Indiana Electricity Projections: The 2009 Forecast

Prepared by:

Forrest D. Holland
Marco A. Velastegui
Douglas J. Gotham
David G. Nderitu
Paul V. Preckel

State Utility Forecasting Group
The Energy Center at Discovery Park
Purdue University
West Lafayette, Indiana

December 2009

Prepared for:

Indiana Utility Regulatory Commission
Indianapolis, Indiana

Table of Contents

Table of Contents

List of Figures

Page

List of Tables

Page

Foreword

This report presents the 2009 projections of future electricity requirements for the state of Indiana for the period 2008-2027. 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 twelfth 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:

State Utility Forecasting Group
Purdue University
Mann Hall, Room 154
203 S. Martin Jischke Drive
West Lafayette, IN 47907-1971
Phone: 765-494-4223
FAX: 765-494-6298
e-mail: sufg@ecn.purdue.edu

Chapter 1

Forecast Summary

Overview

In this report, the State Utility Forecasting Group (SUFG) provides its twelfth set of projections of future electricity usage, peak demand, prices and resource requirements. In its most recent forecast, released in 2007, SUFG identified a need for new resources in the first few years. While this forecast reports a need for resources in the longer term, it does not indicate a need for significant resources in the short term. The primary reasons that this forecast does not include significant short-term resource needs are slower growth in electricity demand resulting from the economic recession, the acquisition of two natural gas-fired combined cycle generators by Indiana utilities, the approval and construction of the Edwardsport integrated gasification plant, new long-term power purchases, and increased efforts in energy efficiency.

This forecast projects electricity usage to grow at a rate of 1.55 percent per year over the 20 years of the forecast. This growth rate is lower than Indiana has historically experienced and lower than previous SUFG projections. As one would expect, the current economic situation and the projected future path of the economy have a dramatic effect on the electricity sales forecast. Peak electricity demand is projected to grow at an average rate of 1.61 percent annually. This corresponds to about 350 megawatts (MW) of increased peak demand per year.

The 2009 forecast predicts Indiana electricity prices to increase significantly in real (inflation adjusted) terms through 2013 and then slowly drift upward through the remainder of the forecast period. The price increase is caused by three factors; the cost of controlling emissions from coal-fired generation facilities to meet the Clean Air Interstate Rule (CAIR), higher purchase power costs, and costs associated with acquiring additional generating facilities.

As in the 2007 forecast, 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 480 MW of peaking, 300 MW of cycling, and 540 MW of baseload resources required by 2015. These requirements are considerably lower than those identified in the 2007 forecast.

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 full report briefly describes SUFG's forecasting methodology. 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/dp/energy/SUFG/

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

- the base scenario, which is intended to represent the most likely electricity forecast, i.e., the forecast has an equal probability of being low or high;
- the low scenario, which is intended to represent a plausible lower bound on the electricity sales forecast and thus, has a low probability of occurrence; and
- the high scenario, which is intended to represent a plausible upper bound on the electricity sales forecast and thus, has a low probability of occurrence.

Chapter 8 examines the effect of a number of economic factors on the forecast. Finally, an Appendix depicts the data sources used to produce the forecast and provides historical 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 this forecast, SUFG has 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. Recently, the regional transmission organizations that encompass Indiana utilities have determined planning reserve requirements for their members. SUFG now uses individual utility reserve margins that reflect the planning reserve requirements of the utility's regional transmission organization 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 16.3 percent. It should be noted that the change from a 15 percent to a 16.3 percent target reserve margin in the SUFG forecasts does not represent an increase in reserves (and hence, an increase in costs) due to the utilities' memberships in the regional transmission organizations. Rather, it represents a change by SUFG to a target reserve margin that is based on a more rigorous analysis.

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 2009 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 1.00 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 0.83 percent. Other key economic projections are:

- Real personal income (the residential sector model driver) is expected to grow at a 1.63 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average a 1.16 percent annual growth rate over the forecast horizon.
- Despite the continued decline of manufacturing employment, manufacturing gross state product (GSP) (the industrial sector model driver) is expected to rise at a 2.23 percent annual rate as gains in productivity offset declines in employment.

---

[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 16.3 percent reserve margin is equivalent to a 14 percent capacity margin.
Capacity Margin = [(Capacity-Demand)/Capacity]
Reserve Margin=[(Capacity-Demand)/Demand]

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

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

Demographic Projections

Population growth for all scenarios is 0.49 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 1.00 percent over the forecast period.

Fossil Fuel Price Projections

SUFG's current assumptions are based on the March 2009 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 price projections exhibit a significant decrease in 2009 coming off of the high prices of 2008. Prices are then projected to remain relatively constant through 2015, 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 gigawatthours (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 1.55 percent, while the growth rate for peak demand is 1.61 percent. The growth rates in the previous forecast for both electricity requirements and peak demand were 2.46 percent.

The growth within sectors varies considerably with higher growth in the residential sector partially offsetting lower growth in the commercial and industrial sectors, but the forecast growth for all sectors is markedly below that forecast in 2007 (see Table 1-1). See Chapters 5 through 7 for more detail on the sectoral forecasts.

The projections of peak demand are for normal weather patterns, and projected peak demand for long-run planning is reduced by interruptible 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 350 MW.

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources to meet forecast demand. Demand-side management (DSM) impacts and interruptible loads are netted from the demand projection and supply-side resources are added as necessary to maintain a 16.3 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.

Table 1-1. Annual Electricity Sales Growth (Percent) by Sector (Current vs. 2007 Projections)

Sector	Current (2008-2027)	2007 (2006-2025)
Residential	1.75	2.21
Commercial	1.18	2.46
Industrial	1.63	2.67
Total	1.55	2.46

[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).

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

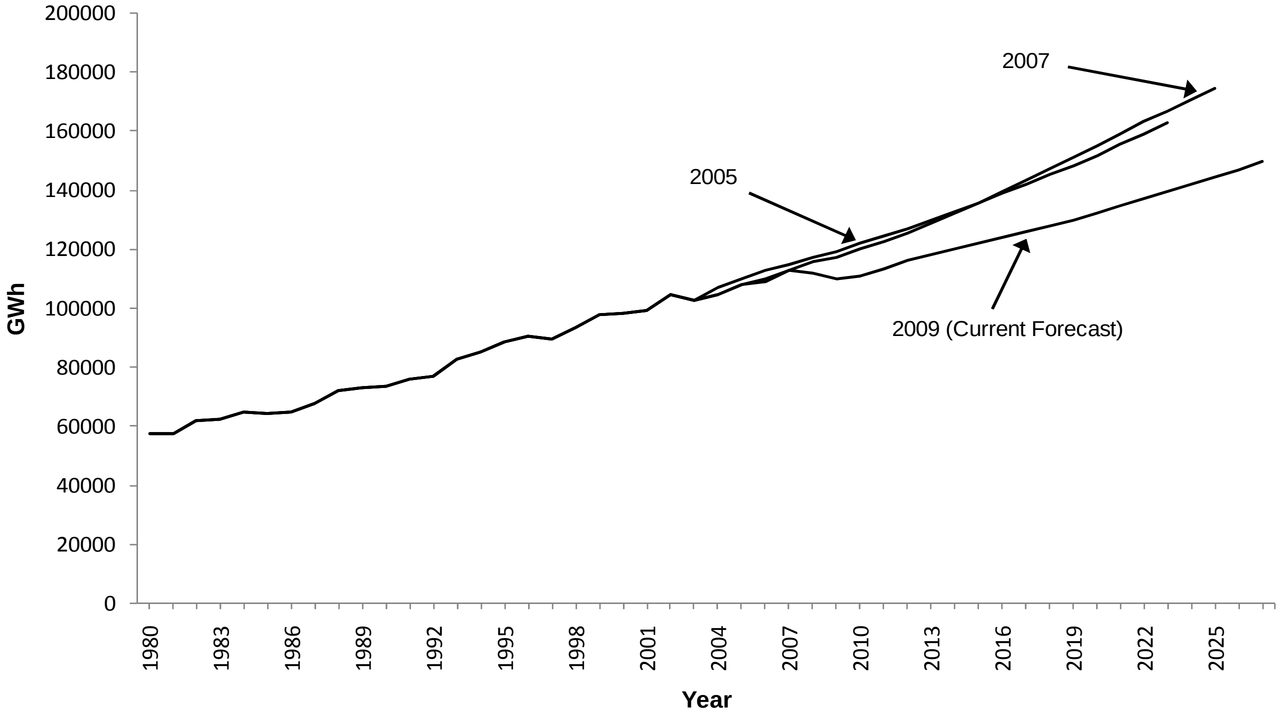
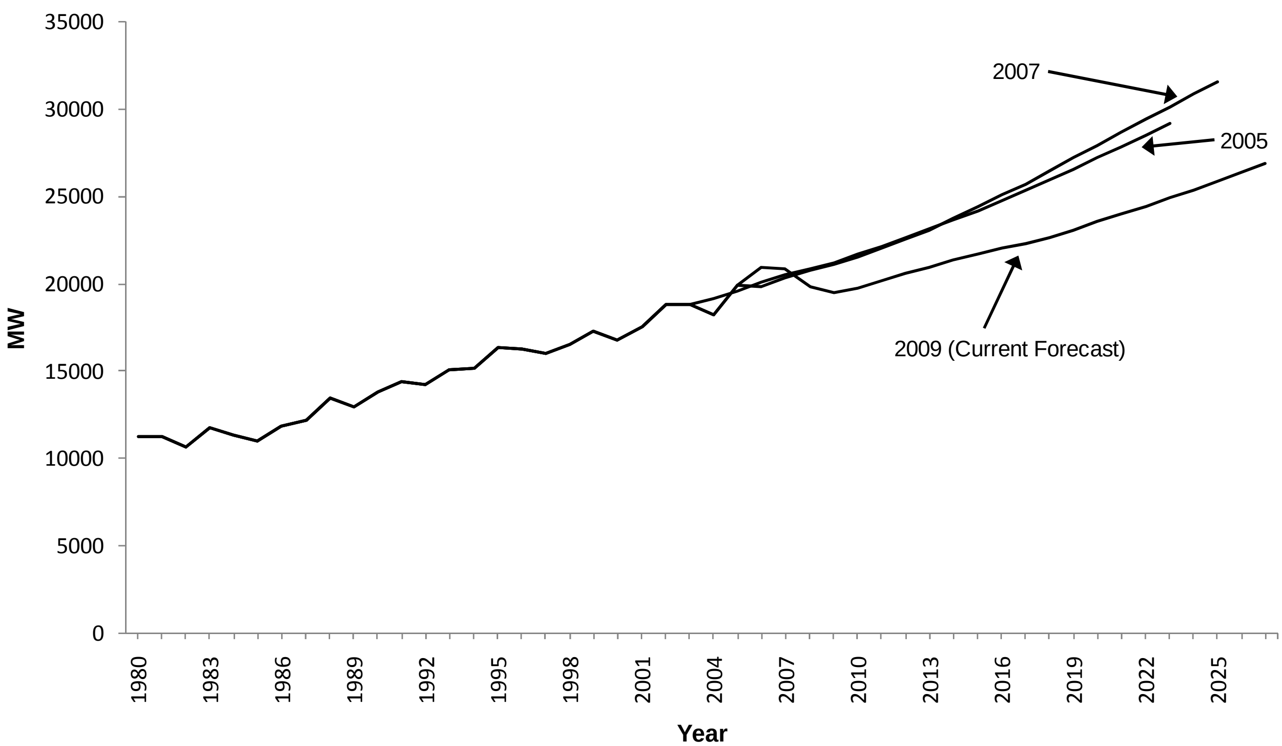


Figure 1-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Demand-Side Resources

The current projection includes the energy and demand impacts of existing or planned utility-sponsored DSM programs. Incremental DSM programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 80 MW at the beginning of the forecast period and by about 700 MW at the end of the forecast.

These DSM projections do not include the reductions in peak demand due to interruptible load contracts with large customers. Interruptible loads are projected to increase from 855 MW to about 970 MW over the forecast horizon. See Chapter 4 for additional information about DSM and interruptible loads.

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. Due to the timing and uncertainty over Duke Energy's shutdown of three Wabash River units, SUFG has not removed those units from the existing mix of generators.[4] 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 16.3 percent reserve margin.

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, nearly 2,200 MW of additional resources are required. The net change in generation includes the retirement of units as reported in the utilities' 2007 Integrated Resource Plan (IRP) filings. Over the second half of the forecast period, an additional 6,000 MW of resources are required to maintain target reserves. If Duke Energy retires the affected Wabash River units, additional resources of approximately 250 MW will be required.

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 is 2007. Therefore, 2008 and 2009 numbers represent projections. The resource requirements identified in Table 1-2 for 2008 and 2009 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.

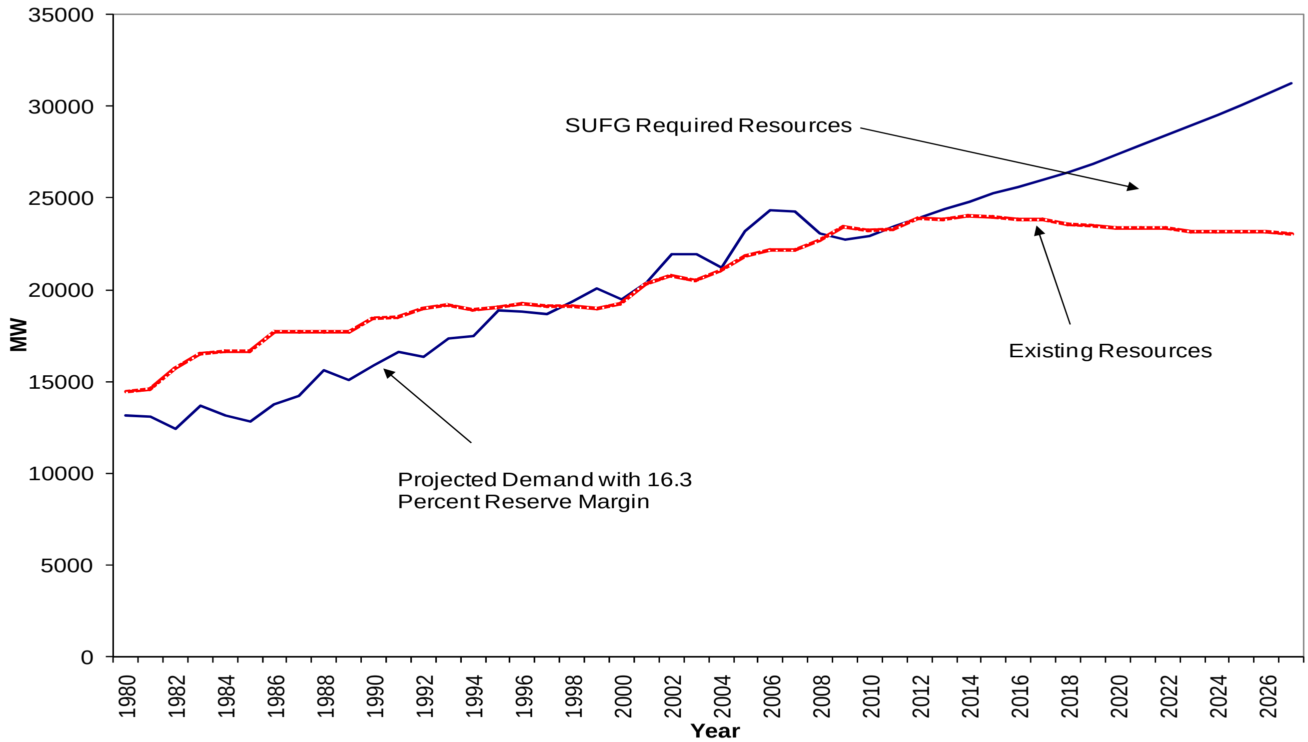
Equilibrium Price and Energy Impact

SUFG's base scenario equilibrium real electricity price trajectory is shown in Figure 1-4. Real prices are projected to increase significantly through 2013 and then slowly drift upward 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 "2007" is the base from SUFG's 2007 forecast and the price projections labeled "2005" is the base case projection contained in SUFG's 2005 forecast. For the prior price forecasts, SUFG rescaled the original price projections to 2007 dollars (from 2003 dollars for the 2005 projection, and from 2005 dollars for the 2007 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

[4] Duke Energy shut down its Wabash River units 2, 3, and 5 in September 2009 as a result of a U.S. District Court ruling regarding alleged violations of the Clean Air Act. At the time this forecast was prepared, the status of any decision to appeal that ruling was unknown.

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



Three major factors primarily determine the differences among the price projections in Figure 1-4: first, the cost of controlling emissions from coal-fired generation facilities to meet air emission standards; second, higher purchase power costs; and third, generation plant additions by acquisition and new plant construction. It should be noted that the costs associated with meeting the first phase of the Clean Air Interstate Rule (CAIR) but not those associated the Clean Air Mercury Rule (CAMR) are included in the current forecast. CAIR was initially vacated by the United States D.C. Circuit Court but subsequently remanded on appeal. The rule remains in effect until the U.S. Environmental Protection Agency replaces it with a rule that conforms to the court's opinion. CAMR was vacated by the same court and has not been replaced with another mercury control measure. The costs of both CAIR and CAMR were incorporated in the 2007 SUFG forecast but not in 2005 forecast.[5] Costs associated with compliance with CAIR are considerably higher in this forecast than in the 2007 SUFG forecast because of large increases in the cost of steel, concrete and other components of the emissions control equipment. Other factors such as energy and demand growth as well as fossil fuel price assumptions, especially coal, also influence the trajectory of future prices.

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. As shown in the figure, the annual growth rates for the low and high scenarios are about 0.30 percent lower and 0.40 percent higher than the base scenario, 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.

[5] SUFG performed two separate analyses that looked at the price impacts of CAIR and CAMR. The reports, "The Projected Impacts of the Clean Air Interstate Rule on Electricity Prices in Indiana" and "The Projected Impacts of Mercury Emissions Reductions on Electricity Prices in Indiana," are available on the SUFG website.

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

	Uncontrolled Peak Demand[1]	Interruptible	Net Peak Demand[2]	Existing/ Approved Capacity[3]	Incremental Change in Capacity[4]	Projected Additional Resource Requirements[5]				Total Resources[6]	Reserve Margin
						Peaking	Cycling	Baseload	Demand[1]		
2007				22,129							
2008	20,687	855	19,832	22,656	527	110	200	220	530	23,186	17
2009	20,394	864	19,530	23,417	762	0	0	10	10	23,427	20
2010	20,611	870	19,741	23,208	-209	10	0	0	10	23,218	18
2011	21,036	880	20,156	23,275	66	170	20	90	280	23,555	17
2012	21,481	884	20,597	23,874	599	280	40	130	450	24,324	18
2013	21,860	894	20,966	23,774	-100	350	120	260	730	24,504	17
2014	22,252	911	21,341	24,036	262	420	150	380	950	24,986	17
2015	22,623	928	21,695	23,918	-118	480	300	540	1,320	25,238	16
2016	22,962	944	22,018	23,796	-122	610	400	780	1,790	25,586	16
2017	23,298	957	22,341	23,796	0	730	460	990	2,180	25,976	16
2018	23,650	971	22,679	23,509	-287	810	750	1,300	2,860	26,369	16
2019	24,046	971	23,075	23,475	-34	980	830	1,550	3,360	26,835	16
2020	24,521	971	23,550	23,320	-155	1,300	920	1,830	4,050	27,370	16
2021	24,963	971	23,992	23,316	-4	1,410	990	2,180	4,580	27,896	16
2022	25,421	971	24,450	23,326	10	1,560	1,050	2,510	5,120	28,446	16
2023	25,875	971	24,904	23,166	-160	1,690	1,260	2,830	5,780	28,946	16
2024	26,360	971	25,389	23,166	0	1,920	1,360	3,090	6,370	29,536	16
2025	26,839	971	25,868	23,158	-8	2,040	1,420	3,450	6,910	30,068	16
2026	27,325	971	26,354	23,141	-18	2,090	1,460	3,960	7,510	30,651	16
2027	27,844	971	26,873	22,991	-150	2,340	1,530	4,360	8,230	31,221	16

1 Uncontrolled peak demand is the peak demand without any interruptible loads being called upon.
2 Net peak demand is the peak demand after interruptible loads are taken into account.
3 Existing/approved capacity includes installed capacity plus approved new capacity plus firm purchases minus firm sales.
4 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.
5 Projected additional resource requirements is the cumulative amount of additional resources needed to meet future requirements.
6 Total resource requirements are the total statewide resources required including existing/approved capacity and projected additional resource requirements.

Figure 1-4. Indiana Real Price Projections in cents/kWh (2007 Dollars) (Historical, Current and Previous Forecasts)

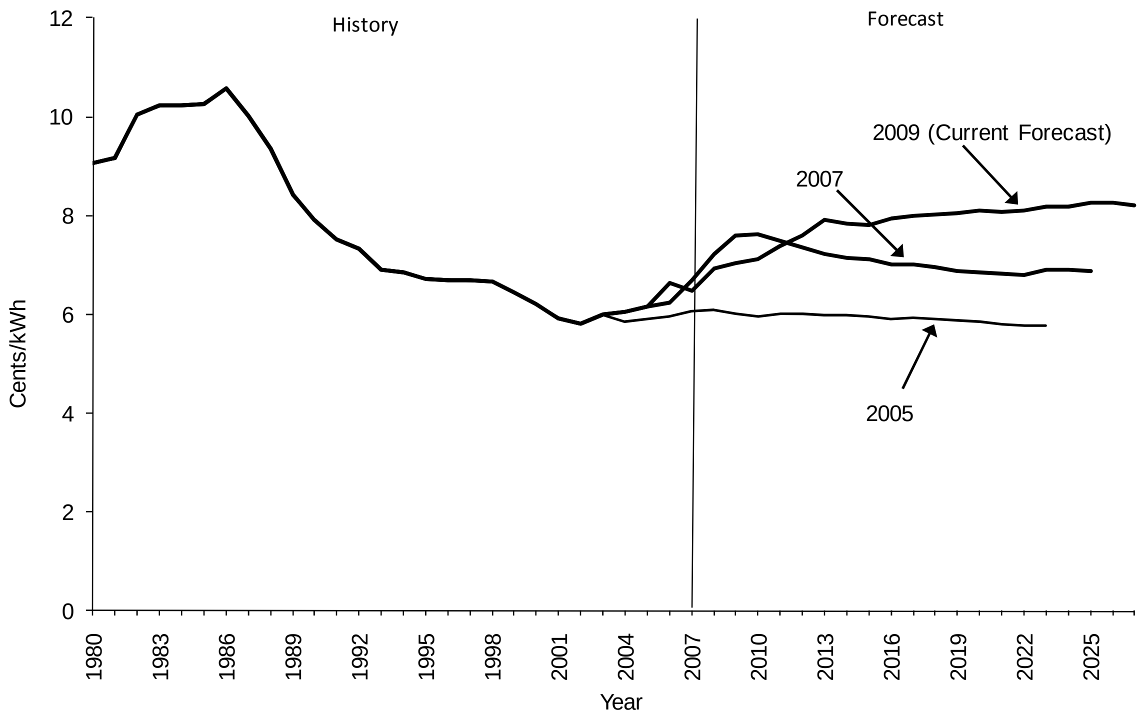
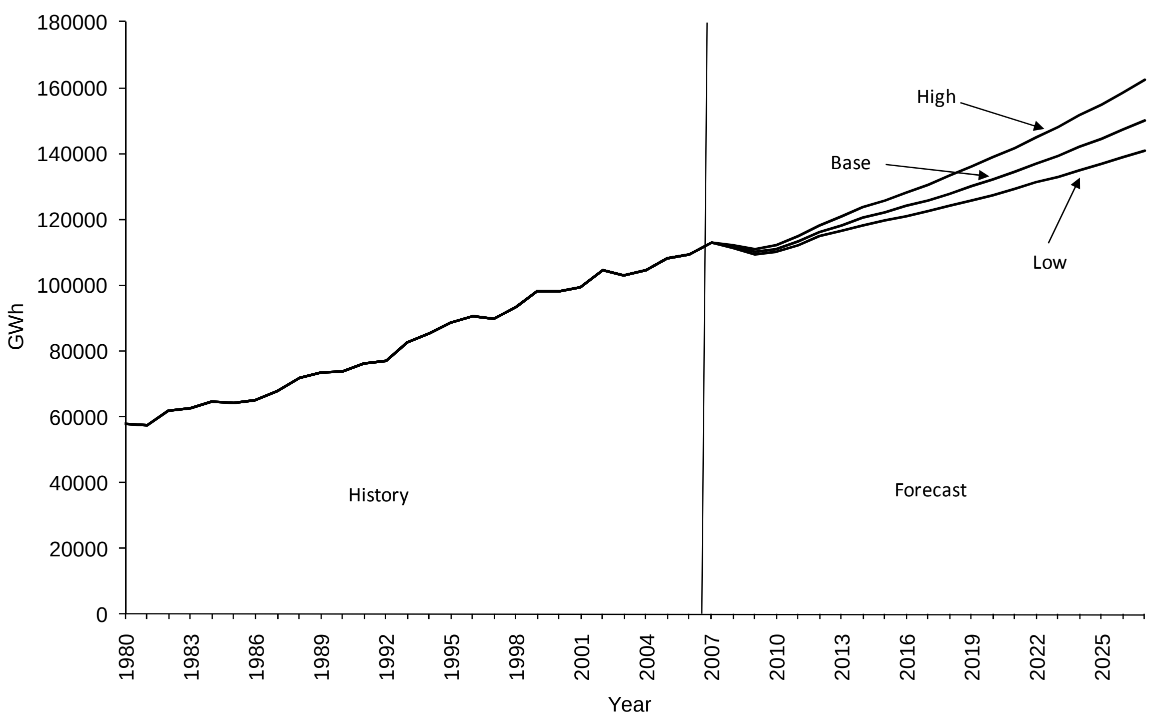


Figure 1-5. Indiana Electricity Requirements by Scenario in GWh



Chapter 2

Overview of 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.

