PURDUE UNIVERSITY

Discovery Park Energy Center

Indiana Electricity Projections:
THE 2007 FORECAST

State Utility Forecasting Group Purdue University, West Lafayette, Indiana

December 2007

Indiana Electricity Projections: The 2007 Forecast

Prepared by:

Douglas J. Gotham
Forrest D. Holland
David G. Nderitu
Paul V. Preckel
Zuwei Yu

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

December 2007

Prepared for:

Indiana Utility Regulatory Commission
Indianapolis, Indiana

Table of Contents

List of Figures

List of Tables

Foreword

This report presents the 2007 projections of future electricity requirements for the state of Indiana for the period 2006-2025. 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 eleventh 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
500 Central Drive, Room 334
West Lafayette, IN 47907-2022
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 eleventh set of projections of future electricity usage, peak demand, prices and resource requirements. In its most recent forecast, released in 2005, SUFG identified a need for new resources in the first few years. This forecast also reports a need in the short term for significant resources, which could be met through new construction, purchases from existing generators, or conservation measures.

This forecast projects electricity usage to grow at a rate of 2.46 percent per year over the 20 years of the forecast. This growth rate is similar to that seen in the late 1990s and slightly higher than the growth in the 2005 SUFG projections. Peak electricity demand is also projected to grow at an average rate of 2.46 percent annually. This corresponds to about 585 megawatts (MW) of increased peak demand per year.

The 2007 forecast predicts Indiana electricity prices to increase significantly in real (inflation adjusted) terms through 2010 and then slowly fall through the remainder of the forecast period. The price increase in the early years of the forecast is caused by two factors; the cost of controlling emissions from coal-fired generation facilities to meet the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) and second, higher purchase power costs.

As in the 2005 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 330 MW of peaking, 1,100 MW of cycling, and 620 MW of baseload resources required by 2010. These requirements are somewhat lower than those identified in the 2005 forecast, primarily as a result of new long-term power purchases by some of the Indiana utilities and an increase in projected interruptible loads.

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.

Finally, the 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.

Resource needs are determined on a statewide basis by matching existing statewide resources to projected diversified statewide peak demand plus reserves. For planning purposes, SUFG assumed a 15 percent reserve margin[1] for the state. The 15 percent reserve margin is a "rule-of-thumb" that reflects recent national average reserve margins. Due to diversity in demand across the utilities, a statewide 15 percent reserve margin occurs when individual utility reserve margins are roughly 11 percent. When the state reserve margin falls below 15 percent, resource additions are chosen from a list of resource options based on an analysis of load versus existing capacity for individual utilities. The dynamic interactions between customer purchases, a utility's operating and investment decisions, and customer rates are captured by cycling through the various submodels until an equilibrium, or balance, among demand, supply and price is attained.

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 2007 projections for its base scenario. A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy. The CEMR Indiana projections are based on a national employment projection of 0.97 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 0.80 percent. Other key economic projections are:

- Real personal income (the residential sector model driver) is expected to grow at a 2.10 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average a 1.12 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 3.49 percent annual rate as gains in productivity offset declines in employment.

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

---

[1] SUFG reports reserves in terms of reserve margins instead of capacity margins. Care must be taken when using the two terms since they are not equivalent. A 15 percent reserve margin is equivalent to a 13 percent capacity margin.
Capacity Margin = [(Capacity-Demand)/Capacity]
Reserve Margin=[(Capacity-Demand)/Demand]

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

Demographic Projections

Population growth for all scenarios is 0.49 percent per year. This projection is from the Indiana Business Research Center (IBRC) at Indiana University.

The SUFG forecasting system includes a housing model that utilizes population and income assumptions to project the number of households. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of 1.00 percent over the forecast period.

Fossil Fuel Price Projections

SUFG's current assumptions are based on the February 2007 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: Gas price projections for all customers decrease moderately through 2013 as current high prices stimulate new liquefied natural gas import capacity, then increase slightly over 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 rates for both electricity requirements and peak demand in this forecast are 2.46 percent compared to 2.22 and 2.24 percent, respectively, in the previous forecast.

In this instance, a comparison of growth rates for electricity requirements between the current and previous forecast can be misleading, since growth rates only depend on the starting and ending values. Despite the higher growth rate, the trajectory for electricity requirements in this forecast actually lies below the one for the 2005 forecast for the first several years of the forecast, before crossing above the 2005 forecast trajectory in the later years.

The industrial electricity sales projections in this forecast grow significantly faster than in the 2005 forecast due to a more robust set of economic projections (see Table 1-1). The electricity sales projections for the commercial sector are consistently below the 2005 projections. The residential electricity sales projections remain slightly below those seen in the previous forecast despite nearly identical growth rates. See Chapters 5 through 7 for more detail on the sectoral forecasts.

The growth in peak demand is slightly higher than that projected in 2005. 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 585 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 15 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. 2005 Projections)

Electricity Sales Growth		
Sector	**Current (2006-2025)**	**2005 (2004-2023)**
Residential	2.21	2.22
Commercial	2.46	2.61
Industrial	2.67	1.99
Total	2.46	2.22

[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)

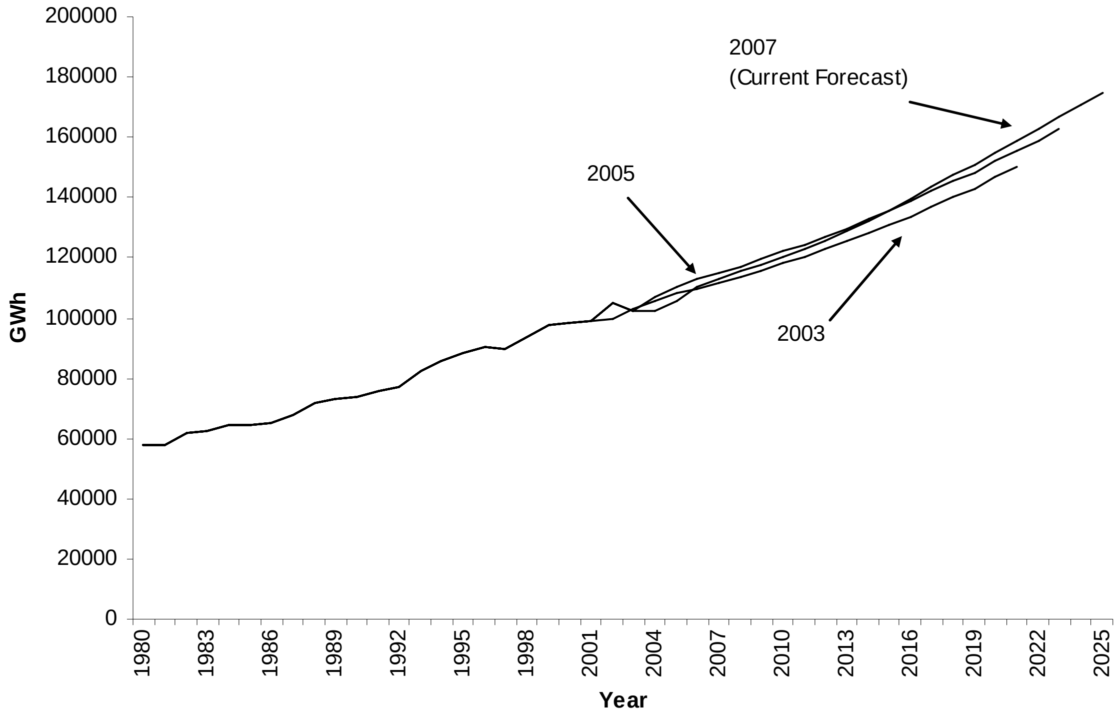
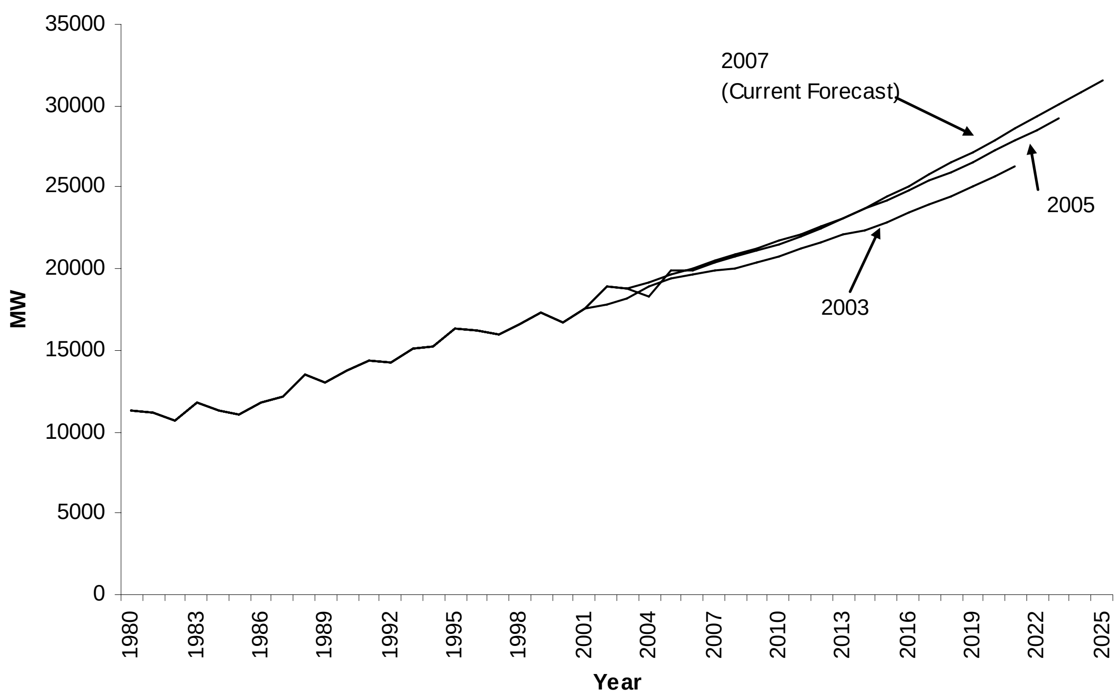


Figure 1-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



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 290 MW early in the forecast. The peak demand reduction is expected to increase to 390 MW by the end of the forecast period. This represents a substantial increase from the 2005 forecast.

These DSM projections do not include the reductions in peak demand due to interruptible load contracts with large customers. Estimated interruptible loads grow from 1,060 MW at the beginning of the forecast to about 1,120 MW at the end. This is slightly higher than the amount of interruptible loads included in the 2005 forecast.

Supply-Side Resources

SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, de-ratings due to pollution control retrofits and net changes in firm out-of-state purchases and sales. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic firm wholesale purchases are then added as necessary during the forecast period to maintain a statewide 15 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 5,600 MW of additional resources are required. The net change in generation includes the retirement of units as reported in the utilities' 2005 Integrated Resource Plan (IRP) filings. Over the second half of the forecast period, an additional 9,100 MW of resources are required to maintain target reserves.

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

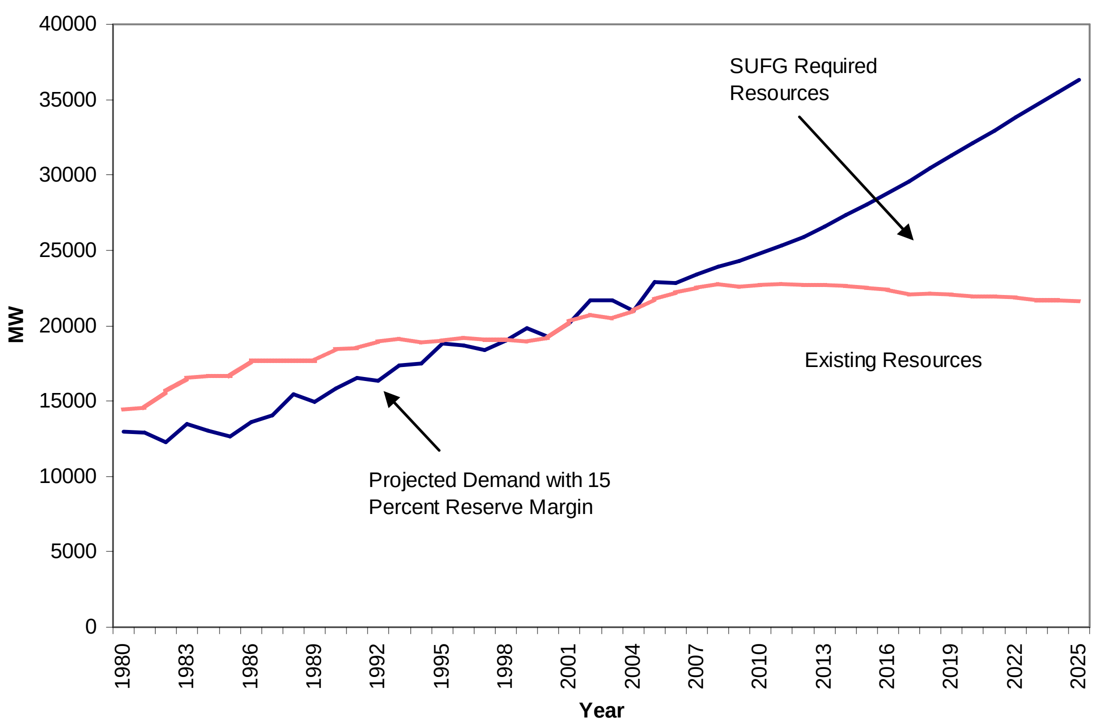


Table 1-2. Indiana Resource Plan in MW (SUFG Base)

	Uncontrolled Peak Demand	Interruptible	Net Peak Demand	Existing/ Approved Capacity	Incremental Change in Capacity	Projected Additional Resource Requirements				Total Resources	Reserve Margin
						Peaking	Cycling	Baseload	Total		
2005				21,777							
2006	20,933	1,059	19,874	22,166	389	90	530	120	740	22,906	15
2007	21,393	1,062	20,331	22,519	353	140	620	90	850	23,369	15
2008	21,865	1,063	20,803	22,779	260	230	730	170	1,130	23,909	15
2009	22,163	1,065	21,099	22,554	-225	310	1,020	390	1,720	24,274	15
2010	22,608	1,067	21,541	22,719	165	330	1,100	620	2,050	24,769	15
2011	23,077	1,068	22,010	22,738	19	480	1,230	880	2,590	25,328	15
2012	23,590	1,071	22,520	22,685	-53	600	1,330	1,290	3,220	25,905	15
2013	24,177	1,073	23,104	22,685	0	770	1,430	1,710	3,910	26,595	15
2014	24,831	1,076	23,756	22,635	-50	1,000	1,510	2,180	4,690	27,325	15
2015	25,464	1,078	24,387	22,511	-125	1,240	1,620	2,710	5,570	28,081	15
2016	26,143	1,081	25,062	22,384	-126	1,440	1,710	3,300	6,450	28,834	15
2017	26,819	1,084	25,736	22,043	-341	1,700	2,090	3,760	7,550	29,593	15
2018	27,562	1,088	26,474	22,149	106	1,940	2,210	4,160	8,310	30,459	15
2019	28,277	1,092	27,185	22,072	-77	2,180	2,310	4,700	9,190	31,262	15
2020	29,016	1,096	27,921	21,909	-163	2,530	2,430	5,220	10,180	32,089	15
2021	29,746	1,100	28,647	21,909	0	2,700	2,520	5,820	11,040	32,949	15
2022	30,504	1,104	29,400	21,869	-41	2,940	2,600	6,400	11,940	33,809	15
2023	31,219	1,108	30,112	21,709	-160	3,100	2,700	7,120	12,920	34,629	15
2024	31,954	1,112	30,843	21,709	0	3,290	2,820	7,640	13,750	35,459	15
2025	32,678	1,116	31,562	21,628	-81	3,470	2,930	8,290	14,690	36,318	15

1 Uncontrolled peak demand is the peak demand with DSM in place but 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.

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 2005. Therefore, 2006 and 2007 numbers represent projections. The resource requirements identified in Table 1-2 for 2006 and 2007 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.

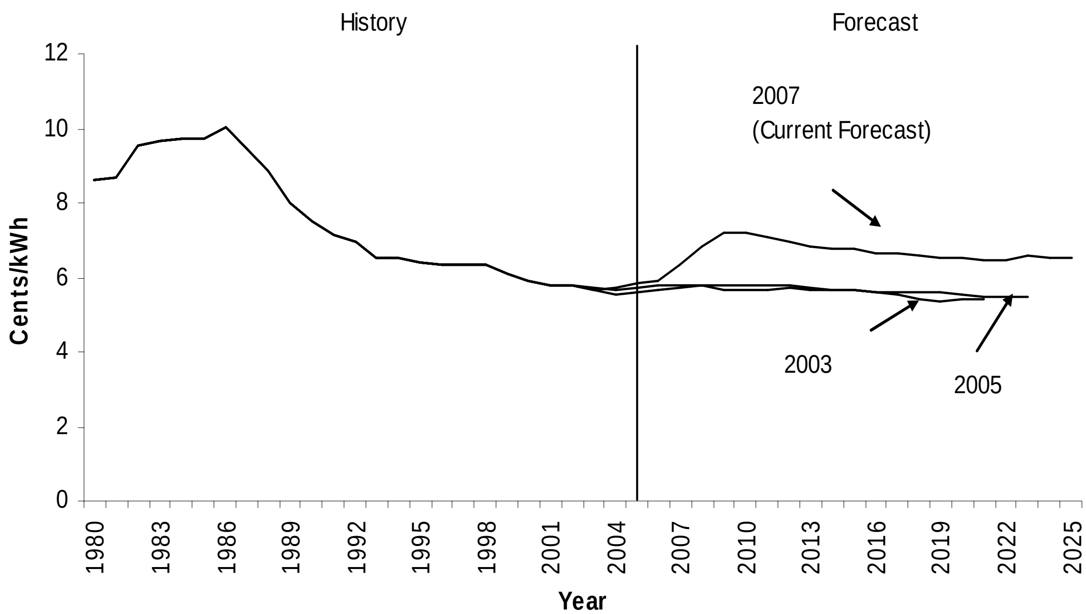
Equilibrium Price and Energy Impact

SUFG's base scenario equilibrium real electricity price trajectory is shown in cents per kilowatthour (kWh) in Figure 1-4. Real prices are projected to increase significantly through 2010 and then drift downward for the remainder of the forecast period. Since the change in prices early in the forecast horizon is significant, price impacts the electricity requirements projection for this portion of the forecast period.

