2018 Report on the

Statewide Analysis of Future Resource Requirements for Electricity

Indiana Utility Regulatory Commission Staff

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I. Introduction and Executive Summary

The 2018 Report (Report) on the Statewide Analysis of Future Resource Requirements for Electricity (Statewide Analysis) was prepared by Indiana Utility Regulatory Commission (IURC or Commission) staff, as delegated by the Commission, for the Governor and Indiana General Assembly. Consistent with the statutory requirements of Indiana Code § 8-1-8.5-3, Commission staff developed the Report by reviewing information provided in the Indiana electric utilities' Integrated Resource Plans from 2015 to 2017, the State Utility Forecasting Group's 2017 Forecast, and other sources in order to summarize and consolidate this information outlining the present condition landscape for all utilities and their stakeholders . Information provided from the State Utility Forecasting Group (SUFG) included results from its recent modeling update funded by the Commission.

Reports regarding the Statewide Analysis are required to be submitted each year according to Ind. Code § 8-1-8.5-3(h). In previous years, the Commission has relied on the reports and forecasts of the SUFG. The 2018 Report is the first one prepared by Commission staff. It is important to note that the Statewide Analysis is not to be construed as a statewide energy plan and does not set policy. In addition, the Statewide Analysis does not determine or predetermine individual electric utility resource decisions or Commission findings and conclusions in any pending or future proceeding before the Commission. The Statewide Analysis is intended to provide information and analysis for consideration by the Governor and the Indiana General Assembly, as well as consideration by the Commission, Indiana electric utilities, and interested stakeholders.

Indiana's electric utilities are required to provide safe and reliable service in an efficient and cost-effective manner. 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. The plan the utility submits 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 options on both a short-term and long-term basis to meet those future electricity requirements.

Based on Commission staff review, 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.

Taking into account plant retirements, the SUFG projected 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,

[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 are intended to 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.

solar, biomass, and hydroelectric generation, as well as maintaining and improving energy efficiency and demand response programs. Generally, the utilities make their resource decisions based on the comparative costs of these resources.

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 Ind. Code § 8-1-8.5-3. In 2014, the Commission provided its recommendations in a letter to the Governor 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 IRPs, in which electric utilities assess their customers' energy needs and the generation 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 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.

In 2015, the Commission opened a new round of stakeholder meetings to modernize and update its IRP rule, and the Commission provided additional funding to the SUFG to update modeling software for more robust forecasts. Since 2014, 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 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 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.

Ind. 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 the 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 early 1980s, Indiana's utilities, like utilities throughout the United States, built enormous amounts of generating capacity to meet the expected burgeoning demand for more electricity. Unfortunately, the utilities' forecasts were overly optimistic, which resulted in the construction of excessive generating capacity. The excess capacity, in turn, led to rapidly escalating electric rates for customers in Indiana and across the country. 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 Ind. Code chapter 8-1-8.5, which established the need for planning and the requirement that utilities 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) is now required and can only be issued by the Commission upon specific findings, including that the proposed additional capacity is necessary and consistent with planning. In 1985, this chapter was amended to establish the 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 in the electric industry since 1995, specifically resource planning. 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 (RTO). Together, these 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 RTOs, the 1995 IRP rule, which is 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 proposed IRP rule in 2012. The 2012 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 stakeholders participated, the Commission developed another 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 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)

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. It is important to note that the IRP process typically takes more than one year to complete. In addition to developing appropriate data inputs, inputting the data into the planning models, and conducting the necessary analysis, the stakeholder engagement 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.

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.

A key consideration in long-term resource planning is the need to retain maximum flexibility in utility resource decisions to minimize risks. An IRP developed by a utility should be regarded as illustrative and not a commitment for the utility to undertake. Essentially, IRPs are a snapshot in time based on the best available information.

Perhaps the greatest benefit of an IRP is that it can provide utilities with an objective and comprehensive assessment of the potential risks and 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 and 1980s. The most obvious risk confronting Indiana utilities, and utilities nationwide, 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.

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 generation resources including combined heat and power and battery storage, as well as the abilities of the transmission system. These many and varying resources are studied on a comparable basis as reasonably possible to give greater assurance that the portfolios of resources considered and selected by the utilities are sufficiently robust and flexible to allow for alterations as conditions warrant.

4. Limitations of this Report

This report summarizes the most recent utility IRPs projecting possible future load growth and resource needs over the 20-year planning horizon. Each utility-specific IRP describes the process used to determine what the utility believes is the best mix of generation, distributed energy resources, and energy efficiency resources to meet their customers' needs for reliable, low-cost, and environmentally acceptable power over the next 20 years. Taken together, the IRPs allow the Commission to better understand how the utilities, both individually and as a group, see the general direction for future load growth needs and resource options. However, as a precaution, 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 one utility's IRP analysis and results in 2015 with another utility's resource analysis 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. It must also be noted that each utility in the development of its IRP uses different methodologies, computer models, and data inputs and assumptions, so any comparisons of utility IRPs, even those prepared within the same year, must keep these considerations in mind.

This report includes not only the utilities' IRPs, but also analysis by the SUFG, the RTOs, and a national perspective. Similar qualifications must be kept in mind when comparing long-term resource planning analysis prepared by these organizations with each other and Indiana electric utilities.

Even though Indiana utilities over the last several years have significantly improved their IRP methodologies, data, risk and uncertainty analysis, and the presentation of their written reports, there is still considerable disagreement among various stakeholders as to all aspects of IRP development and presentation of the results. The flavor or tenor of these debates are reflected in the annual Director's IRP Report, the stakeholder and utility comments provided on the draft Director's report, and the stakeholder comments on each of the utility IRPs. These documents can be found at https://www.in.gov/iurc/2630.htm.

C. State Utility Forecasting Group

The SUFG's projection for Indiana's resource requirements provides a useful perspective as a snapshot in time based on information from Indiana's utilities and using current 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 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 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), the SUFG must keep its modeling system current. In the 2015-2017 contract with the Commission, the 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 system to the North American Industry Classification System.

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 reductions in projected growth rates. 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 analyses, 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), technological changes, and 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-year basis to incorporate new information and developments.

This section of the report shows projections of load growth developed by the SUFG, Indiana electric utilities, MISO, and the EIA. Each organization's load forecast was completed at different points in time and is based on different methodologies, data, and assumptions.

1. Indiana Utilities' Forecasts

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

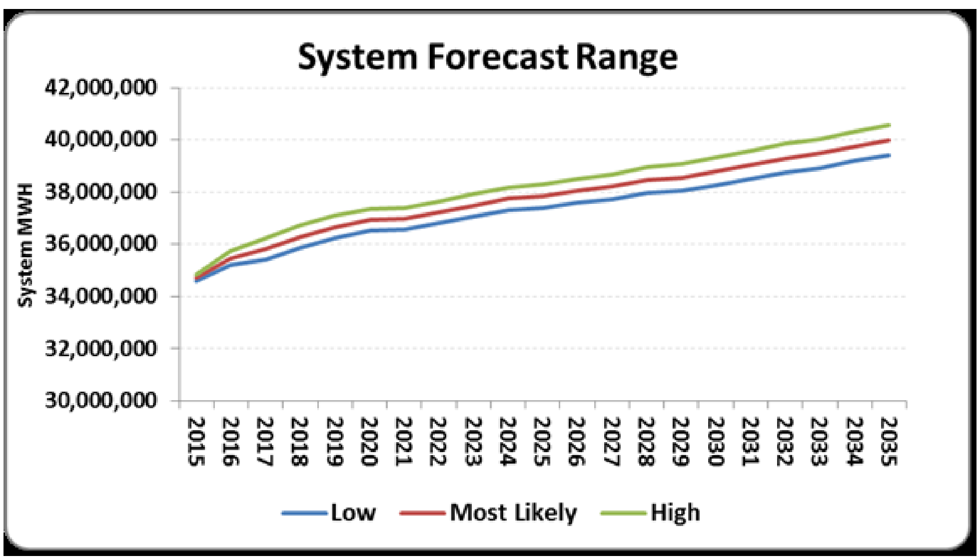
Projected Growth Rate of Energy and Peak Demand over the Planning Period*

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 (2016-2036)	0.5%	0.5%
Wabash Valley (2018-2036)	0.8%	0.8%

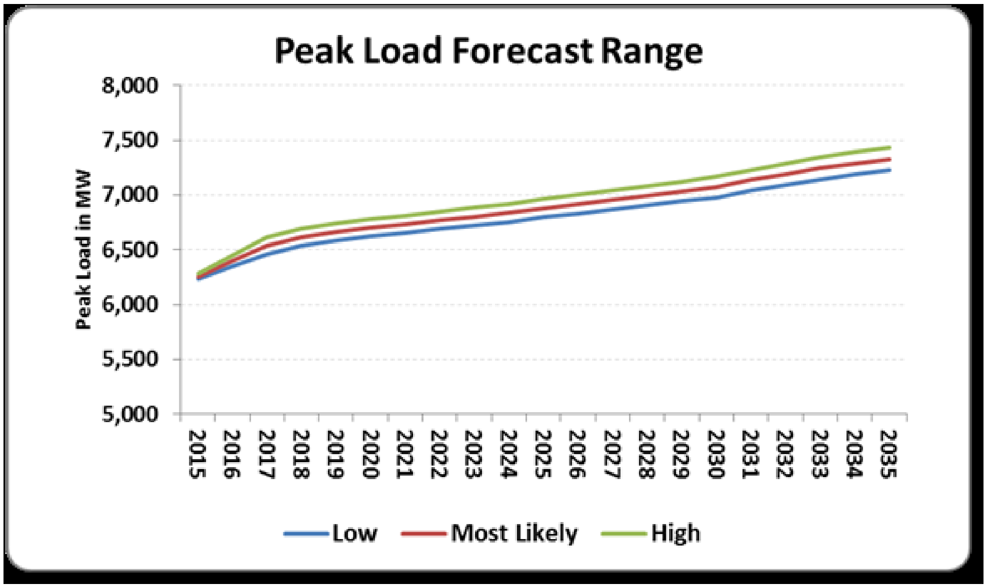
*The percentages are compound annual growth rates over the company-specific planning period.

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.



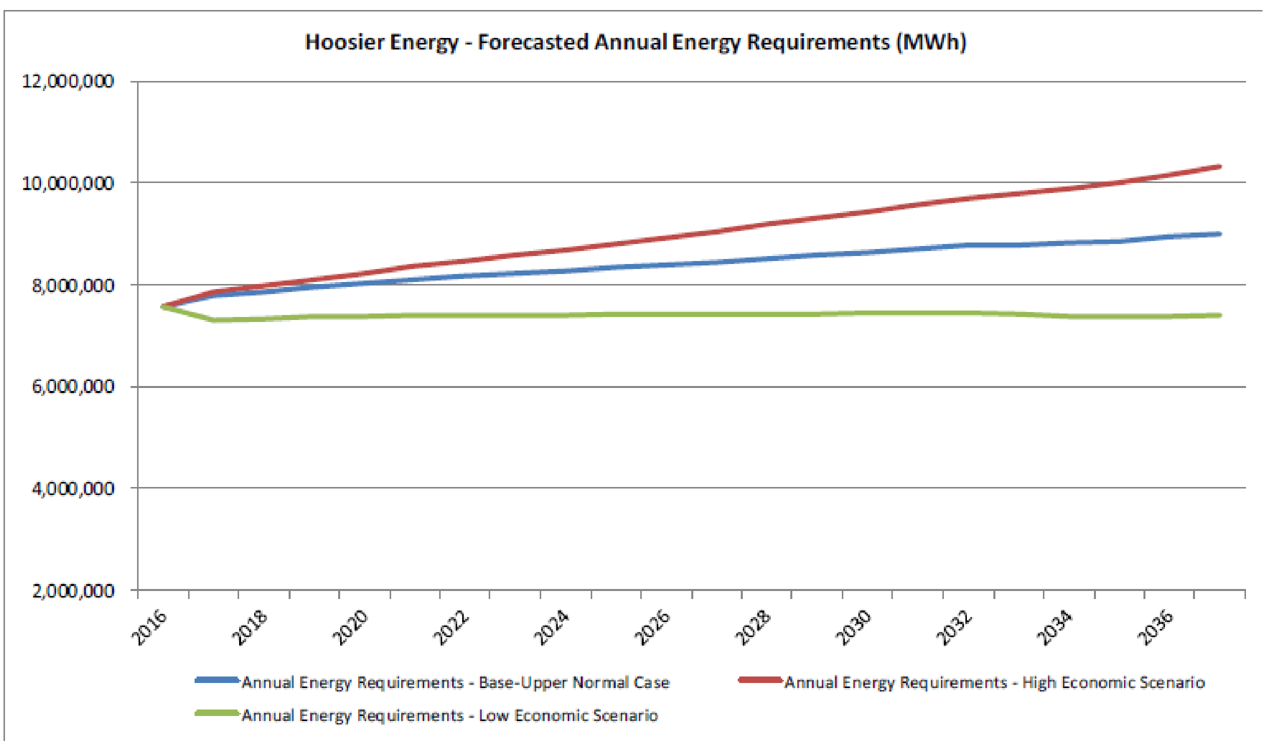
Source: Duke Energy Indiana 2015 IRP. Pg. 44



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.

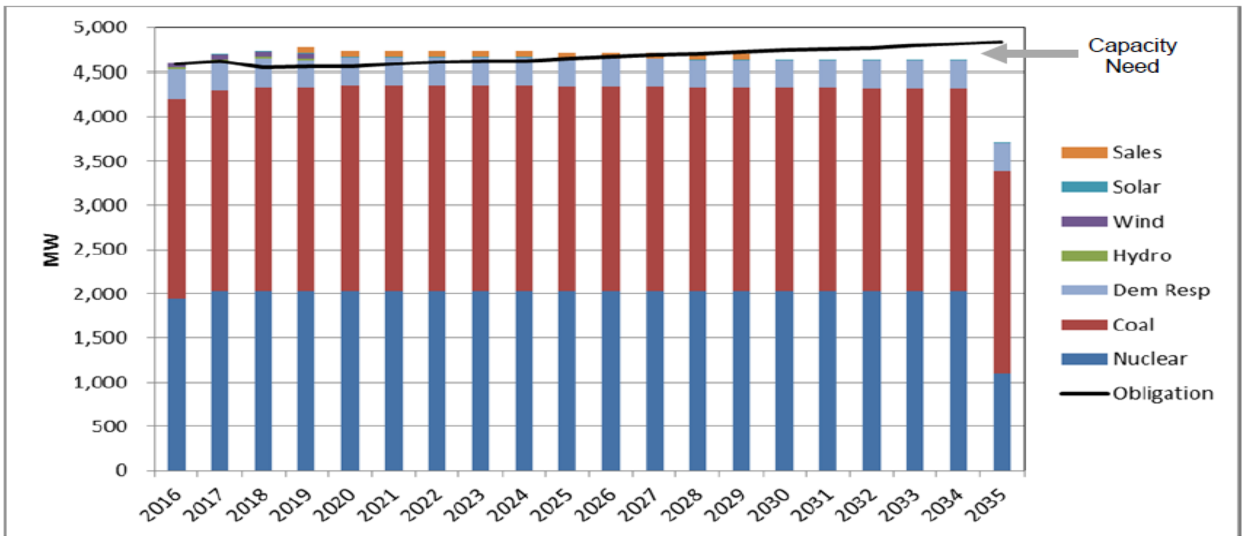


Source: Hoosier Energy 2017 IRP. Pg. 35

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. In 2015, I&M did not anticipate the need for additional capacity until 2035. I&M is reevaluating this assumption as it prepares its 2018 IRP. Energy efficiency and demand response were projected to reduce I&M's retail load by eight percent over the 2016-2035 planning horizon.