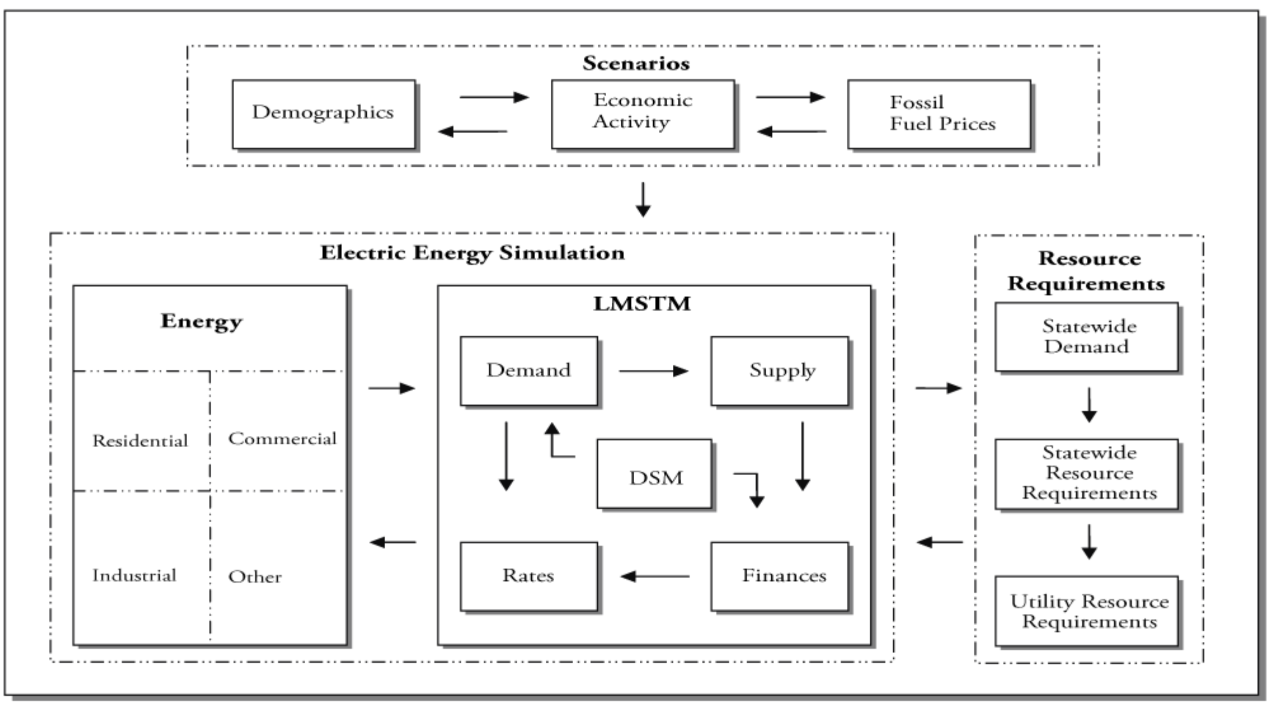
Scenarios

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,

Figure 2-1. SUFG's Regulated Modeling System



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 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 a more recent version of its commercial end-use model. Additional information regarding SUFG's energy models for the residential, commercial and industrial sectors can be found in chapters five, six and seven, respectively.

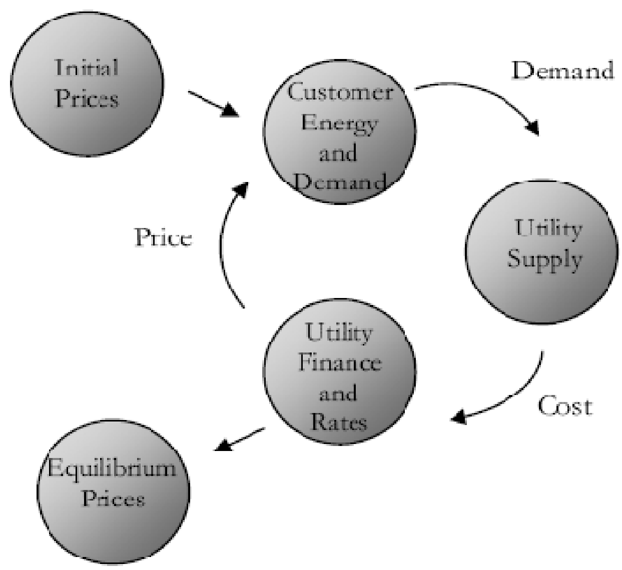
Load Management Strategy Testing Model

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), and 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 this forecast, SUFG has 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. SUFG now uses individual utility reserve margins that reflect the planning reserve requirements of the utility's regional transmission organization 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 16.3 percent. It should be noted that the change from a 15 percent to a 16.3 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 regional transmission organizations. Rather, it represents a change by SUFG to a target that is based on a more rigorous analysis.

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 interruptible 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 16.3 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).

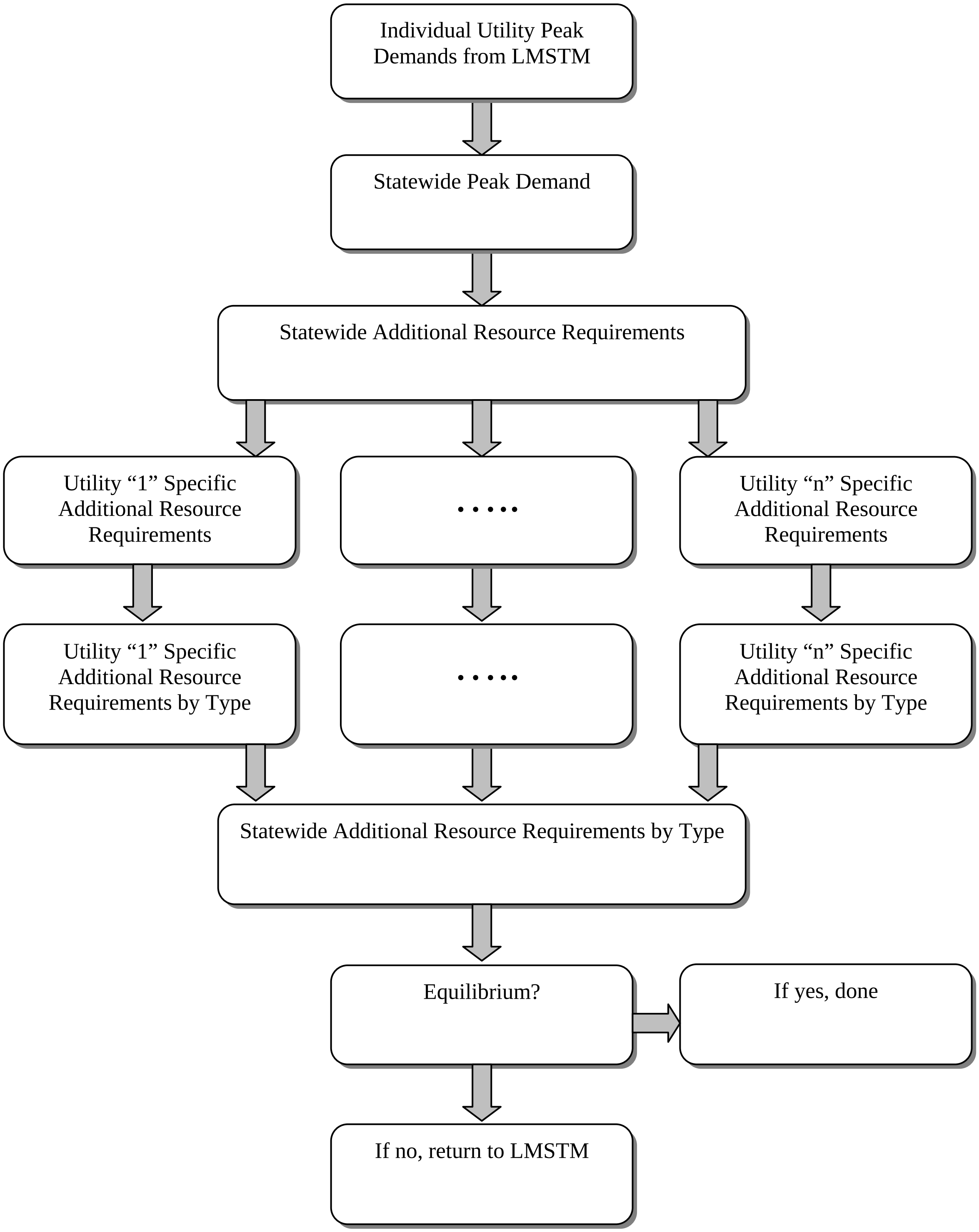
The required resources are then assigned to the individual utilities with the lowest reserve margins, so that all utilities have similar reserve margins. Even if the state's reserve margin meets the 16.3 percent target, resources will be assigned to an individual utility if necessary to bring the utility's reserve margin up to 6 percent. These utility specific additional resource requirements are then assigned to one of the three types. 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. It also includes 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 1.55 percent for electricity requirements and 1.61 percent for peak demand. The numbers listed as "Actual" in the tables indicate historical values. As shown in Table 3-3, the growth rate for electricity sales in this forecast is about 0.9 percent lower than the 2007 forecast. As one would expect, the current economic situation and the projected future path of the economy have a dramatic effect on the electricity sales forecast. The growth within sectors varies considerably with higher growth in the residential and commercial sectors offsetting lower growth in the industrial sector, but the forecast growth for all sectors is markedly below that forecast in 2007. 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 below the previous forecast and that the gap between the projections widens over the forecast horizon. This general pattern is followed in all three sectors.

The growth in peak demand is similarly lower than that projected in 2007 and follows the same pattern in relation to the 2007 projection as is observed for the total energy requirements. Forecast peak demand growth is slightly higher than that of electricity requirements (1.61 versus 1.55 percent) because energy growth in the residential and commercial sectors, both of which have weather sensitive heating and cooling load, tends to affect peak demand more than the industrial sector load. 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 350 MW compared to about 585 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 and interruptible load are netted from the demand projection, and generic resources are added as necessary to maintain a 16.3 percent reserve margin (see Chapter 2 for discussions 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

The current projection includes the energy and demand impacts of existing or planned utility-sponsored DSM programs. Incremental DSM programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 80 MW at the beginning of the forecast period and by about 700 MW at the end of the forecast.

These DSM projections do not include the reductions in peak demand due to interruptible load contracts with large customers. Interruptible loads are projected to increase from 855 MW to about 970 MW over the forecast horizon. See Chapter 4 for additional information about DSM and interruptible loads.

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

		Year of Forecast		
Year	**Actual**	**2005**	**2007**	**2009**
1980	57676			
1981	57648			
1982	61823			
1983	62511			
1984	64717			
1985	64380			
1986	65024			
1987	67794			
1988	71988			
1989	73326			
1990	73742			
1991	76034			
1992	77207			
1993	82669			
1994	85446			
1995	88514			
1996	90637			
1997	89773			
1998	93429			
1999	98001			
2000	98239			
2001	99304			
2002	104670			
2003	102922			
2004	104391	107237		
2005	108103	110069		
2006	109182	112911	110164	
2007	112753	114937	112877	
2008		117223	115702	111873
2009		119318	117484	110073
2010		122126	120066	111037
2011		124565	122717	113524
2012		127052	125618	116112
2013		129762	128829	118201
2014		132740	132458	120339
2015		135689	135847	122200
2016		138882	139551	124045
2017		141991	143223	125898
2018		145183	147253	127819
2019		148501	151122	130006
2020		151927	155092	132184
2021		155404	159011	134540
2022		159020	163096	136972
2023		162617	166895	139376
2024			170826	141954
2025			174667	144495
2026				147082
2027				149873

Average Compound Growth Rates			
Forecast Period	**2004-2023**	**2006-2025**	**2008-2027**
	2.22	2.46	1.55

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

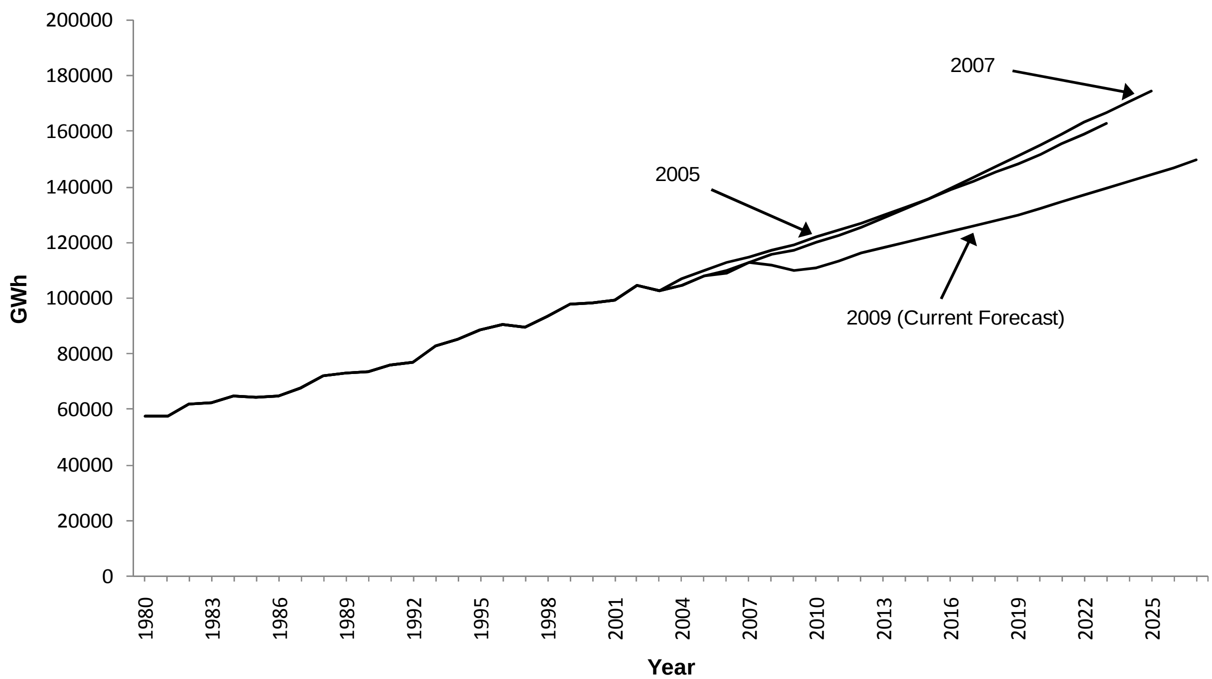


Figure 3-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)

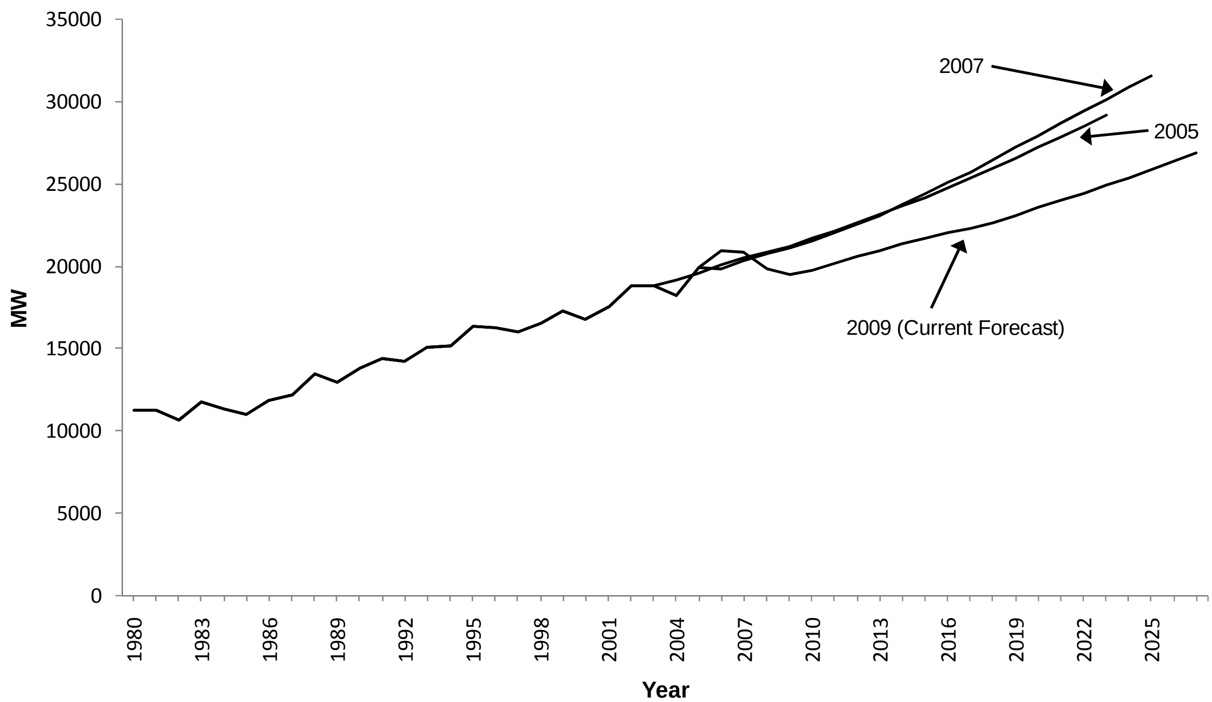


Table 3-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)

		Year of Forecast		
Year	**Actual**	**2005**	**2007**	**2009**
1980	11284			
1981	11235			
1982	10683			
1983	11744			
1984	11331			
1985	11030			
1986	11834			
1987	12218			
1988	13447			
1989	12979			
1990	13775			
1991	14403			
1992	14209			
1993	15103			
1994	15198			
1995	16342			
1996	16254			
1997	15993			
1998	16527			
1999	17266			
2000	16757			
2001	17531			
2002	18851			
2003	18843			
2004	18254	19167		
2005	19966	19599		
2006	20910	20052	19874	
2007	20842	20486	20331	
2008		20820	20803	19832
2009		21201	21099	19530
2010		21712	21541	19741
2011		22167	22010	20156
2012		22620	22520	20597
2013		23121	23104	20966
2014		23666	23756	21341
2015		24206	24387	21695
2016		24790	25062	22018
2017		25362	25736	22341
2018		25954	26474	22679
2019		26574	27185	23075
2020		27211	27921	23550
2021		27855	28647	23992
2022		28526	29400	24450
2023		29196	30112	24904
2024			30843	25389
2025			31562	25868
2026				26354
2027				26873

Average Compound Growth Rates			
Forecast Period	**2004-2023**	**2006-2025**	**2008-2027**
	2.24	2.46	1.61

Table 3-3. Annual Electricity Sales Growth (Percent) by Sector (Current vs. 2007 Projections)

Sector	Current (2008-2027)	2007 (2006-2025)
Residential	1.75	2.21
Commercial	1.18	2.46
Industrial	1.63	2.67
Total	1.55	2.46

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. Due to the timing and uncertainty over Duke Energy's shutdown of three Wabash River units, SUFG has not removed those units from the existing mix of generators. 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 16.3 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.

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), cycling units to be gas-fired combined cycle (CC) plants, and baseload units to be pulverized coal (PC) plants meeting presently existing environmental requirements. 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 a need for only 10 MW of peaking, and no need for cycling or base load resources required by 2010. These requirements are much lower than those identified in the 2007 forecast, primarily as a result of new long-term power purchases of wind generated power, the acquisition of gas fired generation, the approval and construction of the Edwardsport integrated gasification plant, an increase in estimated DSM demand impacts, and the reduced growth in peak demand resulting from the economic recession. By 2015, over 1,300 MW of resource additions are required, with a mix of approximately 36 percent peaking, 23 percent cycling, and 41 percent base load. About 4,000 MW of resource additions are required by 2020, and 6,900 MW by 2025. The net change in generation includes the retirement of units as reported in the utilities' 2007 IRP filings, changes in firm purchases and sales, and the addition of approved new capacity. If Duke Energy retires the affected Wabash River units, additional resources of approximately 250 MW will be required.

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 is 2007. Therefore, 2008 and 2009 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

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. The impact of this feature on the forecast of electricity requirements can be significant if price changes are large.

[1] Duke Energy shut down its Wabash River units 2, 3, and 5 in September 2009 as a result of a U.S. District Court ruling regarding alleged violations of the Clean Air Act. At the time this forecast was prepared, the status of any decision to appeal that ruling was unknown

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

	Uncontrolled Peak Demand[1]	Interruptible	Net Peak Demand[2]	Existing/ Approved Capacity[3]	Incremental Change in Capacity[4]	Projected Additional Resource Requirements[5]				Total Resources[6]	Reserve Margin
						Peaking	Cycling	Baseload	Total		
2007				22,129							
2008	20,687	855	19,832	22,656	527	110	200	220	530	23,186	17
2009	20,394	864	19,530	23,417	762	0	0	10	10	23,427	20
2010	20,611	870	19,741	23,208	-209	10	0	0	10	23,218	18
2011	21,036	880	20,156	23,275	66	170	20	90	280	23,555	17
2012	21,481	884	20,597	23,874	599	280	40	130	450	24,324	18
2013	21,860	894	20,966	23,774	-100	350	120	260	730	24,504	17
2014	22,252	911	21,341	24,036	262	420	150	380	950	24,986	17
2015	22,623	928	21,695	23,918	-118	480	300	540	1,320	25,238	16
2016	22,962	944	22,018	23,796	-122	610	400	780	1,790	25,586	16
2017	23,298	957	22,341	23,796	0	730	460	990	2,180	25,976	16
2018	23,650	971	22,679	23,509	-287	810	750	1,300	2,860	26,369	16
2019	24,046	971	23,075	23,475	-34	980	830	1,550	3,360	26,835	16
2020	24,521	971	23,550	23,320	-155	1,300	920	1,830	4,050	27,370	16
2021	24,963	971	23,992	23,316	-4	1,410	990	2,180	4,580	27,896	16
2022	25,421	971	24,450	23,326	10	1,560	1,050	2,510	5,120	28,446	16
2023	25,875	971	24,904	23,166	-160	1,690	1,260	2,830	5,780	28,946	16
2024	26,360	971	25,389	23,166	0	1,920	1,360	3,090	6,370	29,536	16
2025	26,839	971	25,868	23,158	-8	2,040	1,420	3,450	6,910	30,068	16
2026	27,325	971	26,354	23,141	-18	2,090	1,460	3,960	7,510	30,651	16
2027	27,844	971	26,873	22,991	-150	2,340	1,530	4,360	8,230	31,221	16

1 Uncontrolled peak demand is the peak demand without any interruptible loads being called upon.

2 Net peak demand is the peak demand after interruptible loads are taken into account.

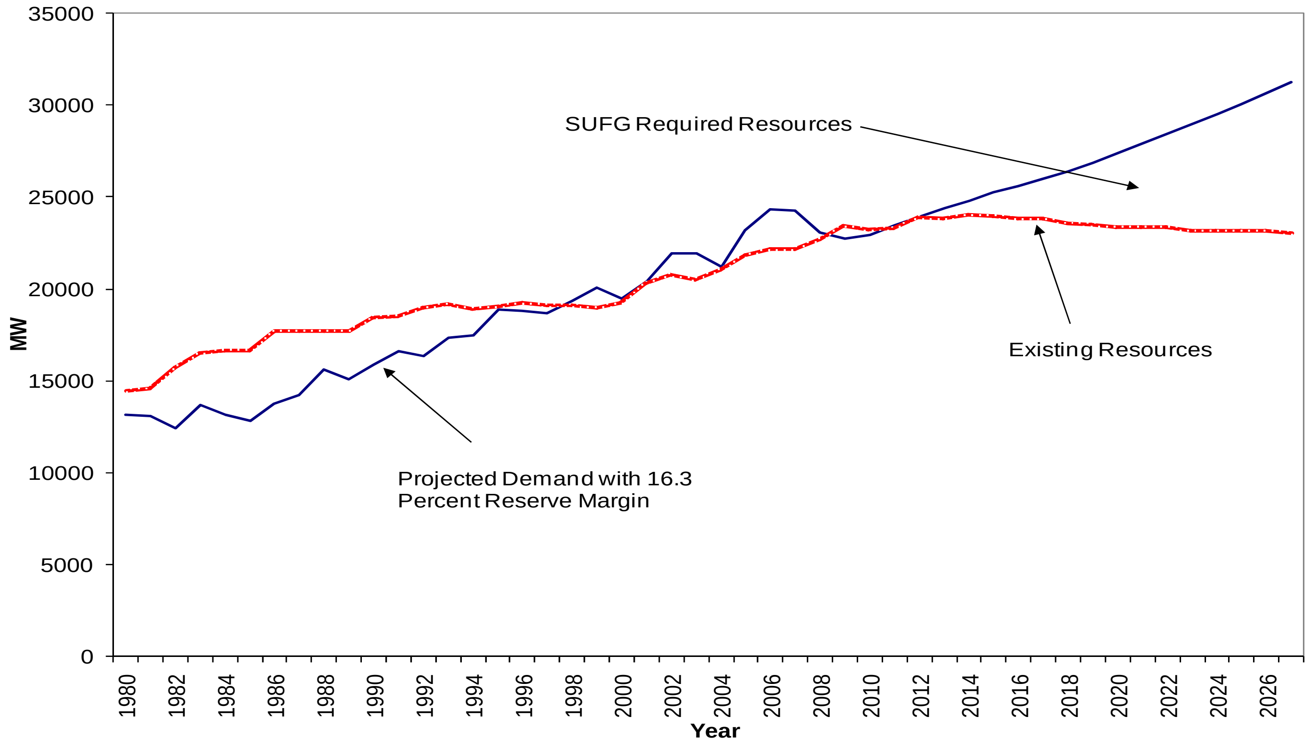
3 Existing/approved capacity includes installed capacity plus approved new capacity plus firm purchases minus firm sales.