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 1-4. The price projection labeled "2005" is the base from SUFG's 2005 forecast and the price projections labeled "2003" is the base case projection contained in SUFG's 2003 forecast. For the prior price forecasts, SUFG rescaled the original price projections to 2005 dollars (from 2001 dollars for the 2003 projection, and from 2003 dollars for the 2005 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

Two 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 the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) and second, higher purchase power costs. It should be noted that the costs associated with meeting CAIR and CAMR were not incorporated in the previous SUFG forecasts.[4] Other factors such as energy and demand growth as well as fossil fuel price assumptions, especially coal, also influence the trajectory of future prices.

Figure 1-4. Indiana Real Price Projections in cents/kWh (2005 Dollars) (Historical, Current and Previous Forecasts)

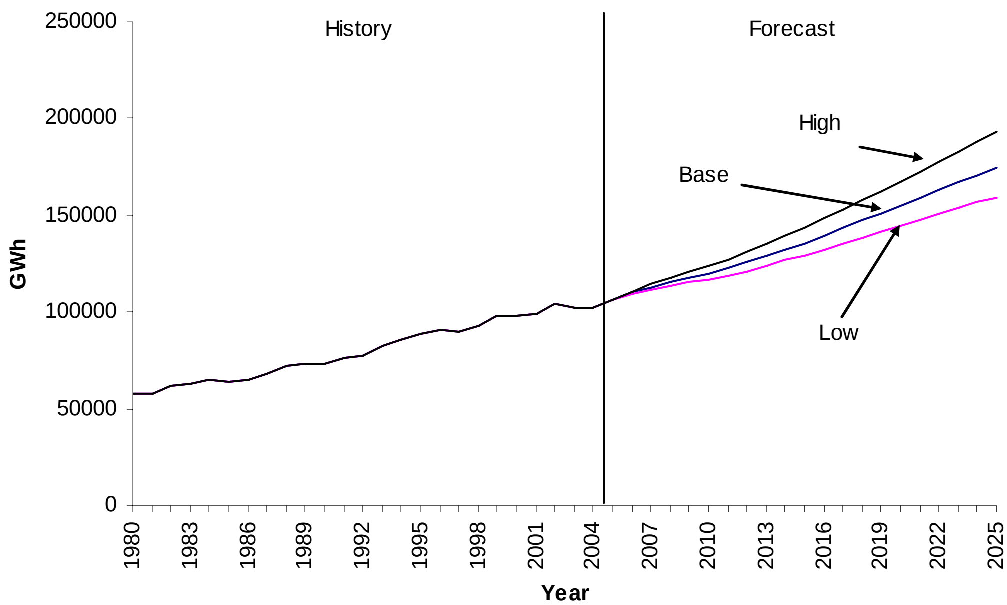


[4] SUFG performed two separate analyses that looked at the price impacts of CAIR and CAMR. The reports, "The Projected Impacts of the Clean Air Interstate Rule on Electricity Prices in Indiana" and "The Projected Impacts of Mercury Emissions Reductions on Electricity Prices in Indiana," are available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

Low and High Scenarios

SUFG has constructed alternative low and high 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 0.45 percent lower and 0.50 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.

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 an 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.

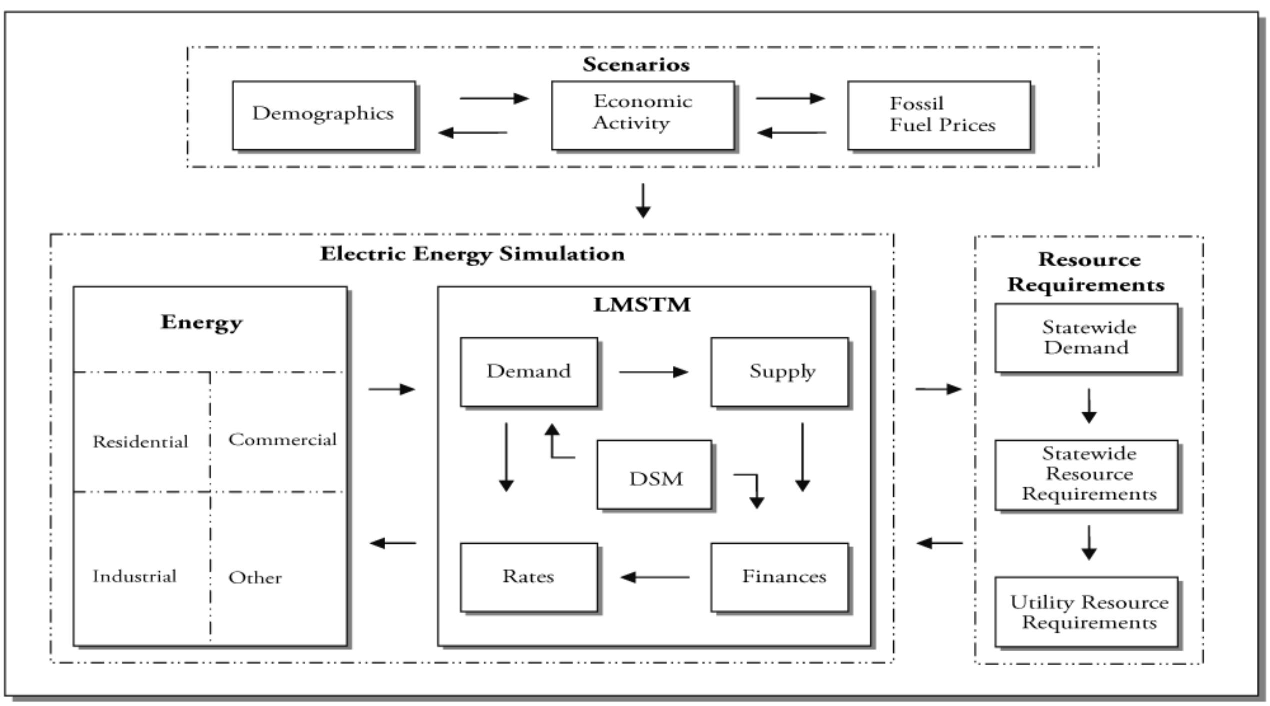
Scenarios

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. Additional information regarding SUFG's energy models for the residential, commercial and industrial sectors can be found in chapters five, six and seven, respectively.

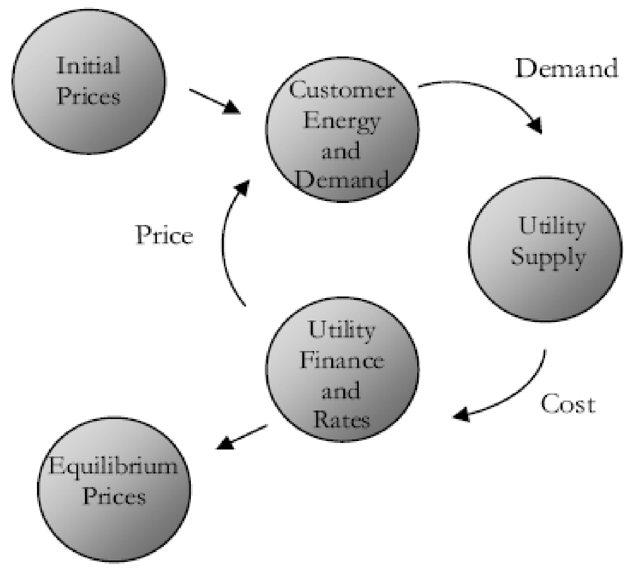
Load Management Strategy Testing Model

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 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 iteration ends. Otherwise, the modeling system continues to cycle through the submodels until an equilibrium is attained as is illustrated in Figure 2-2.

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



Supply-Side Resources

SUFG determines required resources according to a target statewide 15 percent reserve margin, but allocates those resources to three types (peaking, cycling and baseload) according to individual utility needs. This process is illustrated in the flowchart shown 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. 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 he state. The additional resources required are determined for each year by comparing the peak demand with a 15 percent reserve margin to the existing capacity.

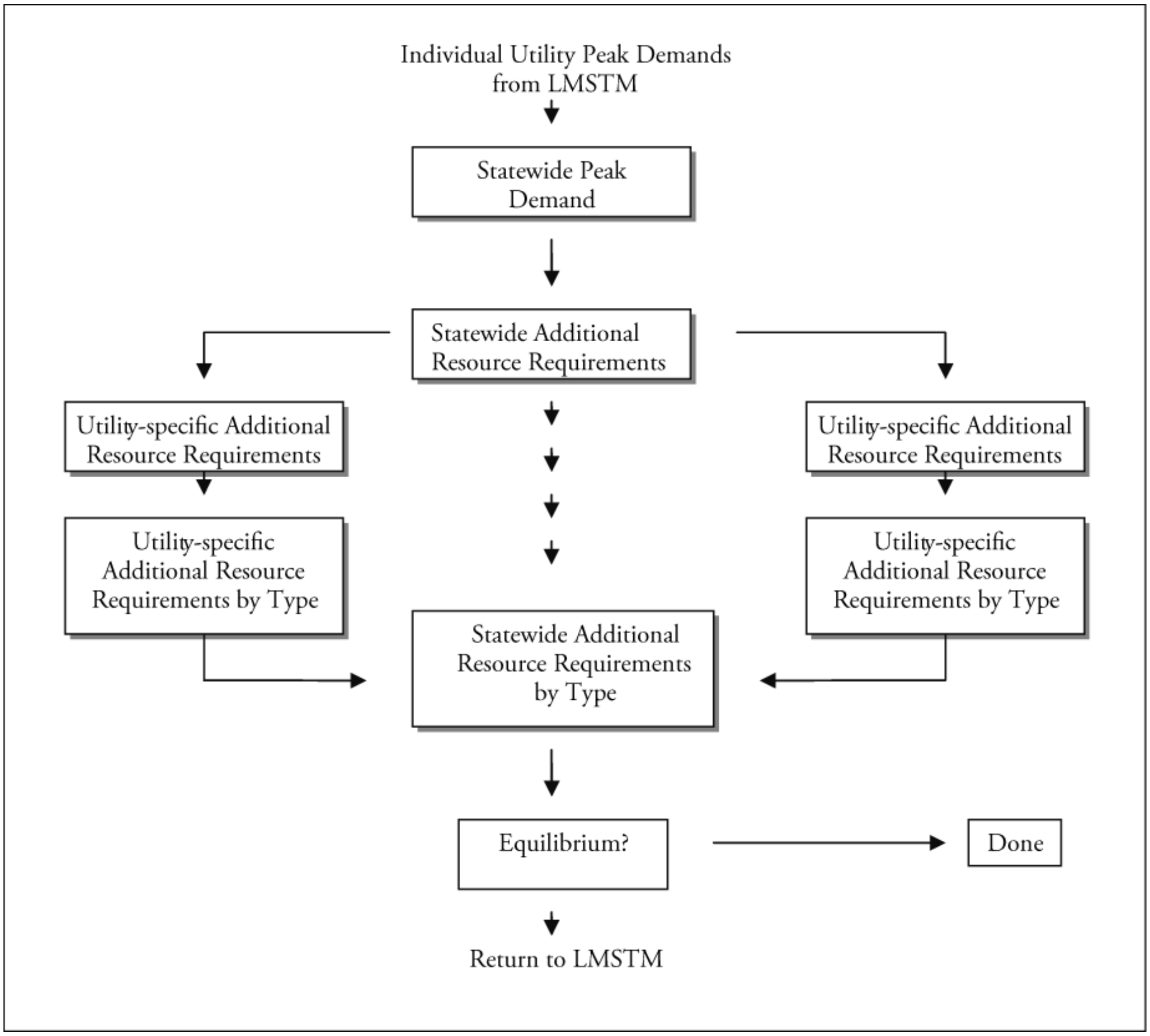
The existing capacity has been adjusted for retirements, utility purchases and sales, and new construction projects that have been approved by the Indiana Utility Regulatory Commission.

The required resources are then assigned to the individual utilities with the lowest reserve margins, so that all utilities have similar reserve margins. 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 loadshapes, 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 an 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.

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 2.46 percent for both electricity requirements and 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 somewhat higher than the 2005 forecast. Even though overall growth rates are similar, the growth within sectors varies considerably with higher growth in the industrial sector offsetting lower growth in the commercial sector.

In this instance, a comparison of growth rates for electricity requirements between the current and previous forecast can be misleading. Despite the higher growth rate, the trajectory for electricity requirements in this forecast actually lies below the one for the 2005 forecast for the first several years of the forecast horizon. The industrial electricity sales projections in the two forecasts exhibit a similar phenomenon, with the current forecast beginning slightly below the previous forecast due to the difference in starting values. Industrial electricity sales grow significantly more in this forecast than in the 2005 projections due to a more robust set of economic projections. The electricity sales projections for the commercial sector are consistently below the 2005 projections. The residential electricity sales projections remain slightly below those seen in the 2005 forecast despite nearly identical growth rates. See Chapters 5 through 7 for more detail on the sectoral forecasts.

The growth in peak demand is similarly higher than that projected in 2005 and follows the same pattern in relation to the 2005 projection as is observed for the total energy requirements. Another measure of peak demand growth can be obtained by considering the average year to year MW load change. In Figure 3-2, the annual increase is 585 MW compared to about 500 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 supply-side resources are added as necessary to maintain a 15 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.

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 290 MW at the beginning of the forecast period and by about 390 MW at the end of the forecast.

These DSM projections, which include new programs and the expansion of existing programs, do not include the reductions in peak demand due to interruptible load contracts with large customers. Interruptible loads are projected to increase from 1,060 MW to about 1,120 MW over the forecast horizon. See Chapter 4 for additional information about DSM and interruptible loads.

Supply-Side Resources

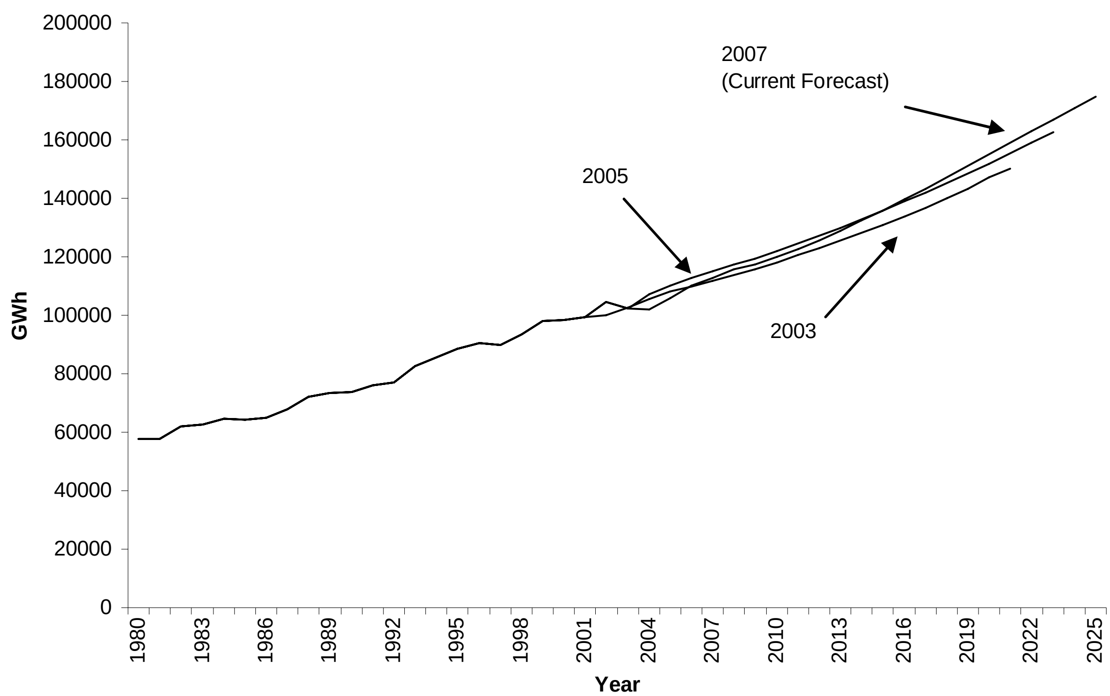
SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, and net changes in firm out-of-state purchases and sales. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place.

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

		Year of Forecast		
Year	**Actual**	**2003**	**2005**	**2007**
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	99934		
2003	102250	102680		
2004	102122	105592	107237	
2005	105889	108053	110069	
2006		109944	112911	110164
2007		111758	114937	112877
2008		113769	117223	115702
2009		115798	119318	117484
2010		118115	122126	120066
2011		120546	124565	122717
2012		122899	127052	125618
2013		125532	129762	128829
2014		128116	132740	132458
2015		130895	135689	135847
2016		133805	138882	139551
2017		136839	141991	143223
2018		139920	145183	147253
2019		143145	148501	151122
2020		147067	151927	155092
2021		150013	155404	159011
2022			159020	163096
2023			162617	166895
2024				170826
2025				174667

Average Compound Growth Rates			
Forecast Period	**2002-2021**	**2004-2023**	**2006-2025**
	2.16	2.22	2.46

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



Generic firm wholesale purchases are then added at prices that reflect SUFG estimates of long-run average costs for these purchases as necessary during the forecast period to maintain a statewide 15 percent reserve margin. The 15 percent reserve margin is a "rule-of-thumb" that reflects recent national average reserve margins. Due to diversity in demand between utilities, a statewide 15 percent reserve margin occurs when individual utility reserve margins are roughly 11 percent.

Three types of generic firm wholesale purchases are included:

1. peaking purchases;
2. cycling purchases; and
3. coal-fired 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. Recent increases in construction costs and in fuel prices have resulted in significantly higher purchase price projections than SUFG has used in the past. In turn, this contributes to a higher electricity price projection.

