STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE GAS TURBINE GENERATION FACILITY ("CCGT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("CULLEY 3 COMPLIANCE PROJECT"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CULLEY 3 COMPLIANCE PROJECTS THROUGH VECTREN SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM; (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE REVENUE REQUIREMENT FOR COSTS, INCLUDING CAPITAL, OPERATING, MAINTENANCE, DEPRECIATION, TAX AND FINANCING COSTS ON THE CULLEY 3 COMPLIANCE PROJECT WITH CARRYING COSTS AND (B) POST-IN-SERVICE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CCGT AND CULLEY 3 COMPLIANCE PROJECT UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) ONGOING REVIEW OF THE CCGT; (7) AUTHORITY TO IMPLEMENT A PERIODIC RATE ADJUSTMENT MECHANISM FOR RECOVERY OF COSTS DEFERRED IN ACCORDANCE WITH THE ORDER IN CAUSE NO. 44446; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CCGT AND CULLEY 3 COMPLIANCE PROJECT ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 ET SEQ, 8-1-8.5-1 ET SEQ., AND 8-1-8.8 -1 ET SEQ.	)	CAUSE NO. 45052

PETITIONER'S PARTIAL DESIGNATION OF EVIDENCE IN SUPPORT OF PRELIMINARY RESPONSE TO MOTION FOR PARTIAL SUMMARY JUDGMENT

Pursuant to Trial Rule 56(C), Petitioner, Southern Indiana Gas & Electric Company d/b/a Vectren South Delivery of Indiana, Inc. ("Vectren South") designates the following materials in opposition to the Motion for Partial Summary Judgment filed by the Office of Utility Consumer Counselor and many of the Intervenors:

1. 2018 Draft Statewide Analysis of Future Resource Requirements for Electricity.

2. Indiana Electricity Projections: The 2017 Forecast Prepared by State Utility Forecasting Group, as well as the earlier forecasts publicly available at the links set forth in footnote 2 of the accompanying Preliminary Response.

3. Final Director's Report for the 2016 Integrated Resource Plans – IRPs Submitted by Indianapolis Power & Light, Northern Indiana Public Service Company, Vectren, and an update by Hoosier Energy.

4. Electricity Director's Final Report – 2015-2016 Integrated Resource Plans Submitted by Duke Energy, Indiana Michigan, Indiana Municipal Power Agency, and Wabash Valley Power Association.

5. Draft Proposed Rule to amend 170 IAC 4-7 (10/4/2012).

6. October 9, 2014 Report to Governor.

7. Executive Order 13-03.

8. IURC Notice of Proposed Rulemaking #15-06 LSA # 18-127.

9. IURC Orders designated by footnote 4 in the accompanying Preliminary Response. Copies of the Orders discussed in the Preliminary Response are attached.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that Vectren South's Partial Designation of Evidence in Support of Preliminary Response to Motion for Partial Summary Judgment was served via electronic transmission to:

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this 27th day of July, 2018.

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DMS 12945834v1

DRAFT – 06-20-2018

2018 DRAFT

Statewide Analysis of Future Resource Requirements for Electricity

Indiana Utility Regulatory Commission Staff

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DRAFT – 06-20-2018

I. Executive Summary

i.e. all stuff they have already done

The 2018 Statewide Analysis of Future Resource Requirements for Electricity ("Statewide Analysis") was prepared by Indiana Utility Regulatory Commission ("IURC" or "Commission") staff for the Governor and Indiana General Assembly. The main portion of this analysis centers on the statutory requirements of Indiana Code § 8-1-8.5-3. To develop this analysis, Commission staff reviewed the information provided in Indiana electric utilities' Integrated Resource Plans from 2015 to 2017and the State Utility Forecasting Group's 2017 forecast, as well as other information sources. Information provided from the State Utility Forecasting Group ("SUFG") included results from its recent modeling update funded by the Commission.

Indiana's electric utilities are required to supply power at the lowest reasonable cost while providing safe and reliable service. An Integrated Resource Plan ("IRP") is a plan submitted by an electric utility to the Commission,[1] and it assists the utility in making sure it has the necessary resources to fulfill this obligation to serve. The plan looks forward over the next 20 years, forecasts the types and quantity of generation that the utility will need to reliably provide electricity to its customers, and evaluates resource alternatives on both a short-term and long-term basis to meet those future electricity requirements.

Indiana's electricity needs will increase between 0.1 percent and 1.12 percent each year over the next 20 years. Electricity demand has shown very low projected growth rates. In the last decade, growth in electricity demand has typically been less than two percent per year. More recently, growth rates of around one percent (or even negative for some utilities) have been common. While much of the low-growth rates and projected growth are attributed to increasing efficiency of electrical appliances (including LED lighting and improved appliance technologies) and industrial and commercial efficiencies for larger electricity users, low growth is also affected by economic swings and demographic changes.

Taking into account plant retirements, the generation and/or other resources required to meet Indiana's future needs are: 3,600 megawatts (MW) by 2025, 6,300 MW by 2030, and 9,300 MW by 2035. The utilities project adding combinations of natural gas, wind, solar, biomass, and hydro, as well as maintaining and improving customer energy efficiency and demand response programs. The utilities make their resource decisions based generally on the comparative costs of these resources. In addition, Indiana electric utilities have gained efficiencies through membership and participation in regional transmission organizations, which provide economic dispatch of generation resources at the wholesale market level and access to resources over a broad region, thereby lowering overall costs to Indiana ratepayers.

Indiana's resource mix is continuing to change. This change is being largely driven by market changes that resulted from lower and stable prices of natural gas. Costs driven by federal

[1] IRPs are discussed in more detail on page 3. IRPs are submitted by Indiana's eight largest electric utilities on a staggered three year cycle. IRPs comprehensively evaluate a broad range of feasible and economically viable resource alternatives over at least a 20 year planning period to assure electric power will be delivered to their customers at the lowest cost reasonably possible while providing safe and reliable service. Indiana utilities utilize state-of-the-art analysis and work with their stakeholders to develop credible Integrated Resource Plans (IRPs).

environmental regulations, and lower costs of renewable energy resources, energy efficiency, and demand response have also contributed to the change in resource mix. The paradigm change in the natural gas markets caused by hydraulic fracturing ("fracking")[2] has resulted in lower prices and reduced price volatility, and future projections show continued significant natural gas reserves. The cumulative effects of federal environmental regulations over decades have imposed significant costs on coal-fired generation. In the IRPs and in discussions with Indiana utilities, it is clear that the ongoing and future environmental costs pale in significance to the projections of low natural gas costs as a driver of future resource decisions. The result is the retirement of some older, smaller, less-efficient coal-fired power plants. Additionally, the lower costs of renewable resources, such as solar and wind, further change Indiana's generation portfolio. Finally, distributed energy resources and new technologies will continue to have an effect on the resource mix composition.

II. Background

A. Overview of Statutory Requirements

This analysis of future electric resource requirements is being provided to the Governor and the Indiana General Assembly pursuant to Indiana Code § 8-1-8.5-3. In 2014, the Commission provided its recommendations that concerned, in part, the need for generation resources in the near and long term and how energy efficiency and demand side management can help reduce that need. The Commission's recommendations focused on the importance of Integrated Resource Plans in which public electric utilities assess their energy needs and the generation and other resources to meet those needs, under a variety of circumstances, in both the short (3-5 years) and long term (20 years or more). In 2015, Senate Enrolled Act ("SEA") 412 was enacted, which codified the requirement that utilities submit IRPs, as well as energy efficiency plans, and amended Ind. Code § 8-1-8.5-3 to clarify the analysis to be performed by the Commission regarding future resource requirements for electricity.

Completed 2014

In 2015, the Commission opened a new round of stakeholder meetings to modernize and update its IRP rule, and the Commission provide additional funding to the State Utility Forecasting Group ("SUFG") for updated modeling software to provide more robust forecasting tools. From 2014 through the fall of 2017, the electric utilities have submitted IRPs in accordance with the additional requirements in the Commission's draft IRP proposed rules. In December 2017, SUFG issued its "Indiana Electricity Projections: The 2017 Forecast," using its new state-of-the-art modeling software. The Commission's updated IRP and energy efficiency rules are expected to be fully promulgated and in effect before the end of the 2018 calendar year.

On April 11, 2018, the Commission issued a General Administrative Order ("GAO"), GAO 2018-2, delegating the authority to perform this annual analysis to Commission staff. GAO

[2] Fracking is the fracturing of rock by a pressurized liquid. Hydraulic fracturing is a technique in which typically water is mixed with sand and chemicals, and the mixture is injected at high pressure into a wellbore to create small fractures to extract oil and natural gas. Oil and Natural Gas *Plays* have been discovered in almost every state.

2018-2 also set forth the approximate timelines and procedures for an open, transparent process to receive comments and hold a public hearing on a draft analysis, prior to the completion and submission of the final analysis each year.

Indiana Code § 8-1-8.5-3(a) states that this analysis must include an estimate of the following:

(1) The probable future growth of the use of electricity;
(2) The probable needed generating reserves;
(3) The optimal extent, size, mix, and general location of generating plants:
(4) The optimal arrangements for statewide or regional pooling of power and arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of Indiana; and
(5) The comparative costs of meeting future growth by other means of providing reliable, efficient, and economic electric service, including purchase of power, joint ownership of facilities, refurbishment of existing facilities, conservation (including energy efficiency), load management, distributed generation, and cogeneration.

In preparing this analysis, and through the Commission's regular involvement in regional and federal energy issues, Commission staff utilized information from Indiana utilities' IRPs, the Midcontinent Independent System Operator ("MISO"), the PJM Interconnection, LLC ("PJM"), the Federal Energy Regulatory Commission ("FERC"), and the U.S Energy Information Administration ("EIA").

B. Integrated Resource Plans

1. What is an Integrated Resource Plan?

Indiana's electric utilities are required to supply power at the lowest reasonable cost while providing safe and reliable service. The integrated resource planning process results in a range of resource portfolios and a preferred plan submitted by each electric utility on a staggered three year cycle to the Commission. The IRP assists the utility in its resource planning, making sure it has the necessary resources to fulfill future obligations. The IRP looks forward over at least the next 20 years to estimate the amount of resources the utility will need to reliably provide electricity to its customers, and evaluates resource alternatives on both a short-term and long-term basis to meet those future electricity requirements on a reliable and economic basis.

2. IRP History and Evolution

During the 1970s and the early 1980s, following the shocks from two oil embargoes and expectations for burgeoning demand for more electricity, Indiana's utilities, like utilities throughout the United States, built enormous amounts of generating capacity. Unfortunately, the utility's forecasts were overly optimistic, which resulted in construction of excessive generating capacity. The excess capacity, in turn, led to rapidly escalating electric rates for customers. Prudence investigations became common-place, which resulted in financial stress on electric utilities. Several electric utilities across the country went into default and, in extreme cases, bankruptcy. This era, and the ramifications of rapidly escalating costs, was transformational for the electric utility industry and for utility regulation – including the widespread adoption of IRP processes and added emphasis on energy efficiency and demand response (collectively referred to as "Demand-Side Management"). "Demand Response" is the reduction in electricity usage for limited periods of time, such as during peak electricity usage or emergency conditions

In 1983, the Indiana General Assembly responded by enacting Indiana Code chapter 8-1-8.5, "Utility Powerplant Construction," which established the need for planning, as well as requiring utilities to petition the Commission for approval of new electric generation facilities prior to their construction, lease or purchase. A "certificate of public convenience and necessity" ("CPCN") was now required and could only be issued by the Commission upon specific findings, including that the proposed additional capacity was necessary and was consistent with planning. In 1985, this chapter was amended to establish the State Utility Forecasting Group ("SUFG") to provide an independent forecast and analysis of future electricity requirements.

In 1995, the Commission promulgated the Integrated Resource Plan Rule ("IRP Rule"), located in the Indiana Administrative Code at 170 IAC 4-7, which established the requirement that certain electric utilities in Indiana submit an IRP to the Commission every two years. The IRP Rule also set out in great detail what should be included in a utility's IRP. The following utilities were (and are) required to submit IRPs:

- Duke Energy Indiana ("Duke")
- Hoosier Energy
- Indianapolis Power & Light Company ("IPL")
- Indiana Michigan Power Company ("I&M")
- Indiana Municipal Power Agency ("IMPA")
- Northern Indiana Power Service Company ("NIPSCO")
- Southern Indiana Gas & Electric Company ("SIGECO")
- Wabash Valley Power Association ("Wabash Valley")

Much has changed since 1995 in the electric industry in general and resource planning specifically. Integrated resource planning has become increasingly sophisticated over the years with new computer modeling and other technologies. In 2001, FERC approved MISO and PJM as regional transmission operators ("RTOs"). Together, those two RTOs cover the entire State of Indiana. The RTOs control the transmission of electricity at the bulk transmission or wholesale level, in contrast to the Indiana utilities who control the distribution or retail level of electricity delivery. Because of the existence of RTOs, some aspects of Indiana utilities' IRPs are no longer performed by the utilities. For instance, although the transmission grid is now operated by the RTO's, the 1995 IRP rule (still in effect) assumed the utilities maintained operational control of their own transmission system.

As a result of these changes at the regional and federal level, the Commission started an investigation in 2009 (IURC Cause No. 43643) to assess the need to reformulate the IRP Rule, taking the modern day grid context into account. In an order issued October 14, 2010, the Commission determined the need existed to update the 1995 IRP rule. Commission staff performed extensive research and facilitated an inclusive stakeholder process. That process resulted in a draft proposed IRP rule in 2012. The 2012 draft proposed rule was not officially promulgated due in part to the rulemaking moratorium, Indiana Executive Order 13-03. Nevertheless, starting with the IRPs that were due in 2013, utilities voluntarily agreed to follow the 2012 draft proposed rule requirements, including:

- A public advisory process to educate and seek input from customers and other interested stakeholders;
- Contemporary Issues Technical Conference, sponsored annually by Commission staff, to provide information on new technologies, computer models, and planning methods;
- Using information reported to and from the relevant RTOs;
- Upgrades to modeling risk and uncertainty; and
- A report on each utility's IRP by the director designated by the Commission (currently the Director of the Research, Policy, and Planning Division).

Following the passage of SEA 412 in 2015, Commission staff again facilitated an inclusive stakeholder process to further update the 2012 draft proposed rule. After numerous public meetings and rounds of comments in which the stakeholders participated, the Commission developed another draft proposed rule. The utilities began voluntarily complying with this updated proposed rule in their 2016 IRPs, including:

- Remodeling the procedural schedule for the submission of IRPs and energy efficiency plans so the filings are now made every three years;
- Removing obsolete requirements;
- Adding a checklist specifying all the required content in the integrated resource plans and energy efficiency plans;
- Updating the transparent stakeholder processes utilities must use to allow stakeholder and public input into the development of the plans; and
- Reframing the resource selection criteria to better reflect modern forecasting models and the modern electricity market.

The most-recent draft proposed IRP rule (IURC RM #15-06; LSA #18-127) was granted an exception to the rulemaking moratorium by the Office of Management and Budget on February 12, 2018. The Notice of Intent to Adopt a Rule was published in the Indiana Register on March 14, 2018, and on May 25, 2018, the State Budget Agency approved the fiscal impact of this rulemaking. The rulemaking is expected to be completed and the updated IRP Rule fully promulgated before the end of 2018. Information regarding this rulemaking can be found on the Commission's website at: https://www.in.gov/iurc/2842.htm.

3. IRP Contents (2015 – 2017)[3]

The fundamental building blocks of an IRP include researching customer electricity needs (i.e., "load research"), forecasting future electricity needs (i.e., "load forecasting") over a number of circumstances or scenarios, assessing existing generation resources, and systematically considering all forms of resources needed to satisfy short-term and long-term (at least 20 years) requirements under the various scenarios. Increasingly, IRPs include planning for generation, transmission, and the distribution system. IRPs assess various risks and their ramifications.

Long-term resource planning starts with a forecast of customers' electricity needs well into the future. Planning the lowest cost resources to provide reliable service over that time horizon is the objective of IRPs. Most states, including Indiana, that review utilities' IRPs require a 20-year load forecast and resource planning horizon. The length of the planning horizon is to better ensure that the planning analysis objectively considers all resources.

All Indiana utilities have embraced the need to retain maximum flexibility in their resource decisions to minimize the risks of uncertainty, so the IRPs should be regarded as illustrative and not a commitment for the utilities to undertake. Rather, the IRPs should always be updated based on new information to minimize risks in adjusting to an uncertain future. Essentially, IRPs are a snapshot in time based on the best available information.

Perhaps the greatest benefit of an IRP is that it provides utilities with an objective and comprehensive assessment of the potential risks and attendant costs associated with forecasting customer needs and the requisite resources to meet those needs. The risk and uncertainties facing Indiana utilities – like other utilities throughout the nation – may be more significant than at any other time in the industry's history with the possible exception of the Great Depression and the energy crisis of the 1970s-1980s. The most obvious risk confronting Indiana utilities (like other utilities across the nation) involves the economics of retiring existing facilities and the economic choice of alternative resources to replace retired generating resources. Since perfect prescience is not possible, utilities have a variety of risk factors to consider, such as:

- Short and long-term projections for the comparative costs of fuels;
- Short and long-term projections for market purchases;
- The range of potential costs for renewable resources;
- The potential for future technologies (e.g., increased efficiencies of renewable resource, energy efficiency, battery storage, distributed energy, continued improvements to combined cycle capabilities, microgrids, fuel cells, future nuclear, coal) to be transformational (such as electrification of transportation); and
- Whether load forecasts are unduly optimistic or pessimistic, among other factors.

IRPs encourage utilities to consider probable scenarios or futures, as well as risks that have a low probability but, if realized, would be highly consequential.

[3] It is important to note that the IRP process typically takes more than one year to complete. In addition to obtaining a full year of data (i.e., the 2017 IRPs rely primarily on 2016 data) the stakeholder process entails a significant time commitment. The Commission considers a robust stakeholder process essential to understanding and expediting cases by narrowing a number of contentious issues.

Integrated resource planning considers all resources. In addition to traditional resources such as coal, natural gas, and nuclear, an effective IRP also objectively considers energy efficiency, demand response, wind, solar, customer-owned combined heat and power, hydro-electric and battery storage, as well as the abilities of the transmission system. These many and varying resources are studied on a comparable basis to give greater assurance that the portfolios of resources considered and selected by the utilities are sufficiently robust and flexible to be altered as conditions warrant.

4. IRP Importance in Analysis

This analysis utilizes the most recent utility IRPs to determine the possible future load growth and generation needs for Indiana. The IRPs describe the process used to determine the best mix of generation and energy efficiency resources to meet their customers' needs for reliable, low-cost, environmentally acceptable power over the next 20 years. Taken together, the IRPs allow the Commission to see the general direction for future load growth needs and generation options. However, as a caution, because each year only about one-third of the utilities submit an IRP due to the new three year cycle, it is difficult to compare on utilities experiences in 2015 with another utility's resource consideration in 2017. Four years ago, for example, utilities were planning for the Clean Power Plan. Natural gas price projections due to fracking seemed to solidify more than expected by experts. Some utilities lost significant loads. Therefore, this analysis includes not only the utilities' IRPs, but also analysis by the SUFG, the RTOs, and a national perspective.

C. State Utility Forecasting Group

The SUFG's projection for Indiana's resource requirements provides a useful perspective as a snap shot in time based on information from Indiana's utilities and using state-of-the-art models. However, the SUFG's analysis is not intended to suggest that it is an *optimal* long-term resource plan, as changing circumstances warrant continued review. Retirements of existing resources and other factors may accelerate or decelerate resource decisions. The SUFG is resource agnostic. Moreover, the SUFG does not assign the capacity requirement to specific utilities; rather, it is a statewide perspective.

1. SUFG History

The SUFG was created in 1985 when the Indiana legislature mandated, as a part of the CPCN statute, that a group be formed to develop and keep current a state-of-the-art methodology for forecasting the probable future growth of electricity usage within Indiana. The Commission works with Purdue and Indiana Universities to accomplish this goal. The SUFG, currently housed on Purdue University's West Lafayette campus, produced its first set of projection in 1987 and has updated these projections periodically, usually biennially. The SUFG released its most recent forecast in December 2017.

2. SUFG Modeling Update

Under Ind. Code § 8-1-8.5-3.5(b), SUFG must keep its modeling system current. In the 2015-2017 contract with the Commission, SUFG acquired a new production costing and resource expansion program (AURORAxmp) and integrated the program in the modeling system. This was a major undertaking that resulted in increased efficiency in producing future forecasts and analyses. AURORAxmp has been populated with data specific to the Indiana utilities and the validation process is ongoing. New programs and modeling updates were part of the SUFG's December 2017 report.

In addition, updates to different components of the modeling system are done regularly on an as-needed basis. Expected areas of focus in 2017-2019 include a re-estimation of the industrial sector models for the investor-owned utilities by supplementing information from the utilities with updated information about various Indiana industries (steel, manufacturing, foundries etc.). This includes production output, and local, state, and national economic information that can provide additional insights into the energy usage patterns of industrial customers, and a conversion of historical data from the Standard Industrial Classification (SIC) system to the North American Industry Classification System (NAICS).

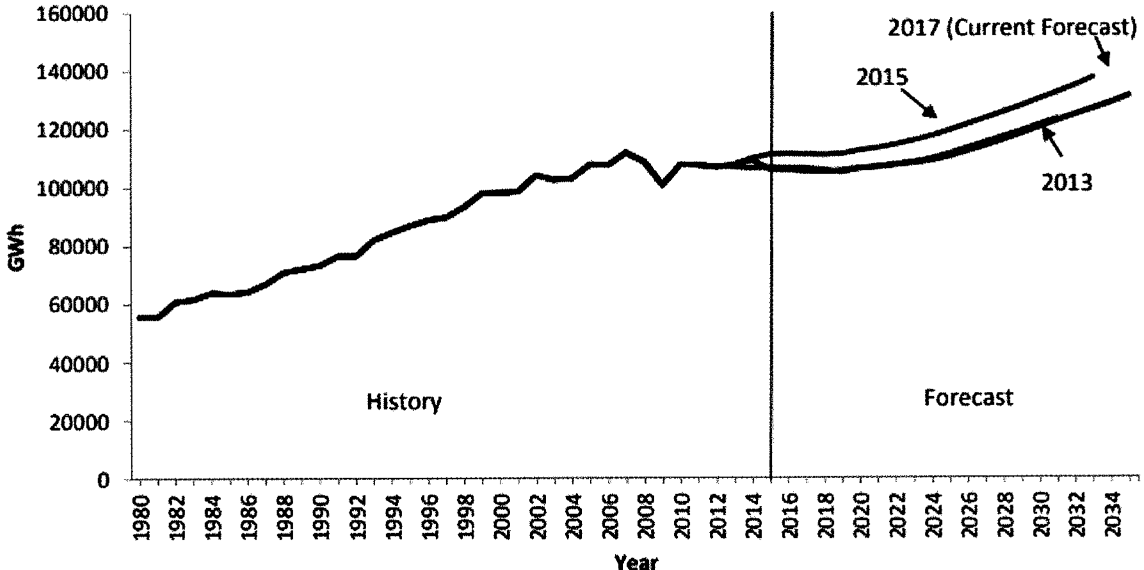
III. Statutorily Required Information

A. Probable Future Growth of the Use of Electricity

Since the 1980s, forecasts for electricity demand by Indiana utilities and utilities across the nation have shown very low projected growth rates. In the last decade, growth in electricity demand has typically been less than two percent per year. More recently, growth rates of around one percent (or even negative for some utilities) have been common. While much of the low-growth rates and projected growth are attributed to increasing efficiency of electrical appliances (including LED lighting and improved appliance technologies) and industrial and commercial efficiencies for larger electricity users, low growth is also affected by economic swings and demographic changes. While recent history is instructive, it is not necessarily indicative of the future sales of electricity. Because of the significant costs and risks associated with either over or under-forecasting electricity requirements, increasingly sophisticated mathematical models and databases are employed to improve the accuracy and credibility of load forecasting. Regardless of the analytical rigor, long-term forecasts of future electric needs cannot always predict unanticipated events (e.g., recessions, inflation, and technological change). As a result, the goal is to have a credible forecast with plausible explanations for the factors that determine electric use, and provide decision makers with a reasonable understanding of factors (e.g., scenarios or sensitivities) that, if changed, would alter the forecast and resource decisions.

Because uncertainties in load forecasting are a significant driving force for the long-term resource planning decisions of utilities, it is imperative that utilities continue to improve the rigor of their analysis, utilize state-of-the-art planning tools, and develop enhanced databases that include more information on their customers' current and future usage characteristics. The relatively rapid evolution of televisions, especially from cathode ray tubes to LEDs, provides an imperfect but reasonable corollary. Unexpected demographic trends, new industries (or closures of existing industries), other technological changes, recessions or more rapid economic growth are all factors that could significantly change the load forecast trajectories of Indiana utilities. It is for this reason that load forecasts and the entire IRP need to be redone on a three yearbasis to incorporate new information and developments.

Indiana Electricity Requirements in GWh (Historical, Current, and Previous Forecasts)



Source: State Utility Forecasting Group's 2017 Electricity Projections. Pg. 1-4

1. Indiana Utilities' Forecasts

Indiana utilities project relatively low load growth and adequate resources to satisfy reliability requirements.

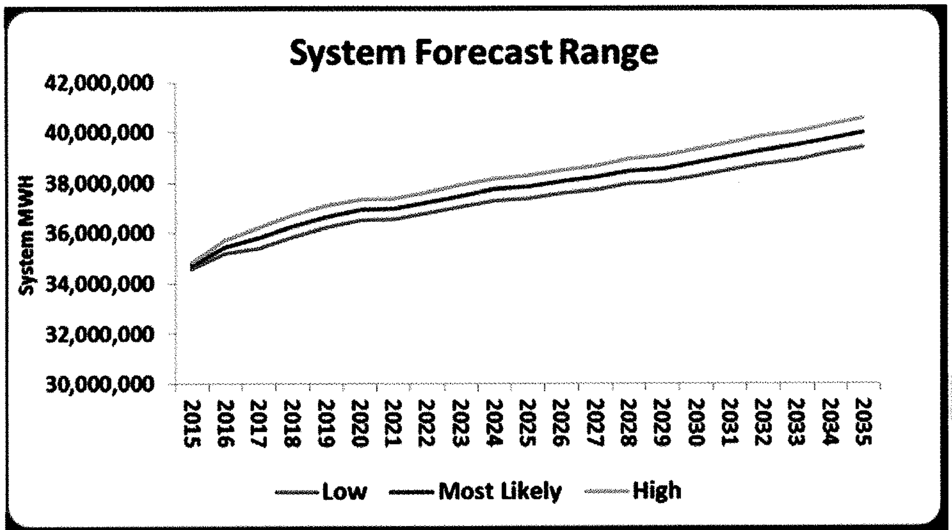
Projected Growth Rate of Energy and Peak Demand over the Planning Period*

Utility	Annual Energy	Peak Demand
Duke Energy (2016-2035)	0.7%	0.8%
Hoosier Energy (2018-2037)	0.7%	0.7%
Indiana Michigan Power Co. (2016-2035)	0.1%	0.2%
IMPA (2018-2037)	0.5%	0.5%
IPL (2016-2037)	0.5%	0.4%
NIPSCO (2017-2037)	0.3%	0.4%
SIGECO South (SIGECO) (2016-2036)	0.5%	0.5%
Wabash Valley (2018-2036)	0.8%	0.8%

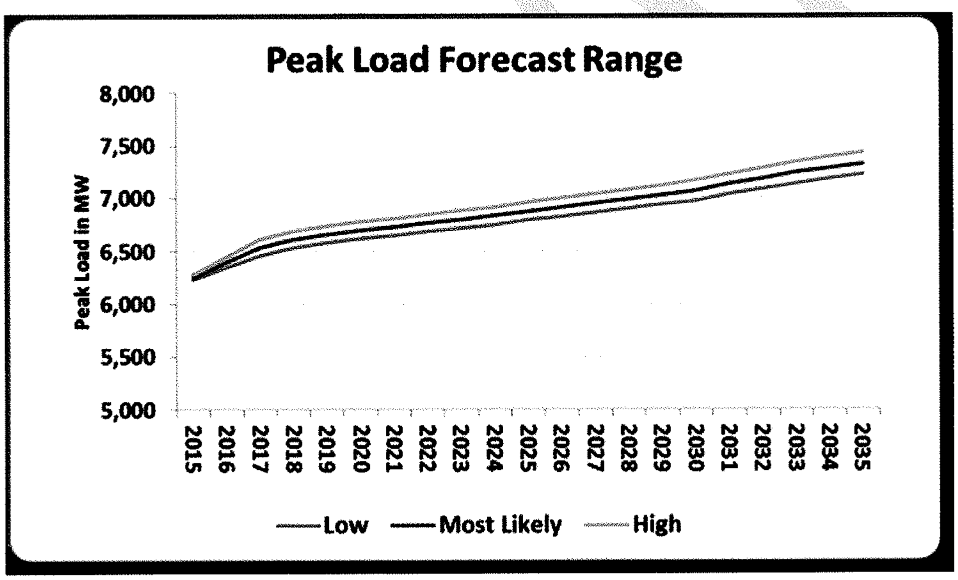
*The percentages are compound annual growth rates over the company-specific planning period.

a) Duke Energy Indiana – 2015 IRP

Duke Energy notes that 2015 energy usage has not returned to pre-2007 (pre-recession) levels. Summer peak demand is forecast to grow at just under one percent per year, which is a little faster than energy use.



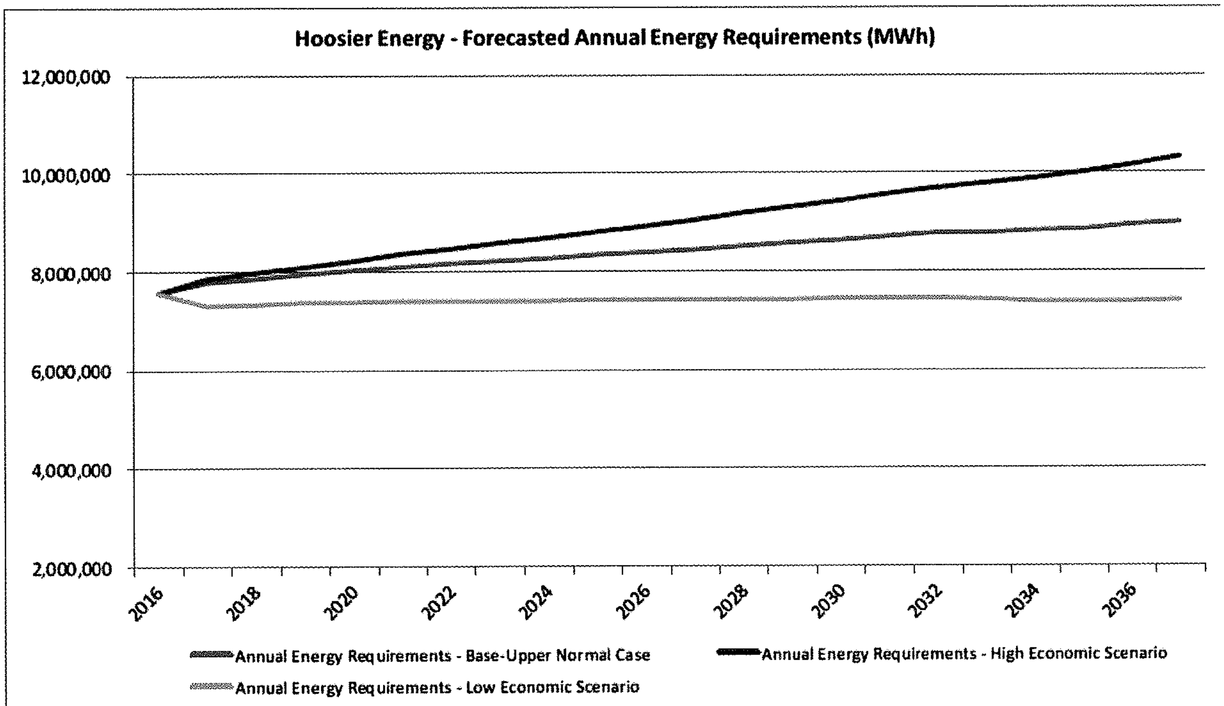
Source: Duke Energy Indiana 2015 IRP. Pg. 44



Source: Duke Energy Indiana 2015 IRP. Pg. 44

b) Hoosier Energy – 2017 IRP

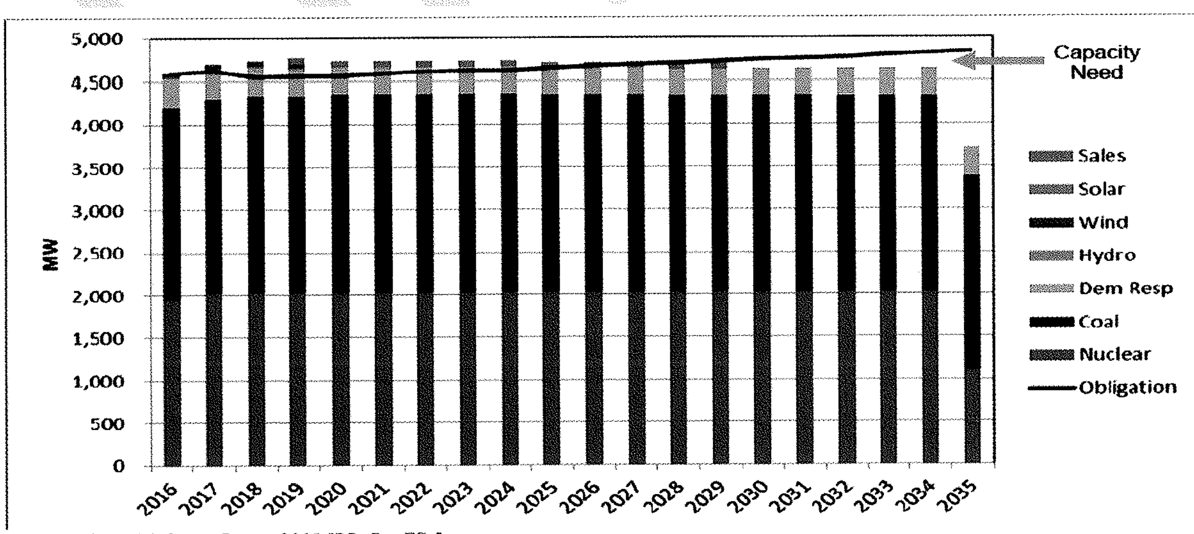
Hoosier Energy's 20-year projection shows both energy and annual peak growing at an annual average of 0.7 percent. Hoosier Energy noted that load growth has slowed due to a combination of energy efficiency gains, economic slowdown, and a decline in the energy intensity of gross domestic product.



Source: Hoosier Energy 2017 IRP. Pg. 35

c) Indiana Michigan Power – 2015 IRP

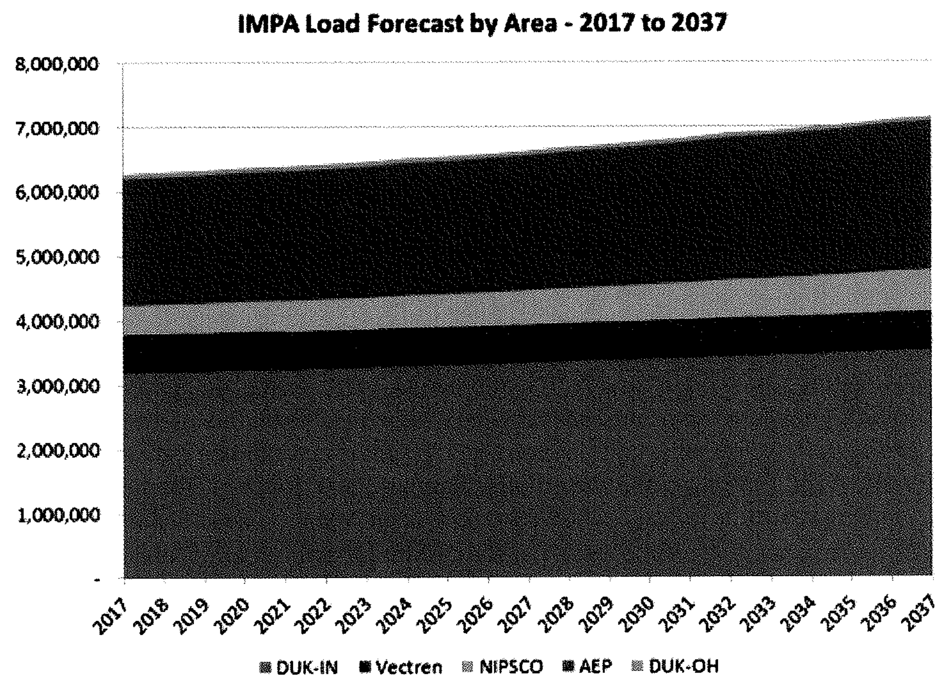
According to its 2015 IRP, I&M is forecasting energy and peak demand requirements to increase at a compound average growth rate of 0.2 percent through 2035. I&M does not anticipate the need for additional capacity until 2035. Energy efficiency and demand response are projected to reduce I&M's retail load by eight percent over the 2016-2035 planning horizon.



Source: Indiana Michigan Power 2015 IRP. Pg. ES-5

d) Indiana Municipal Power Agency – 2017 IRP

In 2017, IMPA's coincident peak demand for its 61 communities was 1,128 MW, and the annual member energy requirements during 2017 were 6,098,477 MWh. IMPA projects that its peak and energy will grow at approximately 0.5% per year. These projections do not include the addition of any new members or customers beyond those currently under contract. Since the last IRP was filed, IMPA has added one new member, the Town of Troy, Indiana. Additionally, in August of 2017, the Village of Blanchester, Ohio, which had been an IMPA customer since 2007, became an IMPA member. Combining all the IMPA's loads (those in MISO and PJM) is expected to see load growth average a 0.6 percent compound annual growth rate ("CAGR") over the next 20 years with those in the Duke, NIPSCO, and AEP areas expected to experience growth, while those in the SIGECO and Duke Ohio region are expected to contract somewhat.



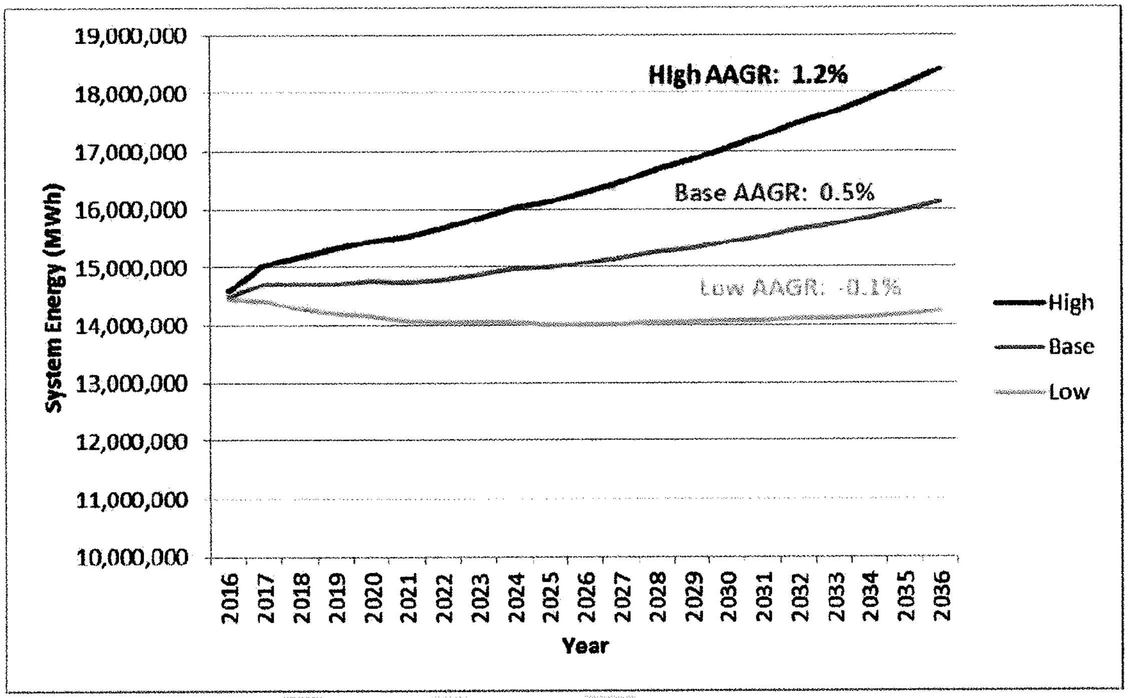
Source: Indiana Municipal Power Agency 2017 IRP, Pg. 5-40

e) Indianapolis Power & Light Company – 2016 IRP

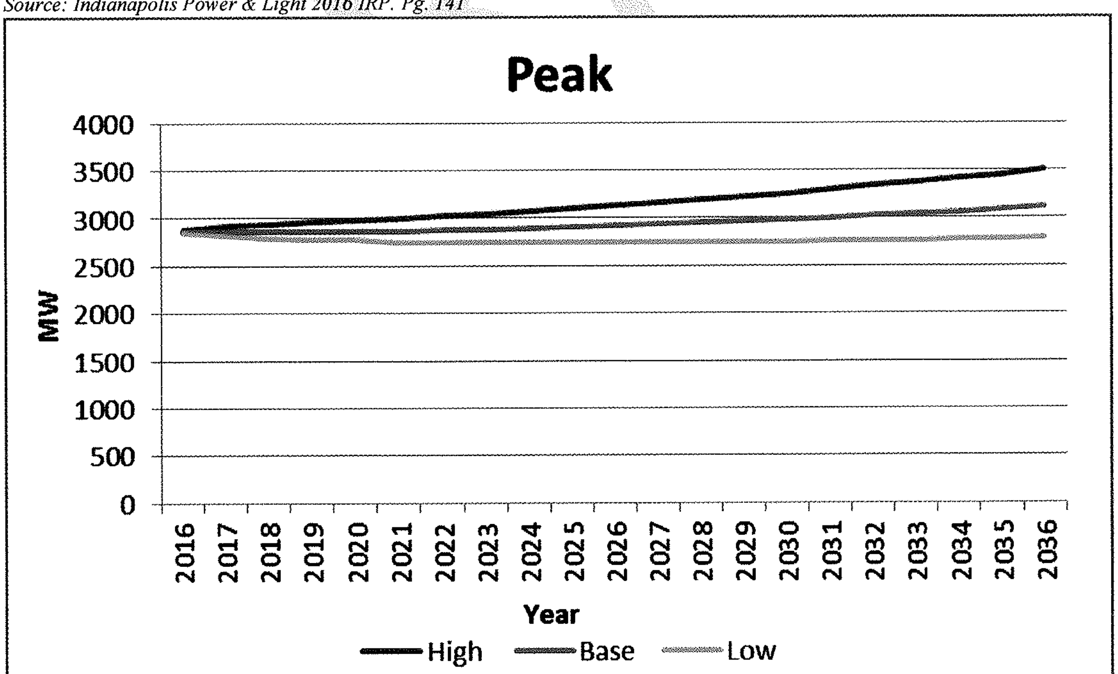
Since 2005, IPL's system energy requirements have been trending down. System energy requirements in 2015 were 14,471 GWh compared with 16,006 GWh in 2005. Energy use, on average, declined one percent annually over this period. IPL attributes the decline in customer usage to significant energy efficiency improvements in lighting, appliances, and end-use efficiency. In its IRP, IPL notes:

> [P]art of the decline can be [attributed] to the 2008 recession and the slow economic recovery. Between 2007 and 2011 customer growth actually declined 0.1% per year. Since 2011, customer growth bounced back with residential customer growth averaging

0.8% per year and non-residential customer growth averaging 0.4% per year. But despite increase in customer growth and business activity, sales have still been falling 1.0% per year. *Over the next twenty years, energy requirements are expected to increase 0.5% annually and system peak demand 0.4% annually, before adjusting for future DSM program savings* (emphasis added) (pg. 40).



* *"AAGR" means "average annual growth rate."*
Source: Indianapolis Power & Light 2016 IRP. Pg. 141

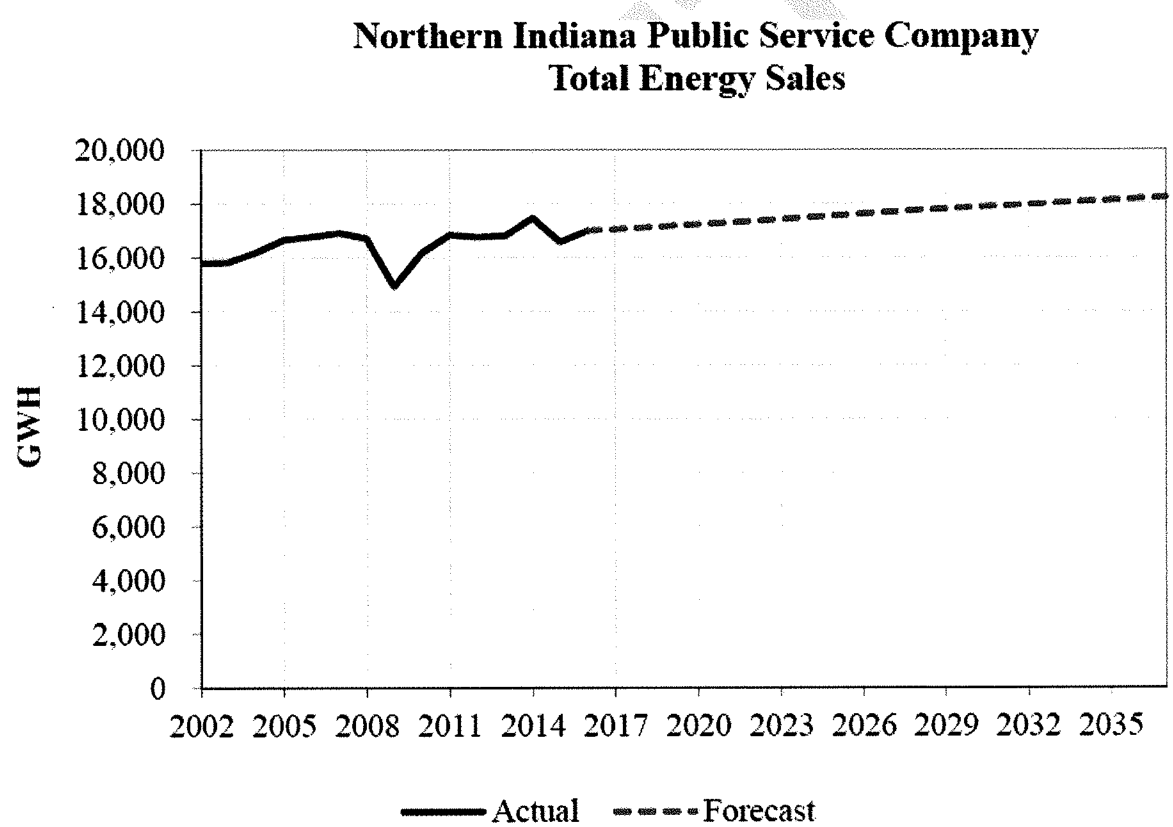


Source: Indianapolis Power & Light 2016 IRP. Pg. 142

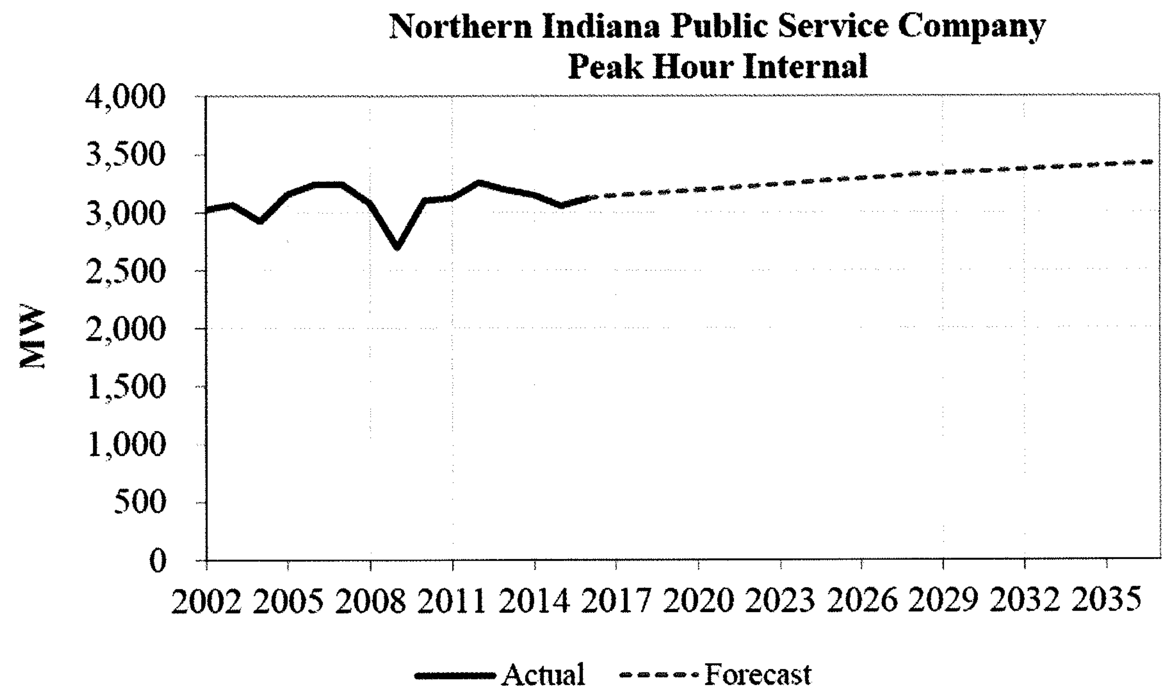
f) Northern Indiana Public Service Company – 2016 IRP

NIPSCO's forecast of its customers' electric requirements "project an increase in overall customer energy usage of 0.33% compound annual growth rate (CAGR) for the period of the IRP (2017 to 2037), while the peak demand for the base case is 0.45%. The total number of NIPSCO electric customers is projected to increase from approximately 464,000 today to about 511,000 by 2037".

Industrial load is particularly significant for NIPSCO. NIPSCO is projecting no growth for industrial load over the planning period. The potential addition or loss of a major customer and the ripple effects – or significant reductions in use due to technological change - could pose significant risks. Some of those risks could be beneficial, but others would not be. The following two graphs depict the low growth in energy sales and demand:



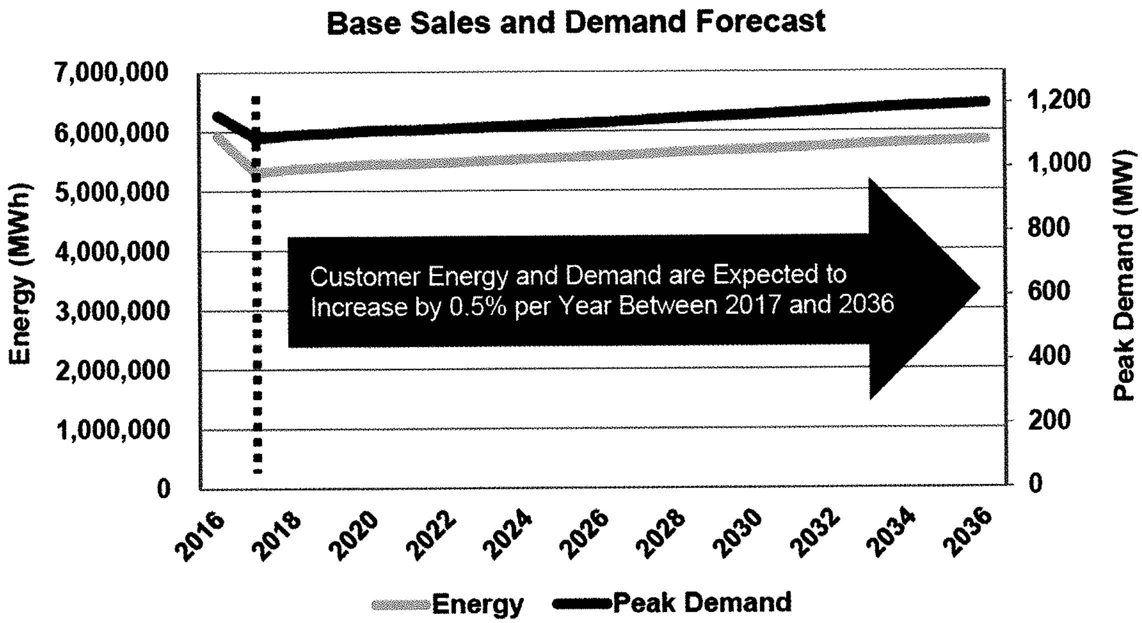
Source: Northern Indiana Public Service Company 2016 IRP. Pg. 28



Source: Northern Indiana Public Service Company 2016 IRP. Pg. 30

g) Southern Indiana Gas & Electric Company – 2016 IRP

SIGECO has experienced very little load growth, and projections are showing this trend to continue through the planning horizon of 2036. Moreover, SIGECO has experienced significant loss of industrial load when a customer decided to meet much of its electricity needs by installing a customer-owned, large combined heat and power facility.



Source: Southern Indiana Gas & Electric Company 2016 IRP. Pg. 36

h) Wabash Valley Power Association – 2017 IRP

Wabash Valley is forecasting 0.9 percent growth in energy sales demand for the 2018-2036 planning horizon. Each Wabash Valley Member serves a variety of residential, commercial and industrial loads. The majority of the load is residential in nature. The Company's winter peak usually occurs at 8:00 p.m. and the summer peak generally occurs in the evening around 7:00 p.m. These peak times reflect the highly residential nature of Wabash Valley's load. Wabash Valley has two large customers whose demand may be interrupted.

Base Case Load Forecast Energy Sales and Summer Coincident Peak Forecast (Net of Pass-Through Loads)

Year	Energy Sales (GWh)	% Change	Summer Coincident Peak (MW)	% Change
2017	7,401		1,475	
2018	7,277	-1.7%	1,472	-0.2%
2019	7,347	1.0%	1,476	0.3%
2020	7,382	0.5%	1,482	0.4%
2021	7,391	0.1%	1,489	0.5%
2022	7,435	0.6%	1,499	0.7%
2023	7,500	0.9%	1,512	0.9%
2024	7,590	1.2%	1,525	0.9%
2025	7,628	0.5%	1,537	0.8%
2026	7,696	0.9%	1,551	0.9%
2027	7,782	1.1%	1,568	1.1%
2028	7,895	1.5%	1,586	1.1%
2029	7,964	0.9%	1,605	1.2%
2030	8,034	0.9%	1,620	0.9%
2031	8,105	0.9%	1,635	0.9%
2032	8,205	1.2%	1,652	1.0%
2033	8,260	0.7%	1,668	1.0%
2034	8,336	0.9%	1,684	1.0%
2035	8,422	1.0%	1,702	1.1%
2036	8,531	1.3%	1,719	1.0%
18-36		0.9%		0.9%

Source: Wabash Valley Power Association 2017 IRP, Pg. 39

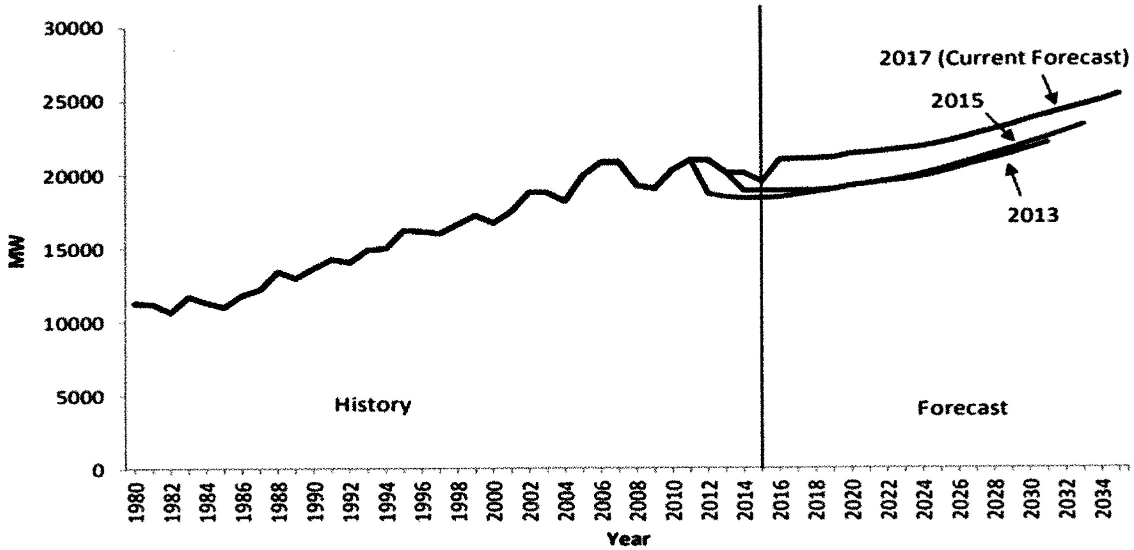
2. State Utility Forecasting Group Forecast

The SUFG summarized its forecast of projected customer electric power needs in its *Indiana Electricity Projections: The 2017 Forecast* as follows:

> The projections in this forecast are lower than those in the 2015 forecast, primarily due to increases in energy efficiency and less optimistic economic projections, compared to the earlier projections. This forecast projects electricity usage to grow at a rate of 1.12 percent per year over the 20 years of the forecast. Peak electricity demand is projected to grow at an average rate of 1.01 percent annually. This corresponds to about 230 megawatts (MW) of increased peak demand per year. The growth in the second half of the forecast period (2026-2035) is stronger than the growth in the first ten years (pg. 1-1).

The 2017 forecast predicts Indiana electricity prices to continue to rise in real (inflation adjusted) terms through 2023 and then slowly decrease afterwards. A number of factors determine the price projections. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity, in addition to production.

Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts



Source: State Utility Forecasting Group's 2017 Electricity Projections. Pg. 1-4

Indiana Peak Demand Requirements Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2017	1.01	2016-2035
2015	1.13	2014-2033
2013	0.90	2012-2031

Source: State Utility Forecasting Group's 2017 Electricity Projections. Pg. 3-1

Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2015 Projections)

Sector	Current (2016-2035)	2015 (2014-2033)
Residential	0.48	0.64
Commercial	0.36	0.59
Industrial	2.04	1.90
Total	1.12	1.17

Source: State Utility Forecasting Group's 2017 Electricity Projections. Pg. 3-3

3. Indiana Forecast Summary

In summary, based on the most recent submitted IRPs, Indiana utilities and the SUFG project relatively low load growth and adequate resources to satisfy reliability requirements. Indiana's utilities in their IRPs project annual growth ranging from 0.1- 0.8 percent over the 20-year forecast horizon. The projected annual growth in peak demand ranges from 0.2- 0.8 percent.

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The SUFG projects a slightly higher growth in electricity usage across Indiana than the individual utilities do in their IRPs, with 1.12% annual growth over the 20 year period and 1.01% annual growth in peak demand.

4. Regional Forecast

The SUFG also conducts a load forecast for MISO. Like the SUFG's load forecast for Indiana, the MISO region is projecting very low growth rates in energy usage and demand. PJM and other regions are also expecting low load growth.

SUFG State Retail Sales (without EE Adjustments) for the MISO Region Compound Annual Growth Rates (2018-2037)

State	CAGR
Arkansas	1.06
Illinois	0.51
Indiana	1.28
Iowa	1.55
Kentucky	0.87
Louisiana	0.80
Michigan	0.88
Minnesota	1.52
Mississippi	1.46
Missouri	0.97
Montana	1.14
North Dakota	0.99
South Dakota	1.65
Texas	1.86
Wisconsin	1.36

LRZ Metered Load Annual Growth Rates (2018-2037)

LRZ	CAGR (without EE Adjustments)	CAGR (with EE Adjustments)
1	1.45	1.34
2	1.32	1.32
3	1.51	1.18
4	0.51	0.31
5	0.81	0.64
6	1.12	1.03
7	0.88	0.76
8	1.06	1.05
9	1.05	0.99
10	1.46	1.46

Source: State Utility Forecasting Group's MISO Independent Load Forecast Update. Pg. ES-2

The maximum peak demand experienced by the MISO and PJM is more relevant to resource planning than the maximum demand incurred by their member systems. Specifically, the MISO and PJM *coincident peak demand* become the primary basis for determining the operating and planning reserve requirements (Resource Adequacy) for their regions. The MISO and PJM system wide reliability requirements are, in turn, allocated to their member utilities (in Load Resource Zones) based on their contributions to the MISO and PJM systems' coincident peak demand (*coincidence factor*).

LRZ Non-Coincident Summer and Winter Peak Demand (with EE Adjustments) Compound Annual Growth Rates for MISO (2018-2037)

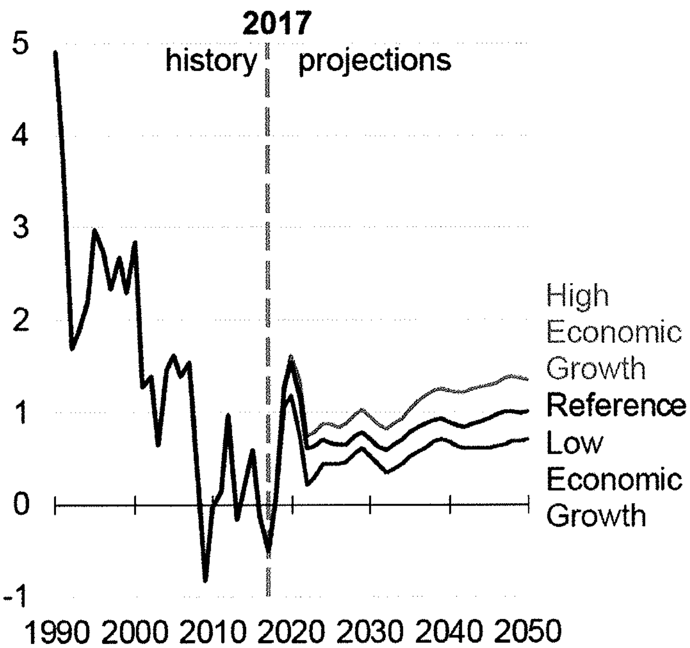
LRZ	CAGR (with EE Adjustments on Non-Coincident Peak)	
	Summer	Winter
1	1.34	1.32
2	1.32	1.32
3	1.19	1.12
4	0.33	0.29
5	0.67	0.64
6	1.03	1.02
7	0.78	0.74
8	1.05	1.05
9	0.99	0.98
10	1.46	1.46

Source: State Utility Forecasting Group's MISO Independent Load Forecast Update. Pg. ES-2

5. National Forecast

According to the Energy Information Administration (EIA) and, consistent with the experience of Indiana utilities and the region, electricity demand is largely driven by economic growth and increasing efficiency of the production and usage of electricity. Nationally, electricity demand growth was negative in 2017 but is projected to rise slowly through 2050. From 2017–2050, the average annual growth in electricity demand reaches about 0.9% in the Annual Energy Outlook 2018 Reference case. Through the projection period, the average electricity growth rates in the High and Low Economic Growth cases deviate from the Reference case the most—where the High Economic Growth case is about 0.3 percentage points higher than in the Reference case, and electricity growth in the Low Economic Growth case is about 0.3 percentage points lower than in the Reference case.

Electricity use growth rate
percent growth (three-year rolling average)



B. Future Resource Needs

With all the utilities, the predicted need for additional generation resources is based on the predicted annual energy requirements. The future generation needs will therefore vary in the predicted energy requirements. IRP's typically will analyze multiple scenarios, or possible states of the world, to bracket differences between forecasts. The utilities may include low-growth and economic-growth scenarios. The needed annual energy changes with the economy, and so too will the need for additional generation. The below summaries of the needs for future generation are therefore only applicable under the specific scenario to which it applies.

1. State Utility Forecasting Group

In its _Indiana Electricity Projections: The 2017 Forecast_, the SUFG summarized its 2017 forecast regarding future generation needs as follows:

> For this forecast, SUFG has incorporated significant revisions to its modeling system. As a result, unlike in previous forecasts, future resource needs are identified by a specific technology rather than by generic baseload, cycling and peaking types. The new utility simulation model can select the lowest cost mix of a number of different supply and demand options. Due to time and data limitations, demand-side resources were modeled as fixed quantities based on utility-provided information rather than allowing the model to select the amounts.

This forecast indicates that additional resources are not needed until 2021. This forecast identifies a need for about 3,600 MW of additional resources by 2025, 6,300 MW by 2030 and 9,300 MW at the end of the forecast period in 2035. In the long term, the projected additional resource requirements are higher than in previous forecasts. This is due to the retirements of additional existing generators that have been announced by Indiana utilities since the previous forecast report (pg. 1-1).

2. Indiana Utilities' Resource Needs

a) Duke Energy Indiana – 2015 IRP

Duke Energy Indiana's IRP for the 2015-2035 planning horizon is shown in the following table. The IRP includes the addition of two combined cycle facilities of 448 MW each – one in 2020 and the other in 2031. The IRP also determined a number of regular additions of wind and solar in relatively small increments, approximately 50 MW a year and 30 MW a year, respectively, from about 2020 through 2030. These additions come mostly after a number of anticipated retirements: five units at Wabash River (668 MW) in 2016; Connersville 1&2 combustion turbines (86 MW) in 2018, Gallagher units 2 & 4 (280 MW) in 2019, and Gibson 5 (310 MW) in 2031.

Duke Energy Indiana Integrated Resource Plan
Portfolio and Recommended Plan (2015-2035)

Year	Retirements	Additions	Renewables (Nameplate MW) [1]			Notable, Near-term Environmental Control Upgrades [2]
			Wind	Solar	Biomass	
2015						
2016	Wabash River 2-6 (668 MW)			20		
2017				20		Ash handling/Landfill upgrades: Cayuga 1-2 & Gibson 1-5
2018	Connersville 1&2 CT (86 MW) Mi-Wabash 1-3,5-6 CT (80 MW)					
2019	Gallagher 2 & 4 (280 MW)					
2020		CC 448 MW Cogen 15MW		10	2	
2021				10	2	
2022			50	20		
2023			50	30	2	
2024			50	30	2	
2025				30		
2026			50	20	2	
2027			50	30		
2028			100	30	2	
2029			50	30	2	
2030				10		
2031	Gibson 5 (310 MW)	CC 448 MW				
2032						
2033		CT 208 MW				
2034						
2035			50			
Total MW	1424	1119	450	290	14	

1: Wind and solar MW represent nameplate capacity.
2: Additional likely or potential control requirements include additives for mercury control, water treatment and

Source: Duke Energy Indiana 2015 IRP. Pg. 158

b) Hoosier Energy – 2017 IRP

Hoosier Energy's IRP does not show a resource deficit until 2024. The Capacity Expansion Plan below shows Hoosier Energy's intention of adding a significant amount of renewable resources beginning in 2020

Capacity Expansion Plan - Summer Peak

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Peak Demand										
Demand Forecast (1)	1,524	1,544	1,562	1,578	1,599	1,628	1,642	1,656	1,670	1,682
Demand Response/Energy Efficiency	(46)	(47)	(46)	(45)	(46)	(47)	(49)	(50)	(50)	(50)
Reserve Requirement (2)	124	126	127	129	130	133	134	135	136	137
Peak Requirement	1,602	1,623	1,643	1,662	1,683	1,714	1,727	1,741	1,756	1,769
Resources (MW)										
Merom	983	983	983	983	983	983	983	983	983	983
Power Purchase	150	150	150	150	150	150	50	50	0	0
Holland	307	307	307	307	307	307	307	307	307	307
Worthington	169	169	169	169	169	169	169	169	169	169
Lawrence	175	175	175	175	175	175	175	175	175	175
Renewables (3)	122	97	247	347	347	347	347	347	347	347
Adj. per MISO RAR (4)	(196)	(171)	(294)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Resources Adjusted	1,709	1,709	1,736	1,756	1,755	1,756	1,656	1,655	1,605	1,605
Total Resources minus Peak Req.										
Excess / (Deficit)	107	87	93	94	72	42	(71)	(86)	(151)	(164)

Source: Hoosier Energy 2017 IRP. Pg. 57

c) Indiana Michigan Power – 2015 IRP

I&M is a case study in how quick and significant market dynamics, combined with legal and regulatory circumstances, can change a utility's resource decisions. Based on I&M's 2018 IRP that is under development, I&M is assessing potentially significant changes beyond those contemplated in its 2015 IRP. According to the 2015 IRP, I&M did not anticipate the need for large scale additional capacity until 2035, when it forecast the need for 1253 MW of natural gas combined cycle generation coupled with a reduction in energy needs based on its energy efficiency programs. It also anticipated the addition of 600 MW of new solar generation throughout the 20 year period.

I&M's 2018 IRP is being developed with a target completion date of November 1, 2018. I&M is planning to thoroughly review the potential for terminating the Rockport Unit 2 contract as early as 2023 and the closing of Rockport 1 by 2028. Economic, legal, and regulatory considerations are driving exploration of these options, among other considerations. It is important to keep in mind that the analysis is not complete and many factors will be considered prior to any decisions being made.

d) Indiana Municipal Power Agency – 2017 IRP

IMPA anticipates a need for market purchases through 2025 to provide a small amount of capacity and energy needed due to the expiration of a 100 MW power purchase agreement in 2021. From 2018 through 2027, IMPA anticipates much of its new resources will be solar and wind. After 2026, IMPA expects to be have adequate resources with the addition of one or more combined cycle units.

Year	Capacity Losses MW Lost	Capacity Losses Resource	Capacity Additions MW Added	Capacity Additions Resource	Net MW
2018	(50)	PPA Expires	12 100	Solar Bilateral Capacity (18-20)	62
2019	(50)	Wind PPA Expires	12 50	Solar Wind PPA	12
2020			12	Solar	12
2021	(100) (100)	PPA Expires Bilateral Capacity Expires	12 200	Solar Bilateral Capacity (21-25)	12
2022			12	Solar	12
2023			12	Solar	12
2024			12	Solar	12
2025			12	Solar	12
2026	(90) (200)	WWVS Retires Bilateral Capacity Expires	12 200 50	Solar Advanced CC Wind PPA	(28)
2027			12	Solar	12
2028			12	Solar	12
2029					
2030					
2031					
2032					
2033					
2034	(190)	PPA Expires	260	Advanced CC	70
2035					
2036					
2037					
Total	(780)		992		212

Source: Indiana Municipal Power Agency 2017 IRP, Pg. 1-13

e) Indianapolis Power & Light Company – 2016 IRP

IPL's IRP includes a table showing all generation retirements and reductions under its six different scenarios.

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Annual Supply-Side Capacity Additions and Retirements

YEAR	Base Case	Robust Economy	Recession Economy	Strengthened Environmental Rules	High Customer Adoption of Distributed Generation	Quick Transition
2017						
2018	**Upgrade Pete 1-4**	**Upgrade Pete 1-4**	**Refuel Pete 1 - 4**	**Retire Pete 1 (-234 MW) Coal, Refuel Pete 2-3&4 (1495 MW) to NG**	**Upgrade Pete 1-4**	**Upgrade Pete 1-4**
2019						
2020				Wind 500 MW PV 280 MW		
2021						
2022				Wind 100 MW PV 50 MW	PV 65 MW Wind 10 MW CHP 75 MW	**Retire Pete 1 (-234 MW) Coal, Refuel Pete 2-3&4 (1495 MW) to NG**
2023	**Retire HS GT 1&2 (-32 MW) Oil**	**Retire HS GT 1&2 (-32 MW) Oil**	**Retire HS GT 1&2 (-32 MW) Oil**	**Retire HS GT 1&2 (-32 MW) Oil** PV 10 MW	**Retire HS GT 1&2 (-32 MW) Oil**	**Retire HS GT 1&2 (-32 MW) Oil**
2024				PV 10 MW		
2025					PV 65 MW Wind 10 MW CHP 75 MW	
2026				PV 10 MW		
2027				PV 10 MW		
2028				PV 10 MW Comm Solar 1 MW		
2029				PV 10 MW Comm Solar 5 MW		
2030	**Retire HS 5&6 (-200MW) NG**	**Retire HS 5&6 (-200MW) NG** Wind 500 MW	**Retire HS 5&6 (-200MW) NG**	**Retire HS 5&6 (-200MW) NG** Wind 500 MW	**Retire HS 5&6 (-200MW) NG**	**Retire Pete 2-4 (-1495 MW) NG, HS GT4-6 (294 MW) NG, HS 5&6 (-200 MW) NG, HS IC1 (3 MW) Oil, Pete IC1-3 (6 MW) Oil** Wind - 6000 MW Solar - 1146 MW Battery - 600 MW
2031		Wind 500 MW Market 200 MW		Wind 500 MW		
2032	**Retire Pete 1 (-234 MW) Coal**	**Retire Pete 1 (-234 MW) Coal** Wind 500 MW PV 370 MW	**Retire Pete 1 (-234 MW) Coal**	Wind 500 MW Comm Solar 3 MW	**Retire Pete 1 (-234 MW) Coal** PV 65 MW Wind 510 MW CHP 75 MW	
2033	**Retire HS7 (-428 MW) NG** Wind 250 MW Market 50 MW PV 90 MW Battery 100 MW	**Retire HS7 (-428 MW) NG** Wind 500 MW PV 440 MW	**Retire HS7 (-428 MW) NG**	**Retire HS7 (-428 MW) NG** Wind 500 MW Comm Solar 5	**Retire HS7 (-428 MW) NG** Wind 500 MW	**Retire HS7 (-428 MW) NG**
2034	**Retire Pete 2 (-417 MW) Coal** H-Class CC 450 MW Wind 250 MW	**Retire Pete 2 (-417 MW) Coal** H-Class CC 450 MW Wind 500 MW	**Retire Pete 2 (-417 MW) NG** H-Class CC 450 MW	**Retire Pete 2 (-417 MW) NG** H-Class CC 450 MW Wind 500 MW Comm Solar 5 MW	**Retire Pete 2 (-417 MW) Coal** H-Class CC 450 MW Wind 500 MW	H-Class CC 450 MW
2035	Wind 250 MW Battery 250 MW Market 150 MW	Wind 500 MW PV 190 MW Battery 250 MW Market 50 MW Comm Solar 1 MW	H Class CC 200 MW	Wind 500 MW PV 70 MW Market 50 MW Comm Solar 5 MW	Wind 500 MW Battery 50 MW Market 50 MW	
2036	Wind 250 MW Battery 150 MW PV 10 MW	Wind 500 MW Battery 50 MW Comm Solar 5 MW		Wind 500 MW PV 60 MW Comm Solar 5 MW	Wind 500 MW PV 60 MW Comm Solar 1 MW	
* Upgrades for Pete 1-4 for NAAQS SO2 and CCR						

Source: Indianapolis Power & Light Company 2016 IRP. Pg. 157

Under the base case, one can see that the IRP calls for additional wind, power purchases, solar and a battery storage in 2033. In 2034, it calls for a new natural gas combined cycle plant as well as additional wind. In the final two years of the 20 year period, it anticipates more wind, solar, power purchases, and battery storage.

In its 2016 IRP and based on the information available in 2015 and 2016, IPL chose a hybrid portfolio made up of various scenario optimized candidate portfolios as its preferred portfolio. The IRP did not include needed generation resources for each scenario using the hybrid portfolio.

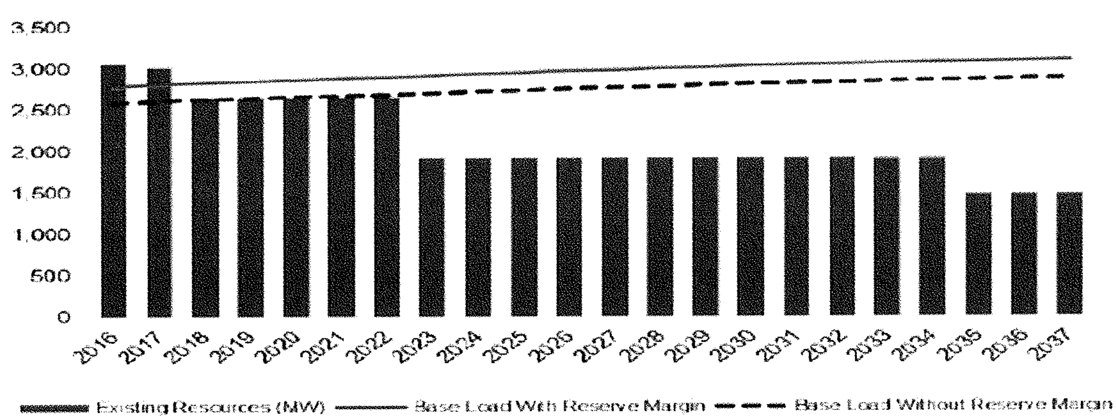
IPL notes, as any of the IRP's could, that additional potential changes not easily modeled may affect future resource portfolios, such as the impacts of elections, technology changes, public policy changes, or stakeholder input.

f) Northern Indiana Public Service Company – 2016 IRP

NIPSCO's 2016 IRP anticipated retiring its Bailly Generating Station ("Bailly") Units 7 and 8 by May 2018. The replacement capacity necessary to meet the customer demand during the short-term action plan period would range from approximately 150-200 MW and would be addressed with either short-term purchase power agreements and/or market capacity purchases, whichever provides the best alignment of costs and mitigation of risks for customers.

The 2016 IRP also indicated that NIPSCO should continue to evaluate the value of developing an environmental compliance option at Schahfer Units 17 and 18. The Preferred plan was based on the likely retirement of Schahfer Units 17 and 18 in 2023. NIPSCO is currently in the process of updating its 2016 IRP and issued an all-source RFP also in May 2018 with the objective to fill a resource gap in 2023.

Resource Adequacy Assessment (MW)



Source: Northern Indiana Public Service Company 2016 IRP. Pg. 55

g) Southern Indiana Gas & Electric Company – 2016 IRP

In IURC Cause No. 45052, SIGECO is proposing to diversify its generation fleet based on its 2016 Integrated Resource Plan ("IRP") by investing in a new combined cycle gas turbine, sized to replace certain coal-fired units that will be retired at the end of 2023. SIGECO is seeking a CPCN to construct the combined cycle gas turbine, with the capacity of 800-900 MW, adjacent to SIGECO's Brown Generating Station.

Consistent with its 2016 IRP, SIGECO plans to retire Culley Unit 2 and the Brown Units 1 and 2 once the new plant is operational. According to SIGECO, Culley Unit 2's age and efficiency will not justify further capital investment to allow it to continue to operate in the future. Brown Units 1 and 2 would require significant capital investment, including construction of a new scrubber, to allow them to continue to operate in the future. Although SIGECO has agreed to continue its joint operation of Warrick Unit 4 through December 31, 2023, the continued operation of that unit is not economic and is further complicated because ALCOA, following its recent organizational and operational changes, is not able to unconditionally commit to use of the jointly-owned unit as part of its future operations. Based on the 2016 IRP and updated IRP modeling completed in 2017, SIGECO plans to retire 73% of its current coal-fired generation fleet and diversify its generation portfolio by adding the combined cycle gas turbine at the end of 2023.

h) Wabash Valley Power Association – 2017 IRP

For the 2017-2036 IRP period, Wabash Valley's IRP indicates capacity needs starting in 2018, and Wabash Valley anticipates meeting these needs in a diversified manner. Wabash Valley, unlike most utilities in Indiana and the MISO region, has winter peak demands that sometimes exceed its summer peak demand.

From 2018 to 2020, Wabash Valley expects to meet its incremental capacity needs primarily by purchasing capacity through the MISO's capacity auctions or bilateral transactions. Wabash Valley will purchase output from three wind projects from 2018 to 2020. After 2020, Wabash Valley's resource plan anticipates building 600 MW of baseload combined cycle resources and 350 MW of peaking combustion turbine resources along with 50 MW of energy efficiency. The expiration of existing purchase power agreements drives the need for these resources.

3. Indiana Future Resource Needs Summary

Based on the most recent submitted IRPs, Indiana utilities project relatively low load growth and adequate resources to satisfy reliability requirements. The utilities contemplate retirement of some generating units, particularly older and smaller coal-fired power plants, largely due to relatively low price forecasts for natural gas that may cause these coal-fired power plants to not be economical in the wholesale power market. Additionally, utilities find it difficult and costly to install or maintain environmental controls on smaller and older coal-fired power plants. The retirement of existing generation units will drive most of the large capacity additions within the forecast horizon. These capacity additions generally consist of gas-fired combined cycle facilities and significant additions of renewable resources.

For some utilities, the investment in more infrastructure and generation capacity is appropriate. For other utilities, their IRPs may suggest more reliance on regional power markets for purchases throughout the MISO and PJM regions. Some may opt for a combination of both. Even for the utilities that anticipate the need to build new generating facilities, they are eschewing capital-intensive facilities with significant lead times and, instead, are issuing requests for proposals for all cost-effective resources. It is clear that to the extent utilities elect to build more traditional generating facilities, the overwhelming preference is to build natural gas-fired combined cycle or natural gas peaking facilities.

C. Resource Mix and Location

In analyzing the possible future resources, it is important to note that the Commission does not have the capability to predict the location of potential future resources. The location of new resources is dependent on the specific utilities' transmission topology, fuel sources, type and size of generation, and other factors. The location of current generation resources will change over time as generating units are retired and new generating units are built. The location of new generating units may also be influenced by energy efficiency, demand response, distributed energy resources and future transmission, distribution, and generation technologies. A map of the current location of generation resources is found in Appendix 7.

Considerations Affecting Resource Decisions

Within the last twenty years, environmental and safety regulations have imposed significant costs on the coal and nuclear-power generating fleets in particular. The capital costs associated with environmental retrofits and equipment necessary to comply with EPA requirements – including fixed Operations and Maintenance expenses (O&M) –were significant but paled in comparison to the cost of building new coal-fired or nuclear generating facilities. Since approximately 2010, hydraulic fractionation (fracking) has resulted in a paradigm change in the natural gas markets that resulted in lower prices and reduced price volatility that has far-reaching ramifications for the costs of gas-fired electric generation and, as a result, coal-fired power plants. These changes, taken as a whole, provide the primary impetus, in particular, for retirement of some coal-fired power plants and the resulting significant changes in the composition of the generating fleets for Indiana, the region, and the nation.

The following three graphics prepared by Northern Indiana Public Service Company in their current 2018 IRP stakeholder process illustrate the combined effects. While the graphics are based on NIPSCO's experience, every Indiana utility, and utilities across the region and the nation, face the same fundamental factors that drive current and future resource decisions.

To illustrate the costs for coal-fired power plants and the dynamics with natural gas-fired units in particular, the following chart shows the key costs for coal-fired generation, broken down into fixed (that is, those costs that remain the same no matter the amount of electricity generated) and variable costs (that is, fuel and other costs that vary with the amount of electricity generated).

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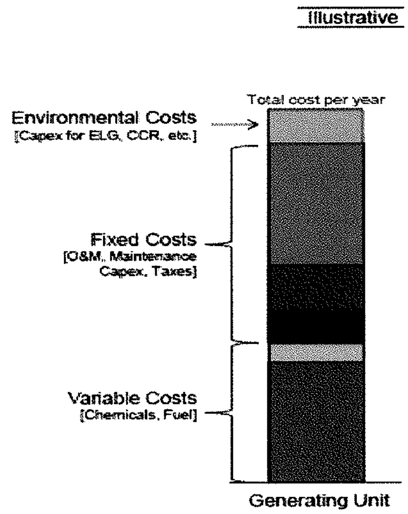
GENERATION OVERVIEW

Generation Costs

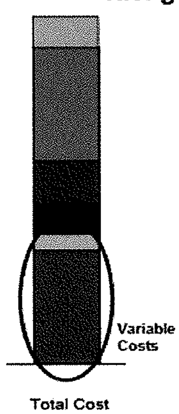
- **Generation costs vary for each NIPSCO unit**
- **Key cost components are:**
  - Environmental costs for controls required to be compliant with future regulations like effluent limitations guidelines (ELG) and coal combustion residuals (CCR)
  - Fixed costs including operations and maintenance (O&M),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

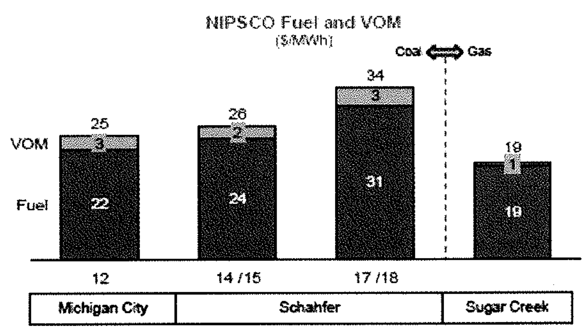


GENERATION OVERVIEW

Variable Costs

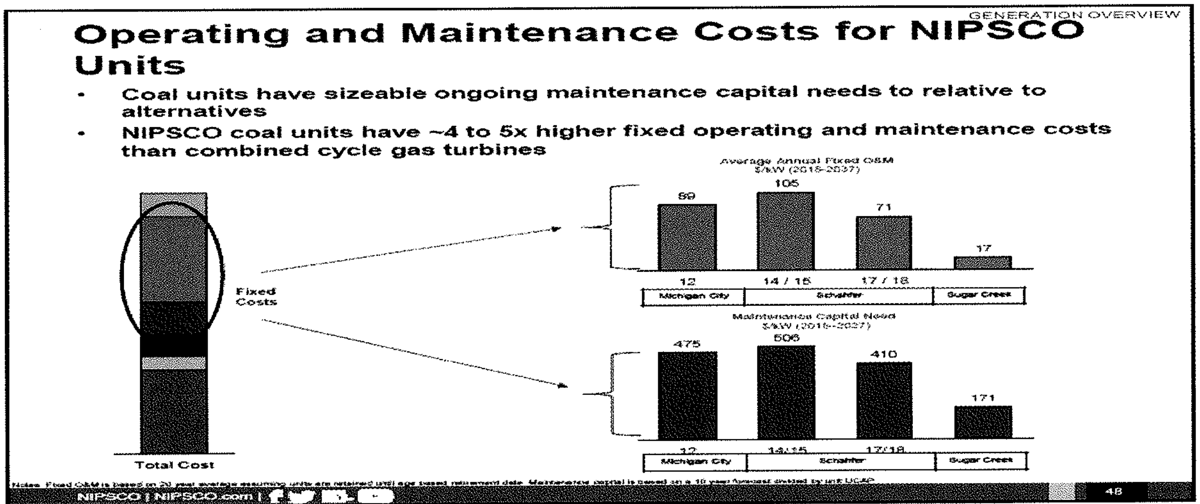
- **Fuel (coal or natural gas) is the largest variable cost for NIPSCO units**
- **Variable Operation and Maintenance (VOM) costs include chemicals for environmental controls and are generally higher for coal versus natural gas fuel generators**



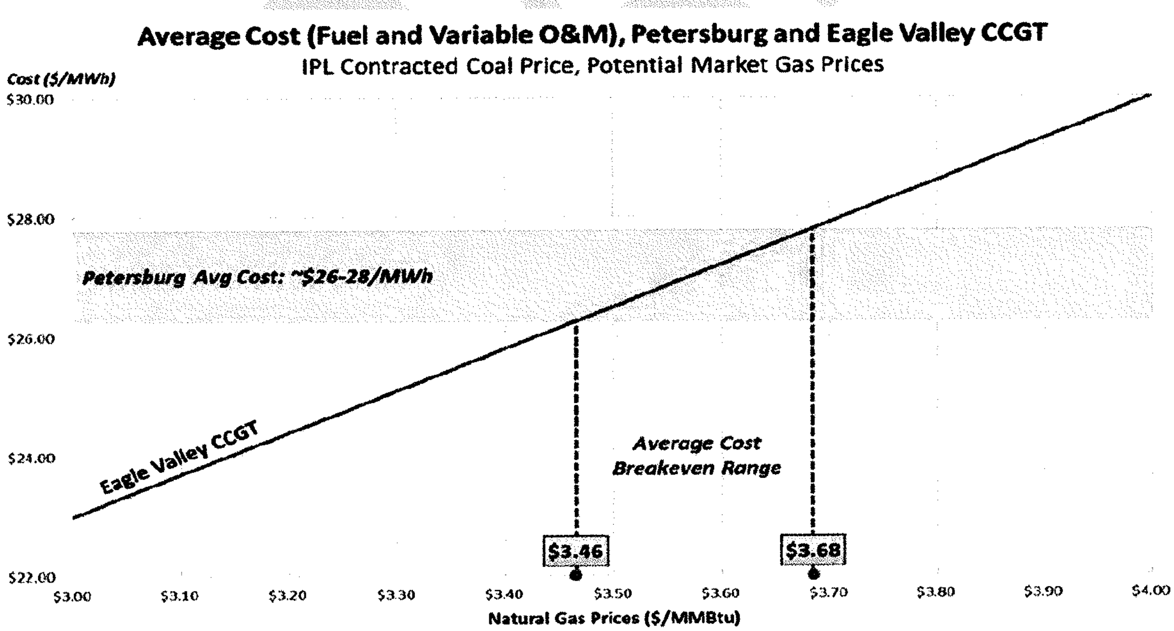


Notes: Cost shown here represent 2018 forecasts based on average annual heat rates, NIPSCO coal and natural gas prices based on 2018 contract prices; coal range from $2.05 - $2.54 $/MMBtu, Natural gas $2.61 $/MMBtu all in real 2017 $. Variable costs can vary based on market conditions.