4 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.

5 Projected additional resource requirements is the cumulative amount of additional resources needed to meet future requirements.

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

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



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 significantly through 2013 and then slowly drift upward 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 "2005" is the base case projection contained in SUFG's 2005 forecast and the one labeled "2007" is the base case projections from SUFG's 2007 report. For the prior price forecasts, SUFG rescaled the original price projections to 2007 dollars (from 2003 dollars for the 2005 projection, and from 2005 dollars for the 2007 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

Three major factors primarily determine the differences among the price projections in Figure 3-4: first, the cost of controlling emissions from coal-fired generation facilities to meet air emission standards, second, higher purchase power costs and third, generation plant additions by acquisition and new plant construction. It should be noted that the costs associated with meeting the first phase of the Clean Air Interstate Rule (CAIR) but not those associated the Clean Air Mercury Rule (CAMR) are included in the current forecast. CAIR was initially vacated by the United States D.C. Circuit Court but subsequently remanded on appeal. The rule remains in effect until the U.S. Environmental Protection Agency replaces it with a rule that conforms to the court's opinion. CAMR was vacated by the same court and has not been replaced with another mercury control measure. The costs of both CAIR and CAMR were incorporated in the 2007 SUFG forecast but not in 2005 forecast.[2] Costs associated with compliance with CAIR are considerably higher in this forecast than in the 2007 SUFG forecast because of large increases in the cost of steel, concrete and other components of the emissions control equipment. Other factors such as energy and demand growth as well as fossil fuel price assumptions, especially coal, also influence the trajectory of future prices.

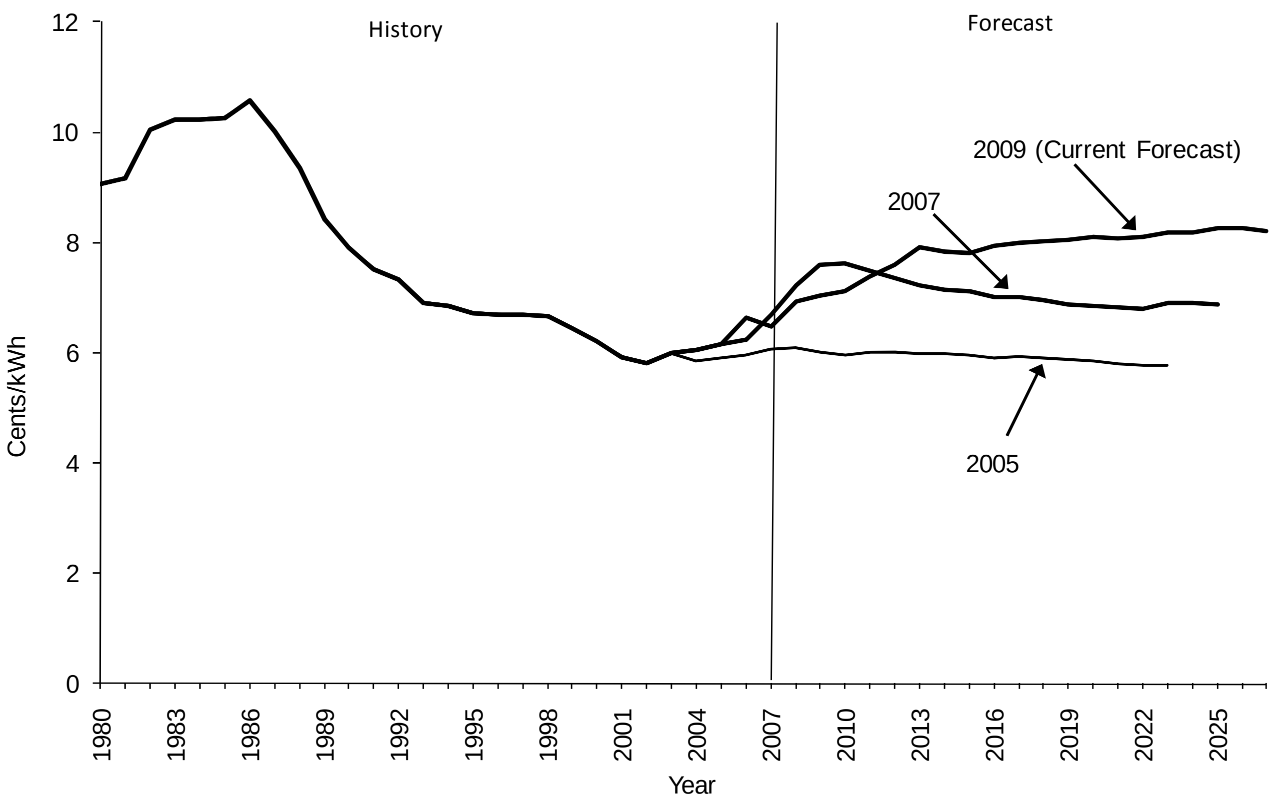
[2] SUFG performed two separate analyses that looked at the price impacts of CAIR and CAMR. The reports, "The Projected Impacts of the Clean Air Interstate Rule on Electricity Prices in Indiana" and "The Projected Impacts of Mercury Emissions Reductions on Electricity Prices in Indiana," are available on the SUFG website.

Table 3-5. Indiana Real Price Projections in cents/kWh (2007 Dollars) (Historical, Current, and Previous Forecasts)

Year	Actual	2005	2007	2009
1980	9.070			
1981	9.163			
1982	10.049			
1983	10.218			
1984	10.236			
1985	10.263			
1986	10.571			
1987	10.011			
1988	9.349			
1989	8.420			
1990	7.909			
1991	7.526			
1992	7.337			
1993	6.911			
1994	6.855			
1995	6.732			
1996	6.705			
1997	6.685			
1998	6.672			
1999	6.445			
2000	6.204			
2001	5.923			
2002	5.807			
2003	5.988			
2004	6.063	5.864		
2005	6.167	5.906		
2006	6.649	5.971	6.232	
2007	6.466	6.071	6.702	
2008		6.090	7.229	6.939
2009		6.005	7.590	7.049
2010		5.966	7.622	7.128
2011		6.004	7.484	7.381
2012		6.021	7.352	7.586
2013		5.998	7.224	7.909
2014		5.986	7.154	7.839
2015		5.957	7.112	7.821
2016		5.904	7.020	7.934
2017		5.927	7.005	7.988
2018		5.911	6.946	8.030
2019		5.887	6.876	8.049
2020		5.847	6.862	8.099
2021		5.810	6.824	8.086
2022		5.780	6.807	8.109
2023		5.763	6.915	8.180
2024			6.896	8.174
2025			6.881	8.252
2026				8.253
2027				8.218

Average Compound Growth Rates			
Forecast Period	**2004-2023**	**2006-2025**	**2008-2027**
	-0.09	0.52	0.89

Figure 3-4. Indiana Real Price Projections in cents/kWh (2007 Dollars) (Historical, Current, and Previous Forecasts)



SUFG does not attempt to incorporate the costs of regulations that are not in place at the time the forecast is prepared. Thus, this forecast does not include costs associated with meeting a renewable energy portfolio standard or controlling carbon dioxide emissions.

Low and High Scenarios

SUFG has used alternative macroeconomic scenarios, reflecting low and high growth. 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 the low and high scenarios are about 0.30 percent lower and 0.40 percent higher than the base scenario for both energy requirements and peak demand. 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 interruptible loads, are the same in all three scenarios, as are retirements of generating units. Table 3-8 shows the statewide resource requirements for each scenario. Approximately 10,700 MW over the horizon are required in the high scenario compared to 6,500 MW in the low scenario. By the end of the forecast period, electricity prices in the high case are about 2.4 percent higher than in the base case. This is because nearly 2,500 MW of additional wholesale purchases are acquired relative to the base scenario. Similarly, prices in the low scenario are about 1.8 percent lower than the base scenario.

Table 3-6. Indiana Electricity Requirements by Scenario in GWh

Year	Actual	Base	Low	High
1980	57676			
1981	57648			
1982	61823			
1983	62511			
1984	64717			
1985	64380			
1986	65024			
1987	67794			
1988	71988			
1989	73326			
1990	73742			
1991	76034			
1992	77207			
1993	82669			
1994	85446			
1995	88514			
1996	90637			
1997	89773			
1998	93429			
1999	98001			
2000	98239			
2001	99304			
2002	104670			
2003	102922			
2004	104391			
2005	108103			
2006	109182			
2007	112753			
2008		111873	111524	112255
2009		110073	109387	110829
2010		111037	110005	112194
2011		113524	112107	115077
2012		116112	114896	118193
2013		118201	116580	120901
2014		120339	118242	123621
2015		122200	119577	125889
2016		124045	121065	128199
2017		125898	122543	130629
2018		127819	123986	133175
2019		130006	125721	135971
2020		132184	127406	138781
2021		134540	129276	141835
2022		136972	131177	145006
2023		139376	133005	148210
2024		141954	134993	151585
2025		144495	136922	155007
2026		147082	138853	158563
2027		149873	140924	162331

Average Compound Growth Rates			
Periods	**Base**	**Low**	**High**
1980-85	2.22	2.22	2.22
1985-90	2.75	2.75	2.75
1990-95	3.72	3.72	3.72
1995-00	2.11	2.11	2.11
2000-05	1.93	1.93	1.93
2005-07	2.13	2.13	2.13
2008-27	1.55	1.24	1.96

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

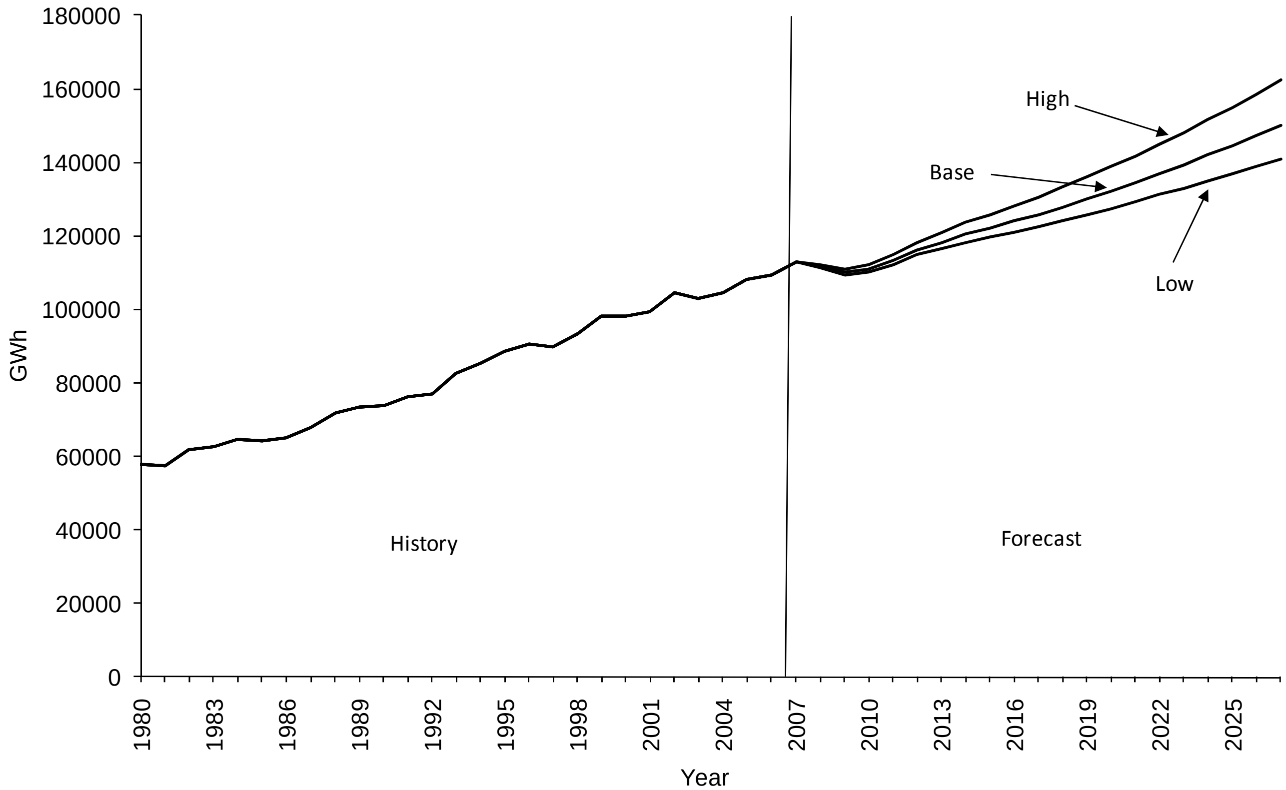


Table 3-7. Indiana Peak Demand Requirements by Scenario in MW

Year	Actual	Base	Low	High
1980	11284			
1981	11235			
1982	10683			
1983	11744			
1984	11331			
1985	11030			
1986	11834			
1987	12218			
1988	13447			
1989	12979			
1990	13775			
1991	14403			
1992	14209			
1993	15103			
1994	15198			
1995	16342			
1996	16254			
1997	15993			
1998	16527			
1999	17266			
2000	16757			
2001	17531			
2002	18851			
2003	18843			
2004	18254			
2005	19966			
2006	20910			
2007	20842			
2008		19832	19775	19898
2009		19530	19417	19659
2010		19741	19571	19938
2011		20156	19923	20419
2012		20597	20394	20954
2013		20966	20697	21433
2014		21341	20990	21909
2015		21695	21255	22333
2016		22018	21519	22737
2017		22341	21780	23155
2018		22679	22038	23602
2019		23075	22358	24101
2020		23550	22754	24684
2021		23992	23110	25244
2022		24450	23473	25828
2023		24904	23829	26418
2024		25389	24211	27035
2025		25868	24586	27661
2026		26354	24960	28312
2027		26873	25357	29000

Average Compound Growth Rates			
Period	**Base**	**Low**	**High**
1980-85	-0.45	-0.45	-0.45
1985-90	4.55	4.55	4.55
1990-95	3.48	3.48	3.48
1995-00	0.50	0.50	0.50
2000-05	3.57	3.57	3.57
2005-07	2.17	2.17	2.17
2008-27	1.61	1.32	2.00

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

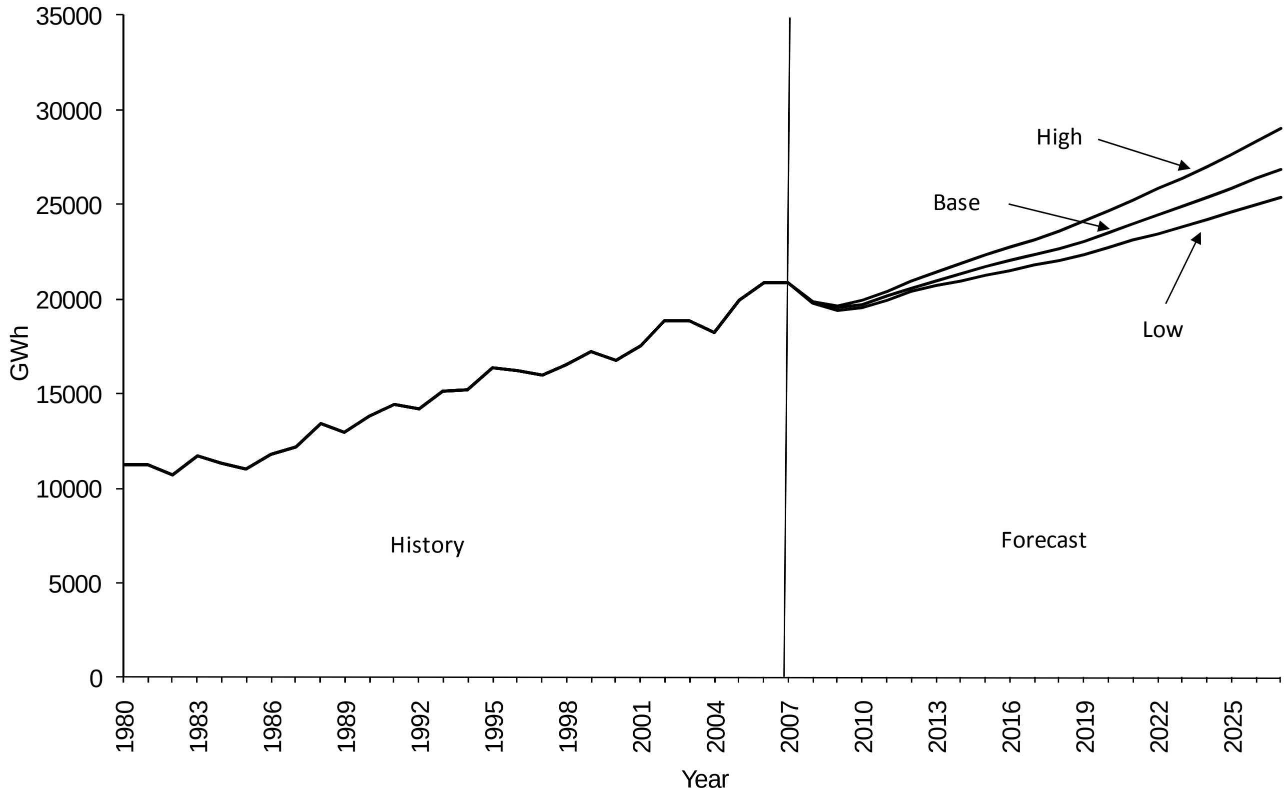


Table 3-8. Indiana Resource Requirements in MW (SUFG Scenarios)

Year	Base				High				Low			
	Peaking	Cycling	Baseload	Total	Peaking	Cycling	Baseload	Total	Peaking	Cycling	Baseload	Total
2008	110	200	220	530	130	210	260	600	100	190	210	500
2009	0	0	10	10	0	0	40	40	0	0	0	0
2010	10	0	0	10	50	0	0	50	0	0	0	0
2011	170	20	90	280	220	60	230	510	120	10	20	150
2012	280	40	130	450	320	50	210	580	260	40	110	410
2013	350	120	260	730	470	230	450	1,150	330	80	210	620
2014	420	150	380	950	570	270	590	1,430	370	130	320	820
2015	480	300	540	1,320	740	470	850	2,060	430	200	430	1,060
2016	610	400	780	1,790	920	550	1,180	2,650	460	280	540	1,280
2017	730	460	990	2,180	1,050	600	1,480	3,130	540	340	660	1,540
2018	810	750	1,300	2,860	1,110	920	1,910	3,940	610	600	920	2,130
2019	980	830	1,550	3,360	1,290	1,000	2,260	4,550	740	660	1,120	2,520
2020	1,300	920	1,830	4,050	1,680	1,080	2,620	5,380	1,030	770	1,320	3,120
2021	1,410	990	2,180	4,580	1,840	1,170	3,020	6,030	1,150	850	1,570	3,570
2022	1,560	1,050	2,510	5,120	2,010	1,260	3,410	6,680	1,230	880	1,840	3,950
2023	1,690	1,260	2,830	5,780	2,210	1,520	3,820	7,550	1,340	1,100	2,100	4,540
2024	1,920	1,360	3,090	6,370	2,380	1,630	4,260	8,270	1,500	1,170	2,310	4,980
2025	2,040	1,420	3,450	6,910	2,520	1,700	4,770	8,990	1,620	1,220	2,590	5,430
2026	2,090	1,460	3,960	7,510	2,670	1,780	5,320	9,770	1,660	1,240	3,000	5,900
2027	2,340	1,530	4,360	8,230	2,990	1,850	5,860	10,700	1,840	1,280	3,370	6,490

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 load 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 2009 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 2008-2029" [CEMR] are:

Federal tax rates are assumed to increase over the projection period. Specifically, the average tax rate on personal income is assumed to rise about 13 percent and the payroll tax rate by close to 19 percent. Federal grants to state and local governments are assumed to grow at about 6.7 percent annually early in the projection period and then decelerate to about a 4.6 percent by the end of the projection period. The federal budget (in nominal terms) rises until 2021 and then declines somewhat.

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

Real exports are assumed to grow at about 5.3 percent through 2017, and then to decelerate gradually to 4.7 percent growth. This produces a (nominal) net export deficit that declines from 3.7 percent of GDP to 2.4 percent (CEMR, 2009).

As a result of these assumptions, real Gross Domestic Product (GDP) for the U.S. economy is projected to grow at an average annual rate of 2.76 percent and U.S. employment growth averages 1.00 percent over the 2008 to 2027 period.

In Indiana, total employment is projected to grow at an average annual rate of 0.83 percent from 2008 through 2027. The key economic projections are:

Real personal income (the residential sector model driver) is expected to grow at a 1.63 percent annual rate.

Non-manufacturing employment (the commercial sector model driver) is expected to average a 1.16 percent annual growth rate over the forecast horizon.

Despite the continued decline of manufacturing employment, manufacturing GSP (the industrial sector model driver) is expected to rise at a 2.23 percent annual rate as gains in productivity offset declines in employment.

CEMR's macroeconomic projections reflect a continuation of the economic recovery. Real Indiana personal income began recovering in 2002. Indiana nonmanufacturing employment shows an increase in 2003, and manufacturing output (real GSP) first began to increase in 2002.

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 a low and high growth alternative 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 0.27 percent per year (to 1.90), non-manufacturing employment growth increases almost 0.08 percent (to 1.24) while Indiana real manufacturing GSP growth is increased nearly 0.66 percent (to 2.89). In the low growth alternative, the average growth rates of real personal income, non-manufacturing employment and real manufacturing GSP are reduced by similar amounts (to 1.38, 1.07 and 1.84 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 2005-2025. This projection was developed in 2004 and includes projections of county population by age group, the fastest growing age groups are those of age 45-64 (0.45 percent) and age 65 and over (2.39 percent). Population growth 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 45 (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 about 1.4 percent currently. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of about 1.00 percent over the forecast period.