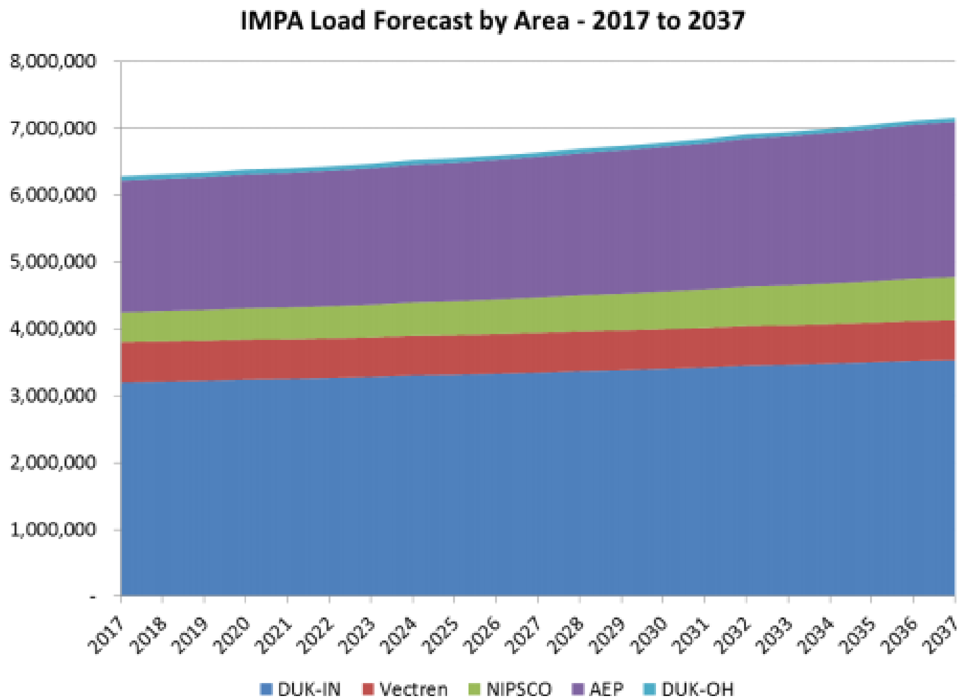
Indiana Michigan Power - Forecasting Energy and Peak Demand Requirements



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 Megawatt hours (MWh). IMPA projects that its peak and energy demand will grow at approximately 0.6 percent 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. Members in the Duke, NIPSCO, and I&M areas are expected to experience growth, while those in the SIGECO and Duke Ohio region are expected to contract somewhat.



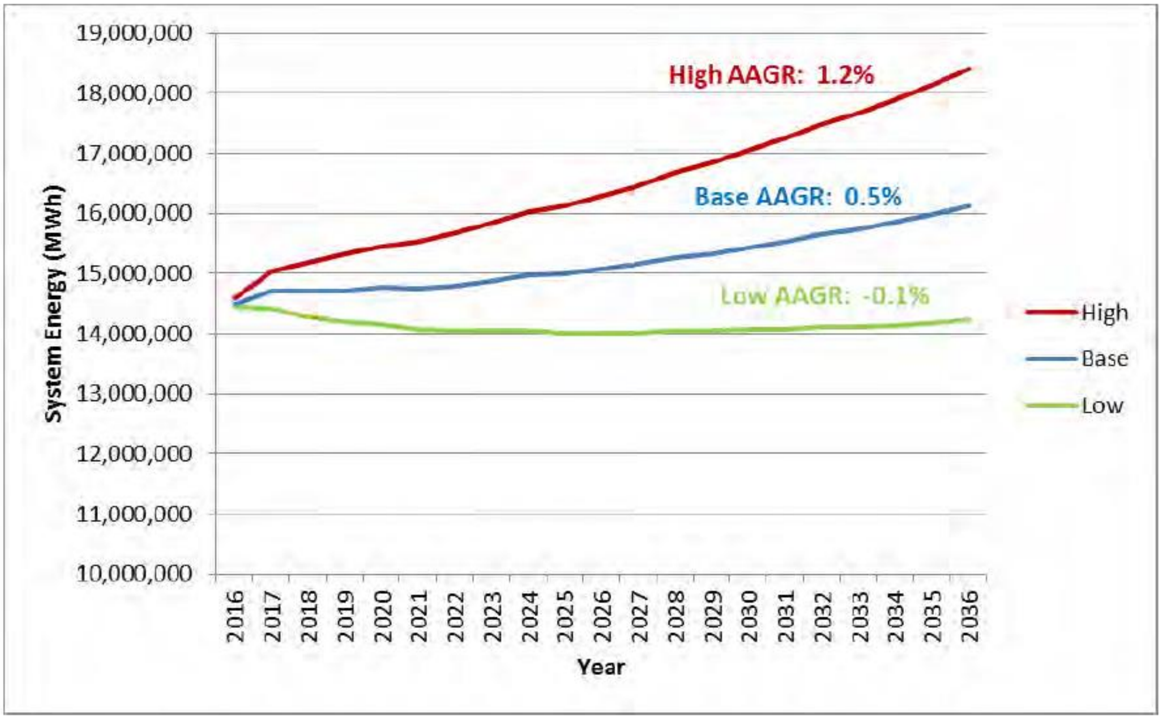
Source: Indiana Municipal Power Agency 2017 IRP. Pg. 5-40

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:

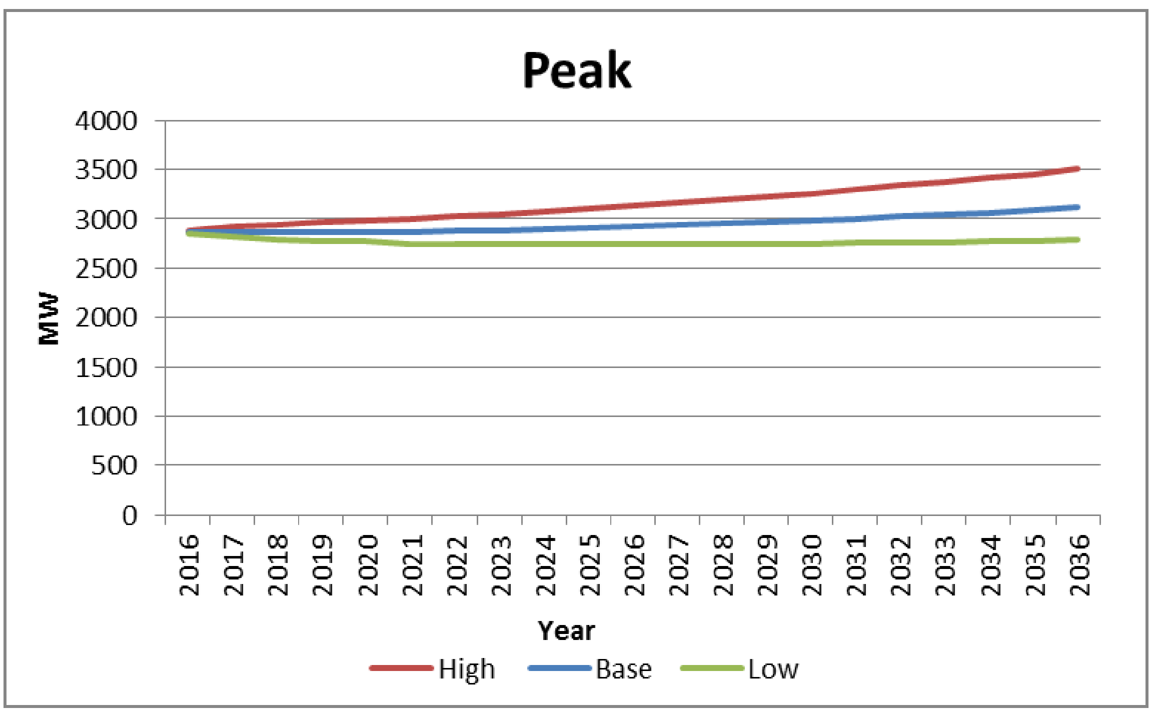
> [P]art of the decline can be [attributed] to the 2008 recession and the slow economic recovery. Between 2007 and 2011 customer growth actually declined 0.1% per year. Since 2011, customer growth bounced back with residential customer growth averaging 0.8% per year and non-residential customer growth 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).

IPL Forecasted Energy Requirements



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

IPL Forecasted Peak Demand

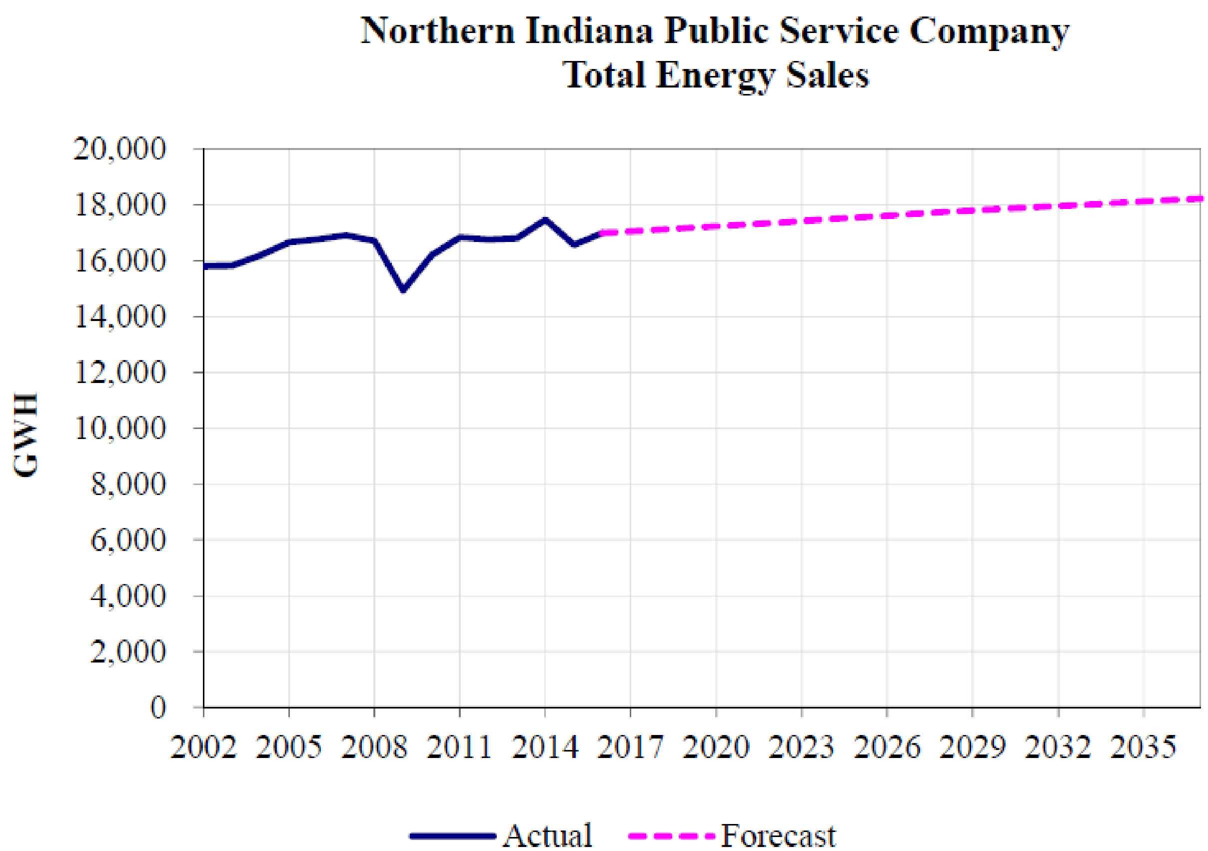


Source: Indianapolis Power & Light 2016 IRP. Pg. 142

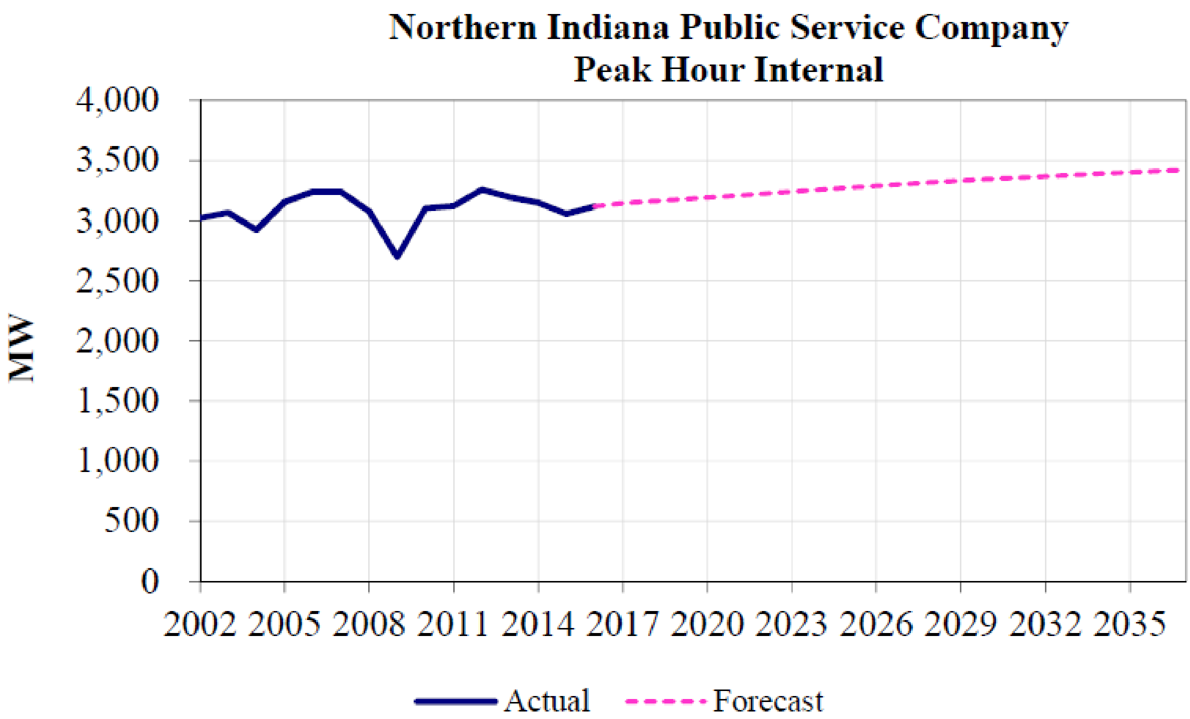
f) Northern Indiana Public Service Company – 2016 IRP

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:



