Indiana Electricity Projections: The 2015 Forecast

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Foreword

This report presents the 2015 projections of future electricity requirements for the state of Indiana for the period 2014-2033. This study is part of an ongoing independent electricity forecasting effort conducted by the State Utility Forecasting Group (SUFG). SUFG was formed in 1985 when the Indiana legislature mandated a group be formed to develop and keep current a methodology for forecasting the probable future growth of electricity usage within Indiana. The Indiana Utility Regulatory Commission contracted with Purdue and Indiana Universities to accomplish this goal. SUFG produced its first set of projections in 1987 and has updated these projections periodically. This is the fifteenth set of projections.

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

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

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

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

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

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

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

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Chapter 1

Forecast Summary

Overview

In this report, the State Utility Forecasting Group (SUFG) provides its fifteenth set of projections of future electricity usage, peak demand, prices and resource requirements. The projections in this forecast are higher than those in the 2013 forecast, primarily due to decreases in the amount of utility-sponsored energy efficiency, compared to the earlier projections. The 2013 forecast included sufficient demand-side management (DSM) programs to meet the Indiana Utility Regulatory Commission (IURC) requirements established in 2009. These requirements were eliminated when Senate Enrolled Act 340 was passed in 2014.

This forecast projects electricity usage to grow at a rate of 1.17 percent per year over the 20 years of the forecast. Peak electricity demand is projected to grow at an average rate of 1.13 percent annually. This corresponds to about 235 megawatts (MW) of increased peak demand per year. The growth in the second half of the forecast period (2024-2033) is generally stronger than the growth in the first ten years.

The 2015 forecast predicts Indiana electricity prices to continue to rise in real (inflation adjusted) terms through 2021 and then slowly decrease until 2027. Afterwards, prices show an upward trend for 2028 and 2029 before decreasing again for the remainder of the forecast period. Four major factors primarily determine the trajectory of the price projections: first, the cost of meeting air emission standards; second, costs associated with resources required to meet future load; third, capital costs associated with IURC-approved generation plant additions and life extension; and fourth, fuel costs.

As in the previous three forecasts, these projections indicate a relatively balanced need for the three types of resources modeled: baseload, cycling (also referred to as intermediate) and peaking. Peaking resources are characterized by relatively low construction costs, but high operating costs. They are intended to be operated only during periods of high electricity usage. Baseload generators, which are intended to be used even during periods of low demand, have relatively high construction costs but low operating costs. Cycling resources have construction and operating cost characteristics between those of peaking and baseload resources. This forecast identifies a need for 290 MW of peaking, 120 MW of cycling, and 310 MW of baseload resources by 2020. These requirements are slightly lower than those identified in the 2013 forecast, primarily due to the expected addition of a new natural-gas combined cycle facility in 2017.

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

Outline of the Report

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

Chapter 2 of the report briefly describes SUFG's forecasting methodology, including changes made from previous forecasts. A complete description of the SUFG regulated modeling system used to develop this forecast was included in the 1999 forecast and is available at the SUFG website:

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

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

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

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

The Regulated Modeling System

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

Beginning with the 2009 forecast, SUFG made a slight modification to the methodology used in determining future resource requirements. For the 1999-2007 forecasts, SUFG determined required resources according to a target statewide 15 percent reserve margin.[1] Forecasts prior to 1999 used a 20 percent statewide reserve margin. These reserve margins were essentially rules-of-thumb, based on industry observations. In 2009 SUFG began using reserve margins that reflect the planning reserve requirements of the utilities' regional transmission organizations to determine the reserve requirements in this forecast. Applying the individual reserve requirements and adjusting for peak load diversity among the utilities provides a statewide reserve requirement of approximately 19.5 percent. This represents a slightly higher reserve margin than the 18.3 percent figure used in the 2013 forecast, due to changing regional transmission organization (RTO) requirements.

Major Forecast Assumptions

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

Economic Activity Projections

One of the largest influences in any energy projection is growth in economic activity. Each of the sectoral energy forecasting models is driven by economic activity projections, i.e., personal income, population, commercial employment and industrial output. The economic activity assumptions for all three scenarios were derived from the Indiana macroeconomic model developed by the Center for Econometric Model Research (CEMR) at Indiana University. SUFG used CEMR's February 2015 projections for its base scenario. A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy. The CEMR Indiana projections are based on a national employment projection of 0.86 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 0.80 percent.

Other key economic projections are:

- Real personal income (a residential sector model driver) is expected to grow at a 2.33 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average a 0.96 percent annual growth rate over the forecast horizon.
- Manufacturing gross state product (GSP) (the primary industrial sector model driver) is expected to rise at a 3.71 percent annual rate as gains in productivity outpace slight gains in employment.

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

---

[1] SUFG reports reserves in terms of reserve margins instead of capacity margins. Care must be taken when using the two terms since they are not equivalent. A 19.5 percent reserve margin is equivalent to a 16.3 percent capacity margin.
Capacity Margin = [(Capacity-Peak Demand)/Capacity]
Reserve Margin = [(Capacity-Peak Demand)/Peak Demand]

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

Demographic Projections

Population growth for all scenarios is 0.49 percent per year. This projection is from the Indiana Business Research Center (IBRC) at Indiana University. The SUFG forecasting system includes a housing model that utilizes population and income assumptions to project the number of households. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of 1.07 percent over the forecast period.

Fossil Fuel Price Projections

SUFG's current assumptions are based on the April 2015 projections produced by the Energy Information Administration (EIA) for the East North Central Region. SUFG's fossil fuel real price[3] projections are as follows:

Natural Gas Prices: Natural gas prices decreased significantly in 2009 relative to the high prices of 2008. Prices then rebounded somewhat in 2010 before declining again through 2012 before increasing back to 2010 levels by 2014. They are projected to remain relatively constant through 2018, with a general increase following for the remainder of the forecast horizon.

Utility Price of Coal: Coal prices are relatively unchanged in real terms throughout the entire forecast horizon as growth in demand is offset by improvements in mining productivity.

The Base Scenario

Figure 1-1 shows the current base scenario projection for electricity requirements in gigawatt-hours (GWh), along with the projections from the previous two forecast reports. Similarly, the base projection for peak demand in MW is shown in Figure 1-2. The annual growth rate for electricity requirements in this forecast is 1.17 percent, while the growth rate for peak demand is 1.13 percent. The growth rates in the previous forecast for electricity requirements and peak demand were 0.74 and 0.90 percent, respectively.

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

The projections of peak demand are for normal weather patterns, and projected peak demand for long-run planning is reduced by demand response loads. Another measure of peak demand growth can be obtained by considering the year to year MW load change. In Figure 1-2, the annual increase is about 235 MW.

Table 1-1. Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2013 Projections)

Sector	Current (2014-2033)	2013 (2012-2031)
Residential	0.64	0.37
Commercial	0.59	0.33
Industrial	1.90	1.29
Total	1.17	0.74

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources to meet forecast demand. Utility-sponsored energy efficiency and demand response[4] loads are netted from the demand projection and supply-side resources are added as necessary to maintain a 19.5 percent reserve margin. Although this approach provides a reasonable basis for estimating future electricity prices for planning purposes, it does not ensure that the resource plans are least cost.

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

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

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

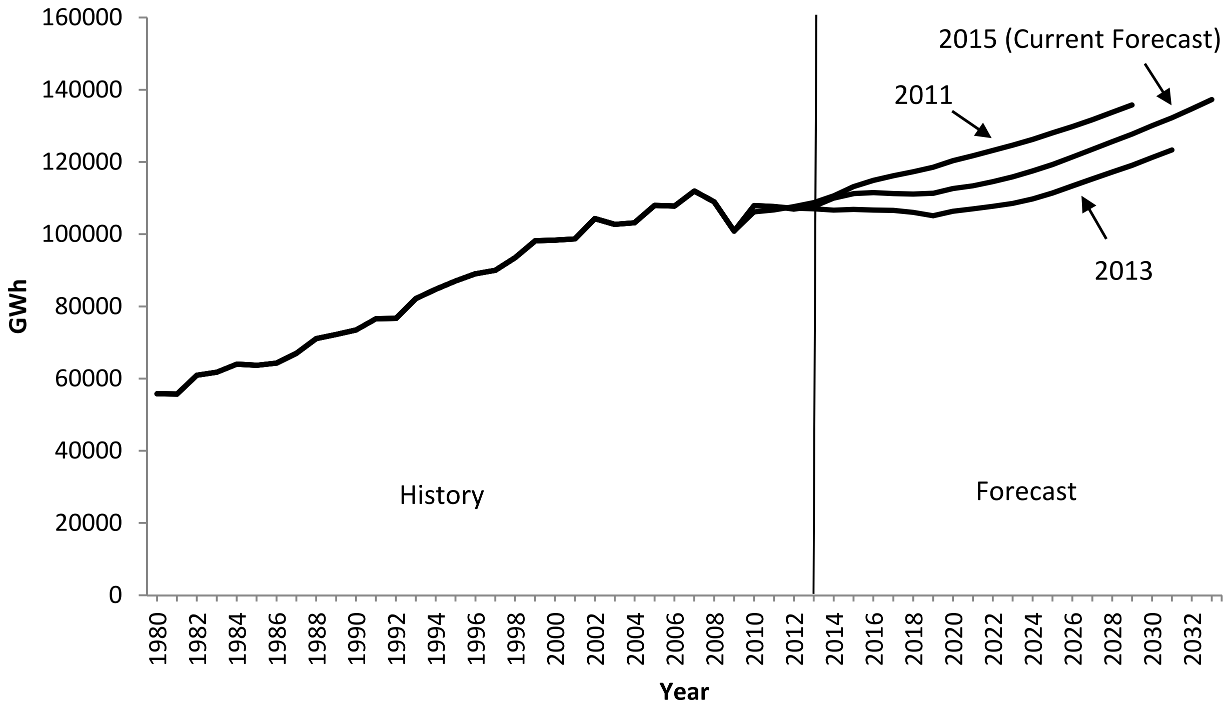
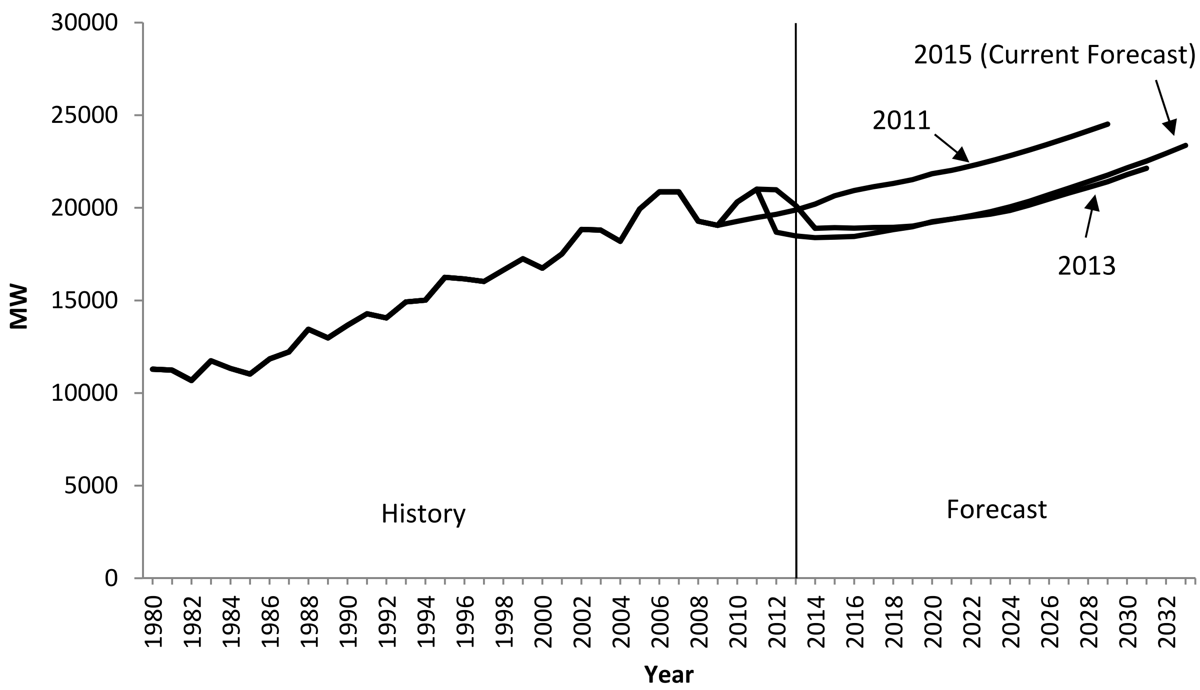


Figure 1-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Demand-Side Resources

The current projection includes the energy and demand impacts of existing or planned utility-sponsored energy efficiency programs. Incremental energy efficiency programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 300 MW at the beginning of the forecast period and by about 745 MW at the end of the forecast. DSM projections were estimated from utility integrated resource plan filings and from information collected directly from the utilities by SUFG.

These energy efficiency projections do not include the reductions in peak demand due to demand response. Demand response loads are projected to increase from approximately 1,000 MW to about 1,200 MW over the forecast horizon. See Chapter 4 for additional information about DSM.

Supply-Side Resources

SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, de-ratings due to pollution control retrofits and net changes in firm out-of-state purchases and sales. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic firm wholesale purchases are then added as necessary during the forecast period to maintain a statewide 19.5 percent reserve margin. Additionally, due to individual utilities having significantly different levels of reserves, small amounts of additional resources may be included to maintain individual utility reserve margins above 6 percent for modeling integrity purposes, even if the state as a whole is at or above the 19.5 percent threshold. This occurs through 2019 in this forecast.

Resource Needs

Figure 1-3 and Table 1-2 show the statewide resource plan for the SUFG base scenario. Over the first half of the forecast period, 1,360 MW of additional resources are required. The net change in generation includes the retirement of units as reported in the utilities' most recent Integrated Resource Plan (IRP) filings or as reported subsequently. Over the second half of the forecast period, an additional 4,500 MW of resources are required to maintain target reserves.

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

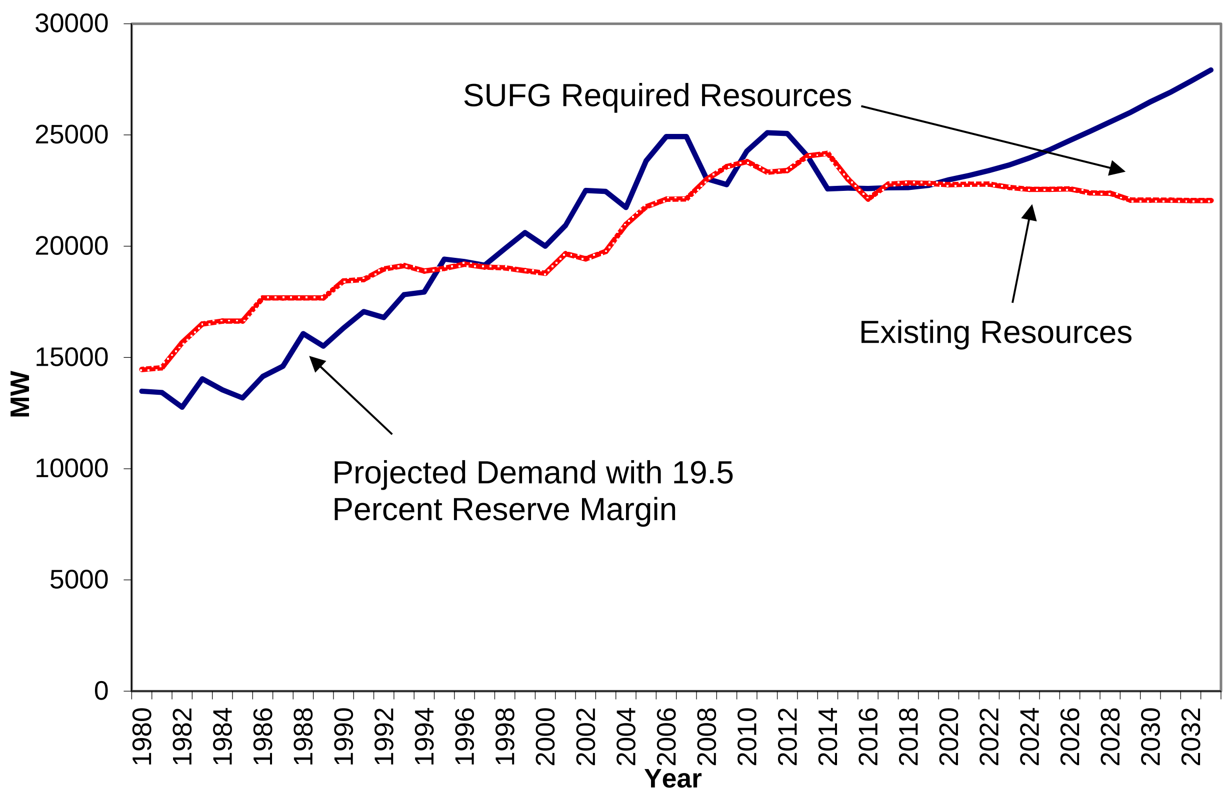


Table 1-2. Indiana Resource Plan in MW (SUFG Base)

	Uncontrolled Peak Demand[1]	Demand Response[2]	Net Peak Demand[3]	Existing/ Approved Capacity[4]	Incremental Change in Capacity[5]	Projected Additional Resource Requirements[6]				Total Resources[7]	Reserve Margin[8] (percent)
						Peaking	Cycling	Baseload	Total		
2013				24,060							
2014	19,860	973	18,887	24,176	116	-	-	-	-	24,176	28
2015	20,068	1,146	18,922	23,016	-1,160	150	90	30	270	23,286	23
2016	20,099	1,196	18,903	22,119	-897	250	170	100	520	22,639	20
2017	20,075	1,141	18,934	22,786	667	220	110	140	470	23,256	23
2018	20,097	1,157	18,939	22,847	61	220	90	180	490	23,337	23
2019	20,184	1,164	19,020	22,824	-23	240	120	240	600	23,424	23
2020	20,398	1,168	19,230	22,770	-54	290	120	310	720	23,490	22
2021	20,564	1,169	19,395	22,789	20	330	140	360	830	23,619	22
2022	20,751	1,172	19,579	22,799	10	390	180	460	1,030	23,829	22
2023	20,969	1,175	19,794	22,647	-152	530	210	620	1,360	24,007	21
2024	21,231	1,177	20,054	22,558	-88	630	260	840	1,730	24,288	21
2025	21,541	1,179	20,361	22,558	0	740	310	940	1,990	24,548	21
2026	21,891	1,181	20,710	22,580	22	840	360	1,120	2,320	24,900	20
2027	22,240	1,183	21,057	22,402	-178	1,010	440	1,410	2,860	25,262	20
2028	22,597	1,185	21,412	22,383	-19	1,150	520	1,560	3,230	25,613	20
2029	22,949	1,185	21,764	22,077	-306	1,310	590	2,030	3,930	26,007	19
2030	23,351	1,186	22,165	22,080	2	1,470	690	2,240	4,400	26,480	19
2031	23,714	1,186	22,528	22,073	-7	1,630	770	2,450	4,850	26,923	20
2032	24,123	1,186	22,937	22,055	-18	1,760	910	2,670	5,340	27,395	19
2033	24,553	1,186	23,367	22,056	1	1,920	1,010	2,930	5,860	27,916	19

1 Uncontrolled peak demand is the peak demand prior to any load reduction from demand response programs being called upon.

2 Demand response is all the measures designed to shift load away from peak demand periods. These include interruptible and direct load control programs affecting peak demand. These numbers are net of the peak reductions that were called on in the calibration year (2013).

3 Net peak demand is the peak demand after load reductions from demand response programs are taken into account.

4 Existing/approved capacity includes installed capacity plus approved new capacity plus firm purchases minus firm sales.

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

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

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

8 Resources may be required by individual utilities even if the state as a whole meets or exceeds the statewide reserve margin. Individual utility reserve margins are not allowed to fall below 6 percent.

Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of actual historical data was 2013. Therefore, 2014 and 2015 numbers represent projections. The resource requirements identified in Table 1-2 for 2014 and 2015 were most likely met by a combination of short-term purchases and longer-term purchases of which SUFG was not aware at the time the forecast was prepared.

Equilibrium Price and Energy Impact

SUFG's base scenario equilibrium real electricity price trajectory is shown in Figure 1-4. Real prices are projected to increase by 26 percent from 2013 to 2021 and then slowly decrease until 2027. Afterwards, prices show an upward trend for 2028 and 2029 before decreasing again for the remainder of the forecast period. The change in prices early in the forecast horizon is significant, thus the electricity requirements projection for this portion of the forecast period is affected.

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 1-4. The price projection labeled "2011" is the base case projection contained in SUFG's 2011 forecast and the one labeled "2013" is the base case projections from SUFG's 2013 report. For the prior price forecasts, SUFG rescaled the original price projections to 2013 dollars (from 2009 dollars for the 2011 projection, and from 2011 dollars for the 2013 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

Four major factors primarily determine the differences among the price projections in Figure 1-4: first, the cost of meeting air emission standards; second, costs associated with resources required to meet future load; third, capital costs associated with IURC-approved generation plant additions and life extension; and fourth, fuel costs. Specifically, costs associated with meeting the Clean Power Plan regulations on carbon dioxide are not included, since the regulation was not finalized until after the model inputs were finalized. Since actions associated with the Mercury and Air Toxics Standards (MATS) had for the most part been commenced by the utilities before the U.S. Supreme Court returned it to EPA for review, those costs are included. The generators that SUFG uses to approximate the costs of new resources are chosen to comply with the greenhouse gas rules for new plants.

Low and High Scenarios

SUFG has constructed alternative low and high economic growth scenarios. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Figure 1-5 provides the statewide electricity requirements for the base, low and high scenarios. The annual growth rates for the base, low and high scenarios are 1.17, 0.78, and 1.55, respectively. These differences are due to economic growth assumptions in the scenario-based projections. The trajectories for peak demand in the low and high scenarios are similar to the electricity requirements trajectories.