The following graph highlights the significant differences in the cost of maintaining coal-fired and gas-fired power plants. Maintenance costs are an important consideration in selecting new resources, as well as the decision to retain existing coal-fired generating units.



IPL, on page 69 of their 2015 IRP, constructed the following graph to describe the break-even point for their new Eagle Valley Combined Cycle facility and their most efficient coal-fired plant in Petersburg.



To be clear, while the cumulative effect of decades of environmental regulations have had a significant effect on coal-fired power plants, the most recent efforts by the Environmental Protection Agency to impose regulations on carbon dioxide (CO_2) were not significant drivers of resource decisions for Indiana's utilities. That is, the potential cost and other ramifications of

CO_2 regulations were dwarfed by the relatively low cost of natural gas as a generating fuel and the very high cost associated with the construction and maintenance of coal-fired generation.

> The number of scheduled or completed coal capacity retirements are increasing through 2021. About 49.5 GW of coal capacity is or was scheduled for retirement between 2013-2-11, an increase from the 41.1 GWs scheduled as of March 27, [2017]. Forty-five coal units are slated to retire from 2017-2021 while 395 unites have been retired since 2012. Some power companies have said that low-priced natural gas continues to drive decisions to retire coal-fired units (SNL based on S&P's Global Market Intelligence, October 11, 2017).

Similarly, as the recent cancelations of a nuclear power plant in South Carolina, significant cost over-runs at the Vogtle nuclear plant under construction in Georgia, as well as efforts by owners of nuclear and coal-fired generation to obtain subsidies, attest, the daunting on-going capital costs and operating cost pose significant hurdles. These were the primary factors in a large Ohio utility's decision to file for bankruptcy in 2018.[4] In the future, there may be technological changes that reduce the capital costs and, as a result, increase the economic viability of coal and nuclear generation units. Unexpected substantial increases in the price of natural gas may also make nuclear (and coal) more economically viable (i.e., more fully dispatched by the MISO and PJM. These market dynamics face every utility in the United States and are manifested in the growing number of retirements.

Unfortunately, other immediate casualties of these market pressures have resulted in bankruptcies of several coal companies.[5]

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[4] FirstEnergy Solutions Corp (FES) filed for bankruptcy March 31, 2018 due to the dramatic changes in fuel prices, low load growth, increasing penetration of renewables. The bankruptcy protection was filed two days after asking the DOE to invoke an emergency declaration that would direct the PJM Interconnection to ensure full cost recovery for FES's at-risk coal and nuclear plants in the region and after FES notified the PJM it will retire its three nuclear plants next two to three years. FES President and board chairman Donald Schneider said:

> *The significant increase in the availability of cheap natural gas due to fracking has given gas-fired generation an advantage. This has had a profound impact on companies that rely on coal and nuclear power*. In addition to increased gas-fired output, the economic downturn of 2008 and 2009, improvements in energy efficiency, and more renewable generation have *continued to place downward pressure on electricity prices and the value of certain generation resources such as coal burning and nuclear-generating units.* He also said tougher emissions rules for coal-burning plants and the removal of federal restrictions on natural gas usage have undermined the coal and nuclear-generating fleets (emphasis added) (SNL April 2, 2018).

[5] CNN (November 1, 2017) Armstrong Energy – filed for bankruptcy in October 2017; Business Insider (December 6, 2016) cited: Peabody Coal – March 2018 (court approved restructuring plan) for a bankruptcy that was filed in April 2016; Arch Coal – January 2018; Alpha Natural Resources – August 2015 (emerged from bankruptcy in July 2016); Patriot Coal (after losing money each year from 2010) – July 9, 2012 (the company filed for bankruptcy after recording $198.5 million in losses); James River Coal first filed for bankruptcy in 2004 and again on April 8, 2017 (James River was forced to close a dozen of its mines due to poor market conditions).

A concern has been expressed that, as a nation, we may be placing too much reliance on natural gas and, thereby, not giving appropriate consideration to _resiliency_ of the power system. As the U.S. Department of Energy's Sandia Laboratory states:

> "Grid resilience is a concept related to a power system's ability to continue operating and delivering power even in the event that low probability, high-consequence disruptions such as hurricanes, earthquakes, and cyber-attacks occur. Grid resilience objectives focus on managing and, ideally, minimizing potential consequences that occur as a result of these disruptions." Sandia, however, notes that "currently, no formal grid resilience definitions, metrics, or analysis methods have been universally accepted."[6] [7]

The FERC currently has a process investigating the relationship between resiliency, reliability, and the performance of the bulk power system.

1. Indiana Utilities' Resource Mix

When analyzing the generation resource mix in Indiana, retirements of existing coal resources are of primary focus. Every Indiana utility has exhibited a keen appreciation for the risks of retiring units compared to the risks of retaining units that may prove to be uneconomic at some point in the future.

Within the last 20 years, environmental regulations have imposed significant costs on coal -fired generation, in particular. The capital costs associated with environmental retrofits and equipment necessary to comply with U.S. EPA requirements, including fixed operations and maintenance expenses, were significant, but paled in comparison to the cost of building new coal-fired or nuclear generation facilities. Beginning about 2010, however, hydraulic fracturing ("fracking") has resulted in a paradigm change in the natural gas markets that resulted in lower prices and reduced price volatility. As a result, the economics of operating coal-fired power plants changed drastically. These changes, taken as a whole, provide the primary impetus for retirement of some coal-fired power plants and the resulting significant changes in the composition of the generation fleets for Indiana, the region, and the nation.

a) Duke Energy Indiana – 2015 IRP

Duke Energy's total installed net summer generation capability owned or purchased by Duke Energy is currently 7,507 MW. This capacity consists of 4,765 MW of coal-fired steam capacity, 595 MW of syngas/natural gas combined cycle capacity, 285 MW of natural gas-fired combined

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[6] Reliance on Regulatory Effects and Electric Power Systems Research - Abstract, Sandia Laboratories, February 2017.

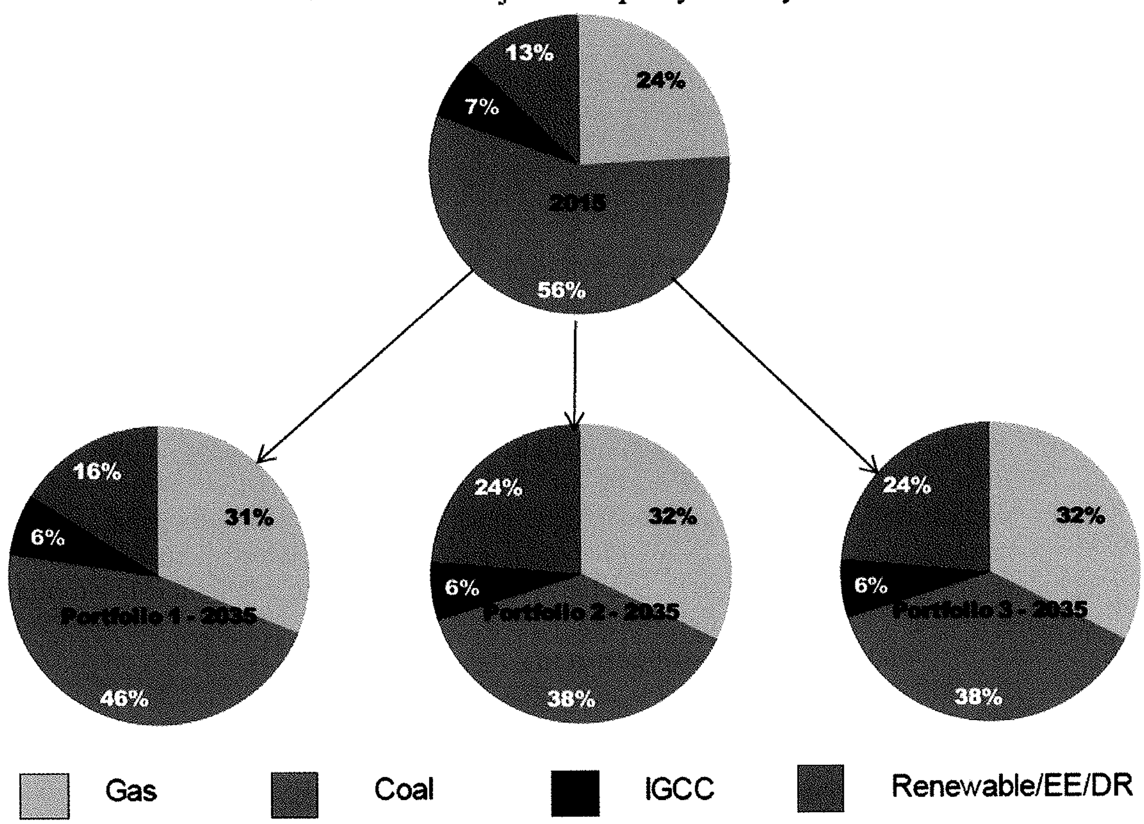
[7] The FERC, in response to the DOE's NOPR on resilience offered that resilience means the "*ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to and/or rapidly recover from such an event.*" Most, however, recognize that this definition is not distinct from the definition of reliability.

cycle capacity, 45 MW of hydroelectric capacity, and 1,804 MW of natural gas-fired or oil-fired peaking capacity. Also included is a power purchase agreement with Benton County Wind Farm (100 MW, with 13 MW contribution to peak modeled).

Duke Energy's recommended plan for the 2015-2035 planning horizon is shown in the following table. The plan includes the retirement of five combustion turbines at Wabash River (668 MW) in 2016, Connersville 1&2 combustion turbines (86 MW) in 2018, Gallagher units 2 & 4 (280 MW) in 2019, and Gibson 5 (310 MW) in 2031. The plan also included the addition of two combined cycle facilities of 448 MW each – one in 2020 and the other in 2031. Resource additions also included regular additions of wind and solar in relatively small increments.

Duke Energy's Generation Mix 2015 and 2035

Current and Projected Capacity Mix by Portfolio



Source: Duke Energy Indiana 2015 IRP. Pg. 16

b) Hoosier Energy – 2017 IRP

Hoosier Energy does not show a resource deficit until 2024-25. Hoosier Energy's preferred capacity expansion plan suggests adding 891 MW of additional solar and wind over the planning period, as well as 205 MW of combustion turbines in 2024. The preferred plan also shows 208 MW of retirements of contracts through the 2018 – 2037 planning horizon.

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Year	Retirements	Additions
2018		Meadow Lake Wind (25 MW); Orchard Hills LFG (16 MW)
2019	Story County PPA (25 MW)	
2020		Meadow Lake Wind (50 MW); Solar PPA (100 MW)
2021		Solar PPA (100 MW)
2022		
2023		
2024	Duke Energy PPA (100 MW)	Combustion Turbine (205 MW)
2025		
2026	Duke Energy PPA (50 MW)	
2027		
2028	Clark-Floyd LFG (4 MW)	
2029	Rail Splitter PPA (25 MW)	
2030		
2031		
2032	Dayton Hydro (4 MW)	
2033		
2034		
2035		Solar PPA (200 MW)
2036		Solar PPA (200 MW)
2037		Solar PPA (200 MW)
Total MW	208	1,096

Source: Hoosier Energy 2017 IRP, Pg. 92

c) Indiana Michigan Power – 2015 IRP

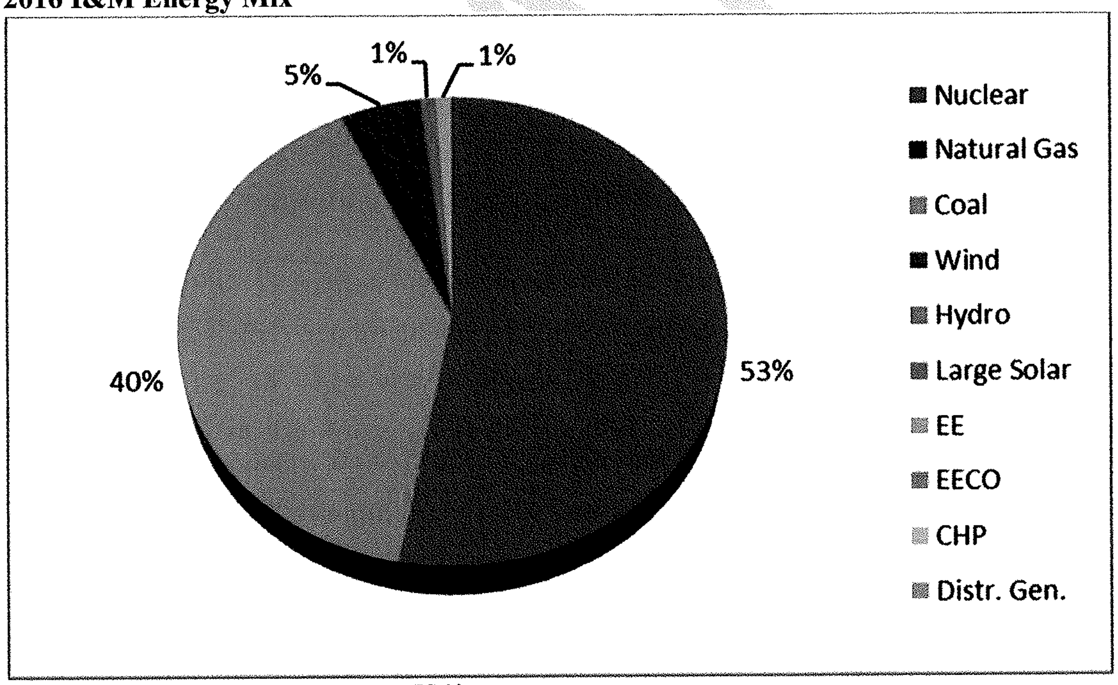
I&M's resource mix will be highly dependent on a decision on the Rockport generating units and its resource alternatives. I&M's 2015 IRP is being updated in 2018 and the future resource mix is likely to be different than predicted in 2015. The 2015 IRP, however, remains the most recently submitted information. It describes the change in its generation mix during its 20 year IRP period based on its preferred resource portfolio. It notes the energy output attributable to coal-based assets decreases from 40 percent to 33 percent, while nuclear generation shows a decrease from 53 percent to 38 percent over the period. Likewise, in addition to energy from a new natural gas combined cycle plant, which would comprise 15 percent of its resource portfolio, renewable energy would be anticipated to increase from 6% to 13% over the planning period.

I&M's Preferred Portfolio

- Maintains I&M's two units at Rockport Plant, including the addition of Selective Catalytic Reduction (SCR) systems in 2017 and 2019; as well as FGD systems in 2025 and 2028
- Continues operation of I&M's carbon free nuclear plant through, minimally, its current license extension period
- Add 600MW (nameplate) of large-scale solar resources
- Add 1,350MW (nameplate) of wind resources
- Adds 1,253MW of NGCC generation in 2035
- Implements end-use energy efficiency programs so as to reduce energy requirements by 914GWh and capacity requirements by 70MW in 2035
- Adds 27MW of natural gas CHP generation
- Recognizes additional distributed solar capacity will be added by I&M's customers, starting in 2016, and ramping up to 5MW (nameplate) by 2035

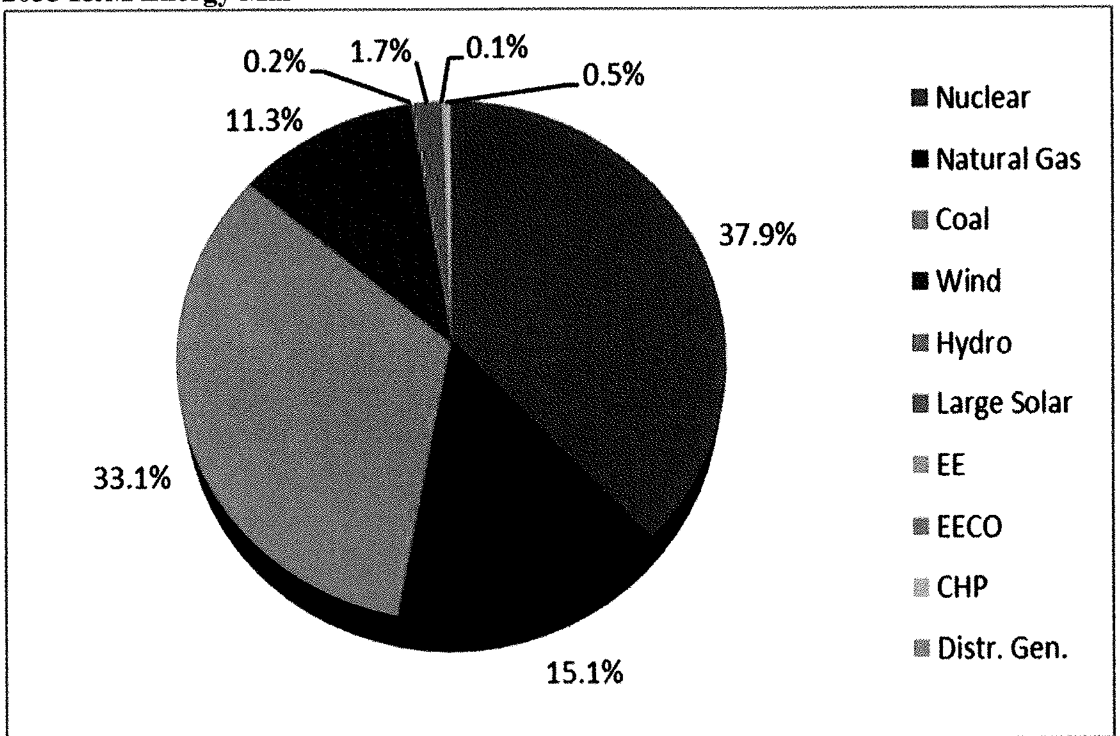
Source: Indiana Michigan Power 2015 IRP, Pg. ES-6

2016 I&M Energy Mix



Source: Indiana Michigan Power 2015 IRP, Pg. ES-10

2035 I&M Energy Mix



Source: Indiana Michigan Power 2015 IRP. Pg. ES-10

Energy efficiency and demand response is projected in the 2015 IRP to reduce I&M's retail load by 8% over the 2016-2035 planning horizon. (Page 50). In addition, DSM programs implemented by I&M in 2015-2018 were expected to result in 37 MW of reduced demand.

I&M's 2018 IRP is being developed with a target completion date of November 1, 2018. I&M is planning to thoroughly review the potential for terminating the Rockport Unit 2 contract as early as 2023 and the closing of Rockport 1 by 2028. Numerous factors are driving exploration of these options including economics, legal, and regulatory considerations. It is important to keep in mind that the analysis is not complete and many factors will be considered prior to any decisions being made.

d) Indiana Municipal Power Agency – 2017 IRP

IMPA anticipates a need for market purchases through 2025 to provide a small amount of capacity and energy needed due to the expiration of a 100 MW power purchase agreement in 2021. From 2018 through 2027, IMPA anticipates much of its new resources will be solar and wind. After 2026, IMPA expects to be have adequate resources with the addition of one or more combined cycle units. The following graphics show IMPA's resource needs and the resources required to serve its member cities' electrical requirements.

Year	Capacity Losses MW Lost	Resource	Capacity Additions MW Added	Resource	Net MW
2018	(50)	PPA Expires	12 100	Solar Bilateral Capacity (18-20)	62
2019	(50)	Wind PPA Expires	12 50	Solar Wind PPA	12
2020			12	Solar	12
2021	(100) (100)	PPA Expires Bilateral Capacity Expires	12 200	Solar Bilateral Capacity (21-25)	12
2022			12	Solar	12
2023			12	Solar	12
2024			12	Solar	12
2025			12	Solar	12
2026	(90) (200)	WWVS Retires Bilateral Capacity Expires	12 200 50	Solar Advanced CC Wind PPA	(28)
2027			12	Solar	12
2028			12	Solar	12
2029					
2030					
2031					
2032					
2033					
2034	(190)	PPA Expires	260	Advanced CC	70
2035					
2036					
2037					
Total	(780)		992		212

Source: Indiana Municipal Power Association 2017 IRP. Pg. 1-13

e) Indianapolis Power & Light Company – 2016 IRP

As confirmation of this strategy, IPL retired 260 MW of coal-fired generation, converted 630 MW of coal-fired generation to gas, and completed the 671 MW Eagle Valley Combined Cycle Gas Turbine ("CCGT") on April 28, 2018. The following table shows how IPL's resource mix changed over the period 2007-2017.

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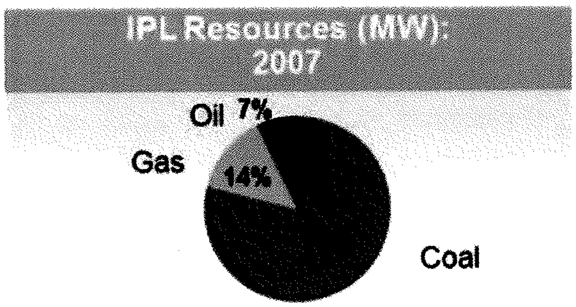
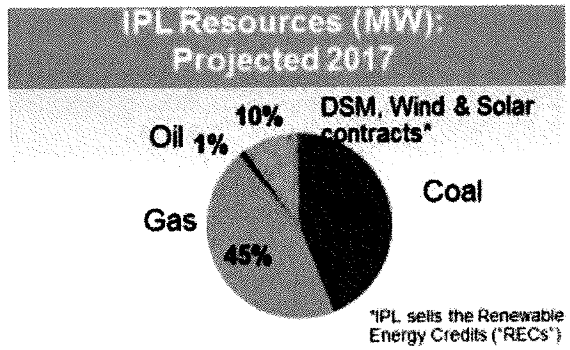




Source: Indianapolis Power & Light 2016 IRP. Pg. 3

In the IRP IPL embraced flexibility for future resources:

> Optionality will take us many places, but at its core, an option is what makes you antifragile and allows you to benefit from the positive side of uncertainty, without a corresponding serious harm from the negative side (Page 2).
>
> IPL has been a leader in Indiana in taking steps to change its portfolio, moving toward cleaner resource options through offering Demand Side Management ("DSM") programs, replacing coal-fired generation with natural gas-fired generation, securing wind and solar long-term contracts known as Purchased Power Agreements ("PPAs"), and building the first battery energy storage system in the Midcontinent Independent System Operator's ("MISO's") region. IPL plans to continue this transition proactively while simultaneously maintaining high reliability and affordable rates (Page 1).

The 2016 IRP, IPL contended, given the information available in 2015 and 2016, the *hybrid preferred resource portfolio* in the last column is a more appropriate solution. IPL cited technology costs that may decrease more quickly than currently projected which would likely drive changes in renewable and distributed generation penetration (Page 9). The below table details the four primary scenarios that were considered by IPL.

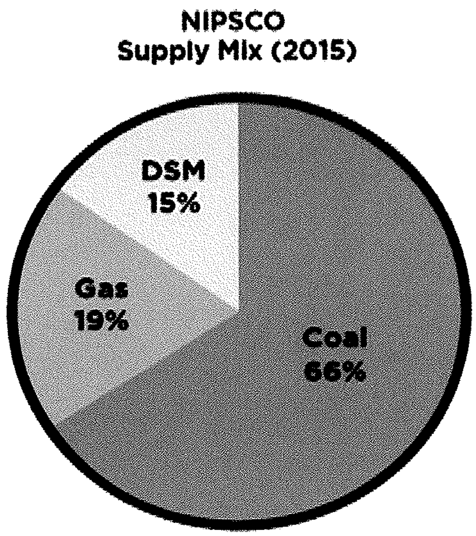
	Final Base Case	Strengthened Environmental	Distributed Generation	Hybrid
Coal	1078	0	1078	1078
Natural Gas	1565	2732	1565	1565
Petroleum	11	11	11	0
DSM and DR	208	218	208	212
Solar	196	645	352	398
Wind with ES*	1300	4400	2830	1300
Battery	500	0	50	283
CHP	0	0	225	225
totals	4858	8006	6319	5060

It should also be noted that IPL has been a leader in the deployment of Advanced Metering Infrastructure (AMI) that provides IPL with sub-hourly usage information. This very discrete data can be used to enhance the credibility of IPL's load forecasting, opportunities to establish more precise rates that recognize the cost of providing electricity varies continuously, aid in the evaluation, measurement, and valuation (EM&V) of energy efficiency programs, demand response, distributed energy resources, and renewable resources, enables IPL to evaluate non-utility resources on a more comparable bases to utility resources, provides information needed to integrated new technologies such Energy Storage (e.g., batteries) and Electric Vehicles (EV), and improves the information need for distribution system planning which may result in improved distribution reliability.

f) Northern Indiana Public Service Company – 2016 IRP

NIPSCO's 2015 coal-fired generation accounted for 66 percent of its resource mix, which was a 24 percent decrease from 2010. Natural gas generation constituted 19 percent in 2015. DSM, particularly the industrial interruptible program, accounted for about 15 percent of the resource mix in 2015.

NIPSCO retired Bailly Generating Station ("Bailly") Units 7 and 8 by May 2018. The replacement capacity necessary to meet the customer demand during the short-term action plan period would range from approximately 150-200 MW and would be addressed with either short-term purchase power agreements and/or market capacity purchases, whichever provides the best alignment of costs and mitigation of risks for customers.



Source: Northern Indiana Public Service Company 2016 IRP. Pg. 4

NIPSCO, like other Indiana utilities, is using a combined cycle generating unit as a proxy for its next resource. However, NIPSCO, in the 2018 IRP under development is issuing an "all source Request for Proposals" as a means of securing future resources. According to NIPSCO, its supply strategy for the next 20 years is expected to:

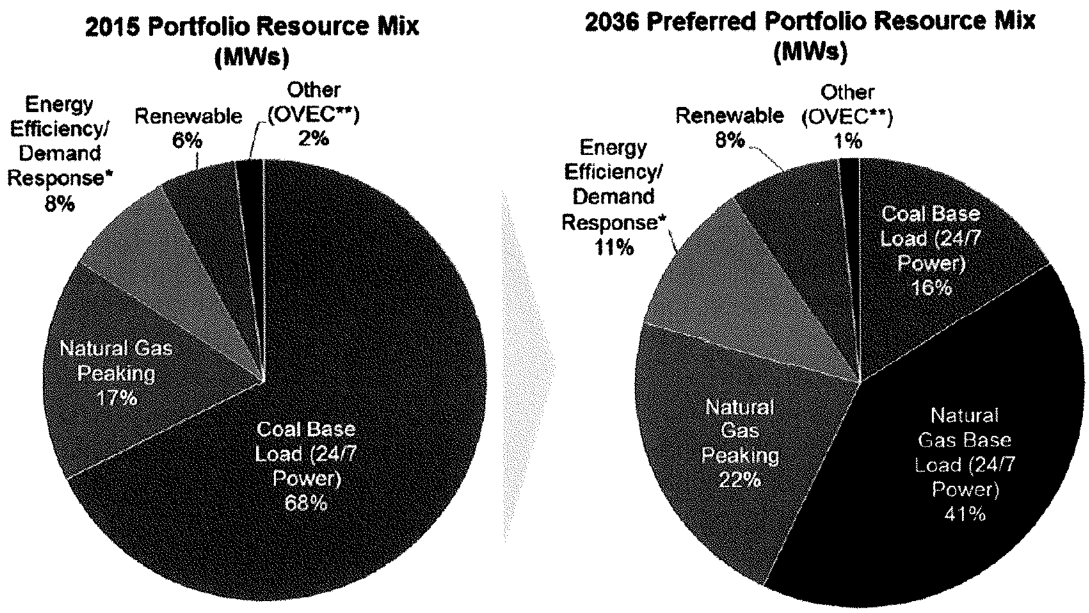
- Lead to a lower cost, cleaner, diverse and compliant portfolio by retiring 50 percent of NIPSCO's coal capacity by the end of 2023;
- Continue the company's commitment to energy efficiency and demand response by including programs that are economically viable for all customers;
- Continue to comply with environmental regulations, specifically the Effluent Limitation Guidelines and Coal Combustion Residuals for the retained coal-fired generation;
- Maintain an appropriate level of interruptible service for NIPSCO's major industrial customers;
- Reduce customer and company exposure to customer load, market, and technology risks by intentionally allocating a portion of the portfolio to shorter duration supply;
- Strongly consider cost to customers, while considering all technologies and fuels as viable to provide shorter duration supply;
- Add combined cycle gas turbine capacity to meet supply needs that are not covered by shorter duration supply options;
- Continue to evaluate additional supply retirements in light of changing market conditions and policy requirements;
- Continue to invest in infrastructure modernization to maintain safe and reliable delivery of energy services; and
- Continue to comply with North American Electric Reliability Corporation Critical Infrastructure Protection cyber security standards.

g) Southern Indiana Gas & Electric Company – 2016 IRP

SIGECO's current generation mix consists of approximately 1,360 MW of installed capacity. This capacity consists of approximately 1,000 MW of coal fired generation (68 percent), 245 MW of gas fired generation, 3 MW of landfill gas generation, purchase power agreements totaling 80 MW from wind, and a 1.5 percent ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to 32 MW. SIGECO's preferred resource plan would have the mix of natural gas and coal essentially swapping places in its generation resource mix. Natural gas would end the 20 year planning period at 63 percent of the resource portfolio, and coal would account for 16 percent. The small difference is made up for with small increases to energy efficiency and renewable.

SIGECO noted on page 9 of the Non-Technical Summary that the cost of renewable resources continue to decline but are still expected to be more expensive in the Midwest over the next several years. SIGECO also expressed the concern that they need to learn more about integrating solar resources in its territory:

> Based on the IRP planning process, SIGECO has selected a preferred portfolio plan that balances the energy mix for its generation portfolio with the addition of a new combined cycle gas turbine facility and solar power plants and significantly reduces its reliance on coal-fired electric generation. SIGECO's preferred portfolio reduces its cost of providing service to customers over the next 20 years by approximately $60 million as compared to continuing with its existing generation fleet… SIGECO will continue to evaluate its preferred portfolio plan in future IRPs to ensure it remains the best option to meet customer needs (Non-Technical Summary, Page 2 and graph on page 5).



Source: Southern Indiana Gas & Electric Company 2016 IRP. Pg. 46

SIGECO is proposing in Cause No. 45052 to diversify its generation fleet based on its 2016 Integrated Resource Plan by investing in a new CCGT sized to replace certain coal-fired units that will be retired at the end of 2023. SIGECO is seeking a CPCN to construct a 2x1 F class technology CCGT with capacity of 800 to 900 MW, to be constructed on the ground adjacent to SIGECO's Brown Generating Station.

Consistent with the 2016 IRP, SIGECO plans to retire Culley Unit 2 and the Brown Units 1 and 2 once the CCGT is operational. According to SIGECO Culley Unit 2's age and efficiency will not justify further capital investment to allow it to continue to operate in the future. Brown Units 1 and 2 would require significant capital investment, including construction of a new scrubber, to allow them to continue to operate in the future. While SIGECO has agreed to continue its joint operation of Warrick Unit 4 through December 31, 2023, the continued operation of that unit is not economic and is further complicated because ALCOA, following its recent organizational and operational changes, is not able to unconditionally commit to use of the jointly owned unit as part of its future operations. Based on the 2016 IRP and updated IRP modeling completed in 2017, SIGECO plans to retire 73% of its current coal-fired generation fleet and diversify its generation portfolio by adding the CCGT at the end of 2023.

h) Wabash Valley Power Association – 2017 IRP

From 2018 to 2020, Wabash Valley expects to meet its incremental capacity needs primarily by purchasing capacity through the MISO's capacity auctions or bilateral transactions. After 2020, Wabash Valley will seek a resource mix that closely aligns with its average load factor of approximately 55-65 percent. That is, Wabash Valley plans to attain a power supply resource ratio of approximately 60 percent baseload/intermediate capacity to 40 percent peaking capacity with a move toward a greater percentage of natural gas units (e.g. combined cycle gas turbines and peaking plants) (Wabash Valley Power Association 2017 IRP pg. 5).

Wabash Valley will purchase output from three wind projects from 2018 to 2020. Wabash Valley members will continue to run and enhance its energy efficiency programs and may choose to continue to build demand response resources in the near term. Past 2020, Wabash Valley's resource plan anticipates building 600 MW of baseload combined cycle resources and 350 MW of peaking combustion turbine resources along with 50 MW of energy efficiency. The expiration of existing purchase power agreements drives the need for these resources. At the end of the 20-year plan horizon in 2036, Wabash Valley's current base expansion plan forecasts that its energy and capacity needs will be served as depicted in the following charts.

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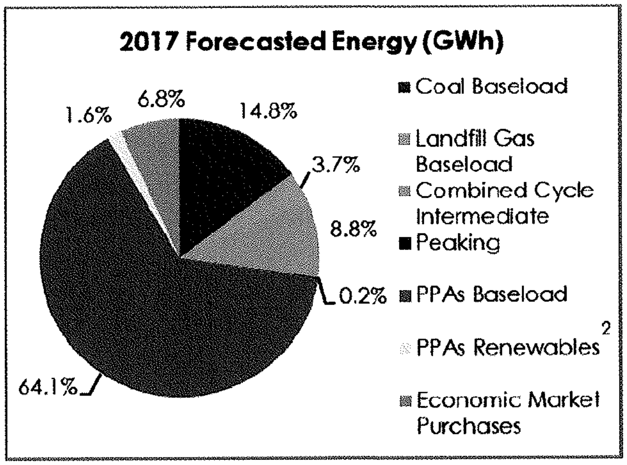
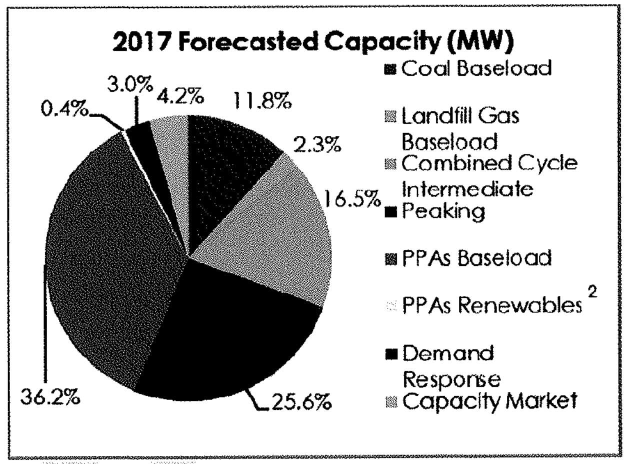
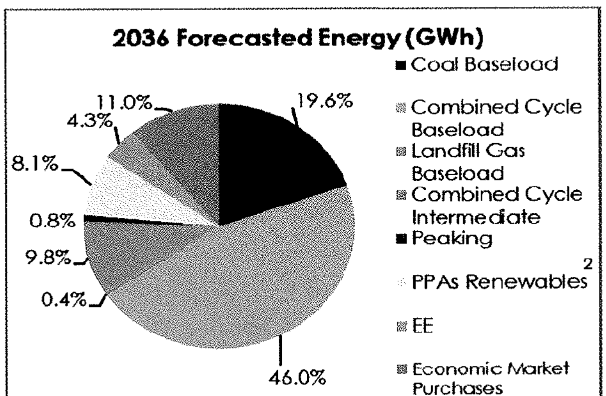
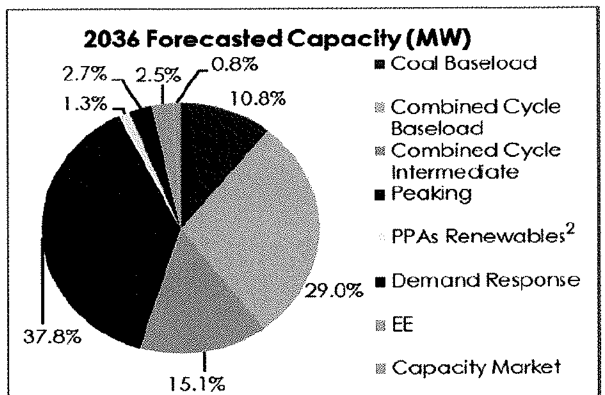




Source: Wabash Valley Power Association 2017 IRP. ES-Page 3

2036 Resources[1]





Source: Wabash Valley Power Association 2017 IRP. ES-Page 7

Each year Wabash Valley works with its Members to evaluate the power supply environment and to determine how to incorporate DR programs into the overall power supply portfolio. Demand Response programs continue to be an integral part of Wabash Valley's power supply portfolio with the primary purpose to keep power supply costs as low as possible. The Company now approaches DR programs as a resource, just like a peaking plant. (Page 24)

In 2011, Wabash Valley created two rate riders that allowed end use commercial and industrial customers the ability to participate in MISO's Emergency Demand Response Initiative and PJM's Emergency Load Response Program. Since 2012, Wabash Valley has offered the PowerShift® program, an updated DLC program. To date, 19 of the 23 Members have signed agreements to participate in the PowerShift® program. The PowerShift® program includes participants' water heaters (WH), air conditioners (AC), pool pumps (PP), field irrigators (FI), entire homes (EH), ditch pumps (DP) and grain dryers (GD). Please see the table below for details as of June 1, 2017. Page 23PowerShift® program, an updated DLC program. To date, 19 of the 23 Members have signed agreements to participate in the PowerShift® program. The PowerShift® program includes participants' water heaters (WH), air conditioners (AC), pool pumps (PP), field irrigators (FI), entire homes (EH), ditch pumps (DP) and grain dryers (GD). Please see the table below for details as of June 1, 2017. (Page 23 of IRP)

Wabash Valley started offering EE programs to its Member cooperatives in 2008 with the Touchstone Energy® Home Program, a residential new construction program focused on helping builders and homeowners construct a high performance, comfortable, durable and low energy cost home. Since 2008, the Company has worked jointly with our Member cooperatives, retail members and our Power Supply staff to develop attainable savings goals that lessen baseload power supply costs and increase retail member satisfaction throughout the service territory (Page 27). In Wabash Valley's 2017 IRP, the generation and transmission cooperative (G&T) said its members realized the following savings from energy efficiency. (Wabash Valley Power Association 2017 IRP, page 21).

Energy Efficiency MWh Savings 2010-2017

Wabash Valley EE Savings (MWh)								
	2010	2011	2012	2013	1/2014 – 6/2015	7/1/2015 – 3/31/2016	4/2016 – 12/2016	1/2017 – 12/2017 (As of 8/2017)
MWh Savings	5,043	4,898	13,579	22,717	27,330 Verified	23,488 Verified	64,604 Verified	25,192 Goal: 34,277

Source: Wabash Valley Power Association 2017 IRP. Pg. 31

Energy Efficiency Cumulative Program Highlights 2008-2017 (As of 8/2017)

Cumulative Program Highlights	
Residential Member Participants	41,481
C&I Member Participants	1,312
Total Amount of Incentives Paid	$14,299,000
Avoided Power Supply Cost @ $40/MWh	$17,268,000

The savings goal for 2017 is 34,277 MWh.

Source: Wabash Valley Power Association 2017 IRP. Pg. 31

2. Indiana Resource Mix Analysis

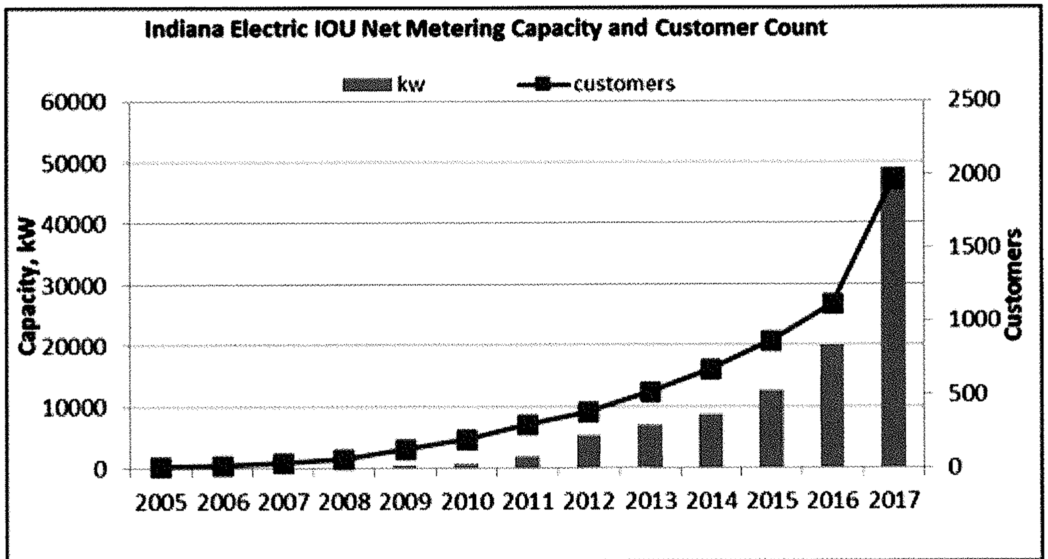
As stated earlier, Indiana's electric resources are changing. Over the next 20 years, a significant number of coal-fired generation plants will likely be retired. Possible resource additions will most often consist of natural gas generation plants and renewable resources, as well as energy efficiency and demand response. While many of these changes started with increased federal environmental regulations regarding coal, the sustained lower prices for natural gas are a major factor, shifting the economics toward generation fueled by natural gas. Because IRPs look at the lowest cost options across multiple scenarios and risk factors, lower cost natural gas is often selected through the modeling as a preferred option for future resource additions.

3. Renewable Resources in Resource Mix

Indiana utilities' resource mix show an increase in renewable resources, particularly wind. As the growth rate of wind and solar has been significant, the total amount of renewable resources, as a percent of all resources in Indiana is still very small but an increasing part of utility resource portfolios.

The total amount of installed wind capacity in Indiana is about 2,023 MW. This constitutes about 85% of all renewable installed resource capacity in Indiana. Much of this power is sold out of state. The amount of wind power under purchase power agreements by the five largest IOUs, is about 1,168 MW with about 301 MW purchased from out-of-state wind generators. As of May 2018, the five IOUs in Indiana have about 866 MW of purchased power agreements for wind, according to IURC data. Based on the IRPs, total wind resources are expected to grow as utilities build or contract for utility-scale wind resources as indicated in their most recent IRPs.

Net metering allows customers with small renewable facilities to receive a credit for excess electricity produced at the retail rate. As the following graph demonstrates, net metering has grown significantly, especially in terms of number of customers, but provides only a small percentage of the generation capacity in Indiana. In 2017 Senate Enrolled Act 309 became law, limiting how long eligible customers could qualify for net metering and creating a new compensation rate when net metering will no longer be available. The 2017 increase in both customer participation and net metering capacity is likely due to the new legislation.



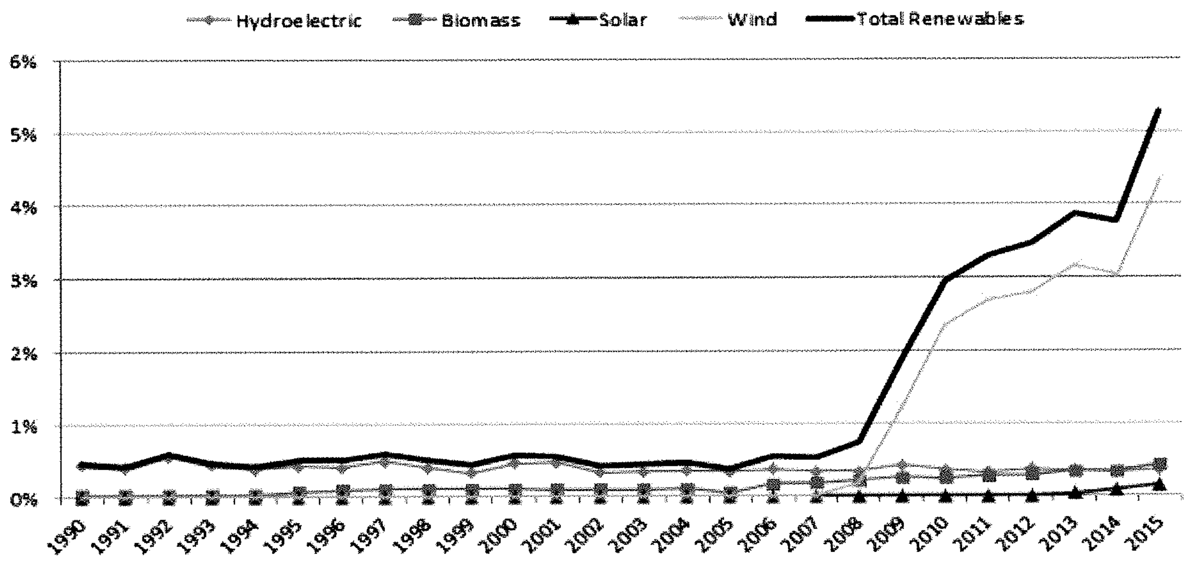
Another option for renewable resources is the Feed-in-Tariff or FIT [8]; however, as evidenced by the table below, this has a very limited application in Indiana. New customers cannot join the IPL FIT, and NIPSCO's FIT is available until participation limits are reached.

	Wind (kW)	Photovoltaic (kW)	Biomass (kW)	Total (kW)
IPL	0	94,384	0	94,384
NIPSCO	180	16,488	14,348	31,016
Total	**180**	**110,872**	**14,348**	**125,400**

The following graph shows through 2015 the rapid growth in wind generation in Indiana as a share of the total electricity generation in the state. It should be noted this graph includes energy for total wind energy generated in Indiana, not just the energy from Indiana wind facilities with long term purchase power contracts with Indiana utilities. Despite the rapid growth in solar, it contributes a very small share to the total electricity generated in Indiana.

[8] A FIT is a policy tool designed to encourage the development of renewable electricity generation by typically offering above market prices for output as well as the assurance that the utility will purchase the output. FITs are typically designed for small-scale renewable energy technologies that use solar, wind, and/or biomass.

Renewables share of Indiana electricity generation (1960-2014) EIA May 2017



Utilities expect roof top and utility scale solar resources to increase (this includes Community solar and concentrating photovoltaic).

Percent of Solar Total 1 kW and Up		
48%	IPL	91.9
15%	IMPA	28.0
20%	Duke	37.3
6%	Hoosier	11.8
6%	NIPSCO	11.5
5%	I&M	10.1
	Total	190.6

In addition, there is an expectation that distributed energy resources ("DERs"), including Combined Heat and Power as well as battery and other storage technologies, will increase their penetration over the 20 year planning horizon, which could be used to improve the reliable capacity of renewable resources. Newer technologies such as fuel cells may become economically feasible in the long-run. In the short-term, uncertainty about tax incentives may retard the growth in some technologies. In the longer-run, several projections suggest that increases in efficiency, combined with coupling intermittent technologies with back up generation or storage, will overcome the cost-effectiveness hurdle. Based on the IRPs, Indiana's utilities are expecting DERs to be an increasing factor in future years.

4. Energy Efficiency and Demand Response

Collectively referred to as Demand Side Management ("DSM"), energy efficiency and demand response have a relatively small but important percentage of the total resource mix (the level of energy efficiency savings achieved by a utility in a year generally ranges from 0.7 percent to around one percent by those customers participating in energy efficiency programs. Energy efficiency also results in some demand reduction.) According to the SUFG, demand response is expected to increase from about 1,000 MW to almost 1,200 MW over the 20-year forecast horizon (State Utility Forecasting Group's 2017 Electricity Projections. Pg. 3-1). Similarly, customer-owned resources, such as combined heat and power, have a small share of the total resource mix but it is growing in significance. These resources add important resource diversity and reliability, and have a positive influence on the timing, size, operational characteristics, and costs of new resources. That is, DSM minimizes risks for the utility and consumer. Moreover, in addition to lowering the cost to customers, these resources give customers greater control over their electric use and the attendant costs. As the sophistication and credibility of all aspects of IRP evolve, it seems certain that these resources will be increasingly essential to the operations of the electric power system.

Under Indiana law, the five investor-owned electric utilities must submit three-year energy efficiency plans to be approved by the Commission. All five utilities have energy efficiency plans that have been approved by the commission or in the review process. One of the basic determinations required by the law is that the Commission must find that the proposed three-year energy efficiency plan is reasonably achievable, consistent with the utility's integrated resource plan, and designed to achieve an optimal balance of energy resources in the utility's service territory.

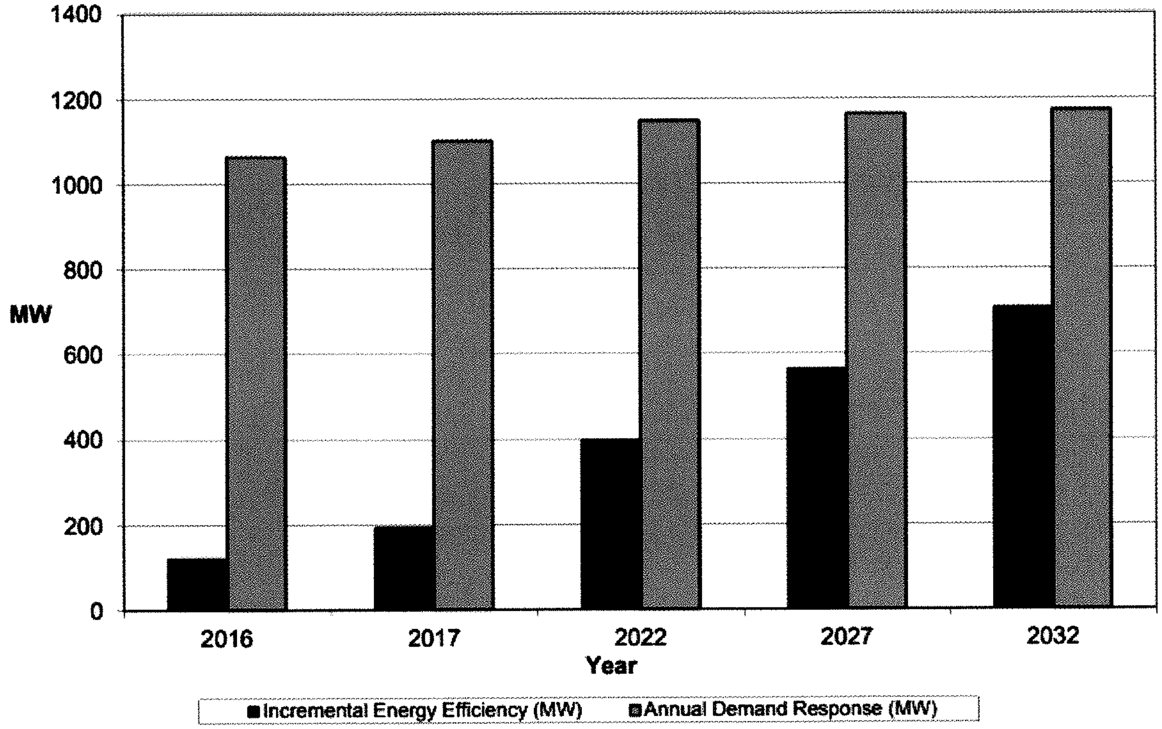
The following graphs are from the SUFG's 2017 statewide load forecast report and shows their projection of the kW impact of energy efficiency programs and demand response programs implemented through 2016.

2015 Embedded DSM and 2016 Incremental Peak Demand Reductions from Energy Efficiency and Annual Demand Response Program (MW)

2015 Embedded DSM	2016 Incremental Energy Efficiency	2016 Annual Demand Response
3,421	121	1,063

Source: State Utility Forecasting Group's 2017 Electricity Projections. Pg. 4-5

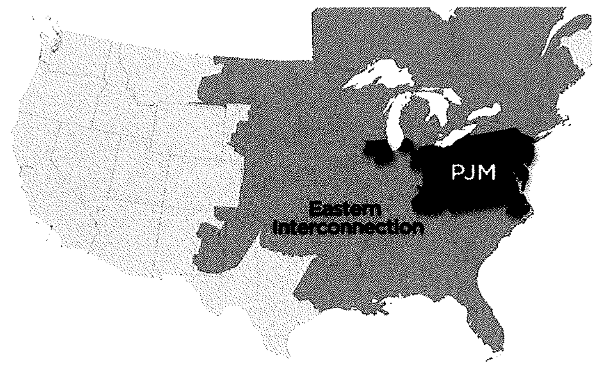
Projections of Incremental Peak Demand Reductions from Energy Efficiency and Demand Response



Source: State Utility Forecasting Group's 2017 Electricity Projections. Pg. 4-5

D. Resource and Operational Efficiencies Gained Through RTOs

With the reformation of the wholesale power markets in the late 1990s that resulted in the establishment of RTOs and Independent System Operators ("ISOs") like the MISO in Carmel, Indiana, and PJM, it became possible to efficiently trade power over great distances due to elimination of artificial anticompetitive barriers and pricing reform. This provided for more efficient and reliable operation of the electric system that tempered retail price increases. Today, all the large investor owned utilities with rates regulated by the Commission have joined, with Commission approval, an RTO. I&M is a member of PJM and the others (Duke, IPL, SIGECO, and NIPSCO) are members of MISO. The following graphics illustrate the geographic scope of these RTOs.



Fair and competitive access to a broadly diverse power supply meant that Indiana utilities no longer needed to plan their resources as if they were not interconnected to a vast and growing electrical grid. Understanding the current and future regional supply and demand for electric power is now an integral part of the Indiana IRP process.

Among other important functions, MISO and PJM facilitate the operations of the competitive wholesale power markets in a number of ways:
(1) Providing for regional control of generations resources that is much more cost effective than having individual utilities only use their own generation resources, which occurred before the RTOs.
(2) Transmission of electric power over vast distances, which is essential for reliability and the economic operation of the power system.
(3) A transmission planning process that allocates costs of new or upgraded transmission based on the principle that those that benefit pay their fair share of the costs.
(4) Increase in grid reliability, including assurances that utilities will have sufficient resources to meet their customers' needs even in unexpected circumstances.
(5) Informing their member utilities of the short- and long-term regional resource availability, which, in turn, enables Indiana utilities to alter their resource decisions to reduce costs for their customers and provide increased diversity of resources.

1. MISO Region

MISO's Value Proposition documents how the region benefits from its operation. In 2017, MISO calculated that its efforts provided between $2.9 billion and $3.7 billion in regional benefits, driven by enhanced reliability, more efficient use of the region's existing transmission and generation assets, and a reduced need for new assets. This collective, region-wide approach to grid planning and management delivers efficiencies that could not be achieved through statewide power pooling alone.

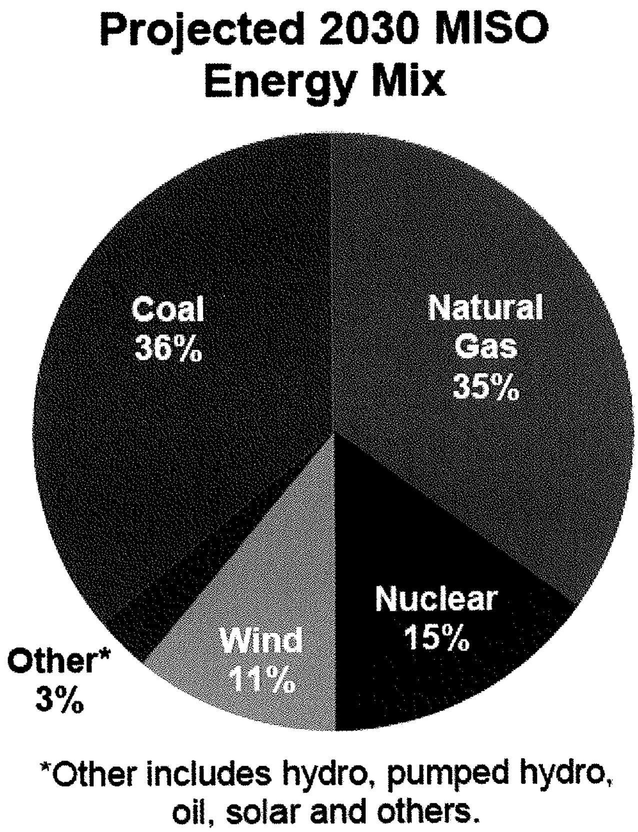
The MISO region is undergoing a significant change in the generating fleet composition. This is due to the cumulative cost effects of environmental controls, the aging of the coal and nuclear generating fleets, the greater than expected penetration of renewable resources, declining cost of energy efficiency, and especially the declining cost of natural gas and projections for low natural gas prices for several years.

On April 25, 2018, the MISO said it will have adequate electricity resources to meet demand for this summer. The regional transmission operator, whose grid covers 15 states in the Midwest and southern U.S., expects demand to peak at 124,700 MW, below available supply of 148,600 MW.[9] Beyond this summer and for the next several years, MISO expects that it will satisfy the reliability requirements promulgated by the North American Electric Reliability Corporation and approved by the Federal Energy Regulatory Commission to assure adequate supply to satisfy the forecasted demand and meet unforeseen contingencies.[10]

Within the MISO region, coal-fired generation constituted 75% of total energy production in 2010 and is projected to decline to about 36% in 2030. From 2000 until April 2016, approximately 9.1 GW of coal-fired capacity has been retired in MISO, according to SNL. By 2030 natural gas-fired generation is projected to increase from 15% in 2014 to 35% in 2030. Increasingly, natural gas sets the market price (Locational Marginal Price – LMP). As the graphic below illustrates, the amount of gas-fired generation is expected to constitute 35% by 2030 compared to 36% for coal-fired power plants.

[9] SNL, April 25, 2018.

[10] Prior to RTOs individual utilities were responsible for meeting their Resource Adequacy (RA includes adequate resources to meet expected needs and a *reserve margin* (RM) above the expected needs in the event of a contingency such as an unexpected outage at a large power plant). Reserve margins in excess of 20% were typical. The amount of reserve margins were based on a *rule of thumb* rather than rigorous analysis. With RTOs, the RA was based primarily on more rigorous mathmatical calcuations for the entire region. Setting RA for a large region afforded greater resource, fuel, and load diversity than was achievable by individual utilities. This reduced need for capacity due to RTO operations, results in savings for utilities and their customers. Generation resources located in the MISO region currently exceed the target level of RA. The current level of resources reflects the resource decisions made by the MISO market participants. These decisions are in reponse to a wide range of market forces and operational decisions besides the target level of RA set by the MISO on an annual basis.



The majority of MISO states are traditionally regulated and the jurisdictional utilities are *vertically integrated.* Statutory authorities of most states in MISO require jurisdictional utilities to provide assurances to their respective regulatory commissions that they have adequate resources and plan to have sufficient resources to meet their customers' electric needs reliably and economically. Indiana utilities, for example, have substantial assurance that prudent investment in resources will be recovered and investors will be adequately compensated. Despite the significant changes in generation resource composition and the anticipated changes as projected by the MISO, the Midwest should have a well balanced portfolio of generation resources and technologies, thus avoiding undue reliance on any one technology or fuel type for the foreseeable future.

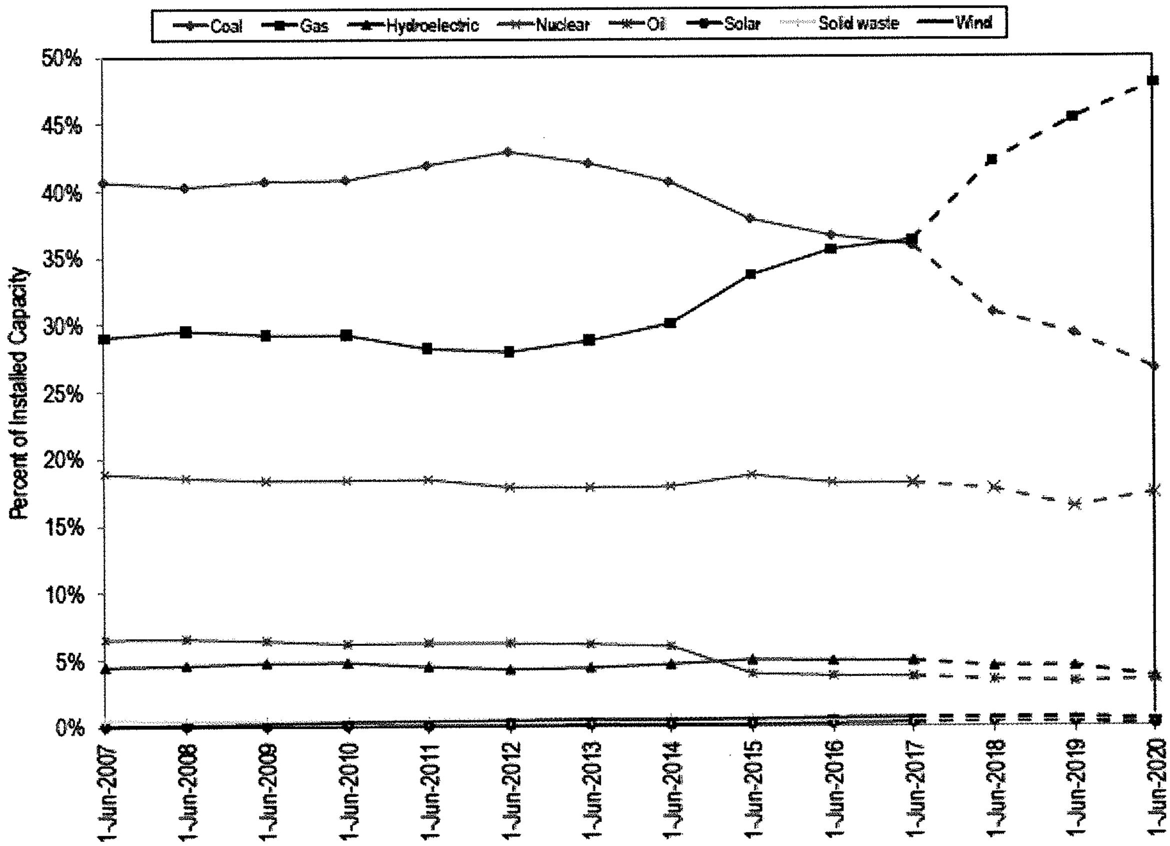
2. PJM Region

In contrast, the PJM is characterized by predominately *restructured states* that have little, if any, regulatory authority over the operation, construction and planning of generating resources. As a result, generation owners in those states are subject to market prices for economic viability. With the sharp decline in natural gas prices, projections for continued low-cost natural gas, and the relatively high capital cost of coal-fired (and nuclear) generating facilities, compared to natural gas generating facilities, a substantial amount of the coal-fired (and nuclear generation) is at considerable risk for continued economic viability. As a result, some states have or are considering additional out-of-market actions to subsidize the operations of coal and nuclear power plants. These PJM market issues do not affect I&M or its parent company, American Electric Power ("AEP"), as they do not participate in PJM's capacity auction. Instead, AEP meets PJM's Fixed Resource Requirement ("FRR"), in which AEP assures that it has sufficient resources to more than meet its customers' needs.

Similar to MISO, PJM provides an annual value proposition, summarizing the benefit of a regional grid and market operations in ensuring reliability, providing the needed generating capacity and reserves, managing the output of generation resources to meet demand and procuring specialized services that protect grid stability. As with all RTOs, PJM reacts to changes in demand in real time, adjusting generation to be in balance with demand and maintain the transmission system at safe operating levels. PJM seeks to manage transmission constraints – limitations on the ability of the transmission system to move power – by adjusting the output of generators whenever possible to promote efficiency. PJM's large footprint makes the transmission planning process more effective by considering the region as a whole, rather than individual states. The fact that PJM plans for resource adequacy over a large region results in a lower reserve margin than otherwise would be necessary.

Like the MISO, PJM is undergoing a significant change in the generating fleet composition. This is also due to the cumulative cost effects of environmental controls, the aging of the coal and nuclear generating fleets, the greater than expected penetration of renewable resources, declining cost of energy efficiency, and especially the declining cost of natural gas and projections for low natural gas prices for several years. Increasingly, distributed energy resources (DERs) are expected to be a factor in future years.

The following graph shows the percentage of PJM installed capacity (by fuel source) for June 1, 2007 through June 1, 2020 (PJM State of the Market Report 2018, Monitoring Analytics. Section 5, Page 240).



PJM is also expected to meet their anticipated demand without major concerns. Beyond this summer and for the next several years, PJM expects to have sufficient resources to satisfy the reliability requirements promulgated by the North American Electric Reliability Corporation and approved by the Federal Energy Regulatory Commission to assure adequate supply for satisfy the forecasted demand and meet unforeseen contingencies.

3. The National Perspective

The same factors that drive resource decisions in Indiana are also driving long-term resource decisions throughout the United States. Specifically, the projections for low natural gas prices relative to coal, continuing low forecasts for growth in energy use, projected costs of renewable resources, energy efficiency, demand response, higher maintenance costs for coal and nuclear generating units, and the relatively high cost of building new coal-fired and nuclear powered generating facilities compared to natural gas-fired generating units.

E. Comparative Costs of Other Means of Meeting Future Needs

Integrated resource planning considers all possible resources, including traditional resources such as coal, natural gas, and nuclear, as well as energy efficiency, demand response, wind, solar, customer-owned combined heat and power, hydro-electric and battery storage. An IRP considers all these resource options on a comparable basis.

A useful first way of estimating and comparing the potential cost of new resources is to consider the Levelized Cost of Electricity ("LCOE"). LCOE represents the per-megawatt hour ("MWh") cost (in discounted real dollars) of building and operating a generating plant over an assumed financial life of the facility. The LCOE includes capital costs, fuel costs, fixed and variable operations and maintenance costs, financing costs, and an assumed utilization rate for different types of resources. The importance of these factors varies among the technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small variable O&M costs, LCOE changes in rough proportion to the estimated capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect LCOE. The availability of various incentives, including state or federal tax credits (e.g., the Production Tax Credit for new wind, geothermal, and biomass and Investment Tax Credit for new solar photovoltaic and thermal plants), also affect the calculation of LCOE.

As with any cost factors forecast over a long period—20 years for IRPs in Indiana—there is uncertainty about all of these factors, and their values can vary as technologies evolve and as fuel prices change. The projected utilization rate (e.g., capacity factor) depends on the forecasted demand for electricity and the existing resource mix in an area where additional capacity is to be added. For Indiana utilities, the expected RTO dispatch will affect the utilization rate. That is, the existing and projected comparison between resources in a region can directly affect the economic viability of those resources. The direct comparison of LCOE across technologies is, therefore, difficult and can be misleading as a method to assess the economic competitiveness of various generation alternatives. Still, in each IRP, the cost comparison over time of all resources is inherent in the modeling process. Below is a table showing comparisons among different resources using the LCOE.

Estimated Levelized Cost of Electricity (Capacity-Weighted Average) for New Generating Resources Entering Service in 2022 (2017 $/ MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[2]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[3]	NB	NB	NB	NB	NB	NB	NA	NB
Coal with 90% CCS[3]	NB	NB	NB	NB	NB	NB	NA	NB
Conventional CC	87	13.0	1.5	32.8	1.0	48.3	NA	48.3
Advanced CC	87	15.5	1.3	30.3	1.1	48.1	NA	48.1
Advanced CC with CCS	NB	NB	NB	NB	NB	NB	NA	NB
Conventional CT	NB	NB	NB	NB	NB	NB	NA	NB
Advanced CT	30	22.7	2.6	51.3	2.9	79.5	NA	79.5
Advanced nuclear	90	67.0	12.9	9.3	0.9	90.1	NA	90.1
Geothermal	91	28.3	13.5	0.0	1.3	43.1	-2.8	40.3
Biomass	83	40.3	15.4	45.0	1.5	102.2	NA	102.2
Non-dispatchable technologies								
Wind, onshore	43	33.0	12.7	0.0	2.4	48.0	-11.1	37.0
Wind, offshore	45	102.6	20.0	0.0	2.0	124.6	-18.5	106.2
Solar PV[4]	33	48.2	7.5	0.0	3.3	59.1	-12.5	46.5
Solar thermal	NB	NB	NB	NB	NB	NB	NB	NB
Hydroelectric[5]	65	56.7	14.0	1.3	1.8	73.9	NA	73.9

Source: Energy Information Administration – Annual Energy Outlook 2018

1. Fuel Price Projections Influence Comparative Costs

As the SUFG stated:

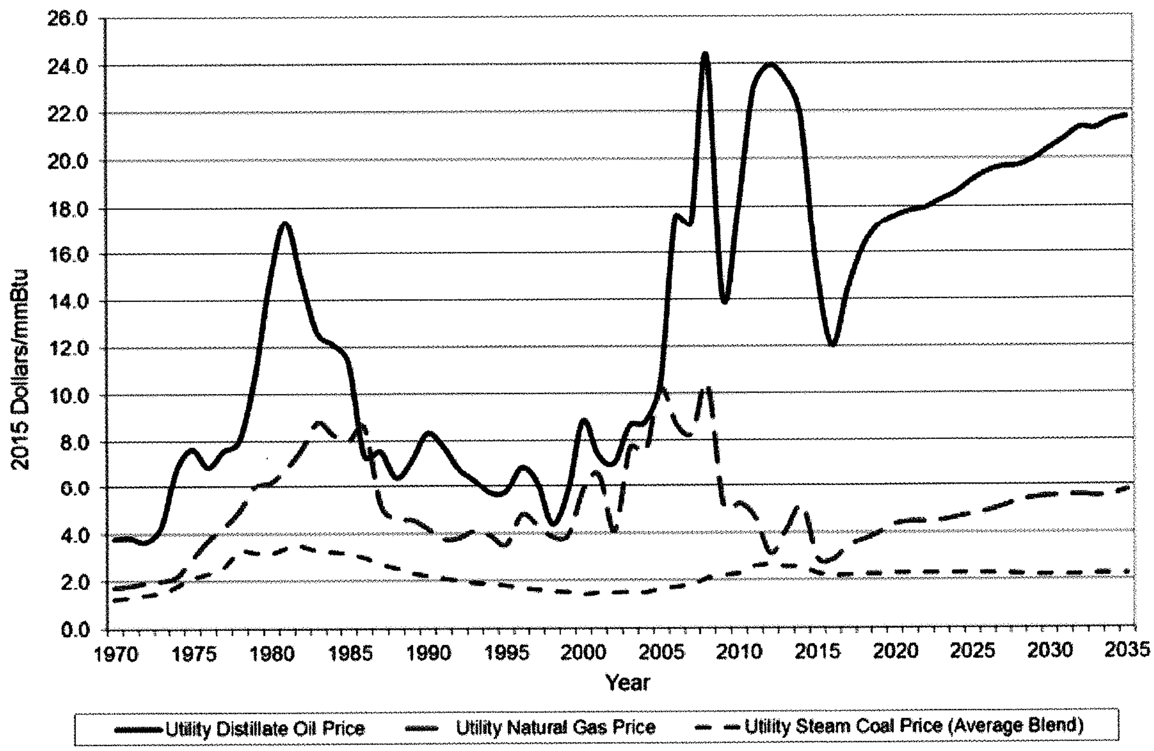
> SUFG's current assumptions are based on the January 2017 projections produced by the Energy Information Administration (EIA) for the East North Central Region. SUFG's fossil fuel real price projections are as follows: Natural Gas Prices: Natural gas prices decreased significantly in 2009 relative to the high prices of 2008. Prices then rebounded somewhat in 2010 before declining again through 2012 before increasing back to 2010 levels by 2014. However, natural gas prices dropped again in 2015 to a level lower than that of 2012, followed by a slight decrease in 2016. They are projected to increase gradually for the remainder of the forecast horizon. Utility Price of Coal: Coal price projections are relatively flat in real terms throughout the entire forecast horizon as coal consumption decreases due to more natural gas and renewable generation observed in the electric power sector (Page 1-3).

Similarly in the Energy Information Administration's Annual Energy Outlook 2018, March 26, 2018:

> Future growth in U.S. crude oil and natural gas production is projected to be driven by the development of tight oil [1] and shale gas [2] resources. However, a great deal of uncertainty surrounds this result. In particular, future domestic tight oil and shale gas

production depends on the quality of the resources, the evolution of technological and operational improvements to increase productivity per well and to reduce costs, and the market prices determined in a diverse market of producers and consumers, all of which are highly uncertain. [D]omestic dry natural gas production increases rapidly (more than 5% annually) through 2021 and then slows to an annual average growth rate of 1% through 2050, reaching 43.0 trillion cubic feet (Tcf) per year in 2050 in the Reference case.

Utility Real Fossil Fuel Prices



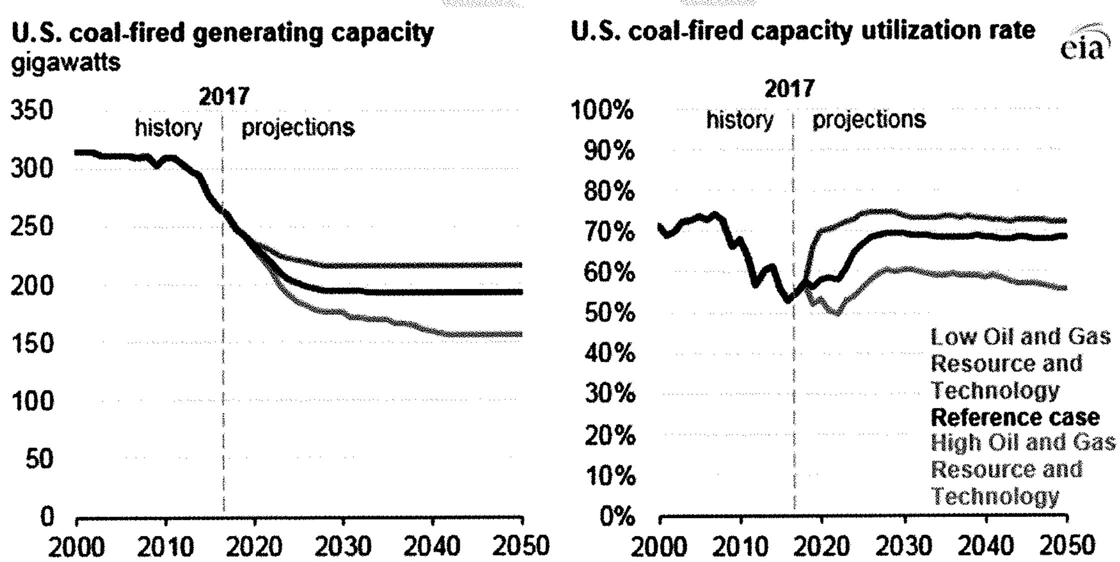
As noted by the SUFG:

> The prices of fossil fuels such as coal, natural gas and oil affect electricity demand in separate and opposing ways. To the extent that any of these fuels are used to generate electricity, they are a determinant of average electricity prices. Around 65% of electricity generation for Indiana consumers was fueled by coal in 2016. Thus, when coal prices increase, electricity prices in Indiana rise and electricity demand falls, all else being equal. On the other hand, fossil fuels compete directly with electricity to provide end-use services, i.e., space and water heating, process use, etc. When prices for these fuels increase, electricity becomes relatively more attractive and electricity demand tends to rise, all else being equal. As fossil fuel prices change, the impacts on electricity demand are somewhat offsetting. The net impact of these opposing forces depends on their impact on utility costs, the responsiveness of customer demand to electricity price changes and

the availability and competitiveness of fossil fuels in the end-use services markets (Indiana Electricity Projections: The 2017 Forecast, SUFG page 4-3).

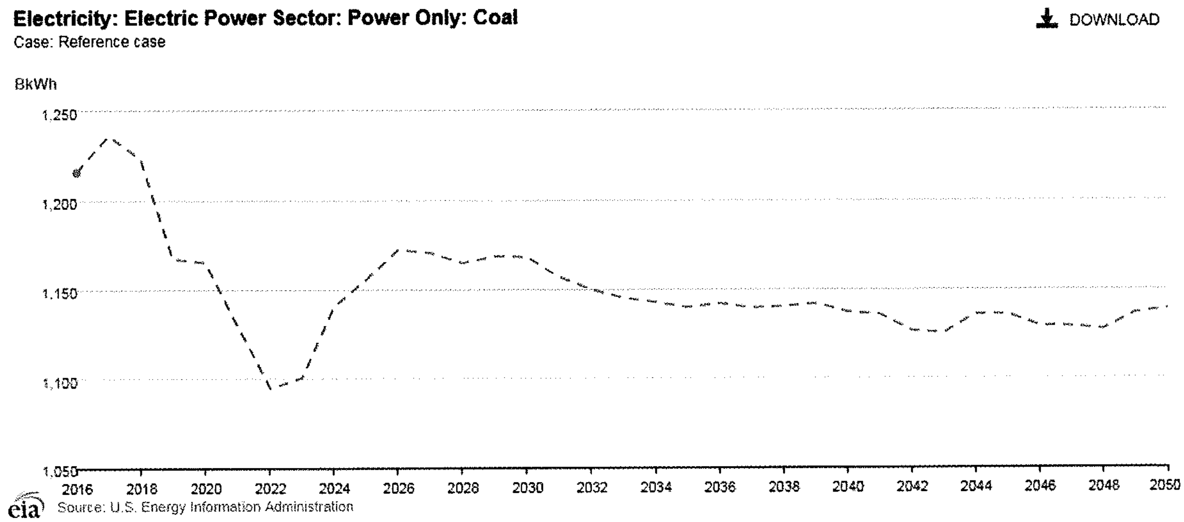
2. The Changing Fuel used in Generation Resources in the United States

The following graphic prepared by the Energy Information Administration projects three different scenarios or possible futures. Specifically, better understand the potential risks, EIA constructed a "base case" (or "reference case" or "most expected case"), a high case that shows fewer coal retirements, and a lower case with more significant retirements of coal-fired generation. In these three potential outcomes, there are still significant decreases in the amount of coal-fired generating capacity in the United States in the first graph. In the second graph, while the utilization rate for coal-fired generation is lower than it was prior to the fracking boom, the remaining coal-fired power plants *may* have higher utilization rates than in the recent past, in large part depending on the price of natural gas relative to coal. In other words, the remaining coal fired fleet in 2019 and beyond may be dispatched more frequently. It is worth noting, however, that the low scenario shows a long-term decline in coal generation utilization (not being as frequently dispatched) if natural gas prices are lower than the base case projections.

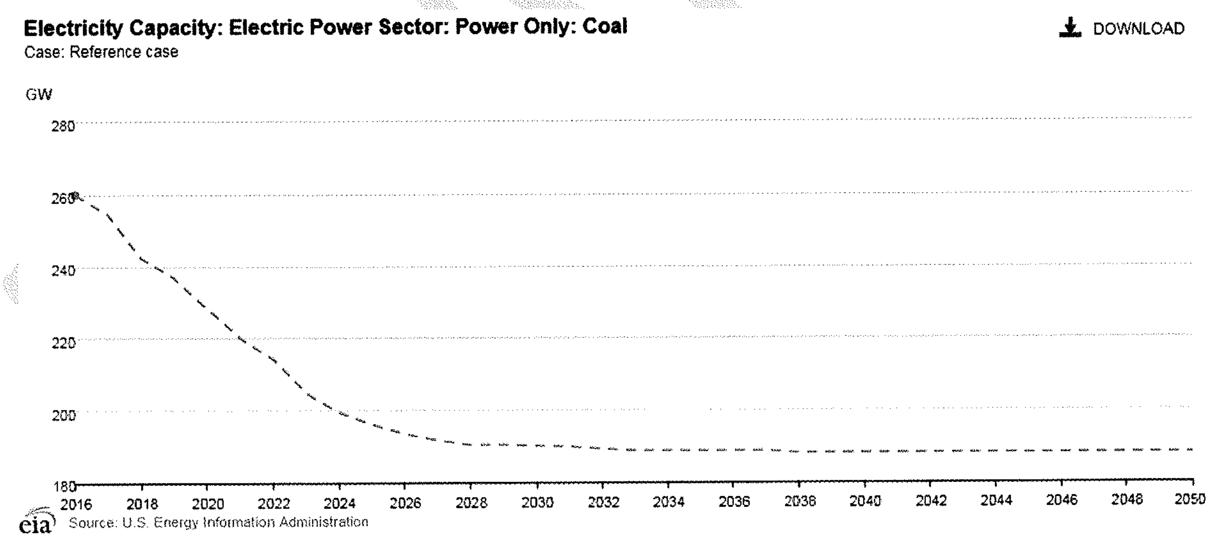


Source: U.S. Energy Information Administration, *Annual Energy Outlook 2018*

The following graph shows EIA's Annual Energy Outlook 2018 reference case (or base case) shows the dynamics caused primarily by retirements of older and smaller coal-fired generating units and the continuing effect of environmental regulations. This graph is a projection of the change in baseload coal-fired generation (billion kWh) over the 2016-2050 planning horizon. While the production of electricity from coal-fired generation drops precipitously until 2022 the remaining coal-fired generating units shows a marked increase in projected output through 2026 and a gradual decline thereafter. Of course, this scenario is just one of several possible future outcomes.



The following EIA "Reference Case" (or "Base Case") graph shows a precipitous decline in the amount of coal-fired capacity (in MW) of the entire 2016-2050 planning horizon. Subsequent graphs layer in other resources to show the relative changes in the nation's resource mix over the 2016-2050 planning horizon.



The graph below represents EIA's reference scenario to depict the projected increases in the capacities (MW) of natural gas combined cycle generation compared to coal-fired generation over the 2016-2050 planning horizon.

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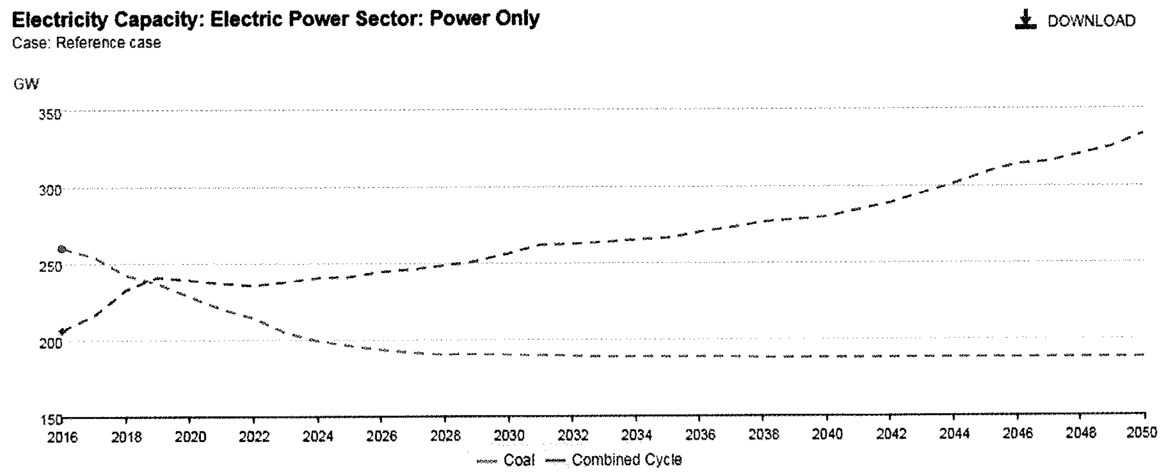
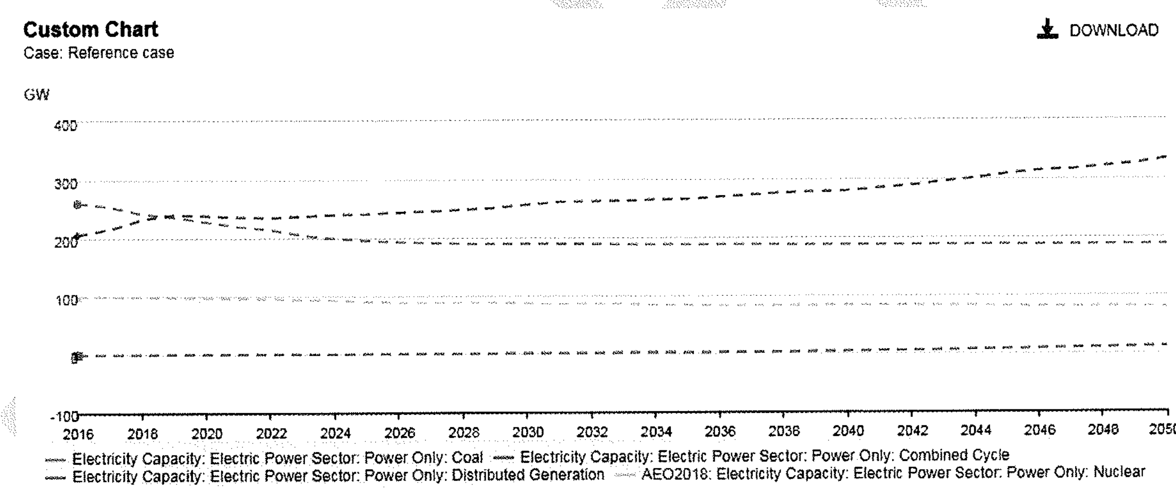


The following graph depicts the EIA's reference case for the projected capacity (MW) supplied by several resources including coal, natural gas combined cycle, nuclear, and distributed generation.



F. Conclusion

The importance of long-term planning is reflected in the commitment of the SUFG, MISO, PJM, and the EIA to continually conduct long-term resource planning that informs the Integrated Resource Planning conducted by Indiana utilities. The IRPs are intended to serve as objective guides for utilities, policymakers, and stakeholders to anticipate possible futures rather than a definitive plan of action. The credibility of the IRP analysis necessitates the use of state-of-the-art planning tools to construct a broad range of scenarios that reflect the dynamic nature of the environment for the electric utility industry. These scenarios, and the resulting resource portfolios, are intended to inform decision-makers of the risks and uncertainties inherent in the planning of future resources and the attendant costs and benefits. The credibility of the analysis is critical to the efforts of Indiana utilities to maintain as much optionality as possible - which includes *off ramps* - to react quickly to changing circumstances and make appropriate changes in the resources.

Based on the 2015 through 2017 IRPs, the SUFG report, information from MISO and PJM as well as information from the EIA, the expectation is that Indiana's electric needs, as well as the electric requirements of the region and the nation will increase gradually over the next 20 years. Indiana utilities take their obligations to provide reliable and economical service very seriously and this commitment is consistent with their long-term resource planning processes. Due in large part to the likely retirement of additional coal-fired power plants, new resources (including traditional generation, energy efficiency, demand response, customer-owned resources / distributed energy resources, and new technologies) will be needed in the 2025-2035 timeframe. Indiana utilities procurement of future resources and maintaining optionality will be facilitated by MISO and PJM.