Table 3-4 and Figure 3-3 show the statewide resource plan for the SUFG base scenario. This forecast identifies a need for 330 MW of peaking, 1,100 MW of cycling, and 620 MW of baseload resources required by 2010. These requirements are somewhat lower than those identified in the 2005 forecast, primarily as a result of new long-term power purchases by some of the Indiana utilities and an increase in estimated interruptible loads. By 2015, over 5,500 MW of resource additions are required, with almost fifty percent being of the base load variety. About 10,000 MW of resource additions are required by 2020. The net change in generation includes the retirement of units as reported in the utilities' 2005 IRP filings, changes in firm purchases and sales, and the addition of approved new capacity.

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

		Year of Forecast		
Year	**Actual**	**2003**	**2005**	**2007**
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	17762		
2003	18843	18231		
2004	18254	18934	19167	
2005	19920	19398	19599	
2006		19633	20052	19874
2007		19845	20486	20331
2008		20047	20820	20803
2009		20400	21201	21099
2010		20794	21712	21541
2011		21224	22167	22010
2012		21581	22620	22520
2013		22044	23121	23104
2014		22410	23666	23756
2015		22900	24206	24387
2016		23413	24790	25062
2017		23945	25362	25736
2018		24489	25954	26474
2019		25057	26574	27185
2020		25709	27211	27921
2021		26231	27855	28647
2022			28526	29400
2023			29196	30112
2024				30843
2025				31562

Average Compound Growth Rates			
Forecast Period	**2002-2021**	**2004-2023**	**2006-2025**
	2.07	2.24	2.46

`

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

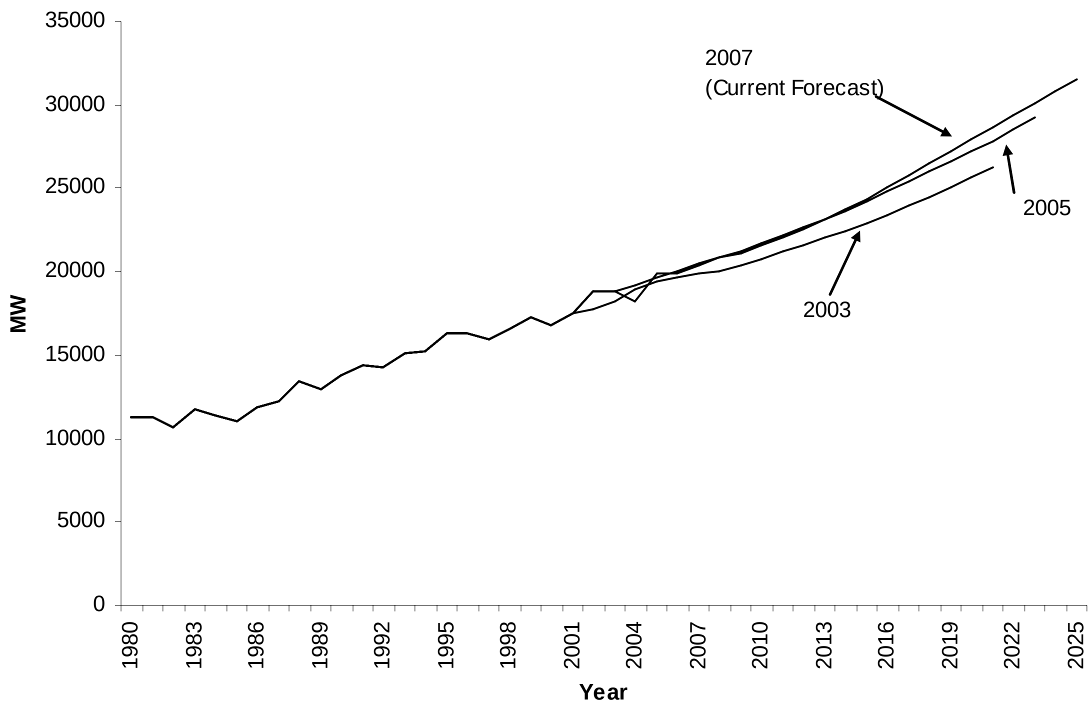


Table 3-3. Annual Electricity Sales Growth (Percent) by Sector (Current vs. 2005 Projections)

Electricity Sales Growth		
Sector	**Current (2006-2025)**	**2005 (2004-2023)**
Residential	2.21	2.22
Commercial	2.46	2.61
Industrial	2.67	1.99
Total	2.46	2.22

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 2005. Therefore, 2006 and 2007 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.

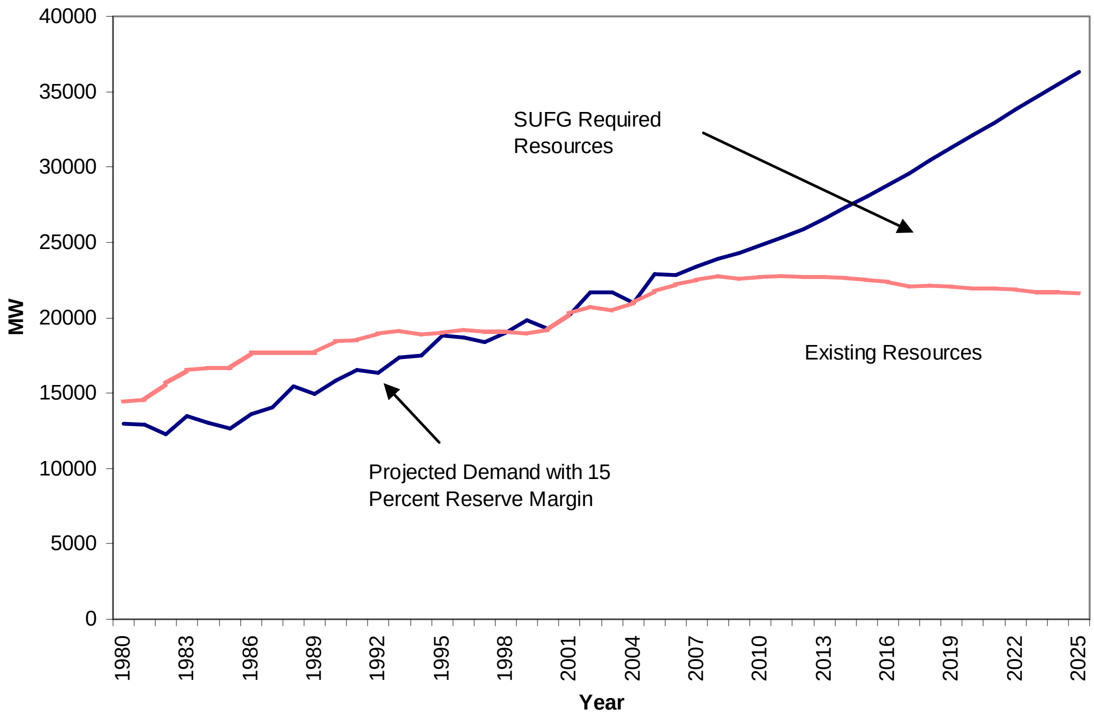
SUFG's base scenario equilibrium real electricity price trajectory is shown in Table 3-5 and Figure 3-4. Real prices are projected to increase significantly through 2010 and then drift downward for the remainder of the forecast period. Since the change in prices early in the forecast horizon is significant, price impacts the electricity requirements projection for this portion of the forecast period.

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

	Uncontrolled Peak Demand	Interruptible	Net Peak Demand	Existing/ Approved Capacity	Incremental Change in Capacity	Projected Additional Resource Requirements				Total Resources	Reserve Margin
						Peaking	Cycling	Baseload	Total		
2005				21,777							
2006	20,933	1,059	19,874	22,166	389	90	530	120	740	22,906	15
2007	21,393	1,062	20,331	22,519	353	140	620	90	850	23,369	15
2008	21,865	1,063	20,803	22,779	260	230	730	170	1,130	23,909	15
2009	22,163	1,065	21,099	22,554	-225	310	1,020	390	1,720	24,274	15
2010	22,608	1,067	21,541	22,719	165	330	1,100	620	2,050	24,769	15
2011	23,077	1,068	22,010	22,738	19	480	1,230	880	2,590	25,328	15
2012	23,590	1,071	22,520	22,685	-53	600	1,330	1,290	3,220	25,905	15
2013	24,177	1,073	23,104	22,685	0	770	1,430	1,710	3,910	26,595	15
2014	24,831	1,076	23,756	22,635	-50	1,000	1,510	2,180	4,690	27,325	15
2015	25,464	1,078	24,387	22,511	-125	1,240	1,620	2,710	5,570	28,081	15
2016	26,143	1,081	25,062	22,384	-126	1,440	1,710	3,300	6,450	28,834	15
2017	26,819	1,084	25,736	22,043	-341	1,700	2,090	3,760	7,550	29,593	15
2018	27,562	1,088	26,474	22,149	106	1,940	2,210	4,160	8,310	30,459	15
2019	28,277	1,092	27,185	22,072	-77	2,180	2,310	4,700	9,190	31,262	15
2020	29,016	1,096	27,921	21,909	-163	2,530	2,430	5,220	10,180	32,089	15
2021	29,746	1,100	28,647	21,909	0	2,700	2,520	5,820	11,040	32,949	15
2022	30,504	1,104	29,400	21,869	-41	2,940	2,600	6,400	11,940	33,809	15
2023	31,219	1,108	30,112	21,709	-160	3,100	2,700	7,120	12,920	34,629	15
2024	31,954	1,112	30,843	21,709	0	3,290	2,820	7,640	13,750	35,459	15
2025	32,678	1,116	31,562	21,628	-81	3,470	2,930	8,290	14,690	36,318	15

1 Uncontrolled peak demand is the peak demand with DSM in place but 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 equilibrium price projections for two previous forecasts are also shown in Table 3-5 and Figure 3-4. The price projection labeled "2003" is the base case projection contained in SUFG's 2003 forecast and the one labeled "2005" is the base case projections from SUFG's 2005 report. For the prior price forecasts, SUFG rescaled the original price projections to 2005 dollars (from 2001 dollars for the 2003 projection, and from 2003 dollars for the 2005 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

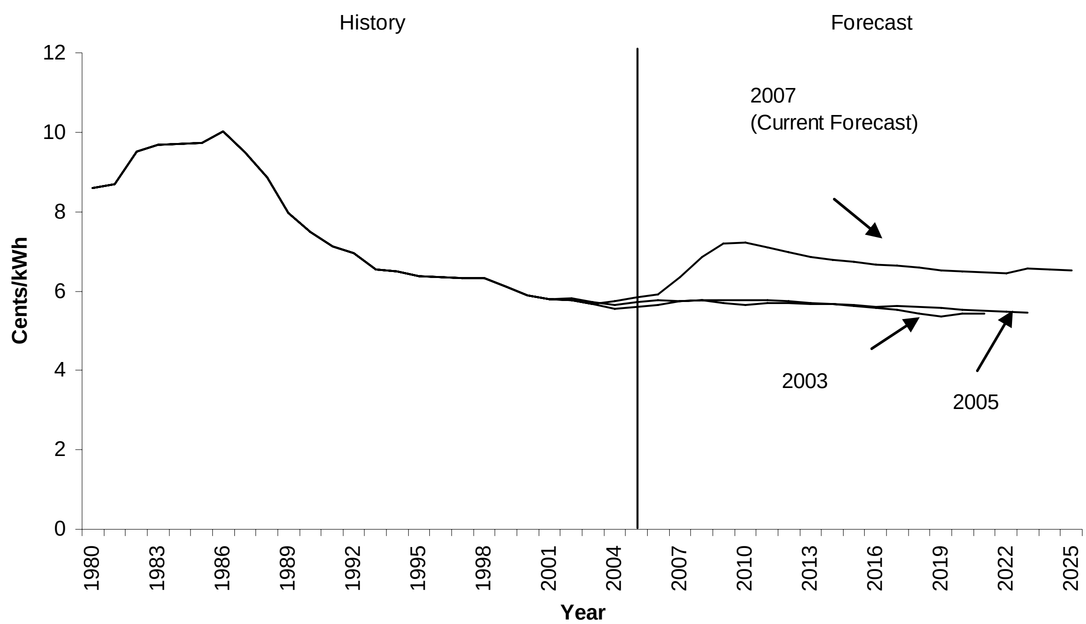
Two major factors primarily determine the differences among the price projections in Figure 3-4; first, the cost of controlling emissions from coal-fired generation facilities to meet the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) and second, higher purchase power costs. It should be noted that the costs associated with meeting CAIR and CAMR were not incorporated in the previous SUFG forecasts.[5] Other factors such as energy and demand growth as well as fossil fuel price assumptions, especially coal, also influence the trajectory of future prices. More detail regarding the assumptions and procedures used in SUFG's price forecasts may be found in previous SUFG reports.

[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 3-5. Indiana Real Price Projections in cents/kWh (2005 Dollars) (Historical, Current and Previous Forecasts)

Year	Actual	2003	2005	2007
1980	8.595			
1981	8.683			
1982	9.523			
1983	9.683			
1984	9.700			
1985	9.725			
1986	10.017			
1987	9.487			
1988	8.860			
1989	7.979			
1990	7.495			
1991	7.132			
1992	6.952			
1993	6.549			
1994	6.496			
1995	6.379			
1996	6.354			
1997	6.335			
1998	6.323			
1999	6.108			
2000	5.880			
2001	5.805			
2002	5.760	5.811		
2003	5.675	5.728		
2004	5.745	5.646	5.556	
2005	5.847	5.715	5.597	
2006		5.779	5.658	5.910
2007		5.755	5.753	6.355
2008		5.766	5.771	6.855
2009		5.782	5.690	7.197
2010		5.780	5.653	7.228
2011		5.774	5.689	7.097
2012		5.757	5.705	6.972
2013		5.703	5.684	6.851
2014		5.675	5.672	6.784
2015		5.632	5.644	6.745
2016		5.576	5.594	6.658
2017		5.532	5.616	6.643
2018		5.438	5.601	6.587
2019		5.355	5.578	6.520
2020		5.440	5.540	6.507
2021		5.421	5.506	6.471
2022			5.477	6.455
2023			5.460	6.557
2024				6.539
2025				6.525

Figure 3-4. Indiana Real Price Projections in cents/kWh (2005 Dollars) (Historical, Current and Previous Forecasts)



Low and High Scenarios

SUFG has used alternative macroeconomic, low and high growth scenarios. 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 0.45 percent lower and 0.50 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 18,600 MW over the horizon are required in the high scenario compared to 11,570 MW in the low scenario. By the end of the forecast period, electricity prices in the high case are about 3 percent higher than in the base case. This is because nearly 4,000 MW of additional wholesale purchases are acquired relative to the base scenario. Similarly, prices in the low scenario are about 2.8 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	102250			
2004	102122			
2005	105889			
2006		110164	109610	111009
2007		112877	111804	114483
2008		115702	114092	117961
2009		117484	115259	120496
2010		120066	117047	123880
2011		122717	119024	127287
2012		125618	121211	130986
2013		128829	123745	135092
2014		132458	126628	139530
2015		135847	129345	143791
2016		139551	132343	148325
2017		143223	135289	152900
2018		147253	138530	157820
2019		151122	141619	162646
2020		155092	144737	167553
2021		159011	147754	172523
2022		163096	150774	177697
2023		166895	153654	182767
2024		170826	156602	187987
2025		174667	159456	193157

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	1.51	1.51	1.51
2006-25	2.46	1.99	2.96

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

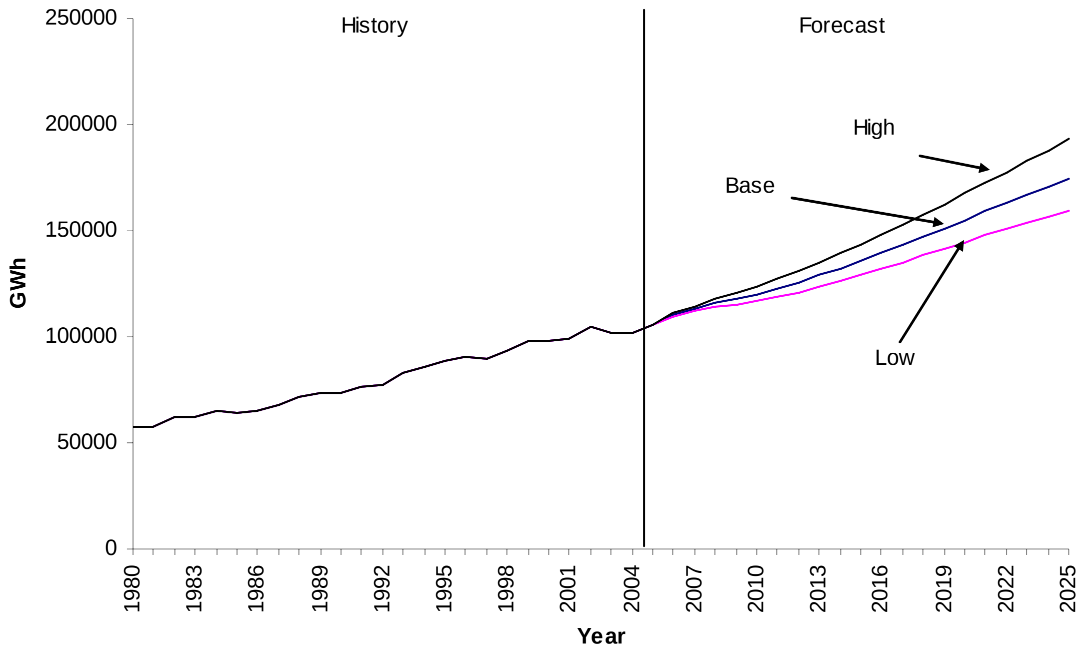


Table 3-7. Indiana Peak Demand Requirements by Scenario in MW

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	19920			
2006		19874	19776	20038
2007		20331	20139	20641
2008		20803	20515	21235
2009		21099	20701	21668
2010		21541	21007	22255
2011		22010	21358	22858
2012		22520	21743	23517
2013		23104	22203	24261
2014		23756	22731	25069
2015		24387	23232	25854
2016		25062	23783	26683
2017		25736	24325	27521
2018		26474	24927	28426
2019		27185	25498	29309
2020		27921	26071	30215
2021		28647	26639	31130
2022		29400	27204	32083
2023		30112	27752	33023
2024		30843	28317	33990
2025		31562	28862	34948

