Ex. AA-D-26

NIPSCO

Northern Indiana Public Service Company LLC

2018
Integrated Resource Plan

October 31, 2018

Ex. AA-D-26

YOUR ENERGY YOUR FUTURE

IRP

2018 Integrated Resource Plan Executive Summary

At NIPSCO, we're proud that our work provides the energy that northern Indiana families and businesses rely on to power their daily lives. We work each day with the goal of growing alongside our communities and responding to our customers' needs.

As our customers' needs have changed, so has the energy market. Now we stand at the crossroads of the future, with the opportunity to invest in balanced energy options and make energy more affordable and cleaner.

With an eye toward the future, we've been performing a comprehensive analysis of our future energy mix and meeting with our customers, our employees and local community leaders over the past year. The result of this process is an Integrated Resource Plan (IRP).

The plan—which presents over $4 billion in long-term cost savings—is a balanced, gradual transition that will strengthen our region now and put us on a path to a more cost-effective, cleaner and more sustainable future.

It's "Your Energy" and it's "Your Future."

NIPSCO®
A NiSource Company

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 percent 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 footprint. This relationship helps ensure reliability and cost-effective operations.

About the 2018 Integrated Resource Plan

To help ensure that we continue to meet the needs of our customers, we must have a road map to prepare for future energy needs. Our 2018 IRP charts a path for how best to meet those needs over the next 20 years. NIPSCO presents this plan to the Indiana Utility Regulatory Commission (IURC).

The electric industry, customer needs, expectations and the way energy is consumed continue to evolve. Technologies are rapidly changing and expanding. The electric generation landscape is shifting dramatically, not just for NIPSCO but for the country as a whole.

NIPSCO's 2018 Integrated Resource Plan

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 risk-based analysis provided by internal and external subject matter experts, we project future energy needs and evaluate available options to meet those needs.

New to NIPSCO's IRP, we issued a formal Request for Proposals (RFP) solicitation to uncover the breadth of actionable projects that were available to NIPSCO within the marketplace across all technology types. The RFP also served to collapse uncertainty about the costs of various technologies, particularly renewables.

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, the evolution of technology—particularly renewables—and demand side resources, as well as laws and environmental regulations.

Portfolio

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

Engaging Customer and Public Stakeholders

Resource planning requires the consideration of diverse points of view, which is one of the reasons that external stakeholder involvement is a critical component throughout the development of the IRP.

We engaged stakeholder groups and individuals in a variety of ways throughout the entirety of the planning process.

NIPSCO initiated stakeholder advisory efforts for its 2018 IRP in March, hosting a public meeting and launching a web page for interested stakeholders to follow the progress. Four additional public meetings followed in May, July, September and October. NIPSCO also hosted public forums to discuss specific topics arising from the IRP.

In addition to posting public invitations on our IRP web page, 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 multiple scenario forecasts to capture the range of uncertainty for both energy requirements and peak demand.

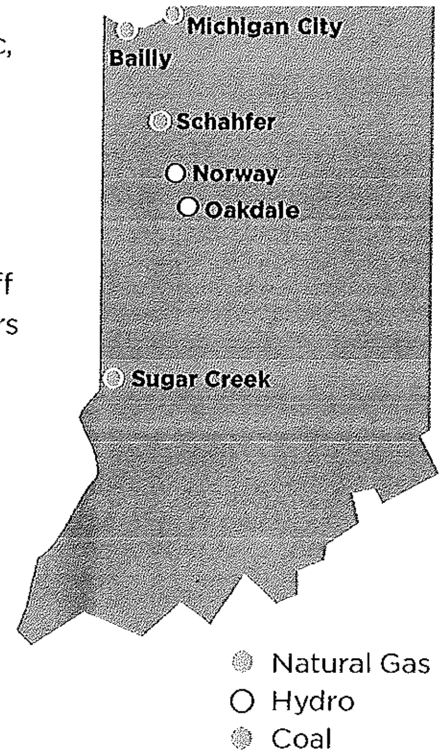
Current Supply

NIPSCO's current resource portfolio is composed 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 more than half of total capacity, followed by natural gas-fired electric generation.

NIPSCO also offers a Net Metering Program and a Feed-in Tariff Program (FIT), which allows commercial and residential customers to generate their own power from renewable resources such as wind, solar, hydro and biomass.

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



NIPSCO Generating Resources

Resource	Unit	Fuel	Capacity NDC (MW)	Year in Service
Michigan City	12	Coal	469	1974
Schahfer	14	Coal	431	1976
	15	Coal	472	1979
	16A	NG	78	1979
	16B	NG	77	1979
	17	Coal	361	1983
	18	Coal	361	1986
Subtotal			1,780	
Sugar Creek		NG	535	2002
Bailly	10	NG	31	1968
Hydro	Norway	Water	4	1923
	Oakdale	Water	6	1925
Subtotal			10	
Wind		Wind	100	2009
NIPSCO			2,925	

Analyzing Future Supply Options—Request for Proposals

New to the process in the 2018 IRP, NIPSCO issued a formal Request for Proposals (RFP) to help inform the planning process, and to gain better information on available, real projects at real costs from within the marketplace.

All energy technologies were eligible to participate, and NIPSCO received 90 proposals—the sum of which represented over three times NIPSCO's current generating capacity.

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.

Results from the RFP provided better information that could be incorporated into the analysis and decision-making process.

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

2018 Proposals Submitted to NIPSCO

Technology	CCGT*	CT*	Coal	Wind	Wind + Solar + Storage	Solar	Solar + Storage	Storage	Demand Resp.	Total Bids
# of Bids	15	1	3	14	1	35	11	9	1	90
Locations	IN, IL	IN	IN, KY	IA, IN, IL, MN	IN	IL, IN, IA	IN	IN	IN	

***CCGT**—Combined Cycle Gas Turbine

***CT**—Combustion Turbine

Energy Efficiency

Promoting energy efficiency not only is good for customers, it can play an important role in helping ensure that we can meet future energy needs. NIPSCO offers a variety of programs to help residential and business customers save energy. The programs are tailored to customers and designed to help ensure energy savings.

Since 2010, NIPSCO customers have saved more than 1 million megawatt hours of electricity by participating in the range of energy efficiency programs offered by NIPSCO.

Technologies continue to change, and it's important that we constantly evaluate our offerings. We regularly track and report on program performance, which helps to inform and improve future program filings and customer offerings.

Findings and Next Steps

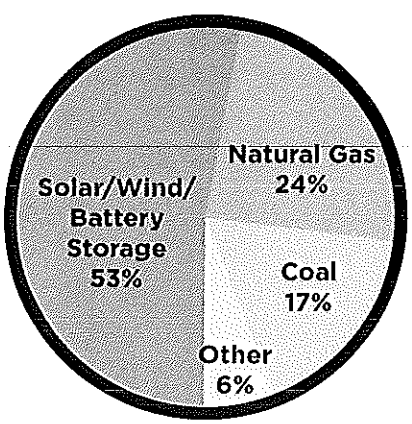
Throughout the IRP analysis, we are striving to balance the needs of our customers, employees and other community stakeholder interests.

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.

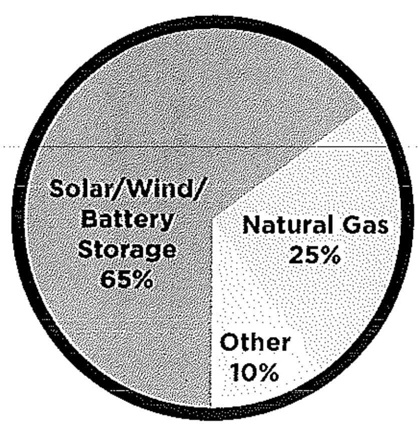
Analysis shows that the most viable path for customers involves accelerating the retirement of a majority of NIPSCO's remaining coal-fired generation in the next five years and all coal within the next 10 years. Replacement options point toward lower-cost renewable energy resources such as wind, solar and battery storage technology.

As we gradually transition to creating a more diversified energy mix that will be more cost effective and better serve customers in the future, we are committed to ensuring that this plan limits the impact on local employees and our economy as a result of the remaining coal retirements.

2023
NIPSCO Capacity
(Projected)



2028
NIPSCO Capacity
(Projected)



Short-Term Action Plans (2019-Through 2021)

The objective of the plan is to ensure that NIPSCO can confidently transition to the least-cost, cleanest supply portfolio available while maintaining reliability, diversity and flexibility for technology and market changes during this period.

- Initiate retirement of R.M. Schahfer Coal-Fired Units 14, 15, 17, and 18 by 2023
- Identify and implement required reliability and transmission upgrades resulting from retirement of the units
- Select replacement projects identified from the 2018 RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve lowest customer cost
- File for Certificate(s) of Public Convenience and Necessity and other necessary approvals for selected replacement projects
- Procure short-term capacity as needed from the MISO market or through short-term PPA(s)
- Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape
- Conduct a subsequent All-Source RFP to identify preferred resources to fill remainder of 2023 capacity need (likely renewables and storage)
- Continue implementation of filed Energy Efficiency Programs Plan for 2019 to 2021
- Comply with North American Electric Reliability Corporation, U.S. Environmental Protection Agency and other regulations
- Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

Long-Term Action Plans (2023-Beyond)

- Fully retire the R.M. Schahfer Coal-Fired Units 14, 15, 17, and 18 by the end of 2023 and the Michigan City Coal-Fired Unit 12 by the end of 2028
- Monitor market and industry evolution and refine future IRP plans

While NIPSCO will continue to update its long-term plan within the next IRP, we believe that these actions coming out of the 2018 IRP will place NIPSCO on a course to continue providing reliable power while enabling lower costs and providing significant environmental benefits.

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Section 1. Integrated Resource Plan

1.1 Short Term Action Plan

Northern Indiana Public Service Company ("NIPSCO" or "Company") developed a short term action plan consisting of the actions NIPSCO will take for the period 2019 through 2021. The objective of the plan is to ensure that NIPSCO can confidently transition to the least cost, cleanest supply portfolio available while maintaining reliability, diversity and flexibility for technology and market changes during this three year period.

NIPSCO's short term action plan will focus on initiating the retirement process for all of the coal units at R. M. Schahfer Generating Station ("Schahfer") and selecting/acquiring replacement projects to fill the capacity gap as a result of the retirements in 2023. The retirements of the Units at Schahfer will likely require upgrades to NIPSCO's transmission system to maintain system reliability, and NIPSCO will identify and begin implementing the necessary upgrades during this period.

The robust response to the all-source request for proposal ("All-Source RFP") (discussed in more detail in Section 4) solicitation indicates that there are more than enough diverse resources and projects to meet NIPSCO supply needs in 2023. NIPSCO will adopt a phased-in approach to selecting and acquiring replacement resources, initially prioritizing replacement resources with expiring tax credits in order to maximize the benefits to customers. NIPSCO intends to make the necessary regulatory filings with the Indiana Utility Regulatory Commission ("IURC" or "Commission") in 2019. During the short-term action plan period, NIPSCO will rely on the Midcontinent Independent System Operator, Inc. ("MISO") market, short term purchase power agreements ("PPAs"), or other bilateral agreements for short term capacity and energy as needed. NIPSCO will continue to monitor technology and MISO market trends while staying actively engaged with project developers and asset owners to maintain flexibility and optionality. NIPSCO expects to conduct another All-Source RFP to acquire resources to fill the remainder of the 2023 supply that was not met in the 2019-2021 time frame.

NIPSCO will continue the implementation of its current Demand Side Management ("DSM") plan through 2021.[1] NIPSCO will also continue to comply with exiting environmental regulations and all North American Electric Reliability Corporation ("NERC") compliance standards and requirements. Lastly NIPSCO will continue to invest and modernize its electric infrastructure to maintain the safe and reliable delivery of electricity to its customers

As described in greater detail in Section 9.4 the action items included in NIPSCO's short term action plan include those listed in Table 1-1:

1 On September 12, 2018, the IURC issued an Order in Cause No. 45011 approving NIPSCO's proposed Electric DSM Program for the period of 2019-2021.

Table 1-1: 2018 IRP Short-Term Action Plan

Initiate retirement of Schahfer units 14,15,17,18 by making required notifications to MISO, NERC and other organizations.
Identify and implement required reliability and transmission upgrades resulting from retirement of the units.
Select replacement projects identified from the 2018 All-Source RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve lowest customer cost.
File for certificate(s) of public convenience and necessity ("CPCN(s)") for selected replacement projects.
Procure short-term capacity as needed from the MISO market or through short-term PPA(s).
Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape.
Conduct a subsequent All-Source RFP in to identify preferred resources to fill remainder of 2023 capacity need (likely renewables and storage).
Continue implementation of approved DSM plan for 2019 to 2021.
Comply with NERC, United States Environmental Protection Agency ("EPA") and other regulations.
Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services.

1.2 Plan Summary

NIPSCO's preferred portfolio 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 9.) NIPSCO utilized the All-Source RFP process to identify the best combination of supply- and demand-side resources, including those obtained through the market, to meet its capacity needs.

The All-Source RFP provided NIPSCO insight into the most relevant prices and types of resources available to meet customer needs. (*See* Section 4.9.) NIPSCO performed both the retirement and replacement analysis using robust scenario and risk-based (stochastic) analyses for different economic, environmental, cost, risk and regulatory uncertainty to inform the optimal plan. NIPSCO also evaluated the impact each of the retirement and replacement alternatives would have on reliability, the local communities and the Company's dedicated employees.

It is important to note that the IRP is a snapshot in time, and while it establishes a direction for NIPSCO, it is subject to change as the operating environment changes. NIPSCO will continue to engage its stakeholders and be transparent in its decisions following submission of this 2018 IRP.

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

- Lead to a lower cost, cleaner, diverse and flexible portfolio by accelerating the retirement of 85% of NIPSCO's coal capacity by the end of 2023 and 100% by the end of 2028.
- Continue the Company's commitment to energy efficiency and demand response by executing DSM plans.
- Replace retired coal generation resources with lower cost renewables including wind, solar and battery storage.
- Identify and implement required reliability and transmission upgrades resulting from retirement of the units.
- Reduce customer and Company exposure to customer load, market and technology risks by intentionally allocating a portion of the portfolio to shorter duration supply.
- Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape.
- Continue to invest in infrastructure modernization to maintain safe and reliable delivery of energy services.
- Continue to comply with NERC and EPA standards and regulations.

1.3 Rationale for NIPSCO 2018 IRP Update Filing

The 2016 IRP action plan was focused on the accelerated retirement of approximately 50% of NIPSCO coal fired generation. Specifically, it called for the retirement of Bailly Generating Station ("Bailly") Units 7 and 8 in 2018 and Schahfer units 17 and 18 in 2023. It projected that the 2023 retirements would create a capacity need of about 600 megawatts ("MW") that NIPSCO would have to address. An IRP in 2018 was necessary to preserve NIPSCO's ability to consider all resource options to meet the capacity need in 2023. Furthermore in light of expected future capital expenditures to comply with the Effluent Limitation Guidelines ("ELG") rules, the 2018 IRP was an opportunity to reexamine the long term viability of the Schahfer and Michigan City Generating Station ("Michigan City") coal units.

1.4 Emerging Issues

NIPSCO's preferred plan follows a diverse and flexible supply strategy, with a mix of market purchases and different low variable cost generation resources, to provide the best balanced mitigation against 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, commercial, and smaller industrial customers comprise most of the remaining demand. While this load is diversified and not likely to change significantly, those sectors would likely see impacts from a loss of load from any of the large 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, which 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 a combined cycle gas turbine ("CCGT") and renewable technologies, 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 capacity prices over the last few planning years. In the 2016/2017 planning year capacity prices rose to $72 per megawatt-day ("MWD") as reserve margins declined; however, in the 2017/2018 planning year prices fell to $1.50MW/MWD, driven by increases in renewable technologies and behind the meter supply resources and the relaxing of import constraints between MISO North and South. In the recent 2018/2019 planning year the capacity prices were $10/MWD and the expectation is for prices to remain relatively low for the foreseeable future under the current market design.

NIPSCO also participates in the energy market in MISO, since all resources are dispatched according to MISO market signals, as opposed to NIPSCO's load. The market is currently undergoing change as coal capacity retires and the generation mix shifts towards renewables and natural gas. In recent years, low natural gas prices have resulted in efficient natural gas plants displacing coal-fired generation in the dispatch stack. This dynamic has altered energy prices and has negatively impacted the economics of coal plants. Wind generation has also increased significantly in parts of MISO, and declining technology costs and federal tax credits are likely to result in increased penetration of solar and wind resources. This additional growth of intermittent resources has the potential to shift system peaks, impact capacity credit calculations, and alter the ancillary services markets.

NIPSCO recognizes that system planning with renewable resources is more complex than with dispatchable resources and that assumptions for capacity credit and resource value streams based on today's market constructs may ultimately change based on future MISO evaluation of Effective Load Carrying Capability and ancillary services market needs in a high renewable environment. NIPSCO also recognizes that congestion and nodal price risk is an important factor for renewable resources and that energy deliverability is critical to realize benefits from renewables. Given these major uncertainties and developments in the market, NIPSCO is committed to tracking market evolutions regarding ancillary services, renewable resource availability, and capacity credit calculations. The preferred plan intentionally leaves room to evaluate market and technology changes on a dynamic basis in order to be flexible and responsive to change.

Section 2. Planning for the Future

2.1 IRP Public Advisory Process

NIPSCO's 2018 IRP stakeholder process focused on continuing to increase transparency around its planning process and enhance public involvement through extensive stakeholder interactions. At each stakeholder meeting, NIPSCO provided information on the processes and assumptions involved in the development of the IRP and solicited relevant input for consideration. Furthermore, to facilitate stakeholder outreach and ongoing communications, NIPSCO maintained a web page on its website with current information about the IRP. NIPSCO posted all meeting agendas, presentations, meeting notes and other relevant documents to the web page.

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

Stakeholders were invited to meet with NIPSCO throughout the IRP process to discuss key issues, concerns and perspectives. NIPSCO extended an invitation to participate in the stakeholder process to the Commissioners and Commission staff, the 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 meeting notes is included in Appendix A.

As part of the 2018 IRP process, NIPSCO hosted four in-person public advisory meetings and one webinar. As a follow up to the public advisory webinar, NIPSCO conducted an additional technical webinar to focus specifically on a single topic - the integration of the All-Source RFP results into the IRP analysis. For all meetings, NIPSCO posted an open invitation on its website for any party wishing to register.

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

2.1.1 Stakeholder Meeting 1

NIPSCO's first stakeholder meeting was held in Merrillville, Indiana on March 23, 2018. For those unable to join in person, a conference call was also made available. In this first meeting, NIPSCO explained the rationale for undertaking an update to its IRP and discussed the process improvements from the 2016 IRP being incorporated in the 2018 update. Furthermore, NIPSCO provided an overview of the resource planning approach, the key drivers of risk and uncertainty and the underlying data. NIPSCO also provided information regarding the All-Source RFP for new capacity, and discussed the public advisory process. 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 presentation (including the agenda), notes (including questions / responses), and registered participants 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 May 11, 2018. For those unable to join in person, a webinar format was also made available. In this second meeting, NIPSCO described the process for modeling risk and uncertainty, and the methodology for modeling DSM in the IRP. Furthermore, the meeting provided an overview of NIPSCO's existing generation resources including the operating costs and key environmental considerations. Lastly, the meeting described the proposed scorecard that would be used to inform the preferred plan, the framework for the retirement and replacement analysis and provided preliminary results from the analysis. Stakeholders requested clarification regarding (1) the construction of scenario themes and the use of stochastics, (2) environmental compliance, (3) scorecard metrics; and (4) All-Source RFP design. Three stakeholders, Dany Brooks; David Chiesa of S&C Electric Company; and a group comprised of Scott Houldieson (United Auto Workers), Barry Halgrimson, and Sam Henderson (Hoosier Environmental Council) provided stakeholder presentations. The meeting presentation (including the agenda), stakeholder presentations, terminology sheet, notes (including questions / responses), and registered participants for Meeting 2 are included in Appendix A, Exhibit 2.