IV. Appendices

APPENDIX 1
Cost and Performance Characteristics of New Central Station Electricity Generating Technologies
Overnight Construction Costs

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost (2017 $/kW)	Project Contingency Factor[2]	Technological Optimism Factor[3]	Total overnight cost[4,10] (2017 $/kW)	Variable O&M[5] (2017 $/MWh)	Fixed O&M (2017$/kW/yr)	Heat rate[6] (Btu/kWh)	nth-of-a-kind heat rate (Btu/kWh)
Coal with 30% carbon sequestration (CCS)	2021	650	4	4,641	1.07	1.03	5,089	7.17	70.70	9,750	9,221
Coal with 90% CCS	2021	650	4	5,132	1.07	1.03	5,628	9.70	82.10	11,650	9,257
Conv Gas/Oil Combined Cycle (CC)	2020	702	3	935	1.05	1.00	982	3.54	11.11	6,600	6,350
Adv Gas/Oil CC	2020	429	3	1,026	1.08	1.00	1,108	2.02	10.10	6,300	6,200
Adv CC with CCS	2020	340	3	1,936	1.08	1.04	2,175	7.20	33.75	7,525	7,493
Conv Combustion Turbine[7]	2019	100	2	1,054	1.05	1.00	1,107	3.54	17.67	9,880	9,600
Adv Combustion Turbine	2019	237	2	648	1.05	1.00	680	10.81	6.87	9,800	8,550
Fuel Cells	2020	10	3	6,192	1.05	1.10	7,132	45.64	0.00	9,500	6,960
Adv Nuclear	2022	2,234	6	5,148	1.10	1.05	5,946	2.32	101.28	10,460	10,460
Distributed Generation - Base	2020	2	3	1,479	1.05	1.00	1,553	8.23	18.52	8,969	8,900
Distributed Generation - Peak	2019	1	2	1,777	1.05	1.00	1,866	8.23	18.52	9,961	9,880
Battery Storage	2018	30	1	2,067	1.05	1.00	2,170	7.12	35.60	N/A	N/A
Biomass	2021	50	4	3,584	1.07	1.00	3,837	5.58	112.15	13,500	13,500
Geothermal[8,9]	2021	50	4	2,615	1.05	1.00	2,746	0.00	119.87	9,271	9,271
MSW - Landfill Gas	2020	50	3	8,170	1.07	1.00	8,742	9.29	417.02	18,000	18,000
Conventional Hydropower[9]	2021	500	4	2,634	1.10	1.00	2,898	1.33	40.05	9,271	9,271
Wind	2020	100	3	1,548	1.07	1.00	1,657	0.00	47.47	9,271	9,271
Wind Offshore[8]	2021	400	4	4,694	1.10	1.25	6,454	0.00	78.56	9,271	9,271
Solar Thermal[8]	2020	100	3	3,952	1.07	1.00	4,228	0.00	71.41	9,271	9,271
Solar PV - tracking[8,11]	2019	150	2	2,004	1.05	1.00	2,105	0.00	22.02	9,271	9,271
Solar PV - fixed tilt[8,11]	2019	150	2	1,763	1.05	1.00	1,851	0.00	22.02	9,271	9,271

Source: Energy Information Administration – Annual Energy Outlook, April 2018

APPENDIX 2
Coal Fleet Retirements

	Retired Coal Units Since 1-1-2010				
	Coal Unit (Year In-service)	Owner	Summer Rating (MW)	Retire Date	Age at Retire Date
1	Edwardsport Unit 7 (1949) Unit 7 (1949)	Duke	45	01-01-10	61
2	Edwardsport Unit 8 (1951) Unit 8 (1951)	Duke	75	01-01-10	59
3	Mitchell Unit 5 (1959)	NIPSCO	125	09-01-10	51
4	Mitchell Unit 6 (1959)	NIPSCO	125	09-01-10	51
5	Gallagher Unit 1 (1959)	Duke	140	01-31-12	53
6	Gallagher Unit 3 (1960)	Duke	140	01-31-12	52
7	State Line Unit 1 (1929)	Merchant	197	01-31-12	83
8	State Line Unit 2 (1929)	Merchant	318	01-31-12	83
9	Harding Street Unit 3 (1941)	IPL	35	07-01-13	72
10	Harding Street Unit 4 (1947)	IPL	35	07-01-13	66
11	Mitchell Unit 9 (1966)	NIPSCO	17	10-01-13	47
12	Ratts Unit 2 (1970) Unit 2 (1970)	Hoosier	121	12-31-14	44
13	Ratts Unit 1 (1970) Unit 1 (1970)	Hoosier	42	03-10-15	45
14	Tanners Creek Unit 1 (1951)	I&M	145	06-01-15	64
15	Tanners Creek Unit 2 (1952)	I&M	142	06-01-15	63
16	Tanners Creek Unit 3 (1953)	I&M	195	06-01-15	62
17	Tanners Creek Unit 4 (1956)	I&M	500	06-01-15	59
18	Whitewater Valley 2 (1973)	IMPA	57	12-31-15	42
19	Eagle Valley 3 (1951)	IPL	40	04-15-16	65
20	Eagle Valley 4 (1953)	IPL	55	04-15-16	63
21	Eagle Valley 5 (1955)	IPL	61	04-15-16	61
22	Eagle Valley 6 (1956)	IPL	100	04-15-16	60
23	Wabash River Unit 2 (1953)	Duke	85	04-15-16	63
24	Wabash River Unit 3 ((1954)	Duke	85	04-15-16	62
25	Wabash River Unit 4 (1955)	Duke	85	04-15-16	61
26	Wabash River Unit 5 (1956)	Duke	95	04-15-16	60
27	Wabash River Unit 6 (1968)	Duke	318	04-15-16	48
28	Bailly Unit 7 (1962)	NIPSCO	160	05-01-18	56
29	Bailly Unit 8 (1968)	NIPSCO	320	05-01-18	50

	Coal to Gas Conversions 01-01-2010				
	Coal Unit (Year In-service)	Owner	Summer Rating (MW)	Conversion Date	Age at Retire Date
1	Harding Street Unit 5 (1958)	IPL	97	12-31-15	57
2	Harding Street Unit 6 (1961)	IPL	97	12-31-15	54
3	Harding Street Unit 7 (1973)	IPL	421	06-01-16	43

Coal Fleet Currently in Operation

Coal Units in Operation - In State

	Coal Unit	Owner	Summer Rating (MW)	Age in 2020	Year In-Service
1	Edwardsport IGCC	Duke	595.0	8	2012
2	Rockport 2	I&M	1,300.0	31	1989
3	Petersburg 4	IPL	537.4	34	1986
4	Schafer 18	NIPSCO	361.0	34	1986
5	Brown 2	SIGECO	233.1	34	1986
6	Rockport 1	I&M	1,300.0	36	1984
7	Merom 1	NIPSCO	505.0	37	1983
8	Schafer 17	NIPSCO	361.0	37	1983
9	Gibson 5	Duke	620.0	38	1982
10	Merom 2	Hoosier	483.0	38	1982
11	Gibson 4	Duke	622.0	41	1979
12	Schafer 15	NIPSCO	472.0	41	1979
13	Brown 1	SIGECO	227.8	41	1979
14	Gibson 3	Duke	630.0	42	1978
15	Petersburg 3	IPL	549.0	43	1977
16	Gibson 1	Duke	630.0	44	1976
17	Michigan City 12	NIPSCO	469.0	44	1976
18	Schafer 14	NIPSCO	431.0	44	1976
19	Gibson 2	Duke	630.0	45	1975
20	Culley 3	SIGECO	257.3	47	1973
21	Cayuga 2	Duke	495.0	48	1972
22	Cayuga 1	Duke	500.0	50	1970
23	Warrick 4 (ALCOA)	SIGECO	134.8	50	1970
24	Petersburg 2	IPL	396.2	51	1969
25	Petersburg 1	IPL	232.0	53	1967
26	Culley 2	SIGECO	88.3	54	1966
27	Gallagher 4	Duke	140.0	59	1961
28	Gallagher 2	Duke	140.0	62	1958

Coal Units in Operation - Out of State

Prairie State 1	IMPA Share	100.0	18	2012
Prairie State 2	IMPA Share	100.0	18	2012
Trimble County 2	IMPA Share	96.0	19	2011
Trimble County 1	IMPA Share	66.0	40	1990

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Coal Units in Operation with Status Notes based on IRPs

Coal Unit	Owner	Summer Rating (MW)	Age in 2020	Year In-Service	
Coal Units in Operation - In State					
Edwardsport IGCC	Duke	595.0	8	2012	
Rockport 2	I&M	1,300.0	31	1989	
Petersburg 4	IPL	537.4	34	1986	
Schafer 18	NIPSCO	361.0	34	1986	NIPSCO's 2018 IRP will review the status of this coal unit, 2016 IRP was retire the unit by 2023
Brown 2	SIGECO	233.1	34	1986	Vectren plans to retire the unit on 12-31-23, usinng updated 2016 IRP modeling in 2017
Rockport 1	I&M	1,300.0	36	1984	
Merom 1	NIPSCO	505.0	37	1983	
Schafer 17	NIPSCO	361.0	37	1983	NIPSCO's 2018 IRP will review the status of this coal unit, 2016 IRP was retire the unit be 2023
Gibson 5	Duke	620.0	38	1982	Duke's 2015 IRP indicates this unit retires in 2019
Merom 2	Hoosier	483.0	38	1982	
Gibson 4	Duke	622.0	41	1979	
Schafer 15	NIPSCO	472.0	41	1979	NIPSCO's 2018 IRP will review the status of this coal unit
Brown 1	SIGECO	227.8	41	1979	Vectren plans to retire the unit on 12-31-23, usinng updated 2016 IRP modeling in 2017
Gibson 3	Duke	630.0	42	1978	
Petersburg 3	IPL	549.0	43	1977	
Gibson 1	Duke	630.0	44	1976	
Michigan City 12	NIPSCO	469.0	44	1976	NIPSCO's 2018 IRP will review the status of this coal unit
Schafer 14	NIPSCO	431.0	44	1976	NIPSCO's 2018 IRP will review the status of this coal unit
Gibson 2	Duke	630.0	45	1975	
Culley 3	SIGECO	257.3	47	1973	Vectren in CN 45052 requests $90M to make unit EPA compliant beyond 12-31-23
Cayuga 2	Duke	495.0	48	1972	
Cayuga 1	Duke	500.0	50	1970	
Warrick 4 (ALCOA)	SIGECO	134.8	50	1970	Vectren plans to end the joint operating agrement with ALCOA on 12-31-23
Petersburg 2	IPL	396.2	51	1969	
Petersburg 1	IPL	232.0	53	1967	
Culley 2	SIGECO	88.3	54	1966	Vectren plans to retire the unit on 12-31-23, usinng updated 2016 IRP modeling in 2017
Gallagher 4	Duke	140.0	59	1961	Duke's 2015 IRP indicates this unit retires in2019
Gallagher 2	Duke	140.0	62	1958	Duke's 2015 IRP indicates this unit retires in2019
Coal Units in Operation - Out of State					
Prairie State 1	IMPA Sh.	100.0	18	2012	
Prairie State 2	IMPA Sh.	100.0	18	2012	
Trimble County 2	IMPA Sh.	96.0	19	2011	
Trimble County 1	IMPA Sh.	66.0	40	1990	

APPENDIX 3
Wind Purchased Power Agreements by Indiana's Investor-Owned Utilities

Wind Energy Purchased Power Agreements (PPAS) by Indiana Utilities (IOUs)			Indiana IOU In State Wind Purchases					
Utility	**Wind Farm**	**PPA (MW)**	**NIPSCO**	**Duke**	**Vectren**	**I&M**	**IPL**	**Total**
NIPSCO	Barton (IA)	50.0	-					-
Duke Indiana	Benton County (IN)	110.7		110.7				110.7
Vectren	Benton County (IN)	30.0			30.0			30.0
NIPSCO	Buffalo Ridge (SD)	50.4	-					-
I&M	Fowler Ridge I (IN)	100.4				100.4		100.4
I&M	Fowler Ridge II (IN)	50.0				50.0		50.0
Vectren	Fowler Ridge II (IN)	50.0			50.0			50.0
IPL	Hoosier (IN)	106.0					106.0	106.0
IPL	Lakefield (MN)	201.0					-	-
I&M	Headwaters (IN)	200.0				200.0		200.0
I&M	Wildcat I (IN)	100.0				100.0		100.0
I&M	Bluff Point	119.0				119.0		119.0
Total Indiana IOU In-State Purchases		866.1	-	110.7	80.0	569.4	106.0	866.1
Total Indiana IOU Out of State Purchases		301.4						
	Total Indiana IOU Purchases	1,167.5						

APPENDIX 4
Solar Photovoltaic Generation Greater than 1 MW (ac)

Operating Solar Photovoltaic Generators in Indiana 1 MW ac and Larger				
Location	Utility	Indiana County	Installed (MW ac)	Source
Crane Solar	Duke	Martin	17.25	Cause Numbers 44932 and 44734
Indy Solar No. 1 (Franklin Township)	IPL	Marion	10.00	IPL Feed-in-Tariff Cause No. 44018
Indy Solar No. 2 (Franklin Township)	IPL	Marion	10.00	IPL Feed-in-Tariff Cause No. 44018
Indianapolis Airport No. 1	IPL	Marion	9.80	IPL Feed-in-Tariff Cause No. 44018
Indianapolis Motor Speedway	IPL	Marion	9.00	IPL Feed-in-Tariff Cause No. 44018
Indy Solar No. 3 (Decatur Township)	IPL	Marion	8.64	IPL Feed-in-Tariff Cause No. 44018
Anderson II Solar Park	IMPA	Madison	8.20	SNL (IMPA)
Vertellus	IPL	Marion	8.00	IPL Feed-in-Tariff Cause No. 44018
Indianapolis Airport Phase II A	IPL	Marion	7.50	IPL Feed-in-Tariff Cause No. 44018
McDonald Solar	Duke	Vigo	5.00	Duke Website and Cause Nos. 44578, 44953
Pastime Farm	Duke	Clay	5.00	Duke Website and Cause Nos. 44578, 44953
Geres Energy	Duke	Howard	5.00	Duke Website and Cause Nos. 44578, 44953
Sullivan Solar	Duke	Sullivan	5.00	Duke Website and Cause Nos. 44578, 44953
Olive	I&M	St. Joseph	5.00	I&M Cause Number 44511
Lifeline Data Centers	IPL	Marion	4.00	IPL Feed-in-Tariff Cause No. 44018
Washington Solar Park	IMPA	Daviess	3.00	SNL (IMPA)
CWA Authority	IPL	Marion	3.83	IPL Feed-in-Tariff Cause No. 44018
Duke Realty #129	IPL	Marion	3.40	IPL Feed-in-Tariff Cause No. 44018
Crawfordsville Solar Park	IMPA	Montgomery	3.00	SNL (IMPA)
Peru Solar Park	IMPA	Miami	3.00	SNL (IMPA)
Greenfield Solar Park	IMPA	Madison	3.00	SNL (IMPA)
Rexnord Industries	IPL	Marion	2.80	IPL Feed-in-Tariff Cause No. 44018
Equity Industrial	IPL	Marion	2.73	IPL Feed-in-Tariff Cause No. 44018
Duke Realty #98	IPL	Marion	2.72	IPL Feed-in-Tariff Cause No. 44018
Duke Realty #87	IPL	Marion	2.72	IPL Feed-in-Tariff Cause No. 44018
Twin Branch	I&M	St. Joseph	2.60	I&M Cause Number 44511
Deer Creek	I&M	St. Joseph	2.50	I&M Cause Number 44511
Indianapolis Airport Phase II B	IPL	Marion	2.50	IPL Feed-in-Tariff Cause No. 44018
Lake County Solar, LLC - East Chicago	NIPSCO	Lake	2.00	NIPSCO Feed-in-Tariff Cause No. 43922
Lake County Solar, LLC - Griffith	NIPSCO	Lake	2.00	NIPSCO Feed-in-Tariff Cause No. 43922
Pendlton Solar Park	IMPA	Madison	2.00	SNL (IMPA)
GSA Bean Finance Center	IPL	Marion	1.80	IPL Feed-in-Tariff Cause No. 44018
Huntingburg Solar Park	IMPA	Dubois	1.80	SNL (IMPA)
Citizens Energy (LNG North)	IPL	Marion	1.50	IPL Feed-in-Tariff Cause No. 44018
Midlebury Solar, LLC	NIPSCO	Elkhart	1.50	NIPSCO Feed-in-Tariff Cause No. 43922
Portage Solar, LLC	NIPSCO	Porter	1.50	NIPSCO Feed-in-Tariff Cause No. 43922
Lincoln Solar, LLC	NIPSCO	Cass	1.50	NIPSCO Feed-in-Tariff Cause No. 43922
Lanesville Solar	Hoosier Energy	Harrison	1.10	SNL (Hoosier Energy)
Frankton Solar Park	IMPA	Madison	1.00	SNL (IMPA)
Bartholomew County Solar Farm	Hoosier Energy	Bartholomew	1.00	SNL (Hoosier Energy)
Decatur County Solar Farm	Hoosier Energy	Decatur	1.10	SNL (Hoosier Energy)
Jackson Solar Farm	Hoosier Energy	Jackson	1.10	SNL (Hoosier Energy)
Johnson County Solar	Hoosier Energy	Johnson	1.10	SNL (Hoosier Energy)
Ellettsville Solar Farm	Hoosier Energy	Monroe	1.08	SNL (Hoosier Energy)
Henryville Solar Farm	Hoosier Energy	Clark	1.08	SNL (Hoosier Energy)
New Haven Solar	Hoosier Energy	Allen	1.08	SNL (Hoosier Energy)
Scotland Solar	Hoosier Energy	Greene	1.10	SNL (Hoosier Energy)
Spring Mill Solar	Hoosier Energy	Lawrence	1.10	SNL (Hoosier Energy)
Grocers Supply Company	IPL	Marion	1.00	IPL Feed-in-Tariff Cause No. 44018
Hobart Solar, LLC	NIPSCO	Lake	1.00	NIPSCO Feed-in-Tariff Cause No. 43922
Valparaiso Solar, LLC	NIPSCO	Porter	1.00	NIPSCO Feed-in-Tariff Cause No. 43922
Waterloo Solar, LLC	NIPSCO	Dekalb	1.00	NIPSCO Feed-in-Tariff Cause No. 43922
New Castle Solar	Hoosier Energy	Henry	1.00	SNL (Hoosier Energy)
Tell City Solar Park	IMPA	Perry	1.00	SNL (IMPA)
Rensselaer Solar Farm	IMPA	Jasper	1.00	SNL (IMPA)
Richmond Solar Farm	IMPA	Wayne	1.00	SNL (IMPA)
		Total	190.63	

Percent of Solar Total 1 kW and Up		
48%	IPL	91.9
15%	IMPA	28.0
20%	Duke	37.3
6%	Hoosier	11.8
6%	NIPSCO	11.5
5%	I&M	10.1
	Total	190.6

APPENDIX 5
Renewable Resource Summary

Indiana Operating Renewable Generation Summary			
	Installed MW	Percent of State Total Installled MW	Percent of State Total Installled MW without Large Wind
Large Wind (above 100kW)	2,023.3	85.0%	
Solar (KW ac)	220.1	9.2%	61.6%
Hydro	58.1	2.4%	16.2%
Landfill Gas	45.6	1.9%	12.8%
Biomass Digesters	14.3	0.6%	4.0%
Coal Bed Methane	13.0	0.5%	3.6%
Small Wind (up to 100 kW)	6.3	0.3%	1.8%
Total	2,380.6	100.0%	100.0%

Note: This table includes the five IOU's and also the projects by Hoosier Energy, IMPA and WVPA. We use SNL to gather data for the three non IOU's.

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Renewable Resource Summary with Details

Installed Megawatts of Renewable Energy Generation in Indiana by Program

Utility	Feed-in-Tariffs			Net Metering		Other Programs							
Utility	Wind	Solar	Biomass Digesters	Wind	Solar	Utility Planned Solar	Utility Sponsored Solar	Small Wind Demos	Large Wind Purchase Power Agreements with Indiana Wind Farms	Merchant Wind (to Indiana or out of state consumers)	Hydro	Landfill Gas	Coal Bed Methane
Duke Indiana				2.2	7.3	4.0	37.3		110.7		45.00		
I&M				0.1	1.7		10.1	0.85	569.4		6.23		
IPL		94.4		0.1	1.6		0		106.0				
NIPSCO	0.2	16.5	14.3	2.8	2.1		0				6.82		
SIGECO				0.0	2.1	4.3	0.0		80.0			2.2	
WVPA							0					40.0	
IMPA							28.0						
Hoosier							10.84					3.4	13.0
Merchant Wind										1,157.2			
TOTAL	0.2	110.9	14.3	5.3	14.7	8.3	86.2	0.9	866.1	1,157.2	58.1	45.6	13.0
GRAND TOTAL	2,380.6												

Installed Megawatts of Renewable Energy Generation in Indiana by Resource

Wind									866.1	1,157.2				2,023.3
Solar		110.9			14.7	8.3	86.2							220.1
Hydro											58.1			58.1
Landfill Gas												45.6		45.6
Biomass Digesters			14.3											14.3
Coal Bed Methane													13.0	13.0
Small Wind	0.2			5.3				0.9						6.3
														2,380.6

		Percent
Wind	2,023.3	85.0%
Solar	220.1	9.2%
Hydro	58.1	2.4%
Landfill Gas	45.6	1.9%
Biomass Digesters	14.3	0.6%
Coal Bed Methane	13.0	0.5%
Small Wind	6.3	0.3%
Total	2,380.6	100.0%

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APPENDIX 6
Generation by Fuel Type for Indiana Consumption

Generation Percentage for Indiana Consumption by Fuel Type

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
Coal	85.5%	86.7%	88.5%	82.6%	77.7%	72.9%	76.3%	76.6%	67.9%	64.6%	64.5%	Coal
Nuclear	9.0%	8.0%	4.6%	7.9%	8.9%	9.6%	9.1%	9.4%	9.8%	9.8%	10.6%	Nuclear
Natural Gas, Other Gases	4.6%	4.3%	4.6%	6.3%	9.1%	13.4%	9.4%	9.2%	16.0%	19.3%	19.2%	Natural Gas, Other Gases
Wind	0.0%	0.2%	1.1%	2.2%	2.5%	2.5%	2.9%	2.7%	3.9%	3.9%	4.2%	Wind
Oil	0.1%	0.1%	0.1%	0.1%	1.0%	0.7%	1.3%	1.1%	1.2%	1.2%	0.1%	Oil
Hydro	0.3%	0.3%	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	Hydro
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%	0.2%	0.3%	Solar
Biomass	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	Biomass
Other	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.3%	0.4%	0.4%	0.3%	Other
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	Total

	2008	2017	Change
Coal	86.7%	64.5%	-22.3%
Nuclear	8.0%	10.6%	2.7%
Natural Gas, Other Gases	4.3%	19.2%	14.9%
Wind	0.2%	4.2%	4.0%
Oil	0.1%	0.1%	0.0%
Hydro	0.3%	0.4%	0.1%
Solar	0.0%	0.3%	0.3%
Biomass	0.2%	0.4%	0.2%
Other	0.3%	0.3%	0.0%
	100.0%	100.0%	100.0%

Notes:

1 This data is based on the EIA electric generation data for 2017 (preliminary) for Indiana

2 The production from the Cook Plant is based on the IM Power FERC Form 1 Data for 2017 and Form PR for 2016.

3 The IM Power Form PR for 2017 is not available as of 5-23-18.

4 This analysis assumes energy transfers in/out of Indiana will not change these percentages signiicantly.

APPENDIX 7
Map of Generating Units

DUKE ENERGY INDIANA
1. Gibson 3,132
2. Wabash River ....Retired
3. Cayuga.......................1,094
4. Edwardsport..................595
5. Gallagher 280
6. Noblesville 285
7. Connersville.....................86
8. Henry County 129
9. Madison (OH)................ 576
10. Miami Wabash 80
11. Vermillion 1-5.................355
12. Wheatland......................460
38. Markland 45

HOOSIER ENERGY
13. Merom 982
14. Holland (IL).....................312
15. Ratts..........................Retired
16. Lawrence 176
17. Worthington 175

INDIANA MUNICIPAL POWER AGENCY
18. Georgetown 2&3 146
19. Trimble County (KY) 162
20. Anderson........................ 139
21. Richmond..........................68
22. Whitewater Valley........Retired
39. Prairie State 200

INDIANA MICHIGAN POWER
23. Rockport......................2,600
24. Cook (MI).....................2,160
25. Tanners Creek............Retired

INDIANAPOLIS POWER & LIGHT
18. Georgetown 1&4............ 150
26. Petersburg......................1,715
27. Harding Street.................628
28. Eagle Valley...(under construction)

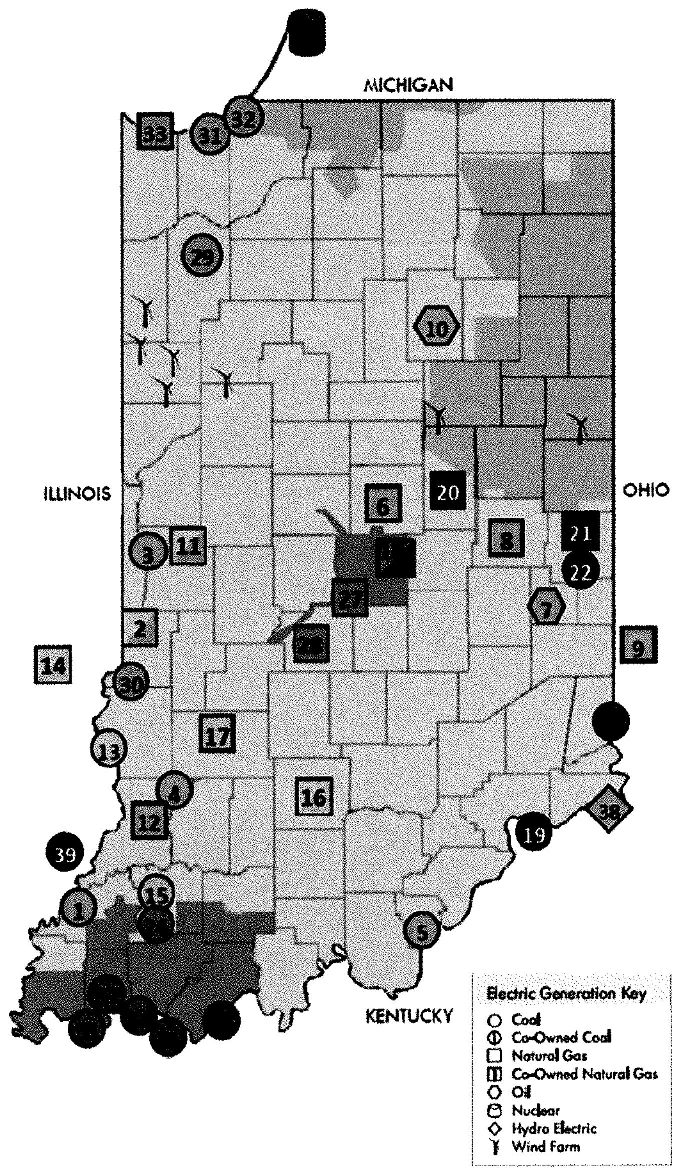
NORTHERN INDIANA PUBLIC SERVICE COMPANY
29. Schahfer 1,780
30. Sugar Creek 535
31. Bailly 511
32. Michigan City 469
33. Mitchell......................Retired

VECTREN SOUTH
34. Warrick.......................... 150
35. Brown 640
36. Culley 360
37. Broadway/Northeast.........85

WABASH VALLEY POWER
2. Wabash River Highland 162
11. Vermilion 6-8..................240
14. Holland (IL).....................314
16. Lawrence 86

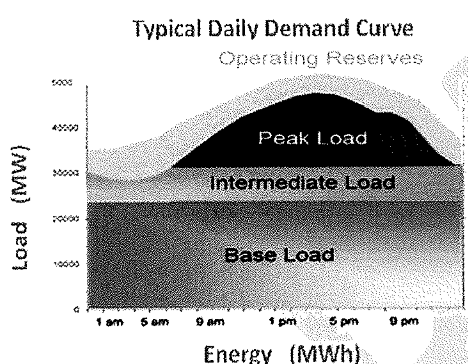
Electric Generation Serving Indiana (Summer MW Ratings)

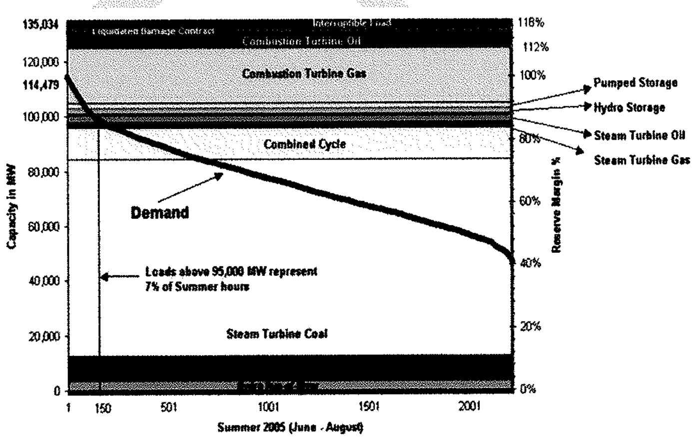
The following map shows the electric generation plants owned by Indiana's five IOUs, IMPA, WVPA, and Hoosier Energy.



APPENDIX 8
DEFINITION OF TERMS and ACRONYMS

Base Load Generation: Traditoinally regarded as generating equipment that is normally operated to meet demand on continous bases (e.g., over a 24-hour basis). The North American Electric Reliability Corporation (NERC) characterization of Base Load: *There is a distinction between baseload generation and the characteristics of generation providing reliable "baseload" power. Baseload is a term used to describe generation that falls at the bottom of the economic dispatch stack, meaning [those power plants] are the most economical to run. Coal and nuclear resources, by design, are designedfor low cost O&M [operation and maintenance] and continuous operation [...] However, it is not the economics nor the fuel type that make these resources attractive from a reliability perspective. Rather, these conventional steam-driven generation resources have low forced and maintenance outage hours traditionally and have low exposure to fuel supply chain issues. Therefore, "baseload" generation is not a requirement; however, having a portion of a resource fleet with high reliability characteristics, such as low forced and maintenance outage rates and low exposure to fuel supply chain issues, is one of the most fundamental necessities of a reliable BPS. These characteristics ensure that "baseload" generation is more resilient to disruptions.* Staff Report to the Secretary on Electricity Markets and Reliability, Page 5, August 2017. It has been suggested that the term "baseload" generation is no longer a meaningful distinction since natural gas combined cycle facilities (NGCC), in particular, are increasingly displacing traditional large coal and nuclear generating units in economic dispatch.





Battery Storage: Has been used as a generating resource, to support transmission, and to enhance reliability of the distribution system. That is, battery storage transcends the three segments. Batteries can facilitate integration of Distributed Energy Resources (DERs) –including solar and other renewable resources, microgrids, DSM, and future technologies.

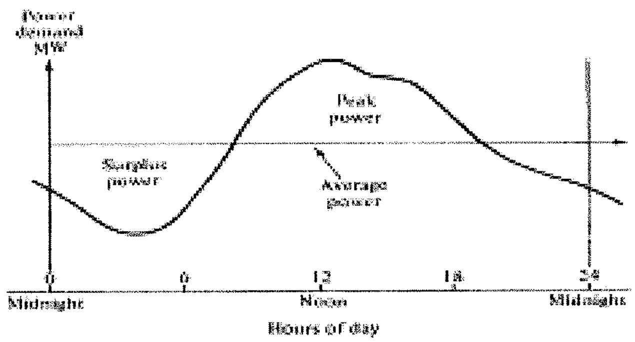
Coincident Demand (CD): Mathematically, it is the sum of two or more demands that occur in the same time interval. Typically, used in planning resources such as generation, transmission, and demand response. So, the contribution by any entity to the RTOs / ISOs peak is that entity's "**Coincidence Factor (CF).**" In regions not served by an RTOs / ISOs, the relevant peak is the contribution of each customer to their utility's peak demand.

Coincident Peak Demand (CP): For example, in regions served by RTOs / ISOs, the relevant peak is the RTOs / ISOs peak demand rather than the peak demand of any utility or other entity. In regions not served by an RTOs / ISOs, the relevant peak is the contribution of each customer to their utility's peak demand. For retail ratemaking CP typically refers to the utility's peak demand since the timing of the RTO / ISO peak is difficult to predict, most Indiana utilities experience a peak that is close to the MISO's and PJM's peak. Therefore, Indiana utilities have a high coincidence factor with MISO and PJM.

Combined Heat & Power (CHP): A plant designed to produce both heat and electricity from a single heat source. *Note: This term is being used in place of the term "cogenerator" that was used by EIA in the past.* CHP better describes the facilities because some of the plants included do not produce heat and power in a sequential fashion and, as a result, do not meet the legal definition of cogeneration specified in the Public Utility Regulatory Policies Act (PURPA).

Congestion of the Transmission or Distribution Systems; Congestion: A condition that restricts the ability to add or substitute one source of electric power for another on a transmission grid or distribution system (more simply: congestion occurs when insufficient transfer capacity is available to implement all of the preferred schedules simultaneously). In regions served by RTO/ISO, this congestion is "cleared" by the use of economic price signals referred to as **Locational Marginal Cost Pricing (LMP)**. Prior to RTO / ISOs and in areas not served by RTO / ISOs, transmission congestion is cleared by the use of "**Transmission Line Loading Relief**" (TLRs). TLRs, in extreme instances, curtail even firm transactions to prevent a blackout condition. Natural gas pipelines may also experience congestion.

Distributed Energy Resource (DER): DER is a resource sited close to customers that can provide all or some of their electric and power needs and can also be used by the system to either reduce customer demand or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, relatively small scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).Note the IEEE Standard 1547 does not include Demand Response (DR) but this is a matter for policymakers. DER can provide back-up power, used to displace relatively high cost energy such as at the time of system peak demand, can stabilize the grid, firm up other resources, potentially reduce back-feed problems, and enhance power quality. Source: Grid Modernization Laboratory Consortium, U.S. Department of Energy.



Some of the potential advantages of DER include: 1) reduced demand on system elements and peak demand which may result in a deferral of transmission and distribution upgades, 2) increase the diversity of the resource mix, 3) provides voltage and frequency support, 4) reduce line losses, 5) provides back-up power in emergencies and may provide spinning reserves and black start capabilities to help restore the system, 6) reduced emissions in heavily populated areasupgades, 2) increase the diversity of the resource mix, 3) provides voltage and frequency support, 4) reduce line losses, 5) provides back-up power in emergencies and may provide spinning reserves and black start capabilities to help restore the system, 6) reduced emissions in heavily populated areas

Diversity Factor: The electric utility system's load is made up of many individual loads that make demands upon the system usually at different times of the day. The individual loads within the customer classes follow similar usage patterns, but these classes of service place different demands upon the facilities and the system grid. The service requirements of one electrical system can differ from another by time-of-day usage, facility usage, and/or demands placed upon the system grid.

Demand Side Management (DSM): The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers to only energy and load-shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shaped changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

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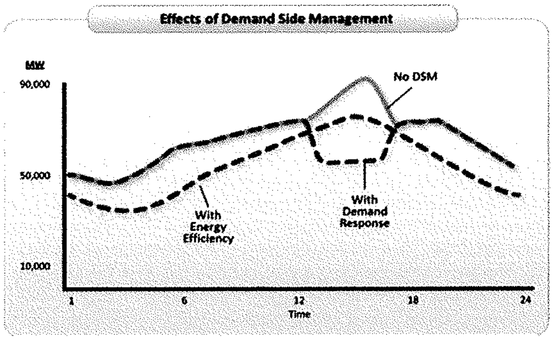

Fracking: The fracturing of rock by a pressurized liquid is **Hydraulic fracturing.** This is a technique in which water is mixed with sand and chemicals, and the mixture is injected at high pressure into a wellbore to create small fractures to extract oil and natural gas. Oil and Natural Gas *Plays* have been discovered in almost every state.

Integrated Resource Planning (IRP): The engagement in a systematic, comprehensive, and open utility / stakeholder analysis of loads and resources to enable planners and stakeholders to achieve greater optimality in the planning of a robust portfolio of resources including transmission, all forms of generation, demand-side management (including energy efficiency) and distribution planning with the aspiration of providing the lowest delivered cost of electricity.

Intermittent Resources: Sometimes referred to as Variable Resources. These are sources of power, such as wind and solar, that cannot operate continuously. These often require "back-up" or supplemental power sources to firm the supply of power.

Levelized Cost of Electricity (LCOE): The National Renewable Energy Laboratory defines LCOE as: The LCOE is the total cost of installing and operating a project expressed in dollars per kilowatt-hour of electricity generated by the system over its life. It accounts for: Installation costs; financing costs; taxes; operation and maintenance costs; salvage value; incentives; revenue requirements (for utility financing options only); and the quantity of electricity the system generates over its life. To use the LCOE for evaluating project options, it must be comparable to cost per energy values for alternative options.

Load Diversity: The difference between the peak of coincident and non-coincident demands of two or more individual loads. From a system planning perspective, diversity is the difference between the individual peak demand of a customer or customer class to the system peak demand of a utility.

Load Forecasting: This is the analytical process of estimating customer demand for electricity over a specified period of time (e.g., 1 day – 30 years) and as a basis for determining the resource requirements to satisfy customer requirements in a reliable and economic manner. Typically a utility will want to forecast maximum demand in the amount of Watts usually Megawatts (MW) or Gigawatts (GW) and energy use in Megawatt hours (MWh) or Gigawatt (GWh) hours. Forecasts that are well developed provide a higher degree of believability (confidence) and can, therefore, reduce the financial risks associated with planning resources over the forecast horizon.

Locational Marginal Cost Pricing (LMP): Determining the cost of power at any one point on the grid (including the opportunity costs created by congestion) is called *location-based marginal costing.* A Locational Marginal Price (LMP) is the market clearing price at a specific Commercial Pricing Node (CPNode) and is equal to the cost of supplying the next increment of load at that location. LMP values have three components for Settlement purposes: marginal energy component, marginal congestion component, and marginal loss component. The value of an LMP is the same whether a purchase or sale is made at that node.CPNode) and is equal to the cost of supplying the next increment of load at that location. LMP values have three components for Settlement purposes: marginal energy component, marginal congestion component, and marginal loss component. The value of an LMP is the same whether a purchase or sale is made at that node.

LOLE (also LOLP determination of Resource Adequacy): Used to set "Planning Reserve Margins." LOLE is normally expressed as the number of days/year that generation resources will be insufficient to meet load. Most widely accepted level: 1 Day (or event) in 10 Years. This, like the "Loss of the Single Largest Generator" or a fixed percentage above forecasted peak demand (e.g., 15%) are all arbitrary measures for attempting to quantify the amount of capacity in excess of peak demand required to reliably serve customers.

Planning Horizon: For purposes of the IRP, utilities' resource plans encompass 20 years. The 20 years is intended to avoid an unintentional bias of selecting lower cost resources when a more costly (capital intensive) resource might be preferable in the longer term due to offsetting costs such as lower fuel cost. Typically, utilities extend their planning horizon beyond 20 years to avoid the *event horizon effect* where resources that might be economically desirable for inclusion in the plan are omitted because their viability occurred just beyond the 20 years).

Planning Reserve Margin (PRM): The amount of forecast dependable resource (i.e., generation, demand-response) capacity required to meet the forecast demand for electricity and reasonable contingencies (e.g., loss of a major generating unit). "Dependable" should be used in preference to "Nameplate" because the Nameplate Rating of a resource may not be able to provide dependable capacity at the time of peak. Often established to meet a "Loss of Load Probability" (or Expectation) of one event (or day) in ten years. Typically this construct has resulted in Planning Reserve Margins of around 15% (i.e., 15% greater than the forecast peak demand). While a specified LOLP is arbitrary, it is generally regarded as a reasonable criteria.

Reserve Margin (RM): The percentage difference between rated capacity and peak load divided by peak load. Reserve Margin = [(Capacity-Demand)/Demand]. A 15 percent reserve margin is equivalent to a 13 percent capacity margin. Capacity Margin = [(Capacity-Demand)/Capacity].

$$\text{Reserve Margin} = \frac{Resources - Peak\ Firm\ Demand}{Peak\ Firm\ Demand}$$

Resource Adequacy (RA): Planning Coordinators such as RTOs / ISOs establish Resource Adequacy requirements (and the resulting long-term_planning reserve margins for their member utilities) to ensure that sufficient resources such as electric generation, transmission, demand response, and customer-owned generation are available to allow Planning Coordinators to reliably meet its forecast requirements. For utilities in RTOs / ISOs, the allocated Reserve Margin and the estimated future prices of capacity, in turn, may be used by individual utilities in the development of their long-term Resource Plans.

Resource Diversity: In an electric system, resource diversity may be characterized as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks. In this way, resource diversity can be considered a system-wide tool to ensure a stable and reliable supply of electricity. Resource diversity itself, however, is not a measure of reliability. Relying too heavily on any one fuel type may create a fuel security or *resilience* issue because the level of resource mix diversity does not correlate directly with a resource portfolio's ability to provide sufficient generator reliability attributes. However, fuel and resource diversity are closely related. Resource diversity entails with more detailed information about the operational characteristics of each resource. Resource diversity is also related to load diversity. The value of resource diversity can change dramatically due to changes in the capital cost of different resources, the profitability of different resources in the dispatch, the of capital costs associated with alternative resources, and the dynamics of the pricing and projected prices of different fuels.

Security Constrained Economic Dispatch (SCED): When congestion occurs, least-cost generation often must be passed over for purposes of system security. For this reason, this market model – where the system operator acts as a clearing agent *and* manager of system security – is called *bid-based, security-constrained economic dispatch.*

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ACRONYMS

AC	Alternating Current
ASM	Ancillary Services Market
CO_2	Carbon Dioxide
CCR	Coal Combustion Residuals Rule
CPCN	Certificate of Public Convenience and Necessity
CAA	Clean Air Act (CAA)
CAAA	Clean Air Act Amendments
CPP	Clean Power Plan Power Plan
CF	Coincidence Factor
CP	Coincident Peak Demand (see also non-coincident peak demand)
CHP	Combined Heat & Power
CC	Combined Cycle generator
CS	Community Solar
CPV	Concentrating Photovoltaic
CSP	Concentrating Solar Power
kW, MW, GW	kilowatts, megawatts, and gigawatts
DR	Demand Response
DSM	Demand-Side Management
DER	Distributed Energy Resources
ED	Economic Dispatch
ELG	Effluent Limitation Guidelines
kWh, MWh, GWh	kilowatt hours, megawatt hours, gigawatt
EE	Energy Efficiency Efficiency
EPA	Environmental Protection Agency Protection Agency
EUR	Estimated Ultimate Recovery of natural gas or oil
FERC	Federal Energy Regulatory Commission
FGD	Flue-Gas Desulfurization
ITC	Investment Tax Credit
LRZ	Local Resource Zones (part of MISO's reliability construct)
LMP	Locational Marginal Cost Pricing
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MPS	Market Potential Studies
MATS	Mercury and Toxic Standard
MTEP	MISO's Transmission Expansion Plan
MVP	MISO's Multi-Value Transmission Projects
NOx	Nitrogen Oxide
NERC	North American Electric Reliability Corporation
O&M	Operations & Maintenance Costs
PRM	Planning Reserve Margin
PPA	Power Purchase Agreements
PVRR	Present Value of Revenue Requirements
PTC	Production Tax Credit
RTP	Real Time Pricing
RTOs	Regional Transmission Organizations (also Independent System Operators)
RPS	Renewable Portfolio Standards
RM	Reserve Margin
RA	Resource Adequacy
RTEP	Regional Transmission Expansion Plan (PJM)
SCED	Security Constrained Economic Dispatch
SOx, SO_2, SO_3	Sulfur Oxides

STATEWIDE ANALYSIS

The Indiana General Assembly enacted Senate Enrolled Act 412 in May 2015, which amended Indiana Code § 8-1-8.5-3 concerning a statewide analysis of long-range needs for expansion of facilities for generation of electricity.

The law requires the Indiana Utility Regulatory Commission (Commission) to prepare a statewide analysis that includes (1) the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) in the judgment of the Commission, the optimal extent, size, mix, and general location of generating plants; (4) in the judgment of the Commission, the optimal arrangements for statewide or regional pooling of power and arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of Indiana; and (5) the comparative costs of meeting future growth by other means of providing reliable, efficient, and economic electric service, including purchase of power, joint ownership of facilities, refurbishment of existing facilities, conservation (including energy efficiency), load management, distributed generation, and cogeneration.

Draft Report

- Draft Statewide Analysis can be found here: PDF | Word version

Comments

Pursuant to GAO 2018-2, Commission staff is seeking comments from any interested stakeholders on the Statewide Analysis. If possible, and if applicable to your comments, please include red-lined edits to the Word version of the draft Statewide Analysis.

Please provide written comments by August 17, 2018. Written comments may be submitted via email to urccomments@urc.in.gov or by mail to:

General Counsel Beth Heline

Re: Statewide Analysis

Indiana Utility Regulatory Commission

101 West Washington Street, Ste. 1500 E.

Indianapolis, IN 46204

Public Hearing

Comments may also be provided at the Commission's public hearing regarding the Statewide Analysis. This public hearing is scheduled for 9:30 a.m. on Friday, August 10, 2018, in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. Click here to view the livestream.

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Indiana Electricity Projections: The 2017 Forecast

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West Lafayette, Indiana

December 2017

Prepared for:

Indiana Utility Regulatory Commission
Indianapolis, Indiana

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Foreword

This report presents the 2017 projections of future electricity requirements for the state of Indiana for the period 2016-2035. This study is part of an ongoing independent electricity forecasting effort conducted by the State Utility Forecasting Group (SUFG). SUFG was formed in 1985 when the Indiana legislature mandated a group be formed to develop and keep current a methodology for forecasting the probable future growth of electricity usage within Indiana. The Indiana Utility Regulatory Commission contracted with Purdue and Indiana Universities to accomplish this goal. SUFG produced its first set of projections in 1987 and has updated these projections periodically. This is the sixteenth set of projections.

The objective of SUFG, as defined in Indiana Code 8-1-8.5 (amended in 1985), is as follows:

To arrive at estimates of the probable future growth of the use of electricity... *"the commission shall establish a permanent forecasting group to be located at a state supported college or university within Indiana. The commission shall financially support the group, which shall consist of a director and such staff as mutually agreed upon by the commission and the college or university, from funds appropriated by the commission. This group shall develop and keep current a methodology for forecasting the probable future growth of the use of electricity within Indiana and within this region of the nation. To do this the group shall solicit the input of residential, commercial and industrial consumers and the electric industry."*

This report provides projections from a statewide perspective. Individual utilities will experience different levels of growth due to a variety of economic, geographic, and demographic factors.

SUFG has maintained a similar format for this report as was used in recent reports to facilitate comparisons. With the exception of the upgrades described in Chapter 2, details on the operation of the modeling system are not included; for that level of detailed information, the reader is asked to contact SUFG directly or to look back to the 1999 forecast that is available for download from the SUFG website located at:

http://www.purdue.edu/dp/energy/SUFG/

The authors would like to thank the Indiana utilities, consumer groups and industry experts who contributed their valuable time, information and comments to this forecast. Also, the authors would like to gratefully acknowledge the Indiana Utility Regulatory Commission for its support, input and suggestions.

This report was prepared by the State Utility Forecasting Group. The information contained in this forecast should not be construed as advocating or reflecting any other organization's views or policy position. Further details regarding the forecast and methodology may be obtained from SUFG at:

State Utility Forecasting Group
Purdue University
Mann Hall, Room 160
203 S. Martin Jischke Drive
West Lafayette, IN 47907-1971
Phone: 765-494-4223
FAX: 765-494-6298
e-mail: sufg@ecn.purdue.edu

Chapter 1

Forecast Summary

Overview

In this report, the State Utility Forecasting Group (SUFG) provides its sixteenth set of projections of future electricity usage, peak demand, prices and resource requirements. The projections in this forecast are lower than those in the 2015 forecast, primarily due to increases in energy efficiency and less optimistic economic projections, compared to the earlier projections.

This forecast projects electricity usage to grow at a rate of 1.12 percent per year over the 20 years of the forecast. Peak electricity demand is projected to grow at an average rate of 1.01 percent annually. This corresponds to about 230 megawatts (MW) of increased peak demand per year. The growth in the second half of the forecast period (2026-2035) is stronger than the growth in the first ten years.

The 2017 forecast predicts Indiana electricity prices to continue to rise in real (inflation adjusted) terms through 2023 and then slowly decrease afterwards. A number of factors determine the price projections. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity in addition to production.

For this forecast, SUFG has incorporated significant revisions to its modeling system. As a result, unlike in previous forecasts, future resource needs are identified by a specific technology rather than by generic baseload, cycling and peaking types. The new utility simulation model can select the lowest cost mix of a number of different supply and demand options. Due to time and data limitations, demand-side resources were modeled as fixed quantities based on utility-provided information rather than allowing the model to select the amounts.

This forecast indicates that additional resources are not needed until 2021. This forecast identifies a need for about 3,600 MW of additional resources by 2025, 6,300 MW by 2030 and 9,300 MW at the end of the forecast period in 2035. In the long term, the projected additional resource requirements are higher than in previous forecasts. This is due to the retirements of additional existing generators that have been announced by Indiana utilities since the previous forecast report.

While SUFG identifies resource needs in its forecasts and reports those needs according to generating unit types, it does not advocate any specific means of meeting them. Required resources could be met through conservation measures, purchases from merchant generators or other utilities, construction of new facilities or some combination thereof. The best method for meeting resource requirements may vary from one utility to another.

Outline of the Report

The current forecast continues to respond to SUFG's legislative mandate to forecast electricity demand. It includes projections of electric energy requirements, peak demand, prices, and capacity requirements. It also provides projections for each of the three major customer sectors: residential, commercial and industrial.

Chapter 2 of the report briefly describes SUFG's forecasting methodology, including changes made from previous forecasts.

Chapter 3 presents the projections of statewide electricity demand, resource requirements, and price, while Chapter 4 describes the data inputs and Chapters 5 through 7 present integrated projections for each major consumption sector in the state under three scenarios.

- The *base scenario* is intended to represent the electricity forecast that is "most likely" and has an equal probability of being high or low.
- The *low scenario* is intended to represent a plausible lower bound on the electricity sales forecast and has a low probability of occurrence.
- The *high scenario* is intended to represent a plausible upper bound on the electricity sales forecast and also has a low probability of occurrence.

Finally, an Appendix depicts the data sources used to produce the forecast and provides historical and forecast data for energy, peak demand and prices.

The Regulated Modeling System

The SUFG modeling system explicitly links electricity costs, prices and sales on a utility-by-utility basis under each scenario. Econometric and end-use models are used to project electricity use for each major customer group — residential, commercial and industrial — using fuel prices and economic drivers to simulate growth in electric energy use. The projections for each utility are developed from a consistent set of statewide economic, demographic and fossil fuel price projections. In order to project electricity costs and prices, generation resource plans are developed for each utility and the operation of the generation system is simulated. These resource plans reflect "need" from both a statewide and utility perspective.

Beginning with the 2009 forecast, SUFG made a slight modification to the methodology used in determining future resource requirements. For the 1999-2007 forecasts, SUFG determined required resources according to a target statewide 15 percent reserve margin.[1] Forecasts prior to 1999 used a 20 percent statewide reserve margin. These reserve margins were essentially rules-of-thumb, based on industry observations. In 2009 SUFG began using reserve margins that reflect the planning reserve requirements of the utilities' regional transmission organizations to determine the reserve requirements in this forecast. Applying the individual reserve requirements and adjusting for peak load diversity among the utilities provides a statewide reserve requirement of approximately 18.9 percent. This represents a slightly lower reserve margin than the 19.5 percent figure used in the 2015 forecast. The reduction in the statewide reserve requirements results from a re-estimation of peak load diversity based on recent historical data.

Major Forecast Assumptions

In updating the modeling system to produce the current forecast, new projections were developed for all major exogenous variables.[2] These assumptions are summarized below.

Economic Activity Projections

One of the largest influences in any energy projection is growth in economic activity. Each of the sectoral energy forecasting models is driven by economic activity projections, i.e., personal income, population, commercial employment and industrial output. The economic activity assumptions for all three scenarios were derived from the Indiana macroeconomic model developed by the Center for Econometric Model Research (CEMR) at Indiana University. SUFG used CEMR's February 2017 projections for its base scenario. A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy. The CEMR Indiana projections are based on a national employment projection of 0.68 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 0.72 percent.

Other key economic projections from CEMR are:

- Real personal income (a residential sector model driver) is expected to grow at a 1.88 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average a 0.94 percent annual growth rate over the forecast horizon.
- Manufacturing gross state product (GSP) (the primary industrial sector model driver) is expected to rise at a 2.93 percent real annual rate.

To capture some of the uncertainty in energy forecasting, SUFG also requested CEMR to produce low and high growth alternatives to its base economic projection. In effect, the alternatives describe a situation in which Indiana either loses or gains shares of national industries compared to the base projection.

Demographic Projections

Population growth for all scenarios is 0.41 percent per year. This projection is from the Indiana Business Research Center (IBRC) at Indiana University. The SUFG forecasting system includes a housing model that utilizes population and income assumptions to project the number of households. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of 1.13 percent over the forecast period.

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[1] SUFG reports reserves in terms of reserve margins instead of capacity margins. Care must be taken when using the two terms since they are not equivalent. An 18.9 percent reserve margin is equivalent to a 15.9 percent capacity margin.
Capacity Margin = [(Capacity-Peak Demand)/Capacity]
Reserve Margin = [(Capacity-Peak Demand)/Peak Demand]

[2] Exogenous variables are those variables that are determined outside the modeling system and are then used as inputs to the system.

Fossil Fuel Price Projections

SUFG's current assumptions are based on the January 2017 projections produced by the Energy Information Administration (EIA) for the East North Central Region. SUFG's fossil fuel real price[3] projections are as follows:

Natural Gas Prices: Natural gas prices decreased significantly in 2009 relative to the high prices of 2008. Prices then rebounded somewhat in 2010 before declining again through 2012 before increasing back to 2010 levels by 2014. However, natural gas prices dropped again in 2015 to a level lower than that of 2012, followed by a slight decrease in 2016. They are projected to increase gradually for the remainder of the forecast horizon.

Utility Price of Coal: Coal price projections are relatively flat in real terms throughout the entire forecast horizon as coal consumption decreases due to more natural gas and renewable generation observed in the electric power sector.

The Base Scenario

Figure 1-1 shows the current base scenario projection for electricity requirements in gigawatt-hours (GWh), along with the projections from the previous two forecast reports. Similarly, the base projection for peak demand in MW is shown in Figure 1-2. The annual growth rate for electricity requirements in this forecast is 1.12 percent, while the growth rate for peak demand is 1.01 percent. The growth rates in the previous forecast for electricity requirements and peak demand were 1.17 and 1.13 percent, respectively. The 2017 forecast is lower than the 2015, primarily due to lower demand at the start of the forecast period resulting from increased energy efficiency.

The growth within sectors varies with higher growth in the industrial sector and lower growth in the residential and commercial sectors (see Table 1-1). See Chapters 5 through 7 for more detail on the sector forecasts.

The growth in peak demand is lower than the 2015 forecast, but the 2017 projection lies above the previous projection. It should be noted that this is driven largely by a methodological change associated with the model upgrade explained in Chapter 2. The peak demand projections in the 2013 and 2015 forecasts were adjusted downward for demand response loads while the 2017 peak demand is not. The projections of peak demand are for normal weather patterns. Another measure of peak demand growth can be obtained by considering the year to year MW load change. In Figure 1-2, the annual increase is about 230 MW.

Table 1-1. Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2015 Projections)

Sector	Current (2016-2035)	2015 (2014-2033)
Residential	0.48	0.64
Commercial	0.36	0.59
Industrial	2.04	1.90
Total	1.12	1.17

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources to meet forecast demand. Utility-sponsored energy efficiency is netted from the demand projection and supply-side resources are added as necessary to maintain an 18.9 percent reserve margin. Demand response[4] loads are treated as an existing resource that can be called on to meet the peak load.

[3] Real prices are calculated to reflect the change in the price of a commodity after taking out the change in the general price levels (i.e., the inflation in the economy).

[4] Demand response includes loads that can be interrupted by the utility during times of high system demand, generation shortages, or high wholesale market prices. They include direct load control and loads under industrial interruptible rates.

Figure 1-1. Indiana Electricity Requirements in GWh (Historical, Current, and Previous Forecasts)

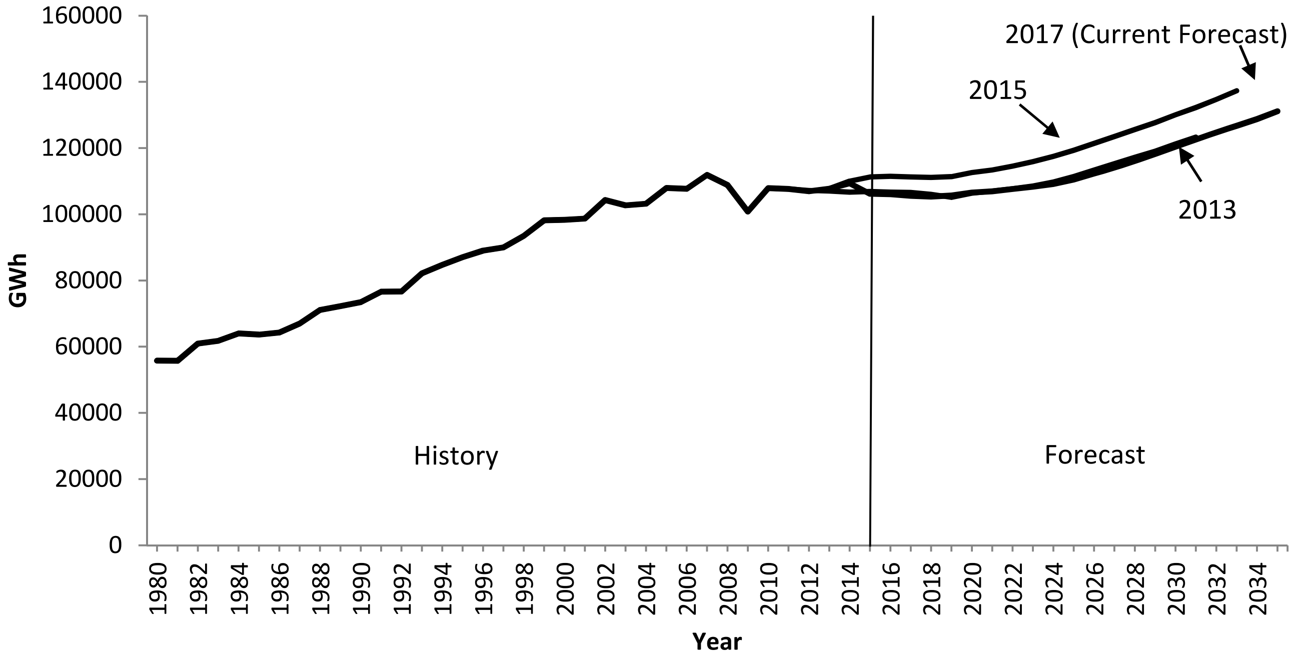
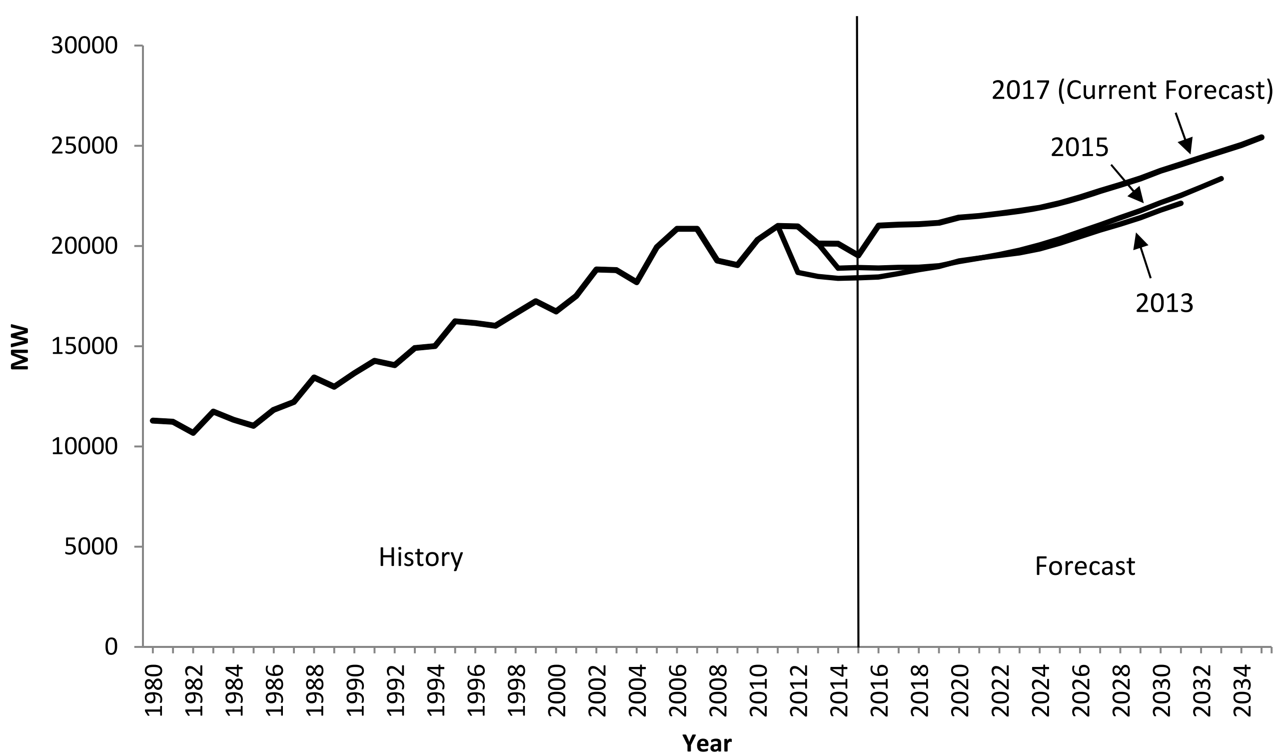


Figure 1-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Demand-Side Resources

The current projection includes the energy and demand impacts of existing or planned utility-sponsored energy efficiency programs. Incremental energy efficiency programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 120 MW at the beginning of the forecast period and by about 700 MW at the end of the forecast. Energy efficiency projections were estimated from utility integrated resource plan filings and from information collected directly from the utilities by SUFG.

These energy efficiency projections do not include the demand response loads, which are projected to increase from approximately 1,000 MW to about 1,200 MW over the forecast horizon. See Chapter 4 for additional information about utility-sponsored energy efficiency and demand response.

Supply-Side Resources

SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, de-ratings due to pollution control retrofits, changes in the amount of demand response that is available, and net changes in firm out-of-state purchases and sales. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic new generation resources are then added as necessary during the forecast period to maintain a statewide 18.9 percent reserve margin. The resource type is selected to minimize the overall cost of meeting the load.

Resource Needs

Figure 1-3 and Table 1-2 show the statewide resource plan for the SUFG base scenario. Over the first half of the forecast period, 3,635 MW of additional resources are required. This net change in generation includes the retirement of units as reported in the utilities' most recent Integrated Resource Plan (IRP) filings or as reported subsequently. Over the second half of the forecast period, an additional 5,632 MW of resources are required to maintain target reserves.

Figure 1-3. Indiana Total Demand and Supply in MW (SUFG Base)

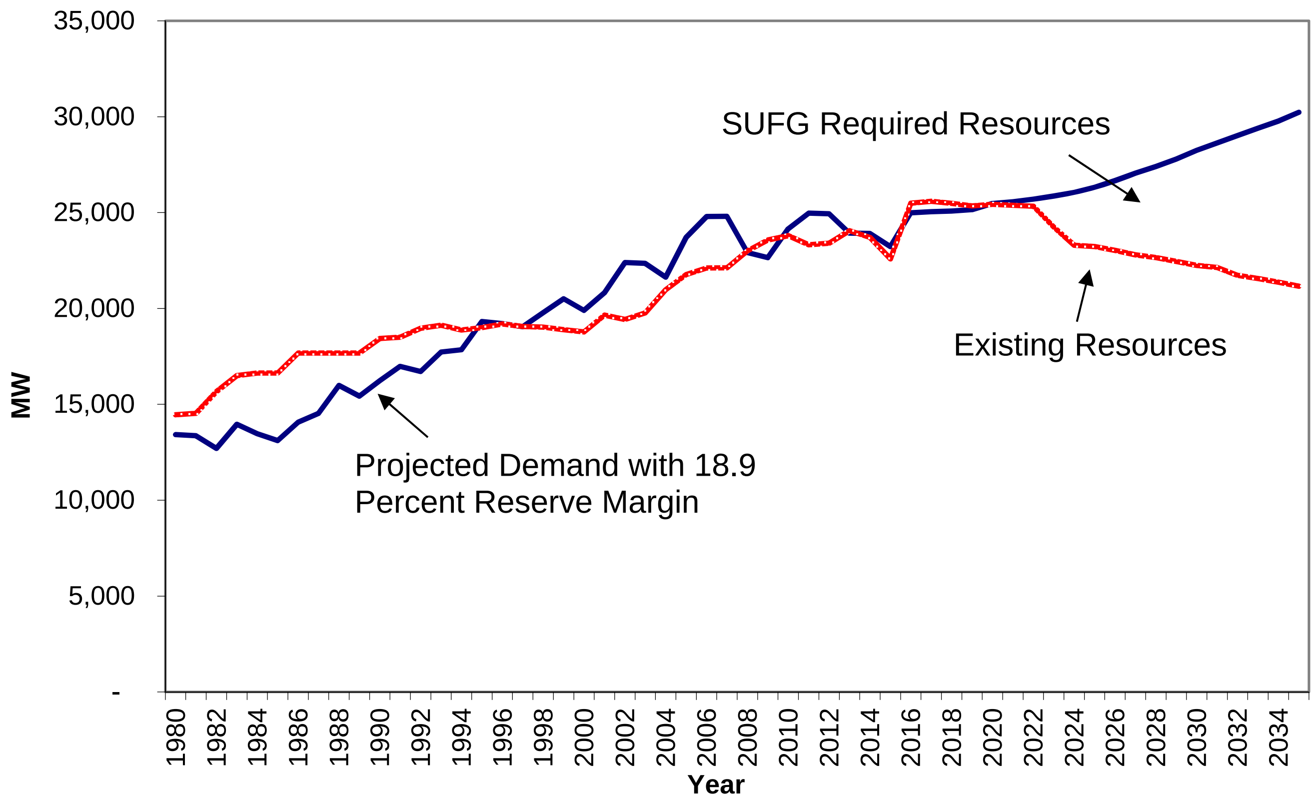


Table 1-2. Indiana Resource Plan in MW (SUFG Base)

Year	Peak Demand[1]	Existing/ Approved Capacity[2]	Incremental Change in Capacity[3]	Projected Additional Resource Requirements[4]			Total Resources[5]	Reserve Margin (percent)
				Peaking	Baseload	Total		
2016	21,017	25,494		0	0	0	25,494	21
2017	21,066	25,594	100	0	0	0	25,594	21
2018	21,089	25,488	-106	0	0	0	25,488	21
2019	21,155	25,354	-133	0	0	0	25,354	20
2020	21,425	25,440	85	0	0	0	25,440	19
2021	21,506	25,384	-56	237	215	452	25,835	20
2022	21,620	25,334	-50	474	215	689	26,022	20
2023	21,754	24,256	-1078	1,422	215	1,637	25,892	19
2024	21,912	23,299	-956	1,896	1,287	3,183	26,482	21
2025	22,139	23,235	-64	2,133	1,502	3,635	26,870	21
2026	22,428	23,036	-199	2,370	1,716	4,086	27,122	21
2027	22,752	22,797	-239	2,844	1,931	4,775	27,572	21
2028	23,049	22,660	-137	2,844	2,145	4,989	27,649	20
2029	23,374	22,456	-204	2,844	2,789	5,633	28,088	20
2030	23,757	22,254	-201	3,318	3,003	6,321	28,575	20
2031	24,077	22,145	-109	3,792	3,003	6,795	28,940	20
2032	24,404	21,734	-411	4,029	3,432	7,461	29,195	20
2033	24,724	21,565	-169	4,503	3,861	8,364	29,929	21
2034	25,040	21,376	-189	4,740	4,076	8,816	30,192	21
2035	25,425	21,166	-210	4,977	4,290	9,267	30,433	20

1 Peak Demand reflects utility-sponsored energy efficiency programs but is not adjusted for demand response loads.

2 Existing/approved capacity includes installed capacity plus approved new capacity plus demand response plus firm purchases minus firm sales.

3 Incremental change in capacity is the change in existing/approved capacity from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, changes in available demand response loads, and changes in firm purchases and sales.

4 Projected additional resource requirements are the cumulative amount of additional resources needed to meet future requirements.

5 Total resource requirements are the total statewide resources required including existing/approved capacity and projected additional resource requirements.

Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of actual historical data was 2015. Therefore, 2016 and 2017 numbers represent projections.

Equilibrium Price and Energy Impact

SUFG's base scenario equilibrium real electricity price trajectory is shown in Figure 1-4. Real prices are projected to increase by 39 percent from 2015 to 2023 and then slowly decrease afterwards. The change in prices early in the forecast horizon is significant, thus the electricity requirements projection for this portion of the forecast period is affected.

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 1-4. The price projection labeled "2013" is the base case projection contained in SUFG's 2013 forecast and the one labeled "2015" is the base case projections from SUFG's 2015 report. For the prior price forecasts, SUFG rescaled the original price projections to 2015 dollars (from 2011 dollars for the 2013 projection, and from 2013 dollars for the 2015 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

A number of factors determine the differences among the price projections in Figure 1-4. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity in addition to production. Environmental rules that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not.

Low and High Scenarios

SUFG has constructed alternative low and high economic growth scenarios. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Figure 1-5 provides the statewide electricity requirements for the base, low and high scenarios. The annual growth rates for the base, low and high scenarios are 1.12, 0.73, and 1.52, respectively. These differences are due to economic growth assumptions in the scenario-based projections. The trajectories for peak demand in the low and high scenarios are similar to the electricity requirements trajectories.

Figure 1-4. Indiana Real Price Projections in cents/kWh (2015 Dollars) (Historical, Current, and Previous Forecasts)

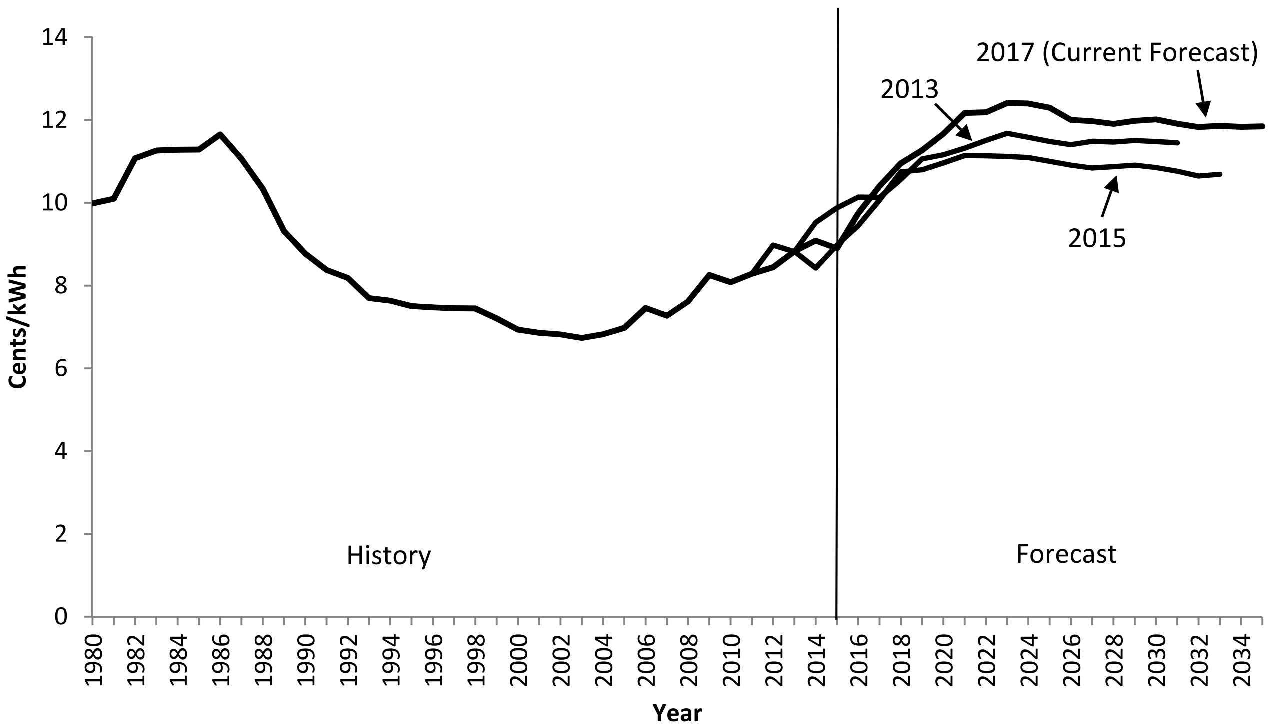
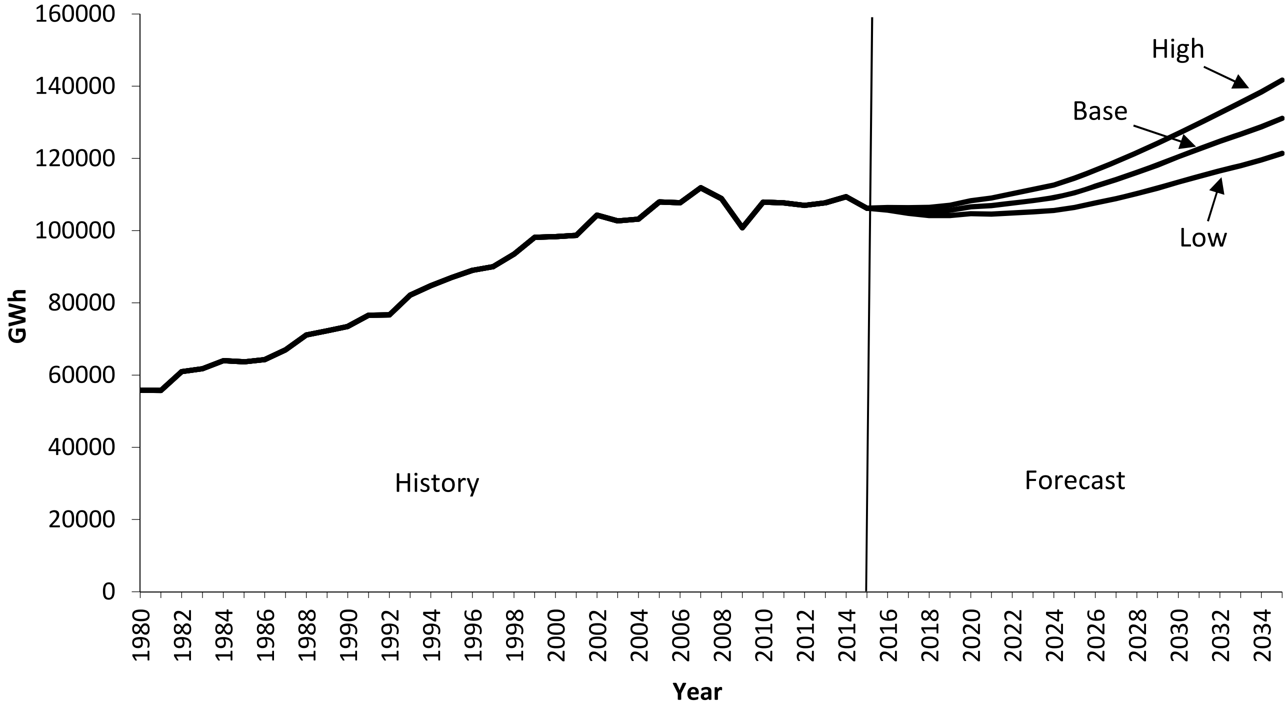


Figure 1-5. Indiana Electricity Requirements by Scenario in GWh



Chapter 2

Overview of the SUFG Electricity Modeling System

Modeling System Changes

Starting in 2016, SUFG performed a significant upgrade to its integrated electricity modeling system, which is used to project electricity demand, supply and price for each electric utility in the state under Indiana's present regulatory structure. The most significant change is replacing the electric utility simulation model, the Load Management Strategy Testing Model (LMSTM), with AURORAxmp.

Due to the manner in which AURORAxmp models demand response (DR) loads, there has been a definitional change in what SUFG reports as peak demand. Previously, the unadjusted peak demands produced by the forecasting models were reduced by the amount of available DR to determine the net peak demand. Because AURORAxmp treats DR as a resource in determining the system economic dispatch and future resource needs, the peak demand projections provided in this report have not been adjusted for DR. DR is now reflected in the existing resource numbers.

Regulated Modeling System

The modeling system captures the dynamic interactions between customer demand, the utility's operating and investment decisions, and customer rates by cycling through the various models until equilibrium is attained. The SUFG modeling system is unique among utility forecasting and planning models because of its comprehensive and integrated characteristics.

A distinctive characteristic of the modeling system is its ability to capture the interaction between future electricity demand and electricity prices through an iterative process. During each cycle of the process, price changes in the model cause customers to adjust their consumption of electricity, which in turn affects system demand, which in turn affects the utility's operating and investment decisions. These changes in demand and supply bring forth yet another change in price and the cycle is complete. After each cycle, the modeling system compares the "after" electricity prices from the utility finance & rates model to the "before" prices input to the energy consumption models. If these prices match, they are termed equilibrium prices in the sense that they balance demand and supply, and the iterative process ends. Otherwise, the modeling system continues to cycle through the models until equilibrium is attained as is illustrated in Figure 2-1.

Figure 2-1. Cost-Price-Demand Feedback Loop

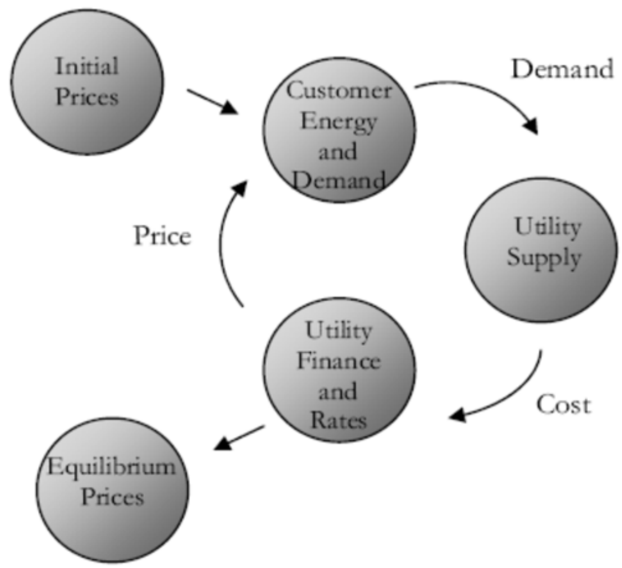
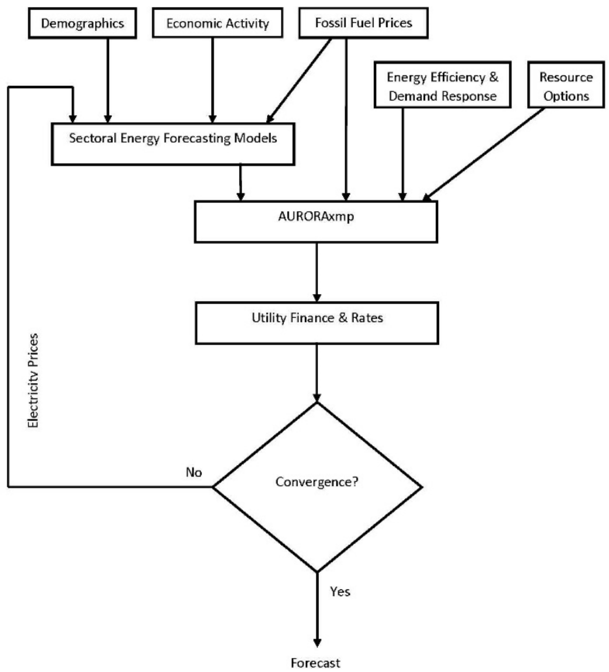


Figure 2-2 is a flowchart that illustrates how the modeling system functions. Projections of demographic, economic, and price drivers are inputs to utility and customer sector specific forecasting models. The energy and peak demand forecasts are inputs to AURORAxmp, which simulates economic dispatch, trade among the utilities, and determines future resources. Cost information from AURORAxmp are passed to the utility finance models to determine the resulting prices. The energy forecasting models are then rerun with the new prices, starting the next iteration. The process is repeated until prices from one iteration to the next are stable, indicating that convergence has been achieved.

Figure 2-2. Forecasting Modeling System Flowchart



Energy Forecasting Models

The energy forecasting models are used to develop projections for each of the five investor-owned utilities (IOUs): Duke Energy Indiana, Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, and Vectren Energy Delivery of Indiana - South. In addition, projections are developed for the three not-for-profit (NFP) utilities: Hoosier Energy Rural Electric Cooperative, Indiana Municipal Power Agency, and Wabash Valley Power Association.

Utility-specific projections of sectoral energy use and prices are developed for each of the three scenarios. These projections are based on projections of demographics, economic activity and fossil fuel prices that are developed outside the modeling system. They are also based on projections of electricity prices for the utilities that are developed within the framework of the modeling system.

SUFG has developed and acquired both econometric and end-use models to project energy use for each major customer group. These models use fuel prices and economic drivers to simulate growth in energy use. The end-use models provide detailed projections of end-use saturations, building shell choices and equipment choices (fuel type, efficiency and rate of utilization). The econometric models capture the same effects but in a more aggregate way. These models use statistical relationships estimated from historical data on fuel prices and economic activity variables. Additional information regarding SUFG's energy models for the residential, commercial and industrial sectors can be found in chapters five, six and seven, respectively.

AURORAxmp

Developed by EPIS, LLC, AURORAxmp is an optimization program that can perform economic dispatch of generators, allowing for trade among utilities, and determine least-cost resource expansion. Within the SUFG integrated modeling system, it is used to determine the operating costs associated with meeting future loads and the costs of expanding the future set of resources necessary to meet future reserve requirements.

AURORAxmp can consider a variety of future supply-side and demand-side resource options. For this forecast, SUFG included utility-scale solar and wind, natural gas-fired combustion turbines and combined cycle units, nuclear, and pulverized coal. Costs and operating characteristics were taken from the Energy Information Administration (EIA). Due to time and data limitations, demand-side resources were not modeled as a resource option. Utility energy efficiency programs and DR were modeled as fixed quantities based on utility-provided information. See Chapter 4 for more information on the modeling of demand-side resources.

Utility Finance & Rates Models

As part of the upgrades to the modeling system, SUFG has incorporated new financial models to project future electric rates. Previously, the finance and rates submodels of LMSTM performed this function. The current financial model is a modified version of the ORFIN model that was developed by Oak Ridge National Lab. The models determine annual revenue requirements based on each utility's costs associated with existing and future capital investments, operational expenses, debt, and taxes. Those costs are then allocated to the customer sectors and rates are determined using the annual energy forecasts.

Resource Requirements

Beginning with the 2009 forecast, SUFG made a slight modification to the methodology used in determining future resource requirements. For the 1999-2007 forecasts, SUFG determined required resources according to a target statewide 15 percent reserve margin. Forecasts prior to 1999 used a 20 percent statewide reserve margin. These reserve margins were essentially rules-of-thumb, based on industry observations. More recently, the regional transmission organizations (RTOs) that encompass Indiana utilities have determined planning reserve requirements for their members. Starting with the 2009 forecast, SUFG has used individual utility reserve margins that reflect the planning reserve requirements of the utility's RTO to determine the reserve requirements in this forecast. Applying the individual reserve requirements and adjusting for peak load diversity[1] among the utilities provides a statewide reserve requirement of approximately 18.9 percent. It should be noted that the change from a 15 percent to an 18.9 percent target in the SUFG forecasts does not represent an increase in reserves (and hence, an increase in costs) due to the utilities' memberships in the RTOs. Rather, it represents a change by SUFG to a target that is based on the more rigorous analyses of the RTOs as compared to the previous rule of thumb method.

Previously, SUFG developed its own method for determining the type of resources (such as peaking or baseload) and for assigning the need for resources to individual utilities. This method was considered to be "reasonable" but not optimal. Now the decisions of what types of resources to add and where are left to AURORAxmp. This results in the lowest cost options for meeting future loads to be selected and removes the need for analyst judgment. Demand response loads are also modeled within AURORAxmp, so they are no longer accounted for using an after-the-fact adjustment.

As before, the existing capacity has been adjusted for retirements, utility purchases and sales, and new construction projects that have been approved by the Indiana Utility Regulatory Commission (IURC).

Scenarios

SUFG's electricity projections are based on assumptions such as economic growth, construction costs and fossil fuel prices. These assumptions are a principal source of uncertainty in any energy forecast. Another major source of uncertainty is the statistical error inherent in the structure of any forecasting model. To provide an indication of the importance of these sources of uncertainty, scenario-based projections are developed by operating the modeling system under varying sets of assumptions. These low probability, low and high growth scenarios capture much of the uncertainty associated with economic growth, fossil fuel prices and statistical error in the model structure.

Presentation and Interpretation of Forecast Results

There are several methods for presenting the various projections associated with the forecast. The actual projected value for each individual year can be provided or a graph of the trajectory of those values over time can be used. Additionally, average compound growth rates can be provided. There are advantages and disadvantages associated with each method. For instance, while the actual values provide a great deal of detail, it can be difficult to visualize how rapidly the values change over time. While growth rates provide a simple measure of how much things change from the beginning of the period to the end, they mask anything that occurs in the middle. For these reasons, SUFG generally uses all three methods for presenting the major forecast projections.

[1] Load diversity occurs because the peak demands for all utilities do not occur at the same time. SUFG estimates the amount of load diversity by analyzing the actual historical load patterns of the various utilities in the state.

Chapter 3

Indiana Projections of Electricity Requirements, Peak Demand, Resource Needs and Prices

Introduction

This chapter presents the forecast of future electricity requirements and peak demand, including the associated new resource requirements and price implications. This report includes three scenarios of future electricity demand and supply: base, low, and high. The base scenario is developed from a set of exogenous macroeconomic assumptions that is considered "most likely," i.e., each assumption has an equal probability of being lower or higher. Additionally, SUFG includes low and high growth macroeconomic scenarios based on plausible sets of exogenous assumptions that have a lower probability of occurrence. These scenarios are designed to indicate a plausible forecast range, or degree of uncertainty underlying the base projection. The most probable projection is presented first.

Most Probable Forecast

As shown in Tables 3-1 and 3-2 and Figures 3-1 and 3-2, SUFG's current base scenario projection indicates annual growth of 1.12 percent for electricity requirements and 1.01 percent for peak demand. As shown in Table 3-3, the overall growth rate for electricity sales in this forecast is about 0.05 percent lower than the 2015 forecast. The 2017 forecast is lower than the 2015, primarily due to lower demand at the start of the forecast period. The growth within sectors varies significantly with higher growth in the industrial sector offsetting lower growth in the residential and commercial sectors. See Chapters 5, 6, and 7 for discussions of the forecast growth in the residential, commercial, and industrial sectors.

The growth in peak demand is also lower than that projected in the 2015 forecast, but the 2017 projection lies above the previous projection. It should be noted that this is driven largely by a methodological change associated with the model upgrade explained in Chapter 2. The peak demand projections in the 2013 and 2015 forecasts were adjusted downward for demand response loads while the 2017 peak demand is not. Forecast peak demand growth is lower than that of electricity requirements (1.01 versus 1.12 percent). Another measure of peak demand growth can be obtained by considering the average year to year peak MW load change. In Figure 3-2, the annual increase is about 230 MW compared to about 235 MW per year in the previous forecast.