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	3.52	3.52	3.52
2006-25	2.46	2.01	2.97

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

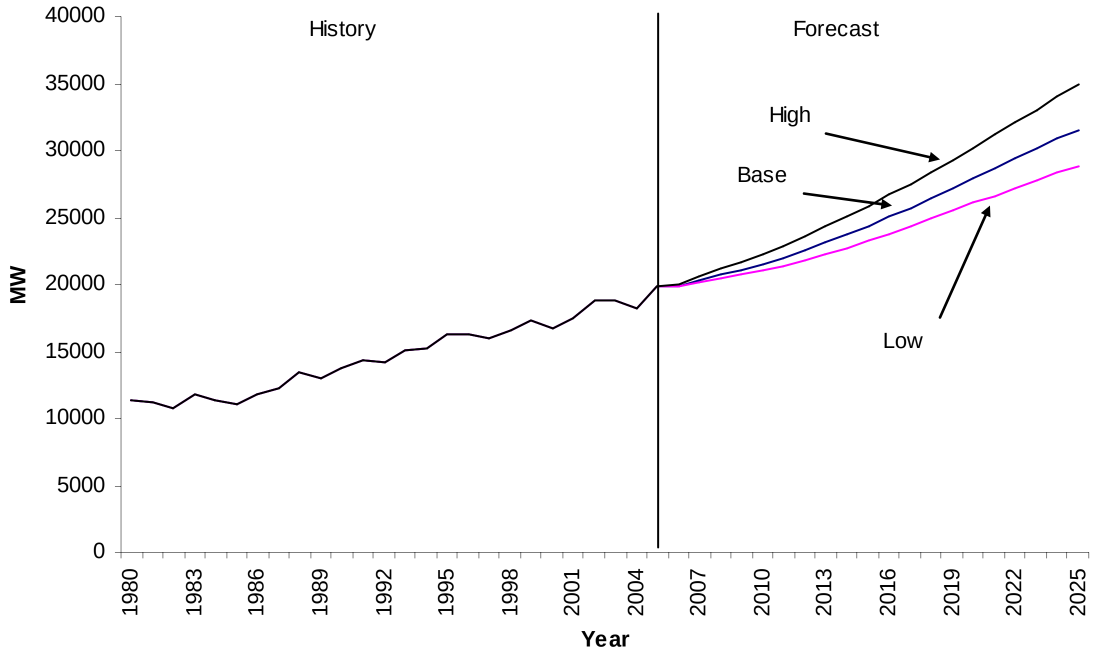


Table 3-8. Indiana Resource Requirements in MW (SUFG Scenarios)

Year	Base				High				Low			
	Peaking	Cycling	Baseload	Total	Peaking	Cycling	Baseload	Total	Peaking	Cycling	Baseload	Total
2006	90	530	120	740	120	600	150	870	70	470	110	650
2007	140	620	90	850	230	760	230	1220	90	520	50	660
2008	230	730	170	1130	340	880	420	1640	160	610	80	850
2009	310	1020	390	1720	460	1150	760	2370	190	850	190	1230
2010	330	1100	620	2050	560	1280	1040	2880	220	920	290	1430
2011	480	1230	880	2590	720	1410	1430	3560	340	1040	450	1830
2012	600	1330	1290	3220	910	1490	1960	4360	420	1150	750	2320
2013	770	1430	1710	3910	1130	1610	2490	5230	520	1240	1080	2840
2014	1000	1510	2180	4690	1400	1730	3070	6200	670	1350	1500	3520
2015	1240	1620	2710	5570	1690	1840	3690	7220	840	1430	1930	4200
2016	1440	1710	3300	6450	1930	1970	4400	8300	1020	1510	2440	4970
2017	1700	2090	3760	7550	2260	2370	4980	9610	1250	1850	2820	5920
2018	1940	2210	4160	8310	2490	2510	5550	10550	1430	1950	3140	6520
2019	2180	2310	4700	9190	2730	2610	6300	11640	1630	2020	3590	7240
2020	2530	2430	5220	10180	3100	2720	7020	12840	1970	2130	3970	8070
2021	2700	2520	5820	11040	3310	2860	7710	13880	2150	2200	4370	8720
2022	2940	2600	6400	11940	3600	3010	8410	15020	2360	2310	4750	9420
2023	3100	2700	7120	12920	3830	3170	9260	16260	2530	2400	5250	10180
2024	3290	2820	7640	13750	4050	3310	9990	17350	2670	2490	5710	10870
2025	3470	2930	8290	14690	4310	3480	10810	18600	2800	2540	6230	11570

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 fuel, 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 2007 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 Outlook 2006-2027" [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 12 percent and the payroll tax rate a little over 11 percent. Federal grants to state and local governments are assumed to grow at about 6% rate in the first half of the projection, and then decelerate to about a 5% rate in the second half. The federal budget (in nominal terms) rises for the first two-thirds of the projection and then recedes somewhat. Relative to gross domestic product (GDP), however, the deficit is declining throughout the projection period, falling to only 0.5% of GDP in 2027.

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 6.1% through 2013, and then to decelerate gradually to 5.2% growth. This produces a net export deficit that declines from 5.6% of real output to 0.8%. In nominal terms, however, the 2027 net export deficit amounts to 4.5% of GDP [CEMR].

As a result of these assumptions, real GDP for the U.S. economy is projected to grow at an average annual rate of 3.20 percent and U.S. employment growth averages 0.97 percent over the 2006 to 2025 period.

In Indiana, total employment is projected to grow at an average annual rate of 0.80 percent from 2006 through 2025. The key economic projections are:

Real personal income (the residential sector model driver) is expected to grow at a 2.10 percent annual rate.

Non-manufacturing employment (the commercial sector model driver) is expected to average a 1.12 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 3.49 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 0.28 percent per year (to 2.38), non-manufacturing employment growth increases almost 0.10 percent (to 1.21) while Indiana real manufacturing GSP growth is increased nearly 0.50 percent to 3.98. 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 1.84, 1.04 and 2.98 percent, respectively).

Demographic Projections

Household 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 Projects of Selected Economic Activity Measures

	Short-Run History for Selected Recent Periods					Long-Run Forecast		
						Aug 2002	Feb 2005	Feb 2007
	1980-1985	1985-1990	1990-1995	1995-2000	2000-2005	2002-2021	2024-2023	2006-2025
United States								
Real Personal Income	3.30	2.95	2.04	4.08	1.73	3.04	3.29	3.25
Total Employment	1.50	2.36	1.38	2.37	0.25	0.98	1.10	0.97
Real Gross Domestic Product	3.13	3.25	2.38	4.36	2.39	3.19	3.25	3.20
Personal Consumer Expenditure Deflator	5.14	3.79	2.77	1.87	2.20	2.28	1.99	1.94
Indiana								
Real Personal Income	1.47	2.50	2.48	3.37	1.17	2.36	2.22	2.10
Employment								
Total Establishment	0.22	2.84	1.91	1.22	-0.28	1.24	0.94	0.80
Manufacturing	-1.49	0.91	1.40	0.07	-2.95	-1.17	-0.02	-1.10
Non-Manufacturing	1.17	3.82	2.20	1.97	0.47	1.79	1.23	1.12
Real Gross State Product								
Total	6.65	6.17	5.83	4.78	1.98	2.14	2.82	3.21
Manufacturing	5.84	4.76	7.95	4.68	3.26	1.50	2.84	3.49
Non-Manufacturing	7.04	6.81	4.86	4.84	1.43	2.41	2.81	3.07
Sources: SUFG Forecast Modeling System and various CEMR “Long-Range Outlooks”								

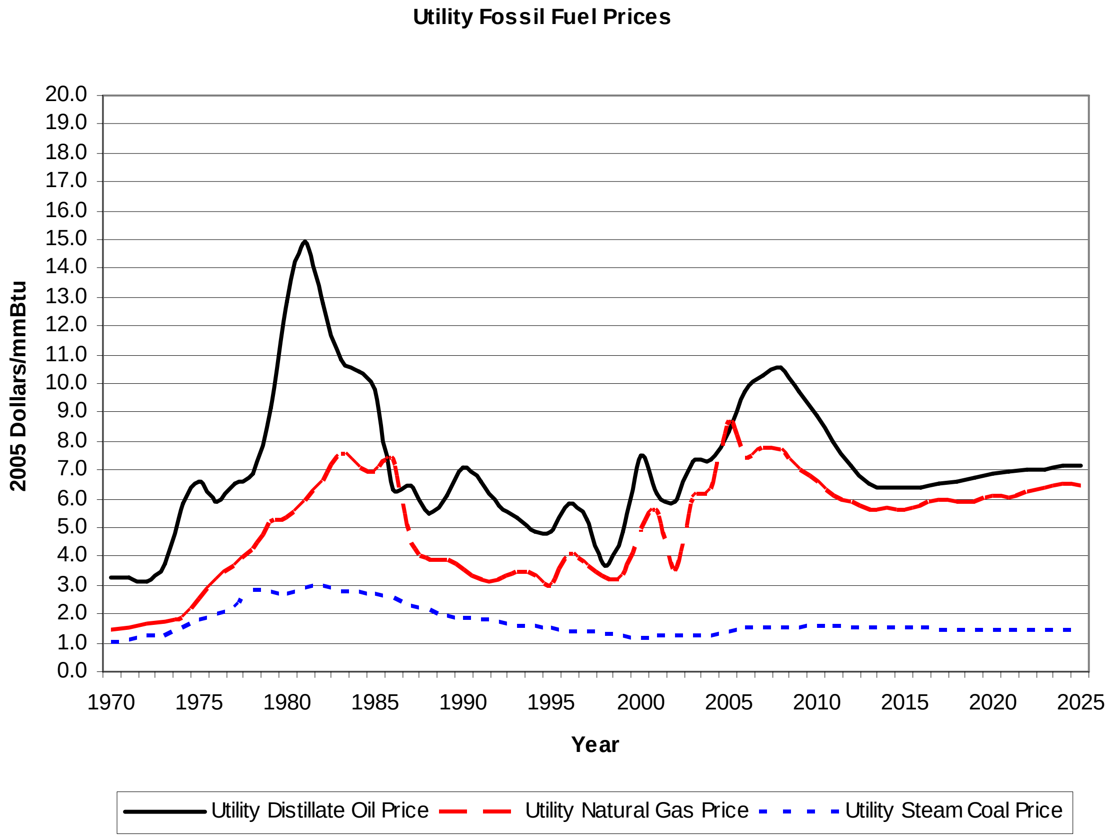
Fossil Fuel Price Projections

The price of fossil fuels such as coal, natural gas and oil affects electricity demand in separate and opposite 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 opposite 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 February 2007 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 (2005 dollars), i.e., projections with the effects of inflation removed. The general patterns of the fossil fuel price projections are that:

- Coal prices are relatively unchanged in real terms throughout the entire forecast horizon as growth in demand is offset by improvements in mining productivity.
- Gas price projections for all customers decrease moderately through 2013 as current high prices stimulate new liquefied natural gas import capacity and the development of unconventional natural gas production. Prices are projected to increase slightly over the remainder of the forecast horizon
- Distillate prices exhibit a pattern similar to natural gas over the entire forecast horizon, with a more pronounced decline early in the horizon and a slight increase in the last two-thirds of this horizon.

Figure 4-1. Utility 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 loadshape, 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 2005 are considered to be embedded in the calibration data, so no adjustments are necessary.

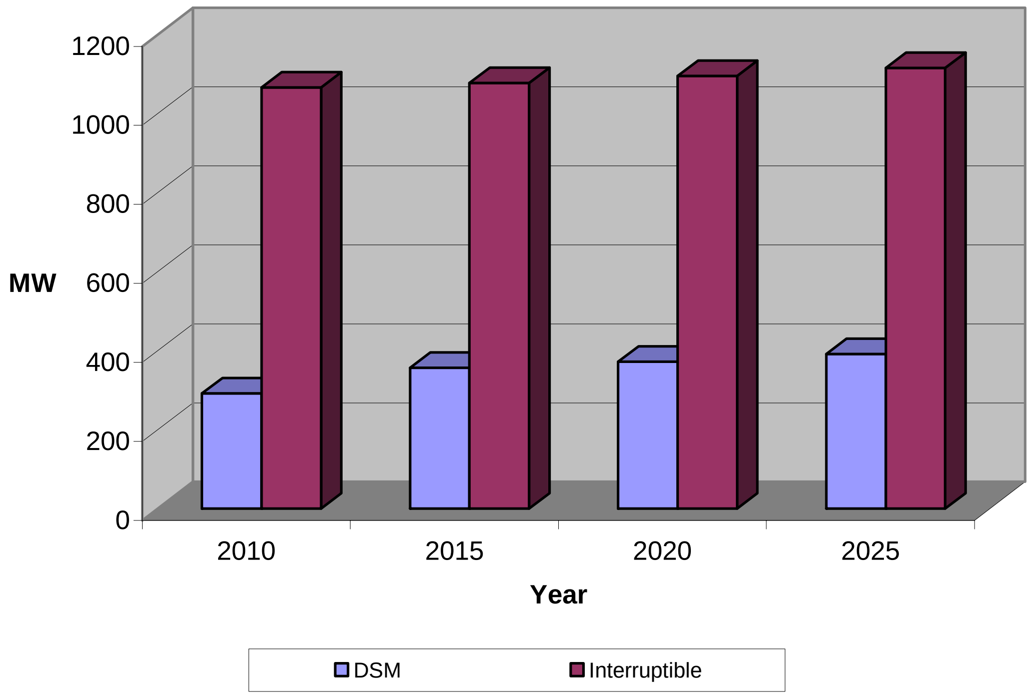
Interruptible loads, such as large customers who agree to curtail a fixed amount of their demand during critical periods in exchange for more favorable rates, are typically treated differently than traditional DSM. Interruptible loads are subtracted from the utility's peak demand in order to determine the amount of new capacity required.

Table 4-2 shows the peak demand reductions from embedded DSM in 2005 and from incremental DSM and interruptible loads available in 2006 in Indiana. These estimates are derived from utility integrated resource plan (IRP) filings and from information collected by EIA. 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.

Table 4-2. 2005 Peak Demand Reductions

Embedded DSM	Incremental DSM	Interruptible
588	347	841

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



The amount of incremental DSM indicates that there is a renewed interest in demand-side options. While the present level of DSM activity is less than that envisioned in the 1990s (900 MW in SUFG's 1996 forecast), it is considerably more than the 28 MW in the 2003 forecast. The decline in incremental DSM from the 1990s to the early 2000s was primarily due to two factors. First, as the new DSM programs of the 1990s matured, the energy and peak demand reductions became embedded in the calibration data with little opportunity for additional incremental reductions. Second, many utilities reevaluated their DSM programs in the face of the changing structure of the electricity industry in the late 1990s.

The renewed interest in DSM can also be attributed to two factors. First, the electricity industry structure seems to have stabilized, providing a greater level of certainty to the utilities. Second, as system-wide demand grows, the utilities face 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.

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 time 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, which include 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 it is using correctly measured data. 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 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 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 Outlook 2006-2027," Indiana University, February 2007.

Energy Information Administration, "Annual Energy Outlook 2007," February 2007.

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. In addition, SUFG acquired a proprietary end-use model, Residential End-Use Energy Modeling System (REEMS), which blends econometric and engineering methodologies to project energy use on a disaggregated basis. REEMS is a descendant of the first generation of end-use models developed at Oak Ridge National Labs (ORNL) during the late 1970s. Although these modeling approaches are complementary, these two models forecast very differently. Given the same set of primary inputs, the econometric model projects nearly twice as much growth as the end-use model. Experience has shown the econometric model to be much more accurate. For this reason, 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

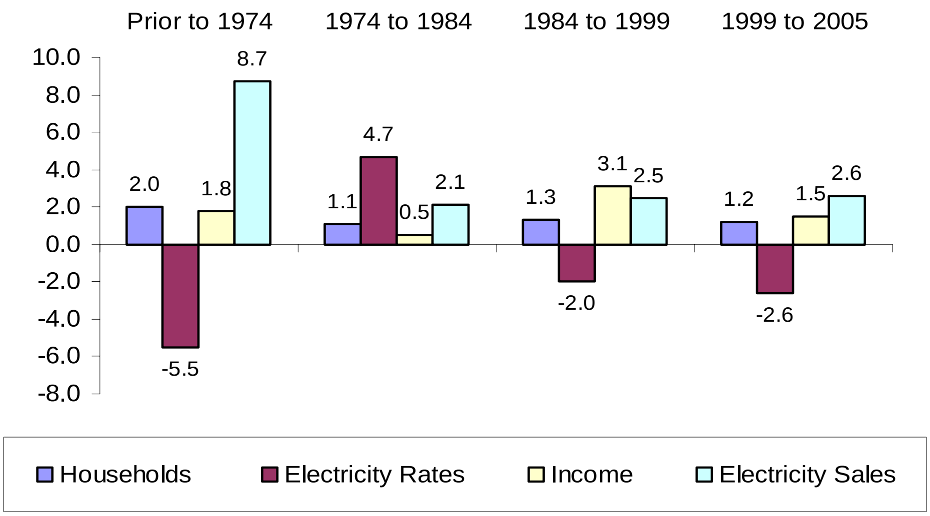
The growth in residential electricity consumption has generally reflected changes in economic activity, i.e., real household income, real energy prices and total households. Each of four recent periods has been characterized by distinctly different trends in these market factors and in each case, residential electricity sales growth has reflected the change in market conditions. Beginning in 1999 economic activity slowed dramatically but has recovered somewhat recently. Despite economic weakness, electric energy sales growth in the residential sector has continued (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 (nearly 2 percent per year in real terms). This period also was marked by a boom in the housing industry as 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 2 percent per year over 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 only at 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 last few years (1999 to present) 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,

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



while positive, has slowed markedly. Despite the slow growth in income, electricity sales have continued to grow at the rate observed during the 1984 to 1999 period.