Figure 1-4. Indiana Real Price Projections in cents/kWh (2013 Dollars) (Historical, Current and Previous Forecasts)

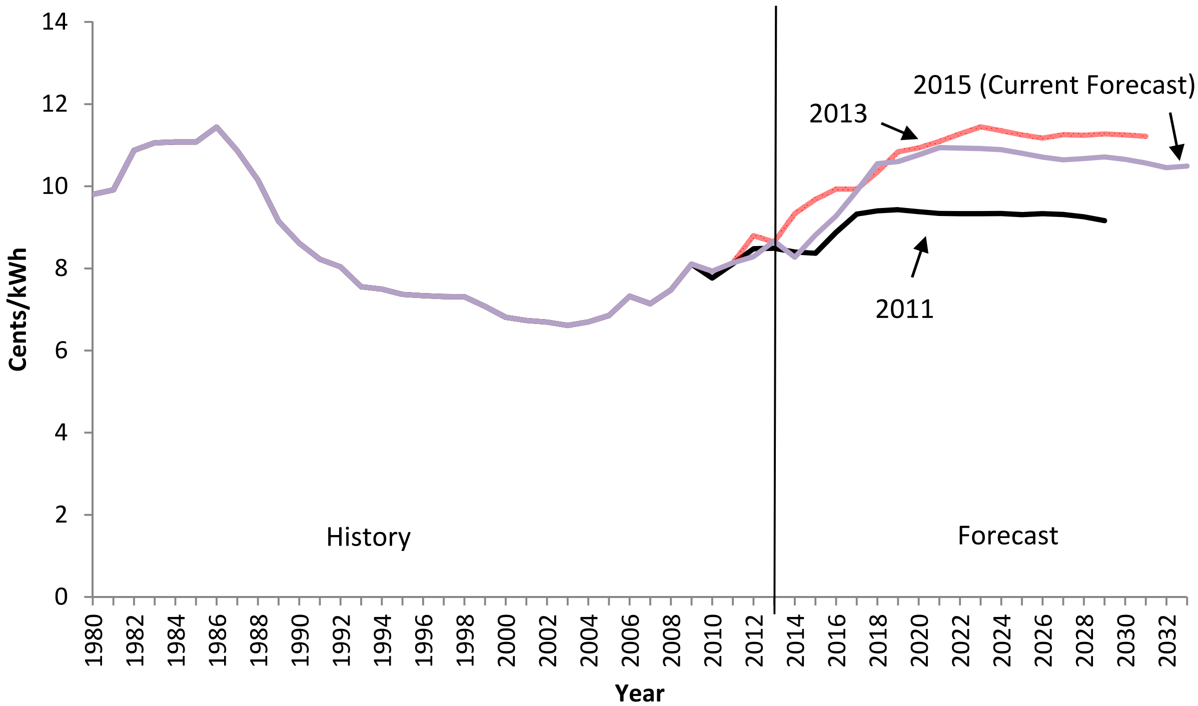
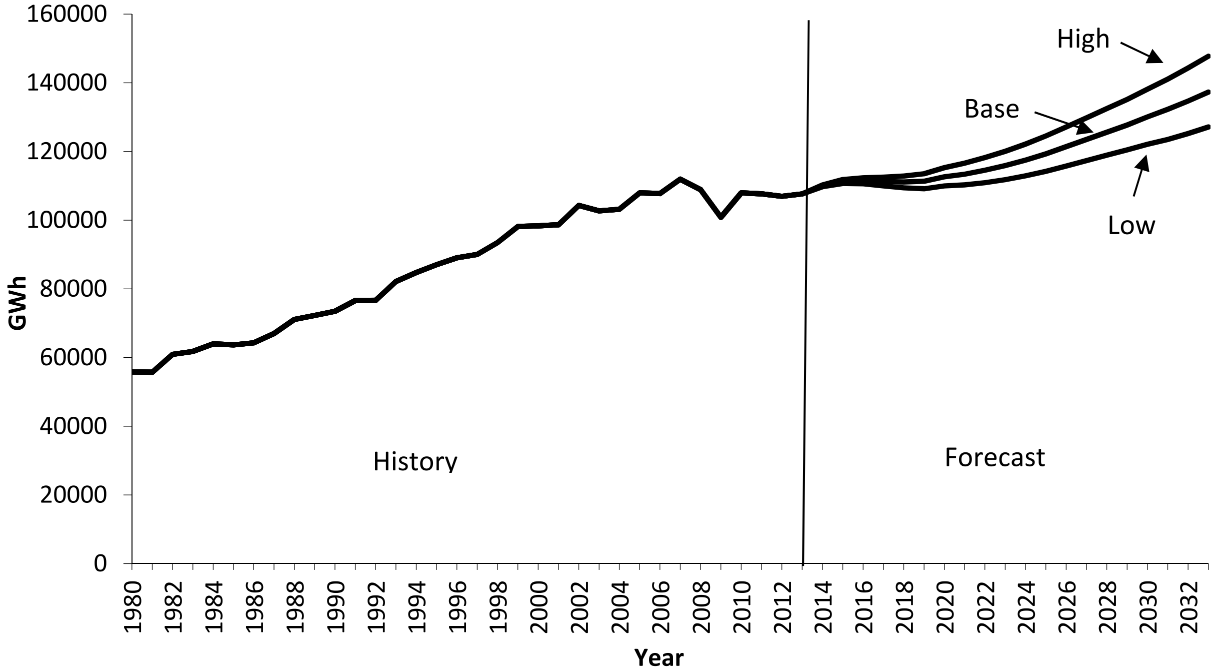


Figure 1-5. Indiana Electricity Requirements by Scenario in GWh



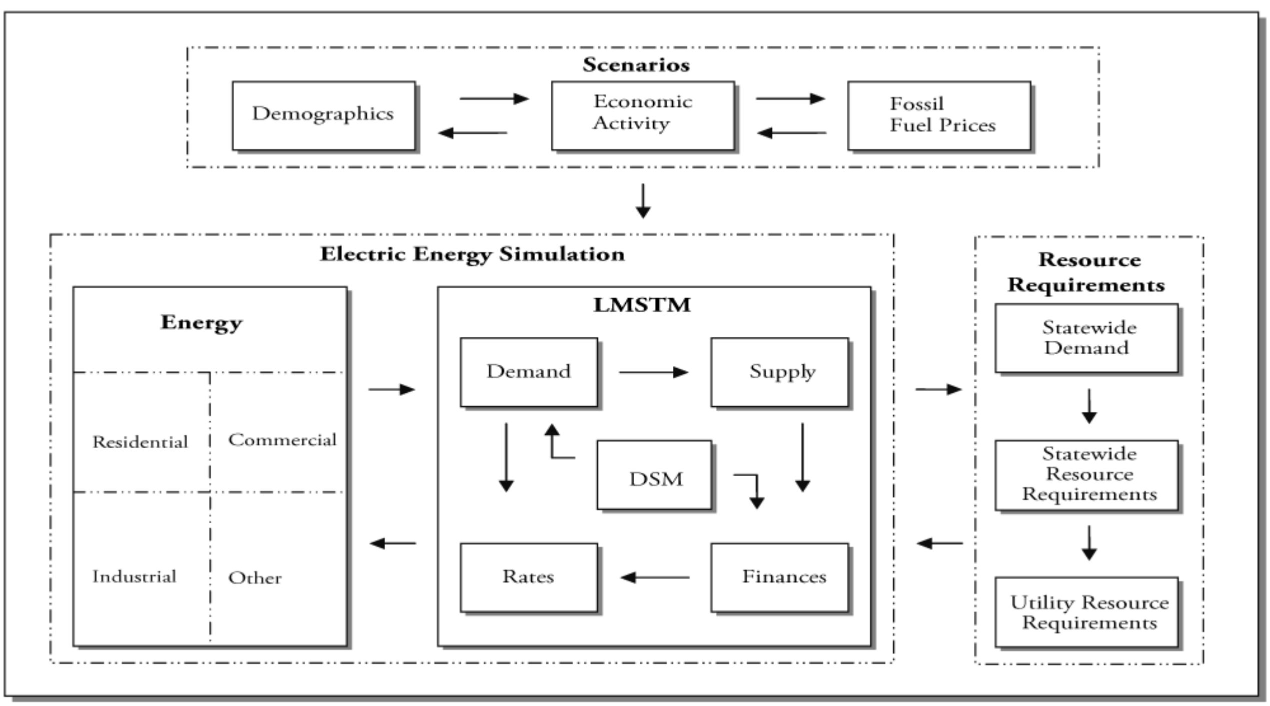
Chapter 2

Overview of the SUFG Electricity Modeling System

Regulated Modeling System

SUFG's integrated electricity modeling system projects electricity demand, supply and price for each electric utility in the state under Indiana's present regulatory structure. The modeling system captures the dynamic interactions between customer demand, the utility's operating and investment decisions, and customer rates by cycling through the various submodels until equilibrium is attained. The SUFG modeling system is unique among utility forecasting and planning models because of its comprehensive and integrated characteristics. The basic system components (submodels) and their principal linkages are illustrated in Figure 2-1 and then briefly described.

Figure 2-1. SUFG's Regulated Modeling System



Scenarios

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

Electric Utility Simulation

The electric utility simulation portion of the modeling system develops projections for each of the five investor-owned utilities (IOUs): Duke Energy Indiana, Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, and Southern Indiana Gas & Electric Company. In addition, projections are developed for the three not-for-profit (NFP) utilities: Hoosier Energy Rural Electric Cooperative, Indiana Municipal Power Agency, and Wabash Valley Power Association.

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

Energy Submodel

SUFG has developed and acquired both econometric and end-use models to project energy use for each major customer group. These models use fuel prices and economic drivers to simulate growth in energy use. The end-use models provide detailed projections of end-use saturations, building shell choices and equipment choices (fuel type, efficiency and rate of utilization). The econometric models capture the same effects but in a more aggregate way. These models use statistical relationships estimated from historical data on fuel prices and economic activity variables. For this forecast, SUFG is using end-use models for the residential and commercial sectors and an econometric model for the industrial sector. Beginning with the 2011 forecast, SUFG switched to the residential end-use model after previously using an econometric model. The change was made for a number of reasons, including the enhanced ability of the end-use model to capture the impacts of federally mandated lighting efficiency standards. Additional information regarding SUFG's energy models for the residential, commercial and industrial sectors can be found in chapters five, six and seven, respectively.

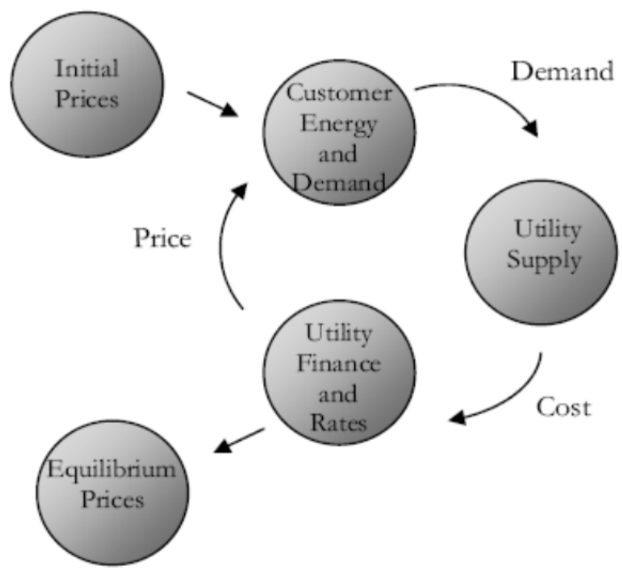
Load Management Strategy Testing Model

Developed by Electric Power Software, the Load Management Strategy Testing Model (LMSTM) is an electric utility system simulation model that integrates four submodels: demand, supply, finance and rates. Combined in this way, LMSTM simulates the interaction of customer demand, system generation, total revenue requirements and customer rates. LMSTM also preserves chronological load shape information throughout the simulation to capture time dependencies between customer demand (including demand side management or DSM), system operations and customer rates.

Price Iteration

The energy modeling system cycles through five integrated submodels: energy, demand, supply, finance and rates. During each cycle, price changes in the model cause customers to adjust their consumption of electricity, which in turn affects system demand, which in turn affects the utility's operating and investment decisions. These changes in demand and supply bring forth yet another change in price and the cycle is complete. After each cycle, the modeling system compares the "after" electricity prices from the rates submodel to the "before" prices input to the energy consumption models. If these prices match, they are termed equilibrium prices in the sense that they balance demand and supply, and the iterative process ends. Otherwise, the modeling system continues to cycle through the submodels until equilibrium is attained as is illustrated in Figure 2-2.

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



Resource Requirements

Beginning with the 2009 forecast, SUFG made a slight modification to the methodology used in determining future resource requirements. For the 1999-2007 forecasts, SUFG determined required resources according to a target statewide 15 percent reserve margin. Forecasts prior to 1999 used a 20 percent statewide reserve margin. These reserve margins were essentially rules-of-thumb, based on industry observations. Recently, the regional transmission organizations that encompass Indiana utilities have determined planning reserve requirements for their members. Starting with the 2009 forecast, SUFG has used individual utility reserve margins that reflect the planning reserve requirements of the utility's RTO to determine the reserve requirements in this forecast. Applying the individual reserve requirements and adjusting for peak load diversity[1] among the utilities provides a statewide reserve requirement of approximately 19.5 percent. This represents a higher reserve margin than the 18.3 percent figure used in the 2013 forecast due to changing RTO requirements. It should be noted that the change from a 15 percent to a 18.3 or 19.5 percent target in the SUFG forecasts does not represent an increase in reserves (and hence, an increase in costs) due to the utilities' memberships in the RTOs. Rather, it represents a change by SUFG to a target that is based on the more rigorous analyses of the RTOs as compared to the previous rule of thumb method.

The process used to determine resource requirements is illustrated in the flowchart in Figure 2-3. Individual utility peak demands developed from LMSTM are aggregated while accounting for load diversity and demand respond loads to determine the statewide peak demand for each year of the forecast. The additional resources required are determined for each year by comparing the peak demand with a 19.5 percent reserve margin to the existing capacity. The existing capacity has been adjusted for retirements, utility purchases and sales, and new construction projects that have been approved by the Indiana Utility Regulatory Commission (IURC).

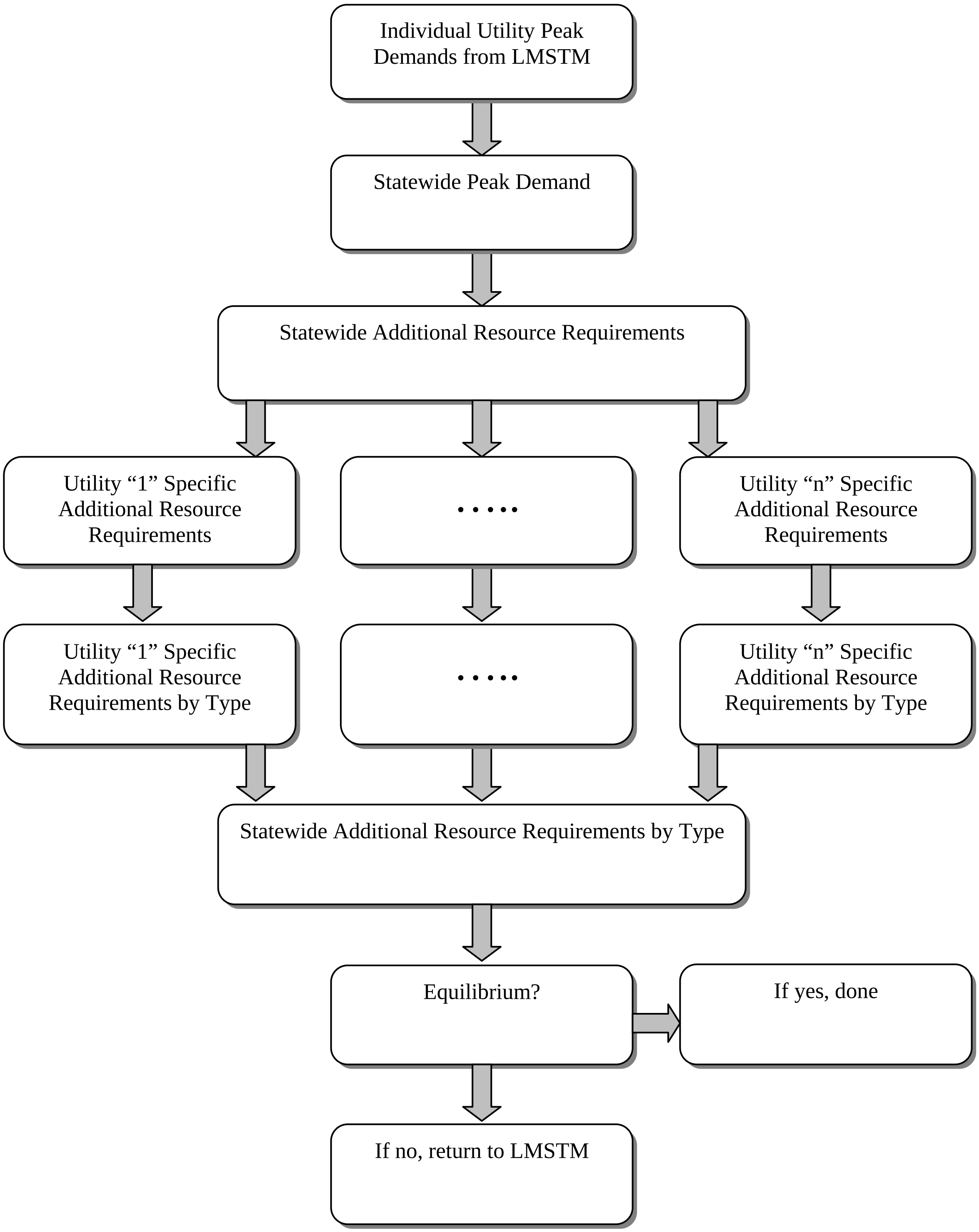
The required resources are then assigned to the individual utilities with the lowest reserve margins, so that all utilities have similar reserve margins. Even if the state's reserve margin meets the 19.5 percent target, resources will be assigned to an individual utility if necessary to bring the utility's reserve margin up to 6 percent. This is done for purposes of model integrity, since the utility dispatch simulation in LMSTM will provide unrealistic results with very low utility reserves. These utility specific additional resource requirements are then assigned to one of three types: base load, intermediate (or cycling), and peaking. This is accomplished by comparing the utility's demand, which is divided into the three types using actual historical annual load shapes, to the utility's existing generation resources, which are also assigned to the three types. The statewide resource requirements by type are determined by summing the individual utility requirements. The overall process is done iteratively until equilibrium is reached where resource requirements do not change from one iteration to the next.

Presentation and Interpretation of Forecast Results

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

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

Figure 2-3. Resource Requirements Flowchart



Chapter 3

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

Introduction

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

Most Probable Forecast

As shown in Tables 3-1 and 3-2 and Figures 3-1 and 3-2, SUFG’s current base scenario projection indicates annual growth of 1.17 percent for electricity requirements and 1.13 percent for peak demand. As shown in Table 3-3, the growth rate for electricity sales in this forecast is about 0.43 percent higher than the 2013 forecast. The growth within sectors varies significantly with higher growth in the industrial sector offsetting lower growth in the residential and commercial sectors, but the forecast growth for all sectors is markedly above the forecast in 2013. See Chapters 5, 6, and 7 for discussions of the forecast growth in the residential, commercial, and industrial sectors.

A comparison of the forecast trajectory of electricity requirements between the current and previous forecast shows that the current forecast starts out above the previous forecast and that the gap between the projections slightly widens over the first two years of the forecast period. Then, the gap between the projections is roughly constant over the rest of the forecast horizon. The upward trend in electricity requirements in 2014 and 2015 is due to less aggressive energy efficiency programs that reflect the elimination of the IURC DSM goals on March 27, 2014. This general pattern is followed in all three sectors.

The growth in peak demand is slightly higher than that projected in 2013 and follows a similar pattern in relation to the 2013 projection but with a less pronounced drop in the beginning of the forecast. The smaller drop in the first year of the forecast (2014) is due to the exclusion of the demand response that was called on in the calibration year (2013). About 1,000 MW of demand response, consisting of direct load control and industrial interruptible loads, is available. The peak demand numbers in the forecast are net of these demand response loads, since additional resources will not be needed in the future to meet these loads during the peak demand time. Forecast peak demand growth is slightly lower than that of electricity requirements (1.13 versus 1.17 percent). Another measure of peak demand growth can be obtained by considering the average year to year peak MW load change. In Figure 3-2, the annual increase is about 235 MW compared to about 180 MW per year in the previous forecast.

Resource Implications

SUFG’s resource plans include both demand-side and supply-side resources to meet forecast demand. DSM impacts (includes energy efficiency and demand response programs) are netted from the demand projection, and generic resources are added as necessary to maintain a 19.5 percent reserve margin (see Chapter 2 for a discussion of the future resource allocation methodology and the target reserve margin). Although this approach provides a reasonable basis for estimating future electricity prices for planning purposes, it does not ensure that the resource plans are obtained at least cost.

Demand-Side Resources

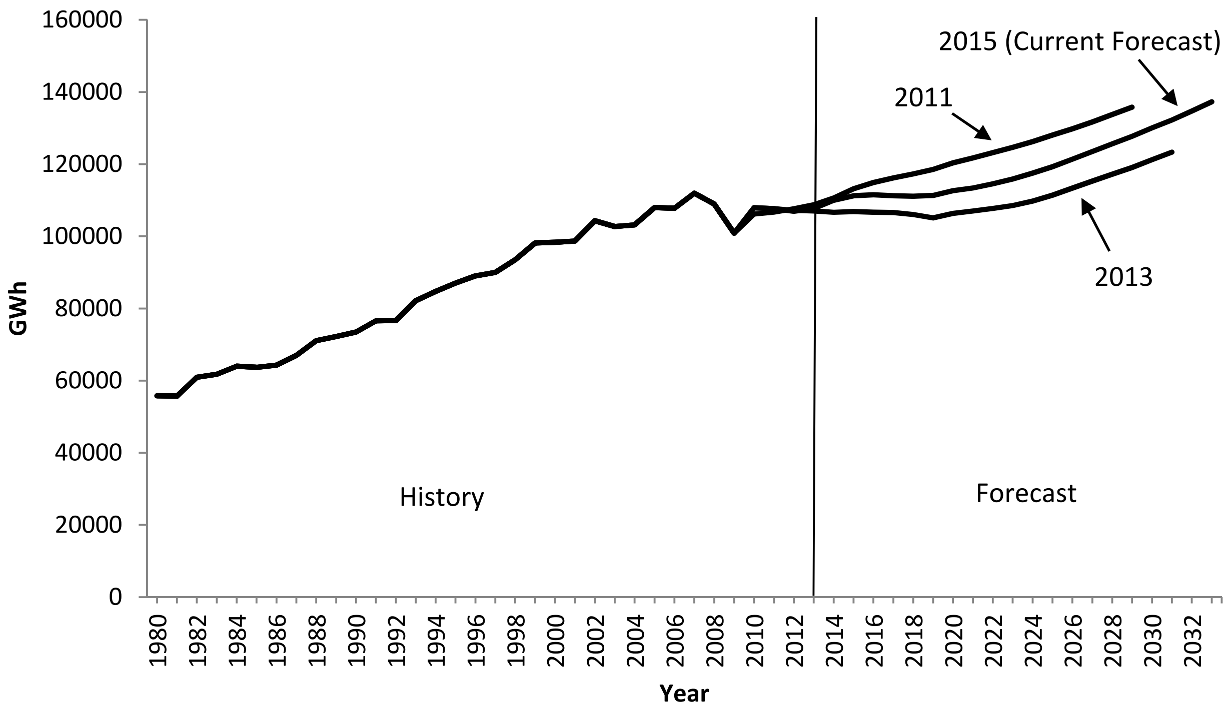
Beginning with the 2013 forecast, SUFG has adjusted its demand-side management (DSM) programs definition to more closely align with the commonly accepted meaning for these types of resources. For previous forecasts, SUFG classified industrial interruptible or buy-through contracts as interruptible loads and utility energy efficiency and direct load control programs as DSM. In this forecast, the term DSM includes two components: energy efficiency (EE) and demand response (DR) programs. The EE component accounts for energy reduction and its correspondent peak load reduction from conservation programs (i.e. high efficiency appliances, changes in behavior or operations, etc.) implemented by utilities. DR programs include all the potential peak load reductions (less the actual reductions called on in 2013) from load management programs (i.e. interruptible, direct load control (DLC), voltage reduction, etc.) that shift energy usage from times of high demand to times of lower demand but do not affect overall energy usage. Since the amount called upon in 2013 is already effectively embedded in the model calibration, it is necessary to net that amount from future DR potential to avoid double counting. The current projection includes the energy and demand impacts of existing or planned utility-sponsored EE programs. Incremental EE programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 300 MW at the beginning of the forecast period and by about 745 MW at the end of the forecast. EE projections reflect the estimated impact of the elimination of the IURC's DSM order.

In addition to EE programs, peak demand projections are reduced due to DR programs. Load reductions from DR programs are projected to increase from approximately 1,000 MW to about 1,200 MW over the forecast horizon. See Chapter 4 for additional information about DSM.