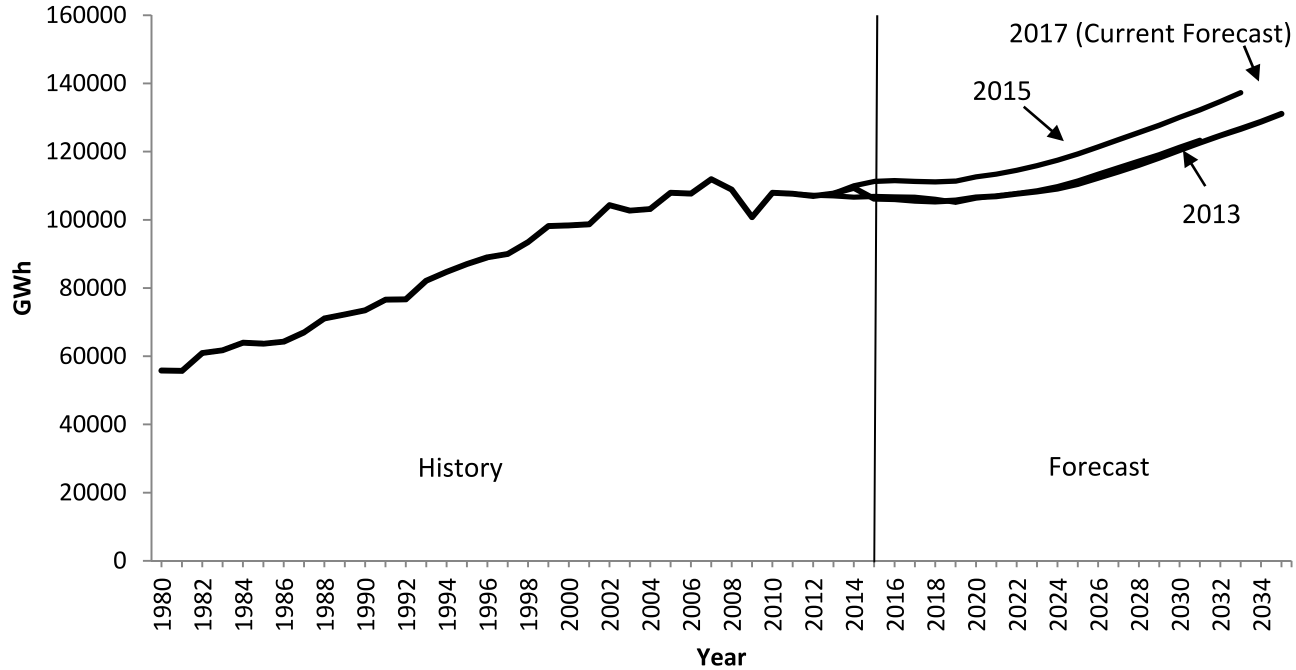
Demand-Side Resources

Beginning with this forecast, SUFG adjusted the manner in which demand response (DR) programs are modeled and how they are reported. This was necessitated by the manner in which DR is modeled within AURORAxmp. DR programs are now treated as a resource within the modeling system; previously an adjustment of peak demand was done to account for them outside the utility simulation model. Thus, the peak demand numbers reported in this report have not been adjusted for DR, while the existing resource numbers now include them. DR programs are projected to increase from approximately 1,000 MW to almost 1,200 MW over the forecast horizon. As in the past, energy efficiency (EE) programs are treated as a reduction in demand. The current projection includes the energy and demand impacts of existing or planned utility-sponsored EE programs. Incremental EE programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 120 MW at the beginning of the forecast period and by about 700 MW at the end of the forecast. See Chapter 4 for additional information about DR and EE.

Table 3-1. Indiana Electricity Requirements Average Compound Growth Rates (Percent)

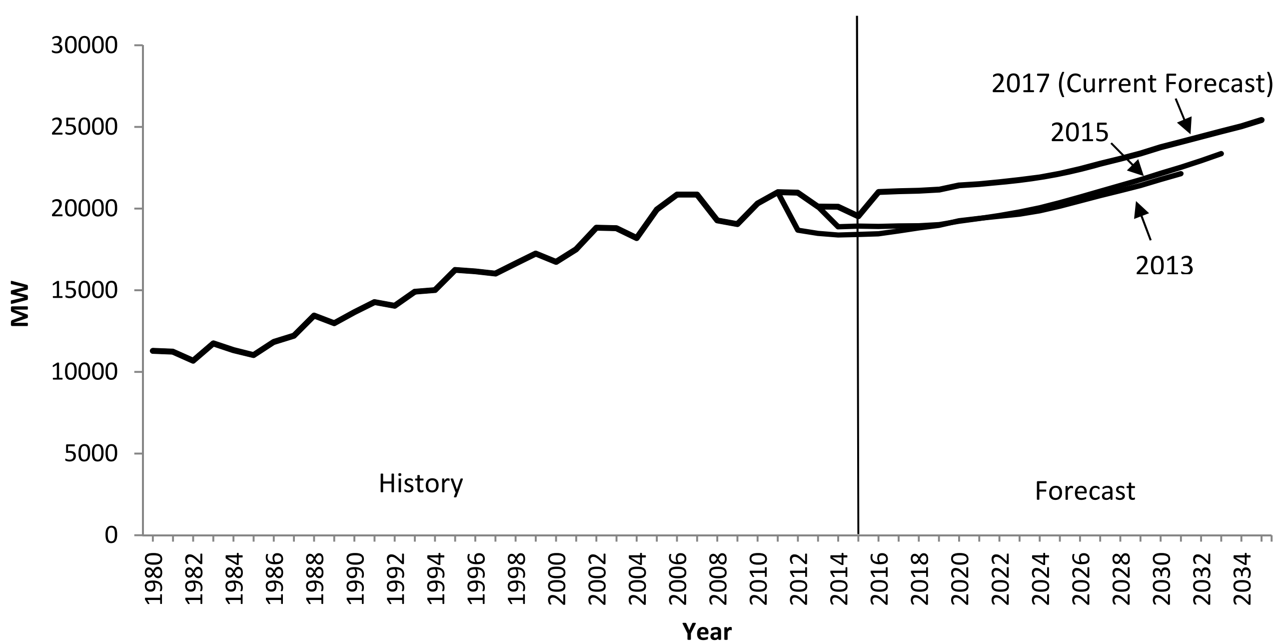
Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2017	1.12	2016-2035
2015	1.17	2014-2033
2013	0.74	2012-2031

Figure 3-1. Indiana Electricity Requirements in GWh (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Figure 3-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Table 3-2. Indiana Peak Demand Requirements Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2017	1.01	2016-2035
2015	1.13	2014-2033
2013	0.90	2012-2031

Table 3-3. Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2015 Projections)

Sector	Current (2016-2035)	2015 (2014-2033)
Residential	0.48	0.64
Commercial	0.36	0.59
Industrial	2.04	1.90
Total	1.12	1.17

Supply-Side Resources

SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, changes in the amount of demand response that is available, and net changes in firm out-of-state purchases and sales.

SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic new generating units are added as necessary during the forecast period to maintain an 18.9 percent statewide reserve margin. This level of statewide reserves is derived from individual utility reserve margins that reflect the planning reserve requirements of the utility's regional transmission organization and the diversity of peak demand across utilities in the state. Note that the reserve margin incorporated in this forecast is lower than the 19.5 percent figure used in 2015. This is due to a re-estimation of the peak demand diversity based on more recent historical data.

AURORAxmp can consider a variety of future supply-side and demand-side resource options. For this forecast, SUFG included utility-scale solar and wind, natural gas-fired combustion turbines and combined cycle units, nuclear, and pulverized coal. Costs and operating characteristics were taken from the Energy Information Administration (EIA). Due to time and data limitations, demand-side resources were not modeled as a resource option. Utility energy efficiency and demand response loads were modeled as fixed quantities based on utility-provided information.

Table 3-4 and Figure 3-3 show the statewide resource plan for the SUFG base scenario. This forecast indicates that the state does not need additional resources until 2021. Unlike in previous forecasts, the upgraded modeling system does not require the addition of resources to maintain model integrity prior to 2021. As the 2015 forecast explained, the additions included from 2016 to 2019 were needed for modeling purposes and resulted from an imbalance in reserves across utilities. This forecast indicates a need for about 3,600 MW of additional resources by 2025, 6,300 MW by 2030 and 9,300 MW at the end of the forecast period in 2035. In the long term, the projected additional resource requirements are higher than in previous forecasts. This is due to the retirements of additional existing generators that have been announced by Indiana utilities since the previous forecast report.

While SUFG identifies resource needs in its forecasts, it does not advocate any specific means of meeting them. Required resources could be met through conservation measures, purchases from merchant generators or other utilities, construction of new facilities or some combination thereof. The best method for meeting resource requirements may vary from one utility to another.

Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of historical data was 2015. Therefore, 2016 and 2017 numbers do not include short term purchases and any longer term purchases of which SUFG was not aware at the time the forecast was prepared.

Table 3-4. Indiana Resource Plan in MW (SUFG Base)

Year	Peak Demand[1]	Existing/ Approved Capacity[2]	Incremental Change in Capacity[3]	Projected Additional Resource Requirements[4]			Total Resources[5]	Reserve Margin (percent)
				Peaking	Baseload	Total		
2016	21,017	25,494		0	0	0	25,494	21
2017	21,066	25,594	100	0	0	0	25,594	21
2018	21,089	25,488	-106	0	0	0	25,488	21
2019	21,155	25,354	-133	0	0	0	25,354	20
2020	21,425	25,440	85	0	0	0	25,440	19
2021	21,506	25,384	-56	237	215	452	25,835	20
2022	21,620	25,334	-50	474	215	689	26,022	20
2023	21,754	24,256	-1078	1,422	215	1,637	25,892	19
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2034	25,040	21,376	-189	4,740	4,076	8,816	30,192	21
2035	25,425	21,166	-210	4,977	4,290	9,267	30,433	20

1 Peak Demand reflects utility-sponsored energy efficiency programs but is not adjusted for demand response loads.

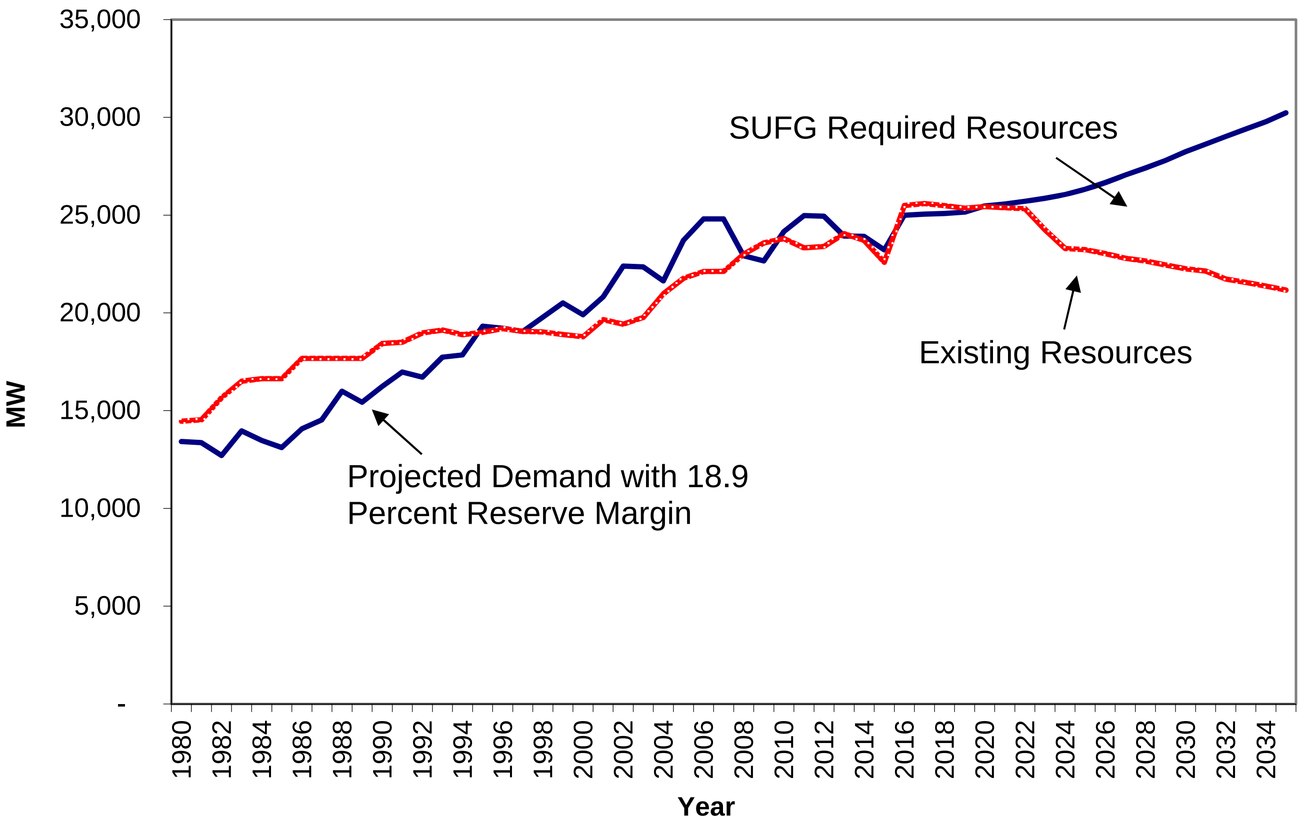
2 Existing/approved capacity includes installed capacity plus approved new capacity plus demand response plus firm purchases minus firm sales.

3 Incremental change in capacity is the change in existing/approved capacity from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, changes in available demand response loads, and changes in firm purchases and sales.

4 Projected additional resource requirements are the cumulative amount of additional resources needed to meet future requirements.

5 Total resource requirements are the total statewide resources required including existing/approved capacity and projected additional resource requirements.

Figure 3-3. Indiana Total Demand and Supply in MW (SUFG Base)



Equilibrium Price and Energy Impact

The SUFG modeling system is designed to forecast an equilibrium price that balances electricity supply and demand. This is accomplished through the cost-price-demand feedback loop, as described in Chapter 2. The impact of this feature on the forecast of electricity requirements can be significant if price changes are large.

SUFG's base scenario equilibrium real electricity price trajectory is shown in Table 3-5 and Figure 3-4. Real prices are projected to increase by 39 percent from 2015 to 2023 and then slowly decrease afterwards. The change in prices early in the forecast horizon is significant, thus the electricity requirements projection for this portion of the forecast period is affected.

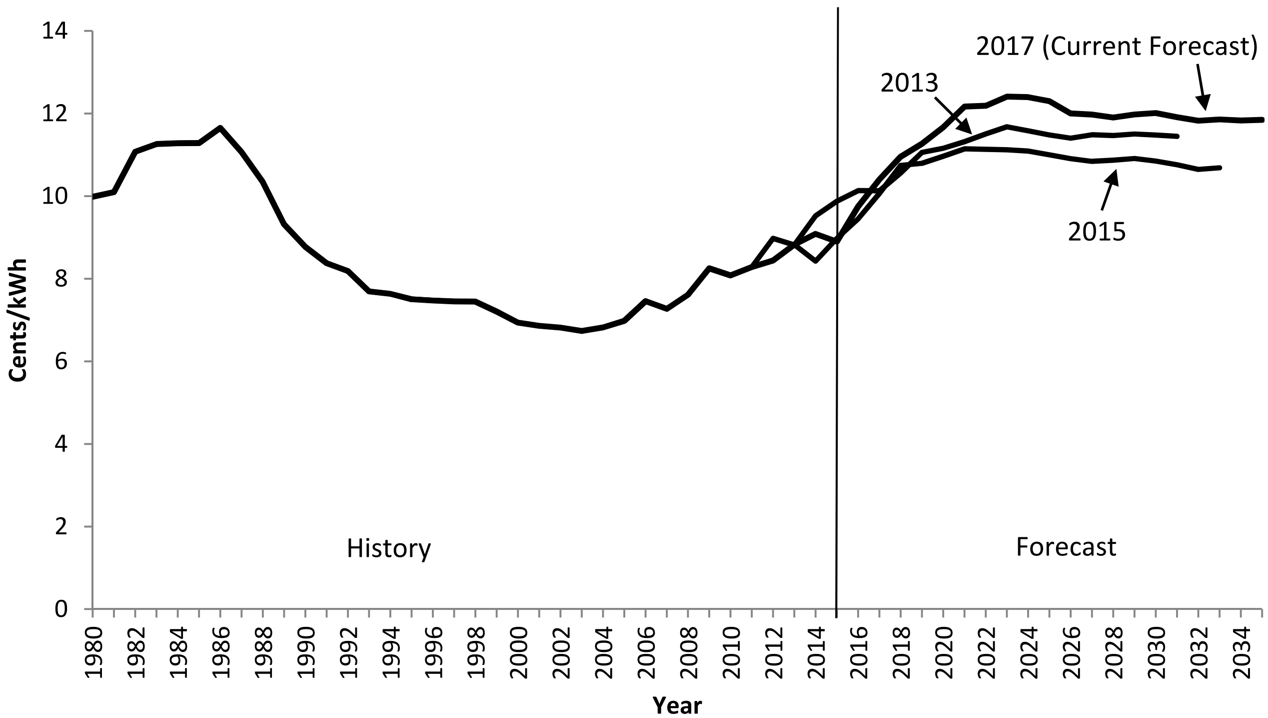
SUFG's equilibrium price projections for two previous forecasts are also shown in Table 3-5 and Figure 3-4. The price projection labeled "2013" is the base case projection contained in SUFG's 2013 forecast and the one labeled "2015" is the base case projection from SUFG's 2015 report. For the prior price forecasts, SUFG rescaled the original price projections to 2015 dollars (from 2011 dollars for the 2013 projection, and from 2013 dollars for the 2015 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

Table 3-5. Indiana Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2017	1.03	2016-2035
2015	1.26	2014-2033
2013	1.29	2012-2031

A number of factors determine the price projections in Figure 3-4. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity in addition to production. Environmental rules that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not.

Figure 3-4. Indiana Real Price Projections in cents/kWh (2015 Dollars) (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Low and High Scenarios

SUFG has used alternative macroeconomic scenarios, reflecting low and high growth in real personal income, non-manufacturing employment and gross state product. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Tables 3-6 and 3-7 and Figures 3-5 and 3-6 provide the statewide electricity requirements and peak demand projections for the base, low and high scenarios. As shown in those figures, the annual growth rates for energy requirements for the low and high scenarios are 0.39 percent lower and 0.40 percent higher than the base scenario. These differences are due to economic growth assumptions in the scenario-based projections.

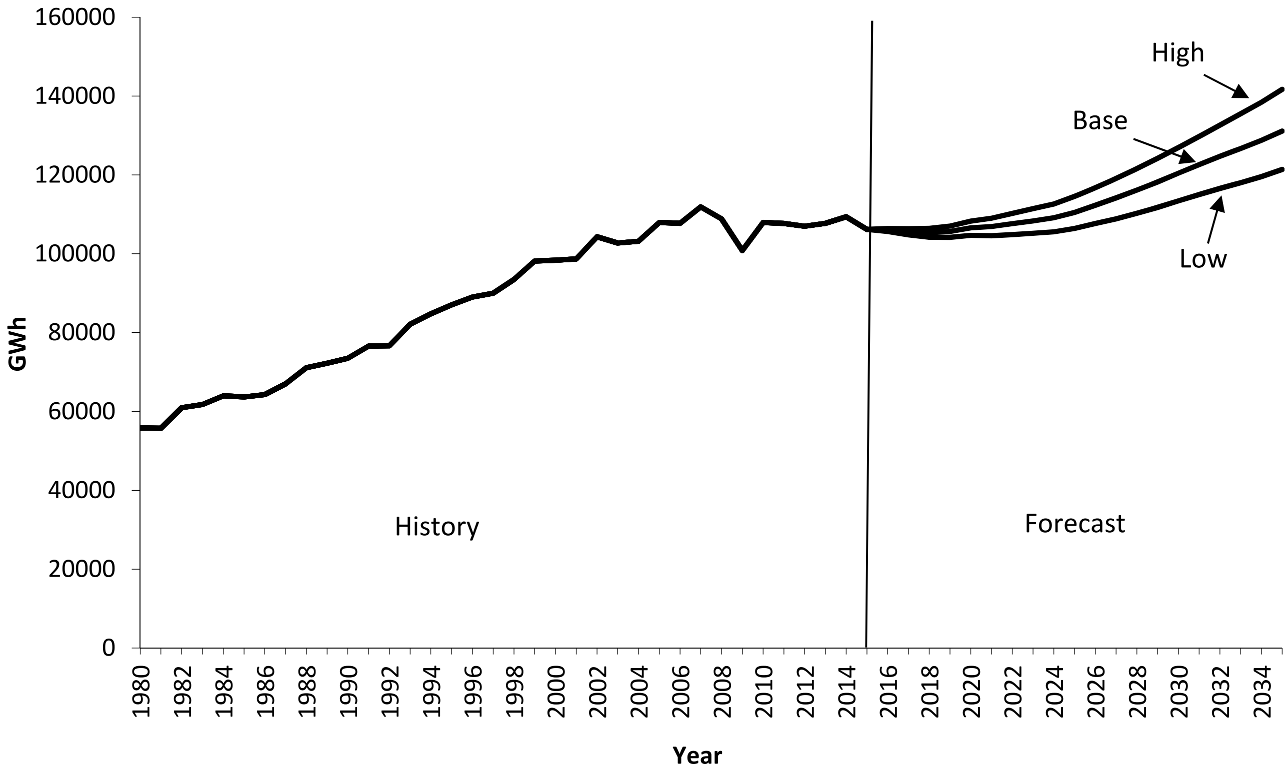
Resource and Price Implications of Low and High Scenarios

Resource plans are developed for the low and high scenarios using the same methodology as the base plan. Demand-side resources, including energy efficiency and demand response loads, are the same in all three scenarios, as are retirements of generating units. Table 3-8 shows the statewide resource requirements for each scenario. Approximately 10,900 MW over the horizon are required in the high scenario compared to 7,900 MW in the low scenario. By the end of the forecast period, electricity prices in both the high case and the low case are within about 0.75 percent of those projected in the base case. This is because the higher costs associated with meeting the increased load for the high case are spread over a greater amount of energy. For the low case, the lower costs are offset by the lower amount of energy.

Table 3-6. Indiana Electricity Requirements Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2016-2035	1.12	0.73	1.52

Figure 3-5. Indiana Electricity Requirements by Scenario in GWh

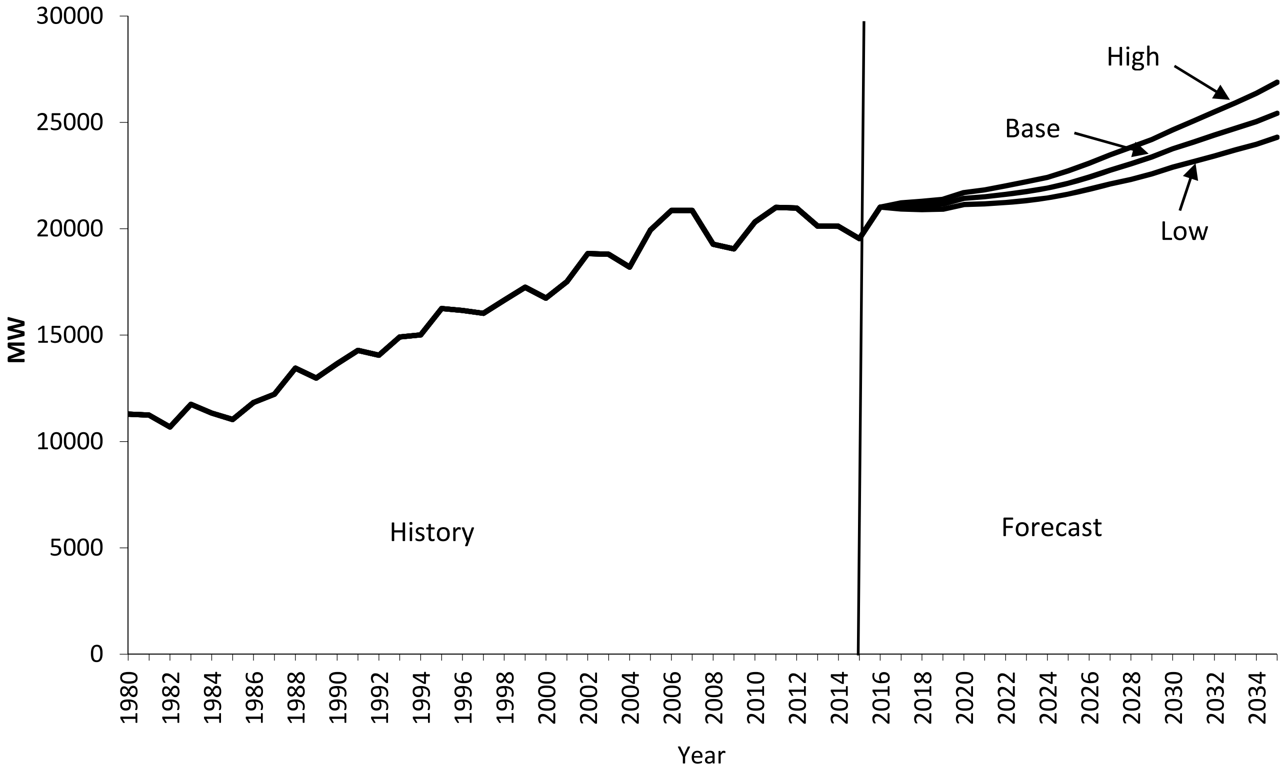


Note: See the Appendix to this report for historical and projected values.

Table 3-7. Indiana Peak Demand Requirements Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2016-2035	1.01	0.77	1.30

Figure 3-6. Indiana Peak Demand Requirements by Scenario in MW



Note: See the Appendix to this report for historical and projected values.

Table 3-8. Indiana Resource Requirements in MW (SUFG Scenarios)

Year	Base			High			Low		
	Peaking	Baseload	Total	Peaking	Baseload	Total	Peaking	Baseload	Total
2016	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	237	0	237	0	0	0
2020	0	0	0	237	215	452	0	0	0
2021	237	215	452	237	429	666	237	0	237
2022	474	215	689	474	643.5	1,118	474	0	474
2023	1,422	215	1,637	1,422	858	2,280	1,185	429	1,614
2024	1,896	1,287	3,183	1,896	1,716	3,612	1,659	1,287	2,946
2025	2,133	1,502	3,635	2,370	1,931	4,301	1,659	1,502	3,161
2026	2,370	1,716	4,086	2,844	1,931	4,775	1,659	1,716	3,375
2027	2,844	1,931	4,775	3,318	1,931	5,249	1,659	1,931	3,590
2028	2,844	2,145	4,989	3,792	1,931	5,723	1,896	2,145	4,041
2029	2,844	2,789	5,633	4,266	2,145	6,411	2,133	2,360	4,493
2030	3,318	3,003	6,321	4,503	2,574	7,077	2,607	2,574	5,181
2031	3,792	3,003	6,795	4,977	2,789	7,766	2,844	2,789	5,633
2032	4,029	3,432	7,461	5,451	3,218	8,669	3,081	3,218	6,299
2033	4,503	3,861	8,364	6,162	3,218	9,380	3,318	3,432	6,750
2034	4,740	4,076	8,816	6,399	3,861	10,260	4,029	3,432	7,461
2035	4,977	4,290	9,267	6,873	4,076	10,949	4,266	3,647	7,913

Chapter 4

Major Forecast Inputs and Assumptions

Introduction

The models SUFG utilizes to project electric energy sales, peak demand and prices require external, or exogenous, assumptions for several key inputs. Some of these input assumptions pertain to the level of economic activity, population growth and age composition for Indiana. Other assumptions include the prices of fossil fuels, which are used to generate electricity and compete with electricity to provide end-use service. Also included are estimates of the energy and peak demand reductions due to utility demand-side management programs.

This section describes SUFG's scenarios, presents the major input assumptions and provides a brief explanation of forecast uncertainty.

Macroeconomic Scenarios

The assumptions related to macroeconomic activity determine, to a large degree, the essence of SUFG's forecasts. These assumptions determine the level of various activities such as personal income, employment and manufacturing output, which in turn directly influence electricity consumption. Due to the importance of these assumptions and to illustrate forecast uncertainty, SUFG used alternative projections or scenarios of macroeconomic activity provided by the Center for Econometric Model Research (CEMR) at Indiana University.

- The *base scenario* is intended to represent the electricity forecast that is "most likely" and has an equal probability of being high or low.
- The *low scenario* is intended to represent a plausible lower bound on the electricity sales forecast and has a low probability of occurrence.
- The *high scenario* is intended to represent a plausible upper bound on the electricity sales forecast and also has a low probability of occurrence.

These scenarios are developed by varying the major forecast assumptions, i.e., Indiana's share of the national economy.

Economic Activity Projections

National and state economic projections are produced by the CEMR twice each year. For this forecast, SUFG adopted CEMR's February 2017 economic projections as its base scenario. CEMR also produced high and low growth alternatives to the base projection for SUFG's use in the high and low scenarios.

CEMR developed these projections from its U.S. and Indiana macroeconomic models. The Indiana economic forecast is generated in two stages. First, a set of exogenous assumptions affecting the national economy are developed by CEMR and input to its model of the U.S. economy. Second, the national economic projections from this model are input to the Indiana model that translates the national projections into projections of the Indiana economy.

The CEMR model of the U.S. economy is a large scale quarterly econometric model. Successive versions of the model have been used for more than 15 years to generate short-term forecasts. The model has a detailed aggregate demand sector that determines output. It also has a fully specified labor market submodel. Output determines employment, which then affects the availability of labor. Labor market tightness helps determine wage rates, which, along with employment, interest rates and several other variables determine personal income. Fiscal policy variables, such as spending levels and tax rates, interact with income to determine federal, state and local budgets. Monetary policy variables interact with output and price variables to determine interest rates.

A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy.

The Indiana model has four main modules. The first disaggregates total U.S. employment into manufacturing and non-manufacturing sectors. The second module then projects the share of each industry in Indiana. Additional relationships are used to project average weekly hours and average hourly earnings by industry. These are used with employment to calculate a total wage bill. The third module projects the remaining components of personal income. In the fourth module, labor productivity combined with employment projections is used to calculate real Gross State Product (GSP), or output, by industry.

The main exogenous assumptions in the national projections used in the CEMR forecast, as cited from "Long-Range Projections 2016-2037" [CEMR] are:

"Federal tax rates are assumed to increase over the projection period. Specifically, the average tax rate on personal income increases 9.4 percent, while the payroll tax rate increases by 3.2 percent. Federal grants to state and local governments are assumed to grow at a 4.7 percent rate early in the projection period, rising to 5.3 percent toward the end. Growth in government purchases is low. Altogether this produces a reduction in the federal government deficit. From 3.5 percent of GDP in 2016, it falls to 2.4 percent by the end of the projection period.

State and local tax rates rise through the projection period, by a total of 2.3 percent. This allows these governments to have budgets that move from 2016 deficits amounting to 1 percent of GDP to virtual balance by 2037.

Real exports are assumed to grow at about 4.9 percent through 2030, and then to slow slightly to 4.8 percent growth. This is significantly above growth of imports, resulting in a nominal net export deficit that declines from 2.7 percent of GDP in 2016 to just 0.8 percent in 2037."

As a result of these assumptions, real GDP for the U.S. economy is projected to grow at an average annual rate of 2.19 percent for the period of 2016 to 2019 and 2.55 percent for the period of 2020 to 2037. Meanwhile, U.S. employment growth averages 1.39 percent and 0.68 percent respectively for the short run and the long run.

In Indiana, total employment is projected to grow at an average annual rate of 0.72 percent from 2016 through 2037. The key Indiana economic projections are:

Real personal income (a residential sector model driver) is expected to grow at a 1.88 percent annual rate.

Non-manufacturing employment (the commercial sector model driver) is expected to grow at a 0.94 percent annual rate over the forecast horizon.

Despite a small decline in manufacturing employment (at an average annual rate of -0.56%), manufacturing Gross State Product (GSP) (the industrial sector model driver) is expected to rise at a 2.93 percent annual rate as gains in productivity far outpace the drop in employment.

A summary comparison of CEMR's projections used in SUFG's previous and current electricity projections and historical growth rates for recent historical periods is provided in Table 4-1.

To capture some of the uncertainty in energy forecasting, CEMR provided low and high growth alternatives to its base economic projection. In effect, the alternatives describe a situation in which Indiana either loses or gains shares of national industries compared to the base projection. In the high growth alternative, the Indiana average growth rate of real personal income is increased by about 0.31 percent per year (to 2.16), non-manufacturing employment growth increases 0.10 percent (to 0.97) while Indiana real manufacturing GSP growth is increased by 0.82 percent (to 3.79). In the low growth alternative, the average growth rates of real personal income, non-manufacturing employment and real manufacturing GSP are reduced by similar amounts (to 1.56, 0.76 and 2.20 percent, respectively).

Demographic Projections

Household demographic projections are a major input to the residential energy forecasting model. The SUFG forecasting system includes a housing model which utilizes population and income assumptions to project households or customers.

The population projections utilized in SUFG's electricity forecasts were obtained from the Indiana Business Research Center at Indiana University (IBRC). The IBRC population growth forecast for Indiana is 0.41 percent per year, for the period 2015-2035. This projection is based on the 2010 Census and includes projections of county population by age group. The fastest growing age groups are those of seniors age 65+ (2.17 percent) and young adults 25-44 (0.25 percent). Older adults aged 45-64 are projected to decline 0.42 percent. Population growth in total is low during the projection period because the age distribution in Indiana is skewed from young adults of childbearing age to older adults with higher mortality rates.

Indiana population growth has slowed markedly in recent years. The number of people over age 65 (the groups with fewer occupants per household) is projected to grow more rapidly than the younger population. Thus, the number of people per household is projected to decline and household formations are expected to grow more rapidly than total population.

The historical growth of household formations (number of residential customers) has slowed down significantly from slightly over 2 percent during the late 1960s and early 1970s to 0.3 percent from 2005-2015. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of about 1.13 percent over the forecast period.

Table 4-1. Growth Rates for CEMR Projections of Selected Economic Activity Measures (Percent)

	Short-Run History for Selected Recent Periods					Long-Run Forecast		
						Feb 2013	Feb 2015	Feb 2017
	1990-1995	1995-2000	2000-2005	2005-2010	2010-2015	2012-2031	2014-2033	2016-2035
United States								
Real Personal Income	2.49	4.78	2.06	1.30	2.83	2.73	2.66	2.35
Total Employment	1.40	2.37	0.30	-0.56	1.70	0.90	0.86	0.77
Real Gross Domestic Product	2.59	4.30	2.53	0.76	2.09	2.83	2.89	2.53
Personal Consumer Expenditure Deflator	2.51	1.71	2.11	1.96	1.50	1.60	1.95	1.92
Indiana								
Real Personal Income	2.89	4.46	0.49	1.15	2.50	2.15	2.33	1.86
Employment								
Total Establishment	2.03	1.50	-0.29	-1.12	1.63	0.88	0.80	0.66
Manufacturing	1.50	0.35	-2.99	-4.77	3.02	0.18	-0.17	-0.55
Non-Manufacturing	2.22	1.77	0.47	-0.05	1.34	0.97	0.96	0.87
Real Gross State Product								
Total	5.83	4.78	1.38	0.75	1.37	2.75	2.80	2.47
Manufacturing	7.95	4.68	1.86	2.75	1.31	3.58	3.71	2.98
Non-Manufacturing	4.86	4.84	1.21	-0.03	1.39	2.40	2.34	2.25
Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"								

Fossil Fuel Price Projections

The prices of fossil fuels such as coal, natural gas and oil affect electricity demand in separate and opposing ways. To the extent that any of these fuels are used to generate electricity, they are a determinant of average electricity prices. Around 65% of electricity generation for Indiana consumers was fueled by coal in 2016.[1] Thus, when coal prices increase, electricity prices in Indiana rise and electricity demand falls, all else being equal. On the other hand, fossil fuels compete directly with electricity to provide end-use services, i.e., space and water heating, process use, etc. When prices for these fuels increase, electricity becomes relatively more attractive and electricity demand tends to rise, all else being equal. As fossil fuel prices change, the impacts on electricity demand are somewhat offsetting. The net impact of these opposing forces depends on their impact on utility costs, the responsiveness of customer demand to electricity price changes and the availability and competitiveness of fossil fuels in the end-use services markets. The SUFG modeling system is designed to simulate each of these effects as well as the dynamic interactions among all effects.

SUFG's modeling system incorporates separate fuel price projections for utility, industrial, commercial and residential sectors. Therefore, SUFG uses four distinct natural gas price projections (one for each sector). Similarly, four distinct oil price projections are used. Coal price projections are included for the utility and industrial sectors only. In this forecast, SUFG has used January 2017 fossil fuel price projections from EIA for the East North Central Region of the U.S. [EIA]. All projections are in terms of real prices (2015 dollars), i.e., projections with the effects of inflation removed. The general patterns of the fossil fuel price projections are:

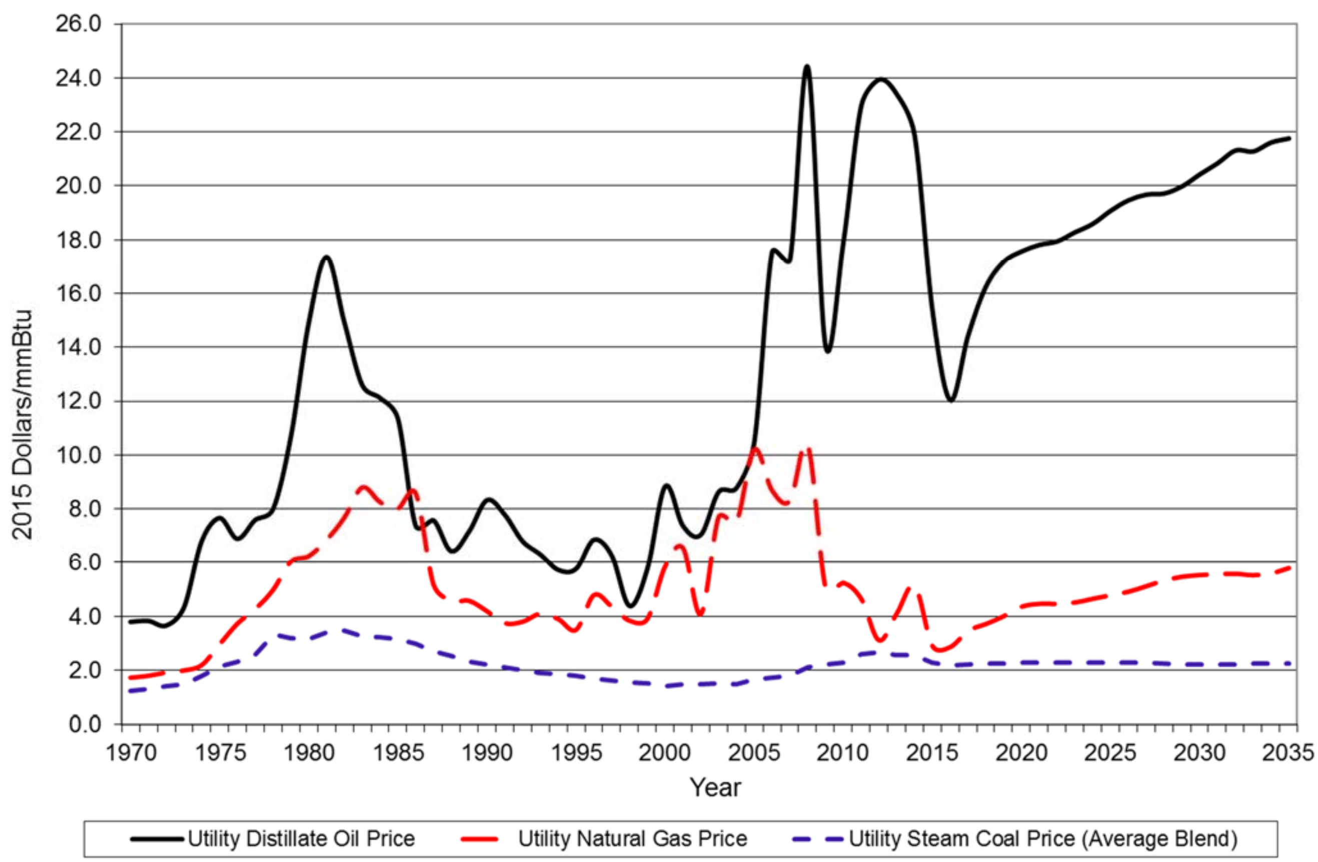
- Coal price projections are relatively flat in real terms throughout the entire forecast horizon as coal consumption decreases due to more natural gas and renewable generation observed in the electric power sector.
- Natural gas prices decreased significantly in 2009 relative to the high prices of 2008. Prices then rebounded somewhat in 2010 before declining again through 2012 before increasing back to 2010 levels by 2014. However, natural gas prices dropped again in 2015 to a level lower than that of 2012, followed by a slight decrease in 2016. They are projected to increase gradually for the remainder of the forecast horizon.
- Distillate prices also decreased significantly in 2009 coming off of the high prices of 2008. Prices

[1] According to the Indiana Utility Regulatory Commission's 2017 Annual Report, available at: http://www.in.gov/iurc/files/IURC%20annual%20report%20web.pdf.

then rebounded significantly through 2012-2013 before declining again in 2014, followed by substantial decreases in 2015 and 2016. They are projected to rebound quickly in 2017 and 2018 before growing at a slower pace over the remainder of the forecast horizon.

The fossil fuel price projections for the utility sector are presented in Figure 4-1. The general trajectories for the other sectors are similar.

Figure 4-1. Utility Real Fossil Fuel Prices



Demand-Side Management, Energy Efficiency and Demand Response

Demand-side management (DSM) refers to a variety of utility-sponsored programs designed to influence customer electricity usage in ways that produce desired changes in the utility's load shape, i.e., changes in the time pattern or magnitude of a utility's load. These programs include energy conservation programs that reduce overall consumption and load shifting programs that move demand from periods of high system demand to times when overall system demand is lower. SUFG considers separately the two components of DSM: energy efficiency (EE), which affects both energy and peak demand, and demand response (DR), which generally affects peak demand but has little impact on energy.

Incremental energy efficiency, which includes new programs and the expansion of existing programs, require adjustments to be made in the forecast. These adjustments are modeled within AURORAxmp by changing the utility's demand by the appropriate level of energy and peak demand for the EE program. EE programs that were in place in 2015 are considered to be embedded in the calibration data, so no adjustments are necessary.

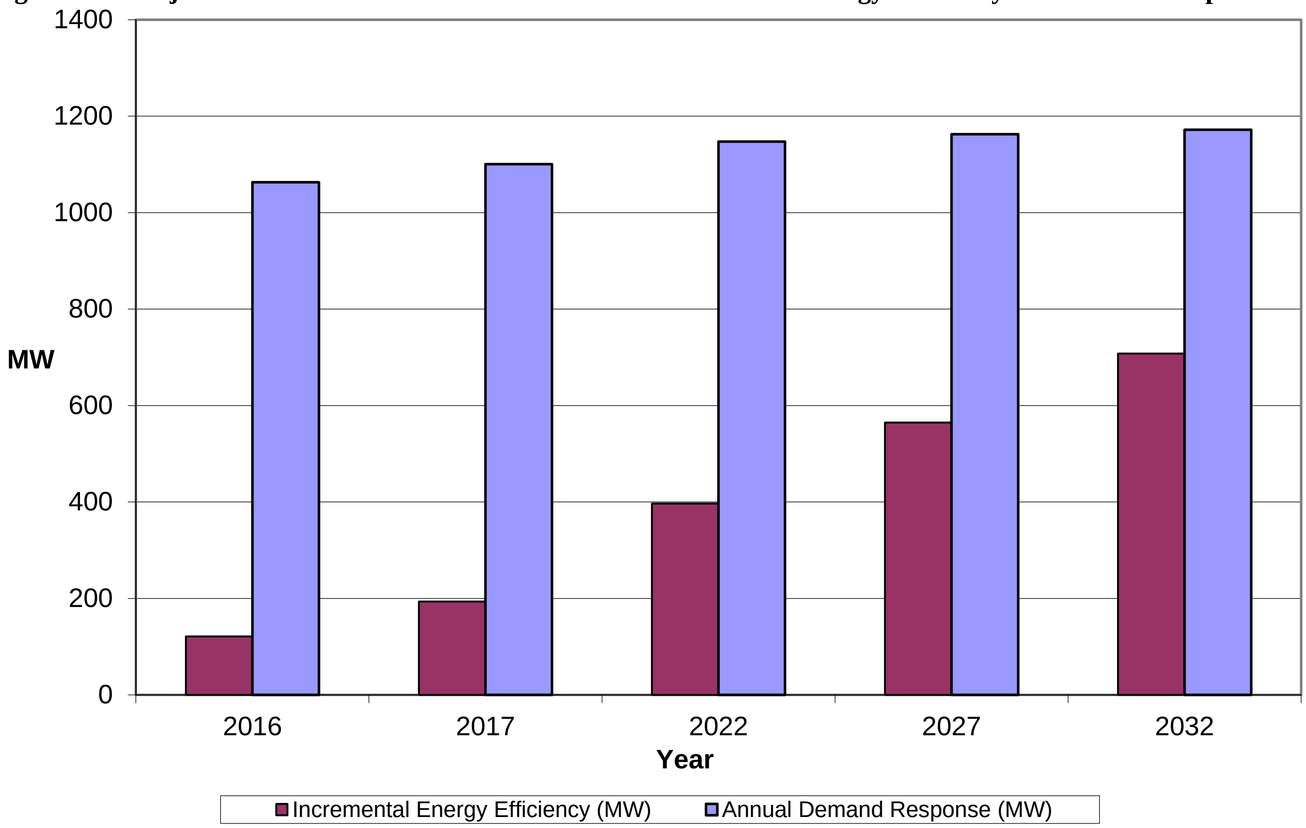
Demand response can include interruptible loads, such as large customers who agree to curtail a fixed amount of their demand during critical periods in exchange for more favorable rates, and direct load control, where the utility has the ability to directly turn off a customer's load for a specified amount of time. DR is typically treated differently than energy efficiency. In previous forecasts, the amount of demand response was subtracted from the utility's peak demand in order to determine the amount of new capacity required. Beginning with this forecast, demand response is modeled within AURORAxmp as a resource instead of as an after-the-fact adjustment as explained in Chapter 2.

Table 4-2 shows the peak demand reductions from embedded DSM in 2015 and from incremental EE and annual DR available in 2016 in Indiana. These estimates are derived from utility integrated resource plan (IRP) filings, from utility filings with the federal Energy Information Administration (EIA) and from information collected by SUFG directly from the utilities. In the 2013 forecast, long-term energy efficiency projections were primarily driven by the IURC's DSM order of December 2009. Since long-term program information was not available for all utilities, SUFG estimated the energy and peak demand savings, as well as the program costs, associated with meeting the DSM rule. With the passage of Senate Enrolled Act 340 in 2014, the targets associated with the rule are no longer applicable. For this forecast, SUFG does not attempt to project additional DSM savings beyond those identified by the utilities at the time this report was prepared. It should be noted that SUFG does not advocate any specific means for meeting future resource requirements, with additional energy efficiency being one of the options available for meeting those requirements. Figure 4-2 shows projected values of peak demand reductions for incremental energy efficiency and demand response for 2016 and at five year intervals starting in the year 2017.

Table 4-2. 2015 Embedded DSM and 2016 Incremental Peak Demand Reductions from Energy Efficiency and Annual Demand Response Programs (MW)

2015 Embedded DSM	2016 Incremental Energy Efficiency	2016 Annual Demand Response
3,421	121	1,063

Figure 4-2. Projections of Incremental Peak Demand Reductions from Energy Efficiency and Demand Response



Changes in Forecast Drivers from 2015 Forecast

The SUFG forecast requires exogenous economic assumptions to project electric energy sales, peak demand and prices. Fluctuations in the national and state economies therefore have direct effects on the forecast. This section compares the CEMR's projections used in SUFG's 2015 and 2017 forecasts.

In the time between CEMR's February 2015 (herein referred to as CEMR2015) and February 2017 (CEMR2017) long-range projections, the U.S. economy recovery has improved somewhat. Tables 4-3 through 4-5 provide comparisons between the two projections. Selected economic variables are reported annually from 2012 through 2018 and for 2020, 2025, 2030, and the last year of the forecast period 2035. The tables show long-run projections of real values and percentage change at annual rates for non-manufacturing employment, real personal income, and total real manufacturing GSP. The tables also show the percentage change between CEMR2015 and CEMR2017. Figures 4-3 through 4-5 show long-run projections of real values for the same selected economic variables from 2009 through 2037. Some of the historical values differ between the two projections because of data revisions and the use of chain-weighted price indices and deflators.

Non-manufacturing Employment

CEMR forecasts employment at the sectoral level, separating employment into sectors for durable goods manufacturing, non-durable goods manufacturing, and non-manufacturing. Analyzing the non-manufacturing (or service) sector's employment provides insight into Indiana's commercial electricity demand.

Table 4-3 and Figure 4-3 show that the current CEMR projection for non-manufacturing employment is very close to that in 2015 projection. In CEMR2017, the projection of non-manufacturing employment for 2017 is about 32,510 employees (or 1.31 percent) lower than that in CEMR2015. Although the gap between the two projections narrows after 2017, the projection in CEMR2017 is always slightly lower (within 1 percent) than that in CEMR 2015.

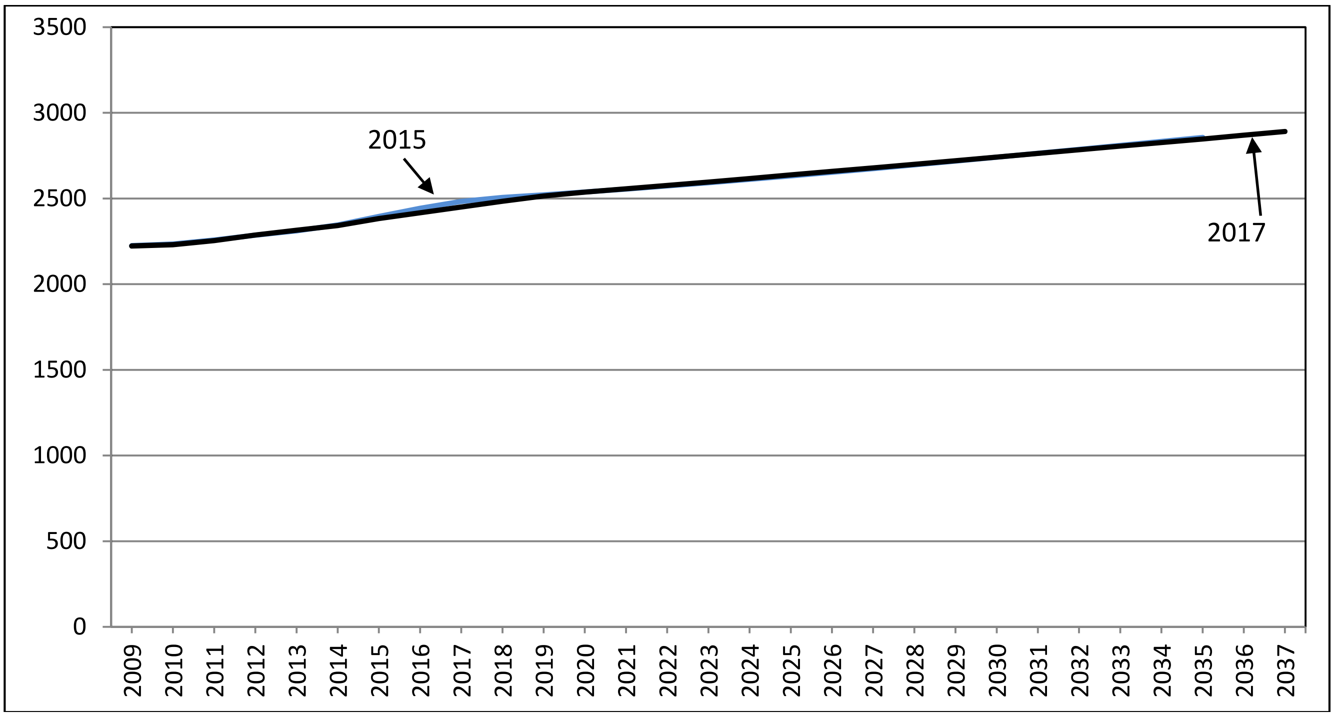
Figure 4-3 illustrates the comparison between past and current projections for employment in non-manufacturing. CEMR2017 exhibits very similar growth to CEMR2015 over the forecast horizon.

Table 4-3. 2015 and 2017 CEMR Projections for Indiana Non-manufacturing Employment

	Year										
	2012	2013	2014	2015	2016	2017	2018	2020	2025	2030	2035
	Thousands of persons										
CEMR 2015	2285.82 (1.22)	2311.54 (1.13)	2345.77 (1.48)	2395.21 (2.11)	2443.16 (2.00)	2482.68 (1.62)	2506.02 (0.94)	2538.02 (0.65)	2632.56 (0.80)	2740.98 (0.85)	2856.39 (0.82)
CEMR 2017	2287.34 (1.46)	2314.50 (1.19)	2342.08 (1.19)	2382.69 (1.73)	2416.93 (1.44)	2450.17 (1.38)	2483.98 (1.38)	2537.34 (0.90)	2638.25 (0.81)	2741.41 (0.78)	2847.72 (0.76)
Percentage change between two projections	0.07	0.13	-0.16	-0.52	-1.07	-1.31	-0.88	-0.03	0.22	0.02	-0.30

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Figure 4-3. Indiana Non-manufacturing Employment (thousands of people)



Real Personal Income

Real personal income provides an important picture of the impacts of the economy on Indiana. Changes in real personal income will directly influence electricity demand. Real personal income is an input to the residential energy forecasting model.

Table 4-4 and Figure 4-4 show the CEMR projections of real personal income. CEMR2017 has a stronger projection for real personal income during the period of 2015-2024, but a weaker projection for the period of 2025-2037 than CEMR2015. CEMR2017 indicates real personal income $17.71 billion (4.59 percent) lower by the end of the forecast period in 2035.

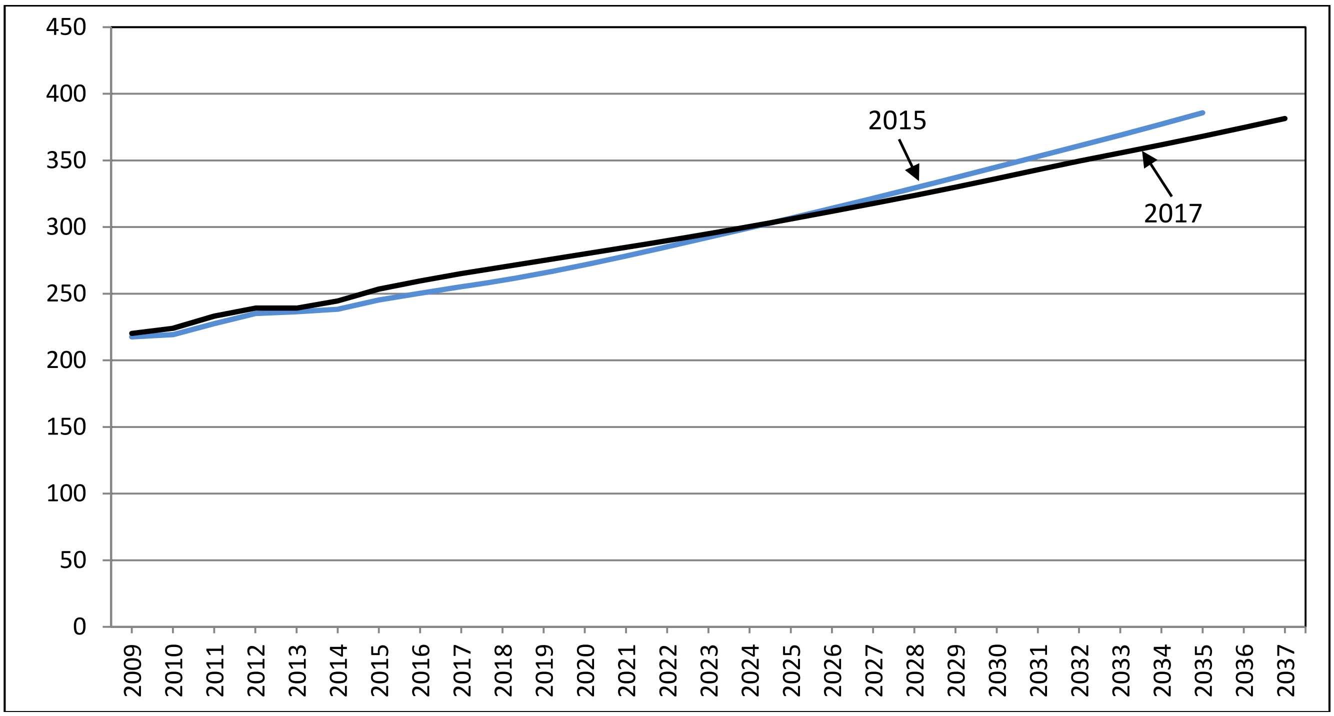
Figure 4-4 illustrates that the CEMR2017 real personal income is projected to be lower than CEMR2015 beginning in 2025 to the end of forecast horizon.

Table 4-4. 2015 and 2017 CEMR Projections for Indiana Real Personal Income

	Year										
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2020**	**2025**	**2030**	**2035**
	Billions of 2009 $										
CEMR 2015	235.07 (3.31)	236.45 (0.59)	238.37 (0.81)	245.30 (2.90)	250.39 (2.07)	255.27 (1.95)	259.76 (1.76)	271.79 (2.37)	306.67 (2.42)	345.20 (2.38)	385.81 (2.27)
CEMR 2017	239.12 (2.58)	239.16 (0.02)	244.57 (2.26)	253.47 (3.64)	259.57 (2.41)	265.09 (2.13)	270.00 (1.85)	279.95 (1.86)	305.98 (1.86)	336.41 (1.96)	368.10 (1.75)
Percentage change between two projections	1.72	1.15	2.60	3.33	3.67	3.85	3.94	3.00	-0.22	-2.55	-4.59

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Figure 4-4. Indiana Real Personal Income (billions of 2009 dollars)



Real Manufacturing Gross State Product

Changes in manufacturing GSP will have significant implications for electricity use in the industrial sector. The recession of 2008-2009 had a larger impact on manufacturing GSP growth than on either non-manufacturing employment or personal income.

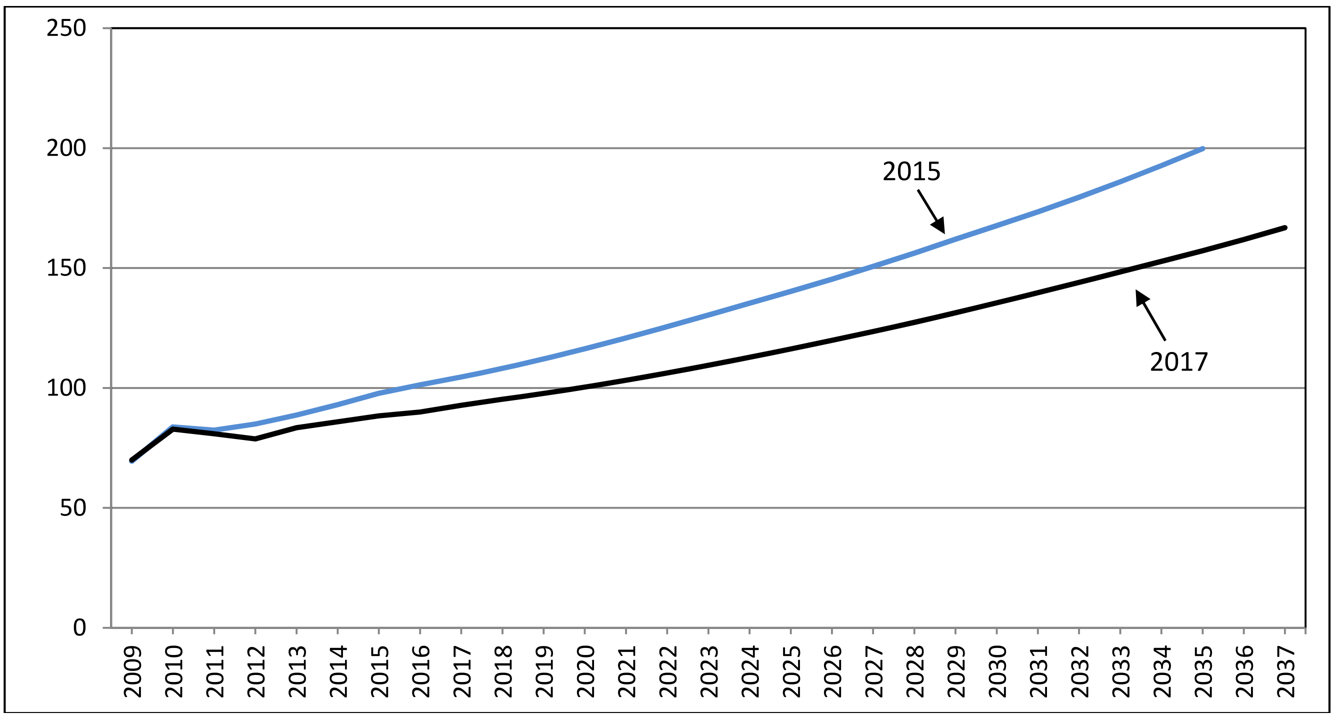
Table 4-5 and Figure 4-5 show the CEMR projections for real manufacturing GSP. As the figure illustrates, the CEMR2017 projection for the entire forecast period is significantly lower than CEMR2015. The projection for 2035 is $42.6 billion (21.32 percent) lower than the CEMR2015 level for that year. The major reason for this revision is that the more recent data show that the slow growth over the period since the recession seems likely to be more long term. A lower projection of employment growth combined with a lower projection of productivity growth lead to a lower projection of the overall growth of real manufacturing GPS.

Table 4-5. 2015 and 2017 CEMR Projections for Indiana Real Manufacturing GSP

	Year										
	2012	2013	2014	2015	2016	2017	2018	2020	2025	2030	2035
	Billions of 2009 $										
CEMR 2015	84.98 (3.06)	88.72 (4.40)	93.08 (4.91)	97.77 (5.05)	101.31 (3.62)	104.60 (3.24)	108.18 (3.43)	116.35 (3.77)	140.27 (3.62)	167.72 (3.53)	199.77 (3.67)
CEMR 2017	78.79 (-2.66)	83.44 (5.90)	85.92 (2.97)	88.41 (2.90)	89.99 (1.79)	92.76 (3.07)	95.30 (2.74)	100.34 (2.68)	116.27 (3.09)	135.45 (3.16)	157.19 (2.95)
Percentage change between two projections	-7.29	-5.95	-7.69	-9.57	-11.17	-11.32	-11.91	-13.76	-17.11	-19.24	-21.32

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Figure 4-5. Indiana Real Manufacturing GSP (billions of 2009 dollars)



Transportation Equipment Industry

The transportation equipment industry, including automobile and auto parts manufacturing, accounts for a considerable portion of the total manufacturing GSP in Indiana. In 2015, this sector represented 31 percent of the total real value of products manufactured in the state.

SUFG felt that CEMR's forecast showed too much growth over the long term for this sector (as in CEMR2013 and CEMR2015 before), so the forecast was again tempered. The "CEMR2017 Adjusted" projection calls for growth over the forecast period 2016-2035 of an annual rate of approximately 3.0 percent.

Table 4-6 shows projected growth rates, actual values and percentage rate changes for the transportation equipment industry and includes the comparison between the adjusted CEMR2015 and adjusted CEMR2017 projections. The industry is projected to keep recovering from the recession for the entire forecast period. However, compared with CEMR2015, CEMR2017 projects growth with a slower pace. In 2035, the level forecasted in CEMR2017 is 24.1 percent lower than that in CEMR2015.

Primary Metals Industry

While the primary metals industry, including production of steel and aluminum, represented approximately 6.9 percent of Indiana manufacturing GSP in 2015, it accounted for 32 percent of the state's industrial electricity sales.

Table 4-7 compares the CEMR projections for 2015 and 2017 for the primary metals industry, which saw a decrease of over 24 percent between 2010 and 2011 followed by an increase of 34 percent in 2012, about a 29 percent increase in 2013. The primary metals industry is projected to be decreasing from 2014-2022 before being steady at the 2022 level for the rest of the forecast horizon. The CEMR2017 projections for the primary metals industry are higher than the CEMR2015 projections before 2019 but lower after. In 2035, the projected GSP level for the primary metals industry in the CEMR2017 is about 19 percent lower than that in the CEMR2015.

Table 4-6. 2015 and 2017 Adjusted CEMR Projections for Indiana Real Transportation Equipment GSP

	Year										
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2020**	**2025**	**2030**	**2035**
	Billions of 2009 $										
CEMR 2015 Adjusted	16.95 (5.94)	18.62 (9.83)	19.54 (4.91)	20.52 (5.05)	21.26 (3.62)	21.95 (3.24)	22.71 (3.43)	24.42 (3.77)	29.44 (3.62)	35.20 (3.53)	41.93 (3.67)
CEMR 2017 Adjusted	15.99 (2.03)	16.86 (5.45)	17.40 (3.23)	17.91 (2.90)	18.23 (1.79)	18.79 (3.07)	19.31 (2.74)	20.33 (2.68)	23.55 (3.09)	27.44 (3.16)	31.84 (2.95)
Percentage change between two projections	-5.70	-9.46	-10.91	-12.73	-14.27	-14.41	-14.98	-16.77	-20.00	-22.06	-24.06

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Table 4-7. 2015 and 2017 CEMR Projections for Indiana Real Primary Metals GSP

	Year										
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2020**	**2025**	**2030**	**2035**
	Billions of 2009 $										
CEMR 2015	5.40 (23.67)	5.26 (-2.68)	5.21 (-0.99)	5.20 (-0.10)	5.13 (-1.41)	5.02 (-2.03)	4.92 (-2.00)	5.05 (1.37)	5.38 (0.88)	5.61 (0.64)	5.79 (0.73)
CEMR 2017	5.61 (34.00)	7.23 (28.88)	6.73 (-6.95)	6.47 (-3.94)	5.91 (-8.55)	5.55 (-6.12)	5.23 (-5.74)	4.63 (-5.88)	4.65 (0.19)	4.68 (0.21)	4.67 (-0.17)
Percentage change between two projections	3.87	37.56	29.27	24.30	15.30	10.49	6.28	-8.27	-13.60	-16.56	-19.30

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Forecast Uncertainty

There are three sources of uncertainty in any energy forecast:

1. exogenous assumptions;
2. stochastic model error; and,
3. non-stochastic model error.

Projections of future electricity requirements are conditional on the projections of exogenous variables. Exogenous variables are those for which values must be assumed or projected by other models or methods outside the energy modeling system. These exogenous assumptions, including demographics, economic activity and fossil fuel prices, are not known with certainty. Thus, they represent a major source of uncertainty in any energy forecast.

Stochastic error is inherent in the structure of any forecasting model. Sampling error is one source of stochastic error. Each set of observations (the historical data) from which the model is estimated constitutes a sample. When one considers stochastic model error, it is implicitly assumed that the model is correctly specified and that the data is correctly measured. Under these assumptions the error between the estimated model and the true model (which is always unknown) has certain properties. The expected value of the error term is equal to zero. However, for any specific observation in the sample, it may be positive or negative. The errors from a number of samples follow a pattern, which is described as the normal probability distribution, or bell curve. This particular normal distribution has a zero mean, and an unknown, but estimable variance. The magnitude of the stochastic model error is directly related to the magnitude of the estimated variance of this distribution. The greater the variance, the larger the potential error will be.

In practice, virtually all models are less than perfect. Non-stochastic model error results from specification errors, measurement errors and/or use of inappropriate estimation methods. SUFG is committed to identifying and correcting potential errors in model specification, data measurement, and appropriate estimation methods.

References

Center for Econometric Model Research, “Long-Range Projections 2016-2037,” Indiana University, February 2017.

Energy Information Administration, “Annual Energy Outlook 2017,” January 2017.

Indiana Utility Regulatory Commission, “2017 Annual Report,” October 2017.

Chapter 5

Residential Electricity Sales

Overview

SUFG has access to both econometric and end-use models to project residential electricity sales. These different modeling approaches have specific strengths and complement each other. The econometric model is used to project the number of customers in two groups, those with and those without electric space heating systems, as well as average electricity use by each customer group. The SUFG staff originally developed the econometric model in 1987 when it was estimated from utility specific data. Since then, it has been updated four times. After the release of the 2007 SUFG Indiana Electricity Projections report, SUFG acquired a proprietary end-use model, Residential Energy Demand Model System (REDMS), which blends econometric and engineering methodologies to project energy use on a disaggregated basis. REDMS was obtained to replace an older residential sector end-use oriented model known as REEMS. Both end-use models are descendants of the first generation of end-use models developed at Oak Ridge National Labs (ORNL) during the late 1970s. Starting with the 2011 forecast, SUFG adopted REDMS as the primary residential sector energy model, and it is used to project residential electricity sales in this forecast. The end-use model has been implemented for the five Indiana investor-owned utilities (IOUs) and SUFG continues to model residential energy for the not-for-profit utilities (NFPs) with an econometric approach.

SUFG chose REDMS as the primary residential sector energy projection model for three reasons. First, the SUFG econometric model divides customers into two distinct classes depending upon the space heating fuel employed: electricity and other fuels. Over time the distinction between electric space heating and natural gas (or liquefied petroleum gas) space heating has blurred due to the emergence and acceptance of hybrid systems.

Second, at least one major Indiana utility no longer offers a specific electric rate schedule to new customers that choose to use electricity for space heating. Also, at least one additional Indiana utility offers a restricted electric space heating rate which is dependent upon equipment efficiency criteria.

Third, federal law mandated lighting efficiency standards which SUFG felt were best modeled in a direct end-use context. The standards called for a 30 percent improvement in lighting efficiency beginning in 2012 with a phased in efficiency improvement of 60 percent by 2020. Econometric methods work reasonably well to capture trends in efficiency over time, but the lighting standards were more aggressive than historical equipment standards in both the level and timing of the mandated efficiency improvements. For this reason SUFG did not feel comfortable relying on the traditional econometric energy model and chose the direct end-use modeling approach rather than make adjustments to the econometric model projections.

Historical Perspective

The growth in residential electricity consumption has generally reflected changes in economic activity, i.e., real household income, real energy prices and total households. Each of five recent periods has been characterized by distinctly different trends in these market factors and in each case, residential electricity sales growth has reflected the change in market conditions. Beginning in 2008 economic activity slowed dramatically. Due in large part to economic weakness, low electric energy sales growth was experienced in the residential sector (see Figure 5-1).

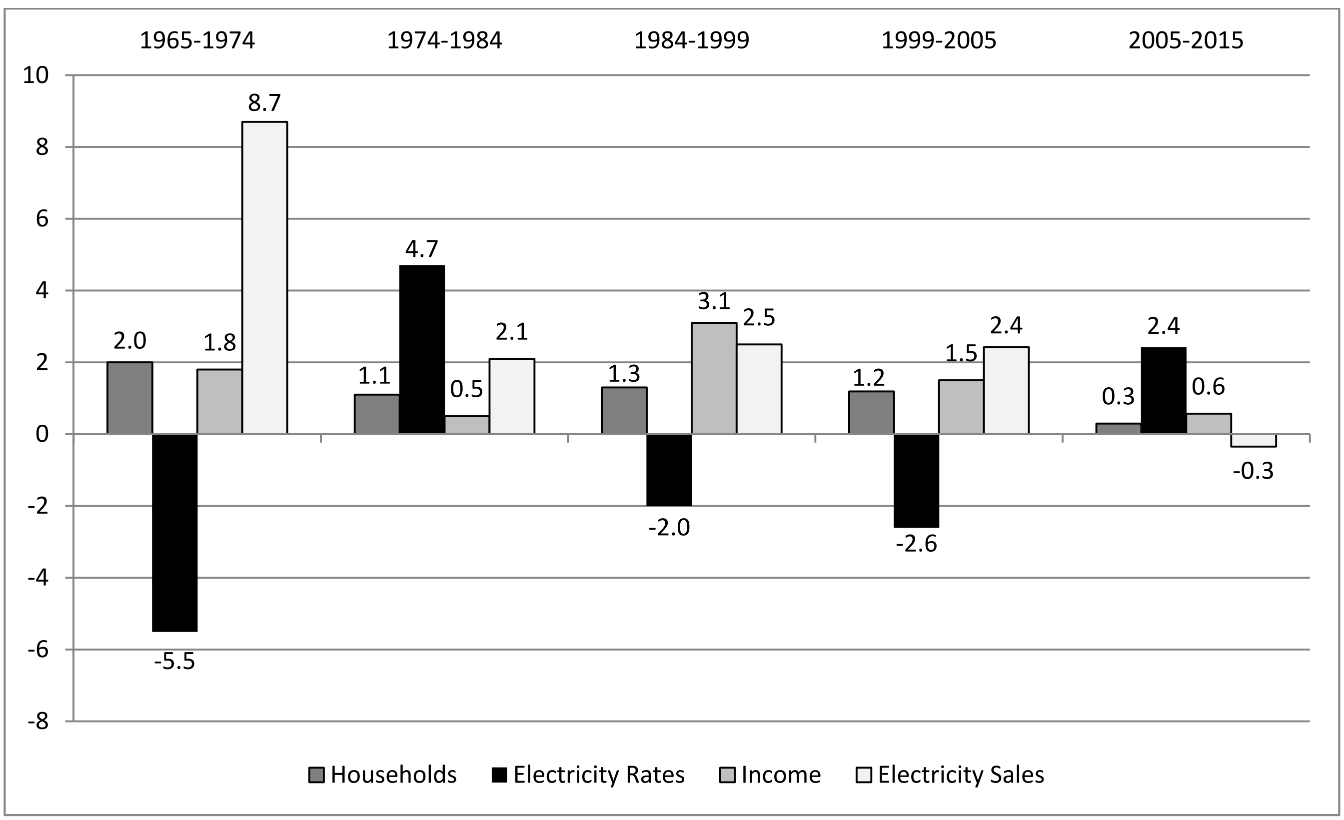
The explosion in residential electricity sales (nearly 9 percent per year) during the decade prior to the Organization of Petroleum Exporting Countries (OPEC) oil embargo in 1974 coincided with the economic stimuli of falling prices (nearly 6 percent per year in real terms) and rising incomes (almost 2 percent per year in real terms). This period also was marked by a boom in the housing industry as the number of residences increased at an average rate of 2 percent per year. In the decade following the embargo, the growth in residential electricity sales slowed dramatically. Except for some softening in electricity prices during 1979-1981, real electricity prices climbed at approximately the same rate during the post-embargo era as they had fallen during the pre-embargo era. This resulted in a swing in electric prices of more than 10 percent. Growth in real household income was a miniscule 0.5 percent, less than one-third of that seen in the previous period. The housing market also went from boom to bust, averaging only half the growth of the pre-embargo period. This turnaround in economic conditions and electricity prices is reflected in the dramatic decline in the growth of residential electricity sales from nearly 9 percent per year 1965-1974, to just over 2 percent per year for the next decade. Events turned again during the mid-1980s. Real household income grew at more than the pre-embargo rate, 3.1 percent per year. Real electricity prices declined 2.0 percent per year at one third the pre-embargo rate. Households grew at only a slightly higher rate than in the post-embargo decade, about 1.3 percent per year. Despite these more favorable market conditions, annual electricity sales growth increased only 0.4 percent to 2.5 percent per year.

Several market factors contributed to the small difference in sales growth between the post-embargo and more recent period. First and perhaps most importantly, is the difference in the availability and price of natural gas between the two periods. Restrictions on new natural gas hook-ups during the post-embargo period and supply uncertainty caused electricity to gain market share in major end-use markets previously dominated by natural gas, i.e., space heating and water heating. More recently, plentiful supply and falling natural gas prices through 1999 caused natural gas to recapture market share. Next in importance are equipment efficiency standards and the availability of more efficient appliances. Appliance efficiency improvement standards did not begin until late in the post-embargo era. Lastly, appliance saturations tend to grow more slowly as they approach full market saturation, and the major residential end uses are nearing full saturation.

From 1999-2005, residential household growth decreased slightly to a 1.2 percent annual rate similar to the 1984-1999 period, real electric rates continued to decline, but the growth in personal income, while positive, slowed markedly. Despite the slow growth in income, electricity sales continued to grow at roughly the rate observed during the 1984-1999 period.

More recently, from 2005-2015, the effects of the economic downturn coupled with rising electricity prices have resulted in much lower growth in electricity sales. Growth of the number of households slowed to one-fourth the rate observed over the preceding twenty years. Real electricity prices increased at an average annual rate of 2.4 percent, reversing the trend of the previous twenty years. Real household income increased at only 0.6 percent over the period, one tenth the rate observed during the previous period. The net effect of these changes was to reduce the electricity sales growth rate to essentially flat over the period.

Figure 5-1. State Historical Trends in the Residential Sector (Annual Percent Change)



Model Description

The residential end-use model REDMS is the residential analogue to CEDMS, the commercial sector end-use model described in the next chapter of this report. For this reason the description of REDMS below is nearly identical to that of CEDMS in the commercial sector chapter.

Figure 5-2 depicts the structure of the residential end-use model. As the figure shows, REDMS uses a disaggregated capital stock approach to forecast energy use. Energy use is viewed as a derived demand in which electricity and other fuels are inputs, along with energy using equipment and building envelopes, in the production of end-use services.

The disaggregation of energy demand is as important in the modeling of the residential sector as it is for modeling the commercial sector. REDMS divides residential dwellings among three dwelling types. It also divides energy use in each dwelling type among ten possible end uses, including a miscellaneous or residual use category. For end uses such as space heating, where non-electric fuels compete with electricity, REDMS further disaggregates energy use among fuel types. (This disaggregation scheme is illustrated at the top of Figure 5-2.) REDMS also divides dwellings among vintages, i.e., the year the dwelling was constructed, and simulates energy use for each vintage and dwelling type.
REDMS projects energy use for each dwelling vintage according to the following equation:

$$Q\ (T, i, k, l, t) = U\ (i, k, l, t) * e\ (i, k, l, t) * a\ (i, k, l, t) * A\ (l, t) * d\ (l, T\text{-}t)$$

where

* = multiplication operator;

T = forecast year;

Q = energy demand for fuel i, end use k, dwelling type l and vintage t in the forecast year;

t = dwelling vintage (year);

U = utilization, relative to some base year;

e = energy use index, kWh/year or Btu/year;

a = fraction of dwelling served by fuel i, end use k, and dwelling type l for dwelling additions of vintage t;

A = dwelling additions by vintage t and dwelling type l; and

d = fraction of dwellings of vintage t still standing in forecast year T.

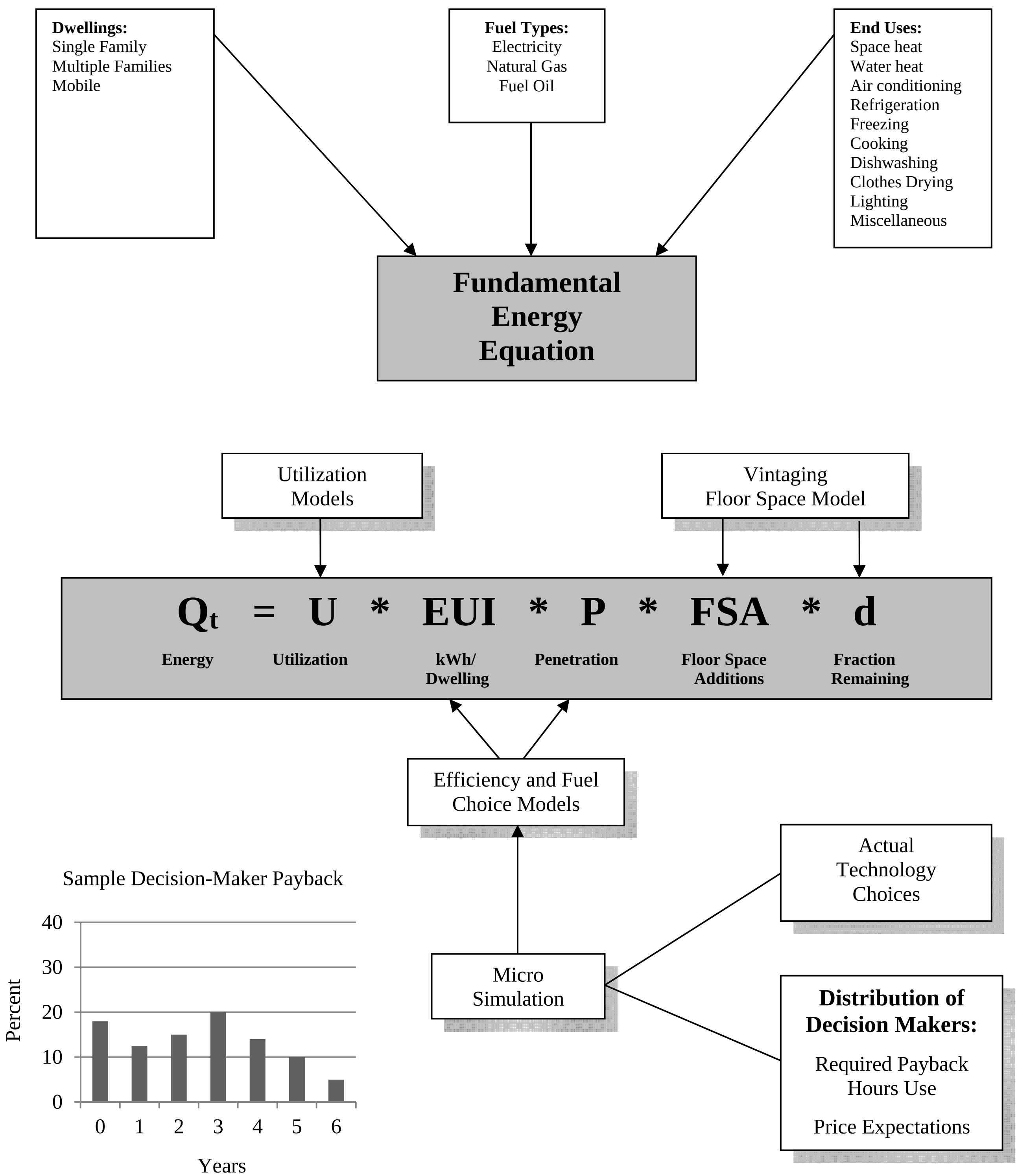
REDMS' central features are its explicit representation of the joint nature of decisions regarding fuel choice, efficiency choice and the level of end-use service, as well as its explicit representation of costs and energy use characteristics of available end-use technologies in these decisions.

REDMS jointly determines fuel and efficiency choices through a methodology known as discrete choice microsimulation. Essentially, sample decision-makers in the model make choices from a set of discrete equipment options. Each discrete equipment option is characterized by its fuel type, energy use and cost. REDMS uses the discrete technology choice methodology to model equipment choices for all major end-uses.

Equipment standards are easily incorporated in REDMS' equipment choice sub-models. Besides efficiency and fuel choices, REDMS also models changes in equipment utilization, or intensity of use. For equipment that has not been added or replaced in the previous year, changes in equipment utilization are modeled using fuel-specific, short-run price elasticities and changes in fuel prices.

For new equipment installed in the current year, utilization depends on both equipment efficiency and fuel price. For example, a 10 percent improvement in efficiency and a 10 percent increase in fuel prices would have offsetting effects since the total cost of producing the end-use service is unchanged.

Figure 5-2. Structure of Residential End-Use Energy Modeling System



Summary of Results

The remainder of this chapter describes SUFG's current residential electricity sales projections. First, the current projection of residential sales growth is explained in terms of the model sensitivities and changes in the major explanatory variables. Next, the current base projection is compared to past base projections and then to the current high and low scenario projections. Also, at each step, significant differences in the projections are explained in terms of the model sensitivities and changes in the major explanatory variables.

Model Sensitivities

The major economic drivers in the residential end-use model include dwellings (residential customers) and electricity prices. The sensitivity of the residential electricity use projection to changes in these variables was simulated one at a time by increasing each variable ten percent above a base scenario level and observing the change in electricity use. The results are shown in Table 5-1. Electricity consumption increases substantially due to increases in the number of customers. As expected, electricity rate increases reduce electric consumption. Changes in natural gas prices, fuel oil prices, and personal income do not affect electricity consumption due in part to the structure of the model and in part due to the vendor's implementation of the model.

Competing fuels (gas and oil) could potentially affect electricity use through two mechanisms; retrofits and penetration in dwelling additions. Once an initial space heating (and subsequently water heating) fuel for a new dwelling is chosen retrofits to an alternative fuel are generally precluded due to the cost hurdle of the capital expense of switching fuels. Such a fuel choice switch would require the addition of gas service and delivery, fuel oil storage and delivery, or an electrical service upgrade and wiring upgrades. In the case of dwelling additions a statistically significant relationship between fuel prices and fuel specific end-use penetrations was not discernable. During the period used for model calibration 1990-2005, electric space heating penetration was remarkably consistent at around 20 percent with natural gas and LPG largely capturing the remainder, real electricity prices were virtually constant, real gas and oil prices drifted upward with considerable volatility but did not exhibit any persistent lasting changes in level.

Personal income effects on fuel and efficiency choices are reflected in the decision makers' behavior through the micro-simulation modeling. On average, one would expect those decision makers facing active income or financial constraints to be the decision makers with shorter payback intervals and those without such constraints to have longer payback horizons. Also, a statistically significant relationship between end-use utilization and personal income could not be identified.

Table 5-1. Residential Model Long-Run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Use
Number of Customers	9.9
Electric Rates	-4.0

Indiana Residential Electricity Sales Projections

Actual sales (GWh), as well as past and current projections, are shown in Table 5-2 and Figure 5-3. The growth rate for the current base projection of Indiana residential electricity sales is 0.48 percent, which is 0.16 percent lower than SUFG's 2015 projection of 0.64 percent. The historic and 2017 forecast numbers are provided in the Appendix of this report. Long-term patterns for the entire forecast horizon show that the current projection lies well below both the 2015 and 2013 projections. Table 5-3 summarizes SUFG's base projections of residential electricity sales growth since 2013.

Table 5-3 breaks these projections down by the portion of the growth rate attributable to the growth in number of customers and growth in utilization per customer, with and without DSM. As the table shows, customer growth is partially offset by decreases in utilization, which is the amount of energy used per household. Use per household decreases because of increasing prices and the implementation of new efficiency standards. It can also be seen from the table that residential DSM cuts the sales growth rate by approximately 28 percent, reducing it from 0.67 percent to 0.48 percent.