Table 4-1. Growth Rates for Current and Past CEMR Projections of Selected Economic Activity Measures

	Short-Run History for Selected Recent Periods					Long-Run Forecast		
						Feb 2005	Feb 2007	Feb 2009
	1985-1990	1990-1995	1995-2000	2000-2005	2005-2010*	2004-2023	2006-2025	2008-2027
United States								
Real Personal Income	2.95	2.04	4.08	1.73	1.77	3.29	3.25	2.76
Total Employment	2.36	1.38	2.37	0.25	0.45	1.10	0.97	1.00
Real Gross Domestic Product	3.25	2.38	4.36	2.39	1.59	3.25	3.20	2.76
Personal Consumer Expenditure Deflator	3.79	2.77	1.87	2.20	2.97	1.99	1.94	1.72
Indiana								
Real Personal Income	2.50	2.48	3.37	1.17	0.87	2.22	2.10	1.63
Employment								
Total Establishment	2.84	1.91	1.22	-0.28	-0.12	0.94	0.80	0.83
Manufacturing	0.91	1.40	0.07	-2.95	-3.37	-0.02	-1.10	-1.29
Non-Manufacturing	3.82	2.20	1.97	0.47	0.68	1.23	1.12	1.16
Real Gross State Product								
Total	6.17	5.83	4.78	1.98	0.47	2.82	3.21	2.62
Manufacturing	4.76	7.95	4.68	3.26	-0.91	2.84	3.49	2.23
Non-Manufacturing	6.81	4.86	4.84	1.43	1.03	2.81	3.07	2.78

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
*2008, 2009 and 2010 values are projections not actual history

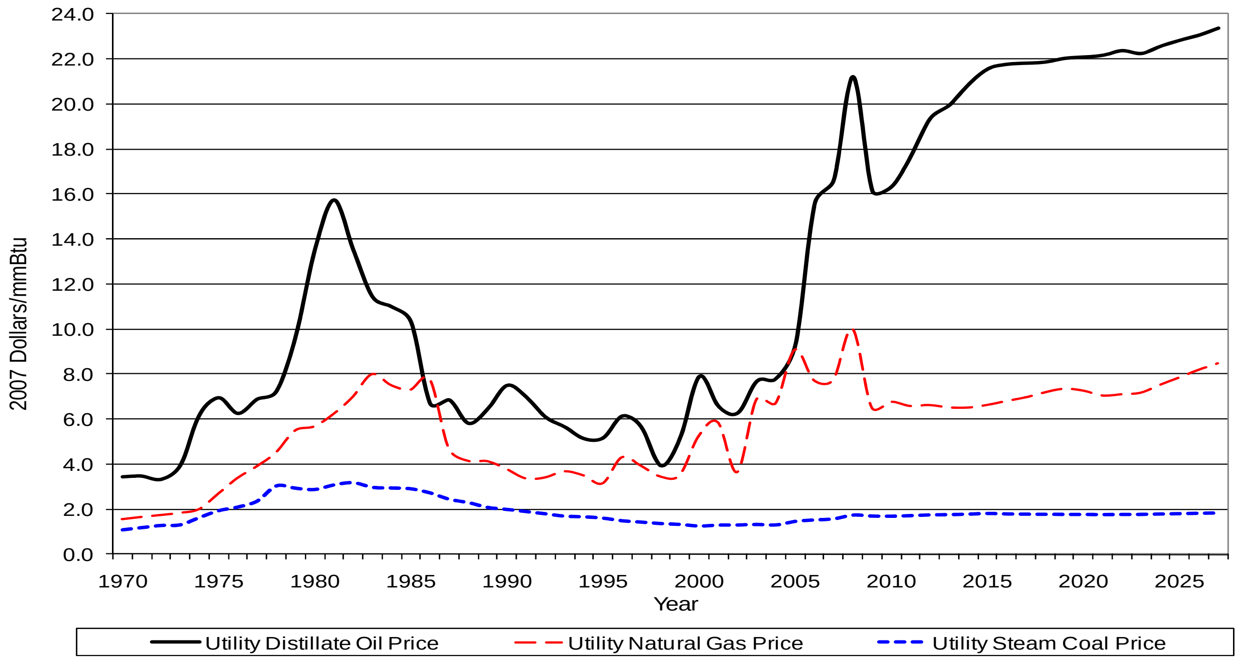
Fossil Fuel Price Projections

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 March 2009 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 (2007 dollars), i.e., projections with the effects of inflation removed. The general patterns of the fossil fuel price projections are:

- Coal prices are relatively unchanged in real terms throughout the entire forecast horizon as growth in demand is offset by improvements in mining productivity.
- Natural gas price projections exhibit a significant decrease in 2009 coming off of the high prices of 2008. Prices are then projected to remain relatively constant through 2015, with a general increase following for the remainder of the forecast horizon.
- Distillate prices also are projected to decrease significantly in 2009, but recover more quickly with a steady increase through the remainder of the forecast horizon.

Figure 4-1. Utility Real Fossil Fuel Prices



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

Demand-Side Management and Interruptible Loads

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 to a time when overall system demand is lower.

Incremental DSM, 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 2007 are considered to be embedded in the calibration data, so no adjustments are necessary.

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, are typically treated differently than traditional DSM. Interruptible loads are subtracted from the utility's peak demand in order to determine the amount of new capacity required.

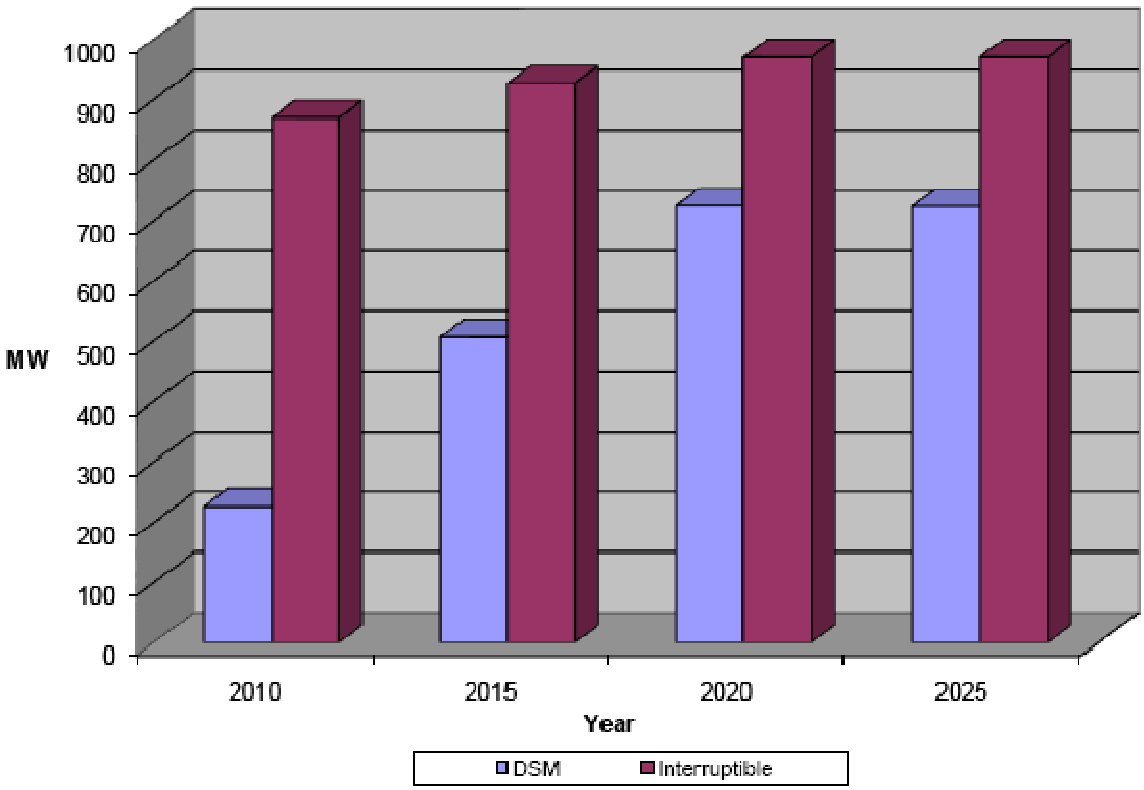
Table 4-2 shows the peak demand reductions from embedded DSM in 2007 and from incremental DSM and interruptible loads available in 2008 in Indiana. These estimates are derived from utility integrated resource plan (IRP) filings and from information collected by EIA. Also included are estimates of the impacts of government sponsored efficiency programs, such as low income weatherization of homes and rebates for high efficiency appliances, that were being implemented when the forecast was prepared. Figure 4-2 shows projected values of peak demand reductions for incremental DSM and interruptible loads at five year intervals starting in the year 2010.

The embedded DSM represents a significant increase from the 588 MW included in the 2007 forecast. This is indicative of a renewed interest in energy efficiency on the part of Indiana utilities. The renewed interest in DSM can also be attributed to two factors. First, the uncertainty over potential deregulation that the electricity industry faced in the late 1990s and early 2000s has dissipated, providing a greater level of certainty to the utilities. Second, as system-wide demand grows, the utilities face a more immediate need for new resources. DSM programs are more likely to be cost-effective if the avoided cost of new supply-side resources enters the equation.

Table 4-2. 2007 Embedded DSM and 2008 Peak Demand Reductions

2007 Embedded DSM	2008 Incremental DSM	2008 Interruptible
857	81	855

Figure 4-2. Peak Demand Reduction from DSM and Interruptible Loads (Projections)



The interruptible load 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.

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 2008-2029,” Indiana University, February 2009.

Energy Information Administration, “Annual Energy Outlook 2009,” March 2009.

Chapter 5

Residential Electricity Sales

Overview

SUFG uses 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 groups. 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, most recently prior to the SUFG 2005 forecast, when major components of the model were partially updated. Since 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. Initial review indicates that given the same set of primary inputs, REDMS produces forecasts similar to the econometric model which SUFG has used for several years. This result is markedly different than the results that SUFG experienced with the older end-use model REEMS which projected much lower growth than the econometric model. SUFG will continue to evaluate REDMS, but for this set of projections SUFG continues to rely on its econometric model to project residential electricity sales. A general description of the residential econometric model follows, along with a brief historical perspective on residential electricity consumption trends in Indiana.

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 is projected in the residential sector for the near term (see Figure 5-1).

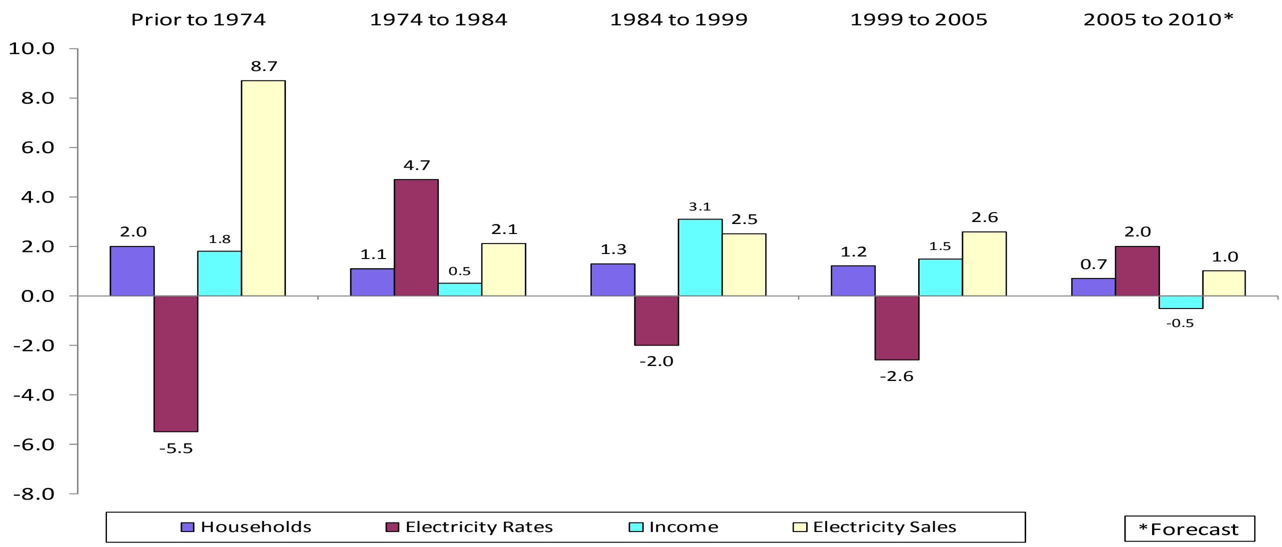
The explosion in residential electricity sales (nearly 9 percent per year) during the decade prior to the Organization of Petroleum Exporting Countries (OPEC) oil embargo in 1974 coincided with the economic stimuli of falling prices (nearly 6 percent per year in real terms) and rising incomes (about 1 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 1979-81, 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 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 prior to 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 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.

In the past few years (1999 to 2005) residential household growth has decreased slightly to 1.2 percent annual rate similar to the 1984 to 1999 period, real electric rates have continued to decline, but the growth in personal income, while positive, has slowed markedly. Despite the slow growth in income, electricity sales have continued to grow at roughly the rate observed during the 1984 to 1999 period.

More recently, from 2005 through the SUFG forecast for 2010, the effects of the economic downturn coupled with rising electricity prices result in much lower growth in electricity sales. Household growth slows to almost one-half the rate observed over the preceding twenty years, real electricity prices increase at an average annual rate of 2.0 percent reversing the trend of the previous twenty years, and real household income turns negative. The net effect of these changes is to cut projected electricity sales growth rate to less than one-half of that observed over the previous twenty years to 1.0 percent per year.

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



Model Description

An important consideration in modeling residential electricity sales is how best to disaggregate electricity use. The SUFG econometric model divides residential customers into two customer groups: electric and non-electric space heating. Sales for each customer group are estimated by multiplying the projected number of customers in each group by their estimated kWh consumption per customer. This market segmentation is necessary since significant differences exist in the appliance portfolios of typical electric and non-electric space heating customers. Households with electric space heating systems tend to have much higher saturations of electric water heating, cooking and clothes drying, and in older dwellings central air conditioning. For these reasons, electric space heating customers consume almost twice the amount of electricity as non-electric space heating customers. In addition to these differences, historical consumption trends for these two customer groups, as shown in Panels E and F of Figure 5-2, have tended to move in opposite directions as well. Yet another reason for dividing residential customers into electric and non-electric space heating groups is shown in Panel B of Figure 5-2. The growth of electric space heating was quite rapid throughout both the pre- and post-embargo period. Panel A of Figure 5-2 depicts the falling price of electricity relative to natural gas during both periods. Relative electricity and gas prices bottomed out in 1983 and since then, the penetration of electricity in the space heating market has fallen markedly.

Space Heating Fuel Choice Model

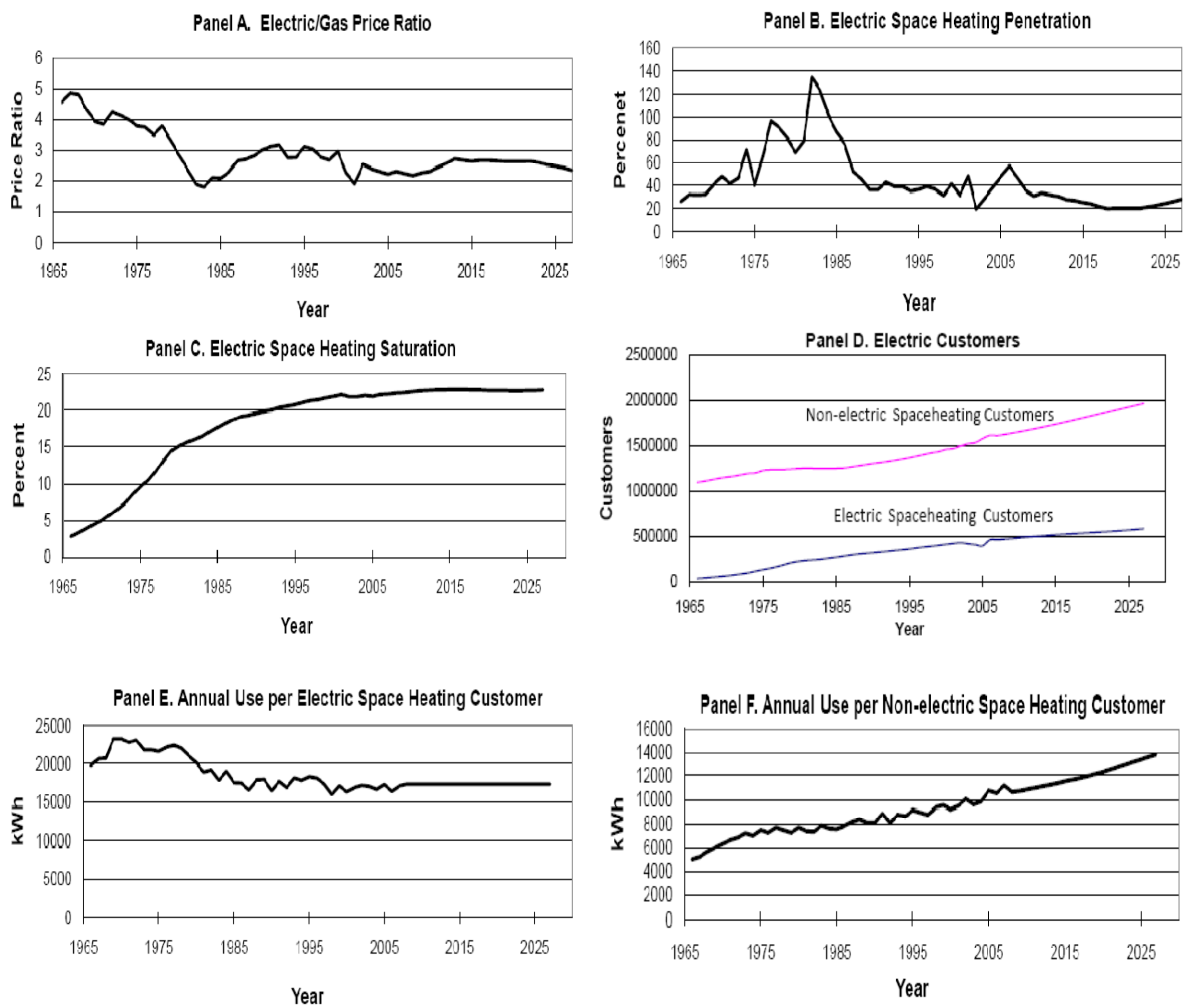
A logit model, based on relative fuel costs, is used to project space heating fuel choice (electric vs. non-electric). This model was estimated from data for the five Indiana IOUs. The dependent variable in this model, referred to as a logit, is the ratio of electricity's share of new space heating systems to that of all other fuels. Market share, or penetration, is defined as the change in the number of electric space heating customers as a fraction of net new customers. Note that penetration may be greater than 100 percent or less than zero due to customers switching to or from electric space heating. The advantages of modeling penetration rather than saturation are that penetration captures current activity, is independent of the rate of customer growth and exhibits greater year-to-year variation. Under SUFG's base case projections of rising real electricity prices through about 2015 and increasing natural gas prices after about 2015, the fuel choice model projects the penetration of electric space heating to range from 20 to over 30 percent over the forecast horizon (for the five IOUs combined). This results in space heating saturation maintaining an average of a little over 20 percent for the forecast horizon (Panel C). The breakdown of customers is shown in Panel D.

After projecting the share of new residential customers choosing electric space heating systems, the residential econometric model projects average electricity consumption for each customer group.

Average kWh Sales: Non-Electric Heating Customers

About 80 percent of all residential customers are non-electric heating customers. Prior to 1975, average electricity consumption by these customers increased about 4.5 percent per year. Since 1975, average use has increased moderately, averaging about 1.0 percent per year. A robust econometric demand model, known as the log-log expenditure share model, is used to estimate the demand for electricity by non-electric heating customers.

Figure 5-2 Drivers of Residential Econometric Model



Average kWh Sales: Electric Space Heating Customers

Average sales to electric space heating customers declined significantly throughout the 1970s and early 1980s (see Panel E in Figure 5-2). This downward trend is most likely attributable to lower consumption by new electric space heating customers (better insulated buildings, heat pumps and a changing mix of type and size of new electrically heated homes) than it is to decreases in consumption by existing customers (i.e., lower thermostat settings and envelope retrofits), although the latter has most likely occurred as well. The application of econometric analysis to capture these effects is not likely to provide reliable or even plausible results on an aggregate level because the heterogeneity among customers over time is too great. SUFG performed limited econometric analysis of this component without success. Consumption data for the last several years indicate that the rapid decline in average energy consumption by electric space heating customers has leveled off after falling nearly 20 percent between the late 1970s and the mid-1980s. A review of the thermal integrity and electric space heating technology curves from the residential end-use model suggested that savings beyond 20 percent would require a substantial increase in the real price of electricity. Given this result, in combination with the outlook for moderately increasing real electricity prices during the forecast period and the apparent leveling off of the decline in usage in recent years, SUFG assumes that the space heating component of an electric space heating customer's consumption will remain constant throughout the forecast period at about 7,500 kWh per year. The non-space heating component of an electric space heating customer's consumption currently averages about 10,000 kWh. Changes in real incomes, real electricity prices and real appliance prices should have little effect on future consumption levels since electric space heating customers already have very high saturations of all major household appliances. Thus, SUFG assumes that this component of a space heating customer's consumption will also remain constant during the forecast period (marginal efficiency improvements will offset marginal saturation and utilization increases). These are the same assumptions made for SUFG's first forecast in 1987. They have been reviewed each year as new data have become available.

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 econometric model include residential customers, household income, and electricity, natural gas and oil 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 the base scenario levels and observing the change in electricity use. The results are shown in Table 5-1. Electricity consumption increases substantially due to increases in both the number of customers and household income. As expected, electricity rate increases reduce electric consumption. Changes in oil prices do not materially affect electricity consumption.

Table 5.1. Residential Model Long-run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Use
Number of Customers	11.1
Electric Rates	-2.4
Natural Gas Price	1.0
Distillate Oil Prices	0.0
Appliance Price	-1.8
Household Income	2.0

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 numbers in the column labeled "Actual" in the table are historical consumption. The growth rate for the current base projection of Indiana residential electricity sales is 1.75 percent nearly 0.5 percent less than SUFG's 2007 projection of 2.21 percent. Table 5-3 shows the growth rates of the major residential drivers for the current scenarios and the 2007 base case. For most of the residential sector drivers, the current base exhibits similar growth, with the exception of the price components. The growth rates for the fossil fuel (oil and natural gas) prices over the forecast horizon are very sensitive to the beginning year due to the recent volatility in prices. While somewhat higher in terms of growth rates, household income drops early in the forecast due to the current recession. Long-term patterns for the entire forecast horizon show that the current projection consistently lies well below both the previous projections. Table 5-4 summarizes SUFG's base projections of residential electricity sales growth since 2005.

These projections are broken down by the portion of the growth rate attributable to the growth in number of customers and growth in utilization per customer, before and after DSM. As the table shows, more than one half of projected sales growth is attributable to customer growth and the remainder to changes in electric intensity (price and income effects). Much of the residential DSM shifts load from peak usage times to off-peak times and has virtually no effect on residential electric intensity growth. Overall, residential DSM reduces sales growth by less than 0.1 percent.