2.1.3 Stakeholder Meeting 3

NIPSCO hosted its third stakeholder meeting as an on-line webinar on July 24, 2018, with the public also invited to attend at NiSource's South Lake or Indianapolis offices. The webinar focused on sharing the preliminary results from the All-Source RFP solicitation. NIPSCO and the All-Source RFP manager Charles River Associates ("CRA") provided an overview of the proposals received and a summary of the pricing. NIPSCO also explained how the All-Source RFP results would be integrated into the IRP analysis and important next steps for both the IRP and All-Source RFP process. Key issues for stakeholders included clarification relating to (1) number of bids vs projects, and (2) integrating the All-Source RFP results into the IRP. The presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 3 are included in Appendix A, Exhibit 3.

2.1.4 Technical Webinar

NIPSCO hosted a technical webinar on August 28, 2018. The webinar focused on addressing follow ups from the July 24, 2018 meeting. Key issues for stakeholders included clarification relating to (1) how the All-Source RFP results will be incorporated into the IRP; (2) tranche development and assessment; (3) portfolio creation; and (4) how unforced capacity ("UCAP") was determined from the bid data. The meeting presentation (including the agenda) and registered participants for the Technical Webinar is included in Appendix A, Exhibit 4.

2.1.5 Stakeholder Meeting 4

NIPSCO's fourth stakeholder meeting was held in Fair Oaks, Indiana on September 19, 2018. For those unable to join in person, a webinar format was also made available. In this fourth meeting, NIPSCO explained the preliminary findings from the modeling. Key issues for stakeholders included (1) an explanation of how NIPSCO plans for the future; (2) an update the energy and demand forecasts; (3) a discussion of how NIPSCO models uncertainties; (4) an overview of NIPSCO's preliminary retirement and replacement analyses; and (5) an update on stakeholder requested scenarios. In addition, the Sierra Club provided a stakeholder presentation. The meeting presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 4 are included in Appendix A, Exhibit 5. Please note, the Sierra Club did not provide an electronic version of its presentation to be included with the materials. If provided, the presentation will be available at nipsco.com/irp. The terminology sheet provided as the first meeting was also provided for the fourth meeting, but is not duplicated in Exhibit 5.

2.1.6 Stakeholder Meeting 5

NIPSCO's fifth stakeholder meeting was held in Fair Oaks, Indiana on October 18, 2018. For those unable to join in person, a webinar format was also made available. In this fifth meeting, NIPSCO provided its preferred plan and preliminary action plan. Key issues for stakeholders included (1) a recap of how NIPSCO plans for the future; (2) an update to the stakeholder requested analyses; (3) an update on the retirement and replacement analyses; and (4) NIPSCO's preferred resource plan. In addition, the Indiana State Conference of the NAACP and Indiana DG provided stakeholder presentations. The meeting presentation (including the agenda), stakeholder presentations, notes (including questions / responses), and registered participants for Meeting 5 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) additional information regarding the All-Source RFP, or (3) running requested scenarios. Information relating to the results of the requested scenarios can be found in the presentation included in Appendix A, Exhibit 5 (Slides 48 through 52) and Appendix A, Exhibit 6 (Slides 11 through 23).

NIPSCO's 2018 IRP is the result of analysis performed by NIPSCO that includes consideration of stakeholder input. NIPSCO has made a good-faith effort to be open and transparent regarding input assumptions and modeling results. NIPSCO appreciates the participation of its stakeholders, including the Commission staff, the OUCC, NIPSCO's largest industrial customers and community action groups, all of which participated extensively throughout the IRP development process. NIPSCO's stakeholders and Commission staff provided valuable feedback throughout the process, which has been considered and incorporated as applicable. Despite best efforts to address and resolve all input from stakeholders, there were instances wherein NIPSCO still incorporated, for example, methodologies that were not supported by all stakeholders.

2.2 IRP Planning Process

NIPSCO's 2018 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) of the IRP) is included in Section 10: Compliance with Proposed Rule.

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

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

NIPSCO recognizes future economic and environmental changes are difficult to accurately predict. The 2018 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:

GDS Associates, Inc. ("GDS") 1850 Parkway Place, Suite800 Marietta, Georgia 30067	Developed DSM measures inputs for a long-term DSM forecast
Itron, Inc. 2111 North Molter Road Liberty Lake, Washington 99019	Provided historical and forecasted end use data
Charles River Associates 200 Clarendon Street Boston, Massachusetts 02116	Provided fundamental long term commodity price forecasts, portfolio modeling and analysis. A separate division of CRA provided assistance in administering the All-Source RFP and evaluating the responses.
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 April 24, 2018. The meeting focused on using IRPs to develop avoided costs for energy efficiency, the planning models used by MISO, distribution system planning, load growth trends, using smart meter data, distributed energy resources and the potential for peak demand reduction. To the extent the information applicable and appropriate, NIPSCO included the items discussed during the technical conference in its analysis.

2.2.2 2016 IRP Feedback and 2018 Process Improvement Efforts

NIPSCO strives to continuously improve all aspects of its resource planning process and, for the 2018 IRP, NIPSCO reviewed the feedback from the 2016 IRP and implemented key improvements to its process. The process improvements in the 2018 IRP are primarily designed to incorporate advanced risk modeling techniques, as well as to continue to enhance the transparency and credibility of NIPSCO's long-term plans by using assumptions based on fundamentals driven analysis and market based data.

Table 2-1 shows feedback received on NIPSCO's 2016 IRP and the improvements that were included in its 2018 IRP process.

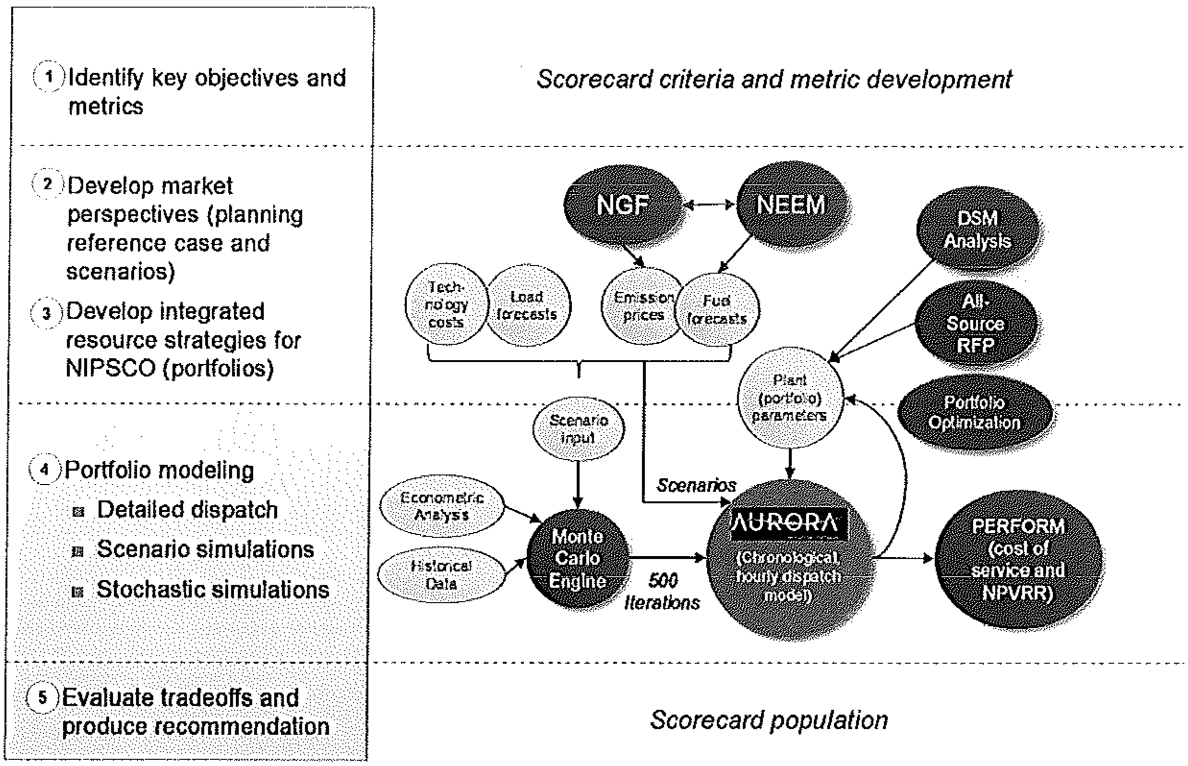
Table 2-1: Process Improvement

Subject	2016 IRP Feedback	2018 Improvement Plan
Commodity Price Forecasts	• Fuel price projections do not capture the nuanced and dynamic relationships between oil and natural gas, or whether the historic market correlations are evolving • No transparency and availability of underlying assumptions for fuel forecasts	• Utilized independently generated commodity price forecasts using an integrated market model • Provided transparent assumptions related to key inputs and outputs • Benchmarked against publicly available forecasts
Risk Modeling	• NIPSCO IRP planning model was limited to scenarios and sensitivities	• Implemented efficient risk informed (stochastics) analysis with the ability to flex key variables
Scenarios and Sensitivities	• NIPSCO's construction of scenarios and sensitivities in the 2016-2017 IRP is a significant advancement over the 2014 IRP. The clarity of the narratives was commendable and transparency was exceptional	• Built upon the progress made in the 2016 IRP with thematic and modeling informed selections for detailed cost analysis
Capital Cost Assumptions	• Capital cost estimates for new capacity resources were based on proprietary consultant information • No scenario or sensitivity covered uncertainties of resource technology cost	• Leveraged 3rd party and publicly available datasets to develop a range of current and future capital cost estimates for new capacity resources • Conducted an "all-source" Request for Proposal solicitation for replacement capacity resources
Preferred Plan and Scorecard	• Provide additional details around selection of the Preferred Plan and the analysis used to develop • Provide a detailed narrative for those metrics that can be quantified as well as those that do not lead to quantification	• Provided detailed analysis on selection of the Preferred Plan • Developed enhanced scorecard methodology to include more quantifiable metrics that better evaluate tradeoffs
DSM Modeling	• DSM groupings are not getting quite the same treatment as the supply side resources	• Utilized new modeling capabilities to enable DSM to be treated equally with other supply side resources

2.3 Resource Planning Approach

Consistent with the principles set out in Section 1.1, the 2018 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. NIPSCO's 2018 IRP was performed according to the detailed planning approach process that is outlined in Figure 2-1 and described in more detail below. While structurally similar to the 2016 IRP process, the 2018 approach has incorporated new software, models and several process enhancements in order to respond to feedback that was received.

Figure 2-1: Overall Integrated Resource Planning Approach



Step 1: Identify key objectives and metrics

The first step in NIPSCO's planning approach was to identify key planning objectives and develop specific metrics against which to evaluate future portfolios. As in the 2016 IRP, this involved the development of multiple scorecard criteria prior to the commencement of any analysis. This ensures that the objectives and metrics are established without any bias that may come from the production of IRP model runs and analysis. The planning criteria used in the 2018 IRP includes cost to customer, cost risk, fuel security, environmental stewardship, and impact to employees and the local economy. Section 9 of this report describes the scorecard objectives and metrics in more detail.

Step 2: Develop market perspectives

Prior to performing any portfolio-specific analysis, NIPSCO developed perspectives on key market drivers and other major planning assumptions. This involved the use of several market models and forecasting approaches in order to arrive at a Base Case set of inputs and a set of scenarios against which to evaluate resource options. This step involved the following major tasks:

- Commodity price forecasting for fuel, emission, and power prices: NIPSCO commissioned CRA to develop forecasts for natural gas prices, coal prices, emission allowance prices, and power prices (energy and capacity) for the Base Case and three integrated market scenarios. The details of all Base Case and scenario forecasts are provided in Section 8. CRA relied on the following models to perform this work:

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

- o CRA's North American Electricity and Environment Model ("NEEM"), which provides an assessment of emission allowance prices, coal consumption and coal pricing, generator retrofit decisions, and capacity expansion and retirements. The NEEM model estimates market prices and unit dispatch using a simplified transmission representation and a select number of representative demand points to produce a fundamentals-based outlook of key macroeconomic outputs for the electricity sector.

- o The Aurora model, which CRA licenses, and which provides hourly MISO market prices at a zonal level based on a fundamental dispatch of the market. Market inputs for the Aurora model include fuel prices, emission prices, and capacity expansion and retirement, which are developed through CRA's other models. CRA also deploys a capacity market model, which produces an internally consistent capacity price outlook based on MISO market rules.

- Load forecasting, performed by NIPSCO's internal load forecasting team, and described in more detail in Section 3.

- Development of technology cost estimates for supply side resource options, which were initially produced on a planning-level basis through market research conducted by NIPSCO and CRA. NIPSCO and CRA's Auction and Competitive Bidding Practice then conducted an All-Source RFP, which provided real market data on the resource types available and their associated costs and operational parameters. Section 4 describes this process in more detail.

Step 3: Develop integrated resource strategies or portfolios

The third major step in the 2018 IRP process was to develop resource strategies or portfolios for further evaluation. The portfolio development process relied on multiple inputs and approaches. It was conducted first for a retirement analysis and then for a full replacement analysis, with key elements summarized as follows:

- The definition of retirement portfolio options was influenced by environmental policy considerations (as discussed in Section 7) and management input on feasible retirement paths.

- An update to NIPSCO's 2016 DSM Market Potential Study was conducted by GDS in order to provide a set of plausible DSM program bundles and associated costs for evaluation. The details of this study are provided in Section 5.

- Portfolio optimization analysis was conducted with the Aurora model's portfolio optimization tool to develop least-cost portfolio concepts under a variety of constraints. Both supply side and demand side resources were evaluated in the portfolio optimization framework. The details of the process and a summary of the integrated portfolios that were evaluated are provided in Section 8.

Step 4: Portfolio Modeling

After detailed portfolios were constructed, each of them was evaluated in CRA's suite of resource planning tools, namely Aurora and a utility financial model known as PERFORM. The Aurora model performs an hourly, chronological dispatch of NIPSCO's portfolio within the MISO power market, accounting for all variable costs of operation, all contracts or PPAs, and all economic purchases and sales with the surrounding market. Aurora produces projections of asset-level dispatch and the total variable costs associated with serving load. It also produces estimates for other key metrics, such as carbon dioxide ("CO_2") emissions over time and capacity and generation by fuel type. The Aurora output is then used by CRA's PERFORM model to build a full annual revenue requirement, inclusive of capital investments, fixed operating and maintenance costs, and financial accounting of depreciation, taxes, and utility return on investment. The PERFORM model produces annual and net present value estimates of revenue requirements.

The full set of portfolio modeling is undertaken for all portfolio options for the Base Case, each individual integrated market scenario, and a full stochastic distribution of potential outcomes associated with select commodity prices. The stochastic analysis relies on CRA's Monte Carlo engine, which simulates future price outcomes based on historical data analysis and specification of key statistical parameters. The details of the stochastic development process and the outputs of all portfolio modeling are discussed in more detail in Section 9.

Step 5: Evaluate tradeoffs and produce recommendations

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

2.3.1 Key Planning Assumptions

While many of the assumptions details are described further in subsequent sections of this report, the following information provides an introductory overview of several major planning inputs that drive the 2018 IRP.

Market Forecast Inputs

Market and commodity price forecasts are important drivers for NIPSCO's IRP, since they influence the variable costs of operation for many resources, the dispatch of certain power plants, and NIPSCO's interaction with the MISO market. As discussed above, CRA produced commodity price forecasts for major inputs, relying on support from NIPSCO's subject matter experts for certain details or assumptions that are specific to NIPSCO's current operating fleet. For example, for coal pricing, delivered coal contract details and expected coal transportation rates were provided by NIPSCO's fuel supply group in order to conform to near-term price expectations for the existing fleet of plants. Long-term fundamental forecasts were blended in over time. Figure 2-2 presents a summary of the source and reference information for each of the major market inputs.

Figure 2-2: Major Market Input Sources

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

Environmental Planning Inputs

As noted above, emissions price assumptions were provided by CRA, with review provided by NIPSCO's environmental group. Estimates were developed by NIPSCO's Major Projects group for projects required to comply with current and future anticipated regulations pertaining to solid waste management, the Clean Water Act ("CWA"), and the Clean Air Act ("CAA"). A comprehensive review of key environmental planning drivers is provided in Section 7.

Energy and Demand Forecast

NIPSCO's internal load forecasting group produced load forecasts, including high and low cases, which were used in the IRP analysis. For the 2018 IRP modeling NIPSCO utilized the MISO Coincident peak demand forecast. All methods, assumptions and detailed forecast results are provided in Section 3.

Existing NIPSCO Portfolio Parameters

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

New Resource Parameters

NIPSCO relied on multiple sources for major input assumptions associated with new resource options. DSM resource options and costs were developed by GDS, as described in Section 5. Supply-side resource options were developed according to the All-Source RFP conducted in 2018. The All-Source RFP provided cost information and resource operational characteristics, including capacities, heat rates, and expected capacity factors for renewable resources. This is described in further detail in Section 4.

Planning Reserve Margin Target

NIPSCO operates in the MISO market and must demonstrate a sufficient planning reserve margin to ensure reliability and resource adequacy. The MISO UCAP planning protocol was used to determine the planning reserve margin target to use in the 2018 IRP update, and NIPSCO set its target to 8.4%, as per current MISO standards. This target is based on NIPSCO's coincident peak in MISO. When performing portfolio optimization analysis, NIPSCO set a maximum reserve margin of 20% and a maximum level of off-system energy sales of 5%. This was done to avoid developing portfolios where NIPSCO would be relying on a significant level of excess energy and capacity sales to offset resource costs.

Financial Assumptions

Several financial assumptions are relevant to projecting annual revenue requirements, such as the expected return on equity and debt, tax rates, and the discount rate used when calculating the net present value ("NPV"). A summary of the major financial assumptions used in the 2018 IRP is provided in Figure 2-3.

Figure 2-3: Major Financial Assumptions

Financial Assumption	Value
Cost of Equity	9.98%
Cost of Debt	5.71%
Equity %	58.44%
Debt %	41.56%
After-Tax Weighted Average Cost of Capital	7.61%
Federal Income Tax Rate	21.00%
State Income Tax Rate	4.90%
Blended Income Tax Rate	24.87%
Property Tax Rate	2.16%
Discount Rate	7.61%
Allowance for Funds Used During Construction%	7.44%
Blended Depreciation Rate for Existing Assets	4.60%

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 remain flat on average 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 2018-2039. The Industrial class is projected to decrease at a rate of 0.7% during this same period.

- NIPSCO's internal Peak demand is expected to grow from 3,051MW in 2018 to 3,169 MW by 2039 representing an annual growth rate of 0.2% during the period 2018-2039.

- NIPSCO MISO coincident peak demand is expected to grow from 2907MW in 2018 to 2970 MW in 2039 representing an annual growth rate of 0.1% during the period 2018 to 2039

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.

