capacity Cost	Electric Avoided T&D Cost	Electric Avoided Energy Cost	Electric MISO Ancillary Market
2016	2.449	0.899	2.449	2.449	0.915	0.915
2017	2.496	0.901	2.496	2.496	0.924	0.924
2018	2.547	0.938	2.547	2.547	0.954	0.954
2019	2.596	0.973	2.596	2.596	1.004	1.004
2020	2.649	0.996	2.649	2.649	1.043	1.043
2021	2.705	1.029	2.705	2.705	1.085	1.085
2022	2.763	1.064	2.763	2.763	1.129	1.129
2023	2.822	1.124	2.822	2.822	1.176	1.176
2024	2.866	1.154	2.886	2.886	1.226	1.226
2025	2.949	1.357	2.949	2.949	1.606	1.606
2026	3.007	1.402	3.007	3.007	1.657	1.657
2027	3.068	1.451	3.068	3.068	1.710	1.710
2028	3.128	1.484	3.128	3.128	1.765	1.765
2029	3.188	1.642	3.188	3.188	1.822	1.822
2030	3.249	1.709	3.249	3.249	1.881	1.881
2031	3.313	1.770	3.313	3.313	1.954	1.954
2032	3.379	1.835	3.379	3.379	2.030	2.030
2033	3.446	1.900	3.446	3.446	2.109	2.109
2034	3.514	1.963	3.514	3.514	2.191	2.191
2035	3.586	2.146	3.586	3.586	2.276	2.276
2036	3.659	2.192	3.659	3.659	2.365	2.365
2037	3.733	2.239	3.733	3.733	2.457	2.457

The avoided cost projections are included in Appendix B, Exhibit 2.

5.3.5 Cost Benefit Analysis of Energy Efficiency Measures

Using refined, projected costs for incentives and program delivery, net-to-gross factors, plus the adjusted participation rates of the Program Potential, the cost benefit analysis was completed to determine if the DSM Grouping was cost effective for NIPSCO from a TRC test perspective. To complete this analysis, the cost effectiveness model DSMore was utilized.

The DSMore tool is an award-winning modeling software that is nationally recognized and used in many states across the country to determine cost-effectiveness. Developed and licensed by Integral Analytics, its cost-effectiveness modeling tool takes hourly prices and hourly energy savings from the specific measures/technologies being considered for the DSM program, and then correlates both to weather. This tool looks at over 30 years of historic weather variability to get the full weather variances appropriately modeled. This allows the model to capture the low probability, but high consequence weather events and apply appropriate value to them. Thus, a more accurate view of the value of the DSM measure can be captured in comparison to other alternative supply options. Inputs into the model include participation rates, incentives paid, energy and demand savings of the measure, life of the measure, net-to-gross factors, implementation costs, administrative costs, and incremental measure costs to the participant.

The industry standard cost-effectiveness tests were performed with the DSMore software tool to gauge the economic merits of the portfolio. Each test compared the benefits of the DSM Groupings to their costs – using its own unique perspectives and definitions – all defined in terms of net present value of future cash flows. The definitions for the four standard tests most commonly used in DSM program design are:

(1) Total Resource Cost (TRC) Test. The benefits in this test are the lifetime avoided energy costs and avoided capacity costs. The costs in this test are the incremental measure costs plus all administrative costs spent by the program administrator and implementer.

$$\textit{TRC Test} = \frac{\textit{Avoided Costs} + \textit{Tax Saved}}{\textit{Utility Costs} + \textit{Participant Costs Net of Incentives}}$$

(2) Utility Cost Test. The benefits in this test are the lifetime avoided energy costs and avoided capacity costs, the same as the TRC benefits. The costs in this test are the program administrator's incentive costs, implementation costs, and administrative costs.

$$\textit{Utility Test} = \frac{\textit{Avoided Costs}}{\textit{Utility Costs}}$$

(3) Participant Cost Test. The benefits in this test are the lifetime value of retail rate savings. The costs in this test are those seen by the participant; in other words: the incremental measure costs minus the value of incentives paid out.

$$\text{Participant Test} = \frac{\text{Lost Revenue}+\text{Incentives}+\text{Tax Savings}}{\text{Participant Costs}}$$

(4) Rate Impact Measure (RIM) Test. The benefits of this test are the same as the TRC benefits. The costs in this test are the same as the UCT, except for the addition of lost revenue. This test attempts to show the effects that energy efficiency programs will have on rates, which is almost always to raise them on a per unit basis. Costs typically outweigh benefits from the point of view of this test, but the assumption is that absolute energy use decreases to a greater extent than per-unit rates are increased – resulting in lower average utility bills.

$$\text{RIM Test} = \frac{\text{Avoided Costs}}{\text{Utility Costs}+\text{Lost Revenue}}$$

The cost-effectiveness results for the NIPSCO program potential portfolio are shown in Table 5-16. Lifetime TRC benefits are $1,004.96 million and costs of $478.64 million result in a robust TRC benefit-to-cost ratio of 2.10. The portfolio passes the cost-effectiveness screen with a benefit cost ratio at 1.0 or higher for all of the standard tests, except the RIM Test.

Table 5-16: DSM Action Plan Cost Effectiveness Summary

Program	NPV TRC Benefits ($ million)	NPV TRC Costs ($ million)	TRC Ratio	UCT Ratio	PCT Ratio	RIM Ratio
Res Appliances	$32.48	$19.42	1.67	2.35	6.09	0.36
Res Cooling	$239.81	$173.48	1.38	1.91	2.80	0.58
Res Electric Heating	$2.91	$7.22	0.40	0.61	2.62	0.17
Res Electric Miscellaneous	$4.58	$2.64	1.73	2.37	4.67	0.46
Res Electric Water Heat	$3.37	$0.53	6.34	9.44	22.67	0.37
Res Exterior Lighting	$10.81	$5.17	2.09	2.56	14.79	0.25
Res Interior Lighting	$86.14	$46.81	1.84	2.33	9.33	0.30
Com Cooling	$142.46	$109.18	1.30	1.67	3.24	0.44

Program	NPV TRC Benefits ($ million)	NPV TRC Costs ($ million)	TRC Ratio	UCT Ratio	PCT Ratio	RIM Ratio
Com Exterior Lighting	$36.82	$12.94	2.85	3.58	15.42	0.19
Com Electric Food Prep	$5.22	$1.33	3.92	4.98	11.84	0.34
Com Electric Heating	$0.02	$0.03	0.73	0.93	4.40	0.16
Com Interior Lighting	$171.55	$62.12	2.76	3.53	8.36	0.30
Com Electric Miscellaneous	$0.11	$0.01	10.08	11.48	53.37	0.39
Com Office Equipment	$24.46	$1.10	22.33	26.23	146.10	0.30
Com Refrigeration	$2.05	$0.81	2.53	3.37	11.64	0.28
Com Ventilation	$0.23	$0.19	1.18	1.50	5.71	0.23
Com Electric Water Heat	$17.19	$6.23	2.76	3.51	11.52	0.28
Ind Cooling	$12.17	$13.92	0.87	1.11	1.61	0.50
Ind Exterior Lighting	$4.61	$1.29	3.57	4.53	10.69	0.35
Ind Interior Lighting	$28.46	$10.74	2.65	3.30	6.28	0.40
Ind Motors	$21.57	$3.43	6.29	8.00	17.72	0.43
Ind Heating	$0.01	$0.05	0.27	0.34	1.47	0.16
Residential Total	$380.11	$255.28	1.49	2.02	4.34	0.44
Commercial Total	$400.11	$193.93	2.06	2.63	6.98	0.32
Industrial Total	$66.82	$29.44	2.27	2.87	5.42	0.42
PORTFOLIO TOTAL	$847.05	$478.64	1.77	2.33	5.61	0.37

5.3.6 Demand Response Groupings

As a part of the MPS process, AEG reviewed several different options for Demand Response programs in NIPSCO's service territory. This was a necessary step because some of the programs require meter technology that NIPSCO does not currently employ. Additionally, some of the other Demand Response programs require specific rates to be in place for implementation. AEG and NIPSCO reviewed the list of potential options and screened out the ones that were not applicable to NIPSCO's service territory in the short term.

5.3.6.1 Demand Response Options Screened Out

The following Demand Response options were qualitatively screened out:

Critical Peak Pricing

Critical Peak Pricing involves significantly higher prices during relatively short critical peak periods on event days to encourage customers to reduce their usage. The customer incentive is a heavily discounted rate during off-peak hours (relative to a standard Time-of-Use rate). Event days are dispatched on relatively short notice (day ahead or day-of) typically for a limited number of days per year. Over time, event-trigger criteria become well-established so that customers can expect events based on hot weather or other factors. Events can also be called during times of system contingencies or emergencies.

Inclining Block Rate

Inclining Block Rate is considered a conservation rate that applies differing rates based on customer usage. This is a volumetric dollar per kWh charge that is applied to a customer's bill. The rate increases as the amount of electricity consumed increases. Typically, the rate is separated into two blocks or tiers by a kWh threshold, the first block below the threshold is charged one rate and the second block above the threshold is charged another higher rate. Unlike other Demand Response and rate-based options, this option has low to zero operation, maintenance, and incentive costs. However, introducing this rate option requires a significant amount of ratemaking and regulatory changes that may not be captured within the modeling.

Time-of-Use Rates

A Time-of-Use rate occurs when the rate for purchasing or using electricity is more expensive during a particular block of hours each day. Relative to a revenue-equivalent flat rate, the rate during on-peak hours is higher, while the rate during off-peak hours is lower. This provides customers with motivation to move consumption out of the higher-priced on-peak hours into the lower-priced off-peak hours. Larger price differentials provide an incentive for customers to shift consumption.

Time-of-Use rates are not event-driven like the other Demand Response programs considered, but are rather a means to achieve predictable, permanent load shifting on a day-to-day basis from peak hours to off-peak hours. Time-of-Use rates can be established to be in effect every day of the year or seasonally. Since the summer peak is the time of most interest in this analysis, it is assumed that the rate is in effect for the summer season. These rates are typically not included as a Demand Response option, per se, because customer response is not event driven. NIPSCO does not currently have plans to include Time-of-Use-based tariffs options, and it would require notable technology and/or infrastructure changes.

NIPSCO completed the installation of 407,000 residential Automated Meter Reading (AMR) meters and 56,000 commercial AMR meters toward the end of 2015. The portion of these meters installed and in service on March 31, 2015 were recognized as utility rate base in NIPSCO's 2016 rate case. The labor and capital savings due to these meters were also reflected in the Company's expenses in the rate case. NIPSCO continues to evaluate the benefits of AMI but is not in a position to move forward with such an investment at this time. In the future, Smart grid is designed to aid in system restoration efforts, grid and circuit reliability planning and integration of DG assets in a more efficient manner.

Smart Appliance Direct Load Control

Smart Appliance Direct Load Control is a relatively unproven and emerging technology. Existing research on impacts by appliance type show relatively low reductions. Additionally, the technical infrastructure investment costs are likely to be prohibitively high in terms of communication and control for enabling reductions from these devices.

Fast Demand Response

Demand Response resources for providing ancillary services need to be Auto-DR enabled, thereby entailing high infrastructure costs. They need to be available 24x7 with a high degree of reliability. Therefore, participation is challenging and likely to be low. Overall, the option is unlikely to be cost-effective under current system conditions. However, with increasing amount of renewable sources coming online, the value of flexible resources like Fast DR are likely to gain value.

Thermal Energy Storage

Although these technologies are becoming more mainstream and have experienced some improvements in technology or price, NIPSCO does not currently have plans to employ any thermal energy storage in its service territory during the short term portion of the IRP action plan. Thus, these technologies were not considered as part of the Demand Response programs. However, as with other emerging technologies, NIPSCO will continue to monitor progress for inclusion in subsequent IRPs.

5.3.6.2 Demand Response Options Considered in MPS

In the MPS, four Demand Response options were considered, plus two additional options for the interruptible tariff. The objective of these options is to realize demand reductions from eligible customers during the highest load hours of the summer as defined by the utility. Each program type provides demand response using different load reduction and incentive strategies designed to target different types of customers. From the utility perspective, each of the different program types can be called with different notification time. Having a mix of programs provides load reduction that can be called under many different conditions.

Table 5-17 provides a description of the Demand Response DSM Groupings.

Table 5-17: Demand Response DSM Groupings

Grouping	Description
Demand Response Residential AC	This grouping allows for load control of central AC units of residential customers
Demand Response Residential Water Heating	This grouping allows for load control of water heating units of residential customers
Demand Response Commercial AC	This grouping allows for load control of central AC units of small and medium sized commercial customers
Demand Response Commercial Water Heating	This grouping allows for load control of water heating units of small and medium sized commercial customers
Demand Response Curtailment	Participating customers agree to reduce their demand by a specific amount or curtail their consumption to a pre-specified level. In return, they would typically receive a fixed incentive payment from the Aggregator in the form of capacity credits or reservation payments (expressed as $/kW-month or $/kW-year). Customers are paid to be on call even though actual load curtailments may not occur.
Demand Response Interruptible	Based on an agreement between the utility and the large and extra large C&I customers, the utility is allowed to curtail their load during MISO system emergencies. This program would be implemented by notifying customers of a possible curtailment event, typically a day in advance, and allowing them to respond by either buying through to the marketplace or shedding load depending on market pricing. If there was a MISO system contingency, however, the customer would have to reduce load.

5.3.7 Cost Benefit Analysis of Demand Response Measures

To complete the cost benefit analysis of the Demand Response program groupings, DSMore was used for modeling. The basic financial assumptions such as avoided costs and discount rates are the same as the energy efficiency analysis to assure consistency. As described above the inputs for the Demand Response programs include the participation, implementation costs, incentives and demand savings. The Demand Load Control AC and Water Heating program groupings were divided into three sizes of customers: (1) Residential, (2) Small C&I, and (3) Medium C&I, so that appropriate load shapes and rates could be applied. The Interruptible Load Tariffs and Curtailment Agreements were divided into two sizes – Large and Extra Large. Again appropriate load shapes and rates were applied.

Table 5-18 shows the cost benefit scores for the TRC, UCT, Participant and RIM tests. All tests are equal to or greater than 1.0 meaning they are cost effective. The TRC scores specifically are from 3.51 to 14.4. It is not unusual for these programs to be cost effective as the interruptions occur during the time of day/year when the avoided cost values are at their highest.

Table 5-18: Cost Effectiveness Scores for DR Programs

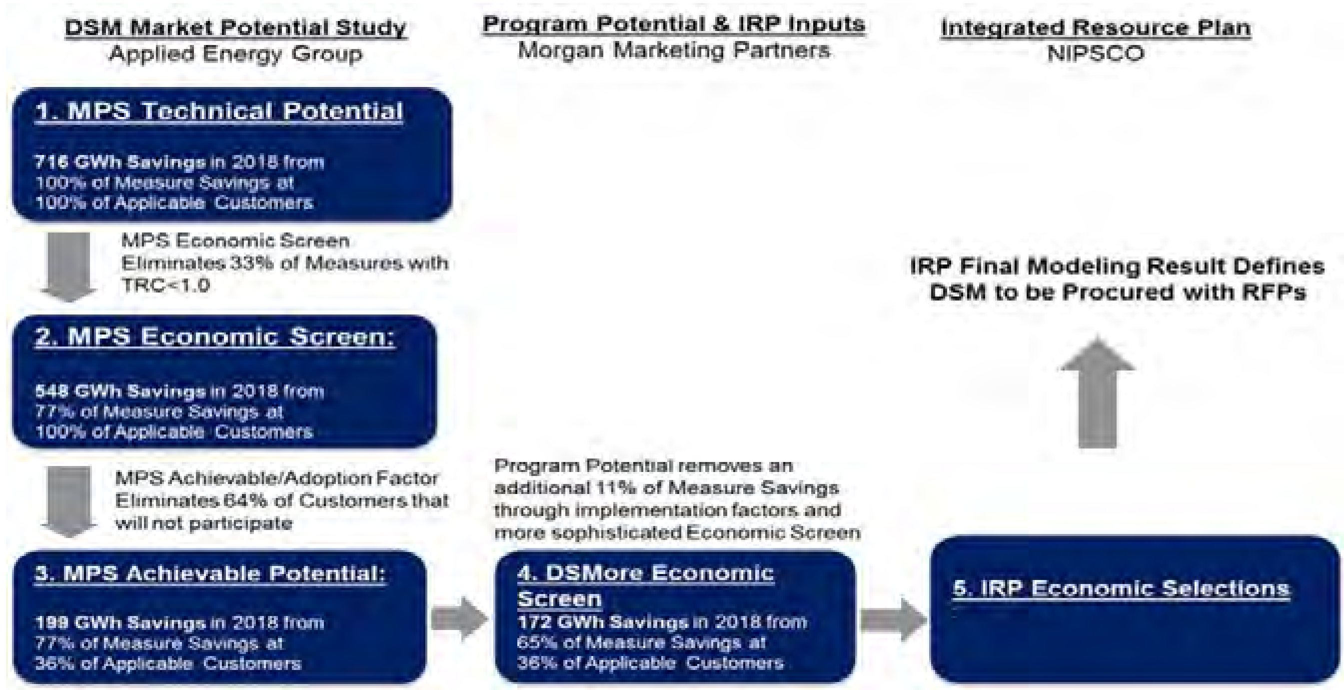
DR Program	TRC	UCT	Participant	RIM
Residential DLC Central AC	1.77	1.77	1.00	1.77
Small C&I DLC Central AC	5.06	5.06	1.00	5.06
Medium C&IDLC Central AC	4.72	4.72	1.69	3.72
Residential DLC Water Heating	2.23	2.23	1.00	2.23
Small C&I DLC Water Heating	5.10	5.10	1.00	5.10
Medium C&IDLC Water Heating	4.18	4.18	1.61	3.37
Large C&I Interruptible Load Tariffs	1.25	1.25	1.04	1.21
Extra Large C&I Interruptible Load Tariffs	1.24	1.24	1.00	1.24
Large C&I Curtailment Agreements	2.17	2.17	1.08	2.06
Extra Large C&I Curtailment Agreements	2.22	2.22	1.00	2.22

It should be noted that the TRC and UCT values are the same since incentives are considered a utility cost and not a transfer payment. This is due to the unknown nature of the incremental costs to participate by the customer. This is the more conservative assumption on incentives for the TRC and UCT tests. Also, it is assumed that the measures that are interrupted will have a complete "rebound" or recovery period before or after the interruption resulting in the total kWh sales being equivalent to the period without interruption, and there is no lost revenue to the utility for the energy portion of the bill. For smaller customers with no demand charges, this means the TRC and RIM will be equal.

5.3.8 Program Potential Results for IRP

The DSMore model produces specific measure energy savings by hour. These hourly savings were aggregated into the IRP groupings and then provided to NIPSCO for use within the IRP model. All cost-effective Energy Efficiency and Demand Response grouping results were shared with NIPSCO's IRP team for inclusion in the Strategist® model, which optimized the DSM Programs for inclusion in the IRP. While a DSM Grouping that was examined through the MPS process may have been shown to be cost-effective, it still may not have been selected as a least cost resource by the Strategist® model when considering all available resources and therefore may not have been included in NIPSCO's IRP. The DSM Grouping data shared with the IRP team for the model includes: savings data (energy and demand), cost, avoided costs and assumptions.

Figure 5-2: Flow of DSM Measures



To better understand the flow of the four-step screening process from Technical Potential to Program Potential, below are the results from the MPS and Program Potential analysis.

- The MPS Technical Potential (Step 1) resulted in 716 GWh savings in 2018 from 100% of the measure savings for 100% of applicable customers.

- During the MPS Economic Potential screening (Step 2), 33% of the measures were eliminated due to having a TRC < 1.0. This resulted in a remaining 548 GWh savings in 2018 for 77% of the measure savings for 100% of applicable customers.

- During the MPS Achievable Potential Customer Adoption screening (Step 3), 64% of customers were eliminated by determining who would not participate. This resulted in a remaining 199 GWh in 2018 from 77% of the measure savings for 36% of applicable customers.

- During the Program Potential screening (Step 4), an additional 10% of measure savings were removed due to implementation factors (specifically relating to the utility) and a sophisticated economic screen at the measure level. This resulted in 172 GWh savings in 2018 from 65% of the measures savings for 36% of applicable customers.

The energy savings, the demand savings, the utility costs, and Grouping load shapes by DSM Grouping were provided to NIPSCO's IRP team for inclusion as inputs into the IRP model.

5.4 Future Resource Options

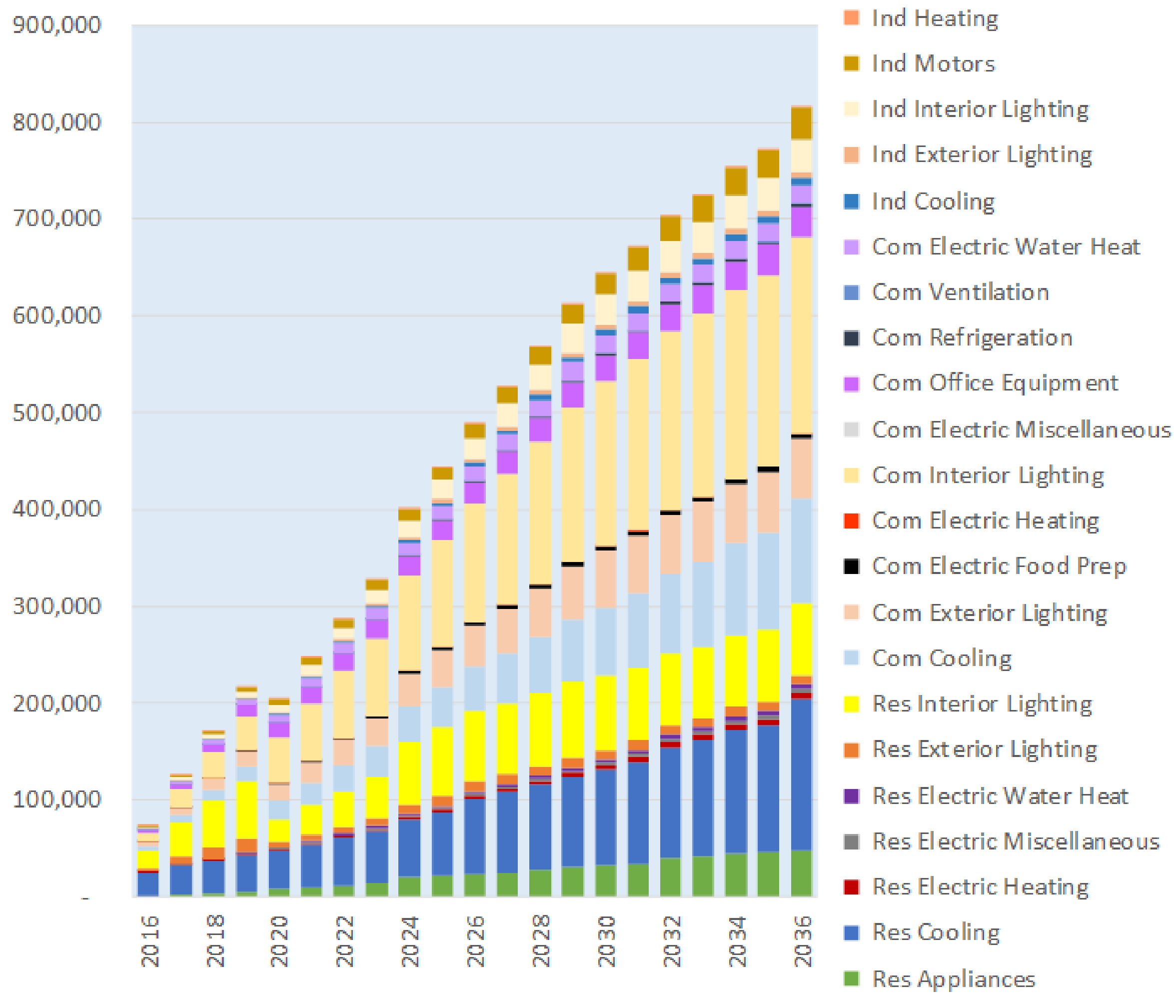
5.4.1 Energy Efficiency Options

The results of the Program Potential step in the form of aggregated measures in DSM Groupings was provided to NIPSCO for inclusion in the IRP model. Table 5-19 lists the distinct program groupings that emerged from this exercise to deliver an effective and balanced portfolio of energy and peak demand savings opportunities across all customer segments. The projected number of participants, the energy and demand savings impact, and the projection of program costs to be borne by the participant, along with budget, savings goals and program costs, for each of the Residential and C&I groupings for 2016-2037 are included in Appendix B, Exhibit 2. Figure 5-3 shows the net cumulative energy savings in each year of the Program Potential by program.

Table 5-19: Energy Efficiency DSM Groupings Provided for Resource Optimization

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

Figure 5-3: Net Cumulative Energy Savings (MWh)



5.4.2 Demand Response Options

In the MPS, a wide variety of possible demand response and pricing options were considered. The demand response options for Residential and Commercial customers included in the MPS are described below:

5.4.3 Direct Load Control

The Direct Load Control program entails control of eligible cooling units (central air conditioners and heat pumps) for the summer peak season as well as space heating units for the winter peak season. Residential participants that have electric water heaters are assumed to be eligible to include their water heater as a curtailable load for both the summer and winter peak seasons. Eligible customers for this program include residential customers with cooling, heating and water heating equipment as well as small and medium C&I customers with space heating and central air conditioners. NIPSCO offered this program in the past for residential and small commercial customers; however, it was discontinued in 2015. Events ran from June through September 2015, and a total of four events were called, with an average of 16.88 MW per event in 2015. The program was included in the analysis for exploratory purposes and expanded to include medium C&I customers as well. Table 5-20 shows the demand response groupings provided for resource optimization in the IRP Model.

Table 5-20: Demand Response (DLC) Groupings Provided for Resource Optimization

DR Program	Eligible Customer Classes	Mechanism	Reliability
Central Air Conditioner Cycling Direct Load Control (DLC)	Residential, Small and Medium C&I	DLC Switch for Central Cooling Equipment	firm
Water Heater Cycling Direct Load Control (DLC)	Residential, Small and Medium C&I	DLC Switch for Water Heating Equipment	firm

NOTE: The Program Potential results provided for resource optimization for the IRP model was originally provided as four DLC Demand Response groupings: (1) AC Cycling DLC (Residential); (2) AC Cycling DLC (Small and Medium C&I); (3) Water Heater Cycling (Res); (4) Water Heating Cycling (Small and Medium C&I)

The demand response options for large and extra-large C&I customers included in the MPS are described below:

5.4.4 Interruptible Load Tariffs

As described above and under Rider 775, large commercial customers enroll directly with NIPSCO in an agreement to curtail their load during system contingencies. This program is implemented by notifying customers of a curtailment event, typically a day in advance, allowing them to respond with load shedding. Customers are paid a credit for curtailed load but charged at market rate if they do not curtail as a penalty for non-performance. In years past, programs like this have actually interrupted customer load at the utility point of service, but this is uncommon in recent times, and the voluntary participation route is now the default standard for future implementation planning. This is NIPSCO's largest and most successful current program. The program is aimed at NIPSCO's largest industrial customers, currently available only to Rates 732, 733 and 734. At the time the MPS was prepared, NIPSCO's program had six (6) participants with a total of 174 economic interruptions called in 2014 with an average of 143 MW per event.

5.4.5 Third Party Aggregator Programs

Participating customers agree to reduce their demand by a specific amount or curtail their consumption to a pre-specified level. In return, they would typically receive a fixed incentive payment from the Aggregator in the form of capacity credits or reservation payments (expressed as $/kW-month or $/kW-year). Customers are paid to be on call even though actual load curtailments may not occur. The amount of the capacity payment varies with the load commitment. In addition to the fixed capacity payment, participants typically receive a payment for energy reduction. Because it is a firm, contractual arrangement for a specific level of load reduction, enrolled load represents a firm resource and can be counted toward installed capacity requirements. Penalties are assessed for under-performance or non-performance and events may be called on a day-of or day-ahead basis as conditions warrant.

This option is delivered by third party load aggregators that have streamlined processes for engaging customers with maximum demand typically greater than 100 kW, particularly those with flexible operations. Customers with 24x7 operations/continuous processes or with obligations to continue providing service (such as schools and hospitals) are often not good candidates. NIPSCO currently has a tariff that could be modified to accommodate this type of program, however there are no third party demand response aggregators currently operating in NIPSCO's service territory, either independently with MISO or contractually with NIPSCO. As shown in Table 5-21, for the analysis, it is assumed that this option will be offered to large and extra-large C&I customers.

Table 5-21: Third Party Aggregator Programs

DR Program	Eligible Customer Classes	Mechanism	Reliability
Interruptible Load Tariffs	C&I, Large and above	Customer enacts their customized, mandatory curtailment plan. Penalties apply for non-performance.	firm
Interruptible Load Tariffs with Third Party Aggregator	C&I, Large and above	Customer enacts their customized, mandatory curtailment plan. Penalties apply for non-performance. Typically managed as a portfolio by third party contractor.	firm

Ultimately, NIPSCO did not include the Industrial Demand Response DSM Groupings in the IRP. Instead of incorporating the estimated amount of Curtailment and Interruptible Load as calculated by AEG and MMP, NIPSCO incorporated the amount to be offered to customers in accordance with the Rate Case Order. The total capacity made available under NIPSCO's Rider 775 – Interruptible Industrial Service Rider is limited to 530 MW and the total sum of credits can not exceed $57,000,000 in any calendar year. Customers with existing Interruptible Capacity under contract (pursuant to previously-effective Rider 675) had priority to re-enroll that same capacity under Rider 775. New capacity was then allocated subject to the capacity and credit limits stated above. Rider 775 now offers an Option E, and now with subscriptions following the Rate Case Order, provides an additional 150 MW as a capacity resource.

5.5 Consistency between IRP and Energy Efficiency Plans

Ind. Code § 8-1-8.5-10 ("Section 10"), which became law on May 6, 2015, requires, among other things, that a utility's energy efficiency goals are (1) reasonably achievable; (2) consistent with the utility's IRP, and (3) designed to achieve an optimal balance of energy resources in the utility's service territory. A utility is required to petition the Commission for approval of an energy efficiency plan under Section 10 beginning not later than calendar year 2017, and not less than once every three years.

To remain consistent with the requirements of Section 10, NIPSCO carried out a lengthy analysis of the DSM resources included in its IRP process. As noted above, NIPSCO completed a market potential study to determine the achievable amount of savings. *See* Appendix B. NIPSCO, through the MPS process discussed above, then conducted an in-depth review of the amount of savings that would be achievable in its service territory with its current customer base. Following that in-depth review process, NIPSCO incorporated 22 energy efficiency DSM groupings and 4 demand response DSM groupings into the model for selection as resources.

As further explained in Section 8.5.1.1: Demand-Side Modeling, while NIPSCO carried out a screening process for the demand-side resources prior to inclusion in the IRP model, NIPSCO performed a similar screen for the supply-side resources prior to inclusion in the model. Once the demand-side resources were included in the IRP model, they were independently and individually available for selection as a resource. The demand-side resources, existing generation resources and supply-side resources are considered on an equal footing.