As shown in Table 5-5 and Figure 5-4, the growth rates for the high and low residential scenarios are about 0.25 percent higher and 0.1 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 in GWh (Historical, Current, and Previous Forecasts)

	Actual	2005	2007	2009
1980	16612			
1981	16118			
1982	19927			
1983	19950			
1984	20153			
1985	19707			
1986	20410			
1987	21154			
1988	22444			
1989	22251			
1990	22037			
1991	24215			
1992	22916			
1993	25060			
1994	25176			
1995	26513			
1996	26833			
1997	26792			
1998	27745			
1999	29238			
2000	28413			
2001	29182			
2002	32087			
2003	30837			
2004	31256	32634		
2005	33756	33300		
2006	32570	33876	33822	
2007	35193	34319	34176	
2008		35013	34616	34513
2009		35657	35005	35026
2010		36516	35669	35512
2011		37318	36339	36033
2012		38088	37080	36596
2013		38929	37935	37114
2014		39858	38890	37684
2015		40774	39812	38238
2016		41764	40813	38843
2017		42740	41815	39439
2018		43756	42965	40073
2019		44900	44037	40795
2020		46041	45180	41579
2021		47175	46332	42421
2022		48357	47563	43305
2023		49521	48794	44213
2024			50050	45163
2025			51246	46120
2026				47071
2027				48031

Average Compound Growth Rates			
Forecast Period	**2005-23**	**2007-25**	**2009-27**
	2.22	2.21	1.75

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

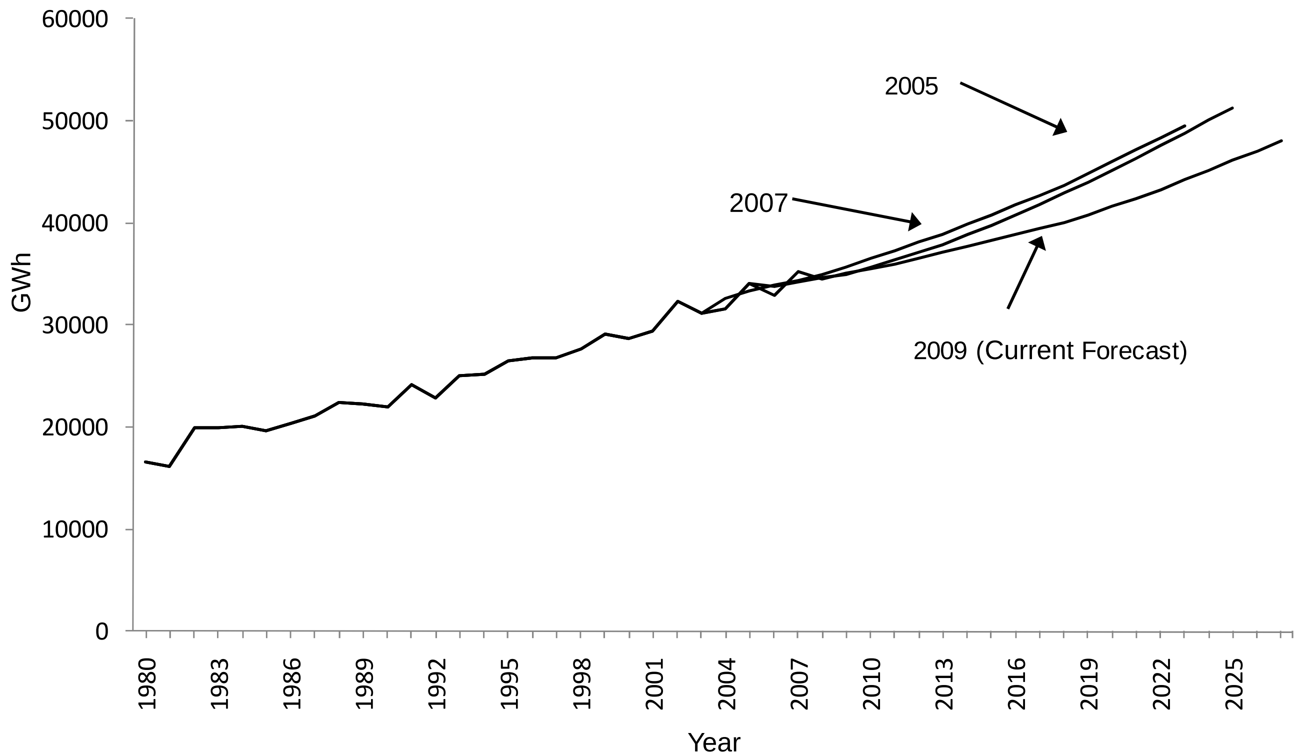


Table 5-3. Residential Model Explanatory Variables - Growth Rates by Forecast (Percent)

Forecast	Current Scenario (2008-2027)			2007 Forecast (2006-2025)
	Base	Low	High	Base
No. of Customers	1.00	1.00	1.00	0.94
Appliance Prices	-3.00	-3.00	-3.00	-3.00
Electric Rates	0.66	0.59	0.74	0.21
Natural Gas Price	0.25	0.25	0.25	-0.96
Oil Prices	0.05	0.05	0.05	-1.33
Household Income	2.35	1.81	3.02	2.02

Table 5-4. History of SUFG Residential Sector Growth Rates (Percent)

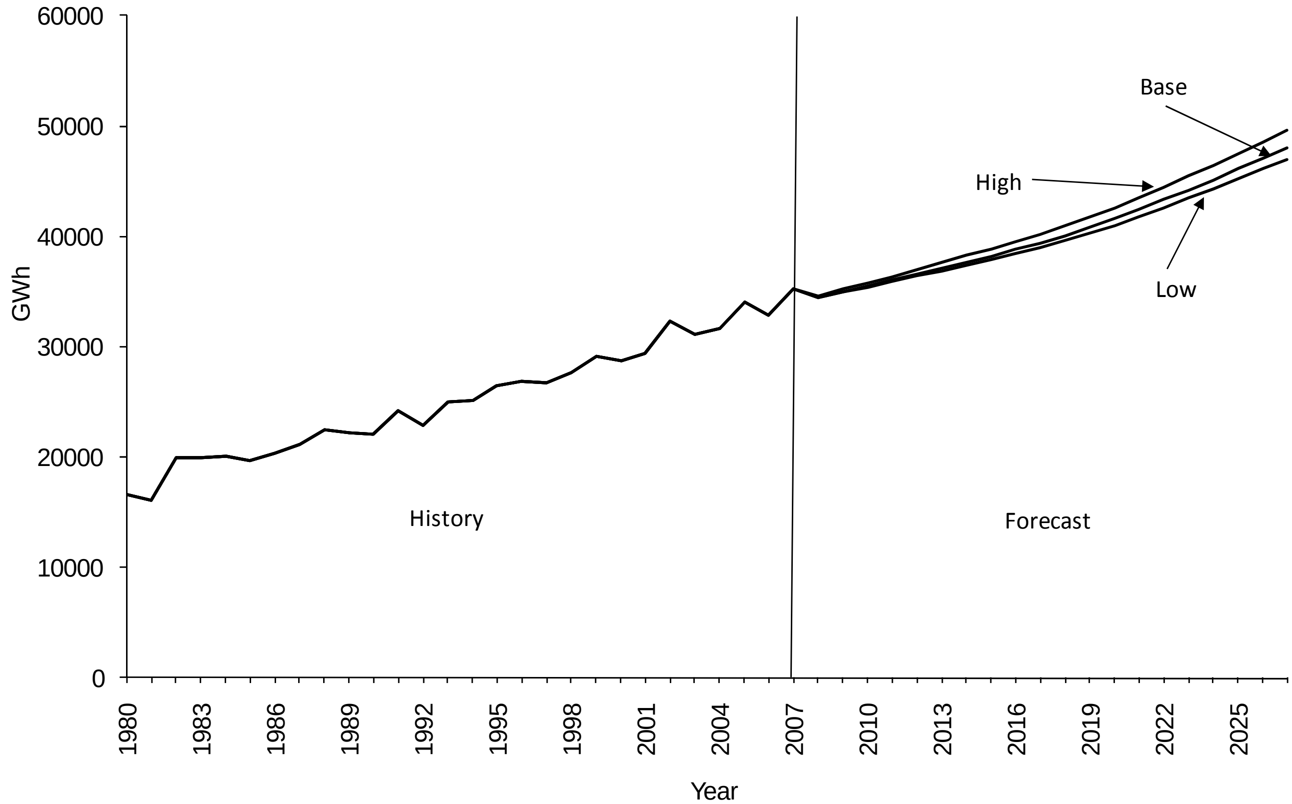
Forecast	No. of Customers	Prior to DSM		After DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2009 SUFG Base (2008-2027)	1.00	0.83	1.83	0.75	1.75
2007 SUFG Base (2006-2025)	0.94	1.29	2.23	1.27	2.21
2005 SUFG Base (2004-2023)	1.00	1.22	2.22	1.22	2.22

Table 5-5. Indiana Residential Electricity Sales by Scenario in GWh

Year	Actual	Base	Low	High
1980	16612			
1981	16118			
1982	19927			
1983	19950			
1984	20153			
1985	19707			
1986	20410			
1987	21154			
1988	22444			
1989	22251			
1990	22037			
1991	24215			
1992	22916			
1993	25060			
1994	25176			
1995	26513			
1996	26833			
1997	26792			
1998	27745			
1999	29238			
2000	28413			
2001	29182			
2002	32087			
2003	30837			
2004	31256			
2005	33722			
2006	32570			
2007	35193			
2008		34513	34479	34610
2009		35026	34958	35194
2010		35512	35407	35754
2011		36033	35888	36349
2012		36596	36402	37002
2013		37114	36878	37620
2014		37684	37395	38281
2015		38238	37883	38894
2016		38843	38460	39555
2017		39439	39036	40211
2018		40073	39601	40952
2019		40795	40278	41745
2020		41579	41001	42599
2021		42421	41790	43515
2022		43305	42617	44471
2023		44213	43465	45456
2024		45163	44364	46451
2025		46120	45260	47482
2026		47071	46154	48524
2027		48031	47028	49577

Average Compound Growth Rates			
Periods	**Base**	**Low**	**High**
1980-85	3.48	3.48	3.48
1985-90	2.26	2.26	2.26
1990-95	3.77	3.77	3.77
1995-00	1.39	1.39	1.39
2000-05	3.48	3.48	3.48
2005-07	2.16	2.16	2.16
2008-27	1.75	1.65	1.91

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



Indiana Residential Electricity Price Projections

Historical values and current projections of residential electricity prices are shown in Table 5-6 and Figure 5-5. 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 2013 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 patterns as the state as a whole, but there are variations across the utilities.

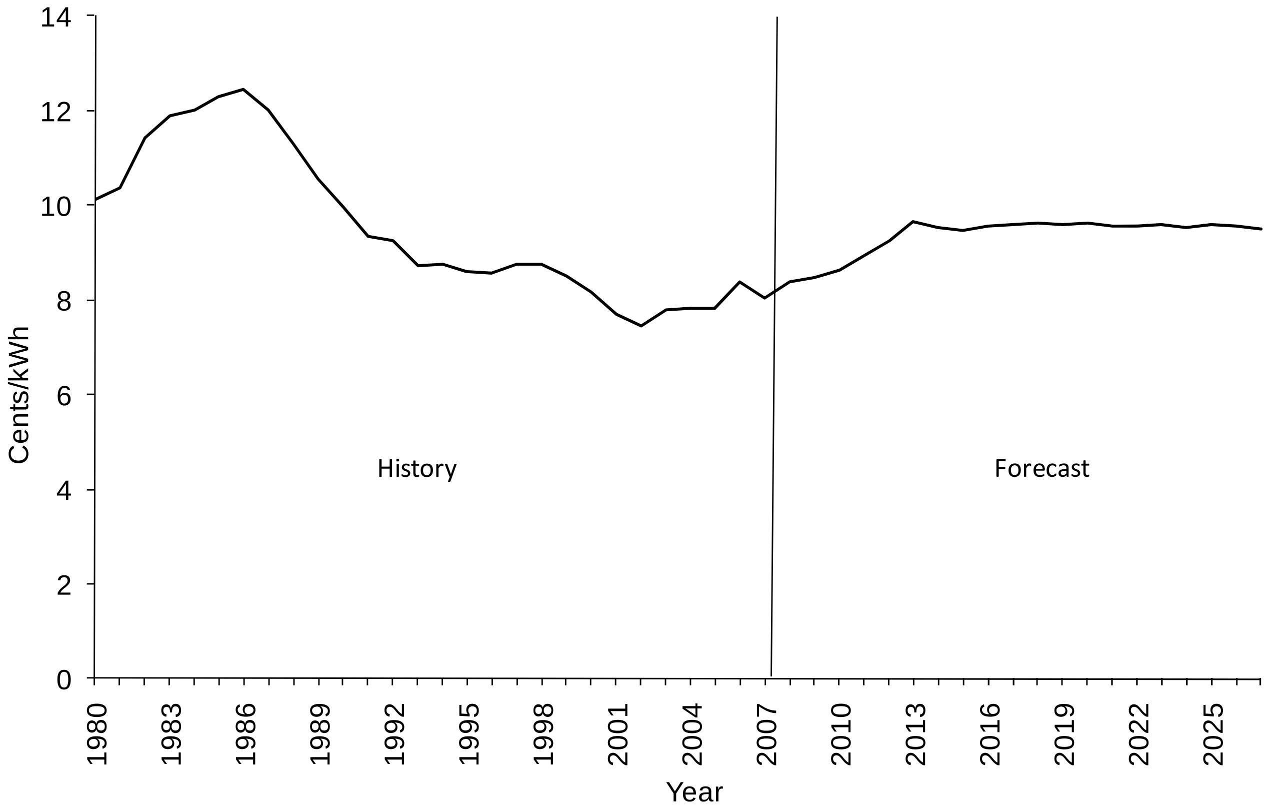
Table 5-6. Indiana Residential Real Price Projections (SUFG Base) (2007 Dollars)

Year	Real Price	Year	Real Price
1980	10.11	2004	7.81
1981	10.36	2005	7.82
1982	11.44	2006	8.37
1983	11.90	2007	8.04
1984	12.01	2008	8.37
1985	12.30	2009	8.48
1986	12.45	2010	8.62
1987	12.01	2011	8.95
1988	11.31	2012	9.24
1989	10.56	2013	9.66
1990	9.95	2014	9.53
1991	9.33	2015	9.46
1992	9.25	2016	9.57
1993	8.72	2017	9.61
1994	8.74	2018	9.62
1995	8.59	2019	9.60
1996	8.57	2020	9.61
1997	8.74	2021	9.56
1998	8.76	2022	9.55
1999	8.50	2023	9.59
2000	8.15	2024	9.54
2001	7.71	2025	9.59
2002	7.46	2026	9.56
2003	7.78	2027	9.48

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	3.99
1985-1990	-4.15
1990-1995	-2.89
1995-2000	-1.05
2000-2005	-0.83
2005-2007	1.41
2008-2027	0.66

Notes: The shaded numbers in the table are historical values. (For an explanation of how SUFG arrives at these numbers, see the Appendix.)

Figure 5-5. Indiana Residential Real Price Projections (SUFG Base) (2007 Dollars)



Chapter 6

Commercial Electricity Sales

Overview

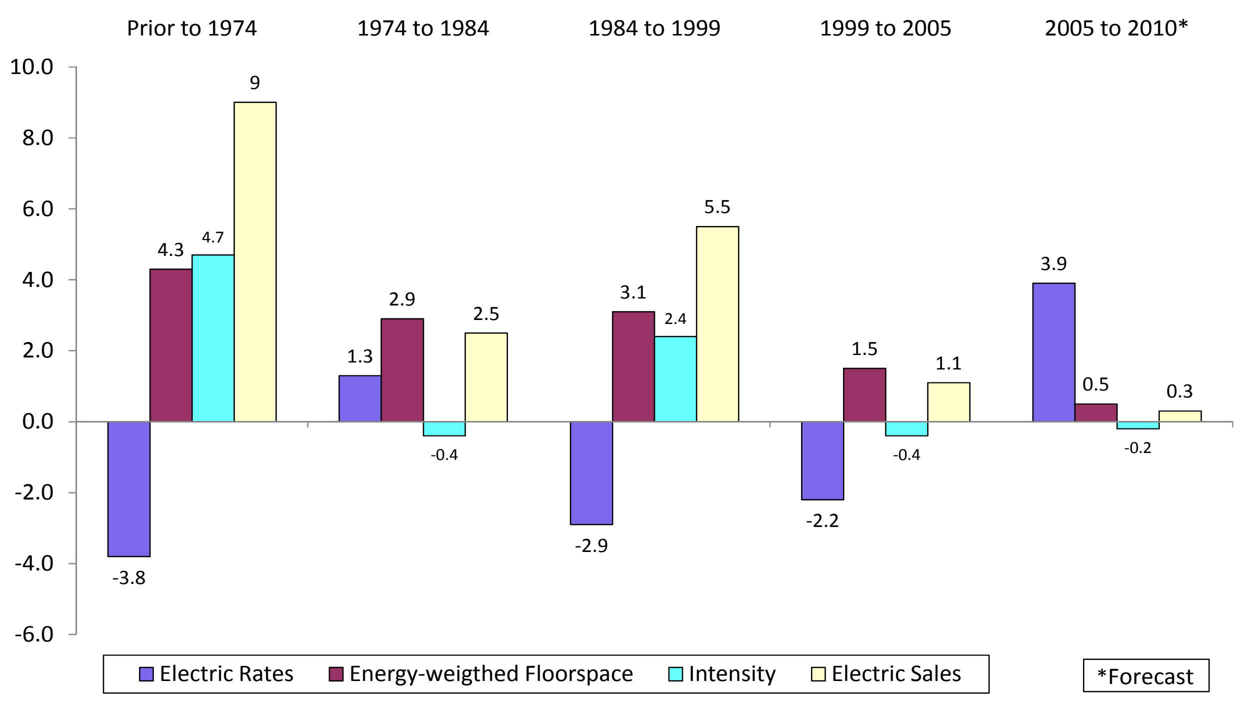
SUFG has two distinct models of commercial electricity sales, econometric and end-use, that have specific strengths and complement each other. SUFG staff developed the econometric model and acquired a proprietary end-use model, Commercial Energy Demand Modeling System (CEDMS). CEDMS is a descendant of 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. 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 the last four 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 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 1974-84, which resulted in a decrease in energy intensity. As electricity prices fell again during the 1984-99 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 to 2005 timeframe, the decrease in economic activity retarded growth in commercial floor stock, intensity of electricity use, and electricity use despite continued declines in real electricity prices. Recently the current recession coupled with increasing real electricity prices has accelerated these trends. For 2005 through 2010 SUFG expects real electricity prices to rise, commercial floor space to grow at one-third the rate observed during the previous few years, intensity of electricity use to continue to decline, and commercial sector electricity use to increase very slowly.

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 divides commercial buildings among 10 building types. It also divides energy use in each building type among 14 possible end uses, including a residual use category. For end uses such as space heating, where non-electric fuels compete with electricity, CEDMS further disaggregates energy use among fuel types. (This disaggregation scheme is illustrated at the top of Figure 6-2.) CEDMS also divides buildings among vintages, i.e., the year the building was constructed, and simulates energy use for each vintage and building type.

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

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

where

* = multiplication operator;

T = forecast year;

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

t = building vintage (year);

U = utilization, relative to some base year;

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

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

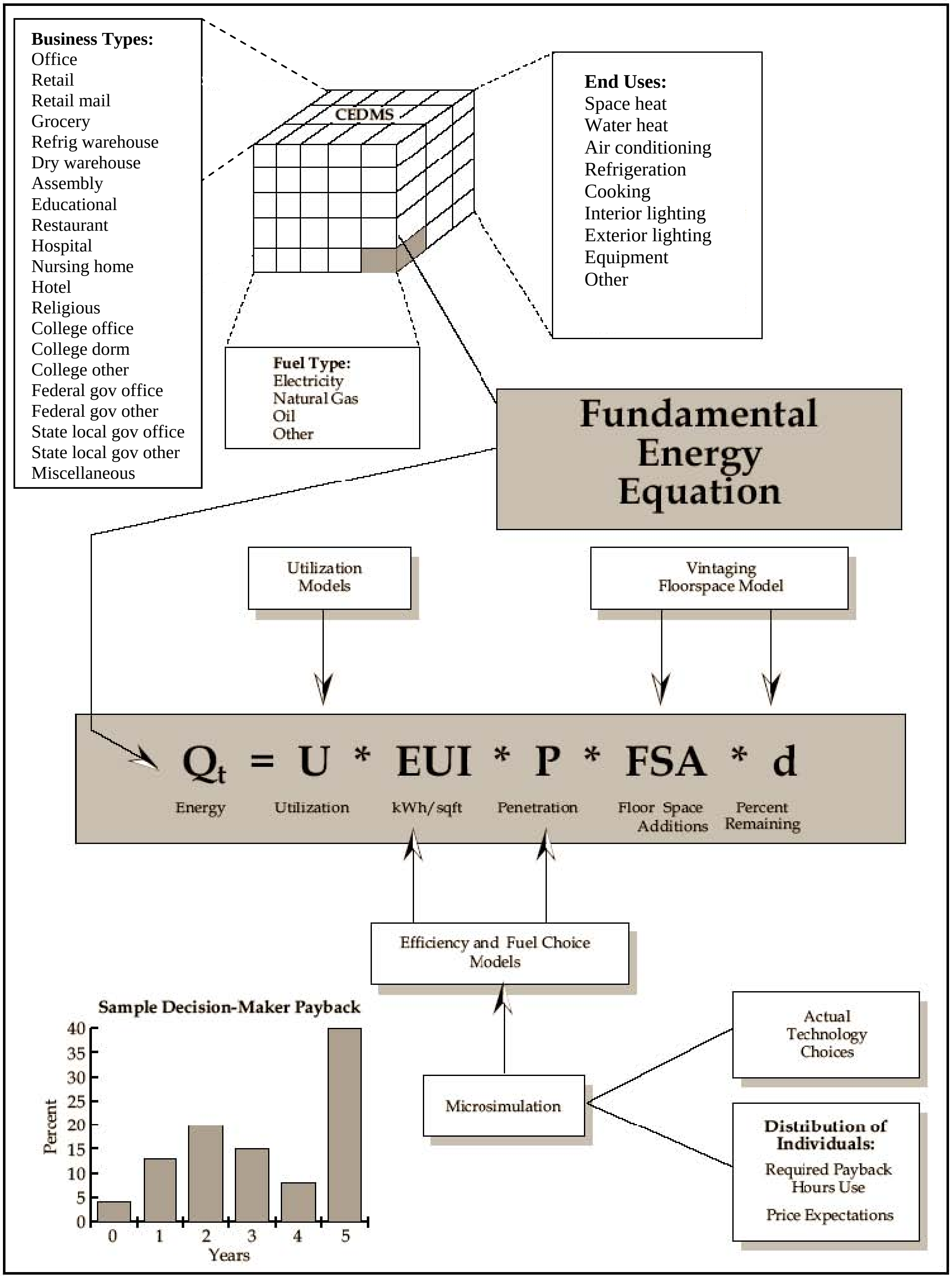
A = floor space additions by vintage t and building type l; and

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

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

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

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



Equipment standards are easily incorporated in CEDMS' equipment choice sub-models. For example, the Energy Policy Act of 1992 (EPACT) significantly affects the forecast for commercial lighting by prohibiting the manufacture of most 40 Watt and 75 Watt lamps (of these standard lamp sizes, only a few specialty lamps now meet both efficiency and color rendering requirements). EPACT's equipment standards for air conditioning and motors are also incorporated in CEDMS. Besides 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.

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, natural gas and oil 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, even though they are more efficient. The table also shows that changes in the price of competing forms of energy have little impact on electricity use.

Table 6-1. Commercial Model Long-run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Sales
Electric Rates	-2.5
Natural Gas Price	0.2
Distillate Oil Prices	0.0
Coal Prices	0.0
Electric Energy-weighted Floor Space	12.0

Indiana Commercial Electricity Sales Projections

Historical data as well as past and current projections are illustrated in Table 6-2 and Figure 6-3. The numbers in the column labeled as "Actual" in the table are historical consumption. As can be seen, the current base projection of Indiana commercial electricity sales growth is 1.18 percent. The growth rates for the major explanatory variables are shown in Table 6-3. Note that the changes from the 2007 forecast for all of the price drivers in Table 6-3 lead to decreased commercial sector electric energy purchases. Table 6-4 summarizes SUFG's base projections of commercial electricity sales growth for the last three SUFG forecasts.

Floor space growth accounts for all of the annual electric energy growth. The net effect of changes in energy prices and the mix in types of floor space on electricity use growth is close to zero. Incremental DSM programs have little effect on electricity sales. Thus, all of the projected electricity sales growth is attributable to floor space growth.

As shown in Figure 6-3, the current projection lies well below the 2007 forecast. The current projection starts out at about the same level but grows at a much lower rate. The slower growth rate is due to a combination of the macroeconomic projections and higher projected commercial sector electricity prices.