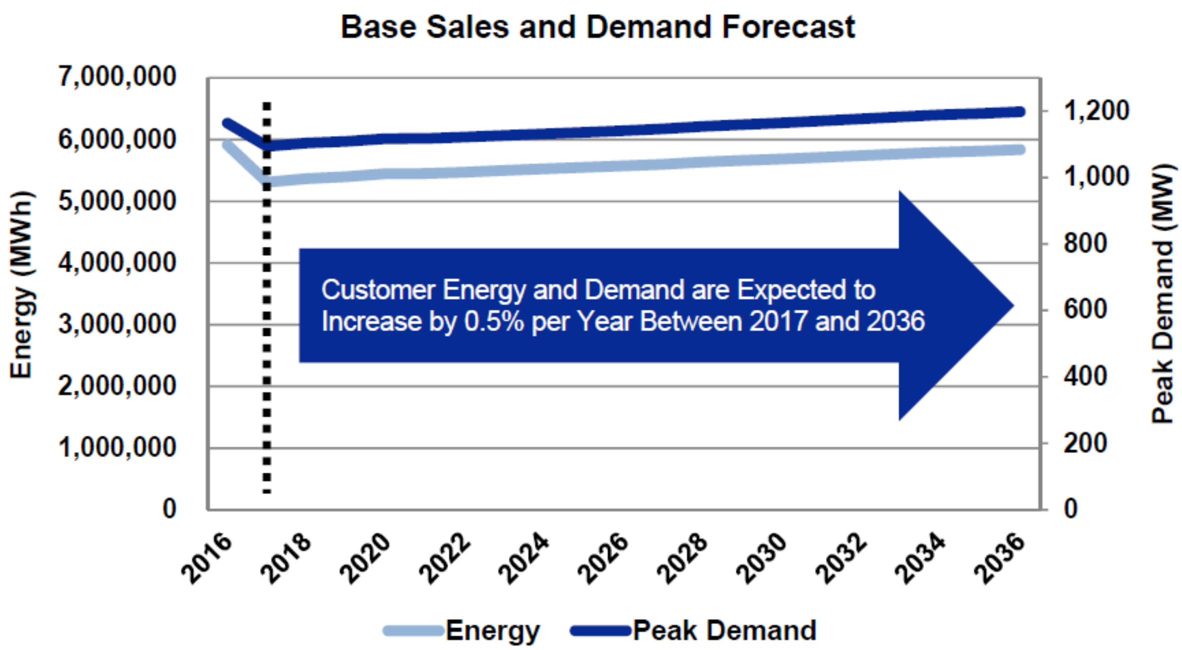
Source: Northern Indiana Public Service Company 2016 IRP. Pg. 28



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

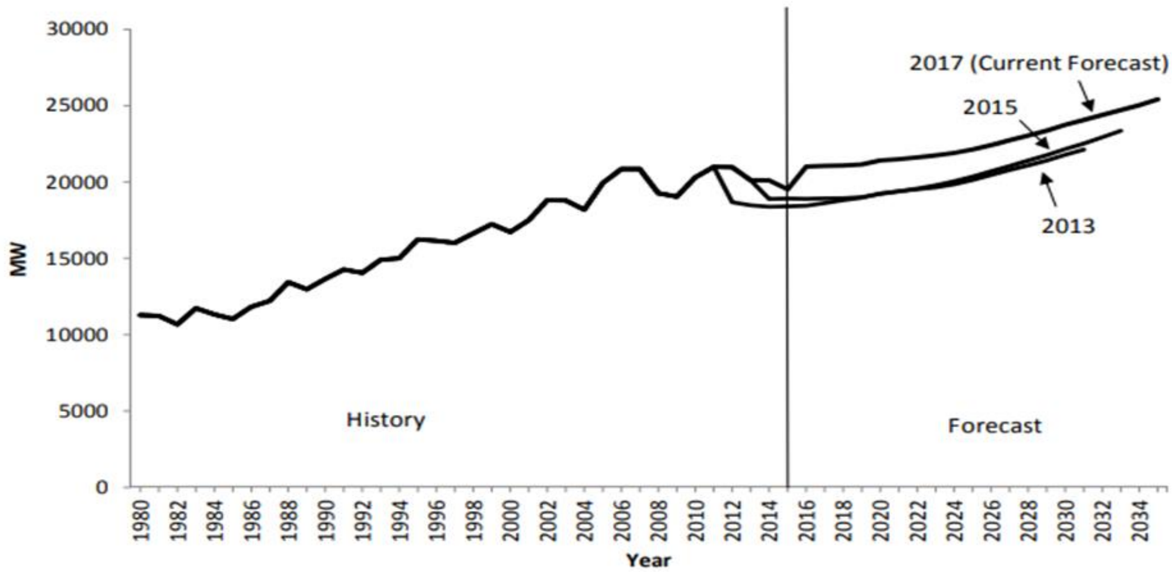
2. State Utility Forecasting Group Forecast

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. 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 MISO and PJM is more relevant to resource planning than the maximum demand incurred by their member systems. Specifically, MISO and PJM *coincident peak demand* [2]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*).

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[2] **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 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.

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

4. National Forecast

According to the 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 percent 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.

B. Future Resource Needs

With all the utilities, the predicted need for additional resources begins with the predicted annual energy and peak demand requirements. Future resource needs will therefore vary with the predicted energy and peak demand requirements. IRPs typically will analyze multiple scenarios, or possible states of the world, to bracket differences between forecasts. The utilities may, for example, include low-growth, base-growth, and high economic-growth scenarios. Energy use changes with the economy, and so too will the need for additional resources. As was noted earlier, each assessment or forecast was prepared at different times with different methodologies, models, data, and assumptions regarding key inputs such as natural gas prices and the impact of technological change on renewables, DERs, and storage. Any analysis is a snapshot in time. The following summaries of the needs for future resources are therefore only applicable under the specific scenario to which it applies.

1. State Utility Forecasting Group Projections

In its _Indiana Electricity Projections: The 2017 Forecast_, the SUFG summarized its 2017 forecast regarding future resource 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' Projections of Resource Needs

a) Duke Energy Indiana – 2015 IRP

Duke'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 intake structure modifications in the 2016 -2023 time frame.

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	1,755	1,755	1,755	1,655	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 1,253 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 February 1, 2019. 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 have adequate resources with the addition of one or more combined cycle units.

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

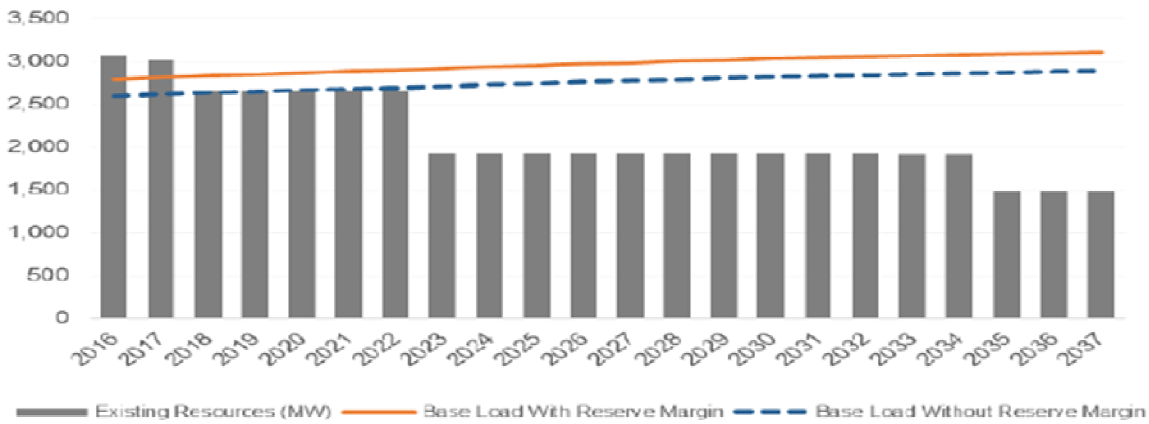
Source: Indiana Municipal Power Agency 2017 IRP. Pg. 1-13

e) Indianapolis Power & Light Company – 2016 IRP

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

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 (8 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: Northern Indiana Public Service Company 2016 IRP. Pg. 55

In September 2018, NIPSCO's IRP update suggests that all four Schahfer units may be retired by year-end 2023 due to being uneconomic in the current wholesale power market. The IRP also indicates that Michigan City may also be retired in 2028 for economic reasons. The preliminary plan is for the retired capacity to be replaced by a combination of renewables based on a competitive bidding process.

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 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 economical 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.[3] Based on the 2016 IRP and updated IRP modeling completed in 2017, SIGECO plans to retire 73 percent of its current coal-fired generation fleet and diversify its generation portfolio by adding the combined cycle gas turbine at the end of 2023.

[3] ALCOA owns and operates four coal-fired generating units that provide electricity to its aluminum operations. SIGECO owns half of unit 4. The uncertainty of the continued operation of Warrick 4 depends on ALCOA's decision to continue its aluminum operations. No final determination has been made but is subject to on-going review.

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 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 power purchase agreements drives the need for these resources.

C. Resource Mix and Location

The location of new resources is dependent on the specific utility's 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.

1. Indiana Utilities' Projected Resource Mix

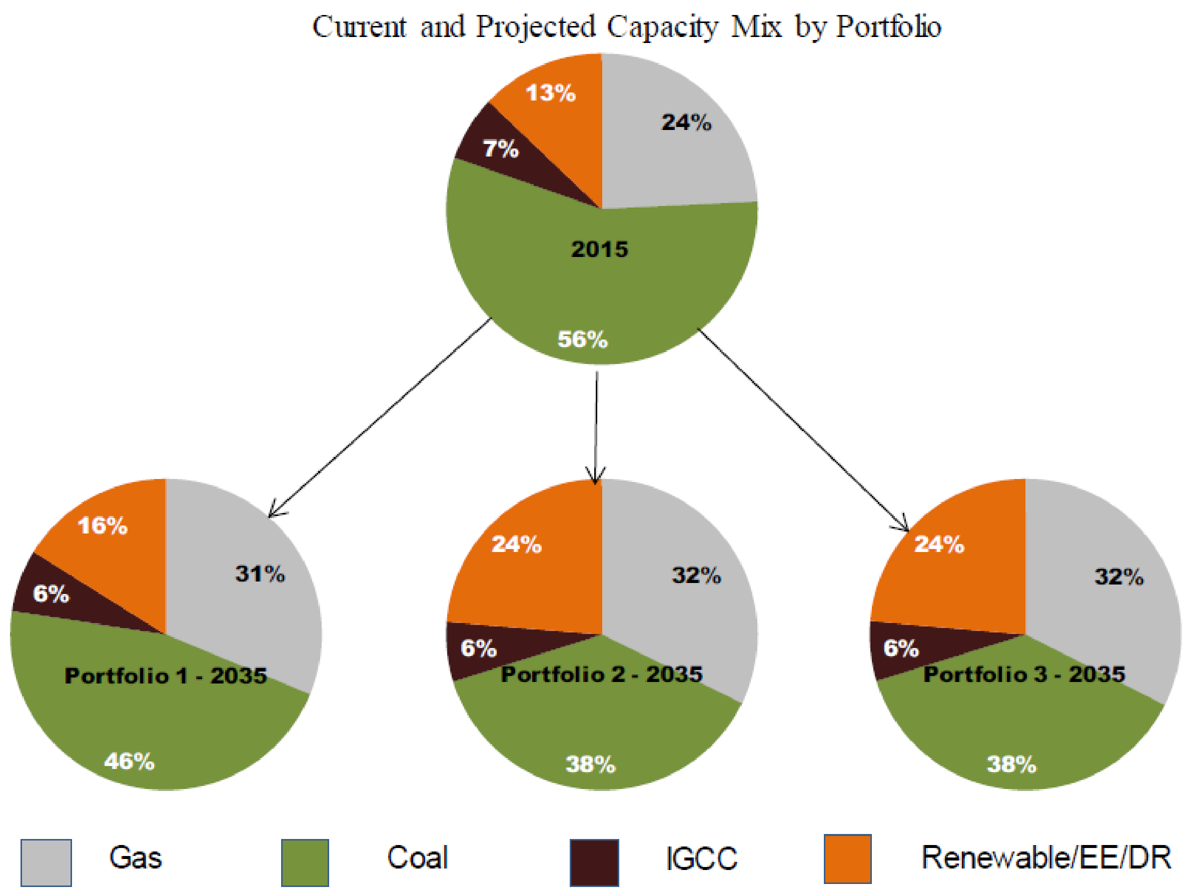
When analyzing the generation resource mix in Indiana, retirements of existing coal resources are of primary focus. Within the last 20 years, environmental regulations have imposed significant costs on coal-fired generation, in particular. The capital costs associated with environmental retrofits and equipment necessary to comply with U.S. EPA requirements, including fixed operations and maintenance expenses, were significant. Beginning around 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. Significant improvements also occurred in the engineering performance and economics of renewable energy resources, distributed energy resources, energy storage, and energy efficiency. As a result, the comparative economics of different energy resources requires closer examination before any resource commitments are made.

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 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



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.

Hoosier Energy Projected Resource Requirements

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

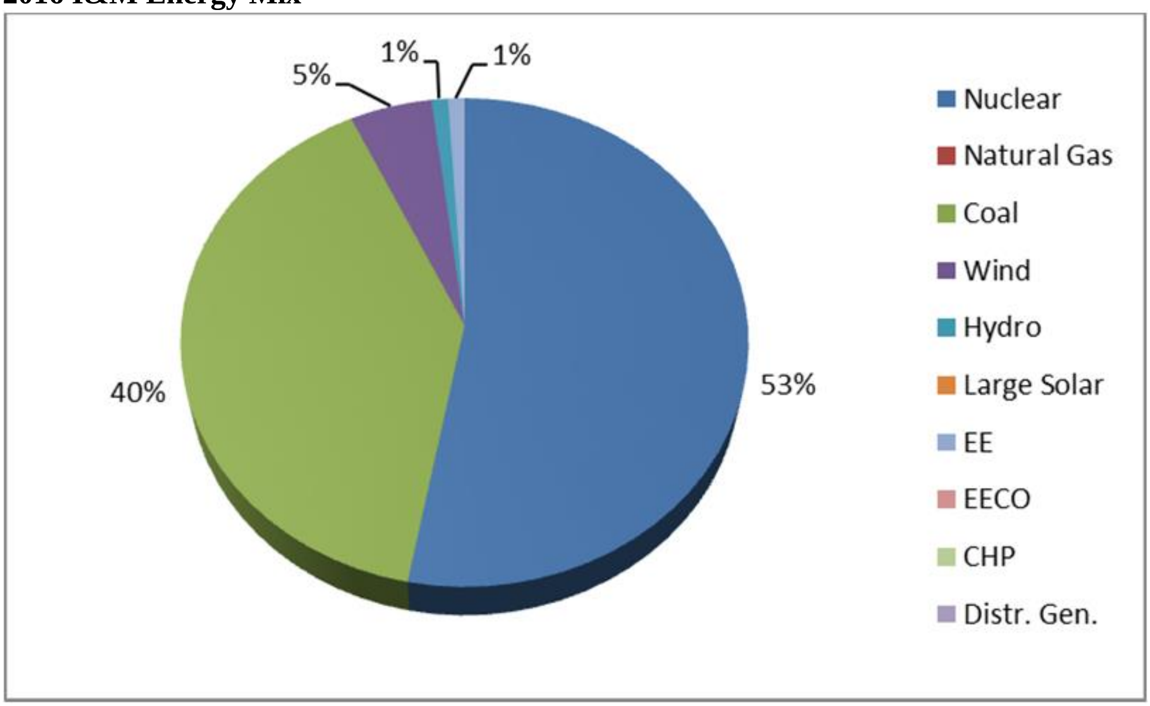
I&M's resource mix will be highly dependent on a decision regarding the Rockport generating units and its resource alternatives. I&M's 2015 IRP is being updated in 2018 and the future resource mix is likely to be different than predicted in 2015. The 2015 IRP, however, remains the most recently submitted 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 percent to 13 percent 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