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, Commercial, and Street Lighting 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 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 through 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 incorporating electric vehicle impacts, the data frequency used in the forecast modeling, and testing 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 North American Industrial Classification System (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 number of residential customers assigned to each station. 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 are 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. 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 five-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- 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 0.9687 in addition to strong T-Stats for each variable and directionally confirms the relationships expected between the independent and dependent variables. Sixteen 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 0.9333 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, HDD, and CDD)

Table 3-1: NIPSCO Residential Customers

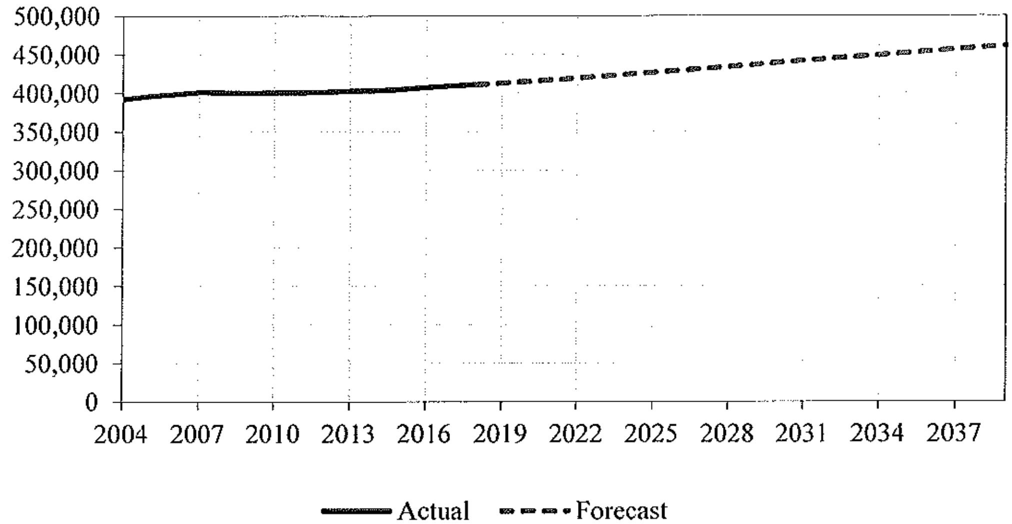
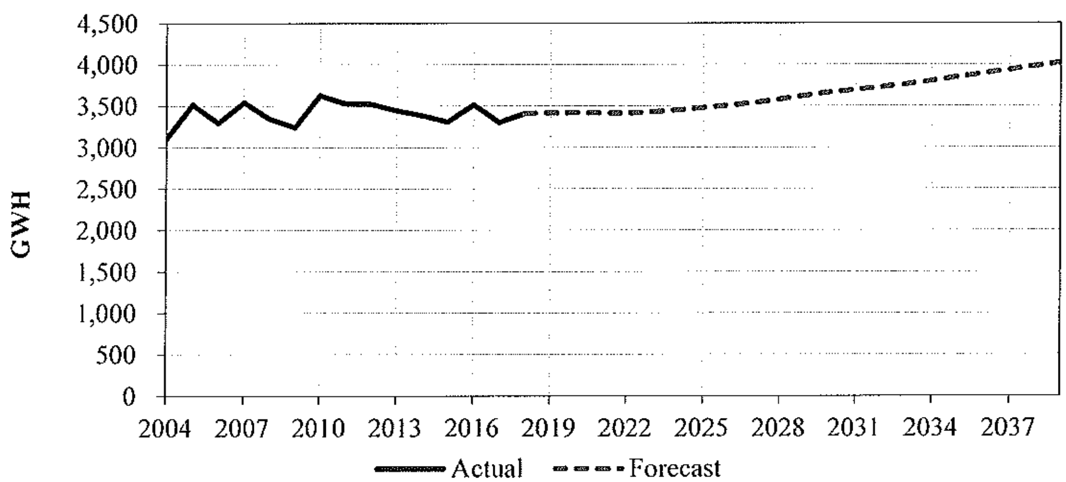


Table 3-2: NIPSCO Residential Energy Sales



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, employment, commercial electric price, CDD, and HDD. As with Residential, the initial five-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. Twenty one years of historical 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. Fifteen years of data was used in the development of the commercial energy long-term outlook. The model yielded an R-Square of 0.9833 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, employment, Commercial Electric Price, CDD, HDD)

Table 3-3: NIPSCO Commercial Customers

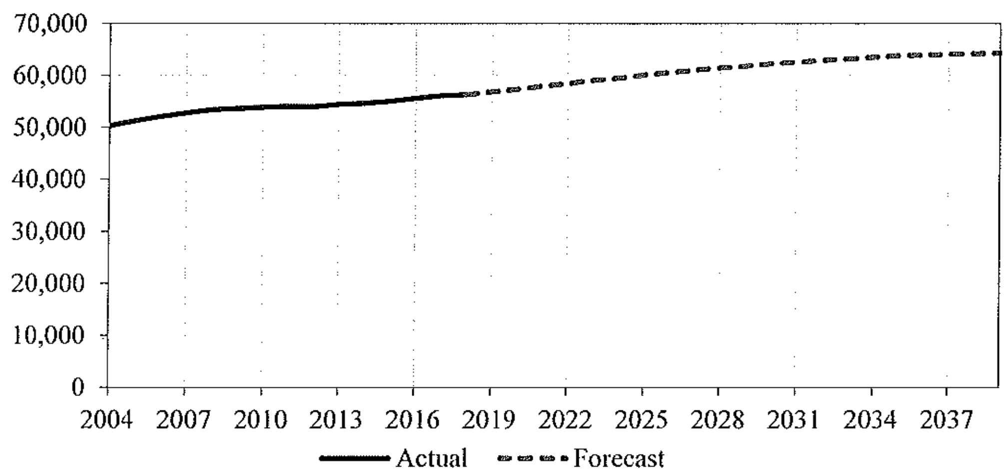
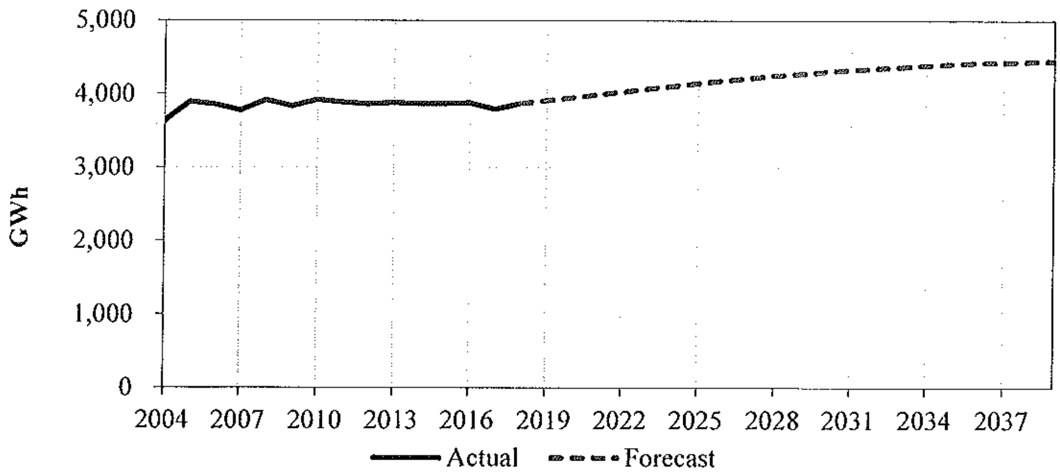


Table 3-4: NIPSCO Commercial Energy Sales



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. This year, the loss of energy demand from a major industrial account customer caused NIPSCO's industrial energy sales forecast to trend downwards compared to previous years' forecasts.

Information specific to the creation of the Industrial sales forecast is obtained through 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 2018 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

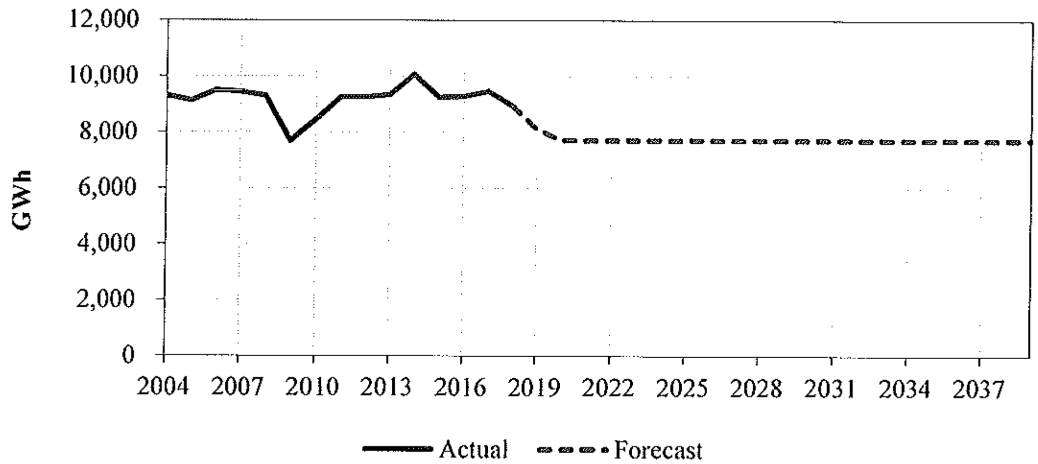


Table 3-6: Total Customers

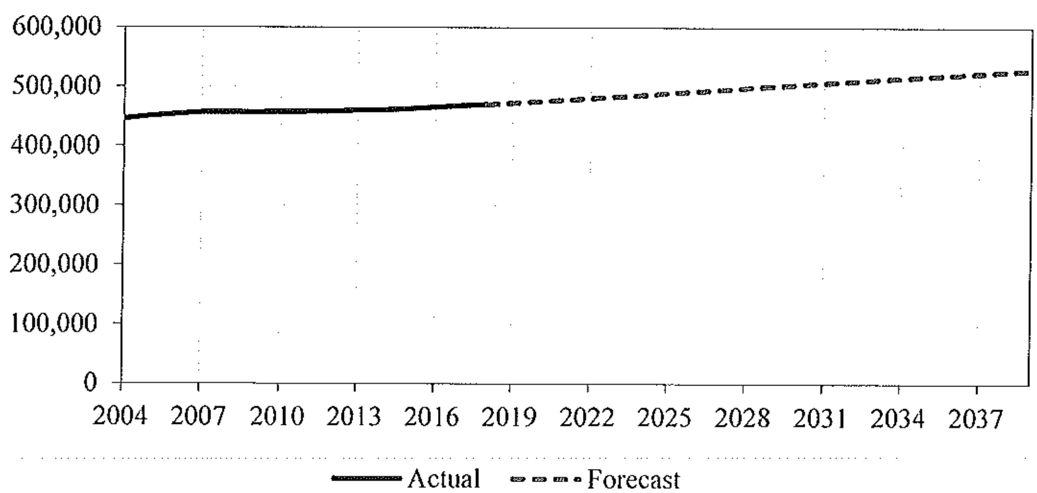
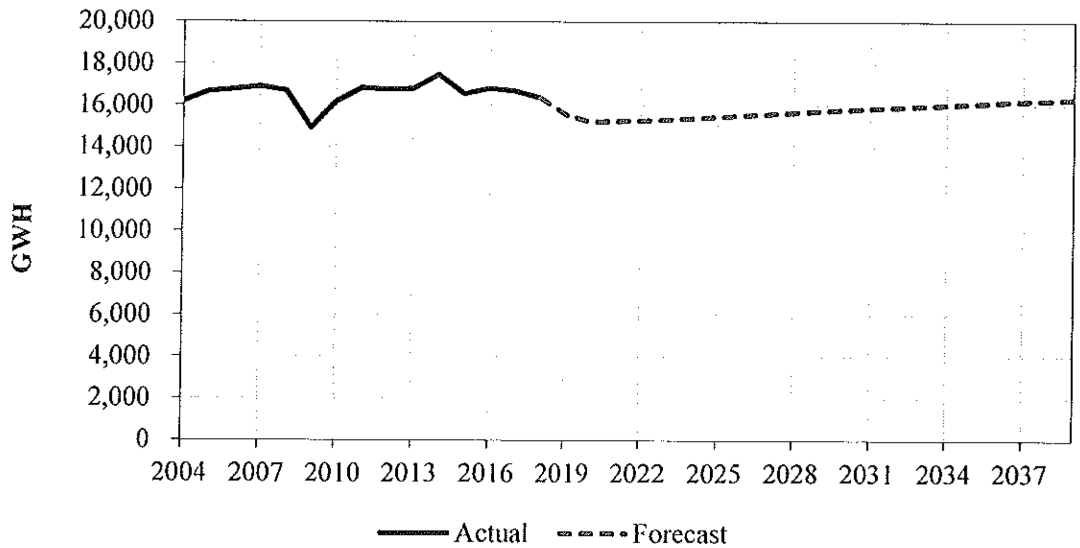


Table 3-7: **Total Energy Sales**



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

The Public Authority, Railroads, Company use and losses forecasts are based on both current usage levels and anticipated future trends. The street lighting model utilizes an econometric model that accounts for the number of hours of dark and anticipated future trends. Nine years of historical data were used in the development of the street lighting long-term outlook. The model yielded an R-Square of 0.9154 and confirms statistically strong relationships between the independent and dependent variables.

Street Lighting Energy Use = f(Number of hours of dark)

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 32 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 32 years of historical data, the model yielded an R-

Square of 0.9428 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

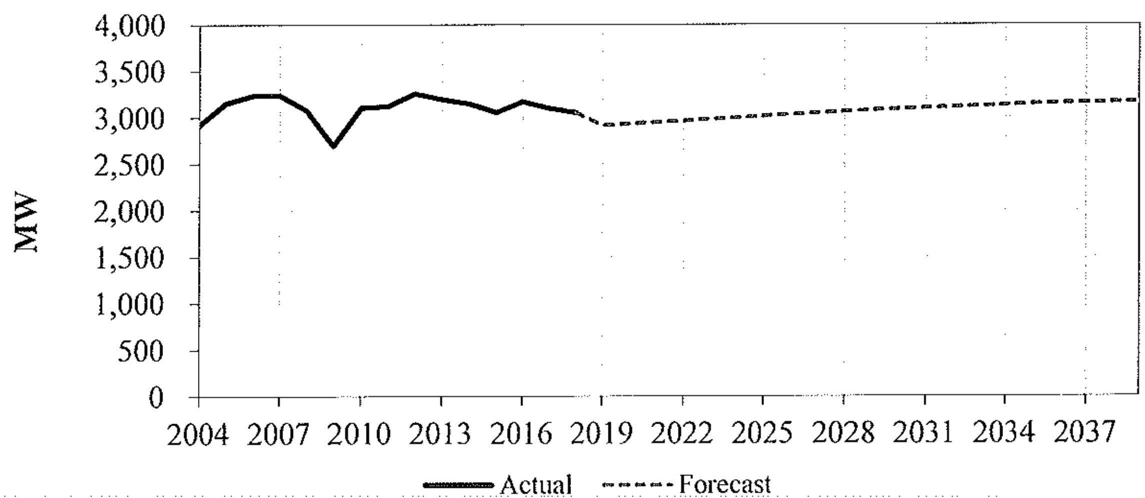
Peak_Step1 = f(Residential Energy, Commercial Energy, Small Industrial Energy, Cooling Degree Hours(Summer), Heating Degree Hours(Winter), Summer Humidity,)

Large Company Load Factor = f(Time, Time²)

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

NIPSCO Peak=Peak_Step1 + Peak_Step2

Table 3-8: Peak Hour



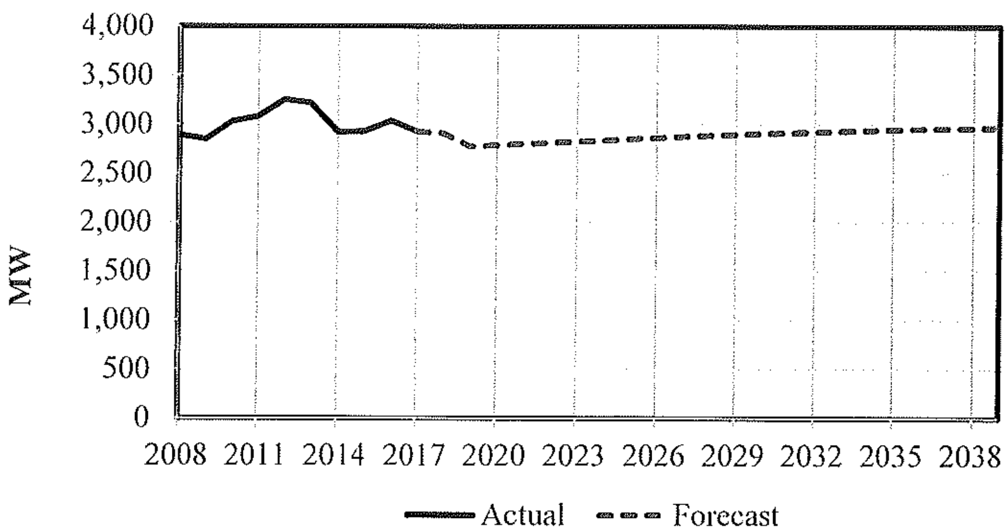
3.8 MISO Coincident Peak

MISO Coincident Peak is NIPSCO's monthly system peak at the time of MISO's system peak. NIPSCO uses an econometric model to project future demand on its system at the time of

MISO's system peak. The model incorporates NIPSCO's monthly peak demand levels and Cooling Degree Hours at the time of MISO's system peak. On average the MISO coincident peak level forecast is about 95% of NIPSCO internal peak level.

MISO Coincident Peak = f(NIPSCO Internal Peak, Cooling Degree Hours)

Table 3-9: MISO Coincident Peak



3.9 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.

3.10 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 the daily baseload, temperature sensitive load (TS) per CDD, TS per HDD, the daily non-temperature sensitive use per customer (NTSUPC), and the daily temperature sensitive use per customer per customer (TSUPC). Several assumptions are made in the normalization procedure. They are:

- May is the base load month and is not normalized for weather
- Heating energy volumes accounted for October through April
- Cooling energy volumes accounted for June through October
- October is accounted for both heating and cooling energy volumes

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 = NTSUPC + ((TSUPC/HDD) * NHDD) + ((TSUPC/CDD) * NCDD))*

Where

NHDD: Normal Heating Degree Day, NCDD: Normal Cooling Degree Day
NTS UPC factor = May UPC /day
*NTSUPC = NTS UPC factor * billing days*
TSUPC = Total UPC – NTSUPC
TSUPC/HDD for heating months except October
TSUPC/CDD for cooling months except October
TSUPC/HDD for Oct = TSUPC/HDD from previous September
TSUPC/CDD for Oct = Average of TSUPC/CDD June-September of current season

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

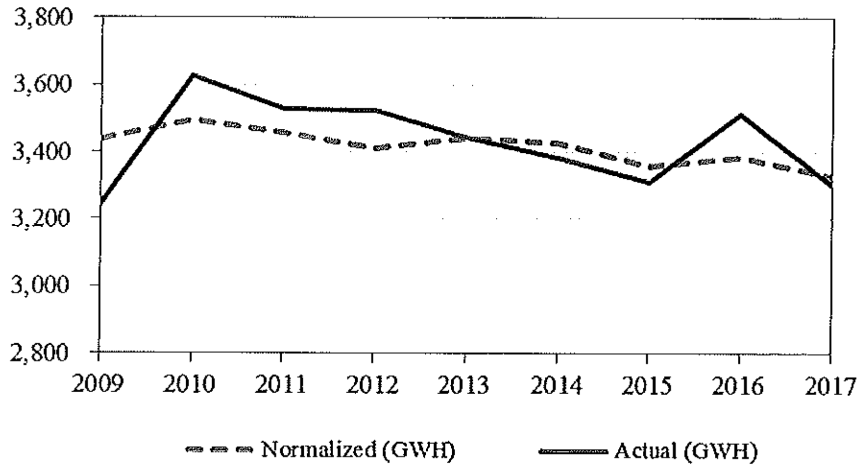
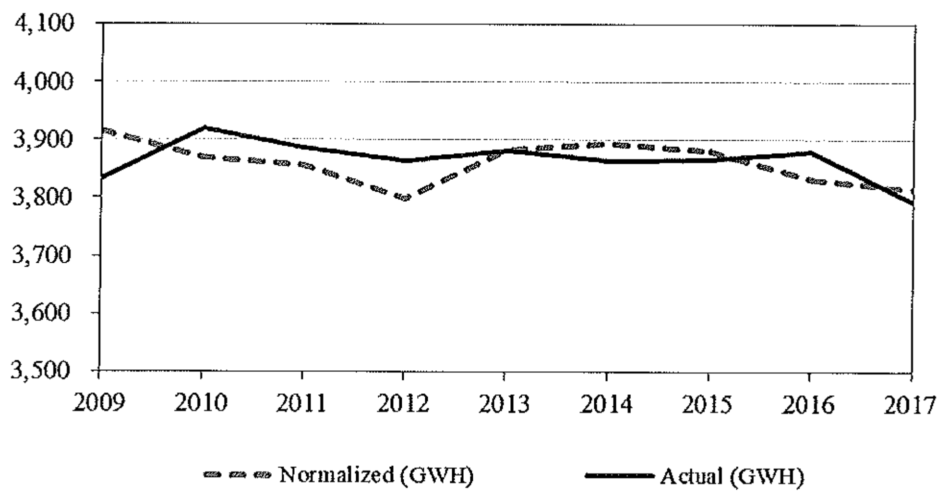


Figure 3-2: NIPSCO Commercial GWh



3.11 Forecast Results – Base Case

Over the forecast period, total energy is projected to remain flat and peak hour demand is projected to grow at 0.2%. NIPSCO expects overall customer growth to increase about 0.6% annually. Table 3-10 illustrates NIPSCO's electric energy and demand forecast.