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

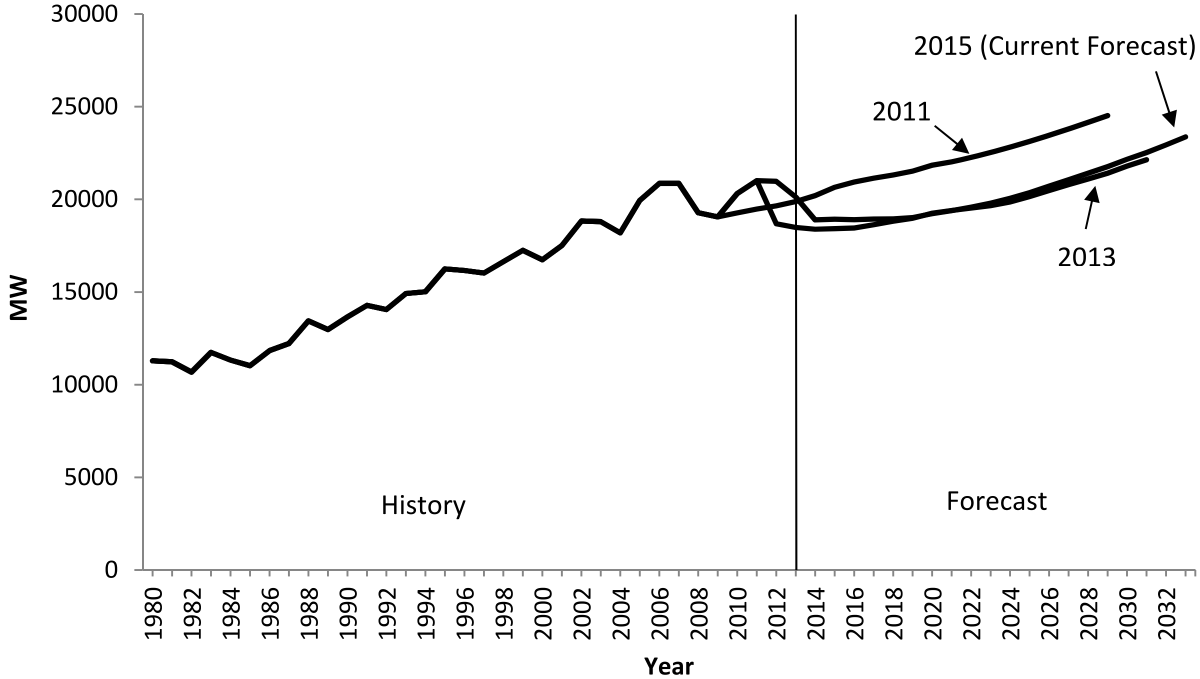
Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2015	1.17	2014-2033
2013	0.74	2012-2031
2011	1.30	2010-2029

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



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

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



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

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

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2015	1.13	2014-2033
2013	0.90	2012-2031
2011	1.28	2010-2029

Table 3-3. Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2013 Projections)

Sector	Current (2014-2033)	2013 (2012-2031)
Residential	0.64	0.37
Commercial	0.59	0.33
Industrial	1.90	1.29
Total	1.17	0.74

Supply-Side Resources

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

SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic firm wholesale purchases are added at prices that reflect SUFG estimates of long-run average costs for these purchases as necessary during the forecast period to maintain a 19.5 percent statewide reserve margin. This level of statewide reserves is derived from individual utility reserve margins that reflect the planning reserve requirements of the utility's regional transmission organization. Note that the reserve margin incorporated in this forecast is higher than the 18.3 percent figure used in 2013. This is due to revisions in planning reserve requirements by the regional transmission organizations.

Three types of generic firm wholesale purchases are included:

1. peaking purchases;
2. cycling purchases; and
3. baseload purchases.

Based on projections of fuel and equipment costs and likely capacity factors for these units, SUFG would expect peaking units to be gas-fired combustion turbines (CT), and both cycling and baseload units to be gas-fired combined cycle (CC) plants. Prior to the 2011 forecast, pulverized coal (PC) units were used as the basis for baseload purchases. This change was made because the fuel price projections and capital cost estimates indicate that CC units would be a lower cost option than PC units. Purchase price projections for each of these purchase types are set to recover the long-run cost of generating electricity from each unit. Continued increases in construction costs have resulted in significantly higher purchase price projections than were used in the previous SUFG forecast.

Table 3-4 and Figure 3-3 show the statewide resource plan for the SUFG base scenario. This forecast identifies the needs for resources in the near term, with 250 MW of peaking, 170 MW of cycling and 100 MW of baseload resources required by 2016. These requirements are slightly higher than those identified in the 2013 forecast primarily because of a higher peak demand projections due to reduced energy efficiency and demand response. By 2022, a total of 1,030 MW of resource additions are required, of which 390 MW is peaking, 180 MW is cycling, and 460 MW is baseload. About 2,860 MW of resource additions are required by 2027, and approximately 5,860 MW by 2033. The net change in generation includes the retirement of units as reported in the utilities' 2013 IRP filings, changes in firm purchases and sales, and the addition of approved new capacity. The required resources indicated through 2019 are needed for purposes of model integrity to prevent individual utility reserves from being too low, rather than because the state falls below the 19.5 percent threshold. This phenomenon can occur when there is an imbalance in reserve margins among utilities. As explained in Chapter 2, SUFG does not allow an individual utility reserve margin to fall below 6 percent, even when the state as a whole has enough resources.

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

Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of actual historical data was 2013. Therefore, 2014 and 2015 numbers do not include short term purchases and any longer term purchases of which SUFG was not aware at the time the forecast was prepared.

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

	Uncontrolled Peak Demand[1]	Demand Response[2]	Net Peak Demand[3]	Existing/ Approved Capacity[4]	Incremental Change in Capacity[5]	Projected Additional Resource Requirements[6]				Total Resources[7]	Reserve Margin[8] (percent)
						Peaking	Cycling	Baseload	Total		
2013				24,060							
2014	19,860	973	18,887	24,176	116	-	-	-	-	24,176	28
2015	20,068	1,146	18,922	23,016	-1160	150	90	30	270	23,286	23
2016	20,099	1,196	18,903	22,119	-897	250	170	100	520	22,639	20
2017	20,075	1,141	18,934	22,786	667	220	110	140	470	23,256	23
2018	20,097	1,157	18,939	22,847	61	220	90	180	490	23,337	23
2019	20,184	1,164	19,020	22,824	-23	240	120	240	600	23,424	23
2020	20,398	1,168	19,230	22,770	-54	290	120	310	720	23,490	22
2021	20,564	1,169	19,395	22,789	20	330	140	360	830	23,619	22
2022	20,751	1,172	19,579	22,799	10	390	180	460	1,030	23,829	22
2023	20,969	1,175	19,794	22,647	-152	530	210	620	1,360	24,007	21
2024	21,231	1,177	20,054	22,558	-88	630	260	840	1,730	24,288	21
2025	21,541	1,179	20,361	22,558	0	740	310	940	1,990	24,548	21
2026	21,891	1,181	20,710	22,580	22	840	360	1,120	2,320	24,900	20
2027	22,240	1,183	21,057	22,402	-178	1,010	440	1,410	2,860	25,262	20
2028	22,597	1,185	21,412	22,383	-19	1,150	520	1,560	3,230	25,613	20
2029	22,949	1,185	21,764	22,077	-306	1,310	590	2,030	3,930	26,007	19
2030	23,351	1,186	22,165	22,080	2	1,470	690	2,240	4,400	26,480	19
2031	23,714	1,186	22,528	22,073	-7	1,630	770	2,450	4,850	26,923	20
2032	24,123	1,186	22,937	22,055	-18	1,760	910	2,670	5,340	27,395	19
2033	24,553	1,186	23,367	22,056	1	1,920	1,010	2,930	5,860	27,916	19

1 Uncontrolled peak demand is the peak demand prior to any load reduction from demand response programs being called upon.

2 Demand response is all the measures designed to shift load away from peak demand periods. These include interruptible and direct load control programs affecting peak demand. These numbers are net of the peak reductions that were called on in the calibration year (2013).

3 Net peak demand is the peak demand after load reductions from demand response programs are taken into account.

4 Existing/approved capacity includes installed capacity plus approved new capacity plus firm purchases minus firm sales.

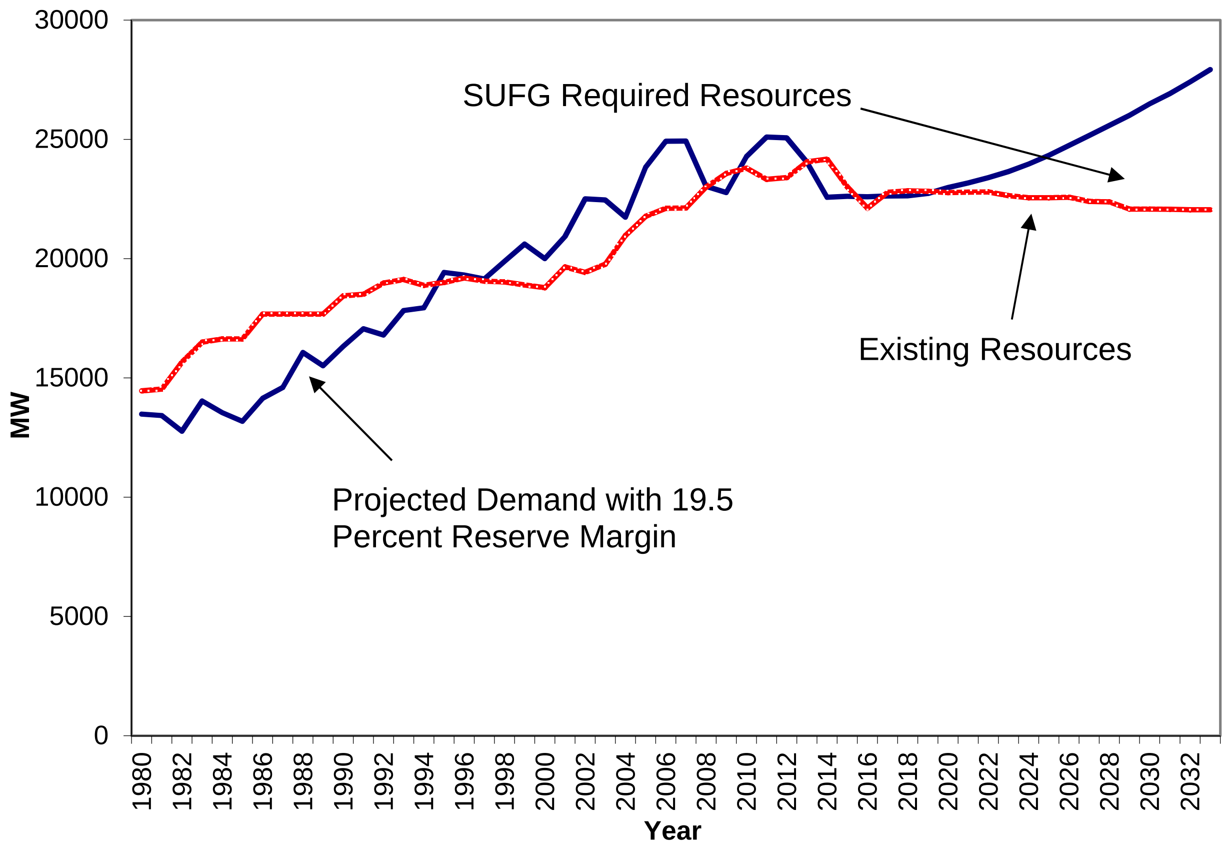
5 Incremental change in capacity is the change in existing/approved capacity from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, and changes in firm purchases and sales.

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

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

8 Resources may be required by individual utilities even if the state as a whole meets or exceeds the statewide reserve margin. Individual utility reserve margins are not allowed to fall below 6 percent.

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



Equilibrium Price and Energy Impact

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

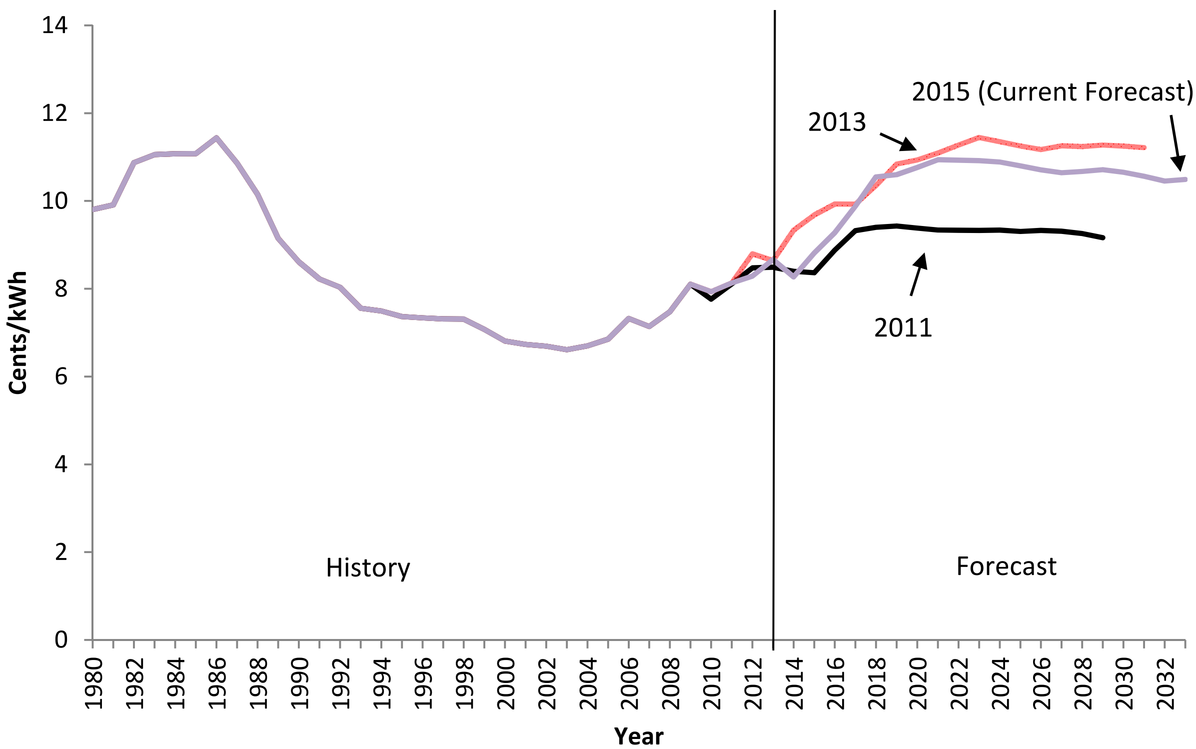
SUFG's base scenario equilibrium real electricity price trajectory is shown in Table 3-5 and Figure 3-4. Real prices are projected to increase by 26 percent from 2013 to 2021 and then slowly decrease until 2027. Afterwards, prices show an upward trend for 2028 and 2029 before decreasing again for the remainder of the forecast period. The change in prices early in the forecast horizon is significant, thus the electricity requirements projection for this portion of the forecast period is affected. SUFG's equilibrium price projections for two previous forecasts are also shown in Table 3-5 and Figure 3-4. The price projection labeled "2011" is the base case projection contained in SUFG's 2011 forecast and the one labeled "2013" is the base case projections from SUFG's 2013 report. For the prior price forecasts, SUFG rescaled the original price projections to 2013 dollars (from 2009 dollars for the 2011 projection, and from 2011 dollars for the 2013 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

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

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2015	1.26	2014-2033
2013	1.29	2012-2031
2011	0.88	2010-2029

Four major factors primarily determine the differences among the price projections in Figure 3-4: first, the cost of meeting air emission standards; second, costs associated with resources required to meet future load; third, capital costs associated with generation plant additions and life extension; and fourth, fuel costs. It should be noted that a new generating facility is only included after a Certificate of Public Convenience and Necessity is granted by the IURC. Similarly, environmental rules that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not. Specifically, costs associated with meeting the Clean Power Plan regulations on carbon dioxide are not included, since the regulation was not finalized until after the model inputs were finalized. Since actions associated with the Mercury and Air Toxics Standards (MATS) had for the most part been commenced by the utilities before the U.S. Supreme Court returned it to EPA for review, those costs are included. The generators that SUFG uses to approximate the costs of new resources are chosen to comply with the greenhouse gas rules for new plants.

Figure 3-4. Indiana Real Price Projections in cents/kWh (2013 Dollars) (Historical, Current and Previous Forecasts)



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

Low and High Scenarios

SUFG has used alternative macroeconomic scenarios, reflecting low and high growth in real personal income, non-manufacturing employment and gross state product. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Tables 3-6 and 3-7 and Figures 3-5 and 3-6 provide the statewide electricity requirements and peak demand projections for the base, low and high scenarios. As shown in those figures, the annual growth rates for energy requirements for the low and high scenarios are 0.39 percent lower and 0.38 percent higher than the base scenario. These differences are due to economic growth assumptions in the scenario-based projections.

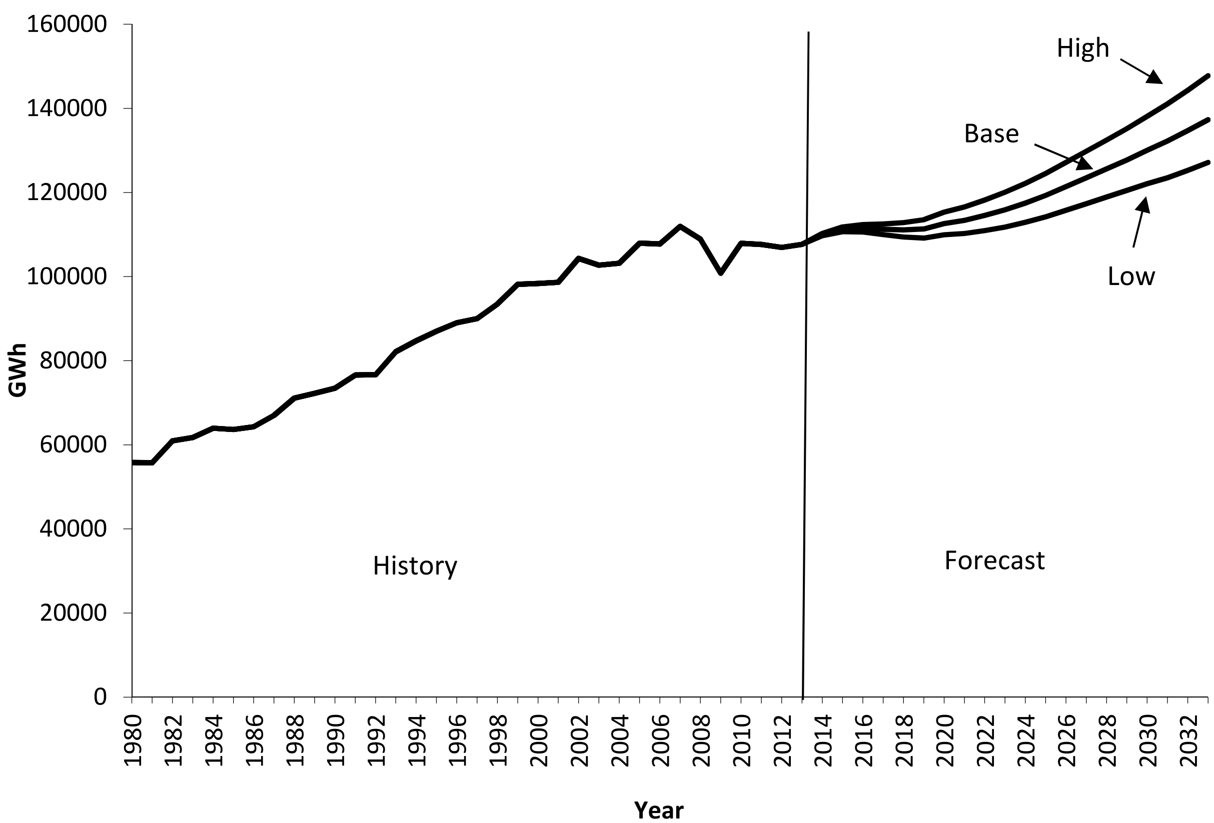
Resource and Price Implications of Low and High Scenarios

Resource plans are developed for the low and high scenarios using the same methodology as the base plan. Demand-side resources, including energy efficiency and demand response loads, are the same in all three scenarios, as are retirements of generating units. Table 3-8 shows the statewide resource requirements for each scenario. Approximately 7,850 MW over the horizon are required in the high scenario compared to 3,950 MW in the low scenario. By the end of the forecast period, electricity prices in both the high case and the low case are within about 3.3 percent of those projected in the base case. This is because the higher costs associated with meeting the increased load for the high case are spread over a greater amount of energy. For the low case, the lower costs are offset by the lower amount of energy.

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

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2014-2033	1.17	0.78	1.55

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

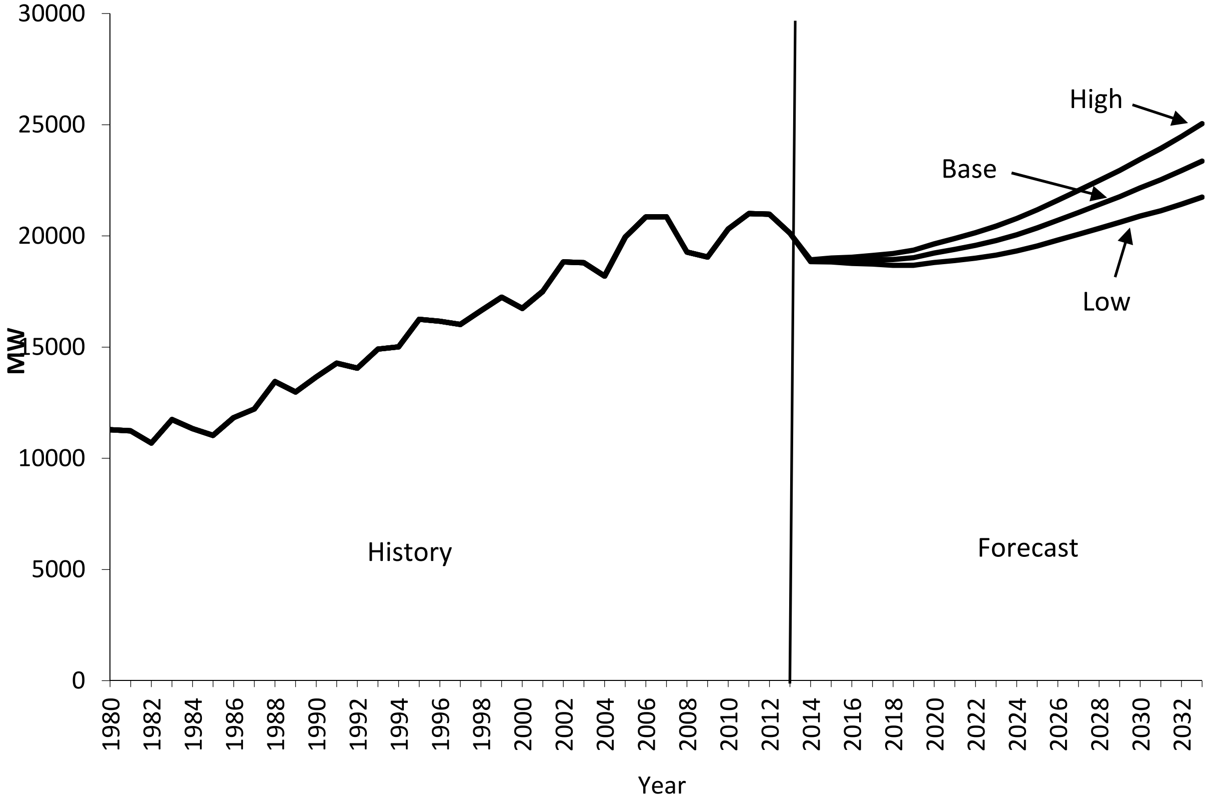


Note: See the Appendix to this report for historical and projected values.