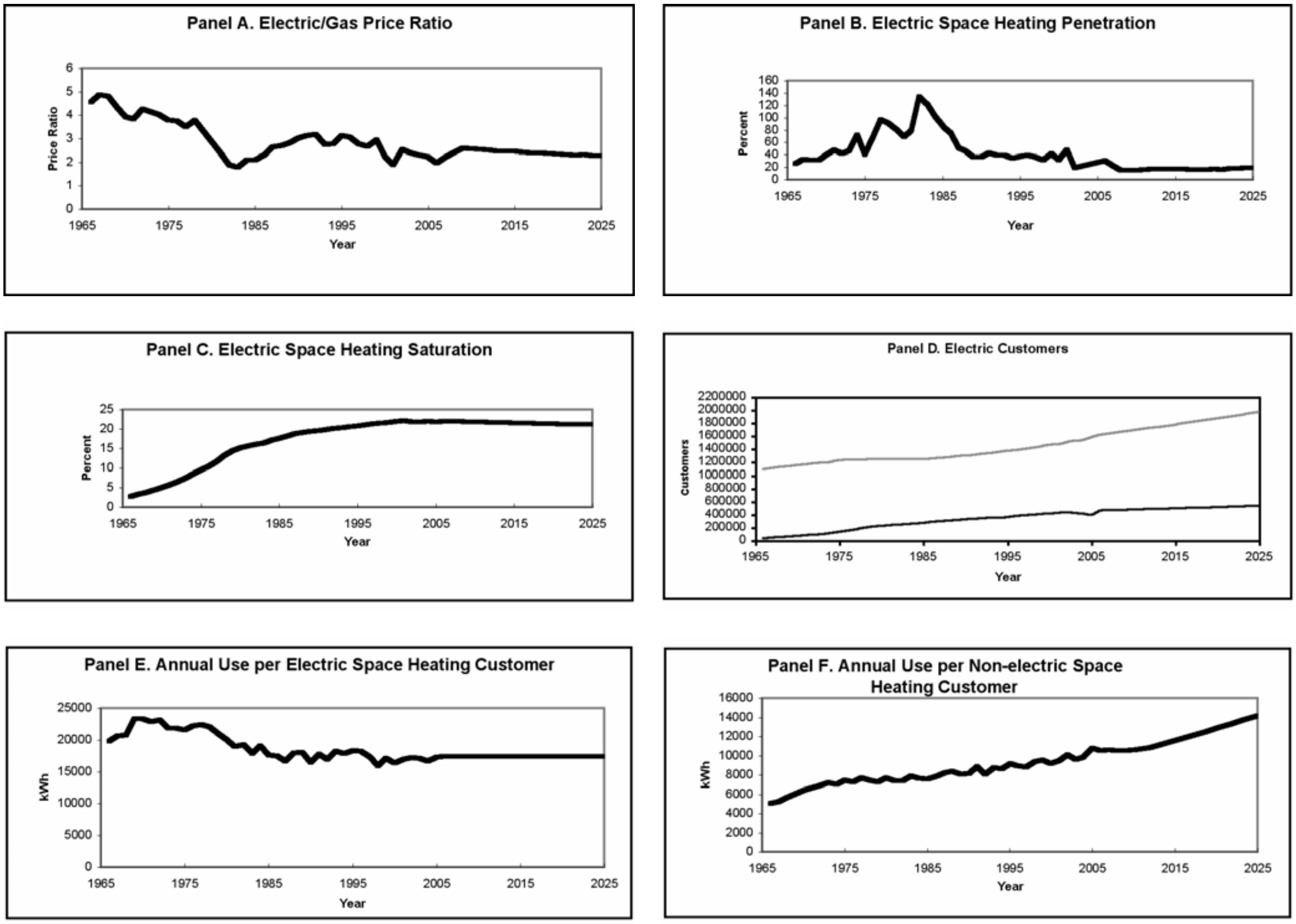
Model Description

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 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 2010 and increasing natural gas prices after about

Figure 5-2 Structure of Residential Econometric Model



2015, the fuel choice model projects the penetration of electric space heating to range from 15 to 20 percent over the forecast horizon (for the five IOUs combined). This results in space heating saturation of about 20 percent over 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 next 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.

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. 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 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, 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 2.21 percent, the same as SUFG's 2005 projection. Table 5-3 shows the growth rates of the major residential drivers for the current scenarios and the 2005 base case. In all of the residential sector drivers, the current base exhibits about the same growth, resulting in a similar electricity use forecast. 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. Long-term patterns for the entire forecast horizon are very similar for both the current and previous projections. Table 5-4 summarizes SUFG's base projections of residential electricity sales growth since 2003.

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, nearly one half of projected sales growth is attributable to customer growth and the remainder to changes in electric intensity (price and income effects). Most of the residential DSM shifts load from peak usage times to off-peak times and has virtually no effect on residential electric intensity growth.

As shown in Table 5-5 and Figure 5-4, the growth rates for the high and low residential scenarios are about 0.3 percent higher and more than 0.1 lower, respectively, than the base scenario. This difference is due to differences in the growth of total customers and household income.

Table 5-2. Indiana Residential Electricity Sales in GWh (Historical, Current, and Previous Forecasts)

	Actual	2003	2005	2007
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	29988		
2003	30837	30615		
2004	31256	31256	32634	
2005	33756	31873	33300	
2006		32335	33876	33822
2007		32742	34319	34176
2008		33244	35013	34616
2009		33785	35657	35005
2010		34433	36516	35669
2011		35103	37318	36339
2012		35742	38088	37080
2013		36461	38929	37935
2014		37148	39858	38890
2015		37903	40774	39812
2016		38709	41764	40813
2017		39612	42740	41815
2018		40427	43756	42965
2019		41285	44900	44037
2020		42444	46041	45180
2021		43317	47175	46332
2022			48357	47563
2023			49521	48794
2024				50050
2025				51246

Average Compound Growth Rates			
Forecast Period	**2002-21**	**2004-23**	**2006-25**
	1.95	2.22	2.21

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

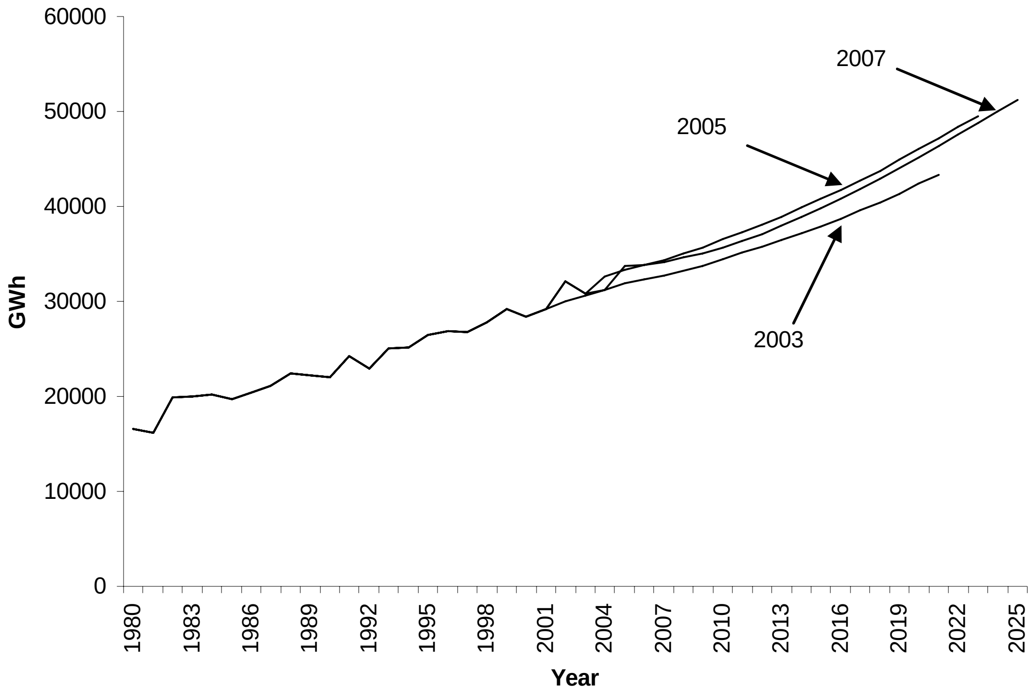


Table 5-3. Residential Model Explanatory Variables - Growth Rates by Forecast (Percent)

Forecast	Current Scenario (2006-2025)			2005 Forecast (2004-2023)
	Base	Low	High	Base
No. of Customers	0.94	0.93	0.97	1.00
Appliance Prices	-3.00	-3.00	-3.00	-3.00
Electric Rates	0.21	0.16	0.27	-0.52
Natural Gas Price	-0.96	-0.96	-0.96	-0.67
Oil Prices	-1.33	-1.33	-1.33	-0.64
Household Income	2.02	1.50	2.83	1.43

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

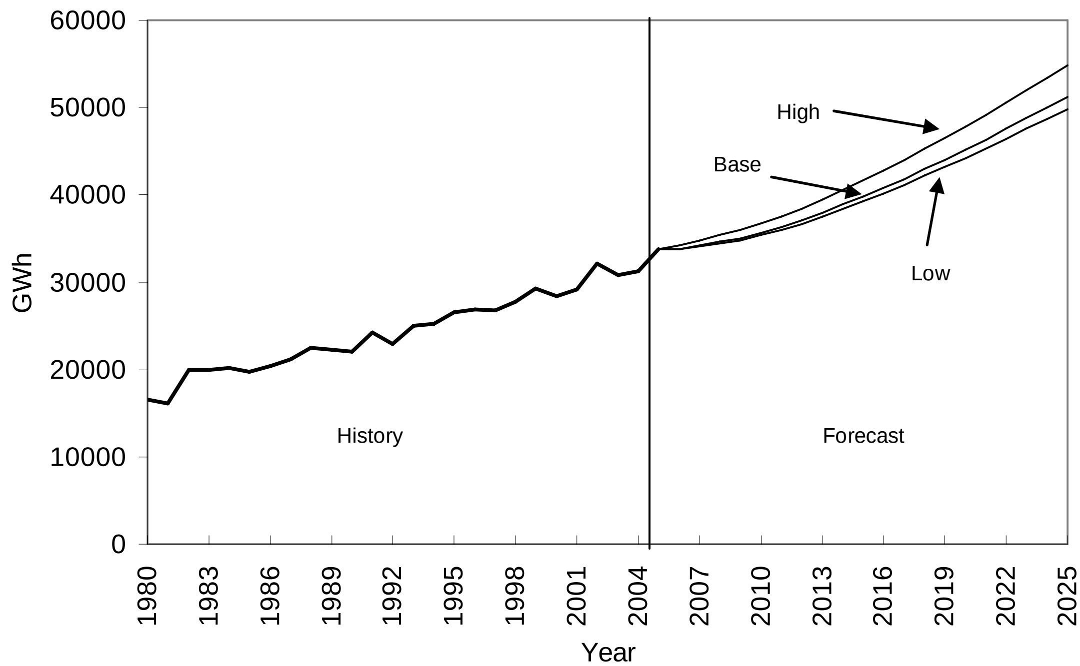
Forecast	No. of Customers	Prior to DSM		After DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2007 SUFG Base (2006-2025)	0.94	1.29	2.23	1.27	2.21
2005 SUFG Base (2004-2023)	1.00	1.22	2.22	1.22	2.22
2003 SUFG Base (2002-2021)	0.66	1.30	1.96	1.29	1.95

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	33756			
2006		33822	33777	34184
2007		34176	34091	34816
2008		34616	34483	35419
2009		35005	34804	35950
2010		35669	35381	36744
2011		36339	35995	37541
2012		37080	36664	38429
2013		37935	37462	39458
2014		38890	38344	40566
2015		39812	39222	41655
2016		40813	40166	42800
2017		41815	41106	43957
2018		42965	42186	45254
2019		44037	43193	46493
2020		45180	44251	47786
2021		46332	45307	49122
2022		47563	46415	50532
2023		48794	47554	51971
2024		50050	48707	53440
2025		51246	49807	54853

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	3.51	3.51	3.51
2006-25	2.21	2.07	2.52

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 have been declining since the mid-1980s. SUFG projects this trend to reverse in the near term due to the need for additional resources and emissions controls leading to increasing constant electricity prices. SUFG's real price projections for the individual IOUs all follow the similar patterns as the state as a whole, but there are variations across the utilities.

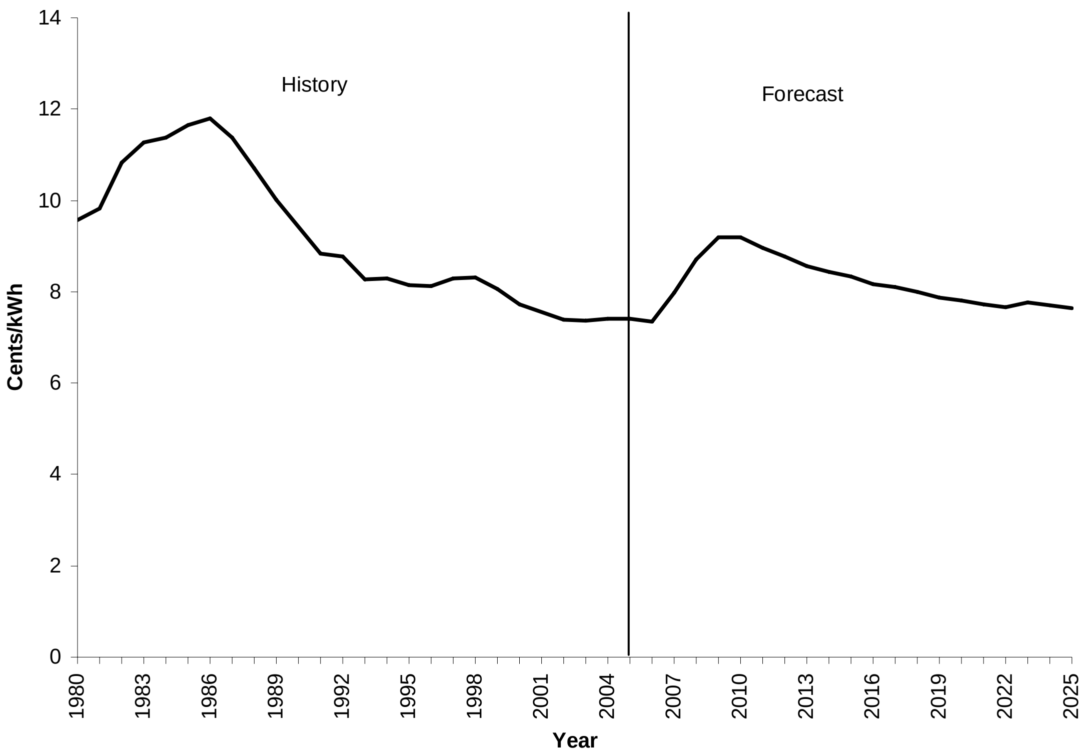
Table 5-6. Indiana Residential Base Real Price Projections (in 2005 Dollars)

Year	Real Price	Year	Real Price
1980	9.58	2003	7.37
1981	9.82	2004	7.41
1982	10.84	2005	7.41
1983	11.28	2006	7.34
1984	11.38	2007	7.97
1985	11.65	2008	8.70
1986	11.80	2009	9.20
1987	11.38	2010	9.19
1988	10.72	2011	8.97
1989	10.01	2012	8.77
1990	9.43	2013	8.57
1991	8.84	2014	8.43
1992	8.77	2015	8.33
1993	8.27	2016	8.17
1994	8.28	2017	8.11
1995	8.14	2018	7.99
1996	8.12	2019	7.87
1997	8.28	2020	7.80
1998	8.30	2021	7.72
1999	8.05	2022	7.66
2000	7.72	2023	7.76
2001	7.56	2024	7.69
2002	7.40	2025	7.64

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	3.99
1985-1990	-4.15
1990-1995	-2.89
1995-2000	-1.05
2000-2005	-0.81
2005-2010	4.40
2010-2015	-1.96
2015-2020	-1.29
2020-2025	-0.43
2006-2025	0.21

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 Base Real Price Projections (in 2005 Dollars)



Chapter 6

Commercial Electricity Sales

Overview

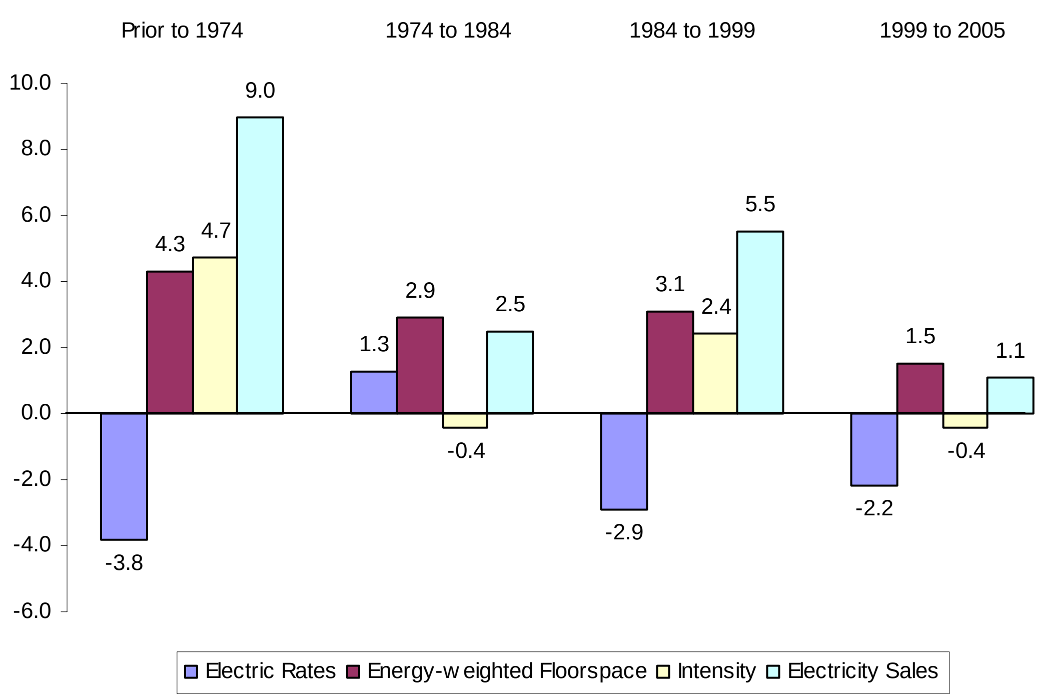
SUFG has two distinct models of commercial electricity sales, econometric and end-use, that have specific strengths and complement each other. SUFG staff developed the econometric model and acquired a proprietary end-use model, Commercial Energy Demand Modeling System (CEDMS). CEDMS, like its residential counterpart, REEMS, is a descendant of the first generation of end-use models developed at ORNL during the late 1970s for the Department of Energy (DOE). 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 models are small since both the econometric model and CEDMS forecast similar changes in electric intensity.