In accordance with Section 10, NIPSCO intends to request approval in 2017 of an energy efficiency plan for implementation in 2019 ("2017 Filing") that includes:

- energy efficiency goals that are (1) reasonably achievable; (2) consistent with NIPSCO's 2016 IRP, and (3) designed to achieve an optimal balance of energy resources in its service territory;

- energy efficiency programs that are (1) sponsored by an electricity supplier and (2) designed to implement energy efficiency improvements;

- program budgets;

- program costs that include (1) direct and indirect costs of energy efficiency programs, (2) costs associated with the EM&V of program results, (3) recovery of lost revenues and performance incentives. For purposes of this filing, the "direct costs" are those associated with implementing the programs, including any costs associated with program start up, while "indirect costs" are the NIPSCO administrative costs; and

- the EM&V procedures that involve an independent EM&V.

NIPSCO intends to develop a DSM Action Plan prior to its 2017 EE program filing based on the energy efficiency DSM Groupings selected by the IRP model. This will serve as a refresh of the MPS as well as providing more specificity around how the DSM Groupings selected by the model will be utilized When creating its DSM Action Plan, NIPSCO will include the energy efficiency DSM Groupings selected by every scenario and also review for inclusion any additional energy efficiency DSM Groupings that were selected by at least one scenario within the IRP or groupings that are appropriate for inclusion for other reasons (i.e. to balance out the portfolio with the gas service territory program offering). The DSM Action Plan will also support NIPSCO's request for proposals for implementation and evaluation of the Energy Efficiency Plan.

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

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

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

Section 6. Transmission and Distribution System

Consistent with the principles set out in Section 1.1, NIPSCO continues to invest in its existing Transmission and Distribution resources to ensure reliable, compliant, flexible, diverse and affordable service to its customers. NIPSCO continually assesses the current physical transmission and distribution system resources for necessary improvements and upgrades to meet future customer demand or other changing conditions. As part of this effort, NIPSCO participates in the planning processes at the state, regional, and federal levels to ensure that its customers' interests are fully represented and to coordinate its planning efforts with others. The goals of the planning process include:

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

6.1 Transmission System Planning

6.1.1 Transmission System Planning Criteria and Guidelines

NIPSCO Transmission System Planning Criteria requires performance analysis of the transmission system for the outage of various system components including but not limited to generators, lines, transformers, substation bus sections, substation breakers, and double-circuit tower lines. Adequacy of transmission system performance is measured in terms of NIPSCO planning voltage criteria, facility thermal ratings, fault interrupting capability, voltage stability, and generator rotor angle stability as documented in the NIPSCO 2016 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (Confidential Appendix J). When a violation of one or more of these requirements is identified, Transmission Planning develops mitigations that may consist of operating measures and/or system improvements.

6.1.2 North American Electric Reliability Corporation

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

6.1.3 Midcontinent Independent System Operator, Inc.

NIPSCO participates in the larger regional transmission reliability planning process through participation in the Midcontinent Independent System Operator, Inc. ("MISO"), which annually performs a planning analysis of the larger regional transmission system through the MISO Transmission Expansion Plan ("MTEP"). The MTEP process identifies reliability adequacy on a larger regional basis and ensures that the transmission plans of each member company are compatible with those of other companies. It should be noted that while any transmission project NIPSCO wishes to build must generally be timely submitted for planning review by MISO to ensure that there is no harm to other systems in MISO, so long as NIPSCO does not request cost sharing of the project with other MISO members, NIPSCO does not have to obtain MISO Board approval to proceed with a transmission project if NIPSCO deems it necessary. Additionally, under extenuating circumstances, NIPSCO can request expedited review of those cost-shared projects that do require MISO Board approval.

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

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

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

Because NIPSCO is situated on a very significant boundary (seam) between MISO and PJM, NIPSCO participates in the coordination of transmission planning efforts between MISO and PJM under the MISO-PJM Joint Operating Agreement.

In addition, MISO may propose transmission system projects or other upgrades that are not reliability based, but are economically based and should relieve congestion. These projects must pass the Benefit Cost Ratio test established by MISO before approval. NIPSCO participates in this effort through the MISO Market Efficiency Planning Study, and the MISO-PJM Interregional

Planning Stakeholder Advisory Committee which performs a coordinated system planning study with PJM.

NIPSCO is also an active participant in the Market Efficiency Project (MEP) planning processes in both MISO and PJM. The MEP processes focus on evaluating potential future transmission projects to lower the overall production cost and lower delivered energy costs to the end use customer for the MISO and/or PJM footprint. These planning efforts require the benefits of proposed projects to exceed the costs (usually 1.25 or greater benefit to cost ratio) before the RTOs will consider it a viable solution. MISO has approved three Market Efficiency Projects in its footprint since the process's inception in 2008.

6.1.4 Market Participants

MISO has developed a process through which market participants can request voluntary upgrades on the NIPSCO transmission system to better accommodate generation outlet capacity, increases in transmission rights, reduce congestion, address reliability considerations, or other market driven needs. If the Market Participant wishes to pursue these types of upgrades, they must submit their proposal to MISO, and NIPSCO and the Market Participant must negotiate payments for these upgrades as defined in the MISO tariff and corresponding Business Practice Manuals. Market Participant-Funded Projects must be filed in a timely manner with MISO for review in its transmission planning process.

6.1.5 Customer Driven Development Projects

NIPSCO may be contacted to undertake transmission upgrades by individual customers based on the customer's plans for economic development or expansion. In coordination with the customer, NIPSCO Major Accounts, and NIPSCO Economic Development, will determine if identified transmission upgrades are identified necessary to meet the customer's development or expansion plans.

6.1.6 Transmission System Performance Assessment

In NIPSCO's 2016 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (Confidential Appendix J), Confidential Part 2 contains the regional power flow cases. The cases include solved real and reactive flows, voltages, detailed assumptions, sensitivity analyses, and model description. Confidential Part 3 contains applicable transmission maps. Part 4 describes the reliability criteria used for transmission planning. Confidential Part 5 presents the assessment practice used.

Confidential Part 6 contains an evaluation of the reliability criteria in relation to the present performance and the expected performance of the NIPSCO transmission system. Performance assessments are conducted annually for the near-term (5 year) and long-term (10 year) planning horizons, for both peak and off-peak load conditions, assuming known or forecasted changes in generation resources and load demand. Sensitivities to baseline forecasts or assumptions may also be considered for performance analysis of the transmission system.

NIPSCO also participates in the MISO and PJM Market Efficiency Project planning processes as discussed in Section 6.1.3: Midcontinent Independent System Operator, Inc. The MISO process includes multiple future scenarios to test future sensitivities against baseline assumptions.

6.1.7 NIPSCO Transmission System Capital Projects

NIPSCO's portfolio of transmission system projects has been identified through its annual transmission system performance assessment to establish base line reliability projects. This portfolio has been expanded to include transmission projects initiated by market participants, by customer driven development projects, and to include regional transmission projects designated as Multi-Value Projects ("MVP") identified through the MISO MTEP planning effort in 2011. NIPSCO's current portfolio includes:

- Hiple Substation redundant protective relaying addition
- MVP 11: Sugar Creek Substation upgrades to accommodate the new 345 kV circuit from Ameren's Kansas West substation to the NIPSCO/DEI jointly-owned Sugar Creek substation
- MVP 12: A new NIPSCO 345 kV circuit from Reynolds to Burr Oak to Hiple substations
- MVP 14: A new NIPSCO/PIONEER jointly-owned 765 kV circuit from the Duke Greentown substation to the NIPSCO Reynolds substation

The approximate cost of this portfolio is $549M assuming NIPSCO's 41% share of the MVP 14 cost.

6.1.8 Electric Infrastructure Modernization Plan

The Transmission, Distribution, and Storage System Improvement Charge (TDSIC) is an initiative to modernize infrastructure through upgrades to the NIPSCO electric and natural gas delivery systems. The Commission issued its Order in Cause No. 44733 on July 12, 2016 approving NIPSCO's 7-Year Electric TDSIC Plan (2016-2022). NIPSCO's 7-Year Electric TDSIC Plan is focused on transmission and distribution investments made for safety, reliability, and system modernization. The Plan also makes provision for appropriate economic development projects in the future, although none are proposed at this time.

NIPSCO's 7-Year Electric TDSIC Plan includes necessary investments that enable NIPSCO to continue providing safe, reliable electric service to its customers into the future. The Plan is comprised of two main segments: (1) investments that target replacement of aging assets (Aging Infrastructure) and (2) investments intended to maintain the capability of NIPSCO's electric system to deliver power to customers when they need it (System Deliverability). In developing its Plan, NIPSCO considered the need to maintain a safe and reliable system.

The approximate cost of the transmission portion of the TDSIC plan is $453M.

6.1.9 Evolving Technologies and System Capabilities

NIPSCO Transmission Planning has provided for the installation of two variable shunt reactors (“VSR”) at the Hiple 345kV substation as part of the Multi-Value Projects. The VSRs, which will enable better and more precise control of transmission system voltage, are a relatively recent development in the industry.

6.2 Distribution System Planning

As part of the long term view, NIPSCO continues to evaluate the benefits of smart grid and distribution automation technology and to assess deployment of various new technologies based upon corporate investment strategies in infrastructure.

NIPSCO’s distribution system is periodically reviewed for local circuit, substation and source feed adequacy. Normal operating status as well as single element or contingency failure loading and voltage operating characteristics are evaluated along with circuit and system wide reliability metrics (i.e., CAIDI, SAIDI, SAIFI).[3] Distribution operating and design criteria rely on NIPSCO design maximums in accordance with Company Standards and equipment manufacturer ratings. Voltage operating criteria are based on ANSI C84.1 and Indiana Administrative Code 170 IAC 4-1-20.

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

Net Metering is an electricity policy for consumers who own renewable (solar, wind, biomass) energy facilities. Its application provides an incentive for customers to install renewable energy systems by reimbursing them for their generation output, at Utility retail rates, for energy in excess of their service’s base load electricity purchase from the utility. Typically this represents the aggregate excess power produced that is not utilized internally by the customer but is instead delivered into the utility’s local electric system.

Feed-In Tariff (renewable energy payments) is another policy mechanism designed to encourage the adoption of renewable energy sources and to help accelerate the move toward renewable energy sources. This tariff provides power developers with a predictable purchase price

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

for self-generation under a long-term power purchase arrangement, which helps support financing opportunities for these types of projects.

NIPSCO implemented its Renewable Feed-In Tariff in July 2011 along with its existing Net Metering program. These programs introduced customer-owned renewable resource based generation onto NIPSCO's electric distribution system. A relatively significant amount of renewable generation projects began coming "on line" in 2012 and that amount has continued to grow. NIPSCO's Net Metering and Feed-In Tariff generation interconnection programs provide an incentive and path for customers to integrate their own distributed generation resources into NIPSCO's electric distribution systems. Solar, wind, and biomass fueled generation resources have been deployed by customers in varying amounts across the service territory.

At the end of 2015, the renewable generation data identified 2.91 MWs associated with the Net Metering program and 34.3 MWs of generation associated with the Feed-In Tariff program. An aggregate breakdown by renewable fuel type is provided below. These values represent generation resources that include landfill gas combustion engines, animal waste gas combustion engines, PV solar array farms, small roof mounted and ground mounted residential solar arrays, intermediate sized commercial wind turbines, and small commercial and residential wind turbines.

Net Meter Generation:

- 0.81 MWs - Solar Generation
- 1.92 MWs - Wind Generation
- 0.17 MWs - Solar/Wind Combination Generation

Feed-In Tariff Generation:

- 19.17 MWs - Solar Generation
- 0.78 MWs - Wind Generation
- 14.35 MWs - Biomass Generation

The above biomass related generation value excludes 13.6 MWs of existing landfill based generation interconnected to NIPSCO's distribution system. Although these renewable generation sources feed into NIPSCO's network, the power deliveries are associated with customer purchase agreements with parties other than NIPSCO. These customers do not participate in NIPSCO's Net Metering or Feed-In Tariff programs. In total, approximately 51 MWs of generation is interconnected to NIPSCO's distribution system.

Based on the implementation of the Net Metering and Feed-In Tariff programs, Distribution Planning has observed voltage related operating impacts on its electric system due to larger customer-owned generation. Impacts on system operations has yet to be fully determined and will depend upon the demonstrated long term performance and reliability of various installed generating resources including solar, wind, and biomass based generation fueled resources.

Differences in operational characteristics, generation penetration, power delivery timing, and location all affect the relative impact on local distribution system operations at any given time. The diverse types of customer-owned generation also have varying effects on the electric system.

NIPSCO has observed that local generation most often varies substantially depending upon individual customer equipment and generation input resources. Fuel resource type affects power delivery in various ways depending upon owner controlled resources as is the case of landfill and animal by-product gas inputs, or external environmental conditions such as wind velocity and solar irradiance. Highly variable outputs have been observed to occur on both solar and wind turbine installations. For instance, rapid changes in solar generation have exhibited swings of 85% of full rated output, within seconds. These conditions represent sizable down-up-down shifts in system operating characteristic on local circuits associated with some of the larger half megawatt or greater rated customer owned solar fields. These swings can present challenges to maintaining good service voltage stability on distribution circuits. In addition to these more rapid changes relating to industry recognized "cloud affect," NIPSCO has also observed that more widespread weather patterns such as seasonal rain or snow storms also dramatically influence individual daily peak PV generation outputs on a longer term scale. Longer duration output reductions of 75% to 92% of rated equipment output are observed during seasonal inclement weather conditions. Significantly reduced output levels can be seen extending over several or more days, especially during winter season months. Wind powered generation was also observed to be as much, if not more, unpredictable and variable in power delivered to the distribution system. On the other hand, large biomass fueled combustion turbines appear to be less volatile in generated outputs in comparison to solar and wind associated generation. Landfill based biomass generation facilities tend to be the most predictable followed by animal waste gas associated generation. However, even though biomass fueled resources exhibit a steadier dispatch of power, there were experiences of random events where customer generation dropped completely off line. The impact of lost generation becomes more significant as the generation level increases since the local distribution system needs to adjust and compensate for fast change in power sources.

Based upon several years of operating data for currently installed renewable generation resources, these technologies present a recognized energy resource that can be utilized in supplementing customer electric energy needs. However, at this time, the impact on local electric distribution service infrastructure has not demonstrated to be sufficiently available or stable to be considered an adequate 24/7 substitute for NIPSCO's local electric sources in reliably meeting electric capacity and service needs. Considering that these distributed generation resources have no guarantee of power dispatch, operate in a "take it as we make it" mode, and can permanently cease operations at any time, results in a lower confidence level regarding the availability of power supply at all times, especially during periods of system stress or problems. Consequently, continued traditional capital investment into local distribution infrastructure is necessary to insure that the utility can meet all of its service obligations to its customers.

6.2.1 Electric Infrastructure Modernization Plan

The Transmission, Distribution, and System Storage Improvement Charge is an initiative to modernize infrastructure through upgrades to electric and natural gas delivery systems. The Commission issued its Order in Cause No. 44733 on July 12, 2016 approving NIPSCO's 7-Year

Electric TDSIC Plan (2016-2022). NIPSCO's 7-Year Electric TDSIC Plan is focused on transmission and distribution investments made for safety, reliability, and system modernization. The Plan also makes provision for appropriate economic development projects in the future, although none are proposed at this time. NIPSCO's 7-Year Electric TDSIC Plan includes necessary investments that enable NIPSCO to continue providing safe, reliable electric service to its customers into the future. The Plan is comprised of two main segments: (1) investments that target replacement of aging assets (Aging Infrastructure) and (2) investments intended to maintain the capability of NIPSCO's electric system to deliver power to customers when they need it (System Deliverability). In developing its Plan, NIPSCO gave top priority to maintaining a safe and reliable system.

6.2.2 Evolving Technologies and System Capabilities

NIPSCO Transmission Planning has provided for the installation of two variable shunt reactors ("VSR") at the Hiple 345kV substation as part of the Multi-Value Projects. The VSRs, which will enable better and more precise control of transmission system voltage, are a relatively recent development in the industry.

NIPSCO Distribution Planning continues the expansion of Distribution Automation ("DA"). DA can be defined as the coordinated automatic control of substation breakers and interrupting-type line switches within an electric distribution system, along with the centralized retrieval of associated operating data for control and monitoring purposes.

NIPSCO's DA System enables control and automatic isolation of electric distribution line faults and the restoration of customer services during various 12.5 kV system outage conditions. This action is accomplished through independent sectionalizing of specific circuits through the use of automatic line switches and computer-controlled substation breakers. Built-in algorithms are utilized to analyze operating conditions such as line and substation loading, to determine best response to system disturbances. Automatic restoration increases distribution system reliability by reducing the number of customers experiencing a sustained outage. In addition to the quick restoration of electric service, real-time operating data can also be retrieved and stored on the electric management system. DA Systems provide timely and accurate outage-related information to restoration teams, speeding up problem identification. This action supports quicker overall response time to identify system problems and develop repair procedures. These factors result in further improvements in customer service and system reliability. An added benefit of real-time data retrieval and device remote control is the more effective use of labor resources for operation and maintenance of the electric distribution system.

NIPSCO currently utilizes DA (communications and remote switching) on 25% of its distribution substations and 30% of its distribution circuit population. Approximately two-thirds of all DA associated circuits utilize autonomous contingency switching equipment in their operations. All new and rebuilt distribution substations, and associated circuits, are equipped with distribution automation as part of their infrastructure projects. As part of annual system capital investment programs, new and/or rebuilt substation projects are being implemented at an approximate rate of one to two stations per year.

NIPSCO continues to evaluate the benefits of smart grid and DA technology and to assess deployment of various new technologies based upon corporate investment strategies in infrastructure as part of its long term approach.

Section 7. Environmental Considerations

7.1 Environmental Compliance Commitment

NIPSCO is committed to complying with all environmental, legal, and other regulatory requirements affecting the environment. This commitment is embodied in NIPSCO's Environmental Policy and is implemented through an environmental management system. NIPSCO operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste and solid waste. Compliance plan options are developed, reviewed, and evaluated for implementation to meet new legislative and regulatory developments. NIPSCO discusses each of the complex environmental issues in this section.

7.2 Environmental Regulations

7.2.1 Clean Air Act

NIPSCO expects a number of new air-quality mandates to be phased-in over the next several years. These mandates may require NIPSCO to make capital improvements to its electric generating stations.

7.2.1.1 Greenhouse Gases

Existing climate-related environmental laws and regulations may be revised in addition to new laws and regulations being adopted or becoming applicable to NIPSCO. Revised or additional laws and regulations could result in significant additional operating expense and restrictions on NIPSCO's facilities and increased compliance costs. Moreover, such costs could affect the continued economic viability of one or more of NIPSCO's facilities.

Because NIPSCO operations involve the use of natural gas and coal fossil fuels, greenhouse gases ("GHG") emissions are inherent in the business. While NIPSCO has reduced GHG emissions through efficiency and other programs, GHG emissions cannot be entirely eliminated. On June 25, 2013, the Executive Office of the President of the United States issued a Climate Action Plan. One of the three pillar components of the plan is to cut GHG emissions and most specifically to cut GHG emissions from power plants. In addition to the plan, the President issued a memorandum directing the EPA to finalize GHG standards for both new and existing electric generating units ("EGUs"). The EPA is using the Clean Air Act to issue New Source Performance Standards ("NSPS") to reduce GHG emissions from both new and existing EGUs. On October 23, 2015, the EPA issued a final rule, the Clean Power Plan ("CPP"),[4] to regulate CO_2 emissions from existing fossil-fuel fired EGUs under section 111(d) of the Clean Air Act ("CAA"). The CPP establishes national CO_2 emission-rate standards that are applied to each state's mix of affected EGUs to establish a state-specific emission-rate and mass-emission limits. The CPP

[4] On February 9, 2016, the U.S. Supreme Court stayed CPP enforcement, pending future court rulings. Challenges to the CPP are currently pending before the U.S. Court of Appeals for the District of Columbia Circuit. These cases are expected to be appealed to the Supreme Court, with a final ruling most likely in 2017-2018. State plan submission dates and final compliance dates will be extended pending final court review.

provides an option for each state to submit a plan indicating how the state will meet the EPA's emission-rate or mass-emission limit, including the possibility of imposing reduction obligations on specific units. If a state takes advantage of available extensions, the state's plan must be submitted to the EPA by September 6, 2018. If a state chooses to not submit a plan or does not submit a satisfactory plan, the EPA will impose a Federal Implementation Plan ("FIP") on that state. The cost to comply with this rule will depend on a number of factors, including the requirements of the final federal regulation and the level of NIPSCO's required GHG reductions. It is possible that this new rule, comprehensive federal or state GHG legislation, or other GHG regulation could increase NIPSCO's cost of producing energy, which could impact customer demand and customer costs.

Based on the CPP and the associated legal challenges, it does not appear likely that widespread GHG reductions will be required until 2022 or later. NIPSCO is estimating that a price on carbon will not be established prior to 2023 in all cases except for a Base Delayed Carbon case, where carbon price comes in 2 years later in 2025.

7.2.1.2 National Ambient Air Quality Standards

The CAA requires the EPA to establish national ambient air quality standards for six criteria pollutants considered harmful to public health and the environment. The EPA imposes new, or modifies existing, National Ambient Air Quality Standards ("NAAQS") periodically and requires states that contain areas that do not meet the new or revised standards to take action toward achieving compliance with the standards through the use of local- or regional-based emission control measures. These actions could include adding pollution controls on EGUs.

The following NAAQS were recently added, modified, or are in the process of being revised:

- Ozone NAAQS - On October 26, 2015, the EPA lowered the ozone standard from 75 ppb to 70 ppb. After the EPA proceeds with new designations, areas where NIPSCO operates may be classified as nonattainment. Porter County (Bailly Generating Station) was designated as nonattainment effective July 20, 2012. Since NO_x control technology already operates on all NIPSCO generating units, NIPSCO does not expect that any current or potential ozone nonattainment designations will change NIPSCO's EGU control requirements.

- SO_2 NAAQS - On December 8, 2009, the EPA revised the SO_2 NAAQS by adopting a new 1-hour primary NAAQS for SO_2. The EPA designated areas that do not meet the new standard. Counties in which NIPSCO has coal-fired generating stations are currently designated as unclassifiable. NIPSCO operates flue gas desulfurization ("FGD") on all of its coal units. Therefore, NIPSCO does not expect that future attainment designations will change NIPSCO's EGU control requirements.

- PM NAAQS - On January 15, 2013, EPA published an update to the annual health standard for Particle Matter ("PM") at 12 micrograms per cubic meter. All counties in which NIPSCO has coal-fired generating stations are currently designated as either attainment or unclassifiable with the PM NAAQS. NIPSCO does not expect that future attainment designations will likely change NIPSCO's EGU control requirements.

7.2.1.3 Acid Rain Program

The CAA Amendments of 1990 introduced a new nationwide approach to reduce the emission of acidic air pollutants. The Acid Rain Program was designed to reduce electric utility emissions of SO_2 and NO_x through a market-based cap and trade system. While the SO_2 reductions were achieved in two phases by the establishment of lower overall emissions caps, NO_x emission controls were required using a two-phased control technology-based emission reduction program. NIPSCO is fully in compliance with the EPA's Acid Rain Program.

7.2.1.4 Regional Pollutant Transport Requirements

The EPA has determined that, for purposes of achieving ozone and particulate attainment, emissions from certain upwind states, including Indiana, 'contribute significantly' to downwind state nonattainment areas. As a result, the Cross State Air Pollution Rule ("CSAPR") was developed to address regional pollutant transport issues. CSAPR reduces overall emissions of SO_2 and NO_x by setting state-wide caps on power plant emissions. The EPA began enforcing CSAPR on January 1, 2015. An update to CSAPR was subsequently proposed in November 2015 and finalized in September 2016. The updated rule reduces regional NO_x emissions starting in the 2017 "ozone season" (May-September). Based on current projections of future emissions and the generation strategy outlined in the 2016 NIPSCO IRP, NIPSCO does not anticipate that capital investments will be needed to comply with the updated CSAPR rule.

7.2.1.5 Utility MATS Rule

On December 16, 2011, the EPA finalized the MATS rule establishing new emissions limits for mercury and other air toxics. Compliance for NIPSCO's affected units was required by April 2015 and April 2016. NIPSCO developed and obtained IURC and Indiana Department of Environmental Management ("IDEM") approval of a plan for environmental controls to comply with the MATS rule. *See* Cause No. 44340 (IURC 10/10/2013).

7.2.1.6 Consent Decree

On September 29, 2004, the EPA issued a Notice of Violation ("NOV") to NIPSCO for alleged violations of the CAA and the SIP. The NOV alleged that modifications were made to certain boiler units at three of NIPSCO's generating stations between the years 1985 and 1995 without obtaining appropriate air permits for the modifications. NIPSCO, the EPA, the Department of Justice, and IDEM settled the matter.

The Consent Decree was entered by the United States District Court for the Northern District of Indiana on July 22, 2011. The Consent Decree covers NIPSCO's four coal generating stations: Bailly, Michigan City, Schahfer and Mitchell. NIPSCO surrendered CAA permits for Mitchell's coal-fired boilers, which have not been used to generate power since 2002. At the remaining three generating stations, NIPSCO was required to install additional control equipment, including three new SO_2 control devices and one new NO_x control device, for which construction of all required control devices was completed by early 2016. The Consent Decree also imposed emissions limits for NO_x, SO_2, and PM, and annual tonnage limits for NO_x and SO_2. NIPSCO is in compliance with the terms of the Consent Decree including installation of new air emission controls.

7.2.2 Clean Water Act

The Clean Water Act ("CWA") establishes water quality standards for surface waters as well as the basic structure for regulating discharges of pollutants into the waters of the United States. Under the CWA, EPA implemented pollution control programs such as setting wastewater standards for industry, including electric utilities. In addition, the CWA made it unlawful to discharge any pollutant from a point source into navigable waters without a permit. The National Pollutant Discharge Elimination System ("NPDES") permit program implements the CWA's provisions and prohibits unauthorized discharges by requiring a permit for point sources impacting waters of the United States. NIPSCO anticipates that the following rules may require NIPSCO to make capital improvements to its electric generating stations.

7.2.2.1 CWA 316(b) Cooling Water Intake Structures

Section 316(b) Cooling Water Intake Structure rule of the CWA became effective October 14, 2014 requiring all large existing steam electric generating stations with cooling water intake structures to deploy the best technology available to minimize adverse environmental impacts to fish and shellfish.

The final 316(b) rule leaves much to the discretion of IDEM and EPA Region V to review and approve NPDES permits. The rule sets separate standards for impingement and entrainment mortality that are established in each facility's NPDES permit based on site specific conditions. Under 316(b), NIPSCO's Michigan City and Schahfer generating stations, which have closed cycle cooling systems, have been deemed to meet Best Technology Available ("BTA") through an IDEM Best Professional Judgement ("BPJ") determination. NIPSCO's Bailly generating station does not have a closed cycle cooling system. According to the NPDES permits, IDEM reserves the right to require further studies which could possibly lead to additional controls in the future at the Michigan City and Schahfer generating stations. It is likely that if NIPSCO's Bailly generating station continues to operate beyond 2018, studies will be required by which a determination could be made on the optimum intake flow control technology for site specific conditions and capital investments may be required to meet 316(b) requirements.

7.2.2.2 Effluent Limitation Guidelines

The EPA issued a final rule regulating wastewater stream processes and byproducts associated with steam electric power generation including targeted Effluent Limitation Guidelines ("ELG"). This complex rule, which became effective on January 4, 2016, was revised to update the regulation of ELGs based on industry and technological advancement since the rule was last updated in1982.

The ELG rule addresses seven different wastewater streams from EGUs. However, the rule impacts only two wastewater streams, ash handling water and FGD wastewater, at NIPSCO's facilities. The rule requires compliance no sooner than November 1, 2018 and no later than December 31, 2023. Specific applicability dates for complying with the rule requirements vary by waste stream and location, and are dependent upon negotiation with IDEM as well as the technologies chosen to address each applicable waste stream. The units at Bailly, Michigan City and Schahfer generating stations are regulated by the ELG rule. Regulated units scheduled for retirement by December 31, 2023, will meet the Zero Liquid Discharge (ZLD) requirement of the rule and therefore will not require additional pollution control technology to comply with the rule.

7.2.2.3 Solid Waste Management

The EPA finalized a rule regulating the disposal of Coal Combustion Residuals ("CCR")[5] which became effective on October 19, 2015. The rule focuses on CCR storage, treatment and disposal units and mandates that each be evaluated for structural integrity and proof that they are not contaminating groundwater, as well as other compliance criteria. The rule applies nationally to electric utilities and independent power producers, including each of NIPSCO's three active coal fired EGUs. Each of NIPSCO's stations will require capital and retirement investments to meet the rule requirements. The level of investment will be dependent on the operational status of each of the units as CCR milestones are met. NIPSCO will request authority from the IURC for cost recovery of all capital investments required to bring each NIPSCO EGU into compliance with the CCR rule.

The CCR rule is self-implementing. Enforcement is driven by citizen suits or states acting as citizens. The CCR rule compliance requirements are phased in over time and may be based on findings and results from earlier phases of data collection. The rule requires documentation and results of compliance related activities be posted on a publicly accessible internet site to provide external stakeholders full access to CCR related activities and determinations. The CCR rule is closely tied to the ELG[6] rule, based on regulation of the liquid and solid portions of the same waste streams by the ELG and CCR rules, respectively.

7.3 Environmental Compliance Plan Development

Since the pace of regulatory change from EPA rulemakings has been and will continue to be highly dynamic, NIPSCO uses a combination of external consulting resources and internal staff to develop and adjust environmental compliance plans. Consultants, architectural firms, and engineering firms are utilized to assist NIPSCO in developing cost estimates and perform modeling of NIPSCO's environmental requirements to develop compliance plans to address proposed and expected EPA rules. As the rules change, the plans are adjusted to comply with the new requirements.

5 40 CFR Parts 257 and 261, Published in the Federal register April 17, 2015.

6 40 CFR Part 423, Published in the Federal Register November 3, 2015.

In 2014, prior to the ELG and CCR rules being finalized, NIPSCO secured the expertise of CH2M to explore market ready compliance options, to study the impact these two rules would have on NIPSCO's generating facilities and to understand how the two rules interfaced. When the ELG and CCR rules were finalized, NIPSCO contracted with Burns and McDonnell and CH2M, respectively, to develop an ELG and CCR integrated compliance plan for each of NIPSCO's generating stations. Compliance Plans were chosen based on requirements to compliance with rule, safety, cost (capital and expense), reliability, performance and constructability. Prior to finalizing, the ELG and CCR Compliance Plans will be reviewed by third parties for feasibility, compliance and cost.

For CCR compliance planning, NIPSCO considered the following options: lined and/or retrofitted CCR ponds, de-watering bins, remote ash conveying and under boiler ash conveying. After a robust selection process, NIPSCO has narrowed the options to remote ash conveying and under the boiler ash conveying. NIPSCO continues to evaluate these two options for feasibility and cost.