Table 3-10: Electric Energy and Demand Forecast

	Energies (Gigawatt hour or "GWh")						Internal Peak Hour		MISO Coincident Peak Level	
Year	Total Retail *	% Change	Losses	Total Output	% Change	Load Factor	MW	% Change	MW	% Change
2008	16,705		897	17,602		65.3%	3,076		2,891	
2009	14,925	-10.7%	858	15,783	-10.3%	66.8%	2,696	-12.4%	2,848	-1.5%
2010	16,191	8.5%	915	17,106	8.4%	62.9%	3,103	15.1%	3,029	6.4%
2011	16,836	4.0%	892	17,728	3.6%	64.8%	3,122	0.6%	3,081	1.7%
2012	16,756	-0.5%	925	17,681	-0.3%	62.0%	3,257	4.3%	3,252	5.6%
2013	16,798	0.2%	839	17,638	-0.2%	63.0%	3,194	-1.9%	3,218	-1.0%
2014	17,467	4.0%	940	18,407	4.4%	66.7%	3,149	-1.4%	2,921	-9.2%
2015	16,563	-5.2%	886	17,449	-5.2%	65.2%	3,055	-3.0%	2,926	0.2%
2016	16,813	1.5%	913	17,726	1.6%	63.8%	3,173	3.9%	3,037	3.8%
2017	16,693	-0.7%	844	17,537	-1.1%	64.8%	3,087	-2.7%	2,927	-3.6%
2018	16,362	-2.0%	889	17,251	-1.6%	64.5%	3,051	-1.2%	2,907	-0.7%
2019	15,582	-4.8%	847	16,429	-4.8%	64.3%	2,916	-4.4%	2,776	-4.5%
2020	15,216	-2.4%	827	16,042	-2.4%	62.5%	2,932	0.6%	2,788	0.4%
2021	15,255	0.3%	829	16,084	0.3%	62.3%	2,949	0.6%	2,801	0.5%
2022	15,287	0.2%	831	16,118	0.2%	62.1%	2,965	0.5%	2,813	0.4%
2023	15,344	0.4%	834	16,178	0.4%	61.9%	2,982	0.6%	2,827	0.5%
2024	15,405	0.4%	837	16,242	0.4%	61.8%	2,999	0.5%	2,839	0.4%
2025	15,471	0.4%	841	16,311	0.4%	61.7%	3,016	0.6%	2,853	0.5%
2026	15,535	0.4%	844	16,379	0.4%	61.7%	3,033	0.6%	2,866	0.5%
2027	15,603	0.4%	848	16,451	0.4%	61.6%	3,048	0.5%	2,877	0.4%
2028	15,677	0.5%	852	16,529	0.5%	61.6%	3,064	0.5%	2,890	0.4%
2029	15,744	0.4%	856	16,600	0.4%	61.6%	3,077	0.4%	2,899	0.3%
2030	15,815	0.4%	859	16,674	0.4%	61.6%	3,091	0.5%	2,910	0.4%
2031	15,870	0.4%	862	16,733	0.4%	61.6%	3,103	0.4%	2,919	0.3%
2032	15,923	0.3%	865	16,788	0.3%	61.6%	3,113	0.3%	2,927	0.3%
2033	15,977	0.3%	868	16,845	0.3%	61.6%	3,123	0.3%	2,934	0.3%
2034	16,037	0.4%	871	16,909	0.4%	61.6%	3,133	0.3%	2,943	0.3%
2035	16,105	0.4%	875	16,981	0.4%	61.6%	3,145	0.4%	2,951	0.3%
2036	16,163	0.4%	878	17,042	0.4%	61.7%	3,152	0.2%	2,957	0.2%
2037	16,213	0.3%	881	17,094	0.3%	61.8%	3,158	0.2%	2,961	0.1%
2038	16,265	0.3%	884	17,148	0.3%	61.9%	3,164	0.2%	2,966	0.2%
2039	16,314	0.3%	887	17,201	0.3%	62.0%	3,169	0.2%	2,970	0.1%
Compound Average Growth Rate 2018-2039										
	0.0%			**0.0%**			**0.2%**		**0.1%**	
** Retail does not include bulk sales*										

Table 3-11 illustrates NIPSCO's electric energy by customer class.

Table 3-11: Energies by Customer Class

Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Other (GWh)	Total * (GWh)	Percent Change
2008	3,346	3,916	9,305	138	17,602	
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	3,514	3,879	9,282	138	17,726	1.6%
2017	3,302	3,793	9,470	128	17,537	-1.1%
2018	3,411	3,871	8,947	134	17,251	-1.6%
2019	3,420	3,910	8,120	131	16,429	-4.8%
2020	3,418	3,949	7,718	129	16,042	-2.4%
2021	3,418	3,992	7,718	127	16,084	0.3%
2022	3,413	4,031	7,718	125	16,118	0.2%
2023	3,430	4,072	7,718	125	16,178	0.4%
2024	3,452	4,109	7,718	125	16,242	0.4%
2025	3,480	4,148	7,718	125	16,311	0.4%
2026	3,507	4,186	7,718	125	16,379	0.4%
2027	3,541	4,219	7,718	125	16,451	0.4%
2028	3,581	4,252	7,718	125	16,529	0.5%
2029	3,624	4,277	7,718	125	16,600	0.4%
2030	3,667	4,305	7,718	125	16,674	0.4%
2031	3,696	4,331	7,718	125	16,733	0.4%
2032	3,728	4,351	7,718	125	16,788	0.3%
2033	3,763	4,371	7,718	125	16,845	0.3%
2034	3,803	4,391	7,718	125	16,909	0.4%
2035	3,849	4,413	7,718	125	16,981	0.4%
2036	3,893	4,426	7,718	125	17,042	0.4%
2037	3,936	4,434	7,718	125	17,094	0.3%
2038	3,979	4,443	7,718	125	17,148	0.3%
2039	4,022	4,450	7,718	125	17,201	0.3%
Compound Average Growth Rate 2018-2039						
	0.8%	**0.7%**	**-0.7%**	**-0.3%**	**0.0%**	

**Includes Total Retail and Losses*

Table 3-12 displays the NIPSCO forecast by customer counts by class.

Table 3-12: Customer Counts by Class

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Total Customers
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	407,268	55,605	2,313	744	465,930
2017	409,401	56,134	2,302	459	468,296
2018	411,114	56,325	2,302	459	470,199
2019	413,090	56,869	2,302	459	472,720
2020	415,157	57,351	2,302	459	475,269
2021	417,318	57,992	2,302	459	478,072
2022	419,577	58,465	2,302	459	480,803
2023	421,883	59,081	2,302	459	483,725
2024	424,236	59,519	2,302	459	486,517
2025	426,636	60,128	2,302	459	489,525
2026	429,083	60,589	2,302	459	492,433
2027	431,569	61,061	2,302	459	495,391
2028	434,147	61,535	2,302	459	498,443
2029	436,719	61,833	2,302	459	501,313
2030	439,303	62,304	2,302	459	504,368
2031	441,836	62,609	2,302	459	507,206
2032	444,249	62,905	2,302	459	509,915
2033	446,620	63,203	2,302	459	512,584
2034	449,029	63,513	2,302	459	515,303
2035	451,458	63,825	2,302	459	518,044
2036	453,890	63,956	2,302	459	520,606
2037	456,306	64,079	2,302	459	523,146
2038	458,698	64,210	2,302	459	525,669
2039	461,083	64,330	2,302	459	528,174
	Compound Average Growth Rate 2018-2039				
	0.5%	**0.6%**	**0.0%**	**0.0%**	**0.6%**

3.12 Discussion of Forecast and Alternative Cases

3.12.1 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 the 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 3-13 reflects NIPSCO's base, high and low load forecast scenarios for selected years.

Table 3-13: NIPSCO IRP Scenarios – Selected Year

NIPSCO IRP Scenarios - Selected Year											
	Energy Sales - GWh				Internal Demand - MW				MISO Coincident Peak - MW		
	Base	High	Low		Base	High	Low		Base	High	Low
Year	GWh	GWh	GWh		MW	MW	MW		MW	MW	MW
2018	17,251	17,587	16,909		3,051	3,119	2,982		2,907	2,972	2,842
2023	16,178	17,271	11,568		2,982	3,178	2,446		2,827	3,012	2,319
2028	16,529	18,134	11,770		3,064	3,358	2,500		2,890	3,167	2,358
2033	16,845	18,850	11,869		3,123	3,510	2,513		2,934	3,298	2,362
2038	17,148	19,639	11,960		3,164	3,666	2,509		2,966	3,437	2,352
		v Base				v Base				v Base	
		High	Low			High	Low			High	Low
		GWh	GWh			MW	MW			MW	MW
2018	-	1.95%	-1.98%		-	2.2%	-2.3%			2.2%	-2.3%
2023	-	6.76%	-28.50%		-	6.6%	-18.0%			6.6%	-18.0%
2028	-	9.71%	-28.79%		-	9.6%	-18.4%			9.6%	-18.4%
2033	-	11.90%	-29.54%		-	12.4%	-19.5%			12.4%	-19.5%
2038	-	14.53%	-30.25%		-	15.9%	-20.7%			15.9%	-20.7%

3.13 Evaluation of Model Performance and Accuracy

NIPSCO tracks its forecast in terms of mean absolute error ("MAE"). Data for 2006-2017 show that the MAE of the one-year-ahead peak hour demand forecast is 3.3% (MAE of the one-year-ahead MISO coincident peak hour demand forecast is 0.2%); the two-year-ahead forecast has a 4.2% MAE; and the MAE for the five-year-ahead forecast is 5.9%. These represent total forecast error including the effect of abnormal weather at peak. The comparable MAE GWh sales is 3.2% for the one-year-ahead forecast; 4.7% for the two-year-ahead forecast; and 3.8% for the five-year-ahead forecast. Class comparisons to weather-normalized actual data show variances with residential and commercial of 2.0% and 3.3% 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 5.7% and 8.3% MAE for the one-year-ahead and the two-year-ahead forecast. NIPSCO does not have any firm wholesale power sales.

Table 3-14 and Table 3-15 show data for 2006-2017 for total GWh sales and peak hour MW and compare forecasts to actual data not normalized for weather. Table 3-16 and 3-17 show GWh sales by class. GWh are compared to actual data normalized for weather. Table 3-18 shows the performance of the MISO coincident peak model performance since 2012.

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

		1-Year Ahead		2-Year Ahead		5-Year Ahead	
Year	Actual *	Forecast	% Var.	Forecast	% Var.	Forecast	% Var.
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%
2016	3,170	3,118	1.6%	3,187	0.5%	3,419	7.8%
2017	3,100	3,113	0.4%	3,146	1.5%	3,349	8.0%
Average			**3.3%**		**4.2%**		**5.9%**

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

Table 3-15: Total GWh including Losses

		1-Year Ahead		2-Year Ahead		5-Year Ahead	
Year	Actual *	Forecast	% Var.	Forecast	% Var.	Forecast	% Var.
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%
2016	17,726	18,103	2.1%	18,537	4.6%	18,995	7.2%
2017	17,537	17,647	0.6%	18,175	3.6%	18,118	3.3%
Average			**3.2%**		**4.7%**		**3.8%**

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

Table 3-16: Residential and Commercial GWh

		1-Year Ahead		2-Year Ahead	
	Normal *	Forecast	% Var.	Forecast	% Var.
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%
2016	7,216	7,323	1.5%	7,476	3.6%
2017	7,140	7,322	2.6%	7,384	3.4%
Average			**2.0%**		**3.3%**

** Adjusted for weather*

Table 3-17: Industrial GWh

		1-Year Ahead		2-Year Ahead	
	Actual *	Forecast	% Var.	Forecast	% Var.
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%
2016	9,282	9,713	4.6%	9,969	7.4%
2017	9,470	9,288	1.9%	9,720	2.6%
Average			**5.7%**		**8.3%**

** No weather effect measured for industrial load*

Table 3-18: MISO Coincident Peak Demand

MISO Coincident Peak Demand - MW
Absolute % Variance of Forecast v Actual

		1-Year Ahead	
Year	Actual *	Forecast	% Var.
2012	2.0%	1.6%	0.4%
2013	3.6%	3.8%	0.2%
2014	2.8%	2.8%	0.0%
2015	2.3%	2.5%	0.2%
Average			**0.2%**

*Actual peak not adjusted for weather. Forecasted peaks assume normal weather; therefore, variance include weather effect. Please note: MISO coincident Peak model performance is filed with MISO annually on November 1st.

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, O&M 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 energy market conditions. Over the past several years, environmental regulations, a significant influx of highly variable renewable generation (e.g. wind and solar), low natural gas prices, and energy efficiency and other demand side initiatives have made coal-fired generation the marginal supply source. Consequently, this has created an environment with highly variable and nearly unpredictable coal purchase requirements. Therefore, NIPSCO's fuel procurement plans must remain as flexible as possible while still maintaining reliable supply. Obtaining volume flexibility can be challenging since coal suppliers and transportation providers typically 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. Energy market dynamics have been heavily influenced by the increased exploration and production of North American shale oil and gas resources and have fundamentally altered the price spread between coal and natural gas. Lower production costs and highly efficient natural gas extraction processes (horizontal drilling and fracking) have kept natural gas a competitive fuel when used in high efficiency, CCGT units. In addition, increases in wet gas production to gather petroleum liquids further increase natural gas supply when oil prices rise. Oil prices have risen steadily over the last year helping to spur wet gas production. 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 CCGTs and increased natural gas export capacity. These market dynamics continue to displace a significant amount of coal-fired electric generation and are keeping coal prices relatively low. Decreased coal demand and higher mining costs driven by government regulations have adversely impacted coal producers' margins and profits causing a number of producer bankruptcies over the last few years. The restructuring of coal companies' debt and other costs through the bankruptcy process should allow them to produce coal in this competitive environment. Supply has been rationalized and any significant increase in demand could result in coal price volatility. However, several factors may limit the upside for coal prices. The first factor is the cost to produce electricity from coal has increased significantly due to stringent environmental regulations placed on coal-fired electric generation. A second factor is utilities continue to retire older, higher cost coal-fired generation and this has reduced demand. Lastly, low energy prices driven by natural gas pricing and renewables will also limit demand for coal if coal prices spike.

The competitive energy market has also driven a shift in coal supply regions. Specifically, the cost to produce coal in the Appalachian regions and low coal prices have resulted in declining coal production and this has increased market share of the lower cost Illinois Basin ("ILB") region. Even with its higher sulfur content, ILB coal has become an export resource, and its use has increased domestically as utilities have installed flue gas desulfurization systems ("FGDs") to meet tighter sulfur dioxide limits and other emission standards. Southeast utilities have started using ILB coal to replace higher cost Columbian and Central Appalachia coal.

The use of Powder River Basin ("PRB") coal from Wyoming and Montana has increased significantly over the last decade. Although PRB coal has a lower heat content than coals mined in other regions, utilities typically blend PRB coal with Central Appalachian, ILB, or Northern Appalachian ("NAPP") coals to reduce their overall fuel costs. Asian demand for PRB coal has also grown as Japan and China have built new, high efficiency coal units and new coal plants are being built in Korea and Taiwan as well as they prepare to meet their future electricity demand. Historically, Central Appalachian and NAPP coal have been exported into metallurgical coal and some steam coal markets abroad. Since the end of 2016, demand for seaborne coal has increased. It appears that exports will remain resilient with export volumes over the last year at or near the top of the five year range. Coal suppliers need this to continue in order to offset losses in domestic markets.

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

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. Domestic demand for coal has continued to trend lower over the last two years; therefore, prices have remained relatively low and stable. NAPP coal, used by NIPSCO as a blend fuel in one of its cyclone units, and ILB coal have had relatively strong price increases off of 2016 lows as export demand and prices have trended higher over the last two years.

Pricing for PRB coal has remained low over the last two years and is close to the marginal cost of production.

The export dynamic will likely keep upward pressure on the market in the near term and this would likely lower domestic demand for coal unless domestic energy prices rise. All domestic coal pricing is expected to remain soft as long as energy prices stay low, and will likely keep coal prices flat for the balance of 2018 into 2019.

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 evolve in a manner that meets current and future 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, delivery rates, reliability of coal supply and station coal handling operations. Adequate inventories are essential to maintaining generation reliability. Uncertainty in consumption rates and variability in delivery performance generally require higher levels of inventory to insure reasonably adequate reliability.

4.1.1.7 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 cost basis, which includes a complete evaluation of all potential logistical issues.

Coal deliveries, excluding exceptional weather conditions, have been somewhat stable from the various supply regions, particularly shipments originating in the PRB region due to infrastructure improvements. Railroads typically make investment in infrastructure and equipment to support anticipated shipment rates. The cyclical nature of the railroad business can create short term transportation constraints and can impact NIPSCO's coal deliveries. These cycles have been shorter in duration and more volatile over the past several years.

Transportation rates have declined somewhat given the competition in the energy markets. Railroads have been willing to rationalize rail rates, as shown in the market assessment plots below, to keep market share.