As shown in Table 6-5 and Figure 6-4, the growth rates for the low and high scenarios are about 0.4 percent lower and 0.4 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 in GWh (Historical, Current, and Previous Forecasts)

	Actual	2005	2007	2009
1980	12418			
1981	12470			
1982	13725			
1983	13665			
1984	14274			
1985	14651			
1986	15429			
1987	16144			
1988	16808			
1989	17205			
1990	17659			
1991	18580			
1992	18556			
1993	19627			
1994	20116			
1995	20646			
1996	20909			
1997	21295			
1998	22166			
1999	23078			
2000	23721			
2001	23953			
2002	24980			
2003	24940			
2004	25411	25444		
2005	26905	26219		
2006	26141	26972	25423	
2007	27090	27677	26022	
2008		28451	26692	27063
2009		29252	27387	27079
2010		30053	28119	27245
2011		30823	28815	27757
2012		31601	29513	28158
2013		32416	30243	28510
2014		33265	31018	28888
2015		34110	31719	29144
2016		34975	32444	29457
2017		35842	33219	29783
2018		36733	33945	29998
2019		37626	34763	30343
2020		38557	35628	30710
2021		39510	36516	31143
2022		40488	37428	31555
2023		41491	38362	31996
2024			39322	32456
2025			40306	32896
2026				33360
2027				33834

Average Compound Growth Rates			
Forecast Period	**2004-23**	**2006-25**	**2008-27**
	2.61	2.46	1.18

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

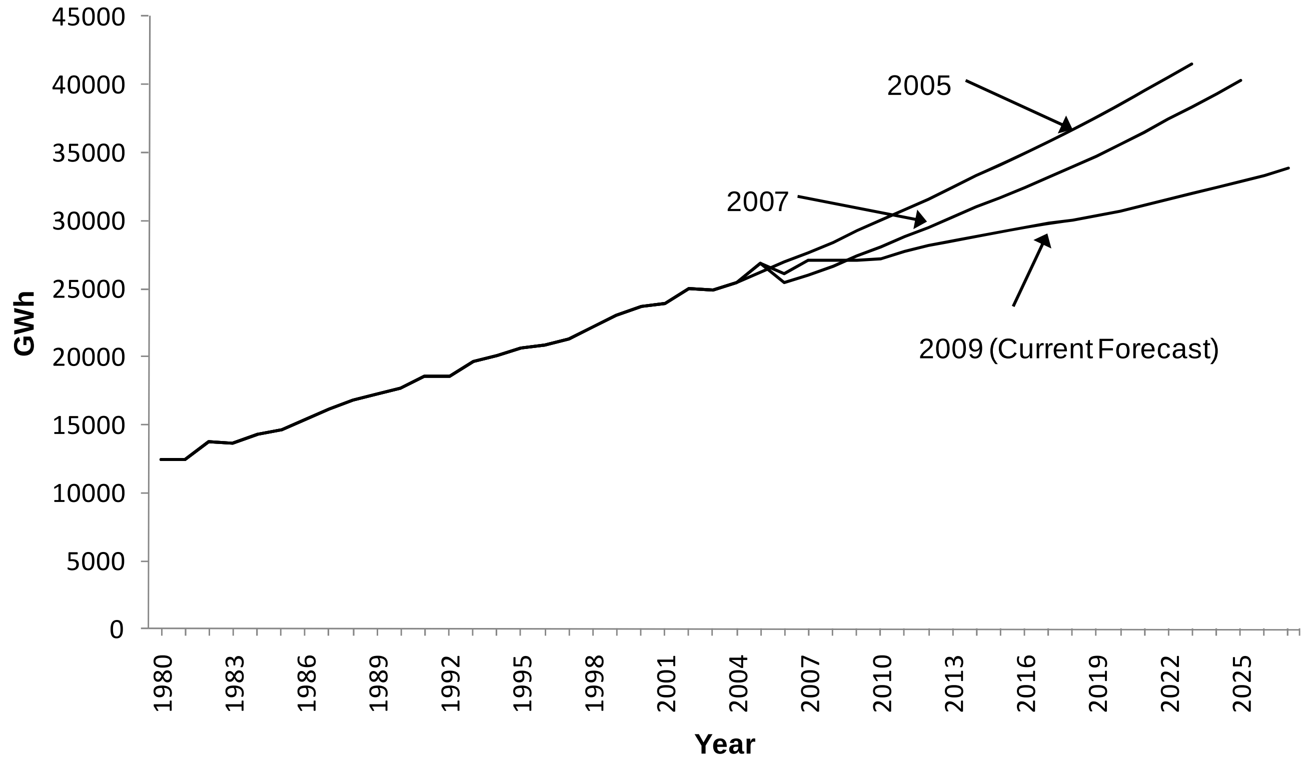


Table 6-3. Commercial Model – Growth Rates (Percent) for Selected Variables (2009 SUFG Scenarios and 2007 Base Forecast)

Forecast	Current Scenario (2008-2027)			2007 Forecast (2006-2025)
	Base	Low	High	Base
Electric Rates	0.73	0.64	0.83	0.26
Natural Gas Price	0.29	0.29	0.29	-1.18
Oil Prices	0.39	0.39	0.39	-1.29
Energy-weighted Floor Space	1.21	1.12	1.33	2.11

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

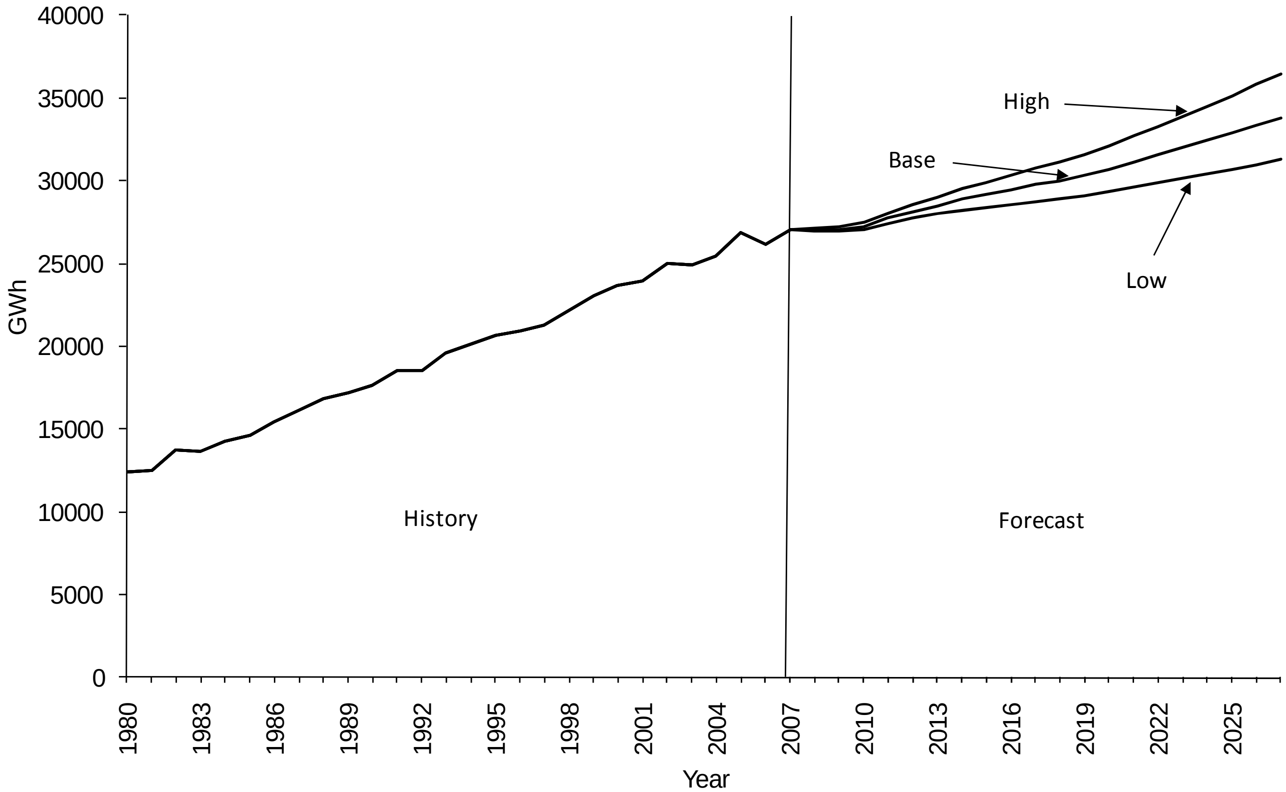
Forecast	Electric Energy-weighted Floor Space	Prior to DSM		After DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2009 SUFG Base (2008-2027)	1.21	0.02	1.23	-0.03	1.18
2007 SUFG Base (2006-2025)	2.11	0.35	2.46	0.35	2.46
2005 SUFG Base (2004-2023)	2.12	0.49	2.61	0.49	2.61

Table 6-5. Indiana Commercial Electricity Sales by Scenario in GWh

Year	Actual	Base	Low	High
1980	12418			
1981	12470			
1982	13725			
1983	13665			
1984	14274			
1985	14651			
1986	15429			
1987	16144			
1988	16808			
1989	17205			
1990	17659			
1991	18580			
1992	18556			
1993	19627			
1994	20116			
1995	20646			
1996	20909			
1997	21295			
1998	22166			
1999	23078			
2000	23721			
2001	23953			
2002	24980			
2003	24940			
2004	25411			
2005	26905			
2006	26141			
2007	27090			
2008		27063	26992	27120
2009		27079	26925	27216
2010		27245	27019	27454
2011		27757	27449	28039
2012		28158	27754	28539
2013		28510	27989	29026
2014		28888	28240	29539
2015		29144	28370	29898
2016		29457	28573	30307
2017		29783	28777	30767
2018		29998	28885	31101
2019		30343	29092	31590
2020		30710	29317	32103
2021		31143	29602	32690
2022		31555	29862	33264
2023		31996	30139	33874
2024		32456	30436	34514
2025		32896	30707	35141
2026		33360	30994	35804
2027		33834	31284	36489

Average Compound Growth Rates			
Periods	**Base**	**Low**	**High**
1980-85	3.36	3.36	3.36
1985-90	3.81	3.81	3.81
1990-95	3.17	3.17	3.17
1995-00	2.82	2.82	2.82
2000-05	2.55	2.55	2.55
2005-07	0.34	0.34	0.34
2006-25	1.18	0.78	1.57

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



Indiana Commercial Electricity Price Projections

Historical values and current projections for commercial electricity prices are shown in Table 6-6 and Figure 6-5. 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 2013 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.

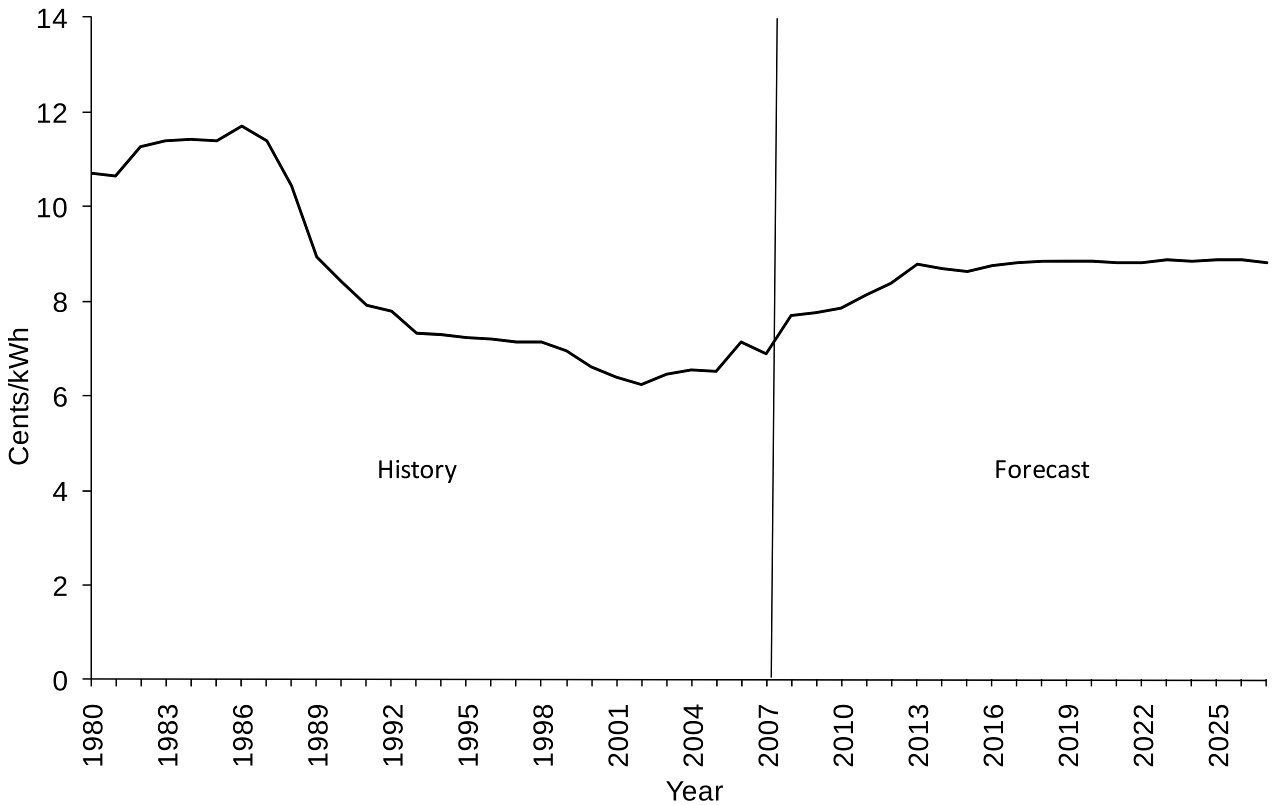
Table 6-6. Indiana Commercial Real Price Projections (SUFG Base) (2007 Dollars)

Year	Cents/kWh	Year	Cents/kWh
1980	10.71	2004	6.56
1981	10.64	2005	6.50
1982	11.26	2006	7.13
1983	11.39	2007	6.90
1984	11.43	2008	7.68
1985	11.39	2009	7.76
1986	11.71	2010	7.86
1987	11.40	2011	8.15
1988	10.43	2012	8.40
1989	8.94	2013	8.77
1990	8.42	2014	8.68
1991	7.91	2015	8.64
1992	7.81	2016	8.75
1993	7.32	2017	8.81
1994	7.30	2018	8.84
1995	7.23	2019	8.83
1996	7.20	2020	8.85
1997	7.13	2021	8.82
1998	7.13	2022	8.82
1999	6.96	2023	8.87
2000	6.60	2024	8.84
2001	6.41	2025	8.89
2002	6.25	2026	8.88
2003	6.46	2027	8.82

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	1.22
1985-1990	-5.86
1990-1995	-2.99
1995-2000	-1.81
2000-2005	-0.29
2005-2007	3.00
2008-2027	0.73

Note: The shaded numbers in the table are historical values. (For an explanation of how SUFG arrives at these numbers, see the Appendix.)

Figure 6-5. Indiana Commercial Real Price Projections (SUFG Base) (2007 Dollars)



Chapter 7

Industrial Electricity Sales

Overview

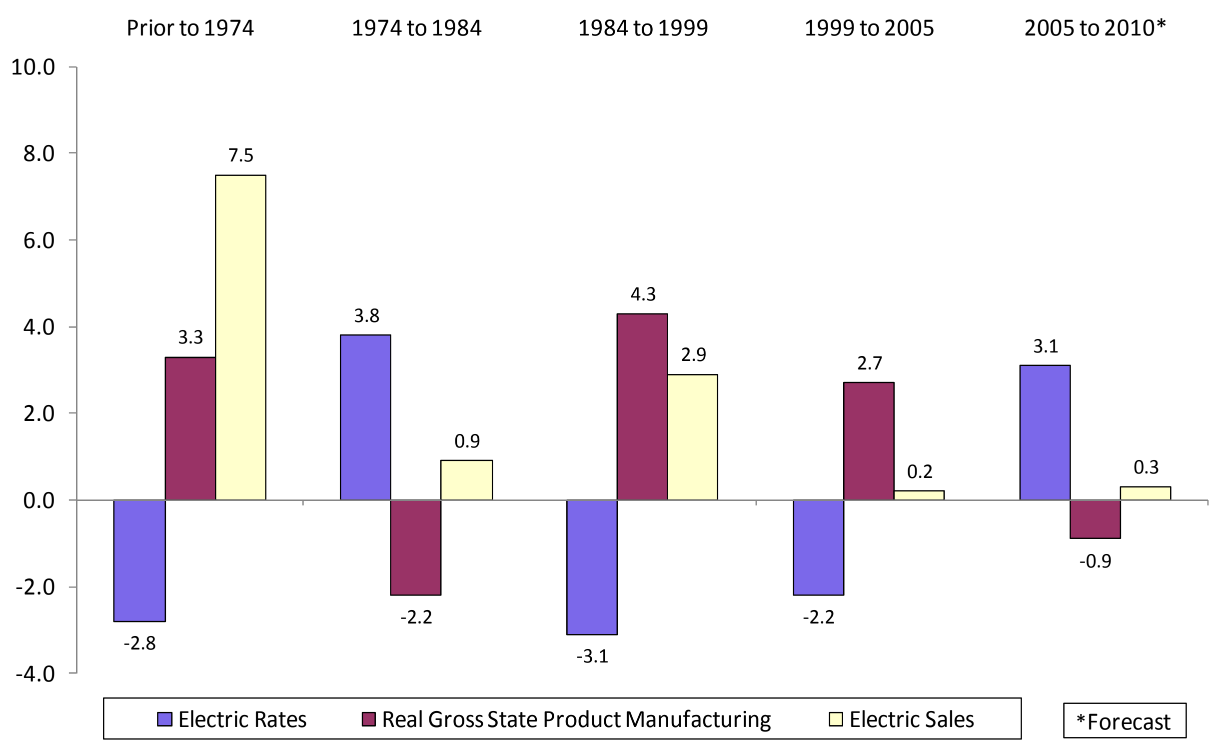
SUFG currently uses several models to analyze and forecast electricity use in the industrial sector. The primary forecasting model is INDEED, an econometric model developed by the Electric Power Research Institute (EPRI), which is used to model the electricity use of 15 major industry groupings in the 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 individual industrial electricity sales for the 15 industries within each of the five IOUs. 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 — the decade prior to the oil embargo of 1974, 1974-1984, 1984-1999, the more recent period, 1999-2005and the current period, 2005-2010. The 2005-2010 period includes data from both historical and projected years. Figure 7-1 shows state growth rates for real manufacturing product, real electric rates and electric energy sales for the four 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 prior to 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 1974-84. 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 prior to 1974. Real electricity prices in Indiana continued to decline in the industrial sector. These conditions caused electricity sales growth to average 2.9 percent per year during these 15 years.

The effect of the economic slowdown from 1999 to 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 declined, and overall growth in industrial electricity has remained positive but small. Like the residential (Chapter 5) and commercial (Chapter 6) sectors, decreased economic activity since 1999 has resulted in slower but positive growth in electricity use; however, manufacturing sector electricity use has increased only slightly.

The Econometric Model

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. Three-fourths of state GSP is accounted for by the following industries: primary metals, 4 percent; fabricated metals, 6 percent; industrial machinery and equipment, 7 percent; chemicals, 12 percent; transportation equipment, 22 percent; and electronic and electric equipment, 23 percent.

The share of total electricity consumed by each industry is shown in column two. Both the chemical and primary metals industries are very electric intensive industries. Combined, they account for nearly one-half of total industrial state electricity use. Column three 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 third 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.

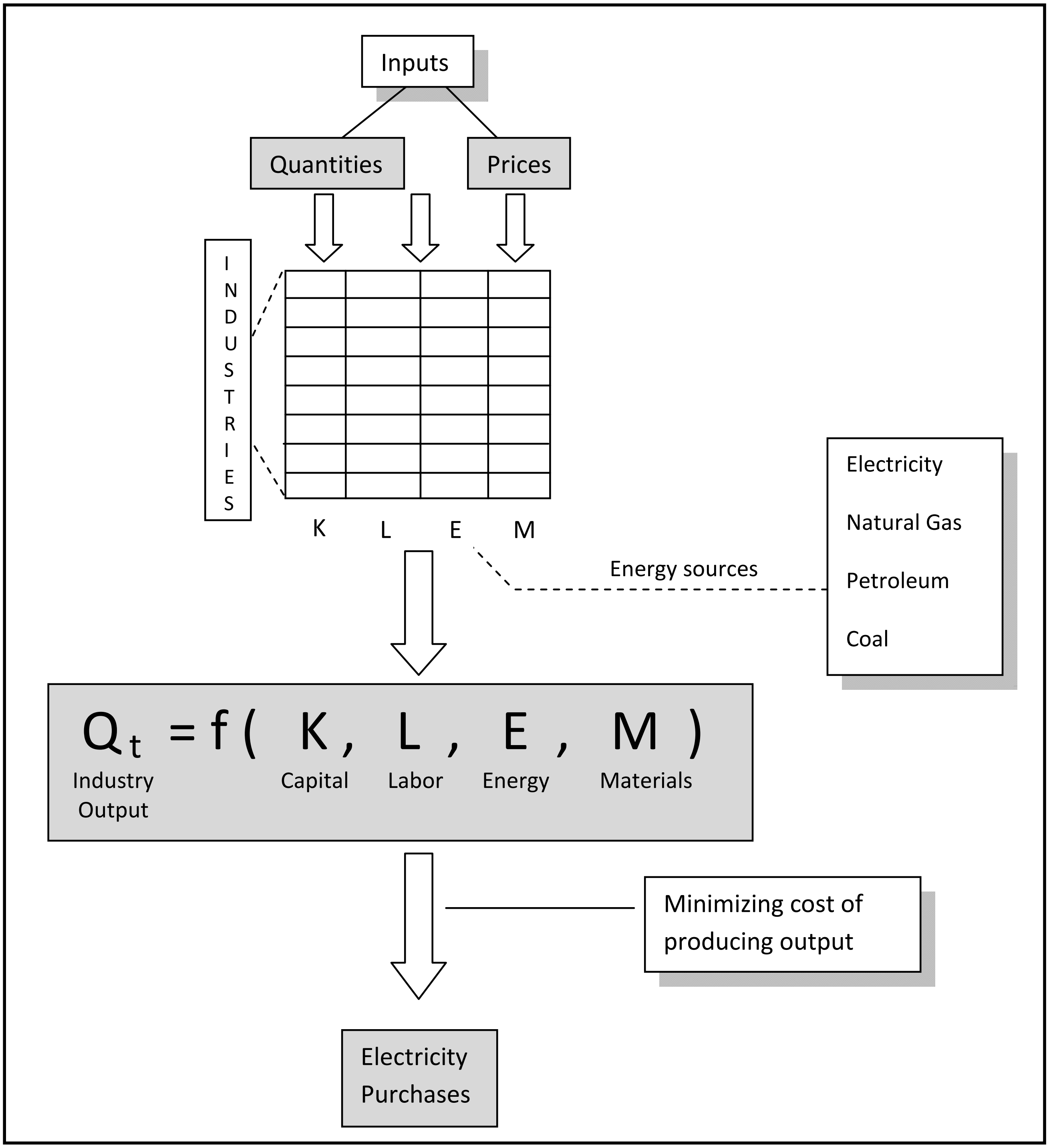
As described earlier in this chapter, INDEED captures the competition between the various inputs for their share of the cost of production by assuming firms seek the mix of inputs that minimize the production cost for a given level of output. Unit costs of gas, oil, coal, capital, labor and materials 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 in the industrial sector "spiked" in 2008, then will decline at about 5.0 percent per year for the next five years and increase at a rate of about 1.4 percent per year thereafter. Distillate fuel prices are assumed to follow a similar pattern, with a maximum real price in 2008 and growing at about the same rate (1.1 percent per year) as gas in the later years. 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 of the intensities expected to decrease, industry-wide electricity intensity is expected to decline modestly 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 1.63 percent per year over the forecast horizon.

Table 7-1. Selected Statistics for Indiana's Industrial Sector (Prior to 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	3.21	5.75	0.71	1.66	-0.85	0.81
24	Lumber & Wood Products	1.78	0.71	0.16	1.66	-0.97	0.69
25	Furniture & Fixtures	1.63	0.44	0.11	2.39	-0.91	1.48
26	Paper & Allied Products	1.24	2.81	0.90	1.66	-0.72	0.94
27	Printing & Publishing	2.33	1.30	0.22	1.66	-1.30	0.36
28	Chemicals & Allied Products	11.93	17.35	0.58	2.23	-0.50	1.73
30	Rubber & Misc. Plastic Products	3.37	6.03	0.71	1.76	-0.86	0.90
32	Stone, Clay, & Glass Products	1.65	5.10	1.23	2.39	-0.92	1.47
33	Primary Metal Products	3.52	32.03	3.60	-0.47	2.40	1.92
34	Fabricated Metal Products	5.57	5.12	0.36	2.76	-1.04	1.72
35	Industrial Machinery & Equipment	6.84	4.33	0.25	2.64	-0.77	1.86
36	Electronic & Electric Equipment	22.50	5.48	0.10	4.32	-0.73	3.59
37	Transportation Equipment	21.72	9.11	0.17	1.76	-0.83	0.93
38	Instruments And Related Products	7.85	0.80	0.04	4.36	-1.47	2.90
39	Miscellaneous Manufacturing	1.19	1.08	0.36	2.39	-3.40	-1.01
Total	Manufacturing	100.00	100.00	0.40	2.82	-1.18	1.63

Figure 7-2. Structure of Industrial Energy Modeling System



Summary of Results

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 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 Energy Projections: Current and Past

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 in both tabular and graphic form. The numbers in the column labeled as "Actual" in the table are historical consumption.

The impact of industrial sector DSM programs on growth rates for the 2005, 2007, and current forecasts are 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. Unlike the residential and commercial sectors, DSM programs have virtually no impact on industrial sector electricity purchases. 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 its 2007 level of approximately 41,500 GWh to over 57,000 GWh by 2027. This growth rate of 1.63 percent per year is higher than the 1.18 percent rate projected for the commercial sector but below the 1.75 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast lies below those of the 2007 and 2005 forecasts throughout the forecast horizon. Like the other sectors, rising real electricity prices coupled with a weaker macroeconomic outlook result in a more conservative forecast of electricity use.

Indiana Industrial Energy Projections: SUFG Scenarios

Table 7-5 and Figure 7-4 shows how industrial requirements differ by scenario. Industrial sales, in the high scenario, are expected to increase to nearly 64,500 GWh by 2027, almost 13 percent higher than the base projection. In the low scenario, industrial sales grow more slowly, which results in 52,500 GWh sales by 2027, more than 8 percent below the base scenario.

The wide range of forecast sales is caused primarily by the equally wide range of the trajectories of industrial output contained in the CEMR low and high scenarios for the state. In the base scenario GSP in the industrial sector grows 2.82 percent per year during the forecast period. That rate is 3.88 percent in the high scenario and 2.00 percent in the low scenario. This reflects the uncertainty regarding Indiana's industrial future contained in these forecasts.