For ELG compliance planning, NIPSCO considered the following options: physical/chemical treatment in combination with adsorptive media, a biological system (e.g. AbMet, fixed bed reactor and moving bed bio-reactor) or a passive biological system, zero valent iron, deep well injection; a spray evaporation system; and zero liquid discharge (ZLD - evaporator only or evaporator and crystallizer). For the Schahfer generating station, ZLD is being considered as the most viable compliance strategy. If all four units at are considered, a ZLD system with an evaporator and crystallizer are required, due to the large amounts of water that Unit 17 and Unit 18 use in the FGD process. Unit 14 and Unit 15 FGDs produce approximately 25% of the flow that Unit 17 and Unit 18 FGDs produce. If only Unit 14 and Unit 15 are considered, a much smaller ZLD system with an evaporator only will be required. Due to the dry FGD system at the Michigan City generating station the facility will be ELG compliant with the implementation of the CCR Compliance Plan.

With respect to compliance planning for a future update to the CSAPR rule (Ozone), NIPSCO assumed NO_x reductions are required for Unit 17 and Unit 18 at Schahfer generating station. This assumption ensures compliance with a rule that has not yet been proposed. To attain these NO_x reductions, SCR (Selective Catalytic Reduction) emission control technology is required. Both Unit 17 and Unit 18 at Schafer generating station are already equipped with Low NO_x Burners and Over Fire Air for NO_x reduction. SCRs and SNCRs are the next level of NOx control. The SCR technology allows for greater NO_x reduction rates which equates to better operational flexibility. Therefore SCR technology was assumed for the plan to comply with the anticipated limits and Class V, conceptual estimates were provided.

With respect to compliance planning for 316(b), the Water Intake Structure rule, NIPSCO utilized an engineering study, prepared by W. F. Baird & Associates, Ltd, that provided cost estimates for a number of compliance alternatives. A porous dike structure was selected as the most cost effective and viable option for compliance at the Bailly generating station. The estimate is a Class V, conceptual estimate.

7.4 Emission Allowance Inventory and Procurement

7.4.1 Title IV Acid Rain - SO_2 Emission Allowance Inventory

In conjunction with CSAPR, the Title IV Acid Rain Program will continue to regulate emissions. Table 7-1 lists by year the actual number of SO_2 Acid Rain Program emission allowances held in inventory by NIPSCO as of September 2016 for the period 2016 through 2046. Based on current projections of future emissions, NIPSCO does not need to procure additional allowances to comply with the Acid Rain Program.

Table 7-1: SO_2 Acid Rain Program Emission Allowances

Acid Rain Program
SO_2 **Allowance Inventory***

Year	Allowances
Bank**	248,485
2016	36,606
2017	50,706
2018	50,706
2019	50,706
2020+	50,706
Total	**1,806,271**

* Allowance inventory available in September 2016
** Reflects emission allowances from 2015 and earlier

7.4.2 CSAPR Emission Allowance Inventory

Under CSAPR, allowances are allocated to NIPSCO and managed separately from the Acid Rain Program. Table 7-2 lists the annual SO_2, annual NO_x and ozone season NO_x allowance inventory issued to NIPSCO. Based on current projections of future emissions, NIPSCO does not need to procure additional allowances to comply with the CSAPR rule.

Table 7-2: CSAPR Allowance Inventory

CSAPR Allowance Inventory*

Year	Annual SO_2	Annual NO_x	Ozone Season NO_x
Bank**	20,720	901	**563**
2016	41,977	14,060	**6,739**
2017	23,522	13,772	
2018	23,522	13,178	
Total	**109,741**	**41,911**	**7,302**

** Allowance inventory available in September 2016.*

*** Reflects emission allowances from 2015.*

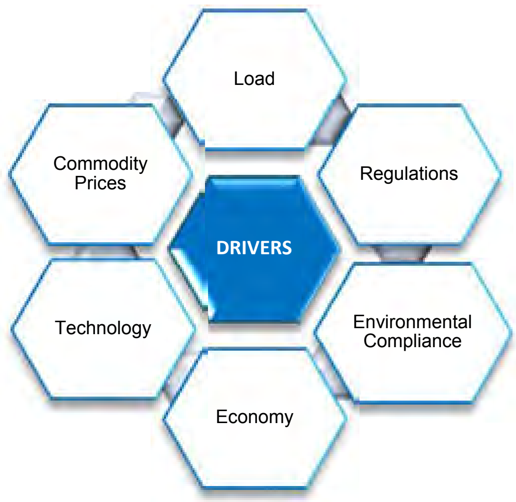
Section 8. Managing Risk and Uncertainty

8.1 Scenario Development

8.1.1 Scenario Methodology

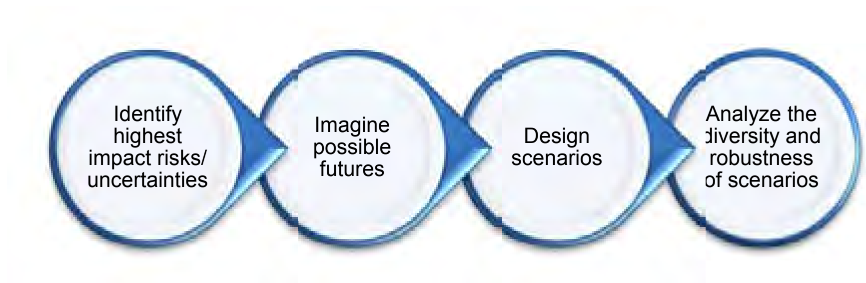
Scenario planning is useful for determining how various business decisions will fare in an uncertain future world. The first step NIPSCO used in developing the 2016 IRP scenarios was to identify key uncertainties or drivers that could potentially affect its business environment. *See* Figure 8-1: Scenario Drivers.

Figure 8-1: Scenario Drivers



These uncertainties were used as building blocks to construct NIPSCO's scenarios. *See* Figure 8-2: Scenario Building Process. After the drivers were identified, NIPSCO developed narratives to describe the possible futures, which were then grouped by common "themes" or scenarios. The scenarios were then assessed for diversity and robustness to ensure that they cover wide range of the most critical uncertainties and are internally consistent across the scenarios.

Figure 8-2: Scenario Building Process



8.1.2 Fundamental Commodity Prices

The fundamental commodity prices that served as the key scenarios assumptions were provided by PIRA Energy Consultants. The following seven long-term commodity pricing cases were developed for *Strategist*®: (1) Base, (2) Base Delayed Carbon, (3) Base No Carbon, (4) Low, (5) Low No Carbon, (6) High, and (7) Very High.

8.1.2.1 Base Commodity Case

This scenario assumes that (1) dry Appalachian gas supply continues to grow, although wet gas supply recovers more slowly than oil prices; (2) industrial gas demand will accelerate as gas prices remain low; (3) coal-fired electric generation will decrease significantly, driven by competition with natural gas and the added costs of compliance with environmental regulations; (4) overall, coal demand will fall significantly, especially for Central Appalachian coal; and (5) a national carbon price will come into effect in 2023, starting at $6.75/ton nominal and increases to ~$36/ton by 2035.

8.1.2.2 Base Delayed Carbon Commodity Case

This scenario reflects a bearish view of commodity prices over the next 20 years. The major changes from the Base Scenario encompass lower load growth, lower fuel prices, lower renewable cost, federal tax credits exemptions and a higher renewable portfolio standard ("RPS") driving renewable growth. The most notable change from the Base Commodity Case is the delayed implementation of a carbon policy with a much slower path to a national carbon policy. Natural gas supplies from the Appalachian shale fields remain strong throughout the study period. Natural gas prices in this scenario are much lower than the Base Commodity Case due to the increased supply growth and weakness in demand from the power sector combined with the later implementation of a national carbon program. In this scenario, coal prices drop, but not as drastically as the gas prices, due to coal prices remaining close to the cost of production. Finally, a national carbon policy, modeled as a carbon price, will take effect starting in 2025 with a gentler path. Carbon price starts at $4.50/ton nominal and increases to ~$35/ton by 2035.

8.1.2.3 Base No Carbon Commodity Case

This scenario utilizes the same assumptions as the Base Commodity Case with the exception of the absence of a national carbon policy.

8.1.2.4 Low Commodity Case

This scenario assumes strong technological innovation and productivity improvements, which decrease shale gas production costs and greatly increase supply. As a result, natural gas prices are significantly lower than in the Base Commodity Case. Lower gas prices and continuing expansion of environmental regulation on coal-fired generation leads to lower coal demand and significantly lower coal prices. A national carbon price, with the same costs as the Base Commodity Case, is introduced in 2023.

8.1.2.5 Low No Carbon Commodity Case

This scenario utilizes the same assumptions as the Low Commodity Case with the exception of the absence of a national carbon policy.

8.1.2.6 High Commodity Case

This scenario assumes that natural gas prices are significantly higher than in the Base Commodity Case as a result of reduced shale gas supply. Shale gas production costs are greater because of environmental regulation of hydraulic fracturing. Other shale gas production factors may include water limitations and methane emissions regulation. Higher gas prices allow coal to compete, leading to greater coal demand and prices. A national carbon policy, with the same costs as the Base Commodity Case, is introduced in 2023.

8.1.2.7 Very High Commodity Case

This scenario assumes a much higher carbon price than the Base Commodity Case (starting at ~$9.50/ton nominal and increasing to ~$68/ton by 2035) resulting from the implementation of stricter regulations on fracking and mining regulations. This leads to higher fuel prices. A 20% renewable portfolio standard (RPS) is introduced in Indiana.

The following set of figures illustrate the long-term projections, of the major commodities on a nominal basis through year 2035 and used as modeling assumptions in the scenario and sensitivity analysis.

Figure 8-3: Natural Gas Chicago City Gate Price

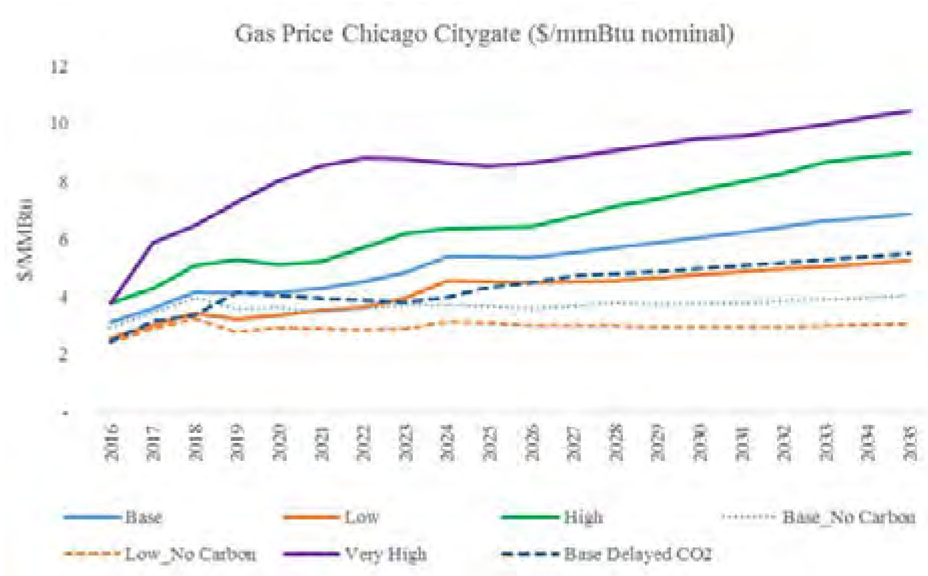


Figure 8-4: Power River Basin (PRB) Coal Prices

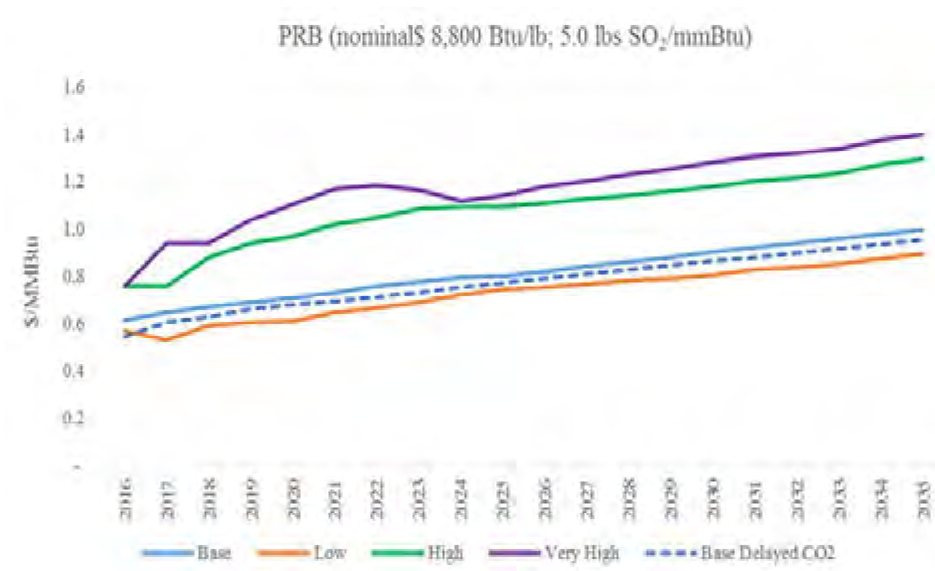


Figure 8-5: Illinois Basin (ILB) Coal Prices

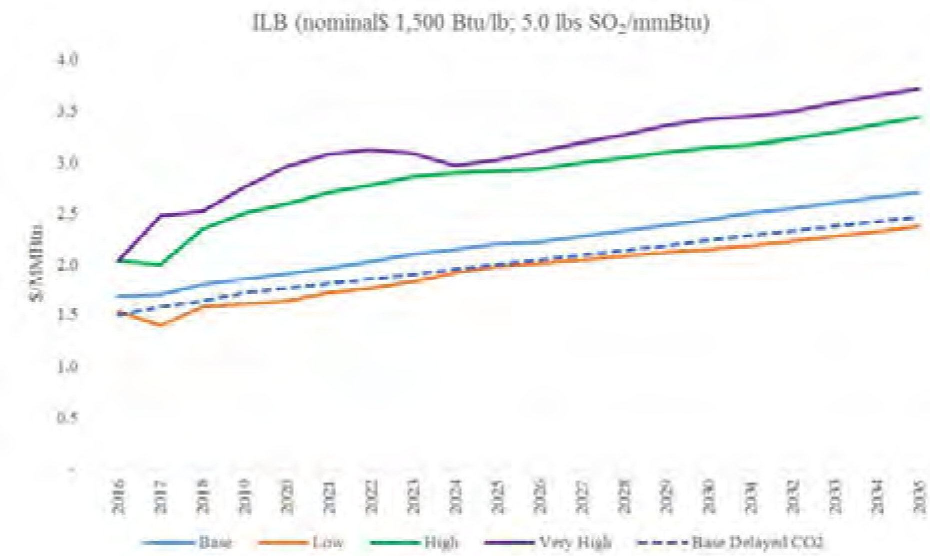


Figure 8-6: CO_2 Prices

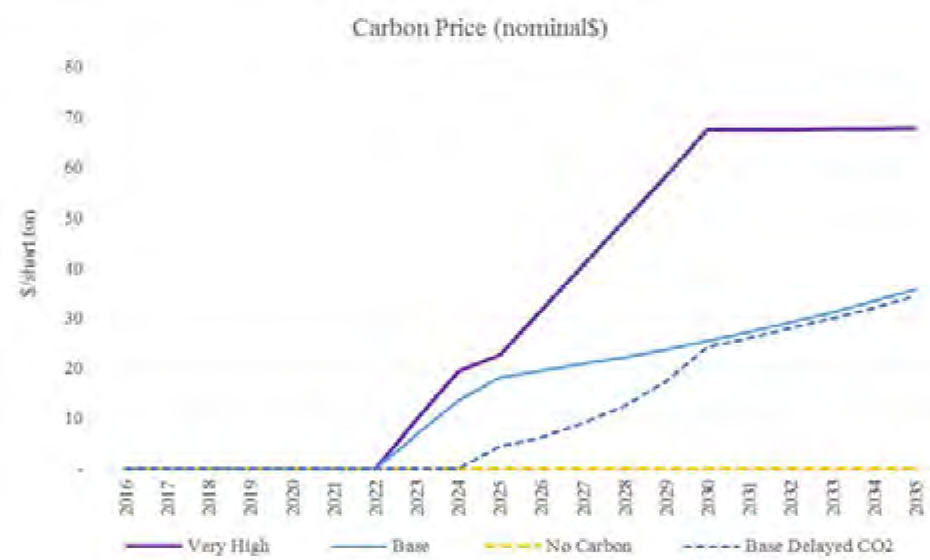


Figure 8-7: On-Peak Power Prices

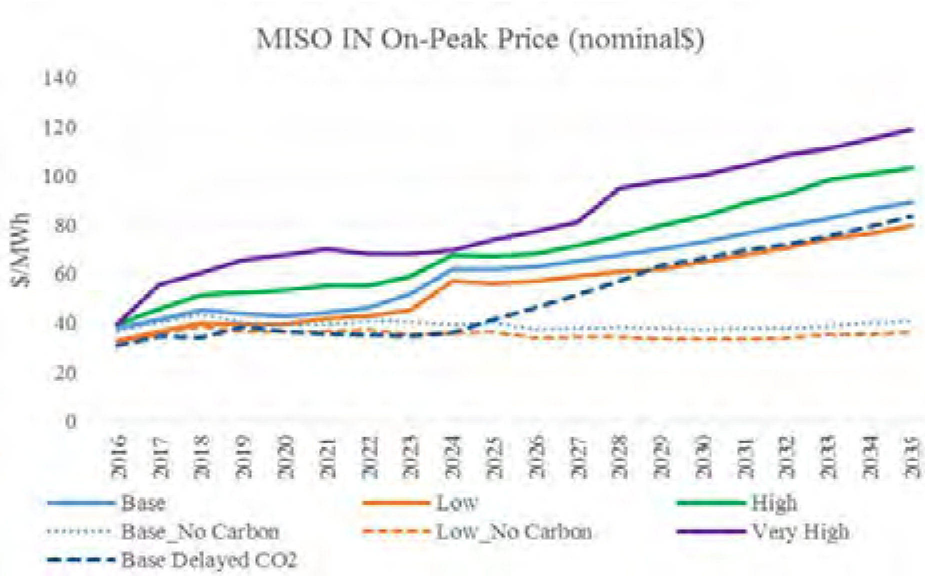


Figure 8-8: Off-Peak Power Prices

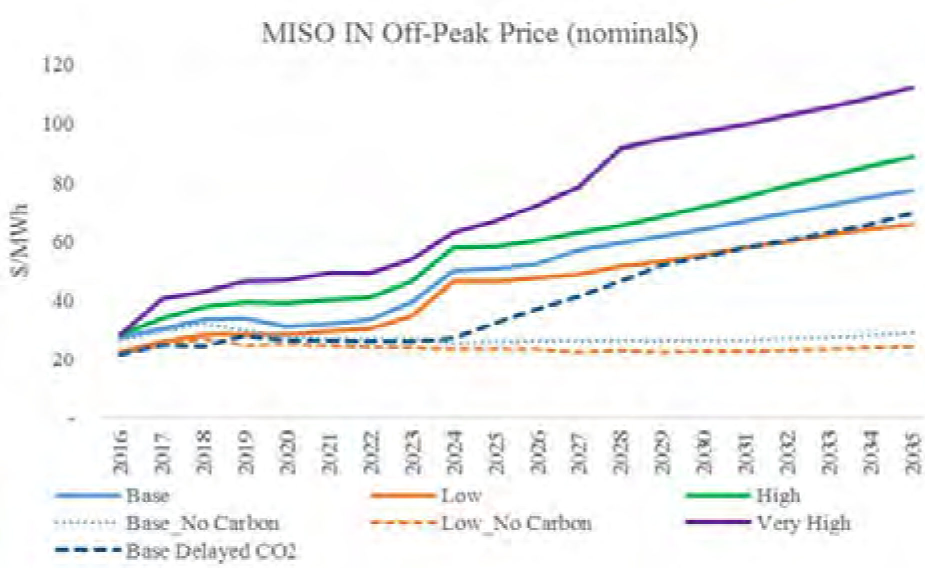


Figure 8-9: Capacity Prices

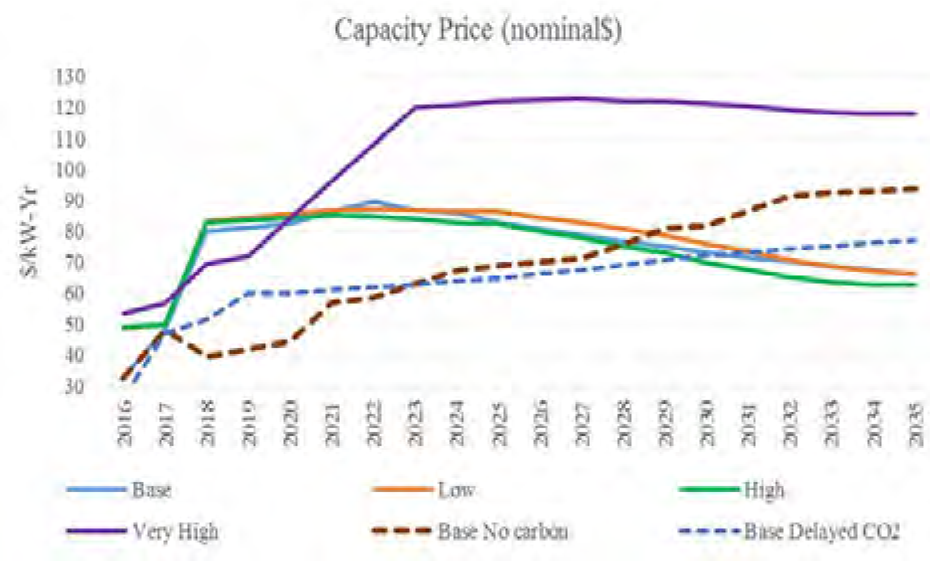
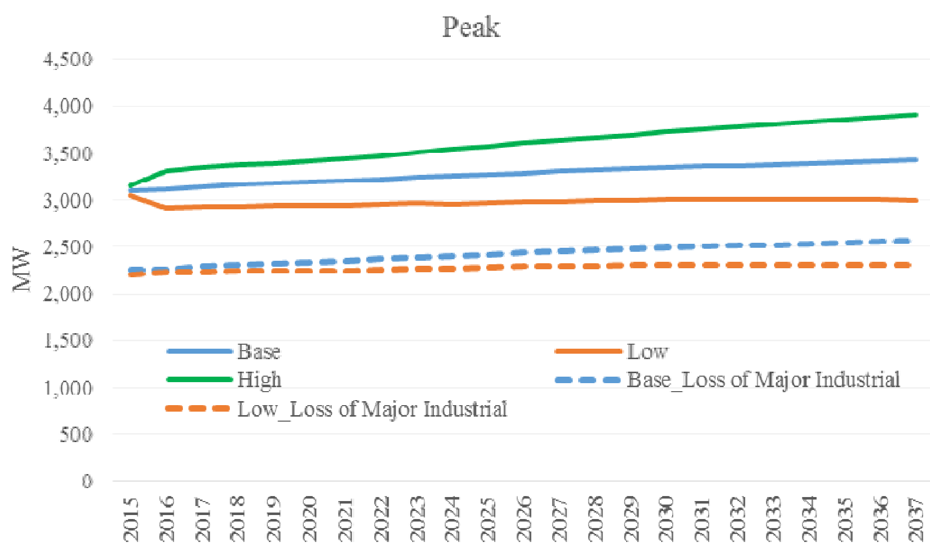


Figure 8-10: Load Requirement Forecasts (MW)



8.1.3 IRP Scenarios

For the 2016 IRP, NIPSCO developed five scenarios or future worlds. Each scenario represents a future that is possible, but distinctly different from the other futures imagined in the other scenarios. Each scenario was modeled separately through the use of different datasets that correspond to the specific future world. For example, a scenario that imagines a future with exceptionally strong economic growth must include forecasts for load growth and commodity prices that reflect strong economic performance. Alternatively, a scenario that captures a future with exceptionally weak economic growth must rely on different load and commodity price forecasts. The following five scenarios were developed: (1) Base (B), (2) Challenged Economy (CE), (3) Aggressive Environmental Regulation (AE), (4) Booming Economy (BE), and (5) Base Delayed Carbon (BDC).

8.1.3.1 Base Scenario (B)

Description

The Base Scenario represents the future that NIPSCO believes is most likely to develop over the next 20 years. National, regional, and local economies will continue to recover with load growth occurring slowly. Natural gas supplies from Appalachian shale fields will remain strong throughout the study period and exports of liquefied natural gas will increase significantly in the early part of the study period, creating a new driver for rising natural gas prices. Coal prices will remain relatively flat across the study period. A national carbon legislation, modeled as a carbon price, will take effect in the middle of the next decade.

Risks Addressed

The Base Scenario addresses the risks that NIPSCO believes are most likely to occur over the next 20 years. The most notable risks are slowly increasing load, a national carbon price taking effect in 2023, and additional compliance costs associated with non-carbon environmental regulations.

Base Scenario Assumptions

- Energy load is increasing at 0.33% and peak demand is increasing at 0.45% (Compound Annual Growth Rate –CAGR 2016-2037) annually over the study period;
- A national carbon price comes into effect in 2023 ($6.75/ton nominal increasing to ~$36/ton in 2035);
- The average price of natural gas remains below $7/MMBtu through 2035;
- The average price for Powder River Basin coal is slightly above $1.00/MMBtu by 2035;
- Average on-peak northern Indiana power prices remain below $50/MWh until 2023 and reach $90/MWh by 2035; the carbon price will cause an increase in power prices in 2023; and
- Non-carbon environmental compliance costs reflect current and proposed regulations, including the Cross-State Air Pollution Rule (CSAPR), Effluent Limitation Guidelines (ELG), and cooling water intake rules covered under Section 316(b) of the Clean Water Act.

8.1.3.2 Challenged Economy Scenario (CE)

Description

The Challenged Economy Scenario represents a future in which economic growth stalls or becomes negative for part of the study period. Constrained economic activity leads to lower load growth. There is reduced demand of natural gas even as production remains strong in unconventional plays, leading to lower prices. Coal prices are also lower as a result of limited demand. Reduced fuel prices drive power prices lower.

Risks Addressed

The Challenged Economy Scenario addresses the risk of an economic downturn. Specifically, this scenario addresses the combined risks of very low load growth and fuel prices that remain lower for a longer period of time. Lower fuel prices are correlated with lower power prices. Risks regarding carbon and non-carbon environmental regulations remain unchanged from the Base Scenario.

Challenged Economy Scenario Assumptions

- Energy load is increasing at 0.08% and peak demand is increasing at 0.15% (CAGR 2016-2037) annually over the study period;
- A national carbon price comes into effect in 2023 ($6.75/ton nominal increasing to ~$36/ton in 2035);
- The average price of natural gas remains below $6/MMBtu through 2035;
- The average price for Powder River Basin coal is slightly below $1.00/MMBtu by 2035;
- Average on-peak northern Indiana power prices remain close to $40/MWh until 2023 and reach ~$80/MWh by 2035; the carbon price will cause an increase in power prices in 2023; and
- Non-carbon environmental compliance costs reflect current and proposed regulations, including CSAPR, ELG, and 316(b).

8.1.3.3 Aggressive Environmental Regulation Scenario (AE)

Description

The Aggressive Environmental Regulation Scenario represents a future in which environmental regulations will be more stringent than currently anticipated for both power generation and natural gas production through the regulation of hydraulic fracturing. As a result, carbon environmental compliance costs will be greater for NIPSCO than in the Base Scenario. Natural gas and coal prices will be greater as increased regulation raises production costs and the combined impact of these more stringent regulations and higher fuel costs will lead to an increase in power prices.

Risks Addressed

The Aggressive Environmental Regulation Scenario addresses the risk that carbon environmental regulations will be more stringent than expected in the Base Scenario. This scenario addresses the risk of higher carbon prices after 2023 and environmental compliance costs. It also addresses the risk of higher prices for fuel and power prices, which are correlated. Risks regarding load growth remain unchanged from the Base Scenario.

Aggressive Environmental Regulation Scenario Assumptions

- Energy load is increasing at 0.68% and peak demand is increasing at 0.80% (CAGR 2016-2037) annually over the study period;
- A national carbon price comes into effect in 2023 (~$9.65/ton nominal increasing to ~$68/ton in 2035);
- The average price of natural gas reaches $9/MMBtu by 2035;
- The average price for Powder River Basin coal remains below $1.35/MMBtu through 2036;
- Average on-peak northern Indiana power prices remain below $60/MWh until 2023 and reach $100/MWh by 2035; the carbon price will cause an increase in power prices in 2023.

8.1.3.4 Booming Economy Scenario (BE)

Description

The Booming Economy Scenario (BE) represents a future in which economic growth is greater than expected for the study period. It assumes that an improved economic outlook provides an opportunity for state and national regulators to introduce more stringent environmental regulations with reduced risk of negatively impacting economic growth. In a more aggressive regulatory environment, natural gas and coal production costs rise and lead to higher fuel and power prices. As a result, load growth, fuel and power prices are greater than those of the Base Scenario.

Risks Addressed

The Booming Economy Scenario addresses the risk of accelerating economic growth in which load growth, is greater than in the Base Scenario, along with higher fuel and power prices as a result of their correlated relationship with demand growth.

Booming Economy Scenario Assumptions

- Energy load is increasing at 0.68% and peak demand is increasing at 0.80% (CAGR 2016-2037) annually over the study period;

- A national carbon price comes into effect in 2023 ($13.50/ton nominal increasing to ~$38/ton in 2035);
- The average price of natural gas reaches $9/MMBtu by 2035;
- The average price for Powder River Basin coal remains below $1.35/MMBtu through 2035;
- Average on-peak northern Indiana power prices remain below $60/MWh until 2023 and reach $100/MWh by 2035; the carbon price will cause an increase in power prices in 2023;

8.1.3.5 Base Delayed Carbon Scenario (BDC)

Description

The Base Delayed Carbon Scenario represents a future in which commodity prices remain relatively low over the next 20 years. There is lower load growth, lower fuel prices, lower renewable cost, federal tax credits exemptions and a higher renewable portfolio standard (RPS) driving renewable growth. Delayed implementation of a carbon policy with a slower path to a national carbon policy. Natural gas supplies from Appalachian shale fields remain strong throughout the study period. Natural gas prices are much lower due to the increased supply growth and weakness in demand from the power sector combined with the later implementation of a national carbon program. Coal prices drop, but not as drastically as the gas prices, due to coal prices remaining close to the cost of production. A national carbon policy, modeled as a carbon price, will take effect starting in 2025 with a gentler path.

Risks Addressed

The Base Delayed Carbon Scenario addresses the risks that the implementation of a carbon policy is delayed, with a slowly increasing load, a national carbon price taking effect in 2025, and lower fuel prices and lower renewable cost, and federal tax credits exemptions and a higher renewable portfolio standard that drive renewable growth.

Base Delayed Carbon Scenario Assumptions

- A national carbon price comes into effect in 2025 ($4.50/ton nominal in 2025 to ~$35/ton in 2035);
- The average price of natural gas remains below $5/MMBtu nominal through 2030 and ~$5.50/MMBtu by 2035;
- The average price for Powder River Basin coal is below $1.00/MMBtu through 2035;
- Average on-peak northern Indiana power prices remain below $40/MWh until 2027 and reach ~$80/MWh by 2035;
- Non-carbon environmental compliance costs reflect current and proposed regulations, including CSAPR, ELG, 316(b); and

- Recent changes to State renewable portfolio standard policies combined with lower renewable cost and federal tax credits exemptions lead to higher renewable growth.