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

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2014-2033	1.13	0.76	1.49

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



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

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

Year	Base				High				Low			
	Peaking	Cycling	Baseload	Total	Peaking	Cycling	Baseload	Total	Peaking	Cycling	Baseload	Total
2014	0	0	0	0	0	0	0	0	0	0	0	0
2015	150	90	30	270	170	90	50	310	130	70	30	230
2016	250	170	100	520	330	210	140	680	180	110	70	360
2017	220	110	140	470	260	120	180	560	170	80	110	360
2018	220	90	180	490	290	130	230	650	160	80	140	380
2019	240	120	240	600	320	150	330	800	160	80	180	420
2020	290	120	310	720	390	180	430	1,000	190	80	230	500
2021	330	140	360	830	470	220	520	1,210	220	100	250	570
2022	390	180	460	1,030	570	280	650	1,500	250	110	280	640
2023	530	210	620	1,360	770	330	840	1,940	360	120	400	880
2024	630	260	840	1,730	880	390	1,120	2,390	420	150	560	1,130
2025	740	310	940	1,990	1,020	470	1,300	2,790	480	170	630	1,280
2026	840	360	1,120	2,320	1,150	530	1,560	3,240	540	200	770	1,510
2027	1,010	440	1,410	2,860	1,420	630	1,920	3,970	650	260	1,020	1,930
2028	1,150	520	1,560	3,230	1,600	730	2,170	4,500	750	310	1,110	2,170
2029	1,310	590	2,030	3,930	1,780	830	2,720	5,330	880	380	1,450	2,710
2030	1,470	690	2,240	4,400	1,960	970	3,000	5,930	960	430	1,530	2,920
2031	1,630	770	2,450	4,850	2,110	1,130	3,270	6,510	1,070	510	1,630	3,210
2032	1,760	910	2,670	5,340	2,290	1,290	3,580	7,160	1,150	600	1,820	3,570
2033	1,920	1,010	2,930	5,860	2,390	1,410	4,050	7,850	1,280	670	2,000	3,950

Chapter 4

Major Forecast Inputs and Assumptions

Introduction

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

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

Macroeconomic Scenarios

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

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

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

Economic Activity Projections

National and state economic projections are produced by the CEMR twice each year. For this forecast, SUFG adopted CEMR's February 2015 economic projections as its base scenario. CEMR also produced high and low growth alternatives to the base projection for SUFG's use in the high and low scenarios.

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

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

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

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

The main exogenous assumptions in the national projections used in the CEMR forecast, as cited from "Long-Range Projections 2014-2035" [CEMR] are:

Federal tax rates are assumed to increase over the projection period. Specifically, the average tax rate on personal income increases 9.2 percent, while the payroll tax rate increases by 2.7 percent. Federal grants to state and local governments are assumed to grow at 4.6 percent annually early in the projection period and then rise to about a 5.1 percent by the end of the projection period. The federal government deficit declines significantly from 3.4 percent of Gross Domestic Product (GDP) in 2014 to 1.5 percent by the end of the projection period.

State and local tax rates are roughly stable over the projection period. This allows these governments to run moderate surpluses during the second half of the projection period.

Real exports are assumed to grow at about 5.3 percent through 2023, and then to decelerate gradually to 4.7 percent growth. This produces a nominal net export deficit that declines from 3.1 percent of GDP to 0.6 percent.

As a result of these assumptions, real GDP for the U.S. economy is projected to grow at an average annual rate of 2.89 percent and U.S. employment growth averages 0.86 percent over the 2014 to 2033 period.

In Indiana, total employment is projected to grow at an average annual rate of 0.80 percent from 2014 through 2033. The key Indiana economic projections are:

Real personal income (a residential sector model driver) is expected to grow at a 2.33 percent annual rate.

Non-manufacturing employment (the commercial sector model driver) is expected to average a 0.96 percent annual growth rate over the forecast horizon.

Despite a small decline in manufacturing employment, manufacturing Gross State Product (GSP) (the industrial sector model driver) is expected to rise at a 3.71 percent annual rate as gains in productivity far outpace the drop in employment.

CEMR's macroeconomic projections reflect a somewhat accelerating recovery from the recession of 2008-2009.

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

To capture some of the uncertainty in energy forecasting, CEMR provided low and high growth alternatives to its base economic projection. In effect, the alternatives describe a situation in which Indiana either loses or gains shares of national industries compared to the base projection. In the high growth alternative, the Indiana average growth rate of real personal income is increased by about 0.30 percent per year (to 2.63), non-manufacturing employment growth increases 0.10 percent (to 1.06) while Indiana real manufacturing GSP growth is increased by 0.82 percent (to 4.53). In the low growth alternative, the average growth rates of real personal income, non-manufacturing employment and real manufacturing GSP are reduced by similar amounts (to 2.03, 0.85 and 2.92 percent, respectively).

Demographic Projections

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

The population projections utilized in SUFG's electricity forecasts were obtained from the Indiana Business Research Center at Indiana University (IBRC). The IBRC population growth forecast for Indiana is 0.49 percent per year, for the period 2010-2030. This projection is based on the 2010 Census and includes projections of county population by age group. The fastest growing age groups are those of seniors age 65+ (2.71 percent) and young adults 25-44 (0.22 percent). Older adults aged 45-64 are projected to decline 0.33 percent. Population growth in total is low during the projection period because the age distribution in Indiana is skewed from young adults of childbearing age to older adults with higher mortality rates.

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

The historical growth of household formations (number of residential customers) has slowed down significantly from slightly over 2 percent during the late 1960s and early 1970s to 0.2 percent from 2005-2013. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of about 1.07 percent over the forecast period.

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

	Short-Run History for Selected Recent Periods					Long-Run Forecast		
						Feb 2011	Feb 2013	Feb 2015
	1985-1990	1990-1995	1995-2000	2000-2005	2005-2013	2010-2029	2012-2031	2014-2033
United States								
Real Personal Income	2.95	2.04	4.08	1.73	1.74	2.80	2.73	2.66
Total Employment	2.36	1.38	2.37	0.25	0.22	1.25	0.90	0.86
Real Gross Domestic Product	3.25	2.38	4.36	2.39	1.24	3.05	2.83	2.89
Personal Consumer Expenditure Deflator	3.79	2.77	1.87	2.20	1.91	1.51	1.60	1.95
Indiana								
Real Personal Income	2.50	2.48	3.37	1.17	1.24	2.02	2.15	2.33
Employment								
Total Establishment	2.84	1.91	1.22	-0.28	-0.11	1.21	0.88	0.80
Manufacturing	0.91	1.40	0.07	-2.95	-1.85	0.30	0.18	-0.17
Non-Manufacturing	3.82	2.20	1.97	0.47	0.42	1.31	0.97	0.96
Real Gross State Product								
Total	6.17	5.83	4.78	1.98	1.02	3.02	2.75	2.80
Manufacturing	4.76	7.95	4.68	3.26	2.55	3.44	3.58	3.71
Non-Manufacturing	6.81	4.86	4.84	1.43	0.42	2.86	2.40	2.34
Sources: SUFG Forecast Modeling System and various CEMR “Long-Range Projections”								

Fossil Fuel Price Projections

The prices of fossil fuels such as coal, natural gas and oil affect electricity demand in separate and opposing ways. To the extent that any of these fuels are used to generate electricity, they are a determinant of average electricity prices. Electricity generation in Indiana is currently fueled almost entirely by coal. 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 increase, the impacts on electricity demand are somewhat offsetting. The net impact of these opposing forces depends on their impact on utility costs, the responsiveness of customer demand to electricity price changes and the availability and competitiveness of fossil fuels in the end-use services markets. The SUFG modeling system is designed to simulate each of these effects as well as the dynamic interactions among all effects.

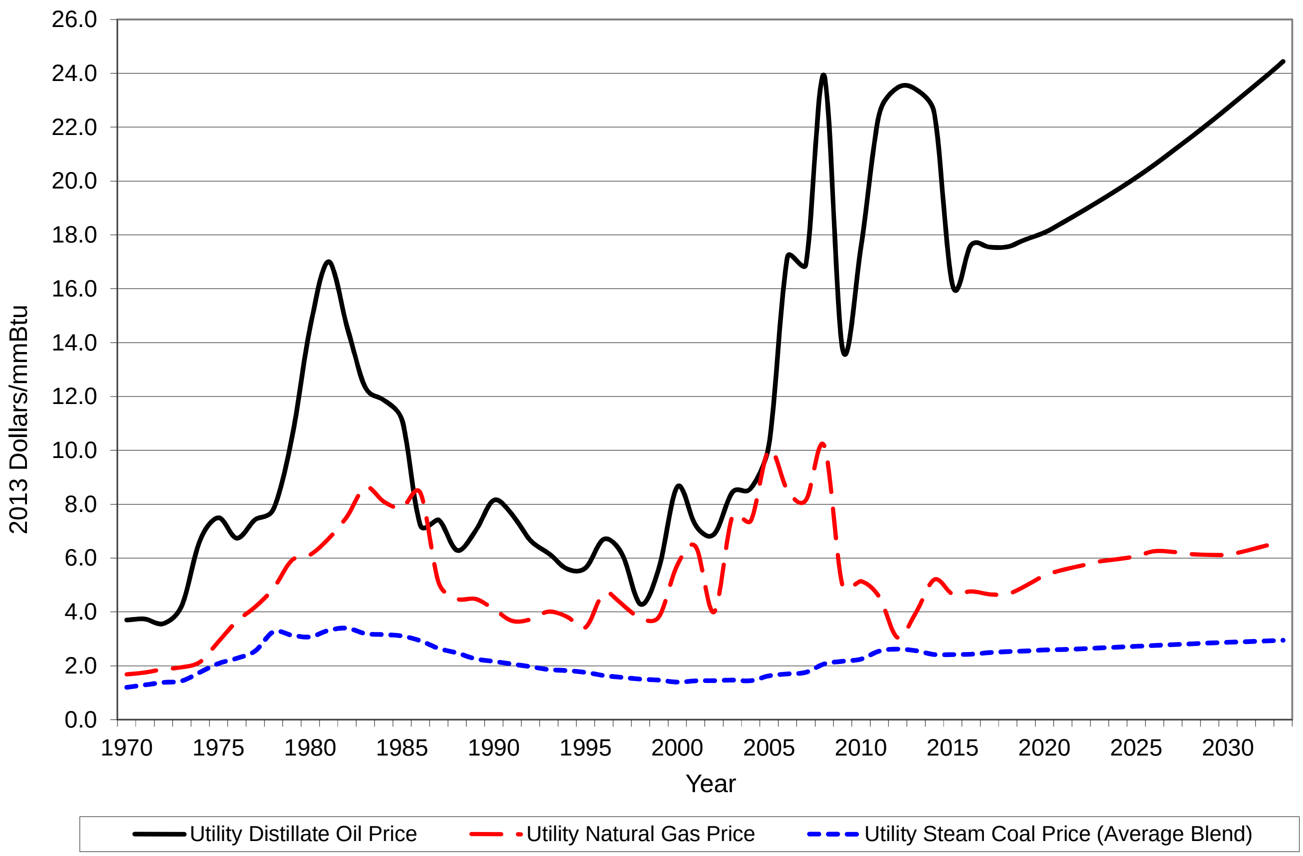
SUFG’s modeling system incorporates separate fuel price projections for each of the utility, industrial, commercial and residential sectors. Therefore, SUFG uses four distinct natural gas price projections (one for each sector). Similarly, four distinct oil price projections are used. Coal price projections are included for the utility and industrial sectors only. In this forecast, SUFG has used April 2015 fossil fuel price projections from EIA for the East North Central Region of the U.S. [EIA]. All projections are in terms of real prices (2013 dollars), i.e., projections with the effects of inflation removed. The general patterns of the fossil fuel price projections are:

- Coal price projections are relatively unchanged in real terms throughout the entire forecast horizon as growth in demand is offset by improvements in mining productivity.
- 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. They are projected to remain relatively constant through 2018, with a general increase following for the remainder of the forecast horizon.
- Distillate prices also decreased significantly in 2009 coming off of the high prices of 2008. Prices then rebounded significantly through 2012-2013 before declining again in 2014. They are projected

to decline significantly in 2015 before rebounding slightly in 2016 and steadily increasing over the remainder of the forecast horizon.

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

Figure 4-1. Utility Real Fossil Fuel Prices



Demand-Side Management, Energy Efficiency and Demand Response

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

Incremental energy efficiency, which includes new programs and the expansion of existing programs, require adjustments to be made in the forecast. These adjustments are made by changing the utility's demand by the appropriate level of energy and peak demand for the DSM program. DSM programs that were in place in 2013 are considered to be embedded in the calibration data, so no adjustments are necessary.

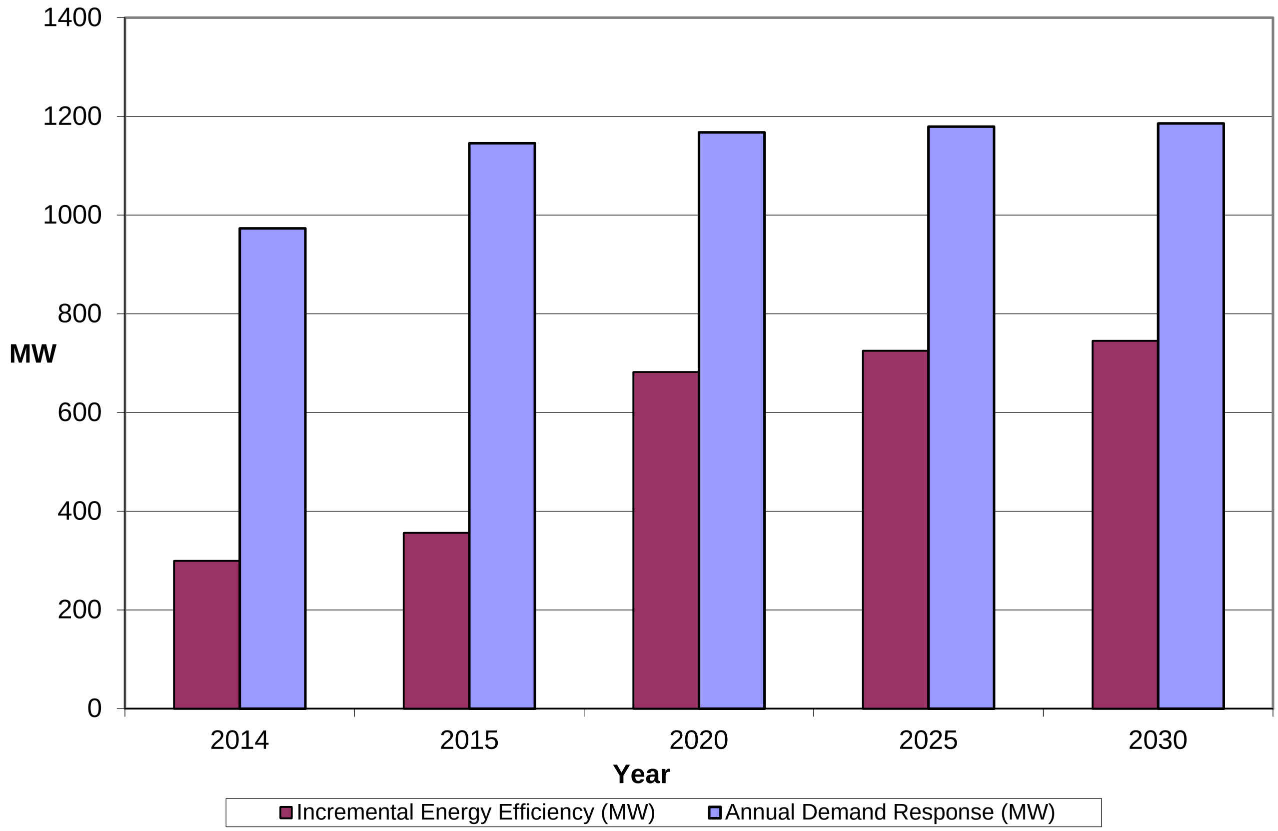
Demand response can include interruptible loads, such as large customers who agree to curtail a fixed amount of their demand during critical periods in exchange for more favorable rates, and direct load control, where the utility has the ability to directly turn off a customer's load for a specified amount of time. Demand response is typically treated differently than energy efficiency. The amount of demand response is subtracted from the utility's peak demand in order to determine the amount of new capacity required.

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

Table 4-2. 2013 Embedded DSM and 2014 Incremental Peak Demand Reductions from Energy Efficiency and Annual Demand Response Programs (MW)

2013 Embedded DSM	2014 Incremental Energy Efficiency	2014 Annual Demand Response
1,939	299	973

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



In addition to direct load control, the demand response numbers include both traditional interruptible contracts, whereby the customer shuts off its load when certain criteria are met, and buy through contracts, whereby the customer has the option of shutting off the load or purchasing the power at the wholesale price. For both types of interruptible load, the utility does not have to acquire additional peak generating capacity ahead of time to meet that load. Therefore, interruptible and buy through loads are subtracted from total peak demand for resource planning purposes. The peak demand projections in this report are net of both types of interruptible loads; that is, those loads have been removed from the projections.

When analyzing wholesale markets, the distinction between interruptible and buy through loads becomes more important. Traditional interruptible loads may be assumed to be absent from the system during times of high demand and prices, while buy through loads may still be present, with the higher prices passed directly to the customer.

Changes in Forecast Drivers from 2013 Forecast

The SUFG forecast requires exogenous economic assumptions to project electric energy sales, peak demand and prices. Fluctuations in the national and state economies therefore have direct effects on the forecast. SUFG analyzed the impact of the recent recession on different economic variables in Indiana to obtain a better understanding of how these changes affect electricity demand in the state. This section compares the CEMR's projections used in SUFG's 2013 and 2015 forecasts.

Electricity demand is a function of a number of factors, including real personal income, manufacturers' electricity consumption, labor usage intensity, and other economic variables. The economy has direct and indirect implications for electricity consumption in Indiana.

In the time between CEMR's February 2013 (herein referred to as CEMR2013) and February 2015 (CEMR2015) long-range projections, the U.S. economy recovery has improved somewhat.

Tables 4-3 through 4-5 provide comparisons between the two projections. Selected economic variables are reported annually from 2010 through 2017 and for 2020, 2025, and the last year of the forecast period 2033. The tables show long-run projections of real values and percentage change at annual rates for non-manufacturing employment, real personal income, and total real manufacturing GSP. The tables also show the percentage change between CEMR2013 and CEMR2015. Figures 4-3 through 4-5 show long-run projections of real values for the same selected economic variables from 2007 through 2035. Some of the historical values differ between the two projections because of data revisions and the use of chain-weighted price indices and deflators.

Non-manufacturing Employment

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

Table 4-3 and Figure 4-3 show that the current CEMR projection for non-manufacturing employment is stronger than in 2013. In CEMR2015, the projection of non-manufacturing employment for 2014 is about 3,000 employees (or 0.13 percent) lower than in CEMR2013. However, in 2015 this gap becomes positive and non-manufacturing employment increases to about 11,200 employees (or 0.47 percent) higher than projected in CEMR2013. From 2016 on, CEMR2015 exhibits even higher growth than previously estimated and employment in this sector continues to be higher than previously expected levels.

Figure 4-3 illustrates the comparison between past and current projections for employment in non-manufacturing. CEMR2015 exhibits stronger growth and remains above CEMR2013 after the first year of the forecast horizon.

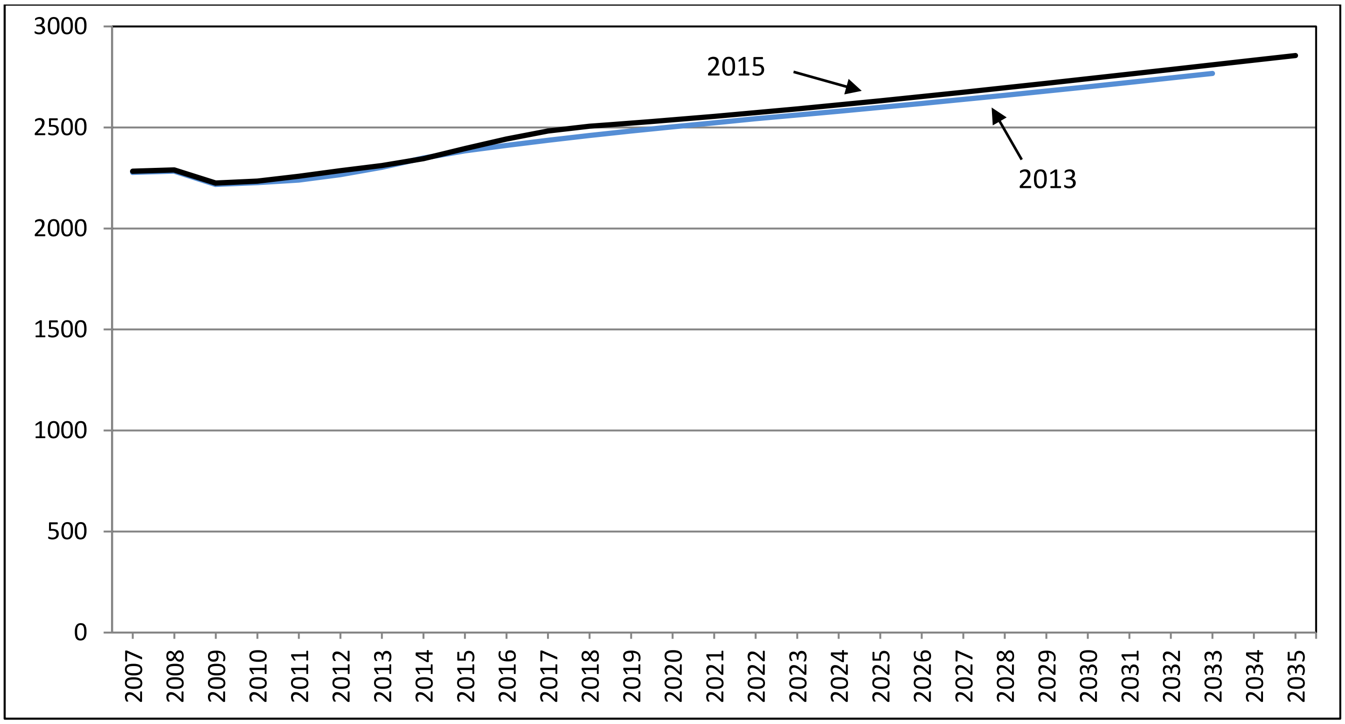
Table 4-3. 2013 and 2015 CEMR Projections for Indiana Non-manufacturing Employment

	Year										
	2010	2011	2012	2013	2014	2015	2016	2017	2020	2025	2033
	Thousands of persons										
CEMR2013	2226.6 (0.38)	2239.4 (0.58)	2266.5 (1.21)	2303.1 (1.62)	2348.8 (1.98)	2384.0 (1.50)	2411.2 (1.14)	2436.6 (1.06)	2503.1 (0.84)	2599.5 (0.73)	2767.5 (0.81)
CEMR2015	2234.1 (0.42)	2258.3 (1.08)	2285.8 (1.22)	2311.5 (1.13)	2345.8 (1.48)	2395.2 (2.11)	2443.2 (2.00)	2482.7 (1.62)	2538.0 (0.65)	2632.6 (0.80)	2810.2 (0.82)
Percentage change between two projections	0.34	0.85	0.85	0.37	-0.13	0.47	1.33	1.89	1.39	1.27	1.54

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: Numbers in parentheses indicate percentage change at annual rate

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



Real Personal Income

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

Table 4-4 and Figure 4-4 show the CEMR projections of real personal income. CEMR2015 has a higher projection for real personal income during the entire forecast period (2014-2033) than CEMR2013. CEMR2015 indicates real personal income $4.9 billion (2.09 percent) higher than CEMR2013 in 2014 growing to $13.9 billion (3.90 percent) higher by the end of the forecast period in 2033.

Figure 4-4 illustrates that the CEMR2015 real personal income is projected to be higher than CEMR2013 and to grow at a steady rate over the entire forecast horizon.