Figure 4-1: PRB Customer Rates

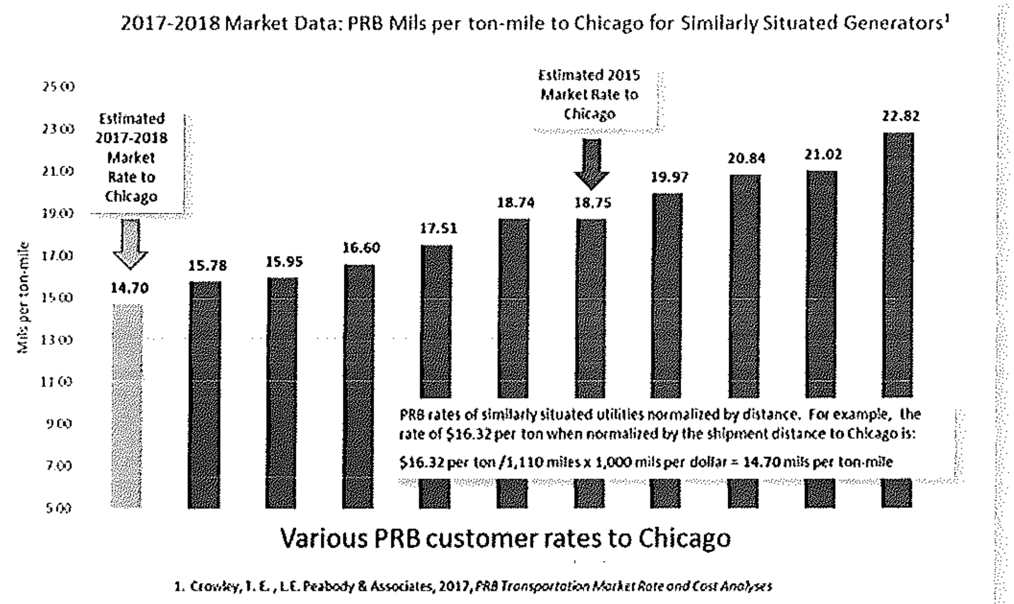
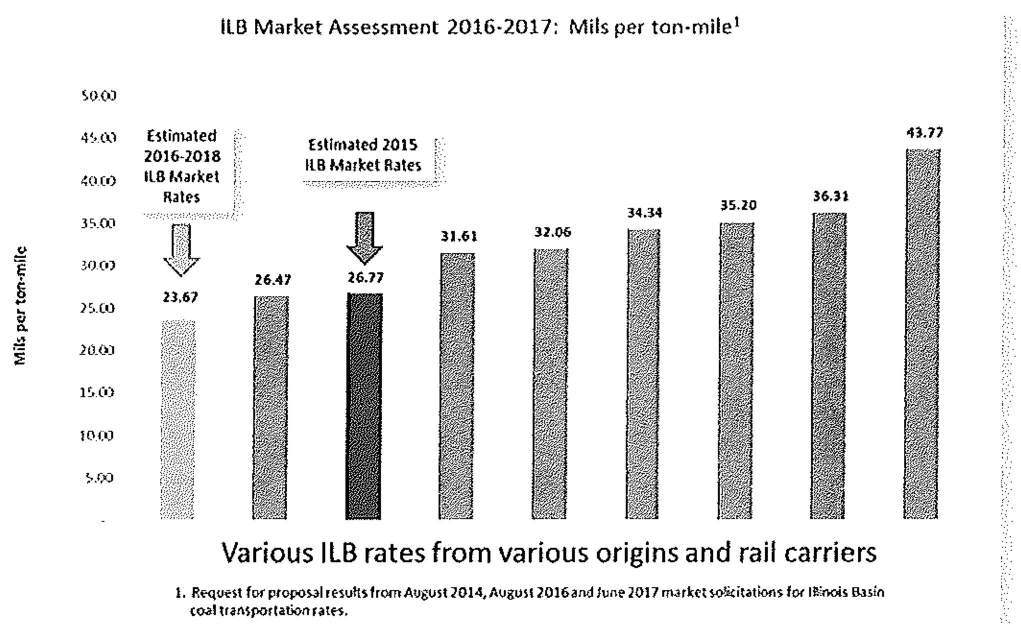


Figure 4-2: ILB Customer Rates



This pricing trend has improved the competitiveness of NIPSCO's coal-fired generation to a certain extent.

4.1.1.8 NIPSCO Transportation Pricing Outlook

NIPSCO has limited rail options from various supply regions 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 or logistically feasible alternatives. NIPSCO's largest generating station, Schahfer, is served by only one railroad. All coal deliveries by this railroad to Schahfer have been transported under agreements that historically escalated transportation rates that also included fuel surcharges indexed to oil prices. However, under this structure, lower power prices lead to a reduction in coal demand. Therefore, NIPSCO and this railroad worked to develop an agreement that lowered rates to improve the station's competitiveness in the market. As stated above, energy markets have forced a rationalization of coal pricing and associated transportation costs. NIPSCO expects this dynamic to continue for the foreseeable future.

As a result, PRB and ILB coal transportation rates have been reduced by nearly 50%. Fuel surcharges continue to fluctuate with the changes in oil prices. The expectation for transportation pricing is also expected to remain soft as long as energy prices stay low, and expect rates to be flat for the balance of 2018 into 2019. Increases in fuel charges could lead to modest transportation cost increases as oil prices trend higher.

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. In addition, coal suppliers have been more amenable to providing some volume flexibility. This has supported NIPSCO's inventory management efforts.

4.1.2 Natural Gas Procurement and Management

NIPSCO currently procures natural gas for its CCGT generating station using a natural gas supply contract with an energy manager that delivers to the interstate pipeline interconnect at the station, or other locations along the interstate pipeline upon request of NIPSCO for balancing purposes. NIPSCO currently holds firm capacity on 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 CCGT generating station. A portion of the gas supply for the Sugar Creek Generating Station ("Sugar Creek") is financially hedged with the intention of smoothing out market price swings over a specific time period. The volatility mitigation plan consists of purchasing monthly NYMEX Henry Hub natural gas contracts that settle at expiration.

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

4.2 Electric Generation Gas Supply Request for Proposal Process

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

4.3 Existing Resources

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

4.4 Supply Resources

NIPSCO owned generating resources consist of coal, natural gas and hydro units. Additionally NIPSCO meets it customer needs with 2 wind purchase power agreements and has an extensive demand response ("DR") program via its large industrial customers. The total Net Demonstrated Capacity ("NDC") of the existing resources is 2,925 MW across multiple generation sites, including the Schahfer (Units 14, 15, 16A, 16B, 17 and 18), Michigan City (Unit 12), Bailly (Units 10), Sugar Creek and two hydroelectric generating sites near Monticello, Indiana (Norway Hydro and Oakdale Hydro). Of the total capacity, 61% is from coal-fired units, 21% is from natural gas-fired units and 18% is from industrial interruptible DR program. Consistent with the 2016 IRP preferred plan NIPSCO retired 2 coal fired units (Units 7 and 8) at the Bailly in May 2018.

Table 4-1 provides a summary of the current generating facilities operated by NIPSCO.

Table 4-1: Net Demonstrated Capacity

Resource	Unit	Fuel	Capacity NDC (MW)
Michigan City	12	Coal	469
Schahfer	14	Coal	431
	15	Coal	472
	16A	NG	78
	16B	NG	77
	17	Coal	361
	18	Coal	361
		Subtotal	1,780
Sugar Creek		NG	535
Bailly	10	NG	31
Hydro	Norway	Water	4
	Oakdale	Water	6
		Subtotal	10
Wind		Wind	100
NIPSCO			2,925

NG=Natural Gas

4.4.1 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 selective catalytic reduction ("SCR") and over-fire air ("OFA") systems to reduce nitrogen oxide ("NO_x") emissions. A new FGD ("") system was placed in service in 2015. The individual unit characteristics of Michigan City are provided in Table 4-2.

Table 4-2: Michigan City Generating Station

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

4.4.2 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 sulfur dioxide ("SO_2") emissions and SCR, SNCR, 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 4-3.

Table 4-3: 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, SNCR, LNB, OFA	FGD, LNB, OFA	FGD, LNB, OFA	----	----

4.4.3 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 CTs and CCGTs were available for commercial operation in 2002 and 2003, respectively. Sugar Creek was purchased by NIPSCO in July 2008, and is its newest 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 4-4.

Table 4-4: 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	---

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

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

Table 4-5: Norway Hydro

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

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

Table 4-6: Oakdale Hydro

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

4.4.5 Barton and Buffalo Ridge Wind (NIPSCO Purchase Power Agreements)

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

Table 4-7: Barton Wind PPA

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

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

Table 4-8: Buffalo Ridge Wind PPA

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

4.5 Total Resource Summary

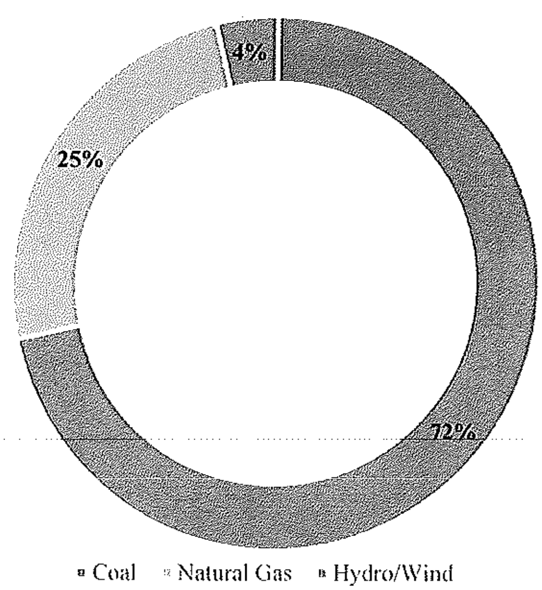
Table 4-9 illustrates various characteristics of NIPSCO's owned and contracted generating units. Figure 4-3 illustrates NIPSCO's existing resources by fuel type.

Table 4-9: Existing Generating Units

Resource	Unit	Fuel	Capacity NDC (MW)	Year in Service
Michigan City	12	Coal	469	1974
Schahfer	14	Coal	431	1976
	15	Coal	472	1979
	16A	NG	78	1979
	16B	NG	77	1979
	17	Coal	361	1983
	18	Coal	361	1986
		Subtotal	1,780	
Sugar Creek		NG	535	2002
Bailly	10	NG	31	1968
Hydro	Norway	Water	4	1923
	Oakdale	Water	6	1925
		Subtotal	10	
Wind		Wind	100	2009
NIPSCO			2,925	

NG=Natural Gas

Figure 4-3: Existing Resources Net Demonstrated Capacity



4.6 Operations Management and Dispatch Implications

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

4.7 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 2018, MISO has members from 15 states and one Canadian province with a generation capacity of 200,000 MW and 65,800 miles of high-voltage transmission. MISO manages one of the world's largest energy and operating markets that includes a Day-Ahead Market, Real-Time Market and Financial Transmission Rights Market.

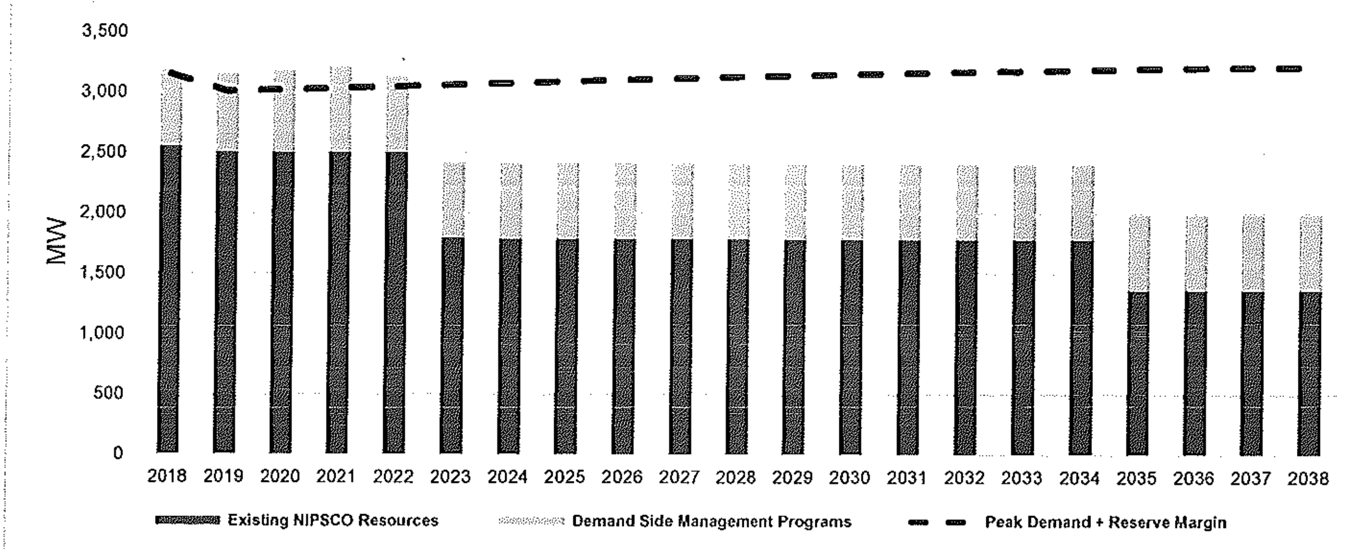
4.8 Resource Adequacy

Consistent with the principles set out in Section 1, NIPSCO is committed to meet the energy needs of its customers with reliable, compliant, flexible, diverse and affordable supply. As part of the Resource Adequacy planning process, NIPSCO is now utilizing the peak demand forecast coincident with the MISO peak demand to determine its capacity requirements. The MISO coincident peak is where NIPSCO demand is projected to be at the time the entire MISO system peaks, which is typically in the summer. The methodology for calculating the coincident peak demand is described in detail in Section 3. NIPSCO's assessment of its existing resources against the future needs of its customers is shown in Table 4-10.

Table 4-10: Assessment of Existing Resources v. Demand Forecast (Base)

	(a)	(b)	(c)	(d)	(e)
Year	**MISO Coincident Peak Demand**	**Peak Demand + Reserve Margin**	**Demand Side Management Programs**	**Existing NIPSCO Resources**	**Capacity Position/Long Short (c+d-b)**
2018	2,907	3,152	621	2,557	26
2019	2,776	3,009	646	2,507	144
2020	2,788	3,022	673	2,507	158
2021	2,801	3,036	702	2,507	173
2022	2,813	3,050	621	2,507	78
2023	2,827	3,064	621	1,799	(644)
2024	2,839	3,078	621	1,791	(666)
2025	2,853	3,092	621	1,791	(680)
2026	2,866	3,106	621	1,791	(694)
2027	2,877	3,119	621	1,791	(707)
2028	2,890	3,132	621	1,791	(721)
2029	2,899	3,143	621	1,785	(737)
2030	2,910	3,154	621	1,785	(748)
2031	2,919	3,164	621	1,785	(758)
2032	2,927	3,173	621	1,785	(767)
2033	2,934	3,181	621	1,785	(775)
2034	2,943	3,190	621	1,785	(784)
2035	2,951	3,199	621	1,367	(1,212)
2036	2,957	3,206	621	1,367	(1,218)
2037	2,961	3,210	621	1,367	(1,222)
2038	2,966	3,215	621	1,367	(1,227)
Notes:					
Reserve Margin Assumption = 8.4%					
Existing Resource Capacity based on NIPSCO UCAP calculation and reflects retirements in 2023 and 2035 *Demand Side Management Programs include Demand Response and Energy Efficiency Programs*					

Figure 4-4: Resource Adequacy Assessment (MW)



Based on the 2016 IRP preferred plan, NIPSCO would need additional capacity resources to meets its customer demand starting in 2023 after the retirements of Schahfer Units 17 and 18. NIPSCO has evaluated a range of resource options to meet that need.

4.9 Future Resource Options

New resources may be needed to meet the future electricity requirements of NIPSCO's customers over time, so it is critical that valid cost and operational estimates are developed for such future resource options in the IRP modeling. In the 2018 IRP, NIPSCO developed a two-step process to improve the new resource evaluation process and to respond to feedback received in the 2016 IRP.[2] This process entailed:

- A review of multiple third-party data sources to assess current and future estimates of resource technology cost, as well as plausible cost ranges, and performance characteristics
- Development of final inputs for IRP modeling based on real bid data that was received from the All-Source RFP.

4.9.1 Third-Party Data Source Review

NIPSCO worked with CRA to perform a screen of third-party sources for new resource cost and operational parameter estimates. The screen included the study NIPSCO commissioned for its 2016 IRP, public sources that develop estimates, such as government forecasts and other

2 Note that a discussion of future demand-side resource options is included in Section 5.

utility IRPs, and subscription services which provide data and capital cost estimates over time. Figure 4-5 provides a list of the sources that were relied upon for the third-party screen.

Based on the source review, NIPSCO identified a list of feasible technology options to be assessed in the initial round of review. These included:

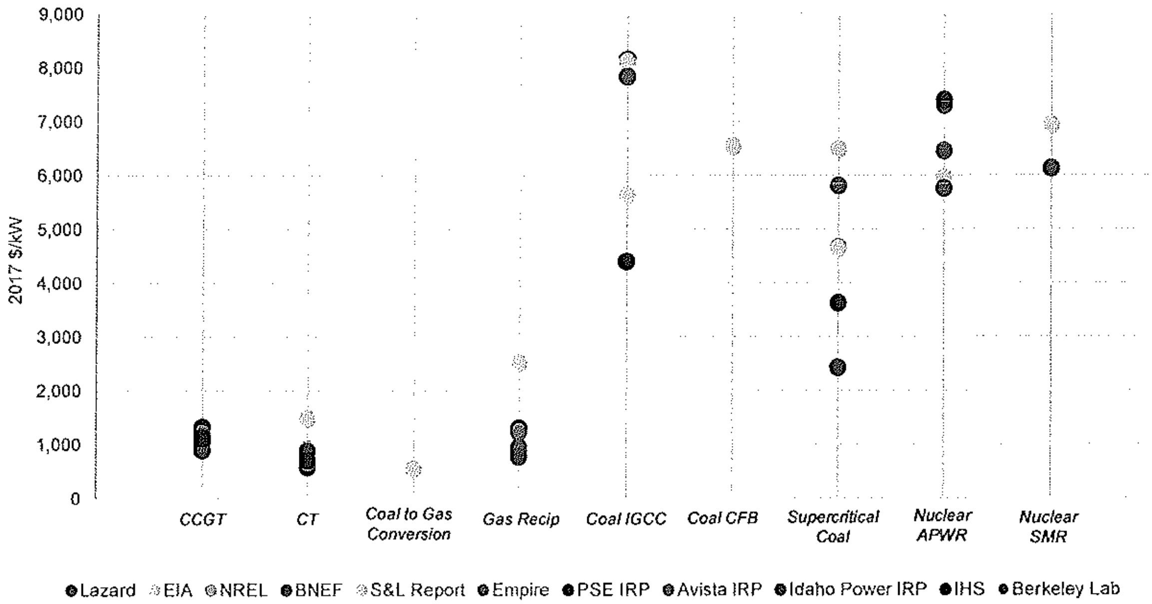
- Coal technologies – integrated gasification combined cycle, circulating fluidized bed, and supercritical pulverized coal
- Natural gas technologies – CTs, CCGTs, reciprocating engines, and coal-to-gas conversion
- Nuclear technologies – small module reactors and advanced pressurized water reactions
- Renewable technologies – onshore wind, offshore wind, distributed wind, utility-scale photovoltaic ("PV") solar, and distributed PV solar
- Other technologies – combined heat and power, battery storage, microturbines, and biomass

Figure 4-5: Data Sources for Third-Party Resource Review

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

NIPSCO then aggregated the cost estimates from all sources by technology type to evaluate current costs on a $/kilowatt ("kW") basis. As part of this assessment, average, median, minimum, and maximum costs were recorded. A summary of the results of the survey is presented in Figure 4-6 and Figure 4-7.