8.2 Sensitivity Development

In addition to the five scenarios discussed in Section 8.1.3: IRP Scenarios, NIPSCO developed ten sensitivities, modifying a single variable within a scenario to analyze the effects of a specific risk on the corresponding scenario. Although each sensitivity focuses on a single risk, it may be necessary to modify more than one input dataset to reflect the changes associated with a risk. For example, a sensitivity to analyze the effects of higher natural gas prices must also include forecasts for data that are correlated to natural gas prices, such as power market prices. The 2016 IRP sensitivities address risks associated with CO_2 emissions pricing, renewable energy adoption, load growth, and prices for fuel (natural gas and coal).

8.2.1 Sensitivities of the Base Scenario (B)

Sensitivity	Description
Base with No Carbon Price (Bs1)	This sensitivity addresses the risk of no national carbon price taking effect during the study period. Prices for natural gas and power reflect a broader energy market that is not subject to a carbon price.
Base with Low Load (Bs2)	This sensitivity addresses the risk of slower load growth than expected.
Base with High Gas (Bs3)	This sensitivity addresses the risk of higher natural gas prices than expected. Correlated with natural gas prices, power prices rise with gas prices. More stringent environmental regulations also drive gas prices higher.
Base with No Major Industrial Load (Bs4)	This sensitivity addresses the risk of significantly lower energy load due to the loss of major industrial load, but still growing slowly within other rate classes.

8.2.2 Sensitivities of the Challenged Economy Scenario (CE)

Sensitivity	Description
Challenged Economy with No Carbon Price (CEs1)	This sensitivity addresses the risk of no national carbon price taking effect during the study period with natural gas and power prices reflecting a broader energy market that is not subject to a carbon price.
Challenged Economy with No Major Industrial Load (CEs2)	This sensitivity addresses the risk of significantly lower energy load due to the loss of major industrial load, but still growing slowly within other rate classes.

8.2.3 Sensitivities of the Aggressive Environmental Regulation Scenario (AE)

Sensitivity	Description
Aggressive Environmental Regulation with High Renewables and Increasing Load (AEs1)	This sensitivity addresses the risks of a mandatory renewable portfolio standard of 20% taking effect in Indiana in 2025 with load growth greater than expected. Natural gas and power prices reflect the renewable penetration rates required by the renewable portfolio standard.
Aggressive Environmental Regulation with High Renewables and Decreasing Load (AEs2)	This sensitivity addresses the risks of a mandatory renewable portfolio standard of 20% takes effect in Indiana in 2025 with load growth lower than expected. Natural gas and power prices reflect the renewable penetration rates required by the renewable portfolio standard.

8.2.4 Sensitivities of the Booming Economy Scenario (BE)

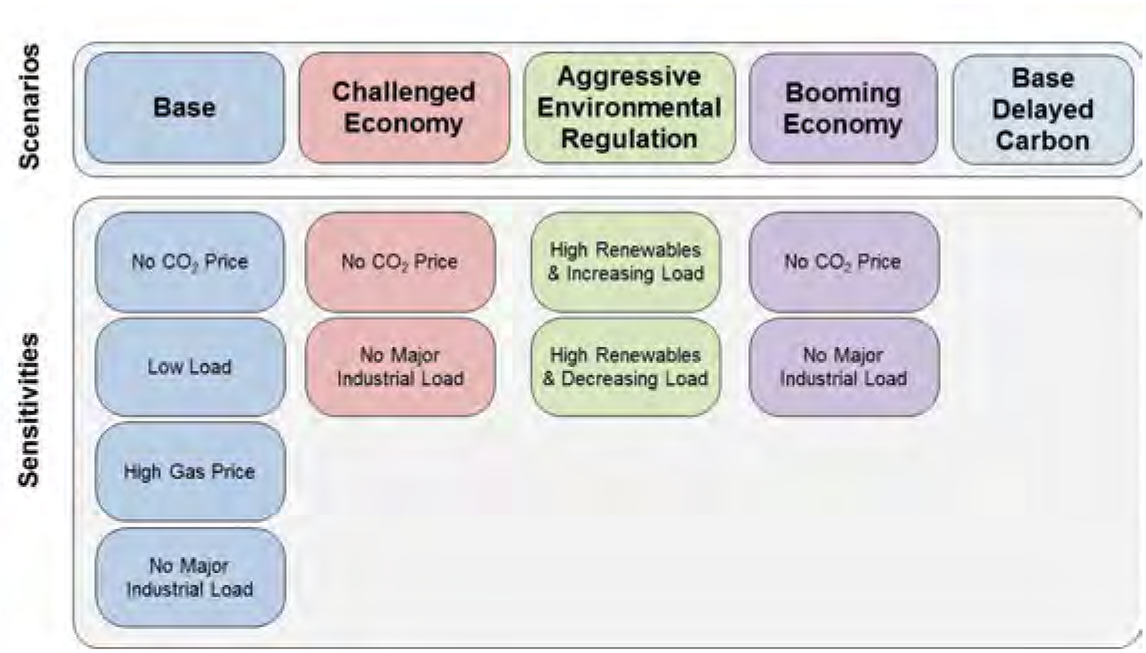
Sensitivity	Description
Booming Economy with No Carbon Price (BEs1)	This sensitivity addresses the risks of no national carbon price taking effect during the study period. Natural gas and power prices reflect a broader energy market that is not subject to a carbon price.
Booming Economy with No Major Industrial Load (BEs2)	This sensitivity addresses the risks of significantly lower energy load due to the loss of major industrial load, but still growing slowly within other rate classes.

8.3 Scenarios and Sensitivities Summary

8.3.1 Risks and Uncertainty Correlation

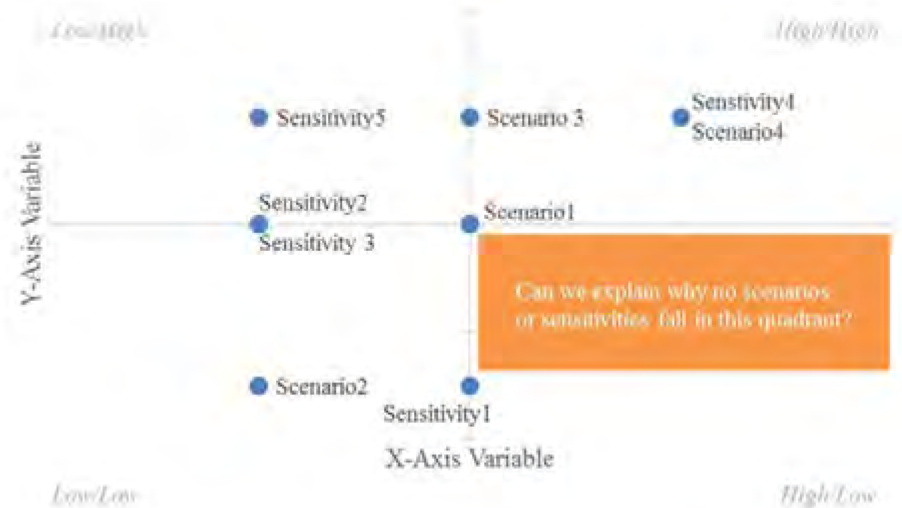
A summary of the scenarios and sensitivities are shown in Figure 8-11.

Figure 8-11: Summary of Scenarios and Sensitivities



To assess the adequacy of the number of the scenarios and sensitivities for the 2016 IRP, NIPSCO employed a scenario variable breadth analysis framework shown in Figure 8-12, where the scenario drivers identified in Table 8-1: Scenarios and Sensitivities Variable Descriptions are mapped on an x-y plot. This step allows NIPSCO to assess the robustness of the scenarios and to determine if certain key scenarios and sensitivities are missing as indicated by the comments in the orange box of the scenario variable breadth template shown in Figure 8-12.

Figure 8-12: Scenario Variable Breadth Analysis



For example, Figure 8-13 shows a scenario matrix that juxtaposes two axes of uncertainty (Natural Gas Prices versus NIPSCO load) and offers the most insight of those two uncertainties within the various scenarios and sensitivities. It also allows NIPSCO to identify and explain why no scenarios fall in a particular quadrant of the x-y plot. As shown in Figure 8-12, few Scenarios or Sensitivities fell in the High/Low quadrant at the bottom right corner of the variable breadth analysis. However, this can be explained by the correlations between gas prices and load, which is further detailed in the orange box. See Appendix F, Exhibit 1 for the complete scenario variable breadth analysis for all identified risks.

Figure 8-13: Natural Gas vs Load Variables Breadth Analysis

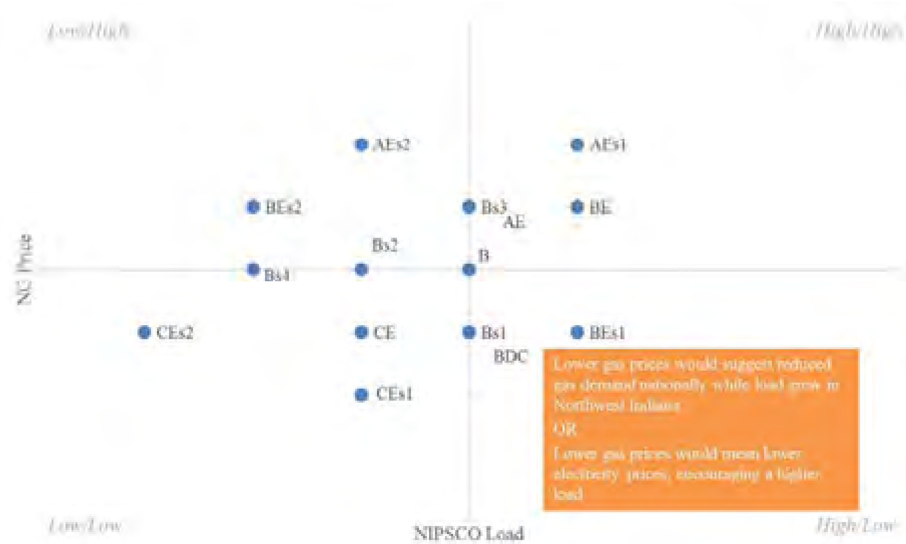


Table 8-1shows how the risks and uncertainties were correlated within the various scenarios and sensitivities. For each scenario, modeling inputs are varied from the starting scenario to reflect the stated risk. Modeling inputs that are not related to the stated risk remain unchanged from the starting scenario.

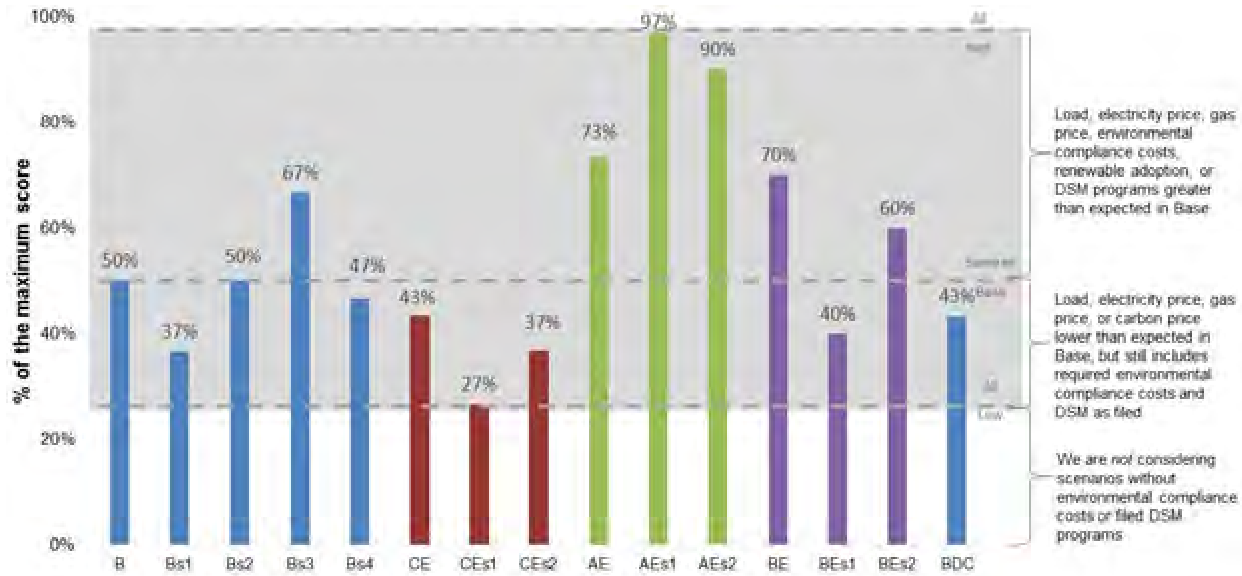
Table 8-1: Scenarios and Sensitivities Variable Descriptions

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

Finally, Figure 8-14 represents the scenario variable diversity analysis, which illustrates the dispersion of the identified scenarios from each other. Any score of less than 50% (corresponding to the Base Scenario) represents risks (load, commodity prices, environmental, and renewable adoption) that are lower than expected in the Base Scenario. Scores above the 50% represent cases where the risks are greater than the Base Scenario.

To arrive at the score, the risks identified by NIPSCO that formed the foundation for the scenarios and sensitivities were scored on a scale of 1 to 5 (1 - very low, 2 - low, 3 - medium, 4 - high, and 5 - very high). For example, in the Base Scenario, a score of medium across four of the five risks (Load, CO_2 Price, Natural Gas Price, and Power Price) shown in Table 8-1: Scenarios and Sensitivities Variable Descriptions total 12 out of a potential score of 25 (maximum score of 5 multiplied by 5 identified risks) for a percentage score of about 50%. See Appendix F, Exhibit 1: Scenarios Planning Variable Breadth and Diversity for the full scoring of all scenarios and sensitivities.

Figure 8-14: Scenario Variable Diversity Analysis



Ultimately, the combination of the scenario breadth and diversity analysis ensures that NIPSCO not only has an adequate number of candidate scenarios and sensitivities but also that there is sufficient diversity in the uncertainties values across the scenarios. Both gauges help to assess the robustness and diversity of the scenarios.

8.3.2 Development of Planning Portfolio

NIPSCO evaluated the results of the scenarios and sensitivities using three planning strategies. These planning strategies are shown in Table 8-2:

Table 8-2: Planning Portfolio Characteristics

Portfolios	Key Characteristics
A: Traditional Utility Planning	Least cost optimization
B: Renewable Focus	Meet targets with cost effective combination of renewables and emerging technologies
C: Low Emissions	Low emissions resources selected to create lower emitting portfolio

NIPSCO used a capacity expansion model called ABB *Strategist*® as the optimization tool for performing the resource optimization. For each optimization run, the tool generates a number of resource portfolios as modeling results and ranks them from lowest to highest cost based on the objective function of NPVRR.

The optimization results from the analysis in Section 8.5: Resource Optimization Modeling will be presented for each scenario and sensitivity and the capacity expansion plans grouped by the three portfolios outlined in Table 8-1: Scenarios and Sensitivities Variable Descriptions. This will result in 45 portfolios (15 scenarios and sensitivities by 3 strategies). All scenarios and sensitivities will be fully optimized and could result in distinct portfolios.

8.4 Retirement Analysis

NIPSCO believes that performing a retirement analysis requires careful planning and consideration of several factors in addition to the cost of generation. To that end, NIPSCO also considered the effect of unit retirements on its employees, the local economies of the communities it serves and the environment. NIPSCO remains committed to providing service to its customers that is affordable and reliable while also remaining compliant with environmental regulations and assuring that it achieves a greater portfolio diversity to meet future needs.

Economic evaluations compare the ongoing costs and benefits of operating an existing unit, including retrofitting it to comply with final, proposed and/or expected environmental rulemakings to the costs and benefits of retiring and replacing a unit with an alternative. The environmental rules and associated compliance costs considered in the retirement analyses included projected costs associated with the final Coal Combustion Residuals ("CCR") rule, the final Section 316(b) Cooling Water Intake Structure rule of the Clean Water Act ("316(b)"), the final Effluent Limitation Guidelines ("ELG"), and the expected National Ambient Air Quality Standards ("NAAQS").

In determining its preferred retirement scenario, NIPSCO also considered its ability to comply with potential Clean Power Plan regulations and attempted to balance stakeholder risk through diversifying its portfolio from both a fuel and a duration of commitments perspective. Secondary impacts, such as the loss of work for employees, service providers and suppliers of the generating units, and the reduction of property tax base for surrounding communities also factored into NIPSCO's decision making process. While these do not directly impact power supply costs to customers, NIPSCO believes they are factors that should not be ignored.

Based on the retirement analyses, NIPSCO's preferred retirement plan is to accelerate the retirement of Bailly Units 7 and 8 and Schahfer Units 17 and 18 and to move forward with compliance investments for its remaining coal units.

8.4.1 Retirement Methodology

Unit retirement analyses were performed for each of NIPSCO's coal-fired units. The unit retirement analyses evaluated the cost of ongoing operations (including any additional environmental compliance requirements) versus replacement of the units with an alternative. The results of the retirement analyses were one of the primary determinants in the Company's decision to control or retire a unit.

8.4.1.1 Ongoing Costs of Continued Operation

Ongoing costs that were included in the analyses included fuel, O&M, maintenance capital, future environmental controls, accelerated recovery of remaining depreciation expenses, and accelerated recovery of decommissioning and demolition costs.

O&M costs included all labor, materials, engineering and support services, and overhead costs necessary to operate the plant. For all units, nine-year projections of incremental O&M budgets were obtained. The average of these budgets was then escalated at 2% per year for the remaining years. Additional detail is provided in Confidential Appendix G.

Maintenance capital costs included the projected capital expenditures necessary to keep the units running through the analysis period at the projected level of operation. Nine-year maintenance capital budgets were gathered from unit level estimates. The average of these budgets was then escalated at 2% per year for the remaining years. Additional detail is provided in Confidential Appendix G.

Environmental control capital and the associated O&M expenditures that are projected to be required for compliance were not included in the ongoing operation expenditures. These incremental capital estimates were provided by NIPSCO's Major Projects department based on outside engineering studies. The most recently available capital estimates, escalated by 2% for inflation, were used in the analyses as specified in the unit retirement studies. For each of the units analyzed, environmental control requirements and dates included in the analyses were based on the expected compliance requirements of final, proposed, and/or expected environmental rules and regulations. Additional detail is provided in Confidential Appendix G.

An additional $25 million of capital expenditure was added to analysis related to transmission and distribution upgrades at Bailly at the time of the Bailly retirement. An additional $30 million of capital expenditures was added to analysis related to transmission and distribution upgrades at Schahfer at the time of the Schahfer retirement. These estimates from NIPSCO's System Reliability reflect NIPSCO's view of reliability impacts, potentially arising from a MISO Attachment Y study.

Recovery of remaining depreciation expenses represents the remaining financial obligation of investments made in the asset that have not yet been recovered. NIPSCO has prudently ensured that each of its facilities has been ready and available to meet customer needs over the past several decades through appropriate capital investment and O&M expenditures. Upon retirement, due to this continued capital investment, there will be a remaining asset value. The retirement analysis was conducted with recovery of the remaining asset value in a single year, amortized over 5 years and 10 years, as well as left to age-based. The rankings of the results were indifferent to the method of recovering the remaining net book value.

Accelerated recovery of decommissioning and demolition costs were included as part of the expense of retiring a unit, along with the remaining asset value, and were treated as a cost to be recovered in the year the retirement takes place. Cost of removal was estimated for age based retirement in NIPSCO's 2016 Electric Rate Case in Cause No. 44688. John J. Spanos, an expert witness supporting the NIPSCO electric depreciation study in that case, updated his analysis for the earlier retirement dates for each unit, with the exception of Scenario 2, Bailly Retirement in 2023. As NIPSCO had estimates for both age based and early retirement in 2018 for Bailly, an average of the two numbers was used to estimate the 2023 cost of removal. The depreciation study is broken down by asset within each FERC account. Some assets are unit specific while others are for the common generating station. To allocate cost of removal to the unit level, each unit level detail was consolidated, and common general station was further allocated to the units based on name plate capacity. The cost of removal, or decommissioning costs, were then linked to the units in Strategist® to be applied at the unit retirement date. Additional detail is provided in Confidential Appendix G.

The costs of each coal retirement combination are countered by savings from avoiding future coal plant capital upgrades, including environmental retrofit upgrades, and from avoiding future fixed operating expenses, allowed return on investment, fuel, variable costs, property and income taxes for the retired unit.

In the retirement analyses, NIPSCO, utilizing Strategist® Proview and its own analysis, evaluated aspects of revenue requirement including remaining asset value, replacement capacity and energy cost, retired asset savings from fuel, O&M and maintenance capital. Strategist® does not consider some costs and/or savings necessary to include in the retirement analyses including "return on," property taxes and income taxes. Therefore, the Strategist® revenue requirements outputs were adjusted to account for these savings to customers when a unit is retired. Additional detail is provided in Confidential Appendix G.

8.4.1.2 Replacement Alternative

As part of the economic analyses, the incremental cost of an existing unit was compared to the expected cost of a generic, repeatable replacement combined cycle gas turbine (CCGT) sited in Indiana. A CCGT was selected as a proxy because of its favorable levelized cost of energy, reliability, dispatchability, and straightforwardness to plan, permit and build. The proxy CCGT was used for retirement analyses only. NIPSCO optimized future supply-side and demand-side resources as identified in other sections of this IRP. *See* Section 8.5.

Replacement costs included ongoing variable costs, ongoing fixed costs and the cost of any future environmental controls for the replacement unit. In all comparison analyses, the costs of the replacement unit were scaled on a megawatt basis to the same generating capacity as the existing unit by using a replacement capacity value of the CCGT. Replacement costs for CCGT capacity are assumed to be $282/MW-day with 3% inflation to fill any capacity gaps due to early retirements. This assumption is in-line with the MISO cost of new entry (CONE) which is based on a greenfield CCGT.

Based on the environmental compliance dates and the associated costs to run the existing coal-fired generation units, the six retirement portfolios shown in Table 8-3 were proposed:

Table 8-3: Retirement Combinations

Combination	Description	% Coal Retired
1	All coal units run to end of life (60 years of service)	0%
2	Retire Bailly in 2023, all other coal units run to end of life	20%
3	Retire Bailly in 2018, all other coal units run to end of life	20%
4	Retire Bailly in 2018, Schahfer Units 17 & 18 in 2023 and all other coal units run to end of life	50%
5	Retire Bailly in 2018, Schahfer Units 14, 15, 17 & 18 in 2023 and all other coal units run to end of life	80%
6	Retire Bailly in 2018, Schahfer Units 14, 15, 17 & 18 by 2023 and Michigan City Unit 12 in 2023	100%

8.4.1.3 Compliance with Clean Power Plan

Each retirement portfolio was evaluated on its ability to comply with potential Clean Power Plan (CPP) regulations. Although final CPP targets for NIPSCO are unknown, NIPSCO estimated a range of plausible CPP targets in 2030, the final target date in the EPA's CPP. Total 2030 CO_2 emission from each retirement portfolio were estimated by using actual emission factors multiplied by typical annual dispatch from each of NIPSCO's generating units. NIPSCO's ability to comply with CPP targets will depend on the final rule as well as actual dispatch of generating units.

8.4.1.4 Portfolio Diversity

The diversity of each retirement portfolio was evaluated from fuel, technology and duration of commitments perspectives. Fuel and technology diversity is important as over-reliance on a single fuel source may leave a utility and its customers unnecessarily exposed to various operational and financial risks from fuel supply disruptions and/or price volatility. Fuel and technology diversity is quantified by the capacity mix by the end of the planning period. Duration diversity is a measure of the length of commitment to any supply option. Electric generating plants are generally long-lived and capital intensive, making these investments inherently risky for utilities and highly sensitive to forecasts of fuel prices and availability. NIPSCO views a supply portfolio with diversity of fuel, technology and duration of commitments to provide less risk for its stakeholders than one with less diversity.

8.4.1.5 Community Impact

As previously discussed, NIPSCO also considered secondary impacts of coal unit retirements on surrounding communities. These impacts include the loss of work for NIPSCO employees and its service providers/suppliers as well as reductions to the property tax base for surrounding communities. While these factors do not directly impact power supply costs for customers, NIPSCO believes they are important considerations in selection of its preferred retirement scenario.

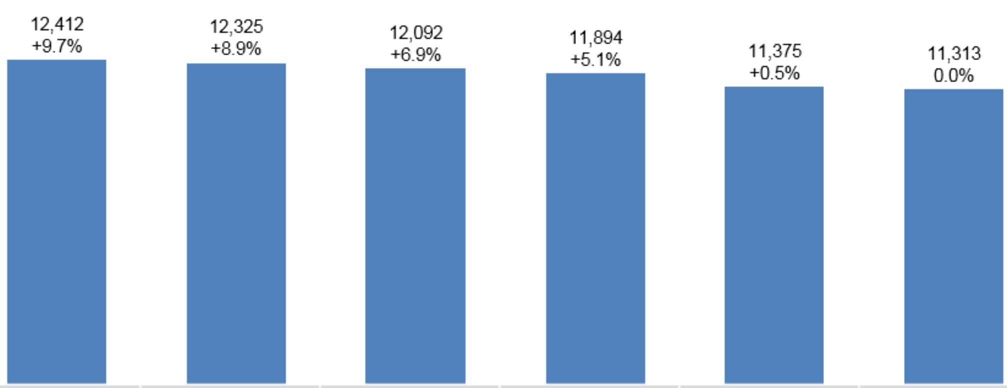
8.4.2 Retirement Analysis Results

The six retirement portfolios shown in Table 8-3: Retirement Combinations were evaluated across all scenarios and sensitivities proposed in the 2016 IRP. Results were ranked from 1 to 6, with 1 being the portfolio having the lowest cost to customers as expressed by net present value of revenue requirement (NPVRR) and 6 having the highest cost. In addition to the NPVRR ranking which takes into consideration the overall costs to customers in selecting its preferred retirement portfolio, NIPSCO also considered portfolio diversity, reliability of the system, employee and community impacts and readiness to meet the above described CPP compliance targets, if and when promulgated. The Retirement Analysis is included as Confidential Appendix G.

8.4.2.1 Retirement Analysis Summary

A summary of the cost to customer impacts of base scenario retirement portfolio combinations is shown in Figure 8-15.

Figure 8-15: Cost To Customer Impacts

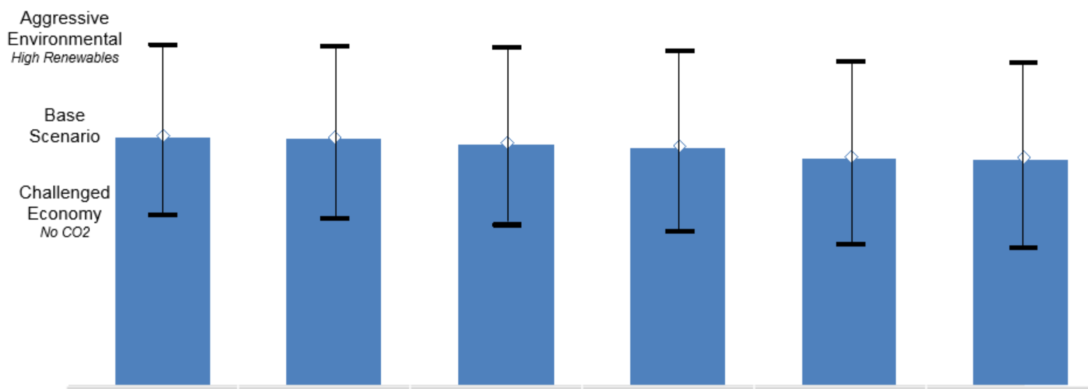


	Age Based	Retire 20% Coal (2023)	Retire 20% Coal (2018)	Retire 50% Coal	Retire 80% Coal	Retire 100% Coal
Combination	1	2	3	4	5	6
Retire:	Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 (2018) Schahfer: 17,18	Bailly: 7,8 (2018) Schahfer: 14,15,17,18	Bailly: 7,8 (2018) Michigan City: 12 Schahfer: 14,15,17,18
Keep:	Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None
Rank (1=Least Cost)	6	5	4	3	2	1

Figure 8-15 shows the NPVRR across each of the retirement combinations for the base scenario. Retirement combination 6, where 100% of the coal portfolio is retired by 2023, is the lowest cost option. Combination 1, where all coal units run to 60 years of service, is the highest cost option. Combination 4, which retires Bailly in 2018, Schahfer Units 17 and 18 in 2023 and all other coal units run to end of life, is the third lowest cost combination, with a total NPVRR of $11.894B. This retirement combination is about 5.1% more expensive than the least cost alternative but represents a significant cost savings over retirement combinations 1-3.

The cost to customer rankings for retirement portfolios remained consistent across a wide range of scenarios as shown in Figure 8-16.

Figure 8-16: Cost to Customer Rankings

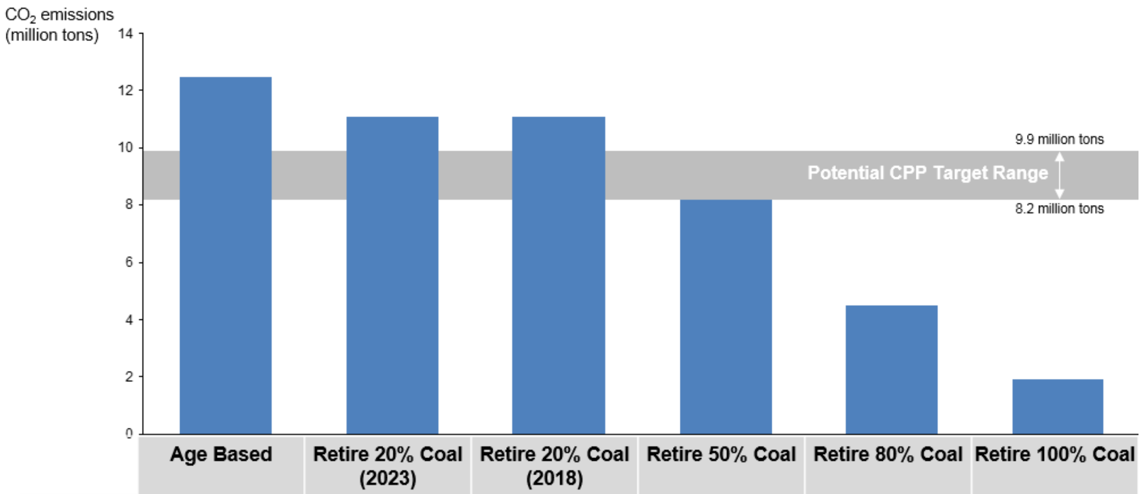


	Age Based	Retire 20% Coal (2023)	Retire 20% Coal (2018)	Retire 50% Coal	Retire 80% Coal	Retire 100% Coal
Combination	**1**	**2**	**3**	**4**	**5**	**6**
Retire:	Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 (2018) Schahfer: 17,18	Bailly: 7,8 (2018) Schahfer: 14,15,17,18	Bailly: 7,8(2018) Michigan City: 12 Schahfer: 14,15,17,18
Keep:	Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None

Figure 8-16 shows the NPVRR of the base scenario (solid blue bar) overlaid with the range of NPVRR from all the NIPSCO's scenarios and sensitivities. The magnitude of the NPVRR changes depending on the specific scenario or sensitivity but the relative rankings of the retirement combinations generally remains the same within each scenario or sensitivity. In all scenarios and sensitivities, combination 4, retirement of 50% of NIPSCO's coal, is always the third least cost retirement combination.