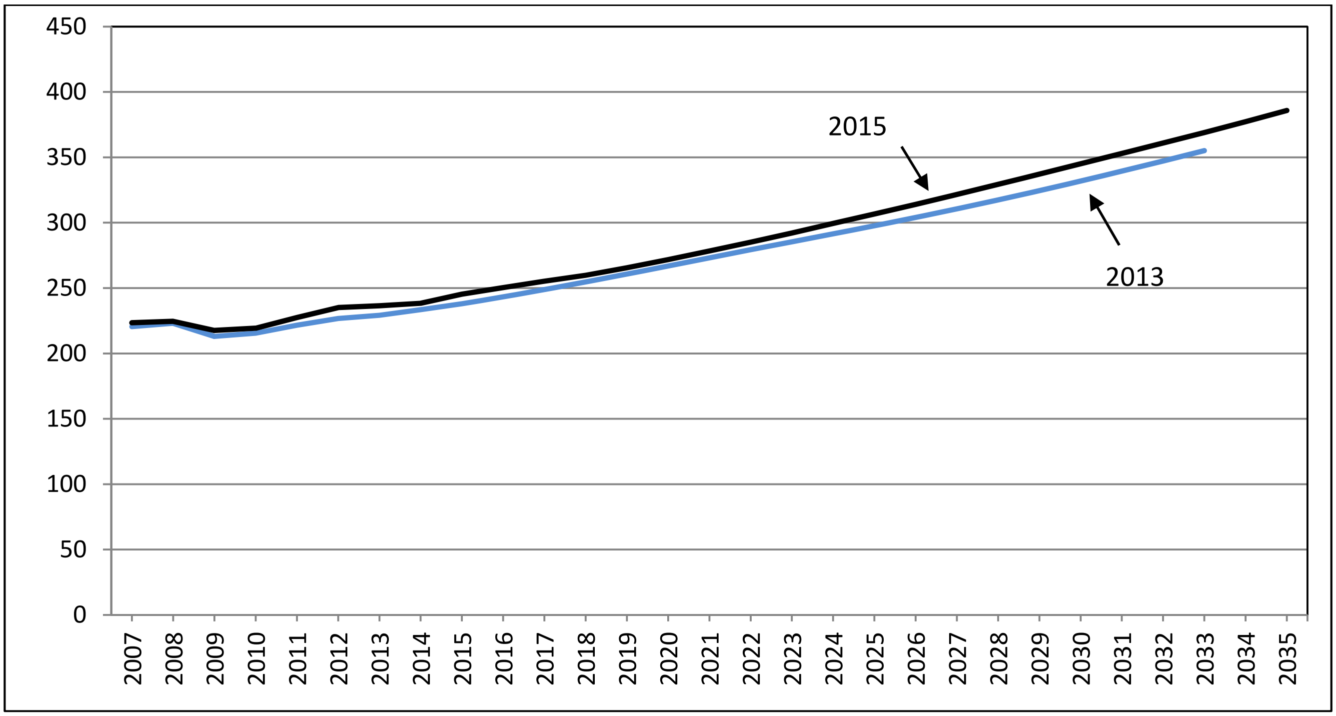
Table 4-4. 2013 and 2015 CEMR Projections for Indiana Real Personal Income

	Year										
	2010	2011	2012	2013	2014	2015	2016	2017	2020	2025	2033
	Billions of 2009 $										
CEMR2013	215.52 (1.17)	221.57 (2.81)	226.80 (2.36)	229.16 (1.04)	233.50 (1.89)	237.96 (1.91)	243.13 (2.17)	248.90 (2.38)	266.87 (2.33)	297.67 (2.13)	355.07 (2.27)
CEMR2015	219.26 (0.76)	227.53 (3.77)	235.07 (3.31)	236.45 (0.59)	238.37 (0.81)	245.30 (2.90)	250.39 (2.07)	255.27 (1.95)	271.79 (2.37)	306.67 (2.42)	368.92 (2.24)
Percentage change between two projections	1.74	2.69	3.65	3.18	2.09	3.08	2.99	2.56	1.84	3.02	3.90

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: Numbers in parentheses indicate percentage change at annual rate

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



Real Manufacturing Gross State Product

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

Table 4-5 and Figure 4-5 show the CEMR projections for real manufacturing GSP. As the figure illustrates, after not increasing in 2008 and 2009, real manufacturing GSP showed growth in 2010. Due to a data revision involving the historical GSP from the transportation equipment industry, the CEMR2015 projection for the entire forecast period is significantly higher than CEMR2013. The projection for 2014 is over $14.8 billion (18.89 percent) higher than the CEMR2013 level for that year. The CEMR2015 projections remain significantly higher than CEMR2013 for the entire forecast period.

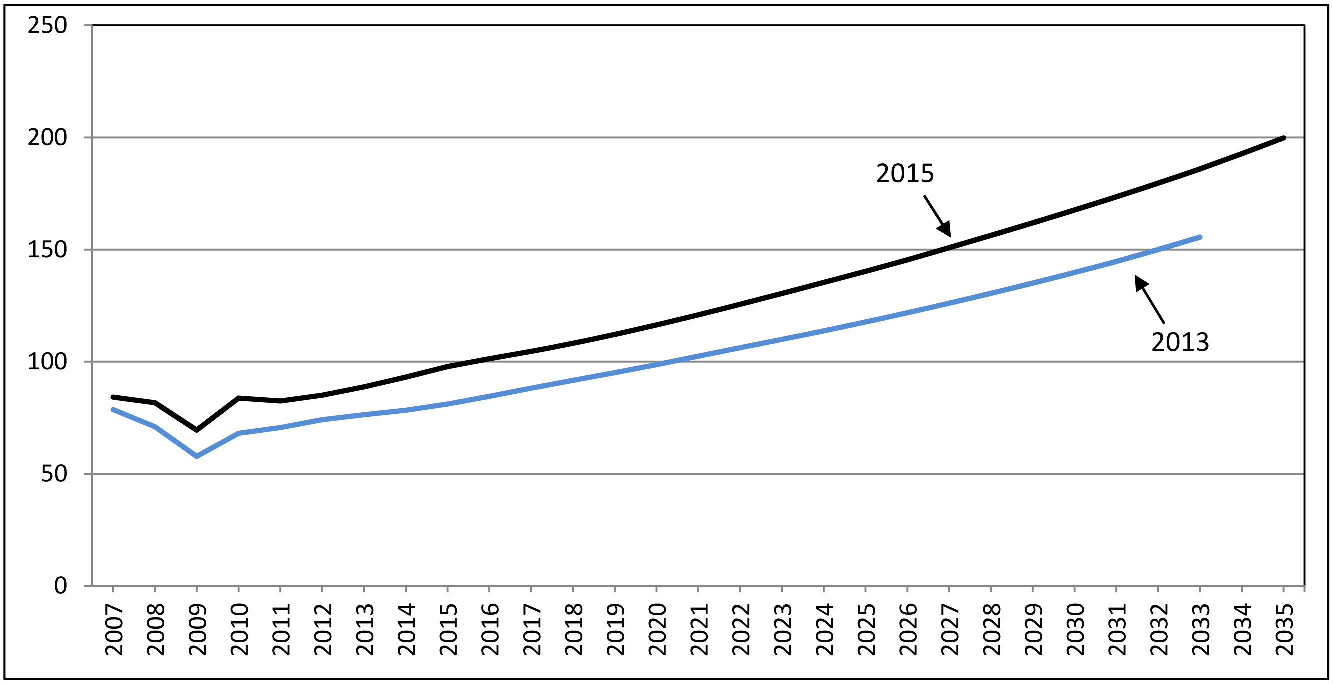
Table 4-5. 2013 and 2015 CEMR Projections for Indiana Real Manufacturing GSP

	Year										
	2010	2011	2012	2013	2014	2015	2016	2017	2020	2025	2033
	Billions of 2009 $										
CEMR2013	67.99 (17.80)	70.62 (3.86)	74.10 (4.94)	76.32 (2.99)	78.28 (2.57)	81.09 (3.59)	84.52 (4.22)	88.15 (4.29)	98.67 (3.78)	117.63 (3.47)	155.51 (3.70)
CEMR2015	83.76 (20.56)	82.46 (-1.55)	84.98 (3.06)	88.72 (4.40)	93.08 (4.91)	97.77 (5.05)	101.31 (3.62)	104.6 (3.24)	116.35 (3.77)	140.27 (3.62)	185.94 (3.58)
Percentage change between two projections	23.19	16.77	14.68	16.24	18.89	20.57	19.87	18.66	17.92	19.24	19.57

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: Numbers in parentheses indicate percentage change at annual rate

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



Transportation Equipment Industry

The transportation equipment industry, including automobile and auto parts manufacturing, accounts for a considerable portion of the total manufacturing GSP in Indiana. In 2013, this sector represented 30 percent of the total real value of products manufactured in the state.

SUFG felt that CEMR's forecast showed too much growth over the long term for this sector (as in CEMR2011 and CEMR2013 before), so the forecast was again tempered. However, although the forecast growth rate was tempered the levels are still significantly higher, approximately double, than in the 2013 forecast due to the revision of some historical numbers. The "CEMR2015 Adjusted" projection calls for growth over the forecast period 2014-2033 of an annual rate of approximately 3.7 percent.

Table 4-6 shows projected growth rates, actual values and percentage rate changes for the transportation equipment industry and includes the comparison between the adjusted CEMR2013 and adjusted CEMR2015 projections. The table indicates that the recession had a significant impact on the performance of the automobile sector but it rebounded strongly in 2010 with a 213 percent gain. The industry is projected to keep recovering from the recession for the entire forecast period.

Primary Metals Industry

While the primary metals industry, including production of steel and aluminum, represented approximately 6.9 percent of Indiana manufacturing GSP in 2013, it accounted for 32 percent of the state's industrial electricity sales.

Table 4-7 compares the CEMR projections for 2013 and 2015 for the primary metals industry, which saw an increase of over 36 percent between 2009 and 2010 followed by a decrease of more than 22 percent in 2011, about a 24 percent increase in 2012 and slight decline in 2013. The primary metals industry is projected to be slightly decreasing from 2013-2018 before showing steadily increasing output for the remainder of the forecast period. The CEMR2015 projections for the primary metals industry are lower than the CEMR2013 projections were.

Table 4-6. 2013 and 2015 Adjusted CEMR Projections for Indiana Real Transportation Equipment GSP

	Year										
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2020**	**2025**	**2033**
	Billions of 2009 $										
CEMR2013 Adjusted	8.24 (194.69)	9.25 (12.19)	9.70 (4.94)	9.99 (2.99)	10.25 (2.57)	10.62 (3.59)	11.07 (4.22)	11.54 (4.29)	12.92 (3.78)	15.40 (3.47)	20.36 (3.70)
CEMR2015 Adjusted	15.31 (212.79)	16.00 (4.55)	16.95 (5.94)	18.62 (9.83)	19.54 (4.91)	20.52 (5.05)	21.26 (3.62)	21.95 (3.24)	24.42 (3.77)	29.44 (3.62)	39.03 (3.58)
Percentage change between two projections	85.75	73.09	74.74	86.34	90.59	93.27	92.16	90.22	89.03	91.15	91.67

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: Numbers in parentheses indicate percentage change at annual rate

Table 4-7. 2013 and 2015 CEMR Projections for Indiana Real Primary Metals GSP

	Year										
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2020**	**2025**	**2033**
	Billions of 2009 $										
CEMR2013	6.15 (24.50)	6.42 (4.46)	6.63 (3.32)	6.62 (-0.24)	6.48 (-2.04)	6.41 (-1.15)	6.37 (-0.60)	6.49 (1.82)	6.78 (1.49)	7.20 (1.07)	7.83 (1.14)
CEMR2015	5.63 (36.66)	4.37 (-22.44)	5.40 (23.67)	5.26 (-2.68)	5.21 (-0.99)	5.20 (-0.10)	5.13 (-1.41)	5.02 (-2.03)	5.05 (1.37)	5.38 (0.88)	5.71 (0.64)
Percentage change between two projections	-8.36	-31.96	-18.57	-20.55	-19.70	-18.85	-19.51	-22.56	-25.52	-25.28	-27.11

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: Numbers in parentheses indicate percentage change at annual rate

Forecast Uncertainty

There are three sources of uncertainty in any energy forecast:

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

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

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

In practice, virtually all models are less than perfect. Non-stochastic model error results from specification errors, measurement errors and/or use of inappropriate estimation methods.

References

Center for Econometric Model Research, "Long-Range Projections 2014-2035," Indiana University, February 2015.

Energy Information Administration, "Annual Energy Outlook 2015," April 2015.

Chapter 5

Residential Electricity Sales

Overview

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

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

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

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

Historical Perspective

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

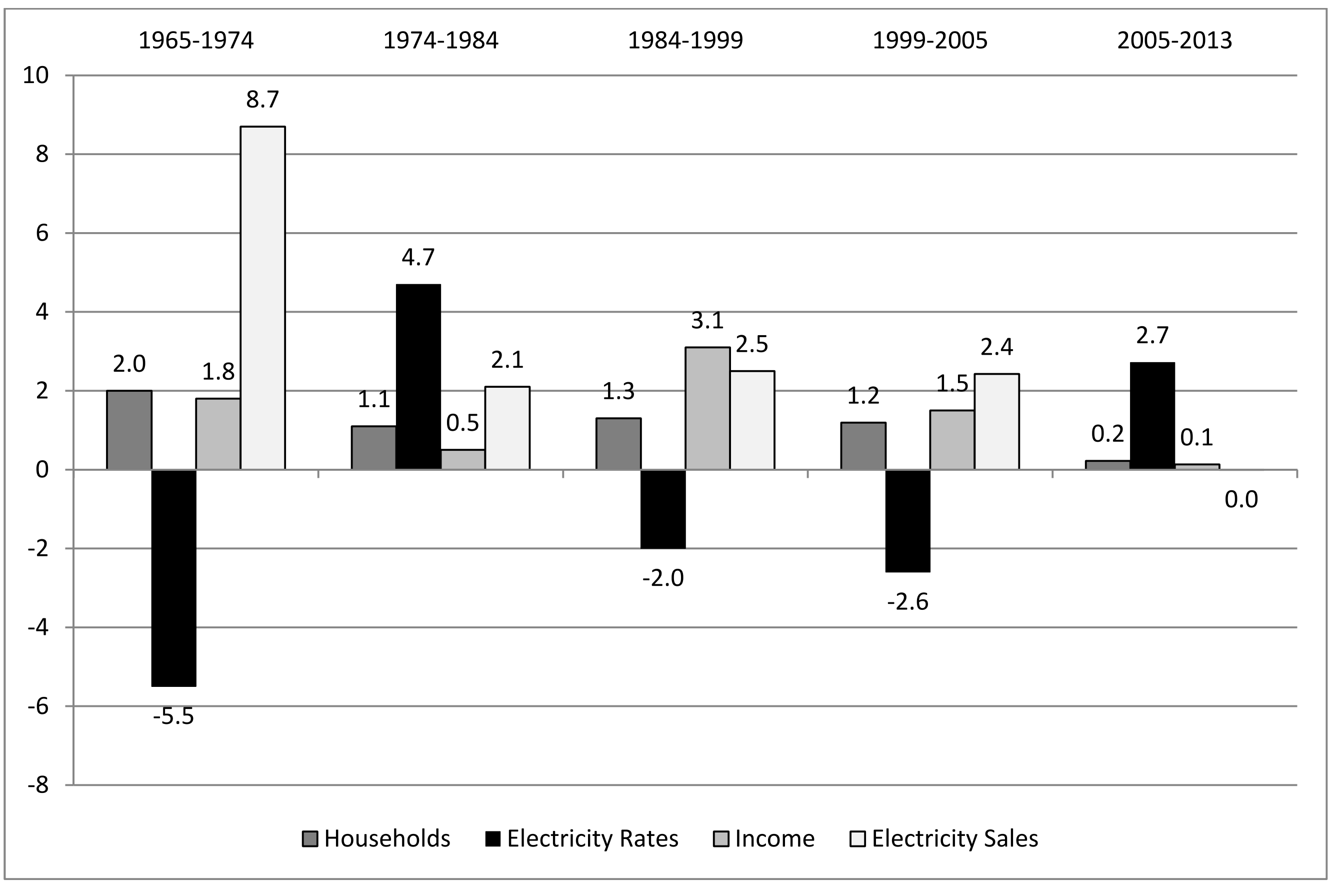
The explosion in residential electricity sales (nearly 9 percent per year) during the decade prior to the Organization of Petroleum Exporting Countries (OPEC) oil embargo in 1974 coincided with the economic stimuli of falling prices (nearly 6 percent per year in real terms) and rising incomes (almost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

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

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

More recently, from 2005-2013, the effects of the economic downturn coupled with rising electricity prices have resulted in much lower growth in electricity sales. Growth of the number of households slowed to one-sixth the rate observed over the preceding twenty years. Real electricity prices increased at an average annual rate of 2.7 percent, reversing the trend of the previous twenty years. Real household income increased at only 0.1 percent over the period, one tenth the rate observed during the previous period. The net effect of these changes was to reduce the electricity sales growth rate to essentially flat over the period.

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



Model Description

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

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

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

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

where

* = multiplication operator;

T = forecast year;

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

t = dwelling vintage (year);

U = utilization, relative to some base year;

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

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

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

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

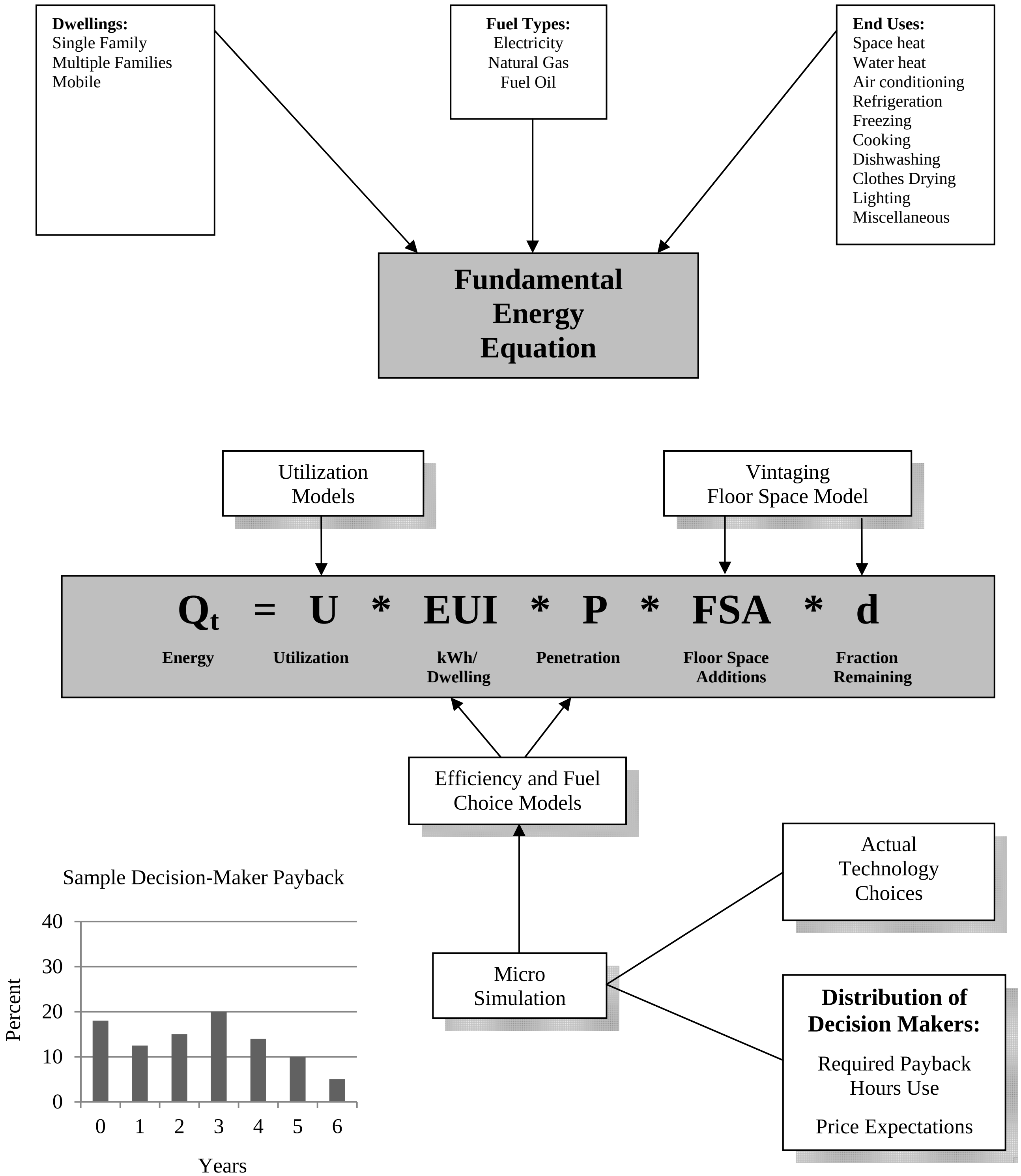
REDMS' central features are its explicit representation of the joint nature of decisions regarding fuel choice, efficiency choice and the level of end-use service, as well as its explicit representation of costs and energy use characteristics of available end-use technologies in these decisions.

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

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

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

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



Summary of Results

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

Model Sensitivities

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

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

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

Table 5-1. Residential Model Long-Run Sensitivities

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

Indiana Residential Electricity Sales Projections

Actual sales (GWh), as well as past and current projections, are shown in Table 5-2 and Figure 5-3. The growth rate for the current base projection of Indiana residential electricity sales is 0.64 percent, which is 0.27 percent higher than SUFG's 2013 projection of 0.37 percent. The historic and 2015 forecast numbers are provided in the Appendix of this report. Long-term patterns for the entire forecast horizon show that the current projection lies well below the 2011 projection but above the 2013 projection after 2016. Table 5-3 summarizes SUFG's base projections of residential electricity sales growth since 2011.

Table 5-3 breaks these projections down by the portion of the growth rate attributable to the growth in number of customers and growth in utilization per customer, with and without DSM. As the table shows, customer growth is partially offset by decreases in utilization, which is the amount of energy used per household. Use per household decreases because of increasing prices and the implementation of new efficiency standards. It can also be seen from the table that residential DSM cuts the sales growth rate by approximately 11%, reducing it from 0.72 percent to 0.64 percent. It should be noted that the 2015 base case has less DSM impact than the 2013 base case had due to the elimination of the IURC DSM requirements in 2014.