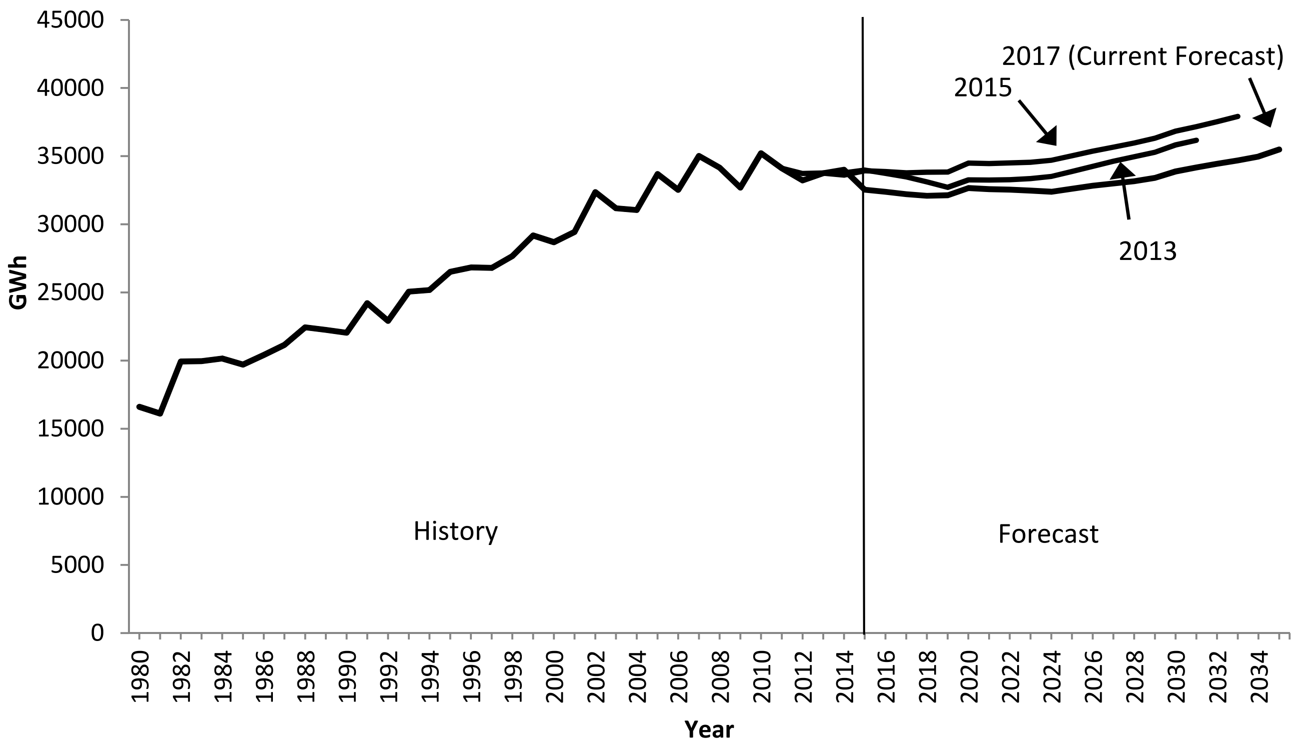
Table 5-4 shows the growth rates of the major residential drivers for the current scenarios and the 2015 base case. Household formation is determined by two factors. Demographic projections are the primary determinant, with personal income having a smaller impact. The demographic projections in all four cases are very similar. While there are some small variations in personal income among the cases, they are not sufficiently large as to result in a significant difference in growth rates for the base and high scenarios.

As shown in Table 5-5 and Figure 5-4, the growth rates for the high and low residential scenarios are about 0.04 percent higher and 0.04 lower, respectively, than the base scenario. This difference is due primarily to differences in the growth of household income.

Table 5-2. Indiana Residential Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2017	0.48	2016-2035
2015	0.64	2014-2033
2013	0.37	2012-2031

Figure 5-3. Indiana Residential Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Table 5-3. History of SUFG Residential Sector Growth Rates (Percent)

Forecast	No. of Customers	Without DSM		With DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2017 SUFG Base (2016-2035)	1.13	-0.46	0.67	-0.65	0.48
2015 SUFG Base (2014-2033)	1.07	-0.35	0.72	-0.43	0.64
2013 SUFG Base (2012-2031)	1.17	-0.32	0.85	-0.80	0.37

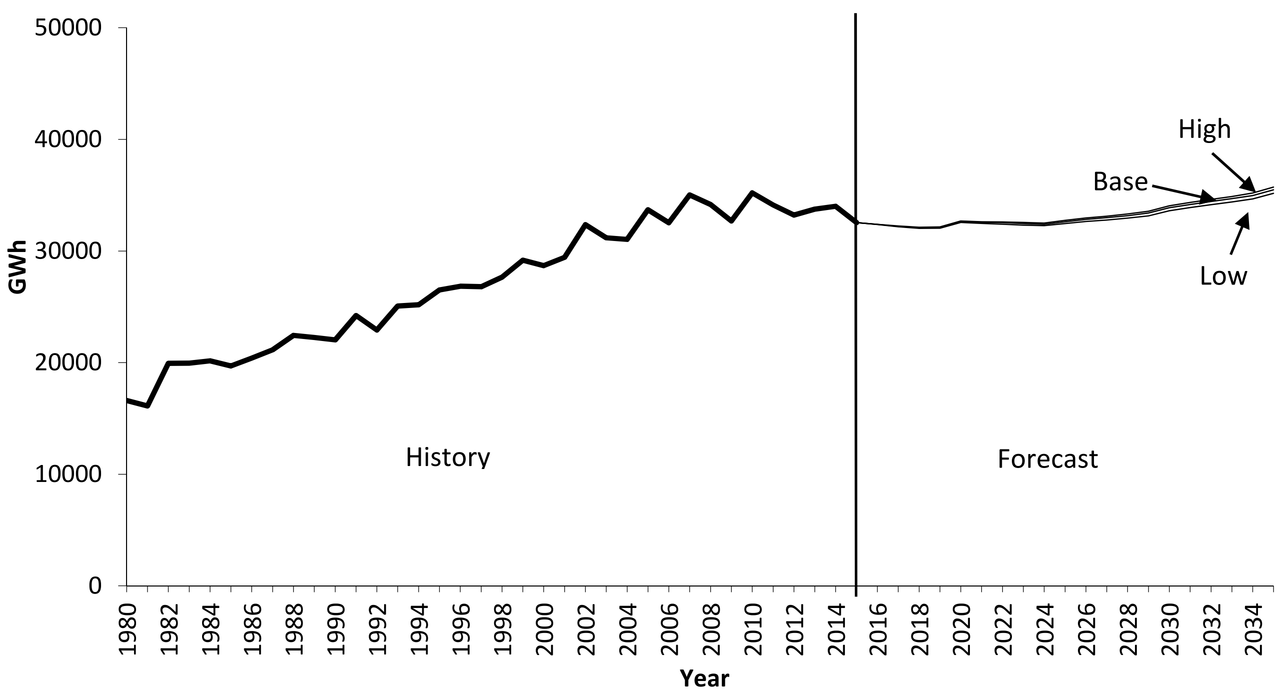
Table 5-4. Residential Model - Growth Rates (Percent) for Selected Variables (2017 SUFG Scenarios and 2015 Base Forecast)

Forecast	Current Scenarios (2016-2035)			2015 Forecast (2014-2033)
	Base	Low	High	Base
No. of Customers	1.131	1.120	1.135	1.07
Electric Rates	1.20	1.18	1.28	1.32

Table 5-5. Indiana Residential Electricity Sales Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	Base	Low	High
2016-2035	0.48	0.44	0.52

Figure 5-4. Indiana Residential Electricity Sales by Scenario in GWh



Note: See the Appendix to this report for historical and projected values.

Indiana Residential Electricity Price Projections

Historical values and current projections of residential electricity prices are shown in Figure 5-5, with growth rates provided in Table 5-6. In real terms, residential electricity prices declined from the mid-1980s until 2002. Real residential electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real residential electricity prices to rise until 2024 and then to remain relatively constant. SUFG's real price projections for the individual IOUs all follow the same patterns as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 5-5. Indiana Residential Base Real Price Projections (in 2015 Dollars)

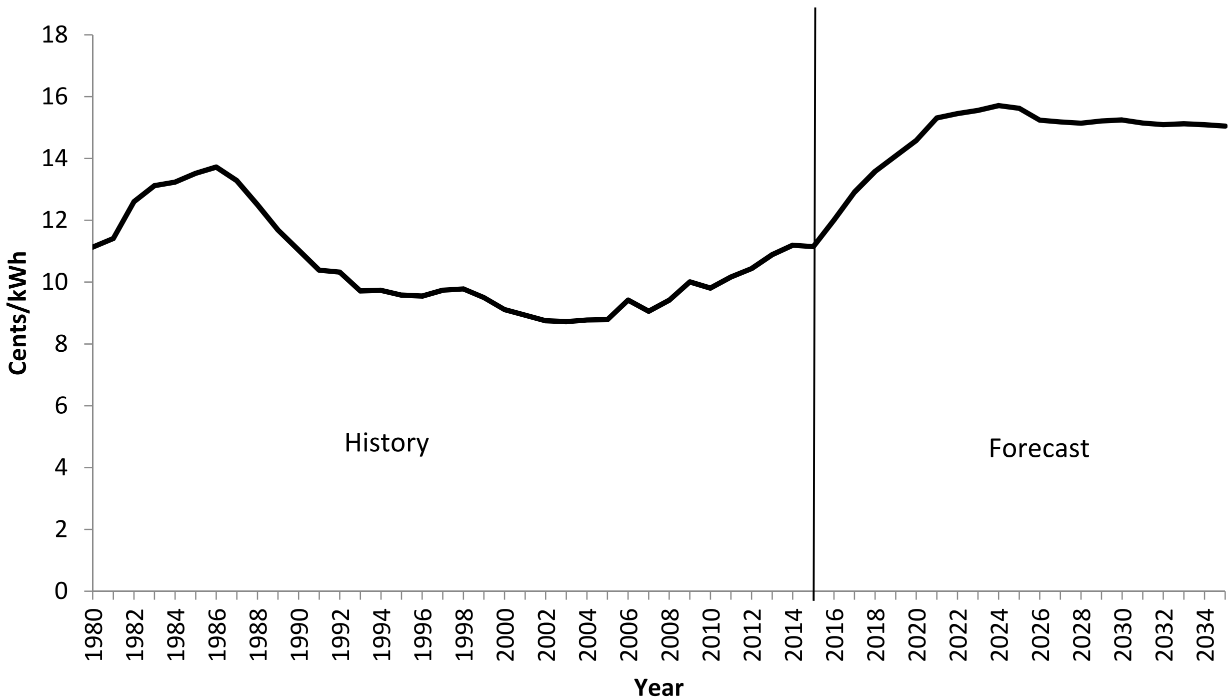


Table 5-6. Indiana Residential Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	3.96
1985-1990	-3.98
1990-1995	-2.80
1995-2000	-0.99
2000-2005	-0.72
2005-2015	2.41
2016-2035	1.20

Note: See the Appendix to this report for historical and projected values and an explanation of how SUFG arrives at these numbers.

Chapter 6

Commercial Electricity Sales

Overview

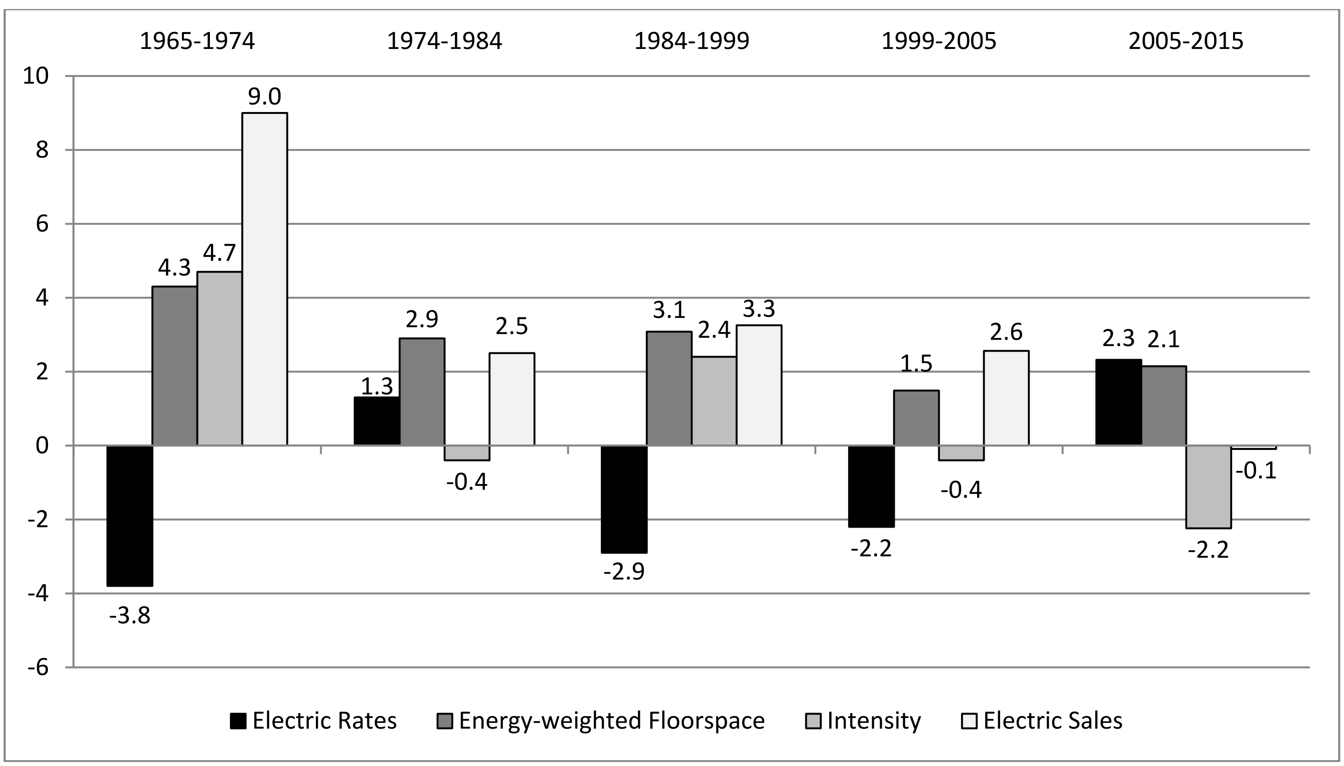
SUFG has two distinct models of commercial electricity sales, econometric and end-use. Both have specific strengths and complement each other. SUFG staff developed the econometric model and acquired a proprietary end-use model, Commercial Energy Demand Modeling System (CEDMS). CEDMS is a descendant of the first generation of end-use models developed at ORNL during the late 1970s for the Department of Energy. CEDMS, however, bears little resemblance to its ORNL ancestor. Like the residential sector end-use model REDMS, Jerry Jackson and Associates actively supports CEDMS, and it continues to define the state-of-the-art in commercial sector end-use forecasting models.

For a few years in the mid-1990s, SUFG relied on its own econometric model to project commercial electricity sales. SUFG used the end-use model for general comparison purposes and for its structural detail. CEDMS estimates commercial floor space for building types and estimates energy use for end uses within each building type. SUFG also took advantage of the building type detail in CEDMS to construct the major economic drivers for its econometric model. SUFG then made CEDMS its primary commercial sector forecasting model for several reasons. First, based on experience with the model over several years, SUFG is confident it provides realistic energy projections under a wide range of assumptions. Second, in contrast to the significant differences between the residential end-use and econometric model projections (discussed in Chapter 5), the differences between the commercial end-use and econometric models are small, since both models forecast similar changes in electric intensity. SUFG used a recently upgraded version of CEDMS for this set of projections.

Historical Perspective

Historical trends in commercial sector electricity sales have been distinctly different in each of five recent periods (see Figure 6-1).

Figure 6-1. State Historical Trends in the Commercial Sector (Annual Percent Change)



Changes in electric intensity, expressed as changes in electricity use per square foot (sqft) of energy-weighted floor space, arise from changes in building and equipment efficiencies as well as changes in equipment utilization, end-use saturations and new end uses. Electric intensity increased rapidly during the era of cheap energy (4.7 percent per year) as seen in Figure 6-1 prior to the OPEC oil embargo. This trend was interrupted by the significant upward swing in electricity prices during 1974-1984, which resulted in a decrease in energy intensity. As electricity prices fell again during the 1984-1999 period, electric intensity rose but at a slower rate (2.4 percent) than that observed during the pre-embargo period. New commercial buildings and energy-using equipment continue to be more energy-efficient than the stock average, but these efficiency improvements are offset by an increased demand for energy services.

Over the 1999-2005 timeframe, a decrease in economic activity retarded growth in the stock of commercial floor space, led to negative growth in intensity of electricity use, and slowed growth in electricity sales despite continued declines in real electricity prices. Recently the current recession coupled with increasing real electricity prices has accelerated these trends, with the notable exception of the stock of commercial floor space. For 2005-2015 real electricity prices have risen, commercial floor space grew at a slightly faster rate than that observed during the previous few years, with intensity of electricity use continuing to decline, and commercial sector electricity use stagnating.

Model Description

Figure 6-2 depicts the structure of the commercial end-use model. As the figure shows, CEDMS uses a disaggregated capital stock approach to forecast energy use. Energy use is viewed as a derived demand in which electricity and other fuels are inputs, along with energy using equipment and building envelopes, in the production of end-use services.

The disaggregation of energy demand is as important in the modeling of the commercial sector as it is for modeling the residential sector. CEDMS categorizes commercial buildings into 21 building types. It also divides energy use in each building type among 9 possible end uses, including a residual use category (labeled “other”). For end uses such as space heating, where non-electric fuels compete with electricity, CEDMS further disaggregates energy use among fuel types. (This disaggregation scheme is illustrated at the top of Figure 6-2.) CEDMS also divides buildings among vintages, i.e., the year the building was constructed, and simulates energy use for each vintage and building type.

CEDMS projects energy use for each building vintage according to the following equation:

$$Q(T, i, k, l, t) = U(i, k, l, t) * e(i, k, l, t) * a(i, k, l, t) * A(l, t) * d(l, T-t)$$

where

* = multiplication operator;

T = forecast year;

Q = energy demand for fuel i, end use k, building type l and vintage t in the forecast year;

t = building vintage (year);

U = utilization, relative to some base year;

e = energy use index, kWh/sqft/year or Btu/sqft/year;

a = fraction of floor space served by fuel i, end use k, and building type l for floor space additions of vintage t;

A = floor space additions by vintage t and building type l; and

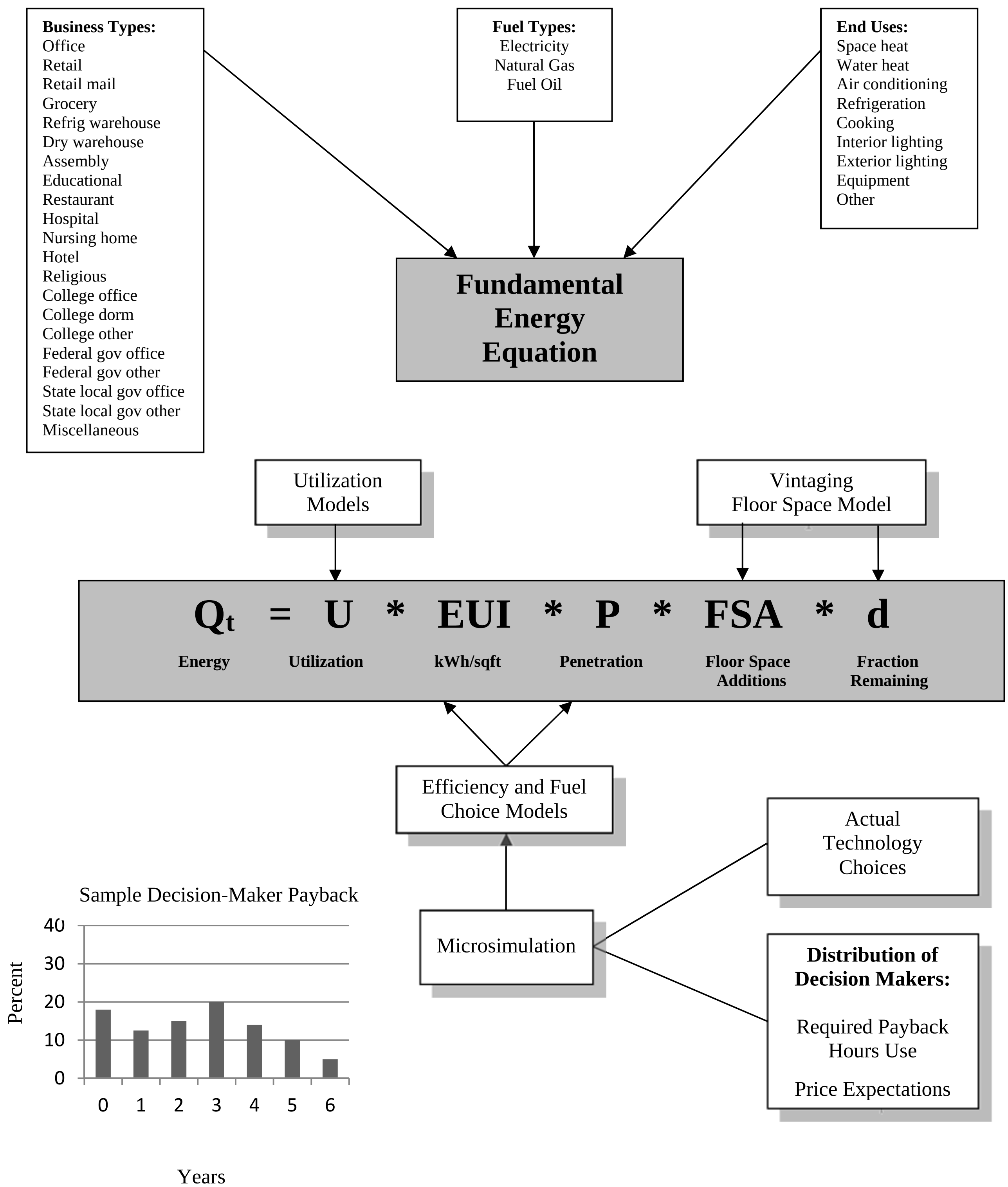
d = fraction of floor space of vintage t still standing in forecast year T.

CEDMS’ central features are its explicit representation of the joint nature of decisions regarding fuel choice, efficiency choice and the level of end-use service, as well as its explicit representation of costs and energy use characteristics of available end-use technologies in these decisions.

CEDMS jointly determines fuel and efficiency choices through a methodology known as discrete choice microsimulation. Essentially, sample firms in the model make choices from a set of discrete heating, ventilation and air conditioning (HVAC) equipment options. Each discrete equipment option is characterized by its fuel type, energy use and cost. CEDMS uses the discrete technology choice methodology to model equipment choices for HVAC, water heating, refrigeration and lighting. HVAC and lighting account for about 80 percent of total electricity use by commercial firms.

Equipment standards are easily incorporated in CEDMS’ equipment choice sub-models. In addition to efficiency and fuel choices, CEDMS also models changes in equipment utilization, or intensity of use. For equipment that has not been added or replaced in the previous year, changes in equipment utilization are modeled using fuel-specific, short-run price elasticities and changes in fuel prices.

Figure 6-2. Structure of Commercial End-Use Energy Modeling System



For new equipment installed in the current year, utilization depends on both equipment efficiency and fuel price. For example, a 10 percent improvement in efficiency and a 10 percent increase in fuel prices would have offsetting effects since the total cost of producing the end-use service is unchanged.

Summary of Results

The remainder of this chapter describes SUFG's commercial electricity sales projections. First, the current base projection of commercial sales growth is explained in terms of the model sensitivities and changes in the major explanatory variables. Next, the current base projection is compared to past base projections and then to the current low and high scenario projections. At each step, significant differences in the projections are explained in terms of the model sensitivities and changes in the major explanatory variables.

Model Sensitivities

The major economic drivers to CEDMS include commercial floor space by building type (driven by non-manufacturing employment and population) and electricity prices. The sensitivity of the electricity sales projection to changes in these variables was simulated one at a time by increasing each variable ten percent above the base scenario levels and observing the change in commercial electricity use. The results are shown in Table 6-1. An interesting result is that changes in commercial floor space lead to more than proportional changes in electricity use. The reason for this is that new buildings tend to have greater saturations of electric end uses, which more than offsets the greater efficiency of those end uses.

Table 6-1. Commercial Model Long-Run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Sales
Floor space	10.5
Electric Rates	-2.6

Indiana Commercial Electricity Sales Projections

Historical data as well as past and current projections are illustrated in Table 6-2 and Figure 6-3. As can be seen, the current base projection of Indiana commercial electricity sales growth is 0.36 percent. As shown in Figure 6-3, the current projection lies well below the 2015 forecast. The current projection lies above the 2013 forecast for the majority of the near term (2017-2022) but is then lower than the 2013 forecast for the remainder of the forecast horizon (2023-2035).

Floor space growth is partially offset by decreases in utilization. Utilization, the amount of energy used per unit of floor space, decreases because of increasing electricity prices and the implementation of new efficiency standards. Incremental DSM programs also have an effect on electricity sales.

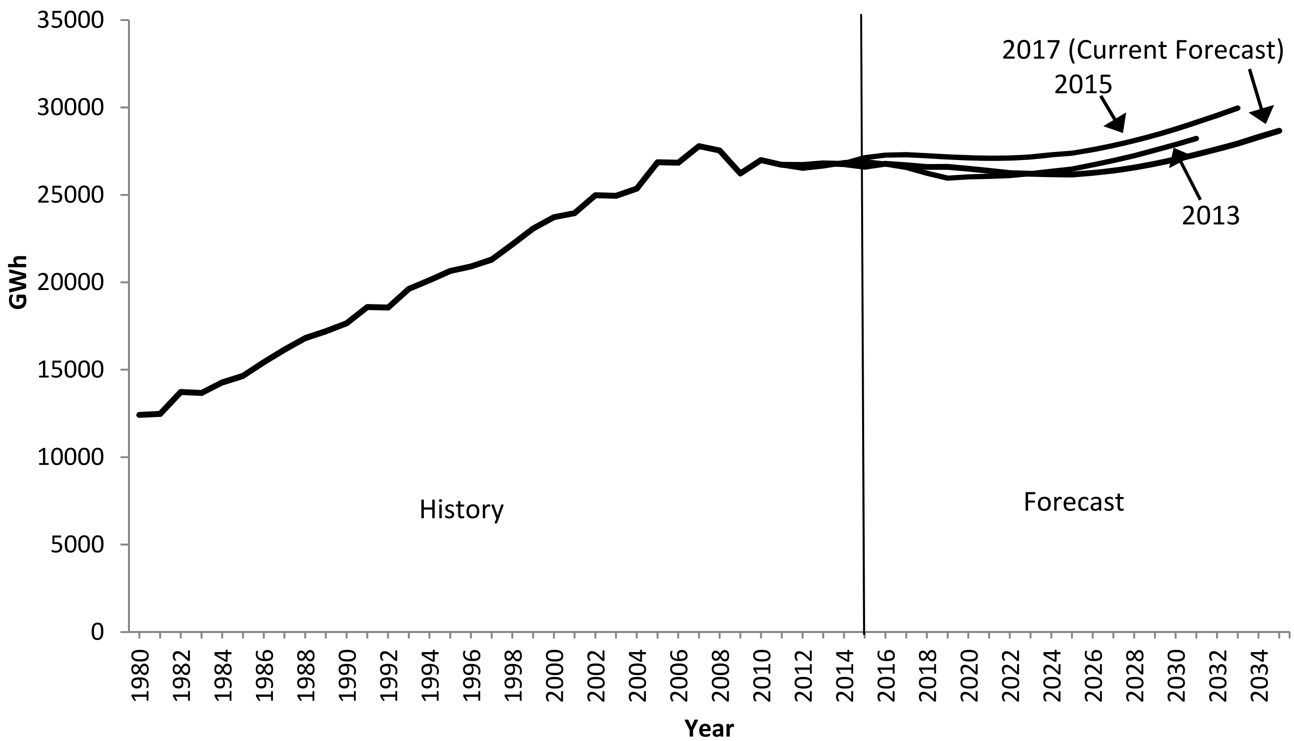
The growth rates for the major explanatory variables are shown in Table 6-3. Note that the growth rate for natural gas prices is inflated by the low value in 2016, the first year of the period. (See Chapter 4 for more information on natural gas prices.) Table 6-4 summarizes SUFG's base projections of commercial electricity sales growth for the last three SUFG forecasts. The historical and 2017 forecast values are provided in the Appendix of this report.

As shown in Table 6-5 and Figure 6-4, the growth rates for the low and high scenarios are about 0.48 percent lower and 0.26 percent higher than the base scenario, respectively. These differences are almost entirely due to a difference in floor space growth.

Table 6-2. Indiana Commercial Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2017	0.36	2016-2035
2015	0.59	2014-2033
2013	0.33	2012-2031

Figure 6-3. Indiana Commercial Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Table 6-3. Commercial Model - Growth Rates (Percent) for Selected Variables (2017 SUFG Scenarios and 2015 Base Forecast)

Forecast	Current Scenarios (2016-2035)			2015 Forecast (2014-2033)
	Base	Low	High	Base
Electric Rates	1.40	1.36	1.51	1.35
Natural Gas Price	2.58	2.58	2.58	1.04
Energy-weighted Floor Space	0.76	0.68	0.84	0.84

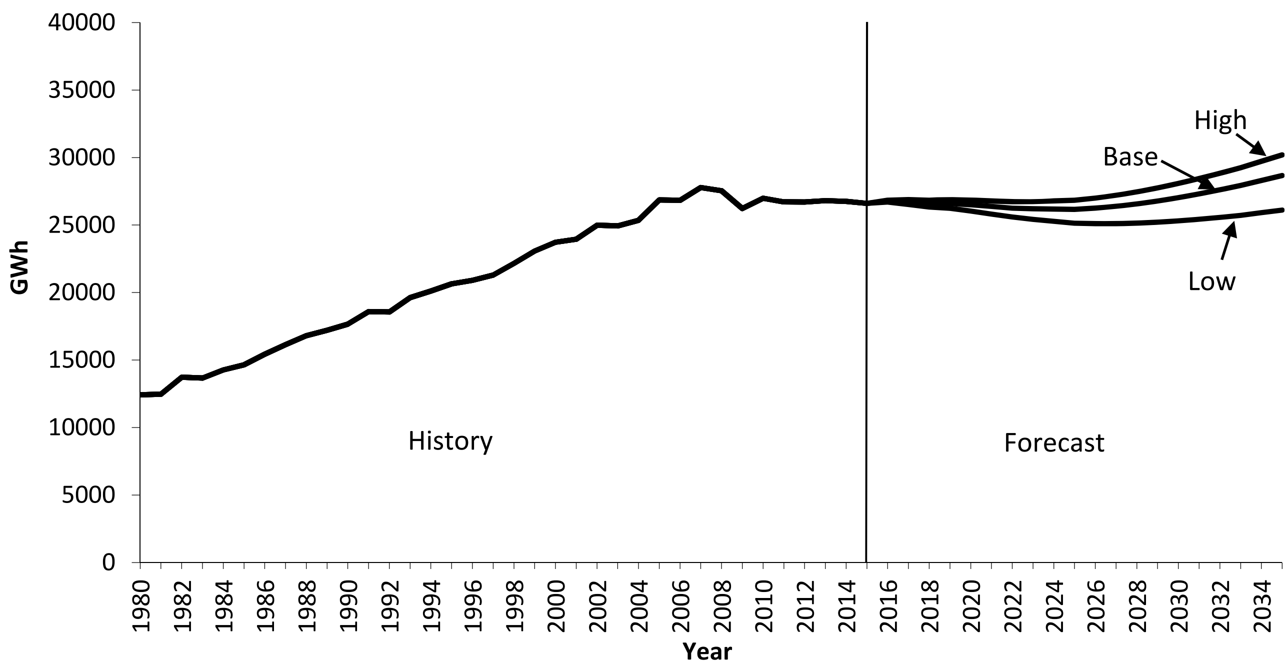
Table 6-4. History of SUFG Commercial Sector Growth Rates (Percent)

Forecast	Electric Energy-weighted Floor Space	Without DSM		With DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2017 SUFG Base (2016-2035)	0.76	-0.04	0.72	-0.40	0.36
2015 SUFG Base (2014-2033)	0.84	-0.13	0.71	-0.25	0.59
2013 SUFG Base (2012-2031)	0.90	-0.07	0.83	-0.57	0.33

Table 6-5. Indiana Commercial Electricity Sales Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2016-2035	0.36	-0.12	0.62

Figure 6-4. Indiana Commercial Electricity Sales by Scenario in GWh



Note: See the Appendix to this report for historical and projected values.

Indiana Commercial Electricity Price Projections

Historical values and current projections of commercial electricity prices are shown in Figure 6-5, with growth rates provided in Table 6-6. The historical and forecast numbers are provided in the Appendix of this report. In real terms, commercial electricity prices declined from the mid-1980s until 2002. Real commercial electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real commercial electricity prices to rise until 2024 and then remain relatively constant. SUFG's real price projections for the individual IOUs all follow the same pattern as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 6-5. Indiana Commercial Base Real Price Projections (in 2015 Dollars)

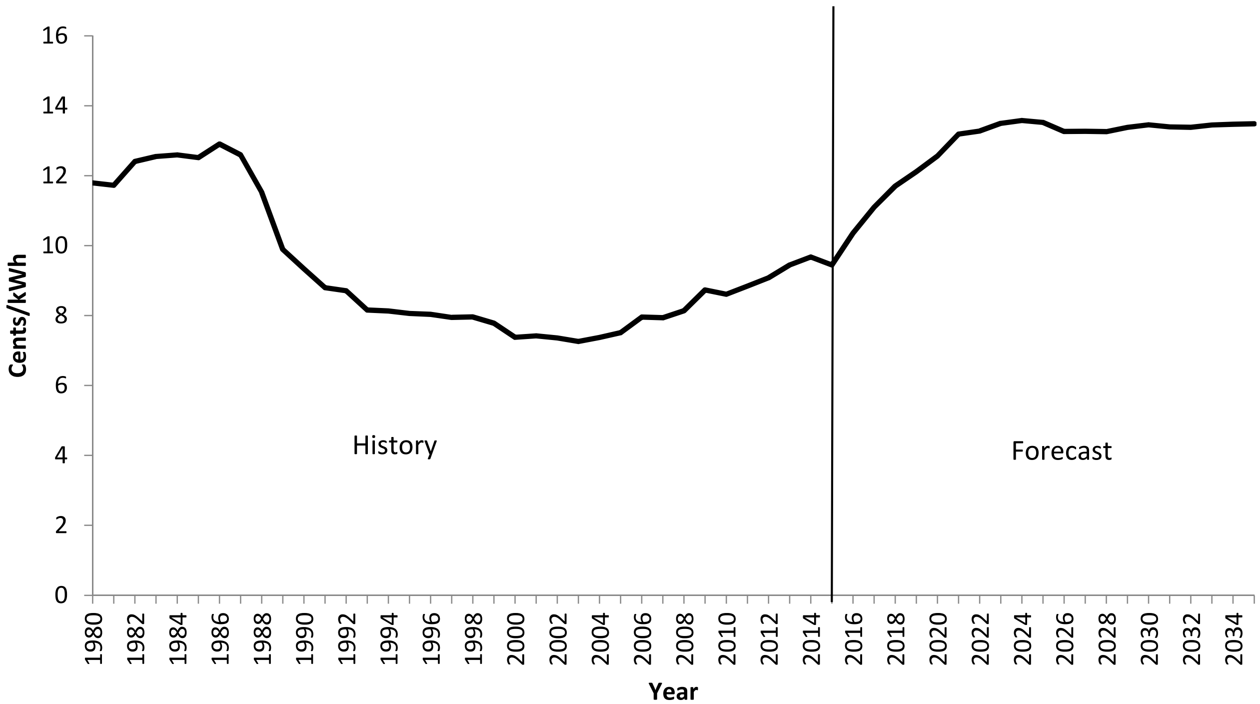


Table 6-6. Indiana Commercial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	1.19
1985-1990	-5.69
1990-1995	-2.90
1995-2000	-1.75
2000-2005	0.36
2005-2015	2.32
2016-2035	1.40

Note: See the Appendix to this report for historical and projected values and an explanation of how SUFG arrives at these numbers.

Chapter 7

Industrial Electricity Sales

Overview

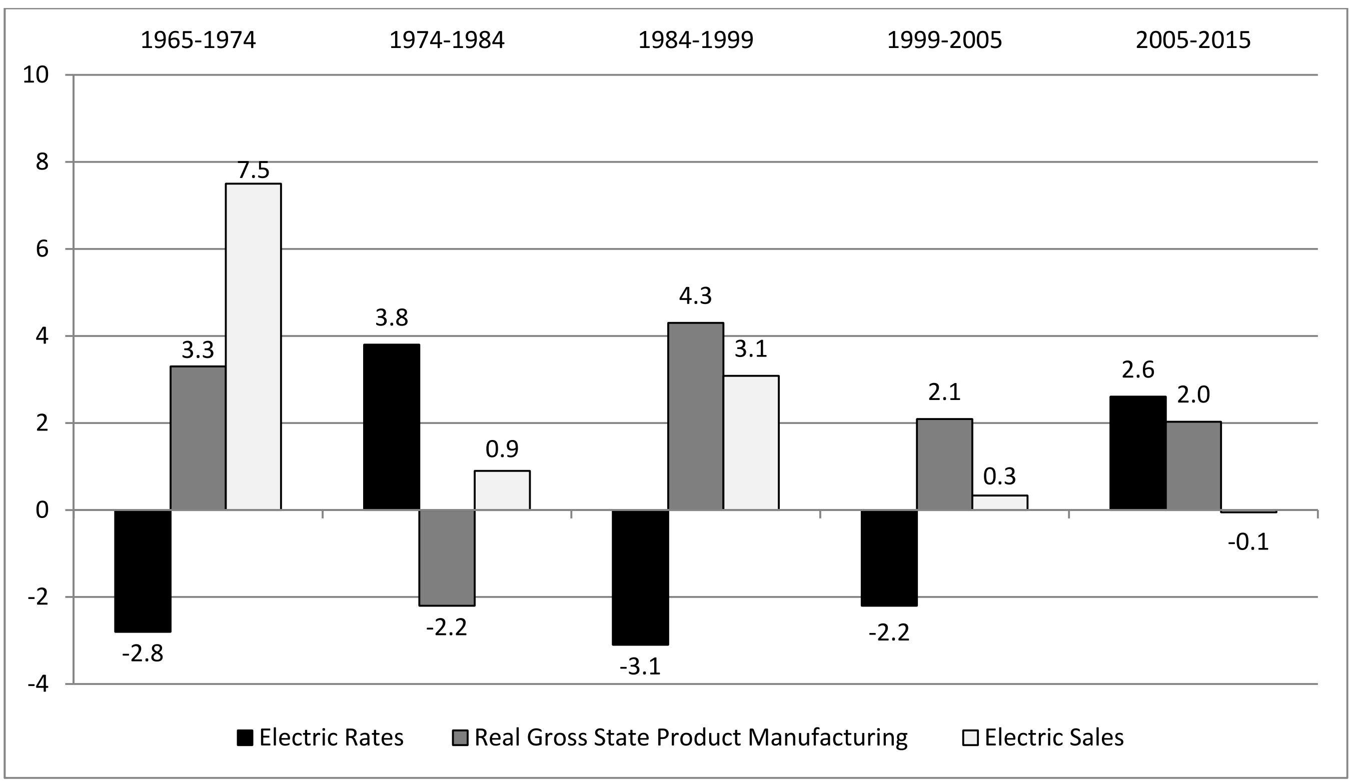
SUFG has used several models to analyze and forecast electricity use in the industrial sector. The primary forecasting model is INDEED, an econometric model developed by the Electric Power Research Institute (EPRI), which is used to model the electricity use of 15 major industry groupings in the state. Additionally, SUFG has used in various forecasts a highly detailed process model of the iron and steel industry, scenario-based models of the aluminum and foundries components of the primary metals industry, and an industrial motor drive model to evaluate and forecast the effect of motor technologies and standards.

The econometric model is calibrated at the statewide level of electricity purchases from data on cost shares obtained from the U.S. Department of Commerce Annual Survey of Manufacturers. SUFG has been using INDEED since 1992 to project electricity sales for the 15 individual industries within each of the five IOU service areas. There are many econometric formulations that can be used to forecast industrial electricity use, which range from single equation factor demand models and fuel share models to "KLEM" models (KLEM denotes capital, labor, energy and materials). INDEED is a KLEM model. A KLEM model is based on the assumption that firms act as though they are minimizing costs to produce given levels of output. Thus, a KLEM model projects the changes in the quantity of each input, which result from changes in input prices and levels of output under the cost minimization assumption. For each of the 15 industry groups, INDEED projects the quantity consumed of eight inputs: capital, labor, electricity, natural gas, distillate and residual oil, coal and materials.

Historical Perspective

SUFG distinguishes five recent periods of distinctly different economic activity and growth - 1965-1974, 1974-1984, 1984-1999, 1999-2005, and the more recent period 2005-2015. Figure 7-1 shows state growth rates for real manufacturing product, real electric rates and electric energy sales for the five periods.

Figure 7-1. State Historical Trends in the Industrial Sector (Annual Percent Change)



During the decade prior to the OPEC oil embargo, industrial electricity sales increased 7.5 percent annually. In Indiana as elsewhere, sales growth was driven by the combined economic stimuli of falling electricity prices (2.8 percent per year in real terms) and growing manufacturing output (3.3 percent per year). During the decade following 1974, sales growth slowed as real electricity prices increased at an average rate of 3.8 percent per year and the state's manufacturing output declined at a rate of 2.2 percent per year. This turnaround in economic conditions and electricity prices resulted in a dramatic decline in the growth of industrial electricity sales from 7.5 percent per year during 1965-1974 to 0.9 percent per year in the decade that followed. The fact that electricity sales increased at all is most likely attributable to increases in fossil fuel prices that occurred during the "energy crisis" of 1974-1984. The ensuing period, 1984-1999, experienced another dramatic turnaround. The growth rate of industrial output once again became positive, and was substantially above the rate observed 1965-1974. Real electricity prices in Indiana continued to decline in the industrial sector. These conditions caused electricity sales growth to average 3.1 percent per year during these 15 years.

The effect of the economic slowdown from 1999-2005 is particularly pronounced in the industrial sector. During this period, real industrial electricity prices declined, but this decline was partially offset by a moderate growth in manufacturing output, resulting in stagnant growth in industrial electricity use. Since 2005 real industrial electricity prices have increased, real growth in manufacturing output has continued to be modest, and overall growth in industrial electricity has remained stagnant.

Model Description

SUFG's primary industrial-sector forecasting model, INDEED, consists of a set of econometric models for each of Indiana's major industries listed in Table 7-1. The general structure of the models is illustrated in Figure 7-2.

Each model is driven by projections of GSP for selected industries over the forecast horizon provided by CEMR. Each industry's share of GSP is given in the first column of Table 7-1. 71 percent of state GSP is accounted for by the following industries: primary metals, 9 percent; fabricated metals, 5 percent; industrial machinery and equipment, 7 percent; chemicals, 15 percent; transportation equipment, 31 percent; and electronic and electric equipment, 4 percent.

The share of total electricity consumed by each industry is shown in the second column of Table 7-1. Both the chemical and primary metals industries are very electric-intensive industries. Combined, they account for 50% of total state industrial electricity use. Column four gives the current base output projections for the major industries obtained from the most recent CEMR forecast. As explained in Chapter 4, CEMR projections are developed using econometric models of the U.S. and Indiana economies. Manufacturing sector GSP projections are obtained by multiplying sector employment projections by a projection of GSP per employee, a measure of labor productivity.

This is the seventh SUFG forecast developed since CEMR switched from the SIC to the newer NAICS (North American Industry Classification System) for categorization of industrial economic activity. Generally, the NAICS is more detailed than the SIC system. Since SUFG is still using the SIC system, SUFG maps industrial economic activity projections from the NAICS measures used by CEMR to the older SIC measures used in SUFG's models. This process was relatively straightforward with the exception of SIC 28, chemical manufacturing. In SIC 28, chemical manufacturing, SUFG used the CEMR GSP growth projections for the manufacturing sector as a whole. This was necessary because CEMR's projections did not specifically include chemical manufacturing, a large purchaser of electricity in Indiana.

Each industrial sector econometric model converts output by forecasting the total cost of producing the given output and the cost shares for each major input, i.e., capital, labor, electricity, gas, oil, coal and materials. The quantity of electricity is determined given the expenditure of electricity for each industry and its price.

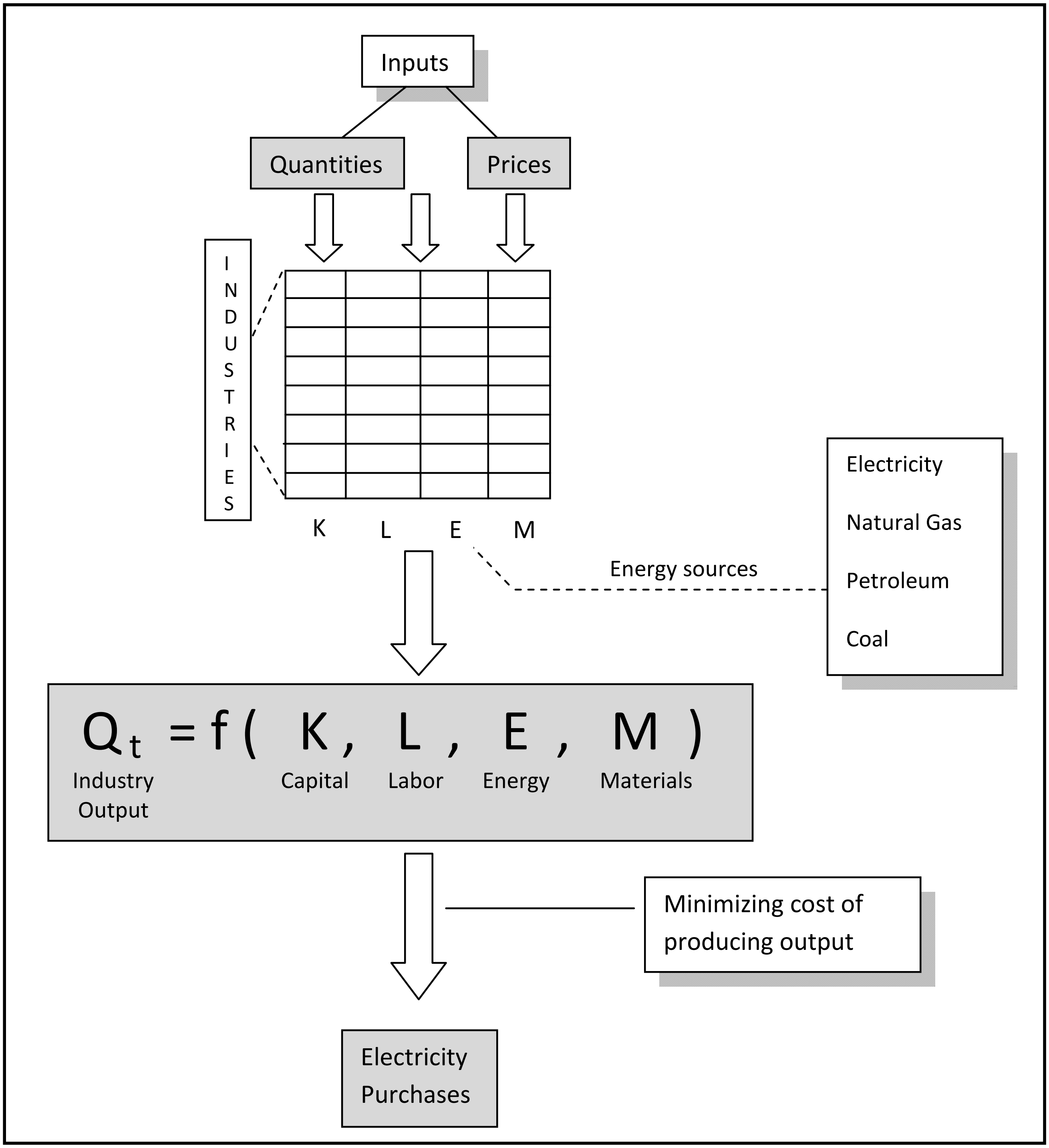
As described earlier in this chapter, INDEED captures the competition between the various inputs for their share of the cost of production by assuming firms seek the mix of inputs that minimize the production cost for a given level of output. Unit costs of natural gas, oil, coal, capital, labor and materials are inputs to the SUFG system, while the cost per kWh of electricity is determined by the SUFG modeling system. For fuel prices SUFG uses the current EIA forecast, which assumes that real natural gas prices, which dropped from 2008 to 2016, will gradually over the forecast horizon. Distillate prices also decreased significantly in 2009 coming off of the high prices of 2008. Prices then rebounded significantly through 2012-2013 before declining again in 2014, followed by substantial decreases in 2015 and 2016. They are projected to rebound quickly in 2017 and 2018 before growing in a slower pace over the remainder of the forecast horizon. Unit costs for capital, labor and materials are consistent with the assumptions contained in the CEMR forecast of Indiana output growth. The changes in electricity intensities, expressed as a percent change in kWh per dollar of GSP, are shown in column five of Table 7-1.

The last column of Table 7-1 contains the projected annual percent increase in electricity sales by major industry. This projected increase is the sum of changes in GSP and kWh/GSP for each industry. Average industrial electricity use across all sectors in the base scenario is expected to increase at an average of 2.05 percent per year, without DSM, over the forecast horizon.

Table 7-1. Selected Statistics for Indiana's Industrial Sector (Without DSM) (Percent)

SIC	Name	Current Share of GSP	Current Share of Electricity Sales	Current Intensity	Forecast Growth in GSP Originating by Sector	Forecast Growth in Electricity Intensity by Sector	Forecast Growth in Electricity Sales by Sector
20	Food & Kindred Products	4.39	6.59	0.53	3.16	-0.42	2.73
24	Lumber & Wood Products	2.44	0.79	0.11	3.16	-1.11	2.05
25	Furniture & Fixtures	2.16	0.48	0.08	0.96	-0.67	0.29
26	Paper & Allied Products	1.70	2.56	0.54	3.16	-0.39	2.77
27	Printing & Publishing	3.20	1.18	0.13	3.16	-1.29	1.87
28	Chemicals & Allied Products	15.25	20.39	0.47	3.16	-0.82	2.34
30	Rubber & Misc. Plastic Products	3.15	6.13	0.69	2.20	-0.72	1.48
32	Stone, Clay, & Glass Products	2.19	5.43	0.88	0.96	-0.51	0.45
33	Primary Metal Products	8.58	29.37	1.21	-1.23	3.31	2.07
34	Fabricated Metal Products	5.23	6.28	0.43	2.07	-0.74	1.33
35	Industrial Machinery & Equipment	7.44	4.63	0.22	1.70	-0.28	1.42
36	Electronic & Electric Equipment	3.93	2.14	0.19	0.51	-0.42	0.09
37	Transportation Equipment	30.76	6.08	0.07	2.95	1.07	4.02
38	Instruments And Related Products	2.94	1.13	0.14	0.96	-1.56	-0.60
39	Miscellaneous Manufacturing	1.59	1.23	0.27	0.96	-2.15	-1.20
Total	Manufacturing	100.00	100.00	0.35	2.40	-0.34	2.05

Figure 7-2. Structure of Industrial Energy Modeling System



Summary of Results

The remainder of this chapter describes SUFG's industrial electricity sales projections. First, the current base projection of industrial sales growth is explained in terms of the model sensitivities and changes in the major explanatory variables. Next, the current base projection is compared to past base projections and then to the current low and high scenario projections. At each step, significant differences in the projections are explained in terms of the model sensitivities and changes in the major explanatory variables.

Model Sensitivities

Table 7-2 shows the impact of a 10 percent increase in each of the model inputs on all industrial electricity consumption in the econometric model. Electricity sales (GWh) are most sensitive to changes in output and electric rates, somewhat sensitive to changes in gas and oil prices, and insensitive to changes in assumed coal prices. Other major variables affecting industrial electricity use include the prices of materials, capital and labor. The model's sensitivities were determined by increasing each variable ten percent above the base scenario levels and observing the percent change in forecast industrial electricity use after 10 years.

Table 7-2. Industrial Model Long-Run Sensitivities

A 10 Percent Increase In	Causes This Percent Change in Electric Sales
Real Manufacturing Product	10.0
Electric Rates	-4.8
Natural Gas Price	1.4
Oil Prices	0.9
Coal Prices	0.2

Indiana Industrial Electricity Sales Projections

Past and current projections for industrial energy sales as well as overall annual average growth rates for the current and past forecasts are shown in Table 7-3 and Figure 7-3. Historical and forecast values are provided in the Appendix of this report.

The impact of industrial sector DSM programs on growth rates for the 2013, 2015, and current forecasts is displayed in Table 7-4. The table also disaggregates the impact on energy growth of output, changes in the mix of output and electricity intensity. Industrial sector DSM programs are expected to have less impact on retail sales than their residential and commercial counterparts, due in part to industrial customers having the ability to opt out. The effect of earlier conservation activities are embedded in the historical data and SUFG's projections.

The current forecast projects that industrial sector electricity sales will grow from the 2015 level of approximately 39,000 GWh to about 57,300 GWh by 2035. This growth rate of 2.04 percent per year is substantially higher than both the 0.36 percent rate projected for the commercial sector and the 0.48 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast is below the 2015 forecast for the entire forecast period, despite having a higher growth rate. This occurs because the 2017 forecast starts at a lower level than the previous forecast did. The 2017 forecast lies above the 2013 forecast.

The growth in industrial electricity sales are projected to be higher in the 2017 forecast than in the previous two despite being driven off of a lower forecast of manufacturing output. This occurs because the 2017 forecast does not project the declines in intensity (electricity usage per dollar of output) that the previous forecasts did. In this case, a tightening of the labor market makes electricity more competitive as a factor in production in the INDEED model. An example of this would be increased automation in the production process that allows for less labor but uses more energy.

Table 7-5 and Figure 7-4 show how industrial electricity sales differ by scenario. Industrial sales, in the high scenario, are expected to increase to 65,355 GWh by 2035, 14.1 percent higher than the base projection. In the low scenario, industrial sales grow more slowly, which results in 51,118 GWh sales by 2035, 10.8 percent below the base scenario.

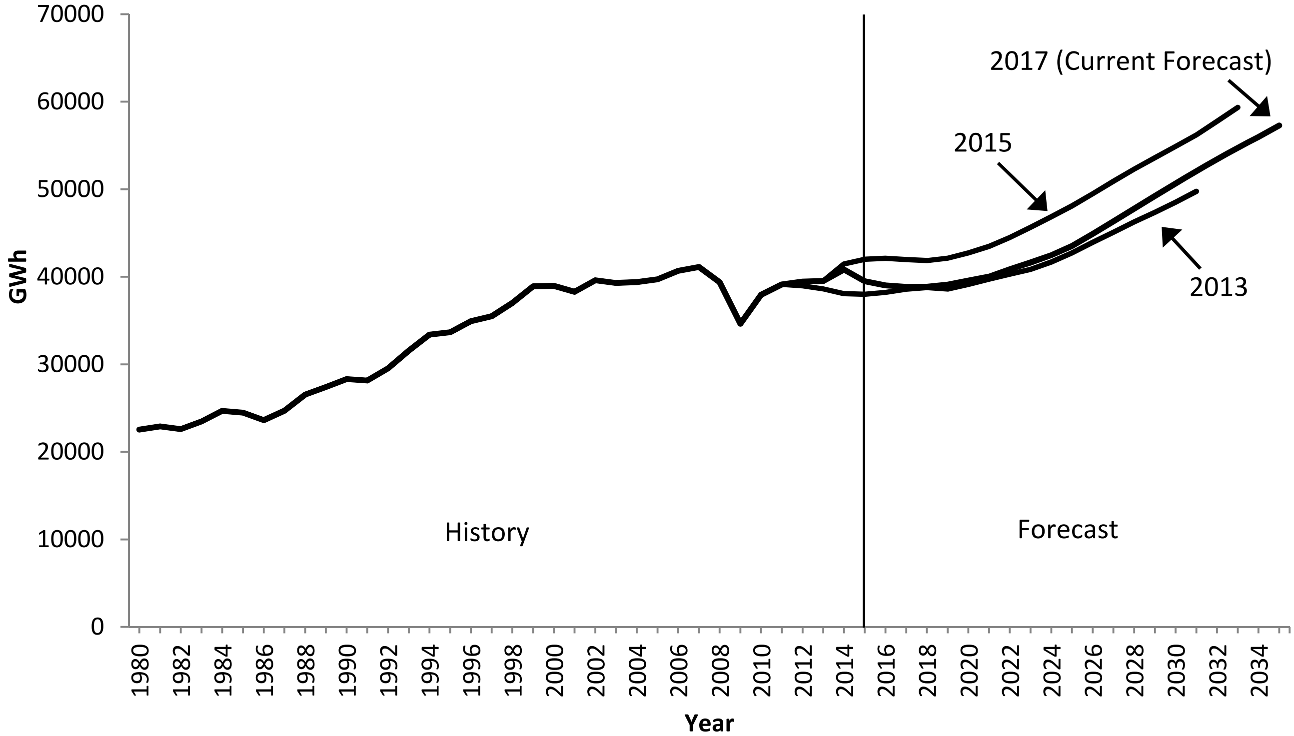
The wide range of forecast sales is caused primarily by the equally wide range of the trajectories of industrial output contained in the CEMR low and high scenarios for the state. In the base scenario GSP in the industrial sector grows 2.40 percent per year during the forecast period. That rate is 3.00 percent in the high scenario and 1.80 percent in the low scenario. This reflects the uncertainty regarding Indiana's industrial future contained in these forecasts.

The high and low scenarios reflect optimistic and pessimistic views, respectively, regarding the ability of Indiana's industries to compete with producers from other states.

Table 7-3. Indiana Industrial Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2017	2.04	2016-2035
2015	1.90	2014-2033
2013	1.29	2012-2031

Figure 7-3. Indiana Industrial Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

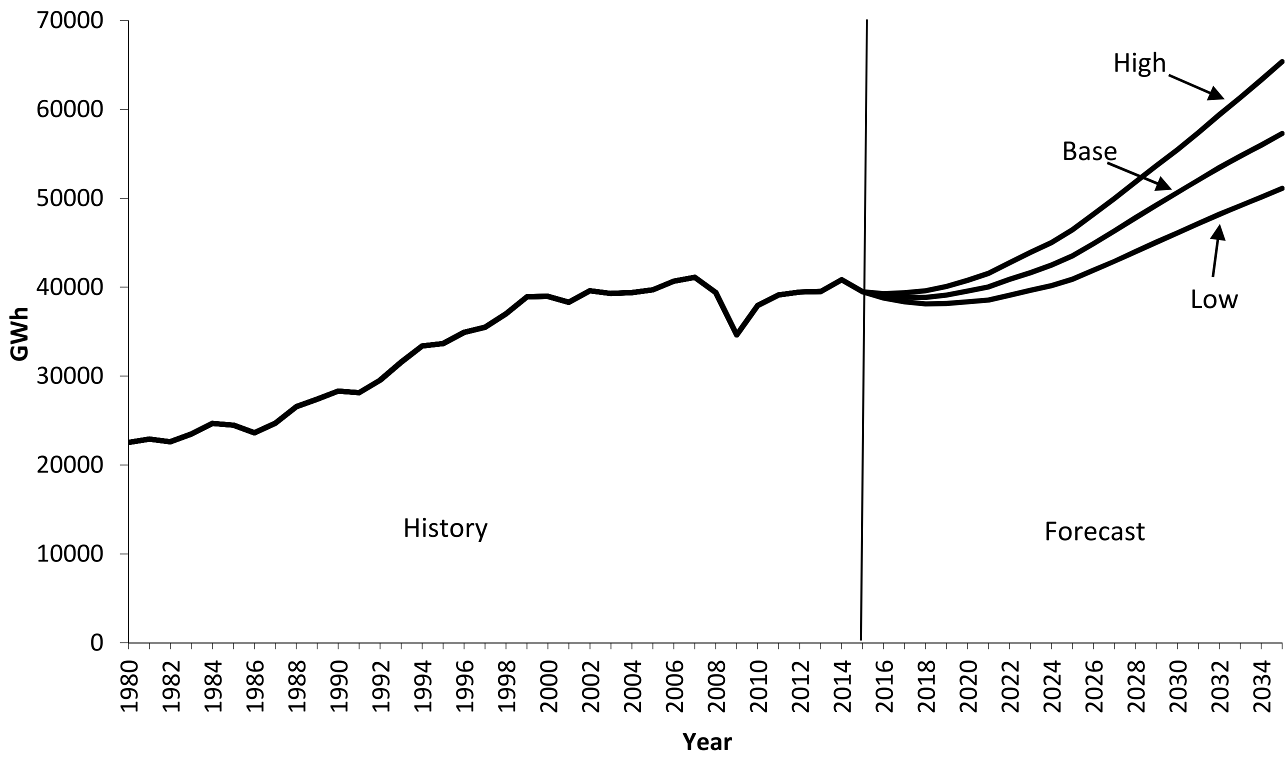
Table 7-4. History of SUFG Industrial Sector Growth Rates (Percent)

Forecast	Output	Mix Effects	Electric Energy-weighted Output	Without DSM		With DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
2017 SUFG Base (2016-2035)	2.40	-0.29	2.11	-0.06	2.05	-0.07	2.04
2015 SUFG Base (2014-2033)	3.02	-0.18	2.84	-0.92	1.92	-0.94	1.90
2013 SUFG Base (2012-2031)	2.86	-0.08	2.78	-1.05	1.73	-1.49	1.29

Table 7-5. Indiana Industrial Electricity Sales Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2016-2035	2.04	1.46	2.72

Figure 7-4. Indiana Industrial Electricity Sales by Scenario in GWh



Note: See the Appendix to this report for historical and projected values.

Indiana Industrial Electricity Price Projections

Historical values and current projections of industrial electricity prices are shown in Table 7-6 and Figure 7-5. In real terms, industrial electricity prices declined from the mid-1980s until 2002. Real industrial electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real industrial electricity prices to rise until 2023 and then decline slightly. SUFG's real price projections for the individual IOUs follow the same patterns as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 7-5. Indiana Industrial Base Real Price Projections (Cents/kWh in 2015 Dollars)

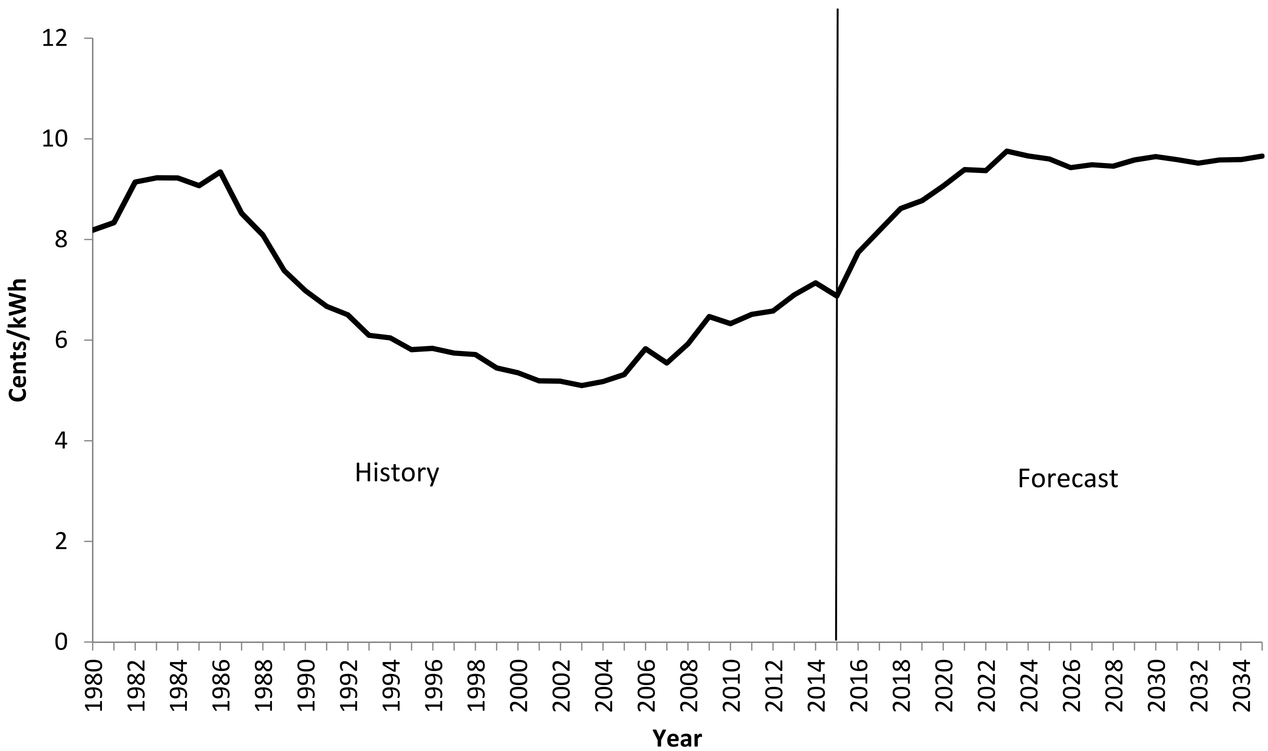


Table 7-6. Indiana Industrial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**Percent**
1980-1985	2.08
1985-1990	-5.10
1990-1995	-3.61
1995-2000	-1.63
2000-2005	-0.12
2005-2015	2.61
2016-2035	1.17

Note: See the Appendix to this report for historical and projected values and an explanation of how SUFG arrives at these numbers.

Appendix

In developing the historical energy, summer peak demand and rates data shown in the body and appendix of this document, SUFG relied on several sources of data. These sources include:

1. FERC Form 1;
2. Rural Utilities Service (RUS) Form 7 or Form 12;
3. Uniform Statistical Report;
4. Utility Load Forecast Reports;
5. Integrated Resource Plan Filings;
6. Annual Reports; and
7. SUFG Confidential Data Requests.

SUFG relied on public sources where possible, but some generally more detailed data was obtained from Indiana utilities under confidential agreements of nondisclosure. All data presented in this report have been aggregated to total Indiana statewide energy, demand and rates to avoid disclosure.

In most instances the source of SUFG's data can be traced to a particular page of a certain publication, e.g., residential energy sales for an IOU are found on page 304 of FERC Form 1. However, in several cases it is not possible to directly trace a particular number to a public data source. These exceptions arise due to:

1. geographic area served by the utility;
2. classification of sales data; and
3. unavailability of sectoral level sales data.

Indiana Michigan Power Company (I&M), Wabash Valley Power Association (WVPA), Indiana Municipal Power Agency (IMPA), and Hoosier Energy serve load outside of the state which SUFG excluded in developing projections for Indiana. I&M's load is split approximately 85-15 percent between Indiana and Michigan. While the majority of WVPA’s load is in Indiana, 72 percent, it does have members in Illinois and Missouri. IMPA has a wholesale member in Ohio although approximately 99 percent of their load is still in Indiana. Hoosier Energy serves members in Indiana and Illinois. Approximately 95 percent of Hoosier’s load is currently in Indiana. These utilities have provided SUFG with data pertaining to their Indiana load.

Some Indiana utilities report sales to the commercial and industrial sectors (SUFG's classification) as sales to one aggregate classification or sales to small and large customers. In order to obtain commercial and industrial sales for these utilities, SUFG has requested data in these classifications directly from the utilities, developed approximation schemes to disaggregate the sales data, or combined more than one source of data to develop commercial and industrial sales estimates. For example, until recently the Uniform Statistical Report contained industrial sector sales for IOUs. This data can be subtracted from aggregate FERC Form 1 small and large customer sales data to obtain an estimate of commercial sales.

SUFG does not have sectoral level sales data for the unaffiliated rural electric membership cooperatives (REMCs) and unaffiliated municipalities. SUFG obtains aggregate sales data from the FERC Form 1, then allocates the sales to residential, commercial, industrial and other sales with an allowance for losses. These allocation factors were developed by examining the mix of energy sales for other Indiana REMCs and municipalities. Thus, the sales estimates for unaffiliated REMCs are weighted heavily toward the residential sector and those for unaffiliated municipalities are more evenly balanced between the residential, commercial and industrial sectors.

SUFG's estimates of losses are calculated using a constant percentage loss factor applied to retail sales and sales-for-resale (when appropriate). These loss factors are based on FERC Form 1 data and discussions with Indiana utility personnel.

Total energy requirements for an individual utility are obtained by adding retail sales, sales-for-resale (if any) and losses. Total energy requirements for the state as a whole are obtained by adding retail sales and losses for the eight entities that SUFG models. Sales-for-resale are excluded from the state aggregate total energy requirements to avoid double counting.

Summer peak demand estimates are based on FERC Form 1 data for the IOUs with the exception of I&M, which provided SUFG with peak demand for their Indiana jurisdiction, and company sources for Hoosier Energy, IMPA and WVPA.

Statewide summer peak demand may not be obtained by simply adding across utilities because of diversity. Diversity refers to the fact that all Indiana utilities do not experience their summer peak demand at the same instant. Due to differences in weather, sectoral mix, end-use saturation, etc., the utilities tend to face their individual summer peak demands at different hours, days, or even months. To obtain an estimate of statewide peak demand, the summer peak demand estimates for the individual utilities are added together and adjusted for diversity.

The historical energy sales and peak demand data presented in this appendix represent SUFG's accounting of actual historical values. In developing the current forecast, SUFG was required to estimate some detailed sector-specific data for a few utilities. This data was unavailable from some utilities due to changes in data collection and/or reporting requirements. In the industrial sector, SUFG estimates two digit, Standard Industrial Code sales and revenue data for two IOUs. This data was estimated from total industrial sales data by assuming the same allocation of industrial sales at the two-digit level as observed during recent years. SUFG was also unable to obtain sales and revenue data for the commercial sector at the same level of detail from some IOUs. The detailed commercial sector data is necessary to calibrate SUFG's commercial sector model, but since the commercial sector model was not recalibrated for this forecast, no estimation was attempted. The not-for-profit utilities have not traditionally been able to supply SUFG with data at this level of detail. However, the not-for-profit utilities were able to provide SUFG with a breakdown of member load by sector.

SUFG feels relatively comfortable with these estimates, but is concerned about the future availability of detailed sector-specific data. If data proves to be unavailable in the future, SUFG will either be forced to develop more sophisticated allocation schemes to support the energy forecasting models or develop less data intensive, less detailed energy forecasting models.

SUFG 2017 Base Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	1988	22,444	16,808	26,546	633	66,431	4,650	71,081	13,447
Hist	1989	22,251	17,205	27,394	661	67,511	4,726	72,237	12,979
Hist	1990	22,037	17,659	28,311	650	68,657	4,806	73,463	13,659
Hist	1991	24,215	18,580	28,141	629	71,564	5,009	76,573	14,278
Hist	1992	22,916	18,556	29,540	619	71,632	5,014	76,646	14,055
Hist	1993	25,060	19,627	31,562	511	76,760	5,373	82,133	14,916
Hist	1994	25,176	20,116	33,395	507	79,193	5,544	84,737	15,010
Hist	1995	26,510	20,646	33,659	510	81,326	5,693	87,019	16,251
Hist	1996	26,833	20,909	34,920	536	83,197	5,824	89,021	16,162
Hist	1997	26,792	21,295	35,499	530	84,116	5,888	90,004	16,021
Hist	1998	27,663	22,166	37,012	520	87,360	6,115	93,476	16,638
Hist	1999	29,180	23,078	38,916	543	91,717	6,420	98,137	17,246
Hist	2000	28,684	23,721	38,957	529	91,890	6,432	98,322	16,738
Hist	2001	29,437	23,953	38,293	526	92,208	6,455	98,663	17,511
Hist	2002	32,363	24,980	39,594	540	97,476	6,823	104,300	18,831
Hist	2003	31,177	24,940	39,285	589	95,992	6,719	102,711	18,794
Hist	2004	31,042	25,351	39,380	644	96,417	6,749	103,166	18,193
Hist	2005	33,691	26,857	39,702	619	100,869	7,061	107,930	19,944
Hist	2006	32,527	26,836	40,683	604	100,649	7,045	107,695	20,855
Hist	2007	35,019	27,782	41,112	646	104,558	7,319	111,877	20,858
Hist	2008	34,158	27,536	39,389	653	101,736	7,121	108,857	19,275
Hist	2009	32,689	26,223	34,631	661	94,204	6,594	100,798	19,054
Hist	2010	35,217	26,989	37,934	694	100,834	7,058	107,892	20,315
Hist	2011	34,117	26,714	39,129	646	100,607	7,042	107,649	21,002
Hist	2012	33,217	26,704	39,448	603	99,972	6,998	106,970	20,972
Hist	2013	33,753	26,807	39,506	607	100,673	7,047	107,720	20,122
Hist	2014	34,010	26,752	40,830	619	102,211	7,155	109,366	20,111
Hist	2015	32,538	26,609	39,484	597	99,228	6,946	106,173	19,532
Frcst	2016	32,382	26,778	39,024	597	98,780	7,232	106,012	21,017
Frcst	2017	32,206	26,695	38,854	597	98,352	7,194	105,546	21,066
Frcst	2018	32,092	26,601	38,843	597	98,133	7,182	105,314	21,089
Frcst	2019	32,129	26,595	39,114	597	98,435	7,205	105,639	21,155
Frcst	2020	32,656	26,496	39,557	597	99,305	7,270	106,574	21,425
Frcst	2021	32,577	26,376	40,029	597	99,579	7,302	106,881	21,506
Frcst	2022	32,544	26,252	40,868	597	100,260	7,360	107,620	21,620
Frcst	2023	32,463	26,200	41,624	597	100,883	7,418	108,301	21,754
Frcst	2024	32,383	26,180	42,477	597	101,636	7,487	109,123	21,912
Frcst	2025	32,610	26,157	43,514	597	102,879	7,593	110,472	22,139
Frcst	2026	32,834	26,255	44,889	597	104,575	7,731	112,306	22,428
Frcst	2027	32,992	26,390	46,298	597	106,277	7,867	114,143	22,752
Frcst	2028	33,164	26,561	47,798	597	108,119	8,010	116,129	23,049
Frcst	2029	33,404	26,783	49,225	597	110,009	8,158	118,167	23,374
Frcst	2030	33,876	27,033	50,630	597	112,135	8,320	120,455	23,757
Frcst	2031	34,171	27,316	52,031	597	114,115	8,471	122,586	24,077
Frcst	2032	34,436	27,599	53,450	597	116,081	8,621	124,702	24,404
Frcst	2033	34,688	27,931	54,722	597	117,938	8,762	126,699	24,724
Frcst	2034	34,968	28,305	55,967	597	119,835	8,906	128,742	25,040
Frcst	2035	35,485	28,669	57,285	597	122,035	9,070	131,105	25,425

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	0.74	2.47	2.47	2.47	0.59
2000-2005	3.27	2.51	0.38	3.19	1.88	1.88	1.88	3.57
2005-2010	0.89	0.10	-0.91	2.29	-0.01	-0.01	-0.01	0.37
2010-2015	-1.57	-0.28	0.80	-2.97	-0.32	-0.32	-0.32	-0.78
2015-2020	0.07	-0.09	0.04	0.00	0.02	0.92	0.08	1.87
2020-2025	-0.03	-0.26	1.93	0.00	0.71	0.87	0.72	0.66
2025-2030	0.76	0.66	3.08	0.00	1.74	1.84	1.75	1.42
2030-2035	0.93	1.18	2.50	0.00	1.71	1.74	1.71	1.37
2016-2035	0.48	0.36	2.04	0.00	1.12	1.20	1.12	1.01

SUFG 2017 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	1988	22,444	16,808	26,546	633	66,431	4,650	71,081	13,447
Hist	1989	22,251	17,205	27,394	661	67,511	4,726	72,237	12,979
Hist	1990	22,037	17,659	28,311	650	68,657	4,806	73,463	13,659
Hist	1991	24,215	18,580	28,141	629	71,564	5,009	76,573	14,278
Hist	1992	22,916	18,556	29,540	619	71,632	5,014	76,646	14,055
Hist	1993	25,060	19,627	31,562	511	76,760	5,373	82,133	14,916
Hist	1994	25,176	20,116	33,395	507	79,193	5,544	84,737	15,010
Hist	1995	26,510	20,646	33,659	510	81,326	5,693	87,019	16,251
Hist	1996	26,833	20,909	34,920	536	83,197	5,824	89,021	16,162
Hist	1997	26,792	21,295	35,499	530	84,116	5,888	90,004	16,021
Hist	1998	27,663	22,166	37,012	520	87,360	6,115	93,476	16,638
Hist	1999	29,180	23,078	38,916	543	91,717	6,420	98,137	17,246
Hist	2000	28,684	23,721	38,957	529	91,890	6,432	98,322	16,738
Hist	2001	29,437	23,953	38,293	526	92,208	6,455	98,663	17,511
Hist	2002	32,363	24,980	39,594	540	97,476	6,823	104,300	18,831
Hist	2003	31,177	24,940	39,285	589	95,992	6,719	102,711	18,794
Hist	2004	31,042	25,351	39,380	644	96,417	6,749	103,166	18,193
Hist	2005	33,691	26,857	39,702	619	100,869	7,061	107,930	19,944
Hist	2006	32,527	26,836	40,683	604	100,649	7,045	107,695	20,855
Hist	2007	35,019	27,782	41,112	646	104,558	7,319	111,877	20,858
Hist	2008	34,158	27,536	39,389	653	101,736	7,121	108,857	19,275
Hist	2009	32,689	26,223	34,631	661	94,204	6,594	100,798	19,054
Hist	2010	35,217	26,989	37,934	694	100,834	7,058	107,892	20,315
Hist	2011	34,117	26,714	39,129	646	100,607	7,042	107,649	21,002
Hist	2012	33,217	26,704	39,448	603	99,972	6,998	106,970	20,972
Hist	2013	33,753	26,807	39,506	607	100,673	7,047	107,720	20,122
Hist	2014	34,010	26,752	40,830	619	102,211	7,155	109,366	20,111
Hist	2015	32,538	26,609	39,484	597	99,228	6,946	106,173	19,532
Frcst	2016	32,368	26,701	38,780	597	98,446	7,206	105,652	21,016
Frcst	2017	32,169	26,527	38,360	597	97,652	7,142	104,793	20,922
Frcst	2018	32,031	26,332	38,114	597	97,073	7,102	104,175	20,897
Frcst	2019	32,048	26,236	38,159	597	97,039	7,100	104,139	20,914
Frcst	2020	32,558	26,032	38,348	597	97,534	7,137	104,671	21,135
Frcst	2021	32,466	25,811	38,545	597	97,418	7,139	104,557	21,169
Frcst	2022	32,404	25,595	39,089	597	97,684	7,164	104,849	21,234
Frcst	2023	32,319	25,422	39,640	597	97,978	7,196	105,174	21,327
Frcst	2024	32,275	25,281	40,166	597	98,319	7,236	105,555	21,445
Frcst	2025	32,465	25,136	40,895	597	99,093	7,304	106,397	21,620
Frcst	2026	32,652	25,104	41,895	597	100,247	7,402	107,649	21,865
Frcst	2027	32,774	25,099	42,895	597	101,365	7,494	108,859	22,103
Frcst	2028	32,952	25,130	43,987	597	102,667	7,599	110,266	22,315
Frcst	2029	33,152	25,210	45,072	597	104,029	7,707	111,736	22,578
Frcst	2030	33,609	25,308	46,098	597	105,613	7,827	113,440	22,893
Frcst	2031	33,890	25,435	47,151	597	107,073	7,940	115,013	23,156
Frcst	2032	34,149	25,558	48,190	597	108,493	8,049	116,542	23,418
Frcst	2033	34,388	25,722	49,141	597	109,848	8,152	118,000	23,705
Frcst	2034	34,660	25,923	50,118	597	111,298	8,262	119,560	23,966
Frcst	2035	35,173	26,113	51,118	597	113,000	8,389	121,389	24,302

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	0.74	2.47	2.47	2.47	0.59
2000-2005	3.27	2.51	0.38	3.19	1.88	1.88	1.88	3.57
2005-2010	0.89	0.10	-0.91	2.29	-0.01	-0.01	-0.01	0.37
2010-2015	-1.57	-0.28	0.80	-2.97	-0.32	-0.32	-0.32	-0.78
2015-2020	0.01	-0.44	-0.58	0.00	-0.34	0.54	-0.28	1.59
2020-2025	-0.06	-0.70	1.29	0.00	0.32	0.46	0.33	0.45
2025-2030	0.70	0.14	2.42	0.00	1.28	1.39	1.29	1.15
2030-2035	0.91	0.63	2.09	0.00	1.36	1.40	1.36	1.20
2016-2035	0.44	-0.12	1.46	0.00	0.73	0.80	0.73	0.77

SUFG 2017 High Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	1988	22,444	16,808	26,546	633	66,431	4,650	71,081	13,447
Hist	1989	22,251	17,205	27,394	661	67,511	4,726	72,237	12,979
Hist	1990	22,037	17,659	28,311	650	68,657	4,806	73,463	13,659
Hist	1991	24,215	18,580	28,141	629	71,564	5,009	76,573	14,278
Hist	1992	22,916	18,556	29,540	619	71,632	5,014	76,646	14,055
Hist	1993	25,060	19,627	31,562	511	76,760	5,373	82,133	14,916
Hist	1994	25,176	20,116	33,395	507	79,193	5,544	84,737	15,010
Hist	1995	26,510	20,646	33,659	510	81,326	5,693	87,019	16,251
Hist	1996	26,833	20,909	34,920	536	83,197	5,824	89,021	16,162
Hist	1997	26,792	21,295	35,499	530	84,116	5,888	90,004	16,021
Hist	1998	27,663	22,166	37,012	520	87,360	6,115	93,476	16,638
Hist	1999	29,180	23,078	38,916	543	91,717	6,420	98,137	17,246
Hist	2000	28,684	23,721	38,957	529	91,890	6,432	98,322	16,738
Hist	2001	29,437	23,953	38,293	526	92,208	6,455	98,663	17,511
Hist	2002	32,363	24,980	39,594	540	97,476	6,823	104,300	18,831
Hist	2003	31,177	24,940	39,285	589	95,992	6,719	102,711	18,794
Hist	2004	31,042	25,351	39,380	644	96,417	6,749	103,166	18,193
Hist	2005	33,691	26,857	39,702	619	100,869	7,061	107,930	19,944
Hist	2006	32,527	26,836	40,683	604	100,649	7,045	107,695	20,855
Hist	2007	35,019	27,782	41,112	646	104,558	7,319	111,877	20,858
Hist	2008	34,158	27,536	39,389	653	101,736	7,121	108,857	19,275
Hist	2009	32,689	26,223	34,631	661	94,204	6,594	100,798	19,054
Hist	2010	35,217	26,989	37,934	694	100,834	7,058	107,892	20,315
Hist	2011	34,117	26,714	39,129	646	100,607	7,042	107,649	21,002
Hist	2012	33,217	26,704	39,448	603	99,972	6,998	106,970	20,972
Hist	2013	33,753	26,807	39,506	607	100,673	7,047	107,720	20,122
Hist	2014	34,010	26,752	40,830	619	102,211	7,155	109,366	20,111
Hist	2015	32,538	26,609	39,484	597	99,228	6,946	106,173	19,532
Frcst	2016	32,391	26,841	39,271	597	99,100	7,256	106,356	21,017
Frcst	2017	32,238	26,876	39,366	597	99,077	7,249	106,325	21,216
Frcst	2018	32,127	26,829	39,602	597	99,154	7,258	106,412	21,294
Frcst	2019	32,162	26,888	40,076	597	99,723	7,303	107,026	21,385
Frcst	2020	32,682	26,835	40,771	597	100,885	7,391	108,276	21,700
Frcst	2021	32,621	26,773	41,564	597	101,554	7,453	109,007	21,826
Frcst	2022	32,607	26,725	42,749	597	102,678	7,543	110,221	22,013
Frcst	2023	32,555	26,736	43,911	597	103,798	7,639	111,438	22,213
Frcst	2024	32,503	26,780	45,017	597	104,897	7,737	112,633	22,416
Frcst	2025	32,745	26,831	46,455	597	106,628	7,879	114,507	22,723
Frcst	2026	32,962	26,999	48,192	597	108,750	8,047	116,797	23,075
Frcst	2027	33,122	27,204	49,958	597	110,880	8,214	119,094	23,473
Frcst	2028	33,321	27,452	51,804	597	113,173	8,394	121,567	23,826
Frcst	2029	33,559	27,756	53,640	597	115,551	8,579	124,130	24,198
Frcst	2030	34,045	28,083	55,448	597	118,173	8,778	126,951	24,647
Frcst	2031	34,353	28,449	57,378	597	120,777	8,978	129,755	25,065
Frcst	2032	34,622	28,820	59,395	597	123,434	9,182	132,616	25,492
Frcst	2033	34,887	29,248	61,322	597	126,053	9,383	135,436	25,918
Frcst	2034	35,196	29,725	63,310	597	128,826	9,595	138,421	26,370
Frcst	2035	35,727	30,200	65,355	597	131,878	9,825	141,703	26,884

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	0.74	2.47	2.47	2.47	0.59
2000-2005	3.27	2.51	0.38	3.19	1.88	1.88	1.88	3.57
2005-2010	0.89	0.10	-0.91	2.29	-0.01	-0.01	-0.01	0.37
2010-2015	-1.57	-0.28	0.80	-2.97	-0.32	-0.32	-0.32	-0.78
2015-2020	0.09	0.17	0.64	0.00	0.33	1.25	0.39	2.13
2020-2025	0.04	0.00	2.64	0.00	1.11	1.29	1.13	0.93
2025-2030	0.78	0.92	3.60	0.00	2.08	2.18	2.08	1.64
2030-2035	0.97	1.46	3.34	0.00	2.22	2.28	2.22	1.75
2016-2035	0.52	0.62	2.72	0.00	1.52	1.61	1.52	1.30

Indiana Base Average Retail Rates (Cents/kWh) (in 2015 Dollars)

Year	Res	Com	Ind	Average
1988	12.51	11.53	8.09	10.34
1989	11.69	9.89	7.38	9.32
1990	11.04	9.34	6.98	8.77
1991	10.38	8.80	6.67	8.38
1992	10.32	8.71	6.50	8.18
1993	9.71	8.15	6.10	7.70
1994	9.74	8.13	6.04	7.63
1995	9.58	8.06	5.81	7.50
1996	9.55	8.03	5.83	7.47
1997	9.74	7.95	5.74	7.45
1998	9.78	7.96	5.72	7.44
1999	9.50	7.78	5.45	7.21
2000	9.11	7.38	5.35	6.94
2001	8.93	7.42	5.19	6.86
2002	8.75	7.36	5.18	6.82
2003	8.72	7.26	5.10	6.73
2004	8.77	7.38	5.18	6.82
2005	8.79	7.51	5.32	6.98
2006	9.42	7.95	5.83	7.46
2007	9.05	7.93	5.55	7.27
2008	9.41	8.14	5.93	7.61
2009	10.01	8.73	6.47	8.25
2010	9.80	8.61	6.33	8.08
2011	10.16	8.84	6.51	8.28
2012	10.44	9.08	6.58	8.44
2013	10.89	9.45	6.90	8.82
2014	11.19	9.68	7.14	9.08
2015	11.15	9.45	6.88	8.90
2016	12.00	10.36	7.74	9.75
2017	12.91	11.10	8.18	10.40
2018	13.58	11.70	8.61	10.95
2019	14.08	12.11	8.77	11.27
2020	14.58	12.56	9.06	11.67
2021	15.31	13.19	9.39	12.17
2022	15.45	13.28	9.37	12.19
2023	15.56	13.49	9.75	12.41
2024	15.71	13.58	9.66	12.40
2025	15.62	13.53	9.60	12.30
2026	15.24	13.26	9.43	12.00
2027	15.18	13.27	9.48	11.97
2028	15.14	13.26	9.46	11.91
2029	15.21	13.38	9.58	11.98
2030	15.25	13.45	9.65	12.01
2031	15.15	13.40	9.59	11.91
2032	15.10	13.38	9.52	11.83
2033	15.12	13.45	9.58	11.86
2034	15.09	13.47	9.59	11.83
2035	15.05	13.48	9.66	11.84
Average Compound Growth Rates (%)				
Year-Year	**Res**	**Com**	**Ind**	**Average**
1990-1995	-2.80	-2.90	-3.61	-3.08
1995-2000	-0.99	-1.75	-1.63	-1.56
2000-2005	-0.72	0.36	-0.12	0.12
2005-2010	2.22	2.76	3.54	2.97
2010-2015	2.61	1.87	1.68	1.95
2015-2020	5.51	5.86	5.67	5.56
2020-2025	1.39	1.49	1.16	1.06
2025-2030	-0.48	-0.11	0.10	-0.47
2030-2035	-0.26	0.04	0.02	-0.28
2016-2035	1.20	1.40	1.17	1.03

Note: Energy Weighted Average Rates for Indiana IOUs.
Results for the low and high economic activity cases are similar and are not reported.