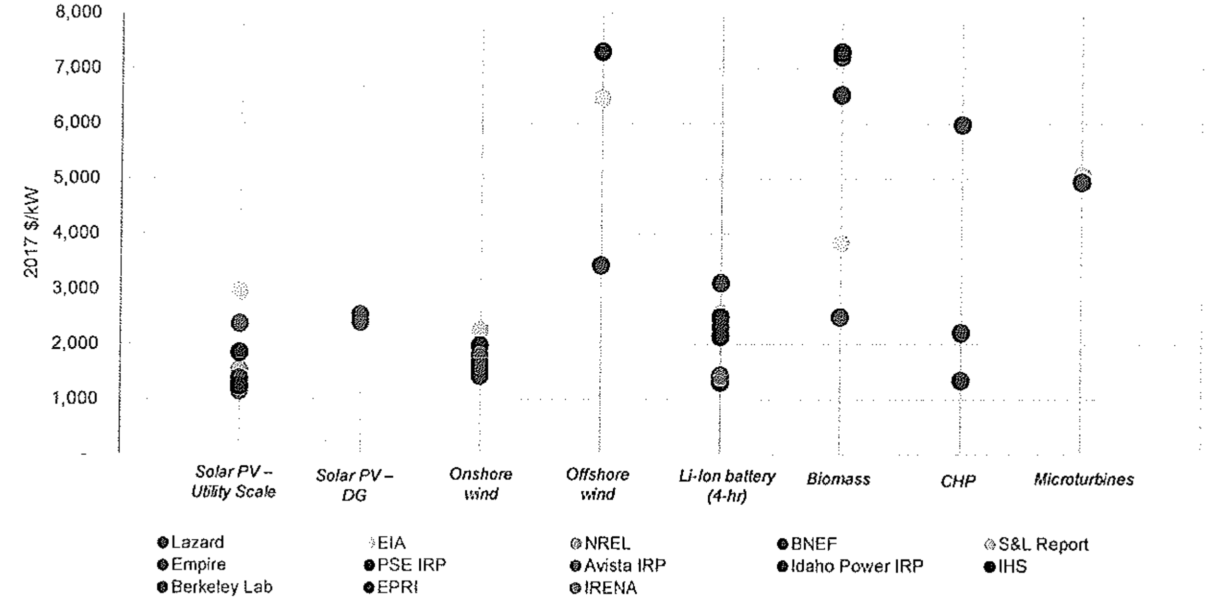
Figure 4-6: Current Capital Cost Summary for Coal, Gas, and Nuclear Technologies (2017$/kW)



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

Gas Recip – Gas Reciprocating Engine
IGCC – Integrated Gasification Combined Cycle
CFB – Circulating Fluidized Bed
APWR – Advanced Pressurized Water Reactor
SMR – Small Modular Reactor

Figure 4-7: Current Capital Cost Summary for Renewable, Storage, and Other Technologies (2017$/kW)[3]



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

Given relatively large uncertainty ranges for certain technologies and given even larger uncertainty regarding future cost trends, NIPSCO determined that it was necessary to conduct an RFP process to collapse the uncertainty and identify transactable projects that could be available for future capacity needs, especially by 2023. In the 2016 IRP, NIPSCO identified several screening criteria to confirm project viability, including technical feasibility, commercial availability, economic attractiveness, and environmental compatibility. In the 2018 IRP, each of these criteria could be tested with actionable data from the RFP process as opposed to solely relying on engineering advice.

4.9.2 All Source Request for Proposals

NIPSCO worked with CRA's Auctions and Competitive Bidding practice to conduct an All-Source RFP during the spring and early summer of 2018. During NIPSCO's first Public Advisory meeting, an overview of the All-Source RFP design was provided to stakeholders and comments were solicited and accepted through April 2018. After incorporating stakeholder feedback, NIPSCO and CRA formally launched the All-Source RFP on May 14, 2018 and closed the window for proposals on June 29, 2018.

[3] Note that renewable cost data from the S&L summary was excluded in the summaries due to vintage concerns. Old solar PV – Utility Scale data was also excluded from the Berkeley Lab source.

The All-Source RFP provided several guidelines to bidders, which are summarized below:

- Technology: The All-Source RFP requested all solutions regardless of technology, including demand-side options and storage

- Size: The All-Source RFP defined a minimum total need of 600 MW for the portfolio, but placed no size restrictions on the potential bidders. The All-Source RFP explicitly allowed for resources below 600 MW to offer their solution as a piece of a potential total need. The All-Source RFP also encouraged larger resources offer their solution for consideration.

- Ownership Arrangements: The All-Source RFP was open to asset purchases (new or existing) and PPAs. However, it required that resources qualify as MISO internal generation (not pseudo-tied) or load in the form of DR.

- Duration: The All-Source RFP requested delivery beginning June 1, 2023, but indicated that it would evaluate deliveries as early as June 1, 2020. The minimum contractual term and/or estimated useful life was requested to be five years, except for DR, which was allowed to offer for a one-year term.

- Deliverability: The All-Source RFP required that bidders have firm transmission delivery to MISO Local Resource Zone 6 ("LRZ6").

- Participants & Pre-Qualification: The All-Source RFP required counterparties be credit-worthy to ensure an ability to fulfill future resource obligations.

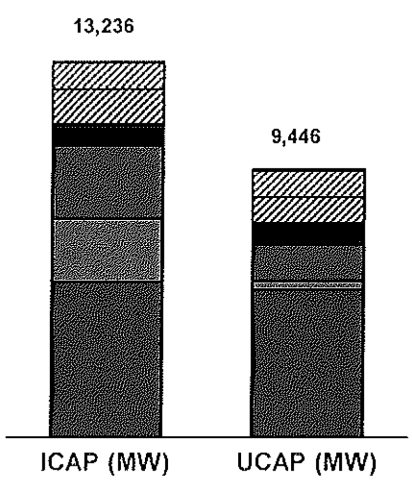
Overall, the All-Source RFP generated a large amount of bidder interest, with 90 total proposals received across a range of deal structures. NIPSCO received bids for 59 individual projects across five states with over 13 GW of installed capacity ("ICAP") represented. Many of the proposals offered variations on pricing structure and term length, and the majority of the projects were in various stages of development. A summary of the total number of proposals received by technology type is shown in Figure 4-8.

Figure 4-8: Summary of Number of Proposals Received by Technology Type

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

On a total MW basis, the 13 GW of ICAP offered represented just under 10 GW of UCAP, providing a sufficiently large set of candidate options for NIPSCO to evaluate for any capacity need during the All-Source RFP delivery window. Over half of the offered UCAP was in the form of natural gas-fired projects, primarily CCGTs. However, a significant amount of renewable, coal-based, and storage resources were also offered. Figure 4-9 shows a summary of total MW offered in response to the All-Source RFP by type.

Figure 4-9: Summary of Total MW of Proposals Received by Type

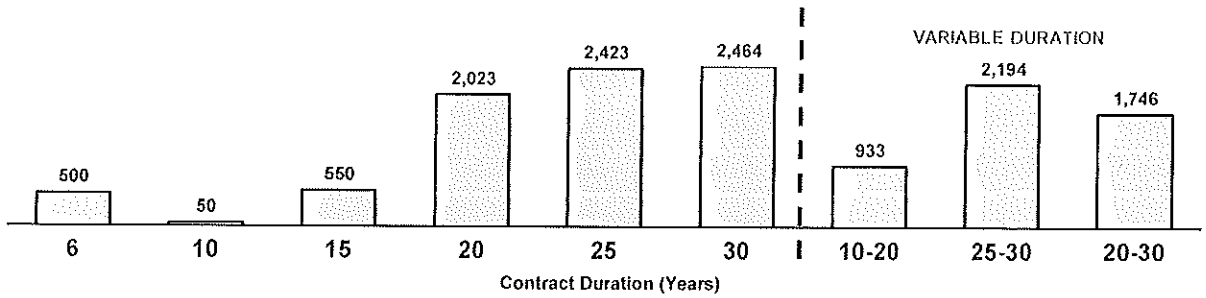


	ICAP (MW)	UCAP (est. MW)
Demand Response	70	70
Storage	925	925
Solar + Storage	1,220	902
Wind + Solar + Storage	0	0
Coal	772	772
Solar	2,580	1,291
Wind	2,209	287
Natural Gas (CT)	0	0
Natural Gas (CCGT)	5,470	5,199
	13,236	9,446

[1]Note that totals are on a project basis, which eliminates double counting of multiple proposals for the same facility.

Most PPA offers were relatively long in duration, with the majority of proposals offering contracts for 20 year terms or longer. Several bidders offered shorter-term options, including a number that provided NIPSCO with options to select from multiple duration possibilities. Figure 4-10 provides a summary of the total UCAP MW offered by duration.

Figure 4-10: Summary of Proposals Received by Duration (UCAP MW)



Most importantly, the All-Source RFP responses provided transactable cost and price information to be incorporated in the IRP analysis. Overall, much of the cost information was relatively consistent with the third-party data review, but renewable offers were at the low end of the estimates observed in the public literature. This indicated that technology change and developer activity in a competitive process are dynamic forces that influence the costs of resource options for NIPSCO in the future. A summary of the various proposals by type and by price is provided in Figure 4-11. Note that due to confidentiality considerations, individual project prices cannot be disclosed.

Figure 4-11: Summary of Proposals by Price

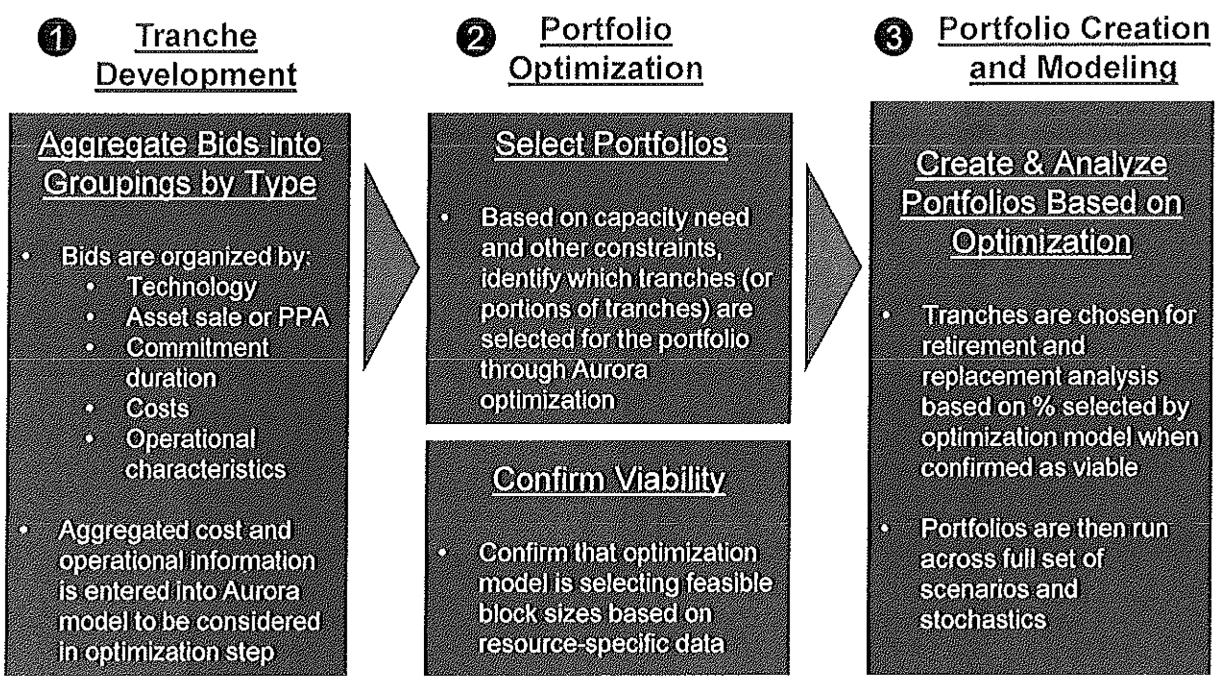
	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage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

4.10 Incorporation of the All-Source RFP Results into the IRP

After gathering the All-Source RFP bidder data, the next step in the process was to organize the information and incorporate the results into the IRP analysis. NIPSCO and CRA developed a three-step process for All-Source RFP-IRP integration, which is outlined in Figure 4-12:

1. Organize the various bids into groupings or tranches according to technology, whether the bid offered a PPA or an asset acquisition, the bid's commitment duration, and the bid's costs and operational characteristics.
2. Perform portfolio optimization analysis based on NIPSCO's potential capacity need and other portfolio design constraints, confirming option viability based on feasible block sizes of All-Source RFP tranche data.
3. Develop comprehensive portfolios with selected tranches from the portfolio optimization step and analyze them across the full set of scenarios and stochastics.

Figure 4-12: Summary of Proposals by Price



4.10.1 Tranche Development

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

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

- The IRP is a highly transparent and public process that requires sharing of major inputs with stakeholders and the public. There would be confidentiality concerns with showing and analyzing asset-level options, which would contain specific cost bids and detailed technology data.

- The IRP modeling is complex, and resource grouping improves the efficiency of the process. Resource evaluation requires organizing large amounts of operational and cost data into IRP models, so a smaller data set would improve the efficiency of setup and run time.

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

For example, the All-Source RFP received multiple CCGT bids, with some being based on the same project. In developing the tranches, the team first separated the PPAs from the asset sales and then sub-divided PPA bids into short and long duration options for evaluation. The sale bids were all long duration, but had meaningfully different costs, so they were organized into two separate tranches for evaluation. This illustrative example is shown in Figure 4-13.

Figure 4-13: CCGT Tranche Development Example

PPA

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)*	Online Year	PPA Term (years)
PPA Bid 1	CCGT	250	250	2023	6
PPA Bid 2	CCGT	625	575	2023	30
PPA Bid 3	CCGT	625	625	2023	30
PPA Bid 4	CCGT	725	700	2023	20
PPA Bid 5	CCGT	600	600	2023	30

Tranche Name	# Of Resources	ICAP (MW)	UCAP (MW)	Online Year	PPA Term (years)	Cost range** ($/kW-mo)
PPA CCGT #1	1	250	250	2023	6	
PPA CCGT #2	4	2,575	2,500	2023	27	

Sale

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)*	Online Year
Sale Bid 1	CCGT	625	625	2023
Sale Bid 2	CCGT	625	625	2023
Sale Bid 3	CCGT	1,025	925	2023
Sale Bid 4	CCGT	725	700	2023

Tranche Name	# Of Resources	ICAP (MW)	UCAP (MW)	Online Year	Price Range** ($/kW)
Sale CCGT #1	2	1,250	1,250	2023	
Sale CCGT #2	2	1,750	1,750	2023	

*Capacity is rounded to the nearest 25 MW.
**Given the small number of projects within each CCGT tranche, PPA costs and asset sale prices are not being shown to preserve confidentiality. Note that PPAs were structured as tolling arrangements with fixed cost capacity payments (in $/kW-mo) plus certain variable charges (in $/MWh).

As another example, the All-Source RFP received 26 solar PPA bids. These bids generally all had similar contract structures, duration commitments, and capacity factors. Therefore, PPA price was the major factor that drove development of the tranches. In this instance, five solar PPA tranches were developed, organizing individual bids into groupings with similar pricing. Figure 4-14 provides an illustrative example of how these bids could be grouped together for evaluation.

Figure 4-14: Solar PPA Tranche Development Example

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)	Online Year	PPA Term (years)	Price*	Capacity Factor
Bid 1	Solar	-	-	••• 2023	20	$27.xx	-
Bid 9	Solar	275	138	2023	20	$32.00	24%
Bid 10	Solar	100	50	2023	20	$34.00	24%
Bid 11	Solar	75	38	2023	20	$34.00	23%
Bid 12	Solar	25	13	••• 2023	20	$35.00	24%
Bid 13	Solar	500	250	2023	25	$35.00	25%
Bid 26	Solar	-	-	2023	20	$73.xx	-

Tranche Name	Tranche Type	# of Resources	ICAP (MW)	UCAP (MW)	Online Year	PPA Term (weighted average years)	Price (weighted average)	Capacity Factor (weighted average)
Indiana Solar #3	Solar	5	975	488	2023	23	$33.93	24.2%

Ultimately, the tranche development process resulted in the production of 17 PPA tranches and 11 asset sale tranches. These are summarized by resource type, size, term, and costs in Figure 4-15 and Figure 4-16 for PPAs and asset sales, respectively.

Figure 4-15: Summary of PPA Tranches Used in Modeling

Tranche	Resource Type	Nameplate Capacity (MW)	UCAP (MW)	Storage Capacity (MW)	PPA Start	PPA Term (yrs)	Pricing ($/MWh)	Pricing ($/kW-mo)	Pricing ($/MW-d)
1	CCGT	250	250	-	2023	6		8.71	
2	CCGT	2,570	2,487	-	2023	27		8.58	
3	CT	685	678	-	2023	30		5.17	
4	Demand Response	70	70	-	2023	1			115.00
5	Solar	500	250	-	2023	20	28.45		
6	Solar	975	488	-	2023	23	33.93		
7	Solar	1,352	676	-	2023	26	37.62		
8	Solar	308	154	-	2022	21	62.87		
9	Solar + Storage	175	92	5	2023	20	24.80		
10	Solar + Storage	295	200	52	2023	20	28.24		
11	Solar + Storage	1,525	1,158	395	2023	22	34.54	2.27	
12	Solar + Storage	25	23	10	2024	20	61.41		
13	Storage	510	510	510	2023	16	12.58	4.31	
14	Storage	400	400	400	2023	20			323.14
15	Wind	945	128	-	2021	19	25.54		
16	Wind	479	72	-	2022	22	38.11		
17	Wind + Solar + Storage	300	95	30	2021	20	28.68		

Figure 4-16: Summary of Asset Sale Tranches Used in Modeling

Tranche	Resource Type	Nameplate	UCAP	Transfer Date	Pricing ($/kW)
1	CCGT	1,255	1,242	2023	962
2	CCGT	1,750	1,633	2023	1,084
3	CT	685	678	2023	615
4	Solar	265	133	2023	951
5	Solar	639	320	2023	1,125
6	Solar	400	200	2023	1,287
7	Solar + Storage	265	183	2023	1,067
8	Solar + Storage	440	330	2023	1,253
9	Storage	100	100	2023	932
10	Wind	1,099	165	2020	1,486
11	Wind + Solar + Storage	300	95	2021	1,406

4.10.2 Renewable Resource Tax Incentives and Tax Equity Partnership

Federal tax incentives are currently in place for renewable and paired renewable/storage resources. Resources are eligible for a production tax credit ("PTC") or an investment tax credit

("ITC"). The PTC provides a credit of $24/megawatt hour ("MWh")[4] for all generation produced by the facility, and the ITC provides a credit as a portion of the total cost of the facility. It is generally advantageous for wind resources to take the PTC, due to their high capacity factors, and solar resources to take the ITC.

The tax incentives are currently in the midst of a phase-out, as summarized in Figure 4-17. In order to qualify for the credits, projects need to begin construction by a certain date and be put into service by a certain date. The start of construction deadline can be met as long as certain equipment purchases and development costs have been "safe harbored" by federal tax authorities. The safe harbor for beginning of construction is investment of at least 5% of the total project cost on or before the specified date.

Figure 4-17: PTC (Wind) and ITC (Solar) Phase-Out Schedule

Wind

Year During Which Equipment is Safe Harbored	Last Year Project Can Be Placed in Service to Qualify for Continuity Safe Harbor	Credit Percentage
2016	2020	100
2017	2021	80
2018	2022	60
2019	2023	40
2020	n/a	

Solar

Year During Which Equipment is Safe Harbored	Last Year Project Can Be Placed in Service to Maximize ITC	ITC Rate
2016	2020	30
2017	2021	30
2018	2022	30
2019	2023	30
2020	2023	26
2021	2023	22
2022	n/a	n/a

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

- For PPAs, no adjustments were needed, since tax incentives flow to the developer and are theoretically reflected in PPA pricing; and

[4] This value is indexed to inflation.

- For asset ownership, tax benefits flow to the utility and ultimately to the customer in rates, so adjustments needed to be made.

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

In order to properly account for the rate base reduction impact of partnering with a tax equity investor, CRA worked with NIPSCO's tax team to develop relevant financial models to estimate the breakdown of capital expenditures. For solar and solar-storage paired projects, the tax equity contribution is estimated to be around 35% of total capital costs, meaning NIPSCO would cover the remaining 65%. For wind assets, the range of tax equity contributions would be between 33 and 60%, depending on the asset's online date and expected capacity factor. Wind assets are assumed to utilize the PTC, while solar assets are assumed to take advantage of the ITC. The expected range of tax equity partner contributions for renewable resources is summarized in Figure 4-18.

Figure 4-18: Capital Cost Adjustments due to Tax Equity Partnership

Resource Type	Tax Equity Capital Cost Contribution
Solar	35%
Wind	33-60%
Solar + Storage	35%
Wind + Solar + Storage	35%

4.10.3 Self-build

As part of the process of evaluating its resource alternatives, NIPSCO investigated the feasibility of building a CCGT facility to meet its resource needs. The study considered an 800MW combine cycle F class 2x1 configuration and a 635MW advance class 1x1 consideration to be located on land at Schahfer.

For the study, NIPSCO developed conceptual site plans, conducted geotechnical studies, established the design criteria, developed single line studies and cost estimates for the two technologies. The study also considered the electric, natural gas and water interconnection requirements.