Retirement combinations were analyzed to estimate their potential to meet Clean Power Plan compliance targets as shown in Figure 8-17.

Figure 8-17: Potential To Meet Clean Power Plan Compliance Targets

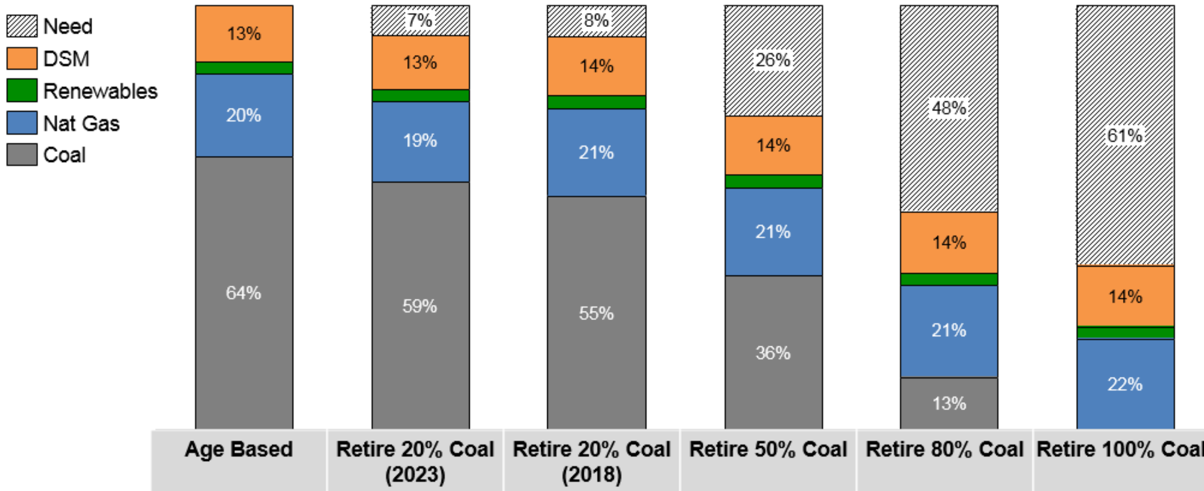


Combination	1	2	3	4	5	6
Retire:	Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 (2018) Schahfer: 17,18	Bailly: 7,8 (2018) Schahfer: 14,15,17,18	Bailly: 7,8 (2018) Michigan City: 12 Schahfer: 14,15,17,18
Keep:	Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None

Figure 8-17 shows forecast 2030 emissions under the base scenario for each retirement combination. The Clean Power Plan range reflects estimates of potential 2030 NIPSCO targets based on section 111(d) of the CAA. Under the proposed federal plan any replacement emissions from either a power purchase agreement or new CCGT would not count towards compliance. Figure 8-17 shows emissions estimated from typical annual capacity factors applied to unit-level emission factors for each retirement portfolio. Retirement combinations 1, 2 and 3 would not meet NIPSCO's estimated targets. Retirement combinations 4, 5 and 6 are estimated to meet potential Clean Power Plan targets.

Retirement combinations were analyzed to estimate their diversity as shown in Figure 8-18.

Figure 8-18: Portfolio Diversity of Each Retirement Combination

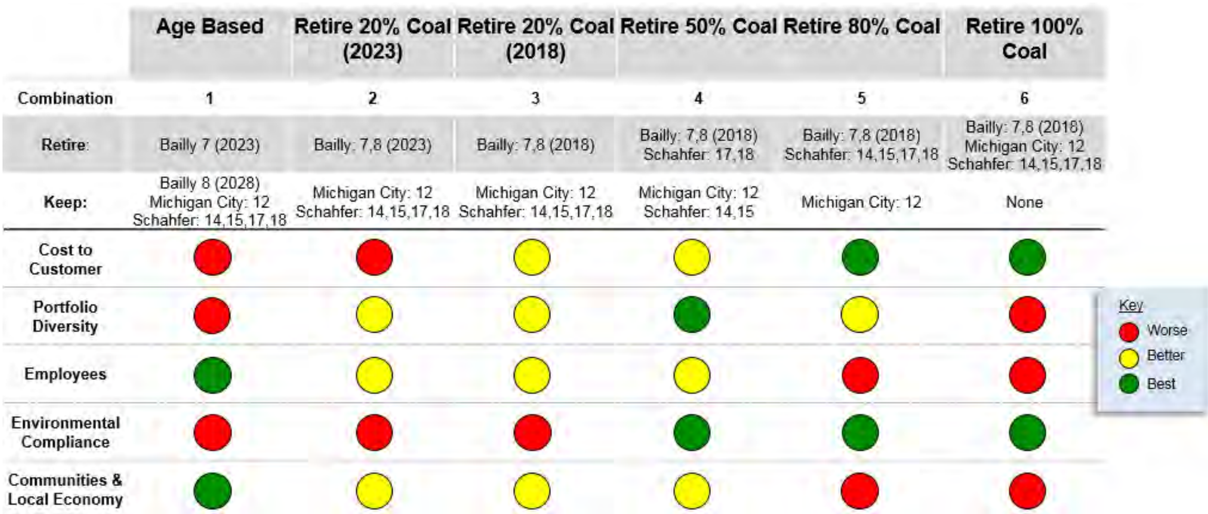


Combination	1	2	3	4	5	6
Retire:	Bailly 7 (2023)	Bailly: 7,8 (2023)	Bailly: 7,8 (2018)	Bailly: 7,8 (2018) Schahfer: 17,18	Bailly: 7,8 (2018) Schahfer: 14,15,17,18	Bailly: 7,8 (2018) Michigan City: 12 Schahfer: 14,15,17,18
Keep:	Bailly 8 (2028) Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15,17,18	Michigan City: 12 Schahfer: 14,15	Michigan City: 12	None

Figure 8-18 shows the diversity of each retirement combination. Portfolio diversity shown as a percentage of forecast installed capacity in 2025 and DSM includes Industrial Interruptibles. Retirement combinations 1, 2 and 3 rely on a single fuel source for more than half of the portfolio. Retirement combinations 4, 5 and 6 have more diversity in fuel and technologies.

Based on the above criteria, NIPSCO created a scorecard to explore relative differences between the retirement portfolios using a number of quantitative and qualitative measures as shown in Figure 8-19.

Figure 8-19: Retirement Combination Scorecard

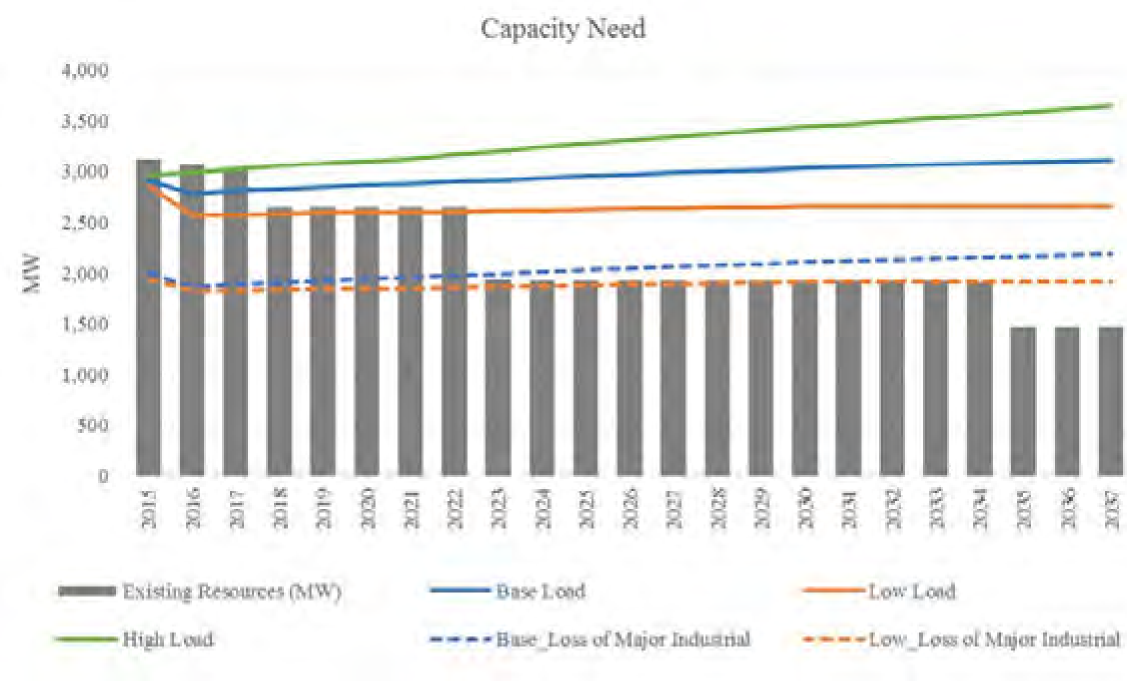


The scorecard simplifies considerations into a red, yellow, green measure. A red measure is viewed as worse, a yellow is better and a green measure is viewed as good. Selecting a retirement portfolio with a red measure may have significant difficulties or hurdles to overcome. No retirement combination has a green score across all measures but retirement combination 4 scores best among all combinations.

8.4.2.2 Preferred Retirement Option

Retirement Option 4 shown in Table 8-3: Retirement Combinations, representing 50% coal retirement, was selected as the preferred retirement option. In this option, NIPSCO has balanced stakeholder risk through fuel diversity and duration of commitment to the communities it serves. Figure 8-20 shows the range of the capacity gaps identified across the five load demand forecast scenarios discussed in Section 3: Energy and Demand Forecast. The analysis used to determine the appropriate level and mix of incremental supply-side and demand-side options required to offset the identified capacity gaps is discussed in Section 8.5: Resource Optimization Modeling.

Figure 8-20: Capacity Gap



8.5 Resource Optimization Modeling

The capacity expansion plans are presented below by the three strategies or portfolios outlined in Section 8.3.2: Development of Planning Portfolio. The portfolios in the expansion plans represent the incremental capacity additions of supply-side and demand-side alternatives for the planning period to fill the capacity gap resulting from the preferred retirement option (*see* Figure 8-20. DSM value in this table represents the total amount of capacity from Demand-Side resources that is available annually. The capacity values represents the unforced firm capacity contribution to the peak. The capacity values for the intermittent resources such as solar and wind reflect a maximum contribution of 50% and 15.6%, respectively, of nameplate capacity rating per MISO in the 2016/2017 planning year. These maximum capacity values are then applied to the peak load based on the hourly shapes of the resources. *See* Confidential Appendix H for the Strategist modeling reports.

8.5.1 Modeling Methodology

ABB Strategist® Proview capacity expansion model has a limit on the number of resource alternatives that can simultaneously be optimized. Increasing the number of selectable resources increases the total model run time as the number of states generated in the optimization algorithm exponentially grows. The resource alternatives utilized in this IRP include 26 demand-side and about 20 supply-side options. To ensure that all resources are assessed on a comparable basis, the resources were optimized sequentially to allow all resources to be evaluated in each optimization run. Each resource option was individually and fully selectable during each optimization run.

8.5.1.1 Demand-Side Modeling

Due to the inability of Strategist® to optimize all 26 DSM groupings simultaneously, the demand-side programs were broken down into the various end users (residential, commercial, and industrial) and optimized against an array of supply-side options. This process is repeated for all 15 scenarios and sensitivities to better understand their value across all the different futures. In the optimization, the industrial demand response /interruptible service was modeled at the 527.75 MW level in accordance with the Commission's Rate Case Order. With the exception of the loss of major industrial load sensitivities, all other scenarios and sensitivities assumed the 527.75 MW industrial interruptible level.

8.5.1.2 Supply-Side Modeling

Each optimization run produces a series of portfolios or plans, which are ranked from the least cost to the most expensive. To further evaluate all the supply-side resources, we utilized the three planning strategies/portfolios, namely least cost, renewable focus, and low emissions portfolios across all scenarios and sensitivities. In the least cost portfolio, the model assessed all supply-side alternatives on equal footing to develop a least cost plan. Next, to assess a renewable focus portfolio in the same future world, the amount of fossil generation was constrained and the amount of renewable resources increased to serve the incremental load requirements resulting from the constraint on fossil generation. Lastly, a low emissions portfolio was evaluated, where the incremental amount of fossil generation and renewables was constrained to allow other lower emitting resources such as nuclear, battery, reciprocating engine, etc. to be selected to see how that portfolio compares with the least cost and renewable focus portfolios.

8.5.2 Scenario Analysis Results

The analysis of each of the scenarios results in a mix of portfolio of supply-side and demand-side resources. The tables that follow show the incremental resources added throughout the planning period.

8.5.2.1 Base Scenario Results

Table 8-4 shows the resources selected as a result of the optimization of the Base Scenario and grouped by the three strategies or portfolios. The Net Present Value of Revenue Requirements (NPVRR) associated with each portfolio is also indicated.

Table 8-4: Base Scenario Expansion Plan

Portfolio	Resources	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	NPVRR ($Billion)
Least Cost	Gas	-	-	-	-	-	-	-	1,258	-	-	-	-	-	-	-	-	-	-	-	629	-	-	$12.82
	DSM	533	538	543	548	546	549	553	556	562	565	567	570	572	575	577	578	580	580	581	579	580	588	
	Purchases	-	-	167	180	199	211	226	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	533	538	710	727	745	760	779	1,814	562	565	567	570	572	575	577	578	580	580	581	1,208	580	588	
Renewable Focus	Gas	-	-	-	-	-	-	-	822	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$14.95
	Wind	-	-	-	-	-	-	-	-	-	16	-	16	16	16	8	8	16	16	16	79	8	8	
	Solar	-	-	-	-	-	-	-	115	13	-	13	-	-	-	-	-	-	-	-	370	-	-	
	Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	
	CHP	-	-	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DSM	533	538	543	548	546	549	553	556	562	565	567	570	572	575	577	578	580	580	581	579	580	588	
	Purchases	-	-	167	180	199	211	226	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	533	538	710	727	745	760	779	1,512	575	581	580	586	588	591	585	587	596	596	597	1,028	588	595	
Low Emission	Gas	-	-	-	-	-	-	-	822	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$15.61
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	488	-	-	-	-	
	Biomass	-	-	-	-	-	-	-	43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Recip	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Wind	-	-	-	-	-	-	-	24	-	-	-	-	8	16	16	8	8	-	-	-	-	-	
	Solar	-	-	-	-	-	-	-	64	26	13	13	13	-	-	-	-	-	-	-	-	13	-	
	Battery	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DSM	533	538	543	548	546	549	553	556	562	565	567	570	572	575	577	578	580	580	581	579	580	588	
	Purchases	-	-	167	180	199	211	226	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	533	538	710	727	745	760	779	1,511	587	578	580	583	580	591	593	586	588	1,068	581	579	592	588	

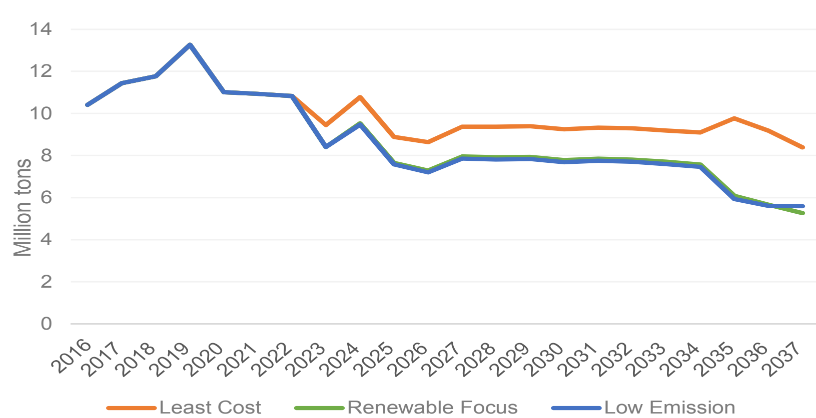
Table 8-5 shows the number of resources selected in the respective portfolios as a result of the optimization of the Base Scenario.

Table 8-5: Base Scenario Number of Selected Resources by Portfolio

Alternative	Brownfield CT	Brownfield CCGT	Reciprocating Engine	Small Modular Reactor	Greenfield Biomass	Battery Storage (Lithium Ion)	Combined Heat and Power	Onshore Wind	Utility Solar	Solar DG	Incemental DSM
Nameplate Capacity	240 MW	700 MW	1 MW	540 MW	50 MW	1 MW	20 MW	100 MW	50 MW	.1 MW	N/A
Firm Capacity	193 MW	629 MW	.92 MW	488 MW	43 MW	.97 MW	19 MW	7.9 MW	12.8 MW	0.002 MW	N/A
Fuel Type	Natural Gas	Natural Gas	Natural Gas/Methane	Nuclear	Biomass	N/A	Natural Gas	Wind	Solar	Solar	N/A
Least Cost	-	3	-	-	-	-	-	-	-	-	13
Renewable	1	1	-	-	-	1	1	28	40	1	13
Low Emission	1	1	1	1	1	1	-	10	11	-	13

Figure 8-21 shows the associated annual CO_2 emissions associated with each of the three portfolios associated with the Base Case.

Figure 8-21: Annual Portfolio CO_2 Emission – Base Case



8.5.2.2 Aggressive Environmental Scenario Results

Table 8-6 shows the resources selected as a result of the optimization of the Aggressive Environmental Scenario and grouped by the three strategies or portfolios. The Net Present Value of Revenue Requirements (NPVRR) associated with each portfolio is also indicated.

Table 8-6: Aggressive Environmental Scenario Expansion Plan

Portfolio	Resources	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	NPVRR ($Billion)
Least Cost	Gas	-	-	-	-	-	-	-	1,258	-	-	-	-	-	-	-	-	-	-	-	629	-	-	$14.51
	DSM	533	538	543	548	546	549	553	556	562	565	567	570	572	575	577	578	580	580	581	579	580	588	
	Purchases	-	-	167	180	199	211	226	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	533	538	710	727	745	760	779	1,814	562	565	567	570	572	575	577	578	580	580	581	1,208	580	588	
Renewable Focus	Gas	-	-	-	-	-	-	-	822	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$16.28
	Wind	-	-	-	-	-	-	-	-	0.01	16	-	16	16	16	8	8	16	16	16	79	8	8	
	Solar	-	-	-	-	-	-	-	115	13	-	13	-	-	-	-	-	-	-	-	370	-	-	
	Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	
	CHP	-	-	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DSM	533	538	543	548	546	549	553	556	562	565	567	570	572	575	577	578	580	580	581	579	580	588	
	Purchases	-	-	167	180	199	211	226	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	533	538	710	727	745	760	779	1,512	575	581	580	586	588	591	585	587	596	596	597	1,028	588	595	
Low Emission	Gas	-	-	-	-	-	-	-	822	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$16.98
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	488	-	-	-	-	
	Biomass	-	-	-	-	-	-	-	43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Recip	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Wind	-	-	-	-	-	-	-	-	-	16	-	-	16	16	16	8	8	-	-	-	-	-	
	Solar	-	-	-	-	-	-	-	89	13	-	13	13	-	-	-	-	-	-	-	-	13	-	
	Battery	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DSM	533	538	543	548	546	549	553	556	562	565	567	570	572	575	577	578	580	580	581	579	580	588	
	Purchases	-	-	167	180	199	211	226	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	533	538	710	727	745	760	779	1,511	576	581	580	583	588	591	593	586	588	1,068	581	579	592	588	

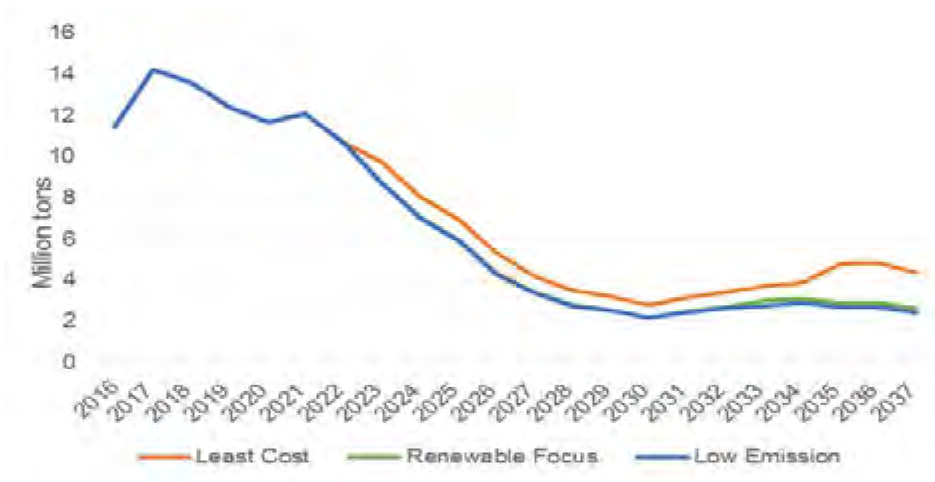
Table 8-7 shows the number of resources selected in the respective portfolios as a result of the optimization of the Aggressive Environmental Scenario.

Table 8-7: Aggressive Environmental Scenario Selected Resources

Alternative	Brownfield CT	Brownfield CCGT	Reciprocating Engine	Small Modular Reactor	Greenfield Biomass	Battery Storage (Lithium Ion)	Combined Heat and Power	Onshore Wind	Onshore Wind	Utility Solar	Incremental DSM
Nameplate Capacity	240 MW	700 MW	1 MW	540 MW	50 MW	1 MW	20 MW	100 MW	1.7 MW	50 MW	N/A
Firm Capacity	193 MW	629 MW	.92 MW	488 MW	43 MW	.97 MW	19 MW	7.9 MW	.01 MW	12.8 MW	N/A
Fuel Type	Natural Gas	Natural Gas	Natural Gas/Methane	Nuclear	Biomass	N/A	Natural Gas	Wind	Wind	Solar	N/A
Least Cost	-	3	-	-	-	-	-	-	-	-	13
Renewable	1	1	-	-	-	1	1	28	1	40	13
Low Emission	1	1	1	1	1	1	-	10	-	11	13

Figure 8-22 shows the associated annual CO_2 emissions associated with each of the three portfolios associated with the Aggressive Environmental Case.

Figure 8-22: Annual Portfolio CO_2 Emission – Aggressive Environmental



8.5.2.3 Challenged Economy Scenario Results

Table 8-8 shows the resources selected as a result of the optimization of the Challenged Economy Scenario and grouped by the three strategies or portfolios. The Net Present Value of Revenue Requirements (NPVRR) associated with each portfolio is also indicated.

Table 8-8: Challenged Economy Scenario Expansion Plan

Portfolio	Resources	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	NPVRR ($Billion)
Least Cost	Gas	-	-	-	-	-	-	-	629	-	-	-	-	-	-	-	-	-	-	-	629	-	-	$10.40
	CHP	-	-	-	-	-	-	-	19	-	-	19	-	-	-	19	-	-	-	-	-	-	-	
	DSM	533	541	547	553	553	559	562	566	572	575	578	580	583	586	588	589	590	591	592	590	591	589	
	Total	533	541	547	553	553	559	562	1,214	572	575	597	580	583	586	607	589	590	591	592	1,219	591	589	
Renewable Focus	Gas	-	-	-	-	-	-	-	629	-	-	-	-	-	-	-	-	-	-	-	193	-	-	$10.60
	Solar	-	-	-	-	-	-	-	-	-	-	13	-	-	13	-	-	-	-	-	255	-	-	
	Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	
	CHP	-	-	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DSM	533	541	547	553	553	559	562	566	572	575	578	580	583	586	588	589	590	591	592	590	591	589	
	Total	533	541	547	553	553	559	562	1,214	572	575	590	580	583	599	588	589	590	591	593	1,038	591	589	
Low Emission	Gas	-	-	-	-	-	-	-	822	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$11.21
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	488	-	-	
	DSM	533	541	547	553	553	559	562	566	572	575	578	580	583	586	588	589	590	591	592	590	591	589	
	Total	533	541	547	553	553	559	562	1,388	572	575	578	580	583	586	588	589	590	591	592	1,078	591	589	

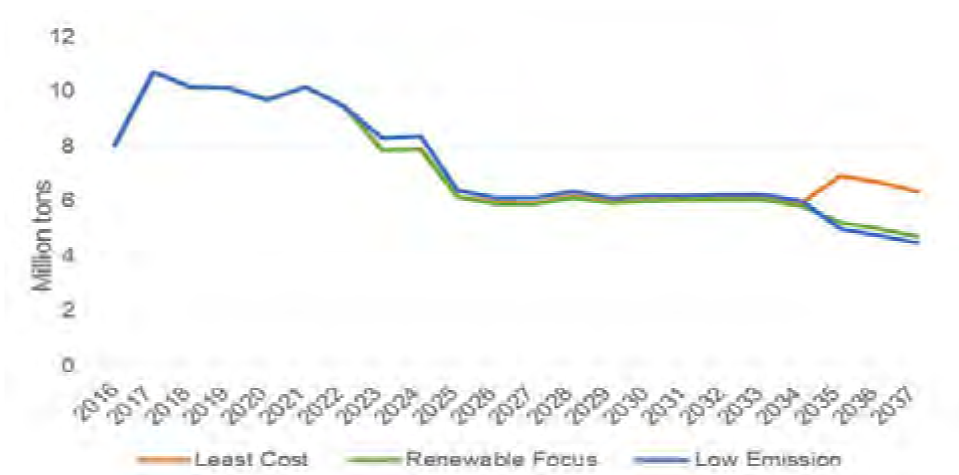
Table 8-9 shows the number of resources selected in the respective portfolios as a result of the optimization of the Challenged Economy Scenario.

Table 8-9: Challenged Economy Scenario Selected Resources

Alternative	Brownfield CT	Brownfield CCGT	Small Module Reactor	Battery Storage (Lithium Ion)	Combined Heat and Power	Utility Solar	Incremental DSM
Nameplate Capacity	240 MW	700 MW	540 MW	1 MW	20 MW	50 MW	N/A
Firm Capacity	193 MW	629 MW	488 MW	.97 MW	19 MW	12.8 MW	N/A
Fuel Type	Natural Gas	Natural Gas	Nuclear	N/A	Natural Gas	Solar	N/A
Least Cost	-	2	-	-	3	-	16
Renewable	1	1	-	1	1	22	16
Low Emission	1	1	1	-	-	-	16

Figure 8-23 shows the associated annual CO_2 emissions associated with each of the three portfolios associated with the Challenged Economy Case.

Figure 8-23: Annual Portfolio CO_2 Emission – Challenged Economy



8.5.2.4 Booming Economy Scenario Results

Table 8-10 shows the resources selected as a result of the optimization of the Booming Economy Scenario and grouped by the three strategies or portfolios. The Net Present Value of Revenue Requirements (NPVRR) associated with each portfolio is also indicated.

Table 8-10: Booming Economy Scenario Expansion Plan

Portfolio	Resources	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	NPVRR ($Billion)
Least Cost	Gas	-	-	-	-	-	-	-	1,258	-	-	629	-	-	-	-	-	-	-	-	629	-	-	$15.40
	CHP	-	-	-	-	-	-	-	-	19	19	-	-	-	-	-	-	-	-	-	-	-	-	
	DSM	533	541	548	554	555	560	564	568	573	576	579	581	584	587	589	590	592	592	593	591	592	588	
	Purchases	-	-	389	406	423	445	477	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	533	541	937	960	977	1,005	1,041	1,826	592	595	1,208	581	584	587	589	590	592	592	593	1,220	592	588	
Renewable Focus	Gas	-	-	-	-	-	-	-	1,015	-	-	-	-	-	-	-	-	-	-	-	629	-	-	$17.63
	Wind	-	-	-	-	-	-	-	71	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Solar	-	-	-	-	-	-	-	128	38	26	38	26	26	38	26	26	26	38	26	-	-	-	
	CHP	-	-	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DSM	533	541	548	554	555	560	564	568	573	576	579	581	584	587	589	590	592	592	593	591	592	588	
	Purchases	-	-	389	406	423	445	477	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	533	541	937	960	977	1,005	1,041	1,801	611	602	617	607	610	625	615	616	617	631	618	1,220	592	588	
Low Emission	Gas	-	-	-	-	-	-	-	1,015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$22.70
	Nuclear	-	-	-	-	-	-	-	-	-	488	-	-	-	-	-	-	-	-	-	1,987	-	-	
	Biomass	-	-	-	-	-	-	-	43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Wind	-	-	-	-	-	-	-	55	24	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Solar	-	-	-	-	-	-	-	115	13	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DSM	533	541	548	554	555	560	564	568	573	576	579	581	584	587	589	590	592	592	593	591	592	588	
	Purchases	-	-	389	406	423	445	477	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	533	541	937	960	977	1,005	1,041	1,796	610	1,064	579	581	584	587	589	590	592	592	593	2,578	592	588	

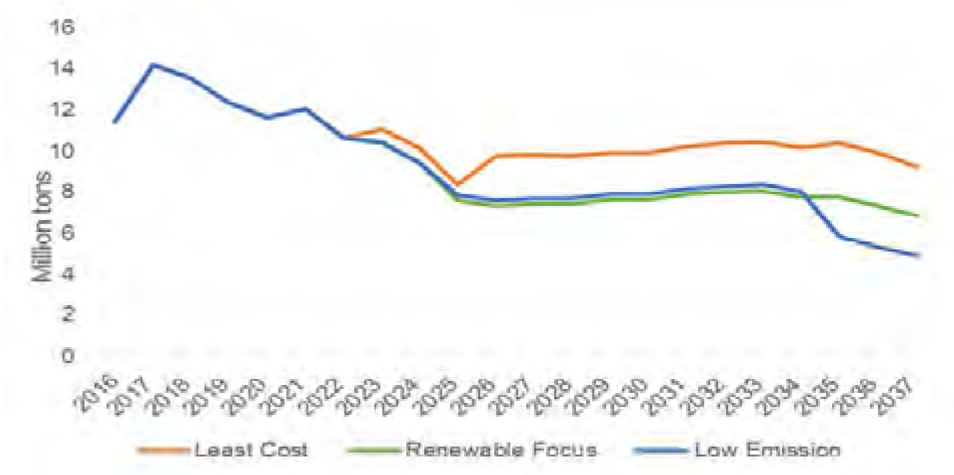
Table 8-11 shows the number of resources selected in the respective portfolios as a result of the optimization of the Booming Economy Scenario

Table 8-11: Booming Economy Scenario Selected Resources

Alternative	Brownfield CT	Brownfield CCGT	AP-1000	Small Module Reactor	Greenfield Biomass	Combined Heat and Power	Onshore Wind	Utility Solar	Incremental DSM
Nameplate Capacity	240 MW	700 MW	2,200 MW	540 MW	50 MW	20 MW	100 MW	50 MW	N/A
Firm Capacity	193 MW	629 MW	1987 MW	488 MW	43 MW	19 MW	7.9 MW	12.8 MW	N/A
Fuel Type	Natural Gas	Natural Gas	Nuclear	Nuclear	Biomass	Natural Gas	Wind	Solar	N/A
Least Cost	-	4	-	-	-	2	-	-	16
Renewable	2	2	-	-	-	1	9	36	16
Low Emission	2	1	1	1	1	-	10	10	16

Figure 8-24 shows the associated annual CO_2 emissions associated with each of the three portfolios associated with the Booming Economy Case.