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

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

Year	Actual	2005	2007	2009
1980	22544			
1981	22907			
1982	22600			
1983	23476			
1984	24678			
1985	24480			
1986	23618			
1987	24694			
1988	26546			
1989	27394			
1990	28311			
1991	28141			
1992	29540			
1993	31562			
1994	33395			
1995	33659			
1996	34920			
1997	35499			
1998	37012			
1999	38916			
2000	38957			
2001	38293			
2002	39594			
2003	39285			
2004	39654	41096		
2005	39950	42310		
2006	40936	43647	42777	
2007	41372	44391	44354	
2008		45048	45881	41981
2009		45554	46466	39778
2010		46507	47485	40035
2011		47200	48598	41331
2012		47966	49862	42791
2013		48832	51267	43874
2014		49826	52917	44923
2015		50811	54447	45846
2016		51930	56166	46645
2017		52982	57806	47448
2018		54048	59667	48384
2019		55102	61375	49352
2020		56223	63057	50227
2021		57371	64662	51144
2022		58579	66320	52115
2023		59766	67689	53003
2024			69131	53992
2025			70526	54959
2026				55949
2027				57112

Average Compound Growth Rate			
Forecast Period	**2004-23**	**2006-25**	**2008-27**
	1.99	2.67	1.63

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

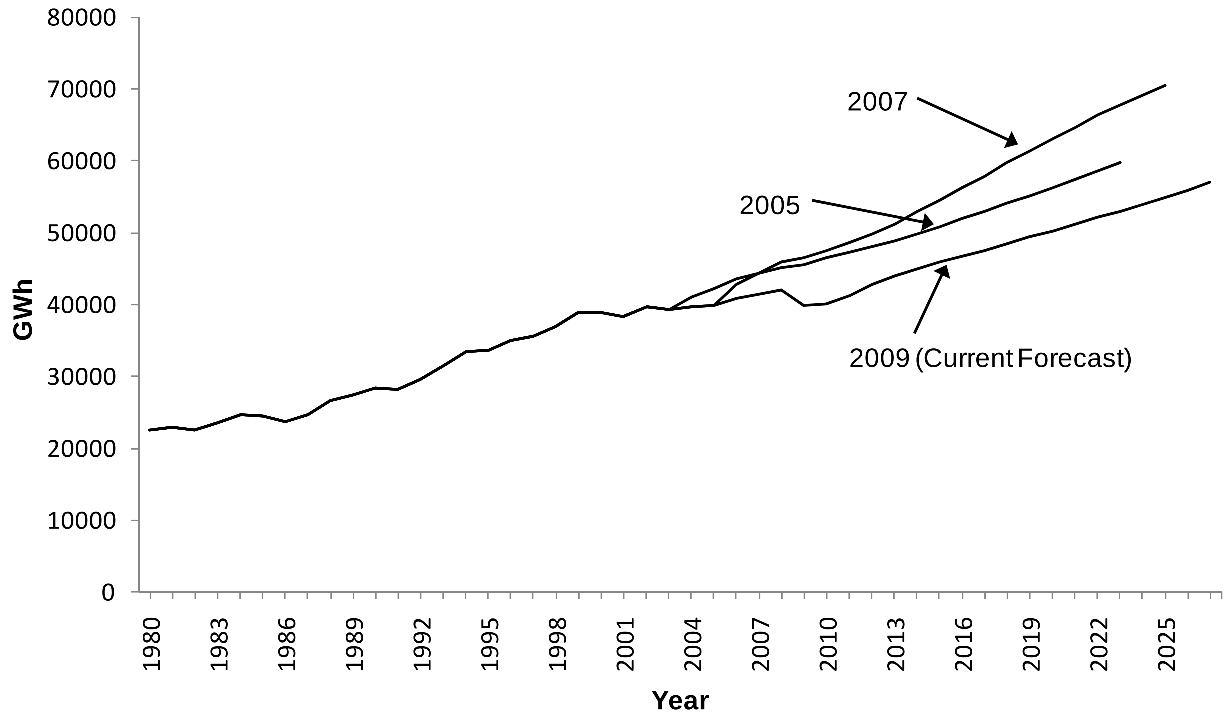


Table 7-4. History of SUFG Industrial Sector Growth Rates (Percent)

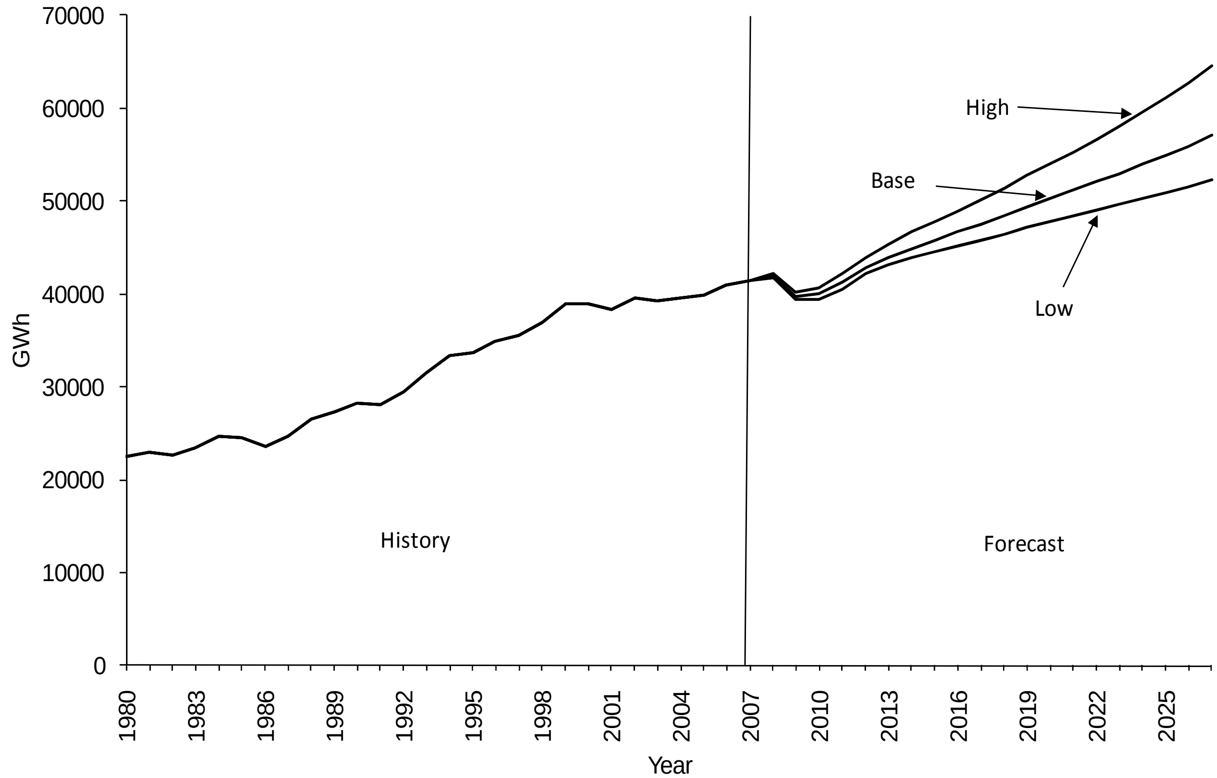
Forecast	Output	Mix Effects	Electric Energy-weighted Output	Prior to DSM		After DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
2009 SUFG Base (2008-2027)	2.82	-0.56	2.26	-0.63	1.63	-0.63	1.63
2007 SUFG Base (2006-2025)	3.48	-0.39	3.09	-0.42	2.67	-0.42	2.67
2005 SUFG Base (2004-2023)	2.53	-0.51	2.02	-0.03	1.99	-0.03	1.99

Table 7-5. Indiana Industrial Electricity Sales by Scenario in GWh

Year	Actual	Base	Low	High
1980	22544			
1981	22907			
1982	22600			
1983	23476			
1984	24678			
1985	24480			
1986	23618			
1987	24694			
1988	26546			
1989	27394			
1990	28311			
1991	28141			
1992	29540			
1993	31562			
1994	33395			
1995	33659			
1996	34920			
1997	35499			
1998	37012			
1999	38916			
2000	38957			
2001	38293			
2002	39594			
2003	39285			
2004	39654			
2005	39950			
2006	40936			
2007	41372			
2008		41981	41761	42182
2009		39778	39362	40176
2010		40035	39406	40659
2011		41331	40468	42177
2012		42791	42260	43937
2013		43874	43126	45361
2014		44923	43912	46724
2015		45846	44541	47859
2016		46645	45147	48938
2017		47448	45745	50084
2018		48384	46417	51375
2019		49352	47147	52695
2020		50227	47766	53944
2021		51144	48433	55284
2022		52115	49115	56706
2023		53003	49691	58093
2024		53992	50345	59598
2025		54959	50972	61124
2026		55949	51587	62724
2027		57112	52349	64492

Average Compound Growth Rates			
Periods	**Base**	**Low**	**High**
1980-85	1.66	1.66	1.66
1985-90	2.95	2.95	2.95
1990-95	3.52	3.52	3.52
1995-00	2.97	2.97	2.97
2000-05	0.51	0.51	0.51
2005-07	1.76	1.76	1.76
2008-27	1.63	1.20	2.26

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



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 through the entire forecast horizon with the need for additional emissions control equipment and additional supply/demand resources. 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.

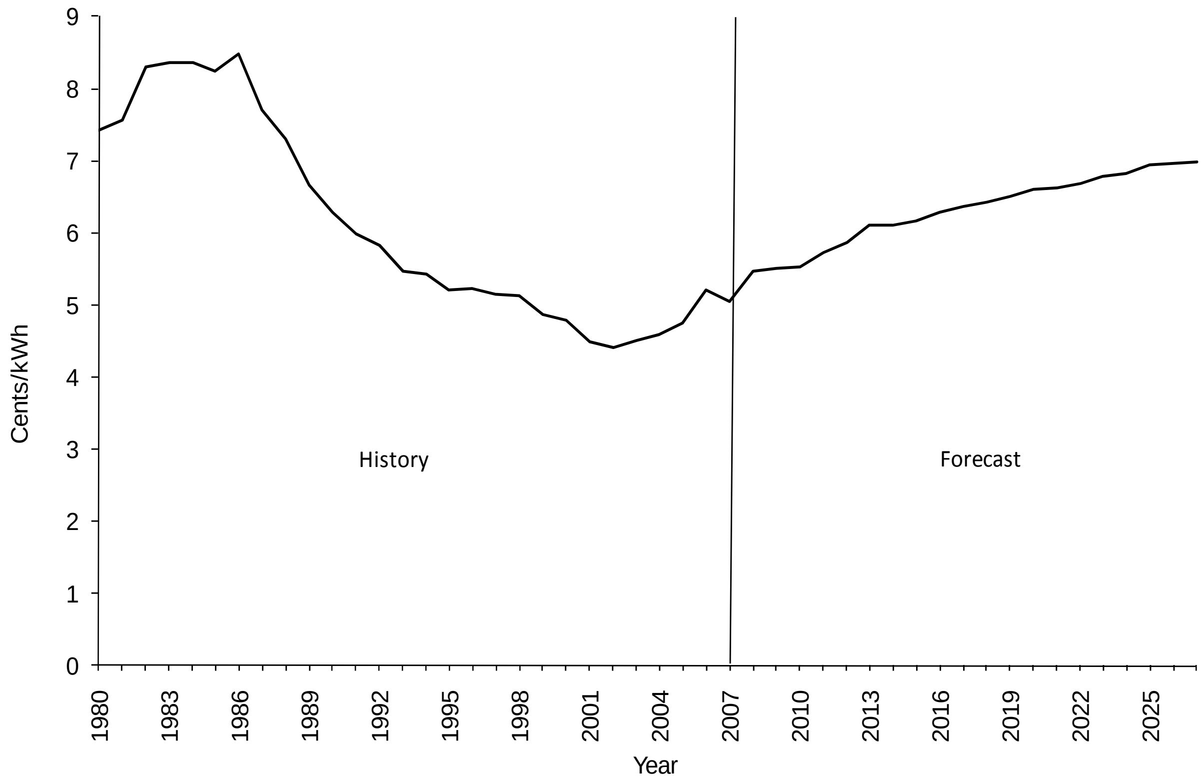
Table 7-6. Indiana Industrial Real Price Projections (SUFG Base) (2007 Dollars)

Year	Cents/kWh	Year	Cents/kWh
1980	7.43	2004	4.58
1981	7.56	2005	4.75
1982	8.29	2006	5.20
1983	8.37	2007	5.05
1984	8.37	2008	5.48
1985	8.25	2009	5.51
1986	8.48	2010	5.52
1987	7.71	2011	5.72
1988	7.31	2012	5.88
1989	6.67	2013	6.12
1990	6.29	2014	6.12
1991	5.99	2015	6.16
1992	5.83	2016	6.30
1993	5.47	2017	6.36
1994	5.43	2018	6.43
1995	5.21	2019	6.50
1996	5.23	2020	6.60
1997	5.15	2021	6.63
1998	5.12	2022	6.69
1999	4.87	2023	6.79
2000	4.79	2024	6.83
2001	4.48	2025	6.94
2002	4.42	2026	6.97
2003	4.51	2027	6.98

Average Compound Growth Rates	
Selected Periods	**Percent**
1980-1985	2.10
1985-1990	-5.26
1990-1995	-3.70
1995-2000	-1.69
2000-2005	-0.15
2005-2007	3.13
2006-2025	1.29

Notes: The shaded numbers in the table are historical values. (For an explanation of how SUFG arrives at these numbers, see the Appendix.)

Figure 7-5. Indiana Industrial Real Price Projections (SUFG Base) (2007 Dollars)



Chapter 8

Implications of Economic Issues for the Forecast

Introduction

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 severe economy recession on different economic variables in Indiana to obtain a better understanding of how these changes affect electricity demand in the state. This chapter compares CEMR's projections before and after the current economic crisis and projected recovery to help ascertain the overall impact of the recession on industries with high electricity demand.

Electricity demand is a function of a number of factors, including real personal income, manufacturer's 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 2007 (herein referred to as CEMR2007) and February 2009 (CEMR2009) long-range projections, the U.S. economy deteriorated, with some economists estimating a recession lasting well into 2010. As a result, CEMR2009 lowered the projected average growth in both output and employment.

Tables 8-1 through 8-3 provide comparisons between the two projections. Selected economic variables are reported annually from 2007 through 2014 and for each five year interval beginning in 2015. The tables show long-run projections of real values and percentage change at annual rates for total manufacturing GSP, non-manufacturing employment and personal income. The tables also show the percentage change between CEMR2007 and CEMR2009.

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 8-1 shows that the impact of the recession on non-manufacturing employment occurs largely in the 2008 to 2012 timeframe. In CEMR2009, the projection of non-manufacturing employment for 2008 is about 21,000 employees (or 0.92 percent) lower than in CEMR2007. In 2009 non-manufacturing employment falls to about 60,000 employees (or 2.56 percent) lower than projected in CEMR2007. From 2010 on, CEMR2009 exhibits higher growth than previously estimated, with employment in this sector returning to previously expected levels in 2014.

Figure 8-1 illustrates the comparison between past and current projections for employment in non-manufacturing. CEMR2009 exhibits a similar pattern to CEMR2007 for almost the entire forecast horizon. The only significant deviation between the two projections occurs between 2008 and 2012. Thus, non-manufacturing employment for Indiana is projected to have only a slight impact on the economy during the recession, with little long-term impact.

Real Personal Income

Real personal income provides an important picture of the recession's effects on Indiana. Changes in real personal income will directly influence electricity demand. Real personal income is therefore a major input in the residential energy forecasting model.

Table 8-2 and Figure 8-2 show the CEMR projections of real personal income. CEMR2009 follows a similar trajectory to the one for non-manufacturing employment in that it slows dramatically in 2008, then decreases in 2009 before beginning to rebound in 2010. However, while the trajectory is similar, the magnitude of the difference between the two sets of projections is much larger. CEMR2009 indicates real personal income more than $24 billion dollars (7.42 percent) below CEMR2007 in 2009, with the difference rising to over $32 billion (12.08 percent) by 2025. Unlike the non-manufacturing employment projection, real personal income does not recover to the level projected in CEMR2007.

Figure 8-2 illustrates that the CEMR2009 real personal income is projected to grow at a steady rate after 2010. However, growth is at a lower rate than in CEMR2007.

Consequently, the CEMR2009 long-range projection for real personal income has an upward trend with no cyclical component, but with billions of dollars lost due to the recession.

Table 8-1. 2007 and 2009 CEMR Projections for Non-manufacturing Employment

	Year										
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**
	Thousands of persons										
CEMR2007	2279.0 (1.41)	2310.0 (1.36)	2336.9 (1.16)	2361.2 (1.04)	2386.3 (1.07)	2412.3 (1.09)	2439.1 (1.11)	2465.6 (1.09)	2492.3 (1.08)	2633.1 (1.10)	2778.7 (1.09)
CEMR2009	2280.8 (1.33)	2288.8 (0.35)	2276.5 (-0.54)	2305.3 (1.27)	2351.6 (2.01)	2395.3 (1.86)	2433.9 (1.61)	2469.0 (1.44)	2502.2 (1.34)	2650.2 (1.15)	2791.9 (1.04)
Percentage change between two projections	0.08	-0.92	-2.58	-2.37	-1.46	-0.71	-0.21	0.14	0.39	0.65	0.47
Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"											
Note: Numbers in parentheses indicate percentage change at annual rate											

Figure 8-1. Indiana Non-manufacturing Employment (thousands of people)

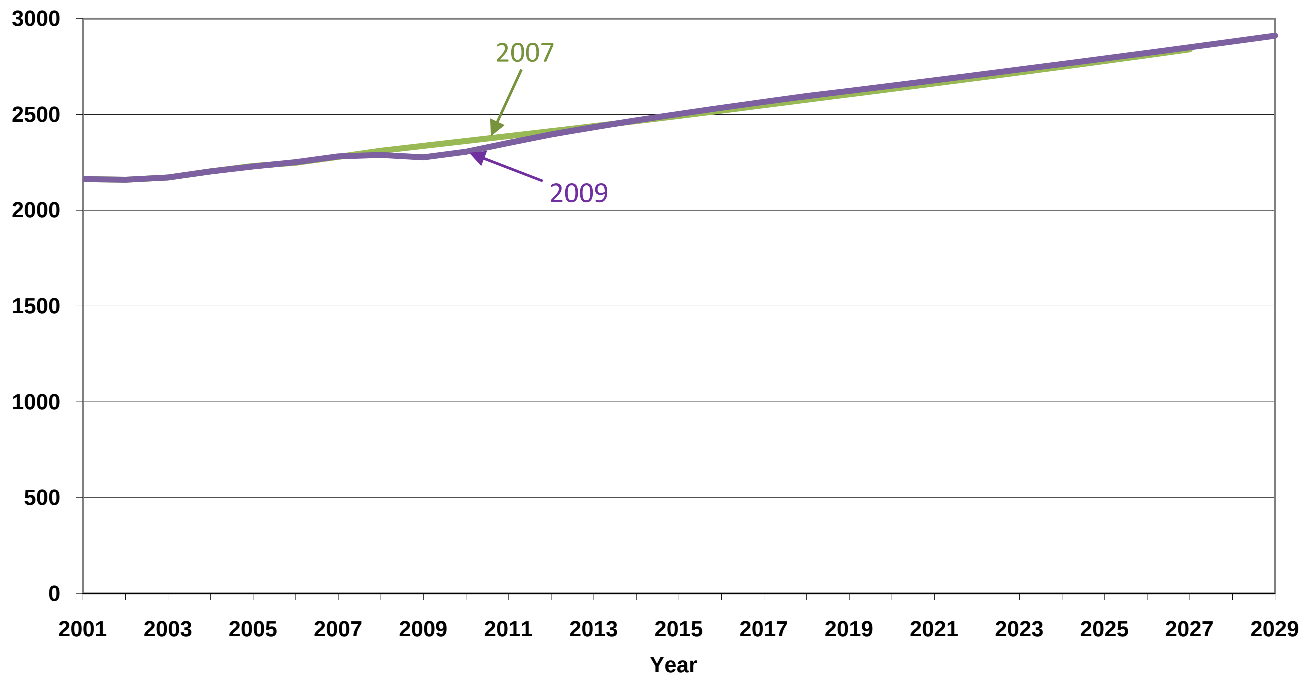
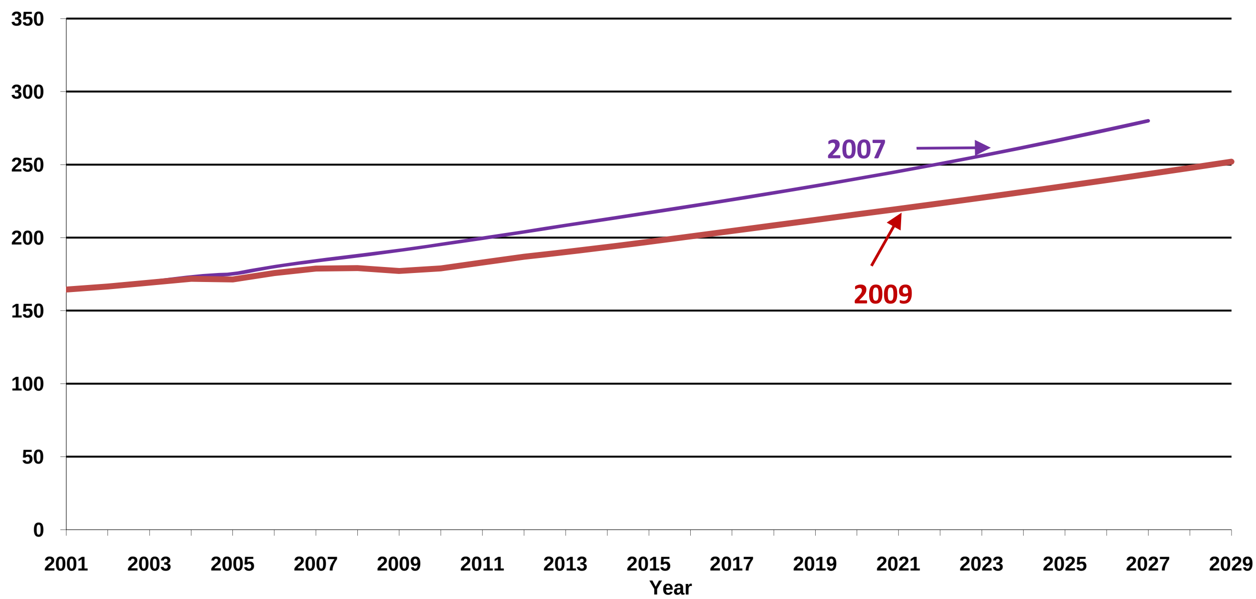


Table 8-2. 2007 and 2009 CEMR Projections for Real Personal Income

	Year										
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**
	Billions of 2000 $										
CEMR2007	184.12 (2.18)	187.56 (1.87)	191.34 (2.02)	195.37 (2.10)	199.56 (2.14)	203.89 (2.17)	208.40 (2.21)	212.83 (2.12)	217.07 (1.99)	240.27 (2.05)	267.67 (2.18)
CEMR2009	178.79 (1.71)	179.14 (0.20)	177.15 (-1.11)	178.88 (0.98)	182.94 (2.27)	186.86 (2.15)	190.14 (1.75)	193.58 (1.81)	197.13 (1.83)	215.90 (1.83)	235.33 (1.73)
Percentage change between two projections	-2.90	-4.49	-7.42	-8.44	-8.33	-8.35	-8.76	-9.05	-9.19	-10.14	-12.08
Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections" ***Note: Numbers in parentheses indicate percentage change at annual rate***											

Figure 8-2. Indiana Real Personal Income (billions of 2000 dollars)



Real Manufacturing Gross State Product

Changes in manufacturing Gross State Product (GSP) will have significant implications for electricity use in the industrial sector. The recession has had a larger impact on manufacturing GSP growth than it has on either non-manufacturing employment or personal income.

Table 8-3 and Figure 8-3 show the CEMR projections for real manufacturing GSP. While the CEMR2009 projection follows a similar pattern to those for non-manufacturing employment and real personal income, the deviation from the CEMR2007 projections is more pronounced. As the figure illustrates, real manufacturing GSP did not increase in 2005 and 2006. Thus, despite modest growth in 2007, the CEMR2009 projection was over $11 billion (15.66 percent) below the CEMR2007 projection for that year. By the time that growth returns to near normal levels in 2011, the CEMR2009 projections are $24.5 billion (28.48 percent) below CEMR2007. After 2011, CEMR2009 continues to grow, albeit at a slightly reduced rate from CEMR2007. By 2025, the difference between the two projections grows to over $44 billion, or 34.20 percent.