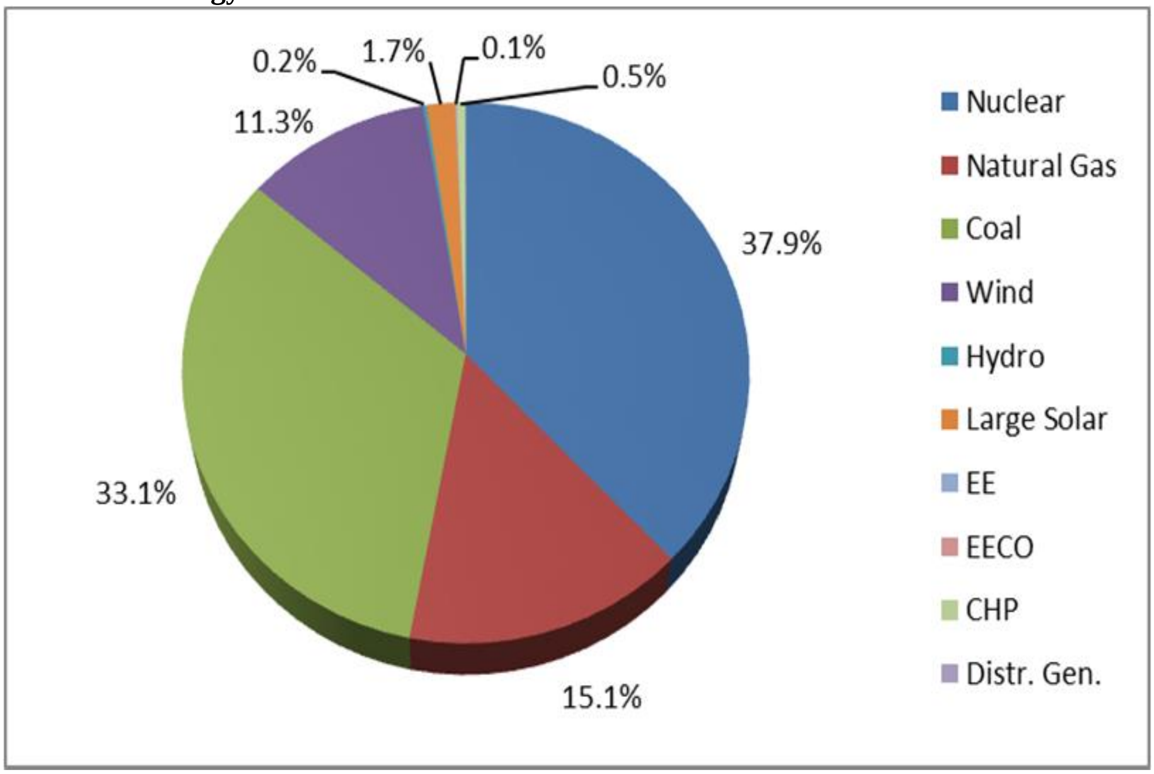
Source: Indiana Michigan Power 2015 IRP. Pg. ES-6

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 percent 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 Unit 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 purchase power agreement in 2021. From 2018 through 2027, IMPA anticipates much of its new resources will be solar and wind. After 2026, IMPA expects to 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.

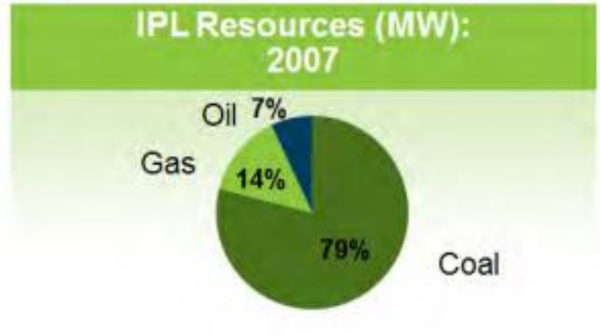
IMPA Future Resource Changes

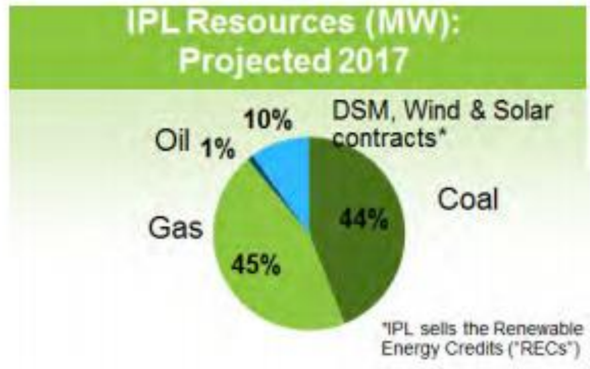
Year	Capacity Losses MW Lost	Resource	Capacity Additions MW Added	Resource	Net MW
2018	(50)	PPA Expires	12 100	Solar Bilateral Capacity (18-20)	62
2019	(50)	Wind PPA Expires	12 50	Solar Wind PPA	12
2020			12	Solar	12
2021	(100) (100)	PPA Expires Bilateral Capacity Expires	12 200	Solar Bilateral Capacity (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

IPL retired 260 MW of coal-fired generation in 2015 and 2016, converted 630 MW of coal-fired generation to gas the spring of 2015, 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.





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).

In 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.

IPL Summary of IRP Scenarios and Potential Future Resources

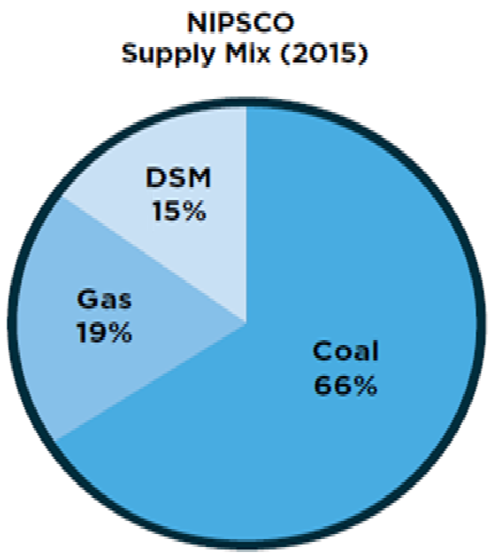
	Final Base Case	Strengthened Environmental	Distributed Generation	Hybrid
Coal	1078	0	1078	1078
Natural Gas	1565	2732	1565	1565
Petroleum	11	11	11	0
DSM and DR	208	218	208	212
Solar	196	645	352	398
Wind with ES*	1300	4400	2830	1300
Battery	500	0	50	283
CHP	0	0	225	225
totals	4858	8006	6319	5060

It should also be noted that IPL has been a leader in the deployment of Advanced Metering Infrastructure (AMI) that provides IPL with customers' 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 vary continuously and aid in the evaluation, measurement, and valuation (EM&V) of energy efficiency programs, demand response, distributed energy resources, and renewable resources. It enables IPL to evaluate non-utility resources on a more comparable basis to utility resources, provides information needed to integrate new technologies such Energy Storage (e.g., batteries) and Electric Vehicles (EV), and improves the information needed 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 in 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 power purchase 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, in the 2018 IRP under development, issued an "all source Request for Proposals" as a means of securing future resources. According to NIPSCO in its September 2018 IRP stakeholder meeting, its IRP update suggests that all four Schahfer units may be retired by year-end 2023 due to being uneconomic in the current wholesale power market. The IRP also indicates that Michigan City may be retired in 2028 for economic reasons. The preliminary plan is for the retired capacity to be replaced by a combination of renewables based on a competitive bidding process.

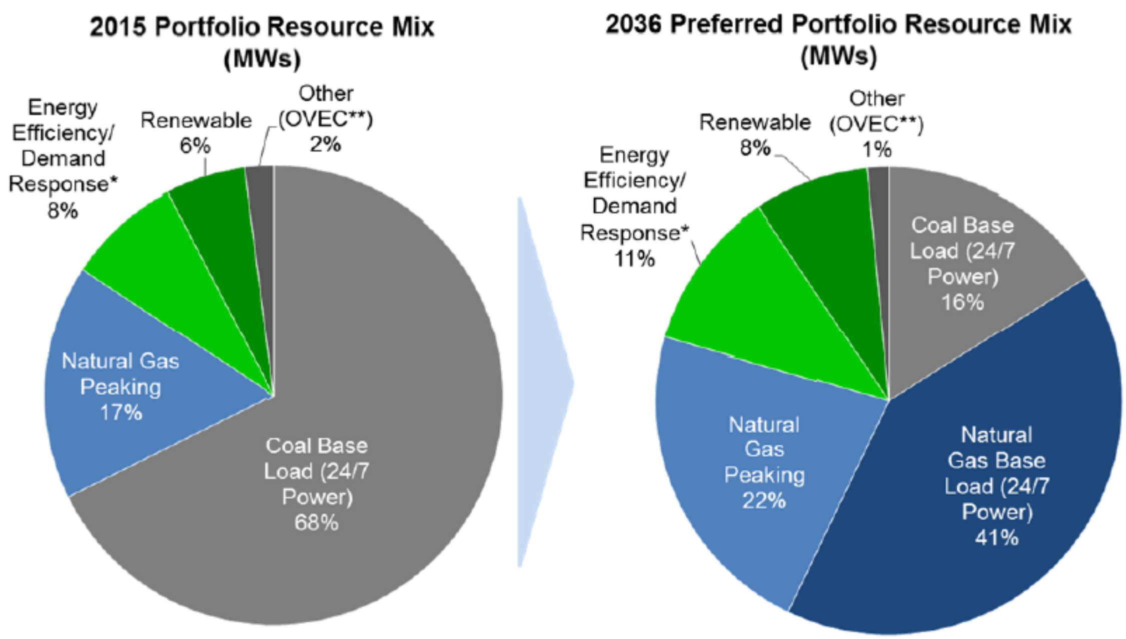
g) Southern Indiana Gas & Electric Company – 2016 IRP

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, 80 MW of wind from power purchase agreements, 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 through small increases in energy efficiency and renewable resources.

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 (Page 2 and graph on page 5).



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

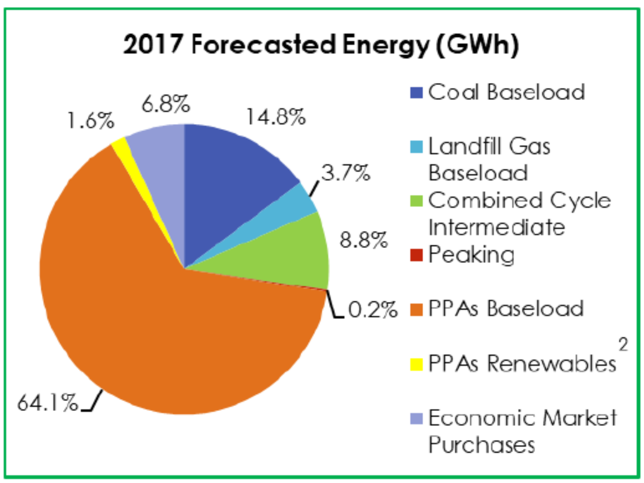
SIGECO is proposing in Cause No. 45052 to diversify its generation fleet based on its 2016 Integrated Resource Plan by investing in a new CCGT sized to replace certain coal-fired units that will be retired at the end of 2023. SIGECO is seeking a CPCN to construct a 2x1 F-class technology CCGT with capacity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

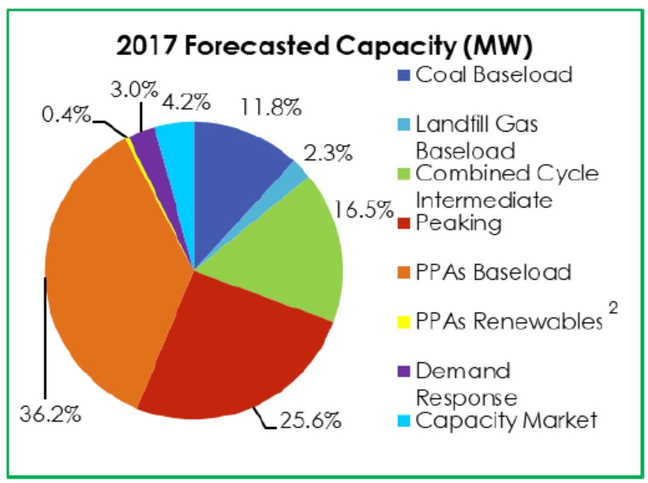
Consistent with the 2016 IRP, SIGECO plans to retire Culley Unit 2 and the Brown Units 1 and 2 once the CCGT is operational. According to SIGECO Culley Unit 2's age and efficiency will not justify further capital investment to allow it to continue to operate in the future. Brown Units 1 and 2 would require 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 percent 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 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) (Page 5).

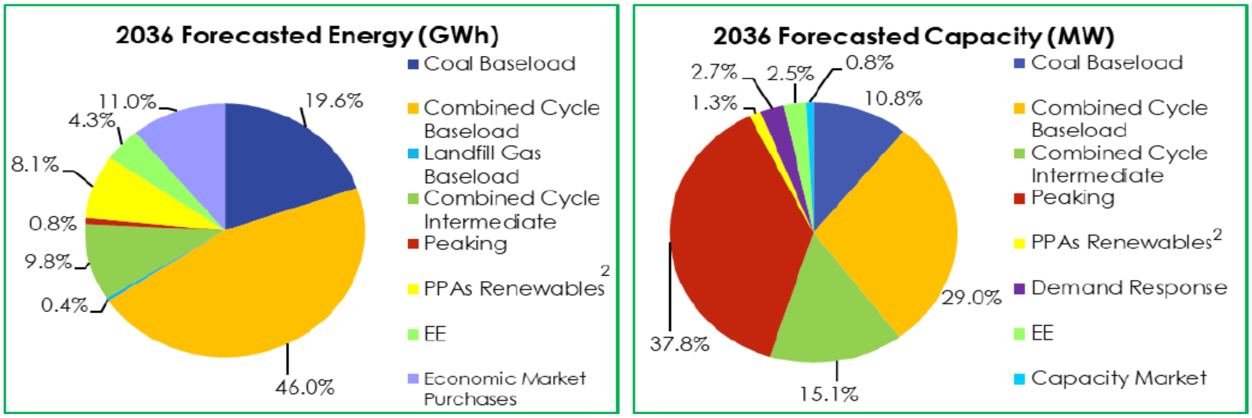
Wabash Valley will purchase output from three wind projects from 2018 to 2020. Wabash Valley members will continue to run and enhance its energy efficiency programs and may choose to continue to build demand response resources in the near term. Past 2020, Wabash Valley's resource plan anticipates building 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 power purchase 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.





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 demand response 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 demand response 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 Direct Load Control program. To date, 19 of the 23 Members have signed agreements to participate in the PowerShift® program. The PowerShift® program includes participants' water heaters, air conditioners, pool pumps, field irrigators, entire homes, ditch pumps, and grain dryers. Please see the table below for details as of June 1, 2017. (Page 23 of IRP.)