From the feasibility study results, NIPSCO determined that a self-build option was a more expensive alternative as compared to the All-Source RFP bid results for similar technology. Consequently, NIPSCO believes that a self-build CCGT is not the best resource alternative to meet customers need at this time.

4.10.4 CCGT Breakeven Analysis

NIPSCO's replacement analysis, as discussed in Section 9.2, found that replacement portfolios with renewable resources from the all source RFP are more cost effective than portfolios without. Furthermore, portfolios with CCGT are higher cost and carry increased risk due to exposure to natural gas prices and dispatch cost volatility. Selection of resource portfolios with new-build CCGT would require criteria other than economics and cost risk to justify.

NIPSCO explored the conditions that could support the inclusion of an additional CCGT into its supply portfolio. A CCGT could be part of a transmission/reliability solution to support renewables but analysis using new-build CCGT costs concludes that other reliability solutions are more cost effective. NIPSCO performed an analysis to identify the purchase price at which CCGT would be economically competitive with renewable resources. NIPSCO's analysis shows that, to be economically competitive with its preferred resource portfolio, CCGT costs would need to be approximately $284/kW or lower in the Base Scenario. This breakeven price does not appear to be likely for new-builds, but may be a possibility for re-sale of existing CCGT. A breakeven price was not achievable in the Aggressive Environmental Regulation Scenario, was $589/kW or lower in the Challenged Economy Scenario, $637/kW or lower in the Booming Economy / Abundant Natural Gas Scenario. Additional details are in Confidential Appendix D.

4.10.5 Coal to Gas Conversion

NIPSCO evaluated the potential to convert one or two units at Schahfer from coal-fired units to natural gas-fired units. As part of this analysis, NIPSCO developed operational assumptions for the potentially converted units as well as cost estimates associated with the conversion. In evaluating the operational parameters for a converted unit, NIPSCO relied on the Sargent & Lundy ("S&L") study conducted as part of the 2016 IRP process. The study concluded that a conversion would result in a 15% capacity de-rate for either Schahfer 17 or 18 when fired by gas instead of coal, as well as a slight efficiency penalty for the plant's heat rate. The key operational parameters for the conversion option are shown on a per-unit basis in Figure 4-19.

Figure 4-19: Coal-to-Gas Conversion Operational Parameters

	Category	NIPSCO Assumption
Operating Parameters	Conversion Capacity(MW) per unit	309.2
	Heat Rate (Btu/kWh)	11,106
	Forced Outage Rate	10%

Separately, NIPSCO developed capital and ongoing maintenance cost assumptions associated with a potential conversion. These costs were developed from the S&L study from 2016, as well as NIPSCO's internal experts in generation, plant operations, and major projects. The key assumptions included:

- The capital cost for conversion, which includes materials, construction labor, contingency, and owners and indirect costs were estimated by S&L .

- Gas interconnection costs were reviewed by S&L and NIPSCO's operational teams. Based on the data from the S&L study and a preliminary review with NIPSCO Gas Systems Engineering, it would be possible to convert Unit 17 or Unit 18 to natural gas without installing an additional pipeline as long as both Units 14 and 15 are retired. Leaving Units 14 and 15 in operation would likely create operational limitations related to when the units would be available to start up. Conversion of Units 17 and 18 to run simultaneously would require an additional pipeline. The size of the additional line could be smaller than the 30" used in the engineering study, but further detailed engineering analysis would be required to determine the appropriate size. Therefore, to be conservative and to evaluate whether conversion would be economic in the event that gas interconnection costs were minimal, NIPSCO assumed zero cost in its analysis.

- Environmental compliance costs were assumed to be zero.

- Maintenance capital needs were assumed to be 25% lower than current coal operations. This assumption was based on a review of NIPSCO's last three years of capital expenditures for Schahfer Units 17/18 that showed 25% of maintenance capital expenditures were for coal-specific components.

- Fixed O&M costs were estimated by S&L in the engineering study.

A summary of the assumptions for each of these cost categories is shown in Figure 4-20.

Figure 4-20: Coal-to-Gas Conversion Capital and Maintenance Cost Estimates

	Category	Estimated Cost
Conversion Investment Costs	Conversion (2015$)	$43M for 17 $87M for 17/18
	Gas Interconnection	$0M
	Environmental Compliance	$0M
Maintenance Capital	Maintenance Capital (Total 2024-2038) Nominal $	$122M for U17 $298M for 17/18
Ongoing Costs	Fixed O&M Costs (2015$/KW-yr)	$39

Ultimately, the analysis showed that converting one unit would cost at least $230 million more than retirement and replacement with economically optimized selections from the All-Source RFP results and replacing both units would cost customers at least $540 million more. Based on this, it is not economically feasible to complete the conversion of either unit. This is discussed more in depth in Section 9.1.7.

Section 5. Demand-Side Resources

5.1 Existing Resources

5.1.1 Existing Energy Efficiency Resources

NIPSCO actively promotes energy conservation and efficiency to customers and works with its third party vendors to offer cost-effective energy efficiency programs. To support the continuance of its program offerings for the period 2019 through 2021, NIPSCO worked with its Oversight Board ("OSB") to develop two DSM RFPs – 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 Lockheed Martin as the vendor to continue implementing both its residential and C&I programs. The OSB also issued a DSMRFP for an evaluation, measurement and verification ("EM&V") vendor and selected ILLUME Advising, LLC to provide an evaluation of both the residential and C&I vendors for all three program years. On November 22, 2017, NIPSCO filed its request with the IURC for approval of the following energy efficiency programs to become effective for the period January 1, 2019 through December 31, 2021 (the "2019-2021 Plan"):[5]

2019-2021 Residential Programs

Residential Heating, Ventilation and Air Conditioning ("HVAC") Energy Efficient Rebates Program

The HVAC Energy Efficient Rebates Program is designed to provide incentives to residential customers to replace inefficient HVAC equipment with energy-efficient alternatives. These measures will be paid per-unit installed, reimbursing customers for a portion of their cost. The program's intent is to help remove the financial barrier associated with the initial cost of these energy-efficient alternatives. The program will promote premium efficiency air conditioners, heat pumps that have high-efficiency, electronically commutated motors, and smart Wi-Fi thermostats.

Residential Lighting Program

The Residential Lighting Program is designed to increase the purchase and use of energy-efficient lighting products among NIPSCO's residential electric customers. The program will provide instant discounts on lighting products that meet the energy efficiency standards set by the United States Department of Energy's ENERGY STAR® Program. ENERGY STAR specifications are an important external factor to certify the quality and efficiency of program measures. As the ENERGY STAR specifications change, the program offerings will be adjusted accordingly. These adjustments ensure that the program offers incentives for lighting products that meet the latest standards and highest quality of efficiency.

[5] The 2019-2021 Plan reflected herein reflects the parties' agreements set forth in the Stipulation and Settlement Agreement reached among NIPSCO, the Indiana Office of Utility Consumer Counselor, and Citizens Action Coalition of Indiana, Inc. (the "Settling Parties"), was approved in Cause No. 45011 on September 12, 2018.

Residential Home Energy Assessment Program

The Home Energy Assessment Program is designed to help eligible customers improve the efficiency and comfort of their homes, as well as deliver an immediate reduction in electricity (kWh) consumption and promote additional efficiency work. This program will provide homeowners with the direct installation of low-cost, energy-efficient measures followed by the delivery of a Comprehensive Home Assessment report.

Residential Appliance Recycling Program

The Appliance Recycling Program is designed to provide an incentive to residential customers who choose to recycle a qualifying primary or secondary working refrigerator and/or freezer. Lockheed Martin will utilize a qualified subcontractor for the implementation of this program.

School Education Program

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

Residential Multifamily Direct Install ("MFDI") Program

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

Residential Home Energy Report Program

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

Residential New Construction Program

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

Residential HomeLife Energy Efficiency EE Calculator Program

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

Employee Education Program

The Employee Education Program is designed to offer valuable information to employees of NIPSCO's C&I customers by providing residential energy efficiency training seminars at the place of employment. At these seminars, educational materials will be provided to inform residential customers of energy savings opportunities and methods to proactively manage their energy consumption. These materials will also direct NIPSCO's customers to navigate to a web portal to request a free energy efficiency kit by entering their account information to confirm eligibility.

Residential Income Qualified Weatherization ("IQW") Program

The IQW Program is designed to provide energy efficiency services to qualifying low-income households. In order for a household to be eligible to participate in the IQW Program, the customer will need to be a NIPSCO residential customer with active service and must not have received weatherization services in the past 10 years from the date of application. If the household meets this initial criteria, they will automatically qualify for services regardless of income if the household receives Low-Income Home Energy Assistance (LIHEAP), Temporary Assistance for Needy Families (TANF), Supplemental Security Income (SSI) or Supplemental Security Disability Income (SSDI). Qualifying participants will receive the direct installation of no-cost energy efficiency measures and a Comprehensive Home Assessment to identify areas of the home where additional energy savings can be achieved to make the home more comfortable and reduce energy costs.

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

Table 5-1: 2019-2021 Projected Residential Energy Savings (MWh)

Residential Programs	2019	2020	2021	Total
HVAC	2,396	2,393	2,389	7,178
Lighting	26,172	26,172	26,172	78,516
Home Energy Assessment	2,145	2,143	2,140	6,428
Appliance Recycling	1,647	1,645	1,643	4,935
School Education	2,580	2,577	2,574	7,731
MFDI	1,127	1,126	1,125	3,378
Home Energy Report	9,786	9,774	9,763	29,323
New Construction	854	854	854	2,562
HomeLife Energy Efficiency Calculator	2,064	2,062	2,059	6,185
Employee Education	1,006	1,005	1,004	3,015
IQW	1,197	1,196	1,195	3,588
Total Residential Programs	**50,974**	**50,947**	**50,918**	**152,839**

Table 5-2 shows the annual total program budget for each of the Residential programs. Program budget includes implementation costs, NIPSCO administration costs, NIPSCO marketing costs, and EM&V costs.[6]

[6] In the Settlement, the Settling Parties agree that NIPSCO (with Oversight Board ("OSB") approval) should be authorized to increase any individual program funding by up to 10% of the total program budget, even if this exceeds the overall 2019-2021 DSM Plan budget approved by the Commission.

Table 5-2: 2019-2021 Residential Program Budget

Residential Programs	2019	2020	2021	Total
HVAC	$531,302	$530,558	$529,843	$1,591,703
Lighting	$4,919,279	$4,919,279	$4,919,279	$14,757,837
Home Energy Assessment	$852,009	$851,003	$850,040	$2,553,052
Appliance Recycling	$431,926	$431,417	$430,928	$1,294,271
School Education	$638,243	$637,491	$636,741	$1,912,475
MFDI	$374,314	$377,243	$376,817	$1,128,374
Home Energy Report	$566,969	$566,298	$565,630	$1,698,897
New Construction	$312,095	$312,095	$312,095	$936,285
HomeLife Energy Efficiency Calculator	$487,374	$486,798	$486,225	$1,460,397
Employee Education	$279,497	$279,167	$278,838	$837,502
IQW	$424,502	$424,003	$423,520	$1,272,025
Total Residential Programs	**$9,817,510**	**$9,815,352**	**$9,809,956**	**$29,442,818**

2019-2021 C&I Programs

C&I Prescriptive Program

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

C&I Custom Program

The Custom Program will be available to C&I customers for installing new energy-saving equipment. Custom incentives are designed for more complicated projects, or those that incorporate alternative technologies. Project pre-approval will be required for all Custom incentives to ensure that only cost-effective projects are approved. Qualifying measures will be required to have a Total Resource Cost ("TRC") test score greater than 1.0, have a simple payback greater than 12 months and not be included as an energy efficiency measure in the Prescriptive Program.

C&I New Construction Program

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

Small Business Direct Install ("SBDI") Program

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

Retro-Commissioning ("RCx") Program

The RCx Program is designed to help NIPSCO C&I customers determine the energy performance of their facilities and identify energy-saving opportunities by optimizing their existing systems. Projects in the program will examine energy consuming systems for cost-effective savings opportunities. The RCx process will identify operational inefficiencies that can be removed or reduced to yield energy savings. Qualifying measures will be required to have a TRC test score greater than 1.0, have a simple payback of less than 12 months and not be included as an energy efficiency measure in the Prescriptive Program.

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

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

C&I Programs	2019	2020	2021	Total
Prescriptive	20,880	23,200	25,520	69,600
Custom	30,240	33,600	36,960	100,800
New Construction	9,360	10,400	11,440	31,200
SBDI	7,920	8,800	9,680	26,400
RCx	3,600	4,000	4,400	12,000
Total C&I Programs	**72,000**	**80,000**	**88,000**	**240,000**

Table 5-4 shows the total annual program budget for each of the C&I programs. Program budget includes implementation costs, NIPSCO administration costs, NIPSCO marketing costs, and EM&V costs.[7]

Table 5-4: 2019-2021 C&I Program Budget

C&I Programs	2019	2020	2021	Total
Prescriptive	$2,454,485	$2,727,206	$2,999,926	$8,181,617
Custom	$3,814,322	$4,238,137	$4,661,950	$12,714,409
New Construction	$1,155,142	$1,283,490	$1,411,838	$3,850,470
SBDI	$1,138,860	$1,265,400	$1,391,940	$3,796,200
RCx	$484,380	$538,200	$592,020	$1,614,600
Total C&I Programs	**$9,047,189**	**$10,052,433**	**$11,057,674**	**$30,157,296**

Table 5-5 shows the projected energy savings (MWh) by year for all Residential and C&I programs included in the 2019-2021 Plan.

Table 5-5: 2019-2021 Projected Combined Energy Savings (MWh)

	2019	2020	2021	Total
Total Residential Programs	50,974	50,947	50,918	152,839
Total C&I Programs	72,000	80,000	88,000	240,000
Total 2019-2021 Plan	**122,974**	**130,947**	**138,918**	**392,839**

Table 5-6 shows the annual total program budget for all Residential and C&I programs included in the 2019-2021 Plan.

Table 5-6: 2019-2021 Combined Program Budget

	2019	2020	2021	Total
Total Residential Programs	$9,817,510	$9,815,352	$9,809,956	$29,442,818
Total C&I Programs	$9,047,189	$10,052,433	$11,057,674	$30,157,296
Total 2019-2021 Plan Budget	**$18,864,699**	**$19,867,785**	**$20,867,630**	**$59,600,114**

Table 5-7 shows the eligible customer classes and rate schedules for each of the Residential and C&I programs included in the 2019-2021 Plan.

7 In the Settlement, the Settling Parties agree that NIPSCO (with Oversight Board ("OSB") approval) should be authorized to increase any individual program funding by up to 10% of the total program budget, even if this exceeds the overall 2019-2021 DSM Plan budget approved by the Commission.

Table 5-7: Customers

Program	Customer Class	Electric Rate Schedule
Residential HVAC Rebates	Residential	711
Residential Lighting	Residential	711
Residential Home Energy Assessment	Residential	711
Residential Appliance Recycling	Residential	711
School Education	Residential	711
Residential MFDI	Residential	711
Residential Home Energy Report	Residential	711
Residential New Construction	Residential	711
Residential HomeLife Energy Efficiency Calculator	Residential	711
Employee Education	Residential	711
IQW	Residential	711
C&I Prescriptive	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744
C&I Custom	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744
C&I New Construction	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744
SBDI	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
RCx	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 in Cause No. 44688, issued July 18, 2016 ("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 participating industrial customers provide a benefit to all customers, and are accordingly compensated through demand credits that are funded by all other customers. The interruptible credits are provided for two reasons, reliability and economic, each of which provides short- and long-term value to all customers.

The Interruptible Contract Demand is the demand that the customer intends to make available for interruptions and/or curtailments from one or more of customers' premises taking service under Rates 732, 733 or 734. Customers electing service under Rider 775 specify a Firm Contract Demand for each affected premise or facility that the Customer intends 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 ("LMR") requirements pursuant to MISO Tariff Module E, or any successor. NIPSCO will register all subscribed 527.776 MW of Rider 775 capacity with MISO. The LMR 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 LMR becomes 586.984 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 LMR. As such, NIPSCO has registered 31.000 MW of LMRs under Rate 734. The Capacity Resource realized from the registration is 34.477 MW that NIPSCO can utilize to meet its MISO resource adequacy requirements.

On October 31, 2018, NIPSCO filed an electric rate case that revises its industrial service structure by replacing Rider 775 and Rates 732, 733, and 734 with Rates 830 and 831. The new industrial service structure requires NIPSCO's largest industrial customers on Rate 831 to designate their firm service with the remainder of their service requirements being registered as a MISO LMR which is by definition curtailable. NIPSCO expects an increase in registered LMRs as a result of this new industrial service structure unless those Rate 831 customers utilize other options within the rate to acquire capacity from the MISO annual Planning Resource Auction or through a bilateral agreement between NIPSCO and a third party entered on their behalf. In addition, the large industrial customers will continue to be eligible to participate in MISO's Demand Response Resource program discussed below.

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 that has a sustainable ability to reduce energy requirements through indirect participation in the MISO wholesale energy market by managing electric usage as dispatched by MISO. Through these Riders, the Customer or Aggregator of Retail Customer (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 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. No Customers are participating in Rider 782 as EDR.

5.2 DSM Electric Savings Update

5.2.1 DSM Electric Savings Update – Purpose and Key Objectives

To update the electric DSM resource potential for the 2018 IRP, NIPSCO contracted with GDS to conduct a DSM Savings Update Report (the "DSM Savings Update") (a copy of which is included in Appendix B, Demand Side Management Savings Update and the 2016 Market Potential Study ("MPS"), and Action Plan.[8] GDS participated in Public Advisory Meeting 2 and provided details of its engagement with the DSM Savings Update. *See* Appendix A, Exhibit 2 (Presentation), Slides 24 through 43.

The DSM Savings Update provides an update of DSM program costs and savings for a 30-year time horizon (2019-2048). The report captures the insights from NIPSCO's prior MPS that was completed in August 2016 as well as NIPSCO's current and planned program offerings for the period 2019 to 2021 described in NIPSCO's testimony filed in Cause No. 45011. The objectives of NIPSCO's DSM Savings Update included:

- Develop a detailed plan identifying recommended cost-effective DSM savings measures and programs, as well as any possible market barriers for each recommended program. Identify best practices and programs and explain how the recommended practices and programs will achieve the desired results in NIPSCO's service territory.
- Place emphasis on innovative energy efficiency and DR programs and technologies.
- Provide detailed budgets for each program and related expenditures.
- Provide a lifetime cost analysis.

[8] A new MPS and Action Plan will be completed in 2019.

- Provide a cost-effectiveness[9] comparison or ranking for all technologies (measures) reviewed.

- Complete cost-effectiveness evaluations for each proposed program.

5.2.2 Impact of Opt-out Customers

GDS reviewed the latest information available from NIPSCO related to energy efficiency program participation, measure and program savings data, results of NIPSCO's 2016 MPS, NIPSCO's electric load and customer forecasts, NIPSCO load research data, electric avoided costs, program evaluation reports and NIPSCO's 2019-2021 Plan. NIPSCO requested that GDS prepare its base case DSM Plan update assuming that C&I electric customers that had opted out of NIPSCO's energy efficiency programs prior to January 1, 2017 would be excluded from the DSM Plan Update. These "opt-out" C&I customers represent over 60 percent of NIPSCO's 2017 non-residential kWh sales. It is important to note that the base case energy efficiency forecast for the DSM Savings Update does not include any energy efficiency savings for these opt-out C&I customers.

5.2.3 Modeling Framework

GDS used its Excel-based energy efficiency and DR planning models to prepare the DSM Savings Update. These models allow the user to develop forecasts of measure and program costs, participants, kWh and kW savings, savings of other fuels, and benefit/cost ratios for planning periods ranging from one to thirty years. These GDS models are transparent and all formulas, model inputs and model outputs can be viewed by the model user. The GDS energy efficiency and DR planning models come with a user guide that explains where to input program data, measure data and assumptions relating to the general rate of inflation, the discount rate for financial analysis, avoided costs, line losses, planning reserve margin and other key input assumptions.