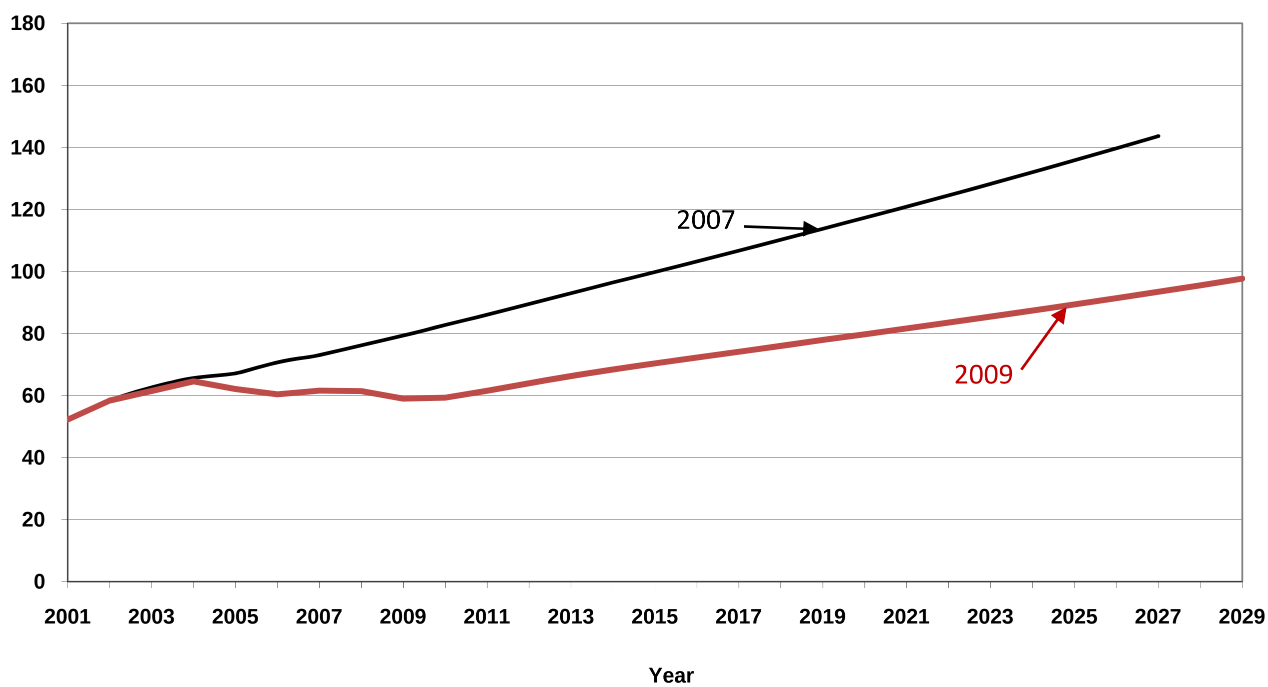
CEMR2009 projects lower real GSP values through the entire forecast horizon, confirming the major effect the recession has had on the manufacturing sector of Indiana's economy.

Table 8-3. 2007 and 2009 CEMR Projections for Real Manufacturing GSP

	Year										
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025
	Billions of 2000 $										
CEMR2007	73.02 (3.22)	76.24 (4.41)	79.31 (4.03)	82.76 (4.35)	86.03 (3.95)	89.56 (4.10)	92.96 (3.80)	96.47 (3.77)	99.80 (3.45)	117.33 (3.28)	135.80 (2.96)
CEMR2009	61.58 (1.97)	61.42 (-0.25)	58.99 (-3.97)	59.30 (0.52)	61.53 (3.77)	63.96 (3.94)	66.29 (3.65)	68.38 (3.15)	70.33 (2.86)	79.74 (2.54)	89.36 (2.30)
Percentage change between two projections	-15.66	-19.43	-25.62	-28.35	-28.48	-28.59	-28.69	-29.12	-29.53	-32.03	-34.20

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
Note: Numbers in parentheses indicate percentage change at annual rate

Figure 8-3. Indiana Real Manufacturing GSP (billions of 2000 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 2007, this sector represented slightly less than one-quarter (23.3%) of the total real value of products manufactured in the state.

Table 8-4 shows projected growth rates, actual values and percentage rate changes for the transportation equipment industry and includes the comparison between the CEMR2007 and CEMR2009 projections. The table indicates that the recession is having a significant impact on the performance of the automobile sector.

CEMR2009 shows a large reduction in the production of transportation equipment from 2007 to 2009, with a decline of over 8 percent each year. The industry is projected to recover in 2011, but does not reach the level of growth projected in CEMR2007. Production does not return to pre-2007 levels until after 2015 and is about 1/3 to 1/2 of that projected in CEMR2007 after 2010.

Primary Metals Industry

While the primary metals industry, including production of steel and aluminum, represented less than 4 percent of Indiana manufacturing GSP in 2007, it accounted for 32 percent of the state's industrial electricity sales.

Table 8-5 compares the CEMR projections for 2007 and 2009 for the primary metals industry, which saw about a 50 percent reduction between 2005 and 2007. As in other sectors of the economy, the primary metals industry is projected to see declining output in the short term. However, unlike other industries, the CEMR2009 does not indicate a sustained recovery for this industry. Real GSP for this sector is not projected to exceed the 2007 levels throughout the forecast horizon.

Table 8-4. Percentage Change Rates for 2007 and 2009 CEMR Projections of Real GSP - Transportation Equipment

	Year										
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**
	Billions of 2000 $										
CEMR2007	19.89 (5.92)	21.28 (6.98)	22.69 (6.65)	24.25 (6.89)	25.82 (6.44)	27.48 (6.46)	29.15 (6.08)	30.89 (5.95)	32.60 (5.56)	41.99 (5.19)	52.63 (4.62)
CEMR2009	14.35 (-8.41)	13.19 (-8.12)	12.04 (-8.69)	12.07 (0.27)	12.52 (3.73)	13.01 (3.90)	13.50 (3.72)	13.93 (3.24)	14.34 (2.95)	16.32 (2.61)	18.30 (2.32)
Percentage change between two projections	-27.84	-38.03	-46.94	-50.23	-51.49	-52.66	-53.71	-54.89	-56.01	-61.14	-65.22
Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections" ***Note: Numbers in parentheses indicate percentage change at annual rate***											

Table 8-5. Percentage Change Rates for 2007 and 2009 CEMR Projections of Real GSP - Primary Metals

	Year										
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**
	Billions of 2000 $										
CEMR2007	6.09 (0.50)	6.20 (1.82)	6.28 (1.17)	6.39 (1.80)	6.48 (1.41)	6.58 (1.60)	6.67 (1.33)	6.76 (1.32)	6.83 (1.03)	7.14 (0.89)	7.35 (0.59)
CEMR2009	2.69 (-4.87)	2.64 (-1.86)	2.49 (-5.63)	2.44 (-2.28)	2.46 (0.89)	2.48 (1.05)	2.51 (0.88)	2.52 (0.41)	2.52 (0.13)	2.50 (-0.19)	2.44 (-0.45)
Percentage change between two projections	-55.90	-57.41	-60.28	-61.87	-62.06	-62.27	-62.44	-62.78	-63.10	-65.03	-66.80
Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections" ***Note: Numbers in parentheses indicate percentage change at annual rate***											

References

Center for Econometric Model Research, "Long-Range Projections 2006-2027," Indiana University, February 2007.

Center for Econometric Model Research, "Long-Range Projections 2008-2029," Indiana University, February 2009.

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. Slightly less than 20 percent of I&M's load is in Michigan and while the majority of WVPA’s load is in Indiana, it does have members in Illinois, Michigan, Missouri, and Ohio. IMPA has a wholesale member in Ohio and Hoosier Energy recently acquired a member cooperative in Illinois. 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 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 ten entities which 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 instance. 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. However, data availability for the

REMCs and municipalities prior to 1982 is limited and the reported values for 1980 and 1981 include SUFG estimates for the not-for-profit utilities for these years. SUFG believes that any errors in statewide energy sales and demand for 1980 and 1981 are relatively small and concentrated in the residential sector.

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 to 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 2009 Base Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	1980	16612	12418	22544	556	52131	5546	57676	11284
Hist	1981	16118	12470	22907	572	52067	5581	57648	11235
Hist	1982	19927	13725	22600	696	56948	4875	61823	10683
Hist	1983	19950	13665	23476	626	57717	4795	62511	11744
Hist	1984	20153	14274	24678	674	59779	4938	64717	11331
Hist	1985	19707	14651	24480	653	59491	4889	64380	11030
Hist	1986	20410	15429	23618	610	60067	4958	65024	11834
Hist	1987	21154	16144	24694	617	62609	5185	67794	12218
Hist	1988	22444	16808	26546	633	66431	5557	71988	13447
Hist	1989	22251	17205	27394	661	67511	5815	73326	12979
Hist	1990	22037	17659	28311	685	68692	5050	73742	13659
Hist	1991	24215	18580	28141	660	71595	4439	76034	14278
Hist	1992	22916	18456	29540	649	71561	5645	77207	14055
Hist	1993	25060	19627	31562	544	76793	5876	82669	14916
Hist	1994	25176	20116	33395	541	79227	6219	85446	15010
Hist	1995	26513	20646	33590	540	81290	7225	88514	16251
Hist	1996	26833	20909	34755	567	83064	7573	90637	16181
Hist	1997	26792	21295	35499	569	84155	5618	89773	16040
Hist	1998	27745	22158	37052	560	87515	5914	93429	16657
Hist	1999	29238	23089	39020	584	91932	6069	98001	17266
Hist	2000	28413	23541	38517	534	91004	7235	98239	16757
Hist	2001	29182	23830	37995	521	91527	7777	99304	17531
Hist	2002	32087	24828	39252	534	96701	7970	104670	18851
Hist	2003	30837	24769	38887	576	95069	7853	102922	18843
Hist	2004	31256	25206	39155	628	96245	8146	104391	18254
Hist	2005	33722	26699	39461	603	100485	7617	108103	19966
Hist	2006	32570	25964	41098	590	100222	6304	109182	20910
Hist	2007	35193	27090	41372	624	104279	6559	112753	20842
Frcst	2008	34513	27063	41981	624	104181	7692	111873	19832
Frcst	2009	35026	27079	39778	624	102507	7566	110073	19530
Frcst	2010	35512	27245	40035	624	103415	7622	111037	19741
Frcst	2011	36033	27757	41331	624	105745	7779	113524	20156
Frcst	2012	36596	28158	42791	624	108168	7944	116112	20597
Frcst	2013	37114	28510	43874	624	110122	8079	118201	20966
Frcst	2014	37684	28888	44923	624	112119	8220	120339	21341
Frcst	2015	38238	29144	45846	624	113852	8348	122200	21695
Frcst	2016	38843	29457	46645	624	115569	8476	124045	22018
Frcst	2017	39439	29783	47448	624	117294	8605	125898	22341
Frcst	2018	40073	29998	48384	624	119079	8740	127819	22679
Frcst	2019	40795	30343	49352	624	121113	8892	130006	23075
Frcst	2020	41579	30710	50227	624	123140	9044	132184	23550
Frcst	2021	42421	31143	51144	624	125333	9207	134540	23992
Frcst	2022	43305	31555	52115	624	127598	9374	136972	24450
Frcst	2023	44213	31996	53003	624	129836	9541	139376	24904
Frcst	2024	45163	32456	53992	624	132234	9720	141954	25389
Frcst	2025	46120	32896	54959	624	134598	9897	144495	25868
Frcst	2026	47071	33360	55949	624	137003	10079	147082	26354
Frcst	2027	48031	33834	57112	624	139600	10273	149873	26873

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	-2.49	2.22	-0.45
1985-1990	2.26	3.81	2.95	0.97	2.92	0.65	2.75	4.37
1990-1995	3.77	3.17	3.48	-4.65	3.43	7.42	3.72	3.54
1995-2000	1.39	2.66	2.77	-0.24	2.28	0.03	2.11	0.61
2000-2005	3.48	2.55	0.49	2.49	2.00	1.04	1.93	3.57
2005-2010	1.04	0.41	0.29	0.67	0.58	0.01	0.54	-0.23
2010-2015	1.49	1.36	2.75	0.00	1.94	1.84	1.93	1.91
2015-2020	1.69	1.05	1.84	0.00	1.58	1.61	1.58	1.65
2020-2025	2.09	1.38	1.82	0.00	1.80	1.82	1.80	1.90
2025-2027	2.05	1.42	1.94	0.00	1.84	1.88	1.84	1.92
2008-2027	1.75	1.18	1.63	0.00	1.55	1.53	1.55	1.61

SUFG 2009 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	1980	16612	12418	22544	556	52131	5546	57676	11284
Hist	1981	16118	12470	22907	572	52067	5581	57648	11235
Hist	1982	19927	13725	22600	696	56948	4875	61823	10683
Hist	1983	19950	13665	23476	626	57717	4795	62511	11744
Hist	1984	20153	14274	24678	674	59779	4938	64717	11331
Hist	1985	19707	14651	24480	653	59491	4889	64380	11030
Hist	1986	20410	15429	23618	610	60067	4958	65024	11834
Hist	1987	21154	16144	24694	617	62609	5185	67794	12218
Hist	1988	22444	16808	26546	633	66431	5557	71988	13447
Hist	1989	22251	17205	27394	661	67511	5815	73326	12979
Hist	1990	22037	17659	28311	685	68692	5050	73742	13659
Hist	1991	24215	18580	28141	660	71595	4439	76034	14278
Hist	1992	22916	18456	29540	649	71561	5645	77207	14055
Hist	1993	25060	19627	31562	544	76793	5876	82669	14916
Hist	1994	25176	20116	33395	541	79227	6219	85446	15010
Hist	1995	26513	20646	33590	540	81290	7225	88514	16251
Hist	1996	26833	20909	34755	567	83064	7573	90637	16181
Hist	1997	26792	21295	35499	569	84155	5618	89773	16040
Hist	1998	27745	22158	37052	560	87515	5914	93429	16657
Hist	1999	29238	23089	39020	584	91932	6069	98001	17266
Hist	2000	28413	23541	38517	534	91004	7235	98239	16757
Hist	2001	29182	23830	37995	521	91527	7777	99304	17531
Hist	2002	32087	24828	39252	534	96701	7970	104670	18851
Hist	2003	30837	24769	38887	576	95069	7853	102922	18843
Hist	2004	31256	25206	39155	628	96245	8146	104391	18254
Hist	2005	33722	26699	39461	603	100485	7617	108103	19966
Hist	2006	32570	25964	41098	590	100222	6304	109182	20910
Hist	2007	35193	27090	41372	624	104279	6559	112753	20842
Frcst	2008	34479	26992	41761	624	103856	7668	111524	19775
Frcst	2009	34958	26925	39362	624	101869	7518	109387	19417
Frcst	2010	35407	27019	39406	624	102456	7549	110005	19571
Frcst	2011	35888	27449	40468	624	104428	7678	112107	19923
Frcst	2012	36402	27754	42260	624	107039	7857	114896	20394
Frcst	2013	36878	27989	43126	624	108617	7963	116580	20697
Frcst	2014	37395	28240	43912	624	110172	8070	118242	20990
Frcst	2015	37883	28370	44541	624	111417	8160	119577	21255
Frcst	2016	38460	28573	45147	624	112804	8260	121065	21519
Frcst	2017	39036	28777	45745	624	114182	8361	122543	21780
Frcst	2018	39601	28885	46417	624	115526	8461	123986	22038
Frcst	2019	40278	29092	47147	624	117141	8580	125721	22358
Frcst	2020	41001	29317	47766	624	118707	8698	127406	22754
Frcst	2021	41790	29602	48433	624	120448	8828	129276	23110
Frcst	2022	42617	29862	49115	624	122218	8959	131177	23473
Frcst	2023	43465	30139	49691	624	123919	9086	133005	23829
Frcst	2024	44364	30436	50345	624	125768	9225	134993	24211
Frcst	2025	45260	30707	50972	624	127563	9359	136922	24586
Frcst	2026	46154	30994	51587	624	129358	9496	138853	24960
Frcst	2027	47028	31284	52349	624	131285	9639	140924	25357

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	-2.49	2.22	-0.45
1985-1990	2.26	3.81	2.95	0.97	2.92	0.65	2.75	4.37
1990-1995	3.77	3.17	3.48	-4.65	3.43	7.42	3.72	3.54
1995-2000	1.39	2.66	2.77	-0.24	2.28	0.03	2.11	0.61
2000-2005	3.48	2.55	0.49	2.49	2.00	1.04	1.93	3.57
2005-2010	0.98	0.24	-0.03	0.67	0.39	-0.18	0.35	-0.40
2010-2015	1.36	0.98	2.48	0.00	1.69	1.57	1.68	1.66
2015-2020	1.59	0.66	1.41	0.00	1.28	1.29	1.28	1.37
2020-2025	2.00	0.93	1.31	0.00	1.45	1.48	1.45	1.56
2025-2027	1.94	0.93	1.34	0.00	1.45	1.48	1.45	1.55
2008-2027	1.65	0.78	1.20	0.00	1.24	1.21	1.24	1.32

SUFG 2009 High Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
Hist	1980	16612	12418	22544	556	52131	5546	57676	11284
Hist	1981	16118	12470	22907	572	52067	5581	57648	11235
Hist	1982	19927	13725	22600	696	56948	4875	61823	10683
Hist	1983	19950	13665	23476	626	57717	4795	62511	11744
Hist	1984	20153	14274	24678	674	59779	4938	64717	11331
Hist	1985	19707	14651	24480	653	59491	4889	64380	11030
Hist	1986	20410	15429	23618	610	60067	4958	65024	11834
Hist	1987	21154	16144	24694	617	62609	5185	67794	12218
Hist	1988	22444	16808	26546	633	66431	5557	71988	13447
Hist	1989	22251	17205	27394	661	67511	5815	73326	12979
Hist	1990	22037	17659	28311	685	68692	5050	73742	13659
Hist	1991	24215	18580	28141	660	71595	4439	76034	14278
Hist	1992	22916	18456	29540	649	71561	5645	77207	14055
Hist	1993	25060	19627	31562	544	76793	5876	82669	14916
Hist	1994	25176	20116	33395	541	79227	6219	85446	15010
Hist	1995	26513	20646	33590	540	81290	7225	88514	16251
Hist	1996	26833	20909	34755	567	83064	7573	90637	16181
Hist	1997	26792	21295	35499	569	84155	5618	89773	16040
Hist	1998	27745	22158	37052	560	87515	5914	93429	16657
Hist	1999	29238	23089	39020	584	91932	6069	98001	17266
Hist	2000	28413	23541	38517	534	91004	7235	98239	16757
Hist	2001	29182	23830	37995	521	91527	7777	99304	17531
Hist	2002	32087	24828	39252	534	96701	7970	104670	18851
Hist	2003	30837	24769	38887	576	95069	7853	102922	18843
Hist	2004	31256	25206	39155	628	96245	8146	104391	18254
Hist	2005	33722	26699	39461	603	100485	7617	108103	19966
Hist	2006	32570	25964	41098	590	100222	6304	109182	20910
Hist	2007	35193	27090	41372	624	104279	6559	112753	20842
Frcst	2008	34610	27120	42182	624	104536	7719	112255	19898
Frcst	2009	35194	27216	40176	624	103210	7619	110829	19659
Frcst	2010	35754	27454	40659	624	104492	7702	112194	19938
Frcst	2011	36349	28039	42177	624	107188	7889	115077	20419
Frcst	2012	37002	28539	43937	624	110101	8091	118193	20954
Frcst	2013	37620	29026	45361	624	112630	8271	120901	21433
Frcst	2014	38281	29539	46724	624	115167	8454	123621	21909
Frcst	2015	38894	29898	47859	624	117275	8613	125889	22333
Frcst	2016	39555	30307	48938	624	119423	8776	128199	22737
Frcst	2017	40211	30767	50084	624	121686	8943	130629	23155
Frcst	2018	40952	31101	51375	624	124052	9123	133175	23602
Frcst	2019	41745	31590	52695	624	126654	9317	135971	24101
Frcst	2020	42599	32103	53944	624	129269	9512	138781	24684
Frcst	2021	43515	32690	55284	624	132112	9723	141835	25244
Frcst	2022	44471	33264	56706	624	135064	9942	145006	25828
Frcst	2023	45456	33874	58093	624	138046	10164	148210	26418
Frcst	2024	46451	34514	59598	624	141187	10398	151585	27035
Frcst	2025	47482	35141	61124	624	144371	10637	155007	27661
Frcst	2026	48524	35804	62724	624	147676	10887	158563	28312
Frcst	2027	49577	36489	64492	624	151182	11149	162331	29000

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	-2.49	2.22	-0.45
1985-1990	2.26	3.81	2.95	0.97	2.92	0.65	2.75	4.37
1990-1995	3.77	3.17	3.48	-4.65	3.43	7.42	3.72	3.54
1995-2000	1.39	2.66	2.77	-0.24	2.28	0.03	2.11	0.61
2000-2005	3.48	2.55	0.49	2.49	2.00	1.04	1.93	3.57
2005-2010	1.18	0.56	0.60	0.67	0.78	0.22	0.75	-0.03
2010-2015	1.70	1.72	3.31	0.00	2.34	2.26	2.33	2.29
2015-2020	1.84	1.43	2.42	0.00	1.97	2.00	1.97	2.02
2020-2025	2.19	1.82	2.53	0.00	2.23	2.26	2.24	2.30
2025-2027	2.18	1.90	2.72	0.00	2.33	2.38	2.34	2.39
2008-2027	1.91	1.57	2.26	0.00	1.96	1.95	1.96	2.00

Indiana Base Average Retail Rates (Cents/kWh) (in 2007 Dollars)

Year	Res	Com	Ind	Average
1980	10.11	10.71	7.43	9.07
1981	10.36	10.64	7.56	9.16
1982	11.44	11.26	8.29	10.05
1983	11.90	11.39	8.37	10.22
1984	12.01	11.43	8.37	10.24
1985	12.30	11.39	8.25	10.26
1986	12.45	11.71	8.48	10.57
1987	12.01	11.40	7.71	10.01
1988	11.31	10.43	7.31	9.35
1989	10.56	8.94	6.67	8.42
1990	9.95	8.42	6.29	7.91
1991	9.33	7.91	5.99	7.53
1992	9.25	7.81	5.83	7.34
1993	8.72	7.32	5.47	6.91
1994	8.74	7.30	5.43	6.85
1995	8.59	7.23	5.21	6.73
1996	8.57	7.20	5.23	6.70
1997	8.74	7.13	5.15	6.69
1998	8.76	7.13	5.12	6.67
1999	8.50	6.96	4.87	6.45
2000	8.15	6.60	4.79	6.20
2001	7.71	6.41	4.48	5.92
2002	7.46	6.25	4.42	5.81
2003	7.78	6.46	4.51	5.99
2004	7.81	6.56	4.58	6.06
2005	7.82	6.50	4.75	6.17
2006	8.37	7.13	5.20	6.65
2007	8.04	6.90	5.05	6.47
2008	8.37	7.68	5.48	6.94
2009	8.48	7.76	5.51	7.05
2010	8.62	7.86	5.52	7.13
2011	8.95	8.15	5.72	7.38
2012	9.24	8.40	5.88	7.59
2013	9.66	8.77	6.12	7.91
2014	9.53	8.68	6.12	7.84
2015	9.46	8.64	6.16	7.82
2016	9.57	8.75	6.30	7.93
2017	9.61	8.81	6.36	7.99
2018	9.62	8.84	6.43	8.03
2019	9.60	8.83	6.50	8.05
2020	9.61	8.85	6.60	8.10
2021	9.56	8.82	6.63	8.09
2022	9.55	8.82	6.69	8.11
2023	9.59	8.87	6.79	8.18
2024	9.54	8.84	6.83	8.17
2025	9.59	8.89	6.94	8.25
2026	9.56	8.88	6.97	8.25
2027	9.48	8.82	6.98	8.22
Average Compound Growth Rates (%)				
Year-Year	**Res**	**Com**	**Ind**	**Average**
1980-1985	3.99	1.22	2.10	2.50
1985-1990	-4.15	-5.86	-5.26	-5.08
1990-1995	-2.89	-2.99	-3.70	-3.17
1995-2000	-1.05	-1.81	-1.69	-1.62
2000-2005	-0.83	-0.29	-0.15	-0.12
2005-2010	1.97	3.85	3.06	2.94
2010-2015	1.89	1.93	2.21	1.87
2015-2020	0.30	0.48	1.39	0.70
2020-2025	-0.04	0.09	0.99	0.37
2025-2027	-0.56	-0.42	0.33	-0.20
2008-2027	0.66	0.73	1.29	0.89

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

Btu	British thermal unit
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CEMR	Center for Econometric Model Research
CC	Combined Cycle
CT	Combustion Turbine
CEDMS	Commercial Energy Demand Modeling System
DSM	Demand-Side Management
EIA	Energy Information Administration
EPACT	Energy Policy Act
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GSP	Gross State Product
GWh	Gigawatthour
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
IMPA	Indiana Municipal Power Agency
KLEM	Capital, labor, energy and materials
kWh	Kilowatthour
LMSTM	Load Management Strategy Testing Model
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
REDMS	Residential Energy Modeling System
REEMS	Residential End-Use Energy Modeling System
SIC	Standard Industrial Classification
SUFG	State Utility Forecasting Group
WVPA	Wabash Valley Power Association