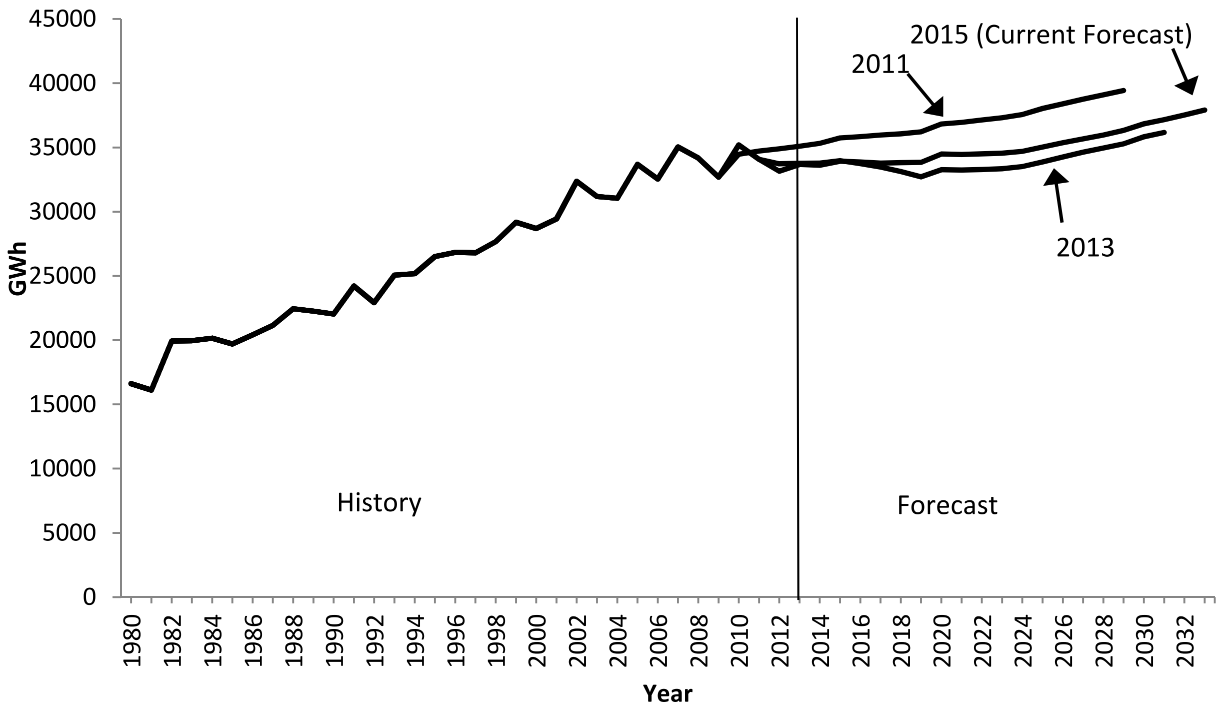
Table 5-4 shows the growth rates of the major residential drivers for the current scenarios and the 2013 base case. Household formation is determined by two factors. Demographic projections are the primary determinant, with personal income having a smaller impact. The demographic projections in all four cases are very similar. While there are some small variations in personal income among the cases, they are not sufficiently large as to result in a significant difference in growth rates for the base and high scenarios.

As shown in Table 5-5 and Figure 5-4, the growth rates for the high and low residential scenarios are about 0.04 percent higher and 0.08 lower, respectively, than the base scenario. This difference is due primarily to differences in the growth of household income.

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

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2015	0.64	2014-2033
2013	0.37	2012-2031
2011	0.71	2010-2029

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



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

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

Forecast	No. of Customers	Without DSM		With DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2015 SUFG Base (2014-2033)	1.07	-0.35	0.72	-0.43	0.64
2013 SUFG Base (2012-2031)	1.17	-0.32	0.85	-0.80	0.37
2011 SUFG Base (2010-2029)	1.00	-0.23	0.77	-0.29	0.71

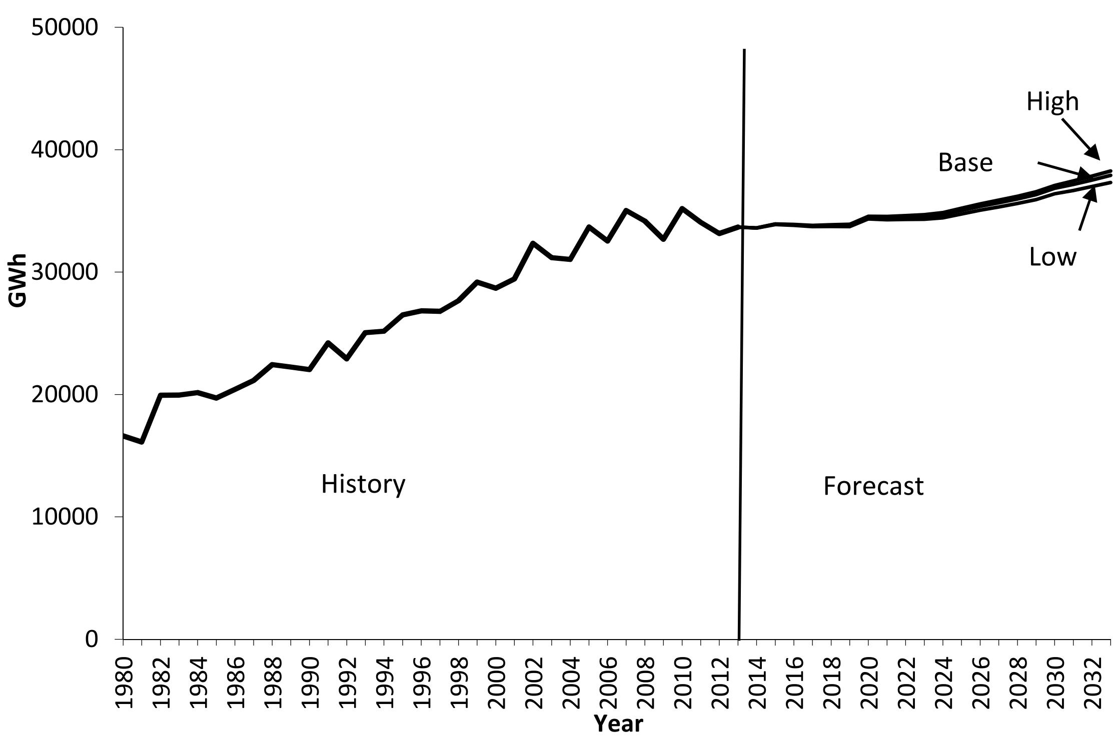
Table 5-4. Residential Model Explanatory Variables - Growth Rates by Forecast (Percent)

Forecast	Current Scenario (2014-2033)			2013 Forecast (2012-2031)
	Base	Low	High	Base
No. of Customers	1.07	1.06	1.08	1.17
Electric Rates	1.32	1.50	1.16	1.34

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

Average Compound Growth Rates			
Forecast Period	Base	Low	High
2014-2033	0.64	0.56	0.68

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



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

Indiana Residential Electricity Price Projections

Historical values and current projections of residential electricity prices are shown in Figure 5-5, with growth rates provided in Table 5-6. In real terms, residential electricity prices declined from the mid-1980s until 2002. Real residential electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real residential electricity prices to rise until 2021, due to the need for additional emissions control equipment, and then to remain relatively constant. SUFG's real price projections for the individual IOUs all follow the same patterns as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 5-5. Indiana Residential Base Real Price Projections (in 2013 Dollars)

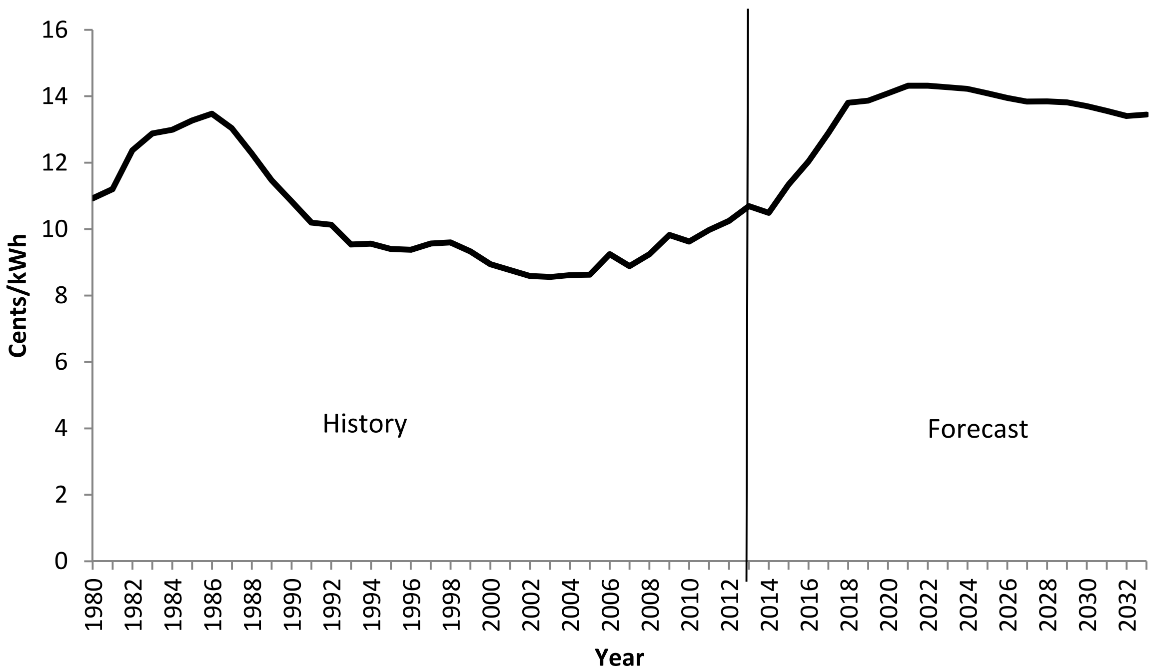


Table 5-6. Indiana Residential Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	3.96
1985-1990	-3.98
1990-1995	-2.80
1995-2000	-0.99
2000-2005	-0.72
2005-2013	2.72
2014-2033	1.32

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

Chapter 6

Commercial Electricity Sales

Overview

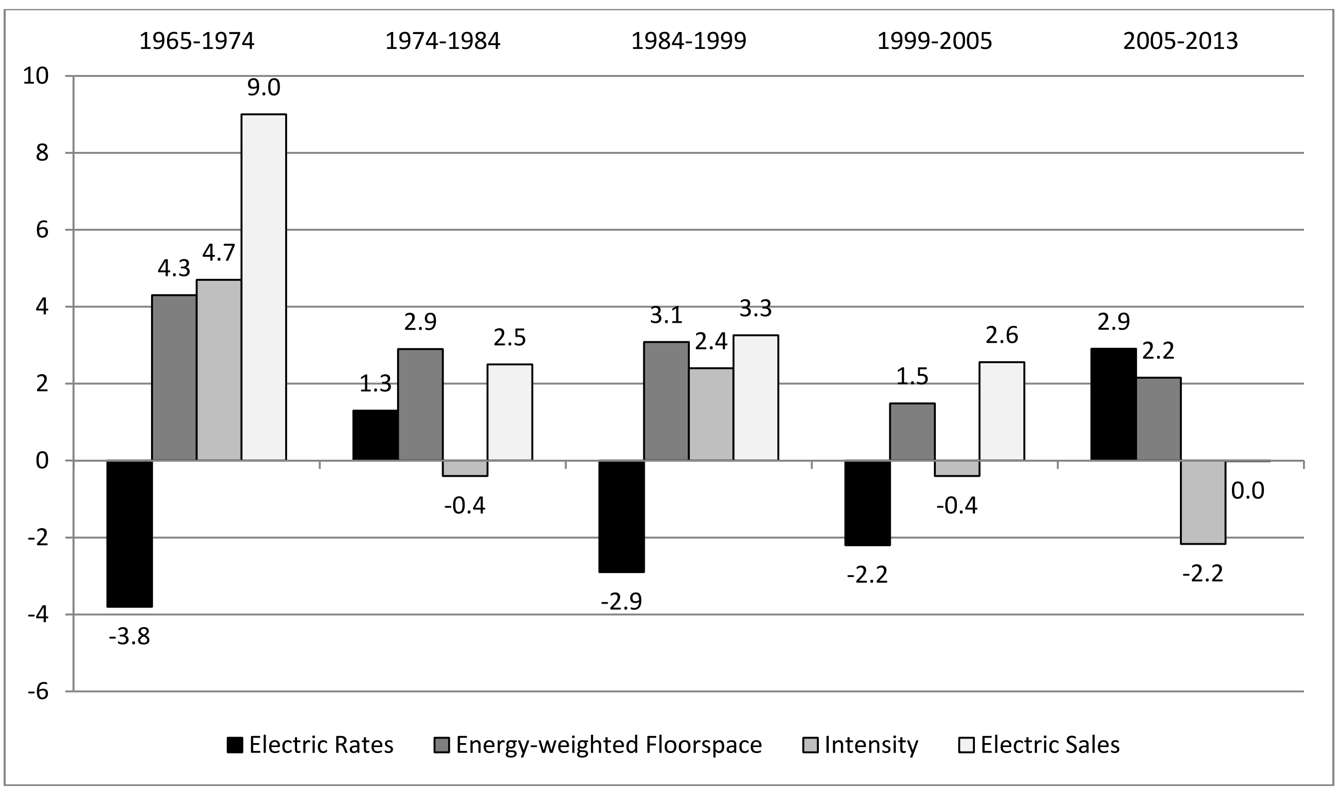
SUFG has two distinct models of commercial electricity sales, econometric and end-use. Both have specific strengths and complement each other. SUFG staff developed the econometric model and acquired a proprietary end-use model, Commercial Energy Demand Modeling System (CEDMS). CEDMS is a descendant of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

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

Historical Perspective

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

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



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

Over the 1999-2005 timeframe, a decrease in economic activity retarded growth in the stock of commercial floor space, led to negative growth in intensity of electricity use, and slowed growth in electricity sales despite continued declines in real electricity prices. Recently the current recession coupled with increasing real electricity prices has accelerated these trends, with the notable exception of the stock of commercial floor space. For 2005-2013 real electricity prices have risen, commercial floor space grew at a slightly faster rate than that observed during the previous few years, with intensity of electricity use continuing to decline, and commercial sector electricity use stagnating.

Model Description

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

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

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

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

where

* = multiplication operator;

T = forecast year;

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

t = building vintage (year);

U = utilization, relative to some base year;

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

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

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

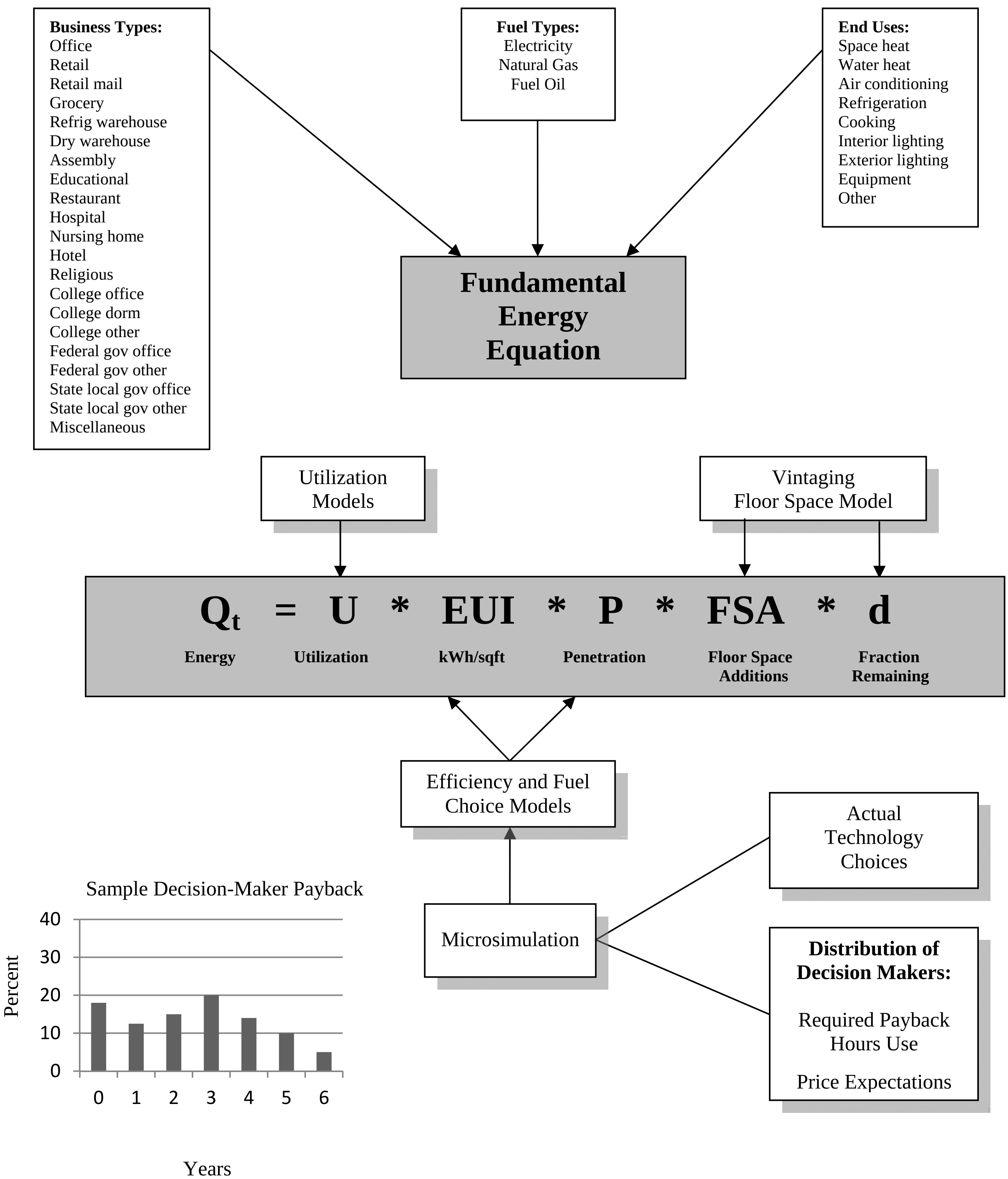
d = fraction of floor space of vintage t still standing in forecast year T.

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

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

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

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



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

Summary of Results

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

Model Sensitivities

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

Table 6-1. Commercial Model Long-Run Sensitivities

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

Indiana Commercial Electricity Sales Projections

Historical data as well as past and current projections are illustrated in Table 6-2 and Figure 6-3. As can be seen, the current base projection of Indiana commercial electricity sales growth is 0.59 percent. As shown in Figure 6-3, the current projection still lies well below the 2011 forecast but is higher than 2013 forecast, despite having slightly lower growth in floor space. The major difference between the 2013 and the 2015 forecasts is the amount of DSM included. The 2013 forecast had higher levels of DSM in order to meet the IURC's DSM requirements, which were eliminated in 2014.

The growth rates for the major explanatory variables are shown in Table 6-3. Table 6-4 summarizes SUFG's base projections of commercial electricity sales growth for the last three SUFG forecasts. The historical and 2015 forecast values are provided in the Appendix of this report.

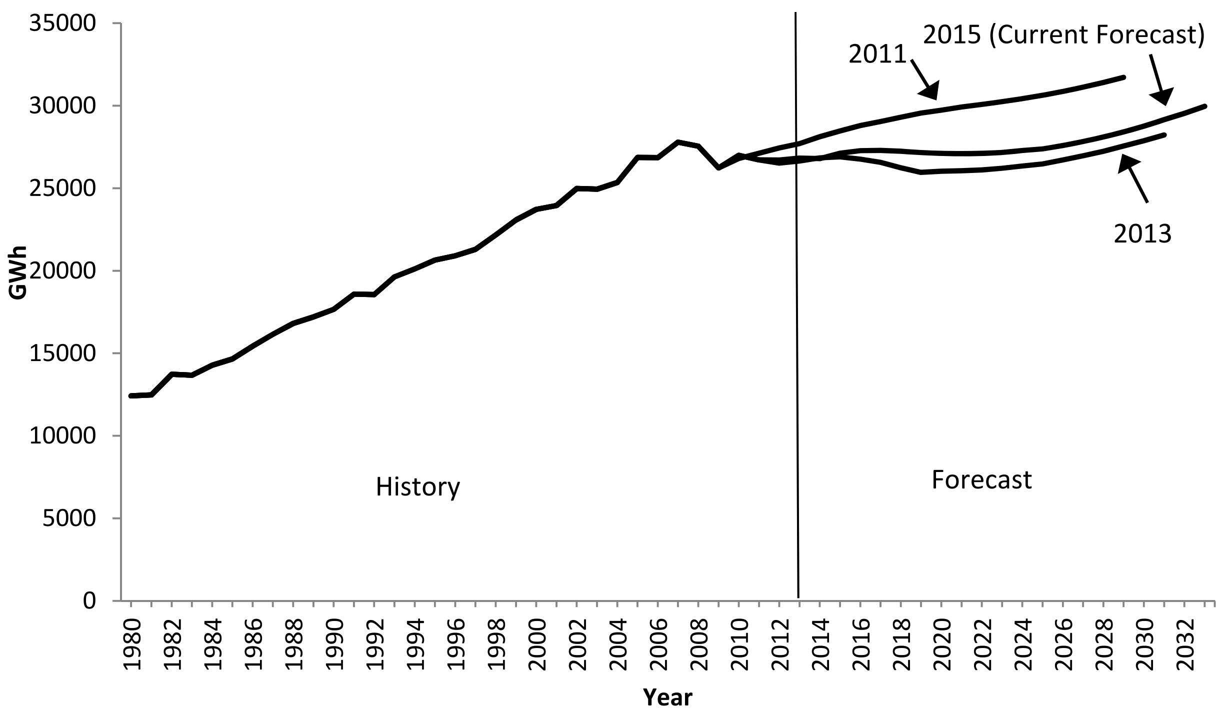
Floor space growth is partially offset by decreases in utilization. Utilization, the amount of energy used per unit of floor space, decreases because of increasing electricity prices and the implementation of new efficiency standards. Incremental DSM programs also have an effect on electricity sales.

As shown in Table 6-5 and Figure 6-4, the growth rates for the low and high scenarios are about 0.48 percent lower and 0.47 percent higher than the base scenario, respectively. These differences are almost entirely due to a difference in floor space growth.