5.3 Energy Efficiency and Demand Response Bundles

For purposes of modeling energy efficiency programs in NIPSCO's 2018 IRP, GDS grouped DSM Plan energy efficiency measures into bundles according to each measure's cost of saved energy over its measure life. For energy efficiency measures, the following three bundle categories were created:

Bundle 1	Measures with a utility incentive cost ranging from $.00 to $.01 per lifetime kWh saved
Bundle 2	Measures with a utility incentive cost ranging from $.011 to $.05 per lifetime kWh saved

[9] GDS calculated the TRC Test, the Utility Cost Test ("UCT"), the Participant Test and the Ratepayer Impact Measure Test ("RIM") for each measure. GDS used the UCT test to determine measure, program and portfolio cost effectiveness. All of the results may be found in Appendices E and F.

Bundle 3	Measures with a utility incentive cost over $.05 per lifetime kWh saved

For purposes of modeling DR programs in NIPSCO's 2018 IRP, GDS grouped DR programs into three bundles by calculating the levelized cost per cumulative kW over the 30-year lifetime of the program. For DR programs, the following three bundles were created:

Bundle 1	$40/kW-year to $60/kW-year: includes C&I Direct Load Control ("DLC") of Air Conditioning ("AC") and DLC of Electric Water Heating Equipment
Bundle 2	$60/kW to $80/kW-year: includes Residential DLC of Water Heating Equipment and the C&I Third-Party Aggregator program
Bundle 3	Over $100/kW-year: includes Residential DLC of AC and Interruptible Rider

Both Residential and C&I DLC of space heating programs were found to be not cost-effective and, therefore, were not included in any DR bundles.

5.4 Energy Efficiency Potential Impacts

5.4.1 Changes That Impacted Energy Efficiency Potential

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

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

In March 2018, NIPSCO sent GDS the latest electric load forecast for 2018 through 2039. CRA then extended the NIPSCO load forecast through the year 2048. GDS used this new load forecast to calculate the percent of electric MWH sales and peak demand saved each year by DSM programs. NIPSCO's new load forecast projects that total MWH sales to ultimate customers will only increase 0.3% a year on average through the year 2048. NIPSCO also provided GDS with updated planning assumptions for the general inflation rate, escalation rates for NIPSCO electric rates, the utility discount rate, line losses by class of service and the planning reserve margin. GDS used these assumptions to develop the DSM Savings Update.

5.4.1.2 NIPSCO DSM Plan Assumptions for Measure Costs, Savings, Useful Lives

GDS reviewed the assumptions for measure costs, savings and useful lives included in the 2019 to 2021 NIPSCO DSM plan and updated these assumptions where appropriate. GDS revised costs and/or savings assumptions for some energy efficiency measures if more recent data was available from NIPSCO evaluation reports or recently published technical resource/reference manuals from Michigan and Illinois.

The largest change for a measure assumption was to the baseline energy efficiency level for residential light bulbs. The NIPSCO 2019 to 2021 DSM plan assumed that the baseline technology for a residential light bulb was a 60-Watt incandescent bulb.

GDS collected information from industry experts and program implementation contractors, showing uncertainty about when the new Energy Independence and Security Act ("EISA") backstop provisions for lighting efficiency will take effect. The EISA lighting backstop provisions specify 45 lumens per Watt efficacy starting January 1, 2020. Efficiency Vermont, however, decided for planning purposes that LEDs would be the baseline standard in 2020. Efficiency Vermont assumed a one-year phase-in period for this efficacy standard. Other experts recommend allowing a sell-through period to the year 2022, or 2023 at the latest. Another recommendation GDS received was to shorten the useful life of LEDs. GDS previously used a useful life of 15 years for LEDs.

The new efficacy standard for lighting is scheduled by law to go into effect on January 1, 2020. Energy industry news articles have indicated a potential for the delay or cancelation of these new lighting efficacy standards. As of August 2018, there is uncertainty about whether these efficacy standards will go into effect on January 1, 2020. The EISA standard will not allow bulbs to be sold that do not meet the new efficacy requirements. Therefore, the new EISA standard will decrease the achievable potential for lighting savings because the baseline efficiency for most light bulbs will be significantly increased. Based on this, for planning purposes, NIPSCO assumed that the baseline technology after 2021 for general service bulbs would be a compact fluorescent light (CFL) or equivalent bulb that meets the EISA backstop provision efficacy level of 45 lumens per Watt.

5.4.1.3 Federal Appliance and Equipment Efficiency Standards

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

The standards program's predictable rulemaking schedule is driven by statutory deadlines the DOE must meet to comply with EPCA. These are amended by subsequent energy legislation and reflect the program's obligation to review all standards every six years and test procedures every seven years. The DOE encourages all stakeholders, including consumers, manufacturers, trade associations, utilities, energy efficiency advocates, and the general public, to participate in the rulemaking process. The standards program established the Appliance Standards and Rulemaking Federal Advisory Committee ("ASRAC") to facilitate deeper stakeholder engagement by allowing for negotiated rulemakings under the guidelines set forth in the Federal Advisory Committee Act (FACA). The process culminates in a final rule in which the DOE is required to set efficiency standards that maximize energy savings that are technologically feasible and economically justified.

The DOE considers the impact on consumers, manufacturers, and small C&I businesses when determining whether any new or amended standard is economically justified. The DSM Savings Update takes into account the impacts of federal appliance and equipment efficiency standards for those standards that are currently in place or expected to be implemented by the DOE after 2021, including the EISA backstop provisions for general service, reflector and specialty light bulbs discussed above.

5.5 Energy Efficiency Measures & Potential

5.5.1 Residential Energy Efficiency Measures

For the residential sector, there were 249 unique electric energy efficiency measures included in the energy efficiency potential analysis update. Table 5.8 provides a summary of the types of measures included for each end use in the residential sector. The measures included in this analysis are based on 2019-2021 Plan with several new measures added by GDS or suggested by NIPSCO's stakeholders. These new measures were included in the NIPSCO 2016 MPS that were not already included in the 2019-2021 Plan. GDS obtained the majority of data on residential energy efficiency measure costs, kWh and kW savings and costs from the 2019-2021 Plan. GDS reviewed this data and updated these measure assumptions for years after 2021 where necessary.

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

End Use	Measure Types Included
Electronic Equipment	ENERGY STAR Desktop and Laptop Computers, Monitors, Printer/Fax/Copier/Scanner, and Sound Bars ENERGY STAR Smart Power Strips ENERGY STAR Televisions
Appliances	ENERGY STAR Refrigerators ENERGY STAR Freezers ENERGY STAR Washing Machines ENERGY STAR Clothes Dryers ENERGY STAR Dehumidifier Refrigerator Pick-up and Recycling Freezer Pick-up and Recycling Refrigerator Replacement in Low Income Homes
Envelope	Building Insulation Improvements (Attic, Wall, Floor, Etc.) Air sealing (Weatherization) High Efficiency Windows Cool Roofing
HVAC Equipment	High Efficiency Heating Equipment (e.g., Heat Pump with electronically commutated motor) HVAC Filter Whistle Heating & Cooling Duct Sealing and Repair High Efficiency Natural Gas Furnace High Efficiency Natural Gas Boiler Wi-Fi Smart Thermostat
Lighting	Interior LED Bulbs and Fixtures Exterior LED Bulbs and Fixtures LED Nightlights
Pools	Pool Pump Controls High Efficiency Pool Pumps High Efficiency Pool Pump Heaters
Space Cooling	High Efficiency Central Air Conditioning System Air Source Heat Pump ENERGY STAR Room Air Conditioner
Water Heating	High Efficiency Water Heater Heat Pump Water Heater Faucet Aerators & Low Flow Showerheads Hot Water Pipe and Tank Insulation Solar Water Heating System
Other	Home Energy Reports and Other Types of Behavioral Programs Energy Efficiency Education Kits for Employees of NIPSCO's Customers High Efficiency Well Pump High Efficiency Hot Tub Dryer Vent Cleaning Refrigerator Coil Cleaning

5.5.2 Achievable Electric Energy Efficiency Potential

The achievable electric energy efficiency potential for the residential sector includes savings associated with measures that are:

- Included in the 2019-2021 Plan.
- Added to the plan by GDS (included in NIPSCO's 2016 MPS or that were suggested by NIPSCO's stakeholders).

Table 5-9 shows the cumulative annual achievable residential sector energy efficiency potential for the years 2019 to 2048 and estimates of the annual NIPSCO energy efficiency budgets for residential sector programs.

Table 5-9: Achievable Residential Sector Incremental Annual Energy Efficiency Potential and Annual Utility Budgets (Base Case)

Year	Incremental Annual Energy Savings (MWh)	Incremental Annual Demand Savings (MW)	Annual Utility Cost ($)
2019	50,974	10	$9,817,510
2020	50,947	17	$9,815,352
2021	50,918	24	$9,809,956
2022	46,240	42	$20,822,174
2023	46,887	61	$21,039,511
2024	47,503	79	$21,266,204
2025	48,178	98	$21,494,687
2026	48,716	117	$21,714,354
2027	49,287	137	$21,941,024
2028	49,744	156	$22,134,851
2029	50,231	175	$22,347,479
2030	50,686	195	$22,551,800
2031	51,166	215	$22,763,349
2032	51,645	234	$22,980,009
2033	52,173	254	$23,222,465
2034	52,411	268	$23,417,367
2035	52,659	281	$23,617,690
2036	53,050	294	$23,829,888
2037	53,050	298	$23,975,771
2038	53,050	301	$24,124,717
2039	53,050	304	$24,276,791
2040	53,050	307	$24,432,059
2041	53,050	310	$24,590,588

Year	Incremental Annual Energy Savings (MWh)	Incremental Annual Demand Savings (MW)	Annual Utility Cost ($)
2042	53,050	311	$24,752,445
2043	53,050	313	$24,917,702
2044	53,050	314	$25,086,429
2045	53,050	315	$25,258,699
2046	53,050	316	$25,434,587
2047	53,050	317	$25,614,169
2048	53,050	318	$25,797,522

5.5.3 Recommended Residential programs

GDS recommends that NIPSCO retain the residential energy efficiency programs that are included in its 2019-2021 Plan, but consider adding a new program such as whole-house retrofit program for qualifying low-income households if such a program can be designed to be administered in an efficient and effective manner. In addition, GDS recommends that NIPSCO add several new energy efficiency measures to its existing programs, including such measures as solar water heating, heat pump water heating, refrigerator coil cleaning brushes, dryer ductwork and vent cleaning, high efficiency clothes washers and other measures that GDS added that were cost effective.

Table 5-10 below provides the UCT benefit/cost ratios for the period 2019 to 2048 for residential programs[10]. All twelve residential energy efficiency programs included in the DSM Savings Update have a UCT ratio greater than or equal to 1.0. The overall UCT benefit/cost ratio for the residential portfolio of energy efficiency programs is 2.1. The NPV savings to NIPSCO's residential customers is $277.1 million for the thirty-year planning horizon.

[10] NIPSCO utilized the UCT as the test for screening measures for inclusion. This is different from prior years when the TRC was utilized.

Table 5-10: Utility Cost Test Benefit/Cost Ratios for Residential Programs (2019 to 2048 Period)

Residential Sector Program	NPV Benefits	NPV Utility Costs	Net Benefits	BC Ratio
HVAC Energy Efficient Rebates	$20,240,111	$7,423,449	$12,816,661	2.7
Residential Lighting	$38,182,714	$13,738,788	$24,443,926	2.8[11]
Home Energy Assessment	$7,720,421	$5,194,212	$2,526,210	1.5
Appliance Recycling	$7,481,400	$4,676,459	$2,804,941	1.6
School Education	$20,025,721	$7,765,296	$12,260,425	2.6
Multifamily Direct Install	$11,325,004	$4,749,094	$6,575,911	2.4
Home Energy Report	$15,204,076	$12,735,292	$2,468,784	1.2
Residential New Construction	$18,270,532	$5,017,439	$13,253,094	3.6
HomeLife Energy Efficiency Calculator	$18,414,941	$6,111,400	$12,303,541	3.0
Employee Education	$6,151,825	$2,864,091	$3,287,734	2.1
IQW	$7,149,749	$4,261,258	$2,888,490	1.7
New Measures	$332,828,064	$174,474,645	$158,353,418	1.9
Total	**$502,994,559**	**$249,011,424**	**$253,983,135**	**2.0**

5.5.4 C&I Energy Efficiency Measures

For the C&I sector, there were 340 unique electric energy efficiency measures included in the energy efficiency potential analysis. Table 5-11 provides a summary of the types of measures included for each end use in the C&I sector. The measures included in this analysis are based on the 2019-2021 Plan with some new measures added by GDS. These new measures are based on a review of measures included in the 2016 MPS and discussions with stakeholders. A total of 167 additional measures were considered. Although NIPSCO's current Custom Program may technically be able to accommodate many of these measures, most would typically be considered to be prescriptive measures.

[11] The NIPSCO 2017 Portfolio Evaluation Reports lists a UCT ratio of 3.4 for the NIPSCO Residential Lighting Program and 2.9 for the Home Energy Analysis Program for calendar year 2017. It is important to note that the 2017 Portfolio Evaluation Report used a nominal discount rate of 6.53%. The DSM Savings Plan Update used a nominal discount rate of 7.65% to be consistent with the IRP modeling.

Table 5-11: Types of Electric Energy Efficiency Measures included in the C&I Sector Analysis

End Use	Measure Types Included
Office Equipment	High Efficiency Servers, Computers and Office Equipment Plug Load Sensors and Smart Power Strips
Compressed Air	Air System Maintenance Variable Frequency Drive Compressed Air Engineered Nozzle Custom Compressed Air Measures Retro-Commissioning
Cooking	Efficient Cooking Equipment Custom Kitchen
Envelope	Building Insulation Improvements High Efficiency Windows Cool Roofing
HVAC Controls	Programmable and Smart Thermostats Custom Energy Management System Installation/Optimization Occupancy Control System Retro-Commissioning
Lighting	Fixture Retrofits Premium Efficiency T8 and T5 lightbulbs High Bay Lighting Equipment LED Bulbs and Fixtures Light Tube Lighting Occupancy Sensors Custom Interior and Exterior Lighting Retro-Commissioning
Pools	Pool Pump Controls High Efficiency Pool Pump Heaters
Refrigeration	Vending Machine Misers Strip Curtains and Auto Door Closers Efficient Refrigerators/Freezers/Ice Machines High Efficiency/Variable Speed Compressors Electronically Commutated Motors Cooler Motors Door Heater Controls Efficient Compressors and Controls Door Gaskets Floating Head Pressure Controls Display Case Lighting and Controls Custom Refrigeration Retro–Commissioning
Space Cooling	Efficient Cooling Equipment Evaporative Pre-Cooler Economizer Air Source Heat Pump Geothermal Heat Pump Chiller/HVAC Maintenance Chilled Water Reset

End Use	Measure Types Included
	Room AC Custom HVAC/Chillers Retro-Commissioning
Ventilation	Enthalpy Economizer Variable Speed Drive Duct Repair and Sealing Controlled Ventilation Optimization Demand Controlled Ventilation Custom Ventilation
Water Heating	Efficient Equipment High Efficiency Hot Water Appliances Faucet Aerator/Low Flow Nozzles Pipe and Tank Insulation Heat Recovery Systems Efficient Hot Water Pump and Controls Solar Water Heating System Pre-Rinse Spray Valves Desuperheater Custom Water Heating
Other	Efficient Point of Sale Terminal Efficient Transformers Custom Motors and Drives Custom Process Custom Pumps/Fans Retro-Commissioning Process Retro-Commissioning Motors and Drives
Agriculture	Engine Block Heater Timer Energy Efficient/Energy Free Livestock Waterer High Volume Low Speed Fans High Efficiency Exhaust Fans Dairy Refrigeration Tune-up

5.5.5 Achievable Electric Energy Efficiency Savings

The achievable electric energy efficiency savings for the C&I sector includes savings associated with measures that are:

- Included in the 2019-2021 Plan
- New energy efficiency measures added to the plan by GDS that pass the UCT.

Table 5-12 shows the cumulative annual achievable energy efficiency savings for the years 2019 – 2048 and estimates of the annual energy efficiency budgets.

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

Year	Cumulative Annual Energy Savings (MWh)	Cumulative Annual Demand Savings (MW)	Annual Cost ($)
2019	72,000	9.4	$9,047,188
2020	152,000	19.8	$10,052,432
2021	240,000	31.3	$11,057,675
2022	325,796	43.1	$11,839,493
2023	419,550	55.1	$12,140,734
2024	510,798	66.9	$12,444,981
2025	602,907	78.9	$12,775,475
2026	696,948	91.0	$13,163,727
2027	786,971	102.8	$13,478,238
2028	873,445	114.6	$13,798,511
2029	959,682	126.5	$14,119,573
2030	1,046,587	138.5	$14,432,594
2031	1,127,019	149.8	$14,849,184
2032	1,206,636	161.1	$15,187,942
2033	1,286,733	172.5	$15,544,398
2034	1,317,466	176.5	$15,824,693
2035	1,342,307	179.7	$16,074,726
2036	1,361,070	182.1	$16,307,510
2037	1,379,659	184.6	$16,544,828
2038	1,397,364	187.0	$16,786,479
2039	1,412,165	189.1	$16,943,342
2040	1,425,373	190.9	$17,103,500
2041	1,437,179	192.6	$17,267,020
2042	1,447,692	194.1	$17,433,974
2043	1,456,960	195.5	$17,604,435
2044	1,465,211	196.7	$17,778,475
2045	1,472,341	197.7	$17,956,170
2046	1,477,839	198.5	$18,137,597
2047	1,482,283	199.2	$18,322,833
2048	1,485,725	199.7	$18,511,960

Table 5-13 shows the cumulative annual energy efficiency savings as a percent of total C&I sector sales, excluding C&I customers that have opted out of NIPSCO's energy efficiency programs.

Table 5-13: Achievable C&I Sector Energy Efficiency Savings as a Percent of Sales (Base Case)

Year	Cumulative Energy Savings (MWh)	C&I Sector Sales Forecast (Excl. Opt-Out) (MWh)	Cumulative Savings Percent of Sales
2019	72,000	4,652,224	1.5%
2020	152,000	4,697,257	3.2%
2021	240,000	4,739,576	5.1%
2022	325,796	4,778,968	6.8%
2023	419,550	4,819,735	8.7%
2024	510,798	4,856,840	10.5%
2025	602,907	4,895,604	12.3%
2026	696,948	4,933,514	14.1%
2027	786,971	4,966,699	15.8%
2028	873,445	5,000,237	17.5%
2029	959,682	5,025,190	19.1%
2030	1,046,587	5,052,855	20.7%
2031	1,127,019	5,078,996	22.2%
2032	1,206,636	5,099,000	23.7%
2033	1,286,733	5,118,796	25.1%
2034	1,317,466	5,139,223	25.6%
2035	1,342,307	5,161,284	26.0%
2036	1,361,070	5,174,258	26.3%
2037	1,379,659	5,181,773	26.6%
2038	1,397,364	5,190,437	26.9%
2039	1,412,165	5,197,508	27.2%
2040	1,425,373	5,209,258	27.4%
2041	1,437,179	5,221,038	27.5%
2042	1,447,692	5,232,850	27.7%
2043	1,456,960	5,244,693	27.8%
2044	1,465,211	5,256,567	27.9%
2045	1,472,341	5,268,473	27.9%
2046	1,477,839	5,280,410	28.0%
2047	1,482,283	5,292,379	28.0%
2048	1,485,725	5,304,379	28.0%

Table 5-14 shows the NPV of benefits, costs, net benefits and the benefit-cost ratio for each program and for the portfolio as a whole.