List of Acronyms

ACGR	Average Compound Growth Rates
Btu	British thermal unit
CC	Combined Cycle
CEDMS	Commercial Energy Demand Modeling System
CEMR	Center for Econometric Model Research
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
DLC	Direct Load Control
DOE	U. S. Department of Energy
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GSP	Gross State Product
GWh	Gigawatt-hour
HVAC	Heating, Ventilation and Air Conditioning
I&M	Indiana Michigan Power Company
IBRC	Indiana Business Research Center
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
IMPA	Indiana Municipal Power Agency
KLEM	Capital, labor, energy and materials
kWh	Kilowatt-hour
LMSTM	Load Management Strategy Testing Model
LPG	Liquefied Petroleum Gas
MATS	Mercury and Air Toxics Standards
MW	Megawatt
NAICS	North American Industry Classification System
NFP	Not-for-Profit
OPEC	Organization of Petroleum Exporting Countries
ORNL	Oak Ridge National Labs
PC	Pulverized Coal-Fired
REMC	Rural Electric Membership Cooperative
REDMS	Residential Energy Modeling System
REEMS	Residential End-Use Energy Modeling System
RTO	Regional Transmission Organization
RUS	U.S. Department of Agriculture Rural Utilities Service
SIC	Standard Industrial Classification
SUFG	State Utility Forecasting Group
WVPA	Wabash Valley Power Association

Final

DIRECTOR'S REPORT

for the

2016 Integrated Resource Plans

Dr. Bradley Borum

IRPs Submitted by

Indianapolis Power & Light Company (IPL)

http://www.in.gov/iurc/files/ipl%202016%20irp_without%20attachments.pdf

Northern Indiana Public Service Company (NIPSCO)

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Vectren (SIGECO)

http://www.in.gov/iurc/files/SIGECO%202016%20IRP.pdf

and

An Update by Hoosier Energy

http://www.in.gov/iurc/files/Hoosier%20Energy_public%20version_2014%20irp%20update_110116.pdf

November 2, 2017

The Final Director's Report for the 2016 Integrated Resource Plans includes the Director's response to comments received from utilities and stakeholders regarding the Draft Director's Report. The Director's specific responses to Indianapolis Power & Light (IPL) are found in Section 2.5, Northern Indiana Public Service Company (NIPSCO) in Section 3.5, and responses to Vectren have been inserted in Section 4.5.

The Director's responses to the Indiana Coal Council (ICC) are in Section 9. Responses to the Citizens Action Coalition (CAC) et al can be found in Section 10. Comments by the Indiana Coal Council and the CAC et are placed at the end of the Final Director's Report since many of the comments are generally applicable to all of the utilities.

The Director sincerely appreciates the excellent analysis conducted by the utilities and the commitment by the utilities' top management and subject matter experts to this endeavor. Because of the increasing importance and complexities of the IRPs, the Director is very appreciative of the contributions by stakeholders, particularly the Citizens Action Coalition et al, the Indiana Coal Council, and the Midwest Energy Efficiency Alliance for their substantive analysis of these IRPs.

EXECUTIVE SUMMARY
2016 INTEGRATED RESOURCE PLANS

Indianapolis Power & Light, Northern Indiana Public Service Company, Vectren, and Hoosier Energy

Purpose of IRPs

By statute[1] and rule,[2] integrated resource planning requires each utility that owns generating facilities to prepare an Integrated Resource Plan (IRP) and make continuing improvements to its planning as part of its obligation to ensure reliable and economical power supply to the citizens of Indiana. One of the primary goals of a well-reasoned, transparent, and comprehensive IRP is to narrow the contested issues and reduce the controversy to expedite Indiana Utility Regulatory Commission (IURC or Commission) proceedings for the benefit of customers, the utility, and the utility's investors. A key element in achieving this goal, as required by law and rule, is a public advisory process, otherwise known as a stakeholder process. At the outset, it is important to emphasize these are the utilities' plans. The Commission, by statute[3], does not take a position on the relative efficacies of any of the utilities' "Preferred Plans."

An IRP is a systematic approach to better understand the complexities of an uncertain future so utilities can maintain maximum flexibility to address resource requirements. Because absolutely accurate resource planning 20 years into the future is impossible, the objective of an IRP is to bolster credibility in a utility's efforts to capture a broad range of possible risks.[4] By identifying uncertainties and their associated risks, utilities will be better able to make timely adjustments to their resource portfolio to maintain reliable service at the lowest delivered cost to customers that is reasonably feasible.

Every utility and stakeholder anticipates substantial changes in the state's resource mix due to several factors,[5] and increasingly, Indiana's electric utilities are using IRPs as a foundation for their business plans. Since Indiana is part of a vast interconnected power system, Indiana is affected by the enormity of changes throughout the region and nation. Inherently, IRPs are very technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of

[1] Indiana Code § 8-1-8.5-3.

[2] 170 IAC 4-7; *see also* "Draft Proposed Rule from IURC RM #11-07 dated 10/04/12", located at: http://www.in.gov/iurc/2843.htm ("Draft Proposed Rule")

[3] Indiana Code § 8-1-1-5.

[4] In addition to forecasting changes in customer use of electricity (load forecasting), IRPs must address uncertainties pertaining to the fuel markets, the future cost of resources and technological improvements in resources, changes in public policy, and the increasing ability to transmit energy over vast distances to access economical and reliable resources due to the operations of the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM).

[5] The primary *driver* of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to *fracking* and improved technologies. As a result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change.

possible narratives about plausible futures. The utilities should utilize IRPs to explore the possible implications of alternative resource decisions.

The IRPs should be regarded as *snap shots in time* that analyze multiple potential resource portfolios. Because IRPs are usually submitted to the Commission in November, changes occurring after submittal, such as any roll-back of environmental regulations through law, rulemaking, or executive orders (e.g., the Clean Power Plan (CPP)), review of Effluent Limitation Guidelines (ELG) rule, policy emanating from international agreements such as the Paris Accord, newly-discovered natural gas opportunities, and changes in technology do not normally require changes to this IRP unless changes are required by the Commission to support a future filing of a Certificate of Need case or other case. As a result, these resource portfolios should not be regarded as being THE Plan that a utility commits to undertake. Rather, it should be regarded as a road map based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost-effectiveness of various resources, customer needs, etc.) and make appropriate and timely mid-course corrections to change their resource portfolios. Again, it is important that these decisions be made with stakeholder involvement.

Four Primary Areas of Focus

The Director recognizes the complexity of the several elements of IRPs and has selected the following four to highlight:

1) Fuel and commodity price forecasts;
2) Construction of resource portfolios based on the development of a wide range of scenarios and sensitivities;
3) The treatment of Demand-Side Management (DSM) on as comparable a basis as possible with all other resources; and
4) Discussion of the metrics that each utility considered to evaluate the IRPs.

The focus on these four areas is due to the complexity and difficulty of these topics but it should not be interpreted as suggesting that other topics such as the stakeholder process, load forecasting, and integration of customer-owned resources are not important to the credibility of the IRPs and the value to utilities and stakeholders.

General Observations

Perhaps due in part to the increasingly consequential decisions that utilities will be making, and in part to the commitment of the utilities and stakeholders to the IRP public advisory processes as good public policy, Indianapolis Power and Light Company (IPL), Northern Indiana Public Service Company (NIPSCO), and Southern Indiana Gas and Electric Company (Vectren) have all made significant improvements in all aspects of their IRPs. Indiana utilities are increasingly using state-of-the-art methods and are making continued enhancements to their planning processes. The utilities have all made a concerted effort to broaden stakeholder participation. All of the utilities have offered unprecedented transparency and candor. It is gratifying that the top management of each utility, top staff and subject matter experts have all been made available to facilitate the collegial stakeholder process.

Consistent with the law and the Draft Proposed Rule, each Indiana utility has recognized areas that will be improved in subsequent IRPs. For example, all three utilities recognized the need for improvements in their load forecasting, and IPL is undertaking an ambitious project to utilize "smart meters" (Advanced Metering Infrastructure or AMI) to increasingly rely on its own customers' usage data rather than reliance on information from other utilities. NIPSCO recognized the need to upgrade its modeling capabilities because its current long-term resource model was not capable of integrating probabilistic analysis or performing multiple optimizations of different resources. All utilities are committed to enhancing their stakeholder process. By going from a two year to three year IRP cycle, utilities can increase stakeholder input by: 1) establishing objective metrics to evaluate their IRP; 2) defining the assumptions (e.g., fuel prices, costs of renewable resources, costs of other resources); 3) constructing scenarios to provide a robust assessment of potential futures; and 4) reviewing the resulting resource portfolios.

In the four focus areas, the Director recognizes there is no right or wrong way to conduct the analysis; different approaches have been useful to advance the understanding of the various elements of IRPs but it is premature to standardize.

1. INTRODUCTION AND BACKGROUND

Since 1995, Indiana utilities that generate electricity have submitted IRPs. In 2016 by explicit statute[6] and rule,[7] the Commission requires each utility that owns generating facilities to prepare an IRP and make continuing improvements to their planning as part of their obligation to ensure the reliable and economical power supply to the citizens of Indiana. For several reasons (such as projected low cost natural gas, aging power plants, environmental regulations, decreasing cost of renewable energy resources, energy efficiency, customer-owned resources, and relatively low load growth), all Indiana utilities, in addition to utilities throughout the region and nation, are facing significant resource decisions that will largely remake the resource mix. One of the primary goals of a well-reasoned, transparent, and comprehensive IRP is to narrow the contested issues and reduce the controversy to expedite Commission proceedings for the benefit of customers, the utility, and the utility's investors. For the IRPs submitted on or after Nov. 1, 2012, the utilities voluntarily adhered to the Draft Proposed Rule from IURC RM #11-07 dated 10/04/2012 (Draft Proposed Rule), which proposed to modify 170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans. The Commission, utilities, and stakeholders collaboratively developed the Draft Proposed Rule, which is available on the Commission's website at http://www.in.gov/iurc/2843.htm

(IPL and NIPSCO submitted their IRPs on Nov. 1, 2016. Also on November 1, Hoosier Energy submitted an update to its 2014 IRP. Vectren was granted an extension to allow for a better understanding of the issues associated with ALCOA and larger customers generally, and submitted its 2016 IRP on December 19, 2016. Links to the IRPs, appendices, and other documents can be found at http://www.in.gov/iurc/2630.htm.

Please note that the links shown below for each utility are public versions of the IRPs and do not include confidential information and most appendices:

[6] Indiana Code § 8-1-8.5-3.

[7] 170 IAC 4-7; *see also* "Draft Proposed Rule from IURC RM #11-07 dated 10/04/12", located at: http://www.in.gov/iurc/2843.htm

1. Indianapolis Power & Light Company (IPL)

   http://www.in.gov/iurc/files/ipl%202016%20irp_without%20attachments.pdf

2. Hoosier Energy REC, Inc. (Hoosier Energy)

   http://www.in.gov/iurc/files/Hoosier%20Energy_public%20version_2014%20irp%20update_110116.pdf

3. Northern Indiana Public Service Company (NIPSCO)

   http://www.in.gov/iurc/files/NIPSCO%202016%20IRP%20Without%20Appendices.pdf

4. Southern Indiana Gas & Electric Company (SIGECO or Vectren)

   http://www.in.gov/iurc/files/SIGECO%202016%20IRP.pdf

Written comments regarding some of the IRPs were submitted by various entities, including:

1. Citizens Action Coalition, Earthjustice, IndianaDG, Sierra Club, Valley Watch (hereinafter referred to as CAC et al.)
2. Midwest Energy Efficiency Alliance
3. Indiana Coal Council
4. Alliance Resource Partners, LP
5. NIPSCO Industrial Group
6. Sunrise Coal, LLC
7. Joe Nickolick
8. Office of the Utility Consumer Counselor.

Written comments on the Draft Director's Report submitted by the following organizations:

1. IPL
2. NIPSCO
3. Vectren
4. CAC et al
5. ICC

Links to these comments can be found at: http://www.in.gov/iurc/2630.htm

Section 2(k) of the Draft Proposed Rule limits the Director's Draft Report and Final Report to the informational, procedural, and methodological requirements of the rule, and Section 2(l) of the Draft Proposed Rule restricts the Director from commenting on the utility's preferred resource plan or any resource action chosen by the utility.

This Draft Report by the Director was issued July 25, 2017. Under the Draft Proposed Rule, supplemental or response comments to the Director's Draft Report may be submitted by the utility or any customer or interested party who submitted written comments on the utility's IRP earlier in the process. Supplemental or response comments must be submitted within 30 days from the date the Director issues the Draft Report. The Director may extend the deadline for submitting supplemental or response comments.

According to the Draft Proposed Rule, the Director shall issue a Final Report on the IRPs within 30 days following the deadline for submitting supplemental or response comments. The Director would be pleased to meet with utilities and/or stakeholders to discuss the Draft or Final Reports.

1.1 Summary

The 2016 IRPs submitted by IPL, NIPSCO, and Vectren were credible, well-reasoned, and represented a substantial improvement over previous years in all aspects of their IRPs. The utilities are increasingly viewing their IRPs as integral to their strategic planning and having substantial ramifications for their customers, investors, communities, and for policymakers. Certainly all three utilities are facing potentially dramatic changes in their resource mix over the next several years due to the following factors affecting the nation as a whole:

- The aging of the coal and nuclear generating fleets when combined with more stringent environmental regulations accelerate retirement decisions. This is especially true for the smaller and older coal-fired generating units. In the next few years, decisions to retire larger and more efficient generating facilities that have far-reaching ramifications for the each utility's customers, the region, and the nation are certain to require increasingly difficult and rigorous analysis.
- In general, coal and nuclear generating units are having difficulties competing with natural gas and renewable resources in the regional economic dispatch of competitive wholesale power markets. That is, for regional economic dispatch by MISO or PJM, coal and even some nuclear units that serve other states are often "out of the money" and not dispatched as fully as they were as recently as two years ago and therefore unable to recover all of their fixed and variable operating costs. As a result, several utilities have planned to retire substantial portions of their coal-fired units. Nuclear units are increasingly struggling in the current market. Utilities in Ohio, Illinois, and other states are seeking state legislation to have customers subsidize the continued use of nuclear- and coal-fired generators. Against this backdrop of declining natural gas prices and increased cost-effectiveness of renewable resources, utilities evaluating the retention of coal and nuclear units will need to continually reevaluate the value of fuel and resource diversity while maintaining resource adequacy.
- Utilities are facing increasing costs due to maintenance and modernization of infrastructure. These utilities are also projecting low or even negative growth in electric sales, which means the increased costs will be spread over fewer kilowatt hour sales.
- Because the decisions about resources will become increasingly complex, contentious, and difficult, utilities will have to continually enhance their planning processes. In addition to dramatic changes in fuel markets and the cost of renewable resources, utilities will have to consider the planning ramifications of future potentially significant public policy changes, such as the roll-back of some environmental regulations (e.g., the CPP, ELG, Presidential Executive Orders, etc.).

With good reason, IPL, NIPSCO, and Vectren have sought to maintain as much optionality as possible in their IRPs. The Navy uses the phrase "point of extremis" to characterize maximum optionality. That is, waiting to make a very difficult decision until the last possible moment. To this end, the IRP analysis –

including the utility's selection of a preferred resource portfolio – should be regarded as an indicative analysis, in that the results are based on appropriate information available at the time the study was being conducted and does not bind the utility to adhere to the preferred resource portfolio, or any other resource portfolio. If there is information to support a different outcome in a matter before the Commission after an IRP used to support a resource decision is completed, the utility should assess whether an update to the IRP is appropriate. Ultimately, in the instance of a case before the Commission, the Commission, after consideration of testimony, will decide whether additional analysis is necessary to provide the Commission with the requisite information.

1.2 Areas of Primary Focus

The Director's Report of the 2016 IRPs for IPL, NIPSCO, Vectren, and an update by Hoosier Energy will primarily address the four most difficult and significant interrelated topics that were the subject of considerable conversation throughout the stakeholder processes. The four topics are: 1) fuel and commodity price projections; 2) scenario and risk analysis; 3) development of metrics for evaluating the IRPs; and 4) the treatment of energy efficiency on as comparable a basis as possible to other resources.

Utilities, in conjunction with stakeholders, will be evaluating future resource modeling programs, databases, and utility planning processes to continually enhance the credibility of the IRP processes. This continual reevaluation is imperative as decisions become increasingly complex. Just because these other topics are receiving a more cursory review should not be construed as being less important. It is also worth emphasizing that the individual topics being reviewed are all interrelated, which makes clear delineation between the topics impossible. The Director wishes to be abundantly clear that the comments address the methods used in the IRP process rather than the selection of a preferred resource portfolio.

The Director believes this has been the most transparent IRP process to date. The new three-year cycles contained in the more recent draft IRP rules will further reduce concerns and questions by affording stakeholders an opportunity to become more involved in the development of the IRPs from their inception through submittal. Most stakeholder concerns and questions about this and previous IRPs centered on the development of portfolios. This included developing assumptions, selection of appropriate data, construction of scenarios, the use of meaningful sensitivities, and the evaluation of model output and the resulting resource portfolios to reliably and economically meet the needs of Indiana. Stakeholder interest and participation in the IRP processes is likely to intensify as decisions to retire and restructure the resource mix are made.

From the analysis and the stakeholder comments, IPL, NIPSCO, and Vectren made significant improvements to their IRP analysis and their approaches. It is abundantly clear that Indiana utilities, like utilities throughout the nation, are facing daunting issues and there is no easy, single or perfect answer to address these issues. In some respects, Indiana utilities are on the cutting edge of long-term resource planning. The advances made by Indiana utilities should result in lower risk for their customers and investors. As Indiana utilities and their stakeholders realize, however, continued improvements is a goal we all share.

1.3 Presentation of Basic Information

The Director tried to compile the same set of basic information for each utility's IRP and found the task surprisingly difficult. For example, the Director tried to compare for each utility how its portfolio changed from the beginning of the forecast period to how it looked in the last year of the period. This information was presented in terms of generation capacity in either the IRP, appendices, or presentations from the public advisory stakeholder meetings. But comparable information showing how much energy was provided by resource type and how this changed over the forecast horizon was not presented by IPL and Vectren. Some of the basic information was presented by each utility in their IRP but no utility had all of the information in its IRP. Some of the information one utility had in its IRP was not included by other utilities but could be found in the stakeholder presentations. Some of the basic information could not be found in the IRPs, stakeholder meeting presentations, or other technical appendices. Even when utilities presented what appeared to be similar information, a closer examination showed the data was not comparable. Based on comments by the CAC et al., it appears they had much the same experience.

The problem is the IRPs and the associated appendices each provide a considerable amount of information but much is also not available, not well presented or must be laboriously sought and compiled, or is not comparable across utilities. These limitations reduce the usefulness of the IRPs to non-utility stakeholders and can be increasingly problematic over time for utilities, stakeholders, and policymakers. Without being unduly prescriptive, but in an effort to improve the immediate and longer-term value of the IRPs, the Director makes several suggestions that he hopes will serve as a starting point for a discussion that will involve the utilities and numerous stakeholders.

1. Make much greater use of tables and figures comparing resource retirements, additions, and other inputs across both the preferred and candidate portfolios. Examples are on Table 23 on page 131 of Indiana Michigan's 2015 IRP. Another example for consideration is Table 2 on Pp. 11 of the CAC et al. comments on Vectren's 2016 IRP.

2. Include tables showing how inputs or assumptions compare across scenarios. To make scenarios clearer, there needs to be a link of each scenario description to specific inputs. (CAC et al. Comments on Vectren IRP, Pp. 19). For example, which fuel forecasts were used in each scenario should be clearly specified.

3. The first year any resource is available for selection in a portfolio should be presented and the reason why some resources might be available later than others should also be noted. More specifically,

   - The first year a resource can be added to a portfolio;
   - The last year a resource can be added to a portfolio;
   - Limitations on the size of the resource that can be added;
   - The minimum and maximum number of units of a particular resource that can be added; and
   - Performance characteristics of generation facilities including forced outage rates, heat rate profiles, emission rates, and typical maintenance outages.

Also, if the availability of potential resources for model selection varied by scenario, then this should also be clearly presented. As mentioned by CAC et al, for each scenario or portfolio, it is important to note which resource changes are fixed (or set by the modeler) as compared to optimized (chosen by the model based on the constraints set by the modeler). (See pp. 10 of CAC's Comments on Vectren IRP)

4. The non-utility stakeholders would benefit from expanded use of graphics and simple tables. Well-developed graphics would aid a wide variety of audiences.

5. Given that future IRPs are going to be increasingly consequential in their ramifications, we urge all utilities to continue their efforts to improve the clarity and explanatory value of their narratives. With the new three-year cycle for IRPs, we recommend the additional time could be used to good effect to solicit input from stakeholders earlier in the process on the data, assumptions, and the development of scenarios and sensitivities. It is expected that stakeholders will also be active participants in this collaboration. The utilities, with input from their stakeholders, should objectively reassess their modeling capabilities and the databases necessary to make full use of state-of-the-art long-term resource modeling.

2. INDIANAPOLIS POWER AND LIGHT COMPANY

2.1 IPL'S Fuel and Commodity Price Analysis for 2016 IRP

Since natural gas price projections and the relationship between gas and coal prices seem to be the primary driver of the IRPs this round, the Director believes more discussion about the assumptions behind the fuel and commodity forecasts and data are warranted. We very much appreciate IPL's willingness to share confidential information from its consultants, which provided a narrative of its fuel and market price projections. However, the narratives did not seem to provide a comprehensive discussion of the complexities of the interrelationships of critical commodities. For example, the production and price relationship of oil to natural gas, natural gas to coal, and fuel prices to MISO market prices.

> *Natural gas/market price correlations – While IPL recognizes potential influences of resource mix changes on market prices, in this IRP correlations between fuel and market prices do not change significantly from recent historic trends. IRP Assumptions, 1.3 page 2*

As a result of giving less consideration to fracking as a significant departure from historic trends, it appears that IPL may minimize the complex and changing interrelationships between oil price and production and the production and price of natural gas. To the extent that this concern may be valid, we offer some potential examples but encourage IPL to consider others.

1. Figures 8.40 and 8.41in the Company's IRP shows a somewhat surprising result that coal price became more important than natural gas prices after 2027. This is certainly an interesting scenario but it might argue for construction of a scenario/sensitivity that has a low natural gas price projection.

2. If natural gas price projections are as complex as we believe, this would seem to make estimates of the market price, which is largely dependent on the price differentials between coal and natural gas (the difference between the market price and coal price is sometimes referred to as the dark spread), more difficult. On page 11 of its IRP, IPL states: "*IPL uses a combination of multi-year contracts with staggered expiration dates to limit the extent of IPL's coal position open to the market in any given year. Many of these multi-year contracts contain some level of volumetric variability as an additional tool to address market variability.*" This seems like a well-reasoned approach but it isn't clear how coal prices varied in the longer-term using stochastic analysis (page 142). Regardless, this IRP analysis, and particularly future IRP analyses, would benefit from more complete discussion of natural gas, coal, and market price intricacies.

3. For IPL, the MISO's economic dispatch and forecast of market prices provide additional data points for consideration. That is, if the projections being used by the MISO show diminishing dispatch of coal-fired power plants, that should be an additional check, but certainly not the only check in determining the reasonableness of the fuel cost assumptions. Similarly, if coal is dispatched more frequently, IPL's planning should be sufficiently flexible to adjust.

The Indiana Coal Council commented that the 2.5% annual escalation rate for coal may be too high. IPL said that might be true but, while they utilized only one coal price forecast, they conducted probabilistic analysis on a wider range of possible forecasts to evaluate their portfolios (IPLs response to Indiana Coal Council on page 1 of the ICC's letter). The Director believes IPL's approach was a reasonable method to address the ICC's concerns. However, we agree with the Indiana Coal Council that it would probably be better to have more expansive scenarios than to rely on sensitivities. As IPL's resource decisions become more difficult, we are confident IPL will be rigorous in its evaluation methods.

2.2 Scenario and Risk Analysis

2.2.1 Models, Drivers, and Scenarios

To IPL's credit, all scenarios were developed in an atmosphere of transparency, and IPL actively solicited input from stakeholders. IPL identified four categories of drivers, which would impact IPL's resource portfolio choice. They are economics affecting load requirements, natural gas and wholesale electric market prices, Clean Power Plan and other environmental costs, and the level of customer distributed generation adoption. IPL considered how these drivers might interact in the future to develop specific scenarios.

1. A Base Case scenario
2. Robust Economy,
3. Recession Economy,
4. Strengthened Environmental, and
5. High Customer Adoption of Distributed Generation
6. Quick Transition

The Base Case included business-as-usual projections for identified drivers trending as currently expected for the study period. Four scenarios were developed by varying projections of the four main categories of drivers mentioned previously. The four scenarios are Robust Economy, Recession Economy, Strengthened Environmental, and High Customer Adoption of Distributed Generation. Another scenario called Quick Transition was formed based on stakeholder feedback. There are six scenarios in total.

The capacity expansion model produced six least-cost portfolios from the six scenarios. IPL then took the six portfolios and modeled them against the Base Case assumptions in the Production Cost Model to examine how each portfolio would fare if Base Case assumptions for the future come to fruition. To better understand the impact of carbon regulation on the Base Case, IPL conducted two deterministic sensitivities on the Base Case by using the Production Cost Model to simulate the Base Case portfolio and dispatched the units subject to different carbon prices. Additionally, stochastic analysis was conducted to assess the financial risk to each portfolio if key variables changed.

Based on the criterion of lowest cost to customers combined with considerations of risk, as well as other economic and environmental impacts, IPL chose a hybrid preferred resource portfolio. The portfolio is a mix of the portfolios from the Base Case, Strengthened Environmental, and Distributed Generation Scenarios. Selecting a Preferred Portfolio that was different from the Base Case, based on IPL's judgment might be regarded as unusual but it is not inconsistent with the IRP draft rule. Selecting a Preferred Plan that incorporates stakeholder and other input demonstrates a flexibility and optionality that the IRP draft rules intended to encourage. Since all of the IRP plans are indicative, they should not be characterized as representing a commitment to adopt the elements of the plan. However, for the integrity of the stakeholder process, the utility's Preferred Plan should be derived from the scenarios that were fully optimized and reflect information developed from sensitivity and probabilistic analyses. A narrative should be sufficiently detailed to track the evolution of the Preferred Plan.

IPL worked with several vendors and utilized multiple models to conduct scenario and sensitivity analysis. The DSM Market Potential Study was conducted by AEG through LoadMap. Load forecasts were performed by Itron using MetrixND. Capacity Expansion Model from ABB was used to develop optimized portfolios under various scenarios. ABB Strategic Planning Portfolio Production Cost Model and Financial Model were adopted to evaluate portfolios by providing present value of revenue requirements (PVRRs) in a Base Case future world.

2.2.2 Issues / Questions

The Director was impressed with the level of scrutiny and in-depth analysis of the computer runs and how the modeling affected the development of scenarios, sensitivities, and, ultimately, the portfolios that were provided by the CAC et al. Giving due regard for stakeholder comments adds credibility, increases understanding, and, hopefully, will reduce the number of contentious issues inherent in the increasing complexity and analytical difficulty of future IRPs. Hopefully, many of the concerns raised by the CAC et al. regarding assumptions, data, development of scenarios, integration of sensitivities, and appropriate metrics for objective review will be addressed earlier in the IRP process consistent with the change in the rule from two to three-year cycles.

All of IPL's optimized portfolios were evaluated under the Base Case Scenario assumptions rather than the assumptions of the corresponding scenarios. IPL argued that the comparison was helpful because it allowed one to see how each portfolio performed under the same set of assumptions. However, in this case, comparison among various portfolios based on the Present Value of Revenue Requirements (PVRR) is less meaningful because the Base Case portfolio has to be the least cost portfolio under Base Case scenario assumptions, according to the least-cost optimization criterion imbedded in the capacity expansion model.

For the probabilistic analysis, IPL evaluated each candidate portfolio under 50 combinations of input variables from random draws using the Production Cost Model. IPL seems to have overlooked changes in the capacity portfolio caused by changes of input assumptions by using this method. Upon reconsideration, would IPL agree that a more appropriate way might be running the capacity expansion model first under each set of assumptions to develop the capacity portfolio and then evaluating the portfolio with consideration of the operation and financial aspects of electrical generating units through the Production Cost Model? With regard to choosing the preferred plan, a more appropriate way might be comparing capacity portfolios derived from different input assumptions first. Resources found in the majority of scenarios might be considered in the preferred portfolio. However, in the end, IPL considered six metrics it regarded as important (page 7 of the Executive Summary) and it is IPL's decision to select a preferred portfolio.

2.3 Energy Efficiency

Like other Indiana utilities, there is a marked improvement in IPL's effort to model demand side management (DSM) in a manner comparable to supply-side resources and to group the resources into bundles that are then entered as selectable resources comparable to supply-side resources in the capacity expansion modeling software. The ability to treat DSM in a manner that is as comparable as possible to other supply-side resources is difficult and there is no single or perfect methodology. Like NIPSCO in this

IRP cycle, IPL contracted the Applied Energy Group (AEG) to use their LoadMap tool to perform a market potential study and Morgan Marketing Partners (MMP) to screen the DSM measures chosen for cost-effectiveness using their DSMore tool. The DSM measures that passed the screening were then grouped into 14 bundles (eight energy efficiency-based and six demand response-based). Seven of the energy efficiency based bundles were further split into three cost tiers.

To estimate the appropriate level of achievable and cost-effective DSM suitable for IPL's service territory, IPL hired AEG to prepare a Market Potential Study (MPS).[8] While the IRP covers the period 2017 to 2036, the MPS started in 2018 and covers DSM opportunities through 2037. A key objective of the MPS was to develop estimates of electric efficiency and demand response potential by customer class for the period 2018 to 2037 in the IPL service territory and develop inputs to represent DSM as a resource in IPL's IRP for the forecast period 2018-2037.

A screening process was used to develop an Achievable Potential for DSM that was used to create the DSM bundles for the IRP modeling. The process starts with all technically possible efficiency measures, or the Technical Potential. AEG prepared a list of available efficiency measures using IPL's current programs, the Indiana Technical Reference Manual version 2.2, and AEG's data base of energy efficiency measures. AEG then applied a cost-effectiveness screen using the Total Resource Cost (TRC) test as the main metric to determine the Economic Potential. This test selects any measure which, if installed in a given year, has a TRC net present value of lifetime benefits that exceed the Net Present Value of Revenue Requirements (NPVRR) of lifetime costs.

AEG estimated two levels of Achievable Potential from the Economic Potential: Maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP). MAP estimates consider customer adoption of economic measures when delivered through DSM programs under ideal conditions and an appropriate regulatory framework. RAP reflects program participation given DSM programs under typical market conditions and barriers to customer acceptance and constrained program budgets. A downward adjustment was applied to the MAP and RAP savings estimates in an amount proportional to the percentage of load that has elected to opt out of efficiency programs.

IPL considered three different DSM bundling options. Option A involved creating the program potential or actual programs - each DSM bundle represented a program. Option B involved creating end-use bundles with similar load shapes that are further disaggregated into cost tiers. Option C used MAP to create bundles based on similar load shape end uses. IPL selected Option B because they thought the method allowed for more creativity in program creation. Also, the cost tiers prevent cost-effective measures from being eliminated because they are bundled with high cost measures, which could happen with Option C. MAP was used to construct the DSM bundle inputs into the IRP.

IPL worked with AEG and Morgan Marketing Partners to create DM bundles using the DSMore cost-effectiveness model. Energy efficiency measures within MAP were bundled by sector and technology to take advantage of load shape similarities among like measures. Bundles were further divided by the direct cost to implement per MWh: up to \$30/MWh, \$30-60/MWh, and \$60+/MWh. IPL decided to use

[8] A MPS assesses how much DSM (energy efficiency and demand response) is potentially achievable in a utility system. A MPS is normally used to estimate the level of Technical Potential, Economic Potential, and Achievable Potential. Technical Potential is the maximum energy efficiency available, assuming that cost and market adoption of technologies are not a barrier. Economic Potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. Achievable Potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences.

$30/MWh as the top-end of the low cost tier because this is roughly the delivery cost for IPL's 2016 DSM portfolio. It was determined the maximum number of bundles the capacity expansion model could reasonably handle was around 45. To meet this model limitation, IPL decided to split the IRP timeframe into a near-term period that is consistent with its next DSM filing period (2018 to 2020) and a long-term period of 2021 to 2036.

DSM in the IRP capacity expansion model is compared to building new generation or purchasing power to meet load requirements. This is done by giving supply-side characteristics, including load reduction or load shape change potential, and levelized cost in $/MWh and $/MW to the DSM bundles.

2.3.1 Issues / Questions

IPL, despite using the same consultants as NIPSCO, modeled DSM slightly differently than NIPSCO and substantially different from Vectren. In fact, all three companies differed as to how they handled model limitations that constrain how DSM can be modeled in the IRP resource optimization model. For IPL, in dealing with the limitation on the number of resources that the capacity expansion model could handle, it appears IPL reduced the DSM decision points to two years, 2018 and 2021. In 2018, the level of DSM for 2018 to 2021 is chosen. In 2021, the level of DSM for 2021 to 2036 is decided. This is according to the explanation in Section 7.3.3 (page 147) of the IRP main document which reads as follows: "For example, let's say the model picks the Residential Lighting block for the 2021–2036 period. The level of DSM within this bundle is pre-set for this period based on the Market Potential Study. DSM within this bundle is static and will not increase in year 2030, if there is a need for additional capacity to meet the reserve margin." To the degree that this is the case, the treatment of DSM in the capacity expansion decision is not quite on par with the supply-side resources whose decisions are made annually in the capacity expansion model to ensure the resources satisfy the reserve margin requirements.

Another problem area for any utility is to project how DSM costs change over time. IPL's costs per bundle appear to be based on costs contained in the MPS. These costs include incremental measure costs (IMC) of installed DSM measures, which is the difference in cost of a base case measure compared to the cost of a higher efficiency alternative. Other costs that were included were incentive costs and administrative costs that cover vendor implementation costs, EM&V costs, and IPL's internal costs. The administrative costs for modeling purposes were assumed to be 20% of IMC. A measure with an IMC of $10.00 would have an administrative cost of $2.00. IPL assumed future DSM costs escalated by 2.0% annually.

2.4 Metrics for Preferred Plan Development

As noted by IPL in its previous IRPs, IPL primarily used the PVRR of scenarios to compare candidate portfolios. In the current IRP, IPL recognizes that PVRR is important but does not tell the entire story of a portfolio's outcomes. For the 2016 IRP, IPL expanded the number of quantitative metrics in addition to PVRR used to evaluate resource portfolios. IPL used metrics that fit into four categories: cost, financial risk, environmental stewardship, and resiliency. In response to stakeholder feedback, IPL added metrics to measure sulphur dioxide (SO_2) and nitrogen oxide (NO_X) emissions, the percentage of IPL's resources that is distributed generation, and IPL's planning reserves. The following table shows the four metric categories, the individual metrics, and the metric definitions.

Category	Metric	Unit	Definition
Cost	Present Value Revenue Requirements (PVRR)	$MM	The total plan cost (capital and operating) expressed as the present value of revenue requirements over the study period
	Incremental Rate Impact (over 5 years)	cents/kWh	The incremental impact to customer rates of adding new resources, shown in five year time blocks
	Average Rate Impact (over 20 years)	cents/kWh	The average 20 year cost impact of adding new resources divided by total kWh sold
Financial Risk	Risk Exposure	$	The difference between the PVRR at the 95th percentile of probability and the PVRR at 50% percentile probability (expected value)
Environmental Stewardship	Annual average CO_2 emissions	tons/year	The annual average tons of CO_2 emitted over the study period
	Annual average SO_2 emissions	tons/year	The annual average tons of SO_2 emitted over the study period
	Annual average NO_x emissions	tons/year	The annual average tons of NO_x emitted over the study period
	CO_2 intensity	tons/MWh	Total tons of CO_2 during the study period per MWh of generation during the study period
Resiliency	Planning Reserves as a percent of load forecast	%	Planning reserves are the MW of supply above peak forecast. This metric measures planning reserves as a percent of peak load forecast
	Distributed Energy Generation	%	Percent of IPL's resources that is distributed generation, shown in five year time blocks
	Market reliance energy	%	Percent of customer load met with market purchases
	Market reliance capacity	MW	Total MW of capacity purchased from MISO capacity auction to meet peak demand plus 15% reserve margin

According to the IRP, the metrics provide a comparison of how the candidate portfolios differ in terms of cost, financial risk, environmental stewardship, and resiliency. The metrics also show the trade-offs that must be considered when selecting a preferred resource portfolio.

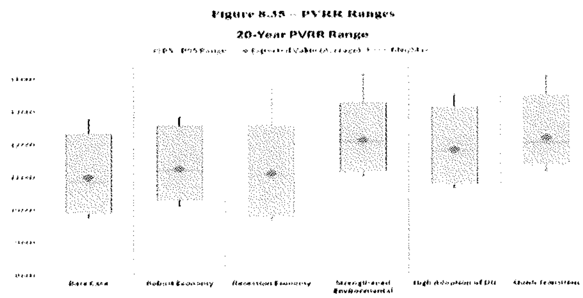
When discussing the model results, IPL introduces a metric/measure that is not mentioned in Figures 7.14 or 7.15 in the metrics development section of the IRP. IPL notes that portfolio diversity is important to mitigate risk of fuel price variation and/or potential fuel shortages. From a cost-mitigation or reliability standpoint, it may not be wise to pursue a portfolio that heavily relies on one fuel (p. 159). The value of fuel and resource diversity is pivotal in this IRP, and it is likely to be a central issue in the future IRPs – perhaps THE central issue for several years. As a result, fuel and resource diversity warrant a much more expansive narrative.

IPL also seems, at least initially, to make a distinction between the metrics used to evaluate and compare the resource portfolios listed above and the quantitative metrics used to review the stochastic analysis results, even though these latter metrics complement the other metrics. According to IPL, the stochastic analysis provides insight into how each portfolio performs against a range of futures. Each portfolio introduces risk by the nature of having varying mixes of resource types, so quantifying that risk and identifying the drivers of that risk helps guide the development of a preferred resource portfolio.

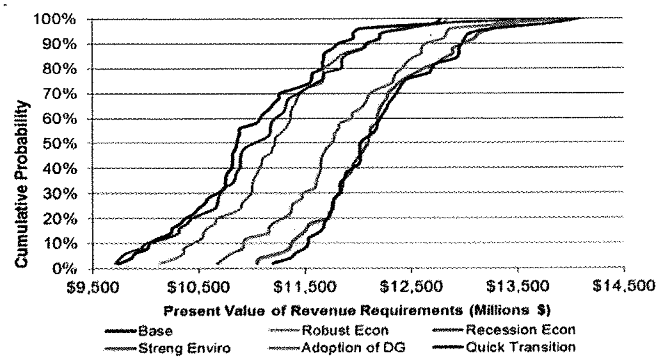
There are several useful metrics presented by IPL to review the stochastic analysis:

1. IRP Figure 8.35 (p. 184) "contains a summary of the range of PVRRs for each portfolio based on results from the stochastic model. The gray box represents the range of PVRRs between the

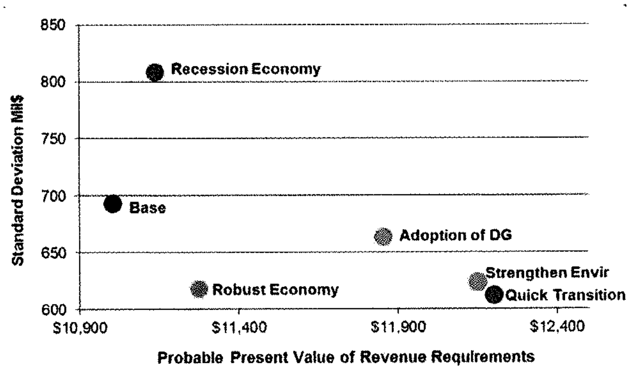
5th and 95th percentiles, which means that 90% of the PVRR outcomes fell in this range. The horizontal bar within that box is the 50th percentile or median value, and the blue diamond is the expected value or average of the outcomes. Two useful comparisons across the portfolios are the expected value and the height of the top of the 5th-95th box."



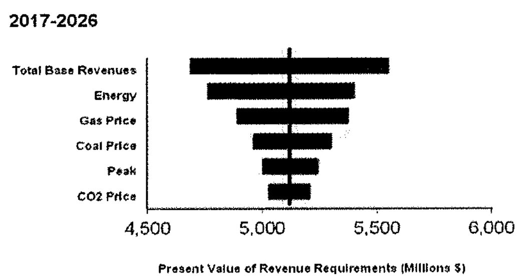
2. IRP Figure 8.36 (p.185), shown below, is a risk profile chart, or a cumulative probability chart. "The risk profile shows the distribution of PVRR outcomes from the fifty stochastic draws, showing the outcomes as the cumulative probability of each occurrence between 0% and 100%." The figure "contains the risk profiles for each portfolio, with PVRR along the X-axis and the cumulative probability on the Y-axis. For each line, the difference between the bottom left point and top right point on the line is the range which 100% of the outcomes are expected to fall." (p. 184)



3. IPL also uses a tradeoff diagram (Figure 8.37 on p.186) with the expected value of each portfolio against the standard deviation of the PVRR outcomes as another way to measure portfolio risk.



4. "An additional step IPL took was to identify the drivers of the risk by creating 'tornado charts' in 10-year periods for each portfolio. A tornado chart uses a regression analysis to measure changes in Total Base Revenues – the dependent variable – in response to changes in independent variables such as load, gas prices, coal prices, and carbon prices. The vertical line is the 'Expected Value,' and the 'Total Base Revenues' bar to the left and right of the Expected Value is the range of PVRRs for that scenario. The independent variables on the tornado chart are listed in order of their impact on the PVRR. For example, Figure 8.38 [shown below] shows that the load forecast, labeled 'energy,' has the highest impact on PVRR for the Base Case 2017-2026, and that CO_2 has the lowest impact. However, the changes to the PVRR are not cumulative through the independent variables: the sum of the independent variable horizontal bars will not equal the horizontal bars of the PVRR. Instead, the horizontal bars of the independent variables indicate the magnitude of change to the PVRR due to changes in one single variable." (p. 186)



In the Scenario Metrics Results section of the IRP report (pp. 193-206), IPL summarizes the results of eleven metrics in the four metrics categories. The metrics are further summarized in Figure 8.65 on page 206.

The stochastic analysis is used only in a limited manner in the Scenario Metrics Results section discussion. First, the Risk Profile chart for the Base Case is presented on page 196 but a better figure to use is Figure 8.36 on page 185, because information on the risk exposure of several scenario portfolios is presented in one place which makes for an easy comparison. The Director understands that the Risk Profile for the Base Case is presented to demonstrate how the difference between the expected value (the mean) and the 95th percentile probability is calculated, and that this is the metric IPL uses to evaluate the risk exposure of each portfolio in Figure 8.53 on page 197. This measure emphasizes the probability of higher costs relative to the expected value but also says nothing about the probability of lower costs. The Director believes consideration needs to be given to both the probability of both good and bad outcomes. This is the benefit of Figure 8.36 on page 185. It shows the probability of revenue requirements both above and below the expected value for each scenario portfolio and each scenario is on the same figure.

The Director believes greater use of the quantitative metrics used to evaluate the stochastic modeling results would have improved the comparison of the overall scenario metric results. The addition of the figures displaying the projected annual emissions of NOx and SO2 by scenario was a nice supplement to the metrics for the average annual SO2 and NOx emissions by scenario.

2.4.1 Portfolio Diversity

As noted above, IPL discusses a metric it calls portfolio diversity. IPL notes in the Model Results section that except for the Recession Economy and Strengthened Environmental scenarios, the scenarios result in a diverse portfolio of resources in 2036. Portfolio diversity is also explicitly presented by portfolio in several figures and discussed on pages 161-171. However, in the Scenario Metrics Results section, nothing is explicitly said about portfolio diversity. Perhaps this is because, as IPL mentioned, except for two portfolios, the remaining portfolios contain a diverse set of resources.

2.4.2 Resiliency

At the same time, one of the four metric categories used by IPL is resiliency, which they define as measuring customer exposure to price volatility and market reliance. IPL goes on to note that, "[b]y securing the required planning reserve margin requirement and limiting market reliance for capacity or energy, IPL and its customers can have a high level of resiliency." (p.202) It is clear that the concepts of portfolio diversity and resilience, as defined by IPL, are very similar but also different. It is unfortunate that IPL did not more clearly explore how each concept was interrelated. This would have added to a richer discussion of fuel and resource diversity.

IPL recognizes the risk of technological change and obsolescence in some metrics. One can argue that this is partially reflected in a couple of metrics (especially portfolio diversity) but more explicit discussion would have been helpful. IPL seems to recognize that some level of reliance on the market for both capacity and/or energy can be economic or risky but they do not seem to recognize that long-term resource acquisition embodied in both owned resources and Purchase Power Agreements (PPAs) represent their own forms of risk when all aspects of the electric utility world are changing rapidly and fundamentally.

IPL summarizes the metric results in Figure 8.65 (p. 206) as noted above but states the metrics are not meant to provide answers. Instead, they are meant to show the results in a way that will improve IPL's and stakeholders' understanding of each scenario, provide a comparison of each scenario, and allow IPL and stakeholders to ask questions and dig deeper into the results (p. 193). Despite the comments above, the Director believes the metrics developed and presented by IPL met this objective.

2.4.3 Assessment

IPL demonstrated a substantial improvement in the development and application of metrics to evaluate resource portfolios compared to the 2014 IRP. More importantly, IPL's 2016 IRP included a more explicit and extensive discussion of risks and uncertainties which were better connected to the metrics. The 2014 IRP had an emphasis on PVRR to evaluate alternative resource portfolios with minor recognition of annual air emissions of SO_2, NOx, and CO_2. The 2016 has an improved use of metrics to explore costs in various ways and includes a number of measures of resilience. The specific criticisms discussed above should not detract from the significant actions of IPL to better use more diverse metrics to evaluate resource portfolios.

2.5 Review of IPL's Comments on the Director's Draft IRP Report

The Director appreciates IPL's commitment in several areas in their comments on the Draft Director's IRP report to seek to continually improve even if IPL does not fully concur with the Director's comments in specific areas. IPL implemented numerous changes in the 2016 IRP and the Director has some understanding of the effort put forth by the IPL staff involved. The Director believes that all involved in the IRP stakeholder advisory process including IPL staff, Commission staff, and other stakeholders, are in a continual learning process. This is a strength of the IRP process and the Director appreciates the willingness of IPL to explore areas of improvement as we all learn.

What follows are responses by the Director to specific points made by IPL in their written comments on the Draft Director's IRP Report. The page numbers shown below refer to a page in IPL's comments.

2.5.1 Resource Portfolios

IPL: p. 3 - IPL suggested an alternative approach to the modeling of scenarios and stochastic analysis in response to comments in the report by the Director and the CAC et al.

The alternative put forth would incorporate stochastics into the capacity optimization upfront. So, instead of developing resource portfolios optimized over five to ten scenarios, the new optimization model being implemented by IPL can select the best portfolio across all the probabilistic simulations. IPL's new modeling system is expected to enable this type of capacity optimization modeling in addition to traditional deterministic scenarios combined with stochastic sensitivities. Some factors such as carbon pricing are difficult to capture stochastically, so IPL expects to rely on multiple methods for developing and evaluating portfolios in the next IRP.

Response: The Director is supportive of evaluating new methodologies. Obviously, however, IPL and the stakeholders will have much to learn as the new modeling system is implemented before any judgment can be rendered as to when and how the different modeling techniques can be most effectively used.

2.5.2 Demand-Side Management

IPL: P. 4 – IPL acknowledged that capturing variability in DSM cost may lead to a more robust analysis. As a follow up, IPL plans to review options to better capture DSM cost variability in the 2019 IRP. IPL went on to say, "the Director's Report was complementary of Vectren and Dr. Richard Stevie's approach in Vectren's 2016 IRP. IPL plans to contact Dr. Stevie and review his methodology."

Response: The Director encourages IPL to explore different ways to capture the range of variability inherent in DSM cost projections. However, the Director wants to be clear that stating the methodology used by Vectren is "interesting" is not intended to be an endorsement. The methodology used by Vectren is conceptually interesting but as noted in the Draft report and follow up comments (see especially the Director's response to Vectren's comments in Section 4.5.5 of this document) there is much additional analysis that must be done and there are numerous questions and issues in need of exploration. IPL is to be commended for their plans to improve the quality of data bases, including for DSM.

3. NIPSCO

3.1 NIPSCO's Fuel and Commodity Price Analysis for 2016 IRP

Given the importance of fuel forecasts in retirement decisions that are a focal point of this IRP, it is surprising that NIPSCO only relied on one projection for fuel prices. The use of a single vendor forecast made the lack of a narrative to articulate the rationale for the forecast more problematic. The fuel forecast narrative is that the price of natural gas and coal is merely a function of demand. This seems to be an over-simplistic explanation to price forecasts for coal and natural gas.

While demand for natural gas and coal are likely to be important variables since much of the "fracking" [9]is for production of oil, it would seem that the production of oil should be a variable in projecting future natural gas prices.[10] Of course, oil prices and production in the United States is likely to be influenced by world-wide events. The export (or import) of Liquefied Natural Gas (LNG) might be an important variable, not just for the quantity but as a reference point for what it tells analysts about future price formation in the natural gas markets.

In the longer-term, NIPSCO should consider technological change in the production of oil, natural gas, and coal. Anecdotally, some coal companies may offer innovative prices that may increase the dark spread. However, the crucial test will be whether short-term coal prices can be sustainable over the longer term.

The CAC et al. raised a significant concern about NIPSCO's fuel and market-price forecasting. Hopefully to address concerns about transparency, analytical rigor, and credibility, these concerns can be minimized in future IRPs by starting the stakeholder process earlier and allowing stakeholders more involvement into the data, assumptions, development of scenarios, and sensitivities. CAC et al. wrote:

> *NIPSCO did not make data developed for it by PIRA available to stakeholders, including its emissions, power, and commodity price forecasts—despite the fact that CAC and Earthjustice have executed a Non-Disclosure Agreement with NIPSCO regarding exchange of confidential information utilized by the Company in its IRP analysis... In a phone call on February 27, 2017, NIPSCO staff* ***indicated that they do possess a narrative explaining and documenting PIRA's forecasts but they could not share it with CAC and Earthjustice. NIPSCO actions in withholding this information are antithetical to transparency and meaningful stakeholder participation****.[Emphasis added] In that same*

[9] Energy Information Administration, Drilling Productivity Report-Key tight oil and shale gas regions, June 2017.

[10] Prior to the development of shale gas, crude oil and natural gas prices tended to move together as they acted as substitutes for each other for various energy demands, such as space heating, electricity generation, and industrial processes. With the development of wet gas fields, that relationship has changed. The prices follow the same general trajectories, with the exceptions of the previously mentioned natural gas price spikes, until 2009, at which point they diverge. With the more moderate oil prices in the past couple years, the positive correlation of the two prices has returned. There appear to be two competing factors affecting the relationship between natural gas and oil prices. On the demand side, they act as substitutes for each other in various processes and end uses. Thus, an increase in oil prices results in an increase in natural gas demand and a corresponding increase in natural gas price. On the supply side, they are co-products in wet gas production. High oil prices spur increased drilling activity, which results in more natural gas supply and lower natural gas prices. From the onset of the shale boom until the drop in crude oil prices, the co-production effect was more significant and the price diverged. With lower oil prices, drilling activity is reduced and the demand substitution effect is more pronounced. The combined effect has been to keep natural gas prices relatively low and stable under both high and low oil prices. SUFG's update to the November 2013 report entitled *Natural Gas Market Study.*

> *call, NIPSCO staff stated that they did not know what the price setting unit was in their Base Case MISO power price forecast.*

The Indiana Coal Council expressed similar concerns and provided information that raised other concerns that NIPSCO's analysis of coal and natural gas price projections could be enhanced.

> *The outlook for natural gas supply, which is clearly the most important consideration in NIPSCO's IRP, is without any depth or context... Without discussion of the respective supply and demand for coal and natural gas, NIPSCO did not (and could not) provide the required discussion of risks and uncertainties for these sources of fuel, as required in the Draft Proposed Rule, §§ 4(23) and (8)(c)(8). More significantly, NIPSCO claims that it does not know what PIRA's assumptions were and PIRA provided no written documents to NIPSCO in support of the forecasts. This is highly unusual. If the forecasts are the consultant's standard forecast, they would come with accompanying assumptions. If the forecasts are customized to the client's request, which is often the case, the specific assumptions would be noted..... By failing to instruct PIRA as to what assumptions should be assumed in the price forecasts, NIPSCO has no way of knowing whether the assumptions in the price forecasts are consistent with other parts of the IRP analysis. By failing to understand PIRA's assumptions vis-à-vis the price forecast, NIPSCO by definition cannot accept full responsibility for the content of the IRP because it claims no knowledge of what those assumptions are.* ICC pages 4-6 (1.11), (1.13), (1.21), (1.22), (1.23) and (1.24).

In conversations with NIPSCO staff, NIPSCO confirmed its belief that the primary driver of natural gas prices was the demand for natural gas. While this is a plausible theory, given the paradigm change in the natural gas markets, total reliance on changes in the demand for natural gas to dictate the price of natural gas seems problematic. Recent history has shown prices going down as demand for natural gas has increased, largely due to increases in oil production. For example, NIPSCO's assumption doesn't capture the nuanced and dynamic relationships between oil and natural gas markets or whether the historic correlations between natural gas and coal markets are changing. To the extent there are other possible explanations for the changing relationships between coal and natural gas prices, these other possible explanations did not influence the development of scenarios or sensitivities and, as a result, did not result in different portfolios that might have provided NIPSCO with additional valuable insights that might alter future plans.

NIPSCO's assumptions for future natural gas and coal prices led the Indiana Coal Council to observe, "[I]f the case assumed high gas prices, it also assumed high coal prices; if the case assumed low gas prices, it also assumed low coal prices. NIPSCO indicated this was the case because it used "correlated" commodity price assumptions. The term correlated was not specifically defined. Page 7 [2.2] and [2.3].

The Director agrees with the Indiana Coal Council that, "NIPSCO's use of a correlated price forecast between coal and gas prices is not explained." Page 10 [2.7].

While the Director agrees several of the comments of the Indiana Coal Council merit consideration by NIPSCO, according to NIPSCO, the ICC's concerns would not have changed the overall results of NIPSCO's IRP analysis.

The ultimate test is the economic dispatch of coal and natural gas generation in the Regional Transmission Organizations' (RTOs') markets. Over the 20-year planning horizon, NIPSCO recognized the need for *optionality* to provide an opportunity for mid-course corrections if the operations of coal-fired generation cover variable operating and fixed capital costs to permit retention and possible extension of the coal fleet. The *off ramps* that NIPSCO built in could allow for new clean coal technologies to be considered.

The importance of credible fuel price projections become increasingly important because future retirement decisions are likely to be increasingly close calls. Prudence dictates that credible and transparent analysis is essential for assessing reliability and cost ramifications.

3.2 Scenario and Risk Analysis

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. The transparency throughout the IRP process afforded to stakeholders was exceptional. NIPSCO provided information that other utilities have not provided. We applaud this openness. To NIPSCO's credit, they were sensitive to the ramifications of these decisions on its employees, communities, and customers.

Resource optimization modeling included a reasonable amount of supply-side and demand-side options; portfolios associated with three planning strategies focusing on least cost, renewable and low carbon emissions, respectively, were identified for each scenario and sensitivity. Especially given what NIPSCO and others knew at the time the analysis was conducted about fuel cost projections and public policy, the analysis was credible. Results were presented in an informative way. However, like other utilities, NIPSCO performed much of the retirement analysis prior to the resource optimization. NIPSCO recognized the modeling limitations and said it intends to procure modeling software that is better able to simultaneously optimize more resources and reduce the reliance on pre-processing important decisions. NIPSCO contended that its Preferred Portfolio "*aligned with NIPSCO's reliability, compliance, diversity, and flexibility criteria; it almost always had lower costs to customers across the scenarios.*" [Page 159].

3.2.1 Models, Drivers, and Scenarios

NIPSCO used the ANN Strategist Proview Capacity Expansion Model to perform the optimization on three portfolios including a least cost portfolio, a renewable portfolio, and a low emissions portfolio (Page 32 of the IRP). The resource alternatives included in this IRP cover 26 demand-side and about 20 supply-side options. Each resource option was individually and fully selectable during each optimization run. The objective of the model is to minimize the Net Present Value of Revenue Requirements (NPVRR).

The first step NIPSCO used in developing the 2016 IRP scenarios was to identify key drivers that could potentially affect its business environment. Then seven long-term commodity pricing cases were developed for the Strategist planning model, taking into consideration the correlations between economic condition, load growth, environmental policy, fuel prices and carbon cost. Those fundamental commodity prices serve as key assumptions for various scenarios in the analysis.

Five scenarios were developed by NIPSCO using different datasets that correspond to specific future worlds. The five scenarios were:

1. Base (B),
2. Challenged Economy (CE),
3. Aggressive Environmental Regulation (AE),
4. Booming Economy (BE), and
5. Base Delayed Carbon (BDC).

Then, a number of sensitivities were developed for each scenario by modifying a single variable each time to analyze the effects of a specific risk on the corresponding scenario. Although each sensitivity focused on a single risk, other related input data were changed accordingly. There were 10 sensitivities in total. In general, NIPSCO did a good job of setting up a comprehensive framework to capture possible futures and address various risk factors. However, there are some inconsistencies in the IRP report regarding the definition of scenarios, which are addressed in detail in the next section.

A separate retirement analysis was conducted before system-wide optimization was performed to identify the future resource mix. Based on the environmental compliance dates and the associated costs to run the existing coal-fired generation units, six retirement portfolios were developed. A combined cycle gas turbine (CCGT) was selected as a proxy for the replacement alternative because of its favorable levelized cost of energy, reliability, dispatchability, and straightforwardness to plan, permit and build. The six retirement portfolios were evaluated across all scenarios and sensitivities and were ranked based on the NPVRR. In addition, the ability of each portfolio to meet Clean Power Plan Compliance Targets, fuel and technology diversity, as well as community impact were considered during portfolio evaluation. A retirement portfolio without any significant difficulties or hurdles for each one of the evaluated criteria was selected as the preferred retirement option. Based on the retirement analysis, NIPSCO's preferred retirement plan is to accelerate the retirement of Bailly Units 7 and 8 and Schahfer Units 17 and 18 and to move forward with compliance investments for its remaining coal units. The entire retirement methodology sounds reasonable. However, some explanations of retirement portfolio design might be necessary to help audiences understand why some older units were set to run to the end of life but some younger units were set to retire soon in a few retirement portfolios to be evaluated. In the seventh page of the Executive Summary, a table lists ages of various coal units owned by NIPSCO. Based on ages shown in the table, Schahfer 17 and 18 are younger than Schahfer 14 and 15. In addition, all Schahfer units are younger than Michigan City. However, for Combination 4 displayed in Table 8-3, which was also the combination chosen as the preferred retirement option after evaluation, Schahfer 17 and 18 were set to retire in 2023, while Schahfer 14 and 15 are set to run to the end of life. In Combination 5, Michigan City was set to run to the end of life, while all Schahfer units were set to retire in 2023.

Results were presented in a clear and logical way. For each scenario, capacity portfolios under the three planning strategies (Least Cost, Renewable Focus and Low Emission) were identified. Numbers of selected resources were listed by technology for each portfolio. Trajectories of annual carbon emissions were depicted by portfolio as well. In addition, energy mixes by planning strategy and scenario were summarized and compared with each other. Summary of NPVRR and DSM selection across the various scenarios and sensitives were provided. A preferred portfolio for the next 20 years was derived from analysis results based on a number of criteria, including providing affordable, flexible, diverse and reliable power to customers while considering the impact to environment, employment and the local economy. In addition, DSM groupings were broken into four categories according to the time of selection across various scenarios and sensitives, providing the basis upon which NIPSCO's 2017 DSM Plan would be determined.

3.2.2 Issues / Questions

In section 8.1.2 titled Fundamental Commodity Prices, descriptions about various commodity cases make sense but seemed to be too simplistic. As discussed in the Fuel and Commodity Price Projections section (e.g., page 15) of this Draft Director's Report, the drivers for the production and price of natural gas and coal seems likely to be more complex than simply the demand for natural gas and coal. However, figures illustrating the long-term projections of the major commodities lacked explanations, which detracted from the explanatory value of the descriptions. The following are some examples.

1. For coal prices in Figure 8-4 on p. 118 and Figure 8-5 on p. 119, the Very High case has a price decrease in the 2022 to 2024 timeframe. Explanations about the driving forces for those outcomes are not obvious and would benefit from a discussion.
2. In Figures 8-7 and 8-8 on p. 120, the on-peak and off-peak power prices show step increases in 2024 in the Base, Low and High cases. As described in scenarios, the carbon price comes into effect in 2023. Why were sudden increases in power prices observed in 2024?
3. Figure 8-9 on p. 121 shows capacity price in $/kW-YR. The specific resource technology is not clear. Is it average capacity price across different technologies? How do capacity price projections shown in the graph correlate with the various commodity pricing cases? A detailed description might need to be added to the report to help the audiences understand the information presented in the graph.

In addition, there seem to be inconsistencies in the description of scenarios presented in different sections of the report.

1. In the Base Scenario Assumptions shown in p. 122, the report mentions that "The average price of Powder River Basin coal is slightly above $1.00/MMbtu by 2035." However, in the coal price trajectories shown in Figure 8-4 in p. 118, no trajectory matches this description. The one closest would be the Base coal price trajectory, but coal price in that trajectory is no more than $1.00/MMbtu in 2035 based on observation. In addition, assumptions about Powder River basin coal price and Illinois Basin coal price were not presented in Table 8-1: Scenarios and Sensitives Variable Descriptions on p. 130. Therefore, there is no way to know exactly which coal price assumption was used for various scenarios and sensitivities.
2. In the Challenged Economy Scenario Assumptions shown on p. 123, it is less clear which Powder River Basin coal trajectory was used in this scenario. In addition, the carbon price increase in 2023 mentioned in the description does not seem to be consistent with the information presented in Figure 8-7 and Figure 8-8.
3. In the Aggressive Environmental Regulation Scenario Assumptions shown on p. 124, the report mentions that "Energy load is increasing at 0.68% and peak demand is increasing at 0.80% (CAGR 2016-2037) annually over the study period." This same load assumption is shown in the Booming Economy Scenario Assumptions at the bottom of p. 124. However, in Table 8-1: Scenarios and Sensitivities Variable Descriptions, "Base Load" is shown for the Aggressive Environmental Regulation Scenario and "High Load" is shown for the Booming Economy Scenario in NIPSCO's explanation.
4. In the Booming Economy Scenario Assumptions shown in the beginning of p. 125, the report mentions that "A national carbon price comes into effect in 2023 ($13.50/ton nominal increasing to $38/ton in 2035)." Table 8-1 on p. 130 shows Base carbon price trajectory for this scenario. However, in Figure 8-6: CO_2 prices shown on p. 119, no trajectory matches the description about carbon prices in the Booming Economy Scenario on p. 125.

There are also some concerns about the DSM modeling mentioned on p. 142. As NIPSCO recognized, due to the inability of Strategist to optimize all 26 DSM groups simultaneously, the demand-side programs were broken down into the various end uses (residential, commercial and industrial) and optimized against an array of supply-side options. One shortcoming of this modeling methodology is a lack of competition among DSM groups of different end-uses, which is highly likely to lead to a portfolio different from modeling all 26 DSM groups simultaneously. Moreover, with the increase in peak demand relative to energy use, it would seem there are opportunities for more demand response that were not modeled. In part, the failure to more comprehensively optimize DSM and to optimize DSM with other resources seems to be a limitation of its current model and should be ameliorated by future models.

In Figure 8-31 on p. 159 the NPVRR for the preferred portfolio appears to be slightly smaller than the NPVRR for the least cost optimal solution, which is not feasible.

Finally, it seems that no scenario or sensitivity covered uncertainties of resource technology cost. Based on information provided at the August stakeholder workshop, capital costs for all technologies increase in nominal dollars at the same rate, based on proprietary consultant information. The reasonability of this is questionable considering that some technologies are less mature commercially (e.g., battery storage) than others.

The Director largely agrees with NIPSCO and its characterization of concerns raised by stakeholders regarding NIPSCO's consideration of retirements of some coal-fired generating units, the dynamics of the natural gas price projections being the primary driver, and NIPSCO's use of Cost of New Entry (CONE) merely as a proxy for the cost of new resources (see below quote).[11] However, the Director is confident that NIPSCO would agree with stakeholders that future IRPs will have to be increasingly rigorous as credible decisions are increasingly difficult and impactful.

> *The Industrial Group and ICC argued that NIPSCO was too aggressive in retiring the four units, while other stakeholders argued that NIPSCO should retire 100% of its coal fired generation almost immediately. NIPSCO endeavors to ensure that a reliable, compliant, flexible, diverse and affordable supply is available to meet customer needs, and its IRP demonstrates that it does just that. In the retirement analysis, the costs and benefits of continuing to operate the NIPSCO units, including the dispatch costs, recovery, maintenance, retrofitting and continuing to operate the affected units with the appropriate effluent limitation guidelines ("ELG") and coal combustion residuals ("CCR") compliance technologies were compared to costs and benefits of retiring and replacing the units with an alternative. The alternative, CONE, was used for retirement analysis only and was not NIPSCO's selection, but intended to be a conservative proxy for what could be readily built or purchased in the market. This analysis was evaluated across the 15 scenarios and sensitivities discussed with all the stakeholders throughout NIPSCO's 2016 IRP process.*
>
> *While cost to customers is a key decision driver, the decision to retire the four units took into account a variety of factors in addition to customer economics, which caused it to be a "preferred" choice for customers from the Company's standpoint. It is important to highlight that the model showed a lowest cost path of retiring 100% of coal which was not selected as the "preferred" path given these other factors.*
>
> *Even with ICC's comments regarding coal availability and pricing, the analysis would not change dramatically regarding the appropriateness to retire Units 7/8 and 17/18. There must be a balance among continued investment in operations and maintenance ("O&M"), maintenance capital, and maintaining the option to keep Units 17/18 open. However, key*

[11] Response Comments of Northern Indiana Public Service Company to Stakeholder Comments on NIPSCO's 2016 Integrated Resource Plan submitted April 28, 2017, pages 8 and 9.

variables such as environmental regulations can change over time and therefore NIPSCO will evaluate the value of developing a compliance option at Units 17/18 as part of its next IRP. It is important to remember that fuel and technology diversity is important as over-reliance on a single fuel-source may leave a utility and its customers unnecessarily exposed to various operational and financial risks from fuel supply disruptions and/or price volatility. Fuel and technology was quantified by the capacity mix by the end of the planning period.

Despite claims to the contrary, NIPSCO considered long-term gas forecasts in its retirement modeling, but NIPSCO's believes gas prices would need to rise dramatically and stay at a sustained high price to make it economical to continue to operate the units proposed for retirement. This, coupled with the correlated coal forecast, indicates that NIPSCO's Retirement Analysis is appropriate.

Additionally, there were concerns that NIPSCO's retirement path did not consider potential future changes to the ELG. NIPSCO believes that United States Environmental Protection Agency's ("EPA's") ELG rule is consistent with the requirements under the Clean Water Act. The ELG rule is a final rule, and NIPSCO has a responsibility to include it in future resource planning. Although it is possible that there may be changes to the rule which could affect compliance requirements, any changes would be speculative at this time.[12] If changes to the final ELG rule are propagated, NIPSCO will include and consider any changes in future resource planning.

Although the IRP is not required to consider factors such as whether or not NIPSCO attempted to sell units it is planning to retire, it does consider if the utility can meet its resource requirements. NIPSCO's IRP meets that standard. In addition, NIPSCO has done an assessment of the market value of the retiring units, and contrary to the ICC's assertions, NIPSCO has been willing to engage with parties interested in purchasing the retiring units.

3.3 Energy Efficiency

It should be noted that NIPSCO's DSM methodology is very similar to that used by IPL. In fact, they both used the same consultants – AEG to prepare a Market Potential Study (MPS) and Morgan Marketing Partners (MMP) to develop the Program Potential based on the MPS and to complete the overall benefit cost results based on the program potential as determined by the MPS.[13]

AEG estimated the technical, economic, and achievable potential at the measure level for energy efficiency and demand response within NIPSCO's service territory over the 2016 to 2036 planning horizon. MMP

[12] NIPSCO recognizes that the U.S. EPA Administrator announced on April 17, 2017, that the EPA issued an administrative stay of outstanding compliance deadlines for ELG and was also petitioning the U.S. Court of Appeals for the 5th Circuit to hold litigation challenging the final ELG rule in abeyance until September 12, 2017. The 2016 IRP was a point-in-time forecast completed in November 2016. Any impacts from the EPA's actions will be addressed in the next IRP.

[13] A MPS assesses how much DSM (energy efficiency and demand response) is potentially achievable in a utility system. A MPS is normally used to estimate the level of Technical Potential, Economic Potential, and Achievable Potential. Technical Potential is the maximum energy efficiency available, assuming that cost and market adoption of technologies are not a barrier. Economic Potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. Achievable Potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences.

used the measure-level savings estimates to develop the program potential. The program potential includes budget and impact estimates for the measures. The final budgets and impacts were then run through cost-effectiveness modeling using the DSMore tool to finalize the cost-effective program savings potential. The program potential step also includes information from NIPSCO's 2014 Evaluation, Measurement, and Verification (EM&V) report and applies that information to the Achievable Potential savings amount.

After the savings potential estimation process, the measures were bundled into DSM groupings. A grouping is defined as a bundle of measures with similar load shapes and end uses. Grouping measures by similar load shapes, end-uses, and customer segment (class) allows the IRP model to analyze large groups of measures more efficiently. NIPSCO elected not to further define its groupings by costs per kWh.

Due to a limit on the number of resource options that can be optimized simultaneously in the IRP model, the DSM program groupings were modeled sequentially by customer class (residential, commercial, and industrial). NIPSCO believes the sequentially optimization is comparable to a simultaneous co-optimization of all DSM programs.

3.3.1 Issues / Questions

NIPSCO made a number of improvements to its DSM analysis and the written description of this analysis in the IRP, and the information presented at the public advisory meetings was a very good improvement over prior IRPs. Nevertheless, improvement is an ongoing process as we all learn through experience. For example, NIPSCO also faced model limitations similar to that experienced by IPL and Vectren but chose a different work around. NIPSCO modeled DSM bundles sequentially; meaning that first residential bundles were optimized compared to supply-side resource options, then commercial sector bundles were optimized compared to supply-side options, and lastly industrial DSM options were optimized. Then NIPSCO generally put in the optimization model those residential, commercial, and industrial bundles that were selected in the sequential optimization. It is not clear if the selected combination of residential, commercial, and industrial DSM was locked in as a package in the optimization process or not. If the combined DSM groupings were locked in for the final supply-side optimization, then it could imply that the DSM groupings are not getting quite the same treatment as the supply side resources which are all included together in each scenario run.

NIPSCO discusses program grouping and portfolio budgets but it is not clear if its methodology for development of bundle costs differs much from that used by IPL. NIPSCO developed bundle costs in line with historic program cost allocations across the different budget categories. Each program grouping or bundle budget included categories for administration, implementation, incentives, and other. Administrative costs include NIPSCO staffing costs, planning and consulting costs, and EM&V costs. The "Other" category includes items such as low income measures which are paid by the utility but not classified as an incentive according to the California Standard Practice Manual. "Other" also includes some additional implementation costs for measures with very low incremental costs to include them in the portfolio. However, it is not clear how DSM bundle costs changed over time.

3.4 Metrics for Preferred Plan Development

NIPSCO's stated intent (p.3) is to develop a Preferred Plan that "follows a diverse and flexible supply strategy, with a mix of market purchases and different low fixed-cost generation types, to provide the best balanced mitigation against customer, technology and market risks." NIPSCO sees customer risk from the large concentration of load from its five largest customers. Approximately 40% of NIPSCO's energy demand and approximately 1,200 MW of peak load plus reserves meets the needs of these five customers. Loss of one or more of these customers would result in a significant decline in billing revenues.

NIPSCO defines technology risk as two separate risks from the perspective of a regulated utility.

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

...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. (p. 4)

NIPSCO continues by stating (p. 154) an important component of its supply strategy for the next 20 years is to reduce customer's and the company's exposure to customer load, market, and technology risks by intentionally allocating a portion of the portfolio to shorter duration supply. Another component is to strongly consider cost to customers, while considering all technologies and fuels as viable to provide shorter duration supply. (p. 155)

3.4.1 Retirement Analysis Metrics

NIPSCO's use of metrics to develop its Preferred Plan is applied to two different stages during the planning process, at the retirement planning stage and the optimization stage. The metrics appear to be the same across the two stages. For the retirement analysis, the six retirement portfolios were evaluated across all scenarios and sensitivities for a total of 90 optimization runs. Each model run was limited to the selection of a combined cycle gas turbine (CCGT) as a proxy. In all comparison analyses, the costs of the replacement unit was scaled on a megawatt basis to the same generating capacity as the existing unit by using a replacement capacity value of the CCGT.

Results for the six retirement scenarios were ranked from 1 to 6 with 1 being the portfolio having the lowest cost to customers or net present value of revenue requirement (NPVRR) and 6 having the highest. Figure 8-16 on page 137 of NIPSCO's IRP shows the NPVRR of the base scenario overlaid with range of NPVRR from all the scenarios and sensitivities. NIPSCO noted the magnitude of NPVRR changes depending on the specific scenario or sensitivity but the relative rankings of the retirement combinations generally remain the same within each scenario or sensitivity.

Retirement options under the Base scenario were analyzed to estimate their potential to meet Clean Power Plan compliance targets as shown in Figure 8-17 on page 138. Three of the six retirement combinations did not meet the CPP targets. Each retirement combination under the Base Scenario was also analyzed to show the diversity of each retirement combination. Portfolio diversity was measured as a percentage of forecast installed capacity in 2025. For example, a retirement combination portfolio might consist of 36% coal, 21% natural gas, 14% DSM, 3% renewables, and 26% other resources. Lastly, NIPSCO created a scorecard to show relative differences between the retirement portfolios using a number of quantitative and qualitative measures. The measures are NPVRR, Portfolio Diversity, Impact on Employees, Impact on

Communities and Local Economy, and Environmental Compliance. The scorecard used red, green, or yellow to show how each retirement combination was graded on each of the five measures. A red measure is viewed as worse, a yellow is better, and a green measure is viewed as good.

While recognizing that developing a "score card" to assess the relative importance of different metrics is a relatively new approach in the IRPs, it is not clear how the different measures are weighted in the score card. The score card would benefit from a more detailed narrative to detail those metrics that can be quantified as well as those metrics that do not lend themselves to quantification. For example, is NPVRR more important than the impact on the local economy? If yes, by how much and why? Also, the measure of portfolio diversity is based on installed capacity but might not a better measure be energy? At a minimum, the percentage of energy by fuel type and technology should have been considered. Also, the diversity consideration is limited since a significant resource "need" is shown in five of the retirement combinations but it is unspecified as to the type of resource. The way the retirement analyses were performed, CCGT capacity served as a proxy for other resources the model might have selected if given the opportunity. As noted by the CAC et al., the presentation of a retirement combination scorecard (p. 140 NIPSCO IRP) is qualitative and something of a *black box*. (p. 46 CAC comments on NIPSCO IRP)

3.4.2 Optimization Metrics

In the resource optimization modeling, NIPSCO broke down the DSM resources into residential, commercial, and industrial groups and sequentially modeled each group against an array of supply-side resources. This process was repeated for all 15 scenarios and sensitivities. NIPSCO developed a DSM plan based on these modeling results which was then used to evaluate the supply-side resources. NIPSCO utilized three planning strategies/portfolios, namely least cost, renewable focus, and low emissions portfolios across all scenarios and sensitivities. For the least-cost portfolio the model assessed all supply-side alternatives to develop a least cost plan. The model assessed a renewable focus portfolio by constraining the amount of fossil generation and increasing the amount of renewables. A low emissions portfolio was evaluated where the incremental amount of fossil generation and renewables was constrained to allow other low or non-emitting resources such as nuclear and batteries to be selected.

For each scenario the number of selected resources for each of the three strategies was listed by technology in tables. The trajectory of annual carbon emissions by scenario for each of the three strategies was compared. The cumulative 2015 to 2037 energy mix was also compared by scenario for each strategy. Lastly, the NPVRR by scenario and sensitivities was compared for each of the three portfolios.

NIPSCO notes on page 158 of its plan that it used a number of criteria to evaluate and select its Preferred Plan and that economics played a significant role. However, as noted by the CAC et al., it is not at all clear where the Preferred Plan came from or how it was determined. Nor is it clear how the various metrics were used. All that we can tell is that NIPSCO says it emphasized economics and that it used information provided by other metrics; but we can say little more. It is a problem when NIPSCO develops a Preferred Plan but the connection between this plan and the preceding analyses is murky at best. This should be addressed in the narrative.

Information is poorly presented regarding the components of the Preferred Portfolio such that a reader can read the entire IRP and not have a clear picture of the Preferred Portfolio. For example, Table 8-21 (p. 158) presents the assets retired and added by year over the forecast period. But there are no units of measure to tell the reader, for example, how much DSM is acquired in 2023. The same criticism can be made with regard to purchases. The lack of basic information about the Preferred Plan, combined with the poor discussion relating the Preferred Plan to the IRP's analyses and metrics, makes any evaluation of the Preferred Portfolio problematic at best. Overall, the IRP would have benefited from having one location where each metric was defined and was clearly stated how these metrics, individually or as a group, addressed the three key risks identified by NIPSCO – customer, technology and market risks. The narratives for each of the metrics need to clearly tie back to the important risks on which presumably the company based its IRP.

It is important to note that NIPSCO's planning model is not capable of stochastic analyses so it relied on scenario analyses and sensitivity analyses in preparing its IRP. The result was that NIPSCO's IRP analyses and methodology differed considerably from that presented by Vectren and IPL, both of whom did perform a stochastic analysis in addition to scenario analyses. To be clear, the Director believes stochastic analyses is not a substitute for scenario analyses; rather, they are complements that provide different information which can be combined to hopefully make better resource decisions. The result is that NIPSCO's metrics to compare resource portfolios necessarily differed in several ways from the type of metrics utilized by IPL and Vectren. NIPSCO recognizes this modeling limitation and, to its credit, is in the process of evaluating options to improve its modeling capability.

3.4.3 Assessment

The circumstances NIPSCO encountered developing the 2016 IRP differed considerably from those for the 2014 IRP. As a result, NIPSCO had a much more thorough discussion of risks and uncertainties and various metrics used to evaluate how the different resource portfolios might perform given the future is unknown. The previous IRP had almost exclusive reliance on PVRR to compare the portfolios. That is not to say there was no recognition of other factors, but the discussion of these other factors was much less developed. NIPSCO explicitly included in the 2016 IRP metrics covering portfolio performance in the areas of portfolio diversity, impact on employees, impact on communities and the local economy, and environmental compliance. The various questions or issues discussed above are not meant to detract from the substantial improvement seen when comparing the 2014 and 2016 IRPs.

3.5 Review of NIPSCO's Comments on the Director's Draft IRP Report

The Director appreciates NIPSCO's commitment in several areas in their comments on the Draft Director's IRP report to seek to continually improve even if NIPSCO does not fully concur with the Director's comments in specific areas. NIPSCO implemented numerous changes in the 2016 IRP and the Director has some understanding of the effort put forth by the NIPSCO staff involved. The Director believes that all involved in the IRP stakeholder advisory process including NIPSCO staff, Commission staff, and other stakeholders, are in a continual learning process. This is a strength of the IRP process and the Director appreciates the willingness of NIPSCO to explore areas of improvement as we all learn.

What follows are responses by the Director to specific points made by NIPSCO in their written comments on the Draft Director's IRP Report. The page numbers shown below refer to a page in NIPSCO's comments.

3.5.1 Demand-Side Management

NIPSCO: P. 7 – Although NIPSCO did sequentially optimize the residential, commercial, and industrial groupings, there were two follow up steps to ensure that it was equivalent to optimizing the whole 26 groupings simultaneously.

Response: NIPSCO's comments do not say what these two follow up steps were nor where they are described if not in these comments.

NIPSCO: NIPSCO is unclear what additional DR programs it could have modeled outside of the AC and water heating programs. Two programs, Curtailment and Interruptible, were not considered in the DSM Groupings, but were included in the IRP, in accordance with the Order in Cause No. 44688. Provided as a whole, this provides a robust amount of DR, but NIPSCO will continue to research additional programs to be considered in future IRP models.

Response: The Director agrees that NIPSCO appears to have done a reasonably thorough review of DR programs but believes it would have been helpful for NIPSCO to have included the Industrial Demand Response DSM Groupings in the IRP. The Director understands the results coming out of the IRP optimization process might have been very different compared to the amount of curtailment and interruptible load agreed to in Cause No. 44688. But any difference and the effort to understand the reason for the difference would have been informative.

3.5.2 Scorecards

NIPSCO: P. 4 –The concept of a scorecard was a significant step towards a more robust decision making process for its customers, employees and stakeholders. As with the introduction of most new concepts, there is progress but also clear opportunities for improvement. In the future, NIPSCO will consider and incorporate appropriate feedback into the scorecard process.

Response: Staff appreciates the willingness of NIPSCO to evaluate opportunities for improvement. Staff agrees there is no one correct way to use or interpret metrics and develop a scorecard. Ideally, objective metrics would be decided at the outset of the IRP process and in consultation with stakeholders to reduce controversy. To the extent reasonably feasible, efforts to quantify the metrics should be considered while recognizing that some measures will be, to varying extents, more subjective.

4. VECTREN

4.1. Vectren's Fuel and Commodity Price Analysis for 2016 IRP

Vectren's consideration of multiple fuel price forecasts is very commendable and appropriate given the importance of the decisions that Vectren faces. On Page 74, Vectren said it relied on an averaging of forecasts from several sources[14] to form a consensus forecast for natural gas, coal, and carbon. This single averaged forecast for all commodities constituted the base forecast. Vectren also constructed alternative commodity price forecasts that were phased in relative to the base forecast. So near-term, a natural gas price was limited to a fairly small deviation from the base forecast, and the difference could grow in the medium-term and more so in the long-term.

We understand Vectren considered averaging of higher and lower forecasts but felt that was problematic due to different assumptions and different planning horizons. We will defer to Vectren's professional judgment but hope future IRPs will make use of lower and higher forecasts to provide a more complete scenario analysis. On p. 194 of its IRP report, Vectren describes how stochastic distributions of each of the key variables were developed, with select values that are either one standard deviation above or below the base case values for the variable.

The Director agrees with Vectren that the phasing in of an increasing range of commodity forecasts is appropriate going from the short-, to mid-, and to longer-term projections to capture most expected risks. However, to better understand the risks there is concern that reliance on just one standard deviation that only captures approximately 68% of the expected variation around the mean (expected value) is more appropriate for short-term fuel price forecasts, while for forecasts beyond five years (or so), a wider range of forecasts is appropriate. Two standard deviations to capture about 95% of the expected variation around the mean would seem more appropriate to gain insights on the potential risks of low probability events that are very consequential. As Vectren aptly describes "*stochastic distributions that reflect a combination of historical data and informed judgment tend to capture 'black swan events' that are impossible to forecast but tend to occur quite frequently.*" [Page 194].

Consistent with the previous comment, the Director agrees with the ICC that a higher natural gas price case might have provided useful information. A narrative that is based on widespread anti-fracking policies might provide a plausible, even if unlikely case (note, in Vectren's "High Regulatory" scenario there was at least some reduction in gas supply growth and increased cost due to restrictions on fracking – Page 183). That is, a broad fracking ban is a low probability event that could result in significant price increases for natural gas if realized. Similarly, with new oil and gas assessments upgraded by the U.S. Geological Survey in the Permian Basin just after Vectren submitted its IRP, a lower natural gas price case might also be warranted. However, given Vectren's considerable expertise in natural gas by virtue of being a combination utility, some deference is reasonably accorded.

The Director appreciates the ICC's review of Vectren's IRP but disagrees that "*Vectren's failure to include scenarios without the CPPs (Clean Power Plan) is a serious flaw of its analysis.*" The ICC would seem to hold Vectren to an untenably high requirement to integrate new information rather than the intention of the IRP to be a *snap shot in time* based on reasonable assumptions and empirical information at the time the

[14] For natural gas and coal, 2016 spring forecasts from Ventyx, Wood Mackenzie, EVA, and PIRA are averaged. For carbon, forecasts from Pace Global, PIRA, and Wood Mackenzie were averaged.

IRP was being developed. While speculation about changes in environmental policies are interesting, the still-unfolding changes in environmental policy are well outside the snap shot in time that Vectren was required to comply with by the draft IRP Rule. This is why the IRPs are done periodically to capture established and emerging trends.

Similarly, because the modeling process takes place over several weeks – perhaps months - the Director would not require Vectren to reconsider projections of natural gas prices based on the U.S. Geological Survey's news release on November 16, 2016 of a massive natural gas potential in the Permian Basin[15] which was before Vectren submitted their IRP which might further reduce the use of coal. Moreover, the ICC noted that the start of Vectren's analysis of the potential ramifications of the CPP didn't occur until the 2021 to 2026 time frame. In the Director's opinion, it was appropriate for Vectren to give some effect to the CPP based on the best information available at the time it was conducting its analysis. Additionally, it is conceivable that some form of CO_2 regulation may occur in the 2021 to 2026 time frame. Regardless of the specific facts that the ICC raised, it is important to memorialize the chronology of events to ensure that Vectren's planning processes were not misconstrued to be deficient regarding the information used in its IRP analysis.

More broadly, the ICC raises an issue that is applicable to all Indiana utilities – specifically, under what conditions should a utility update an IRP in response to significant events or changes in assumptions to important drivers? Nevertheless, it is important to keep in mind the Northwest Power Planning Council principle for its planning process that there are "no facts about the future."

4.2 Scenario and Risk Analysis

Vectren's analysis and processes improved significantly over its last IRP due to the immediacy of some decisions as well as providing for flexibility in making significant longer-term decisions over the next 10 to 20 years. The context for this round of IRPs included concerns about the potential loss of significant customers, largely unforeseen changes in the Clean Power Plan, low natural gas price forecasts relative to coal prices, and a precipitous drop in the price of renewable resources, highlight the need to regard IRPs—as Vectren observed—as a *compass* rather than a commitment to a specific resource strategy. Therefore, as Vectren correctly noted, the IRPs must be resilient to allow for mid-course adjustments in the plan. On page 50 and 51, Vectren articulates its integrated resource planning objectives:

- Maintain reliability
- Minimize rate/cost to customers

[15] November 16, 2016 **USGS Estimates 20 Billion Barrels of Oil in Texas' Wolfcamp Shale Formation.** This is the largest estimate of continuous oil that USGS has ever assessed in the United States. The Wolfcamp shale in the Midland Basin portion of Texas' Permian Basin province contains an estimated mean **of** 20 billion barrels of oil, **16 trillion cubic feet of associated natural gas,** and 1.6 billion barrels of natural gas liquids. The estimate of continuous oil in the Midland Basin Wolfcamp shale assessment is nearly three times larger than that of the 2013 USGS Bakken-Three Forks resource assessment, making this the largest estimated continuous oil accumulation that USGS has assessed in the United States to date."*The fact that this is the largest assessment of continuous oil we have ever done just goes to show that, even in areas that have produced billions of barrels of oil, there is still the potential to find billions more*," said Walter Guidroz, program coordinator for the USGS Energy Resources Program. "*Changes in technology and industry practices can have significant effects on what resources are technically recoverable, and that's why we continue to perform resource assessments throughout the United States and the world.*"[Emphasis Added].