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

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2015	0.59	2014-2033
2013	0.33	2012-2031
2011	0.89	2010-2029

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



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

Table 6-3. Commercial Model – Growth Rates (Percent) for Selected Variables (2015 SUFG Scenarios and 2013 Base Forecast)

Forecast	Current Scenario (2014-2033)			2013 Forecast (2012-2031)
	Base	Low	High	Base
Electric Rates	1.35	1.50	1.21	1.43
Natural Gas Price	1.04	1.04	1.04	1.56
Energy-weighted Floor Space	0.84	0.77	0.92	0.90

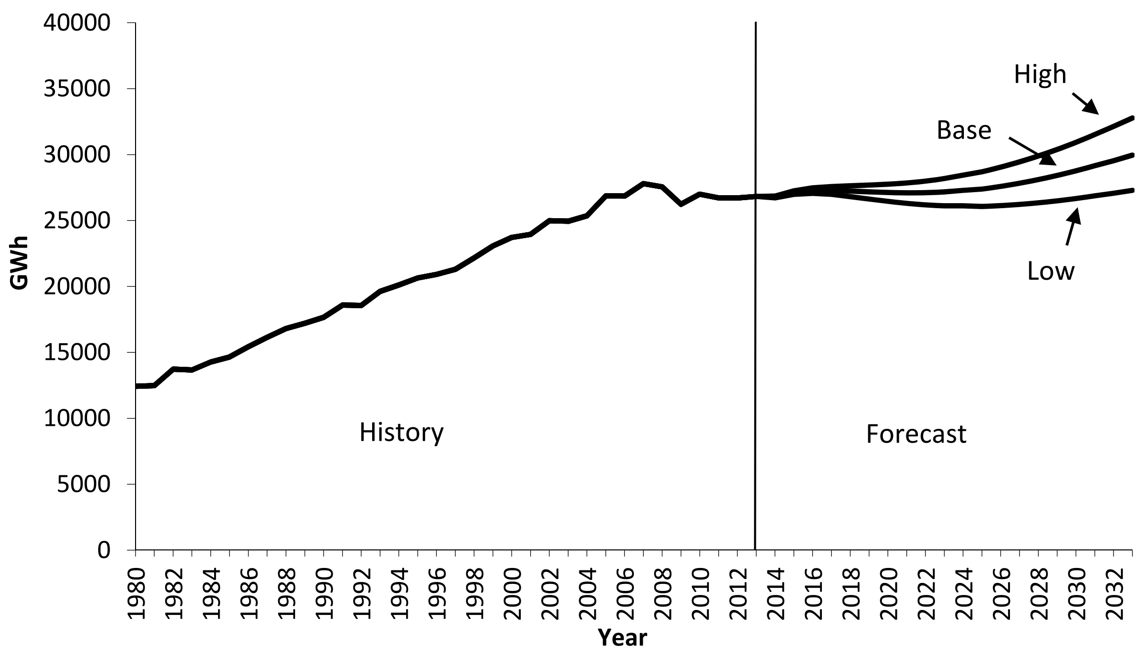
Table 6-4. History of SUFG Commercial Sector Growth Rates (Percent)

Forecast	Electric Energy-weighted Floor Space	Without DSM		With DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2015 SUFG Base (2014-2033)	0.84	-0.13	0.71	-0.25	0.59
2013 SUFG Base (2012-2031)	0.90	-0.07	0.83	-0.57	0.33
2011 SUFG Base (2010-2029)	1.18	-0.23	0.95	-0.29	0.89

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

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2014-2033	0.59	0.11	1.06

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



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

Indiana Commercial Electricity Price Projections

Historical values and current projections of commercial electricity prices are shown in Figure 6-5, with growth rates provided in Table 6-6. The historical and forecast numbers are provided in the Appendix of this report. In real terms, commercial electricity prices declined from the mid-1980s until 2002. Real commercial electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real commercial electricity prices to rise until 2021 with the need for additional emissions control equipment and then remain relatively constant. SUFG's real price projections for the individual IOUs all follow the same pattern as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 6-5. Indiana Commercial Base Real Price Projections (in 2013 Dollars)

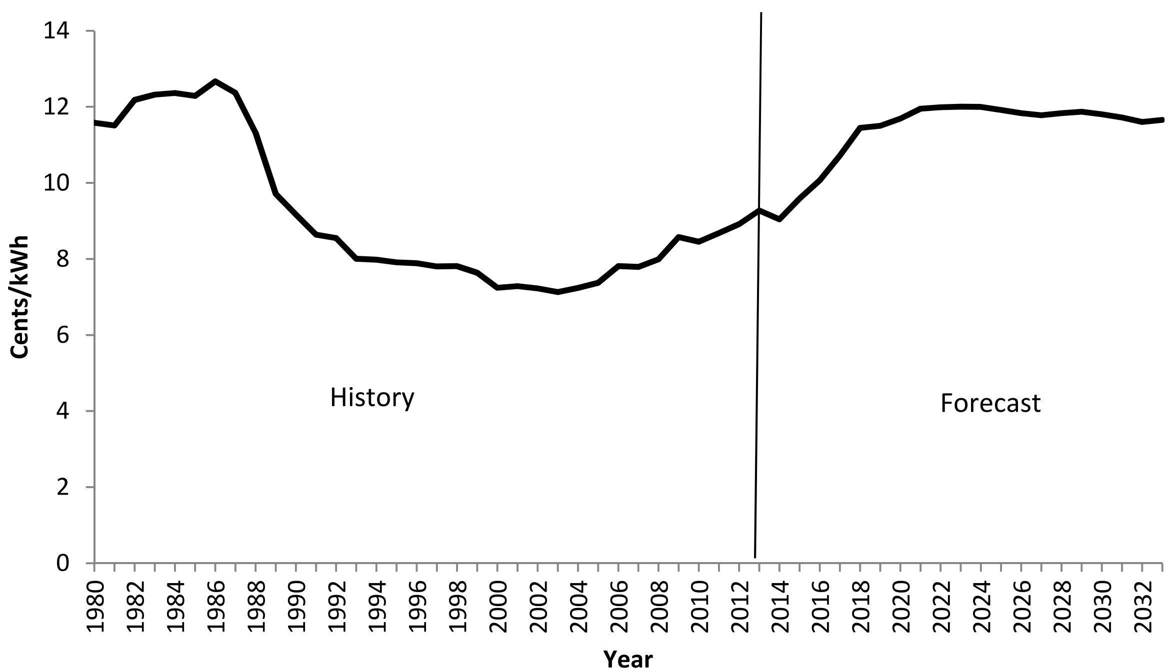


Table 6-6. Indiana Commercial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	1.19
1985-1990	-5.69
1990-1995	-2.90
1995-2000	-1.75
2000-2005	0.36
2005-2013	2.91
2014-2033	1.35

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

Chapter 7

Industrial Electricity Sales

Overview

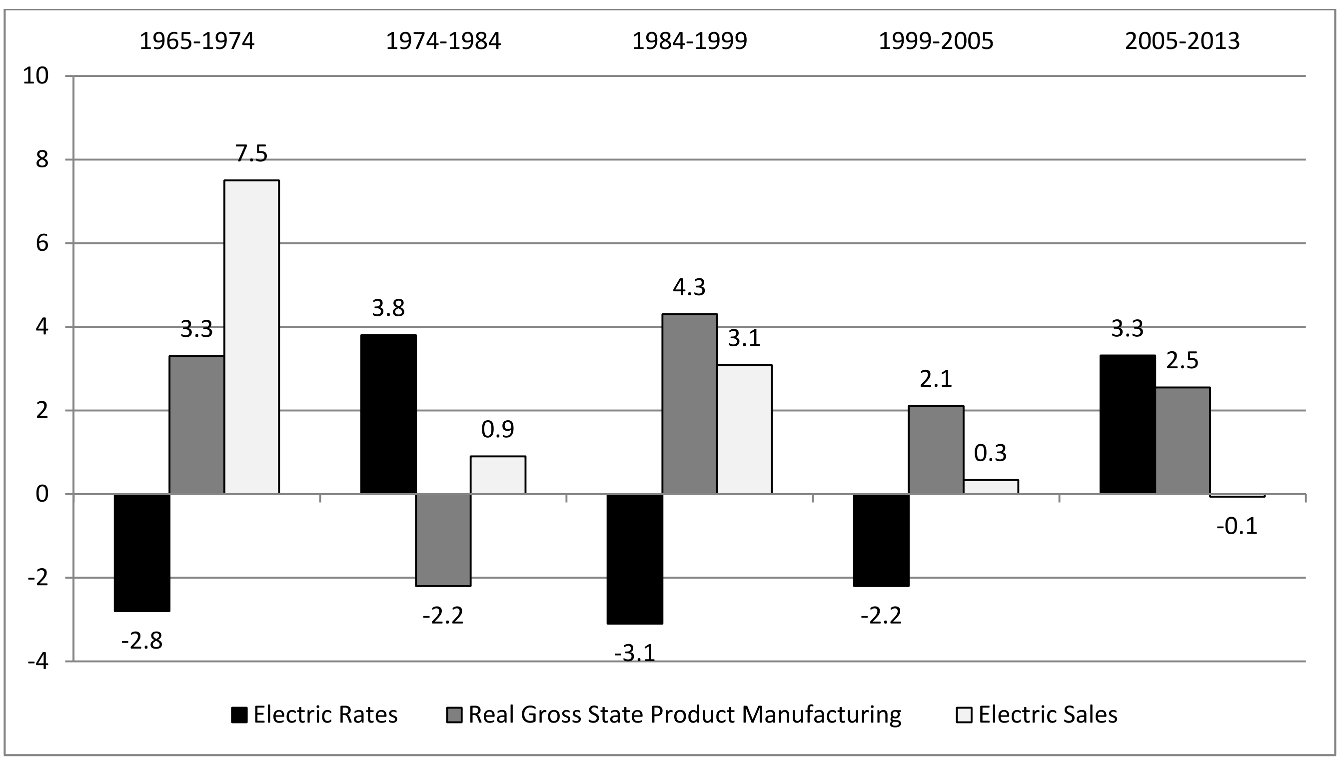
SUFG has used several models to analyze and forecast electricity use in the industrial sector. The primary forecasting model is INDEED, an econometric model developed by the Electric Power Research Institute (EPRI), which is used to model the electricity use of 15 major industry groupings in the state.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

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

Historical Perspective

SUFG distinguishes five recent periods of distinctly different economic activity and growth - 1965-1974, 1974-1984, 1984-1999, 1999-2005, and the more recent period 2005-2013. Figure 7-1 shows state growth rates for real manufacturing product, real electric rates and electric energy sales for the five periods.

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



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

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

Model Description

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

Each model is driven by projections of selected industrial GSP over the forecast horizon provided by CEMR. Each industry's share of GSP is given in the first column of Table 7-1. Over 69 percent of state GSP is accounted for by the following industries: primary metals, 7 percent; fabricated metals, 5 percent; industrial machinery and equipment, 7 percent; chemicals, 15 percent; transportation equipment, 30 percent; and electronic and electric equipment, 5 percent.

The share of total electricity consumed by each industry is shown in the second column of Table 7-1. Both the chemical and primary metals industries are very electric-intensive industries. Combined, they account for 52% of total state industrial electricity use. Column four gives the current base output projections for the major industries obtained from the most recent CEMR forecast. As explained in Chapter 4, CEMR projections are developed using econometric models of the U.S. and Indiana economies. Manufacturing sector GSP projections are obtained by multiplying sector employment projections by a projection of GSP per employee, a measure of labor productivity.

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

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

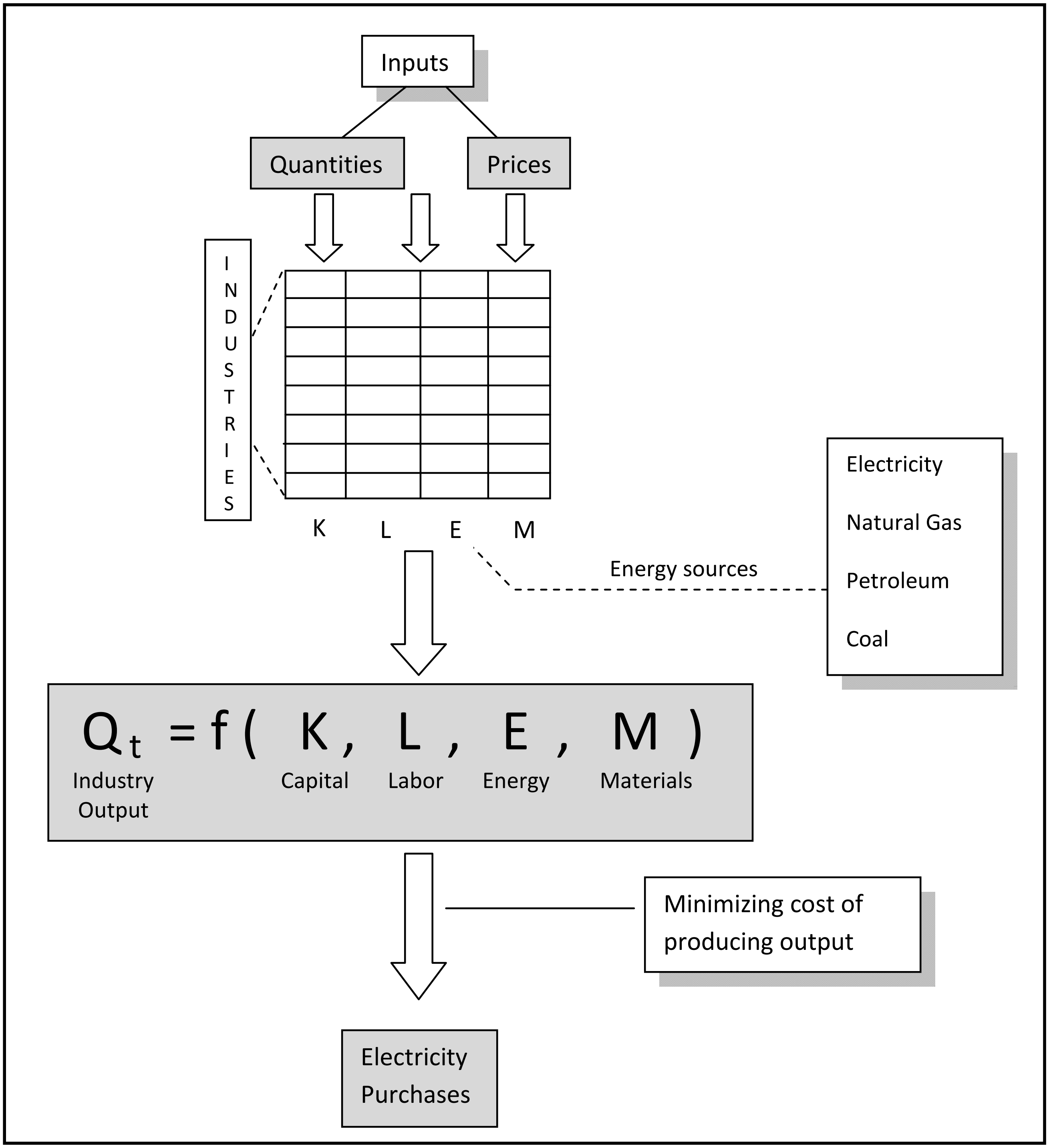
As described earlier in this chapter, INDEED captures the competition between the various inputs for their share of the cost of production by assuming firms seek the mix of inputs that minimize the production cost for a given level of output. Unit costs of natural gas, oil, coal, capital, labor and materials are inputs to the SUFG system, while the cost per kWh of electricity is determined by the SUFG modeling system. For fuel prices SUFG uses the current EIA forecast, which assumes that real natural gas prices, which dropped by 29 percent from 2008 to 2014, will decline by about 12 percent in 2015, before steadily increasing after that resulting in a projected increase at a rate of about 1.2 percent per year over the forecast horizon 2014-2033. Distillate fuel prices were also high in 2008, before falling sharply by 42 percent in 2009, and were then 58 percent higher in 2014. They are projected to decline by about 28 percent in 2015 before generally increasing at a rate of about 2.1 percent per year over the remainder of the forecast period. Unit costs for capital, labor and materials are consistent with the assumptions contained in the CEMR forecast of Indiana output growth. The changes in electricity intensities, expressed as a percent change in kWh per dollar of GSP, are shown in column five of Table 7-1. With all but one (primary metals) of the intensities expected to decrease, industry-wide electricity intensity is expected to decline over the forecast horizon.

The last column of Table 7-1 contains the projected annual percent increase in electricity sales by major industry. This projected increase is the sum of changes in GSP and kWh/GSP for each industry. Average industrial electricity use across all sectors in the base scenario is expected to increase at an average of 1.94 percent per year, without DSM, over the forecast horizon.

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

SIC	Name	Current Share of GSP	Current Share of Electricity Sales	Current Intensity	Forecast Growth in GSP Originating by Sector	Forecast Growth in Electricity by Intensity by Sector	Forecast Growth in Electricity Sales by Sector
20	Food & Kindred Products	4.31	6.40	0.53	3.46	-1.01	2.44
24	Lumber & Wood Products	2.40	0.69	0.10	3.46	-0.71	2.75
25	Furniture & Fixtures	2.90	0.39	0.05	1.76	-1.36	0.40
26	Paper & Allied Products	1.66	2.80	0.60	3.46	-1.04	2.42
27	Printing & Publishing	3.14	1.14	0.13	3.46	-1.86	1.60
28	Chemicals & Allied Products	14.96	19.76	0.47	3.46	-1.30	2.16
30	Rubber & Misc. Plastic Products	2.83	5.92	0.75	3.44	-0.95	2.48
32	Stone, Clay, & Glass Products	2.94	5.07	0.62	1.76	-0.81	0.95
33	Primary Metal Products	6.92	32.25	1.67	0.48	1.15	1.63
34	Fabricated Metal Products	4.72	5.56	0.42	3.22	-1.20	2.02
35	Industrial Machinery & Equipment	6.95	4.28	0.22	2.57	-1.12	1.44
36	Electronic & Electric Equipment	4.98	2.56	0.18	1.20	-0.58	0.61
37	Transportation Equipment	30.25	7.75	0.09	3.67	-1.11	2.56
38	Instruments And Related Products	3.94	1.02	0.09	1.76	-1.81	-0.05
39	Miscellaneous Manufacturing	2.13	1.09	0.18	1.76	-3.04	-1.29
Total	Manufacturing	100.00	100.00	0.36	3.02	-1.08	1.94

Figure 7-2. Structure of Industrial Energy Modeling System



Summary of Results

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

Model Sensitivities

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

Table 7-2. Industrial Model Long-Run Sensitivities

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

Indiana Industrial Electricity Sales Projections

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

The impact of industrial sector DSM programs on growth rates for the 2011, 2013, and current forecasts is displayed in Table 7-4. The table also disaggregates the impact on energy growth of output, changes in the mix of output and electricity intensity. Industrial sector DSM programs are expected to have less impact on retail sales than their residential and commercial counterparts, due in part to industrial customers having the ability to opt out. The effect of earlier conservation activities are embedded in the historical data and SUFG's projections.

The current forecast projects that industrial sector electricity sales will grow from the 2013 level of approximately 40,000 GWh to over 59,000 GWh by 2033. This growth rate of 1.90 percent per year is substantially higher than both the 0.59 percent rate projected for the commercial sector and the 0.64 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast, while higher than the 2011 forecast for the first few years, is still below the 2011 forecast for the remainder of the forecast period. The current forecast, however, lies above the 2013 forecast for the entire forecast horizon. The macroeconomic drivers for the 2015 forecast, while somewhat higher than the 2013 forecast, are not as strong as in previous projections. This, combined with changes in intensity resulting from different expected prices, results in a forecast that lies between the previous two.

Table 7-5 and Figure 7-4 shows how industrial electricity sales differ by scenario. Industrial sales, in the high scenario, are expected to increase to 65,920 GWh by 2033, 11.1 percent higher than the base projection. In the low scenario, industrial sales grow more slowly, which results in 53,169 GWh sales by 2033, 10.4 percent below the base scenario.

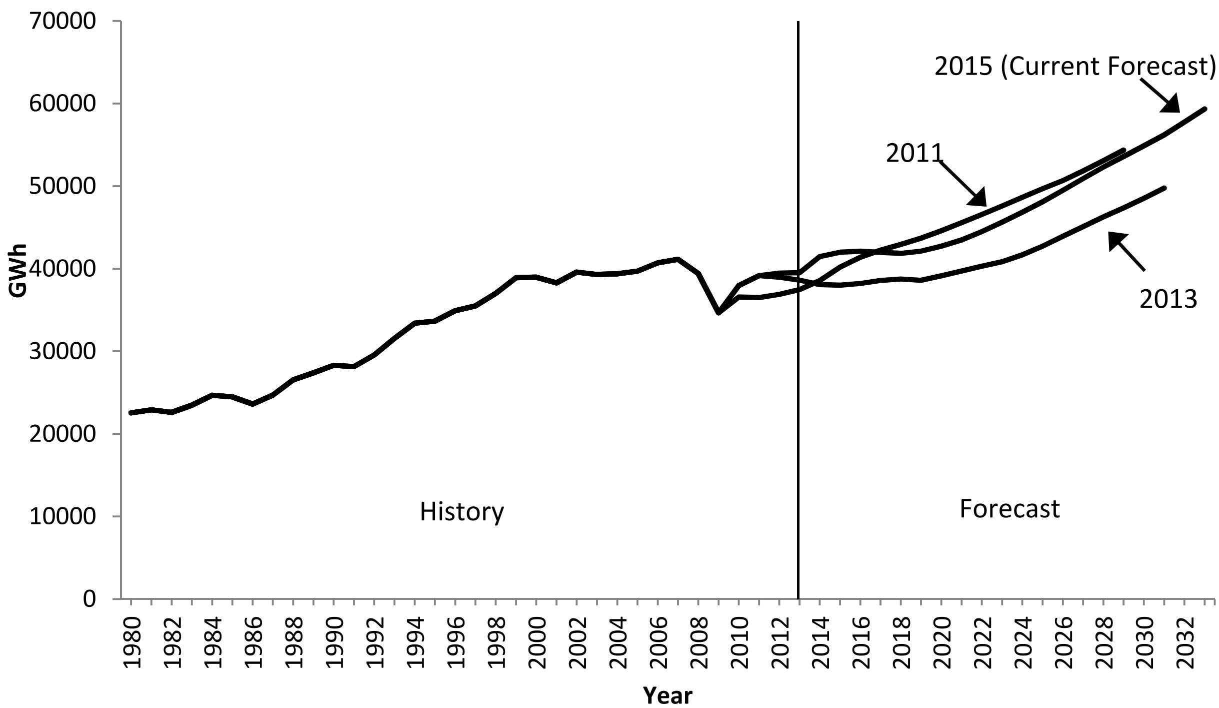
The wide range of forecast sales is caused primarily by the equally wide range of the trajectories of industrial output contained in the CEMR low and high scenarios for the state. In the base scenario GSP in the industrial sector grows 3.02 percent per year during the forecast period. That rate is 3.62 percent in the high scenario and 2.41 percent in the low scenario. This reflects the uncertainty regarding Indiana's industrial future contained in these forecasts.