Wabash Valley started offering energy efficiency 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 member cooperatives, retail members and power supply staff to develop attainable savings goals that lessen baseload power supply costs and increase retail member satisfaction throughout its 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. (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	23,488	64,604	25,192
					Verified	Verified	Verified	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.

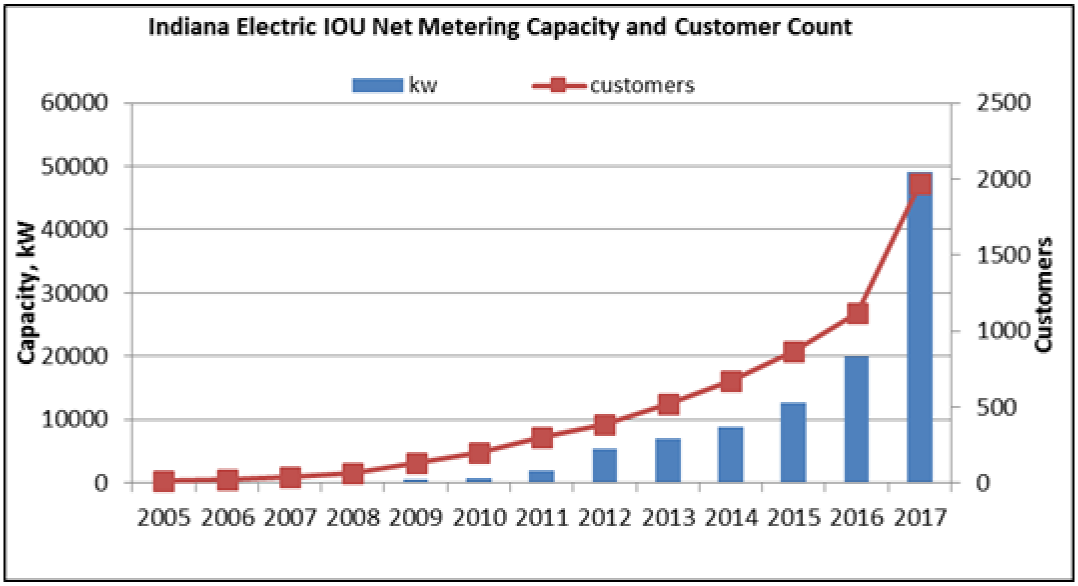
Source: Wabash Valley Power Association 2017 IRP. Pg. 31

2. 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 2,114 MW. This constitutes about 85 percent 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 Indiana utilities is about 1,098 MW with about 301 MW purchased from out-of-state wind generators. As of May 2018, Indiana utilities have about 797 MW of power purchased agreements for wind. 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, SEA 309 became law, limiting how long eligible customers could qualify for net metering and created 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, which created a cutoff date for being grandfathered in.



Another option for renewable resources is the Feed-in-Tariff or FIT [4]. However, as evidenced by the table below, this has a very limited application in Indiana. New customers cannot join IPL's FIT, and NIPSCO's FIT is available until participation limits are reached.

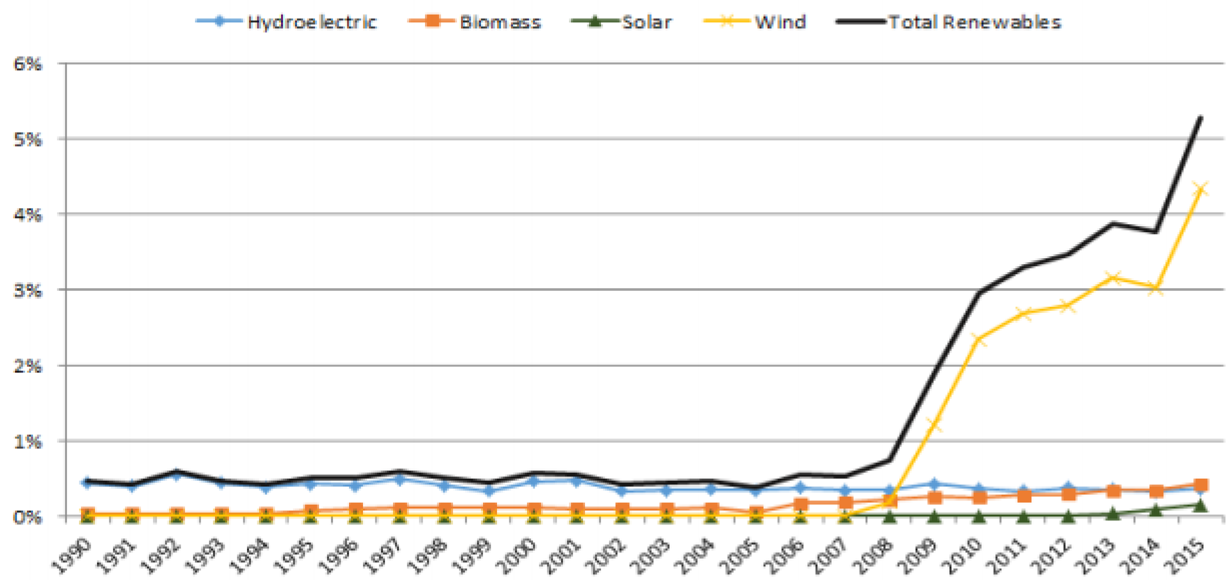
Summary of Resources Participating in the Feed-In-Tariff Option

	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 illustrates the rapid growth in wind generation in Indiana as a share of the total electricity generation in the state through 2015. 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 power purchase contracts with Indiana utilities. Despite the rapid growth in solar, it contributes a very small share to the total electricity generated in Indiana.

[4] 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 concentrated photovoltaic).

Percent of Solar Total 1 MW and Larger		
Utility	**MW**	**Percent**
IPL	**91.94**	**46.8%**
IMPA	**39.10**	**19.9%**
Duke	**37.25**	**18.9%**
Hoosier	**11.84**	**6.0%**
NIPSCO	**11.50**	**5.8%**
IM	**5.00**	**2.5%**
WVPA	**-**	**0.0%**
Vectren	**-**	**0.0%**
Total	**196.63**	

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 hinder 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.

3. 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 (SUFG's 2017 Electricity Projections. Pg. 3-1). These resources add important resource diversity and reliability. That is, DSM reduces risks for the utility and customer. 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 the 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 are 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.

Hoosier Energy, IMPA, and WVPA are not required to submit three-year energy efficiency plans under state law, but each organization offers a spectrum of DSM programs to their customers.

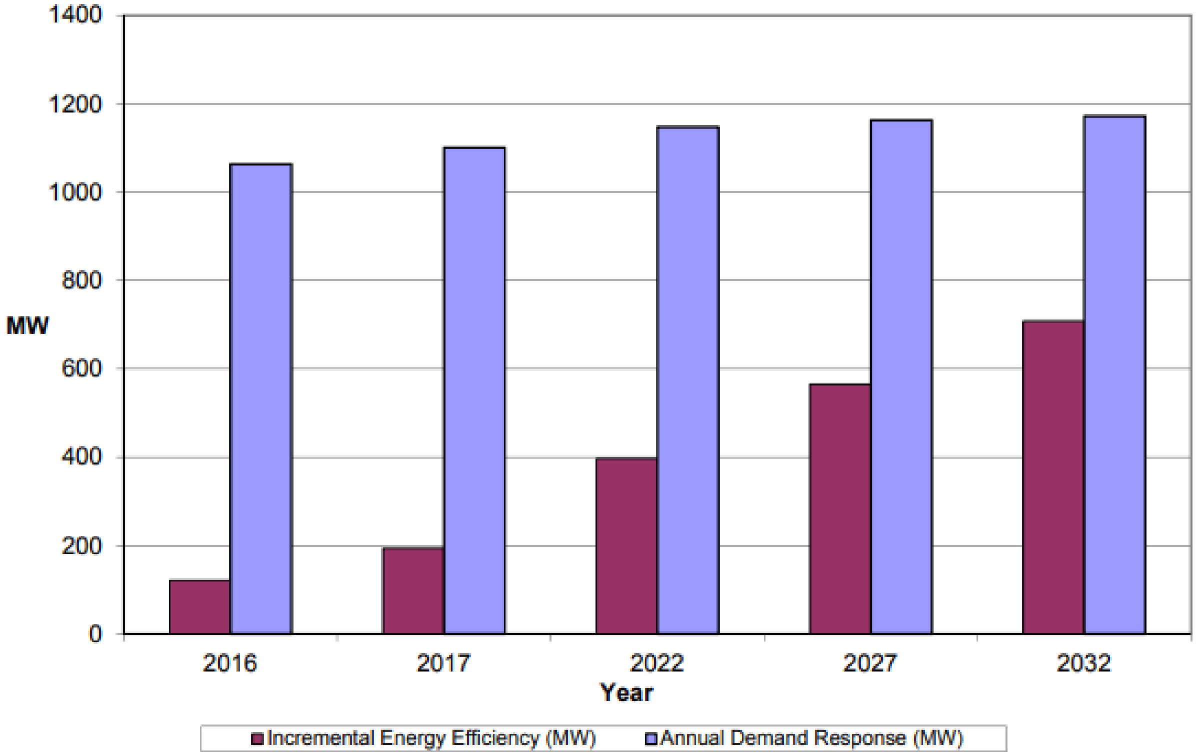
The following graphs are from the SUFG's 2017 statewide load forecast report and shows their projection of the kW impact of energy efficiency programs and demand response programs implemented through 2016.

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

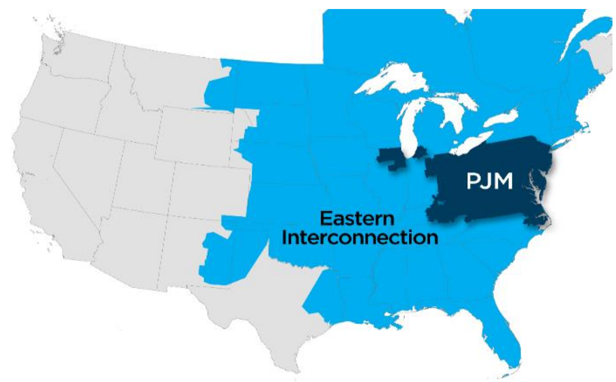
Projections of Incremental Peak Demand Reductions from Energy Efficiency and Demand Response



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 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. Hoosier Energy is a member of MISO, and IMPA and WVPA are members of both RTOs given the dispersion of their members across the two RTOs. 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 generation 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

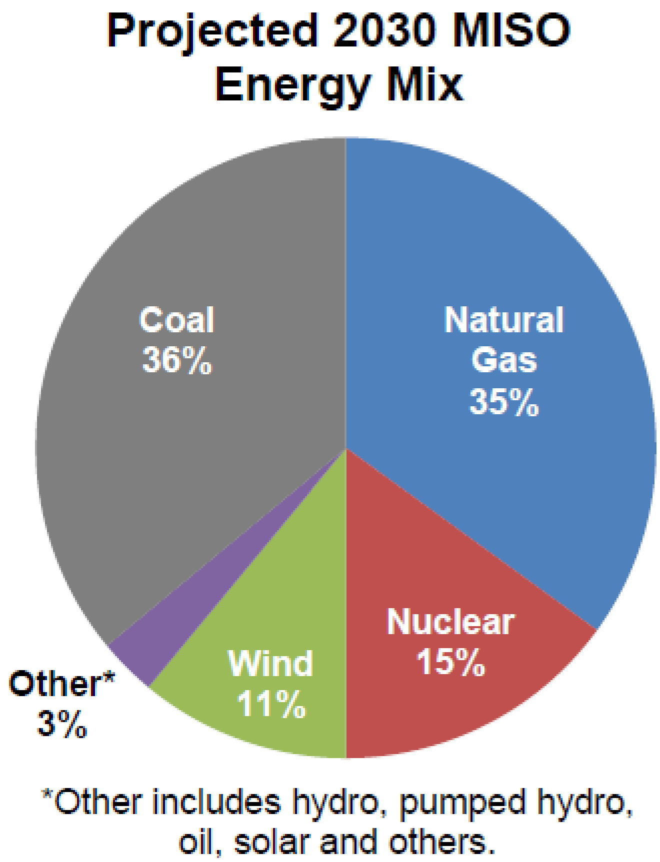
MISO's Value Proposition documents how the region benefits from its operation. In 2017, MISO calculated that its efforts provided between $2.9 billion and $3.7 billion in regional benefits, driven by enhanced reliability, more efficient use of the region's existing transmission and generation assets, 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 due to declining costs, declining cost of energy efficiency, and the declining cost of natural gas and projections for low natural gas prices for several years.

MISO had adequate electricity resources to meet demand for the 2018 summer. The regional transmission operator, whose grid covers 15 states in the Midwest and southern U.S., expects, beyond this summer and for the next several years, 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.[5]

Within the MISO region, coal-fired generation constituted 75 percent of total energy production in 2010 and is projected to decline to about 36 percent 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 percent in 2014 to 35 percent in 2030. Increasingly, natural gas sets the market price (i.e., the Locational Marginal Price, or LMP). As the graphic below illustrates, the amount of gas-fired generation is expected to constitute 35 percent by 2030 compared to 36 percent for coal-fired power plants.

[5] 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.

Despite the significant changes in generation resource composition and the anticipated changes as projected by 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.

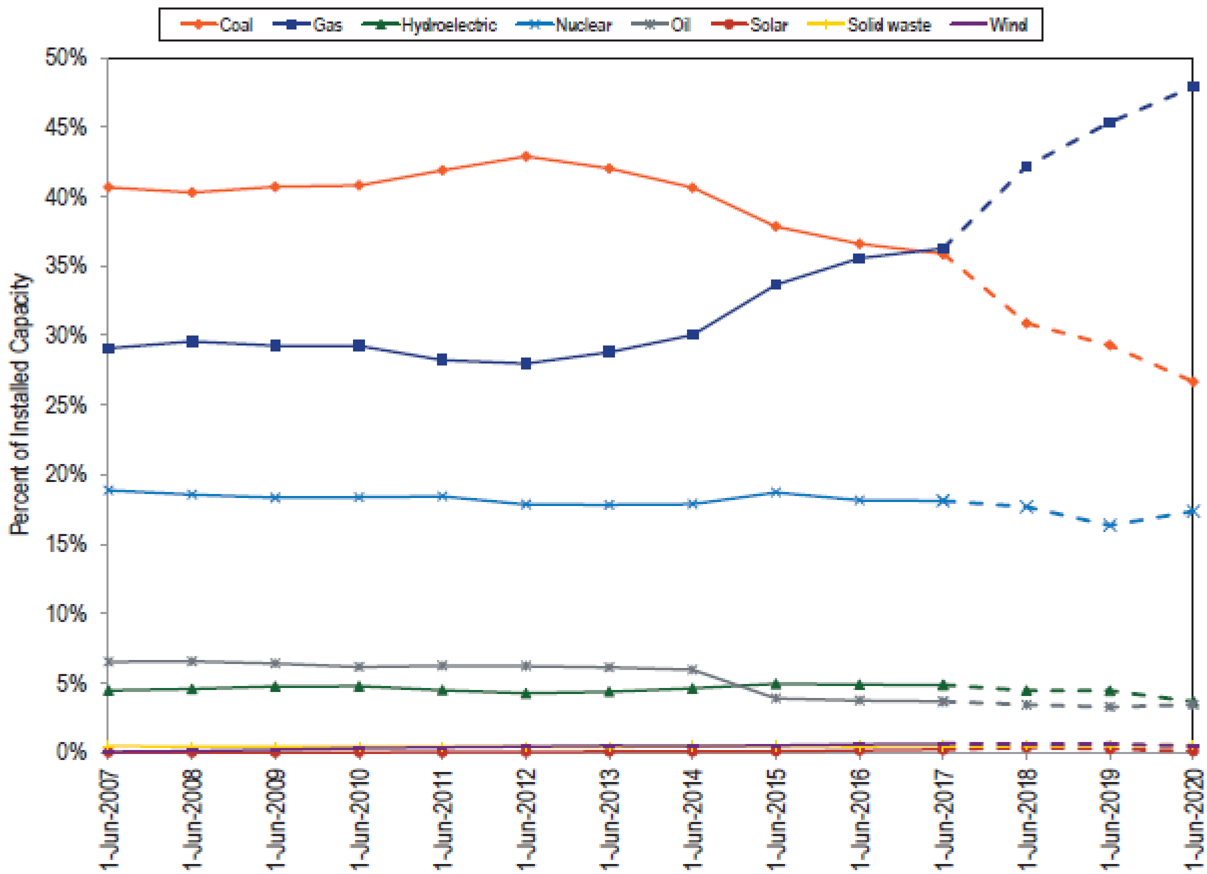
2. PJM Region

In contrast, 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 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 the declining cost of natural gas and projections for low natural gas prices for several years. Increasingly, 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



Source: 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 to satisfy the forecasted demand and meet unforeseen contingencies.