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.

Since 1999, the decrease in economic activity has retarded growth in commercial floorstock, intensity of electricity use, and electricity use despite continued declines in real electricity prices. Even though few years of data are available since 1999, the decrease in the growth in the commercial sector is unmistakable.

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;

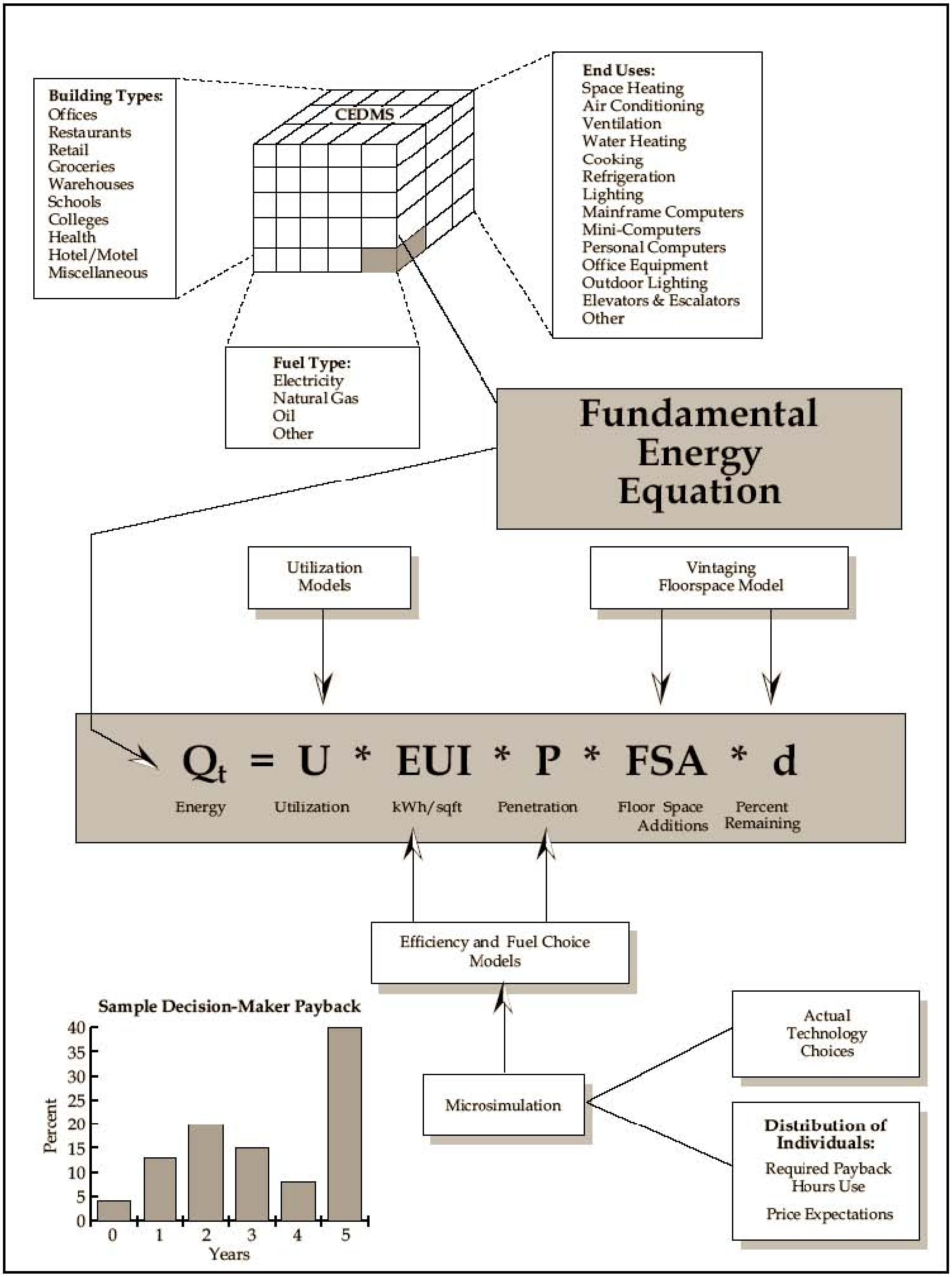
A = floor space additions by vintage t and building type l; and

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 accounts 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 submodels. 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 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 Use
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 2.46 percent. The growth rates for the major explanatory variables are shown in Table 6-3. Note that the changes from the 2005 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 just over 2 percent electric energy growth annually. The net effect of changes in energy prices and the mix in types of floor space is to increase electricity use slightly less than 0.4 percent per year. Incremental DSM programs have virtually no effect on electricity sales. Thus, slightly more than 85 percent of projected sales growth is attributable to floor space growth, with the remaining contribution from increased intensity.

As shown in Figure 6-3, the current projection is very similar to the 2005 forecast. The current projection starts out at about the same level but grows at a slightly lower rate. The relatively similar starting point is due to the continued slow down in the economy and the slower growth rate is due to similar, but lower growth in electric intensity in the current forecast.

As shown in Table 6-5 and Figure 6-4, the growth rates for the low and high scenarios are about 1.2 percent lower and 1.0 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	2003	2005	2007
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	18456			
1993	19627			
1994	20116			
1995	20646			
1996	20909			
1997	21295			
1998	22158			
1999	23089			
2000	23541			
2001	23830			
2002	24828	24206		
2003	24165	24855		
2004	23189	25663	25444	
2005	24637	26451	26219	
2006		27195	26972	25423
2007		27960	27677	26022
2008		28751	28451	26692
2009		29524	29252	27387
2010		30327	30053	28119
2011		31145	30823	28815
2012		31923	31601	29513
2013		32765	32416	30243
2014		33582	33265	31018
2015		34462	34110	31719
2016		35355	34975	32444
2017		36247	35842	33219
2018		37184	36733	33945
2019		38133	37626	34763
2020		39309	38557	35628
2021		40240	39510	36516
2022			40488	37428
2023			41491	38362
2024				39322
2025				40306

Average Compound Growth Rates			
Forecast Period	**2002-21**	**2004-23**	**2006-25**
	2.71	2.61	2.46

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

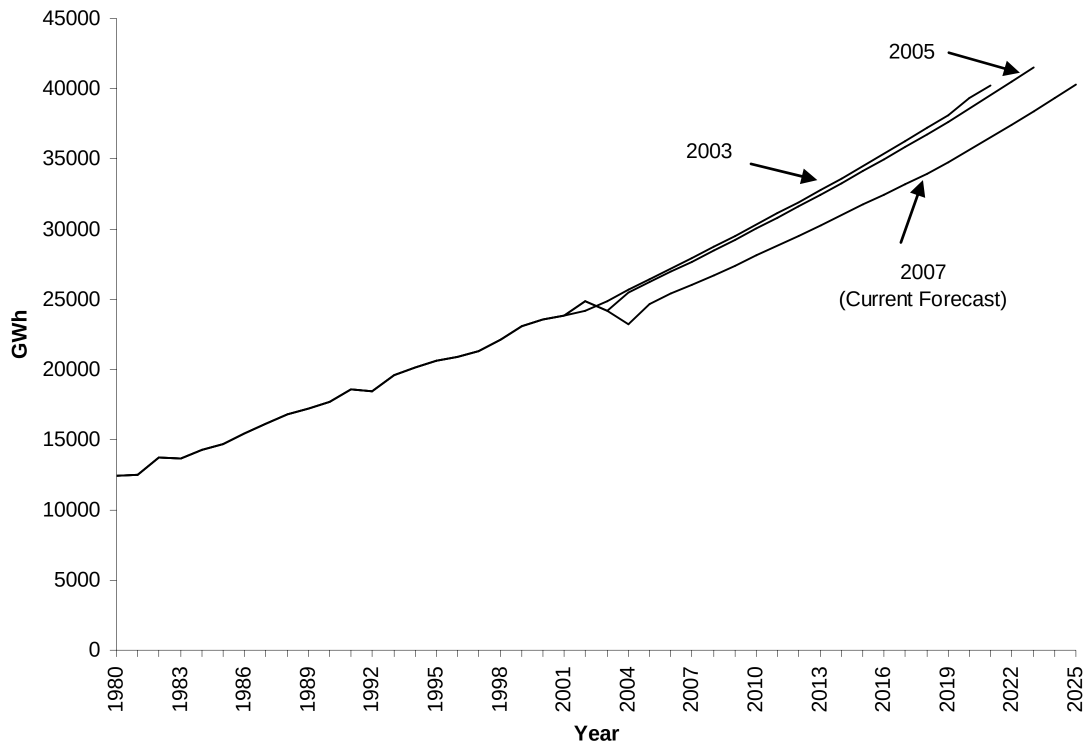


Table 6-3. Commercial Model – Growth Rates (Percent) for Selected Variables (2007 SUFG Scenarios and 2005 Base Forecast)

Forecast	Current Scenario (2006-2025)			2005 Forecast (2006-2025)
	Base	Low	High	Base
Electric Rates	0.26	0.17	0.37	-0.26
Natural Gas Price	-1.18	-1.18	-1.18	0.55
Oil Prices	-1.29	-1.29	-1.29	0.60
Energy-weighted Floor Space	2.11	1.05	3.01	2.12

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

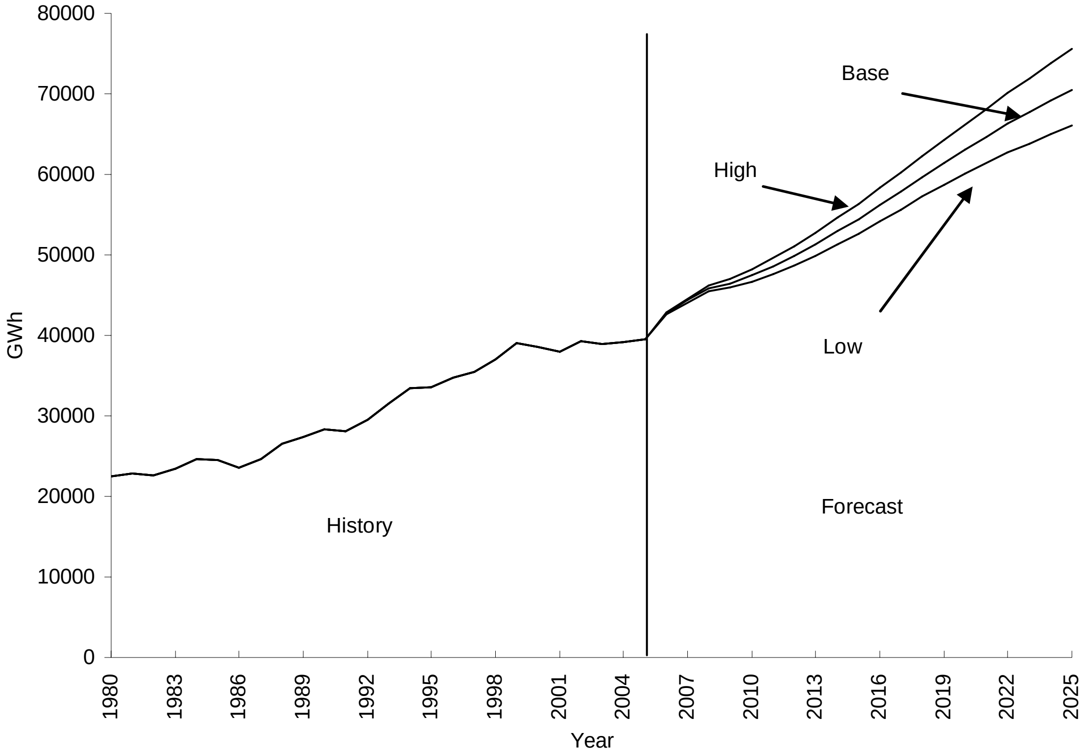
Forecast	Electric Energy-weighted Floor Space	Prior to DSM		After DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2007 SUFG Base (2006-2025)	2.11	0.35	2.46	0.35	2.46
2005 SUFG Base (2004-2023)	2.12	0.49	2.61	0.49	2.61
2003 SUFG Base (2002-2021)	2.11	0.46	2.57	0.46	2.57

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	18456			
1993	19627			
1994	20116			
1995	20646			
1996	20909			
1997	21295			
1998	22158			
1999	23089			
2000	23541			
2001	23830			
2002	24828			
2003	24165			
2004	23189			
2005	24637			
2006		25423	25092	25730
2007		26022	25357	26662
2008		26692	25692	27681
2009		27387	26021	28726
2010		28119	26382	29813
2011		28815	26720	30859
2012		29513	27044	31928
2013		30243	27395	33062
2014		31018	27769	34233
2015		31719	28071	35349
2016		32444	28390	36492
2017		33219	28753	37709
2018		33945	29047	38864
2019		34763	29437	40157
2020		35628	29852	41485
2021		36516	30273	42860
2022		37428	30700	44281
2023		38362	31133	45751
2024		39322	31573	47272
2025		40306	32020	48846

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	2.66	2.66	2.66
2000-05	0.91	0.91	0.91
2006-25	2.46	1.29	3.43

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 have been declining since the mid-1980s. SUFG projects this trend to reverse as the need for additional generation resources and emissions controls lead to rising real electricity prices through 2010. Real prices are projected to slowly fall through the remainder of the forecast period. 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.

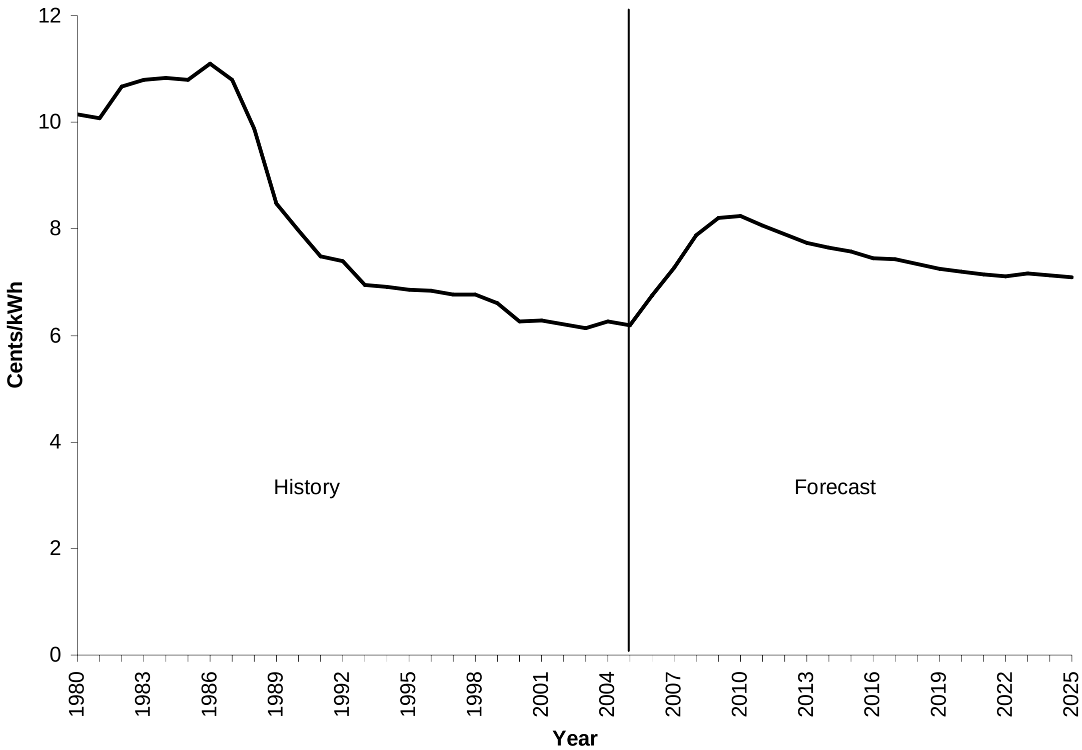
Table 6-6. Indiana Commercial Base Real Price Projections (in 2005 Dollars)

Year	Cents/kWh	Year	Cents/kWh
1980	10.15	2003	6.14
1981	10.08	2004	6.26
1982	10.67	2005	6.20
1983	10.79	2006	6.74
1984	10.83	2007	7.26
1985	10.79	2008	7.88
1986	11.10	2009	8.21
1987	10.80	2010	8.24
1988	9.88	2011	8.06
1989	8.47	2012	7.90
1990	7.98	2013	7.74
1991	7.49	2014	7.64
1992	7.40	2015	7.57
1993	6.94	2016	7.45
1994	6.91	2017	7.43
1995	6.85	2018	7.34
1996	6.83	2019	7.25
1997	6.76	2020	7.20
1998	6.76	2021	7.14
1999	6.60	2022	7.10
2000	6.26	2023	7.17
2001	6.28	2024	7.12
2002	6.20	2025	7.09

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	1.22
1985-1990	-5.86
1990-1995	-2.99
1995-2000	-1.81
2000-2005	-0.19
2005-2010	5.85
2010-2015	-1.68
2015-2020	-0.98
2020-2025	-0.32
2006-2025	0.26

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 Base Real Price Projections (in 2005 Dollars)



Chapter 7

Industrial Electricity Sales

Overview

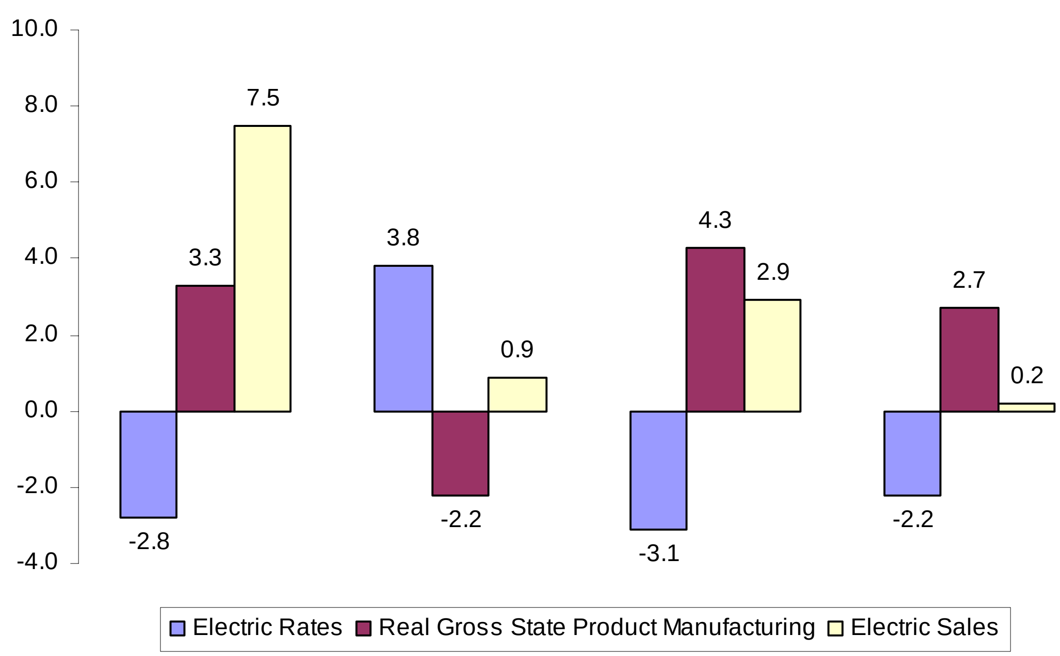
SUFG currently uses several models to analyze and forecast electricity use in the industrial sector. The primary forecasting model is INDEED, an econometric model developed by the Electric Power Research Institute (EPRI), which is used to model the electricity use of 15 major industry groupings in the 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 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 were 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 four recent periods of distinctly different economic activity and growth — the decade prior to the oil embargo of 1974, 1974-1984, the more recent period, 1984-1999, and the current period, 1999 to the present. 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 more recent period, 1984-1999, has witnessed another dramatic turnaround. The growth rate of industrial output once again becomes positive, and is 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 recent economic slowdown is particularly pronounced in the industrial sector. Since 1999, real industrial electricity prices have continued to decline, but this decline has been partially offset by a moderate growth in manufacturing output, which in turn has led to stagnant industrial electricity use. 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 barely increased.