Figure 8-24: Annual Portfolio CO_2 Emission – Booming Economy



8.5.2.5 Base Delayed Carbon Scenario Results

Table 8-12 shows the resources selected as a result of the optimization of the Base Delayed Carbon Scenario and grouped by the three strategies or portfolios. The Net Present Value of Revenue Requirements (NPVRR) associated with each portfolio is also indicated.

Table 8-12: Base Delayed Carbon Scenario Expansion Plan

Portfolio	Resources	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	NPVRR ($Billion)
Least Cost	Gas	-	-	-	-	-	-	-	1,258	-	-	-	-	-	-	-	-	-	-	-	629	-	-	$11.76
	DSM	531	534	536	539	543	546	549	553	558	561	565	568	571	575	578	580	582	583	585	586	588	589	
	Purchases	-	-	175	189	202	214	229	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	531	534	711	728	745	761	779	1,811	558	561	565	568	571	575	578	580	582	583	585	1,215	588	589	
Renewable Focus	Gas	-	-	-	-	-	-	-	822	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$14.02
	Wind	-	-	-	-	-	-	-	-	-	8	16	8	16	16	8	8	8	16	16	79	8	16	
	Solar	-	-	-	-	-	-	-	128	13	-	-	-	-	-	-	-	-	-	-	370	-	-	
	Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	
	CHP	-	-	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DSM	531	534	536	539	543	546	549	553	558	561	565	568	571	575	578	580	582	583	585	586	588	589	
	Purchases	-	-	175	189	202	214	229	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	531	534	711	728	745	761	779	1,521	570	569	580	576	587	591	586	588	590	600	601	1,035	595	605	
Low Emission	Gas	-	-	-	-	-	-	-	822	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$14.58
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	488	-	-	-	-	
	Biomass	-	-	-	-	-	-	-	43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Recip	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	
	Wind	-	-	-	-	-	-	-	-	-	-	8	16	8	16	8	16	8	-	-	-	-	-	
	Solar	-	-	-	-	-	-	-	102	13	13	-	-	-	-	-	-	-	-	-	-	-	13	
	Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	
	MT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	-	-	-	-	-	-	-	
	DSM	531	534	536	539	543	546	549	553	558	561	565	568	571	575	578	580	582	583	585	586	588	589	
	Purchases	-	-	175	189	202	214	229	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	531	534	711	728	745	761	779	1,520	570	574	572	584	579	591	588	596	590	1,071	585	586	588	602	

Table 8-13 shows the number of resources selected in the respective portfolios as a result of the optimization of the Base Delayed Carbon Scenario.

Table 8-13: Base Delayed Carbon Scenario Selected Resources

Alternative	Brownfield CT	Brownfield CCGT	Reciprocating Engine	Microturbine	Small Module Reactor	Greenfield Biomass	Battery Storage (Lithium Ion)	Combined Heat and Power	Onshore Wind	Onshore Wind	Utility Solar	Incremental DSM
Nameplate Capacity	240 MW	700 MW	1 MW	.4 MW	540 MW	50 MW	1 MW	20 MW	100 MW	1.7 MW	50 MW	N/A
Firm Capacity	193 MW	629 MW	.92 MW	.35 MW	488 MW	43 MW	.97 MW	19 MW	7.9 MW	.01 MW	12.8 MW	N/A
Fuel Type	Natural Gas	Natural Gas	Natural Gas/Methane	Natural Gas	Nuclear	Biomass	N/A	Natural Gas	Wind	Wind	Solar	N/A
Least Cost	-	3	-	-	-	-	-	-	-	-	-	11
Renewable	1	1	-	-	-	-	1	1	28	1	40	11
Low Emission	1	1	1	1	1	1	1	-	10	-	11	11

Figure 8-25 shows the associated annual CO_2 emissions associated with each of the three portfolios associated with the Base Delayed Carbon Case.

Figure 8-25: Annual Portfolio CO_2 Emission – Base Delayed Carbon

8.5.2.6 Summary Scenario Cumulative Energy Mix

Table 8-14, 8-15 and 8-16 show what percent of total NIPSCO customer energy requirement is served by the various resource types over the 2015-2037 time frame for the three portfolios. The net purchases represent total purchases minus total sales. A negative net purchases value represent a “long” position, where by NIPSCO is selling to the market and a positive value represent a “short” position, where by NIPSCO is buying from the market. Over the 2015-2037 planning horizon, NIPSCO is long and short throughout the year at different times.

Table 8-14: Cumulative 2015-2037 Energy Mix Least Cost

Least Cost Portfolio								
Scenario	**Coal**	**Gas**	**Wind**	**CHP**	**Hydro**	**FIT**	**DSM**	**Net Purchases**
Base	25.2%	55.4%	0.9%	-	0.3%	0.8%	2.8%	14.7%
Challenged Economy	24.0%	44.4%	1.1%	0.6%	0.3%	0.9%	3.2%	25.3%
Aggressive Environmental	22.2%	32.8%	0.9%	-	0.3%	0.8%	2.8%	40.3%
Booming Economy	26.0%	42.1%	0.9%	-	0.2%	0.7%	2.6%	16.8%
Base Delayed Carbon	18.6%	51.5%	0.9%	-	0.3%	0.8%	2.6%	25.3%

Table 8-15: Cumulative 2015-2037 Energy Mix Renewable Focus

Renewable Focus Portfolio									
Scenario	**Coal**	**Gas**	**Wind**	**CHP**	**Solar**	**Hydro**	**FIT**	**DSM**	**Net Purchases**
Base	25.5%	38.2%	12.6%	0.5%	4.8%	0.3%	0.8%	2.8%	12.9%
Challenged Economy	23.8%	41.4%	1.1%	0.4%	1.5%	0.3%	0.9%	3.2%	27.0%
Aggressive Environmental	22.1%	23.6%	12.6%	0.3%	4.8%	0.3%	0.8%	2.8%	31.0%
Booming Economy	26.9%	33.1%	10.7%	0.4%	2.2%	0.2%	0.7%	2.6%	18.3%
Base Delayed Carbon	18.4%	35.6%	11.9%	0.3%	5.1%	0.3%	0.8%	2.6%	23.1%

Table 8-16: Cumulative 2015-2037 Energy Mix Low Emission

Low Emission Portfolio												
Scenario	**Coal**	**Gas**	**Wind**	**Battery**	**Biomass**	**Solar**	**Hydro**	**Nuclear**	**Recip**	**FIT**	**DSM**	**Net Purchases**
Base	25.5%	38.2%	9.2%	-	0.1%	2.1%	0.3%	-	-	0.8%	2.8%	19.3%
Challenged Economy	23.4%	43.5%	1.1%	-	-	-	0.3%	1.5%	-	0.9%	3.2%	26.1%
Aggressive Environmental	21.9%	23.5%	8.4%	0.006%	0.0%	2.9%	0.3%	-	0.0%	0.8%	2.8%	38.2%
Booming Economy	27.2%	30.8%	9.5%	-	0.1%	2.5%	0.2%	4.1%	-	0.7%	2.6%	18.8%
Base Delayed Carbon	18.1%	35.5%	8.2%	0.0%	0.1%	3.0%	0.3%	-	-	0.8%	2.6%	29.4%

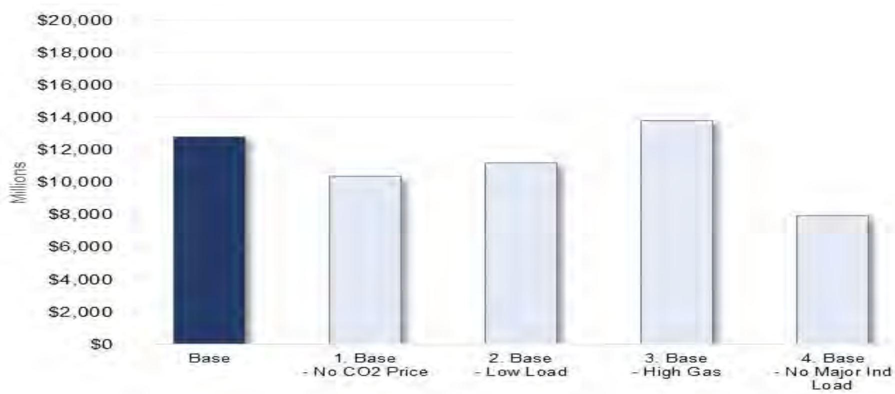
8.5.3 Sensitivity Analysis Results

Similar to the scenarios, the analysis of each of the sensitivities results in a mix of portfolio of supply-side and demand-side resources. The figures that follow show the NPVRR of the sensitivities and how they compare with the respective scenarios.

8.5.3.1 Base Sensitivities

The NPVRRs of the Base sensitivities compared to the scenario for the least cost portfolios can be viewed in Figure 8-26.

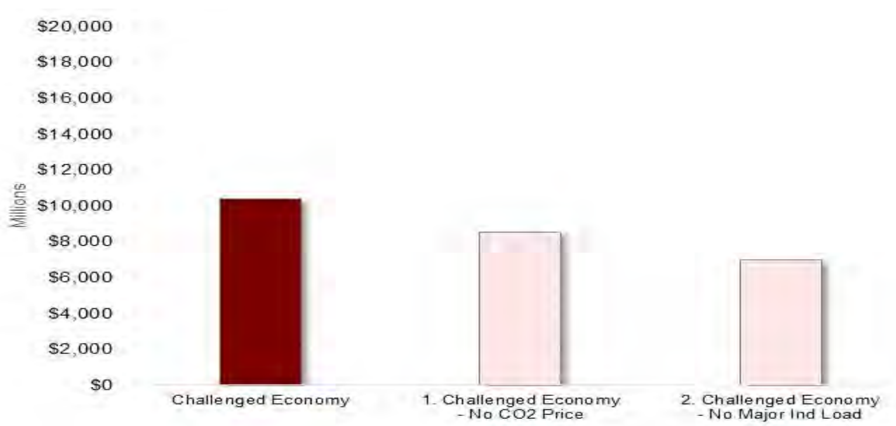
Figure 8-26: Base Scenario and Sensitivities NPVRR



8.5.3.2 Challenged Economy Sensitivities

The NPVRRs of the Challenged Economy sensitivities compared to the scenario for the least cost portfolios can be viewed in Figure 8-27.

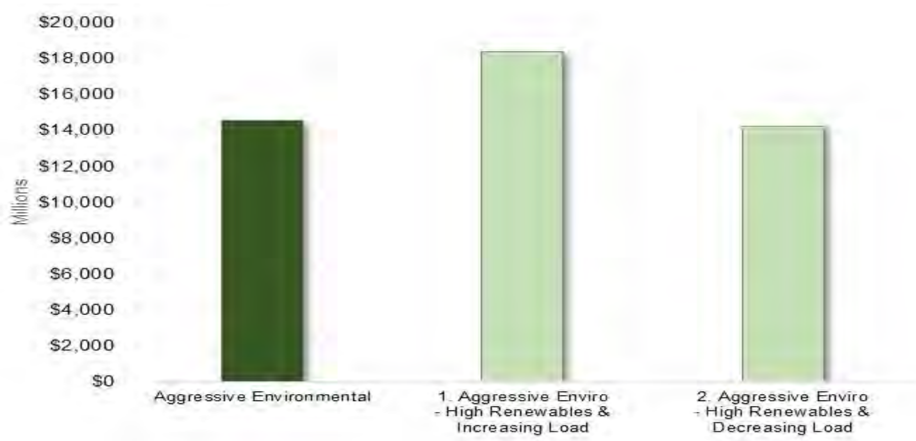
Figure 8-27: Challenged Economy Scenario and Sensitivities NPVRR



8.5.3.3 Aggressive Environmental Regulation Sensitivities

The NPVRRs of the Aggressive Environmental Regulation sensitivities compared to the scenario for the least cost portfolios can be viewed in Figure 8-28.

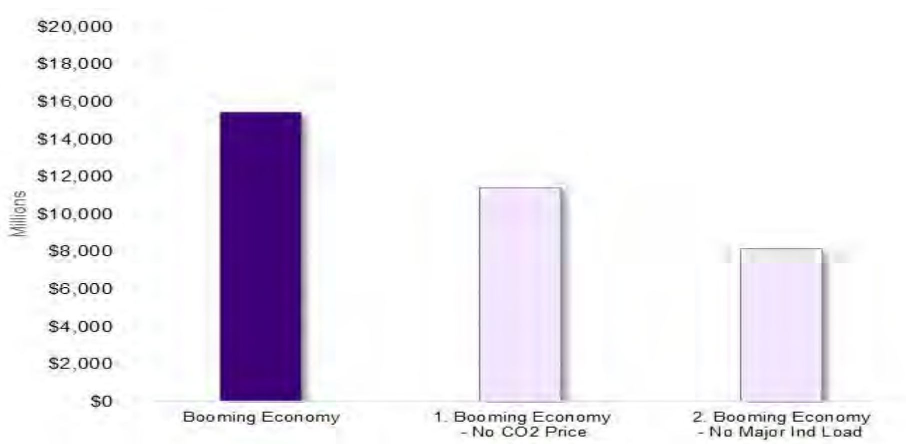
Figure 8-28: Aggressive Environmental Regulation Scenario and Sensitivities NPVRR



8.5.3.4 Booming Economy Sensitivities

The NPVRRs of the sensitivities compared to the scenario for the least cost portfolios can be viewed in Figure 8-29.

Figure 8-29: Booming Economy Scenario and Sensitivities NPVRR



8.5.3.5 Sensitivity Results Summary

Table 8-17 shows the NPVRR associated with the three portfolio types for the scenarios and sensitivities. *See* Appendix F, Exhibit 2: Sensitivity Modeling Results for the detailed capacity expansion plans and the cumulative energy mixes for the sensitivities.

Table 8-17: NPVRR Summary of Scenarios and Sensitivities

Net Present Value Of Revenue Requirements ($Millions)	Least Cost	Renewable	Low Emissions
Base Scenario (B)	12,819	14,955	15,607
1. No Carbon Price (BS1)	10,347	13,868	16,882
2. Low Load (BS2)	11,161	11,352	12,008
3. High Natural Gas Prices (BS3)	13,784	15,686	17,927
4. No Major Industrial Load (BS4)	7,932	11,571	8,725
Challenged Economy Scenario (CE)	10,396	10,599	11,209
1. No Carbon Price (CES1)	8,514	8,684	9,182
2. No Major Industrial Load (CES2)	7,004	8,299	7,612
Aggressive Environmental Regulation Scenario (AE)	14,511	16,276	16,981
1. High Renewables and Increasing Load (AESs1)	18,363	22,483	21,233
2. High Renewables and Decreasing Load (AES2)	14,213	18,519	14,755
Booming Economy Scenario (BE)	15,404	17,628	22,697
1. No Carbon Price and Low Natural Gas Prices (BES1)	11,371	13,928	18,953
2. No Major Industrial Load (BES2)	8,152	11,254	8,942
Base Delayed Carbon Scenario (BDC)	11,762	14,023	14,577

Table 8-18 shows the number of DSM selected across the various scenarios and sensitivities.

Table 8-18: NPVRR Summary of Scenarios and Sensitivities

		Residential							Commercial										Industrial					Demand Response				
Scenario	**Sensitivity**	REAP	RECG	REHG	REMS	REWH	REEL	REIL	COCG	COEL	COFP	COHG	COIL	COMS	COOE	CORF	COVE	COWH	INCG	INEL	INIL	INMT	INHG	DRRA	DRCA	DRRH	DRCH	**Total**
Base						1	1	1		1	1		1	1	1	1		1		1	1	1						**13**
	Bs1					1				1				1	1			1		1	1	1						**8**
	Bs2				1	1	1	1		1	1		1	1	1	1		1		1	1	1			1		1	**16**
	Bs3					1	1	1		1	1		1	1	1	1		1		1	1	1						**13**
	Bs4					1	1	1		1	1		1	1	1	1		1		1	1	1						**13**
CE					1	1	1	1		1	1		1	1	1	1		1		1	1	1			1		1	**16**
	CEs1					1							1	1	1					1	1	1		1	1		1	**10**
	CEs2					1	1			1	1		1	1	1	1		1		1	1	1						**12**
AE						1	1	1		1	1		1	1	1	1		1		1	1	1						**13**
	AEs1	1	1		1	1	1	1		1	1		1	1	1	1	1	1	1	1	1	1			1			**19**
	AEs2	1			1	1	1	1		1	1		1	1	1	1	1	1		1	1	1			1			**17**
BE						1	1	1		1	1	1	1	1	1	1	1	1		1	1	1				1		**16**
	BEs1		1			1				1	1		1	1	1			1		1	1	1			1			**12**
	BEs2					1	1	1		1	1		1	1	1	1		1		1	1	1						**13**
BDC						1				1	1		1	1	1	1		1		1	1	1						**11**
Scenario	Mode (5)	0	0	0	1	5	4	4	0	5	5	1	5	5	5	5	1	5	0	5	5	5	0	0	1	1	1	
All	Mode (15)	2	2	0	4	15	11	10	0	14	13	1	14	15	15	12	3	14	1	15	15	15	0	1	6	1	3	

	Tier 1	Tier 2	Tier 3	Not Picked	Total
All Cases	9	4	10	3	26
Scenarios Only	11	2	6	7	26

Table 8-19 shows the DSM groupings key by residential, commercial and industrial.

Table 8-19: DSM Groupings Key

Residential EE Groupings	Commercial EE Groupings	Industrial EE Groupings
Res Appliances (REAP)	Com Cooling (COCG)	Industrial Cooling (INCG)
Res Cooling (RECG)	Com Exterior Lighting (COEL)	Industrial Exterior Lighting (INEL)
Res Electric Heating (REHG)	Com Electric Food Prep (COFP)	Industrial Interior Lighting (INIL)
Res Electric Miscellaneous (REMS)	Com Electric Heating (COHG)	Industrial Motors (INMT)
Res Electric Water Heat (REWH)	Com Interior Lighting (COIL)	Industrial Heating (INHG)
Res Exterior Lighting (REEL)	Com Elec Miscellaneous (COMS)	
Res Interior Lighting (REIL)	Com Office Equipment (COOE)	
	Com Refrigeration (CORF)	
	Com Ventilation (COVE)	
	Com Electric Water Heat (COWH)	

Residential DR Groupings	Commercial DR Groupings
Res Cooling Direct Load Control (DRRA)	Commercial Cooling Direct Load Control (DRCA)
Residential Water Heating Direct Load Control (DRRH)	Commercial Water Heating Direct Load Control (DRCH)

8.5.4 Preferred Portfolio

From a customer perspective, NIPSCO's preferred portfolio plan was developed to ensure that a reliable, compliant, flexible, diverse and affordable supply was available to meet future customer needs. NIPSCO, also, carefully planned and considered the impacts to its employees, the environment and impacts on the local economy as the plans were developed. It is important to remember that the integrated resource plan is a snapshot in time and while it establishes a direction for NIPSCO it is subject to change as the operating environment changes. In addition, the submission of this plan and its resulting preferred portfolio does not stop the transparency of the process or engagement with stakeholders.

The major components of NIPSCO's supply strategy for the next 20 years are expected to:

- Lead to a lower cost, cleaner, diverse and compliant portfolio by retiring 50% of NIPSCO's coal capacity by the end of 2023
- Continue the Company's commitment to energy efficiency and demand response by including programs that are economically viable for all customers
- Continue to comply with environmental regulations, specifically effluent limit guidelines and coal combustion residuals, for the retained coal generation
- Maintain an appropriate level interruptible service for the Company's major industrial customers
- Reduce customer's and the Company's exposure to customer load, market and technology risks by intentionally allocating a portion of the portfolio to shorter duration supply

- Strongly consider cost to customers, while considering all technologies and fuels as viable to provide shorter duration supply

- Add combined cycle gas turbine capacity to meet supply needs that are not covered by shorter duration options

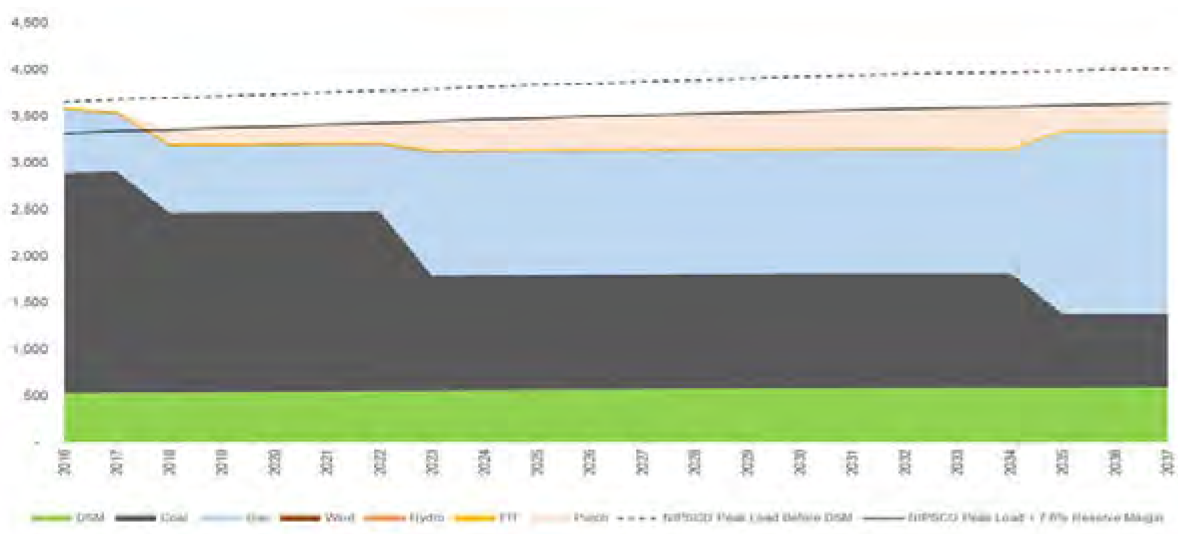
- Continue to evaluate additional supply retirements in light of changing market conditions and policy requirements

- Continue to invest in infrastructure modernization to maintain safe and reliable delivery of energy services.

8.5.5 Plan Summary

Figure 8-30 shows NIPSCO's annual capacity position that incorporated the preferred portfolio considering NIPSCO's load obligation as well as MISO's reserve margin requirements. It also shows the cumulative energy mix associated with the preferred portfolio.

Figure 8-30: Preferred Plan Capacity Expansion



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

All but four DSM Groupings were selected by at least one case, with six of the DSM Groupings selected by all 15 cases. Table 8-20 breaks each DSM Grouping into four categories. Column 1 shows the DSM Groupings that were selected by all 15 cases; Column 2 shows the DSM Groupings that were selected by at least 10 cases; Column 3 shows one of the DSM Groupings that was selected by fewer than 10 cases; Column 4 shows the other three DSM Groupings that were selected by fewer than 10 cases. These categories will provide the basis upon which NIPSCO's 2017 DSM Plan will be determined.

Table 8-20: DSM Groupings Selection

Column 1	Column 2	Column 3	Column 4
Selected Program Groupings	**Program Groupings That Will Receive Further Consideration**	**Program Groupings That Will Receive Further Consideration in Conjunction with a Gas Program**	**Program Groupings Not Selected**
These programs were selected in the majority of the IRP optimization runs	*These programs were occasionally selected in several of the optimization runs*	*These programs were not selected by the IRP optimization runs*	*These programs were not selected by the IRP optimization runs*
<u>13 Program Groupings</u> – Res Electric Water Heat – Res Exterior Lighting – Res Interior Lighting – Com Exterior Lighting – Com Electric Food Prep – Com Electric Water Heat – Com Interior Lighting – Com Elec Miscellaneous – Com Office Equipment – Com Refrigeration – Industrial Exterior Lighting – Industrial Interior Lighting – Industrial Motors	<u>9 Program Groupings</u> – Res Appliances – Res Electric Miscellaneous – Com Electric Heating – Com Ventilation – Industrial Cooling – Res Cooling Direct Load Control (DLC) – Res Water Heating DLC – Com Cooling DLC – Com Water Heating DLC	<u>1 Program Groupings</u> – Res Electric Heating	<u>3 Program Groupings</u> – Res Cooling – Com Cooling – Industrial Heating

Table 8-20 above is a different way of illustrating the various categories and how NIPSCO will consider the groupings as part of its DSM planning efforts. Since most of the groupings were in Category 1 "Selected Program Groupings" or Category 2 "Program Groupings That Will Receive Further Consideration," NIPSCO will include those as it continues to model DSM to meet its ongoing needs. Additionally, since NIPSCO has a combined service territory that includes natural gas, there is one program that may make sense to include, particularly as part of a residential heating, air conditioning and ventilation program. This program is included in Category 3 "Program Groupings That Will Receive Further Consideration in Conjunction with a Gas Program" to indicate such a distinction. The remaining three groupings in Category 4 "Program Groupings Not Selected" will not be considered further at this this time.

Table 8-21 shows NIPSCO's long-term plan consisting of both resource retirements and additions. Specifically, over planning period NIPSCO's capacity mix attributable to coal would decline to 50%. To offset the decline, CCGT, DSM EE and Purchases would be added over the 20 year planning horizon.

Table 8-21: Preferred Portfolio

Year	Resources Retired (MW)	Resources Added (MW)
2016		DSM EE
2017		DSM EE, DR
2018	Bailly 7 (160) Bailly 8 (320)	DSM EE, DR Purchases
2019		DSM EE, DR, Purchases
2020		DSM EE, DR, Purchases
2021		DSM EE, DR, Purchases
2022		DSM EE, DR Purchases
2023	Bailly 10 (31) Schahfer 17 (361) Schahfer 18 (361)	CCGT (660) DSM EE, DR, Purchases
2024	Buffalo Ridge Wind (50)	DSM EE, DR, Purchases
2025		DSM EE, DR, Purchases
2026		DSM EE, DR, Purchases
2027		DSM EE, DR, Purchases
2028		DSM EE, DR, Purchases
2029	Barton Wind (50)	DSM EE, DR, Purchases
2030		DSM EE, DR, Purchases
2031		DSM EE, DR, Purchases
2032		DSM EE, DR, Purchases
2033		DSM EE, DR, Purchases
2034	Michigan City 12 (469)	DSM EE, DR, Purchases
2035		CCGT (660) DSM EE, DR, Purchases
2036		DSM EE, DR, Purchases
2037		DSM EE, DR, Purchases

As stated above, NIPSCO used a number of criteria to evaluate and select its preferred plan, with economics playing a significant role. After reviewing the optimization results, NIPSCO identified that the cost estimates for CCR/ELG excluded approximately $50 million of overhead expense. Due to the timing of the finding, NIPSCO was unable to re-run the analysis in time to submit the IRP by November 1. It is important to note that both the retirement analysis and the preferred plan incorporated NIPSCO's current and best cost estimates for CCR/ELG, including the appropriate level of overhead expenses. The variance in assumptions between the optimization and the preferred plan results has caused the stylized portfolios in Figures 8-31, 8-32 and 8-33 to show lower values by the 20-year present value of the revenue requirement because of the missing overhead expense while the preferred portfolio includes the full NPVRR. While NIPSCO expects that adding the missing overhead expense to the optimization results will lead to a uniform increase of all of the stylized portfolio's NPVRRs, it does intend to re-run the optimization results to create NPVRRs that are truly comparable with the preferred plan. These updated results will be available to support CCR/ELG testimony and rebuttal. In the optimization results and risk modeling sections NIPSCO identified 5 scenarios and 10 additional sensitivities across which three stylized portfolios were evaluated: (1) Least Cost, (2) Renewable Focus, and (3) Low Emissions. As shown in Figures 8-31, 8-32 and 8-33, to evaluate NIPSCO's preferred plan the Company compared the Net Present Value of Revenue Requirement of the preferred plan against the stylized portfolio's Net Present Value of Revenue Requirements in each scenario Sensitivity. This comparison showed clearly that not only was the preferred portfolio aligned with NIPSCO's reliability, compliance, diversity and flexibility criteria; it almost always had lower costs to customers across the scenarios.