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, hydroelectric, and battery storage. An IRP considers all these resource options on a comparable basis as reasonably possible.

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 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. 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. For technologies with significant fuel cost, both fuel cost and overnight construction cost estimates significantly affect 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. The IRP models go beyond an analysis of potential resource choices on the basis of LCOE by reflecting the value of different resource choices within the context of the utility and regional resource portfolio and how these portfolios might evolve over time. With this background, below is a table showing comparisons among different generating 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:

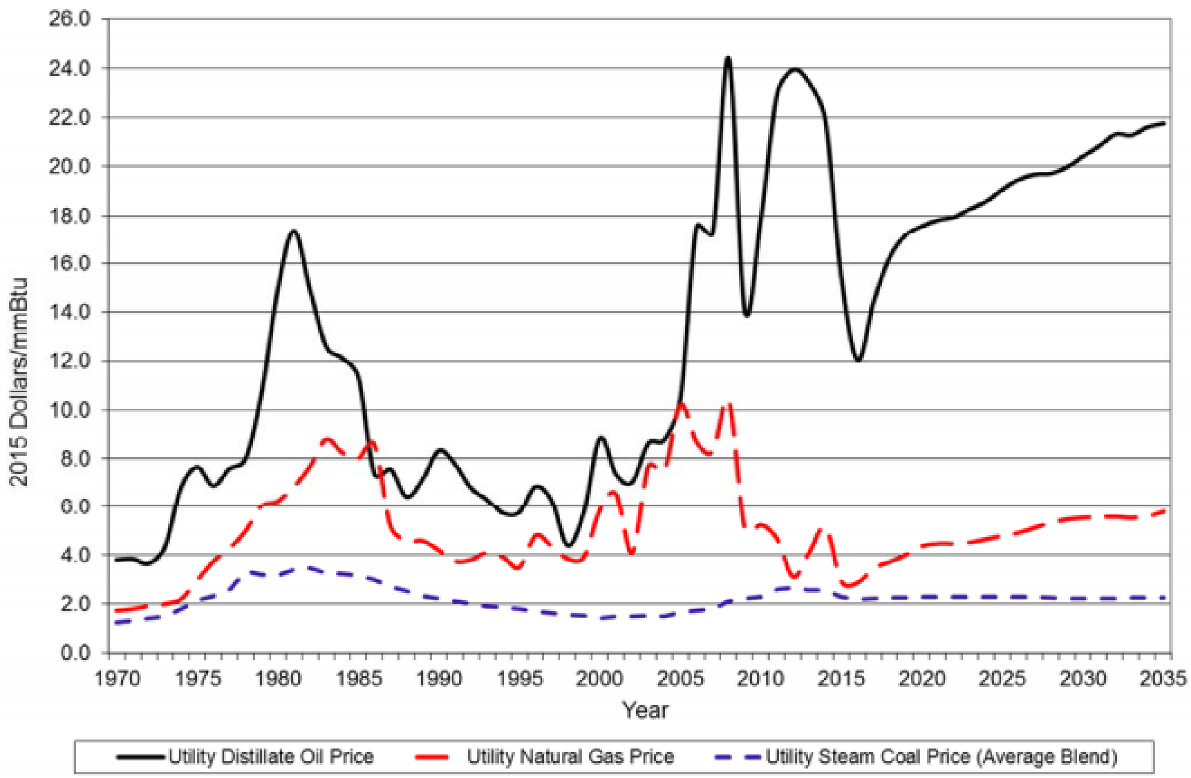
> SUFG's current assumptions are based on the January 2017 projections produced by the Energy Information Administration (EIA) for the East North Central Region. SUFG's fossil fuel real price projections are as follows: Natural Gas Prices: Natural gas prices decreased significantly in 2009 relative to 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 EIA'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

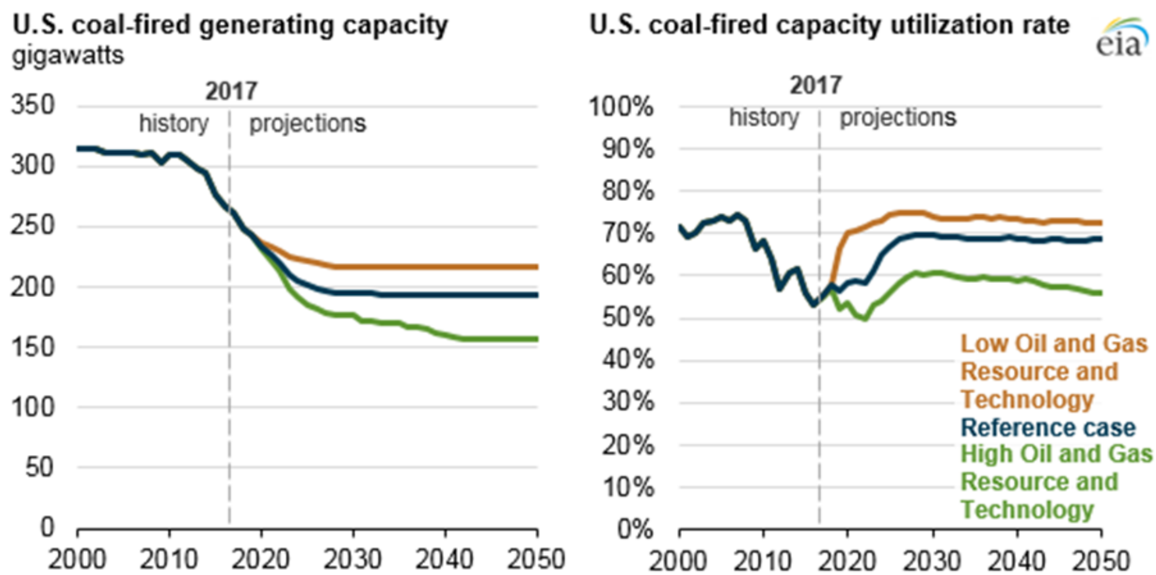


As noted by the SUFG:

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 (SUFG page 4-3).

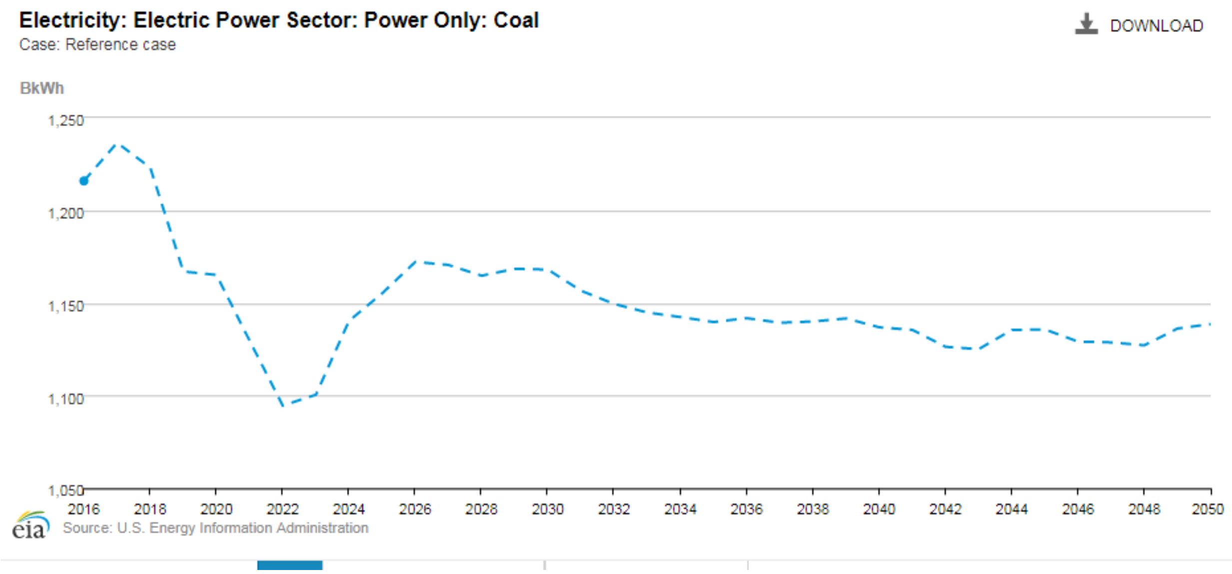
2. The Changing Fuel used in Generation Resources in the United States

The following graphic prepared by the EIA projects three different scenarios or possible futures. Specifically, to 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 may be run more in 2019 and beyond even though the aggregate amount of coal-fired generation will be diminished due to retirements. 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.

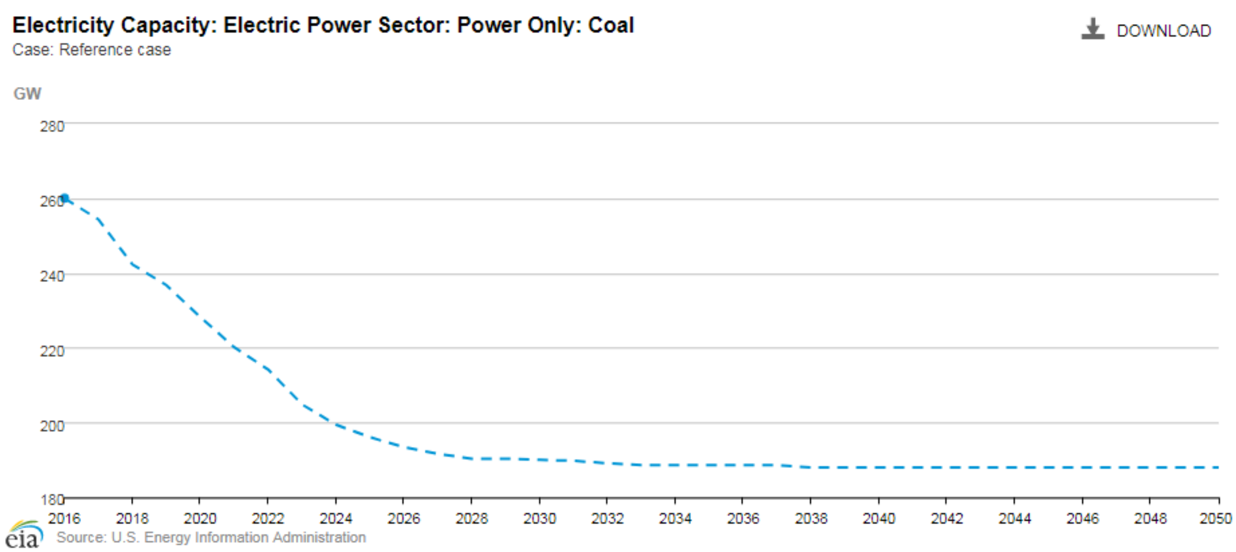


Source: U.S. Energy Information Administration, *Annual Energy Outlook 2018*

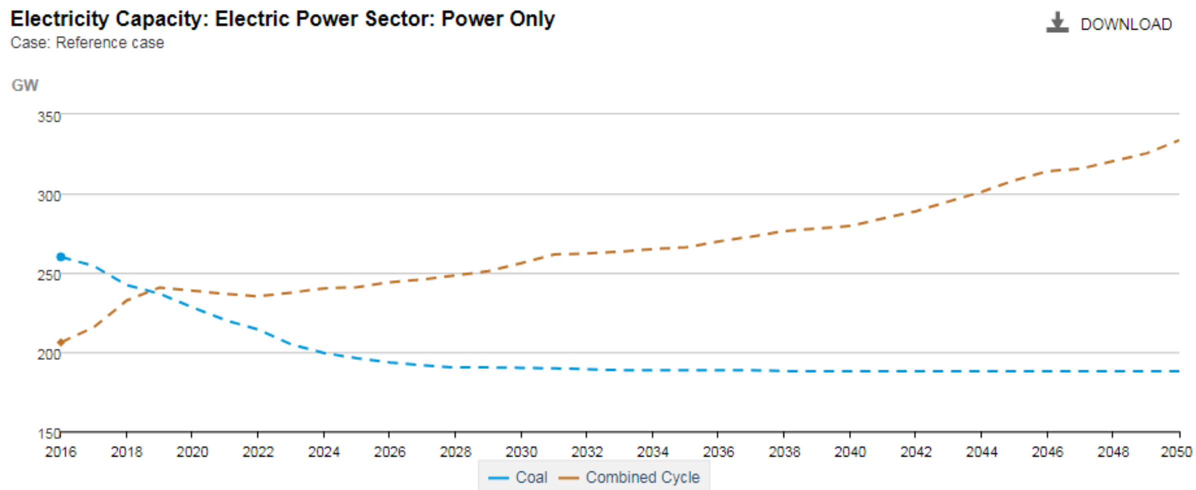
The following graph is EIA's Annual Energy Outlook 2018 reference case (or base case) showing the dynamics caused primarily by retirements of older and smaller coal-fired generating units and the continuing effect of environmental regulations. This graph is a projection of the change in baseload coal-fired 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 due to the high cost of operating coal-fired generating facilities relative to the other resource alternatives. 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.