Model Description

Figure 7-2 depicts the relationship between the models used by SUFG to characterize electricity use in the industrial sector. Electricity used in the sector can be broken down in three ways — Level I, by industry; Level II, by process step; and Level III, by energy end use. Each corresponds to a dimension of the cube in Figure 7-2. Currently, electricity use is subdivided into the 15 manufacturing industries listed in Table 7-1. Manufacturing industries corresponding to Standard Industrial Classification (SIC) 21 (Tobacco Products), 22 (Textile Mill Products), 23 (Apparel & Other Textile Products), and 31 (Leather and Leather Products) are excluded due to their relative unimportance in the Indiana economy, while SIC 29 (Petroleum & Coal Products) is excluded due to data unavailability since there is only one petroleum refinery in Indiana. At this time, only the iron and steel, foundries and aluminum portions of SIC 33 are broken down to Level II models. In addition, a Level III model of electricity use by motors in industry projects the impact of motor technologies and standards geared toward particular end uses.

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.

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: fabricated metals, 6 percent; industrial machinery and equipment, 7 percent; primary metals, 9 percent; chemicals, 14 percent; electronic and electric equipment, 16 percent; and transportation 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 second SUFG forecast developed since CEMR switched from the SIC to the newer North American Industry Classification System (NAICS) 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 mapped industrial economic activity projections from the NAICS measures used by CEMR to the older SIC measures used in SUFG's models. This process was straightforward with the exception of SICs 28, chemical manufacturing, and 37, transportation equipment. For these industries SUFG made adjustments. In SIC 28, chemical manufacturing, SUFG used the CEMR GSP growth projections for the manufacturing sector as a whole. This was necessary since CEMR's projections did not specifically include chemical manufacturing, a large purchaser of electricity in Indiana.

Table 7-1. Selected Statistics for Indiana's Industrial Sector (Prior to DSM) (Percent)

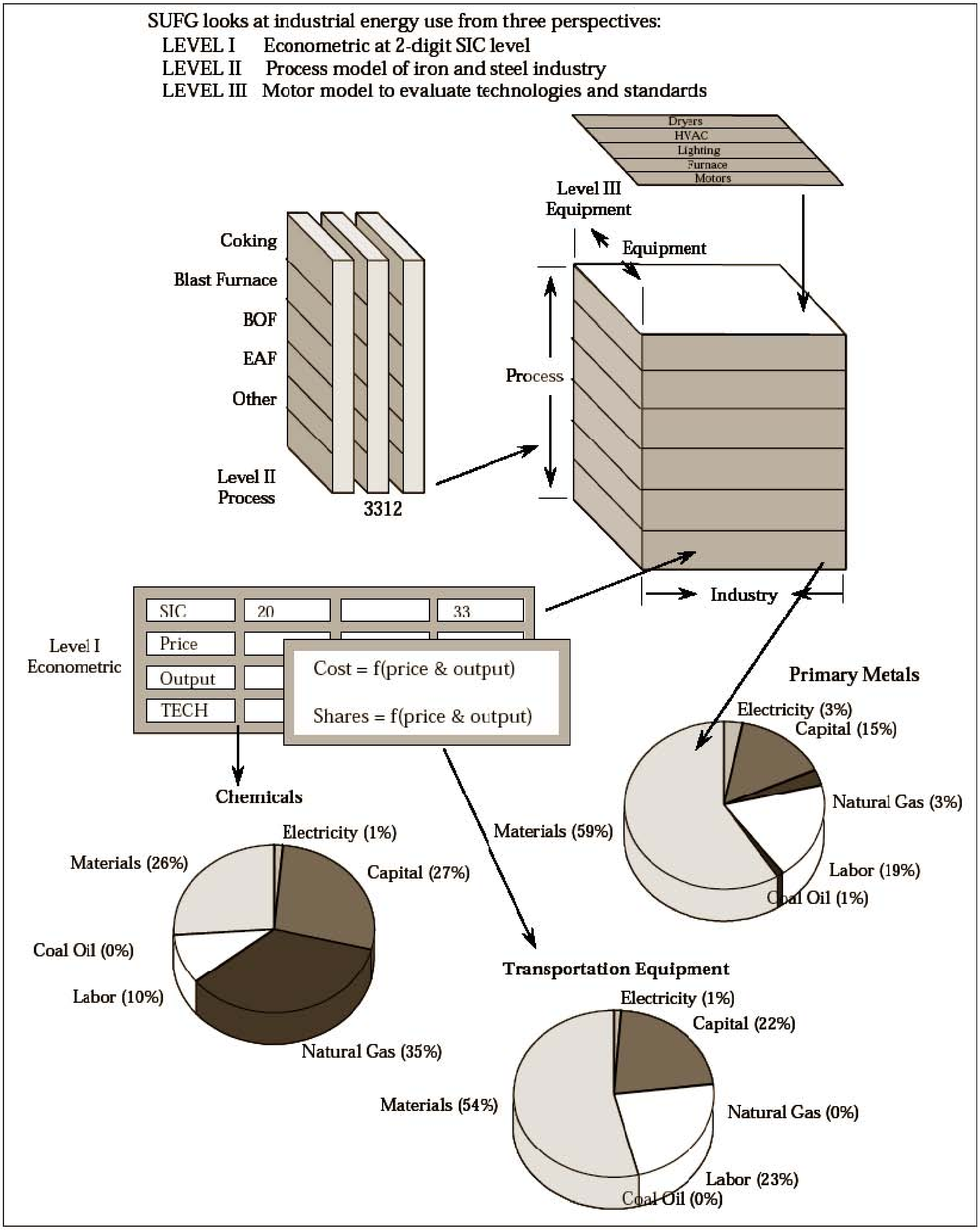
SIC	Name	Current Share of GSP	Current Share of Electricity Use	Forecast Growth in GSP Originating by Sector	Forecast Growth in Electricity by Intensity by Sector	Forecast Growth in Electricity Use by Sector
20	Food & Kindred Products	3.51	5.61	0.96	-0.79	0.17
24	Lumber & Wood Products	1.95	0.70	0.96	-0.42	0.54
25	Furniture & Fixtures	1.60	0.46	0.62	-0.64	-0.02
26	Paper & Allied Products	1.36	2.96	0.96	-0.56	0.40
27	Printing & Publishing	2.55	1.30	0.96	-0.96	0.00
28	Chemicals & Allied Products	14.25	17.10	3.49	-0.80	2.70
30	Rubber & Misc. Plastic Products	4.77	6.25	4.52	-0.67	3.85
32	Stone, Clay, & Glass Products	1.76	5.30	0.96	-0.67	0.29
33	Primary Metal Products	8.55	31.34	1.02	1.76	2.77
34	Fabricated Metal Products	6.25	5.29	2.51	-0.76	1.75
35	Industrial Machinery & Equipment	6.73	4.44	1.05	-0.68	0.37
36	Electronic & Electric Equipment	16.19	5.54	5.33	-0.56	4.77
37	Transportation Equipment	22.89	9.38	3.87	-0.68	3.19
38	Instruments And Related Products	4.98	0.77	5.33	-0.86	4.47
39	Miscellaneous Manufacturing	1.63	1.06	4.19	-5.24	-1.05
Total	Manufacturing	100.00	100.00	3.48	-0.81	2.67

In another large electricity using industry, transportation equipment (SIC 37), SUFG used the CEMR average GSP for all industries rather than industry-specific GSP projections. The rationale for this substitution is twofold. First, the CEMR projection of economic activity for this industry is higher than that for any other major industry, in terms of GSP or electricity use, in the state. Second, even though the transportation equipment industry has experienced rapid growth over the past several years, SUFG felt that it was unlikely that that level of growth would be sustained over a 20-year period. Thus, SUFG chose to use a more conservative estimate of future growth in this large electricity use industry by replacing the CEMR above average growth projection with a more modest projection.

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 cost of the 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 2005, then will decline at about 2.9 percent per year until the year 2015 and increase at a rate of about 0.9 percent per year thereafter. Distillate fuel prices are

Figure 7-2. Structure of Industrial Energy Modeling System



assumed to follow a similar pattern, with a maximum real price in 2007 and growing at about the same rate (1.0 percent per year) as gas after the year 2015. 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 four 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 industry electricity use across all sectors in the base scenario is expected to increase at an average of 2.67 percent per year over the forecast horizon.

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 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

10 Percent Increase In	Causes This Percent Change in Electric Use
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 2003, 2005, and current forecasts are contained in Table 7-4. The table also disaggregates the impact on energy growth of output, changes in the mix of output and electricity intensity. As in the residential and commercial sectors, DSM programs have virtually no impact on industrial sector electricity purchases. Current incremental DSM measures focus on peak shaving and load shifting rather than conservation. The effect of conservation activities during the 1990s are embedded in the historical data and SUFG's projections.

The current forecast projects that industrial sector electricity sales will grow from its 2005 level of approximately 39,500 GWh to over 70,000 GWh by 2025. This growth rate of 2.67 percent per year is higher than the 2.46 percent rate projected for the commercial and the 2.21 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast exceeds those of 2005 and 2003 forecasts by 2010 and the increase continues until the end of the forecast horizon.

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 over 75,000 GWh by 2025, more than 7 percent higher than the base projection. In the low scenario, industrial sales grow more slowly, which results in 66,000 GWh sales by 2025, more than 6 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, after SUFG adjustments, GSP in the industrial sector grows 3.48 percent per year during the forecast period. That rate is 3.97 percent in the high scenario and 3.01 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	2003	2005	2007
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	33590			
1996	34755			
1997	35499			
1998	37052			
1999	39020			
2000	38517			
2001	37995			
2002	39252	37697		
2003	38887	38973		
2004	39155	40224	41096	
2005	39555	41101	42310	
2006		41650	43647	42777
2007		42166	44391	44354
2008		42736	45048	45881
2009		43304	45554	46466
2010		43994	46507	47485
2011		44751	47200	48598
2012		45512	47966	49862
2013		46386	48832	51267
2014		47272	49826	52917
2015		48207	50811	54447
2016		49196	51930	56166
2017		50200	52982	57806
2018		51296	54048	59667
2019		52471	55102	61375
2020		53713	56223	63057
2021		54623	57371	64662
2022			58579	66320
2023			59766	67689
2024				69131
2025				70526

Average Compound Growth Rate			
Forecast Period	**2002-21**	**2004-23**	**2006-25**
	1.97	1.99	2.67

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

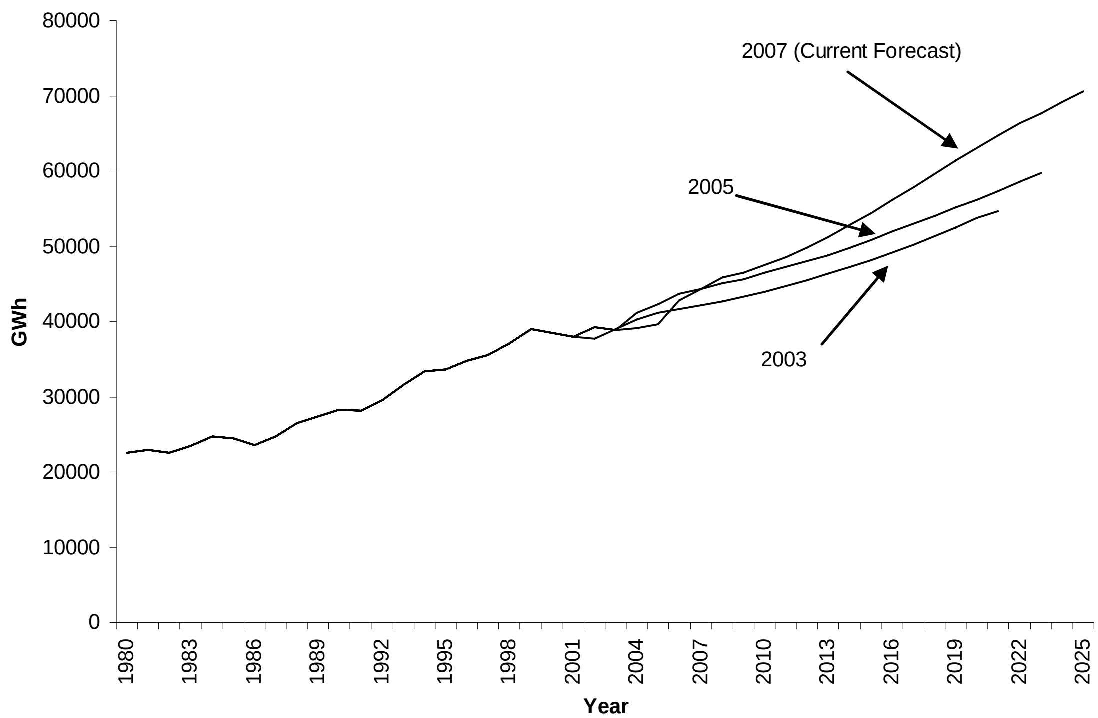


Table 7-4. History of SUFG Industrial Sector Growth Rates (Percent)

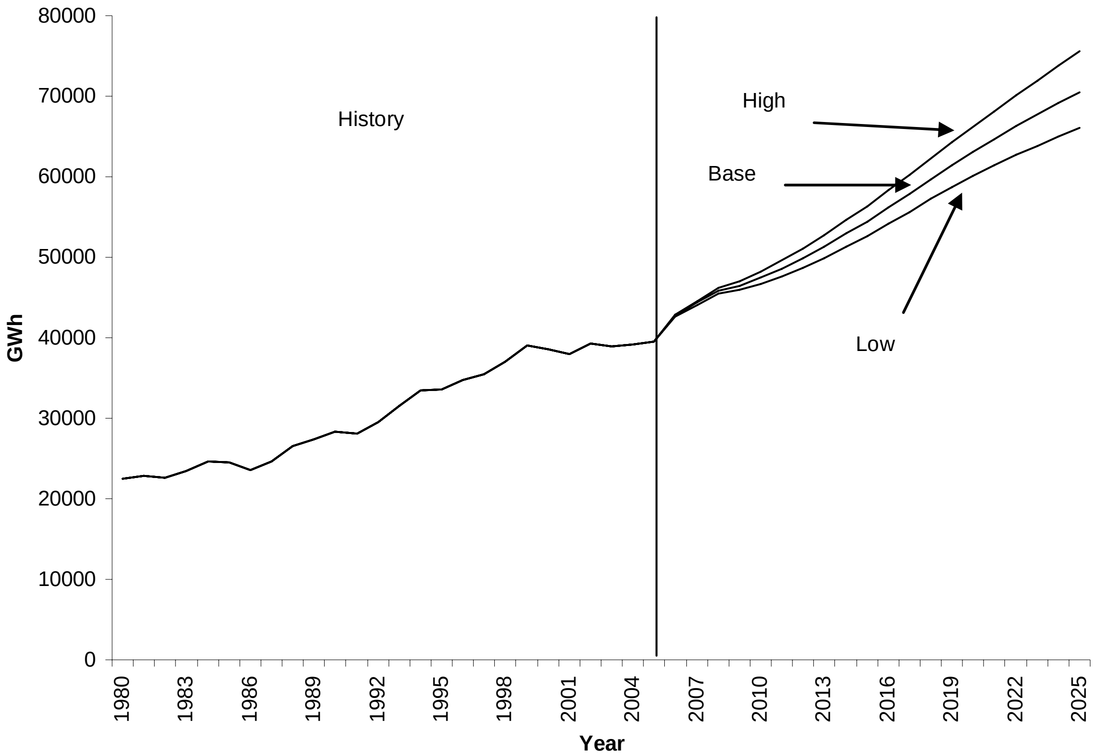
Forecast	Output	Mix Effects	Electric Energy-weighted Output	Prior to DSM		After DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
2007 SUFG Base (2006-2025)	3.48	-0.39	3.09	-0.42	2.67	-0.42	2.67
2005 SUFG Base (2004-2023)	2.53	-0.51	2.02	-0.03	1.99	-0.03	1.99
2003 SUFG Base (2002-2021)	1.50	-0.23	1.27	0.70	1.97	0.70	1.97

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	33590			
1996	34755			
1997	35499			
1998	37052			
1999	39020			
2000	38517			
2001	37995			
2002	39252			
2003	38887			
2004	39155			
2005	39555			
2006		42777	42637	42895
2007		44354	44104	44570
2008		45881	45514	46194
2009		46466	45959	46988
2010		47485	46701	48265
2011		48598	47602	49603
2012		49862	48649	51092
2013		51267	49860	52752
2014		52917	51289	54607
2015		54447	52636	56366
2016		56166	54159	58296
2017		57806	55597	60180
2018		59667	57224	62295
2019		61375	58698	64252
2020		63057	60123	66197
2021		64662	61451	68111
2022		66320	62723	70096
2023		67689	63827	71906
2024		69131	64974	73774
2025		70526	66081	75599

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	3.48	3.48	3.48
1995-00	2.77	2.77	2.77
2000-05	0.53	0.53	0.53
2006-25	2.67	2.33	3.03

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 have been declining since the mid-1980s. SUFG projects industrial real electricity prices to rise with the need for additional generation resources and additional emissions control equipment through about 2010 then to remain relatively constant. SUFG's real price projections for the individual IOUs all follow the same patterns as the state as a whole, but there are variations across the utilities.