Figure 8-31: Comparison of Preferred Plan To Scenario Portfolios

(Net Present Value Revenue Requirement)

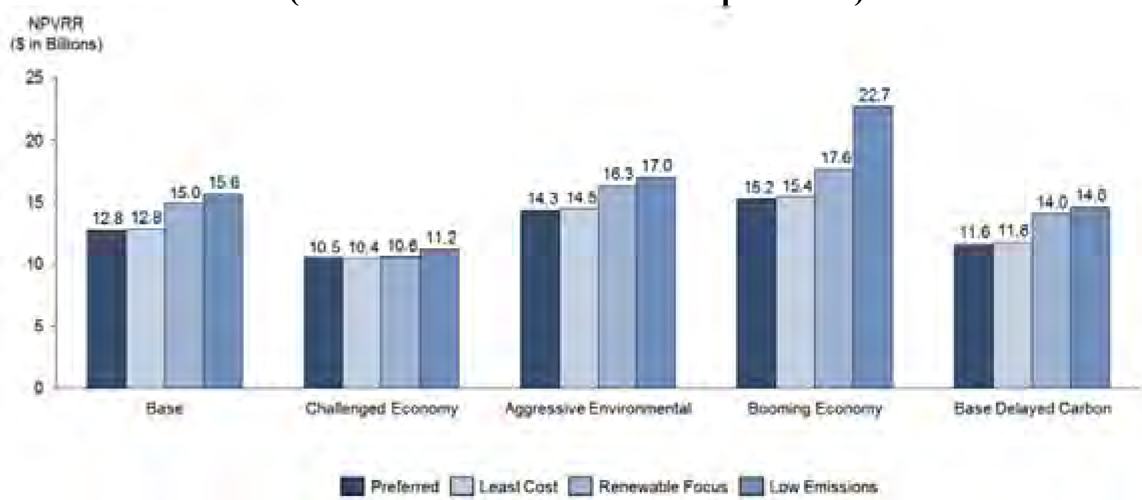


Figure 8-32: Comparison of Preferred Plan To Sensitivity Portfolios 1-5

(Net Present Value Revenue Requirement)

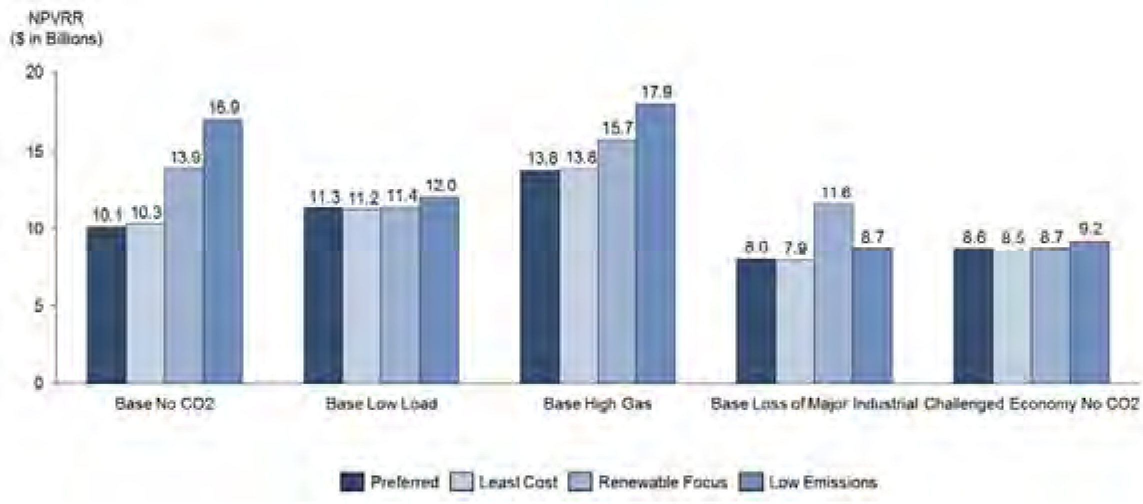
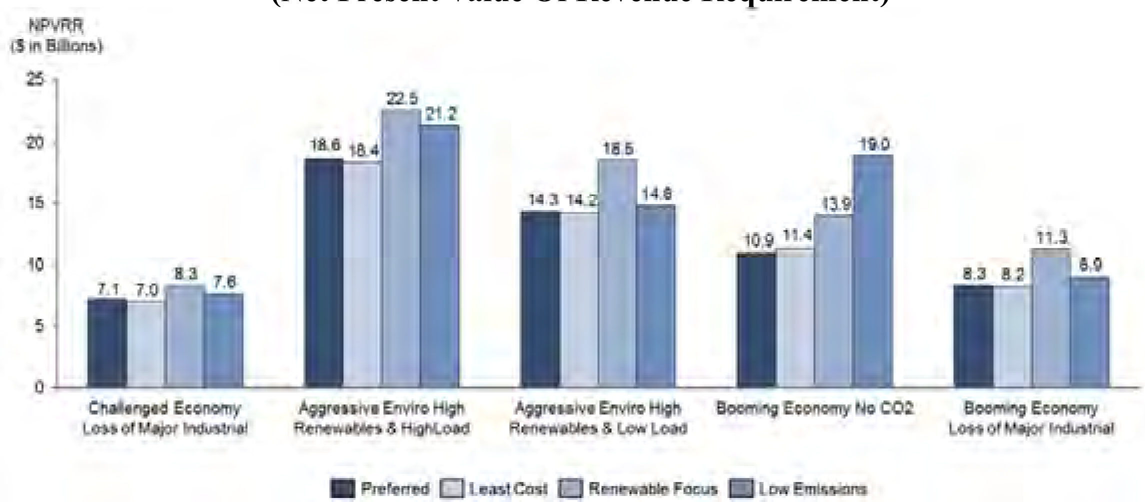


Figure 8-33: Comparison of Preferred Plan To Sensitivity Portfolios 6-10

(Net Present Value Of Revenue Requirement)



8.5.6 Financial Impact

Table 8-22 shows NIPSCO's financial impact of the preferred plan over the planning period. The NPVRR is broken down into operating and capital costs. The operating costs include the cost of operations of both existing units and future resources (CCGT and net market interchange). The capital costs include all capital projects such as environmental regulation compliance capital, DSM, and building of CCGT.

Table 8-22: Preferred Portfolio Financial Impact

Financial Impact Summary	
Operating Costs ($000)	26,056,755
Capital Costs ($000)	3,418,550
Total Revenue Requirement ($000)	29,475,306
Total Energy Requirement (GWh)	426,714
cents/kWh	**6.91**

NIPSCO expects that existing cash balances, cash generated from operating activities and funding through inter-company loan arrangements with its parent company will meet anticipated operating expenses and capital expenditures associated with NIPSCO's short term action plan.

In the long term, future operating expenses as well as recurring and nonrecurring capital expenditures are expected to be obtained from: (i) existing cash balances; (ii) cash generated from operating activities; (iii) inter-company loan arrangement; (iv) additional external debt financing with unaffiliated parties; and/or (v) new equity capital. NiSource, Inc. and its wholly owned financing subsidiary, NiSource Finance Corp., procure external funding from the bank and capital markets (debt and equity). NiSource's long-term debt ratings are currently BBB+ at S&P and Baa2 at Moody's.

NIPSCO intends to fulfill its commitment in Cause No. 44688, in regard to electric related projects, to "finance, in aggregate, any project, or set of projects in an approved plan, estimated to cost more than $100 million for which it receives a Certificate of Public Convenience and Necessity pursuant to Ind. Code Chapters 8-1-8.4, 8-1-8.5, 8-1-8.7, 8-1-8.8, or 8-1-39 with at least 60% debt capital."

The modeling in *Strategist*® does not include the existing rate base (generation, transmission, or distribution).

8.5.7 Short-Term Action Plan

NIPSCO's short-term action plan covering the period 2016 through 2019 will focus on the implementation of retirements and identification of replacement capacity. Assuming approval from MISO, NIPSCO plans to retire Bailly Units 7 and 8 by May 2018. The replacement capacity necessary to meet the customer demand during the short term action plan will range from approximately 150 MWs to 200 MWs and this capacity need will be addressed with either short term purchase power agreements and/or market capacity purchases, whichever provides the best alignment of costs and mitigation of risks for customers.

NIPSCO will continue to provide economically viable demand side management for customers during the short term action plan period. *See,* Table 8-20: DSM Groupings Selection. NIPSCO will also pursue approval to invest in and associated recovery of environmental capital related to ELG and CCR for Michigan City Unit 12 and Schahfer Units 14 and 15. While preliminary analysis shows that compliance with ELG and CCR is not preferred, NIPSCO will evaluate the value of developing a compliance option at Schahfer Units 17 and 18.

Finally, prior to the end of the first quarter of 2019, NIPSCO expects to complete a request for proposals to build a CCGT to meet supply needs beginning in 2023. This evaluation will create a baseline for comparison of other technology and supply options. Table 8-23 summarizes this short-term plan and its expected costs.

Table 8-23: Short-Term Action Plan Summary

2016 IRP Short-Term Action Plan Item
Retire Bailly Units 7 and 8 by May 2018
Meet capacity needs with shorter duration purchase power agreements or market purchases
Offer service options for customers, including demand-side management
Utilize available interruptible resources, as needed, to meet requirements
Evaluate building a CCGT to meet supply needs beginning in 2023
Invest in infrastructure modernization to maintain safe and reliable delivery of energy services
Comply with NERC CIP cyber security standards
Comply with regulations, including Environmental Protection Agency regulations

Table 8-24 is a summary of the actions NIPSCO has taken to date relating to the Short Term Action Plan items included in its 2014 IRP.

Table 8-24: 2014 IRP Short-Term Plan Summary and NIPSCO Action

2014 IRP Short-Term Action Plan Item	NIPSCO Action
Utilize available interruptible resources as needed to meet requirements	NIPSCO continued the interruptible program with its major industrial customers This program was expanded by 30 MW to 530 MW and an increase of the dollar cap to $57 million in the 2016 Electric Rate Case
Invest in infrastructure modernization to maintain safe and reliable delivery of energy services	NIPSCO filed and is executing a 7-Year Electric TDSIC Plan
Explore the potential for increased interruptible resources	The interruptibles offering was expanded by 30 MW to 530 MW and an increase of the dollar cap to $57 million as approved in the Rate Case Order
Offer service options for customers, including demand-side management	NIPSCO has consistently made DSM program filings for economically viable programs

2014 IRP Short-Term Action Plan Item	NIPSCO Action
Comply with NERC Critical Infrastructure Protection ("CIP") cyber security standards	NIPSCO continues to adapt to the changing CIP Standards and reassess its environment to ensure security and compliance
Comply with new regulations, including EPA regulations	NIPSCO monitors new and changing environmental regulations and develops compliance plans to address regulatory requirements
Develop a distributed generation strategy	NIPSCO continues to evaluate distributed generation opportunities with customers through the Feed in Tariff program
Implement revisions to the Feed in Tariff	Phase II of NIPSCO's Feed-in Tariff was approved on February 4, 2015 in Cause No. 44393. NIPSCO released Phase II of the FIT program in March of 2015, allowing for an additional 16 MW of renewable capacity, bringing the total FIT capacity cap up to 46 MW.

8.5.8 Conclusion

The NIPSCO Integrated Resource Plan seeks to ensure reliable, cost effective electric service for customers while maintaining a robust and diverse pool of supply-side generation and demand-side options. This IRP quantifies changes associated with the emerging energy market place to best accommodate risks associated with customer cost and service. No longer is it possible to view the world in terms of choosing a simple least cost option; it is now necessary to think it terms of minimizing future environmental impacts and maximizing resource diversification all the while ensuring affordable service to customers.

The IRP process and document are ever evolving and no filed document is ever up-to-date with the world as it stands the day after filing. Rather than trying to model our future world with exact precision, this IRP seeks to utilize a broad set of scenarios and sensitivities which inform and develop NIPSCO's preferred plan.

Section 9. Customer Engagement

9.1 Enhancing Customer Engagement

NIPSCO is focused on enhancing how we serve and interact with our customers. Whether upgrading our energy infrastructure to make sure it's prepared to meet their future needs, providing more convenient options to connect with us online or via phone or expanding energy efficiency programs, our customers are our central focus.

9.1.1 Leveraging Stakeholder Feedback

We rely on customer feedback to uncover service improvement opportunities. Those feedback mechanisms include the J.D. Power Customer Satisfaction Surveys, Thoroughbred Surveys, online customer panels, comments and complaints that are emailed or called into NIPSCO's Call Center, as well as the IURC's consumer affairs division. We also research best practices that have been demonstrated by those within the utility sector, as well as those outside of our industry.

This data is the primary driver behind many of the operational changes, improvements in customer communications, enhancements to services and added programs and other offerings that have been instituted in recent years.

For example, our JD Power Electric Customer Satisfaction survey results have highlighted the need to expand how we communicate with customers during power outages. As a result, we launched NIPSCO Alerts, which enables our customers to receive updates regarding power outages, including estimated restoration time via text, email, or phone. We also added the option for customers to text us to report a power outage. With this new offering, NIPSCO customers can now choose the option that is most convenient for them – phone, online (desktop and mobile) and text.

9.1.2 NIPSCO's Annual Energy Symposium

NIPSCO hosted its 4th Annual Energy Symposium at the Radisson Star Plaza in Merrillville, Indiana on October 14, 2015. Attendance included 130 of NIPSCO's Commercial and Industrial ("C&I") customers from various markets within the NIPSCO Northwest Indiana territory. As with other years, the Symposium provided an opportunity to learn more about advancements in the energy field and how to use energy more efficiently.

Customers were able to attend 1-hour workshops of their choice on a broad range of topics that were selected based on customer values, customer requests, and customer advantage after the review of previous symposium events. Among the nine workshops that were offered, topics included: Renewable Energy, Energy Market Assessments, Power Quality and Global Energy. In recent years, as a result of customer feedback, enhanced workshops were added to provide customers with more information to gain a better understanding of the advantages of energy efficiency. New to the 2015 Symposium was the addition of two panel discussions: Energy Market Assessments and Renewable Energy. This gave attendees an opportunity to listen and discuss in an open forum. The workshops and the panel discussions were presented by experts outside of NIPSCO.

Customers also had an opportunity to visit the resource booths for information that can benefit their company. Last year, NIPSCO successfully doubled the number of resource booths, from the previous year.

9.1.3 Automated Meter Reading Technology

At the end of 2015, NIPSCO completed a three year project to install 425,000 electric meters with Automated Meter Reading ("AMR") technology. This technology allows NIPSCO to automatically collect meter readings from its residential customers and a large portion of its commercial and industrial customers without leaving a company vehicle. The AMR meter readings are gathered on a monthly basis utilizing wireless technology. This method replaces the previous method of a meter reader walking up to each meter and recording the index in a handheld device.

AMR technology improves the safety of NIPSCO's meter readers and the satisfaction of customers, by eliminating the need to enter a customer's property. It virtually eliminates dog hazards in addition to slip, trip and fall incidents. Benefits also include improving meter reading accuracy and the elimination of estimated bills.

9.1.4 New Business Department

The New Business Department was formed in July of 2015 to add value for customers and stakeholders by providing a focus on new business activities for all customers (residential, commercial and industrial). The goals include:

- Continuous improvement of the new business process "from first call to install"
- Single source accountability for policy maintenance
- Enhancing relationships with builder/developer community
- Improving metrics to inform on efficiency and effectiveness
- Supporting capital budget methodology to increase clarity
- Managing growth programs including Electric Vehicle, Feed-In Tariff, Green Power, Compressed Natural Gas

The New Business Department has responsibility for any customer that requests new service, upgrade of service, retirement of service, or relocation of service. NIPSCO's call center representatives are specifically trained in the details of these transactions and provide a resource for customer issues. Since its inception, the New Business Department has undertaken initiatives to:

- Create a single Site Readiness policy for NIPSCO
- Provide automated emails to customers with project status updates
- Revise key performance indicators to better inform on execution levels
- Simplify agreements for all customer classes
- Establish new accounting codes to provide clarity into new service costs

The New Business Department expanded in 2016 and now includes external, customer facing representatives and internal support to assist customers with their new service connections. The New Business Department continues its efforts to evaluate the new business process to determine opportunities for increased efficiency and improved customer service. An end-to-end process map has been completed, which has helped to identify additional areas of opportunity.

9.1.5 Customer Feedback

Customer feedback is essential in NIPSCO's development of customer support and service offerings to provide for an exceptional customer experience. NIPSCO utilizes an on-line group of customers to provide feedback on project offerings and channel options. NIPSCO utilized this on-line group, along with an additional in-person focus group, in the redesign of its customer bill that launched in the Spring of 2016. NIPSCO also surveys customers to determine customer satisfaction with the call center and interactions with field personnel, as well as with on-line experiences such as Mobile, Integrated Voice Response and Web. Customer surveys are also used to capture specific customer issues and to gain immediate feedback on the quality of NIPSCO's customer service. NIPSCO uses the results of these surveys, as well as the information obtained through the J.D. Power Customer Satisfaction Surveys, to identify potential ways to improve the overall customer experience including training and development for customer service representatives and field personnel.

In addition to the J.D. Power Customer Satisfaction Surveys, NIPSCO also relies on customer feedback obtained through Thoroughbred Surveys, online customer panels, comments and complaints that are emailed or called into NIPSCO's Call Center, as well as the Commission's consumer affairs division to discover service improvement opportunities. NIPSCO also researches best practices that have been demonstrated by those within the utility sector, as well as those outside of the utility industry.

Customer feedback is the primary driver behind many of the operational changes, improvements in customer communications, enhancements to services and additional programs and other offerings that have been instituted in recent years.

NIPSCO's recent J.D. Power Customer Satisfaction Survey results highlight the need for NIPSCO to enhance its communication with its customers during power outages. As a result, NIPSCO launched *NIPSCO Alerts*, which enables customers to receive updates on the cause of their power outage and estimated restoration times via text, email, or phone. NIPSCO also added an option for customers report a power outage via text. NIPSCO's customers can now choose the option that is most convenient for them – phone, online (desktop and mobile) or text.

9.1.6 Community Partnerships - Community Advisory Panels

Another avenue used by NIPSCO to engage with its customers and stakeholders is the use of Community Advisory Panels ("CAPs"), which serve as a forum to discuss new company initiatives and programs as well as to educate and facilitate feedback regarding service and other NIPSCO-related matters in their communities. NIPSCO has established five regions across the Company's footprint for the CAPs. CAPs are comprised of individual customers as well as local government and community leaders representing a broad cross-section of NIPSCO customers. NIPSCO senior management meets with each of the regional CAPs three times a year to share the Company's strategic direction and to ask members of the CAPs for insight on emerging issues.

9.2 Customer Programs

9.2.1 Feed-in Tariff – Rate 765

NIPSCO's Renewable Feed-in Tariff ("FIT") Phase I was approved on July 13, 2011 in Cause No. 43922. Implementation began immediately as a three-year pilot program with a 30 MW capacity cap. Phase I offered a rate greater to participants selling electricity than the retail electric rate in the current approved sales tariffs and provided an incentive to encourage development of renewable generating resources. The pilot program was designed to help maximize the development of renewable energy in Indiana, which welcomed biomass, wind, hydro and solar resources. The FIT provides the customer a sell-back opportunity to NIPSCO at a predetermined price for up to 15 years through a Renewable Power Purchase Agreement ("RPPA"). Participating customers receive payment from NIPSCO for the amount of electricity generated and delivered to NIPSCO through an approved interconnection and metering point.

Additional program details:

- The participating generator must be an existing NIPSCO electric customer.
- An Interconnection Agreement ("IA") and RPPA are required to reserve capacity or enter the queue.
- The customer is responsible for interconnection fees and installation costs in accordance with the Indiana Administrative Code.
- The customer is responsible for maintenance and proper operation of the generating device in a safe manner consistent with the IA.

Phase I concluded in March of 2015 with a total subscription of 29.7 MW and is summarized in the Table 9-1.

Table 9-1: FIT Phase I In-Service

Technology	Total FIT (kW)
Biomass	14,350
Solar (large)	14,500
Solar (small)	695
Wind (large)	150
Wind (small)	10
New Hydro	0
Total	**29,705**

NIPSCO's FIT Phase II was approved on February 4, 2015 in Cause No. 44393. NIPSCO released Phase II of the FIT program in March of 2015. Phase II allows for an additional 16 MW of renewable capacity, bringing the total FIT capacity cap up to 46 MW. Table 9-2 shows the subscription for Phase II in February, 2016.

Table 9-2: FIT Phase II Project Totals

Technology	In-Service Projects (kW)	In-Queue (kW)	Total FIT (kW)
Biomass	0	0	0
Solar (interm.)	200	3,734	3,934
Solar (micro)	50	0	50
Wind (interm.)	0	600	600
Wind (micro)	20	0	20
Total	**270**	**4,334**	**4,604**

With over 30 MW currently interconnected in the FIT program, as of December 31, 2015, NIPSCO has a total metered generation from customers selling electricity of 251,228,362 kilowatt hours ("kWh").

Table 9-3 shows the annual production and growth by technology segment.

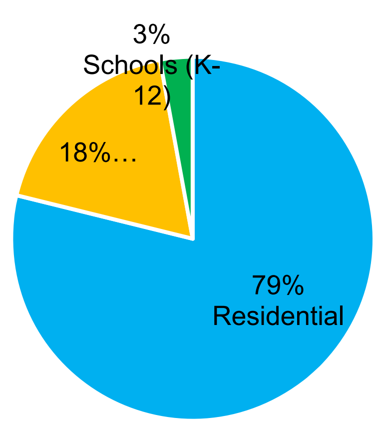
Table 9-3: Annual Production by Technology – Generation (kWh)

Technology	2011	2012	2013	2014	2015	Total
Small Solar		118,895	471,806	718,758	818,332	2,127,791
Large Solar		433,758	15,789,457	21,665,115	22,436,103	60,324,433
Small Wind		3,588	15,721	12,051	9,462	40,822
Large Wind			90,113	165,880	217,949	473,942
Biomass	6,219,791	19,152,432	31,602,728	49,916,700	81,369,723	188,261,374
Total	**6,219,791**	**19,708,673**	**47,969,825**	**72,478,504**	**104,851,569**	**251,228,362**

9.2.2 Net Metering – Rider 780

NIPSCO's Net Metering Rider allows customers to install renewable energy generation to offset all or part of their own electricity requirements. Net metering is the measurement of the difference between the electricity that is supplied by NIPSCO and the electricity that is supplied back to NIPSCO by an eligible net metering customer. Production is measured on a kWh basis. To be eligible, a customer must be in good standing and operating a solar, wind, biomass or hydro generating facility that has a nameplate capacity less than or equal to 1 MW. NIPSCO follows the rules and guidelines set forth in the Indiana Administrative Code with respect to Net Metering and the interconnection process. Customers with a fully executed Net Metering Agreement and Interconnection Agreement receive a credit for each kWh provided to NIPSCO above their own usage requirement. NIPSCO's Net Metering program capacity cap is limited to 30 MW and total subscription is as of December 31, 2015 was 2.91 MW. The total measured generation by the Net Metering customers for 2015 was 2,173,692 kWh. The current classification of NIPSCO's 104 Net Metering customers is shown in Figure 9-1.

Figure 9-1: Classification of Net Metering Customers



9.2.3 Electric Vehicle Programs (Phase I and Phase II) – Rider 785

9.2.3.1 NIPSCO IN-Charge Electric Vehicle Program – At Home (Phase I)

NIPSCO's IN-Charge Electric Vehicle ("EV") Pilot Program was approved on February 1, 2012 in Cause No. 44016 through January 31, 2016. NIPSCO launched its IN-Charge Electric Vehicle Program - At Home on April 2, 2012. On October 29, 2014, the Commission approved NIPSCO's 30-day filing to extend its EV Program an additional two years through January 31, 2017. Under the extended EV Program, the incentive of up to $1,650 per customer continued for a period through January 31, 2017 or until such time as the funds were exhausted, which occurred earlier. As of June 30, 2016, 250 customers had received program incentives. On August 5, 2016, NIPSCO requested approval of a modification of its Rider 785 to provide that EV Participants of record as of January 31, 2017 would be subject to an energy charge of $0.070894 per kWh for all kwH used per month in the PEV Off-Peak Hours, plus all applicable Riders for a period of 23 months (expiration of December 31, 2018). NIPSCO's modification request is currently pending in Cause No. 44828.

As of January 31, 2016, NIPSCO had received 378 customer enrollment requests, 241 of which have gone well beyond the initial inquiry. Of these 241 requests, home charger and second meter installations have been completed for 228 customers and an additional 13 customers are moving forward with scheduling installations. Estimates for installation costs, including the cost of a home EV charger, ranged from $667 to $6,325 with an average of $2,046. The average incentive amount used by customers with completed installations was $1,628.

A detailed customer request status breakdown as of January 31, 2016 is provided in Table 9-4.

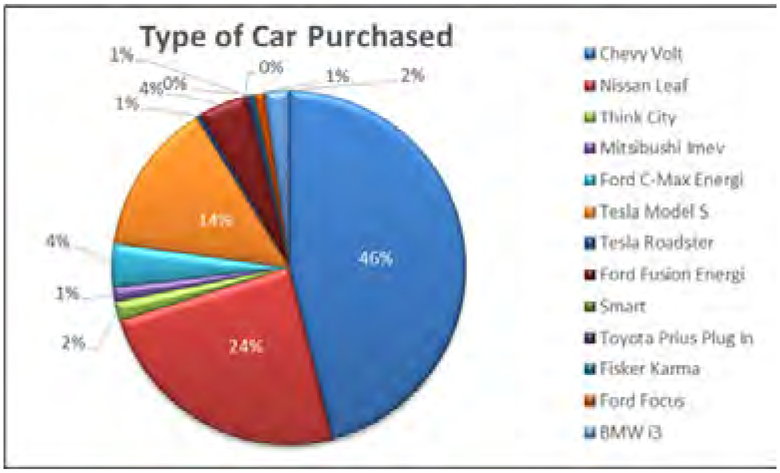
Table 9-4: NIPSCO's Electric Vehicle Customer Request Breakdown

NIPSCO's IN-Charge Electric Vehicle Program - At Home
(Status Summary as of January 31, 2016)

Meter Installation Process	Completed	228
	In Scheduling Process	6
Home Charger Installation Process	Completed & Waiting on Customer to Proceed	1
	In Scheduling Process	6
Site Survey Process	Survey Completed - Waiting on More Information from Customer	7
	In Scheduling Process	3
Enrollment Process	Waiting for Customer Response to Complete Online Survey	1
	Requested to be Re-contacted at Later Date	1
	General Inquiry	8
	Decided Not to Proceed	83
	Customer Not Qualified	33
	Waiting on NIPSCO	1
Total Requests to Enroll		**378**

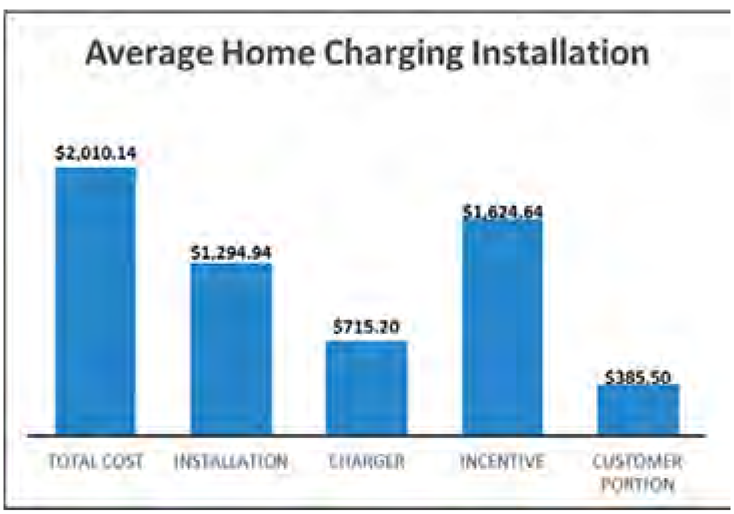
A breakdown of the type of electric vehicles purchased by the 228 customers who have completed the entire process is shown in Figure 9-2.

Figure 9-2: Type of Electric Vehicles Purchased



The average cost to install a Level II home charging station during the pilot was just over $1,950. A cost breakdown for the home charging station from the pilot is provided in Figure 9-3.

Figure 9-3: Average Home Charging Installation



On average, EV customers use approximately 220 kWh per month to charge their electric vehicle. The actual amount of consumption will vary by individual customer. Customer vehicle type will impact the consumption significantly as well as the demand on the grid. A Tesla Model S charging demand is 10 kW, while a Chevy Volt charging demand is only 3.3 kW. The Nissan Leaf charging demand ranges from 3.3 kW to 6.6 kW depending on the options installed in the car. To put demand in perspective, an average size residential home has approximately 33 kW in connected load of which, on average, 18 kW might be on during coincidental peak time. For comparison, typical residential demand breakdown by appliance is listed below:

- Water Heater – 4.5 kW
- Range / Oven – 8.0 kW
- Central Air Conditioner – 6.0 kW
- Clothes Dryer – 5.0 kW
- Dishwasher – 2.0 kW
- Lighting, Fans, Appliances, Other – 7.5 kW

NIPSCO's most recent electric rate case (Cause No. 44688) indicates that its typical residential electric customer used 698 kWh per month on average during the weather normalized test year. The average EV consumption during the pilot period was approximately 220 kWh or approximately 31 percent of the average home consumption. The type of vehicle purchased and the number of miles driven by the customer will directly impact the average consumption of the vehicle for each individual customer.

NIPSCO found that the "free" energy during the off-peak times of 10 p.m. to 6 a.m. (local time) had a significant impact on charging behavior during the pilot. The typical usage by hour over the recent three month period analyzed (November 2015 through January 2016) is shown in Figure 9-4. The vast majority of the time, EV residential customers began their charging session at 10 p.m. when the energy discounted period began and their vehicles were fully charged by 6 a.m. when the energy discounted period ended. As predicted, the total energy consumption was higher during the work week, when owners typically drove their vehicles more than they did on weekends. The analysis indicates that Time of Use ("TOU") rates do have an impact on pushing 80% of EV loads to more preferred off-peak time for utilities.

Figure 9-4: Response to Time of Use Pricing

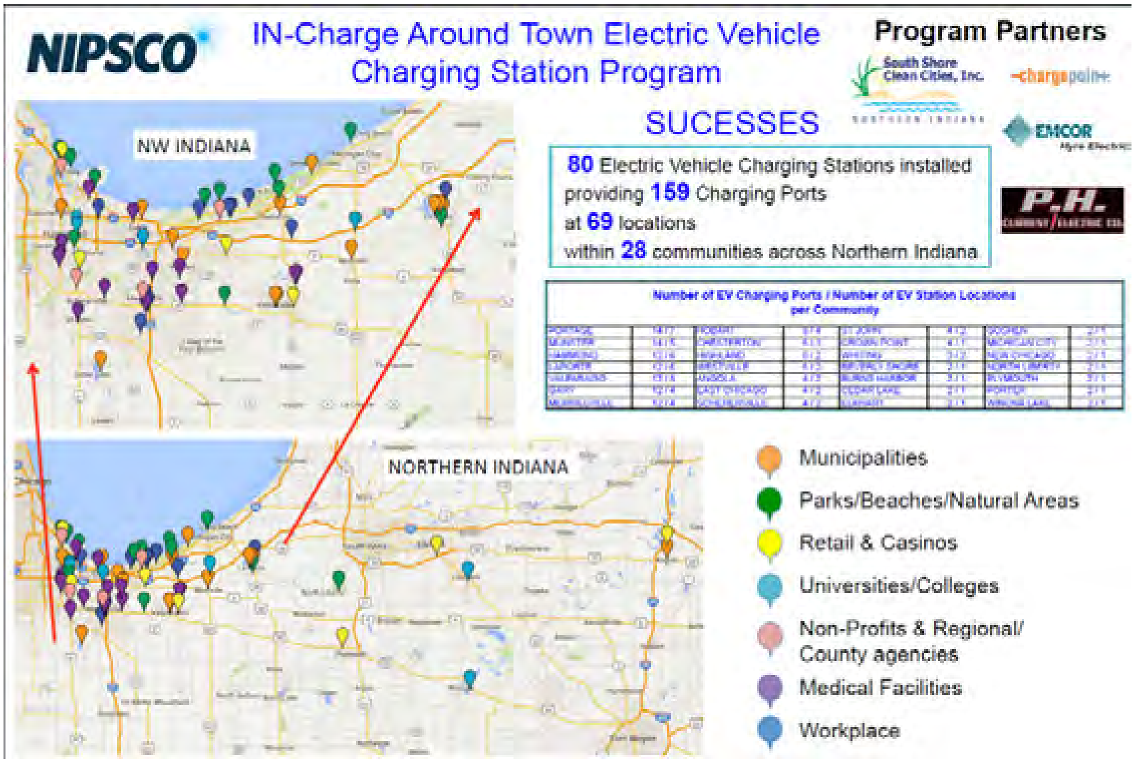
9.2.3.2 NIPSCO IN-Charge EV Program – Around Town (Phase II)

NIPSCO partnered with South Shore Clean Cities to expand opportunities for alternative fuel, through the launch of a public charging station incentive program in February 2014. The NIPSCO IN-Charge EV Program – Around Town made it easier and more affordable for businesses and organizations to install public charging infrastructure. The In-Charge – Around Town program was available to commercial / industrial electric customers across northern Indiana and was offered until program funds were exhausted in June 2016.

For every unit of electricity used by IN-Charge Around Town charging stations during the program, NIPSCO bought an equivalent amount of renewable energy certificates ("RECs") – the environmental attributes associated with electricity that is generated from renewable sources, such as wind power.

As of June 30, 2016, NIPSCO had installed 80 public charging stations providing 159 charging ports at 69 locations. Figure 9-5 shows a map of the station locations and application status:

Figure 9-5: Station Locations and Application Status



9.2.4 Green Power Program – Rate 760

NIPSCO's Green Power Rider ("GPR") program was approved on December 19, 2012 in Cause No. 44198 through December 31, 2014. NIPSCO request for extension of its GPR Program, with certain modifications, and as a component of NIPSCO's approved tariff on a non-pilot basis, was approved on December 30, 2014 in Cause No. 44520. The GPR Program is a voluntary program that allows a customer to designate a portion or all of its monthly electric usage to be attributable to power generated by renewable energy sources. Customers can enroll online, through the Integrated Voice Response or through NIPSCO's Call Center.