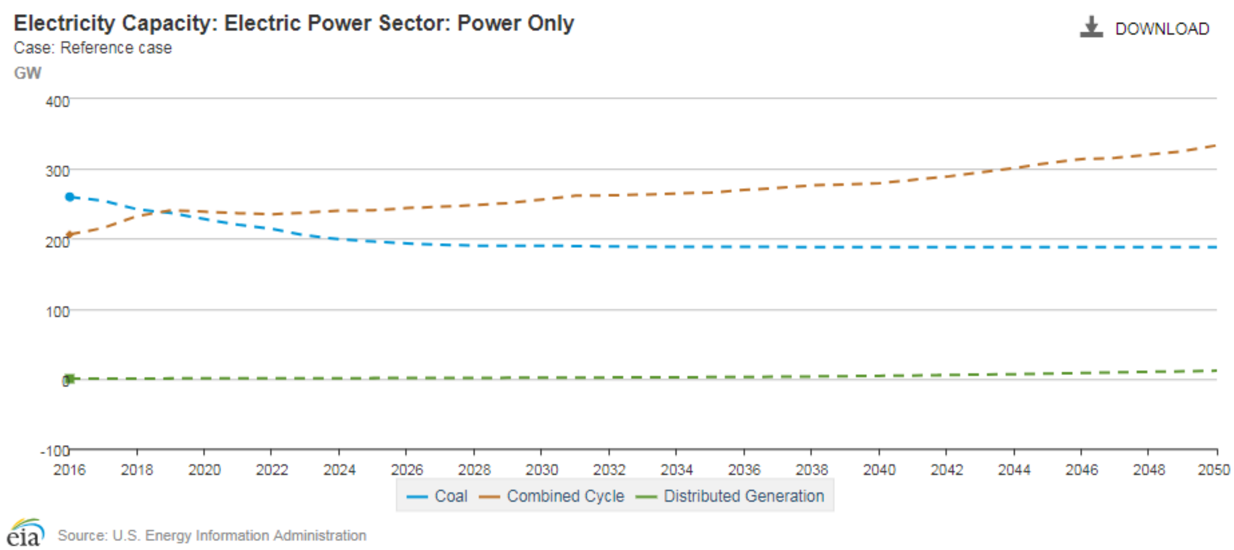


The graph below represents EIA's reference scenario to depict the projected increases in the capacities (MW) of natural gas combined cycle generation compared to coal-fired generation over the 2016-2050 planning horizon.



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.

Projections for Future Generation Capacity by Fuel Type for the U.S.



F. Conclusion

The importance of well-developed and thoughtful long-term planning cannot be overstated given the long-lived nature of electric resource decisions and the extensive degree of uncertainty impacting the industry. 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 costs and benefits. The credibility of the analysis is critical to the efforts of Indiana utilities to maintain as many options 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, PJM, and 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. 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 as many options as possible 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 Contin-gency Factor[2]	Techno-logical 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)	Duke	45	01-01-10	61
2	Edwardsport 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	Ratts Unit 2 (1970)	Hoosier	121	12-31-14	44
10	Ratts Unit 1 (1970)	Hoosier	42	03-10-15	45
11	Tanners Creek Unit 1 (1951)	I&M	145	06-01-15	64
12	Tanners Creek Unit 2 (1952)	I&M	142	06-01-15	63
13	Tanners Creek Unit 3 (1953)	I&M	195	06-01-15	62
14	Tanners Creek Unit 4 (1956)	I&M	500	06-01-15	59
15	Eagle Valley 3 (1951)	IPL	40	04-15-16	65
16	Eagle Valley 4 (1953)	IPL	55	04-15-16	63
17	Eagle Valley 5 (1955)	IPL	61	04-15-16	61
18	Eagle Valley 6 (1956)	IPL	100	04-15-16	60
19	Wabash River Unit 2 (1953)	Duke	85	04-15-16	63
20	Wabash River Unit 3 (1954)	Duke	85	04-15-16	62
21	Wabash River Unit 4 (1955)	Duke	85	04-15-16	61
22	Wabash River Unit 5 (1956)	Duke	95	04-15-16	60
23	Wabash River Unit 6 (1968)	Duke	318	04-15-16	48
24	Bailly Unit 7 (1962)	NIPSCO	160	05-31-18	56
25	Bailly Unit 8 (1968)	NIPSCO	320	05-31-18	50

Coal Fleet Changes Since 2010 - Total MW				
	Operating	**Retired**	**Total**	**Pct. Red.**
1-1-2010	18,018	---	18,018	---
1-1-2013	16,853	1,165	18,018	6.5%
8-23-2018	14,624	3,394	18,018	18.8%

Coal Fleet Changes Since 2010 - Number of Units				
	Operating	**Retired**	**Total**	**Pct. Red.**
1-1-2010	60	---	61	---
1-1-2013	53	8	61	13.1%
8-23-2018	36	25	61	41.0%

Conversions from Coal to Natural Gas			
Unit	**Owner**	**MW**	**Date**
Harding Street Unit 5 (1958)	IPL	97	12-31-15
Harding Street Unit 6 (1961)	IPL	97	12-31-15
Harding Street Unit 7 (1973)	IPL	421	06-01-16

TOTAL MW: 615

APPENDIX 3
Coal Fleet Currently in Operation

Coal Units in Operation - In State					
	Coal Unit	Ownership	Summer Rating (MW)	Age in 2020	Year In-Service
1	Edwardsport IGCC	Duke	595.0	8	2012
2	Rockport 2	Investor Group	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	Hoosier	501.0	37	1983
8	Schafer 17	NIPSCO	361.0	37	1983
9	Gibson 5	Duke, IMPA, WVPA	620.0	38	1982
10	Merom 2	Hoosier	482.0	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	Whitewater Valley 2	IMPA	60.0	47	1973
22	Cayuga 2	Duke	495.0	48	1972
23	Cayuga 1	Duke	500.0	50	1970
24	Warrick 4 (ALCOA)	SIGECO	134.8	50	1970
25	Petersburg 2	IPL	396.2	51	1969

26	Petersburg 1	IPL	232.0	53	1967
27	Culley 2	SIGECO	88.3	54	1966
28	Gallagher 4	Duke	140.0	59	1961
29	Gallagher 2	Duke	140.0	62	1958
30	Whitewater Valley 1	IMPA	30.0	47	1973
31	Clifty Creek 1	Various	211.0	65	1955
32	Clifty Creek 2	Various	200.0	65	1955
33	Clifty Creek 3	Various	212.0	65	1955
34	Clifty Creek 4	Various	193.0	65	1955
35	Clifty Creek 5	Various	220.0	65	1955
36	Clifty Creek 6	Various	191.0	65	1955
Coal Units in Operation - Out of State					
	Prairie State 1	IMPA Share	103.0	8	2012
	Prairie State 2	IMPA Share	103.0	8	2012
	Prairie State 1	WVPA Share	41.5	8	2012
	Prairie State 2	WVPA Share	41.5	8	2012
	Trimble County 2	IMPA Share	96.0	9	2011
	Trimble County 1	IMPA Share	66.0	30	1990

APPENDIX 4
Coal Units in Operation with Status Notes based on IRPs

	Coal Units in Operation - In State					
	Coal Unit	Ownership	Summer Rating (MW)	Age in 2020	Year In-Service	
1	Edwardsport IGCC	Duke	595.0	8	2012	
2	Rockport 2	Investor Group	1,300.0	31	1989	
3	Petersburg 4	IPL	537.4	34	1986	
4	Schafer 18	NIPSCO	361.0	34	1986	*NIPSCO's preliminary 2018 IRP update indicates unit retirement in 2023
5	Brown 2	SIGECO	233.1	34	1986	*Vectren plans to retire the unit on 12-31-23, Cause No. 45052 - pending
6	Rockport 1	I&M	1,300.0	36	1984	
7	Merom 1	Hoosier	501.0	37	1983	
8	Schafer 17	NIPSCO	361.0	37	1983	*NIPSCO's preliminary 2018 IRP update indicates unit retirement in 2023
9	Gibson 5	Duke, IMPA, WVPA	620.0	38	1982	
10	Merom 2	Hoosier	482.0	38	1982	
11	Gibson 4	Duke	622.0	41	1979	
12	Schafer 15	NIPSCO	472.0	41	1979	*NIPSCO's preliminary 2018 IRP update indicates unit retirement in 2023
13	Brown 1	SIGECO	227.8	41	1979	*Vectren plans to retire the unit on 12-31-23, Cause No. 45052 - pending
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	*NIPSCO's preliminary 2018 IRP update indicates unit retirement in 2028
18	Schafer 14	NIPSCO	431.0	44	1976	*NIPSCO's preliminary 2018 IRP update indicates unit retirement in 2023
19	Gibson 2	Duke	630.0	45	1975	
20	Culley 3	SIGECO	257.3	47	1973	*Vectren in CN 45052 requests $90M to make unit EPA compliant beyond 12-31-23 - pending
21	Whitewater Valley 2	IMPA	60.0	47	1973	
22	Cayuga 2	Duke	495.0	48	1972	
23	Cayuga 1	Duke	500.0	50	1970	
24	Warrick 4 (ALCOA)	SIGECO	134.8	50	1970	*Vectren plans to end the joint operating agreement with ALCOA on 12-31-23, CN 45052- pending
25	Petersburg 2	IPL	396.2	51	1969	
26	Petersburg 1	IPL	232.0	53	1967	
27	Culley 2	SIGECO	88.3	54	1966	*Vectren plans to retire the unit on 12-31-23, Cause Number 45052 - pending
28	Gallagher 4	Duke	140.0	59	1961	
29	Gallagher 2	Duke	140.0	62	1958	
30	Whitewater Valley 1	IMPA	30.0	47	1973	
31	Clifty Creek 1	Various	211.0	65	1955	
32	Clifty Creek 2	Various	200.0	65	1955	
33	Clifty Creek 3	Various	212.0	65	1955	
34	Clifty Creek 4	Various	193.0	65	1955	
35	Clifty Creek 5	Various	220.0	65	1955	
36	Clifty Creek 6	Various	191.0	65	1955	

APPENDIX 5
Status of Indiana Wind Farms

Operating Indiana Wind Farms

IURC Cause No.	Wind Project	County	Nameplate Capacity (MW)	Completion Year
43068	Benton County Wind Farm	Benton	130.5	2008
43338	Fowler Ridge Wind Farm I	Benton	301.3	2009
43443	Fowler Ridge Wind Farm II-A	Benton	199.5	2009
43444	Fowler Ridge Wind Farm III	Benton	99.0	2009
43484	Hoosier Wind Farm	Benton	106.0	2009
43602	Meadow Lake Wind Farm I	White	199.7	2009
43678	Meadow Lake Wind Farm II	White	99.0	2010
43747	Meadow Lake Wind Farm III	White	110.4	2010
43758	Meadow Lake Wind Farm IV	White	98.7	2010
44044	Wildcat Wind Farm I	Madison/Tipton	200.0	2012
44358	Headwaters Wind Farm	Randolph	200.0	2014
44438	Fowler Ridge IV Wind Farm (Amazon)	Benton	150.0	2015
43876	Meadow Lake Wind Farm V	White	100.8	2017
44299	Bluff Point Wind Farm	Jay/Randolph	119.0	2017

TOTAL MW: 2,113.9

Indiana Wind Farms Under Construction

45010	Meadow Lake Wind Farm VI	White	200.4	2018
44978	Jordan Creek Wind Farm	Warren	400.0	2019

+TOTAL UNDER CONSTRUCTION IN 2018: 600.4

Indiana Wind Farms Approved - Construction Not Started

43781	Spartan Wind Farm	Newton	100.0	
45047	West Fork Wind Farm	Fayette	102.0	2019

+ TOTAL WITHOUT CONSTRUCTION START: 202.0

=TOTAL APPROVED WIND FARMS: 2916.3 MW

APPENDIX 6
Wind Purchased Power Agreements by Indiana's Utilities

Wind Energy Power Purchase Agreements (PPAs) by Indiana Utilities			PPAs for Indiana Wind Only (in MW)								
Utility	**Wind Farm**	**Power Purchase Agreement (MW)**	**Total IN Only**	**NIPSCO**	**Duke**	**Vectren**	**I&M**	**IPL**	**IMPA**	**WVPA**	**Hoosier**
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				
WVPA/Hoosier	Meadow Lake V (IN)	50.0	50.0							25.0	25.0
		TOTAL: 1,098.5	**797.1**		**110.7**	**80.0**	**450.4**	**106.0**		**25.0**	**25.0**

*IMPA has a 48 MW PPA with Crystal Lake in Iowa that expires Dec. 31, 2018.

Utility PPAs with Indiana Wind Farms: 797.1 MW
Utility PPAs with Out of State Wind Farms: 301.4 MW
Total Utility PPAs: 1,098.5 MW

APPENDIX 7
Solar Photovoltaic Generation Greater than 1 MW (ac)

	Operating Solar Photovoltaic Generators in Indiana 1 MW ac and Larger				
	Location	Utility	County	Installed (MW ac)	Source
1	Crane Solar	Duke	Martin	17.25	Cause Numbers 44932 and 44734
2	Indy Solar No. 1 (Franklin Township)	IPL	Marion	10.00	IPL Feed-in-Tariff Cause No. 44018
3	Indy Solar No. 2 (Franklin Township)	IPL	Marion	10.00	IPL Feed-in-Tariff Cause No. 44018
4	Indianapolis Airport No. 1	IPL	Marion	9.80	IPL Feed-in-Tariff Cause No. 44018
5	Indianapolis Motor Speedway	IPL	Marion	9.00	IPL Feed-in-Tariff Cause No. 44018
6	Indy Solar No. 3 (Decatur Township)	IPL	Marion	8.64	IPL Feed-in-Tariff Cause No. 44018
7	Anderson Solar Park	IMPA	Madison	8.10	IMPA IRP
8	Vertellus	IPL	Marion	8.00	IPL Feed-in-Tariff Cause No. 44018
9	Indianapolis Airport Phase II A	IPL	Marion	7.50	IPL Feed-in-Tariff Cause No. 44018
10	McDonald Solar	Duke	Vigo	5.00	Duke Website and Cause Nos. 44578, 44953
11	Pastime Farm	Duke	Clay	5.00	Duke Website and Cause Nos. 44578, 44953
12	Geres Energy	Duke	Howard	5.00	Duke Website and Cause Nos. 44578, 44953
13	Sullivan Solar	Duke	Sullivan	5.00	Duke Website and Cause Nos. 44578, 44953
14	Anderson I Solar Park	IMPA	Madison	5.00	IMPA IRP
15	Olive	I&M	St. Joseph	5.00	I&M Cause Number 44511
16	Lifeline Data Centers	IPL	Marion	4.00	IPL Feed-in-Tariff Cause No. 44018
17	Washington Solar Park	IMPA	Daviess	3.90	IMPA IRP
18	CWA Authority	IPL	Marion	3.83	IPL Feed-in-Tariff Cause No. 44018
19	Duke Realty #129	IPL	Marion	3.40	IPL Feed-in-Tariff Cause No. 44018
20	Crawfordsville Solar Park	IMPA	Montgomery	3.00	IMPA IRP
21	Peru Solar Park	IMPA	Miami	3.00	IMPA IRP
22	Greenfield Solar Park	IMPA	Hancock	2.80	IMPA IRP
23	Rexnord Industries	IPL	Marion	2.80	IPL Feed-in-Tariff Cause No. 44018
24	Equity Industrial	IPL	Marion	2.73	IPL Feed-in-Tariff Cause No. 44018
25	Duke Realty #98	IPL	Marion	2.72	IPL Feed-in-Tariff Cause No. 44018
26	Duke Realty #87	IPL	Marion	2.72	IPL Feed-in-Tariff Cause No. 44018
27	Twin Branch	I&M	St. Joseph	2.60	I&M Cause Number 44511
28	Deer Creek	I&M	St. Joseph	2.50	I&M Cause Number 44511
29	Indianapolis Airport Phase II B	IPL	Marion	2.50	IPL Feed-in-Tariff Cause No. 44018
30	Huntingburg Solar Park	IMPA	Dubois	2.10	IMPA IRP
31	Lake County Solar, LLC - East Chicago	NIPSCO	Lake	2.00	NIPSCO Feed-in-Tariff Cause No. 43922
32	Lake County Solar, LLC - Griffith	NIPSCO	Lake	2.00	NIPSCO Feed-in-Tariff Cause No. 43922
33	Pendleton Solar Park	IMPA	Madison	2.00	IMPA IRP
34	GSA Bean Finance Center	IPL	Marion	1.80	IPL Feed-in-Tariff Cause No. 44018
35	Citizens Energy (LNG North)	IPL	Marion	1.50	IPL Feed-in-Tariff Cause No. 44018
36	Middlebury Solar, LLC	NIPSCO	Elkhart	1.50	NIPSCO Feed-in-Tariff Cause No. 43922
37	Portage Solar, LLC	NIPSCO	Porter	1.50	NIPSCO Feed-in-Tariff Cause No. 43922
38	Lincoln Solar, LLC	NIPSCO	Cass	1.50	NIPSCO Feed-in-Tariff Cause No. 43922
39	Tell City Solar Park	IMPA	Perry	1.10	IMPA IRP