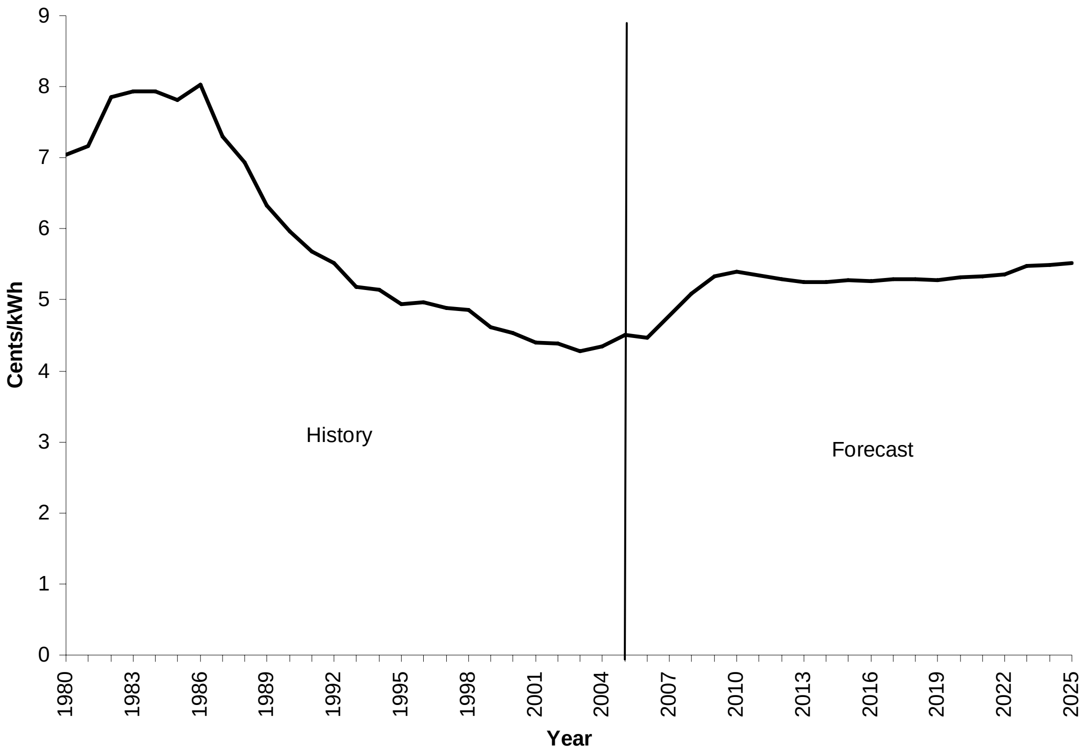
Table 7-6. Indiana Industrial Base Real Price Projections (in 2005 Dollars)

Year	Cents/kWh	Year	Cents/kWh
1980	7.04	2003	4.28
1981	7.17	2004	4.34
1982	7.86	2005	4.51
1983	7.93	2006	4.47
1984	7.93	2007	4.78
1985	7.82	2008	5.09
1986	8.03	2009	5.33
1987	7.31	2010	5.39
1988	6.93	2011	5.34
1989	6.32	2012	5.29
1990	5.96	2013	5.25
1991	5.68	2014	5.25
1992	5.52	2015	5.28
1993	5.19	2016	5.26
1994	5.14	2017	5.29
1995	4.94	2018	5.29
1996	4.96	2019	5.28
1997	4.88	2020	5.32
1998	4.85	2021	5.33
1999	4.62	2022	5.35
2000	4.54	2023	5.47
2001	4.39	2024	5.49
2002	4.38	2025	5.51

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	-0.14
2005-2010	3.66
2010-2015	-0.42
2015-2020	0.14
2020-2025	0.73
2006-2025	1.11

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 Base Real Price Projections (in 2005 Dollars)



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.

Both Indiana Michigan Power Company (I&M) and Wabash Valley Power Association (WVPA) 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. Both I&M and WVPA 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 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 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 upon 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, Indiana Municipal Power Agency 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 2007 Base 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	13775
Hist	1991	24215	18580	28141	660	71595	4439	76034	14403
Hist	1992	22916	18456	29540	649	71561	5645	77207	14209
Hist	1993	25060	19627	31562	544	76793	5876	82669	15103
Hist	1994	25176	20116	33395	541	79227	6219	85446	15198
Hist	1995	26513	20646	33590	540	81290	7225	88514	16342
Hist	1996	26833	20909	34755	567	83064	7573	90637	16254
Hist	1997	26792	21295	35499	569	84155	5618	89773	15993
Hist	1998	27745	22158	37052	560	87515	5914	93429	16527
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	24165	38887	552	94441	7809	102250	18843
Hist	2004	31256	23189	39155	524	94125	7998	102122	18254
Hist	2005	33756	24637	39555	500	98447	7442	105889	19920
Frcst	2006	33822	25423	42777	500	102522	7642	110164	19874
Frcst	2007	34176	26022	44354	500	105052	7825	112877	20331
Frcst	2008	34616	26692	45881	500	107689	8013	115702	20803
Frcst	2009	35005	27387	46466	500	109358	8126	117484	21099
Frcst	2010	35669	28119	47485	500	111773	8293	120066	21541
Frcst	2011	36339	28815	48598	500	114252	8465	122717	22010
Frcst	2012	37080	29513	49862	500	116955	8663	125618	22520
Frcst	2013	37935	30243	51267	500	119945	8884	128829	23104
Frcst	2014	38890	31018	52917	500	123325	9133	132458	23756
Frcst	2015	39812	31719	54447	500	126478	9369	135847	24387
Frcst	2016	40813	32444	56166	500	129923	9628	139551	25062
Frcst	2017	41815	33219	57806	500	133340	9883	143223	25736
Frcst	2018	42965	33945	59667	500	137077	10176	147253	26474
Frcst	2019	44037	34763	61375	500	140675	10447	151122	27185
Frcst	2020	45180	35628	63057	500	144365	10727	155092	27921
Frcst	2021	46332	36516	64662	500	148010	11001	159011	28647
Frcst	2022	47563	37428	66320	500	151811	11285	163096	29400
Frcst	2023	48794	38362	67689	500	155345	11550	166895	30112
Frcst	2024	50050	39322	69131	500	159003	11823	170826	30843
Frcst	2025	51246	40306	70526	500	162578	12089	174667	31562

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	4.55
1990-1995	3.77	3.17	3.48	-4.65	3.43	7.42	3.72	3.48
1995-2000	1.39	2.66	2.77	-0.24	2.28	0.03	2.11	0.50
2000-2005	3.51	0.91	0.53	-1.31	1.58	0.57	1.51	3.52
2005-2010	1.11	2.68	3.72	0.00	2.57	2.19	2.54	1.58
2010-2015	2.22	2.44	2.77	0.00	2.50	2.47	2.50	2.51
2015-2020	2.56	2.35	2.98	0.00	2.68	2.74	2.69	2.74
2020-2025	2.55	2.50	2.26	0.00	2.40	2.42	2.41	2.48
2006-2025	2.21	2.46	2.67	0.00	2.46	2.44	2.46	2.46

SUFG 2007 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales					Losses	Energy Required	Summer Demand
		Res	Com	Ind	Other	Total			
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	13775
Hist	1991	24215	18580	28141	660	71595	4439	76034	14403
Hist	1992	22916	18456	29540	649	71561	5645	77207	14209
Hist	1993	25060	19627	31562	544	76793	5876	82669	15103
Hist	1994	25176	20116	33395	541	79227	6219	85446	15198
Hist	1995	26513	20646	33590	540	81290	7225	88514	16342
Hist	1996	26833	20909	34755	567	83064	7573	90637	16254
Hist	1997	26792	21295	35499	569	84155	5618	89773	15993
Hist	1998	27745	22158	37052	560	87515	5914	93429	16527
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	24165	38887	552	94441	7809	102250	18843
Hist	2004	31256	23189	39155	524	94125	7998	102122	18254
Hist	2005	33756	24637	39555	500	98447	7442	105889	19920
Frcst	2006	33777	25092	42637	500	102006	7604	109610	19776
Frcst	2007	34091	25357	44104	500	104052	7752	111804	20139
Frcst	2008	34483	25692	45514	500	106189	7903	114092	20515
Frcst	2009	34804	26021	45959	500	107284	7975	115259	20701
Frcst	2010	35381	26382	46701	500	108964	8083	117047	21007
Frcst	2011	35995	26720	47602	500	110817	8207	119024	21358
Frcst	2012	36664	27044	48649	500	112857	8354	121211	21743
Frcst	2013	37462	27395	49860	500	115217	8528	123745	22203
Frcst	2014	38344	27769	51289	500	117902	8726	126628	22731
Frcst	2015	39222	28071	52636	500	120429	8916	129345	23232
Frcst	2016	40166	28390	54159	500	123215	9128	132343	23783
Frcst	2017	41106	28753	55597	500	125956	9333	135289	24325
Frcst	2018	42186	29047	57224	500	128957	9573	138530	24927
Frcst	2019	43193	29437	58698	500	131828	9791	141619	25498
Frcst	2020	44251	29852	60123	500	134726	10011	144737	26071
Frcst	2021	45307	30273	61451	500	137531	10223	147754	26639
Frcst	2022	46415	30700	62723	500	140338	10436	150774	27204
Frcst	2023	47554	31133	63827	500	143014	10640	153654	27752
Frcst	2024	48707	31573	64974	500	145754	10848	156602	28317
Frcst	2025	49807	32020	66081	500	148408	11048	159456	28862

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	4.55
1990-1995	3.77	3.17	3.48	-4.65	3.43	7.42	3.72	3.48
1995-2000	1.39	2.66	2.77	-0.24	2.28	0.03	2.11	0.50
2000-2005	3.51	0.91	0.53	-1.31	1.58	0.57	1.51	3.52
2005-2010	0.94	1.38	3.38	0.00	2.05	1.67	2.02	1.07
2010-2015	2.08	1.25	2.42	0.00	2.02	1.98	2.02	2.03
2015-2020	2.44	1.24	2.70	0.00	2.27	2.34	2.27	2.33
2020-2025	2.39	1.41	1.91	0.00	1.95	1.99	1.96	2.05
2006-2025	2.07	1.29	2.33	0.00	1.99	1.99	1.99	2.01

SUFG 2007 High Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	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	13775
Hist	1991	24215	18580	28141	660	71595	4439	76034	14403
Hist	1992	22916	18456	29540	649	71561	5645	77207	14209
Hist	1993	25060	19627	31562	544	76793	5876	82669	15103
Hist	1994	25176	20116	33395	541	79227	6219	85446	15198
Hist	1995	26513	20646	33590	540	81290	7225	88514	16342
Hist	1996	26833	20909	34755	567	83064	7573	90637	16254
Hist	1997	26792	21295	35499	569	84155	5618	89773	15993
Hist	1998	27745	22158	37052	560	87515	5914	93429	16527
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	24165	38887	552	94441	7809	102250	18843
Hist	2004	31256	23189	39155	524	94125	7998	102122	18254
Hist	2005	33756	24637	39555	500	98447	7442	105889	19920
Frcst	2006	34184	25730	42895	500	103309	7700	111009	20038
Frcst	2007	34816	26662	44570	500	106548	7935	114483	20641
Frcst	2008	35419	27681	46194	500	109794	8167	117961	21235
Frcst	2009	35950	28726	46988	500	112164	8332	120496	21668
Frcst	2010	36744	29813	48265	500	115322	8558	123880	22255
Frcst	2011	37541	30859	49603	500	118503	8784	127287	22858
Frcst	2012	38429	31928	51092	500	121949	9037	130986	23517
Frcst	2013	39458	33062	52752	500	125772	9320	135092	24261
Frcst	2014	40566	34233	54607	500	129906	9624	139530	25069
Frcst	2015	41655	35349	56366	500	133870	9921	143791	25854
Frcst	2016	42800	36492	58296	500	138088	10237	148325	26683
Frcst	2017	43957	37709	60180	500	142346	10554	152900	27521
Frcst	2018	45254	38864	62295	500	146913	10907	157820	28426
Frcst	2019	46493	40157	64252	500	151402	11244	162646	29309
Frcst	2020	47786	41485	66197	500	155968	11585	167553	30215
Frcst	2021	49122	42860	68111	500	160593	11930	172523	31130
Frcst	2022	50532	44281	70096	500	165409	12288	177697	32083
Frcst	2023	51971	45751	71906	500	170128	12639	182767	33023
Frcst	2024	53440	47272	73774	500	174986	13001	187987	33990
Frcst	2025	54853	48846	75599	500	179798	13359	193157	34948

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	4.55
1990-1995	3.77	3.17	3.48	-4.65	3.43	7.42	3.72	3.48
1995-2000	1.39	2.66	2.77	-0.24	2.28	0.03	2.11	0.50
2000-2005	3.51	0.91	0.53	-1.31	1.58	0.57	1.51	3.52
2005-2010	1.71	3.89	4.06	0.00	3.21	2.83	3.19	2.24
2010-2015	2.54	3.47	3.15	0.00	3.03	3.00	3.03	3.04
2015-2020	2.78	3.25	3.27	0.00	3.10	3.15	3.11	3.17
2020-2025	2.80	3.32	2.69	0.00	2.88	2.89	2.88	2.95
2006-2025	2.52	3.43	3.03	0.00	2.96	2.94	2.96	2.97

Indiana Base Average Retail Rates (Cents/kWh) (in 2005 Dollars)

Year	Res	Com	Ind	Average
1980	9.58	10.15	7.04	8.60
1981	9.82	10.08	7.17	8.68
1982	10.84	10.67	7.86	9.52
1983	11.28	10.79	7.93	9.68
1984	11.38	10.83	7.93	9.70
1985	11.65	10.79	7.82	9.73
1986	11.80	11.10	8.03	10.02
1987	11.38	10.80	7.31	9.49
1988	10.72	9.88	6.93	8.86
1989	10.01	8.47	6.32	7.98
1990	9.43	7.98	5.96	7.49
1991	8.84	7.49	5.68	7.13
1992	8.77	7.40	5.52	6.95
1993	8.27	6.94	5.19	6.55
1994	8.28	6.91	5.14	6.50
1995	8.14	6.85	4.94	6.38
1996	8.12	6.83	4.96	6.35
1997	8.28	6.76	4.88	6.34
1998	8.30	6.76	4.85	6.32
1999	8.05	6.60	4.62	6.11
2000	7.72	6.26	4.54	5.88
2001	7.56	6.28	4.39	5.80
2002	7.40	6.20	4.38	5.76
2003	7.37	6.14	4.28	5.68
2004	7.41	6.26	4.34	5.75
2005	7.41	6.20	4.51	5.85
2006	7.34	6.74	4.47	5.91
2007	7.97	7.26	4.78	6.36
2008	8.70	7.88	5.09	6.86
2009	9.20	8.21	5.33	7.20
2010	9.19	8.24	5.39	7.23
2011	8.97	8.06	5.34	7.10
2012	8.77	7.90	5.29	6.97
2013	8.57	7.74	5.25	6.85
2014	8.43	7.64	5.25	6.78
2015	8.33	7.57	5.28	6.74
2016	8.17	7.45	5.26	6.66
2017	8.11	7.43	5.29	6.64
2018	7.99	7.34	5.29	6.59
2019	7.87	7.25	5.28	6.52
2020	7.80	7.20	5.32	6.51
2021	7.72	7.14	5.33	6.47
2022	7.66	7.10	5.35	6.45
2023	7.76	7.17	5.47	6.56
2024	7.69	7.12	5.49	6.54
2025	7.64	7.09	5.51	6.53
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	-0.81	-0.19	-0.14	-0.11
2005-2010	4.40	5.85	3.66	4.33
2010-2015	-1.96	-1.68	-0.42	-1.37
2015-2020	-1.29	-0.98	0.14	-0.71
2020-2025	-0.43	-0.32	0.73	0.06
2006-2025	0.21	0.26	1.11	0.52

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
DOE	Department of Energy
DSM	Demand-Side Management
EIA	Energy Information Administration
EPACT	Energy Policy Act
EPRI	Electric Power Research Institute
GDP	Gross Domestic Product
GSP	Gross State Product
GWh	Gigawatthours
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
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
REEMS	Residential End-Use Energy Modeling System
RUS	Rural Utilities Service
SIC	Standard Industrial Classification
SUFG	State Utility Forecasting Group
WVPA	Wabash Valley Power Association