Green Power is energy generated from renewable and/or environmentally-friendly sources or a combination of both, which meets the Green-e® Energy National Standard for Renewable Electricity Products in all regions of the United States. Eligible sources of Green Power include: solar; wind; geothermal; hydropower that is certified by the Low Impact Hydropower Institute; solid, liquid, and gaseous forms of biomass; and co-firing of biomass with non-renewables. Green Power includes the purchase of RECs from the sources described above. For the GPR Program, NIPSCO's residential electric customers can designate 25%, 50% or 100% of their total electricity usage to be attributable to Green Power. In addition to those options, although to date no commercial or industrial customer has selected) NIPSCO's commercial and industrial customers also have the option to designate 5% or 10% of their total electricity usage to be attributable to

Green Power. As of December 31, 2015, 930 customers were participating in the GPR Program. Figure 9-6 shows the breakdown among residential customers as of December 31, 2015.

Figure 9-6: Residential Customer Count

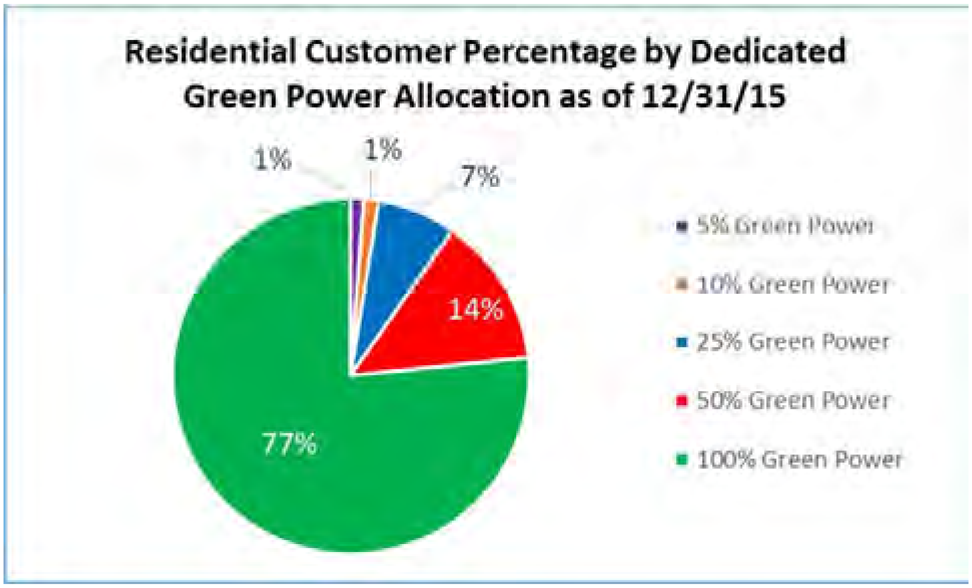
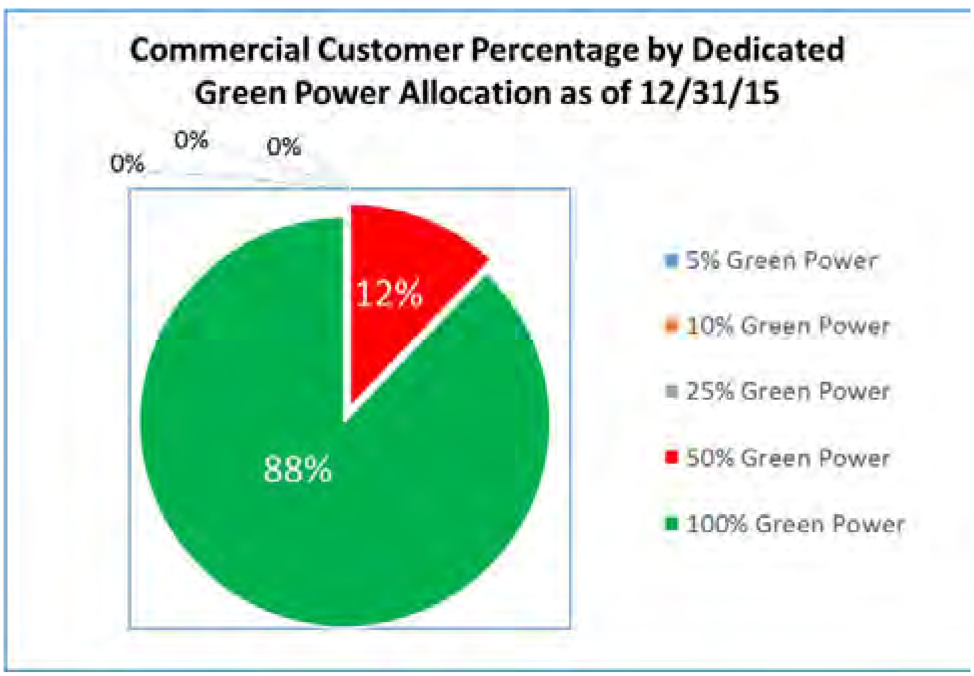


Figure 9-7 shows the breakdown of commercial and industrial customers as of December 31, 2015.

Figure 9-7: Commercial Customer Count



NIPSCO's GPR Program for the period of January 1 through December 31, 2015 accounted for 6,340,786 kWh energy consumption designated as Green Power. Residential customers accounted for 5,867,303 kWh of energy consumption and commercial and industrial customers accounted for 473,483 kWh of energy consumption of designated Green Power. For both residential and commercial customers, the majority of the GPR Program enrollments designate 100% of their energy as Green Power. Table 9-5 shows the energy consumption designated as Green Power for participating customers by rate for the period January 1 through December 31, 2015.

Table 9-5: Green Power Customers by Rate (kWh)

	2015 Customer KWH by Rate													
RATE	GPR PARTICIPTN %	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
660	100%	625	534	541	466	407	391	384	388	455	482	565	645	5,883
660 Total		**625**	**534**	**541**	**466**	**407**	**391**	**384**	**388**	**455**	**482**	**565**	**645**	**5,883**
611	5%	541	480	532	444	362	408	540	567	536	428	347	466	5,651
	10%	850	782	690	651	674	808	1,016	1,147	1,183	744	636	743	9,924
	25%	13,710	11,890	11,267	9,179	8,107	9,522	12,311	14,862	12,888	8,803	7,638	9,143	129,320
	50%	43,205	36,647	37,396	29,248	26,084	34,707	42,639	52,573	47,196	30,439	26,303	33,983	440,420
	100%	482,261	411,015	430,484	348,701	340,566	391,734	479,288	550,279	503,498	364,809	319,977	389,352	5,011,964
611 Total		**540,567**	**460,814**	**480,369**	**388,223**	**375,793**	**437,179**	**535,794**	**619,428**	**565,301**	**405,223**	**354,901**	**433,687**	**5,597,279**
612	25%	418	383	345	309	315	450	698	737	694	497	350	416	5,612
	50%	3,642	3,422	3,517	2,102	1,370	1,449	1,670	2,177	1,936	1,427	1,877	2,877	27,466
	100%	21,570	19,921	20,049	15,795	12,445	14,001	16,263	18,401	18,783	15,259	14,114	19,586	206,187
612 Total		**25,630**	**23,726**	**23,911**	**18,206**	**14,130**	**15,900**	**18,631**	**21,315**	**21,413**	**17,183**	**16,341**	**22,879**	**239,265**
613	100%	2,540	2,275	2,852	2,196	2,077	1,394	1,830	2,115	1,817	1,633	1,495	2,652	24,876
613 Total		**2,540**	**2,275**	**2,852**	**2,196**	**2,077**	**1,394**	**1,830**	**2,115**	**1,817**	**1,633**	**1,495**	**2,652**	**24,876**
621	5%	414	486	335	297	257	1,201	234	161	75				3,460
	50%	107	90	85	114	85	302	541	1,070	622	223	3,256	2,927	9,422
	100%	26,735	28,494	30,290	26,543	27,261	29,688	52,063	57,622	55,428	45,847	39,343	41,287	460,601
621 Total		**27,256**	**29,070**	**30,710**	**26,954**	**27,603**	**31,191**	**52,838**	**58,853**	**56,125**	**46,070**	**42,599**	**44,214**	**473,483**
Total		**596,618**	**516,419**	**538,383**	**436,045**	**420,010**	**486,055**	**609,477**	**702,099**	**645,111**	**470,591**	**415,901**	**504,077**	**6,340,786**

Participating customers are billed under their current applicable rate, with a separate line item showing the premium to participate in the GPR Program. This premium is calculated by multiplying the GPR Rate by the kWhs the customer specifies to be subject to the GPR. Table 9-6 shows the Green Power premiums applicable during the period January 1, 2015 through December 31, 2016.

Table 9-6: Green Power Premiums

January 2015 through June 2015	July 2015 through December 2015	January 2016 through June 2016	July 2016 through December 2016
$0.001238	$0.001481	$(0.000212)*	$0.000765

* Due to an over-collection during the reconciliation period driven by actual REC prices being lower than the estimated price for RECs during that period.

9.3 Corporate Development and Community Support

9.3.1 Supporting Economic Growth

NIPSCO partners with community leaders and state, regional, and local economic development organizations to attract and support the expansion of new and existing businesses and to help create more jobs across the NIPSCO's service territory. In addition to being one of the largest employers in the region, NIPSCO spends $1 million in economic development efforts each year, which has resulted in 80 new businesses or expansions and 8,600 local jobs in the last 10 years.

NIPSCO's Rider 777 – Economic Development Rider ("EDR") offers discounts on existing tariff services for qualifying projects that bring new jobs and investment from outside its service territory. When coupled with local and state incentives, a powerful package is created with often positive results.

Among the many recent successes were NIPSCO's efforts to help relocate Hoists Lift Truck—a global heavy-duty forklift manufacturer—from Illinois to East Chicago, Indiana, which will result in up to 500 new jobs and a $46 million dollar investment. NIPSCO also partnered with its communities to bring Pratt Industries—a $250 million state of the art 100% Recycled Paper Mill—to Valparaiso.

Even with the continued growth, NIPSCO's transmission and distribution system is designed to provide all customers with reliable energy services, and NIPSCO's resource plans focus on maintaining and developing resources in NIPSCO's service territory. Additionally, the investments NIPSCO is making to modernize and upgrade its energy infrastructure continue to have a positive, direct impact on local businesses.

9.3.2 Support of Local Communities / Schools through Property Taxes

In addition to being a major employer in its service territory, NIPSCO's facilities, and most notably, generating stations also contribute to the support of local economies through property taxes that help fund government services, schools and libraries. This contribution also factors into the careful planning and consideration for the future of serving customers. Specifically as an example, NIPSCO recognizes that retirements of its facilities will have an economic impact on communities and has accommodated for such in its resource planning process.

A recent NIPSCO analysis of 2014 property taxes assessed for NIPSCO's Schahfer Generating Station and Bailly Generating Station illustrates how important these facilities are to the tax base and residents in both Jasper and Porter Counties. Table 9-7 shows the results of that analysis.

Table 9-7: 2014 Property Tax Analysis

Schahfer Generating Station	
	Percentage of Jasper County Property Tax base attributable to Schahfer Generating Station (%)
County Tax	16.50
Township Tax	72.74
School Tax	30.18
Library Tax	17.78
Airport Authority Tax	9.14
TOTAL	10.37

Bailly Generating Station	
	Percentage of Porter County Property Tax base attributable to Bailly Generating Station (%)
County Tax	1.58
Library Tax	9.14
School Tax	5.45
Special Unit Tax	1.63
Township Tax	38.03
TOTAL	3.44

9.3.3 Supplier Diversity

Cultivating a diverse pipeline of suppliers helps innovate ideas and processes, gain a competitive advantage and benefit NIPSCO's communities. NIPSCO has created a supplier diversity program that strengthens and widens the playing field for qualified suppliers that are typically underutilized in the supply chain of a large corporation.

9.3.4 Workforce Development

NIPSCO is proud to assist in building its local economy through employment and training. In 2015, NIPSCO helped unveil a new Energy Lab for local students—a partnership between NIPSCO and Ivy Tech Community College. The state-of-the-art lab, housed at Ivy Tech's Valparaiso campus, was made possible thanks to a $60,000 grant from NIPSCO, who helped fund the construction of the Energy Lab along with support from other energy industry members, including EN Engineering, Eaton, G&W Electric and KV Steel who provided design, equipment and software support.

The NIPSCO Energy Lab consists of a seven-pole distribution system containing all the equipment, wires and functions of an actual electric distribution system. The Energy Lab helps prepare northwest Indiana students for high-demand jobs in the electronics, energy and utility industries.

9.3.5 NIPSCO Sustainability Approach

NIPSCO is actively involved in sustainability efforts both in how it does business as well as in the communities it serves. NIPSCO's focus is on finding shared value opportunities with its stakeholders through enhancing the economic, social, and environmental ways it does business. In 2014, NIPSCO conducted a sustainability materiality survey with internal and external stakeholders to gain a better understanding of which sustainability issues are most important to them. Those aspects that ranked highest in materiality to both internal and external stakeholders align with NIPSCO's well-established business strategy and focus: Employee Safety, Public Safety, Service Reliability and Emergency/Storm Response. Other highly rated categories were Ethics and Transparency and Overall Customer Satisfaction. Using these areas of materiality, NIPSCO has identified goals it is working to achieve, and will report on its progress.

NIPSCO has aligned its strategy and reporting to present a sharpened focus on sustainability through the lens of four of its stakeholder commitments:

- Industry-leading safety performance: Keeping our customers, communities, employees and business partners safe.
- Top-tier customer satisfaction: Making it easy for our customers to do business with us.

- Investments that systematically and efficiently deliver service integrity: Improving environmental performance, reliability and safety, providing value to our customers and communities through our investment programs.
- Recognized among the best places to work by all in our communities: Continuing to strengthen our culture and what we're known for – serving our customers with integrity and the highest of ethical business standards, while building diverse, inclusive teams with opportunities to engage and develop.

Details of NIPSCO's sustainability efforts can be found in the NiSource 2015 Sustainability Report at www.nisource.com/sustainability/sustainability-report.

9.3.6 Philanthropy

NIPSCO believes that reinvesting in the communities where its employees live and work will enhance the quality of life for everyone. Each year, NIPSCO donates time, money, and other resources to hundreds of local philanthropic programs and organizations across its 30-county service area, focusing on:

- Basic Human Needs
- Education
- Public Safety & Emergency Response
- Environmental Stewardship
- Economic Development

Through these programs and partnerships, NIPSCO is working hard with its communities to build a brighter future for years to come.

9.3.7 Volunteerism

NIPSCO employees have a passion for volunteering and giving back to their local communities. Through a program called "Dollars for Doers," cultivated by NIPSCO's parent company, NiSource Inc., employees translate their community service into financial support for organizations they care about most. The program contributes up to $500 per employee to an organization in return for volunteer time. In 2015, NIPSCO employees contributed 5,277 volunteer hours, equating to $104,540 donated to charities of their choice.

List of Appendices

Appendix A	Stakeholder Meetings
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Confidential Appendix H	NIPSCO Scenarios and Sensitivity Reports
Confidential Appendix I	Sargent & Lundy Engineering Study Technical Assessment
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Section 10. Compliance with Proposed Rule

Rule	Section(s)
170 IAC 4-7-2: Integrated Resource Plan Submission	
(d) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents: (1) The integrated resource plan.	Submitted via email and hand delivery on November 1
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the assumptions in the IRP.	Confidential Appendix H
(3) An IRP summary that communicates core IRP concepts and results to non-technical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) the IRP public advisory process; and (vi) any additional details the commission staff may request. (B) A simplified discussion of resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	Executive Summary
(e) Contemporaneously with the submission of an IRP, a utility shall provide to the director the following: (1) The name and address of each known entity considered by the utility to be an interested party. (2) A statement that the utility has sent each known interested party, electronically or by deposit in the United States mail, First Class postage prepaid, a notice of the utility's submission of the IRP to the commission. The notice must include the following information: (A) A general description of the subject matter of the submitted IRP. (B) A statement that the commission invites interested parties to submit written comments on the utility's IRP within 120 days of the IRP submittal.	Transmittal Letter

Rule	Section(s)
An interested party includes any business, organization, or customer that participated in the utility's previous public advisory process. A utility is not required to separately notify all of its customers. (3) A statement that the utility has served a copy of the documents submitted under subsection (d) above on the office of the consumer counselor.	
170 IAC 4-7-2.6: Public Advisory Process	
(a) The following utilities are exempt from this section: (1) A municipally owned utility; (2) A cooperatively owned utility; and (3) A utility submitting an IRP under subsection 2(b) of this rule. (b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP. (c) The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by interested parties, the commission, and its staff. (d) The utility retains full responsibility for the content of its IRP.	N/A
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following: (A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable energy and non-energy benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and its rationale. (2) The utility is encouraged to hold additional meetings as appropriate. (3) The schedule for meetings shall be determined by the utility and shall:	Section 2.1, Appendix A

Rule	Section(s)
(A) be consistent with its internal IRP development schedule; and (B) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP. (4) The utility or its designee shall: (A) chair the participation process (B) schedule meetings; and (C) develop and publish to its website agendas and relevant material for those meetings at least seven calendar days prior to the meeting; and (D) develop and publish to its website minutes within fifteen calendar days following each meeting; (5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility. (6) The utility shall take reasonable steps to notify its customers; the commission; and interested parties of its public advisory process.	
170 IAC 4-7-2.7: Contemporary Issues	
(a) The commission or its staff may host an annual technical conference to facilitate: (1) identifying contemporary issues; (2) identifying best practices to manage contemporary issues; and (3) instituting a standardized IRP format. (b) The agenda of the technical conference shall be set by the commission staff. Utilities and interested parties may request commission staff include specific contemporary issues and presenters. (c) The director may designate specific contemporary issues for utilities to address in the next IRPs by providing the utilities and interested parties with the contemporary issues to be addressed. The utility shall address the designated contemporary issues in its next IRP. In addition, prior to its next IRP the utility shall provide to interested parties either a discussion of the impacts of such issues on its IRP or describe how it has taken the contemporary issues into account.	N/A
(d) A utility shall address new issues raised in a contemporary issues technical conference if the contemporary issues technical conference occurred at least one (1) year prior to the submittal date of a utility's IRP.	Section 2.2.1
170 IAC 4-7-4: Integrated Resource Plan Contents	

Rule	Section(s)
An IRP must include the following:	
(1) At least a 20 year future period for a predicted or forecasted analysis.	Used throughout
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with subsection 5(a) of this rule.	Section 3.2 Section 3.3 Section 3.4 Section 3.5 Section 3.6 Section 3.7 Section 3.8 Section 3.83.9 Section 3.10
(3) At least three alternative forecast scenarios of peak demand and energy usage in compliance with subsection 5(b) of this rule.	Section 3.10 Section 3.11
(4) A description of the utility's existing resources in compliance with subsection 6(a) of this rule.	Section 4.3 Section 4.4 Section 4.5 Section 5.1
(5) A description of possible alternative methods of meeting future demand for electric service in compliance with subsection 6(b) of this rule.	Section 5.1 Section 5.4
(6) The resource screening analysis and resource summary table required in subsection 7(a) of this rule.	Section 4.9 Section 5.3 Section 5.4 Confidential Appendix J
(7) The information and calculation of tests required for potential resources in compliance with subsections 7(b)-7(e) of this rule.	Section 4.9.1 Section 5.3.1 Confidential Appendix J
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with subsection 8(a) and 8(b) of this rule.	Section 8.1 Section 8.2 Section 8.3 Appendix F
(9) A description of the utility's preferred resource portfolio and the information required in compliance with subsection 8(b) of this rule.	Section 8.5.4
(10) A short term action plan listing plans for the next three year period to implement the utility's preferred resource portfolio and its workable strategy. The short term action plan shall comply with section 9 of this rule.	Section 1.2 Section 8.5.7
(11) A discussion of the inputs; methods; and definitions used by the utility in the IRP.	Definitions Section 2.1 Section 2.2 Section 2.3

Rule	Section(s)
	Section 2.4 Section 2.5 Section 3.2 Section 3.10 Section 3.11 Section 4.4 Section 4.9 Section 5.1 Section 5.4 Section 7.3 Section 8.1 Section 8.2 Section 8.4 Section 9.2.1 Section 9.2.2 Appendices A through F and Confidential Appendices G through J
(12) Appendices of the data sets and data sources used to establish alternative forecasts in subsection 9(b) of this rule. If the IRP references a third party data source, the IRP must include the following for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of any adjustments made to the data. The data must be submitted with the IRP in a manipulable format.	Section 2.2 Appendix D
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by the following: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use.	Section 3.2.1 See Note 1
(14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility.	Section 3.2

Rule	Section(s)
(D) Engineering estimates. (E) Load data developed by a non-utility source.	
(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	See Note 2
(16) A discussion detailing how information from Advanced Metering Infrastructure (AMI) and smart grid will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	Section 5.3.6.1 See also Section 9.1.3
(17) A discussion of distributed generation within the service territory and its potential effects on generation, transmission, and distribution planning and load forecasting.	Section 3.8 Section 6.2 Section 9.2.1 Section 9.2.2
(18) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Section 2.2.2 Appendix C
(19) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	Section 4.1
(20) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission have been taken into account and influenced the IRP development.	Section 7.4
(21) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Section 2.3
(22) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	Section 7.3 Section 8.1.3
(23) A discussion of how the utilities' resource planning objectives, such as cost effectiveness, rate impacts, risks and uncertainty, were balanced in selecting its preferred resource plan.	Section 8.5 Section 2.4
(24) A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs.	Section 8.1.3.1

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(B) Include existing federal environmental laws; existing state laws, such as renewable energy requirements and energy efficiency laws; and existing policies, such as tax incentives for renewable resources that are certain. Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (C) Not include future resources, laws, or policies unless the utility receives stakeholder input on the inclusion and it meets the following conditions: (i) Future resources have obtained regulatory approvals. (ii) Future laws and policies have a high probability of being enacted. A base case need not align with the utility's preferred resource portfolio.	
(25) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	Section 8.1.3
(26) A brief description, focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies, and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. This description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) the limits of the utility's transmission use; (ii) the utility's assessment practices developed through experience and study; and (iii) operating restrictions and limitations particular to the utility.	Confidential Appendix J
(27) A list and description of the contemporary methods utilized by the utility in developing the IRP, including the following:	Section 2.2 Section 3.2 Section 8.1

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(A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.	Section 8.2 Section 8.3 Section 8.4 Section 8.5 Appendix B Appendix C
(28) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	Section 5.3.4 Appendix B, Exhibit 2
(29) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically in a manipulable format. For purposes of comparison, a utility must maintain three (3) years of hourly data.	Section 3.1 Appendix D
(30) A summary of the utility's most recent public advisory process, including: (A) Key issues discussed. (B) How the utility responded to the issues (C) A description of how stakeholder input was used in developing the IRP.	Section 2.1 Appendix A
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	Section 4.9 Section 5.4 Appendix B Confidential Appendix I
170 IAC 4-7-5: Energy and Demand Forecasts	
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following: (A) Annual load shapes.	Section 3 Section 3.9 Section 3.10 Appendix D,

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(B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	Appendix E
(2) Disaggregation of historical data and forecasts by customer class, interruptible load, end-use where information permits.	Section 3.3 Section 3.4 Section 3.5 Section 3.6 Section 3.7 Section 3.10
(3) Actual and weather normalized energy and demand levels.	Section 3.9
(4) A discussion of methods and processes used to weather normalize.	Section 3.9
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	Section 3.10 Section 3.11
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes, rate classes, or both. (C) Firm wholesale power sales.	Section 3.12
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	Section 3.2
(8) Justification for the selected forecasting methodology.	Section 3
(9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data, such as described in subdivision 4(10) of this rule.	No Response Needed
(b) In providing at least three (3) alternative forecasts of peak demand and energy usage the utility shall include high, low, and most probable peak demand and energy use forecasts to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most likely based on alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices, including competition. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption.	Section 3.11

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(10) State and federal energy policies. (11) State and federal environmental policies.	
(c) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, analysis as part of the on-going efforts to improve the credibility of the load forecasting process.	Section 3.2
170 IAC 4-7-6: Resource Assessment	
(a) In describing its existing electric power resources, the utility must include in its IRP the following information: (1) The net dependable generating capacity of the system and each generating unit.	Section 4.4 Section 4.5
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	Section 4.8
(3) A fuel price forecast by generating unit.	Section 8.1.2
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and (D) subsequent disposal; and (E) water consumption and discharge; at each existing fossil fueled generating unit.	Section 4.4.1 Section 4.4.2 Section 4.4.3 Section 4.4.4
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network. (D) An assessment of the transmission component of avoided cost.	Section 5.3.4 Section 6.1.6 Section 6.1.7 Section 6.1.8
(6) A discussion of DSM programs and their estimated impact on the utility's historical and forecasted peak demand and energy.	Section 3.2 Section 5.1.1 Section 5.4.1 Appendix B, Exhibit 2

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The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Innovative rate design as a resource in meeting future electric service requirements.	Section 5.3.6.1
(2) Demand-side resources, including Demand response programs, and Energy efficiency programs. For a demand-side resource identified in the IRP, the utility shall, include the following: (A) A description of the program considered. (B) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to programs under consideration such as project life and seasonal operation. (C) The customer class or end-use, or both, affected by the program. (D) A participant bill impact projection and participation incentive to be provided in the program. (E) A projection of the program costs to be borne by the participant. (F) Estimated annual and lifetime energy (kWh) and demand (kW) savings per participant for each program. (G) The estimated program penetration rate and the basis of the estimate. (H) The estimated impact of a DSM program on the utility's load, generating capacity, and transmission and distribution requirements. (I) whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	Section 5.3.3 Section 5.4 Section 5.2.1 Appendix B, Exhibit 2 See Note 3
(3) For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered, including: (i) Size (MW). (ii) Utilized technology and fuel type.	Section 4.4 Section 4.5 Section 4.9

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(iii) Additional transmission facilities necessitated by the resource. (B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	
(4) transmission facilities as a resource including new projects, upgrades to transmission facilities, efficiency improvements, and smart grid technology.	Section 6.1.7 Section 6.1.8 Section 6.2.1 Section 6.2.2
In analyzing transmission resources, the utility shall include the following: (A) A description of the timing, types of expansion, and alternative options considered.	Section 6.1.7 Section 6.1.8 Section 6.2.1 Section 6.2.2
(B) The approximate cost of expected expansion and alteration of the transmission network.	Section 6.1.7 Section 6.1.8
(C) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.	Section 6.1.3
(D) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	Section 6.1.3
170 IAC 4-7-7: Selection of Resources	
(a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	Section 4.9 Section 5.3 Section 5.4
(b) The following information must be provided for a resource selected for further analysis: (1) A description of significant environmental effects, including the following: (A) Air emissions. (B) Solid waste disposal. (C) Hazardous waste and subsequent disposal. (D) Water consumption and discharge.	Confidential Appendix I

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(2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan and the commission analysis to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.	
(c) For each DSM program analyzed under this section, the IRP must include one (1) or more of the following tests to evaluate the cost-effectiveness of the program. (1) Participant cost test. (2) Ratepayer impact measure. (3) Utility cost test. (4) Total resource cost test. (5) Other reasonable tests accepted by the commission.	Section 5.3.5 Section 5.3.7
(d) A utility is not required to calculate a test result in a specific format.	N/A
(e) For each program in subsection (c), a utility must calculate the net present value of the program's impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the interest rate used in the net present value calculation.	Section 5.3.5 Table 5-9
(f) For a test performed under subsection (c), an IRP must: (1) specify the components of the benefit and the cost for the test; and (2) identify the equation used to calculate the result.	Section 5.3.5 Section 5.3.7
(g) If a reasonable cost-effectiveness analysis for a program cannot be performed using the tests in subsection (c), because it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	N/A
(h) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	N/A
170 IAC 4-7-8: Resource Portfolios	
(a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios. In selecting the candidate resource portfolios, the utility shall consider the following: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty;	Section 8.3

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(7) economic factors; and (8) technological change.	
(b) With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how each candidate resource portfolio performed across a wide range of potential futures. (2) The results of testing and rank ordering the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metric(s). (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Section 8.5 Appendix F
(c) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information: (1) A description of the utility's preferred resource portfolio.	Section 8.5.4
(2) Identification of the variables used.	Section 2.5 Section 8.5
(3) Identification of the standards of reliability.	Section 8.5.4
(4) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Section 8.4
(5) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following: (A) safety; (B) reliability (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Section 8.5
(6) An analysis showing the preferred resource portfolio utilizes, to the extent practical, all economical supply-side resources and demand-side resources as sources of new supply.	Section 8.5.4
(7) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility including their impacts on the utility's transmission and distribution system for the first ten years of the planning period.	Section 5.3.4
(8) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity	Section 8.5.6 Confidential Appendix I

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price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	
(9) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (x) operating costs; (v) construction costs; (vi) resource performance; (vii) load requirements; (viii) wholesale electricity and transmission prices; (ix) RTO requirements; and (x) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	Section 8.5.4
(10) A description of the utility's workable strategy allowing it to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including the following changes: (A) The demand for electric service. (B) The cost of a new supply-side resources or demand-side resources.. (C) Regulatory compliance requirements and costs. (D) Changes in wholesale market conditions. (E) Changes in fuel costs. (F) Changes in environmental compliance costs. (G) Changes in technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	Section 8.5.4
(11) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, and	Section 2.2.1

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analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	
170 IAC 4-7-9: Short Term Action Plan	
(a) A short term action plan shall be prepared as part of the utility's IRP, and shall cover a three (3) year period beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period. (b) The short term action plan must include, but is not limited to, the following: (1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective. (2) Identification of energy efficiency goals for implementation of energy efficiency that can be produced by reasonably achievable, cost effective plans developed in accordance with 170 IAC 4-8-1 *et seq*. and consistent with the utility's longer resource planning objectives. (3) The implementation schedule for the preferred resource portfolio. (4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts. (5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired.	Section 1.2 Section 8.5.7
Note 1: NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumption patterns by DSM program. The savings associated with DSM programs are gauged and claimed based on various TRMs, including the Indiana TRM, and the DSM programs are evaluated by program year by a third party EM&V administrator. NIPSCO will continue to consider its options. NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumptions patterns by end use.	
Note 2: As part of its DSM functions, DSM programs are evaluated by program year by a third party EM&V administrator. As part of the EM&V process, we survey a sample of customers who have and have not participated in NIPSCO's DSM program. However, there has been no proposed schedule for surveys to be done on end use appliances to obtain penetration, saturation rate, etc.; however NIPSCO has previously completed lighting and market effect studies. NIPSCO would consider using customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns, if we find value in doing so.	

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Note 3: Customer bill impacts are calculated directly in DSMore utilizing the customers rate and the savings of each measure/participant. Appropriate escalators and discount rates are used to determine the Net Present Value of these savings and then Aggregated across all measures/participants. Incentives are also included in the cost benefit analysis through DSMore as an input on a per participant/measure basis. Appropriate escalators and discount rates are applied through DSMore and the Net Present Value calculated.	