40	Frankton Solar Park	IMPA	Madison	1.00	IMPA IRP
41	Bartholomew County Solar Farm	Hoosier Energy	Bartholomew	1.00	Hoosier Energy IRP
42	Decatur County Solar Farm	Hoosier Energy	Decatur	1.10	Hoosier Energy IRP
43	Jackson Solar Farm	Hoosier Energy	Jackson	1.10	Hoosier Energy IRP
44	Johnson County Solar	Hoosier Energy	Johnson	1.10	Hoosier Energy IRP
45	Ellettsville Solar Farm	Hoosier Energy	Monroe	1.08	Hoosier Energy IRP
46	Henryville Solar Farm	Hoosier Energy	Clark	1.08	Hoosier Energy IRP
47	Lanesville Solar	Hoosier Energy	Harrison	1.10	Hoosier Energy IRP
48	New Haven Solar	Hoosier Energy	Allen	1.08	Hoosier Energy IRP
49	Scotland Solar	Hoosier Energy	Greene	1.10	Hoosier Energy IRP
50	Spring Mill Solar	Hoosier Energy	Lawrence	1.10	Hoosier Energy IRP
51	New Castle Solar	Hoosier Energy	Henry	1.00	Hoosier Energy IRP
52	Grocers Supply Company	IPL	Marion	1.00	IPL Feed-in-Tariff Cause No. 44018
53	Hobart Solar, LLC	NIPSCO	Lake	1.00	NIPSCO Feed-in-Tariff Cause No. 43922
54	Valparaiso Solar, LLC	NIPSCO	Porter	1.00	NIPSCO Feed-in-Tariff Cause No. 43922
55	Waterloo Solar, LLC	NIPSCO	Dekalb	1.00	NIPSCO Feed-in-Tariff Cause No. 43922
56	Rensselaer Solar Farm	IMPA	Jasper	1.00	IMPA IRP
57	Richmond Solar Farm	IMPA	Wayne	1.00	IMPA IRP
				TOTAL: 196.63 MW	

Percent of Solar Total 1 MW and Larger		
Utility	**MW**	**Percent**
IPL	91.94	46.8%
IMPA	39.10	19.9%
Duke	37.25	18.9%
Hoosier	11.84	6.0%
NIPSCO	11.50	5.8%
I&M	5.00	2.5%
WVPA	---	0.0%
Vectren	---	0.0%
TOTAL	**196.63**	

APPENDIX 8
Renewable Resource Summary

Indiana Operating Renewable Generation Summary			
	Installed MW	Percent of State Total Installed MW	Percent of State Total Installed MW without Large Wind
Large Wind (above 100kW)	2,114.0	84.8%	
Solar (KW ac)	254.3	10.2%	67.2%
Hydro	58.1	2.3%	15.4%
Landfill Gas	45.6	1.8%	12.1%
Biomass Digesters	14.6	0.6%	3.9%
Small Wind (up to 100 kW)	5.6	0.2%	1.5%
TOTAL	2,492.2	100.0%	100.0%

APPENDIX 9
Renewable Resource Summary with Details

Installed Megawatts of Renewable Energy Generation in Indiana

	Feed-in-Tariffs			Net Metering			Utility Solar		Miscellaneous					
Utility	**Wind**	**Solar**	**Biomass Digesters**	**Wind**	**Biomass**	**Solar**	**Utility Owned Solar**	**Utility Solar PPAs**	**Small Wind Demos**	**Large Wind PPAs with Indiana Wind Farms**	**Merchant Wind (to Indiana or out of state consumers)**	**Hydro**	**Landfill Gas**	**Total**
Duke Indiana				2.2		15.7	17.3	19.4		110.7		45.00		210.28
I&M				0.3	0.2	9.9	12.7		0.85	450.4		6.23		480.59
IPL		94.4		0.1		2.3				106.0				202.75
NIPSCO	0.2	18.8	14.3	2.0		8.6						6.82		50.88
Vectren				0.0		7.8				80.0			2.2	90.00
WVPA							0.6			25.0			40.0	65.64
IMPA							36.7							36.70
Hoosier							10.0			25.0			3.4	38.40
Merchant Wind											1,316.9			1,316.9
TOTAL	**0.2**	**113.2**	**14.3**	**4.6**	**0.2**	**44.3**	**77.3**	**19.4**	**0.9**	**797.1**	**1,316.9**	**58.1**	**45.6**	**2,492.1**

Wind										**797.1**	**1,316.9**			2,114.0
Solar		**113.2**				**44.3**	**77.3**	**19.4**						254.3
Hydro												**58.1**		58.1
Landfill Gas													**45.6**	45.6
Biomass Digesters			**14.3**		**0.2**									14.6
Small Wind	0.2			**4.6**					**0.9**					5.6
														2,492.1

	MW	**Percent**
Wind	2,114.0	84.8%
Solar	254.3	10.2%
Hydro	58.1	2.3%
Landfill Gas	45.6	1.8%
Biomass Digesters	14.6	0.6%
Small Wind	5.6	0.2%
Total	2,492.1	100.0%

APPENDIX 10
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%
Nuclear	9.0%	8.0%	4.6%	7.9%	8.9%	9.6%	9.1%	9.4%	9.8%	9.8%	10.6%
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%
Wind	0.0%	0.2%	1.1%	2.2%	2.5%	2.5%	2.9%	2.7%	3.9%	3.9%	4.2%
Oil	0.1%	0.1%	0.1%	0.1%	1.0%	0.7%	1.3%	1.1%	1.2%	1.2%	0.1%
Hydro	0.3%	0.3%	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%	0.2%	0.3%
Biomass	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%
Other	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.3%	0.4%	0.4%	0.3%
TOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

	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%
TOTAL	100.0%	100.0%	100.0%

Notes:

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

2. The production from the Cook Plant is based on 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 significantly.

APPENDIX 11
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.... Inactive
39. Prairie State............... 200
O. Other Cities

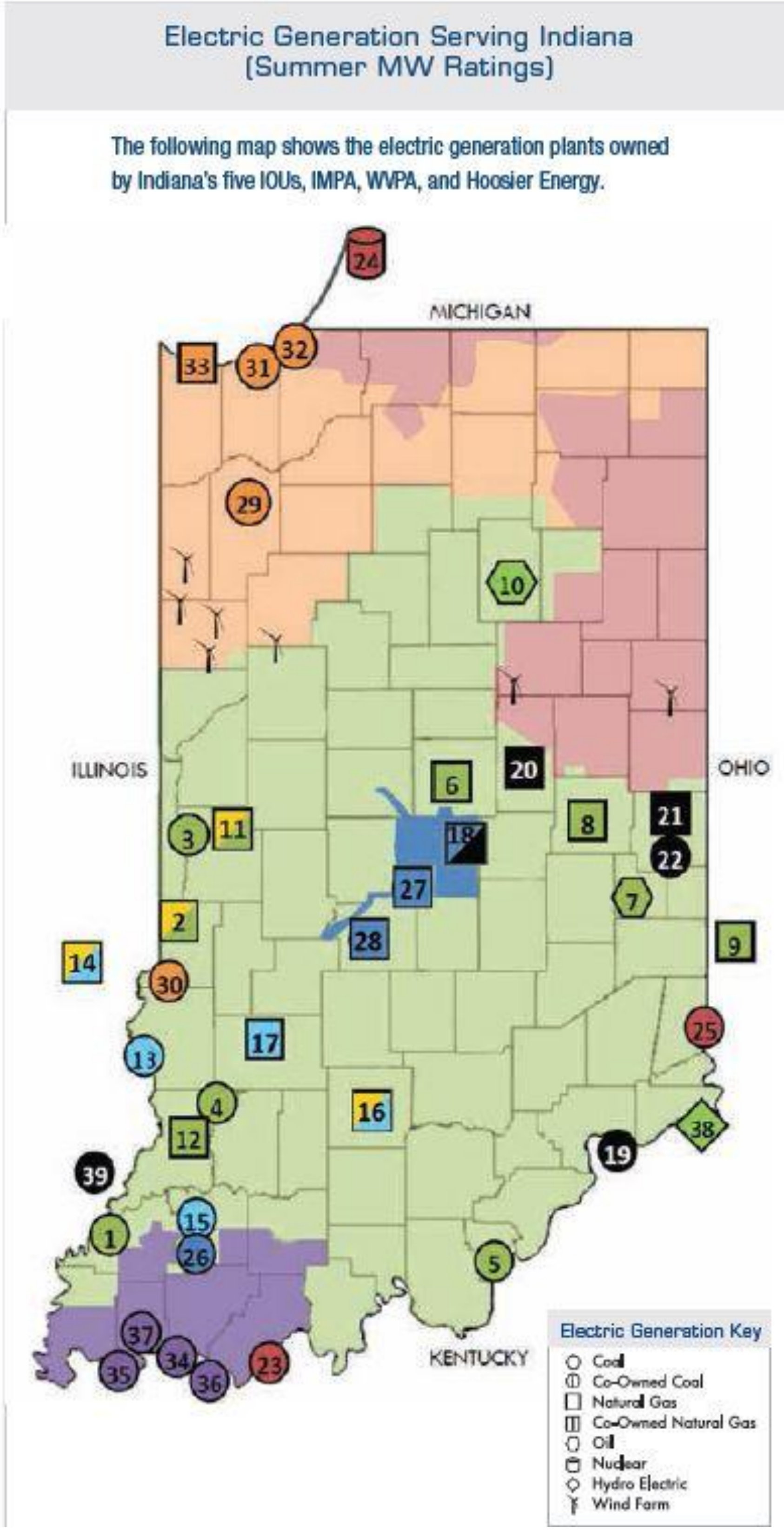
INDIANA MICHIGAN POWER
23. Rockport 2,600
24. Cook (MI)................ 2,160
25. Tanners Creek .... Retired

INDIANAPOLIS POWER & LIGHT
18. Georgetown 1&4 150
26. Petersburg.............. 1,715
27. Harding Street 628
28. Eagle Valley 671

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

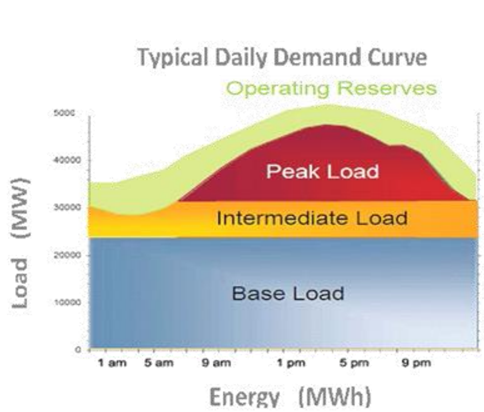
VECTREN SOUTH
34. Warrick 150
35. Brown 640
36. Culley 360
37. Broadway/Northeast..... 85

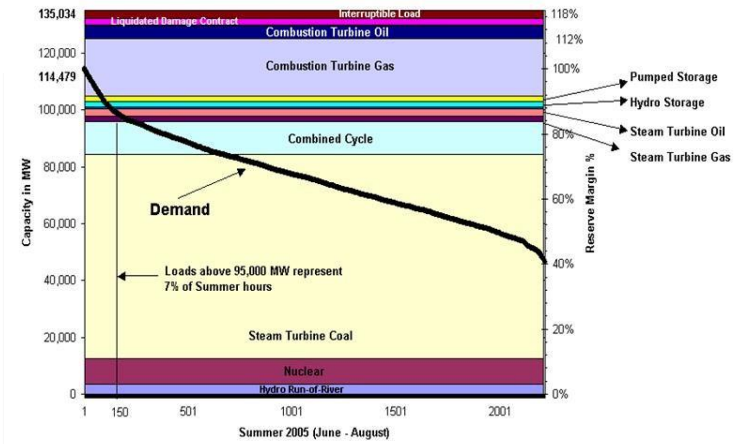
WABASH VALLEY POWER
2. Wabash River Highland . 162
11. Vermilion 6-8 240
14. Holland (IL)................. 314
16. Lawrence..................... 86



APPENDIX 12
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 designed for 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.

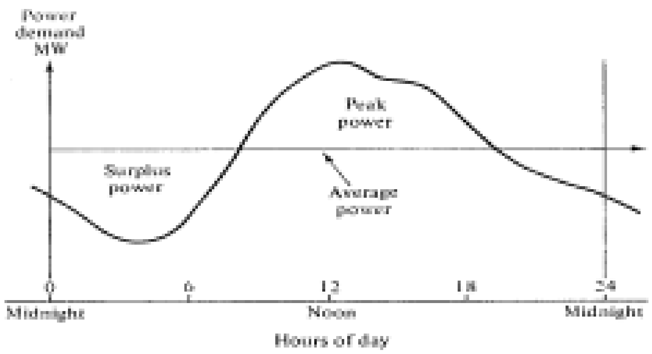
Coincident Demand (CD): Mathematically, it is the sum of two or more demands that occur in the same time interval. Typically, used in planning resources such as generation, transmission, and demand response. So, the contribution by any entity to the RTOs / ISOs peak is that entity's "**Coincidence Factor (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 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.

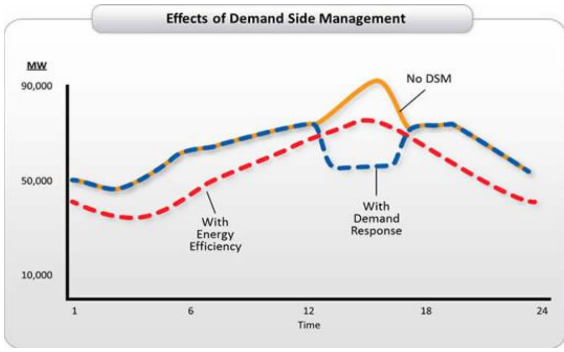
Distributed Energy Resource (DER): DER is a resource sited close to customers that can provide all or some of their electric and power needs and can also be used by the system to either reduce customer demand or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution 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 upgrades, 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, 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.



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 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.*

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
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
SO_x, SO_2, SO_3	Sulfur Oxides