- Mitigate risk to Vectren customers and shareholders
- Provide environmentally acceptable power leading to a lower carbon future
- Include a balanced mix of energy resources
- Minimize negative economic impact to the communities that Vectren serves

The changing environmental regulations warrant emphasis, not only because of the potential effects on the utility's resource decisions, but also because they highlight an inherent difficulty in developing public policy assumptions in IRP modeling. That is, what is the probability of changes in public policy? The question highlights the need to interject more diverse scenario analysis into the IRP process since scenarios and sensitivities are more suitable for addressing the possible ramifications of changes in public policy. Moreover, it adds to the rationale for maintaining maximum optionality. As Vectren stated:

> *While future carbon regulations are less certain than prior to the election, it is likely that new administrations will continue to pursue a long term lower carbon future. SIGECO's preferred portfolio positions the company to meet that expectation. (p. 47)*
>
> *Several developments have occurred since the last IRP was submitted in 2014, which helps to illustrate the dynamic nature of integrated resource planning. The IRP analysis and subsequent write up represent the best available information for a point in time. The following sections discuss some of the major changes that have occurred over the last two years. The robust risk analysis recognizes that conditions will change. Changes over the last few years provided SIGECO with valuable insight on how modeled scenario outcomes can change over time. (p. 52)*

In the Preferred Portfolio (beginning on page 33 see also page 44), Vectren mentions greater reliance on energy efficiency, the possible addition of a combined cycle gas turbine in 2024, and solar power plants (2018 and 2019). Vectren's Preferred Portfolio also contemplates the potential retirement of Bags natural gas unit 1 (in 2018) and unit 2 (2025), Northeast Units 1 and 2 (natural gas) in 2019, Brown coal-fired units 1 and 2 (2024), FB Culley Unit 2 (2024), exiting joint operations at Warrick 4 (2020), and upgrade at Culley 3 for compliance with National Effluent Limitation Guidelines (ELG) and Coal Combustion Residuals (CCR). Vectren noted the ELG/CCR, which it characterized as the main drivers of closing Vectren coal plants, will be much more difficult to change than the Clean Power Plan (CPP). However, this potential Preferred Plan would significantly reduce Vectren's reliance on coal and result in a significant reduction in CO_2 emissions.

Similarly, Vectren's request for a short delay in the submittal of its IRP in order to better understand the potential implications of ALCOA's decisions is an example of good planning practice, especially given the importance of ALCOA to the Vectren system. To accentuate the importance of ALCOA, Vectren noted on page 203 that "*Under all scenarios, additional resources were not selected until joint operations cease at Warrick 4, causing a planning reserve margin shortfall.*" However, given the importance of Warrick to Vectren's resource adequacy and since Vectren did not know the status of ALCOA at the time the IRP was prepared, it would seem reasonable for Vectren to have run at least one scenario that retained the Warrick 4 unit.

The narratives for the scenarios were well reasoned and clear. For the 2016-2017 IRP, Vectren developed its Base Case (not the Preferred Case) predicated on what Vectren considered to be the most likely future at the time this IRP was being developed. This included pre-processing analysis of the retirement of some of their coal-fired generating units to reduce the complexity of the modeling analysis. Vectren also segmented its analysis of all scenarios into short-, medium-, and longer-term (see pages 170-173). This appears to give Vectren more focus on maintaining a high degree of optionality which is commendable. Vectren initially prepared ten additional alternative scenarios that considered input from its stakeholders (ultimately, the number of alternative scenarios were reduced to 6 optimized scenarios). The reduction in the number of scenarios is common. The differences in the scenarios were not sufficient to cause significant changes in the resulting portfolios and didn't provide additional insights that were valuable to Vectren's decision-making processes.

4.2.1 Models, Drivers, and Scenarios

ITRON developed the long-term, bottom-up energy and demand forecasts (see page 170). As discussed in the Fuel and Commodity Price Analysis and on page 74 of the IRP, Vectren developed a consensus base case projection that was informed by several independent firms for development of its analysis. Pace Global also provided future perspectives on the Midcontinent ISO's on- and off-peak prices. Burns and McDonnell and Pace Global provided cost projections for a variety of different resource technologies that, along with other resources, were modeled for economic dispatch using AURORAxmp. Dr. Richard Stevie developed cost forecasts for DSM. Strategist was used as the primary long-term resource planning model. Vectren's objective was to minimize the Net Present Value of all of the scenarios to find the optimum scenario.

Vectren relied on traditional drivers such as the load forecast, appliance/end-use saturation, energy efficiency, weather, economic factors, etc. As stated previously, projections about the cost of natural gas and coal were the primary drivers of this IRP. MISO market prices were also a factor. Known environmental costs and potential environmental costs were a significant driver as well, but it is important to be mindful that the Clean Power Plan had relatively minor effects on the final portfolios.[16] Historically, load growth was the primary driver for long-term planning for Vectren and most – if not all – utilities in the nation. For Vectren, changes in load such as the loss of ALCOA and the development of customer-owned generation by another large customer was a major consideration in this IRP. It is possible that Vectren will see some economic growth but because this is too speculative; the potential for load growth was treated as a scenario with a hypothetical load. Energy efficiency and the potential for other customers to install their own generating resources are also important considerations in this IRP.

Against this backdrop of significant uncertainty regarding environmental rules and dramatic changes in inter-fuel relationships, Vectren's 2016-2017 IRP represents a significant expansion of the number of scenarios and sensitivities from the 2014 IRP and provides a broader range of uncertainties and their attendant risks. Vectren's objective was "to test a relevant range for each of the key market drivers on how various technologies are selected under boundary conditions." (Vectren 2016 IRP, page 182).

For the 2016 IRP, Vectren developed fourteen portfolios (pages 82 and 83). Seven portfolios (including the Base Case) were optimized, but Vectren concluded the remaining scenarios would not provide sufficient insights to warrant optimization. Below are the 15 portfolios that were tested (Business as Usual, seven optimized portfolios, two stakeholder portfolios, and five diversified portfolios). Vectren hired Burns and McDonnell to find the best possible combinations of resource additions under various scenarios by using the optimization software Strategist. The risk analysis for various portfolios was conducted by Pace Global

[16] Arguably, the accumulation of the costs for environmental rules such as ELG, CCR, MATs, etc, taken as a whole, would have been a more significant driver. However, many of these costs were already _sunk costs_ at the time the IRP modeling was done.

using EPIS' AURORAxmp dispatch model combined with Monte Carlo simulation for the selection of possible future states as inputs to AURORAxmp.

1. Business As Usual (Continue Coal) Portfolio (Optimized)
2. Base Scenario (aka Gas Heavy) Portfolio (Optimized)
3. Base + Large Load Scenario Portfolio (Optimized)
4. High Regulatory Scenario Portfolio (Optimized)
5. Low Regulatory Scenario Portfolio (Optimized)
6. High Economy Scenario Portfolio (Optimized)
7. Low Economy Scenario Portfolio (Optimized)
8. High Technology Scenario Portfolio
9. Stakeholder Portfolio
10. Stakeholder Portfolio (Cease Coal 2024)
11. FBC3, Fired Gas, & Renewables Portfolio
12. FBC3, Fired Gas, Early Solar, & EE Portfolio
13. FBC3, Unfired Gas .05, Early Solar, EE, & Renewables Portfolio
14. Unfired Gas Heavy with 50 MW Solar in 2019 Portfolio
15. Gas Portfolio with Renewables Portfolio

4.2.2 Issues / Questions

Warrick 4 was assumed to be retired in all of the scenarios due to the loss of ALCOA. This raised the question of whether there are any set of circumstances – including MISO market value - in which Warrick 4 would be retained.

It bears reiterating from the fuel and commodity price discussion that the range of fuel price projections may have been unduly limited by using only one standard deviation from the expected value (mean). The relatively recent (5 years or so) experience in the natural gas industry provides support for a wider range of price trajectories. That is, few analysts ten years ago – even five years ago – would have thought the current price projections for natural gas to be within the realm of reasonable probabilities. Ten years ago, the notion of a *black swan event* might have been ascribed to the current projections for natural gas prices [17] and the attendant ramifications for coal in regional economic dispatch. Given Vecten's appropriate emphasis on maintaining options, having a more robust analysis of natural gas and commodity prices – higher and lower – would seem to be appropriate, especially for the mid and longer-term analysis.

Apart from whether the scenarios provided Vectren and its stakeholders with the most important information to make significant resource decisions, a more fundamental concern is capability of the model to handle the broad array of resource options in a holistic manner. That is, the capacity expansion model had limited ability to simultaneously evaluate and optimize more than a handful of resources. We recognize excessive run times may always be a consideration but the concern goes beyond run time. For example, was the model capable of simultaneously considering DSM, dynamic market conditions for buying and selling opportunities, renewable energy resources, possible new generating resources, and changes to the existing generating resource mix? Would other capacity expansion models be less limiting in their capabilities to conduct several multiple optimizations to better assess all resources and incorporate risk analysis?

Modeling results were evaluated via multiple metrics using a scorecard. The purpose was to find an appropriate balance of all metrics across the several scenarios so the choice of a portfolio performs well across the different metrics. On pages 33 and 44, Vectren identified a Preferred Portfolio Plan that, Vectren contends, balances the energy mix for its generation portfolio with the addition of a new combined cycle gas turbine facility (2024), solar power plants (2018 and 2019), and energy efficiency, while significantly reducing reliance on coal-fired electric generation and results in a significant reduction of CO_2 using Mass Compliance limits. In addition to retiring Warrick 4 in 2020, Vectren's Preferred Portfolio also contemplates the potential retirement of Bags natural gas unit 1 (in 2018) and unit 2 (2025), Northeast Units 1 and 2 (natural gas) in 2019, Brown coal-fired units 1 and 2 (2024), FB Culley Unit 2 (2024), and upgrade Culley 3 for compliance with National Effluent Limitation Guidelines (ELG) and Coal Combustion Residuals (CCR). Vectren noted the ELG/CCR, which they characterized as the main drivers of closing Vectren coal plants, will be much more difficult to change than the CPP.

While the narratives for the scenarios were well done, the Director is confident that Vectren would agree that there are reasonable scenarios that could result in different portfolios and provide a more robust assessment of potential risks. On p. 81 of the IRP report, Vectren mentioned that the seven optimized portfolios created using Strategist "looked very similar with a heavy reliance on gas resources and varying levels of energy efficiency. Some included renewables in the late 2020s through the 2030s." Therefore, Vectren continued with self-identified stakeholder portfolios (non-optimized) and the so-called diversified portfolios because "Vectren believes there is value in a balanced portfolio as a way to reduce risk." The

[17] The EIA's Short-Term Energy Outlook (May 8) 2007 stated *The Henry Hub natural gas spot price is expected to average $7.84 per thousand cubic feet (mcf or $7.56 per MMBtu) in 2007, a 90-cent increase from the 2006 average, and $8.16 per mcf ($7.87 per MMBtu) in 2008.* Natural gas reached an all-time high of $15.39 per MMBtu ($15.96 / Mcf) during December of 2005. On June 22, 2017, the Henry Hub Natural Gas spot price was 2. 88 per Mcf ($2.77 MMBtu). In EIA's Annual Energy Outlook for 2017 (page 56), said: *Reference case prices rise modestly from 2020 through 2030 as electric power consumption increases; however, natural gas prices stay relatively flat after 2030 as technology improvements keep pace with rising demand.*

modeling results gave credence to the preferred portfolio being one of the diversified portfolios that was analyzed based on the scorecard evaluation. For Vectren, like all utilities, future IRPs need to critically examine the value of resource diversity and to do so in the context of the MISO and state requirements for reliability and economic benefits.

Two of the optimized portfolios, one from Scenario D: High Regulatory Scenario and the other one from Scenario F: High Economy Scenario, were derived from scenarios with relatively high natural gas prices (please refer to Figure 2.3 on p.78). If the model still chose to invest heavily in gas, it means investment in gas makes economic sense even with much higher gas prices. Wouldn't a better way to test the risk be to raise the gas price to more extreme levels and see what the model selects based on the least cost criterion, rather than subjectively identifying some so-called diversified portfolios to test? More broadly, and while recognizing the number of resource options are more limited for Vectren, the usefulness of the scenario analysis may have been lessened due to the narrowness of the ranges for the important drivers that resulted in portfolios that were not often very distinct from other portfolios.

In addition, according to evaluation results shown in the scorecard on p. 85, Portfolio F actually performed well in terms of creating the right balance between satisfying the competing objectives. While the approach for ranking the portfolios according to several different criteria is good, the distinctions between rankings (red/yellow/green) seemed arbitrary. The arbitrariness of these rankings was subsequently confirmed in a data request by the CAC et al.[18] The arbitrariness, combined with the significant effects on overall rankings, raises concern. For example, the preferred portfolio ranks ninth in terms of NPVRR but gets the same green light as the lowest cost portfolio. While the use of only 3 possible rankings may be visually appealing, it exacerbates the importance of arbitrary distinctions.

Has Vectren done any retrospective analysis to see if their DSM analysis may have been limited by the same inability to optimize DSM and other resources simultaneously? As intimated by comments on Page 80 of the IRP that the iterative nature of Strategist resulted in considering only options that seemed to be viable. More broadly, has Vectren done any analysis to determine if modeling limitations resulted in a more restricted list of resources?

Despite some concerns, Vectren prepared credible and well-reasoned scenarios. As with other Indiana utilities, the degree of analytical rigor needs to be continually enhanced as the decisions become more controversial and difficult.

4.3 Energy Efficiency

Vectren used the same methodology in its 2014 IRP to analyze and model energy efficiency, which is one reasonable approach and is consistent with current practices by some utilities to address this difficult topic. Specifically, Vectren's effort to model DSM resources in a manner reasonably comparable to supply-side resources is similar to the approach taken by other Indiana utilities filing their IRPs in 2016. Vectren starts off with a DSM Market Potential Study (MPS) to assess how much DSM (energy efficiency and demand

[18] CAC et al.'s Data Request 1.20 asked: Please provide the spreadsheet used to develop Figure 2.6 including the metrics measured for each of the objectives and the ranges used to determine whether a particular portfolio has a green bubble, red bubble, partially green and partially yellow bubble, etc. Vectren responded initially: Please see the Risk Analysis section (page 41-70) of the final stakeholder deck presented on November 29, 2016 (included in attachment 3.1 Stakeholder Materials) for details on how the IRP Portfolio Balanced Scorecard was developed. See the legends in the slides for each of the variables where the specifics were provided. In some instances, we used "break points" as the basis for colors.

response) is potentially achievable in its system. The methodology combines a dedicated MPS carried out by the EnerNOC Consulting Corporation in 2013 with a 2014 Electric Power Research Institute (EPRI) study "U.S. Energy Efficiency Potential Through 2035." The sole purpose of the Market Potential Study (MPS) was to construct an annual 2% incremental energy efficiency cap. However the construction of DSM bundles to be offered to the capacity expansion model differs substantially with the other utilities in that it didn't rely on the MPS. Instead of constructing DSM bundles by assembling measures with similar load shapes, end uses, and customer classes, Vectren set an annual cap of 2% of total eligible retail sales from the MPS. It then chose generic DSM savings in 8 blocks of 0.25% of eligible retail sales (not including large customers that have opted out) for each year of the 20 year planning horizon.

The two Market Potential Studies used by Vectren in the IRP estimated the level of Technical Potential, Economic Potential, and Achievable Potential. Technical Potential is the maximum energy efficiency available, assuming that cost and market adoption of technologies are not a barrier. Economic Potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. Achievable Potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences. The Market Potential studies were used solely to guide the level of DSM resources to be included in the IRP analytical process as well as the maximum levels that seem reasonable.

The component programs for the blocks are assumed to initially be those approved in Cause No. 44645. For the first two years of the planning horizon (2016 and 2017), it is assumed that the current set of approved programs are being implemented. No minimum level of energy efficiency impacts have been locked in for the planning process. The 0.25% blocks already reflect a 20% adjustment for free riders. As a starting point, the cost of the energy efficiency programs approved in Cause No. 44645 is used for the 2017 DSM resource options.

Vectren developed estimates of how the cost of each energy efficiency bundle increases as the penetration of energy efficiency increases. The estimates are based on a study done by Dr. Richard Stevie with Integral Analytics, Inc. The study found that program costs per kWh increase as the cumulative penetration of energy efficiency increases. This means that achieving 1% savings in a given year means that achieving an additional 1% the next year and every year thereafter causes the costs of EE bundles to achieve that incremental 1% to increase by 4.12% each year of the planning period. The starting cost for the second 1% of blocks is assumed to be the ending cost (in real dollars) for the first 1%. A different growth rate in cost is applied to the second set of four blocks. The second set of four blocks is expected to grow at a rate of 1.72%. The lower growth rate in cost applied to blocks 5-8 allows for economies of operation within a given year, while the higher growth rate applied to blocks 1-4 tries to capture the impact on cost over time.

Based on Dr. Stevie's modeling results, high and low energy efficiency cost trajectories were developed using the estimated standard errors of the model coefficients used to develop the Base energy efficiency cost projection. The high and low cost trajectories were created by applying plus and minus one standard deviation to the model coefficients (which would capture about 68% of the variation of outcomes around the "expected value" – or the "mean").

4.3.1 Issues / Questions

Vectren should be recognized overall for its improved analysis and interesting approaches to address a number of difficult issues that arise when evaluating energy efficiency programs. But these interesting approaches also raise a number of questions. Vectren assumed the decision to select any amount of energy efficiency is made in 2018; meaning once a bundle is selected in 2018 that bundle is kept in place every following year through the planning horizon. The implication is that a new set of energy efficiency program participants had to be recruited each year at a cost that increased 4% per year. It is unclear whether the model optimization only considered the cost of the initial year the DSM bundle was selected or if it somehow considered the cost over all the remaining years in the 20 year planning horizon as well. As noted by CAC et al. on page 36 of their comments, it is not clear "whether connecting the initial years' savings to later years would serve to bias the model against selection of energy efficiency that is not realistic." In response, Vectren performed additional analysis which looked at the competitiveness of energy efficiency over a 3-year block from 2018-2020 rather than selecting the block for the entire study period. The results showed that blocks 1-4 in 2018-2020 are relatively similar in cost as a plan with no blocks of energy efficiency under the base scenario. It is not clear to the Director whether the additional analysis performed by Vectren really answers the issue expressed by CAC et al.

Vectren should be commended for making an interesting effort to project how bundle costs changed over time and as program penetration increased. As a starting point, the cost of energy efficiency programs approved in Cause No. 44645 was used for the DSM resource options. Vectren also contracted with Dr. Richard Stevie, VP of Forecasting with Integral Analytics Inc., to evaluate how the cost to achieve incremental energy efficiency savings changes as the cumulative market penetration of energy efficiency increases. Market penetration represents the cumulative achievement of energy efficiency savings as a percent of retail energy sales. The concept is that as market penetration increases and the available Market Potential begins to deplete, the cost to achieve additional program participants may increase.

The analysis was based on the Energy Information Administration's (EIA) Form 861 which contains data by utility on DSM program spending and load impacts. There are a number of limitations when using this data, which Dr. Stevie recognizes and tries to minimize by using the most recent 3 years of data, 2010 to 2012. Another way to minimize data limitations was to look at total annual spending relative to the first year impacts.

The Director appreciates the analysis performed by Dr. Stevie but is concerned that if the adjustments made to correct for admitted serious data limitations is sufficient to overcome the problems being addressed. Drawing strong policy recommendations in such circumstances is probably not warranted. More on this topic is discussed below in CAC et al.'s comments on energy efficiency. Hopefully, future analysis will be more reliant on empirical data derived from DSM effects by Vectren's customers.

4.4. Metrics for Preferred Plan Development

Vectren states the main objective of its IRP is to select a Preferred Portfolio of resources to best meet customers' needs for reliable, reasonably priced, environmentally acceptable power over a wide range of future market and regulatory conditions, taking into account risk and uncertainty. Specifically, Vectren's objectives are:

- Maintain reliability
- Minimize rate/cost to customers
- Mitigate risk to Vectren customers and shareholders
- Provide environmentally acceptable power leading to a lower carbon future
- Include a balanced mix of energy resources

- Minimize negative economic impact to the communities Vectren serves

Vectren analyzed 15 portfolios using a number of metrics each of which were given a green color for the best performers, a red color for a worst performer, and a yellow or caution color for something between. A scorecard was used to show the color for each portfolio under seven metrics. The seven metrics were:

- Portfolio NPVRR
- Risk
- Cost Risk Trade-off
- Balance/Flexibility
- Environmental
- Local Economic Impact
- Overall

Most of these metrics consisted of multiple measures.

A. *Portfolio NPVRR* looked at which portfolio had the lowest mean or average costs across 200 modeling iterations. Portfolios within 5% of the lowest expected cost portfolio were given a green color, and portfolios that were 10% or more expensive than the lowest were given a red color.

B. The *Risk Metric* included four different measures, each designed to capture a different risk. One measure of risk was volatility which is the standard deviation of the mean NPVRR. Portfolios whose standard deviation was within 10% of the least volatile portfolio were given a green color. Portfolios that had standard deviations 15% or more than the lowest volatile portfolio were given a red.

The second measure of risk is exposure to volatilities in the wholesale energy market prices. The portfolio with the lowest average purchases from the market is subject to the least market price volatility. Those with less than 800 GWhs per year on average were given a green color and those above 1,200 GWhs were given a red color.

The third measure assessed is the exposure to MISO capacity market prices. The average number of additional capacity purchases across all 200 iterations was computed to see which needed the most incremental capacity purchases. Portfolios purchasing less than 20 MW per year on average received a green color and those above 35 MW received a red color.

The fourth risk measure is remote generation. Portfolios with generation assets located away from Vectren's service territory are thought to be exposed to greater risk of transmission congestion and outages.

C. *Cost-Risk Tradeoff* relates two variables: expected costs and the standard deviation of cost. It is meant to provide a metric of whether a portfolio hedges risk in a cost effective manner. Vectren presented a figure (p. 229) that measured portfolio standard deviation along the vertical axis and expected portfolio cost along the horizontal axis.

D. All of the portfolios would easily meet or exceed the requirements of the CPP. Also, nearly all of the portfolios will reduce SO_2 and NOx levels by over 80%.

E. According to Vectren, balance and flexibility are important objectives to "ensure that Vectren has a diverse generation mix that does not rely too heavily on the economics and viability of one technology or one site." (p. 229). Portfolios with the greatest number of technologies are ranked higher than those with fewer technologies. Also, portfolios with more net sales into the wholesale market have the flexibility to adapt to unexpected breakthroughs in technology.

Sub-measures for Balance and Flexibility include the following:

- Percentage of the portfolio consisting of the largest technology in MW (for example wind or gas-fired generation)
- The largest power source (for example a combined cycle unit or a coal-fired unit)
- Percentage reliance of the largest technology to meet energy requirements in 2036 (for example gas or wind)
- Balanced energy metric based on the number of technologies relied on (for example gas, wind, solar EE, coal)
- Market flexibility as measured by net sales into the wholesale market.
- There was also a summary metric based on the other six sub-measures in this category

F. The last metric is local economic impact to the community. According to the IRP, this includes local output reductions and tax losses if local generation facilities are closed. Construction additions and operation of replacement generation was considered.

The customer rates metric, which is actually based on the portfolio's NPVRR, is useful, but is, by itself, limited. Knowing the mean or average NPVRR for one portfolio compared to other portfolios is of limited value without having information on the variability within the metric. Fortunately, Vectren presents information related to costs risks under other performance metrics. The risk metric included, as one element, the standard deviation of 20 year cost NPVRR. Another metric evaluated the cost-risk tradeoff by relating the expected value (or mean) of the 20 year NPVRR for a portfolio to the portfolio's standard deviation.

4.4.1 Risk Metric

Vectren presented three different measures relating to the NPVRR but each was discussed separately with no reference to the other two measures. It is often the case that a portfolio with a higher average NPVRR and a lower variability will be preferable to a resource portfolio with a lower average NPVRR but higher variability. Based on the information presented by Vectren, it is difficult to determine how the portfolios compare. It looks like Portfolio D has the best Cost Risk tradeoff but how the other portfolios compare is difficult to determine, given the information presented. The Director wonders if the cost-risk tradeoff could have been better presented using some other measure such as a cumulative probability chart. The risk probability chart would have shown the distribution of PVRR outcomes from the stochastic draws, showing the outcomes as the cumulative probability of each occurrence between 0% and 100%. The figure contains the risk profiles for each portfolio, with PVRR along the X-axis and the cumulative probability on the Y-axis. For each line, the difference between the bottom left point and top right point on the line is the range which 100% of the outcomes are expected to fall. This type of figure was used by IPL and has been used by other Indiana utilities including IMPA and I&M.

As noted above, the risk metric consists of four separate measures and each receives equal weight. Two of the measures relate to exposure to different aspects of the MISO markets. One measures exposure to the MISO wholesale energy market and the other measures exposure to the MISO capacity market. A third measure considered the risk from transmission issues from remote sources to Vectren which primarily affected those resource portfolios with greater reliance on wind generation.

An obvious question is how the thresholds were developed for exposure to the MISO capacity and energy markets? There is no discussion of thresholds in the IRP itself or the slides for the November 29, 2016 stakeholder meeting that addressed the performance metrics. Especially without a narrative that has been informed by discussions with MISO, it is hard to avoid the conclusion that the thresholds for good levels and bad levels of exposure is arbitrary. Without knowing why the thresholds were set where they are it is difficult to understand the significance when one portfolio receives a green light while another receives a red light. As for the third measure dealing with remoteness of resources to Vectren, there does not appear to be a definition of remoteness. Is it merely any resource that is not directly interconnected to the Vectren transmission system? Are there different degrees of "remoteness"? If yes, on what are these degrees based? If remoteness is based only on whether a resource is directly connected to Vectren's transmission system, then this is a blunt measure. Again, it would seem that MISO would be a good resource to help Vectren quantify the metrics.

4.4.2 Flexibility Metric

The balance and flexibility metric discussion in the IRP differs quite a bit from that in the November 29, 2016 stakeholder meeting presentation. For example, the IRP (p. 230) states that portfolios with more net sales have the flexibility to adapt to unexpected breakthroughs in technology. The November 29 stakeholder presentation says portfolios with higher net sales provide a cushion against higher than expected load, as well as redundancy to quickly adapt to unexpected change. The idea is to reduce the likelihood of exposing customers to wholesale energy market volatilities (p. 72). It is not clear to the Director why higher net sales is protection against unexpected change - be it technological change or something else. For example, higher net sales could also indicate greater sunk costs associated with generation facilities.

4.4.3 Diversity Metric

To some extent, flexibility concerns are addressed by Vectren's diversity metric, which uses four measures. These measures cover both the percentage of energy and capacity requirements satisfied by one technology, the largest single generation source, and the total number of technologies utilized. It is important to note that these measures are based on the projected load and resources for 2036. Again, it is not clear how the thresholds were set for green, yellow, or red classification for the specific measures. Nor is it clear how the summary metric was developed based on the four diversity measures and the net sales measure.

CAC et al. (on pages 47-57) has a number of criticisms of the black box scorecard assessment used by Vectren. Its exercise demonstrates how small changes to the scorecard ranking system implemented by Vectren can result in very different rankings of portfolios. As CAC et al. noted, the scorecard methodology used by Vectren is not robust to small changes in metric assumptions nor is it the only possible interpretation of the data on which Vectren relies. (CAC et. al. comments on Vectren IRP, p. 51) The Director concurs with this criticism.

4.4.4 Assessment

Vectren's circumstance is quite similar to NIPSCO's, in that both utilities are considering the reasonableness of making significant changes to its resource portfolio in the next several years. Similar to NIPSCO, Vectren relied extensively on PVRR to compare resource portfolios in its 2014 IRP, but has made a significant number of improvements in the 2016 IRP. There is an extensive discussion of risks and uncertainties and an explicit effort to have metrics that specifically address these risks and uncertainties to evaluate portfolio performance. Vectren included metrics to measure balance and flexibility of portfolios, local economic impact, cost-risk tradeoff, and environmental compliance. The specific questions and issues discussed above are not meant to detract from the significant improvements in the use of metrics implemented by Vectren in the 2016 IRP. Rather, the questions and issues are intended to further discussion amongst the various stakeholders and Vectren to make ongoing improvements.

4.5 Review of Vectren's Comments on Draft 2016 Director's IRP Report

Vectren implemented numerous changes in the 2016 IRP and the Director has some understanding of the effort put forth by the Vectren staff involved. The Director believes that all involved in the IRP stakeholder advisory process including Vectren staff, Commission staff, and other stakeholders, are in a continual learning process. This is a strength of the IRP process and helps to facilitate the exploration of potential areas of improvement as we all learn.

What follows are responses by the Director to specific points made by Vectren in their written comments on the Draft Director's IRP Report. The page numbers shown below refer to a page in Vectren's comments.

4.5.1 Modeling Resource Options in a Holistic Manner

Vectren: pp. 2-3 – The Director in the draft report raised some questions about the ability of the model used by Vectren to perform complex modeling analysis compared to other models now available. In response, Vectren describes the Strategist model and the how this model was used to effectively conduct the complex analysis involved in exploring the retirement and replacement of existing generation facilities.

Response: Models are all different and it is a weighing of different capabilities that drives which model is most appropriate for the current circumstances. The question is not so much model constraints, but how these constraints are handled by the utility while still making as full use of the model's capabilities. Do different approaches give different results? For example, Vectren's modeling of energy efficiency is very different compared to other Indiana utilities. The evaluation of blocks of energy efficiency over an entire planning horizon instead of several multi-year time periods is one example. Also there is the conceptually odd methodological choice of pricing the fifth block of EE in 2016 at the fourth block price in the year 2036. The narrative for this modeling decision is lacking. That is, it requires more discussion of why this approach is reasonable and does not distort outcomes.

We cannot say whether Vectren's approach to handling model limitations is better or worse than other methodologies but it is an open question that might be better answered as experience is gained over time.

4.5.2 Portfolio Diversity

Vectren: P. 7 – Vectren believes that sound planning bases decisions on circumstances that have some material degree of probability. Determining lower probability scenarios impact on resource alternatives may provide some useful data, but is unlikely to change outcomes. Vectren has also used the phrase "reasonably possible future states."

Response: The Director agrees with Vectren that one measure of the strength of a portfolio is if it does well over a number of scenarios, but it could also suggest that the scenarios were not sufficiently distinct to assess different risks. What seems implausible today can change quickly. For example, just a few years ago, projections of natural gas were substantially higher than current price forecasts. The technological improvements in wind and solar resources have resulted in sharper cost declines than were expected just a few years ago. The difficulty of estimating customer-owned distributed energy resources (DER) is a problem vexing almost all utilities but, as Vectren can attest, there seems little doubt that DER will be increasing. The election of Donald Trump and the resulting effects on environmental regulations was highly unexpected. Also, history is but one sample of what could have happened. Yes, a number of scenarios should be based on "some material degree of probability," but some scenarios should be examined, even if plausible, albeit, unlikely.

Unlikely scenarios can provide useful information when evaluating a preferred resource portfolio and near term resource decisions. Vectren cites an analysis they did not include in the IRP that shows a 50% reduction in coal prices would be required for the IRP optimization models to select coal over natural gas. This is an important piece of information that helps one better understand how strong the results are. Similarly, as Vectren correctly stated, the continued operation of Warrick 4 was not considered to be plausible at the time Vectren constructed their IRP but the situation has changed somewhat.

Vectren: Bottom of page 7, Vectren states "Only the screening analysis used one standard deviation above or below the mean. The risk analysis utilized the full distribution of natural gas prices in the 200 iterations."

Response: Vectren's use of the phrase "screening analysis" in their reply comments is unusual because it is applied to the development of scenarios and the development of resource portfolios based on those scenarios. Staff acknowledges Vectren does not appear to have limited the commodity price ranges to plus or minus one standard deviation when doing the stochastic analysis, but such a limitation was imposed when developing the scenarios. Limitation in the development of scenarios may unreasonably constrain the potential range of resource portfolios that are, then, subjected to the optimization process. And it is these optimized resource portfolios that are then evaluated with the stochastic analysis.

Vectren: Vectren states "the probabilities of these black swan [19]events are so low that it would not have materially changed the risk analysis and the ultimate recommended portfolio."

[19] A black swan event is a metaphor to describe a low probability event with major significance. For utility planning, it is useful to *stress* the system to evaluate the potential ramifications of a low probability event that would have significant ramifications. Because it is unrealistic and prohibitively expensive to try to plan a utility with no probability of failure, it would seem unlikely that any utility would be planned on the basis of a black swan event. The *Polar Vortex* of 2013 / 14 might be regarded as a black swan event. It is also possible that the precipitous drop in natural gas prices in recent years would have been regarded as a black swan event prior to the widespread use of fracking. The term is based on an ancient saying which presumed black swans did not exist, but the saying was revised after black swans were discovered in the wild.

Response: The Director acknowledges that the recommended portfolio might not change. But on p. 194 of Vecren's IRP report they note that black swan events are impossible to forecast, but tend to occur quite frequently. Vectren also argues in the IRP that probabilistic distributions that reflect a combination of historical data and informed judgment tend to capture black swan events.

The Director is open to the possibility that probabilistic distributions based on a combination of historical data and informed judgement may capture many black swan events but thinks many of these types of events are better addressed explicitly in the development of scenarios and the accompanying narratives. Moreover, the portfolios being reviewed are determined before the stochastic analysis is performed. Scenario and stochastic analysis are complements to each other, not substitutes.

Vectren: pp. 7-8 – Vectren clarified that the full distribution of gas prices was used in the 200 iterations for the stochastic analysis.

Response: The Director agrees based on information presented.

4.5.3 Benefits of Flexibility in the Planning Process

Vectren: P. 8 – Vectren South approaches its scenario and risk assessment in a manner intended to maintain flexibility and balance risk. Generally, Vectren South shares the view of the Director in this regard. Draft Report, p. 5. However, Vectren South suggests the Director consider the potential risk that could be created by waiting until the last possible moment to make decisions. Such an approach presents its own challenges. Waiting until the last possible moment to make decisions may place too much emphasis on the present and therefore increase risk because there is no time left to evaluate how trends will work out in the longer run. Options may also be limited because of the time required to obtain replacement capacity or approval to build new facilities. Adequate time is necessary for proper evaluation and planning in order to manage a large project to properly balance cost minimization with reliability and safety.

Response: An appropriate planning aspiration is to maintain flexibility while also waiting as long as reasonably possible to commit to a resource. This flexibility allows initial resource analysis to be reversed if there is new information that makes the initial selection less desirable compared to other options.

4.5.4 Metrics for the Preferred Plan

Vectren: P. 12 – There is no threshold for considering what a reasonable maximum exposure to these markets (MISO capacity and energy markets) would be in the analysis. There is only limited experience in these markets to draw upon. That is, there is not enough empirical data to determine what an appropriate level of exposure is in the MISO markets. At this point, the MISO markets are not very liquid and hence can be quite volatile.

The "higher net sales" Vectren South has in mind is the ability to make greater wholesale energy or capacity sales. A utility that lacks sufficient generation resources to serve its load faces significant market risk that can lead to fluctuating prices. The utility also is better able to serve new load in its service territory. On the other hand, a utility that has a reasonable reserve of generation beyond its capacity is able to offer this into the market which, in Vectren South's case, benefits customers and protects it against market risks resulting from changing prices. The utility and its customers are at risk of increases in the cost of purchasing electricity if available energy or capacity becomes scarcer in the market.

Response: The following is a general response to Vectren's comments on metrics for development of the preferred resource plan.

The Director appreciates the explanation of the remoteness metric of a resource located outside the Vectren service territory and the additional discussion provided on some of the other metrics on which the Director had specific questions. The Director also appreciates Vectren's statement, "[w]hile the determination of what constitutes good and bad is subjective, on a relative basis between portfolios, it is an accurate assessment." (p. 12 Vectren comments on Director's Draft Report)

The Director thinks consideration of risks and uncertainties in a long-term planning exercise involving numerous decision points is by definition complex and the "preferred portfolio" as determined by the utility is dependent on many quantitative but also qualitative decisions based largely on the utility's expertise, experience, and judgment. Among the complexities is how the utility weighs the various risks and uncertainties and how they also consider the various metrics used to evaluate the plans. There is no one absolutely "right" way to evaluate these risks and uncertainties and different parties can look at the same information and reasonably derive different choices as to what the preferred portfolio should be.

Nevertheless, the distinction between rankings (red, yellow, green) often appears arbitrary due to a lack of distinction between the ratings. It is also not always clear why something is considered positive or negative. For this IRP, this is especially the case for the metrics involving exposure to wholesale energy and capacity markets, remoteness of a resource from Vectren's service territory, and the ability to make higher net sales which all appear to be very subjective. Surely the risks seen by Vectren vary by degree but, without more definitive thresholds or discussion of how these risks change at different levels of exposure, it appears somewhat arbitrary. It is difficult to have objective metrics without an ability to quantify the metrics so some degree of arbitrariness is unescapable in something as complex as evaluating alternative resource portfolios. Awareness of this circumstance is, however, critical for all IRP stakeholders.

The Director recommends that Vectren, like other Indiana utilities, should consider the establishment of metrics in advance of the IRP process and with the input of stakeholders; recognizing there may be need for some adjustments. To the extent reasonably feasible, the metrics should be quantifiable. However, stakeholders should recognize that some metrics are inherently subjective. Ideally, for those metrics that are subjective (e.g., the value of resiliency or fuel / resource diversity), there should be general understanding about how those metrics will be evaluated and weighted. Mutual understanding of the metrics should reduce misunderstandings as the preferred portfolio is determined.

4.5.5 Energy Efficiency

Vectren: P. 13 – **Vectren responded to questions the Director had on some aspects of how Vectren modeled energy efficiency. One involved how Vectren modeled EE over the full planning period and the other area involved how Vectren projected EE program costs over the 20-year planning period.**

Response: Vectren has several reasonable responses to a number of questions raised by CAC et al. but there are other questions that should be kept in mind if a utility chooses to use the results of Dr. Stevie's study.

1. Stevie's model examines the impact of explanatory variables on direct program spending. The model excludes indirect costs which Dr. Stevie states in his study can add as much as 30 percent to total program spending. Indirect costs includes costs that have not been included in any program category, but could be meaningfully identified with operating the company's DSM programs (e.g., Administrative, Marketing, Monitoring & Evaluation, Company-Earned Incentives, Other). Direct Costs are those costs that are directly attributable to a particular DSM program and include incentive payments provided to a customer for program participation, whether cash payment, in-kind services (e.g. design work), or other benefits directly provided customer for their program participation.

   It is the Director's opinion that the nature of indirect costs means they are likely to grow at a slower pace relative to direct program expenditures due to experience, economies of size, customer awareness / acceptance, etc. Thus, the exclusion of indirect costs from the analysis is likely to overstate the growth in portfolio costs over time.

2. The fundamental problem that Dr. Stevie was attempting to mitigate is the lack of data credibility. The inconsistent data collected by utilities and submitted to the Energy Information Administration's (EIA), adversely affects the EIA's data base. The cumulative MWh data in the EIA data base likely has problems, the extent and significance of which is unknown. The instructions for the 2012 version of Form 861 states the cumulative effects of energy efficiency programs includes new and existing participants in existing programs (those implemented prior to the current reporting year that were in place during prior reporting year), all participants in new programs (those implemented during current reporting year), <u>and participants in programs terminated since 1992 (those effects continue even though the programs have been discontinued</u>) (emphasis added). The instructions go on to say that DSM programs have a useful life, and the net effects of these programs will diminish over time. To the extent possible, the cumulative effects should consider the useful life of efficiency and load control measures by accounting for building demolition, equipment degradation, and program attrition.

   It is not clear how individual utilities handle in their EIA reporting the diminishing impact of programs over time. Again, it is almost certain that each utility treats the diminishing effects of DSM differently. Thus, the EIA data may include a program that was in place 20 years ago but no longer has an effect, which would impact the estimated model results.

3. Vectren states there is a great deal of uncertainty in projecting how EE program costs might change over the planning period. Vectren argues that averaging estimated coefficients from the two models analyzed in the study is one way of combining information in a way that appropriately acknowledges the extensive uncertainty.

   The Director agrees that there is a large degree of uncertainty in projecting future program costs but questions in this circumstance whether the averaging of two separate model results is reasonable. The results of the second model raises questions whether it should have been used at all. The second model was estimated using data for only the year 2012, as opposed to the first model based on data for the period 2010-2012. The second model has considerably less explanatory power[20], a marginal significance on the price of electricity, and the program size variable is not significant. The failure of program size to have much explanatory power on program costs calls into question reliance on any of the second model's results.

4. When developing the projected costs of energy efficiency programs through the forecast period, the Director is persuaded that Dr. Elizabeth Stanton, a consultant for CAC et al., is correct that not including the price of electricity affects the projected cost of energy efficiency programs over time.[21] Similarly, it appears that the impact of current or incremental program savings is also excluded. If this assessment is correct, then only the coefficient on the cumulative kWh impacts was used. It can be argued that, if these variables are not going to be used to project the rate of cost change of energy efficiency programs, then perhaps the models should be re-estimated without them (Of course, adding or removing an independent variable will change the coefficients of the other variables. The Director understands that removing these variables will cause other estimation problems). Essentially, the methodology used to project program costs increases over time and saturation levels assumes that the values for electricity price and current (or incremental) kWh savings do not change over the 20 year planning period and thus have no impact.

   Dr. Stevie chose to exclude the price variable for two reasons. First, the price variable was significant only in the first model but not the second so it did not seem appropriate to include the impact of the variable. Second, Vectren's average retail price of electricity has been flat in nominal terms in recent years which means the price is declining in real terms. So if he had included the price it would have increased the cost projection. He chose to be conservative.

   Excluding the price because it was not significant in one form of the model, even though it is significant in the other model, is questionable. Also Vectren's recent price history says nothing about how the price will change over the next 20 years. Ignoring the price of electricity means the energy efficiency program cost projections are based on the assumption of no electricity price changes over the 20 year period. At a minimum, given the resource changes for Vectren over the 20 year planning horizon, it seems unrealistic to assume no price increases for electricity.

The Director continues to believe the analysis performed by Dr. Stevie is interesting but it is not without numerous questions. The EIA DSM data is well-known for many problems that are recognized by Dr. Stevie and the study methodology tries to limit the impact of these problems. But the paper also acknowledges the uncertainty of the results and states that much additional analysis needs to be conducted to feel confident about the relationships affecting energy efficiency program costs over time and as saturation levels change. The additional comments or questions discussed above, whether correct or not, serve to emphasize the extent of uncertainty about the results and how they might best be used.

[20] It is the ability of a model, hypothesis or theory to explain a concept or subject in a credible manner. Or in this case, the ability of the independent or explanatory variables to explain movements in the dependent variable.

[21] See the Direct Testimony of Elizabeth A. Stanton, Cause No. 44927, CAC Exhibit 1, pages 20-21.

5. HOOSIER ENERGY

5.1 Scenario and Risk Analysis

Hoosier Energy filed an update, rather than a full IRP, as part of the change to a three-year IRP cycle. Its update was well-organized and credible.

5.1.1 Models

Hoosier Energy contracted with GDS Associates to perform IRP analysis by using the Strategist Integrated Planning System developed by *Ventyx*. The model simulates production operations of all combinations of potential resource additions, then compares across those combinations to determine the portfolio of expansion units necessary to achieve planning reserve margin criteria at the lowest cost. The model is the same as the one used in 2014 IRP process.

5.1.2 Method

Hoosier Energy started with a Base Case scenario. Eight sensitivities were developed for the Base Case by incorporating different assumptions about load and energy, fuel prices, renewable prices, carbon prices and overnight costs for Combined Cycle and Combustion Turbine construction. In addition to the Base Case scenario, an Environmental Future scenario was developed, which included carbon emissions limits and a limited amount of wind over the 2017 to 2036 timeframe. Seven sensitivities were developed for the Environmental Future Scenario with varying limits on wind and solar and those limits combined with low power and gas prices.

Hoosier Energy reported the least cost plans under each scenario and sensitivity. Nevertheless, it did not reach a preferred resource plan after the analysis. A short-term action plan indicated that the next major resource increment would be required around the years 2023/2024 based on modeling results.

5.1.3 Issues

In Hoosier Energy's IRP analysis, only supply-side alternatives were included in the modeling. The demand-side resource options were predetermined and incorporated into the load forecast. The supply-side and the demand-side alternatives were not evaluated on the same basis in the resource plan process.

Hoosier Energy included a very limited number of scenarios: Base Case scenario and Environmental Future scenario. Usually, a scenario represents a possible future depicted by a set of input assumptions about economy, market condition, load and energy forecast, environmental regulation, and so on. From the perspective of identifying possible future states, two scenarios seem insufficient.

In addition, Hoosier Energy lacked a systematic framework to compare various portfolios. Except cost, no other criteria were established to make comparison. Modeling results were presented in a way less informative, which did not lead to a preferred portfolio plan.

5.2 Energy Efficiency

Hoosier Energy's circumstance is quite different from that of the other three utilities that submitted IRPs this round. NIPSCO, IPL, and Vectren all prepared completely new IRPs consistent with the schedule in the draft IRP rule. Hoosier Energy was scheduled to provide only an update of the IRP with a completely new IRP to be prepared for 2017. This is part of the transition to a three-year cycle for each utility to prepare an IRP going forward.

Hoosier Energy's discussion of demand-side resources is minimal but it appears DSM was reflected in the IRP a couple of different ways. First, DSM resource options were selected and developed as part of the 2013 GDS Associates market potential study and incorporated into the load forecast. Second, GDS developed a 2016 update of its study. Based on the updated assumptions, an additional 3.5 MW of DSM was selected in 2017 in some of the Strategist scenarios. How either step was done is not discussed.

The Director understands that Hoosier Energy was only providing an update to its IRP as requested under the draft rule. He anticipates that Hoosier Energy will have a fuller discussion of how DSM resources are accounted for in their 2017 IRP.

5.3 Metrics for Preferred Plan Development

Hoosier Energy developed two scenarios that were analyzed with Strategist – a Base Case and an Environmental Future. Eight sensitivities were analyzed for the base case and seven sensitivities for the environmental future scenario. Tables for each scenario and sensitivity showed the five lowest cost expansion plans (from the top 100) selected by the Strategist model. The NPVRR of each resource portfolio was the only information presented. No other metrics for plan evaluation was discussed.

Staff understands that Hoosier Energy was only providing an update to their IRP as requested under the draft rule. We anticipate that Hoosier Energy will have a fuller discussion of performance metrics in its 2017 IRP to inform its decision as to the composition of the preferred resource plan.

6. CAC ET AL. COMMENTS

CAC et al. raised a number of concerns as to how the utilities modeled DSM. Attention was especially focused on the use of market potential studies, bundle creation, and the projection of energy efficiency costs over a 20-year forecast horizon. CAC et al. also proposed an alternative DSM modeling methodology that they think avoids many of the difficulties they see with the methodologies used by the utilities.

CAC et al. commented that much of the analysis reflected in the market potential studies is opaque with assumptions that are unspecified or less than clear. (CAC et al. Comments on IPL IRP, pp. 39 – 42) They are also concerned how the market potential studies were used to screen potential EE programs multiple times. (CAC et al. Comments on NIPSCO IRP, pp. 28-30) Essentially, CAC et al. have a number of questions regarding the movement from the MPS to what is included for consideration in the optimization model and how the energy efficiency in the Preferred Plan relates to what occurred throughout the process.

CAC et al. thought Vectren's treatment of DSM was in many respects superior to that done by IPL and NIPSCO. Much of this is the direct result of how Vectren created its DSM bundles compared to the methodology used by IPL and NIPSCO. In CAC et al's opinion, they thought Vectren's approach had beneficial attributes because it "does not rely on such black box elements as 'achievable potential' rates. In addition it does not appear that Vectren performed any cost-effectiveness pre-screening of measures, which generally serves only to result in more screens for the energy efficiency than supply-side measures." (CAC et al. Comments on Vectren IRP, p. 35)

Perhaps CAC et al. reserved their largest concern for how efficiency program costs were projected to change over the 20-year planning period. As noted above, both IPL and NIPSCO assume initial bundle costs similar to existing DSM programs or base information on market potential studies, and each company made assumptions as to the rate of annual escalation in bundle costs. It is not clear on what these annual cost increase projections are based. Vectren's approach based initial bundle costs on programs they are currently marketing, but the rate of cost increase is based on a study done by Dr. Richard Stevie.

CAC et al consultants prepared a paper critiquing the analysis done by Dr. Stevie. (CAC et al. Comments on Vectren IRP, Attachment A) They found that Stevie's analysis:

- is based on highly questionable data sources,
- relies on regression analysis that is sensitive to the inclusion or exclusion of problematic data entries, and seems to depend on unusual choices in variable and model specification, and
- is applied incorrectly and incompletely in the utility filing where the consultants were able to review confidential workpapers.

CAC et al. concludes the "result is higher energy efficiency costs than would otherwise be expected in utility planning and, consequently, less efficiency chosen in optimal resource planning." (CAC et al. Comments on Vectren IRP, Attachment A, p. 3)

To Vectren's credit, they recognize that DSM resource costs are a component of the integration of DSM into the resource plan. The uncertainty around DSM costs, especially considering a 20-year implementation period, means that alternate views of these costs should be examined in the context of the scenario and stochastic risk analyses. (Vectren IRP p. 134)

Vectren developed high and low DSM resource cost trajectories using the estimated standard errors of the model coefficients used in the development of the base case cost projection. These high and low load cost trajectories were created by applying plus and minus one standard deviation error to the DSM costs regression model coefficients. (Vectren IRP p. 135)

The use of high, low, and base DSM costs forecasts is very useful conceptually, but the Director shares CAC et al's concern about the methodology and data used to develop the base case DSM costs trajectories based on EIA data. For example, the costs for an individual DSM block 1- 4 increases by 4.9% per year in the high case, 4.2% in the base case, and 3.4% in the low case. Given low inflation rates all three rates of DSM costs increase translates into substantial increases in the real (meaning inflation-adjusted) costs of DSM. This appears to be inconsistent with other historical evidence. Also, while using high and low DSM cost trajectories is methodologically reasonable to evaluate how sensitive modeling results are to changes in DSM costs, the apparent high increases in real costs over time across all three projections raises questions about how the method was applied and the reasonableness of the results. More fundamentally, the methodology used by Vectren appears to underestimate the role of technological change and changing public attitudes about energy consumption. It is not clear to the Director that this can be adequately captured when using only three years of data. The ideal solution would be to develop a Vectren specific load research – including DSM load research – database, but this takes time. Borrowing data from neighboring utilities and selected utilities that have substantial experience and expertise is a second-best alternative. However, as Vectren knows, borrowing data from other utilities must be carefully done since there are considerable differences in how utilities treat DSM. The lack of uniformity in treatment and reporting of DSM to the EIA is a primary reason that reliance on EIA DSM data is concerning.

CAC et al. recommends moving away from the current approach of using bundles to evaluate the potential for EE in IRP modeling and instead trying to focus on the value of EE. This, they suggest, can be done by moving to an avoided cost proxy for DSM. A utility will use IRP modeling to estimate the value of increasing zero cost decrements of load so that an implicit avoided cost for each decrement is developed. Under this approach, the appropriate level of energy savings is calculated in a DSM proceeding but relies on avoided costs developed from the IRP. This approach eliminates the need at the IRP modeling stage to develop assumptions about the cost and performance of DSM over the 20-year planning horizon. CAC et al. notes the avoided cost proxy requires having portfolios with distinct levels of energy savings but similar resource choices and other input assumptions so that the cost differences between the portfolios is driven by the level of energy savings rather than some unrelated characteristic. (See p. 40 CAC et al's. Comments on IPL IRP and p. 38 of CAC's Comments on NIPSCO's IRP)

The Director shares CAC et al.'s concern about the ability to develop assumptions about DSM bundle characteristics and cost trajectories over a 20-year modeling horizon. As a result, the Director appreciates the alternative methodology proposed by CAC et al. While conceptually reasonable, the idea, however, has to be more fully developed and analyzed using appropriate models so there is better understanding of how use of the technique compares to other techniques of EE modeling being used across the nation.

7. MIDWEST ENERGY EFFICIENCY ALLIANCE (MEEA) COMMENTS

MEEA shared many of the same concerns expressed by the CAC et al. They liked each utility choosing to model EE as a selectable resource but also expressed a number of concerns about the EE modeling methodologies used by NIPSCO and IPL, which are listed below.

1. Each utility used its respective MPS to screen EE programs which MEEA believes unreasonably limits the amount of EE included as an input to the IRP optimization modeling. They prefer the "Technical Potential" be input to the IRP models. (MEEA NIPSCO comments, p. 3)
2. Each bundle was based on individual measures which could be leaving savings on the table that could be achieved with a well-designed portfolio of programs. (p. 2 MEEA NIPSCO Comments)
3. The savings levels are too low. In MEEA's experience it is not uncommon that higher levels of cost-effective energy savings can be achieved as technology, program design, and program delivery mature. (MEEA Comments on NIPSCO, p.4)

MEEA did like IPL's method of separating the bundles into cost-tiers compared to the no-tiers approach used by NIPSCO. They believe bundles based on cost tiers prevent an all-or-nothing selection in the IRP modeling. (MEEA Comments on IPL, p. 2)

MEEA especially liked Vectren's approach to bundle construction, as compared to IPL and NIPSCO. But MEEA had one caveat – the 2% cap on incremental annual energy savings appears to be arbitrary, as do the 0.25% size of the bundle increments. They questioned if the 2% level was too low. Also, they wondered if smaller increments of 0.10% had been used would more energy savings have been selected. (MEEA Comments on Vectren, p. 2) MEEA, in addition, thought Vectren's approach of allowing the model to select EE by cost per kWh in a measure-agnostic fashion avoids limiting what EE is available to the IRP model. This avoids limiting the utility's later DSM planning because it selects savings rather than specific measure types. (MEEA Vectren Comments, p. 3)

According to MEEA, NIPSCO used Version 1 of the Indiana Technical Reference Manual (TRM) in its MPS whereas IPL used Version 2.2. They asked the commission to provide guidance on which version of the TRM should be used in IRP modeling. It is the Director's opinion that the most recent version or data should be used whenever possible. (MEEA Comments on IPL, p. 3)

7.1 Utility Responses to MEEA

Both IPL and NIPSCO disagree with MEEA that their modeling is flawed because they failed to include MPS Technical Potential in the IRP optimization. IPL says they intentionally chose to input MAP in the IRP modeling rather than the lower RAP so as not to limit the amount of DSM available for the IRP model to select. (p. 3, IPL Reply to Stakeholder Comments). NIPSCO states it made a conscious decision to screen EE measures for what was not just possible in its service territory, but also what was practical. (NIPSCO Reply Comments p. 6) In order for the EE bundles to be the most accurate representation of what is available, NIPSCO elected to use the more conservative, but more typical market by also running the EE program potential on all of its measures before including them in the optimization. (NIPSCO Reply Comments, p. 7)

As to the assertion that the savings level is too low, IPL emphasizes that, after opt-outs are considered, the IRP-selected energy efficiency amounts are more than 1% per year of the eligible load. (IPL Reply Comments p. 3) NIPSCO noted that many DSM programs passed the DSM pre-screening process but were ultimately not selected in the model optimization process. As a result, any DSM program that was unable or narrowly able to pass the screening would be highly unlikely to be chosen in the resource optimization. (pg. 2-3 NIPSCO Reply to Stakeholder Comments)

8. GENERAL COMMENTS

8.1 Fuel and Commodity Price Analysis for Director's Report on 2016 IRP

The Director recognizes any expectation of precisely accurate forecasts of future fuel and market prices, especially long-term price forecasts, is an impossible objective to attain. Rather, the emphasis should be placed on the plausibility and credibility of different narratives and assumptions that, considered with other factors, provide a broad range of possible outcomes. Given the significance of decisions being confronted by Indiana utilities and their stakeholders, it is important to memorialize the importance of fuel prices—particularly natural gas prices—in relation to coal prices. Similarly, it is important to note that environmental policies affecting coal are changing at the national level but, at this point, it is difficult to anticipate the ramifications. These changes were made after utilities conducted their analysis and generally occurred after the IRPs were submitted. The importance of fuel prices is preeminent in this IRP cycle and warrant well-constructed scenarios, sensitivities, probabilistic analysis, and multiple data sources. Moreover, since Indiana utilities are members of the Midcontinent ISO (MISO) or the PJM, it is also necessary for Indiana utilities to consider market prices and regional resources to maximize the value of their own resources over the 20-year planning horizon.

8.1.1 Construction of Fuel Forecasts

Developing low probability, but highly consequential scenarios, as well as more likely scenarios, is consistent with good industry practice.[22] Similarly, for fuel price projections, forecasts of market energy and capacity costs, load forecasts, environmental regulations and other important variables, especially those that are likely to be primary drivers of resource decisions, should capture a wide variety of assumptions and projections. Analysis of more extreme fuel price assumptions and forecasts should result in different resource portfolios that provide useful insights that could not be provided by too narrow a view.

Just as well-reasoned narratives are essential in the construction of scenarios, it is also imperative that well-reasoned narratives support fuel price projections. Even extreme fuel price forecasts should be supported

[22] The Northwest Power and Conservation Council "Northwest Conservation and Electric Power Plan". The Council's planning process is based on the principle that "there are no facts about the future." The Council tests thousands of resource strategies across 800 different futures to identify the elements of these strategies that are the most successful (i.e., have lower cost and economic risk) over the widest range of future conditions. (page 3-30). The Regional Portfolio Model (RPM) [A stochastic not deterministic model] uses both natural gas and wholesale electricity prices as the basis for creating 800 futures. Each future has a unique series of natural gas and electricity prices through the 20-year planning period. [For natural gas prices] These price series include excursions below and above the price ranges shown here for both electricity and natural gas to reflect the volatility and uncertainty in future commodity prices. (page 8-2). The high and low forecasts are intended to be extreme views of possible future prices from today's context… In reality, prices may at various times in the future resemble any of the forecast range. Such cycles in natural gas prices, as well as shorter-term volatility, are captured in the Council's Regional Portfolio Model.(page 8-8). The future is uncertain. Therefore, the ultimate cost and risk of resource development decisions made today are impacted by factors that are largely out of the control of decision makers. To assess the potential cost and risk of different resource strategies, it is essential to identify those future uncertainties that have the potential to significantly affect a resource strategy's cost or risk, and to bracket the range of those uncertainties. (page 15-4). Seventh Power Plan, Adopted February 10, 2016.

by a credible narrative story. For example, what can history—especially recent history—tell us?[23] What combination of factors might cause significant natural gas price escalations (or significant price declines)? What factors, taken together, might cause a significant increase in forecast market energy and/or capacity costs that would alter resource decisions?

To be clear, there is no expectation that the utilities' preferred resource plans will be based on very extreme cases. However, it is important to know the point of inflection when extreme scenarios result in dramatic changes in resource portfolios. For example, what price do natural gas and coal price projections have to reach for utilities to retain their coal-fired generation? Similarly, what natural gas and coal price projections would cause a utility to retire all coal-fired generation? For either of these two examples of high and low fuel and market prices, how does the capacity expansion planning model's selection of other resources change and what are the ramifications?

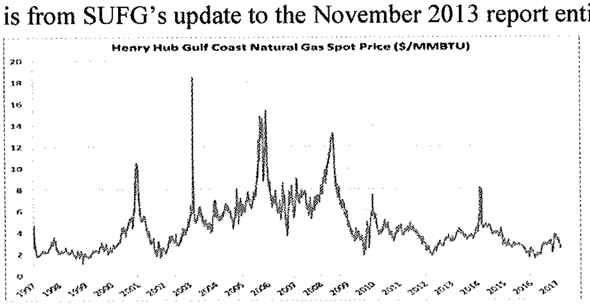
Because business decisions are likely to be increasingly formulated as a result of the IRP process, analysis, and data, and because of the importance of fuel as a driver, utilities should consider using multiple (two or more) independent fuel price forecasts. Ideally, at least one of these forecasts should be a credible forecast in the public domain such as from the Energy Information Administration (EIA). Each of the fuel price forecasts should be supported by a reasonable and credible narrative.

8.1.2 Commodity Forecast Framework

Since the MISO and PJM conduct security constrained economic dispatch to ensure the lowest cost combination of resources are dispatched at any moment in time, subject to constraints, it is essential that Indiana utilities give consideration to a variety of different energy and capacity market price scenarios and sensitivities that could affect their operational and longer-term resource decisions. As with fuel and other forecasts, long-term regional estimates should be supported by credible narratives. For example, regardless of the spread between coal and natural gas prices used in economic dispatch decisions, if a resource is not frequently "in the money" for MISO's and PJM's dispatch, this should be part of a narrative and should be a reference point for the reasonableness of portfolios.

A statewide and regional perspective could provide useful insights and it would be consistent with the IRP statute and draft rules. A statewide (ideally a regional) analysis could provide additional perspectives to

[23] With the exception of a brief spike in early 2014 that was related to an extreme cold spell (commonly referred to as the polar vortex), natural gas prices have remained low since 2013. It should be noted that the 2014 spike was less extreme than those during the winters of 2000/2001, 2003, 2006, and 2008. Horizontal drilling and hydraulic fracturing has allowed the U.S. to capture significant amounts of natural gas from shale formations, where it was previously uneconomic. The result has been a transformation of the characteristics of natural gas prices. This is illustrated by the graph on the following page (data source: Energy Information Administration (EIA)). Information is from SUFG's update to the November 2013 report entitled Natural Gas Market Study. (p. 1).



inform the Commission, policymakers, and stakeholders, and help Indiana utilities assess retirement, retention, and repowering decisions, as well as the potential for future joint projects if technology improvements result in making certain resources economically viable.

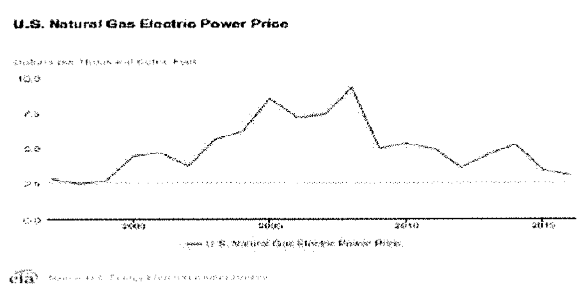
Ideally, Indiana utilities would work with their respective RTOs to consider the broader regional implications of a variety of short, mid-term, and long-run resource options that are comparatively economical and provide appropriate reliability. For example, if a significant amount of coal-fired capacity is being retired in the MISO and/or PJM regions, would this influence retirement decisions for coal units in Indiana?

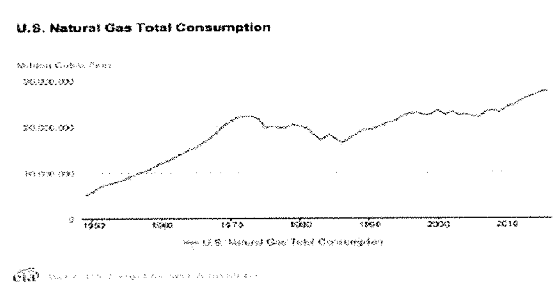
8.1.3 Discussion of Common Issues / Questions

IPL, NIPSCO, and Vectren all used reputable consultants that specialize in energy price forecasts. IPL and Vectren used more than one fuel price projection in their IRPs which seemed appropriate given the importance of fuel prices in this round of IRPs. Especially with the natural gas expertise of NIPSCO and Vectren, as combination utilities, the expectation is higher for well-reasoned narratives to explain the price projections.

To varying extents and owing to the complex interactions of fuel and wholesale electric market prices on load and resources, the narratives offered by IPL, NIPSCO, and Vectren to support their development of assumptions about fuel and wholesale electric market price projections may be too constrained. On page 170 of Vectren's IRP, for example, Vectren said: "…The current over-supply of natural gas continues to dominate the market dynamics. However, low prices eventually result in restricted production and reduced gas supply. Coupled with new LNG export terminals and new heavy industrial facilities, demand rise and gas markets begin to tighten, …Meanwhile coal prices remain depressed in the near short-term as domestic markets remain soft , with a modest price recovery beginning in in 2018." While all of the utilities made similar observations which have considerable merit and plausibility, the fuel and commodity markets seem far more nuanced than traditional supply and demand analysis would offer. For example, none of the utilities advanced an argument predicated on significant technological enhancements and the complex and, often non-intuitive, price elasticity of supply interactions among oil, natural gas, and coal. For future IRPs, foreign trade complexities should also be included in the analysis.[24] It seems that natural gas supplies, for instance, can change quite quickly to changes in the price of oil or natural gas. To the extent that the fuel

[24] According to the EIA (2016), significant improvements in drilling efficiency, well completion techniques, fracturing technologies, and multi-well drill sites (8 to 10 horizontal wells from a single well pad) have substantially increased gas supply.. From 2012 – 2016, well productivity has increased by roughly 300 percent. As a result, natural gas prices are likely to be steadier and less volatile than in the past. As oil and gas producers continue to improve well completion technologies, each well will become more productive and impactful on overall supply.





and market price projections were too constrained, it has an adverse effect on the development of scenarios and sensitives. For example, depending on assumptions for price projections, couldn't reasonable scenarios be constructed for Indiana utilities to address the following types of potentialities?

- Is it possible for natural gas and coal prices to diverge during periods over the 20-year planning horizon?
- Is it possible that reduced customer demand for electricity (perhaps a recession) may not result in lower natural gas or coal prices? Recall the recessions of the 1970s and 1980s where the price of natural gas, coal, and nuclear fuel were very high.
- Would the utilities agree that some level of increased customer demand may not always result in higher coal and/or natural gas prices? Recent history provides an example.
- Are there opportunities for the coal industry, perhaps in concert with the railroads, to lower the delivered cost of coal to a point that may slow the retirement rate of coal-fired power plants?
- Suppose the FERC and the courts reject current attempts by states to subsidize the continued operation of coal and/or nuclear generating units. Does this affect the economics of Indiana generating resources? Correspondingly, did the utilities consider the implications that might result from most utilities retaining much of their coal (and nuclear) generating fleets?
- Suppose state and/or federal law bans fracking in much of the United States. While an admittedly unlikely event, should this be considered in the development of scenarios?
- After the IRPs were submitted, substantial fracking opportunities were discovered (e.g., the Permian Basin). Recognizing the IRPs are a snap shot in time and the IRP analysis was completed before substantial new natural gas potential was public, do the utilities feel the lower natural gas prices projections used in their scenarios might have been even lower?
- Recognizing that the IRPs were developed with the expectation there would be no change in environmental policy, would it have been useful to model a diminished environmental policy?
- What, if any effect, was given to coal and natural gas industry bankruptcies? Did these influence the narratives to justify the fuel price projections?
- What would be the ramifications of lower renewable and EE prices - perhaps due to increased efficiencies beyond those currently projected - on fuel and commodity price forecasts?
- In developing utilities' scenarios and sensitivities from the narratives provided by independent experts for fuel price projections, did the companies' fuel price projections consider international trade and markets for coal and liquefied natural gas exports (imports) over the 20-year planning horizon and the effect on domestic markets?
- What happens to this scenario if trade practices become very restrictive?

Of course there are other potential scenarios. We urge the utilities to give increased consideration to plausible scenarios, including those that have significant ramifications but relatively low probabilities of occurrence. To be clear, there is no intended implication that utilities should run several additional scenarios. Rather, the intention is an expansion of the narratives for the scenarios to have considered a wider range of possible fuel and commodity price projections in the construction of scenarios.

Historically, fuel and resource diversity was also thought to provide greater reliability and serve to moderate volatile commodity prices. More diverse resource portfolios, however, are not necessarily more reliable. The historical price volatility that characterized the natural gas industry for decades may be largely a thing of the past due to fracking, but future prices could be influenced by global markets. Long-term decisions should be informed by an understanding of the dynamics and inter-related complexities of U.S. commodity markets and the influence of global markets. It is incumbent on the utilities to continually evaluate the commodity markets and assess the complex U.S. market interactions while valuing fuel and resource diversity.

8.2. Scenario and Risk Analysis

All Indiana utilities, as well as utilities throughout the nation, are confronting significant uncertainties and risks that seem certain to result in changes in their resource portfolios due, primarily, to projections of low natural gas prices compared to coal. The aging of the existing coal fleet and the very high cost of building new coal-fired generating units poses a significant economic challenge to coal as a fuel source. Even nuclear units in many regions struggle to be cost competitive in the current markets. The rapidly declining cost of renewable resources and the increased capability of the transmission system to carry these resources to distant markets is also a factor. DSM, including improved appliance and end-use efficiencies, is a resource that is likely to be increasingly utilized, even at a time when load growth is minimal or even declining.

Based on these national uncertainties and risks, the Director sees challenges to valid concerns about the rigor and credibility of load forecasting for larger customers in Indiana. Because of the importance of larger customers for NIPSCO and Vectren, in particular, the risks of over- or under-forecasting the demand and energy use of larger customers is important. Especially taken together, changes in the operations and business climate have significant ramifications for these utilities, their employees, customers, communities, and investors.

Each utility said they were taking steps to improve its forecasting for its customers – including the largest customers. These factors heighten the importance of recognizing, assessing, and bracketing the broad range of potential risks and provides opportunities for utilities to develop resilient strategies to minimize adverse consequences of risks. IPL and Vectren made excellent progress in attempting to interject greater use of probabilistic analysis into traditional scenario-based analysis with the recognition that it is a work in progress. Consistent with the IRP draft rule, these initial efforts will mature in future cycles. NIPSCO's efforts to improve its risk analysis were not as successful due to the inability of its models to integrate probabilistic analysis into its IRP. As a result, NIPSCO's IRP was almost certainly not as informative as NIPSCO would have preferred. According to NIPSCO, future IRPs, using more comprehensive state-of-the-art models and improved databases, will not suffer the same limitations.

8.3 Energy Efficiency Issues / Questions

Each of the three utilities is to be congratulated on the significant methodological improvements made so that DSM and other supply-side resource options are treated more comparably. A comparison of the methodologies across the utilities is informative but brings a number of questions to mind.

NIPSCO and IPL used a very similar approach to create DSM bundles, which is in sharp contrast to that used by Vectren. To be clear, the differences in approach should not imply that one method is more efficacious than another. IPL and NIPSCO combined measures with similar load shapes, customer classes, and end uses into bundles. Vectren chose to base bundles on generic DSM savings in eight blocks of 0.25% each year of the planning horizon. The component programs for the blocks developed by Vectren are assumed to initially be those approved in Cause No. 44645.

With regard to Vectren's methodology, every bundle is exactly the same except for costs. More importantly, the load shape of the energy efficiency bundles was exactly the same across the bundles and through time. Vectren used the Strategist default DSM load shape for each bundle which is very comparable to the DSMore load shape used in the 2013 Vectren MPS. In contrast, the bundles prepared by IPL and NIPSCO had load shapes that differed across bundles at any point in time. It is unclear if the load shapes were held constant over time but that appears to be the case. It is not obvious to the Director which approach to developing bundles is superior. Is a uniform bundle, with a uniform load shape, preferable to bundles based on end-use with associated load shapes? Is a resource optimization model going to select a different aggregate amount of DSM based on how these bundles are assembled?

Based on the information available from IPL, NIPSCO, and Vectren, it is not clear that one approach to handle limitations in optimization modeling is superior to another. Certainly, the state-of-the-art computing capability – including reduced run times and modeling sophistication to conduct simultaneous optimization rather than painstaking iterations – has advanced significantly in the last five years. It is likely that models will grow increasingly capable, thus reducing the limitation over time. Regardless of advances in modeling capabilities that are warranted to address the increasingly complex and financially consequential decisions that utilities have to confront in the next few years, the benefits of these new capabilities may not be fully realized until utilities have additional statistically-credible experience to better document the changes in how different customer's use energy and the effects on system peak demand, both within Indiana and across the country, to better inform resource decisions in the future. IPL, in particular, should be commended for its expansive deployment of Advanced Metering Infrastructure (AMI) and its willingness to explore how to more fully develop the information needed for the next generation of DSM analysis.

For Vectren, the different bundle creation processes also demonstrated an entirely different role for - or use of - the respective Market Potential Studies. Vectren's use of identical bundles with a generic load shape was not based in any way on its MPS except to provide indicative information as to the maximum amount of energy efficiency available in its service territory. In other words, Vectren used the MPS to decide if the maximum annual potential savings was 2% or something else. Thus, the MPS was used to decide how many bundles should be considered in any one year which Vectren decided was eight bundles. At this early stage of DSM analysis, the Director takes no position on the efficacy of this approach compared to alternatives except to suggest that the MPS may provide more useful information than was utilized by Vectren.

Both IPL and NIPSCO made extensive use of their respective MPS. Each company used the Market Potential Study to determine the different levels of DSM potential: technical, economic, and achievable. This information was then used by MMP to develop bundles that would be used as resource options in the IRP optimization process. Importantly, the MPS analyses was based on individual measure data and so were the bundles that were fed into the optimization model. The penetration of the measures in each bundle was based on information contained in the MPS.

For both IPL and NIPSCO, MMP utilized the DSMore economic analysis tool to perform a final screening to determine whether the measures coming out of the MPS were cost effective, taking into account utility specific rates, cost escalation rates, discount rates, and avoided costs. Vectren did not perform this step given how they developed its DSM bundles. Vectren instead used its most recent MPS to make sure that Vectren's 2016 levelized DSM cost (the starting point for this analysis) was reasonable.

For all the similarity in overall methodology used by NIPSCO and IPL, there are a couple of differences to note.

1. Both NIPSCO and IPL used the Achievable Potential as determined in their respective MPS. IPL divided the Achievable Potential into 2 levels - MAP and RAP. MAP estimates consider customer adoption of economic measures when delivered through DSM programs under ideal conditions and an appropriate regulatory framework. RAP reflects program participation given DSM programs under typical market conditions and barriers to customer acceptance and constrained program budgets. IPL used the MAP measure estimates to construct the DSM bundles input into the IRP optimization modeling. NIPSCO used a Program Potential based on cost-effectiveness analyses at the measure level by MMP using the screening tool DSMore. Measures that came out of this analyses were combined into bundles by end-use and load shape. IPL also used MMP "to create the DSM bundles using the DSMore cost-effectiveness model."

It appears that NIPSCO used a more conservative version of Achievable Potential than IPL on which it based the DSM bundles. NIPSCO defined Achievable Potential as refining the Economic Potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of DSM measures (p. 77). As noted above, IPL used MAP to develop bundles, and MAP estimates consider customer adoption of economic DSM measures under ideal market, implementation, and customer preference conditions, and an appropriate regulatory framework. It would appear that NIPSCO was more conservative because its definition of Achievable Potential is probably closer to IPL's RAP rather than MAP.

2. IPL and NIPSCO both developed bundles by grouping measures by sector, end use, and similarity of load shape. However, IPL went one step further and disaggregated its bundles by the direct cost to implement per MWh. The three price tiers were: up to $30/MWh, $30-60/MWh, and $60 plus/MWh. As IPL noted, creating cost tiers addresses the issue of having highly cost-effective measures lumped into bundles with marginally cost-effective measures. Such a structure could result in some cost-effective measures not being selected. NIPSCO recognizes the potential problem of mixing higher cost and lower cost DSM measures in the same bundle.

Perhaps the most difficult area to compare and try to draw conclusions is how the cost of the bundles were developed by each utility and how the cost varied both across bundles and within the same bundle over the forecast period. CAC et al. expressed concerns the DSM bundle methodologies implemented by each of the utilities required a forecast of DSM bundle cost and performance trajectories over a 20-year period regardless of the specific cost projection methodology used. Vectren used an approach for bundle cost projections that was very different from that implemented by NIPSCO and IPL.

8.4. Metric Definitions and Interrelatedness

The Director appreciates the development and implementation of metrics used by the utilities in their respective IRPs. Our primary interest is to enter into a conversation to further everyone's understanding of the usefulness of individual metrics and how to best consider the metrics and the story they tell in a holistic manner. Clearly some metrics are more directly relevant to the specific risk being evaluated than others and that needs to be better understood. Another issue is how metrics are weighted. Should all risk measures be weighted equally or are there circumstances where a different weighting is reasonable? Also, some of the metrics probably need to be more clearly defined in a narrative so that their limitations and strengths can be better understood. Lastly, the interrelationships between various measures needs to be more fully understood. That is, are some redundant, are some telling the same story from different perspectives, and are other measures more appropriately evaluated only when also considering other metrics? What are the limitations and strengths of using a scorecard based on informed judgment to evaluate the performance of various resource portfolios across a diverse range of potential futures?

Examples of clearer and more specific definitions can be found in the PJM Interconnection report titled "PJM's Evolving Resource Mix and System Reliability," published March 30, 2017. PJM notes,

> *Fuel diversity in the electric system generally is defined as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility and fuel supply disruptions, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks. In this way, fuel supply diversity can be considered a system-wide hedging tool that helps ensure a stable, reliable supply of electricity. (p. 8)*

PJM also says diversity consists of three basic properties: variety, balance and disparity. As each of these properties increase, diversity also increases. PJM defines the characteristics of diversity as:

- Variety is a measure of how many different resource types are on the system. A system with more resource types in its generation mix has greater variety.
- Balance is a measure of how much grid operators rely on certain resource types. Balance increases as the reliance on different resource types in a generation mix is becoming more evenly distributed.
- Disparity is a measure of the degree of difference among the resource types relative to each other. Disparity can relate to the geographic distribution of resource types – generation resources that are evenly distributed across the system are more disparate than concentrated pockets of generation resources. Disparity also relates to operational characteristics of resources – a system with resource types that have different operational characteristics is more disparate than a system with in which all of the resource types have similar operational characteristics. (p. 9)

PJM also defines resilience differently than how this term is used by IPL in its risk metric discussion.

The Director recognizes that the metrics and definitions developed for a region as large as a RTO may not be applicable to a single utility, but the specificity in the definitions used by PJM is worthy of emulation where appropriate. Also, the PJM report makes clear that the relationship between diversity and reliability is not linear. More generally, the costs, benefits, and reliability values of fuel and resource diversity is dynamic and extremely important. Future IRPs should devote considerable attention to developing and interpreting different risk metrics and should be informed by experts and stakeholders.

A critical objective should be a robust or resilient plan. How is this defined? How should it be measured? The utilities seem to be using different definitions but a key common aspect is exposure to the wholesale power market. More specifically, exposure beyond some undefined level is generally thought to be bad but there seems to be little recognition, except for NIPSCO, that length of commitment to a specific resource – particularly one that is capital intensive and long-lived can also be a problem. Steel in the ground eliminates market exposure in a sense but has the downside that the costs are sunk and thus are probably exposed to the highest degree of technological risk. Again, a more detailed discussion of the uncertainties, risks, and ramifications of fuel and resource diversity under a variety of scenarios would be helpful.

9. DIRECTOR's RESPONSE TO THE INDIANA COAL COUNCIL

The Director is pleased that the Indiana Coal Council (ICC), because of its status as an important stakeholder, provided useful and insightful comments in this IRP cycle. The Director agrees with many of the comments made by the ICC. IPL, NIPSCO and Vectren, to varying extents, have also agreed with some of the comments made by the ICC.

At the outset, the Director understands the *ICC does not agree "that natural gas prices will be lower cost in the long-term due to fracking and improved technologies"* and with some of the other analysis conducted by the utilities. Perhaps, if the ICC had participated in the stakeholder processes of the utilities, the ICC's input might have been given specific effect but, at a minimum, the differences of opinion might have been narrowed and misunderstandings about the IRP process might have been avoided. The Director hopes the ICC will avail itself of the next stakeholder processes.

9.1 Fuel and Market Pricing Dynamics

The ICC made the following comment on page 1:

> "*The ICC respectfully disagrees with the statement in the Draft Director's Report (footnote 5) that suggests that every utility and stakeholder agrees that natural gas prices will be lower cost in the long-term due to fracking and improved technologies. At a minimum, that is not ICC's opinion.*"

To be clear, footnote 5 of the Draft Director's Report does not suggest that "*every utility and stakeholder agrees natural gas prices will be lower in the long-term.*" Rather, the footnote merely states the fact that the utilities' IRPs found that: *The primary driver of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies.*[25]

The Director, IPL, NIPSCO, and Vectren agree to varying extents with some of the comments provided by the ICC regarding the need for greater emphasis on the narratives supplied to the utilities by independent and objective experts. The Draft Director's Report also encouraged utilities to be more expansive in their risk analysis by considering a broader spectrum of fuel prices – including higher natural gas prices and lower coal prices. The Director addresses both of these topics in greater detail below.

If the narratives from the independent experts that were retained by the utilities had provided more details about the drivers for the prices of fuels, and if the ICC had participated in the IRP stakeholder processes, it seems possible that at least some of the concerns raised by the ICC might have been addressed. However, the Director's and the utilities' views were also informed by the following empirical facts:

[25] The complete footnote 5: *The primary driver of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies.* As a result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change.

A. Coal-fired generating units are not being dispatched as fully as they had been. This is evidenced by reduced capacity factors in competitive wholesale markets facilitated by the MISO. Some utilities have requested subsidies from states to support some generators.
B. The retirements of several coal-fired generating units have been announced in this region despite the recent increase in natural gas prices.
C. The only coal-fired plant under construction in the continental U.S., will probably be cancelled.[26]
D. Against the backdrop of cost overruns and delays at Southern Company's Kemper IGCC unit, it seems unlikely that there will be any new coal-fired generating units being built in the continental United States.
E. The above competitive market-based indicators, combined with a preponderance of confirming studies,[27] add additional credence to the results from the Indiana utilities' IRPs.

The Director agrees with the ICC that expanded analysis of a broader range of coal and natural gas prices would have been informative. Utilities and stakeholders might have found using extreme changes in price assumptions for natural gas and / or coal would provide useful information to determine the point of inflection where changes in price assumptions would affect resource decisions.

The Director believes IPL, NIPSCO, and Vectren fully recognized that planning their systems based upon highly unlikely events / assumptions would not be consistent with good planning. Indiana's utilities' IRPs should continue to recognize the value of fuel and resource diversity, even if they cannot quantify the

[26] Topeka — A controversial plan to build an 895-megawatt coal fired power plant in southwest Kansas now appears to be dead, company officials behind the project have said. In an August filing with the Securities and Exchange Commission, Denver-based Tri-State Generation and Transmission Association described as "remote" the chances that it will ever build the plant, and it said the company is writing off as a loss more than $93 million it has already spent on the project. "*Although a final decision has not been made by our Board on whether to proceed with the construction of the Holcomb Expansion, we have assessed the probability of us entering into construction for the Holcomb Expansion as remote...Based on this assessment, we have determined that the costs incurred for the Holcomb Expansion are impaired and not recoverable.*" Lawrence Journal World, Sept 19, 2017.

[27] Trump Administration's "Staff Report on Electricity Markets and Reliability" released by the Department of Energy on August 2017. This recent DOE study is replete with commentary such as:

> *The biggest contributor to coal and nuclear plant retirements has been the advantaged economics of natural gas-fired generation. Low-cost, abundant natural gas and the development of highly-efficient NGCC plants resulted in a new baseload competitor to the existing coal, nuclear, and hydroelectric plants. In 2016, natural gas was the largest source of electricity generation in the United States—overtaking coal for the first time since data collection began. The increased use of natural gas in the electric sector has resulted in sustained low wholesale market prices that reduce the profitability of other generation resources important to the grid. The fact that new, high-efficiency natural gas plants can be built relatively quickly, compared to coal and nuclear power, also helped to grow gas-fired generation. Production costs of coal and nuclear plants remained somewhat flat, while the new and existing, more flexible, and relatively lower-operating cost natural gas plants drove down wholesale market prices to the point that some formerly profitable nuclear and coal facilities began operating at a loss. The development of abundant, domestic natural gas made possible by the shale revolution also has produced significant value for consumers and the economy overall.* (Page 13 – Emphasis added).

value of diversity. Based on the utilities' recognition of the critical importance of fuel price projections and representations made by IPL, NIPSCO, and Vectren, the Director is confident that future IRPs will devote increased effort to capture the complexities of fuel price dynamics.

> *"For a utility to craft a resource plan without consideration of the complexities of the natural gas market (including plans to address the volatility) is problematic for customers.*
> Comments of the Indiana Coal Council on the Draft Director's Report for the 2016 Integrated Resource Plans, Page 2 of their letter.

Again, the Director, IPL, NIPSCO, Vectren will, to varying extents, agree with the ICC's comments that the natural gas markets are becoming increasingly complex. The Director is confident that utilities not only recognize the increasing complexities but will insist that narratives supplied by independent experts for future IRPs reflect the degree of uncertainty and complexity inherent in fuel price forecasts. The Director believes the analysis conducted for this IRP by IPL and NIPSCO especially combined with the commitment to continued enhancements, should help allay concerns.

> **IPL**
> *IPL agrees that the interrelationship between commodities and power markets will continue to evolve with the changing landscape of natural gas production and demand, the changing national and regional resource mix, and stagnant regional load growth projections. The forecasts and projections have a major influence on the portfolios generated as part of an IRP process, and IPL is committed to enhancing robust modeling techniques and discussing assumptions in an open and transparent manner as part of the stakeholder process. IPL is confident that ABB's Reference Case methodology is consistent with forecasting best practices and relies on fully integrated energy models that ultimately build up to the power prices used in the production cost modeling. In the next IRP, IPL will commit more to fully describing the fundamentals underlying the forecasts used.* Indianapolis Power & Light Company Reply to Director's Report on the 2016 Integrated Resource Plans August 28, 2017, Page 2.
>
> **NIPSCO**
> *The Director expressed concern that NIPSCO's fuel price projections do not capture the 'nuanced and dynamic relationships between oil and natural gas or whether the historic correlations between natural gas and coal markets are changing.' NIPSCO takes note that the Director also noted that NIPSCO needs to do more than simply have a correlated price forecast. NIPSCO accepts the Director's observation and will do so in future IRPs.* Northern Indiana Public Service Company's Response to the Director's Draft Report on NIPSCO's 2016 Integrated Resource Plan, Page 1
>
> *NIPSCO has engaged a consultant that independently forecasts fuel prices using an integrated market model. Moreover, the consultant intends to provide underlying assumptions, alongside benchmarking to publicly available forecasts, to support its analysis. NIPSCO also notes the Director's agreement that several of the Indiana Coal Council's ("ICC") comments merit consideration. To that end, NIPSCO has had follow up meetings with the ICC to discuss its concerns.* Page 2

Director's Summary of Fuel and Market Pricing Dynamics
These increasing complexities and interrelations of the natural gas market and the resulting fuel price projections is one of the four primary focal points of the Draft Director's Report. These complexities and interrelationships were also addressed in the other topics; particularly in the construction of scenarios,

sensitivities and, ultimately, in the resource portfolios. Particularly as the resource decisions become increasingly close calls, the Director is confident that Indiana utilities and their stakeholders will appreciate the importance of independent, objective, and comprehensive fuel and market price projections and will insist on well-reasoned narratives.

9.2 Scenario Development and Risk Analysis

> *The ICC is confused by the Commission's position that the IRP is limited to being "a point in time analysis". While the revised Rule 7 has not been finalized, every draft version that ICC has seen contains a new Section 10 which specifically addresses Major Unexpected Change following that publication of the IRP... ICC respectfully requests that the Draft Director's Report consider more forceful language related to the limited validity of IRP findings acknowledging that no material actions should be taken without new analysis at the time of a filing and include reconsideration of what has turned out to be dated findings.* [Page 3 of the ICC letter]

The Director believes the ICC may misunderstand the purpose of the IRPs and any concerns are premature. The Director reiterates on page 5 of the Draft Report "*With good reason, IPL, NIPSCO, and Vectren have sought to maintain as much optionality as possible in their IRPs... To this end, the IRP analysis – including the utility's selection of a preferred resource portfolio – should be regarded as an indicative analysis, in that the results are based on appropriate information available at the time the study was being conducted and does not bind the utility to adhere to the preferred resource portfolio, or any other resource portfolio. If there is information to support a different outcome in a matter before the Commission after an IRP used to support a resource decision is completed, the utility should assess whether an update to the IRP is appropriate. Ultimately, in the instance of a case before the Commission, the Commission, after consideration of testimony, will decide whether additional analysis is necessary to provide the Commission with the requisite information.*"

9.3 Continued Improvements in the IRP

> *The ICC is surprised by the standard to which the Commission is holding for the utilities which have submitted IRP's. A "better than last time" performance should not be acceptable if there have been significant flaws in their analyses, be it with respect to assumptions and/or methodology.* Page 3 of the ICC letter.