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

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

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2015	1.90	2014-2033
2013	1.29	2012-2031
2011	2.11	2010-2029

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



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

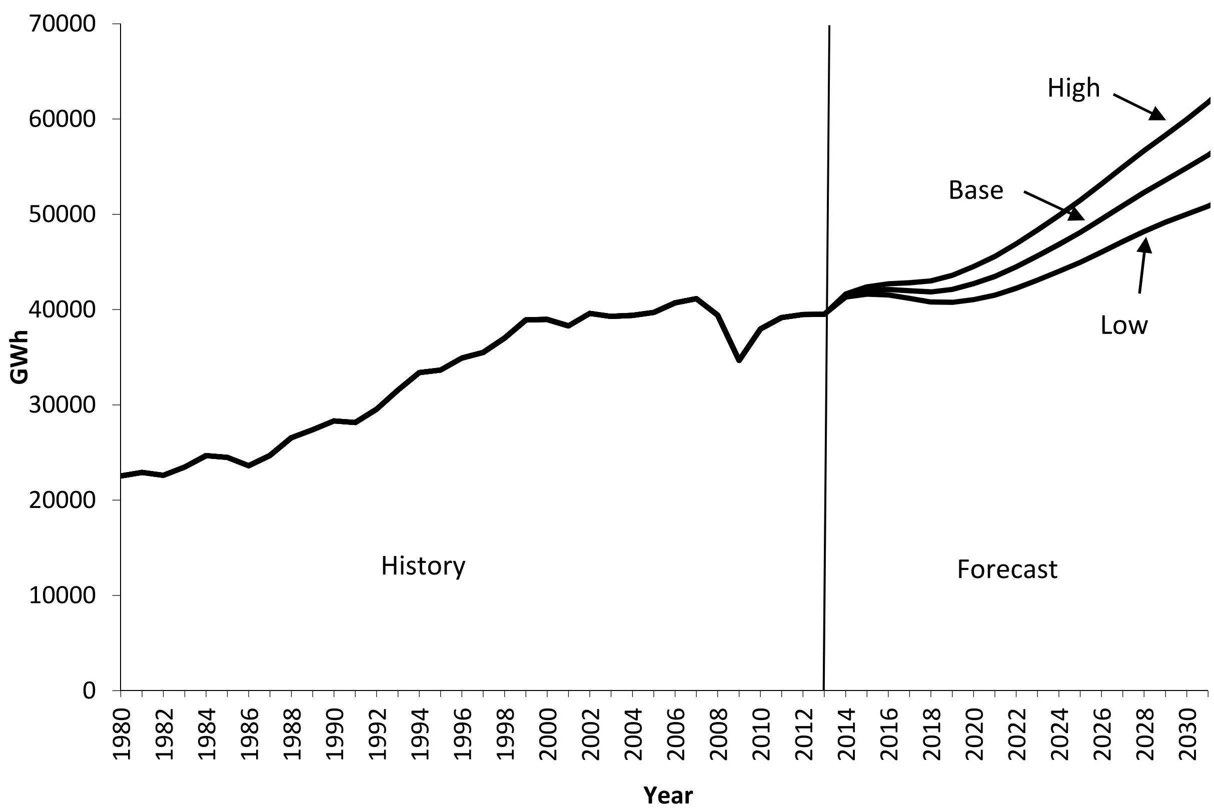
Table 7-4. History of SUFG Industrial Sector Growth Rates (Percent)

Forecast	Output	Mix Effects	Electric Energy-weighted Output	Without DSM		With DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
2015 SUFG Base (2014-2033)	3.02	-0.18	2.84	-0.92	1.92	-0.94	1.90
2013 SUFG Base (2012-2031)	2.86	-0.08	2.78	-1.05	1.73	-1.49	1.29
2011 SUFG Base (2010-2029)	3.95	-0.12	3.83	-1.67	2.16	-1.72	2.11

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

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2014-2033	1.90	1.34	2.45

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



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

Indiana Industrial Electricity Price Projections

Historical values and current projections of industrial electricity prices are shown in Table 7-6 and Figure 7-5. In real terms, industrial electricity prices declined from the mid-1980s until 2002. Real industrial electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real industrial electricity prices to rise until 2021 with the need for additional emissions control equipment and then remain relatively constant. SUFG's real price projections for the individual IOUs follow the same patterns as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 7-5. Indiana Industrial Base Real Price Projections (Cents/kWh in 2013 Dollars)

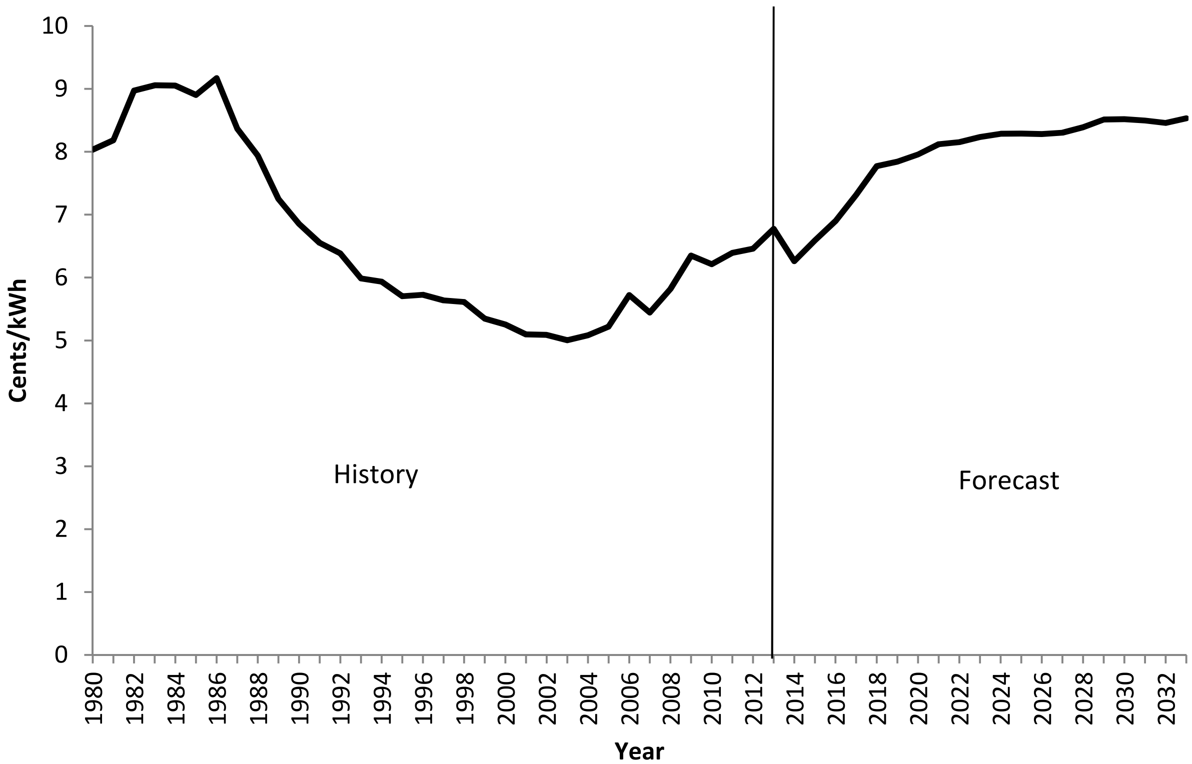


Table 7-6. Indiana Industrial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**Percent**
1980-1985	2.08
1985-1990	-5.10
1990-1995	-3.61
1995-2000	-1.63
2000-2005	-0.12
2005-2013	3.31
2014-2033	1.64

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

Appendix

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

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

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

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

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

Indiana Michigan Power Company (I&M), Wabash Valley Power Association (WVPA), Indiana Municipal Power Agency (IMPA), and Hoosier Energy serve load outside of the state which SUFG excluded in developing projections for Indiana. I&M's load is split approximately 85-15 percent between Indiana and Michigan. While the majority of WVPA’s load is in Indiana, 81 percent, it does have members in Illinois, Missouri, and Ohio. WVPA had one member in Ohio at the time of the previous forecast, but that member left at the end of 2014. IMPA has a wholesale member in Ohio although approximately 99 percent of their load is still in Indiana. Hoosier Energy serves members in Indiana and Illinois. Approximately 95 percent of Hoosier’s load is currently in Indiana although that’s expected to decline to approximately 93 percent by 2017. These utilities have provided SUFG with data pertaining to their Indiana load.

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

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

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

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

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

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

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

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

SUFG 2015 Base Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales					Losses	Energy Required	Summer Demand
		Res	Com	Ind	Other	Total			
Hist	1986	20,410	15,429	23,618	610	60,067	4,205	64,271	11,834
Hist	1987	21,154	16,144	24,694	617	62,609	4,383	66,992	12,218
Hist	1988	22,444	16,808	26,546	633	66,431	4,650	71,081	13,447
Hist	1989	22,251	17,205	27,394	661	67,511	4,726	72,237	12,979
Hist	1990	22,037	17,659	28,311	650	68,657	4,806	73,463	13,659
Hist	1991	24,215	18,580	28,141	629	71,564	5,009	76,573	14,278
Hist	1992	22,916	18,556	29,540	619	71,632	5,014	76,646	14,055
Hist	1993	25,060	19,627	31,562	511	76,760	5,373	82,133	14,916
Hist	1994	25,176	20,116	33,395	507	79,193	5,544	84,737	15,010
Hist	1995	26,510	20,646	33,659	510	81,326	5,693	87,019	16,251
Hist	1996	26,833	20,909	34,920	536	83,197	5,824	89,021	16,162
Hist	1997	26,792	21,295	35,499	530	84,116	5,888	90,004	16,021
Hist	1998	27,663	22,166	37,012	520	87,360	6,115	93,476	16,638
Hist	1999	29,180	23,078	38,916	543	91,717	6,420	98,137	17,246
Hist	2000	28,684	23,721	38,957	529	91,890	6,432	98,322	16,738
Hist	2001	29,437	23,953	38,293	526	92,208	6,455	98,663	17,511
Hist	2002	32,363	24,980	39,594	540	97,476	6,823	104,300	18,831
Hist	2003	31,177	24,940	39,285	589	95,992	6,719	102,711	18,794
Hist	2004	31,042	25,351	39,380	644	96,417	6,749	103,166	18,193
Hist	2005	33,691	26,857	39,702	619	100,869	7,061	107,930	19,944
Hist	2006	32,544	26,846	40,707	604	100,701	7,049	107,750	20,855
Hist	2007	35,038	27,793	41,139	646	104,616	7,323	111,939	20,858
Hist	2008	34,177	27,548	39,417	653	101,795	7,126	108,920	19,275
Hist	2009	32,684	26,233	34,657	661	94,235	6,596	100,832	19,054
Hist	2010	35,195	26,995	37,961	694	100,845	7,059	107,904	20,315
Hist	2011	34,069	26,717	39,156	646	100,588	7,041	107,629	21,002
Hist	2012	33,153	26,702	39,475	603	99,934	6,995	106,929	20,972
Hist	2013	33,675	26,826	39,507	607	100,616	7,043	107,659	20,122
Frcst	2014	33,607	26,787	41,468	607	102,469	7,509	109,979	18,887
Frcst	2015	33,918	27,124	41,989	607	103,638	7,600	111,239	18,922
Frcst	2016	33,865	27,277	42,103	607	103,852	7,615	111,468	18,903
Frcst	2017	33,776	27,291	41,962	607	103,636	7,595	111,231	18,934
Frcst	2018	33,815	27,239	41,850	607	103,512	7,582	111,093	18,939
Frcst	2019	33,831	27,160	42,125	607	103,723	7,602	111,326	19,020
Frcst	2020	34,483	27,106	42,728	607	104,925	7,692	112,617	19,230
Frcst	2021	34,449	27,099	43,480	607	105,635	7,751	113,387	19,395
Frcst	2022	34,499	27,104	44,486	607	106,696	7,835	114,531	19,579
Frcst	2023	34,549	27,164	45,637	607	107,958	7,935	115,894	19,794
Frcst	2024	34,698	27,288	46,845	607	109,439	8,052	117,491	20,054
Frcst	2025	35,033	27,383	48,103	607	111,126	8,182	119,307	20,361
Frcst	2026	35,369	27,588	49,488	607	113,053	8,328	121,381	20,710
Frcst	2027	35,667	27,826	50,904	607	115,004	8,477	123,481	21,057
Frcst	2028	35,971	28,108	52,296	607	116,983	8,630	125,613	21,412
Frcst	2029	36,323	28,410	53,582	607	118,923	8,781	127,704	21,764
Frcst	2030	36,841	28,764	54,885	607	121,098	8,948	130,046	22,165
Frcst	2031	37,161	29,152	56,209	607	123,130	9,106	132,235	22,528
Frcst	2032	37,523	29,539	57,750	607	125,419	9,281	134,701	22,937
Frcst	2033	37,911	29,961	59,343	607	127,822	9,464	137,286	23,367

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	0.74	2.47	2.47	2.47	0.59
2000-2005	3.27	2.51	0.38	3.19	1.88	1.88	1.88	3.57
2005-2010	0.88	0.10	-0.89	2.29	0.00	0.00	0.00	0.37
2010-2015	-0.74	0.10	2.04	-2.62	0.55	1.49	0.61	-1.41
2015-2020	0.33	-0.01	0.35	0.00	0.25	0.24	0.25	0.32
2020-2025	0.32	0.20	2.40	0.00	1.16	1.24	1.16	1.15
2025-2030	1.01	0.99	2.67	0.00	1.73	1.81	1.74	1.71
2030-2033	0.96	1.37	2.64	0.00	1.82	1.89	1.82	1.78
2014-2033	0.64	0.59	1.90	0.00	1.17	1.23	1.17	1.13

SUFG 2015 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

		Retail Sales							
Year		Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
Hist	1986	20,410	15,429	23,618	610	60,067	4,205	64,271	11,834
Hist	1987	21,154	16,144	24,694	617	62,609	4,383	66,992	12,218
Hist	1988	22,444	16,808	26,546	633	66,431	4,650	71,081	13,447
Hist	1989	22,251	17,205	27,394	661	67,511	4,726	72,237	12,979
Hist	1990	22,037	17,659	28,311	650	68,657	4,806	73,463	13,659
Hist	1991	24,215	18,580	28,141	629	71,564	5,009	76,573	14,278
Hist	1992	22,916	18,556	29,540	619	71,632	5,014	76,646	14,055
Hist	1993	25,060	19,627	31,562	511	76,760	5,373	82,133	14,916
Hist	1994	25,176	20,116	33,395	507	79,193	5,544	84,737	15,010
Hist	1995	26,510	20,646	33,659	510	81,326	5,693	87,019	16,251
Hist	1996	26,833	20,909	34,920	536	83,197	5,824	89,021	16,162
Hist	1997	26,792	21,295	35,499	530	84,116	5,888	90,004	16,021
Hist	1998	27,663	22,166	37,012	520	87,360	6,115	93,476	16,638
Hist	1999	29,180	23,078	38,916	543	91,717	6,420	98,137	17,246
Hist	2000	28,684	23,721	38,957	529	91,890	6,432	98,322	16,738
Hist	2001	29,437	23,953	38,293	526	92,208	6,455	98,663	17,511
Hist	2002	32,363	24,980	39,594	540	97,476	6,823	104,300	18,831
Hist	2003	31,177	24,940	39,285	589	95,992	6,719	102,711	18,794
Hist	2004	31,042	25,351	39,380	644	96,417	6,749	103,166	18,193
Hist	2005	33,691	26,857	39,702	619	100,869	7,061	107,930	19,944
Hist	2006	32,544	26,846	40,707	604	100,701	7,049	107,750	20,855
Hist	2007	35,038	27,793	41,139	646	104,616	7,323	111,939	20,858
Hist	2008	34,177	27,548	39,417	653	101,795	7,126	108,920	19,275
Hist	2009	32,684	26,233	34,657	661	94,235	6,596	100,832	19,054
Hist	2010	35,195	26,995	37,961	694	100,845	7,059	107,904	20,315
Hist	2011	34,069	26,717	39,156	646	100,588	7,041	107,629	21,002
Hist	2012	33,153	26,702	39,475	603	99,934	6,995	106,929	20,972
Hist	2013	33,675	26,826	39,507	607	100,616	7,043	107,659	20,122
Frcst	2014	33,592	26,717	41,312	607	102,229	7,491	109,720	18,846
Frcst	2015	33,888	26,977	41,622	607	103,094	7,559	110,654	18,830
Frcst	2016	33,819	27,060	41,535	607	103,022	7,553	110,575	18,762
Frcst	2017	33,713	26,978	41,184	607	102,483	7,509	109,992	18,738
Frcst	2018	33,729	26,828	40,795	607	101,960	7,466	109,426	18,677
Frcst	2019	33,717	26,614	40,761	607	101,700	7,450	109,150	18,676
Frcst	2020	34,342	26,448	41,048	607	102,445	7,507	109,952	18,809
Frcst	2021	34,273	26,307	41,520	607	102,708	7,533	110,241	18,896
Frcst	2022	34,298	26,190	42,237	607	103,332	7,583	110,916	19,005
Frcst	2023	34,314	26,114	43,088	607	104,124	7,649	111,772	19,139
Frcst	2024	34,436	26,106	44,018	607	105,167	7,733	112,899	19,322
Frcst	2025	34,747	26,064	44,960	607	106,378	7,827	114,205	19,547
Frcst	2026	35,059	26,126	46,038	607	107,830	7,939	115,769	19,814
Frcst	2027	35,325	26,216	47,140	607	109,288	8,051	117,339	20,077
Frcst	2028	35,603	26,346	48,192	607	110,749	8,165	118,913	20,343
Frcst	2029	35,922	26,489	49,181	607	112,199	8,279	120,479	20,612
Frcst	2030	36,395	26,671	50,007	607	113,680	8,394	122,075	20,893
Frcst	2031	36,672	26,875	50,851	607	115,005	8,499	123,504	21,135
Frcst	2032	36,989	27,071	51,946	607	116,613	8,623	125,236	21,426
Frcst	2033	37,319	27,288	53,169	607	118,384	8,759	127,143	21,745

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	0.74	2.47	2.47	2.47	0.59
2000-2005	3.27	2.51	0.38	3.19	1.88	1.88	1.88	3.57
2005-2010	0.88	0.10	-0.89	2.29	0.00	0.00	0.00	0.37
2010-2015	-0.75	-0.01	1.86	-2.62	0.44	1.38	0.50	-1.51
2015-2020	0.27	-0.40	-0.28	0.00	-0.13	-0.14	-0.13	-0.02
2020-2025	0.23	-0.29	1.84	0.00	0.76	0.84	0.76	0.77
2025-2030	0.93	0.46	2.15	0.00	1.34	1.41	1.34	1.34
2030-2033	0.84	0.77	2.06	0.00	1.36	1.43	1.37	1.34
2014-2033	0.56	0.11	1.34	0.00	0.78	0.83	0.78	0.76

SUFG 2015 High Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	1986	20,410	15,429	23,618	610	60,067	4,205	64,271	11,834
Hist	1987	21,154	16,144	24,694	617	62,609	4,383	66,992	12,218
Hist	1988	22,444	16,808	26,546	633	66,431	4,650	71,081	13,447
Hist	1989	22,251	17,205	27,394	661	67,511	4,726	72,237	12,979
Hist	1990	22,037	17,659	28,311	650	68,657	4,806	73,463	13,659
Hist	1991	24,215	18,580	28,141	629	71,564	5,009	76,573	14,278
Hist	1992	22,916	18,556	29,540	619	71,632	5,014	76,646	14,055
Hist	1993	25,060	19,627	31,562	511	76,760	5,373	82,133	14,916
Hist	1994	25,176	20,116	33,395	507	79,193	5,544	84,737	15,010
Hist	1995	26,510	20,646	33,659	510	81,326	5,693	87,019	16,251
Hist	1996	26,833	20,909	34,920	536	83,197	5,824	89,021	16,162
Hist	1997	26,792	21,295	35,499	530	84,116	5,888	90,004	16,021
Hist	1998	27,663	22,166	37,012	520	87,360	6,115	93,476	16,638
Hist	1999	29,180	23,078	38,916	543	91,717	6,420	98,137	17,246
Hist	2000	28,684	23,721	38,957	529	91,890	6,432	98,322	16,738
Hist	2001	29,437	23,953	38,293	526	92,208	6,455	98,663	17,511
Hist	2002	32,363	24,980	39,594	540	97,476	6,823	104,300	18,831
Hist	2003	31,177	24,940	39,285	589	95,992	6,719	102,711	18,794
Hist	2004	31,042	25,351	39,380	644	96,417	6,749	103,166	18,193
Hist	2005	33,691	26,857	39,702	619	100,869	7,061	107,930	19,944
Hist	2006	32,544	26,846	40,707	604	100,701	7,049	107,750	20,855
Hist	2007	35,038	27,793	41,139	646	104,616	7,323	111,939	20,858
Hist	2008	34,177	27,548	39,417	653	101,795	7,126	108,920	19,275
Hist	2009	32,684	26,233	34,657	661	94,235	6,596	100,832	19,054
Hist	2010	35,195	26,995	37,961	694	100,845	7,059	107,904	20,315
Hist	2011	34,069	26,717	39,156	646	100,588	7,041	107,629	21,002
Hist	2012	33,153	26,702	39,475	603	99,934	6,995	106,929	20,972
Hist	2013	33,675	26,826	39,507	607	100,616	7,043	107,659	20,122
Frcst	2014	33,617	26,849	41,634	607	102,707	7,527	110,235	18,927
Frcst	2015	33,938	27,252	42,384	607	104,181	7,641	111,822	19,012
Frcst	2016	33,895	27,475	42,708	607	104,686	7,678	112,364	19,041
Frcst	2017	33,818	27,567	42,811	607	104,804	7,682	112,486	19,128
Frcst	2018	33,874	27,636	43,011	607	105,128	7,702	112,831	19,207
Frcst	2019	33,910	27,672	43,592	607	105,781	7,755	113,536	19,362
Frcst	2020	34,567	27,739	44,515	607	107,429	7,878	115,307	19,646
Frcst	2021	34,558	27,860	45,577	607	108,603	7,972	116,574	19,889
Frcst	2022	34,618	27,988	46,902	607	110,115	8,089	118,204	20,150
Frcst	2023	34,695	28,182	48,346	607	111,830	8,223	120,053	20,445
Frcst	2024	34,859	28,443	49,872	607	113,781	8,374	122,155	20,785
Frcst	2025	35,213	28,690	51,458	607	115,968	8,541	124,509	21,177
Frcst	2026	35,565	29,048	53,182	607	118,403	8,726	127,129	21,612
Frcst	2027	35,882	29,450	54,943	607	120,882	8,915	129,797	22,050
Frcst	2028	36,196	29,901	56,673	607	123,377	9,106	132,483	22,495
Frcst	2029	36,562	30,383	58,315	607	125,867	9,300	135,166	22,944
Frcst	2030	37,092	30,930	59,973	607	128,603	9,509	138,112	23,446
Frcst	2031	37,453	31,526	61,747	607	131,334	9,719	141,053	23,934
Frcst	2032	37,845	32,129	63,759	607	134,341	9,948	144,289	24,471
Frcst	2033	38,260	32,780	65,920	607	137,567	10,193	147,761	25,048

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	0.74	2.47	2.47	2.47	0.59
2000-2005	3.27	2.51	0.38	3.19	1.88	1.88	1.88	3.57
2005-2010	0.88	0.10	-0.89	2.29	0.00	0.00	0.00	0.37
2010-2015	-0.72	0.19	2.23	-2.62	0.65	1.60	0.72	-1.32
2015-2020	0.37	0.36	0.99	0.00	0.62	0.61	0.62	0.66
2020-2025	0.37	0.68	2.94	0.00	1.54	1.63	1.55	1.51
2025-2030	1.05	1.52	3.11	0.00	2.09	2.17	2.10	2.06
2030-2033	1.04	1.96	3.20	0.00	2.27	2.34	2.28	2.23
2014-2033	0.68	1.06	2.45	0.00	1.55	1.61	1.55	1.49

Indiana Base Average Retail Rates (Cents/kWh) (in 2013 Dollars)

Year	Res	Com	Ind	Average
1986	13.47	12.67	9.17	11.44
1987	13.04	12.37	8.37	10.86
1988	12.28	11.32	7.94	10.15
1989	11.47	9.71	7.25	9.15
1990	10.84	9.17	6.85	8.61
1991	10.19	8.64	6.55	8.22
1992	10.13	8.55	6.38	8.04
1993	9.53	8.01	5.98	7.55
1994	9.56	7.98	5.93	7.50
1995	9.40	7.91	5.70	7.37
1996	9.37	7.89	5.73	7.34
1997	9.56	7.80	5.64	7.31
1998	9.60	7.81	5.61	7.31
1999	9.33	7.64	5.35	7.07
2000	8.94	7.24	5.25	6.81
2001	8.77	7.29	5.10	6.73
2002	8.59	7.23	5.09	6.69
2003	8.56	7.13	5.01	6.61
2004	8.61	7.24	5.08	6.70
2005	8.62	7.38	5.22	6.85
2006	9.24	7.81	5.72	7.32
2007	8.89	7.79	5.45	7.14
2008	9.24	7.99	5.82	7.48
2009	9.82	8.57	6.35	8.10
2010	9.62	8.45	6.21	7.93
2011	9.97	8.68	6.39	8.13
2012	10.25	8.92	6.46	8.29
2013	10.69	9.27	6.78	8.66
2014	10.49	9.04	6.26	8.27
2015	11.34	9.59	6.59	8.81
2016	12.04	10.07	6.90	9.28
2017	12.89	10.72	7.31	9.88
2018	13.81	11.45	7.77	10.55
2019	13.87	11.50	7.84	10.60
2020	14.09	11.69	7.96	10.76
2021	14.31	11.95	8.12	10.94
2022	14.31	11.99	8.15	10.93
2023	14.27	12.00	8.24	10.92
2024	14.22	12.00	8.29	10.89
2025	14.09	11.92	8.29	10.80
2026	13.95	11.83	8.28	10.71
2027	13.84	11.78	8.30	10.64
2028	13.84	11.83	8.39	10.67
2029	13.82	11.87	8.51	10.71
2030	13.70	11.80	8.52	10.65
2031	13.56	11.72	8.50	10.56
2032	13.40	11.60	8.46	10.45
2033	13.45	11.66	8.53	10.49
Average Compound Growth Rates (%)				
Year-Year	**Res**	**Com**	**Ind**	**Average**
1990-1995	-2.80	-2.90	-3.61	-3.08
1995-2000	-0.99	-1.75	-1.63	-1.56
2000-2005	-0.72	0.36	-0.12	0.12
2005-2010	2.22	2.76	3.54	2.97
2010-2015	3.33	2.56	1.20	2.13
2015-2020	4.44	4.04	3.84	4.08
2020-2025	0.00	0.39	0.82	0.07
2025-2030	-0.55	-0.19	0.55	-0.27
2030-2033	-0.62	-0.42	0.06	-0.51
2014-2033	1.32	1.35	1.64	1.26

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

List of Acronyms

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