The draft rules recognize that IRPs (e.g., the data, analysis, methods, computer capabilities, and stakeholder process) are evolutionary in the quest for continual improvements rather than the impossible requirement for utilities to accurately project optimal resource requirements over the 20 year planning horizon. The Director disagrees with the ICC's characterization on pages 3 and 4 of their letter that the utilities had "*significant flaws in their analyses, be it with respect to assumptions and / or methodology.*" The Director stands by the well-deserved comment that utilities have made continual enhancements to their IRP processes.

9.4 ICC's Suggestion for Commission Consideration

> *The ICC strongly believes the utilities' and the Commission's* ***consideration of the broad public*** *interest can be improved upon and should include an analysis of the resource plans' impact on the state economy.* (Page 4 of the ICC letter)

This is a matter for the Commission to consider, consistent with its statutory authorities. Moreover, in addition to the proposed draft IRP rules, the utilities gave considerable consideration to the potential ramifications for their employees, customers, and communities.

SUMMARY

The Director cannot over-state the technical complexities inherent in the development of credible IRPs. The comments offered by stakeholders that participated in the process, as well as those offered by the ICC, highlight the daunting task. The Director takes this opportunity to commend IPL and NIPSCO for their commitments to make future enhancements to subsequent IRPs.

10. Director's Response to the CAC et al

10.1 Stakeholder Process

Stakeholders, like the CAC et al, that have participated in the IRP process for several years and have made significant contributions to the IRP processes have commended Indiana's utilities for substantial improvements in all aspects of the IRPs, including the stakeholder processes. The Director and utilities agree with the CAC et al that, future enhancements to the stakeholder process are desirable. As the Director noted:

> *All utilities are committed to enhancing their stakeholder process. By going from a two year to three year IRP cycle, utilities can increase stakeholder input by: 1) establishing objective metrics to evaluate their IRP; 2) defining the assumptions (e.g., fuel prices, costs of renewable resources, costs of other resources); 3) constructing scenarios to provide a robust assessment of potential futures; and 4) reviewing the resulting resource portfolios.* Page 3 of the Draft Director's Report.

Beyond the CAC et al's contribution to the IRP processes, it is incumbent upon all other stakeholders to make an effort to understand the complexities of IRP to provide well-reasoned input. It was commendable that utilities, on their initiative, provided a primer on long-term resource planning to help stakeholders increase their knowledge of the processes. For the benefit of stakeholders, utilities should continue to provide information on the building blocks of long-term resource planning. For stakeholders that have expertise and experience in IRP, utilities might consider a *deeper dive* into some of the elements such as the inputs for the IRP, how the models work and constraints on their operations, and how difficult topics such as DSM and Distributed Energy Resources (DER) are modeled.

There are limits to what can be done in a stakeholder process to facilitate education beyond starting earlier to permit greater sharing of information and limiting - to the maximum extent possible – the withholding of information due to proprietary and confidentiality concerns. The Director appreciates the increased burden on the utility as well as stakeholders. However, the improved processes should reduce controversies or, at least, focusing the areas of controversy more narrowly. To reiterate:

> *The utilities have all made a concerted effort to broaden stakeholder participation. All of the utilities have offered unprecedented transparency and candor. It is gratifying that the top management of each utility, top staff and subject matter experts have all been made available to facilitate the collegial stakeholder process.* Page 2 of the Draft Director's Report.

10.2 Formatting Material

The Director is pleased that IPL, NIPSCO, and Vectren have made substantial enhancements to the content and clarity of their IRP's but agree with the CAC et al's comment that "*utilities [should] endeavor to present basic information in a more readable and accessible fashion.*" (Page 1 of CAC et al's comments) The Director appreciates the utilities commitment to make continued improvements. From the inception of the IRP process in Indiana, the Director has been reluctant to be too prescriptive in how the IRPs should be formatted. However, there is some core information that the utility, the Commission, the OUCC, stakeholders, the RTOs, and others would like to have available in the IRPs and in formats (narratives, graphics, tables, and mathematics) that are informative and easily understood. The Director welcomes suggestions.

10.3 Referencing Stevie's section we share many of the concerns

Comments made by the CAC et al regarding the interesting work done by Dr. Dick Stevies' were excellent and very much appreciated. The Director agreed with many, but not all, of the concerns raised by the CAC et al. For a more detailed discussion, the reader is invited to read the Director's response to Vectren.

10.4 Metrics

The Director agrees with the CAC et al that the metrics used to evaluate the efficacy of the portfolios should be improved upon but recognizes this is the first time that metrics have been expressly detailed. Especially given the newness of the metrics, the Director recommends all Indiana utilities, with input from stakeholders, consider establishing metrics early in the stakeholder advisory IRP process. Stakeholders should recognize the possible need for adjustments to the metrics as the modeling proceeds. To the extent reasonably feasible, the metrics should be quantifiable. However, stakeholders should recognize some metrics are inherently subjective (e.g., the value of resiliency or fuel / resource diversity) but this should not mean that there is no effort to gain a general understanding about how those metrics will be evaluated and weighted. Ideally, mutual understanding of the metrics will reduce misunderstandings as the utilities' preferred portfolio and the other portfolios are assessed.

10.5 Modeling

The Director agrees with the CAC et al that all models (e.g., long-term planning models, DSM models, forecasting models, financial models) have limitations or constraints. Stakeholders and the Director would appreciate as much transparency as possible to understand the limitations of specific models. It is not obvious to the Director that these modeling limitations don't adversely affect the results compared to an idealized model with no such limitations. Nor is it apparent to the Director that alternative methods of working through the model limitations don't provide different results. The run times are greater for models that rely on multiple iterations rather than those models that have greater capability to conduct simultaneous optimizations. Ultimately, it seems likely that modeling a single bundle of all resources would enable more comparable treatment of all resources than multiple iterations of multiple selected bundles of resources. As the computer capabilities expand current modeling constraints will be reduced. Of course, it is the discretion of the utility to evaluate, compare, and value the different strengths and weaknesses embodied in different models

10.6 The Future of IPL Stochastic Analysis

The CAC et al raised a potential concern that IPL may be placing too much reliance on stochastic analysis at the expense of scenario analysis. A statement by IPL in their comments on the Draft Director's Report might cause further concern for CAC et al:

> *IPL could accommodate showing a similar table in the next IRP, but believes that the probabilistic modeling effectively accomplished the same thing in a more robust manner by showing how each portfolio performed across 50 simulations using alternative assumptions, not just the three to four drivers that changed with each scenario. An alternative approach to each of these methods would be to incorporate stochastics into the capacity optimization up front. Rather than generating five to ten*

> *portfolios from deterministic scenarios, the optimization engine would select the best portfolio across all of the probabilistic simulations. IPL's new modeling software is expected to enable this type of capacity optimization modeling in addition to traditional deterministic scenarios combined with stochastic sensitivities. Some binary factors such as regulation or carbon pricing are difficult to capture stochastically, so IPL expects to rely on multiple methods for developing and evaluating portfolios in the next IRP.* (Page 3) – Emphasis added.

But the Director trusts that IPL recognizes that some planning analysis is best suited to scenario analysis and IPL's inference that their new long-term resource planning models will facilitate probabilistic analysis is not to the exclusion or detriment of scenario analysis. More broadly, for all Indiana utilities, the Director has tried to emphasize that scenario and probabilistic analysis are complimentary rather than being substitutes or mutually exclusive.

INDIANA UTILITY REGULATORY COMMISSION

ELECTRICITY DIRECTOR'S
FINAL REPORT
2015 - 2016 INTEGRATED RESOURCE PLANS SUBMITTED BY
DUKE ENERGY, INDIANA MICHIGAN, INDIANA MUNICIPAL POWER AGENCY, AND WABASH VALLEY POWER ASSOCIATION

Date of the Report: August 30, 2016

ELECTRICITY DIRECTOR'S FINAL REPORT
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INTRODUCTION TO THE FINAL DIRECTOR'S REPORT
FOR 2015-2016 INTEGRATED RESOURCE PLANS
Issued August 30, 2016

A. INTRODUCTION AND BACKGROUND

With the passage of P.L. 246-2015 (SEA 412-2015) on May 6, 2015, Indiana law now explicitly requires long-term resource planning for the State of Indiana. For the Integrated Resource Plans (IRPs) submitted on or after Nov. 1, 2012, the utilities voluntarily adhered to the Draft Proposed Rule (Proposed Rule) to modify 170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans (RM 11-07). The Indiana Utility Regulatory Commission (Commission), utilities, and stakeholders collaboratively developed the Proposed Rule, which is available on the Commission's website at http://www.in.gov/iurc/2674.htm.

Four Indiana utilities submitted their IRPs on Nov. 1, 2015. Links to the IRPs can be found at http://www.in.gov/iurc/files/2015_to_16_IRP_DRAFT_REPORT_MAY_20_2016.pdf. Links to the utilities' comments regarding the Director's Draft Report and other stakeholders' comments are included here. Please note that these are the public versions of the IRPs and do not include confidential information and most appendices:

1. **Duke Energy Indiana** (DEI)
http://www.in.gov/iurc/files/DUKE_Reply_Comments_to_Directors_Draft_2015_IRP_6_20_2016.pdf
2. **Indiana Michigan Power Company** (I&M)
http://www.in.gov/iurc/files/I_and_M_Reply_Comments_to_Directors_Draft_2015_IRP_6_20_2016.pdf
3. **Indiana Municipal Power Agency** (IMPA)
http://www.in.gov/iurc/files/IMPA_Reply_Comments_to_Directors_Draft_2015_IRP_6_20_2016.pdf
4. **Wabash Valley Power Association** (WVPA)
http://www.in.gov/iurc/files/WVPA_Reply_Comments_to_Directors_Draft_2015_IRP_6_20_2016.pdf

Written comments regarding the IRPs and the Director's Draft Report also were submitted by various entities, including Citizens Action Coalition, Earthjustice, Indiana Distributed Energy Alliance, Michael A. Mullett, Sierra Club, and Valley Watch, referred to as Joint Commenters. These comments can be found at
http://www.in.gov/iurc/files/JOINT_COMMENTERS_Reply_Comments_to_Directors_Draft_2015_IRP_6_20_2016.pdf.

Section 2 (h) of the Proposed Rule requires the Director to issue a Draft Report on the IRPs no later than 120 days from the date a utility submits an IRP to the Commission. Section 2(k) of the Proposed Rule limits the Director's Draft Report and Final Report to the informational, procedural, and methodological requirements of the rule, and Section 2(l) of the Proposed Rule restricts the Director from commenting on the utility's preferred resource plan or any resource action chosen by the utility.

THE IMPORTANCE OF THE IRP PROCESS

Although businesses dedicate varying degrees of effort to forecasting demand for their products and planning to meet their customers' needs, few industries are as important as the electric system, which has been called the most complex manmade system in the world. Because of the critical importance of the industry, state-of-the-art planning processes are essential. The need for continual and immediate improvements is heightened by the risks resulting from significant changes due to aging infrastructure, increasingly rigorous environmental regulation, substantially reduced costs of natural gas, a potential paradigm change resulting in long-term low load growth, declining costs of renewable resources, and technologies including combined heat and power. The Proposed Rule anticipates continual improvements in all facets of the planning processes of Indiana utilities. The Director recognizes that DEI, I&M, IMPA, and WVPA place great reliance on their IRPs as being integral to their business planning. Utilities have made substantial progress in enhancing the credibility, clarity, and all technical aspects of their IRPs. However, given the increasing risks and their attendant financial risks, there is a need for continued improvements.

PRIMARY ISSUES IN THE IRP PROCESS—GENERAL COMMENTS

The Final Report primarily focuses on the importance and need for continued improvement in load forecasting, demand-side management (DSM), and integration of DSM into the load forecast because these were common areas of concern and interest among all four utilities. The focus on these three areas should not be construed as suggesting that the Director is not interested in continuing improvements in risk analysis in IRPs, the need for continuing enhancements to the stakeholder process, continued efforts to integrate renewable and customer-owned resources into the IRPs, mutually beneficial interactions with the regional transmission organizations' (RTOs') long-term planning as it affects the utilities' IRPs, improvements to databases, and continued development of state-of-the-art planning tools. To a large extent, all four of the utilities made substantial improvements in these areas.

COMMITMENTS TO CONTINUAL IMPROVEMENTS

DEI, I&M, IMPA, and WVPA all have committed to continual improvements in the development of more easily understandable and internally consistent narratives for all aspects of the IRP. Although the Director does not intend to be prescriptive in the form of the IRPs, it is imperative that utilities write for both a lay audience and an expert audience. Meeting these two different and disparate objectives is a difficult but essential undertaking. The utilities should consider stakeholder input to provide one means of evaluating drafts of the report. In addition to a concise executive summary, the primary effort to educate a wider audience should include concise narratives, easy-to-understand graphics, and understandable examples. It may be that more in-depth analysis of subject matters could be contained in appendices. Utilities, as part of their articulation of potential continual improvements, might use this as an opportunity to expound on specific approaches, innovative ideas, the efficacy of software, the development of enhanced databases, and how the Commission might be of assistance.

All Indiana electric utilities are commended for making a concerted effort to improve stakeholder understanding and active participation. To this end, the utilities conducted a primer on Integrated Resource Planning. For specific stakeholder processes, the top management and technical staff of I&M was particularly actively engaged. DEI's technical staff was very engaged.

The Director is appreciative to the utilities and stakeholders that participated in the process, particularly those that offered comments. With the longer IRP cycles, the Director hopes there will be greater opportunity to explore difficult issues more thoroughly and to have more meaningful input into the development of databases, assumptions, scenarios, sensitivities, and analysis of the various portfolios. Based on the helpful clarifications and constructive criticisms, the Director intends to have more dialogue with utilities and stakeholders throughout the process.

B. COMMENTS ON EACH UTILITY'S INTEGRATED RESOURCE PLAN

1. DEI's INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

This Final Director's Report reflects the following issues and emphasizes those that the Director regards as important concerns. Because of the significant improvements in risk analysis and other aspects of the IRP, combined with uncertainties about the Clean Power Plan (CPP), this report does not address all the questions and concerns raised by the Director or stakeholders in the Draft Director's Report. The issues are:

- Load forecasting
- Demand Side Management (DSM)
- Relationship between load forecasting and DSM

DEI's written response to the Draft Report and subsequent meeting with technical staff was helpful and informative. The Director notes the questions contained in the three topic headings are intended to stimulate further thought and discussion rather than promoting or advocating specific methodologies. The intent of the Director's Report is to challenge processes, analysis, and tools if they might be done better, not just be done differently. Many, if not most, of the issues addressed throughout this report are quite new, and our collective knowledge and experience are too limited to make definitive recommendations at this time.

At the outset, the Director recognizes that IRPs provide a snapshot of optimal resource development based on current information and assumptions. Noting that the primary drivers of resource decisions are dynamic, the Director recognizes that DEI used this IRP as part of their business plan to objectively assess retirements and additions to the resource mix as well as their DSM filings, which is a primary purpose of the IRPs.

DEI has undertaken an innovative stakeholder process. The uncertainties, particularly regarding the status of the CPP, afforded DEI an opportunity to experiment with the stakeholder process. DEI was able to gain broad acceptance of the portfolios and then constructed scenarios and sensitives to evaluate those portfolios. Although this is in contrast to the normal practice of constructing scenarios and sensitivities and allowing the long-term planning models to develop optimized (based on the underlying assumptions) resource portfolios, DEI's *reverse engineering* of selecting the portfolios first and deriving the scenarios to support the portfolios provided useful insights. Having served the purpose of confidence building between DEI and stakeholders, for DEI's next IRP in the 2018 – 2019 cycle, the Director anticipates DEI will use a more conventional approach to long-term resource planning for DEI's 2018-2019 cycle.

The IRP stakeholder process also served an important purpose of confirming that DEI and its stakeholders share many common goals in the consideration of long-term resources. The recognition of shared goals should give all Indiana utilities confidence that they can find common ground on important issues of reliability, cost of delivering power, and meeting environmental requirements in a rapidly changing electric industry.

DEI also made significant improvements in their IRP analysis. During the stakeholder meetings, DEI recognized the increasing risks associated with dramatic changes in the resource mix throughout the region and Eastern Interconnection. This places added emphasis on the need to inform its resource planning analysis with information from the Midcontinent Independent System Operator (MISO), especially if the CPP is upheld by the Supreme Court. Assessing the potential ramifications of various risks make the development of a broad range of scenarios and sensitivities more important to better assess potential risks of achieving reliability metrics and avoiding a higher cost of delivering electricity. These various risk factors include the following:

- Future wholesale power prices for coal-fired generation
- The projections for low-cost natural gas
- The decreasing cost and increasing efficiency of renewable resources
- Technological changes for DSM that make this resource more cost effective
- Increasing potential for customer-owned generation
- Small increases in (or perhaps even declining) load growth
- Increasing capital costs of traditional coal-fired and nuclear generating resources
- Increasingly stringent environmental policies

To this end, DEI's IRP had improved narratives to describe alternative futures associated with each scenario. In addition, DEI employed state-of-the-art analytical tools that add credibility to the IRP analysis, and their efforts to treat DSM comparably to other possible resources is commendable.

The Director also appreciates Scott Park, Melanie Price, Dick Stevie, Phil Stillman, and Tom Wiles meeting with the Commission's IRP staff to clarify questions and address concerns expressed in the Draft Director's Report. The Director's intent is that the comments in this Final Report reflect the improved understandings from this meeting. Among those understandings is that DEI is committed to continual improvements in describing the scenarios, sensitivities, assumptions, and methods such as the construction of DSM bundles and the treatment of DSM on as comparable a basis as is reasonably feasible to other resources.

DEI's offer to share the modeling results with stakeholders; as long as this does not interfere with the IRP's timely completion is appreciated. With the three-year cycle in the new Draft Proposed IRP Rule, it is hopeful that this will afford more opportunity for stakeholders to have meaningful input from the inception of the IRP through the preparation of the submittal of the IRP.

The Director acknowledges the time commitment involved in the stakeholder process by DEI's technical staff. In prior years, Doug Essaman attended the sessions, which gave the stakeholder process gravitas by confirming its importance to DEI. Hopefully, the level of commitment to a useful, credible, and robust IRP will continue.

Load Forecasting

DEI's Load Forecasting

DEI uses ITRON's Statistically Adjusted End Use (SAE) model for residential and commercial forecasts. The basic industrial forecast econometric model structure is largely unchanged from prior years. However, DEI replaced Regional Manufacturing GDP with the Industrial Production Index. In addition to industrial production, employment and the effect of electricity prices also are primary drivers.

The Director's Draft Report
The Draft Director's Report asked DEI to discuss the rationale for some changes in the load forecasting model's specifications to discuss how weather normalization was done, explain the calculations for coincident peak demand, specify whether DEI plans to enhance their load research database and increase reliance on DEI- and Indiana-specific data, and specify whether DEI is considering enhancements to their commercial and industrial forecasts.

DEI's Reply Comments
DEI, in their response to the Draft Director's Report, explained the rationale for changes in the load forecast for each type of customer. DEI, on an ongoing effort, planned to enhance the credibility of their weather normalization to a 30-year history and increase their use of Indiana-specific data, including enhanced use of DEI-specific load research.

The Director's Response
DEI and its stakeholders recognize that the load forecast is the foundation of the IRP process. The ramifications of over- or under-forecasting customers' long-term electricity needs pose a significant financial and reliability risk to DEI and its customers. Because of its primacy in the planning process, the Director and the Citizens Action Coalition (CAC), et al. devoted considerable attention to DEI's load forecasting processes, analytical tools, and methodology.

Based on the information provided by DEI in their reply comments and in conversation, the Director believes that DEI's load forecast methodologies, analytical tools, and processes are reasonable. Of course, as with all aspects of the IRP, it is anticipated that there will be ongoing scrutiny of forecasting methods and data. For example, the Director expressed concerns about too much reliance on intelligence gained from conversations with the large account representatives or quarterly earnings calls (page 22 of DEI's response). The information gained from these sources has value, but it may be primarily short term. As DEI noted, industrial customers have a relatively short planning horizon. Also, industrial customers might not be comfortable or even legally able to share long-term information about their operational and production plans.

As evidenced by changes DEI has made to the forecasting models, it is clear that DEI is committed to continual improvement. DEI agreed that increased data from AMI and Smart Grid will enhance the forecasting and DSM databases (page 21 of DEI's response). For purposes of more robust risk analysis, DEI also committed to "exploring high and low load grow scenarios or sensitivities when making resource decisions…in its next IRP" (page 19 of DEI's response).

DEI's Demand-Side Management

DEI's DSM Analysis
DEI created two types of energy-efficiency (EE) bundles. A base bundle was modeled to reflect the general level of savings and aggregate performance characteristics similar to the 2015 programs and those proposed for the 2016 – 2018 period. DEI also created an incremental DSM bundle with characteristics identical to the base bundle except higher cost because they are trying to increase customer participation. DEI's optimization model always selected the base bundle and at times augmented the base bundle with an incremental bundle. In sum, the optimization model could choose more DSM than the base bundle, but it did so only on a limited basis based on cost effectiveness.

The bundles reflected general measure characteristics and load shape, and this information was included in the optimization process rather than any specific measures.

The Director's Draft Report
The Director and CAC et al. asked for elaboration on whether the DSM bundles might be more discrete to take better advantage of one of the inherent benefits of DSM relative to traditional resources. The Director also asked for DEI's thoughts on whether sub-hourly demand data might provide valuable insights that could appropriately affect the comparisons with other resources.

DEI's Reply Comments
With regard to the construction of DSM bundles, DEI said, "Simultaneous optimization did occur in the modeling because the IRP model was given the opportunity to select from multiple bundles of EE (page 6 of DEI's response). DEI notes that incremental DSM has an opportunity to be selected by the planning model without being tied to specific measures (page 8 of DEI's response). Because simultaneous optimization was conducted for DSM and all resources, the results were not hardwired. DEI also noted, "The Economic Potential DSM from the Market Potential Study was used as an upper limit to the overall size of all of the Base and Incremental Bundles combined which was not reached by any of the IRP scenarios." DEI did not "start with the overall Technical Potential and work backwards, but rather to start with a well-known set of programs and build upwards" (page 9 of DEI's response). That is, in advance of resource optimization, no DSM was screened out.

Based on the IRP and DEI's written and verbal responses, the Director understands that DEI pre-screens measures for the same end use to use the most cost-effective measures and bundles them based on the initial expected cost and avoided costs. The first base DSM bundle was based on a combination of the 2015 approved portfolio, the 2016 – 2018 proposed portfolio, and an expectation that the EE programs in 2019 and beyond would provide the same level of EE impacts as 2018. This initial portfolio was evaluated for cost effectiveness but was only the starting point for the creation of a set of EE bundles to be evaluated in the IRP. No pre-screening was performed to eliminate programs. In fact, no cost-effectiveness testing was performed on any of the other nine DSM bundles prior to being analyzed in the IRP model. Tom Wiles and Dick Stevie discussed how DEI analyzed EE. Dick Stevie provided an analysis of the process. This additional clarification was helpful, and it might be of interest to other Indiana utilities. Recognizing there is no consensus on the right way to analyze EE, this approach may serve as useful discussion for further enhancements of the analysis of EE.

The Director's Response
The Director understands from the written response as well as from conversations with DEI's technical staff that DEI initially developed bundles that were screened based on their familiarity with the expected cost of individual DSM programs. DEI states the DSM measures were subjected to analysis by "DSMore" (a DSM planning model) which "requir[es] imputing information regarding the energy efficiency measure or program to be analyzed, as well as the program cost, avoided costs, and rate information of the utility" (page 14 of DEI's response). The System Optimizer (the long-term planning model) was allowed to select base and incremental DSM bundles based on their costs and load shape ramifications on the same basis as any other resource.

The construction of DSM bundles, the "roll off" of DSM effects from the load forecast, and the treatment of EE on as comparable a basis as is reasonably feasible seemed to be well regarded by the CAC and other stakeholders during the stakeholder meetings. However, from questions and concerns raised by the Director and CAC, these topics remain a matter of continued interest and questions. DEI's written response to the Draft IRP Report, the CAC's comments, and our subsequent meeting with DEI clarified how EE was modeled. In recognition of this ongoing interest, DEI committed to a more detailed discussion of these topics in future IRPs.

The Director is pleased that DEI intends to investigate improvements for future IRP analysis, including modeling the incremental DSM bundles with more granularity related to individual programs and potentially shortening the operating period of each bundle (page 14 of DEI's response). With increased deployment of advanced metering infrastructure (AMI), DEI recognizes that increased granularity of data (e.g., sub-hourly load data) would be a further refinement to future IRPs (page 20 of DEI's response). This level of usage detail, especially when combined with appliance/end-use data and demographics, would give appropriate advantage in the resource modeling to smaller amounts of DSM compared to natural gas peaking generation and, certainly, other relatively large ("lumpy") generating resources that have higher minimum capacities.

Relationship between Load Forecasting and DSM

DEI's Load Forecasting and DSM Integration
Scott Park, Dick Stevie, Phil Stillman, and Tom Wiles provided a good clarification of how EE was integrated into DEI's load forecasting. DEI's load forecast includes the EE forecast that is based on the expected implementation of the portfolio proposed in Cause No. 43955 DSM-3 and assumptions for incremental EE that is contained in DEI's proposed portfolio (page 23 of DEI's IRP; also see the table on page 78 of DEI's IRP). DEI stated that, based on "stakeholder and Commission staff recommendations, EE was modeled as a supply-side resource. This is particularly challenging due to the way EE is included in the load forecasting process, the uncertainty of EE forecasting, and combining EE programs into a bundle that can be modeled with supply side resources like natural gas fired combined cycle or solar resources" (page 9 of DEI's IRP).

The Director's Draft Report
Because of the complexities of accounting for the effect of EE on the load forecast, most of the questions regarding the DSM-load forecasting relationship were about the potential for double-counting some EE, under-counting some EE, and the effects of EE on load shapes. In an effort to obtain clarification, the Director asked DEI several questions and requested more detail on how EE is "rolled off" (sometimes referred to "degraded" due diminished effects) of the load forecast so that the amount of EE is more accurately presented in the load forecast.

DEI's Reply Comments
DEI integrates DSMore with the Statistically Adjusted End-Use Model. DEI states, "DSMore outputs an hourly savings profile for each measure that is aggregated across all of the DSM programs and this hourly savings profile is provided to the Load forecasting and IRP group for the purpose of modeling DSM savings on an equivalent basis to other resources" (page 13 of DEI's response). DEI said accelerated benefits (i.e., usage reductions that would not have occurred for some time absent the utility's promotion) and "naturally occurring energy reductions" (from Energy Information Administration [EIA] data for the West North Central Region), "roll off" and "roll on." DEI provided a helpful example of roll-off. Specifically, assume a seven-year average measure of life for 100 MWh. These savings are rolled off in years five through nine as the naturally occurring

efficiencies are expected to roll on by means of incorporating the naturally occurring efficiencies in the end use models (i.e., SAE and the load forecast).

Director's Response
DEI's clarifications were helpful and answered questions raised by the Director and possibly the questions and concerns raised by the CAC et al. DEI said they were committed to ongoing improvements in evaluating DSM and its integration into the load forecasting process. In addition to ongoing review of the treatment of DSM, DEI agreed that increased data from AMI and Smart Grid will, overtime, enhance the forecasting and DSM databases (page 21 of DEI's response).

DEI's integration of DSM into their load forecasts appears well reasoned. However, the Director urges DEI and all Indiana utilities to provide a detailed and, to the extent possible, understandable, comprehensible discussion of the process for the treatment of EE within the load forecasts. The Director hopes DEI will make continued improvements to the quality, quantity (sub-hourly), and granularity of its databases used to evaluate DSM and to develop DEI's load forecasts. Improved data will make more effective use of DEI's modeling tools and, as a result, improve the quality of the analysis and enhance the credibility of all aspects of the IRP.

Summary and Conclusions

DEI's significant improvements in the 2015 – 2016 IRP and the commitment to continuing improvements are consistent with the Draft Proposed Rule and are very much appreciated. Without being prescriptive on the formatting of future IRPs, we hope DEI and other Indiana utilities will further address lay audiences as well as those who have varying degrees of expertise. This is a difficult undertaking. One potential strategy would be to have a somewhat less technical version with illustrations as footnotes or endnotes and technical appendices that address specific topic areas with both a more general and a more detailed technical discussion.

Among several commitments, "DEI agrees additional Stakeholder involvement in future IRP processes might improve the understanding of the assumptions and treatment of EE as a resource and this recommendation will be incorporated into the future IRP stakeholder process" (page 5 of DEI's response). More broadly, with the longer IRP planning cycles, stakeholders can provide greater meaningful input into improved narratives for the portfolios, scenarios, and sensitivities. DEI continues to evaluate the load forecasting methods, model specifications, and opportunities to enhance the databases.

The Director acknowledges that DEI used this IRP as part of their own business analysis and the IRP stakeholder process to build confidence that stakeholders and DEI share many fundamental objectives. Especially given the uncertainty of natural gas costs, dynamic changes in the market value of coal-fired generating units in the MISO facilitated markets, the costs of renewable technologies, innovation in DSM, the potential for customer-owned generation, the CPP, and the potential ramifications of other environmental rules, this IRP was an appropriate time for DEI to concentrate on the future composition of its resource mix. However, the Director trusts that future IRPs will be more expansive beyond the three (or four) scenarios that were optimized in this IRP. Because of the uncertainties mentioned previously, though, this year's IRP provides a foundation for DEI's future IRPs.

If, for example, the CPP survives legal challenges, DEI and other utilities may have additional information available to conduct a more in-depth analysis of potential risks associated with the CPP in future IRPs. Regardless, future IRPs need to consider a broad range of scenarios and sensitivities to enable DEI and stakeholders to better consider all resources and their attendant risks.

With the risk factors previously discussed and the potential benefits of broad regional action such as compliance with the CPP and to mitigate adverse ramifications of a changing regional resource mix, the Director is pleased that DEI recognizes the need to inform their IRP with the long-term resource planning of MISO (page 263 of DEI's response; see also pages 22, 40, 86. 93, 267 – 8, and 271 of DEI's IRP). Future IRPs seem certain to address concerns about the profitability of coal-fired generation, the integration of additional renewable resources, and issues that are unexpected.

2. I&M's INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

This Final Director's Report reflects the following issues and emphasizes those that the Director regards as important concerns. This report does not address all the questions and concerns raised by the Director or stakeholders in the Draft Director's Report. The issues addressed are

- Load forecasting
- Demand Side Management (DSM)
- Relationship between load forecasting and DSM

I&M's written response to the Draft Report and subsequent conference call was helpful and informative. The Director notes the questions contained in the three topic headings are intended to stimulate further thought and discussion rather than promoting or advocating specific methodologies. The intent of the Director's Report is to challenge processes, analysis, and tools, and to gauge whether they might be done better, not just be done differently. Many, if not most, of the issues we address throughout this report are quite new and vexing for the industry, and we do not wish to make definitive recommendations until we have gained further experience with the new issues.

The Director recognizes the benefit of I&M using this IRP as part of their business plan to better examine the viability of the Rockport units over the 20-year planning horizon. The decision to retain or retire one or more of the Rockport units may be the most important resource decision I&M will have to address. The Director also commends I&M for significant analytical and process improvements in this IRP as well as I&M's commitment to continual enhancements to their IRP stakeholder processes, development of scenarios and sensitivities with improved narratives, the use of state-of-the-art analytical tools such as PLEXOS, improved methodologies to treat DSM on as comparable a basis as possible to other resources, and I&M-specific databases. Specifically, I&M

- Recognizes opportunities for greater stakeholder involvement in the development of assumptions, scenarios, sensitivities, and data sources as a result of moving from a two-year to three-year IRP cycle;
- Stated their commitment to improving the narratives that tell an internally consistent and well-reasoned story;
- Expressed a willingness to improve the discussion of complex planning issues and methods such as:
  - (a) the efforts to treat DSM on as equal a basis as possible to other resources;
  - (b) allowing the long-term planning model to select the optimal array of resources based on objective assumptions and data; and
  - (c) consider methods for giving effect to calculating Transmission & Distribution (T&D) related costs that might affect the cost-effectiveness of DSM or other non-utility owned resources (page 26 of I&M's response).
- Will review alternative programs to enhance their load research database with sub-hourly demand information that will improve I&M's DSM analysis and add credibility to I&M's load forecasting (page 7 of I&M's response).
- Will work with stakeholders, the Commission's IRP staff, and others to examine other risk metrics that might be useful in evaluating future IRPs (page 23 of I&M's response).

Load Forecasting

I&M's Load Forecasting
For residential and commercial load forecasting, I&M uses a blended short-term Auto-Regressive Integrated Moving Average (ARIMA) model as something of a sanity check to ITRON's Statistically Adjusted End-Use (SAE) model for longer-term load forecasting. Professional judgement is used to resolve differences—if any—between the two models. For industrial load forecasts, I&M relies heavily on customer service engineers who are assigned to specific industrial clients to augment ARIMA and econometric methods. Historically, I&M models 10 of the larger industrial customers in Indiana and 10 in Michigan. I&M supplements this information with market intelligence data from Moody's Analytics.

The Director's Draft Report
The Director asked clarifying questions about the integration of the SAE and the ARIMA forecasting methods. The Director noted the importance of large customers—and the attendant risks—and asked whether I&M placed undue reliance on customer service engineers to prepare industrial forecasts. The Director also expressed concern that I&M may be too reliant on the experience of industries served by other AEP companies to construct high and low load forecasts and may not place as much reliance on independent market forecasts or other forecasting methods. The Director also asked I&M what enhancements I&M was considering for future IRPs, including enhanced databases.

With regard to databases, the Director noted that I&M uses a Residential Customer Survey to supplement information from the Energy Information Administration (EIA) for use in the SAE Model. However, there was no comparable survey for commercial and industrial customers (page 25 of I&M's IRP).

I&M's Reply Comments
In response to the Director's question regarding the blending of the SAE with the ARIMA forecasts, I&M explained that the short-term models were used as something of a sanity check on the SAE models to better capture short-term forecast volatility (pages 4 and 6 of I&M's response). "Even though the long-term models were ultimately selected, the short-term forecasts still play a vital role in evaluating whether or not the final forecast is reasonable and makes sense, especially with regard to the monthly variations. By comparing the model results from the two independent forecast methodologies, we are leveraging the strengths of both models to provide a better understanding of the key drivers" (page 4 of I&M's response).

In clarification discussions with I&M, I&M committed to provide a narrative in future IRPs to explain any professional judgement adjustments from the ARIMA Model to the long-term model in future IRPs.

With regard to the lack of a commercial and industrial end-use survey, I&M contended that the commercial and industrial classes were too heterogeneous and would be costly and difficult to conduct. As a default, I&M relies on the SAE model with EIA data. (page 7 of I&M's response)

The Director's Response
I&M recognizes that the load forecast is the foundation of the IRP process. The ramifications of over- or under-forecasting customers' long-term electric demand pose a significant financial and

reliability risk. Because of its primacy in the planning process, the Director devoted considerable attention to I&M's load forecasting processes, analytical tools, and methodology.
The blended approach has merit but as I&M recognized, additional discussion of how the short-term and long-term models are integrated would be useful for future IRPs. I&M has committed to reduce reliance on information from other AEP-East utilities. Although the use of some—perhaps all—information may be effective, it seems appropriate to rely more heavily on I&M-specific data in part due to different regulatory structures and circumstances (page 11 of I&M's response).

Based on the information provided by I&M in their reply comments and in conversation, the Director believes that I&M's load forecast methodologies, analytical tools, databases, and processes are reasonable. However, these are always areas for continued improvement.

To I&M's credit, they recognized that technologies such as Smart Grid and Advanced Metering Infrastructure (AMI) would provide enormous data for load forecasting and DSM analysis. I&M states, "an expansion of AMI was not considered within the context of this IRP. I&M recognizes that sub-hourly data may help inform the load forecasting process relied upon in IRP modeling, especially in DR [Demand Response] applications" (page 7 of I&M's response). In addition to more discrete time intervals for metering residential customer usage, I&M recognizes the value of supplementing this load data with appliance/end-use surveys for residential customers. Similarly, the Director urges I&M to use more granular metered load data in concert with selected commercial surveys on specific types/groups of commercial customers to provide a more comprehensive assessment of their current and potential consumption patterns. To some extent, both load data and detailed end-use surveys could be done in coordination with other utilities to supplement I&M's load research. For example, there may be commonalities among different types of stores (e.g., North American Industry Classification System) to make reasonable statistical inferences based on usage and selected commercial surveys to obtain end-use information.

I&M's DSM

I&M's DSM Analysis
I&M relied extensively on Electric Power Research Institute's (EPRI's) "2014 U.S. Energy Efficiency Potential Through 2035" report to perform its analysis of DSM in the IRP. Each EE measure initially was screened based on cost compared to other measures that addressed the same end use. Higher cost measures were omitted. The judgement of DSM/EE program administrators also eliminated measures that were deemed impractical or were not popular with I&M's customers. Next, the remaining measures were included in bundles that were then analyzed in the IRP analysis on a reasonably comparable basis as other resources.

I&M did not include industrial DSM due to state law that allows industrial customers to opt out of utility-sponsored DSM programs and the belief that industrial customers, "by and large, self-invest in EE based on unique economic merit irrespective of the existence of utility-sponsored programs" (page 12 of I&M's response). Naturally occurring DSM is accounted for in the industrial load forecast.

The Director's Draft Report
The construction of DSM bundles is difficult. There is no unambiguously correct way to form bundles. As such, the Director had several questions about how I&M evaluated DSM measures and

constructed bundles. Questions about the potential for double-counting new utility-sponsored DSM with existing and naturally occurring DSM were posed.

I&M's Reply Comments
I&M noted that, in the spring of 2016, they completed a Market Potential Study (MPS). Unfortunately, this was not available for this IRP, although it will be used in future IRPs.

Based on the IRP and I&M's written and verbal responses, the Director understands that I&M pre-screens DSM measures to create bundles based on initial measure cost and avoided costs. High-cost measures were removed from consideration for inclusion in the final bundles. Measures were then reviewed with I&M's DSM/EE program coordinators to eliminate any that were thought to be impractical to implement or previously had not been embraced by customers. The remaining bundles are associated with specific load shapes and their cost-effectiveness is refined in the PLEXOS model. The PLEXOS model was allowed to select the optimal level of EE bundles (page 16 of I&M's response).

I&M said it avoids double-counting of EE, degrades the Commission-approved DSM programs, and subtracts the amount from the initial sales forecast to account for the effect of the DSM programs.

The Director's Response
The treatment of EE on as comparable a basis as is reasonably feasible was a matter of concern for the CAC et al. and all other stakeholders, the Commission's IRP staff, and I&M. I&M and Duke Energy Indiana (DEI) offer methods that appear to have both similarities and differences. Both I&M and DEI pre-screened and eliminated some measures from further consideration. The details of how the bundles were created after the measures were screened probably differ, but it appears many similarities exist. Again, the Director makes no judgment as to one method being superior to another. For example, DEI has greater reliance on Indiana-specific data compared to I&M's heavy reliance on EPRI data.

I&M said (page 12 of I&M's response) that they did not rely on specific technical or research-related literature to substantiate the belief that industrial customers will undertake investments in EE that are cost effective. Although the Director admits that some industries—maybe the most energy-intensive industries—might capture all cost-effective DSM, without empirical studies based on end-use analysis, it is difficult to assess this assertion. The utilities' planning horizon might be longer, which can make more DSM attractive to both the utility and the industrial customer. In addition, firms face capital budget limitations that can hinder investment in all cost-effective EE. Moreover, because industrial customers provide an important revenue source but with considerable risk, additional analysis into the reasonableness of this assertion would seem warranted—especially if there are major effects on I&M's resource mix or if the additional DSM would be beneficial for future environmental compliance.

I&M did set DSM programs through 2017 and allowed the IRP model to select incremental EE programs only beginning in 2018. The decision to allow the model to select incremental EE programs beginning in 2018 shows that I&M could not know what the new modeling approach would produce until after the IRP was prepared. It takes time to plan, design, and gain approval of a DSM/EE plan based on the new modeling approach. Therefore, 2016 and 2017 were treated as transition years. In contrast, DEI set a base bundle in 2016 – 2018 that reflected already approved and proposed programs but did allow the model to choose incremental bundles. The model rarely selected these incremental bundles. To be clear, the Director takes no position on whether this treatment represents best practice, but I&M's approach appears to be reasonable. For future IRPs, the Director urges I&M, and all Indiana utilities, to continually reassess their methodology and prepare a sufficiently detailed and—to the extent possible—basic discussion of the methods to assist all those involved with IRPs to better understand the methodologies, data, and assumptions on which the analysis is based.

As noted previously, I&M expressed their commitment to examine potential improvements in the DSM analysis. This includes tailoring the DSM analysis to I&M's service territory, reducing reliance on the EPRI and the Energy Information Administration (EIA) (see pages 25 and 26 of I&M's response for examples), and enhancing their load research program by using sub-hourly load data. I&M states they are "reviewing alternative programs that can yield sub-hourly data in a cost-effective manner from larger customer (participant) base where the impacts from these programs can be modeled within a future IRP" (pages 7 and 8 of I&M's response). In reply comments, I&M also noted that in 2016 it completed a DSM market potential study of both its Indiana and Michigan service territories. I&M states the MPS will be a basis to update and align I&M EE data in future IRPs.

Relationship between Load Forecasting and DSM

I&M's Load Forecasting and DSM Integration
The foundation for the load forecasting and DSM analysis is the Statistically Adjusted End Use Model. I&M's forecast attempts to capture the embedded DSM, which includes both the existing and the forecasted EE that has been approved by the Commission and to do so without double-counting. I&M periodically reviews the methodology for estimating the effects of EE.

Director's Draft Report
From the narratives provided by I&M, it was not clear how the various models interacted. Moreover, it was not clear how the EE bundles were created and how I&M rolled off EE programs and avoided the double-counting of EE.

I&M's Reply Comments
I&M, in their written response and subsequent conversations, addressed concerns raised by the CAC et al. and the Commission's IRP staff about I&M's process for including EE in their load forecast, avoiding double-counting of EE (page 4 of I&M's response) by initially constructing a matrix of DSM programs that include the degraded value over time, the roll-off (or degradation) of existing EE, and the integration of new EE (efficiency gains to increasing appliance standards, programs approved by the Commission for three years, and evaluation of longer-term programs using PLEXOS).

Director's Response
I&M's commitment to improve the DSM and load forecasting databases by improving the quality, quantity, and granularity (e.g., sub-hourly demand data) will make more effective use of PLEXOS, improve the quality of the analysis, and enhance the credibility of all aspects of the IRP.

I&M's development of a 2016 Market Potential Study should improve the credibility of both the load forecast and the DSM programs.

The Director understands I&M's rationales for not including new utility-sponsored industrial DSM in the load forecast. However, there is a concern that the amount of cost-effective DSM might be understated because some industrial customers may have a shorter planning horizon than the utilities' planning horizons which adds to the challenge of long-term forecasting and planning. Understating the amount of cost-effective DSM would result in a higher load forecast, which would increase the amount of resources needed to satisfy the planning reserve requirements. The effect on load forecasts of unduly optimistic (or pessimistic) DSM projections could significantly affect the long-term resource decisions at a high cost to customers and the utility. Recognizing the merit of I&M's reluctance to quantify DSM for industrial customers, perhaps I&M might consider reducing (or increasing) the load forecast for industrial customers to give some effect to more (or less) DSM.

Similarly, the Director appreciates the sensitivity in showing forecasts for each industrial customer or making projections for combined heat and power (CHP) attributable to a specific customer for fear it may create problems for I&M and specific customers. For all of these circumstances, the Director wonders whether I&M could construct scenarios or sensitivities that put in a load and energy reduction in one scenario without attribution to a specific cause or customer. Similarly, recognizing there is a possibility of new industrial load over the 20-year planning horizon, would I&M consider a load increase without attributing the increase to a specific customer or a specific reason?

Summary and Conclusions

I&M's significant improvements in the 2015 – 2016 IRP and the several commitments to enhancements in future IRPs discussed previously could not have been done without the strong commitment by I&M's Chief Operating Officer Dr. Paul Chodak, other top management, and expert staff. The Director recognizes that I&M used this IRP as part of their own business analysis to assess the long-term viability of the Rockport units and potential alternative resources.

Given the uncertainty of natural gas costs, dynamic changes in the market value of coal-fired generating units in the RTO facilitated markets, the costs of renewable technologies, innovation in DSM, the potential for customer-owned generation, the CPP, and the potential ramifications of other environmental rules, this IRP was an appropriate time for I&M to concentrate on the future of the Rockport units because of their historic and future importance to the I&M system and I&M's customers. The Rockport units will be important considerations in future IRPs, but the Director trusts that future IRPs will be more expansive beyond the ongoing assessment of the Rockport units.

If, for example, the CPP is upheld by the Supreme Court, I&M and other utilities may have additional information available to conduct a more in-depth analysis of potential risks associated with the CPP in future IRPs. Regardless, future IRPs need to consider a broad range of scenarios and sensitivities to enable I&M and stakeholders to better consider all resources and their attendant risks.

With the risk factors previously discussed and the potential benefits of broad regional action such as compliance with the CPP and to mitigate adverse ramifications of a changing regional resource mix, the Director shares I&M's recognition of the need to inform their IRP with information from the operations and long-term resource planning of PJM Interconnection, LLC (PJM). Examples of this can be found on pages 59, 61, and 81 of I&M's IRP and page 7 of I&M's response. Future IRPs seem certain to address concerns about the profitability of coal-fired generation and, even, the Cook

Nuclear station within the PJM markets. The integration of additional renewable resources, customer-owned resources, EE, and demand response are all likely to warrant closer working relationships with PJM's operation and planning functions. Of course, there will always be unexpected issues.

Finally, as part of I&M's concerted efforts to improve the quality of the IRPs and make the IRPs more meaningful for stakeholders, the Director appreciates I&M's commitment to expanding the stakeholder process to encourage greater involvement by industrial and commercial customers. Hopefully, the additional year in the new IRP cycles will enable both I&M and its stakeholders to contribute to improvements in the quality and extent of participation from the inception of the IRP cycle to the analysis.

3. INDIANA MUNICIPAL POWER AGENCY'S INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

This Final Director's Report reflects the following issues and emphasizes those that the Director regards as important concerns. This report does not address all the questions and concerns raised by the Director or stakeholders in the Draft Director's Report. The issues are:

- Load forecasting
- Demand Side Management (DSM)
- Relationship between load forecasting and DSM

IMPA's response to the draft report was helpful and informative. The Director wishes to note the following questions are to stimulate further thought and discussion and not to promote or advocate specific methodologies. The intent of the annual report is to challenge whether things can be done better, not just be done differently. Many, if not most, of the issues we address throughout this report are quite new and our collective knowledge and experience is too limited to make definitive recommendations.

Load Forecasting

IMPA's Load Forecasting

IMPA uses an auto-regressive approach (Auto-Regressive Integrated Moving Average - ARIMA) and includes explanatory variables such as Indiana real per capita income, U.S. unemployment, cooling degree days, and heating degree days for load forecasting. An ARIMA model uses lagged values of the dependent variable (kWh sales in this case) as predictors of future kWh sales. The integration component of the model provides a means of accounting for trends within a time series (pages 5 – 33 of IMPA's 2015 IRP).

IMPA adjusted the load forecast data. First, IMPA excluded from the forecast model 24 months of load data for the period 2009 – 2010. The intent was to exclude the effects of the December 2007 - June 2009 recession to better analyze the base trends and growth in load requirements affecting IMPA's service territory. Second, IMPA added the reductions in load from EE programs implemented from 2011 through 2014 back into the historical energy allowing the load forecasting statistical models to analyze the natural load growth.

Director's Draft Report

The Director asked a number of questions relating to these adjustments to better understand the basis for the changes and to determine how IMPA evaluated the potential limitations of using an ARIMA-based forecasting methodology. In addition, the Director wanted to know whether IMPA had explored alternatives to reliance on the ARIMA methodology.

IMPA's Reply Comments

IMPA explained it adjusts its historical loads to account for load variations not attributable to the explanatory economic variables. Although the economic explanatory variables included in the load forecast model may explain most, if not all of the recessionary impacts on load, the recessionary period did cause issues with the ARIMA function of the model. Therefore, IMPA excluded load data for the period 2009 – 2010 to allow both the ARIMA and econometric functions of the model to perform properly. No dummy variables were included in the models because creating dummy variables could introduce unintended bias. In IMPA's opinion, the rapid loss and subsequent partial recovery of electric load was such an unusual occurrence that this period is a statistical outlier and should be excluded from the load history.

Director's Response
The Director appreciates the difficulty and the need for judgement exercised by IMPA. However, the Director has a couple of conceptual questions for consideration. Is not the exclusion of data the same as using a dummy variable? If adding a dummy variable can introduce an unintended bias, then how or why does excluding the data avoid introducing a bias? Also, the Director is not sure what is meant by the statement that removal of the data helped both the ARIMA and the econometric functions of the forecasting models to perform better. Statistical measures normally used to test model performance will always improve when troublesome data is removed. The real question is whether the troublesome data is saying something that is lost when the data is removed.

Aside from IMPA's treatment of significant anomalies, in the Director's opinion ARIMA methods tend to be more suitable for short-term forecasting in which the relationship between the numerous factors affecting energy consumption over time is relatively stable or changing in a steady trend. It is poorly suited to capturing the effects of significant economic changes or other extraordinary events. We understand that IMPA used other economic explanatory variables to augment the ARIMA-type analysis, but it was not clear how well this worked. This is because IMPA stated that the economic variables may have explained most of the load impacts but still chose to remove the data for the period 2009 – 2010. The Director acknowledges that regardless of the methodology used it is very difficult to capture the effects of sudden extraordinary events on energy consumption. The Director is encouraged that IMPA continually evaluates its forecasting methodology and looks for additional data sources (page 2 of IMPA's response).

Demand-Side Management

IMPA's Demand-Side Management
IMPA, like other Indiana utilities, recently has started to include EE bundles in the optimization modeling process as a means to better compare EE with other resource options. This methodology contrasts with the primary method, used until quite recently, of including EE as an adjustment to the load forecast, which then is used to optimize the supply-side resource portfolio. In other words, the optimization of generation resources mainly was done separately from the determination of the demand-side resources. The new methodology requires EE to be packaged into bundles or blocks for inclusion in the resource optimization models.

Director's Draft Report
There appear to be numerous similarities and differences as to how Indiana utilities create these EE bundles. IMPA's IRP provided a good but incomplete overview of how it developed the EE bundles or blocks. In the draft report, the Director sought more detail to better understand how IMPA built its bundles and the information used.

IMPA's Reply Comments
In lieu of attempting to model many existing as well as yet-to-be-defined future EE offerings, IMPA chose to model representative EE blocks. This avoided the use of DSM screening models that rely heavily on static avoided costs. The basis for the creation of the costs and load shapes of the EE blocks was IMPA's actual EE results observed during the Energizing Indiana program.

To develop a load shape, data from all five Energizing Indiana programs was used to compile an 8,760 hourly load shape for the EE block. All blocks used the same load shape. The five programs were Residential Lighting, C&I rebates, Home Energy Audits, Schools, and Low-income

Weatherization. The cost of the blocks is the primary differentiating characteristic. The blocks were divided into three cost levels to represent the increasing cost of EE programs as more difficult and expensive programs are implemented. As with the cost of supply-side resources, the cost of EE programs escalated through the expansion period. There was no attempt to model technological improvements (page 8 of IMPA's response).

Director's Response
The information on EE block preparation included in the IRP and IMPA's reply comments is helpful but still leaves a major question unanswered. How were the EE block costs determined for each level, and how were these costs escalated over time? IMPA is not alone in this circumstance. None of the utilities that prepared 2015 IRPs provided a satisfactory level of detail. Another question or concern is that IMPA did not attempt to account for technological change. This is understandable given the complexity of projecting technological change. However, is this reasonable given the rapid technological change being seen and probably to some extent reflected in the load forecast? The issue of how to treat technological change when modeling EE is an open question and is being addressed differently by different utilities.

IMPA developed its EE blocks based on its experience, primarily with the Energizing Indiana programs for the period 2011 – 2014. Recognizing IMPA's unique relationship as a wholesale provider, is sole reliance on experience an adequate substitute for not having a DSM market potential study? Could IMPA make good use of market potential studies prepared for other Indiana utilities? What is the relationship between a market potential study and the development of EE blocks? The Director recognizes that these questions are not unique to IMPA and may be in a sense problematic for IMPA given their structure and relationship with their members which limits IMPA's authority over DSM decisions.

Relationship between Load Forecasting and DSM

Relationship Between IMPA's Load Forecasting and DSM
As noted previously, IMPA adjusts its historical load data to account for load variations not attributable to the explanatory economic variables. According to IMPA, historical EE programs implemented by IMPA for the period 2011 – 2014 require such a modification.

Director's Draft Report
The Director asked a number of questions in the draft report to attempt to better understand what adjustments were made and how. The primary concern expressed by the Director was to better understand how IMPA attempts to avoid double-counting energy efficiency. A potential for double-counting exists because the load forecast reflects at least in part the historic EE improvements caused by both naturally occurring EE improvements over time and those improvements resulting from utility's EE programs. The issue is how to avoid double-counting the effects of EE captured in the load forecast and efficiency improvements from current and future utility programs.

IMPA's Reply Comments
IMPA notes EE reductions attributable to IMPA's EE program are driven by program incentives rather than explanatory economic variables, so the program-related EE reductions are added back to IMPA's historical load data. For EE installed for the period 2011 – 2014, IMPA assumes the effects of the measures will not disappear over time. For example, if a customer replaced inefficient lights in a factory by participating in an IMPA EE program, then even after the lights eventually burn out,

the factory will replace them with similar (or better) light bulbs. The adding back of energy saved through IMPA EE programs provides a consistent historical database for developing the "gross" load forecast. The load forecast model is estimated using this gross load historical data. After the gross load forecast is estimated, the historical EE reductions are subtracted from the gross load forecast resulting in the "net" or final load forecast, which does not include the historic EE (pages 2 – 3 of IMPA's response).

IMPA also says it uses its scenario process to address improving efficiency over time by adjusting the load factors. For example, the Green Revolution scenario improves the load factor by 3% by 2030 due to residential rooftop solar, batteries, and energy efficiency (page 5 of IMPA's response).

Director's Response
The issue of how best to prepare a load forecast and avoid or minimize the potential for double-counting between EE reflected in the load forecast and utility-sponsored EE programs is a subject of debate with different methodologies being subject to various pros and cons. The discussion here is more to provoke greater thought than specific changes or methodologies. Utility EE programs move up EE that probably would have occurred at a later date. The impacts or effects of historical, utility-sponsored EE should taper off over time and be replaced as naturally occurring (organic) EE replaces these program effects. This appears to be what IMPA assumes in its modeling. IMPA's methodology is reasonable.

IMPA's statement that in the various scenarios the load factor is adjusted to account for improving efficiency over time raises multiple questions. How is the adjustment determined? This adjustment represents incremental EE improvements for the specific scenario relative to the base case. Because the efficiency improvement included in the base case seems to be unknown, is there double-counting or under-counting when the load factor is adjusted?

IMPA notes in its reply comments that it is possible to miss some of the effects of organically occurring EE in future load requirements. For example, in the Director's opinion, IMPA's load forecasting methodology has difficulty capturing the effects of government appliance efficiency standards that will take effect in the future. This is especially the case if these standards are significant structural changes that cause improvements in appliance efficiencies beyond trends reflected in historical data. These types of changes are better or more easily captured in SAE models. However, these type of models are difficult for IMPA to implement given its role as a wholesale provider of electric power and its relationship with its retail municipal members. IMPA states it will continue to investigate ways to assess the impact of organically occurring EE as well as free riders. The Director notes the limited scale of IMPA's EE programs means that the treatment of energy efficiency, both organic and utility-sponsored EE programs, in the load forecast is probably a smaller concern than for other utilities with more extensive EE programs over time.

Other Matters

The Director wishes to acknowledge the extensive risk metrics IMPA provided in its IRP. These included

- Stochastic risk profiles
- Tornado charts with detailed metrics of 10 independent variables
- Stochastic mean comparisons
- Risk profile comparisons

- Trade-off diagram between present value of revenue requirements (PVRR) and average system rate (ASR)
- Efficient frontier of ASR versus standard deviation
- Comparison of levelized ASR
- Comparison of levelized PVRR
- Risk confidence bands around ASR
- Several charts detailing CO_2 and natural gas risk

Summary and Conclusions

For the most part, IMPA uses state-of-the-art models to develop its IRP and applies interesting techniques while making use of data developed by the Energy Information Administration. This is especially true when it comes to the risk and uncertainty analysis performed by IMPA. However, IMPA's status as a wholesale supplier of bulk power to its members imposes limitations in the IRP development process that are especially obvious in the areas of load forecasting, DSM analysis, and the interrelationship between the two.

The Director encourages IMPA to explore its ability to develop a DSM market potential study to improve its DSM analysis. Recognizing IMPA's position, it might be possible for IMPA to place some reliance on the market potential studies developed by other Indiana utilities. Such an approach is likely to be cost effective. Supplementing IMPA-specific data with data from other Indiana utilities that serve areas in close proximity to those served by IMPA's members would have the added benefit of enhancing credibility by capturing applicable similarities. In addition, for energy efficiency, demand response, and customer-owned resources, integrating data from other somewhat comparable utilities enables IMPA's analysis to be more forward-looking using data that reflects Indiana circumstances rather than heavily relying on historical programs and experience. Consideration of program experience is important but perhaps slightly less so when technology is changing so rapidly.

The previous discussion has a number of questions that are designed to provoke additional thought as to if and how some aspects of the IRP can be improved. Similar to other Indiana electric utilities that submitted 2015 IRPs, IMPA could provide better descriptions and more information in the specified areas to improve a reader's understanding of what it did and why. The Director acknowledges IMPA's statements in its reply comments to explore several areas for possible improvement in the future.

4. WVPA's INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

This Final Director's Report reflects the following issues and emphasizes those that the Director regards as important concerns. This report does not address all the questions and concerns raised by the Director or stakeholders in the Draft Director's Report. The issues are

- Load forecasting
- Demand Side Management (DSM)
- Relationship between load forecasting and DSM
- Resource optimization

Wabash Valley Power Association's (WVPA's) response to the draft report was helpful and informative. The Director wishes to note the following questions are to stimulate further thought and discussion and not to promote or advocate specific methodologies. The intent of the annual report is to challenge whether things can be done better, not just be done differently. Many, if not most, of the issues we address throughout this report are quite new and our collective knowledge and experience is too limited to make definitive recommendations.

Load Forecasting

WVPA's Load Forecasting
WVPA's forecast consists of the summation of the individual member systems, so the forecast represents a bottom-up approach. The number of customers and energy sales were projected at the customer class level and aggregated to produce the total system forecast. Econometric methods were used to forecast the number of residential and small commercial customers and average use per residential or small commercial customer. For example, the projected number of residential customers in a given year is multiplied by the projected average use per residential customer for that year to derive the total residential load for that member. According to the IRP, energy sales and peak demand for large commercial customers were developed by cooperative member staff using historical trends and information made available by the individual customers, such as knowledge of expansions, new construction, and so on.

Director's Draft Report
The Director recognizes that WVPA's relationship with its member cooperatives imposes some limitations on the forecasting process. Combining the load forecasts for each of the members poses some challenges. The Director sought to clarify whether a full SAE model for the residential class was used by WVPA and to clarify whether the large commercial forecast was based on informed opinion alone or if some type of econometric techniques also were used.

WVPA's Reply Comments
WVPA said the load forecasts for large commercial customers are based on informed opinion. They generally adjust only the first one to two years for probable load growth. Beyond the first two years, WVPA assumes 0.0% – 2 .0% load growth for any individual customer. WVPA also indicated they have not attempted to model the load of these larger customers using econometric techniques.

Director's Response
The techniques used to model the residential and small commercial customer energy requirements seem to be reasonable, but the large commercial customer methodology raises some questions. Over what period does each member provide its judgement-based large customer load forecast: 1 year, 5 years, 10 years, or some other time period? How does WVPA decide which load growth rate to

apply to individual customers? Does this growth rate differ across customers, and on what basis is this decision made? How is the trend of increasing EE over time captured in an industrial load forecast based entirely on professional judgement?

Demand-side Management

WVPA's Demand-side Management
WVPA, like other Indiana utilities, recently started to include EE bundles in the optimization modeling process as a means to better compare EE with other resource options. This methodology contrasts with the primary method until quite recently of including EE as an adjustment to the load forecast, which was then used to optimize the supply-side resource portfolio. In other words, the optimization of generation resources was done largely separate from the determination of the demand-side resources. The new methodology requires EE to be packaged into bundles or blocks for inclusion in the resource optimization models. That is, the model selects the most appropriate resource based on its relative merits and is indifferent to the type of resource.

Director's Draft Report
There appear to be numerous similarities and differences as to how Indiana utilities create these EE bundles. In its IRP, WVPA provided an incomplete overview of how it developed the EE bundles or blocks because the discussion focused almost entirely on their internal administrative process for developing an EE plan. WVPA's IRP noted the use of a condensed study of achievable efficiency potential. In the draft report, the Director sought more detail to better understand how WVPA built its EE packages (expansion alternatives) and the information used.

WVPA's Reply Comments
WVPA clarified that the condensed study of achievable efficiency potential was based on a "compilation of studies prepared for other clients with similar customer demographics" (page 11 of WVPA's response). Navigant Consulting conducted a meta-review of other recently completed potential studies for utilities in a similar geographical territory to WVPA. Navigant reviewed potential studies for Entergy Arkansas (2015), Kansas City Power and Light (2013), and Commonwealth Edison (2013) (page 12 of WVPA's response). WVPA did not research or consider technical or economic potential specific to WVPA. The meta-analysis of other potential studies focused solely on achievable potential (page 12 of WVPA's response). WVPA determined that a meta-analysis was a reasonable and appropriate methodology to estimate achievable EE market potential when weighed against available resources and the cost of a potential study specific to WVPA's service territory.

Director's Response
The Director does not disagree with the decision to rely on a study that consisted of a meta-analysis of other utility market potential studies. The Director now understands that the EE resource alternatives included in the resource optimization are based on a combination of market potential studies developed for three specific utilities thought to have similar geographic and demographic characteristics. It is appropriate to consider information from other utilities. However, the credibility of the narrative supporting the analysis would be enhanced if there was greater reliance on WVPA- and state-specific data.

The Director also still does not really know how the EE resource alternatives were developed. Which EE measures are included in the 1 MW Residential, 1 MW Small Commercial, and 1 MW

Large Commercial EE resource alternatives? How were the load shapes for the resource alternatives developed from the individual measure characteristics? How were the costs derived for each resource alternative, given the cost and performance characteristics of the measures reflected in the resource alternative?

The Director notes that had WVPA provided adequate detail, an informed reader of the IRP could more fully understand the data and analytical process used to create the three resource alternatives. The Director also recognizes that determining how much detail is enough but not too much is also a matter of judgment. For example, what to include in the body of the IRP report and what should be put in an appendix? The Director would like to acknowledge that WVPA's role as a wholesale supplier of electric service and its relationship with its cooperative members also affects WVPA's long-term resource planning process and resource acquisition.

Relationship between Load Forecasting and DSM

WVPA's Load Forecasting and DSM Integration
The difficult question is what part of future EE programs is truly incremental to what has been captured in the historical data and is thus already reflected in the load forecast? The interrelationship between a load forecast and how to reflect the impact of future incremental utility EE programs is complex because it depends on at least a couple of considerations. One is the methodology used to develop the forecast; another probably involves the scale of the utility EE programs over time and whether they are increasing, decreasing, or holding steady over a period of several years. For example, how does this historical performance compare to the scale of future EE programs included in the utility resource acquisition plan?

Both Duke and I&M use an SAE model for developing their forecasts of residential and commercial loads. Both Duke and I&M also use primarily econometric methods for industrial and other customer classes. SAE models enable one means of explicitly reflecting naturally occurring EE and capturing historical trends. However, even here, considerable professional judgment is required to adjust how current and future EE programs impact the load forecast.

As noted previously, WVPA explained in the IRP that they used econometric methods to forecast the number of residential and small commercial customers and the average use for each class. The models include variables to capture space heating and cooling. They also include a base index from an SAE model in the residential average use model. The base index is said to capture the general trend associated with increasing penetration of plug-in appliances, lighting, and water heating. The index is modified to include the impacts associated with the price of electricity, household income, and number of people in the household.

The Director's Draft Report
In the Draft Report, the Director sought additional information to better understand how the interrelationship between EE and the load forecast was addressed.

WVPA's Reply Comments
WVPA clarified that they did not use an SAE model. WVPA also clarified that they did not remove the effects of utility program EE from the historical load data prior to estimating the residential and small commercial models. They note that all existing EE programs are embedded as a reduction to their historical load numbers.

Director's Response
The Director reiterates the complexity of these matters and acknowledges that there is no single correct answer to these questions or issues. Rather, the focus is on asking questions to stimulate thoughtful consideration of whether something can be improved upon, not merely done differently.

Given the information provided by WVPA in the IRP and their reply comments, it is clear WVPA is not directly addressing the issue of whether it is double-counting or under-counting the impacts of utility EE programs going forward. As noted previously, much depends on the modeling techniques used and what has happened historically regarding the scale of utility-sponsored EE programs and what is projected to be acquired in the forecast period.

One clear difficulty is associated with how WVPA forecast load for large commercial customers. The reliance on informed opinion to specify specific annual growth rates for individual customers leaves open the question of whether historical efficiency trends are being captured in these customer-specific forecasts. Econometric methodologies at least capture these trends because they are reflected in the historical load data and are carried forward in the forecast. How is this done in a process that relies entirely on informed opinion?

Resource Optimization

WVPA's Resource Optimization
It needs to be emphasized that WVPA acquired the PLEXOS modeling system several months prior to using it for the first time in the 2015 IRP. The new model provides significant capability, and WVPA acknowledges they will be able to more fully exploit this as they gain experience with the model. The Director appreciates the difficulty associated with transitioning to a new, complex model and WVPA's desire to improve their resource planning capabilities. To the extent fuller use of the PLEXOS model requires different databases, the Director encourages WVPA to explore ways to develop the requisite information.

WVPA used a sequence of scenario analysis and stochastic analysis to develop potential resource plans. The stochastic analysis was used to review the impact of various risk components on the resource plans developed under the various scenarios. The risk components included load; both peak demand and energy; market prices for wholesale electric power, natural gas, and coal; and a carbon tax.

The Director's Draft Report
The Director asked several questions related to various aspects of the modeling performed by WVPA. For example, the Director specifically sought to clarify the extent to which WVPA actually used scenario analysis, asked why the model results tended to reflect short-run overbuilds of generation resources in particular years, and requested more details on how the stochastic analysis was performed.

WVPA's Reply Comments
According to the IRP, WVPA developed four alternative scenarios in addition to a base scenario for which resource plans were developed. The performance of these resource plans was further reviewed with stochastic analysis, which is another means to review the impact of uncertainty on a resource plan. WVPA's reply comments noted that the term *sensitivity* is probably a better

description of all WVPA's alternative expansion plans as they made minimal changes to the model to see how the expansion plans changed in the PLEXOS LT Plan (page 6 of WVPA response).

The Director's Draft Report also noted the power expansion planning analysis results tended, in the short run, to overbuild or to acquire more resources than necessary at any given point in time. WVPA acknowledged the model tends to overbuild. This is a result of allowing only fossil fuel construction in only certain years of obvious need. According to WVPA, the alternative would be to allow for construction of a 59 MW CT/CC in 2016, another 123 MWs in 2017, and 86 MW in 2018. They state this is not how WVPA manages its portfolio. Another alternative would be to allow the model to purchase capacity, but this could lead to under-building (page 7 of WVPA's response).

WVPA also notes large generation additions are expensive and, for use in the resource planning models, makes these resources relatively "lumpy" compared to DSM and some renewable resources that can be modeled in lower capacity amounts. Care must be taken so that there is neither a bias in favor of or against any type of resource. So WVPA intends to manage short-term short or long capacity positions with market capacity transactions to help manage large capacity investment costs (page 7 of WVPA's response).

WVPA eliminated market sales and limited market purchases in their analysis. Due to this underlying assumption, generation needs were mainly provided through expansion alternatives (page 9 of WVPA's response).

WVPA also clarified that they modeled the scenarios/sensitivities (Optimistic Economy, Pessimistic Economy, Carbon Emissions Regulation, and pulverized Coal Resource Addition) as separate expansion plans and executed them with all combinations of defined stochastic variables (Load, energy Price, Natural Gas Price, Coal Price, Energy Price, and Carbon Tax). (page 9 of WVPA's response).

Director's Response
The Director appreciates WVPA's clarification that what was described in the IRP as scenarios is more appropriately seen as sensitivities. *Scenarios* are more commonly thought of as alternative visions or stories of potential futures. A *sensitivity* is basically where there is a specific scenario and only a single variable (or a very limited number of interrelated variables) is changed to see how the resource plan is altered or performs under the limited change.

The Director believes that the analysis could be made better if WVPA developed several true distinct scenarios that were optimized and the resulting resource plans were subjected to stochastic analysis. This limitation may be less problematic because WVPA seems to have performed a reasonable stochastic analysis to better understand the impact of uncertainty across several variables on the various resource plans. Tornado charts were presented for each expansion plan showing the range of the impact of the individual risk factors on the plan, which is helpful.

With respect to the model's tendency to overbuild resources in certain years, the Director appreciates the clarifications but finds the rationale confusing. WVPA states that the overbuilding is a result of allowing fossil fuel construction in only certain years of obvious need. They also limited the model's ability to make market purchases and eliminated market sales entirely. WVPA dismisses the alternative as inconsistent with how they manage their portfolio.

It is the Director's opinion and observation that the rejected alternative is exactly how WVPA operates. Because WVPA recognizes the inherent "lumpiness" of major investments in resources, they rely on numerous purchase power agreements to smooth their resource development. Then, they build or purchase generation facilities when circumstances warrant. It would be surprising if expanded DSM would not be objectively selected by PLEXOS as part of the smoothing of future resource plans. The Director thinks that a portfolio that allows necessary additions in all years instead of limiting it to certain years would provide the same guidance when evaluating resource opportunities without giving the impression that WVPA has biased resource decisions by substituting its constraints for the objective computer analysis of PLEXOS. It will be interesting to see whether WVPA's concerns about the operation of the PLEXOS model are resolved for the next IRP. The Director also recognizes that it is not clear whether either method is better in any important sense.

Summary and Conclusions

The Director appreciates WVPA's acquisition and use of the PLEXOS modeling system and WVPA's willingness to use it in this IRP even as WVPA is still learning how to make better use of the model's capabilities. It is no small task to transition to a new, complex model over a relatively short period of time.

WVPA's ability to perform risk and uncertainty analysis should be improved as the PLEXOS model is used more effectively in the future. Nevertheless, an improved model cannot offset a failure to develop multiple true scenarios in the IRP process. WVPA acknowledges they relied on what can more properly be called sensitivities. WVPA appears to have conducted a reasonable stochastic analysis, but WVPA's risk and uncertainty analysis would have been improved if the stochastic analysis had been applied to results derived from optimizing well-developed scenarios.
The Director understands WVPA's use of a meta-analysis of other utilities' DSM market potential studies as a cost-effective way to improve the information relied on by WVPA. However, all these market potential studies were for non-Indiana utilities. The Director believes greater reliance on Indiana-specific data would be a better choice. This could be done as a meta-analysis of market potential studies performed for other Indiana utilities. Like the other Indiana electric utilities that submitted 2015 IRPs, WVPA made significant changes to make the treatment of EE more comparable to other resource options. As was the case with the other Indiana utilities, WVPA created DSM bundles that could be included in the model resource optimization process. Similar to these other utilities, in future IRPs, WVPA needs to provide greater detail and clarity as to how the bundles were developed and the data and assumptions used.

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TITLE 170 INDIANA UTILITY REGULATORY COMMISSION

Proposed Rule
LSA Document #12-xxx

DIGEST

Amends 170 IAC 4-7 to update the commission's rule requiring electric utilities to prepare and submit integrated resource plans. Effective 30 days after filing with the Publisher.

170 IAC 4-7-0.1
170 IAC 4-7-1
170 IAC 4-7-2
170 IAC 4-7-2.1
170 IAC 4-7-2.2
170 IAC 4-7-3
170 IAC 4-7-4
170 IAC 4-7-5
170 IAC 4-7-6
170 IAC 4-7-7
170 IAC 4-7-8
170 IAC 4-7-9
170 IAC 4-7-10

SECTION 1. 170 IAC 4-7-0.1 IS ADDED TO READ AS FOLLOWS

ARTICLE 4. ELECTRIC UTILITIES
Rule 7. Guidelines for Electric Utility Integrated Resource Plans

170 IAC 4-7-0.1 Applicability
Authority: IC 8-1-1-3
Affected: IC 8-1-2.2; IC 8-1-2.3-2; IC 8-1-2.4; IC 8-1-8.5; IC 8-1-8.8-10; IC 8-1.5

Sec. 0.1 (a) To assist the commission in its administration of the Utility Powerplant Construction Law, IC 8-1-8.5, this rule applies to the following electric utilities:
(1) Public investor owned.
(2) Municipally owned.
(3) Cooperatively owned.
(4) A joint agency created under IC 8-1-2.2. An individual member of a joint agency is not required to submit to the commission a separate IRP.
(b) This rule does not apply to a person who is exempt pursuant to IC 8-1-8.5-7.
(c) The following electric utilities are exempt from the public advisory process requirement in section 2.1 of this rule:
(1) Municipally owned.
(2) Cooperatively owned.
(3) A joint agency created under IC 8-1-2.2.

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(Indiana Utility Regulatory Commission; 170 IAC 4-7-0.1)

SECTION 2. 170 IAC 4-7-1 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-1 Definitions
Authority: IC 8-1-1-3
Affected: IC 8-1-2.2; IC 8-1-2.3-2; IC 8-1-2.4; IC 8-1-8.5; IC 8-1-8.8-10; IC 8-1.5

Sec. 1. (a) **The definitions in this section apply throughout this rule.**
~~(a)~~ **(b)** ~~As used in this rule,~~ "Allowance" or "emission allowance" means the authority to emit one (1) ~~ton of sulfur dioxide (SO2), as defined under Section 7651 of the Clean Air Act Amendments of 1990, 42 U.S.C. 7401 to 7671q, effective November 15, 1990~~ **unit of any air pollutant as specified by a federal or state emission allowance system.**
~~(b) As used in this rule,~~ **(c)** "Avoided cost" means the amount of fuel, operation, maintenance, purchased power, labor, capital, taxes, and other cost not incurred by a utility if an alternative supply or demand-side resource is included in the utility's integrated resource plan.
~~(c) As used in this rule, "Clean Air Act Amendments of 1990" or "CAAA" means Title IV, Acid Deposition Control, of the federal Clean Air Act Amendments of 1990, 42 U.S.C. 7401 to 42 U.S.C. 7671q, in effect November 15, 1990.~~
(d) "Candidate resource portfolio" means a long-term resource mix selected through the utility's portfolio screening process to be further analyzed as necessary to determine the preferred resource portfolio.
~~(d) As used in this rule,~~ **(e)** "Cogeneration facility" means the following:
(1) A facility that simultaneously generates electricity and useful thermal energy and meets the energy efficiency standards established for a cogeneration facility by the Federal Energy Regulatory Commission (FERC) under 16 U.S.C. 824a-3, in effect November 9, 1978.
(2) The land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility.
(3) The transmission or distribution facility necessary to conduct the energy produced by the facility to a user located at or near the project site.
~~(e) As used in this rule,~~ **(f)** "Commission" means the Indiana utility regulatory commission.
~~(f) As used in this rule,~~ **(g)** "Conservation" means reducing the amount of energy consumed by a customer for a specific end-use. Conservation includes behavior changes such as thermostat setback. Conservation does not include changing the timing of energy use, switching to another fossil fuel source, or increasing off-peak usage.
(h) "Contemporary issues" means any topic that may affect the inputs, methods, or judgment factors in an IRP that is common to all Indiana jurisdictional utilities. Topics may include, but are not limited to, the following types of issues:
(1) Economic.
(2) Financial.
(3) Environmental.
(4) Energy.
(5) Demographic.
(6) Customer.

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(7) Methodological.
(8) Regulatory.
(9) Technological.

(i) "Contemporary methods" means any methodological aspect involved with developing an IRP that represents the best practice of the electric industry to improve the quality of an IRP analysis.

~~(g) As used in this rule,~~ **(j)** "Demand-side management" or "DSM" means the planning, implementation, and monitoring of a utility activity designed to influence customer use of electricity that produces a desired change in a utility's load ~~shape~~. DSM includes only an activity that involves deliberate intervention by a utility to alter load ~~shape~~.

~~(h) As used in this rule,~~ **(k)** "Demand-side measure" means a particular end-use device, technology, service, or rate design at a targeted customer's premises or a utility's energy delivery system for a specific DSM program.

~~(i) As used in this rule,~~ **(l)** "Demand-side program" means a utility program designed to implement a demand-side measure.

~~(j) As used in this rule,~~ **(m)** "Demand-side resource" means a resource that reduces the demand for electrical power or energy by applying a demand-side program to implement one (1) or more demand-side measures.

(n) "Director" means the director of the electricity division of the commission.

~~(k) As used in this rule,~~ **(o)** "Discount rate" means the interest rate used in determining the present value of future cash flows.

~~(l) As used in this rule, "dispersed~~**(p) "Distributed** generation" means electric generation technology that is relatively small in size, and ~~its~~ whose implementation favors installation near a load center or remote location on the subtransmission or distribution system. **Distributed generation can includes self-generation.**

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~~(m) As used in this rule,~~ **(q)** "End-use" means the light, heat, cooling, refrigeration, motor drive, microwave energy, video or audio signal, computer processing, electrolytic process, or other useful work produced by equipment using electricity.

~~(n) As used in this rule,~~ **(r)** "Energy efficiency improvement" means reduced energy use for a comparable level of energy service.

~~(o) As used in this rule,~~ **(s)** "Energy service" means the light, heat, motor drive, and other service for which a customer purchases electricity from the utility.

~~(p) As used in this rule,~~ **(t) "Energy storage" means a:**
(1) technology; or
(2) set of technologies;
Capable of storing previously generated electric energy and ~~dispatching~~ discharging that energy as electricity at a later time.

(u) "Engineering estimate" means an estimate of energy (kWh) and demand (kW) impact resulting from a demand-side measure based on an engineering calculation procedure. An engineering estimate addresses change in energy use of a building or system resulting from installation of a DSM measure. If multiple DSM measures are installed, an engineering estimate accounts for the interactive effect between the DSM measures.

(v) "FERC Form 715" means the annual transmission planning and evaluation report required by the Federal Energy Regulatory Commission (FERC), as adopted in 58 FR 52436, Oct. 8, 1993, and as amended by Order 643, 68 FR 52095, Sept. 2, 2003.

~~(q) As used in this rule,~~ **(w)** "Firm wholesale power sale" means a power sale intended to be available to the purchaser at all times, including under adverse conditions, during the period covered by the commitment.

~~(r) As used in this rule, "hourly system lambda" means the change in a utility's total cost associated with a marginal change in hourly load. The hourly system lambda is a short run measure that reflects the change in fuel cost and includes incremental (or decremental) operation and maintenance expenses.~~

~~(s) As used in this rule,~~ **(x)** "Integrated resource ~~planning", "~~plan" or "IRP" means a utility's ~~assessment of a variety of demand-side and supply-side resources to cost-effectively meet customer electricity service needs. The IRP may also include, but is not limited to, the following:~~

~~(1) A public participation procedure .~~

~~(2) An analysis of the uncertainty and risk posed by different resources and external factors~~ **document submitted in order to meet the requirements of this rule.**

~~(t) As used in this rule,~~ **(y)** "Load building" means a program intended to increase electricity consumption without regard to the timing of the increased usage.

~~(u) As used in this rule,~~ **(z)** "Load research" means the collection of electricity usage data through a metering device associated with an end-use, a circuit, or a building. The metered data is used to better understand the characteristics of electric loads, the timing of their use, and the amount of electricity consumed by users. The data may be collected over a variety of time intervals, usually sixty (60) minutes or less.

~~(v) As used in this rule,~~ **(aa)** "Load shape" means the time pattern of customer electricity use and the relationship of the level of energy use to a specific time during the day, month, and year.

~~(w) As used in this rule, "Lost opportunity" means a situation where a cost-effective demand-side measure could have been installed at a site during construction, renovation, or replacement of equipment, but was not, rendering a subsequent equal or more extensive modification to the site not cost-effective.~~

~~(x) As used in this rule,~~ **(bb)** "Non-utility generator" or ~~"NUG"~~ means a facility for generating electricity that:

(1) is not exclusively owned by a public utility;

(2) operates connected to an electric utility system; and

(3) sells electricity to a utility for resale to retail customers.

(cc) "North American industrial classification system" or "NAICS" means a system developed by the United States Department of Commerce for use in the classification of establishments by type of activity in which engaged, for purposes of facilitating the collection, tabulation, presentation and analysis of data relating to establishments, and for promoting uniformity and comparability in the presentation of statistical data collected by various agencies of the United States Government, state agencies, trade associations, and private research organizations.

~~(y) As used in this rule,~~ **(dd)** "Participant" means a utility customer participating in a utility-sponsored DSM program.

~~(z) As used in this rule,~~ **(ee)** "Participant test" means a cost-effectiveness test that measures the difference between the cost incurred by a participant in a demand-side program and the value received by the participant. A participant's cost includes all costs borne by the participant. A participant's value from a DSM program consists of only the direct economic benefit received by the participant.

~~(aa) As used in this rule,~~ **(ff)** "Penetration" means the ratio of the number of a specific type of new units installed to the total number of new units installed during a given time.

(gg) "Power transfer capability" means the amount of power that can be transferred from one point or part of the bulk electric system to another without exceeding any reliability criteria pertinent to the utility.

(hh) "Preferred resource portfolio" means the utility's selected long-term resource mix that safely and reliably meets electric system demand ~~at the lowest reasonable cost by balancing cost minimization with cost-effective reduction of associated risks and uncertainties~~, taking cost, risk, and uncertainty into consideration.

~~(bb) As used in this rule,~~ **(ii)** "Present value" means today's value of a future payment, or stream of payments, discounted at some appropriate compound interest or discount rate.

~~(cc) As used in this rule,~~ **(jj)** "Program cost" means all expenses incurred by a utility in a given year for operation of a DSM program whether the cost is capitalized or expensed. An expense includes, but is not limited to, the following:

(1) Administration.
(2) Equipment.
(3) Incentives paid to program participants.
(4) Marketing and advertising.
(5) Monitoring and evaluation.

~~(dd) As used in this rule,~~ **(kk)** "Public ~~participation~~ **advisory process**" means ~~a procedure~~ **the procedures referenced in section 2.1 of this rule** ~~where a customer or interested party is provided~~ **in which customers and interested parties have** the opportunity to ~~participate~~ **receive information and provide input for the utility to consider in the development of the IRP and** comment on a utility's ~~integrated resource plan~~**IRP** prior to the submission of the IRP to the commission.

~~(ee) As used in this rule,~~ **(ll)** "Ratepayer impact measure" or "RIM" test means a cost-effectiveness test which analyzes how a rate for electricity is altered by implementing a DSM program. This test measures the change in a revenue requirement expressed on a per unit of sale basis.

(mm) "Regional transmission organization" or "RTO" means the regional transmission organization approved by the Federal Energy Regulatory Commission for the control area that includes the utility's assigned service area (as defined in IC 8-1-2.3-2).

~~(ff) As used in this rule,~~ **(nn)** "Renewable resource" means a ~~generation facility or technology utilizing a fuel source such as, but not limited to, the following:~~

~~(1) Wind.~~
~~(2) Solar.~~
~~(3) Geothermal.~~
~~(4) Waste.~~
~~(5) Biomass.~~
~~(6) Small hydro.~~

renewable energy resource as defined in IC 8-1-8.8-10.

~~(gg) As used in this rule,~~ **(oo)** "Resource" means a facility, project, contract, or other mechanism used by a utility to provide electric energy service to the customer.

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(pp) "Resource action" means a resource change or addition proposed by a utility in a formally docketed proceeding.

(qq) "Risk metric" means a measure used to gauge the risk associated with a resource portfolio. As applied to the cost of a resource portfolio, this includes measures of the variability of costs and the magnitude of outcomes.

~~(hh) As used in this rule,~~ **(rr)** "Saturation" means the ratio of the number of a specific type of similar appliance or equipment to the total number of customers in that class or the total number of similar appliances or equipment in use.

~~(ii) As used in this rule,~~ **(ss)** "Screening" means an evaluation performed by a utility to determine whether a demand-side or supply-side resource option is eligible for potential inclusion in the utility's ~~integrated resource plan~~**preferred resource portfolio**.

~~(jj) As used in this rule,~~ **(tt)** "Self-generation" means an electric generation facility primarily for the customer's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation.

~~(kk) As used in this rule,~~ **(uu)** "Short term action plan" means a schedule of activities and goals developed by a utility to begin efficient implementation of its ~~integrated resource plan~~**preferred resource portfolio**.

(vv) "Smart grid" means use of digital electronics or data, and the associated communications networks, to monitor and control any aspects of the electrical transmission and distribution system from generation to consumption.

~~(ll) As used in this rule, "standard industrial classification" or "SIC" means a system developed by the United States Department of Commerce for use in the classification of establishments by type of activity in which engaged, for purposes of facilitating the collection, tabulation, presentation and analysis of data relating to establishments, and for promoting uniformity and comparability in the presentation of statistical data collected by various agencies of the United States Government, state agencies, trade associations, and private research organizations.~~

~~(mm) As used in this rule,~~ **(ww)** "Supply-side resource" means a resource that provides a supply of electrical energy or capacity, or both, to a utility. A supply-side resource **may** include the following:

(1) A utility-owned generation capacity addition.
(2) A wholesale power purchase from another utility or non-utility generator.
(3) A refurbishment or upgrading of an existing utility-owned generating facility.
(4) A cogeneration facility.
(5) A renewable resource technology.
(6) Distributed generation.

~~(nn) As used in this rule,~~ **(xx)** "Targeted demand-side management" or "targeted DSM" means a demand-side program designed to defer or eliminate investment in a transmission or distribution facility.

~~(oo) As used in this rule,~~ **(yy)** "Total resource cost test" means a cost-effectiveness test that eliminates the distinction between a participant and nonparticipant by analyzing whether a resource is cost-effective based on the total cost and benefit of the program, independent of the precise allocation to a shareholder, ratepayer, and participant.

~~(pp) As used in this rule,~~ **(zz)** "Utility" means:

(1) a public, municipally owned, or cooperatively owned utility; or
(2) a joint agency created under IC 8-1-2.2.

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~~(qq) As used in this rule,~~ (aaa) "Utility cost test" or "revenue requirements test" means a cost-effectiveness test designed to ~~minimize~~ **measure the** ~~impact on~~**ratio of the benefits (to the utility) to the costs incurred by the utility (** ~~the net present value of a utility's~~ revenue requirements**)**.
(Indiana Utility Regulatory Commission; 170 IAC 4-7-1; filed Aug 31, 1995, 9:00 a.m.: 19 IR 16; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)

SECTION 3. 170 IAC 4-7-2 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-2 Procedures and effects of filing integrated resource plans
Authority: IC 8-1-1-3
Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2. (a) **The following utilities, or their successors in interest, must submit to the commission an IRP that covers at least a 20 year planning horizon consistent with this rule according to the following schedule**:

(1) Duke Energy Indiana, Indiana Michigan Power Company, Indiana Municipal Power Agency, and Wabash Valley Power Association on November 1, 2013, and biennially thereafter.

(2) Hoosier Energy Rural Electric Cooperative, Indianapolis Power and Light Company, Northern Indiana Public Service Company, and Southern Indiana Gas and Electric Company on November 1, 2014, and biennially thereafter.

Upon request of a utility, the ~~commission's electricity division~~ director